Chasing reserves – Incentives and ownership[1]

by

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The oil companies are concerned to replace the petroleum reserves they produce in order to maintain their future level of activity. Booked reserves also represent an important input when analysts value these companies. Many producer countries want to control their own resources, a goal which can come into conflict with the desire of the international companies for booked reserves. Where oil companies do not own the reserves, they may have insufficient incentives to maximise value – harmonising goals between resource country and oil company can be difficult. This article discusses the relationship between reserves and financial incentives, and between reserves and valuation. The issues are illustrated throughout with reference to two cases: StatoilHydro's projects on Shtokman in Russia and Peregrino in Brazil.

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[1] I would express my thanks for rewarding conversations with and comments on the article from a number of key specialists in the oil industry and academia. Address for correspondence: Petter Osmundsen, Department of Industrial Economics and Risk Management, University of Stavanger, NO-4036 Stavanger, Norway. Tel: +47 51 83 15 68. Mobile: +47 99 62 51 43. E-mail: Petter.Osmundsen@uis.no. Website: http://www5.uis.no/kompetansekatalog/visCV.aspx?ID=08643&sprak=BOKMAL

1. Introduction

In the Norwegian petroleum tax system, ownership of the resources rests with the participants in a licence subject to conditions specified in the licence, the licence agreement and more general regulations. The state often has its own share of the licence through the State's Direct Financial Interest (SDFI), which is managed by Petoro. Many would say that ownership of the resources is very important, not only for the companies but also for the resource state. This is fairly obvious in the case of the companies. Ownership makes it possible to carry the reserves on the balance sheet, which financial markets want to see. Great attention is currently being paid to the reserve replacement rate (RRR) of oil companies. We see constant references, for instance, to basic valuation methods in which the value of an oil company is equated with reserves in different countries multiplied by an estimated value per barrel of oil equivalent (boe) in each country of production. For these figures to be meaningful, however, one must operate with expected rather than booked reserves.

Private ownership in the licences is important for the state because it establishes incentives to maximise value creation. Replacing ownership with other types of incentives is difficult, which presents a major challenge to producer countries where the government will not allow foreign companies to own petroleum resources for one reason or another. Ownership provides long-term incentives, where the companies wish to maximise value throughout the life cycle of the field. At the same time, achieving homogenous ownership composition in licences across field areas with reservoir contact (unitisation) is important in order to avoid sub-optimisation.

In everyday parlance, people often say that the oil companies own their share of the resources in a field on the Norwegian continental shelf (NCS). However, this is not strictly correct. The oil companies are only *licensees*, who produce the petroleum resources on behalf of the state. Ownership of underground resources is vested in the state, which gives the government the legal authority to regulate various aspects of reservoir management. On the other hand, the licensees own and control the oil and gas once it comes to the surface. That ensures financial incentives to maximise the value of the resources. When regulating the oil companies, moreover, the government is subject to the Act on Public Administration and the standards this sets for objectivity and orderly procedures. That is relevant at present in connection with the development of the Goliat field in the Barents Sea. When the licensees have received a production right, the government cannot refuse to allow the licence partners to develop the field (as some seem to believe). However, it can impose objectively justified and non-discriminatory requirements related to the development.

2. Booked reserves

Since estimating actual expected cash flow for oil companies is difficult and time-consuming (asymmetrical information), analysts use various indicators to make rough estimates of value. A key indicator today is the reserve replacement rate. This expresses how large a proportion of production in the present year has been replaced by new reserves. The ability of the companies to maintain reserves ready for production in relation to on-going recovery says something about sustainability and growth opportunities for the company, which is clearly highly relevant for valuation. That depends, of course, on the indicator being free of measurement errors. Preliminary results from analyses we have undertaken in the Department of Industrial Economics at the University of Stavanger indicate that no clear relationship exists between the reserve replacement rate shown in the accounts and valuation; see e.g., Misund et al. (2008).

Several factors explain this lack of correspondence between booked reserves and valuation. First, the figures on reserves comply with the conservative accounting principles of the US Securities and Exchange Commission (SEC). These involve such substantial measurement errors that they fail to provide a good expression of the actual position for reserves. Second, investors will make their own reserve estimates in any event. They are clearly not going to overlook the fact that StatoilHydro has a substantial share in the Shtokman development, for instance. Focusing on single indicators underestimates investors. They are concerned with cash flow, and cannot be deceived by high figures for booked reserves.

The information value of booked reserves suffers from a number of weaknesses. Reserves are recognised on the basis of the spot oil price at the balance sheet date, which does not necessarily represent a best estimate for future oil price developments. Booked reserves do not provide a consistent picture of reserves under different contracts (an income tax system, for instance, will yield higher reserves than one based on production sharing for identical cash flows). Perhaps the most important objection to the conservative rules, however, is that the reserve figures do not provide complete information on the subsequent growth of the company and thereby on the sustainability of its operations. This is because they do not include less mature reserves, which can vary a great deal from one company to another. In any event, the attention given to booked reserves helps to make the NCS more attractive. The Norwegian licence model gives companies greater opportunities to carry reserves than is the case in nations which operate with production sharing agreements, contractor contracts and the like.

2.1 Differences between PSC and concession reserves

Traditional oilfield concession ownership is found in the OECD-area. Under this system, if producers generate a profit from ongoing extraction, they pay corporation tax, sometimes supplemented with royalty or other taxes. In this instance, producers own the underlying reserves, with reported reserves being the recoverable reserves from the reservoir in total, and future physical reserve entitlement is unaffected by price volatility.

