

The Sakhalin II PSA – a Production ‘Non-Sharing’ Agreement

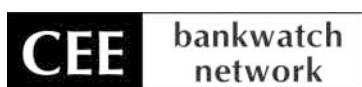
Analysis of Revenue Distribution

Dr Ian Rutledge

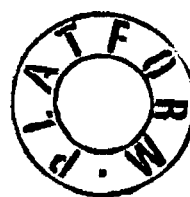


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A Report for:



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About the author

Dr Ian Rutledge graduated in Economics at the University of Cambridge in 1968, and gained a PhD in Economic History in 1973. Between 1985 and 2003 he taught Energy Economics on the Sheffield University MA/Msc Energy Studies Program where he delivered the module on Petroleum Fiscal Regimes. Rutledge's recent academic publications include articles in the *Cambridge Journal of Economics*, *Economia e Politica Industriale* (Milan) and the *Journal of Energy Literature*. He is a member of the British Institute for Energy Economics and the International Association for Energy Economics. Since 1989 Rutledge has been a Partner in SERIS (Sheffield Energy & Resources Information Services). SERIS' services have been utilised worldwide, not only in the corporate sector but also in government and non-governmental organisations. To date, those services have been provided to clients in the UK, France, Czech Republic, Canada, Cuba, Colombia and Venezuela.

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By

Dr Ian Rutledge



Sheffield Energy & Resources Information Services (SERIS)

November 2004

www.seris.co.uk
info@seris.co.uk

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Contents

Executive summary	3
Glossary	6
1. The correct method of measuring the benefits from Sakhalin II	7
2. Background: Sakhalin oil and gas projects and their reserves	9
3. Description of the project	11
4. Origins of the Sakhalin II Production Sharing Agreement	12
5. General features of 'standard' PSAs	13
6. The key feature of the Sakhalin II PSA	15
7. Other features of the Sakhalin II PSA	17
8. Economic analysis of Phase One	19
9. Economic analysis of total Sakhalin II benefits to the Russian Party	22
10. Distribution of the Russian Party's benefits between the Russian Federation and Sakhalin Oblast	25
APPENDIX 1 – Hypothetical Example of the FANCP methodology	26
APPENDIX 2 – Analysis of impact of the FANCP methodology on hypothetical oil and gas project	27
APPENDIX 3 – Allowable recoverable expenditure categories under the Sakhalin II PSA	29
APPENDIX 4 – Explanation of Net Present Value (NPV) and Internal Rate of Return (IRR)	31
APPENDIX 5 – Basic methodology of the SERIS Model	33
References	34

Executive Summary

This report analyses the revenue distribution of the Sakhalin II oil and gas project in Russia's Far East. The project is being developed by Sakhalin Energy Investment Company (SEIC), a consortium consisting of Shell, Mitsui and Mitsubishi.

The distribution of revenues between the consortium and the Russian government is defined in the Production Sharing Agreement (PSA), signed in June 1994 by SEIC and the Russian Federation.

PSAs are a common contractual mechanism, used throughout the oil-producing world. It is not the role of this report to discuss the pros and cons of PSAs in general. It is noted though that for this particular high-cost, high-risk project, it is unlikely that the SEIC consortium would have proceeded with the project without the fiscal stability that a PSA confers.

However, the particular terms of the Sakhalin II PSA are not typical of those incorporated in most PSAs throughout the world. The Sakhalin II PSA is particularly disadvantageous to the Russian Party, and it is surprising that the Russian Party agreed to these terms.

RISK CARRIED BY RUSSIAN STATE; COMPANY PROFITS ASSURED

- It is a central feature of typical Production Sharing Agreements that the oil company undertakes its investment *at its own risk*. In the event that fewer hydrocarbons are found than expected, that greater investment is required or that the oil or gas price falls substantially, the oil company makes a lower rate of return. These risks are the price that is normally accepted for the prospect of making considerable profits if things go as planned (or indeed, better).
- However, in the case of Sakhalin II, most of the risk is instead carried by the Russian state. Since the oil and gas fields had already been discovered by Russian companies before the PSA was signed, exploration risk was already removed from the outset. Moreover, by radically altering the standard PSA mechanism, SEIC has also transferred most of the risks of both construction overspend and change in the oil / gas price to the Russian government.
- It is usual in PSAs that the majority of the income (not usually all) from the first few years of production ('cost oil') is used to recoup investment costs; once they have been covered, the remaining production ('profit oil') is divided between the host country and the foreign oil company, in agreed proportions.

- In marked contrast, in Sakhalin II, the Russian government only starts receiving its share of extracted oil revenues once SEIC has recovered both its costs AND a 17.5% real rate of return. Even after this point, the Russian government receives only 10% of the revenues for two years, and then 50% until SEIC has achieved a 24% real rate of return. Only after that does the distribution adjust to give the Russian government the long-term rate of 70%.
- As a result, the Russian government only receives any share of the revenues (the 'available hydrocarbons') after SEIC's profit is assured. Furthermore, as a result, the economic impact of any cost over-run is felt primarily as a loss of income to the state, rather than as a loss of profits to the consortium. This is of particular concern, given that in summer 2004 SEIC announced a cost increase on the project, reported to be from \$10 billion to \$12 billion.
- In fact, during the operational phase of the project, SEIC could choose to invest more capital (for example, expanding by adding another LNG train), thereby continuing to deny the Russian state its share of hydrocarbons, which are only obtained after a return on invested capital has been achieved.

OTHER UNFAVOURABLE FEATURES OF THE PSA

- The duration of the Sakhalin II PSA contract is indeterminate. The initial phase is set at 25 years, but the PSA contains the proviso that should the SEIC consider further exploitation of the fields to be 'economically practicable' it can renew the licence, without any changes in the PSA terms, for a further five years, followed by a further five years *ad infinitum*. Such an indeterminate contract length has more in common with the 'oil concessions' agreed by Middle East rulers at the beginning of the 20th century than with a modern, standard PSA.
- The royalty payable to the Russian government on volumes of oil extracted is low by international standards, at just 6%. Among the countries which use PSAs and where the field size and production levels are comparable to those in Sakhalin, royalty rates generally fall within the range 10% - 20%.
- The profit tax (32%) is lower than the standard Russian national rate at the time of the PSA signing (35%).
- There is no annual 'cost cap' as is usual in a PSA. Nor is there a statement of costs which are not eligible for recovery (as is frequently the case in PSAs): in short, the SEIC is free to charge almost anything it wishes in the concept of 'recoverable costs'.

Table:
Economic Analysis of Sakhalin II (Phases 1 plus 2) using three oil/gas price scenarios

	A: 'SEIC investment plan scenario' oil price: \$24/b; gas price: \$3.83/MMBTU	B: 'Base Case' IEA oil price scenario; \$4.40/MMBTU	C: 'Continued high oil price scenario' \$43/b; \$6.86/MMBTU
Project IRR	17.3%	20.7%	28.3%
Project NPV	\$1,751m	\$3,011m	\$7,282m
Company NPV	\$299m	\$1,179m	\$2,637m
Company IRR	13.1%	16.1%	20.7%
State Share of Available Hydrocarbons	0%	0%	19%
State NPV	\$1,452m	\$1,833m	\$4,645m
State Take of Project NPV	83%	61%	64%

The profitability of projects such as Sakhalin II is generally assessed using two measures (both used to take account of the fact that the value of any income depends on when in the life of the project it is received, as income early income can be invested and grow):

- The **net present value (NPV)** is a measure of the total profit received, but converted ('discounted') into the equivalent value as if it were all received at the start of the project.
- The **internal rate of return (IRR)** is a measure of the annual percentage return on capital (ie the amount of profits for each dollar invested). This should be compared with the cost of capital (roughly speaking, what it costs to borrow money – through interest payments and payments to equity investors) plus a risk premium, which combined are generally around 12-15%. If the IRR is higher than the cost of capital, then the project is profitable (and the higher the IRR, the more profitable). If the IRR is lower than the cost of capital, it is not profitable.

The table above shows these both for the project as a whole, and how they are divided between company and state

RUSSIA'S LOW SHARE OF INCOME – OVER-STATED BY CONSORTIUM

- In calculating the total fiscal benefit which the project will bring to the Russian Party (\$45.2 bn), the SEIC simply adds together the amounts to be received in each year of the project (in 'Money of the Day'). No oil company would measure its own cash flow or profits in this manner, as it ignores the fact that for a long-lifetime project, income is worth far more early in the project than later (as it can be invested and grow).
- The correct method of measuring the economic benefits is by establishing the discounted Net Present Value (NPV) of the project (also called the 'Economic Rent'). This is effectively the equivalent income that would be received, were it all to accrue at the start of the project. When this is done, the NPV for the state, over a 25-year project lifetime, is \$1.8 bn (See the 'Base Case' below).
- Employing three different oil/gas price scenarios and a 12% (real) discount rate, we find the benefits to the companies and to the state over a 25 year project lifetime to be as follows:

- In the 'Base Case' the share of the 'Profit Oil' received by the state is zero. Even in the 'high price' scenario, the share is only 19%, which is remarkably low. Given this outcome of the PSA it would be better to describe it as a 'Production Non-Sharing Agreement'.

The terms of the Sakhalin II PSA are a major departure from standard PSA terms worldwide and are losing Russia considerable amounts income.

- The benefits which flow to the Russian Party under the Sakhalin II PSA ('Base Case') fall a long way short of those which would have been received had a 'standard' type PSA been used (with the same 'Base Case' price scenario). Under a 'standard' type PSA (even a relatively weak one compared with many operational PSAs worldwide) the Russian Party would receive 45% more economic rent.
- Those benefits are also below those which would have been received had a Royalty plus Profits Tax regime been used, although this is of course contingent on the actual size of the royalty and tax rates. The table below puts the Royalty + Profits Tax regime as worse than a 'standard' PSA; however in the model we used a single profits tax of 35% - whereas the current proposal in Russia is for a

Table:
Sakhalin II project benefits under three different fiscal regimes

	Sakhalin II PSA (Base Case)	'Standard' type PSA	Royalty and Profit Tax regime
Project IRR	20.7%	20.7%	20.7%
Project NPV	\$3,011m	\$3,011m	\$3,011m
Company NPV	\$1,179m	\$360.m	\$741.5m
Company IRR	16.1%	13.5%	14.7%
State Share of available hydrocarbons	0%	31%	n.a.
State NPV	\$1,833m	\$2,651m	\$2,270m
State Take of Project NPV	61%	87%	75%

Note: for details of the two alternative fiscal regimes used above see the text accompanying Report Table 6 (Page 23).

standard business / corporation tax of 24% on profits PLUS a special petroleum tax of up to 60% PLUS a royalty – as such, this type of regime could be made more favourable to Russia than a 'standard' PSA model, depending on the rates chosen, and the details of the mechanism.

