

Oil and Gas Development
Company Limited

Pakistan

Reserves Evaluation 2010

June 2011

TRACS International
(a wholly owned subsidiary of AGR Peak Group (Holdings) Limited)

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1. Executive Summary

TRACS International Consultancy Ltd. ("TRACS"), a wholly owned subsidiary of AGR Petroleum Services, was on August 1, 2010 requested by the Oil and Gas Development Company Ltd. ("OGDCL") to prepare a remaining reserves evaluation with an effective date of July 1, 2010.

At OGDCL's request, the remaining reserves statement was prepared in accordance with the definitions and guidelines set forth in the 2007 Society of Petroleum Engineers Petroleum Resources Management System (SPE PRMS), jointly issued by the Society of Petroleum Engineers (SPE), the World Petroleum Council, the American Association of Petroleum Geologists (AAPG), and the Society of Petroleum Evaluation Engineers (SPEE).

Reserves Statement

The gross reserves were estimated by preparing production forecasts and cash flows for each of the fields in OGDCL's portfolio. The production forecasts were extended to meet the economic limit under the prevailing conditions. Wellhead gas streams were adjusted as appropriate to arrive at sales gas profiles. The gross remaining reserves for all fields in which OGDCL has an interest, as per July 1, 2010 are fairly stated as follows:

	Remaining Reserves – July 1, 2010								
	Operated Fields			Non-operated Fields			Total		
	Oil + Condensate	Sales Gas	Total	Oil + Condensate	Sales Gas	Total	Oil + Condensate	Sales Gas	Total
	MMstb ¹	Bscf ²	MMboe ³	MMstb	Bscf	MMboe	MMstb	Bscf	MMboe
Proven Developed Producing	50.00	2402	292.6	24.1	1333	242.4	74.10	3735	535.0
Proven Developed Non-producing	0.36	85	9.3	0.00	0	0.0	0.36	85	9.3
Total Proven Developed	50.36	2487	301.9	24.1	1333	242.4	74.46	3820	544.3
Proven Undeveloped	25.05	2055	324.6	0.98	127	21.4	26.03	2182	346.0
Proven (1P)	75.41	4542	626.5	25.08	1459	263.9	100.49	6001	890.4
Probable	58.17	2559	388.9	18.26	1057	191.7	76.43	3616	580.6
Proven plus Probable (2P)	133.58	7101	1015.4	43.34	2516	455.6	176.92	9617	1471.0
Possible	87.57	3085	459.2	26.3	1477	269	113.87	4562	728.2
Proven plus Probable plus Possible (3P)	221.15	10186	1474.5	69.64	3993	724.6	290.79	14179	2199.1

Table 1-1: Remaining reserves consolidation for OGDCL (Gross)

Proven reserve have been sub-categorised into Proven Developed and Proven Undeveloped, with the former further sub-categorised into Proven Developed Producing and Proven Developed Non-Producing. The distinction between the Proven Undeveloped and Proven Non-producing is made on the

¹ MMstb: million stock-tank barrels, an industry standard measurement unit for stabilised oil and condensate suitable for export or sale; equivalent to 42 U.S. gallons or approximately 0.159 m³.

² Bscf: billion standard cubic feet, and industry standard measurement unit for gas at a standard pressure and temperature of 1 atm and 60 °F.

³ MMboe: million barrels of oil equivalents, a summation of oil and gas volumes on an energy equivalent basis; a conversion factor of 6 million British thermal units (btu) per barrel has been used.

basis of the expenditure level required to bring the project to production, for Proven Non-Producing this is typically less than 10% of the total project expenditure.

From the gross remaining reserves, OGDCL's entitlement was honoured to calculate the remaining reserves net to OGDCL. The remaining reserves, net to OGDCL, as per July 1, 2010 are fairly stated as follows:

	Remaining Reserves net to OGDCL – July 1, 2010								
	Operated Fields			Non-operated Fields			Total		
	Oil + Condensate	Sales Gas	Total	Oil + Condensate	Sales Gas	Total	Oil + Condensate	Sales Gas	Total
	MMstb	Bscf	MMboe	MMstb	Bscf	MMboe	MMstb	Bscf	MMboe
Proven Developed Producing	43.93	2224	259.5	8.97	421	78.6	52.90	2645	338.1
Proven Developed Non-producing	0.27	74	7.4	0.00	0	0.0	0.27	74	7.4
Total Proven Developed	44.19	2298	266.9	8.97	421	78.6	53.16	2719	345.5
Proven Undeveloped	19.00	1745	270.5	0.42	65	10.8	19.42	1810	281.3
Proven (1P)	63.19	4043	537.4	9.39	486	89.4	72.58	4529	626.8
Probable	47.78	2270	333.1	6.01	329	60.1	53.79	2599	393.2
Proven plus Probable (2P)	110.97	6314	870.5	15.4	815	149.5	126.37	7129	1020.0
Possible	70.65	2733	385.3	8.75	435	80.4	79.40	3168	465.7
Proven plus Probable plus Possible (3P)	181.62	9046	1255.8	24.15	1250	229.9	205.77	10296	1485.7

Table 1-2 Remaining reserves consolidation for OGDCL (Net)

In addition, the following estimates of Contingent Resources, net to OGDCL, as per July 1, 2010, have been made:

	Contingent Resources net to OGDCL								
	Operated Fields			Non-Operated Fields			Total		
	Oil + Condensate	Sales Gas	Total	Oil + Condensate	Sales Gas	Total	Oil + Condensate	Sales Gas	Total
	MMstb	Bscf	MMboe	MMstb	Bscf	MMboe	MMstb	Bscf	MMboe
1C	3.23	541	93.4	10.07	176	39.4	13.30	717	132.8
2C	5.81	941	162.6	20.24	360	80.2	26.05	1301	242.9
3C	9.50	1688	290.8	36.29	681	149.8	45.79	2369	440.6

Table 1-3 Contingent Resources consolidation for OGDCL (Net)

Contingent Resources are remaining recoverable volumes associated with projects that do not meet the certainty requirements for classification as reserves (reasonably certain). Such projects may be technically immature or there may be an as yet un-clarified market for the product streams. Also, volumes associated with fields currently under force majeure have been classified as Contingent Resources. The commercial risk associated with each of the projects has not been independently quantified.

Methodology

The estimates of remaining reserves were prepared by the use of standard geological and engineering methods generally accepted by the petroleum industry. The method or combination of methods used in the analysis of each reservoir was tempered by experience with similar reservoirs, stage of development, quality and completeness of basic data, and production history.

When applicable, material-balance, decline analysis and other engineering methods were used to estimate recovery factors. In such cases, an analysis of reservoir performance, including production rate, reservoir pressure, water cut development and gas-oil ratio behaviour, was used in the estimation of remaining reserves. For depletion-type reservoirs or those whose performance disclosed a reliable decline in producing-rate trends or other diagnostic characteristics, remaining reserves were estimated by the application of appropriate decline curves or other performance relationships. In selected cases, full static and dynamic reservoir models were built to provide reliable estimates. In the analysis, reserves were estimated only to the limits of economic production based on current economic conditions.

Data source

For the preparation of this reserves statement, TRACS used technical and economic data, including but not limited to well logs, seismic data, production data and historical price and cost information, provided by OGDCL. There were no limitations or restrictions imposed on the provision of providing information and data required for the preparation of this statement.

Assumptions

The legal title to production has not been independently checked; where development and production or mining licences have expired, it has been assumed that they will be renewed. All production profiles were extrapolated to the economic limit.

The Brent futures oil price dated September 15th 2010 was used as the reference price. This price forecast is shown below. Individual field product streams were benchmarked against the Brent price according to historical data.

Gas prices have been collated on an asset per asset basis, from published data and/or from field specific gas sales agreements. For prediction of future prices, the gas prices were, where applicable, tied to the oil price.

