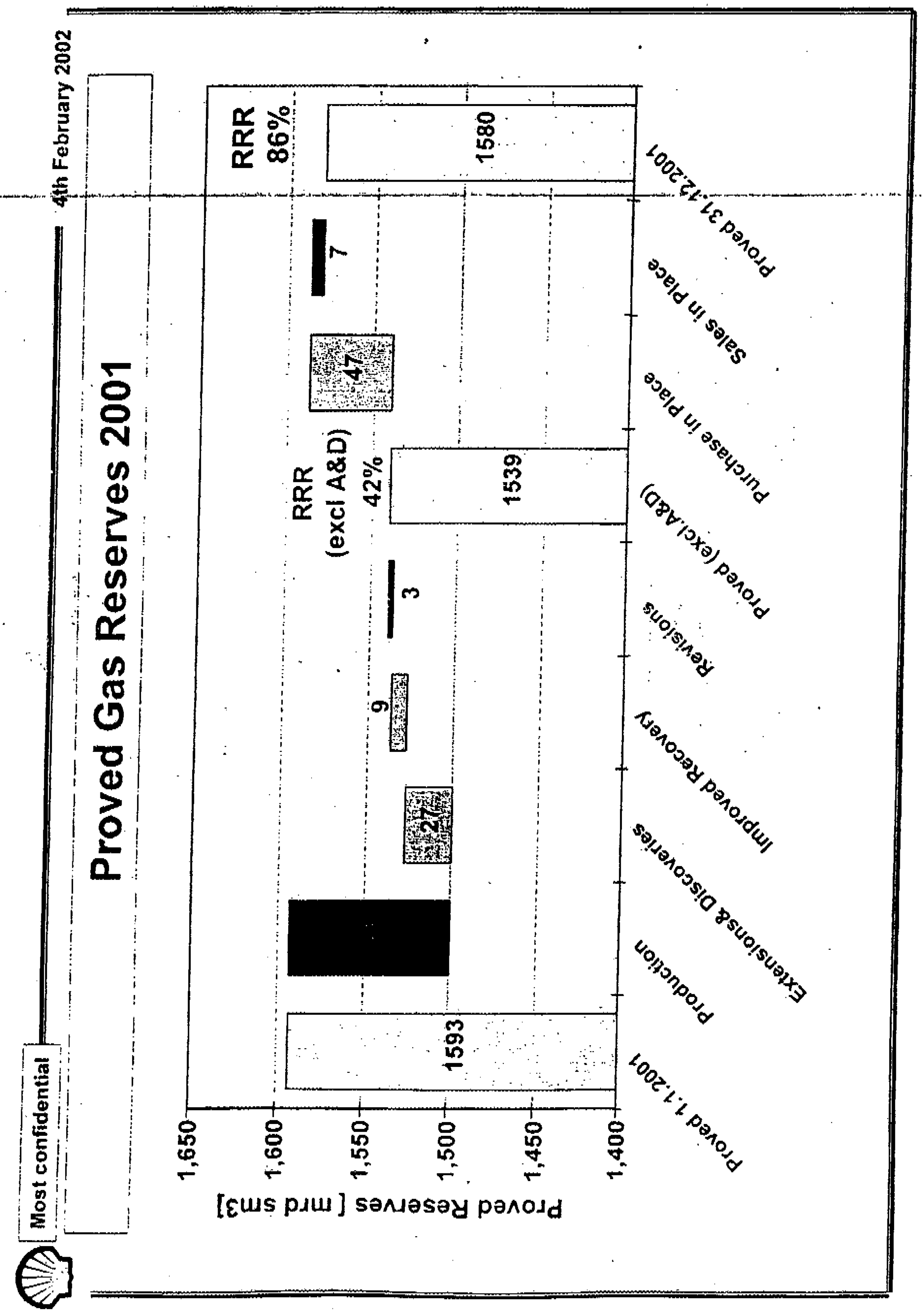
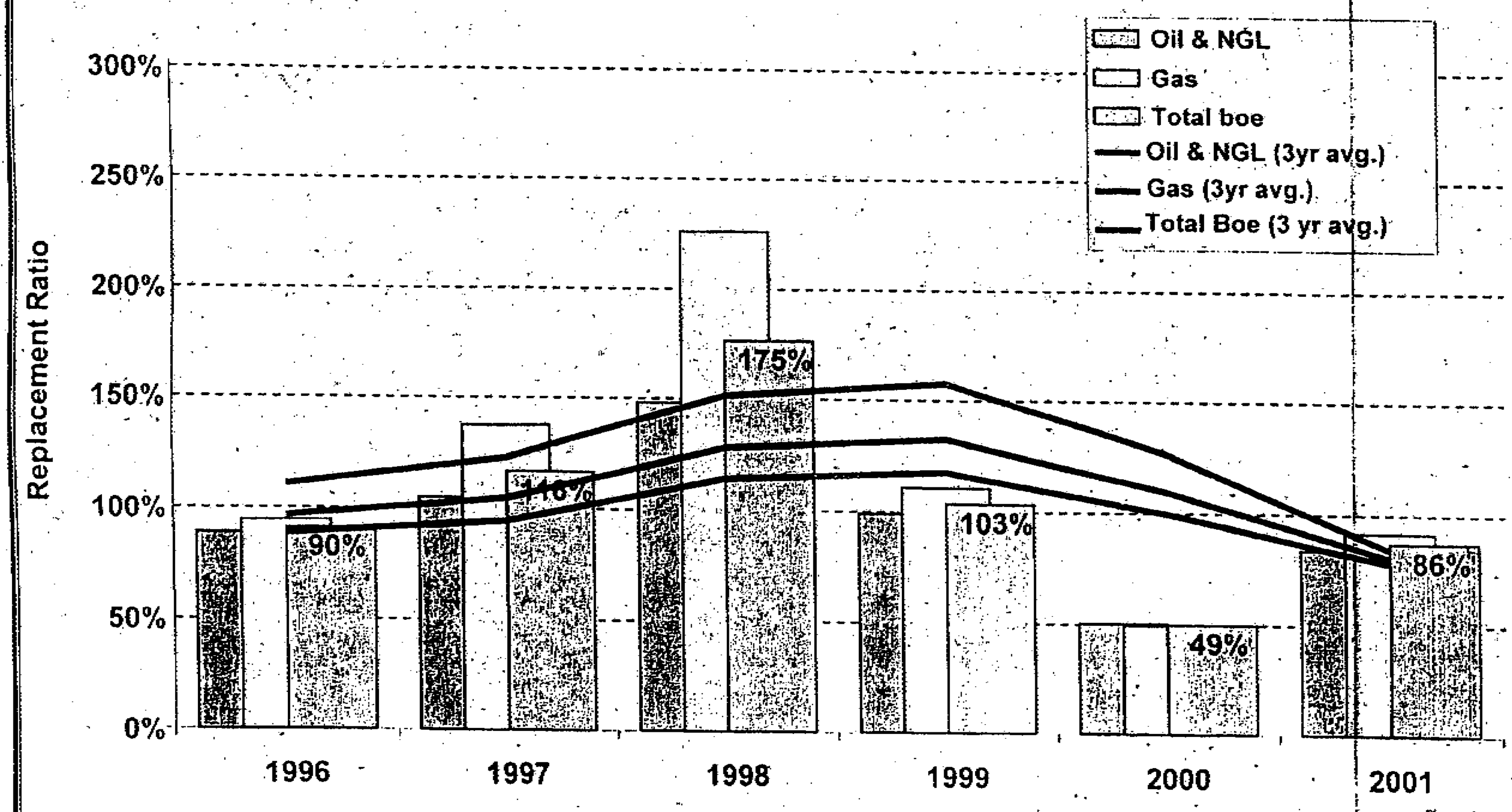
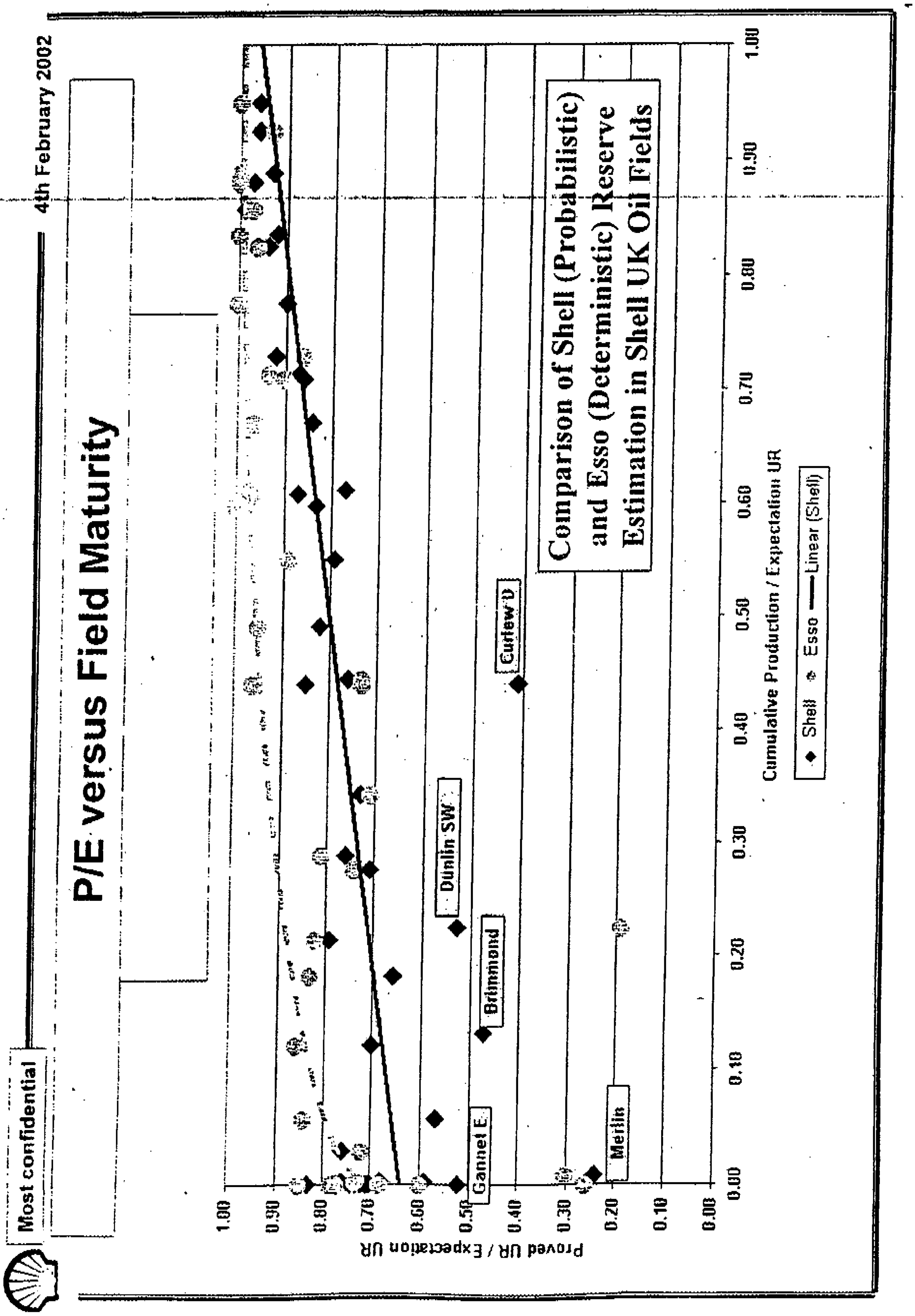

Most confidential
4th February 2002
Proved Gas Reserves 2001
Proved Reserves [mrd sm3]
1,650
1,600
1,550
1,500
1,450
1,400
1593
27
9
3
1539
47
7
1580
RRR
(excl A&D)
42%
RRR
86%
Proved 1.1.2001
Production
Extensions & Discoveries
Improved Recovery
Revisions
Proved (excl.A&D)
Purchase in Place
Sales in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

Most confidential

4th February 2002

Proved Developed RRR




Most confidential
4th February 2002
P/E versus Field Maturity
Comparison of Shell (Probabilistic) and Esso (Deterministic) Reserve Estimation in Shell UK Oil Fields
Curlew D
Dunlin SW
Brimmond
Gannet E
Merlin
Proved UR / Expectation UR
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
Cumulative Production / Expectation UR
Shell
Esso
Linear (Shell)

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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

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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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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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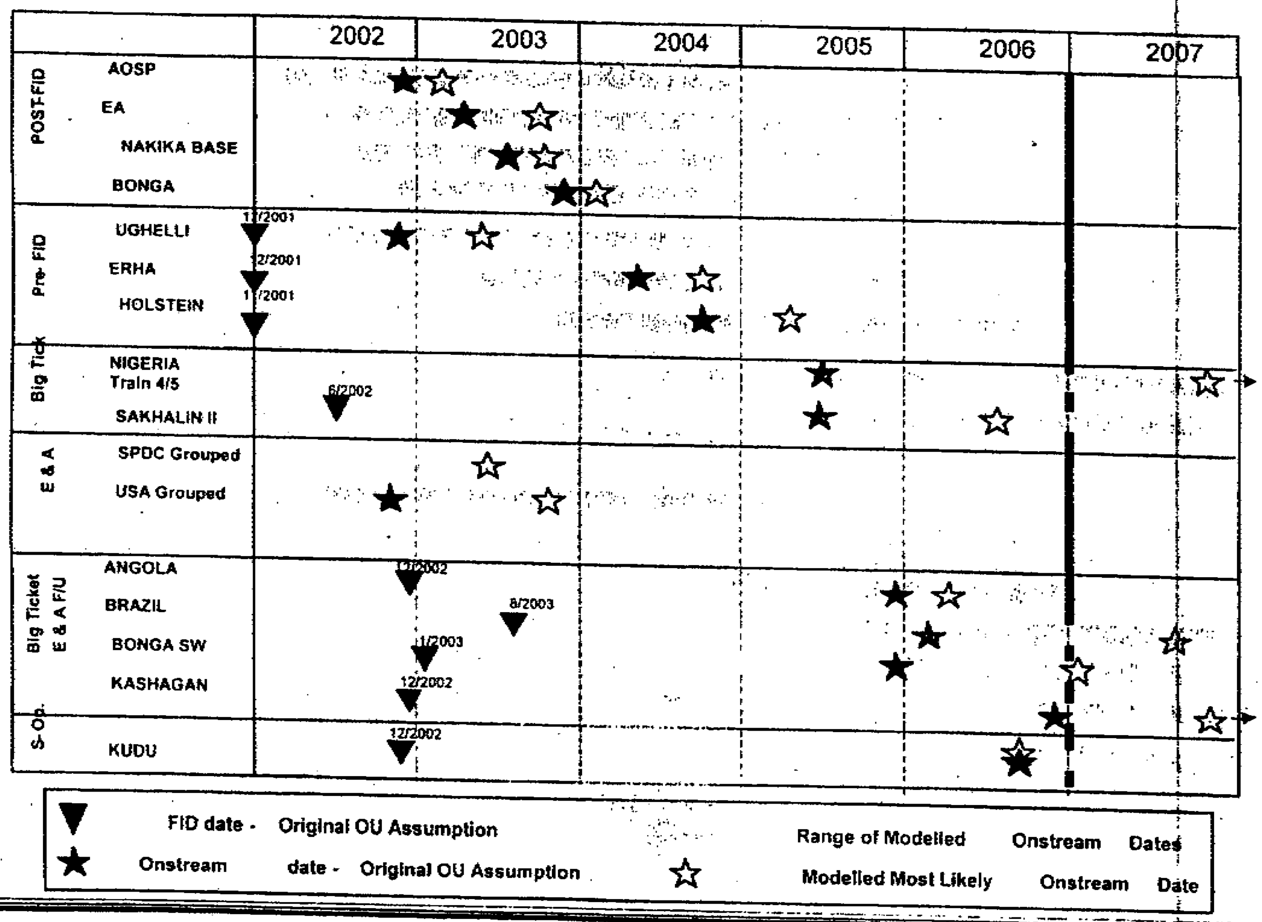
Major Project Assumptions



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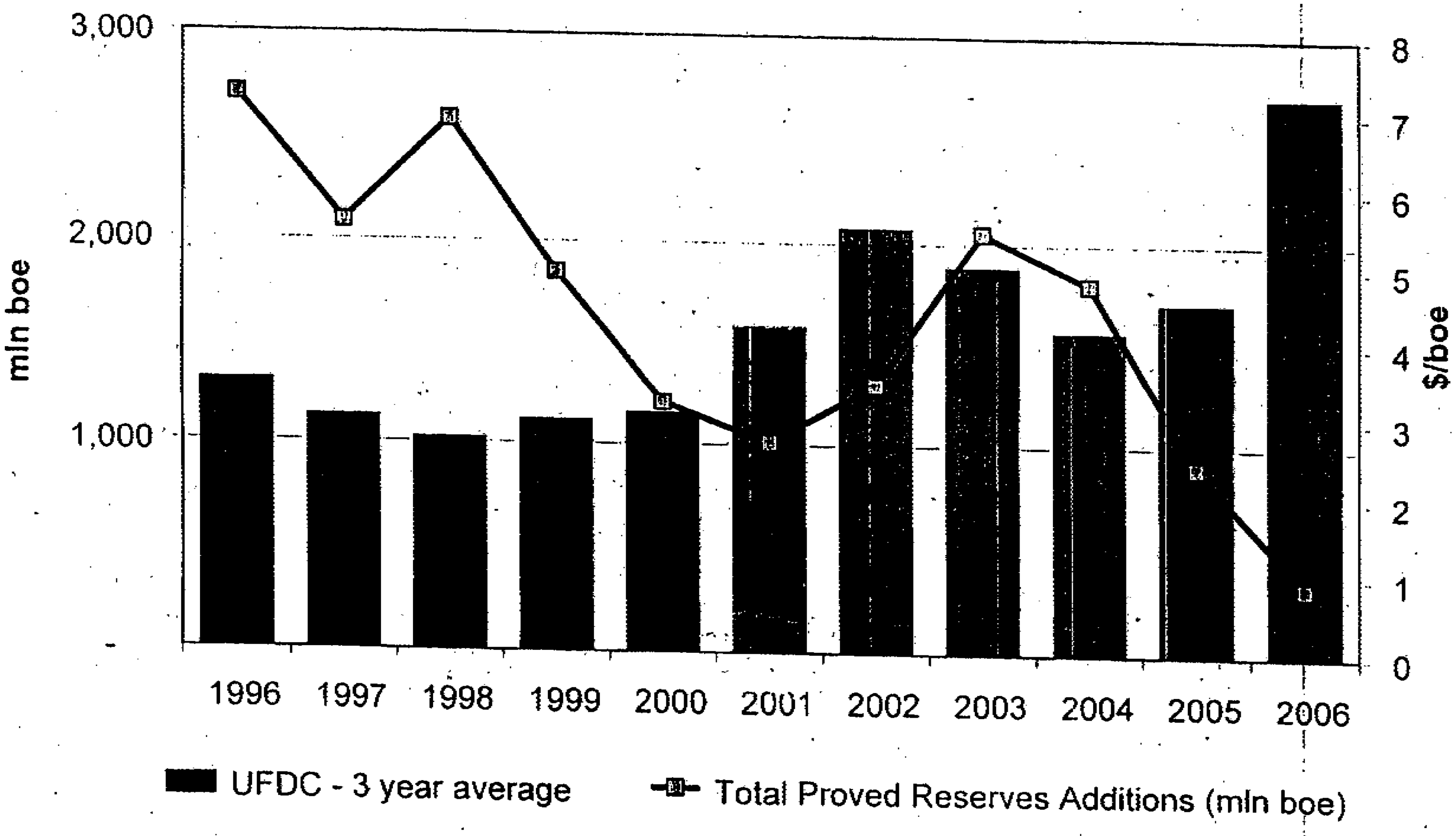
Unit Finding and Development Costs - Proved Reserves



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Note For Information 4th February 2002

Summary of End 2001 Proved Reserves

This note summarises the end 2001 Group Resources, especially proved and proved developed reserves, cleared by External Audit, ahead of the 4Q01 and FY01 press release.

