Exhibit 68

NOTE – 30 January 2001 **CONFIDENTIAL**

From:	Anton A. Barendregt	Group Reserves Auditor, SIEP EPB-GRA
To:	Lorin Brass	Director, EP Business Development, SIEP EPB
Copy:	✓ Phil B. Watts	EP Chief Executive Officer, SIEP
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	✓ John Bell	Vice Pres. Strategy, Planning, Portfolio and Economics, SIEP EPB-P
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REVIEW OF GROUP END-2000 PROVED OIL AND GAS RESERVES SUMMARY PREPARATION

In accordance with prescribed US Accounting Principles (SFAS69), SIEP staff have prepared a summary of Group equity proved and proved developed oil and gas reserves for the year 2000. The summary (Att. 3) forms part of the supplementary information that will ~~be~~ presented in the 2000 Group Annual Reports and has been prepared on the basis of information provided by Group and Associated companies. The submissions by these companies (excluding those by Shell Canada) are based on the procedures laid down in the "Petroleum Resource Volumes Guidelines" (EP 2000-1100/1101) which in turn are based on the requirements of SFAS 69. Shell Canada's submissions are subject to their own procedures and reviews.

I have reviewed the process of preparing the above summary of proved and proved developed oil and gas reserves in as far as these relate to companies outside Canada. This review included, where possible, a verification of the reasonableness of major reserves changes and any omissions of such changes, as appropriate.

The end-2000 Group share Proved Reserves (excluding Canadian oil sands) can be summarised as follows:

Oil mln m3 Gas bln m3	1.1.2000 Proved Tot'l	2000 Prod'n	1.1.2001 Proved Tot'l	Repl.Ratio (RR) Totl	RR Tot'l ex-A&D	1.1.2001 Prov. Dev'd	RR Dev'd	RR Dev'd ex A&D
Oil+NGL	1554	132	1550	97%	142%	711	50%	86%
Gas	1657	85	1593	25%	46%	737	49%	57%
Oil Equivalent	3157	215	3091	69%	105%	1424	49%	75%

Following the issue of new Group Reserves Guidelines in 1998, some 150 mln m3oe (oil equivalent) had been added to Proved Reserves in mature fields over 1998 and 1999. A further 50 mln m3oe has been added this year. Although most OUs have now implemented the new guidelines, some still offer scope for reserves additions. The issue will continue to be addressed by SIEP staff and by myself during forthcoming SEC Reserves Audits.

Externally reported Proved and Proved Developed Reserves need to be confined to those volumes producible within the duration of existing production licences. With progressing maturity, a number of OUs are seeing their scope for increasing Proved Reserves severely curtailed because any increase in field volumes cannot be produced within constrained production forecasts and licence durations. At present, some 25% of total Group Expectation Reserves is deemed to be non-recoverable within current licences. The corresponding figure for Proved Reserves is not reported.

Group Proved Reserves receive increasingly close attention by Group Management. Target reserves additions are set annually, both to OUs and to SIEP Divisions and progress is monitored throughout the year. With future Proved Reserves additions becoming much more challenging, the resulting pressure on staff raises possible concerns with respect to the quality of future reserves bookings.

Excellent correspondence was found this year for the first time between annual production volumes as reported through the separate Finance and SIEP systems. SIEP and Finance staff are highly commended for their efforts.

The system of monthly monitoring of OU reserves bookings, plus strictly controlled electronic reserves submissions has led to a particularly smooth process of preparing Group reserves statements this year.

During 2000 I made Reserves Audit visits to a total of six Group OUs. Audit opinions on all of these were 'satisfactory'. Many of the audit recommendations have been followed up in the 2000 submissions, particularly those aimed at raising Proved Reserves in mature fields.

The overall finding from the audit visits and from the end-year review in SIEP is that the SIEP statements fairly represent the Group entitlements to Proved Reserves at the end of 2000. The 2000 changes in the Proved Reserves can be fully reconciled from the individual OU submissions.

A more detailed list of ~~findings and~~ observations is included in Attachment 1.

30/1/01

A.A. Barendregt

Attachments 1 - 8

DEPOSITION EXHIBIT
Barendregt
#21 2/21/07

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Attachment 1	Main Observations end-2000 Reserves
Attachment 2	Significant Reserves Changes
Attachment 3	Group Proved Reserves Summaries
Attachment 4	Production Reconciliation Ceres vs. Reserves Submissions
Attachment 5	Scope for increasing Proved Reserves – by OU
Attachment 6	Angola Block 18 Initial Reserves Booking
Attachment 7	Main observations 2000 Reserves Audits
Attachment 8	Reserves Audit Plan 2001

Attachment 1

REVIEW OF GROUP END-2000 PROVED OIL AND GAS RESERVES SUMMARY PREPARATION

MAIN OBSERVATIONS

1. Significant reserves changes during 2000 were as follows:

New Group Reserves Guidelines, issued in 1998 prescribe that expectation values should be used for externally reported Proved Reserves in mature fields. This year, **PDO(Oman), SOGU(Denmark) and SDA(Australia)** were able to add in total some 50 mln m3oe* to Proved Reserves.

SEPCo(USA) were able to add some 39 mln m3oe to Proved Reserves, following project maturation and/or drilling in Oregano, Brutus, Nakika and Mars.

Improved recovery was identified by **PDO(Oman)** in Qam Alam, Al-Huwaisa and Lekhwair (+18 mln m3), by **Shell Canada** in Peace River (+14 mln m3) and by **SOGU(Denmark)** in Halfdan and other fields (+5 mln m3oe). Opportunities for further development through additional drilling were identified by **SVSA(Venezuela)** in the Urdaneta West field (+17 mln m3).

A first-time reserves booking was made by **SDAN(Angola)** in Block 18 (+12 mln m3). This volume reflects a first attempt at defining an economically viable development plan for the area. In its present form, the plan is marginally commercial but not economic, i.e. the economics present positive NPVs for a majority of scenarios, but the project does not pass Group investment screening criteria. For a more detailed note on Angola reserves see Attachment 6.

A field extension and a discovery were identified by **SNEPCO(Nigeria)** in Bonga and Abo (+11 mln m3)

Field Studies led to increased reserves bookings by **SPDC(Nigeria)** (+15 mln m3oe developed), **BSP(Brunei)** (+8 mln m3) and **Norske Shell** (+7 mln m3oe).

Corrections had to be made to Proved Gas reserves in the **USA (SNEPCo and Aera),** to exclude own **use / fuel** volumes, in line with a 2000 Audit recommendation and SEC requirements (-6 mln m3oe).

Economic revisions led to a shift from NGL to gas reserves by **Gisco(Oman)** (+22 mln m3oe net), which was offset by a reduction due to lower future cost projections (-17 mln m3oe). Improved future cash flow projections led to additions in **Iran** (+8 mln m3) and tax gross-up volumes were included in Proved Reserves by **SNEPCO(Nigeria)** (+8 mln m3oe).

