Energy Economics 116 (2022) 106401

Contents lists available at ScienceDirect

Energy Economics

journal homepage: www.elsevier.com/locate/eneeco

Risk and benefit sharing schemes in oil exploration and production☆

Semyon Fedorov [a,*], Maria Lavrutich [a], Verena Hagspiel [a], Thomas Lerdahl [b]

[a] *Norwegian University of Science and Technology (NTNU), Norway*
[b] *OKEA ASA, Norway*

ARTICLE INFO

JEL classification:
Q02
Q35
Q47
D86
L24
G32

Keywords:
Risk sharing
Smaller oil companies
Real options

ABSTRACT

The volatile environment of oil exploration and production sets new challenges to market players prompting them to explore new business models. In this paper, we analyze a novel type of partnering in oil and gas operations, i.e. risk and benefit sharing schemes, that enable an oil field operator to bring third parties into the field development process. We develop a valuation method to assess the feasibility of such risk and benefit sharing schemes based on the real options approach and identify the optimal contract policy from the perspective of both the oil company (field operator) and the contractor. We analyze an application case where a field operator collaborates with a drilling contractor to share risks and benefits resulting from the oil field development. We propose three different risk sharing contract structures that allow various levels of risk distribution to be achieved. In one of the proposed contracts, we incorporate an "exit" clause in the contract as an instrument to provide flexibility for the parties to withdraw from the partnership as uncertainty unfolds. Our results show that the risk and benefit sharing schemes with embedded flexibility have the potential to become an alternative form of contracting in the oil and gas industry.

1. Introduction

The maturation of the main E&P areas in the world imposes significant risks for stakeholders. New discoveries in mature production regions are characterized by smaller sizes and more challenging technical conditions for development. Investment in such fields is expected to be exposed to even more risks in the future, which stem from, among other things, public pressure considering the environmental impact, increasing emissions taxes and a peak in global demand for fossil fuels. Evidence from the Norwegian Continental Shelf (NCS) shows that major E&P companies become less interested in relatively more risky production areas.[1] The market share of several international majors in Norway has been taken over by smaller companies. However, in order to make profit in these areas, smaller companies need to find new business models.

In order to ensure the profitability of hydrocarbon production in the future, oil companies and especially the smaller ones need to consider various novel engineering, economic and contractual solutions. In this paper, we focus on the latter. Specifically, we study contracts that allow oil companies to share risks and benefits with their contractors, which include financial institutions, service and drilling companies, license partners and other oil companies and suppliers. Through risk and benefit sharing schemes, the contractors can become involved in the field development process with a possibility to share costs, operational risks and future revenues with the operator. Novel contract schemes used on the NCS, including integrated contracts (Equinor, 2022) and alliances (AkerBP, 2021) already enable greater integration between operators and suppliers and result in more extensive risk sharing between the parties involved. However, they rely on standard compensation formats, where the operator covers time and material for a performed task rather than establishing long-term frameworks for sharing production and/or oil price risks.

Within the risk and benefit sharing agreement that we propose in this paper, the field operator is responsible for only a portion of capital costs, while the rest is covered by a contract partner. In return, the partner receives an incentive tied to the level of future oil production or future profit. We identify if there exists a fair (i.e., transparent and

☆ This research is a part of BRU21 NTNU Research and Innovation Program on Digital and Automation Solutions for the Oil and Gas Industry (www.ntnu.edu/bru21) and supported by OKEA ASA. The authors acknowledge the contribution made by Babak Jafarizadeh from Heriot-Watt University. This research has greatly benefited from discussions with him.

* Corresponding author.
E-mail address: semyon.fedorov@ntnu.no (S. Fedorov).

[1] The number of international majors acting on the NCS decreased from 8 in 2000 to 3 in 2021, which corresponds to 29% of the total number of players in 2000 and 8% in 2021. At the same time, the share of small and mid-sized companies increased from 50% in 2000 to 81% in 2020. However, in terms of total oil production, small oil companies deliver only about 1%, while mid-sized players contribute to 37% of total oil production in Norway.

https://doi.org/10.1016/j.eneco.2022.106401
Received 27 January 2022; Received in revised form 31 October 2022; Accepted 10 November 2022
Available online 17 November 2022

balanced) contract that would be attractive for both the field operator and the contractor. We also consider the regulator/government as the third party that must ensure that establishing the risk and benefit sharing scheme does not lead to a reduction of tax revenues. We analyze several contractual alternatives between the parties and compare the project valuation results to a benchmark of a standard hiring agreement without risk and benefit sharing. The first risk and benefit sharing contract we consider reflects a case in which only oil production risk is shared and the benefit amount is solely linked to the oil production rate. We then extend this contract to take into account that apart from the production risk, the contractor can take a portion of the oil price risk by balancing it with an upside potential through an increased benefit amount. A consequence of this is that the benefit amount depends on the future profit after petroleum tax. Finally, we introduce an “exit” clause that allows both the operator and the contractor to withdraw from the risk and benefit sharing scheme. This clause introduces flexibility in the contract, that can be used to avoid suboptimal outcomes. We use an algorithm based on the real options approach (ROA) that allows to optimize the contract policies for both the operator and the contractor in order to ensure a fair risk distribution and proper incentives to participate in the contract. We quantitatively assess the impact of various parameters (oil production rates, the oil price and costs) on the project value (and value of the contract) and calculate the exact value of incentives that are necessary to balance the contractual risks.

The real-world applications of risk and benefit sharing contracts vary from large infrastructure projects (Alonso-Conde et al., 2007) to movie rental studios (Cachon and Lariviere, 2005). In these cases, using the risk and benefit sharing schemes allows project risks connected with uncertain demand to be distributed and provides certain guarantees for participants against unexpected variations in project outcomes (Alonso-Conde et al., 2007). Cachon and Lariviere (2005) and Yao et al. (2008) also demonstrate that such contracts might improve supply chain performance by increasing the total profit of the participants.

In the oil and gas industry, however, risk and benefit sharing is hardly used. In Appendix A we discuss an existing example of cooperation between an oil company (Pertra) and its contractors (Maersk and Halliburton) that involved compensation in the form of a tariff per barrel produced (Børve et al., 2017). This is the only case of risk and benefit sharing on the NCS documented in the literature known to the authors. Pertra’s case can be viewed as an exceptional arrangement arising from a situation where the following important conditions came together:

- small-sized field operator under capital constraints that needed external expertise;
- sluggish market for drilling contractors that made them interested in taking part in an experimental project;
- involvement of the authorities that played a coordinating role in establishing and procuring the scheme.

There are a number of reasons why risk and benefit sharing has not been widely used in the oil and gas industry. However, several trends point out the relevance of these schemes in the current market conditions. First, the market has been dominated by large oil companies that have little or no incentives to share risks in the field development process as they can cover losses from unsuccessful projects by cash flow generated by profitable assets and by taking advantage of access to cheap debt (Osmundsen et al., 2010). However, smaller companies that are emerging in the market normally have much less ability to preserve their activities in case of an unfavorable outcomes due to scarce portfolios and higher cost of capital (Weijermars et al., 2011).

Second, oil majors typically contract out a relatively small range of tasks in order to reduce costs. Their contractors such as drilling and service companies, and rig providers have been responsible for the respective tasks with very limited involvement in overall operations of E&P projects. However, for smaller companies, involving other parties can be attractive not only due to cost reduction, but also due to potential access to external resources and expertise, as well as the ability to share risks (Osmundsen et al., 2010).

Third, the risk and benefit sharing scheme requires much more commitment both from field operators and contractors and more extensive information sharing from the principal. Osmundsen et al. (2010) analyzes incentive schemes for drilling operations and argues that major oil companies remain reluctant to disclose comprehensive reservoir data as there are only a small number of contractors in the industry and most of them work with several oil companies. However, smaller oil companies, for which the information sharing with contractors might be the only way to survive, typically do not have this concern.

Fourth, Osmundsen (2011) argues that for many contractors, accepting the reservoir and oil price risk is too costly as their strategy is to be industrial enterprises, not oil companies. In order to realistically assess the potential of the risk and benefit sharing schemes, contractors must significantly improve their competence in reservoir engineering and risk management as well as have opportunities for follow-up and control during the production phase. In this work, we demonstrate how this issue can be resolved by building a flexible agreement, where risk and benefits are distributed fairly. Our results allow the estimation of the range of uncertainty and value at risk for all parties involved, making the agreement transparent.

Lastly, the legal base for risk and benefit sharing has not been developed yet. This is why we put particular emphasis of the role of regulator in establishing the framework for such a cooperation in the oil and gas industry. We demonstrate how the risk and benefit sharing contract terms can be designed such that the collaboration ensures at least the same level of tax revenues for the regulator as the state-of-the-art business models.

A higher risk exposure of smaller oil companies leads to a higher cost of capital for these firms compared to the oil majors. We demonstrate that this novel form of cooperation has the potential to decrease the cost of capital for smaller oil companies in the presence of capital market imperfections. Myers (2001) shows that these imperfections arise from the inability of financial institutions to adequately assess risks related to field development, which in turn may result in high interest rates on loans that are offered to small companies (Magri, 2009; Czarnitzki and Hottenrott, 2011). Smaller independent E&P companies also frequently face more limited access to financial markets to raise capital (Ferriani et al., 2019).[2] This motivates such companies to look for alternative ways of project financing that potentially allows them to decrease downside risks and the cost of capital. Risk and benefit sharing schemes, where some portion of capital cost is provided by a contract partner (thus avoiding capital loans from a bank, issuing debt or seeking for equity investors), are one of the potential instruments to cope with the low accessibility of cheaper finance. In our model, we assume that the contractor can provide financing for drilling operations, which avoids a costly bank loan. In addition, we show that risk and benefit sharing can be attractive for those contractors that are ready to take and manage additional unsystematic risk and are interested in diversification of their core businesses.[3] Differences in the liquidity and equity position between small oil companies and large suppliers that enables contractors to act as banks for oil companies can be used. In these conditions, it is important for the service company to have a wide

[2] During the low oil price environment in 2015, 2016 and 2020 low rated smaller E&P firms faced significant difficulties accessing both debt and equity markets (Dezember and Sider, 2018; Restrepo et al., 2020), while low interest rates were still available for oil majors due to higher credit ratings (Weijermars et al., 2011). This made, for example, 113 US oil and gas producers go bankrupt in 2015 and 2016. In 2020 the number of bankruptcies of E&P companies in the US totaled 46 (Boone, 2021).

[3] For example, this might be relevant for well-established major players such as Schlumberger, Halliburton, and Baker Hughes.

portfolio of projects where some are successful and profitable, while others involve taking risks and might have marginal financial outcome.

The remainder of this paper is organized as follows. In Section 2, we provide a literature review and discuss our contributions. In Section 3, we formulate the problem statement and introduce the modeling approach project valuation under four different contract schemes. Section 4 presents the results and sensitivity analysis. Section 5 concludes the paper.

2. Literature review

Our model offers several contributions to the petroleum economics and contract theory literature. First, we contribute to the emerging stream of literature on new incentive contracts in the oil and gas industry. Here, among the few existing contributions is Børve et al. (2017) that evaluates to which extent partnering practices observed in the construction industry are applied in offshore drilling projects and provides a systematic description of partnering practices. Another contribution is Osmundsen et al. (2010) that argues that oil service companies must be challenged to design contracts which are suitable for new small companies. Such new contracts will require a different approach to risk sharing than in existing agreements as smaller companies will want to pass more risk on to contractors. To satisfy this demand, contractors must expand their expertise base and develop suitable risk management systems. However, Osmundsen et al. (2010) neither provides a modeling approach to design these contracts nor defines necessary contract parameters. We add to this literature by designing a fair risk and benefit sharing contract with embedded flexibility that addresses the challenge of high risk exposure of smaller oil companies. Our approach enables both parties to assess risks associated with the participation in the agreement and optimize the decisions once the risk and benefit sharing framework is established.

Second, we consider a new application for methods used in contract theory literature. Risk and benefit sharing contracts have been studied extensively in the context of general contract, incentive and agency theories (Bolton et al., 2005). Such collaborative arrangements are characterized by parties' mutual interest in sharing and spreading the risk associated with large, complex or long-term contracts (Akintoye and Main, 2007). In such cases, the risk and benefit sharing contracts can also serve as instruments that allow to avoid principal–agent problems and conflicts resulting from traditional contracts (Osipova, 2015). In the oil field development, these conflicts may arise because field operators focus on long-term value creation, whereas contractors (e.g. drilling and service companies) deal with relatively short-term tasks and try to minimize the cost of operations. Incentive contracts, and risk and benefit sharing agreements in particular, have been suggested by contract theory literature as instruments that allocate uncertain outcomes and motivate an agent to act in the interests of a principal based on two perspectives: a value-creation perspective and a risk sharing perspective (Melese et al., 2017). The value-creation perspective focuses on the possibility to gain additional value through synergies within an incentive contract and optimal allocation of value from cooperation. Holt et al. (2000) and Cachon and Lariviere (2005) provide examples of how the principal and agent can engage in collaborative relations that create mutual benefits. Govindan and Popiuc (2014) show that performance and total supply chain profits are improved through coordination with revenue sharing contracts in supply chains. Carbonara et al. (2014) build a win-win risk sharing mechanism via efficient concession terms in PPP. Wang et al. (2021) implement a revenue sharing coordination mechanism in a coal-fired power supply chain. The authors prove that coal and electric power enterprises cooperating under revenue sharing contracts achieve higher profits and lower carbon emissions compared to a decentralized decision-making mechanism without such a contract. The risk sharing perspective focuses on how to distribute risks in the optimal way between parties involved in an incentive contract (see, e.g., Pratt, 2000, Lam et al., 2007, Medda, 2007 and Nasirzadeh et al., 2014). Ghadge et al. (2017) proposes a risk sharing contract to distribute the risk of demand uncertainty and price volatility among different stakeholders.