It is perhaps unsurprising then that SEIC's Chief Executive Officer Stephen McVeigh has commented that the Sakhalin II project has the *"best PSA terms that you will ever get in Russia."* This is confirmed by Harvard Business School:

"The specific details of the Sakhalin II PSA were widely considered to be favourable for SEIC...the Sakhalin II agreement was designed to be attractive to the investors".

However, looking at it from the perspective of the Russian Party, the Sakhalin II PSA is an example of those so-called 'modern' petroleum fiscal regimes which the eminent petroleum law expert Professor Thomas Walde, has described as "fraught with risk" and which "may lose countries significant amounts of income."

CONCERNS FOR PROJECT LENDERS

Despite the heavy weighting of the PSA terms in favour of the SEIC, there are still questions over the project's viability for international finance, in light of the cost overruns. Our financial analysis shows that if the oil price returned to \$24/b – the value on which the project was apparently planned – the project's post-tax internal rate of return would fall to 13.1%. This is at the low end of most oil companies' threshold rates of return, and even our base case is subject to further downside should Shell continue to lose control of its costs.

Meanwhile, weakening market conditions are reflected in the fact that to date, SEIC has only signed contracts for about 35% of its planned supplies. Recently it was reported that Shell is now, in effect, planning to buy gas from itself, by building a regasification plant in Mexico from which it will pipe gas to California, a move which some observers might conclude is an act of desperation designed to make Sakhalin II more 'bankable' from the perspective of potential project finance.

TRANSITION IMPACT

These findings will also present further concerns to the European Bank for Reconstruction and Development. The key measure for EBRD of whether a project should receive financing is its transition impact – the impact on supporting a country's transition from former Soviet Bloc member to western market democracy.

The EBRD identified the key transition impact of Phase 1 of the Sakhalin II project (which EBRD financed) as: "to provide a demonstration effect, which will facilitate the implementation of an effective production-sharing framework in Russia."¹ That the PSA for this project is so unfavourable to Russia risks compromising the country's development prospects were future PSAs to follow a similar model; meanwhile its demonstration value is limited, given the instability inherent in an unfavourable deal.

¹ EBRD website, Project summary document, <http://www.ebrd.com/projects/psd/psd1997/3321.htm>

Glossary

\$/b:	US dollars per barrel (oil price)
\$/MMBTU:	US dollars per million British thermal units (gas price) (1 MMBTU is approximately the energy content of 1,000 cubic feet of natural gas)
ACRF:	Audit Chamber of the Russian Federation
API:	American Petroleum Institute (which publishes many of the standard specifications in the oil industry)
b/d:	barrels (of oil) per day
bcf:	billion cubic feet (of gas)
CEO:	Chief Executive Officer
CIF:	Cost, Insurance and Freight (a pricing term for commodities such as oil or LNG. For any oil or gas price, it must be specified whether it is FOB or CIF, and with reference to a particular location. CIF indicates that the exporter's price includes all charges up to the arrival of the goods at the point of discharge from the vessel including the cost of insuring them against loss or damage whilst in transit.)
EBRD:	European Bank for Reconstruction and Development (one of the core lender group for the Sakhalin II project)
FANCP:	First level of Accumulated Net Cash Proceeds (<i>see section 6</i>)
FOB:	Free On Board (A pricing term for commodities such as oil or LNG, indicating that the quoted price includes responsible for all costs (including loading costs) up to the point where the goods actually cross the ship's rail, at the specified place - see also CIF, above).
FOC:	foreign oil company
IEA:	International Energy Agency (an intergovernmental organisation, whose role is to ensure the energy security of industrialised nations; we use forecasts in its authoritative <i>World Energy Outlook</i>)
IRR:	Internal Rate of Return (a measure of the annual percentage return on capital (ie the amount of profits for each dollar invested). This should be compared with the cost of capital (roughly speaking, what it costs to borrow money – through interest payments and payments to equity investors) plus a risk premium, which combined are generally around 12-15%. If the IRR is higher than the cost of capital, then the project is profitable (and the higher the IRR, the more profitable). If the IRR is lower than the cost of capital, it is not profitable) (See chapter 1 and appendix 4)
LNG:	liquefied natural gas
Mb:	million barrels (of oil)
Mmcf/d:	million cubic feet (of gas) per day
NCF:	Net Cash Flow of project
NPV:	Net Present Value (a measure of the total profit received, but converted ('discounted') into the equivalent value as if it were all received at the start of the project – in order to take account of the fact that the value of any income depends on when in the life of the project it is received, as income early income can be invested and grow) (See chapter 1 and appendix 4)
PA:	the Piltun-Astokhskoye field (one of the two fields involved in the Sakhalin II project: PA contains primarily oil, while the other, Lunskeye, contains primarily gas)
SANCP:	Second level of Accumulated Net Cash Proceeds (<i>see section 6</i>)
SEC:	Securities and Exchange Commission (the US financial regulator. SEC publishes a set a standard rules for the accounting of company oil reserves)
SEIC:	Sakhalin Energy Investment Company (the consortium developing the Sakhalin II project, consisting of Shell, Mitsui and Mitsubishi)
PSA:	Production Sharing Agreement (the contractual mechanism defining the share of revenues between company and state of an oil or gas project)
TEPCO:	Tokyo Electric Power (one of the buyers of gas from the Sakhalin II project)

1. The correct method of measuring the benefits from Sakhalin II

Sakhalin Energy Investment Company (SEIC), the Shell-led consortium which is developing the Sakhalin II oil and gas project in Russia's far east, has recently launched what the *Financial Times* refers to as a 'Charm Offensive', to explain the benefits to Russia of the project (*Financial Times*, 2004a).

According to the SEIC's 32-page document, over the total lifetime of Sakhalin II the project will provide the Russian Party to the production sharing agreement with \$45.2 billion in royalties, profit taxes, special payments and the share of hydrocarbons to which the Russian Party is entitled (SEIC 2004a, p.12).

Since this announcement by SEIC is currently in the news and since the issues it raises have significant methodological implications for the remainder of our report, we shall address it first.

This figure of \$45.2 billion seems large and impressive – especially when the Russian party is told that it will get the money for nothing – “without their investment of one rouble”, according to SEIC's CEO Stephen McVeigh. (McVeigh, 2002).² In reality however **this figure has no real economic significance**, This is because it is simply calculated in terms of “Money of the Day”.³ (See SEIC, 2004b).

However it is axiomatic in any serious economic analysis of a project with a very long lifetime (such as this one) that **the flow of economic benefits is discounted to the start of the project** using an appropriate rate of interest. When this approach is taken, it soon becomes clear that project benefits which are received well into the future count much less than benefits which accrue earlier.

This is common sense (and is nothing to do with inflation): if the Sakhalin Oblast were to be offered £1 billion today or \$1 billion in 25 years time, we know very well which they would prefer – and the reason why: because they could immediately invest today's \$1 billion (either in financial or fixed assets) and in 25 years time have a capital sum worth many times the \$1 billion they might have chosen to receive at that future date.

(For a more detailed explanation of 'Discounting' and the related concepts of Net Present Value (NPV) and Internal Rate of Return (IRR) used in this report, see **APPENDIX 4**)

To give some idea of the impact of 'discounting', we can compare the SEIC's estimate of the cumulative amount of benefits to the Russian Party from Sakhalin II over 40 years in 'Money of the day' i.e. *without* discounting – \$45 billion – with the discounted Net Present Value (NPV) of those same benefits – \$7 billion.⁴

No oil company would consider calculating its cash flow or profits from an investment in the undiscounted mode. It is therefore misleading for the SEIC to present the benefits to the Russian Party in this manner.

In fact as we shall show, even on a discounted basis the SEIC's estimate of benefits to the Russian Party seem to be considerably exaggerated, probably because they are based on what are now out of date project cost estimates.

In fact, the impact of discounting is particularly severe where a project is subject to cost over-runs which postpone the arrival date of benefits. In 'Money of the Day' terms, it matters very little if there is a huge cost over-run and the commencement of a particular payment to the Russian Party is pushed back into the future – a dollar in 2022 is worth a dollar in 1997. Of course, in reality, *it matters a great deal* as we have seen and this is nothing to do with inflation but is a reflection of the time value of money in a capitalist economy.

Consequently in this report we focus on the following questions:

- What is the discounted value (Net Present Value) of benefits from the Sakhalin II project which will flow to the Russian Party, given the cost and production data already in the public domain, certain reasonable assumptions about the likely production profile of the project, a 12% interest rate and three different oil/gas price scenarios?

² McVeigh's implication that the financial benefits are 'cost free' to the Russian Party is incorrect for two reasons: first, the Russian party is depleting a non-renewable natural resource and thereby incurring a 'user cost', and secondly there may be considerable *external* costs to the Russian Party in the form of environmental losses.

³ It is not clear from the SEIC publications whether this 'Money of the Day' is after or before inflation. Since the benefits analysis is carried out in terms of a \$24 per barrel *constant* price, one might assume that the 'Money of the Day' is also in constant prices. If it is not, then our argument against using undiscounted values is all the stronger, because future benefits would now not only be given equal weight with near-term benefits, but those future benefits would actually be inflated via the falling value of money.

⁴ Assuming benefits to the state begin to flow in the fourth year of the project. The NPV of a hydrocarbon or mineral project is conventionally described as the 'Economic Rent' of the project. This rent is then divided between the two parties to the PSA.

- How do the terms of the Sakhalin II PSA compare with alternative 'petroleum fiscal regimes' which could have been adopted without prejudicing the project?
- What rate of profit (Internal Rate of Return) will the SEIC earn under different price scenarios and alternative petroleum fiscal regimes?
- What are the relative shares of the total Russian Party benefits which will accrue to the Russian Federation and Sakhalin Oblast respectively?

The considerations about discounting discussed above have also affected our views about how to construct the spreadsheet model which we shall use in the comparative financial analysis. We have decided to limit the analysis to the 25 years of the initial licence rather than continue for a further, and at present, unknown time period over which the project might eventually

extend. SEIC and other sources have variously talked of a total project lifetime of 30, 40 and 49 years. In reality it matters very little whether we choose 25 years or 49, because (a) in the later years, the project is producing fewer and fewer hydrocarbons as the reservoir pressures decline, and (b) the reduced revenues from these small quantities of hydrocarbons will now be so heavily discounted that they will amount to very little. For example, even if we assume an equal payment of, say, \$1 dollar per year over 40 years, discounted at 12% its present value today will only be 5.5% higher than it would be if we had finished counting at 25 years. Against this small discrepancy, using the 25 years of the licence has the advantage of precision and rules out guess work about the true size of the recoverable reserves and exactly how long they will actually last, a subject which – as we shall see – is by no means clear from the available public domain information.

2. Background: Sakhalin oil and gas projects and their reserves

Oil production on Sakhalin began at the Okha field in 1922. However, by the 1990s the Island was only producing around 30,000 barrels per day of onshore oil. Only the Mongi and Okha fields had a significant economic impact with most of Sakhalin's oil coming from a large number of very small fields. Oil was transported by pipeline across the north of the Island and under the sea to the mainland where it was subsequently piped to the region's two refineries at Komsomolsk-on-Amur and Khabarovsk. In addition a gas pipeline fed gas from the Okha fields to Komsomolsk.