Operating expenditures have been extracted from three years' accounts and averaged on an asset by asset basis. Capital expenditures have been taken from OGDCL's budgets were available, and estimates, based on reasonable industry standards, have been made where not available. All costs have been escalated by 1.6% per annum in line with US inflation.

Period	Brent price (US\$/bbl)	Source
2H 2010	77.89	Spot average
1H 2011	81.31	CME Brent Futures (15.09.2010)
2H 2011	83.78	
1H 2012	85.51	
2H 2012	86.63	
1H 2013	87.56	
2H 2013	89.05	
1H 2014	89.80	
2H 2014	90.65	
1H 2015	90.65	
2H 2015	91.58	
1H 2016	92.71	
2H 2016	93.46	
1H 2017	94.25	
2H 2017	95.04	
2018+	Escalated with US inflation (1.6% p.a.)	

Qualifications

TRACS International Consultancy Ltd. provides a wide range of geological, petrophysical, engineering, drilling and commercial services. TRACS has prepared numerous reserves estimates for use by companies, banks, governments and regulatory authorities and is recognised as a Competent Person by the London Stock Exchange. TRACS staff is familiar with the recognized industry reserves and resources definitions, including but not limited to, those promulgated by the U.S. Securities and Exchange Commission, by the Alberta Securities Commission, by the London Stock Exchange, by the Hong Kong Stock Exchange and by the Russian Central Reserves Committee.

TRACS was engaged for the sole purpose of preparing this reserves statement on the 1st of August 2010 by Mr. Mansoor Humayon, General Manager Reservoir management of OGDCL. TRACS is an independent evaluator; TRACS, including any member of its staff, does not own an interest in the properties evaluated, nor has TRACS been remunerated on a contingent basis.

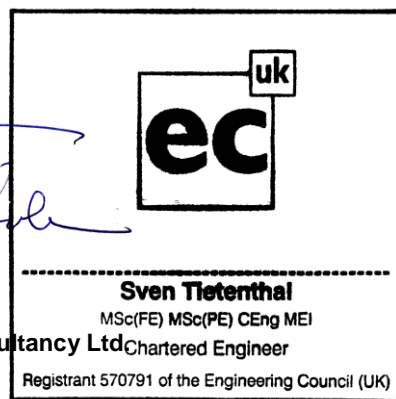
This assessment has been led by Sven Tiefenthal. Sven Tiefenthal has more than 25 years experience in the industry, has more than 10 years experience as a reserves auditor and has Master of Science degrees in Petroleum Engineering and in Financial Economics. Sven Tiefenthal is a Member of the Energy Institute and is a Chartered Engineer under the Engineering Council (UK).

Yours Sincerely,

June 15, 2011

Sven Tiefenthal
Senior Reserves Auditor

TRACS International Consultancy Ltd Chartered Engineer
Registrant 570791 of the Engineering Council (UK)



2. Portfolio Overview

2.1. Asset Overview

The fields in Pakistan, covering the four provinces of Khyber Pakhtunkhwa, Punjab, Sindh and Balochistan, separate into three distinct geological-geographical regions: North, Central and South.

Within these regions the fields are encountered in similar stratigraphic horizons with similar fluid contents.

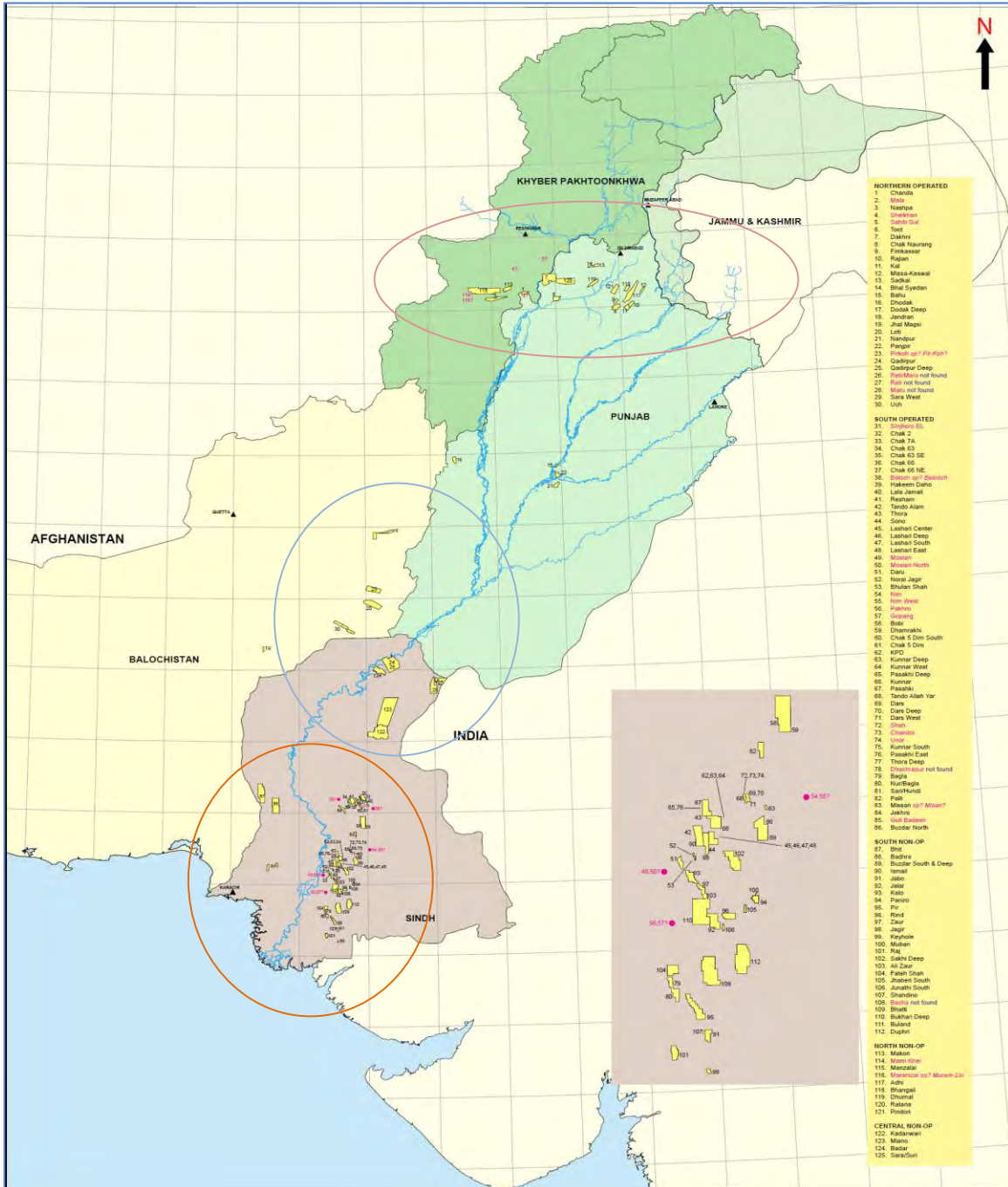


Figure 2-1 Location Map

The following table presents a list of the properties evaluated as part of this reserves statement:

