On the Design of Oil Production Contracts: Insights from a Dynamic Model[1]

Abbas Ghandi and C.-Y. Cynthia Lin Lawell

Abstract

An oil production contract is a financial and legal framework that host governments of some oil producing nations use to engage with international oil companies for oil production. We develop a dynamic model of oil production and well drilling to analyze three different types of oil production contracts: technical service contracts, buy-back contracts, and production sharing contracts. Our theory model suggests that it may be possible to increase the economic efficiency of one type of contract by combining it with features of another. We apply our model to the Rumaila oil field in Iraq, which is under development through a technical service contract. The Rumaila technical service contract is predicted to result in a deadweight loss of 14.2% relative to the first-best. Results of our application to the Rumaila oil field show that production sharing contracts tend to be the most efficient, followed by technical service contracts. Buy-back contracts tend to be the least efficient of the three. Consistent with our theory model, we find that it may be possible to increase the efficiency of a technical service contract by combining it with features from production sharing contracts. On the other hand, combining a technical service contract with features from buy-back contracts can decrease efficiency.

Keywords: Iraq; technical service contract; buy-back contract; production sharing contract; oil production; dynamic optimization; Hotelling; service contract
***JEL* Classification:** Q39, L71, L24
This draft: July 2020

---

[1] Ghandi: Massachusetts Institute of Technology; aghandi@mit.edu. Lin Lawell: Cornell University; clinlawell@cornell.edu. The authors would like to thank the Sustainable Transportation Energy Pathways (STEPS) Program at the Institute of Transportation Studies (ITS) at the University of California at Davis for funding this research project. We are grateful to Joan Ogden, Jim Bushnell, Dan Bernhardt, Ujjayant Chakravorty, Bryan Jenkins, Lester Hunt, and Sonia Yeh for their helpful comments. We thank Deutsche Bank Securities Inc. for providing data. Our research has also benefited from comments from participants at STEPS seminars and poster sessions; the U.S. Association for Energy Economics (USAEE) conference; and the meeting of the Euro Working Group on Commodities and Financial Modeling. We would also like to acknowledge several individuals from international oil companies for their invaluable input and feedback. All errors are our own.

1. Introduction

An oil production contract is a financial and legal framework that host governments of some oil producing nations use to engage with international oil companies (IOCs) for oil production. In an oil production contract, the international oil company brings the technology and makes the upfront capital investment (Ghandi and Lin, 2014). The two main categories of oil production contracts are production sharing contracts and service contracts.[2]

Production sharing contracts were first introduced in Indonesia in 1966, and subsequently spread to all oil producing regions in the world except western Europe (Bindemann, 1999). In recent years, however, some oil producing countries have shown an increasing interest in adopting service contracts rather than production sharing contracts in their oil production projects. Venezuela, Kuwait, and Iran signed their first service contracts in 1991, 1992, and 1995, respectively. More recently, Iraq, Mexico, Bolivia, Ecuador, and Turkmenistan have also shown more interest in and/or signed service contracts as well (Ghandi and Lin, 2014).

Under a production sharing contract, countries share produced crude ownership rights with the international oil company (IOC), and the IOC is compensated with a share of production. With production sharing contracts, sovereignty concerns arise in part because these contracts give decision-making power to the international oil companies in handling the development, exploration, production, and operation (Ghandi and Lin, 2014).

Under a service contract, the international oil company (IOC) develops or explores oil or natural gas fields on behalf of the host government. In contrast to production sharing contracts, in a service contract the host government does not hand over the control of the extracted or subsoil or sub-surface resources to the IOCs. Service contracts therefore enable countries to give up less control over the fields and over the produced crude to foreign oil companies while still using the expertise of these companies (Ghandi and Lin, 2014). Several major OPEC and non-OPEC oil producing countries have found service-type contracts a means to address both sovereignty concerns, which are reflected in these countries' constitutions and petroleum laws and regulations,

---

[2] An oil production contract is different from an oilfield service contract in which service companies receive a fixed return for their short term services. While oil production contracts are contracts between host governments and international oil companies, oilfield service contracts are contracts between an operator and a service provider. There are oilfield service firms, such as Halliburton, Schlumberger, and Baker Hughes, that provide oilfield services and that may specialize in services such as drilling. These firms are awarded oilfield service contracts to fulfill particular jobs as part of broader development or exploration plans.

and the need for IOCs' capital and expertise capabilities (Ghandi and Lin, 2012; Ghandi and Lin, 2014). In Iran, for example, the country's Constitution restricts the types of contracts the National Iranian Oil Company can sign with IOCs (Ghandi and Lin, 2012).

Two main types of service contracts are technical service contracts (TSC) and buy-back contracts. Under a technical service contract (TSC), there is a production cap, and sometimes a cost ceiling as well. Under a buy-back contract, cost reductions are not recoverable and the number of wells is predetermined (Ghandi and Lin, 2012; Ghandi and Lin, 2014).

In this paper, we develop a dynamic model of oil production and well drilling to analyze three different types of oil production contracts: technical service contracts, buy-back contracts, and production sharing contracts. Our theory model suggests that it may be possible to increase the economic efficiency of one type of contract by combining it with features of another.

We apply our model to the Rumaila oil field in Iraq, which is under development through a technical service contract. As our theory model suggests that the economic efficiency of oil production contracts can increase if features of different types of contracts are combined, in our numerical application we analyze not only technical service contracts, buy-back contracts, and production sharing contracts, but also novel combinations of features of these three types of contracts.

We choose to apply our model to the Rumaila oil field for several reasons. First, the Rumaila oil field is a large oil field: once reaching the plateau production target in its technical service contract, Rumaila will be the second largest producing field in the world after Saudi Arabia's Ghawar oil field. As a consequence, a dynamic model of optimal oil production and well drilling and an analysis of the efficiency of oil production contracts on this field are important for the world oil industry.

A second reason why we choose to apply our model to the Rumaila oil field is that the Rumaila oil field is under development through a technical service contract, and the literature to date on technical service contracts has been sparse.

Third, the Rumaila oil field is in Iraq, an important and increasingly important oil producing country. Iraq is the second largest crude oil producer among OPEC members, ranking below Saudi Arabia but above Iran (EIA, 2019b), and oil production in Iraq is estimated to reach an astonishing 10.5 million barrels per day by 2035 (IEA, 2012),[3] which is significant considering that Saudi Arabia's crude oil production in 2018 is 10.4 million barrels per day (EIA, 2019a).

Fourth, unlike in some other oil producing countries such as Iran, the Constitution in Iraq allows the Iraqi government to choose from a range of possible contracts with IOCs, including service contracts and production sharing contracts (Blanchard, 2008). Thus, an analysis of the efficiency of oil production contracts in Iraq is not only interesting and important, but is also potentially of use to policy-makers in Iraq.

Fifth, our choice of fields is limited by data availability; while we were fortunate enough to obtain access to data and information on Rumaila and to have the opportunity to interview industry experts familiar with the Rumaila oil field, we have yet to obtain data and information at the same level of detail for other fields in Iraq.

While the literature on technical service contracts is sparse, we build on the previous literature analyzing other forms of oil production contracts. Bindemann (1999) conducts an economic analysis of production sharing contracts. Smith (2014) develops a model of petroleum exploration and development to analyze the performance of production sharing contracts and alternative tax systems. Marcel and Mitchell (2006) review the terms of buy-back contracts with an emphasis on their differences with production sharing contracts. Shiravi and Ebrahimi (2006) review the history of buy-back contracts in Iran. Van Groenendaal and Mazraati (2006) discuss risk factors in buy-back contracts. Ghandi and Lin (2012) examine whether Iran's buy-back contracts lead to dynamically optimal oil production. Ghandi and Lin Lawell (2017) analyze the rate of return and risk factors to international oil companies in Iran's buy-back contracts. Feng, Zhang and Gao (2014) develop a theoretical model to compare investment and production levels under production sharing and buy-back contracts. Stroebel and van Bentham (2013) examine resource extraction contracts under threat of expropriation. Smith (2013) provides a comprehensive review of research methods and models for analyzing the effects of fiscal regimes on extractive resources. Ghandi and Lin (2014) review service contracts around the world.

---

[3] The International Energy Agency (IEA) estimates that technical service contracts in Iraq could bring the country's oil production to 5.3, 8.3, or 10.5 million barrels per day in the IEA Iraq Energy Outlook's delayed, high, and central scenarios, respectively (IEA, 2012). The IEA's central scenario estimate of 10.5 million barrels per day is lower than the cumulative contractual plateau production targets of all technical service contracts in Iraq, which is 12 million barrels per day by 2020 (Sankey, Clark and Micheloto, 2010).

Our dynamic model of oil production and well drilling builds on the model of optimal nonrenewable resource extraction that was first examined by Hotelling (1931), and which was reformulated by Anderson, Kellogg and Salant (2018) as a drilling problem. The Hotelling model has also been expanded upon by many others in other ways as well (see e.g., Solow and Wan, 1976; Hanson, 1980; Pesaran, 1990; Pindyck, 1978; Pindyck, 1980; Farzin, 1992; Farzin, 1995; Young and Ryan, 1996; Lin and Wagner, 2007; Lin, 2009; Lin et al., 2009; Ghoddusi, 2010; Leighty and Lin, 2012; Almansour and Insley, 2016; Zhang and Lin Lawell, 2017; Lin Lawell, 2020; Kheiravar, Lin Lawell and Jaffe, 2020). Our dynamic model builds in particular on Gao, Hartley and Sickles (2009), who model the economically optimal dynamic oil production decisions for a stylized oilfield resembling the largest developed field in Saudi Arabia, Ghawar, and who pay particular attention to the engineering aspects of oil production.

We make several innovations to the literature. First, while some of the seminal papers analyzing oil production contracts have used a static model (see e.g., Bindemann, 1999), we analyze the economic efficiency of oil production contracts using a dynamic model. Second, while previous papers have analyzed production sharing contracts (Bindemann, 1999; Smith, 2014), buy-back contracts (Shiravi and Ebrahimi, 2006; Van Groenendaal and Mazraati, 2006; Ghandi and Lin, 2012; Ghandi and Lin Lawell, 2017), or both (Marcel and Mitchell, 2006; Feng, Zhang and Gao, 2014), we are the first paper to date to our knowledge to analyze the economic efficiency of technical service contracts; to compare technical service contracts, buy-back contracts, and production sharing contracts; and to analyze novel combinations of features of these three types of contracts. Third, our application to and analysis of the Rumaila oil field in Iraq, a large oil field in an important oil producing country, is novel.

According to the results of our application to the Rumaila oil field in Iraq, production sharing contracts tend to be the most efficient, followed by technical service contracts. Buy-back contracts tend to be the least efficient of the three. The efficiency of a technical service contract can be increased by increasing the contractual plateau production target so that the production cap is less stringent; or, when additional factors that impose an implicit cost ceiling and constrain production are present, by combining a technical service contract with features from production sharing contracts such as using a fixed price contractual unit revenue condition. On the other hand, combining a technical service contract with features from buy-back contracts can decrease efficiency.

The remainder of the paper proceeds as follows. We present our dynamic model in Section 2. We describe our application to the Rumaila oil field in Iraq in Section 3. We describe the scenarios we analyze in Section 4. We present our results in Section 5. We provide a discussion and conclusion in Section 6.

2. Dynamic Model

We develop a dynamic model of oil production and well drilling to analyze the economic efficiency of oil production contracts. As technical service contracts, buy-back contracts, and production sharing contracts each impose different sets of constraints, our theory model suggests that it may be possible to increase the efficiency of one type of contract by combining it with features of another.

Suppose the international oil company (IOC) is choosing how many wells to drill and how much oil to produce each year *t*. For each year *t*, let q_t denote daily oil production (in million barrels per day), n_t denote the number of new wells drilled, and P_t denote the exogenous oil price. Let r denote the discount rate.

The stock of oil remaining in the ground at the beginning of year *t* is S_t, which has the following equation of motion:

$$S_{t+1} = S_t - 365 q_t . \tag{1}$$

The number of wells already producing at the beginning of year *t* is N_t, which has the following equation of motion:

$$N_{t+1} = (1-d) N_t + n_t , \tag{2}$$

where *d* is the proportion of the N_t already producing wells that deplete by the next year.[4]

The cost of oil production q_t and well drilling n_t when there are N_t wells already producing is $c(q_t, n_t, N_t)$. Since current costs depend on past drilling through the stock N_t of

[4] In the theory model, for notational and expositional simplicity, we treat current drilling n_t and the stock N_t of already producing wells as continuous variables. In the numerical application, we round their values to the nearest integer.

already producing wells, current drilling n_t can affect future costs by increasing the future stock N_{t+1} of already producing wells.

Per-period profits $\pi(q_t, n_t, N_t)$ are given by:

$$\pi(q_t, n_t, N_t) = P_t q_t - c(q_t, n_t, N_t). \tag{3}$$

Oil production q_t is constrained by several technical, geological, and feasibility constraints. First, oil production is constrained by the number of wells available for production during year *t*, which is the sum of the N_t wells already producing and the n_t new wells drilled, as captured in the following well productivity constraint:

$$q_t \leq \omega \cdot (N_t + n_t), \tag{4}$$

where $\omega > 0$ is the well productivity.

Second, oil production is also constrained by technical and geological factors, as captured in the following geological feasibility constraint:

$$q_t \leq \tilde{f}(W_t, S_t, n_t, N_t) = f(q_t, S_t, n_t, N_t), \tag{5}$$

where $W_t = W(q_t, n_t, N_t)$ is the water injection rate. Because the geological feasibility constraint depends on previous production and previous drilling through the stock S_t of oil reserves remaining and the stock N_t of already producing wells, respectively, current production q_t and current drilling n_t not only affect current geological feasibility, but also affect future geological feasibility, and therefore future production, by decreasing the future stock S_{t+1} of reserves remaining and increasing the future stock N_{t+1} of already producing wells, respectively.

The change in production from the production level in the previous year is constrained by the following production change constraint:

$$|q_t - q_{t-1}| \leq \delta, \tag{6}$$

where $\delta > 0$ represents constraints to ramping out or ramping down production. Because the production change constraint depends on previous production q_{t-1}, current production q_t can affect future production.

Annual production is also constrained by the stock S_t of reserves remaining, as captured in the following stock constraint:

$$365 q_t \leq S_t. \tag{7}$$

Because the stock constraint depends on previous production through the stock S_t of reserves remaining, current production q_t can affect future production by decreasing the future stock S_{t+1} of reserves remaining.

Finally, production is constrained by the following minimum production constraint:

$$q_t \geq \underline{q} , \tag{8}$$

where $\underline{q} \geq 0$ is the minimum level of production.

There are two technical, geological, and feasibility constraints on the number of new wells drilled. First, there is a limit to the number of new wells that can be feasibly drilled, as captured by the following well drilling feasibility constraint:

$$n_t \leq \overline{n}_t^f , \tag{9}$$

where $\overline{n}_t^f$ is the maximum feasible number of new wells that can be drilled in year *t*.

Second, the number of new wells drilled is constrained to be non-negative in the following non-negative well drilling constraint:

$$n_t \geq 0 . \tag{10}$$

2.1. First-Best

The first-best outcome arises when the IOC does not face any additional constraints imposed by contracts and makes dynamically optimal decisions as if it were the sole owner of the field. The first-best outcome therefore also represents the outcome that would arise if the dynamically optimal decision were being made in a cooperative manner between the IOC and the Iraqi government with the sole objective of maximizing the present discounted value of the entire stream of per-period profits over the lifetime of the contract, where the profits are the joint profits to both the IOC and host government.

As we wish to model the optimal production and drilling, we assume that the IOC knows all the information needed to solve the dynamic optimization problem, including the revenue function $P_t q_t$; cost function $c(q_t, n_t, N_t)$; profit function (3); and technical, geological, and feasibility constraints (4)-(10). This is a reasonable assumption since one primary reason host countries are interested in oil production contracts with IOCs in the first place is to benefit from the IOCs' expertise in oil development and production (Ghandi and Lin, 2012; Ghandi and Lin, 2014); in an oil production contract, the IOC brings the technology and makes the upfront capital investment (Ghandi and Lin, 2014). Moreover, if the dynamically optimal decision were being made in a cooperative manner between the IOC and the host government with the sole objective of maximizing the present discounted value of the entire stream of per-period profits over the lifetime of the contract, then it is reasonable to assume that any and all relevant information would be shared in such a way that the dynamically optimal decision would be made with full knowledge of all the information needed, even if neither party alone had all the information.

In addition, as we wish to model the optimal production and drilling, we abstract from any principal-agent problems between the host government and the IOC, as well as from any issues of asymmetric information and/or risk aversion, and defer consideration of these issues to future work.

In the absence of any constraints imposed by contracts, the IOC will maximize the present discounted value of the entire stream of its per-period profits subject to the equations of motion (1)-(2) and the technical, geological, and feasibility constraints in equations (4)-(10). The IOC's dynamic optimization problem is given by the following Bellman equation (Bellman, 1957):

$$v_t^{FB}(S_t, N_t, q_{t-1}) = \max_{q_t, n_t} \left(P_t q_t - c(q_t, n_t, N_t) + \frac{1}{1+r} v_{t+1}^{FB}(S_{t+1}, N_{t+1}, q_t) \right) \tag{11}$$

s.t.

$$\begin{aligned}
& q_t \leq \omega \cdot (N_t + n_t) && :\mu_t^{\omega} \\
& q_t \leq f(q_t, S_t, n_t, N_t) && :\mu_t^{\overline{q}} \\
& |q_t - q_{t-1}| \leq \delta && :\mu_t^{\delta} \\
& 365 q_t \leq S_t && :\mu_t^{S} \\
& q_t \geq \underline{q} && :\mu_t^{\underline{q}} \\
& n_t \leq \overline{n}_t^{f} && :\mu_t^{\overline{n}} \\
& n_t \geq 0 && :\mu_t^{\underline{n}} \\
& S_{t+1} = S_t - 365 q_t && \\
& N_{t+1} = (1-d) N_t + n_t\,, &&
\end{aligned}$$

where the state variables are the stock S_t of reserves remaining, the stock N_t of already producing wells, and previous production q_{t-1}; $v_t^{FB}(S_t, N_t, q_{t-1})$ is the value function under the first-best at time *t*, and gives the present discounted value of the entire stream of per-period profits from time *t* to the terminal period *T* as a function of the state variables S_t, N_t, and q_{t-1} when production and well drilling are chosen optimally; *r* is the discount rate; and μ_t^{ω}, $\mu_t^{\overline{q}}$, μ_t^{δ}, μ_t^{S}, $\mu_t^{\underline{q}}$, $\mu_t^{\overline{n}}$, and

$\mu_t^{\underline{n}}$ are the non-negative multipliers on the well productivity constraint, geological feasibility constraint, production change constraint, stock constraint, minimum production constraint, well drilling feasibility constraint, and non-negative well drilling constraint, respectively. The first-order conditions for the IOC's profit maximization problem in the absence of contractual constraints are given by:

$$P_t - \frac{\partial c(\cdot)}{\partial q_t} - \frac{365}{1+r}\frac{\partial v_{t+1}^{FB}(\cdot)}{\partial S_{t+1}} + \frac{1}{1+r}\frac{\partial v_{t+1}^{FB}(\cdot)}{\partial q_t} - \mu_t^{\omega} + \mu_t^{\bar{q}}\left(\frac{\partial f(\cdot)}{\partial q_t} - 1\right) - \mu_t^{\delta}\cdot s(q_t - q_{t-1}) - 365\mu_t^{S} - \mu_t^{\underline{q}} = 0 \quad (12)$$

$$-\frac{\partial c(\cdot)}{\partial n_t} + \frac{1}{1+r}\frac{\partial v_{t+1}^{FB}(\cdot)}{\partial N_{t+1}} + \mu_t^{\omega}\omega + \mu_t^{\bar{q}}\frac{\partial f(\cdot)}{\partial n_t} - \mu_t^{\bar{n}} - \mu_t^{\underline{n}} = 0\,, \quad (13)$$

where $s(q_t - q_{t-1})$ is the sign of $q_t - q_{t-1}$:

$$s(q_t - q_{t-1}) = \begin{cases} 1 & \text{if } q_t \geq q_{t-1} \\ -1 & \text{otherwise} \end{cases} \,. \quad (14)$$

Applying the envelope theorem to solve for and simplify the derivatives of the value function $v_t^{FB}(\cdot)$ with respect to each of the state variables, the first-order conditions become:

$$\begin{aligned} P_t - \frac{\partial c(\cdot)}{\partial q_t} - 365\sum_{\tau=t+1}^{T}\left(\frac{1}{1+r}\right)^{T-\tau+1}\left(\mu_\tau^{\bar{q}}\frac{\partial f(\cdot)}{\partial S_\tau} + \mu_\tau^{S}\right) + \frac{1}{1+r}\left(\mu_{t+1}^{\delta}\cdot s(q_{t+1} - q_t)\right) \\ - \mu_t^{\omega} + \mu_t^{\bar{q}}\left(\frac{\partial f(\cdot)}{\partial q_t} - 1\right) - \mu_t^{\delta}\cdot s(q_t - q_{t-1}) - 365\mu_t^{S} - \mu_t^{\underline{q}} = 0 \end{aligned} \quad (15)$$

$$-\frac{\partial c(\cdot)}{\partial n_t} + \sum_{\tau=t+1}^{T}\left(\frac{1-d}{1+r}\right)^{T-\tau+1}\left(-\frac{\partial c(\cdot)}{\partial N_\tau} + \mu_\tau^{\omega}\omega + \mu_\tau^{\bar{q}}\frac{\partial f(\cdot)}{\partial N_\tau}\right) + \mu_t^{\omega}\omega + \mu_t^{\bar{q}}\frac{\partial f(\cdot)}{\partial n_t} - \mu_t^{\bar{n}} - \mu_t^{\underline{n}} = 0\,. \quad (16)$$

The solution to the IOC's dynamic optimization problem (11) in the absence of contractual constraints yields the maximum present discounted value $v_t^{FB}(\cdot)$ of the entire stream of per-period profits that a sole owner of the oil field can achieve, which is also the maximum present discounted value of the entire stream of per-period joint profits between the IOC and the host government that can be achieved if the IOC and the Iraqi government cooperated to maximize joint profits. We therefore call the outcome to the IOC's dynamic optimization problem (11) in the absence of contractual constraints the first-best "dynamically efficient" outcome, since it maximizes the present discounted value of the entire stream of per-period joint profits between the IOC and the

Iraqi government.[5] The first-order conditions (15)-(16) therefore characterize the first-best oil production and well drilling.

2.2. Contractual Constraints

We now expand our dynamic model to model optimal IOC oil production and well drilling decisions under different types of oil production contracts. Because the objectives of the host government and the IOC may differ from each other (Bindemann, 1999; Kheiravar, Lin Lawell and Jaffe, 2020), different types of oil production contracts have different contractual features to address various frictions that may arise.

First, owing to sovereignty concerns and a desire on the part of the host country to maintain control over production decisions (Bindemann, 1999; Ghandi and Lin, 2014), a contract may stipulate a maximum level $\overline{q}_t$ for production in each year *t*. We call this particular contractual feature (or constraint) a "production cap".

A second possible contractual feature is that, owing to concerns about cost (Ghandi and Lin, 2017), a contract may stipulate a maximum level $\overline{c}_t$ for costs in each year *t*. We call this particular contractual constraint a "cost ceiling".

Third, again owing to concerns about cost (Ghandi and Lin, 2017), a contract may stipulate a predetermined level for costs $\underline{c}_t$ for each year *t* such that the IOC must incur its full costs whenever its costs in year *t* exceed $\underline{c}_t$, but the IOC must still pay $\underline{c}_t$ when costs are lower than $\underline{c}_t$. In other words, the costs the IOC faces under this contractual arrangement would be $\max\{c(q_t, n_t, N_t), \underline{c}_t\}$. Under this contractual feature, any cost overrun over the predetermined

---

[5] In this paper, we use the terms "dynamically efficient" and "efficient" to describe the first-best outcome, since it maximizes the present discounted value of the entire stream of per-period joint profits between the IOC and the Iraqi government. Under certain conditions, our first-best outcome will maximize social welfare (as defined as the present discounted value of the entire stream of net benefits to society) as well, and therefore be efficient in the sense of maximizing social welfare as well. In particular, assuming that the social and private discount rates are the same, that there are no externalities, and that the marginal utility of income is constant so that the total benefits are given by the area under the demand curve, the social planner's dynamic optimization problem would also yield the same first-order conditions as our first-best first order conditions (15)-(16). As a consequence, the solution to the IOC's dynamic optimization problem (11) in the absence of any constraints imposed by contracts would maximize social welfare, and is therefore dynamically efficient. The reasoning for this is similar to that which generates the result that, in the absence of externalities, a perfectly competitive market maximizes social welfare and is dynamically efficient (Hotelling, 1931, Weitzman, 2003; Lin and Wagner, 2007; Lin et al., 2009; Lin, 2009; Lin Lawell, 2020): using total benefits instead of revenue yields the same first-order conditions when the oil producer takes price as given.

level for costs $\underline{c}_t$ is not recoverable by the IOC since the IOC must incur its full costs whenever its costs in year *t* exceed $\underline{c}_t$. Also under this contractual feature, the IOC does not benefit from reducing its costs below $\underline{c}_t$. We call this particular contractual feature "cost reduction not recoverable".

A fourth possible contractual feature is that, owing to sovereignty concerns and a desire on the part of the host country to maintain control over production and drilling decisions (Bindemann, 1999; Ghandi and Lin, 2014), a contract may stipulate a maximum number $\overline{n}_t$ of wells drilled (a "well cap") and/or a minimum number $\underline{n}_t$ of wells drilled (a "well floor") in each year *t*. When the contract stipulates the exact number $\tilde{n}_t$ of wells to be drilled in each year *t* (i.e., $\tilde{n}_t = \overline{n}_t = \underline{n}_t$), we call this particular contractual constraint "wells predetermined".

A fifth possible contractual feature is that, in order for the host government to balance incentivizing (or rewarding) the IOC while also ensuring an adequate government take (Bindemann, 1999), a contract may stipulate that instead of receiving the oil price P_t for every barrel of oil the IOC produces, the IOC instead receives contractual unit revenue $R(P_t)$. We call this particular contractual feature "contractual unit revenue instead of price".

Allowing for all possible combinations of the contractual features above, and once again assuming that the IOC has all the information needed to solve the dynamic optimization problem, and once again abstracting away from principal-agent problems, asymmetric information, and/or risk aversion in order to model the optimal production and drilling under oil production contracts, the IOC's contractually constrained dynamic optimization problem becomes:

$$v_t(S_t, N_t, q_{t-1}) = \max_{q_t, n_t}\left(R(P_t)q_t - \max\{c(q_t, n_t, N_t), \underline{c}_t\} + \frac{1}{1+r} v_{t+1}(S_{t+1}, N_{t+1}, q_t) \right) \tag{17}$$

s.t.

$$\begin{array}{ll}
q_t \le \omega \cdot (N_t + n_t) & :\mu_t^{\omega} \\
q_t \le f(q_t, S_t, n_t, N_t) & :\mu_t^{\overline{q}} \\
|q_t - q_{t-1}| \le \delta & :\mu_t^{\delta} \\
365 q_t \le S_t & :\mu_t^{S} \\
q_t \ge \underline{q} & :\mu_t^{\underline{q}} \\
n_t \le \overline{n}_t^{f} & :\mu_t^{\overline{n}} \\
n_t \ge 0 & :\mu_t^{\underline{n}} \\
S_{t+1} = S_t - 365 q_t &
\end{array}$$

$$
\begin{aligned}
&N_{t+1} = (1-d)N_t + n_t \\
&q_t \le \overline{q}_t \qquad\qquad\qquad :\lambda_t^q \\
&c(q_t, n_t, N_t) \le \overline{c}_t \qquad :\lambda_t^c \\
&n_t \le \overline{n}_t \qquad\qquad\qquad :\lambda_t^{\overline{n}} \\
&n_t \ge \underline{n}_t \qquad\qquad\qquad :\lambda_t^{\underline{n}}
\end{aligned} \quad ,
$$

where $v_t(S_t, N_t, q_{t-1})$ is the value function allowing for all possible combinations of the contractual features above at time t, and gives the present discounted value of the entire stream of per-period profits from time t to the terminal period T as a function of the state variables S_t, N_t, and q_{t-1} when production and well drilling are chosen optimally under the contract; and λ_t^q, λ_t^c, $\lambda_t^{\overline{n}}$, $\lambda_t^{\underline{n}}$ are the non-negative multipliers on the production cap, cost ceiling, well cap, and well floor constraints, respectively. The first-order conditions are given by:

$$
\begin{aligned}
&R(P_t) - I\{c(\cdot) \ge \underline{c}_t\}\frac{\partial c(\cdot)}{\partial q_t} - 365\sum_{\tau=t+1}^{T}\left(\frac{1}{1+r}\right)^{T-\tau+1}\left(\mu_\tau^{\overline{q}}\frac{\partial f(\cdot)}{\partial S_\tau} + \mu_\tau^S\right) + \frac{1}{1+r}\left(\mu_{t+1}^{\delta}\cdot s(q_{t+1}-q_t)\right) \\
&\quad - \mu_t^{\omega} + \mu_t^{\overline{q}}\left(\frac{\partial f(\cdot)}{\partial q_t} - 1\right) - \mu_t^{\delta}\cdot s(q_t - q_{t-1}) - 365\mu_t^S - \mu_t^{\underline{q}} - \lambda_t^q - \lambda_t^c\frac{\partial c(\cdot)}{\partial q_t} = 0
\end{aligned}
\tag{18}
$$

$$
\begin{aligned}
&-I\{c(\cdot) \ge \underline{c}_t\}\frac{\partial c(\cdot)}{\partial n_t} + \sum_{\tau=t+1}^{T}\left(\frac{1-d}{1+r}\right)^{T-\tau+1}\left(-I\{c(\cdot) \ge \underline{c}_\tau\}\frac{\partial c(\cdot)}{\partial N_\tau} + \mu_\tau^{\omega}\omega + \mu_\tau^{\overline{q}}\frac{\partial f(\cdot)}{\partial N_\tau} - \lambda_\tau^c\frac{\partial c(\cdot)}{\partial N_\tau}\right) \\
&\quad + \mu_t^{\omega}\omega + \mu_t^{\overline{q}}\frac{\partial f(\cdot)}{\partial n_t} - \mu_t^{\overline{n}} - \mu_t^{\underline{n}} - \lambda_t^c\frac{\partial c(\cdot)}{\partial n_t} - \lambda_t^{\overline{n}} - \lambda_t^{\underline{n}} = 0
\end{aligned} \quad ,
\tag{19}
$$

where $I\{c(\cdot) \ge \underline{c}_t\}$ is an indicator for whether costs exceed the predetermined level $\underline{c}_t$:

$$
I\{c(\cdot) \ge \underline{c}_t\} = \begin{cases} 1 & \text{if } c(\cdot) \ge \underline{c}_t \\ 0 & \text{otherwise} \end{cases} \quad .
\tag{20}
$$

As before, when the IOC is not constrained by contracts (i.e., $R(P_t) = P_t$, $I\{c(\cdot) \ge \underline{c}_t\} = 1$, and $\lambda_t^q = \lambda_t^c = \lambda_t^{\overline{n}} = \lambda_t^{\underline{n}} = 0$ for all t, q_t, n_t, S_t, N_t), then the IOC's dynamic optimization problem (17) reduces to its contractually unconstrained dynamic optimization maximization problem (11), yielding the first-best first-order conditions (15)-(16).

Under a technical service contract (TSC), there is a production cap (i.e., $\lambda_t^q \ge 0$) but there are no other contractual constraints (i.e., $R(P_t) = P_t$, $I\{c(\cdot) \ge \underline{c}_t\} = 1$, and $\lambda_t^c = \lambda_t^{\overline{n}} = \lambda_t^{\underline{n}} = 0$ for all t, q_t, n_t, S_t, N_t). If the production cap binds in year t, then this means that oil production q_t is lower with the contract than the contractually unconstrained profit-maximizing oil production is.

Under a technical service contract (TSC) with a cost ceiling, there is a production cap (i.e., $\lambda_t^q \geq 0$) and a cost ceiling (i.e., $\lambda_t^c \geq 0$) but no other contractual constraints (i.e., $R(P_t) = P_t$, $I\{c(\cdot) \geq \underline{c}_t\} = 1$, and $\lambda_t^{\overline{n}} = \lambda_t^{\underline{n}} = 0$ for all t, q_t, n_t, S_t, N_t).

Under a buy-back contract, cost reductions are not recoverable (i.e., the IOC faces costs $\max\{c(q_t, n_t, N_t), \underline{c}_t\}$) and the number of wells is predetermined (i.e., $\tilde{n}_t = \overline{n}_t = \underline{n}_t$, $\lambda_t^{\overline{n}} \geq 0$, and $\lambda_t^{\underline{n}} \geq 0$) (Ghandi and Lin, 2012; Ghandi and Lin, 2014), but there are no other contractual constraints (i.e., $R(P_t) = P_t$, and $\lambda_t^q = \lambda_t^c = 0$ for all t, q_t, n_t, S_t, N_t). If cost reductions are not recoverable and the number of wells is predetermined, then all else equal the IOC may produce more in some years than in the case in which the number of wells is predetermined but cost reductions are recoverable, since in the former case the IOC does not benefit if it cuts costs below the predetermined level $\underline{c}_t$ by keeping production low.

Under a production sharing contract, the IOC faces a contractual unit revenue $R(P_t)$ instead of the oil price P_t, where the contractual unit revenue is a function of the contractual oil price, the royalty rate, the cost recovery rate, the profit oil split, and the tax rate (Bindemann, 1999); but there are no other contractual constraints (i.e., $I\{c(\cdot) \geq \underline{c}_t\} = 1$ and $\lambda_t^q = \lambda_t^c = \lambda_t^{\overline{n}} = \lambda_t^{\underline{n}} = 0$ for all t, q_t, n_t, S_t, N_t).

2.3. Theory Results and Intuition

Table 1 presents the first-order conditions (15)-(16) from the first-best, as well as the special cases of the first-order conditions (18)-(19) for the technical service contract, technical service contract with a cost ceiling, buy-back contract, and production sharing contract, respectively.

To measure any inefficiencies introduced by contracts, we define the deadweight loss DWL^X of contract X as the percentage lower the present discounted value $v_t^X(\cdot)$ of the entire stream of per-period profit from that contract is relative to the present discounted value $v_t^{FB}(\cdot)$ of the entire stream of per-period profit under the first-best:

$$DWL^X = \frac{v_t^{FB}(\cdot) - v_t^X(\cdot)}{v_t^{FB}(\cdot)} \cdot 100 \quad . \tag{21}$$

We say that a contract is "more efficient" if its deadweight loss is lower and "less efficient" if its deadweight loss is higher.

We can glean several qualitative results from our model and the first-order conditions in Table 1. First, comparing the first-order conditions for the technical service contract, technical service contract with a cost ceiling, buy-back contract, and production sharing contract, respectively, with the respective first-order conditions (15)-(16) under the first-best, we can see that because they impose additional constraints, contracts will lead to economically inefficient outcomes because the present discounted value of the entire stream of per-period profits under a contract will be lower than that under the first-best.

Second, comparing the first-order conditions for the technical service contract, technical service contract with a cost ceiling, buy-back contract, and production sharing contract, respectively, with each other, it is not obvious which contracts will yield higher present discounted values of the entire stream of per-period profits. Which contracts will yield higher present discounted values of the entire stream of per-period profits depends on the particular functional forms of the functions and the values of the parameters, including the sign and magnitudes of first-order derivatives, second-order derivatives, and cross partials. We will therefore compare the contracts for the particular case of the Rumaila oil field in Iraq, which is under development through a technical service contract.

A third qualitative result that can be gleaned from our model and the first-order conditions in equations (18)-(19) and Table 1 is that some contractual features may offset each other. As a consequence, it is possible that some combinations of contractual features may increase the present discounted value of the entire stream of per-period profits under a contract relative to other combinations, and/or relative to certain contractual features in isolation.

For example, in comparing the first-best first-order condition (15) with the respective contractually constrained first-order condition (18), we see that while a production cap (a feature of technical service contracts) results in a non-negative multiplier λ_t^q that is subtracted from the left-hand side of equation (18), the effect of subtracting this multiplier may potentially be offset if the IOC also faces contractual unit revenue $R(P_t)$ instead of price P_t (a feature of production sharing contracts), such as a contractual unit revenue $R(P_t)$ that is lower than price P_t. Thus, it may be possible to increase the efficiency of technical service contracts by combining them with some features from production sharing contracts.

3. Application to Rumaila Oil Field

We apply our dynamic model of oil production and well drilling to the Rumaila oil field in Iraq, which was discovered in 1953 by the Iraq Petroleum Company in partnership with BP, and which is under development through a technical service contract. We discuss technical service contracts in Iraq and components of a technical service contract in detail in Appendix A.

The Rumaila technical service contract was the first contract awarded in the first round of auctioning in Iraq in 2009. The winner was a consortium of BP, CNPC, and the Iraqi State Oil Marketing Organization (SOMO), with 38%, 37%, and 25% working interests, respectively.[6] The proposed plateau production target, which, as explained in detail in Appendix A, is the "net production rate that is to be achieved and sustained for the plateau production period, was 2.85 million barrels per day (Sankey, Clark and Micheloto, 2010). Once reaching the plateau production target, Rumaila will be the second largest producing field in the world after Saudi Arabia's Ghawar oil field.

