Exhibit 95

NOTE – 31 May 2002 CONFIDENTIAL

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SEC PROVED RESERVES AUDIT - BRUNEI SHELL PETROLEUM SDN BHD, 29 Apr - 3 May 2002

I have audited the Proved Reserves submissions of Brunei Shell Petroleum Sdn Bhd (BSP) for the year 2001 and the processes that were followed in their preparation. These submissions present the BSP contribution to the Group's externally reported Proved and Proved Developed Reserves and associated changes as at 31 December 2001.

Total Group share Proved Reserves booked by BSP at the end of 2001 were 72 mln m3 oil+NGL and 100 bln sm3 of gas. This represents some 5.6 % of total Group share Proved Reserves on an oil-equivalent basis. Proved reserves replacement ratios for BSP over 2001 were 152% for oil+NGL and 112% for gas.

The last previous SEC proved reserves audit for BSP was carried out in 1998. This current audit followed the procedures laid down in the "Petroleum Resource Volume Guidelines, SIEP 2001-1100/1101" (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. It also included a verification that the annual production (sales) submission through the Finance system was consistent with the reserves submission. The audit took the form of detailed discussions about technical details of many of BSP's fields with BSP Asset Unit staff and about the reserves reporting process with BSP reserves coordination staff.

The audit found that BSP follow well documented procedures in their annual reserves reporting process. Audit trails have historically been a strong feature in BSP reserves reporting and their high quality was confirmed during the audit. The most significant comment related to the conservative nature of BSP's Proved reserves, in particular Proved developed reserves, many of which were not in accordance with current Group guidelines. Although decreased substantially in recent years, the continued presence of 'legacy reserves' remains an area of concern. These are undeveloped reserves which have historically been booked in reservoirs but for which no clear activies had been identified (in line with prevailing practice at the time). These reserves should be addressed at the first available opportunity, while striving to avoid major reserves swings.

The audit finding is that the BSP statements fairly represent the Group entitlements to Proved Reserves at the end of 2001. There is a possibility of a small (3 %?) understatement of entitlement reserves due to the conservatism in particularly the Proved developed reserves. The changes in the Proved Reserves during 2001 can be reconciled from the documents at hand. The overall opinion from the audit regarding the state of BSP's 2001 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

Attachments 1, 2, 3, 4

EXHIBIT
8
PENGAD 800-631-6989

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RJW01001253

Attachment 1

SEC PROVED RESERVES AUDIT - BRUNEI SHELL PETROLEUM SDN BHD, 29 Apr.- 3 May 2002

MAIN OBSERVATIONS

1. Brunei Shell Petroleum Sdn Bhd are a 50% Group company with their established head office in Seria, Brunei Darussalam. The remaining 50% of the company is held by the State of Brunei. The company operates a large number of offshore fields and some onshore fields. The three largest fields are the onshore Seria field, with first production in 1929 and the offshore SW Ampa and Champion fields where first production started in 1964 and 1972 respectively. Although the area is largely mature, there are still some smaller, recently discovered fields awaiting development.

   Reserves are approximately evenly divided between oil+NGI and gas. Gas has been produced to the Brunei LNG plant since 1972. The 20-year gas contract.with Japanese buyers was extended for another 20 years in 1992 on the basis of then available proved gas reserves. This basis, being somewhat conservative, has since then grown and there is now a surplus of some 1.5 Tcf proved gas and some 5 Tcf of expectation volumes.

2. The Brunei fields consist of stacked near-shore reservoir sequences, broken up by clay diapir induced or tectonically induced faulting, resulting in numerous small reservoirs that show variable but generally poor communication. Initial fluid levels are therefore largely individual to reservoirs and each needs separate evaluation, although often in conjunction with its neighbours. A total of some 4000 reservoirs is currently recognized (of which some 1000 with Proved reserves), presenting a challenging task for reserves evaluation and development planning.

   All of the fields are in relatively shallow offshore areas (up to 100 m water depth). Exploration focus is shifting towards deep offshore turbidite sequences, in which one field (Merpati) is carrying proved undeveloped reserves at this stage.

   With the largest reservoirs developed first, BSP have faced several cycles of active development. Development tended to become temporarily reduced when the then available technology slowed down the maturation of new economically viable well targets. A recent upturn in development has been seen in the late 1990's when a number of factors contributed to an enhanced capability of reservoir performance modeling and development planning. These factors included enhanced 3D seismic acquisition (with Ocean Bottom Cable) and seismic processing (PSDM), more recently followed by geological modeling through the Petrel package, yielding greatly improved speed and accuracy of reservoir definition. Automatic downloading into MoReS dynamic simulation models allows this improved accuracy yield its benefits in dynamic modeling too. Through-tubing C-O logs allowed a much more widespread monitoring of dynamic fluid levels, greatly improving the accuracy of simulation models and predictions. Significant progress has been made in reducing drilling costs and improving drilling flexibility in well targeting, eg through short-radius horizontal drilling and multi-target sub-horizontal wells.

   The result of these successful technological developments is that new reserves developed per well show a steady trend, with no signs of any levelling off as yet.

3. Expectation developed ultimate recoveries (DURs) are determined from performance decline extrapolations in those cases where there is no active history matched simulation model. The standard method of determining Proved DURs is through fitting a symmetrical triangular distribution around the Expectation estimates with the lower end point halfway between cumulative production and expectation UR. This tends to result in a Proved developed reserves volume that is invariably some 75% of Expectation (see Att. 4.1). This is highly artificial and not in accordance with current Group guidelines (which in turn follow SEC guidelines).

   It is strongly recommended that proved developed reserves are derived from expectation developed reserves by multiplying the latter by a factor that is dependent on reservoir maturity and which approaches or equals 1 for the more mature reservoirs, where in-place volumes are well known.

4. In line with general Group practice in the 1970's and 1980's, BSP have tended to determine total reservoir recoveries from volumetrics with recovery factors either assumed or derived from analogues, obtained from analytical reservoir studies or obtained from assumed well numbers and notional recoveries per well. After the start of field development, the developed reserves became based on production performance extrapolations but undeveloped reserves remained poorly defined as they were maintained as the difference between total URs (which were kept largely unchanged) and DURs.

   With the introduction of new Group guidelines in 1993, requiring all reserves to be based on identified projects (i.e. well targets, numbers, costs and forecasts) the undeveloped reserves thus calculated became non-conformant with Group reserves guidelines. BSP have long recognized the non-conformance of these 'legacy' reserves. However, any temptation to 'wipe the slate clean' (i.e. set all undefined undeveloped reserves to zero) was resisted because it was considered likely that in many reservoirs it would be possible to replace them by properly defined reserves, i.e with well targets, forecasts and robust economics. It was felt that major reserves swings needed to be avoided and the decision was therefore taken to keep these reserves in the books until the proper studies had been made. Significant progress has been made in this respect and the amount of reserves now covered by simulation models and studies is some 70% on average. As a result, the portion of 'legacy' reserves in undeveloped reserves (currently some 9% of Expectation, much less of Proved) is now considerably reduced.

A further reason why 'legacy' reserves have reduced in size was the conservatism in the original field in-place estimates (caused possibly by too rigorous petrophysical cut-offs?). As a result, developed URs continued to grow and in many cases they overtook the original total proved (and sometimes even expectation) UR estimates. Hesitation was observed in simply zeroising these negative reserves because reservoir crossflow was a common phenomenon and it was possible that the underestimate in one reservoir could be due to an overestimate in a neighbouring reservoir. A regional study was therefore required before proper updates could be made. Lack of resources and priority caused a continuous deferment of such studies in a number of areas. Negative reserves continued in many reservoirs (particularly in the Champion Main field), until concerted efforts in 2000/2001 brought back the total of such reserves to more reasonable, but still low proportions.

The continued existence of 'legacy' undeveloped reserves is still a cause for concern. BSP have therefore started and resourced a study that will address this issue and that of the too conservative Proved developed and undeveloped reserves that are not in accordance with Group guidelines. This study is fully supported. BSP are also strongly supported in their present drive for complete coverage of all developed and to-be-developed reservoirs by proper studies. One of the root causes for the present problems has been the practice of assessing total (developed + undeveloped) reservesas on estimate. Instead, developed and undeveloped reserves should both be defined <u>separately</u> and properly, preferably by a joint simulator model.