In this paper, rather than focusing on the role of risk and benefit sharing in deterring agency problems and moral hazard (as done, for example, by Shi et al., 2019), we analyze whether the novel contracting form can create incentives for both oil field operators and contractors to cooperate during the field production phase. We focus on monetary effects provided by the risk and benefit sharing and disregard potential effect on efficiency of the field development, such as drilling quality and speed. In our case, two main opportunity windows created by the risk and benefit sharing from the field operator's perspective are the access to cheaper financing amid capital market imperfections and the opportunity to decrease the volatility of the project cash flows. In that respect, most of the literature assumes that financial markets are efficient, that is, external funding is plentiful and relatively inexpensive, allowing firms to make financial and operational decisions separately (Modigliani and Miller, 1958). However, for small oil companies capital shortage caused by high cost of debt and limited access to equity financing might become a bottleneck. Emtehani et al. (2021) demonstrate that coordination among supply chain members can overcome such bottlenecks and improve the supply chain's performance, benefiting all participants. Kouvelis and Zhao (2012) and Kouvelis and Zhao (2016) identify the benefits created by revenue sharing contracts with capital coordination within supply chains when capital market frictions are present. Xiao et al. (2017) design a revenue sharing contract allowing for flexible profit allocation between members of a financially constrained supply chain. Fatehi and Wagner (2019) provide another example of monetary benefit created by risk and benefit sharing applied in crowdfunding, where a firm borrows capital and then pays back investors via revenue sharing contracts. The authors identify that revenue sharing contracts provide a higher net present value (NPV) and a lower probability of bankruptcy than equity crowdfunding or a fixed rate loan.

Third, we contribute to the literature on real options and risk-neutral valuation applied to the incentive contracts, typically in public–private partnerships (PPP). There, the minimum revenue guarantee (MRG) (also called revenue-sharing bands) approach is used to distribute risks between the contract parties (Shan et al., 2010; Rouhani et al., 2018; Wang et al., 2018). According to the MRG concept, the public authority ensures a minimum revenue for its private partner, lowering the risk of the project's returns and increasing the returns to the private capital providers. A similar mechanism can be applied to share the surplus revenue (Ashuri et al., 2012). This mechanism is often referred to as toll revenue cap (TRC). The real options approach is then used to value a revenue sharing contract with MRG and TRC options (Brandao and Saraiva, 2008). Quiggin (2005) stresses that the use of put and call options can add transparency and improve the risk allocation of PPP contracts because both parties will be protected from any substantial losses arising from contract disputes. Cerqueti and Ventura (2020) propose a stochastic optimization approach for designing concession contracts for oil production, designing them such that they are not only feasible, but also optimal. Silaghi and Sarkar (2021) analyze the optimal contract design of a PPP project within a real-options framework, taking into account incentive mechanisms to ensure effort exertion and optimal investment timing. Ashuri et al. (2010) argue that appropriate risk and reward sharing mechanisms are critical factors in the concessionaire entry decision and identify an optimal combination of MRG and TRC options for an effective risk and reward sharing strategy between the government and the concessionaire. We use the ROA in order to value the opportunity to enter and exit the risk sharing scheme from both the field operator's and contractor's perspective. The proposed "exit" clause resembles the MRG and TRC and allows the parties to partly hedge their risks and avoid a "contract disaster". We contribute to this strand of literature by introducing a least-squares Monte Carlo algorithm to optimize the contract policies for both parties under technical and market uncertainty.

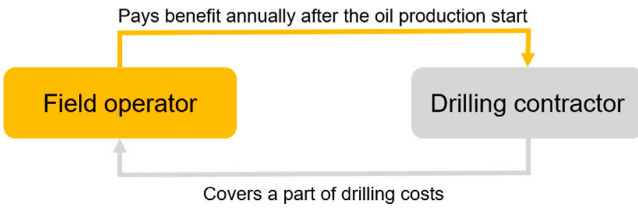


Fig. 1. Risk and benefit sharing scheme.

Table 1
Forms of the agreement between the field operator and the contractor.

Contract	Type of risk shared	Possibility to exit
Contract 1	No risk sharing (standard hiring agreement)	–
Contract 2	Production rate	No
Contract 3	Production rate and oil price (profit)	No
Contract 4	Production rate and oil price (profit)	Yes, both field operator and contractor

3. Modeling approach

3.1. Problem statement

In this paper, we study an investment problem faced by an E&P company, that can be regarded as a relatively small firm with a scarce portfolio. The investment opportunity in question is an offshore oil field, where the reserves are highly uncertain due to the limited potential to invest in an additional appraisal program. The prominent downside risk makes the field operator seek solutions that would enable it to transfer some part of the risk to other parties, whose risk attitude allows them to bear these additional risks in return for participation in the upside potential of the project.

The field operator faces the choice whether to enter a partnership with a third party under the classic development solution (industry standard hiring agreement), where all the risks and benefits are carried by the field operator itself, or to use one of the proposed risk and benefit sharing schemes. The risk and benefit sharing scheme is designed such that the contractor receives long-term incentives tied to the level of future hydrocarbon production or profits, in return for covering some portion of capital investment in the field development. Fig. 1 illustrates the relationship between the field operator and the drilling contractor that enters the risk and benefit sharing scheme by partly covering drilling costs.

The state-of-the-art drilling contracts such as day-rate and turnkey contracts often include various types of incentives, e.g., compensation for rapid progress. However, it remains challenging to tie incentives to more overarching parameters such as future production. Osmundsen et al. (2010) argue that it is difficult to design contracts that can perfectly distribute risks and benefits due to technical uncertainties. An incomplete contract is often exposed to renegotiation, which weakens incentives and limits contract opportunities (Osmundsen et al., 2010). As a result, we are looking for contract criteria that will ensure a fair division of risks and rewards by thoroughly assessing the impact of uncertainties on project values as faced by the field operator and the contractor.

First, we consider the perspective of the field operator. Its expected net present value, NPV_{FO}, under different contracts configurations is given by

$$NPV_{FO} = \sum_{t=t_0}^{T} \frac{\mathbb{E}\left[q_t p_t - CAPEX_t - OPEX_t - Benefit_t - Loan_t - TaxFO_t\right]}{(1+r)^t}, \quad (1)$$

where $\mathbb{E}$ denotes the expectation operator, q_t is the production rate in year t; q_t is the annual average oil price in year t; $CAPEX_t$ and $OPEX_t$ are capital and operational expenditures, respectively; $Benefit_t$ is the amount of annual benefit paid by the field operator to the contractor after the oil production start; $Loan_t$ is the amount of annual bank loan repayment; $TaxFO_t$ is the annual amount of tax paid by the field operator and r is the discount rate. We analyze and compare valuation results based on four contracting forms, which are summarized in Table 1.

The project value as seen by the field operator and the regulator is subject to two main uncertain factors: the oil price and the field production rate. Under the risk and benefit sharing, the contractor participates in production risk sharing in Contracts 2–4 and additionally shares oil price risk in Contracts 3 and 4. The proposed valuation procedure accounts for the impact of these uncertainties on contract design. For Contracts 1–3, a simple discounted cash flow (DCF) valuation procedure is used, because these contracts do not include any kind of flexibility. The DCF approach ignores the values of the embedded options, as it is based on a "static" view, in which the future decisions are assumed to depend only on the information available at present (Jafarizadeh and Bratvold, 2012). As opposed to the other contracts, Contract 4 contains an "exit" clause and, thus, requires different valuation tools. The contract policy optimization used to evaluate Contract 4 implies the use of real options analysis (ROA). The ROA allows to accurately capture the managerial ability to change the course of the project, taking in to account additional information that may be available at later stages. In contrast to DCF, the ROA can consider this flexibility and evaluate the additional value associated with it (Jafarizadeh and Bratvold, 2012).[4]

We analyze if using a contract with built-in flexibility (Contract 4) allows to avoid the hurdles stated by Osmundsen et al. (2010). Having the opportunity to withdraw from the incentive scheme can become an important instrument to conclude a contract that does not have to be renegotiated if the environment changes.

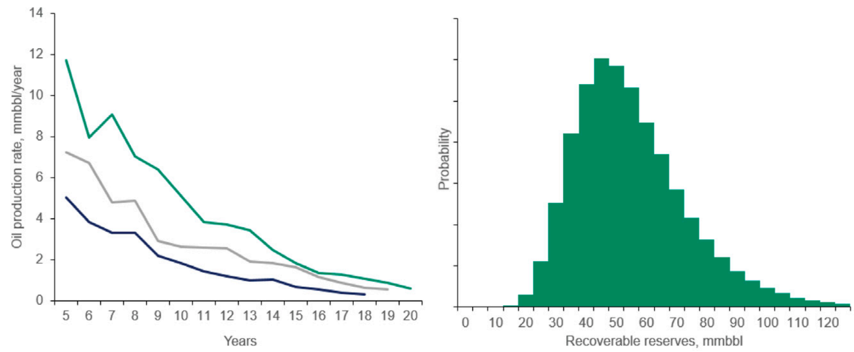
In what follows we also analyze the potential of all the proposed contract schemes from the contractor's perspective. Our goal is to design contracts that are attractive for all parties involved. This means that the risk and benefit sharing agreements should ensure that the contractor is compensated for additional unsystematic risk taken by the opportunity to participate in the upside potential of the project. The expected project net present value, NPV_{DC}, as viewed from the drilling contractor's perspective is given by

$$NPV_{DC} = \sum_{t=t_0}^{T} \frac{\mathbb{E}\left[Installment_t - DRILLEX_t + Benefit_t - TaxDC_t\right]}{(1+r)^t}, \quad (2)$$

where $Installment_t$ is the payment made by the field operator to the drilling contractor to cover the drilling costs (applies only to Contract 1 and includes contractor's margin); $DRILLEX_t$ is the actual cost of drilling of production and injection wells.

We also consider the regulator's perspective, whose goal is to ensure that all taxable revenues payable under the state-of-the-art conditions are also paid under the risk and benefit sharing. We ensure that the novel type of partnership does not disrupt the social benefits and does not allow any parties involved to avoid taxation. In order to do so, we design a tax neutral contract and verify that the level of tax paid is not decreasing under the risk and benefit sharing agreement. As we consider an offshore field on the NCS, we account for the Norwegian

[4] We refer to Jafarizadeh and Bratvold (2009), Guedes and Santos (2016) and Fedorov et al. (2021) for further comparison between the DCF and ROA and benefits of ROA for valuation of projects with flexibility.



(a) Oil production profile simulation examples **(b) Probability density function of the recoverable reserves**

Fig. 2. Reservoir uncertainty modeling.

tax policy, where a 56% special profit tax rate is effective. The project net present value, NPV_R, as viewed from the regulator's perspective is given by

$$NPV_R = \sum_{t=t_0}^{T} \frac{\mathbb{E}\left[TaxFO_t + TaxDC_t\right]}{(1+r)^t}. \tag{3}$$

In the following section, we present an approach to model cash flow components and present parameters used in our case study. These parameters can be straightforwardly changed to reflect characteristics of a different field development case, including production rates, costs, and tax regime.

3.2. Cash flow modeling

In this section, we first present a modeling approach to simulate field production profiles. We then discuss the oil price, costs and tax simulation. Note that all these parameters are kept unchanged in the different contract frameworks. The valuation of the proposed contracts is discussed in Section 3.3.

Production rate modeling. We follow the approach suggested in Fedorov et al. (2021) to model the technical uncertainty. We use the probability density function of the initial production rate of the field (in the first year of production) that is assumed to be provided by field engineers. The Monte Carlo simulation is then used to generate initial production rate samples in the whole range of the distribution. This allows us to capture the whole range of probable initial production rates of the field, rather than only discretized values representing "high", "medium" and "low" cases, as is typically done in decision analysis problems using decision trees. This gives a more accurate assessment of the impact of the reservoir uncertainty on the decision optimization. The proposed methodology can be easily adopted for other industry cases due to the fact that we specify neither an underlying reservoir model nor a design basis of the field development.

Based on the simulated samples for the initial production rates, we estimate the future production profile. The production rate is assumed to follow the general exponential equation (Fetkovich, 1980),

$$q_{i_t} = q_{i_{t-1}} e^{-a}, \tag{4}$$

where q_{i_t} is the production rate in year t, and a denotes the nominal decline rate.

Unlike Fedorov et al. (2021), we also account for the uncertainty in the decline factor. This results in a fluctuating production rate curve, that reflects potential increases or steeper than expected declines of the field production rate.

For our case study, we assume that the buildup phase takes four years, and oil production starts in Year 5. The oil field's initial production rate Q_0 (annual production at the first year of production) is assumed to be log-normally distributed $Q_0 \sim logN(\mu, \sigma^2)$, $\mu = 2.38$, $\sigma^2 = 0.25$. The Monte Carlo simulation is used to generate 10,000 samples of the initial production rate. Eq. (4) is then used to estimate production rate path until the field shut down for each of the simulated cases (see Fig. 2(a) for an example of production rate simulation). The nominal decline rate a is assumed to be normally distributed $a \sim \mathcal{N}(\mu, \sigma^2)$, $\mu = 0.225$, $\sigma^2 = 0.15$. This approach accounts for both the uncertainty in the recoverable volume and the depletion of the oil field. Fig. 2(b) illustrates the distribution of recoverable reserves based on the simulation.