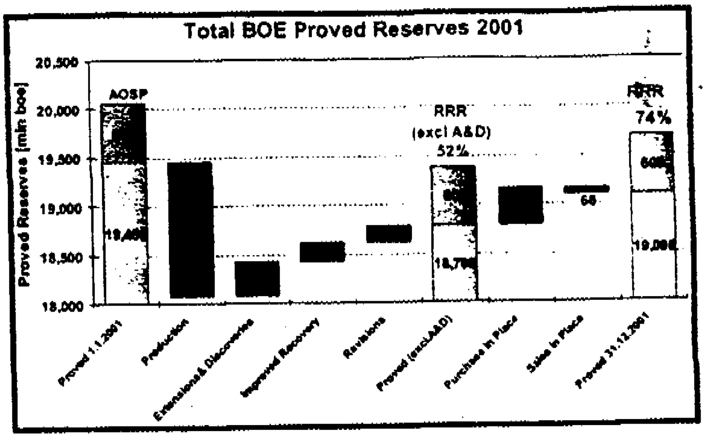
Summary

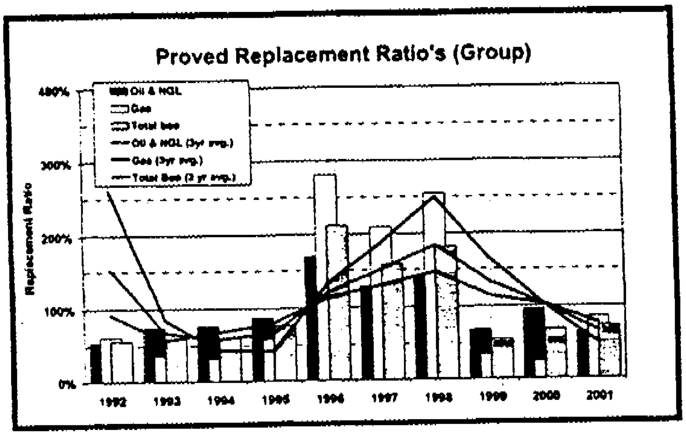
The total barrel of oil equivalent proved hydrocarbon reserves replacement ratio (HC-RRR) in 2001 is 74%. (*2000 69%*). The three years average proved HC-RRR is 67% (*2000 102%*, excluding AOSP) and the three years average proved developed HC-RRR is 79% (down from *109%* in *2000*).

	Unit	Proved Reserves 1.1.2001	Proved Reserves 31.12.2001	Actual Production 2001	Proved RRR	HCC-RRR (excl. A&D)
Oil/NGL	mln m^3	1552	1506	129	65%	58%
Gas	mrd sm^3	1593	1580	93	86%	42%
Total BOE	**bln boe**	**19.5**	**19.1**	**1.4**	**74%**	**52%**
AOSP	bln boe	0.6	0.6	-	-	-

Proved oil/NGL and gas reserves for the Group are split 50/50. During 2001 there have been no changes in the proved HC "mining" reserves for Canada AOSP. Inclusive AOSP reserves, the three years average proved HC-RRR is 81% (*2000 117%*)

The 74% proved HC-RRR amounts to a reserves addition of 1.02 bln boe, split between Discoveries & Extensions 0.36 bln boe, Revisions & Improved Recovery 0.35 bln boe and net impact of A&D 0.31 bln boe. The revisions also includes changes in Minority Interests.





The proved HC-RRR in 2001 excluding the reserves changes resulting from acquisitions and divestments (A&D) was 52%, below versus the 2001 EP scorecard target of 80% excluding A&D (range 50%-110%). (*2000 HC-RRR was 105% excl. A&D*).

Total SFR maturation to expectation reserves over 2001 was 1.5 bln boe or 4.0% versus SFR-commercial 1/1/2000 of 37.0 bln boe, below the 2001 EP scorecard target of 2.5% (range 2.0%-3.0%).

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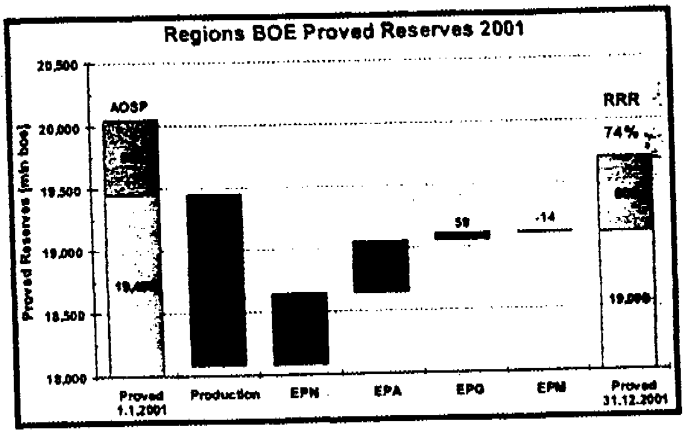
Changes during 2001

As a result of the Fletcher acquisition, Brunei FCE reports as a new entry (+ 6 mrd m^3 gas, +1 mln m^3 oil). Reserves reporting of Sakhalin is now consolidated which added +14 mln m^3 oil to the reserves (+6% RRR on total boe basis). No new ventures booked first time proved reserves in 2001. A summary by region is given below.

	OIL/NGL [mln m3]					Gas [mrd sm3]					
	Proved 1.2001	Proved 1.2002	Prod 2001	Delta	RRR	Proved 1.2001	Proved 1.2002	Prod 2001	Delta	RRR	RRR boe
EPN	411	393	59	-18	70%	859	848	61	-10	83%	76%
EPM	364	351	29	-12	58%	94	70	9	-29	-128%	-6%
EPA	173	180	19	7	136%	528	548	20	20	198%	168%
EPG	603	581	22	-21	3%	107	114	3	6	331%	38%
Total	1550	1506	129	-45	65%	1593	1580	93	-13	86%	74%

The changes in proved reserves split by Region shows net oil/NGL reserves declining in all Regions except EPA, leading to an oil/NGL RRR of 65% (*2000 97%*). The RRR of gas reserves was 86%, much better than the 25% of 2000.



Variance analysis

Major positives(in mln m3 boe)

- Netherlands: proved booking in Groningen +22 as performance keeps matching expectation.
- USA: Holstein +11, Pinedale acquisition +10 and dvt drilling results
- New Zealand: Maui +27, downward revision –11, inclusion pre-paid gas +6
- Denmark: Halfdan, Dan West improved recovery +10, moving proved to expectation +8
- Brunei FCE: acquisition, plus minor revisions +7
- UK: Penguins and Carrack +7,

Major negatives

- Pakistan: -3 net effect of dissolution of PSP –5 and increases in WI +2
- Egypt: Obayied updated FDP –5
- Aera: Belridge diatomite downward revision –3
- Canada: Sable –9 update on geological info and well performance
- Gisco: impact of accelerated repayments –16

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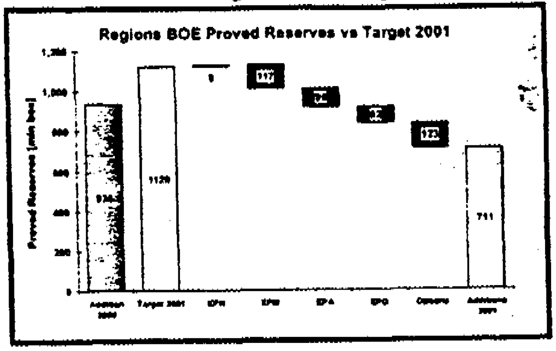
Actual versus Target

For 2001 the target RRR in the EP scorecard was 79% excluding A&D, or an addition of 1120 mln boe at target production. The actual addition was 710 mln boe, or 52% RRR at actual production, well below the scorecard target (range 50-110%).

	EPN	EPA	EPM	EPG	Options	
Target (excl A&D)	511	228	101	156	123	1120
Actual (excl A&D)	519	111	6	74	0	710
Delta	8	-117	-95	-82	-123	-409
A&D	47	295	-20	-15	0	307
Actual (incl A&D)	**566**	**407**	**-14**	**59**	**0**	**1018**

The main variances behind the lower than planned RRR were

- None of the strategic options that planned to book reserves in 2001 materialized, e.g. Saudi Gas, T2T, Salym, Bangestan, Felix, Oscar, Libya etc. The impact was –123 mln boe or –9% RRR
- In EPN the negative revisions from Canada and Aera and the overall disappointing results from the UK were balanced by upward revisions in the Netherlands and Denmark and large first bookings in the USA.
- In EPM results are suffering mainly from Gisco, Egypt (Obaiyed revised FDP) and PDO where new bookings are not likely to occur in the medium term.
- In EPA China (no booking in Changbei) and Brunei (legacy debookings) were outweighed by positive bookings in Malaysia and Woodside.
- In EPG SNEPCO (Bonga SW) and Brazil (despite 6 discoveries) could not book reserves, only to be compensated by gas additions in SPDC and revisions in Venezuela.



Breakdown of Proved Changes by Category

The net change in reserves is the result of Production and Divestments (Sales in Place), the reductions are mostly offset for oil/NGL and only partly offset for gas by increases from Discoveries & Extensions, Improved Recovery, Revisions & Reclassifications and Acquisitions (Purchases in Place).

	Oil/NGL [mln m3]	Gas [mrd sm3]
Proved Reserves 1.1.2001	**1550.4**	**1592.8**
Revisions & Reclassifications	23.4	3.3
Improved Recovery	20.9	9.1
Extensions & Discoveries	30.4	27.2
Purchases in Place	13.3	47.5
Sales In Place	-3.9	-6.8
Production 2001	-128.8	-93.1
Proved Reserves 31.12.2001	**1505.6**	**1592.8**
Proved RRR incl. A&D	65%	86%

The gas RRR of 86% is an increase from the 25% in 2000.

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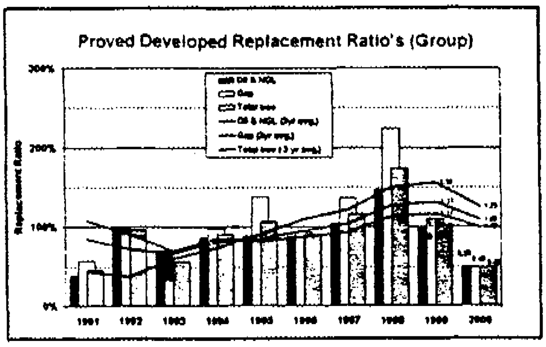
Proved Developed Reserves

The proved developed reserves as of 31.12.2001 stand at 689 mln m^3 oil/NGL and 729 mrd sm^3 gas, showing an decrease of 22 mln m3 and 8 mrd sm^3 for oil/NGL and gas respectively after taking account of 2001 production. Proved developed RRR is 83% for oil/NGL and 91% for gas, and 86% for total boe.

	Oil/NGL [mln m3]	Gas [mrd sm3]
Proved Dev. Reserves 1.1.2001	**710.7**	**737.0**
Transfer Undev to Dev Reserves	84.6	79.6
Revisions	22.1	5.0
Production 2001	-128.8	-93.1
Proved Dev. Reserves 31.12.2001	**688.7**	**728.6**
Proved Dev RRR incl. A&D	83%	91%

Proved developed oil/NGL reserves increased largely from new developments in USA, UK and Malaysia, offset by the divestment of Altura and new accounting in Oman-GISCo. Proved developed gas reserves increased from new developments in Malaysia (F6 compression), UK and USA-SEPCo partly offset by divestment of USA-Altura, and USA excluding of own use gas.

The three years average proved developed RRR is 95% for oil/NGL, 83% for gas and 79% for total boe.



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Major Proved Reserves Changes by Category and Country

Breakdown of the major changes is as follows :

	Oil/NGL [mln m3]
Sales in Place (Divestments)	-4
Argentina (La Ventana)	-2
USA (TMR, Aera)	-2
Purchases in Place (Acquisitions)	13
New Zealand (Fletcher)	12
Other	1
Extensions & Discoveries	29
USA (Holstein, Kepler, etc)	22
Brunei (Bugat)	3
UK (Penguins, Carrack)	2
Others	2
Improved Recovery	21
Denmark (Halfdan)	9
Oman	6
Others	6
Revisions & Reclassifications	23
Sakhalin consolidation	14
Denmark (proved toward expect)	7
USA (Brutus, Mars, etc)	5
USA Aera (Belridge diatomite)	-4
Abu Dhabi (+6 NGL, -5 Oil)	-1
Nigeria-SPDC(+15NGL, -17Oil)	-2
Oman PDO (adjusted forecast)	-8
Others	12

	Gas [mrd sm3]
Sales in Place (Divestments)	-7
Pakistan	-5
Other	-2
Purchases in Place (Acquisitions)	48
New Zealand (Fletcher)	31
USA (Pinedale)	10
Brunei (Fletcher)	5
Pakistan	2
Extensions & Discoveries	27
USA (Holstein, Kepler, etc)	11
UK (Penguins, Carrack)	4
Brunei (Bugat)	3
Egypt (Rosetta)	3
Others	6
Improved Recovery	9
Malaysia	5
Others	4
Revisions & Reclassifications	3
Netherlands (Groningen update)	22
USA (Brutus, Mars, etc)	4
Nigeria	6
New Zealand (Maui - pre-paid)	-4
Egypt (Obayied)	-5
Canada (Sable Island)	-8
Oman – Gisco (new deal)	-14
Others	-6

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Major Issues

End of License

In 2001, 18% of EP's production is in countries where no new reserves can be booked: PDO, Abu Dhabi and SPDC. This means that if all other OUs had achieved 100% replacement of production, the RRR of EP would still have been only 82%. The reserves in these OUs have been frozen since it is no longer 'reasonably certain' that the proved forecast will be produced.

- SPDC: the R/P exceeds the license period by 50%, which means that unless growth materializes soon, more then 1 bln bbls is exposed.
- Abu Dhabi: at flat production the exposure is 200mln bbls.
- PDO: here the challenge is to keep production at the 850 kbpd. For every 10 kbpd under that level Shell would have to debook 14 mln bbls.

All three OUs are also sensitive to OPEC constraints.

	mln boe				
	Prod. 2001	Proved 1.2002	R/P years	License expiry	Exposed volume
SPDC	105	3170	30	2019	1000
Abu Dhabi	34	587	17	2014	200
PDO	103	1021	10	2012	~100
Total	**242**	**4778**			**1,300**

Major ticket bookings

- Gas projects
  - o T4/5, VLNG, Sakhalin not in 2001
  - o Gorgon vs Sunrise: swap?
- Deepwater in frontier areas not materializing
  - o Angola: gas disposal showstopper, 70mln bbls proved reserves exposure
  - o Brazil: 6 discoveries, heavy oil, no proved reserves booked
  - o SNEPCO: Bonga SW and Bolia large discoveries, no proved reserves
- Options
  - o Saudi gas not in 2001, not likely now before xxx?
  - o Whale

Outlook 2002: early signals

- FLNG Namibia, Whale, Sakhalin, T4/5
- EOL, SPDC is now at 100kbpd constrained
- Angola: make or break (debooking)?
- UK

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Attachment 1

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Proved Reserves 31.12.2001 by Region by Country

Proved Reserves Summary

	Crude Oil and NGL in million M3					Gas in milliard SM3					
	Proved Reserves 01/01/00	Proved Reserves 31/12/00	Prod 2000	DELTA	Repl. Ratio	Proved Reserves 01/01/00	Proved Reserves 31/12/00	Prod 2000	DELTA	Repl. Ratio	BOE Repl. Ratio
Netherlands	5.77	4.96	0.75	-0.81	-8%	413.425	399.851	14.828	-13.574	8%	8%
UK	129.92	102.25	21.98	-27.67	-26%	109.447	98.606	11.583	-10.841	6%	-15%
Norway	33.26	32.76	5.07	-0.50	90%	89.897	89.781	2.060	-0.116	94%	91%
Denmark	39.15	43.54	7.53	4.39	158%	30.440	29.352	3.105	-1.088	65%	132%
Germany	3.37	3.05	0.31	-0.32	-3%	59.422	55.988	4.659	-3.434	26%	24%
Austria	0.23	0.23	0.03	0.00	100%	1.476	1.596	0.175	0.120	169%	158%
Shell Oil (USA)	92.00	97.17	16.18	5.17	132%	96.232	96.317	16.592	0.085	101%	116%
Shell Oil (Aera)	79.26	69.09	7.23	-10.17	-41%	5.530	1.287	0.117	-4.243	-3526%	-94%
Shell Oil (Altura)	47.87	0.00	0.70	-47.87	-6739%	8.068	0.000	0.112	-8.068	-7104%	-6788%
Shell Oil (MCC)	1.86	0.00	0.00	-1.86		1.552	0.000	0.000	-1.552		
Shell Oil (TMR)	0.93	0.98	0.16	0.05	131%	1.693	1.142	0.202	-0.551	-173%	-36%
Canada	47.16	56.87	3.36	9.71	389%	88.310	84.699	6.153	-3.611	41%	167%
EPN	**480.78**	**410.90**	**63.30**	**-69.88**	**-10%**	**905.492**	**858.619**	**59.586**	**-46.873**	**21%**	**5%**
Oman - (PDO)	139.50	179.40	16.62	39.90	340%	0.000	0.000	0.000	0.000		340%
Oman - (Gisco)	33.18	18.48	2.36	-14.70	-523%	45.693	55.207	4.758	9.514	300%	21%
Abu Dhabi	103.26	97.70	5.58	-5.56	0%	0.000	0.000	0.000	0.000		0%
Egypt	9.06	5.89	0.58	-3.17	-447%	31.272	27.881	1.455	-3.391	-133%	-224%
Syria	19.81	15.72	2.92	-4.09	-40%	1.012	0.704	0.234	-0.308	-32%	-39%
Iran	23.85	31.59	0.00	7.74		0.000	0.000	0.000	0.000		
Russia - (Sakhalin)	7.69	15.10	0.51	7.41	1553%	0.000	0.000	0.000	0.000		1553%
Kazakhstan - (Temir)	2.00	0.00	0.01	-2.00	-19900%	0.000	0.000	0.000	0.000		-19900%
Pakistan	0.00	0.00	0.00	0.00		11.339	9.866	0.189	-1.473	-679%	-679%
Bangladesh	0.00	0.00	0.00	0.00		4.713	4.825	0.384	0.112	129%	129%
EPM	**338.35**	**363.88**	**28.58**	**25.53**	**189%**	**94.029**	**98.483**	**7.020**	**4.454**	**163%**	**184%**
Australia - (SDA)	32.49	29.04	4.20	-3.45	18%	176.638	176.917	2.356	0.279	112%	51%
Australia - (Woodside)	11.85	17.04	2.28	5.19	328%	40.205	40.184	1.450	-0.021	99%	240%
Brunei	59.28	69.36	5.54	10.08	282%	102.612	99.899	4.656	-2.713	42%	174%
New Zealand	4.60	5.00	0.41	0.40	198%	12.646	14.811	1.381	2.165	257%	243%
New Zealand - (Pecten)	0.80	0.74	0.11	-0.06	45%	2.314	1.755	0.247	-0.559	-126%	-72%
Malaysia	25.55	26.85	3.28	1.30	140%	183.819	171.791	5.723	-12.028	-110%	-17%
Philippines	3.82	3.50	0.00	-0.32		19.436	16.914	0.000	-2.522		
Thailand	14.17	15.35	1.04	1.18	213%	6.226	6.189	0.437	-0.037	92%	178%
China	3.24	5.97	1.43	2.73	291%	0.000	0.000	0.000	0.000		291%
China - (Pecten)	3.29	0.00	0.00	-3.29		0.000	0.000	0.000	0.000		
EPA	**159.09**	**172.85**	**18.29**	**13.76**	**175%**	**543.896**	**528.460**	**16.250**	**-15.436**	**5%**	**96%**
Nigeria - (SPDC)	448.10	434.17	13.93	-13.93	0%	95.930	85.710	1.836	-10.220	-457%	-52%
Nigeria - (SNEPCO)	71.41	89.54	0.00	18.13		5.700	7.020	0.000	1.320		
Gabon	19.91	18.94	3.99	-0.97	76%	0.000	0.000	0.000	0.000		76%
Venezuela	21.43	35.55	2.54	14.12	656%	0.000	0.000	0.000	0.000		656%
Argentina	3.43	3.54	0.22	0.11	150%	7.284	9.389	0.036	2.105	5947%	943%
Angola	0.00	11.85	0.00	11.85		0.000	0.000	0.000	0.000		
DR Congo (Zaire)	3.22	3.04	0.17	-0.18	-6%	0.000	0.000	0.000	0.000		-6%
Brazil - (Pecten)	0.81	0.92	0.09	0.11	222%	4.384	5.141	0.326	0.757	332%	308%
Cameroon - (Pecten)	7.75	5.17	1.21	-2.58	-113%	0.000	0.000	0.000	0.000		-113%
EPG	**576.06**	**602.72**	**22.15**	**26.66**	**220%**	**113.298**	**107.260**	**2.198**	**-6.038**	**-175%**	**186%**
EP World	**1554.28**	**1550.35**	**132.32**	**-3.93**	**97%**	**1656.715**	**1592.822**	**85.054**	**-63.893**	**25%**	**69%**
		R/P	11.7				R/P	18.7			
EP World (bbl/boe)	**9775.3**	**9750.6**	**832.2**	**-24.7**	**97%**	**10093.4**	**9704.1**	**518.2**	**-389.3**	**26%**	**69%**
EP Total Oil + Gas (boe)	19868.7	19454.7	1350.4	-414.0	69%						
Divestments				-67.21					-19.16		
Acquisitions				7.94					1.58		
Total A&D				**-59.27**					**-17.59**		
EP World	**excl A&D**		**132.32**	**58.34**	**142%**			**85.05**	**-46.30**	**46%**	**105%**
EP World (bbl/boe)	**excl A&D**		**832.2**	**348.1**	**142%**			**518.2**	**282.1**	**48%**	
EP Total Oil + Gas (boe)	excl A&D		1350.4	65.9	105%						
Canada (AOSP)	95.40	95.40	0.00	0.00		0.000	0.000	0.000	0.000		70%