Field Names	Operator Name	Op/ NonOP	Zone/GS	Fluid Type	Production Status	Province	Working Interest
Bagla	OGDCL	Op	South	Cond	NonProducing	Sind	100
Bahu	OGDCL	Op	Center	Gas	NonProducing	Punjab	100
Baloach	OGDCL	Op	South	Cond	Producing	Sind	60
Bhal Syedan.	OGDCL	Op	North	Cond	Producing	Punjab	100
Bhulan Shah	OGDCL	Op	South	Cond	Producing	Sind	77.5
Bobi	OGDCL	Op	South	Oil/Cond	Producing	Sind	100
Buzdar North	OGDCL	Op	South	Oil	NonProducing	Sind	100
Chak 2	OGDCL	Op	South	Cond	NonProducing	Sind	60
Chak 5 Dim	OGDCL	Op	South	Cond	Producing	Sind	100
Chak 5 Dim South	OGDCL	Op	South	Cond	Producing	Sind	100
Chak 63SE	OGDCL	Op	South	Cond	NonProducing	Sind	60
Chak 66	OGDCL	Op	South	Cond	NonProducing	Sind	60
Chak63	OGDCL	Op	South	Oil	NonProducing	Sind	60
Chak66NE	OGDCL	Op	South	Oil	NonProducing	Sind	60
Chak7A	OGDCL	Op	South	Cond	NonProducing	Sind	60
ChakNaurang	OGDCL	Op	North	Oil	Producing	Punjab	85
Chanda	OGDCL	Op	North	Oil	Producing	KPK	72
Chandio	OGDCL	Op	South	Cond	NonProducing	Sind	77.5
Dachrapur	OGDCL	Op	South	Gas	NonProducing	Sind	100
Dakhni	OGDCL	Op	North	Cond	Producing	Punjab	100
Dars	OGDCL	Op	South	Cond	NonProducing	Sind	77.5
Dars Deep	OGDCL	Op	South	Cond	NonProducing	Sind	77.5
Dars West	OGDCL	Op	South	Cond	NonProducing	Sind	77.5
Daru	OGDCL	Op	South	Cond	NonProducing	Sind	100
Dhamrakhi	OGDCL	Op	South	Cond	Producing	Sind	100
Dhodak	OGDCL	Op	Center	Cond	Producing	Punjab	100
Fimkassar	OGDCL	Op	North	Oil	Producing	Punjab	100
Gopang	OGDCL	Op	South	Gas	Producing	Sind	77.5
Hakeem Dahu	OGDCL	Op	South	Cond	NonProducing	Sind	60
Hundi/Sari	OGDCL	Op	South	Gas	Producing	Sind	100
Jakhro	OGDCL	Op	South	Cond	NonProducing	Sind	100
Jandran	OGDCL	Op	Center	Gas	NonProducing	Baloachistan	100
Jhal Magsi South	OGDCL	Op	Center	Gas	NonProducing	Baloachistan	56
Kal	OGDCL	Op	North	Oil	Producing	Punjab	100
Kunnar Deep	OGDCL	Op	South	Cond	NonProducing	Sind	100
Kunnar Oil Field	OGDCL	Op	South	Oil	Producing	Sind	100
Kunnar South	OGDCL	Op	South	Cond	NonProducing	Sind	77.5
Kunnar West	OGDCL	Op	South	Cond	NonProducing	Sind	100
Lala Jamali	OGDCL	Op	South	Cond	NonProducing	Sind	60
Lashari Center	OGDCL	Op	South	Oil	Producing	Sind	100
Lashari South	OGDCL	Op	South	Cond	NonProducing	Sind	100
Loti	OGDCL	Op	Center	Gas	Producing	Baloachistan	100

Field Names	Operator Name	Op/ NonOP	Zone/GS	Fluid Type	Production Status	Province	Working Interest
Maru	OGDCL	Op	Center	Gas	NonProducing	Sind	55.26
Mela	OGDCL	Op	North	Oil	Producing	KPK	56.45
Missa Keswal	OGDCL	Op	North	Oil	Producing	Punjab	100
Missan	OGDCL	Op	South	Oil	Producing	Sind	100
Moolan	OGDCL	Op	South	Gas	NonProducing	Sind	100
Moolan North.	OGDCL	Op	South	Oil	Producing	Sind	100
Nandpur	OGDCL	Op	Center	Gas	Producing	Punjab	100
Nashpa	OGDCL	Op	North	Oil	Producing	KPK	56.45
Nim	OGDCL	Op	South	Cond	NonProducing	Sind	77.5
Nim West	OGDCL	Op	South	Gas	Producing	Sind	77.5
Norai Jagir	OGDCL	Op	South	Cond	Producing	Sind	77.5
Nur	OGDCL	Op	South	Cond	NonProducing	Sind	100
Pakhro	OGDCL	Op	South	Cond	Producing	Sind	77.5
Palli	OGDCL	Op	South	Oil	NonProducing	Sind	100
Panjpir	OGDCL	Op	Center	Gas	Producing	Punjab	100
Pasakhi Deep	OGDCL	Op	South	Cond	NonProducing	Sind	100
Pasakhi East	OGDCL	Op	South	Cond	NonProducing	Sind	77.5
Pasakhi NE-01	OGDCL	Op	South	Oil	Producing	Sind	100
Pasakhi West Deep-01	OGDCL	Op	South	Cond	NonProducing	Sind	100
Pasakhi/Pasakhi North	OGDCL	Op	South	Oil	Producing	Sind	100
Pirkoh	OGDCL	Op	Center	Gas	Producing	Baloachistan	100
Qadirpur	OGDCL	Op	Center	Gas	Producing	Sind	75
Rajian	OGDCL	Op	North	Oil	Producing	Punjab	100
Resham	OGDCL	Op	South	Cond	NonProducing	Sind	60
Reti	OGDCL	Op	Center	Gas	NonProducing	Sind	55.26
Sadkal	OGDCL	Op	North	Cond	Producing	Punjab	100
Sara West	OGDCL	Op	Center	Gas	NonProducing	Sind	100
Shah	OGDCL	Op	South	Cond	NonProducing	Sind	77.5
Sheikhan	OGDCL	Op	North	Gas	NonProducing	KPK	30
Sono	OGDCL	Op	South	Oil	Producing	Sind	100
Tando Alam	OGDCL	Op	South	Oil	Producing	Sind	100
Tando AllahYar	OGDCL	Op	South	Cond	NonProducing	Sind	77.5
TAY North	OGDCL	Op	South	Oil	NonProducing	Sind	77.5
Thora	OGDCL	Op	South	Oil	Producing	Sind	100
Thora Deep	OGDCL	Op	South	Cond	NonProducing	Sind	100
Toot	OGDCL	Op	North	Oil	Producing	Punjab	100
Uch	OGDCL	Op	Center	Gas	Producing	Baloachistan	100
Unner	OGDCL	Op	South	Cond	NonProducing	Sind	77.5
Ali Zaur S	BPP	NonOp	South	Oil	Producing	Sind	15
Baqar Deep	BPP	NonOp	South	Cond	Producing	Sind	49
Buzdar South Deep	BPP	NonOp	South	Cond	Producing	Sind	49
Buzdar Unit	BPP	NonOp	South	Gas	Producing	Sind	56.65
Fateh Shah North	BPP	NonOp	South	Gas	Producing	Sind	15
Jabo	BPP	NonOp	South	Oil	Producing	Sind	49