Oil price modeling. In order to account for the oil price uncertainty, we model oil prices as a two-factor stochastic price process as proposed by Schwartz and Smith (2000). Based on the results in Fedorov et al. (2021), this price process allows capturing the oil price risk and probable developments of the future prices in a more realistic manner compared to simpler one-factor geometric Brownian motion (GBM) and mean reversion (MR) models.[5]

In Schwartz and Smith (2000)'s model the commodity price dynamics are described by the stochastic long-term ξ_t and short-term χ_t factors. The former is modeled as a Brownian motion with drift rate μ_ξ and volatility σ_ξ, while the latter is modeled as an Ornstein–Uhlenbeck process with the mean-reversion coefficient κ and volatility σ_χ.

The discretized risk-neutral versions of the two price process components are then used for Monte Carlo simulation to generate future price paths as given by

$$\xi_t^* = \xi_{t-1}^* + \mu_\xi^* \Delta t + \sigma_\xi \varepsilon_\xi \sqrt{\Delta t}. \tag{5}$$

$$\chi_t^* = \chi_{t-1}^* e^{-\kappa \Delta t} - (1 - e^{-\kappa \Delta t}) \frac{\lambda_\chi}{\kappa} + \sigma_\chi \varepsilon_\chi \sqrt{\frac{(1 - e^{-2\kappa \Delta t})}{2\kappa}}, \tag{6}$$

where ε_ξ and ε_χ in (5) and (6) are correlated standard normal random variables with the correlation coefficient denoted by $\rho_{\xi\chi}$.

We calibrate the oil price process parameters in (5) and (6) based on the historical market data by using the Kalman filter. We use the Refinitiv Eikon® data on the ICE Brent historical futures contracts and Dated Brent spot prices from March 2006 to June 2021. The resulting oil price process parameters are reported in Table 2.

Fig. 3 illustrates the confidence bands and expected value for the risk-neutral price process based on the 10,000 simulated paths. The thin colored lines represent examples of the simulated price paths used for our valuation procedure. The resulting expected (mean) price remains relatively stable from 2021 (Year 1 in our procedure) to 2040 (Year 20).

[5] We additionally refer to Al-Harthy (2007), Xu et al. (2012) and Bastian-Pinto et al. (2021) who perform a comparison between the above-mentioned price models for real options applications, including petroleum projects valuation.

Table 2
Calibrated parameter values used for the Schwartz–Smith two-factor price process simulation.

Parameter	Value	Std error	Parameter	Value	Std error
ξ_0	4.07	–	χ_0	0.1	–
σ_ξ	11.5%	0.005	σ_χ	56%	0.023
μ_ξ^*	−0.45%	0.001	$\rho_{\xi\chi}$	0.12	0.036
κ	0.45	0.006	λ_χ	10.9%	0.011

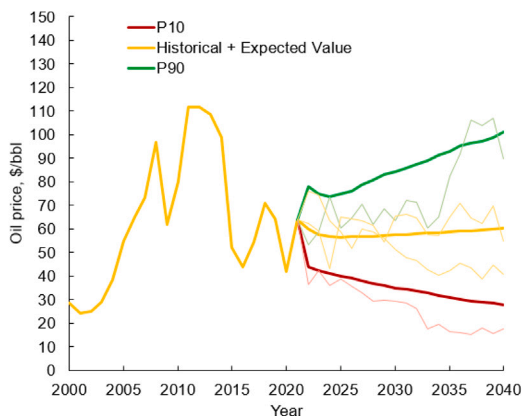


Fig. 3. Historical oil price and confidence bands resulting from simulation. (For interpretation of the references to color in this figure legend, the reader is referred to the web version of this article.)

Costs and abandonment. As we analyze the same field development case in all four contracts, cost components such as the cost of drilling production and injection wells, facility staffing and operations, fuel costs are the same in all the contracts. There are, however, different scenarios depending on who carries the costs and the source of their financing. Specific assumptions regarding the cost structure of each type of contract are used for illustrative purposes and can easily be adjusted to reflect configurations of different projects and contract parties.

When no risk and benefit sharing is used (Contract 1), the field operator is assumed to cover 50% of the drilling costs from its own funds, with the remaining 50% being financed by a bank loan for 5 years at 10% rate.[6] In Contracts 2–4, the field operator equally shares the drilling costs with the contractor, using only own funds to cover its half (see Table 3).

We account for the uncertainty in CAPEX, assuming that it can deviate by up to 15% from the expected value. This is the main source of uncertainty for contractors' project values. The average cost of drilling and including one oil production well in the production system is equal to 36 $ million. This value is assumed to be able to vary by up to 15%. Overall, six production wells are planned to be drilled to develop the discovery. The annual amount of CAPEX (with uncertainty) for the field operator under the standard agreement and the risk and benefit sharing schemes is reported in Table 4. The only difference occurs in Year 4, when wells are being drilled.

The OPEX are assumed to consist of a fixed (c_t) and a variable parameters, the latter of which depends on the yearly production rate of the field (q_t):

[6] The interest rate assumption is based on the information from our industry partner regarding the prevailing level of rates for risky petroleum projects in Norway. This estimate reflects the presence of strong capital market imperfections leading to high cost of bank loan financing for risky petroleum investment. We provide a sensitivity analysis on the interest rate in Section 4.3.

Table 3
Source of the drilling costs financing depending on the contract type.

Contract	Who covers drilling costs	Source of finance for drilling costs
Contract 1 (no risk sharing)	100% is covered by the operator	50% own funds, 50% bank loan
Contracts 2–4 (risk sharing)	Shared 50/50 with the contractor	Own funds

Table 4
Capital expenditure, $ million.

Contract	Year 1 (P10-EV (mean)-P90)	Year 2	Year 3	Year 4
Contract 1 (no risk sharing)	0.2–0.3–0.4	18–21–24	24–28–31	236–270–305
Contract 2–4 (risk sharing)	0.2–0.3–0.4	18–21–24	24–28–31	193–219–247

$$OPEX_t = c + dq_t + Lease_t, \tag{7}$$

where d is the coefficient, representing the relationship between the production rate and OPEX; $Lease_t$ is the production facility (Floating Production Storage and Offloading — FPSO) annual leasing rate. For our case study, c = \$84 million and d = 0.6. The field operator leases an FPSO at the stipulated rate that is not affected by the production rate. The lease rate for the first year of production is assumed to be fixed at \$108.4 million and then decreases annually by 25%.

We assume that production is ceased and the field is abandoned once the project cash flow reaches negative values owing to the reservoir depletion and/or oil price decline.

Taxes. An important factor that we have to account for is the tax system. Both the standard and the risk sharing agreements must comply with local taxation rules and ensure that all the taxes that would have been paid under state-of-the-art contracts are paid under the risk and benefit sharing contracts as well. In our case of an oil field offshore Norway, we build the contract terms in line with the system applied to companies operating on the NCS.

In principle, the Norwegian petroleum tax system is profit based. That is, company's net profit is taxable at 78% (of which 22% is the ordinary company tax rate – the contractor is subject only to this tax – and 56% is the special tax rate applied to oil companies). When the ordinary tax and special tax base is calculated, investments are written off using straight-line depreciation over six years from the year the expense was incurred. An extra deduction, called uplift, is used to calculate the special tax base. The uplift rate is set at 20.8% of the investments (5.2% per year). The system provides several incentives: consolidation between fields is allowed, taxable losses and unused uplift may be carried forward with interest, companies may apply for a refund of the tax. In June 2020, the Norwegian authorities introduced temporary changes in the petroleum taxation in order to help oil and gas companies execute their investment plans. In our model, we do not take these temporary changes into account.

The tax base for the field operator is calculated as follows:

$$\begin{aligned} Base\ for\ corporate\ tax(22\%)_t &= q_t p_t - Benefit_t - OPEX_t \\ &- CAPEX\ depreciation_t - d_t, \end{aligned} \tag{8}$$

where d_t are deficits from previous years.

$$Base\ for\ special\ tax(56\%)_t = Base\ for\ corporate\ tax(22\%)_t - Uplift_t - u_t, \quad (9)$$

where u is unused uplift from previous years.

3.3. Project valuation under different contract terms

In this section, we introduce methodology for project valuation under four different contract schemes. We calculate the project values under Contracts 1–3 based on a DCF approach, whereas for Contract 4, we use ROA. We apply the risk-neutral valuation procedure[7] to estimate the economic value of the project under Contract 4 in a consistent, from the methodological point of view, manner. In order to allow for a fair comparison between all contract schemes, we decide to use the same tool to evaluate Contracts 1–3 as well. In each case, we take the perspectives of the field operator, contractor and regulator.

We allow the contractor to ask for a compensation for additional risk taken under the risk and benefit sharing. In our case, we take a conservative approach by assuming that the contractor demands that the expected value (EV) of the project under the incentive scheme must exceed the EV under the standard agreement by at least 20%. This level is based on discussions with our industrial partners. However, different amounts of compensation can be tested using our model. This introduces an element of contractor's risk-aversion in the process of identifying parameters that balance the contract. Players' risk-aversion can be also introduced into the valuation procedure in a more explicit way by using certainty equivalents and/or utility functions (Smith and McCardle, 1999). More risk-averse contractors will require more compensation and have less incentives to engage in the risk-sharing contract. In Appendix B, we introduce an alternative valuation approach that accounts for the different attitudes of the decision makers to the downside and upside variability of project valuation results.

In our model, we make two important assumptions. First, we assume that there is no information asymmetry between the field operator and the contractors. This allows us to use a single representation of the oil production model and oil price process. Information asymmetry is presumed to be eliminated due to information sharing and due to the fact that the contractor has sufficient expertise in handling reservoir and oil price risk. This expertise is also important for avoiding adverse selection, which may occur if field operators offer only the riskiest projects for risk sharing. This assumption could be relaxed by introducing different representations of the reservoir risk as seen from the field operator's and the contractor's perspectives.

Second, all the proposed contract schemes are assumed to be complete. This allows us to calculate project values under different incentive schemes where the contract structure remains unchanged over the duration of the agreement and derive an optimal contract policy for the field operator and contractor. In reality, unforeseen events might appear, and renegotiation-proof contracts can be hard be achieved.

Overall, our model provides valuable insights as we demonstrate how contract terms and embedded flexibility affect the incentives to use the risk and benefit sharing scheme. We find a certain combination of the risk and benefit sharing contract terms that make the incentive contract attractive for the parties involved. The presented model can also be easily adapted to other types of partnership and project cases. In what follows, we provide details regarding each contract scheme analyzed in this study.

Contract 1: Standard agreement. The standard agreement implies that the field operator hires the contractor to perform drilling based on a day-rate contract, which may include some incentives that were described in Section 1. However, such an agreement does not imply that the contractor takes any part in the future production or the oil price risk.

We assume that the contractor's margin is 25%, meaning that out of \$100 million that the service company receives from the principal, \$75 million would be actual cost to perform drilling, while \$25 million is then contractor's gross profit.

After combining the simulated production and cost profiles as well as the trajectories for the oil prices based on the risk-neutral process, we generate project cash flows for the operator, the contractor and the regulator, and calculate respective NPVs using (1)–(3).

Contract 2: Production risk sharing. Contract 2 represents a simplest form of a risk and benefit sharing agreement. In return for participation in capital investment in the field development, the contractor is remunerated annually at the end of each calendar year based on the annual oil production rate of the field. The benefit amount is based on a simple formula as given by

$$Benefit_t = a + bq_t, \quad (10)$$

where q_t is the annual oil production rate in million bbl, a and b are coefficients, which in our case are chosen such that the expected value of the project for the contractor in Contract 2 is increased by 20% compared to Contract 1 in order to compensate the contractor for participating in risk and benefit sharing ($a = 0.15$, $b = 2.52$).

Contract 3: Production and oil price risk sharing (profit sharing). In Contract 3, the agent is entitled to a share in profits after petroleum tax, which means that apart from the production risk, it takes a part of the oil price risk. Clearly, such a contracting form requires careful analysis from the regulator and additional legal base, since an industrial enterprise represented by the drilling contractor in this case, in some sense, acts as an oil company, which is subject to a special tax and legal regime. Hence, by constructing the tax-neutral incentive scheme and checking that the regulator's NPV is not reduced, we provide foundation for future development of the legal base for such agreements.

In order to calculate the benefit that the field operator has to share, we must first determine the tax base for the special tax as it would have been without risk and benefit sharing.

$$\begin{aligned} &Base\ for\ special\ tax(only\ for\ benefit\ calculation) \\ &= q_t p_t - OPEX_t - CAPEX\ depreciation_t - d_t - Uplift_t - u_t \end{aligned} \quad (11)$$

Note that (11) is only used to calculate the benefit amount. The tax base for the settlement with the regulator will include the benefit amount as a cost component as given by (8) and (9).

We then calculate profit after special tax as follows

$$\begin{aligned} &Profit\ after\ special\ tax = q_t p_t - CAPEX_t - OPEX_t \\ &- 0.56 Base\ for\ special\ tax(56\%)_t. \end{aligned} \quad (12)$$

The benefit amount then equals

$$Benefit_t = s\ Profit\ after\ special\ tax_t, \quad (13)$$

where s is the share of profit stipulated in the risk and benefit sharing contract. Again, s is chosen to be 13.8% to satisfy contractor's requirements for taking additional risks (+20% of expected value compared to Contract 1).

