Economic Evaluation Report
On Manas Petroleum Corporation's
Concessions in Albania

Blocks A, B, D and E

Effective Date: 1 November 2008

Submitted to:

Manas Petroleum Corporation

MANAS
Petroleum Corp.

Submitted By:

GUSTAVSON ASSOCIATES
5757 CENTRAL AVE. SUITE D BOULDER, COLORADO 80301 USA

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1. EXECUTIVE SUMMARY

Gustavson Associates LLC (the Consultant) has been retained by Manas Petroleum Corporation (the Client, Manas) to prepare an Economic Evaluation Report regarding the entire concession position in Albania currently licensed by Manas.

The license position is described as Blocks A, B, D & E that are subject to two Production Sharing Contracts (PSC) with the Albanian government that were signed on July 31, 2007 and ratified by the Albanian government as of December 13, 2007. These concession blocks contain a total of approximately 780,853 acres (3,160 square kilometers)[1] located along the NW-SE trending fold belt of northwestern Albania. The plays include potential conventional exploration targets involving sub-thrust hydrocarbon accumulations in fractured carbonates.

Manas' primary exploration targets are deep (approximately 13,123 feet or 4,000 meters), sub-thrust fractured carbonate reservoirs. Seismic imaging from the 1990s revealed a large carbonate sub-thrust, extending over blocks B, D and E on the Manas blocks known as the Ionian carbonate, which is the targeted reservoir and holds all Albanian hydrocarbon reserves.

There are nine prospects included in this report known as Rinas and Gyurice in Block B; Nikel, Kashari and Kamez in Block D; Rova, Rova West, Sauk and Papri in Block E. There are also a number of lead areas that will be delineated by seismic and may be explored in the future on all four Blocks.

The hydrocarbon type that could occur in these reservoirs is an unknown, due to their depth and lack of exploration nearby. This report considers three possible cases: (1) Oil with associated gas, (2) Oil with gas cap, and (3) Gas with condensate. It is expected that if oil is present at the depths of these prospects, it will be good quality oil with API gravity in the range of 30 to 37 degrees.

[1] All values are presented in both US standard and metric units. Standard conversions were used for distance, area and volume values. For Oil, a 33^o API was assumed for a 7.33 Bbl/tonne conversion; for Condensate a 50^o API was assumed for an 8.41 Bbl/tonne conversion and for Gas a 35.315 ft^3/m^3 conversion was used.

Manas Petroleum Corporation operates under two PSCs that cover Blocks A and B and Blocks D and E, respectively. Each PSC specifies the work commitment and fiscal terms. The work commitment represents the capital investments that Manas Petroleum Corporation will spend on the exploration of their blocks, while fiscal terms govern the allocation of revenues resulting from oil and gas production.

The objective of the economic model constructed by Gustavson Associates is to estimate the Net Present Value (NPV_{10}) based on the exploration and development of the P_{50} Resource Estimates[2] from the "Resource Evaluation Report on Manas Petroleum Corporation's Concessions in Albania (Revision 1.0)" dated October 1, 2008 was prepared by Gustavson Associates.

In the model[2a], three scenarios are considered. Under the first scenario (Complete Success), it is assumed that the exploration program will be successful leading to the discovery of commercial hydrocarbons at each one of the nine prospects. Under the second scenario (Partial Success), it is assumed that the exploration program will be successful only at five prospects: Gyurice, Rova, Sauk, Papri, and Rova West. Under the third scenario (Complete Failure), it is assumed that no discovery of commercial hydrocarbons is made at any of the three initial prospects that include Rinas, Gyurice, and Rova and the blocks are abandoned.

There are many variables in a success case scenario such as drilling and operating costs, the number of rigs used, flow rates, pipeline diameters, pricing, etc. that could change which would have a material impact on the potential value of this project. Gustavson Associates used the best current estimates available as well as input from Manas for this report.

[2] The P_{50} resource numbers in the economic report differ slightly from those in the resource report. The difference is well within the margin of error, since there is considerable uncertainty about the prospects at this time. The two reports use different timing assumptions. Parameters for the well type curves were selected so that production over 30 years would be equal to the P_{50} resources, given an assumed well spacing. The economic model used the same type curve parameters, but did not restrict production to 30 years. Rather, the economic model includes a schedule of drilling and production so that wells come on-stream at different times, and continue producing until the economic limit is reached or the year 2050, assuming that sufficient extensions of the PSC term will be allowed. The small difference in resources between the two reports is dwarfed by the much larger range of uncertainty about the size of the potential resources.

[2a] Results are as of June 15, 2008

The results of the economic modeling of the Manas project conditioned on success of the Manas exploration program are summarized in the table below with both Imperial and Metric volumes.

Parameters	**Oil**		**Oil with Gas Cap**		**Gas**	
	Complete success	**Partial success**	**Complete success**	**Partial success**	**Complete success**	**Partial success**
Oil production						
MMBbl	3,024	1,515	1,389	700	280	141
MMTonnes	413	207	189	95	38	19
Gas production						
BCF	3,050	1,530	13,691	7,743	29,639	14,928
BCM	86	43	388	219	839	423
NPV_{10} **$B**	$18.6	$11.9	$9.7	$6.3	$10.8	$6.1

There is uncertainty about the outcomes that may occur as a result of the exploration program on the Manas blocks. This means that the chance of success at *all* of the prospects is very small. So, the results for success scenarios should be viewed as an indication of the potential upside for the blocks, which may only have a small chance of occurring.

In the complete failure scenario, the capital expenditures are estimated to be $67MM. This would include the acquisition of seismic data and the drilling and testing of three exploratory wells.

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3. INTRODUCTION

3.1 AUTHORITY

Gustavson Associates LLC (the Consultant) has been retained by Manas Petroleum Corporation (the Client, Manas) to prepare an Economic Evaluation Report regarding the entire concession position in Albania currently licensed by Manas.

3.2 PURPOSE OF REPORT

The purpose of this Report is to provide independent information and opinions on the potential value of the Client's concessions and their attractiveness to investors, who might choose to support the Client's exploration effort in Albania. The intended users of the Report are the officers and employees of Manas Petroleum, and any potential investors or financers with whom they may choose to share it.

3.3 SCOPE OF WORK

This Report is intended to describe and quantify the potential economic results of exploring for and developing the potential oil and gas resources contained within the license area that is located in the concession Blocks A, B, D and E granted by the Albanian government.

3.4 ASSUMPTIONS AND LIMITING CONDITIONS

This Report is limited to a report on the potential economic results of the license area. This Report does not attempt to place a Market Value thereon.

The accuracy of any resource estimate is a function of available time, data, and of geological, engineering, and commercial interpretation and judgment. While the resource estimates presented herein are believed to be reasonable, they should be viewed with the understanding that additional analysis or new data may justify their revision and we reserve the right to make such revision.

The costs used in this report are the best estimates available to the Consultant at the time of this report; actual costs may be different. Some of the cost estimates were provided by outside vendors.

3.5 INDEPENDENCE/ DISCLAIMER OF INTEREST

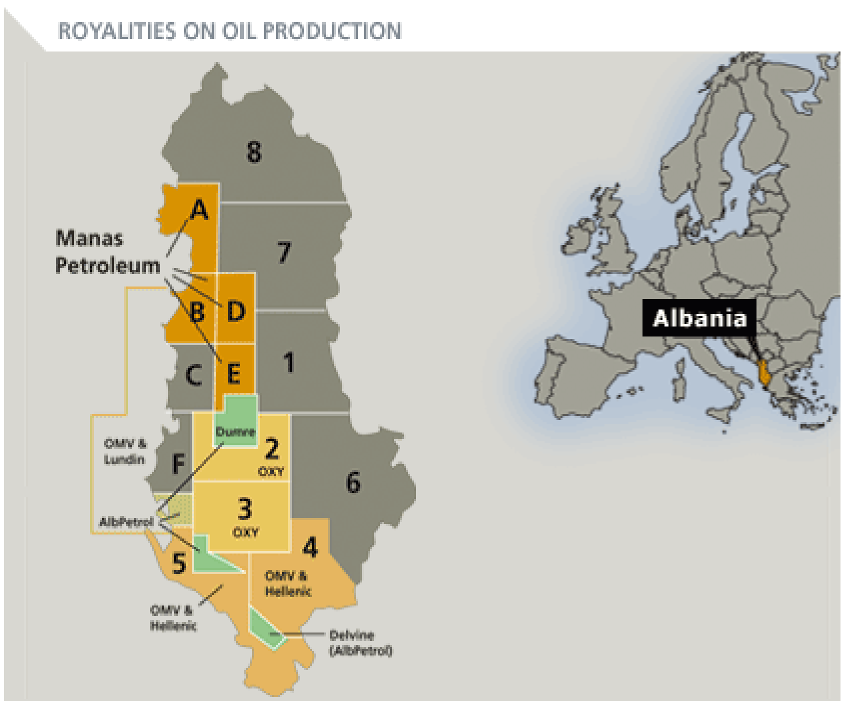
Gustavson Associates LLC has acted independently in the preparation of this Report. The company and its employees have no direct or indirect ownership in the property appraised or the area of study described.

Our fee for this Report and the other services that may be provided is not dependent on the amount of resources or potential value estimated.

4. PROPERTY DESCRIPTION

4.1 DESCRIPTION OF MANAS BLOCKS

The license position is described as Blocks A, B, D & E that are subject to Production Sharing Contracts (PSC) with the Albanian government that were signed on July 31, 2007 and ratified by the Albanian government as of December 13, 2007. These concession blocks contain a total of approximately 780,853 acres (3,160 square kilometers) located along the NW-SE trending fold belt of northwestern Albania. The plays include potential conventional exploration targets involving sub-thrust hydrocarbon accumulations in fractured carbonates.



4.2 LOCATION

The Republic of Albania (*Republika e Shqipërisë)* is located on the eastern side of the Adriatic Sea in Southeast Europe and has significant natural resources that include oil and gas. It has common borders with Montenegro to the North, Kosovo to the Northeast, Macedonia to the East and Greece to the Southeast. The capital of the Republic of Albania is Tirana, which has 800,000 inhabitants, and is located near the center of the country. Albania has a total area of 11,100 square miles (28,750 square kilometers). Its coastline is 225 miles (362 kilometers) long and stretches along the Adriatic Sea and the Ionian Sea.

Detailed descriptions of these concessions can be found in Section 5.1 of the Resource Evaluation Report[2].

4.3 ACCESS AND INFRASTRUCTURE

Oil and gas infrastructure in Albania is limited to the southern part of the country where there is current oil and gas production. In the Manas concession areas of Block A, B, C and D, there is no existing usable infrastructure.

Facilities are being constructed in the port of Durres for the importation of refined petroleum products and liquid petroleum gas. This terminal could be modified to enable oil exports from the Manas blocks.

4.4 OWNERSHIP

These potential resources are owned by the Republic of Albania and have been licensed for development to DWM Petroleum AG, a Swiss corporation, which is a subsidiary of Manas Petroleum Corporation.

4.5 FISCAL TERMS OF THE PRODUCTION SHARING AGREEMENT

The Production Sharing Contracts (PSCs) for Exploration, Development and Production of Petroleum in Onshore Albania were signed on July 31, 2007 between the Government of Albania represented by the Ministry of Economy, Trade and Energy of Albania and Manas Petroleum Corporation represented by DWM Petroleum AG (see press release below). These agreements

[2] "Resource Evaluation Report on Manas Petroleum Corporation's Concessions in Albania (Revision 1.0)" dated March 15, 2008 was prepared by Gustavson Associates.

govern exploration, development and production of blocks A, B, C and D in northern Albania and were ratified by the Albanian government as of December 13, 2007. The PSC terms establish a framework designed to provide flexibility and fair return to the company and the government while limiting undue administrative burden and interference.

Manas Petroleum Corporation operates under two PSCs. Each of these contracts cover Blocks A and B and Blocks D and E, respectively. PSC terms specify two primary economic aspects related to the work commitment and fiscal terms. The work commitment represents the capital investments that Manas Petroleum Corporation will spend on the exploration of their blocks, while fiscal terms govern the allocation of revenues resulting from oil and gas production. The PSC terms are summarized in Table 4-1 through Table 4-4.

Table 4-1 PSC Duration Terms

PSC Terms	Block A-B	Block D-E
Exploration		
Initial exploration period, years	3	3
First extension period, years	2	2
Second extension period, years	2	2
Relinquishment		
If entering first and second extension period, % of acreage	25%	25%
At termination of exploration period, relinquish all the remaining acreage except a development and production area, % of acreage	100%	100%
Commercial Production		
Production period, years	20	20
Extension of production period (subject to approval), years	5	5
Total Duration of production license, years	25	25

Table 4-2 PSC Terms Related to Labor and Subcontracts

Employment Rights and Training		
Contractor is free to select its employees: Select Albanian personnel if their professional skills are adequate	Applicable	Applicable
Training Programs during Exploration periods (Part of exploration cost), $ million per year	0.10	0.10
Subcontracts		
Competitive bidding for any contracts with the estimated value in excess of the specified limit	$2,000,000	$2,000,000

Table 4-3 PSC Work Commitments

Work Program	**Block A-B**	**Block D-E**
Initial Exploration period		
A.) Geological and geophysical, $ million	$0.40	$0.40
B.) Seismic re-processing, $ million	$0.12	$0.15
C.) Seismic acquisition (186 miles (300 km) 2D), $ million	$2.50	$2.50
Or		
D.) Drilling an Exploration Well (9,843 ft (3,000m) or until it reaches Eocene or Cretaceous age Carbonates), $ million	$6.00	$6.00
Min. Work Program, $ million (A+B+C / A+B+D)	$3.02 / $6.52	$3.05 /$6.55
First Extension Period		
Geological and geophysical, $ million	$0.30	$0.30
Drilling an Exploration Well (9,843 ft (3,000m) or until it reaches Eocene or Cretaceous age Carbonates), $ million	$6.00	$6.00
Min. Work Program, $ million	$6.30	$6.30
Second Extension Period		
Geological and geophysical, $ million	$0.30	$0.30
Drilling an Exploration Well (9,843 ft (3,000m) or until it reaches Eocene or Cretaceous age Carbonates), $ million	$6.00	$6.00
Min. Work Program, $ million	$6.30	$6.30
If Contractor has Failed to Complete a Firm Obligation		
Pay $13,417/mile ($8,333/km) for every line km of new quality 2D seismic data not acquired and processed	Applicable	Applicable
Pay $966/mile ($600/km) for every line km of existing 2D seismic data not processed	Applicable	Applicable
Failure to drill an obligatory exploratory well or abandon the well, Contractor pays the balance of Min. Expenditure on exploratory well	Applicable	Applicable

Table 4-4 PSC Fiscal Terms

	Block A-B		Block D-E	
Government Allocation on Production	Government % of Available Petroleum		Government % of Available Petroleum	
R-Factor less than 1.5	10.0%		10.0%	
R-Factor more than 1.5 but less than 2.0	12.5%		12.5%	
R-Factor more than 2.0	15.0%		15.0%	
Recovery of Cost and Expenses				
Costs and Expenses recovered from the Cost Recovery Petroleum which is the Available Petroleum less the Government Allocation	100%		100%	
Carry Forward: Unrecovered costs can be carried forward until fully recovered.	Applicable		Applicable	
Profit Sharing (for Oil and Gas)	Contractor	Government	Contractor	Government
R-Factor less than 1.5	100%	0%	100%	0%
R-Factor more than 1.5 but less than 2.0	95%	5%	95%	5%
R-Factor more than 2.0 but less than 2.5	90%	10%	90%	10%
R-Factor more than 2.5	85%	15%	85%	15%
Taxes				
Albanian Income Tax	50%		50%	
Value Added Tax	0%		0%	
Exemption from VAT, duties, and other levies with respect to the importation of equipment, machinery, materials	Applicable		Applicable	
Bonuses				
Signature bonus, $ million	$0.10		$0.10	
Production bonus on the start of commercial production, $ million	$0.10		$0.10	
Production Bonus when average daily Oil production reaches 15,000 bpd (2,046 tonnes per day), $ million	$0.50		$0.50	
Production Bonus when average daily oil production reaches 30,000 bpd (4,093 tonnes per day), $ million	$1.00		$1.00	
Abandonment Cost				
Annual contribution, percent of Operating Costs	1%		1%	
Accruing abandonment cost on unit of production basis whichever of the conditions is met	Last 10 years or cum production exceeds 75% of exp recovery		Last 10 years or cum production exceeds 75% of exp recovery	

Government production allocation and the entitlement of contractor and government to profit petroleum are determined by the R-Factor. The R-Factor is calculated as the ratio of Contractor's cumulative receipts from the effective date until the end of the preceding calendar year to the Contractor's cumulative expenditures incurred from the effective date until the end of the preceding calendar year. The Contractor's cumulative receipts are calculated as the aggregate value of the Contractor's share of profit petroleum plus cost recovery petroleum and less Albanian taxes paid from the effective date until the end of the preceding calendar year. The Contractor's cumulative expenditures are estimated as the aggregate value of all bonuses, costs, expenses and expenditures previously incurred by Contractor under the contract.