At the beginning of the 1990s, proven and probable onshore oil reserves on Sakhalin were estimated to be around 225 Million barrels. Offshore oil reserves were estimated to be much larger but were less well evaluated. Total oil 'resources' offshore Sakhalin – in the Sea of Okhotsk – including the highly speculative 'potential' and 'hypothetical' categories, were estimated to be 5,850 Mb, and gas resources 135,610 billion cubic feet. These estimates relate to the year 1994, but according to the *Oil and Gas Journal*, by 1999 "it is unlikely to have changed much." (OGJ,1999 p.40).

During the late Soviet period, exploration drilling offshore, mainly by the Rosneft subsidiary, Sakhalinmorneftegaz, identified a number of potential oil and gas fields. Following the collapse of the Communist government and the break-up of the Soviet Union the offshore oil and gas deposits were grouped into six major project areas, eventually to be designated by the production sharing agreements (PSAs) which were signed or proposed for each area and numbered Sakhalin I through VI. The most detailed description of Sakhalin II reserves is provided by the following Russian source:

Turning to the SEIC's published figures for reserves, we encounter some considerable discrepancies in their published data. While most of their pronouncements agree on a figure of around 1,000 Mb for liquids, data disclosed for gas "reserves" vary between 14,000 Bcf given by W. Tudor Jones, Coordinating Manager for SEIC (OGJ,1999, p.44), 18,000 Bcf stated by Andrew Seck, SEIC PSA Affairs Manager, (CEPMLP, 2002) and a 20,000 Bcf figure given by CEO, Steve McVeigh (SEIC, 2002). And in a recent press release by Tokyo Electric Power (TEPCO) relating to the signing of Heads Of Agreement for gas supplies from Sakhalin II, a figure of 17,658 Bcf (500 BCM) is given (TEPCO, 2003).⁵

These differences are not insubstantial: for example at a price per million Btu of, say, \$4, the difference between Tudor Jones and McVeigh of 6,000 Bcf would be worth around \$24 billion!⁶ Perhaps there was some re-evaluation of the gas reserves between 1999 and 2001, but we are unaware of any published report to that effect and in any case McVeigh's figure of 20,000 Bcf for 2001 would be inconsistent with the lower figure given by TEPCO for 2003.

Given the highly publicised concern raised in 2004 over Shell's misstatement of its reserves in other operational regions, the absence of published reserves figures for Sakhalin in Shell's annual report might lead to further questions about the reliability of the reserves figures stated by Shell personnel in SEIC's publicity material and on its website.

Some grounds for concern are raised by the fact that McVeigh states that "the oil reserves equate to more than one year of crude oil exports from Russia at the current level of around 2.5 million barrels per day" (SEIC,

Table 1:
Sakhalin II oil and gas reserves

	Oil (Mb)	Condensate (Mb)	Total Liquids (Mb)	Gas (Bcf)
Piltun-Astokhskoye	660	100	760	6,463
Lunskoye	58.6	320	379	13,561
Total	718.3	420	1,139	20,024

Source: OAO Rosneft-Sakhalin Morneftegaz, *Development of the far eastern fuel and energy complex, Sakhalin I and Sakhalin II projects implementation*, May 1997 p.3. Original figures given in million tonnes of oil/condensate and billion cubic metres of gas converted into million barrels (1 tonne oil = 7.33 barrels; 1 tonne condensate = 10 barrels), and 1 billion cubic feet (1 cubic metre = 35.315 cubic feet).

⁵ Unfortunately, no light can be thrown on this issue by an inspection of the annual reports of the three companies currently making up the SEIC. As is well known, Shell, the operating company does not provide a geographical breakdown of its proven oil and gas reserves in the SEC reserves section of its Annual Reports other than 'Eastern Hemisphere' and 'Western Hemisphere', although more recently it disclosed a figure for its total Russian and Caspian reserves in the *Financial Times* (which is not much help and still doesn't identify the proven Sakhalin II reserves.) Neither of the two other partners in SEIC, Mitsui & Co and Mitsubishi Corporation publish SEC standard oil and gas reserve figures. For further clarification we requested a current estimate of Sakhalin II's proven oil and gas reserves from Dr Seck of SEIC, by email, but to date we have received no reply.

⁶ One million Btu (conventionally written MMBTU) is approximately the energy content of 1,000 cubic feet of natural gas.

2001) implying that the reserves are *all* economically recoverable. However, in the preceding sentence he describes his 1 billion barrels of liquids and 20,000 Bcf of gas as “in place reserves” studiously avoiding any mention of proven or proven-plus-probable reserves – the categories which would justify an expectation of economic recovery. The term ‘in place reserves’ is often employed to refer to an amount of hydrocarbons considerably larger than that which can be economically extracted and sold.

Clearly, this lack of clarity about the size of the economically recoverable reserves at Sakhalin II also implies uncertainty as to the expected lifetime of the project (which may explain the very different project lifetime figures given by different SEIC personnel). This reinforces our decision to base our own model on a 25 year project lifetime (the length of the initial licence) since we can, at least, be certain that, even using the smallest of the reserve estimates referred to above, they will not be depleted before then.

3. Description of the project

The Piltun-Astokhskoye (PA) field is an oil field with some associated gas production. It lies around 16 Km offshore the northeastern coast of Sakhalin Island in a relatively shallow water depth of between 26 and 33 metres. PA oil is a light, sweet crude with an API index of 36 degrees which should command a reasonably high price.

However, PA is situated in a region of the sea of Okhotsk which freezes over for half the year when pack ice forms between October and May and temperatures drop to as much as – 40 degrees centigrade – comparable with the North Slope of Alaska.

The Lunskeye field, 150 Km further south is outside the pack-ice zone. It is situated 13 Km offshore in 50 metres of water and is a large gas field with some associated condensate (a light oil) production.

The Sakhalin II project involves two phases. Phase One was to develop the Astokh feature of the PA field⁷ to ensure an early supply of oil, the cash flow from which would contribute towards SEIC's investment in the second, much larger phase of the project based on the Lunskeye field. This first phase also involved some appraisal work and general pre-development expenditure on Lunskeye. The nominal full-capacity production level of Phase One is 90,000 barrels per day (Thornton, 2000, p.9), but in practice, because it could only operate in ice-free conditions, its annualised production would only be half that – averaging 45,000 b/d or 16.4 Mb/year.

The total investment cost of Phase One was originally variously put at \$660 million (ACRF 2000, p.24), \$685 million according to the *Oil & Gas Journal* (OGJ, 19/7/1999, p.46) and \$780 million according to the EBRD (EBRD, 2004).⁸

Phase Two of the Sakhalin II project is a much larger project. A second drilling platform (Piltun-B, full capacity oil production 70,000 b/d and gas production 100 Mmcf/d) is planned to develop the remainder of the PA field, with an underwater pipeline transporting oil and gas to land. This enables PA to produce oil on a year-round basis. At the same time a drilling platform is planned at the Lunskeye field (full capacity gas production 1,800 Mmcf/d plus some condensate production) with its own underwater pipeline to Sakhalin Island where a gas receiving and conditioning plant is being built. A 800 Km gas and oil pipeline system will transport the hydrocarbons from both PA and Lunskeye fields to the south of the island where a huge liquefied natural gas

plant and oil export terminal is being constructed at Prigorodnoye. The LNG plant will be one of the largest in the world with two LNG 'trains' each capable of supplying 4.8 million tonnes of LNG per year for export by tanker to Asian markets and possibly to the west coast of the USA.

The cost of Phase Two was originally put at \$8 billion (OGJ, 2001, p.59), or \$8.5 billion (McVeigh 2002, p.2)

Ultimately the whole Sakhalin II project will be capable of producing (at full capacity) 60 Mb of liquids (oil and condensate) per year (164,000 b/d) and 9.6 million tonnes of LNG.

The original schedule for Sakhalin II was for initial oil production from Phase One (PA) to begin in mid-1999, all-year-round PA oil production "by the end of 2003" and the beginning of LNG deliveries "in the middle of 2005". (ACRF, 2000, p.25)

However, the project has been subject to considerable cost over-runs. By 2003, the actual Company expenditures on Phase One were already somewhere between \$1.6 billion (*Alexander's Gas & Oil Connections*, 2001; Harvard Business School, 2004, p.7) and \$2 billion (CEPMLP, 2002, p.5) – an overspend of more than \$800 million, largely due to some erroneous projections by SEIC.

As a result, the total project cost (Phase One plus Phase Two) has generally been stated since 2003 as \$10 billion. However, in summer 2004 it became clear that costs would be higher than this. According to leaked documents widely reported in the media, the revised projected investment for the total project is \$12 billion – reflecting a cost increase on Phase Two as well. We therefore use this investment cost in our model.

⁷ The Astokh feature would be developed by an oil producing complex called Vityaz comprising a fixed drilling platform (named Molikpaq) connected to a SALM Buoy, also fixed to the sea floor, from where oil is piped to a double-hulled Floating Storage and Offloading Vessel (FSO) (the Okha) capable of holding up to 1 million barrels of liquids. Using a floating offloading hose, the Okha would then supply oil to incoming oil export tankers for shipping to Asian oil markets.

⁸ It is possible that the EBRD figure includes the SEIC's \$100 million contribution to the Sakhalin Development Fund (see below)

4. Origins of the Sakhalin II Production Sharing Agreement

The Sakhalin II PSA was signed on 22 June 1994 between the Russian Party (the Russian Federation and the Sakhalin Oblast Administration) and the Sakhalin Energy Investment Company (SEIC), originally comprising the US companies Marathon Oil (30%) and McDermott (20%), together with Mitsui & Co. (20%), Royal Dutch/Shell Group (20%) and Mitsubishi Corporation (10%). It was the first PSA to be signed in Russia.

Subsequently, McDermott sold its 20% stake to the remaining shareholders on a pro-rata basis leaving the remaining four companies, of which Marathon Oil with the largest equity share (37.5%) remained the project operator. However in December 2000, Marathon left the project leaving Shell with 62.5%, Mitsui with 25% and Mitsubishi with 12.5%. Finally, a few days later, Shell sold part of its holding to Mitsubishi leaving the final SEIC structure as Shell (55%), Mitsui (25%) and Mitsubishi (20%).

The Sakhalin and other PSAs signed in the early years of the post-Soviet era, conflicted in a number of key respects with other laws governing the use of Russia's sub-soil resources. In a first attempt to regularise PSAs in 1995 the Russian Parliament passed a law giving them a degree of legitimacy and which was subsequently amended in 1999. While generally supporting the use of PSAs in the Russian oil and gas sector, the new PSA legislation included a number of clauses which conflicted with the Sakhalin II (and Sakhalin I) contracts; however, the 1999 law (amending 1995) 'grand-fathered' the first two Sakhalin PSAs, in effect, exempting them from the 1995 and 1999 legislation.