Contract 4: Profit sharing with possibility to exit. The main concern that the participation in Contract 3 may bring to the parties is that they are both locked in the contract that has the potential to harm the partnership under unfavorable conditions. From the contractor's perspective, further participation in the risk and benefit sharing scheme becomes disadvantageous if reservoir properties prove to be inferior to what is expected, and/or the oil price plummets. From the field operator's perspective, higher than expected production rate and high oil prices mean that the benefit amount in absolute terms becomes too expensive. Therefore, we propose Contract 4 that includes all the

[7] This implies that it is possible to risk-adjust individual sources of risk that affect the cash flow (in our case, the oil price and the production rate), and then discount cash flows at the risk-free rate reflecting only time value of money.

features of Contract 3 with additional flexibility that allows both the field operator and the drilling contractor to withdraw from the risk and benefit sharing scheme within a stipulated period of time after the start of the oil production. By including the exit clause in the agreement, the contractor is confident that even in an unfavorable scenario they are able to recover most of the costs due to the compensation, which will never make such a partnership a "disaster" for them.

Exit clause. Once the drilling is complete and the oil field starts production, contract parties can observe the production level and oil market condition in order to decide whether they are interested in continuing the current partnership or whether it would be a better decision to terminate the agreement. We assume that the field operator can pay a certain amount of money to the contractor after the drilling is completed to avoid any liabilities in the future. The contractor, in turn, can exit the agreement and give up its share in production revenues by requesting a fixed compensation, which would largely cover the contractor's share in capital costs in the project. Such compensation mechanisms are often used in public–private partnerships, ensuring a reasonable rate of return for a concessionaire if the government wants to take over the project and operate it on its own (Xiong et al., 2016).[8]

The flexibility offered by the exit clause eliminates the need for contract renegotiation in the future, as neither the field operator nor the contractor are locked in the contract. This approach mitigates a problem that opportunities to renegotiate undermine the whole basis of the incentive scheme (Osmundsen et al., 2010; Alexander et al., 2012). In standard drilling contracts, where a contractor may be incentivized by additional bonuses for overperformance, the agreement is often renegotiated because the principal believes the contractor's bonus is too high.

In Contract 4, both parties have an option to exit for a certain number of years after the production start. Even in unfavorable current conditions they might decide to wait for another year in order to learn more. Thus, the contract policy optimization from both perspectives requires valuation of an American type option.

Valuation approach. We first start the analysis from the field operator's perspective in order to identify the simulation cases where it terminates the agreement by paying the compensation to the contractor, and optimize exit timing. Here, we apply the LSM method, introduced by Longstaff and Schwartz (2001). Based on a large number of cash flow samples, the optimization algorithm works in the backward fashion starting from the last decision point when the exit is possible. At each decision point t_n, the algorithm compares then present expected values of the "exit" decision, with the estimated value from the "remain in partnership until the end of next year" decision, and takes the maximum of the two for each simulated case. Both parameters are unknown as they are dependent on future oil prices and production rates, which are not observable for the decision maker at time t_n. However, we can estimate the expected values conditional on the current information regarding the oil price and the production rate. The LSM algorithm uses a linear regression to perform this estimation and identifies the optimal exit time. Further details on the implementation of the LSM algorithm are provided in Appendix D.

Once the optimal policy for the field operator is determined for each of the simulation paths, we review the contractor's optimal strategy to exit/remain in the partnership. By terminating the risk sharing agreement next year rather than now, the contractor receives its share in profit for the current year (based on oil prices and production rate that are known at that point in time) and a fixed compensation for exit next year (also known).

The optimization problem from the contractor's perspective is simpler. Here we compare the estimated value from the "remain in partnership until the end of next year" decision with a known amount of compensation that is associated with the decision to terminate the risk and benefit sharing.

Table 5
Exit compensation amount, risk and benefit sharing with the drilling contractor, million $.

	After the 1st	2nd	3rd	4th	5th
	year of production				
Field operator decides to exit and pays	196.7	141.6	102.0	73.4	52.9
Contractor decides to exit and receives	43.7	30.6	21.4	15.0	10.5

After optimizing exit policies of the two actors separately, we integrate them in order to build an accurate scenario for each of the simulated paths. Both the field operator and the contractor might be willing to exit the partnership within a single simulated scenario. The optimization from the contractor's side might indicate that it is optimal for them to exit after five years of production. In the meantime, the field operator's policy optimization might show that the field operator should terminate the agreement after the first year of production. Therefore, we make sure that the partnership terminates as soon as either of the parties initiates the exit, as this affects the future cash flows of both decision makers.

Implementation. We assume the project build-up phase to be four years. Oil production starts in Year 5 and at the end of that year (Y1 after the production start) both the field operator and the contractor can make the decision to terminate the risk and benefit sharing agreement for the first time. Both parties are assumed to hold the option to "exit" for the first five years after the production start. The LSM algorithm works backwards from Year 9 (Y5 after the production start) to Year 5 (Y1 after the production start), determining the timing when either the field operator or the contractor are willing to "exit" for each of the 10,000 simulation cases. We use a risk-free rate of 2.5% to discount cash flows within a risk-neutral valuation routine. We apply an iterative approach to design contract parameters such that:

- the contractor's expected value is 20% higher compared to the Contract 1;
- the risk and benefit sharing agreement holds until the field is shut down in approximately 50% of total simulation cases;
- the operator and the contractor have equal incentives to terminate the risk and benefit sharing early, i.e. the operator and the contractor initiate the exit in 25% of cases each;
- the compensation amount decreases gradually in order to keep the incentive either to exercise the option to exit or to wait to exit both for the operator and the contractor.

This is done to create symmetric conditions for the field operator and the contractor, providing equal opportunities to maintain the partnership until the field shut down and use the "exit" clause. These assumptions also allow easier and more transparent comparison of different contract schemes. Fixing these parameters also allows the sensitivity analysis on the contract terms to be performed.

In order to ensure that all the above mentioned conditions are fulfilled, the following parameters for the risk and benefit sharing contract must hold in our field development case: the field operator shares 15.26% of profit after special (56%) tax. The amount of compensation for the contractor is $196.7 million in case the field operator triggers the exit after the first year and $43.7 million in case the decision to exit is made by the contractor. The amount is decreasing annually by 28% in the former case and by 30% in the latter case as shown in Table 5.

Based on the optimization for each simulated case, we calculate the values of the investment opportunity for all the parties in order to see what impact the contract with flexibility has, compared to other schemes.

[8] Additional details regarding the compensation mechanism are provided in Appendix C.

Table 6
Project values for the field operator (after tax), $ million.

	P10	P50	EV (mean)	P90
Contract 1 (no risk sharing)	−30	177	223	533
Contract 2 (production risk sharing)	5	183	233	526
Contract 3 (profit sharing)	11	186	233	515
Contract 4 (profit sharing+exit)	10	184	233	520

Table 7
Project values for the drilling contractor (after tax), $ million.

	P10	P50	EV (mean)	P90
Contract 1 (no risk sharing)	25	39	39	53
Contract 2 (production risk sharing)	9	43	47	89
Contract 3 (profit sharing)	−5	35	47	110
Contract 4 (profit sharing+exit)	1	44	47	97

Table 8
Amount of tax received by the regulator, $ million.

	P10	P50	EV (mean)	P90
Contract 1 (no risk sharing)	−20	601	791	1828
Contract 2 (production risk sharing)	26	647	830	1855
Contract 3 (profit sharing)	36	652	827	1829
Contract 4 (profit sharing+exit)	36	647	828	1840

4. Results

Section 4.1 presents the results of the economic valuation of the project under the four contract schemes from three perspectives: the field operator, the contractor and the regulator. Section 4.2 presents decision rules obtained when performing contract policy optimization using the real options analysis in Contract 4. In Section 4.3, we perform the sensitivity analysis, testing the main assumptions made in this study. Additionally, in Appendix B, we address the fact that the decision makers can have different risk attitudes to the downside and upside variability of the project value uncertainty. There, we present valuation results adjusted for the field operator's and contractor's risk attitudes.

4.1. Valuation results

Tables 6–8 summarize the results of the project valuation under the different contract schemes. The project value distribution is characterized by the 10th, 50th and 90th percentiles as well as by the expected value.

Table 6 shows that under all forms of the risk sharing agreement, the field operator is able to slightly increase the expected value of the investment opportunity compared to the standard agreement. The main reason for this is that the operator can avoid lending capital from a bank to cover 50% of the drilling costs.[9]

Despite a higher expected value, the upside potential of the project (represented by the P90 value) under the risk and benefit sharing becomes more limited. This is because the field operator has to comply with its obligation to share a portion of profit after special tax amid high oil prices or to pay large compensation in case of the early termination of Contract 4. However, the field operator sacrifices its upside potential in order to have an opportunity to decrease exposure to downside risks, as all types of analyzed risk sharing contracts can substantially increase the P10 value compared to Contract 1. This is the main benefit of the risk sharing agreement for the field operator.

Despite different contract structures, all forms of risk and benefit sharing have the same expected value for the field operator. The main difference between Contracts 2, 3 and 4 is the degree of the field operator's exposure to the downside risk and ability to realize the upside potential. Comparing Contract 2 and Contract 3, we can see that sharing not only the production risk, but also the oil price risk in Contract 3, reduces both the lower and upper variability of the project economy. However, losing a significant part of the upside potential can outweigh the possibility to mitigate the downside risk for some decision makers. Contract 4 provides the means to better balance the distribution of low and high returns. The introduction of the exit clause gives the operator enough flexibility to secure the participation in the upside potential compared to Contract 3, while still reducing the exposure to the downside risk compared to Contract 2. Adjusting such parameters as the amount of benefit to be shared and/or the amount of compensation to exit, the parties can redistribute the value surplus. However, the contractor's risk-aversion might be high enough to access this surplus as insufficient to compensate for the risk of participation in the risk and benefit sharing.

[9] We perform a sensitivity analysis in Section 4.3 to analyze how the changes in the bank loan interest rate affect the ability of the Contract 4 to increase the project value for the operator.

Results in Table 7 show that Contracts 2–4 satisfy the contractor's requirement to increase the EV by 20% compared to Contract 1. In fact, the additional value created for the field operator would be larger than shown in Table 6 if the contractor was willing to accept a lower compensation for additional risks. We can also see that the risk sharing schemes make the revenues of the contractor more uncertain compared to the standard agreement. However, in unfavorable scenarios, under Contracts 2 and 4, the contractor has a very low chance to end up with negative returns. In Contract 3, the contractor is relatively more exposed to both domains of uncertainty. In this case, using Contract 4 with flexibility to exit achieves a better balance between the downside risk and the upside potential of the project for the contractor. The compensation that the contractor receives when it terminates the agreement in unfavorable scenarios allows achieving a positive NPV in 67% of simulated cases. Moreover, the average project NPV for the contractor in those cases, where the field operator triggers the exit, is $89 million, which is more than twice as large as that under Contract 1. Therefore, including the possibility to exit for the field operator does not significantly reduce the attractiveness of the scheme for the contractor, while at the same time enables it to participate in the upside potential of the project.

An additional long-term incentive for the drilling contractor, which is created by the risk sharing, might lead to an increase in the production rate and a longer production phase. In fact, close integration between the field operator and the contractor is expected to lead to new information from the formation making it desirable to adjust the original plan in order to achieve optimal drainage. The financial importance of such changes can far outweigh other considerations, including a desire to minimize drilling costs. However, we do not account for these factors in order to allow for fair comparison between the schemes based on economic effects only.

Table 8 shows that the regulator is among the beneficiaries of the risk and benefit sharing. The main reason for that is the depreciation effect on the tax values of the investments that the operator writes off using straight-line depreciation. In case of the standard agreement, the field operator writes off 100% of drilling expenses over six years from the year the expense was incurred (Year 4 in our case). In case of the risk and benefit sharing, the operator writes off only 50% of drilling costs, but has an additional cost component — the benefit paid to the contractor. This makes the tax base slightly higher in the short term, but lower in the long term. The project economy as seen by the regulator under Contracts 2–4 does not differ much in terms of the expected value. Despite different estimates for P10 and P90 values, the regulator's downside or upside variability does not change much compared to Contract 1. As we do not consider the regulator to be an active player aiming to maximize its monetary value in the contract negotiation process, Contracts 2–4 can be regarded as equally beneficial for the authorities.

In Appendix B, we perform valuation of the different contract schemes accounting for risk attitudes to uncertainty in losses and to uncertainty in gains both from the field operator's and the contractor's perspective. There we evaluate how different risk attitudes affect optimal contract choice.

4.2. Decision policy rule for the exit option

The project values in Contract 4 (and Contract 4a that is discussed in Appendix B) are derived after optimizing the contract policy both for the operator and the contractor that hold an option to terminate the partnership. Fig. 4 illustrates the optimal contract policy after the first year of field production for each of the simulated cases depending on the oil price and the production rate of the field. These results confirm our intuition regarding the incentives to exit. The field operator initiates the exit when it anticipates that it is better to pay a compensation to the contractor, rather than share the profit. This might happen when oil prices are high and/or the production rate is higher than expected. The contractor, in contrast, exits when oil prices or production are unfavorable.