OM 000362

V00102214

FOIA Confidential Treatment Requested

Unknown

From:	Bell, John J SIEP-EPB-P
Sent:	04 March 2002 08:44
To:	Van De Vijver, Walter SI-MGDWV
Cc:	Gardy, Dominique D SIEP-EPF; Brass, Lorin LL SIEP-EPB
Subject:	RE: CMD input

Walter,

1. The standardised measure has not traditionally been submitted to ExCom in the past; it is simply a means of putting a value, based on actual.end year prices, to our proved reserves (which of course were fully discussed at ExCom). As Dominique said the $ 9 bln drop in IBVc from BP 2000 to BP 2001 was at $ 14/bbl. The standardised measure was for end 2000 $ 63 bln (as measured at end 2000 actual price of $ 20/bbl for oil/NGL and $ 14.91/boe for gas) and at end 2001 $ 46 bln (as measured at end 2001 actual price of $ 15.92/bbl and $ 11.44 /boe for gas).,

The drop in the USA is marked because end year oil/NGL prices dropped from $ 27.02/bbl to $ 16.24/bbl and gas even more from $ 34.45 /boe to $ 12,64/boe. In Europe gas prices remained roughly constant whereas oil/NGL dropped $ 22.89/bbl to $ 17.16/bbl.

All of our competitors will feel similar reductions due to the prices used for the standardised measure (moreso for those with larger NA gas portfolios).

2. Re the external auditors

a) the report is written not by Jan Willem but by Anton Barendregt , who has been doing this job for some 3 years, and we did moderate it, particularly in regard of the negative impact of scorecards
b) the external auditors are simply reporting the facts of our booking practices relative to others in the industry which in the face of changing SEC guidance does create an exposure; the external auditors are simply doing their job, painful though the underlying reserves situation is for us.

John

-----Original Message-----
From: Van De Vijver, Walter SI-MGDWV
Sent: 03 March 2002 22:33
To: Gardy, Dominique D SIEP-EPF
Cc: Bell, John J SIEP-EPB-P
Subject: RE: CMD input

Dominique,
Quite amazing:
1)?!
2) EPB issue
3) we should know
4) why already at CMD?

Regards,
Walter

-----Original Message-----
From: Gardy, Dominique D SIEP-EPF
Sent: 03 March 2002 20:59

To: Gardy, Dominique D SIEP-EPF; Van De Vijver, Walter SI-MGDWV
Cc: Bell, John J SIEP-EPB-P
Subject: RE: CMD input

Walter,

RE:
1)I have not seen these papers nor this standardized measure of the 2001 finacial results.
What I did present at Appraisal was a drop of some 9 Bln $ of IBVc between teh 2 BPlans all at 14 $/bbl.
2)Nothing to add re comment from auditors on reserves
3)Claims/garantees/Contingencies;managed at OU level.Will have to come back on aggregate numbers.
4)I have not reviewed the EP LoR letter yet.

> -----Original Message-----
> From: VanDeVijver, Walter W.
> Sent: 03 March 2002 12:50
> To: Gardy, D.
> Cc: Bell, John J.
> Subject: CMD input
>
>
>
> Dominique,
>
> 1) looking at the standardized measure in the 2001 financial
> results,they show a dramatic decrease in value compared to
> the year before.I know wehad lost a lot of speculative value
> in our options but this reduction of some $ 17 billion of
> which nearly $ 5 billion in Europe and nearly $ 8 billion in
> USA is very painful to look at.This is all in my CMD
> papers,never came to Excom,never saw any
> background.
>
> 2) external audit report to CMD again refers to our reserves
> problem ,too early with proved reserves and negative impact
> of scorecards.This is all the farewell present from
> Jan-Willem Roosch,has anyone tried to manage him?
>
> 3)there is a document on claims/guarantees/contingencies at
> CMD also highlighting a raft of EP items.Do we give adequate
> profile to these within EP and are we comfortable with
> provisions/reserves made (what are the numbers?).
> 4) have you reviewed the EP LoR yet?
>
> Walter van de Vijver
> EP CEO and Group Managing Director
> Shell International B.V.
> PO Box 162, 2501 AN The Hague, The Netherlands
>
> Tel: +3170377 7427 Fax: 2555 Other Tel: +3170377 1675
> Email: Walter.W.VanDeVijver@si.shell.com
> Internet: http://www.shell.com
>
>

Unknown

From: Henry, Simon S SI-FI
Sent: 25 March 2002 08:07
To: Boynton, Judith G SI-FN
Subject: FW: EB Business day at Business week

judy, would you take this as a no?

comments from walter all valid for fergus' contribution. simon

-----Original Message-----
From: Van De Vijver, Walter SI-MGDWV
Sent: 24 March 2002 13:03
To: Henry, Simon S SI-FI
Cc: Gardy, Dominique D SIEP-EPF; Boynton, Judith G SI-FN
Subject: RE: EB Business day at Business week

'mon,
,nanks for your offer,most appreciated.
It may be appropriate but:

- a lot of the leaders in the business do feel very bad about the external negative atmosphere because they feel it is not of their making
- ulimately accountability rest with the EP Excom who set plans for exploration,for NBD development and did not work the fundamentals of M&A.
- the latest is the embarrassment on reserves replacement some of which driven by reserve bookings that should not have been made
- operational performance (asset utilisation etc) has been pretty good,Expro sucked last year (management problem),PDO failure missed by Excom.Obviously Shearwater and Brutus are technical competency issues.
- we have too many targets out there,some near impossible to achieve and some of them driven by you.

I basically get sick and tired of looking backwards and will only be interested if it involves a refreshing and constructive input.
I will discuss with Dominique.
Regards,
Walter

-----Original Message-----
From: Henry, Simon S SI-FI
Sent: 21 March 2002 08:51
To: Walter Van De Vijver
Cc: Dominique Gardy; Judith Boynton
Subject: EB Business day at Business week

Walter, you are probably aware that the Group day at Business week will include a session on external perceptions, with a presentation from Fergus Macleod. Given the high profile of the EP business in the investor community, and probably the interest within your EP community, it struck me that the EP Business day may be an opportunity for me to share some of the issues with your leadership team. I would certainly be interested in their views on how we can most positively manage the messages going forwards. I don't know what plans you have in mind for the day, but I would be happy to discuss possibilities with you if you think this would be time well spent.

Thank for your consideration, Simon

Simon Henry
Head of Group Investor Relations
Shell International Limited
Shell Centre, London SE1 7NA, United Kingdom

Tel: +44 20 7934 3855 **Other Tel:** +44 7799 034799
Email: simon.s.henry@si.shell.com
Internet: http://www.shell.com

EXHIBIT 1/25/07
14
Gardy
PENGAD 800-631-6989

V00020233

DB 00998

FOIA Confidential
Treatment Requested

Unknown

From: Henry, Simon S SI-FI
Sent: 02 July 2002 14:46
To: Van De Vijver, Walter SI-MGDWV
Cc: Powell, Ceri CM SIEP-EPB; Gardy, Dominique D SIEP-EPF
Subject: RE: Enterprise messages

Walter, thanks for the guidance, fully understood. On Enterprise we are working closely with Lorin and team to ensure we have the right story (= as you describe it) and information, this particular issue was perhaps broader about the level of EP capex intensity. I support the closing of the chapter looking backwards, and concentration on shorter term delivery until we have a refreshed and more complete EP story looking ahead.

Simon

-----Original Message-----
From: Van De Vijver, Walter SI-MGDWV
Sent: 02 July 2002 11:17
To: Gardy, Dominique D SIEP-EPF; Henry, Simon S SI-FI
Cc: Powell, Ceri CM SIEP-EPB
Subject: RE: Enterprise messages

I do not want to go into the totality of the EP story,also having the benefit of our early input
for next year's business plan where value erosion appears very high on the agenda again (base production declining faster
with new projects no able to fill the gap towards 3 % and at higher capital intensity) whilst lacking E&A follow-up
into proved (GoM delivery,monetising Brasil,dry holes).
I strongly agree with Dominique comments on the concept proposed.
Storyline on Enterprise at Q2:
- significant progress on integration and even more confident on claimed synergy delivery ($$ and pace)
(financials are actually looking worse due to higher cost base and project slippages/assumptions post 2004,plus tax!)

-----Original Message-----
From: Gardy, Dominique D SIEP-EPF
Sent: 02 July 2002 11:45
To: Henry, Simon S SI-FI
Cc: Gardy, Dominique D SIEP-EPF; Powell, Ceri CM SIEP-EPB; Van De Vijver, Walter SI-MGDWV
Subject: FW: Enterprise messages

Simon,

Thanks for asking.
I think this is a dangerous route.

Why do we want to come back to the past?No appetite,I think,To give any opportunity to reopen the debate 5 down to 3 %.

Integrating EO as proposed could give the signal that EO was done to help us on 3 % production growth.

EXHIBIT 1/25/07
PENGAD 800-631-6989
15
Gardy

V00230860

VIJVER 0860

So in sumary I do not like this story at all.

-----Original Message-----
From: Simon S. Henry
Sent: 01 July 2002 13:26
To: D. Gardy
Subject: FW: Enterprise messages

Dominique, I would appreciate your advice on the latter in your role as EP CFO - with Frank not yet available. Attached slide is a schematic of a thought Phil shared with me about communicating some of the rationale behind the Enterprise deal. The basic message is that we underspent for 2 years, and Enterprise is, in one sense, a catch up! Over a 5 year period we have spent on average at the lower end of our $7-8bln range, and - including 6% from Enterprise - delivered a significant volume increase. not sure yet what the number may be on vol increase but most likely 4-5%. also the message is that it is perfectly feasible and logical to include Enterprise volumes in statements about vol growth and reserves replacement, phil seems already mentally to have included Enterprise reserves in this year's RRR.

my concern is that i know walter is a bit more conservative around this subject, and I don't want to get caught between them 1 day before results announcement trying to decide what our position is. It also seems like post event rationalisation, as if this is such a good argument we should have used it on April 2nd.

I haven't discussed this with anyone else yet as I would like your views on 1) is the argument strong enough to take forward, and if so 2) (more importantly) how should this be handled with Walter?

Please give me a call anytime, thanks, Simon

From:	Gardy, Dominique D SIEP-EPF
To:	Henry, Simon S SI-FI
CC:	Gardy, Dominique D SIEP-EPF; Powell, Ceri CM SIEP-EPB; Van De Vijver, Walter SI-MGDWV
BCC:	
Sent Date:	2002-07-02 09:45:14.000
Received Date:	2002-07-02 09:45:14.000
Subject:	FW: Enterprise messages
Attachments:	Loose slide v02.ppt

Simon,

Thanks for asking.
I think this is a dangerous route.

Why do we want to come back to the past?No appetite,I think,To give any opportunity to reopen the debate 5 down to 3 %.

Integrating EO as proposed could give the signal that EO was done to help us on 3 % production growth.

So in sumary I do not like this story at all.

-----Original Message-----
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Sent: 01 July 2002 13:26
To: D. Gardy
Subject: FW: Enterprise messages

Dominique, I would appreciate your advice on the latter in your role as EP CFO - with Frank not yet available. Attached slide is a schematic of a thought Phil shared with me about communicating some of the rationale behind the Enterprise deal. The basic message is that we underspent for 2 years, and Enterprise is, in one sense, a catch up! Over a 5 year period we have spent on average at the lower end of our $7-8bln range, and - including 6% from Enterprise - delivered a significant volume increase. not sure yet what the number may be on vol increase but most likely 4-5%. also the message is that it is perfectly feasible and logical to include Enterprise volumes in statements about vol growth and reserves replacement, phil seems already mentally to have included Enterprise reserves in this year's RRR.

my concern is that i know walter is a bit more conservative around this subject, and I don't want to get caught between them 1 day before results announcement trying to decide what our position is. It also seems like post event rationalisation, as if this is such a good argument we should have used it on April 2nd.

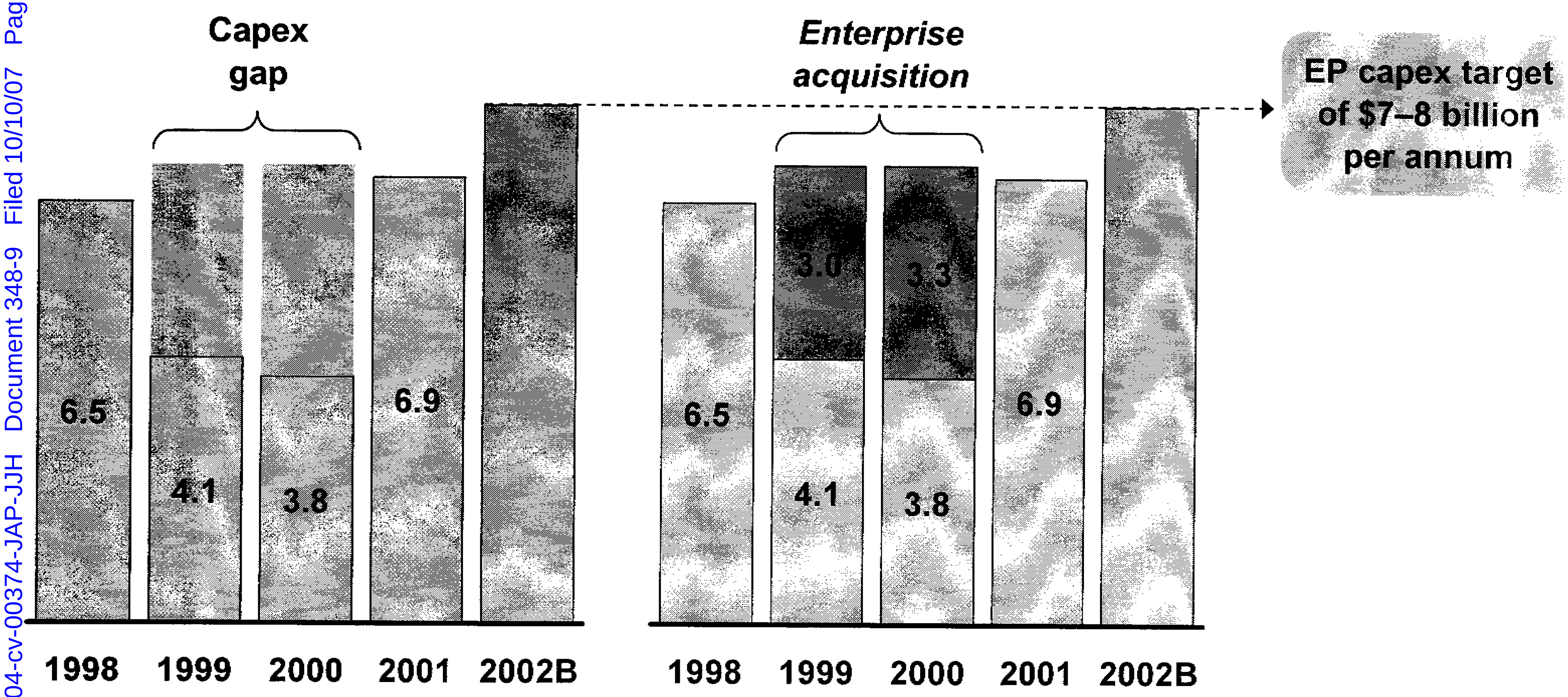
EXHIBIT 2507
16
Gardy

I haven't discussed this with anyone else yet as I would like your views on 1) is the argument strong enough to take forward, and if so 2) (more importantly) how should this be handled with Walter?