Acquisitions and divestments led to additions being booked by **Shell Sakhalin** following an increase in Astokh equity (+8 mln m3) and to reductions in the **USA** due to the sale of Altura (-48 mln m3) and in the **UK** (-13 mln m3oe), following divestments in Foinaven, Franklin and Elgin.

Development activities led to increased Proved Developed Reserves being booked by **Shell UK Expro** (+27 mln m3oe), **SSB/SSPC(Malaysia)** (+23 mln m3oe), **SEPCo(USA)** (+22 mln m3oe) and **BSP(Brunei)** (+11 mln m3oe).

A tabulation of these changes is given in Attachment 2.

2. The 1.1.2001 Group share Proved Reserves (excluding Canadian oil sands) can be summarised as follows:

Oil mln m3 Gas bln m3	1.1.2000 Proved Tot'l	2000 Prod'n	1.1.2001 Proved Tot'l	Repl.Ratio (RR) Totl	RR Tot'l ex-A&D	1.1.2001 Prov. Dev'd	RR Dev'd	RR Dev'd ex A&D
Oil+NGL	1554	132	1550	97%	142%	711	50%	86%
Gas	1657	85	1593	25%	46%	737	49%	57%
Oil Equivalent	3157	215	3091	69%	105%	1424	49%	75%

Hence, the Oil+NGL replacement ratio target of 100% has been largely met, but the replacement ratios for Gas fell short.

Group share Proved Reserves divided by Group share annual production (**R/P ratio**) stands at 12 years for Oil+NGL and at 19 years for Gas.

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* 1 mln m3oe = 1 mln m3 oil equivalent = 1.03 bln sm3 gas

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A full overview of end-2000 Proved and Proved Developed Reserves is presented in Attachments 3.1-3.2.

3. Although the tabulations in Attachment 3 include volumes for **Shell Canada's Athabasca Oil Sands** Project (AOSP), these volumes are not strictly oil and gas reserves as defined by the SEC. Hence, they will be reported separately as 'mining reserves' to the SEC and excluded from the Group's SEC submission of oil and gas reserves.

4. The 17 mln m3 additional development identified by **SVSA in Urdaneta West** amounts to a significant rise in SVSA's Group share Proved Reserves (+78%). Whilst the end-1999 Reserves Audit confirmed the scope for significant upside, an increase of this magnitude should be supported by a technical review and it is noted that a VAR review is planned early in 2001. The viability of these reserves should be confirmed by the SIEP Reserves Coordinator and the Group Reserves Auditor through review of the VAR report and relevant SVSA documentation during 2001.

5. As mentioned before, new Group Reserves Guidelines were issued in 1998, which prescribed that externally reported **Proved and Proved Developed Reserves** should be brought closer to, or made equal to, **Expectation Reserves in mature fields.** The reason for this change was to align Group practice more to that of other major oil operators. Significant Proved Reserves additions (+150 mln m3oe) have been booked by many OUs over 1998 and 1999. PDO(Oman), SOGU(Denmark) and SDA(Australia) have followed suit this year (+50 mln m3oe). OUs that still seem to offer significant scope for raising Proved Reserves are BSP(Brunei), Shell UK Expro, BEB(Germany, gas only) and NAM and SPDC (both for developed reserves only). Some smaller targets are still left in Norske Shell and SOGU. Potential additions could amount to more than 100 mln m3oe. The issue will be addressed during SEC Reserves Audits with Shell UK Expro, SOGU, NAM and BEB during 2001. BSP are addressing the issue with the authorities but point out that raising Proved Reserves will result in higher tax and reduced cashflow.

   A method of visualising the relative position of OUs and their fields is through plotting the ratio between Proved and Expectation reserves versus field / OU maturity. The latter is defined as cumulative production as a fraction of total Expectation Ultimate Recovery (not constrained by e.g. licence expiry). Plots showing the OU positions for Developed and Undeveloped Oil+NGL and Gas reserves, plus their respective target volumes, are presented in Attachments 5.1-5.2.

   Uptake of the new Reserves Guidelines in the OUs has in some cases been somewhat slower than anticipated. The issue is raised continuously by SIEP staff with OUs with potential for Proved Reserves additions, and by the Group Reserves Auditor during SEC Proved Reserves Audits. The latter approach, with its higher profile, tends to be the most effective. During the audits, it was found that the slow uptake could partly be due to the new rules for Proved Reserves in mature fields not being emphasised enough in the Group Guidelines. Although these rules are certainly explained in the text, it is possible that their impact may not be immediately obvious to casual readers. In addition to their ongoing efforts of keeping the issue alive with OUs concerned, SIEP staff are encouraged to consider ways of strengthening the message in the updated Guidelines due out in 2001 and re-emphasise it in the cover letter.

6. Externally reported Proved and Proved Developed Reserves need to be confined to those volumes **producible within** the duration of **current production licences**, or their extensions if there is a right to extend. With progressing maturity, a number of OUs are seeing their scope for increasing Proved Reserves severely curtailed because any increase in field volumes cannot be produced within (generally constrained) production forecasts and licence durations. With ongoing annual production, these OUs will in fact see their remaining Proved reserves decline either until forecast production rates can be lifted or until licence extensions have been agreed with Authorities. OUs most affected by this are **SPDC(Nigeria), Shell Abu Dhabi** and **PDO(Oman).**

   At present, some 1200 mln m3oe Expectation Reserves are reported by OUs as being non-producible within existing licences. This corresponds to 25% of the current Group portfolio. The corresponding Proved volumes are not captured by the present submissions and are difficult to assess from centrally available data, but could exceed 100 mln m3oe. This volume is likely to increase in coming years. Consideration should be given to capturing this data properly through the annual submissions, to assist in focusing attention towards early agreements on licence extensions.

7. Group Proved Reserves receive increasingly close attention by Group Management. **Target reserves additions** are set annually, both to OUs and to SIEP Directorates and progress is monitored throughout the year. Targets are also set in scorecards for those on variable pay. Whilst these measures are effective in ensuring proper attention to Proved Reserves bookings, the resulting pressure on staff does raise **concerns** with respect to the **quality of future reserves bookings.**

In future, finding additions to Proved and Proved Reserves will be more of a challenge than hitherto. The reason is that the scope for relatively easy further additions due to the new Reserves Guidelines (Proved close to Expectation in mature fields) will reduce in the coming years, whilst a number of OUs will find themselves constrained to volumes producible within existing production licences. Finding genuine reserves additions will become an increasing challenge and the Group's desire to maintain future reserves additions at the same level as annual production (100% Replacement Ratio) will raise pressure on the staff responsible. Such pressures have this year led to the extremely marginal reserves booking for Block 18 fields in Angola, where e.g. the operator (BP) has considered the fields still to be too immature for any bookings at this stage. Further development along this trend should be closely watched by the SIEP Reserves Coordinator, who continue insisting on adherence to Group Reserves Guidelines in all cases. A similar role will be played by the Group Reserves Auditor.