5. In the original approach followed by BSP, <u>Proved undeveloped reserves</u> were simply the difference between proved total and proved developed reserves. In the new approach, whereby undeveloped reserves are determined independently, the method of determining Proved volumes is less well defined. The impression is that in many cases, a conservative approach is still followed. Group guidelines clearly state that in such cases a number of simulator scenarios should be run, with a reasonable P85 scenario picked as the Proved case at first, which can gradually become updated by a scenario that grows closer to or equal to expectation values with increasing field maturity.

6. Undeveloped reserves in a number of fields and reservoirs do not yet fulfil the condition (to be introduced in Group guidelines at end 2002) that such identified reserves must be <u>economically robust</u> in order to be certain of their future development. Many of these reserves and associated forecasts are still notional and BSP are confident that, with proper study and with present technology (eg cheaper horizontal wellbores) they can be made economic. This is accepted.

7. BSP have historically been one of the strongest proponents of probabilistic reserves estimation and initial volumetric estimates are still done probabilistically. Any incomplete hydrocarbon column penetrations are thus also addressed probabilistically, i.e. <u>'proved areas'</u> (ref. SEC definitions) are not adhered to rigidly. Although accepted Group practice in the past, this is no longer in line with Group guidelines. This should be addressed.

8. Asset depreciation is done at a field level. Hence, guidelines would in principle allow <u>probabilistic addition</u> of reservoirs within a field. This is not done at present but is being considered by BSP as a possible method of bringing field Proved reserves closer to Expectation volumes.

   The auditor opinion is that probabilistic addition of reservoir reservoirs to field level is not to be recommended. The reasons for this recommendation are as follows:

   - Probabilistic volumetric estimates become irrelevant for mature fields. Probabilistic parameter ranges (bulk volume, porosity etc) can often not realistically be changed to capture the effects of field performance data and any change in volumetrics could therefore become arbitrary and not auditable.
   - Reservoir dependency will become a critical issue in proper probabilistic addition of reservoir volumes. This will also be susceptible to subjective judgment and will also present audit trail problems.
   - The need for probabilistic addition should diminish significantly if the calculation methods of Proved developed and undeveloped reserves are brought closer in line with Group guidelines, thereby bringing Proved reserves much closer to Expectation volumes.

9. Somewhat exceptionally, BSP REs keep track of condensate production from oil wells in oil+associated gas reservoirs, even though these liquids are produced through the oil stream. This condensate production is added to the condensate balance in these reservoirs and reflected in individual field condensate volumes. Reported NGL reserves are however based on produced streams, i.e. reported NGLs are only those condensates produced and sold separately. Reported oil reserves similarly include condensate produced in the oil stream. The main justification for this extra accounting of condensate volumes (outside production and reserves reporting) is said to obtain a correct reflection of the condensate material balance in reservoirs with very large gas caps. However, it does not add to the clarity of the audit trail – no documents were sighted showing a clear connection between condensates and reported oil/NGL volumes. With the oil production of large gas cap reservoirs now coming to an end, thought should be given to either abandoning this complexity or at least provide a better audit trail on this aspect.

10. It is noted that there is no complete correspondence between reserves volumes and production forecasts in the Business Plan. This is largely due to the 'legacy' reserves, for which no forecasts are available. However, there are also other discrepancies (eg in Land ('Darat') Business Unit where the BP contains forecasts for which there are no reserves (only SFR) in the books. The impression is that some of this SFR is sufficiently mature to warrant inclusion as reserves. This should be rectified.

11. Fairley Baram undeveloped oil reserves appear to be positive at Proved level, but the Expectation undeveloped volume is zero. This is inconsistent and should be rectified.

12. Current BSP production licences expire as follows:
Onshore and 'first offshore' (eg SWA): 22 Dec 2003,
Second offshore area (eg FA): 31 Dec 2007,
Third offshore area: 31 Dec 2026.
There is a right to extend these licences by two successive periods of 15 years, at terms and conditions to be agreed upon. Any failure to agree such new terms would still lead to extension by one period of 15 years largely on existing terms. Discussions on the new terms and conditions for the onshore and first offshore licences are currently underway. The approach by both parties is said to be positive and there are no indications that an acceptable set of new terms and conditions cannot be agreed with the Government. Hence, BSP management are fully confident that a new licence extension (and an option for a further extension in the future) will be granted.

13. Various documents describing the reserves determination process are in place (eg a DUR review procedure guide). The annual reserves review process is kicked off by a note by the reserves coordinator, setting out the requirements, target dates and responsibilities. All reserves changes are documented in reports or notes, depending on their complexity. Full field (or part-field) reviews and FDPs are documented comprehensively. An annual report 'End-year Resource Volumes for External and Internal reporting' is issued, together with a summary of results. This provides for an excellent audit trail and is fully commended.

    In addition to these documents and in preparation for the audit, BSP had made a special effort to provide documents summarising the status of reserves in the three Asset Units (Land, East and West). Apart from a brief summary per field, these documents also contained overviews of proved, expectation reserves and SFR, historical reserves changes over the last few years etc. This was highly useful and is commended.

14. Consistency with field reserves and reserves changes was good. The one exception appeared to be the oil vs condensate issue (see 9 above).

15. Very good consistency with Finance reporting has been observed in the matters of annual production volumes and Unit of Production factors (UPF) for asset depreciation. This is seen to be the result of close cooperation between Finance Accounts and Reserves Coordination and is fully commended.

Recommendations

1. Replace the present method of deriving proved developed reserves from Expectation developed reserves (triangular distribution starting at Cum.prod + 0.5 * [Exp'n dev'd – Cum.prod]) by multiplying Expectation reserves by a factor which gradually approaches or equals 1 with increasing reservoir maturity (defined as Cum.prod / Exp'n UR). The initial value of this factor may reflect the uncertainties in the individual reservoirs.
2. Assess undeveloped reserves separately (and not as stopgap between developed and total reserves). Estimate Porved undeveloped reserves by selecting a realistic P85 scenario of future activities, which scenario should be updated as more field performance is obtained and which should therefore grow closer to the Expectation scenario.
3. Complete the recently started study into 'legacy' reserves and the appropriate level of Proved vs Expectation reserves in line with the present plan per end 2002.
4. Address the issue of 'proved areas', in particular in relation to the non-allowed booking of volumes below 'lowest known hydrocarbons' (LKH, see guidelines), unless supported by strong evidence (eg seismic amplitudes).
5. Review the need for maintaining the oil vs condensate split in reservoirs or improve the audit trail on this aspect
6. Critically evaluate the justification for probabilistic addition of reservoir reserves to field level.
7. Review the appropriateness of booking some BP forecast volumes in Land/Darat BU as reserves and not as SFR as at present.
8. Rectify Fairley Baram Proved (>0) vs Expectation (=0) undeveloped reserves.