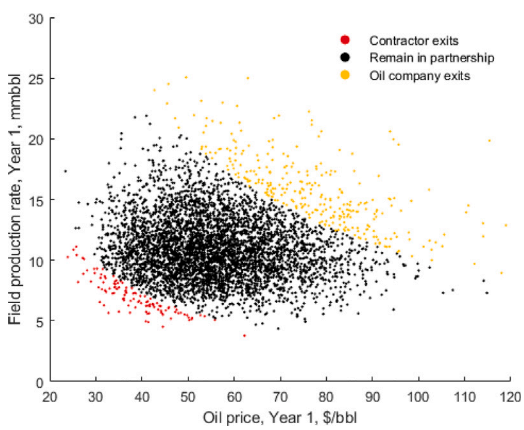


Fig. 4. Optimal contract policy.

The realized contract policies in all simulation paths using the LSM algorithm allow us to see what oil prices and what production rates trigger the "exit" decision in each year. Fig. 5 illustrates the realization of the optimal option policy for all the simulated cases in each year when early termination of the risk and benefit sharing scheme is possible. The decision to exit is directly dictated by the then-current state of the oil price and the production rate. We can conclude that at each decision point between the end of the first and the fifth year after production starts both parties have pretty clear boundaries representing the combination of oil price and production level which can possibly trigger the termination of the risk sharing scheme. If the combination of the two parameters is above the threshold (falls in the stopping region), the optimal decision is to withdraw from the risk and benefit sharing and pay the compensation to the contractor. For instance, if the average oil price throughout the first year of production is above 70 $/bbl and the production rate exceeds 15 million bbl, the optimal decision is to exit from the agreement. If the oil price and production rate combination is below the boundary (falls in the continuation region), the value of waiting is higher that an immediate exercise and the operator, therefore, should wait until the next decision point and reevaluate the decision based on the updated oil price and production rate. If at the last decision point, after five years of production, the oil price and production rate are still below the threshold, the operator gives up the option to exit and remains in the partnership, sharing the profits from oil production until the field shut down. As shown in Fig. 5(f), the threshold boundary shifts to the lower left corner with every next year, meaning that lower oil prices and lower production rates can trigger early termination of the risk and benefit sharing in the future.

As mentioned in Section 3.3, the parameters of Contract 4 were selected such that (1) in 50% of simulated cases the partnership holds until the field shut down; (2) the field operator and the contractor have equal incentives to terminate the risk and benefit sharing scheme early. Fig. 6(a) illustrates that based on the simulation with given contract terms, the optimal contract policy from operator's perspective is to remain in the risk and benefit sharing agreement until the field shut down in 75.0% of total simulated cases, while in 6.0% realizations the optimal decision is to withdraw after the first year of production, in 3.1% of cases — after the second year, in 3.2% of cases — after the

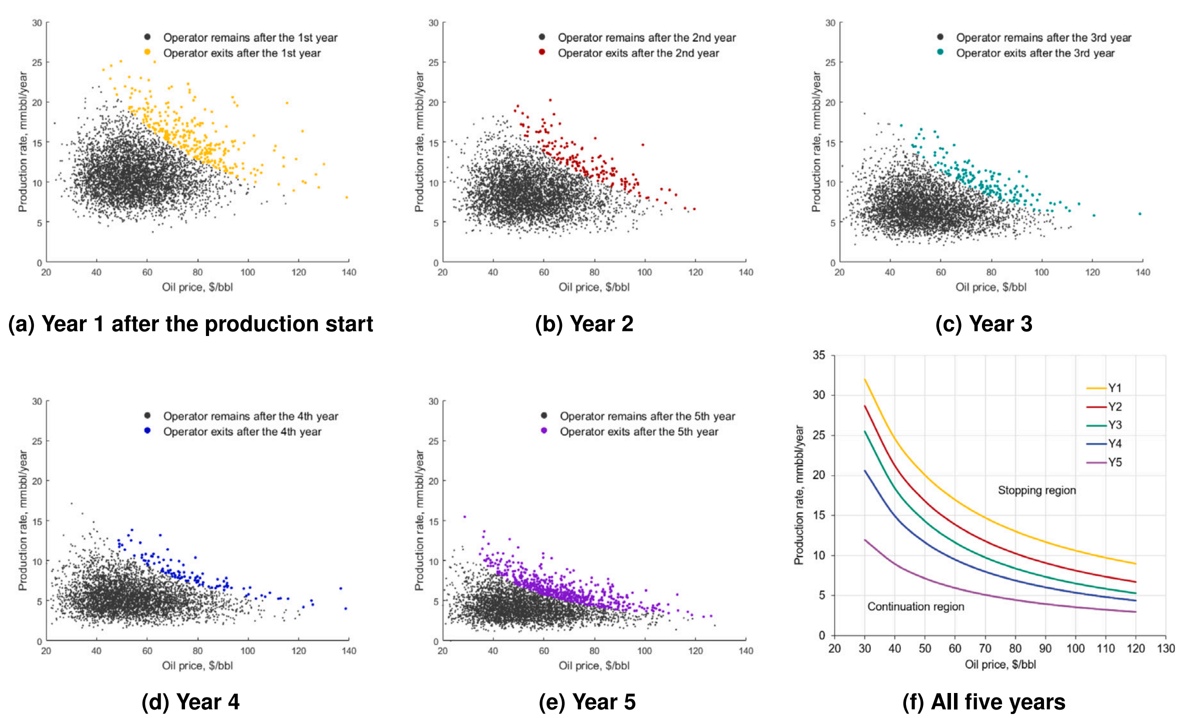


Fig. 5. Exercise boundaries, field operator.

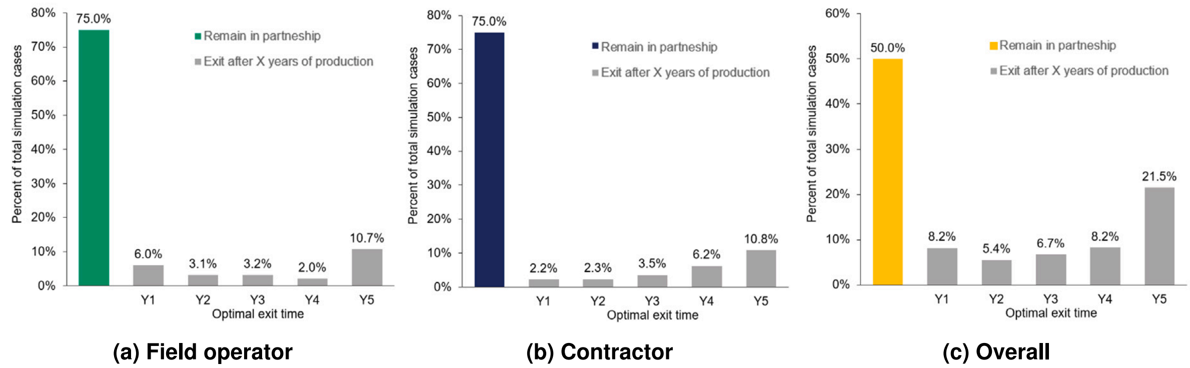


Fig. 6. Optimal contract policy.

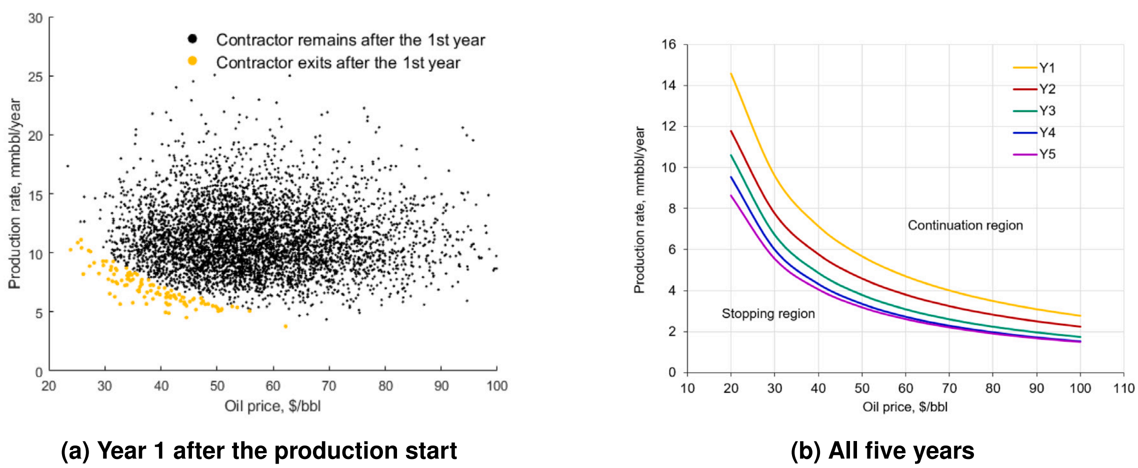


Fig. 7. Exercise boundaries, contractor.

third year, in 2.0% of cases — after the fourth year and in 10.7% after the fifth year.

The same analysis can be performed from the contractor's perspective. Fig. 7 illustrates the threshold boundaries. The difference with the boundaries in Fig. 5 is that the stopping region for the contractor is below the threshold, while the continuation region is above it. Similarly to the results for the operator, the boundary is shifting to the lower left corner each year.

Fig. 6(b) shows that, as for the operator, the contractor triggers the termination of the risk and benefit sharing scheme in 25.0% of the total simulated cases, while in 75.0% of cases the optimal policy is to remain in the partnership.

After optimizing exit policies of the two actors separately, we integrate them. Fig. 6(c) shows the results of exit policy optimization taking in to account the decisions of both parties.

4.3. Sensitivity analysis

Fig. 8 illustrates the sensitivity of the project value under the standard hiring agreement to changes of the bank loan interest rate. The value added by the risk and benefit sharing in Contract 4 if the field operator can get a zero-interest loan reduces from 4.4% to 0.8%. This indicates that our assumption regarding the bank loan interest rate reflects the presence of imperfections in capital markets that advise the field operator to use alternative sources of financing than the bank loan. The prominent reservoir uncertainty in our case is the main cause of the high interest rate. Our results imply that strong information asymmetries between oil companies and investors/lenders resulting from the fact that the latter have less knowledge about the future production risks, leaves room for such sources of financing of E&P

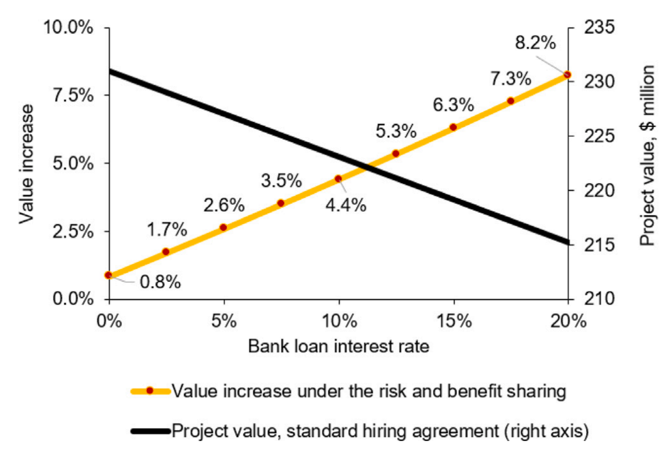


Fig. 8. Project value under the standard hiring agreement depending on the bank loan interest rate.

projects as risk and benefit sharing. In that sense our analysis also finds under which conditions the risk and benefit sharing becomes more beneficial. As presented in Fig. 8, even if the field operator has an access to cheap financing, there is still a monetary benefit of the risk and benefit sharing agreement for the field operator. In this case, the additional value is created only due to redistributing cash flows and tax in time as shown in Fig. 9.

In the base case we assume that the field operator and the contractor share the drilling costs equally. Fig. 10 illustrates how the terms of Contract 4 (share of profit after special tax to be paid to the contractor

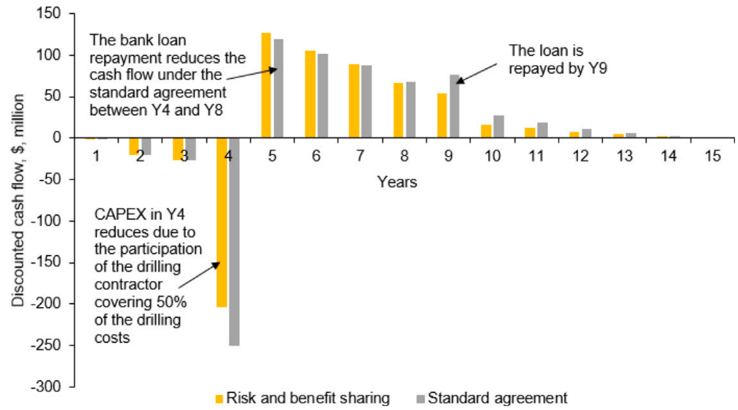


Fig. 9. Expected (mean) net project cash flows for the field operator.

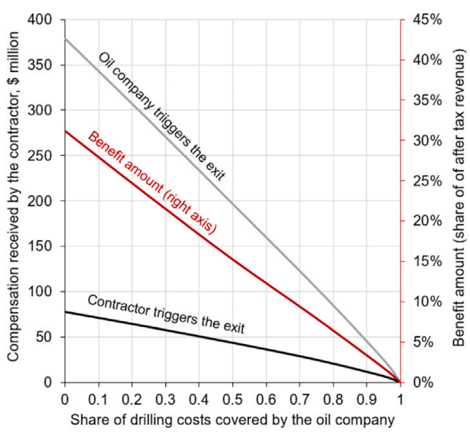


Fig. 10. Contract parameters depending on the share of drilling costs covered by the field operator.

and amount of compensation to exit) must be changed to keep it balanced as shown in Tables 6–8 and Figs. 6(a)–6(c). The more the portion of the drilling costs covered by the contractor is, the more benefit (percent of after tax profit) must be shared by the field operator and the more compensation amounts to exit are, and vice versa.