Subsequently further legislation, reflecting a growing Russian hostility to PSAs, was passed in June 2003, which placed severe new restrictions upon them and which, according to Russian legal experts, "put in doubt the viability of the PSA regime for future oil and gas production projects." (Bakoulev and Keefe, 2003). Needless to say, these developments created considerable anxiety in the ranks of Shell and SEIC executives, who held back from beginning Phase Two of the Sakhalin II project until they had received a letter of support from the Russian Prime Minister, Mikhail Kasyanov, on May 15th 2003. According to Shell's Rein Tamboezer, the letter showed "the government's clear understanding that the Sakhalin II PSA is grand-fathered and sets out the legal justification for this view." (Harvard Business School, 2004, p.13).

5. General features of 'standard' PSAs

Before we proceed any further we must say a few words about Production Sharing Agreements (PSAs) in general. They have two main features: their contractual status; and their specific terms as a petroleum 'fiscal regime'.

PSAs are contracts in civil law whose terms are fixed for the duration of the contract. As such they over-ride any national or state laws which bear upon petroleum taxation or any other aspects of what may be termed the 'eminent domain' rights of the state. So, for example, they may embody a specific rate of taxation upon the profits of the foreign oil company (FOC) that is party to the PSA, which is different from that of the general fiscal regime in the country as a whole, and which is immune to changes in that regime.

As contracts, PSAs can only be changed by mutual agreement between the FOC and the other party to the agreement – which may be the national or regional government or, more usually, a state oil company. Any differences arising from interpretation of the PSA must be settled, not by the national courts of the host country but by international arbitration. As regards the duration of the PSA, this is normally for a fairly lengthy, but fixed, period: 25 years could be considered typical.

Such agreements are common throughout the oil-producing world. Their purpose is to provide an FOC, which is planning a very large capital investment with a long life-time, with legally-binding assurances that the payments it makes to the state in return for extracting hydrocarbons will not

be arbitrarily changed at some future date. Without such an assurance it would be very difficult for the FOC to calculate the profitability of the project and whether it should enter into project in the first place. It is for this reason that Shell executives stated that without the signing of the SEIC PSA they would not have proceeded with the Sakhalin II project (See Harvard Business School, 2004, p.8).

Although there is a wide range of variation among the specific terms of PSAs, almost all of them have the following key features:

Firstly, the PSA will specify a fixed exploration period (typically two years) during which the FOC is required to carry out a certain program of operations, usually involving the drilling a number of exploration wells. At the end of this period, and depending on whether the FOC has made a discovery or not, the FOC has the option either to terminate the PSA or to proceed to the development stage, in which it appraises the initial

exploration prospect and begins to drill development wells to extract the oil and gas.

Secondly, the PSA will contain a clause specifying how, once the development decision has been taken, the oil or gas in the discovered field will be divided into 'cost oil' and 'profit oil'. As the FOC begins to develop the field, spending money on drilling wells, building infrastructure, paying out operating costs etc., it is remunerated for these costs out of the 'cost oil', which is valued at the going market price. The FOC's capital expenditures may be either expensed (100% re-imbursed in the current year) or depreciated over a number of years. Interest payments on loans may or may not be allowable costs – most commonly, not. The oil company receives the cost oil and sells it on the open market – or perhaps back to the state oil company.

Thirdly, when all the costs have been recovered, the amount of oil left in the field, which is the 'profit oil', is divided between the FOC and the state company according to an agreed proportion, typically 40 per cent to the FOC and 60 per cent to the state oil company.⁹ But if the field is a particularly large one with great economies of scale, the amount of 'profit oil' remaining might be huge. In such cases the company will normally have to accept a much lower share of the profit oil, in some cases as little as 20 per cent. Alternatively, there may be a graduated profit oil split such that the state's share begins quite low but increases as the amount of production, and profit oil grows with it.

Fourthly, there is usually a 'cap' on the annual amount of 'cost oil' that can be recovered out of gross annual revenues (e.g. 70 per cent of total annual production). If there is such a 'cap', the amount of cost which exceeds the cap is carried over into the next financial year and added to that year's annual costs. The intention behind this element of the standard PSA is to ensure that the State or state oil company receives some profit oil from the very beginning; this is particularly important in cases where the PSA does not include a royalty payment element (a percentage of oil sales revenue which is also paid to the State as soon as production begins) or where the percentage royalty is small, and/or where capital expenditures are expensed (rather than depreciated).

Fifthly, the FOC will normally pay a profit tax which may, or may not, be equal to the rate applying to other commercial activities in the country. For the purposes of calculating the annual amount of profit tax, capital expenditures are typically depreciated over a period of 5 to 10 years.

⁹ It is rare for a PSA to have a profit oil distribution where the State gets less than 51% of the profit oil. (See e.g. Petroconsultants, 1995)

Finally, some PSAs include an element of super-profits tax to ensure that if the field turns out to be a 'bonanza' the state gets extra annual payments. This tax is usually geared to the FOC's return on capital (calculated on the basis of the FOC's net cash flow 'Internal rate of Return' [IRR]).

It is important to emphasise one central point about the standard PSA (and one which applies to most other forms of petroleum fiscal regime). The oil company undertakes its investment *at its own risk*. If the exploration operations do not find oil, the FOC loses the money it has invested in its exploration operations. Similarly, if a discovery is made the FOC recovers its

exploration capital; but if the quantities of hydrocarbons (proved reserves) turn out to be less than expected, or if the investment required to extract them proves much larger than anticipated, or if the oil or gas price falls substantially, then the FOC is not going to make the rate of return on capital which it originally anticipated. On the other hand this risk is to a certain extent offset by the possibility that these factors may prove positive rather than negative, i.e. that the discovery may prove to be a bonanza, or that the oil price suddenly increases. Nevertheless, the FOC's investment is always *risked capital*.

6. The key feature of the Sakhalin II PSA

When we examine the Sakhalin II PSA we can see how very different it is from the 'standard' model described above. Firstly, the duration of the contract is indeterminate. The initial phase is set at 25 years, but the PSA contains the proviso that should the SEIC consider further exploitation of the fields to be 'economically practicable' it can renew the licence, without any changes in the PSA terms, for a further five years, followed by a further five years *ad infinitum* (Sakhalin PSA, 1994, s.3 c (i) pp.17-18). The Russian Party can appeal against this continuation of the licence, but such an appeal would have to go to international arbitration and it is difficult to see on what grounds Russia could win such an appeal provided that the SEIC was indeed still making profits. Such an indeterminate contract length has more in common with the 'oil concessions' agreed by Middle East rulers at the beginning of the 20th century than with a modern, standard PSA.

Since both the PA and Lunskeye fields had already been discovered by Russian companies, the SEIC did not need to worry about the existence of *in situ* oil and gas. So that initial element of risk was removed from the outset. Moreover, by radically altering the standard production sharing mechanism described above, the SEIC has substantially reduced its degree of financial risk in the project by transferring most of this risk to the Russian Party, as we shall now demonstrate.

This aspect of the PSA was engineered by abandoning the standard production sharing formula, whereby an agreed proportion of the profit oil is allocated to the host country once the costs of developing and operating the project has been recovered and replacing this by a requirement that the allocation of the hydrocarbons to the Russian party (with the exception of small royalty) would only take place once the SEIC had not only recovered its investment outlay, but in addition *had achieved a 17.5% real rate of return on its capital*.

The key section of the PSA is section 14, and it is worthwhile reviewing its contents in some detail in order to understand precisely how this aspect of the Sakhalin II PSA works. (The reader may skip the following brief mathematical section and its accompanying **Appendix 1**, and move straight to the substantive conclusion which follows).

The Sakhalin II PSA uses a novel approach, which it calls the FANCP (and SANCP) Index. FANCP means 'First level of Accumulated Net Cash Proceeds' and SANCP, the Second level etc... The technical details are shown in the box below.

The two indices are a device which ensure that SEIC receives not just its investment costs, but also a comfortable rate of profits.

Specifically:

- 1) At first, ALL proceeds from oil and gas sales (apart from a small royalty) are treated as 'cost oil', until both the capital investment AND an IRR (internal rate of return) of 17.5% (a comfortable profit) for SEIC have been received.
- 2) Once costs and the 17.5% return have been received by SEIC, the Russian Party receives 10% of the hydrocarbons for the following two years.
- 3) After those two years, the Russian Party receives 50% of the hydrocarbons until SEIC has received a 24% IRR (a large rate of profits).
- 4) Only after that 24% IRR has been obtained does the mechanism shift to its final sharing of 70% of hydrocarbons to the Russian party.

The FANCP mechanism is such an important feature of the Sakhalin II PSA that we (in APPENDIX 2) carry out a test of the mechanism, abstracting from other less important features of the PSA. Rather than carry out the test on the actual Sakhalin II project (the structure and timing of which is very complex) we shall construct a simpler, hypothetical oil/gas project, roughly on the scale of Phase One of Sakhalin II, which will better elucidate the main results of the comparison. (We return to the *actual* Sakhalin II project later).

From the results in **APPENDIX 2**, the message is clear: the FANCP mechanism, which is the key feature of the Sakhalin-type PSA, **is explicitly designed so that the adverse economic consequences of any major cost over-run fall almost entirely upon the State, postponing the date at which production sharing with the Russian Party commences**, while leaving the Company with a comfortable rate of profit.

It should also be pointed out that if the SEIC decides to add further tranches of investment later in the project – a third LNG 'train' for example – this could easily make the FANCP index negative again, in which case any current sharing of the 'available hydrocarbons' would cease. It is thus conceivable that the SEIC could pursue a strategy whereby it earned a rate of return just under the 17.5% threshold (a modest but comfortable rate), making investments from time to time intended to increase production but also to hold the FANCP index negative, thereby preventing any sharing of the available hydrocarbons with the Russian Party. This possibility appears to have been considered by Dr Pedro Van Meurs

Exposition of the FANCP/SANCP mechanism

The key concept is the FANCP (and SANCP) Index. FANCP means 'First level of Accumulated Net Cash Proceeds' and SANCP, the Second level etc... For any year t the FANCP is defined as follows:

$$\text{FANCP}_t = \text{FANCP}_{t-1} \times (1.175 + r) + \text{NCF}_t$$

Where $t - 1$ is the prior year, r = the current rate of inflation of US industrial goods and NCF_t means the Net Cash Flow from the project in the current year. (PSA, s14 (i) (cc), p.43). Logically, in the first year of the project FANCP_{t-1} will be zero, so in that first year the formula reduces to

$$\text{FANCP}_{t=1} = \text{NCF}_{t=1}$$

At first the NCF (and therefore the FANCP) will be negative as capital expenditures are made prior to oil and gas being produced. With the compounding forward of the negative NCF, the negative FANCP will become larger and larger until eventually the addition of sufficient positive NCF makes the FANCP positive also. At this point the FANCP formula changes back to:

$$\text{FANCP}_t = \text{NCF}_t$$

The SANCP is calculated in the same way but with the factor 1.175 (+17.5%) replaced by 1.24 (+24%).