Production sharing contracts exist in many of the world's newer oil producing and non-OECD regions including West Africa, Kazakhstan, Indonesia and Egypt. The proliferation of these agreements in the 1990s has been a direct result of government desire to reclaim control of natural resources once a fair return has been earned by the corporate producers.

PSC agreements vary widely but typically provide oil companies with a guarantee to cover a return on their capital costs and, in exchange, impose a reserve entitlement structure. The contract generally escalates participation sharing by the local government based on the price of oil and in some cases the volume of oil pumped. As explained by Kretzschmar et al. (2007), the PSC allows contractual contingent claims (often in forms of taxation or production sharing) to be made against producer reserves when an agreed threshold of return is met and costs have been covered.

This interpretation recognises the contractual nature of possible fiscal claims against oilfields (Lund 1992).

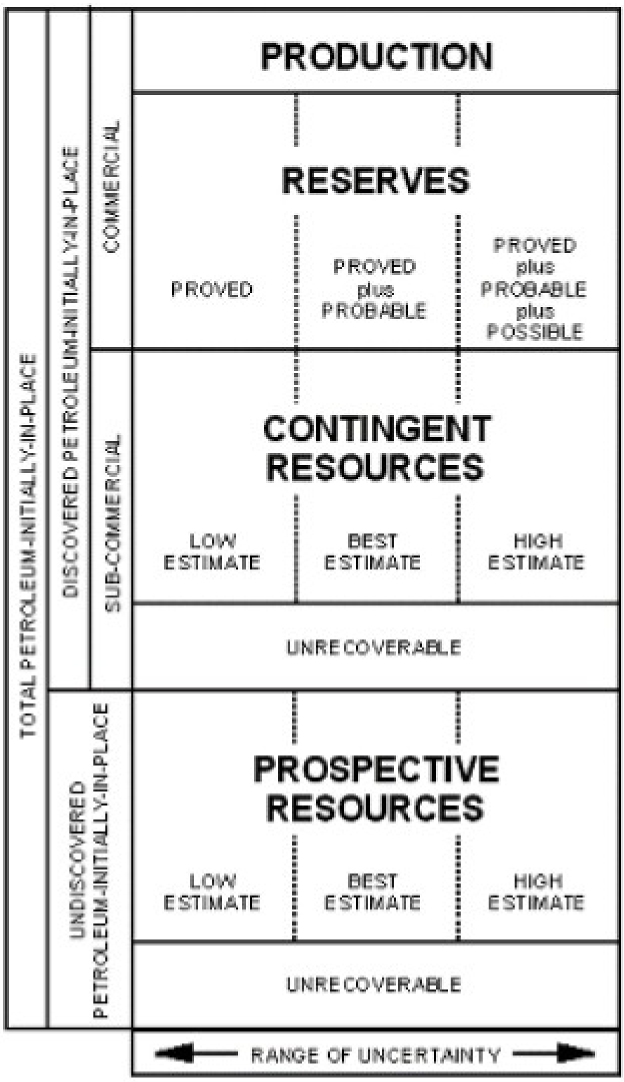
The most marked difference between concession ownership and production sharing disclosures is that reserves and production do not vary in response to oil price movements for concession fields, while both production and reserves vary under PSC regimes. Under a PSC contract the oil company is to be paid a certain amount of oil to cover costs (cost oil) and profits (profit oil). When oil prices rise the number of barrels of oil needed to pay for costs and profits are reduced. Kretzschmar et al. (2007) illustrate this with field data from the Golf of Mexico, where reserve and production entitlement remains unchanged across the full price range USD$ 22.5 – USD$90. Angolan PSC reserves, by comparison, actually decrease by 0.451 percent per 1 percent oil price change in the range USD$ 22.5 – USD 33.75 and decrease by 0.388 percent in the range USD 67.5 - USD 90. Production entitlement, by comparison, also reduces in Angola, but by 0.291 percent and 0.181 percent respectively over the same price intervals. In line with Rajgopal (1999), Kretzschmar et al. recommend that supplementary information should disclose the effects of oil and gas price changes on underlying reserve disclosures.

2.2 Petroleum reserves – definitions

Figure 1 is a graphical representation of various definitions of petroleum reserves. The horizontal axis represents the range of uncertainty in the estimated potentially recoverable volume for an accumulation, whereas the vertical axis represents the level of status/maturity of the accumulation.

Resources Classification System Graphical Representation

FIGURE 1 - RESOURCES CLASSIFICATION SYSTEM



Not to scale

Figure 1. Petroleum resource classification. Society of Petroleum Engineers.[2]

Resources definitions vary. Some define it as including all quantities of petroleum which are estimated to be initially-in-place; however, some users consider only the estimated recoverable portion to constitute a resource. In any event, it should be understood that reserves in an accounting sense constitute a subset of resources, being those quantities that are discovered (i.e. in known accumulations), recoverable, commercial and remaining.

The most widely used reserve disclosure is the one required by the Securities and Exchange Commission (SEC), owing to the importance of US capital markets and the fact that most major private oil companies have a US listing. Here companies are required to report their 'proven' reserves in a deterministic way, quite different from the probabilistic ways allowed on other exchanges.

Arnott (2004) points out that it should always be remembered that the SEC rules were introduced with the sole purpose of protecting shareholders. They were brought in at a time when most of the US oil industry was still onshore, where regular grid well-spacing was common and therefore it was fairly easy, using deterministic methods, to calculate not just the volume of remaining oil in place but also its value. However, the oil and gas industry has subsequently witnessed a major technological revolution. It is therefore ironic, according to Arnott, that at the very time that the oil and gas industry is basing more and more of its investment decisions on the results of measurements from new technologies, the SEC has tightened up its definition of what can or cannot be reported and by inference has ruled out measurements from these technologies.