Field Names	Operator Name	Op/ NonOp	Zone/GS	Fluid Type	Production Status	Province	Working Interest
Jagir	BPP	NonOp	South	Gas	Producing	Sind	24
Jalal	BPP	NonOp	South	Gas	Producing	Sind	49
Jhaberi South	BPP	NonOp	South	Gas	Producing	Sind	15
Junathi South	BPP	NonOp	South	Gas	NonProducing	Sind	15
Kato	BPP	NonOp	South	Gas	Producing	Sind	49
KeyHole G	BPP	NonOp	South	Oil	NonProducing	Sind	24
MI & MI Deep	BPP	NonOp	South	Cond	Producing	Sind	49
Muban	BPP	NonOp	South	Oil	Producing	Sind	24
Paniro	BPP	NonOp	South	Oil	Producing	Sind	49
Pir	BPP	NonOp	South	Gas	NonProducing	Sind	49
Raj	BPP	NonOp	South	Gas	NonProducing	Sind	24
Rind	BPP	NonOp	South	Gas	Producing	Sind	49
Sakhi Deep	BPP	NonOp	South	Gas	NonProducing	Sind	24
Shah Dino	BPP	NonOp	South	Gas	Producing	Sind	15
Zaur	BPP	NonOp	South	Oil	Producing	Sind	49
Bhadra	ENI	NonOp	South	Gas	Producing	Sind	20
Bhit	ENI	NonOp	South	Gas	Producing	Sind	20
Kadanwari	Eni	NonOp	Center	Gas	Producing	Sind	50
Makori	MOL	NonOp	North	Cond	Producing	KPK	27.763
Mamikhel	MOL	NonOp	North	Cond	NonProducing	KPK	27.763
Manzalai	MOL	NonOp	North	Cond	Producing	KPK	27.763
Maramzai	MOL	NonOp	North	Cond	NonProducing	KPK	27.763
Miano	OMV	NonOp	Center	Gas	Producing	Sind	52
Bhangali	OPI	NonOp	North	Gas	Producing	Punjab	50
Dhurnal	OPI	NonOp	North	Oil	Producing	Punjab	20
Ratana	OPI	NonOp	North	Cond	Producing	Punjab	25
Badar	PEL	NonOp	Center	Gas	Producing	Sind	50
Pindori	POL	NonOp	North	Oil	Producing	Punjab	50
Adhi	PPL	NonOp	North	Cond	Producing	Punjab	50
Sara/Suri	Tullow	NonOp	Center	Gas	Producing	Sind	40

Note that not all of the above fields have remaining reserves associated with them; some have only contingent resources and some, where the future cash flow was deemed to be negative, have neither.

2.2. Reserves and Production Overview

The portfolio is separated into the three broad geographical regions: North, Central and South. The fields evaluated have been grouped into these regions. A distinction has also been made between the Operated assets and the Non-operated assets.

The production history, when separated by region, demonstrates that the North and South regions dominate oil production, whilst the gas is primarily produced from the Central region (Figure 2-2).

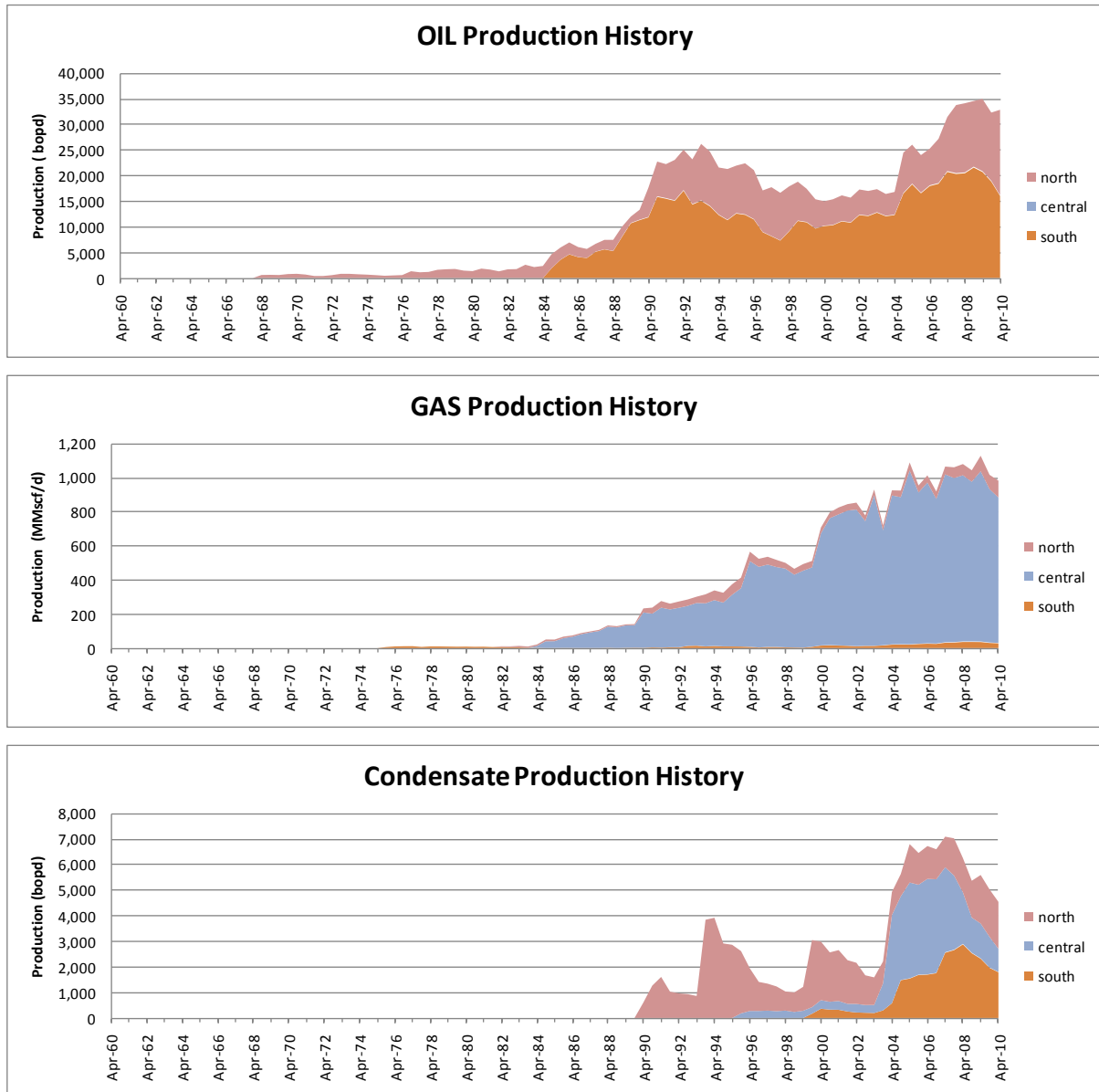


Figure 2-2 Historic Production by Region

Up until mid 2010, the Operated fields have produced 5227 Bscf of gas, 191 MMstb of oil, and 24 MMstb of condensate. Condensate is sometimes registered as oil in OGDCL so oil and condensate should be viewed in combination. The OGDCL net share (using current shareholding) of cumulative production was 4664 Bscf gas, 185 MMstb oil, and 23 MMstb condensate.

The oil production from the developed fields is generally in decline, and this decline is forecast to continue (Figure 2-3). Gas production will be maintained and even increased through the implementation of new projects, specifically in the large Qadirpur and Uch gas fields, and bringing on

new fields such as Kunnar Deep and Pasakhi Deep. Condensate production may temporarily offset the oil production decline, but in the medium term a decline is expected.

The projects, which are currently considered sufficiently robust for classification as Reserves, are largely in line with the OGDCL business plan and are presented in Table 2-1.