Rumaila has three known formations: the Main Pay reservoir, the Mishrif carbonate formation, and the Yamama formation. In the beginning years, the production increase is to be based on the recovery of 275 existing wells. Main Pay is the main reservoir for the initial production. The sustained peak production at the plateau production target is to be based on production from Mishrif formation (Daly, 2010).

The Rumaila technical service contract is a 20-year contract (Sankey, Clark and Micheloto, 2010). Since the contract effective date was December 2009, and since in reality BP and its partners took over the field at the beginning of 2010, it is reasonable to use 2010 as the first year for our model. We thus model oil production and well drilling decisions starting the year 2010 and ending 20 years later at the end of the 20-year contract, in 2030. Since the IOC does not benefit from any oil that is left in the ground at the end of its contract, for all scenarios we use a finite horizon T that ends at the end of the 20-year Rumaila technical service contract in 2030, with

---

[6] In this paper, we refer to BP and its partners as the "IOC" or the "IOCs".

no continuation value after year T. We solve the finite-horizon dynamic programming problem numerically via backwards iteration.

For prices in our base case, we use Rumaila-specific price estimates based on the Energy Information Administration (EIA)'s 2010 Reference price forecast from 2010 to 2030, the end of the contract. In order to capture the possibility of large increases in oil production by Iraq that may potentially suppress world oil prices, we also run a specification of our model using Rumaila-specific price estimates based on the EIA 2010 Low Oil Price scenario for robustness.[7] In addition, since price volatility through time could affect our optimization results, we also run a specification of our model using Rumaila-specific price estimates based on the EIA 2012 Reference case price projection for robustness as well. As seen in the results of our robustness checks in Appendix B, the results for oil production, well drilling, and costs are robust to the oil price specification. For more details on the price estimates we use and the results of our robustness checks for price, see Appendix B.

Estimating a Rumaila-specific cost function is out of the scope of this paper since we do not have access to the data and tools necessary for such estimation. In fact, the IOCs involved in the Rumaila technical service contract are spending huge resources to accomplish this extraordinary task.[8] Instead, we approximate the cost function for Rumaila by using the cost function estimated by Gao, Hartley and Sickles (2009) for Arabian light and medium crude. Gao, Hartley and Sickles' (2009) annual cost function has the following five main components:[9]

$$c(q_t, n_t, N_t) = c_I q_t + c_O(q_t) + c_W(W(q_t, n_t, N_t)) + c_N(N_t) + c_n n_t \,, \tag{22}$$

---

[7] Any influence oil production on the Rumaila field in Iraq may have on the oil price would likely be through OPEC and the OPEC quota. Even if OPEC may have exercised market power in the 1970s and 1980s (Griffin, 1985; Lin Lawell, 2020), however, there is evidence to suggest that OPEC has been less successful in exerting market power in more recent years (Marcel and Mitchell, 2006; Lin, 2009; Sperling and Gordon, 2010). Nevertheless, in addition to using Rumaila-specific price estimates based on the EIA 2010 Low Oil Price scenario to account for a possibly large ramp up in oil production in Iraq, we also further account for OPEC considerations in the "TSC Actual Optimal" and "TSC Actual Optimal, Cost Ceiling" scenarios.

[8] Personal communication with industry experts

[9] Gao, Hartley and Sickles' (2009) production cost function also includes exploration costs. They assume the exploration cost to be 20% of the development and operation cost combined. Even though the Ghawar oil field is a producing field, it still incurs exploration costs, which include "geological and geophysical surveys for discovery, and delineation of reservoirs and the drilling of exploration wells" (Gao, Hartley and Sickles, 2009, p.164). Since there is no exploration is involved in the Rumaila technical service contract, however, we do not include any exploration costs in our cost function.

<Footnote continues next page.>

where c_I is the surface infrastructure maintenance cost per barrel, $c_O(\cdot)$ is the variable operating cost, $c_W(\cdot)$ is the water injection cost, $W(\cdot)$ is the water injection rate (in million barrels per day), $c_N(\cdot)$ is the maintenance cost for old wells, and c_n is the cost of a new well.

For each component of the cost function, we use the functional form and parameter assumptions based on Gao, Hartley and Sickles (2009) for the base case.[10] For robustness, we also run specifications that vary the parameters and functional form used for each component. We describe the functional form and parameter assumptions for each component of the cost function, and present the robustness checks we conduct in which we vary the value of each parameter of each component for robustness, in Appendix C. The functional form and parameter assumptions based on Gao, Hartley and Sickles (2009) that we use for the base case, as well as the parameter values we use in our robustness checks, are summarized in Table 2.

There are several reasons why the cost function that Gao, Hartley and Sickles (2009) estimate for Arabian light and medium crude may be a reasonable approximation to the cost function for Rumaila. First, the Rumaila oil field and crude are likely to be similar to the field and crude in Gao, Hartley and Sickles' (2009) study. Gao, Hartley and Sickles (2009) use data on Arabian light and medium fields from the Center for Global Energy Studies (1993) to estimate the surface infrastructure maintenance cost c_I per barrel and the surface infrastructure maintenance cost component of the cost c_n of a new well. Their estimate of the drilling cost component of the cost c_n of a new well is for Arabian light crude.

Second, Gao, Hartley and Sickles' (2009) cost function is for a field similar to Saudi Arabia's Ghawar oil field that has an important water injection component.[11] The water injection rate they use is based on a generalized simulation approach for a field similar to the Ghawar oil field. Since the production plans in Rumaila are also based on water injection, using Gao, Hartley and Sickles' (2009) cost function enables us to capture water injection related costs in our model.

---

[10] Following Gao, Hartley and Sickles (2009), who assume their cost parameters are constant over the 100 years they simulate, we assume the parameters are constant over the 20 years we simulate.

[11] Water injection is used in secondary oil recovery operations on aged fields with depleted natural pressure. Water injected through water injection wells increases the reservoir pressure and facilitates oil transition in the reservoir towards the producing wells. Each producing field may have several water injection wells located in different patterns depending on the characteristics of the reservoir. It is also possible that a single water injection well is used for several producing wells (Rigzone, 2012).

Since geological differences between Rumaila and Ghawar may cause these two fields to have different cost functions, we also run specifications in which we vary the value of each parameter of each component of our cost function. We present the results of these robustness checks in Appendix C. As seen in Appendix C, the results for oil production, well drilling, and revenue are robust to the parameter values we use in the cost function. As expected, the values of some of the cost parameters affect costs and sometimes the present discounted value of the entire stream of per-period profit as well. In other cases, the present discounted value of the entire stream of per-period profit is fairly robust to the values of the cost parameters. Nevertheless, since the results for oil production, well drilling, and revenue are robust to the parameter values we use in the cost function, our qualitative results regarding the relative ranking of various scenarios with respect to the present discounted value of the entire stream of profit, and therefore the relative ranking of the deadweight losses from various contract scenarios, are robust to the cost parameters.

A third argument for using Gao, Hartley and Sickles' (2009) cost function is that it gives us cost estimates for the year 2010 close to BP's actual announced budget for Rumaila for the year 2010, the first year of the contract. For this year, BP's $1.7 billion annual work plan includes drilling new producing wells and maintaining the production over the 275 producing wells that already were in operation in order to add an incremental production of up to 200,000 barrels per day. The 2010 total production target, including the incremental production from the new wells as well as production from existing wells, is 1.2 million barrels per day (GDS Publishing, Inc., 2010). As presented in Table 3, we estimate the cost of these production and drilling plans for 2010 to be $1.47 billion (in 2010 dollars)[12] using the cost function and parameters from Gao, Hartley and Sickles (2009) that we calibrate to Rumaila. Our 2010 cost estimate is therefore fairly close to the company's announced budget for the year 2010 of $1.7 billion, which increases our confidence in using this cost function in our dynamic model of oil production and well drilling for Rumaila.

We discuss our choice of discount rate and present results of robustness checks for the discount rate in Appendix D. Following Gao, Hartley and Sickles (2009), we set the proportion d of the N_t already producing wells that deplete by the next year to 0.05.[13]

[12] $1.45 billion dollars in 2008 dollars

[13] Following Gao, Hartley and Sickles (2009), we do not distinguish between different types of wells. We therefore assume that in each year t, the N_t wells already producing and the n_t new wells drilled on average exhibit the same <Footnote continues next page.>

4. Scenarios

4.1. Most likely to be realized scenario

The first scenario we analyze represents the annual production and new well drilling that are predicted to be realized on the Rumaila oil field under its technical service contract. For this "Most Likely to be Realized" scenario, we use the Deutsche Bank forecasts for annual production and new well drilling in Rumaila from its Iraq production and well drilling outlook. Deutsche Bank's Iraq production and well drilling outlook is a "bottom-up field-by-field forecast, which is based on a mosaic of company data, company comments, press reports, industry chatter, contract targets/thresholds, etc." (Personal communication with Deutsche Bank Securities Inc., September 2011).[14] As the Deutsche Bank forecasts are the most realistic estimates available and consider all possible factors that could affect production plans on Rumaila in coming years, we use these forecasts in our "Most Likely to be Realized" scenario to represent the annual production and new well drilling that are predicted to be realized on the Rumaila oil field under its technical service contract.

To calculate the cost, revenue, and the present discounted value of the entire stream of per-period profit for the "Most Likely to be Realized" scenario, we evaluate our cost and revenue functions at these Deutsche Bank values for production and new wells drilled.

We use our "Most Likely to be Realized" scenario to calculate the deadweight loss that is predicted to result from the Rumaila technical service contract, a deadweight loss that includes inefficiencies due to constraints imposed by the contract itself as well as inefficiencies due to other factors. Nevertheless, our analyses of the economic efficiency of oil production contracts and the

---

average characteristics in the way that they enter the maintenance cost $c_N(N_t)$ for old wells, the water injection rate $W(q_t, n_t, N_t)$, and the geological feasibility function $f(q_t, S_t, n_t, N_t)$; and that each year the average cost of a new well is c_n, the average well productivity is ω, and the average rate of depletion of the wells already producing is *d*. For a first-order approximation, it seems reasonable to assume that, on average, the wells have similar average characteristics as those that informed our choice of the functional forms and parameter values, even if there may be some heterogeneity among individual wells. The Deutsche Bank forecast does not distinguish between well types. Moreover, because the buy-back contract predetermines the number of new wells drilled each year but not the type, distinguishing between well types is likely to be an unnecessary complexity.

[14] While we have been fortunate enough to obtain access to the Deutsche Bank forecast, we unfortunately do not have access to specific details about the functional forms and parameter values, etc., of the propriety and confidential model Deutsche Bank used to generate the forecast.

deadweight losses that arise from the constraints imposed by the respective contracts themselves involve comparing outcomes of our contract scenarios below with the first-best scenario below, and therefore does not rely on our "Most Likely to be Realized" scenario. As a consequence, our analyses of the efficiency of various oil production contracts does not depend on the Deutsche Bank forecast and therefore is robust to any inaccuracies in these forecasts.

4.2. First-best scenario

For our "First-Best" scenario, we solve the IOC's dynamic optimization problem (11) in the absence of contractual constraints to determine the optimal production path and the optimal trajectory for drilling new wells subject to technical, geological, and feasibility constraints only.

We summarize the technical, geological, and feasibility constraints in Table 4, and describe them in detail in Appendix E. In Appendix E we also present results of robustness checks in which we vary each of the parameters of the geological feasibility function $f(\cdot)$. According to the results of the robustness checks, which are described in detail in Appendix E, the results for oil production, well drilling, revenue, and costs are robust to changes in the values of the geological feasibility parameters, and the present discounted value of the entire stream of per-period profit is unaffected by changes in these parameters.

Since the IOC does not benefit from any oil that is left in the ground at the end of its contract, for all scenarios we use a finite horizon T that ends at the end of the 20-year Rumaila technical service contract in 2030, with no continuation value after year T. Since we impose this finite horizon on our "First-Best" scenario as well, the present discounted value of the entire stream of profit in the absence of contractual constraints would potentially be even higher without the finite horizon. As a consequence, the present discounted value of the entire stream of profit under our "First-Best" scenario is a lower bound on the actual first-best present discounted value of the entire stream of profit in the absence of contractual constraints, and the deadweight losses we calculate for the various contracts represent a lower bound to the actual deadweight loss from these contracts.

4.3. Technical service contract (TSC) scenarios

In order to account for the realities that the IOC and the Iraqi government face in implementing the Rumaila technical service contract (TSC), and to account for factors that could affect the overall economic efficiency of the Rumaila TSC, we consider several TSC scenarios. Comparing these scenarios with our first-best scenario enables us to assess factors that could affect the overall economic efficiency of the Rumaila TSC.

Our "TSC Optimal" scenario represents the maximum present discounted value of the entire stream of profits that can be achieved under the Rumaila TSC if there were no other sources of inefficiency aside from the terms of the contract. In our "TSC Optimal" scenario, we impose a production cap in order to account for the performance factor and plateau production target specified in the Rumaila TSC. The term plateau production target refers to the "net production rate that is to be achieved and sustained for the plateau production period." The plateau production period starts once the field's production reaches and stays for 30 consecutive days at the plateau production target level. The performance factor is defined as the ratio of the net production rate to the bid plateau production target and should never exceed 1.0 (Republic of Iraq, Ministry of Oil, 2011); as a consequence, the IOC is obligated to reach the plateau production target. See Appendix A for more details on the components of a technical service contract.

In the Rumaila TSC, the contractual plateau production target is 2.85 million barrels per day and the production plateau period starts in 2022. Due to the performance factor in the contract, the operator cannot reach the plateau production target before the start of the plateau production period as specified in the contract. Therefore, to account for the performance factor and plateau production target specified in the Rumaila TSC, in the "TSC Optimal" scenario we set the production cap to the contractual plateau production target in the Rumaila TSC of 2.85 million barrels per day for the years 2022-2030. For the years 2010-2021, in accordance with the production change constraint and Rumaila's proposed work plans, which include installing additional incremental production capacity at 200,000 barrels per day in some years, we set the production cap to 2.65 million barrels/day .

When implementing a contract, there may be more sources of inefficiency than those introduced by the terms of the contract itself. For example, in implementing the Rumaila TSC, misaligned responsibilities among different Iraqi government entities involved in the contract may lead to an implicit cost ceiling being imposed on the IOC. The Iraqi government entity awarding the contracts is different from the one making cost decisions, which is different from the one receiving the revenue. The Ministry of Oil and its Petroleum Contracts and Licensing Directorate, which awards the contract, follow a policy of maximizing revenue with an emphasis on garnering a higher plateau production target in the bidding process. In contrast, the state-owned South Oil Company, which oversees the Rumaila operation and has to approve the IOC's work plans and capital expenditures, is primarily concerned with cost. The revenue goes through the Ministry of Oil's Treasury department. The South Oil Company therefore decides on the cost without seeing the revenue.[15] Thus, even though the contract awarded by the Petroleum Contracts and Licensing Directorate is agnostic about how much it would cost to reach the plateau production target, the South Oil Company is able to enforce a cost constraint on the IOCs after the contract is awarded.

To account for the implicit cost ceiling that might result from the implementation of the Rumaila TSC, our "TSC Optimal, Cost Ceiling" scenario adds a cost ceiling to the "TSC Optimal" scenario. For the cost ceiling, we use the annual costs from our "Most Likely to be Realized" scenario, which represent the costs that are predicted to be realized on the Rumaila oil field under its technical service contract. Therefore, the cost ceiling is partially based on the Deutsche Bank production and well drilling estimates and partially based on the functional form of our cost function.

In implementing the Rumaila TSC, the IOC and the Iraqi government may face factors that constrain oil production beyond the production cap in the contract, leading to a lower effective plateau production target than the plateau production target specified in the Rumaila TSC. One such factor is the future OPEC quota for Iraq, which has the potential of limiting oil production in Iraq if the country decides to join and comply with the OPEC quota system, unless the new quota accommodates production expansions in Iraq.[16] The effect of the OPEC quota on Iraq will likely be higher on its larger fields, especially Rumaila. A second factor that may constrain production is that, for the next few years, export capacity constraints in Iraq due to constraints on its export terminals and pipelines may limit the production level of its developed fields, which might prevent the IOC from reaching the plateau production target.[17] In anticipation of these factors that may

---

[15] Personal communication with industry experts

[16] Iraq has not had an OPEC quota since 1990 after the Iraqi invasion of Kuwait. Nevertheless, the country hopes to return to the OPEC quota system with a potentially conflicting quota higher than the OPEC quota for Iran of 3.34 million barrels per day. A lower OPEC quota for Iraq may affect production plans in Iraq, assuming the country decides to comply with the OPEC quota system (Ajrash and DiPaola, 2011).

[17] In the case of Rumaila, the produced crude could reach the export points through the Strategic Pipeline 1 (SP1) to the north or through the Southern Distribution Pipeline System to the Fao terminal in the south on the Persian Gulf shore. The pipelines and the terminal are not in full capacity working conditions due to years of war and poor maintenance, however. The Iraqi government's oil infrastructure expansion plans could cost $50 billion dollars
<Footnote continues next page.>

constrain oil production beyond the production cap in the contract, Deutsche Bank estimates an effective plateau production target of 2.35 million barrels per day, which is lower than the plateau production target specified in the Rumaila TSC.

In our "TSC Actual Optimal" scenario, we account for the additional factors that the IOC and the Iraqi government may face in implementing the Rumaila TSC that may constrain oil production beyond the production cap in the contract by using a more stringent production cap based on Deutsche Bank's lower effective plateau production target estimate. In particular, in the "TSC Actual Optimal" scenario we set the production cap to Deutsche Bank's lower effective plateau production target estimate of 2.35 million barrels per day for the years 2022-2030. For the years 2010-2021, in accordance with the production change constraint and Rumaila's proposed work plans, which include installing additional incremental production capacity at 200,000 barrels per day in some years, we set the production cap to 2.15 million barrels/day .

To account for both the implicit cost ceiling that might result from the implementation of the Rumaila TSC, and the additional factors that the IOC and the Iraqi government may face in implementing the TSC that may lead to a lower effective plateau production target than the plateau production target specified in the Rumaila TSC, our "TSC Actual Optimal, Cost Ceiling" scenario adds a cost ceiling to the "TSC Actual Optimal" scenario.

Table 5 summarizes the contractual constraints we impose in our technical service contract scenarios. These contractual constraints are imposed in addition to the technical, geological, and feasibility constraints in Table 4.

4.4. Buy-back contract scenario

Under a buy-back contract, cost reductions are not recoverable (i.e., the IOC faces costs $\max\{c(q_t, n_t, N_t), \underline{c}_t\}$) and the number of wells is predetermined (i.e., $\tilde{n}_t = \overline{n}_t = \underline{n}_t$, $\lambda_t^{\overline{n}} \geq 0$, and $\lambda_t^{\underline{n}} \geq 0$) (Ghandi and Lin, 2012; Ghandi and Lin, 2014).

In our "Buy-Back Optimal" scenario, we assume that, for each year *t*, the predetermined cost level $\underline{c}_t$ is the cost under the Deutsche Bank well drilling and production estimates, and the

(Sankey, Clark and Micheloto, 2010). The country's struggle in securing funds for these costly plans may suggest that insufficient export facilities could restrict production.

predetermined number of wells $\tilde{n}_t$ is Deutsche Bank forecast of the number of new wells drilled drilled that year.

Table 5 summarizes the contractual constraints we impose in our buy-back contract scenario. These contractual constraints are imposed in addition to the technical, geological, and feasibility constraints in Table 4.

4.5. Production sharing contract scenarios

Under a production sharing contract, the IOC faces contractual unit revenue $R(P_t)$ instead of oil price P_t (Bindemann, 1999). As explained in Bindemann (1999), the contractual unit revenue $R(P_t)$ faced by the IOC is given by:

$$R(P_t) = P_t^c(P_t) \cdot \big((1-\rho)\kappa + (1-\rho)(1-\kappa)\sigma(1-\gamma)\big), \tag{23}$$

where $P_t^c(P_t)$ is the contractual oil price, ρ is the royalty rate, κ is the cost recovery rate, σ is the profit oil split, and γ is the tax rate. Following Bindemann (1999), we assume that the royalty is 10% (i.e., $\rho = 0.1$); cost recovery is 33.3% (i.e., $\kappa = 0.333$); the profit oil split is 40% to the IOC and the remaining 60% to the Iraqi government (i.e., $\sigma = 0.4$); and tax is 30% (i.e., $\gamma = 0.3$).

In the base case, we assume that each year the contractual oil price is the oil price for that year (i.e., $P_t^c(P_t) = P_t$). For robustness, we also try specifications in which the contractual oil price is a constant set at the minimum ($66.34/barrel), maximum ($119.54/barrel), and mean ($99.59/barrel), respectively, of our oil price estimates over the years 2010-2030.

Table 5 summarizes the contractual constraints we impose in our production sharing contract scenarios. These contractual constraints are imposed in addition to the technical, geological, and feasibility constraints in Table 4.

4.6. TSC with higher contractual plateau production target

To see if we can increase the efficiency of the technical service contract, we first examine the effects of increasing the contractual plateau production target in a technical service contract. In the "TSC Optimal" scenario above, we set the production cap to the contractual plateau production target in the Rumaila TSC of 2.85 million barrels per day for the years 2022-2030. For the years 2010-2021, in accordance with the production change constraint and Rumaila's proposed work plans, which include installing additional incremental production capacity at 200,000 barrels per day in some years, we set the production cap to 2.65 million barrels/day .

We examine the effects of increasing the contractual plateau production target to 2.90 million barrels per day, so that the production cap is set to 2.70 million barrels/day in accordance with the production change constraint and Rumaila's proposed work plans for the years 2010-2021, and to the higher contractual plateau production target of 2.90 million barrels per day for the years 2022-2030.

We also examine the effects of further increasing the contractual plateau production target to 2.95 million barrels per day, so that the production cap is set to 2.75 million barrels/day in accordance with the production change constraint and Rumaila's proposed work plans for the years 2010-2021, and to the higher contractual plateau production target of 2.95 million barrels per day for the years 2022-2030.

4.7. TSC with fixed price contractual unit revenue

As seen in our model in Section 2, since some contractual features may offset each other, it is possible that some combinations of contractual features may increase the present discounted value of the entire stream of per-period profits under a contract relative to other combinations, and/or relative to certain contractual features in isolation.

To analyze whether some novel combination of the contractual features in technical service contracts and production sharing contracts may yield a higher present discount value of the entire stream of per-period profits than the features of either type of contract alone, we also consider adding an additional "contractual unit revenue instead of price" feature to the technical service contract.

In particular, we run another version of each of our TSC scenarios ("TSC Optimal", "TSC Optimal, Cost Ceiling", "TSC Actual Optimal", "TSC Actual Optimal, Cost Ceiling"), this time using contractual unit revenue $R(P_t)$ instead of price P_t. We set the contractual unit revenue $R(P_t)$ equal to the mean of the oil price over the years 2010-2030. In other words, $R(P_t)$ is constant at \$99.59 per barrel for all years. We therefore assume that the IOC is basing its optimal decision using contractual unit revenue $R(P_t)$ instead of price P_t, even though the actual revenue and profit that is realized is based on the price P_t.

Table 6 summarizes the contractual constraints we impose in our TSC with fixed price contractual unit revenue scenarios. These contractual constraints are imposed in addition to the technical, geological, and feasibility constraints in Table 4.

4.8. Combining features of TSC and buy-back

To analyze whether some novel combination of contractual features in technical service contracts and buy-back contracts may yield a higher present discount value of the entire stream of per-period profits than the features of either type of contract alone, we also consider several alternative contract scenarios that combine features of technical service contracts and buy-back contracts.

The "Buy-Back Optimal, Wells Not Predetermined" scenario is similar to the "Buy-Back Optimal" scenario in that cost reductions are not recoverable (i.e., the IOC faces costs $\max\{c(q_t, n_t, N_t), \underline{c}_t\}$). Unlike the "Buy-Back Optimal" scenario, however, in the "Buy-Back Optimal, Wells Not Predetermined" scenario the number of wells is not predetermined (i.e., and $\lambda_t^{\overline{n}} = \lambda_t^{\underline{n}} = 0$ for all t, q_t, n_t, S_t, N_t).

The "Buy-Back Optimal, Cost Reduction Recoverable" scenario is similar to the "Buy-Back Optimal" scenario in that the number of wells is predetermined (i.e., $\tilde{n}_t = \overline{n}_t = \underline{n}_t$, $\lambda_t^{\overline{n}} \geq 0$, and $\lambda_t^{\underline{n}} \geq 0$). Unlike the "Buy-Back Optimal" scenario, however, in the "Buy-Back Optimal, Cost Reduction Recoverable" scenario, cost reductions are recoverable (i.e., $\underline{c}_t$ is low enough that $I\{c(\cdot) \geq \underline{c}_t\} = 1$ for all t, q_t, n_t, S_t, N_t).

The "TSC Optimal, Cost Reduction Not Recoverable" scenario is similar to the "TSC Optimal" scenario in that there is a production cap set to 2.65 million barrels/day for the years 2010-2021, and set to the contractual plateau production target in the Rumaila TSC of 2.85 million barrels per day for the years 2022-2030. Unlike the "TSC Optimal" scenario, however, in the "TSC Optimal, Cost Reduction Not Recoverable" scenario cost reductions are not recoverable (i.e., the IOC faces costs $\max\{c(q_t, n_t, N_t), \underline{c}_t\}$).

Table 7 summarizes the contractual constraints we impose in our scenarios combining features of technical service contracts and buy-back contracts. These contractual constraints are imposed in addition to the technical, geological, and feasibility constraints in Table 4.

5. Results

5.1. Technical service contract

The results for oil production, well drilling, revenue, and costs for the first-best scenario, "Most Likely to be Realized" scenario, and technical service contract (TSC) scenarios are presented in Figure 1. The first-best production increases each year until the year 2020, declines from 2020 to 2028, and increases in the final 2 years. The first-best well drilling is high in the first year, drops in the second year, increases steadily from the second year to the second-to-last year of well drilling, and declines somewhat in the final year of well drilling.

When comparing the TSC scenarios with the first-best, we see that, owing to the production cap, maximum production in all the TSC scenarios is not as high as in the first-best. Production in the later years also does not decline as much in the TSC scenarios as it does in the first-best. The number of new wells drilled fluctuates more in the TSC scenarios than it does in the first-best. Per-period costs are lower under the TSC scenarios than under the first-best for the initial years, but then exceed the per-period costs under the first-best in the later years.

In comparing the different TSC scenarios with each other, we see that, as expected, the TSC scenarios with the more stringent production cap ("TSC Actual Optimal" and "TSC Actual Optimal, Cost Ceiling") have a lower maximum production than the TSC scenarios with the less stringent production cap based on the contract terms in the Rumaila TSC ("TSC Optimal" and "TSC Optimal, Cost Ceiling").

In the absence of a cost ceiling, well drilling under a technical service contract (in both "TSC Optimal" and "TSC Actual Optimal") closely matches the first-best well drilling in the early years of the contract. Nevertheless, as this yields a cost higher than the cost under the "Most Likely to be Realized" scenario, when a cost ceiling is imposed, well drilling in the first year under a technical service contract (in both "TSC Optimal, Cost Ceiling" and "TSC Actual Optimal, Cost Ceiling") is very low in the first year, increases in the second year, then falls below the first-best well drilling in the third year.

Compared to the optimal well drilling under the TSC scenarios, the predicted well drilling under the "Most Likely to be Realized" scenario peaks earlier than is optimal under a technical service contract. Compared to the optimal well drilling under the first-best, the predicted well drilling under the "Most Likely to be Realized" scenario fluctuates more than is first-best.

Figure 2 presents the present discounted value of the entire stream of profits under the first-best scenario, the "Most Likely to be Realized" scenario, and the TSC scenarios. Under the first-best, the present discounted value of the entire stream of profits is $627 billion (in 2008 dollars). As represented by the "Most Likely to be Realized" scenario, the present discounted value of the entire stream of profits under the Rumaila TSC is predicted to be $538 billion (in 2008 dollars), which is $89 billion lower than the first-best, representing a deadweight loss of 14.2% relative to the first-best.

Compared to the first-best, the "TSC Optimal" scenario, which represents the maximum present discounted value of the entire stream of profits that can be achieved under the Rumaila TSC if there were no other sources of inefficiency aside from the terms of the contract, yields a maximum present discounted value of the entire stream of profits of $620 billion (in 2008 dollars), representing a deadweight loss of 1.1% relative to the first-best. If the IOC faced an implicit cost ceiling under the Rumaila TSC ("TSC Optimal, Cost Ceiling"), it would achieve at best $578 billion (in 2008 dollars), representing a deadweight loss of 7.9% relative to the first-best. If the implicit production cap under the Rumaila TSC was actually lower than the contractual production cap ("TSC Actual Optimal"), then the IOC would achieve at best $576 billion (in 2008 dollars), representing a deadweight loss of 8.1% relative to the first-best; if, in addition, the IOC faced an implicit cost ceiling ("TSC Actual Optimal, Cost Ceiling"), then it would achieve at best $537 billion (in 2008 dollars), representing a deadweight loss of 14.4% relative to the first-best. As represented by the "Most Likely to be Realized" scenario, the IOC is predicted to achieve $538 billion (in 2008 dollars), which is roughly comparable to the present discounted value of the entire stream of profits under the "TSC Actual Optimal, Cost Ceiling" scenario.

As seen in the robustness checks in Appendix B, Appendix C, Appendix D, and Appendix E, our qualitative results are robust to the price estimates, cost parameters, discount rate, and geological feasibility parameters, respectively.

In order to analyze whether a technical service contract incentivizes the IOC to pursue a dynamically optimal policy, we model the Rumaila technical service contract cash flow from the

IOC's perspective in order to calculate the IOC's net present value and rate of return under the contract. We describe this cash flow analysis and its results in detail in Appendix G. As detailed in Appendix G, our results suggest that, assuming no additional sources of inefficiency aside from possibly an implicit cost ceiling, the structure of a technical service contract does incentivize the IOC to pursue a dynamically optimal policy of oil production and well drilling rather than the policy predicted under the "Most Likely to be Realized" scenario, as doing so not only yields a higher discounted value of the entire stream of joint profits to the IOC and the Iraqi government than was predicted under the "Most Likely to be Realized" scenario, but also a higher net present value and higher rate of return to the IOC as well.

5.2. Buy-back contract and production sharing contract

The results for oil production, well drilling, revenue, and costs for the "Buy-Back Optimal" scenario are presented in Figure F.1 in Appendix F. Oil production under a buy-back contract is very similar to the first-best oil production, though it is slightly lower in the initial years of the contract and slightly higher in the final 3 years of the contract. As a consequence, revenue under a buy-back contract is very similar to the first-best revenue, though it is slightly lower in the initial years of the contract and slightly higher in the final 3 years of the contract. Because cost reductions are not recoverable under a buy-back contract, the IOC does not reduce production much below the first-best to reduce costs even when the pre-determined well drilling is high. Thus, because the number of wells is predetermined and therefore not chosen optimally, the costs under the buy-back contract are higher than costs under the first-best even though production is similar.

The results for oil production, well drilling, revenue, and costs for the "Production Sharing Optimal" scenario are presented in Figure F.2 in Appendix F. Oil production under a production sharing contract is very similar to the first-best oil production, though its peak is slightly lower and production in the final 2 years is slightly lower. Even though the total revenue under production sharing similarly tracks the first-best revenue, the revenue the IOC receives is lower because it faces the contractual unit revenue $R(P_t)$ instead of the price P_t. Because changes in price P_t result in smaller changes in contractual unit revenue $R(P_t)$, even though oil price is increasing, oil production under production sharing peaks at a lower level than is first-best. Well drilling under production sharing is also very similar to the first-best, though it is slightly lower than is first-best during the year of peak production.

Figure 3 compares the present discounted value of the entire stream of profits under the "TSC Optimal", "Buy-Back Optimal", and "Production Sharing Optimal" scenarios, which represent the maximum present discounted value of the entire stream of profits that can be achieved under the Rumaila technical service contract, our base case buy-back contract, and our base case production sharing contract, respectively, if there were no other sources of inefficiency aside from the terms of the respective contract. Of the three types of contracts, the production sharing contract is the most efficient: the "Production Sharing Optimal" incurs a deadweight loss of only 0.02% relative to the first-best. The next most efficient contract is the technical service contract: the "TSC Optimal" scenario incurs a deadweight loss of 1.1% relative to the first-best. The least efficient of the 3 contract types is the buy-back contract: the "Buy-Back Optimal" scenario incurs a deadweight loss of 2.5% relative to the first-best.

We conduct robustness checks for our production sharing contract scenario in which we vary the contractual price $P_t^c(P_t)$ upon which the contractual unit revenue $R(P_t)$ is based. In our base case production sharing contract above, we assume that each year the contractual oil price is the oil price for that year (i.e., $P_t^c(P_t) = P_t$). For robustness, we also try specifications in which the contractual oil price is a constant set at the minimum ($66.34/barrel), maximum ($119.54/barrel), and mean ($99.59/barrel), respectively, of our oil price estimates over the years 2010-2030. According to the results in Figure F.3 in Appendix F, the lower the contractual price upon which contractual unit revenue is based, the lower is the peak production and the well drilling during the year of peak production. As seen in Figure F.4 in Appendix F, the present discounted value of the entire stream of profits is robust to the contractual price specification: it is unaffected by whether the contractual oil price is set to the price, the maximum price, or the mean price; and is only 0.04% lower when the contractual oil price is set to the minimum oil price.

5.3. TSC with higher contractual plateau production target

Figure F.5 in Appendix F presents the results for oil production, well drilling, revenue, and costs when the technical service contract has a higher contractual plateau production target than the 2.85 million barrels per day that was specified in the Rumaila TSC. The higher the contractual plateau production target, the closer the production, drilling, revenue, and costs are to the first-best. As seen in Figure F.6 in Appendix F, when the contractual plateau production target is set to

2.95 million barrels per day instead of the 2.85 million barrels per day that was specified in the Rumaila TSC, the deadweight loss decreases from 1.1% relative to the first-best under "TSC Optimal", to 0.72% relative to the first-best under "TSC Optimal, Contractual Plateau Production Target = 2.95 million barrels/day". Thus, increasing the contractual plateau production target can increase the efficiency of a technical service contract.

5.4. TSC with fixed price contractual unit revenue

To analyze whether some novel combination of contractual features in technical service contracts and production sharing contracts may a yield higher present discount value of the entire stream of per-period profits than features of either type of contract alone, we run another version of each of our TSC scenarios ("TSC Optimal", "TSC Optimal, Cost Ceiling", "TSC Actual Optimal", "TSC Actual Optimal, Cost Ceiling"), this time using contractual unit revenue $R(P_t)$ instead of price P_t, where the contractual unit revenue $R(P_t)$ is fixed at the mean of the oil price over the years 2010-2030.

As seen in Figure 4, the qualitative results for oil production, well drilling, revenue, and costs when a fixed price contractual unit revenue condition is added to each technical service contract scenario are similar to the respective TSC results in Figure 1. Comparing Figure 5 with Figure 2, adding a fixed price contractual unit revenue condition does not change the present discounted value of the entire stream of profits under "TSC Optimal", and only slightly changes the present discounted value of the entire stream of profits under "TSC Optimal, Cost Ceiling" and "TSC Actual Optimal".

Nevertheless, adding a fixed price contractual unit revenue condition increases the present discounted value of the entire stream of profits under the "TSC Actual Optimal, Cost Ceiling" scenario, which represents the dynamically optimal production and drilling under a technical service contract when additional factors that impose an implicit cost ceiling and constrain production are present. In particular, when additional factors that impose an implicit cost ceiling and constrain production are present, adding a fixed price contractual unit revenue condition to the technical service contract increases the present discounted value of the entire stream of profits by 15.8%.

Furthermore, when a technical service contract is combined with a fixed price contractual unit revenue condition, "TSC Actual Optimal, Cost Ceiling" no longer yields a present discounted value similar to that under the "Most Likely to be Realized" scenario, but instead is more efficient than "TSC Optimal", which represents the dynamically optimal production and drilling under a technical service contract when there are no other sources of inefficiency aside from the terms of the contract, with or without the fixed contractual unit revenue condition. The deadweight loss under "TSC Actual Optimal, Cost Ceiling with Fixed Price" is 0.87% relative to the first-best.

Thus, when additional factors that impose an implicit cost ceiling and constrain production are present, the efficiency of technical service contracts can be increased by combining a technical service contract with features from production sharing contracts such as using a fixed price contractual unit revenue condition.

5.5. *Combining features of TSC and buy-back*

Figure 6 presents the results for oil production, well drilling, revenue, and costs for our alternative contract scenarios that combine features of technical service contracts and buy-back contracts. Production paths under "TSC Optimal" and "TSC Optimal, Cost Reduction Not Recoverable" are similar, suggesting that the production cap in a technical service contract largely determines the production in these scenarios, whether or not cost reductions are recoverable. In terms of well drilling, however, combining a technical service contract with a condition that cost reduction is not recoverable leads to well drilling that increases costs.

As seen in Figure 7, the technical service contract (as depicted by "TSC Optimal") is more efficient than the buy-back contract (as depicted by "Buy-Back Optimal") and also more efficient than any combination of the TSC and buy-back features considered. On the other hand, buy-back contracts become more efficient when they are combined with technical service contract features such as not predetermining the number of wells drilled or allowing cost reductions to be recoverable.

6. Discussion and Conclusion

In this paper we develop a dynamic model of oil production and well drilling to analyze the economic efficiency of three different types of oil production contracts: technical service contracts, buy-back contracts, and production sharing contracts. We apply our model to the Rumaila oil field in Iraq, which is under development through a technical service contract.