The complaint about booked reserves is that this does not reflect economic reality or the reserves that the company is using when formulating its internal plans

[2] http://www.spe.org/spe-app/spe/industry/reserves/mapping.htm

and projects. By only counting proven reserves, the SEC rules systematically understate the true extent of the resource base. Another obvious example of measurement bias is oil produced in Canada from mining operations in tar sands. The SEC does not allow such oil to be booked as petroleum reserves on the grounds that it is a mining product – although it is at least as predictable as the oil from underground reservoirs. Some instances of overbooking have raised uncertainty regarding booked reserves. According to Arnott (2004) the practice of 'smoothing' reserves bookings in order to show steady reserves growth can be just as misleading to investors as over-booking.

2.3 **The role of the reserves report**

Oil company reserves disclosures are according to Arnott (2004) one of the most important pieces of information that the financial sector requires in order to analyse, compare and contrast the past and prospective operational performance of oil and gas exploration and production firms. Recent reserves re-categorizations by several companies have only served to highlight the inadequacy of the published information.

Arnott states that a company's internal information structure of future production estimates is not suitable for communication outside the company for many reasons:

- It would be dynamic, complex and difficult to interpret without full knowledge of all the company's practices and parameters – in other words without being inside the company.

- It would prejudice the company in competitive bids and negotiations if this information were available to its competitors and counter-parties in negotiation.
- It is often subject to confidentiality agreements.

Obviously some communication with respect to reserves is necessary for private companies with equity or bonds held on public stock and bond markets, since:

- The expectations of future production are an important predictor of a company's future capacity to reward shareholders and repay debt-holders.
- The reported current profits depend on the allocation of exploration and developmentcosts between depreciation (charged over the lifetime of production) and current expense (charged to current profits). Reported accounts therefore require a definition of expected future production – typically described as '*proven' reserves* (see Figure 1) on a base which can be understood by investors and creditors of the company.

3. Shtokman

Ownership has been much discussed in connection with Russia's big Shtokman field in the Barents Sea. This discovery is estimated to contain a total of 3 700 billion cubic metres of gas, making it 10 times larger than the Ormen Lange field in the Norwegian Sea. StatoilHydro signed an agreement with Gazprom on 27 October 2007 concerning participation in the first phase of a Shtokman project. Gazprom, Total and StatoilHydro have concluded a shareholder agreement over the Shtokman Development AG company, which will be responsible for designing, developing, constructing, financing and utilising the facilities in a first Shtockman development phase[3]. Gazprom has 51 per cent, Total 25 per cent and StatoilHydro 24 per cent of this company, which is registered in Switzerland. Total and StatoilHydro will own the phase one infrastructure for 25 years from the start of production on the field. StatoilHydro has indicated that the company's share of the gas resources corresponds to roughly 800 million barrels of oil[4]. Investment in phase one alone is likely to exceed NOK 100 billion.

Basically, the incentives in this case do not look correctly configured. The development company appears to own the infrastructure rather than the actual field. OOO Sevmorneftegaz, a wholly owned subsidiary of Gazprom, reportedly holds the exploration and production licence for gas and condensate. The relationship between Shtokman Development and Sevmorneftegaz will build on a contract which specifies that the latter bears all financial, geological and technical risk related to production of gas and condensate and to gas liquefaction. It would thereby seem that the Russians will retain the aspects which normally fall to an oil company. OAO Gazprom owns all the shares in Sevmorneftegaz, and all the rights to market the output.

This is a contract which appears to lie closer to the type of agreement concluded by a contractor, rather than to those to which an oil company normally becomes party. Furthermore, Total and StatoilHydro only own the infrastructure for the first development stage. It is doubtful whether this provides sufficient incentive to maximise total value creation over time for the whole field. This breaches elementary principles for framing incentives – a supplier should have responsibility for the areas it can affect. Knowledge of reservoir conditions represents specialist oil company expertise. Even without ownership of the actual reserves, it would have been possible to create incentives by allowing rewards to be conditional on the production portfolio.

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[3] http://www.statoilhydro.com/no/NewsAndMedia/News/2008/Pages/ShtokmanDevelopmentAG.aspx

[4] *Dagens Næringsliv*, 22 February 2008.

This contract recalls contractor agreements on the NCS, where the contractor bears responsibility for delays and cost overruns but does not participate in the upside or downside related to production and gas price trends. The limited upside – which is a certain return on capital invested or a fixed sum – will often be balanced in such cases by a limited downside (both in the formulation of the contract and in its application), so that the limited opportunities for a return are proportionate to a limited risk. StatoilHydro has also concluded contractor-like contracts in Iran. These service fee deals specify what the oil company will receive, with the government taking the rest. This is the opposite of the practice in most other producer countries, where the government's share is specified and the oil company receives the residual income. Payment takes the form of oil. Cash reimbursement of costs, known as buy-back, is converted to oil at an agreed price. That makes it possible for StatoilHydro to book the reserves. The problem in this case is that the limited upside is not balanced by any downside limits. A substantial challenge has also been that the regulatory authorities, the state oil company, and supplier companies are represented by the same people and ownership. That clearly puts the foreign oil company in a weak negotiating position. Conditions in Russia are related.