Project	Status
Dakhni-13	Scheduled for 2010-2011
Mela-03	Well drilled; production scheduled 2H 2011
Mela-04	Scheduled for 2H 2012
Nashpa-02	Scheduled for 1H 2012
Rajian-06	Scheduled for 1H 2012
Pasakhi-07	Scheduled for 2H 2011
Chanda-04	Scheduled for 2H 2011
Pasakhi-07	Scheduled for 2H 2011
Qadirpur Project 1	Scheduled for 2H 2010
Qadirpur Project 2	Scheduled for 2H 2011
Qadirpur Projects 3 and 4	Scheduled for 1H 2012
Thora-08	Production started 1H 2011
Uch Project 1	Scheduled for 1H 2011
Sinjhor Development	Scheduled for 1H 2013
KPD/TAY Development	Scheduled for 1H 2013
Nim Development	Scheduled for 1H 2012

Table 2-1 Projects included in Reserves Classification

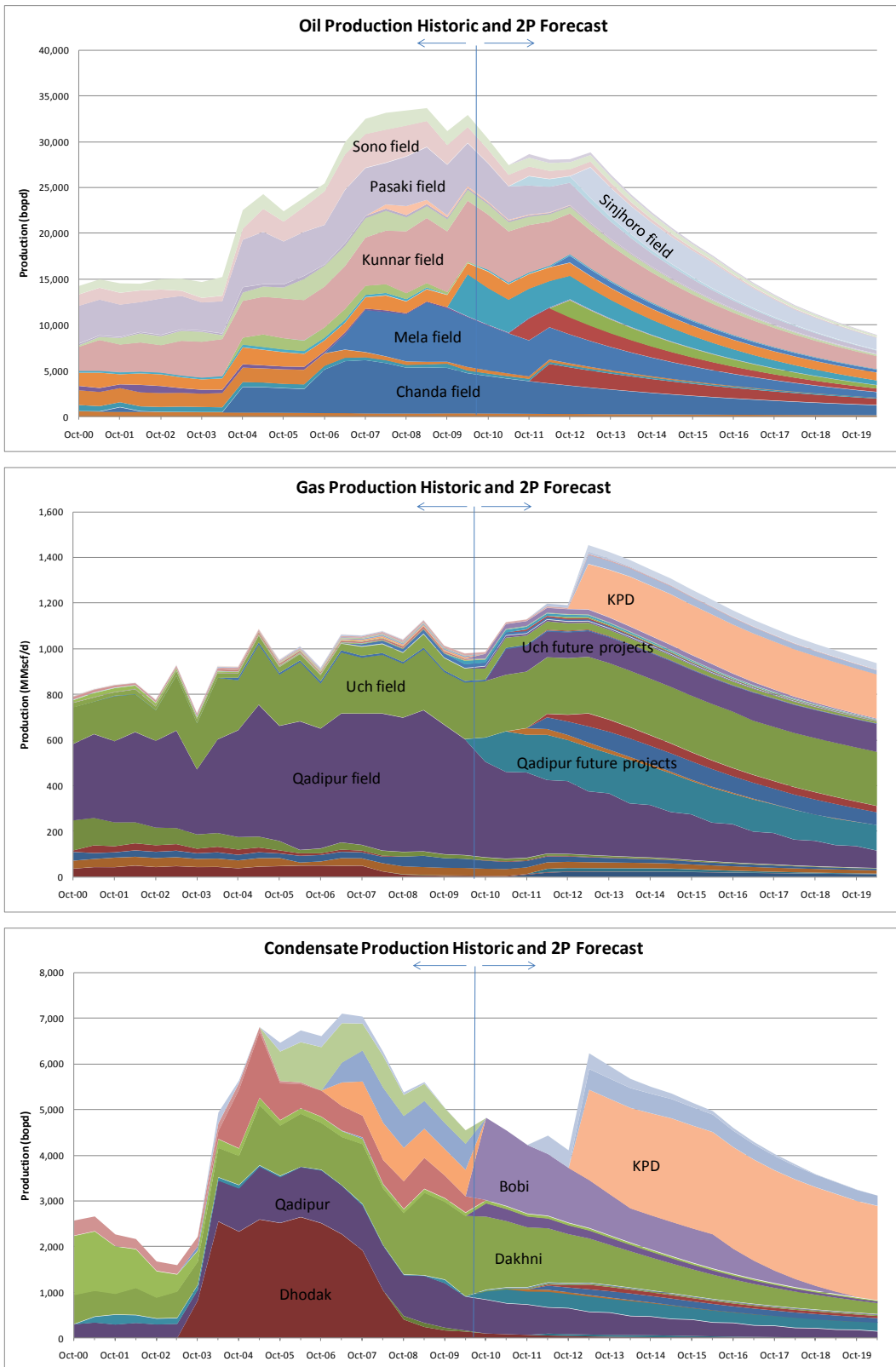


Figure 2-3 Operated Historic and 2P Forecast Field Total Production

The distribution of Reserves for the Operated fields is presented in Figure 2-4. The northern fields of Chanda, Mela and Rajian and Southern fields of Pasakhi and Kunnar dominate the oil Reserves, whilst the Central fields of Qadirpur and Uch, together with the KPD development, dominate the gas Reserves.

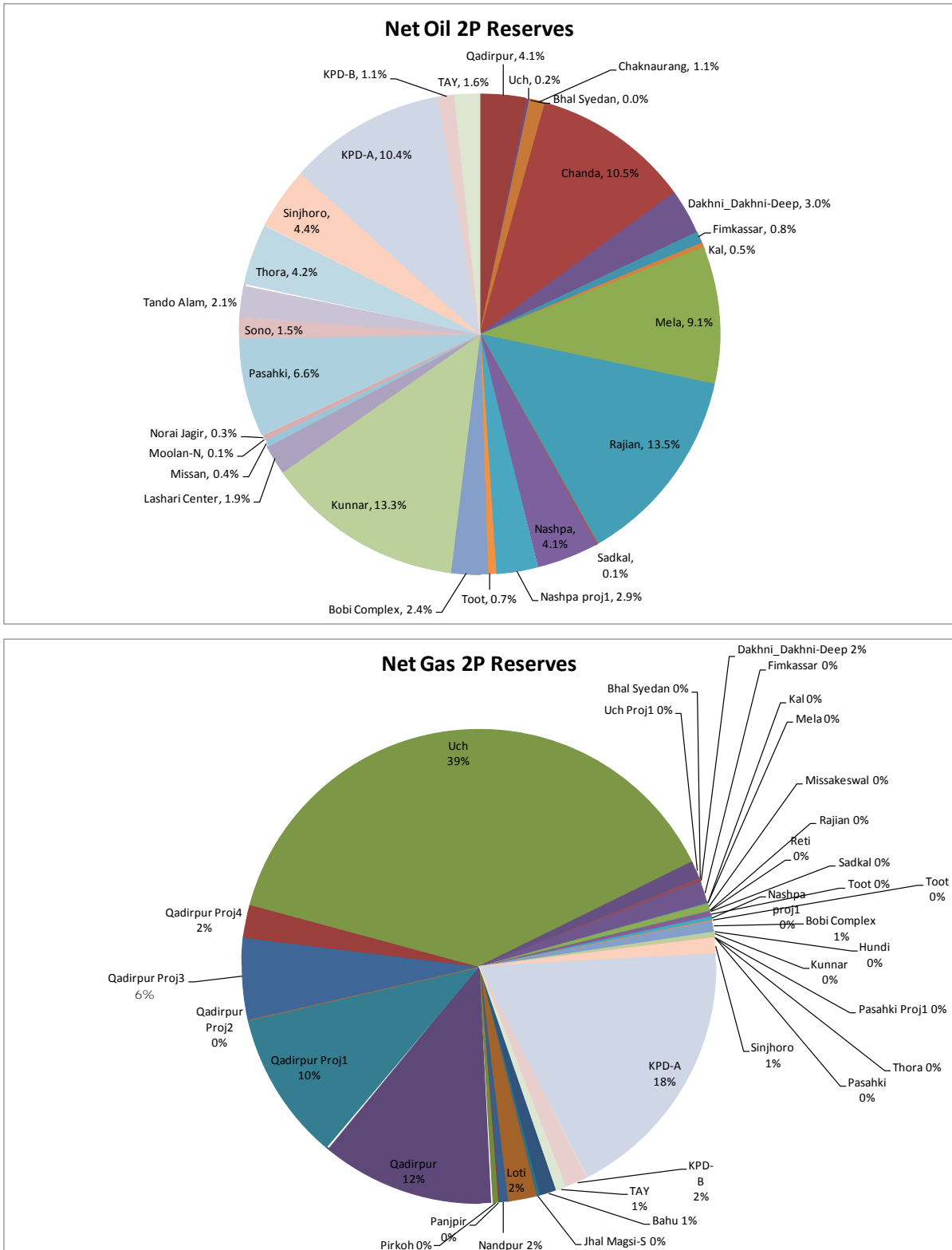


Figure 2-4 Oil and Gas 2P Net OGDCL Reserves Distribution

The Reserves evaluated during this audit are compared to the end 2009 OGDCL estimates (Table 2-2, Table 2-3, Table 2-4). The comparison highlights differences in several fields, with comments on the perceived reason for the change. The most substantial adjustment is with respect to Uch; this is caused by additional pressure data suggesting that the gas in place most likely is lower than currently believed.