Recoverable costs are recoverable first from the cost recovery crude oil, if any, and second from the cost recovery gas, if any. PSC terms specify that exploration, development and operating expenditures, including those accumulated prior to the date of initial commercial production, are recoverable in full without amortization: (1) in the month when they are incurred or (2) in the month in which the Date of Initial Commercial Production has occurred.

The effective date as determined by the PSC terms is the date on which a decision of the Council of Ministers of the Government of Albania approves the contract and is published in the "Gazeta Zyrtare", the local newspaper. The effective date of the Manas PSCs in Albania is December 13, 2007; therefore, the initial 3-year exploration period will end on December 13, 2010. Assuming that Manas completes the work program (Table 4-3) for the initial exploration period and decides to exercise the option of using the first 2-year extension period, the second exploration period will continue until December 13, 2012. Provided Manas completes the work program for the second exploration period (Table 4-3) and decides to exercise the option of using the second 2-year extension period, the third exploration period will end on December 13, 2014.

Upon a discovery and the approval of the development plan by the Government of Albania, the production period will continue for 20 years for each field from its date of initial commercial production and based on the Petroleum Law, the production period may be extended by 5 years. Assuming that a discovery is made during the second exploration period and the initial commercial production begins on January 1, 2013, the 20-year production period will continue until January 1, 2033 and with the extension until January 1, 2038. Assuming the discovery is made during the third exploration period and the initial commercial production begins on January 1, 2015, the 20-year production period will continue until January 1, 2035 and with the extension until January 1, 2040. If the discovered fields continue producing beyond the 25-year production period, Manas should renegotiate the duration of the production period specified in the PSCs.

5. EXPLORATION AND DEVELOPMENT PROGRAM

5.1 CURRENT STATUS

5.1.1 Summary of Geological and Geophysical Findings

The primary exploration targets are sub-thrust fractured carbonate reservoirs similar to those discovered in the 1990s in the Apennines of Italy. During the same time Shell and Coparex discovered a deep under-thrust structure within the blocks that, by their calculations, has the potential to contain a combined 820 million barrels (MMB) (112 million tonnes (MMT) of recoverable oil. Manas has this opportunity because Shell and Coparex suspended all exploration activity and abandoned the blocks in reaction to the extreme unrest in Albania and the conflict in neighboring Kosovo, allowing Manas to later acquire these superbly defined, giant, virtually drill-ready prospects.

Manas' primary exploration targets are deep (approximately 13,123 feet or 4,000 meters), sub-thrust fractured carbonate reservoirs. Seismic imaging from the 1990s revealed a large carbonate sub-thrust, extending over blocks B, D and E on the Manas blocks known as the Ionian carbonate, which is the targeted reservoir and holds all Albanian hydrocarbon reserves.

The Ionian thrust sheet's source rocks are more ancient Jurassic age carbonates and shales formed 199 to 145 million years ago. These strata are covered by Cretaceous through Eocene age limestone reservoir rocks that are then sealed by thick Miocene age (Neogene) flysch.

Manas is currently reprocessing up to 435 miles (700 kilometers) of existing 2D seismic data in order to better delineate the optimal drilling locations to test their prospective areas over the Gyurice/Rinas and Rova areas. The existing 2D seismic data over the concession area totals approximately 2,485 miles (4,000 kilometers) and was shot by AlbPetrol, Shell, INA, Premier Oil and Coparex.

Shell shot 254 miles (409 kilometers) of new data in Block B in 1996 and reprocessed 534 miles (860 kilometers) of 2D seismic that Albseis (Albpetrol) acquired over Block B between 1981 and 1990, all of which needs to be reprocessed.

Coparex reprocessed 480 miles (773 kilometers) in 1995 that was shot by Albseis in Block E and shot an additional 193 miles (310 kilometers) in 1995 and 1996.

All vintages of data suffer from data quality deterioration in areas of rugged surface topography and complex subsurface geology.

Manas will acquire 373 miles (600 kilometers) of new data in Block B, D and E over their prospects prior to drilling the exploration wells. They will acquire additional data in the future, if needed.

There are nine prospects included in this report. They are known as Rinas and Gyurice in Block B; Nikel, Kashari and Kamez in Block D; Rova, Rova West, Sauk and Papri in Block E. A map of Manas license blocks and prospect locations is shown on Figure 5-1. There are also a number of lead areas that will be delineated by seismic and may be explored in the future.

Rinas and Gyurice are located to the northwest of Tirana and the surface areas are flat and easily accessible. The other prospects are located in areas that are topographically more difficult to access. Manas' plan is to delineate and drill the Rinas, Gyurice and Rova prospects first. The remaining prospects will be drilled following a successful outcome.

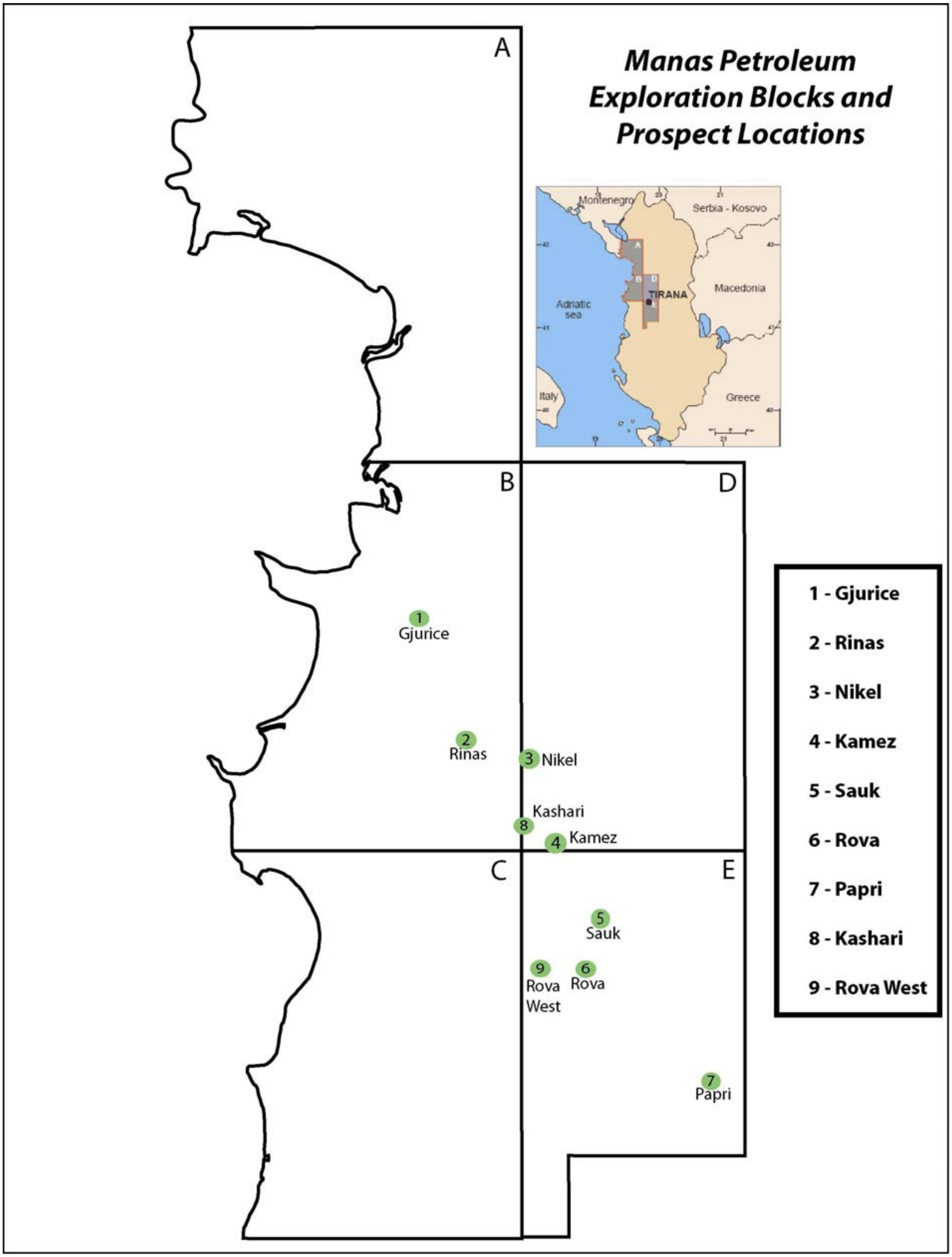


Figure 5-1 Map of Manas License Blocks and Prospect Locations

5.1.2 Exploration Risk Analysis

The quantification of risk for this play can be characterized with the following variables:

- Structure: defined as the presence of a structure that could act as a trap for hydrocarbons;
- Seal: defined as an impermeable barrier that would prevent hydrocarbons from leaking out of the structure;
- Reservoir: defined as the rock that is in a structurally favorable position having sufficient void space present whether it be matrix porosity or fracture porosity to accumulate hydrocarbons in sufficient quantities to be commercial and
- Presence of Hydrocarbons: defined as the occurrence of hydrocarbon source rocks that could have generated hydrocarbons during a time that was favorable for accumulation in the structure.

Table 5-1 shows the Probability of Success (POS) that the above-defined variables would occur, for any one prospect. This POS would be for the first well drilled in the project area and may change depending on the results of the first well. The Overall POS is the product of all four variables.

Table 5-1 Probability of Success (POS)

Probability of Success (POS)	**%**	**Comments**
Structure	60	Seismically defined by older seismic
Seal	75	Marl section occurrence pervasive
Reservoir	50	Dependent on fracture and joint presence
Presence of Hydrocarbons	80	Analogous field production; source beds contained in section
Overall	18	- Shell calculated with a COS rate of 10% - Coparex calculated with a COS rate of 15%

The overwhelming risk, in these prospects, is in the interpretation of these complex structural plays and the presence of reservoir quality Ionian carbonate. Some of the 2D seismic has difficulty imaging the earth clearly below the shallowest thrust faulting. Although the Kruja limestone has been encountered in wells drilled on these concession blocks, the Ionian carbonate has not been penetrated in a drilled well at present. The seismic suffers from multiples and other artifacts that may taint the interpreter's view of the deeper structure. The seismic data may benefit from reprocessing as well as better velocity control from an exploratory well. The interpreted seismic lines should include the surface geology with the type, strike and dip of rock units and any surface expressions of faults with their strike and dip so that these data are incorporated into the interpretation. The structural sections need to be balanced and undergo palinspastic reconstruction to make sure that the interpretation makes sense and to mitigate risk.

Despite the low calculated POS for any single prospect, for a wildcat well in a structurally complex area such as this and the multiple prospects, the potential for success is relatively high due to the fact that it is in a structurally favorable area, there exists a proven hydrocarbon source and production from analogous structures is located only 12.4 to 18.6 miles (20 to 30 kilometers) away.

5.1.3 Summary of Resource Estimates

The hydrocarbon type that could occur in these reservoirs is an unknown, due to their depth and lack of nearby exploration. Therefore, three cases were assumed to be possible in this estimation: 1) Oil with associated gas, 2) Oil with gas cap, and 3) Gas with condensate. It is expected that if oil is present at the depths of these prospects, it will be good quality oil with API gravity in the range of 30 to 37 degrees.

A draft report, "Resource Evaluation Report on Manas Petroleum Corporation's Concessions in Albania (Revision 1.0)" dated March 15, 2008 by Gustavson Associates, presented probabilistic resources for the Manas prospects. The median (P_{50}) resource estimates for the three hydrocarbon scenarios are shown in Table 5-2. These resource estimates assume that the prospects will be successful and fully developed. The prospects have not yet been drilled, and it is possible that there will not be commercial hydrocarbons in some or all of the prospects. It is also possible that there may be more resources than shown in Table 5-2.

Table 5-2 P_{50} Resources Conditional on Success[3]

(a) Imperial Units

Case	Oil		Oil with Gas Cap		Gas with Condensate	
Prospect	Oil, MMBbl	Gas, BCF	Oil, MMBbl	Gas, BCF	Condensate, MMBbl	Gas, BCF
Papri	351	352	164	1,816	31	3,285
Gyurice	644	652	304	3,377	58	6,105
Rinas	611	617	290	3,142	54	5,669
Nikel	373	375	175	1,972	34	3,576
Kamez	367	369	173	1,943	33	3,521
Sauk	404	407	190	2,119	37	3,913
Rova	54	55	26	295	5	541
Rova W	42	42	20	212	4	385
Kashari	184	185	86	961	17	1,724
Total	3,030	3,054	1,428	15,837	273	28,719

(b) Metric Units

Case	Oil		Oil with Gas Cap		Gas with Condensate	
Prospect	Oil, MMTonnes	Gas, BCM	Oil, MMTonnes	Gas, BCM	Condensate, MMTonnes	Gas, BCM
Papri	48	10	22	51	4	93
Gyurice	88	18	41	96	7	173
Rinas	83	17	40	89	6	161
Nikel	51	11	24	56	4	101
Kamez	50	10	24	55	4	100
Sauk	55	12	26	60	4	111
Rova	7	2	4	8	1	15
Rova W	6	1	3	6	0	11
Kashari	25	5	12	27	2	49
Total	413	86	195	448	32	813

[3] The P_{50} resource numbers in the economic report differ slightly from those in the resource report. The difference is well within the margin of error.

Due to the significant geological risk associated with the identified prospects, there is uncertainty about resource estimates in the Manas blocks. The chance of success at all of the prospects is very small. Therefore, the resource estimates for all prospects should be viewed as an indication of the potential upside for the blocks, which may have only a small chance of occurring.

5.2 PROPOSED EXPLORATION AND DEVELOPMENT PROGRAM

5.2.1 Exploration

Manas' exploration program plan will include the reprocessing of selected existing 2D seismic data, acquire new 2D seismic data and drill the first well at Rinas in the most structurally favorable position.

