EP 2003-1102 Appendix C Confidential

Part 2: After the end of the Reporting Year

Continued from the previous page

Regional management January, weeks 1 & 2	Notification of reserves	Reserves Reporting Workbooks placed on EPS global server or e-mailed to HRC.
HRC, GRA January weeks 2 & 3	Clarify and challenge Region/Asset Holder submissions as required	Verify that changes reported for the year can be supported.
HRC, Regions/Asset Holders January week 3	Resubmissions	If required.
HRC January weeks 3 & 4	Provide summary data to external Group Auditors for review	
HRC, GRA, SI-FCGB January week 4	Agree final production data	Production reported in the Reserves Reporting Workbook must be consistent with FIRST reporting.
HRC, Reserves Committee January week 4	Preliminary report and presentation to EP Executive	Note for Discussion plus presentation. NB: preliminary figures
GRA, external Group Auditors End of January	Agree final proved reserves for external disclosure	
GRA, HRC End of January	Present final reserves to Reserves Committee (and EP Executive if necessary)	Declaration of satisfaction with the figures to be reported at year-end for proved and proved developed reserves. EPS & EPF sign "Letter of Comfort" to external auditors, sent via SI-FCG
HRC on behalf of Reserves Committee, GRA End of January	Reserves Meeting	Report and Presentation of proved reserves information to external Group Auditors and Deputy Group Controller.
HRC, EPS Early February	Final report to EP Executive and CMD on year-end proved reserves	Note for Information plus presentation if required.
HRC, external Group Auditors Early February	Agree final Standardized Measure data for external disclosure	EPS & EPF sign "Letter of Comfort" to external auditors, sent via SI-FCG
HRC Early February	Parent Company Annual Report	Reserves figures passed to SI-FCGB. Including copy of initialled schedules from external Group Auditors.
HRC, EPS End of May	EP Reserves and Scope For Recovery	Reference report describing changes in Group Hydrocarbon Resources during the reporting year.

A detailed timetable is prepared annually by HRC in consultation with SIEP-EPF, SI-FCGB (Group Reporting) and SI-PXXC (External Affairs).

HRC: EP Hydrocarbon Resource Coordinator GRA: Group Reserves Auditor

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EP Hydrocarbon Resource Coordinator: Accountabilities

The EP Hydrocarbon Resource Coordinator reports (indirectly) to the Corporate Support Director, EPS. He or she ensures that hydrocarbon resource volume assessment and reporting practices are aligned with the Petroleum Resource Volume Guidelines (EP yyyy-1100) and related documentation (EP yyyy-1101 and EP yyyy-1102), that proved reserves estimates comply with the relevant accounting standards and regulations (i.e. as defined by the SEC), and that future changes in the hydrocarbon resource volumes in each category are estimated commensurate with the requirements of business planning within EP.

Accountabilities (in relation to proved reserves):

(a) Deliver a realistic view of proved reserves additions that can be expected to result from the overall hydrocarbon maturation process as part of, and consistent with, the optimized EP business plan.

(b) Deliver accurate progress reports (based on data supplied via EPMIS) of short-term reserves maturation (proved reserves additions) in close cooperation with regional management and Asset Holder reserves focal points.

(c) Maintain inventories of proved reserves bookings that are potentially under threat (Potential Reserves Exposure Catalogue) and opportunities to add to the proved reserves base (Opportunities Catalogue).

(d) Provide systems that ensure the timely and accurate collection of information on petroleum resource volumes from the Asset Holders.

(e) Compile and submit quality-assured internal and external reserves reports.

(f) Maintain Petroleum Resource Volume Guidelines (EP yyyy-1100) and Submission Requirements (EP yyyy-1101) that are to be used within the Group and which aim to ensure that Shell's practices are aligned with statutory standards, internal needs and industry practice.

(g) Analyse hydrocarbon maturation performance versus target and (perceived) potential, the latter in close cooperation with appropriate technical specialists in the Group.

(h) Maintain interfaces with the Group Reserves Auditor, EP management, regional organizations, Asset Holders and Finance. In particular to act as a first point of reference for any topic related to proved reserves that requires consideration, clarification or approval of the appropriate course of action to be taken. This includes the approach to be taken in the reporting of significant proved reserves changes and points of clarification on the interpretation and implementation of the appropriate rules.

(i) Maintain external interfaces with external Group Auditors and the SEC.

(j) Provide *ad hoc* input to Group Control, Investor Relations, Group General Financial Accounting Policies (GFAP) or other internal interfaces as may be required from time to time.

(k) Monitor developments on resource reporting in the industry (SEC, SPE, etc).

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Letter of Comfort: Proved Reserves

The Hague
3 February, 2003

Royal Dutch/Shell Group Auditors
c/o KPMG Accountants N.V.
Attn.: Mr. J. van Delden
Churchillplein 6
2517JW THE HAGUE

Dear Sirs,

In connection with your limited procedures, in respect of the unaudited oil and natural gas reserves information included in the supplementary information accompanying the 2002 financial statements of the Royal Dutch/Shell Group of Companies, we confirm, to the best of our knowledge and belief, the following representations made to you during your review:

1. We are responsible for the fair presentation of the oil and natural gas reserves information mentioned above in conformity with generally accepted US accounting principles.

2. The information has been properly prepared and disclosed in accordance with SFAS 69 and SEC Rules and Regulations, and as clarified by subsequent SEC staff accounting bulletins and interpretive guidance issued by the SEC. During review of the final figures, certain areas of potential concern were brought to our attention (list attached). We are satisfied that these are not material to the total Shell Group proved reserves, but we will review them and take corrective action if necessary during 2003.

3. The information and the underlying data have been prepared and reviewed by employees having appropriate experience and qualifications for estimating oil and natural gas reserves.

4. No matters have come to our attention to the present time which would materially affect the information in respect of oil and gas reserves included in the supplementary information referred to above.

The representations made under 2 and 3 do not apply to Shell Canada as we do not participate directly in their reserves estimating process.

Yours faithfully,
Shell International Exploration and Production B.V.

Frank Coopman
Chief Finance Officer

Lorin L. Brass
Director

Letter of Comfort: Standardized Measure

The Hague
20 February, 2003

Royal Dutch/Shell Group Auditors
c/o KPMG Accountants N.V.
Attn.: Mr. J. van Delden
Churchillplein 6
2517JW THE HAGUE

Dear Sirs,

In connection with your limited procedures, in respect of the unaudited Standardized Measure of discounted future net cash flows and changes therein, relating to proved oil, natural gas liquids and natural gas reserves quantities as included in the supplementary information accompanying the 2002 financial statements of the Royal Dutch/Shell Group of Companies, we confirm, to the best of our knowledge and belief, the following representations made to you during your review:

1. We are responsible for the fair presentation of the Standardized Measure information mentioned above and the assumptions used therein, in conformity with generally accepted US accounting principles.

2. The Standardized Measure information has been properly prepared and disclosed in accordance with SFAS 69 and SEC Rules and Regulations, and as clarified by subsequent SEC staff accounting bulletins and interpretive guidance issued by the SEC.

3. The Standardized Measure information and the underlying data have been prepared and reviewed by employees having appropriate experience and qualifications for estimating the basis of future net cash flows.

4. No matters have come to our attention to the present time which would materially affect the Standardized Measure information included in the supplementary information referred to above.

The representations made under 2 and 3 do not apply to Shell Canada, as we do not participate directly in the estimation of their Standardized Measure.

In order to prepare the information in the required manner, a number of assumptions about future conditions are prescribed which do not take into account political, commercial and technical uncertainties. As a result, the information so calculated does not provide a reliable measure of future cash flows from proved reserves, nor does it permit a realistic comparison to be made of one entity with another because the assumptions used cannot reflect the varying circumstances within each entity.

Yours faithfully,
Shell International Exploration and Production B.V.

Frank Coopman
Chief Finance Officer

Lorin L. Brass
Director

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Group Reserves Auditor: Terms of Reference

The Group Reserves Auditor reports directly to the EP Chief Financial Officer (EPF) but acts independently in:

1. The auditing of submitted Proved Reserves of Regions/Asset Holders by visits to those units.

   The Reserve Audits verify that all the required processes are in place and adhered to which ensure that the reported Group share Proved Reserves are estimated in accordance with the most recent version of the Group Petroleum Resource Volume Guidelines. The audits address the Technical Maturity, the Commercial Maturity and the 'Reasonable Certainty' of the reported reserves and also verify that the Group share calculation and the consistency with Finance reporting are in order and that appropriate audit trails are in place.

   A report is prepared for each Reserves Audit that is addressed to the Chief Executive of the Region/Asset Holder concerned, to the EP Chief Financial Officer (EPF), to the EP Corporate Support Director (EPS) and to the external Group Auditors. Copies are sent to selected individuals in the Region/Asset Holder, the EP Internal Audit function, and the Hydrocarbon Resource Coordination function in EPS and to the external Group Auditors. A summary of the year's audit findings is included in the end-year Group Reserves Auditor report.

   The Reserve Audits form part of an annually agreed plan, aiming at an audit frequency of one audit every four years for each Asset Holder. Terms of Reference for these audits are to be found in the Group Petroleum Resource Volume Guidelines (EP yyyy-1100).

   Due to local restrictions, the Group Reserves Auditor does not audit the resources reported by Shell Canada.

2. Witnessing and verifying the accumulation of the Group's Proved Reserves at the end of each year for inclusion into the Group Annual Reports and the SEC Form 20-F report on the basis of information supplied by Regions/Asset Holders.

   In this task the assembled data as received are audited in cooperation with representatives of KPMG Accountants (as external Group Auditors). Changes compared with the previous year are reviewed and their reasonableness is assessed on the basis of the information available. Where necessary, additional information is requested from the Region/Asset Holder concerned.

   Production volumes for the reporting year are compared for consistency with data supplied via the Group financial information system (FIRST) to Group Reporting.

   At the end of this process a Reserves Auditor Report with Auditor findings is written to the external Group Auditors, the EP Chief Financial Officer (EPF) and the EP Corporate Support Director (EPS). It is copied to the EP Chief Executive. The Chief Financial Officer and Corporate Support Director thereupon release the 'The Letter of Comfort', addressed to the external Group Auditors (KPMG and PWC). In addition KPMG Accountants issue a note with Supplementary Information to the Group Auditors (PWC).

   The Reserves Auditor Report is also presented and discussed in a meeting between Group Auditors (KPMG, PWC), The Deputy Group Controller (SI-FCG), representatives from SIEP Corporate Support / Hydrocarbon Resource Coordination and the Group Reserves Auditor at the end of January.

3. The provision of general advice with respect to Petroleum Resource Volume Guidelines and Procedures.

   Petroleum Resource Volume Guidelines are in principle reviewed and, where necessary, updated annually by the EP Hydrocarbon Resource Coordination function. The Group Reserves Auditor will provide advice regarding the changes proposed. He or she may also be called upon to provide other advice regarding issues that may arise from time to time with respect to Reserves reporting methods and procedures.

Schedule of Authorities: Proved Reserves and Standardized Measure

Based on EP 86-0725 (1986), updated 1996, 2002 and 2003

	Title of document or activity	Responsible for Preparation	Responsible for Approval	Final submission for use to
1	Proved Reserves Replacement Target Setting	HRC	EP Executive	EP Regions /Asset Holders
2	Reserves Audit Reports (Region / Asset Holder audits)	GRA		EPS, EPF, Regions, Asset Holders
3	Resource Management and Reporting Guidelines			
	a) Process, responsibilities, definitions, requirements	HRC, GRA	Reserves Committee	Asset Holders
	b) Technical methodologies	EPT/T&OE	EPT/T&OE	Asset Holders
	c) Matters relating to proved and proved developed reserves estimating procedures	GRA, HRC	Reserves Committee	SI-FCGB and Asset Holders
4	Annual reserves return from Regions/Asset Holders	Region/AH Technical &Finance functions	Region Technical and Financial Management	GRA, HRC
5	Audit trail in support of annual reserves return from Asset Holder.	Asset Holder Senior RE	Region / Asset Holder PE Manager (or equiv't)	Region /AH Technical Management
6	Preliminary report on year-end proved reserves to EP Executive	HRC	Reserves Committee	EP Executive
7	Reserves Auditor Report	GRA		Reserves Committee
8	Standardized Measure Report			
	- Region / Asset Holder annual submission (together with proved reserves – see (4) above)	Region/AH Technical &Finance functions	Region Technical and Financial Management	HRC
	- Group submission to SEC Form 20-F	HRC	EPS, EPF	SI-FCGB
9	Proved reserves & Standardized Measure "Letters of Comfort" to external Group Auditors.	GRA	EPS, EPF	Group Auditors
10	Statement of crude oil and natural gas reserves for inclusion in Annual Report submission to the US Securities and Exchange Commission (Form 20-F) and other Parent Company publicly disclosed reports.	HRC	Reserves Committee	SI-FCGB

HRC: EP Hydrocarbon Resource Coordinator GRA: Group Reserves Auditor AH: Asset Holder

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RJW.00122208

O. Christie

DRAFT NOTE – 19 Oct 2000 COPY **CONFIDENTIAL**

From:	Anton A. Barendregt	Group Reserves Auditor, SIEP – EPB - GRA
To:	Lorin Brass	Director, Business Development, SIEP - EPB
	Alan Parsley	CEO, Shell Development Australia (SDA)
Copy:	Robert Blaauw	E&P Manager, SDA
	David Christie	Finance Manager, SDA
	Wim Hein Grasso	Commercial Director, SDA
	Jeroen Regtien	Development Manager, SDA
	(circulation)	SIEP – EPF: Gardy, van Nues
	(circulation)	SIEP - EPB-P: Bell, McKay, Aalbers
	Rob Jager	Business Advisor, SIEP (EPA)
	Egbert Eeftink	Director, KPMG Accountants NV
	Stephen L. Johnson	PriceWaterhouseCoopers

SEC PROVED RESERVES AUDIT - SHELL DEVELOPMENT AUSTRALIA, 9-13 Oct 2000

I have audited the proved reserves submissions of SDA for the year 1999 and the processes that were followed in their preparation. These submissions present the SDA contribution to the Group's externally reported Proved and Proved Developed Reserves and associated changes as at 31 December 1999.

The audit followed the procedures laid down in the "Petroleum Resource Volume Guidelines, SIEP 99-1100/1101" (based, inter alia, on FASB Statement 69). It included a verification of the technical and commercial maturity of the reported reserves, a verification that margins of uncertainty were appropriate, that Group share and net sales volumes had been calculated correctly and that reported reserves changes were classified correctly. The last previous SEC proved reserves audit for SDA was carried out in 1996. The audit took the form of technical discussions with staff from Woodside Energy Ltd (the operator for a large part of the assets with SDA interest) and detailed discussions about the reserves reporting process with SDA staff.

Total booked Group share proved reserves at the end of 1999 were 44 mln m3 of oil + NGL (of which 20 mln m3 developed) and 217 bln sm3 of gas (of which 27 bln sm3 developed). 1999 Reserves replacement ratios were 48% for oil+NGL and -340% for gas.

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 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. 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. This could increase Group entitlement by some 12 mln m3oe. 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.

The audit finding is that the SDA statements fairly represent the Group entitlements to Proved Reserves at the end of 1999. There is a possibility of a small (appr. 4%) understatement of entitlement reserves due to the reporting of P85 (proven) reserves instead of expectation reserves in mature fields. The overall opinion from the audit regarding the state of SDA's 1999 Proved Reserves submission, taking account of the scoring in Attachment 3, is therefore <u>satisfactory</u>.

A summary of the findings and observations is included in the Attachments.

A.A. Barendregt

DEPOSITION EXHIBIT
Barendregt
#11 2/20/04

Attachments 1, 2, 3

SDA-Covn.doc

13/10/00

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Attachment 1

SEC PROVED RESERVES AUDIT SDA, 9-13 Oct 2000

MAIN OBSERVATIONS

1. SDA report their Group share reserves in two separate submissions. The first contains the 'direct' share of SDA in the successive licences and ventures in which Shell have an interest, together with other co-venturers. The second submission relates to the 34.27% shareholding that Shell have in Woodside Petroleum Ltd, who are co-venturer and operator in many of the fields in which SDA have an interest. The effect is an increase in the net reported share of the Woodside operated fields.

2. Commendation is made of the excellent quality of the technical work carried out by Woodside Energy Ltd in assessing the subsurface risks and in evaluating and quantifying the probability ranges of the in-place and reserves estimates. The fact that production history in the mature fields largely confirmed the original estimates provides evidence for this quality. Woodside can be commended for a significant improvement of their internal work processes in this respect. It was also noted that co-venturer support, e.g. through regular peer reviews and SIEP reviews (VARs and others) helped to further contribute to this success.

3. 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.

4. Group reserves guidelines prescribe that externally reported 'Proved' reserves should be made equal to expectation volumes (in stead of P85 proven or Low volumes) in mature fields, i.e. fields with significant production in relation to their ultimate recovery. Hence, the externally reported proved reserves in N-Rankin, Wanaea and Cossack (and possibly Goodwyn plus, in the near future, Laminaria and Corallina) should be taken as equal to expectation reserves. The same reserves should then also be applied for asset depreciation calculations for Group accounting.

5. One of the requirements of a reserve audit is that OU Group share submissions can be reconciled with reserves volumes and changes in individual fields. The audit should also establish that Group share reserves changes have been reported in the correct category (revisions, field extensions and discoveries, purchases / sales in place etc.). This process was greatly hampered by the lack of a concise audit note, with full detail at field level and by the lack of a proper record of 1999 produced volumes by individual fields. As a result, only a very partial match could be obtained with individual field volumes and changes as reported by Woodside and Chevron, see Attachments 2.1-2.4. In particular, no explanation could be found for the sizeable reduction in proved total gas reserves during 1999 (causing an alarming reserves replacement ratio of –340%!).

   New guidelines for preparing a proper audit trail have recently been published on the SIEP-EPB web site. It is the strong opinion of the auditor that a good audit trail will not only facilitate the auditor's task but also, and more importantly, will greatly enhance clarity and transparency of the reserves reporting process in the OU organisation. This will undoubtedly lead to less staff time being required during staff handovers, queries etc.

6. GHVs are measured and a record is maintained at field level (and apparently even lower) by Woodside, who do the calculation of Nm3 from sm3 volumes. An attempt was made at reconciling the SDA Nm3

submission with average Gorgon and NWS GHVs, but no match could be obtained (Att. 2.4). This problem will disappear in the end-2000 cycle when reporting in Nm3 will no longer be required.

7. Asset depreciation for Group accounts is done correctly through proved developed reserves depletion (proved total reserves for the full North Rankin facilities, which act as a hub for the entire NWS offshore gas system). Correct reserves values are being used, but no copy could be found of the formal end-1999 note of advice to Finance with the proper new reserves volumes to be used.

8. Full monthly production and sales statistics (100% field volumes) are received by ~~telex~~ fax from Woodside, who are the only operator at present with fields in production in SDA-held acreage. A selection of these figures (e.g. totals by assets only, not fields) is manually transcribed into the Finance system for monthly / quarterly reporting. A parallel system (also with manual input) is maintained by the Development Manager for e.g. KPI and MIS reporting. There would appear to be opportunities for synergy and rationalisation, also through electronic transfer of data. Incorporation of data at field level could help the end-year audit trail.

electronic transmission [illegible] directly into the [illegible]

Recommendations

1. Maintain the presently booked volume of Gorgon reserves until a clearly positive event (extension of the Retention Lease or LOI with a buyer) has occurred.
2. Raise externally proved and proved developed reserves in N-Rankin and Wanaea / Cossack, plus possibly those in Goodwyn and Laminaria / Corallina to expectation levels, in line with Group guidelines.
3. Prepare a proper audit trail note, in line with published guidelines, for the 1.1.2001 reserves reporting cycle.
4. Consider possible synergy and rationalisation between production / sales reporting through Finance and the Development function.