Field	Oil and Condensate Reserves (MMstb)		Gas Reserves (Bscf)		Comments
	TRACS 2P (1.7.2010)	OGDCL 2P (1.1.2010)	TRACS 2P (1.7.2010)	OGDCL 2P (1.1.2010)	
Bhal Syedan	0.03	0.06	0.46	0.03	
Chak Naurang	1.44	1.76	0.00	0.50	No sales gas production history
Chanda	16.57	6.73	27.73	29.50	More liquids expected
Dakhni_Dakhni-Deep	3.36	5.46	88.41	167.75	Further wells beyond -13 may be possible.
Fimkassar	0.87	1.85	0.82	3.61	Forecast and adjustments considered robust
Kal	0.61	1.19	0.16	0.44	Forecast and adjustments considered robust
Mela	15.93	8.34	49.38	29.28	Includes new projects
Nashpa	12.04		52.64		No OGDCL reserves
Missa-Keswal	0.05	0.72	0.15	8.40	Forecast and adjustments considered robust
Rajian	15.29	0.97	2.75	0.09	Includes Rajian-05 (on production) and Rajian-06 in 2012
Sadkal	0.15	0.81	4.26	1.91	
Toot	0.83	3.07	3.33	3.69	Production dropped in 2009
Total	67.17	30.96	230.09	245.2	More liquids, less gas

Table 2-2 Reserves Comparison, Northern Operated Fields

Field	Oil and Condensate Reserves (MMstb)		Gas Reserves (Bscf)		Comments
	TRACS 2P (1.7.2010)	OGDCL 2P (1.1.2010)	TRACS 2P (1.7.2010)	OGDCL 2P (1.1.2010)	
Bahu	0.00	0.00	75.18	98.86	Reasonable agreement
Dhodak	0.00	11.84	0.00	197.13	Dhodak 1H 2010 < 10% of 2009; remaining production uneconomic
Jandran	0.00	0.00	0.00	14.23	Force Majeure
Jhal Magsi-S	0.08	0.03	27.01	67.12	Forecast robust
Loti	0.00	0.00	122.29	28.76	35 MMscf/d; RF consistent with GIIP
Nandpur	0.00	0.00	40.35	65.54	Reasonable agreement
Panjpir	0.00	0.00	4.05	41.60	Field production dependent on workovers.
Pirkoh	0.00	0.00	19.50	610.77	Contingent Resources of 353 Bscf for unconnected blocks. OGDCL Proven is 35.36 Bscf
Qadirpur	4.75	6.62	2544.1	2755.53	Difference due to new project schedule
Uch	0.25	0.00	2515.51	4043.22	Main change due to lower evaluated GIIP
Total	5.08	18.49	5347.99	7922.76	Reduction from Dhodak, Pirkoh and Uch.

Table 2-3 Reserves Comparison, Central Operated Fields

Field	Oil and Condensate Reserves (MMstb)		Gas Reserves (Bscf)		Comments
	TRACS 2P (1.7.2010)	OGDCL 2P (1.1.2010)	TRACS 2P (1.7.2010)	OGDCL 2P (1.1.2010)	
Bagla	0.00	0.00	0.00	0.00	Contingent Resource
Bhulan Shah	0.00	0.17	0.00	4.31	Shut in
Bobi Complex	2.69	5.54	38.40	56.95	faster CGR decline
Buzdar North	0.00	0.01	0.00	0.14	Shut in
Daru	0.00	0.22	0.00	7.72	Shut in
Hundi	0.00	0.00	0.53	1.06	
Jakhro	0.00	0.41	0.00	7.31	Contingent Resource
Kunnar	15.07	7.21	19.20	49.38	Lower GOR
Lashari Center	2.15	0.53	0.00	2.67	No gas sales
Missan	0.46	0.51	0.00	0.02	No gas sales
Moolan North	0.10	1.22	0.00	0.00	Shut in
Nim EL (incl. Norai Jagir)	0.41	0.77	10.93	8.43	
Nur	0.00	0.06	0.00	13.41	Contingent Resource
Pali	0.00	0.14	0.00	0.17	Shut in
Pasahki	7.50	3.53	0.50	2.45	More liquids
Sari	0.00	0.00	0.00	0.93	
Sono	1.65	3.00	0.00	2.31	No gas since 2004
Tando Alam	2.38	6.05	0.00	4.28	No gas since 2008
Thora	4.72	12.99	0.00	4.07	Production in decline
Sinjhero	8.37		107.45		Not previously booked
KPD (100% assets)	11.80		1159.52		Not previously booked
KPD (77.5% assets)	1.67		132.94		Not previously booked
Tando Allah Yar	2.36		53.12		Not previously booked
Total	37.13	42.36	69.56	165.61	Excluding Sinjhero and KPD/TAY

Table 2-4 Reserves Comparison, Southern Operated Fields

The total gross remaining reserves for the Operated fields are presented in Table 2-5. The TRACS estimates include the most recent projects prepared by OGDCL as well as the Sinjhero, TAY, and KPD fields. The oil plus condensate reserves are very similar to the OGDCL estimates, when the additional volumes from Sinjhero, TAY, and KPD fields are excluded, but there is a substantial reduction in the gas volumes. A significant proportion of this difference originates from the Uch field where a lower GIIP is evaluated than used in the 2006 reserves assessment. A smaller downward revision is evident for most of the gas fields and a recent update in the Qadirpur project schedule has also led to a decrease in the reserves.

	TRACS 1.7.2010			OGDCL 2P 1.1.2010
	1P	2P	3P	
Gas (Bscf)	4242	7101	10186	8334
Oil plus Condensate (MMstb)	75.41	133.58	221.15	91.81

Table 2-5 Gross Reserves (incl. Sinjhero and KPD/TAY)

The comparison of historic and forecast production (Figure 2-3) demonstrates that the TRACS forecast is consistent with the field recent performances.

The OGDCL five-year business plan production forecast as presented to EXCOM in July 2010 is compared against the TRACS forecasts below (Figure 2-5). The comparison highlights some differences:

The TRACS 2P oil forecast is slightly lower on a number of fields due to lower oil production rates being realised in 1H 2010 than forecast and the Pasakhi-07 well now not forecast to commence production until 2H 2011 (rather than 2H 2010 as originally planned). The rate of decline in the condensate production in the TRACS profile reflects expected decreases in the producing condensate gas ratio (CGR) in several fields as the reservoir pressure decline; the combination of the declining gas rate and the declining CGR gives a steeper decline than forecast by OGDCL.

The gas forecasts are very similar, with the TRACS forecast being marginally higher than OGDCL's forecast over the five year period. The other differences in the five year period are relatively minor.

