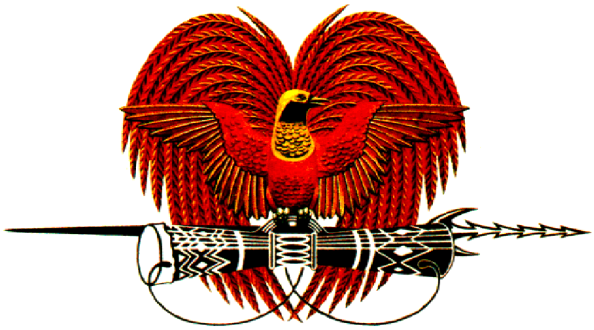
PETROLEUM DIVISION



DEPARTMENT OF PETROLEUM AND ENERGY

2001 ANNUAL REPORT

ON

PETROLEUM ACTIVITY IN PAPUA NEW GUINEA

Compiled by the Exploration Branch

December 2001

PREFACE

The information contained herein summarises all petroleum activities for the year 2001, as reported by the Licensees and / or Operating Oil Companies, to the Department of Petroleum and Energy.
Information of a confidential nature has purposely been omitted from the report. The report covers exploration, development, production and facility activities of petroleum companies, as well as associated policy and coordination aspects.

All costs are quoted in United Sates Dollar (US$) as reported by the oil companies. Where appropriate, these have been converted to Kina equivalent at the average yearly exchange rate.

All branches of the Petroleum Division have contributed relevant information towards the 2001 Annual Report. The information included in this report, alongside previous reports, is intended to provide a continuous and summarised historical review of the petroleum activities in Papua New Guinea.

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ATTACHMENTS

TABLE OF ABBREVIATIONS

APF	Agogo Production Facility
APDL	Application for Development Licence
APPL	Application for Petroleum Prospecting Licence
APRL	Application for Petroleum Retention Licence
BBL	Barrel
BCF	Billion Cubic Feet
BHP	Bottom Hole Pressure
BOPD	Barrels of Oil Per Day
BSP	Bank South Pacific
BWPD	Barrels of Water Per Day
CGS	Concrete Gravity Structure
CNGL	Chevron Niugini Limited
CPF	Central Production Facility (Kutubu)
CTU	Coil Tubing Unit
EWT	Extended Well Test
GM	Gobe Main Field
GOR	Gas Oil Ratio
GPF	Gobe Production Facility
GTQ	Gas To Queensland
ILG	Incorporated Land Groups
KB	Kelly Bushing
Km	Kilometer
LNG	Liquefied Natural Gas
LPG	Liquefied Petroleum Gas
LTC	Land Titles Commission
M	Thousand
MD	Measured Depth
MM	Million
MMSCF	Million Standard Cubic Feet
MMSCFD	Million Standard Cubic Feet per Day
MMSTB	Million Stock Tank Barrels
MOA	Memorandum of Agreement
MPLT	Multi Production Logging Tool
NGL	Natural Gas Liquids
OGOC	Original Gas-Oil Contact
OOIP	Original Oil In Place
OWOC	Original Water-Oil Contact
PDL	Petroleum Development Licence
PLL	Pipeline Licence
PLT	Production Logging Tool
PPL	Petroleum Prospecting Licence
PRL	Petroleum Retention Licence
RMT	Reservoir Monitoring Tool
RR	Rig Released
SEG	South East Gobe Field
SS	Sub-Sea
STB	Stock Tank Barrel
STB/D	Stock Tank Barrel per Day
ST	Sidetrack
STOIIP	Stock Tank Oil Initially In Place
TCF	Trillion Cubic Feet
TD	Total Depth
TVD	True Vertical Depth
US $	United States Dollar

MONTHLY HIGHLIGHTS

January	• PPL 186 cancelled • PPL 187 cancelled
February	• PDL 5 awarded to Esso
March	• IDT 20 development well spudded • Esso's Kaukau Phase 2 Seismic Survey completed
April	• Continuing normal operations
May	• Santos' Okari Phase 2 Seismic Survey completed • Hon. Roy Yaki appointed as Minister replacing Hon. Chris Haiveta
June	• Moran 6 development well spudded • Moran 6 ST 1 development well spudded
July	• SEG 10 development well spudded • PPL 228 awarded to Barracuda Ltd • PPL 202 relinquished by Santos Ltd • PPL 213 relinquished by Santos Ltd.
August	• Moran 6 ST 2 development well spudded • PPL 179 surrendered by Oil Search Ltd
September	• Gobe Main 5 development well spudded • Environmental site visit to Napa Napa Refinery
October	• Gobe Main 5 ST 1 development well spudded • Gobe Main 5 ST 2 development well spudded • PPL 227 awarded to Oil Search Ltd
November	• Gobe Main 5 ST 3 development well spudded • Oil and Gas Act Amendment sent to NEC for Approval
December	• Saunders-1 exploration well spudded in PDL 4 by Chevron Texaco Ltd. • Annual Inspection of petroleum projects undertaken by engineers and environmental scientists • Bakari-1 exploration well spudded in PPL 138 by Esso Ltd • Oil and Gas Act Amendment passed in Parliament. Locations were revoked in respect of lapsed PDL application and in respect of certain blocks of PPL 138 and PPL 219.

Section 1.0 SUMMARY

Petroleum activities for the year 2001 remained at a relatively low level. Exploration work carried out in PNG was again focused in the Papuan Basin. Two Petroleum Prospecting Licences and one Petroleum Development Licence were granted, and three licences were either surrendered or cancelled. All licences granted were for acreage in the Papuan Basin. The active PPLs in PNG numbered 23 at year-end.
Five field surveys were conducted in the various PPLs during the year comprised of one geological field survey and four geophysical surveys. A total of US$ 7.88 MM was spent on seismic surveys alone. Summaries of these surveys are covered in Section 3.0.

Nine development wells including sidetracks were drilled this year. Two exploration wells were also spudded, however they were still drilling at year-end.
Kutubu and Moran Oil production in 2001 averaged 39,000 BOPD. Gobe Oil production averaged 21,000 BOPD for the same period. The Hides gas field produced a total of 5,075.8 MMSCF of gas despite facing continuous problems with the microstills.

Liaison with impacted communities in Kutubu, Gobe, Moran and Hides continued through the year.

Matters in relation to GTQ negotiations, Moran economic benefits and environmental issues within the industry were the main policy activities addressed.

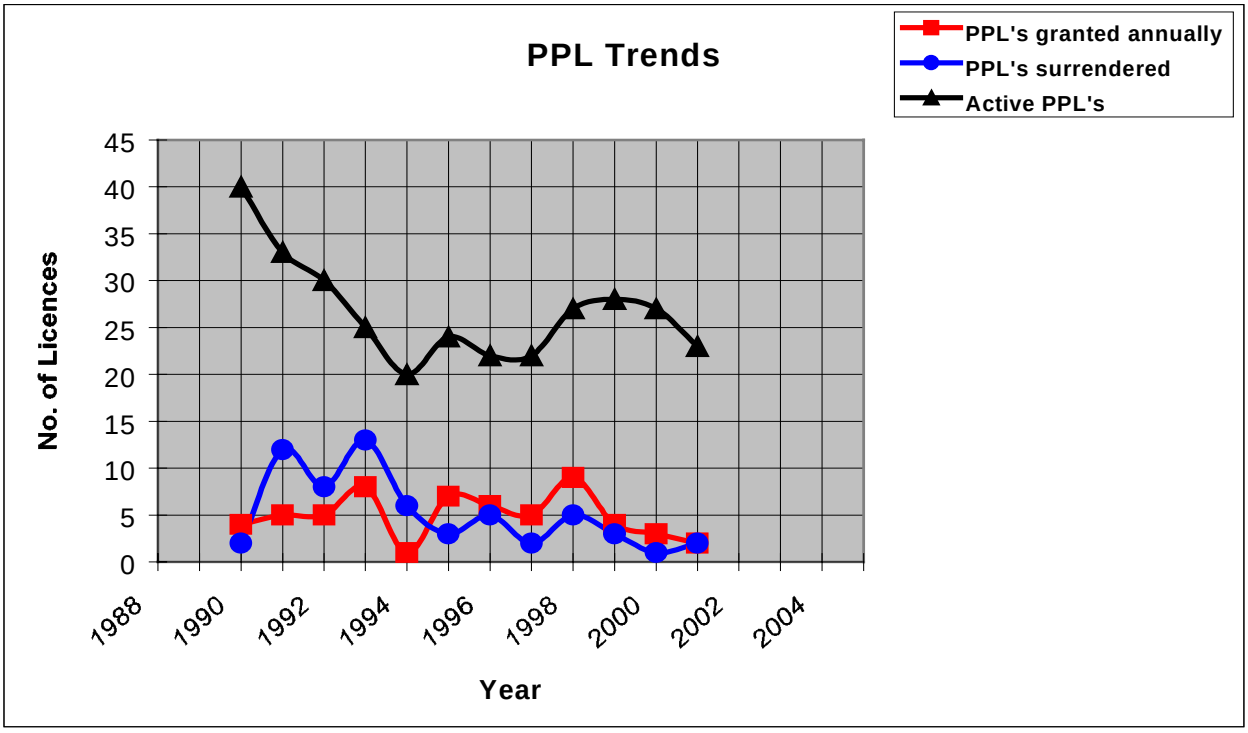
Section 2.0 LICENCE MANAGEMENT

A total of twenty three (23) petroleum prospecting licences (PPL), five (5) development licences (PDL), five (5) petroleum retention licences (PRL) and one PPFL existed in Papua New Guinea as at 31st December 2001. Among the PPLs, two (PPLs 138 & 157) are extended licences currently in their second five-year terms.

There was only one licence surrendered this year. The licensee for PPL 179 surrendered all 128 blocks. An application to surrender one of the two extended licences (PPL 157) and two other applications to surrender PPLs (PPLs 201 and 208) were still pending by year-end.
Twenty-one (21) of the PPLs, the five (5) PDLs and the five (5) PRLs are for acreage in the Papuan Basin. The North New Guinea Basin has two (2) PPLs while the other two (2) PPLs previously in the Cape Vogel Basin have been cancelled.

This year saw the granting of two new PPLs (PPL 227 & 228) and one new PDL (PDL5) by the Minister. Three applications (APPL) for PPLs and three (3) outstanding APRLs (lodged in December 1999) were with the Department as at year-end. These included APPLs 229, 230 and 231 and APRLs 8, 9 and 10. **Figure 1** shows the trend for PPLs over the past decade and attachments 2 & 3 contain a summary of the licences and their location.

Figure 1: PPL Trends



Section 3.0 EXPLORATION & DRILLING

The number of surveys carried out this year dropped as compared to the previous years. Five (5) surveys were conducted in the various licences. **Tables 1** & **2** contain summaries of all the Field surveys for the year. Two exploration wells and nine development wells were spudded during the year.

3.1 Geological Field Mapping

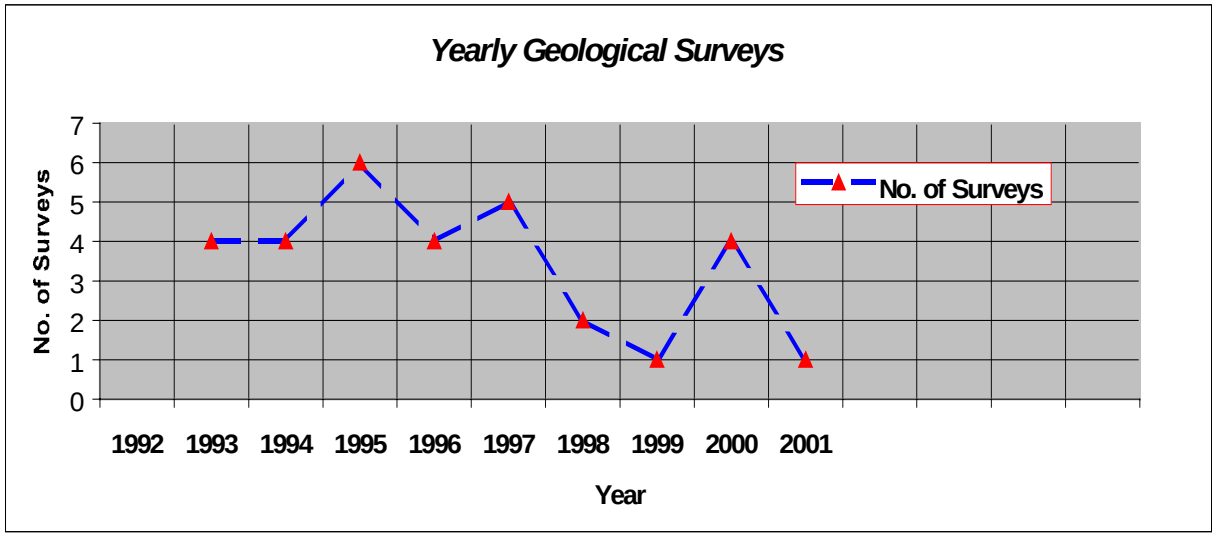
Only one geological survey was conducted during the year. The survey is summarised below. **Figure 2** shows the number of geological surveys undertaken yearly since 1992.

Oil Search carried out the Tiba geological survey in PPL 199 in which a total of 16 km of geological data was acquired. The aim of the survey was to obtain new surface geological data to better constrain the Mubi, Augu and Wage anticlines.

Table 1:
GEOLOGICAL SURVEY

Licence / Permit	Operator	Geographic Area	Tectonic Area	Name / Contractor	Line Length - Km
PPL 199	Oil Search	SHP	Foldbelt	N/A	16 Km
TOTAL					**16**

Figure 2: Yearly Geological Surveys



3.2 Geophysical Field Surveys

The number of geophysical surveys conducted in 2001 was the same as that of the previous years. All four were conducted onshore. These are summarised below. **Figure 3** shows the total number of line kilometers of seismic acquired since 1992.

The KauKau (Bakari) and KauKau Phase 2 Seismic Survey was conducted by Esso in PPL 138. The survey commenced in February and it was a continuation of the 2000 KauKau Seismic Survey. The aim of the survey was to provide subsurface structural control over the Bakari Lead and to tie into the existing seismic grid in the Moran areas.

Santos conducted the Okari Phase 2 Seismic Survey in PPL 206. This was a continuation of the 2000 Okari Seismic Survey and was designed to define the Bosavi Lead.

The Saunders Strike Line Seismic Program was conducted in PPL 190, PDL 3 and PDL 4 and commenced in February. The objective of the survey was to prove the southeast plunge closure on the South East Gobe Deep Footwall prospect.

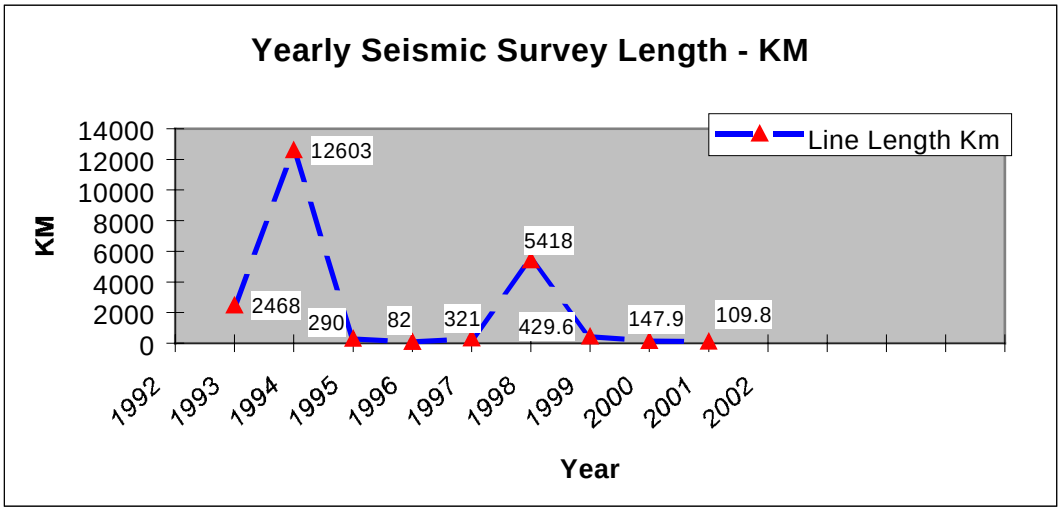
Chevron carried out the South East Moran PN 01-505 Seismic Survey in PPL 219 and PDL 2. The aim of this survey was to define the SE Moran prospect along the southeastern end of the Moran anticline.