Several main results can be gleaned from our analysis. First, when comparing the optimal outcome under the Rumaila technical service contract, our base case buy-back contract, and our base case production sharing contract, and assuming no other sources of inefficiency aside from the terms of the respective contract, the production sharing contract is the most efficient, followed by the technical service contract, and the least efficient of the 3 contract types is the buy-back contract (Section 5.2; Figure 3).

Second, the efficiency of technical service contracts can be increased by increasing the contractual plateau production target so that the production cap is less stringent (Section 5.3; Figure F.6 in Appendix F); or, when additional factors that impose an implicit cost ceiling and constrain production are present, by combining a technical service contract with features from production sharing contracts such as using a fixed price contractual unit revenue condition (Section 5.4; Figure 5). On the other hand, combining a technical service contract with features from buy-back contracts can decrease efficiency (Section 5.5; Figure 7).

Third, when implementing a contract, there may be more sources of inefficiency than those introduced by the terms of the contract itself. As represented by the "Most Likely to be Realized" scenario, the Rumaila TSC is predicted to result in a deadweight loss of 14.2% relative to the first-best, which is higher than the deadweight loss due to the terms of the Rumaila technical service contract alone (as represented by "TSC Optimal") of 1.1% relative to the first-best (Section 5.1; Figure 2). These additional sources of inefficiency include an implicit cost ceiling (which we account for in our "TSC Optimal, Cost Ceiling" and "TSC Actual Optimal, Cost Ceiling" scenarios); and production constraints due to OPEC and/or export capacity constraints (which we account for in our "TSC Actual Optimal" and "TSC Actual Optimal, Cost Ceiling" scenarios).

Our results suggest that, in order to reduce the deadweight loss that may result from technical service contracts such as the Rumaila TSC, Iraq may wish to consider improving the design of its oil production contracts and reforming its oil sector. The efficiency of technical service contracts can be increased by increasing the contractual plateau production target; or, when additional factors that impose an implicit cost ceiling and constrain production are present, by combining a technical service contract with features from production sharing contracts such as using a fixed price contractual unit revenue condition. In addition, Iraq may consider improving the efficiency of its technical service contracts by not enforcing an implicit cost ceiling, and by expanding its future OPEC quota and its export capacity. Iraq may also consider adopting production sharing contracts, which may be more efficient than technical service contracts, since the Iraqi Constitution allows other contractual frameworks, although the implementation of other frameworks in Iraq might not be possible unless it is accompanied with more general reforms in the governing organizations, institutions, and companies in its oil sector.

In this paper we focus on analyzing the economic efficiency of various oil production contracts, and do so by comparing the present discounted value of the entire stream of profits that can be obtained if oil production and well drilling were chosen in a dynamically optimal manner subject to the constraints imposed by the contracts. Countries may care about other criteria in addition to, or aside from, economic efficiency when choosing and designing their contracts, however.

In almost all countries with service contracts such as technical service contracts and buy-back contracts, the primary motivation for pursuing service contracts rather than production sharing contracts is to garner the IOCs' cooperation and expertise for their development and exploration projects without having to transfer the control of the reserves and extracted resources to the IOCs. As explained in Ghandi and Lin (2014), one main driving factor why many countries are adopting a variation of service contracts is their concern for maintaining their sovereignty over their natural resources. Under a service contract, countries maintain field ownership and in most cases produced crude ownership rights as well, and do not have to allocate them to the foreign company. Countries are interested in adopting service contracts because service contracts enable them to give up less control over the fields and over the produced crude to foreign oil companies while still using the expertise of these companies.

In designing their contracts, host countries may also want oil price insurance in addition to operational expertise from the IOCs.[18] Because oil resources are a significant source of revenues for countries like Iraq, oil price variability can severely affect the country's finances. In Iraq, for example, where oil revenues constitute 90% of the revenues to the Iraqi government, falling oil prices have caused oil revenues to decline by 85% in 2016 relative to earlier years even though oil production has increased to 3.6 million barrels per day, causing a financial crisis for the Iraqi

[18] Stroebel and van Bentham (2013) show theoretically and verify empirically that oil price insurance provided by tax contracts is increasing in a country's cost of expropriation and decreasing in its production expertise.

government (Kennedy, 2016). Countries may therefore favor contracts that guard them against oil price variability.

Although the focus of our paper is on economic efficiency rather than on guarding against oil price variability, our results do provide some insight on this issue, which we hope to more fully analyze in future work. Our analysis of production sharing contracts shows that the present discounted value of the entire stream of profits is robust to the contractual price specification: it is unaffected by whether the contractual oil price is set to the price, the maximum price, or the mean price; and is only 0.04% lower when the contractual oil price is set to the minimum oil price (Section 5.2; Figure F.4 in Appendix F). Thus, our results suggest that a production sharing contract may be robust to oil price volatility: even if the price is more volatile than anticipated by the contract, the present discounted value of the entire stream of profits does not change by much, if at all.

Our results also show that, when additional factors that impose an implicit cost ceiling and constrain production are present, the efficiency of technical service contracts can be increased by combining a technical service contract with features from production sharing contracts such as using a fixed price contractual unit revenue condition (Section 5.4; Figure 5). Thus, when additional factors that impose an implicit cost ceiling and constrain production are present, combining a technical service contract with features from production sharing contracts such as using a fixed price contractual unit revenue condition may help guard against oil price variability and be more efficient than a technical service contract even if the price is more volatile than anticipated by the contract.

Since price volatility through time could affect our optimization results, we also run a specification of our model using Rumaila-specific price estimates based on the EIA 2012 Reference case price projection rather than the EIA 2010 Reference case price projection for robustness. In addition, to capture the possibility of low oil prices, we also run a specification of our model using Rumaila-specific price estimates based on the EIA 2010 Low Oil Price scenario for robustness as well. As seen in the results of our robustness checks in Appendix B, the results for oil production, well drilling, and costs are robust to the oil price specification, which suggests that our results are robust to oil price volatility. We hope to more fully analyze the design of contracts to guard against oil price variability in future work.

Although we apply our model to the Rumaila oil field in particular, many of our qualitative results and insights can be generalized to other oil fields. First, our qualitative result from our model in Section 2 and the first-order conditions in Table 1 that since some contractual features may offset each other, it is possible that some combinations of contractual features may increase the present discounted value of the entire stream of per-period profits under a contract relative to other combinations, and/or relative to certain contractual features in isolation, holds generally for all oil fields.

Second, our qualitative results that sources of inefficiencies in contracts include both terms and constraints in the contracts themselves as well as other factors such as implicit cost ceilings or production constraints apply generally to all oil fields as well.

Third, since the relative efficiency of various contracts depends on the particular functional forms of the functions and the values of the parameters, including the sign and magnitudes of first-order derivatives, second-order derivatives, and cross partials, our results on the relative efficiency of production sharing contracts and technical service contracts over buy-back contracts, and on how to improve technical service contracts are generalizable to other oil fields with Arabian light and/or medium crude and an important water injection component, since these features govern our choices for many of the functions and parameters we use in our model, including those for cost and revenue. In future work, we hope to apply our model to our fields as well.

In addition to the sources of inefficiency in the implementation of the Rumaila TSC that we analyze in this paper, there may be other sources of inefficiency as well that we hope to further analyze in future work. One additional source of inefficiency is that the objectives of the Iraqi government and its entities may differ from the maximization of the present discounted value of the entire stream of joint profits between the IOC and the Iraqi government. The Iraqi government entity awarding the contracts is different from the one making cost decisions, which is different from the one receiving the revenue, and each may have a different objective. The Ministry of Oil and its Petroleum Contracts and Licensing Directorate, which awards the contract, follow a policy of maximizing revenue with an emphasis on garnering a higher plateau production target in the bidding process. In contrast, the state-owned South Oil Company, which oversees the Rumaila operation and has to approve the IOC's work plans and capital expenditures, is primarily concerned with cost. The revenue goes through the Ministry of Oil's Treasury department. Thus, the South

Oil Company decides on the cost without seeing the revenue.[19] The different Iraqi government entities involved in the contract may therefore have different objectives which are not well-aligned with that of maximizing the present discounted value of the entire stream of joint profits between the IOC and the Iraqi government.

Although objectives that differ from profit maximization may be a source of inefficiency in theory, in their analysis of buy-back contracts in Iran, Ghandi and Lin (2012) find that the contract's production profile neither maximizes the present discounted value of the entire stream of profits nor maximizes cumulative production, even though the latter was the National Iranian Oil Company's purported objective. Thus, objectives other than maximizing the present discounted value of the entire stream of profits may not fully explain any inefficiencies that arise from oil production contracts.

Other additional sources of inefficiency that we hope to analyze in future work include principal-agent problems between the Iraqi government and the IOC, informational asymmetries, and risk aversion. As we wish to model the optimal production and drilling, we abstract from these considerations in this paper. We hope to study the optimal design of oil production contracts in the presence of principal-agent problems, asymmetric information, and risk aversion in future work.

[19] Personal communication with industry experts

References

Adelman, M.A. (1993). Modelling world oil supply. *Energy Journal*, 14, 1-32.

Ajrash, K., and DiPaola, A. (2011). Iraq aims to join OPEC quota system in 2014. *Bloomberg*, 26 October 2011.

Almansour, A., and Insley, M. (2016). The impact of stochastic extraction cost on the value of an exhaustible resource: An application to Alberta oil sands. *Energy Journal,* 37 (2), 61-88.

Anderson, S.T., Kellogg, R., and Salant, S.W. (2018). Hotelling under pressure. *Journal of Political Economy*, 126 (3), 984-1026.

Bakir, S. (2012). Iraq awards water-injection oil project to CH2M instead of ExxonMobil. *IHS Global Insight*, 11 October 2012.

Bellman, R. (1957). *Dynamic programming.* Princeton: Princeton University Press.

Bindemann, K. (1999). *Production-sharing agreements: An economic analysis*. Oxford Institute for Energy Studies WPM 25.

Blanchard, C.M. (2008). *Iraq: Oil and Gas Legislation, Revenue Sharing, and U.S. Policy.* Congressional Research Service.

BP p.l.c. (2012). *Field of the Future.* Retrieved August 14, 2012. URL: http://www.bp.com/sectiongenericarticle.do?categoryId=9025118&contentId=7047802

Center for Global Energy Studies. (1993). *Oil Production Capacity in the Gulf, Vol. II: Saudi Arabia.*

Daly, M.C. (2010, February). *BP in Rumaila.* Retrieved June 3, 2013, from BP.com: http://www.bp.com/liveassets/bp_internet/globalbp/STAGING/global_assets/downloads/P/PR_daly_rumaila_speech.pdf

Dow Jones & Company. (2010-2012). *Dow Jones Newswires, Dow Jones Energy Service*. Retrieved October 2012, from Dow Jones & Company Inc.: Factiva

Energy Information Administration [EIA]. (1996a). *International Energy Outlook*. DOE/EIA-0484. Washington, DC.

Energy Information Administration [EIA]. (1996b). *The 1992 Oil Market Simulation Model.* Washington, DC.

Energy Information Administration [EIA]. (2010). *Annual Energy Outlook 2010.* Washington, DC.

Energy Information Administration [EIA]. (2012). *Annual Energy Outlook 2012.* Washington, DC.

Energy Information Administration [EIA]. (2019a). *Crude Oil Production, Saudi Arabia, Annual*. Retrieved December 23, 2019. URL: https://www.eia.gov/opendata/qb.php?category=1039874&sdid=STEO.COPR_SA.A

Energy Information Administration [EIA]. (2019b). *Petroleum and other liquids production - 2018.* Retrieved December 23, 2019. URL: https://www.eia.gov/beta/international/?fips=IZ

Farzin, Y.H. (1992). The time path of scarcity rent in the theory of exhaustible resources. *Economic Journal*, 102, 841-851.

Farzin, Y.H. (1995). Technological change and the dynamics of resource scarcity measures. *Journal of Environmental Economics and Management*, 29, 105-120.

Feng, Z., Zhang, S.-B., and Gao, Y. (2014). On oil investment and production: A comparison of production sharing contracts and buyback contracts. *Energy Economics*, 42, 395-402.

Gao, W., Hartley, P.R., and Sickles, R.C. (2009). Optimal dynamic production from a large oil field in Saudi Arabia. *Empirical Economics*, 37 (1), 153-184.

GDS Publishing, Inc. (2010). Rebirth of Rumaila. *Next Generation Oil & Gas,* 5 (Exploration).

Ghandi, A., and Lin, C.-Y.C. (2012). Do Iran's buy-back service contracts lead to optimal production?: The case of Soroosh and Nowrooz. *Energy Policy*, 42, 181-190.

Ghandi, A., and Lin, C.-Y.C. (2014). Oil and gas service contracts around the world: A review. *Energy Strategy Reviews*, 3, 63-71.

Ghandi, A., and Lin Lawell, C.-Y.C. (2017). On the rate of return and risk factors to international oil companies in Iran's buy-back service contracts. *Energy Policy*, 103, 16-19.

Ghoddusi, H. (2010). Dynamic investment in extraction capacity of exhaustible resources. *Scottish Journal of Political Economy*, 57 (3), 359-373.
Griffin, J.M. (1985). OPEC behavior: A test of alternative hypotheses. *American Economic Review*, 75 (5), 954-963.
Hafidh, H. (2010). Iraq lauds licensing auction after awarding three fields. *Wall Street Journal*, 20 October 2010.
Hafidh, H. (2012). UPDATE: Iraq delays energy bidding round to May 30-31. *Dow Jones News Service*, 30 January 2012. Hanson, D.A. (1980). Increasing extraction costs and resource prices: Some further results. *Bell Journal of Economics*, 11 (1), 335-342.
Hotelling, H. (1931). The economics of exhaustible resources. *Journal of Political Economy*, 39 (2), 137-175.
ICE Crude Oil. (2012). Retrieved October 5, 2012, from IntercontinentalExchange, Inc.: https://www.theice.com/publicdocs/ICE_Crude_Oil.pdf
International Energy Agency [IEA]. (2012). *Iraq Energy Outlook. World Energy Outlook 2012 Special Report* . Organization for Economic Co-operation and Development (OECD), Paris, France.
Jassim, S.Z., and Goff, J.C. (2006). *Geology of Iraq.* Prague: Dollin.
Kennedy, C. (2016). Iraq on the brink of chaos as oil revenues fall. *OilPrice.com*, 19 February 2016.
Kheiravar, K.H., Lin Lawell, C.-Y.C., and Jaffe, A.M. (2020). The world oil market and OPEC: A structural econometric model. Working paper, Cornell University.
Lando, B., and Dourian, K. (2010). Output at Iraq's Rumaila field stabilized; BP led consortium says October saw high activity level. *Platts Oilgram News*, 6 November 2010.
Leighty, W., and Lin, C.-Y.C. (2012). Tax policy can change the production path: A model of optimal oil extraction in Alaska. *Energy Policy*, 41, 759-774.
Lin, C.-Y.C. (2009). Insights from a simple Hotelling model of the world oil market. *Natural Resources Research*, 18 (1), 19-28.
Lin Lawell, C.-Y.C. (2020). Market power in the world oil market: Evidence for an OPEC cartel and an oligopolistic non-OPEC fringe. Working paper, Cornell University.
Lin, C.-Y.C., Meng, H., Ngai, T.Y., Oscherov, V., and Zhu, Y.H. (2009). Hotelling revisited: Oil prices and endogenous technological progress. *Natural Resources Research*, 18 (1), 29-38.
Lin, C.-Y.C., and Wagner, G. (2007). Steady-state growth in a Hotelling model of resource extraction. *Journal of Environmental Economics and Management*, 54 (1), 68-83.
Marcel, V., and Mitchell, J. (2006). *Oil Titans: National Oil Companies in the Middle East*. Washington, DC: Brookings Institution Press.
Pesaran, M.H. (1990). An econometric analysis of exploration and extraction of oil in the U.K. Continental Shelf. *Economic Journal*, 100 (401), 367-390.
Pindyck, R.S. (1978). The optimal exploration and production of nonrenewable resources. *Journal of Political Economy*, 86 (5), 841-861.
Pindyck, R.S. (1980). Uncertainty and exhaustible resource markets. *Journal of Political Economy*, 88 (6), 1203-1225.
Republic of Iraq, Ministry of Oil. (2011). *Technical Service Contract.* Retrieved November 29, 2011. URL: http://www.oil.gov.iq/Technical_Service_Contract.pdf
Reuters. (2012, January 4). *UPDATE 1-Iraq delays 4th energy auction to Apr 11-12-official.* Retrieved January 25, 2012. URL: http://www.reuters.com/article/2012/01/04/iraq-energy-auction idUSL6E8C418720120104
Rigzone. (2012). *How Does Water Injection Work.* Retrieved February 22, 2012. URL: http://www.rigzone.com/training/insight.asp?insight_id=341&c_id=4
Sankey, P., Clark, D.T., and Micheloto, S. (2010). *The Mother of All Oil Stories.* Deutsche Bank, Global Market Research.
Shiravi, A., and Ebrahimi, S.N. (2006). Exploration and development of Iran's oilfields through buyback. *Natural Resources Forum*, 30 (3), 199-206.

Smith, J.L. (2013). Issues in extractive resource taxation: A review of research methods and models. *Resources Policy*, 38, 320-331.
Smith, J.L. (2014). A parsimonious model of tax avoidance and distortions in petroleum exploration and development. *Energy Economics*, 43, 140-157.
Solow, R.M., and Wan, F.Y. (1976). Extraction costs in the theory of exhaustible resources. *Bell Journal of Economics*, 7 (2), 359-370.
Sperling, D., and Gordon, D. (2010). *Two Billion Cars: Driving Toward Sustainability*. Oxford University Press.
Stroebel, J., and van Bentham, A. (2013). Resource extraction contracts under threat of expropriation: Theory and evidence. *Review of Economics and Statistics*, 95 (5), 1622-1639.
Sund, K., and Hausken, K. (2012). Fixed price contract versus incentive based contract in the oil and gas industry. *International Journal of Global Energy Issues*, 35 (5), 371-410.
The Petroleum Services Group (PSG) at Deloitte. (2011). *Launch of the 4th Licensing Round in Iraq 2011*. Retrieved January 25, 2012. URL: http://www.psg.deloitte.com/NewsLicensingRounds_IQ_110610.asp
Van Groenendaal, W.J.H., and Mazraati, M. (2006). A critical review of Iran's buyback contracts. *Energy Policy*, 34 (18), 3709-3718.
Weitzman, M.L. (2003). *Income, Wealth, and the Maximum Principle*. Harvard University Press, Cambridge, MA.
Young, D., and Ryan, D.L. (1996). Empirical testing of a risk-adjusted Hotelling model. *Resource and Energy Economics*, 18, 265-289.
Zhang, W., and Lin Lawell, C.-Y.C. (2017). Market power in nonrenewable resource markets: An empirical dynamic model. *Land Economics*, 93 (1), 74-86.

Table 1. First-order conditions

First-best

$$P_t-\frac{\partial c(\cdot)}{\partial q_t}-365\sum_{\tau=t+1}^{T}\left(\frac{1}{1+r}\right)^{T-\tau+1}\left(\mu_\tau^{\bar{q}}\frac{\partial f(\cdot)}{\partial S_\tau}+\mu_\tau^{S}\right)+\frac{1}{1+r}\left(\mu_{t+1}^{\delta}\cdot s(q_{t+1}-q_t)\right)-\mu_t^{\omega}+\mu_t^{\bar{q}}\left(\frac{\partial f(\cdot)}{\partial q_t}-1\right)-\mu_t^{\delta}\cdot s(q_t-q_{t-1})-365\mu_t^{S}-\mu_t^{\underline{q}}=0$$

$$-\frac{\partial c(\cdot)}{\partial n_t}+\sum_{\tau=t+1}^{T}\left(\frac{1-d}{1+r}\right)^{T-\tau+1}\left(-\frac{\partial c(\cdot)}{\partial N_\tau}+\mu_\tau^{\omega}\omega+\mu_\tau^{\bar{q}}\frac{\partial f(\cdot)}{\partial N_\tau}\right)+\mu_t^{\omega}\omega+\mu_t^{\bar{q}}\frac{\partial f(\cdot)}{\partial n_t}-\mu_t^{\bar{n}}-\mu_t^{\underline{n}}=0$$

Technical service contract

$$P_t-\frac{\partial c(\cdot)}{\partial q_t}-365\sum_{\tau=t+1}^{T}\left(\frac{1}{1+r}\right)^{T-\tau+1}\left(\mu_\tau^{\bar{q}}\frac{\partial f(\cdot)}{\partial S_\tau}+\mu_\tau^{S}\right)+\frac{1}{1+r}\left(\mu_{t+1}^{\delta}\cdot s(q_{t+1}-q_t)\right)-\mu_t^{\omega}+\mu_t^{\bar{q}}\left(\frac{\partial f(\cdot)}{\partial q_t}-1\right)-\mu_t^{\delta}\cdot s(q_t-q_{t-1})-365\mu_t^{S}-\mu_t^{\underline{q}}-\lambda_t^{q}=0$$

$$-\frac{\partial c(\cdot)}{\partial n_t}+\sum_{\tau=t+1}^{T}\left(\frac{1-d}{1+r}\right)^{T-\tau+1}\left(-\frac{\partial c(\cdot)}{\partial N_\tau}+\mu_\tau^{\omega}\omega+\mu_\tau^{\bar{q}}\frac{\partial f(\cdot)}{\partial N_\tau}\right)+\mu_t^{\omega}\omega+\mu_t^{\bar{q}}\frac{\partial f(\cdot)}{\partial n_t}-\mu_t^{\bar{n}}-\mu_t^{\underline{n}}=0$$

Technical service contract with a cost ceiling

$$P_t-\frac{\partial c(\cdot)}{\partial q_t}-365\sum_{\tau=t+1}^{T}\left(\frac{1}{1+r}\right)^{T-\tau+1}\left(\mu_\tau^{\bar{q}}\frac{\partial f(\cdot)}{\partial S_\tau}+\mu_\tau^{S}\right)+\frac{1}{1+r}\left(\mu_{t+1}^{\delta}\cdot s(q_{t+1}-q_t)\right)-\mu_t^{\omega}+\mu_t^{\bar{q}}\left(\frac{\partial f(\cdot)}{\partial q_t}-1\right)-\mu_t^{\delta}\cdot s(q_t-q_{t-1})-365\mu_t^{S}-\mu_t^{\underline{q}}-\lambda_t^{q}-\lambda_t^{c}\frac{\partial c(\cdot)}{\partial q_t}=0$$

$$-\frac{\partial c(\cdot)}{\partial n_t}+\sum_{\tau=t+1}^{T}\left(\frac{1-d}{1+r}\right)^{T-\tau+1}\left(-\frac{\partial c(\cdot)}{\partial N_\tau}+\mu_\tau^{\omega}\omega+\mu_\tau^{\bar{q}}\frac{\partial f(\cdot)}{\partial N_\tau}-\lambda_\tau^{c}\frac{\partial c(\cdot)}{\partial N_\tau}\right)+\mu_t^{\omega}\omega+\mu_t^{\bar{q}}\frac{\partial f(\cdot)}{\partial n_t}-\mu_t^{\bar{n}}-\mu_t^{\underline{n}}-\lambda_t^{c}\frac{\partial c(\cdot)}{\partial n_t}=0$$

Buy-back contract

$$P_t-I\{c(\cdot)\geq\underline{c}_t\}\frac{\partial c(\cdot)}{\partial q_t}-365\sum_{\tau=t+1}^{T}\left(\frac{1}{1+r}\right)^{T-\tau+1}\left(\mu_\tau^{\bar{q}}\frac{\partial f(\cdot)}{\partial S_\tau}+\mu_\tau^{S}\right)+\frac{1}{1+r}\left(\mu_{t+1}^{\delta}\cdot s(q_{t+1}-q_t)\right)-\mu_t^{\omega}+\mu_t^{\bar{q}}\left(\frac{\partial f(\cdot)}{\partial q_t}-1\right)-\mu_t^{\delta}\cdot s(q_t-q_{t-1})-365\mu_t^{S}-\mu_t^{\underline{q}}=0$$

$$-I\{c(\cdot)\geq\underline{c}_t\}\frac{\partial c(\cdot)}{\partial n_t}+\sum_{\tau=t+1}^{T}\left(\frac{1-d}{1+r}\right)^{T-\tau+1}\left(-I\{c(\cdot)\geq\underline{c}_\tau\}\frac{\partial c(\cdot)}{\partial N_\tau}+\mu_\tau^{\omega}\omega+\mu_\tau^{\bar{q}}\frac{\partial f(\cdot)}{\partial N_\tau}\right)+\mu_t^{\omega}\omega+\mu_t^{\bar{q}}\frac{\partial f(\cdot)}{\partial n_t}-\mu_t^{\bar{n}}-\mu_t^{\underline{n}}-\lambda_t^{\bar{n}}-\lambda_t^{\underline{n}}=0$$

Production sharing contract

$$R(P_t)-\frac{\partial c(\cdot)}{\partial q_t}-365\sum_{\tau=t+1}^{T}\left(\frac{1}{1+r}\right)^{T-\tau+1}\left(\mu_\tau^{\bar{q}}\frac{\partial f(\cdot)}{\partial S_\tau}+\mu_\tau^{S}\right)+\frac{1}{1+r}\left(\mu_{t+1}^{\delta}\cdot s(q_{t+1}-q_t)\right)-\mu_t^{\omega}+\mu_t^{\bar{q}}\left(\frac{\partial f(\cdot)}{\partial q_t}-1\right)-\mu_t^{\delta}\cdot s(q_t-q_{t-1})-365\mu_t^{S}-\mu_t^{\underline{q}}=0$$

$$-\frac{\partial c(\cdot)}{\partial n_t}+\sum_{\tau=t+1}^{T}\left(\frac{1-d}{1+r}\right)^{T-\tau+1}\left(-\frac{\partial c(\cdot)}{\partial N_\tau}+\mu_\tau^{\omega}\omega+\mu_\tau^{\bar{q}}\frac{\partial f(\cdot)}{\partial N_\tau}\right)+\mu_t^{\omega}\omega+\mu_t^{\bar{q}}\frac{\partial f(\cdot)}{\partial n_t}-\mu_t^{\bar{n}}-\mu_t^{\underline{n}}=0$$

Table 2. Components of cost function $c(q_t, n_t, N_t)$

	Equation	Base Value	Robustness
Surface infrastructure maintenance cost per barrel (dollars per barrel)	c_I	$c_I = 315.49$	$c_1 \in \{220.84, 410.14\}$
Variable operating cost (dollars)	$c_O(q_t) = V_1 \cdot (365 q_t)^{1+V_2}$	$V_1 = 0.7714$ $V_2 = -0.2423$	$V_1 \in \{0.25, 0.5, 1.0\}$ $V_2 \in \{-0.5, 0.24\}$
Water injection cost (millions of dollars)	$c_W(W_t) = 365 w_1 W_t^{w_2}$	$w_1 = 0.20$ $w_2 = 1$	$w_1 \in \{0.05, 0.5\}$ $w_2 \in \{0.5, 2\}$
Maintenance cost for old wells (millions of dollars)	$c_N(N_t) = m_1 N_t^{m_2}$	$m_1 = 0.2819$ $m_2 = 1$	$m_1 \in \{0.05, 0.5\}$ $m_2 \in \{0.5, 2\}$
Cost of a new well (millions of dollars per well)	c_n	$c_n = 2.882$	$c_n \in \{3.74, 2.02\}$
Water injection rate (million barrels per day)	$W(q_t, n_t, N_t) = e^{h_1} q_t^{h_2} (N_t + n_t)^{h_3}$	$h_1 = 0.7999$ $h_2 = 0.9509$ $h_3 = 0.0306$	$h_1 \in \{0.7, 0.9\}$ $h_2 \in \{0.8, 1.1\}$ $h_3 \in \{0.02, 0.05\}$

Notes: Base values of parameters are based on Gao, Hartley and Sickles (2009). Costs are in constant 2008 dollars.

Table 3. Our cost estimates for 2010 based on BP's 2010 work plan

Cost Component	Cost (Million 2008 Dollars)	Cost (Million 2010 Dollars)	Percentage of Total Cost (%)
Surface infrastructure maintenance cost $c_I q_t$	378.59	383.51	26%
Variable operating cost $c_O(\cdot)$	152.04	154.02	10%
Water injection cost $c_W(\cdot)$	453.27	459.16	31%
Maintenance cost $c_N(\cdot)$ for old wells	152.29	154.27	10%
Cost $c_n n_t$ of new wells	317.05	321.16	22%
Total Cost	1453.23	1472.11	100%

Table 4. Technical, geological, and feasibility constraints

Constraint	Equation	Value	Source of Data and/or Information
Well productivity constraint	$q_t \le \omega \cdot (N_t + n_t)$	ω = 3240 barrels per well per day	Calculated from Deutsche Bank forecast
Geological feasibility constraint	$q_t \le f(q_t, S_t, n_t, N_t)$	See Appendix E for the equation for $f(\cdot)$ and robustness checks for each parameter in $f(\cdot)$	Based on method and model of Gao, Hartley and Sickles (2009), modified and applied to Rumaila-specific data and information.
Production change constraint	$\lvert q_t - q_{t-1} \rvert \le \delta$	δ = 200,000 barrels per day	Based on Ghandi and Lin (2012), modified and applied to Rumaila-specific data and information from Rumaila's proposed work plans
Stock constraint	$365 q_t \le S_t$	S_t = 16.08 billion barrels in 2010	Estimate of 2010 Rumaila recoverable reserves from International Energy Agency (IEA, 2012); and personal communication with Deutsche Bank Securities Inc. (September 2011)
Minimum production constraint	$q_t \ge \underline{q}$	$\underline{q}$ = 500,000 barrels per day	Half of Rumaila baseline production in 2009
Well drilling feasibility constraint	$n_t \le \overline{n}_t^f$	$\overline{n}_t^f$ = 285 wells until 2020 $\overline{n}_t^f$ = 0 after 2020	Based on information from Daly (2010); GDS Publishing, Inc. (2010); Deutsche Bank forecast; Sankey, Clark and Micheloto (2010); and personal communication with industry experts
Non-negative well drilling constraint	$n_t \ge 0$	$n_t \ge 0$	Self-explanatory

Notes: The technical, geological, and feasibility constraints are described in more detail in Appendix E. Appendix E also present results of robustness checks in which we varying each of the parameters of the geological feasibility function $f(\cdot)$.

Table 5. Contractual constraints imposed in technical service, buy-back, and production sharing contract scenarios

	TSC Optimal	TSC Optimal, Cost Ceiling	TSC Actual Optimal	TSC Actual Optimal, Cost Ceiling	Buy-Back Optimal	Production Sharing Optimal
Production cap based on contract	X	X				
Production cap based on Deutsche Bank estimates (more stringent)			X	X		
Cost ceiling		X		X		
Cost reduction not recoverable					X	
Wells predetermined					X	
Contractual unit revenue instead of price						X

Notes: These contractual constraints are imposed in addition to the technical, geological, and feasibility constraints in Table 4.

Table 6. Contractual constraints imposed in TSC with fixed price contractual unit revenue scenarios

	TSC Optimal with Fixed Price	TSC Optimal, Cost Ceiling with Fixed Price	TSC Actual Optimal with Fixed Price	TSC Actual Optimal, Cost Ceiling with Fixed Price
Production cap based on contract	X	X		
Production cap based on Deutsche Bank estimates (more stringent)			X	X
Cost ceiling		X		X
Contractual unit revenue instead of price	X	X	X	X

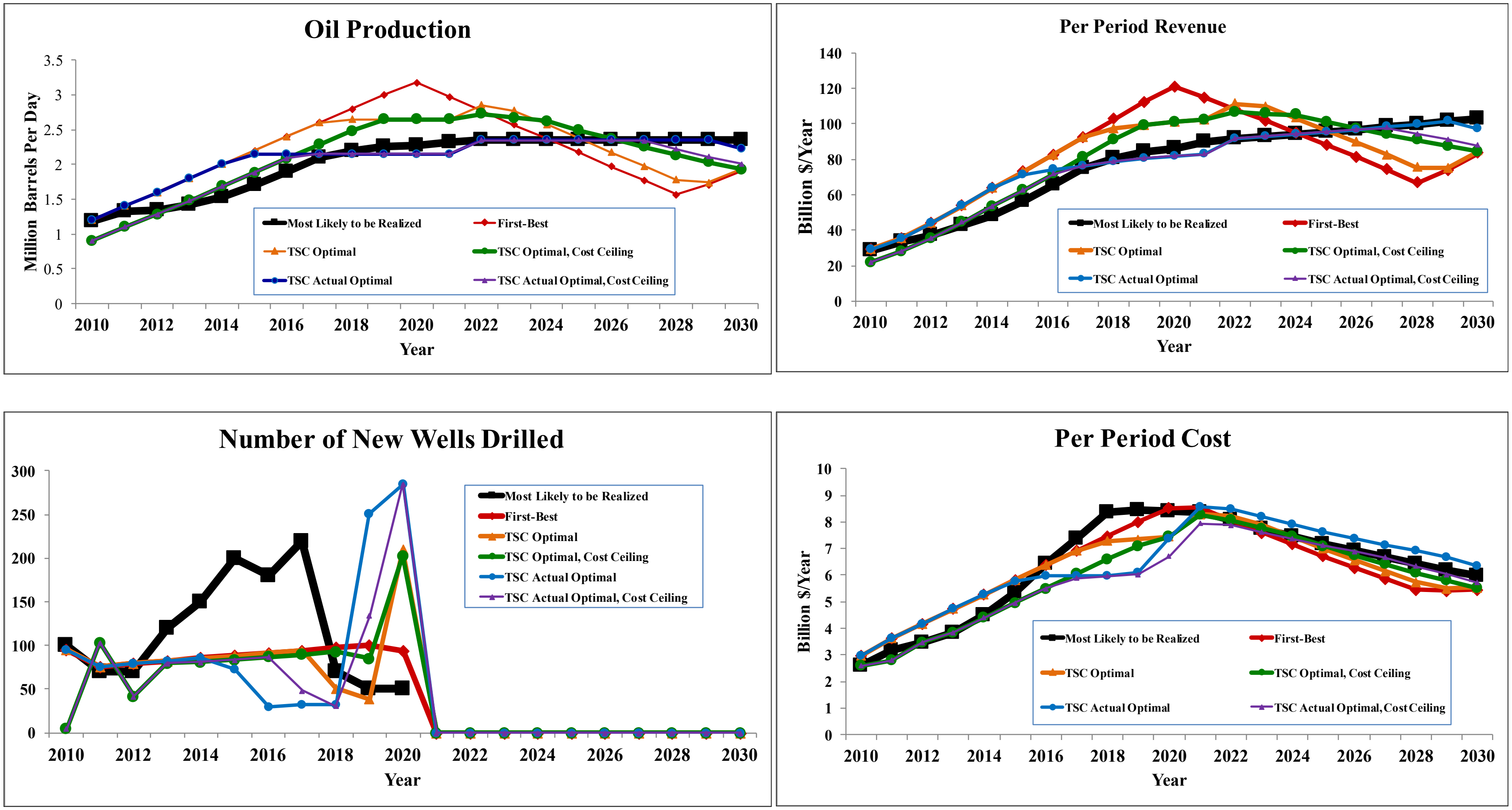
Notes: These contractual constraints are imposed in addition to the technical, geological, and feasibility constraints in Table 4.

Table 7. Contractual constraints imposed in scenarios combining features of TSC and buy-back

	TSC Optimal	Buy-Back Optimal	Buy-Back Optimal, Wells Not Predetermined	Buy-Back Optimal, Cost Reduction Recoverable	TSC Optimal, Cost Reduction Not Recoverable
Production cap based on contract	X				X
Cost reduction not recoverable		X	X		X
Wells predetermined		X		X	

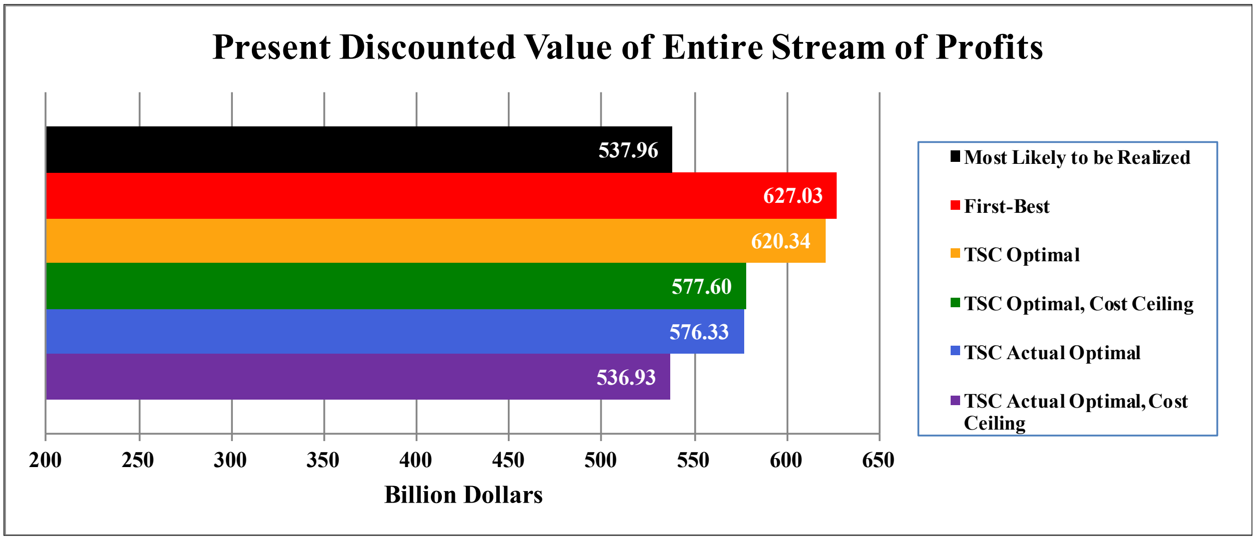
Notes: These contractual constraints are imposed in addition to the technical, geological, and feasibility constraints in Table 4.