Experience specifically from Iran makes it unlikely that StatoilHydro will be willing to accept a traditional contractor agreement. In this context, it is worth noting a comment from the head of the company's Moscow office, Bengt Lie Hansen: "Our exposure will be normal for an oil company – in other words, to both revenue and costs from operation of the field"[5]. This must mean that Sevmorneftegaz, which has been allocated all upside in the field under the terms of the shareholder agreement, will pass some of it on to the other participants. The upshot is that this will actually become something which resembles an income tax system. How far and in what way upside will be transferred to the foreign companies is unlikely to be determined until 2009. Instead of relating the incentives directly to ownership in the licence, in other words, ownership is being established

[5] http://web3.aftenbladet.no/innenriks/okonomi/article536237.ece

in the infrastructure and efforts are being made to create synthetic incentives which will imitate the terms ordinarily enjoyed by international oil companies.

Obvious challenges here will be the credibility of the terms and the threat of renegotiation. However, it could be objected that these challenges are also present in other producer countries. Given their desire for greater predictability, the oil companies have often sought production sharing agreements because these – unlike income taxes – represent legal contracts which are more binding on the resource country. However, developments in recent years – not least in Russia – have demonstrated that production sharing agreements are incomplete contracts which give the international companies no protection worth mentioning. According to industry sources, the Russians do not want a production sharing agreement for Shtokman. Instead, they want the field to be taxed in accordance with the Russian tax regime for the petroleum sector. The exact terms will nevertheless be subject to negotiation. The Russians are likely to insist that the international participants carry the bulk of the financial risk. A normal method of doing this would be to let StatoilHydro and Total carry (pay in advance) Gazprom's development costs and pay substantial royalties charged on top of ordinary income tax regardless of the financial position of the project. With such terms, StatoilHydro and Total are guaranteed the downside in the project. The question is whether that is balanced by a corresponding and credible upside.

The decision to give Gazprom-owned Sevmorneftegaz full control of the gas resources is usually referred to as an example of the resource nationalism widespread in producer countries outside the Opec area. In Russia, the starting point was a few oligarchs who had become billionaires in a very short time through unreasonably favourable deals. A key element in Putin's agenda, which Norwegians not least must respect, was precisely that the petroleum resources should benefit the Russian people. However, the problem in Russia and many other producer countries is that a nationalistic superstructure can hinder the foreign participation needed to maximise the value of the resources for the population at large. Ownership of and control over resources are the very core of resource nationalism. Politicians in Russia could not say to their people that part of the ownership or control had been transferred to foreign companies, even though this might be just what is required by pragmatic prosperity considerations.

An article in Norwegian technical weekly *Teknisk Ukeblad* of 21 November 2007 notes that Russian legislation hinders reserves being booked on the balance sheet, and that the Russians are unlikely to amend the law simply to please the shareholders of StatoilHydro or Total. Pursuant to Russian law, Gazprom has the sole right to sell gas from Russia. This provision must be changed if StatoilHydro is to be able to carry reserves from Shtokman on its books. Such an amendment must be submitted to the Duma (parliament), says third secretary Alexey Rybkin at the Russian embassy in Norway. The accounting rules are probably being interpreted too narrowly in this case. If StatoilHydro and Total, through their participation in Shtokman, secure rights to some of the production (because cost reimbursement and profits are paid in the form of gas), they can recognise the reserves even without direct ownership. This is the approach taken by StatoilHydro in Iran. What may be a bigger challenge is that resource nationalism has proved to encourage a number of populist decisions – typically a failure to respect signed agreements – which benefit neither the oil companies nor the population of the host country in the long run. In Russia, for instance, this could take the form of renegotiating terms if the project goes well and StatoilHydro and Total make money. The same willingness to renegotiate cannot be expected if project progress is poor and the companies suffer losses. An asymmetry of this kind in frame conditions clearly represents poor business economics.

"When presenting the interim figures, [StatoilHydro CEO] Lund said that the Shtokman partnership had to be viewed in a strategic light, both because Russia is an interesting country for StatoilHydro and because the company will get the opportunity to continue the development of technology for Arctic regions."[6]

"We hope that more opportunities will open for us through this innovative contract and the special connections we have with Gazprom,"[7] said Arnaud

[6] DN.no, 27 February.
[7] DN.no, 19 March.

Breuillac, the man responsible for Total's projects in central Europe and the Asian mainland.

The word "strategic" is often used by chief executives in connection with projects which do not satisfy their company's general internal rate of return requirements. In such cases, the investment decision is based on an assessment of supplementary value, which is often relatively subjective. An example is that moving into a new area can generate additional opportunities (bridgehead investment – growth options).

Since the merger, StatoilHydro has inherited the reserve replacement challenges which faced Hydro as a separate enterprise. Like virtually all the international oil companies, it is accordingly under pressure to secure new resources. With today's record oil prices, a danger exists that future production will be purchased at an excessive price. StatoilHydro has a balanced portfolio, where activities are spread over a number of fields in many producer countries. It has a high weighting of projects with low country risk – typically in the OECD area. This also goes for new projects. Nevertheless, it is uncertain whether increasing exposure to Shtokman makes sense in portfolio terms (risk spreading). Excessive exposure to a single project will normally be undesirable, and Russia poses a substantial country risk. Other oil companies have had their assets in Russia confiscated with little compensation, and it is difficult to find examples of oil companies who have actually made money there. The tax system is unpredictable, including uncoordinated taxation at several levels, and demands can be made to sell part of the production locally at below international market price. In addition, main partner Gazprom – with the Russian state as its principal shareholder – is used as a political instrument. That said, the risk must be measured against the alternatives in other producer countries, which are not necessarily better. Account must also be taken of the fact that the renegotiated tax agreements in Russia were not initially framed in an optimum manner from the perspective of the Russian government. Among other facts, they were drawn up at a time when the Russian state had been weakened. The oil companies should have expected a re-negotiation. Putin has also done a good deal to improve predictability in Russia, partly through greater centralisation of resource taxation.