Table 2:

GEOPHYSICAL SURVEYS

Licence Area	Operator	Geographic Area	Name/Survey Type/Contractor	Line Length Km	Cost US$
PPL 138 Onshore	Esso	Southern Highlands Province	**KauKau (Bakari) Seismic Survey & KauKau Phase 2.** Exploration Services Providers Int'l	58 km	4.5 MM
PPL 206 Onshore	Santos	Southern Highlands, Gulf & Western Provinces.	**Okari Seismic Survey Phase 2.** Exploration Services Providers Int'l	20 km *NB: Phase 1= 33 km & Phase 2= 20 km*	1.3 MM *NB: Phase 1=$2.75 MM Phase 2= $1.3 MM Total= $4.05 MM.*
PPL 190 PDL 3 PDL 4 Onshore	Chevron	Gulf & Southern Highlands Provinces.	**Saunders Strike Line Seismic Program** Exploration Services Providers Int'l	22 km	Est. USD 1.38 MM (given USD 63,000 / km).
PPL 219 PDL 2 Onshore	Chevron	Southern Highlands Province	**SE Moran PN 01-505 Seismic Survey** Exploration Services Providers Int'l	9.8 km	700,000
TOTAL				**109.8**	**7,880,000**

Figure 3: Yearly Seismic Survey Length



3.3 Drilling and Rig Activities

Summary of Development Wells

All the development wells drilled in 2001 were in the Kutubu, Gobe Main, South-East Gobe and Moran Fields. A total of nine wells were drilled including sidetracks. Four wells were completed as oil producers and five were sidetracks. Of these four producing wells, two were deviated and two were horizontal. **Table 3(a)** shows development wells drilled in 2001. The total footage of the nine development wells drilled was 51,136 feet at a cost of US$ 49.366MM.

IDT 20

IDT-20 well was spudded on 06 March 2001. The well objective was to produce an incremental Toro C oil reserve, at a lower GOR than the existing wells. The well kicked off directionally in the Ieru formation at a depth of 5241 feet after setting 13-3/8" casing. Drilling phase continued as building inclination angle proceeded, reaching horizontal (90°) at 10,020 feet MD. The horizontal section was maintained to a total depth of 11,590 feet MD (8761 ft TVD). The formation tops were picked initially from lithology sampling and LWD gamma ray/resistivity and confirmed by wireline logs. IDT-20 well penetrated the objective Toro C sand. The horizontal wellbore drilled a total of 1663 feet MD of Toro C section in which all sands were interpreted as oil bearing. A total of 1075 feet of reservoir was perforated and the well was completed as an oil producer. The well was completed in 8-1/2" hole section with External Casing Packers (ECP) isolating the zones. The rig was released on 21 May 2001 with a cumulative cost of US$ 11.047MM.

Moran 6

Moran 6 well was proposed as a Central Moran Unit delineation/production well located in Block J of the Moran Field in PDL 5. The well was designed as a directional well to penetrate Toro C and Digimu reservoirs. Moran 6 well was spudded on 15 June 2001. Drilling proceeded but the drillstring got stuck within the Darai Limestone. After several attempts to free the drillstring failed, the drillstring was finally cut and the hole plugged back for a sidetrack (ST) well. Moran 6 total depth was at 3965 feet MD. The final cost of Moran 6 was US$ 5.781MM and the rig was released on 28 June 2001 for ST1 well.

Moran 6 ST1

The Moran 6 ST1 well kicked off in the Darai limestone at 2654 feet and proceeded into Ieru formation. After setting 13-3/8" casing, the hole was drilled ahead. Drilling through Ieru formation, the hole experienced lost circulation problems. Erratic high torque was experienced during the drilling phase. While pulling out of hole to check for washout, the drillstring got stuck. Several attempts failed to free the drillstring. The drillstring was severed and the hole plugged back for a sidetrack well. The hole total depth was at 8899 feet MD, (8161 ft TVD). Moran 6ST1 well was drilled at a cost of US$ 6.522MM and the rig was released on 17 August 2001 for a second sidetrack (ST2) well.

Moran 6 ST2

Moran 6 ST2 well was kicked off at 7950 feet MD. The ST2 well drilling encountered fluid losses and experienced high torque. Drilling proceeded through the Ieru formation, but due to very high torque experienced, 9-5/8" casing was set higher to case off the hole section. The 8-1/2" hole section was then drilled to encounter Toro and Imburu formation. 7" liner was set and 6-1/8" hole section drilled to a total depth of 13,650 feet MD, (11,855 ft TVD). After well evaluation, the well was completed for oil production. The rig was released on 3 December 2001 at a cost of US$12.613MM.
Cumulative Moran 6 well cost including sidetracks is at US$ 24.916MM.

SEG 10

SEG–10 was spudded on 15 July 2001 and reached a total depth of 8782 feet MD within the lower Imburu formation. The objective of the well was the Upper Iagifu sandstone. Initially, the well was planned as a pilot hole for a subsequent sidetrack. This well was to constrain the structure and oil-water contact for the sidetrack well. However, after reaching the total depth, the evaluation data interpreted showed the pilot hole intersected sufficient hydrocarbon column to be completed as a producer. The well was completed and the rig released on 20 August 2001 with an accumulated cost of US$ 5.907MM. Upon being put on production, the well produced large quantities of sand and was subsequently shut in due to sand handling constraints. The well was scheduled to be worked over pending finalisation of the program.

Gobe Main 5 (GM 5)

GM 5 well was spudded on 03 September 2001. The well was a pilot well proposed for a subsequent follow-up of Gobe Main Iagifu horizontal development well. The pilot well was designed to constrain the proposed horizontal section of the sidetrack well, as well as delineate the oil-water contact (OWC). While drilling through to the bottom hole target, the OWC could not be established. The well was eventually plugged back for a second pilot sidetrack well. The rig was released on 02 October 2001 with a cumulated cost of US$ 5,395,085. The GM 5ST1 well was the second pilot hole to be drilled.

GM 5 ST1

GM 5ST1 well sidetracked on 03 October 2001. The objective of this well was to further delineate the OWC and establish the constraint objectives which were not achieved by the GM 5 well. The well was drilled to a total depth of 8880 feet MD (8081 ft TVD). Upon completion of the well evaluation program, the OWC was established. The GM 5ST1 pilot hole was plugged back and GM 5ST2 was designed as a horizontal completion. The rig was released on 17 October 2001 at cumulative cost of US$ 1.293MM.

GM 5ST2

The well was sidetracked on 17 October 2001 and continued to build inclination angle up to horizontal. This horizontal section was maintained to a total measured depth of 9637 feet (7821 ft TVD). While in the completion stages of reaming, it was noted from survey results that a new sidetrack hole has been made updip. Hence, a new ST3 well was designated. The final cost of GM 5ST2 was at $US 2.562MM.

GM 5ST3

GM 5ST3 well was a new sidetrack hole from GM 5ST2 well. The well was drilled from 9225 feet to the original well total depth of 9637 feet (7821ft TVD). The well was completed horizontally with excluder screens in the lower Iagifu sands. The rig was released on 20 November 2001 at a cost of $US 0.91MM. Gobe Main 5 (GM 5) total well cost including sidetracks was $US 10.242MM.

The total cost of development wells drilled in 2001 was US$ 49.366MM.

Summary of Exploration Wells

There were two exploration wells, both of which spudded in 2001 and will be completed in year 2002. At the time of this report the wells are currently active. They are Saunders 1 and Bakari 1 wells, which were spudded on 03 December and 25 December 2001 respectively. **Table 3(b**) shows the exploration wells drilled in 2000

There were no offshore exploration wells drilled this year.

Saunders 1

Saunders 1 well was a proposed exploration well designed to test the structure and potential fluid contacts in the seismically defined structure east of the SE Gobe Field. The Upper Iagifu Sandstone was the primary target. The well was designed to be a deviated well and was kicked off in the Juha member of the Ieru formation. The well was spudded on 3 December 2001 and drilling is progressing ahead with no major problems encountered.

Bakari 1

The objective of Bakari 1 well was to evaluate the potential hydrocarbon in the Toro and Digimu reservoirs within the hanging wall of Bakari structure. The well was planned as a vertical hole.

Bakari 1 well spudded on 25 December 2001 and is currently an active drilling well at the time of this report.

Table 3: Drilling Activities

3(a) Development Wells

WELL I.D.	LICENSEE	PPL / PDL	SPUD DATE	R.R. DATE	T.D. (MD)	FOOTAGE DRILLED	RESULT	COST US$	TYPE OF SIDETRACK (GEOL / MECH)
IDT 20	Chevron	PDL 2	06/03/01	21/05/01	11590	11590	Oil	11,047,201.99	-
SEG 10	Chevron	PDL 4	15/07/01	20/08/01	8782	8782	Oil	5,907,333.30	-
GM 5	Chevron	PDL 4	03/09/01	02/10/01	8860	8860	-	5,395,085	Pilot
GM 5ST1	Chevron	PDL 4	03/10/01	17/10/01	8880	2290	-	5,195,915	Pilot
GM 5ST2	Chevron	PDL 4	17/10/01	13/11/01	9637	3292	-	2,562,554	Mechanical
GM 5ST3	Chevron	PDL 4	13/11/01	20/11/01	9637	412	Oil-	907,566	-
Moran 6	Chevron	PDL 5	15/06/01	28/06/01	3965	3965	-	5,781,847	Mechanical
Moran 6ST1	Chevron	PDL 5	28/06/01	17/08/01	8899	6245	-	6,522,186	Mechanical
Moran 6ST2	Chevron	PDL 5	17/08/01	03/12/01	13650	5700	Oil	9,864,834	-
TOTALS						**51,136**		**$49,366,11.29**	

3(b) Exploration Wells

WELL I.D.	LICENSEE	PPL / PDL	SPUD DATE	R.R. DATE	T.D. (MD)	FOOTAGE DRILLED	RESULT	COST US$	TYPE OF SIDETRACK (GEOL / MECH)
Saunders 1	Chevron	PDL 4	03/12/01	Still Drilling		Still Drilling			Still Drilling
Bakari 1	Esso	PPL138	25/12/01	Still Drilling		Still Drilling			Still Drilling

3.4 PNG Petroleum Drilling History

The Papuan Basin is currently the most explored and developed of the five petroleum basins in PNG. The Papuan Basin has had a total of 385 wells drilled to date, since the commencement of exploration in PNG. It is also the location for all the discovery wells to-date. ***Table 4*** contains a summary of all the discoveries to-date.

Table 4: Summary of Discoveries to Date

ORIGINAL LICENCE/ PERMIT	ORIGINAL OPERATOR	FIELD	DISCOVERY YEAR	CURRENT LICENCE	CURRENT OPERATOR	TYPE OF DISCOVERY	EXISTING WELLS IN FIELD	PROVINCE
Permit 37	Island Exploration	Barikewa	1958	PPL 189	Barracuda	Gas	2	Gulf
Permit 37	APC	Bwata	1960	PPL 191	Barracuda	Gas/ Condensate	1	Gulf
Permit 12	APC	Iehi	1960	PPL 189	Barracuda	Gas	1	Gulf
Permit 39	Phillips	Uramu	1968	PPL 188	Oil Search	Gas	1	Gulf
PPL 18	Niugini Gulf Oil	Juha	1983	APRL 2	Chevron	Gas/ Condensate	3	Western
PPL 17	Chevron	Kutubu	1986	PDL 2	Chevron	Oil / Gas	47	SHP
PPL 27	BP	Hides	1987	PDL 1 / PPL 138	Oil Search/ Esso	Gas/ Condensate	4	SHP
PPL 100	Chevron	SE Hedinia	1987	PDL 2	Chevron	Gas	5	SHP
PPL 82	IPC	Pandora	1988	PRL 1	IPC	Gas	2	Gulf
PPL 100	Chevron	Usano	1989	PDL 2	Chevron	Oil	2	SHP
PPL 100	Chevron	Agogo	1989	PDL 2	Chevron	Oil	1	SHP
PPL 27	BP	Angore	1990	PPL 138	Esso	Gas/ Condensate	1	SHP
PPL 81	BP	Elevala	1990	PPL 157	Santos	Gas/ Condensate	1	Western
PPL 101	Chevron	P'nyang	1990	APRL 3	Chevron	Gas/ Condensate	2	Western
PPL 81	BP	Ketu	1991	PPL 157	Santos	Gas/ Condensate	1	Western
PPL 56	Command	SE Gobe	1991	PDL 3	Chevron	Oil / Gas	5	SHP / Gulf
PDL 2	Chevron	SE Mananda	1991	PDL 2 / PPL 161	Chevron	Oil / Gas	2	SHP
PPL 100	Chevron	Gobe Main	1993	PDL 4	Chevron	Oil / Gas	6	SHP
PPL 138	BP	Paua	1995	PPL 138	Esso	Oil	1	SHP
PDL 2, PPL 161/138	Chevron	Moran	1996	PDL 2, PPL 161/138	Chevron	Oil	4	SHP
PPL 157	Santos	Stanley	1999	PPL 157	Santos	Gas	1	Western
PPL 193	Oil Search	Kimu	1999	PPL 193	Oil Search	Gas	2	Western

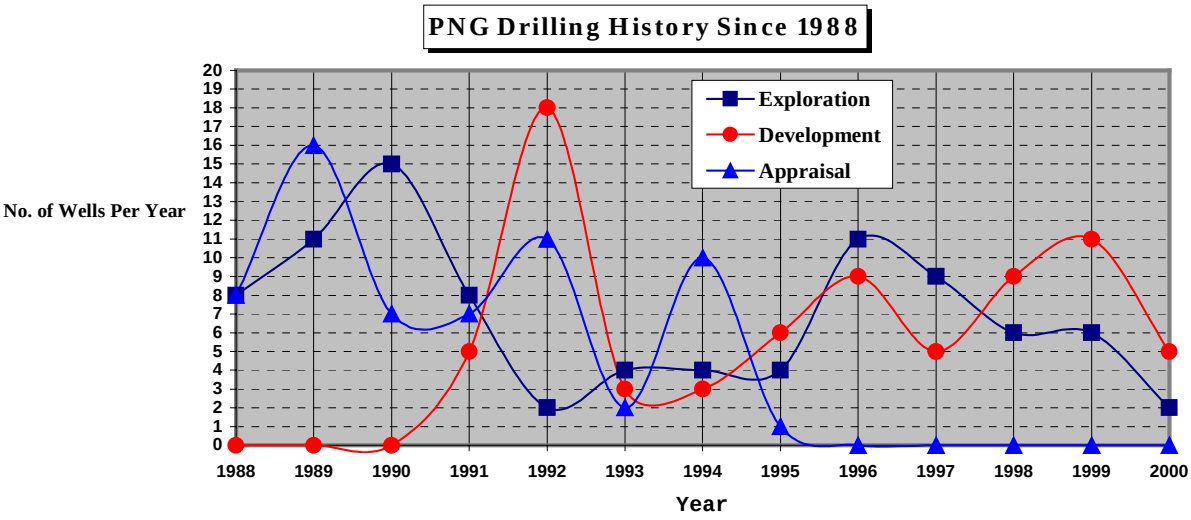


Figure 4: Total Yearly Wells

Section 4.0 FIELD DEVELOPMENT

4.1 Hides

During the year, Hides produced a total of 5075.8MMSCF of gas. The total liquid production was 110,499 barrels of condensate, of which there was 49,784 barrels of naphtha, 21,251 barrels of diesel and 2,775 barrels of residue.

The Hides Gas plant underwent normal operation throughout the year. The major concern during the year was the continuous problem experienced with the Micro-stills. The problem has been ongoing and is currently being addressed and managed. Production from the micro-still has however been constant and the wellheads encountered no major problems for the duration of the year. The pipeline was checked monthly and was maintained in good condition.

The two high-pressure methyl ethylene glycol (MEG) injection pumps experienced mechanical problems and are waiting on repair parts. This caused some problems with hydrate formation on the Hides-1 wellhead choke and flowline. All scheduled preventive maintenance tasks were completed for all months during the year.

4.2 Kutubu

Routine checks, preventative maintenance and minor modifications to the project facilities were predominant activities undertaken in Kutubu this year. The major activities that were undertaken to the project facilities during the year are covered alone in detail forthwith. Otherwise production operations at Kutubu have been normal through out the year.

A low Pressure Test Separator modification was completed at the Central production facility (CPF) to accommodate well test requirements for low-pressured wells which could not otherwise flow into the system pressure separators. The initial beneficiary wells are IDT-18, UHT-1 and UDT-3A.
The annual Pipeline Integrity Monitoring Program (PIMP) survey commenced with the mobilization of the specialised vessels to the Kumul Platform to inspect the platform legs subsea, the pipeline from the land fall to the platform, the pipeline from platform to the pipeline end manifold together with a full inspection of the single point mooring and its mooring. Final reports are pending.
Production operations halted for 4 days in September when CPF and APF were shutdown to execute all critical work on the CPF plant as were identified during the CPF Hazop study. All programmed work was completed with the exception of the function testing of the pressure safety valves on the test separator due to late arrival of a spare part.