Attachment 2.1

SEC RESERVES AUDIT - VOLUMES RECONCILIATION
BSP 1.1.2002

Proved Oil / NGL / Gas Reserves as at 1.1.2002

Area / field	Proven HIIP	Exp'n HIIP	Cum. Prod = Sales 31.12.01	Proved Rem. Recov. Dev'd	Proved Rem. Recov. Undev	Exp'n Rem. Recov. Tot'l	Maturity (Cum.pr / Exp'n UR)	Dev. / Tot'l Proved UR.	Proved RF Tot'l	Exp'n RF Tot'l	Excl ownuse & loss Pr.Dev.	Excl ownuse & loss Pr.Undv	Within Licence comtd Pr.Dev.	Within Licence comtd Pr.Tot'l	Shell share %	Net Shell Equity Dev.	Net Shell Equity Tot'l	1.1.2002 Subm'n Dev	1.1.2002 Subm'n Tot'l	Prov. Res / Prod Dev. yrs	Prov. Res / Prod Totl yrs
	10^6 m3 / 10^9 sm3	10^6 m3 / 10^9 sm3	10^6 m3 / 10^9 sm3	10^6 m3 / 10^9 sm3	10^6 m3 / 10^9 sm3	10^6 m3 / 10^9 sm3	%	%	%	%	%	%	10^6 m3 / 10^9 sm3	10^6 m3 / 10^9 sm3	%	10^6 sm3/ 10^9 sm3	10^6 sm3/ 10^9 sm3	10^6 sm3/ 10^9 sm3	10^6 sm3/ 10^9 sm3		
Oil																					
SW Ampa	289.18	355.45	120.06	12.57	9.19	29.92	80%	94%	45%	41%	100.0%	100.0%	12.57	21.75	50.00%	6.28	10.88			5	9
Other main fields - West	94.54	126.07	28.33	5.35	5.79	16.07	64%	85%	36%	35%	100.0%	100.0%	5.35	11.13	50.00%	2.67	5.57			6	12
Champion	427.42	553.76	87.47	24.05	6.46	52.67	62%	95%	22%	25%	100.0%	100.0%	24.05	30.51	50.00%	12.02	15.25			7	9
Other main fields - East	164.13	240.68	26.96	7.50	25.82	55.86	33%	57%	32%	34%	100.0%	100.0%	7.50	33.31	50.00%	3.75	16.66			3	14
Seria	410.32	495.70	167.66	5.80	7.30	18.48	90%	96%	43%	38%	100.0%	100.0%	5.80	13.11	50.00%	2.90	6.55			7	17
Other main fields - Land	24.89	31.15	5.95	1.61	1.08	3.85	61%	87%	28%	31%	100.0%	100.0%	1.61	2.69	50.00%	0.81	1.35			20	8
Other small fields	14.96	35.78	0.10	0.00	1.71	4.30	2%	6%	12%	12%	100.0%	100.0%	0.00	1.71	50.00%	0.00	0.85				61
Condensate produced in oil stream				2.37	4.71		0	33%	0	0	100.0%	100.0%	2.37	7.08	50.00%	1.19	3.54				
Total Oil (MMstb)	1425.44	1848.59	436.53	59.24	62.06 121.30	181.14	71%	89%	35%	33%	100.0%	100.0%	59.24	121.30	50.00%	29.62	60.65	29.62	60.65	6	12
NGL																					
SW Ampa	62.51	79.06	15.75	6.46	4.59	14.79	52%	83%	33%	39%	100.0%	100.0%	6.46	11.05	50.00%	3.23	5.52			12	21
Other main fields - West	12.09	16.02	4.07	0.44	1.96	3.43	54%	70%	50%	47%	100.0%	100.0%	0.44	2.40	50.00%	0.22	1.20			6	34
Champion	3.54	5.38	0.40	0.32	0.45	1.37	22%	62%	24%	33%	100.0%	100.0%	0.32	0.77	50.00%	0.16	0.39			162	386
Champion-West	12.14	19.65	0.35	0.10	4.27	6.75	5%	10%	38%	36%	100.0%	100.0%	0.10	4.37	50.00%	0.05	2.19				
Other main fields - East	5.77	8.05	0.48	0.67	1.91	3.38	12%	37%	41%	48%	100.0%	100.0%	0.67	2.58	50.00%	0.34	1.29				
Seria	1.07	1.34	0.53	0.00	0.14	0.20	72%	79%	63%	55%	100.0%	100.0%	0.00	0.14	50.00%	0.00	0.07				
Other main fields - Land	0.28	0.40	0.13	0.01	0.02	0.06	69%	89%	54%	48%	100.0%	100.0%	0.01	0.03	50.00%	0.00	0.01				2
LLG	0.00	0.00	0.90	6.46	0.00	6.46	12%	100%	0	0	100.0%	100.0%	6.46	6.46	50.00%	3.23	3.23				14
Other small fields	11.43	17.60		0.00	2.46	3.95	0%	0%	21%	22%	100.0%	100.0%	0.00	2.46	50.00%	0.00	1.23				
Condensate produced in oil stream				-2.37	-4.71		0	33%	0	0	100.0%	100.0%	-2.37	-7.08	50.00%	-1.19	-3.54				
Total NGL (MMstb)	108.85	147.51	22.61	12.09	11.09 23.17	40.40	36%	76%	31%	43%	100.0%	100.0%	12.09	23.17	50.00%	6.04	11.59	6.04	11.59	13	26
Gas (Dry, sales gas volumes)																					
SW Ampa	347.664	402.402	200.792	60.252	32.747	128.327	61%	89%	67%	82%	92.3%	92.3%	55.64	85.88	50.00%	27.82	42.94			10	15
Other main fields - West	114.768	146.785	61.094	5.295	27.478	46.799	57%	71%	77%	74%	92.3%	92.3%	4.89	30.26	50.00%	2.44	15.13			4	24
Champion	34.257	49.269	12.308	4.085	3.014	12.791	49%	84%	45%	51%	92.3%	92.3%	3.77	6.56	50.00%	1.89	3.28			8	14
Champion-West	47.451	71.018	3.675	2.625	29.569	47.351	7%	18%	70%	72%	92.3%	92.3%	2.42	29.73	50.00%	1.21	14.86			5	57
Other main fields - East	62.622	88.222	6.675	9.217	27.392	52.707	11%	37%	54%	67%	92.3%	92.3%	8.51	33.81	50.00%	4.26	15.90			7	27
Seria	39.898	47.179	39.966	2.079	2.018	5.267	88%	95%	105%	96%	92.3%	92.3%	1.92	3.78	50.00%	0.96	1.89			11	22
Other main fields - Land	6.426	7.781	2.786	0.677	1.422	2.811	50%	71%	65%	72%	92.3%	92.3%	0.63	1.94	50.00%	0.31	0.97				12
LLG			-0.667	-4.792		-4.792	12%	100%	0	0	92.3%	92.3%	-4.42	-4.42	50.00%	-2.21	-2.21				
Other minor fields	30.665	48.916	0.017	0.000	14.507	23.001	0%	0%	47%	47%	92.3%	92.3%	0.00	13.40	50.00%	0.00	6.70				
Total Gas (10^9 sm3)	683.781	861.572	326.649	79.438	138.148 217.586	314.262	51%	75%	68%	74%	92.3%	92.3%	73.354	200.921	50.00%	36.677	100.461	36.667	100.461	8	21

Conversion factors used by BSP
1 stb = 1 m3
1scf = 1 sm3

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

Licence expiry dates:

Audit Trail: 100% volumes from 'Report no. 1.1' (Att.3) from CSS NFF 2002/001 (except condensate-as-oil volumes, for which no evidence was sighted)
Overall, good match

BSP-All2, ResvsTotl

31-5-2002, 12.10

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RJW01001257

Attachment 2.2

SEC RESERVES AUDIT - VOLUMES RECONCILIATION
BSP 1.1.2002

Proved Oil Reserves Changes 2001 (100%, 10^6 m3)

