Attachment 7

COUNTRY	Size**	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	Comments
MALAYSIA	L		X				X				A				15-19 Apr 2002
BRUNEI	L		X				X				A				22-26 Apr 2002
BRAZIL (Pecten)	M/S										P1?				Not yet accepted
SYRIA	M/S	X			X						A				2-5 June 2002
PAKISTAN	M/S					$					A1				Sept 2002
IRAN	L							$			A1				Oct 2002
USA (AERA)	L					$					A1				11-15 Nov 2002
ANGOLA	M/S								$		A1?				Dependent on project progress
NIGERIA - SNEPCO	L					$		X			P?				To be considered
ABU DHABI	L			X				X				P			
NIGERIA -SPDC	L	X				X		X				P			
OMAN	L			X				X				P			
EGYPT	M/S		X					X				P			
VENEZUELA	L				$			X				P			
ARGENTINA	M/S			X				X				P			Combine with Venezuela
CAMEROON (Pecten)	M/S											P1			
AUSTRALIA	L				X				X				P		
NORWAY	L				X				X				P		
USA (SEPCo)	L								X				P		
PHILIPPINES	M/S					$		X					P		
THAILAND	M/S		X					X					P		
KAZAKHSTAN-OKIOC											$?		P1?		
RUSSIA - SALYM												$?	P1?		
GABON	M/S			X					X					P	
BANGLADESH	M/S					$			X					P	
RUSSIA - SAKHALIN	M/S					$			X					P	
NAMIBIA												$?		P1?	
NETH. NAM	L	X				X				X				P	
GERMANY	L	X				X				X				P	
UK	L			X		X				X				P	
DENMARK	L	X				X				X				P	
CHINA	M/S		$							X					
AUSTRIA	M/S			X						X					
NEW ZEALAND	L				X					X					
CANADA	L														No direct involvement
CHAD	M/S			X											Divested 2000
KAZAKHSTAN-TEMIR	M/S							$							Divested 2000
USA (ALTURA)	L					$									Divested 2000
ZAIRE	M/S		X												To be divested?

P = Proposed
A = Accepted
X = Completed
()1 = First audit
$ = First SEC resvs subm'n
* = First SEC subm'n via SIEP

** L : > 30 mln m3oe ss
M/S : < 30 mln m3oe ss

Audit frequency:

Large OUs once every 4 years,
Medium/Small OUs every 5 years,
First audit within 2 yrs after first submission.

Exceptions possible in case of:
- major reserves changes,
- critical audit reports etc,
- when combinable with other audits.

Attachment 7 - SEC Reserves Audit Plan 2002

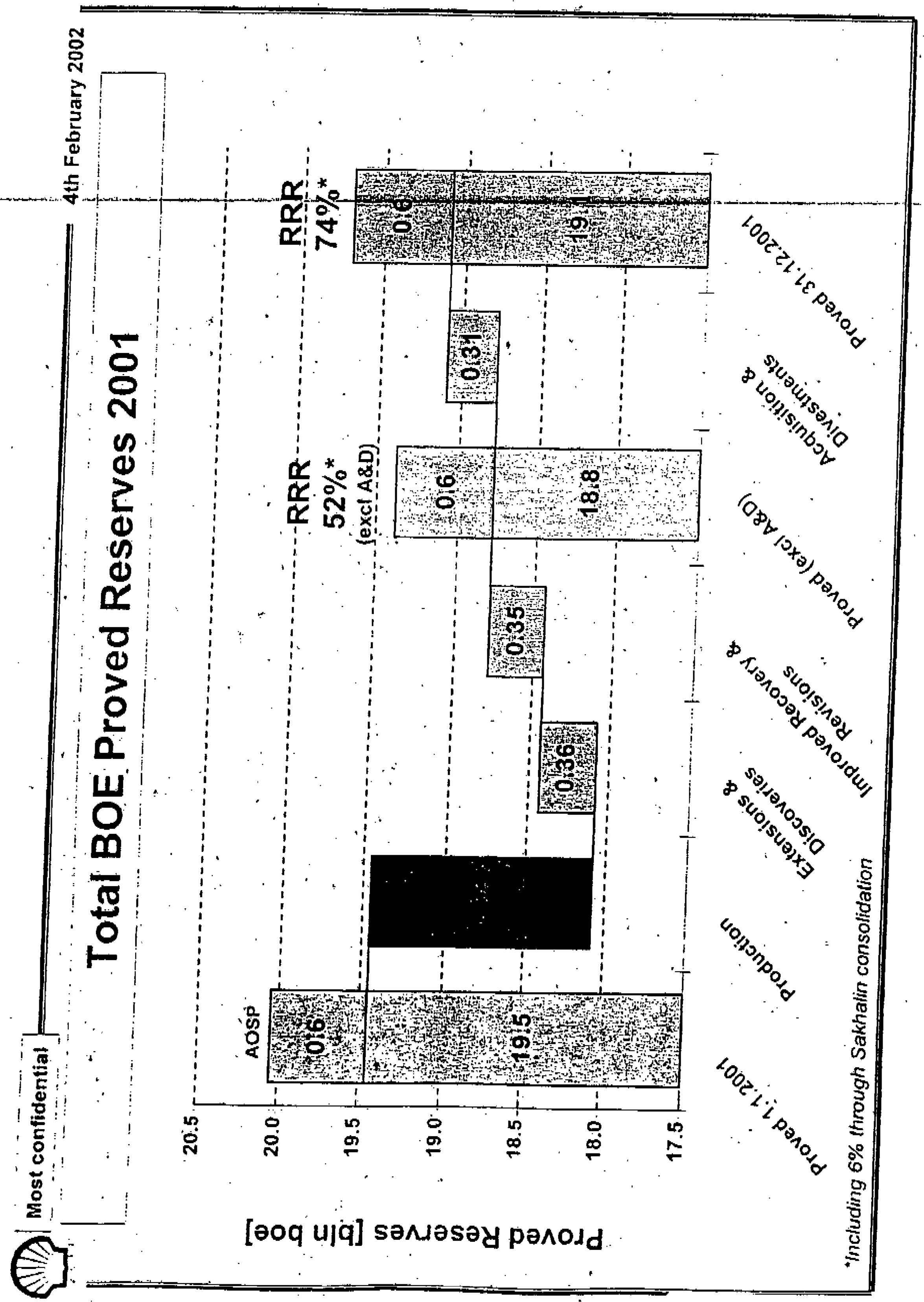
Most confidential

4th February 2002

Reserves presentation

- **Proved reserves 31.12.2001**
  - Overview
  - Main changes
  - Variances vs Target
- **Main issues**
  - New fields
  - End of License
  - SEC guidelines
- **Way forward**
  - Target 2002
  - Reserves roadmap

EXHIBIT
van der Vijver
10
2/1/07



Most confidential
4th February 2002
Total BOE Proved Reserves 2001
Proved Reserves [bln boe]
20.5
20.0
19.5
19.0
18.5
18.0
17.5
AOSP
0.6
19.5
0.36
0.35
RRR 52%* (excl A&D)
0.6
18.8
0.31
RRR 74%*
0.6
19.1
Proved 1.1.2001
Production
Extensions & Discoveries
Improved Recovery & Revisions
Proved (excl A&D)
Acquisition & Divestments
Proved 31.12.2001
*Including 6% through Sakhalin consolidation

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4th February 2002

MAIN CHANGES

			OIL/GAS
Extensions & Discoveries:		**+357 mln boe**	**191/166**
– USA	+205	Holstein, Kepler, etc	
– UK	+44	Penguins, Carrack, etc	
– Brunei	+37	Bugan, Seria	
Acquisitions & Divestments:		**+307 mln boe**	**59/248**
– NZ, Brunei	+296	Fletcher, with 44 still to be divested	
– USA	+64	Pinedale	
– Pakistan, Argentina, TMR	-59		
Revisions & Improved Recovery:		**+354 mln boe**	**279/75**
– Netherlands	+130	Groningen	
– Denmark	+113	Halfdan, Dan West	
– Sakhalin	+88	Consolidation (45% Ashtok)	
– Canada	-50	Sable	
– New Zealand	-51	Maui –91 + pre-paid gas + Kapuni	
– Oman Gisco	-107	Accelerated repayments	
Production:		**1377 mln boe**	**810/567**
Developed Reserves Additions		**1187 mln boe**	**671/447**
– Australia, Philippines, Argentina, SPDC, Iran, Denmark, UK, USA			

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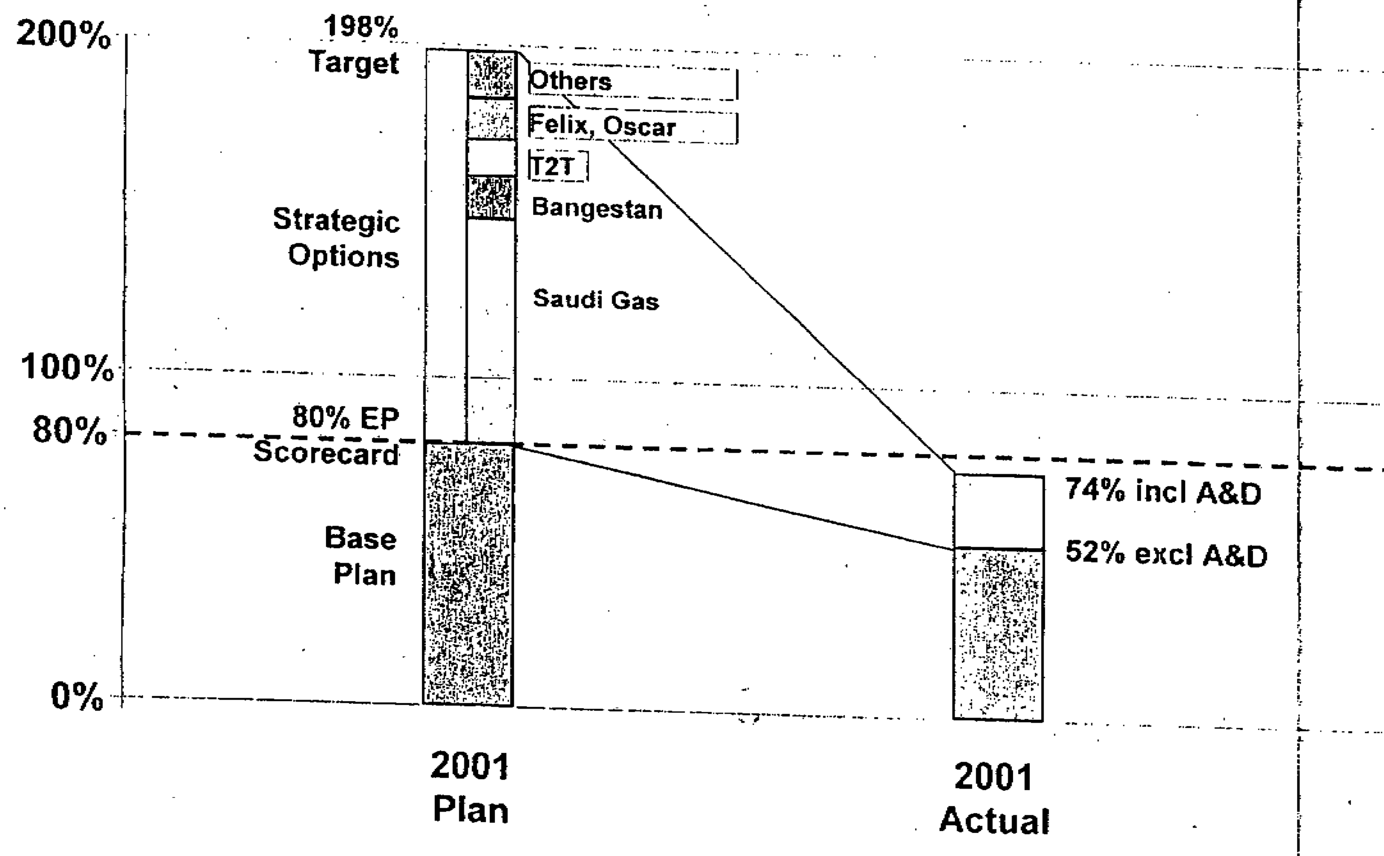
2001 RRR Target vs Actual



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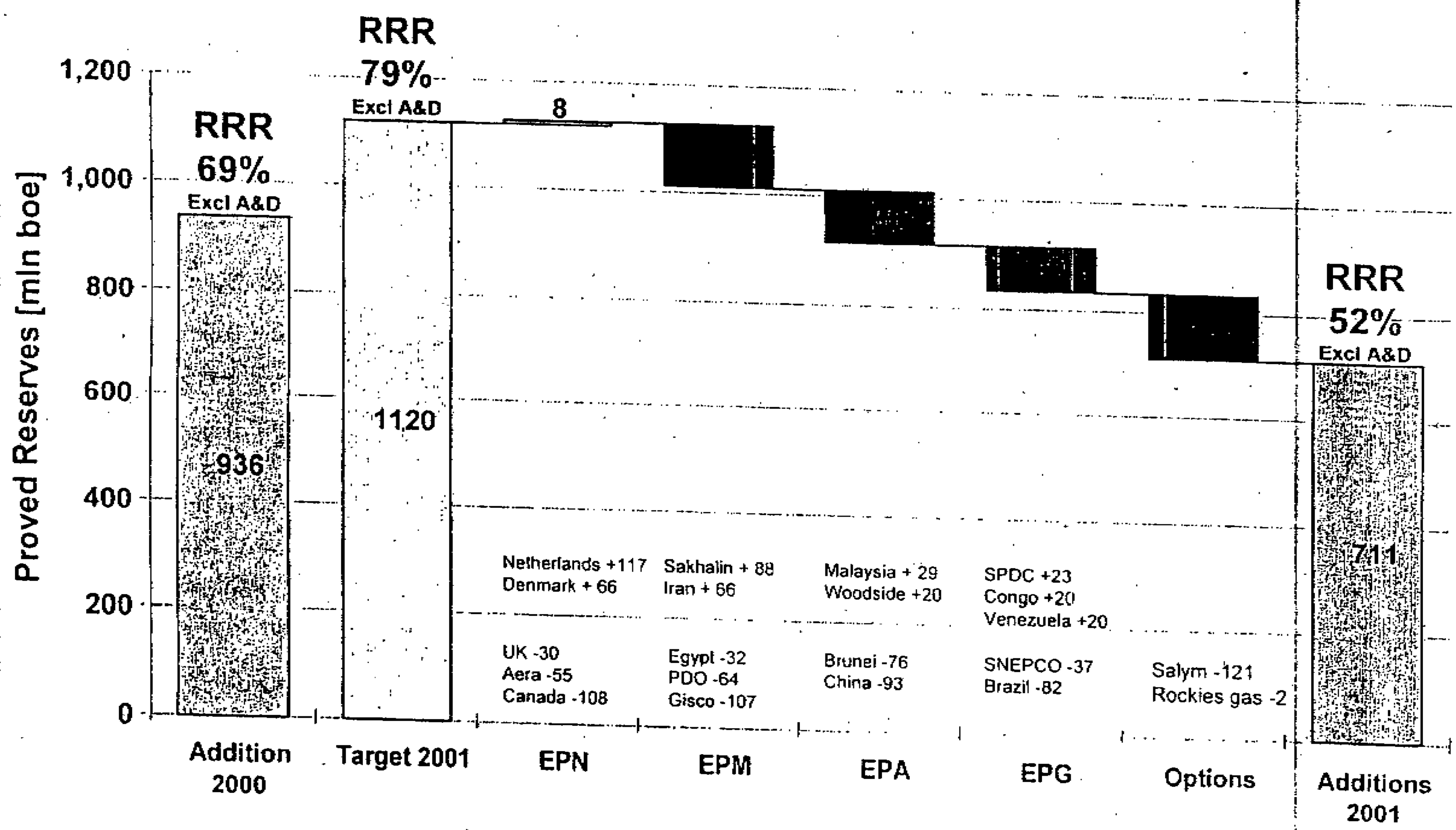
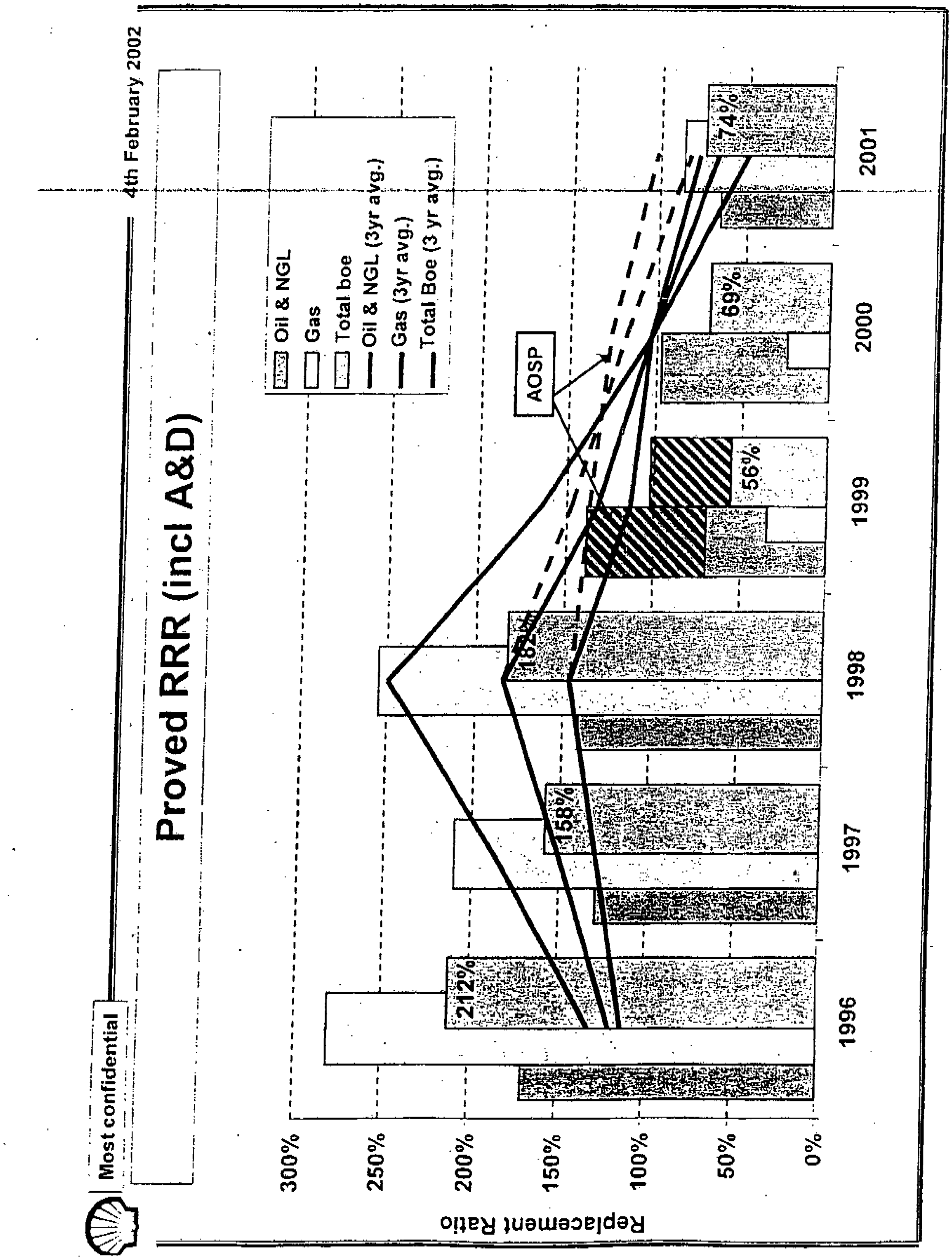
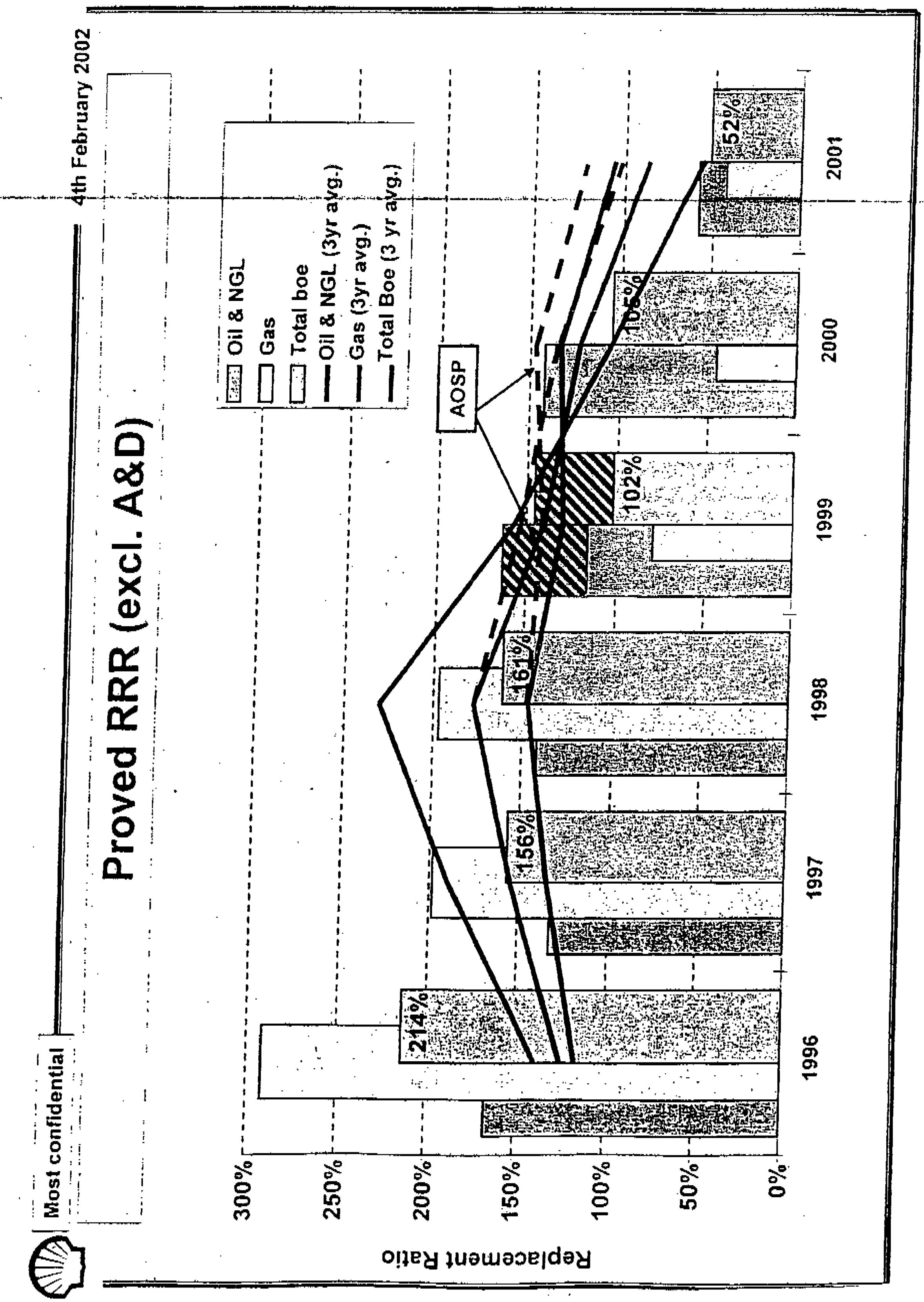
4th February 2002

