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Energy Advisory Services

Evaluation of the Petroleum Exploration and Production Assets of PetroSaudi International Limited

Prepared for:
The Directors of
1MDB PetroSaudi Limited
and
1Malaysia Development Berhad
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Private and Confidential

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DISCLAIMER

The analyses, opinions and conclusions presented in this report are based on our best economic judgments on the data that were made available to us by the managements of PetroSaudi International Limited and 1MDB PetroSaudi Limited. We used our best efforts to provide a fair and reasonable economic assessment of a number of potential projects. We make no claim to expertise on the geology of the fields in questions and we developed conclusions based on the normal uncertainties associated with extractive industry concerning market, political, and fiscal parameters that might have an impact on project economics. We therefore cannot guarantee the accuracy or correctness of our analysis and cannot be held liable for matters beyond our control.

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i. Summary and Conclusions

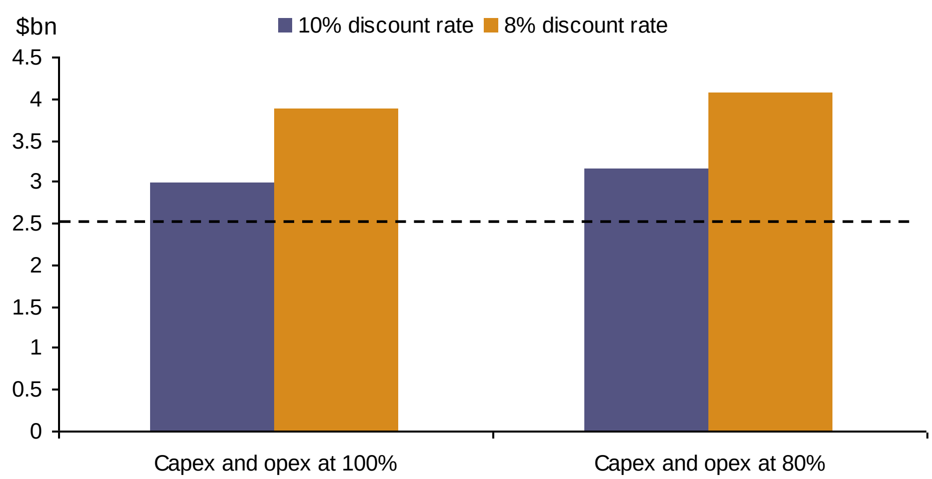
This report provides an independent valuation of the hydrocarbon assets of PetroSaudi International Limited ('PSI') and its subsidiary companies (the 'PSI Assets'). The PSI Assets consist of the production license relating to: Block III area in the Turkmenistan Sector of the Caspian Sea; Laguna el Loro in Rio Negro, Argentina; and Confluencia, Pampa Salamanca, San Bernardo, Rio Senguerr, Buen Pasto and Sierra Cuadrada in Chubut, Argentina.

This report undertakes a thorough review of the materials provided by PSI regarding the PSI Assets and has come to a conclusion regarding the potential value of the PSI Assets, using internationally recognised standards and procedures in order to determine the range of prospective values.

With respect to the Turkmenistan Serdar project, using the probability weighting of 20:40:40 for Novas' low, base, and high production scenarios, we can construct the expected value of the contractor's NPV at various discount rates and cost assumptions.

Expected Value of Contractor NPV with Novas Production Assumptions		
($ bn)	Capex and opex at 100%	Capex and opex at 80%
10% discount rate	2.983	3.158
8% discount rate	3.877	4.055

We find that at all discount and capital and operating expenditure assumptions, the NPV of the Serdar project exceeds the informal hurdle level of $2.5bn.



To summarize, we find a range for fair net present value for Serdar's assets to be $2.983 billion to $4.055 billion.

Summary: Contractor NPV ($ bn)	
Lower Bound	2.983
Upper Bound	4.055
Benchmark	3.518

A reasonable benchmark that assumes an equal 50% chance weighting across discount factors (10% to 8%) and capex/opex costs (100% benchmark to 80% reduction) provides a fair value estimate of $3.518 billion, comfortably exceeding the $2.5 billion informal hurdle.

With respect to the Argentinian POG assets, based on the analyses we conducted, we came up with the following valuation range for gross and net POG assets.

Summary: Net Assets Expected Value	
Lower Bound	$29,748,867
Upper Bound	$199,868,194
Benchmark	$108,109,651

This range is similar to the range of estimates made by PetroSaudi management. Their minimum-maximum range was $30-$120 million, while our estimated range is $29.7 million (based on a 50% risk factor discount), to $199.9 million (based on a 25% risk factor discount). A reasonable benchmark using the average implied reserve valuations over three years and a 35% risk discount factor provides a fair value estimate of $108.1 million.

In short, based on available information and the economic analysis we conducted, we believe a fair value for the combined Turkmenistan and Argentine assets to be $3.625 billion, within a range than is bounded at the low end at $3.012 billion and the upper range at $4.154 billion.

Our conclusion is based on our judgment of realistic price projections that can be achieved through forward market hedging and the medium term outlook that justifies a lower discount rate than what has been prevailing recently and lower capital expenditure costs over the next few years.

1. Turkmenistan – Serdar Field

I.1 Overview of Assets

We have used documents provided to us by PetroSaudi with respect to reserve estimates and production made by the management of PetroSaudi and by Buried Hill Energy. These documents indicate a range of recoverable resources over the contract period for the Production Sharing Agreement in place. BHE's estimate of 946 million barrels of oil and 2.633 trillion cubic feet of natural gas is the highest of the estimates for oil and higher than management's base estimate for natural gas. PetroSaudi management's own analysis sees a base case of 427 million barrels of recoverable oil and 2.202 trillion cubic feet of natural gas under the terms of the contract. The low case foresees 260 million barrels of recoverable oil and 722 trillion cubic feet of natural gas, while the high case envisages 607 million barrels of oil and 2.925 trillion cubic feet of natural gas.

The block was originally held by Buried Hill Energy under a PSA with the Government of Turkmenistan. The license area is located in the Caspian Sea in relatively shallow water depths ranging from 85 to 125 meters, some 120 km from the Turkmenistan coast. The Apsheron Ridge where Serdar is located also features British Petroleum's supergiant Gunashli-Chirag-Azeri (GCA) field in Azerbaijan, which was discovered in 1987 and alone is estimated to have about 10 billion barrels of recoverable oil.

We reviewed the project economics without making any judgment about either the geology of the resources in question or on the property rights, including the contractual rights to the field.

I.2 Regional Issues

Turkmenistan is a successor state to the USSR and is located in a land-locked area of the Caspian Sea region. As has historically been the case with all landlocked producing areas, problems associated with evacuation of hydrocarbons has meant that projects have historically been delayed as third-party access to pipelines or rail transport limit and tend to under-optimize evacuation and therefore of production. In the case of natural gas even more than in the case of oil, exports from Turkmenistan have been particularly vulnerable to access to the Russian pipeline system and through it to third countries.

Nonetheless, the Caspian region has become a major frontier area for hydrocarbon exploitation since the collapse of the Soviet Union. Its growth has been explosive despite the political and physical obstacles involved, from moving drilling equipment into the region, to undertaking seismic work, conducting exploratory and delineation drilling and financing projects and completing them. As can be seen below, the growth of production since the collapse of the Soviet Union has been explosive and is still accelerating.

