Competitiveness of shallow water hydrocarbon development projects in Mexico after 2015 actualization of fiscal reforms: Economic benchmark of new production sharing agreement versus typical U.S. federal lease terms

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HIGHLIGHTS

• Mexico’s Energy Reform opens up the country to foreign petroleum companies.
• Contractor and government takes are compared under each jurisdiction.
• Contract terms for Mexico are much less favorable than those offered by the U.S.

ABSTRACT

Development of Mexican hydrocarbon reservoirs by foreign operators has become possible under Mexico’s new Hydrocarbon Law, effective as per January 2015. Our study compares the economic returns of shallow water fields in the Gulf of Mexico applying the royalty and taxes due under the fiscal regimes of the U.S. and Mexico. The net present value (NPV) of the base case scenario is US$1.4 billion, assuming standard development and production cost (opex, capex), 10% discount rate accounting for the cost of capital and revenues computed using a reference oil price of $75/bbl. The impact on NPV of oil price volatility is accounted for in a sensitivity analysis. The split of the NPV of shallow water hydrocarbon assets between the two contractual parties, contractor and government, in Mexico and the U.S. is hugely different. Our base case shows that for similar field assets, Mexico’s production sharing agreement allocates about $1,150 million to the government and $191 million to the contractor, while under U.S. license conditions the government take is about $700 million and contractor take is $553 million. The current production sharing agreement leaves some marginal shallow water fields in Mexico undeveloped for reasons detailed and quantified in our study.

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1. Introduction

Mexico was a textbook example of a hydrocarbon-rich nation with underdeveloped resource potential due to a restrictive resource management policy. The restriction of access to production rights has impeded the timely development of both Mexico’s onshore and offshore hydrocarbon fields. This becomes evident by comparing the density of Mexican oil and gas installations with those in the U.S. for the Mexican Gulf Region (Fig. 1). In the Mexican sector, producing assets are largely restricted to coastal lands with some offshore activity, mostly in relatively shallow territorial waters. In contrast, the U.S. Gulf of Mexico hosts over 4000 active production platforms and includes ultra-deep water operations (in up to 9000 feet deep water).

What has evidently handicapped the development of hydrocarbon projects in Mexico’s Gulf sector is that no concession or contracts could be granted to private companies prior to the reforms of 2014 (effective as of January 2015). All exploration and production work was to be carried out by Pemex, the national oil company (Tordo et al., 2010; Seelke et al., 2014, 2015). Pemex has used financed public work contracts (FPWCs) to secure supplementary technical support for natural gas production and development. However, the bid process for FPWCs was only of interest to service providers as no reserves could be booked by any participating company. Consequently, lack of takers marred some of the bidding rounds for FPWCs over the past decade (Tordo et al., 2010).
The lack of competitive exploration and production (E&P) licensing means Pemex may have remained too constrained to ensure the extraction of maximum rent for the nation.

Historically, Pemex provided about a third of the government’s annual revenue (Moroney and Dieck-Assad, 2005, 2008). Declines in both reserves and revenues of hydrocarbons prompted the need for energy reforms. Nations with substantial income from hydrocarbon activities must ensure their energy policies remain at-tractive and ef-ficient resource policies may leave nat-ural resources undeveloped (Weijermars, 2016). Mexico instated in year 2000 a sovereign wealth fund based on oil revenues (Moroney and Dieck-Assad, 2005, 2008). Declines Extraction of maximum rent for the nation.

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offshore deep water development.

A crucial difference (among others) between the three types of concessions is the degree of cost recovery allowance (lowering income tax payments due to depreciation of capital cost incurred to develop the field). For example, license agreements do not allow for any cost recovery of capital investments, production sharing agreements allow for partial cost recovery (see Appendix A) and deep water field development projects allow for full cost recovery. Another difference is that the bid process for license agreements involves a signature bonus, unlike the production and profit sharing agreements, which are awarded on the basis of the percentage of production offered by the company to the government share offering and work program investment commitment, both to be specified in the bid.

In order to attract the intended foreign investments, the terms offered by Mexico need to be competitive with the ruling terms for similar plays in the U.S. section of the Gulf. The reforms of Mexico’s fiscal regime and licensing system need to offer scope for competitive returns for operators. This paper compares the economic performance of an offshore shallow-water reference field under the respective federal fiscal regimes of Mexico and U.S. Two separate studies cover the other contracts types offered (Fig. 2). One benchmark compares typical Eagle Ford economics under U.S. private landownership royalties and taxes due to state and U.S. federal government with the license terms offered by the Mexican Government (Weijermars et al., 2016a). Another forthcoming study (Weijermars et al., 2016b) provides a competitive benchmark of deepwater fields at either side of the so-called Transboundary Zone under the respective fiscal regimes (i.e., profit-sharing agreement in Mexico and federal license in the U.S). Ultimately, the impact of the fiscal burden on a project’s performance in the corporate portfolio determines whether and where a company’s final investment decision will be allocated (Weijermars et al., 2014).
Our present study compares the fiscal takes and return on investment for the contractor in a reference field in Mexico with investment alternatives in an analog field in the U.S. This paper is organized as follows. The distinction of Mexico’s typical shallow water fields as a specific class of resource occurrence in relation to other hydrocarbon assets is outlined in Section 2. The technical aspects of a reference asset are detailed in Section 3 (reservoir characterization and field development concept) because these constrain the input parameters for the cash flow benchmark study. The benchmark model and results detailing the cash flow takes of contractor and government under the respective fiscal regimes of Mexico and the U.S. are outlined in Section 4. A discussion and conclusions are given in Sections 5 and 6. Appendices A-C contain descriptions of the key levers in the fiscal frameworks of Mexico and the U.S. and the applicable rates of royalties and other excises due.

2. Shallow-water prospects

2.1. Round 1 field assets

The Mexican energy reform aims to catalyze a game-change that opens up the country for competitive E&P activity. Eligible contractual partners must be companies registered as Mexican residents for tax purposes; any foreign parent company is entitled to open a suitable subsidiary. The first bidding round in Mexico for 2015 originally planned for a mixture of onshore conventional and unconventional tracts, shallow water offshore tracts and deepwater tracts (Fig. 3). The new hydrocarbon law assigned key roles to the Secretariat of Energy (SENER) for awarding the concessions; the Mexico Petroleum Fund is earmarked for administering the State’s proceeds from oil and gas contracts. The National Hydrocarbons Commission (CHN) was made responsible for the management of field data in a national repository (e.g., logs, cores, seismic data; HL, Ch. 3, Art. 32-38; DOF, 2014). The interests of Pemex are accounted for in the new Hydrocarbon Law [“Ley de Hidrocarburos” - Hydrocarbon Law (HL); DOF, 2014] by stating that in licenses near the cross-border region governed by the U.S.-Mexico Transboundary Hydrocarbons Agreement at least 20% participation by Pemex is required (LH, Article 17; DOF, 2014). Pemex participations in projects are advocated by SENER not to exceed 30% of the investments in tendered projects (LH, Article 16; DOF, 2014).

The low oil prices of 2015 have lead to some revisions in the Mexican government’s auction schedule for Round 1 shallow-water assets. The initial offering was limited to 14 blocks located on the Mexican seaboard directly west of the Pemex operated Cantarell oil field complex (Fig. 4). Production at the nearby Akal field of Cantarell began in 1979, and onset of field decline due to falling reservoir pressure was reversed in the last 1990s by injecting nitrogen into the reservoir (Guzmann, 2014). Peak production reached 2.2 million bbl/d in 2004, but decline resumed. Cantarell produced 440,000 bbl/d of crude oil in the middle of the last decade but gradually declined in 2013 to ~80% below peak production rate of 2004 (Guzmann, 2014). Northwest of Cantarell the prolific Ku-Maloob-Zaap (KMZ) field production decline was also reversed by a nitrogen reinjection program, supporting

Fig. 3. Location of assets that were earmarked for Bid Round 1 to be auctioned in 2015. The low oil price in the first half of 2015 has lead to postponement of the planned auction for unconventional assets as well as for all deep water tracts indicated on the original lease map for Bid Round 1. After presentation by Mexican government (CNH, 2015a, 2015b).
production to reach about 850,000 bbl/d (Perez-Martinez et al., 2013).

The new production sharing agreement (PSA) for shallow water tracts auctioned in the first bid round of 2015 (posted on the web pages of the National Hydrocarbon Commission, CNH; www.ronda1.gob.mx) provided the basis of our study. PSA contracts are awarded for 25 years with the possibility of two 5-year extensions. Eligible parties must comply with a number of requirements, such as prior experience with offshore projects, qualified personnel with a minimum of 10 years of experience, and market capitalization of at least $10 billion with an investment-grade credit rating, or shareholder’s equity of at least $1 billion ($600 million for the lead operator in a consortium, and the remaining US$400 million to be covered by partners). The goods and services procured for oil and gas operations under the PSA should observe a minimum national content percentage of 13% for the exploration period, 25% during the development period, and must subsequently grow to at least 35% by 2025.