According to press reports, Total will pay USD 800 million simply for the right to *book* reserves for Shtokman. If this is correct, the Russians have understood the oil companies' need to carry reserves on their books and they have charged separately for this. StatoilHydro, on the other hand, is not paying anything at present. Assuming that the company has had a genuine choice in this respect, the decision to pass on recognising reserves appears basically sensible[8]. The different strategies pursued by the two companies relate to their need to make themselves attractive to investors. All companies want to present accounts which ensure the highest possible market valuation. When Total pays USD 800 million for its 25 per cent of the Shtokman development company, the aim is to be able to book reserves for the field. StatoilHydro will not be able to carry corresponding reserves on its balance sheet, since it has not paid anything. But the booked reserves have no intrinsic value. Total and StatoilHydro will have the same cash flow from operation of the field. According to press reports, Total has thereby paid a substantial sum in order to improve its balance sheet – assuming that these reports are correct. The consequence is that the cash flow to Total shareholders will be weakened. StatoilHydro's shareholders are in the opposite position. Since the company has paid nothing in advance, net cash flow will be higher. But it must also live with lower booked reserves. However, it remains unclear how differences in payment could produce different rights for booking reserves – and how this relates to the relevant accounting rules. Will Total own reserves in the usual way as well as owning part of the development company? Will it acquire different rights from Statoil? Will it receive payment in a different way? The companies have not been allowed to make any further comments on the terms. Nor have the final frame conditions been established. Negotiations on actual participation in the Shtokman project took no less than 18 years. Lund told *Dagens Næringsliv* on 29

[8] However, reports concerning the recognition of reserves in the field are conflicting. Oslo business daily *Dagens Næringsliv* reported on 10 January that StatoilHydro may be able to carry these reserves regardless.

October 2007 that what has been concluded so far is a commercial frame agreement, and that he would provide more details in 2009[9]. Nor will the last word be said in 2009 – continuous renegotiation seems to be the guiding principle of Russia's petroleum administration. Moscow chief Hansen told the *Stavanger Aftenblad* daily that a bonus is to be paid in 2009 to participate in the project and that this represents the point when the investment decision will be taken[10]. Experienced industry sources say that Total is a highly competent international player, and that the USD 800 million it has paid is probably not solely for the right to carry reserves but more of a regular signature bonus – and as such not particularly surprising. However, it is not entirely normal to begin conceptual studies for developing a field before the frame conditions have been settled. The impression one gets is that Total is in the driving seat for these studies. Is this a reflection of the fact that it has already paid a signature bonus, or the result of pure expertise considerations? Whatever the answer, it is a matter of concern if the two international participants in the field do not obtain the same incentive structure. During the award phase, the Russians demonstrated to the full that they are applying the principle of divide and rule. The question is whether they understand that running a licence in this way will be inappropriate once the award has been made. Have they grasped that constant renegotiation weakens incentives for the companies to make a long-term commitment to optimising value creation from the field?

4. Peregrino

Is StatoilHydro reserve-driven? Hydro's poor reserve replacement rate is also making its mark on the merged company – proven reserves at 31 December 2007 were 6 010 million boe, compared with 6 101 million a year earlier. That represents a decline of 91 million boe. Reserves in 2007 grew by 542 million boe through revisions, extensions/expansions and new discoveries, compared with a

[9] http://www.dn.no/energi/article1214983.ece
[10] http://web3.aftenbladet.no/innenriks/okonomi/article536237.ece

growth of 383 million in 2006 from the same sources. The reserve replacement rate was 86 per cent in 2007, compared with 61 per cent in 2006, while the average three-year replacement rate – including the effect of sales and acquisitions – was 81 per cent at 31 December 2007 compared with 76 per cent at the end of 2006[11].

Does this put the company under pressure to obtain reserves quickly? Securing reserves through exploration is a time-consuming process and would not help to alleviate the acute reserve problem. However, the company has an active exploration programme which is likely to contribute future additions to reserves. The short-term problem is that today's price level means reserves are very much a seller's market. By acquiring a 50 per cent holding in Brazil's Peregrino heavy oil field this March, the company will – according to certain analysts – be able to report a reserve replacement rate of more than 100 per cent for 2008. But little is certain. Statoil learnt that when it had to write down its reserves in Ireland, as did Hydro when it wrote down the Spinnaker acquisition in the Gulf of Mexico.

With reference to the Peregrino acquisition, oil commentator Arnt Even Bøe wrote in *Stavanger Aftenblad* on 5 March that StatoilHydro used to discover oil fields but is now buying them up – while prices are at a peak. According to Bøe, proper oil companies find their own reserves. However, he added that the acquisitions also contain a number of bright spots. According to StatoilHydro, experience off Norway with the Grane heavy oil field and drilling on Troll could provide a substantial increase in Peregrino's recovery factor. In addition come strategic considerations such as strengthening the company's core areas and securing the operatorship for the production phase. StatoilHydro was originally operator only for the development stage, with Anadarko due to take over once production began.

Many people would agree with Bøe that a long-term and sustainable oil company will primarily find oil through its own exploration efforts. This is where

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11 http://www.statoilhydro.com/no/InvestorCentre/results/QuarterlyResults/Pages/FourthQuarter2007.aspx

the greatest value creation occurs. Farming in and out of licences can be a favourable supplementary activity, but must then be counter-cyclical (buy cheap and sell expensive) rather than pro-cyclical. But determining whether the oil price is high or low can be difficult. It is not many years since oil cost USD 50 per barrel, and many people would have said at the time that this represented a peak. Over time, prices will bear a certain relationship to marginal costs, and these have been rising sharply in recent years. (But a large part of these cost increases, such as the tripling of rig rates, is reversible. Ordering of new rigs has hit record levels.) However, most market analysts would maintain that the current price level of more than USD 100 per barrel is difficult to explain on the basis of fundamental market conditions, and that a downturn is more likely than not.