Please give me a call anytime, thanks, Simon

Enterprise acquisition fills the 1999 and 2000 capex underspending gap

EP autonomous capital expenditures 1998 - 2002
$ billion



EP GP OP Ch R

Royal Dutch / Shell Group of Companies

Unknown

From: Frost, David DB SEPI-EPA
Sent: 29 September 2002 10:47
To: Gardy, Dominique D SEPI-EPA
Subject: FW: Australian Gas Reserves

Dominique fyi,

The attached files explain in detail the reserves booking history of both the NWS and Gorgon. As you know we will not book any additional reserves at the NWS due to the Guangdong contract as they had been previously booked. At Gorgon, we believe we now have a strong case for leaving the reserves booked, due to the current project activities and indications from Kogas that they are again interested in taking new LNG volumes. I had requested these papers back in August when Walter and Linda Cook had questions regarding booking reserves associated

David B. Frost
Regional Business Advisor
Shell EP International B.V.
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Tel: +31 (70) 377 7345 **Fax:** 3889
Email: d.frost@shell.com
Internet: http://www.shell.com

> -----Original Message-----
> **From:** Johnson, Dave SDA-OE
> **Sent:** 19 September 2002 10:30
> **To:** Pay, John JR SIEP-EPB-P; Frost, David DB SEPI-EPA
> **Cc:** Bell, Sarah SDA-OE/21; Faulkner, Andrew A SIG-GPA
> **Subject:** Australian Gas Reserves
>
> John / David
>
> Sarah forwarded me a copy of your note of yesterday on the
> above and I thought we should respond not only with comments
> on your note (attached) but also to share a couple of recent
> developments.
>
> Firstly, Sarah has, in the last few days, completed two Notes
> for Information on both the SDA reserves bookings for Gorgon
> and for NWS. I have circulated these notes to our management
> team for comment and had intended to pass copies of both
> papers to you next week. These papers document the history of
> these reserve bookings and aim to provide a factual basis for
> discussion of SDA resource categorisation in the upcoming
> ARPR 2003 process. I now attach copies of the draft papers
> and would welcome your input, especially with regard to
> interpretation of the updated reserves guidelines. I must
> stress, however, that I am not at this stage, looking to make
> a decision on the future categorisation of these volumes and
> would ask that you give Tim & myself the opportunity to
> incorporate your input before anything is passed onwards to Walter.
>

GARDY 0025

V00250526

> Secondly, I presented the background to these bookings to
> both Walter and Malcolm Brinded yesterday morning. Both MD's
> now understand the history and categorisation of these
> volumes. Malcolm commented that had Gorgon volumes been
> currently classed as SFR, we would not currently be able to
> reclassify these volumes as reserves. However, given that the
> booking had already occurred and given the planned activities
> in the first half of next year, it was probably not
> appropriate that they be de-booked just now. With the
> concurrence of both MD's I wish to solicit your opinions
> before any final decision is taken for the ARPR 01.01.03.
>
> As I'm away overseas next week, please contact Sarah if
> you've any immediate queries. I look forward to hearing from you.
>
> Cheers
>
> Dave
>
>
> Australia Gas NFF_sarah.ZIP
> Gorgon Field - Resource Categori...
> NWS Resource Categorisation - ...
>
>
> **David A. Johnson**
> General Manager
> JV Operations & Exploration
>
> Shell Development (Australia) Pty Ltd.
> 250 St George's Terrace, Perth, WA 6000
>
> **Tel:** +61-8-9213 4812 **Fax:** +61-8-9213 4678
> **Email:** david.a.johnson@shell.com.au
>

EPB-P

18 September 2002

Note For File

Australia Proved Gas Reserves

Following the award of the China Guangdong LNG supply contract to North West Shelf LNG, the question arose as to the impact on EP gas reserves in Australia.

There is no impact of this deal on ~~Ep~~total 100%~~-~~proved gas reserves in Australia. All North West Shelf EP technical P85 ~~proved~~ gas reserves (excluding Gorgon) are already considered to be proved. Although contracts have not been signed which cover the entire NWS resource base, the total economically producible volume is considered to be reasonably certain of being sold and thus commercial (and technical) maturity requirements for reserves bookings as specified in the Group Petroleum Resource Volume Guidelines are deemed to be satisfied. This methodology was sanctioned during the latest SEC reserves audit carried out in October 2000.

~~committed to contract.~~ Under the recently awarded CLNG venture, CNOOC will be entitled to a percentage, currently ~5%, of NWS reserves, which will be divested equally from the current six NWS JV partners. Upon finalisation of this contract, and subsequent payments for the equity, SDA will be required to reduce its equity share of proved reserves booking by the appropriate percentage. Currently this approximates to a reduction of ~0.2 Tscf Shell direct share proved reserves. Similarly a reduction in indirect proved volumes will result form the divestment of Woodside equity to CNOOC.

The contract status at the end of 2001 is summarized in Attachment 1. SDA advises that the Guangdong deal and other events will have changed the contractual situation, which is currently under review. Any changes will be reflected at the 31.12.2002 ARPR: Train 5 volumes are likely to be included as committed volumes, but at the expense of Train 1-3 and domestic gas extensions. Regardless, the range of technical reserves for the Australian subsurface assets (as defined by the Proved and Expectation figures) straddles the volumes that are considered committed to contract. As such, any adjustments to the contractual situation are unlikely to affect the EP (technical) reserves situation, apart from the divestment to CNOOC as described above.

Attachment 2 provides a summary of the recent changes in proved gas reserves in Australia~~.~~. Substantial proved reserves additions were made in 1996~~, and~~ 1997, and 1998 principally in the Gorgon, Perseus and North Rankin fields. Woodside has no share of Gorgon, which was first booked as proved reserves in 1998~~7~~ (wrong in attachment 2 - not 1997!) in the expectation that project sanction and sales agreements were imminent with the Korean market~~.~~. As a result of the current market uncertainty, Gorgon volumes were defined as uncommitted for the ARPR 1.1.2002~~. The proportion of reserves committed to contract was increased in 2001 following review of assurances that the volumes would be brought to market (see above and Attachment 1).~~

Attachment 1

Australia Gas Reserves: Contract Status

EPB-P estimates of the status at 31.12.2001, based on information supplied by SDA:

Contract Billion Nm^3 at 9500 kcal/Nm^3	Note	100%	Shell share Direct SDA	 Indirect Woodside	 Total Shell
Domestic Gas Contracts	a	66.0	10.4	4.6	15.0
LNG Contracts	a	101.3	16.0	7.0	23.0
Trains 1-3 Contract Extensions	b	248.2	39.2	17.2	56.3
Domestic Gas Contract Extensions	b	63.3	10.0	4.4	14.4
Train 4	a~~b~~	136.4	21.5	9.4	31.0
Wedge	b	7.0	1.1	0.5	1.6
Methanex	b	51.4	8.1	3.6	11.7
Total committed to contract			106.4	46.5	152.9
As reported at 31.12.2001 (ARPR)			106.4	46.5	152.9
Excluding Gorgon:					
ARPR Proved Reserves (technical)			94.7	42.9	137.6
ARPR Expectation Reserves (technical)			116.1	53.0	169.0

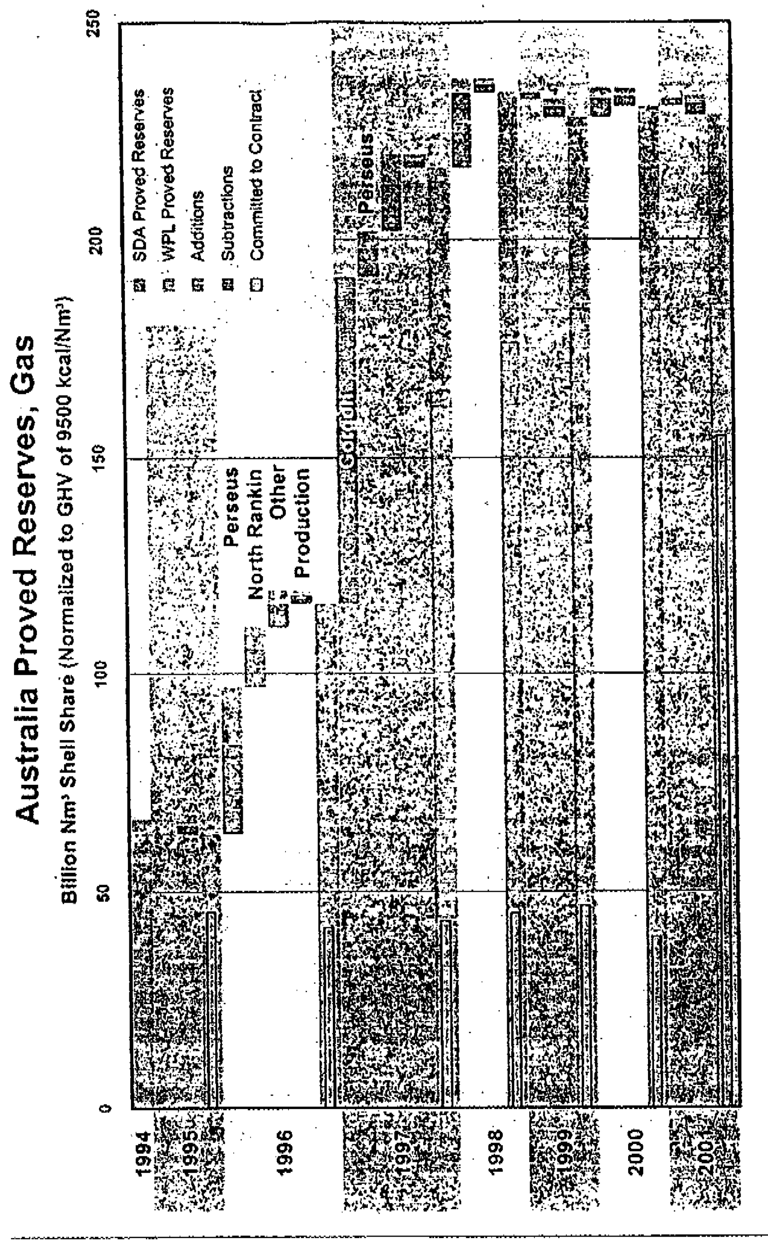
Notes:

a Existing contract

b Included as "committed" under the definition (EP 2001-1100. section 4.3.9) which states that .... *"In countries with a mature gas market all gas reserves, which have a near certainty of market take-up can be classified as committed"*.. ~~on the grounds that (at least)~~SDA considered that, for the NWS mature market, any contract for which either ~~a~~-LOI was in place, and/or with "near certainty" that the volumes will eventually be contracted, to be "committed" under these definitions.~~be marketed.~~

Attachment 2

Gorgon was first booked a proved in 1998



1020 MMboe Gas and 110 MMboe NGL added 1996 - 1997: 21% of the EP total during that period.
~~All gas reserves except Gorgon are considered committed to contract.~~

Gorgon Field Resource Categorisation – Note for Information

September 2002

Shell Development (Australia) Pty Ltd

Contents

1. BACKGROUND..3
2. RESERVES GUIDELINES...4
3. HISTORY OF GORGON RESERVES BOOKINGS...........................5
4. BENCHTEST OF GORGON VOLUMES AGAINST 2002 GROUP GUIDELINES.......7
5. POTENTIAL ISSUES / RISKS......................................10
6. REFERENCES..12

APPENDIX 1 – Group Definition of Reserves (EP 2002-1100)
APPENDIX 2 – Extracts from SEC Proved Reserves Audit – SDA 9-13th Oct 2000
APPENDIX 3 – Summary of Gorgon Economics
APPENDIX 3 – Statutory accounts for WA-25P
APPENDIX 5 – Gorgon OPREP
APPENDIX 6 – Summary of Gorgon Direct/Indirect reserves booked at 1.1.2002

Gorgon Field Resource Categorisation - Note for Information
11/04/2004

1. BACKGROUND

The Gorgon Field lies ~150 kms offshore of Dampier in NW Australia. This major gas field (c. 25 Tcf GIIP) was discovered in 1980 and is operated by ChervonTexaco (57.14% equity) on behalf of a venture including Shell Development Australia (28.57% equity) and ExxonMobil (14.28% equity).

Proved Gorgon "Reserves" were first booked by SDA at 1.1.1998, at which point market conditions had supported work to FEED on a 2-Train, Burrup-based LNG project. A draft LOI had been delivered to Kogas and a high degree of confidence of imminent market capture existed.

In mid-1998, there was a down-turn in the Asian economy and despite receiving a "letter of comfort" from Kogas, the Korean market failed to mature as expected.

Since that time, technical work has continued - the preferred development concept now involving tie-back of an offshore sub-sea infrastructure to an LNG plant and/or Domgas plant on Barrow Island. Significant marketing efforts continued during this period, however, to-date, no LOI's have been secured.

The continued classification of the Gorgon resource volumes as "Reserves" was re-examined during a Group Reserves audit in October 2000, which reported that:

"Maintaining the preliminarily booked volume of Gorgon gas reserves was supported on the grounds that a gas market was highly likely to be established in due course and that it must be considered likely that an extension of the current 5-year Retention Lease will be granted in 2002. "

In April 2002, updated Group Reserves Reporting Guidelines were issued. These guidelines include an updated and refined definition of the term "Reserves"; a definition requiring that stringent, technical and commercial maturity conditions be satisfied before resource volumes may be included in this category.

This note for information summarises the history of Gorgon resource bookings and gives an overview of the current level of technical and commercial maturity of the project, in relation to the criteria set out in the group reserves guidelines. It aims to provide a factual basis for discussion as to the classification of the Gorgon resource volumes in the upcoming ARPR 2003 process.

2. RESERVES GUIDELINES

Updated Group guidelines for distinguishing resources volumes between Reserves and Scope for Recovery (SFR) have been issued (Reference 1). Relevant extracts are given in Appendix 1 of this note and are summarised below.

The term **"Reserves"** is used for resource volumes associated with a project that is technically and commercially mature to the extent that funding is reasonably certain to be secured. Volumes can move from Scope for Recovery to reserves when:

(1) The Shell Shareholder technical* and commercial** assurance processes have been satisfactorily passed and no significant issues exist that could preclude proceeding with the project.

(2) Support to fund the project is reasonably certain (e.g. the project survives the business planning processes of Capital Allocation) and the project forms (or is reasonably certain to form) part of the relevant business plan.

** Technical maturity - VAR3 must have been completed for major projects.*
***Commercial maturity - (i) profitability meets Groups criteria, (ii) market availability is assured and (iii) Group funding is reasonably certain.*

Assurance of market availability for gas projects means either (i) "the gas must be contracted to sales or (ii) the gas is "considered as reasonably certain of being sold based on expectation of availability of markets, along with transportation/delivery facilities". A previous third qualification has been deleted from the 2002 Guidelines, namely:

….."*that, whilst not firmly planned,* (the gas volumes) *have been ear-marked for future development and hence may reasonably be anticipated to be sold based upon expectation of availability of markets and project financing*".

The new guidelines state that for major projects critically dependent on new gas market capture, reserves booking should in-principle be deferred until agreements have been signed, until near project FID. They also clearly state that if proved reserves cannot be assigned to a project, then the related petroleum resource should be retained/downgraded as/to SFR i.e. there can be no Expectation reserves reported without proved reserves.

In addition, Section 3.3.1 of the new guidelines states that externally reported Group share of proved reserves "is limited to future production within the existing licence or contract period, including any agreed extensions as may be covered by documented evidence".

3. HISTORY OF GORGON RESERVES BOOKINGS

An historical overview of Gorgon reserves volumes, as reported by SDA in its "Annual Review of Petroleum Resources", is given in Figure 1 and Table 1 below.

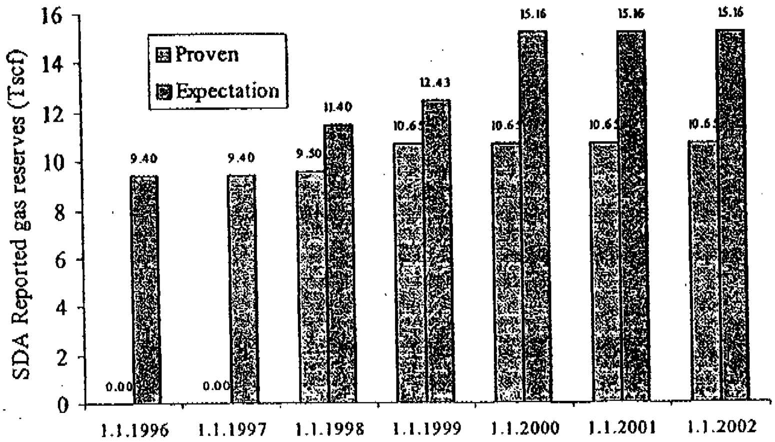


Figure 1 Historical overview of Gorgon reserves volumes, as reported in SDA ARPR

All 100% recoverable hydrocarbon volumes

	SDA Annual Reserves Report Submission				Comment
	GAS (Tscf)		CONDENSATE (mln bbl)		
	Proven	Expectation	Proven	Expectation	
1.1.1996	0.00	9.40	0	33.7	No proven reserves booked
1.1.1997	0.00	9.40	0	33.7	No proven reserves booked
1.1.1998	9.50	11.40	109	137	Certified by NSAI (1P = 9.63, 2P = 12.52 Tscf)
1.1.1999	10.65	12.43	109	131.3	Increase as result of two appriasl wells Q4 1998
1.1.2000	10.65	15.16	110.7	131.3	Further increase as result of Shell technical review (proved fixed)
1.1.2001	10.65	15.16	110.7	131.3	No change
1.1.2002	10.65	15.16	110.7	131.3	No change

Proved Gorgon reserves were first booked by SDA at 1.1.1998, at which point market conditions had supported work to FEED on a 2-Train, Burrup-based LNG project. A draft LOI had been delivered to Kogas and a high degree of confidence of imminent market capture existed.

Gorgon reserves were independently certified in 1998 by Netherland, Sewell & Associates (NSAI), immediately after the final two appraisal wells were drilled in Q4 1998. The proven volume of 9.63 Tscf was very close to the 1.1.1998 SDA booked volumes of 9.50 Tscf, and some 10% lower than the Shell reported volumes at 1.1.1999 of 10.65 Tscf.

A technical review was carried out by Operator in 1999 (Ref 6), which resulted in a further increase in technical reserves following incorporation of appraisal information from the two 1999 wells. This work was reviewed by SDA (Ref 7) and resulted in an increase of 'technical' volumes from 10.65 Tscf to 12.59 Tscf proven (12.43 to 15.16 Tscf Expectation). However, due to market availability uncertainty at the time SDA deemed it cautious to freeze the 1.1.2000

ARPR reported proven reserves at the 1.1.1999 level of 10.65 Tscf. This number has been frozen ever since - a decision supported by the 2000 SEC audit as described below. **Hence the currently reported proven volumes are some 20% lower than the technically accepted volumes.**

A more detailed breakdown of the gas and condensate volumes as booked in SDA's 1.1.2002 ARPR is given in Appendix 6.

Chevron currently carry Gorgon recoverable gas volumes as 12.4 Tscf (P90) and 14.8 Tscf (Expectation) (Ref 5), although it is believed that they do not report SEC proved volumes and carry under a Scope for Recovery Category. These volumes are very close to the 1999 SDA technical review.

3.1 SEC Proved Reserves Audit 2000

Continued booking of Gorgon reserves was supported by the Group Reserves audit (October 2000), as summarised below.

"Maintaining the preliminarily booked volume of Gorgon gas reserves (first done at 1.1.1999) was supported on the grounds that a gas market was highly likely to be established in due course and that it must be considered likely that an extension of the current 5-year Retention Lease will be granted in 2002. "

Further extracts from the reserves audit findings are shown in Appendix 2, and conclude that there was little doubt that a market for Gorgon gas would be found in the long term. Group reserves reporting guidelines at the time allowed this gas, in-principle, to be reported as reserves. One outstanding issue related to whether or not the current retention lease (expiring in 2002) would be renewed. Although there was little doubt that an extension would be granted, there was no automatic right and Group guidelines were not clear on the issue as to whether this would affect a reserves booking. As such it was recommended to maintain the current booked volume of Gorgon proven reserves of 10.65 Tscf (even when the actual volume had been superseded by a 20% larger volume, following new technical work). and not book any increases until either the Retention Lease had been extended or until e.g. a letter of intent with a prospective buyer had been signed.