8. Group share **annual hydrocarbon production** is reported separately through the **Ceres** system by Group Finance and through the reserves submissions accumulated by SIEP. Both reports find their separate ways into the Group annual report and it is therefore important that the two reports are **consistent**. In previous years, this consistency often presented problems, particularly with respect to reported gas sales / production volumes. Three important improvements have been made during 2000:

   – The definition for the reported gas stream under Ceres has been changed from Gas Sales (which could be affected by e.g. LNG plant losses and UGS storage swing in integrated OUs) to Upstream Gas Production available for Sale. This aligns it with the definition of Proved Reserves and thus with production as reported through the SIEP system.
   – The unit of reporting for gas production in Ceres has been changed from Normalised m3 (Nm3, at 9500 kCal/m3) to standard m3 (sm3), thus avoiding numerous conversion errors.
   – The paper copies of the OU reserves submissions, to be signed by a senior member of OU management, now include a statement confirming that the OU's Ceres and reserves submissions are consistent.

   These three measures have resulted in a significant improvement in consistency between the two reported production streams, particularly those for gas. As far as can be ascertained, this is the first year that full consistency has been obtained between the two streams, after some minor errors (mostly rounding) had been forced out or cleared up. This is a significant achievement and SIEP / Finance staff must be commended for their efforts. A summary table of the two submissions and their reconciliation is presented in Attachments 4.1-4.2.

9. **SEC Reserves Audits** are carried out by the Group Reserves Auditor in all OUs every 4-5 years. All audits carried out during 2000 resulted in 'satisfactory' opinions. The audits have been particularly successful at identifying scope for increasing Proved and Proved Developed Reserves in mature fields. A summary of audit findings is presented in Attachment 7. The forward Audit Plan is given in Attachment 8.

10. Since end 1998, OU reserves submissions are made by means of strictly controlled electronic workbooks, which greatly accelerate and streamline the process of accumulation of Group reserves within SIEP. The process of gathering and accumulating OU submissions has been particularly smooth this year, not least because the Reserves Coordinator has urged the OUs to address potential problems and issues with him well ahead of the submission dates. In addition, the system of monthly monitoring of OU reserves bookings tends to avoid end-year surprises. This is commended. The submissions provide also good detail on major reserves changes and on individual field Proved and Expectation volumes. Both represent excellent audit trails and SIEP staff are commended for their continuing efforts.

Recommendations to SIEP Reserves Coordination:

1. Vigilance should continue to be applied by the SIEP Reserves Coordinator to ensure that all future Proved Reserves changes will be fully in accordance with Group Reserves Guidelines.
2. Confirm the viability of the 78% Proved Reserves increase booked by SVSA by a review of the planned VAR report and associated SVSA documentation during 2001.
3. Include the volume of Proved and Proved Developed Reserves not producible within current production licences in annual OU reserves submissions.
4. Strengthen the message that externally reported Proved and Proved Developed Reserves should be brought close to (made equal to) expectation reserves in mature fields in the Group Reserves Guidelines to be updated during 2001 and in the cover letter.

Attachment 2

SIGNIFICANT 2000 PROVED AND PROVED DEVELOPED RECOVERY CHANGES

(Shell Group share)

MAJOR TECHNICAL REVISIONS					
Country	Oil+NGL (10^6 m^3)		Gas (10^9 sm^3)		Description
	Dev'd	Total	Dev'd	Total	
Oman - PDO	+7	+31			Full alignment with Group guidelines - exp'n values for mature fields (following 1999 Audit)
USA		+20		+19	Transfers to Proved due to project maturation or drilling (Oregano, Brutus, Nakika, Mars a.o.)
Oman - PDO		+18			Improved recovery (Qarn Alam, Al-Huwaisa, Lekhwair)
Venezuela		+17			Urdaneta-West – go ahead for further development
Canada	+2	+14			Peace River - revised development plan, based on new technology
Nigeria - SPDC	+13		-2		Field reviews
Angola		+12			First Block 18 reserves booking
Nigeria - SNEPCO		+11		+1	Bonga (in-field opportunities) and Abo (discovery)
Denmark	+12	+10	+1	-0	Alignment with Group guidelines
Brunei	+3	+8	-1	+0	Performance reviews (Champion, SW-Ampa)
Australia	+7	+6	+3	+3	Alignment with Group guidelines (following 2000 Audit)
Norway	+3	+5	-3	+2	Technical studies (Troll, Draugen a.o.)
Gabon	+3	+4			Alignment with Group guidelines (following 2000 Audit)
Denmark		+4		+1	Improved recovery (Halfdan a.o.)
USA (SEPCo, Aera)			-5	-6	Corrections for own use & fuel (following 2000 Audit)
UK	+15		+12		Development in Shearwater, Schiehallion, Gannet a.o.
Malaysia	+3		+20		Development in F6 (compression installed) a.o.
USA (SEPCo)	+12		+10		Development in Conger, Ursa, Europa a.o.
Brunei	+6		+5		Development in Champion, Iron Duke, SW-Ampa a.o.
Others	+27		+9		New developments (Transfers from undev)
Total Major Techn'l	+114	+160	+49	+20	

OTHER MAJOR CHANGES					
Country	Oil+NGL (10^6 m^3)		Gas (10^9 sm^3)		Description
	Dev'd	Total	Dev'd	Total	
Oman - Gisco	-7	-11	+19	+32	Re-apportionment Gisco reserves between NGL and gas
Russia - Sakhalin	+3	+8			Astokh equity increase to 55%
Iran		+8			Improved future cashflow
Nigeria - SNEPCO		+7		+1	Ehra + Bonga - tax gross-up recalculations
UK	-5	-10		-3	Divestments (Foinaven, Franklin, Elgin)
Oman Gisco	-0	-0	-18	-17	Revisions to economic model (lower future cost estimates)
USA	-40	-48	-7	-8	Altura venture sold
Total Other Major	-49	-46	-6	+5	

OTHER MINOR CHANGES AND TOTAL					
Country	Oil+NGL (10^6 m^3)		Gas (10^9 sm^3)		Description
	Dev'd	Total	Dev'd	Total	
Other Minor Chgs	+1	+14	-1	-3	
Production	-132	-132	-85	-85	
Grand Total	-66	-4	-43	-63	

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2000 GROUP RESERVES SUBMISSIONS