Another way of explaining the FANCP methodology is to say that it is a device whereby each year the SEIC's target rate of profit (17.5%) is added to any negative cash flows and is compounded forwards until sufficient positive cash flows have been added so that the rate of profit on the project to date (using the standard Internal Rate of Return [IRR] calculation) reaches 17.5%. It reaches this IRR when the FANCP first becomes positive. A hypothetical numerical example may cast further light on the mechanism (See **APPENDIX 1**)

Returning to the actual Sakhalin II PSA,

"In the Financial Year with the positive FANCP index and also in the following year, 10% [of the value of hydrocarbons produced goes] to the Russian Party and 90% to the Company. (PSA s.14 (e) (aa), p.41) [my emphasis]

So the Russian Party only gets 10% of the hydrocarbons in the first instance and it only gets this once the SEIC has made a 17.5% real return on its investment. Moreover it is restricted to this 10% for *two* successive years.

Attention now switches to the SANCP index which will still be negative. The PSA now states that:

In the Financial Year following a year with the positive FANCP index and the negative SANCP index, which corresponds to the Company's rate of return of no less than 17.5%: 50% [of the value of hydrocarbons produced goes] to the Russian Party and 50% to the Company. (PSA s.14 (e) (bb), p.41)

Finally, if the SANCP becomes positive also, the share-out of the hydrocarbons becomes 70% to the Russian Party and 30% to the Company. (PSA s14 (e) (cc)). This share-out becomes permanent in the Financial Year after the last of the initial PA and Lunskeye licences expire {PSA s14 (e) (ee), p.42} i.e. after 25 years. However, as our analysis demonstrates, it is highly unlikely that the SANCP index will ever become positive and therefore the Russian Party will not receive 70% of the hydrocarbons until 2021.

of Van Meurs Associates (Calgary), a world expert on Petroleum Fiscal Regimes, who is reported to have concluded that in the case of the Sakhalin II PSA, "under certain conditions it becomes attractive to make investments for the sole purpose of reducing payments to government", (Van Meurs, reported by Fineberg, 2000, p.3).¹⁰

¹⁰ Such a policy would not be incompatible with a policy of stringent cost saving in areas such as environmental protection, since the investments to which we and Van Meurs refer are production-increasing investments.

7. Other features of the Sakhalin II PSA

In addition to the FANCP/SANCP mechanism the following features of the Sakhalin II project apply:

1. There is a signature bonus for the signing of Phase One of the project of \$30 million paid out in instalments in 1996, 1997 and 1998. A further bonus of \$20 million is paid when Phase Two begins.
2. The exploration costs incurred by the Russian Party prior to signing the PSA are repaid to the Russian party in quarterly instalments of \$4 million, commencing in the fourth quarter of 1999 and continuing until \$80 million has been disbursed. When the Company has exceeded a 17.5% real return on its investment and the share of hydrocarbon revenues switches to 50/50, the disbursement of a further \$80 million commences in the same manner.
3. There is a 6% royalty – *ad valorem* charge on gross revenues – paid in kind or in cash equivalent, paid when production of hydrocarbons commences.
4. The Company pays to the Sakhalin Oblast a contribution to the Sakhalin Development Fund of \$100 million spread over five years from the commencement of development activities (1997).
5. Once the Company begins to make a surplus in its profit and loss account, the taxable profit is taxed at a rate of 32%. For the purposes of taxing the profit, capital expenditures are depreciated over three years on a straight line basis. Initial losses incurred in the profit and loss account can be carried over to the next year for a maximum of 15 years.
6. In calculating the Company's Net Cash Flow (used for constructing the FANCP Index) the list of allowable deductions from the 'Available Hydrocarbon Production' revenues (Gross revenues minus the royalty) is considerable and virtually open-ended. It includes

Total sum of the Company's Expenditures in [the] Financial Year plus all sums of taxes and other charges, bonuses and payments not considered as Expenditures (except for the Royalty and bonusespaid by the Company in this Financial year to any Governmental Body). (PSA s14 (i) (iii), p.44)

All 'Expenditures' are "reimbursed ...during the month in which they are incurred" which means that in calculating the NCF all capital expenditures are expensed in the current year. (This would be the normal procedure in Cash Flow accounting).

Definition of allowable 'Expenditures; is given the PSA Appendix A (Accounting Principles) and lists the following:

Capital Expenditures: expenditures of no less than \$1,000 on fixed assets with a lifetime of more than one year.

Current Expenditures: all expenditures which do not fall in to the category of Capital Expenditures.

In a later section of the Appendix A (s.4) of the PSA more detail is included on what these Expenditures include. But there is no accompanying statement of which costs are *not* deemed to be recoverable – a feature common to most standard PSAs. These Expenditures which "include, but are not limited to" those listed are included in **APPENDIX 3** of this report.

If and when gas is sold to the Russian domestic market, the price for 1 million BTU of gas (approximately 1 thousand cubic feet) as quoted for the Average West-East Border price in the monthly edition of *World Gas intelligence* would be used.¹¹ However, if the actual price paid by Russian customers is lower than this price, the difference will be reimbursed as an 'Expenditure' when calculating the project NCF (but not in calculating the Taxable Profit).

Because the actual Sakhalin II PSA involves additional contributions to the State over and above the share of 'profit oil' determined by the FANCP mechanism (bonus, royalty, profit tax, contribution to the Sakhalin Development Fund and reimbursement of prior exploration expenses incurred by the Russian Party) the adverse impact of the FANCP mechanism is to some degree offset by these additional payments such that part of the project risk is passed back to the Company. (For example the Royalty must be paid whatever the extent of cost over-run by the project).

On the other hand, it should be noted that the actual size of the royalty (6%) is low by international standards, and lower than in the other Sakhalin PSAs. Among the countries which use PSAs and where the field size and production levels are comparable to those in Sakhalin, royalty rates generally fall within the range 10% - 20% (cf. Petroconsultants, 1995). The Sakhalin II profit tax rate (32%) is lower than the standard national rate at the time of the PSA signing (35%).

¹¹ Revenues for the project are calculated using free-on-board (FOB) arms-length free-market prices for oil and condensate and actual contracted FOB prices for LNG. In the case of the LNG prices, where these are quoted cost-insurance freight (CIF), this would involve making deductions from the CIF price for shipping costs, insurance and the small amount of 'boil-off' LNG losses which occur during transportation.

There is no 'cost cap' (as is usual in most PSAs) which allows the state to obtain a share of the 'available hydrocarbons' once the project is actually producing; and there is no statement in the PSA as to which costs might *not* be deemed recoverable (thereby allowing the SEIC a completely free hand to charge almost anything it wishes in the concept of 'recoverable costs').

It is also questionable whether the refund of the Russian Party's prior exploration expenses should be regarded as a net benefit to the State since these costs had already been incurred by the Russian Party and their payment by the Company merely cancels a previous State expenditure.

In summary, we compare, in Table 2 below, the features of the Sakhalin II PSA with those of a 'standard' PSA.

Overall, there can be no doubt that ***the Sakhalin II PSA terms are highly favourable to the Company*** and disadvantageous to the Russian Party. As it happens we do not need to rely only on our own analysis in making this judgement. According to the Harvard Business School,

The specific details of the Sakhalin II PSA were widely considered to be favourable for SEIC...the Sakhalin II agreement was designed to be attractive to the investors. (Harvard Business School, 2004, p.8)

Furthermore SEIC's CEO McVeigh, is quoted as saying that Sakhalin II has the "best PSA terms that you will ever get in Russia." (Harvard Business School, 2004, p.8). Conversely, looking at it from the perspective of the Russian Party, the Sakhalin II PSA is an example of those so-called 'modern' petroleum fiscal regimes which the eminent petroleum law expert Professor Thomas Wälde, has described as "fraught with risk" and which "may lose countries significant amounts of income" (Wälde, 1996).

Table 2:
Summary comparison of Sakhalin II PSA with common features of PSAs worldwide

'Standard' PSA	Sakhalin II PSA
1) Exploration risk carried by company	Hydrocarbons already found, so no exploration risk for SEIC
2) Costs recovered during 'cost oil' phase, then 'profit oil' shared between company and state	Cost and profits (17.5% IRR) go to SEIC before state receives any share
3) Annual cap on 'cost oil' during early years – so some share of surplus to state	No cap on annual cost recovery
4) Clear definition of what expenditures can and cannot be included in calculation of cost oil and profits tax	No clear limits to recoverable expenses
5) Typical royalty 10-20%	Royalty 6%

8. Economic analysis of Phase One

By 2003, the actual Company expenditures on Phase One already involved a substantial overspend. The Company had spent \$1.6 billion on the project (*Alexander's Gas & Oil Connections*, 2001; Harvard Business School, 2004, p.7)¹² – an overspend of more than \$800 million – a large part of which was the result of additional contract work required to make the Molikpaq platform suitable for operations in the deeper waters and extremely adverse conditions of the Okhotsk Sea, and because the company came to realise that “the geological structure of the PA deposit is more complex than was estimated earlier.” (ACRF,2000, p.26). Indeed, the decline in the oil flow from the PA field appears to have commenced earlier and more dramatically than anticipated and a \$300 million secondary recovery investment was required to restore pressure in the reservoir. The company also claimed that it been adversely affected by the decline in the value of the dollar and there were also allegations by the Russian Audit Chamber that the Company generally overpaid non-Russian suppliers and contractors.

As we should expect from our previous analysis of the workings of the FANCP mechanism, such a large overspend would wipe out the profit oil share which should have accrued to the Russian Party. The Russian party would still receive the royalty, Sakhalin Development Fund payments, some profit tax receipts, but only half of the projected exploration expenses reimbursement since the second half of the \$160 million payment is only triggered when the State begins to recover 50% of the profit oil – and, as we have stated – this would not now occur.

The following **Table 3** compares the Russian Party benefits which were originally projected by the SEIC for Phase One (and assuming a constant real oil price of \$24/b) with the benefits which the State would earn with the same projected oil price but with the *actual* oil production profile (up to 2003) and the *actual* project expenditures which were incurred. The SEIC's figures were undiscounted; for comparative purposes ours are also undiscounted in this case.¹³

As predicted, the substantial development cost overspend ensures that the Russian Party does not receive any share of the 'profit oil' (because the FANCP Index remains negative throughout the project's life). However, because this means the company retains 100% of the available hydrocarbons throughout, its taxable profit exceeds that implied by the SEIC development plan and therefore the State's profit tax revenues also exceed those predicted. On the other hand, since the State never reaches the point where it would receive 50% of the profit oil, it is not entitled to the remaining half of the prior exploration expense refund. On balance, one can say that, the specific terms of the Sakhalin II PSA ensure that the Russian Party is forced to participate in the financial loss suffered by SEIC as a result of the company's over-spend. Alternative commonly employed petroleum fiscal regimes would not have this effect, or at least, the effect under these alternatives would be less pronounced.

