Quantitative risk analysis process of oil and gas upstream service contracts

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Abstract

Contracts are means to allocate the scope of work and associated risks to owners and contractors involved. In case of megaprojects, since there are many stakes involved, identifying risk factors of megaprojects and estimating their likelihoods and consequences are entirely vital. Likewise, analyzing how the contract risks are shared between parties and predicting the possibilities of achieving the contract goals are important practices as well. This paper, through an exploratory research, describes a risk analysis procedure and the results of applying probabilistic risk analysis (PRA) techniques on the new Iranian upstream contract framework for a real world gas megaproject. Such a process consists of: (a) gathering and reporting all risk factors affecting construction schedule, cost, IRR, Gross and Net revenue, (b) eliciting and de-biasing expert judgments, (c) building a mathematical model to implement Monte Carlo simulation, (d) providing the Probability Distribution Function (PDF) of project financial parameters. Results of this paper are of interest to practitioners involved in contractual negotiations as well as those who are responsible for developing financial framework of upstream service contracts.

Keywords: Contractual Risks, Risk Identification, Risk quantification, Monte Carlo, Oil and gas contract, IPC

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Introduction

An upstream service contract can be defined as a contractual framework that controls the relation between international oil companies (IOCs) and a host government in which the IOCs develop or explore petroleum fields on behalf of the host government in return for some remuneration. In most cases, especially in major exporting oil countries, the host government seeks to maximize its control over extracted oil or sub-surface resources, while minimizing its risk in upstream contracts. This approach has made these types of contracts unattractive to IOCs, resulting in less investment in these countries (Ghandi and Lin 2014). In recent years, some of these countries which were unable to absorb enough investment to develop their fields have shown a growing interest in adopting some variations of upstream contracts to make their upstream contracts more attractive to investors (Ghandi and Lin 2014). One type of these new contracts is new Iranian petroleum contract (IPC).

IPC is a new upstream contract which is similar to Buy-Back contract (previous upstream contract in Iran) while adding some features to share the contract risks between parties more reasonable. The economic performance of the buy-back, specially the low share of contractor in the final take were among the major drawbacks of Buyback that resulted in Iranian authorities' willingness to ameliorate buy back model in favor of contractor.

By reviewing upstream contracts, contractual risk allocation, risk sharing and incentive contracts literature, it has been concluded that a comprehensive research to identify and quantify major risks in upstream industry with the aim of comparing actual contract parameters with the possible outcomes is necessary to fill the gap in this literature and analyze the attractiveness of IPC. This study aims to evaluate the economic and fiscal performance of new Iranian Petroleum contracts to answer the question that what are major risks in this new type of contract and how much it is possible to reach the actual contract fiscal goals. The data used are derived from a qualitative research and a case study by brainstorming and interviewing experts and also from data of a real Gas field contract in Persian Gulf. In this exploratory research, economic measures are derived to determine the various fiscal regimes' performance under three major criteria; i) Petroleum costs; ii) Contractor's IRR; iii)) The amount of government revenues . In short, this paper assesses the risk factors that international oil companies (IOC) face in Iran's oil and natural gas IPC and their effects on the IOC's rate of return (ROR) on this type of contract.

literature review

Oil and Gas industry, which is divided in upstream and downstream segments, play a critical role in the world economy, especially in the Middle East countries (Chaarani 2019). Upstream segments include exploration and production of crude oil and natural gas as well as drilling and operating wells. Downstream segments, on the other hand, deal with refining and processing petroleum crude oil and natural gas, and distributing the derived products. (Hutagalung et al 2019, Kim and Choi 2019). Although interrelated, these Segments deal with different environment and different project risks. This study does not include the downstream issues and is mainly concerend with upstream contracts and risks.