The operator has not had an incineration system in operation at Kutubu over the last five to six years to burn produced sand and sludge for safe disposal. An incinerator was installed at the CPF and commissioned, but various upstream process problems and shortcomings still require rectification prior to full operation.

In field flowline installations, modifications, repairs and integrity tests were performed on the IDD-1, IDT-20 wells, ADT-1 & 2 header and the IST-4 and UHT-1 wells.

Kutubu Reservoir surveillance study initiated last year by the Kutubu Reservoir Management Team was completed this year with the provision of surveillance study report distributed to DPE and other parties concerned.

Coiled Tubing Unit has been used interchangeably between Kutubu and Gobe fields to successfully execute some of the well work requirements on the horizontal and highly deviated wells. Foam gel gas shut off workover procedures have been developed for few selected candidate wells in the Main Block Toro. Execution of this program has been re-scheduled to first quarter in the New Year due to availability of moving equipment.

Kutubu Oil production continued to decline at a steady rate. The Operator has continued to take an aggressive approach utilising conventional techniques available to identify potential well work to stabilise the rapidly declining oil production trend. These efforts have resulted in the accomplishments of seven workovers, a number of successful wireline inter-zonal isolations and the new development well drilling of IDT-20 during the year.

4.2.1 Agogo Gas Deliverability for Moran Field

Chevron Niugini has made known its intentions of utilising gas reserves from the Agogo field as a source for injection into the Moran field. The gas supplied from the Agogo field would be used as part of a miscible operation to drive the oil towards proposed oil producing wells.
In light of this, the evaluation of the individual Agogo production well gas rates has been continuing. The evaluation would assist the scope of work required to ensure Agogo can supply Moran's supplemental gas requirement for injection. Most of the critical Agogo gas supply wells for injection at Moran have been tested and the ability of these wells to supply the required amount of gas has also been assessed.

The Agogo Production Facility (APF) and the new flare relocation work commenced in March to handle production from the Central Moran Petroleum Development Project. The APF flare relocation has been completed and is currently in operation burning 500 MCFD. Agogo production operations have been normal through out the year.

4.3 Gobe Main

The total Gobe oil production for 2001 was 7,183,436 barrels. This is a decrease of 3,157,307 barrels from the previous reporting period. This is due to increasingly high GOR production coupled with limited surface gas handling capacity as well as natural decline in field production. The total gas produced for Gobe Main and SE Gobe were 11,873,584 MSCF and 13,280,821 MSCF respectively.

The total volume of gas flared for the plants operational requirement and at emergency was 4,719.169 MMSCF. Total gas injected into the formation during the year was 18,861.585 MMSCF. This was aimed at providing reservoir energy as well as storing gas for future use.
The operator has attempted to utilise conventional oil field practices to identify well-work opportunities to stabilise the rapid declining oil trend. This has had limited success.

The total oil exported from Gobe was 7,325,405 barrels with Gobe Main and SE Gobe contributing 2,741,319 and 4,584,086 barrels respectively.

4.3.1 Gobe Well Work

Coiled tubing programs executed on the Gobe wells include perforation jobs, production zone changes, retrieval of plugged sand screens and MPLT. Coiled tubing perforation jobs were completed on G 7XST3 and GM 3ST1. Post workover production rates were 324 bopd and 720 bopd respectively. Production interval switches were made on SEG 7 from Lower Iagifu layers 10 & 11 to layer 8 and SEG 9 from Upper Iagifu layers 3 & 4 to layer 2 using wireline equipment.
The attempt to pull the plugged sand screen in SEG 9 using a CTU and slickline failed.
Bottom hole pressure surveys were predominantly carried out utilising wireline equipment on all the production wells to satisfy the Inspectorate's requirement for routine reservoir measurements. The bottom hole pressure surveys included both static and dynamic pressure gradient surveys.

4.3.2 Gobe Processing Facility

All maintenance and preventive maintenance operations were routine.

Compressor shutdown was common throughout the year. Main problems included broken blades on the gas producer turbine, blocked strainers, and temperature and vibration problems. The compressors at Gobe were also shutdown at times to do normal maintenance and services that included faulty high lube oil header temperature transmitter, compressor control valves, and slug related carryover from the stabilizers.

The incinerator was shutdown with a failed refractory and damage to the shell and exhaust stack. Vendor representatives were on site to carry out minor repairs and inspection. The major parts or the incinerator were received and installed around August and vendor commissioning of the Burner Management System is pending.

Due to high levels in the crude storage tanks, production had to be curtailed on 2nd April and returned to normal operation/production on 4th of April.

Sand production continued to be a problem in the separators after pigging activity in the SE Gobe fields through the year. The SEG separator and the Gas Floatation Unit have been de-sanded regularly to prevent sand from getting into the Media Filter in the Produced Water system. Due to erosion by sand, the seals on the Scrubber pump on the Media filter and Filter Feed pump on the Gas Floatation were replaced.

An excessive pipe erosion on the SEG 4" by-pass caused failure of the line resulting in an atmospheric discharge of hydrocarbons. SEG field was shut in for half a day to rectify the problem.

High rate water injectivity test was conducted by running both injection pumps A and B in parallel. The test was to assess the maximum water injection rate for the pumps. The maximum rate achieved was 9,900 bwpd. This exercise was the first step in the proposal to convert inlet separator C to a water surge vessel to cater for the increase in water production.

All other operations were normal and routine.

The maintenance groups (Mechanical, Instrumentation and Electrical) completed all the monthly equipment maintenance and compliance checks each month as scheduled.

4.4 Moran

The Moran Petroleum Development Licence (PDL) was granted by the Government in February. This paved way for the Moran full field development and unitisation to proceed. Necessary conditional regulatory approvals pertaining to the Moran Petroleum Production Facility location, construction and operation together with metering permits for Moran-4 and 6 production wells were issued to the operator in order to kick-start field construction and oil production.

Moran Full Field Development Project commenced field construction activity in March. The construction work included earth works, camp and temporary facilities, APF flare relocation and APF expansion.

Reservoir simulation models have been upgraded to the latest version of Chevron's CHEARS simulation software in an effort to better automate prediction runs. The latest results of Moran 6 ST#2 well were incorporated into the existing Moran simulation model to derive preliminary OOIP and reserves estimates.

The Moran Reservoir fluid analysis to determine the likelihood of paraffin or asphaltenes solidifying in the reservoirs was completed. The results of the analysis show that the Moran oils would neither precipitate asphaltenes nor wax within the range of expected reservoir pressures and temperatures.

4.4.1 MFI Meters

MFI-Roxar multiphase meters were used at the Moran 1X, 2X, 5X and 4 wellheads. Moran 6 used the Moran 4 MFI meter for the measurement of production from the Moran 6 well as Moran 4 would be converted to a gas injection well. The MFI multiphase meters have been operating satisfactorily to measure fluid flow from the Moran wells.

4.4.2 Moran Landslide

Geotechnical evaluations along the Moran Flowline route have indicated that isolated portions along the flowline route are geotechnically unstable. As a result minor landslips continued to occur.

Monthly geotechnical inspections and monitoring of known landslides sections as well as along the Moran flowline route have been ongoing through the year by Pacific Geotechnics Ltd.

The long term re-routing of the flowline is expected to be executed after the Moran infield road construction is completed.

Moran flowline was shut-in from 26th to 31st of July as a precautionary measure after landslips occurred at two separate locations causing the main flowline linking Moran field to Agogo Production Facility to be buried and displaced by 10 m by debris and overburden from the Moran road construction. The flowline was uncovered, damaged assessed and metallurgical tested. Performance indicated no damage and was returned to production.

Electrical Gauge Pig (EGP) or intelligent pig has been sent through the flowline to ensure the wall thickness and the flowline interior remained intact. The result of the internal inspection showed no abnormalities.

Section 5.0 PRODUCTION

Oil production in Kutubu has continued on a steady natural decline from a high of 28,000 BOPD in January to a low of 24,000 BOPD in December 2001. With prudent reservoir management, swing well management, CT workovers, slickline zonal switches, field trials and the flowing of new IDT-20 development well, oil production stabilized at 28,000 BOPD for a period of four months, from May to August.

Moran oil production operation was at times disrupted as a result of landslips affecting the flowline, landowner unrest as well as the shutdown of the APF & CPF for scheduled maintenance. With the reservoir pressure depletion of the field, oil production averaged at about 11,647 BOPD through out the year. Oil production in Moran increased by flowing low GOR oil from the new Moran-6 well to 12,700 BOPD in November. Wells alternatively produced from the Moran are Moran 1X, 2X, 4 and 6.

Table 5, 6, 7, 8,& 9 and ***Figures 5, 6, 7, 8, & 9*** summarise monthly and yearly figures for the various field in 2001.

5.1 Hides

Table 5: Hides Monthly Gas Production

	GAS		LIQUID			
MONTH	Total Production	Total sales	Condensate	Naphtha	Diesel	Residue
	(MMSCF)	(MMSCF)	(BBL)	(BBL)	(BBL)	(BBL)
January	448.42	448.42	10,165.34	6,931.14	2,511.24	387.51
February	350.92	350.92	7,972.55	5,230.90	1,868.98	362.8
March	450.15	450.15	9,929.09	6,560.81	2,621.57	419.41
April	422.8	422.8	9,184.15	6,153.26	2,543.26	353.34
May	445.18	445.18	9,687.62	6,156.52	3,084.38	293.45
June	429.94	429.94	9,133.27	5,763.92	2,767.62	151.9
July	430.53	430.53	9,276.70	3,423.02	1,542.72	234.17
August	475.86	475.86	9,935.40	4,020.10	1,945.27	215.71
September	433.29	433.29	9,141.20	677.38	313.87	42.58
October	371.44	371.44	8,027.76	3,360.64	1,384.13	230.71
November	386.71	386.71	8,573.43	1,093.72	497.09	76.8
December	430.56	430.56	9,422.86	413.38	171.08	7.23
TOTALS	5075.8	5075.8	110,449.37	49,784.79	21,251.21	2775.61

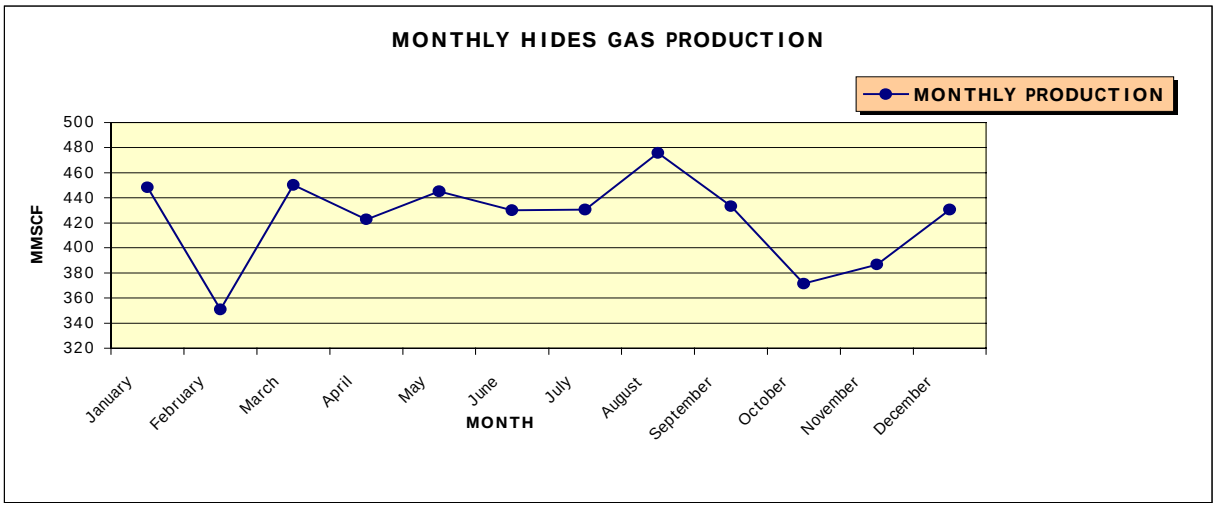


Figure 5: Hides Monthly Gas Production Graph

5.2 Kutubu

Table 6: Monthly Kutubu Production

MONTH	MONTHLY OIL PRODUCTION	MONTHLY GAS PRODUCTION	CUMULATIVE OIL PRODUCTION	CUMULATIVE GAS PRODUCTION	AVG. DAILY OIL RATE	AVG.DAILY GAS RATE
	BBL	MSCF	BBL X 1000	MMSCF	BOPD	MSCFD
JANUARY	866,920	6,704,138	258,841.43	549,284.10	27,965	216,263
FEBRUARY	739,220	5,860,400	259,580.65	555,144.50	26,401	209,300
MARCH	814,588	6,456,969	260,395.23	561,601.47	26,277	208,289
APRIL	777,688	6,035,354	261,172.92	567,636.82	25,923	201,178
MAY	810,082	6,315,025	261,983.00	573,951.85	26,132	203,710
JUNE	854,752	6,129,500	262,837.76	580,081.35	28,492	204,317
JULY	874,588	6,384,040	263,712.34	586,465.39	28,213	205,937
AUGUST	879,117	6,733,565	264,591.46	593,198.95	28,359	217,212
SEPTEMBER	688,192	5,331,363	265,279.65	598,530.32	22,940	177,712
OCTOBER	812,931	6,514,983	266,092.58	605,045.30	26,224	210,161
NOVEMBER	741,835	6,283,567	266,834.42	611,328.87	24,728	209,452
DECEMBER	747,889	6,528,070	267,582.31	617,856.94	24,125	210,583
YEARLY AVERAGE	800,650	6,273,081				
SUB-TOTALS						
YEARLY TOTALS	9,607,802	75,276,974				

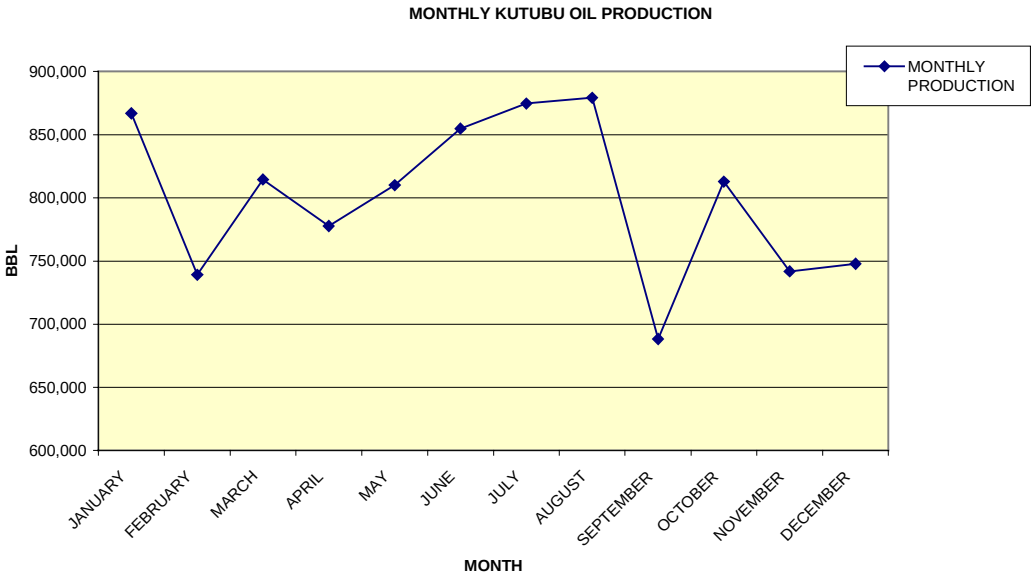


Figure 6: Kutubu Monthly Oil Production Graph

5.3 Gobe Main

Table 7: Monthly Gobe Main Production

MONTH	MONTHLY OIL PRODUCTION	MONTHLY GAS PRODUCTION	CUMULATIVE OIL PRODUCTION	CUMULATIVE GAS PRODUCTION	AVG. DAILY OIL RATE	AVG.DAILY GAS RATE
	BBL	MSCF	MBBL	MMSCF	BOPD	MSCFD
JANUARY	344,905	987,136	15,519.43	33,554.28	11,126	31,843
FEBRUARY	269,485	1,059,479	15,788.92	34,613.76	9,624	37,839
MARCH	292,739	1,131,353	16,081.66	35,745.11	9,443	36,495
APRIL	250,472	973,658	16,332.13	36,718.77	8,349	32,455
MAY	199,407	1,038,998	16,531.54	37,757.77	6,432	33,516
JUNE	208,167	987,290	16,739.70	38,745.06	6,939	32,910
JULY	192,703	1,036,881	16,932.41	39,781.94	6,216	33,448
AUGUST	211,942	954,767	17,144.35	40,736.71	6,837	30,799
SEPTEMBER	175,922	931,635	17,320.27	41,668.34	5,864	31,055
OCTOBER	165,676	892,566	17,485.95	42,560.91	5,344	28,792
NOVEMBER	166,614	909,112	17,652.56	43,470.02	5,554	30,304
DECEMBER	156,973	970,708	17,809.53	44,440.73	5,064	31,313
YEARLY AVERAGE	219,584	989,465				
SUB-TOTALS						
YEARLY TOTALS	2,635,005	11,873,584				