Manas will drill an exploration well as a straight hole on the prospect. If the well has indications of the presence of hydrocarbons, after running a full suite of wireline logs, Manas will then drill a directional sidetrack well oriented at an optimum angle and azimuth to intersect the most fractures. Manas will test the well for 15 days to determine if commercial flow rates can be established, and to collect data to aid in the optimization of field development. Upon completion of a successful exploration well at a prospect, two appraisal or delineation wells will be drilled and tested at that prospect. If these wells are successful, Manas will then commence drilling development wells.

Manas will drill and test Rinas first followed by Gyurice and Rova. If all three tests fail, then Manas will abandon the project.

This evaluation assumes a variety of drilling times and costs, depending on depth, for exploratory, appraisal, and development wells, as shown in Table 5-3.

5.2.2 Development

The assumed spacing of development wells depends on the hydrocarbon type encountered. In the case of oil and oil with gas cap, a 160-acre (0.65 square kilometer) spacing plan is used. In the gas with condensate case, a 320-acre (1.30 square kilometer) spacing plan is used.

Table 5-3 Drilling and Testing Times and Costs, by Prospect

Prospect	Exploration well				Appraisal well				Development well			
	Days			Capex $M	Days			Capex $M	Days			Capex $M
	Drill	Test	Total		Drill	Test	Total		Drill	Test	Total	
Rinas	117	15	132	$18,668	105	15	120	$14,246	90	0	90	$11,636
Gyurice	127	15	142	$17,803	113	15	128	$15,443	97	0	97	$12,663
Rova	132	15	147	$18,511	118	15	133	$16,062	101	0	101	$13,193
Nikel	127	15	142	$17,766	113	15	128	$15,410	97	0	97	$12,635
Kashari	122	15	137	$17,040	108	15	123	$14,775	93	0	93	$12,090
Kamez	128	15	143	$17,915	114	15	129	$15,541	98	0	98	$12,747
Sauk	129	15	144	$18,045	115	15	130	$15,655	98	0	98	$12,844
Rova W	105	15	120	$14,694	94	15	109	$12,722	80	0	80	$10,331
Papri	122	15	137	$17,114	109	15	124	$14,840	93	0	93	$12,146

6. MARKET ANALYSIS

6.1 REGIONAL ENERGY MARKETS

6.1.1 Current Status

6.1.1.1 Oil

Albanian domestic oil production is low and the country is highly dependent on oil imports to meet its consumption needs (Table 6-1). Thus, in 2007 oil production declined to 6.4 MB/D (0.9 MT/D) while the 2007 oil consumption is expected to reach 33 MB/D (4.5 MT/D). For 2007, oil import is estimated at 27 MB/D (3.7 MT/D).

In 2007, the total proved oil reserves in Albania are estimated at 198 MMB (27 MMT)[4].

Albania does not have sufficient refining capacity to process oil that may be produced by Manas. There are two refineries located at Ballsh and Fier, 100 kilometers (62 miles) south of the capital city of Tirana. The capacity of these two refineries is about 26,000 BPD (3,600 TPD). These refineries are technically inefficient and require modernization. To address this issue, on February 19, 2008, the Government of Albania announced an international tender for the privatization of an 85% interest in the Albanian refineries[5].

6.1.1.2 Gas

The gas market in Albania is undeveloped due to a lack of gas distribution infrastructure in the country. For more than a decade, Albanian annual gas production and consumption has been held constant at 1.1 BCF (31 MMCM). Existing residential consumers rely on LPG imported from Greece.

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[4] http://tonto.eia.doe.gov/country/country_time_series.cfm?fips=AL
[5] http://www.balkaninsight.com/en/main/news/8030/

As of 2007, total proved gas reserves in Albania are estimated at 30 BCF (0.8 BCM)[6]. The principal source of gas production in Albania is from associated gas from existing oil operations in the southern part of Albania.

Table 6-1 Oil Production and Consumption in Albania

(a) Imperial Units

Year	**1990**	**1995**	**2000**	**2001**	**2002**	**2003**	**2004**	**2005**	**2006**	**2007***
Oil Production (includes condensate), MBPD	30.0	10.0	5.7	6.0	6.4	6.7	6.7	7.0	7.7	6.4
Consumption (petroleum products and direct combustion of crude oil), MBPD	20.0	15.0	21.0	23.0	24.0	27.0	29.0	29.0	31.0	F 33.0
Net Exports/Imports (-), MBPD	10.0	-5.0	-15.0	-17.0	-18.0	-21.0	-22.0	-22.0	-23.0	F-27.0
Refinery Capacity, MBPD	--	40.0	26.0	26.0	26.0	26.0	26.0	26.0	26.0	26.0
Proved Reserves, MMB	--	165.0	165.0	165.0	165.0	165.0	165.0	165.0	198.0	198.0

(b) Metric Units

Year	**1990**	**1995**	**2000**	**2001**	**2002**	**2003**	**2004**	**2005**	**2006**	**2007***
Oil Production (includes condensate), MTPD	4.1	1.4	0.8	0.8	0.9	0.9	0.9	1.0	1.1	0.9
Consumption (petroleum products and direct combustion of crude oil), MTPD	2.7	2.0	2.9	3.1	3.3	3.7	4.0	4.0	4.2	F 4.5
Net Exports/Imports (-), MTPD	1.4	-0.7	-2.0	-2.3	-2.5	-2.9	-3.0	-3.0	-3.1	F - 3.7
Refinery Capacity, MTPD	--	5.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5
Proved Reserves, MMT	--	22.5	22.5	22.5	22.5	22.5	22.5	22.5	27.0	27.0

* F - forecast value

Source: EIA, Albania Energy Profile

[6] http://tonto.eia.doe.gov/country/country_time_series.cfm?fips=AL

Table 6-2 Gas Production and Consumption in Albania

(a) Imperial Units

Year	**1990**	**1995**	**2000**	**2001**	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**
Production, BCF	9	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	NA
Consumption, BCF	9	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	NA
Net Exports/Imports (-)	0	0	0	0	0	0	0	0	NA	NA
Proved Reserves, BCF	NA	70	100	100	100	100	100	100	30	30

(b) Metric Units

Year	**1990**	**1995**	**2000**	**2001**	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**
Production, BCM	0.25	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	NA
Consumption, BCM	0.25	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	NA
Net Exports/Imports (-)	0	0	0	0	0	0	0	0	NA	NA
Proved Reserves, BCM	NA	2.0	2.8	2.8	2.8	2.8	2.8	2.8	0.8	0.8

Source: EIA, Albania Energy Profile

6.1.1.3 Oil and Gas Pipelines

Since Albania has been isolated from the rest of Europe for many years, the existing oil and gas pipelines of Albania do not have connections to international oil and gas pipelines. The domestic oil pipelines connect operating oil fields to the existing oil refineries. The limited indigenous gas infrastructure in many places is out of operating condition and needs rehabilitation. Some parts of the network are unable to transport gas due to their corrosion and destruction. The gas pipeline network would need to be totally replaced.

6.1.2 Possible Options to Connect to European Oil and Gas Markets

6.1.2.1 Oil

Manas plans to export their oil to Italy since Italy has seventeen major refineries, with a total refining capacity of 2.3 MMBPD (0.31 MMTPD), concentrated along the Mediterranean coastline. In Albania, there are two ports that could be used for exporting oil from the Manas project, Durres and Vlore.

An oil terminal known as the Romano Port Jetty is under construction near Durres in Albania. This terminal is scheduled to be operational by July 2008 and its primary purpose is to import refined oil products and LPG into Albania. However, if the Manas project starts producing oil, the terminal will have the capacity to export oil by tanker from Albania to Italy.

The other potential alternative to exporting oil would be through the Port of Vlore in southern Albania also on the Adriatic. This port would be expanded if it becomes the termination point of the proposed Albania-Macedonia-Bulgaria (AMBO) oil pipeline. The 570-mile (920 kilometer) pipeline would have a capacity of 750,000 BPD (102,320 TPD) (Figure 6-1).

The comparison of these two options for exporting oil showed that the oil terminal at the port of Durres is the preferable alternative for Manas because of its proximity to the Manas blocks. Therefore, this report assumes that an oil pipeline would be built from the Manas prospects to the oil terminal at Durres for sale of produced oil.

Figure 6-1 Route of Proposed Balkan Oil Pipeline

6.1.2.2 Gas

There is almost no gas infrastructure in Albania. Consequently this will limit the ability to market and sell gas in the short term. In fact, the production-sharing contract includes the possibility of an extension if gas is discovered.

Gazprom of Russia and Eni, an Italian multinational oil and gas company, have proposed to build a 560-mile (900 kilometer) gas pipeline from Russia to southern Europe (Figure 6-2). The South Stream pipeline would go under the Black Sea and then continue from Bulgaria through Greece to southern Italy with a new major gas hub created in Serbia. The expected annual capacity of the southern branch of the gas pipeline is estimated at 333 BCF (10 BCM).

A feasibility study is expected to be completed by the end of 2008. Construction is planned to be completed less than three years after approval from the European Union Commission and regulatory authorities. Construction of the Serbian stretch is scheduled to start by 2010. Deliveries through the South Stream gas pipeline are scheduled to start by 2013.

Figure 6-2 Proposed Gas Pipelines

For this report, it is assumed that the South Stream gas pipeline would have sufficient capacity to accommodate the Manas gas production and Manas would be able to connect to this pipeline and, therefore, gain access to the European gas markets. Under these assumptions, Manas would build gas pipelines from its prospect area to the southern Albanian border with Greece.

Another potential gas market is domestic gas-fired power generation. Over the past several years, Albania has experienced an acute energy crisis with regular power outages throughout the country, including the capital city of Tirana. The current hydropower generation capacities are insufficient and negatively impact the economic development of the country. Surplus electricity might be exported to the EU. This would require improvements to the existing power grid and connections to the EU power grid that is another consequence of Albania's lengthy isolation from Europe.

6.2 <u>OIL AND GAS PRICES</u>

The Client requested that Gustavson Associates use a price of \$50.00/Bbl (\$366.50/tonne) for 2008 for oil. As a comparison, on April 4, 2008, Brent 38º API oil price was \$101.35/Bbl

($742.90/tonne) and the Russian Urals 32º API price (f.o.b.) to Mediterranean destinations was $96.24/Bbl ($705.44/tonne).

In order to account for the uncertainty regarding the gas market in Albania, a conservative estimate of the gas price of $2.50/MCF ($88.29/MCM) is used for 2008. In comparison, the Gazprom export gas price for 2008 in Central and South Eastern Europe is in the range of $7.50/MCF to $9.00/MCF ($264.86/MCM to $317.84/MCM).

7. ECONOMIC ANALYSIS

7.1 METHODOLOGY

Gustavson Associates built an economic model to estimate the Net Present Value (NPV) of the Manas project in Albania.

Three scenarios were considered for this report. Under the first scenario, it was assumed that the exploration program would be successful at each one of the nine prospects leading to the discovery of commercial hydrocarbons. Under the second scenario, it was assumed that the exploration program would be successful at only five prospects: Gyurice, Rova, Sauk, Papri and Rova West. Under the third scenario, it was assumed that no discovery of commercial hydrocarbons is made at any of the three initial prospects: Rinas, Gyurice and Rova.

For the scenarios with success, three different cases were estimated due to the fact that the hydrocarbon type that could occur in these reservoirs is an unknown. Therefore, three cases were assumed to be possible in this estimation: (1) Oil with associated gas, (2) Oil with gas cap, and (3) Gas with condensate.

The scheduling of exploration and development programs for each prospect within each block was based on estimates of the time required to drill exploration, appraisal and development wells including the time required to move a rig from one location to another and to build surface facilities and pipelines. It was assumed that a second rig would be contracted to start the development drilling of the first successful prospect after the first successful exploration well was drilled. This report assumes that a maximum of two rigs would be used for this project, however; if Manas were successful in discovering hydrocarbons more rigs would be deployed to accelerate development. Therefore, the economics or NPV_{10} in this report are considered to be conservative.

The scheduling of the drilling of the development wells would be the basis for determining when the field will be ready to start production. It was assumed that Manas would be able to extend its

PSC beyond the duration of the 25-year production period specified in the PSC and continue operations to at least 2050.

The production schedule within the blocks covered by each PSC was determined with the consideration of the economic limit of production; however, the cases as currently evaluated do not reach an economic limit before 2050.

Production would begin at some fields before development drilling was completed. For each prospect, the start date of production would be determined by two factors: (1) after five development wells are completed and (2) after the construction of surface facilities was completed. To start production at each oil or gas field discovered within the block, both conditions would have to be met. Thus, in some cases the start of production may have to be delayed until the construction of surface facilities was completed at the field, even though five wells may have been completed before that time.

For each block, the capital costs included in the model consist of exploration and development costs. The exploration costs include the costs of acquiring and processing seismic data and the costs of drilling exploration wells and testing them. The development costs include the drilling, testing and completion costs of appraisal and development wells and the costs of field production facilities and pipelines.

Separate oil and gas pipelines are assumed to be built for each block with gathering systems for each prospect. For the oil and gas with condensate cases, the pipeline capacity is sized to meet the maximum throughput rate during the project life. For the oil with gas cap case, a second gas pipeline will be built to handle increased gas production during the gas-cap blowdown phase of the project. The capacity of the second gas pipeline would meet the maximum throughput rate of the additional gas production. The timing relative to the construction of the second gas pipeline is determined by the production schedule.

The operating costs are different for oil and gas production. Two components of operating costs are estimated: cost per well and cost per year for each field.

The capital and operating costs are estimated in 2008 dollars and then escalated.

The estimate of abandonment costs consists of two components: the abandonment costs per operating well and the abandonment costs per each successful prospect where a commercial discovery of hydrocarbons was made. The abandonment costs in 2008 dollars were escalated to estimate the abandonment costs in the nominal dollars of the final years of the project life.

The allocation of abandonment costs is determined according to the rules specified by the PSCs. The abandonment costs are accrued 10 years prior to the estimated date of termination of production operations or at the end of the year in which cumulative production reached 75% of expected recovery of petroleum, whichever occurred first. For this calculation, petroleum is estimated in barrels of oil equivalent. For each year of the period over which the abandonment costs are accrued, the costs are prorated on a unit of production basis over the expected remaining recovery of petroleum within the blocks covered by the PSC.

The oil and gas prices in constant 2008 dollars are escalated to determine the oil and gas prices in nominal dollars.

All recoverable costs are recovered from the portion of available petroleum production known as the total cost recovery petroleum available. It is equal to 100% of the available petroleum production after the Government Allocation that is determined according to the rules specified in the PSC. The available petroleum is defined as the wellhead production less shrinkage.

The government's profit share and the contractor's profit share are determined by the fiscal terms of the PSC. For blocks covered by each PSC, the R-factors were calculated. The R-factor is the ratio of the contractor's cumulative receipts from the Effective Date of the PSC until the end of the preceding calendar year to the estimate of contractor's cumulative expenditures incurred from the Effective Date of the PSC until the end of the preceding calendar year.

Cumulative receipts consist of the contractor's share of profit petroleum plus the cost recovery petroleum less the estimates of Albanian taxes to be paid by the contractor. Cumulative expenditures include all costs and expenses that are incurred by the contractor under the PSC. The schedule of production bonus payments is based on projections of when the average daily oil production would reach the rates specified in the PSC.

The total government's share and the contractor's take were estimated based on the projected cash flows.

A discount rate of 10% is used for estimating the NPVs of the exploration and development program within each PSC and for the total NPV of the Manas project in Albania.