Attachment 2.1

SEC RESERVES AUDIT - VOLUMES RECONCILIATION
SDA 1.1.2000

Proved Oil / NGL / Gas Reserves as at 31.12.99

Area / field	Proven HIP MMstb / Bscf	Exp'n HIP MMstb / Bscf	Cum. Prod = Sales 31.12.99 MMstb / Bscf	Proved Rem. Recov. Dev. MMstb / Bscf	Proved Rem. Recov. Tot'l MMstb / Bscf	Exp'n Rem. Recov. Tot'l MMstb / Bscf	Maturity (Cum.pr / Exp'n UR) %	Dev. / Tot'l Proved UR %	Proved RF Tot'l %	Exp'n RF Tot'l %	Fract'n wl lic. & comtd Pr.Dev. %	Fract'n wl lic. & comtd Pr.Tot'l %	Within Licence & comtd Pr.Dev. MMstb / Bscf	Within Licence & comtd Pr.Tot'l MMstb / Bscf	Venture Shell share %	Shell Equity Dev. 10^6 sm3/ 10^9 sm3	Shell Equity Tot'l 10^6 sm3/ 10^9 sm3	1998 Subm'n Dev 10^6 sm3/ 10^9 sm3	1999 Subm'n Tot'l 10^6 sm3/ 10^9 sm3
Oil																			
Wanaea	283.30	340.30	43.80	96.20	104.80	141.10	23.7%	94.2%	52.5%	54.3%	100.0%	100.0%	97.20	104.80	16.67%	2.58	2.78		
Cossack	76.60	120.10	34.20	14.20	14.20	37.60	47.6%	100.0%	63.2%	59.8%	100.0%	100.0%	14.20	14.20	16.67%	0.38	0.38		
Lambert	55.60	74.50	1.10	14.50	22.30	32.10	3.3%	65.7%	42.1%	44.6%	100.0%	100.0%	14.50	22.30	16.67%	0.38	0.59		
Hermes	22.10	28.10	7.70	1.80	3.00	5.60	57.9%	88.8%	48.4%	47.3%	100.0%	100.0%	1.80	3.00	16.67%	0.05	0.08		
Egret	18.60	37.60			6.00	13.10	0.0%	0.0%	32.3%	34.8%	100.0%	100.0%	0.00	6.00	16.67%	0.00	0.16		
Laminaria	162.30	204.00	3.00	85.60	95.60	126.90	2.3%	89.9%	60.8%	63.7%	100.0%	100.0%	85.60	95.60	25.00%	3.40	3.80		
Corallina	71.50	97.00	0.70	37.60	38.40	55.20	1.3%	98.0%	54.7%	57.6%	100.0%	100.0%	37.60	38.40	25.00%	1.49	1.53		
Barrow Island (WAPET)	1353.61	1353.61	284.85	51.70	51.70	77.70	78.6%	100.0%	24.9%	26.8%	55.8%	55.8%	28.86	28.86	28.57%	1.31	1.31		
Thevenard Island (WAPET)	282.91	282.91	134.45	23.97	23.97	33.95	79.8%	100.0%	56.0%	59.5%	100.0%	100.0%	23.97	23.97	35.71%	1.36	1.36		
NWS + WAPET Oil - SDA 'direct' share																10.95	11.88	11.64	12.63
Wan., Coss., Lamb., Herm., Egret (W=16.67%)													127.70	150.30	5.71%	1.16	1.36		
Lamainaria, Corallina (Woods = 50%)													123.20	134.00	17.14%	3.36	3.65		
SDA 'indirect' 34.27% share in Woodside																4.52	9.02	4.28	5.44
Total Oil (MMstb)	2326.52	2538.12	509.80	325.57	359.97	523.25							303.73	337.13	31.7%	15.47	17.00	15.82	18.07
NGL																			
North Rankin	313.50	347.30	127.80	15.00	68.20	89.40	58.8%	72.9%	62.5%	62.5%	100.0%	100.0%	15.00	68.20	15.66%	0.37	1.70		
Perseus	308.30	377.80	18.20	22.10	164.70	215.40	7.8%	22.0%	59.3%	61.8%	100.0%	100.0%	22.10	164.70	15.66%	0.56	4.10		
Goodwyn	530.76	629.70	117.10	84.50	194.00	251.10	31.8%	84.8%	58.6%	58.5%	100.0%	100.0%	84.50	194.00	15.66%	2.10	4.83		
Angel	129.90	165.30			65.60	87.00	0.0%	0.0%	50.7%	52.6%	100.0%	100.0%	0.00	65.60	15.66%	0.00	1.64		
Other NWS gas + oil fields	261.00	396.30	2.10	3.70	103.20	152.90	1.4%	5.5%	40.3%	39.1%	100.0%	100.0%	3.70	103.20	15.66%	0.09	2.57		
Gorgon field (WAPET)	170.00	210.40			110.69	131.30	0.0%	0.0%	65.1%	62.4%	100.0%	100.0%	0.00	110.69	28.57%	0.00	5.03		
Chrysaor, W-Trial Rocks (WAPET)	69.00	90.00				53.00	0.0%	0	0.0%	58.9%	100.0%	100.0%	0.00	0.00	28.57%	0.00	0.00		
Total SDA 'direct' share																3.12	19.87	3.12	19.88
SDA 'indirect' 34.27% share in Woodside cond. (19.74% of NWS cond.)													125.30	595.90	6.76%	1.35	6.41	1.35	6.41
Total NGL (MMstb)	1782.40	2216.80	265.20	125.30	706.59	980.10							125.30	706.59	23.39%	4.47	26.28	4.47	26.27
Gas (Dry, sales gas volumes)																			
North Rankin	11620.00	12190.00	4200.00	1730.00	6180.00	6810.00	38.1%	57.1%	89.3%	90.3%	96.3%	96.3%	1665.99	5951.34	15.64%	7.374	26.341		
Perseus	8770.00	10680.00	500.00	930.00	7010.00	8830.00	5.4%	19.0%	85.6%	87.4%	96.3%	96.3%	895.69	6750.63	15.64%	3.964	29.879		
Goodwyn	7040.00	8390.00	660.00	1610.00	4330.00	5420.00	10.9%	45.5%	70.9%	72.5%	96.3%	96.3%	1550.43	4169.79	15.64%	6.862	18.456		
Angel	2270.00	2790.00			1390.00	1770.00	0.0%	0.0%	61.2%	63.4%	96.3%	96.3%	0.00	1338.57	15.64%	0.000	5.925		
Other NWS gas + oil fields	4440.00	6350.00	40.00	130.00	2360.00	3410.00	1.2%	7.1%	54.1%	54.2%	96.3%	96.3%	125.19	2272.68	15.64%	0.554	10.059		
Gorgon field (WAPET)	20936.86	24828.94			10650.00	15200.00	0.0%	0.0%	50.9%	61.2%	100.0%	100.0%	0.00	10650.00	28.57%	0.000	86.113		
Chrysaor, W-Trial Rocks (WAPET)	4550.98	7343.34				3300.00	0.0%	0	0.0%	44.9%	100.0%	100.0%	0.00	0.00	28.57%	0.000	0.000		
Thevenard Island	153.00	153.00	70.00	33.00	39.00	55.00	56.0%	94.5%	65.9%	76.7%	100.0%	100.0%	33.00	39.00	35.71%	0.333	0.394		
Total SDA 'direct' share																19.088	177.167	18.583	176.839
SDA 'indirect' 34.27% share in Woodside gas (20.37% of NWS sales gas)													4237.20	20483.01	6.98%	8.371	40.466	8.147	40.205
Total Gas (Bscf)	59790.85	72745.28	5470.00	4433.00	31959.00	44795.00	10.9%	28.5%	62.6%	69.1%			4270.20	31172.01	24.7%	27.459	217.833	26.730	218.843

Conversion factors used by SDA
1 stb = 0.158 m3
1scf = 0.0283 sm3

Conversion factors used by SEPIV:
1 stb = 0.159 m3
1 scf = 0.0283 sm3

Licence expiry dates:

Audit Trail:
Oil: SDA submission not corrected for beyond-licence oil from Barrow Island; Minor error in Woodside share % in Laminaria (double correction for unitisation share)
NGL: Good match
Gas: Fractions 'wl licence & comtd' reflect 3.7% correction for future upstream fuel and flare.

FOIA Confidential
Treatment Requested

Attachment 2.2

SEC RESERVES AUDIT - VOLUMES RECONCILIATION
SDA 1.1.2000

Proved Oil Reserves Changes 1999 (100%, MMstb)

Field	Prov.Res. 1.1.99	Revisions/ Reclasfns	Improved Recovery	Extens./ Discov's	Purchase in-place	Sales in-place	New Devel'd Reserves	Producti = Sales 1999	Prov.Res 31.12.99	Shell Equity Share % 1.1.1999	Shell Equity Share % 1999 Prod	Shell Equity Share % 1.1.2000	Net Shell Equity 1.1.1999 (10^6 m3)	Net Shell Equity 1.1.2000 (10^6 m3)	Comments
Proved Developed Reserves															
Wanaes									97.20	16.67%	16.67%	16.67%	0.00	2.58	
Cossack									14.20	16.67%	16.67%	16.67%	0.00	0.38	
Lambert									14.50	16.67%	16.67%	16.67%	0.00	0.38	
Hermes									1.80	16.67%	16.67%	16.67%	0.00	0.05	
Egret									0.00	16.67%	16.67%	16.67%	0.00	0.00	
Laminaria							85.60		85.80	25.00%	25.00%	25.00%	0.00	3.40	Laminaria ?coralina new developed
Coralina							37.80		37.60	25.00%	25.00%	25.00%	0.00	1.49	
Legendre sold to Woodside						25.90				19.00%	19.00%	19.00%	0.00	0.00	Legendre sold to Woodside
Barrow Island (WAPET)									28.86	28.57%	28.57%	28.57%	0.00	1.31	
Thevenard Island (WAPET)									23.97	35.71%	35.71%	35.71%	0.00	1.36	
NWS + WAPET Oil - SDA 'direct' share															
Legendre sold to Woodside					25.90					9.22%	9.22%	9.22%	0.00	0.00	Legendre sold to Woodside
Wan., Coss., Lamb., Herm., Egret (W=16.67%)									127.70	5.71%	5.71%	5.71%	0.00	1.16	
Lamainaria, Coralina (Woods = 50%)							123.40		123.20	17.14%	17.14%	17.14%	0.00	3.36	
SDA 'indirect' 34.27% share in Woodside															
Prov.Dev.Resvs (MMstb)	0.00	0.00 307.83	0.00	0.00	25.90	25.90	248.80	0.00	554.63				0.00	15.47	
Proved Total Reserves															
Wanaes									104.60	16.67%	16.67%	16.67%	0.00	2.78	
Cossack									14.20	16.67%	16.67%	16.67%	0.00	0.38	
Lambert									22.30	16.67%	16.67%	16.67%	0.00	0.59	
Hermes									3.00	16.67%	16.67%	16.67%	0.00	0.08	
Egret				6.00					6.00	16.67%	16.67%	16.67%	0.00	0.16	Egret booked first time
Laminaria									95.60	25.00%	25.00%	25.00%	0.00	3.80	
Coralina									38.40	25.00%	25.00%	25.00%	0.00	1.53	
Legendre sold to Woodside						25.90				19.00%	19.00%	19.00%	0.00	0.00	Legendre sold to Woodside
Barrow Island (WAPET)									28.86	28.57%	28.57%	28.57%	0.00	1.31	
Thevenard Island (WAPET)									23.97	35.71%	35.71%	35.71%	0.00	1.38	
NWS + WAPET Oil - SDA 'direct' share															
Legendre sold to Woodside					25.90					9.22%	9.22%	9.22%	0.00	0.00	
Wan., Coss., Lamb., Herm., Egret (W=16.67%)				6.00					150.30	5.71%	5.71%	5.71%	0.00	1.38	Egret booked for first time
Lamainaria, Coraline (Woods = 50%)									134.00	17.14%	17.14%	17.14%	0.00	3.85	
SDA 'indirect' 34.27% share in Woodside															
Tot'l Prov.Res (MMstb)	0.00	0.00 609.43	0.00	12.00	25.90	25.90		0.00	621.43				0.00	17.00	
Net Group Equity 10^6 m3															
Prov.Dev. Res	0.00	7.60	0.00	0.00	0.38	0.78	8.27	0.00	15.47						
Prov Tot'l Res	0.00	17.19	0.00	0.21	0.38	0.78		0.00	17.00						
1999 Submission 10^6 m3															
Prov.Dev.Res	7.83	1.45					8.03	1.38	15.92	15.92					
Prov.Tot'l Res	18.73	0.92		0.21	0.38	0.78		1.39	18.07	18.07					

Conversion factors used by SDA
1 stb = 0.159 m3
1scf = 0.0283 sm3

Conversion factors used by SEPIV:
1 stb = 0.159 m3
1 scf = 0.0283 sm3

Audit Trail:

Main changes:
Legendre sold to Woodside (resulting in change of SDA share % from 'direct' to 'indirect')
Laminaria/Coralina new developed during 1999
Egret booked for first time

General: 1.1.1999 field data and individual 1999 field productions not available.
Laminaria/Coralina new developed reserves do not fully match submission

13/10/00, 11:28

FOIA Confidential Treatment Requested

PER00070683

Attachment 2.3

SEC RESERVES AUDIT - VOLUMES RECONCILIATION
SDA 1.1.2000

Proved NGL Reserves Changes 1999 (100%, MMstb)

Field	Prov.Res. 1.1.99	Revisons/ Reclasfns	Improved Recovery	Extens./ Discov's	Purchase in-place	Sales in-place	New Devel'd Reserves	Product'n + Sales 1999	Prov.Res 31.12.99	Shell Equity Share % 1.1.1999	Shell Equity Share % 1999 Prod	Shell Equity Share % 1.1.2000	Net Shell Equity 1.1.1999 (10^6 m3)	Net Shell Equity 1.1.2000 (10^6 m3)	Comments
Proved Developed Reserves															
North Rankin									15.00	15.66%	15.66%	15.66%	0.00	0.37	
Perseus									22.10	15.66%	15.66%	15.66%	0.00	0.55	
Goodwyn									84.50	15.66%	15.66%	15.66%	0.00	2.10	
Angel									0.00	15.66%	15.66%	15.66%	0.00	0.00	
Other NWS gas + oil fields									3.70	15.66%	15.66%	15.66%	0.00	0.09	
Gorgon field (WAPET)									0.00	28.57%	28.57%	28.57%	0.00	0.00	
Chrysaor, W-Trial Rocks (WAPET)									0.00	28.57%	28.57%	28.57%	0.00	0.00	
Total SDA 'direct' share															
SDA 'indirect' 34.27% share in Woodside cond. (19.74% of NWS cond.)									125.30	6.76%	6.76%	6.76%	0.00	1.35	
Prov.Dev.Resvs (MMstb)	0.00	0.00 - 250.60	0.00	0.00	0.00	0.00	0.00	0.00	250.60	0	0	11.21%	0.00	4.47	
Proved Total Reserves															
North Rankin									66.20	15.66%	15.66%	15.66%	0.00	1.70	
Perseus									164.70	15.66%	15.66%	15.66%	0.00	4.10	
Goodwyn									194.00	15.66%	15.66%	15.66%	0.00	4.83	
Angel									65.60	15.66%	15.66%	15.66%	0.00	1.64	
Other NWS gas + oil fields									103.20	15.66%	15.66%	15.66%	0.00	2.57	
Gorgon field (WAPET)									110.69	28.57%	28.57%	28.57%	0.00	5.03	
Chrysaor, W-Trial Rocks (WAPET)									0.00	28.57%	28.57%	28.57%	0.00	0.00	
Total SDA 'direct' share															
SDA 'indirect' 34.27% share in Woodside cond. (19.74% of NWS cond.)									595.90	6.76%	6.76%	6.76%	0.00	6.41	
Tot'l Prov.Res (MMstb)	0.00	0.00 1302.49	0.00	0.00	0.00	0.00		0.00	1302.49	0	0	12.69%	0.00	26.28	

Net Group Equity	Prov.Res. 1.1.99	Revisons/ Reclasfns	Improved Recovery	Extens./ Discov's	Purchase in-place	Sales in-place	New Devel'd Reserves	Product'n + Sales 1999	Prov.Res 31.12.99	
Prov.Dev. Res	0.00	4.47	0.00	0.00	0.00	0.00	0.00	0.00	4.47	
Prov Tot'l Res	0.00	26.28	0.00	0.00	0.00	0.00		0.00	26.28	
10^6 m3										
1999 Submission										
Prov.Dev.Res	9.64	-3.79						1.38	4.47	4.47
Prov.Tot'l Res	24.75	2.90						1.38	26.27	28.27
10^6 m3										

Conversion factors used by SDA
1 stb = 0.159 m3
1scf = 0.0283 sm3

Conversion factors used by SEPIV:
1 stb = 0.159 m3
1 scf = 0.0283 sm3

Audit Trail: General: 1.1.1999 field data and individual 1999 field productions not available. Match incomplete; Overall auditability of changes poor.

FOIA Confidential
Treatment Requested

PER00070684

Attachment 2.4

SEC RESERVES AUDIT - VOLUMES RECONCILIATION
SDA 1.1.2000

Gas Reserves Changes 1999 (100%, Bscf) - Dry sales gas volumes

Field	Prov.Res. 1.1.99	Revisions/ Reclassns	Improved Recovery	Extens./ Discov's	Purchase in-place	Sales in-place	New Devel'd Reserves	Productn = Sales 1999	Prov.Res 31.12.98	Shell Equity Share % 1.1.1999	Shell Equity Share % 1999 Prod	Shell Equity Share % 1.1.2000	Net Shell Equity 1.1.1999 (10^9 sm3)	Net Shell Equity 1.1.2000 (10^9 sm3)	GHV (Btu/scf)	Net Shell Equity 1.1.1999 (10^9 Nm3)	Net Shell Equity 1.1.2000 (10^9 Nm3)	Comments
Proved Developed Reserves																		
North Rankin									1665.890	15.64%	15.64%	15.64%	0.000	7.374	1055	0.000	7.287	
Perseus									895.590	15.64%	15.64%	15.64%	0.000	3.964	1055	0.000	3.918	
Goodwyn									1550.430	15.64%	15.64%	15.64%	0.000	6.862	1055	0.000	6.782	
Angel									0.000	15.64%	15.64%	15.64%	0.000	0.000	1055	0.000	0.000	
Other NWS gas + oil fields									125.190	15.64%	15.64%	15.64%	0.000	0.554	1055	0.000	0.548	
Gorgon field (WAPET)									0.000	28.57%	28.57%	28.57%	0.000	0.000	1073	0.000	0.000	
Chrysaor, W-Trial Rocks (WAPET)									0.000	28.57%	28.57%	28.57%	0.000	0.000	1073	0.000	0.000	
Thevenard Island									33.000	35.71%	35.71%	35.71%	0.000	0.333	1124	0.000	0.351	
Total SDA 'direct' share																		
SDA 'indirect' 34.27% share in Woodside gas (20.37% of NWS sales gas)									4237.200	6.98%	6.98%	6.98%	0.000	8.371	1055	0.000	8.273	
Prov.Dev.Resvs (Bscf)	0.000	0.000 8507.400	0.000	0.000	0.000	0.000	0.000	0.000	8507.400	0	0	0.00%	0.000	27.459	1056	0.000	27.158	
Proved Total Reserves																		
North Rankin									5951.340	15.64%	15.64%	15.64%	0.000	26.341	1055	0.000	26.032	
Perseus									6750.630	15.64%	15.64%	15.64%	0.000	29.879	1055	0.000	29.529	
Goodwyn									4169.790	15.64%	15.64%	15.64%	0.000	18.456	1055	0.000	18.240	
Angel									1338.570	15.64%	15.64%	15.64%	0.000	5.925	1055	0.000	5.855	
Other NWS gas + oil fields									2272.680	15.64%	15.64%	15.64%	0.000	10.059	1055	0.000	9.941	
Gorgon field (WAPET)									10650.000	28.57%	28.57%	28.57%	0.000	86.113	1073	0.000	86.565	
Chrysaor, W-Trial Rocks (WAPET)									0.000	28.57%	28.57%	28.57%	0.000	0.000	1073	0.000	0.000	
Thevenard Island									39.000	35.71%	35.71%	35.71%	0.000	0.394	1124	0.000	0.415	
Total SDA 'direct' share																		
SDA 'indirect' 34.27% share in Woodside gas (20.37% of NWS sales gas)									20483.010	6.98%	6.98%	6.98%	0.000	40.466	1055	0.000	39.991	
Tot'l Prov.Res (Bscf)	0.000	0.000 51655.020	0.000	0.000	0.000	0.000		0.000	51655.020	0	0	0.00%	0.000	217.633	1062	0.000	216.558	

	Prov.Res. 1.1.99	Revisions/ Reclassns	Improved Recovery	Extens./ Discov's	Purchase in-place	Sales in-place	New Devel'd Reserves	Productn = Sales 1999	Prov.Res 31.12.98	
Net Group Equity Prov.Dev. Res Prov Tot'l Res 10^9 sm3	27.459 217.633	27.459 217.633	0.000 0.000	0.000 0.000	0.000 0.000	0.000 0.000	0.000	0.000 0.000	27.459 217.633	
1999 Submission Prov.Dev.Res Prov.Tot'l Res 10^9 sm3	81.589 229.560	-31.136 -8.984						3.733 3.733	26.730 218.843	26.730 216.843
Net Group Equity Prov.Dev. Res Prov Tot'l Res 10^9 Nm3 @ 9500 kCal/Nm3	27.158 216.568	27.158 216.558	0.000 0.000	0.000 0.000	0.000 0.000	0.000 0.000	0.000	0.000 0.000	27.158 216.558	
1999 Submission Prov.Dev.Res Prov.Tot'l Res 10^9 Nm3 @ 9500 kCal/Nm3	63.444 233.887	-29.874 -1.374						4.064 4.064	29.406 228.249	29.406 228.249

Conversion factors used by SDA

1 stb =	0.159	m3
1 scf =	0.0293	sm3
1 sm3 =	0.948	Nm3
and 1 sm3 =	1.0526	Nm3@9500
(i.e. avge GHV =	10548	kcal/Nm3
or	1123.7	Btu/scf
or	44.16	MJ/Nm3
cf avg GHV of	1062.2	kcal/Nm3 from above columns

Conversion factors used by SEPIV:

1 stb =	0.159	m3
1 scf =	0.02834	sm3
1 sm3 =	0.948	Nm3
and 1 sm3 =	0.948	Nm3 @ 9500
(if GHV =	9500	kcal/Nm3
or	1012.0	Btu/scf
or	38.77	MJ/Nm3

Audit Trail:

1.1.1999 field data and individual 1999 field productions not available.
Match incomplete;
Reduction in developed reserves due to correction for
(as yet undeveloped) reserves attributable to compression
No individual field GHV data available, hence Nm3 volumes not verifiable.
Overall auditability of changes poor

13/10/00, 11:26

FOIA Confidential Treatment Requested

PER00070685

SDA, Oct 2000 CHECKLIST SEC RESERVES AUDITS Attachment 3

COMPANY: SHELL DEVELOPMENT AUSTRALIA LTD AREA / FIELD: ALL

Dimensions (100% field figures as at 1.1.2000): **Average Group share: 25 - 37%**

1.1.2000 Proved Oil Reserves	45	10^6 m3	(Group share 18 10^6 m3)
1.1.2000 Proved Developed Oil Reserves	40	10^6 m3	(Group share 16 10^6 m3)
1999 Oil Production	6	10^6 m3	(Group share 1.4 10^6 m3)
	16	10^3 m3/d	(Group share 3.8 10^3 m3/d)
1.1.2000 Proved Gas Reserves	900	10^9 sm3	(Group share 216 10^9 sm3)
1.1.2000 Proved Developed Gas Reserves	124	10^9 sm3	(Group share 27 10^9 sm3)
1999 Gas Production	16	10^9 sm3	(Group share 4.1 10^9 sm3)
	45	10^6 sm3/d	(Group share 11 10^6 sm3/d)
Number of fields in area	20		
Number of wells drilled / in production			

	Audit criteria	Result	Comments
1	**TECHNICAL MATURITY**		
1.01	Is 3D seismic available and used for the field(s) in question?	+	3D seismic has been shot and interpreted over all the fields
1.02	Are seismic processing and interpretation state-of-the-art?	+	Although much of the seismic vintage is from the early 1990's, re-processing and re-interpretation using the latest techniques is gradually being introduced (eg Lambert/Hermes, Laminaria)
1.03	Is well log data quantity and quality adequate?	+	Extensive log and core data have been gathered in appraisal wells and in development wells as appropriate.
1.04	Is well data coverage adequate?	+	Certainly in developed fields; Subsurface uncertainties are properly accounted for in undeveloped fields and proved reserves are in principle not booked until data coverage is adequate.
1.05	Has a 'proved area' been defined (lowest known fluid contact, no major/sealing faults) and is it realistic?	+	Proved reserves are not booked until well data coverage is adequate.
1.06	Is reservoir producibility for undeveloped reserves supported by production tests or other evidence?	+	Yes, most notably in Gorgon
1.07	Is there a proper volumetric estimate?	+	For Woodside operated fields, SPACE probabilistic estimates, validated against selected low- and high realisations in a static model, are standard practice. For the Gorgon area there is a full static model.
1.08	Are representative PVT data available and have they been properly accounted for in the volumetric estimate?	+	Yes, extensive PVT analyses are standard practice and these are properly reflected in static and dynamic models.
1.09	Is a static model available / adequate?	+	For Woodside operated fields, SPACE probabilistic estimates, validated against selected low- and high realisations in a static model, are standard practice. For the Gorgon area there is a full static model.
1.10	Is a dynamic model available / adequate?	+	Yes, detailed dynamic models (downloaded from static models) are available for all fields with proved reserves.
1.11	Is a history match available / adequate?	+	History matches, to the extent that there is sufficient production history, are good and are kept up-to-date on a regular basis.
1.12	Is the recovery factor for proved reserves realistic?	+	Yes, the RFs fully reflect the range of possible subsurface realisations and possible development scenarios.
1.13	Are developed reserves based on proper NFA (No Further Activity) forecasts?	+	Yes; dedicated NFA dynamic model runs are made, incorporating existing facilities' constraints, as relevant.
1.14	Are developed reserves based on existing wells, completions and facilities, or do they require only minor costs (<10% project cost) to be hooked up?	+	Yes. A proper correction was made at 1.1.2000 to reflect the as yet undeveloped state of gas reserves obtainable through compression.
1.15	Has/have (a) development project(s) been defined for undeveloped reserves or can it/they be defined?	+	Yes
1.16	Is/are the project(s) 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. In the large Gorgon gas field, there is also a technically (and economically) robust development plan.
1.17	Is/are there (an) auditable development project plan(s) with costs, benefits and economics?	+	Yes
1.18	Are improved recovery estimates based on a successful pilot or analogue or are they otherwise supportable?	N.A.	Apart from ongoing gas recycling in Goodwyn and some LPG/gas injection in Laminaria/Corallina, there are no improved recovery projects planned.
1.19	Has the project been subjected to a VAR review or other external review and if so, what have been the main conclusions?	+	All projects in which SDA have an interest are subjected to regular peer reviews and VAR reviews with SIEP-EPT assistance. In particular the SIEP assistance to Woodside can be classified as intensive.
2	**COMMERCIAL MATURITY**		
2.01	Is/are the project(s) commercially mature (positive NPV for Group Ref. Crit. over a range of possible future scenarios / low case reserves)?	+	Yes; those that are not are classified as SFR

+ = Good O = Satisfactory X = Unsatisfactory N.A. = Not Applicable

2.02	Is/are the project(s) economically viable (meeting Group Scr. Crit. over range of possible future scenarios / low case reserves)?	+	Yes, with the possible (minor) exception of Egret, see 1.16 above.
2.03	Have forecasts been cut off when rates become uneconomic?	+	Yes; those that are not are classified as SFR
2.04	Have the latest Group Screening / Reference Criteria been used?	+	Yes (standard Group practice)
2.05	Are assumed prices and costs RT (or justified if not)?	+	Yes (standard Group practice)
2.06	Has/have the project(s) been approved by Shareholders?	O	Shareholder approval is usually not sought until start of project activity.
2.07	Is project financing available or can it reasonably be expected to be available?	+	Yes, no foreseeable problems in this respect.
2.08	Are developed reserves actually in production?	+	Yes
2.09	Have all proved gas reserves been contracted to sales?	O	Not all of these. There is still uncontracted gas in the NWS fields, whilst Gorgon gas is as yet wholly uncommitted.
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 (Japan and Korea, but also Taiwan, China, India), 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 Australian shelf.
3	**REASONABLE CERTAINTY**		
3.01	Is the uncertainty range of volumetric parameters and STOIIP estimates adequate?	+	The established procedure of fully probabilistic volumetrics and multi-realisation static modelling ensures that proper ranges are taken for each of the volumetric parameters.
3.02	Is the uncertainty range of developed recovery adequate?	+	Yes, it takes account of the maturity of the field
3.03	Is the uncertainty range of undeveloped recovery adequate?	+	Yes, reflected through the multi-scenario dynamic modelling
3.04	Have market / production constraint uncertainties been taken into account?	N.A.	Since there are no end-of -licence issues for the NWS fields, market/facilities constraints have essentially no effect on reserves estimates. For a discussion on Gorgon, see 4.01.
3.05	What is ratio of field(s) cum.prod. / proved total recovery?		Ranges from 0 to 40% (excluding Barrow island and Thevenard, see also Att 2.1)
3.06	Can the field(s) be considered mature?		Some (N-Rankin, Wanaea, Cossack), yes. The very mature fields Barrow Island and Thevenard have been sold during 2000.
3.07	Are proved (developed and total) reserves benchmarked against expectation reserves for 'proved areas' when field(s) are mature (deterministic approach)?	X	No; Guidelines allow externally reported proved reserves in N-Rankin, Wanaea and Cossack (and possibly Goodwyn plus, in the near future, Laminaria and Corallina) to be taken as equal to expectation reserves.
3.08	Are proved reserves for fields (or other entities used for asset depreciation) added together arithmetically?	+	Proved reserves for fields are added together arithmetically. Depreciation for e.g. the NWS gas fileds is done on a combined asset basis and probabilistic addition within those assets would in principle be allowed.
3.09	Are proved reserves within fields (or within entities used for asset depreciation) added together probabilistically?	+	Probabilistic estimates for entities (areas, reservoir sands) within fields are added together probabilistically.
3.10	Is any assumed dependency in probabilistic addition appropriate?		
4	**GROUP SHARE CALCULATION**		
4.01	Are proved and proved developed reserves fully producible within the licence period (or its extension if there is a legal right) and within production ceilings/constraints?	O	Licences start with an exploration permit for up to 6 years, renewable for up to 5 years, to be followed by a Production Licence if commercial production is undertaken. Production Licences last for 21 years, with one extension option of another 21 years, followed by a further extension option of indefinite duration. The Production Licence lapses only if there has been no production for 5 successive years. Hence there is no end-of-licence cut-off in effect for any of the NWS or Laminaria/Corallina fields.

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			Fields for which the exploration licence has ended and for which no production licence has been applied for can be granted a Retention Lease for a period of 5 years. This can be followed by an indefinite number of successive 5-year extension options, which carry the conditions 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. Currently, the fields in the Gorgon area are held under a Retention Lease, of which the current extension ends in 2002. Although it is considered likely that the interest holders can convince the authorities that commercial viability on these fields is actively being pursued, it is not clear whether this can be seen as a 'right to extend'.
4.02	Are the forecasts required to demonstrate the above condition consistent with those presented in the latest Business Plan?	N.A.	
4.03	Is the company's hydrocarbons Equity share calculated properly?	+	Yes, total Shell equity is calculated as the sum of 'direct' Shell (SDA) participation share in the respective ventures, plus the 'indirect' Shell share (34.27%) in Woodside Petroleum Ltd, which has separate holdings in the respective ventures.
4.04	Is the net Shell share calculated properly (100% for consolidated Shell companies, with minority reserves reported separately, or actual percentage if less than 50%)?	+	Yes, actual percentage is reported.
4.05	Is the hydrocarbons PSC entitlement share (net cost oil + profit oil only) calculated properly?	N.A.	
4.06	Is the hydrocarbons Purchase Right share (to the extent that economic benefit is derived from production while still bearing share of risks and rewards) calculated properly?	N.A.	
4.07	Are royalties in cash (legally or customarily) counted as reserves?	+	All royalties are paid in cash and corresponding volumes are included in reserves.
4.08	Are royalties in kind excluded from reserves?	N.A.	
4.09	Are volumes given away or received as fees in kind (e.g. for infrastructure use by third parties) excluded from reserves?	N.A.	
4.10	Has historic Group under-or overlift (compared with other co-venturers) been accounted for?	N.A.	
4.11	Have gas volumes produced from the reservoir but not yet sold (e.g. through UGS, gas re-injection into another reservoir or a swap deal with another field) been properly maintained in reserves?	N.A.	
4.12	Have separate submissions been made for Equity, Entitlement and Purchase Right volumes?	N.A.	Separate submissons have been made for 'Direct' and 'Indirect' Shell share volumes.
5	**AUDIT TRAILS**		
5.01	Are proved and proved developed reserves estimates up-to date?	+	Reserves for the Woodside operated fields (NWS and Laminaria/Corallina) are being kept up-to-date annually and revised as necessary.
5.02	Can reported net Group equity reserves be reconciled with individual field reserves estimates?	O	Largely, yes. A good match (or reconciliation of minor errors) was obtained for Oil and NGL figures, but gas volumes appeared to show discrepancies of 1-3%, see Att. 2.1.
5.03	Can reported net Group equity reserves be reconciled with other relevant data (e.g. production constraints, gas markets, etc.)?	N.A.	Not really relevant
5.04	Can reserve changes be reconciled with individual field changes?	X	No individual field reserves (100%) from last year's submission were available, neither were individual field production data for 1999 (see also 6.06-07). Specific categories for oil (purchases/sales in place, new discoveries, new developed reserves) could be broadly reconciled to individual fields. A significant reduction in developed gas reserves was due to a correction for (as yet undeveloped) reserves attributable to future compression. The cause for the reduction of total gas reserves could not be established.
5.05	Are reserve changes reported in the appropriate categories?	+	Yes, see above.
5.06	Are technical reports available describing reasons and justifications for new reserves estimates in sufficient detail?	O	Most field reserves are in line with estimates in the latest FDP reports, with remarkably little change being required in e.g. Wanaea / Cossack and Laminaria / Corallina. However, the latest correction in developed gas reserves (correcting for compression) was not found to have been documented anywhere.

+ = Good O = Satisfactory X = Unsatisfactory N.A. = Not Applicable

SDA, Oct 2000 **CHECKLIST SEC RESERVES AUDITS** Attachment 3

5.07	Are reports numbered / indexed properly and is there a central library where copies are kept?	X	FDP reports are indexed and identified properly and full sets of copies are kept by the operators. It was found however, that a number of SDA copies of Woodside documents were unavailable following the office move from Melbourne to Perth.
5.08	Is the annual reserves submission supported by a sufficiently detailed summary note explaining the reserves changes (classified in revisions, extensions, sales-in-place etc) per field, with references to detailed reports as appropriate?	X	A brief summary note (text only) was produced but this was insufficient to provide a comprehensive audit trail (e.g. only expectation volumes mentioned, no tabulated details by field, etc).
5.09	Are data bases containing historic submissions' data and current reserves status (e.g. RISRES) in place and accessible?	O	In view of the limited number of fields, data are kept in spreadsheets only.
5.10	Do these data bases also contain references to detailed reports?	X	No.
6	**CONSISTENCY WITH FINANCIAL REPORTING**		
6.01	Are proved and proved developed reserves based on fiscalised volumes under sales conditions?	+	Yes
6.02	Are oil, NGLs and sales gas reported in their appropriate categories?	+	Yes, in particular LPGs are reported correctly as gas
6.03	Are own use, fuel, losses etc excluded?	O	Upstream own use, fuel and losses (estimated at 3.7% in the Woodside 'Version-7' submission to SDA, although 2.9% was shown in a later submission) are excluded from the NWS gas volumes. No such correction is made for the Gorgon volumes, which is acceptable in view of the as yet preliminary nature of these volumes. Downstream fuel and losses (i.e. in the LNG plant) are correctly included in reserves.
6.04	Are gas GHVs properly measured for sales gas conditions and accounted for in reserves submissions?	O	GHVs are measured and a record is maintained at field level (and apparently even lower) by Woodside, who do the calculation of Nm3 from sm3 volumes. An attempt was made at reconciling the SDA Nm3 submission with average Gorgon and NWS GHVs, but no match could be obtained (Att. 2.4).
6.05	Are reported proved developed reserves consistent with those used for asset depreciation in Group Accounts?	O	Yes, although the audit trail was poor: a copy of the original note by SDA Petroleum Engineers advising SDA Finance about the reserves to be used could not be found. Upon advice from SIEP early in 2000, asset depreciation for North Rankin facilities is done on total North Rankin reserves, whilst those for the other fields are done on proved developed reserves.
6.06	Are annual Oil+NGL production volumes in reserves submissions consistent with Upstream sales volumes reported into the Finance (Ceres) system, i.e. Ceres line 0933, which is the sum of line 7385 (Reward Oil/NGL) and line 0871 (= 8462-Oil + 8464-NGL for Consolidated Companies + line 3596 (= 0931-Oil + 0932-NGL) for Assoc. Companies?	+	The end-1999 submissions for 1999 oil+NGL production through Ceres and through SIEP were, after some corrections, identical.
6.07	Are annual gas production (sales) volumes in reserves submissions consistent with Upstream sales volumes reported into the Finance (Ceres) system, i.e. Ceres line 0323 = 0934 (Group Cy net NG sales) + 3598 (Assoc.Cy NG sales), corrected for 1404+4796 (Gas purchases) and 4100+4510+4575+0873 (Trade, other Sales and Transfers)?	X	The end-1999 submissions for 1999 gas sales through Ceres and through the reserves reporting line (SIEP) were inconsistent with each other (some 9% different). This was due to LNG plant fuel and flare being excluded from the Ceres figures, in line with then prevailing definitions. The new 1.1.2000 definitions in Ceres should remove this inconsistency.
7	**OVERALL**		
7.01	If Group guidelines should not or not completely have been followed, are results still reasonable / overstated / understated?	O	Group guidelines were not completely followed with respect to proved and proved developed reserves in mature fields (see 3.07). The potential understatement in total proved reserves could be some 12 mln m3oe Group share, or some 4% of SDA booked reserves. Gorgon gas reserves (some 86 bln sm3 or 30% of SDA's m3oe Group share volume) can be maintained at their present level in the reserves portfolio and should only be changed if definitive new information regarding the project and/or the retention lease extension becomes available.
7.02	Do the reported proved and proved developed reserves estimates give a reasonably accurate reflection of shareholder value?	O	Bearing in mind the above remarks, the SDA statement of proved and proved developed reserves at end 1999 can be considered to give a reasonably accurate reflection of shareholder value.

+ = Good O = Satisfactory X = Unsatisfactory N.A. = Not Applicable

DRAFT NOTE – 21 Nov 2000 **CONFIDENTIAL**

From:	Anton A. Barendregt	Group Reserves Auditor, SIEP – EPB - GRA
To:	Lorin Brass	Director, Business Development, SIEP - EPB
	Alan Parsley	CEO, Shell Development Australia (SDA)
Copy:	Robert Blaauw	E&P Manager, SDA
	David Christie	Finance Manager, SDA
	Wim Hein Grasso	Commercial Director, SDA
	Jeroen Regtien	Development Manager, SDA
	(circulation)	SIEP – EPF: Gardy, van Nues
	(circulation)	SIEP - EPB-P: Bell, McKay, Aalbers
	Rob Jager	Business Advisor, SIEP (EPA)
	Egbert Eeftink	Director, KPMG Accountants NV
	Stephen L. Johnson	PriceWaterhouseCoopers

SEC PROVED RESERVES AUDIT - SHELL DEVELOPMENT AUSTRALIA, 9-13 Oct 2000

I have audited the proved reserves submissions of SDA for the year 1999 and the processes that were followed in their preparation. These submissions present the SDA contribution to the Group's externally reported Proved and Proved Developed Reserves and associated changes as at 31 December 1999.

The audit followed the procedures laid down in the "Petroleum Resource Volume Guidelines, SIEP 99-1100/1101" (based, inter alia, on FASB Statement 69). It included a verification of the technical and commercial maturity of the reported reserves, a verification that margins of uncertainty were appropriate, that Group share and net sales volumes had been calculated correctly and that reported reserves changes were classified correctly. The last previous SEC proved reserves audit for SDA was carried out in 1996. The audit took the form of technical discussions with staff from Woodside Energy Ltd (the operator for a large part of the assets with SDA interest) and detailed discussions about the reserves reporting process with SDA staff.

Total booked Group share proved reserves at the end of 1999 were 44 mln m3 of oil + NGL (of which 20 mln m3 developed) and 217 bln sm3 of gas (of which 27 bln sm3 developed). 1999 Reserves replacement ratios were 48% for oil+NGL and -340% for gas.

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 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. 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. This could increase Group entitlement by some 12 mln m3oe. 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.

The audit finding is that the SDA statements fairly represent the Group entitlements to Proved Reserves at the end of 1999. There is a possibility of a small (appr. 4%) understatement of entitlement reserves due to the reporting of P85 (proven) reserves instead of expectation reserves in mature fields. The overall opinion from the audit regarding the state of SDA's 1999 Proved Reserves submission, taking account of the scoring in Attachment 3, is therefore satisfactory.

A summary of the findings and observations is included in the Attachments.

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PER00020307

A.A. Barendregt

DEPOSITION
EXHIBIT
Barendregt
#12 2/20/07

Attachments 1, 2, 3

Attachment 1

SEC PROVED RESERVES AUDIT - SDA, 9-13 Oct 2000

MAIN OBSERVATIONS

1. SDA report their Group share reserves in two separate submissions. The first contains the 'direct' share of SDA in the successive licences and ventures in which Shell have an interest, together with other co-venturers. The second submission relates to the 34.27% shareholding that Shell have in Woodside Petroleum Ltd, who are co-venturer and operator in many of the fields in which SDA have an interest. The effect is an increase in the net reported share of the Woodside operated fields.

2. Commendation is made of the excellent quality of the technical work carried out by Woodside Energy Ltd in assessing the subsurface risks and in evaluating and quantifying the probability ranges of the in-place and reserves estimates. The fact that production history in the mature fields largely confirmed the original estimates provides evidence for this quality. Woodside can be commended for a significant improvement of their internal work processes in this respect. It was also noted that co-venturer support, e.g. through regular peer reviews and SIEP reviews (VARs and others) helped to further contribute to this success.

3. 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.

4. Group reserves guidelines prescribe that externally reported 'Proved' reserves should be made equal to expectation volumes (in stead of P85 proven or Low volumes) in mature fields, i.e. fields with significant production in relation to their ultimate recovery. Hence, the externally reported proved reserves in N-Rankin, Wanaea and Cossack (and possibly Goodwyn plus, in the near future, Laminaria and Corallina) should be taken as equal to expectation reserves. The same reserves should then also be applied for asset depreciation calculations for Group accounting.