Attachm[illegible] 3.1

OIL + NGL (10^6 m3) All volumes net Shell Group Share

Country Name	Proved Resvs 1.1.2000	Rev'ns and Reclass-ific'ns	Improv-ed Recov-ery	Ext'ns and Discov-eries	Purch-ases in Place	Sales in Place	Prod'n (avail. for sales) 2000	Proved Resvs 1.1.2001	Proved Dev'd Resvs 1.1.2000	Transf. Undev to Dev'd	Revis-ions	Prod'n (avail. for sales) 2000	Proved Dev'd Resvs 1.1.2001	Minority Resvs incl. 1.1.2000	Minority Resvs incl. 1.1.2001	R / P Tot (yr)	Repl'mt Ratio TotRes (%)	Repl.R. TotRes (%) Excl Pur/ Sales iP	Repl'mt Ratio DevRes (%)
Australia (SDA)	32.49	4.18		.07		3.5	4.2	29.04	14.76		.52	4.2	11.08			7	18%	101%	12%
Australia (WPL)	11.85	2.64		4.83			2.28	17.04	5.63		2.26	2.28	5.61			7	328%	328%	99%
Brunei	59.28	8.92	2.8	3.9			5.54	69.36	28.19	6.04	6.19	5.54	34.88			13	282%	282%	221%
China	3.24	4.16					1.43	5.97	2.83	.7	3.18	1.43	5.27			4	291%	291%	271%
China (Shell Oil EH)	3.29	-3.29							2.87		-2.87								
Malaysia	25.55	-.94	2.84	2.68			3.28	26.85	13.95	3.	.09	3.28	13.76			8	140%	140%	94%
New Zealand	4.6	-.17		.98			.41	5.	2.6	.11	-.04	.41	2.26			12	198%	198%	17%
New Zealand (Shell Oil EH)	.8	.05					.11	.74	.67		.06	.11	.62			7	45%	45%	55%
Philippines	3.82	.38				.7		3.5											
Thailand	14.17	.89	1.34				1.04	15.35	3.78	.95	.33	1.04	4.02			15	214%	214%	123%
Angola				11.85				11.85											
Argentina	3.43	.26		.07			.22	3.54	2.03	.06	-.03	.22	1.84			16	150%	150%	14%
Brazil (Shell Oil WH)	.81	.2					.09	.92	.81		.2	.09	.92			10	222%	222%	222%
Cameroon (Shell Oil EH)	7.75	-1.68	.2	.11			1.21	5.17	7.28	.29	-1.36	1.21	5.		1.03	4	-113%	-113%	-88%
Congo (DR)	3.22	-.01					.17	3.04	2.3		-.02	.17	2.11			18	-6%	-6%	-12%
Gabon	19.91	3.83				.81	3.99	18.94	17.45	1.12	2.5	3.99	17.08	4.97	4.74	5	76%	96%	91%
Nigeria (SNEPCO)	71.41	7.15		10.98				89.54											
Nigeria (SPDC)	448.1						13.93	434.17	113.19	4.29	13.33	13.93	116.88			31	0%	0%	126%
Venezuela	21.43	16.66					2.54	35.55	11.61	1.03	1.19	2.54	11.29			14	656%	656%	87%
Abu Dhabi	103.26	.02					5.58	97.7	83.71	2.11	.94	5.58	81.18			18	0%	0%	55%
Bangladesh																			
Egypt	9.06	-2.59					.58	5.89	5.73	.01	-1.69	.58	3.47			10	-447%	-447%	-290%
Iran	23.85	7.74						31.59											
Kazakhstan (Temir)	2.	.01				2.	.01			.01		.01				0	-19900%	100%	100%
Oman	139.5	34.88	18.43	3.21			16.62	179.4	85.	4.95	6.67	16.62	80.			11	340%	340%	70%
Oman Gisco	33.18	-12.34					2.36	18.48	27.32		-8.2	2.36	16.76	4.98	2.77	8	-523%	-523%	-347%
Pakistan																			
Russia (Sakhalin Holding)	7.69	-.01			7.93		.51	15.1	2.81	1.19	2.59	.51	5.88			30	1553%	-2%	741%
Syria	19.81	-1.17					2.92	15.72	12.29	.98	1.	2.92	11.35			5	-40%	-40%	68%
Austria	.23	.02		.01			.03	.23	.19		.03	.03	.19			8	100%	100%	100%
Canada	47.16	-1.42	14.43	.07		.01	3.36	56.87	29.13		1.11	3.36	26.88	10.36	12.49	17	389%	389%	33%
Canada (AOSP)	95.4							95.4						21.2	21.08				
Denmark	39.15	7.17	4.34	.41			7.53	43.54	27.63	1.41	11.44	7.53	32.95			6	158%	158%	171%
Germany	3.37	-.01					.31	3.05	3.07	.17	-.02	.31	2.91			10	-3%	-3%	48%
Netherlands	5.77	-.06					.75	4.96	3.93	.41	.1	.75	3.69			7	-8%	-8%	68%
Norway	33.26	5.34				.77	5.07	32.76	20.65	4.56	3.44	5.07	23.58			6	90%	105%	158%
Shell Oil (MCC)	1.86	-1.86							1.56		-1.56								
Shell Oil (TMR)	.93	.16		.13		.08	.16	.98	.58	.07	.14	.16	.61			6	131%	181%	131%
UK	129.92	.49	2.89	1.42		10.49	21.98	102.25	90.35	14.56	-7.35	21.98	75.58			5	-26%	22%	33%
USA	92.	2.24		20.04	.01	.94	16.18	97.17	54.12	11.54	6.34	16.18	55.82			6	132%	138%	111%
USA (Aera)	79.28	-3.07	.26			.13	7.23	69.09	59.01	4.08	1.39	7.23	57.25			10	-41%	-39%	76%
USA (Altura)	47.87	.61				47.78	.7		40.24		-39.54	.7				0	-6739%	87%	-5649%
Total excl Can. AOSP	1,554.28	79.38	47.53	60.76	7.94	67.21	132.32	1,550.36	777.05	63.64	2.36	132.32	710.72	20.31	21.03	12	97%	142%	50%
Grand Total	1,649.68	79.38	47.53	60.76	7.94	67.21	132.32	1,645.76	777.05	63.64	2.36	132.32	710.72	41.51	42.11	12	97%	142%	50%

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2000 GROUP RESERVES SUBMISSIONS