7.2 PRODUCTION FORECAST

Oil and gas rates were estimated for an average well for each of the prospects. This was roughly based on information regarding rates tested at the Occidental Spiragu #1 well, along with variations in most likely average net hydrocarbon thickness calculated for each prospect by dividing the P_{50} bulk volume values by the area of each prospect. The initial rates at the other prospects were then calculated assuming that the initial rate will be proportional to average net pay. Note that these assumptions result in quite high rates for some of the prospects (about 20,000 BPD (2,728 TPD) for a Rinas well and 18,000 BPD (2,456 tonnes/day) for a Gyurice well). These rates are considered to be reasonable based on the very large average net pays at these prospects (4,388 ft (1,337 m) and 4,016 ft (1,224 m), respectively). Twenty-four wells were found in the US Gulf of Mexico and South Texas with initial oil rates in this range or higher. Note that large tubulars will be required to handle these rates, probably using pipe generally considered as small casing for the production tubing string. Alternatively, depending on local regulations, a tubingless completion may be possible, with production flowing up the casing all the way to the wellhead. The estimates of initial production rates are shown in Table 7-1.

Table 7-1 Estimated Initial Production Rates, per Well

(a) Imperial Units

Case	Oil		Oil with Gas Cap		Gas with Condensate	
Prospect	Oil, BPD	Gas, MCF/D	Oil, BPD	Gas, MCF/D	Oil, BPD	Gas, MCF/D
Rinas	20,100	20,281	9,400	9,400	1,256	132,100
Gyurice	18,400	18,639	8,600	8,600	1,143	120,900
Rova	8,100	8,254	3,800	3,800	506	53,100
Nikel	12,300	12,362	5,700	5,700	944	100,000
Kashari	14,600	14,688	6,800	6,800	924	96,400
Kamez	15,500	15,593	7,300	7,300	970	102,300
Sauk	14,400	14,530	6,700	6,700	887	94,700
Rova W	3,000	3,030	1,400	1,400	181	19,700
Papri	15,200	15,276	7,100	7,100	946	100,000

(b) Metric Units

Case	Oil		Oil with Gas Cap		Gas with Condensate	
Prospect	Oil, Tonnes/D	Gas, MCM/D	Oil, Tonnes/D	Gas, MCM/D	Condensate, Tonnes/D	Gas, MCM/D
Rinas	2,742	574	1,282	266	149	3,741
Gyurice	2,510	528	1,173	244	136	3,423
Rova	1,105	234	518	108	60	1,504
Nikel	1,678	350	778	161	112	2,832
Kashari	1,992	416	928	193	110	2,730
Kamez	2,115	442	996	207	115	2,897
Sauk	1,965	411	914	190	106	2,682
Rova W	409	86	191	40	22	558
Papri	2,074	433	969	201	112	2,832

For the oil case, the oil rates and were estimated as described above, and gas rates were estimated based on the oil rates and the average gas/oil ratio (GOR) of about 1000 SCF/bbl (28 CM/tonne) over the field life.

For the gas case, gas rates were explicitly estimated, and condensate rates were estimated based on the gas rates and the average condensate/gas ratio (CGR) over the field life. For example the gas case, an initial gas rate for the Papri prospect of 100,000 MCFPD (2,832 MCMPD) was assumed in order to achieve a production of the total P_{50} resources over a 30-year life with a reasonable production rate decline. Again, rates were adjusted from prospect to prospect assuming that rate will be proportional to average net pay. The high gas rates for some prospects are again considered to be reasonable for the large net pay, and again will require large tubulars. Eleven gas wells in the US Gulf of Mexico were located with initial production at these rates or higher.

For the oil with gas cap case, rates from the oil only case were adjusted downward based on the lower oil-saturated reservoir thickness, and GOR was varied from an initial ratio of 1,000CF/B (200 CM/T) up to 5,000 CF/B (1,000 CM/T), to simulate the gradual increase of gas expansion with decreases in reservoir pressure[7].

Additionally, for the oil with gas cap case, it is assumed that the first twenty years of production of each field (successful prospect), will focus on optimizing production of the oil "leg" (oil-saturated portion of the hydrocarbon column), while attempting to minimize gas production in order to preserve the reservoir energy of the gas cap and realize the benefits of gas cap expansion as a reservoir drive mechanism. In a reservoir with a large vertical hydrocarbon column, such as many of these prospects, gas cap expansion can be a highly efficient drive mechanism. Average net pay for each prospect was divided into oil net pay and gas net pay based on the P_{50} percentage of the gas cap volume. The initial oil rates were reduced proportionally from the oil case based on these lower oil net pay estimates. The GOR was assumed to increase over the first 20 years of field life from 1,000 to 5,000 SCF/bbl (28 to 142 CM/tonne) to allow for some coning of gas into the oil completions from the gas cap. After this 20-year period, it is assumed that the majority of the economic oil reserves will have been produced, and field operations will proceed to focus on the exploitation of the remaining gas reserves in the gas cap. This phase of production is typically known as gas "blowdown". Gas rates at the start of blowdown were estimated based on the gas rates for the gas case, reduced by a factor of 0.85 to allow for some

[7] To simplify the economic modeling, there are minor immaterial differences between the economic and engineering models.

depletion in reservoir pressure, and further reduced by the amount of net pay assumed to be in the gas column.

At this time, all or a portion of the wells would be recompleted to add perforations in the gas cap. If water production at that time is high from any of the wells, all or the lower portions of the existing perforations in the oil leg may be plugged off, either with cement or with a bridge plug set in an unperforated portion of the casing. The tubing would be repositioned, and production would be resumed focusing on gas production. The initial rates per well were estimated for this phase of production, based on rates for the gas case, varying proportions of average gas-saturated net pay, and assuming a 15% reservoir pressure reduction during the first 20 years of production. The estimates of initial blowdown production rates are summarized in Table 7-2.

Table 7-2 Estimated Initial Blowdown Production Rates, per Well

Case	**Gas Cap Blowdown**			
Prospect	**Gas**		**Oil**	
	MMCFPD	**MMCMPD**	**BPD**	**TPD**
Rinas	59,300	1,679	297	41
Gyurice	54,300	1,538	272	37
Rova	23,800	674	119	16
Nikel	36,400	1,031	182	25
Kashari	43,300	1,226	217	30
Kamez	45,900	1,300	230	31
Sauk	42,500	1,203	213	29
Rova W	8,800	249	44	6
Papri	44,900	1,271	225	31

For the oil and oil with gas cap cases, hyperbolic decline behavior was assumed as typical behavior of water-drive reservoirs, with decline parameters adjusted in order to recover the average P_{50} reserves per well in a 40-year and 20-year life, respectively. For the gas and gas blowdown cases, exponential declines were assumed, with decline rates adjusted to recover the average P_{50} reserves per well in a 30-year and 20-year life, respectively.

Using these initial rates and the exploration and development schedule discussed above, total oil and gas rates for each prospect were forecast. Graphs of each success case prospects' forecast rates for each of the hydrocarbon scenarios (oil, oil with gas cap, and gas) are shown in Section 7.5.

7.3 PRICE FORECAST

The initial prices for oil and gas are discussed above in Section 6.2. These prices are escalated by 2.5% after the second year.

7.4 COST ESTIMATES

7.4.1 Drilling Costs

Several drilling contractors were asked to participate in providing cost estimates for the drilling of wells in Albania for the Manas project. The following equipment specifications were used in the well drilling cost estimates:

- 2,000 horsepower SiliconeControledRectifier rig;
- 1,300,000 lb. mast with Midco U-1220-EB (or equivalent) drawworks;
- Canrig 650 ton 1165E Top Drive System (or equivalent);
- Three 1,600 horsepower Continental Emsco FB-1600 mud pumps (or equivalent);
- Power plant of five Caterpillar 3512B engines (or equivalent) with 1,400 horsepower each.

Nabors International Drilling was the only United States-based drilling contractor that provided a cost estimate. Helmerich & Paine required that a contract be signed before doing any analysis work or cost estimating for the project. The Nabors estimate was based on the qualification that they would require a year's contract to mobilize a rig to Albania. Helmerich & Paine would have similar requirements written into their contract.

The rig proposed to be used for the Manas project by Nabors International Drilling would be the Rig 218, which is currently in Dubai, U.A.E. This rig meets all the specifications listed above, and can handle the various total depths of the wells proposed for this project.

For their drilling cost estimate, Nabors assumed 110 drilling days for an exploration well with a total depth of 14,764 feet (4,500 meters). Using Nabors' information, Gustavson estimated a cost for drilling a 21,325-feet (6,500-meter) well that would take 136 days to drill. With these two numbers a linear relationship was developed to estimate costs for wells of various depths (Figure 7-1).

For example, based on this equation, drilling costs for a well with a depth of 17,274 feet (5,265 meters) is estimated to be:

$$\$0.00058 \text{ MM} \times 17{,}274 + \$5.676 \text{ MM} = \$15.7 \text{ MM}$$

$$\$0.0019 \text{ MM} \times 5{,}265 + \$5.676 \text{ MM} = \$15.7 \text{ MM}$$

Since each prospect has a different surface elevation as well as estimated depth to the top of the reservoir and estimated reservoir thickness, the total depth for the wells in each prospect varies. Thus, the cost versus depth relationship can be used to estimate the costs of drilling wells in a specific prospect area accounting for the variations in total depth.

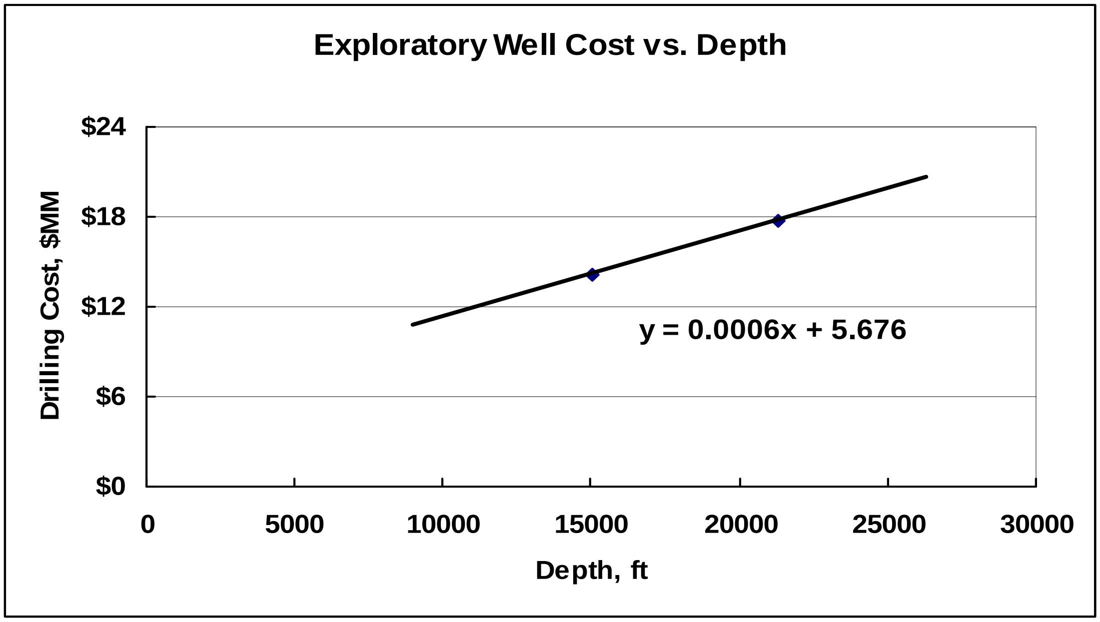
A relationship between depth and drill days was also determined for use in project scheduling (Figure 7-2).

For example, the number of drill days required to drill a well with a total depth of 17,274 feet (5,265 meters) is estimated by using the equation as follows:

$$0.0041 \times 17{,}274 + 48.344 = 119 \text{ drill days}$$

$$0.0135 \times 5{,}265 + 48.344 = 119 \text{ drill days}$$

(a) Imperial Units



(b) Metric Units

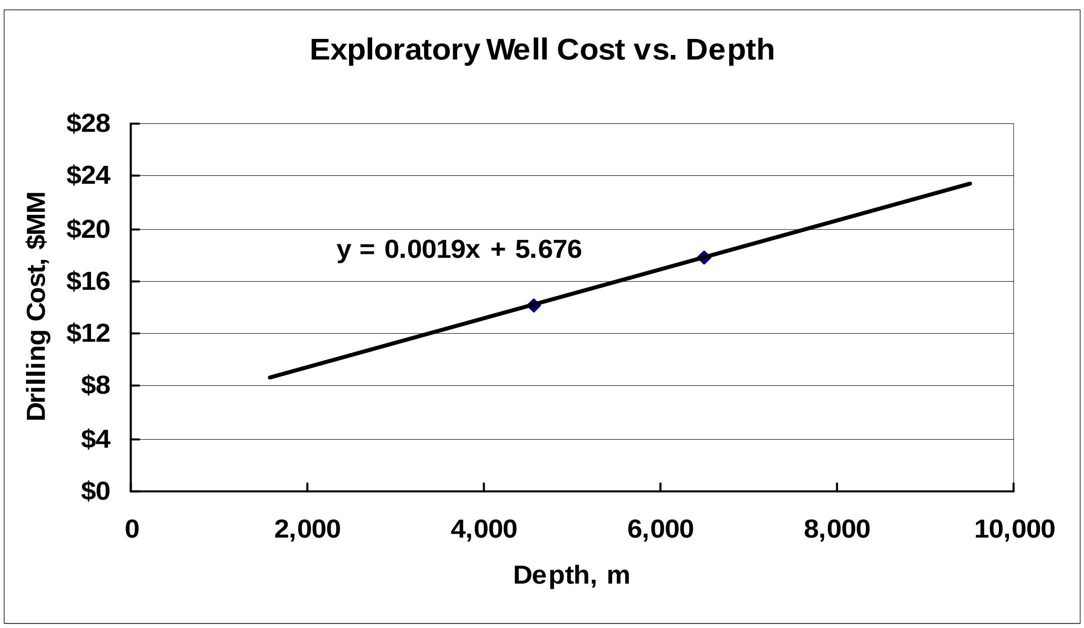
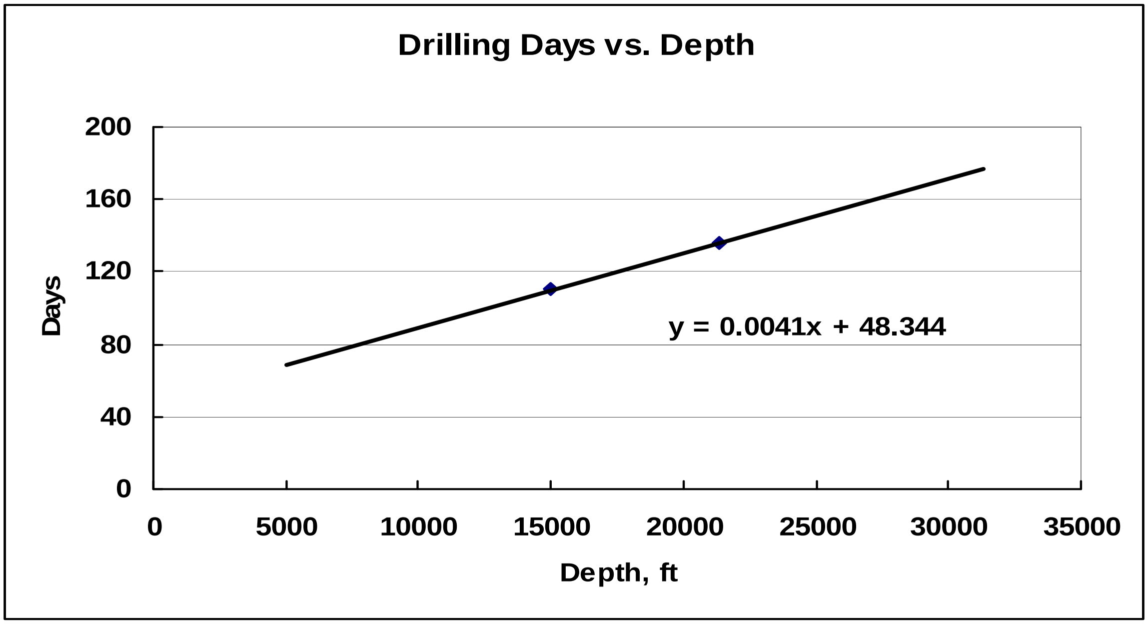