4. BENCHTEST OF GORGON VOLUMES AGAINST 2002 GROUP GUIDELINES

4.1 Technical Maturity

The following summarises the status of The Gorgon project technical maturity at 1/9/02:

1. Gorgon technical reserves have been independently certified by NSAI (Dec 1998, Ref 3). A comprehensive review of the operator subsurface work was undertaken by SDA in late 1999 (Ref 7).
2. Significant work has been carried out to improve the 1998 development scenario, with a sub-sea tie-back to Barrow Island LNG facility currently the preferred option. Economics of the current 1-Train LNG-based scenario are robust to + 30% CAPEX (summarised in Appendix 3).
3. A full EP VAR3 and GP VAR2 are currently planned for Q2 2003. In preparation for this VAR a sub-surface technical review is planned for September 2002. Within this timeframe a detailed cost review of the onshore Barrow Island LNG plant is also planned.
4. Operator has submitted the 2002 Retention Lease renewal and results are pending. It is highly likely that renewal will be granted, on the strength of significant technical and commercial work done to-date, although the minimal work obligations proposed by Operator could be challenged. Hence the currently booked Gorgon proved reserves are not strictly limited to future production with existing licence periods (Section 3.3.1, ref 1), although it is considered highly likely that these production licences will be granted in the future.
5. One key issue for the current development scenario is access to Barrow Island. A sustainability review (Economic, Social, Environmental) of a Barrow Island development is currently being carried out by the State Government - an 'in-principle' decision is expected from Cabinet mid-2003, after which a normal Environmental Impact Assessment would be required. Fall-back options include using a GBS-mounted LNG plant (FLNG technology) close to the island or seeking Government support for a pipeline to the mainland.
6. Another key technical issue is related to the sequestration of large volumes of reservoir CO_2 in a local aquifer system. Significant technical work has been carried out, with results indicating that the aquifer can easily accommodate the volumes, with minimal risk of losses to surface. However, underground CO_2 sequestration has not yet been carried out in Australia. Considerable industry-academia research is being progressed on this issue, funded by SDA and ChevronTexaco amongst others.

4.2 Commercial Maturity

A project is deemed **commercially mature**, when (1) its profitability meets the Group's criteria (as applied through Shell's corporate Capital Allocation process), (2) market availability is assured (see below) and (3) funding by the Group is 'reasonably certain'. These three criteria are addressed as follows:-

Profitability meets Group's Criteria

Appendix 3 summarises the current integrated economics for a 2009 RFSU to a 1-Train LNG plant at Barrow Island (7 year ramp-up). Business Plan Integrated project economics at Mid PSV were NPV7 SS US$ 200 million and VIR7 0.32. Project economics are currently robust to +30% CAPEX at current LNG mid-PSV.

At low PSVs the project is exposed, but there is scope to mitigate this (and make project NPV, VIR neutral at Low PSV) by structuring a variable transfer price.

Market Availability is Assured

A down-turn in the Asian economy around mid-1998 resulted in the Korean market not maturing as expected, although a "letter of comfort" had been secured from Kogas. Since that time significant marketing efforts to find alternative markets have continued and technical solutions to a 1-train design case as well as Domgas development scenarios have developed - however to date no LOIs have been signed.

Although sales are not yet contracted and tough competition exists within the Asia Pacific region, SDA considers that the gas is "reasonably certain of being sold based on an expectation of the availability of markets" as follows:

1. The current Gas and Power Asia-Pacific supply-demand picture, as shown in Figure 2 below, suggests a reasonable base case expectation for Australia to capture sufficient volumes for three new LNG trains (after NWS Train 4) over the next decade, i.e. two trains into North East Asia and one into US West coast - with two or four in the Low and High cases respectively. The rational for this level of market capture is described in SDA Gas Master Plan (Ref 2), which has been endorsed by both SDA management and GP Excom.
2. In the expected three-train growth scenario, it is considered probable that the NWS T5 and Sunrise FLNG will secure two of the trains. For the third train it is currently considered that NWS T6 is extremely unlikely to be successful in competition with Gorgon for a number of reasons (outlined in Ref 2). Hence - on condition that the Gorgon venture is successful in pursuit of a green-field development - it is considered reasonably certain that market availability exists.
3. A draft LOI has been developed with Sasol-Chevron to provide an initial volume of 4 TCF for a GtL plant, to be built on an integrated site with the LNG plant on Barrow Island. Fiscal support for GtL is required from the Federal Government - whose position is expected to be made clear within the next months. In the event of a positive decision it is likely that the LOI will be signed in the near future, to be followed with an SPA in approximately one year.

4. Evidence of the intense commercial work currently being carried out is shown in Chevron's "OPREP" roadmap in Appendix 5.

In summary, Gorgon is a major gas project dependent on new gas market capture. Agreements have not yet been signed and it has not yet reached FID, although it is considered reasonably certain that market availability exists.

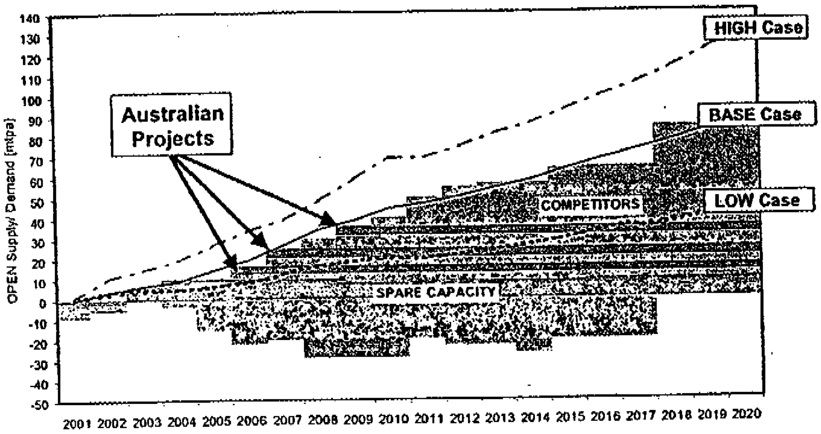


Figure 2 Asia Pacific Supply and Demand outlook (includes USA West Coast) - Ref SDA Gas Master Plan, April 2002.

Funding by Group is Reasonably Certain

Although described in the SDA Gas Master Plan as a 'firm' project, the Gorgon project has not yet been tested in the Capital Allocation Base Plan process. It is included in the SDA Business Plan 2003-2007 as an Option.

4.3 Benchtest Summary

From the above discussion, the current categorisation of Gorgon resource volumes as "Reserves" is considered equivocal. A strict interpretation of the guidelines might suggest that reclassification of these volumes, as Scope for Recovery, would not be unreasonable. However, it may also be argued that current and planned near-term activities might lead to confirmation of the booking of the resources as "Reserves".

5. POTENTIAL ISSUES / RISKS

The following paragraphs highlight a number of other issues / considerations that are affected by the choice of resource category to which Gorgon volumes are assigned:

5.1 Reserves Replacement Ratio.

Re-categorisation of the Gorgon hydrocarbon volumes as SFR, would lead to reduced SDA and Shell Group reported proven reserves of 10.65 Tscf. The impact of such a move on Reserves Replacement Ratio needs to be quantified and managed.

5.2 Market Confidence in Gorgon Development

De-booking Gorgon reserves could potentially have a detrimental effect on the current marketing effort. Potential customers would query why Shell no longer had reserves confidence. However, as previously noted, it is believed that Chevron Texaco do not carry their equity Gorgon volumes as "Reserves".

5.3 SDA Financial Accounting

PRRT Status

The status of Gorgon volumes (in Reserves or Scope for Recovery category) will have no effect on SDA's PRRT status unless either (i) future exploration activity in the permit were to be effected and/or (ii) Gorgon were to be farmed-out or relinquished. None of these scenarios would be a likely result of de-booking Gorgon volumes to the Scope for Recovery category.

Statutory Accounts

The statutory accounts carrying value for the Gorgon WA 25-P permit is A$155.1 million (cf Appendix 4). These historical costs predominantly relate to exploration and appraisal wells in both the Gorgon and West Tryal fields. Continued carrying of these historical costs is justified as long as the SDA is actively pursuing development and is largely independent on the categorisation of Gorgon volumes as SFR or reserves.

5.4 Exploration/Appraisal Carry

The group carrying value for Gorgon is currently A$32.9 million, comprising:

- Gorgon 3 A$12.9 million
- Gorgon 6 A$4.9 million
- Gorgon appraisal A$9.9 million
- IAGO 1 A$2.4 million
- Mob/Demob A$2.8 million

These costs are being carried on the basis that we have plans to develop Gorgon volumes in the future. A de-booking of volumes from reserves to Scope for Recovery would be on the basis that the volumes are not deemed commercially/technically mature at this stage but would not imply that SDA no longer plan to develop the reserves. As with the statutory accounts position, there should be no reason to write these costs off against EP NIAT.

5.5 Depreciation

Gorgon volumes are not being carried in the SDA depreciation calculations, hence a de-booking of volumes to Scope for Recovery would have no effect on SDA's depreciation position.

6. REFERENCES

1. Petroleum Resource Volume Guidelines Resource Classification and Value Realisation (EP 2002-1100)
2. Gas Master Plan - Revision 3 (April 2002) Shell Development (Australia)pty Ltd
3. Reserves Certification study of the Gorgon field located in Permit areas WA-2-R and WA-3-R (Netherlands, Sewell & Associates, INC) December 1998.
4. 1999 Shell technical review (internal note for file)
5. 2001 Reserves Report Greater Gorgon Area (Chevron Texaco 31st May 2002)
6. Gorgon Gas Field Resource Assessment, Feb 2000
7. Gorgon Development - Technical Maturity and Issues for future focus, Feb 2000

APPENDIX 1

GROUP DEFINITION OF RESERVES (EP 2002-1100)

Resource Volume Classification – Definition

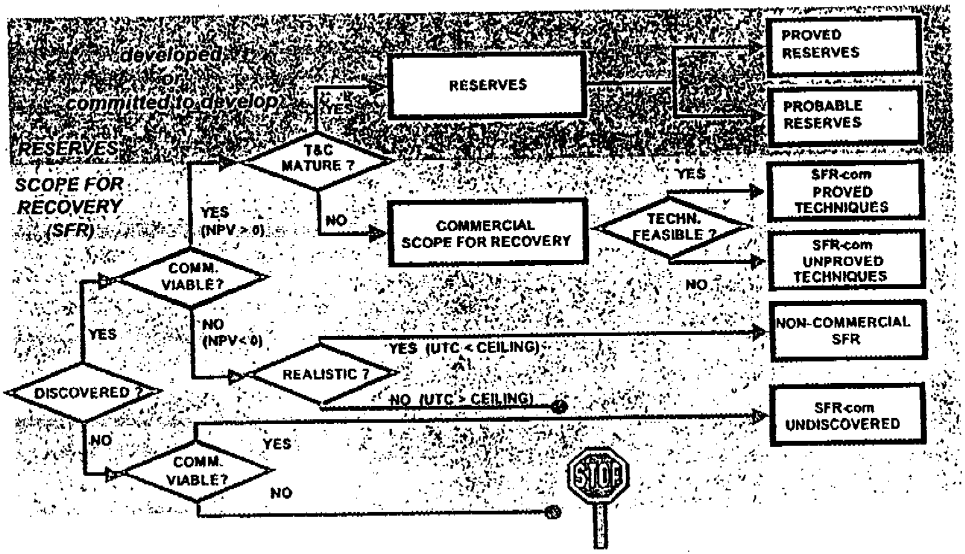
A petroleum resource is any accumulation of hydrocarbons that is known or anticipated to exist in a sub-surface rock formation, located in the company's current exploration and production acreage.

Resource volumes are reported as the quantities of sales product for crude oil, natural gas and natural gas liquids. The corresponding quantities of field recovery should be maintained by the OU (See Appendix 6). The reporting of petroleum resource volumes should further indicate the petroleum type, the reporting units and conditions, and the Group share.

Reserves and Scope for Recovery (SFR) (Figure 1)

Resource volumes are tied to the project or activity that develops them and are generally reported by field. The term **reserves** is used for resource volumes associated with a project that is **technically and commercially mature** to the extent that funding is 'reasonably certain' to be secured. Resource volumes that do not meet these criteria are classified as **Scope for Recovery** (SFR). **Proved reserves** are the portion of reserves that is reasonably certain to be produced and which will be reported externally. If no Proved reserves can be assigned to a project, then the related resource volumes are to be retained as SFR.

The concept of 'reasonable certainty' requires 'hard' field data, contracts and thorough evaluation to underlie the numbers. The implication is that as more data becomes available, upward revision is much more likely than negative revision.



Technical and Commercial Maturity

For a resource volume to pass from scope for recovery (SFR) to reserves (for internal as well as external reporting), the associated project(s) will have to reach both **technical** and **commercial maturity**. This is deemed to be the case when:

1. The Shell shareholder assurance processes have been satisfactorily passed both technically and commercially and no significant issues that could preclude proceeding with the project exist1.
2. Support to fund the project is reasonably certain (e.g. the project survives the business planning processes of Capital Allocation) and the project forms (or is reasonably certain to form) part of the relevant business plan.

Major reserves volumes that are no longer judged to be commercially mature should only be de booked after thorough (re-)evaluation.

Project Basis

Reserves being future hydrocarbon product available for sale are tied to projects (development) and activities (production operations). A project is any planned creation or modification of wells, surface production facilities and/or production policy, aimed at changing a company's sales product forecast. The aggregated production forecast of an OU must therefore be consistent with its reported reserves. This also holds for the 'proved forecast', as defined by the aggregated 'reasonably certain' amount of hydrocarbons forecast to be produced by the appropriate development/production scenario, duly respecting license duration and overall constraints (e.g. quota).

Technical Maturity

For a project to be **technically mature**, there should be a documented definition of a viable project that is anticipated to be implemented with 'reasonable certainty'. Such project definition should be based on resource and development scenario descriptions, with drilling/engineering cost estimates, a production forecast (including sensitivities) and economics.

For project reserves to enter into the Proved category, independent review and challenge is required (as a control) to preserve integrity of the external disclosures. For major projects such review is routinely executed through the Group's Value Assurance Review process. Note that concept selection (VAR3) must at least have been completed. In all cases, there should be 'reasonable certainty' that nothing is standing in the way of a firm development plan (i.e. there are no technical issues that could de-rail the project).

For smaller projects a documented development plan should suffice, which may be notional if a well-established analogue is in place. The

1 Examples: Gas sales contracts, major infrastructure needs, government approvals, un-tried technology

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quality of such plan should be a sufficient basis on which to judge the likelihood of project funding (see below).

Commercial Maturity

A project is deemed commercially mature, when (1) its profitability meets the Group's criteria (as applied through Shell's corporate Capital Allocation process), (2) market availability is assured (see below) and (3) funding by the Group is 'reasonably certain'.

Assurance of market availability for oil (and/or NGL) means at least the 'reasonably certain' availability of a pipeline to a shipping terminal or other outlet (e.g. a refinery), whilst for gas this means that the product is:

1. contracted to sales; or
2. considered as reasonably certain of being sold based on an expectation of the availability of markets, along with transportation/ delivery facilities.

For major gas projects critically dependent on new gas market capture, reserves booking should in principle be deferred until agreements have been signed, which is generally at or around project sanction (FID).

The condition of marketability for gas reserves also applies to the NGL products of a non-associated gas project: If the gas market is not assured, neither the gas nor the NGL volumes can be reported externally.

APPENDIX 2

Extracts from SEC Proved Reserves Audit – SDA 9-13th Oct 2000

"Some 10 Tcf (or 86 bln m3 Group share) of proved gas reserves have been booked for the giant Gorgon field since 1.1.1999. This was done on the strength of work done by the operator (WAPET, later Chevron) showing that development of this field through an LNG facility (stand-alone or, preferably, shared with the existing Woodside / North West Shelf LNG facility) was commercially robust. An important challenge is finding a buyer in a market that is fully supplied until 2005 and in which there is still significant competition thereafter. In the long term, however, there can be little doubt that a market will be found for this gas in the East- or South Asian rim. Hence, the Group reserves reporting guidelines do in-principle allow this gas to be reported as reserves.

The outstanding issue is whether the stated Gorgon reserves can be shown to be producible within the prevailing production licence. Gorgon is presently held under a Retention Lease, renewable for successive periods of 5 years under the condition that the field can be considered likely to become commercially viable within the next 15 years and that the lessee is actively pursuing the evaluation of commercial viability, including the conclusion of long term sales contracts. The current Retention Lease expires in 2002. Although there is little doubt that, on the strength of the significant technical and commercial work done todate, an extension of the Retention Lease will be granted, there is no formal right to this extension. Hence the Group guidelines are not fully clear on this issue.

The practical way forward (and recommendation from this audit) is to maintain the presently booked volume of Gorgon reserves (even when the actual volume has been superseded by a 20% larger volume, following new technical work) and not book any increases until either the Retention Lease has been extended or until e.g. a letter of intent with a prospective buyer has been signed."

APPENDIX 3

SUMMARY OF CURRENT ECONOMICS

The following economics for 1T LNG onshore BWI to End of Reserves (including wellhead compression) show that even at +30% capex project remains robust with VIR > 0.2 at mid PSV. Ramp-up assumption of 7 yr is pesismistic,.

At low PSVs the project is exposed, but there is scope to mitigate this (and make project NPV, VIR netural at Low PSV) by structuring a variable transfer price.

Note that CA 2003 submission for Stand-alone Gorgon LNG indicated 100% EP NPV (7%, mid PSV) of 200 mln US$ with a VIR of 0.32.