For the 14 shallow water blocks offered in the first phase of bid Round 1 (bid closed on 15 July 2015) minimum work programs provisioned for the drilling of at least 26 exploratory wells in the next 3 years. Companies must commit to a minimum work schedule as specified for each contract area in Table 1. Half of any area remaining undeveloped in the 3rd year must be returned to the government; 50% of the remaining other half of any undeveloped area must be relinquished in the 4th year. In the 5th year of the PSA, any area that remains undeveloped will be returned to the government. An exploration phase rental fee is due in order to ensure no acreage remains idle without a reason. The average block size auctioned in Round 1 is about 200 km$^2$ (14 blocks with a

Table 1
Minimum work program for shallow water blocks Round 1 [from Round 1 bidding guidelines (CNH Round 1, 2015a)].

<table>
<thead>
<tr>
<th>Contract Area</th>
<th>Minimum Number of Wells to be Drilled</th>
<th>Area (km$^2$)</th>
<th>Estimated Cost Seismic (US$)</th>
<th>Estimated Cost Drilling (US$)</th>
<th>Estimated Cost Studies (US$)</th>
<th>Total Estimated Cost (US$)</th>
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<tbody>
<tr>
<td>1</td>
<td>2</td>
<td>195</td>
<td>$875,000</td>
<td>$109,560,000</td>
<td>$2,150,000</td>
<td>$112,585,000</td>
</tr>
<tr>
<td>2</td>
<td>2</td>
<td>194</td>
<td>$900,000</td>
<td>$109,560,000</td>
<td>$2,150,000</td>
<td>$112,585,000</td>
</tr>
<tr>
<td>3</td>
<td>2</td>
<td>233</td>
<td>$805,000</td>
<td>$100,200,000</td>
<td>$2,150,000</td>
<td>$103,310,000</td>
</tr>
<tr>
<td>4</td>
<td>2</td>
<td>233</td>
<td>$900,000</td>
<td>$100,200,000</td>
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</tr>
<tr>
<td>5</td>
<td>2</td>
<td>466</td>
<td>$6,525,000</td>
<td>$80,000,000</td>
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<tr>
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<td>$8,300,000</td>
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<tr>
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<td>11</td>
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<td>309</td>
<td>$750,000</td>
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<td>$2,850,000</td>
<td>$171,000,000</td>
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<td>12</td>
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<tr>
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<td>$111,000,000</td>
<td>$2,850,000</td>
<td>$114,655,000</td>
</tr>
</tbody>
</table>
combined surface area of 4223 km²; see Table 1) which gives a benchmark figure for the rental fees to be paid.

Company bids for Round 1 were evaluated based on the initial share of production offered to the government (SG) and the percentage of the investment amount in excess of the sums specified in the minimum work program (Table 1), which gives a so-called Additional Investment Factor for the relevant contract area. Ranking of the bids was based on the weighted scores, $V$, using the following formula (CNH Round 1, 2015a):

$$V = 0.90 \times SG + 0.10 \times \text{Additional Investment Factor}$$

We perform in our study a sensitivity analysis to establish what bid offer remains competitive with similar investment in a comparable U.S. field. Our below analysis includes a sensitivity analysis for $SG = 1 - SCI$ (with SCI being the initial contractor share in the bid offer), which may be adjusted (lowered) to SCA by a profit trigger clause such that the government share may effectively increase to $SG = 1 - SCA$. Ranking value $V$ as per Eq. (1) is graphed in Fig. 5 for the full range of Investment Factors and (initial) Government Share offered.

2.2. Round 1 results

During the completion phase of our fiscal benchmark study, some interesting details emerged from the bidding process of Round 1 (CNH-R01-L01/2015). For example, 39 companies paid $0.5 million to access the data room for shallow water exploration auction blocks, of which 34 prequalified. The original pool of companies with data room access included (CNH Round 1, 2015): US majors (Exxon, Chevron), US independents (Marathon, Hunt, Hess, Murphy Oil, Sierra Oil & Gas), EU majors (Shell, BP, TOTAL, ENI), EU minors (Statoil, BG, Galp, Maersk, Cepsa, Premier Oil), other majors (CNOC, ONGC, BHP Billiton, Petronas, Petrobras, Lukoil), and Japanese companies (Mitsubishi, Japan Oil and Japan PEC).

However, no more than 4 consortia and 5 individual companies proceeded submitting bids for only six of the blocks on offer (CNH Round 1, 2015). Ultimately, of the 14 blocks offered, only two block (Blocks 2 and 7) were awarded, both to the same consortium of smaller operators (Talos, Sierra and Premier Oil) lead by Sierra Oil. The common explanation for the low response to the auction was that terms offered were unattractive. The fact that of the 6 blocks for which bids were submitted, 4 were not awarded was due to a minimum government share requirement, a condition that was neither previously disclosed nor part of the published bidding guidelines. Only after the bidding process was closed on July 15 (2015), the Ministry of Finance announced the minimum required government share should be $SG \geq 0.25$ (25%) for Blocks 8 and 11-14 and $SG \geq 0.4$ (40%) for all other Blocks. As a result, even bids of some very experienced international operators like Statoil, ONGC, and Hunt Oil did not qualify because they did not meet the (unknown) minimum rate requirement.

Sierra Oil won the two auction blocks by offering a relatively large initial pre-tax government share of $SG = 55.99\%$ for Block 2 and $SG = 68.99\%$ for Block 7. Interestingly, the only other bidder for Block 2, Hunt Oil, narrowly missed the bid by offering a government share of 54.5% and its weighted bid score $V$ was 50.213 as compared to 51.972 for the winning bid of Sierra Oil’s consortium. Block 7 received 5 bids in total, one was rejected due to $SG < 40\%$, but the other 4 remaining bids had very closely ranked weighted scores as follows: Sierra Oil 63.672, Statoil 63.136, Hunt Oil 60.535, and ENI 53.536 (CNH Round 1, 2015: posted on the web pages of the National Hydrocarbon Commission,CNH; www.rondal.gob.mx).

Block 12, the asset studied in detail by us, received a bid from ONGC with a 20% government share, but was declared void because it did not meet the threshold of $SG \geq 0.25$. Our analysis below (Section 4) confirms that for government shares larger than 20% the economic return for any contractor of Block 12 will rapidly deteriorate.

In addition to the 14 blocks with shallow-water assets featuring in the first stage of auction Round 1 (CNH-R01-L01/2015), a second stage of auction Round 1 in the second half of 2015 offered 5 more blocks (CNH-R01-L02/2015; see Fig. 4). The contractual areas comprised nine discovered (but undeveloped) oil fields. Blocks 1, 2 and 4 were awarded, whereas Blocks 3 and 5 did not receive any bids that met the minimum government share requirements (of 30.2 and 35.2%, respectively). Block 1 was won by ENI ($SG = 0.8375$), Block 2 by PanAmerican ($SG = 0.7$), and Block 4 by Fieldwood Energy ($SG = 0.74$). The relatively high government shares conceded by the contractors can be attributed to the fact these were all blocks with derisked acreage, each comprising several proven oil fields.

3. Reference asset description

Our benchmark uses Block 12 as a reference asset, which merits a detailed description of the reservoir characteristics (Section 3.1), which is the basis for our proposed field development concept (Section 3.2).

3.1. Reservoir characterization

The reference field adopted here for our fiscal benchmark study is located in contract area 12 (Fig. 4 and Table 1). Fig. 6 shows the location of the shallow water blocks overlain on a map of the principal tectonic provinces. An up to 7 km deep sedimentary section has accumulated onto a passive margin made up of metamorphic and igneous basement rocks (Fig. 6b). The base of the Mesozoic-Cenozoic sedimentary sequence is comprised of Callovian salt, a Middle Jurassic evaporite which accommodated tectonic deformation, acted as a major detachment zone and was the source layer of salt diapirs with a variety of shapes. For detailed discussion of the litho-facies and salt tectonics, please consult the following key studies (Ricoy, 1989; Garcia-Molina, 1994; Gomez-Cabrera and Jackson, 2009a, 2009b).

All 14 auction areas are affected by salt tectonics, and occur across several belts, each of which has a distinct structural style (Fig. 6). Our reference Area 12 is located in a central section of the
Comalcalco Basin, which is a major graben structure bound by growth faults (Fig. 6b). The Miocene section is relatively thick in the Comalcalco Basin because the graben was subsiding and extending during the Miocene, creating a depositional sink for the Miocene sediments. A detailed section across the Comalcalco Basin (Fig. 6c) shows the growth faults soling into the basal autochthonous salt layer as well as into the allochthonous salt canopy that was emplaced between the Lower and Middle Pliocene strata. Part of the salt canopy has been evacuated and became welded (Gomez-Cabrera and Jackson, 2009a, 2009b).