Attachment 3.2

GAS (10^9 sm3) — **All volumes net Shell Group Share**

Country Name	Proved Resvs 1.1.2000	Rev'ns and Reclass-ific'ns	Improv-ed Recov-ery	Ext'ns and Discov-eries	Purch-ases in Place	Sales in Place	Prod'n (avail. for sales) 2000	Proved Resvs 1.1.2001	Proved Dev'd Resvs 1.1.2000	Transf. Undev to Dev'd	Revis-ions	Prod'n (avail. for sales) 2000	Proved Dev'd Resvs 1.1.2001	Minority Resvs incl. 1.1.2000	Minority Resvs incl. 1.1.2001	R/P Tot (yr)	Repl'mt Ratio TotlRes (%)	Repl.R. TotlRes (%) Excl Pur/ Sales IP	Repl'mt Ratio DevRes (%)
Australia (SDA)	176.638	2.576		.453		.394	2.356	176.917	18.583		1.824	2.356	18.051			75	112%	129%	77%
Australia (WPL)	40.205	1.274		.155			1.45	40.184	8.147		1.305	1.45	8.002			28	99%	99%	90%
Brunei	102.612	-2.08		4.023			4.656	99.899	40.744	5.442	-3.601	4.656	37.929			21	42%	42%	40%
China																			
China (Shell Oil EH)																			
Malaysia	183.819	-11.93	5.625				5.723	171.791	37.748	20.212	-1.27	5.723	50.965			30	-110%	-110%	331%
New Zealand	12.646	.031		3.361	.154		1.381	14.811	11.704	.016	.19	1.381	10.529			11	257%	246%	15%
New Zealand (Shell Oil EH)	2.314	-.312					.247	1.755	2.014		-.319	.247	1.448			7	-126%	-126%	-129%
Philippines	19.436	1.029				3.551		16.914											
Thailand	6.226	.338	.063				.437	6.189	2.769	.263	.238	.437	2.833			14	92%	92%	115%
Angola																			
Argentina	7.284	1.522		.619			.036	9.389	.547	.056	-.501	.036	.066			261	5947%	5947%	-1236%
Brazil (Shell Oil WH)	4.384	1.083					.326	5.141	4.384		1.083	.326	5.141			16	332%	332%	332%
Cameroon (Shell Oil EH)																			
Congo (DR)																			
Gabon																			
Nigeria (SNEPCO)	5.7	.57		.75				7.02											
Nigeria (SPDC)	95.93	-8.384					1.836	85.71	37.837		-1.987	1.836	34.014			47	-457%	-457%	-108%
Venezuela																			
Abu Dhabi																			
Bangladesh	4.713	.039		.457			.384	4.825	2.846		-.2	.384	2.262			13	129%	129%	-52%
Egypt	31.272	-2.326	.39				1.455	27.881	14.059	1.624	-.722	1.455	13.506			19	-133%	-133%	62%
Iran																			
Kazakhstan (Temir)																			
Oman																			
Oman Gisco	45.693	14.272					4.758	55.207	45.693		3.825	4.758	44.76	6.854	8.281	12	300%	300%	80%
Pakistan	11.339	-.752				.532	.189	9.866	3.347			.189	3.158			52	-879%	-398%	0%
Russia (Sakhalin Holding)																			
Syria	1.012	-.074					.234	.704	.598	.013	-.038	.234	.337			3	-32%	-32%	-11%
Austria	1.476	.191		.104			.175	1.596	1.441		.228	.175	1.494			9	169%	169%	130%
Canada	88.31	3.231		.206		.895	6.153	84.699	72.2		.688	6.153	66.735	19.402	18.608	14	41%	56%	-11%
Canada (AOSP)																			
Denmark	30.44	.941	.711	.365			3.105	29.352	18.73	.518	2.307	3.105	18.45			9	65%	65%	91%
Germany	59.422	1.225					4.659	55.988	46.423	1.565	1.023	4.659	44.352			12	26%	26%	56%
Netherlands	413.425	.132		1.122			14.828	399.851	211.215	3.23	.73	14.828	200.347			27	8%	8%	27%
Norway	89.897	2.15				.208	2.06	89.781	42.194	.224	-3.466	2.06	36.892			44	94%	104%	-157%
Shell Oil (MCC)	1.552	-1.552							1.504		-1.504								
Shell Oil (TMR)	1.693	-.364		.128		.113	.202	1.142	1.193	.062	-.16	.202	.893			6	-173%	-117%	-49%
UK	109.447	1.493	2.27	.075		3.096	11.583	98.606	67.734	11.532	-.223	11.583	67.48			9	6%	33%	98%
USA	96.232	-1.091		18.564	1.421	2.217	16.592	96.317	76.788	10.178	-3.968	16.592	68.406			6	101%	105%	37%
USA (Aera)	5.53	-4.036	.052			.142	.117	1.287	3.145	.761	-2.803	.117	.986			11	-3526%	-3405%	-1745%
USA (Altura)	8.068	.062				8.018	.112		6.985		-8.873	.112				0	-7104%	55%	-8137%
Total excl Can. AOSP	1,656.715	-.742	9.111	30.382	1.576	19.164	85.054	1,592.822	780.568	55.696	-14.194	85.054	737.018	26.256	26.889	19	25%	46%	49%
Grand Total	1,656.715	-.742	9.111	30.382	1.576	19.164	85.054	1,592.822	780.568	55.696	-14.194	85.054	737.018	26.256	26.889	19	25%	46%	49%

2 PRODUCTION RECONCILIATION - OIL+

Attachment 4.1

Country	Original CERES mln bbl	Original CERES 10^6m3	Org'l Resvs Subm'n	Org'l Resvs Subm'n 10^6m3	Difference	Final CERES mln bbl	Final CERES 10^6m3	Final Resvs Subm 10^6m3	Difference 10^6m3	Comment
Australia (SDA)			4.2							
Australia (WPL)			2.28							
Australia Total	40.749	6.48		6.48		40.749	6.48	6.48		OK
Brunei	34.84	5.54		5.54		34.84	5.54	5.54		OK
China			1.37							
China (Shell Oil EH)										
China Total	9.024	1.43		1.37	-.06	9.024	1.43	1.43		Errors in SEC submission - corrected.
Malaysia	20.618	3.28		3.27	-.01	20.618	3.28	3.28		Rounding error - SEC submission corrected
New Zealand			.42					.41		
New Zealand (Shell Oil EH)			.12					.11		
New Zealand Total	3.573	.57		.54	-.03	3.27	.52	.52		Correction to Ceres plus minor corr'n for gasolines (excluded) in SEC submission.
Thailand	6.548	1.04		1.04		6.548	1.04	1.04		OK
Argentina	1.397	.22		.22		1.397	.22	.22		OK
Brazil (Shell Oil WH)	.562	.09		.09		.562	.09	.09		OK
Cameroon (Shell Oil EH)	7.595	1.21		1.21		7.595	1.21	1.21		OK
Congo (DR)	1.064	.17		.17		1.064	.17	.17		OK
	25.117	3.99			-.08	25.117	3.99	3.99		SEC subm'n omitted production from Echira (sold) - corrected
Gabon				3.91						
Nigeria (SPDC)	87.585	13.93		13.93		87.585	13.93	13.93		OK
Venezuela	15.998	2.54		2.54		15.998	2.54	2.54		OK
Abu Dhabi	35.108	5.58		5.58		35.108	5.58	5.58		OK
Egypt	3.632	.58		.58		3.632	.58	.58		OK
Oman			16.61							
Oman Gisco			2.36							
Oman Total	119.34	18.98		18.97	-.01	119.34	18.98	18.98		Rounding error - SEC submission corrected
Russia (Sakhalin Holding)		3.12	.51		.01			.51		
Kazakhstan (Temir)		.016						.01		
Russia Total	3.136	.5		.51		3.246	.52	.52		Ceres based on unreconciled volumes - corrected; Rounding correction for Temir SEC submission
Syria	18.349	2.92		2.92		18.349	2.92	2.92		OK
Austria	.176	.03		.03		.176	.03	.03		OK
Canada	21.142	3.36		3.36		21.142	3.36	3.36		OK
Denmark	47.38	7.53		7.54	.01	47.38	7.53	7.53		Rounding error; SEC submission corrected
Germany	1.965	.31		.31		1.965	.31	.31		OK
Netherlands	4.701	.75		.75		4.701	.75	.75		OK
Norway	31.908	5.07		5.07		31.908	5.07	5.07		OK
UK	138.239	21.98		21.97	-.01	138.239	21.98	21.98		Rounding error - SEC submission corrected
USA			16.18							
USA (Aera)			7.23							
USA (Altura)	.6375	.1	.8							
Shell Oil (MCC)										
Shell Oil (TMR)			.16							
USA Total	152.638	24.27		24.37	.1	152.638	24.27	24.27		Ceres submission excluded Altura prodn - too late to correct, hence SEC submission corrected
Total	832.384	132.36		132.27	-.08	832.191	132.32	132.32		Not fully reconciled - match forced