5. One of the requirements of a reserve audit is that OU Group share submissions can be reconciled with reserves volumes and changes in individual fields. The audit should also establish that Group share reserves changes have been reported in the correct category (revisions, field extensions and discoveries, purchases / sales in place etc.). This process was greatly hampered by the lack of a concise audit note, with full detail at field level and by the lack of a proper record of 1999 produced volumes by individual fields. As a result, only a very partial match could be obtained with individual field volumes and changes as reported by Woodside and Chevron, see Attachments 2.1-2.4. Bottom-line corrections, not necessarily linked to individual fields (e.g. those made for the revised Woodside share in Domgas sales), could (and should) also be addressed in such a note.

   New guidelines for preparing a proper audit trail have recently been published on the SIEP-EPB web site. It is the strong opinion of the auditor that a good audit trail will not only facilitate the auditor's task but also, and more importantly, will greatly enhance clarity and transparency of the reserves reporting process in the OU organisation. This will undoubtedly lead to less staff time being required during staff handovers, queries etc.

6. GHVs are measured and a record is maintained at field level (and apparently even lower) by Woodside, who do the calculation of Nm3 from sm3 volumes for NWS fields. An attempt was made at reconciling the

SDA Nm3 submission with individual field's and Gorgon GHVs, but the resulting average GHV did not seem to match with the average GHV implied by the submission (Att. 2.4).

7. Asset depreciation for Group accounts is done correctly through proved developed reserves depletion (proved total reserves for the full North Rankin facilities, which act as a hub for the entire NWS offshore gas system). Correct reserves values are being used, but no copy could be found of the formal end-1999 note of advice to Finance with the proper new reserves volumes to be used.

8. Full monthly production and sales statistics (100% field volumes) are received by fax from Woodside, who are the only operator at present with fields in production in SDA-held acreage. A selection of these figures (e.g. totals by assets only, not fields) is manually transcribed into the Finance system for monthly / quarterly reporting. A parallel system (also with manual input) is maintained by the Development Manager for e.g. KPI and MIS reporting. There would appear to be opportunities for synergy and rationalisation, also through electronic transfer of data. Incorporation of data at field level could help the end-year audit trail.

Recommendations

1. Maintain the presently booked volume of Gorgon reserves until a clearly positive event (extension of the Retention Lease or LOI with a buyer) has occurred.
2. Raise externally proved and proved developed reserves in N-Rankin and Wanaea / Cossack, plus possibly those in Goodwyn and Laminaria / Corallina to expectation levels, in line with Group guidelines.
3. Prepare a proper audit trail note, in line with published guidelines, for the 1.1.2001 reserves reporting cycle.
4. Consider possible synergy and rationalisation between production / sales reporting through Finance and the Development function.

R. Aalbers

NOTE – 5 Dec 2000 **CONFIDENTIAL**

From:	Anton A. Barendregt	Group Reserves Auditor, SIEP – EPB - GRA
To:	Lorin Brass	Director, Business Development, SIEP - EPB
	Alan Parsley	CEO, Shell Development Australia (SDA)
Copy:	Robert Blaauw	E&P Manager, SDA
	David Christie	Finance Manager, SDA
	Wim Hein Grasso	Commercial Director, SDA
	Jeroen Regtien	Development Manager, SDA
	(circulation)	SIEP – EPF: Gardy, van Nues
	(circulation)	SIEP - EPB-P: Bell, McKay, Aalbers
	Rob Jager	Business Advisor, SIEP (EPA)
	Egbert Eeftink	Director, KPMG Accountants NV
	Stephen L. Johnson	PriceWaterhouseCoopers

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The audit followed the procedures laid down in the "Petroleum Resource Volume Guidelines, SIEP 99-1100/1101" (based, inter alia, on FASB Statement 69). It included a verification of the technical and commercial maturity of the reported reserves, a verification that margins of uncertainty were appropriate, that Group share and net sales volumes had been calculated correctly and that reported reserves changes were classified correctly. The last previous SEC proved reserves audit for SDA was carried out in 1996. The audit took the form of technical discussions with staff from Woodside Energy Ltd (the operator for a large part of the assets with SDA interest) and detailed discussions about the reserves reporting process with SDA staff.

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The audit finding is that the SDA statements fairly represent the Group entitlements to Proved Reserves at the end of 1999. There is a possibility of a small (appr. 4%) understatement of Proved Reserves due to the reporting of P85 (or Low) reserves instead of expectation reserves in mature fields. The overall opinion from the audit regarding the state of SDA's 1999 Proved Reserves submission, taking account of the scoring in Attachment 3, is therefore <u>satisfactory</u>.

A summary of the findings and observations is included in the Attachments.

A.A. Barendregt

DEPOSITION EXHIBIT
Barendregt
#13 2/20/07

Attachments 1, 2, 3

SDA-Covn.doc 05/12/00

FOIA Confidential Treatment Requested

RJW00060528

Attachment 1

SEC PROVED RESERVES AUDIT - SDA, 9-13 Oct 2000

MAIN OBSERVATIONS

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3. 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.

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   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.

4. Group reserves guidelines (approved by external auditors) prescribe that externally reported 'Proved' and 'Proved Developed' reserves should be made equal to expectation volumes (in stead of P85 or Low volumes) in mature fields, i.e. fields with significant production in relation to their ultimate recovery. Hence, the externally reported proved reserves in N-Rankin, Wanaea and Cossack (and possibly Goodwyn plus, in the near future, Laminaria and Corallina) should be taken as equal to expectation reserves. The same reserves should then also be applied for asset depreciation calculations for Group accounting.

5. One of the requirements of a reserve audit is that OU Group share submissions can be reconciled with reserves volumes and changes in individual fields. The audit should also establish that Group share reserves changes have been reported in the correct category (revisions, field extensions and discoveries, purchases / sales in place etc.). This process was greatly hampered by the lack of a concise audit note, with full detail at field level and by the lack of a proper record of 1999 produced volumes by individual fields. As a result, only a very partial match could be obtained with individual field volumes and changes as reported by Woodside and Chevron, see Attachments 2.1-2.4. Bottom-line corrections, not necessarily linked to individual fields (e.g. those made for the revised Woodside share in Domgas sales), could (and should) also be addressed in such a note.

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7. Asset depreciation for Group accounts is done correctly through proved developed reserves depletion (proved total reserves for the full North Rankin facilities, which act as a hub for the entire NWS offshore gas system). Correct reserves values are being used, but no copy could be found of the formal end-1999 note of advice to Finance with the proper new reserves volumes to be used.

8. Full monthly production and sales statistics (100% field volumes) are received by fax from Woodside, who are the only operator at present with fields in production in SDA-held acreage. A selection of these figures (e.g. totals by assets only, not fields) is manually transcribed into the Finance system for monthly / quarterly reporting. A parallel system (also with manual input) is maintained by the Development Manager for e.g. KPI and MIS reporting. There would appear to be opportunities for synergy and rationalisation, also through electronic transfer of data. Incorporation of data at field level could help the end-year audit trail.

Recommendations

1. Maintain the presently booked volume of Gorgon reserves until a clearly positive event (extension of the Retention Lease or LOI with a buyer) has occurred.
2. Raise externally reported proved and proved developed reserves in N-Rankin and Wanaea / Cossack, plus possibly those in Goodwyn and Laminaria / Corallina to expectation levels, in line with Group guidelines.
3. Prepare a proper audit trail note, in line with published guidelines, for the 1.1.2001 reserves reporting cycle.
4. Consider possible synergy and rationalisation between production / sales reporting through Finance and the Development function.

Attachm..... 2.1

SEC RESERVES AUDIT - VOLUMES RECONCILIATION
SDA 1.1.2000

Proved Oil / NGL / Gas Reserves as at 31.12.99

Area / field	Proven HIP MMstb / Bscf	Exp'n HIP MMstb / Bscf	Cum. Prod = Sales 31.12.99 MMstb / Bscf	Proved Rem. Recov. Dev. MMstb / Bscf	Proved Rem. Recov. Tot'l MMstb / Bscf	Exp'n Rem. Recov. Tot'l MMstb / Bscf	Maturity (Cum.pr / Exp'n UR) %	Dev. / Tot'l Proved UR %	Proved RF Tot'l %	Exp'n RF Tot'l %	Fract'n wi lic. & comtd Pr.Dev. %	Fract'n wi lic. & comtd Pr.Tot'l %	Within Licence & comtd Pr.Dev. MMstb / Bscf	Within Licence & comtd Pr.Tot'l MMstb / Bscf	Venture Shell share % %	Shell Equity Dev. 10^6 sm3/ 10^9 sm3	Shell Equity Tot'l 10^6 sm3/ 10^9 sm3	1998 Subm'n Dev 10^6 sm3/ 10^9 sm3	1999 Subm'n Tot'l 10^6 sm3/ 10^9 sm3
Oil																			
Wanaea	283.30	340.30	43.80	96.20	104.80	141.10	23.7%	94.2%	52.5%	54.3%	100.0%	100.0%	97.20	104.80	16.67%	2.58	2.78		
Cossack	76.60	120.10	34.20	14.20	14.20	37.60	47.6%	100.0%	83.2%	59.8%	100.0%	100.0%	14.20	14.20	16.67%	0.38	0.38		
Lambert	55.60	74.50	1.10	14.50	22.30	32.10	3.3%	66.7%	42.1%	44.6%	100.0%	100.0%	14.50	22.30	16.67%	0.38	0.59		
Hermes	22.10	28.10	7.70	1.80	3.00	5.60	57.9%	88.8%	48.4%	47.3%	100.0%	100.0%	1.80	3.00	16.67%	0.05	0.08		
Egret	18.60	37.60			6.00	13.10	0.0%	0.0%	32.3%	34.8%	100.0%	100.0%	0.00	6.00	16.67%	0.00	0.16		
Laminaria	162.30	204.00	3.00	85.60	95.60	126.90	2.3%	89.9%	60.8%	63.7%	100.0%	100.0%	85.60	95.60	25.00%	3.40	3.80		
Coralina	71.50	97.00	0.70	37.60	38.40	55.20	1.3%	98.0%	54.7%	57.6%	100.0%	100.0%	37.60	38.40	25.00%	1.49	1.53		
Barrow Island (WAPET)	1353.61	1353.61	284.85	51.70	51.70	77.70	78.6%	100.0%	24.9%	26.8%	55.8%	55.8%	28.88	28.86	28.57%	1.31	1.31		
Thevenard Island (WAPET)	282.91	282.91	134.45	23.97	23.97	33.95	79.8%	100.0%	56.0%	59.5%	100.0%	100.0%	23.97	23.97	35.71%	1.36	1.36		
NWS + WAPET Oil - SDA 'direct' share																10.85	11.98	11.64	12.83
Wan., Coss., Lamb., Herm., Egret (W= 16.67%)													127.70	150.30	5.71%	1.16	1.36		
Lamainaria, Coralina (Woods = 50%)													123.20	134.00	17.14%	3.36	3.65		
SDA 'indirect' 34.27% share in Woodside																4.82	5.02	4.28	5.44
Total Oil (MMstb)	2326.52	2538.12	509.80	325.57	359.97	523.25							303.73	337.13	31.7%	15.47	17.00	15.82	18.07
NGL																			
North Rankin	313.50	347.30	127.80	15.00	58.20	89.40	58.8%	72.9%	62.5%	62.5%	100.0%	100.0%	15.00	68.20	15.66%	0.37	1.70		
Perseus	308.30	377.80	18.20	22.10	164.70	215.40	7.8%	22.0%	59.3%	61.6%	100.0%	100.0%	22.10	164.70	15.66%	0.55	4.10		
Goodwyn	530.70	629.70	117.10	84.50	194.00	251.10	31.8%	64.8%	58.6%	58.5%	100.0%	100.0%	84.50	194.00	15.66%	2.10	4.83		
Angel	129.90	165.30			65.80	87.00	0.0%	0.0%	50.7%	52.6%	100.0%	100.0%	0.00	65.80	15.66%	0.00	1.64		
Other NWS gas + oil fields	261.00	396.30	2.10	3.70	103.20	152.90	1.4%	5.5%	40.3%	39.1%	100.0%	100.0%	3.70	103.20	15.66%	0.09	2.57		
Gorgon field (WAPET)	170.00	210.40			110.69	131.30	0.0%	0.0%	65.1%	62.4%	100.0%	100.0%	0.00	110.69	28.57%	0.00	5.03		
Chrysaor, W-Trial Rocks (WAPET)	69.00	90.00				53.00	0.0%	0	0.0%	56.9%	100.0%	100.0%	0.00	0.00	28.57%	0.00	0.00		
Total SDA 'direct' share																3.12	18.87	3.12	18.88
SDA 'indirect' 34.27% share in Woodside cond. (18.74% of NWS cond.)													125.30	595.90	6.78%	1.35	6.41	1.35	6.41
Total NGL (MMstb)	1782.40	2216.80	265.20	125.30	706.59	980.10							125.30	706.59	23.38%	4.47	26.28	4.47	26.27
Gas (Dry, sales gas volumes)																			
North Rankin	11620.00	12190.00	4200.00	1730.00	6180.00	6810.00	38.1%	57.1%	89.3%	90.3%	96.3%	96.3%	1665.99	5951.34	15.64%	7.374	28.341		
Perseus	8770.00	10680.00	500.00	930.00	7010.00	8830.00	5.4%	19.0%	85.6%	87.4%	96.3%	96.3%	895.59	6750.83	15.64%	3.964	29.679		
Goodwyn	7040.00	8390.00	660.00	1610.00	4330.00	5420.00	10.9%	45.5%	70.9%	72.5%	96.3%	96.3%	1550.43	4169.79	15.64%	6.862	18.456		
Angel	2270.00	2790.00			1390.00	1770.00	0.0%	0.0%	61.2%	63.4%	96.3%	96.3%	0.00	1338.57	15.64%	0.000	5.925		
Other NWS gas + oil fields	4440.00	6360.00	40.00	130.00	2360.00	3410.00	1.2%	7.1%	54.1%	54.2%	96.3%	96.3%	125.19	2272.68	15.64%	0.554	10.059		
Gorgon field (WAPET)	20936.86	24828.94			10650.00	15200.00	0.0%	0.0%	50.9%	61.2%	98.0%	98.0%	0.00	10437.00	28.57%	0.000	84.391		
Chrysaor, W-Trial Rocks (WAPET)	4550.98	7343.34				3300.00	0.0%	0	0.0%	44.9%	98.0%	98.0%	0.00	0.00	28.57%	0.000	0.000		
Thevenard Island	163.00	163.00	70.00	33.00	39.00	55.00	56.0%	94.5%	66.9%	76.7%	100.0%	100.0%	33.00	39.00	35.71%	0.333	0.394		
Total SDA 'direct' share																19.088	175.445	18.583	178.638
SDA 'indirect' 34.27% share in Woodside gas (20.37% of NWS sales gas)													4237.20	20483.01	6.98%	8.371	40.466	8.147	40.206
Total Gas (Bscf)	59790.85	72745.28	5470.00	4433.00	31959.00	44795.00	10.9%	26.5%	62.6%	69.1%			4270.20	30959.01	24.6%	27.459	215.911	26.730	218.843

Conversion factors used by SDA:
1 stb = 0.159 m3
1scf = 0.0283 sm3

Conversion factors used by SEPIV:
1 stb = 0.159 m3
1 scf = 0.0283 sm3

Licence expiry dates:

Audit Trail:

Oil: SDA submission not corrected for beyond-licence oil from Barrow Island; Minor error in Woodside share % in Laminaria (double correction for unitisation share)
Gas: Fractions 'wi licence & comtd' reflect 3.7% correction for future upstream fuel and flare.
Good match for NGL, but matches for oil and gas are poor.

SDA-Att2.xls, ResvsTot

05/12/00, 13:09

FOIA Confidential Treatment Requested

RJW00060531

Attachment 2.2

SEC RESERVES AUDIT - VOLUMES RECONCILIATION
SDA 1.1.2000

Proved Oil Reserves Changes 1999 (100%, MMstb)

Field	Prov.Res. 1.1.99	Revisons/ Reclasfns	Improved Recovery	Extens / Discov's	Purchase In-place	Sales in-place	New Dev'd Reserves	Product'n = Sales 1999	Prov.Res 31.12.99	Shell Equity Share % 1.1.1999	Shell Equity Share % 1999 Prod	Shell Equity Share % 1.1.2000	Net Shell Equity 1.1.1999 (10^6 m3)	Net Shell Equity 1.1.2000 (10^6 m3)	Comments
Proved Developed Reserves															
Wanaea															
Cossack									97.20	16.67%	18.67%	18.67%	0.00	2.58	
Lambert									14.20	16.67%	16.67%	16.67%	0.00	0.38	
Hermes									14.50	18.67%	16.67%	16.67%	0.00	0.38	
Egret									1.60	18.67%	16.67%	18.67%	0.00	0.05	
Laminaria									0.00	16.67%	16.67%	16.67%	0.00	0.00	
Coralina							85.60		85.60	25.00%	25.00%	25.00%	0.00	3.40	Laminaria ?coralina new developed
Legendre sold to Woodside							37.80		37.60	25.00%	25.00%	25.00%	0.00	1.49	
Barrow Island (WAPET)						25.90				19.00%	19.00%	19.00%	0.00	0.00	Legendre sold to Woodside
Thevenard Island (WAPET)									28.66	28.57%	28.57%	28.57%	0.00	1.31	
NWS + WAPET Oil - SDA 'direct' share									23.87	35.71%	35.71%	35.71%	0.00	1.38	
Legendre sold to Woodside															
Wan., Coss., Lamb., Herm., Egret (W=16.67%)					25.90					9.22%	9.22%	9.22%	0.00	0.00	Legendre sold to Woodside
Laminaria, Coralina (Woods = 50%)									127.70	5.71%	5.71%	5.71%	0.00	1.18	
SDA 'indirect' 34.27% share in Woodside							123.40		123.20	17.14%	17.14%	17.14%	0.00	3.36	
Prov.Dev.Resvs (MMstb)	0.00	0.00 307.83	0.00	0.00	25.90	25.90	246.80	0.00	554.63				0.00	15.47	
Proved Total Reserves															
Wanaea															
Cossack									104.80	16.67%	16.67%	16.67%	0.00	2.78	
Lambert									14.20	16.67%	16.67%	16.67%	0.00	0.36	
Hermes									22.30	16.67%	16.67%	16.67%	0.00	0.59	
Egret				6.00					3.00	16.67%	16.67%	16.67%	0.00	0.08	
Laminaria									8.00	16.67%	16.67%	16.67%	0.00	0.18	Egret booked first time
Coralina									95.60	25.00%	25.00%	25.00%	0.00	3.80	
Legendre sold to Woodside									38.40	25.00%	25.00%	25.00%	0.00	1.53	
Barrow Island (WAPET)						25.90				19.00%	19.00%	19.00%	0.00	0.00	Legendre sold to Woodside
Thevenard Island (WAPET)									28.88	28.57%	28.57%	28.57%	0.00	1.31	
NWS + WAPET Oil - SDA 'direct' share									23.97	35.71%	35.71%	35.71%	0.00	1.36	
Legendre sold to Woodside															
Wan., Coss., Lamb., Herm., Egret (W=16.67%)					25.90					9.22%	9.22%	9.22%	0.00	0.00	
Laminaria, Coralina (Woods = 50%)				6.00					150.30	5.71%	5.71%	5.71%	0.00	1.36	Egret booked for first time
SDA 'indirect' 34.27% share in Woodside									134.00	17.14%	17.14%	17.14%	0.00	3.65	
Tot'l Prov.Res (MMstb)	0.00	0.00 609.43	0.00	12.00	25.90	25.90		0.00	821.43				0.00	17.00	

Net Group Equity	Prov.Res. 1.1.99	Revisons/ Reclasfns	Improved Recovery	Extens / Discov's	Purchase In-place	Sales in-place	New Dev'd Reserves	Product'n = Sales 1999	Prov.Res 31.12.99	
Prov.Dev. Res	0.00	7.60	0.00	0.00	0.38	0.76	8.27	0.00	15.47	
Prov Tot'l Res	0.00	17.19	0.00	0.21	0.38	0.76		0.00	17.00	
10^6 m3										
1999 Submission										
Prov.Dev.Res	7.83	1.45					8.03	1.38	15.92	15.92
Prov.Tot'l Res	18.73	0.92		0.21	0.39	0.78		1.39	18.07	18.07
10^6 m3										

Conversion factors used by SDA
1 stb = 0.159 m3
1 scf = 0.0283 sm3

Conversion factors used by SEPIV:
1 stb = 0.159 m3
1 scf = 0.0283 sm3

Audit Trail:

Main changes:
Legendre sold to Woodside (resulting in change of SDA share % from 'direct' to 'indirect')
Laminaria/Coralina new developed during 1999
Egret booked for first time

General: 1.1.1999 field data and individual 1999 field productions not available.
Laminaria/Coralina new developed reserves do not fully match submission

SDA-Att2.2 resvChg

05/ 13:09

RJW00060532

FOIA Confidential Treatment Requested

Attachment 2.3

SEC RESERVES AUDIT - VOLUMES RECONCILIATION
SDA 1.1.2000

Proved NGL Reserves Changes 1999 (100%, MMstb)