The target zone for auction Area 12 lies below the NW-wing of an hourglass-shaped salt diapir (Fig. 6c). The structural style of the hydrocarbon trap for Area 12 is similar to that of the adjacent Xulum field, which has been drilled and established as an oil producer (with some associated gas).

Two source layers of hydrocarbons occur in the Upper Jurassic, i.e. Oxfordian and Tithonian age deposit; two additional source rocks occur in the Middle Cretaceous and Miocene (Fig. 7). The principal hydrocarbon source for the shallow water region is considered to be the Tithonian horizon. The Tithonian source rock is comprised of shale and mudstone (4–7% TOC) varying between 100–400 m in thickness. The petroleum system consist of Type II
kerogen ($S_2 = 50 \text{mg/g}$, $HI = 712 \text{mg/g}$ TOC and $SPI = 4 \text{THC/m}^2$), and supplies light to medium gravity API oil. Darcy migration of hydrocarbons occurred along the brecciated zone on the flank of the salt diapirs. The salt diapirs are typically formed by downbuilding of the sedimentary mini-basins. Hourglass shaped diapirs as in Xulum and Area 12 (Fig. 6c) form when the early deposition rate is accelerating (reflected by initial tapering) and then decelerates (reflected in the upward flaring and lateral spreading of the diapir; e.g., Weijermars et al., 2015). The hydrocarbon trap is closed by anhydrite and salt in the overhang of the downbuilt rootzone of the mini-basins (Fig. 6c).

Wells Xulum 101 and 101A, drilled in 2007, encountered bituminous shales and shaly limestone/mudstone of Tithonian age closing against salt and reverse faults (PEMEX, 2008). Two pressure-production tests were run in the reservoir and 16.5° API oil was found in both tests. The crest of the structural closure occurs at 5656 m depth below the mudline. Water saturation is 21% and reservoir pressure is 1066 kg/m² ($\sim 15,000 \text{ psi or 100 MPa}$). The rig day rate is assumed to be $250,000 and drilling of 2 production wells is assumed to take 300 days in total. Cost of the platform and other tangibles like wellhead, tubulars and flow lines is set at $150 million. Adding well completion cost total Capex amounts to $275 million of which $210 million is the minimum contingency for full field appraisal. The appraisal sum exceeds the estimated minimum bid cost of $171 million for the working program (Area 12, Table 1), which establishes our Additional Investment Factor (Eq. 1) at 0.22 (percentage of the investment amount in excess of the sums specified in the minimum work program of Table 1).

3.2. Field development concept

We assume Area 12 prospect located in 100 m deep water can be developed with a fixed leg platform. A mobile platform rig is hoisted on the future production platform to drill the prospect at a low angle. The crest of the structural closure occurs at 5,400 m depth below the mudline. Water saturation is 21% and reservoir pressure is 1066 kg/m² ($\sim 15,000 \text{ psi or 100 MPa}$). Other fields, such as the Cantarell and the KMZ fields produce heavy crude. We are aware that the petrophysics, geological structure, geothermic genesis and any resulting hydrocarbon charge often develop as unique features in a particular region. In our study, we assume the relatively large range of hydrocarbon systems recognized in the various parts of the U.S. Gulf of Mexico...
will include counterparts of the Mexican section of the Gulf. On that basis we adopted a scalable reference field with the characteristics specified in Table 2.

### Table 2

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Value</th>
</tr>
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<tbody>
<tr>
<td>Water depth</td>
<td>100 m</td>
</tr>
<tr>
<td>Total vertical depth (TVD)</td>
<td>5500 m</td>
</tr>
<tr>
<td>EUR (P50)</td>
<td>50 MMbbls</td>
</tr>
<tr>
<td>Oil gravity</td>
<td>16.5°API</td>
</tr>
<tr>
<td>Initial pressure</td>
<td>15,000 psi</td>
</tr>
<tr>
<td>GOR (Mcf/bbl)</td>
<td>0.12</td>
</tr>
<tr>
<td>WOR (bbl/bbl)</td>
<td>0.21</td>
</tr>
<tr>
<td>Sulphur (%)</td>
<td>0.02</td>
</tr>
<tr>
<td>First year production (yearly average)</td>
<td>5 Mmbls/day</td>
</tr>
<tr>
<td>Peak production (2nd year average)</td>
<td>10 Mmbls/day</td>
</tr>
<tr>
<td>Decline rate after year 2</td>
<td>7%</td>
</tr>
<tr>
<td>Economic limit</td>
<td>Year 20</td>
</tr>
<tr>
<td>Platform, wellhead and pipelines</td>
<td>$150 million</td>
</tr>
<tr>
<td>Exploration &amp; Production Drilling</td>
<td>$75 million</td>
</tr>
<tr>
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<tr>
<td>Abandonment cost</td>
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<tr>
<td>Opex (fixed)</td>
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<tr>
<td>Opex (variable)</td>
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</tr>
<tr>
<td>Transport oil</td>
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</tr>
<tr>
<td>Transport gas (flat rate assumption)</td>
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</tr>
<tr>
<td>Benchmark price gas (flat rate assumption)</td>
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<td>U.S. rental fee (Appendix B)</td>
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<td>U.S. signing bonus (Appendix B)</td>
<td>$2.50/acre</td>
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<tr>
<td>Lease Area (U.S. area wide sale)</td>
<td>5,670 acres</td>
</tr>
<tr>
<td>Area 12 (MX auction block)</td>
<td>387 km²</td>
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#### 4. Cash flow benchmark models

##### 4.1. Production profile and other base case assumptions

Two after tax cash flow models were developed: one model using the Mexican production sharing structure, the other using the typical U.S. federal offshore tax regime. The respective deduction schedules for U.S. and Mexico shallow water assets are summarized in Appendices A and B, respectively. Appendix C reviews the lengthy negotiations between the U.S. federal government and the coastal states that ultimately lead to the assertion of federal rights to offshore natural resources. We use discrete, deterministic inputs for algorithms embedded in coupled Excel spreadsheets and apply several sensitivity analyses (oil prices, government share, capex, opex, royalty rate and discount rate) to account for uncertainty in key input parameters. The input parameters for our reference field are given in Table 2. The oil price for our base case scenario is set at $75/bbl, escalated at 2.5% inflation rate per year. We assume the low oil price scenario of 2015 to be short-lived. Our sensitivity analysis for an oil price range of $50/bbl to $200/bbl is considered adequate for the current assessment.

A range also reveals that even marginal fields become profitable at a certain, higher oil price, provided the discount rate assumption) is never profitable, not even for 100% operator share (see Section 4.2.2).

Fig. 8 shows the production profile for the 20 year production life cycle with assumed abandonment cost incurred in 2037. For the Mexico case, production was cut off around 3,000 bbl/day for which fixed opex will exceed revenue and EBITDA will turn negative. For the U.S. case, given the low offshore royalty rate, the reference asset may be economically produced for much longer (likely for another 10 years or so), but the same cutoff was applied for the U.S. and Mexican cases to remain comparable for a given field life, focusing on the primary fiscal takes. Nonetheless, leaving resources in the ground is a direct consequence of a fiscal framework that grants only marginal to sub-marginal profits for the contractor (such as was the case for several fields in Mexico’s Round 1 auction of shallow water prospects completed on 15 July 2015, see economic appraisal below).

#### 4.2. Mexico project: after tax cash flow analysis

##### 4.2.1. Impact of initial government share

Table 3 gives the yearly after tax cash flow for the reference field applying Mexican shallow water contract fees, royalties and tax rates (for details, see Appendix A), for a base case oil price scenario of $75/bbl (with 2.5% escalation) and initial contractor share of 80% (SC1 = 0.8) and government share of 20% (SG = 0.2). The corresponding breakdown of revenues is graphed in Fig. 9. For the Mexican case, both the contractor take and government take are greatly affected by (1) the actual oil price and (2) the contractor share initially agreed in the bid offer (SC1).

Fig. 10a shows that the base case oil price of $75/bbl gives a contractor NPV of $191 million assuming an initial split of government share and contractor share 20:80. After the auction (see Section 2.2) a minimum government share of 25% was mandated for Block 12. If such a 25% minimum government share is applied, Fig. 10a indicates that a 75% initial contractor share (SC1) at $75/bbl for Block 12 results in a slightly more modest NPV of $185 million for the contractor. The 5% increase in government share from 20% to 25% reduces the contractor NPV from $191 million to $185 million.

When the government and contractor shares are split 40:60, only at $100/bbl will the contractor NPV be maximum (at $170 million). Clearly, the contractor exposure to the risk of NPV declines due to oil price fluctuations is very high as follows from the sensitivity analysis of Fig. 10a. The contractor NPV for a high oil price (e.g., $100/bbl) will be highest for an initial contractor share of 60% (SC1 = 0.6) and for that oil price decreases steeply for smaller initial SC1 with NPV turning negative for SC1 < 0.5. However, for oil prices lower than $100/bbl, the contractor will retain the highest NPV when SC1 is larger than 60%; the optimal contractor NPV occurs for progressively higher SC1 as oil prices drop (Fig. 10a).