To make money farming into licences at a time when oil prices are high, the company must be able to estimate reserves better than the seller or to develop and operate the field more efficiently. StatoilHydro has very extensive exploration operations both in Norway and abroad, and is likely to replace reserves by its own efforts over time. But the company faces a short-term problem with reserves. The question is then whether to bide one's time or make acquisitions. Virtually all the international oil companies are in the same boat after cutting back their exploration operations in the 1990s and also experiencing poor drilling results.

A good deal of information about the Peregrino acquisition is provided in a stock market announcement from StatoilHydro on 5 March 2008[12]. Expected reserves from this big heavy oil field are estimated at about 500 million barrels, excluding upsides. Production is scheduled to begin in 2010 and to provide StatoilHydro with additional output in the order of 100 000 barrels per day. The company already had a 50 per cent holding in the field, which lies off Rio de Janeiro, and now becomes the sole licensee. StatoilHydro reports that the Peregrino project can cope with an oil price of less than USD 50 per barrel. At the same time, the purchase contract has a clause worth recognising. StatoilHydro is paying

[12] This can be accessed at the company's website. See http://www.statoilhydro.com/en/NewsAndMedia/News/2008/Pages/Peregrino4March.aspx

NOK 9 billion for the share of Peregrino and 25 per cent of the deepwater Kaskida discovery in the Gulf of Mexico[13]. A possible additional compensation of up to NOK 1.5 billion may be paid for Peregrino if future oil prices are above predefined levels up to 2020. This shares the risk between buyer and seller. StatoilHydro has clearly hedged the downside through this agreement, but also appears to have ceded a substantial part of the upside.

The average price paid for proven and probable reserves in the international oil industry was USD 4.67 per boe in 2007, down from USD 5.18 in 2006[14]. Higher oil prices have been more than offset by cost and tax increases. In an interview with *Dagens Næringsliv* on 4 March 2008, share analyst Gudmund Hille Isfeldt in DnB Nor Markets estimated that StatoilHydro is paying USD 1.4 billion for Peregrino, plus an optional USD 300 million from 2010 to 2020 depending on oil price trends. USD 1.4 billion translates into a price of USD 5.60 per barrel, excluding the USD 300 million related to oil prices in the production period. Isfeldt added that the price per barrel becomes substantially lower when the upside in the reserves is taken into account.

Two aspects are of particular interest for a closer look:

1) After the acquisition, StatoilHydro will be the sole licensee.

Normal practice is for international oil companies to hold licences through joint ventures with each other. The advantages relate partly to operations and partly to risk sharing. More participants in a licence provide access to a wider range of expertise, and the companies can jointly arrive at optimum technical and commercial decisions. This also permits the sharing of project-specific risks, which can often be substantial – such as cost overruns and surprises related to the reservoir and production. It is accordingly unusual to be the sole licensee of a field of this size. The risk will quite simply be too large. An explanation for the acquisition could be that an increased holding provides greater potential for carrying reserves on the

[13] The latter acquisition was subject to approval by the other partners in the licence and has been turned down. This promising equity position is instead taken over by the partners.

balance sheet. Another possible reason could be differences of opinion over the way the field should be developed. StatoilHydro has ambitions of achieving a higher recovery factor than would have been the case with the original plans, which also calls for much larger investment. The opportunity to bring in other licensees at a later date will nevertheless remain open, subject to approval by the authorities.

2) The payment for the licence transfer is a function of the future oil price.

The settlement for the licence share takes the form of a fixed amount plus a possible supplementary compensation of up to NOK 1.5 billion if future oil prices rise above predefined levels by 2010. Tying payments to future oil prices might be regarded as risk hedging at project level. StatoilHydro reduces the amount it has to pay today in exchange for ceding part of the future upside in the project. However, risk hedging at project level would not be recommended on the basis of economic research. What means something to the owners of a company is its aggregate risk profile. Risk management should accordingly be based exclusively on assessments of the risk exposure of the company's overall portfolio. Since individual company projects will have risk profiles which cancel each other out to some extent, hedging need only be considered for part of the residual risk. If the company hedges at a lower level, such as a project, overall risk management could become excessive. This will lead in turn to sub-optimisation, and contribute in part to excessive transaction costs for hedging. It is otherwise also the case that investors who buy oil shares are precisely seeking to include oil price risk in their portfolio, and will react negatively if profits fail to grow sufficiently in line with rising oil prices. The possible unfortunate effects of the risk-sharing agreement on Peregrino – such as results failing to improve sufficiently as the price of oil increases – could however be reversed through the company's general risk management. One option would be transactions in the forward market. But this illustrates precisely the point that conducting risk management at two levels is pointless.

[14] This emerges from a survey conducted by analysis company John S Herold and Standard Chartered Bank. See www.dn.no for 11 March 2008.

However, the agreement terms need not have anything to do with risk sharing. Licence farm-ins occur internationally where the settlement is conditional on specific outcomes (such as a specified level of oil prices). An optimum solution for two parties who take different views of the future could be to conclude such agreements[15]. If that is the case, it means that Anadarko has a more positive view of oil price trends than StatoilHydro.