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Jan30Note-tbl.xls, OilNGLRecn-Att4.1

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2000 PRODUCTION RECONCILIATION - GAS

Attachment 4.2

Country	Org'l CERES	Org'l Resvs Subm'n		Difference	Final CERES	Final Resvs Subm'n	Difference	Comment
	10^9sm3		10^9sm3		10^9sm3	10^9sm3		
Australia (SDA)		2.355						
Australia (WPL)		1.45						
Australia Total	3.806		3.805	-.001	3.806	3.806		Rounding error; SEC submission corrected
Brunei	4.656		4.656		4.656	4.656		OK
Malaysia	5.723		5.722	-.001	5.723	5.723		Rounding error; SEC submission corrected
New Zealand	1.381		1.381		1.381	1.381		OK
New Zealand (Shell Oil EH)	.247		.247		.247	.247		OK
Thailand	.455		.437	-.018	.437	.437		Ceres corrected
Argentina	.021		.036	.015	.036	.036		Ceres submission in error - corrected
Brazil (Shell Oil WH)	.326		.325	-.001	.326	.326		Rounding error; SEC submission corrected
Nigeria (SPDC)	1.836		1.838	.002	1.836	1.836		Rounding error; SEC submission corrected
Bangladesh	.384		.38	-.004	.384	.384		Rounding error; SEC submission corrected
Egypt	1.455		1.455		1.455	1.455		OK
Oman Gisco	4.758		4.758		4.758	4.758		OK
Pakistan	.189		.191	.002	.189	.189		Rounding error; SEC submission corrected
Syria	.425		.236	-.189	.234	.234		Ceres corrected + minor correction to SEC
Austria	.175		.182	.007	.175	.175		SEC submission corrected (own use etc)
Canada	6.182		6.15	-.032	6.153	6.153		Q4 correction in Ceres (adjusted plant yields) to be applied - corrected (+ minor correction to SEC)
Denmark	3.105		3.105		3.105	3.105		OK
Germany	4.692		4.659	-.033	4.659	4.659		Ceres corrected
Netherlands	14.828		14.828		14.828	14.828		OK
Norway	2.06		2.06		2.06	2.06		OK
UK	11.583		11.583		11.583	11.583		OK
USA		16.615						
USA (Aera)		.117						
USA (Altura)		.112						
Shell Oil (MCC)		-						
Shell Oil (TMR)		.202						
USA Total	17.023		17.046	.023	17.023	17.023		Difference due to different conversion factors; SEC submission corrected
Total	**85.31**		**85.08**	**-.23**	**85.054**	**85.054**		

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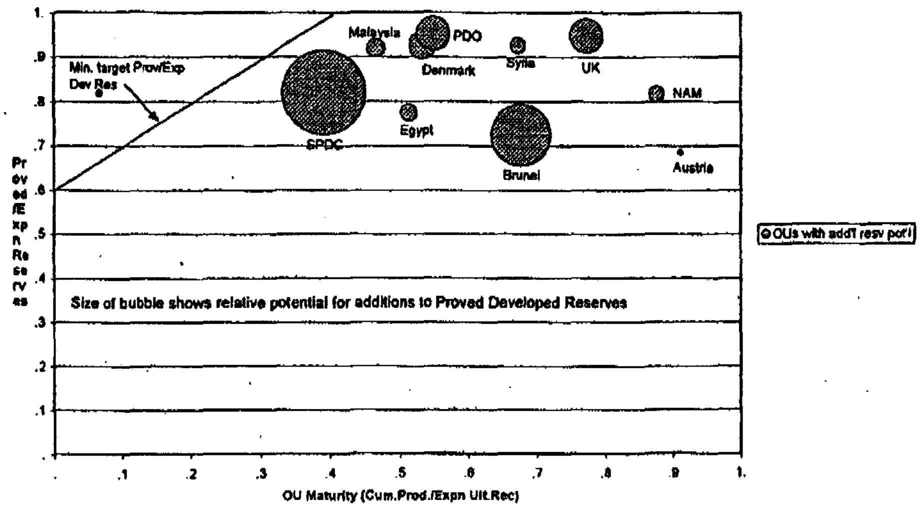
Attachment 5.1