Figure 1. Results for technical service contract: Oil production, well drilling, revenue, and cost



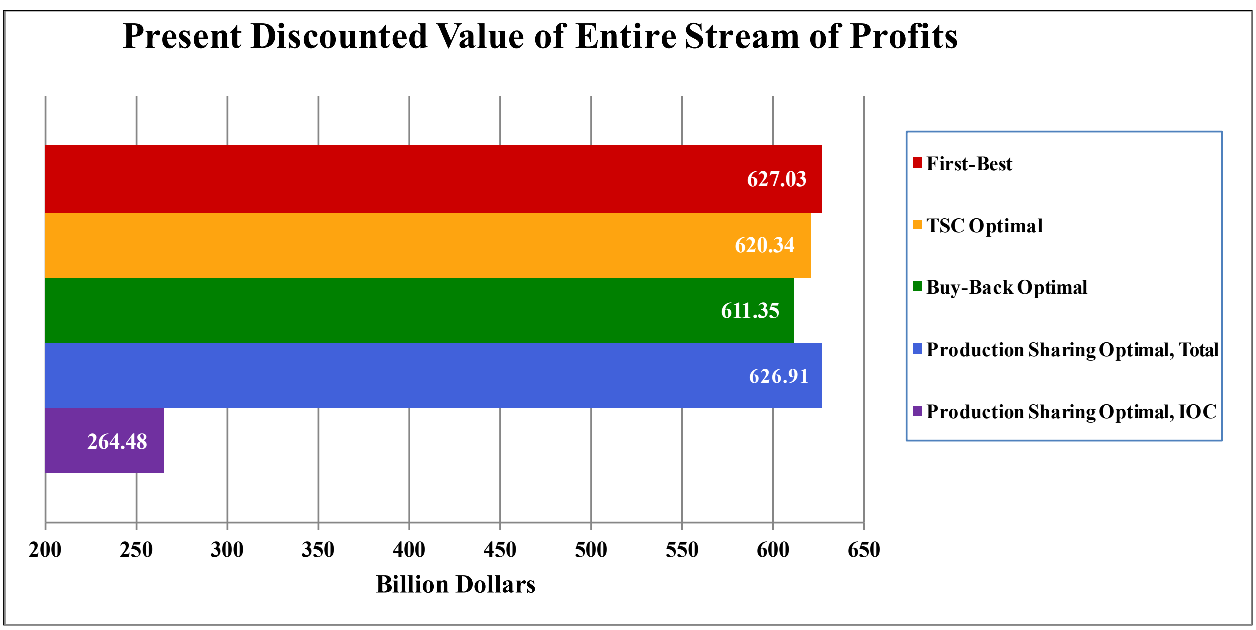
Note: Dollars are constant 2008 dollars.

Figure 2. Results for technical service contract: PDV of entire stream of per-period profit



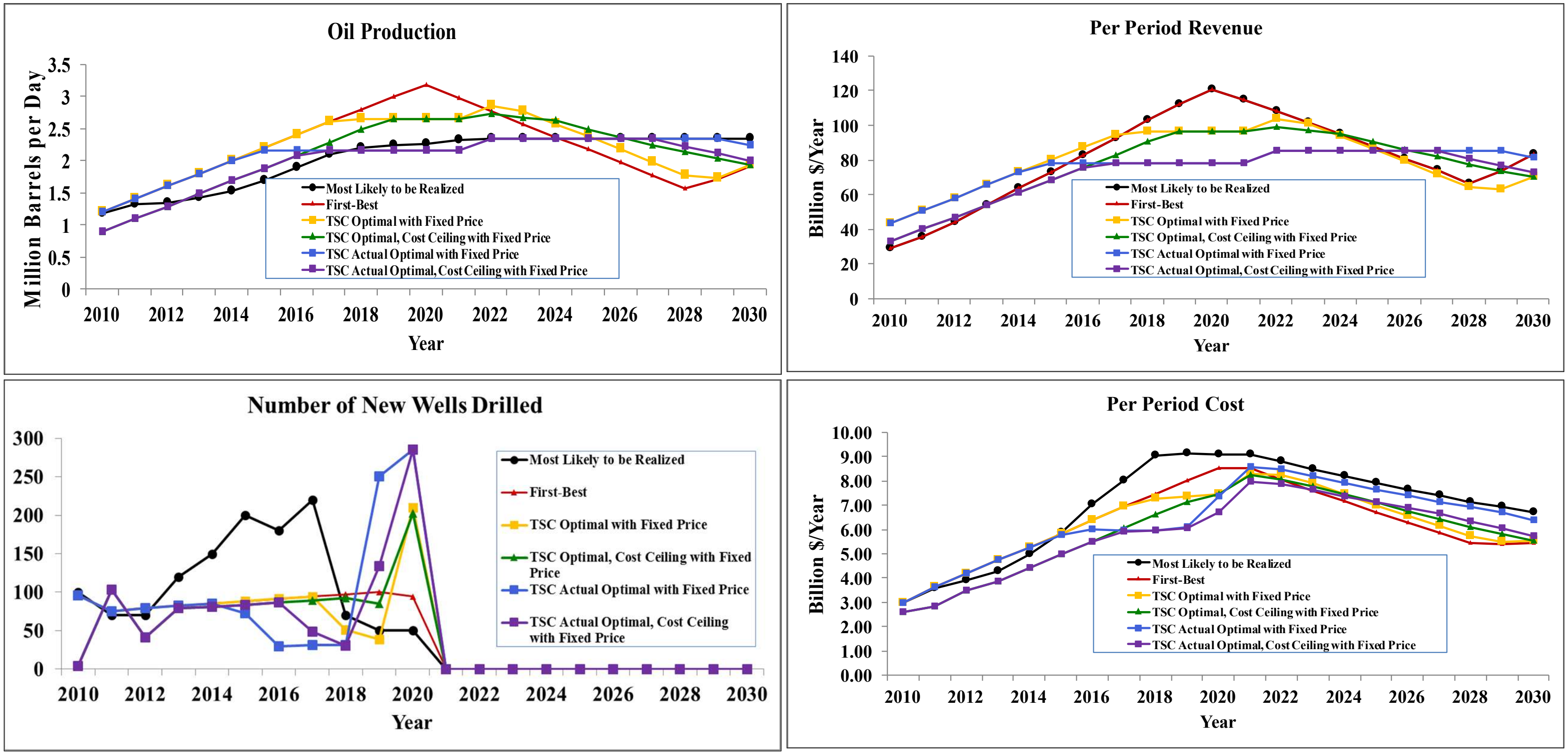
Note: Dollars are constant 2008 dollars.

Figure 3. Results for TSC, buy-back, and production sharing contracts: PDV of entire stream of per-period profit



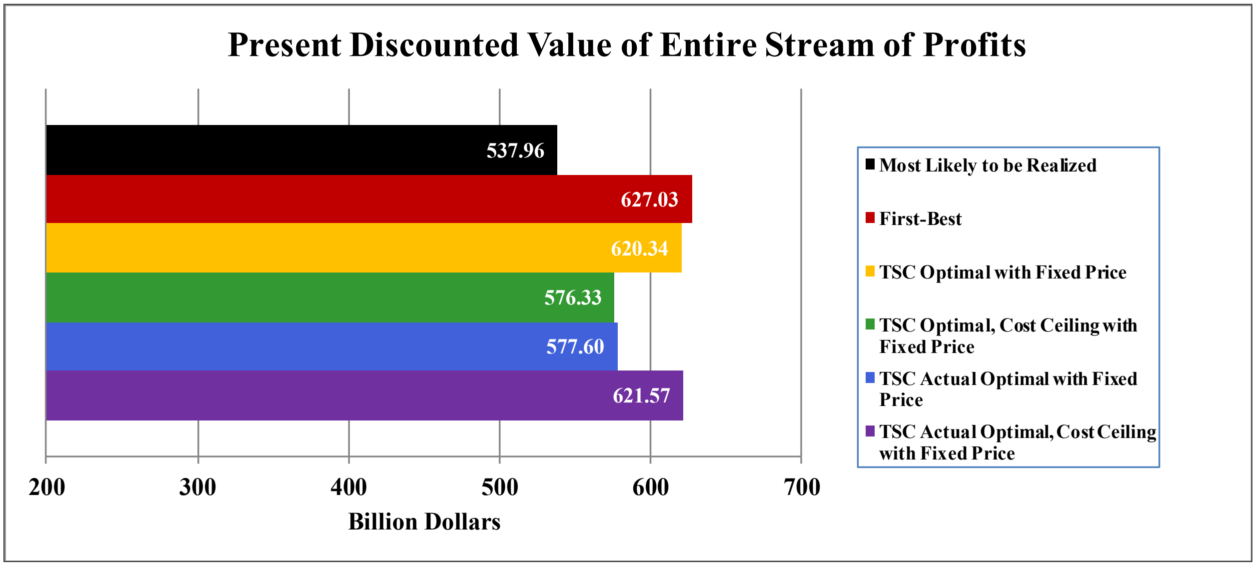
Note: Dollars are constant 2008 dollars. "Production Sharing Optimal, Total" is the total present discounted value of the entire stream of profits under the "Production Sharing Optimal" scenario; "Production Sharing Optimal, IOC" is the total present discounted value of the entire stream of profits under the "Production Sharing Optimal" scenario that the IOC receives.

Figure 4. Results for TSC with fixed price contractual unit revenue: Oil production, well drilling, revenue, and costs



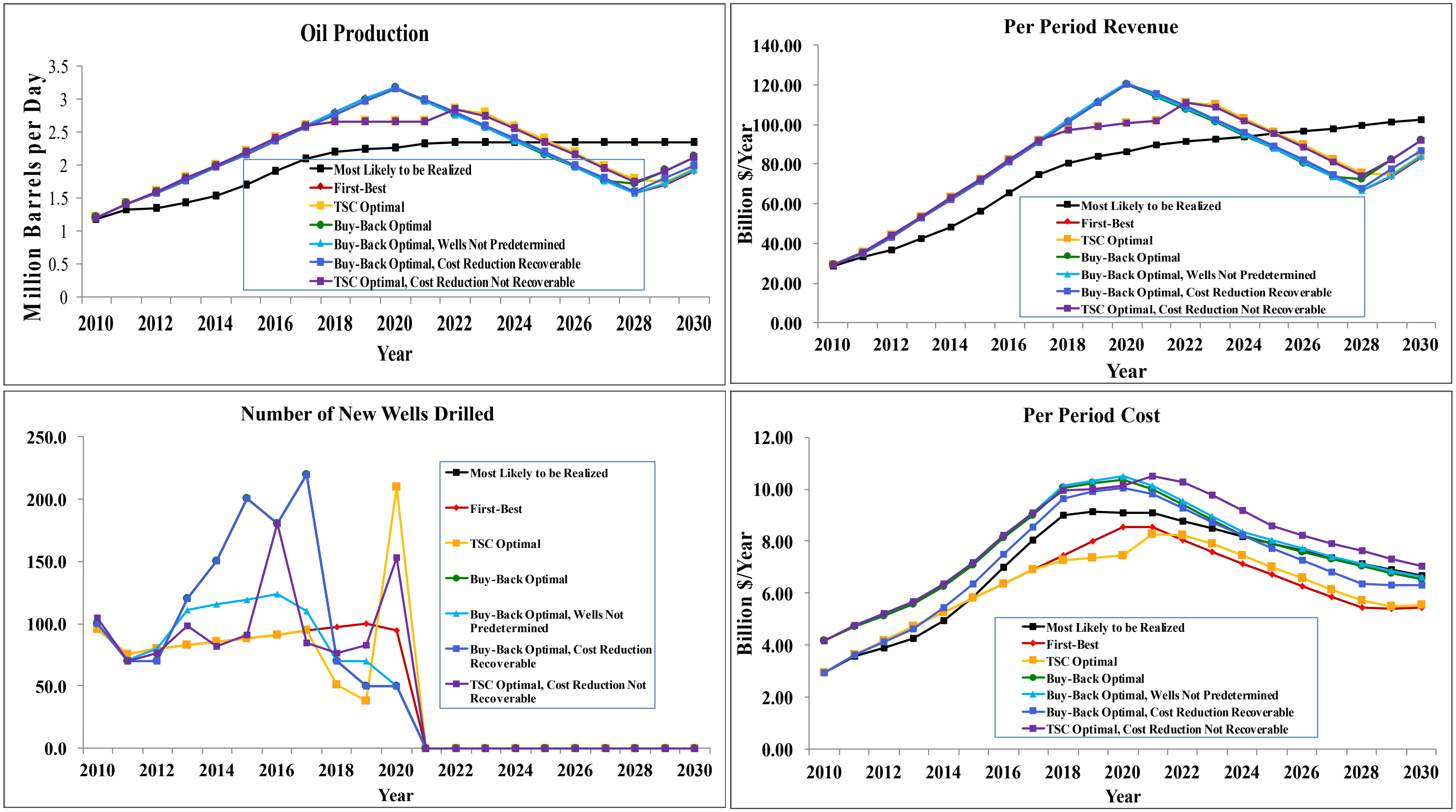
Note: Dollars are constant 2008 dollars. Revenue is calculated using price rather than contractual unit revenue.

Figure 5. Results for TSC with fixed price contractual unit revenue: PDV of entire stream of per-period profit



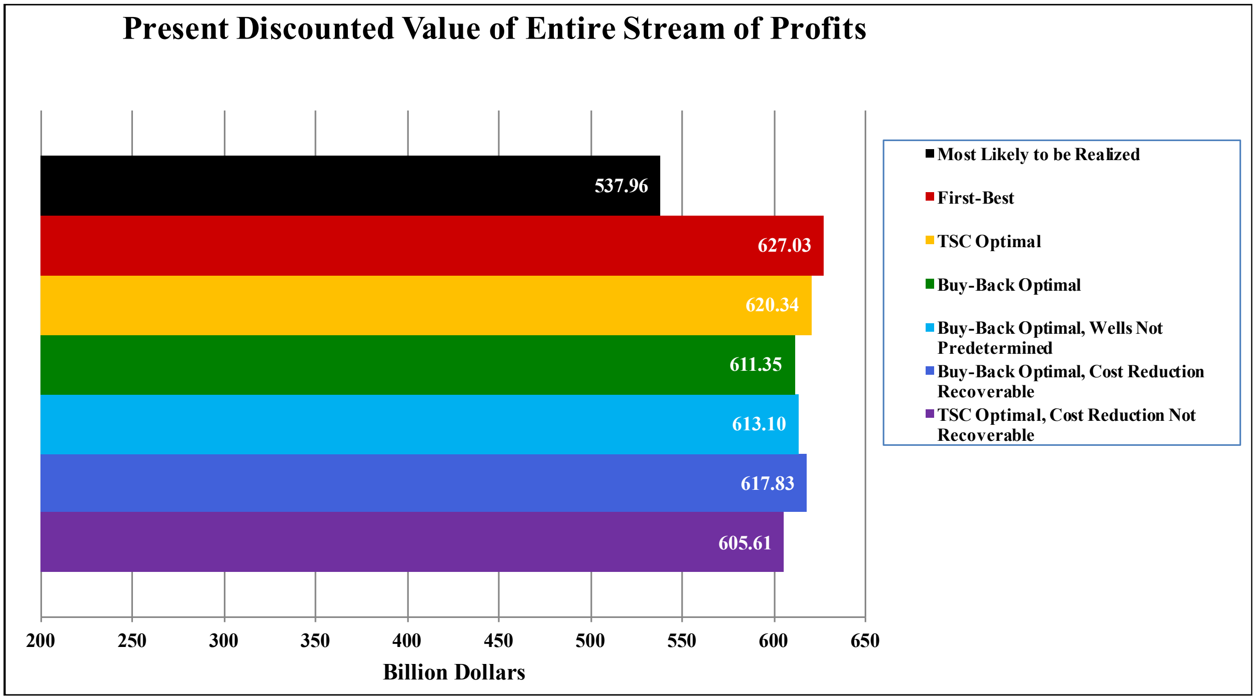
Note: Dollars are constant 2008 dollars. The present discounted value of the entire stream of profits is calculated using price rather than contractual unit revenue.

Figure 6. Results from combining features of TSC and buy-back: Oil production, well drilling, revenue, and costs



Notes: Dollars are constant 2008 dollars. The number of new wells drilled is the same under the "Most Likely to be Realized", "Buy-Back Optimal", and "Buy-Back Optimal, Cost Reduction Recoverable" scenarios.

Figure 7. Results from combining features of TSC and buy-back: PDV of entire stream of per-period profit



Note: Dollars are constant 2008 dollars.

Appendix

Appendix A. Technical Service Contracts

A.1. Technical Service Contracts in Iraq

The Iraqi government has held three rounds of licensing for its technical service contracts since June 2009, with 12 oil technical service contracts awarded in the first two rounds, and three non-associated natural gas technical service contracts[20] awarded in the third round as shown in Table A.1. The fourth round, which consists of 12 exploration projects,[21] was held in May 2012. Of the 12 fields with service contracts that were awarded in the first two rounds, 6 fields are considered very large or large. The Iraqi government has awarded producing field technical service contracts for three of the very large fields[22] since they were already in production before the signing of the contracts, and the contracts' scope involve increasing the production levels. The remaining 9 service contracts use a framework known as a development and production technical service contract. Since the Rumaila technical service contract is a producing field technical service contract, we focus our analysis of technical service contracts in this paper on producing field technical service contracts.

---

[20] The Korea Gas Corp.-led consortium won the bid on the Akkas natural gas field by offering a remuneration fee of U.S. $5.50 per barrel oil equivalent with an expected investment of U.S. $4.4 billion. Kuwait Energy and Turkish Petroleum International Co. together were awarded the Siba and Mansouriya non-associated natural gas fields with remuneration fees of U.S. $7.50 and U.S. $7 per barrel oil equivalent for each field, respectively (Hafidh, 2010).
[21] The bidders have to bid on fees in return for their exploration activities (Hafidh, 2012).
[22] These three fields include Rumaila, West Qurna 1, and Zubair.

Table A.1. Summary of the four licensing rounds in Iraq

Round	# Pre-Qualified Bidders	Important Dates	Project Scope	Outcome
1	35 [1]	Results announced: June 30, 2009 [1]	To develop 6 oil and 2 non-associated natural gas fields [1]	One contract was awarded (Rumaila). Three other oil production contracts were signed later. [1]
2	9 [1]	Results announced: December 12, 2009 [1]	To develop 10 oil fields [1]	Seven contracts were awarded. Three contracts did not have any bidders. [1]
3	13 [4]	Results announced: October 20, 2010 [4]	To develop 3 non-associated natural gas fields including two from the first round [4]	Three fields were awarded to two international consortia. [4]
4	46 [3]	Promotional Conference: August 2011 [2] Final Tender: November 2011 [2] Bidding Event: May 2012 [5]	To explore 12 oil and natural gas blocks [2]	Not yet determined

Sources:

[1] Sankey, Clark and Micheloto (2010)
[2] The Petroleum Services Group (PSG) at Deloitte (2011)
[3] Reuters (2010)
[4] Hafidh (2010)
[5] Hafidh (2012)

A.2. Components of a Technical Service Contract

The main cash flow components of a technical service contract are either related to production or to fees/costs. The four production-related terms are the baseline production rate, the incremental production rate, the plateau production target, and the improved production rate. Producing fields are those whose initial production began before the start of the new development that is taking place through a technical service contract. For these fields, the baseline production rate,[23] which declines annually at a 5% rate, is the fields' production rate before any development. The incremental production is any production above the baseline production.[24] The baseline and incremental production levels are used in the recovery of supplementary costs and petroleum costs via the supplementary fees and service fees parts of the cash flow of a technical service contract, respectively. The term plateau production target refers to the "net production rate that is to be achieved and sustained for the plateau production period." The plateau production period starts once the field's production reaches and stays for 30 consecutive days at the plateau production target level.[25] The plateau production target is bid on in the contract and is used for the remuneration calculation as part of the service fees of the cash flow. The next production-related term is the improved production target, which is defined as 10% higher than the initial production rate. Once production reaches and stays for 30 consecutive days at this level, the service fees eligibility date of the contract starts. After the service fees eligibility date, the IOC is eligible to recover the service fees of the contract (Republic of Iraq, Ministry of Oil, 2011).

The three important fee-related terms are: supplementary fees, which cover supplementary costs;[26] service fees, which cover petroleum costs;[27] and the remuneration fee. Supplementary fee

---

[23] This term has been used in the technical service contracts for the three very large producing fields: Rumaila, West Qurna 1, and Zubair (Sankey, Clark and Micheloto, 2010). In the official contract language, baseline production "constitutes the amount for any incremental production being derived from an assumed decline from the initial production rate at a compounded annual rate of 5%" (Republic of Iraq, Ministry of Oil, 2011).

[24] In the official contract language, incremental production means "the incremental volume of net production that is realized in excess of deemed net production volume at the baseline production rate" (Republic of Iraq, Ministry of Oil, 2011).

[25] The plateau production period may last 7 years.

[26] Supplementary costs are non-petroleum costs, which mostly include the signature bonus and de-mining costs (Republic of Iraq, Ministry of Oil, 2011).

[27] According to the Iraq Ministry of Oil, "Petroleum Costs means recoverable costs and expenditures incurred and payments made by Contractor and/or Operator in connection with or in relation to the conduct of Petroleum Operations (except corporate income taxes) determined in accordance with the provisions of this Contract and the Accounting Procedures" (Republic of Iraq, Ministry of Oil, 2011).

<Footnote continues next page.>

payments are funded based on 10% of the revenue from the baseline production, and the payments start with the start of the contract or the effective date as defined in Article 19 of a technical service sample contract.[28] Service fees and remuneration are due and payable to the IOC once the contract reaches the service fees eligibility date with priority given to petroleum cost repayments.[29] The total remuneration that the IOC receives in each quarter is based on the bid per barrel applicable remuneration fee and the incremental production as well as the performance factor. The bid per barrel applicable remuneration fee is determined in accordance to the stage of the IOC's cost recovery in the contract, which is based on an index called the R-Factor. The R-Factor, calculated annually, is a coefficient of the IOC's overall payback over the IOC's total expenditure. The R-Factor is used to gradually adjust the IOC's per barrel remuneration with the increase in the IOC's cost recovery, as described in Table A.2. In the early stages of the contract, the R-Factor is lower than 1, and therefore, the applicable remuneration is the same as the per barrel bid remuneration. Later on with the increase of the R-Factor, however, the applicable remuneration declines. The remuneration fee is also adjusted with the performance factor during the plateau production period. The performance factor is defined as the ratio of the net production rate to the bid plateau production target and should never exceed 1.0 (Republic of Iraq, Ministry of Oil, 2011); as a consequence, the IOC is obligated to reach the plateau production target. We therefore model the primary contractual constraint imposed in a technical service contract as a production cap.

---

[28] Article 19.3 specifies that the supplementary fees are paid in kind or in cash in U.S. Dollars. If paid in kind, the price of oil is determined based on provisions of the Valuation of Export Oil Article in the contract (Republic of Iraq, Ministry of Oil, 2011).

[29] It is also important to mention that the service fees payments to the IOC cannot exceed 50% of the deemed revenues of the incremental production. In other words, 50% of the revenue from the incremental production is the only source for the service fees payments (Republic of Iraq, Ministry of Oil, 2011).

Table A.2. Remuneration Fee and R-Factor in a Technical Service Contract

R-Factor	Remuneration Fee per Barrel (USD)
Less than 1.0	100%
1.0. to less than 1.25	80%
1.25 to less than 1.5	60%
1.5 to less than 2.0	50%
2.0 and above	30%

Source: Republic of Iraq, Ministry of Oil (2011)

Appendix B. Price Estimates

For prices, we use Rumaila-specific price estimates based on the Energy Information Administration (EIA)'s 2010 Reference price forecast from 2010 to 2030, the end of the contract. We use the 2010 price forecast since we assume that the IOC's optimization takes place at the beginning of the contract in 2010.

In order to use the EIA 2010 Reference estimates, we implicitly follow the EIA's Reference case assumption that OPEC's share of world oil production will stay at the current 40% level through the year 2035. Nevertheless, a large increase in oil production by Iraq may have the potential to suppress world oil prices. The EIA 2010 Low Oil Price accounts for a possibly large ramp up in oil production in Iraq by assuming a sharp increase in OPEC's share of world oil production to 50% by 2035 (EIA, 2010). Therefore, in order to capture the possibility of large increases in oil production by Iraq that may potentially suppress world oil prices, we also run a specification of our model using Rumaila-specific price estimates based on the EIA 2010 Low Oil Price scenario for robustness.[30] In addition, since price volatility through time could affect our optimization results, we also run a specification of our model using Rumaila-specific price estimates based on the EIA 2012 Reference case price projection for robustness.

The EIA 2010 world oil price projection is a price forecast of a "light, low-sulfur (or 'sweet') crude oil delivered at Cushing, Oklahoma" (EIA, 2010, p. 36). In a more detailed description, the EIA 2012 forecast "is defined as the average price of light, low-sulfur crude oil delivered in Cushing, Oklahoma, which is similar to the price for light, sweet crude oil, West Texas Intermediate (WTI), traded on the New York Mercantile Exchange" (EIA, 2012, p.23). In addition, the EIA 2012 Reference case projection relies on the assumption that WTI and Brent price differences will disappear once the Cushing, Oklahoma and Gulf of Mexico pipeline is completed (EIA, 2012). Since we use a price formula based on the Brent price, as we discuss

[30] Any influence oil production on the Rumaila field in Iraq may have on the oil price would likely be through OPEC and the OPEC quota. Even if OPEC may have exercised market power in the 1970s and 1980s (Griffin, 1985; Lin Lawell, 2020), however, there is evidence to suggest that OPEC has been less successful in exerting market power in more recent years (Marcel and Mitchell, 2006; Lin, 2009; Sperling and Gordon, 2010). Nevertheless, in addition to using Rumaila-specific price estimates based on the EIA 2010 Low Oil Price scenario to account for a possibly large ramp up in oil production in Iraq, we also further account for OPEC considerations in the "TSC Actual Optimal" and "TSC Actual Optimal, Cost Ceiling" scenarios.

below, we extend the EIA 2012 Reference case assumption to the EIA 2010 Reference and Low Oil Price scenarios, and we assume that the EIA 2010 Reference and Low price forecasts could be used as appropriate forecasts for the Brent price until 2030. We need to make this assumption in order to calculate Rumaila-specific crude price estimates until 2030 based on the average 2010-2012 price discounts discussed below.

A giant field, Rumaila produces at least three blends, including Basra Light, Basra Medium, and Basra Heavy with 34˚, 30˚, 22˚-24˚ API and 2.1%, 2.6%, 3.4% sulphur, respectively (Jassim and Goff, 2006). Nevertheless, we treat all Rumaila production as Basra Light that is exported as a simplifying assumption in order to estimate the Rumaila production price forecast. The State Oil Marketing Organization (SOMO) in Iraq announces the next month Basra Light Official Selling Price (OSP), as discounts to three international market price indices, based on Basra Light U.S., Europe, and Asia export. As the other simplifying assumption, we assume that all Rumaila production is exported to Europe and its price follows the Basra Light Official Selling Price (OSP) price. Table B.1 shows Basra Light monthly OSP for U.S. and Europe destinations from November 2010 to August 2012 with a two-year average price at $3.96 below the North Sea Spot BFOE[31] (Brent) and $1.65 per barrel below the Argus Sour Crude Index.

Table B.2 shows the three Rumaila-specific price estimates that we calculate for our model based on the EIA 2010 Reference (our base case), the EIA 2010 Low Oil Price, and the EIA 2012 Reference, respectively, with a $3.96 per barrel premium.

As seen in the results of the robustness checks in Figure B.1, the results for oil production, well drilling, and costs are robust to the oil price specification. As expected, the oil price specification affects revenue, and, as seen in Figure B.2, the present discounted value of the entire stream of per-period profit. Nevertheless, as the results for oil production, well drilling, and costs are robust to the oil price specification, our qualitative results regarding the relative inefficiencies of oil production contracts are robust to the oil price specification as well.

[31] BFOE stands for Brent-Forties-Oseberg-Ekofisk, a "family of North Sea crude oils, each of which has a separate delivery point. Many of the crude oils traded as a basis to Brent actually are traded as a basis to Dated Brent, a cargo loading within the next 10-21 days (23 days on a Friday)" (ICE Crude Oil, 2012).

Table B.1. Basra Light discount price, 2010-2012

Month	For U.S. Delivery Discounted against Argus Sour Crude Index ($/Barrel)	For Europe Delivery Discounted against North Sea Spot BFOE (($/Barrel)
Nov 2010	1.10	2.30
Dec 2010	1.15	2.55
Jan 2011	1.15	1.90
Feb 2011	1.35	3.40
Mar 2011	1.35	4.60
Apr 2011	1.65	4.60
May 2011	1.95	6.50
Jun 2011	2.10	7.05
Jul 2011	2.00	5.25
Aug 2011	1.75	4.55
Sep 2011	1.85	4.05
Oct 2011	1.70	3.00
Nov 2011	1.60	4.10
Dec 2011	1.60	3.15
Jan 2012	1.50	2.50
Feb 2012	1.70	4.35
Mar 2012	2.00	2.55
Apr 2012	2.00	2.55
May 2012	1.90	6.10
Jun 2012	1.80	4.50
Jul 2012	1.65	4.40
Aug 2012	1.5	3.2
Average 2010-2012	1.65	3.96

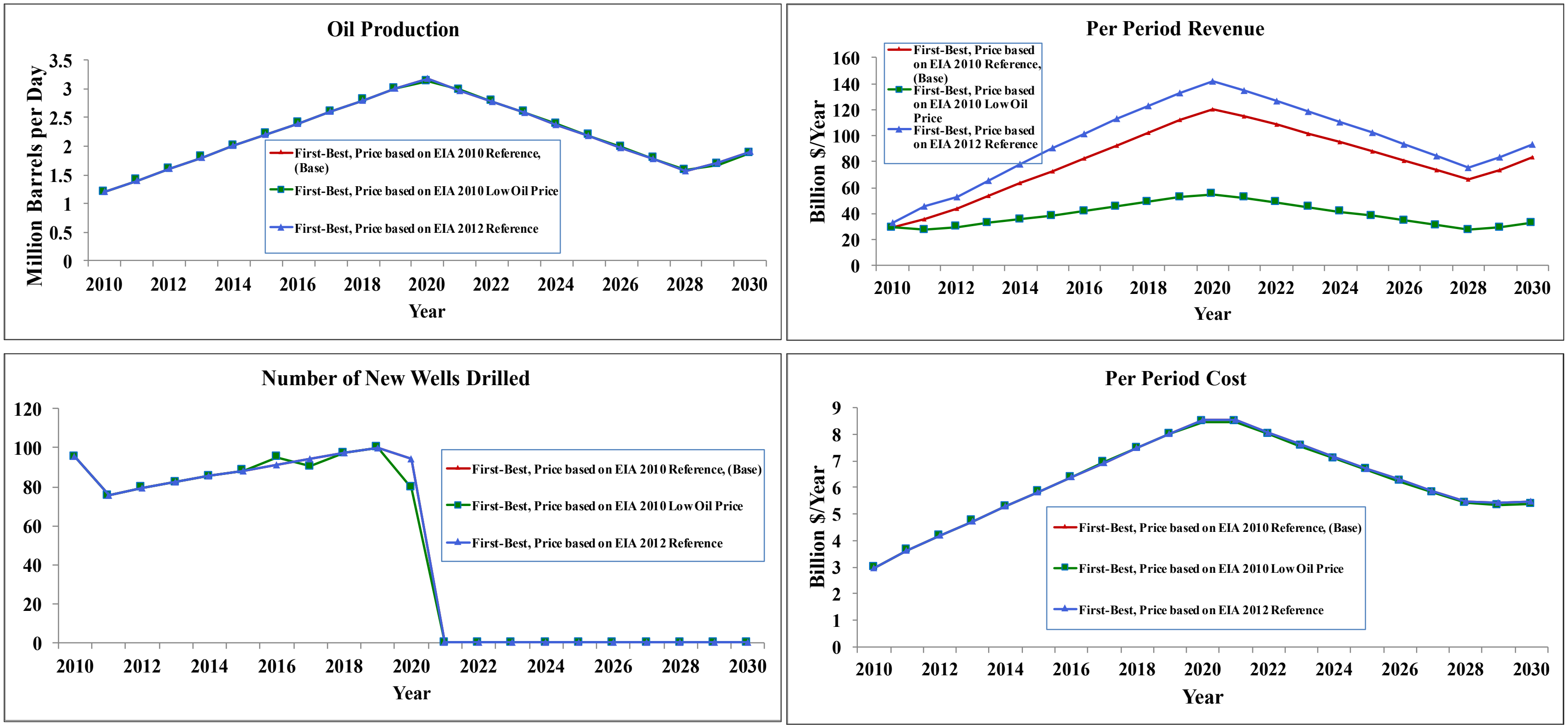
Source: Dow Jones Newswires, Dow Jones Energy Service (Dow Jones & Company, 2010-2012).

Table B.2. Rumaila-specific price estimates

Year	Based on EIA 2010 Reference Case (2008 $/Barrel)	Based on EIA 2010 Low Oil Price Case (2008 $/Barrel)	Based on EIA 2012 Reference Case (2010 $/Barrel)
2010	66.34	66.34	75.43[32]
2011	69.10	53.88	88.90
2012	75.45	50.92	90.77
2013	81.78	49.90	99.74
2014	86.95	48.83	106.93
2015	90.56	47.63	112.95
2016	94.27	47.77	115.95
2017	97.27	47.82	118.93
2018	100.45	47.86	120.04
2019	102.51	47.95	121.26
2020	104.32	47.90	122.71
2021	105.56	47.87	124.03
2022	106.96	47.86	125.46
2023	108.36	47.84	126.52
2024	109.67	47.80	127.57
2025	111.13	47.77	128.60
2026	112.65	47.75	129.51
2027	114.36	47.75	130.38
2028	116.17	47.70	131.42
2029	118.08	47.66	133.07
2030	119.54	47.67	134.53

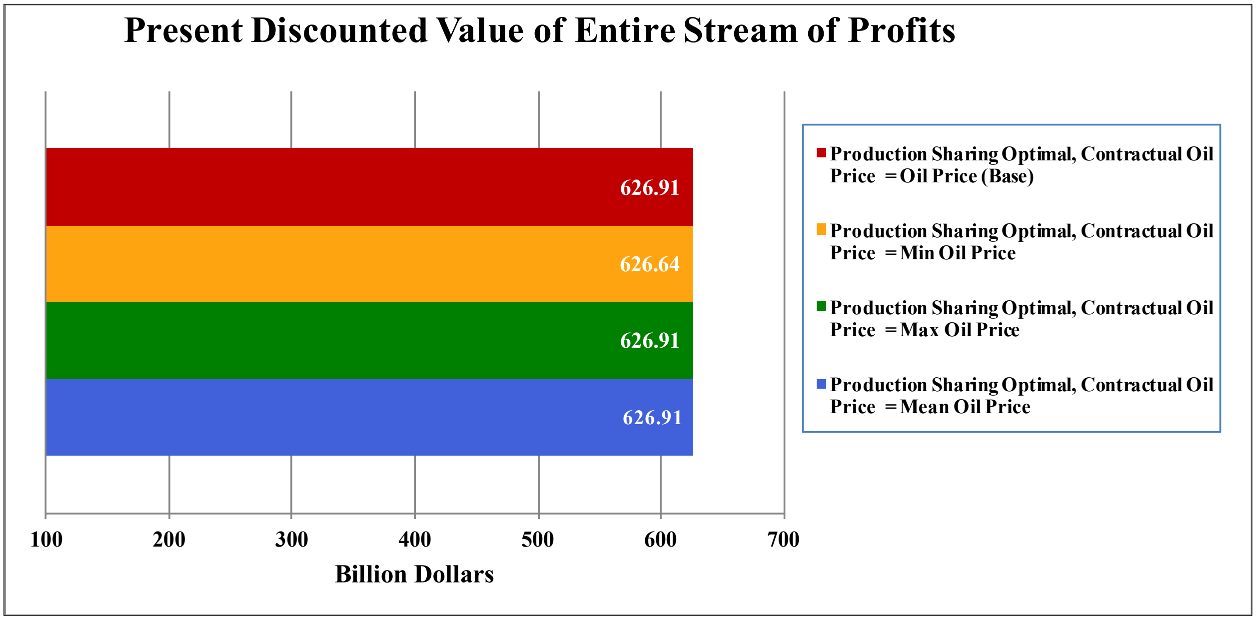
[32] This represents actual Basra Light average price in 2010.

Figure B.1. Robustness check results for oil price: Oil production, well drilling, revenue, and costs



Note: Dollars are constant 2008 dollars.

Figure B.2. Robustness check results for oil price: PDV of entire stream of per-period profit



Note: Dollars are constant 2008 dollars.