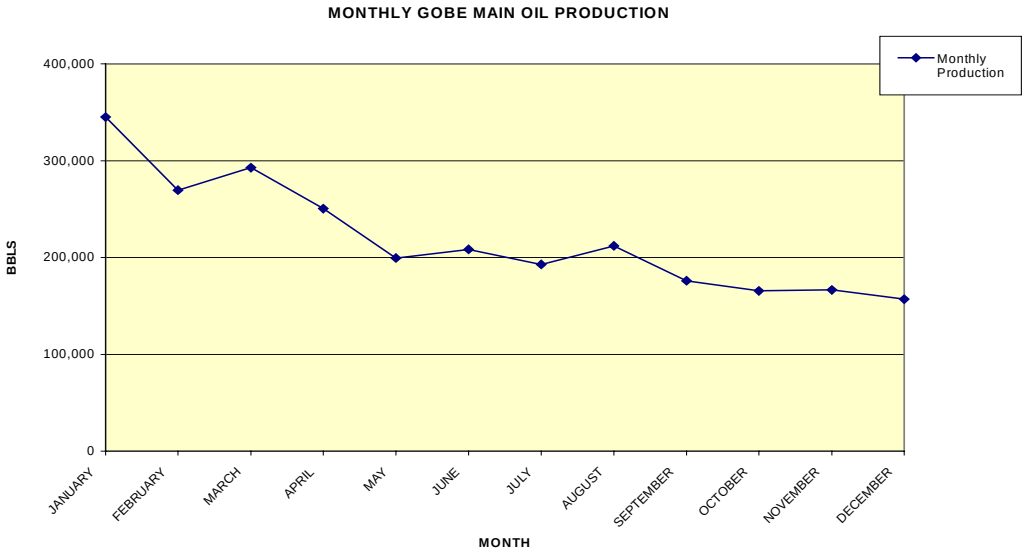


Figure 7: Gobe Main Monthly Production Graph

5.4 South East Gobe

Table 8: Monthly S.E. Gobe Production

MONTH	MONTHLY OIL PRODUCTION	MONTHLY GAS PRODUCTION	CUMULATIVE OIL PRODUCTION	CUMULATIVE GAS PRODUCTION	AVG. DAILY OIL RATE	AVG.DAILY GAS RATE
	BBL	MSCF	MBBL	MMSCF	BOPD	MSCFD
JANUARY	316,170	1,224,745	15,085.10	39,076.01	10,199	39,508
FEBRUARY	289,704	1,043,198	15,374.81	40,119.20	10,347	37,257
MARCH	381,774	1,149,727	15,756.58	41,268.93	12,315	37,088
APRIL	427,150	983,857	16,183.73	42,252.79	14,238	32,795
MAY	435,251	1,135,051	16,618.93	43,387.84	14,040	36,615
JUNE	402,662	1,130,205	17,021.64	44,518.04	13,422	37,674
JULY	416,180	1,195,104	17,437.82	45,713.15	13,425	38,552
AUGUST	401,822	1,149,491	17,839.65	46,862.64	12,962	37,080
SEPTEMBER	378,078	1,055,991	18,217.72	47,918.63	12,603	35,200
OCTOBER	395,951	1,158,072	18,613.67	49,076.70	12,773	37,357
NOVEMBER	353,836	993,094	18,967.51	50,069.80	11,795	33,103
DECEMBER	349,853	1,062,286	19,317.36	51,132.08	11,286	34,267
YEARLY AVERAGE	379,036	1,106,735				
SUB-TOTALS						
YEARLY TOTALS	4,548,431	13,280,821				

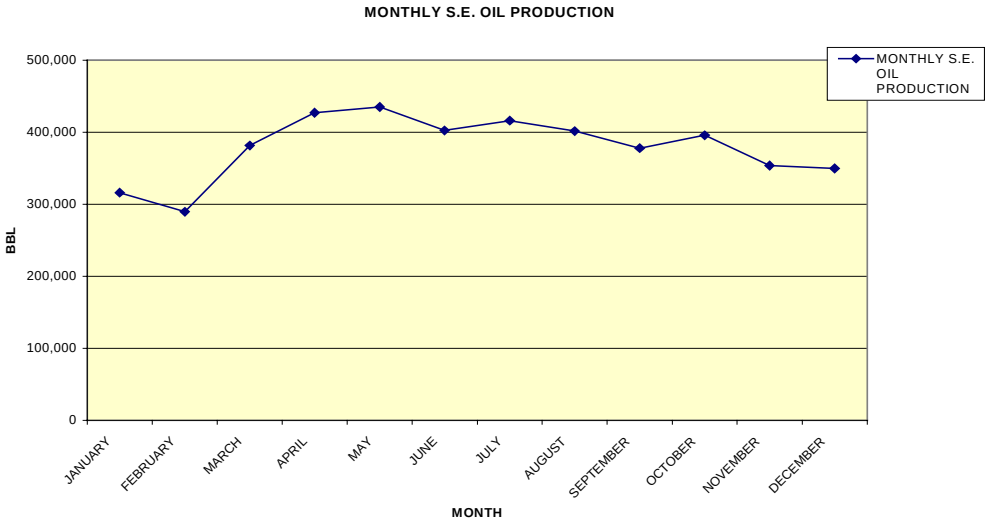


Figure 8: S.E. Gobe Monthly Oil Production Graph

5.5 Moran

Table 9: Monthly Moran Oil Production

MONTH	MONTHLY OIL PRODUCTION	MONTHLY GAS PRODUCTION	CUMULATIVE OIL PRODUCTION	CUMULATIVE GAS PRODUCTION	AVG. DAILY OIL RATE	AVG.DAILY GAS RATE
	BBL	MSCF	BBL X 1000	MMSCF	BOPD	MSCFD
JANUARY	303,959	607,192	11,171.85	22,865.19	9,805	19,587
FEBRUARY	365,324	695,626	11,537.18	23,560.82	13,047	24,844
MARCH	375,502	835,066	11,912.68	24,395.88	12,113	26,938
APRIL	347,097	842,536	12,259.78	25,238.42	11,570	28,085
MAY	370,610	918,958	12,630.39	26,157.38	11,955	29,644
JUNE	431,298	970,688	13,061.68	27,128.07	14,377	32,356
JULY	342,391	808,416	13,404.07	27,936.48	11,045	26,078
AUGUST	365,646	722,392	13,769.72	28,658.87	11,795	23,303
SEPTEMBER	313,757	671,429	14,083.48	29,330.30	10,459	22,381
OCTOBER	298,225	711,667	14,381.70	30,041.97	9,620	22,957
NOVEMBER	381,095	802,560	14,762.80	30,844.53	12,703	26,752
DECEMBER	349,340	906,024	15,112.14	31,750.55	11,269	29,227
YEARLY AVERAGE	353,687	791,046				
SUB-TOTALS						
YEARLY TOTALS	4,244,244	9,492,554				

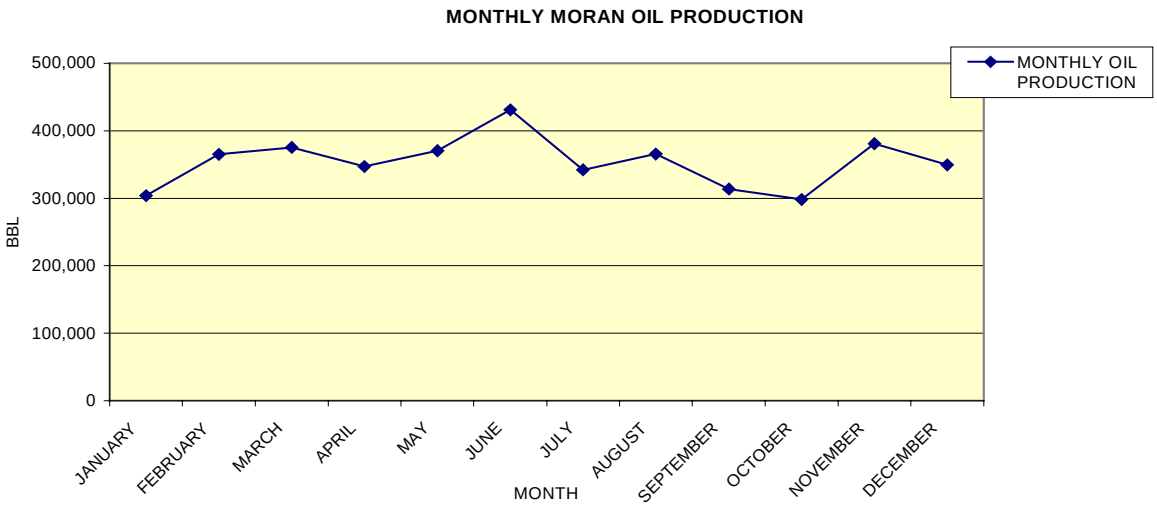
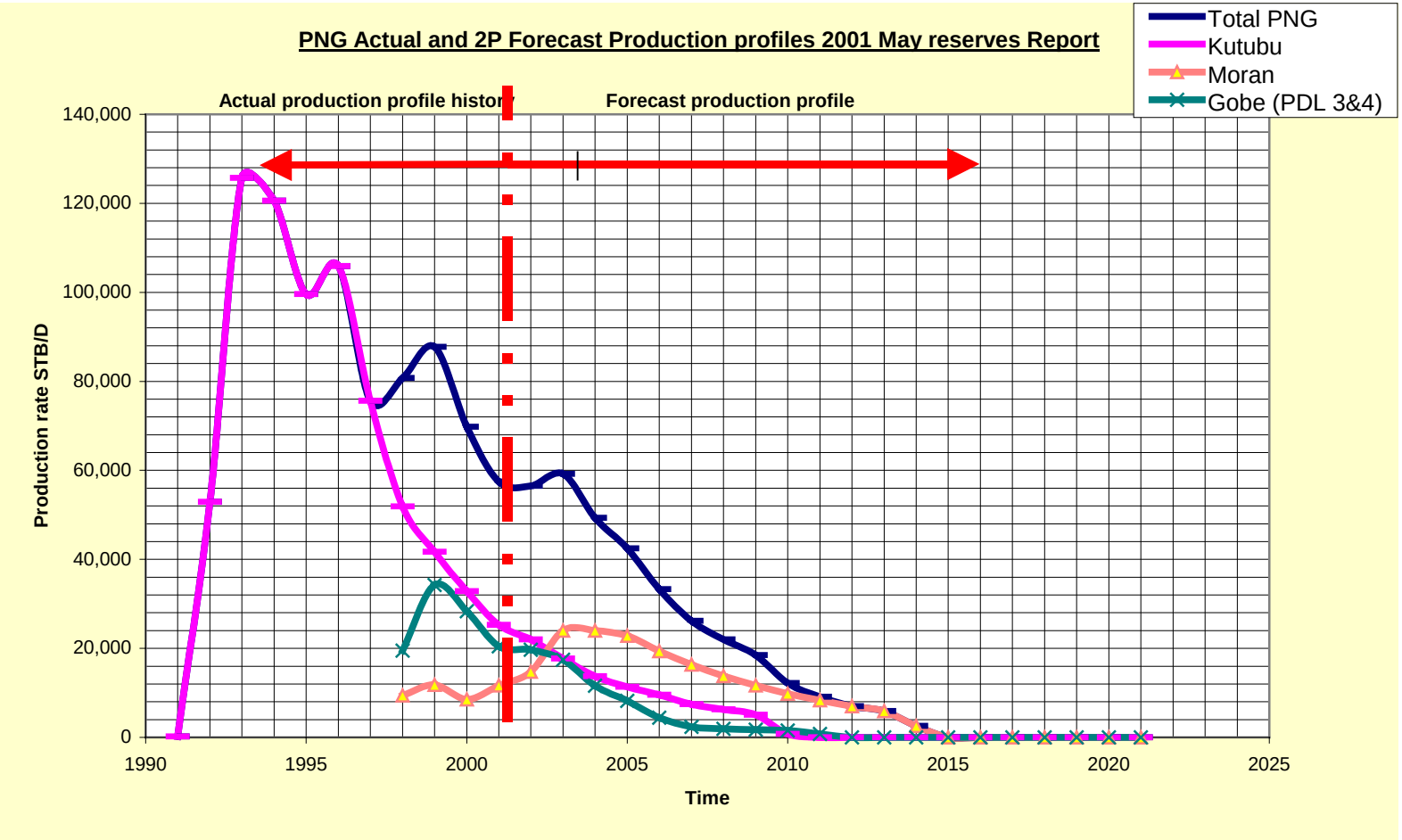


Figure 9: Moran Monthly Production Graph

Figure 10: Yearly Oil Production Showing History and Forecast



5.6 Others

Table 10: Yearly Production – Oil and Gas

YEAR	KUTUBU YEARLY CUM. OIL PROD. (BBLS)	KUTUBU YEARLY CUM GAS PROD. (MSCF)	GOBE YEARLY CUM OIL PROD. (BBLS)	GOBE YEARLY CUM GAS PROD. (MSCF)	S.E GOBE YEARLY CUM OIL PROD. (BBLS)	S.E GOBE YEARLY CUM GAS PROD. (MSCF)	MORAN YEARLY CUM OIL PROD. (BBLS)	MORAN YEARLY CUM GAS PROD. (MSCF)	TOTAL YEARLY CUM OIL PROD. (BBLS)	TOTAL YEARLY CUM GAS PROD. (MSCF)
1991	68,162	84,532							68,162	84,532
1992	19,314,212	16,951,949							19,314,212	16,951,949
1993	45,883,975	49,059,949							45,883,975	49,059,949
1994	44,007,868	58,666,246							44,007,868	58,666,246
1995	36,344,233	61,184,516							36,344,233	61,184,516
1996	38,640,602	65,343,500							38,640,602	65,343,500
1997	27,592,364	66,960,036							27,592,364	66,960,036
1998	18,926,772	69,562,381	3,568,005	8,568,296	3,539,421	6,718,805	3,445,286	3,445,286	29,479,484	88,294,768
1999	15,210,458	77,238,216	6,109,245	12,333,827	6,402,314	15,032,976	4,298,414	4,298,414	32,020,431	108,903,433
2000	11,985,875	77,528,038	5,606,744	11,725,851	4,834,999	16,057,105	3,124,070	3,124,070	25,551,688	108,435,064
2001	9,607,802	75,276,974	2,635,005	11,873,584	4,548,431	13,280,821	4,244,244	9,492,554	21,035,482	109,923,933
CUM. PROD	**267,582,323**	**617,856,337**	**17,918,999**	**44,501,558**	**19,325,165**	**51,089,707**	**15,112,014**	**20,360,324**	**319,938,501**	**733,807,926**

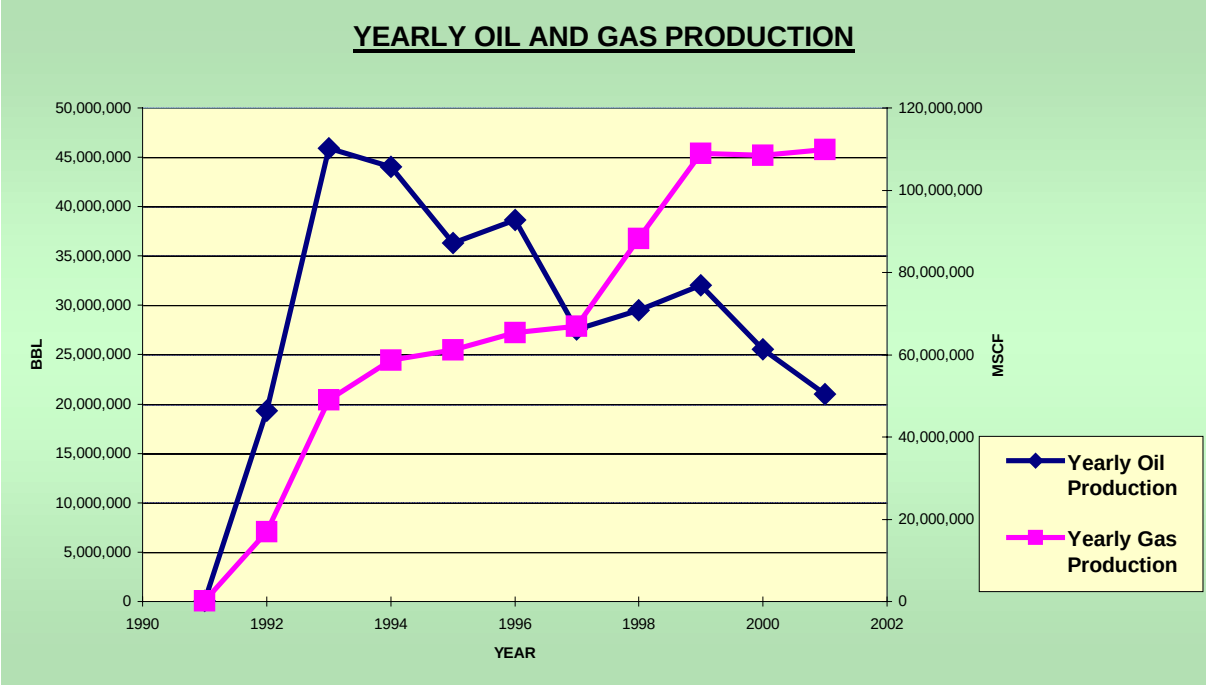


Figure 11: Yearly Oil and Gas Production since 1991

Section 6.0 SPECIAL PROJECTS

6.1 PNG GTQ Gas Project

The GTQ project is proposed to be the most important gas development to commercialise the substantial gas reserves in PNG. The planned project will utilise the gas associated with existing oil production and the large associated gas caps of the producing oil fields together with production from the large Hides gas field and transported via pipeline to offshore marine facilities in the Gulf of Papua. At the marine facility, LPG will be extracted before dry gas is transported through a 3250 kilometers pipeline to customers in Australia.