Integrated Economic Results - 1T LNG EoR @ BWI

	Profitability Indicators	
	NPV US$MM (100%Equity, RT 1.7.2002)	
Project Screening Value	7%	VIR 7 %
Low PSV	(147)	-0.10
Medium PSV	697	0.49
High PSV	1272	0.90

		Sensitivity Analysis for Medium PSV	
Item		NPV US$MM (100% Equity, RT 1.7.2002)	
		7%	VIR 7 %
Gas transfer Price	0.70	738	0.52
	1.00	615	0.44
Capex +30%	30%	392	0.21

Assumptions

Depreciation - 20 yrs u/s, 15 yrs d/s
FX - A/US0.55
Full PRRT
7 yr Ramp-up
RFSU 2009
Gas transfer Price = US$0.80/mmBtu
LNG PSV: CIF Tokyo Bay less US$0.68/mmBtu freight

APPENDIX 4

STATUTORY ACCOUNTS FOR WA-25-P

Permits	SDA - CAPITALISED INTANGIBLES ENDING DECEMBER 2001 Description	well number	
WA25P	spar 1		1,417,000.00
	bluebell	ME909	4,704,000.00
AP01/AP06	gorgon 1	ME900	5,850,000.00
	sultan 1		1,302,000.00
	nth tryal 1		554,000.00
	nth gorgon 1	ME905	7,599,000.00
	west tryal 3	MA901	8,306,000.00
	west tryal reentry	AP01ME903	2,475,000.00
	general drilling	AP01MOBLN	-
	west tryal 2		862,000.00
	central gorgon	MA910	15,824,394.00
	venture 1	AP01ME922	3,624,000.00
	permit total		28,000.00
	surveys/eol to 31/12/87)	AP01ME923	1,280,000.00
	WA25/WA205P/WA213p	AP01ME947	96,548.99
	XU	AP01ME960	723,398.00
	YANNUT	AP01ME961	244,675.00
	CUE	AP01ME962	602,244.00
	North gorgon	AP01ME948	7,844,374.00
	OBI One		-
	Secure Old WE		287,718.00
	Z56M		550,089.72
	Gorgon 3		13,235,036.41
	Gorgon 6		4,898,580.80
	Trans Gorgon		42,503.00
	surveys wef 1/1/88		10,161,000.00
	allocate from AP01		2,495,500.00
	Iago 1		2,381,054.90
	Pre drill WA25		16,760.47

Gorgon Field Resource Categorisation - Note for Information
11/04/2004

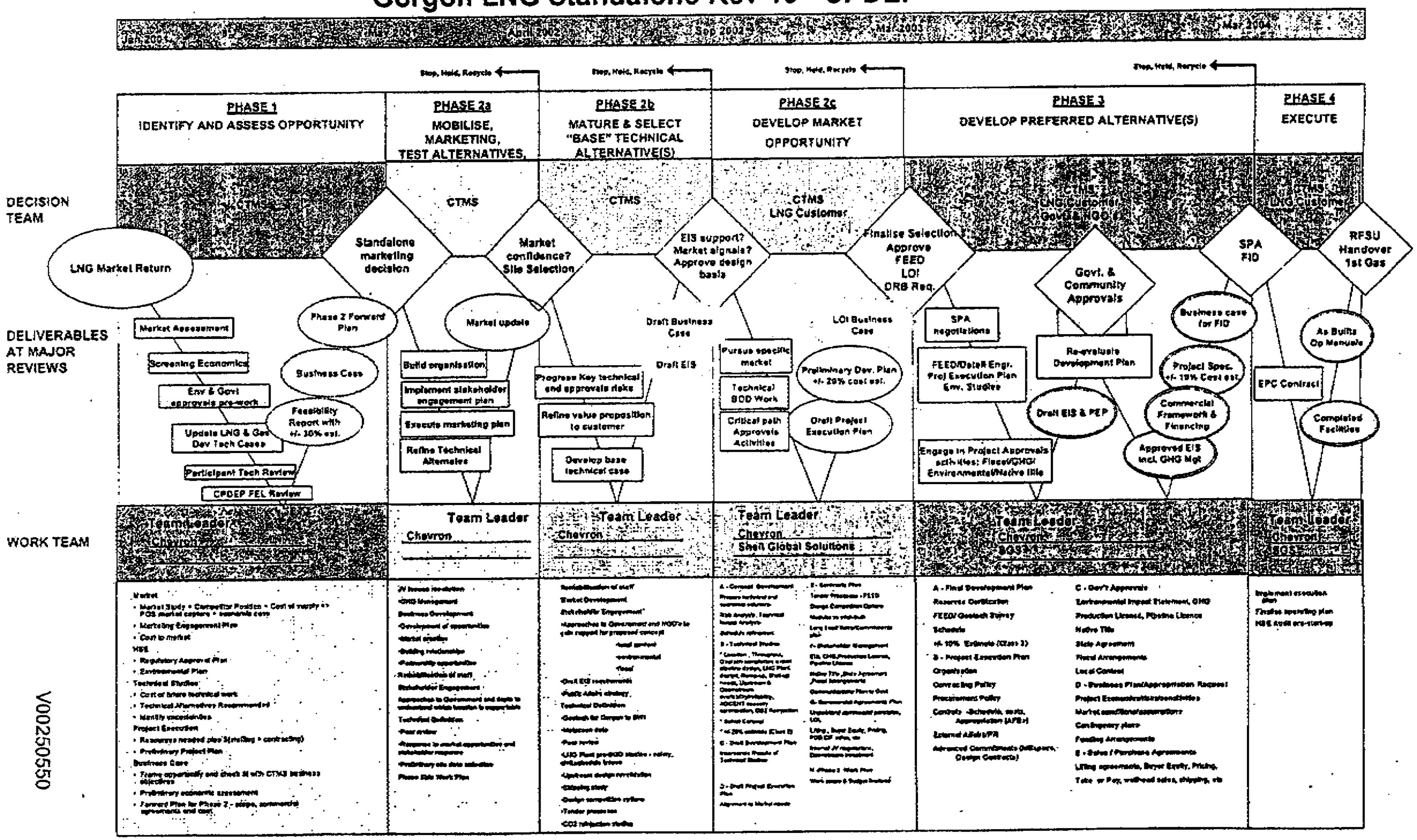
	casing	58,553.41
	explore,off,lab	57,655,923.87
WA25P	permit total	155,119,354.57

APPENDIX 5

APPENDIX 6 SUMMARY OF DIRECT/INDIRECT GORGON RESERVES BOOKED 1.1.2002

Gorgon LNG Standalone Rev 10 - CPDEP

Version: 14/11/01



FOIA Confidential Treatment Requested

Gorgon (currently reserves) - PROVED

WEL	0.00%	Equity
SDA =	28.57%	Equity

	Gas (TSCF)	Condensate (mln bbls)	Gas mln boe	Total boe
Total	10.65	110.69	1837.3	1948.0
Shell Direct	3.043	31.626	524.9	556.6
Shell Indirect	0.000	0.000	0.0	0.0
Shell Direct+Indirect	3.043	31.626	524.9	556.6

Gorgon (currently reserves) - EXPECTATION

WEL	0.00%	Equity
SDA =	28.57%	Equity

	Gas (TSCF)	Condensate (mln bbls)	Gas mln boe	Total boe
Total	15.16	131.32	2615.4	2746.7
Shell Direct	4.331	37.520	747.2	784.8
Shell Indirect	0.000	0.000	0.0	0.0
Shell Direct+Indirect	4.331	37.520	747.2	784.8

North West Shelf Gas Resource Categorisation - Note for Information

September 2002

Shell Development (Australia) Pty Ltd

Contents

1. BACKGROUND..3

2. HISTORY OF NWS RESERVES BOOKING.....................................4

3. SEC AUDIT OCTOBER 2000...5

4. EXISTING LICENCE PERIOD..6

5. COMMITTED VOLUMES..6

6. IMPACT OF CLNG DEAL..7

APPENDIX 1 - History of NWS Gas Reserves Booking

APPENDIX 2 - Extract from EP-2001-1100 - Requirements for commercial maturity for reserves bookings

1. BACKGROUND

This note for information summarises the current methodology used to determine externally reported proved reserves for the North West Shelf group of gas fields. It summarises what was defined as "committed" under the Shell guidelines at ARPR1.1.2002, and qualifies the impact that the recent successful CLNG contract will have on proved reserves bookings.

The entire expectation "economically and technically" producible resource base (excluding Scope for Recovery) for the NWS is currently booked as expectation reserves. Of this expectation volume, historically the entire P85 technical volumes have been externally reported as proved reserves, regardless of the status of signed contractual volumes. This is on the grounds that [quote from 2000 SEC audit]…

" there are likely to be ample opportunities for expansion of the LNG market in South and East Asia, particularly post 2005. Although there is competition on the supply side, there can be little doubt that buyers can eventually be found for all economically producible gas on the NWS".

Although contracts have not been signed which cover the entire NWS resource base, the total economically producible volume is considered to be reasonably certain of being sold and thus commercial (and technical) maturity requirements for reserves bookings as specified in the Group Petroleum Resource Volume Guidelines are deemed to be satisfied. This methodology was sanctioned during the latest SEC reserves audit carried out in October 2000.

There is a legal right under the "Petroleum Submerged Land Act" to extend production licenses beyond 2022, thus reserves have been recorded for the total producing field life.

As a result of the SEC audit in 2000, the proved reserves volumes for the NWS gas fields were further increased by assuming Proved Developed volumes for mature fields to be equal to Expectation Developed volumes. Thus since 1.1.2001 the Proved reserves volumes are greater than the sum of the individual P85 field volumes as provided by Operator. Currently only the North Rankin field is considered to be mature - thus the increase to date has been minimal.

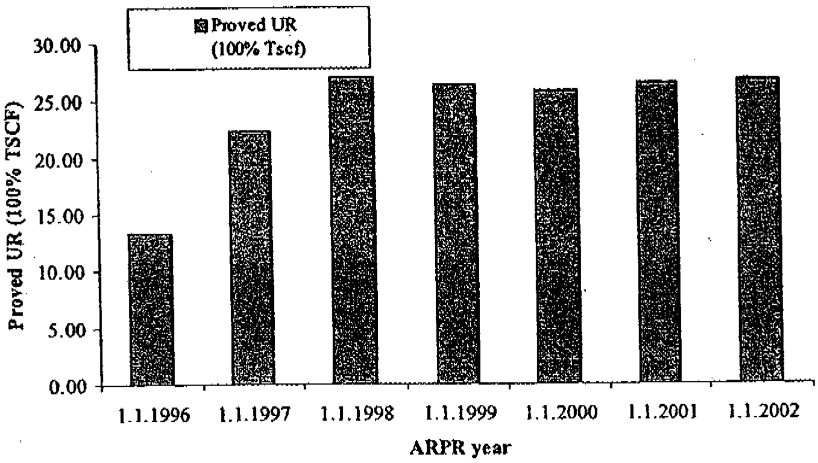
The result of probabilistically adding the field volumes has not been included in the externally reported proved reserves volume. If this were to be done it would add a further 2 TCF to the total proved volumes.

Under the recently awarded CLNG venture, CNOOC will be entitled to a percentage, currently ~5%, of NWS expectation reserves, which will be divested equally from the current six NWS JV partners. Upon finalisation of this contract, and subsequent payments for the equity, SDA will be required to reduce its proved reserves booking by the appropriate percentage. Currently this approximates to a reduction of ~0.2 Tscf Shell direct share proved reserves.

2. HISTORY OF NWS RESERVES BOOKING

An historical overview of the 100% Ultimate Recovery Proved volumes (reserves + cumulative production) as reported in the ARPR since 1.1.1996 is shown in the following figure. Details, change explanations and Shell direct share volumes are shown in Appendix 1.

History of NWS Proved reserves



Historically NWS reserves have been booked by Shell Development Australia on a field-by-field technical and commercial maturity basis, irrespective of the volumes associated with signed gas contracts in place. This was on the grounds that there are likely to be ample opportunities for expansion of the LNG market in South and East Asia, particularly post 2005. Although there is competition on the supply side, there can be little doubt that buyers can eventually be found for all economically producible gas on the NWS. Thus market availability criteria set out in EP 2001-1100, Section 2.3.4, (extracts in Appendix 2) were deemed to be satisfied for all economically producible gas. Under this scenario the successful China deal only serves to accelerate proved reserves production from currently assumed contract extensions.

Major changes of externally booked proved reserve since 1996 have been as follows:-

- At 1.1.1996 only four fields were considered technically mature (Angel, Perseus, North Rankin and Goodwyn). Recovery factors were low and did not include depletion compression.
- Major increase at 1.1.1997:- The Echo yodel field was considered technically mature for the first time. Significant increased recovery for North Rankin and Perseus as a result of compression being included.

- Major increase at 1.1.1998:- A number of smaller gas fields (Dixon, Keast, Dockrell etc) were transferred from SFR to reserves post technical/economic studies. North Rankin and Perseus recoveries increased as a result of simulation work and production data.
- Minor decrease at 1.1.1999 - as a result of Goodwyn drilling results
- Minor decrease at 1.1.2000 - various technical revisions
- Minor increase at 1.1.2001 - Gaea discovery and increasing North Rankin proved developed reserves to equal expectation developed volumes post SEC recommendation for mature fields.
- Minor increase at 1.1.2002 - as a result of including Athena volumes for the first time (extension of Perseus field into non-equity acreage).

The above changes reflect technical recovery factor changes, discoveries and maturation of field specific volumes from SFR to reserves with the execution of technical/economic studies. They do not reflect changes in the volume of gas committed to signed contracts.

3. SEC AUDIT OCTOBER 2000

SDA proved reserves as at 1.1.2000 were audited by the Group Reserves Co-ordinator (Anton Barendrecht) in October 2000. The inclusion of all economically producible NWS volumes into proved reserves (regardless of signed contracts) was endorsed. In fact it was recommended to increase externally reported proved reserves for mature fields by booking expectation, as opposed to P85, volumes. Specific audit review comments pertaining to technical/commercial maturity are as follows:

<u>Table 1 extraction from SEC reserves audit check-list</u>

2.09	Have all proved gas reserves been contracted to sales	Not all of these. There is still uncontracted gas in the NWS fields.
2.10	If not – can they reasonably be expected to be sold in existing markets and through existing facilities?	Existing NWS gas buyers are likely to be quite willing to extend current contracts: Existing facilities' life span is not seen as a constraint
2.11	If neither, can they reasonably be expected to be developed and sold in a future market?	There are likely to be ample opportunities for expansion of the LNG market in South and East Asia, particularly post 2005. Although there is competition on the supply side, there can be little doubt that buyers can eventually be found for all economically producible gas on the NWS.
1.16	Are projects technically mature or is further data gathering necessary?	Those projects pertaining to proved reserves are mature, with the possible exception of Egret, where the low reserves estimate does not appear to pass screening criteria
2.01	Are projects commercially mature (positive NPV for Group ref criteria over a range of possible future scenarios/low case reservoirs?	Yes ; those that are not are classified as SFR
2.02	Are projects economically viable	Yes, with the possible (minor) exception of Egret)

4. EXISTING LICENCE PERIOD

Whilst there is little doubt that buyers can eventually be found for all economically producible gas on the NWS and market availability criteria can be satisfied, externally booked proved reserves should be limited to future production within the existing production license period, unless there is a legal right to extend the production license (EP 2001-1100, Section 4.3.1) . The NWS production licences expire in September 2022. Under the PSLA (Petroleum Submerged Land Act) the NWS venture have a statutory right to extend the production licences until the end of field life. Thus reserves have been recorded for the total producing field life.

5. COMMITTED VOLUMES

The guidelines for committed gas at 1.1.2002 (EP 2001-1100, section 4.3.9, unchanged in the updated 2002 guidelines) state that ....

"In countries with a mature gas market all gas reserves, which have a near certainty of market take-up can be classified as committed" . .

Under these definitions SDA considered gas reserves to be "Committed Reserves" if there is an LOI in place or if there was a "near certainty" that the volumes will be marketed. For the ARPR 1.1.2002 it was concluded that Current Domgas Contracts & LNG Contracts, **NWS trains 1-3 & Domgas extensions to 2029**, and Methanex but not Syntroleum or BHP DRI could be classified as committed volumes as summarised in the following table:-

Committed Volumes as at 1/1/2002 (Tscf, 100%)	ARPR 2002
Production as at 1.1.2001	6.40
Remaining contract volumes as at 1.1.2001:-	
Current Domgas Contracts	2.26
Current LNG Contracts	3.47
T1-3 Extensions	8.50
Domgas Extensions	2.17
T4	4.67
Wedge	0.24
BHP DRI	0.00
Syntroleum	0.00
Methanex	1.76
Remaining contract volumes at 1.1.2001	23.07
Production as at 31/12/2001	6.96
Remaining contract volumes at 1.1.2002	22.51

Out of the expectation NWS reserves volumes of 24.6 Tscf, 22.51 Tscf was considered "committed" under the guidelines/assumptions above. This resulted in an indirect share "fraction of committed expectation " of 91.7%. Externally reported proved reserves of 20.0 Tscf (100%) were reported at 1.1.2002 i.e. under the interpretation of "committed volumes as discussed above, the committed volume exceeded Proved reserves.

The above reflects a snapshot as agreed at 1.1.2002, clearly the impact of China and other events will have changed the situation. CLNG volumes will now be included as committed - but at the expense of Train 1-3 and Domgas extensions. The latest view of post-China committed contracts is currently under investigation and will be included in the ARPR 1.1.2003. It is possible that extensions to current contracts will no longer be considered as committed.

6. IMPACT OF CLNG DEAL

Under the recently awarded CLNG venture, CNOOC will be entitled to a percentage, currently ~5%, of NWS expectation reserves, which will be divested equally from the current six NWS JV partners. Upon finalisation of this contract, and subsequent payments for the equity, SDA will be required to reduce its proved reserves booking by the appropriate percentage. Currently this approximates to a reduction of ~0.2 Tscf Shell direct share proved reserves.

APPENDIX 2 Extract from EP-2001-1100 – Requirements for commercial maturity for reserves bookings

2.3.3 Commercially Mature

A **commercially mature** project is commercially viable over a sufficiently large portion of the range of possible scenarios that reflect the remaining resource uncertainties as well as the remaining commercial uncertainties, including the availability of markets (see below). The definition of what constitutes 'a sufficiently large portion' may vary from case to case but it does require the project NPV for the proved reserves scenario to be positive for appropriate commercial criteria. It is also likely to include an assessment of the capital exposure in case of project failure due to adverse resource realisations. The selected range of scenarios should be documented and auditable.

2.3.4 Market availability

An essential requirement for commercial maturity is also that a market must be available or reasonably expected to be available for the hydrocarbon products. For oil and NGL this means at least the (expected) availability of a pipeline to a shipping terminal or other outlet (e.g. a refinery). For gas this means an expectation that access to a gas market will be available, i.e. the gas must be:

1. contracted to sales; or
2. considered as reasonably certain of being sold based on a reasonable expectation of the availability of markets, along with transportation/ delivery facilities that are in place; or
3. whilst not firmly planned, have been earmarked for future development and hence may reasonably be anticipated to be sold based upon expectation of availability of markets and project financing.

For major gas projects critically depending on new gas market capture, reserves booking should in principle be deferred until agreements have been signed, generally at or around project sanction (FID).

The condition of marketability to gas reserves also applies to the NGL products of a non-associated gas project. If the gas market is not matured (or likely to be matured) and the go-ahead of the project is still uncertain, neither the gas reserves nor the NGL reserves can be booked.

2.3.5 Commercially Viable

A scenario is **commercially viable** if the NPV is expected to be positive under the applicable (or expected) terms and conditions for the acreage and for the current advised Group reference criteria for commerciality.

2.3.6 Economically Viable

A project is **economically viable** if the expected NPV under the applicable terms and conditions for the acreage exceeds the separately advised Group project screening criteria or if the project has already been approved by shareholders. Projects generally have to demonstrate economic viability in order to obtain investment approval (See Ref. 13).

Appendix 1 History of NWS reserves booking

	Cum production (100% TSCF)	Proved Remaining Reserves (100% Tscf)	Proved UR (100% Tscf)	Increase in 100% UR	Shell direct share	Shell direct reserves (Tscf)	Shell direct UR (Tscf)	Change from previous year
1.1.1996	3.21	10.09	13.30	0.00	14.25%	1.44	1.90	Angel, Perseus, North Rankin and Goodwyn fields only considered technically/commercially mature
1.1.1997	3.78	18.56	22.34	9.04	14.26%	2.65	3.19	Significant improved recovery as a result of compression being included for North Rankin and Perseus. Echo Yodel volumes included as technically mature for first time
1.1.1998	4.38	22.61	26.99	4.65	14.27%	3.23	3.85	A number of smaller NWS gas fields (Dixon,Keast Dockrell, Lambert Deep, rankin/Sculptor, Tidepole and Wilcox) were transferred from commercial SFR to reserves. North Rankin/Perseus recovery factor increasing as a consequence of reservoir modelling work and detailed simulation of production and pressure data.
1.1.1999	4.93	21.43	26.36	-0.63	14.28%	3.06	3.77	Goodwyn drilling results - reduction in proced UR
1.1.2000	5.52	20.34	25.86	-0.50	15.64%	3.18	4.04	Net efect of technical revisions reduction in 100% volumes. Recalculation of Shell direct share resulted in increased shell direct volumes
1.1.2001	6.13	20.34	26.47	0.61	15.74%	3.20	4.17	Gaea discovery. North Ranking proved increased to expectation volumes post 2000 SEC recommendation for mature fields
1.1.2002	6.73	19.96	26.69	0.22	15.79%	3.15	4.21	Athena volumes included and offset 2000 production

Unknown

From: Van der Laan, Marian M SI-MGDWV/DIRMB on behalf of Van De Vijver, Walter SI-MGDWV
Sent: 26 September 2002 13:32
To: Bichsel, Matthias M SIEP-EPX; Brass, Lorin LL SIEP-EPB; Cook, Linda LZ SIG-GP; Coopman, Frank F SIEP-EPF; 'Darley, John J SIEP-EPT'; Dubnicki, Carol C SIEP-EP-HR; Gardy, Dominique D SEPI-EPA; Megat, Zaharuddin Z SEPI-EPM; Sprague, Bob RM SEPI-EPW; 'Ward, Brian BJ SEPI-EPG'; Van De Vijver, Walter SI-MGDWV
Subject: FW: EP Delivery

Importance: High

Please note that these slides are strictly confidential and therefore, not meant for further distribution.

