

NOTES:


To conclude , here again is the global EP strategy I showed you at the beginning. This morning we covered all the elements of the strategy. and gave you specific examples of how we are delivering now and will deliver in the future. Let me summarise the key points

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*Summary*

Excellent track record	Sustained value growth
<ul style="list-style-type: none"><li>• Diverse portfolio Robust through commodity cycle 50% ROACE @ \$26/bbl</li><li>• Operational excellence \$2.1 bln cost improvement RIL embedded</li><li>• Capital discipline \$11 bln opportunities ranked .... the best \$8 bln selected</li><li>• Technology Expandable tubulars, Smart wells, Under balanced drilling, 4D seismic</li></ul>	<ul style="list-style-type: none"><li>• Diverse portfolio Production growth 3% a.a.i. 15% ROACE normalised</li><li>• Operational excellence Unit cost leadership Accelerate, increase global coverage</li><li>• Capital discipline \$7-8 bln .... Identified short / long term opportunities</li><li>• Technology Monetise further opportunities e.g. Floating LNG</li></ul>

 Royal Dutch / Shell Group of Companies

**NOTES:**

We have an excellent track record, yes we have revised our volume growth forecast., but remain firmly focused on sustained value growth.

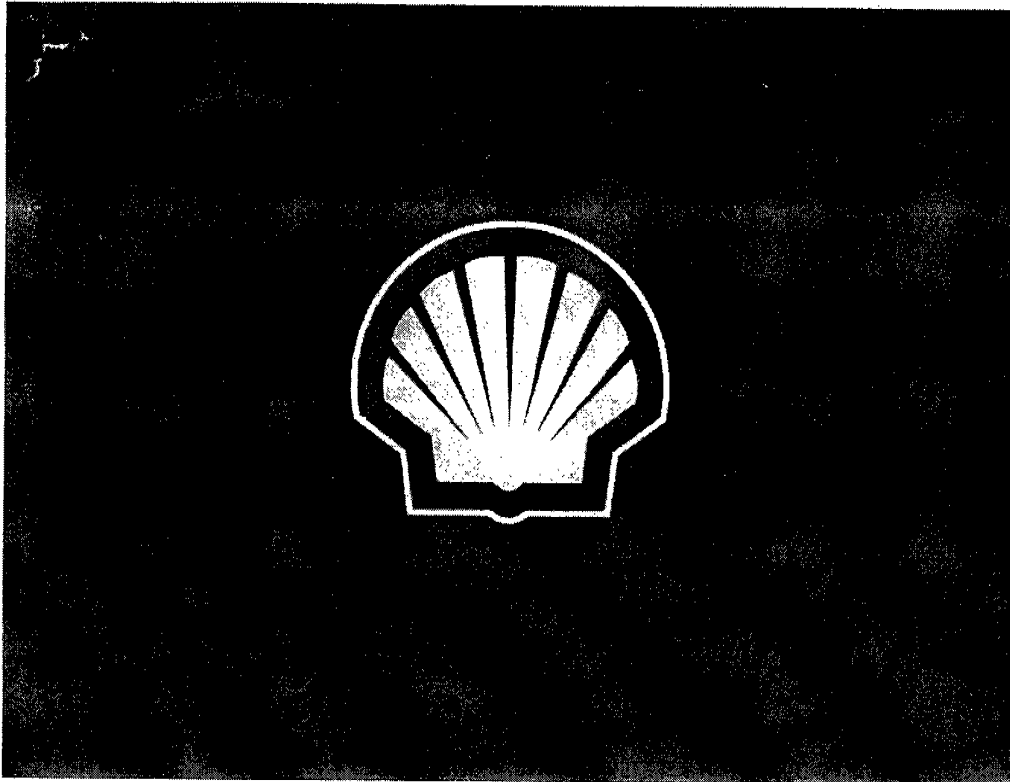
We will build on our diverse portfolio.

We will maintain operational excellence and capital discipline.

We will exploit our technology advantage.

Bottom line, we are committed to a 3% growth target and normalised ROACE of 15% over the long term.

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NOTES:

Ladies and gentlemen, thank you very much.  
Now we would be delighted to take your  
questions.

Would you please use a microphone and  
clearly state name and company for the  
benefit of our listeners joining us via  
teleconference or webcast.

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**From:** McKay, Aidan A SIEP-EPB-P  
**To:** Sprague, Bob RM SI-SEPI-EPN  
**CC:**  
**BCC:**  
**Sent Date:** 2001-12-06 13:28:32.000  
**Received Date:** 2001-12-06 13:28:32.000  
**Subject:** FW: Production Forecast & Tragic World Events  
**Attachments:**

Bob,  
I accept its important to be nice, but just maybe its also important not to be plain stupid too..... I dont like plain stupid.