The produced raw gas is generally rich in gas liquids and condensate and will need to be processed to meet sales gas specifications and to extract, store and export the valuable natural gas liquids.

The marine processing facility will be required to produce up to:

- 600 MMCSFD of specification sales gas to North Queensland
- 22 MBPD of propane
- 10 MBPD of butane, as separate fractionated products; and
- 6MBPD of naphtha type condensate that can be blended with crude oil for export.

The platform proposed for the project would be steel jacket platform connected by a walkway.

Customers in Queensland have been identified who may be able to take up to 5 TCF of gas from PNG. The gas reserve in PNG is estimated at approximately 14 TCF that is adequate to supply GTQ market and another similar project.

The Gas Agreement between the State and the producers has taken well over 18 months to negotiate. Negotiations have been intense through 2001 and a number of terms in the Agreement had been agreed to except for three major outstanding issues. These issues are the fiscal stability, State participation in Hides and the PNG infrastructure, and foreign exchange controls.

ExxonMobil is driving the Sales Agreement Terms with potential gas buyers. Two large potential customers, Comalco and Townsville Gas Power Station are expected to make announcements soon as to their suppliers of gas. Comalco has indicated support for the PNG gas and the Townsville Gas Power Station will make an announcement in March 2002 on its choice of gas supply.

Front End Engineering and Design should commence as soon as the Gas Agreement and Sales Agreement are in place.

Equity financing sources should follow upon completion of the Front End Engineering and Design stage.

Project construction should begin immediately following financial close, and with the completion of the construction, the first gas should flow.

6.2 NAPA NAPA REFINERY

This project was the third refinery proposal and the first to be received by the Department of Petroleum & Energy after the functions of downstream processing in the petroleum sector were transferred from the Department of Commerce and Industry (DCI).

The Napa Napa Oil Refinery was also the first downstream petroleum project to be granted a Petroleum Processing Facility License (PPFL) by the Government in February 2000.

Refinery Process:

The refinery will be basically a "hydro-skimming" process. The process will be relatively small and simple. The basic process will include crude distillation, an LPG – gas recovery unit and naphtha process.

Crude Distillation: - is the first stage of any refinery process and will distillate LPG, naphtha, diesel, kerosene and gas oil.

The ***LPG – Gas Recovery Unit: -*** will be to basically produce LPG from the gas recovered from the refinery process. Some gas will also be used as fuel gas for the refinery operations.

The ***Naphtha Unit: -*** naphtha will be converted to reformate which will be used as feedstock for gasoline production. Most of the naphtha will be sold as stock-feed for petrochemical industry in Japan.

Refinery Construction

InterOil has contracted Clough Engineering based in Perth, Western Australia to carry out the engineering design, procurement and construction of the refinery. The construction will start as soon as all refinery components are inspected and verified by the third party inspection that will be nominated by InterOil and formally endorsed by DPE. The refinery is expected to be in operation in 2004 after successful commissioning and performance testing.

The design of the refinery has been modified from the original concept. The new design entails the construction of the refinery on shore. The original design was to fabricate the refinery on two barges and have it towed into place.

The new design reduces the risk of oil spillage and caters for future expansion to the facilities. The tank farm has been located further inland to minimise the risk of oil spillage into the bay.

The project site has been prepared and the main marine causeway has reached completion.

Inter Oil is yet to nominate a third party certification & inspection agency to do the verification and inspection for the refinery components. DPE will approve and endorse the nominee for the certification.

Refinery Feedstock

The feedstock to the refinery will be at 32,000 barrels per day. Most of this stock will be from the Kutubu export crude and from a spot market in Singapore.

6.3 World Bank Loan

A project is currently underway in the Petroleum Division for training and institutional strengthening. A World Bank Loan was signed for on 16 June 2000 and made effective on 14 August 2000. Following basic preparations and a ramp period lasting six weeks, project implementation substantially commenced from 01 October 2000.

The project has the objective to build the capacity in the Government for the efficient management of gas sector development through:

- strengthening of policy and regulatory framework to promote investment in gas development.
- formulation and analysis of gas development schemes.
- promotion of investment opportunities in gas.
- enhancing of monitoring and regulation capacity of the Government to ensure optimal gas sector development.

The Petroleum Division is implementing the project activities in the context of the existing policies for gas sector development. It is also making efforts to develop policies further and prepare associated guidelines and regulations for sector development. Gas development has been actively promoted based on gas reserves in the Papuan basin. The regulatory capacity is being enhanced in preparation for gas development.

The institutional strengthening of the Petroleum Division is being achieved through a needs-based program of activities, provided as components in the project design.

These include skills upgrading, studies, promotions, provision of equipment, an institutional study, and project management support.

Section 7.0 RESERVES

All the petroleum reserves discovered to date are located in the Papuan Basin, both onshore and offshore.

7.1 Oil Fields

7.1.1 Kutubu Oil Fields (PDL 2)

The Kutubu oil fields comprise Iagifu Hedinia, Usano, and Agogo reservoir blocks.

The Kutubu field 3P ultimate oil recovery increased by 1.1 million barrels (mmstbo) from the 2001 estimate. Additional reserves were assigned to proven and possible reserves in Usano Toro and Agogo Toro due to better performance over the past twelve months.

The current 3P estimated ultimate recovery is 310.8 mmstbo. The Kutubu field contains original oil in place of 557 mmstbo.
The cumulative production as of December 2001 is 267.58 mmstbo. The remaining recoverable reserve is 43.22 mmstbo.

The 2P recoverable gas reserves are 1400 BCF (billion cubic feet).
The original gas in place is 2000 BCF.

As of December 2001, remaining recoverable reserves in the field are:

Proven:	27.4	mmstbo
Probable:	6.5	mmstbo
Possible:	9.3	mmstbo
Total Remaining:	43.2	mmstbo

7.1.2 Gobe Oil Fields (Gobe Main and Gobe 2X) (PDL 4)

The 3P estimated ultimate oil recovery for Gobe Main and Gobe 2x blocks is 31.2 mmstbo. The original oil in place is 100.6 mmstbo.

Cumulative production to year-end is 17.81 mmstbo.
The estimated recoverable 2P gas reserve is 208 BCF. The Original gas in place is 298 bcf.

As of 31st December 2001, remaining recoverable reserves in the field are:

Proven:	3.1 mmstbo
Probable:	3.8 mmstbo
Possible:	6.5 mmstbo
Total Remaining:	13.4 mmstbo

7.1.3 SE Gobe (PDL 3)

The 3P estimated ultimate recovery for SE Gobe is 44.1 mmstbo.

The original oil in place is estimated at 156.7 mmstbo.

Cumulative production as of 31st December 2001 is 19.3 mmstbo. SE Gobe came on production in April 1998.

The estimated recoverable 2P reserve is 268 bcf.
The original gas in place is 409.7 bcf.

As of 31st December 2001:

Proven:	16.45	mmstbo
Probable:	2.47	mmstbo
Possible:	5.89	mmstbo
Total Remaining:	24.81	mmstbo

7.1.4 Moran (PDL 5)

The estimated ultimate recovery (3P) is 127.8 mmstbo. The original oil in place is 258.9 mmstbo.

Cumulative production as of December 2001 is 15.1 mmstbo.

Total estimated recoverable gas reserve at Moran is 352 BCF. Original gas in place 539.4 bcf.
As of 31st December 2001:

Proved:	40.7	mmstbo
Probable:	25.3	mmstbo
Possible:	46.8	mmstbo
Total Remaining:	112.8	mmstbo

7.1.5 SE Mananda (PDL 2)

The 3P Ultimate Oil Recovery for the SE Mananda field is 33.5 mmstbo.

The original oil in place is 107 mmstbo.

Estimated recoverable 2P gas reserve is 226 BCF. Total gas in place is 301 bcf.

7.1.6 SE Hedinia (PDL 2)

SE Hedinia is a dry gas discovery. The estimated recoverable gas reserve is 157 BCF.

Total gas in place is 209 BCF.

7.1.7 Saunders Field (PDL 4)

Saunders field is a new field wildcat discovery. Original oil in place is estimated at 17 mmbo, with an ultimate estimated recoverable reserve of 7 mmbo.

Table 11: Oil Reserves

FIELD	OOIP (MMSTB)	1P (MMSTB)	2P (MMSTB)	3P (MMSTB)	2001 PRODUCTION (MMSTB)	CUMULATIVE PRODUCTION (MMSTB)	ULTIMATE RECOVERY (MMSTB)
KUTUBU	557.00	27.40	33.90	43.20	9.60	267.60	310.80
MORAN	258.90	40.70	66.00	112.80	4.20	15.10	127.90
GOBE MAIN	100.60	3.10	6.90	13.40	2.60	17.80	31.20
SE GOBE	156.70	16.40	18.90	24.80	4.50	19.30	44.10
SE MANANDA	107.00	-	-	33.50	-	-	33.50
TOTALS	**1,180.20**	**87.60**	**125.70**	**227.70**	**20.90**	**319.80**	**547.50**

7.2 Gas Fields

Hides is a large onshore gas field, located in the central Papuan Foldbelt. Minor production for gas sales to the Porgera Gold Mine for electricity commenced in late 1991. Minor amounts of condensate are refined on site and sold locally. The gas produced in the oil fields is reinjected back into the reservoir to maintain reservoir pressure and conservation for future gas demand. Full field development of Hides and other fields are contingent upon the viability of markets as envisaged gas export projects such as the GTQ. ***Table 12*** gives a summary of all known gas fields.

Table 12: Gas Reserves

						Gas Reserves			Condensate Reserves		
Field/reservoir	**Year discovered**	**Type**	**STOIIP MMBO**	**STCIIP MMBO**	**GIIP BCF**	**1P BCF**	**2P BCF**	**3P BCF**	**1P MMB**	**2P MMB**	**3P MMB**
Pandora	1988	gas	-	-	1,358.57	511.27	772.83	1,265.70	-	-	-
Pasca		gas	-	28.85	435.00	-	160.00	-	-	6.00	-
Uramu	1968	gas	-	-	178.00	-	91.50	122.00	-	-	-
Kimu	1999	gas	-	-	4.00	-	3.00	-	-	-	-
Barikewa	1958	gas	-	-	759.00	-	605.00	691.50	-	-	-
Iehi	1960	gas	-	-	104.00	-	11.00	72.00	-	-	-
Bwata	1960	gas/cond	-	-	138.50	48.00	66.00	127.50	-	-	-
Gobe	1992	oil/gas	257.30		708.00			476.00			
Kutubu	1986	oil/gas	552.31	-	2,170.00	790.00	1,082.00	1,523.00	-	-	-
Moran	1996	oil	258.90	-	539.40	147.00	219.00	377.00	-	-	-
SEMananda	1991	oil/gas	107.00	-	301.00	86.00	84.00	51.00	-	-	-
Angore	1990	gas/cond	-	100.47	6,951.22	-	3,327.55	5,881.20	-	4.99	33.36
Hides	1987	gas/cond	-	182.10	9,584.00	3,814.00	5,371.00	7,513.00	56.50	101.00	136.00
Juha	1983	gas/cond	286.10	268.85	5,293.14	637.50	1,562.58	3,805.00	32.00	37.60	90.04
Elevala	1990	gas/cond	-	35.34	611.38	-	432.86	526.40	-	2.50	15.22
Ketu	1991	gas/cond	-	-	703.66	-	17.68	585.45	-	0.10	16.10
Pnyang	1990	gas/cond	-	23.02	3,439.02	-	1,159.63	2,553.89	-	9.10	16.48
TOTAL			1,461.61	638.62	33,277.89	6,033.77	14,965.63	25,570.64	88.50	161.30	307.19

Section 8.0 POLICY

8.1 Moran APDL5 Review

The Moran Application for Petroleum Development Licence 5 review commenced in May and was completed by early August 2000. Immediately after the review, DPE sent out a Section 56 (1) Notice.

Section 56(1) Notice is a provision of the Oil and Gas Act whereby the State notifies the project proponents that the State is prepared to approve the proposals and grant a development licence subject to certain conditions. The oil companies then revert back with a Section 57 Notice requesting the Minister to grant the licence; hence replying whether they will accept the licence or not.

Should they accept the offer, the oil companies must pay the first annual fee. Upon receipt of the Section 57 Notice, the Department refers the matter to the PAB to deliberate on the grant of the development licence.

All parties satisfactorily complied with the relevant provisions for the issuance of a PDL and subsequently PDL5 was granted by the Minister on the 17 February 2001.

8.1.1 State participation

Consistent with the PPL138 Petroleum Agreement, the State has the right to take up to 22.5% participation interest in that part of the Moran project within PPL 138. Should Orogen (which has the first right to exercise an option in all future petroleum projects), decide not to exercise its option in the Moran project and the State decides to take up the equity, the State pursuant to the PPL138 Petroleum Agreement will be carried. Under this arrangement the State will repay 22.5% of the past cost plus interest from its share of foregone production. A nominee will represent the State.

In the circumstances where Orogen does opt to exercise its option, it will pay the fair market price for 22.5% equity in the project and the interest of the State will transfer to Orogen, but 2% will remain with the State nominee who will manage the equity on behalf of the landowners.
However, the State has introduced new legislation to remove Orogen from any of such arrangements. Under the new arrangement, the 22.5% interest remains with the State who deals with the equity as it deems fit. The 2% interest remains with the State nominee MRDC who will manage the equity on behalf of the landowners.

8.2 Moran Accumulated Liability

Accumulated Liability is generally the past cost (allowable exploration expenditure) incurred in a Petroleum Prospecting Licence and the development cost (allowable capital expenditure) and operating cost incurred in a Petroleum Development Licence plus interest. Pursuant to the Income Tax Act, if a Petroleum Development Licence is derived out of a Petroleum Prospecting Licence, the past cost may be transferred out to the Petroleum Development Licence at the time of award of the development licence.

In the case of Moran, a substantial past cost from PPL138 was eligible for transfer into the proposed PDL5. The State analysed these costs and based on the results of analysis decided that the project was not viable for State participation. However, due to the high oil prices in the latter part of 2000,reduction of costs by income from the continuing EWT production and DPE reconciliation of past costs, the State share of the proposed accumulated liability has been reduced thus making the project now marginally attractive for State participation.

The State share of accumulated liability balance has been finalised as of PDL5 award date, 17 February 2001 pursuant to PPL138 Petroleum Agreement.

8.3 Gas to Queensland (GTQ) Negotiations

The GTQ negotiations between the State and the project proponents have been ongoing since 1996. Progress on major issues such as fiscal stability and State participation in the upstream and the infrastructure vehicle were slow, although efforts were made to speedily resolve matters with the mid-year appointment of a coordinator for the State negotiation team.

Negotiations between the State and the Australian Government concerning project financing for PNG's 30% participation in the infrastructure vehicle were unsuccessful. However, Itochu, a Japanese conglomerate has submitted a proposal for the State's financing requirements for the investment. Under the proposal Itochu will provide financing and also become a participant in both the upstream and the infrastructure vehicle segments of the project in partnership with the State. No decision in this has been made at the time of this report.