Figure 7-1 Relationship between Exploratory Well Cost and Depth

(a) Imperial Units



(b) Metric Units

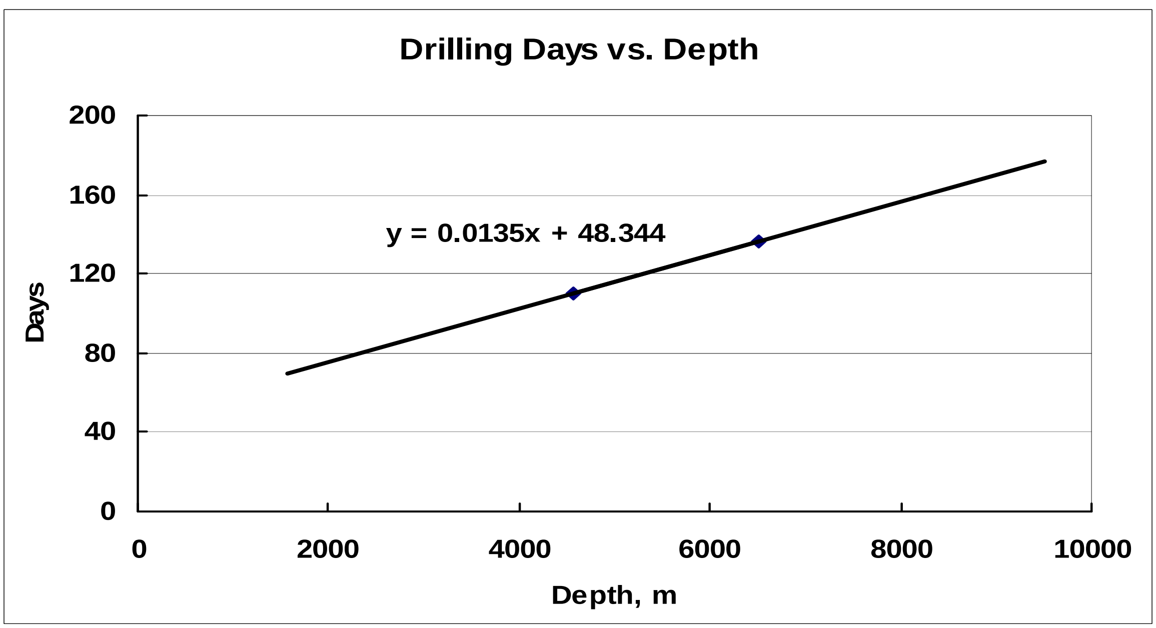


Figure 7-2 Relationship between Depth and Drilling Time

These equations were used for each exploration prospect to generate drilling cost and drilling time estimates. The development wells are assumed to have a 25% cost savings for potential drilling efficiencies that will develop with a better understanding of local drilling conditions. These potential cost savings run the gamut of a reduced number of casing strings, to a more efficient mud system, to increased penetration rates due to better bit selection, as well as elimination of some of the data gathering planned for the exploration wells. The appraisal wells costs were calculated using an average of the exploration and development wells costs.

European prices are assumed for the drilling tangibles such as casing, tubing and wellheads. The directional equipment, mud and cementing costs are based on USA prices that have had a differential multiplier of 1.5 (or a 50% increase) applied to approximate the likely European markets.

The cost of mobilization and demobilization of the first rig has been allocated as follows; the first prospect absorbs the entire cost of the mobilization of $2,483,000. The remaining eight prospects bear an allocation portion of the cost of the demobilization of $2,000,000, so each prospect was allocated $250,000. In field rig mobilization was accounted for in the drilling days allocated for each well.

Estimated drilling costs by prospect are shown in Table 5-3 above. For the blowdown case, recompletion costs are estimated to be $1 million per well and well abandonment costs of $30,000 per well are included. All drilling and abandonment costs were escalated by 2.2% per year.

7.4.2 Other Capital Costs

7.4.2.1 Pipeline Costs

Two gas and two oil pipelines were assumed (one each for Block A-B and Block D-E), with the oil pipeline extending to Durres, Albania, and the gas pipeline extending south to connect to the proposed South Stream gas pipeline at the border of Albania and Greece. For the blowdown case (oil with gas cap), two additional gas pipelines are added at the time of blowdown, rather than sizing the initial gas pipelines large enough to handle the much larger blowdown gas rates. All pipeline costs and pipeline facilities costs are calculated for each model scenario proportionally to the maximum flow rates in each case, which vary depending on which prospects are successful, and which hydrocarbon case is evaluated. Pipeline costs are escalated at 2.2% per year.

A relationship of the cost of $75,000 per inch of pipe diameter, per mile of length was used to estimate pipeline costs with an additional cost adjustment factor of 1.3 to adjust for Albania. For example, the costs of building in Albania a 100-mile (161 km) pipeline with a diameter of 20 inches (50.8 cm) are estimated as follows:

$$1.3 \text{ x } \$75{,}000 \times 20" \times 100 \text{ miles} = \$195 \text{ MM}$$

The oil pipeline size is based on choosing a diameter large enough for the volume and pressure while attempting to keep the fluid velocity between 3 and 15 ft/sec (1 to 5 m/sec)[8]. The sizing of gas pipeline diameters was based on a calculation routine using five different industry-accepted equations[9] for gas flow in horizontal pipes, that calculates gas flow rates based on gas properties, pressure drop, and line diameter and length. Using these methods, tables of required pipeline diameter versus required maximum throughput were developed, which were then used as inputs into the economic model.

A pipeline length of 56 miles (90 km) for Blocks A-B and a pipeline length of 59 miles (95 km) for Blocks D-E were used for estimating oil pipeline costs. For gas pipelines, a pipeline length of 125 miles (200 km) was used for estimating gas pipeline costs for Blocks A-B, while 100 miles (160 km) km were used for Blocks D-E. The estimated lengths are not sufficient to reach all the way from the outermost prospects, such as Papri, to the terminus. The estimates do not take into account that smaller pipeline diameters would actually be required at the furthest points of the system, with line size increasing as various successful prospects enter the system; nor do the

[8] Petroleum Engineering Handbook, pg 15-2
[9] www.peteng.com

estimates account for the fact that various portions of the pipeline would not be needed, or would need to be larger, depending on which prospects are ultimately successful. Thus, the logic used was intended to provide reasonable cost approximations, not exact costs or designs.

The pipeline facilities were sized for varying volume throughput. The oil pipeline will require pumps, and the gas pipeline will require compressors. Compression and pumping on the pipelines must manage the pressure change due to friction and elevation changes. The estimated cost for pumps, compressors and ancillary equipment as a function of throughput are presented in Table 7-3.

Table 7-3 Estimated Pipeline, Pumps, and Compression Cost Parameters

	Oil		**Gas**	
	$M/MBPD	**$M/MTPD**	**$M/MMCFPD**	**$M/MMCMPD**
Costs	$3.782	$27.722	$19.950	$704.530

For the oil with gas cap case an additional gas pipeline as well as additional surface facilities will be sized and constructed for the blowdown phase of production. These additional costs have been accounted for in the model. Compression cost estimates have been provided by UE Compression and pump cost estimates were provided by Sulzer Pumps in the USA.

Gustavson Associates assumed that natural gas and not electricity would be used as fuel for all field and pipeline facilities.

A large amount of horsepower is required to move these volumes of hydrocarbons and this accounts for the bulk of the facilities cost. Horsepower requirements are based on an assumption of discharge pressure. A discharge pressure of 1,500 psig was used in the compression calculations, corresponding with an assumed upstream pressure of the gas pipelines. These fixed costs were calculated using a relationship graph that similar to the one used to calculate drilling costs and days. A linear relationship was established of cost versus throughput for both oil and gas to estimate the numbers presented in Table 7-3.

For each block, the summary of pipeline costs for each case and scenario is presented in Table 7-4.

Table 7-4 Summary of Pipeline Costs

Parameters	**Oil**		**Gas with Condensate**		**Oil with Gas Cap**	
	Complete success	**Partial success**	**Complete success**	**Partial success**	**Complete success**	**Partial success**
Oil Pipeline						
Pipeline Cost, $MM						
A-B	$122	$89	$33	$22	$67	$56
D-E	$155	$122	$33	$22	$78	$77
Capacity, MBPD						
A-B	250	183	22	13	119	87
D-E	366	258	33	17	169	122
Pipe Diameter, inch						
A-B	22	16	6	4	12	10
D-E	28	22	6	4	14	14
Gas Pipeline						
Pipeline Cost, $MM						
Initial A-B	$249	$223	$608	$466	$249	$223
Initial D-E	$275	$249	$703	$523	$274	$223
Blowdown A-B					$493	$436
Blowdown D-E					$495	$436
Capacity, MMCFD						
Initial A-B	253	186	2,360	1,345	260	180
Initial D-E	369	260	3,491	1,793	314	206
Blowdown A-B					1,480	1,069
Blowdown D-E					1,575	1,084
Pipe Diameter, inch						
Initial A-B	20	18	46	36	20	18
Initial D-E	22	20	52	40	22	18
Blowdown A-B					38	34
Blowdown D-E					38	34

7.4.2.2 Surface Facilities Costs

Centralized facilities at each field would allow for the most economic and efficient operation. Each field will have separate oil storage tank facilities, high-pressure separators, gas dehydrators, and the pumps and compressors necessary to get the product into the pipelines. Gas lift would be used as the optimal lifting method for oil wells if they can no longer flow naturally. As the prospects vary dramatically, there is a large variation in facility cost, as shown in Table 7-5. Although water production may eventually be likely at these fields, at this time no costs have been included for water disposal wells, water storage, or disposal pumps.

Facility abandonment costs of $100,000 per field have been included. All of these costs are escalated at 2.2% per year.

Table 7-5 Summary of Facility Cost Estimates, by Prospect

	Surface Facility Capex, $M		
Prospect	**Oil**	**Oil with Gas Cap**	**Gas with Condensate**
Rinas	$505	$644	$800
Gyurice	$921	$638	$937
Rova	$387	$386	$375
Nikel	$935	$459	$926
Kashari	$550	$453	$621
Kamez	$944	$583	$1,007
Sauk	$946	$584	$1,085
Rova W	$375	$374	$352
Papri	$942	$580	$997
Total	$6,506	$4,700	$7,100

7.4.3 Operating Costs

Operating costs are estimated at $10,000 per well per month for oil wells, and $5,000 per well per month for gas wells and recompleted oil wells under gas blowdown. Additional field level operating costs were estimated at $1,000,000 per field per year. All of these costs are escalated at 2.2% per year.

7.5 DISCOUNTED CASH FLOW ANALYSIS

7.5.1 Overview

This section presents the results of the economic model created by Gustavson Associates. It is important to recognize that these results are a preliminary estimate of the value of the four Manas blocks. The actual value will depend on the outcome of the actual exploration programs. The economics in the success scenarios may be better than presented here, since it will be possible to optimize exploration and development scheduling, and the sizing of facilities in a way that has not yet been considered as well as the actual price realized from oil and gas sales. For example, it may be desirable to (a) change the sequence in which prospects are explored depending on earlier results, (b) order additional rigs, and/or (c) save on capital expenditures by reducing the capacity of facilities and pipelines even though this may delay production.

Three scenarios are considered, two success scenarios that each have three different hydrocarbon cases modeled: (1) a complete success scenario in which all of the nine prospects are successful, (2) a partial success scenario in which Rinas fails, exploration wells are not drilled at Nikel, Kashari and Kamez due to the Rinas failure, and all of the other prospects are successful, and (3) a total failure scenario in which the initial exploratory well drilled on the Rinas, Gyurice and Rova structures are all dry-holes, after which there is no further drilling.

A summary of the economic results for the three scenarios and three hydrocarbon cases modeled is shown in Table 7-6.

As seen in Table 7-11, the best outcome would be if all of the prospects are successful and contain oil with no gas cap. The NPV_{10}[10] in this scenario is estimated to be about $18.6 billion, although the NPV_{10} is still an impressive $11.9 billion in the partial success scenario. If all of the prospects are successful but contain gas (and condensate), the NPV_{10} is estimated to be about $10.8 billion, and the partial success NPV_{10} for this scenario is about $6.1 billion.

Curiously, the scenario with oil and a gas cap has the lowest NPV_{10}. We believe that this is because the oil production rates are lower than in the oil case without a gas cap case, and the high gas rates associated with blowdown in this case will occur late in the life of the fields, when their value is discounted according to the time value of money.

Table 7-6 Overall Summary of Economic Results

Parameters	**Oil**		**Oil with Gas Cap**		**Gas**		
	Complete success	**Partial success**	**Complete success**	**Partial success**	**Complete success**	**Partial success**	**Failure**
Oil production							
MMB	3,024	1,515	1,389	699	280	141	0
MMT	413	207	189	95	33	17	0
Gas production							
BCF	3,050	1,530	13,691	7,743	29,639	14,928	0
BCM	86	43	388	219	839	405	
NPV_{10} **$B**	$18.6	$11.9	$9.7	$6.3	$10.8	$6.1	($0.1)
NPV_{10} **$/BOE**	$5.3	$6.7	$2.6	$3.2	$2.1	$2.3	
IRR	159%	156%	101%	101%	73%	80%	

We estimate the capital expenditures in the total failure scenario will be approximately $66 million, including dry-hole costs for four exploratory wells and seismic acquisition costs over the prospects.

Details of the methodology and assumptions for each hydrocarbon case and the scenarios are presented below.

[10] Assuming a 10% discount rate.

7.5.2 Oil

7.5.2.1 Complete Success Scenario

In the complete success scenario all nine of the prospects are successful and each of them contains oil with associated gas (but not a gas cap). Based on the relationship between the Total Depth of the wells and the drilling time as seen in Figure 7-2, the estimated schedule for exploration and development wells based on the use of only two rigs is shown in Table 7-7.

Note that the exploration and appraisal period would continue until September 2018 in this scenario, which is beyond the end of the exploration period of 2050 specified in the PSC. It should be noted that it would be important to actually commission more than two rigs in this case, in order to ensure that the exploration drilling was completed within the PSC exploration period or the agreement should be renegotiated prior to 2050.