Field	Prov.Res. 1.1.2001	Revisons/ Reclasfns	Improved Recovery	Extens./ Discov's	Purchase in-place	Sales in-place	New Deverd Reserves	Product'n 2001	Prov.Res 1.1.2002	Shell Equity Share % 1.1.2001	Shell Equity Share % 2001 Prod	Shell Equity Share % 1.1.2002	Net Shell Equity 1.1.2001 (10^6 m3)	Net Shell Equity 1.1.2002 (10^6 m3)	Comments
Proved Developed Reserves															
SW Ampa		-0.71					3.80	2.54	12.57	50.00%	50.00%	50.00%	0.00	6.28	
Other main fields - West		2.21						0.90	5.35	50.00%	50.00%	50.00%	0.00	2.87	
Champion		0.52					2.52	3.25	24.05	50.00%	50.00%	50.00%	0.00	12.02	
Other main fields - East		1.01						2.43	7.50	50.00%	50.00%	50.00%	0.00	3.75	
Seria		2.74					0.50	0.79	5.80	50.00%	50.00%	50.00%	0.00	2.90	
Other main fields - Land		-0.03					0.30	0.32	1.61	50.00%	50.00%	50.00%	0.00	0.81	
Other small fields									0.00	50.00%	50.00%	50.00%	0.00	0.00	
Condensate produced in oil stream								0.12	2.37	50.00%	50.00%	50.00%	0.00	1.19	
Prov.Dev.Resvs (10^6 m3)	0.00	62.47 5.74					7.51	10.34	59.24	0	50.00%	50.00%	0.00	29.62	
Proved Undeveloped Reserves															
SW Ampa		1.57	1.78						9.19	50.00%		50.00%	0.00	4.59	
Other main fields - West		-1.13	0.52						5.79	50.00%		50.00%	0.00	2.89	
Champion		2.16	0.18						6.46	50.00%		50.00%	0.00	3.23	
Other main fields - East		0.90		4.18					25.82	50.00%		50.00%	0.00	12.91	Bugan appr + discov.
Seria		0.37		1.29					7.30	50.00%		50.00%	0.00	3.65	SMR appraisal
Other main fields - Land		-0.22							1.08	50.00%		50.00%	0.00	0.54	
Other small fields									1.71	50.00%		50.00%	0.00	0.85	
Condensate produced in oil stream									4.71	50.00%		50.00%	0.00	2.36	
Prov.Undev.Res (10^6 m3)	0.00	54.12 3.65	2.47	5.48	0.00	0.00			62.06	0		50.00%	0.00	31.03	

Net Group Equity	Prov.Res. 1.1.2001	Revisons/ Reclasfns	Improved Recovery	Extens./ Discov's	Purchase in-place	Sales in-place	New Deverd Reserves	Product'n 2001	Prov.Res 1.1.2002	
Proved Developed Reserves	0.00	2.87					3.55	5.17	29.62	1.25
Proved Total Reserves 10^6 m3	0.00	4.89	1.23	2.74	0.00	0.00		5.17	60.65	3.49

2000 Submission	Prov.Res. 1.1.2001	Revisons/ Reclasfns	Improved Recovery	Extens./ Discov's	Purchase in-place	Sales in-place	New Deverd Reserves	Product'n 2001	Prov.Res 1.1.2002	
Prov.Dev.Res	28.40	2.82					3.57	5.17	29.62	29.62
Prov.Tot'l Res 10^6 m3	57.22	4.63	1.23	2.74				5.17	60.65	60.65

Conversion factors used by BSP
1 m3 = 1 m3
1 sm3 = 1 sm3

Conversion factors used by SIEP:
1 slb = 0.159 m3
1 scf = 0.0283 sm3

Audit Trail: *Overall, fair match.*
1.1.2001 field volumes not available

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RJW01001258

SEC RESERVES AUDIT - VOLUMES RECONCILIATION
BSP 1.1.2002

Attachment 2.3

Proved NGL Reserves Changes 2001 (100%, 10^6 m3)

Field	Prov.Res. 1.1.2001	Revisons/ Reclasfns	Improved Recovery	Extens./ Discov's	Purchase in-place	Sales in-place	New Devel'd Reserves (Transf. Und. to Dev)	Producfn 2001	Prov.Res 1.1.2002	Shell Equity Share % 1.1.2001	Shell Equity Share % 2001 Prod	Shell Equity Share % 1.1.2002	Net Shell Equity 1.1.2001 (10^6 m3)	Net Shell Equity 1.1.2002 (10^6 m3)	Comments
Proved Developed Reserves															
SW Ampa		-0.04					0.08	0.32	6.46	50.00%	50.00%	50.00%	0.00	3.23	
Other main fields - West		-0.13						0.07	0.44	50.00%	50.00%	50.00%	0.00	0.22	
Champion								0.00	0.32	50.00%	50.00%	50.00%	0.00	0.16	
Champion-West		-0.02						-0.03	0.10	50.00%	50.00%	50.00%	0.00	0.05	
Other main fields - East		0.08						0.00	0.67	50.00%	50.00%	50.00%	0.00	0.34	
Seria		0.00						0.00	0.00	50.00%	50.00%	50.00%	0.00	0.00	
Other main fields - Land								0.01	0.01	50.00%	50.00%	50.00%	0.00	0.00	
LLG								0.45	6.46	50.00%	50.00%	50.00%	0.00	3.23	
Other small fields									0.00	50.00%	50.00%	50.00%	0.00	0.00	
Condensate produced in oil stream								-0.12	-2.37	50.00%	50.00%	50.00%	0.00	-1.19	
Prov.Dev Resvs (10^6 m3)	0.00	12.91 -0.11					0.08	0.91	12.09	0	50.00%	50.00%	0.00	6.04	
Proved Undeveloped Reserves															
SW Ampa		-0.21	0.05						4.59	50.00%		50.00%	0.00	2.30	
Other main fields - West		0.08							1.96	50.00%		50.00%	0.00	0.98	
Champion		-0.07							0.45	50.00%		50.00%	0.00	0.22	
Champion-West		-0.20							4.27	50.00%		50.00%	0.00	2.13	
Other main fields - East		0.06							1.91	50.00%		50.00%	0.00	0.96	
Seria		0.00							0.14	50.00%		50.00%	0.00	0.07	
Other main fields - Land		0.07							0.02	50.00%		50.00%	0.00	0.01	
LLG									0.00	50.00%		50.00%	0.00	0.00	
Other small fields									2.46	50.00%		50.00%	0.00	1.23	
Condensate produced in oil stream									-4.71	50.00%		50.00%	0.00	-2.36	
Prov.Undev.Res (10^6 m3)	0.00	11.04 -0.26	0.05	0.00	0.00	0.00			11.09	0		50.00%	0.00	5.54	
Net Group Equity															
Proved Developed Reserves	0.00	-0.05					0.04	0.45	6.04	-0.46					
Proved Total Reserves 10^6 m3	0.00	-0.18	0.02	0.00	0.00	0.00		0.45	11.59	-0.61					
2001 Submission															
Prov.Dev.Res	6.48	-0.05					0.03	0.42	6.04	6.04					
Prov.Tot'l Res 10^6 m3	12.14	-0.15	0.02					0.42	11.59	11.59					

Conversion factors used by BSP
1 m3 = 1 m3
1 sm3 = 1 sm3

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

Audit Trail: Fair match
1.1.2001 field volumes not available.