8.4 Legal Issues

8.4.1 Amendments to Oil and Gas Act

The Oil and Gas Act was passed by Parliament on Monday 16th November 1998 and came into effect on the 18th February 1999.

It is now almost three years since the coming into effect of the Oil and Gas Act. The Department of Petroleum and Energy, which is responsible for the administration of the Act, had over this period

identified certain provisions of the Act that needed changes to facilitate a smooth administration of the Act.

Also since 1999, a Gas Agreement has been under negotiation between the State and the proponents of the Gas to Queensland project. During the course of the negotiations, various provisions of the Act including those related to licence tenure and administration have been identified as provisions that would require some change to facilitate the Gas Project.

In 2001 the Oil and Gas (Amendment) Bill 2001 was prepared to introduce amendments to the Act. The Oil and Gas (Amendment) Bill 2001 sought to introduce a variety of amendments that will provide for better administration of the Act; clarification of certain sector matters, and better definition of some features of the Act for which there were inadequately transitionary provisions.

Relevant amendments were prepared and submitted to Parliament as the Oil and Gas (Amendment) Bill 2001 in the November session of Parliament for enactment. The Oil and Gas (Amendment) Bill 2001 was passed by Parliament and is awaiting certification and gazettal before it can come into operation.

8.4.2 Oil and Gas Regulations

A set of Regulations was prepared several years ago but due to repeated changes of Ministers, the NEC Statutory Paper relating to the proposed Regulation, which was prepared for NEC, has failed to be presented to the NEC. In 2001, a brief was finalised for the new Minister on the Regulations and the NEC Statutory Paper was re-presented to the new Minister. It is hoped to put the Regulations into place in early 2002.

8.4.3 Draft Gas Agreement

Progress on the Gas Agreement has been slow due to the slow progress of the negotiations themselves. In August a new draft Gas Agreement was circulated. By year's end issues that remain outstanding were issues related to State participation and the Central Bank requirements. The State and the producers however reached some understanding on fiscal stability, tax issues, particularly APT, local content and domestic market obligation, and the Kikori/Tari road concept, among others. The negotiation and documentation of the Gas Agreement is still in progress and it is envisaged that the document will be settled by the end of first quarter 2002.

8.4.4 Deed of Amendment – PPL 138 Petroleum Agreement

A Deed of Amendment relating to the PPL 138 Petroleum Agreement was finalised for execution between the State and the PPL 138 partners. The Deed relates to the treatment of State participation in PDL5 and the interest rate that the State or its relevant entities can pay the PPL 138 partners for such participation.

8.4.5 Standard Petroleum Agreement

This is has been an outstanding issue since 1997. The SPA has been reviewed together with Oil Search and Central Bank legal officers. It is envisaged that a final SPA will be settled in the New Year.

8.5 Environmental Issues

8.5.1 Appraisal of Environment Plans

Gas To Queensland

The environment section of the Policy Branch was tasked to appraise the GTQ Environmental Plan. The primary purpose of carrying out the appraisal was to identify areas where further information was required in order to adequately assess:

- the risk of environmental impact
- the social and economic implications and potential impacts of the project; and
- various methods and means proposed in the Environmental Plan to avoid or mitigate any damaging or adverse impacts that might otherwise occur.

The review also sought to assess whether the information requested by Office of Environment and Conservation (OEC) under the Conditions of Approval was adequate to meet these requirements.

Preliminary findings from the appraisal of the EP included:

- further and more detailed environmental baseline information would be required on the section of the pipeline route that extends from the Kopi to the Omati River landfall before the sound and accurate assessment could be made of the potential environmental impacts arising from the pipeline's construction, and its subsequent operation.
- further considerations would need to be given to the potential biophysical environmental impacts and mitigation measures relating to the construction and operation of the project road from Kutubu to Kikori.
- further consideration would also need to be given to some of the potential social and economic impacts and mitigation measures relating to the operation of the project road from Kutubu to Kikori.
- the proposed Erave –Semberigi-Paia Inlet road albeit not part of the gas project, has been proposed by the Governors of the Gulf and Southern Highlands Provinces and has potential implications for the gas project which include; bringing road access and improving transportation to areas that would benefit a greater number of people then would the completion of the Kutubu Kikori road, which runs through relatively sparsely populated country. The road would also reduce the use by through traffic

of the Kutubu-Kikori road and alleviate high traffic densities on this road, which would otherwise pose a safety risk to the integrity of the pipeline.

The Petroleum Division and its relevant branches have a key role to play in this process, which would have been better undertaken in the inception of the EIA process when the various options and potential benefits were first identified and assessed.

Moran

The Moran Environmental Plan was submitted by the proponent project developer as an Environmental Plan Variance Submission. This E.P Variance Submission provided little detailed information, other than that an updated and Revised Version of the Kutubu Environmental Management and Monitoring Plan would be later provided. Whether this updated EMMP has been submitted to OEC, DPE is yet to be confirmed. The OEC has been informed and will follow up the matter with the respective operator.

Napa Napa Oil Refinery

The Napa Napa Oil Refinery had its Environmental plan approved, but on a conditional basis whereby the developer, InterOil, would furnish to the Office of Environment and Conservation and subsequently the Department of Petroleum and Energy, the necessary plans as required by the Environment Planning Approval granted by OEC in June 1998. Additional information is required in certain stages of construction and operation of the facilities. Following financial closure the operator is required to submit to the OEC, a pre construction phase Environmental Management Plan and a Community Assistance Programme.

8.5.2 Review of Environmental Documents

The environmental documents reviewed this year included:

- NEC Submission on Carbon Trading System in PNG
- Queensland 13% Gas Scheme
- Marine Pollution Prevention Bill (On-going)
- UNEP report on Persistent Organic Pollutants (POPs)

Carbon Trading System

Environmental officers have reviewed the potential impact of carbon Trading Systems and possible benefits that gas exports might prompt, were such systems to be endorsed or adopted by the PNG Government.

QLD 13% Gas Scheme

The objective of the scheme is to reduce the growth in greenhouse gas emissions associated with Queensland's electricity load by encouraging a greater use of gas in meeting the State's future energy

requirements. The scheme requires liable parties to surrender Gas Electricity Certificates (GECs) each year equivalent to 13% of their liable electricity load.

This seeks to reduce their GHG emissions and may assist in increasing the likelihood of marketing for PNG gas in Queensland.

Persistent Organic Pollutants (POPs)

In August, The Environment section reviewed and appraised the UNEP (United Nations Environment Programme) report of the Intergovernmental Committee (4th Working session) for Implementing International Action on Persistent Organic Pesticides (POPs).

8.5.3 Marine Pollution

National Marine Oil Spill Contingency Plan

The Environment section also prepared comments on response to specific questions from the Assistant Director-Policy on the National Marine Oil Spill Contingency Plan.

Marine Pollution Prevention Bill

The Department of Transport and Works has drafted the Marine Pollution Prevention Bill and circulated it for review.

The Environmental section is currently in the process of reviewing the bill to ensure that there are no inconsistencies between the Marine Pollution Prevention Bill and the Oil and Gas Act and other relevant Acts.

8.5.4 Annual Inspection

Two environment officers undertook a field inspection of Chevron's operations in the Southern Highlands and Gulf Provinces, at year's end. This was carried out in collaboration with the Engineering Branch. The officers were specifically tasked to look at the Health, Safety and Environment (HS&E) aspect of field operations. A report describing the findings and recommendations of this inspection is expected in the New Year.

8.6 Crude Oil Prices in 2001

The Organisation of Petroleum Exporting Countries (OPEC) maintained a Policy to cut production when the oil price was below their benchmark price level of US$22 for more than 10 working days or increase production when the oil price was above their benchmark US$28 for more than 20 working days. OPEC's efforts to effect its policy worked to keep the prices within the US$23 and US$29 range from January to mid-September.

Following the 11th September 2001 terrorist attack in USA, oil prices took a sharp dive and continued declining to the close of the year. Sinking consumer confidence, job losses, and economic woes in the airline, travel and tourism industries, world recession fears and rising refinery stocks, caused the oil prices to decline to the close of the year. Prices in the last quarter of the year traded in the US$17 and US$23 range.

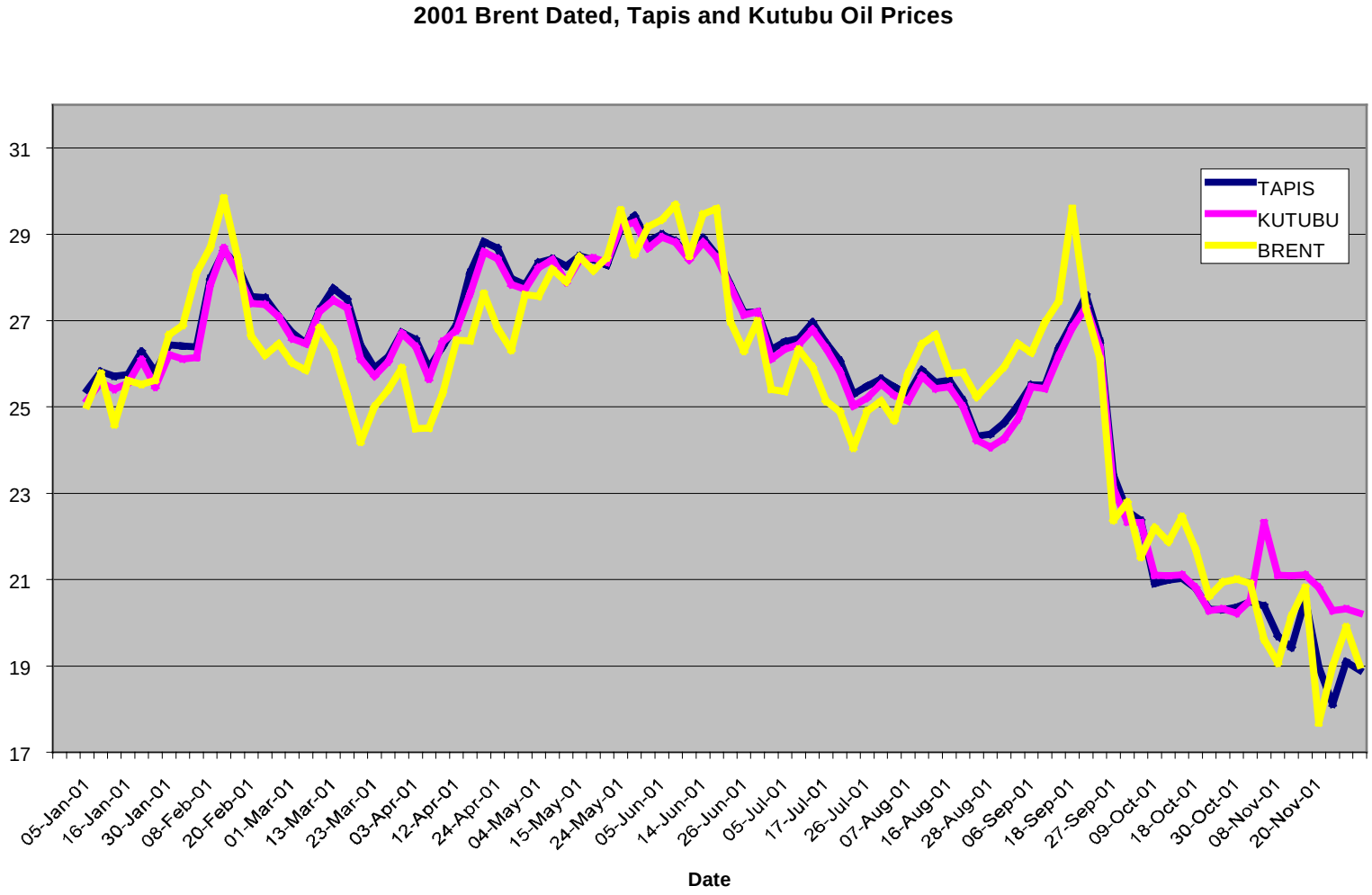
Throughout the year, oil prices traded within the US$29 and US$17 range. Prices started at US$25 and ended at US$19, averaging at US$25 per barrel over the year.

Global economic slow down had been the major factor in pushing prices down against the OPEC policy to cut production and push prices up. Steady refinery stock ups, IEA data release indicating low demand and the resumption of Iraqi oil exports were three other major factors that tended to push prices down.

Fears of a gasoline shortage in the US ahead of the traditional summer driving season in US, Nigeria's unrest causing supply disruption, escalating violence in the Middle East and fears of US refinery shutdowns on the other hand helped push prices up.

The average price for the year stayed around US$25 a barrel. This was good for the selling of PNG's Kutubu crude. The gross sale value for PNG Kutubu crude for the year was more than US$500 million, which amounted to approximately Kina 1.7 billion. ***Figure 12*** summarises the Crude Oil Prices in 2001.

Figure 12: Year 2001 Oil Price Graph



Section 9.0 COORDINATION

9.1 OVERVIEW

9.1.1 Branch Objectives

The Coordination Branch has moved confidently over the last five years in terms of its roles and responsibilities. It was initially regarded as a mere support branch to the ongoing exploration and petroleum development activities; however, it now carries lawful responsibilities under the Oil & Gas Act and Government policies. The petroleum industry is a major revenue earner for the State, comprising more than 23% of the total exports. One of the main duties of the Branch is to ensure the smooth operation of petroleum projects from a lands and community perspective. The Coordination Branch of the Petroleum Division is the first point of contact for landowning communities and provincial and local level governments who are impacted or affected by petroleum projects. The Branch is at the forefront of liaison work with affected communities and lower level governments and managing and coordinating activities relating to the implementation of Project Memorandum of Agreements (MOAs) that such stakeholders have with the National Government and managing other socio-economic issues that affect the project area people. The Branch endeavours to maintain a National Government presence in project areas and be the first point of contact between the landowners and the National Government. The Coordination Branch has an important role to play in:

- liaising with affected communities and affected provincial and local level governments to ensure that all their queries or issues relating petroleum projects affecting them are diligently dealt with and that relevant information is disseminated to them;

- organising and coordinating meetings with representatives of National and Provincial Governments, Industry, Landowner Associations, project area communities to discuss land and community issues affecting specific petroleum projects;

- planning and coordinating the staging of Development Forums for new petroleum projects and review of Project Memorandum of Agreements relating to existing projects;

- reviewing social impacts on developments and prepare programmes for community assistance for inclusion in development agreements and MOAs;

- assist and oversee landowner identification and related social mapping work undertaken by Developers in the petroleum license areas;

- ensure that royalty payments are made to correct beneficiaries and advice the Mineral Resources Development Company (MRDC), on behalf of the Department of Petroleum and Energy, of clans who should benefit from equity from the petroleum projects.
-

9.1.2 Staff on strength

Current petroleum development projects matters are managed by each senior project coordinator, and assisted by a coordinator and senior liaison officers out on the project sites. The current projects are Hides, Kutubu, Gobe, Moran and Gas to Queensland. The GTQ pipeline project is being considered for development and full time coordinators have been assigned to handle issues as outlined above in the Branch objectives. This has been a very busy year for the officers.

9.1.3 Branch Milestones

Milestones achieved during the year include:

- The Coordination Branch has successfully implemented its first year of its two-year programme after the launching of the Gas Development and Utilization TA Project.

- A MOA Coordination Unit has been established in the Branch and a Memorandum of Understanding has been signed with the Department of Works (Mendi), under which the Department of Works will assist in the supervision of the implementation of infrastructure projects agreed to under various Project Memorandum of Agreements..

- Successful resolution of the Fasu leadership issue with the two factions making peace and completed the Foi ILG Review exercise.
- First payment of Benefits made to Moran landowners under an Interim Ministerial Determination.

9.2 Moran Project

Despite stern challenges from the self styled 14 ILGs that were incorporated outside of the Moran Unit Operator and DPE sanctioned ILG work, the project in itself was manageable throughout 2001.

On the 5th of November 2001, the Homa Paua People's Association (HPPA) as the representative mouthpiece of the Huli people endorsed the 14 challengers as well as additional 17 land groups to be independent ILGs from the initial 12 ILGs.

The Department is yet to make a final l decision on the number of recognized Huli ILGs for the project.
Highlights of the project include the following:

- stabilisation of the 12 and 14 ILG recognition challenges and the subsequent cheque payment of the first PDL 5 royalty payments to all Huli beneficiaries at the project area village (Paua 2).

- with the assistance of BSP, 135 passbook accounts were opened for the PDL 5 beneficiaries. This will make it easy for the Department to disburse royalty payments direct to beneficiaries' accounts in the future.

- setting up of a crude electronic database for Huli landowner beneficiaries, which include photos of all beneficiary groups' signatories. This system will promote transparency and accountability in the distribution of benefits both at DPE and at the village level. BSP will also have a copy on their system to manage the distribution of royalty benefits.