5. Conclusion

Recent developments in the upstream oil market create challenges that can be regarded as opportunities for innovation in the agreements used between field operators and their contractors. In this paper, we propose risk and benefit sharing contracts as an instrument that can be especially beneficial for smaller oil companies due to their willingness to attract external expertise, sensitivity to the downside risks and higher cost of capital. Depending on the problem at hand and the sources of financing that are used, establishing the risk and benefit sharing scheme might also benefit other main players involved: contractors and the regulator. The incentive scheme can also promote long-term relationships between the parties involved, benefiting innovation in the supply chain, increasing efficiency and prolonging the field lifetime due to more active information sharing, trust and mutual incentives.

Using the synthetic field development case and the “layered” approach, we gradually introduce complexity into the risk and benefit sharing scheme to compare resulting project values under four different contracts. Even under weak market imperfections and the absence of information asymmetries between the field operator and the contractor, we find that the incentive contract value can be beneficial. The built-in flexibility to exit the incentive scheme also allows for better balancing the project outcomes between the parties. Moreover, we show how contract terms can be tuned to make it attractive for the operator and the contractor depending on their attitudes to the downside and the upside variability of the project.

The uptake of risk and benefit sharing in the future will also depend on the willingness of contractors to develop their expertise in the overall field development process and readiness to accept additional risks and extend their traditional business models. Our analysis can help oil companies and their contractors to estimate the value of embedded flexibility and facilitate the uptake of risk and benefit sharing.

The proposed partnership schemes are unlikely to become a disruptive business model due to the presence of unsystematic risk for contractors. However, the risk and benefit sharing can be considered for portfolios of large drilling and service companies, FPSO leasing companies and other oil and gas contractors, where risks can be diversified between risky (and smaller) and deep-in-the-money projects.

Our framework can be also utilized to find optimal contract terms with flexibility in other problem settings. Possible extensions of our research include addressing the presence of information asymmetries between the parties, self-interest and principal–agent problems, including the risk of adverse selection. Also, comparing the performance of different contract schemes and types of partnerships (integrated contracts, alliances, etc.) in achieving fair risk and benefit distribution can be matters of considerable interest.

CRediT authorship contribution statement

Semyon Fedorov: Conceptualization, Methodology, Software, Data curation, Visualization, Writing – original draft, Writing – review & editing. **Maria Lavrutich:** Conceptualization, Methodology, Writing – original draft. **Verena Hagspiel:** Conceptualization, Methodology, Supervision, Reviewing and editing, Data curation. **Thomas Lerdahl:** Conceptualization, Supervision, Reviewing and editing, Data curation.

Appendix A. An existing case of risk and benefit sharing on the ncs

The only case of risk and benefit sharing on the NCS documented in the literature (by Børve et al., 2017) dates back to 2003, when a then-recently founded Norwegian company with 6 employees, Pertra, acquired a 70% operated working interest in the Varg field in the Norwegian North Sea. Pertra was highly motivated to prolong the lifetime of this brown field by postponing production shutdown, which was already approved by the authorities. They initiated a new drilling program that resulted in a significantly improved representation of the reservoir and new understanding of the field properties. Maersk, a drilling rig owner and operator, provided drilling rigs, while Halliburton provided a full range of drilling services. Both contractors received a compensation as a tariff per produced barrel (Norwegian Petroleum Directorate, 2003). Such a contract, where service companies participated in the field development and shared the reservoir risks with the field operator in return for the possibility to benefit from the upside, represented an entirely new arrangement on the NCS (Osmundsen et al., 2010). This was the reason why considerable effort was invested in evaluating contractual scenarios. The risk sharing scheme allowed the utilization of novel drilling tools provided by Halliburton that would be too expensive for a company such as Pertra if a standard hiring agreement was used. The Norwegian Petroleum Directorate advised the parties to systematically analyze the consequences of the incentive mechanism in unexpected scenarios like accidents, bankruptcy and mergers. Overall, the incentive-based partnering project resulted in finding an additional 40 million barrels of oil reserves that allowed the field life to be extended to July 2016 (Børve et al., 2017). Despite the favorable results, the collaboration ended relatively soon after its start because the incentive amount that Pertra had to pay to the contractors became unreasonably high. This was caused by the fact that additional reserves found were much larger than expected. Moreover, Pertra was sold to Talisman Energy in early 2005. This fact highlights the importance of having clearly stated options to react to the outcome of uncertainty built into the contract. Despite the fact that both contractors indicated interest in future collaboration, this scheme was not applied to new projects.

Appendix B. Valuation results under different risk preferences

The results presented in Section 4.1 can lead to the conclusion that all presented forms of the risk and benefit sharing outperform Contract 1 from the field operator's perspective. However, as already mentioned, the upside potential in Contracts 2–4 is reduced compared to Contract 1. Therefore, a decision maker that does not focus on the downside risk mitigation, but values the chance to exploit the upside potential, might see participation in the risk and benefit sharing as an inferior strategy. In order to derive a single measure that can lead to a clearer comparison between the valuation results in four contract cases, we follow an approach presented in Santos et al. (2017). This approach adjusts the derived project values to the decision maker's attitude to uncertainty in losses (aversion to downside risk) and to uncertainty in gains (expectation of upside potential).

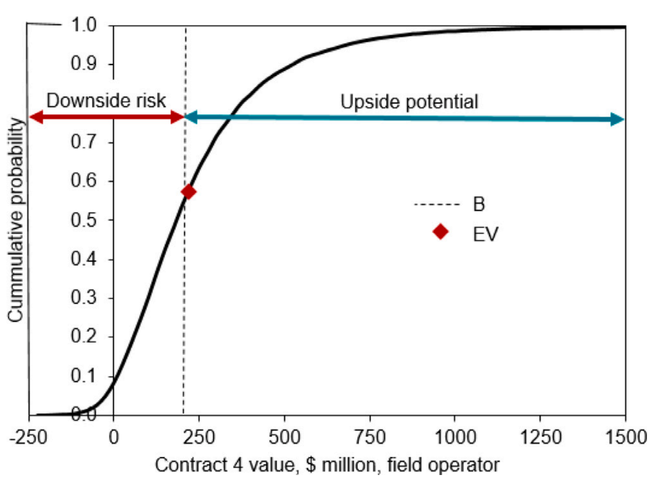


Fig. 11. Downside risk and upside potential of Contract 4, field operator, based on an idea by Santos et al. (2017).

Santos et al. (2017) suggest that project value variability below a targeted or benchmark return (B) is regarded as a downside risk, while variability above B is considered to be an upside potential. We assume that, in our case, the expected project values under the standard agreement (Contract 1) as seen from the field operator's and contractor's perspectives are benchmarks for the field operator B_{FO} and the contractor B_{DC}, respectively. Fig. 11 illustrates how the field operator's project value risk curve under the Contract 4 is divided into two domains: (i) the downside risk or uncertainty in losses, i.e., the undesirable domain of uncertainty, which is below B_{FO} = \$223 million and (ii) the upside potential or uncertainty in gains, i.e., the optimistic tail of the risk curve above B_{FO}.

To estimate the value of a project adjusted to the decision maker's attitude (Santos et al., 2017) propose the following objective-function:

$$\epsilon(NPV) = EV - \frac{S^2_{B-}}{\tau_{dr}} + \frac{S^2_{B+}}{\tau_{up}}, \tag{14}$$

where $\epsilon(NPV)$ is the economic value of the project adjusted for the decision maker's attitude; EV is the expected value of the project for the risk-neutral decision maker; S_{B-} and S_{B+} are the lower and upper semi-variance from the benchmark B, respectively; and τ_{dr} and τ_{up} are the strictly positive tolerance (or indifference) levels to downside risk and to upside potential, respectively.

$$S^2_{B-} = \mathbb{E}\{min[(NPV - B), 0]^2\} \tag{15}$$

$$S^2_{B+} = \mathbb{E}\{max[(NPV - B), 0]^2\} \tag{16}$$

In (14), the lower semi-variance decreases the EV, while the upper semi-variance increases it, in accordance with the risk in the project and the decision maker's tolerance of it. $\tau_{dr} \rightarrow 0$ implies aversion towards the downside risk, while $\tau_{up} \rightarrow \infty$ implies risk neutrality. $\tau_{up} \rightarrow 0$ implies that the decision maker places a high value on the upside potential, while $\tau_{up} \rightarrow \infty$ implies that the decision maker is indifferent to high returns. When $\tau_{up} \rightarrow \infty$ and $\tau_{up} \rightarrow \infty$, decisions are based on EV.

Assigning values for τ_{dr} and τ_{up} is an important task that can significantly affect the valuation results. Santos et al. (2017) use subjective estimates for these parameters, assuming that the decision maker can precisely estimate his/her attitude to two different variabilities of the project value. We take a conservative approach by testing different possible combinations of τ_{dr} and τ_{up} both for the field operator and for the drilling contractor, motivating this choice by the difficulty of obtaining such an estimate from industrial decision makers. This approach also demonstrates the sensitivity of the project value adjustment to the decision maker's attitudes. In general, τ_{dr} and τ_{up} below B mean that the decision maker is sensitive to both types of variability. The more τ_{dr} and τ_{up} exceed B, the more the decision maker is indifferent to either the downside risk or the upside potential. If $\tau_{dr} < \tau_{up}$, then the decision maker is more sensitive to the undesirable domain of uncertainty, and vice versa.

We build a set of possible τ_{dr} and τ_{up} in the range $0.3B_{FO}$ - $2.5B_{FO}$ for the field operator and $0.3B_{DC}$ - $2.5B_{DC}$ for the drilling contractor and calculate $\epsilon(NPV)$ for both parties. Fig. 12(a) illustrates valuation results of Contract 1 for the field operator, while Fig. 12(b) shows adjusted values for the drilling contractor. The results demonstrate that the field operator's $\epsilon(NPV)$ is sensitive to the choice of τ_{dr} and τ_{up}. For a field operator that has much more focus on the downside risk mitigation (low τ_{dr}), rather than on exploiting the upside potential (high τ_{up}), the economy of the project becomes marginal. The contractor's adjusted project value is less sensitive to the choice of τ_{dr} and τ_{up}. However, the general attitude to the contract is the same as in the case of the field operator: the value is reduced when the decision maker is much more sensitive to low returns.

Next, we investigate how the use of risk and benefit sharing schemes affects the valuation results when accounting for the parties' attitudes to two domains of uncertainty. Figs. 13(a) and 13(b) illustrate the difference between $\epsilon(NPV)'s$ of Contract 2 and Contract 1 for the field operator and the drilling contractor, respectively. As can be seen, for most of the combinations of τ_{dr} and τ_{up} for both players, the simplest form of risk and benefit sharing is more beneficial than the standard

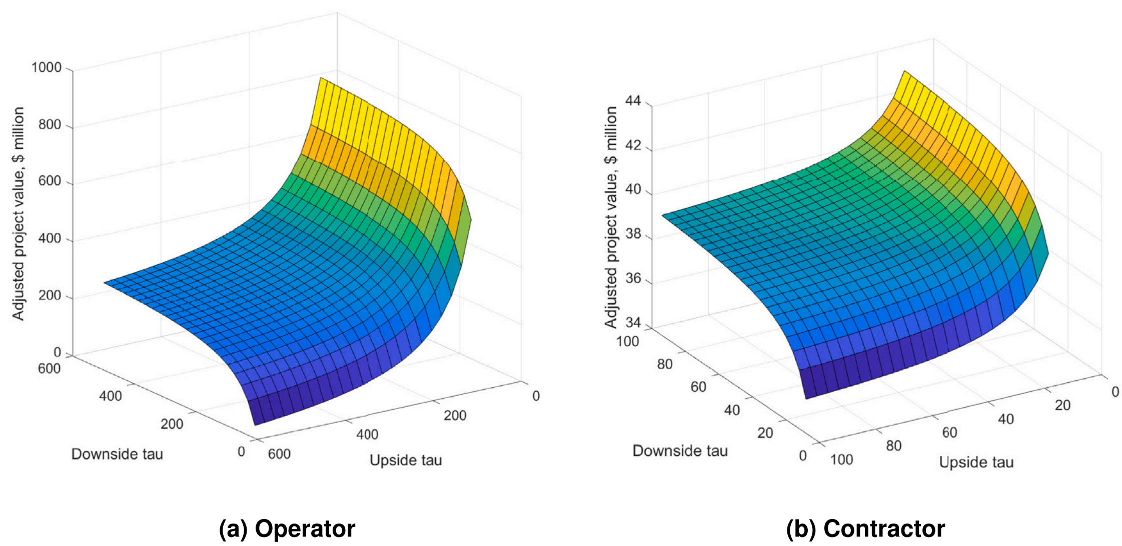


Fig. 12. Risk-adjusted project value in Contract 1.