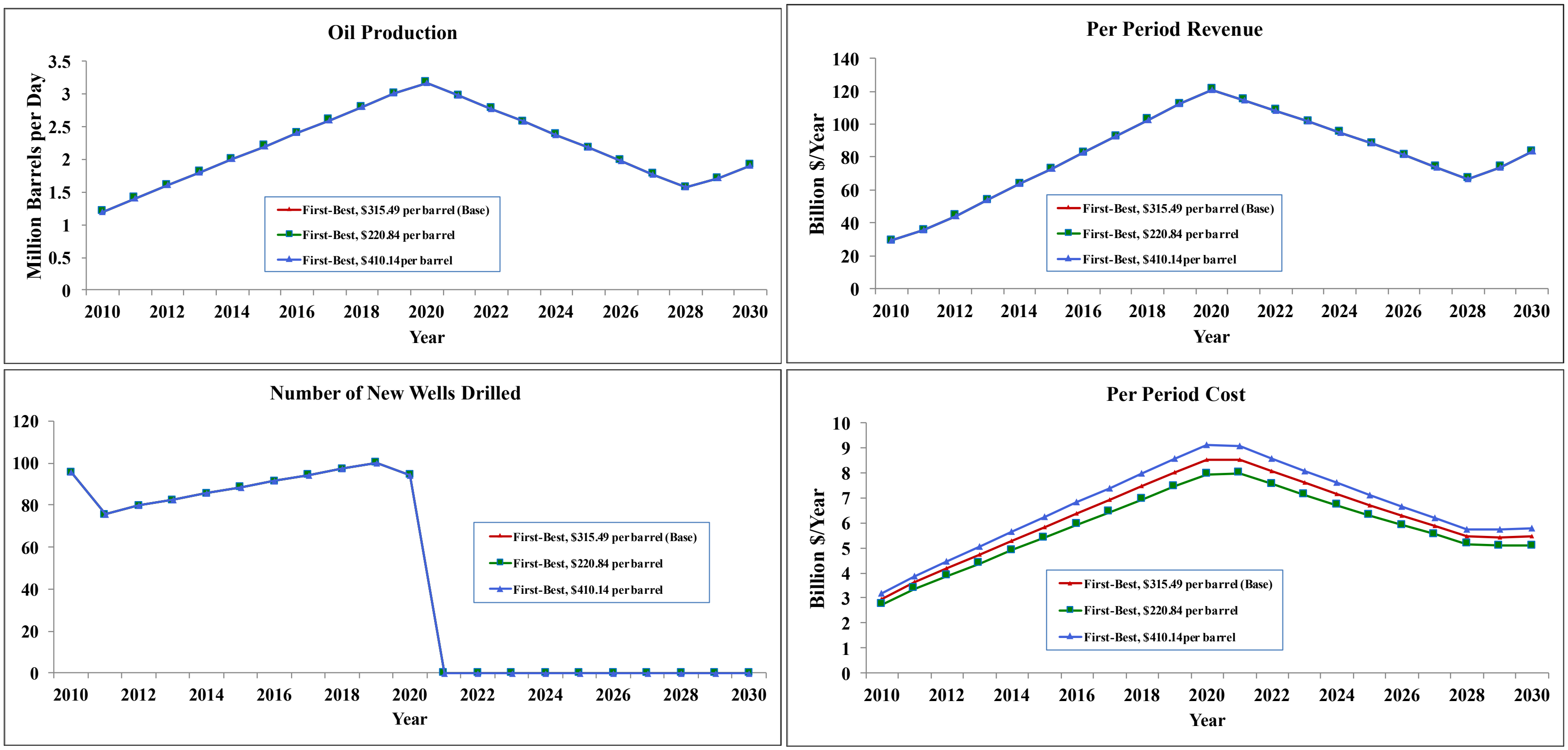
Appendix C. Cost

C.1. Surface infrastructure maintenance cost c_I per barrel

Based on data from the Center for Global Energy Studies (1993), Gao, Hartley and Sickles (2009) estimate the daily surface infrastructure maintenance cost per barrel on Arabian light and medium fields to be $0.44 per barrel in 1986 dollars, which yields an annual surface infrastructure maintenance cost per barrel of $160.6 per barrel in 1986 dollars. Since $160.6 per barrel in 1986 dollars is equivalent to $315.49 per barrel in 2008 dollars, we use an annual surface infrastructure maintenance cost c_I of $315.49 per barrel. For robustness, we also run our model using annual surface infrastructure maintenance cost c_I of $220.84 per barrel and of $410.14 per barrel, representing values 30% lower and 30% higher than the base case, respectively, as well.

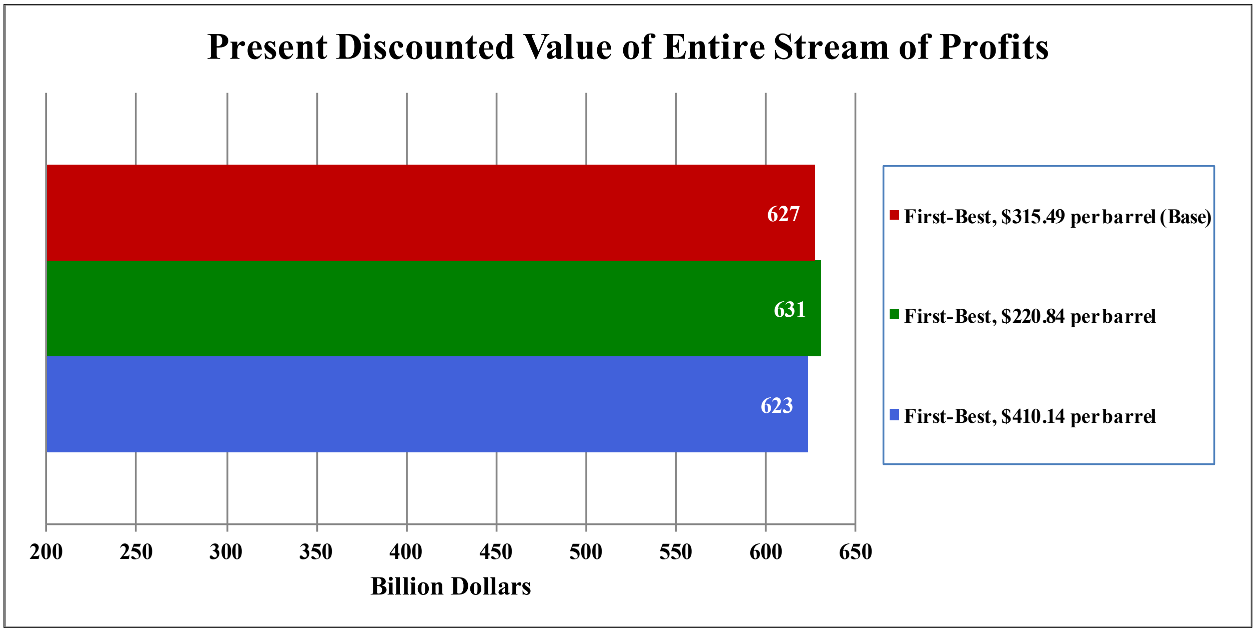
As seen in the results of the robustness checks in Figure C.1, the results for oil production, well drilling, and revenue are robust to the annual surface infrastructure maintenance cost c_I per barrel. As expected, the value of the annual surface infrastructure maintenance cost c_I per barrel affects costs. Nevertheless, as seen in Figure C.2, the present discounted value of the entire stream of per-period profit is fairly robust to the annual surface infrastructure maintenance cost c_I per barrel.

Figure C.1. Robustness check results for surface infrastructure maintenance cost c_I per barrel: Oil production, well drilling, revenue, and costs



Note: Dollars are constant 2008 dollars.

Figure C.2. Robustness check results for surface infrastructure maintenance cost c_I per barrel: PDV of entire stream of per-period profit



Note: Dollars are constant 2008 dollars.

C.2. Variable operating costs $c_O(\cdot)$

The variable operating cost $c_O(\cdot)$ includes annual expenditures on manpower and other variable operating costs, and is a function of annual production. We use the following functional form estimated by the Energy Information Administration (EIA) using the EIA's Estimator database (EIA, 1996a; EIA, 1996b), which includes discovered and/or undiscovered fields and production specifications of 8 geological plays with different field sizes, based on different recovery estimations, and with similar geology, geography, and temporal specifications (Gao, Hartley and Sickles, 2009):

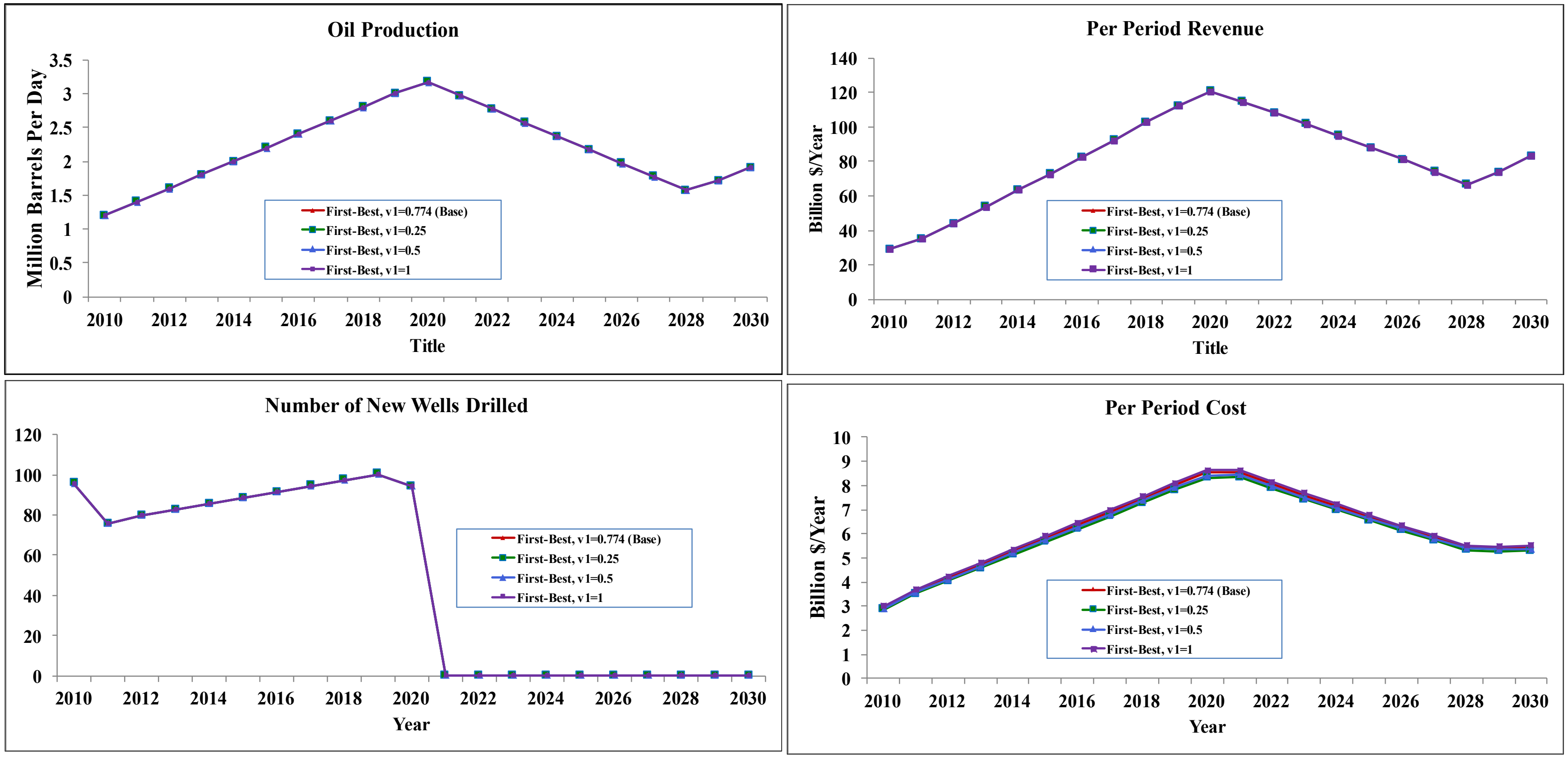
$$c_O(q_t) = V_1 \cdot (365 q_t)^{1+V_2} .$$

Following Gao, Hartley and Sickles (2009), we use as our base case parameter values $V_1 = 0.7714$ and $V_2 = -0.2423$. For robustness, we also run specifications with $V_1 \in \{0.25, 0.5, 1.0\}$ and $V_2 \in \{-0.5, 0.24\}$.

When $V_2 < 0$, as is the case with Gao, Hartley and Sickles (2009), and therefore our base case specification, variable operating costs are concave with respect to production, implying an economy of scale in operation. For robustness, we also run a specification in which $V_2 > 0$ so that variable operating costs are convex with respect to production instead.

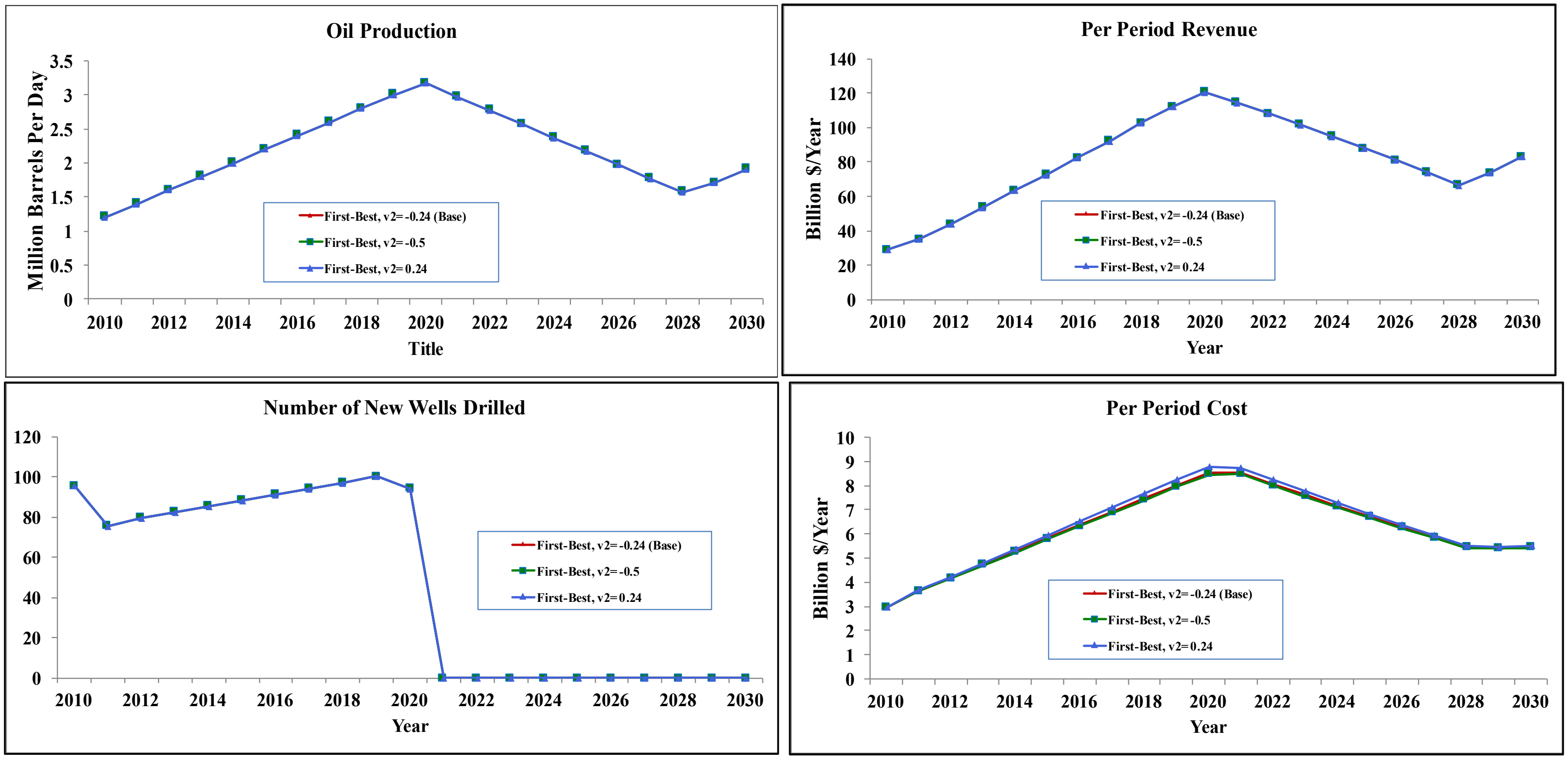
As seen in the results of the robustness checks in Figure C.3 and C.4, which vary the values of the variable operating cost parameters V_1 and V_2, respectively, the results for oil production, well drilling, and revenue are robust to the variable operating cost $c_O(\cdot)$, including to whether variable operating costs are concave or convex. As expected, the values of the variable operating cost parameters V_1 and V_2 affect costs. Nevertheless, as seen in Figures C.5 and C.6, the present discounted value of the entire stream of per-period profit is fairly robust to the variable operating cost $c_O(\cdot)$, including to whether variable operating costs are concave or convex.

Figure C.3. Robustness check results for variable operating cost parameter V_1: Oil production, well drilling, revenue, and costs



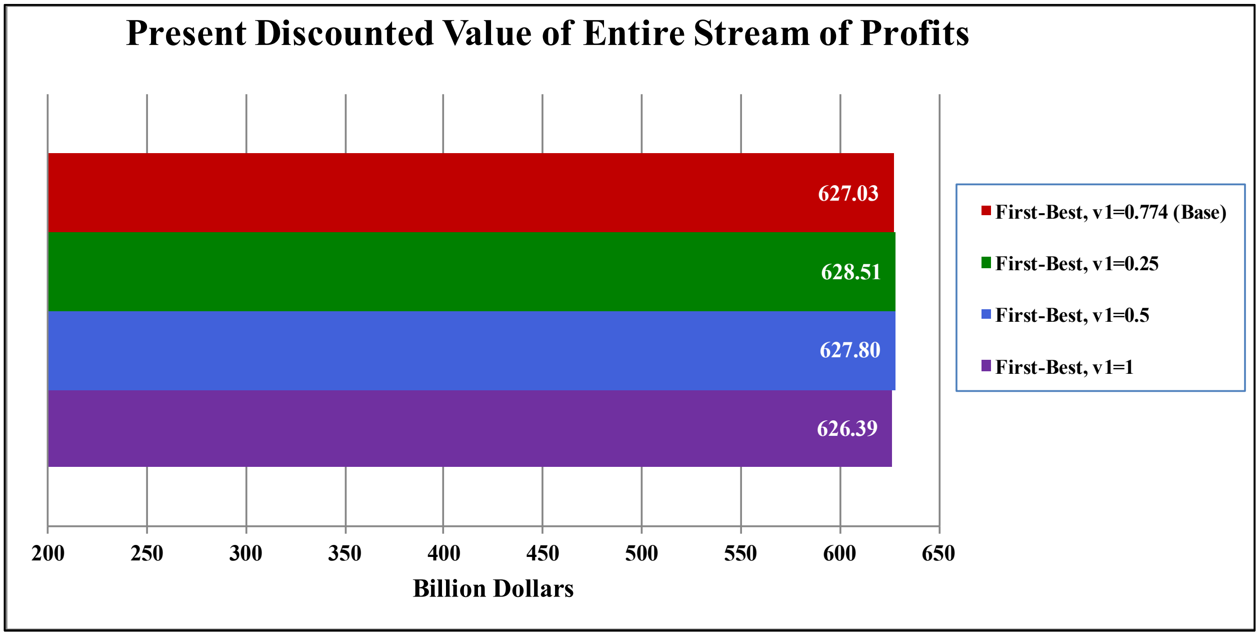
Note: Dollars are constant 2008 dollars.

Figure C.4. Robustness check results for variable operating cost parameter V_2: Oil production, well drilling, revenue, and costs



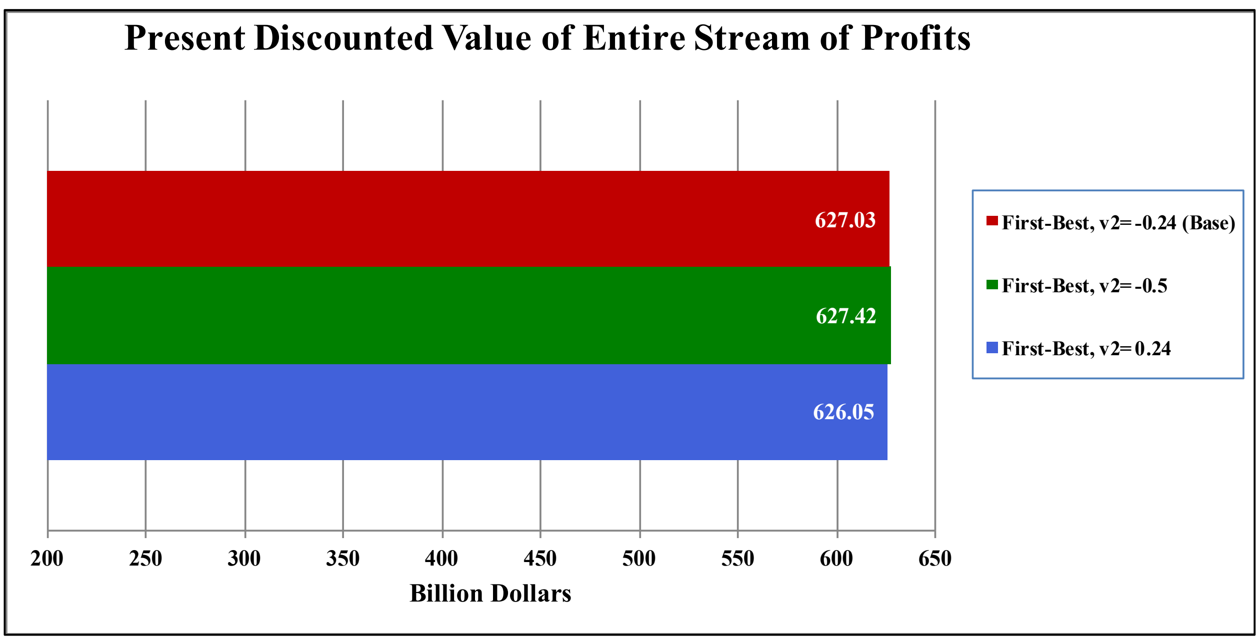
Note: Dollars are constant 2008 dollars.

Figure C.5. Robustness check results for variable operating cost parameter V_1: PDV of entire stream of per-period profit



Note: Dollars are constant 2008 dollars.

Figure C.6. Robustness check results for variable operating cost parameter V_2: PDV of entire stream of per-period profit



Note: Dollars are constant 2008 dollars.

C.3. Water injection cost $c_W(\cdot)$

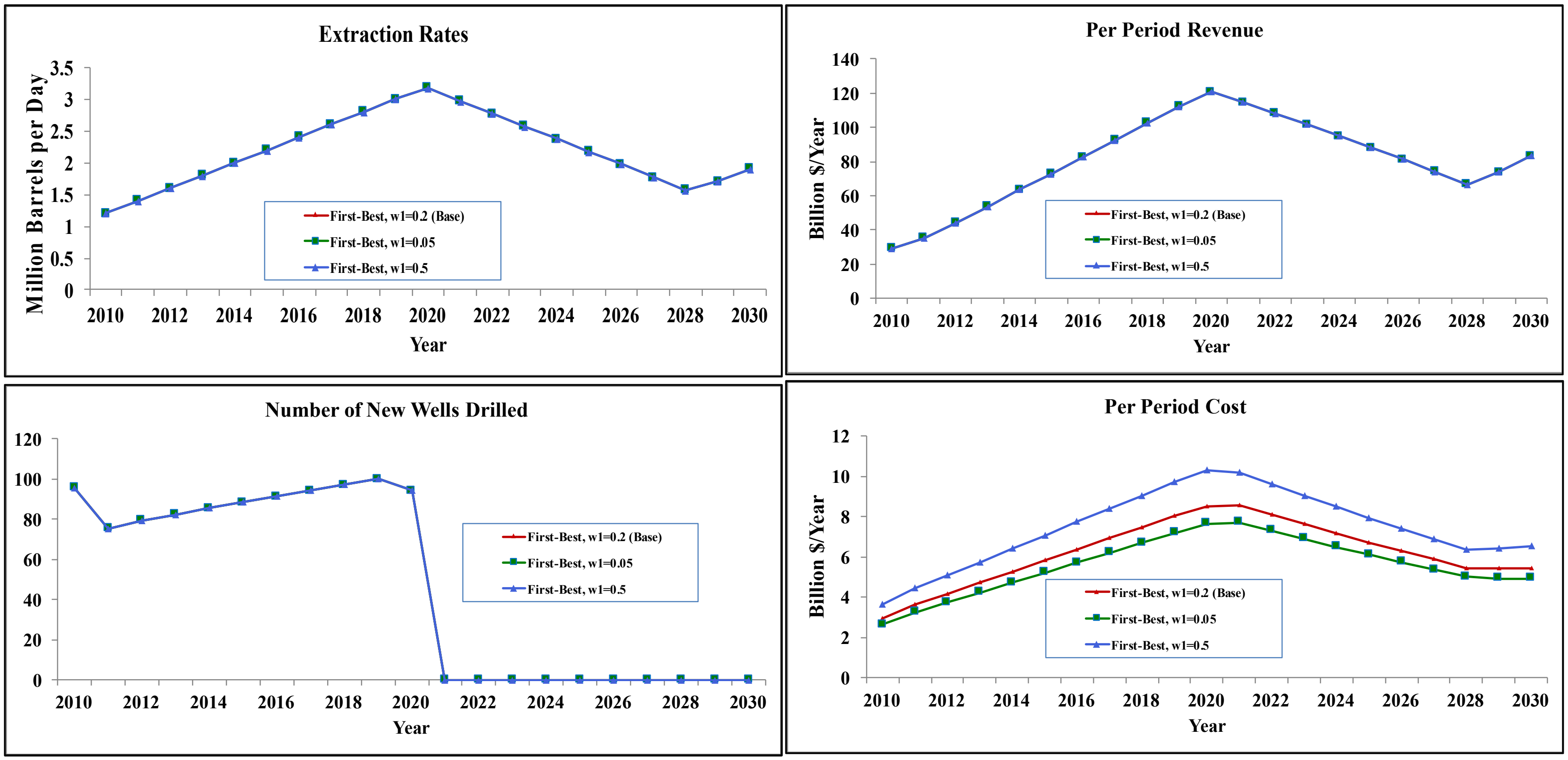
The annual water injection cost $c_W(\cdot)$ (in millions of dollars) captures reservoir engineering cost. We use the following general functional form:

$$c_W(W_t) = 365 w_1 W_t^{w_2} .$$

Following Gao, Hartley and Sickles (2009), who base their parameter values on industry studies, in our base case we assume a daily water injection rate of \$0.20 per barrel (i.e., \$0.20 million per $W(\cdot)$, which is in million barrels per day) so that $w_1 = 0.20$ and $w_2 = 1$. For robustness, we also run specifications where $w_1 \in \{0.05, 0.5\}$ and $w_2 \in \{0.5, 2\}$.

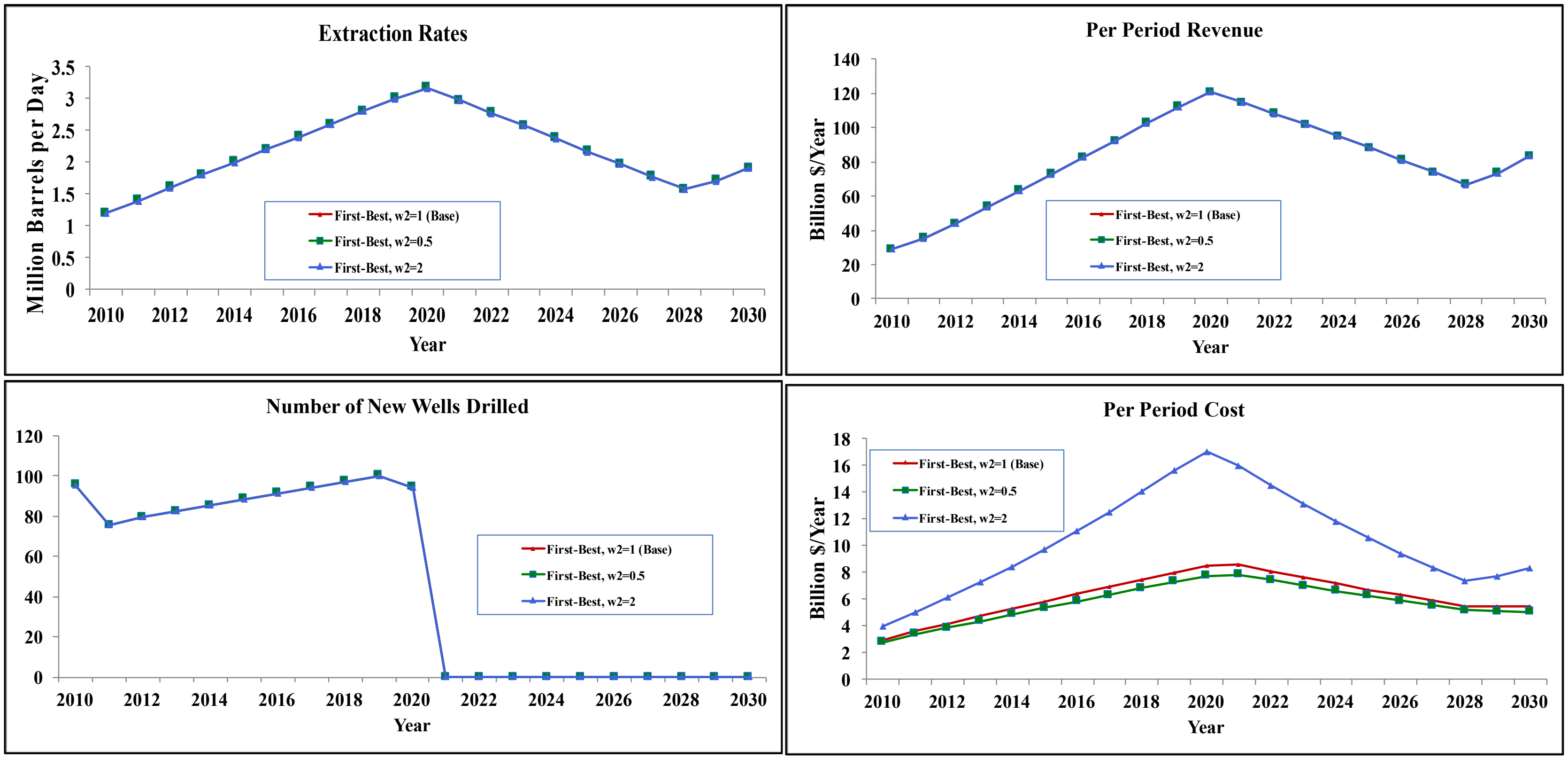
As seen in the results of the robustness checks in Figure C.7 and C.8, which vary the values of the water injection cost parameters w_1 and w_2, respectively, the results for oil production, well drilling, and revenue are robust to the water injection cost $c_W(\cdot)$. As expected, the values of the variable operating cost parameters w_1 and w_2 affect costs, and, as seen in Figures C.5 and C.6, the present discounted value of the entire stream of per-period profit. Nevertheless, as the results for oil production, well drilling, and costs are robust to the water injection cost $c_W(\cdot)$, our qualitative results regarding the relative inefficiencies of oil production contracts are robust to the water injection cost as well.

Figure C.7. Robustness check results for water injection cost parameter w_1: Oil production, well drilling, revenue, and costs



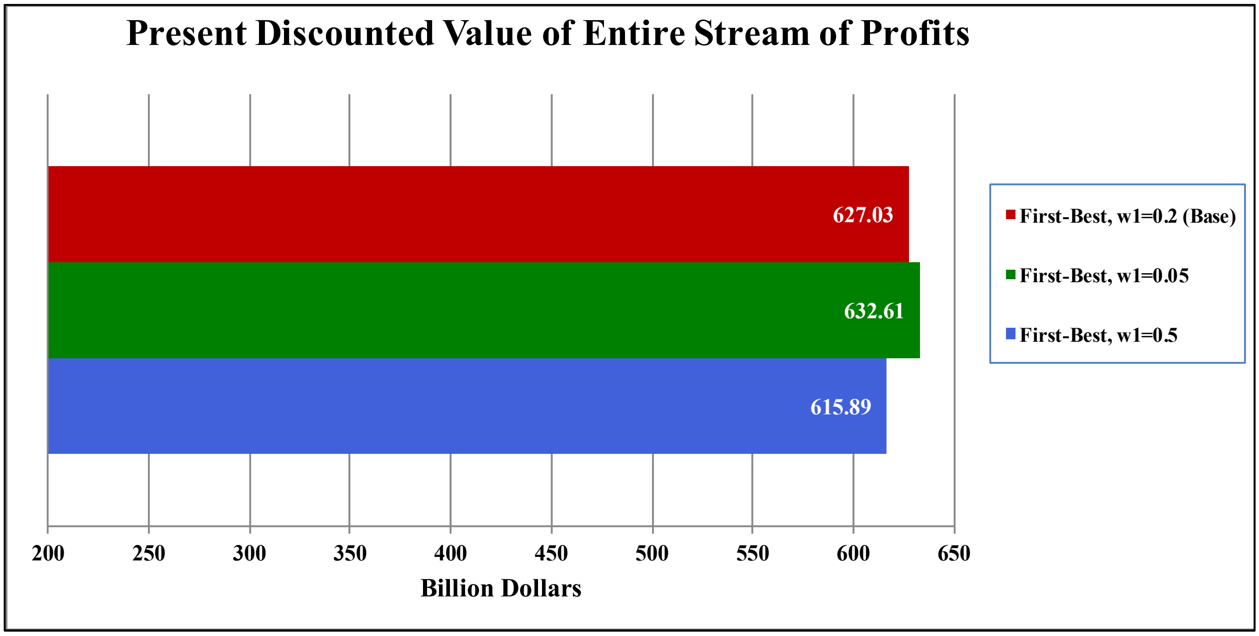
Note: Dollars are constant 2008 dollars.

Figure C.8. Robustness check results for water injection cost parameter w_2: Oil production, well drilling, revenue, and cost



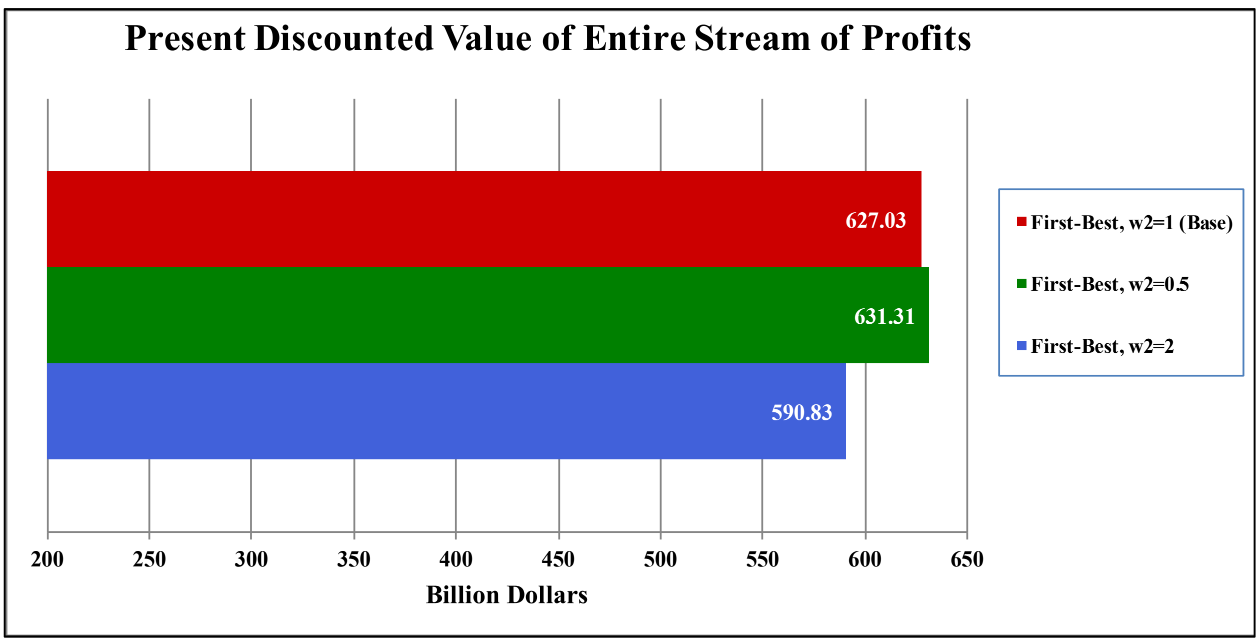
Note: Dollars are constant 2008 dollars.

Figure C.9. Robustness check results for water injection cost parameter w_1: PDV of entire stream of per-period profit



Note: Dollars are constant 2008 dollars.

Figure C.10. Robustness check results for water injection cost parameter w_2: PDV of entire stream of per-period profit



Note: Dollars are constant 2008 dollars.