1.1.2001 DEVELOPED OIL+NGL RESERVES



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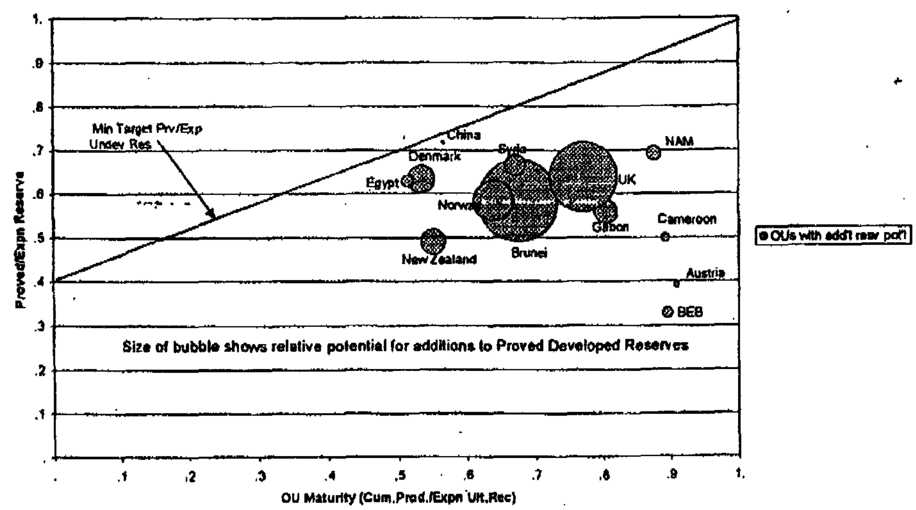
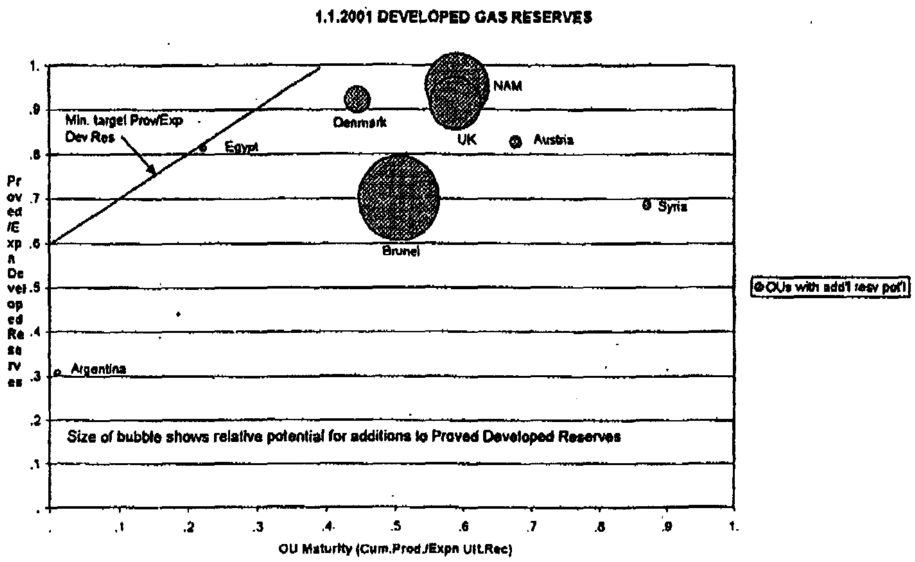
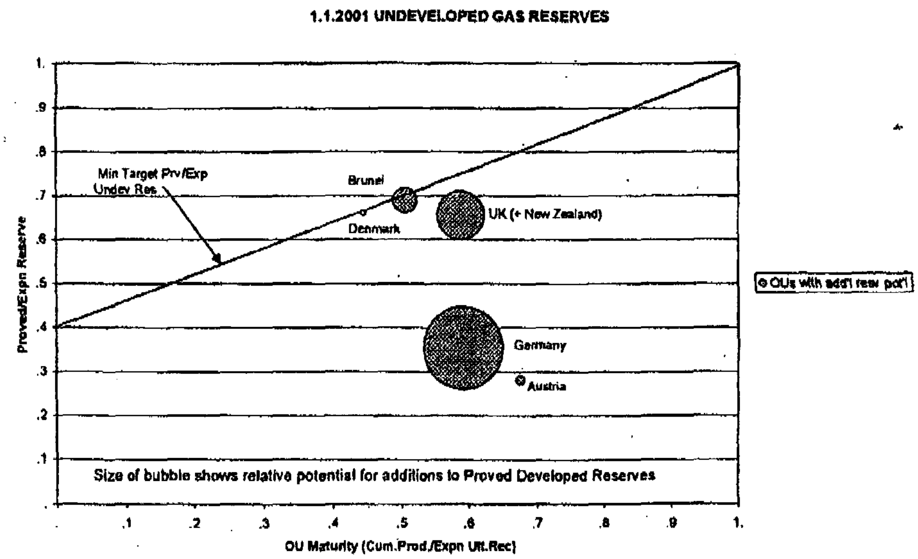
1.1.2001 UNDEVELOPED OIL+NGL RESERVES



Scope for additions to Proved Oil+NGL Reserves - by OU
(overall 50 mln m3 Developed plus 35 mln m3 Undeveloped)

Attachment 5.2





Scope for additions to Proved Gas Reserves - by OU
(overall approx. 30 mln m3 Developed plus 15 mln m3 Undeveloped)

(BP) - opgehalen

Attachment 6

ANGOLA BLOCK 18 - INITIAL RESERVES BOOKING 1.1.2001

Group Reserves Auditor Comments

Shell Development Angola (SDAN) intend to book Proved (and Expectation) reserves volumes for some of their deep water turbidite discoveries in the deep offshore Block 18 area per 1.1.2001. This is the first booking of reserves for this venture, following a series of six successful exploration wells drilled during 1999 and 2000. The necessary development planning work has been carried out by Shell Deepwater Services (SDS) in Houston, at the request of SDAN. SDS have produced a report (Ref. 1) documenting the basis for a reserves booking for two structures, Plutonio ('73' Channel Sand) and Cobalto ('72' Sheet Sand). For other sands and for the other four discovered structures in the area it was not possible to define a commercial development at this stage.

In spite of the exploration successes (six discoveries from six wells) the area is severely challenged to define a technically and commercially robust development. The root causes for this are the high development costs, the modest size of the discovered accumulations (150-400 mln stb STOIIP), the potentially poor lateral reservoir connectivity in the turbiditic sands and the relatively wide spread of the accumulations (40 km overall). The most likely development concept at this stage is an FPSO with vertical sub-sea wells tied back via sub-sea manifolds. This concept has been used for the presently postulated ('Phase I') development plan, which foresees a net Shell share Proved Reserves volume of 74 mln stb (12 mln m3). SDS have made it clear that this postulated plan is only designed to support a reserves booking at this stage. Further work (and appraisal drilling) is foreseen during 2001-2002 with the objective of defining an integrated development plan for most of the Block 18 area.

Prior to preparation of the present Stage I development plan, two meetings were held late in 2000 between SDS/SDAN and SIEP/SEPCo advisers, including myself. In the face of prevailing uncertainties, marginal to poor economics, plus a failed VAR2 review in October 2000, SDS were advised to look for a 'creaming' development plan. This plan should be aimed at the largely crestal areas of high seismic amplitude around the existing wellbores, where reservoir properties would probably be best and unit development costs lowest. This confinement to 'high confidence areas' would also have the benefit that associated recoverables could all be classed as Proved Reserves (a SEC requirement: Proved reserves should be associated with a 'Proved area' around existing wells). In addition, SDS were advised to look at the valuable set of turbidite reservoir connectivity data available within SEPTAR (BTC) and SEPCo to verify the well and reservoir recoveries that were obtained from other sources. This advice was largely followed and the resulting work has been documented in Ref. 1.

My remaining comments to Ref. 1 and the associated Proved Reserves are as follows:

1. The development plan, even if notional at this stage, is well documented and SDS must be commended for preparing this within a short time frame. In particular the relatively detailed reservoir simulations are noted.
2. The 'high confidence areas' defined by SDS may not all fulfil the stringent requirements for defining 'Proved areas' as used by SEPCo (Ref. 2). This should be verified in due course.
3. Simulator recoveries in the Cobalto sheet sand have not been corrected for potential lateral connectivity effects (SEPTAR data set). With the postulated well spacings this could expose this reservoir to a potential downside of a 10-30% lower recovery or a correspondingly higher well count.
4. Recoveries depend critically on successful water injection from the start of the project. If the viability of water injection is not proven by a pilot injection, Group guidelines require "a comprehensive assessment of uncertainties". Although well injectivity and bottom hole injection pressure have been correctly modelled, further evaluation work (e.g. sea water / formation water compatibility tests, potential well plugging) has not yet been done. However, experience in turbidite reservoirs off the Angolan coast and elsewhere suggest that any water injection problems cannot be expected to be a show stopper.
5. Gas re-injection (for conservation purposes) is postulated from the start of the project. No injection is intended into any of the oil reservoirs but a potential target reservoir has not been identified yet. Hence, no studies have been done yet regarding possible reservoir over-pressuring effects.
6. Project economics are marginal (VIR of 5%, UTC of 8 $/bl in the mid-case). Some 70% of postulated alternative cost and well scenarios have positive NPVs. Well count variations (+/- 20%) are probably too narrow, particularly for the P85 case. Hence the project barely passes commerciality criteria for reserves.