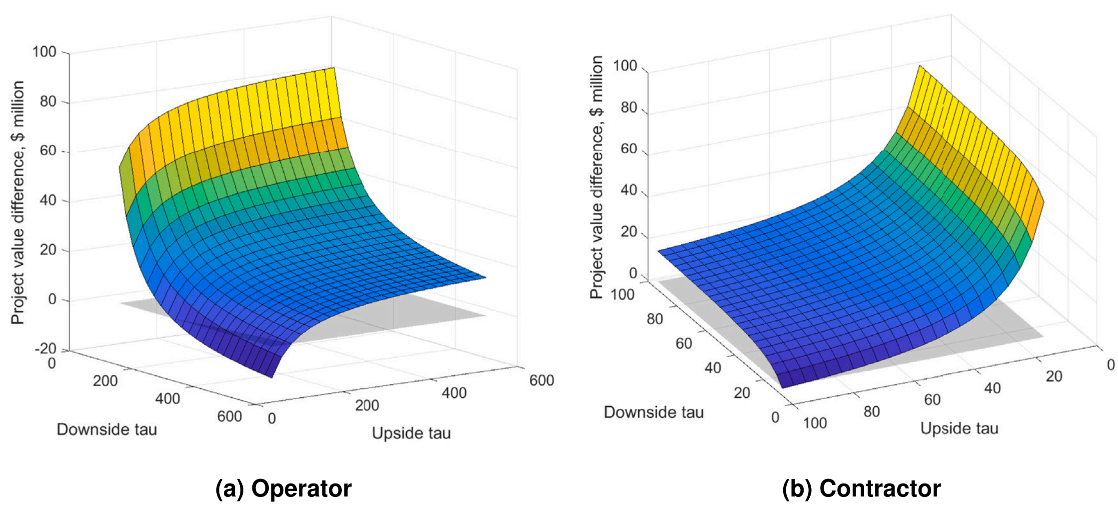


Fig. 13. Difference between risk-adjusted project values in Contract 2 and Contract 1.

agreement. Contract 1 is more attractive only for a field operator with a very strong preference towards exploiting the upside potential (low τ_{up}), while being almost completely insensitive to the presence of the downside risk (high τ_{dr}). This is because under Contract 2 the field operator has to share the upside of the oil production uncertainty. In contrast, only those contractors who are focused mainly on the downside risk mitigation would prefer Contract 1 because of the additional risks associated with the participation in Contract 2.

Figs. 14(a) and 14(b) show the difference between adjusted project values of Contract 3 and Contract 2. Contract 3 proves to be less beneficial for the field operator in most of the cases because a significant part of the upside potential is shared with the contractor. Only a field operator who places much importance on avoiding low outcomes and is relatively insensitive to high returns would be interested in Contract 3. For most the combinations of τ_{dr} and τ_{up}, the potential of participation in the upside potential of the project outweighs a much higher exposure to the downside risk under Contract 3 for the contractor. Again, only strictly risk-averse contractors would prefer Contract 2.

Figs. 15(a) and 15(b) illustrate the adjusted values difference between Contract 4 and 3. We can conclude that under terms underlying Contract 4, it is highly beneficial for the operator, but not for the contractor.

However, as mentioned earlier, the contract parameters can be tuned in order to redistribute value surplus from the operator to the contractor to make Contract 4 more attractive for some combinations of the contractor's τ_{dr} and τ_{up}. This can be done, for example, by increasing the benefit amount from 15.26% to 17% and by adjusting the exit compensation amounts after the first year of production to $219 million if the field operator triggers the exit and to $49 million if the contractor initiates the withdrawal. Under these conditions, the EV for the risk-neutral contractor will be increased to $57 million, while operator's EV is reduced to $230 million. We refer to this adjusted contract as Contract 4a. Figs. 16(a) and 16(b) illustrate the difference in project valuations under Contract 4a compared to Contract 3. Under new conditions, there are feasible combinations of risk attitudes that make Contract 4a more beneficial. However, for the field operator that seeks to reduce exposure to the downside risk without placing importance on the upside potential, Contract 3 would still be a better option. From the contractor's perspective, Contract 3 remains more beneficial for those decision makers that focus more on the participation in the upside potential.

Overall, by performing the analysis of the project values adjusted for parties' attitudes to two domains of uncertainty based on different combinations of τ_{dr} and τ_{up}, we extend the approach proposed

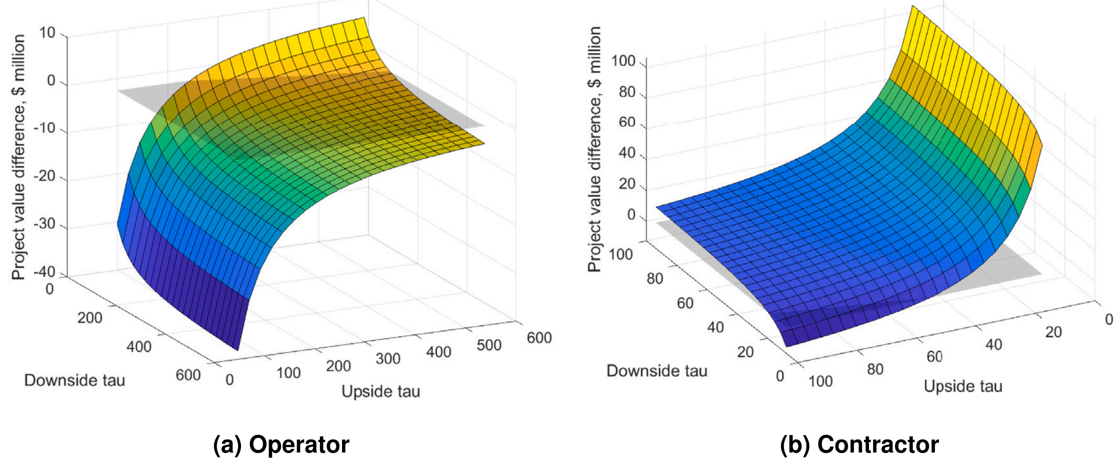


Fig. 14. Difference between risk-adjusted project values in Contract 3 and Contract 2.

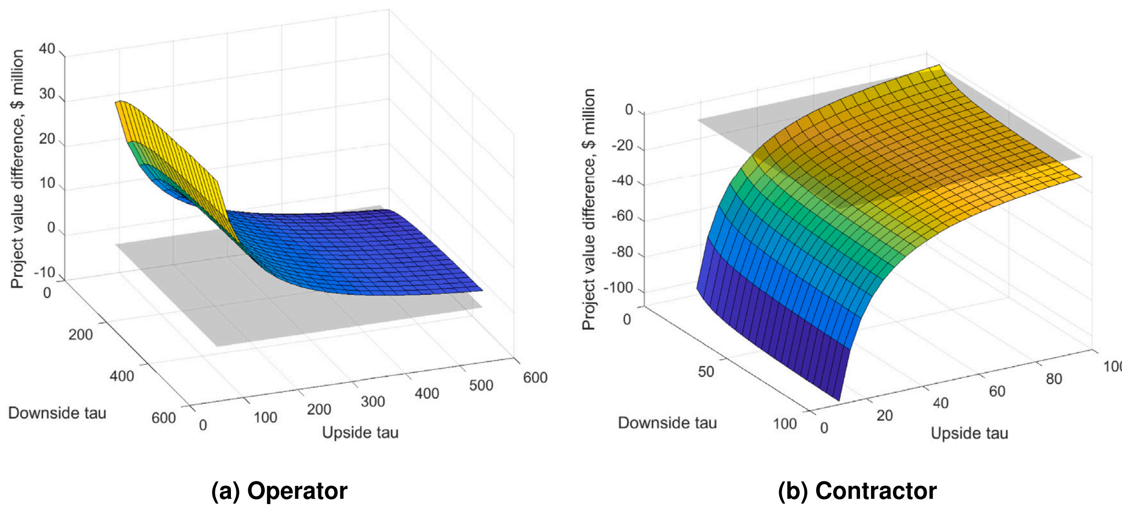


Fig. 15. Difference between risk-adjusted project values in Contract 4 and Contract 3.

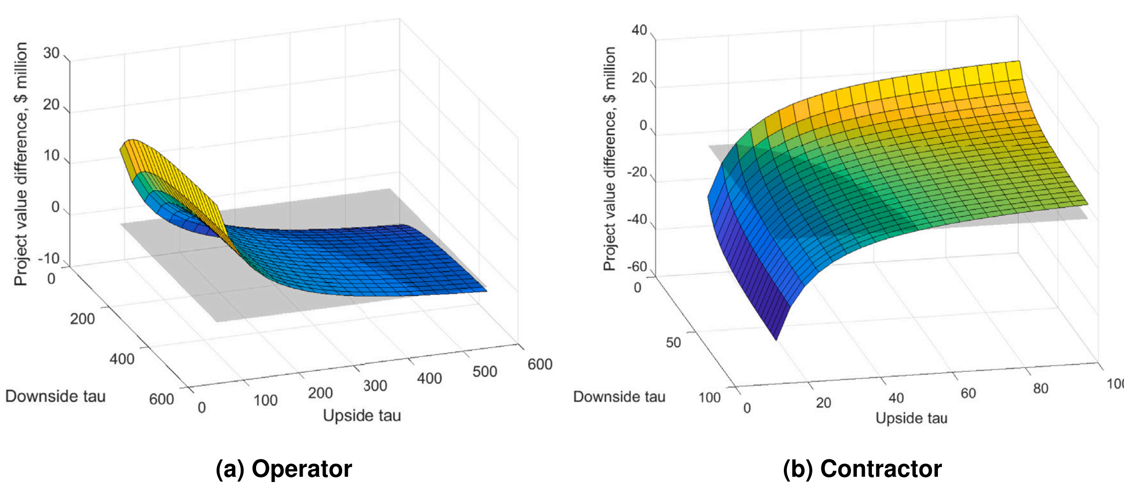


Fig. 16. Difference between risk-adjusted project values in Contract 4a and Contract 3.

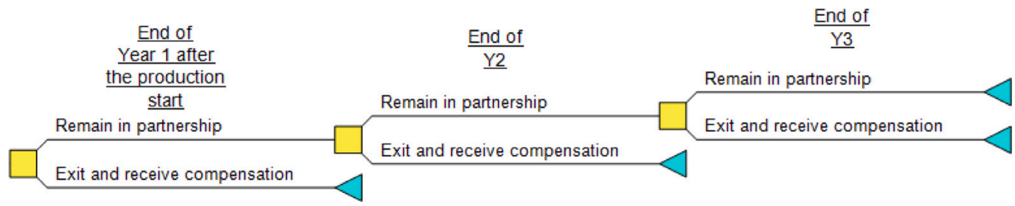


Fig. 17. Illustration of the risk and benefit sharing contract policy choices for the contractor.

by Santos et al. (2017). We show that the optimal contract choice is dependent on the decision maker's attitudes. In all cases, there were feasible combinations of τ_{dr} and τ_{up} that would make less advanced forms of risk sharing more beneficial for either of the parties. However, we highlight that additional flexibility offered by the exit clause in Contract 4 (and Contract 4a) can become an important instrument in balancing incentive schemes. However, the choice of the risk and benefit sharing scheme strongly depends on the problem at hand and willingness of the parties to share and accept additional risks.

Appendix C. Compensation mechanism of the "exit" clause

We assume that at the end of each year after the production start, both the field operator and the contractor evaluate whether it is optimal to remain in the partnership or to exit by paying/requesting a certain amount of money. As current state of the field production level and the oil market condition in year X affects future expectations, which the contractor might assess as unfavorable, it can decide to exit the partnership by receiving a compensation (see Fig. 17). Doing so, it gives up its share in profits that the oil field would generate from year X and on. However, there is value of waiting for the "exit". A likely increase of the production level or oil price might give additional incentive to the contractor to stay in partnership and vice versa. The exit clause is a real option, which provides a value of waiting to the decision maker. In our case, both the field operator and the contractor hold an option for N years and each year they decide whether it is optimal to exercise now or wait for one year more.

In order to exit from the risk sharing scheme and secure its exclusive rights for the profit, the field operator can pay the compensation to the contractor. The main reason for this decision might be a higher than expected production level and/or high oil price. We assume that the compensation is payable in equal amounts over four years.

We assume that both the amount of compensation that the field operator pays when it decides to terminate the partnership itself, and the amount that the contractor requests when the contractor decides to exit, decrease yearly. For the operator, this adds another incentive to wait for the next decision point to exit the partnership. The field operator might decide to hold an option until the last year, when the exit is possible, not only due to learning on the reservoir and oil market, but also due to a significant reduction in compensation that it has to pay to the contractor. The yearly decrease in compensation in case the contractor decides to exit ensures a fairer contract structure by providing the contractor with larger amount of compensation at earlier stages of the project and lesser amount later, when the field production already largely covered contractor's participation in the scheme.

The two main parameters of the contract, the percentage of profit after special tax that the contractor receives annually from the production, and the amount of compensation in case of termination of the partnership, can be tuned such that even a risk averse contractor would see a potential in such deal. This means that the field operator has to make concessions on their part by sacrificing their upside potential in order to make the partnership attractive for the service and drilling contractors.

Appendix D. Contract policy optimization using the LSM algorithm

Field operator. At each decision point t_n, the algorithm compares then present expected values of the "exit" decision, denoted by $\Pi_o(t_n, P_{t_n}, Q_{t_n})$, with the estimated value from the "remain in partnership until the end of next year" decision, expressed as $\Phi_o(t_n, P_{t_n}, Q_{t_n})$, and takes the maximum of the two for each simulated case. The optimal value function F at time step t_n can be obtained using the following Bellman equation (Rodrigues and Rocha Armada, 2006):

$$F_o = \max\left\{\mathbb{E}^*_{t_n}\left[\Pi_o(t_n, P_{t_n}, Q_{t_n})\right], \mathbb{E}^*_{t_n}\left[\Phi_o(t_n, P_{t_n}, Q_{t_n})\right]\right\}, \tag{17}$$

where P_{t_n} is the oil price at t_n, Q_{t_n} is the field's annual production rate.