Oil output from Caspian region, excluding Russia and Iran (in m b/d)				
Year	**1990**	**2000**	**2004**	**2008**
Azerbaijan	254	282	315	914
Kazakhstan	551	744	1297	1554
Turkmenistan	120	144	193	205
Total	**925**	**1171**	**1805**	**2673**

Turkmenistan is particularly well endowed with natural gas resources. BP's annual *Statistical Review of World Energy* places the country fourth in the world, behind number 1 Russia, number 2 Iran and number 3 Qatar, and just about equal to Saudi Arabia. Its natural gas resources are about equal to all of South America or all of North America. Even so, we have not in our study of the economics of the Serdar Field untaken an evaluation of Serdar's natural gas production potential.

The country's main non-associated gas fields are located in the central part of the country and its current main markets are captive and include Russia, and Ukraine, as well as other European countries that can be serviced only through Gazprom's pipeline system. The country is however both a target of and participant in the Nabucco natural gas pipeline project, which is competing with a Gazprom/Russian-led project for servicing European buyers. With announced reserves of natural gas at 7.94 trillion cubic meters in 2008 (280.6 tcf), Turkmenistan officials are now indicating that reserves on the onshore South Yolotan-Osman field alone are double that at 14 trillion cubic meters. That would also mean in all likelihood significantly higher petroleum resources. Three new wells in the region, which borders Afghanistan, have confirmed this new play. Reports from the country, confirmed by outside consultants, say that the new field is five times larger than Dualetabad, which has up to now been the country's largest field. Two new wells are being drilled into lower layers that appear to be oil-bearing zones.

The country has two major basins with proven and probable petroleum resources, including the South Caspian Sea, where, just west of the country massive fields have been discovered in Azerbaijan, as well as the northwestern areas of the country where there are huge resources in neighboring Kazakhstan.

Petroleum discoveries in the South Caspian Basin are similar to those in neighboring Azerbaijan. These crude oil streams are highly valued light crude oil streams that are low in sulfur content and high in condensate and carry a premium in Mediterranean markets.

I.3 Current Industry Issues

Licensing has been slow to develop, with an initial flurry in the period 1996-2002. No additional licenses were made until 2007, when both CNPC and Buried Hill signed PSC agreements. Interest in the country has since expanded dramatically as witnessed by the multiple meetings that took place in New York in September 2009 between the President of the country and the CEOs and other officials of some of the largest oil companies in the world.

Consultants Wood McKenzie estimate that total production in the country could grow by over 60% over the coming 6-7 years, including condensate output, which is now estimated at 100k b/d. This estimate is highly conservative in light of developments over the past few months.

Production-sharing contracts are offered only for offshore blocks. Onshore blocks are reserved for the state and its firms except for stringent service contracts. Recent winners of Turkmenistan blocks have been Itera, a Russian firm that beat out two other Russian firms for Block 21, and RWE-DEA, German utility giant RWE's upstream arm. Itera became the first Russian firm to enter the country and it won in competition with TNK-BP and Lukoil. Given Russia's hold on the country's natural gas exports to Ukraine and Europe, the fact that a Russian firm has gained acreage has been noteworthy. Itera has ties to the country and has been shipping gas from Turkmenistan to Ukraine for about 15 years. Itera, in announcing the deal, projects oil output from Block 21 plateauing at 400 thousand barrels a day and natural gas at 10 billion cubic meters per year. If this is correct the Wood McKenzie production estimates are now out of date. The PSC was signed in the presence of both countries' Presidents at a time when Turkmen natural gas exports to Ukraine were being blocked by Russia. With respect to onshore PSCs, George Schoning, RWE's chief executive has said publicly that he has pressed President Gurbanguly Berdimuhammedov to offer onshore acreage to foreign firms on a PSC basis and the President "did not exclude that forever."

The country has become a major target not only of companies but of governments. With Russia controlling its only natural gas export route, the country has announced start up of a new pipeline to Iran to diversify exports from Daletabad, which is near the Iranian border. The country has a history of exports to Iran. China, the EU and Russia have also entered the contest, given the enormity of the country's gas reserves and its potential choices on new evacuation routes.

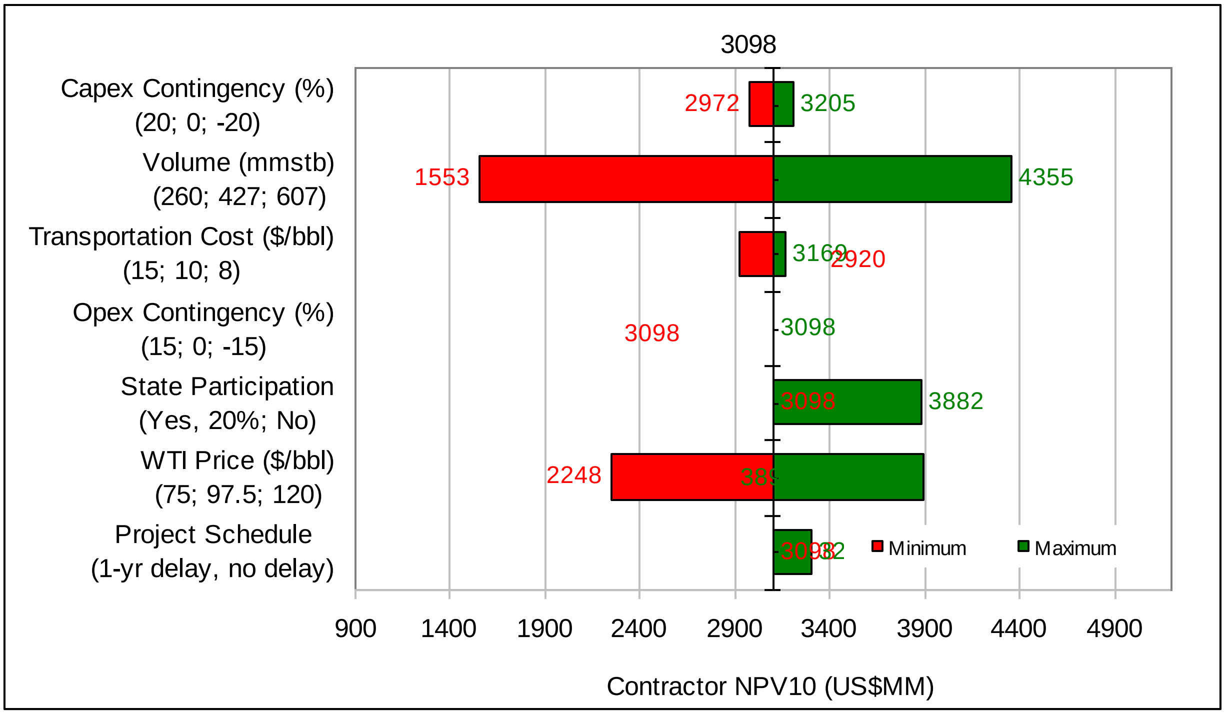
I.4 Valuation Methodologies

Valuation of the Serdar assets in Turkmenistan was aided greatly by the provision of a detailed net present value (NPV) model by PetroSaudi management. Furthermore, the valuation is aided by a Technical Update on likely production scenarios done by Novas Consulting Ltd., which updates production scenarios estimated by Mintaka and the original estimates provided by Buried Hill Energy.