2001 Reserves Actual versus Target




Most confidential
4th February 2002
Proved RRR (incl A&D)
Oil & NGL
Gas
Total boe
Oil & NGL (3yr avg.)
Gas (3yr avg.)
Total Boe (3 yr avg.)
AOSP
Replacement Ratio
300%
250%
200%
150%
100%
50%
0%
212%
158%
56%
69%
74%
1996
1997
1998
1999
2000
2001



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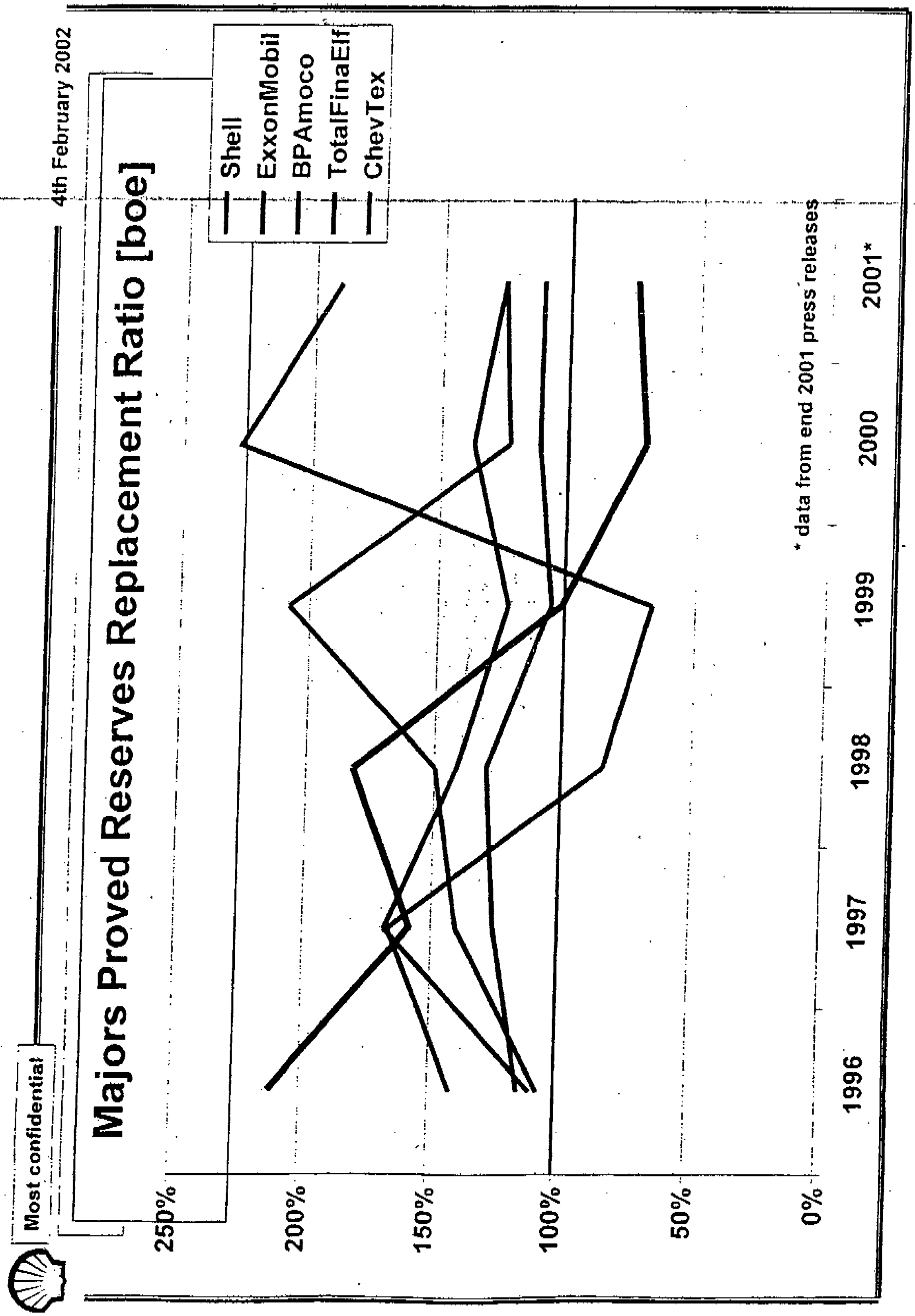
4th February 2002
Majors Proved Reserves Replacement Ratio [boe]
Shell
ExxonMobil
BPAmoco
TotalFinaElf
ChevTex
250%
200%
150%
100%
50%
0%
1996
1997
1998
1999
2000
2001*
* data from end 2001 press releases
Most confidential

V00010195

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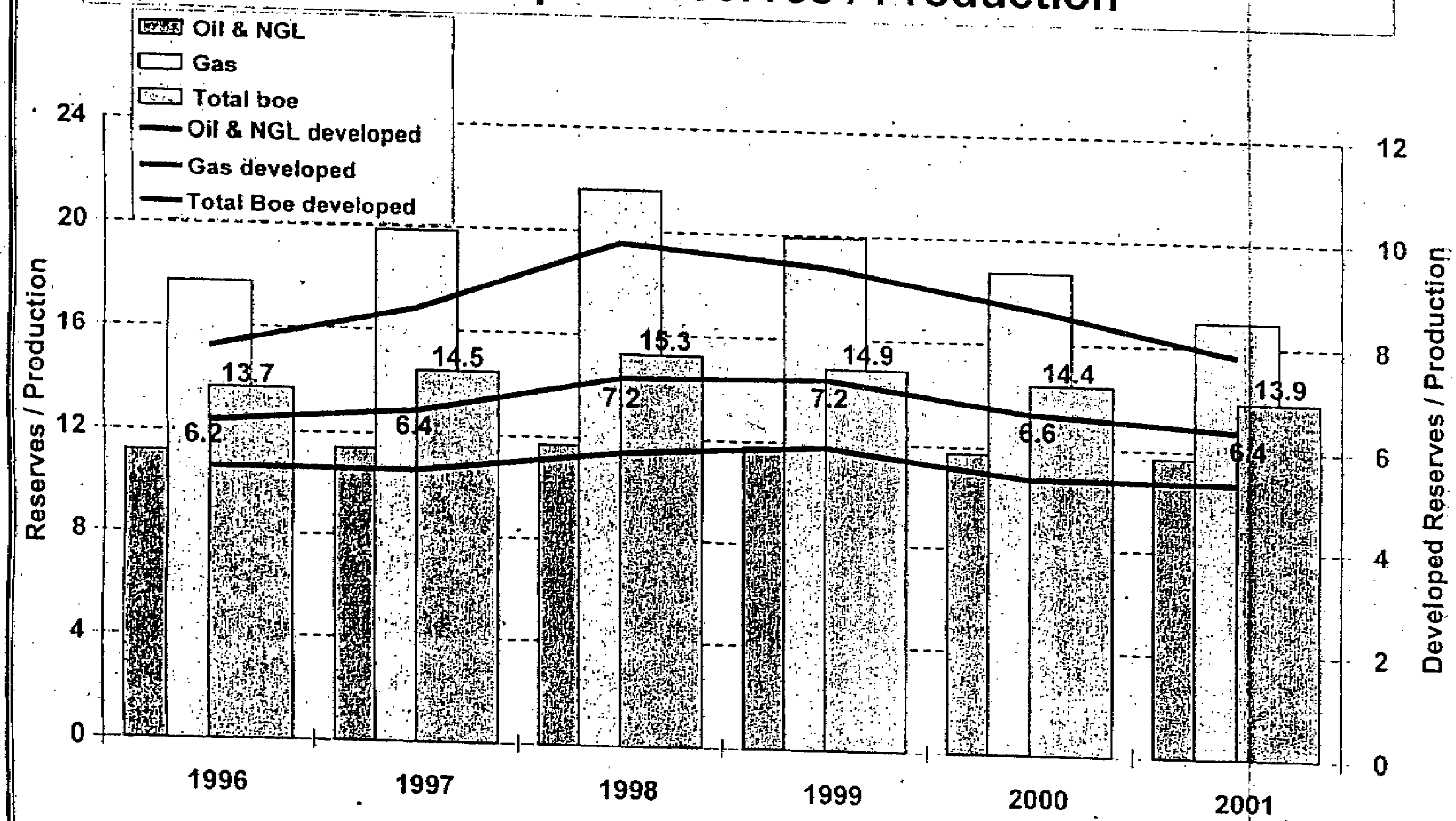
Developed Reserves / Production



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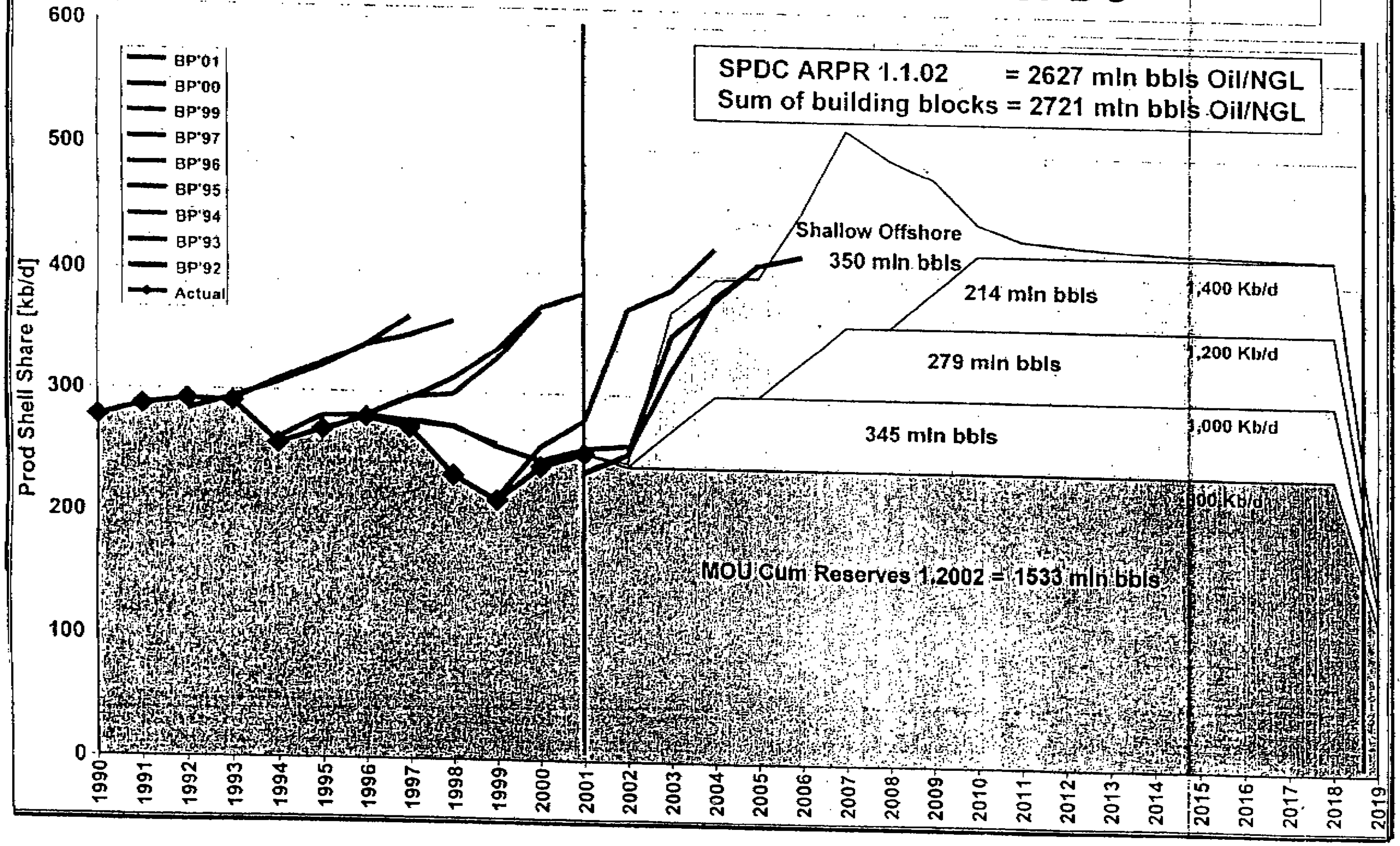
Proved Oil/NGL Reserves Forecast SPDC



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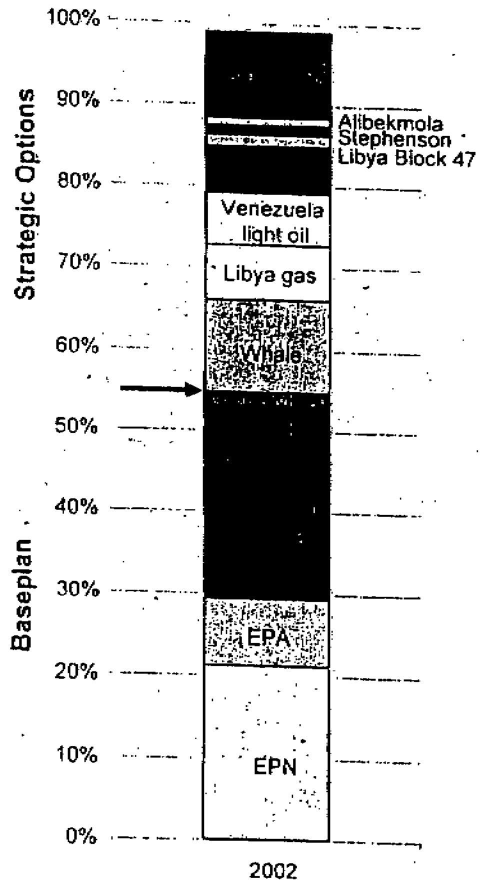
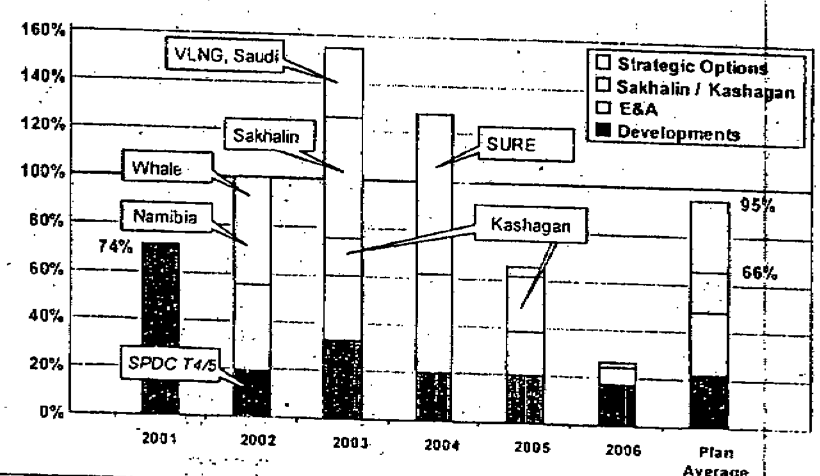
2002 RRR Target of 100%: a Challenge



- **LE Baseplan Variances**
  - Oman no booking: -70 mln bbls
  - Brazil, Angola freeze: -70 mln bbls
  - SNEPCO: +50 mln bbls
  - Canada, T4/5 not in target: + 100 mln bbls
- **Almost 50% from Strategic Options New Business and Frontier**
  - KUDU: not proven technique
  - Whale, Libya: MRH access
  - WE Pipeline?



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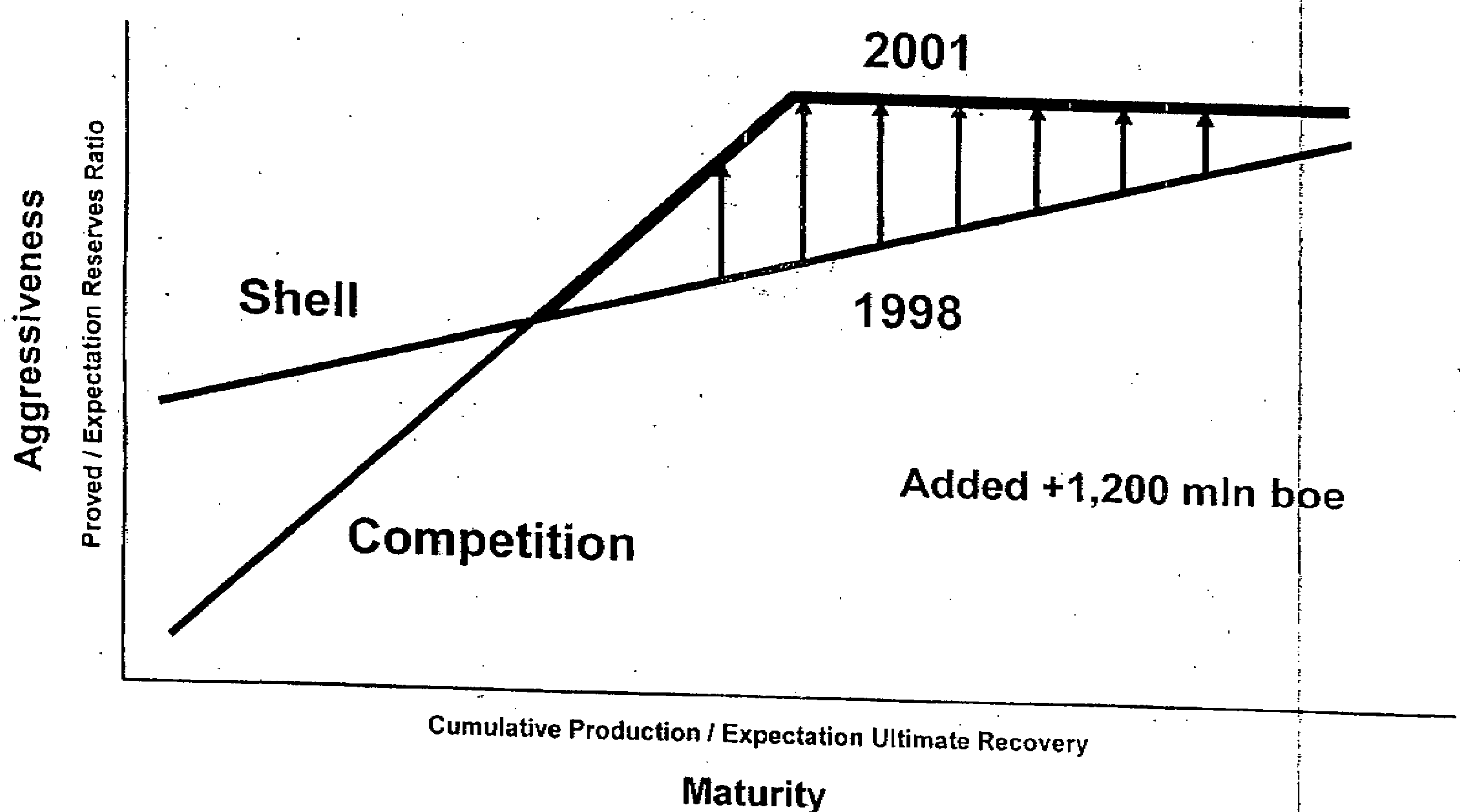
Mature Fields : OUs Follow Guidelines Universally



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New Fields : Guidelines currently too lenient

- **SEC clarifications**
  - insisting on full project maturity
  - company commitment
  - absence of possible show stoppers

- **New Fields** **-800 mln boe**
  - Gorgon
  - Ormen Lange
  - Block 18
  - Vincent/Enfield
  - Waddenzee

- **End of License** **-1,300 mln boe**
  - Oman
  - Abu Dhabi
  - SPDC

Most confidential

4th February 2002

2002+ RRR Management

- **Shell guidelines need sharpening / clarifying**
  - New Fields
  - End of License
  - Commercial versus Economic
- **Raise awareness of SEC clarifications**
  - OUs / RBA Focal points / EPT / SDS
  - Establish links between EPB-P, HMF and V2V
  - Reserves summit Q2 '02 – EPB-P & Auditor to host
- **Tie Projects to Maturation at Capital Allocation**
  - Incomplete OU returns in 2001
  - For 2002: full picture of resource maturation linked to projects
- **Roadmap for Big Ticket Bookings**
  - Kudu, Train 4/5, Whale, West-East-pipeline, Kashagan, Sakhalin LNG