BSP-Att2. NGLResvChg

31-5-2002, 11:36

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RJW01001259

Attachment 2.4

SEC RESERVES AUDIT - VOLUMES RECONCILIATION
BSP 1.1.2002

Gas Reserves Changes 2001 (100%, 10^9 sm3) - Dry sales gas volumes

Field	Prov Res. 1.1.2001	Revisons/ Reclas'ns	Improved Recovery	Extens / Discov's	Purchase in place	Sales in-place	New Devel'd Reserves (Transf.	Product'n 2001	Prov.Res 1.1.2002	Shell Equity Share % 1.1.2001	Shell Equity Share % 2001 Prod	Shell Equity Share % 1.1.2002	Net Shell Equity 1.1.2001 (10^9 sm3)	Net Shell Equity 1.1.2002 (10^9 sm3)	GHV (Btu/scf)	Net Shell Equity 1.1.2001 (10^9 Nm3	Net Shell Equity 1.1.2002 (10^9 Nm3	Comments
Proved Developed Reserves																		
SW Amps		-2.473					3.172	6.340	60.252	45.65%	46 %	46.17%	0.000	27.819	1150	0.000	29.986	
Other main fields - West		0.395						1.352	5.295	46.65%	46 %	46.17%	0.000	2.445	1147	0.000	2.528	
Champion		0.654					0.376	0.504	4.085	46.65%	46.%	46.17%	0.000	1.886	1050	0.000	1.854	
Champion-West		1.569						0.561	2.625	45.65%	46.%	46.17%	0.000	1.212	1150	0.000	1.306	
Other main fields - East		2.563						1.344	9.217	46.65%	46.%	46.17%	0.000	4.256	1105	0.000	4.408	
Seria		0.957					0.179	0.183	2.079	46.65%	46 %	46.17%	0.000	0.960	1180	0.000	1.062	
Other main fields - Land		-0.093					0.133	0.178	0.677	46.65%	46 %	46.17%	0.000	0.313	1139	0.000	0.334	
LLG								-0.337	-4.792	45.65%	46.%	46.17%	0.000	-2.212	1139	0.000	-2.352	
Other minor fields									0.000	46.65%	46.%	46.17%	0.000	0.000	1139	0.000	0.000	
Prov.Dev.Resvs (10^9 sm3)	0.000	85.703 / 3.592					3.860	10.125	79.438	.%	46.%	46.17%	0.000	36.677	1141	0.000	39.215	
Proved Undeveloped Reserves																		
SW Amps		1.545	0.665						32.747	46.65%		46.17%	0.000	15.119	1150	0.000	16.297	
Other main fields - West		-1.143							27.478	46.55%		46.17%	0.000	12.687	1113	0.000	13.235	
Champion		0.468	0.375						3.014	46.85%		46.17%	0.000	1.392	1050	0.000	1.370	
Champion-West		2.278							29.569	46.65%		46.17%	0.000	13.652	1150	0.000	14.716	
Other main fields - East		-2.096		6.915					27.392	46.65%		46.17%	0.000	12.647	1150	0.000	13.532	Bugan appr + discov
Seria		0.234							2.019	46.85%		46.17%	0.000	0.932	1180	0.000	1.031	
Other main fields - Land		0.637							1.422	46.65%		46.17%	0.000	0.657	1139	0.000	0.701	
LLG									0.000	46.55%		46.17%	0.000	0.000	1139	0.000	0.000	
Other minor fields									14.507	46.65%		46.17%	0.000	6.698	1139	0.000	7.151	
Tot'l Prov Res (10^9 sm3)	0.000	130.193 / 2.144	1.040	6.915	0.000	0.000			136.148	.%		46.17%	0.000	53.784	1140	0.000	58.133	

	Prov Res. 1.1.2001	Revisons/ Reclas'ns	Improved Recovery	Extens / Discov's	Purchase in place	Sales in-place	New Devel'd Reserves	Product'n 2001	Prov.Res 1.1.2002	
Net Group Equity Prov.Dev. Res / Prov Tot'l Res 10^9 sm3	0.000 / 0.000	1.658 / 2.648	0.480	3.193	0.000	0.000	1.782	4.658 / 4.658	36.677 / 100.461	-1.217 / 1.664
2001 Submission Prov.Dev.Res / Prov.Tot'l Res 10^9 sm3	37.929 / 99.899	1.685 / 1.547	0.480	3.257			1.785	4.722 / 4.722	36.667 / 100.461	36.677 / 100.461
Net Group Equity Prov.Dev. Res / Prov Tot'l Res 10^9 Nm3 @ 9500 kCal/Nm3	0.000 / 0.000	1.721 / 2.785	0.501	3.441	0.000	0.000	1.906	4.974 / 4.974	39.218 / 107.351	-1.346 / 1.754
2001 Submission Prov.Dev.Res / Prov.Tot'l Res 10^9 Nm3 @ 9500 kCal/Nm3	39.374 / 106.230	2.240 / 2.730	0.517	3.509			1.923	5.110 / 5.110	38.427 / 107.876	38.427 / 107.876

Conversion factors used by BSP
1 m3 = 1 m3
1 sm3 = 1 sm3
1 sm3 = 0.948 Nm3
and 1 sm3 = 1.0738097 Nm3@9500
(i.e. avge GHV = 10761 kcal/Nm3
or 10201 kcal/sm3
or 45.05 MJ/Nm3
or 42.71 MJ/sm3
or 1146 Btu/scf
of avg GHV of 1140 Btu/scf from above field data.

Conversion factors used by SIEP:
1 stb = 0.159 m3
1 scf = 0.0283 sm3
1 sm3 = 0.948 Nm3
and 1 sm3 = 0.948 Nm3 @ 9500
(if GHV = 9500 kcal/Nm3
or 9006 kcal/sm3
or 39.77 MJ/Nm3
or 37.71 MJ/sm3
or 1011 Btu/scf

Audit Trail:

Slight mis-match in production and end-year Nm3 volumes.
Mis-match in revisions probably due to different method of calculation.

BSP-... GasResvChg

31-5-2002, 11:35

FOIA Confidential Treatment Requested

RJW01001260

COMPANY: BRUNEI SHELL PETROLEUM Sdn Bhd AREA / FIELD: ALL FIELDS

Dimensions (100% field figures as at 1.1.2002): Average Group share: .%

1.1.2002 Proved Oil Reserves		10^6 m3	(Group share	10^6 m3)
1.1.2002 Proved Developed Oil Reserves		10^6 m3	(Group share	10^6 m3)
2000 Oil Production		10^6 m3	(Group share	10^6 m3)
	0	10^3 m3/d	(Group share	10^3 m3/d)
1.1.2002 Proved Gas Reserves		10^9 sm3	(Group share	10^9 sm3)
1.1.2002 Proved Developed Gas Reserves		10^9 sm3	(Group share	10^9 sm3)
2000 Gas Production		10^9 sm3	(Group share	10^9 sm3)
	0	10^6 sm3/d	(Group share	10^6 sm3/d)
Number of fields in area				
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 coverage is almost universal over the main producing area in the shallow offshore. For new seismic surveys the OBC (seabottom cables) technique is used, particularly to avoid acquisition problems around the densely spaced platforms. An important area where such new 3D acquisition is now planned is the Champion Main field, where the poor quality seismic mapping todate (caused by seabottom reefs) has hindered advancement of reservoir simulation and performance definition.
1.02	Are seismic processing and interpretation state-of-the-art?	+	PSDM is applied (where the data are available) to obtain better definition of fault planes. A major advance in interpretation quality has been obtained by the introduction of the Petrel geological modelling package which allows a rapid and complete integration of the seismic data with the dense well data and with structural interpretations.
1.03	Is well data coverage adequate?	+	Most of the fields are mature and well data is more than adequate. Adequate appraisal well data is available in undeveloped fields.
1.04	Has a 'proved area' been defined (lowest known fluid contact, no major/sealing faults) and is it realistic?	O	BSP have historically been one of the strongest proponents of probabilistic reserves estimation and volumetric estimates are still done probabilistically. Any incomplete hydrocarbon column penetrations are therefore addressed probabilistically.
1.05	Is this 'proved area' supported by seismic amplitude studies and/or reservoir analogues in the area?	N.A.	Good DHI amplitude data are available in some cases, eg the deeper offshore.
1.06	Are petrophysical well data quality and quantity adequate?	+	Log selection in new wells is state-of-the-art and fully adequate. Log interpretation seems historically to have been somewhat conservative (too severe cut-offs?), resulting in STOIIPs that are too low in comparison with present performance. A major breakthrough has been the availability of through-tubing C-O tools (RST Schlumberger, RPM Becker-Atlas) by which moving fluid levels in reservoirs can be traced much more accurately and on a much wider scale than before.
1.07	Is reservoir producibility for undeveloped reserves supported by production tests or other evidence?	+	Appraisal wells in undeveloped fields are rarely production tested. Fully adequate data are obtained from sampling tools (MDT). Very good data are also obtained through modern NMR logs. Finally, there is ample analogue data in the area.
1.08	Are there proper volumetric estimates?	+	Static reservoir models (CPS-3, now being replaced by Petrel) are generally used as the method of making volumetric estimates upon first discovery. Petrel geological models are prepared following well drilling (if not already before) and volumetric estimates are obtained from these. Refined features like porosity maps, saturation-height curves etc can thus be included in an early stage. Historical HIIP estimates tend in some cases to be too conservative, probably caused by too conservative petrophysical interpretations (cut-offs).
1.09	Are representative PVT data available and have they been properly accounted for in the volumetric estimate?	+	PVT samples are obtained and interpreted through the proper tools
1.10	Are static models available / adequate?	+	Historically, GEOCAP models were often used to replace the initial CPS-3 models prior to major field studies. More recently, Petrel models have become the standard. Coverage is not complete yet - areas with higher development priority are being addressed first.