The original cash-flow model provided a contractor net present value of cash flow of $3.1 billion, using the Mintaka base production assumptions, a 10% discount rate, benchmark assumptions on capital and operating expenditures, and critically, a benchmark price assumption fixing WTI prices at $97.5/bbl and assuming a 2.5% price escalation rate annually.

The graph below shows the robustness of the NPV result to key assumptions, including production volume, benchmark oil prices, transportation costs, capital and operating expenditures, state participation, and project delays. As may be expected, the production volume is the most important contingency factor in determining ultimate value realization, followed by assumptions over the benchmark WTI price.

Our approach was essentially a "robustness test," where we observed the variability of the NPV output to variations around reasonable assumptions over the project economics. In particular, we considered alternative assumptions over the price trajectory, the discount rate, and the capital/operating expenditure to develop reasonable bounds for the "fair value" of the Serdar assets.



I.5 Valuation Assumptions

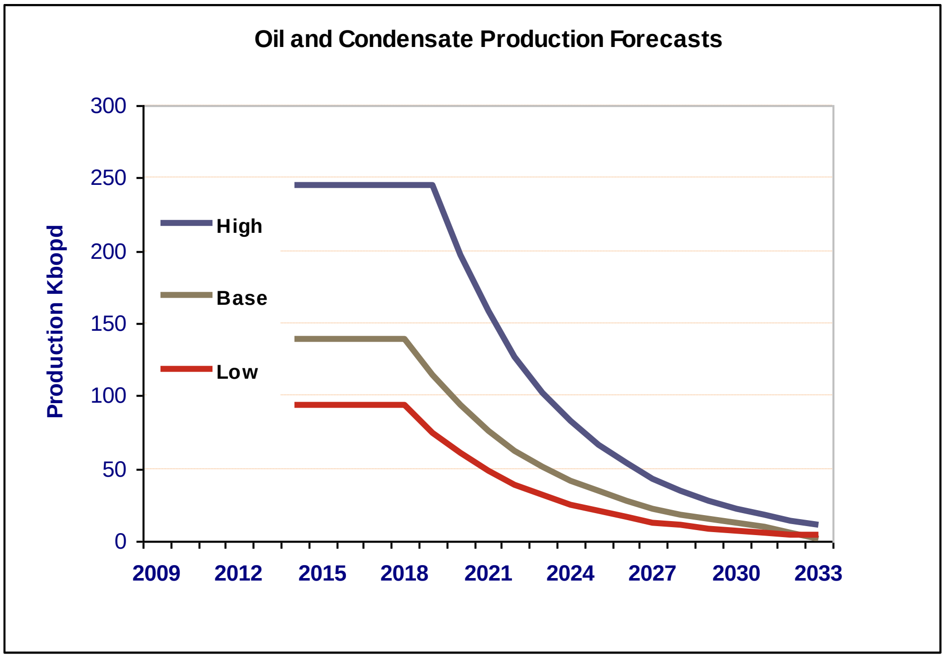
I.5a Production

Mintaka provided low, base, and high estimates over the eventual production flow, varying from a low of 260 million barrels of oil equivalent to 607 million barrels, with the base at 427 million barrels. The resulting contractor NPV10% varied between as low as $1.553 billion to $4.355 billion.

Subsequently, Novas provided technical updates on the Serdar field by reviewing data from the current license holder BHE. Novas estimates ultimate recoverable oil will range from a low of 309 million barrels to as high as 893 million barrels, with a base around 462 million barrels. These are somewhat higher than estimates provided by Mintaka.

Asset	Novas Estimate of Recoverable Resources (mm bbls)		
	Low	**Best**	**High**
Pereryva	254	332	637
Balakhany	55	130	256
Total	**309**	**462**	**893**

These new estimates of recoverable resources allow us to construct new production scenarios, keeping all other assumptions about the decline rate, etc. ceteris paribus with Mintaka's scenarios:



As mentioned above, we do not make any judgment about the geology of the project and hence, relied solely upon Novas' provided production estimates. Hence, we use Novas' provided low, base, and high estimates for petroleum and gas production as given, at the same probability weighting of 20%, 40%, and 40% respectively.

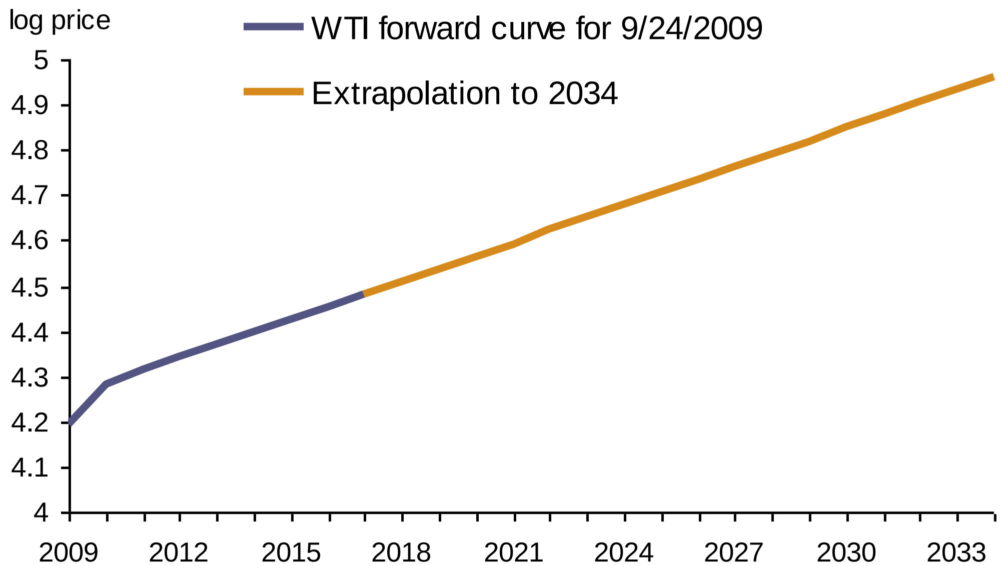
I.5b Petroleum Prices

The next most important economic assumption was the potential trajectory of prices over the lifetime of the project. Accurate forecasts for the future trajectory of oil prices is notoriously challenging, coping with extreme price volatilities. We do note that even the lower bound WTI price assumption placed at $75/bbl in 2009 is significantly above both the prompt WTI price at time of writing and also the average price for 2009. The benchmark price assumption of $97.5/bbl and the high case of $120/bbl has the potential to overstate the value of the project even further.