Table 3:
State Benefits, Sakhalin II Phase One assuming \$24/b oil price (undiscounted values)

State Revenues	SEIC Development Plan, \$m	SERIS projected Outcome with actual overspend, \$m	Difference \$m
Bonuses	50.0	50.0	-
Royalties	417.0	417.6	+0.6
Sakhalin Development Fund	100.0	100.0	-
Profit Taxes	854.9	1452.1	+ 597.2
Exploration Reimbursement	160.0	80.0	- 80.0
Share of Profit Oil	1137.5	0	- 1137.5
TOTAL	2719.4	2099.7	- 619.7

Source: Thornton, 2000, p.13; and SERIS Model. For a general description of the Model methodology see **APPENDIX 5**
Note: in 2003, SEIC also paid the bonus for the start of Phase Two.

¹² \$2 billion by 2002, according to SEIC's Dr Andrew Seck (CEPMLP,2002 p.5) Some other SEIC sources give a figure of \$1.5 billion by 2001.

¹³ We have used a 25 year project life

We now turn to an economic analysis based on discounted values. Commercial reports which analyse petroleum fiscal systems, such as *Petroconsultants* and *Van Meurs Associates*, use a number of different test indicators applied to a suite of theoretical oil and gas fields to assess whether a particular fiscal regime is advantageous to an investing oil company (and by implication, disadvantageous to the state) and to what degree. In our view the five listed below are the most relevant in a context (such as Sakhalin) where the hydrocarbon reserves have already been discovered by prior exploration operations.

For the Company we use two profitability indicators:

1. Net Present Value (NPV) of Company Net Cash Flow at 12% discount rate.¹⁴
2. Company Internal Rate of Return (IRR) on the project.

For the State we use three indicators:

1. NPV of State Cash Flow at 12% discount rate
2. State 'Take' (share) of the Project's Total NPV
3. State 'Take' of the Undiscounted Project Net Cash Flow.

To which we add a fourth indicator, reflecting the peculiar reality of the actual Sakhalin II PSA:

4. Share of 'available hydrocarbons' received by the state.

The economic significance of the discount rate, as we explained above, is that it represents the 'time value of money'. Specifically in the case of the oil company, it

represents the company's 'cost of capital' – the opportunity cost of using its funds in this particular project defined by the minimum (post tax, post inflation) return it would expect to earn on some alternative investment.

The rate of profit used – the Internal Rate of Return (IRR) is the rate of profit on the project over its whole lifetime and mathematically, is the rate of discount which would reduce the Project's NPV to zero (See **APPENDIX 4**). Thus, in our model, if the Company has a positive NPV its IRR must be greater than 12%. Vice versa, if the Company's IRR is greater than or equal to 12% the NPV for the project will be positive – the project 'has value'.

In **Table 4** we analyse Phase One using three different oil price scenarios. In scenario A we use the SEIC's assumption of a \$24/b real oil price throughout the project lifetime. There was a major increase in oil prices in 2004, rising to an estimated average price for the year for Sakhalin II type crude, of around \$43/b. In scenario C, therefore, we assume that in 2004 the price changes to \$43/b and remains at that level (in real terms) for the rest of the project lifetime. However, In scenario B, our 'Base Case', we assume the oil price follows a trajectory compatible with the most recent forecast for world oil prices made by the International Energy Agency (IEA).

The following conclusions can be drawn from **Table 4**. It is clear that at a \$24/b oil price, and after payments to the Russian Party are deducted (relatively small though these may be), Phase One becomes loss-making for the SEIC while the State's NPV is only slightly above half

Table 4:
Economic Analysis of Sakhalin II (Phase 1) using three price scenarios.

	A: 'SEIC Investment plan scenario' \$24/b	B: 'Base Case' IEA price scenario	C: 'Continuing high oil price scenario' \$43/b
Project IRR	19.0%	23.6%	26.0%
Project NPV	\$472.1m	\$879.7m	\$1387.5m
Company NPV	-\$54.4m	\$123.3m	\$393.9m
Company IRR	11.7%	14.6%	17.8%
State Share of Available Hydrocarbons	0%	0%	8%
State NPV	\$526.4m	\$756.4m	\$993.1m
State Take undiscounted	54%	54%	56%
State Take of Project NPV	111%	86%	72%

Source: SERIS Model

Notes: The 'Base Case' oil prices are in line with the IEA's 2004 *World Energy Outlook* which sees currently high oil prices falling (in real terms) from 2006, rising to \$27/b in 2010 and rising further to \$31/b by 2020. The IEA's figures are for US oil prices. Ours have been set \$2 per barrel below this to allow for quality differences.

¹⁴ Discount rates and (therefore) minimum target rates of return for oil companies typically range between 12-15%. A government may use a lower discount rate in project evaluation but so as not to bias the analysis, throughout this report we have used the same rate for both Company and State, situating this at the lower end of the Company's expectations. Petroconsultants uses a 15% nominal discount rate with 3% inflation, which is equivalent to our own 12% real rate.

a million dollars. This conclusion is supported by an SEIC report quoted by *Sakhalin Environment Watch* which states, "Economic analysis shows that Phase One by itself will not be profitable." (SEW, July, 2002, p.1)

The situation is somewhat better with the 'Base Case' price scenario, although even here the company's IRR is modest, while the State's NPV only increases to three quarters of a million dollars.

Since, in neither of these two cases, does the SEIC's rate of return reach 17.5%, the Russian Party does not receive any share of the available hydrocarbons.

However, in the 'continuing high prices' scenario, with a \$43/b oil price, the economics of the project are improved considerably, although it will be observed that even in this case, the share of 'available hydrocarbon' revenues received by the Russian party is still only 8% (and the 50% share-out does not materialise until 2017). Were Phase One to be a stand-alone project, a continuation of the dramatic rise in the oil price, unanticipated in 2002, would be remunerative to both parties, although as our analysis in **APPENDIX 2** suggests, the Russian Party achieves a much smaller total income (discounted or undiscounted) than it would under either a 'standard-type' PSA or a Royalty plus Profit Tax contract.

9. Economic analysis of total Sakhalin II benefits to the Russian Party

In this section we have built onto our spreadsheet model for Phase One the additional Phase Two development data, insofar as we have been able to obtain these from the company's publicity and other public domain sources.

From **Table 5** it can be observed that, under the SEIC's assumption of a \$24/b real oil price, and a gas price equivalent, based on the most recent public domain information about the project's likely costs, the gross project economics of Sakhalin II would be distinctly marginal and the project would be unlikely to attract outside finance. A 17.3% IRR (internal rate of return) *before tax* is low by international standards, as is an NPV (Net Present Value)/barrel sold of \$0.91.¹⁵

After tax, the company's IRR falls to 13.1%: with a cost of capital of between 12-15%, Sakhalin II would not provide any 'economic rent' to the company. The State would do little better. Although it would get the lion's share of the total NPV, the project NPV itself is very small. It will also

be noted that because the company's IRR never exceeds 13.1%, the Russian Party never participates in the 'profit oil'. As we argued earlier, the huge cost overrun combined with the FANCP mechanism of the PSA has meant that the State has had to postpone its entitlement to a share of the profit oil until after 2021.

In the second scenario we have assumed that oil revenues until 2003 are as historically recorded by the company but, as in our analysis of Phase One ('Base Case'), we assume the oil price jumps to \$43/b in 2004 and 2005, but thereafter declines, following a trajectory in line with the most recent IEA *World Energy Outlook* forecast. In the case of the gas price (FOB), LNG netbacks from Australia to Japan were averaging \$4.04/MMBTU¹⁶ at the time the development of Phase Two began. In September 2004 the same netback price for LNG gas had only risen to \$4.40/MMBTU (*World Gas Intelligence*, 29/9/04).¹⁷

Table 5:
Economic Analysis of Sakhalin II (Phases 1 plus 2) using three price scenarios.

	A: 'SEIC investment plan scenario' Oil price: \$24/b; Gas price: \$3.83/MMBTU	B: 'Base Case' (IEA) oil price scenario; \$4.40/MMBTU	C: 'Continued high oil price scenario' \$43/b \$6.86/MMBTU
Project IRR	17.3%	20.7%	28.3%
Project NPV	\$1,750.9m	\$3,011.3m	\$7,281.7m
Project NPV/barrel sold	\$0.91/b	\$1.55/b	\$3.76/b
Company NPV	\$299.4m	\$1,178.8m	\$2,636.7m
Company IRR	13.1%	16.1%	20.7%
State Share of Available Hydrocarbons	0%	0%	19%
State NPV	\$1,451.5m	\$1,832.5m	\$4,645.0m
State Take undiscounted	37%	37%	57%
State Take of Project NPV	83%	61%	64%

Source: SERIS Model

¹⁵ Petroconsultants (1995) designates as 'Marginal' projects with a pre-tax IRR of between 15.9% and 30.8%, and an NPV/b of between \$0.2/b and \$2.2/b.

¹⁶ MMBTU = One million British Thermal Units, approximately the calorific value of 1,000 cubic feet of natural gas.

¹⁷ Over this period of time the oil price increased by about 50%. It would therefore appear that there has been a considerable degree of de-coupling between the world oil price and the world LNG price. Given the increasing liberalisation of gas markets worldwide, there is a growing tendency in all gas contracts for the element of oil-price indexation to play a reduced role. Also, the amount of LNG being sold 'spot' is increasing and there is a growing propensity for over-supply in Asian-Pacific LNG markets: the Japanese gas market is growing only very slowly and the growth of the US West Coast market (a target market for SEIC) is being hindered by strong local opposition to the construction of new LNG terminals. With a large number of new LNG export projects coming on stream some experts are warning of a "possible supply surplus" by 2007, just when Sakhalin II begins gas production (*Financial Times*, 2004c).

Weakening market conditions are also reflected in the fact that to date, SEIC has only signed contracts for about 35% of its planned supplies. As of March 2004, SEIC announced that so far it had only signed agreements with four Japanese utilities, Tokyo Electric Power Co (TEPCO) (1.2 MTPY), Tokyo Gas (1.1 MTPY), Kyushu Electric (0.5 MTPY) and Toho Gas (0.3 MTPY). Recently it was reported that Shell is now, in effect, planning to buy gas from itself, by building a regasification plant in Mexico from which it will pipe gas to California (Pacific Russia Information, 2004), a move which some observers might conclude is an act of desperation designed to make Sakhalin II more 'bankable' from the perspective of potential project finance.

Overall, these market considerations lead us to conclude that the LNG price could remain in the doldrums for a some years ahead. However, we have taken what we consider to be relatively optimistic view of world LNG prices, assuming it remains at around \$4.40 per MMBTU for the duration of the project.