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

1.11	Are dynamic models available / adequate?	O	Dynamic model coverage is not complete (some 70%) over reservoirs with proved and expectation reserves. Coverage is complete for areas under study, i.e. those areas where further development is seen as likely and as having priority. Models are almost invariably downloaded from geological models.
1.12	Are history matches available / adequate?	+	History matches are complicated by both water and gas breakthrough in these fields (many primary gas caps) and by pressure communication with neighbouring reservoirs through partially sealing faults. Improved geological modelling has improved the quality of these matches.
1.13	Are the recovery factors for proved reserves realistic?	+	Recovery factors are generally based on simulation studies or on production performance data. Gas recoveries take account of installed and future compression.
1.14	Are developed reserves based on proper NFA (No Further Activity) forecasts?	+	Yes
1.15	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; Most behind-pipe volumes are not counted as developed until they are properly completed.
1.16	Have development projects been defined for undeveloped reserves or can they be defined?	O	The large majority of undeveloped reserves are covered by well targets (some notional or even undetermined and in need of further study) and forecasts. A small amount (around 9% of expectation undeveloped, much less of proved), sometimes referred to as 'legacy reserves') is not covered by targets and/or forecasts yet.
1.17	Are there auditable development project plans with costs, benefits and economics?	+	Projects with forecasts are included in the BSP Business Plan and have project costs (some preliminary) and economics associated with them.
1.18	Are the projects technically mature or is further data gathering necessary?	O	Projects are ranked and their development sequence is set accordingly. Those with later target dates tend to require further study work before they can be matured. Their associated recoveries tend to be based on earlier, preliminary study work or on analogues.
1.19	Are improved recovery estimates based on a successful pilot or analogue or are they otherwise supportable?	+	A successful gas injection project (within-well, from deeper gas horizons) is in operation in SW Ampa. Water injection is in operation on some areas in Champion and expansion of this into neighbouring areas is being considered. For any undeveloped reserves, no pilots are deemed necessary.
1.20	Have the projects successfully passed a VAR3 review or are they otherwise ready for application for funding?	O	New field developments are subjected to VAR reviews, but in-field projects are generally too small for these. The projects with lower priority tend to require more study work before they can be matured.
1.21	Are the projects firmly planned to go ahead - are there any potential show stoppers?	O	In principle there are no show stoppers. Projects will go ahead in due course as and when they can be made technically and economically robust.
2	COMMERCIAL MATURITY		
2.01	Are the projects economically viable (meeting Group Scr. Crit. over range of possible future scenarios / low case reserves)?	O	Most projects pass economic screening criteria. Those that at this stage do not, are felt to become economically viable with further work and updated cost estimating
2.02	Have forecasts been cut off when rates become uneconomic?	+	Yes; minimum economic rates are determined by field.
2.03	Have the latest Group Screening / Reference Criteria been used?	+	Yes
2.04	Are assumed prices and costs RT (or justified if not)?	+	Yes
2.05	Is export infrastructure (pipelines, terminals etc) available or, if not, is it firmly planned and fully included in the economics?	+	Yes, any new infrastructure required (flow lines, well jackets etc) are included in the cost estimates and economics
2.06	Is project financing available or can it reasonably be expected to be available?	+	Yes
2.07	Are developed reserves actually in production?	+	Yes; A regular review is held of 'shut-in potential' and it is rare for wells with developed reserves to remain shut in for a long time.
2.08	Have all proved gas reserves been contracted to sales?	O	The BLNG plant is the main customer for BSP gas. Additional, smaller gas sales streams are for local domestic use and for power generation. The BLNG contract was extended in 1992 on the basis of then available proved gas reserves. This base, being somewhat conservative, has since then grown and there is now a surplus of some 1.5 Tcf proved gas and some 5 Tcf of expectation volumes.

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

2.09	If not, can they reasonably be expected to be sold in existing markets and through existing / firmly planned facilities?	+	There is no doubt that any surplus gas will be able to be contracted to the existing supply outlets. Additional local outlet possibilities are being pursued.
2.10	If neither, is there a firm commitment (eg FID) that supports the assumption and maturing of a future market?	N.A.	
3	REASONABLE CERTAINTY		
3.01	Is the uncertainty range of volumetric parameters and STOIIP estimates adequate?	O	Probabilistic volumetric estimates tend to become irrelevant for mature fields since they cannot capture reservoir performance data properly. Volumetric Proved HIIPs therefore tend to become too low.
3.02	Is the uncertainty range of developed recovery adequate?	X	Expectation developed recoveries are determined from performance decline extrapolations in those cases where there is no active history matched simulation model. The standard method of determining proved developed volumes is through fitting a symmetrical triangular distribution around the expectation estimates with the lower end point halfway between cumulative production and expectation value. This invariably results in a 'proved' developed reserves volume that is some 70-78% of expectation. This is highly artificial and not in accordance with current Group guidelines.
3.03	Is the uncertainty range of undeveloped recovery adequate?	X	Historically, total reservoir recoveries were determined from volumetrics with recovery factors derived from analogues or from preliminary simulation studies. A significant portion of total recoveries in BSP are still based on these estimates. Developed reserves were based on performance extrapolations and undeveloped reserves were the difference between total and developed reserves. With time, developed reserves grew and in many cases overtook the original total proved (sometimes even expectation) estimates. Hesitation was applied in updating these negative reserves because reservoir crossflow was a common phenomenon and any such updates required a regional study. Lack of resources and priority caused a continuous deferment of such studies in many cases. Negative reserves continued in many reservoirs (particularly in the Champion Main field), until concerted efforts in 2000/2001 brought back the total of such reserves to more reasonable, but still low proportions. The proper way of determining undeveloped reserves is through a simulation study whereby these reserves are calculated from identified activities, with well targets. Developed reserves can be determined from the same (history matched) simulation model or from well performance extrapolations. With progressing field development, both developed and undeveloped reserves are updated in the light of reservoir performance, new drilled wells, changed future well targets etc. Total reserves are always the sum of both developed and undeveloped reserves and are therefore no longer fixed 'target' recoveries that do not (or only poorly) become updated with progressing field life. This is now the norm in the large majority of Group OUs and in BSP this is also the approach in the field areas with simulation models. In the original approach followed by BSP, proved undeveloped reserves were simply the difference between proved total and proved developed reserves. In the new approach, whereby undeveloped reserves are determined independently, the method of determining proved volumes is less well defined. The impression is that in many cases, a conservative approach is still followed. Group guidelines clearly state that in such cases a number of simulator scenarios should be run, with a reasonable P85 scenario picked at first, which can gradually become updated by a scenario that grows closer to or equal to expectation values with increasing field maturity.
3.04	Have market / production constraint uncertainties been taken into account?	N.A.	There are production constraints but these are taken account of in field planning and present no uncertainties.
3.05	What is ratio of field(s) cum.prod. / expectation total recovery?		Quite variable, from 0 (undeveloped fields) to 92% (Seria field). BSP average is 70% for oil and 50% for gas.
3.06	Can the field(s) be considered mature?		Approximately half is mature to very mature.
3.07	Are proved (developed and total) reserves consistent with 'proved areas'?	O	Proved areas are not adhered to rigidly, although partial penetrations etc are taken account of in the probabilistic estimates, see also 1.04.