Fig. 10b shows the corresponding contractor IRR for a range of oil prices similar to those used in Fig. 10a using a range of initial contractor shares. Note that the contractor IRR for all oil prices is highest when the contractor’s initial share is SC1 = 1. However, the highest IRR does not correspond to the highest NPV, because for different oil prices the optimal NPV occurs for different SC1 values (Fig. 10a). The appraised asset value of Block 12 is such that for any oil price regime below $70/bbl the lease is unlikely to
Table 3
Example of yearly cash flow calculation for Mexican base case; ROC—result of contractor; CR—cost recovery; opex—operating expenditure; EBITDA—earnings before interest payment, tax, depreciation and amortization; capex—capital expenditure.

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<tbody>
<tr>
<td>Crude (mbbl/d)</td>
<td>0.0</td>
<td>0.0</td>
<td>10.0</td>
<td>20.0</td>
<td>18.0</td>
<td>16.2</td>
<td>14.6</td>
<td>13.1</td>
<td>11.8</td>
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<td>Sales Gas (mcf/d)</td>
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<td>0.0</td>
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<td>2.4</td>
<td>2.2</td>
<td>1.9</td>
<td>1.7</td>
<td>1.6</td>
<td>1.4</td>
</tr>
<tr>
<td>Total Production (mboe/d)</td>
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<td>0.0</td>
<td>10.2</td>
<td>20.4</td>
<td>18.4</td>
<td>16.5</td>
<td>14.9</td>
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<td>76.9</td>
<td>78.8</td>
<td>80.8</td>
<td>82.8</td>
<td>84.9</td>
<td>87.0</td>
<td>89.2</td>
<td>91.4</td>
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<tr>
<td>Brent ($/bbl)</td>
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<td>3.6</td>
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<tr>
<td>Cash Flow ($MM)</td>
<td>0.0</td>
<td>0.0</td>
<td>149.7</td>
<td>412.3</td>
<td>381.0</td>
<td>348.3</td>
<td>320.5</td>
<td>297.5</td>
<td>257.7</td>
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be profitable for the contractor if the government insists on a minimum share of 25%.

4.2.2. Profit trigger effects

The cause of the unprofitable outcome for Block 12 is the profit trigger built into the Mexican production sharing agreement that adjusts the contractor share from SC1 to SCA due to a profit ceiling (see Eq. 9 in Appendix A). At $75/bbl and initial contractor share of SC1 = 0.8, the net present value (NPV) of the project to contractor amounts to $191 million (after tax and at 10% discount rate). However, when the oil price drops to $50/bbl assuming an unchanged initial contractor share of SC1 = 0.8, then the contractor NPV will be drastically reduced to about $200 million (Fig. 10a). Bidding for a lower initial contractor share is a strategy which can protect the contractor against the steep NPV decline that occurs when oil prices increase. However, this also requires an asset quality that will give a positive contractor NPV for such small initial contractor shares.

Fig. 9. Base-case revenue for Mexico over the full project life-cycle with breakdown into contractor free cash flow, government take and cost (opex, capex).

Fig. 10. a: Contractor NPV with respect to SC1 under various oil price assumptions. b: Contractor IRR with respect to SC1 under various oil price assumptions.
separately graphed in Fig. 12a. This graph indicates that for a lower oil price, a relatively high initial contractor share is optimal. The government share in any bidding round with a lower oil price environment is likely smaller than it would have been when oil prices are higher (e.g., closer to $100/bbl). The sensitivity of contractor NPV for the base case SC1 = 80% (80%) to oil price changes is graphed in Fig. 12b. Below $60/bbl oil price, the contractor NPV drops dramatically from about $200 million (at $60/bbl) to about $80 million at $50/bbl (Fig. 12b).

4.3. U.S. project: after tax cash flow analysis

Table 4 gives the yearly after tax cash flow for the reference field applying typical U.S. offshore contract fees, royalty and tax rates (for details, see Appendix B), for a base case $75/bbl oil price scenario. The corresponding breakdown of revenues and annual cash flows for the base case NPV scenario is graphed in Fig. 13. For the U.S. case, contractor NPV will increase linearly with any oil price increases (Fig. 14a). The contractor NPV of the same reference field asset is for the $75/bbl oil base case nearly 3 times higher under the federal U.S. offshore royalty scheme than in Mexico (compare Fig. 14a with Fig. 12b). This difference in NPV is due to the impact of the profit trigger in the Mexican agreement (see Section 4.2.2) which suppresses the contractor’s NPV in that jurisdiction.

4.4. Benchmark of contractor NPV and IRR in Mexico and U.S. projects

Our cash flow analysis and benchmark of the reference field performance at either side of the U.S.-Mexico fiscal border can be summarized as follows. The contractor NPV of the reference field asset, under the federal U.S. offshore fiscal regime, will rise in step with any oil price increase (Fig. 15a). For example, contractor NPV for reference field (Table 2) with base case inputs (Table 4) is $550 million at $75/bbl oil price, $750 million at $85/bbl and $980 million at $95/bbl. Contractor take rises faster than U.S. government take when oil prices move up from $75/bbl to $95/bbl as can be inferred from the pie charts showing revenue partitioning between capex, opex, government and contractor net cash (Fig. 15a).

In contrast, the profit trigger mechanism in Mexican contracts (Section 4.2.2) means any oil price rise will not substantially benefit the contractor (Fig. 15a). Contractor NPV for the same reference project at base case assumptions under the Mexican fiscal regime (Table 3) will not exceed $200 million for any of the three discrete oil prices considered ($75/bbl, $85/bbl and $95/bbl). In fact, an oil price rise may even lead to a decline in the contractor NPV depending upon the initially agreed contractor share (SC1) as was already highlighted in Figs. 10a and 12b.

In the U.S. fiscal setting, the contractor IRR will substantially rise when the oil price moves up (Fig. 15b). There is no sensitivity to government share in the U.S., where federal leases for offshore
tracts only allow for a royalty and income tax take. However, the Mexican fiscal regime results in IRR decline for the contractor (at any SC1) when oil prices rise (Fig. 15b). The decline in operator IRR for increasing oil price becomes particularly pronounced when the contractor’s initial share is 70% rather than 100%. Clearly, our

Table 4
Base-case yearly cash flow calculations for U.S. case; for abbreviations see caption of Table 3.

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<tr>
<td>Crude (mmbbl/d)</td>
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<td>20.0</td>
<td>18.0</td>
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<td>0.0</td>
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<td>2.4</td>
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<td>20.4</td>
<td>18.4</td>
<td>16.5</td>
<td>14.9</td>
<td>13.4</td>
<td>12.0</td>
</tr>
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</table>

Realized Price

| Brent ($/bbl) | 75.0 | 76.9 | 78.8 | 80.8 | 82.8 | 84.9 | 87.0 | 89.2 | 91.4 |
| Gas Price ($/Mcf) | 3.5  | 3.6  | 3.7  | 3.8  | 3.9  | 4.0  | 4.1  | 4.2  | 4.3  |

Cash Flow ($mm)

| Gross Revenue | 0.0  | 0.0  | 296.4 | 607.7 | 560.6 | 517.2 | 477.1 | 440.1 | 406.0 |
| Royalty       | 0.0  | 0.0  | (55.6) | (113.9) | (105.1) | (97.0) | (89.5) | (82.5) | (76.1) |
| Opex          | (0.1) | (0.1) | (126.5) | (242.7) | (225.6) | (210.0) | (195.6) | (182.3) | (170.1) |
| EBITDA        | (0.1) | (0.1) | 114.3  | 251.0  | 229.9  | 210.2  | 192.1  | 175.2  | 159.8  |
| Capex         | (134.2) | (67.2) | (17.2) | (13.2) | (13.6) | (4.6)  | 0.0    | 0.0    | 0.0    |
| Income Tax    | 0.0  | 0.0  | (24.5) | (56.0) | (51.0) | (46.4) | (42.2) | (38.2) | (34.6) |
| iCash Flow    | (134.3) | (67.3) | 72.7  | 181.8  | 165.3  | 159.2  | 149.9  | 137.0  | 125.2  |

Fig. 13. Base-case revenue for U.S. case over the project life-cycle with breakdown into contractor free cash flow, government take and cost (opex, capex).

Fig. 14. a: Contractor NPV under various oil price assumptions. b: Contractor IRR under various oil price assumptions. U.S. case.

Fig. 15. a: Contractor NPV in U.S. and Mexico under various oil price assumptions. Pie graphs detail relative takes of contractor and government, opex and capex for each jurisdiction and are valid for the oil prices indicated at the NPV graph. b: Contractor IRR in U.S. and Mexico under various oil price assumptions. Mexican case assumes base case contractor share of SC1 = 0.8 (80%).
analysis shows that for comparable shallow water assets, the return on investment for the contractor companies is much higher in the U.S. than in Mexico, which is entirely attributable to the different fiscal regimes. The NPV gap has already been deemed so large that few oil companies have submitted bids for the smaller field assets offered by Mexico in its initial license auction rounds (Section 2.2). The number of bids for shallow water leases in Round 1 may have been larger if contractual terms were more attractive to companies.