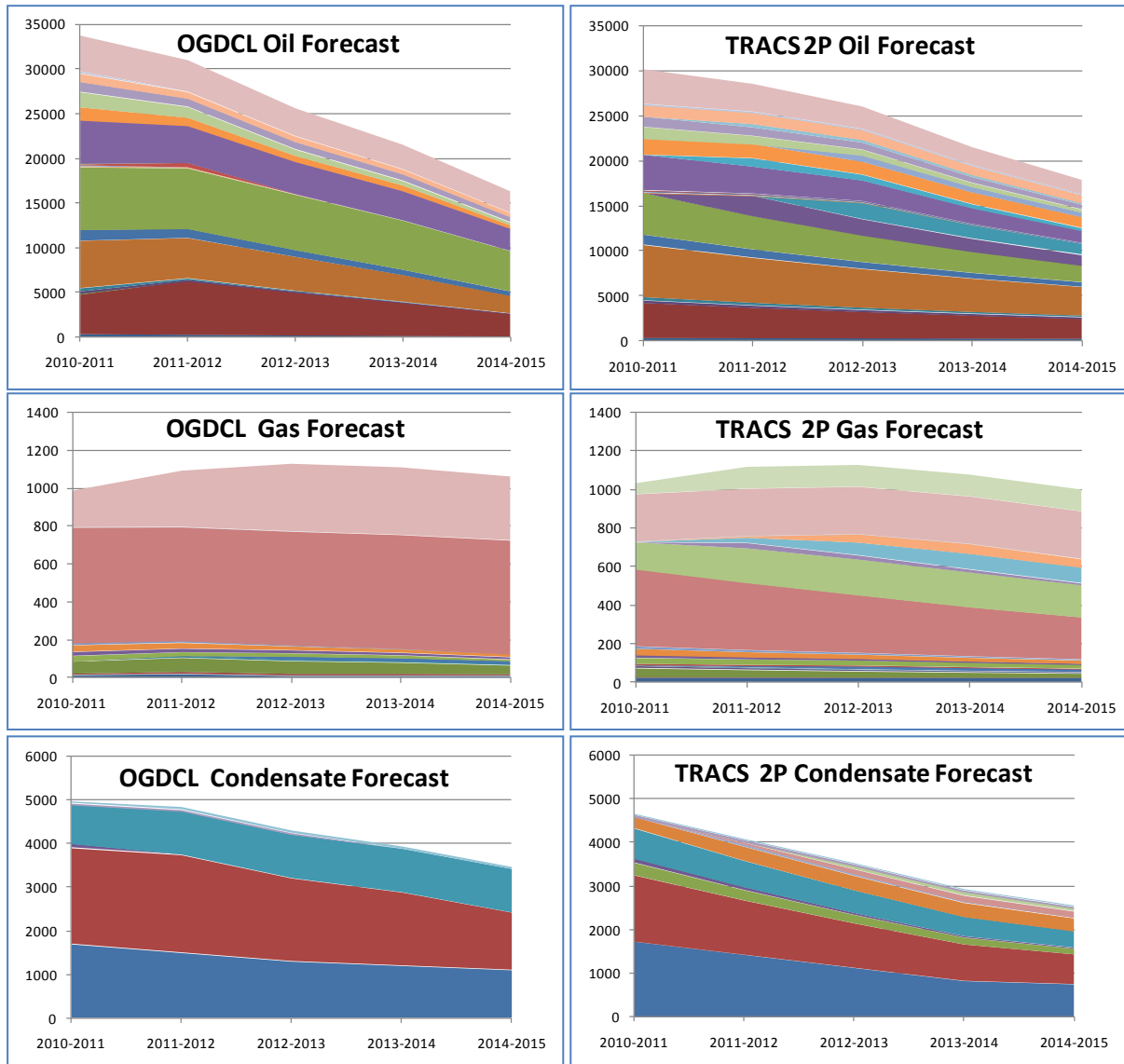


Figure 2-5 OGDCL Business Plan forecast compared with the TRACS 2P forecast (liquid volumes in bpd, gas volumes in MMscf/d)

The field total reserves for the Non-Operated fields are presented in Table 2-6.

	TRACS 1.7.2010			OGDCL 2P 1.1.2010	Comments
	1P	2P	3P		
Gas (Bscf)	1459.5	2516.2	3993.2	2492.6	Makori early watercut honoured; Miano lower
Oil (MMstb)	4.25	8.06	15.29	33.1	TRACS estimates are higher for Manzalai (the OGDCL reserves are inconsistent with the OGDCL forecast)
Condensate (MMstb)	20.83	35.28	54.35		
NGL (MMstb)	15.80	19.77	22.14		
LPG (M tons)	0.90	1.16	1.35		

Table 2-6 Gross Reserves, Non-Operated Fields

2.3. Contingent Resources

Contingent Resources are remaining recoverable volumes associated with projects that do not meet the certainty requirements for classification as reserves (reasonably certain). Such projects may be technically immature or there may be an as yet un-clarified market for the product streams. Also, volumes associated with fields currently under force majeure have been classified as Contingent Resources. The commercial risk associated with each of the projects has not been independently quantified.

Projects contributing to contingent resources are listed in Table 2-7, with associated contingent resource volumes net to OGDCL:

Field	Gas Resources (Bscf)			Oil/Condensate Resources (MMstb)			Comments
	1C	2C	3C	1C	2C	3C	
Chanda	25.9	39.3	56.5	0.73	1.28	2.23	Lumishwal 20% RF on STOIP requires further development
Dakhni	11.3	17.4	35.3	0.42	0.66	1.34	Dakhni-13
Toot	0.7	1.4	2.2	0.18	0.36	0.54	Recompletions
Nashpa	6.5	12.6	20.7	1.54	2.81	4.26	Two appraisal wells planned with good potential
North - Total	44.4	70.8	114.7	2.88	5.11	8.37	
Dhodak Deep	30.0	60.0	90.0				Two Dhodak deep wells remain poorly defined
Jandran	10.0	25.5	30.0				Currently under Force Majeure
Nandpur	1.0	5.0	10.0				Recompletions and velocity strings
Panjpir	11	21	34				Recompletion in Chichiali Formation
Pirkoh	0.0	108.0	343.0				Planned wells contingent on security issues
Qadirpur Deep	0.2	12.0	60.0				Very little information on potential volumes available.
Reti/Maru	21.1	36.3	66.0				Dependent on gas export and development status.
Sara West	164.0	317.0	624.0				Dependent on a potential use for low heating value gas
Uch	240.0	250.0	260.0	0.02	0.03	0.03	Planned wells contingent on security issues
Central - Total	477.3	834.8	1517	0.02	0.03	0.03	
Moolan	2.5	7.1	13.2	0.06	0.16	0.29	Awaiting installation of facilities and approval from DGPC
Nim E. L. incl. Norai Jagir	1.0	2.0	3.0	0.02	0.04	0.06	Compression installation
Bagla	5.7	8.5	11.3	0.09	0.13	0.17	Awaiting export route
Nur	6.6	9.6	14.4				Awaiting export route
Jakhro	4.0	8.5	14.5	0.16	0.34	0.58	Sale of resources cancelled in September 2010, status unclear.
South - Total	19.8	35.7	56.4	0.33	0.67	1.10	
Total	541.5	941.3	1688.1	3.23	5.81	9.50	

Table 2-7 Operated Projects included in Contingent Resources (Net OGDCL resources)

Attachment - Summary of SPE PRMS Definitions

SPE Petroleum Resources Management System Guide for Non-Technical Users

This guide is to help non-technical users understand how the petroleum industry assesses and quantifies the major driver of value for exploration and production companies – oil and natural gas reserves and resources. Clear terms and definitions that result in reliable and easily comparable reserves estimations are essential for investors, regulators, governments and consumers not only in assessing a petroleum company's current and future value, but in determining the outlook for the world's energy supply.

Completed in 2007, the PRMS provides updated definitions and the related classification system for petroleum reserves and resources that reflect advances in technology, the international expansion and the increasing role of unconventional resources in the industry. These updated definitions establish a universal language which can be used for estimating and classifying quantities of oil and gas discovered in a reservoir.