Oil and gas companies have employed various project management methods specially managing project risks in recent decades to deal with the diverse risks existing in this particular industry. (Jergeas and Ruwanpura 2010, Dehghan et al 2020, Thuyet et al 2007, Chan 2011, Dehdashti et al 2017, Rui et al 2017, Chitra and Halder 2017, Akhbari 2018, Kassem et al 2019, Kraidi et al 2019, Danforth et al 2019). A wide range of definitions for risks exist in open literature. For instance, risk in technology and economics literature is described as an anticipated value which an event will be accompanied by unwelcome outcomes, measured by the likelihood of the event and the possibility of the outcomes (Armstrong et al 2019, Asness et al 2020, Chernobai et al 2020, Chernyakov and Chernyakova 2018, Woodroffe 2008). In finance literature, financial risk is defined as the variation in market values and cash flows due to unforeseen changes in the financial terms (Silva et al 2017, Chatterjee et al 2017, Bigio and d'Avernas 2019). Risk management also has been defined in different fields as distinguishing and managing finance risk of a firm (Hubbard 2020, Rampini et al 2019).

Risk management can affect several issues in oil and gas industry so that it has become an integral part in decision making process especially in oil and gas upstream industry as decisions related to petroleum exploration and production are still very complex (Kraidi 2019, Mortazavi 2020). On the other hand, as new technologies advances develop, uncertainty and risk analysis are more applied, leading to clarification of the range and the impacts of new oil and gas field discoveries and the risks existed in a contract between companies in this industry (Aven 2016).

Exploration and production of oil and gas are considered high-risk projects because of the existed worldwide diversity in terms of geographical and socioeconomic environments (Khadem et al 2018). Most uncertainties at the exploration phase are concerned with volumes in place and reservoir structure and uncertainties related to recovery factor, (Suslick et al 2009). Offshore fields have inherently higher uncertainties with more unknown situations coupled with higher required investments and lower flexibility (Pinto et al 2001). Regarding development phase, field management decisions are also complex with a large number and different type of decisions along with several types of uncertainty with potential considerable effects on risk quantification (Yang et al 2018). Furthermore, economic risks existed due to the uncertainty of the cash flow and the probability of finding and producing in enough volume (Motta et al 2000). Moreover, the oil and gas due to its economic importance and environmental sensitivity is subject to pressure from various stakeholders adding to its complication (Suslick and Schiozer 2004).

Risk analysis has been increasingly applied in various projects in upstream segments during last decades (Suslick and Schiozer 2004, Shafiee et al 2019, Sule et al 2019, Tang 2017, Santos et al 2017, Briggs et al 2012). Moazami et al (2015) point out that project delivery methods and contract price arrangements are two main elements of the contractual risk allocation, through which the project risks can be assigned to the contracting parties.

Decisions making in oil and gas industry needs considering major uncertainties, long term periods, and several alternatives issues in the decision model. Therefore, risk analysis can be applied on multiple levels in oil and gas exploration and production stages (Suslick et al 2004).

Several authors like Temmy D. and Tumbur P (2002) due to its significance, analyzed profitability of Fiscal regimes, however, risk and uncertainties were not accounted for.

Table 1 defines searched terms used in the following fields, using the following keywords: “contractual risk allocation” OR “risk allocation” OR “risk sharing” OR “risk allocation ratio” OR “risk sharing ratio” OR “risk sharing in petroleum contracts” OR “risk allocation” AND “petroleum contracts” OR “incentive” OR “incentive” AND “Petroleum Contracts”. The Google Scholar database has been chosen because of its widely used in academic research. The search criterion included articles published in scientific journals of social sciences and humanities and energy.

As the IPC model is a new type of upstream contracts and there are limited research regarding its concept and risks, this research aims to fill the gap regarding the contractual risk allocation with regard to IPC contract in terms of its attractiveness to answer these questions:

- What are the associated risks in IPC?
- How these risks are allocated and shared?
- What are the effects of these risks in fiscal terms?

Research goals and methods

This article discusses the risk analysis process and the results for an offshore development of a gas field project (P1). The purpose of this study here is to (a) gather and report all the risk factors affecting the construction schedule, cost, contractor’s IRR, Owner's Gross and Net revenue by qualitative research, (b) elicit expert judgments regarding the variability and uncertainty of identified factors affecting the project outcome, (c) quantify the risks and build the mathematical model of the project to do Monte Carlo simulation on the project outcome, (d) run Monte Carlo simulation on the mathematical model of the schedule, cost, and revenue, (e) provide the probability distribution function (PDF) and the cumulative distribution function (CDF) of the project financial forecast. The total project is analyzed using the Palisade @Risk software. Monte Carlo simulations are performed by applying the risk factors (quantified by probability density functions) to the model to calculate the resulted distributions for outcomes: contractor's IRR, owner's gross and net revenue and, actual DCC and IDC, FEE, and other economic elements. Some key project assumptions were made to complete the risk analysis.