- initiated the Warden(s) provision in the Oil and Gas Act thus two Petroleum Wardens have been appointed and can be used in the industry.

Some outstanding issues in the Moran Project relate to the following:-

- the sharing of royalty between the Fasu and the Huli.

- setting up of the Moran EIC.

- establishment of the Moran Trust and Equity finalisation with MRDC.

9.3 Gobe Project

Gobe project production and other normal operations continued without major problems this year. All lands and community affairs issues were somewhat dragged due to the ongoing Lands Titles Commission hearings and appeals in relation to Gobe project land ownership disputes. Landownership could not be determined prior to granting a Development Licence, therefore, the LTC was appointed to determine the ownership of lands. The Commission headed by Justice Salika made a decision on February 1996, but other clans within the Gobe Project area challenged this decision. A three member Special Land Title Commission was set up in mid 1996 to review Justice Salika's ruling on the Gobe landownership dispute. The work continued until the Commission handed down its decision on their findings in May this year. However, this decision was challenged in the National Court by various aggrieved clans, which was upheld and the Commission's decision stayed. Judge Sheehan ruled the decision null and void and referred the entire matter back for fresh hearing under a new LTC.

The landowners requested for an Out of Court Settlement, which the Judge agreed to. After several attempts the landowners could not reach an Agreement to take to the Judge.

DPE then initiated a mediation process that Judge Sheehan agreed to and the process began with the 22 disputing clans signing a mediation agreement, basically agreeing to settle the dispute Out of Court.

After several meetings both in Port Moresby and Samberigi, the landowners requested the Mediators to put an option together for them to decide on the sharing of the benefits. When this was put to them in September, some disagreed and went on their own and conducted another mediation and produced a document titled the Bluff Inn Agreement.
Since then, there has been several rounds of court litigation by the landowners, either against themselves the State and the MRDC. The mediation process now is awaiting the outcome of these court challenges.
The interim Petroleum Resource Gobe (PRG) Board has been suspended by MRDC. This suspension is subject to court proceedings by the suspended Board members and its outcome will be known in the New Year.

It is anticipated that a review on the Gobe MOA that was signed in 1997 with all the parties except the Gulf Province landowners will be done soon. The MOA is long overdue for review but is prolonged due to landownership issue and the pending Court decisions.

The Gobe Leadership Committee (GLC) was set up under a Charter built into the Gobe MOA. GLC consisted of a group of influential leaders from the Project area to work with the Government and the Developer to address and resolve landowner issues. The Committee now appears defunct and maybe unable to be revived until after the various court decisions. All landowner equity and royalty benefits and compensation are held in Trust by MRDC and the DPE respectively. Payments will be made through Incorporated Land Group once the final ownership is determined after the various court decisions.

There are two landowner umbrella companies for the landowners. Gobe Hongu for the Southern Highlands landowners and Gulf Oil Ltd. for the Gulf landowners. To date Gobe Hongu has done poorly and is in receivership.

9.4 Kutubu Project

Normal operations were maintained and oil flowed without major problems though Kutubu landowner issues remained a challenge this year. Major threats were issued in various manners but remained manageable.

New petroleum projects over the years have been able to draw experiences from the first oil project in PNG, the Kutubu project. Being the first, unforeseen problems have now surfaced and have become National issues when they should have been solved at a village level.

Highlights of some of these problems:

1. Fragmentation of ILGs (Incorporated Land Groups)
2. Leadership struggles by Landowner Associations and Political interference.
3. Unequal distribution of benefits.

All royalty payments to landowners have been done well, although payment has been behind by up to three months. Moran PDL 2 royalty has being incorporated into the Kutubu payments.

The Landowner Association Leadership struggle among the Foes has led to the Lower Foes pressuring for recognition. However, this is pending the Chief Justice's decision on the Foe ILG review.

The Gulf landowners after 10 years without a Landowner Association have finally incorporated the Kikori Pipeline landowners association as their mouthpiece. However, the association became defunct after 3 months in operation. The major infrastructure development-taking place in the area is the Kikori Airport development.

9.5 Hides Gas Project

It has been a busy year for the Developer OSL in its operations during the year.

The year started off with disturbance from the Huli's in relation to the Tari/Nipa warfare. The Huli's tried to storm the operations camp to forcefully obtain vehicles and fuel to assist in the transportation of warriors to the battlefield, however this was prevented by the local landowner clans living around the project facilities.

There was continuing tribal fighting among landowner clans within the project area, however operations were not affected. The peace and good order committee comprising of clan leader managed to bring the situation under control and compensations were paid and the situation is returning to normalcy in the project area.

Royalties for the 2nd half of the year 2000 were disbursed into clan accounts in March 2001 and the January – June 2001, payments disbursed in September and all recipients have received their shares. The main royalty issue had been the ineffective distribution of royalty by agents. There was a minor distribution issues among the Tabu clans, which was resolved and royalty released to the clan in early October. A Kenamu clan member took two Branch officers to court over their share of royalties, however this case was thrown out by the Port Moresby District Court.

After 7 years of court proceedings, the landownership challenge between the Pina clans and the Hiwa Koma clans was finally settled on the 20th July, and all royalties held in the DPE trust account since July 1998 was released to the Pina clan in early October.

Hiwa Tuguba Hides L/O Association, who is the mouthpiece of the project landowners, was not operational through out the year; this was due to security reason for executive members because of tribal conflict among clans. The situation has improved and leaders are now back in the project area.

The OSL zone ILG concepts are still under the microscope since 1999 and the Department is yet to confirm its position on the concept. Several meetings were held, however no agreements have been reached to date.

Bakari 1X well drilling preparation commenced in early September with social mapping and ground truthing for the landowner clans in the area. All clan agency agreements have been completed and OSL is in the process of paying out the environment compensation payments to the identified resident landowner clans. The drilling operations have been progressing smoothly without landowner disruption at year's end.

Security was a major problem in project area because of a general break down of law and order in the Hela region and the Southern Highlands. Despite this, there was no disruption or problems faced directly in relation to the Hides project.

9.6 PNG Gas Project

The Lands and Community Affairs aspect of the Gas Project has been stagnant since the last joint DPE/Chevron Loloata workshop in mid 2000. There was little activity following ExxonMobil's take over the operation of the Project in 2001. The main focus of the State team was on the Negotiations of the Gas Agreement.

However, some effort was taken by the Branch to review the Loloata work plan recommendations and action items. In November 2001, ExxonMobil and DPE met to revisit the Loloata papers and modify where necessary. Some action items have been identified for both DPE / ExxonMobil to pursue and implement. There has been some delay due to resourcing of the work plan.
One task in the Community Affairs work plan that received attention was the Zone ILG concept. Dr. Goldman who was commissioned by the industry made a presentation on Incorporated Land Groups (ILG) reforms on the 30 November 2001. During the presentation, it appeared that the Developers were not in alignment, thus DPE is unable to make any firm decision until the industry agrees on its next move.

Subsequently, an ILG joint risk assessment workshop was staged recently to develop options for both government and Developer to pursue and adopt model(s) for the industry. Oil Search Ltd. and ExxonMobil showed a strong desire for the Zone concept while Chevron is yet to decide, hence, DPE has not come up with its position. Further meetings will be held to pursue this issue.

9.7 Planned activities 2002

One key area of work will include the formulation and issuing of a regulation, in accordance with the Act in areas relating to Social Mapping and Landowner Identification and getting clarifications and amendments, where necessary in relation to provisions of the Act that relate to benefits.

An integral part of the Branch two-year program is to recruit an *Advisor on Community Affairs* to facilitate the process of reviewing the related legal and regulatory framework, and dissemination of the new regulation. The Coordination Branch will need to be supported by a knowledgeable expert who will continue to assist the Branch in the initial implementation process. Other planned activities include:

Facilitating Development Forums - The forum negotiations need to be facilitated by a professional who will control the meeting to achieve a desired outcome. Past meetings were often controlled by the landowners, which resulted in delays in reaching agreements and became expensive and time consuming. The process could be expedited under the guidance of an experienced and independent facilitator.

Assistance in Drafting of Development Agreements - The Development Agreements need to be standardized to be consistent with the Oil and Gas Act, the Organic Law on Local Level and Provincial Governments and other relevant Acts. A consultant would be required to formulate a standard agreement to reflect the requirements of the these Acts to be used as a guide to future negotiations and consequent drafting of agreements;

Landowners Information Campaign - In a joint effort with the Coordination Branch, resources would be required to prepare the information material and proceed with the Landowners information campaign;

Staff training - Will be given priority as well as other important duties;

Database on Landowners - The number of landowners within land groups continues to expand and land groups continue multiplying to accommodate individual families and other landowners. There is a need to set up a database that can be easily accessed to manage day-to-day landowners concerns. The database among others should include information on landownership and land group executives;

Procurement of Equipment - Necessary for the field liaison activities.

Section 10.0 CONCLUSION

Oil and Gas activities generally remained at a low level for 2001.
Exploration drilling commenced before the close of the year, and may encourage exploration work to pick up in the New Year.
Successful completion of the Moran Development Forum and the issuance of the licence to the PDL 5 applicants have seen the payment of benefits to the landowners and the affected LLGs.

Following the terrorist attack in the United States, oil prices plummeted and have continued to decline since.

Other milestones achieved included the enactment of the Amendments to the Oil and Gas Bill 2001 by Parliament. It now awaits certification and gazettal.

The project site for the Napa Napa oil refinery, and the main marine causeway have been prepared and completed. Construction should begin shortly in light of necessary inspections and certifications. The GTQ negotiations although slow are still ongoing. ExxonMobil is now the driver behind the Sales Agreement Terms. Two large potential customers have been identified and they are yet to announce their suppliers of gas.

PETROLEUM EXPLORATION & PRODUCTION STATISTICS

		1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
NEW PPL's GRANTED **(a)**		16	6	5	4	5	5	8	1	7	6	5	9	4	3	2
PPL's EXPIRED, SURRENDERED OR CANCELLED		4	1	5	2	12	8	13	6	2	7	3	5	3	1	4
TOTAL NUMBERS OF PPL's **(b)**		33	38	38	40	33	30	25	20	25	25	22	27	28	27	23
TOTAL NUMBER OF BLOCKS						2684	2143	1283	995	1130	1395	1372	1494	1535	1508	1066
TOTAL AREA UNDER LICENCE (KM^2)						228140	182155	109055	84575	96050	118575	116620	126990	130475	122148	90610
NEW PDL's GRANTED		0	0	0	2	0	0	0	0	0	2	0	0	0	0	1
PDL's EXPIRED, SURRENDERED OR CANCELLED		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL NUMBER OF PDL's		0	0	0	2	2	2	2	2	2	4	4	4	4	4	5
TOTAL NUMBER OF BLOCKS (PDL)		0	0	0	16	16	16	16	16	16	21	21	21	21	21	22
NEW PLL's GRANTED		0	0	0	2	0	0	0	0	0	1	0	0	0	0	0
TOTAL PLL's GRANTED		0	0	0	2	2	2	2	2	2	3	3	3	3	3	3
NEW PRL's GRANTED		0	0	0	0	0	0	0	0	0	0	0	1	0	4	0
TOTAL NUMBER OF PRL's		0	0	0	0	0	0	0	0	0	0	0	1	1	5	5
APPROXIMATE EXPENDITURE		K74M	K116M	K149M	K225M	K170M	K80M	K60M	K70M	K117M	K190M	K258M	K120M	K144M	K157M	K238M
EXPLORATION WELLS DRILLED **(c)**		7	10	27	21	11	7	4	10	4	5	9	5	5	2	2
DISCOVERY WELLS **(c)**		3	6	14	9	5	4	2	2	1	2	2	2	1	0	1
NEW FIELD DISCOVERIES **(d)**		2	2	1	4	3	2	1	0	0	1	0	0	1	0	0
CUMULATIVE FIELDS		11	13	14	18	21	23	24	24	24	26	26	26	27	27	27
CUMULATIVE WELLS		155	165	192	213	224	231	235	245	249	254	263	268	273	273	276
% SUCCESS RATE		7.1	7.9	7.3	8.5	9.4	10	10.2	9.8	9.6	10.2	9.9	9.7	9.9	9.9	10.2
SEISMIC SURVEYS		7	8	14	15	6	8	3	1	1	3	5	7	2	4	4
LINE KMS SEISMIC	ONSHORE	423	700	1630	2901	744	751	43	35	16	446.2	321.2	28.2	142	147	109.8
	OFFSHORE	4769	1878	1139	2576	661	879	2425	12568**(e)**	0	0	0	5390	0	0	0
	TOTAL	5192	2578	2769	5477	1405	1630	2468	12603	16	446.2	321.2	5418.2	142	147	109.8
PRODUCTION **(f)**	OIL 000 BBLPD					1	53	126	120	100	106	130	81	88		56
Average per day	GAS MMCFPD					3.7	5.8	7.9	9.2	9.6	13.5	11.5	13.3	13.1	70	14

NOTES

(a) PPL is a Petroleum Prospecting Licence
PDL is a Petroleum Development Licence
PPL is a Pipeline Licence
PRL is a Petroleum Retention Licence

(b) Figures at year end

(**c)** Excludes development wells but includes extensions discoveries and purposeful sidetracks drilled and completed in c 1999 = KIMU.

(d) 1986 = IAGIFU
1987 = SE HEDINIA, HIDES
1988 = HEDINIA, PANDORA
1989 = AGOGO
1990 = ANGORE, ELEVALA, P'NYANG, USANO
1991 = KETU, SE MANANDA, SE GOBE
1992 = GOBE 2X, PANDORA B
1993 = GOBE MAIN
1996 = MORAN
1999 = KIMU

(e) 3-D Pasca Survey

(f) Oil Production – Kutubu/Moran/Gobe
Gas Production – Hides

THE INDEPENDENT STATE OF PAPUA NEW GUINEA PETROLEUM PROSPECTING LICENCES AS AT 31st DECEMBER, 2001

LICENCE NO:	BASIN	ON/OFF SHORE	PROVINCE	DATE GRANTED (Expiry)	NO. OF BLOCKS (5"x 5")	LICENCEES (% HELD)(op=Operator)	CONTACT ADDRESS
138(E)	Papuan	On	Southern/ Western Highlands	9 Sept 91 (8 Sept 2002)	21	Esso Highlands Ltd (47.5%) (op) Oil Search Limited (52.5%)	Dr. Douglas A. Schwebel Esso Highland Pty Ltd GPO Box 400C MELBOURNE VIC 3001 AUSTRALIA Ph: (3) 9270 3901 Fx: (3) 9270 3944
157(E/A.S)	Papuan	On	Western	2 June 93 (1 June 04)	30	Santos Niugini Exploration Limited (35.25%) (op) Trans-Orient Pet. (PNG) Ltd (7.50%) SPI Ltd (20.00%) Greenslope Ltd (15.00%) Carnarvon Petroleum N.L. (15.00%) Bligh PNG Limited (7.25%)	Ian Trevitt Barracuda Limited P.O. Box 1159 PORT MORESBY, NCD Ph: 2312633 Fx: 3212847
184	North New Guinea (Ramu)	On	Madang	18 June 96 (17 June 02)	68	Ramu Niugini Limited (1. 0%)(op) Ramu Caymans LDC (99%)	Ramsay A. Barrett, 7831 Carters Run Drive, MARSHALL, VA 2011, U.S.A. Ph: 01 540 3498246 Fx: 01 540 3494693
185	North New Guinea (Sepik)	On	East & West Sepik	18 June 96 (17 June 02)	49	Ramu Niugini Limited (op)(1.0%) Ramu Camans LDC (99%)	See PPL 184

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THE INDEPENDENT STATE OF PAPUA NEW GUINEA PETROLEUM PROSPECTING LICENCES AS AT 31st DECEMBER, 2001