4.5. Government NPV versus contractor NPV

In our analysis we have also made explicit the government NPV versus the contractor NPV (Fig. 16a and b). Project NPV for the contractor is made up of after tax profit (at 10% discount) and for government is made up by the total fiscal take (also at 10% discount). NPVs for government and company are equivalently shared under the U.S. fiscal regime (Fig. 16a). For example, at $75/bbl contractor NPV is $553 million and government NPV is $700 million. When the oil price increases, contractor and government share of NPV will both rise and converge to become equal at about $100/bbl. Higher oil prices result in NPV for the company increasing faster than for the U.S. government (Fig. 16a). In our analysis we have strictly applied all taxes due after depletion, depreciation and amortization in practice, U.S. operators can defer taxes (TCS, 2014a, 2014b), which may result in higher shares of NPV being retained by oil companies.

In contrast to the U.S. base case, the NPVs of the contractual parties are very disparate under the Mexican fiscal regime, and increasingly so for higher oil prices (Fig. 16b). Our base case oil price at $75/bbl provides for Block 12 the highest NPV for the contractor ($191 million), and median NPV for the government ($1150 million). However, the contractor NPV will decline when the oil price is either higher or lower (due to the profit trigger mechanism, see Section 4.2.2). While an NPV decline for lower oil prices is a risk commonly accepted by oil companies, not being able to capture NPV gains when oil prices rise (and instead receiving a lower NPV; Fig. 16b) is an unusual form of inequitable risk-sharing.

Previous studies have benchmarked global variations of government take (IMF, 2012; Weijermars, 2016). A disproportionately high government take are those taxation rates that leave not enough room for return on investment for the contractor to compensate shareholders for the risk assumed. Such aggressive fiscal energy resource policies will deter companies from making investments and leave marginal resources undeveloped. Although larger fields may still attract investments (like Blocks 2 and 7 in Mexico’s Round 1) overall return for the state may be higher when the development of marginal resources is stimulated by adjustments to fiscal policies. Appropriate incentives being absent will result in companies refraining from any investment in sub-commercial assets.

4.6. Sensitivity analysis NPV and IRR contractor

Some additional conclusions about the effectiveness of the U.S. versus Mexico’s hydrocarbon resource development policies can be drawn based upon a sensitivity analysis of contractor NPV and IRR under the two fiscal regimes. The tornado plot for contractor NPV under the Mexican fiscal regime (Fig. 17a) responds asymmetrically to changes in key contractual and operational metrics that deviate from our base case assumptions. For example, the base case contractor NPV of $191 million will reduce by 12.6% to $167 million when the crude oil price increases 20%. This asymmetric risk-reward profile stems from the fiscal terms: an oil price up-surge increases contractor IRR in initial years and triggers SC1 ratio adjustment to SCA, which reduces contractor’s share of production, thus NPV, in subsequent years.

Sensitivity analysis of contractor IRR in Mexico (Fig. 17b) reveals a similar pattern, where the contractor is exposed to more downside risk than upside potential with financial and operational uncertainties. For example, a 20% reduction of opex as compared to the base-case scenario will increase the contractor IRR only from 29% to 33%. A 20% increase in opex will reduce the contractor IRR from 29% to 20%. The magnitude of asymmetry sensitivity of the contractor IRR is somewhat less than that for the contractor’s NPV. This is primarily due to the self-correction mechanism that the Mexico fiscal regime has for contractor’s investment return: a high IRR triggers SC1 ratio adjustment which in turn reduces investment return, until it reaches a level of equilibrium.

Under the U.S. fiscal regime the base case gives a contractor NPV of $553 million (Fig. 17c) which is nearly 3 times higher (290%) than for the Mexican base case (with NPV of $191 million). The NPV and IRR tornado plots of the U.S. base case (Fig. 17c and d) are more symmetrical than those for Mexico (Fig. 17a and b) indicating that the U.S. fiscal regime represents a more balanced risk-reward system where contractors are exposed to similar magnitude of any upside and downside risks due to market and operational uncertainties.

5. Discussion

The Mexican energy reform may be a game-changer that can open up the country for competitive E&P activity. The future
success of hydrocarbon E&P activities in Mexico critically depends on the details of contracts offered within the framework of the reforms. Eligible contractual partners must be Mexican residents for tax purposes. Competition with Pemex is one of the explicit goals of the energy reform described in the new Hydrocarbon Law \["Ley de Hidrocarburos" – Hydrocarbon Law (HL), DOF, 2014].

Energy legislation reforms in Mexico initiated in 2014 open up a whole new suite of competitive bidding options for E&P rights, allowing private companies to participate in profit-sharing, production-sharing and concession type of royalty and tax arrangements.

Whereas nations with natural energy resources want to attract companies to invest in resource development and assume the associated risk, petroleum companies must ensure the fiscal burden on their corporate portfolio will remain minimal. The benchmark of this study assesses whether the new fiscal framework and the various contractual arrangements offered by Mexico create a competitive investment climate for hydrocarbon development. We argued that in effect, the U.S. provides the benchmark for what could make a competitive hydrocarbon investment climate in Mexico for a range of hydrocarbon assets. Play openers in Mexico may prefer a tax discount equal to the value of information that is lacking and the company must invest in to acquire the missing data in order to reduce a level of risk higher than in a comparable asset opportunity for investment elsewhere.

In fact, no such tax discount is offered and the actual tax burden for shallow-water assets in Mexico is much higher than in the U.S. Our study has evaluated whether Mexico’s licensing system offers scope for contractual terms that provide the lure of competitive returns.

A typical field development project in a shallow water section of the Gulf of Mexico was used to compare the competitive investment potential under the Mexican and U.S. fiscal regimes for natural resource development. We have observed a number of effects built into Mexico’s shallow-water production-sharing contracts that may be detrimental to effective development of its hydrocarbon resource potential. These detrimental factors are as follows:

1. Our assessed reference field (Block 12) would yield a NPV for the contractor which is under Mexico’s production sharing contract 1/3th that due under the U.S. offshore license system using a $75/bbl oil price scenario.
2. Windfall profits due to an oil price rise are under the U.S. offshore licenses proportionally shared between the government and the contractor. In contrast, oil price increases result in lower NPV for the operator in the Mexican production sharing contracts for shallow water hydrocarbon leases (see Figs. 15a and b and 16a and b).

Fig. 17. a,b: Sensitivity analysis of contractor NPV and IRR in Mexico and (c, d) U.S., the former for base case contractor share of 50% and base case oil price of $75/bbl for both U.S. and Mexico.

![Sensitivity analysis graphs](image-url)
3. The profit trigger mechanism in the Mexican contracts, detailed in elaborate formulas (see Appendix A), is rendered wholly ineffective by the requirement of a minimum government share of 40% and partially ineffective for a minimum share of 25%. With such a minimum requirement contractual terms and formulas could be significantly simplified to increase transparency for the bidders. In our opinion, the current contract is extremely convolute in design and may deter bidders because of the implied risk arising from the intricate effects (even when using versatile spreadsheet solutions) of the profit trigger, which varies not only with oil price, but also is subjective to episodic adjustments related to the actual government share.

All in all, there currently is no adequate up-mark in contractor NPV and IRR for companies to invest in Mexico’s marginal shallow-water assets which are more risky investments than the U.S. counterparts for a mixture of quantifiable uncertainties, risks and conjectural circumstances:

a. Less subsurface data is available in Mexico due to a lack of previous investments in exploration. Consequently, a higher risk premium is required equivalent to the value of the lacking information.

b. Fiscal risk in Mexico remains high as demonstrated by the last minute requirement imposed during the bidding of Round 1, phase 1 with minimum government shares (of 25% and 40%) undeclared prior to the bid offers. Such capricious changes undermine the trust that needs to be built between the government and investors whose future investments and fortunes are dependable on the policies issued.

c. Political risk remains elevated in Mexico as nationalization has frequently occurred in Latin-American nations (e.g., Argentina, Venezuela, Ecuador). Mexico is positively reforming toward a market-oriented economy, but political risk rating agencies give Mexico an elevated political risk profile. Risk of corruption in Mexico also remains high according to international ranking organizations.

d. Mexican hydrocarbon assets remain property of the state. This is sometimes interpreted as companies being unable to book reserves, while others allege the stated intention of the energy reform is that any company successful in exploration efforts may substantiate a fair value of the discovered oil and gas properties (Seeleke et al., 2015). It would be useful if the new contracts could redeem any confusion and state explicitly that companies are entitled to their production share so the corresponding reserves may be rightfully booked for that share in accordance with the PRMS guidelines (PRMS, 2011).

e. Currency risk is high as Mexico’s sovereign credit rating is BBB+ as compared to AAA for the U.S. (Fitch, 2014). The sovereign rating for Mexico was in junk bond terrain before the Millennium turn (1995–2000: BB/BB+), but since has been hovering in bankable debt-ratings ranging between BBB- and BBB+. Pemex credit rating concurs with the sovereign rating for Mexico. The USD/Mexican Pesos valuation has fluctuated between 1/9th and 1/15th over the past decade, which implies considerable exchange risk, as well as opportunities for currency exchange gains. Our benchmark study assumed such currency risks are hedged with a neutral fiscal impact.

f. Local worker unions frequently call for strikes which may cause costly delays when drilling, according to experts who have worked in Mexico before.