Risk analysis of a real new Iranian upstream contract (IPC)

According to IPC, contractors can participate in operation phase in addition to other phases of upstream activities, contrarily to buy-back contract in which the contractors was not allowed to take part in operation phase. IPC contract is an open Capex contract, which means all costs incurred during the project would be recovered to contractors. Furthermore, in order to motivate contractors to be more efficient, contractors are compensated by fee per barrel of the production. Figure 1 illustrates costs and payment scheme in IPC. Under IPC, contractors payment is commenced from First Targeted Production (FTP) which is determined during contract negotiation, depending on a mutuall agreement regarding an early acceptable production. When recovery costs are due, cost of money is applicable. If full cost recovery cannot be paid because of cost ceiling, all remaining costs are carried forward to the next quarter, subjected to COM. The details of fiscal parameters used in this type of contract are discussed as bellow.

- Direct Cost of Capital (DCC) means any and all capital costs and expenses which are incurred and actually paid by contractors directly related to and connected with the development operations phases.
- Indirect cost (IDC) means any costs and expenses which are incurred and actually paid by contractors to the government.

- Cost of Money (COM) means the costs of financing, which is directly related to London Interbank Offered Rate (LIBOR)
- Operating expense (OPEX) means any and all costs and expenses incurred and actually paid by contractors directly related to and connected with the operation phases.

Research assumptions

- In this research, It has been assumed that costs accured before signing the contract is zero and the owner, which in here is National Iranian Oil Company (NIOC) is not responsible for the recovery of such costs to the contractor.
- NIOC is not going to either stop or reduce production under any circumstance (e.g. technical, mechanical failure, repair, political circumstances, …)
- NIOC is always ready to take delivery of the produced raw gas
- The contract duration is 20 years
- The cost stop is 50% of SP raw gas production, unless the crude oil price drops down to less than $30/bbl in which case the cost stop ceiling may be increased to 75%
- Payment of Fee and recovery of petroleum costs under the contract are made in the following order of priority: OPEX, IDC, DCC, COM, Fee

Research data Based on a real contract

- DCC recovery
    - DCC occurring before FTP will be recovered from the date of FTP and will be amortized over 10 years.

    - DCC occurring after FTP, except the part of DCC related to compression activities, will be recovered the year following the financial year in which such DCC occurs and will be amortized over 10 years.
    - DCC occurring for compression activities including designing, construction, commissioning and startup will be recovered from the date of compression platform startup and will be amortized over 10 years.
- All DCC regarding possible extra work after compression platform will be reimbursed 5 years after such costs incurred. IDC recovery

  The initial estimation of the IDC is 10% of DCC. The 3.75% Income Tax (of DCC + FEE) is embedded in this amount.

    - IDC occurring before FTP will be recovered from the date of FTP up to the amount not exceeding the cost stop.
    - IDC occurring after FTP will be recovered on current basis.
    - In case that IDC incurred and actually paid by contractor before FTP exceeds ten percent (10%) of the DCC incurred and actually paid by contractor before FTP, the recovery subject to cost stop for the period of the first four (4) Quarters after FTP may be increased as required up to seventy five percent (75%).
- Cost of Money calculation
    - LIBOR means the twelve (12) months London Inter-Bank Offered Rate (as applied to US Dollars). Cost of Money (COM) is equal to LIBOR+0.5%, which shall not exceed 2.5%.
    - COM will not be applied in case there is a project delivery delay due to the contractor's fault.