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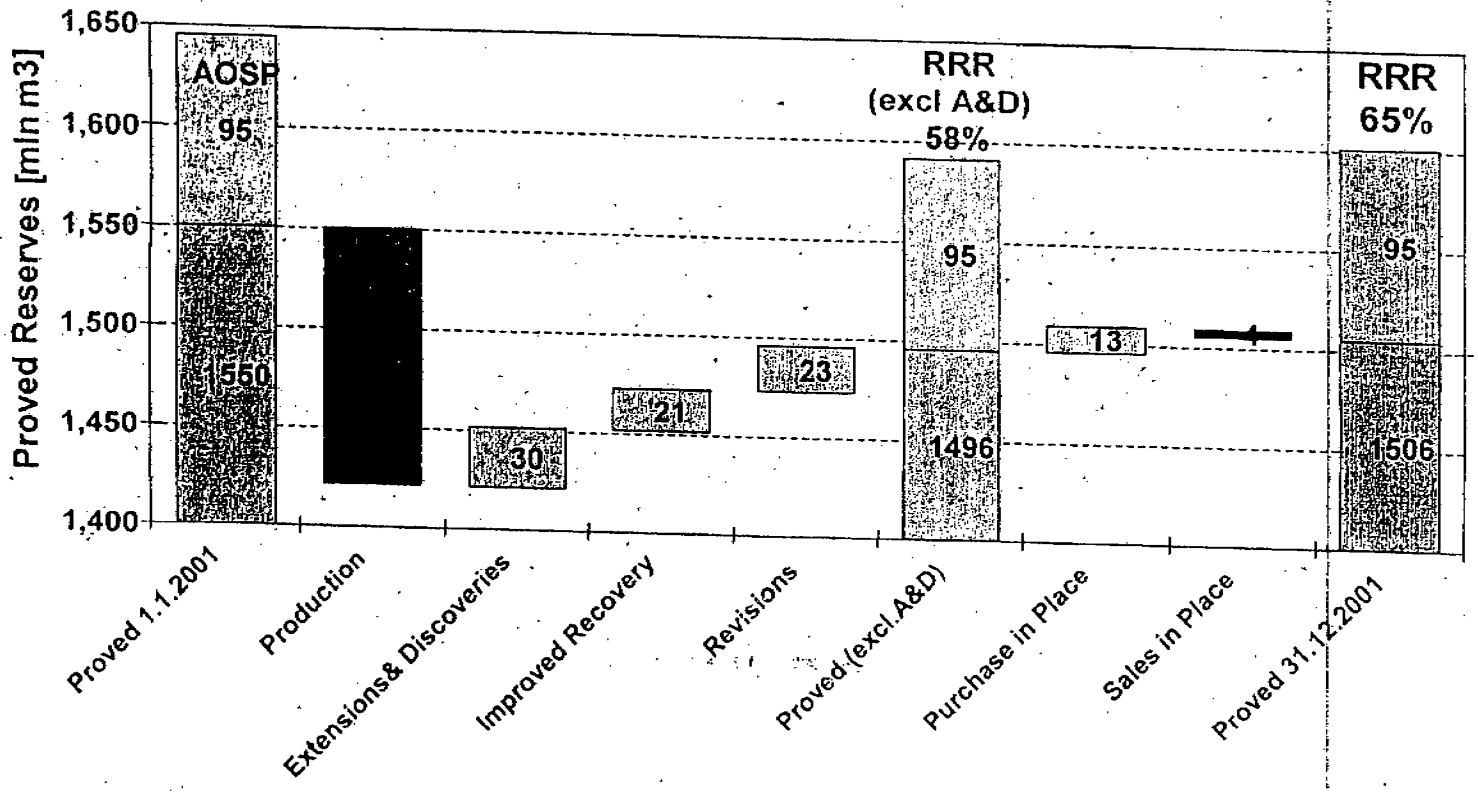
4th February 2002

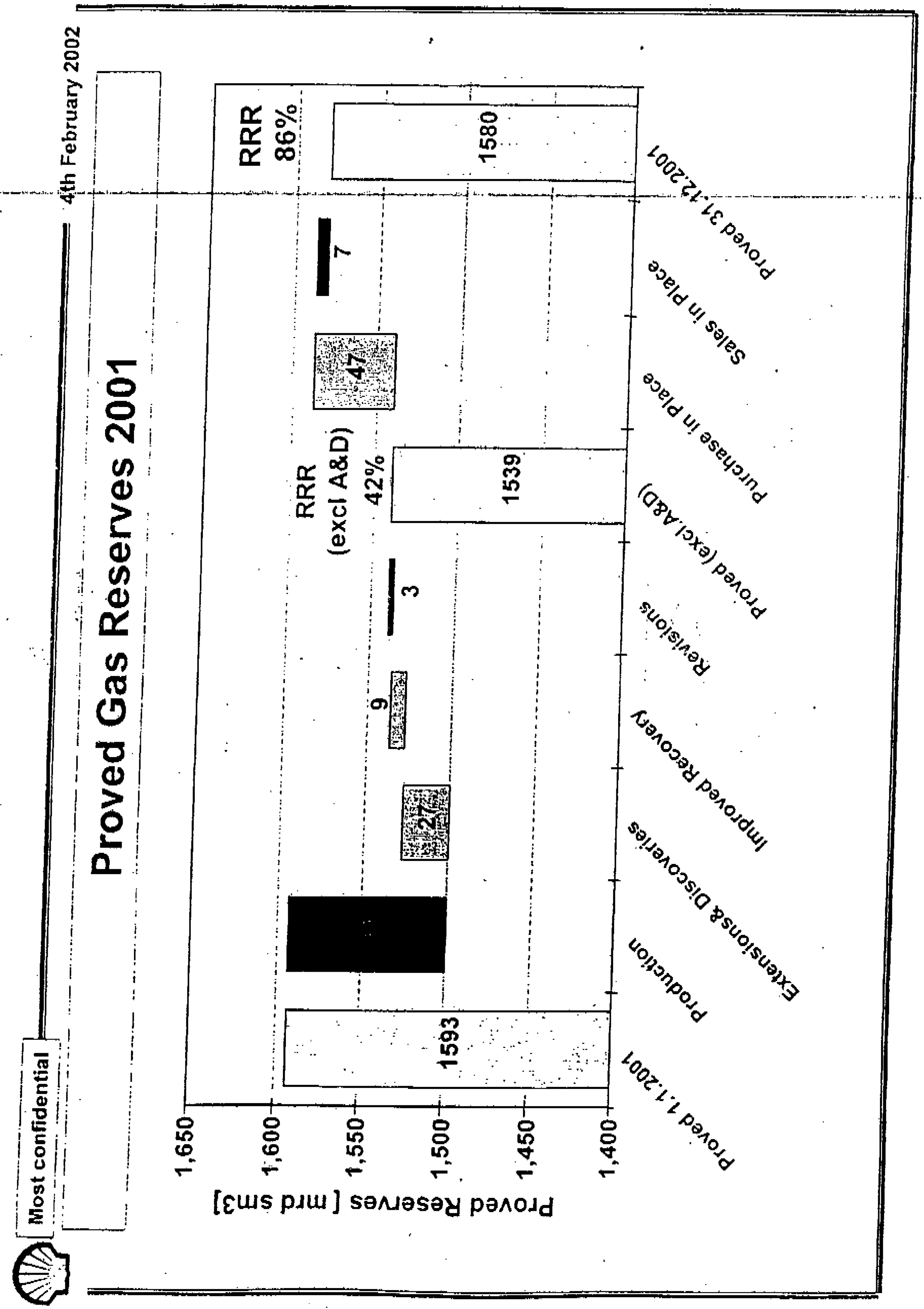
BACK-UP

Most confidential

4th February 2002

Proved Oil/NGL Reserves 2001



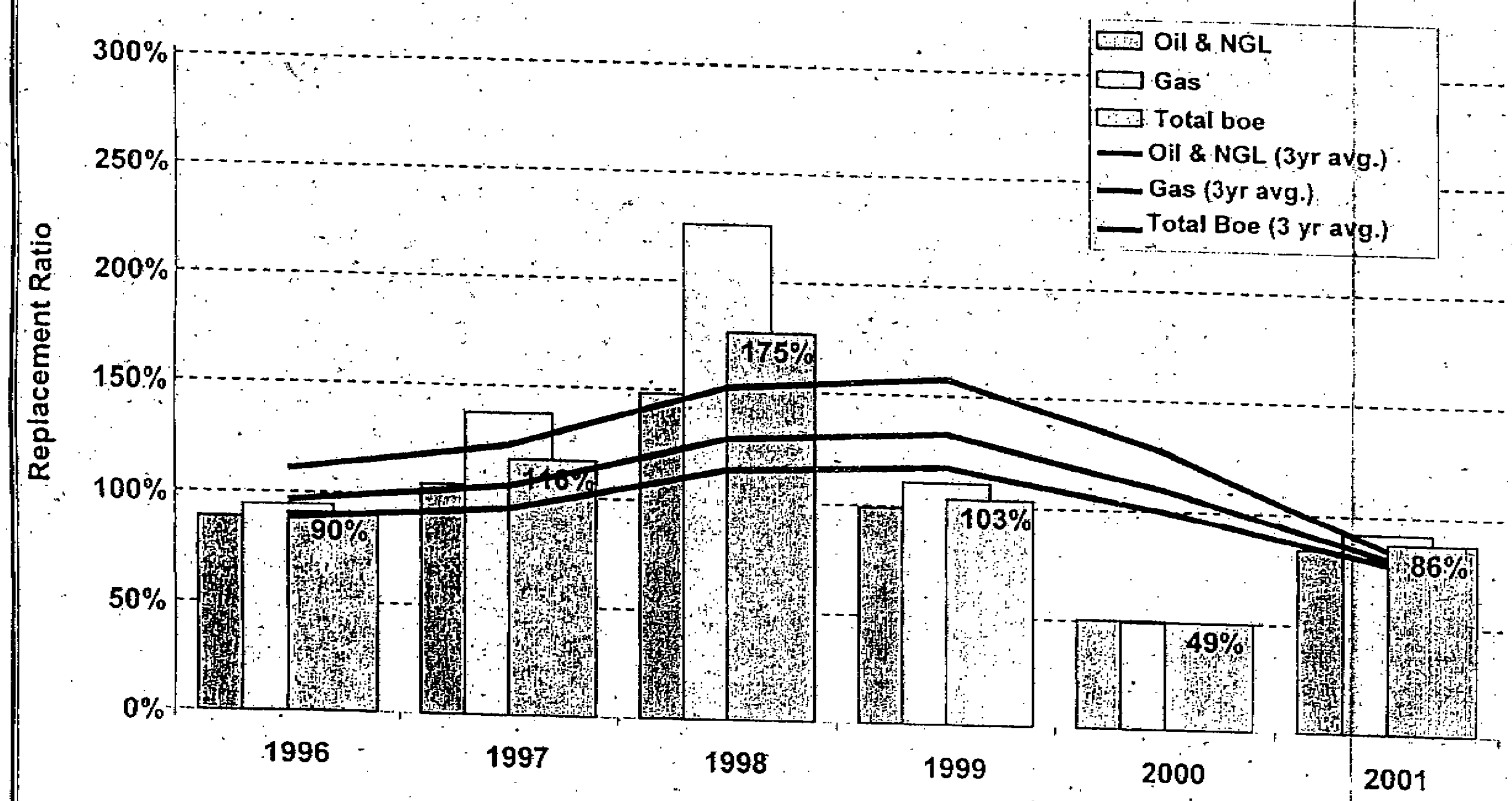


4th February 2002
Proved Gas Reserves 2001
Most confidential
Proved Reserves [mrd sm3]
1,650
1,600
1,550
1,500
1,450
1,400
1593
27
9
3
RRR (excl A&D) 42%
1539
47
7
RRR 86%
1580
Proved 1.1.2001
Production
Extensions& Discoveries
Improved Recovery
Revisions
Proved (excl.A&D)
Purchases in Place
Sales in Place
Proved 31.12.2001

Most confidential

4th February 2002

Proved Developed RRR



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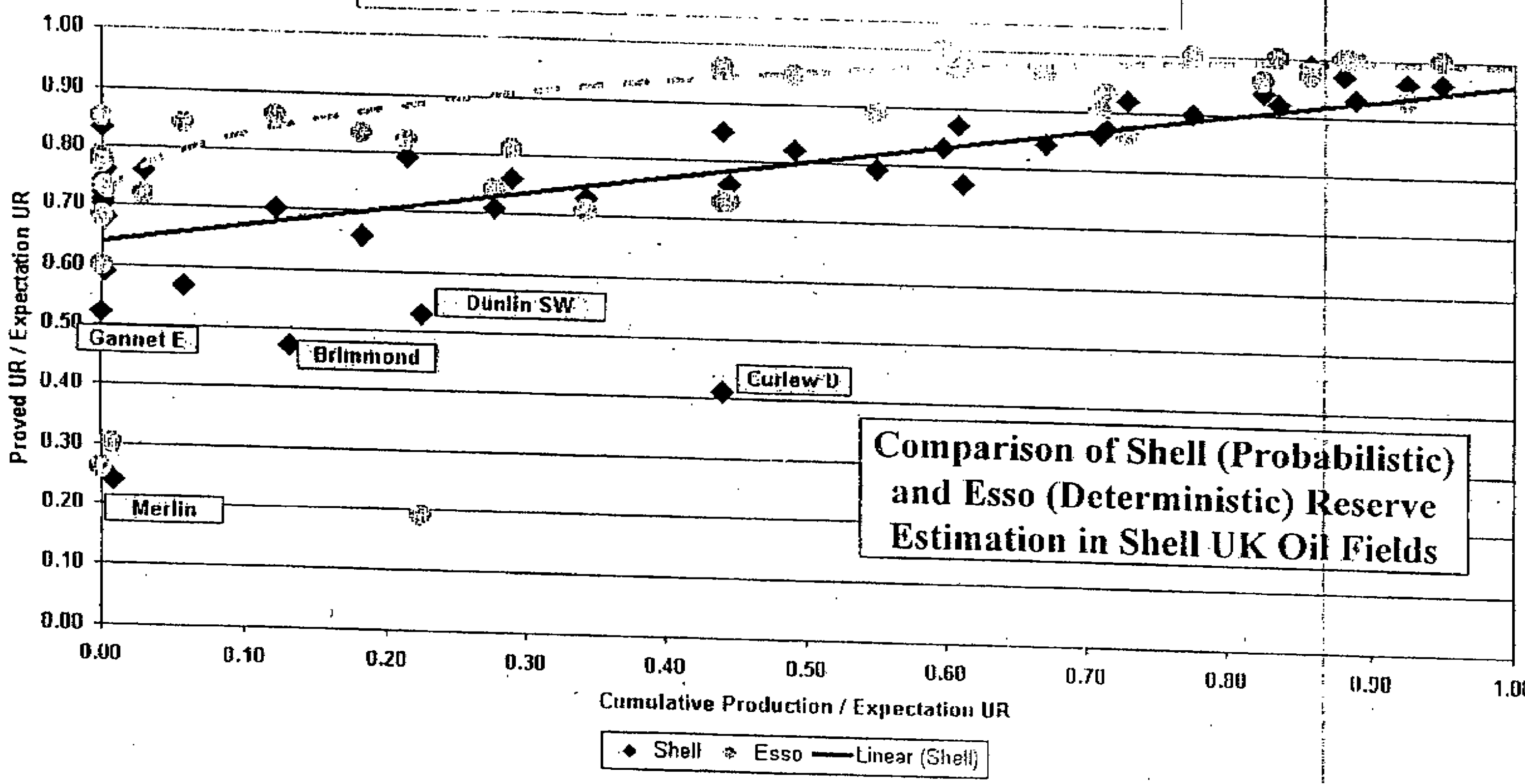
4th February 2002

P/E versus Field Maturity



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4th February 2002

New Fields : Guidelines currently too lenient

SEC clarifications in 2001 clearly insist on full project maturity, company commitment and absence of possible show stoppers

Item	SEC	Group
'Proved Area'	Not below 'Lowest Known Hydrocarbons' (LKH) level in reservoir; Laterally confined to 'legal location' (US only – min. well spacing), unless seismic amplitude and log support; Proven producibility from production test or analague log and core data; Proven continuity of production..	Below LKH OK if supported by pressure evidence (not always from same reservoir); Laterally confined to fault block or other area with continuous good quality seismic amplitudes (BTC method preferred); Producibility from production test or wireline test or log and/or core analogy. Group practice still probabilistic P85 estimates in some cases.
'Improved Recovery'	Successful pilot project in that specific rock volume in the field	Assessment of uncertainties (VOI) Confirmed in analogous reservoirs; Project FID available/expected without pilot
'Reasonable Certainty'	Requires a serious commitment to develop (AFE, FID, MOU or contracts, firm plans); No 'reasonable doubt' (show stoppers!) Market must be 'reasonably certain'.	'Technically and commercially mature' (economic viability not necessary!); In principle a successful VAR3 or FID; 'Reasonable expectation that a plan can be matured with time'; Commitment by including development or its preparation in Business Plan; Market (expected to be) available

20

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4th February 2002

New Fields – Reserves at Risk

- **Australia (SDA) – Gorgon** **- 550 mln boe**
  - Market SE Asia
- **Norway – Ormen Lange** **- 100 mln boe**
  - Instability
- **Angola – Block 18** **- 75 mln boe**
  - VAR3: Marginal economics, gas disposal solution
- **Australia (WEL) – Vincent/Enfield** **- 50 mln boe**
  - No economic development
- **Netherlands – Waddenzee** **- 25 mln boe**
  - Government

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4th February 2002

End Licence – Reserves at Risk

- **SPDC, PDO and SAD represent 18% of EP production, here proved reserves can no longer be booked due to license constraints**
- **Oman PDO (2012)**
  - Proved forecast assumes flat 850 kbpd production
    - Exploration & Improved Recovery +48 mln bbls
    - Adjusted short-term forecast -53 mln bbls
  - RISK: production adjustment becomes long-term **-100 mln bbls**
- **Abu Dhabi (2014)**
  - Proved forecast includes 50% growth to 1,500 kbbpd plateau
    - NGL of GASCO included (+15 kbpd) + 37 mln bbls
    - 50% increase delayed from 2006 to 2010: - 30 mln bbls
  - RISK: production stays flat **- 200 mln bbls**
- **Nigeria SPDC (2019)**
  - Proved forecast includes 70% growth to 1,400 kbpd plateau
    - Gas getting hooked up +35 mln boe
    - Oil/NGL forecast under pressure -12 mln boe
  - RISK: production stays flat **- 1,000 mln bbls**

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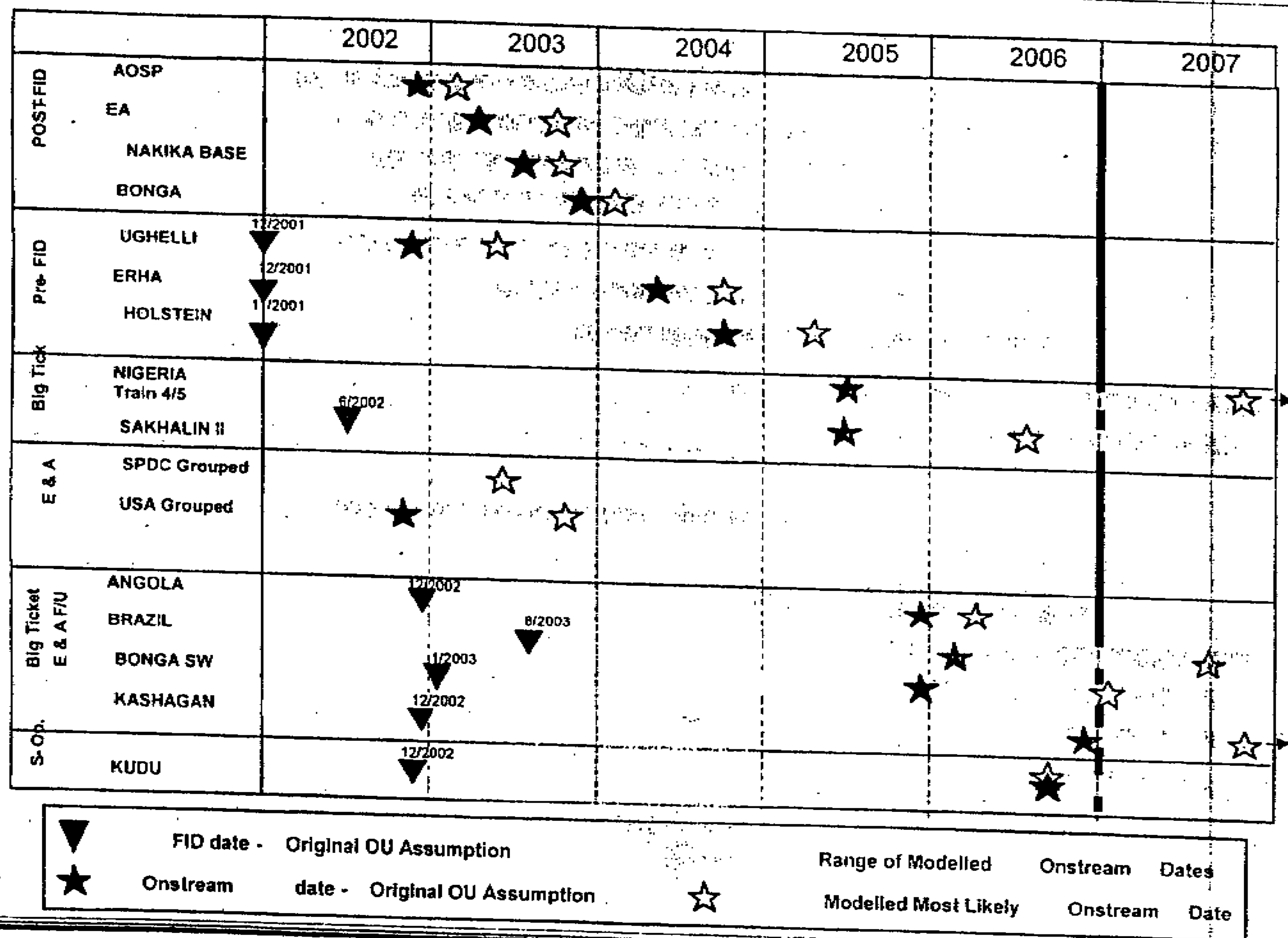
4th February 2002