Table 7-7 Exploration and Development Schedule – Oil Case, Complete Success

Prospect	Seismic		Exploration & Appraisal Drilling Period		Development Drilling		Total Wells	Start of production
	Start	End	Start	End	Start	End		
Rinas	Sep-08	Dec-08	Dec-08	Dec-09	Dec-09	Aug-14	22	Sep-10
Gyurice	Oct-08	Jan-09	Dec-09	Jan-11	Aug-14	Jun-20	25	Mar-15
Rova	Nov-08	Feb-09	Feb-11	Mar-12	Sep-18	Apr-19	5	Apr-19
Nikel	Dec-08	Mar-09	Apr-12	May-13	Apr-19	May-24	22	Nov-19
Kashari	Jan-09	Apr-09	May-13	Jun-14	Jul-20	Jan-22	9	Jan-21
Kamez	Feb-09	Jun-09	Jun-14	Jul-15	Jan-22	Oct-25	17	Aug-22
Sauk	Mar-09	Jul-09	Aug-15	Sep-16	May-24	Dec-28	20	Dec-24
Rova W	May-09	Aug-09	Sep-16	Aug-17	Nov-25	May-27	10	Apr-26
Papri	Jun-09	Sep-09	Aug-17	Sep-18	May-27	Dec-30	17	Dec-27
Overall	Sep-08	Sep-09	Dec-08	Sep-18	Dec-09	Dec-30	147	

Notice also that production begins at some fields before development drilling is completed. We assume that production can begin[11] at a field once 5 wells are completed. This includes the 3 wells drilled for the purpose of exploration and appraisal. A forecast of the total production for this scenario is shown in Figure 7-3.

Oil production rates are estimated to be about 250,000 BPD (34,100 TPD) in 2015, and increase to more than 400,000 BPD (54,600 TPD) in 2023 as additional prospects are developed. Gas production rates follow a similar pattern reaching about 250 MMCFPD (7.1 MMCMPD) by 2015 and exceeding 400 MMCFPD (11.3 MMCMPD) in 2023.

A summary of the total production by prospect and the capital expenditures for the prospects (in constant 2008 dollars excluding pipelines) is shown in Table 7-8.

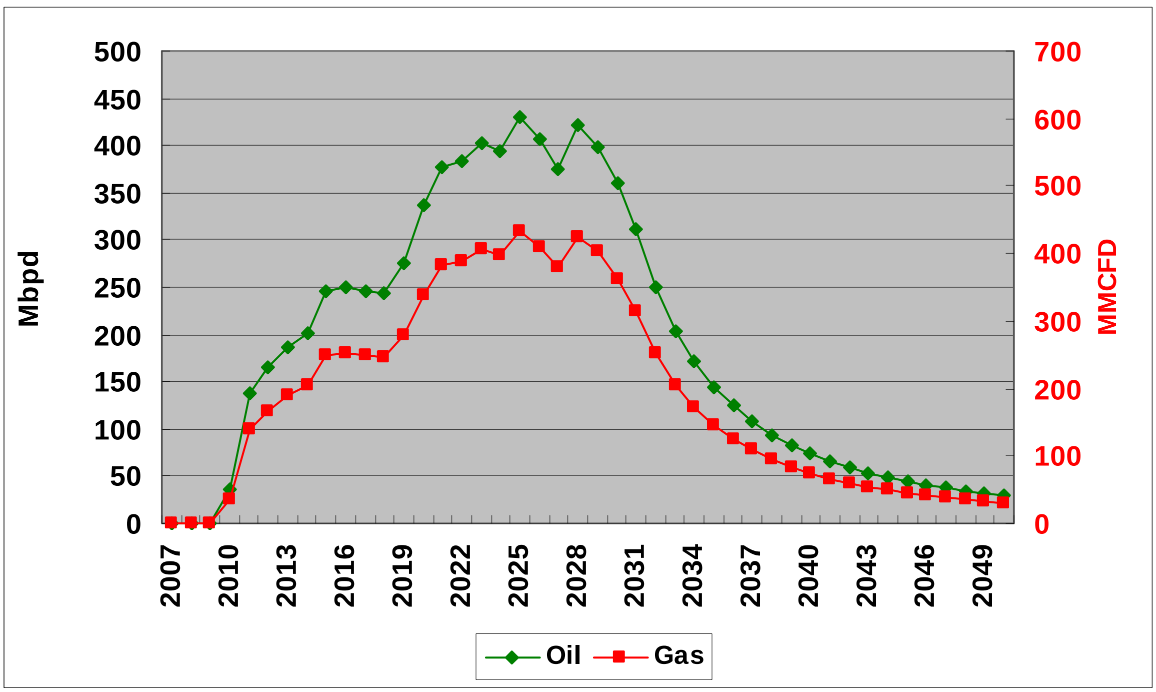


Figure 7-3 Production Forecast – Oil Case, Complete Success

[11] In some cases, the start of production may be delayed until the construction of surface facilities is completed at the field, even though 5 wells have been completed before that time.

Table 7-8 Total Production and Capex – Oil Case, Complete Success

Prospects Blocks	Oil		Gas		Field Capex
	MMB	MMT	BCF	BCM	MM$(2008)
Rinas	624	85	629	18	$265
Gyurice	651	89	659	19	$324
Rova	55	8	56	2	$78
Nikel	372	51	374	11	$286
Kashari	183	25	184	5	$120
Kamez	364	50	366	10	$226
Sauk	395	54	398	11	$266
Rova W	42	6	42	1	$112
Papri	339	46	341	10	$216
Total	3,024	413	3,049	86	$1,893
Block AB	1,274	174	1,287	36	$589
Block DE	1,750	239	1,762	50	$1,304
Total	3,024	413	3,049	86	$1,893

An economic summary grouped by PSC agreements is shown in Table 7-9. The capital expenditures in this table are shown in inflated (nominal) dollars.

Table 7-9 Economic Summary – Oil Case, Complete Success

Parameters	Block AB	Block DE	Total
Year of first production	2010	2019	2010
Oil MMB (MMT)	1,274 (174)	1,750 (239)	3,024 (413)
Gas BCF (BCM)	1,287 (36)	1,762 (50)	3,049 (86)
Hydrocarbon MMBOE	1,489	2,043	3,532
Field Capex MM$ (nominal)	$683	$2,739	$3,422
Pipeline Capex MM$ (nominal)	$379	$535	$914
NPV_{10} $MM	$11,023	$7,622	$18,645
NPV_{10} $/BOE	$7.40	$3.73	$5.28
IRR	165%	49%	159%
Profit Ratio	15.02	10.66	12.87

The NPV_{10} for this scenario is estimated to be about $18.6 billion. The NPV_{10} per BOE is lower for Block D-E because prospects in that block, in this scenario, are developed later than prospects in Block A-B.

7.5.2.2 Partial Success Scenario

In the Partial Success Scenario only six of the nine prospects are successful and each of them contains oil with associated gas (but not a gas cap). Based on the relationship between the Total Depth of the wells and the drilling time as seen in Figure 7-2, the estimated schedule for exploration and development wells based on the use of only two rigs is shown in Table 7-10. In this scenario it is assumed that the Rinas prospect exploration well is a dry hole and that the related prospects at Nikel, Kashari and Kamez are not drilled. The remaining prospects are all successful.

In this scenario, it will be possible to complete all exploration and appraisal drilling within the exploration period of the PSC, since fewer wells are drilled. The corresponding production forecast is shown in Figure 7-4.

The peak oil rate in 2019 of 350,000 BPD (47,750 TPD) is slightly lower than in the complete success scenario and declines almost immediately. The total production by prospect and the field capital required (in constant 2008 dollars, excluding pipeline capital) are shown in Table 7-11.

Table 7-10 Exploration and Development Schedule – Oil Case and Oil/Gas Cap Partial Success Scenario

Prospect	Seismic		Exploration & Appraisal Drilling Period		Development Drilling		Total Wells	Start of production
	Start	End	Start	End	Start	End		
Rinas	Sep-08	Dec-08	Dec-08	Apr-09	N/A	N/A	1	N/A
Gyurice	Oct-08	Jan-09	May-09	Jun-10	Jun-10	Apr-16	25	Feb-11
Rova	Nov-08	Feb-09	Jun-10	Jul-11	Oct-14	Apr-15	5	Apr-15
Nikel	Dec-08	Mar-09	N/A	N/A	N/A	N/A	0	N/A
Kashari	Jan-09	Apr-09	N/A	N/A	N/A	N/A	0	N/A
Kamez	Feb-09	Jun-09	N/A	N/A	N/A	N/A	0	N/A
Sauk	Mar-09	Jul-09	Aug-11	Sep-12	May-15	Dec-19	20	Nov-15
Rova W	May-09	Aug-09	Sep-12	Aug-13	Apr-16	Oct-17	10	Sep-16
Papri	Jun-09	Sep-09	Sep-13	Sep-14	Nov-17	Jun-21	17	May-18
Overall	Sep-08	Sep-09	Dec-08	Sep-14	Jun-10	Jun-21	78	

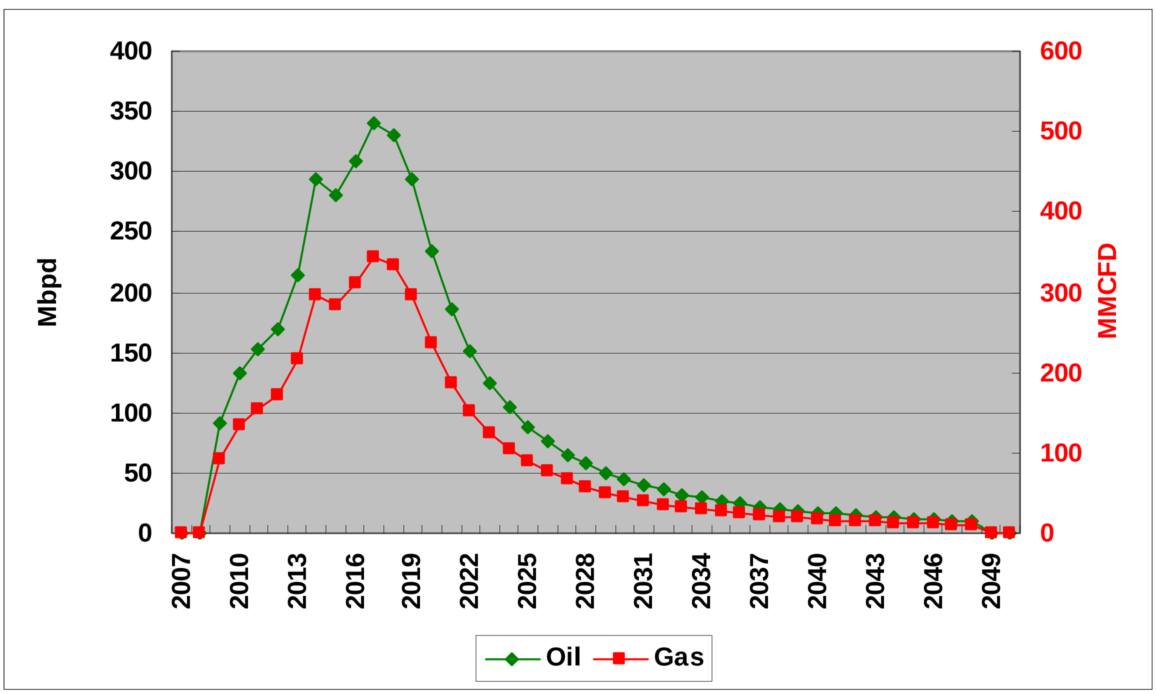


Figure 7-4 Production Forecast – Oil Case, Partial Success

Table 7-11 Total Production and Capex – Oil Case, Partial Success

Prospects Blocks	Oil		Gas		Field Capex
	MMB	MMT	BCF	BCM	MM$(2008)
Rinas	0	0	0	0	$20
Gyurice	657	90	665	19	$329
Rova	55	8	56	2	$78
Nikel	0	0	0	0	$1
Kashari	0	0	0	0	$1
Kamez	0	0	0	0	$1
Sauk	408	56	411	12	$270
Rova W	43	6	44	1	$114
Papri	352	48	354	10	$219
Total	1,515	207	1,530	43	$1,033
Block AB	657	90	665	19	$349
Block DE	858	117	865	24	$684
Total	1,515	207	1,530	43	$1,033

A summary of the economic results grouped by PSC is shown in Table 7-12. The capital expenditures in this table are shown in inflated (nominal) dollars.

The project has an NPV_{10} of about $11.9 billion in this scenario.

Table 7-12 Economic Summary – Oil Case, Partial Success

Parameters	Block AB	Block DE	Total
Year of first production	2011	2015	2011
Oil MMB (MMT)	657 (90)	858 (117)	1,515 (207)
Gas BCF (BCM)	665 (19)	865 (25)	1,530 (43)
Hydrocarbon MMBOE	768	1,003	1,770
Field Capex MM$ (nominal)	$383	$1,440	$1,823
Pipeline Capex MM$ (nominal)	$326	$422	$748
NPV_{10} $MM	$6,221	$5,724	$11,945
NPV_{10} $/BOE	$8.11	$5.71	$6.75
IRR	172%	75%	156%
Profit Ratio	11.94	9.28	10.50

7.5.3 Gas

7.5.3.1 Complete Success Scenario

In the complete success scenario all nine of the prospects are successful and each of them contains gas with associated condensate. Based on the relationship between the Total Depth of the wells and the drilling time as seen in Figure 7-2, the schedule for complete success in the gas case is shown in Table 7-13.

The schedule for seismic, exploration and development drilling is the same as for the oil case. However, development drilling will be completed more quickly, since the total number of wells needed is about one-half that required in the oil case. Correspondingly, the start of production for most prospects will occur sooner than in the oil case.

A forecast of the total production for this scenario is shown in Figure 7-5.