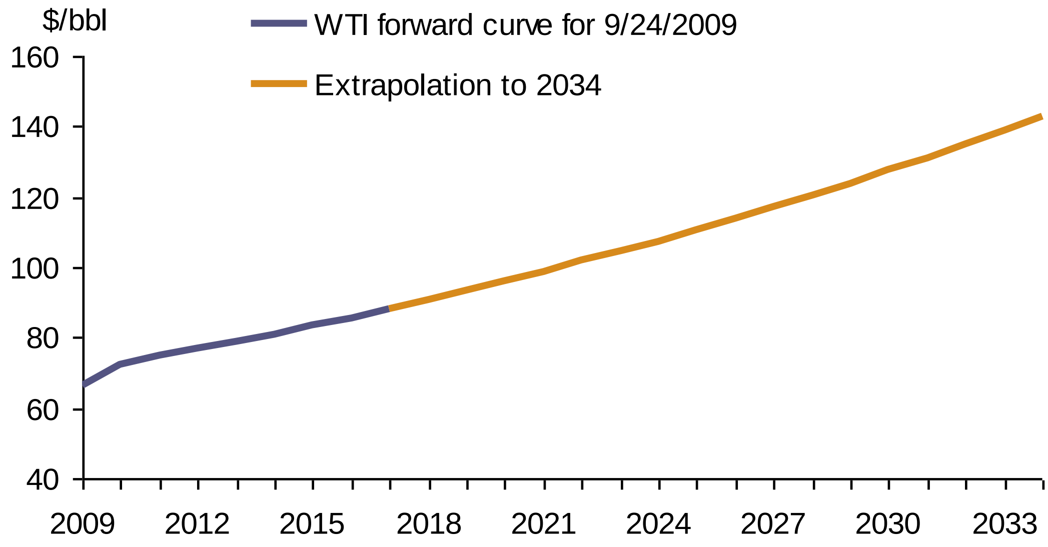
Instead of moving through vacuous price scenarios, we decide to firmly anchor price trajectories based on the WTI futures price traded on NYMEX at September 24, 2009. Using financial futures prices presents many advantages:

First, futures markets present expectations of the likely future price of spot WTI prices based on the best information of market participants. Second, upstream producers can financially hedge and theoretically "lock-in" its expected delivery of the given futures prices, thus removing uncertainty risk over this critical economic assumption input.

We used the most liquid contracts with delivery on December of their respective years to form our futures price "strip." However, NYMEX currently only features traded contracts to 2017, while Serdar's oil production lifecycle is projected to continue to 2034. Hence, we extend the futures price from 2017 to 2034 by linearly extrapolating the natural logarithm of the futures price at the same escalating rate as was observed from 2010 to 2017. The resulting logarithmic price trajectory is shown below:



Taking the natural exponent of this linear extrapolation provides the following "strip price" assumption over the benchmark nominal WTI price trajectory:



We left the trajectory of natural gas prices unchanged as they form only a marginal component of the total value of the asset, but one may perform a similar exercise of using the extrapolated NYMEX Henry Hub strip prices for deliverable natural gas; or, one might link the natural gas price to oil prices as is common in Asian contracts..

I.5c Discount Rate

We also consider variations to the discount rate. Economically, the discount rate is supposed to reflect many characteristics of the decision-maker, including his inter-temporal consumption preferences, his tolerance for risk, and access to capital. In practice, many decision-makers use simple round numbers or market signals over the risk-free rate of return, such as the 10-year US Treasury yield interest rate.

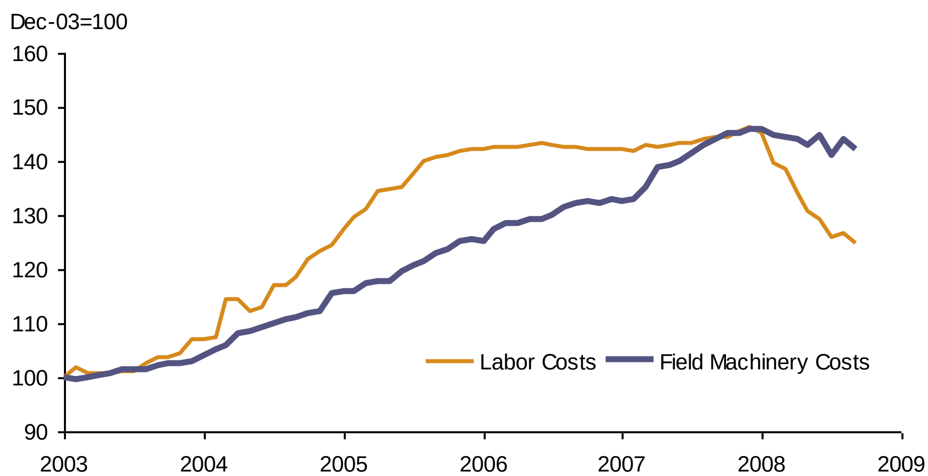
However, we felt that the original benchmark discount rate, at 10%, was too high. Strictly speaking, this would suggest a prevailing capital interest rate of 10% annually. However, prevailing 10-year Treasury yields at time of writing was around 3.5% annualized. Furthermore, it is expected that the global economy will progress through an extended period of low interest rates. This stems from a combination of loose monetary policy by central banks to a world still recovering from a difficult economic contraction and continued capital account surpluses from China, Japan, and other Asian and Middle Eastern exporters, who will largely re-inject the surplus through the US Treasury market.

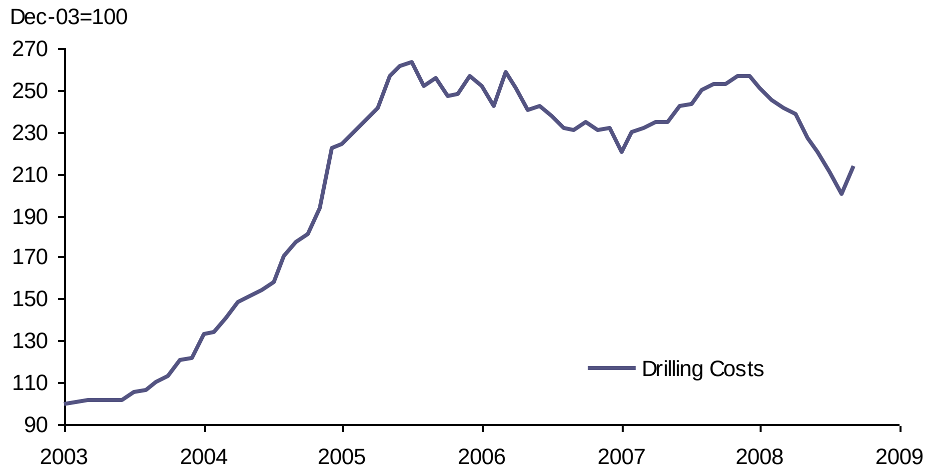
Hence, reflecting also the risk and inter-temporal preferences of PetroSaudi, we felt a less conservative discount rate of 8% may be more appropriate for formulating an NPV valuation of Serdar's assets.

I.5c Capital and operating expenditures

We also felt that the original cash flow model has the potential to overestimate the capital and operating costs of the project due to the likelihood of continued deflation in upstream production costs.

Cyclically, the hydrocarbon industry has emerged from a multi-decade period of under-investment and infrastructure constraints, incentivized in part by higher oil and gas prices throughout much of this decade. Coupled with a slowdown in the world economy, this has contributed to significant deflation in the upstream costs of oil and gas production. Below is a graph of upstream oil and gas producer price indices as tracked by the US Bureau of Labor Statistics.





We see how after a period of substantial inflation starting from 2003 to 2008, the costs of labor, machinery, and drilling in the upstream hydrocarbon sector have now significantly reversed.

Hence, in our analysis, we shall consider the impact of reducing their benchmark capital and operating cost assumptions by 20%. In the event, as noted above, assumptions over capital and operating expenditures do not dramatically impact the ultimate contractor NPV.