Major Project Assumptions



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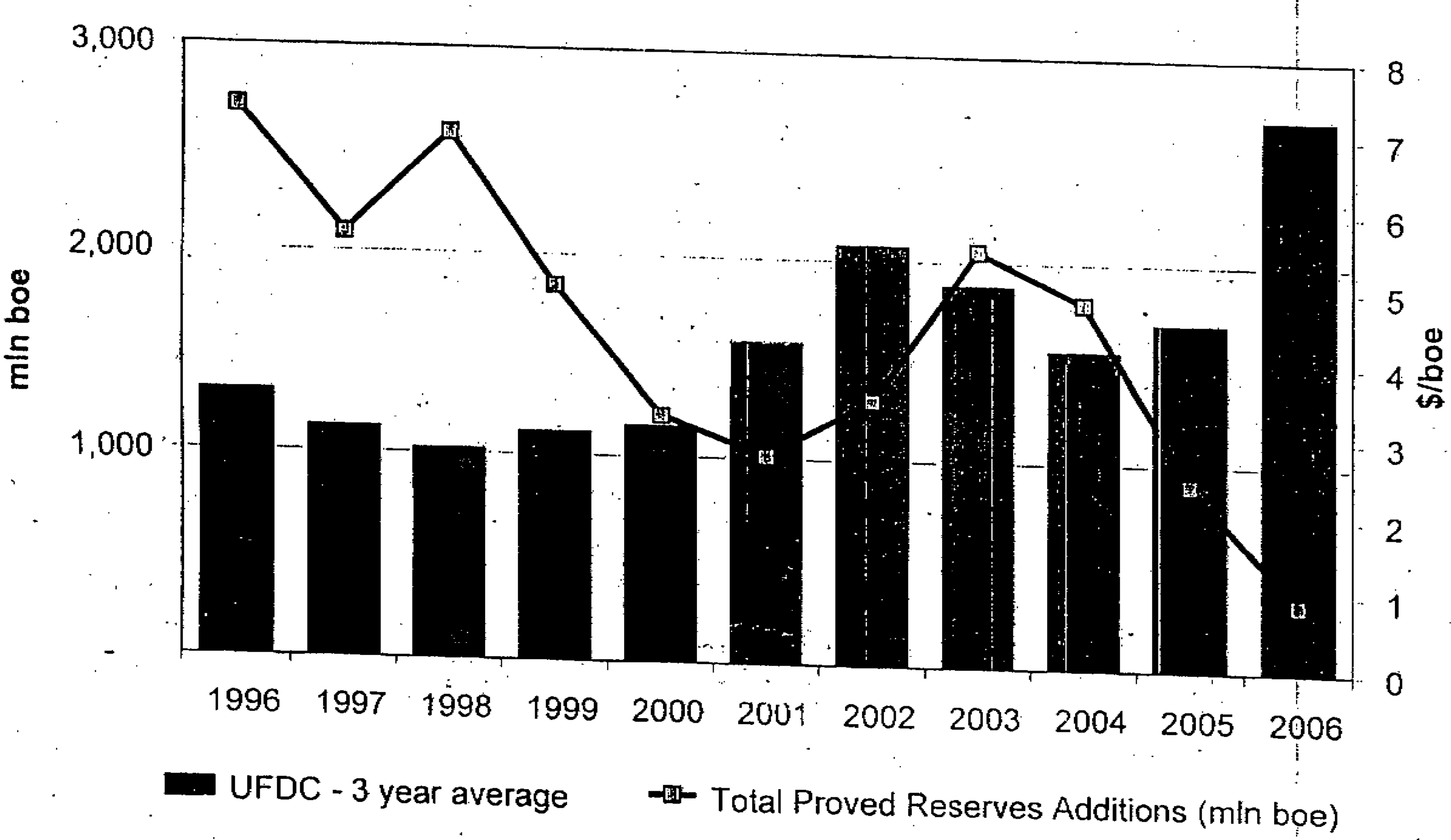
4th February 2002

Unit Finding and Development Costs - Proved Reserves



V00010211

FOIA CONFIDENTIAL
TREATMENT REQUESTED

Unknown

From: Brass, Lorin L.L.
Sent: 20 February 2002 07:02
To: Gardy, D.; Cook, Linda Z.; Megat, Zaharuddin Z.; Warren, Tim T.; Sprague, Robert M.; WARD, BRIAN B.J.; Darley, John J.; Bichsel, Matthias M.; Dubnicki, Carol C.; VanDeVijver, Walter W.
Subject: Note For Information - Reserves - CMD - February 2002

CMD_NFI_FINAL1_RRR.ZIP CMD note tachments final.ZIP

Excom,

The following was the NFI to CMD regarding our Reserves situation. I should've put in Excom preread for last Monday but forgot. At the end are some of the "action items" identified, but clearly there are more.

EXHIBIT
Van der Vijver
2/1/07

DB 07635

V00120472

Note For Information
CMD 11th February 2002
EP Hydrocarbon Resources Update 1/2002

This note summarises the end 2001 Group resources situation, cleared by external audit, and in part reported in the Q4'01 and FY'01 press release. All numbers include the effects of A&D activities unless otherwise indicated.

Summary

The total barrel of oil equivalent proved hydrocarbon reserves replacement ratio (RRR) for 2001 was **74%** (52% excluding A&D), leading to a proved RRR three year rolling average, including AOSP additions (mining reserves) in 1999 of 81%, 101% excluding A&D). The 2001 RRR is below the results quoted by our main competitors (BP 191%, XOM 110%), and highlights a portfolio that is under-performing in terms of adding reserves through exploration and maturing existing scope. Future RRR performance over the plan period relies on the delivery of 'big ticket' bookings, *e.g.* Kudu, Sakhalin LNG and Kashagan.

Our overall resource base contains some 20 bln boe of proved reserves (c.f BP 16 bln boe, XOM 22 bln boe) , some 13 bln boe of expectation reserves (of which some 8 bln boe currently fall outside of license expiry), some 17 bln boe of discovered Scope for Recovery (SFR). Our total discovered resources base is thus ca. 50 bln boe (c.f. XOM 70 bln boe) and additionally we have some some 27 bln boe of undiscovered SFR. Together with any volumes resulting from new exploration licenses and acquisitions these volumes represent a significant opportunity to increase our proved reserves replacement performance and the EP organization is being geared up to tackle each and every element.

Reserves and Resources

2001 Actual Additions (See Table 1)

The Group proved reserves base at end 2001 is 19.1 bln boe (19.7 incl. AOSP) and remains split at 50:50 oil/gas. The 2001 proved RRR of 74% amounts to a reserves addition of 1020 mln boe, which in Figure 1 is broken out by type of revision;

- 360 mln boe of Discoveries & Extensions, mainly in USA, UK and Brunei
- 350 mln boe of Revisions & Improved Recovery, mainly Netherlands, Denmark and Sakhalin offsetting negatives from Canada (50 mln boe based on field performance), New Zealand (50 mln boe based on studies on Maui field) and Oman Gisco (110 mln boe as a consequence of the renegotiation of the GISCO contract and acceleration of repayments)
- 310 mln boe of Acquisitions & Divestments, mainly Fletcher and Pinedale.

The proved **oil** RRR is 65%, taking the 3 year average to 102% including mining reserves and 77% without, and the proved **gas** RRR is 86% contributing to a 3 year

DB 07636

average of some 50%. During 2001 there were no changes to the reserves for AOSP. Including AOSP, the three year average proved boe RRR is 81% (101% excl A&D) and excluding AOSP, the equivalent numbers are 67% (86%).

The Total Resource base (the sum of expectation reserves and commercial discovered SFR) has increased by 2.7 bln boe to 49.4 bln boe (see Table 2); this includes a 1.3 bln boe addition from Venezuela Urdaneta West which falls outside of the current licence period. It should be further noted that total resources include some 1.1 bln boe from the consolidation of Sakhalin.

The Unit Finding and Development Cost (UFDC) for 2001 defined as the exploration and development cost incurred ($6.1bln) divided by Group oil and gas additions, excl. purchases and sales, (0.73 bln boe) now stands at $8.3/boe for the year 2001, and $4.8/boe on a 3-year rolling average base (up from $3.50/boe in 2000, see Figure 2). An increase in UFDC was forecast at the time of developing the Business Plan in 2000 when it was recognised that there would be a lag between stepping up capital spending and the increase in subsequent reserves bookings. Together with the lower than planned bookings in 2001 this impacts directly on our competitive position on this indicator where, up until this year, we were the leading player. The Unit Finding Cost (funding share) is $1.0/boe yielding a 3-year average of $0.62/boe, reflecting a continuation of an improving trend. Unit Finding Costs on a proved reserves additions basis are $ 3.8/boe.

Comparison versus Business Plan

The EP scorecard target for 2001 was 80% (excl. A&D and strategic options), or 1120 mln boe at target production. The actual addition excl. A&D and strategic options was 710 mln boe, or 52% RRR at actual production. The main contributors to the lower than planned RRR are detailed in Figure 3.

None of the strategic options associated with reserves bookings in 2001 materialised, e.g. Saudi Gas, T2T, Salym, Bangestan, China, Libya.

Total SFR maturation to expectation reserves over 2001 was 0.92 bln boe or 2.2% of the commercial SFR.

Exposures

Securities and Exchange Commission (SEC) Alignment

Recently the SEC issued clarifications that make it apparent that the Group guidelines for booking Proved Reserves are no longer fully aligned with the SEC rules. This may expose some 1,000 mln boe of legacy reserves bookings (*e.g.* Gorgon, Ormen Lange, Angola and Waddenzee) where potential environmental, political or commercial 'showstoppers' exist.

End of License

In Oman PDO, Abu Dhabi and Nigeria SPDC (18% of EP's current production) no further proved reserves can be booked since it is no longer 'reasonably certain' that the proved reserves will be produced within license. The overall exposure should the OU business plans not transpire is 1,300 mln boe. Work has begun to address this important issue.

DB 07637

Appraisal

Historical Perspective

In 1999 - 2001 the proved reserves additions have not fully replaced production and the 2001 3-year rolling average RRR's no longer benefit from the recent 'bookings rich' period of 1996-98 (see Figures 4/5, reflecting performance with and without the effects of A&D and showing the impact of AOSP). Over that period, substantial proved reserves additions were realised from major discoveries (Australia,Gorgon, SNEPCo (Bonga), total 1.2bln boe), major revisions (Venezuela 0.3mln boe) and new business (Oman GISCO, 0.4bln boe). In addition, in 1998 significant bookings were made by bringing proved reserves closer to expectation in mature fields (total 1.2 bln boe) - this action brought us to industry standard from a much more conservative position.

Competitive Landscape

The Group RRR of 74% is low in comparison with competitors who all posted RRRs in excess of 100% (Figure 6). The competitors are able to draw benefit from portfolios which, following the rounds of industry rationalisation, appear to offer wider choices in key exploration and scope maturation targets.

2002 and Beyond: Outlook for RRR

The outlook for Group reserves replacement in 2002 and beyond remains challenging (see Figure 7);

- We can expect fewer additions through the base plan, because of OUs affected by 'end of license', OUs with limited remaining exploration potential and the challenge to find ways to increase expectation reserve levels in mature fields.
- And an increased reliance on strategic options and other big-ticket bookings. Control on timing of these bookings is an issue, as they are commonly occur in frontier areas (Kashagan), face fierce competition for markets (T4/T5, Sakhalin LNG), rely on emerging technologies (Kudu, SURE), or are in areas with limited control (Saudi, Whale). The subsequent reserves booking profile may be "lumpier" than in the past and these major bookings will require additional steer to ensure delivery of new reserves within the tighter SEC framework.

Actions taken

In Q4 2001 and Q1 2002 a number of actions have been initiated to address this emerging issue;

- even greater focus is being placed on succeeding in exploration, a key challenge is to focus on the maturation of our 27 bln boe of undiscovered scope for recovery
- similarly EP is refocusing the organization to reinstate Technical and Operational Excellence across the whole of its core operations; hydrocarbon resources maturation is a key element of this drive
- EP is looking again at the opportunities to accelerate the maturation of our 17 bln boe of discovered scope for recovery and specifically with GP looking at the opportunities to monetize gas SFR

DB 07638

- Stepping up the drive to extend licenses e.g. in Abu Dhabi, Nigeria, Brunei, Oman and open up the opportunity to move the 8 bln boe expectation reserves which currently fall outside of license expiry back into our within license resource base and ultimately move to proved reserves.

Conclusion

Our reserves replacement performance over the past few years clearly illustrates the emerging problems with our resource base and is becoming a source of competitive disadvantage. Over the plan period, the challenge will be to secure sufficient volumes from major bookings to supplement additions from a base plan portfolio and ensure that existing exposures, if they transpire, are adequately offset.

However, we do have some nearly 50 bln boe of SFR and expectation reserves currently outwith license in our overall resource base which presents a significant opportunity. We are refocusing our efforts on exploration and will pursue more aggressively the transfer from SFR to reserves but this will not be sufficient to reverse the trends – success in major strategic options in MRH's or a major acquisition is necessary.

Table 1 : Summary of 2001 Reserves/Resources Replacement

proved RRR	Production	1 year 2001 Incl A&D Incl AOSP	1 year 2001 Incl A&D Excl AOSP	1 year 2001 Excl A&D Incl AOSP	1 year 2001 Excl A&D Excl AOSP	3 year 1999-2001 Incl A&D Incl AOSP	3 year 1999-2001 Incl A&D Excl AOSP	3 year 1999-2001 Excl A&D Incl AOSP	3 year 1999-2001 Excl A&D Excl AOSP
Oil/NGL	0.81	65%	65%	58%	58%	102%	77%	130%	106%
Gas	0.57	86%	86%	42%	42%	50%	50%	55%	55%
Total BOE	1.38	74%	74%	52%	52%	81%	67%	101%	86%

Production	2002 Target Incl A&D	2002 Target Excl A&D
0.83	91%	49%
0.58	113%	69%
1.41	100%	57%

Additions bln boe	Production	1 year 2001 Incl A&D Incl AOSP	1 year 2001 Incl A&D Excl AOSP	1 year 2001 Excl A&D Incl AOSP	1 year 2001 Excl A&D Excl AOSP	3 year 1999-2001 Incl A&D Incl AOSP	3 year 1999-2001 Incl A&D Excl AOSP	3 year 1999-2001 Excl A&D Incl AOSP	3 year 1999-2001 Excl A&D Excl AOSP
Oil/NGL	0.81	0.53	0.53	0.47	0.47	0.82	0.63	1.05	0.86
Gas	0.57	0.49	0.49	0.24	0.24	0.28	0.28	0.31	0.31
Total BOE	1.38	1.02	1.02	0.72	0.72	1.12	0.92	1.39	1.18

Production	2002 Target Incl A&D	2002 Target Excl A&D
0.83	0.76	0.41
0.58	0.66	0.40
1.41	1.42	0.81

Resources (bln boe)	2000	2001	Delta
SFR (com discovered)	14.1	16.7	
Expectation (incl proved)	32.6	32.7	
Total	46.7	49.4	2.74
less Urdaneta West (license)			1.28
Resources added (net)			1.46
Production			1.38
Resources added (gross)			2.84

Reserves (bln boe)		Proved		Developed	
Balance 31.12.2000			20.1		9.0
Additions	Extensions	0.36			
	Revisions	0.35		0.17	
	A&D	0.31			
	Transfer to Dev			1.02	
			1.02		1.19
Production			-1.38		-1.38
Balance 31.12.2001			19.7		8.8

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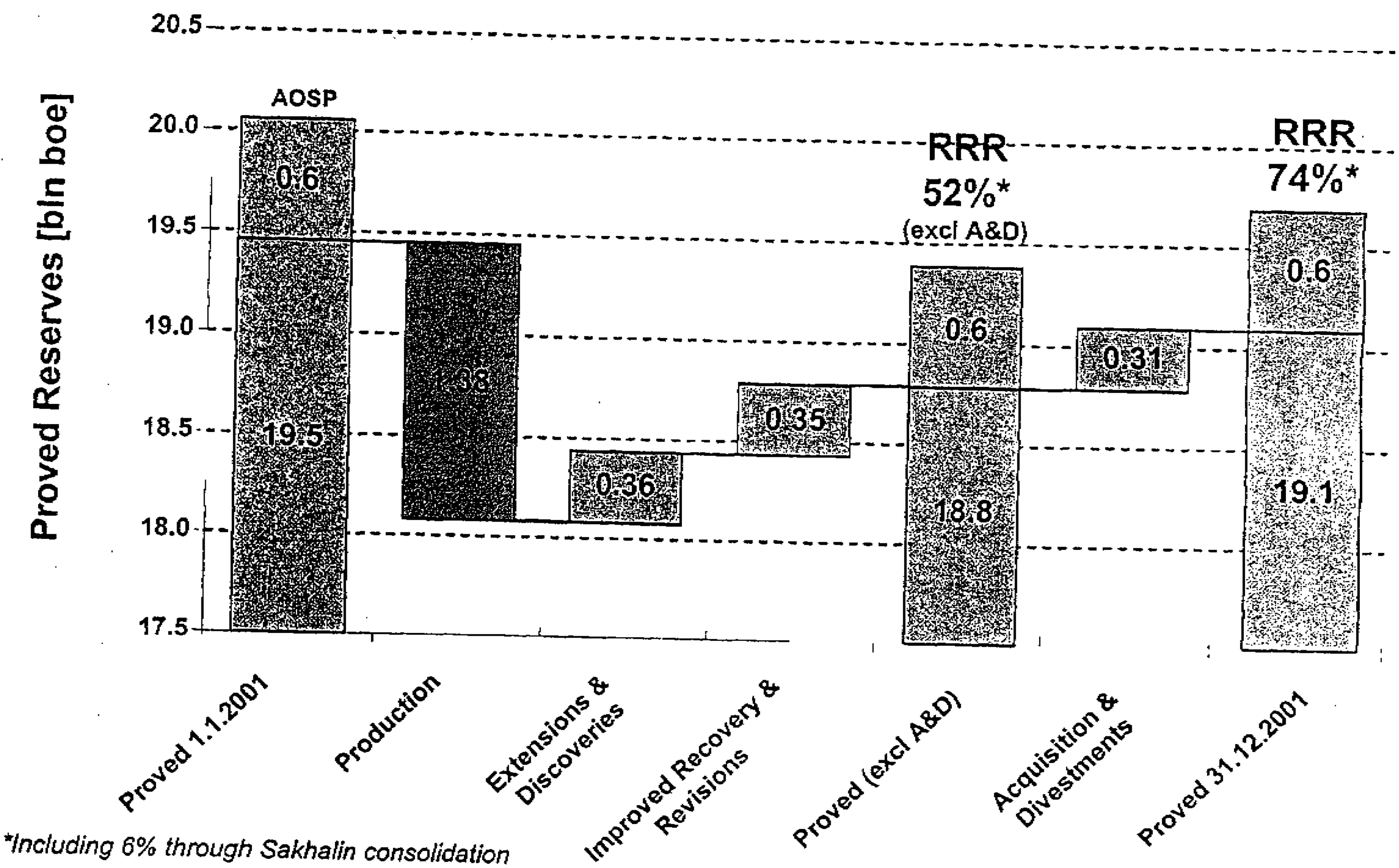
Table 2: Total Resource Base as at 31.12.01

bln boe	Oil&NGL	Gas	Total
Proved Developed	*4.3*	*4.4*	*8.8*
Proved Undeveloped	*5.7*	*5.2*	*10.9*
Total Proved	**10.1**	**9.6**	**19.7**
Expectation minus Proved	*6.5*	*6.2*	*12.7*
Total Expectation	**16.9**	**15.8**	**32.7**
(of which in license)	*(12.7)*	*(12.0)*	*(24.7)*
SFR			
Proved techniques	*7.9*	*5.9*	*13.8*
Unproved techniques	*2.7*	*0.2*	*2.9*
Total Resources	**27.5**	**21.9**	**49.4**
Undiscovered	*15.6*	*11.9*	*27.5*
Non commercial	*2.4*	*2.6*	*5.0*
Total Volume	**45.5**	**36.4**	**81.9**