Regards,

Walter

-----Original Message-----
From: Van der Laan, Marian M SI-MGDWV/DIRMB **On Behalf Of** Van De Vijver, Walter SI-MGDWV
Sent: 26 September 2002 13:00
To: Bichsel, Matthias M SIEP-EPX; Brass, Lorin LL SIEP-EPB; Cook, Linda LZ SIG-GP; Coopman, Frank F SIEP-EPF; Darley, John J SIEP-EPT; Dubnicki, Carol C SIEP-EP-HR; Gardy, Dominique D SEPI-EPA; Megat, Zaharuddin Z SEPI-EPM; Sprague, Bob RM SEPI-EPW; Van De Vijver, Walter SI-MGDWV; Ward, Brian BJ SEPI-EPG
Subject: EP Delivery

Attached you will find the package I had for the CMD on 24th September.

EP Delivery CMD
24-09-2002.ZIP...

Regards,
Walter

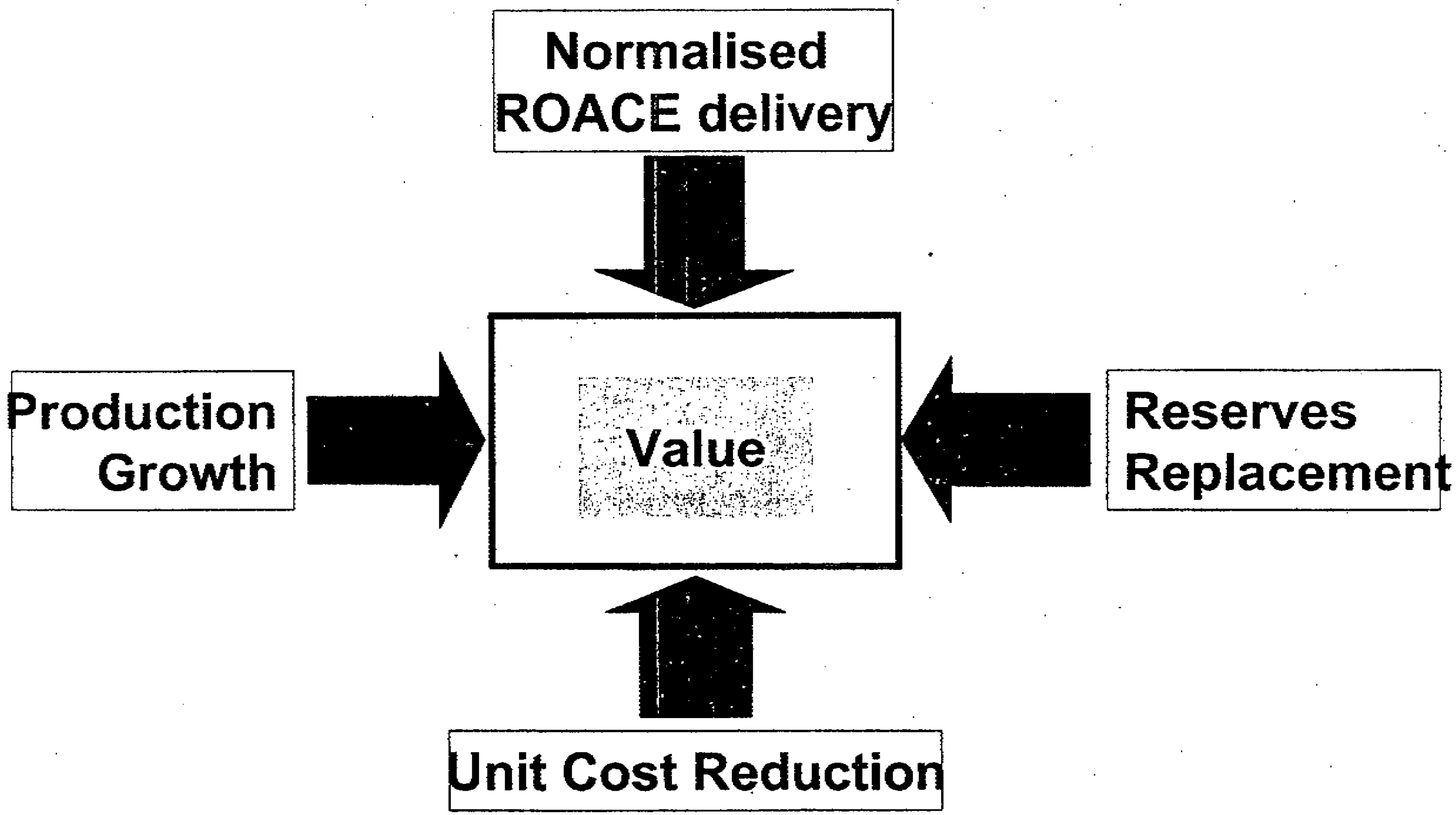
Incoming mail is certified Virus Free.
Checked by AVG anti-virus system (http://www.grisoft.com).
Version: 6.0.567 / Virus Database: 358 - Release Date: 24/01/2004

PENGAD 800-631-6989 EXHIBIT 1/25/07
18
Gardy

VIJVER 1035

V00231035

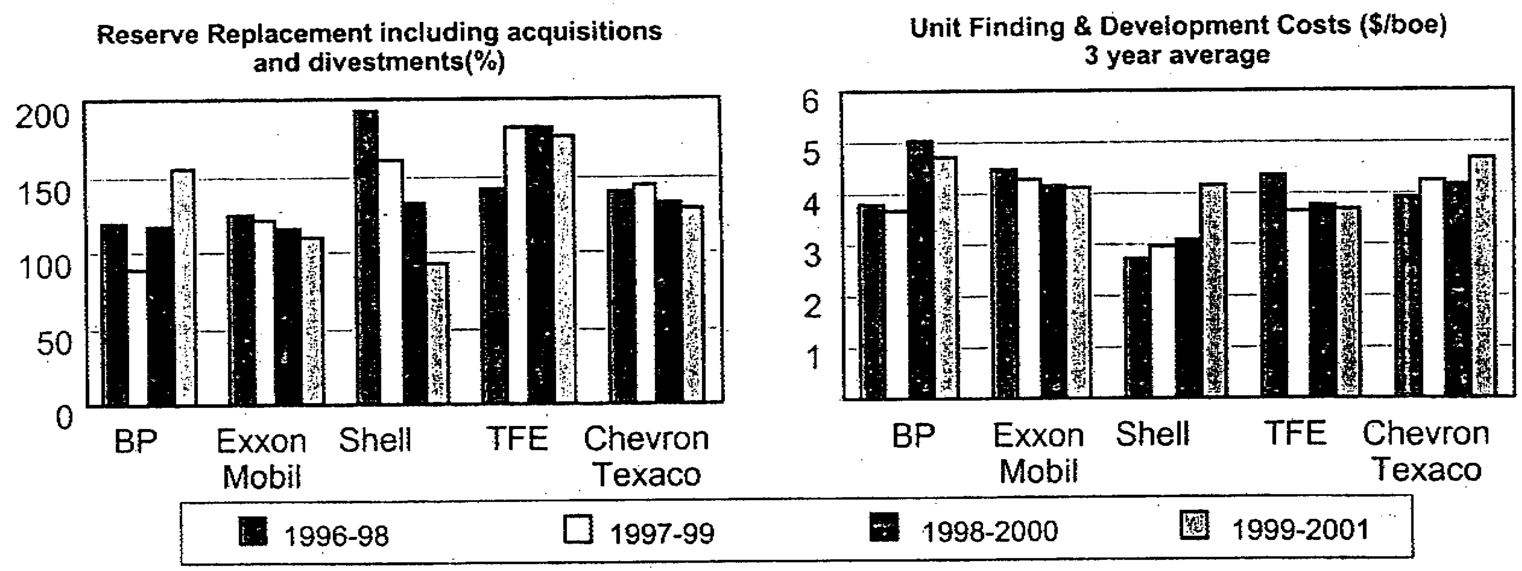
The EP Dilemma: Caught in the box?



VIJVER 1036

Reserves Replacement & Unit F&D Costs

Shell is losing its historical edge



Source: Prudential July 2002

VIJVER 1037

V00231037

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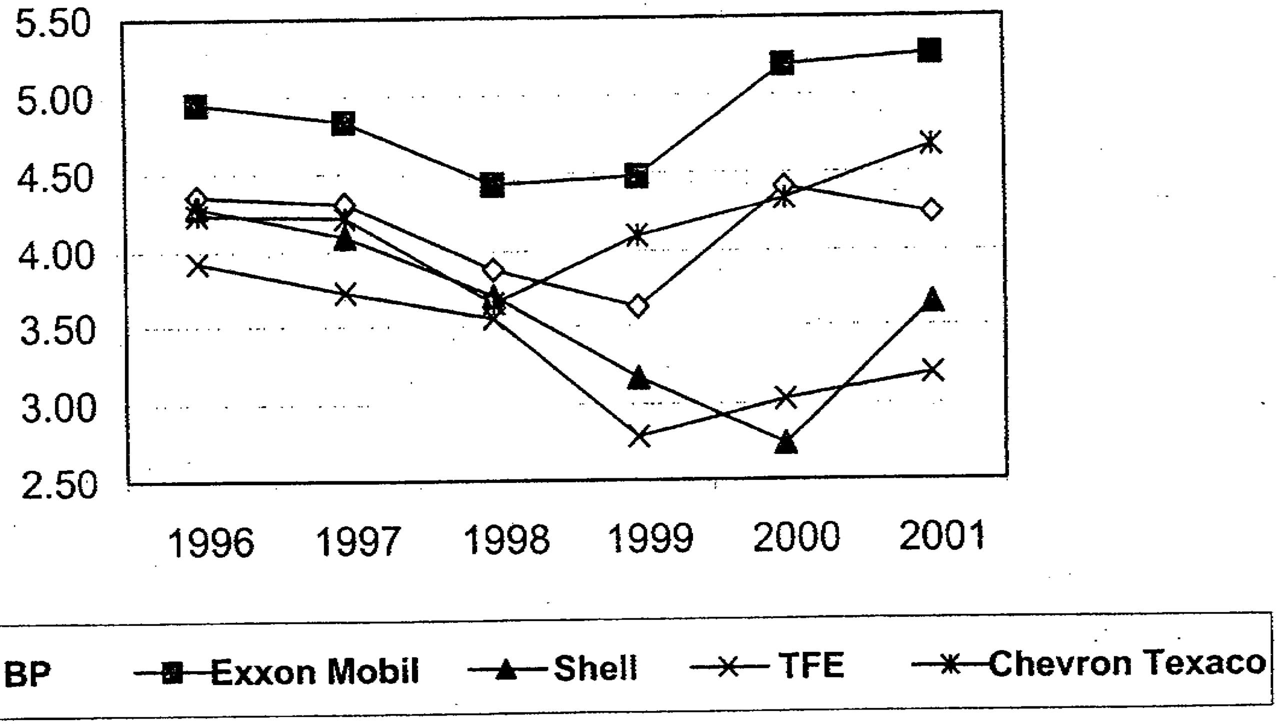
Treatment Requested

Unit Adjusted Production Costs Worldwide

Shell is # 2 after TFE.



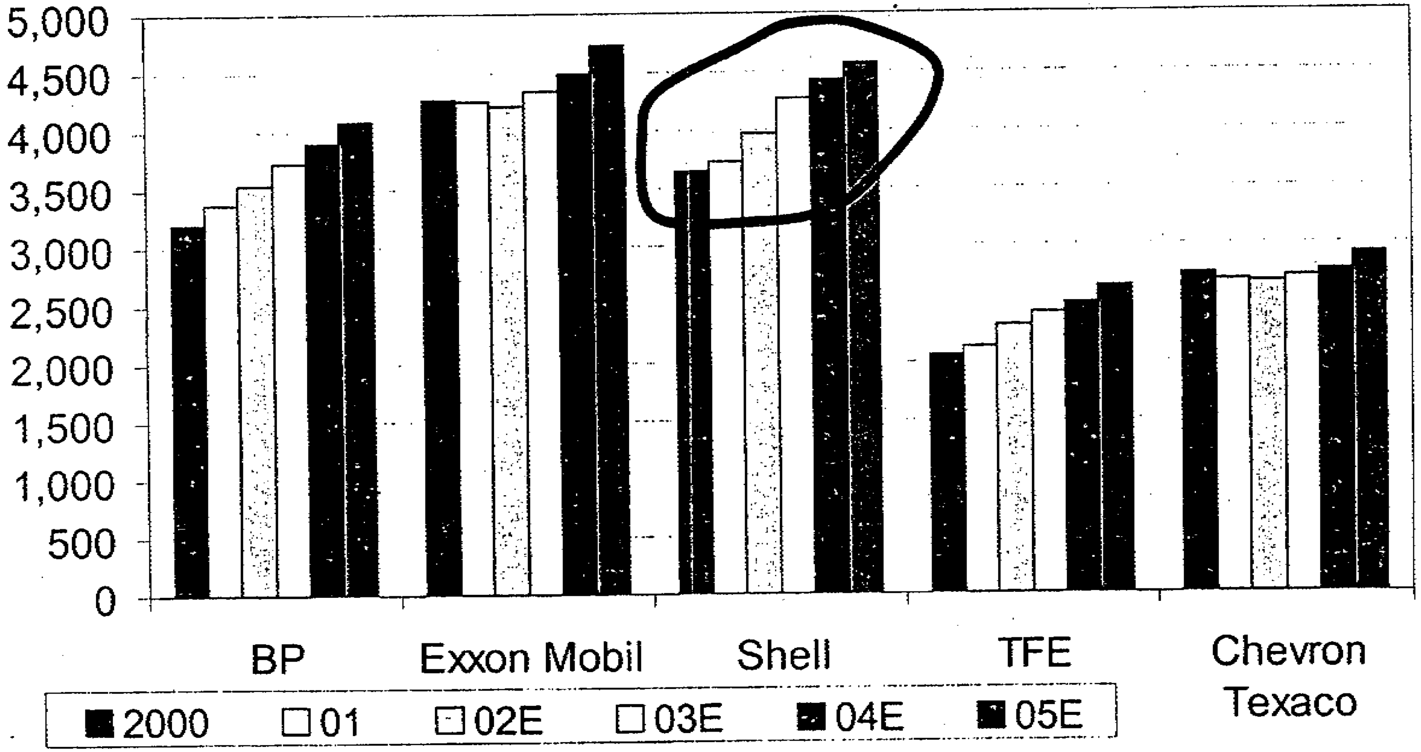
Source: Prudential July 2002

VIJVER 1038

V00231038

Production forecasts

The market still expects us to deliver!



Source: Lehman Brothers September 2002

VIJVER 1039

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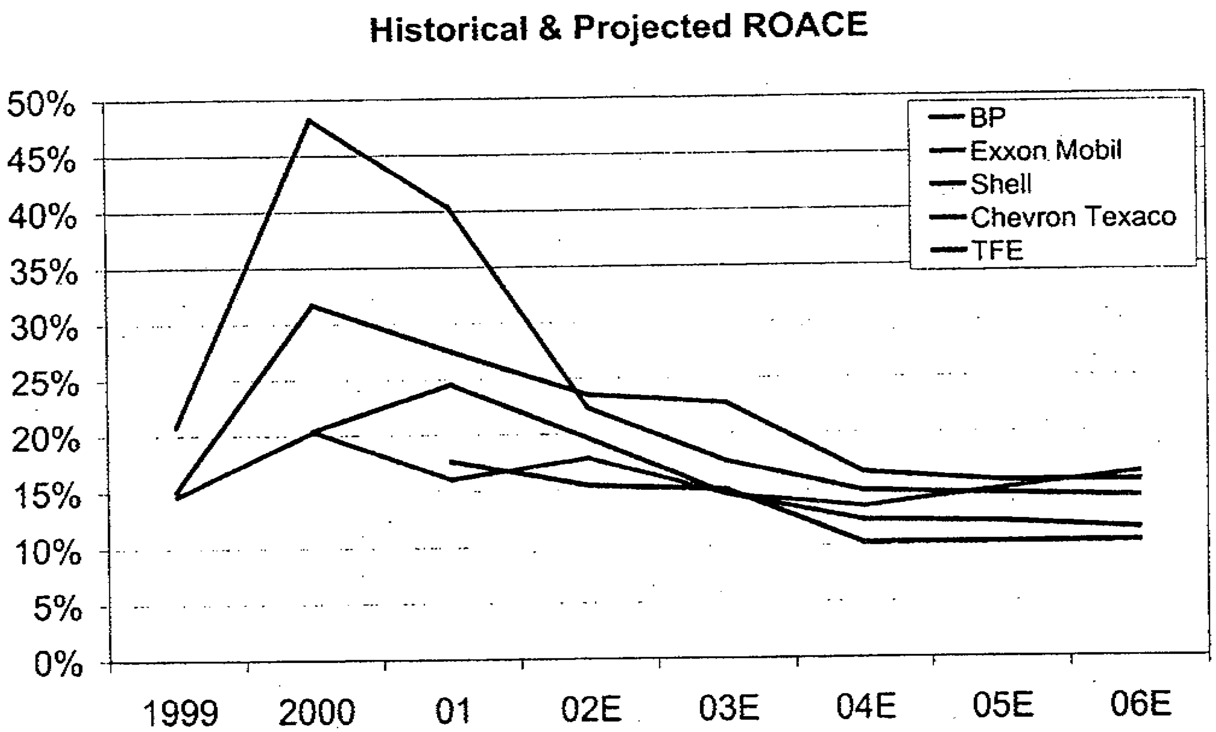
V00231039

ROACE forecasts

Shell loses historical advantage...