1.6. Valuation Summary

First, we review the original NPV results provided by the cash-flow model. Below is a table summarizing the NPVs at a 10% and 8% discount rate at Mintaka's base case for production and the three price scenarios:

Mintaka Production Base Case (462 mn bbls)			
2009 price scenarios ($/bbl)	**Contractor NPV10% ($bn)**	**Contractor NPV8% ($bn)**	**IIR**
75	2.248	2.980	51%
97.5	3.098	3.987	62%
120	3.890	4.934	72%

The NPV10% varies between $2.248 billion and $3.890 billion, with the internal rate of return varying between 51% and 72%.

If instead we use the NYMEX WTI strip assumption, we result in the following NPV and IIRs over various levels of discount rate and capex/opex costs in the Mintaka base production scenario:

Mintaka Base (40% probability)		
NPV	Capex and opex at 100%	Capex and opex at 80%
10% discount rate	2.144	2.373
8% discount rate	2.861	3.102

IIR	Capex and opex at 100%	Capex and opex at 80%
10% discount rate	50%	58%
8% discount rate	50%	58%

First, we note that inputting the NYMEX WTI strip price substantially reduces the NPV10%, ceteris paribus, from $3.098 billion to $2.144 billion. However, reducing the discount rate from 10% to 8% raises the NPV to $2.861 billion. Furthermore, reducing the capex/opex costs by a factor of 20% raises the NPV slighter further, to $3.102 billion. The internal rate of return drops to 50% in the case of benchmark costs, while it rises to 58% in the case of reduced costs.

We perform similar exercises for the new production scenarios- base, low, and high, estimated by Novas:

Novas Base (40% Probability)		
NPV ($ bn)	Capex and opex at 100%	Capex and opex at 80%
10% discount rate	2.353	2.515
8% discount rate	3.106	3.271

IIR	Capex and opex at 100%	Capex and opex at 80%
10% discount rate	53%	61%
8% discount rate	53%	61%

Novas Low (20% Probability)		
NPV ($ bn)	Capex and opex at 100%	Capex and opex at 80%
10% discount rate	1.227	1.362
8% discount rate	1.644	1.774

IIR	Capex and opex at 100%	Capex and opex at 80%
10% discount rate	44%	52%
8% discount rate	44%	52%

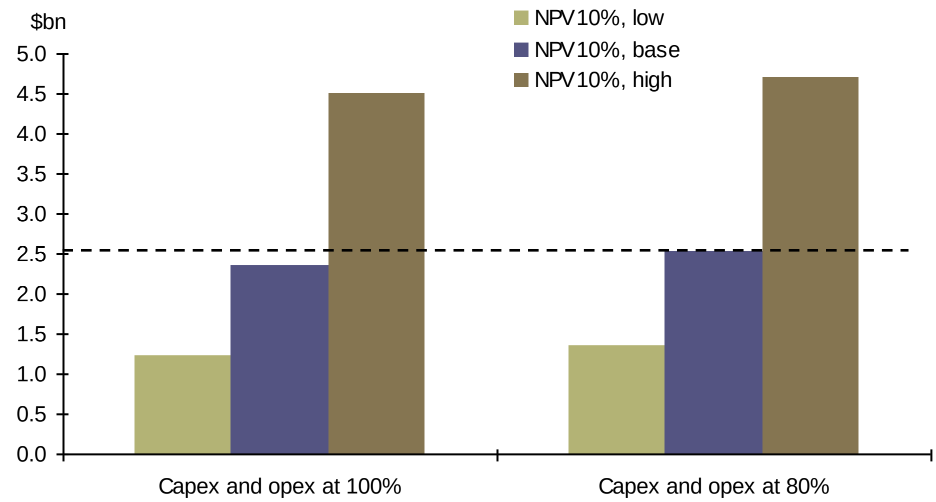
Novas High (20% Probability)		
NPV ($ bn)	Capex and opex at 100%	Capex and opex at 80%
10% discount rate	4.491	4.700
8% discount rate	5.764	5.980

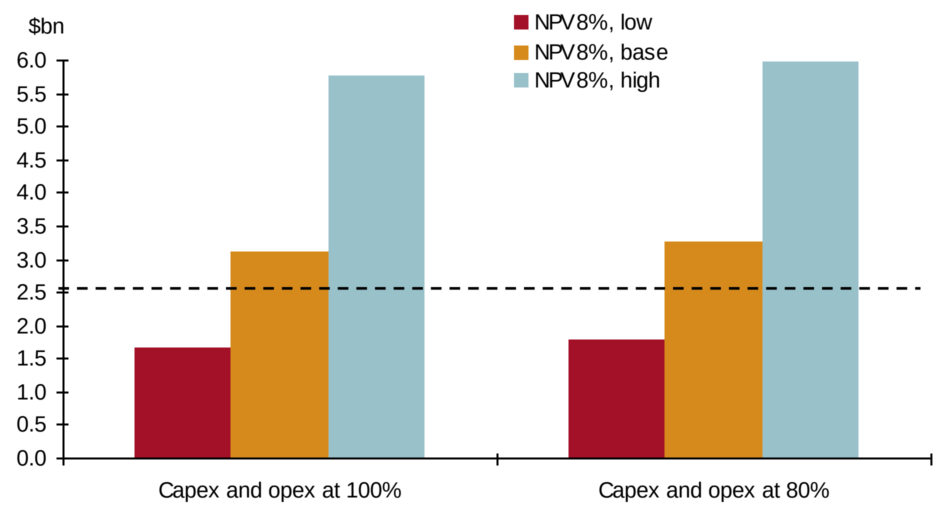
IIR	Capex and opex at 100%	Capex and opex at 80%
10% discount rate	69%	79%
8% discount rate	69%	79%

For the Novas base case, the NPV varies somewhere between $2.353 billion and $3.271 billion, with most of the variation driven by the lower discount factor.

We also note that in the case of the low production scenario, the NPV is never higher than the informal $2.5 billion hurdle level suggested by 1MDB PetroSaudi Limited, while in the case of high production, the NPV is always higher. The lowering of the discount rate generally proves decisive in moving NPVs higher than the hurdle level.

However, it is worthwhile noting that, as per discussions with PSI management and their consultants, the expert technical opinion is that assigning a 20% probability to the low production scenario is likely overestimating its probability, and may be disregarded. However, it is an industry analysis standard to include such low estimates and we keep its assigned weighting to be conservative.





Using the probability weighting of 20:40:40 for Novas' low, base, and high production scenarios, we can construct the expected value of the contractor's NPV at various discount rates and cost assumptions.