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

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RJW01001263

3.08	Are proved reserves for fields (or other entities used for asset depreciation) added together arithmetically?	+	Yes
3.09	Are proved reserves within fields (or within entities used for asset depreciation) added together probabilistically?	+	Asset depreciation is done at a field level. Hence, guidelines would allow probabilistic addition of reservoirs within a field. This is not done at present. In view of the impractical aspects and intransparency of results (dependency!) this is supported.
3.10	Is any assumed dependency in probabilistic addition appropriate?	N.A.	
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?	+	Current production licences expire as follows: Onshore and 'first offshore' (eg SWA): 22 Dec 2003, Second offshore area (eg FA): 31 Dec 2007, Third offshore area (rest): 31 Dec 2026. There is a right to extend these licences by two successive periods of 15 years, at terms and conditions to be agreed upon. Discussions on the terms and conditions for the onshore and first offshore licences are currently in progress. There are no indications that an acceptable set of new terms and conditions cannot be agreed with the Government and BSP management are fully confident that a licence extension will be obtained.
4.02	Are the forecasts required to demonstrate the above condition consistent with the firm Base Case presented in the latest *Business Plan?*	+	Yes, all reserves for which forecasts are available are included in the Business Plan.
4.03	Is the hydrocarbon Equity share calculated properly (regular production contracts)?	+	BSP is a 50% owned Shell company, with the remainder being held by the Brunei government. All licences are 100% BSP owned, BSP has full title to the produced oil and gas and Group share is thus uniformly 50%
4.04	Is the hydrocarbon PSC entitlement share (net cost oil + profit oil only) calculated properly?.	N.A.	
4.05	Is the hydrocarbon 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.	
4.06	Are royalties that are (formally or customarily) paid in cash included in reserves?	+	Royalties (between 8 and 12.5%, dependent on area) are paid in cash and are thus not subtracted from reserves.
4.07	Are royalties paid in kind excluded from reserves?	N.A.	
4.08	Are volumes delivered free of charge as fees in kind (e.g. for infrastructure use by third parties) included in reserves? Similarly, are volumes received as fees in kind excluded from reserves?	N.A.	
4.09	Has historic Group under-or overlift (e.g. compared with other co-venturers) been accounted for?	N.A.	
4.10	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?	+	Gas production and re-injection volumes involved in the intra-well gas re-injection project in SW-Ampa are properly recorded , subtracted from the source reservoirs as production and added (as negative production) to the target reservoirs. Gas ultimate recoveries in the latter are from time to time re-evaluated, taking account of possible future losses due to residual gas saturations in gas flooded oil zones.
4.11	Have gas volumes paid for by the buyer but not yet produced and sold ('take-or-pay' gas) been properly maintained in reserves?	N.A.	
4.12	Have separate submissions been made for Equity , Entitlement and Purchase Right volumes?	N.A.	
5	**AUDIT TRAILS**		
5.01	Are proved and proved developed reserves estimates up-to date?	O	Developed reserves are reviewed annually in many, but not all reservoirs. Undeveloped reserves in the 70% (approx.) of reserves that are covered by 'active' simulation models are reviewed regularly as well. Undeveloped reserves in the remaining 30% are generally derived from older total recovery estimates and are thus less up-to-date.
5.02	Can reported net Group equity reserves be reconciled with individual field reserves estimates?	O	Yes, with the exception of the condensate-produced as oil (see 6.02)
5.03	Can reserves changes be reconciled with individual field changes?	+	Largely, yes, with the exception of the condensate-produced as oil (see 6.02)
5.04	Are reserve changes reported in the appropriate categories?	+	Yes
5.05	Is there a document in place describing the OU's reserves reporting procedures?	+	Various documents are in place (eg a DUR review procedure guide). The annual reserves review process is kicked off by a note by the reserves coordinator, setting out the requirements, target dates and responsibilities.

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

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5.06	Are technical reports available describing reasons and justifications for new reserves estimates in sufficient detail?	+	All reserves changes are documented in reports or notes, depending on their complexity. Full field (or part-field) reviews and FDPs are documented comprehensively.
5.07	Are reports numbered / indexed properly and is there a central library where copies are kept?	+	Yes
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?	+	Yes, an annual report 'End-year Resource Volumes for External and Internal reporting' is issued, together with a summary of results.
5.09	Are electronic data bases containing both historic submissions' data and current reserves data in place and accessible?	+	Yes, a comprehensive RISRES data base is in place
5.10	Do these data bases also contain references to detailed reports?	+	Yes (a very rare feature among OUs)
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?	+	Oil, NGL and gas are reported by stream. The condensate stream (consisting of gas well liquids or 'CHPS' and slugcatcher liquids plus other liquids from the BLNG plant, called 'LLG') is sold and exported separately. Somewhat exceptionally, BSP REs keep track of condensate production from oil wells in oil+associated gas reservoirs, even though these liquids are produced through the oil stream. This condensate production is added to the condensate balance in these reservoirs and reflected in individual field condensate volumes. Reported NGL reserves are however based on produced streams, i.e. NGLs are only those condensates produced and sold separately. Reported oil reserves similarly include condensate produced in the oil stream. The main justification for this extra accounting (not in the EPPROMS system) is to obtain a correct reflection of the condensate in reservoirs with very large gas caps. The LLG stream has been included in the sales and reserves accounting since 2000. The reason for their inclusion was that BSP have effective title to these liquids (with the BLNG ga
6.03	Are own use, fuel, losses etc excluded?	+	Own use, fuel and losses are deducted as a bottom line correction from annual production and from reserves before the annual Group reserves submission. The percentage is calculated annually (around 8%).
6.04	Are gas GHVs measured properly for sales gas conditions and accounted for in reserves submissions?	+	Yes, gas samples are taken regularly and evaluated with the proper tools.
6.05	Are annual Oil+NGL production volumes in reserves submissions consistent with Upstream sales volumes reported into the Finance (Ceres) system? (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).	+	Yes, close cooperation is observed between Finance accounts and the reserves coordinator.
6.06	Are annual gas production volumes in reserves submissions consistent with Upstream Gas production available for Sales (GpafS) volumes reported into the Finance (Ceres) system? (Ceres line 9130).	+	Yes, close cooperation is observed between Finance accounts and the reserves coordinator.
6.07	Are the Financial and Reserves accounting of production / sales fully consistent with each other also in cases like royalties, fees-in-kind, underlift/overlift, gas re-injection/UGS, take-or-pay gas?	+	Yes (only relevant for annual production)
6.08	Are the net Shell share reserves reported properly and consistently with Finance reporting (100% for consolidated Shell companies, with minority reserves reported separately, or actual percentage if less than 50%)?	N.A.	BSP is a 50%, i.e. an associate company and accounts and reserves are reported on a net Group share basis.
6.09	Are reported proved developed reserves consistent with those used for asset depreciation in Group Accounts?	+	Yes, Proved developed reserves and Unit of Production Factors are advised annually by the reserves coordinator to Finance accounts.
7	OVERALL		
7.01	If Group guidelines should not or not completely have been followed, are results still reasonable / overstated / understated?	O	Proved reserves are likely to be somewhat understated due to the conservative procedures still in place
7.02	Do the reported proved and proved developed reserves estimates give a reasonably accurate reflection of shareholder value?	O	Whilst expectation estimates appear quite reasonable, the proved estimates are too conservative in comparison with Group guidelines

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		Weight	Score (0-100%)
1	TECHNICAL MATURITY	25%	82%
2	COMMERCIAL MATURITY	16%	81%
3	REASONABLE CERTAINTY	14%	37%
4	GROUP SHARE CALCULATION	9%	100%
5	AUDIT TRAILS	16%	90%
6	CONSISTENCY WITH FINANCIAL REPORTING	11%	100%
7	OVERALL OPINION	8%	50%
	TOTAL SCORE	100%	78%