C.4. Maintenance cost $c_N(\cdot)$ for old wells

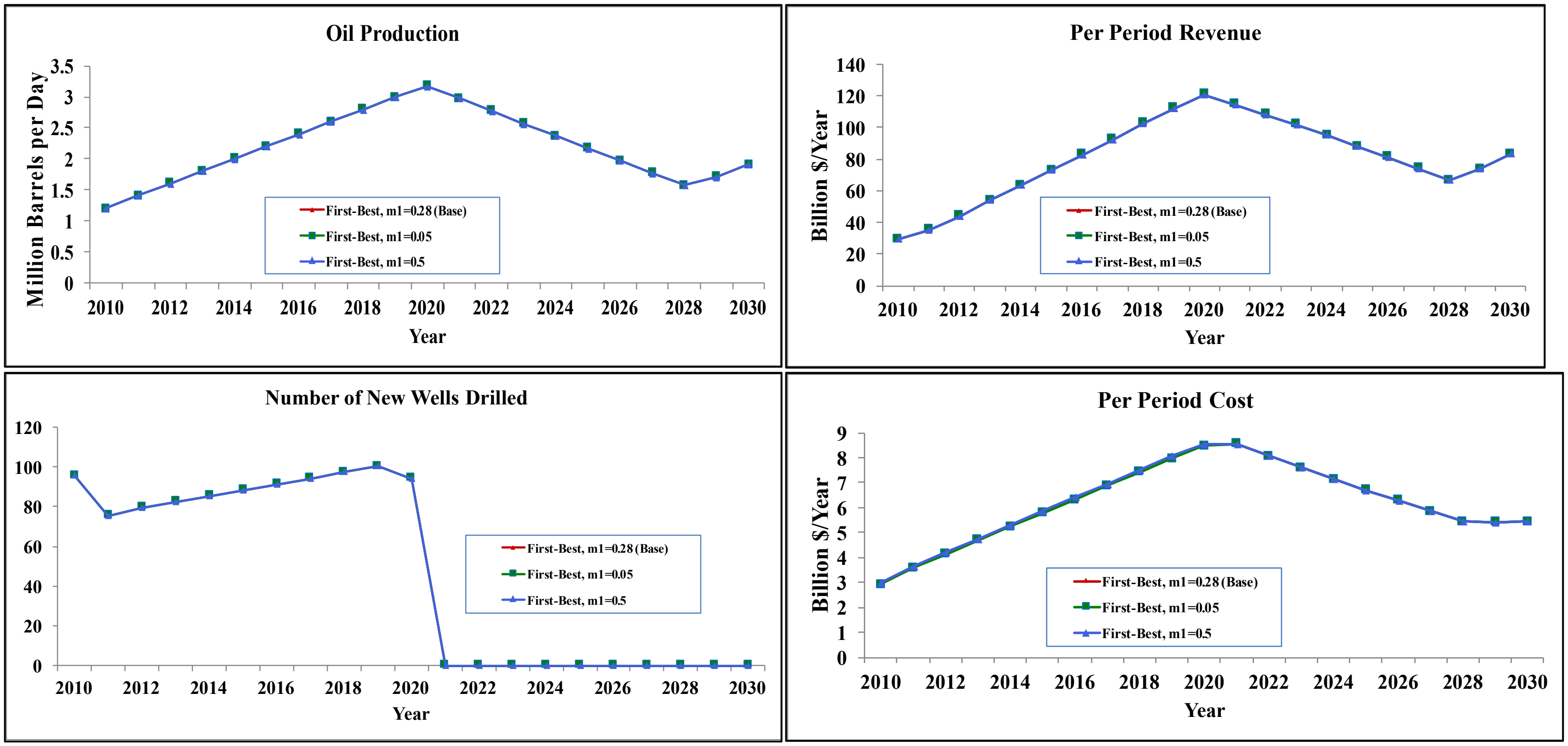
The annual maintenance cost $c_N(\cdot)$ (in millions of dollars) for old wells, which does not include the annual surface infrastructure maintenance cost c_I, is given by:

$$c_N(N_t) = m_1 N_t^{m_2}.$$

Following Gao, Hartley and Sickles (2009), in our base case we assume $m_1 = 0.2819$ and $m_2 = 1$. These values are based on two main assumptions. First, producing wells phase out gradually at a 5% rate during the wells' 20-year simulated assigned life. Second, the present value, at a 10% discount rate, of the needed investment to maintain the well productivity during the 20-year period is the same as the initial well infrastructure investment (Gao, Hartley and Sickles, 2009). For robustness, we also run specifications with $m_1 \in \{0.05, 0.5\}$ and $m_2 \in \{0.5, 2\}$.

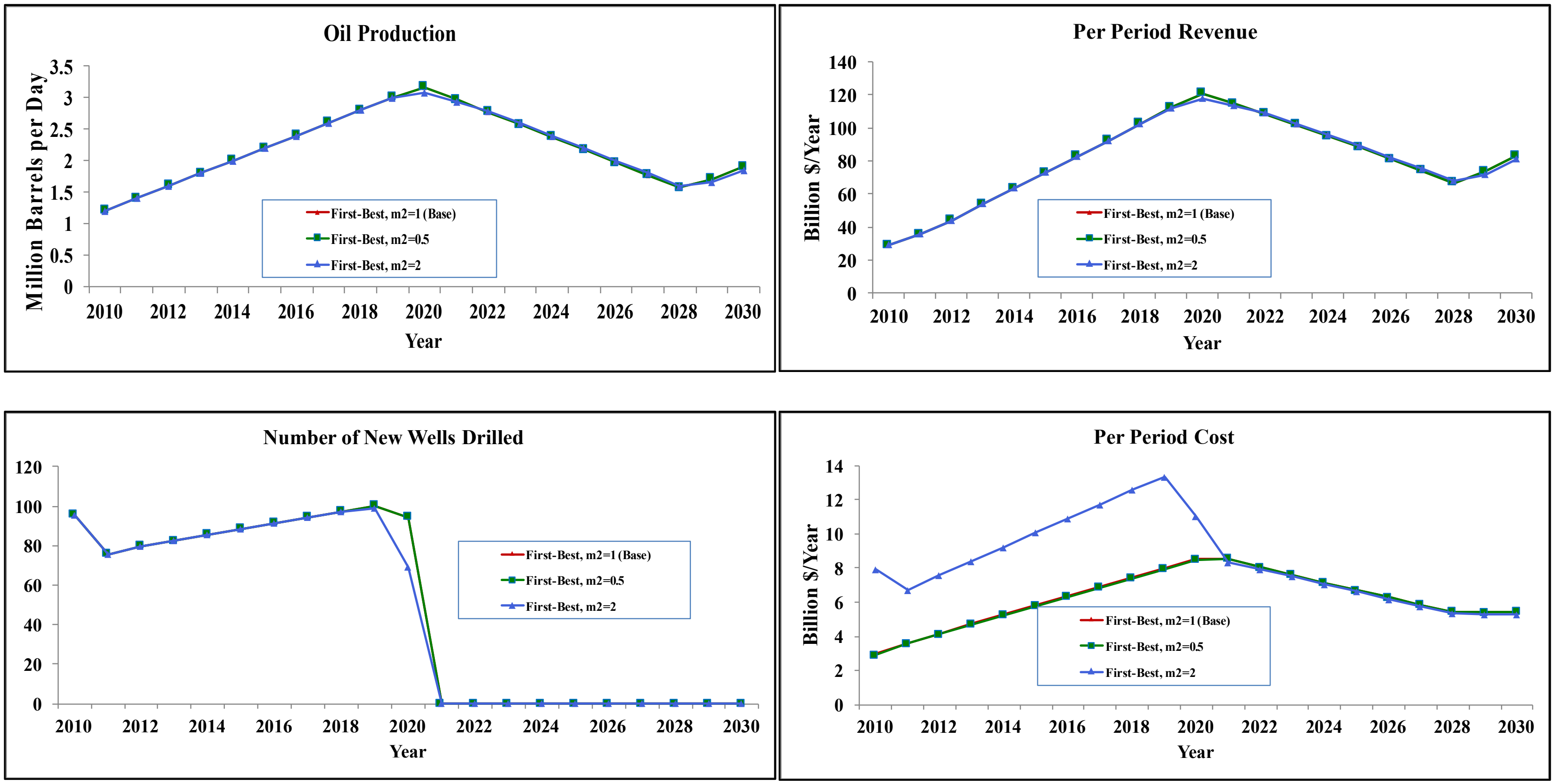
As seen in the results of the robustness checks in Figures C.11 and C.12, which vary the values of the maintenance cost parameters m_1 and m_2, respectively, the results for oil production, well drilling, and revenue are robust to the maintenance cost $c_N(\cdot)$ for old wells. As expected, the values of the maintenance cost parameters m_1 and m_2 affect costs. As seen in Figures C.13 and C.14, while the maintenance cost parameter m_2 affects the present discounted value of the entire stream of per-period profit, the present discounted value of the entire stream of per-period profit appears fairly robust to the maintenance cost parameter m_1. As the results for oil production, well drilling, and costs are robust to the maintenance cost $c_N(\cdot)$ for old wells, our qualitative results regarding the relative inefficiencies of oil production contracts are robust to the maintenance cost for old wells as well.

Figure C.11. Robustness check results for maintenance cost parameter m_1: Oil production, well drilling, revenue, and costs



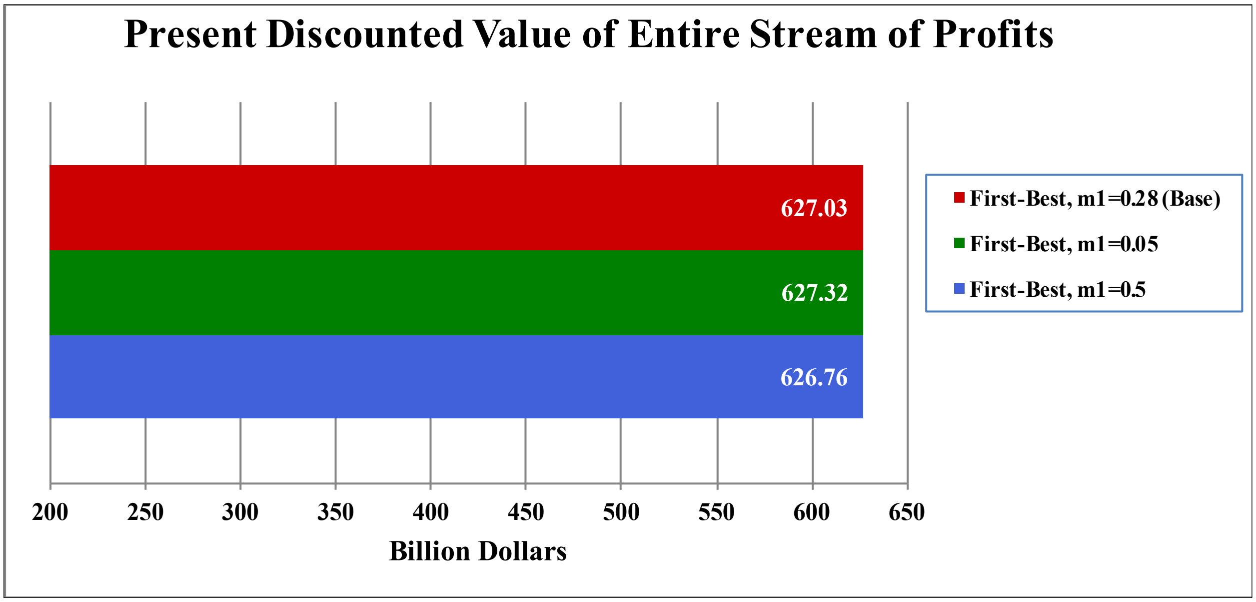
Note: Dollars are constant 2008 dollars.

Figure C.12. Robustness check results for maintenance cost parameter m_2 : Oil production, well drilling, revenue, and costs



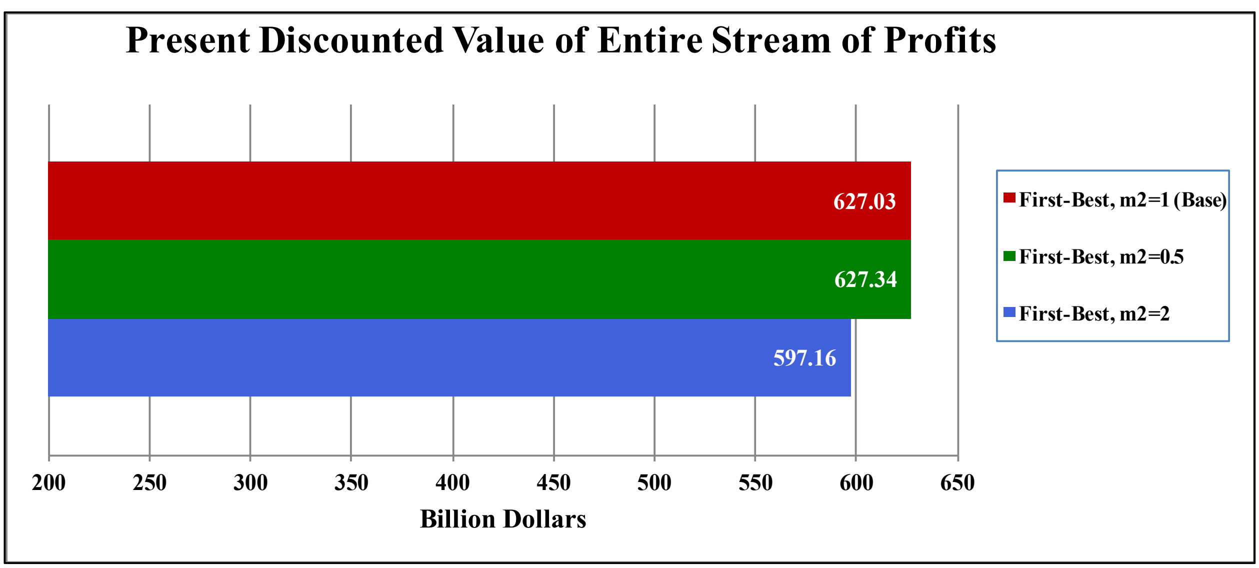
Note: Dollars are constant 2008 dollars.

Figure C.13. Robustness check results for maintenance cost parameter m_1: PDV of entire stream of per-period profit



Note: Dollars are constant 2008 dollars.

Figure C.14. Robustness check results for maintenance cost parameter m_2: PDV of entire stream of per-period profit



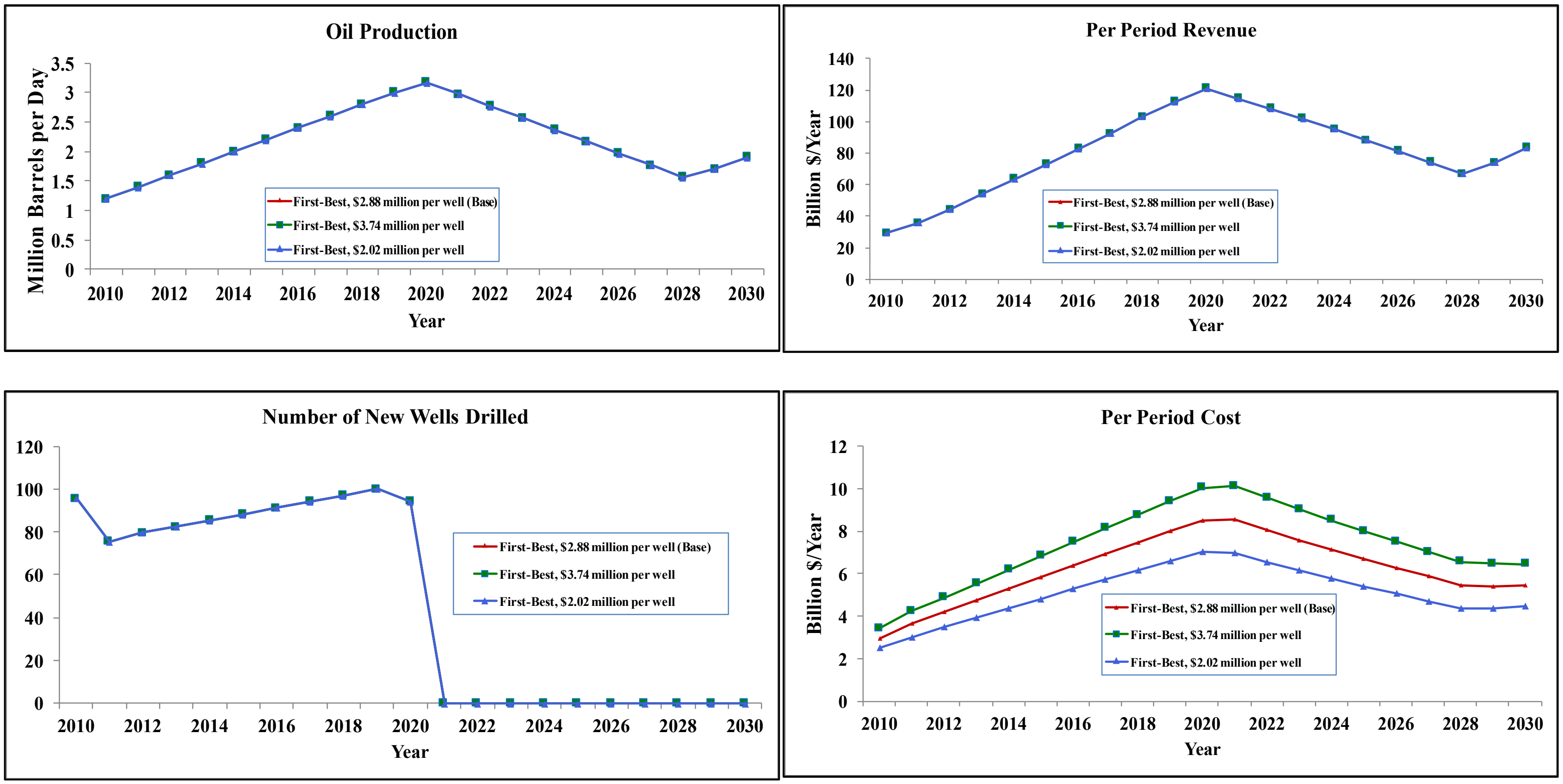
Note: Dollars are constant 2008 dollars.

C.5. Cost c_n of a new well

The cost c_n of a new well includes drilling cost plus surface infrastructure cost (Gao, Hartley and Sickles, 2009). Gao, Hartley and Sickles (2009) estimate the drilling cost for Arabian light crude to be \$2.4 million per well. Based on data from the Center for Global Energy Studies (1993), Gao, Hartley and Sickles (2009) estimate the surface infrastructure maintenance cost on Arabian light and medium fields to be \$482,000 per well. We therefore use a base case value for cost of a new well c_n of \$2.882 million per well. For robustness, we also try specifications with cost of a new well c_n set to \$3.74 million per well and \$2.02 million per well, representing values 30% higher and 30% lower than the base case, respectively.

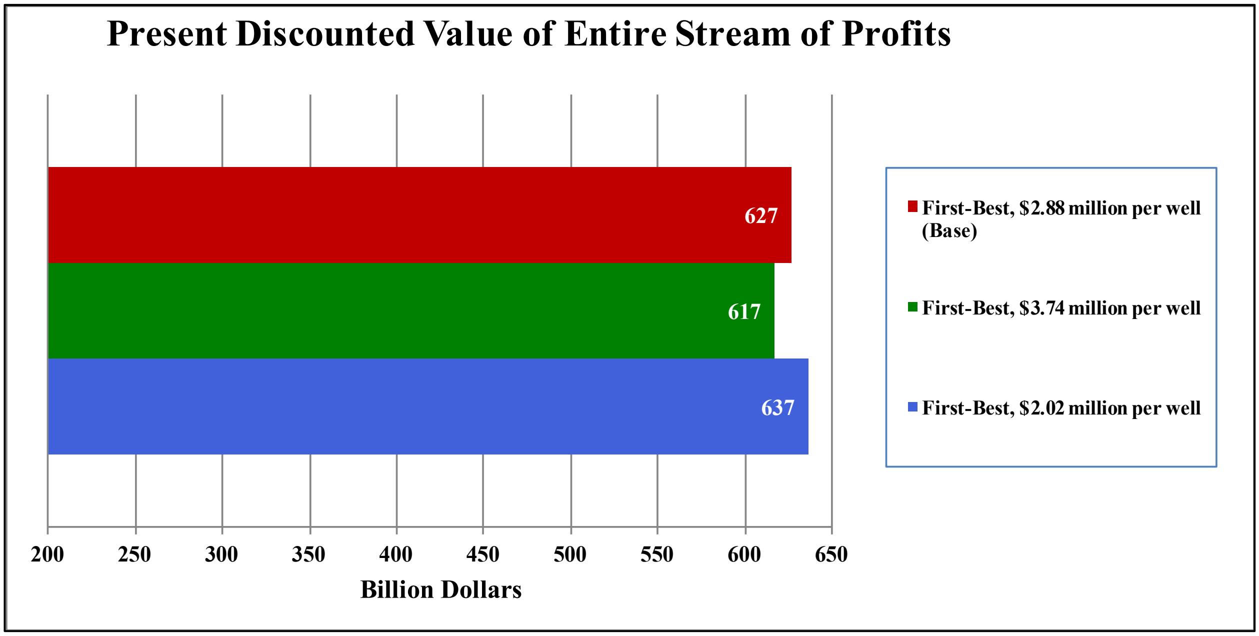
As seen in the results of the robustness checks in Figure C.15, the results for oil production, well drilling, and revenue are robust to the cost c_n of a new well. As expected, cost c_n of a new well affects costs, and, as seen in Figure C.16, the present discounted value of the entire stream of per-period profit. Nevertheless, as the results for oil production, well drilling, and costs are robust to the cost c_n of a new well, our qualitative results regarding the relative inefficiencies of oil production contracts are robust to the cost of a new well as well.

Figure C.15. Robustness check results for cost c_n of a new well: Oil production, well drilling, revenue, and costs



Note: Dollars are constant 2008 dollars.

Figure C.16. Robustness check results for cost c_n of a new well: PDV of entire stream of per-period profit



Note: Dollars are constant 2008 dollars.

C.6. Water injection rate $W(\cdot)$

The water injection rate $W(\cdot)$ (in million barrels per day) is the following function of oil production q_t, existing wells N_t, and new wells drilled n_t:

$$W(q_t, n_t, N_t) = e^{h_1} q_t^{h_2} (N_t + n_t)^{h_3}.$$

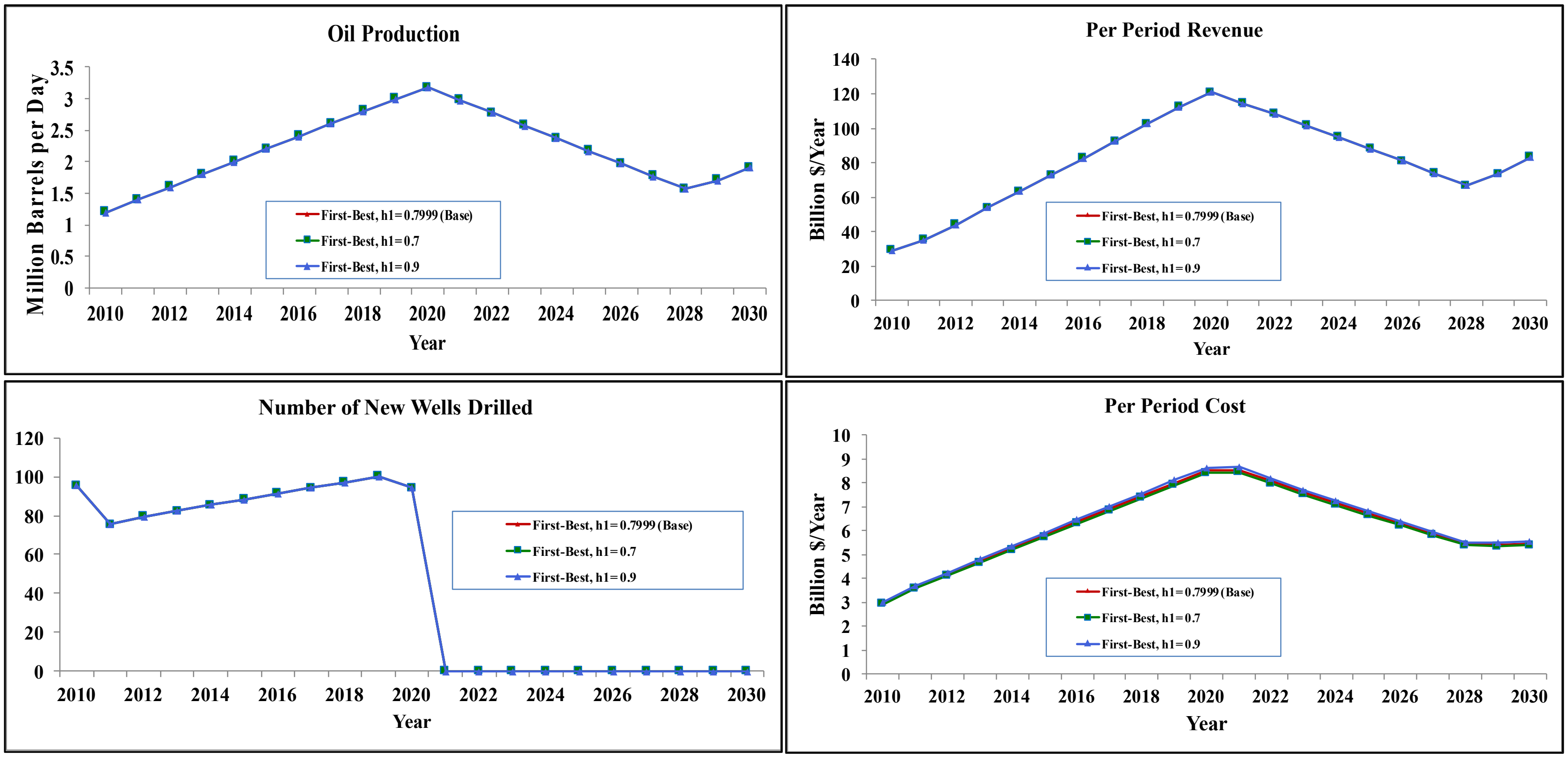
To determine the water injection rate $W(\cdot)$, Gao, Hartley and Sickles (2009) use engineering-economic simulations based on the *WorkBench* Black Oil Simulator developed by Scientific Software Intercomp, which simulates the fluid movements[33] in the reservoirs using partial differential equations describing the movement of the fluids that take into account the reservoirs' geological and technological constraints. Gao, Hartley and Sickles (2009) use the *WorkBench* Black Oil Simulator to generate data on the required water injection rates and number of producing wells in accordance to the simulation assigned production target on a field with similar physical characteristics to their field of study. They use the simulated data to econometrically estimate the parameters in the water injection rate $W(\cdot)$, and obtain parameter estimates of $h_1 = 0.7999$, $h_2 = 0.9509$, and $h_3 = 0.0306$.

Following Gao, Hartley and Sickles (2009), in our base case we assume $h_1 = 0.7999$, $h_2 = 0.9509$, and $h_3 = 0.0306$. For robustness we also try specifications with $h_1 \in \{0.7, 0.9\}$, $h_2 \in \{0.8, 1.1\}$, and $h_3 \in \{0.02, 0.05\}$.

As seen in the results of the robustness checks in Figures C.17-C.22, which vary the values of the water injection rate parameters h_1, h_2, and h_3, the results for oil production, well drilling, revenue, costs, and the present discounted value of the entire stream of per-period profit are robust to the water injection rate $W(\cdot)$.

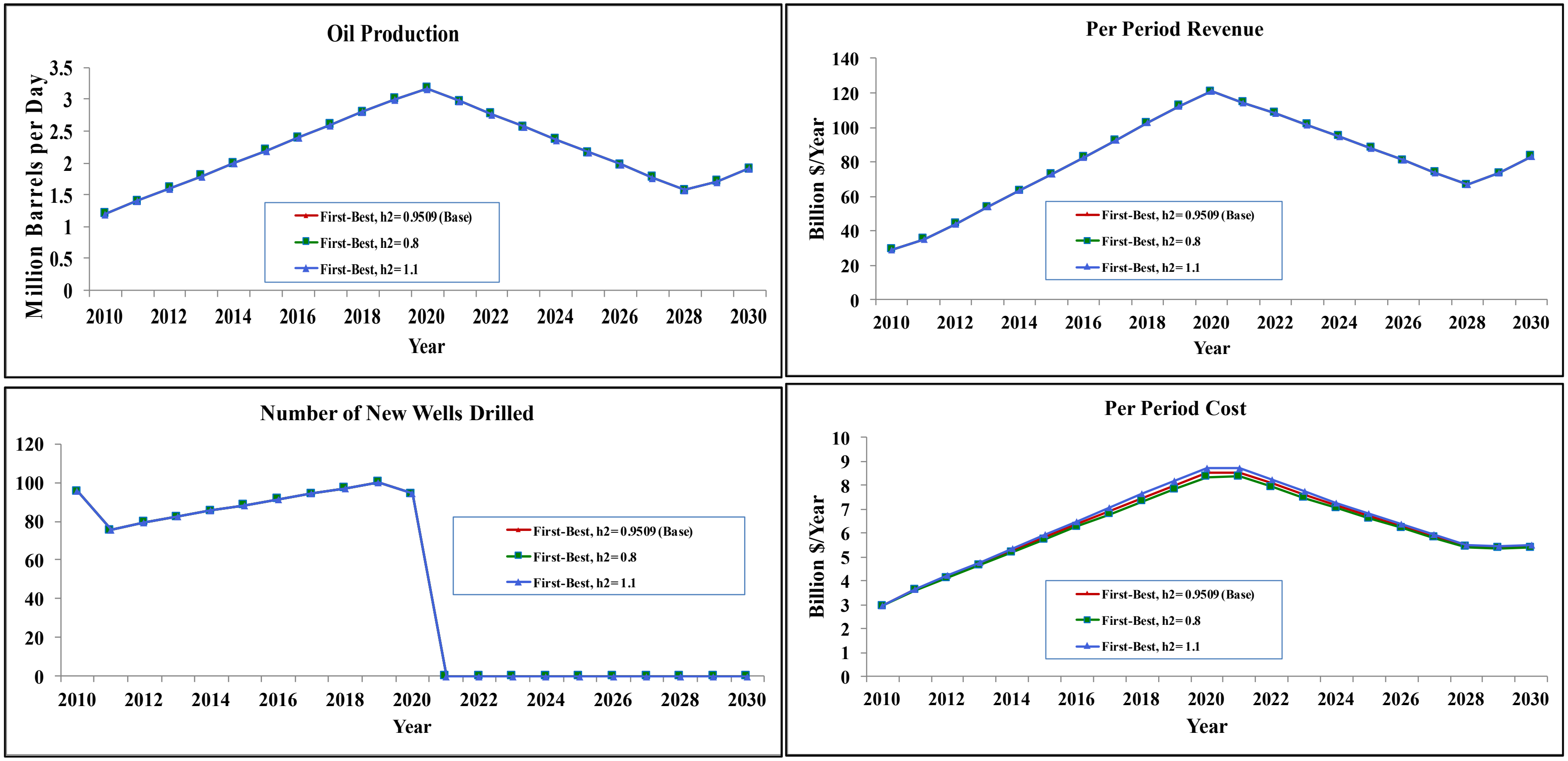
[33] These fluid movements include water injection to the reservoir, fluid transition in the reservoir, and oil extraction from the reservoir's producing wells.

Figure C.17. Robustness check results for water injection rate parameter h_1 : Oil production, well drilling, revenue, and costs



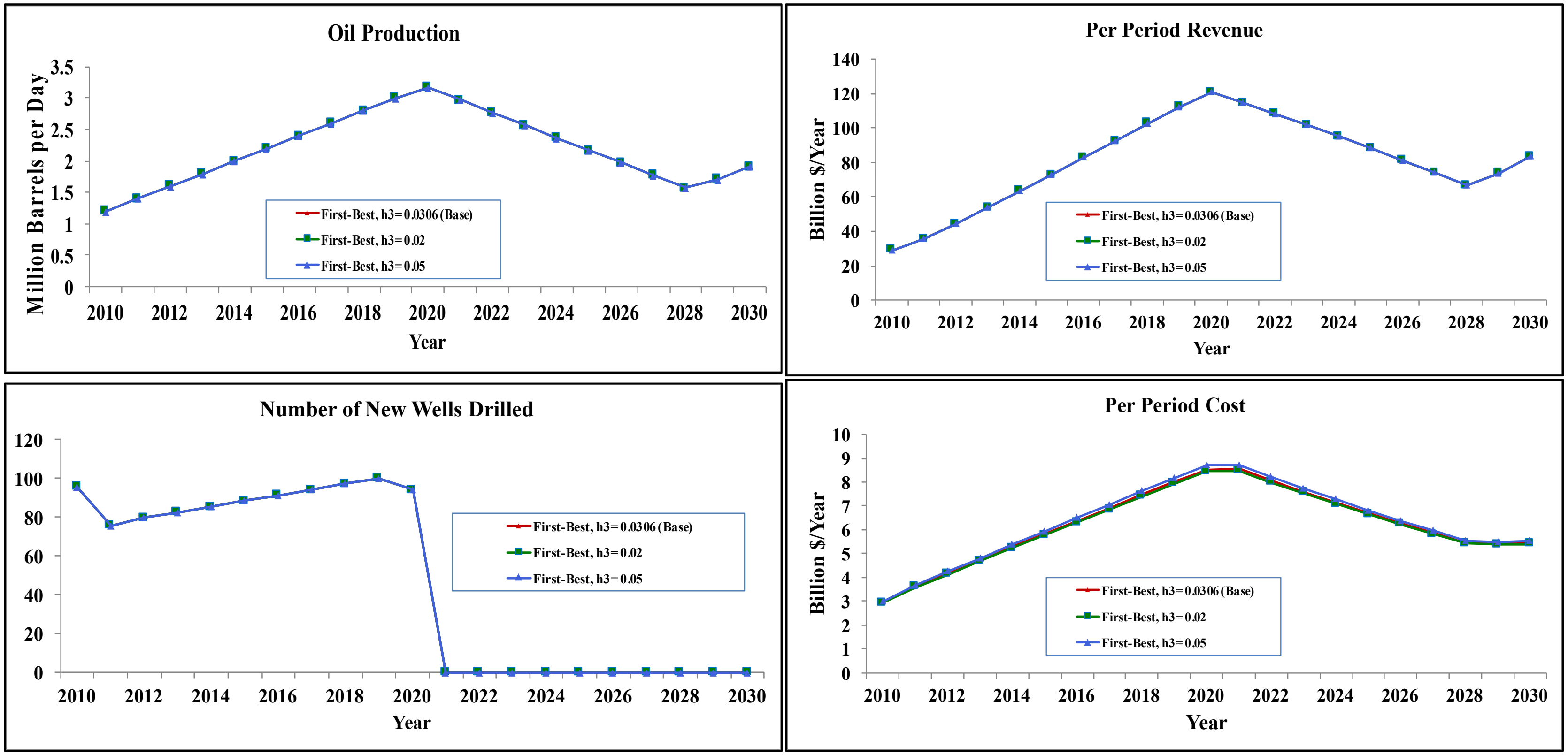
Note: Dollars are constant 2008 dollars.

Figure C.18. Robustness check results for water injection rate parameter h_2: Oil production, well drilling, revenue, and costs



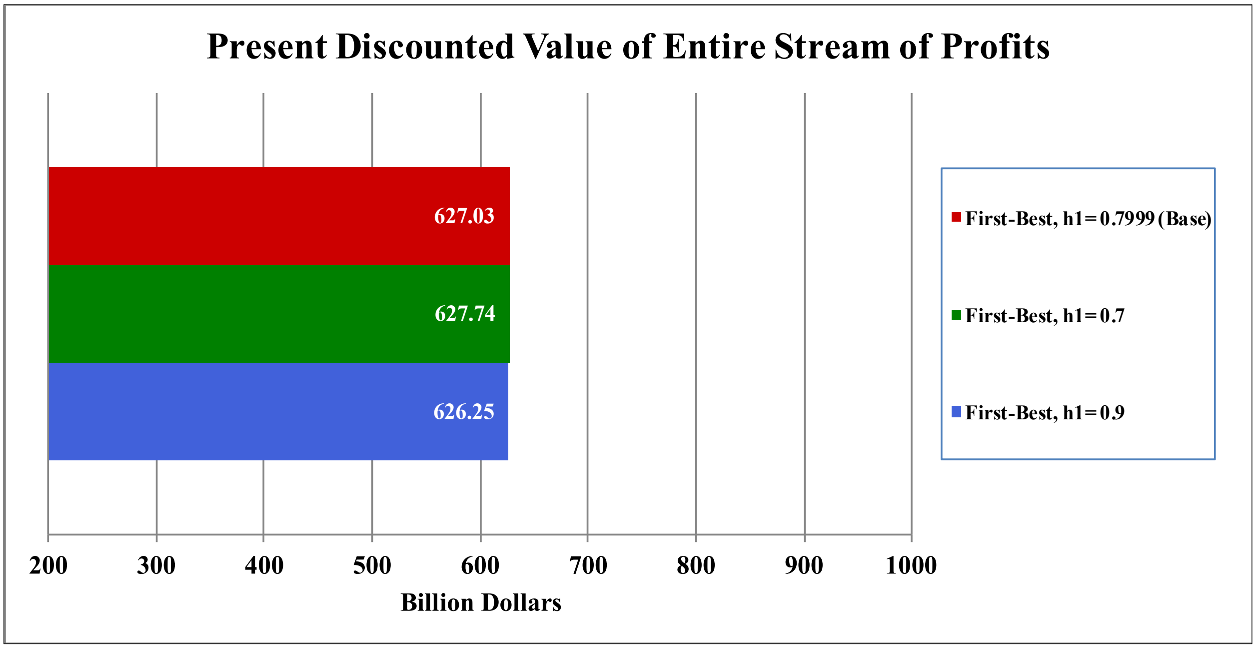
Note: Dollars are constant 2008 dollars.