- For any Quarter, COM will be calculated and applied to the unrecovered incurred and actually paid DCC and any carried forward due amounts (OPEX, IDC, Fee, COM), if any.
- COM shall be calculated monthly. In each Quarter, COM shall be payable to considering the Monthly Cost of Money (MCOM) Rate, compounded monthly.
- The actual MCOM Rate for the calculation of COM amount shall be computed in accordance with the following formula:

$$r_m = (1 + r)^{(1/12)} - 1 \tag{1}$$

  - r is the COM rate. r = LIBOR + 0.5%, up to 2.5% in total.
  - r_m is the Monthly Cost of Money Rate (MCOM Rate)

- The applicable monthly COM rate for the calculation of COM payable by NIOC in case of delay in payment ("Delay MCOM Rate") shall be computed in accordance with the following formula:

$$r_m = (1 + r)^{(1/12)} - 1 \tag{2}$$

  - r is the is the delay COM rate. r = LIBOR + 0.5%, up to 2.5% in total.
  - r_m is the monthly delay cost of money rate

- Gas price calculation
  - Raw gas value is equal to unit raw gas value as applicable, multiplied by Net Production. All payments to contractor for recovery of petroleum costs and payment of Fee shall be paid out of a percentage of raw gas value ("Recovery and Payment Ceiling Ratio" or "RPCR"). Such RPCR shall be used to calculate a ceiling (hereinafter "Recovery and Payment Ceiling" or "RPC") in any Quarter, in US$, based on the following formulas:
  - For crude oil prices more than or equal to $50/bbl the $PRPC = 50\%$ and the price of net production of raw gas will be determined based on the following formula:

$$RPC(\$) = (Raw\ gas\ Pruduction;\ MMBtu)(3.3 + 0.02\ P_{OIL};\ \frac{\$}{MMBtu}) \quad (3)$$

- For crude oil prices more than $\$30/bbl$ and less than $\$50/bbl$ the $PRPC = 50\%$ and the price of net production of raw gas will be determined based on the following formula:

$$RPC(\$) = (Raw\ gas\ Pruduction;\ MMBtu)(3.0 + 0.02\ P_{OIL};\ \frac{\$}{MMBtu}) \quad (4)$$

- For crude oil prices less than $\$30/bbl$, the $PRPC = 75\%$ and the price of net production of raw gas will be determined based on the following formula:

$$RPC(\$) = (Raw\ gas\ Pruduction;\ MMBtu)(2;\ \frac{\$}{MMBtu}) \quad (5)$$

- In case the recoverable petroleum costs and payable Fee cannot be recovered fully before the end of the contract term, then ecovery and payment ceiling ratio will be increased to seventy five percent (75%) for maximum last three (3) Years of the Contract.

- The conversion factors for energy content, obtained from the EIA (U.S. Energy Information Agency) website, were 1.032 MMBtu per thousand cubic foot (Mscf) for natural gas, 6.287 MMBtu for residual fuel oil, and 5.800 MMBtu per barrel for WTI crude oil. The price of WTI crude oil at the time of this analysis was $45.72/barrels and the Natural gas price was $2.96/MMBtu. It is assumed that 70% of the heat value of the raw gas is Methane with a price of 6% of crude oil. The 30% heat value of the produced gas is heavier than Methane. Again, in this analysis, it is assumed that one $Mscf$ (thousand cubic foot) of produced gas has 1.032 MMBtu heat value.

Monte Carlo simulation

Monte Carlo simulation is a method to calculate uncertainty stochastically to determine the status of a varibale. (Hulett 2009). Monte Carlo simulation can also be used to determine the project completion date as the completion date is affected by multiple uncertainties in the durations of many subactivities (Hulett 2017). In recent years, Monte Carlo simulation has been applied to project management uncertainty issues such as the project completion date and the project cost estimate (Naderpour et al 2019, Enyinda and Gebremikael 2010, Fonseca et al 2017, Shafiee et al 2019, Naderpour et al 2019).

Basically, Monte Carlo simulation first calculates the CPM schedule in several times, applying probable combinations of the uncertain durations, then registers the results for the date of completions in uncomplicated charts or tables specyfying the frequency that different results happened (Hulett et al 2011). Derived from the risk interviews and questionaries, probability distributions, would be used for estimating durations (Asta et al 2016). This procedure can be used for estimating costs and other variables as well. In this paper, this method was used to calcualte the schedule and cost and revenue distribution. The following esteps have been used to detemined the mentioned variables.