In conclusion, the Proved Reserves booked for Block 18 are extremely marginal with respect to criteria for technical and commercial robustness and hence are only just supportable. Much appraisal and study work will be required to address reservoir connectivity (i.e. well counts) and further cost reductions before a Block 18 project can be put forward for FID in 2002, as presently planned.

A.A. Barendregt, 17 January 2001

References:

1. "Angola Block 18: Phase I Development Area, Reserve Report Documentation", EP2001-4002, SEPTAR, Houston, January 2001.
2. "Estimating Pay Probability Downdip from Well Control Using Seismic amplitudes", A. Jackson, SEPTAR, Houston, 2000.

Attachment 7

2000 RESERVES AUDITS - MAIN OBSERVATIONS

Australia: The audit commended the high quality technical work that had been carried out by Woodside, particularly in assessing the subsurface uncertainties and in evaluating the ranges of in-place and reserves estimates. Intensive SIEP assistance through VAR- and other reviews was noted. Maintaining the preliminarily booked volume of Gorgon gas reserves (first done at 1.1.1999) was supported because a gas market was highly likely to be found in due course and because it must be considered likely that an extension of the current 5-year Retention Lease will be granted in 2002. Proved reserves in some mature fields (N-Rankin, Goodwyn and the four oil fields) should be increased to expectation levels, in line with the guidelines. Concern was expressed about the lack of a concisely documented audit trail, which hampered a proper assessment of the reasons for the end-1999 reserves changes. Audit opinion was **satisfactory**. Proved Reserves have been increased by some 9 mln m3oe, in line with recommendation.

Bangladesh: The most significant comment related to the conservative nature of the proved and proved developed reserves estimates. Recovery factors tend to underestimate the recovery efficiencies obtainable through compression, whilst discounting of in-place volumes in some undrained reservoirs tends to be conservative. Audit opinion was **satisfactory**. Apart from an 0.5 mln m3oe addition due to successful appraisal, no changes were made in Proved Reserves, pending further field performance.

Gabon: Commendation was made of the well organised set of field notes and annual ARPR report, providing the basis for a good audit trail. The most significant comment related to the unnecessarily conservative (and somewhat arbitrary) assumption of proved developed and undeveloped reserves for producing fields being a flat 85% of expectation values. Group guidelines prescribe that, for mature fields like those in Gabon, the proved values should be taken as equal to expectation values. The Rabi production licence expires at 30 June 2007. Until a new agreement (possibly a PSC) has been signed, some 2 mln m3 of Group share proved oil reserves remain out-of-licence and thus unbookable. Audit opinion was **satisfactory**. Proved Reserves have been increased by some 4 mln m3oe, in line with recommendation.

Norway: It was noted that operators Norsk Hydro and Statoil (Troll and Statfjord fields) appeared strangely reluctant to provide no-further-activities forecasts on which to base developed reserves. As a result, Troll developed gas reserves could be somewhat overstated. The reserves audit trail was incomplete due to table inaccuracies in the respective reserves notes. Commendable development option screening work had been done on the Ormen Lange field. Although seabed stability could still be a show stopper, a first discounted slice of gas reserves was booked for this field in 1999. Audit opinion was **satisfactory**. Troll Proved Developed Reserves have been reduced by some 4 mln m3oe.

Sakhalin: Presently carried oil recoveries are low because of the need to re-inject associated gas into the oil reservoir, but significant upside exists through lifting of this need and through optimisation of wells and application of horizontal wells. Comments were made regarding the incomplete state of the audit trail and the overdue completion of important EPT reports. Audit opinion was **satisfactory**.

USA (SEPCo): The comprehensive system of quarterly and annual internal reserves audits was noted and commended. Main deviations from Group reserves guidelines are due to SEPCo adhering to strict interpretations of the SEC rules, which are enforceable in the US. These differences relate mainly to government royalties in cash (excluded from reserves), fuel and flare gas volumes (included) and 'behind-pipe' developed volumes (over-included). The latter two are to be corrected, but the present SEC rules forbid the inclusion of US royalty volumes, even if paid in cash. Audit opinion was **satisfactory**. The correction for fuel-and-flare has led to a 6 mln m3oe reduction in gas volumes, mainly in the Aera venture.

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TIME TABLE SEC RESERVES AUDITS

Attachment 8

COUNTRY	Size**	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	Comments
NETH. NAM	L	X				X				P				P	March 2001
GERMANY	L	X				X				P				P	April 2001?
UK	L			X		X				P				P	June 2001
DENMARK	L	X				X				P				P	April / June 2001?
CHINA	M/S		$							P1					Sept 2001?
NEW ZEALAND	M/S				X					P					Oct 2001?
AUSTRIA	M/S			X						P					Nov 2001
BRUNEI	L		X				X				P				Combine with Malaysia
MALAYSIA	L		X				X				P				Combine with Brunei
USA (AERA)	L					$					P1				
BRAZIL (Pecten)	M/S						*				P1				In Houston?
CAMEROON (Pecten)	M/S						*				P1				In Houston?
IRAN	L							$			P1				}
SYRIA	M/S	X			X						P				} Combine?
PAKISTAN	M/S					$					P				}
ABU DHABI	L			X				X				P			
NIGERIA -SPDC	L	X				X		X				P			
NIGERIA - SNEPCO	L					$		X				P			
OMAN	L			X				X				P			
EGYPT	L		X					X				P			
NAMIBIA											$?	P1?			
RUSSIA - SALYM											$?	P1?			
AUSTRALIA	L				X				X				P		
NORWAY	L				X				X				P		
USA (SEPCo)	L						*		X				P		
VENEZUELA	L				$			X					P=		
ARGENTINA	M/S			X				X					P		
PHILIPPINES	M/S					$		X					P		
THAILAND	M/S		X					X					P		
GABON	M/S			X					X					P	
BANGLADESH	M/S					$			X					P	
RUSSIA - SAKHALIN	M/S					$			X					P	
KAZAKHSTAN-OKIOC												$?		P1?	
CANADA	L														No direct involvement
CHAD	M/S			X											Divested 2000
COLOMBIA	-		X												Hocol/Homcol interest sold 1997
KAZAKHSTAN-TEMIR	M/S							$							Divested 2000
USA (ALTURA)	L					$									Divested 2000
ZAIRE	M/S		X												Divested 2000 (subject govt approval)

X = Completed
P = Planned
P1 = First audit
$ = First SEC resvs subm'n
* = First SEC subm'n via SIEP

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

Audit frequency:

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

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

Jan30Note-tbl.xls, AudSched-Att8

26/01/01

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