Figure C.19. Robustness check results for water injection rate parameter h_3: Oil production, well drilling, revenue, and costs



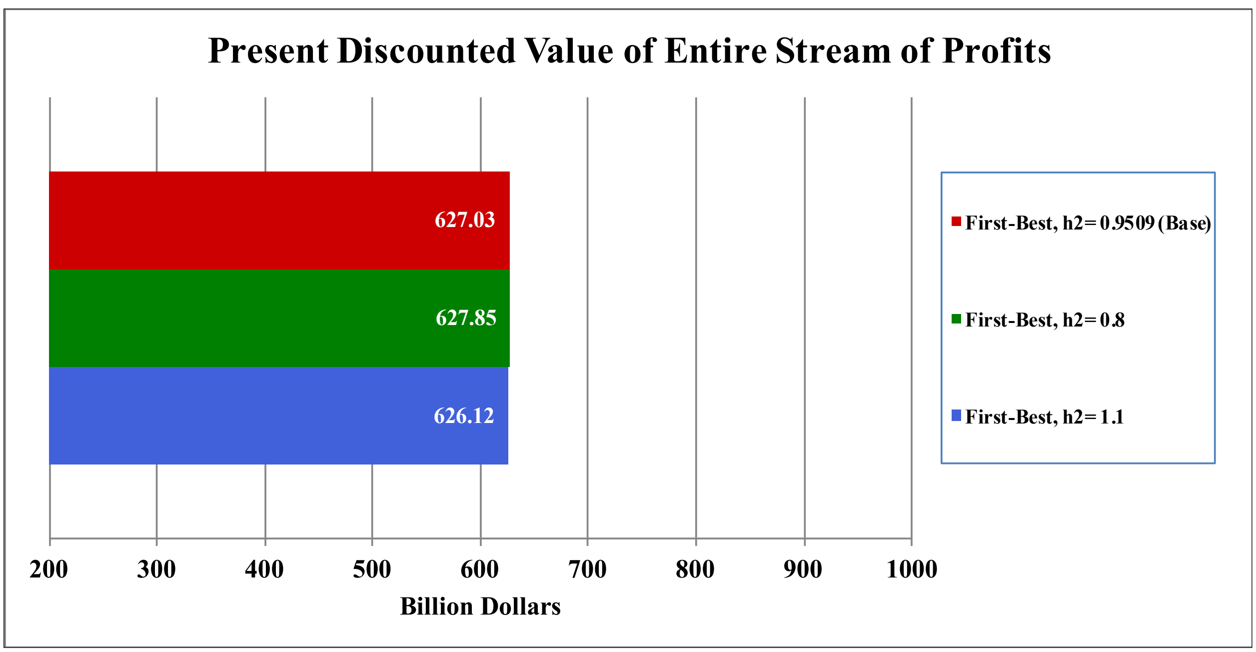
Note: Dollars are constant 2008 dollars.

Figure C.20. Robustness check results for water injection rate parameter h_1 : PDV of entire stream of per-period profit



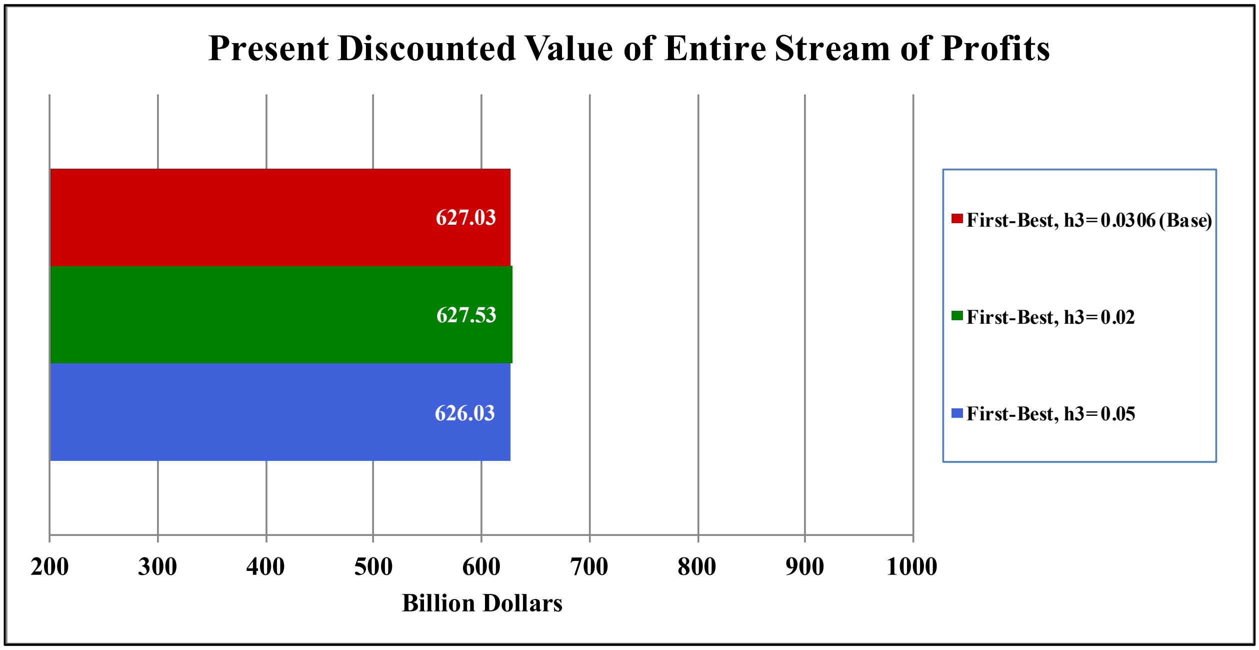
Note: Dollars are constant 2008 dollars.

Figure C.21. Robustness check results for water injection rate parameter h_2 : PDV of entire stream of per-period profit



Note: Dollars are constant 2008 dollars.

Figure C.22. Robustness check results for water injection rate parameter h_3: PDV of entire stream of per-period profit



Note: Dollars are constant 2008 dollars.

Appendix D. Discount Rate

Following Gao, Hartley and Sickles (2009), who use discount rates of 10% and 30%, we use a discount rate of 10%. For robustness, we also run our model using the discount rates 5% and 20% as well.

We choose the 10% discount rate for our base case for two reasons. First, IOCs treat their internal discount rate as propriety information, and in order to avoid revealing it, they use a 10% discount rate in their joint cash flows with their partners. In the same way, the IOCs negotiate deals with their partners and host governments over net present value of cash flow using a 10% discount rate (NPV10).[34] Second, in contrast to the oil sector in Iraq, other parts of the economy in Iraq are not growing fast enough to absorb current oil revenues. Therefore, for the government of Iraq, future profits might be more valuable. This perception towards future gain implies low discount rates. And it seems that a discount rate as low as 10% is reasonable.

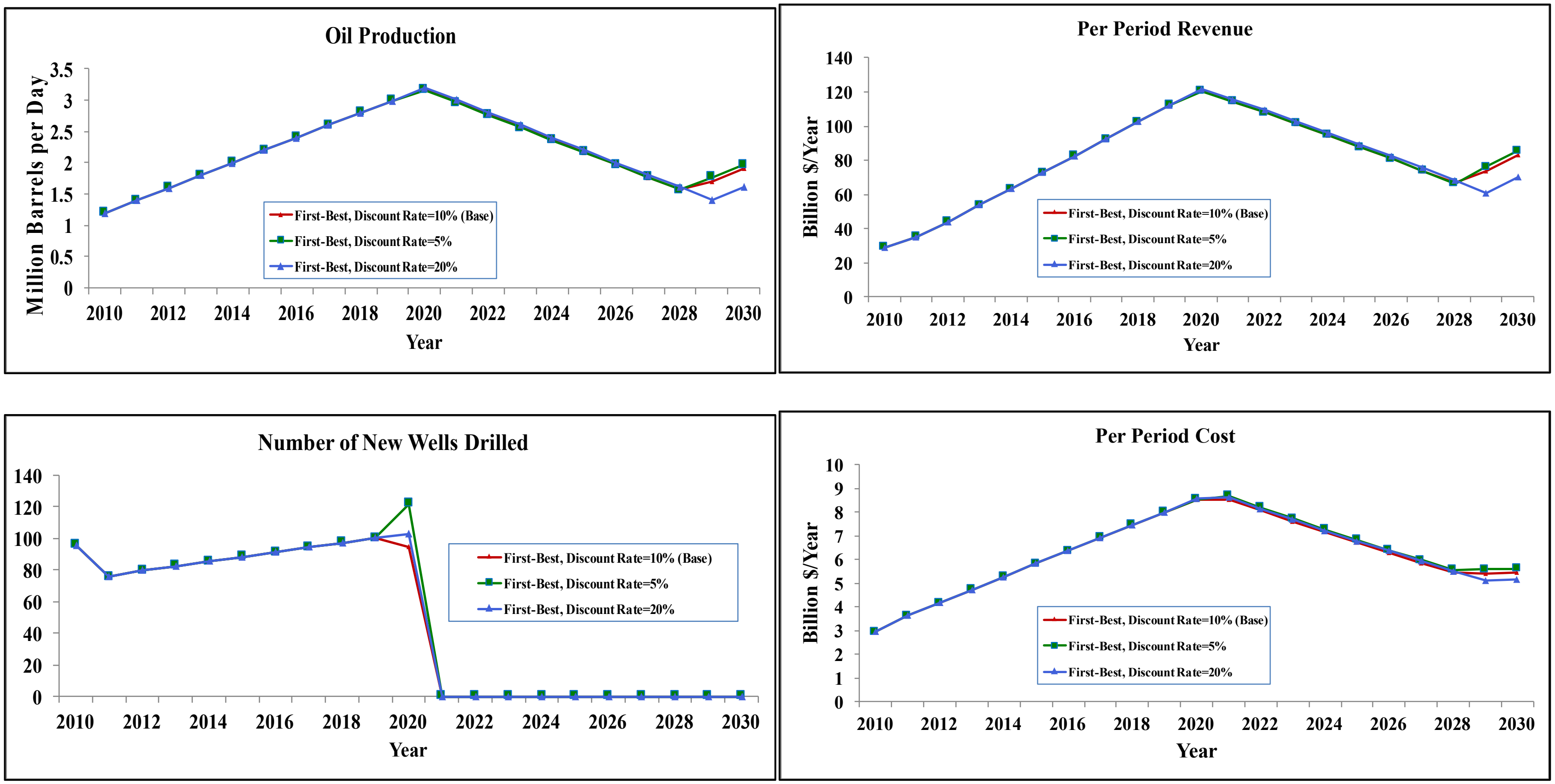
For robustness, we choose a 20% discount rate for two reasons. First, as Adelman (1993) argues, a discount rate 20% or higher is the suitable discount rate for countries such as Iraq for which oil revenue is the largest portion of the government's revenue. Since oil revenue is their governments' main source of income, these countries prefer present to future production, and therefore should have a high discount rate. This is also the basis for Gao, Hartley and Sickles' (2009) choice of 30% as their higher discount rate. Second, similar to what Ghandi and Lin (2012) suggest for the case of buy-back contracts in Iran, the presence of international oil companies in technical service contracts in Iraq may imply a discount rate lower than 20% since, as argued above, IOCs may have a lower discount rate. In contrast to Gao, Hartley and Sickles (2009), whose choice of discount rate represents the Saudi Aramco or the Saudi government, we are looking for a discount rate that represents the IOC and the Iraqi government as if they were cooperating in deciding the optimal production and drilling.

We therefore use a discount rate of 10% for the base case, and run our model using discount rates of 5% and 20% for robustness as well. As seen in the results of the robustness checks in Figure D.1, the results for oil production and revenue are robust to the discount rate in all but the final 2 years of the contract (2029 and 2030), well drilling is robust to the discount rate in all but

[34] Personal communications with industry experts

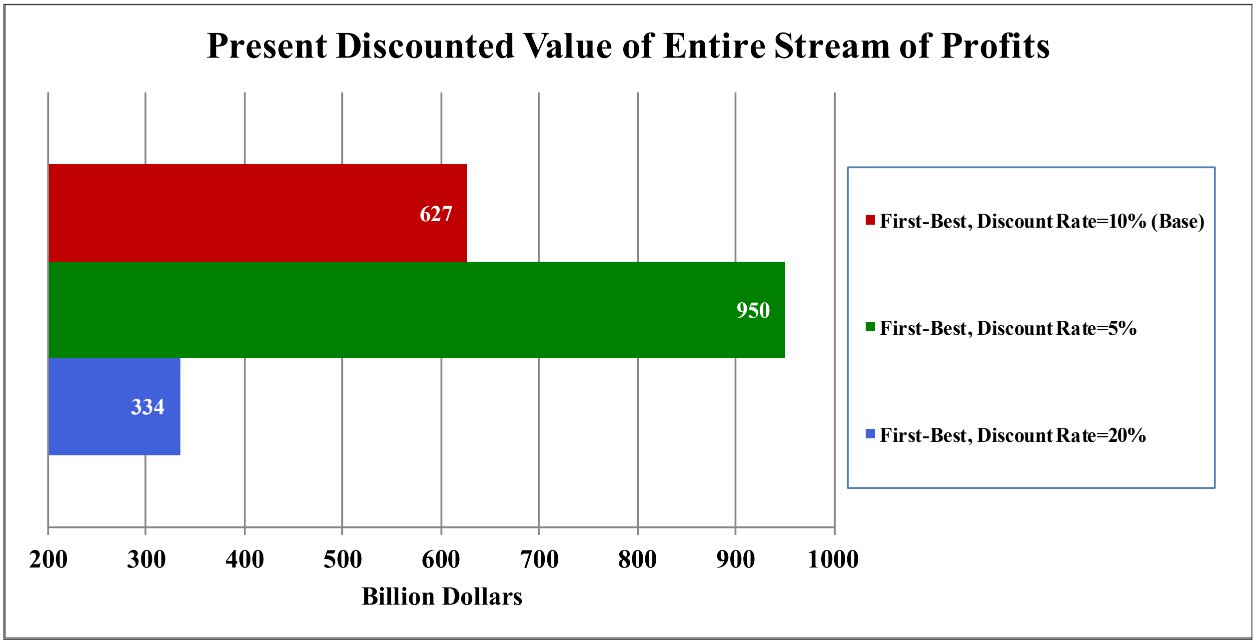
the final year of well drilling (2020), and costs are relatively robust in all but the final 2 years of the contract (2029 and 2030). As expected, as seen in Figure D.2, the present discounted value of the entire stream of per-period profit is higher when the discount rate is lower. Nevertheless, as the results for oil production, well drilling, and costs are relatively robust to the discount rate, our qualitative results regarding the relative inefficiencies of oil production contracts are robust to the discount rate as well.

Figure D.1. Robustness check results for discount rate: Oil production, well drilling, revenue, and costs



Note: Dollars are constant 2008 dollars.

Figure D.2. Robustness check results for discount rate: PDV of entire stream of per-period profit



Note: Dollars are constant 2008 dollars.

Appendix E. Technical, geological, and feasibility constraints

E.1. Well productivity constraint

To determine the maximum well productivity ω, we calculate the maximum well productivity in the Deutsche Bank forecast. Each year we divide the Deutsche Bank total production forecast for that year by the Deutsche Bank forecast of the total number of producing wells in that year, and obtain a maximum well productivity over all years of 3,240 barrels per day. We therefore set well productivity at its maximum level of 3,240 barrels per producing well per day.

E.2. Geological feasibility constraint

For the geological feasibility function $f(q_t, S_t, n_t, N_t)$, we follow Gao, Hartley and Sickles' (2009) methodology and estimated functional forms that address geological and technological limitations of extraction from an onshore oil field in Saudi Arabia.

Gao, Hartley and Sickles' (2009) dynamic optimization model for Saudi Arabia's giant Ghawar oil field benefits from engineering-economic simulations based on the *WorkBench* Black Oil Simulator developed by Scientific Software Intercomp, which simulates the fluid movements[35] in the reservoirs using partial differential equations describing the movement of the fluids that take into account the reservoirs' geological and technological constraints. Gao, Hartley and Sickles (2009) use the *WorkBench* Black Oil Simulator to generate data on the required water injection rates and number of producing wells in accordance to the simulation assigned production target on a field with similar physical characteristics to their field of study. They use the simulated data to estimate the maximum production capacity in the vicinity of an average oil well using a semi-log functional form that best matches the simulated data. This functional form captures the geological constraint in the reservoir since it takes into account the effect of reservoir engineering on the production capacity. By extending the geological feasibility function to the field as a whole, they arrive at the following functional form for the geological feasibility function:

---

[35] These fluid movements include water injection to the reservoir, fluid transition in the reservoir, and oil extraction from the reservoir's producing wells.

$$\begin{aligned} f(q_t, S_t, n_t, N_t) &= \tilde{f}(W(q_t, n_t, N_t), S_t, n_t, N_t) \\ &= \tilde{f}(W_t, S_t, n_t, N_t) \\ &= \left(f_0 + f_1 \ln W_t + f_2 \ln W_t \ln\left(S_0 - S_t\right) + f_3 \ln\left(S_0 - S_t\right)\right)(N_t + n_t), \end{aligned} \tag{E.1}$$

where S_0 is the initial recoverable reserves and $W_t = W(q_t, n_t, N_t)$ is the water injection rate. As the Rumaila cumulative production level and recoverable reserve estimates in the beginning of 2010 are 13.08 and 16.08 billion barrels, respectively,[36] we set S_0 to 29.08 billion barrels.

Assuming that the average oil well of their study has an annual cumulative production equal to 5% of the reservoir reserve, the results of Gao, Hartley and Sickles' (2009) econometric estimation yields $f_0 = 0.0451$, $f_1 = 0.0362$, $f_2 = -0.0038$, and $f_3 = -0.0044$.

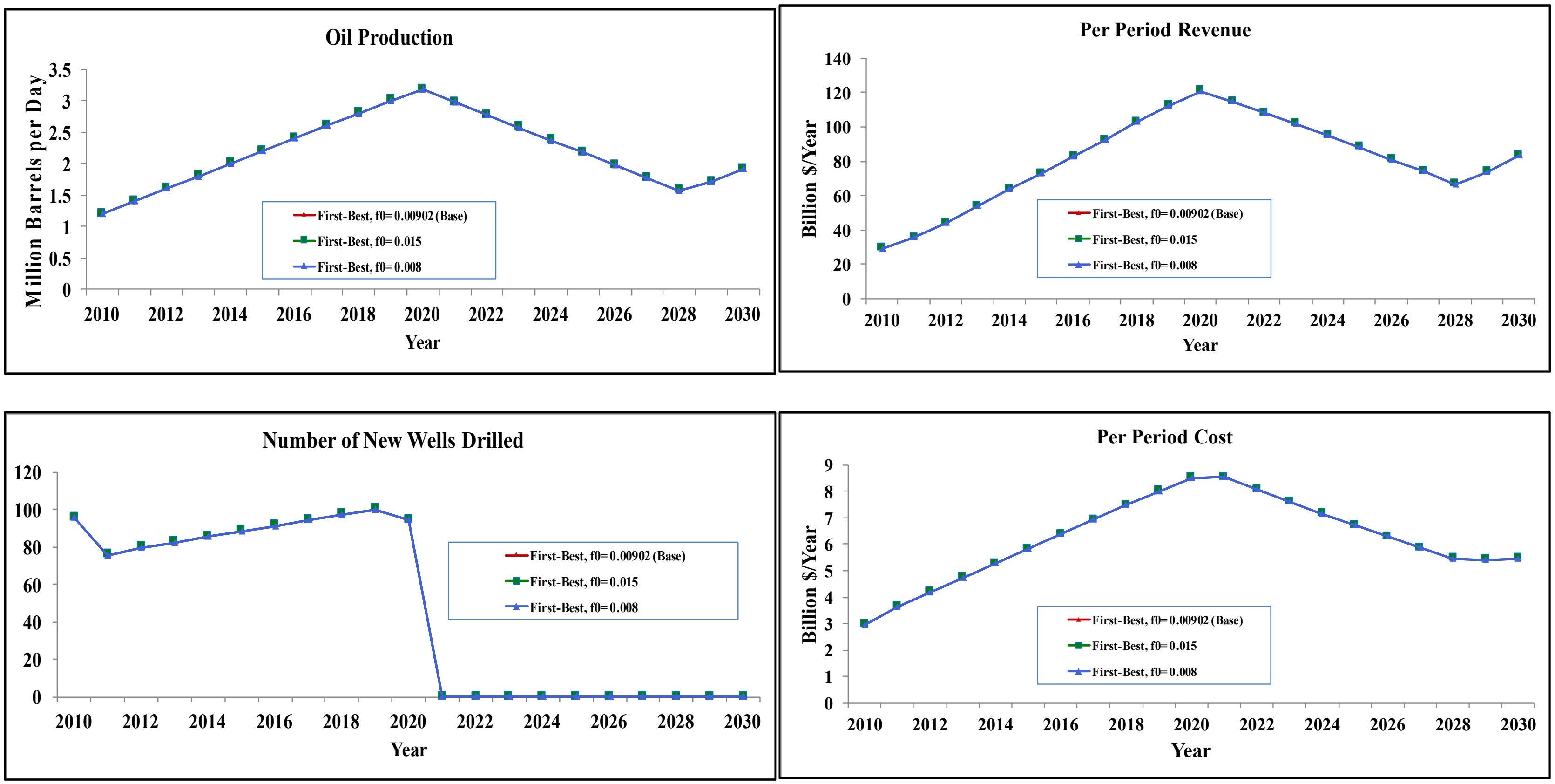
Based on their results, we assume that 5% of the Saudi Arabia's Ghawar reserve is at least 5 million barrels per day. Therefore, in order to apply Gao, Hartley and Sickles' (2009) geological feasibility function to Rumaila, which had one million barrels per day production in the beginning of 2010, amounting to about one fifth of the production in Saudi Arabia's Ghawar reserve, we divide the whole geological feasibility function, and therefore each of the geological feasibility parameters f_0, f_1, f_2, and f_3 in the function, by 5. Thus, in our base case we use $f_0 = 0.00902$, $f_1 = 0.00724$, $f_2 = -0.00076$, and $f_3 = -0.00088$. For robustness, we also try specifications with $f_0 \in \{0.015, 0.008\}$, $f_1 \in \{0.009, 0.006\}$, $f_2 \in \{-0.0009, -0.0006\}$, and $f_3 \in \{-0.001, -0.0007\}$.

As seen in the results of the robustness checks in Figures E.1 to E.4, which vary the values of the geological feasibility parameters f_0, f_1, f_2, and f_3, respectively, the results for oil production, well drilling, revenue, and costs are robust to changes in the values of the geological feasibility parameters f_0, f_1, f_2, and f_3. Moreover, as seen in Figures E.5 to E.8, which present the present discounted value of the entire stream of per-period profit for different values of the geological feasibility parameters f_0, f_1, f_2, and f_3, respectively, the present discounted value of the entire stream of per-period profit is unaffected by changes in the geological feasibility parameters f_0, f_1, f_2, and f_3.

---

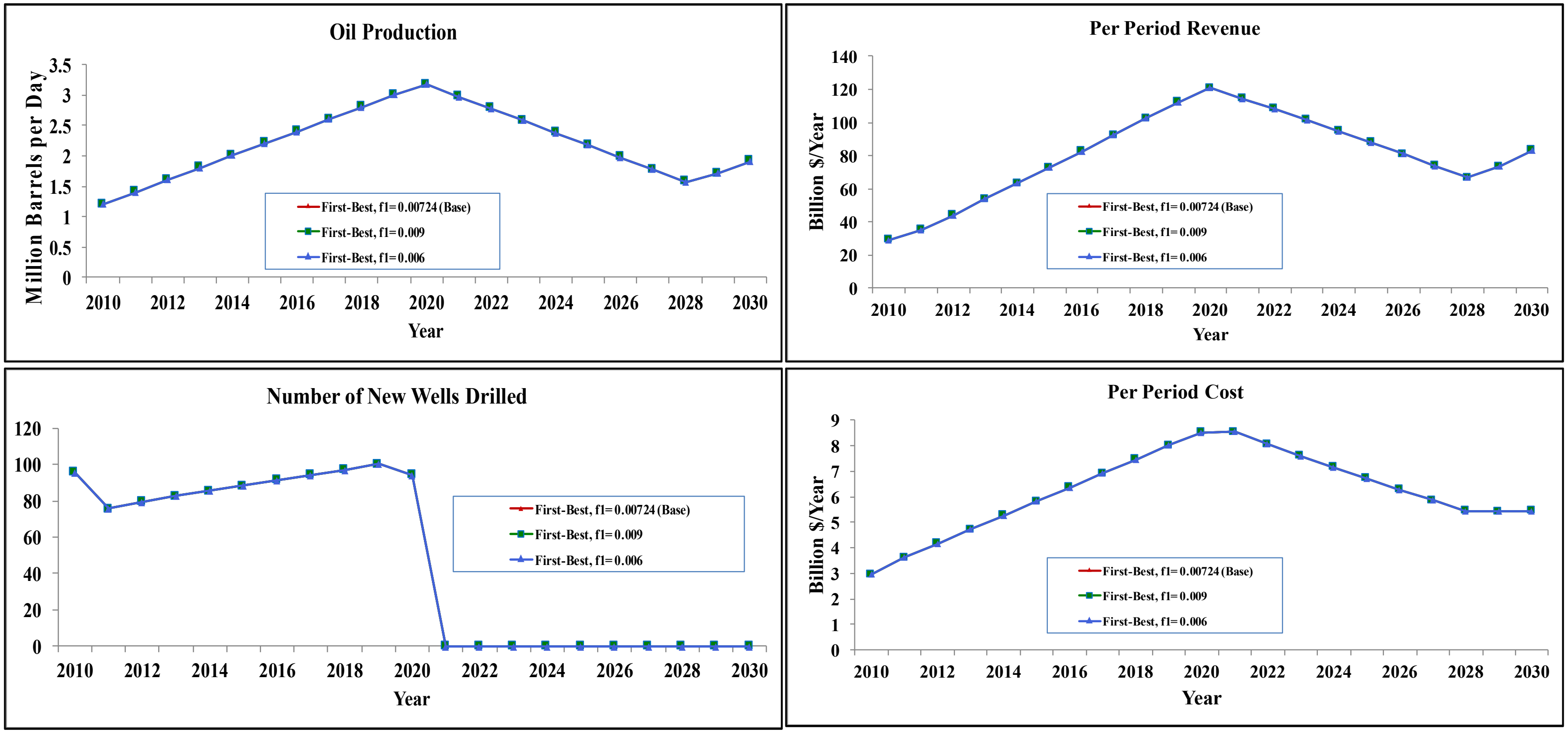
[36] These estimates are based on the International Energy Agency (IEA) Iraq Energy Outlook (IEA, 2012) and personal communication with Deutsche Bank Securities Inc., September 2011.

Figure E.1. Robustness check results for geological feasibility parameter f_0: Oil production, well drilling, revenue, and costs



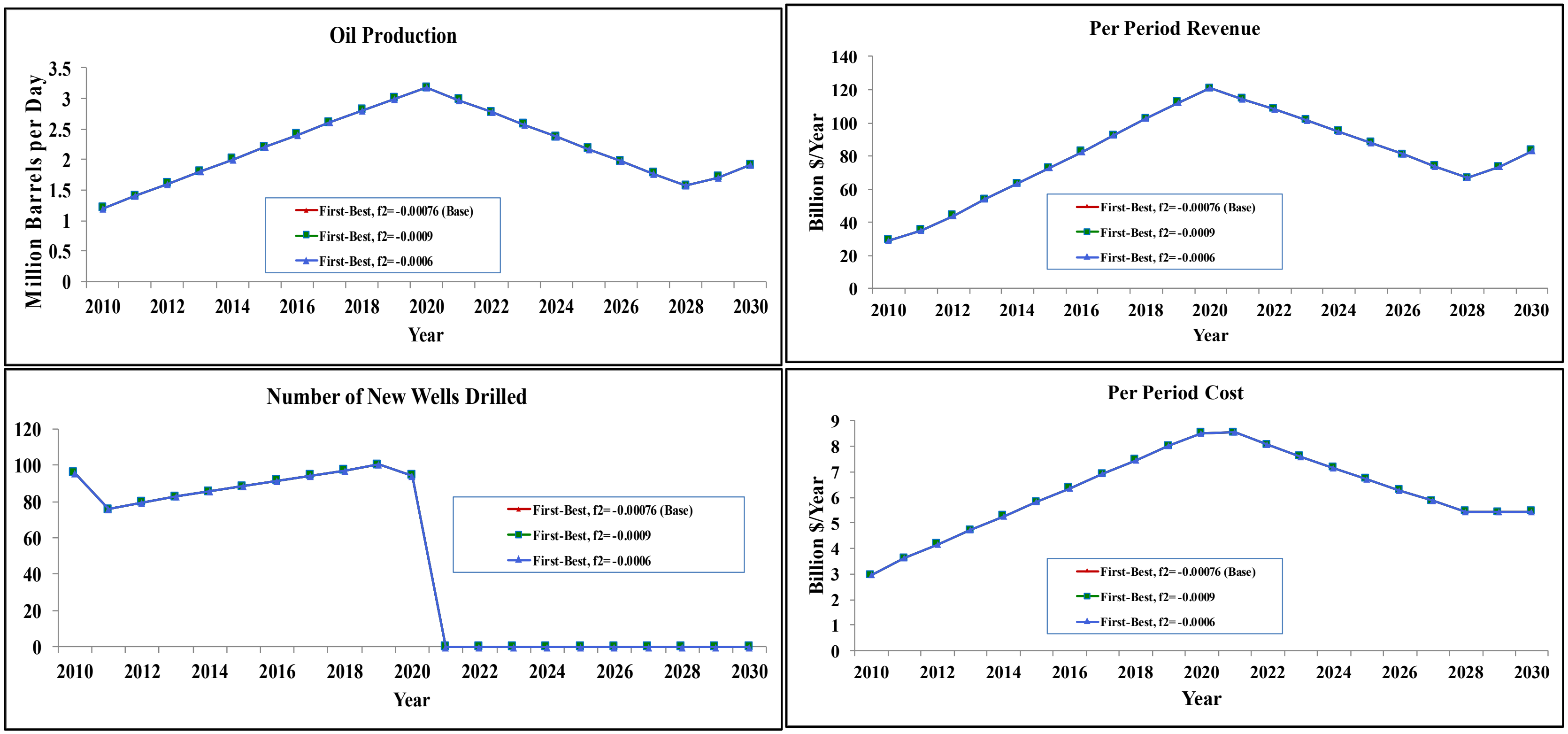
Note: Dollars are constant 2008 dollars.

Figure E.2. Robustness check results for geological feasibility parameter f_1: Oil production, well drilling, revenue, and costs



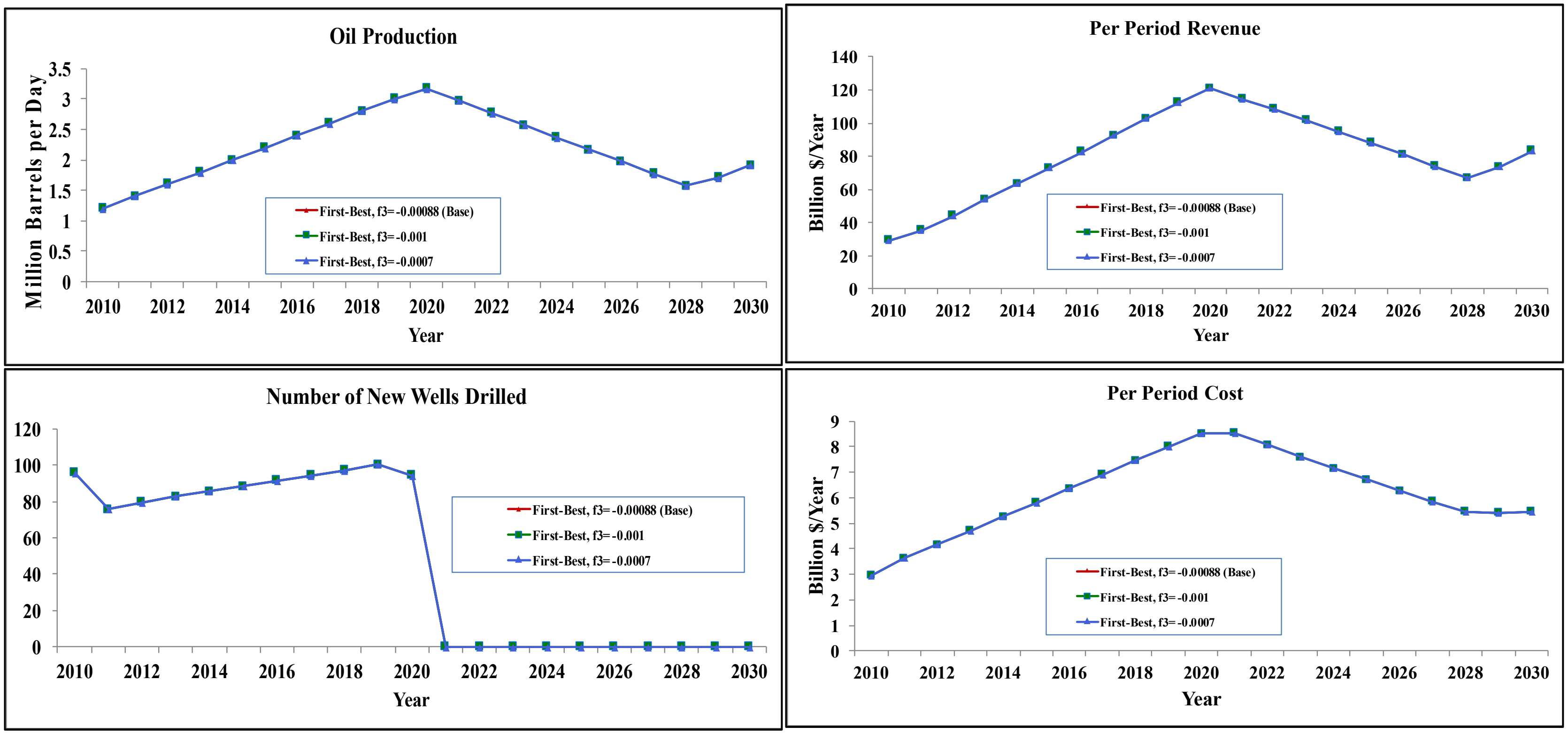
Note: Dollars are constant 2008 dollars.

Figure E.3. Robustness check results for geological feasibility parameter f_2: Oil production, well drilling, revenue, and costs



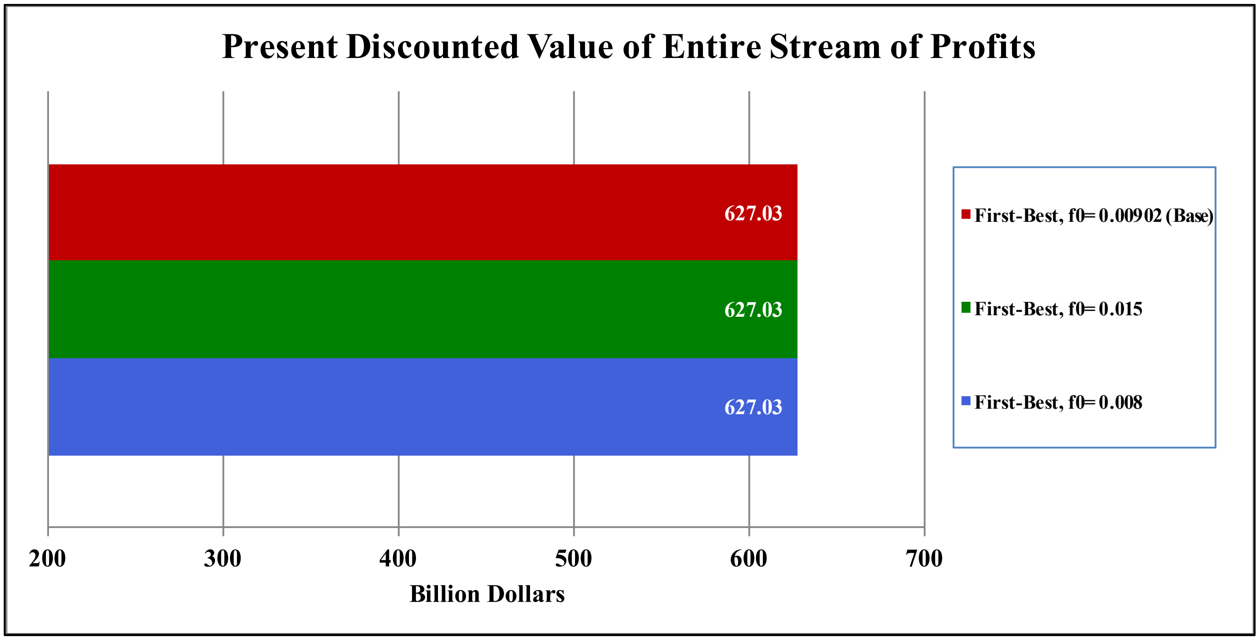
Note: Dollars are constant 2008 dollars.