In this second scenario, our 'Base Case', the gross project economics (IRR= 20.7% and NPV/b = \$1.55) remain marginal, however, both company and State do somewhat better than in the first scenario. The company's post-tax rate of return (IRR= 16.1%) exceeds the putative cost of capital and would probably be considered acceptable, but the Russian Party's rent is only \$1.8 billion, largely because the Russian Party does not obtain any share of the available hydrocarbons, since the company's IRR is less than the 17.5% threshold.

Only if the oil price remains high, at around \$43/b and the gas price quickly rises with it in the same proportion (i.e. no de-coupling), as it does in our third scenario, will

the project prove significantly remunerative to both parties.

However, the foregoing discussion assumes the same Sakhalin II contract terms in each of the three price scenarios. In fact, there have been a number of opportunities when these terms could, and should, have been re-negotiated, and yet for some unknown reason the Russian Party failed to do so. **Table 6**, using the 'Base Case' as an example, gives some idea of the potential losses being incurred by the Russian state as a result of the extremely unfavourable contract terms in the Sakhalin II PSA.

The Base Case analyses the benefits to both parties under the Sakhalin II PSA, while in the alternative analyses we apply:

- A 'standard'-type (albeit relatively generous to the company¹⁸) PSA, with a 6% royalty (as in the actual Sakhalin II PSA), but *with no profits tax, no cost cap and a 50/50 share of hydrocarbon revenues* once the company recovers its costs; capital expenditure is expensed.
- A Royalty and Profits Tax regime using a 12.5% royalty rate (as in US private leases) and a 35% profits tax (again, this is a generous rate, compared to actual rates applied worldwide¹⁹); for the purposes of calculating the profits tax, capital expenditure is depreciated over three years on a straight line basis (as in the actual Sakhalin II PSA).

In both the alternative scenarios we assume that bonuses, the contributions to the Sakhalin Development Fund and the refund of prior exploration expenses are paid, the last two being cost-recoverable by the company.

Table 6:
Sakhalin II project benefits under three different fiscal regimes

	Sakhalin II PSA (Base Case)	'Standard' type PSA	Royalty and Profit Tax regime
Project IRR	20.7%	20.7%	20.7%
Project NPV	\$3,011.3m	\$3,011.3m	\$3,011.3m
Company NPV	\$1,178.8m	\$360.3m	\$741.5m
Company IRR	16.1%	13.5%	14.7%
State Share of available hydrocarbons	0%	31%	n.a.
State NPV	\$1,832.5m	\$2,651m	\$2,269.8m
State Take undiscounted	37%	55%	45%
State Take of Project NPV	61%	87%	75%

Source: SERIS Model

¹⁸ If we applied an 'average' or more common PSA model, the difference with the Sakhalin II PSA would be even starker. As noted above, royalty (where applied) is more commonly 10-20%, state share of hydrocarbons more often 70%, and a cost cap is usually applied during the 'cost oil' phase

¹⁹ Most commonly, where a royalty and profits tax system exists, there is a normal profits tax / corporation tax, AND a special petroleum tax – combined these usually amount to more than 35%

It must be emphasised that in all three cases, it is assumed that SEIC is able to commercialise all of the gas supplies available to it, something which might not occur, in which case the project economics would be seriously damaged in all three scenarios.

From the comparison it is immediately apparent that a standard-type PSA, even with some features quite generous to the company (no cost cap, no profits tax), would have been far superior from the perspective of the Russian Party than the terms of the actual Sakhalin PSA: the state's share of the 'profit oil' increases from 0% to 31% (far higher than in the highest price scenario in **Table 4**) and the state's NPV is 45% larger, even so, the company would still achieve a rate of return within the putative range of acceptability (13.5%) if the project continued.

The Royalty and Tax regime is also superior than the actual Sakhalin II PSA from the perspective of the state, although the relative merits of this obviously depend

upon the actual royalty and tax rates used. Here we have used 12.5%% and 35% respectively. A higher rate of tax would not be at all unreasonable; indeed, the current proposal in Russia is for a standard business / corporation tax on profits PLUS a special petroleum tax of up to 60% PLUS a royalty – as such, this type of regime could be made more favourable to Russia than a 'standard' PSA model, depending on the rates chosen, and the details of the mechanism.

In this context it is worth noting that in 1999 the Audit Commission of the Russian Federation concluded that, in 'Money of the Day' terms, and using the original cost data supplied by SEIC, Russia would be \$19 billion worse off with the Sakhalin II PSA than it would have been using the current standard petroleum fiscal regime (See ACRF, 2000, p.58)

10. Distribution of the Russian Party's benefits between the Russian Federation and Sakhalin Oblast.

Table 7 identifies the distributional shares to which the two members of the Russian Party are entitled.

Table 7:
Russian Party Distributional Shares

Type of benefit	Federation	Sakhalin
Bonus	40%	60%
Royalty	50%	50%
Sakhalin Development Fund	-	100%
Repayment of prior exploration cost	50%	50%
Profit Tax @ 32%	62.8%	37.1%
Profit Oil Share	50%	50%

Sources: Auditing Chamber of the Russian Federation (2000); Thornton (2000)

Applying these shares to the actual cash flows from our Base Case, we obtain the following net present values of benefits in Table 8:

Table 8:
Distribution of Sakhalin II benefits (NPV \$bn)

Russian Federation:	\$1.0 bn	(56%)
Sakhalin Oblast:	\$0.8 bn	(44%)

Source: SERIS model

This result is perhaps rather surprising given that the Sakhalin Oblast receives the whole of the Development Fund and the larger part of the bonus, but over the lifetime of the project these effects are outweighed by the Russian Federation's much larger share of the Profit Tax revenues. As noted above, the Profit Oil shares for either party amount to zero, since there is no entitlement to profit oil in the 'Base Case'.

APPENDIX 1

HYPOTHETICAL EXAMPLE OF THE FANCP METHODOLOGY

To illustrate the implications of the FANCP mechanism, we examine a hypothetical oil/gas project – a proven oil and gas reserve whose exploitation will last 25 years with total capital costs of \$1,000 million. These receipts reach a peak in year 5 of the project and then begin to decline exponentially, as the production of hydrocarbons declines due to falling pressure in the reservoirs.

Table APP1:
Hypothetical Example of the FANCP methodology

PROJECT YEAR	PROJECT CASH FLOW, \$M	FANCP INDEX	SANCP INDEX	COMPANY NET CASH FLOW, \$M	COMPANY IRR
1	-100	-100.0	-100.0	-100	-
2	-700	-817.5	-824.0	-700	-
3	-200	-1160.6	-1221.8	-200	-
4	100	-1263.7	-1415.0	100	-
5	350	-1134.8	-1404.6	350	-
6	325.5	-1007.9	-1416.2	325.5	-
7	302.7	-881.6	-1453.3	302.7	-
8	281.5	-754.3	-1520.6	281.5	-
9	261.8	-624.5	-1623.8	261.8	-
10	243.5	-490.3	-1770.0	243.5	-
11	226.4	-349.6	-1968.3	226.4	-
12	210.6	-200.2	-2230.1	210.6	-
13	195.9	-39.4	-2569.5	195.9	17.3%
FANCP positive, IRR =17.5% 14	182.1	135.8	-3004.0	163.9	17.9%

APPENDIX 2

ANALYSIS OF IMPACT OF THE FANCP METHODOLOGY ON HYPOTHETICAL OIL AND GAS PROJECT

We now look at the hypothetical oil/gas project of APPENDIX 1, and compare the simplified Sakhalin II-type PSA (using an FANCP mechanism, but excluding the other elements of the Sakhalin II PSA) with two alternative 'fiscal regimes': a standard PSA of the type described in the section 5, and a royalty/profit tax regime (assuming this is a contract whereby the royalty and tax rates cannot later be changed by the State). It must be emphasised that the outcomes illustrated here are based on a purely hypothetical project and with highly simplified fiscal regimes.

The Gross Project Economics of the project (its economic characteristics, taken on its own, before any production sharing or payment of tax or royalty) are as follows:

1. The Net Present Value of the project at a 12% discount rate is \$421 million;
2. The project's rate of profit – its Internal Rate of Return – is 19.6%.

This would be a positive but modestly profitable project, whose economic characteristics are typical of one which has higher than average capital costs in relation to its revenues (as does the real-life Sakhalin II project).

We now examine the impact of imposing three alternative 'fiscal regimes' upon the economics of the project from the separate perspectives of the Company and the State. These are

1. A 'Sakhalin' Type PSA with the FANCP/SANCP mechanism, no royalty, no profits tax; capital expenditure expensed.
2. A 'Standard' Type PSA with no royalty, no cost cap and a 50/50 profit oil split; capital expenditure expensed.
3. A Royalty plus Profit Tax regime with a 12.5% royalty rate (as in US private leases) and a 35% profit tax; capital expenditure depreciated over three years on a straight line basis.

For the Company we use two profitability indicators:

- Net present value of company net cash flow at 12% discount rate.
- Company Internal Rate of Return (IRR) on the project.

For the State we use three indicators:

- NPV of state cash flow at 12% discount rate
- State 'Take' (share) of the undiscounted project net cash flow.
- State 'Take' of the project NPV

The following Tables APP2 and APP3 show the main results of our test:

Table APP2:
Economic Indicators for three 'fiscal regimes' applied to the same oil/gas project.

	Sakhalin-type PSA	Standard-type PSA	Royalty and Profit Tax Contract
Project NPV @ 12%	\$421.0 m	\$421.0 m	\$421.0 m
Project IRR	19.6%	19.6%	19.6%
Company NPV @12%	\$350.2m	\$79.9m	\$79.6 m
Company IRR	18.9%	13.9%	13.7%
State's NPV @ 12%	\$70.8 m	\$341.0 m	\$341.4 m
State Take of Undiscounted cash flow	20.5%	50.0%	83.4%
State NPV Take	16.8%	81.0%	81.1%

Source: SERIS Model

Under all three regimes, the Company NPV is positive and the Company IRR greater than the minimum required rate of return (12%). However, from the Company perspective the Sakhalin-type PSA is far superior to either the Standard-type PSA or the Royalty + Profit Tax contract whose results are very similar.

However, it is when we investigate the impact of a major cost over-run on the project that the difference between the three fiscal regimes really emerges. In **Table APP3** we assume a 20% capital cost over-run, in the form of an increase of \$200m capital expenditure in year 2 of the project.

Table APP3:
Economic Indicators for three 'fiscal regimes' applied to the same oil/gas project, with 20% cost over-run

	Sakhalin-type PSA*	Standard-type PSA**	Royalty and Profit Tax Contract ***
Project NPV @ 12%	\$261.5m	\$261.5m	\$261.5m
Project IRR	16.1%	16.1%	16.1%
Company NPV @12%	\$261.5 m	- \$37.2 m	- \$53.0 m
Company IRR	16.1%	11.3%	11.0%
State's NPV @ 12%	\$ 0 m	\$298.7 m	\$314.5 m
State Take of Undiscounted cash flow	0 %	50%	82%
State NPV Take	0 %	114%	120%

Source: SERIS Model

Note: The greater than 100% State take of the NPV under the standard PSA and Royalty + Tax regime is simply the mathematical consequence of the company's negative NPV in these cases.