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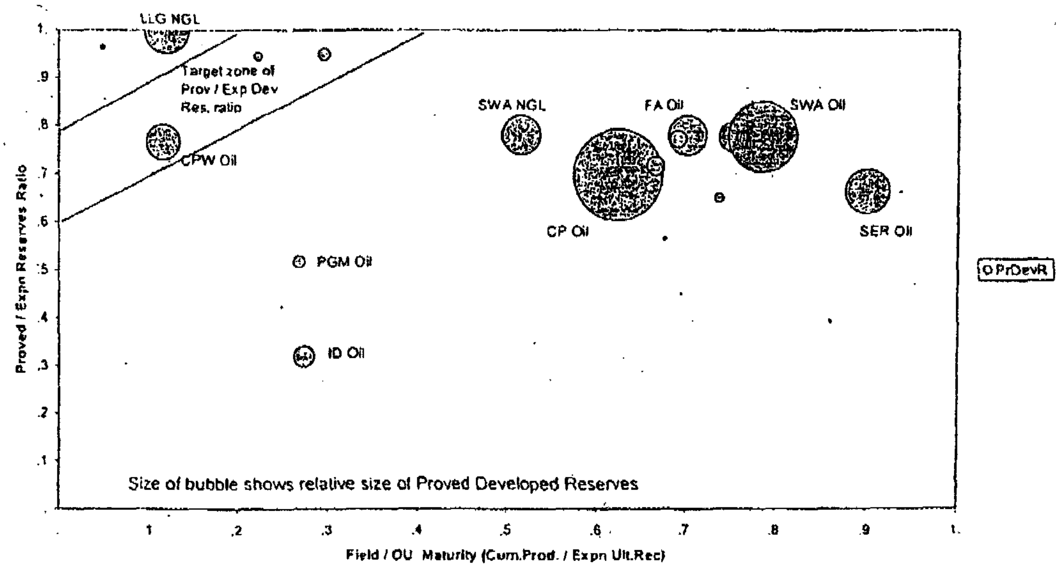
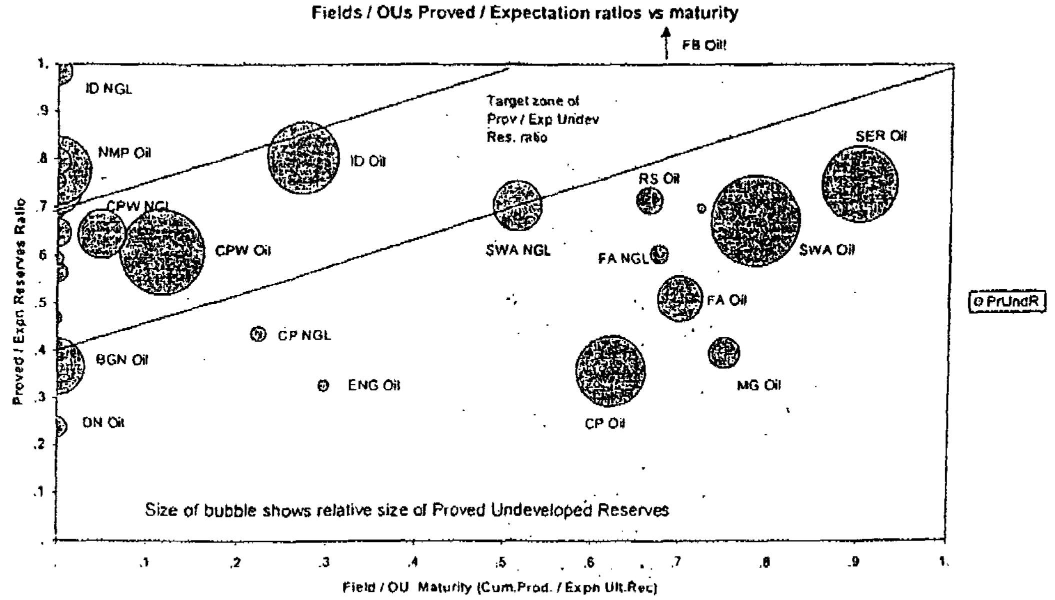
Attachment 4.1

Proved / Expectation Oil+NGL Reserves versus field maturity

1.1.2002 BSP DEVELOPED OIL+NGL RESERVES
Fields / OUs Proved / Expectation ratios vs maturity



1.1.2002 BSP UNDEVELOPED OIL+NGL RESERVES
Fields / OUs Proved / Expectation ratios vs maturity



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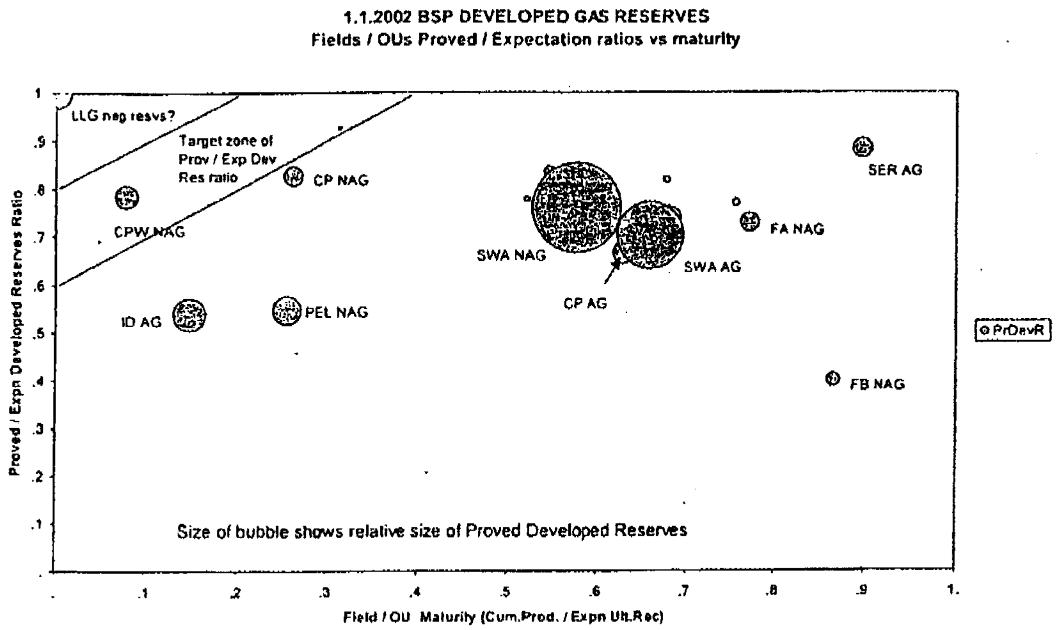
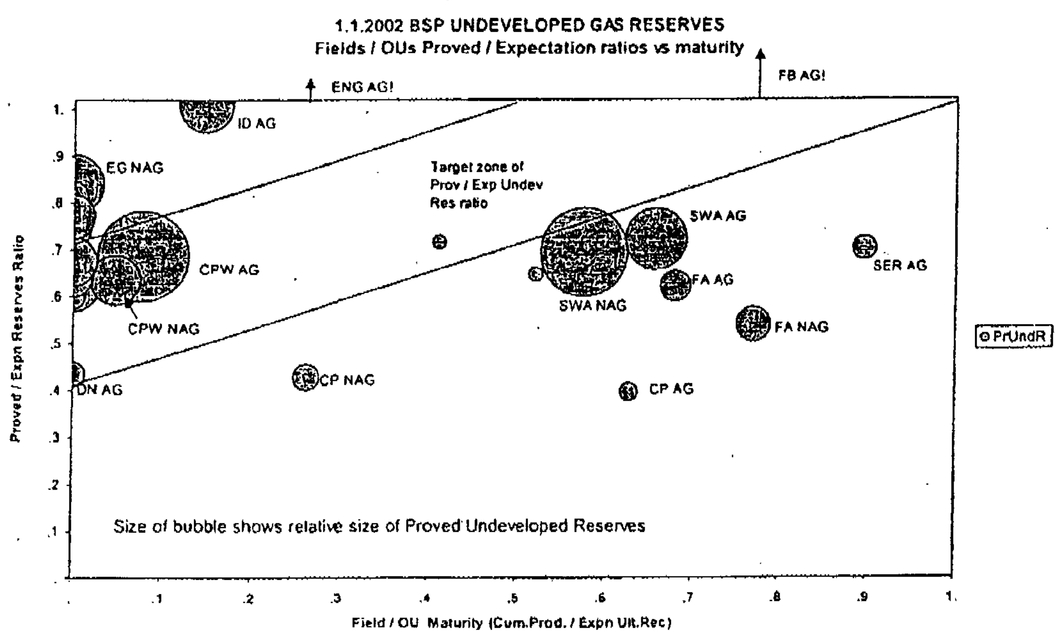
Attachment 4.2

Proved / Expectation Gas Reserves versus field maturity





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