Field	Prov.Res. 1.1.99	Revisons/ Reclasfns	Improved Recovery	Extens./ Discov's	Purchase in-place	Sales in-place	New Devel'd Reserves	Product'n = Sales 1999	Prov.Res 31.12.99	Shell Equity Share % 1.1.1999	Shell Equity Share % 1999 Prod	Shell Equity Share % 1.1.2000	Net Shell Equity 1.1.1999 (10^6 m3)	Net Shell Equity 1.1.2000 (10^6 m3)	Comments
Proved Developed Reserves															
North Rankin															
Perseus									15.00	15.66%	15.66%	15.66%	0.00	0.37	
Goodwyn									22.10	15.66%	15.66%	15.66%	0.00	0.55	
Angel									84.50	15.66%	15.66%	15.66%	0.00	2.10	
Other NWS gas + oil fields									0.00	15.66%	15.66%	15.66%	0.00	0.00	
Gorgon field (WAPET)									3.70	15.66%	15.66%	15.66%	0.00	0.09	
Chrysaor, W-Trial Rocks (WAPET)									0.00	28.57%	28.57%	28.57%	0.00	0.00	
Total SDA 'direct' share									0.00	28.57%	28.57%	28.57%	0.00	0.00	
SDA 'indirect' 34.27% share in Woodside cond. (19.74% of NWS cond.)									125.30	6.76%	6.76%	6.76%	0.00	1.35	
Prov.Dev.Resvs (MMstb)	0.00	0.00 250.60	0.00	0.00	0.00	0.00	0.00	0.00	250.60	0	0	11.21%	0.00	4.47	
Proved Total Reserves															
North Rankin															
Perseus									66.20	15.66%	15.66%	15.66%	0.00	1.70	
Goodwyn									164.70	15.66%	15.66%	15.66%	0.00	4.10	
Angel									194.00	15.66%	15.66%	15.66%	0.00	4.83	
Other NWS gas + oil fields									65.80	15.66%	15.66%	15.66%	0.00	1.64	
Gorgon field (WAPET)									103.20	15.66%	15.66%	15.66%	0.00	2.57	
Chrysaor, W-Trial Rocks (WAPET)									110.69	28.57%	28.57%	28.57%	0.00	5.03	
Total SDA 'direct' share									0.00	28.57%	28.57%	28.57%	0.00	0.00	
SDA 'indirect' 34.27% share in Woodside cond. (19.74% of NWS cond.)									595.90	6.76%	6.76%	6.76%	0.00	6.41	
Tot'l Prov.Res (MMstb)	0.00	0.00 1302.49	0.00	0.00	0.00	0.00		0.00	1302.49	0	0	12.69%	0.00	28.28	

Net Group Equity									
Prov.Dev. Res	0.00	4.47	0.00	0.00	0.00	0.00	0.00	0.00	4.47
Prov Tot'l Res 10^6 m3	0.00	28.28	0.00	0.00	0.00	0.00		0.00	28.28

1999 Submission										
Prov.Dev.Res	9.64	-3.79						1.38	4.47	4.47
Prov.Tot'l Res 10^6 m3	24.75	2.90						1.38	26.27	28.27

Conversion factors used by SDA
1 stb = 0.159 m3
1scf = 0.0283 sm3

Conversion factors used by SEPW
1 stb = 0.159 m3
1 scf = 0.0283 sm3

Audit Trail: General: 1.1.1999 field data and individual 1999 field productions not available. Match incomplete; Overall auditability of changes poor.

SDA-Att2.xls, NGLResvChg

05/12/00, 13:09

RJW00060533

Attachment 2.4

SEC RESERVES AUDIT - VOLUMES RECONCILIATION
SDA 1.1.2000

Gas Reserves Changes 1999 (100%, Bscf) - Dry sales gas volumes

Field	Prov.Res. 1.1.99	Revisons/ Reclasfns	Improved Recovery	Extens./ Discov's	Purchase in-place	Sales in-place	New Devel'd Reserves	Productn = Sales 1999	Prov.Res 31.12.99	Shell Equity Share % 1.1.1999	Shell Equity Share % 1999 Prod	Shell Equity Share % 1.1.2000	Net Shell Equity 1.1.1999 (10^9 sm3)	Net Shell Equity 1.1.2000 (10^9 sm3)	GHV (Btu/scf)	Net Shell Equity 1.1.1999 (10^9 Nm3)	Net Shell Equity 1.1.2000 (10^9 Nm3)	Comments
Proved Developed Reserves																		
North Rankin									1665.990	15.64%	15.64%	15.64%	0.000	7.374	1118	0.000	7.723	
Perseus									895.590	15.64%	15.64%	15.64%	0.000	3.964	1157	0.000	4.296	
Goodwyn									1550.430	15.64%	15.64%	15.64%	0.000	6.862	1121	0.000	7.206	
Angel									0.000	15.64%	15.64%	15.64%	0.000	0.000	1228	0.000	0.000	
Other NWS gas + oil fields									125.190	15.64%	15.64%	15.64%	0.000	0.554	1187	0.000	0.616	
Gorgon field (WAPET)									0.000	28.57%	28.57%	28.57%	0.000	0.000	1044	0.000	0.000	
Chrysaor, W-Trial Rocks (WAPET)									0.000	28.57%	28.57%	28.57%	0.000	0.000	1044	0.000	0.000	
Thevenard Island / Total SDA 'direct' share									33.000	35.71%	35.71%	35.71%	0.000	0.333	1191	0.000	0.372	
SDA 'indirect' 34.27% share in Woodside gas (20.37% of NWS sales gas)									4237.200	6.98%	6.98%	6.98%	0.000	8.371	1144	0.000	8.971	
Prov.Dev.Resvs (Bscf)	0.000	0.000 8507.400	0.000	0.000	0.000	0.000	0.000	0.000	8507.400	0	0	0.00%	0.000	27.459	1135	0.000	29.184	
Proved Total Reserves																		
North Rankin									5951.340	15.64%	15.64%	15.64%	0.000	26.341	1118	0.000	27.587	
Perseus									6750.630	15.64%	15.64%	15.64%	0.000	29.879	1157	0.000	32.384	
Goodwyn									4169.790	15.64%	15.64%	15.64%	0.000	18.456	1121	0.000	19.381	
Angel									1338.570	15.64%	15.64%	15.64%	0.000	5.925	1228	0.000	6.815	
Other NWS gas + oil fields									2272.680	15.64%	15.64%	15.64%	0.000	10.059	1187	0.000	11.185	
Gorgon field (WAPET)									10437.000	28.57%	28.57%	28.57%	0.000	84.391	1044	0.000	82.531	
Chrysaor, W-Trial Rocks (WAPET)									0.000	28.57%	28.57%	28.57%	0.000	0.000	1044	0.000	0.000	
Thevenard Island / Total SDA 'direct' share									39.000	35.71%	35.71%	35.71%	0.000	0.394	1191	0.000	0.440	
															0			
															0			
SDA 'indirect' 34.27% share in Woodside gas (20.37% of NWS sales gas)									20483.010	6.98%	6.98%	6.98%	0.000	40.466	1144	0.000	43.365	
Tot'l Prov.Res (Bscf)	0.000	0.000 51442.020	0.000	0.000	0.000	0.000		0.000	51442.020	0	0	0.00%	0.000	215.911	1106	0.000	223.686	

Field	Prov.Res. 1.1.99	Revisons/ Reclasfns	Improved Recovery	Extens./ Discov's	Purchase in-place	Sales in-place	New Devel'd Reserves	Productn = Sales 1999	Prov.Res 31.12.99	
Net Group Equity										
Prov.Dev. Res	27.459	27.459	0.000	0.000	0.000	0.000	0.000	0.000	27.459	
Prov Tot'l Res (10^9 sm3)	215.911	215.911	0.000	0.000	0.000	0.000		0.000	215.911	
1999 Submission										
Prov.Dev.Res	61.599	-31.136						3.733	28.730	28.730
Prov.Tot'l Res (10^9 sm3)	229.560	-8.184						3.733	218.843	216.843
Net Group Equity										
Prov.Dev. Res	29.184	29.184	0.000	0.000	0.000	0.000	0.000	0.000	29.184	
Prov Tot'l Res (10^9 Nm3 @ 9500 kCal/Nm3)	223.688	223.686	0.000	0.000	0.000	0.000		0.000	223.688	
1999 Submission										
Prov.Dev.Res	63.444	-29.974						4.064	29.408	29.406
Prov.Tot'l Res (10^9 Nm3 @ 9500 kCal/Nm3)	233.687	-1.374						4.064	228.249	228.249

Conversion factors used by SDA			Conversion factors used by SEPIV:		
1 stb =	0.159	m3	1 stb =	0.159	m3
1 scf =	0.0283	sm3	1 scf =	0.02834	sm3
1 sm3 =	0.948	Nm3	1 sm3 =	0.948	Nm3
and 1 sm3 =	1.0528	Nm3@9500	and 1 sm3 =	0.948	Nm3 @ 9500
(i.e. avge GHV =	10548	kcal/Nm3	(if GHV =	9500	kcal/Nm3
or	1123.7	Btu/scf	or	1012.0	Btu/scf
or	44.18	MJ/Nm3	or	39.77	MJ/Nm3
cf avg GHV of	1106.0	kcal/Nm3 from above columns			

Audit Trail:

1.1.1999 field data and individual 1999 field productions not available.
Match incomplete;
Reduction in developed reserves due to correction for
(as yet undeveloped) reserves attributable to compression
Individual field GHV data do not seem to match with overall GHV average from submission
Overall auditability of changes poor

SDA-Att2.x ResvChg

05/12/... 13:09

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R JW00060524

SDA, Oct 2000 CHECKLIST SEC RESERVES AUDITS Attachment 3

COMPANY: SHELL DEVELOPMENT AUSTRALIA LTD AREA / FIELD: ALL

Dimensions (100% field figures as at 1.1.2000): **Average Group share: 25 - 37%**

1.1.2000 Proved Oil Reserves	45	10^6 m3	(Group share 18 10^6 m3)
1.1.2000 Proved Developed Oil Reserves	40	10^6 m3	(Group share 16 10^6 m3)
1999 Oil Production	6	10^6 m3	(Group share 1.4 10^6 m3)
	16	10^3 m3/d	(Group share 3.8 10^3 m3/d)
1.1.2000 Proved Gas Reserves	900	10^9 sm3	(Group share 216 10^9 sm3)
1.1.2000 Proved Developed Gas Reserves	124	10^9 sm3	(Group share 27 10^9 sm3)
1999 Gas Production	16	10^9 sm3	(Group share 4.1 10^9 sm3)
	45	10^6 sm3/d	(Group share 11 10^6 sm3/d)
Number of fields in area	20		
Number of wells drilled / in production			

	Audit criteria	Result	Comments
1	**TECHNICAL MATURITY**		
1.01	Is 3D seismic available and used for the field(s) in question?	+	3D seismic has been shot and interpreted over all the fields
1.02	Are seismic processing and interpretation state-of-the-art?	+	Although much of the seismic vintage is from the early 1990's, re-processing and re-interpretation using the latest techniques is gradually being introduced (eg Lambert/Hermes, Laminaria)
1.03	Is well log data quantity and quality adequate?	+	Extensive log and core data have been gathered in appraisal wells and in development wells as appropriate.
1.04	Is well data coverage adequate?	+	Certainly in developed fields; Subsurface uncertainties are properly accounted for in undeveloped fields and proved reserves are in principle not booked until data coverage is adequate.
1.05	Has a 'proved area' been defined (lowest known fluid contact, no major/sealing faults) and is it realistic?	+	Proved reserves are not booked until well data coverage is adequate.
1.06	Is reservoir producibility for undeveloped reserves supported by production tests or other evidence?	+	Yes, most notably in Gorgon
1.07	Is there a proper volumetric estimate?	+	For Woodside operated fields, SPACE probabilistic estimates, validated against selected low- and high realisations in a static model, are standard practice. For the Gorgon area there is a full static model.
1.08	Are representative PVT data available and have they been properly accounted for in the volumetric estimate?	+	Yes, extensive PVT analyses are standard practice and these are properly reflected in static and dynamic models.
1.09	Is a static model available / adequate?	+	For Woodside operated fields, SPACE probabilistic estimates, validated against selected low- and high realisations in a static model, are standard practice. For the Gorgon area there is a full static model.
1.10	Is a dynamic model available / adequate?	+	Yes, detailed dynamic models (downloaded from static models) are available for all fields with proved reserves.
1.11	Is a history match available / adequate?	+	History matches, to the extent that there is sufficient production history, are good and are kept up-to-date on a regular basis.
1.12	Is the recovery factor for proved reserves realistic?	+	Yes, the RFs fully reflect the range of possible subsurface realisations and possible development scenarios.
1.13	Are developed reserves based on proper NFA (No Further Activity) forecasts?	+	Yes; dedicated NFA dynamic model runs are made, incorporating existing facilities' constraints, as relevant.
1.14	Are developed reserves based on existing wells, completions and facilities, or do they require only minor costs (<10% project cost) to be hooked up?	+	Yes. A proper correction was made at 1.1.2000 to reflect the as yet undeveloped state of gas reserves obtainable through compression.
1.15	Has/have (a) development project(s) been defined for undeveloped reserves or can it/they be defined?	+	Yes
1.16	Is/are the project(s) 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. In the large Gorgon gas field, there is also a technically (and economically) robust development plan.
1.17	Is/are there (an) auditable development project plan(s) with costs, benefits and economics?	+	Yes
1.18	Are improved recovery estimates based on a successful pilot or analogue or are they otherwise supportable?	N.A.	Apart from ongoing gas recycling in Goodwyn and some LPG/gas injection in Laminaria/Corallina, there are no improved recovery projects planned.
1.19	Has the project been subjected to a VAR review or other external review and if so, what have been the main conclusions?	+	All projects in which SDA have an interest are subjected to regular peer reviews and VAR reviews with SIEP-EPT assistance. In particular the SIEP assistance to Woodside can be classified as intensive.
2	**COMMERCIAL MATURITY**		
2.01	Is/are the project(s) commercially mature (positive NPV for Group Ref. Crit. over a range of possible future scenarios / low case reserves)?	+	Yes; those that are not are classified as SFR

+ = Good O = Satisfactory X = Unsatisfactory N.A. = Not Applicable

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2.02	Is/are the project(s) economically viable (meeting Group Scr. Crit. over range of possible future scenarios / low case reserves)?	+	Yes, with the possible (minor) exception of Egret, see 1.16 above.
2.03	Have forecasts been cut off when rates become uneconomic?	+	Yes; those that are not are classified as SFR
2.04	Have the latest Group Screening / Reference Criteria been used?	+	Yes (standard Group practice)
2.05	Are assumed prices and costs RT (or justified if not)?	+	Yes (standard Group practice)
2.06	Has/have the project(s) been approved by Shareholders?	O	Shareholder approval has been obtained for imminent projects and projects in progress. For projects further into the future it will be soughtin die course.
2.07	Is project financing available or can it reasonably be expected to be available?	+	Yes, no foreseeable problems in this respect.
2.08	Are developed reserves actually in production?	+	Yes
2.09	Have all proved gas reserves been contracted to sales?	O	Not all of these. There is still uncontracted gas in the NWS fields, whilst Gorgon gas is as yet wholly uncommitted.
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 (Japan and Korea, but also Taiwan, China, India), 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 Australian shelf.
3	**REASONABLE CERTAINTY**		
3.01	Is the uncertainty range of volumetric parameters and STOIIP estimates adequate?	+	The established procedure of fully probabilistic volumetrics and multi-realisation static modelling ensures that proper ranges are taken for each of the volumetric parameters.
3.02	Is the uncertainty range of developed recovery adequate?	+	Yes, it takes account of the maturity of the field
3.03	Is the uncertainty range of undeveloped recovery adequate?	+	Yes, reflected through the multi-scenario dynamic modelling
3.04	Have market / production constraint uncertainties been taken into account?	N.A.	Since there are no end-of -icence issues for the NWS fields, market/facilities constraints have essentially no effect on reserves estimates. For a discussion on Gorgon, see 4.01.
3.05	What is ratio of field(s) cum.prod. / proved total recovery?		Ranges from 0 to 40% (excluding Barrow island and Thevenard, see also Att 2.1)
3.06	Can the field(s) be considered mature?		Some (N-Rankin, Wanaea, Cossack), yes. The very mature fields Barrow Island and Thevenard have been sold during 2000.
3.07	Are proved (developed and total) reserves benchmarked against expectation reserves for 'proved areas' when field(s) are mature (deterministic approach)?	X	No; Guidelines allow externally reported proved reserves in N-Rankin, Wanaea and Cossack (and possibly Goodwyn plus, in the near future, Laminaria and Corallina) to be taken as equal to expectation reserves.
3.08	Are proved reserves for fields (or other entities used for asset depreciation) added together arithmetically?	+	Proved reserves for all individual fields are added together arithmetically. Depreciation for e.g. the NWS gas fields is done on a combined asset basis and probabilistic addition within those assets would in principle be allowed.
3.09	Are proved reserves within fields (or within entities used for asset depreciation) added together probabilistically?	+	Probabilistic estimates for entities (areas, reservoir sands) within fields are added together arithmetically, with the exception of the reservoirs in Goodwyn, which are added together probabilistically.
3.10	Is any assumed dependency in probabilistic addition appropriate?	O	The probabilistic ranges for the reservoirs in Goodwyn are assumed to be independent. This is probably too optimistic, since dependencies in the estimates must be present. However, the issue will disappear if expectation reserves are used (see 3.07).
4	**GROUP SHARE CALCULATION**		
4.01	Are proved and proved developed reserves fully producible within the licence period (or its extension if there is a legal right) and within production ceilings/constraints?	O	Licences start with an exploration permit for up to 6 years, renewable for up to 5 years, to be followed by a Production Licence if commercial production is undertaken. Production Licences last for 21 years, with one extension option of another 21 years, followed by a further extension option of indefinite duration. The Production Licence lapses only if there has been no production for 5 successive years. Hence there is no end-of-licence cut-off in effect for any of the NWS or Laminaria/Corallina fields.

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			Fields for which the exploration licence has ended and for which no production licence has been applied for can be granted a Retention Lease for a period of 5 years. This can be followed by an indefinite number of successive 5-year extension options, which carry the conditions 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. Currently, the fields in the Gorgon area are held under a Retention Lease, of which the current extension ends in 2002. Although it is considered likely that the interest holders can convince the authorities that commercial viability on these fields is actively being pursued, it is not clear whether this can ~~be seen as a 'right to extend'.~~
4.02	Are the forecasts required to demonstrate the above condition consistent with those presented in the latest Business Plan?	N.A.	
4.03	Is the company's hydrocarbons Equity share calculated properly?	+	Yes, total Shell equity is calculated as the sum of 'direct' Shell (SDA) participation share in the respective ventures, plus the 'indirect' Shell share (34.27%) in Woodside Petroleum Ltd, which has separate holdings in the respective ventures.
4.04	Is the net Shell share calculated properly (100% for consolidated Shell companies, with minority reserves reported separately, or actual percentage if less than 50%)?	+	Yes, actual percentage is reported.
4.05	Is the hydrocarbons PSC entitlement share (net cost oil + profit oil only) calculated properly?	N.A.	
4.06	Is the hydrocarbons Purchase Right share (to the extent that economic benefit is derived from production while still bearing share of risks and rewards) calculated properly?	N.A.	
4.07	Are royalties in cash (legally or customarily) counted as reserves?	+	All royalties are paid in cash and corresponding volumes are included in reserves.
4.08	Are royalties in kind excluded from reserves?	N.A.	
4.09	Are volumes given away or received as fees in kind (e.g. for infrastructure use by third parties) excluded from reserves?	N.A.	
4.10	Has historic Group under-or overlift (compared with other co-venturers) been accounted for?	N.A.	
4.11	Have gas volumes produced from the reservoir but not yet sold (e.g. through UGS, gas re-injection into another reservoir or a swap deal with another field) been properly maintained in reserves?	N.A.	
4.12	Have separate submissions been made for Equity, Entitlement and Purchase Right volumes?	N.A.	Separate submissons have been made for 'Direct' and 'Indirect' Shell share volumes.
5	**AUDIT TRAILS**		
5.01	Are proved and proved developed reserves estimates up-to date?	+	Reserves for the Woodside operated fields (NWS and Laminaria/Corallina) are being kept up-to-date annually and revised as necessary.
5.02	Can reported net Group equity reserves be reconciled with individual field reserves estimates?	O	Largely, yes. A good match (or reconciliation of minor errors) was obtained for Oil and NGL figures, but gas volumes appeared to show discrepancies of 1-3%, see Att. 2.1.
5.03	Can reported net Group equity reserves be reconciled with other relevant data (e.g. production constraints, gas markets, etc.)?	N.A.	Not really relevant
5.04	Can reserve changes be reconciled with individual field changes?	X	No individual field reserves (100%) from last year's submission were available, neither were individual field production data for 1999 (see also 6.06-07). Specific categories for oil (purchases/sales in place, new discoveries, new developed reserves) could be broadly reconciled to individual fields. A significant reduction in developed gas reserves was due to a correction for (as yet undeveloped) reserves attributable to future compression. Both developed and total reserves had to be reduced to account for the larger share that Woodside will take in future Domgas sales.
5.05	Are reserve changes reported in the appropriate categories?	+	Yes, see above.
5.06	Are technical reports available describing reasons and justifications for new reserves estimates in sufficient detail?	O	Most field reserves are in line with estimates in the latest FDP reports, with remarkably little change being required in e.g. Wanaea / Cossack and Laminaria / Corallina. However, the latest correction in developed gas reserves (correcting for compression) was not found to have been documented anywhere.