Our study provides the first independent benchmark of Mexico’s shallow water production sharing contracts for lease blocks in bidding Round 1. We adopted Block 12 as a reference field and assumed a particular production profile (P50) based on analogy and scarce subsurface data. Likewise, our field development concept is provisional and based on our academic assessment in order to be able to complete our benchmark. With access to only limited subsurface data our production profile for the shallow-water asset studied remains speculative and our field development budget for opex and capex is likewise subject to change when more detailed analyses are performed. Although the assumptions made to obtain the reference field asset NPV estimates may need adjustments when more data become available, the general conclusions about the fiscal impact on the asset NPV and IRR will not change. We therefore think our benchmark study, in spite of the inevitable simplifications, provides a valid contribution with both quantitative and qualitative outcomes useful for both policy makers and oil company executives.

6. Conclusion and policy implications

Mexico’s energy reform has been an important event creating potential investment opportunities for the global petroleum industry. The energy reform is widely viewed as a key step to revitalize Mexico’s energy sector that has seen steady decline over the years (Seeleke et al., 2014, 2015). Our study provides an analysis, based on detailed financial modeling of a sample field from a recent auction, in order to benchmark the new production sharing agreement (PSA) for shallow water tracts auctioned in the first bid round of 2015. Our study demonstrates a few concerning factors that reduce attractiveness of the on-going licensing rounds and thus may hamper the effectiveness of this vitally important energy reform:

1. Our sample field would yield a NPV for the contractor which under Mexico’s production sharing contract is 1/3th of that due under the U.S. offshore license system assuming $75/bbl oil price and 20% government share.

2. In the event of favorable commodity prices and successful operational development, such as an upsurge of crude prices and capex/opex savings, the contractor of shallow water assets in Mexico is exposed to very limited, or in certain circumstances even negative, economic benefits, due to the effective ceiling of contractor’s return on investment by the SCI to SCA adjustment mechanism triggered by the capping of contractor profits.

3. Compared with a more transparent and straight-forward licensing system on the U.S. side of the Gulf of Mexico, the current contract terms in Mexico are highly convolute and require excessive elaboration in order for companies to properly interpret the prices and profit triggers in the current contracts.

4. Certain features of the current contract terms de-incentivize contractors from deploying adequate capital and resources for effectively and efficiently developing shallow water fields in Mexico. Lack of positive incentives, may bar some companies from participating in the upstream reform.

The Mexican energy reform opens up new project opportunities to consider and the profitability of such projects is principally affected by financial metrics such as risk premium, depreciation mechanism, royalties and taxes as specified in the fiscal terms. Investment decisions for hydrocarbon field development are based on such factors as project feasibility and profitability under risk and uncertainty. Forward looking statements about tactical investment decisions by companies typically account for future uncertainty and allow ample room for possible adjustments of any decisions, by using verbs like to anticipate, budget, estimate,
expect, intend, plan, target, project. As for now, companies are likely to apply these tactical terms with little commitment to investments in Mexico’s marginal shallow-water field assets. Bidding for any field assets with likelihood of larger resource volumes may still attract investors, but marginal and satellite fields under the shallow-water contracts terms of Round 1 are less likely to attract investments. Mexico’s current production-sharing contract stipulations, in particular the profit-trigger mechanism, result in low contractor takes even when oil prices were to rise.

We are generally positive about the long-term future success of the Mexican energy reform. The current shallow-water contracts can be interpreted as part of a fair-value seeking process. The Mexican government has evidently chosen to start at the bottom-end of the value-sharing scale. In order to move forward, future adjustments of contractual terms are likely to occur in order to arrive at more equitable agreements that provide investment incentives that may accelerate the energy reform at the intended pace. That may help to bring down the domestic consumer prices for gas, oil and electrical power, which currently are substantially higher than in the rest of North America (IMF, 2014). In contrast to our negative appraisal of the current shallow-water contractual terms, our companion study of license terms offered by Mexico for onshore shale asset development (Weijermars et al., 2016a) reveals terms that are favorable and nearly at par with the typical onshore royalty contracts in Texas.

Acknowledgment

Fred Dupriest at Texas A&M University kindly provided some input for our field development concept. We emphasize our analysis has been performed from an independent vantage point, being sponsored neither by the Mexican government nor any oil company active in the bidding process.

Appendix A. Business terms in Mexico offshore production sharing agreements

The Mexican production sharing agreement is similar to the type of contract used in many non-OECD nations. The total fees to be paid by the operator to the government, for shallow water projects, are as follows: (1) rental fee per acreage for exploration, (2) royalty on the value of production volumes, (3) share of production sales value, and (4) corporate tax (Fig. A1). Each of these fees is detailed below.

1. Federal exploration rental fee (“cuota contractual”) for exploration period until production starts (CQEP) is due:
   - During first 60 months: 1150 pesos/km² (~ $78/km² @31 Dec 2014)
   - From 6th month onward: 2750 pesos/km² (~$187/km² @31 Dec 2014)

   It should be noted that the Hydrocarbons Revenue Law (HRL; DOF, 2014) contains some ambiguity regarding the amounts to be paid, because two pertinent articles state different amounts (Ley de Ingresos sobre Hidrocarburos, Artículos 45 and 55; DOF, 2014). The former article states the fee for the exploration phase is 1150 pesos/km² and the latter 1500 pesos/km². However, the draft PSA states the rental fee as 1150 pesos/km² for the first 60 months. The value of the monthly fees may be adjusted annually based on the National Consumer Price Index. The production rental fee (“cuota contractual” for production of 6,000 pesos/km² ~$407/km² @31 Dec 2014) specified in the HRL does not apply to shallow water PSA’s as any part of the acreage that remains undeveloped reverts to the government after 5 years from the award of the lease.

2. Federal royalties (“regalías”) for oil, gas and NGL’s are not-negotiated but are revenue-based, with the royalty rate (R) fixed using a contractual price benchmark (P, Table 1) according to the following formulas:

1. Oil royalties (Fig. A2a):

   \[ R_{\text{Oil}} = \left( B_{\text{PC-OIL}} + 1.5 \right) \% \quad \text{for } P_{\text{PC-OIL}} \geq A_n \]

   \[ R_{\text{Oil}} = 7.5 \% \quad \text{for } P_{\text{PC-OIL}} < A_n \]

   The critical threshold price \( A_n \) for reference year 2015 is \( A_n = \$48/bbl \) and fraction \( B_n = 0.125 \) [bbl/$]. For subsequent years the adjustments for price inflation, \( \pi \), for \( A_n \) and \( B_n \) are as follows:

   \[ A_n = A_{n-1}(1 + \pi_{n-1}) \quad \text{[$/bbl$]} \]

   \[ B_n = B_{n-1}(1 + \pi_{n-1}) \quad \text{[bbl/$$]} \]

   The contractual oil price, \( P_{\text{PC-OIL}} \), to be used for oil royalty calculations is prescribed as a benchmark price for Mexican oil based on Brent spot price and Louisiana Light Sweet (LLS) as detailed in Table A1.

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**Fig. A1.** Payment schedule for production sharing agreement (PSA) for shallow water projects in Mexico’s Bid Round 1. Exploration rental fee is also due until production starts.
1. Natural gas royalties

- **Associated gas:**

  \[ R_{\text{A-GAS}} = \frac{P_{\text{C-GAS}}}{C_0} \times \% \]  

  The fraction \( C_n = C_0 = 100 \) [$/mmbtu] for the reference year 2015. For subsequent years inflation adjustments of \( C_n \) occur as follows:

  \[ C_n = C_{n-1}(1 + \alpha_{n-1}) \]  

  The contractual gas price, \( P_{\text{C-GAS}} \), to be used for gas royalty calculations will be communicated by the Energy Regulatory Commission, and the method is not specified at this stage.