The stock market announcement specified repeatedly that the acquisition was *strategic*. If this also means *expensive*, as experience would suggest, it could be appropriate to take a closer look at the agreed payment mechanism[16]. In addition to the fixed settlement, StatoilHydro has given Anadarko an option conditional on the price of oil. Whether that is the intention, this helps to camouflage the real breakeven price. Given the limited information provided, it is impossible to calculate the value of this option. At first glance, the acquisition looks cheaper than it actually is and people refer to a breakeven price of roughly USD 50 per barrel. The option payment must be added if the true breakeven price is to be identified. To achieve comparability with light oil projects – such as developments on the NCS – the spread between light and heavy oil must also be taken into account. The oil prices referred to in the press, Brent Blend and West Texas Intermediate (WTI), relate to light oil. At a press conference held after the acquisition, it was explained that the breakeven price of USD 50 cited by StatoilHydro for a heavy oil project referred to the Brent Blend reference crude, so comparability is maintained.

Heavy oil is priced considerably lower than light crudes, not least because of scarce refining capacity. Price trends for heavy crude could improve were capacity to be built up in the refining sector, but the development of a growing volume of heavy oil reserves has prompted doubts among analysts about the progress of heavy crude prices. Today's spread between heavy and light oils is said to be

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[15] Buyer and seller could achieve the same effect to some extent by taking positions in the forward oil market.

USD 15-25 per barrel. Another specific project off Brazil operates with a spread of USD 23 per barrel. In other words, this amount must be deducted from quoted Brent Blend and WTI prices to find the heavy oil price.

The discount on various oil grades depends on the supply and demand of a given grade and how many potential buyers can handle heavier oils. Where heavy crude is concerned, the discount will depend on how heavy it is, often expressed as degrees API, as well as on other factors such as its viscosity, how complex it is to refine, whether it could be blended with lighter oils to permit refining and so forth. Rather than a *single* spread, a whole range of prices exist. According to industry specialists, the Peregrino oil has an API around 14, with an expected sales price 25 to 30 per cent lower than WTI.

It was Hydro which acquired the first 50 per cent of Peregrino (then called Chinook) for USD 350 million from Canada's EnCana in 2005. According to Isfeldt, StatoilHydro has paid USD 1.4 billion for the remaining 50 per cent plus an option of USD 300 million from 2010 to 2020, depending on oil price developments[17]. We are talking here of a virtual quadrupling over three years. An increased recovery factor and higher oil price expectations play a big part, and StatoilHydro has upgraded the expected reserves during the development phase. But it appears that a good deal of strategic value may also have been assigned to the actual operatorship.

When Hydro acquired 50 per cent of the BM-C-7 licence in 2005, the recovery factor for this heavy oil field was estimated at nine per cent. With today's reservoir development plan, which utilises water injection and rock compaction, the estimated recovery factor has risen to about 20 per cent. That means estimated recoverable reserves have more than doubled[18]. When valuing this expansion, ac-

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[16] However, strategic considerations are not necessarily wrong – if the next steps are clearly profitable, they can justify the entry price. But even oil can be bought at too high a price.

[17] http://www.dn.no/energi/article1328359.ece

[18] See http://www.statoilhydro.com/en/NewsAndMedia/News/2007/Pages/PeregrinoOperatorship.aspx

count must also be taken of the fact that increased reservoir utilisation has a substantial cost side. When assessing the value of reserves today compared with earlier valuations, it is important to determine whether the upgrades are based on new reservoir information. That appears to be only partly the case. The stock market announcement states that the potential supplementary resources are indicated by three-dimensional seismic surveys and have been partly proven by drilling a new well (3-PRG-0001-RSJ) in 2007. It also states that further appraisal wells will be needed to confirm remaining upsides in the south-western and southern extensions of the field.

The number of wells to be drilled and their spatial positioning – the well network – are of great significance for the recovery factor. But reservoir properties also mean a lot – the size of the residual oil saturation behind a water front, for instance. This can be difficult to estimate without a production history and measurements.

Historical experience in the oil industry indicates that oil companies over-invest when crude prices are high, and are therefore cautious about expressing high breakeven prices for new projects. At the same time, they need additional reserves – which place them in a dilemma. StatoilHydro is in good company here, along with virtually all the major international oil companies. A possible solution is optimistic cost and reserve estimates. The latter incorporate various growth options in the form of improved recovery from the main reservoir and supplementary resources. StatoilHydro is far more optimistic for Peregrino in this respect than was Anadarko (and all other potential bidders), and this undoubtedly represents part of the basis for the transaction. On the other hand, the company is also highly competent in getting a lot out of fields. The recovery factor on the NCS is the highest in the world. However, sub-surface experts are doubtful about how much of this high NCS recovery should be attributed to advantageous natural conditions and how much to expertise. It has been claimed, for instance, that seawater injection in Ekofisk has not only hindered seabed subsidence but also affected the wettability of the chalk in a more water-wetting direction, and thereby improved recovery. Furthermore, it has transpired that a number of the large Norwegian sandstone reservoirs have a naturally mixed wettability, ensuring a very high recovery factor through water injection or natural water drive from the underlying aquifer.

5. Conclusion

International oil companies face problems replacing reserves through their own exploration and development activities. Reasons for this include a reduced exploration commitment in the 1990s, fewer large discoveries and reduced access to oil fields in regions with large resources[19]. Efforts are being made to compensate for replacement challenges through extensive purchasing of reserves. The danger is that such acquisitions are made at a high price. Sharply rising costs in the oil companies could represent a substantial challenge if oil prices decline significantly. A focus on reserves and volume could then be at the expense of profitability. This is a normal condition for the industry, which has historically overinvested when oil prices were high. It represents a problem in today's circumstances if normal conditions continue to prevail for the oil market – namely, cyclical fluctuations in the oil price, which has a normal level substantially below current spot prices. However, many market players argue that the strong growth in demand for petroleum and the substantial problems faced in replacing reserves have resulted in a permanent upward shift in the oil price. A number of serious players go so far as to say that the cost of crude cannot fall below the present level. We have nothing to guide us here, so that remains to be seen.