Expected Value of Contractor NPV with Novas Production Assumptions		
($ bn)	Capex and opex at 100%	Capex and opex at 80%
10% discount rate	2.983	3.158
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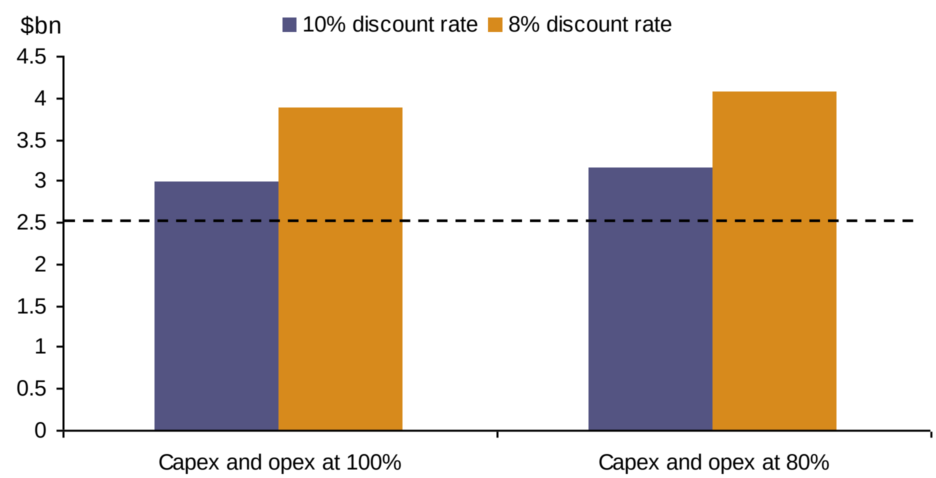
We find that at all discount and capital and operating expenditure assumptions, the NPV of the Serdar project exceeds the informal hurdle level of $2.5bn.



To summarize, we find a range for fair net present value for Serdar's assets to be $2.983 billion to $4.055 billion, which is considerably higher than the $2.248

billion and $3.890 billion range suggested by Mintaka's base case. A reasonable benchmark that assumes an equal 50% chance weighting across discount factors (10% to 8%) and capex/opex costs (100% benchmark to 80% reduction) provides a fair value estimate of $3.518 billion, comfortably exceeding the $2.5 billion informal hurdle.

Summary: Contractor NPV ($ bn)	
Lower Bound	2.983
Upper Bound	4.055
Benchmark	3.518

Argentina: Patagonia Oil & Gas Blocks

II. 1 Overview of Assets

POG holds significant working interests in seven onshore exploration blocks in the San Jorge and Neuquến basins, the two most significant of the five main sedimentary basins in the country. PetroSaudi reports and evaluations conducted for the firm indicate that for two of the seven blocks, reserve best estimates for them are Confluencia at 7,660,840 barrels and Laguna el Loro at 14,745,300 barrels, for a total best estimate net attributable risked resources of 22,406,140 barrels (with low P90 estimates of 8.5 million barrels and high P10 estimates of 39.1 million barrels).

We review the project economics with making no judgment about either the geology of the resources in question or on the property rights including the contractual rights to the field.

II.2 Regional Issues

Latin America has been at the forefront of resource nationalism since oil and natural gas resources were first discovered more than 100 years ago. In the most recent cyclical expansion period, which began in 2002-2003, Latin American governments were among the most aggressive globally in finding ways to raise government take and reduce the role of foreign contractors. This has been especially true in the cases of Bolivia, Ecuador and Venezuela. The cyclical downturn following the collapse in oil prices after July 2008 has severely impacted hydrocarbon-producing countries in the region, with the exception of Brazil, where major discoveries have facilitated significant new investments and where contractor terms remain globally competitive.

In Argentina, where the government's response to rising international prices was to freeze domestic prices for both natural gas and petroleum, governmental budgets have been squeezed significantly by the strains associated with steep subsidies and by the financial disincentives to industry to invest in a price-controlled environment. Indeed, the price controls established in 2002 resulted in a reduction in investments in new oil and gas production and a steep decline in both reserves and output. As a result, the government started to relax restrictions on investment and take steps to encourage investment even as oil prices were rising in late 2007 and the first half of 2008.

New government incentives have been most noteworthy in natural gas, where the government agreed in 2008 to raise gas prices to encourage domestic production and reduce highly expensive imports. Even so, it has to ration gas and the new price incentives have thus far failed to encourage adequate exploration or to boost output. In July 2008, President Cristina Fernandez de Kirchner signed an agreement with the hydrocarbon producing provinces to increase wellhead gas prices paid by utilities (which are 60% dependent on natural gas for power generation) from $1.60 per MMBTU to $2.60. While this change makes current production more profitable, it is still inadequate for boosting exploration, which requires a minimum $3 per MMBTU. More incentives are expected, as the government is relying on imports from Bolivia ($4.50) and via LNG (between $6 and $8 per MMBTU). Both of these sources are costly, as are substitutes from gas oil and fuel oil. The government's subsidy for these imports is running at about $7 billion annually. In order to reduce these costs, the government has been raising residential tariffs, which has been one of the factors undermining the government's approval.

In terms of oil, the government in late 2008 announced new tax incentives both to increase exploration and production and to expand domestic refining. Two new programs were implemented, the Petroleum Plus program and the Refining Plus program. In the former, the government is granting tax credits or tax exemptions to producers presenting new projects. The petroleum program was modeled on the plan established earlier in 2008 for natural gas.

Historically, the Argentine government has gone through multiple cycles of market liberalization and reform followed by resource nationalism and fixed prices. As a result, the country's reserves have grown and shrunk rapidly, as has the country's production base. When openings have occurred, the industry's response has been rapid and both reserves and production have responded quickly. The table below demonstrates this rapid response:

The late 1970s saw a rise in resource nationalism and a decline in investment, which resulted in reserve falling by 600 million barrels between 1980 and 1983 and production declining in subsequent years from 517 thousand barrels a day to 465 thousand barrels a day. The most significant market reforms occurred in the late 1980s and early 1990s, a period which saw reserves growing from 1.6 billion barrels in 1990 to 3 billion barrels in 1992, only to tail off with the rebirth of resource nationalism and tighter fiscal requirements and the reintroduction of fixed product prices after 2002. Once market reforms are re-introduced, as we expect they will be, reserve values tend to increase rapidly and dramatically.

Argentina's Proven Oil Reserves (mmb/d) and Production (mb/d), 1980-2008															
Year	1980	1982	1984	1986	1988	1990	1992	1994	1996	1998	2000	2002	2004	2006	2008
Reserves	2.5	1.9	2.3	2.2	2.3	1.6	2.0	2.3	2.6	2.8	3.0	2.8	2.5	2.6	2.6
Production	506	517	509	465	481	517	587	695	823	890	819	818	754	716	682

II.3 Current industry issues

Although some companies initially responded positively to the government's new incentives, the industry as a whole has taken the view that more incentives will be in the offing. There is also clear evidence that some foreign and domestic producers, comfortable with working in Argentina, are looking to acquire assets at a competitive price.

Ten transactions of consequence have taken place since 2006. As follows:

Date	BUYERS	SELLERS
9/3/2009	Pluspetrol Resources Corp	Petro Andina Resources Inc
8/28/2009	Connacher Oil and Gas Limited	Petrolifera Petroleum Limited
4/29/2008	Delta Hydrocarbons BV	Trefoil
12/24/2007	Petrobras Energia SA; Petroleo Brasileiro SA	Noble Energy Incorporated
12/21/2007	Petersen Group	Repsol YPF SA
11/27/2007	Pluris Energy Group Inc	Clear Srl
11/6/2007	Apco Oil and Gas International Inc; Petrolera Entre Loma	Petrobras Energia SA; Petrouruguay S
3/1/2007	Petrobras Energia SA; Petroleo Brasileiro SA	ConocoPhillips
9/18/2006	Apache Corporation	Pan American Energy LLC
1/17/2006	Apache Corporation	Pioneer Natural Resources Company

It would appear that interest in the country is picking up. At a recent John S. Herold conference in Greenwich, CT a number of independent producers from the United States expressed an interest in entering the country or expanding their operations.