- Through a brainstorimg session with eight experts, the Pre-Contract costs are estimated between 15 and 20 MM$, it includes the geoscience studies, drilling preparation studies, update of basic engineering for Phase 1, screening study for Phase 2 and CFT preparations. The DCC after Contract signature of the reference case development scheme are detailed in the following section for DCC for drilling, Phase 1 project, Phase 2 project and integrity DCC. Table 2 shows the Best Case, Most Likely and Worst Case scenarios for the costs in both phases and drilling.

According to Creswell (2000), there are three ways to validate a qualitative research; Triangulation, Member checking and Audit trail. As for Triangulation, the authors here used different sources such as multiple interviews, brainstorming and analyzing simillar past data. With regard to Member checking. Participants were asked whether or not the collected data make sense, or data were deducted with sufficient evidence. Regarding audit trail, external individuals to projects were asked to review the study.

therefore, from the outset of this study three university professors famillar with qualitative research were asked to review the procedure and giving their feeedback throughout the study.

The following milestones and activity durations have been elicited first by interviewing 17 experts who have at least 5 year experience in offshore fields. The raw data then were adjusted and validated by a separte brainstorming group consisting of 7 senior managers and experts who had at least 10 year expereince in offshore fields.

- The IPC Effective date will happen 60 days after signing the IPC.
- The Jackets' contract award happen 60, 75, and 90 days after the IPC effective date for the best case, most likely, and worst-case scenarios, respectively.
- Jacket A EPC will take 14, 18, and 19 months after the contract award for the best case, most likely, and worst-case scenarios, respectively.
- Installation of Jacket A will take 2.5, 3, and 4.5 months after the EPC of Jacket A for the best case, most likely, and worst-case scenarios, respectively.
- Jacket B EPC will take 14, 18, and 19 months after the contract award for the best case, most likely, and worst-case scenarios, respectively.
- Installation of Jacket B will take 2.5, 3, and 4.5 months after the EPC of Jacket B for the best case, most likely, and worst-case scenarios, respectively.
- Jacket B will be installed 3 months after jacket A.
- The contract award of the topsides will happen in 180, 195, and 210 days after the IPC effective date for the best case, most likely, and worst-case scenarios, respectively.
- Installation of Topside A will take 900, 960, and 1080 days after contract award of topsides for the best case, most likely, and worst-case scenarios, respectively.
- Installation of Topside B will take 900, 960, and 1080 days after contract award of topsides for the best case, most likely, and worst-case scenarios, respectively.
- The contract award of the Sealines will happen in 180, 195, and 210 days after the IPC effective date for the best case, most likely, and worst-case scenarios, respectively

- Installation of Sealines A will take 990, 1050, and 1200 days after contract award of Sealines for the best case, most likely, and worst-case scenarios, respectively.
- Installation of Topside B will take 990, 1050, and 1200 days after contract award of Sealines for the best case, most likely, and worst-case scenarios, respectively.
- The contract award of the Tie-ins will happen in 70, 80, and 150 days after the IPC effective date for the best case, most likely, and worst-case scenarios, respectively
- The Tie-Ins EPC and Installation will take 510, 640, and 700 days after the Tie-In contract award for the best case, most likely, and worst-case scenarios, respectively
- The First Gas Production A happens after Jacket A Installation, Topside A Installation, and Tie-In A Installation.
- The First Gas Production A happens after Jacket A Installation, Topside A Installation, and Tie-In A Installation.
- Time to First Gas is assumed to be 36 months. Based on the analysis of the schedule risks involved, it is forecasted that the time to first gas will have the distribution shown in Figure 2. It can be seen that the probability of time to first gas being 36 months or less is zero.
- The Long Lead Items (LLI) contract award will take 240, 255, and 275 days after the IPC effective date for the best case, most likely, and worst-case scenarios, respectively.
- The contract award for Well Rigs will happen 90, 120, and 180 days after the Long Lead Items (LLI) contract award for the best case, most likely, and worst-case scenarios, respectively.
- The construction of Well Rigs will happen 240, 270, and 330 days after the Well Rigs contract award for the best case, most likely, and worst-case scenarios, respectively.
- Drilling Wells for Platform A will take 35, 36, and 41 months after the contract award for Well Rigs for the best case, most likely, and worst-case scenarios, respectively.
- Drilling Wells for Platform B will take 35, 36, and 41 months after the construction of Well Rigs for the best case, most likely, and worst-case scenarios, respectively. The drilling for wells for platform B will be finished 2 months after drilling wells for platform A

- The gas production Ramp-Up will take place after all wells for platforms A and B are drilled.