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5.07	Are reports numbered / indexed properly and is there a central library where copies are kept?	X	FDP reports are indexed and identified properly and full sets of copies are kept by the operators. It was found however, that a number of SDA copies of Woodside documents were unavailable following the office move from Melbourne to Perth.
5.08	Is the annual reserves submission supported by a sufficiently detailed summary note explaining the reserves changes (classified in revisions, extensions, sales-in-place etc) per field, with references to detailed reports as appropriate?	X	A brief summary note (text only) was produced but this was insufficient to provide a comprehensive audit trail (e.g. only expectation volumes mentioned, no tabulated details by field, etc).
5.09	Are data bases containing historic submissions' data and current reserves status (e.g. RISRES) in place and accessible?	O	In view of the limited number of fields, data are kept in spreadsheets only.
5.10	Do these data bases also contain references to detailed reports?	X	No.
6	**CONSISTENCY WITH FINANCIAL REPORTING**		
6.01	Are proved and proved developed reserves based on fiscalised volumes under sales conditions?	+	Yes
6.02	Are oil, NGLs and sales gas reported in their appropriate categories?	+	Yes, in particular LPGs are reported correctly as gas
6.03	Are own use, fuel, losses etc excluded?	O	Upstream own use, fuel and losses (estimated at 3.7% in the Woodside 'Version-7' submission to SDA, although 2.9% was shown in a later submission) are excluded from the NWS gas volumes. A similar 2% correction was made for the Gorgon volumes. Downstream fuel and losses (i.e. in the LNG plant) are correctly included in reserves.
6.04	Are gas GHVs properly measured for sales gas conditions and accounted for in reserves submissions?	O	GHVs are measured and a record is maintained at field level (and apparently even lower) by Woodside, who do the calculation of Nm3 from sm3 volumes for NWS fields. An attempt was made at reconciling the SDA Nm3 submission with individual field's and Gorgon GHVs, but the resulting average GHV did not seem to match with the average GHV implied by the submission (Att. 2.4).
6.05	Are reported proved developed reserves consistent with those used for asset depreciation in Group Accounts?	O	Yes, although the audit trail was poor: a copy of the original note by SDA Petroleum Engineers advising SDA Finance about the reserves to be used could not be found. Upon advice from SIEP early in 2000, asset depreciation for North Rankin facilities is done on total North Rankin reserves, whilst those for the other fields are done on proved developed reserves.
6.06	Are annual Oil+NGL production volumes in reserves submissions consistent with Upstream sales volumes reported into the Finance (Ceres) system, i.e. Ceres line 0933, which is the sum of line 7385 (Reward Oil/NGL) and line 0871 (= 8462-Oil + 8464-NGL for Consolidated Companies + line 3596 (= 0931-Oil + 0932-NGL) for Assoc. Companies?	+	The end-1999 submissions for 1999 oil+NGL production through Ceres and through SIEP were, after some corrections, identical.
6.07	Are annual gas production (sales) volumes in reserves submissions consistent with Upstream sales volumes reported into the Finance (Ceres) system, i.e. Ceres line 0323 = 0934 (Group Cy net NG sales) + 3598 (Assoc.Cy NG sales), corrected for 1404+4796 (Gas purchases) and 4100+4510+4575+0873 (Trade, other Sales and Transfers)?	O	The end-1999 submissions for 1999 gas sales through Ceres and through the reserves reporting line (SIEP) were inconsistent with each other (some 9% different). This was due to LNG plant fuel and flare being excluded from the Ceres figures, thus effectively reporting the downstream sales, not the upstream production. The new 1.1.2000 definitions in Ceres should remove this inconsistency.
7	**OVERALL**		
7.01	If Group guidelines should not or not completely have been followed, are results still reasonable / overstated / understated?	O	Group guidelines were not completely followed with respect to proved and proved developed reserves in mature fields (see 3.07). The potential understatement in total proved reserves could be some 12 mln m3oe Group share, or some 4% of SDA booked reserves. Gorgon gas reserves (some 86 bln sm3 or 30% of SDA's m3oe Group share volume) can be maintained at their present level in the reserves portfolio and should only be changed if definitive new information regarding the project and/or the retention lease extension becomes available.
7.02	Do the reported proved and proved developed reserves estimates give a reasonably accurate reflection of shareholder value?	O	Bearing in mind the above remarks, the SDA statement of proved and proved developed reserves at end 1999 can be considered to give a reasonably accurate reflection of shareholder value.

+ = Good O = Satisfactory X = Unsatisfactory N.A. = Not Applicable

RJW00060538

Regtien, Jeroen SDA-EP/2

From:	Barendregt, Anton AA SIEP-EPB-GRA
Sent:	Wednesday, November 22, 2000 12:47 AM
To:	Christie, David DA SDA-FP; Regtien, Jeroen JMM SDA-EP/2
Cc:	Graham, Sheila S SDA-FP/421; Blaauw, Robert R SDA-EP
Subject:	RE: DRAFT AUDIT NOTE

David, Jeroen,

Many thanks for yor comments and apologies for my lateness in replying - the US audit took longer than I anticipated.

As for your comments:

GHV reconciliation - I did indeed manage to extract the individual field GHVs from the various sheets that Sheila gave to me - they were not immediately obvious at the time and I missed them in the rush to get the report finalised. Yet, even with these individual GHVs (see extra sheet added to Att.2) I do not seem to get a match with your overall average GHV, see Att.2.4.

I changed the wording on shareholder approval somewhat (2.06 in Att.3). Trust the present version is OK.

Gorgon losses - again a victim of the hurry to get the report out. I meant to check with Sheila, but forgot. Apologies.

The 'unsatisfactory' rating for the mismatch in 1999 gas production/sales figures: I hope you can understand that I can hardly rate this as 'good'. Trust that 'satisfactory' is a good compromise. I did check with EPF here and it seems that the old Ceres guidelines left an integrated OU like SDA with no option but reporting the way you did.

As for the issue of expectation reserves to be used for externally reported Proved Reserves, I trust that we're all aligned now. I will admit that the wording 'Proved' is confusing. I prefer to use 'P85' if I refer to low case reserves.

Finally, one small issue regarding point 3.10 in Att.3: Do we use partial or full independency in the in-field probabilistic addition in Perseus and Goodwyn?. Grateful your reply and comment about the appropriateness of the choice.

I'll issue the report as soon as I receive your reply.

Best regards,

Anton

SDA-Covn.doc SDA-Att2.xls SDA-Att3.xls

DEPOSITION EXHIBIT
Barendregt
#14 2/20/07

-----Original Message-----
From: **Christie, David SDA-FP**
Sent: 24 October 2000 05:42
To: Barendregt, Anton SIEP-EPB-GRA
Cc: Graham, Sheila SDA-FP/421; Blaauw, Robert SDA-EP; Parsley, Alan SDA-CEO; Grasso, Wim Hein SDA-DC
Subject: DRAFT AUDIT NOTE

Anton,
My comments and incorporating Sheila Graham's:

MAIN OBSERVATIONS:

ITEM 4: See comment against 6.08 below.

ITEM 6: Incorrect observation. This reconciliation was performed and a spreadsheet was given to the auditor which included the reconciliation referred to.

ITEM 8. Finance in fact receive the sales and production data as part of a monthly fax (not telex) containing financial data which is also sent to the other JVPs. Finance feel that electronic transmission of this data from Woodside is feasible and would save approximately 2 manhours of work per month.

CHECKLIST:

2.06 Not strictly speaking correct.

6.03 Incorrect. A 2% correction was made for Gorgon losses.

6.04 Incorrect. A reconciliation sheet was given by Sheila Graham to the auditor.

6.07 How can this finding be graded as "Unsatisfactory" when SDA complied strictly with CERES guidelines and have already implemented the new definitions from 1/1/2000?

6.08 This matter has been discussed with Group Finance who support SDA's current treatment. Initial further enquiries have indicated a divergence of views between the reserves auditor and Group Finance on the acceptability of using Expectation reserves for depreciation purposes. SDA will attempt to resolve this difference by year end, but we are puzzled why this divergence should exist on such a fundamental issue.

Many thanks again for your useful review.

regards,

David

David A Christie
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Shell Development Australia
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Email: david.a.christie@shell.com.au

DRAFT NOTE – 21 Nov 2000 **CONFIDENTIAL**

From:	Anton A. Barendregt	Group Reserves Auditor, SIEP – EPB - GRA
To:	Lorin Brass	Director, Business Development, SIEP - EPB
	Alan Parsley	CEO, Shell Development Australia (SDA)
Copy:	Robert Blaauw	E&P Manager, SDA
	David Christie	Finance Manager, SDA
	Wim Hein Grasso	Commercial Director, SDA
	Jeroen Regtien	Development Manager, SDA
	(circulation)	SIEP – EPF: Gardy, van Nues
	(circulation)	SIEP - EPB-P: Bell, McKay, Aalbers
	Rob Jager	Business Advisor, SIEP (EPA)
	Egbert Eeftink	Director, KPMG Accountants NV
	Stephen L. Johnson	PriceWaterhouseCoopers

SEC PROVED RESERVES AUDIT - SHELL DEVELOPMENT AUSTRALIA, 9-13 Oct 2000

I have audited the proved reserves submissions of SDA for the year 1999 and the processes that were followed in their preparation. These submissions present the SDA contribution to the Group's externally reported Proved and Proved Developed Reserves and associated changes as at 31 December 1999.

The audit followed the procedures laid down in the "Petroleum Resource Volume Guidelines, SIEP 99-1100/1101" (based, inter alia, on FASB Statement 69). It included a verification of the technical and commercial maturity of the reported reserves, a verification that margins of uncertainty were appropriate, that Group share and net sales volumes had been calculated correctly and that reported reserves changes were classified correctly. The last previous SEC proved reserves audit for SDA was carried out in 1996. The audit took the form of technical discussions with staff from Woodside Energy Ltd (the operator for a large part of the assets with SDA interest) and detailed discussions about the reserves reporting process with SDA staff.

Total booked Group share proved reserves at the end of 1999 were 44 mln m3 of oil + NGL (of which 20 mln m3 developed) and 217 bln sm3 of gas (of which 27 bln sm3 developed). 1999 Reserves replacement ratios were 48% for oil+NGL and -340% for gas.

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 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. 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. This could increase Group entitlement by some 12 mln m3oe. 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.

The audit finding is that the SDA statements fairly represent the Group entitlements to Proved Reserves at the end of 1999. There is a possibility of a small (appr. 4%) understatement of entitlement reserves due to the reporting of P85 (proven) reserves instead of expectation reserves in mature fields. The overall opinion from the audit regarding the state of SDA's 1999 Proved Reserves submission, taking account of the scoring in Attachment 3, is therefore satisfactory.

A summary of the findings and observations is included in the Attachments.

A.A. Barendregt

Attachments 1, 2, 3

PER00081989

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27/11/00

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Attachment 1

SEC PROVED RESERVES AUDIT - SDA, 9-13 Oct 2000

MAIN OBSERVATIONS

1. SDA report their Group share reserves in two separate submissions. The first contains the 'direct' share of SDA in the successive licences and ventures in which Shell have an interest, together with other co-venturers. The second submission relates to the 34.27% shareholding that Shell have in Woodside Petroleum Ltd, who are co-venturer and operator in many of the fields in which SDA have an interest. The effect is an increase in the net reported share of the Woodside operated fields.

2. Commendation is made of the excellent quality of the technical work carried out by Woodside Energy Ltd in assessing the subsurface risks and in evaluating and quantifying the probability ranges of the in-place and reserves estimates. The fact that production history in the mature fields largely confirmed the original estimates provides evidence for this quality. Woodside can be commended for a significant improvement of their internal work processes in this respect. It was also noted that co-venturer support, e.g. through regular peer reviews and SIEP reviews (VARs and others) helped to further contribute to this success.

3. 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.

4. Group reserves guidelines prescribe that externally reported 'Proved' reserves should be made equal to expectation volumes (in stead of P85 proven or Low volumes) in mature fields, i.e. fields with significant production in relation to their ultimate recovery. Hence, the externally reported proved reserves in N-Rankin, Wanaea and Cossack (and possibly Goodwyn plus, in the near future, Laminaria and Corallina) should be taken as equal to expectation reserves. The same reserves should then also be applied for asset depreciation calculations for Group accounting.

5. One of the requirements of a reserve audit is that OU Group share submissions can be reconciled with reserves volumes and changes in individual fields. The audit should also establish that Group share reserves changes have been reported in the correct category (revisions, field extensions and discoveries, purchases / sales in place etc.). This process was greatly hampered by the lack of a concise audit note, with full detail at field level and by the lack of a proper record of 1999 produced volumes by individual fields. As a result, only a very partial match could be obtained with individual field volumes and changes as reported by Woodside and Chevron, see Attachments 2.1-2.4. Bottom-line corrections, not necessarily linked to individual fields (e.g. those made for the revised Woodside share in Domgas sales), could (and should) also be addressed in such a note.

   New guidelines for preparing a proper audit trail have recently been published on the SIEP-EPB web site. It is the strong opinion of the auditor that a good audit trail will not only facilitate the auditor's task but also, and more importantly, will greatly enhance clarity and transparency of the reserves reporting process in the OU organisation. This will undoubtedly lead to less staff time being required during staff handovers, queries etc.

6. GHVs are measured and a record is maintained at field level (and apparently even lower) by Woodside, who do the calculation of Nm3 from sm3 volumes for NWS fields. An attempt was made at reconciling the SDA Nm3 submission with individual field's and Gorgon GHVs, but the resulting average GHV did not seem to match with the average GHV implied by the submission (Att. 2.4).

7. Asset depreciation for Group accounts is done correctly through proved developed reserves depletion (proved total reserves for the full North Rankin facilities, which act as a hub for the entire NWS offshore gas system). Correct reserves values are being used, but no copy could be found of the formal end-1999 note of advice to Finance with the proper new reserves volumes to be used.

8. Full monthly production and sales statistics (100% field volumes) are received by fax from Woodside, who are the only operator at present with fields in production in SDA-held acreage. A selection of these figures (e.g. totals by assets only, not fields) is manually transcribed into the Finance system for monthly /. quarterly reporting. A parallel system (also with manual input) is maintained by the Development Manager for e.g. KPI and MIS reporting. There would appear to be opportunities for synergy and rationalisation, also through electronic transfer of data. Incorporation of data at field level could help the end-year audit trail.

Recommendations

1. Maintain the presently booked volume of Gorgon reserves until a clearly positive event (extension of the Retention Lease or LOI with a buyer) has occurred.
2. Raise externally proved and proved developed reserves in N-Rankin and Wanaea / Cossack, plus possibly those in Goodwyn and Laminaria / Corallina to expectation levels, in line with Group guidelines.
3. Prepare a proper audit trail note, in line with published guidelines, for the 1.1.2001 reserves reporting cycle.
4. Consider possible synergy and rationalisation between production / sales reporting through Finance and the Development function.

Attachment 2.1

SEC RESERVES AUDIT - VOLUMES RECONCILIATION
SDA 1.1.2000

Proved Oil / NGL / Gas Reserves as at 31.12.99

Area / Field	Proven HIIP MMstb / Bscf	Exp'n HIIP MMstb / Bscf	Cum. Prod = Sales 31.12.99 MMstb / Bscf	Proved Rem. Recov. Dev. MMstb / Bscf	Proved Rem. Recov. Tot'l MMstb / Bscf	Exp'n Rem. Recov. Tot'l MMstb / Bscf	Maturity (Cum.pr / Exp'n UR) %	Dev. / Tot'l Proved UR. %	Proved RF Tot'l %	Exp'n RF Tot'l %	Fract'n w/i lic. & comtd Pr.Dev. %	Fract'n w/i lic. & comtd Pr.Tot'l %	Within Licence & comtd Pr.Dev. MMstb / Bscf	Within Licence & comtd Pr.Tot'l MMstb / Bscf	Venture Shell share %	Shell Equity Dev. 10^6 sm3/ 10^9 sm3	Shell Equity Tot'l 10^6 sm3/ 10^9 sm3	1999 Subm'n Dev 10^6 sm3/ 10^9 sm3	1999 Subm'n Tot'l 10^6 sm3/ 10^9 sm3
Oil																			
Wanaea	283.30	340.30	43.80	96.20	104.80	141.10	23.7%	94.2%	52.5%	54.3%	100.0%	100.0%	97.20	104.80	16.67%	2.58	2.78		
Cossack	78.80	120.10	34.20	14.20	14.20	37.60	47.6%	100.0%	83.2%	59.8%	100.0%	100.0%	14.20	14.20	16.67%	0.38	0.38		
Lambert	55.60	74.50	1.10	14.50	22.30	32.10	3.3%	66.7%	42.1%	44.6%	100.0%	100.0%	14.50	22.30	16.67%	0.38	0.59		
Hermes	22.10	28.10	7.70	1.80	3.00	5.60	57.9%	88.8%	46.4%	47.3%	100.0%	100.0%	1.80	3.00	16.67%	0.05	0.08		
Egret	18.60	37.60			6.00	13.10	0.0%	0.0%	32.3%	34.8%	100.0%	100.0%	0.00	6.00	16.67%	0.00	0.16		
Laminaria	162.30	204.00	3.00	85.60	95.60	128.90	2.3%	89.0%	80.5%	63.7%	100.0%	100.0%	85.60	95.60	25.00%	3.40	3.80		
Corallina	71.50	97.00	0.70	37.60	38.40	55.20	1.3%	98.0%	54.7%	57.6%	100.0%	100.0%	37.60	38.40	25.00%	1.49	1.53		
Barrow Island (WAPET)	1353.61	1353.61	284.85	61.70	61.70	77.70	78.8%	100.0%	24.9%	26.8%	55.8%	55.8%	28.86	28.86	28.57%	1.31	1.31		
Thevenard Island (WAPET)	282.91	282.91	134.45	23.97	23.97	33.95	79.8%	100.0%	56.0%	59.5%	100.0%	100.0%	23.97	23.97	35.71%	1.36	1.36		
NWS + WAPET Oil - SDA 'direct' share																10.85	11.99	11.84	12.83
Wan., Coss., Lamb., Herm., Egret (W=16.67%)													127.70	150.30	5.71%	1.16	1.36		
Laminaria, Corallina (Woods = 50%)													123.20	134.00	17.14%	3.36	3.66		
SDA 'indirect' 34.27% share in Woodside																4.52	5.02	4.28	5.44
Total Oil (MMstb)	2328.52	2538.12	509.80	325.57	359.97	523.25							303.73	337.13	31.7%	15.47	17.00	15.92	18.07
NGL																			
North Rankin	313.50	347.30	127.80	15.00	68.20	89.40	58.8%	72.8%	62.5%	62.6%	100.0%	100.0%	15.00	68.20	15.66%	0.37	1.70		
Perseus	308.30	377.60	18.20	22.10	164.70	215.40	7.8%	22.0%	59.3%	61.8%	100.0%	100.0%	22.10	164.70	15.66%	0.55	4.10		
Goodwyn	530.70	629.70	117.10	84.50	194.00	251.10	31.8%	64.8%	58.6%	56.5%	100.0%	100.0%	84.50	194.00	15.66%	2.10	4.83		
Angel	129.90	165.30			65.80	87.00	0.0%	0.0%	50.7%	52.8%	100.0%	100.0%	0.00	65.80	15.66%	0.00	1.84		
Other NWS gas + oil fields	281.00	398.30	2.10	3.70	103.20	152.90	1.4%	5.5%	40.3%	38.1%	100.0%	100.0%	3.70	103.20	15.66%	0.09	2.57		
Gorgon field (WAPET)	170.00	210.40			110.69	131.30	0.0%	0.0%	65.1%	82.4%	100.0%	100.0%	0.00	110.69	28.57%	0.00	5.03		
Chrysaor, W-Trial Rocks (WAPET)	69.00	90.00				53.00	0.0%	0	0.0%	58.9%	100.0%	100.0%	0.00	0.00	28.57%	0.00	0.00		
Total SDA 'direct' share																3.12	19.87	3.12	19.88
SDA 'indirect' 34.27% share in Woodside cond. (19.74% of NWS cond.)													125.30	595.90	6.76%	1.35	6.41	1.35	6.41
Total NGL (MMstb)	1782.40	2218.80	265.20	125.30	706.59	960.10							125.30	706.59	23.39%	4.47	26.28	4.47	26.27
Gas (Dry, sales gas volumes)																			
North Rankin	11620.00	12180.00	4200.00	1730.00	8160.00	8810.00	38.1%	57.1%	89.3%	90.3%	96.3%	96.3%	1665.99	5951.34	15.64%	7.374	28.341		
Perseus	8770.00	10680.00	500.00	930.00	7010.00	8830.00	5.4%	19.0%	85.8%	87.4%	96.3%	96.3%	895.59	6750.63	15.64%	3.964	29.879		
Goodwyn	7040.00	8380.00	660.00	1610.00	4330.00	5420.00	10.9%	45.5%	70.9%	72.5%	96.3%	96.3%	1550.43	4169.79	15.64%	6.862	18.456		
Angel	2270.00	2790.00			1390.00	1770.00	0.0%	0.0%	61.2%	63.4%	96.3%	96.3%	0.00	1338.57	15.64%	0.000	5.925		
Other NWS gas + oil fields	4440.00	6360.00	40.00	130.00	2360.00	3410.00	1.2%	7.1%	54.1%	54.2%	96.3%	96.3%	125.19	2272.68	15.64%	0.564	10.059		
Gorgon field (WAPET)	20936.86	24826.94			10650.00	15200.00	0.0%	0.0%	50.9%	61.2%	98.0%	98.0%	0.00	10437.00	28.57%	0.000	84.391		
Chrysaor, W-Trial Rocks (WAPET)	4550.98	7343.34				3300.00	0.0%	0	0.0%	44.9%	98.0%	98.0%	0.00	0.00	28.57%	0.000	0.000		
Thevenard Island	163.00	163.00	70.00	33.00	39.00	55.00	56.0%	94.5%	68.9%	76.7%	100.0%	100.0%	33.00	39.00	35.71%	0.333	0.394		
Total SDA 'direct' share																19.088	175.445	18.883	176.638
SDA 'indirect' 34.27% share in Woodside gas (20.37% of NWS sales gas)													4237.20	20483.01	6.98%	8.371	40.466	8.147	40.205
Total Gas (Bscf)	59790.85	72745.28	5470.00	4433.00	31969.00	44795.00	10.9%	26.5%	82.6%	69.1%			4270.20	30959.01	24.8%	27.459	215.911	26.730	216.843

Conversion factors used by SDA:
1 stb = 0.159 m3
1scf = 0.0283 sm3

Conversion factors used by SEPIV:
1 stb = 0.159 m3
1 scf = 0.0283 sm3

Licence expiry dates:

Audit Trail:
Oil: SDA submission not corrected for beyond-licence oil from Barrow Island; Minor error in Woodside share % in Laminaria (double correction for unitisation share)
Gas: Fractions 'w/i licence & comtd' reflect 3.7% correction for future upstream fuel and flare.
Good match for NGL, but matches for oil and gas are poor.