II.4. Valuation methodologies

Valuation of the POG assets in Argentina is difficult because PetroSaudi was unable to offer us a cash flow model comparable to the one provided for the Serdar assets and because they lacked an ability to judge the nature of the evolving royalty and fiscal regimes or to view the precedents for value comparison purposes.

Nonetheless, we felt the terms of similar upstream resource transactions – either asset or corporate purchases – brokered over the last three years in Argentina may provide a useful basis for evaluating the POG assets, even though these remain contingent resources. However, we excluded the most recent transaction, where Pluspetrol Resources purchased the El Corcobo Norte (ECN) field from

Petro Andina Resources, due to the fact that the assets were not of conventional reserves but were of heavy oil. The remaining transactions were all over conventional reserves and thus formed the basis for our valuation methodology:

First, we took the low, best, and high estimates compiled by Ragusa for the two assets in question, Confluencia and the Laguna el Loro licenses:

Asset	**Estimates of Contingent Resources (mm bbls)**		
	Low	**Best**	**High**
Confluencia:	2.396	16.654	30.709
Laguna el Loro:	0.168	32.055	118.925
Total	**2.564**	**48.709**	**149.634**

It is important to note that these are contingent resources, i.e. petroleum that is estimated to be potentially recoverable but currently not considered commercially recoverable. Hence, these are technically not reserves. However, Ragusa notes that the low, best, and high estimates have a rough comparability with Proved or 1P, Proved plus Probable or 2P, and Proved plus Probable plus Possible or 3P, reserve classifications. In probability terms, these reserve levels may be considered to be 90%, 50%, and 10% confidence levels over the amount of ultimate recoverable reserves. In other words, one may be 90% confident that the total recoverable petroleum from Confluencia and Laguna el Loro will be at least 2.564 million barrels. Our methodology for estimating expected value will proceed on this basis.

Next, we compiled the minimum, arithmetic average, median, and maximum of implied Proved, 2P, and 3P reserve values for Argentine upstream conventional assets over the last three years.

Contingent Resource Evaluations Based on 3 years of Transactions			
	Proven	**2P**	**3P**
Minimum	$3.56	$3.21	$1.13
Average	$8.20	$6.36	$4.55
Median	$8.08	$6.50	$4.77
Maximum	$14.89	$9.25	$7.75

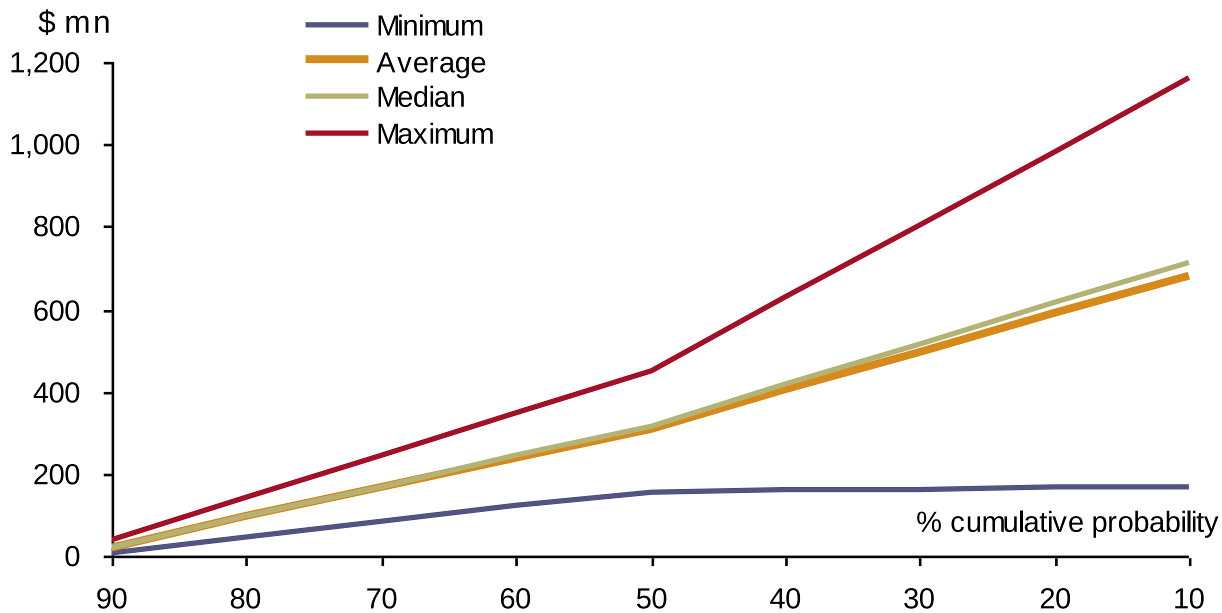
The implied values are computed in US dollar per barrel-of-oil-equivalent by dividing the reserve size by the transactional dollar amount. Assuming that previous deals over the last three years were conducted at reasonably efficient prices, the implied reserve valuations may provide reasonable valuation bounds for the POG assets. We then valuated total assets at various levels of probability:

Undiscounted "fair value" bounds for Total POG assets:			
	Proved	**2P**	**3P**
Minimum	$9,127,840	$156,355,890	$169,086,420
Average	$21,024,800	$309,789,240	$680,834,700
Median	$20,717,825	$316,421,577	$713,711,685
Maximum	$38,177,960	$450,558,250	$1,159,663,500

Next, we constructed a uniform probability distribution, running from 10% to 90% cumulatively probable states of likelihood:

Cumulative Probability Distribution of total POG contingent assets									
Probability (%)	90	80	70	60	50	40	30	20	10
Minimum	$9,127,840	$45,934,853	$82,741,865	$119,548,878	$156,355,890	$159,538,523	$162,721,155	$165,903,788	$169,086,420
Average	$21,024,800	$93,215,910	$165,407,020	$237,598,130	$309,789,240	$402,550,605	$495,311,970	$588,073,335	$680,834,700
Median	$20,717,825	$94,643,763	$168,569,701	$242,495,639	$316,421,577	$415,744,104	$515,066,631	$614,389,158	$713,711,685
Maximum	$38,177,960	$141,273,033	$244,368,105	$347,463,178	$450,558,250	$627,834,563	$805,110,875	$982,387,188	$1,159,663,500

The graph below shows the lower and upper bands of total reserve valuation at descending levels of likelihood:



From this, we can provide probabilistic expected values of the total POG assets at various levels of implied reserve value. Further, we consider various degrees of discounting to account for the risky and contingent nature of the resources. Based on input from PetroSaudi management, we consider discounts on the order of 25% - 50% would be reasonable, with 35% being a median:

Expected Value of Total Assets:				
Expected Value:	No discount	discount 25%	discount 35%	discount 50%
Minimum	$118,995,468	$89,246,601	$77,347,054	$59,497,734
Average	$332,645,079	$249,483,809	$216,219,301	$166,322,539
Median	$344,640,009	$258,480,007	$224,016,006	$172,320,005
Maximum	$532,981,850	$399,736,388	$346,438,203	$266,490,925

And finally, from here, we can construct the expected value of net assets of the 50% share in the POG licenses:

Expected Value of Net Assets:				
Expected Value:	No discount	discount 25%	discount 35%	discount 50%
Minimum	$59,497,734	$44,623,300	$38,673,527	$29,748,867
Average	$166,322,539	$124,741,905	$108,109,651	$83,161,270
Median	$172,320,005	$129,240,003	$112,008,003	$86,160,002
Maximum	$266,490,925	$199,868,194	$173,219,101	$133,245,463

This helps us form bounds for our fair market valuation, running from roughly $29.7 million using low implied reserve values and a high 50% discount, to $199.9 million from using high implied reserve values and a low 25% discount.