The following information have been elicited from the contract and a brainstorming group:

- For the 1st Phase: the production profile of the reservoir is assumed to have a linear increase from first gas of 0.4 Bscf/d to a ramp-up maximum of 1860 Bscf/d.
- The added compression increases the production to the maximum plateau of 1.860 Bscf linearly in a duration of 1 year
- The plateau production of 1.860 Bscf will last 12, 8, and 5 years for the best case, most likely, and worst-case scenarios.
- After maximum plateau production duration, the production decreases with the rate of 10% per year until the end of contract in year 2037 (Figure 3).

One iteration of production profile, considering all the above assumptions and Subject Matter Experts' (SME) inputs costs for the phase 1 are assumed to have a Triangular distribution.

There is 10% chance that the cost is less than $2,249 MM, the most likely cost is $2,479, and there is 10% chance that the cost is more than $2,778 MM(Figure 4).

The costs for the Compression Phase are assumed to have a Triangular distribution. There is 10% chance that the cost is less than $2,030 MM, the most likely cost is $2,400, and there is 10% chance that the cost is more than $2,848 MM (Figure 5).

The IDC ercentage is estimated to be around 10% of the DCC. For this simulation, we assume that the IDC has a Triangular distribution with the minimum at 8.0 % and maximum at 13.5%. the 10% is considered to be the most likely case (Figure 6).

The IDC cost for both phases itself has the distribution shown in Figure 7. There is 10% chance that the cost is less than $420.3 MM, the most likely cost is $497.53, and there is 10% chance that the cost is more than $616.3 MM (Figure 7).

The OPEX Percentage is estimated to be around 4% of the DCC. For this simulation, we assume that the OPEX has a Triangular distribution with the minimum at 3.5% and maximum at 5%, the 4% is considered to be the most likely case (Figure 8).

There is 10% chance that the cost is less than $173.5 MM, the most likely cost is $202 MM, and there is 10% chance that the cost is more than $240.8 MM (Figure 9).

For simulating the price of oil, the focus has been on the historical price of the oil over the past 40 years and the price shocks should were studied (Figure 10) .In this paper, it has been also assumed that the oil price has a normal distribution with mean $50/bbl, and standard deviation $15/bbl truncated at $20/bbl as the minimum price and $100/bbl as the maximum price.

Results and Conclusion

After running Monte Carlo simulation, the following results have been elicited. Estimation of conractor's IRR is shown in Figure 11. The median (P_{50}) is 13.04% and the mean IRR for the contractor is 13.396 %. Since the curve is a cumulative probability of non-exceedance, $(P_{10}) = 11.81\%$ and $(P_{90}) = 14.02\%$.

The NIOC Gross Revenue has the distribution shown in figure 12. The median (P_{50}) is $\$42{,}805\ MM$. Since the curve is a cumulative probability of non-exceedance, $(P_{10}) = \$40{,}783\ MM$ and $(P_{90}) = \$44{,}500\ MM$

The NIOC Net Revenue has the distribution shown in Figure 13. The median (P_{50}) is $\$29{,}153\ MM$. Since the curve is a cumulative probability of non-exceedance, $(P_{10}) = \$27{,}285\ MM$ and $(P_{90}) = \$30{,}782\ MM$.

The contractor FEE has the distribution shown in Figure 14. The median, (P_{50}), is $\$6{,}008\ MM$. Since the curve is a cumulative probability of non-exceedance, $(P_{10}) = \$5{,}746\ MM$ and $(P_{90}) = \$6{,}222\ MM$.

The contractor take which is FEE divided by NIOC Net Revenue has the distribution shown in figure 15. The median (P_{50}) is 20.607 %. Since the curve is a cumulative probability of non-exceedance, (P_{10}) $=$ 20.03% and (P_{90}) $= 21.3\%$.