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SDA, Oct 2000 **CHECKLIST SEC RESERVES AUDITS** **Attachment 3**

COMPANY: SHELL DEVELOPMENT AUSTRALIA LTD **AREA / FIELD: ALL**

Dimensions (100% field figures as at 1.1.2000): **Average Group share: 25 - 37%**

1.1.2000 Proved Oil Reserves	45	10^6 m3	(Group share 18 10^6 m3)
1.1.2000 Proved Developed Oil Reserves	40	10^6 m3	(Group share 16 10^6 m3)
1999 Oil Production	6	10^6 m3	(Group share 1.4 10^6 m3)
	16	10^3 m3/d	(Group share 3.8 10^3 m3/d)
1.1.2000 Proved Gas Reserves	900	10^9 sm3	(Group share 216 10^9 sm3)
1.1.2000 Proved Developed Gas Reserves	124	10^9 sm3	(Group share 27 10^9 sm3)
1999 Gas Production	16	10^9 sm3	(Group share 4.1 10^9 sm3)
	45	10^6 sm3/d	(Group share 11 10^6 sm3/d)
Number of fields in area	20		
Number of wells drilled / in production			

	Audit criteria	Result	Comments
1	**TECHNICAL MATURITY**		
1.01	Is 3D seismic available and used for the field(s) in question?	+	3D seismic has been shot and interpreted over all the fields
1.02	Are seismic processing and interpretation state-of-the-art?	+	Although much of the seismic vintage is from the early 1990's, re-processing and re-interpretation using the latest techniques is gradually being introduced (eg Lambert/Hermes, Laminaria)
1.03	Is well log data quantity and quality adequate?	+	Extensive log and core data have been gathered in appraisal wells and in development wells as appropriate.
1.04	Is well data coverage adequate?	+	Certainly in developed fields; Subsurface uncertainties are properly accounted for in undeveloped fields and proved reserves are in principle not booked until data coverage is adequate.
1.05	Has a 'proved area' been defined (lowest known fluid contact, no major/sealing faults) and is it realistic?	+	Proved reserves are not booked until well data coverage is adequate.
1.06	Is reservoir producibility for undeveloped reserves supported by production tests or other evidence?	+	Yes, most notably in Gorgon
1.07	Is there a proper volumetric estimate?	+	For Woodside operated fields, SPACE probabilistic estimates, validated against selected low- and high realisations in a static model, are standard practice. For the Gorgon area there is a full static model.
1.08	Are representative PVT data available and have they been properly accounted for in the volumetric estimate?	+	Yes, extensive PVT analyses are standard practice and these are properly reflected in static and dynamic models.
1.09	Is a static model available / adequate?	+	For Woodside operated fields, SPACE probabilistic estimates, validated against selected low- and high realisations in a static model, are standard practice. For the Gorgon area there is a full static model.
1.10	Is a dynamic model available / adequate?	+	Yes, detailed dynamic models (downloaded from static models) are available for all fields with proved reserves.
1.11	Is a history match available / adequate?	+	History matches, to the extent that there is sufficient production history, are good and are kept up-to-date on a regular basis.
1.12	Is the recovery factor for proved reserves realistic?	+	Yes, the RFs fully reflect the range of possible subsurface realisations and possible development scenarios.
1.13	Are developed reserves based on proper NFA (No Further Activity) forecasts?	+	Yes; dedicated NFA dynamic model runs are made, incorporating existing facilities' constraints, as relevant.
1.14	Are developed reserves based on existing wells, completions and facilities, or do they require only minor costs (<10% project cost) to be hooked up?	+	Yes. A proper correction was made at 1.1.2000 to reflect the as yet undeveloped state of gas reserves obtainable through compression.
1.15	Has/have (a) development project(s) been defined for undeveloped reserves or can it/they be defined?	+	Yes
1.16	Is/are the project(s) 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. In the large Gorgon gas field, there is also a technically (and economically) robust development plan.
1.17	Is/are there (an) auditable development project plan(s) with costs, benefits and economics?	+	Yes
1.18	Are improved recovery estimates based on a successful pilot or analogue or are they otherwise supportable?	N.A.	Apart from ongoing gas recycling in Goodwyn and some LPG/gas injection in Laminaria/Corallina, there are no improved recovery projects planned.

+ = Good O = Satisfactory X = Unsatisfactory N.A. = Not Applicable

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1.19	Has the project been subjected to a VAR review or other external review and if so, what have been the main conclusions?	+	All projects in which SDA have an interest are subjected to regular peer reviews and VAR reviews with SIEP-EPT assistance. In particular the SIEP assistance to Woodside can be classified as intensive.
2	COMMERCIAL MATURITY		
2.01	Is/are the project(s) commercially mature (positive NPV for Group Ref. Crit. over a range of possible future scenarios / low case reserves)?	+	Yes; those that are not are classified as SFR
2.02	Is/are the project(s) economically viable (meeting Group Scr. Crit. over range of possible future scenarios / low case reserves)?	+	Yes, with the possible (minor) exception of Egret, see 1.16 above.
2.03	Have forecasts been cut off when rates become uneconomic?	+	Yes; those that are not are classified as SFR
2.04	Have the latest Group Screening / Reference Criteria been used?	+	Yes (standard Group practice)
2.05	Are assumed prices and costs RT (or justified if not)?	+	Yes (standard Group practice)
2.06	Has/have the project(s) been approved by Shareholders?	O	Shareholder approval has been obtained for imminent projects and projects in progress. For projects further into the future it will be soughtin die course.
2.07	Is project financing available or can it reasonably be expected to be available?	+	Yes, no foreseeable problems in this respect.
2.08	Are developed reserves actually in production?	+	Yes
2.09	Have all proved gas reserves been contracted to sales?	O	Not all of these. There is still uncontracted gas in the NWS fields, whilst Gorgon gas is as yet wholly uncommitted.
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 (Japan and Korea, but also Taiwan, China, India), 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 Australian shelf.
3	REASONABLE CERTAINTY		
3.01	Is the uncertainty range of volumetric parameters and STOIIP estimates adequate?	+	The established procedure of fully probabilistic volumetrics and multi-realisation static modelling ensures that proper ranges are taken for each of the volumetric parameters.
3.02	Is the uncertainty range of developed recovery adequate?	+	Yes, it takes account of the maturity of the field
3.03	Is the uncertainty range of undeveloped recovery adequate?	+	Yes, reflected through the multi-scenario dynamic modelling
3.04	Have market / production constraint uncertainties been taken into account?	N.A.	Since there are no end-of -icence issues for the NWS fields, market/facilities constraints have essentially no effect on reserves estimates. For a discussion on Gorgon, see 4.01.
3.05	What is ratio of field(s) cum.prod. / proved total recovery?		Ranges from 0 to 40% (excluding Barrow island and Thevenard, see also Att 2.1)
3.06	Can the field(s) be considered mature?		Some (N-Rankin, Wanaea, Cossack), yes. The very mature fields Barrow Island and Thevenard have been sold during 2000.
3.07	Are proved (developed and total) reserves benchmarked against expectation reserves for 'proved areas' when field(s) are mature (deterministic approach)?	X	No; Guidelines allow externally reported proved reserves in N-Rankin, Wanaea and Cossack (and possibly Goodwyn plus, in the near future, Laminaria and Corallina) to be taken as equal to expectation reserves.
3.08	Are proved reserves for fields (or other entities used for asset depreciation) added together arithmetically?	+	Proved reserves for fields are added together arithmetically. Depreciation for e.g. the NWS gas fileds is done on a combined asset basis and probabilistic addition within those assets would in principle be allowed.
3.09	Are proved reserves within fields (or within entities used for asset depreciation) added together probabilistically?	+	Probabilistic estimates for entities (areas, reservoir sands) within fields are added together probabilistically. Examples are Main, Perseus-West and Capella (added probabilistically to form greater Perseus and the individual reservoirs in Goodwyn).
3.10	Is any assumed dependency in probabilistic addition appropriate?		??
4	GROUP SHARE CALCULATION		

+ = Good O = Satisfactory X = Unsatisfactory N.A. = Not Applicable

SDA, Oct 2000 **CHECKLIST SEC RESERVES AUDITS** **Attachment 3**

4.01	Are proved and proved developed reserves fully producible within the licence period (or its extension if there is a legal right) and within production ceilings/constraints?	O	Licences start with an exploration permit for up to 6 years, renewable for up to 5 years, to be followed by a Production Licence if commercial production is undertaken. Production Licences last for 21 years, with one extension option of another 21 years, followed by a further extension option of indefinite duration. The Production Licence lapses only if there has been no production for 5 successive years. Hence there is no end-of-licence cut-off in effect for any of the NWS or Laminaria/Corallina fields.
			Fields for which the exploration licence has ended and for which no production licence has been applied for can be granted a Retention Lease for a period of 5 years. This can be followed by an indefinite number of successive 5-year extension options, which carry the conditions 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. Currently, the fields in the Gorgon area are held under a Retention Lease, of which the current extension ends in 2002. Although it is considered likely that the interest holders can convince the authorities that commercial viability on these fields is actively being pursued, it is not clear whether this can be seen as a 'right to extend'.
4.02	Are the forecasts required to demonstrate the above condition consistent with those presented in the latest Business Plan?	N.A.	
4.03	Is the company's hydrocarbons Equity share calculated properly?	+	Yes, total Shell equity is calculated as the sum of 'direct' Shell (SDA) participation share in the respective ventures, plus the 'indirect' Shell share (34.27%) in Woodside Petroleum Ltd, which has separate holdings in the respective ventures.
4.04	Is the net Shell share calculated properly (100% for consolidated Shell companies, with minority reserves reported separately, or actual percentage if less than 50%)?	+	Yes, actual percentage is reported.
4.05	Is the hydrocarbons PSC entitlement share (net cost oil + profit oil only) calculated properly?	N.A.	
4.06	Is the hydrocarbons Purchase Right share (to the extent that economic benefit is derived from production while still bearing share of risks and rewards) calculated properly?	N.A.	
4.07	Are royalties in cash (legally or customarily) counted as reserves?	+	All royalties are paid in cash and corresponding volumes are included in reserves.
4.08	Are royalties in kind excluded from reserves?	N.A.	
4.09	Are volumes given away or received as fees in kind (e.g. for infrastructure use by third parties) excluded from reserves?	N.A.	
4.10	Has historic Group under-or overlift (compared with other co-venturers) been accounted for?	N.A.	
4.11	Have gas volumes produced from the reservoir but not yet sold (e.g. through UGS, gas re-injection into another reservoir or a swap deal with another field) been properly maintained in reserves?	N.A.	
4.12	Have separate submissions been made for Equity, Entitlement and Purchase Right volumes?	N.A.	Separate submissons have been made for 'Direct' and 'Indirect' Shell share volumes.
5	**AUDIT TRAILS**		
5.01	Are proved and proved developed reserves estimates up-to date?	+	Reserves for the Woodside operated fields (NWS and Laminaria/Corallina) are being kept up-to-date annually and revised as necessary.
5.02	Can reported net Group equity reserves be reconciled with individual field reserves estimates?	O	Largely, yes. A good match (or reconciliation of minor errors) was obtained for Oil and NGL figures, but gas volumes appeared to show discrepancies of 1-3%, see Att. 2.1.
5.03	Can reported net Group equity reserves be reconciled with other relevant data (e.g. production constraints, gas markets, etc.)?	N.A.	Not really relevant

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5.04	Can reserve changes be reconciled with individual field changes?	X	No individual field reserves (100%) from last year's submission were available, neither were individual field production data for 1999 (see also 6.06-07). Specific categories for oil (purchases/sales in place, new discoveries, new developed reserves) could be broadly reconciled to individual fields. A significant reduction in developed gas reserves was due to a correction for (as yet undeveloped) reserves attributable to future compression. Both developed and total reserves had to be reduced to account for the larger share that Woodside will take in future Domgas sales.
5.05	Are reserve changes reported in the appropriate categories?	+	Yes, see above.
5.06	Are technical reports available describing reasons and justifications for new reserves estimates in sufficient detail?	O	Most field reserves are in line with estimates in the latest FDP reports, with remarkably little change being required in e.g. Wanaea / Cossack and Laminaria / Corallina. However, the latest correction in developed gas reserves (correcting for compression) was not found to have been documented anywhere.
5.07	Are reports numbered / indexed properly and is there a central library where copies are kept?	X	FDP reports are indexed and identified properly and full sets of copies are kept by the operators. It was found however, that a number of SDA copies of Woodside documents were unavailable following the office move from Melbourne to Perth.
5.08	Is the annual reserves submission supported by a sufficiently detailed summary note explaining the reserves changes (classified in revisions, extensions, sales-in-place etc) per field, with references to detailed reports as appropriate?	X	A brief summary note (text only) was produced but this was insufficient to provide a comprehensive audit trail (e.g. only expectation volumes mentioned, no tabulated details by field, etc).
5.09	Are data bases containing historic submissions' data and current reserves status (e.g. RISRES) in place and accessible?	O	In view of the limited number of fields, data are kept in spreadsheets only.
5.10	Do these data bases also contain references to detailed reports?	X	No.
6	**CONSISTENCY WITH FINANCIAL REPORTING**		
6.01	Are proved and proved developed reserves based on fiscalised volumes under sales conditions?	+	Yes
6.02	Are oil, NGLs and sales gas reported in their appropriate categories?	+	Yes, in particular LPGs are reported correctly as gas
6.03	Are own use, fuel, losses etc excluded?	O	Upstream own use, fuel and losses (estimated at 3.7% in the Woodside 'Version-7' submission to SDA, although 2.9% was shown in a later submission) are excluded from the NWS gas volumes. A similar 2% correction was made for the Gorgon volumes. Downstream fuel and losses (i.e. in the LNG plant) are correctly included in reserves.
6.04	Are gas GHVs properly measured for sales gas conditions and accounted for in reserves submissions?	O	GHVs are measured and a record is maintained at field level (and apparently even lower) by Woodside, who do the calculation of Nm3 from sm3 volumes for NWS fields. An attempt was made at reconciling the SDA Nm3 submission with individual field's and Gorgon GHVs, but the resulting average GHV did not seem to match with the average GHV implied by the submission (Att. 2.4).
6.05	Are reported proved developed reserves consistent with those used for asset depreciation in Group Accounts?	O	Yes, although the audit trail was poor: a copy of the original note by SDA Petroleum Engineers advising SDA Finance about the reserves to be used could not be found. Upon advice from SIEP early in 2000, asset depreciation for North Rankin facilities is done on total North Rankin reserves, whilst those for the other fields are done on proved developed reserves.
6.06	Are annual Oil+NGL production volumes in reserves submissions consistent with Upstream sales volumes reported into the Finance (Ceres) system, i.e. Ceres line 0933, which is the sum of line 7385 (Reward Oil/NGL) and line 0871 (= 8462-Oil + 8464-NGL for Consolidated Companies + line 3596 (= 0931-Oil + 0932-NGL) for Assoc. Companies?	+	The end-1999 submissions for 1999 oil+NGL production through Ceres and through SIEP were, after some corrections, identical.

+ = Good O = Satisfactory X = Unsatisfactory N.A. = Not Applicable

6.07	Are annual gas production (sales) volumes in reserves submissions consistent with Upstream sales volumes reported into the Finance (Ceres) system, i.e. Ceres line 0323 = 0934 (Group Cy net NG sales) + 3598 (Assoc.Cy NG sales), corrected for 1404+4796 (Gas purchases) and 4100+4510+4575+0873 (Trade, other Sales and Transfers)?	O	The end-1999 submissions for 1999 gas sales through Ceres and through the reserves reporting line (SIEP) were inconsistent with each other (some 9% different). This was due to LNG plant fuel and flare being excluded from the Ceres figures, thus effectively reporting the downstream sales, not the upstream production. The new 1.1.2000 definitions in Ceres should remove this inconsistency.
7	**OVERALL**		
7.01	If Group guidelines should not or not completely have been followed, are results still reasonable / overstated / understated?	O	Group guidelines were not completely followed with respect to proved and proved developed reserves in mature fields (see 3.07). The potential understatement in total proved reserves could be some 12 mln m3oe Group share, or some 4% of SDA booked reserves. Gorgon gas reserves (some 86 bln sm3 or 30% of SDA's m3oe Group share volume) can be maintained at their present level in the reserves portfolio and should only be changed if definitive new information regarding the project and/or the retention lease extension becomes available.
7.02	Do the reported proved and proved developed reserves estimates give a reasonably accurate reflection of shareholder value?	O	Bearing in mind the above remarks, the SDA statement of proved and proved developed reserves at end 1999 can be considered to give a reasonably accurate reflection of shareholder value.

+ = Good O = Satisfactory X = Unsatisfactory N.A. = Not Applicable

NOTE – 8 Feb 2000

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From:	Anton A. Barendregt	Group Reserves Auditor, SIEP
To:	Linda Z Cook	(Previous) Director, EP Business Development, SIEP
	Lorin Brass	Director, EP Business Development, SIEP
Copy:	Phil B. Watts	EP Chief Executive Officer, SIEP
	Roelof J. Platenkamp	Vice Pres. Strategy, Planning, Portfolio and Economics, SIEP
	Remco D. Aalbers	Group Hydrocarbon Resource Coordinator, SIEP
	Egbert Eeftink	Director, KPMG Accountants NV
	Stephen L. Johnson	PriceWaterhouseCoopers

REVIEW OF GROUP END-1999 PROVED OIL AND GAS RESERVES SUMMARY PREPARATION

In accordance with prescribed US Generally Accepted Accounting Principles (SFAS69), SIEP staff have prepared a summary of Group equity proved and proved developed oil and gas reserves for the year 1999. The summary (Att. 3) forms part of the supplementary information that will be presented in the 1999 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 99-1100/1101) 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 a verification of the reasonableness of major reserves changes and any omissions of such changes, as appropriate. The review also included a comparison between 1999 production (i.e. sales) volumes as reported in the OU reserves submissions and those reported separately through the Finance system in Ceres.

Two significant additions to the Group's proved hydrocarbon portfolio have not been included in SEC externally reported reserves this year. These are the heavy oil volumes recoverable from oil sands in Canada and the proved oil entitlements under the new Iran contract. The first is a mining project and as such cannot be reported under oil&gas reserves, in line with SEC and Group guidelines. As for the Iran entitlements, SEC and Group guidelines prescribe that these should be classified as reserves. On host government insistence, this has not been done.

The challenge by SIEP to constrain Group entitlement reserves increases in companies facing production ceilings and impending production licence expirations (this year primarily in Nigeria) is supported.

There appears to be significant scope for further increasing proved reserves in some areas (Brunei, Oman, and others), where estimates tend to be conservative in comparison with expectation volumes and thereby not fully in line with latest Group guidelines.