A number of producer countries – typically those with the biggest resources – are not prepared to cede ownership or control over their petroleum to foreign companies. This creates challenges for gross value creation, since control of resources is often closely related to incentives for maximising the value of reserves. It also limits opportunities for the international companies in these countries. However, there should be scope for establishing synthetic incentives which

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[19] On the other hand, access to gas is simpler.

imitate to some extent those provided by normal licence terms. Both oil companies and producer countries stand to benefit from such a solution.

This article has reviewed two cases involving StatoilHydro: the Shtokman field off Russia and Brazil's Peregrino discovery. StatoilHydro has manoeuvred itself in a competent manner into key positions in Russia and Brazil, which are clearly among the most promising producer nations in coming years. The company has established a close collaboration with Gazprom and Petrobras, and has acquired promising licences in these two countries. Since Shtokman and Peregrino will absorb big personnel and capital resources, however, they cannot simply be assessed on the basis of the strategic opportunities which they could open for further growth. They must also deliver in relation to StatoilHydro's on-going value creation. Analysts and the stock market have been lukewarm or negative to Shtokman and positive to Peregrino.

The problem with buying reserves in other countries is that one typically bids against companies with experience from the area (asymmetric information). One can then end up suffering the winner's curse – paying above the true value. StatoilHydro has had some experiences of that kind. The opposite position prevailed in the Peregrino licence, however, in that StatoilHydro already had a 50 per cent holding. This was perhaps part of the reason why the company wanted to become the sole licensee, which is unusual for such a large field. Ceding part of the upside to the seller through an option related to the sale is unfortunate from the shareholders' perspective. On the other hand, StatoilHydro has acquired an operatorship where it can utilise its experience and expertise from similar developments. If the company succeeds in achieving high reservoir utilisation, as it has managed on the NCS, the investment will still provide an upside providing costs are kept under control. It could then also represent an important reference project for the company, which could make it easier to acquire other reserves. However, high reservoir utilisation calls for a lot of drilling, and rig rates are exceedingly high today. But it is possible that the substantial volume in the field could justify this. A high spread between light and heavy crude prices as well as special costs associated with recovering heavy oil could represent challenges for project economics. A good deal of environment-related uncertainty also attaches to heavy oil projects.

A way of overcoming the problem presented by asymmetric information when bidding for reserves would be to specialise in specific geographic areas and geological structures. That avoids having to bid constantly against companies who know more than oneself. Other considerations also favour a concentration, such as becoming familiar with regulations and their enforcement and establishing relations with the supplies industry. StatoilHydro has had a system of geographic core areas, but this does not always appear to have been effective in limiting the spread of activities.

Where Shtokman is concerned, StatoilHydro has entered into a contractor contract where its payment appears on paper to comprise a regulated maximum return for leasing production equipment over a 25-year period. This type of deal is more suitable for contractor companies. Its remuneration profile is not what investors in oil companies are looking for – namely, a cash flow which varies with production and gas prices. In addition to the long payback period in a country with substantial political risk, a substantial downside risk probably exists in relation to delays and overruns. Basically, there does not appear to be an upside which can compensate for the downside in the project. However, the commercial terms are still subject to negotiation, and efforts are being made to introduce synthetic incentives to the contract which will give StatoilHydro an upside related to the development of gas prices and produced gas volumes. If such terms cannot be incorporated in a credible way (through having the contract refer to *international* gas prices, for instance), it is difficult to see why StatoilHydro should want to give final consent to the agreement in 2009. The Shtokman involvement will lay claim to many competent people in a period when expertise is in short supply, and will also call for very substantial capital outlays. These aspects must be balanced against corresponding upside opportunities. Compared with Total, StatoilHydro may have a strategic advantage in the final negotiation since it has not paid a signature bonus yet. Ultimately, however, both companies are dependent on the Russians sticking to their agreements. That does not appear to have been the case so far, but the Russians are in good company with other producer countries in this respect.

The Russian authorities have so far had the advantage that the oil companies, in their hunt for reserves, have been queuing up to develop fields in Russia. As experienced negotiators, they have also organised the playing field in such a way that the foreigners are pushing hardest for an agreement. However, negative experiences for foreign oil companies in Russian have shortened the queue to some extent. Moreover, plans and milestones for the Shtokman development now appear to have been established. It would not look so good for the Russians if StatoilHydro were to jump ship in 2009, which could give the latter a certain negotiating strength. This is the type of raw bargaining power which the Russians seem to understand. However, it remains unclear whether they fully comprehend that an agreement which provides StatoilHydro and Total with sufficient upside is necessary to harmonise their goals with those of the Russian authorities in order to achieve the largest possible value creation from the field. The willingness of the Russians to observe agreements is also questionable. As a result, it may be simpler in today’s circumstances for the supplier companies to make money in Russia since they are paid on a continuous basis and can pull out should payment fail to be made. That will not be an option for StatoilHydro or Total once they have locked many billions of kroner into irreversible infrastructure investments.

While StatoilHydro can recognise booked reserves in Peregrino quickly, how far it will be able to do so with Shtokman remains an open question. Recognising reserves in the field will be possible in formal terms, and the Russian authorities would have nothing to lose from foreign companies doing so. Any barrier to recognising reserves would be raised by resource nationalism, but it is hard to believe that such considerations would be stronger in Russia than in Iran. In any event, Shtokman cannot relieve reserve replacement challenges in the short term, since it is unlikely that the field can be booked as reserves for many years because technological, legal and financial conditions have yet to be clarified.

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