Table 7-13 Exploration and Development Schedule – Gas Case, Complete Success

Prospect	Seismic		Exploration & Appraisal Drilling Period		Development Drilling		Total Wells	Start of production
	Start	End	Start	End	Start	End		
Rinas	Sep-08	Dec-08	Dec-08	Dec-09	Dec-09	Dec-11	11	Sep-10
Gyurice	Oct-08	Jan-09	Dec-09	Jan-11	Dec-11	Aug-14	13	Jun-12
Rova	Nov-08	Feb-09	Feb-11	Mar-12	Aug-14	Aug-14	3	Aug-14
Nikel	Dec-08	Mar-09	Apr-12	May-13	Aug-14	Oct-16	11	Mar-15
Kashari	Jan-09	Apr-09	May-13	Jun-14	Oct-16	Apr-17	5	Apr-17
Kamez	Feb-09	Jun-09	Jun-14	Jul-15	May-17	Dec-18	9	Nov-17
Sauk	Mar-09	Jul-09	Aug-15	Sep-16	Sep-18	Nov-20	11	Apr-19
Rova W	May-09	Aug-09	Sep-16	Aug-17	Dec-18	Aug-19	6	Jun-19
Papri	Jun-09	Sep-09	Aug-17	Sep-18	Aug-19	Mar-21	9	Mar-20
Overall	Sep-08	Sep-09	Dec-08	Sep-18	Dec-09	Mar-21	78	

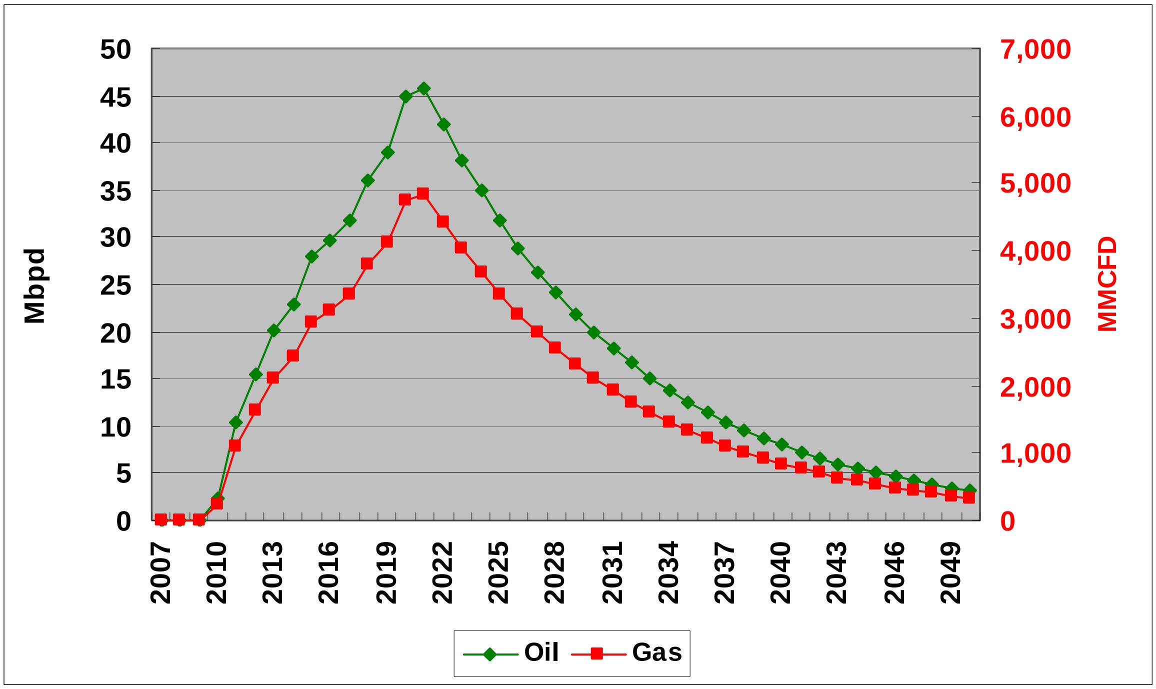


Figure 7-5 Production Forecast – Gas Case, Complete Success

Gas production would begin in 2010 increasing rapidly and reaching a peak of about 5 BCFPD (142 MMCMPD) in 2021. The operator would most likely choose to lay a smaller diameter pipeline, to save costs, than that used in this scenario and would consequently need to curtail production in the early years. For the purposes of this report the pipeline was sized for the peak flow rate. The condensate production rate will reach a peak of about 45,000 bpd (6,140 tonnes per day) in 2020.

The total production by prospect and the field capital (in constant 2008 dollars, excluding pipeline capital) are shown in Table 7-14.

An economic summary grouped by PSC for this scenario is shown in Table 7-15.

Table 7-14 Total Production and Capex – Gas Case, Complete Success

Prospects Blocks	Condensate		Gas		Field Capex
	MMB	MMT	BCF	BCM	MM$(2008)
Rinas	56	7	5,939	168	$142
Gyurice	60	7	6,348	180	$177
Rova	7	1	737	21	$65
Nikel	34	4	3,642	103	$152
Kashari	17	2	1,754	50	$72
Kamez	34	4	3,579	101	$127
Sauk	37	4	3,943	112	$154
Rova W	4	0	400	11	$72
Papri	31	4	3,297	93	$122
Total	280	33	29,639	839	$1,084
Block AB	116	13	12,286	348	$319
Block DE	164	20	17,353	491	$765
Total	280	33	29,639	839	$1,084

Table 7-15 Economic Summary – Gas Case, Complete Success

Parameters	Block AB	Block DE	Total
Year of first production	2010	2014	2010
Condensate MMB (MMT)	116 (14)	164 (20)	280 (33)
Gas BCF (BCM)	12,286 (348)	17,353 (491)	29,639 (839)
Hydrocarbon MMBOE	2,164	3,056	5,220
Field Capex MM$ (nominal)	$342	$1,521	$1,863
Pipeline Capex MM$ (nominal)	$655	$822	$1,477
NPV_{10} $MM	$5,506	$5,261	$10,767
NPV_{10} $/BOE	$2.54	$1.72	$2.06
IRR	77%	53%	73%
Profit Ratio	6.56	5.70	6.11

7.5.3.2 Partial Success Scenario

In the Partial Success Scenario only six of the nine prospects are successful and each of them contains gas with associated condensate. Based on the relationship between the Total Depth of the wells and the drilling time as seen in Figure 7-2, the estimated schedule for exploration and development wells based on the use of only two rigs is shown in Table 7-16. In this scenario it is assumed that the Rinas prospect exploration well is a dry hole and that the related prospects at Nikel, Kashari and Kamez are not drilled. The remaining prospects are all successful.

Table 7-16 Exploration and Development Schedule – Gas Case, Partial Success

Prospect	**Seismic**		**Exploration & Appraisal Drilling Period**		**Development Drilling**		**Total Wells**	**Start of production**
	Start	End	Start	End	Start	End		
Rinas	Sep-08	Dec-08	Dec-08	Apr-09	N/A	N/A	1	N/A
Gyurice	Oct-08	Jan-09	May-09	Jun-10	Jun-10	Jan-13	13	Feb-11
Rova	Nov-08	Feb-09	Jun-10	Jul-11	Feb-13	Feb-13	3	Feb-13
Nikel	Dec-08	Mar-09	N/A	N/A	N/A	N/A	0	N/A
Kashari	Jan-09	Apr-09	N/A	N/A	N/A	N/A	0	N/A
Kamez	Feb-09	Jun-09	N/A	N/A	N/A	N/A	0	N/A
Sauk	Mar-09	Jul-09	Aug-11	Sep-12	Feb-13	Apr-15	11	Sep-13
Rova W	May-09	Aug-09	Sep-12	Aug-13	Oct-14	Jun-15	6	Mar-15
Papri	Jun-09	Sep-09	Sep-13	Sep-14	Apr-15	Nov-16	9	Oct-15
Overall	Sep-08	Sep-09	Dec-08	Sep-14	Jun-10	Nov-16	43	

The timing for the seismic, exploration and appraisal drilling is the same as in the oil case, but the development drilling is completed sooner since there are fewer wells. The corresponding production forecast is shown in Figure 7-6.

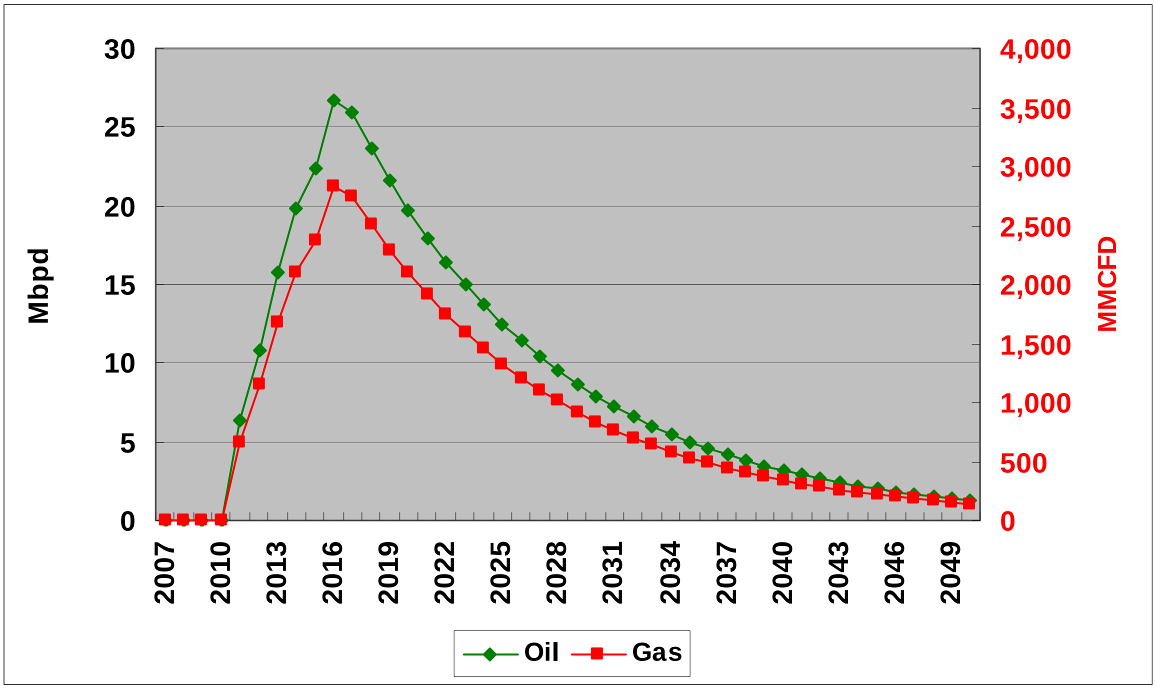


Figure 7-6 Production Forecast – Gas Case, Partial Success Scenario

Gas production is forecast to reach a peak rate of about 2.8 BCFPD (79.3 MMCMPD) in 2016 and to decline thereafter. The operator would most likely choose to lay a smaller diameter pipeline then that used in this scenario and would consequently need to curtail production in the early years. For the purposes of this report the pipeline was sized for the peak flow rate. The peak condensate rate of about 27,000 BPD (3,680 TPD) for this case is forecast to occur in 2016.

The total production by prospect and the total capital required (in constant 2008 dollars, excluding pipeline capital) are shown in Table 7-17.

Table 7-17 Total Production and Capex – Gas Case, Partial Success

Prospects Blocks	Oil		Gas		Field Capex
	MMB	MMT	BCF	BCM	MM$(2008)
Rinas	0	0	0	0	$20
Gyurice	60	7	6,377	181	$177
Rova	7	1	740	21	$65
Nikel	0	0	0	0	$1
Kashari	0	0	0	0	$1
Kamez	0	0	0	0	$1
Sauk	38	5	4,042	114	$154
Rova W	4	0	406	11	$72
Papri	32	4	3,363	95	$122
Total	141	17	14,928	423	$613
Block AB	60	7	6,377	181	$197
Block DE	80	10	8,551	242	$417
Total	141	17	14,928	423	$613

An economic summary grouped by PSC for this scenario is shown in Table 7-18.

The overall NPV_{10} for the Partial Success scenario is estimated to be about $6.1 billion. This is lower than the oil case primarily due to the low initial gas price of $2.50/MCF ($88.29/MCM) that is used in the model.

Table 7-18 Economic Summary – Gas Case, Partial Success

Parameters	Block AB	Block DE	Total
Year of first production	2011	2013	2011
Oil MMB (MMT)	60 (7)	80 (10)	141 (17)
Gas BCF (BCM)	6,377 (181)	8,551 (242)	14,928 (423)
Hydrocarbon MMBOE	1,123	1,506	2,629
Field Capex MM$ (nominal)	$208	$839	$1,048
Pipeline Capex MM$ (nominal)	$510	$595	$1,105
NPV_{10} $MM	$2,916	$3,193	$6,109
NPV_{10} $/BOE	$2.60	$2.12	$2.32
IRR	88%	65%	80%
Profit Ratio	5.06	4.69	4.86

7.5.4 Oil with Gas Cap

7.5.4.1 Complete Success Scenario

The forecast of scheduling for the oil with a gas cap case is the same as that for the oil scenario, since we estimate that the same number of wells will be required and that drilling times will be the same. However, the recompletion of wells will occur after about 20 years of oil production, at which time oil rates will be low enough that it is economically optimal to begin producing large quantities of gas from the gas cap.

A forecast of the estimated total production rates is shown in Figure 7-7.

The oil rate is forecast to reach about 120,000 BPD (16,370 TPD) in 2015, then to rise further to almost 200,000 BPD (2,730 TPD) in 2025. The gas rate is forecast to increase to about 400 MMCFPD (11.3 MMCMPD) by 2025. We estimate that 2031 would be the optimal time for the recompletion of the oil wells in the Rinas field into the gas cap, leading to a significant increase in gas production, to about 1.5 BCFPD (42.5 MMCMPD). The rest of the fields will be put on gas-cap blowdown when the oil production rates fall. This large increase in gas rate will require investment in a new gas pipeline to handle the higher rates. The fields will be capable of producing significant quantities of gas long after the expiration of the PSC production period. Investment in the new gas pipeline should be made conditional upon an extension of the production period; however, such extensions are not a part of the current PSC.

The change in gas production rates over time as seen in Figure 7-7 after 2031 are due to the well recompletions in the other fields that will occur in subsequent years. We forecast that gas rates will first reach 2 BCFPD (56.6 MMCMPD) in about 2036. Gas rates will be between 1.5 and 2.3 BCFPD (42.5 and 65.1 MMCMPD) late in the life of the field from about 2040 to 2050.

The total production by prospect and the total capital required (in constant 2008 dollars, excluding pipeline capital) are shown in Table 7-19.

An economic summary grouped by PSC for this scenario is shown in Table 7-20.

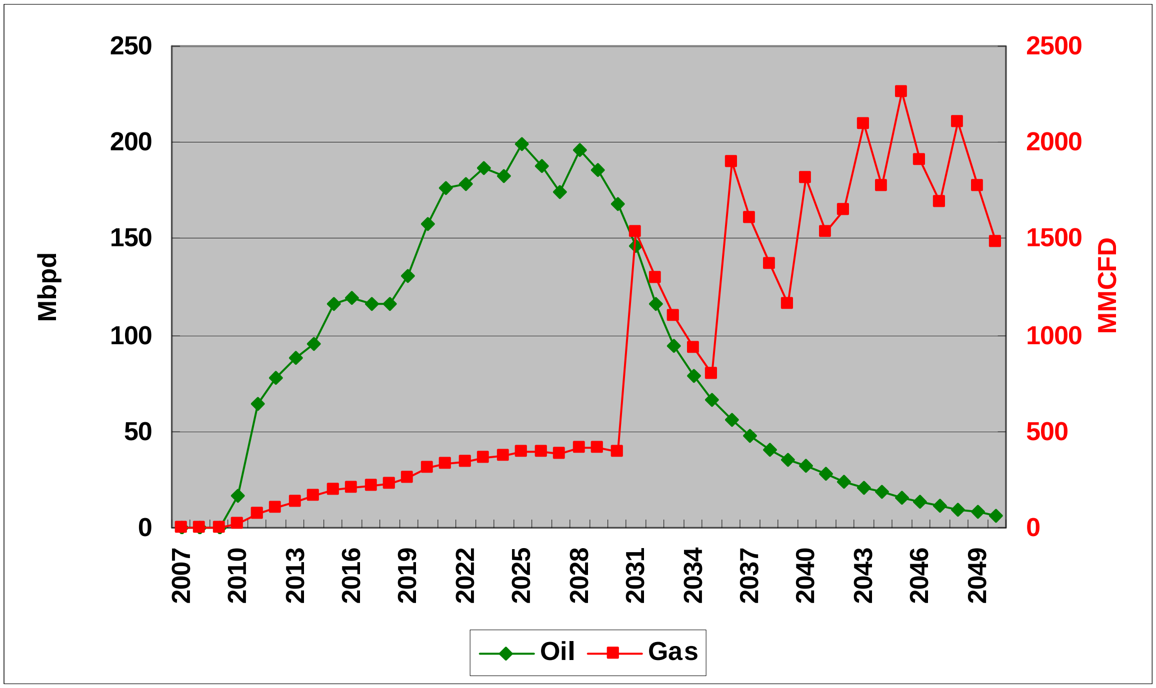


Figure 7-7 Production Forecast – Oil/Gas Cap Case, Complete Success

Table 7-19 Total Production and Capex – Oil/Gas Cap Case, Complete Success

Prospects Blocks	**Oil**		**Gas**		**Field Capex**
	MMB	**MMT**	**BCF**	**BCM**	**MM$(2008)**
Rinas	287	39	3,210	91	$292
Gyurice	300	41	3,356	95	$354
Rova	26	4	265	8	$ 83
Nikel	153	21	1,765	50	$312
Kashari	86	12	818	23	$130
Kamez	171	23	1,601	45	$246
Sauk	186	25	1,567	44	$289
Rova W	19	3	130	4	$124
Papri	161	22	980	28	$235
Total	1,389	189	13,692	388	$2,065
Block AB	587	80	6,566	186	$646
Block DE	802	109	7,126	202	$1,420
Total	1,389	189	13,692	388	$2,065

Table 7-20 Economic Summary – Oil/Gas Cap Case, Complete Success

Parameters	Block AB	Block DE	Total
Year of first production	2010	2019	2010
Oil MMB (MMT)	587 (80)	802 (109)	1,389 (189)
Gas BCF (BCM)	6,566 (186)	7,126 (202)	13,692 (388)
Hydrocarbon MMBOE	1,681	1,989	3,670
Field Capex MM$ (nominal)	$764	$2,857	$3,621
Pipeline Capex MM$ (nominal)	$1,118	$1,409	$2,526
NPV_{10} $MM	$5,873	$3,823	$9,696
NPV_{10} $/BOE	$3.49	$1.92	$2.64
IRR	108%	39%	101%
Profit Ratio	7.46	5.20	6.37

7.5.4.2 Partial Success Scenario

In the Partial Success Scenario only six of the nine prospects are successful and each of them contains oil with a gas cap. Based on the relationship between the Total Depth of the wells and the drilling time as seen in Figure 7-2, the estimated schedule for exploration and development wells based on the use of only two rigs is shown in Table 7-10. In this scenario it is assumed that the Rinas prospect exploration well is a dry hole and that the related prospects at Nikel, Kashari and Kamez are not drilled. The remaining prospects are all successful.