II.5 Valuation Assumptions

As noted in the previous section, there was no direct way to construct an evaluation methodology based on cash flows stemming from a combination of oil price assumptions or fiscal factors. We chose to focus on valuations stemming from the recent flow of transactions for assets in Argentina, recognizing the fact that we were comparing contingent resources with producing resources in some cases. Hence, the assumption that the implied reserve valuations from the recent upstream transactions were "fair" is critical to our methodology.

On the other hand, because the fiscal regime in Argentina is likely to improve considerably in the coming years, we felt that the transactions record provided a reasonable proxy for evaluating the assets in question. Since the contingent resources evaluated came from only two of the seven blocks held by POG, and only for oil rather than for any potential associated gas that might be in place, we felt that there was an even more conservative bias to our study.

II.6. Valuation Summary

Based on the analyses we conducted, we came up with the following valuation range for gross and net POG assets.

Summary: Net Assets Expected Value	
Lower Bound	$29,748,867
Upper Bound	$199,868,194
Benchmark	$108,109,651

This range is similar to the range of estimates made by PetroSaudi management. Their minimum-maximum range was $30-$120 million, while our estimated range is $29.7 million (based on a 50% risk factor discount), to $199.9 million (based on a 25% risk factor discount). A reasonable benchmark using the average implied reserve valuations over three years and a 35% risk discount factor provides a fair value estimate of $108.1 million.

III. Biographical Background

This report is submitted by Dr. Edward L. Morse and Dr. Daniel P. Ahn.

Dr. Edward L. Morse

Dr. Morse is widely recognized as one of the world's leading experts on the commercial aspects of the world petroleum and natural gas industries. He joined Louis Capital Markets as Managing Director and Head of Research in October 2008. He had previously been at Lehman Brothers until the firm declared bankruptcy in September 2008, where he was Managing Director and Chief Energy Economist, working across the firm's energy activities, from commodities trading to private equity and investment banking. At Lehman he built a world class research team covering petroleum and petroleum products, natural gas, power, uranium and nuclear, emissions, base and precious metals, and soft commodities, working closely with the commodities trading group in the Lehman Fixed Income Division, but also across the bank.

A leading analyst of the international oil and gas sector, his career in energy spans three decades and includes senior positions in business, government, academia and publishing. Before joining Lehman, Morse spent seven years at Hess Energy Trading Co., LLC (HETCO), providing strategic advice to the firm as well as to its clients and counterparts on oil and natural gas market trends. He secured for HETCO a unique niche in dealing commercially with leading OPEC countries and through his initiative co-led a group that established a full-scale risk-management capability for SONATRACH, the state-owned oil company of OPEC member Algeria. He also led the consulting effort that established the contractual framework and organization of the International Mercantile Exchange for Qatar. For a decade before then he served as publisher and CEO of Petroleum Intelligence Weekly and other industry newsletters published by the Energy Intelligence Group.

He received his Ph.D. from Princeton University, where he taught for six years before joining the senior research staff at the Council on Foreign Relations and where he became director of the "1980s Project," the largest research effort undertaken by the CFR up to that point. During the Carter and Reagan administrations, Morse held various positions in the Department of State, including Deputy Assistant Secretary for International Energy Policy, the most senior official at State with full time responsibilities in energy. He represented the United States at the International Energy Agency, where he chaired the Standing Committee on Long-Term Cooperation, as well as various bilateral energy working groups with such other countries as Norway, Japan, the UK, Nigeria, and Iran.

Included in his industry experience is a management position at Phillips Petroleum and co-founder of PFC Energy in Washington DC. At Phillips Petroleum he was Director of International Affairs and sat on the firm's management committee which had responsibility for reviewing every capital project of the firm, including upstream, downstream, midstream, petrochemicals and retail services. Among the consulting assignments he has undertaken are the establishment of the oil export formula for Yemen when the country became a net exporter and negotiation of Yemen's initial set of export contracts on behalf of the Supreme Petroleum Council of that country. He also served as the lead negotiator for the United Nations Security Council and the UN Compensation Commission on Iraq with the government of Iraq in the establishment of the export mechanisms associated with the oil-for-food program for Iraq. Additionally he has served as consultant to the US Departments of State, Energy and Defense on oil and natural gas issues and on issues related to markets and speculation.

In the winter and spring of 2001 Morse chaired a Task Force on Energy Security, jointly sponsored by the Council on Foreign Relations of New York and the James A. Baker III Institute, and issued two reports recommending urgent changes in US domestic and international energy policy. He currently is a member of the Federal Advisory Committee on Energy & Environment Cooperation with China under the direction of Treasury Secretary Paulson.

Morse is Chairman of the New York Energy Forum and serves on a number of academic advisory boards, including those of the energy programs at Columbia University and Johns Hopkins School of Advanced International Studies. He is a member of the Council on Foreign Relations and of the Oxford Energy Policy Club, as well as a member of the editorial committee of *The Geopolitics of Energy* and of the journal *Oil*. He is a member of the Board of Trustees of American Ballet Theatre. Morse is the author of a number of books and dozens of articles on energy, economics and international affairs. He is also the recipient of a prize from the International Association for Energy Economics.

Dr. Daniel P. Ahn

Dr. Daniel P. Ahn is currently Director of Macroeconomic Research and Portfolio Strategy at LCM in New York, where he is responsible for developing firm-wide global macro fundamental perspectives and contributes to LCM Commodities research through weekly briefings and special reports. . Previously, he was head of Portfolio Engineering for Barclays Capital Fund Solutions in the Americas, where he engineered quantitative models and developed risk management and structuring methods for multi-asset portfolio index products. He also initiated and developed the Global Markets Monitor to provide review and outlook on major macro asset classes and managed a team of analysts. He joined Barclays directly from Lehman Brothers, where he was senior energy economist and where he built robust and quantitatively sophisticated economic models for team research. He was the lead researcher and author of Lehman's Commodities reports on financial bubbles and commodity prices. Before joining Lehman he was a research at the National Bureau of Economic Research in Cambridge.

Dr. Ahn received his Ph.D. at Harvard University under the supervision of Martin Feldstein and Kenneth Rogoff. His dissertation was "Essays in Finance, International Economics and National Security," He also was a member of the Energy Security Working Policy Group at the John F. Kennedy School of Government, and was also a teaching fellow.

Ahn is on the Advisory Board for Global Flows, a technology start up, participates on the economics and Geopolitics research team at the Council on Foreign Relations, Inc., in New York, and is a member of the Executive Board of Young Professionals in Energy as well as of the New York Energy Forum. He is regularly quoted in major daily newspapers and wire services, and his research has been cited in US Senate testimony.