Table 2 *Total resource base at 1.1.2002. AOSP Mining reserves are included*

DB 07641

Figure 1: Total BOE Proved Reserves 2001

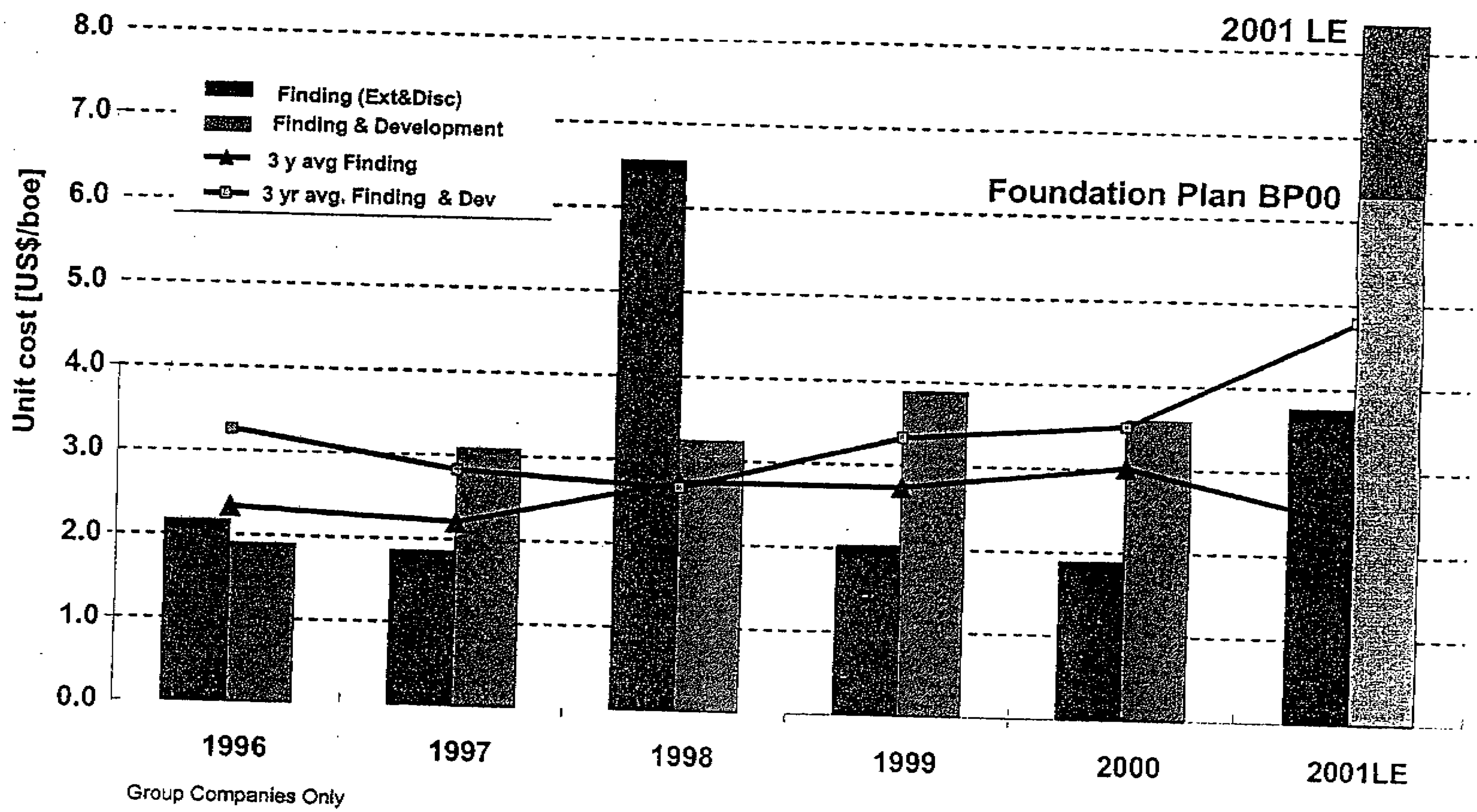


*Including 6% through Sakhalin consolidation

DB 07642

3

Figure 2 : Finding and Development Cost



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4

Figure 3 : 2001 Reserves Actual versus Target

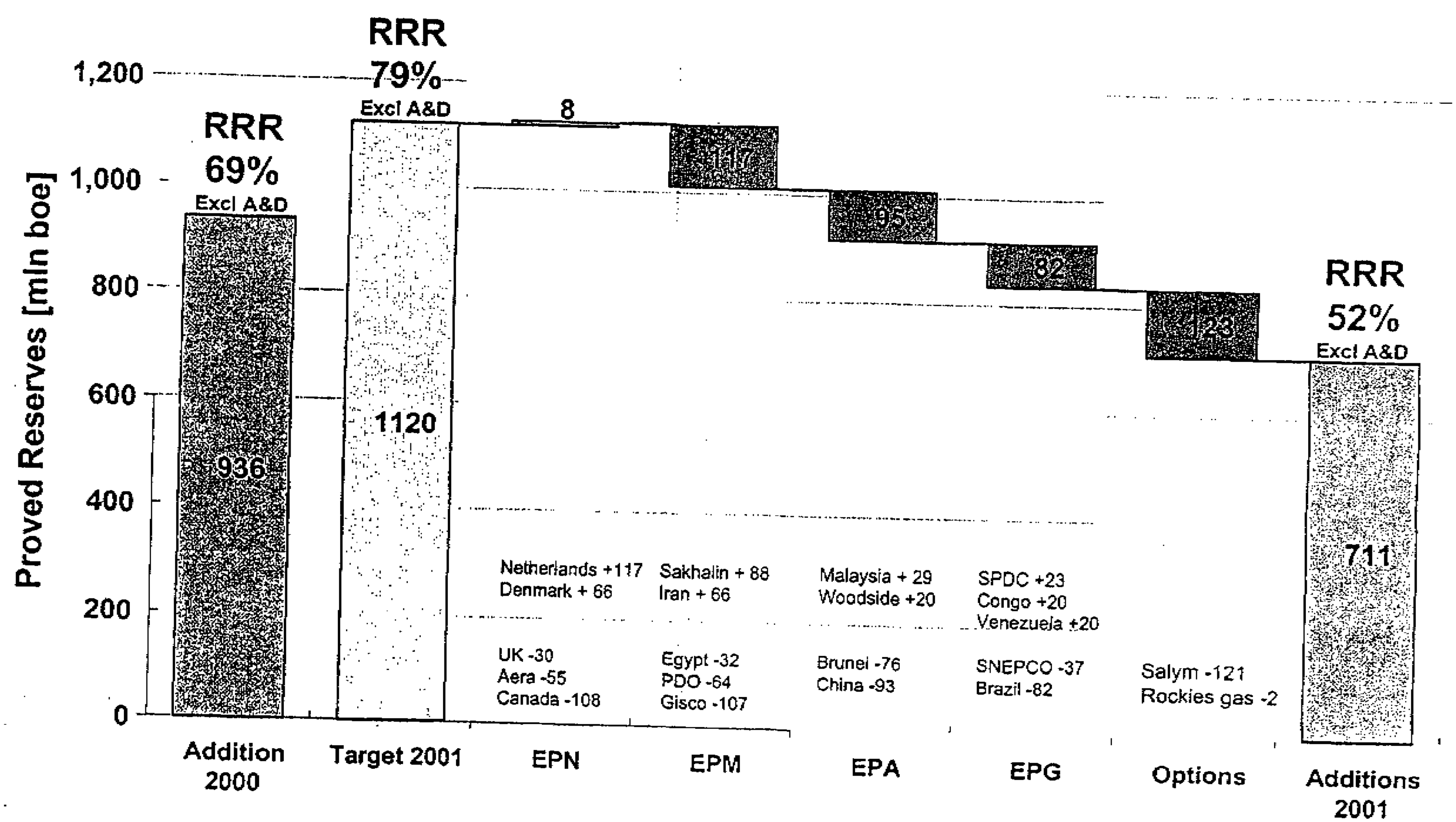

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Figure 4 : Proved RRR (incl A&D)

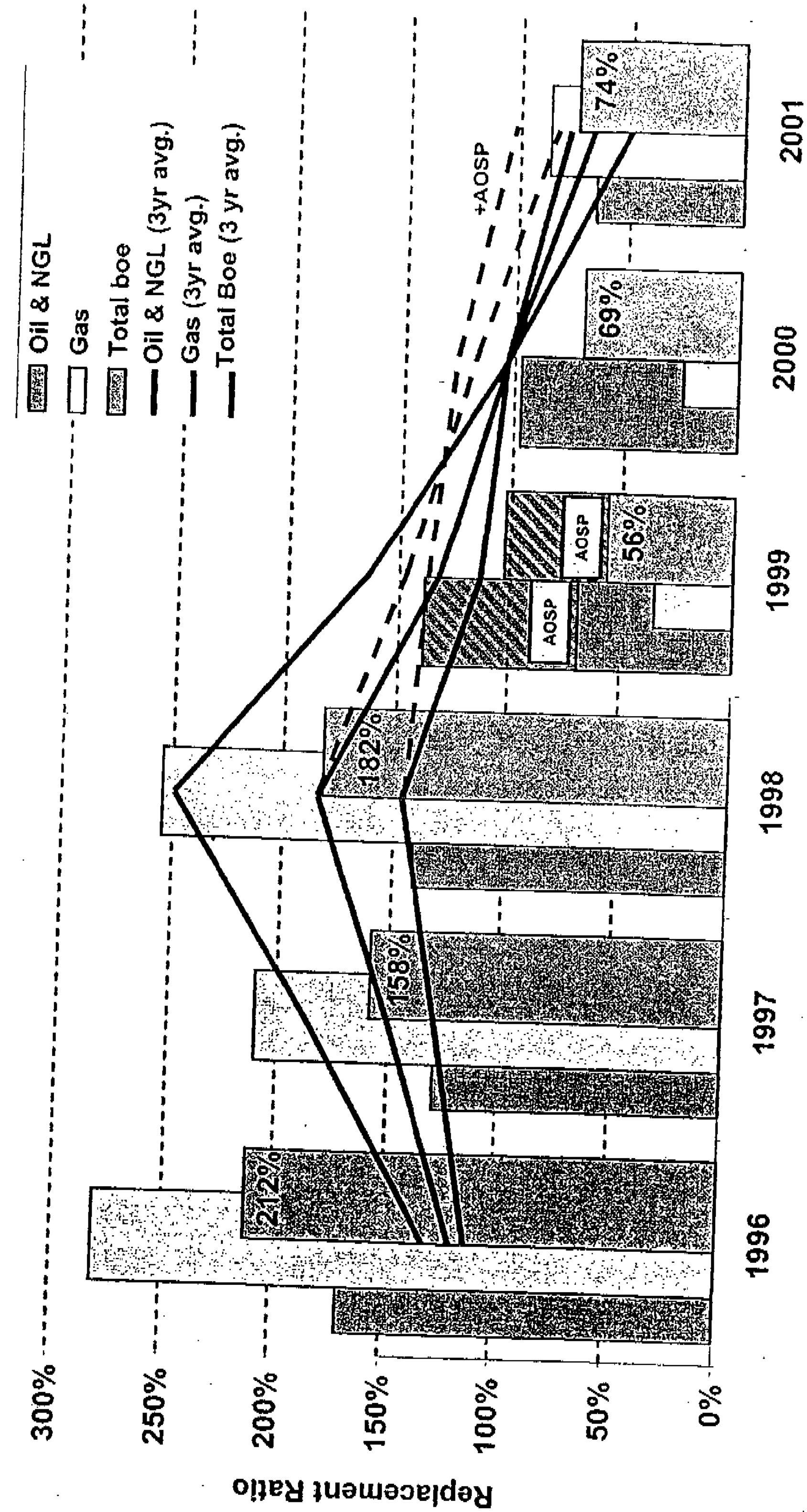

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Figure 5 : Proved RRR (excl. A&D)

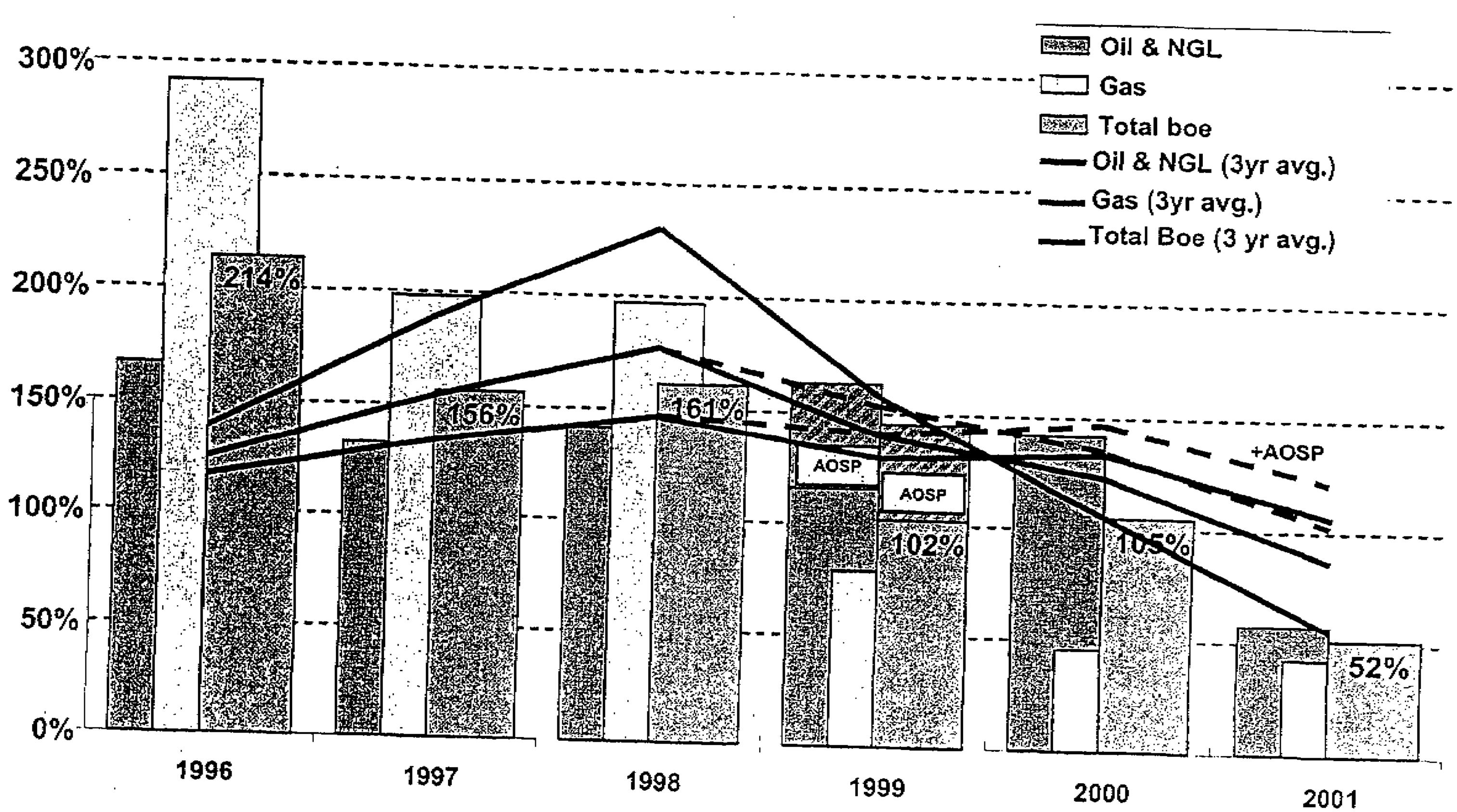

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Figure 6 : Majors Proved Reserves Replacement Ratio [boe]

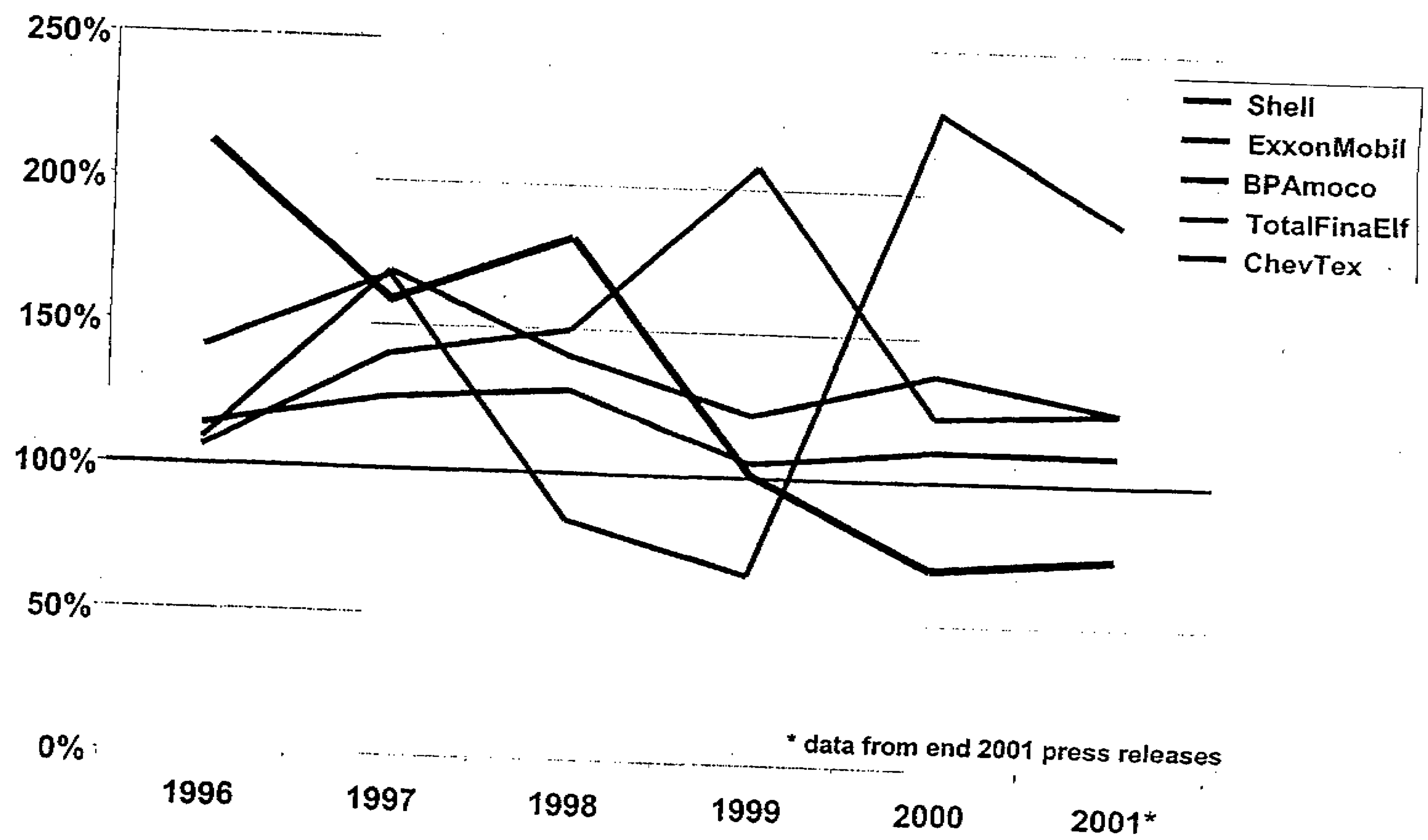
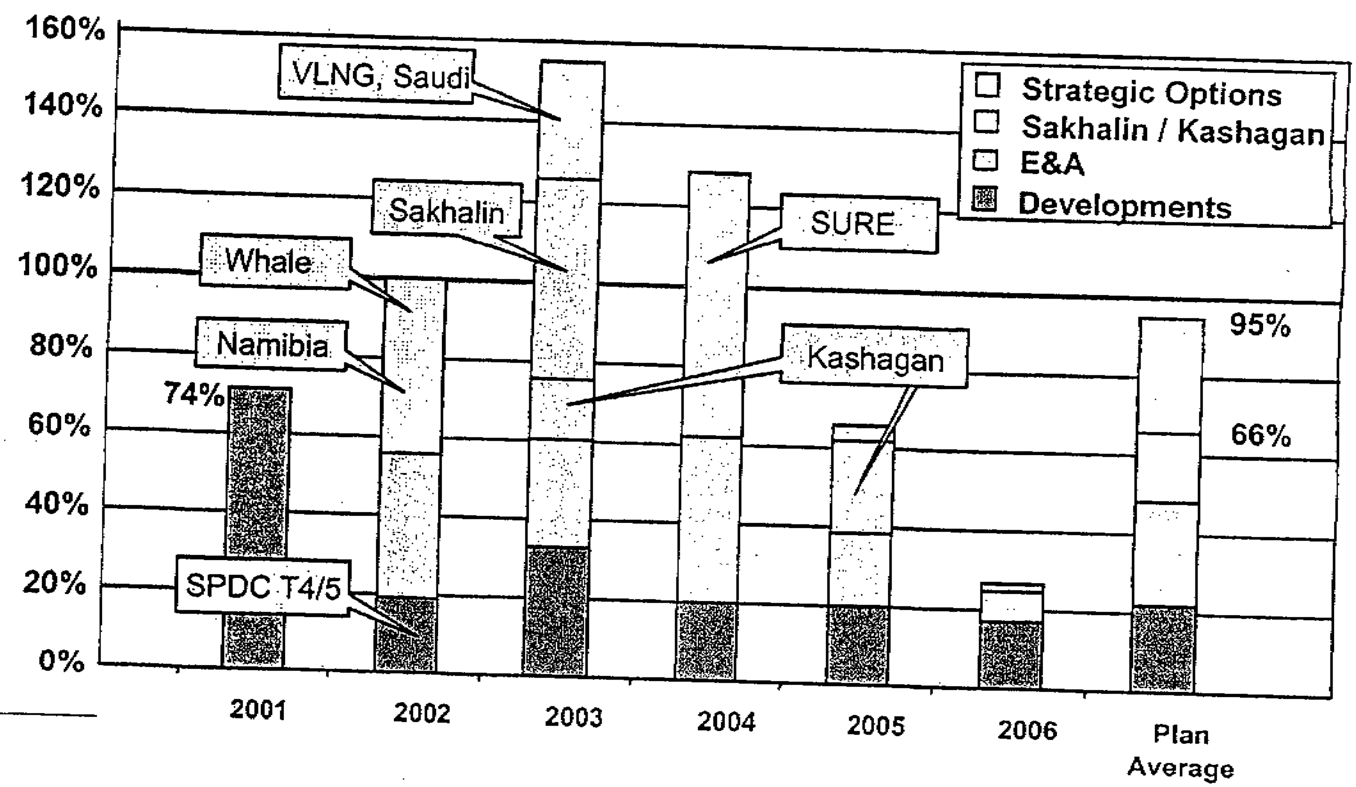


Figure 7 : BP'01 Planned Reserves Replacement



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9

Oman Visit 8-11th May 2002

Introduction

I visited Oman from 8-11th May (last visit was in September 2001). The objectives were to carry out an overall "health check" on the management team and on the overall state of the business.
The programme included sessions with the individual management team members, the Omani Staff Committee and Government officials (Minister of Oil & Gas , Minister of National Economy, Chairman of PDO/Undersecretary of MOG).
Also various briefings on topical issues were included (including watching an on-line bid for a $ 150 million Gas Plant in Saih Nihayda!) and a talk to all SG3 above staff (some 250) completed the well-organized programme.