- **Non-associated gas** (Fig. A2b):

  \[ R_{\text{NA-GAS}} = \frac{P_{\text{C-GAS}}}{F_n} \times \% \]  

  for \( P_{\text{C-GAS}} \geq E_n \) [$/mmbtu]

  \[ R_{\text{NA-GAS}} = 60.5(P_{\text{C-GAS}} - D_n) \times \% \]  

  for \( D_n < P_{\text{C-GAS}} < E_n \) [$/mmbtu]

  \[ R_{\text{NA-GAS}} = 0 \times \% \]  

  for \( P_{\text{C-GAS}} \leq D_n \) [$/mmbtu]

  The critical threshold prices for the non-associated gas royalty formulas in 2015 are \( D_n = D_0 = 5$/mmbtu \) and \( E_n = E_0 = 5.5$/mmbtu \) for the reference year 2015. For subsequent years inflation adjustments of \( D_n \) and \( E_n \) occur as follows:

  \[ D_n = D_{n-1}(1 + \alpha_{n-1}) \]  

  \[ E_n = E_{n-1}(1 + \alpha_{n-1}) \]  

  The correction fraction \( F_n = F_0 = 100 \) [mmbtu/$] for the reference year 2015. For subsequent years inflation adjustments of \( F_n \) occur as follows:

  \[ F_n = F_{n-1}(1 + \alpha_{n-1}) \]  

  The contractual price, \( P_{\text{C-GAS}} \), to be used for gas royalty calculations will be communicated by the Energy Regulatory Commission, and the method is not specified at this stage.

1. Condensates Royalties (Fig. A2c):

  \[ R_{\text{CONDENS}} = (H_n P_{\text{C-CONDENS}} - 2.5) \times \% \]  

  for \( P_{\text{C-CONDENS}} \geq G_n \) [$/bbl]

  \[ R_{\text{CONDENS}} = 5 \times \% \]  

  for \( P_{\text{C-CONDENS}} < G_n \) [$/bbl]

  The critical threshold prices for condensates in 2015 is \( G_n = G_0 = 60$/bbl \) and fraction \( H_n = 0.125 \) [bbl/$]. For subsequent years inflation adjustments of \( G_n \) and \( H_n \) occur as follows:

  \[ G_n = G_{n-1}(1 + \alpha_{n-1}) \]  

  \[ H_n = H_{n-1}(1 + \alpha_{n-1}) \]  

  The contractual condensate price, \( P_{\text{C-CONDENS}} \), to be used for royalty calculations is prescribed as a benchmark price for Mexican oil based on Brent spot price:

  \[ P_{\text{C-CONDENS}} = 6.282 + 0.905\text{Brent} \]  

3. Share of production sales value. This is calculated on a monthly as follows. First operator sales is calculated as the sum of all produced liquid volumes times their respective contractual prices (accounting for the daily variation in benchmarks):

  \[ VCH = P_{\text{C-OIL}} \times \text{VOLC-OIL} + P_{\text{C-GAS}} \times \text{VOLC-GAS} + P_{\text{C-CONDENS}} \times \text{VOLC-CONDENS} \]  

  \[ U_{\text{NET}} = VCH - CR - \sum R + AI \]
The cost recovery CR is subject to condition that it may not exceed 0.6\(U_{\text{NET}}\), in which case the remaining value of cost recovery may be carried forward to the next month. \(Al\) is any additional income received by operator from services provided to third parties such as from infrastructure built by operator for which he receives a tariff for utilization of infrastructure capacity.

Note that in the PSA, cost recovery of capital investments does not occur by depreciation as a deductible on corporate income tax but by subtraction of the VCH. The recovery of the total capital cost \(\Sigma CR\) is subject to certain ceilings (detailed in HRL, articles 41, 42, and 64; DOF, 2014), which specifies the allowance for cost recovery:

- 100% of capital investments for exploration (including drilling) and secondary recovery production development (including non-capitalized maintenance)
- 25% of capital investments for the development of oil and natural gas deposits
- 100% of capital investments in infrastructure such as storage facilities and pipelines. When an asset share is sold on to another company already expensed investments need to be reimbursed to the state.

The draft contract for shallow water projects proposes the result of the operator/contractor \(\text{(ROC)}\) should be calculated as follows and provides a check for over-royalty:

\[
\text{ROC} = (U_{\text{NET}}SCA) + CR - OPEX - 3MP \quad [\$] \quad (6)
\]

\(MP\) is the recovery of eligible cost (certain OPEX and CAPEX) spent on the minimum work program incurred in the reporting period. SCA is the adjusted fractional share of the operator, and operating expenses, OPEX, incurred in the production month of reporting. The adding back in of CR means the operator share of production is inflated by capital cost that is first deducted but effectively remains partly unrecovered. This becomes obvious when rearranging expression (6) for the operator share:

\[
SCA = \frac{(ROC - CR + OPEX + 3MP)}{U_{\text{NET}}} \quad \text{[fraction; multiply by 100 for \%]} \quad (7a)
\]

Substituting expression (5) simplifies (7a) to:

\[
SCA = \frac{(ROC - CR + OPEX + 3MP)}{(VCH - CR - \sum R)} \quad \text{[fraction; multiply by 100 for \%]} \quad (7b)
\]

The production share due to the federal government, SG, is:

\[
SG = 1 - SCA \quad \text{[fraction; multiply by 100 for \%]} \quad (8)
\]

The SCA specified in expressions (7a and b) and (8) will be adjusted based on a profitability trigger \((\text{IRR})\).

1. For \(\text{IRR} < 25\%\), \(SCA = SC_{1}\), which is the production share initially agreed with the operator.

2. For \(\text{IRR} > 40\%\), \(SCA = 0.25SC_{1}\), which is the minimum share for the operator's success.

3. For \(25\% \leq \text{IRR} \leq 40\%\), \(SCA\) is determined from the following formula:

\[
SCA = SG - (0.75 * SG) \left( \frac{(IRR/100) - 0.25}{0.15} \right) \quad \text{[fraction; multiply by 100 for \%]} \quad (9)
\]

Although no royalty override ("sobre-regalía") is applied in the PSA (which would be due in addition to the regular royalty "regalía básica" when commodity prices escalate), the above adjustment mechanism progressively suppresses the IRR for the operator when pre-tax profits escalate. The operator's production share originally agreed as a contractual share of \(SC_{1}\) applies as long as \(\text{IRR} < 25\%\) but will gradually sink to 0.25 \(SC_{1}\) when \(\text{IRR} \geq 25\%\). In fact, this formula encourages operators to avoid realizing any excessive IRR. The IRR trigger brackets were respectively 15 and 30% in the original draft of the shallow water contract published 11 December 2014, but was in the 1st amendment of 25 March 2015 changed to 20 and 35%, and as per 2\textsuperscript{nd} modification of 29 May 2015 it has settled on 25 and 40% (CNH Round 1, 2015a)

1. The nominal rate of internal return, \(r_{n}\) on a monthly basis is found by solving the following expression for a given ROC:

\[
\sum_{i=1}^{\text{ROC}} \frac{ROC}{(1 + r_{n})^{i-1}} = 0 \quad [\$] \quad (10a)
\]

2. The effective rate of internal return, \(\text{IRR}\), is:

\[
\text{IRR} = (1 + r_{n})^{12} - 1 \quad \text{[fraction, multiply by 100 for \%]} \quad (10b)
\]

4. \textbf{Corporate Income Tax} is due at a rate of 30\%. Dividends to shareholders are subject to 10% withholding tax (unless there is a tax treaty in place that may reduce the rate to zero for foreign shareholders).

\textbf{Appendix B. Business terms of U.S. licenses}

Oil and gas companies operating in the U.S. section of the Gulf of Mexico will generate the following gross revenues:

1. \textbf{Revenue}:

\[
R_{\text{Oil}} = \text{Oil Production} * \text{Realized Oil Price} \quad (11a)
\]
In order to realize their contractor’s share of free cash flow, companies must incur various types of operating and capital expenses, and pay the following fees to the U.S. government (Fig. B1). (1) signing bonus, (2) rents, (3) royalties, and (4) income tax. The step-by-step model calculations and common rates for each of these fees are detailed below.

1. **Signing Bonus**

Prior to a federal sale of U.S. offshore drilling leases, a minimum per-acre signature bonus is specified and auction participants may make competitive bids based on their perceived risks and other factors. Resulting signature bonuses vary significantly per bid round, with peak value of $96.25/acre in 1982. For the larger, area-wide leases introduced in 1983, typically covering 3 mile square blocks (5670 acres; see Appendix C), signing bonuses came down from $28/acre in 1983 and average bonus paid in 2014 was just $2.50/acre (Fig. B2b and c). The signing bonus is assumed to be capitalized and provides a tangible basis for cost depletion.

2. **Annual Rental Payment**

Annual rents are payable on or before the first day of each leasing year up to the commercial discovery of oil and gas. Rental rates payable for offshore leases in the Gulf of Mexico are given in Table B1. The trend in average rental payment/acre for any given year is graphed in Fig. B3. Rental payments are specified as an opex sum in our cash flow model.