It was disappointing to see that, in spite of some progress through SIEP efforts, the persistent problem of inconsistencies between the annual sales volumes reported through the Finance system (Ceres) and those in the reserves submissions had not yet been resolved during 1999. The matter is of importance, because both submissions find their separate ways into the Group annual report and discrepancies are in principle detectible.

SIEP staff is commended for the effective system of electronic spreadsheets and controls governing the OU submissions. This has greatly improved auditability of the results.

During 1999 I made reserves audit visits to a total of nine Group OUs. Audit opinions on six of these were 'satisfactory', whilst three of them were classed as 'good'. A summary of these audit findings is attached (Att. 6). It was found that most recommendations had already been followed up in the 1999 submissions. Similar audits are planned in six OUs in the course of 2000. An updated Audit Plan is attached (Att. 7).

The finding from the audit visits and the end-year review in SIEP is that the SIEP statements fairly represent the Group entitlements to Proved Reserves at the end of 1999. The 1999 changes in the Proved Reserves can be fully reconciled from the individual OU submissions.

A summary of the findings and observations is included in Attachment 1.

A.A. Barendregt

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Attachments 1 - 7

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DEPOSITION EXHIBIT 2
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Attachment 1	Main Observations end-year process
Attachment 2	Major Reserves Changes
Attachment 3	Group Proved Reserves Summaries
Attachment 4	Proved/Expn reserves vs field maturity
Attachment 5	Production Reconciliation Ceres vs Reserves Submissions
Attachment 6	Main observations 1999 Reserves Audits
Attachment 7	Reserves Audit Plan 2000

Attachment 1

REVIEW OF GROUP END-1999 PROVED OIL AND GAS RESERVES SUMMARY PREPARATION

MAIN OBSERVATIONS

1. Significant reserves changes are listed in Attachment 2.

   In **Nigeria**, Exxon have discovered and appraised the **Ehra** field (Shell share 44%) and are close to producing a field development plan. On the basis of work done to date and with the analogue of SNEPCO's Bonga field, economic viability of the project is not under doubt. The proved volumes (24 10^6 m3 oil) have therefore been included in the externally reported reserves. This is supported.

   Field studies have led to sizable proved field volume increases in **Nigeria** and **Oman**, but these have been partially capped to reflect the requirement that proved reserves must be producible before end-of-licence (see below).

   An **equity increase** was booked for the Troll field in **Norway**. **Equity decreases** had to be booked in **Australia** (corrected gas share in line with contract) and **Oman-Gisco** (lower funding and reward gas).

   Add-back of volumes previously (and wrongly) excluded as **royalties in kind** has led to reserves increases in **Canada.**

   Project start-ups (Oman-Gisco, Sable Island, F23 compression, Obaiyed) and development drilling have helped to maintain developed reserves.

   Dilution or divestment of equity has led to reserves reductions in the **USA, Philippines and Canada.**

2. Two significant additions to the Group's proved hydrocarbon portfolio have not been included in externally reported reserves this year. These are the **Muskeg oil sands** in Athabasca, Canada (95 10^6 m3heavy oil), following project FID in 1999 and the proved reserves under the new **Iran contract** (Soroosh/Nowrooz, 24 10^6 m3 oil). The first is a mining project and as such cannot be reported under oil&gas reserves, in line with SEC and Group guidelines. The Iran contract and associated oil volume entitlements are similar in nature to those for the Venezuelan and Oman-Gisco contracts. The SEC and Group guidelines therefore prescribe that these entitlements be classified as reserves. However, host government insistence has led to the decision not to include these in the externally reported volumes for 1.1.2000.

3. In **Australia**, WAPET have re-evaluated the gas reserves in their large, undeveloped **Gorgon field**, indicating that some 20% more reserves would be economically recoverable. The most likely market for this gas would be LNG. However, customers for this additional gas cannot at this stage be readily identified and the incremental volumes (some 20 10^9 Nm3 Group share) have not been included in externally reported proved reserves at this stage. This is in line with Group guidelines and is therefore supported.

4. In the **Netherlands**, NAM have written down exploration costs related to the **Waddenzee** finds, because no development was likely to occur within the next five years, following the new Government moratorium (for an indefinite period, but not permanent) on drilling in that area. However, the proved gas volumes are economic to develop, a market is readily available and the licence duration is indefinite. Hence, the proved volumes have been maintained in externally reported reserves. This is supported.

5. SEC and Group guidelines prescribe that proved and proved developed reserves can be demonstrated to be producible before the **expiry of current production licences** (or their extension if a right to extend is formally agreed). Whilst not a severe constraint in many cases, it is becoming a serious issue for large resource holders that are facing production or export level constraints, i.e. **SPDC Nigeria** and **ADCO Abu Dhabi** and **PDO Oman.** The first two companies carry significant aspirational upturns in future offtake levels in order to justify their proved reserves levels. In view of the need for reasonable certainty of these levels, total proved reserves for SPDC Nigeria have been capped this year by not booking a bottom line increase of 49 10^6 m3, arising from recovery improvements in a series of fields. This is supported. Abu Dhabi reserves had already been capped in previous submissions. Vigilance will be required to ensure that forecasts in future submissions remain realistic.

6. A review of the margin between proved an expectation reserves for major OU fields has shown a tendency for **conservative estimating**, in particular in some mature fields (see Att. 4). Potential increases in proved reserves could be up to 100 10^6 m3 oil equivalent. Field proved reserves are in principle expected to grow closer to expectation reserves with increasing field maturity. Group guidelines also recommend that proved developed reserves are made equal to expectation developed reserves for mature fields (e.g. where cumulative production exceeds some 30-40% of expectation ultimate recovery).

   From Attachment 4 it is clear that many fields do not fulfill these requirements. Main exceptions for undeveloped reserves are in **Norway, UK and Oman**, whilst **Brunei** and **Denmark** tend to be too conservative for both total and developed proved reserves. It is noted that Denmark have compensated for this by introducing, justifiably but somewhat unconventionally, probabilistic addition of their field volumes. For Oman, this conservatism has already been flagged during the October 1999 audit and PDO have undertaken to address this conservatism in their future field reviews. Norway will be audited in 2000.

It may be observed that there are a number of fields that show proved reserves close to or equal to expectation reserves, even for low maturity levels. Whilst a number of these fields are from Shell Canada (with only 'proved', no 'probable' reserves carried), most of these tend to be exceptions of some sort, e.g. small fields in a larger cluster (UK, Netherlands), or reserves constrained by licence expiry (Abu Dhabi).

7. Until this year, **Shell Oil** made their separate reserves submission to SEC, following their own internal and SEC guidelines. In line with the Group's efforts at globalisation, Shell Oil's separate status was discontinued in 1999 and they were expected to adhere to Group guidelines in their reserves submission. It was noted that Shell Oil include **own use gas** in their reserves on the premise that this gas is in principle available for sale into a market and SEC guidelines do not forbid (nor prescribe) their inclusion. Group guidelines specifically forbid inclusion of own use, fuel and flare volumes. The volume affected is some 6.5 10^9 Nm3, mainly in the Area and Altura ventures. Although in contravention of current Group guidelines, Excom advice has been received that Shell Oil reserves submission should not be changed in this respect, pending an analysis of EP industry practice. The issue should be resolved, if necessary through an update of the Group guidelines.

8. In **Venezuela,** it was noted during the 1999 reserves audit that reserves booked by SVSA were **100%** of their operated field **reserves**, even when the net fee received for the oil amounted to only half the prevailing oil price. The Oman Gisco contract and all PSC contract entitlements booked for other OUs take account of the net effective volumes or prices received. Current Group reserves guidelines are not clear on the issue. For Venezuela, it was subsequently decided that, with fees in the near future likely to rise to levels very close to full oil price, the booking of 100% of field volumes was justified. To facilitate booking of future contracts, a more structural solution, through Group guidelines, is recommended.

9. Part of the requirements made in the Group guidelines is that **1999 production**, to be deducted from 1.1.1999 reserves in the reserves submission, should be equal to sales volumes reported under the Finance system through **Ceres**, since both volumes are reported externally. Comparison between the two submissions is made for Oil+NGL (in m3) and gas (in Nm3 at 9500 kCal/Nm3). Results of the comparison are shown in Attachment 5.

 From the comparison, it is clear that the final correspondence between the two submissions is good for **Oil+NGL**, with the main exception being **Shell Canada**, who erroneously exclude royalties in cash from their Ceres submission. The reserves submission has been corrected for this, in line with Group and SEC guidelines.

 For **gas**, the comparison is far less favourable. An outstanding discrepancy of 2.5 10^9 Nm3 (or 3% of 1999 sales) remains, which, because of ingrained procedures, cannot be corrected readily. Main reasons for the discrepancy are:

 - Ceres submissions for **integrated companies (Australia, Germany, Shell Oil, Canada, UK)** report sales as ex-downstream, not upstream sales. Hence, downstream effects like LNG plant fuel, gas storage movement, take-or-pay gas not taken etc cause a variety of distortions.
 - Although both submissions should be in Nm3 at 9500 kCal/Nm3 equivalent, the **unit conversions** from scf or sm3 volumes is often done inconsistently within OUs and between OUs. Conversions in the reserves submissions appear to be correct more often than in the Ceres submissions. It was noted that OU staff, particularly on the Finance side, tend to be reluctant to change their established procedures.
 - **Kingfisher** gas in the **UK** is delivered free of payment as tariff in kind for oil processing services by a third party (Marathon). Kingfisher volumes and production are correctly included in the reserves submission, but are still excluded from the Ceres submission. Shell UK Expro have undertaken to correct this for the 2000 Ceres submission.

 It is disappointing to see that these problems, most of which have been present for several years, have not yet been resolved, in spite of strenuous SIEP efforts. The matter is of importance, because **both submissions** find their separate ways into the **Group annual report** and any discrepancies are in principle detectible. I note that steps are now underway to re-define the externally reported gas volumes under Ceres as sales ex-upstream only and that gas volumes in both reports should from 2000 onwards be in sm3 tel quel, i.e. not normalised for GHV content. These changes should help to bring consistency in the gas volumes to the same level as that for oil+NGL and they are therefore fully supported.

10. Similar to last year, reserves submissions from OUs were made in strictly unified format through SIEP-designed **electronic workbooks**, with strict controls embedded. The ample use of consistency validation in these workbooks has greatly improved the quality of the submissions and the auditability of the accumulation process. Further improvements this year included the tables for individual field data and

volume changes for major fields, plus the request for new developed proved reserves volumes (i.e. transfers from undeveloped to developed reserves). These improvements have enhanced the review process and SIEP staff are to be commended for this. A further refinement, by including an entry for purchases/sales-in-place for proved developed reserves changes by field would be welcomed.

Recommendations:

1. Encourage OUs with low proved reserves in comparison with their expectation levels, to review and upgrade these on an urgent basis.
2. Ensure that OU forecasts to calculate proved within-licence recoverable volumes remain realistic.
3. Implement current plans to unify submission requirements for annual (upstream) sales volumes in both Ceres and the reserves submissions, addressing volume units (sm3 for all) and strict upstream sector delineation.
4. Address the issue of own use gas in the Shell Oil / Pecten reserves submissions, if necessary by adapting the definitions in the Group reserves (and Ceresl) guidelines.
5. For the benefit of future reserves bookings, amend the guidelines to address the issue of the appropriate Shell share to be used in the new type of incentive contracts as in force in Oman-Gisco and Venezuela.
6. Include an entry for sales/purchases-in-place in the proved developed reserves field changes in the reserves submission spreadsheet.

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Attachment 2

MOST SIGNIFICANT 1999 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	
Nigeria - SPDC	-	+39	-	+12	Field reviews.
Nigeria - SPDC	+7	+27	-	-	Late implementation of new (1998) guidelines in a number of reservoirs.
Nigeria - SNEPCO	-	+24	-	-	Ehra discovery (no market yet, hence no gas reserves)
Oman - PDO	+9	+19	-	-	Field reviews, incl. +7 10^6 m3 improved recovery (undev'd) in Marmul
USA – Shell Oil	-	+10	-	+9	Field extensions/discoveries?
Norway	-1	+1	-8	+15	Equity re-determination Troll.
Norway	-	+1	-	+12	Field extension in Ormen Lange (undev'd)
Nigeria – SPDC	-	+5	-	+6	Discoveries/extensions in K1, K1 South, Uzuaku
Oman - Gisco	+27	-	+59	-	Project start-up June '99
USA – Shell Oil	+18	-	+11	-	Development activities
Canada	+5	-	+22		Sable Island start-up Dec '99
UK	+18	-	+8	-	Development activities
Nigeria - SPDC	+15	-	-	-	Development activities
Malaysia	+1	-	+11	-	F23-KA compression installed
Egypt	+4	-	+7	-	Obaiyed on stream Aug '99
Oman	+9	-	-	-	Development activities
Abu Dhabi	+8	-	-	-	More detailed analysis per field
Australia	-3	-	-34		Correction for N-Rankin developed reserves requiring (not yet installed) compression

OTHER MAJOR CHANGES					
Country	Oil+NGL (10^6 m^3)		Gas (10^9 sm^3)		Description
	Dev'd	Total	Dev'd	Total	
Canada	+4	+5	+10	+14	Add-back of cash royalties, previously not included.
Nigeria - SPDC	-	+11	-	-	Effective Shell share increased from 30% to 77% in EA/EJA offshore fields following new funding agreement.
Australia	-0	-0	-0	-7	Re-calculation of NWS net Shell share (direct share up, indirect share down), to bring in line with contract provisions.
Oman - Gisco	+1	+2	-12	-12	Increased NGL due to allocation of early production to GISCO for tax payments. Overall reduction in GISCO cashflow due to lower funding agreed in September 1999.
Canada	-7	-11	-2	-3	Plains BU divested Nov '99
Oman	-17	-	-	-	Correction to reflect proper no-activity forecast to end-of-licence.
Philippines	-	- 4	-	-19	Divestment of 45% of Malampaya to Texaco
Nigeria SPDC	-	-49	-	-	Correction for field increases to reflect total bookable SPDC proved reserves being constrained by an already ambitious forecast and end of licence in 2019.
USA – Shell Oil	-25	-44	-5	-15	Divestments to Apache, Enterprise, plus dilution of three Gulf of Mexico fields

OTHER MINOR CHANGES					
Country	Oil+NGL (10^6 m^3)		Gas (10^9 sm^3)		Description
	Dev'd	Total	Dev'd	Total	
Chad, Khazakstan	-	+2	-	-	Divestment in Chad (-0.4), First discovery in Khazakstan (+2)
Other	+57	+30	+24	+17	

TOTAL CHANGES					
Country	Oil+NGL (10^6 m^3)		Gas (10^9 sm^3)		Description
	Dev'd	Total	Dev'd	Total	
	+130	+68	+91	+29	

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1999 GROUP RESERVES SUBMISSIONS

Attachment 3.1

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

Country Name	Proved reserves 1.1.1999	Revisions and Reclassifications	Improved recovery	Extensions and Discoveries	Purchases in place	Sales in place	Production (i.e. net sales) during 1999	Proved reserves at 31.12.1999	Proved developed reserves at 1.1.1999	Transfer Undeveloped to Developed	Revisions	Production (i.e. net sales) during 1999	Proved developed reserves at 31.12.1999	Minority Reserves included 1.1.1999	Minority Reserves included 31.12.1999	Replacement Ratio (%) DevRes	Replacement Ratio (%) TotRes
Argentina	3.88	-.19	.	.	.	.	.26	3.43	1.97	.01	.31	.26	2.03	.	.	123%	-73%
Bangladesh	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.		
Denmark	35.57	4.1	.32	6.02	.	.	6.86	39.15	28.22	2.77	3.49	6.85	27.63	.	.	91%	152%
Egypt	9.15	-.03	.	.31	.	.	.37	9.06	2.31	3.83	-.04	.37	5.73	.	.	1024%	76%
Kazakhstan - Temir	.	.	.	2.	.	.	.	2.	.	.	.	.	.	.	.		
Nigeria (SNEPCO)	50.4	-2.97	.	23.98	.	.	.	71.41	.	.	.	.	.	.	.		
Nigeria (SPDC)	429.82	25.79	.	4.78	.	.	12.29	448.1	103.25	14.99	7.24	12.29	113.19	.	.	181%	249%
Oman Gisco	32.34	1.72	.	.	.	.	.88	33.18	.	26.75	1.45	.88	27.32	4.85	4.98	3205%	195%
Pakistan	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.		
Philippines	7.4	.	.	.	.	3.58	.	3.82	.	.	.	.	.	.	.		
Russia Sakhalin	8.71	-4.75	3.78	.	.	.	.05	7.69	.	2.65	.	.04	2.61	.	.	8825%	-1940%
Chad	.42	-.42	.	.	.	.	.	.	.	.	.	.	.	.	.		
Venezuela	25.27	-1.47	.	.	.	.	2.37	21.43	9.6	4.9	-.52	2.37	11.61	.	.	185%	-82%
Congo (DR)	4.34	-.96	.	.	.	.	.16	3.22	1.27	.94	.25	.16	2.3	.	.	744%	-600%
Abu Dhabi	108.78	-.72	.	.	.	.	4.8	103.28	81.	.	7.51	4.8	83.71	.	.	156%	-15%
Austria	.25	.01	.	.	.	.	.03	.23	.2	.	.02	.03	.19	.	.	67%	33%
Australia (Direct)	31.03	4.05	.	.18	.	.78	1.97	32.49	12.95	4.78	-.98	1.97	14.76	.	.	192%	174%
Australia (Indirect)	12.45	-.24	.	.05	.38	.	.79	11.85	4.52	3.27	-1.37	.79	5.63	.	.	241%	24%
Brunei	55.23	4.19	3.	1.86	.	.	5.	59.28	23.72	5.87	3.61	5.	28.19	.	.	190%	181%
Canada	56.13	5.72	.	.01	.	10.54	4.16	47.16	30.68	5.1	-2.49	4.16	28.13	12.33	10.36	63%	-116%
China	2.79	1.03	.	.	.	.	.58	3.24	2.38	.52	.51	.58	2.83	.	.	178%	178%
Gabon	20.2	4.89	.	.	.	.	5.18	19.91	15.86	1.17	5.61	5.19	17.45	5.06	4.97	131%	94%
Germany	4.04	-.34	.	.	.	.	.33	3.37	3.67	.	-.27	.33	3.07	.	.	-82%	-103%
Malaysia	27.12	2.02	.09	.13	.	.	3.81	25.55	13.41	3.23	1.13	3.81	13.95	.	.	114%	59%
Netherlands	6.09	.43	.	.01	.	.	.76	5.77	3.36	.97	.37	.76	3.93	.	.	176%	58%
Norway	38.75	-1.45	.	.78	.	.	4.82	33.26	23.48	3.84	-1.83	4.82	20.65	.	.	42%	-14%
New Zealand	3.59	-.01	.	1.46	.	.	.44	4.6	2.95	.	.1	.45	2.6	.	.	22%	330%
Oman	134.09	11.73	8.46	1.68	.	.	16.46	139.5	100.22	8.8	-7.56	16.46	85.	.	.	8%	133%
Shell Oil (Aera)	83.38	5.64	.	.	.05	2.15	7.66	79.26	63.85	1.02	1.8	7.66	59.01	.	.	37%	46%
Shell Oil (Altura)	42.03	5.74	2.63	.	.17	.08	2.64	47.87	39.13	.	3.75	2.64	40.24	.	.	142%	321%
Shell Oil (MCC)	4.91	-2.11	.	.1	.01	.5	.55	1.86	3.55	.35	-1.79	.55	1.56	.	.	-262%	-455%
Shell Oil (TMR)	.67	.27	.	.17	.	.	.18	.93	.45	.	.29	.18	.56	.	.	161%	244%
Shell Oil (EH) - China	3.84	.04	.	.	.	.	.59	3.29	3.2	.26	.	.59	2.87	.	.	44%	7%
Shell Oil (EH) - Cameroon	9.04	.02	.	.	.	.	1.31	7.75	8.31	.11	.16	1.3	7.28	.	.	21%	2%
Shell Oil (EH) - New Zeala	.77	.14	.	.	.	.	.11	.8	.64	.	.14	.11	.67	.	.	127%	127%
Shell Oil (USA) cons	149.43	-4.87	.	10.02	.	44.37	18.21	92.	79.79	18.04	-25.5	18.21	54.12	.	.	-41%	-215%
Shell Oil (USA) - Oil Shale	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.		
Shell Oil (WH) cons	.93	.	.	.	.	.	.12	.81	.93	.	.	.12	.81	.	.	0%	0%
Syria	22.78	1.14	.	.	.	.	4.11	19.81	14.63	.93	.84	4.11	12.29	.	.	43%	28%
Thailand	12.73	1.74	.37	.35	.	.	1.02	14.17	5.57	.28	-1.05	1.02	3.78	.	.	-75%	241%
UK	156.4	-2.54	.	.	.	.6	23.34	129.82	94.35	18.2	1.13	23.33	90.35	.	.	83%	-13%
Tot Oil+NGL	1,594.76	57.34	18.65	53.87	.61	62.58	132.21 Check	1,530.43 1530.43	779.4	133.56	-3.69	132.19 Check	777.05 777.08	22.24	20.31	98%	61%

FOIA Confidential Treatment Requested

OUVol&Chgs-Anton.xls Oil+NGLm3

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