LICENCE NO:	BASIN	ON/OFF SHORE	PROVINCE	DATE GRANTED (Expiry)	NO. OF BLOCKS (5"x 5")	LICENCEES (% HELD)(op=Operator)	CONTACT ADDRESS
188	Papuan	On/Off	Gulf	16 Dec 1996 (15 Dec 2002)	116	Oil Search Ltd (49.55%) (op) Woodside Pet. (PNG) P/L (40.45%) Gedd (PNG) Ltd (10.00%)	Peter Botten, Oil Search Ltd P.O.Box 1031 PORT MORESBY NCD Ph: 3213177 Fx: 3214379
189	Papuan	Onshore	Gulf	18 Feb 1997 (17 Feb 2003)	23	Barracuda Limited (42.553%)(op) Iona Limited (42.553%) Cue PNG Oil Company Pty Ltd (14.894%)	See PPL 157
190	Papuan	Onshore	Gulf/Southern H/Lands	18 Feb 1997 (17 Feb 2003)	22	Barracuda Limited (31.278%) (op) Murray Petroleum Co. Ltd (26.497%) Iona Pty Limited (31.278%) Cue PNG Oil Company Pty Ltd (10.947%)	See PPL 157
192	Papuan	Onshore	Western	28 Jan 1997 (27 Jan 2003)	60	Indo-Pacific Energy (PNG) Pty Ltd (40%) (op) Mosaic Oil Niugini Pty Ltd (15%) Continental Oil (PNG) Pty Ltd (5%) Durum Energy (PNG) Pty Ltd (20%) Trans Orient Petroleum (PNG) Pty Ltd (20%)	David Bennett Indo-Pacific Energy P.O. Box 17258 KARORI WELLINGTON New Zealand Ph: 64 4 476 2717 Fx: 64 4 476 0120
194	Papua	Onshore	Enga/Southern H/Lands & Chimbu	27 Nov 1998 (26 Nov 2004)	71	Toro Oil Pty Ltd (100%)	Cue PNG Oil Company Pty Ltd 25th Floor, 500 Collins Street, Melbourne Victoria 3000, Australia Ph: 3 9629 7577 Fx: 3 9629 7318

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THE INDEPENDENT STATE OF PAPUA NEW GUINEA PETROLEUM PROSPECTING LICENCES AS AT 31st DECEMBER, 2001

(A= Application); (E = Extension)
(O = Offered); (R = Refused); (S = Surrender) (1 Block = 85 sqkm approx')

LICENCE NO:	BASIN	ON/OFF SHORE	PROVINCE	DATE GRANTED (Expiry)	NO. OF BLOCKS (5"x 5")	LICENCEES (% HELD)(op=Operator)	CONTACT ADDRESS
199	Papuan	Onshore	Southern H/Lands	19 Nov 98 (18 Nov 2004)	15	Oil Search Limited (50%) (op) Woodside (PNG) Pty Ltd (35%) SPI (199) Pty Ltd (15%)	See PPL 188
	(Due to S. 136 Direction 2nd licence anniversary date now 30/9/01)						
200	Papuan	Offshore	Gulf	29 May 98 (28 May 2004)	72	Lundin Oil Ltd (35%)(op) Oil Search Ltd (50%) SP InterOil LDC (15%)	General Manager Lundin Oil Limited c/o Talisman (Asia) Ltd Setiabudi Atrium Suite 410 4th Floor, Jl. H. R. Said Kav. 62, Kuningan, Jakarta 12920 INDONESIA Ph: (62) (21) 521 0654 Fax: (62) (21) 521 0732
201 (A.S.)	Papuan	Onshore	Gulf	22 Aug 98 (21 Aug 2004)	9	Bligh Oil & Minerals NL (55%) (op) Auriga Petroleum Pty Ltd (45%)	Neil Malloy GPO Box 363 Brisbane, QLD 4001 Ph: (7) 3221 6022 Fx: (7) 3221 6625
203	Papuan	Onshore	Gulf	18 Mar 98 (17 Mar 2004)	12	Oil Search Ltd (89.474%) (op) Gedd (PNG) Pty Ltd (10.526%)	See PPL 188
204	Papuan	Onshore	Western	22 Aug 98 (21 Aug 2004)	60	Carnarvon Petroleum NL (50%) (op) Greenslopes Pty Limited (50%)	Tony Sparks Carnarvon Petroleum NL P.O. Box 1598 WEST PERTH WA 6872 Ph: (8) 9322 8344 Fx: (8) 9322 8311

THE INDEPENDENT STATE OF PAPUA NEW GUINEA PETROLEUM PROSPECTING LICENCES AS AT 31st DECEMBER, 2001

LICENCE NO:	BASIN	ON/OFF SHORE	PROVINCE	DATE GRANTED (Expiry)	NO. OF BLOCKS (5"x 5")	LICENCEES (% HELD)(op=Operator)	CONTACT ADDRESS
206	Papuan	Onshore	Gulf/Western & S/Highlands	10 June 98 (9 June 2004)	58	Bligh Papua Ltd (24%) Bligh Kanau Ltd (24%) Santos Niugini Exploration Pty Ltd (48%) (op) Garnet PNG Corporation (2%) Niugini Energy, Inc (2%)	See PPL 157
208 (A.S.)	Papuan	On/Off	Gulf	12 April 99 (11 April 05)	122	SPI (208) Limited (50%)(op) Oil Search Ltd (25%) Woodside Petroleum (25%)	Christian Vinson P.O. Box 1971 PORT MORESBY NCD Ph: 320 2600 Fax: 320 2601
210	Papuan	On/off	Central	11 Feb 99 (10 Feb 05)	60	SPI (210) Limited (100%)(op)	See PPL 208
215	Papuan	On	Western-Province & Southern Highlands	6 May 99 (5 May 05)	28	Indo-Pacific Energy (PNG) Ltd (40%) Trans-Orient Petroleum (PNG) Pty Ltd (40%) Mosaic Oil Niugini Pty Ltd (15%) Continental Oil (PNG) Pty Ltd (5%)	See PPL 192
218	Papuan	On	Western Province	12 April 00 (11 April 06)	41	Oil Search Ltd 50%(op) Woodside PetroleumLtd (50%)	See PPL 188
219	Papuan	On	Southern Highlands	15 Feb 00 (14 Feb 06)	37	Ampolex (Highlands) Ltd (18.7330%) Orogen(Exploration) Inc (12.5000%) Chevron Niugini (25.0000%)(op) Merlin Petroleum Company (8.7500%) Oil Search Limited (35.0170%)	Isikiel Taureka Chevron Niugini P/L, P. O. Box 842 PORT MORESBY Ph: 3211088 Fx: 3224488 Tlx:NE2205

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THE INDEPENDENT STATE OF PAPUA NEW GUINEA PETROLEUM PROSPECTING LICENCES AS AT 31st DECEMBER, 2001

LICENCE NO:	BASIN	ON/OFF SHORE	PROVINCE	DATE GRANTED (Expiry)	NO. OF BLOCKS (5"x 5")	LICENCEES (% HELD)(op=Operator)	CONTACT ADDRESS
220	Papuan	On/Off	Gulf Province	4 Sept 2000 (3 Sept 2006)	23	SPI (220) Ltd (100%)(op)	See PPL 208
227	Papuan	On	Western/Gulf Provinces	16 Oct 2001 (15 Oct 2007)	36	Oil Search (87.50%) (op) Gedd (PNG) Inc (12.50%)	See PPL 188
228	Papuan	On	Western Province	26 Jul 2001 (25 Jul 2007)	33	Barracuda Limited (20%) (op) Santos Niugini Expl. Ltd (20%) Victoria Expl. (PNG) Ltd (15%) First Australian Resources (PNG) Ltd (12.5%) Highland Petroleum Ltd (12.5%) Trans-Orient Petroleum (PNG) Ltd (10.0%) Bligh PNG Ltd (10.0%)	See PPL 157

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APPLICATION FOR PETROLEUM EXPLORATION LICENCES

229 (A)	Papuan	On	Gulf		9	Barracuda Limited (42.553%)(op) Iona Limited (42.553%)	See PPL 157
230 (A)	Papuan	On/Off	Gulf/Central/Eastern Highlands/Chimbu		199	SPI (208) Limited (100%)	See PPL 208
231 (A)	Papuan	On	Western		34	Indo-Pacific Energy (PNG) Ltd (40%)(op) Trans-Orient Petroleum (PNG) Ltd (40%) Mosaic Oil Niugin I Ltd (15%) Continental Oil (PNG) Ltd (5%)	See PPL 192

THE INDEPENDENT STATE OF PAPUA NEW GUINEA PETROLEUM PROSPECTING LICENCES AS AT 31st DECEMBER, 2001

LICENCE NO:	BASIN	ON/OFF SHORE	PROVINCE	DATE GRANTED (Expiry)	NO. OF BLOCKS (5"x 5")	LICENCEES (% HELD)(op=Operator)	CONTACT ADDRESS

(A= Application); (E = Extension)
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PETROLEUM DEVELOPMENT LICENCES (PDL

01	Papuan	On	Southern H/Lands Prov.	27 Sept 1990 (27 Sept 2015)	4	Oil Search (Tumbudu) Ltd (14.0%) Oil Search Ltd (7.5%) Esso Highlands Ltd (47.5%) (op) Zan Star Ltd (25.0%) Lavana Ltd (6.0%)	John Speed Oil Search Ltd GPO Box 2442 SYDNEY, NSW Australia. Ph: (2) 9251 8400 Fax: (2) 9251 1232
02	Papuan	On	Southern H/Lands Prov.	10 Dec 1990 (10 Dec 2015)	12	Merlin Pacific Oil Company NL (2.906250%) Chevron Niugini Limited (19.375000%) (op) Merlin/Mitsubishi (Japan PNG Pet) (6.781250%) ExxonMobil (Ampolex PNG Pet. Inc) (11.611825%) Oil Search (Kutubu) Pty Ltd (27.138175%) Petroleum Resources Kutubu Pty Ltd (6.75000%) Orogen Minerals (Kutubu) Pty Limited (25.4375%)	See PPL 219
03	Papuan	On	Gulf Province	24 Dec 1996 (23 Dec 2021)	1	Chevron Niugini Ltd (0%) (op) Barracuda Pty Limited (15.5000%) Cue PNG Oil Company Pty Ltd (5.4250%) Oil Search (Gobe) Pty Ltd (15.5000%) Mountains West Exploration Inc. (1.9375%) Southern Highlands Petroleum Co. Ltd (39.1375%) Petroleum Resources Gobe Pty Ltd (2.0000%) Orogen Minerals (Gobe) Pty Limited (20.5000%)	See PPL 219 & PPL 157

THE INDEPENDENT STATE OF PAPUA NEW GUINEA PETROLEUM PROSPECTING LICENCES AS AT 31st DECEMBER, 2001

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LICENCE NO:	BASIN	ON/OFF SHORE	PROVINCE	DATE GRANTED (Expiry)	NO. OF BLOCKS (5"x 5")	LICENCEES (% HELD)(op=Operator)	CONTACT ADDRESS
04	Papuan	On	Southern Highlands/ Gulf Provinces	24 Dec 1996 (23 Dec 2021)	4	ExxonMobil (Ampolex Highlands)Ltd (14.518075%) Chevron Niugini Limited (19.375%) (op) Merlin/Mitsubishi (Japan PNG Pet) (6.781250%) Oil Search Limited (27.138175%) Orogen Minerals (Gobe) Pty Ltd (30.1875%) Petroleum Resources (Gobe) Pty Ltd (2.0%)	See PPL 219
05	Papuan	On	Southern Highlands	17 Feb 2001 (16 Feb 2026)	1	Esso Highlands Limited (47.5%) (op) Oil Search (Moran) Limited (45%) Oil Search Limited (7.5%)	See PPL 138
				PIPELINE LICENCES (PLL)			
01	Papuan	On	Southern Highlands	27 Sept 1990 (27 Sept 2015)		Oil Search Limited (5%) Oil Search (Tumbudu) Pty Limited (95%)	See PPL 188
02	Papuan	On/Off	Southern Highlands & Gulf	10 Dec 1990 (10 Dec 2015)		as in PDL 02	See PPL 219
03	Papuan	On	Southern Highlands & Gulf	24 Dec 1996 (23 Dec 2021)		Ampolex (PNG Pet) Pty Ltd (11.251508%) Chevron Niugini Pty Limited (15.015624%) Merlin Petroleum Company (5.255469%) Oil Search Limited (24.519585%) Mountains West Exploration Inc (0.435938%) Southern Highlands Petroleum Co., Ltd (8.805938%) Barracuda Pty Limtied (3.487500%) Cue PNG Oil Company Pty Ltd (1.220625%) Orogen Minerals (Gobe) Pty Limited (28.007813%) Petroleum Resources Gobe Pty Limited (2.0%)	See PPL 219

THE INDEPENDENT STATE OF PAPUA NEW GUINEA PETROLEUM PROSPECTING LICENCES AS AT 31st DECEMBER, 2001

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LICENCE NO:	BASIN	ON/OFF SHORE	PROVINCE	DATE GRANTED (Expiry)	NO. OF BLOCKS (5"x 5")	LICENCEES (% HELD)(op=Operator)	CONTACT ADDRESS

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PETROLEUM RETENTION LICENCES (PRL)

01	**Papuan**	**Offshore**	**Gulf (Pandora)**	**20 Feb 1998 (19 Feb 2003)**	**9**	**Lundin Oil limited (48.16%) (op) Ampolex (Pandora Reef) (16.36%) Command Pet.(Gulf) 12.73% Claremont Pet. PNG (6.36%) Pacrim Energy Ltd (6.36%) Oil Search Ltd (5.00%) Secab Niugini P/L (5.00%)**	**See PPL 200**
02	**Papuan**	**On**	**Western (Juha)**	**12 April 00 (11 April 05)**	**10**	**Chevron Niugini (21.5000%) (op) Oil Search Limited (6.0102%) ExxonMobil (55.9898%), Orogen (Exploration) Inc (4.0000%) Merlin Petroleum (12.5000%)**	**See PPL 219**
03	**Papuan**	**On**	**Western (P'nyang)**	**12 April 00 (11 April 05)**	**5**	**Chevron Niugini Ltd (25.0000%) (op) Oil Search (6.0102%) ExxonMobil (48.9898%), Orogen (Exploration) Inc (7.5000%) Merlin Petroleum Company (12.5000%)**	**See PPL 219**
04	**Papuan**	**On**	**Western (Stanley)**	**1 Sept 2000 (31 Aug 2006)**	**4**	**Santos Niugini (35.25%) (op) SPI (20.00%) Greenslopes (15.00%) Carnarvon (15.00%) Trans-Orient (7.50%) Bligh Oil (7.25%)**	**See PPL 157**

THE INDEPENDENT STATE OF PAPUA NEW GUINEA PETROLEUM PROSPECTING LICENCES AS AT 31st DECEMBER, 2001

LICENCE NO:	BASIN	ON/OFF SHORE	PROVINCE	DATE GRANTED (Expiry)	NO. OF BLOCKS (5"x 5")	LICENCEES (% HELD)(op=Operator)	CONTACT ADDRESS
05	Papuan	On	Western (Ketu/Elevala)	15 Feb 00 (14 Feb 05)	9	Santos Niugini (35.25%) (op) SPI Limited (20.00%) Greenslopes Ltd (15.00%) Carnarvon Petroleum N.L. (15.00%) Trans-Orient (7.50%) Bligh Oil (7.25%)	See PPL 157
APPLICATION FOR PETROLEUM RETENTION LICENCES (APRL)							
APRL 8	Papuan	On	Gulf (Kimu)		6	Oil Search Ltd (31.25%) (op) Amplex (Papua New Guinea) Pty Limited (30.00%) Mosaic Oil Niugini Limited (20.00%) Gedd ((PNG) Limited (11.25%) Omati Oil Pty Ltd (7.50%)	See PPL 179
APRL9	Papuan	On	Gulf (Barikewa)		7	Barracuda Limited (42.553%) (op) Iona Pty Limited (42.553 %) Cue PNG Oil (14.894%)	See PPL 190
APRL 10	Papuan	Off	Gulf (Uramu)		1	Oil Search Limited (49.55%)(op) Woodside Petroluem (PNG) Pty Ltd (40.5%) Gedd Inc. (PNG) Ltd (10%)	See PPL 188

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THE INDEPENDENT STATE OF PAPUA NEW GUINEA PETROLEUM PROSPECTING LICENCES AS AT 31st DECEMBER, 2001

(A= Application); (E = Extension)
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SUMMARY

Number of PPLs	**23 (2 of which Applications for Surrender lodged).**
Number of Blocks	**1066**
Number of PDLs	**5**
Number of Blocks	**22**
Number of PRLs	**5**
Number of Blocks	**37**
Total number of Blocks under Licence	**1135**
Total area under Licence	**96475 km^2**

OPERATOR	LICENCES
SANTOS NIUGINI EXPLORATION LTD/BARRACUDA LTD	157, 189, 190, 206, 228, PRL4, PRL5
BLIGH OIL & MINERALS NL	201
CARNAVON PETROLEUM NL	204
CHEVRON NIUGINI LTD	219, PDL2, PDL3, PDL4; PDL5, PLL2, PLL3, PRL2, PRL3
CUE PNG OIL COMPANY	194
ESSO HIGHLANDS LTD	138, PDL1
INDO PACIFIC ENERGY (PNG) PTY LTD	192, 215
LUNDIN OIL LIMITED	200, PRL 1
OIL SEARCH LIMITED	188, 199, 203, 218, 227, PLL1
RAMU NIUGINI LIMITED	184, 185
SPI LIMITED	208, 210, 220

ADDRESSES OF OPERATORS

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