Lehman Brothers estimates		02E	03E	04E	05E	06E	
	Brent	23.20	19.00	17.00	17.00	17.00	($/bbl)
	H Hub	2.93	3.00	3.00	3.00	3.00	($/mmbtu)

Source: 1999-2001 PX adjusted actuals; 2002 forward, Lehman Brothers September 2002

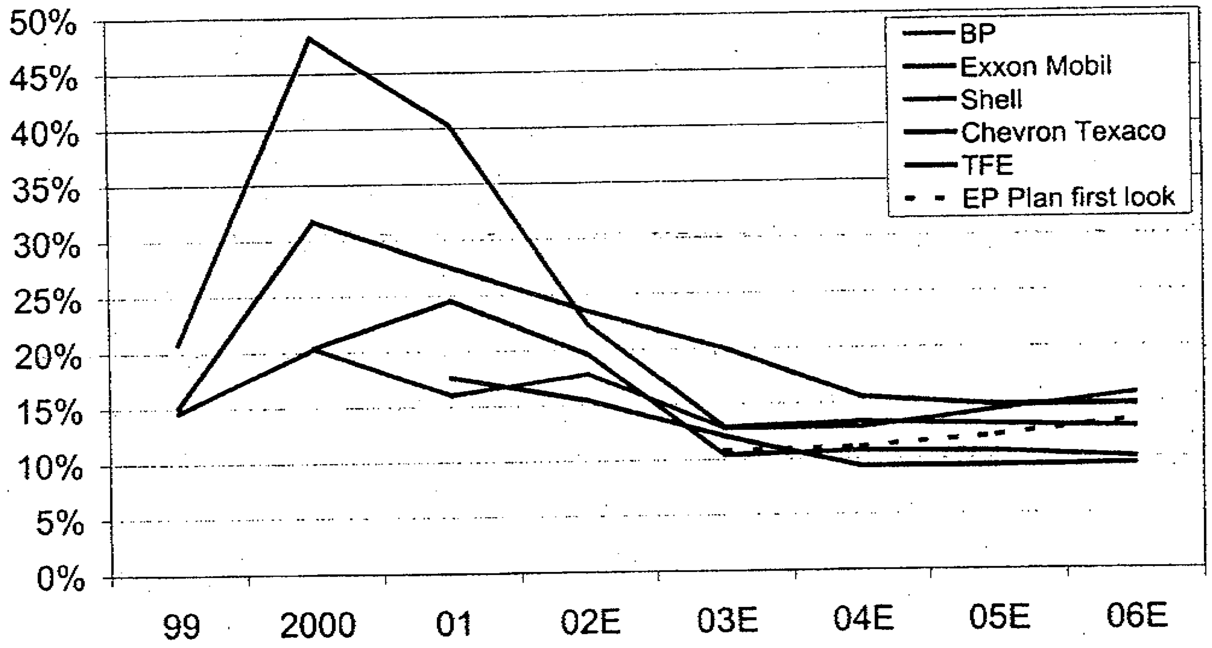
VIJVER 1040

V00231040

Normalised ROACE forecasts

... and "in the pack" when normalised

Historical & Projected Normalised ROACE



Lehman Brothers estimates							
	Brent	23.20	16.00	16.00	16.00	16.00	($/bbl)
	H Hub	2.93	3.00	3.00	3.00	3.00	($/mmbtu)

Source: 1999-2001 PX adjusted actuals; 2002 forward, Lehman Brothers September 2002

VIJVER 1041

Announcements from SuperMajors 1st half 2002

- Plutao discovery in Block-31 Angola
- Iron Horse discovery (1tcf)
- Sakhalin 5 exploration JV with Rosneft

Chevron

- Discovery in Liaodong Bay
- Discovery Gabela-1 in Block 14 (Angola)

TOTAL FINA ELF

- Akpo discovery, est. reserves 900mln bbl.
- $2bln investment on Vankorskoe field, (JV with Yukos)

ExxonMobil

- Deepwater Discovery OPL222 (5000 b/d)
- Agreement PNG- Queensland pipeline
- First oil from Larut field (Malaysia)

Announcement from SuperMajors 1st half 2002

- Kashagan Discovery Declared Commercial
- Agreement for West East China Gas Pipeline with PetroChina and Sinopec
- Selected to participate in LNG project with 30% in Mariscal Sucre
- Discovery exploration block BS-4, (68m of net oil pay in deepwater sands)
- Nigeria LNG Plus project unlocking $7.5 billion of new projects in Nigeria
- Discovery of oil 300m beneath the Kebabangan field offshore Malaysia
- Acquisition of Enterprise Oil

VIJVER 1043

Expected incremental Production Growth from Major Projects 2003

	bp	ExxonMobil	Chevron	TOTALFINAELF
6.1%	5.1%	4.4%	3.0%/4.4%	7.6%
Athabasca	Valhal	Syncrude	Hebron	Matterhorn
Penguins	Na Kika	Train 2	Cabinda Exp.	NC-137
EA	ALNG Train 3	Hebron	Doba Basin	Bonga
Bonga	In Salah	Grane	Madu	Amenam
Nowrooz		MikkelJotu	Anyala	EA
Bintulu		Bonga	Tengiz	Dorood
Groningen		Erha	Karachaganak	
Na Kika		Cepu	Huizhou 19-3	
Suape LNG		Sable Island		
K-fields		Fram West		
NWS Train 4		Groningen		
		RasGas (Trains 3 & 4)		

VIJVER 1044

Source: ABN Amro January 2002

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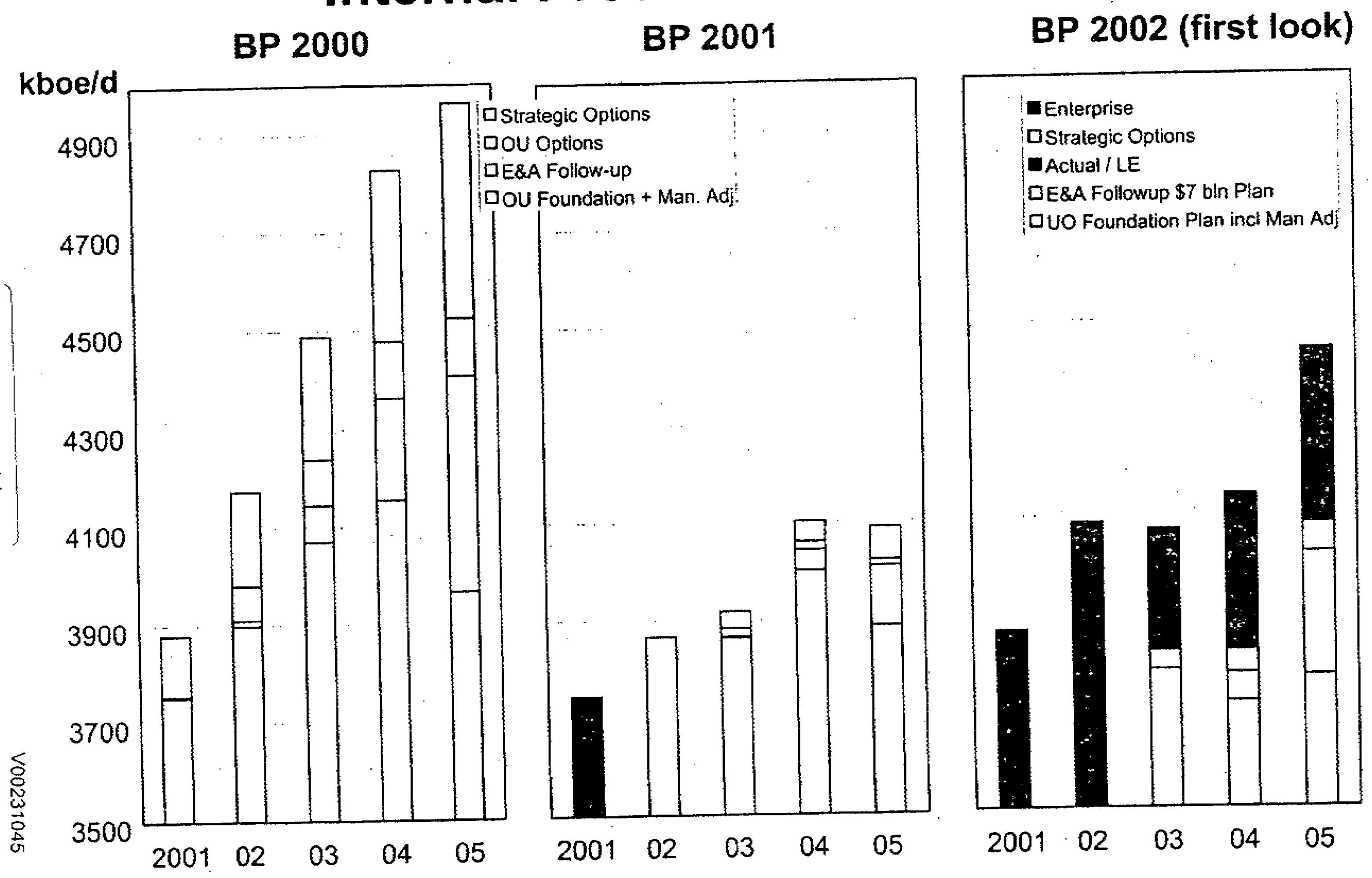
V00231044

Internal Production forecasts



VIJVER 1045

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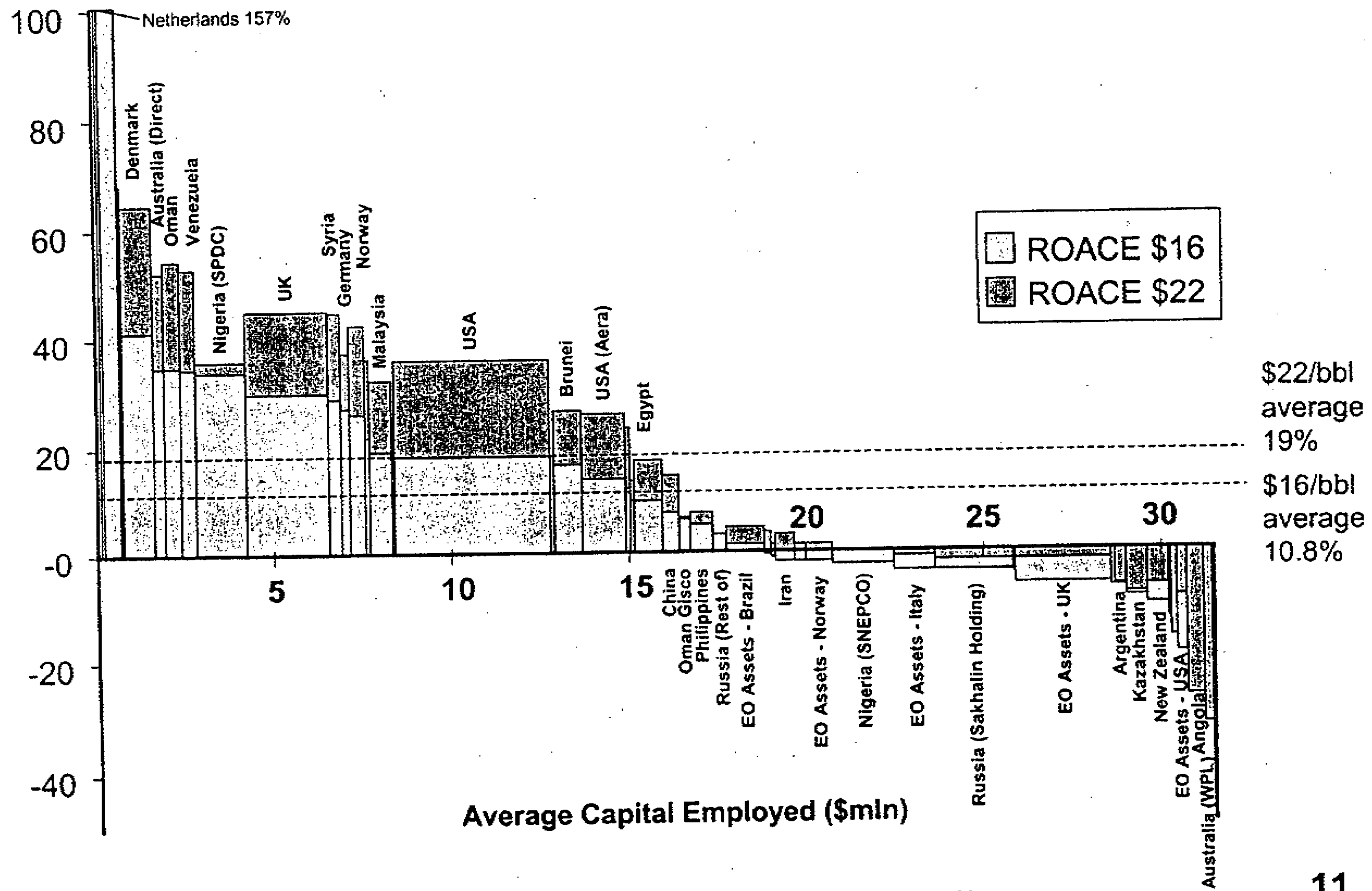
V00231045

Breakdown of 2003 ROACE



VIJVER 1046

11

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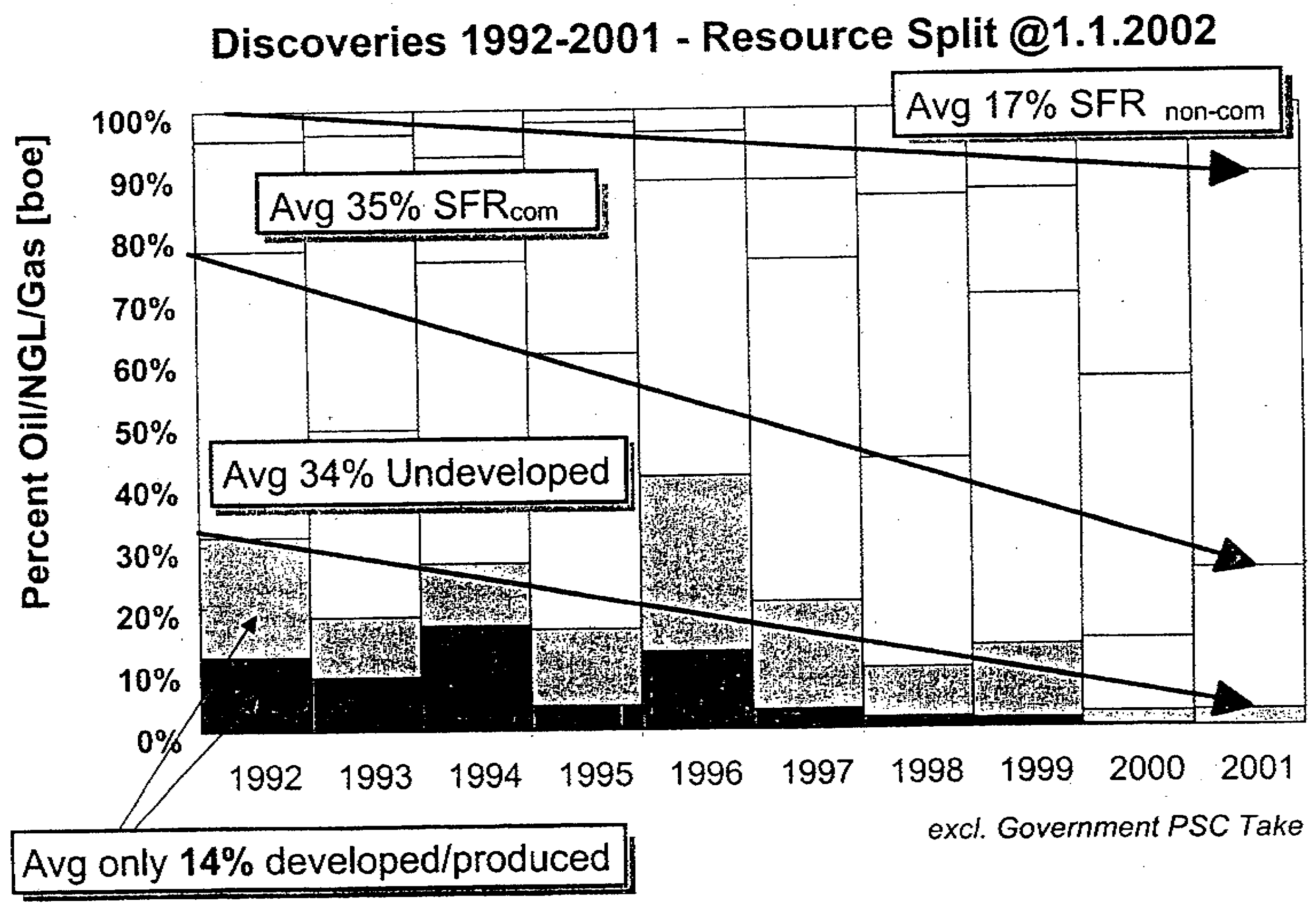
V00231046

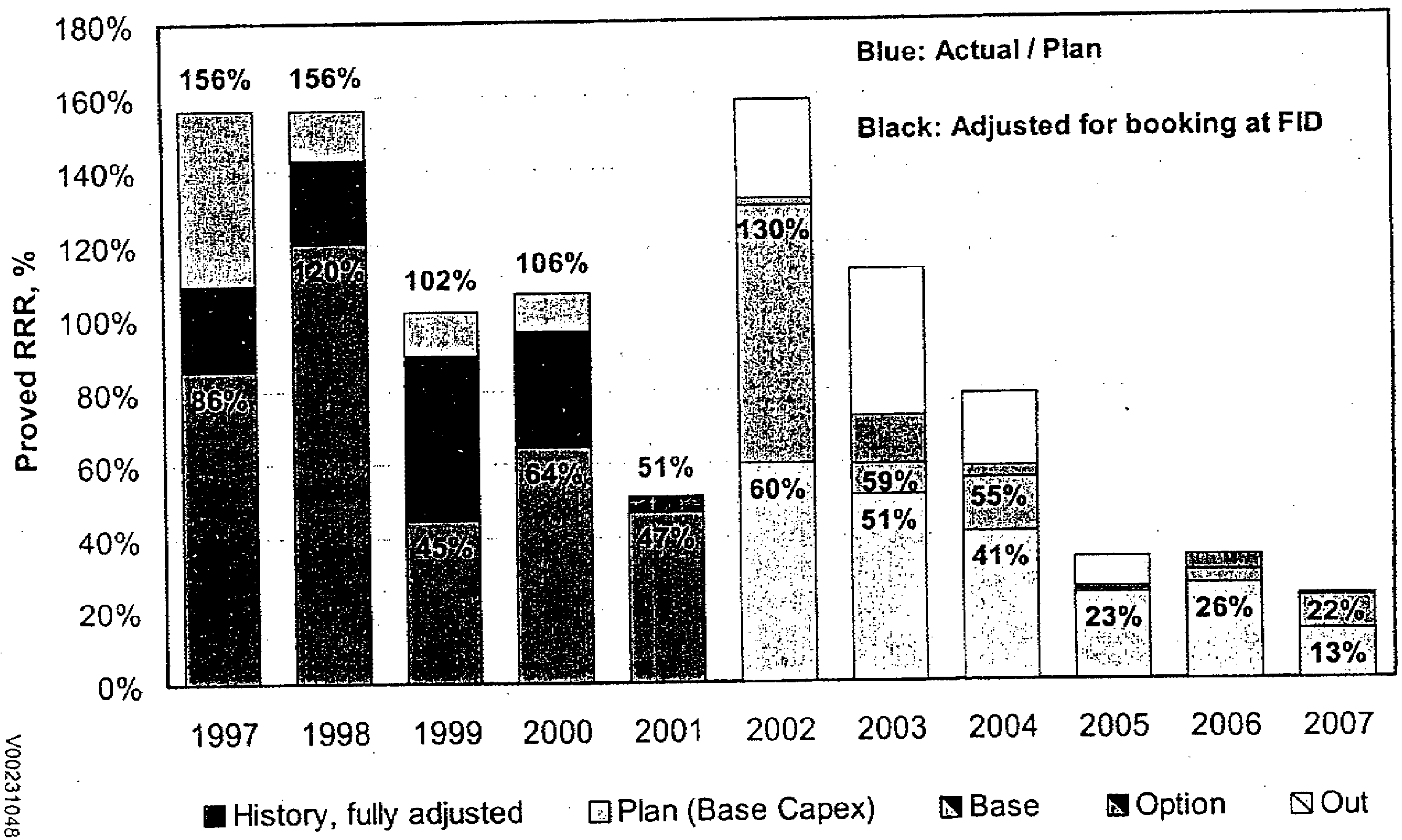
Development of Exploration discoveries



VIJVER 1047

V00231047

Proved RRR: Effect of aligning to FID



VIJVER 1048

13

V00231048

The EP Vision

How can we shape the future of energy?

Recognised as the World's Best EP Company

Reputation for superior **performance** and admired for the way we deliver it

Unlocking tomorrow's global **portfolio** and unleashing the value from today's

Technological and commercial innovation delivered by **people** that thrive on challenge

Belief in **sustainable development** – continually turning principles into reality.

Shell EP

VIJVER 1049

V00231049