The production forecast is shown in Figure 7-8.

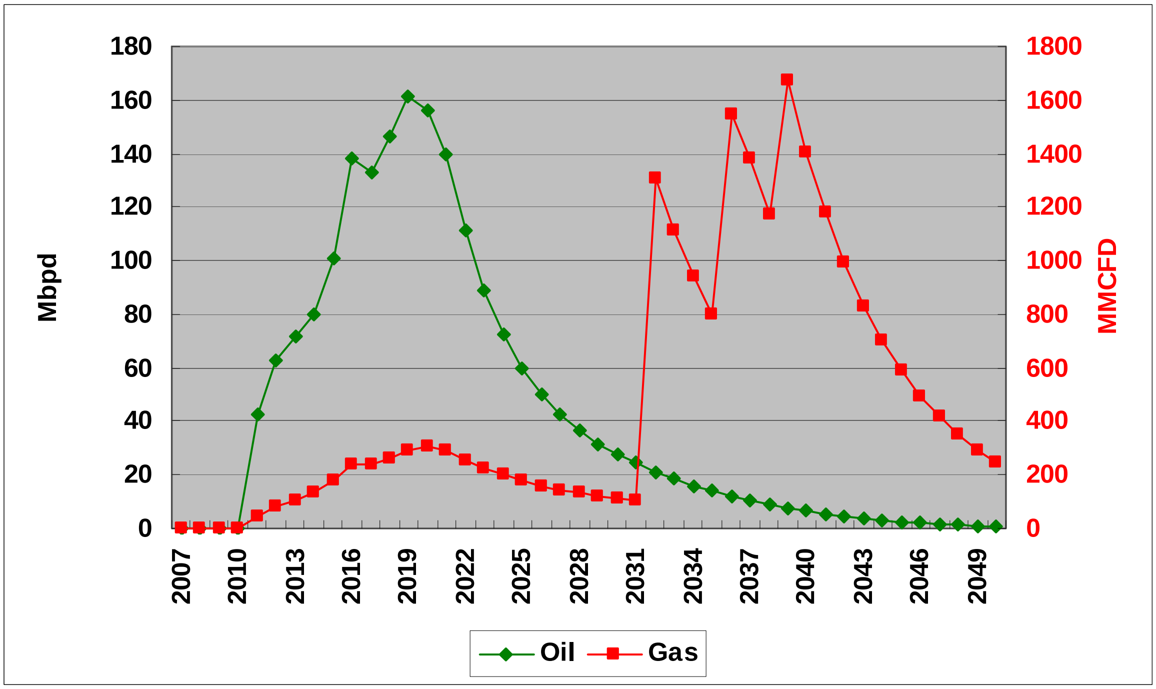


Figure 7-8 Production Forecast – Oil/Gas Cap Case, Partial Success

The oil rate reaches a peak of about 160,000 BPD (21,830 TPD) in 2019 and then declines quickly. This peak rate is slightly lower than the complete success scenario, and the decline occurs more quickly. The gas rate is forecast to be below 300 MMCFPD (8.5 MMCMPD) during the primary production phase (pre-blowdown). Gas-cap blowdown is forecast to occur in 2032, the same as in the complete success scenario. A second gas pipeline will be required to transport the higher gas volumes during blow down. The gas production rates will be between approximately 800 MMCFPD (22.7 MMCMPD) and 1.7 BCFPD (48.1 MMCMPD) from 2032 through 2043 as the various fields are successively recompleted over time into the gas cap.

The total production by prospect and the total capital required (in constant 2008 dollars, excluding pipeline capital) are shown in Table 7-21.

An economic summary grouped by PSC for this scenario is shown in Table 7-22.

Table 7-21 Total Production and Capex – Oil/Gas Cap Case, Partial Success

Prospects Blocks	Oil		Gas		Field Capex
	MMB	MMT	BCF	BCM	MM$(2008)
Rinas	0	0	0	0	$20
Gyurice	301	41	3461	98	$354
Rova	26	4	284	8	$83
Nikel	0	0	0	0	$1
Kashari	0	0	0	0	$1
Kamez	0	0	0	0	$1
Sauk	188	26	2083	59	$289
Rova W	20	3	203	6	$124
Papri	164	22	1711	48	$235
Total	699	95	7742	219	$1,109
Block AB	301	41	3461	98	$374
Block DE	398	54	4281	121	$735
Total	699	95	7742	219	$1,109

Table 7-22 Economic Summary – Oil/Gas Cap Case, Partial Success

Parameters	Block AB	Block DE	Total
Year of first production	2011	2015	2011
Oil MMB (MMT)	301 (41)	398 (54)	699 (95)
Gas BCF (BCM)	3,461 (98)	4,281 (121)	7,742 (219)
Hydrocarbon MMBOE	878	1,112	1,990
Field Capex MM$ (nominal)	$424	$1,441	$1,865
Pipeline Capex MM$ (nominal)	$1,010	$1,128	$2,137
NPV_{10} $MM	$3,304	$2,980	$6,285
NPV_{10} $/BOE	$3.76	$2.68	$3.16
IRR	114%	56%	100%
Profit Ratio	5.74	4.67	5.18

7.5.5 Failure Scenario

If each of the exploration wells in Rinas, Gyurice and Rova are failures then both blocks would be relinquished by Manas. The capital expenditures by prospect in constant 2008 dollars are shown in Table 7-23 below.

Table 7-23 Total Capex – Failure Scenario

Prospects Blocks	**Field Capex MM$(2008)**
Rinas	$21
Gyurice	$19
Rova	$21
Nikel	$1
Kashari	$1
Kamez	$1
Sauk	$1
Rova W	$1
Papri	$1
Total	$67
Block AB	$40
Block DE	$27
Total	$67

We assume that 2-D seismic would be acquired over all of the prospects before the results of all of the exploration drilling are known, so there is a small expenditure for seismic acquisition, processing and interpretation for each field. The total capital expenditure in inflated (nominal) dollars would be about $67 million in this scenario. Exploratory drilling would be completed by about February 2010.

7.5.6 Expected Value Analysis

To complete the economic assessment of the Manas blocks including the consideration of potential measures to mitigate the risk, the probability of success for each prospect has to be estimated. These probabilities can be used to weight the NPVs of the various possible outcomes to determine the statistical expected value (EV) of the licenses. With nine prospects, each of which can be a success or a failure, there are $2^9 = 512$ possible outcomes. Therefore, determining the EV of Manas blocks is a large numerical task requiring the use of special software to deal with this large number of cases and can be undertaken at the Client request.

This economic report has presented the net present value (NPV_{10}) for only seven of the many possible outcomes that may occur in the execution of this exploration program. The scenarios include the complete and partial success for three hydrocarbon cases and total failure of the first three prospects that will then condemn all of the remaining prospects on both blocks.

The NPV_{10}s of these scenarios cover a range of possible values of the exploration program, from -$62 million loss in the Total Failure Scenario to +$18.6 billion in the Complete Success Scenario with the oil case.

EV represents the amount that the licenses are worth to a risk-neutral investor.

7.6 SENSITIVITY ANALYSIS

The results of sensitivity analysis for oil pricing and pipeline costs show the impact on the value of the Manas blocks in Albania. The basic sensitivities related to the possibility of the discovery of different types of hydrocarbons as well as the possibility of different success scenarios for the exploration program (full success, partial success, or failure) have been addressed in Section 7.5 and the range of possible outcomes has been presented in Table 7-6.

In this section, as an example, the effects of varying several uncertain parameters on the value of the partial success oil case of the Manas exploration program are considered.

7.6.1 Oil Price

Figure 7-9 shows the effect of changes in the oil price on the value of the Manas blocks. The change in oil price has a significant effect on the value. A 10% change in oil price results in a 10% change in the value of the Manas project.

7.6.2 Pipeline Costs

Figure 7-10 shows the effect of changes in pipeline costs on the value of the Manas blocks.

As Figure 7-10 indicates, an increase in pipeline costs causes a very small decrease in the value of the Manas project. However, this declining trend is not consistent for different pipeline costs. In some ranges of pipeline costs, the increase in pipeline costs is offset by the increase in the profit share attributable to the Contractor. This can be explained by the step-type mechanism for profit sharing between the Contractor and the Government incorporated in the fiscal terms of the PSCs.

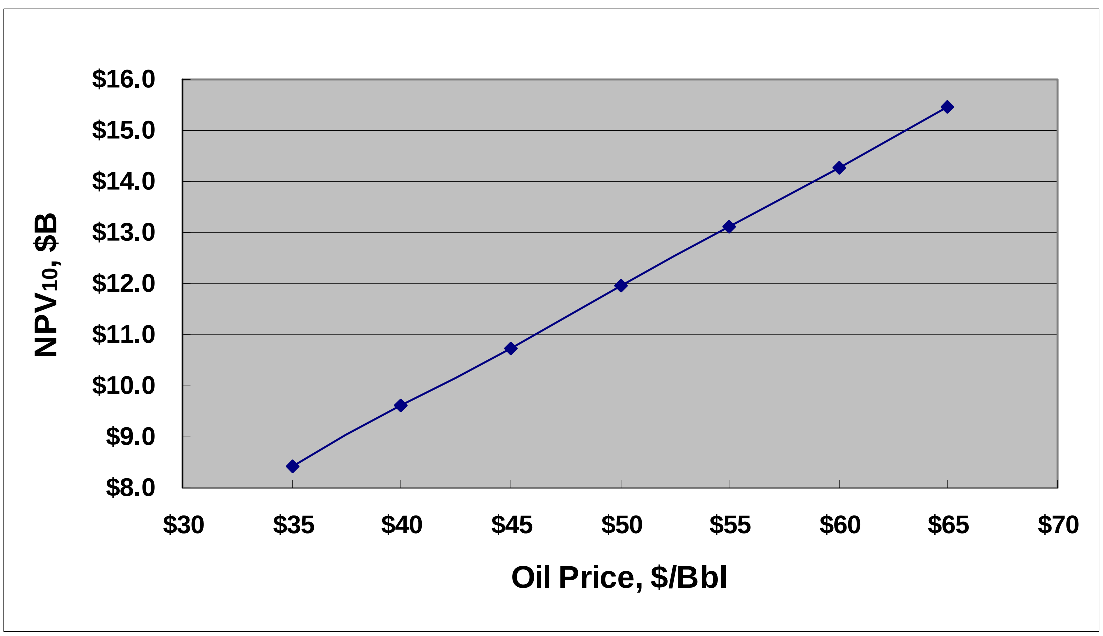


Figure 7-9 NPV_{10} Sensitivity to Oil Price

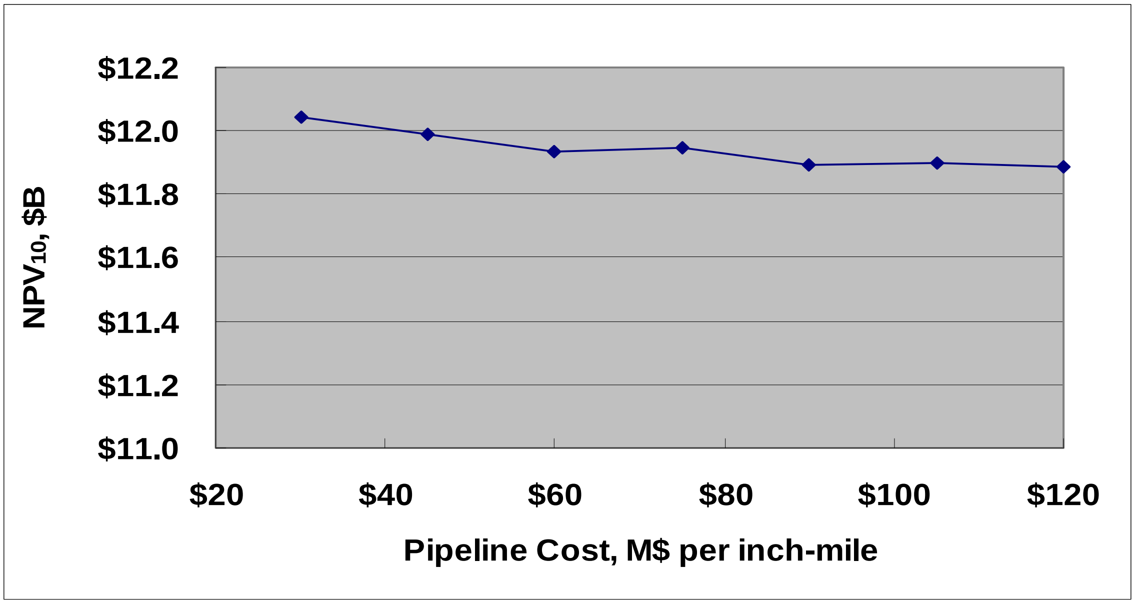


Figure 7-10 NPV$_{10}$ Sensitivity to Pipeline Cost

7.7 RISK ANALYSIS

This project, due to the potential reward and multiple opportunities, is very attractive from an exploration perspective; however, there is considerable uncertainty about the outcomes that may occur as a result of the exploration program on the Manas blocks in Albania. The current economic report has presented the net present value (NPV$_{10}$) for only seven of these scenarios, namely complete and partial success for three hydrocarbon cases and failure at the first three prospects which is assumed to condemn all of the remaining prospects on both blocks. This range of results should be viewed as an indication of the uncertainty of the success of the prospects identified within the Manas blocks.

Even though the concession area is fairly close to analogous production, there is significant geological and mechanical risk associated with the prospects identified within the Manas blocks. The overwhelming risk, in these prospects, is in the interpretation of these complex structural plays and the presence of reservoir quality Ionian carbonate. The structural risk may be mitigated by the acquisition of new seismic data and the reprocessing of the old seismic data.