Summary

Overall my patience has been tested too long with PDO and it's management, progress over the last year (is it not just about delivered production!) has been less than expected, less than promised and less than could have been possible. Changes will have to be made.

Highlights/lowlights were:

- Leadership at the top is very poor and not aligned. There are poor team dynamics and a lack of forward vision/direction/focus to the organization
- Production continues to slide (now some 770,000 b/d oil versus 800,000 b/d year average target with formally agreed "stretch" of 815,000 b/d) with totally unreliable monthly short-term forecasts
- Credibility of PDO, and therefore of Shell, is at a very low level. Confidence in forward action plan and production outlook needs to be achieved by end September latest (before October Board and prior to Government Budget finalisation in November).
  The situation with PDO obviously will also have a negative impact on OLNG where difficult negotiations are ongoing (intra-plant price, Train 3, mercury removal)
- High level of frustration in the organization (low morale), not just in Government and in management team!
- Omanisation talent pipeline below the "old guard" is still weak, some emerging talent at SG 2/3 but large talent pipeline with less than 5 years experience.
- Continued pressure on downward revision of reserves.

\+ SAP is a success although there are still many issues at operational level (maintenance/well engineering) linked to purchasing/stocks/invoice backlogs

\+ Top-down drive on "new" procurement business model is demonstrating real impact

\+ Good progress on "government gas" related activity (capacity planning for growth, continued reserves growth)

\+ Holistic review of asset portfolio (long-term reservoir management, issues, segmentation) finally kicked-off

\+ New organization effective 1/5/02 should be more "fit for purpose".

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12
2/1/07

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Company Direction

MD has "seen the light" last week and is trying to mobilize his leadership team (and simultaneously government!) from the starting point that the "company is in a mess" (quote) and that forward action should be focused on delivering new production from 7 strategic focus areas:

- Exploration (shift to near field exploration, near term oil)
- Output from study effort (some 80 man-years ongoing, Shell support up to 50 man-years)
- Reservoir and well management (focus on productivity enhancement, water injection, etc.)
- Reduction in drilling costs/timings
- Technology application
- EOR project delivery
- New contractor relationships (use their skills/technological capabilities and revise contracts).

MD claimed his management team was "confused" but on a journey from complacency to denial to confusion to transforming, i.e. progress is being made!

Although the above themes for production focus may be appropriate it will not deliver the "goodies" without addressing other activities:

- There is a distinct lack of focus in the organization with too many initiatives and "hobby horses" that should be killed off/deferred e.g.:
    - Long-term GW related activities (beyond "prudent operatorship")
    - Internal activities on power generation (outsourcing potential?)
    - CAO expansion in a low-tech world with a need for employment
    - Safety drive without focus on line responsibility/accountability
    - Culture of meetings/offsite sessions without clear agenda's/prioritisation
    - The business model for staff has to change. Staff currently move around too quickly (lack of continuity and lack of performance tracking) and the need for specialist skills (including progression/recognition/business needs) is not well communicated. Without this "new ways of working" PDO will fail.
    - Portfolio review needs to be integrated into the totality of the forward action plan and company direction also as:
        - Forward portfolio needs to be risk balanced (no over-reliance on EOR, continue selected infill drilling and new field hook-ups, focus on large assets for reservoir management)
        - Big issues such as depletion rates, voidage control, ESP's impact, management failures and learnings (Yibal "complications", reservoir pressures too low, lack of well drainage control) should be incorporated.
    - Clarity on resourcing strategy incl. Omanisation and use of contract staff should be dealt with pro-actively
    - Better alignment is needed (recognizing that PDO is not a Shell OU) with our global drive in EP
    - Better role definition is needed between the management team, foremost between MD and DMD

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- A positive culture is needed; there is too much a blame culture and a looking backwards mentality top-down in the organization. Staff need to be energized and need to understand what's in it for them:
  - Company direction
  - Celebrate successes and recognize role models
  - Transition team needs to be strengthened to be more than an "enthusiastic group of staff" i.e. need to be seen an extension of PDO leadership.
  - Job satisfaction and pride
- Harweel and Mukhaizna development promises (each delivering 100,000 b/d by 2007/2008) appear to lack credibility and robustness. Are these being managed with the appropriate horsepower and transparency?

<u>Operational Performance</u>

- Given the historical emphasis on creaming for short-term production benefits and given the generally high uptime, there will be no quick wins on the production side. Whilst keeping the pressure on the organization, I expect that production will further slide before recovering. This will be a very difficult message to sell to the Government
- There appears to be a lack of focus on HSE, foremost in follow through of earlier improvement drives (STOP programme, vehicle monitoring equipment, accountability drive). Reporting LTIF/TRCF in two decimals is also quite unique!
- More needs to be done on pro-active engagement with Government on "big ticket" procurement items (strategy engagement, local content, evaluation standards), the "old way" in PDO will not work anymore
- Exploration is too much focussed on the reserves addition targets (70 mmbo/year, 1 Tcf gas/year) and should be more integrated with the business needs (UTC, production impact)
- Government Gas Organization appears somewhat slow on action w.r.t. mercury removal solutions; more pressure/focus needed?
- CBP (competency based progression) is off to a slow start in petroleum engineering
- Petroleum study effort can be better integrated with the operational/implementational phase of well engineering/petroleum engineering in PDO
- Extreme reliance on ESP's (approx. 45% of production): is the technical justification as artificial lift method as sound as the commercial one?
- Young Omani talent available but working in a difficult environment (low morale, many contractor staff). Large gap between "old guard" and the new generation, very few in between.
- Reserves will continue to be an area for exposure as aggressive bookings in the past have not translated (yet) in production.

Government

- M.O.G. (Al-Ruhmy)
  Friendly discussion with the Minister. He clearly is under a lot of pressure personally and feels very frustrated with PDO's performance and PDO's management transparency.
  Although recognizing assistance from Shell over the last 9 months, he is quite naturally (also given his own credibility within the Government) questioning whether Shell is doing enough, foremost on petroleum engineering side. Also questioning large efforts ongoing by Shell in other ME countries (who is more important?) and likes to portray "PDO in trouble" being a Shell OU. Continued dialogue needed.

- M.O.G. (Shaban)
  Somewhat tense discussion with the Undersecretary influenced by MD presentation a few days earlier.
  It does not help that this relationship with the Minister is not very strong (he is HM appointee!) but he is a career member of the ministry and feels marginalized by Shell and the PDO MD.

- M.N.E. (Macki)
  Warm meeting with the Minister.
  He is prepared to wait for the new numbers in Q3 but still hopes to get 815,000 b/d plus for 2003 with subsequent upwards recovery to 850,000 b/d in later years.
  He reported that he receives a lot of challenge on Shell performance rather than PDO performance; he wants government to have increased responsibility on the good and bad things of PDO.
  Simply hopes that Shell will deliver.
  He admitted to increasing "social costs" in Oman, needing nearly $10/b price equivalent just to pay government/army employment bills! Obviously higher oil prices help to more than compensate for production shortfall in 2002.
  Some careful expectation management needed!

- General
  It appears that it is becoming politically less acceptable for the "old guard" to be seen to be too close to Shell.
  Given the "open-door" policy of the Government many messages from PDO reach the Government, tainted by the low morale in the organization.
  Although still good things happen in PDO (exploration successes, low deferments, procurement, etc.), the impact of not meeting production targets has had a dramatic effect on the overall confidence level towards PDO delivery.

Management Team PDO

The following are my summary observations on the management team:

Overall
The team is not cohesive and there are clear personal (unspoken) agenda's and not all providing the body language to be behind their MD.
Amazing how long several members were hoping that PDO was just experiencing a temporary "blib" in performance and that a few initiatives would fix it.

Ollereanshaw
A very capable individual in terms of broad business knowledge, tenacity and work capacity. It is evident that he attempts to drive improvement initiatives, however:

- He has a somewhat negative approach and does not engage well with his team, nor energizes the organization
- He is prone to "panic management", rapidly changing the direction, not adequately thinking through the consequences of his actions. Examples are messages to staff, behaviour at MOG, relationship with DMD (Lamki) and his recent "wake-up call" to MOG and to his management team
- He is a poor listener. Notwithstanding repeated messages on what needed to be done for a year, he chose his own approach and speed/scope of action.

He remains very keen to continue in his current role and is re-energized by events over the last week but the bottomline is that he lacks fundamental leadership characteristics.

Lamki (DMD)
Very impressive trackrecord in PDO and highly respected. He is a proud man and wants to leave a legacy behind in PDO. He is struggling accepting that avoidable mistakes were made in the last 5 years (Omanisation "effectiveness", organizational structure, lack of check and balance, lack of portfolio/reservoir management studies, drilling "unmanageable" wells, spreading too thin with too many initiatives) but these were somewhat masked by overall company success form the old modus operandi (infill drilling and new field hook-ups to increase production).
The latter may also explain why by some in the organization he is referred to as "the Wall". The relationship with Ollereanshaw is difficult.

Al-Hinai (Oil Director-North)
Lacks leadership skills and foremost deciveness, which he acknowledges. Has gone through a difficult period, as he was last year responsible for all operations in Oman, clearly a role that was beyond his capabilities.
He feels underappreciated by Shell management. He actually handles the situation very well and indeed should be supported, also given the overall work atmosphere and Omanisation shortfalls.

Al-Kharusi (HR)
Not well-motivated and struggling to follow through on actions/changes. Needs a stronger team below him.

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Ruitenbeek (Technical Services Director)
On his way out to Brunei.
Although capable, he is far too defensive in his style and takes criticism far too personal and hence struggles with appropriate breakthrough changes.
Basically the job was beyond his capacity.

Peters (Oil Director-South, formerly Exploration-Director)
Significant challenge in his new role. Motivated to make it a success. Understandably still naïve and his tendency to overcomplicate team dynamics particularly vis-à-vis Omanis. Overall this job is the test he needs to assess his overall capacity.

Eulderink (to replace Ruitenbeek)
Very encouraging start as Change Director, excellent people skills and pragmatic approach. Clearly "right man in the right place and at the right time".

Al-Kharusi (FM)
Still somewhat remote from the remainder of the business. Needs stimulation/coaching to be effective.

Overall organizational "healthcheck"
From the above it is not too difficult to conclude that PDO does not have a high performing management team. More would be possible if the MD was better capable to understand individual issues and engage in a more transparent and consistent manner. Some of his management team were openly challenging the effectiveness of the MD and his credibility internally and externally.
The strength of the top leadership (SG2+) is also still uncertain.

Unknown

From: Van De Vijver, Walter SI-MGDWV
Sent: 29 May 2002 07:49
To: Watts, Phil B SI-MGDPW
Subject: RE: Reserves Replacement

Phil,

You will appreciate that this has my highest attention:

- remaining legacy proved reserves (de-booking risks)
- constraints on further appreciation
- negative impact of Oman and Nigeria growth absence (losing volumes to post leicense expiry dates)
- hit squads to find other growth opportunities on bookings
- impact of FID's

No easy shortterm fixes possible.organic (prior to Enterprice) RRR stands at approx. 50 % for 2002.
With Enterprise we will exceed 100%.
On agenda for 9/7.

-----Original Message-----
From: Watts, Phil B SI-MGDPW
Sent: 28 May 2002 10:59
To: Van De Vijver, Walter SI-MGDWV
Subject: Reserves Replacement

Walter,
You will be bringing the issue to CMD shortly. I do hope that this review will include consideration of all ways and means of achieving more than 100% in 2002 - to mix metaphors .... considering the whole spectrum of possibilities and leaving no stone unturned. Of course, it's the big FIDs that really make the difference. Also I'm wondering what Enterprise does to reserves life, replacement ratio and finding and development costs.

Phil Watts
Chairman of the Committee of Managing Directors
Royal Dutch/Shell Group of Companies
Shell Centre London SE1 7NA
Tel: +44 (020) 7934 5556 Fax: +44 (020) 7934 5557
Internet: Phil.B.Watts@SI.shell.com

EXHIBIT
Van der Vijver
13
2/1/07

NI 000933

Rec'd 3/8/02

Presentation Item: Sponsored by MGDWV

22 JUL 2002

NOTE TO CMD

Subject : RESERVES OUTLOOK

Date : 18th July 2002

FROM : MGDWV

TO : CMD and Mrs. J.G. Boynton

Please find attached a comprehensive note on the reserves position in EP.

Key objectives of this note are 1) to provide full transparency on the nature of our resource base, 2) to outline the challenges we face in maturing volumes to proved reserves, and 3) to indicate actions that will enhance performance.

Obviously reserves should be seen in the overall cycle of capital efficiency (F&D cost) and production growth and this will be further addressed in our upcoming business plan.

Supported by ____________________
W. van de Vijver

3/14.2% / 14 YR PROD LIFE

(1) RETAIN SAKHALIN CONSOLIDATION MKT WILL SEE THROUGH

(2) W/ SAKHALIN & OTHERS -- ANSWER TO THIS IS NOT TO THROW MONEY AT IT. WE WILL BE PUNISHED BY THE MKT. THEY WILL NOT SEE SAKHALIN AS VALUABLE AT ALL IF IT DILUTES RETURNS FOR ~~[illegible]~~ >5 YRS + SELL LNG INTO COMMODITY MKT.

(3) NEED TO CHANGE THE GAME - GO FOR VALUE.

LON01210315

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14
2/1/07

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Note for Discussion

RESERVES OUTLOOK

Executive Summary

Shell faces a challenge to achieve 100% organic Proved Reserves Replacement Ratio (RRR) over the coming years - particularly during 2002 and 2003 – and simultaneously to achieve its 3% p.a. production growth target whilst maintaining expenditure restraint.

One third of the total commercial hydrocarbon resource base of 76 billion boe is currently positioned beyond licence expiry. Other technical and commercial constraints further reduce the Scope For Recovery (SFR) portfolio that is available for maturation to Proved Reserves over the medium term, with the result that only 60 – 70% of production is likely to be replaced organically (i.e. excluding A&D) during the Plan Period. This equates to a shortfall of 2 - 3 billion boe Proved Reserves additions.

Until recently, the outlook for organic RRR in 2002 was bleak, at some 40%, but the Kashagan Declaration of Commerciality paves the way for around 380 million boe to be booked this year, raising the organic LE to 63%. This is some 540 million boe short of full organic Proved Reserves replacement, and there are only limited options available with which to materially reduce this shortfall. The Enterprise acquisition raises the total LE (including A&D) to 133%, potentially also providing organic upside (up to 5% RRR).

Accelerating the booking of Kashagan to 2002 weakens the outlook for 2003 to some 70% organic RRR - some 480 million boe short of full organic Proved Reserves replacement, with further downside in the event that Sakhalin does not go ahead. No mature projects are currently planned with Proved Reserves bookings in 2004 that could offer firm acceleration potential to cover the 2003 shortfall.

The OUs will continue to focus on the maturation of reserves, supported by input from RtL and T&OE initiatives. However, given the magnitude of the Plan Period shortfall, and the intangible nature of much of the Ultimate Recovery gains that we are aiming for, it is imperative that we press ahead with additional measures that will help to address the situation. One option for the short term could be the retention of Sakhalin as a consolidated entity, although this would serve only to temporarily mask our underlying problem. Clear focus must therefore remain on unlocking reserves beyond licence, particularly in SPDC, Abu Dhabi and possibly Oman, with every opportunity being taken to table this issue in negotiations with host governments.

TRUE

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1. Hydrocarbon Resource Base

At 1.1.2002, the Group's commercial discovered resource base was 51 billion boe (risked expectation basis, including oil sands and shales: Attachment 1a). This is believed to compare with ca. 70 and 60 billion boe for ExxonMobil and BP respectively, leaving us the least favourably positioned of the three to replace production. Nevertheless, when the (risked) Undiscovered SFR portfolio is added in, the total rises to 76 billion boe, indicating a total resource life at current production rates in excess of 50 years. On the face of it, there appears to be little cause for concern in terms of reserves replenishment.

However, one third of the commercial resource base is locked beyond the lifetime of current licences (Attachment 1b) and is largely inaccessible for the Proved Reserves inventory until licence extension is secured. In principle, projects could be executed to accelerate at least a portion of these resources to the within-licence period, but scope is severely limited in the two OUs that together account for 75% of the volumes concerned, SPDC and Abu Dhabi. In both cases production must increase substantially simply to produce the within-licence Proved Reserves that have already been booked. New bookings in these OUs will not be feasible at least until such production growth has occurred.

Consequently, licence expiry reduces the effective commercial resource base in the meantime from 76 to 50 billion boe. This licence-constrained volume includes 1.9 billion boe recovery from oil sands and shales, most or all of which is classified as mining resources under SEC rules. It also includes the consolidated volumes for Sakhalin - deconsolidation to 40% Group share will cause a reduction of 2.3 billion boe in the resource inventory (Attachment 1c).

Of the balance remaining after taking these factors into account (45 billion boe), approximately 10 billion boe can be classed as "challenging", being subject to commercial or technical risk (e.g. Pacific region gas market, heavy oil), or relying on substantial increases in production rate in order to be realized (notably SPDC and Abu Dhabi, Attachment 1d). In addition, reserves in Oman would be under threat if production rates cannot be sustained. Attachments 1e and 1f provide further detail on Reserves Life per OU, while Attachment 1g summarizes the main issues by OU.

In summary, although there is clear potential for longer-term growth, the effective resource base on which we rely for organic Proved Reserves Replacement over the next few years is restricted. As will be shown below, these restrictions make their presence felt in our ability to replace reserves in the short- to medium-term. Consequently our continuing production growth target will come under threat over time.

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2. Outlook for 2002 and 2003

2.1 2002 Latest Estimate

Compared with the 2001 Business Plan (56% organic RRR) downward revisions to the 2002 LE have outweighed the positives of Angola Block 18 and the deferment of Sakhalin dilution (Attachment 2a). However, declaration of commerciality on Kashagan and the expected first phase of development FID should allow 380 million boe to be booked in 2002. On this basis the organic LE is 63%, above plan, although it should be noted that Kashagan was carried as a separate "big ticket" item in the Business Plan.

UFDC[1] would be approximately US$ 10.3 per boe, including Kashagan. Even if reserves could be fully replaced, the figure would reduce only to US$ 6.4 per boe, significantly above the US$ 3 – 5 per boe "comfort zone". BP, if they deliver on external reserves replacement promises, are likely to be at the lower end of that UFDC range, while ExxonMobil's recent performance (to 2001) is towards its upper limit.

Enterprise clearly dominates the A&D picture, driving a net RRR from A&D of 71%. Of the 600 mln boe Strategic Options originally in the plan for 2002 (a 42% contribution to total RRR), only 180 mln boe remain in the LE, mainly a risked volume associated with the "Whale" coded project which realistically is now unlikely to be secured this year.

2.2 2002 Upside

The focus on project delivery continues, augmented by T&OE (although quick wins are elusive at this early stage).

Further upside may stem from organic revisions to the acquired Enterprise portfolio. Review of their practices shows that they were conservative in their approach to SEC reserves declarations compared with Shell. Application of the Shell guidelines should yield a few tens of millions of barrels, possibly with more to come from the natural flow of revisions within the portfolio. The OU integration teams will pay particular attention to this as the year progresses. In the meantime, and subject to confirmation by receipt of more detailed plan data, it is assumed that Enterprise will provide some 50 million boe Proved Reserves additions in 2002 and in each successive year of the Plan Period.

With these upsides, and neglecting Strategic Options, the total LE (including A&D) for the year would approach 140% RRR, of which 66%+ would be organic.

---

[1] Unit Finding and Development Cost. Based on plan Capex and Expex, including estimates for Enterprise. UFDC figures are essentially similar whether expressed on GA or OA basis.

2.3 2003

The following is based on the Capital Allocation project definitions that are "current" and under discussion at the Capex and Expex Workshops, July 2002. As such, and since the Business Plan is some distance from being finalized, the view is subject to revision.

The unconstrained portfolio of "organic" projects available to be ranked for the 2003 plan would deliver 1530 mln boe Proved Reserves additions during the year (Attachment 2b), yielding 99% RRR and a UFDC of ca. US$ 7.7 per boe. The initial outlook is that this will reduce to somewhere in the range 45 – 70% RRR after the application of expenditure constraints, the bulk of the range being driven by the inclusion or otherwise of Sakhalin[2]. The upper end of the RRR range equates to a shortfall of some 480 million boe compared with full organic Proved Reserves replacement.

Again taking the upper end of the RRR range for illustration, this would correspond to a UFDC of approximately US$ 9.3 per boe, US$ 1.6 per boe higher than for the unconstrained portfolio. This figure is broadly in line with the expected result for 2002 and is still well above the level that our main competitors are likely to achieve. The increase in UFDC on applying expenditure constraints is explained by the fact that many of the projects that are likely to rank into the final programme have already had their corresponding reserves booked. ??