Figure E.4. Robustness check results for geological feasibility parameter f_3: Oil production, well drilling, revenue, and costs



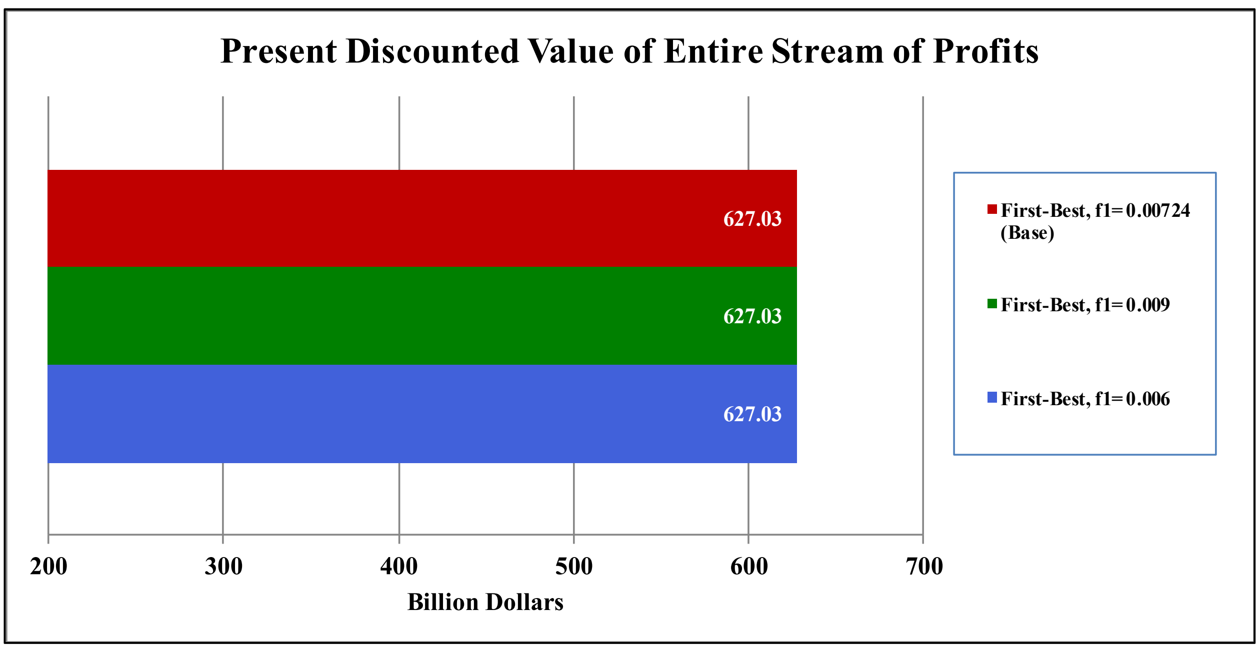
Note: Dollars are constant 2008 dollars.

Figure E.5. Robustness check results for geological feasibility parameter f_0: PDV of entire stream of per-period profit



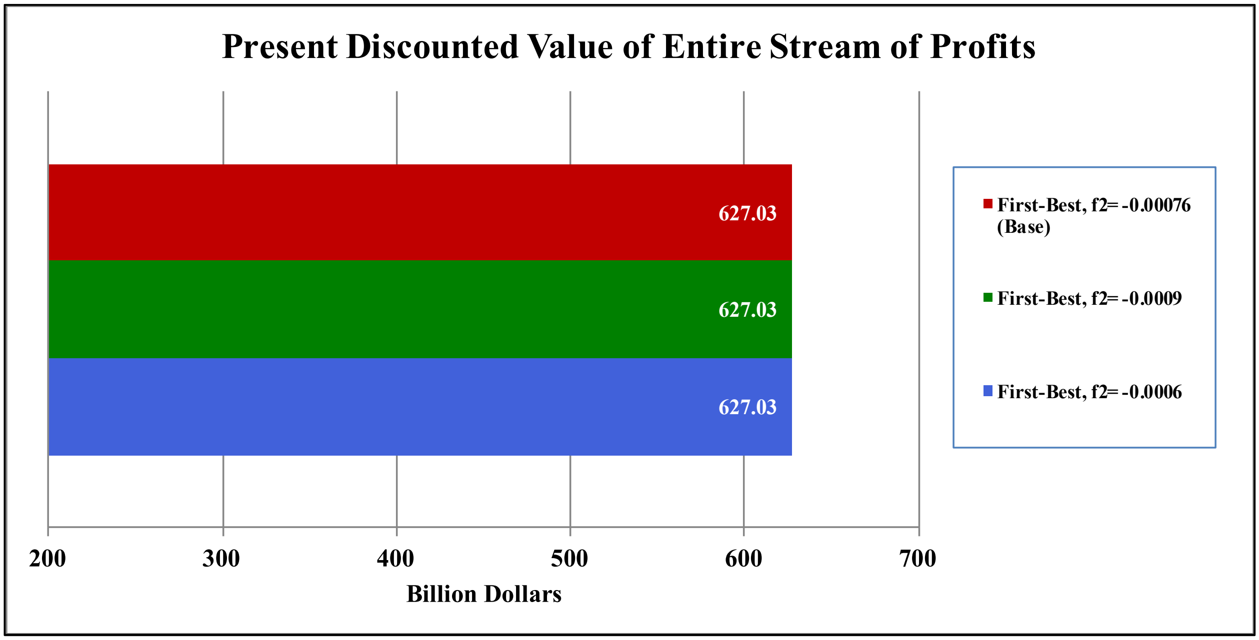
Note: Dollars are constant 2008 dollars.

Figure E.6. Robustness check results for geological feasibility parameter f_1: PDV of entire stream of per-period profit



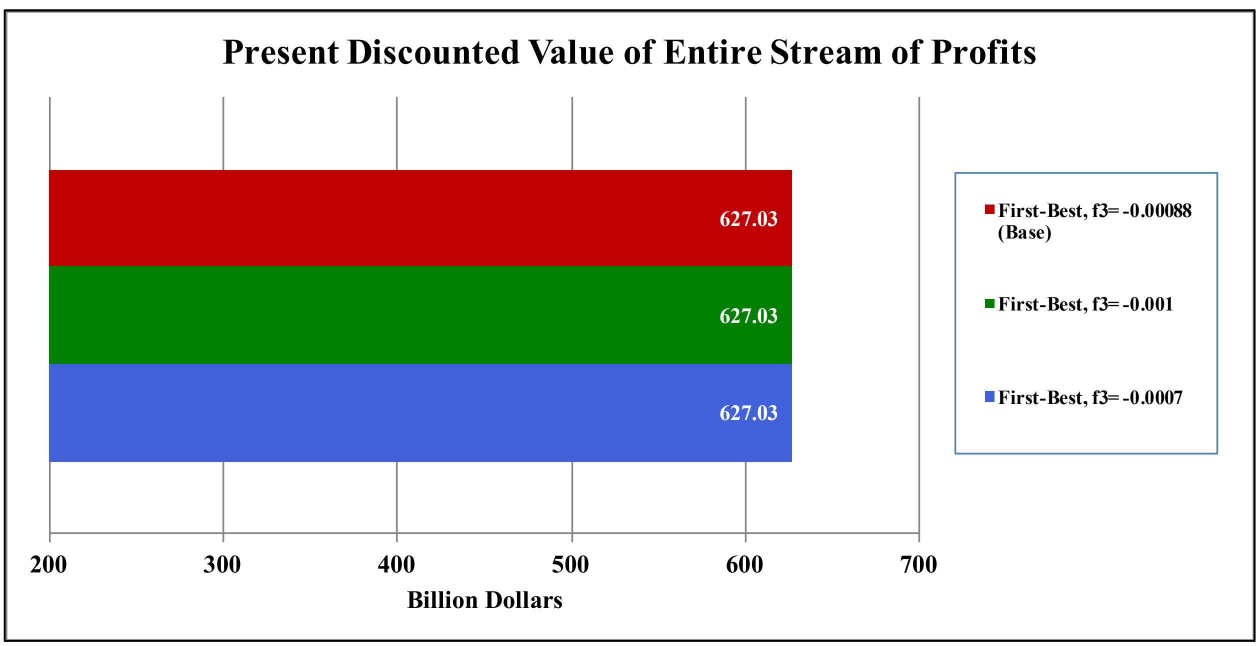
Note: Dollars are constant 2008 dollars.

Figure E.7. Robustness check results for geological feasibility parameter f_2: PDV of entire stream of per-period profit



Note: Dollars are constant 2008 dollars.

Figure E.8. Robustness check results for geological feasibility parameter f_3: PDV of entire stream of per-period profit



Note: Dollars are constant 2008 dollars.

E.3. Production change constraint

Following Ghandi and Lin (2012), we also consider a production change constraint, which sets a cap δ on the largest possible absolute difference between the production level of two consecutive periods. The maximum feasible production change used by Ghandi and Lin (2012) is 10,000 barrels per day for two fields with a combined production of about 190,000 barrels per day. For Rumaila, with a baseline production of 1.01 million barrels per day and a target plateau production of 2.85 million barrels per day, it is reasonable to set the maximum feasible production change in a range between 50,000 to 150,000 barrels per day. Nevertheless, Rumaila's proposed work plans also include installing additional incremental production capacity at 200,000 barrels per day in some years. Therefore, we set the Rumaila maximum feasible production change δ to 200,000 barrels per day.

E.4. Stock constraint

For the stock constraint, we use the estimate of Rumaila recoverable reserves in the beginning of 2010 of 16.08 billion barrels. This estimate is based on International Energy Agency (IEA) Iraq Energy Outlook (IEA, 2012) and personal communication with Deutsche Bank Securities Inc. (September 2011). For the value of the stock S_t of oil remaining in the ground at the beginning of each subsequent year, we apply the equation of motion (1) for the stock S_t of oil remaining in the ground at the beginning of each year t.

E.5. Minimum production constraint

We set the minimum production constraint to 500,000 barrels per day, which is roughly half of Rumaila's 2009 baseline production of 1.01 million barrels per day before the start of the contract. As this constraint never binds in any of our scenarios or robustness checks, our results are robust to our setting a non-zero minimum production constraint.

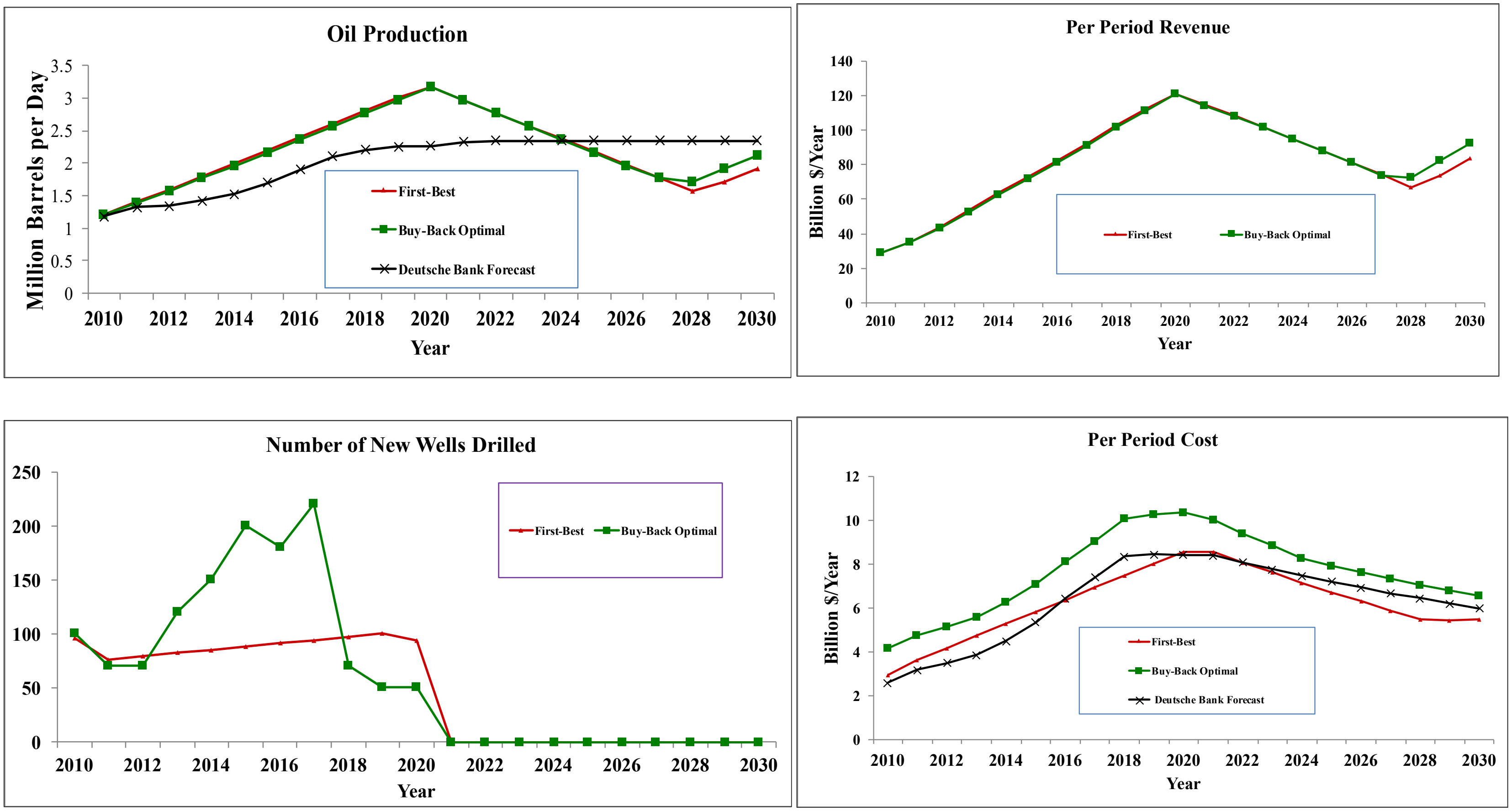
E.6. Well drilling feasibility constraint

The well drilling feasibility constraint accounts for any possible shortage of drilling rigs in Iraq due to the need for such rigs from other development projects. In general, a drilling rig can drill 12 wells per year on average.[37] Considering BP's announced plan for having 20-25 rigs at the maximum (Daly, 2010), it is reasonable to expect 240 to 300 wells as feasible number of wells to be drilled in each year. Therefore, we set the maximum feasible number $\overline{n}_t^f$ of new drilled wells in each period to 285, which is in the upper range of the feasible number of wells. A maximum feasible number of wells of 285 is slightly higher than the maximum number estimated by Deutsche Bank of 220 wells and the 275 wells that BP plans to bring online in the first three years of the development starting in 2010 (GDS Publishing, Inc., 2010), since it may be possible that the optimal number of wells is higher than BP's well rehabilitation plan in 2010. Following Sankey, Clark and Micheloto (2010), we do not consider any new well drilling after 2020 and therefore set $\overline{n}_t^f = 0$ after 2020.

[37] Personal communication with industry experts

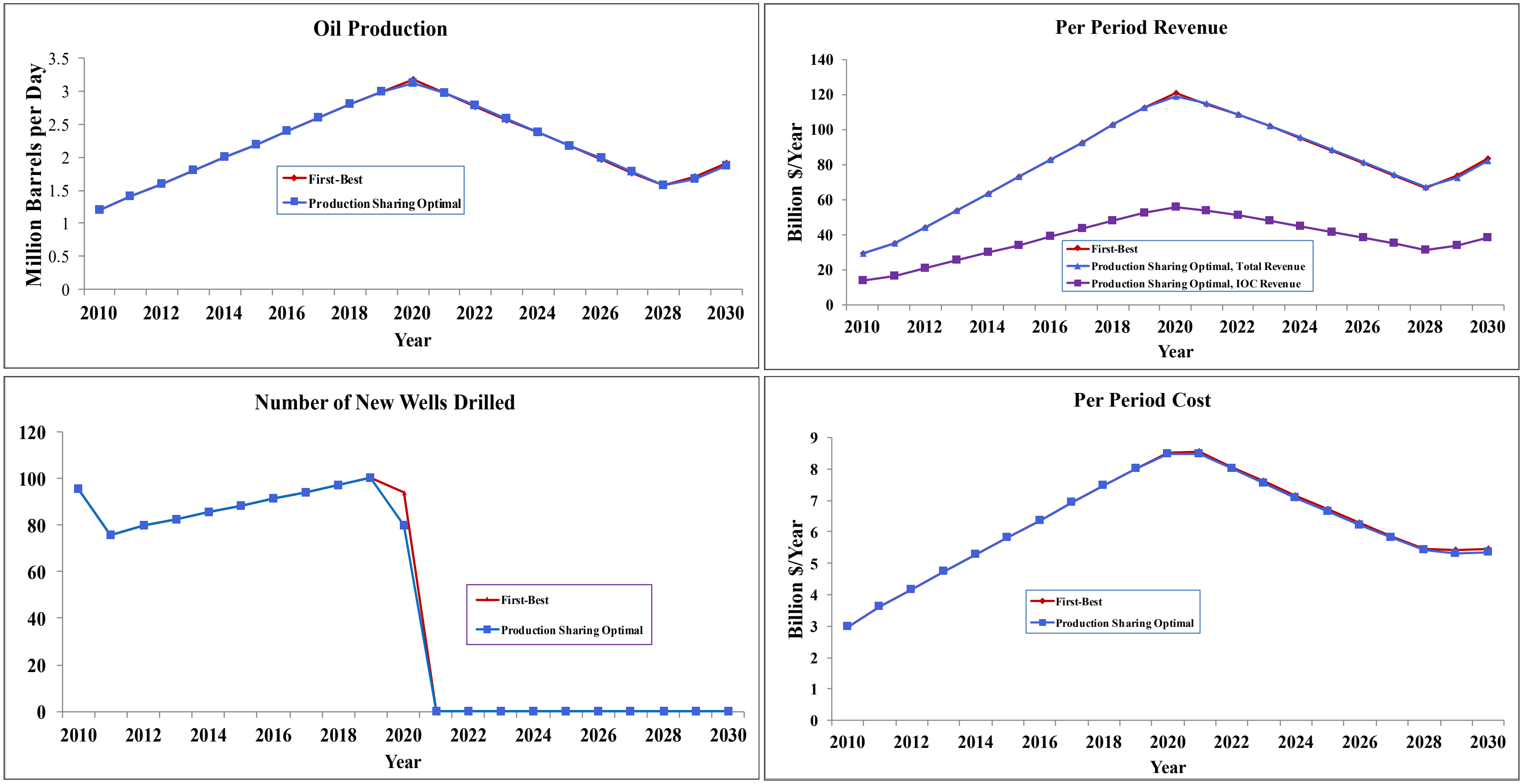
Appendix F. Supplementary Results Figures

Figure F.1. Results for buy-back contract: Oil production, well drilling, revenue, and costs



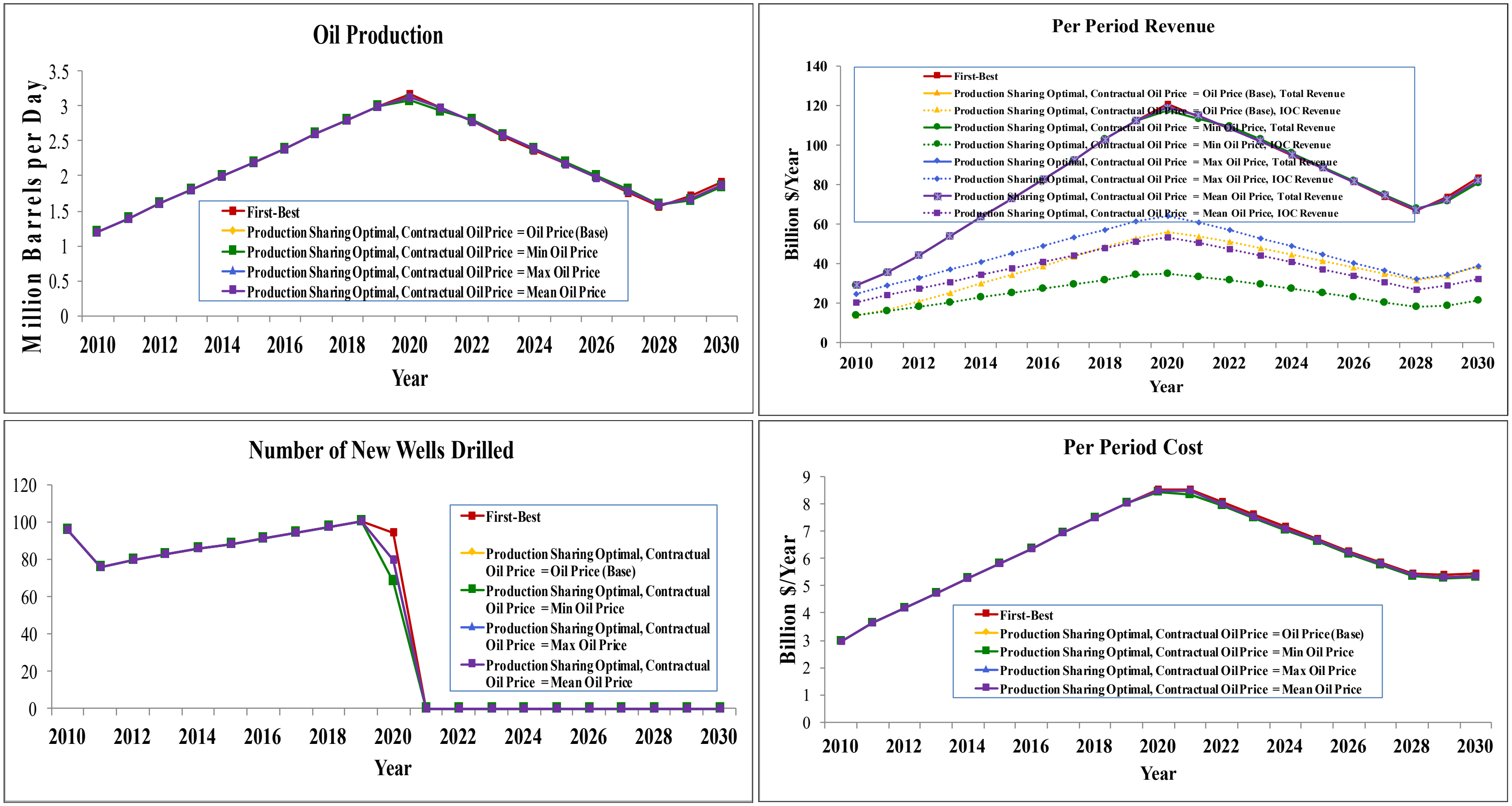
Note: Dollars are constant 2008 dollars.

Figure F.2. Results for production sharing contract: Oil production, well drilling, revenue, and costs



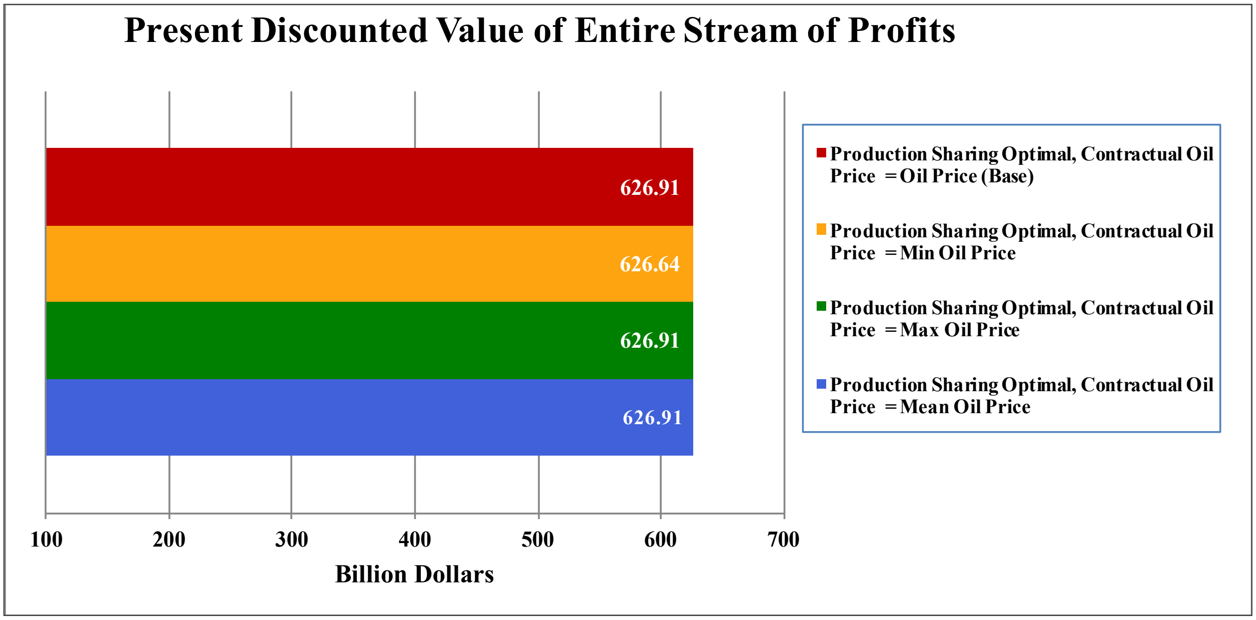
Note: Dollars are constant 2008 dollars.

Figure F.3. Robustness results for production sharing contractual unit revenue: Oil production, well drilling, revenue, and costs



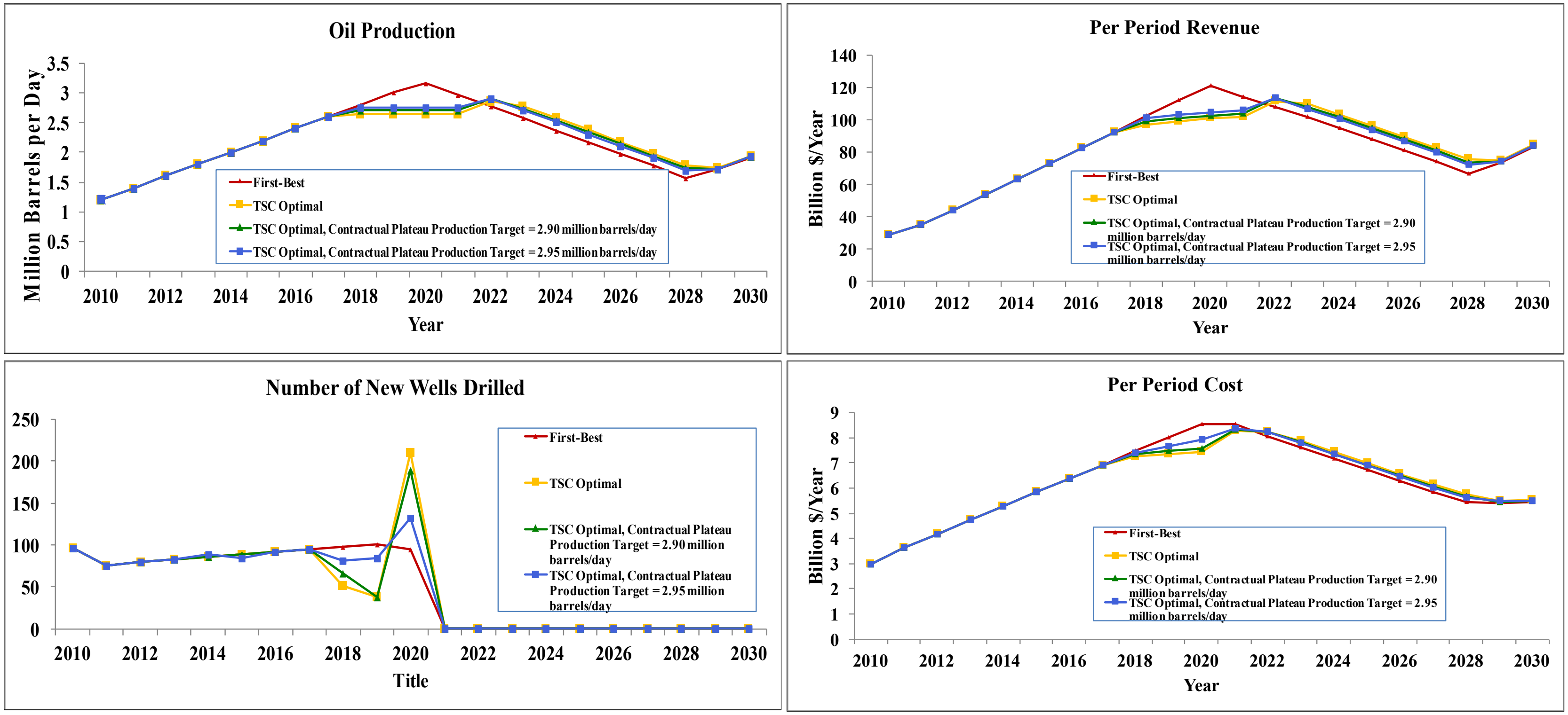
Note: Dollars are constant 2008 dollars.

Figure F.4. Robustness results for production sharing contractual unit revenue: PDV of entire stream of per-period profit



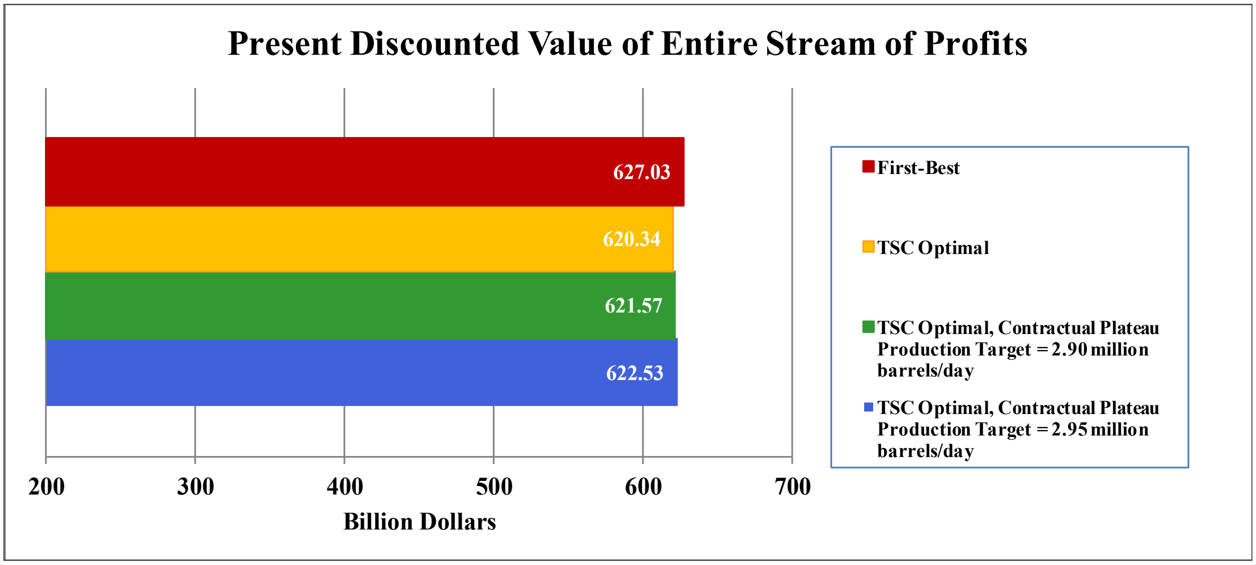
Note: Dollars are constant 2008 dollars.

Figure F.5. Results for TSC with higher contractual plateau production target: Oil production, well drilling, revenue, and costs



Note: Dollars are constant 2008 dollars.

Figure F.6. Results for TSC with higher contractual plateau production target: PDV of entire stream of per-period profit



Note: Dollars are constant 2008 dollars.

Appendix G. Cash Flow Analysis of Rumaila TSC

As represented by the "Most Likely to be Realized" scenario in Figure 2, the Rumaila TSC is predicted to result in a deadweight loss of 14.2% relative to the first-best. If the IOC and the Iraqi government cooperated to maximize joint profits, then both the IOC and the Iraqi government would be better off by following the dynamically optimal policy under "TSC Optimal", "TSC Optimal, Cost Ceiling", or "TSC Actual Optimal" than they would be by following the predicted policy. Nevertheless, it is possible that the structure of the technical service contract does not incentivize the IOC to pursue the dynamically optimal policy.

In order to analyze whether a technical service contract incentivizes the IOC to pursue a dynamically optimal policy, we model the Rumaila technical service contract cash flow from the IOC's perspective in order to calculate the IOC's net present value and rate of return under the contract. We evaluate the Rumaila technical service contract cash flow using the terms of the Rumaila technical service contract described in Appendix A; for the Rumaila TSC, the bid remuneration fee was $2 per barrel (Sankey, Clark and Micheloto, 2010). We therefore condition on the terms of the Rumaila technical service contract and examine whether, given these terms, the IOC has an incentive to pursue a dynamically optimal policy instead of the predicted policy under the "Most Likely to be Realized" scenario.[38]

If the optimal policy not only leads to a higher overall present discounted value of the entire stream of joint profits but also a higher net present value for the IOC and a higher rate of return to the IOC than was predicted under the "Most Likely to be Realized" scenario, then the IOC would have an incentive under the technical service contract to follow the dynamically optimal policy instead of the predicted policy under the "Most Likely to be Realized" scenario. On the other hand, if the dynamically optimal policy does not yield a higher net present value or rate of return to the IOC, then the IOC would not have an incentive under the technical service contract to follow

[38] As we condition on the terms of the Rumaila TSC, we abstract away from modelling and analyzing the strategies pursued by the IOCs when bidding for the contract. Since the terms of the Rumaila TSC were determined in part by the IOCs' bidding strategies, and since these contract terms then affect production and drilling decisions, we hope to model the bidding behavior of the IOCs and the efficiency of these bidding strategies in future work.
<Footnote continues next page.>

the dynamically optimal policy instead of the predicted policy under the "Most Likely to be Realized" scenario.

As shown in Figure G.1, our cash flow analysis suggests that at a 10% discount rate, BP and its partners would benefit from a net present value of around $1.57 billion if they follow the first-best production and well drilling policy, which is 59.6% higher than the $0.98 billion[39] they would earn under the "Most Likely to be Realized" scenario. The IOC would also obtain a higher net present value and a higher rate of return than was predicted under the "Most Likely to be Realized" scenario if it pursued the dynamically optimal policy in the "TSC Optimal", "TSC Optimal, Cost Ceiling", and "TSC Actual Optimal, Cost Ceiling" scenarios, but not if they pursued the dynamically optimal policy in the "TSC Actual Optimal" scenario.

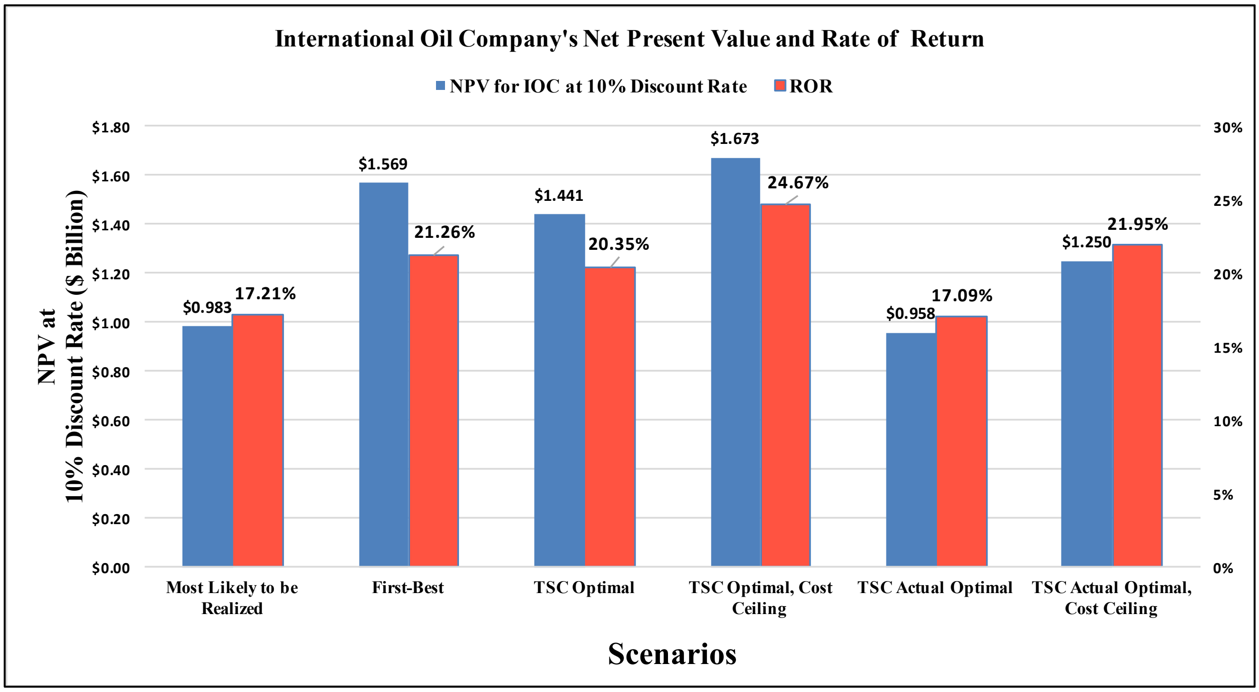
The production and drilling policies under the first-best, the "TSC Optimal", and "TSC Optimal, Cost Ceiling" scenarios therefore not only yield a higher discounted value of the entire stream of joint profits to the IOC and the Iraqi government than was predicted under the "Most Likely to be Realized" scenario, but also a higher net present value and higher rate of return to the IOC as well. Thus, under these scenarios, the IOC would have an incentive to pursue the dynamically optimal policy rather than the policy predicted under the "Most Likely to be Realized" scenario.

Our results suggest that, assuming no additional sources of inefficiency aside from possibly an implicit cost ceiling, the structure of a technical service contract does incentivize the IOC to pursue a dynamically optimal policy of oil production and well drilling rather than the policy predicted under the "Most Likely to be Realized" scenario, as doing so not only yields a higher discounted value of the entire stream of joint profits to the IOC and the Iraqi government than was predicted under the "Most Likely to be Realized" scenario, but also a higher net present value and higher rate of return to the IOC as well.

---

[39] Our findings that BP and its partners' net present value and the rate of return are $1.57 billion (2008 dollars) and 22%, respectively, under the first-best are comparable with the Rumaila NPV and IRR estimates of Sankey, Clark and Micheloto (2010), with the difference that their calculation is for BP only while we consider BP and its partners as a single IOC. This was a simplifying assumption in order to avoid complication with regards to the capital expenditure share of each partner since we do not include that feature in our cost function.

Figure G.1. Net present value (NPV) and rate of return (ROR) to the IOC under a TSC



Note: Dollars are constant 2008 dollars.