Table 3 compares the actual data from the contract and the results from the simulation. The analysis shows that although the new contract is more favorable to IOCs compared with former buy back framework, still there are major risks for contractors. For example in this analyzed project, the contractual IRR was about 14.5 percent but the analysis showed that there is less than 10 percent possibility for contractors to achieve this amount. As it is shown major cost of this project such as DCC an IDC would probably cost more than the determined amount in contract while the payment to contractor as Fee would probably be less than the contractual amount. Furthermore, there is less than 10 percent possibility for NIOC to achieve the Gross Revenue based on the contract.

Based on the results, it can be concluded that the contractual parameters are too optimistic that most of them may not be achievable. Not only may not contractor possibly reach its IRR, but also there would be less revenue for NIOC, making the contract less attractive for both sides.

Future research and Discussion

It is crucial to apprehend the limitations of Probabilistic Risk Assessment when it comes to assess the final results of the stated risk procedure in this article thoroughly. These limitations involve inherent uncertainty in all risk assessment processes, and the integrity of the output highly dependent on the correctness and integrity of the input data. Furthermore, it should be stated that the goal of a risk assessment process is not reaching a zero risk level, but identifying ways for reducing risk to an appropriate level. Due to these basic limitations, a certain amount of personal judgment is unavoidable even in risk quantification. However, such judgment by itself does not wane the value or credibility of the risk assessment process.

The findings of this research speacially in the Risk identification and quantification can be used in other types of contracts as it is not inherently just for IPC contracts. For the future reasearch, the sensitivity analysis for IRR regarding major variables such as oil price sensitivity, contracor failure to reach the FTP, cost overrun and the schedule sensitivity can be suggested. Moreover, this area lacks research regarding contrtors oportunistic behavour. By studying the real behaviour of the contractors in simillar type of contracts in future research, the contract can be improved in favour of both parties.

Data Availability Statement

Some or all data, models, or code generated or used during the study are proprietary or confidential in nature and may only be provided with restrictions. These items include the name of the project which has been studied as a case study and its actual price and cost of the contract.

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Table 1 Terminologies used in Contract Risk Assessment

Terminology	References
contractual risk allocation	Wan M. Zulhafiz (2018, 2017) Shuibo Zhang; Shuaijun Zhang; Ying Gao; and Xiaoming Ding (2016) CY Chang (2014) Garshasb Khazaeni; Mostafa Khanzadi; Abas Afshar (2012) Joseph H.L. Chan, Daniel W.M. Chan, Patrick T.I. Lam, Albert P.C. Chan (2011) Yongjian Ke; ShouQing Wang Albert P.C. Chan; Patrick T.I. Lam (2010) M. Loosemore and C. S. McCarthy (2008) K.C. Lam; D.Wang; Patricia T.K. Lee; Y.T. Tsang (2007)
Risk sharing	Abhijeet Ghadge; Samir Dani; Ritesh Ojha; Nigel Caldwell (2017) Kislaya Prasad and Tim C. Salmon (2013) Borys Grochulski and Yuzhe Zhang (2011) Tessa Bold (2009) Chris Chapman and Stephen Ward (2008) Tarun Khanna and Yishay Yafeh (2005) Konstantinos Serfes (2005)
Incentive contract	Anna M.Costello (2013) Knut Arne Sund and Kjell Hausken (2012) Nutavoot Pongsiri (2004) Jin Fang Shr and Wei Tong Chen (2004) Abdulaziz A.Bubshait (2003)

Table 2 DCC estimates

	Best Case Scenario (MM$)	Most Likely (MM$)	Worst Case Scenario (MM$)
DCC for drilling	1,074	1,190	1,307
Phase 1 DCC	1,175	1,289	1,471
Phase 2 DCC	2,030	2,400	2,848
Overall DCC	**4,279**	**4,879**	**5,626**

Table 3 Simulation result

	Simulation result			Contractual data
	P10	**P50**	**P90**	
IRR	11.64	13.05	14.15	14.5
DCC	4563	4916	5309	4,879
IDC	410	514	622	488
Fee	5754	6010	6266	6570
NIOC Gross Revenue	40905	42700	44493	45,000