2.4 2003 Upside

Backfilling 2003 by accelerating bookings from later years might be feasible. However, currently there are no firm big-tickets of a size to compare with Sakhalin and Kashagan. Many of the projects that appear to make attractive targets for acceleration (due to their large associated resource volumes) are currently phased later because of overriding critical path constraints, not the least of which being completion of E&A activities in several cases (Attachment 2c).

There is scope to manage the overall situation for 2003 without accelerating from 2004 (Attachment 2d), with the two major potential contributors being project "Whale" and the retention of Sakhalin on a consolidated basis. Securing the former is not under our direct control, and the project probably would not qualify as "organic" growth. The latter (Sakhalin), whilst essentially being a "paper" gain, would in effect solve our reserves replacement issues at least until the end of 2004. Unpalatable though this might be in terms of financial performance and market exposure, acceleration of other projects could also be achieved only at a cost and with less assurance of delivery in view of POS (to FID) at this stage.

[2] Net of the effect of eventual deconsolidation to 40% Group share.

2.5 T&OE: Status of Global Hydrocarbon Resource Base Review

The Global Hydrocarbon Resource Base Review has been in progress for several weeks now. Its objective is to gain improved insight into the technical state of the Group's hydrocarbon resource base and the scope to improve recovery efficiency. The results and findings will drive future Technical and Operational Excellence initiatives.

Data is being gathered on all the major fields in the Group. At this stage the focus is on inventorising and categorising the major elements of the resource base with a view to identifying opportunities for improved recovery through comparative benchmarking and comparison with best practice. For example, it is expected to confirm that waterfloods in medium- to complex environments present both significant exposure and opportunity, albeit in the longer rather than the immediate short-term.

To date, twenty-two OUs have been engaged in the information and data gathering. On-site reviews have been completed on six of the twelve largest OUs – the remaining six will be completed by the end of July. Many issues related to the maturation of volumes into reserves and production have been identified from which a collective picture will emerge.

As part of the process, OUs are being challenged on their progress against plan for 2002 and 2003 reserves additions, and being offered support where required. However, at this stage it seems unlikely that this review will identify material opportunities to enhance the 2002 reserves replacement situation, although any opportunities uncovered on an exception basis will be pursued.

Data analysis and reporting will be completed in August/September. This is expected to identify Global Themes for the development and integration of best practice into OUs and help to ensure that the skills and technologies available within the Group are aligned with the OUs, projects and recovery processes from which we have the most to gain.

3. Outlook For Remainder of Plan Period

3.1 Historical Context

Over the last decade, Proved RRR has averaged 102%, 94% being "Core Organic" (i.e. derived from pre-existing business – Attachment 3a). Major revisions had been made in 1990 (Proved RRR of *330%*), on the back of which very few revisions were made in the subsequent five years – the majority of additions during this period came from E&A. 1996 – 1998 were the only recent years in which organic RRR exceeded 100%, the additions preparing Shell for its concerted effort to grow production in 2000 and beyond.

With the benefit of hindsight, some of the organic revisions made in recent years now appear somewhat aggressive: principally Australia (Gorgon, struggling to reach maturity) and SPDC (bookings continued on the back of expected production growth that has still to materialize, contributing to a bow-wave problem in the remainder of the licence). Factoring these out (Attachment 3b), the effective total Proved RRR over the last 10 years would be reduced from 102% to 88%. The underlying organic Proved RRR contribution from pre-existing businesses was 81%, of which 45% came from revisions and improved recovery and the remaining 36% from discoveries and extensions.

These observations help to set the scene for assessing performance going forward.

3.2 Plan Period

The following is based on the preliminary Capital Allocation ranking process and considerable further work remains to be done, particularly on building the programme for 2004 and beyond. Whilst changes in the detail can be expected as this takes place, they are unlikely to materially affect the broader conclusions.

The portfolio of projects submitted for Capital Allocation would deliver Proved RRR in the range 59 - 83% averaged over the Plan Period (2003 – 2007), the exact position in the range being determined primarily by expenditure constraints that have yet to be applied to 2004 and beyond. The upper end of this range would equate almost identically to actual "Core Organic" performance over the last 10 years (Attachments 3c and 3d).

Assuming a final outcome for the Plan in the range 60 - 70% RRR on average, this would clearly be well short of full organic reserves replacement, the deficit equating to 2 - 3 billion boe in Proved Reserves Additions. On this basis, and with corresponding expenditure likely to continue at or close to current ceilings, UFDC is unlikely to be brought significantly below US$ 7 per boe.

Consequently, for the short to medium term at least, we continue to rely on the delivery of new business to the portfolio to underpin long-term growth, whether this be from delivery of Strategic Options, A&D, or the release of licence-locked reserves.

3.3 Upside Potential

The additional 2 - 3 billion boe that is likely to be required to bridge the gap to 100% organic reserves replacement over the Plan Period represents a challenging target. Notwithstanding the continued efforts of the OUs to improve on production and recovery efficiency, augmented by RtL and T&OE, it is clear that we will rely on major initiatives to ensure that this target can be met. Of most significance are:

Licence Extensions

Estimates of the volumes that could materialize during the Plan Period are speculative. However, given that the total prize is a 26 billion boe resource volume, even a relatively modest "win" could make a major contribution to Plan Period organic RRR. Unlocking 10% of the licence-locked Expectation Reserves would yield a corresponding Proved Reserves addition in the order of 500 million boe, with the advantage that such a gain would hopefully be achieved at relatively low cost. Consequently the ongoing efforts to tap into this resource must continue, with every opportunity being taken to table the matter and apply leverage to our advantage in negotiations with host governments.

SPDC: End of Reserves Moratorium

So far, it has been assumed that the moratorium on new Proved Reserves bookings in SPDC Nigeria will remain in place throughout the Plan Period. However, if production growth is achieved as currently planned, scope may emerge to relax this. Without wishing to understate the challenges that we face in this regard, the total unconstrained SPDC portfolio of projects submitted for Capital Allocation has the potential to yield a further 970 million boe Proved Reserves over the Plan Period, generating a 13% p.a. average additional contribution to RRR and shaving US$ 1.0 per boe from average Group UFDC. To reiterate, however, we can only begin to tap into this additional volume after having first secured the production growth that is required to realize the reserves that have been booked already.

Sakhalin: Retain Consolidated

Discussed above (section 2.4). Of the total 2.3 billion boe resource base that would continue to be reflected in our consolidated accounts, some 900 million boe would come into the Proved Reserves inventory during the Plan Period, providing an average 12% p.a. contribution to RRR and a $US 0.4 per boe reduction in average UFDC.

4. External Storyline

4.1 2001 Investor Relations

Presentations to investors in 2001 highlighted the revised 3% a.a.i. hydrocarbon production growth rate 2000 – 2005, implying (if not specifically stating) that this would be achieved organically. We did not explicitly commit ourselves on RRR, but it has been noted externally that a figure of 140% p.a. would be required if we were to achieve this sustained rate of production growth and leave reserves life intact. Thanks mainly to bookings in 1996 – 1998, our oil reserves life of 12 years is now exactly in line with our peers, while our position in long-term gas extends reserves life on a boe basis to 14 years.

Inevitably the external community has detected from our relatively poor Proved RRR, and the resulting weakened UFDC performance, a risk that Shell will struggle to deliver its production growth target.

In discussing resource volumes, Shell has stressed that the total contribution of additions (particularly discoveries) to the "expectation" hydrocarbon resource base is a more reliable barometer for growth potential, thereby already distancing itself from the Proved RRR measure.

4.2 2002 Latest Estimate and Forward Plan

Notwithstanding the efforts that will continue to be made to improve on the outlook for 2002, we must prepare to deal with the fact that organic Proved RRR might not exceed 63% (with Kashagan), although 70%+ could be within reach after pursuit of possible gains from the Enterprise portfolio and other upsides in the overall portfolio.

A&D, of which by far the biggest contributor clearly is Enterprise, provides an additional 71% RRR and brings the total towards 140%, even if no Strategic Options are secured. This figure is consistent with our stated production growth ambition, if stated on a total basis.

Looking forward through the Plan Period, it is unlikely that the average organic Proved RRR will rise much above 70%, implying (with current expenditure ceilings) an average UFDC in the order of US$ 7 per boe.

4.3 2002 Investor Relations Script

In relation to RRR (and indirectly to production growth and UFDC performance), the following messages are proposed:

- Continue to stress the strength of the total resource base.

- Continue to highlight the major projects fuelling growth in the short and long-term.

- If required, acknowledge that organic RRR is less than 100% but distance ourselves from it as a reliable "instantaneous" measure of growth potential.

- Again if required, note that Shell has experienced prolonged periods throughout its recent history during which organic Proved RRR was less than 100% and yet has continued to deliver world-class technical and financial performance.

- Link the high Proved RRR of the late 1990s to our stated 3% a.a.i. production growth target for 2000 – 2005, the one presaging the other. We continue with the process of actively managing our portfolio and taking stock of opportunities for further growth beyond that. However we will not pursue growth to the detriment of business value and shareholder return. Profitability is the key focus: the quality of the (booked) barrel is what counts. Key But we need A story

?

- Build on the RtL messages already delivered externally by elaborating on the focus that T&OE will bring to improving production, reserves, cost and skills deployment. This will inevitably enhance the performance of our existing asset base and, we expect, position us even more favourably as partner and operator of choice in new ventures.

?

5. Forward Actions

The following are receiving attention for addressing the short to medium term situation on reserves replacement:

- T&OE: The much-increased focus on production and recovery efficiency improvements must inevitably yield results. Additional resources have been deployed on the Global Hydrocarbon Resource Base Review, and in addition opportunities for "quick wins" are actively being sought.

- Licence extensions: Particularly SPDC, Abu Dhabi and Oman, but also smaller opportunities in Syria, Denmark (although Shell is not concessionaire) and Venezuela. Every opportunity to leverage access to post-licence volumes will be explored.

- Russia: Opportunities to bolster our portfolio in Russia are being pursued (e.g. Salym, Zapo).

- Oil sands: Scope to increase the proved volumes associated with the Athabasca project, and potential future expansions, is being investigated.

- E&A follow-up: Ways to increase the pace at which E&A discoveries are matured and commercialized to proved volumes will be pursued with high priority.

- OU Initiatives: Identification and pursuit of opportunities within the established core business portfolio continue with high priority, assisted by RtL and T&OE as required. "Major" gains are likely to be few and far between, however examples such as Groningen upside (2003?) hold real promise.

Attachment 1a

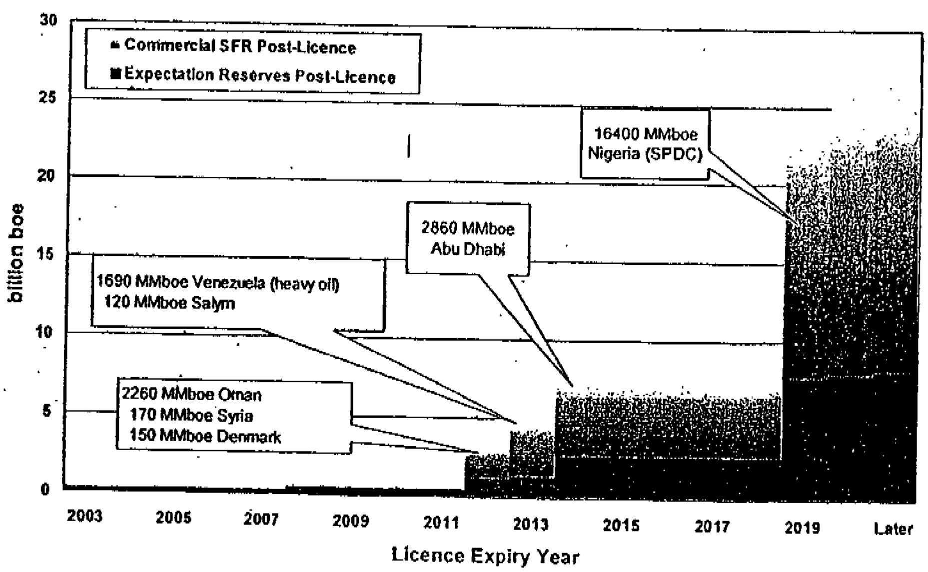
Inventory of Group Resources at 1.1.2002 (billion boe)

Category	Oil / NGL	Gas	Total
Proved Developed Reserves	4.3	4.4	8.8
Proved Undeveloped Reserves	5.7	5.2	10.9
Probable Reserves	6.8	6.2	13.0
SFR Proved Techniques	8.0	6.0	14.0
SFR Unproved Techniques	3.5	0.4	3.9
Total Commercial Resources, Discovered	**28.4**	**22.3**	**50.6**
SFR Undiscovered	14.1	11.3	25.5
Total Commercial Resources	**42.5**	**33.6**	**76.1**
SFR Non-Commercial	7.0	2.4	9.4
Total Resources	**49.5**	**36.0**	**85.5**

Includes Oil Sands and Oil Shales. Rounding effects may be apparent

Attachment 1b

Resources Locked beyond Licence Expiry



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Attachment 1c

Firm Constraints on Within-Licence Resources (at 1.1.2002)

Million boe		Proved Res.	Prob. Res.	Disc. SFR	Undisc. SFR	Total
Oil Sands and Shales: no (eventual) contribution to SEC Proved Reserves						
Canada	Muskeg River Mine	600	299	83		982
Shell Oil	Oil shales			745		745
Corresponding Gas Volumes				*175*		*175*
Total		600	300	1000		1900
Sakhalin: Reduction applicable on deconsolidation to 40%						
Oil		117	55	310	20	497
NGL				162	21	183
Gas				1456	172	1630
Total		120	60	1930	210	2310

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Attachment 1d

Possible Constraints on Within-Licence Resources (at 1.1.2002)

Million boe		Proved Res.	Prob. Res.	Disc. SFR	Undisc. SFR	Total
Gas: (Potentially) Stranded SFR						
Australia	Greater Sunrise			555		555
	Scot Reef / Brecknock			736		736
	Other			384	403	787
Canada	MacKenzie Delta (infrastructure)			152	46	198
Namibia	Kudu (likely to be deleted at 1.1.2003)			431	577	1010
Corresponding NGL Volumes				*234*	*44*	*278*
Total				**2490**	**1070**	**3560**
Heavy Oil: SFR difficult to commercialize						
Brazil	All fields and prospects			200	573	773
Canada	Peace River			999		999
	MacKenzie Delta			31	94	125
UK	Atlantic Margin				93	93
Venezuela	Urdaneta West			123		123
Corresponding Gas Volumes				*10*	*118*	*128*
Total				**1360**	**880**	**2240**
Oil Reserves that rely upon significant increase in production rate						
Nigeria (SPDC)		955	838			1793
Abu Dhabi		136				136
Australia (WPL)		11	20			30
Total		**1100**	**860**			**1960**
Gas Reserves that rely upon significant increase in production rate						
Nigeria (SPDC)		302	376			678
Norway		208	86			294
Malaysia		337	114			451
Brunei		65	272			337
Denmark			9			9
Total		**910**	**860**			**1770**
Gas: Reserves (Possibly) Prematurely Booked						
Australia	Gorgon	525	222			747
Norway	Ormen Lange	102	73			175
Corresponding NGL Volumes		*39*	*10*			*49*
Total		**670**	**310**			**970**

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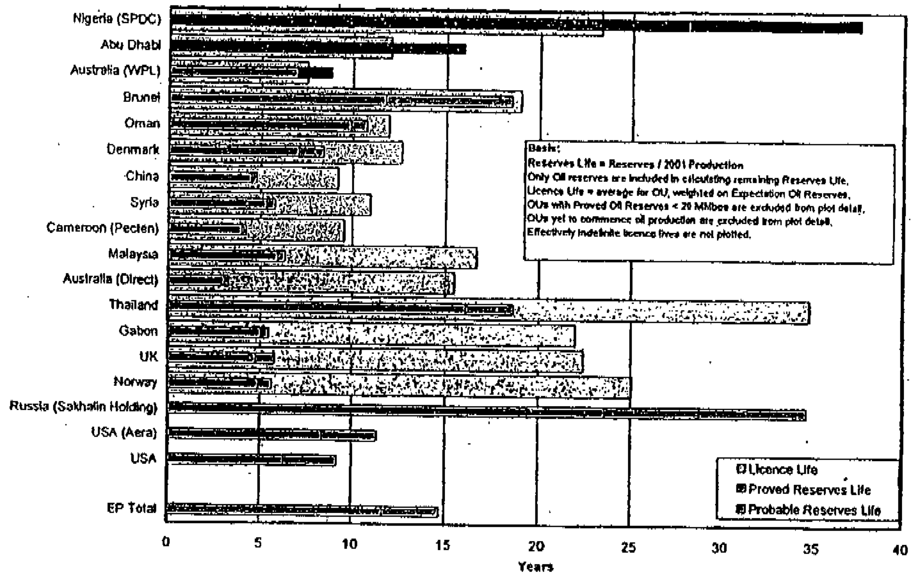
Attachment 1e

Oil: Reserves Life compared with Licence Life (1.1.2002)



SPDC and Abu Dhabi cannot produce their currently booked oil reserves without significant increases in production rate compared with 2001. For illustration, production must increase by 70% and 40% respectively by 2008 to ensure production of Proved Reserves within licence. The corresponding figures for Expectation Reserves are 140% and 40%.

Woodside ("Australia (WPL)") must maintain 2001 production levels to ensure production of Proved Reserves within licence, increasing slightly to secure Expectation Reserves.

Brunei and Oman (PDO) must maintain current production levels throughout the remaining licence duration to ensure production of Expectation Reserves: this might prove to be a challenge for the latter.

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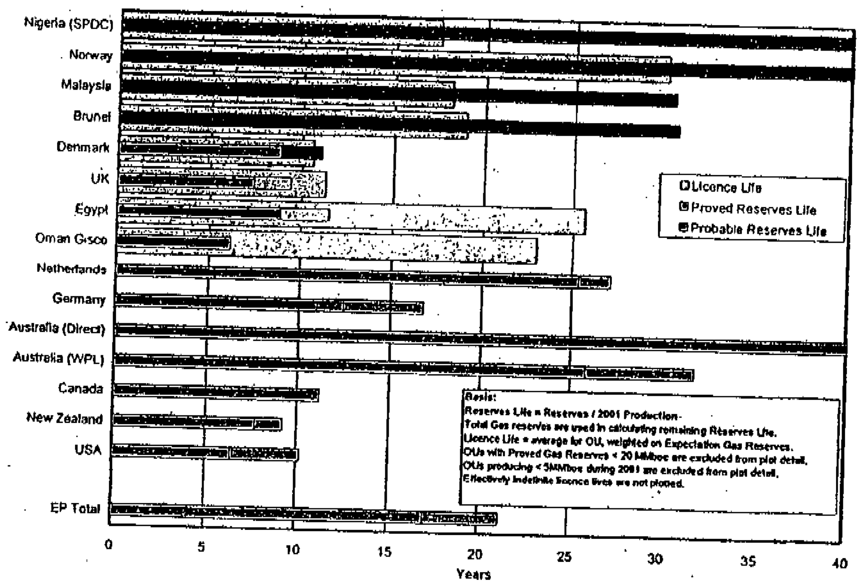
Attachment 1f

Gas: Reserves Life compared with Licence Life (1.1.2002)



SPDC, Norway, Malaysia and Brunei cannot produce their currently booked gas reserves without significant increases in production rate compared with 2001. For illustration, production would need to increase by the following amounts in each case by 2008 – and hold constant thereafter - to ensure production of the booked within-licence reserves:

	Proved	Expectation
SPDC (Train 4/5 &6?)	150%	340%
Norway (Ormen Lange to FID?)	70%	100%
Malaysia (MLNG-TIGA?)	60%	80%
Brunei	15%	70%

Denmark and the UK must maintain current production levels throughout the remaining licence duration to ensure production of Expectation Reserves.

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Attachment 1g

Hydrocarbon Resource Challenges by OU

Nigeria (SPDC):	Oil production must increase by 70% by 2008 in order to produce the currently booked Proved Oil Reserves (2500 MMboe). Alternatively, licence extension must be secured. 50% of gas proved reserves (some 250 MMboe) is "dedicated" to non-LNG outlets, unlikely to materialize – transfer to Train 4 & 5 (&6?). Moratorium on new Proved Reserves bookings.
SNEPCO:	Has one of the highest Proved:Expectation Reserves ratios of any OU (0.78), despite not yet having commenced production. Possible Bonga and Erha over-bookings are to be managed, severe challenge to mature Bonga SW in 2002 (appraisal and development studies outstanding).
Abu Dhabi:	Production must increase by 40% by 2008 to enable production of booked Proved Reserves. Alternatively, licence extension must be secured.
Australia:	Gorgon stranded gas (560 MMboe Proved Reserves booked), possible barriers to commercialization of much of the SFR portfolio.
Brazil:	900 MMboe commercial resource, mostly undiscovered. Heavy oil (assumed), possibly presenting both technical and commercial constraints.
Brunei:	ca. 20 MMboe legacy Proved Reserves still to be unwound.
Canada:	Peace River – 1200 MMboe SFR, heavy oil, possibly difficult to commercialize. Mackenzie Delta – 200 MMboe commercial gas resource stranded by lack of infrastructure.
Kazakhstan:	1200 MMboe SFR, scope to accelerate pace of maturation?
Namibia:	1000 MMboe gas SFR (Discovered & Undiscovered) at risk due to lack of critical mass for development.
Netherlands:	Waddenzee: ca 25 MMboe Proved Reserves at risk if project does not go ahead. Possible GIIP- and compression-related upsides in Groningen currently being worked.
Norway:	Ormen Lange booking to date at risk if project does not go ahead (100 MMboe Proved Reserves already booked, 400 MMboe total resource).
PDO:	Challenge to yield target production rates and hence reserves delivery.
Russia:	Sakhalin SFR maturation constrained (or not?) by LNG contract fixtures. 3800 MMboe total commercial resource on consolidated basis: reduced by 2300 MMboe on deconsolidation.
Venezuela:	Urdaneta West: 2100 MMboe commercial resource, heavy oil, much of it currently "licence locked", but the real issue is technology and economic project maturation.