3. **Royalty**

For offshore Gulf of Mexico, the royalty rate for leases granted before 2008 range between 12.5% and 16.667%. For all new leases granted on or after March 19, 2008, the applicable royalty rate has been set at 18.75% of gross revenue offshore Gulf of Mexico. Deepwater royalty relief may be applicable to certain fields in water depths of 200 meters or deeper. For example, deepwater fields in leases issued after 2000 may be eligible for a designated royalty suspension volume on a per-lease basis where a fixed amount of hydrocarbon productions can be excluded from royalty payment calculations. The deepwater royalty relief requires a formal application with detailed economic analysis demonstrating that economic viability of the project is
Earnings Before Interest, Taxes, Depreciation and Amortization
Internal Rate of Return (IRR)

Fig. B3. Times series (1954–2014) for average rental fees paid for leased acres in any given year. Deeper than 200 m rental fees currently are $11/acre, and less than 200 m deep is rented at $7/acre. Based on data from BOEM (2015).

depending upon and sensitive to royalty relief, as compared to projects without such a requirement (IMMS, 2010). The reference field used in our study is assumed to be auctioned after March 2008 and a shallow water and no deepwater asset. As a result, a royalty rate of 18.75% is applied to total revenue ($_{\text{total}}$) as calculated from (11d):

\[
\text{Royalty}_{\text{total}} = R_{\text{total}} \times 0.1875
\]

4. Corporate Income Tax

According to the Internal Revenue Code, U.S. Code Title 26 (26 U.S.C.), federal income tax is payable, at a corporate level, on all income generated in the United States. As a result, all leaseholders conducting oil and gas extraction activities in the U.S. are liable to pay corporate income tax at a rate of 35%. Petroleum activities offshore Gulf of Mexico are subject to federal income tax only and no state-level income tax is applicable. Federal income tax is levied on taxable income, which equals EBITDA minus DD&A deductions as detailed below.

A. Earnings Before Interest, Taxes, Depreciation and Amortization (“EBITDA”):

With revenue, royalty and OPEX available, EBITDA is calculated as a cash flow metric before including tax payment and CAPEX. The cash flow model is assumed to be on the field level rather than on a corporate level. As a result, no borrowing nor interest expenses are applied (but time value of money is accounted for by applying a discount rate to the free cash flow):

\[
\text{EBITDA} = R_{\text{total}} - \text{Royalty}_{\text{total}} - \text{OPEX}
\]

Rental payment is treated as an OPEX item based on Table B1 and area of the adopted reference field (see Table 2 main text). Income before tax is equal to EBITDA minus DD&A. For example, expenses for leasehold acquisition may be capitalized and constitute depreciable/depletable property. The federal fiscal regime for U.S. oil and gas activities is defined by the U.S. Internal Revenue Service (IRS, 2013). Two methods of depreciation, cost depletion and percentage depletion, are calculated based on the IRS regulations. With cost depletion, the actual capital investment is recovered throughout the period of income production. A portion of the original capital investment is deducted each year equal to the fraction of the estimated remaining recoverable reserves that have been produced and sold that year, less previous deductions. The IRS details the recovery period for each group of assets used in the petroleum industry: e.g., assets and services used in drilling of wells (6 years), offshore drilling vessels, platforms and equipment (7.5 years), E&P facilities (14 years), and LNG plant (22 years). Deductions normally include royalty payment, operating expenses, expendable exploration costs (such as exploration cost related to dry holes), intangible development cost and depletion, depreciation and amortization (DD&A). The signing bonus is assumed to be capitalized and provides a tangible basis for cost depletion. In addition, losses from previous years can be carried forward and account for part of deductions for a maximum of 20 years. The cumulative depletion under the cost depletion method may not exceed the original capital investment.

When the producer prefers to apply the percentage depletion, the allowance deduction for recovery of the capital investment is calculated using a fixed percentage of the gross income (sales revenue). Independent producers and/or royalty owners may use for leasehold assets in the U.S. a depletion rate of 15% of the annual gross income from the property based on the average daily production of domestic crude oil or domestic natural gas up to the depletable oil or natural gas quantity. When percentage depletion is applied, the cumulative depletion deductions may become greater than the capital amount spent by the taxpayer to acquire the property, which is permissible (Freeman, 1955; Roussel, 1983; Zoller and Marrisson, 2012).

B. Free Cash Flow (“FCF”):

FCF represents available cash for distribution to unit holders of the operating entity of the reference field and is therefore a key financial metric based on which investment return metrics such as NPV and IRR are calculated. Here working capital items such as inventory, account receivables and account payables are assumed to be held constant over the life of the reference field.

\[
\text{FCF} = \text{EBITDA} - \text{Income Tax} - \text{CAPEX}
\]

C. Internal Rate of Return (“IRR”) and Net Present Value (“NPV”):

Once FCF is available for each year, IRR and NPV can be calculated using standard Microsoft Excel formulae under various discounted rates.

In addition, functionalities are incorporated into the fiscal model to enable sensitivity analysis around key exogenous inputs such as production, OPEX, CAPEX, commodity prices and discounted rates.

Appendix C. Brief history of U.S. Gulf licenses

Offshore E&P activity in the U.S. section of the Gulf of Mexico first succeeded to attract major field development investments only after federal ownership of offshore resources was reassured, which occurred when the so-called Tidelands controversy was resolved (Engler 1961; Cicin-Sain and Knecht 1987). Congress passed in 1953, both the Submerged Land Act (SLA, asserting federal rights to offshore waters) and the Outer Continental Shelf Act (OCSA, asserting federal ownership of all resources occurring under the “federal” offshore waters). States adjacent to the seaboard hold title to only a narrow seaboard stretch within 3 miles of the shoreline. For historical reasons both Texas and Florida hold title to an offshore corridor including the mineral rights, up to 9 nautical miles (17 km) out from the shore. Federal ownership was asserted by the OCSA for all resources occurring under the “federal” offshore water. Subsequently, offshore oil and gas leases were offered through a competitive bidding process since 1954. The effect of the federal leasing policies and fiscal stimuli on the development of production in the U.S. Gulf of Mexico becomes particularly apparent when the covariance of tax measures and annual oil and gas production are highlighted over time (Fig. C1).

In 1978, the OCSA was amended by the Outer Continental Shelf Land Act Amendment (OCSLAA), which stated purpose was to open
the decision-making process to a wider audience and avoid collusion between a small group of bidders and top-officials of the Department of the Interior (Krueger and Singer, 1979). The effect was a renewed surge in E&P activity and increased production output (Fig. C1). In 1983, the U.S. Mineral Management Service (MMS; now renamed BOEM) introduced area-wide leases typically covering 3 mile square blocks (5670 acres) with some leases in greater water depths offered with a royalty discount, demanding only one-eighth of the gross resource value produced (12.5% instead of one sixth 16,666 % of the total value of offshore resources extracted) to stimulate deep water E&P (Freudenberg and Gramling, 2011).

In 1995, U.S. congress passed the Outer Continental Shelf Deepwater Royalty Relief Act (DWRRA, 1995). This is a royalty waiver program aimed at stimulating development of hydrocarbons in the deepwater Gulf of Mexico. Royalties were suspended for 5 years in a tiered system that allowed royalty free production in deep water areas of the GOM, defined as water depths below 200 meters, as follows:

- 200–400 m: 98.5 bcf gas and 17.5 MMbbls oil royalty free
- 400–800 m: 295.6 bcf gas and 52.5 MMbbls oil royalty free
- > 800 m: 492.6 bcf gas and 87.5 MMbbls oil royalty free

The mineral rights in all offshore areas starting from the Texan coastline outward are administered by the federal government, which shares a portion of the revenues with the coastal states. The U.S. offshore E&P license system generates revenues for the federal government in the form of license signature bonus payments, royalties, rents, and corporate income tax payments. The fiscal take from U.S. offshore production in the Gulf of Mexico has been summarized in reports by the U.S. Government Accountability Office (GAO, 2007, 2013). For example, bonus revenues in 1992 grossed $85 million, $1.43 billion in 1997 and $865 million in 2006 (Humphries, 2008). The Gulf of Mexico Energy Security Act (GOMESA; Pub. Law 109-432, signed Dec 20, 2006) covers OCS oil and gas leasing activities and revenue sharing in the Gulf of Mexico. Minerals located in the Outer Continental Shelf (OCS), DOI submits 5-year leasing programs, the current 5-year program spans July 2012–2017. DOI estimated in its inventory of Feb 2006 total U.S. OCS oil reserves at 8.5 billion bbls and gas at 29.3 tcf. Additionally, 86 billion bbls of oil is classified as undiscovered resource, as well as another 420 tcf of natural gas (Humphries, 2008). The U.S. fiscal regime and royalty rates for hydrocarbon production are subject to continued review (GAO, 2013) with a clear mission to balance the fiscal take from hydrocarbon activities and improve security of domestic oil supply from the Gulf and other U.S. offshore regions. The original terms and conditions of the DWRRA expired in November 2000, but the MMS continues the review royalty suspension applications based on oil and gas prices and its lease-specific assessment of how royalty suspensions may support field development economics. The U.S. Government Accountability Office (GOA) accounted that the DWRRA has reduced the tax burden of oil and gas companies by $50 billion over the life of their leases (GAO, 2007). Although production in the U.S. sector of the Gulf is declining, the U.S. fiscal regime has been carefully engineered to maximize resource development from the OCS.

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