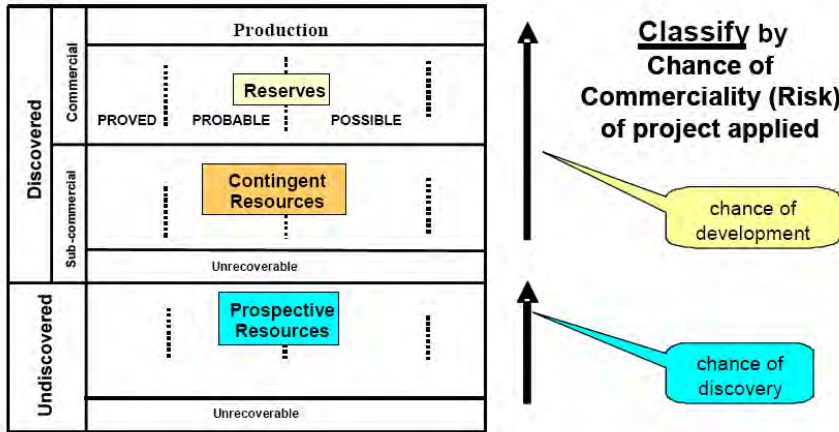
SPE's Role in Developing the PRMS

For decades, the SPE has been a leader in developing the technical definitions that have become the industry standard for evaluating petroleum reserves and resources. The SPE historically draws together the scientific and engineering expertise of the global oil industry in this effort. The PRMS is the result of more than two years of collaboration by the SPE, the World Petroleum Council (WPC), the American Association of Petroleum Geologists (AAPG) and the Society of Petroleum Evaluation Engineers (SPEE), with considerable input from the industry at large. The new system builds on the previous set of definitions and incorporates best practices identified in other international petroleum and mineral classification systems. These technical definitions are offered for any company, agency, country or other stakeholder to use.

Fundamentals of the PRMS

Oil and gas reserves and resources are defined as volumes that will be commercially recovered in the future. Unlike the inventory of a manufacturing company, reserves are physically located in reservoirs deep underground and cannot be visually inspected or counted, but rather are estimates based on the evaluation of data that provides evidence of the amount of oil and gas present. There is no definitive answer until the end of a reservoir's producing life. All reserve estimates involve some degree of uncertainty. The estimation of reserves volumes is generally performed by highly-skilled individuals who use their experience and professional judgment in the calculation of those volumes.

To take into account this uncertainty, the PRMS incorporates a central framework that categorizes reserves and resources according to the level of certainty associated with their recoverable volumes (horizontal axis in the figure below), and classifies them according to the potential for reaching commercial producing status (vertical axis).



Categorize based primarily on technical uncertainty of sales quantities associated with a project

When applying PRMS, technical specialists must determine a specific *project* that will be used to recover the reserves and resources and determine the chance that it will be commercially successful, then must estimate the *volume* expected to be recovered from the “project.” It is important to remember when applying the PRMS that, as shown above, reserves are a subset of resources.

Differences in Classes (Vertical Axis)

The four major recoverable resources classes defined by the PRMS are production, reserves, contingent resources, and prospective resources. There is also a distinct class for unrecoverable petroleum. These classes are shown on the vertical axis of the PRMS framework.

Production is the quantity of oil and natural gas that has been recovered already (by a specified date). This is primarily output from operations that has already been produced for use by consumers.

Reserves represent that part of resources which are commercially recoverable and have been justified for development, while contingent and prospective resources are less certain because some significant commercial or technical hurdle must be overcome prior to there being confidence in the eventual production of the volumes.

Contingent resources are less certain than reserves. These are resources that are potentially recoverable but not yet considered mature enough for commercial development due to technological or business hurdles. For contingent resources to move into the reserves category, the key conditions, or contingencies, that prevented commercial development must be clarified and removed. As an example, all required internal and external approvals should be in place or determined to be forthcoming, including environmental and governmental approvals. There also must be evidence of firm intention by a company’s management to proceed with development within a reasonable time frame (typically 5 years, though it could be longer).

Prospective resources are estimated volumes associated with undiscovered accumulations. These represent quantities of petroleum which are estimated, as of a given date, to be potentially recoverable from oil and gas deposits identified on the basis of indirect evidence but which have not yet been drilled. This class represents a higher risk than contingent resources since the risk of discovery is also added. For prospective resources to become classified as contingent resources, hydrocarbons must be discovered, the accumulations must be further evaluated and an estimate of quantities that would be recoverable under appropriate development projects prepared.

Some petroleum will be classified as “unrecoverable” at this point in time, not being producible by any projects that the company may plan or foresee. While a portion of these quantities may become

recoverable in the future as commercial circumstances change or technological developments occur, some of the remaining portion may never be recovered due to physical or chemical constraints in the reservoir. The volumes classified using the system represent the analysis of the day, and should be regularly reviewed and updated, as necessary, to reflect changing conditions.

A project may have recoverable quantities in several resource classes simultaneously. As barriers to development are removed, some resources may move to a higher classification. One of the primary distinctions between resources and reserves is that while resources are technically recoverable, they may not be commercially viable. Reserves are always commercially viable and there is intent development them.

Differences in Categories (Horizontal Axis)

Within any resource class other than production, volumes are placed into different categories based on their certainty of eventually coming out of the ground. Decisions to upgrade volumes to any category within a class are generally based on the technical certainty of recovering the volumes. In this discussion, the focus is on the reserve class, as these volumes are commonly the focus of public discussions of oil and gas company producing assets.

The highest valued category of reserves is “proved” reserves. Proved reserves have a “reasonable certainty” of being recovered, which means a high degree of confidence that the volumes will be recovered. To be clear, reserves must have all commercial aspects addressed. It is technical issues which separate proved from unproved categories.

“Probable” or “possible” reserves are lower categories of reserves, commonly combined and referred to as “unproved reserves,” with decreasing levels of technical certainty. Probable reserves are volumes that are defined as “less likely to be recovered than proved, but more certain to be recovered than Possible Reserves”. Possible reserves are reserves which analysis of geological and engineering data suggests are less likely to be recoverable than probable reserves.

The term 1P is frequently used to denote proved reserves, 2P is the sum of proved and probable reserves and 3P the sum of proved, probable and possible reserves. The best estimate of recovery from committed projects is generally considered to be the 2P sum of proved and probable reserves. Note that these volumes only refer to projects that are currently justified for or already in development. Total value of any resource base must include an assessment of the contingent and prospective resources as well as reserves.

In order for volumes to move from one category to the next, the technical issues which cause them to be placed in less certain categories must be resolved. In the majority of cases, this requires that additional data must be obtained before any greater certainty can be recognized. This may include, among other things, the drilling of additional wells, the monitoring of current production to better understand performance or the implementation of a pilot to have greater confidence in the volumes that full scale development projects may eventually produce.

Conclusion

The PRMS is designed to provide a framework for the classification of oil and gas volumes which a company may have associated with its portfolio of assets. It is not specific to any particular geographic location and can be applied to both conventional and unconventional reserves and resources anywhere in the world, in any fiscal regime.

When summarizing these volumes, some key points must be kept in mind:

- 1) All oil and gas reserve and resource volumes are not the same, and should generally not be added together without taking into consideration the risk and uncertainty associated with each volume. Some volumes are clearly less certain and more risky than others. Whether the focus is only on reserves, or on the resource base as a whole (remember, reserves are a subset of resources!), expressing these volumes as one number may be misleading.

2) Risk and uncertainty are key but significantly different concepts. Risk is primarily associated with the classification of volumes and is a measure of the certainty of a *project* progressing to production. Uncertainty is the driver for categorization and is a measure of the technical factors impacting the *volumes* ultimate producibility.

3) The PRMS was developed as a collaborative system, designed to support a wide group of stakeholders. Throughout the early drafting stages, advice and input was sought not only from the petroleum industry, but from the financial, accounting, governmental sectors, in addition to the mining industry.

The PRMS is available on the SPE website at

<http://www.spe.org/spe-app/spe/industry/reserves/index.htm>.

It is highly recommended that users visit the website to gain a deeper understanding of the terms and definitions, learn more about the system and its application, and other aspects of reserves and resources estimation.