DO WE THINK MARKET WILL NOT UNDERSTD THAT CONSOL RESERVES ARE NOT OURS?

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Attachment 2a

2002 Proved Reserves Additions: Latest Estimate

Million Boe	↑↓	Proved Reserves Additions Plan	LE	Delta	Reserves Replacement Ratio Plan, %	LE, %
Organic						
Kazakhstan	Kashagan Declaration of Commerciality + Arman		384	384		27.4
USA	Mars WF/Auger/Glider/OSO Marlin↑ Shawnee, Crossbones& others↓	139	145	5	9.8	10.3
Angola	Block 18 FID ↑	33	95	62	2.3	6.8
Brunei		67	66	0	4.7	4.7
Canada		50	50		3.5	3.6
Nigeria (SNEPCO)	Bonga SW challenge to reach VAR3 in 2002	116	49	-67	8.2	3.5
UK	Carrack West/Curlew↑, Shearwater/Cormorant/N&S↓, Scoter deferred	68	36	-31	4.8	2.6
Denmark		24	32	8	1.7	2.3
Venezuela	Not a gain; Plan figure was inadvertently omitted from EP total		25	25		1.8
Netherlands		30	25	-5	2.1	1.8
Malaysia	PSV/PSC effect, Tiga Papan/Ubah/Ramin↓, 075/St Joseph↑	31	23	-8	2.2	1.6
Syria		13	15	2	0.9	1.1
Egypt		11	11		0.8	0.8
Gabon		7	7		0.5	0.5
Pakistan	Bahdra-3 well result(↑). Query Plan figure.	10	5	-5	0.7	0.4
Australia (SDA)		0	4	4	0.0	0.3
Brunei (FCE)		3	3		0.2	0.2
Argentina		3	3		0.2	0.2
Germany	Changed / deferred drilling programme	17	2	-15	1.2	0.2
Thailand	Reduction pending completion of studies Q3/Q4	4	1	-3	0.3	0.0
Australia (WPL)		0	0		0.0	0.0
Russia	Deconsolidation deferred	-92		92	-6.5	
USA (Ass Comp)	Aera included in USA LE	4		-4	0.3	
Bangladesh	Changed / reduced activity level	4		-4	0.3	
Brazil	BS-4 deferred	41		-41	2.9	
Oman (PDO)	Production forecast exposure / uncertainty	76		-76	5.4	
Namibia	Kudu appraisal	125		-125	8.8	
Brazil (Pecten)			-3	-3		-0.2
Norway		7	-8	-15	0.5	-0.6
Oman (GISCO)	Virtual PSV / PSC effect		-23	-23		-1.7
New Zealand	Pohokura	4	-28	-32	0.3	-2.0
Iran	PSV effect		-41	-41		-2.9
Total Organic, without upside		796	878	82	56	63
Upside:						
Enterprise	Application of Shell guidelines & Growth - TBC		50	50		3.6
Total Organic		796	928	132	56	66
Production	Includes ExCom adjustment	1419	1399	-21		
A&D						
	Adjust total RRR so far for effect of A&D production					-3.0
ENTERPRISE (KMOC@46%)	KMOC = 131 mln boe		1141	1141		77.9
Norway	Draugen		33	33		2.2
USA	Rockies		27	27		1.8
TOPCO NZ			9	9		0.6
UK	Goldeneye		7	7		0.5
DR Congo (Zaire)			-17	-17		-1.2
Iran	Farm out		-38	-38		-2.6
New Zealand	Portfolio rationalization + transfer to TOPCO NZ		-71	-71		-4.9
Total A&D			1091	1091		71
Total Organic + A&D		796	2019	1223	56	138
Production Organic + A&D		1419	1465	45		
Strategic Options						
Whale		154	154		10.9	10.5
Libya Block 47		21	21		1.5	1.4
Stephenson		13	7	-7	0.9	0.4
Alibekmola notional		13		-13	0.9	
AIOC notional		81		-81	5.7	
Venezuela light oil		86		-86	6.0	
Libya gas		90		-90	6.3	
Namibia Gas (FLNG) incremental		145		-145	10.2	
OU projects		-2	-2		-0.1	-0.1
Total Strategic Options		601	180	-421	42	12
Grand Total		1397	2199	802	98	150
Production Grand Total		1419	1465	45		

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Attachment 2b

2003 Organic Proved Reserves Additions: Unconstrained Capital Allocation Portfolio

		Proved Reserves Additions 2003 only: Million boe	Reserves Replacement Ratio %
Organic			
Russia (Sakhalin Holding)	Piltun-Lunskoye Deconsolidated basis	398	25.8
Norway	Ormen Lange Post FID Development	118	7.7
China	West to East Upstream	110	7.1
Nigeria (SNEPCO)	Bonga South-West (if deferred from 2002)	72	4.7
USA	RMPA-Pinedale 02 5-Rig Base	61	4.0
Nigeria (SNEPCO)	Erha Main Field Development	56	3.6
China	Changbei Upstream	54	3.5
Enterprise	Enterprise Growth 2003+ (estimate)	50	3.2
USA	Ursa 02 Inc9 Waterflood	36	2.3
China	East China Sea Development	22	1.4
Nigeria (SNEPCO)	Bolia	21	1.4
UK	564 - Phyllis	21	1.4
USA	RMPA-Yugo 02 Base	20	1.3
China	Bonan Oil: BZ25-1 Oil Development	20	1.3
Brunei	CA03 WB 100 AU West Existing	15	1.0
Netherlands	Onshore Rotliegend Play	14	0.9
Brunei (FCE)	ML South Cluster Exploration	14	0.9
USA	Brutus 02 Base	13	0.8
Syria	AFPC Project - Tranche 1a (FID 2002)	12	0.8
China	East China Sea Exploration	12	0.8
UK	568 - Starling	12	0.8
Brunei	CA03 WB 248 Champion SE Water Injection	11	0.7
Netherlands	Offshore Rotliegend Play	11	0.7
UK	559 - Harrier Shallow	10	0.7
Denmark	SOGU Tranche 1	10	0.6
USA	SOC.Tr.1.MarsBasin.EB2	10	0.6
Brunei	CA03 WB 200 AU East Existing	9	0.6
UK	504 - Nessie	9	0.6
Germany	Tranche 1/ 2003	9	0.6
USA	SOC.Tr.2Fwd.Texas1 (Forward Curve)	9	0.6
Brunei	CA03 WB 429 1704A BANGAU Exploration	8	0.5
UK	454 - Schiehallion Claw (420)	8	0.5
China	Bonan Gas	8	0.5
UK	001 - Existing Assets	7	0.5
Malaysia	PM302: Bunga Dahlia	7	0.5
Australia (Direct)	T1-4 EP	7	0.4
Denmark	SOGU Tranche 2	6	0.4
USA	RMPA-Pinedale 02 6th Rig.Option	6	0.4
UK	501 - Firm E&A - Cutler	6	0.4
Oman	Existing Assets (including Corporate Overheads)	6	0.4
UK	336 - Tranche 2b - FID2003	6	0.4
UK	114 - Penguin (416)	6	0.4
UK	330 - Tranche 1 - FID2003	5	0.4
Gabon	Existing Assets (ga)	5	0.3
Pakistan	Indus Deepwater Exploration Well (Notional)	5	0.3
Brunei	CA03 WB 314 AU Darat Tr1 FID04	5	0.3
Other projects		185	12.0
Grand Total		1526	99
Production Grand Total		1541	

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Attachment 2c

Projects with major Proved Reserves Additions in 2004 – accelerate to 2003?

The following would be the prime contenders, as viewed today, for acceleration from 2004 in order to redress the 2003 deficit against the 100% RRR aspiration. They are the *only* projects (as submitted for Capital Allocation) with unrisked Proved Reserves Additions in 2004 that exceed 100 mln boe, or 7% RRR:

Project	POS to FID	Category	Unrisked PRA[3]	Unrisked RRR
Australia Ceduna	10%	E&A	130	+9%
Australia Sunrise LNG	15%	Development	340	+23%
Egypt NEMED gas	24%	E&A	130	+9%
Egypt NEMED Lc 59	11%	E&A	340	+23%
Iran Bangestan	15%	SO[4] (organic?)	300	+21%
Qatar SMDS	50%	SO (organic?)	350	+24%
Russia Zapolyarnoye Neocomian	50%	SO (organic?)	760	+53%
Saudi Arabia CV1 Upstream	10%	SO (organic?)	730	+51%

Attachment 2d

2003 Other Upside Potential

In addition to the ongoing efforts within the OUs (the fruits of which are not yet sufficiently mature as to be reflected firmly in OU plans), the following specific items can be identified from the Capital Allocation project portfolio and from assessment of the overall business:

Project	PRA	RRR
Secure Whale Strategic Option, de-risk, "organic"?	600	+42%
Secure Salym Strategic Option (de-risked)	120	+8%
Other Strategic Options (Itau, Kuwait OSA), risked basis	150	+10%
Retain Sakhalin consolidated	600	+42%
T&OE quick wins (highly uncertain)	up to 150	up to 10%
Total potential gain identified	**up to 1630**	**up to 112%**

[3] Proved Reserves Additions in 2004, million boe
[4] Strategic Option

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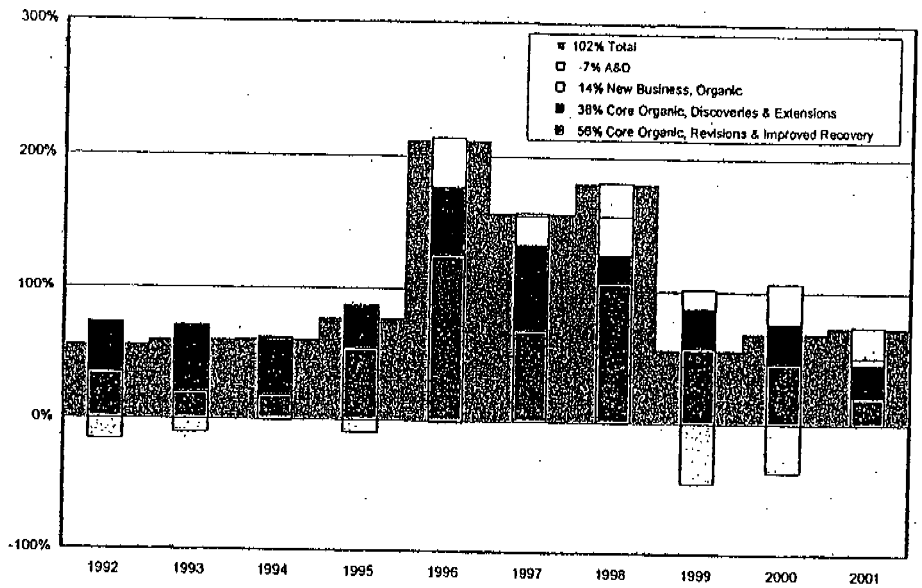
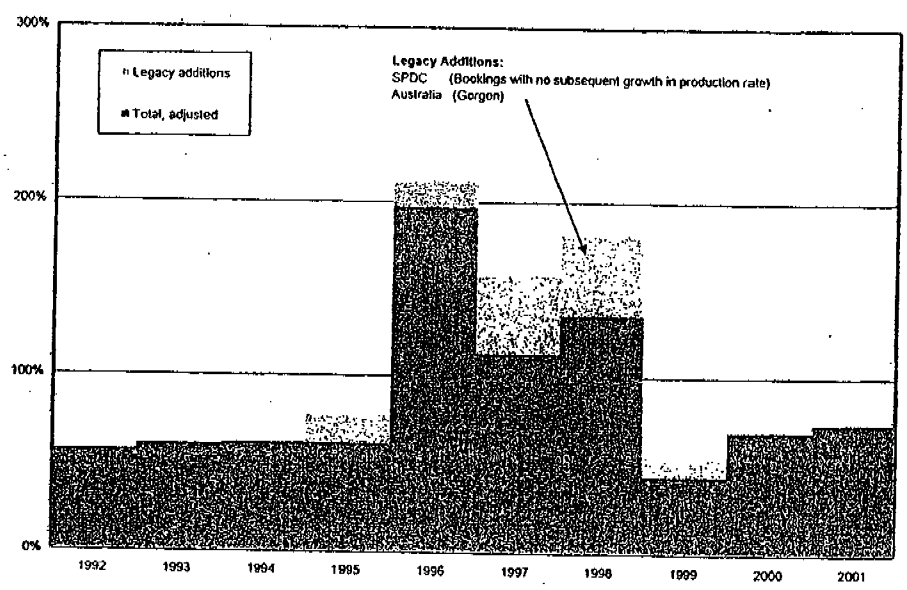
Attachment 3a

Historical Contributions to Proved RRR



Attachment 3b

Legacy / Premature Bookings



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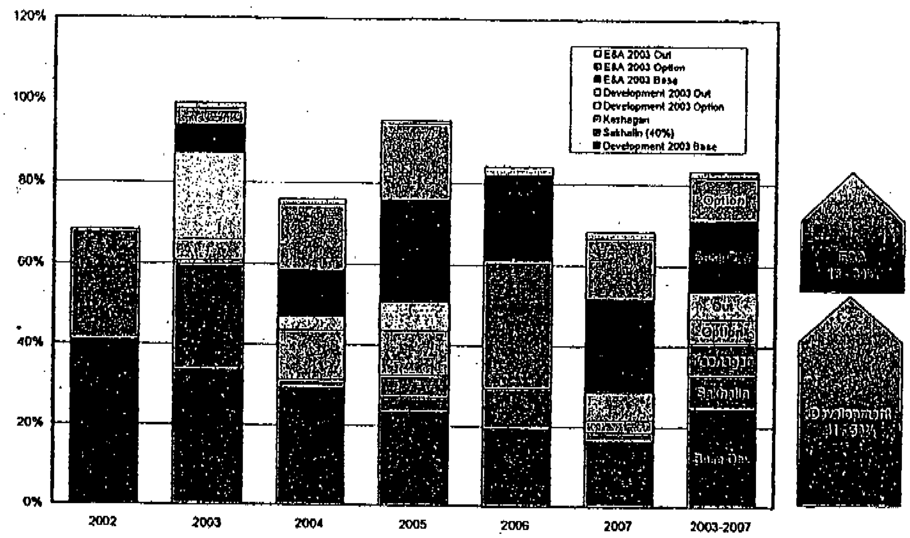
Attachment 3c

Plan Period Organic Proved RRR



"Base, Option and Out" rankings apply to 2003 only: the programme for 2004+ has yet to be built and rankings may change for later years

This plot shows the full 2002 Capital Allocation data set for Existing Business. Only the programme for 2003 has so far been ranked and constrained to fit within Capex and Expex budget ceilings (the "Base" elements referred to in the plot), and this ranking must be viewed as very preliminary.

Enterprise is carried in "Base Development" at 4% a.a.i. production growth and 50 million boe per year Proved Reserves Additions: these figures to be confirmed upon receipt of Enterprise plan data..

Indications are that organic RRR averaged over the Plan Period (2003 – 2007) will be at least 59% (41% from Development activities, including Sakhalin and Kashagan; 18% from new Exploration and Appraisal activities).

Without expenditure restraint, the maximum deliverable organic RRR would be 83% (53% from Development, 30% from new E&A).

With expenditure restraint applied to 2004 and beyond, the organic RRR delivered by the Plan will clearly be at some point between these two extremes.

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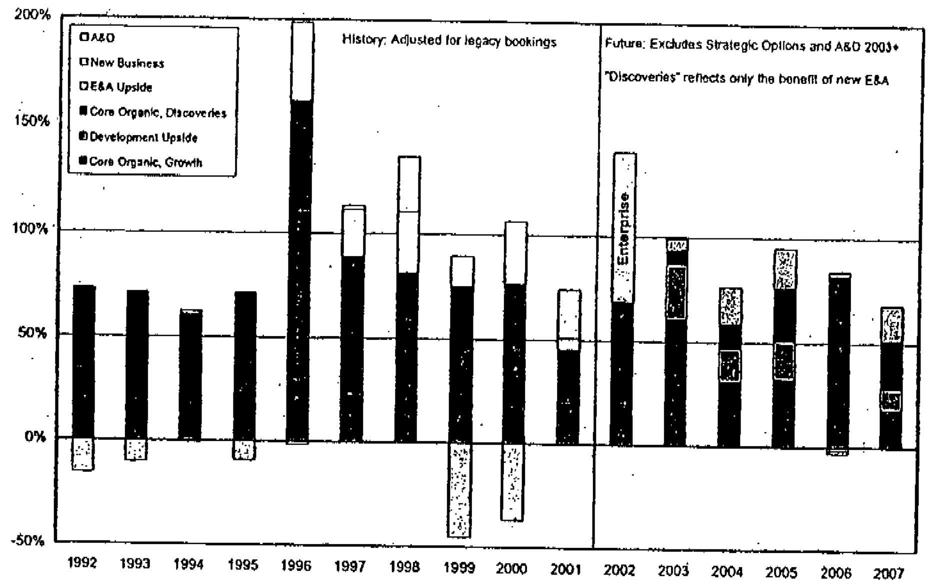
Attachment 3d

Plan Period Organic Proved RRR in context with History



This plot attempts to show the outlook for organic Proved RRR in context with the past. Full consistency in the view cannot be achieved, since the Capital Allocation data for the future is not segregated to show the true contribution from (historical) E&A activities:

"Core Organic, Growth" equates to "Revisions and Improved Recovery" in the historical part of the plot, but to "Development activities" in the future. Consequently this includes reserves that actually stem from recent exploration discoveries.

"Core Organic, Discoveries" equates to "Discoveries and Extensions" in the historical part of the plot, but only reflects the contribution of new E&A activities going forward.

Enterprise is carried in "Core Organic, Growth" at 4% a.a.i. production growth and 50 million boe per year Proved Reserves Additions: these figures to be confirmed upon receipt of Enterprise plan data.

1200 - 1230 → 17/10

Van der Laan, Marian M SI-MGDWV/DIRMB

From:	Mair, Jim JH SIEP-EPB-B
Sent:	23 September 2002 08:57
To:	Van De Vijver, Walter SI-MGDWV
Cc:	Brass, Lorin LL SIEP-EPB; Coopman, Frank F SIEP-EPF
Subject:	RE: Australia Visit

Walter,

Thanks for the debrief. If possible I'd like a face to face this week to cover the issues and way forward. Appreciate you have CMD today and tomorrow. Also I'm out from Wednesday morning until next Tuesday so may have to be by phone. Will contact Marian re. a suitable time for you, Lorin and Frank. Attached is an update on Westminster activities for your information.

Jim

~$arification email for Blanch...

-----Original Message-----

From:	Van De Vijver, Walter SI-MGDWV
Sent:	Sunday, September 22, 2002 11:32 PM
To:	Mair, Jim JH SIEP-EPB-B
Cc:	Brass, Lorin LL SIEP-EPB; Coopman, Frank F SIEP-EPF
Subject:	FW: Australia Visit

Wrt Westminster.

Obviously I did not raise it with Akehurst/Goode.Akehurst apparently enjoys disliking them ,foremost as they do not want to appear to spend a money on NWS.
Any thoughts about Akehurst being ready to retire forget it,he is obsessed with status and money!
Goode got so fed-up with him that he only has 2 years contract (base UK 1 million base) from 3/2002 onwards eventhough he acknowledges himself that there is no successor in Woodside and that he does not know anyone better,
Also met briefly with Peter Mason of JP Morgan.Nothing really new,he believes that BHP will not be stopped acquiring Woodside (will only be required again to confirm headquaters in Melbourne) ,timing ideal to be October/November (also to finish before planned Telstra privatisation next year).
The obvious waste in the current set-up is obvious but than again they seem to want to make things as complicated as possible down under.I must admit that I really wonder why we need to re-create SDA if ultimately operations will need outsourcing to the new merged company and furture revenue is solely linked to partner alignment with Phillips,CT etc to get the stranded reserves in the cue for development.
I will need a very convincing portfolio and metrics to make it happen.Paying a premium upfront is going to make value realisation difficult.
Have to got a forward process defined to 1) close valuation gap 2) resolve NWS model (Shell gas marketing does not appear that relevant anymore) 3) get fail-safe tactics ?!
The difference with base case (an im proved as per attached) needs to be prepared.
Thanks,
Walter

-----Original Message-----

From:	Van De Vijver, Walter SI-MGDWV
Sent:	22 September 2002 18:01
To:	Watts, Philip B SI-MGDPW; Van der Veer, Jeroen J SI-MGDJV; Skinner, Paul PD SI-MGDPS; Brinded, Malcolm A SI-MGDMB
Cc:	Boynton, Judith G SI-FN; Gardy, Dominique D SEPI-EPA; Van De Vijver, Walter SI-MGDWV
Subject:	Australia Visit

I just returned from 4 days in Australia (Perth,Karratha,Melbourne).Malcolm and I shared a day with SDA (Shell Development Australia).Malcolm's visit was focused on his RMD/G&P role whilst my visit was driven by wanting to get a first-hand experience of the Shell /Woodside relationship.

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HAG00084944

EXHIBIT Van der Vijver 15 2/1/07

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