At time t_n both Π_o and Φ_o are unknown as they are dependent on future oil prices and production rates, which are not observable for the decision maker at time t_n. Based on our assumptions regarding the oil price process and production rates,[10] we can estimate the expected value of Π_o and Φ_o conditional on the current information regarding the oil price and the production rate. The LSM algorithm uses a linear regression to perform this estimation as given by

$$\mathbb{E}^*_{t_n}\left[\Pi_o(t_n, P_{t_n}, Q_{t_n})\right] = \alpha_1 P_{t_n} + \alpha_2 Q_{t_n} + \alpha_3 P_{t_n}^2 + \alpha_4 Q_{t_n}^2 + \alpha_5 P_{t_n} Q_{t_n}, \tag{18}$$

$$\mathbb{E}^*_{t_n}\left[\Phi_o(t_n, P_{t_n}, Q_{t_n})\right] = \beta_1 P_{t_n} + \beta_2 Q_{t_n} + \beta_3 P_{t_n}^2 + \beta_4 Q_{t_n}^2 + \beta_5 P_{t_n} Q_{t_n}, \tag{19}$$

where $\alpha_{1\ldots5}$ and $\beta_{1\ldots5}$ denote the regression coefficients.

We then optimize the exit policy in the precedent years and find the optimal time to exit the partnership for the operator (if the exit happens) for each path of the simulation.

Drilling contractor. The Bellman equation from the contractor's perspective is given by

$$F_c = \max\left\{C_{t_n}, \mathbb{E}^*_{t_n}\left[\Phi_c(t_n, P_{t_n}, Q_{t_n})\right]\right\}, \tag{20}$$

where C_{t_n} is the compensation amount in year t_n.

As in the case of the operator, the expected value of Φ_c is estimated using a linear regression.

$$\mathbb{E}^*_{t_n}\left[\Phi_c(t_n, P_{t_n}, Q_{t_n})\right] = \gamma_1 P_{t_n} + \gamma_2 Q_{t_n} + \gamma_3 P_{t_n}^2 + \gamma_4 Q_{t_n}^2 + \gamma_5 P_{t_n} Q_{t_n}, \tag{21}$$

where $\gamma_{1\ldots5}$ denote the regression coefficients.

References

AkerBP, 2021. New well intervention and stimulation alliance established to accelerate and unleash production potential. URL: https://akerbp.com/en/new-well-intervention-and-stimulation-alliance-established-to-accelerate-and-unleash-production-potential/.

Akintoye, A., Main, J., 2007. Collaborative relationships in construction: the UK contractors' perception. Eng. Constr. Archit. Manag.

Al-Harthy, M.H., 2007. Stochastic oil price models: Comparison and impact. Eng. Econom. 52 (3), 269–284.

[10] The two-factor oil price process that we use is a Markov process, where the future state of a variable is determined by the current state with an element of randomness. The assumptions about the development of production rate also allow to link the future production to current production level.

Alexander, C., Ivanic, R., Rosch, S., Tyner, W., Wu, S.Y., Yoder, J.R., 2012. Contract theory and implications for perennial energy crop contracting. Energy Econ. 34 (4), 970–979.
Alonso-Conde, A.B., Brown, C., Rojo-Suarez, J., 2007. Public private partnerships: Incentives, risk transfer and real options. Rev. Financ. Econ. 16 (4), 335–349.
Ashuri, B., Kashani, H., Lu, J., 2010. Financial valuation of risk and revenue sharing options in Build-Operate-Transfer (BOT) highway projects. In: Proceedings of Engineering Project Organizations Conference. USA.
Ashuri, B., Kashani, H., Molenaar, K., Lee, S., Lu, J., 2012. Risk-neutral pricing approach for evaluating BOT highway projects with government minimum revenue guarantee options. J. Constr. Eng. Manag. 138 (4), 545–557.
Bastian-Pinto, C.d.L., Brandão, L.E.T., Ozorio, L.d.M., do Poço, A.F.T., 2021. A parameter based approach to single factor stochastic process selection for real options applications. Eur. J. Finance 27 (15), 1533–1552.
Bolton, P., Dewatripont, M., et al., 2005. Contract Theory. MIT Press.
Boone, H., 2021. Oil patch bankruptcy monitor. URL https://www.haynesboone.com/-/media/project/haynesboone/haynesboone/pdfs/energy_bankruptcy_reports/oil_patch_bankruptcy_monitor.pdf?rev=61c2606a5be547598c8d716d1a795c39&hash=97ECA4B149560404B19497FA37CB2B50/.
Børve, S., Ahola, T., Andersen, B., Aarseth, W., 2017. Partnering in offshore drilling projects. Int. J. Manag. Proj. Bus.
Brandao, L.E.T., Saraiva, E., 2008. The option value of government guarantees in infrastructure projects. Constr. Manag. Econ. 26 (11), 1171–1180.
Cachon, G.P., Lariviere, M.A., 2005. Supply chain coordination with revenue-sharing contracts: strengths and limitations. Manage. Sci. 51 (1), 30–44.
Carbonara, N., Costantino, N., Pellegrino, R., 2014. Concession period for PPPs: A win–win model for a fair risk sharing. Int. J. Proj. Manag. 32 (7), 1223–1232.
Cerqueti, R., Ventura, M., 2020. Optimal concession contracts for oil exploitation. Energy Policy 147, 111900.
Czarnitzki, D., Hottenrott, H., 2011. R&D investment and financing constraints of small and medium-sized firms. Small Bus. Econ. 36 (1), 65–83.
Dezember, R., Sider, A., 2018. Oil producers buying back shares after years of selling new stock. URL: https://www.wsj.com/articles/oil-producers-buying-back-shares-after-years-of-selling-new-stock-1519045200.
Emtehani, F., Nahavandi, N., Rafiei, F.M., 2021. A joint inventory–finance model for coordinating a capital-constrained supply chain with financing limitations. Financ. Innov. 7 (1), 1–39.
Equinor, 2022. Extending contracts for drilling and specialist services worth NOK 20 billion. URL: https://www.equinor.com/news/20220506-extending-contracts-drilling-specialist-services.
Fatehi, S., Wagner, M.R., 2019. Crowdfunding via revenue-sharing contracts. Manuf. Serv. Oper. Manag. 21 (4), 875–893.
Fedorov, S., Hagspiel, V., Lerdahl, T., 2021. Real options approach for a staged field development with optional wells. J. Pet. Sci. Eng. 205, 108837.
Ferriani, F., Natoli, F., Veronese, G., Zeni, F., 2019. Risk Premium in the Era of Shale Oil. Bank of Italy Temi Di Discussione (Working Paper) No, 1215.
Fetkovich, M.J., 1980. Decline curve analysis using type curves. J. Pet. Technol. 32 (06), 1065–1077.
Ghadge, A., Dani, S., Ojha, R., Caldwell, N., 2017. Using risk sharing contracts for supply chain risk mitigation: A buyer-supplier power and dependence perspective. Comput. Ind. Eng. 103, 262–270.
Govindan, K., Popiuc, M.N., 2014. Reverse supply chain coordination by revenue sharing contract: A case for the personal computers industry. European J. Oper. Res. 233 (2), 326–336.
Guedes, J., Santos, P., 2016. Valuing an offshore oil exploration and production project through real options analysis. Energy Econ. 60, 377–386.
Holt, G.D., Love, P.E., Li, H., 2000. The learning organisation: toward a paradigm for mutually beneficial strategic construction alliances. Int. J. Proj. Manag. 18 (6), 415–421.
Jafarizadeh, B., Bratvold, R.B., 2009. Real options Analysis in petroleum exploration and production: A new paradigm in investment analysis. In: EUROPEC/EAGE Conference and Exhibition. OnePetro.
Jafarizadeh, B., Bratvold, R., 2012. Two-factor oil-price model and real option valuation: an example of oilfield abandonment. SPE Econ. Manag. 4 (03), 158–170.
Kouvelis, P., Zhao, W., 2012. Financing the newsvendor: Supplier vs. bank, and the structure of optimal trade credit contracts. Oper. Res. 60 (3), 566–580.
Kouvelis, P., Zhao, W., 2016. Supply chain contract design under financial constraints and bankruptcy costs. Manage. Sci. 62 (8), 2341–2357.
Lam, K.C., Wang, D., Lee, P.T., Tsang, Y.T., 2007. Modelling risk allocation decision in construction contracts. Int. J. Proj. Manag. 25 (5), 485–493.
Longstaff, F.A., Schwartz, E.S., 2001. Valuing American options by simulation: a simple least-squares approach. Rev. Financ. Stud. 14 (1), 113–147.
Magri, S., 2009. The financing of small innovative firms: the Italian case. Econ. Innov. New Technol. 18 (2), 181–204.
Medda, F., 2007. A game theory approach for the allocation of risks in transport public private partnerships. Int. J. Proj. Manag. 25 (3), 213–218.
Melese, Y., Lumbreras, S., Ramos, A., Stikkelman, R., Herder, P., 2017. Cooperation under uncertainty: Assessing the value of risk sharing and determining the optimal risk-sharing rule for agents with pre-existing business and diverging risk attitudes. Int. J. Proj. Manag. 35 (3), 530–540.
Modigliani, F., Miller, M.H., 1958. The cost of capital, corporation finance and the theory of investment. Amer. Econ. Rev. 48 (3), 261–297.
Myers, S.C., 2001. Capital structure. J. Econ. Perspect. 15 (2), 81–102.
Nasirzadeh, F., Khanzadi, M., Rezaie, M., 2014. Dynamic modeling of the quantitative risk allocation in construction projects. Int. J. Proj. Manag. 32 (3), 442–451.
Norwegian Petroleum Directorate, 2003. Audit of the rig hiring process for drilling of sidetrack well on varg, tilsyn med intaksprosessen av rigg på varg.
Osipova, E., 2015. Establishing cooperative relationships and joint risk management in construction projects: Agency theory perspective. J. Manage. Eng. 31 (6), 05014026.
Osmundsen, P., 2011. Collaboration in Norway's Offshore Sector. Contracts and Incentives. Technical Report, University of Stavanger.
Osmundsen, P., Sørenes, T., Toft, A., 2010. Offshore oil service contracts new incentive schemes to promote drilling efficiency. J. Pet. Sci. Eng. 72 (3–4), 220–228.
Pratt, J.W., 2000. Efficient risk sharing: The last frontier. Manage. Sci. 46 (12), 1545–1553.
Quiggin, J., 2005. Public–private partnerships: options for improved risk allocation. Aust. Econ. Rev. 38 (4), 445–450.
Restrepo, N., Uribe, J.M., Manotas, D.F., 2020. Dynamic capital structure under changing market conditions in the oil industry: An empirical investigation. Resour. Policy 69, 101808.
Rodrigues, A., Rocha Armada, M.J., 2006. The valuation of real options with the least squares monte carlo simulation method. available at SSRN 887953.
Rouhani, O.M., Geddes, R.R., Do, W., Gao, H.O., Beheshtian, A., 2018. Revenue-risk-sharing approaches for public-private partnership provision of highway facilities. Case Stud. Transp. Policy 6 (4), 439–448.
Santos, S.M., Botechia, V.E., Schiozer, D.J., Gaspar, A.T., 2017. Expected value, downside risk and upside potential as decision criteria in production strategy selection for petroleum field development. J. Pet. Sci. Eng. 157, 81–93.
Schwartz, E., Smith, J.E., 2000. Short-term variations and long-term dynamics in commodity prices. Manage. Sci. 46 (7), 893–911.
Shan, L., Garvin, M.J., Kumar, R., 2010. Collar options to manage revenue risks in real toll public-private partnership transportation projects. Constr. Manag. Econ. 28 (10), 1057–1069.
Shi, L., He, Y., Onishi, M., Kobayashi, K., 2019. Double moral hazard and risk-sharing in construction projects. IEEE Trans. Eng. Manage.
Silaghi, F., Sarkar, S., 2021. Agency problems in public-private partnerships investment projects. European J. Oper. Res. 290 (3), 1174–1191.
Smith, J.E., McCardle, K.F., 1999. Options in the real world: Lessons learned in evaluating oil and gas investments. Oper. Res. 47 (1), 1–15.
Wang, Y., Cui, P., Liu, J., 2018. Analysis of the risk-sharing ratio in PPP projects based on government minimum revenue guarantees. Int. J. Proj. Manag. 36 (6), 899–909.
Wang, B., Ji, F., Zheng, J., Xie, K., Feng, Z., 2021. Carbon emission reduction of coal-fired power supply chain enterprises under the revenue sharing contract: Perspective of coordination game. Energy Econ. 102, 105467.
Weijermars, R., et al., 2011. Credit ratings and cash-flow analysis of oil and gas companies: competitive disadavantage in financing costs for smaller companies in tight capital markets. SPE Econ. Manag. 3 (02), 54–67.
Xiao, S., Sethi, S.P., Liu, M., Ma, S., 2017. Coordinating contracts for a financially constrained supply chain. Omega 72, 71–86.
Xiong, W., Zhang, X., Chen, H., 2016. Early-termination compensation in public–private partnership projects. J. Constr. Eng. Manag. 142 (4), 04015098.
Xu, L., Sepehrnoori, K., Dyer, J.S., Van Rensburg, W.C., 2012. Application of real options to valuation and decision-making in the petroleum E&P industry. In: SPE Hydrocarbon Economics and Evaluation Symposium. OnePetro.
Yao, Z., Leung, S.C., Lai, K.K., 2008. The effectiveness of revenue-sharing contract to coordinate the price-setting newsvendor products' supply chain. Suppl. Chain Manag.: Int. J.