Under all three regimes, the cost over-run reduces the project NPV and IRR, as we would expect. However, it is clear that under the 'Sakhalin' type PSA a major cost over-run is paid for entirely by the state, leaving the company with the whole NPV of the project: the state gains absolutely nothing from depleting a non-renewable resource. On the other hand, under the 'standard' type PSA and the Royalty + Profit Tax contract, the impact of the cost over-run falls largely upon the company which now, fails to make its target rate of return (12%).

APPENDIX 3

ALLOWABLE RECOVERABLE EXPENDITURE CATEGORIES UNDER THE SAKHALIN II PSA

- (i) Rent
- (ii) Acquisition of Fixed Assets
- (iii) Materials and equipment
- (iv) Payments to Contractors
- (v) Compensation of Employees
- (vi) Business Trips Expenses
- (vii) Insurance
- (viii) Legal Costs
- (ix) Payments to Advisors and Consultants
- (x) Contribution to the Sakhalin Development Fund
- (xi) Refund of the Russian party's prior exploration expenses
- (xii) Tender-related expenses
- (xiii) Taxes (except Profit Tax), Dues, Fees, Levies, all kinds of payments "which are actually paid in compliance with the legislative and other acts of any jurisdiction that is entitled to set such taxes..." (PSA Appendix A s.4, p.69)
- (xiv) Acquisition of Land Right
- (xv) Restoration of damaged property
- (xvi) Office facilities
- (xvii) Currency exchange losses
- (xviii) Personnel Training
- (xix) Personnel expenses of affiliated companies outside Russia where those companies are fully or partially involved in the project
- (xx) Administrative overhead expenses
- (xxi) Miscellaneous expenses: "All other expenses which are not included in the previous subsections of this section 4 which the Company makes in accordance with the approved budgets ...which entitle the Company to make such Expenditures." (PSA, Appendix A, s.4 p.71)

In the calculation of the Profit Tax (excluded in the above list used in calculating NCF Expenditures). The allowable expenditures include all the above NCF-related expenditures plus the following:

- (xxii) Costs of drawing-up Financial Documents
- (xxiii) Interest payments not exceeding a rate determined by the London Interbank Lending Rate (LIBOR) plus a risk premium
- (xxiv) "All actually paid salaries and other payments for personal services" (This would seem to be a repetition of 5. above)
- (xxv) Commencement Date bonuses and Development Date bonuses.

Losses may be carried over for 15 years.

Ambiguity in one section of the PSA document

One particular difficulty in deciding which expenditures are included in the calculation of the NCF is interpretation of the phrase quoted below referring to the total deductions which can be made in calculating the NCF (and therefore the FANCP). It will be recalled that the PSA states that these deductions comprise the,

Total sum of the Company's Expenditures in [the] Financial Year plus all sums of taxes and other charges, bonuses and payments *not considered as Expenditures*...(PSA s14 (i) (iii), p.44) [my emphasis]

In the list of NCF allowable expenditures (i.....xxi), it is stated that the Profit Tax is not an 'Expenditure'; but then the above quotation states that allowable deductions for the calculation of the NCF include 'taxes*not* considered as expenditures' This would seem to suggest that the calculation of the NCF, the FANCP and therefore the company's implied IRR (critical for determining when the hydrocarbon revenues are shared) *does* involve the deduction of the profit tax. This would make economic sense since the company's rate of return (IRR) should be based on all cash receipts and all cash payments in a given year. Excluding the profit tax payments would give a very misleading picture of the company's rate of return. Furthermore, our interpretation of this part of the PSA regarding the deductibility of profit tax in making the NCF calculation is supported by an analysis of the fiscal terms of another of the Sakhalin PSAs – Sakhalin IV, according to which "production shares depend on the company's accounting IRR *after* payment of profit taxes." (Thornton, 2000 p.12)

APPENDIX 4

EXPLANATION OF NET PRESENT VALUE (NPV) AND INTERNAL RATE OF RETURN (IRR)

Present Value, or more precisely Net Present Value (NPV), is the standard method of assessing the value today of a future sum of wealth, or a future stream of net cash flows.

The NPV method is based on 'Discounting' which we now explain.

If we invest a sum of money **P** for one year (**t = 1**), at a rate of interest **r**, then at the end of that year the future sum **F** (the sum of money in our bank account) will be -

$$F = P (1 + r)^{t=1}$$

The formula tells us that in one year's time the sum of money **P**, invested now, will be worth **P (1 + r)**.

If we invest the same sum for two years (**t = 2**) we will eventually receive,

$$F = P (1 + r)^1 (1 + r)^1$$

$$= P (1 + r)^2 \text{ and so on. We call this 'compound interest'.$$

Now let us manipulate the first equation slightly by dividing both sides by

(1 + r), so we get

$$\frac{F}{(1 + r)^t} = P \text{ which we can also reverse as } P = \frac{F}{(1 + r)^t}$$

Assume we are going to receive the sum of £1,000 in three years time and the rate of interest **r** is 10% (0.1 in decimals), what is the Present Value of that future sum of money now? If the future value is **F** and the Present Value is **P**, therefore,

$$P = \frac{F}{(1 + r)^t} = \frac{\text{£ } 1000}{(1 + 0,1)^3} = \frac{\text{£ } 1000}{(1.331)} = \text{£ } 751.31$$

It should be clear that this is simply another way of saying that if we had put £751.31 in the bank at a 10% interest rate, with compound interest it would have accumulated to £1,000 after three years.

Thus, the basic idea behind the concept of **Present Value** is that cash received today is worth more than cash received sometime in the future. If someone has to wait a certain amount of time before receiving money from an investment this is less attractive than if he started receiving the money right away. This is not so much because of inflation (although inflationary expectations may have to be built into the calculation) but because if he received the cash this year rather than in three years time, **he could immediately reinvest the cash and earn further profit**. The individual or company should therefore 'discount' the future cash according to the rate of interest. It should also be clear from this example that **the Present Value of the future cash will be lower the higher is the chosen interest rate and the further into the future the cash is received**. (as **r** and **t** increase)

Where does the rate of interest come from?

The basic idea behind this concept of **Present Value**, is that financial resources have an **opportunity cost** - they could be invested somewhere else, for example in a bank deposit or Government bond where the rate of interest is known in advance and where there is little risk of losing the money. Consequently an individual or company may use this 'risk free' rate of interest in making the calculation. However if the investment is a risky one it will be necessary to use a higher rate of interest as a kind of target or hurdle which the investment project under consideration must achieve as a bare minimum.

We speak of '**Net** Present Value' when we are thinking in terms of an actual investment in capital equipment or some fixed asset like an oil well where the initial capital expenditure must be 'netted off' from the future profits from the investment. Moreover in such a case, the profits will be expected to occur not just once, but over a number of future years. For example, an oil company will assess the size of its proved reserves and then estimate (a) the capital expenditure necessary to develop them for production (by drilling development wells etc.) and (b) the future annual profits expected to be received from extracting and selling those reserves. In such a case the formula for the Net

present Value of the oil reserves would be written as follows. Assuming all the capital expenditure was completed in the year prior to commencement of production, then –

$$\text{NVP} = -C_0 + \frac{F_1}{(1+r)^1} + \frac{F_2}{(1+r)^2} + \frac{F_3}{(1+r)^3} + \dots + \frac{F_n}{(1+r)^n}$$

Where C_0 is the capital expenditure in the year *prior* to production commencing, F_t is now the net profit in year t , r is the interest (discount) rate and n is the year in which the reserves will be ‘exhausted’ (given current technology and economics).

It should be clear from the above equation that if we increase r , the expression $\frac{F_t}{(1+r)^t}$ will become smaller, and therefore so will the **NPV**.

If we keep on increasing r more and more eventually we will reach the point where **the NPV** become zero.

The rate of interest (discount) at which this occurs is called the **Internal Rate of Return (IRR)** of the project (be it the exploitation of an oil reserve or any other economic or financial project). This is the true, long-term, **rate of profit** of the project.

Calculating NPVs can be done ‘manually’ using **discount factors**. For example, if the rate of interest is 10% then the ‘one year **discount factor**’ is:

$$\frac{1}{(1+10\%)^1} = \frac{1}{(1+0,1)^1} = \frac{1}{(1.1)^1} = 0,909$$

The two year discount factor is: $\frac{1}{(1.1)^2} = \frac{1}{1.21} = 0,826$ and so on.

However, it is not possible (for you and I) to calculate the **IRR** without using a computer. Fortunately we can use the **Function Wizard** in an **EXCEL** spreadsheet to do it for us (and we can also use EXCEL to calculate the **NPV**).

APPENDIX 5

BASIC METHODOLOGY OF THE SERIS MODEL

For the period 1996-2003, production figures, revenues and costs are those reported in SEIC documents and/or the report of the Auditing Chamber of the Russian Federation.

For the period since 2003 and until the end of the initial licence, prices are as stated in the three price scenarios in Tables 4 and 5, however the 'Base Case' scenario is based on oil prices as forecast by the latest International Energy Agency (IEA) *World Energy Outlook*.

Full capacity hydrocarbon production levels are as stated in SEIC literature. Post-peak decline rates are assumed to be exponential with rates derived from Van Meurs Associates for the appropriate size of field reserves. However where secondary recovery methods are introduced (Astokh feature, Phase One) we have assumed production recovers to a second peak and then 'plateaus' for 7 years before decline sets in. Projected hydrocarbon production profiles are necessarily speculative (although based on conventional industry assumptions) and it is possible that further secondary recovery technologies may be introduced, new production platforms added and an additional LNG train constructed in the later years of the project. However were this to happen the additional investment costs incurred could make the FANCP Index become negative once again. As explained in the Report this would have an additional negative impact upon the Russian party's income receipts.

Fixed operating costs are calculated as a percentage of initial capital investment, again using Van Meurs Associates guidelines. Variable operating (lifting) costs for oil are \$1/b (cf. Petroconsultants, 1995) and \$0.03/Mcf for gas. LNG plant investment and upstream gas costs (are taken from Van Meurs and total Phase 2 costs are as reported by SEIC, Industry Trade Journal sources, and the Press. LNG operating costs are expressed as a fixed percentage of total LNG plant cost.

Throughout the analysis it is assumed that sales of all hydrocarbons, including LNG gas are conterminous with their extraction. This is somewhat unrealistic since it ignores storage and the actual timing of LNG supply contracts. As mentioned in the Report it is possible that some gas might remain unsold if SEIC fails to find sufficient markets.

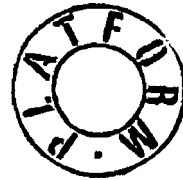
The SERIS model was constructed using the Microsoft Office EXCEL spreadsheet program.

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