(And yes I have all the investor relations presentation speeches, you & everybody else ever made since about 1991).  
My book is going to be factual ! It might not sell, but I'll feel better doing it!.

Aidan

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

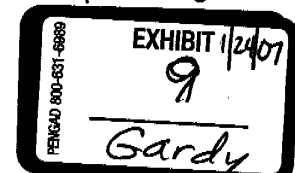
**From:** McKay, Aidan A SIEP-EPB-P  
**Sent:** 06 December 2001 14:15  
**To:** Gardy, Dominique D SIEP-EPF  
**Cc:** Brass, Lorin LL SIEP-EPB  
**Subject:** RE: Production Forecast & Tragic World Events

Dominique,  
My other response did not shake you. Well you asked so here is what I think.....  
I'm not politically shrewd, so I offer no expertise in decide if your going to get caught out for telling IR stories (in a transparent world) and what the likely punishments will be!  
It may depends if you feel we will do a rock in the pond acquisition in the next 24 months or not.....Cutlass is marginally big enough for this...but has min upside. I desire that we tell a message close to the expectation reality or historical reality.

If I was Walter I would use this tragic event to introduce a little more conservatism (buying flexibility) into our story around both production growth (stating that it will be slower at eg 2 % to 3 % ) and also that reserves replacement (potentially still hitting 100 % at the end but not putting it in a target framework). They will simply take everything in that framework for granted, and it will buy us a bit of time but then they will punish us if we fail on any one of them!

You, need to tone down the v/g on production growth to 2-3 % and also RRR of 100 %..... My Walter statement for the charts would be :

"As you can see financial efficiency is well in hand and that production growth and reserves are in really good shape both technically and operationally, but we can still improve a great



deal and we have plans to do so. ....we are not complacence at all !

The impact of the tragic September 11th events on the world are still evolving in terms of both their economic impact on hydrocarbon demand and on the impact various governments around the world who are resource owners. It is still to early to say conclusively but we do see a slight slowdown, we remain flexible and focussed equally on profitability (our ROACE) and our longer term prospects beyond the next 5 years. We have looked at the rate of growth we are comfortable with and have decided to make adjustments to the engineers estimates and we feel we are comfortable with the 2-3 % growth rate on average over the next five years are very comfortable with our portfolio, but we know well that some of these giant projects (which will be legacy assets of the future) will take time.

I repeat this is not a change.....my predecessors have been reminding you for the last 30 years (including on the devt of the Brent platforms I know so well) that these big new projects in new areas whether its Kashagan or Sakhalin or DW Nigeria or Angola will take time to bring them onstream! As you are all aware, we are not alone in this phenomenon. We are making every effort to ensure this "maturing of new business" goes as fast as possible, but in reality it is not always completely within our control and to an extent we are dependent on political will and gas market demand in some of these projects. This will have an effect to on the rate at which we can "book" proven reserves....

Therefore we continue to aspire to replace 100 % of our reserves but post 11th September we feel a prudent level for planning would be 80 % for the next 3 years growing to 100 % if our efforts in MRH and in gas markets materialise at the pace we expect and are comfortable with. But I want to say this one more time..... we are going to deliver 15 % ROACE at mid cycle prices.....and higher ROACEes above this price point....punto,..... irrespective of minor delays on these big projects which are partially outside my control!"

This approach buys us time and flexibility, and reduces the "obvious doggy factor" in our story just a little. If you don't go this route you run as ever the risk that Raymond or Longwell will correctly say....

"Hell we have more projects than anybody else, more growth than anybody else, you can forecast with a crystal ball for all we care, Exxon is comfortable with 2-3 % growth as we have been since we took Mobil and we will not promise 100 % replacement every year! We have every intention of being the best company at replacing reserves in the business and have the enviable track record over the last decade without methodology games, but a suggestion of 100 % RRR is plain nuts! Look at the facts over the last ten years on ROACE, absolute earnings, production volumes, portfolio spread, RRR devt opportunities & exploration performance. I'll suggest as Rawl did & Garvin did before me ....you analysts have got start looking at historical results and actuals and spend less time listening to crap at meetings like these!"

Regards  
Aidan

PS Why has nobody else in EP read Bob Spragues IR stories made 95 & 96, without spin doctors or other stuff. It is really good learning if you are remotely fact driven.  
[He made the same points as Exxon.....and avoided all this nonesense as far as I can

tell.....! ]

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

From: Gardy, Dominique D SIEP-EPF

Sent: 05 December 2001 07:23

To: Bell, John J SIEP-EPB-P; Gardy, Dominique D SIEP-EPF; McKay, Aidan A SIEP-EPB-P; Powell, Ceri CM SIEP-EPB-B; Thorkildsen, Alf A SIEP-EPF

Cc: Brass, Lorin LL SIEP-EPB

Subject: RE: Production forecast

Aidan,

Good start.....but what about the answer?

> -----Original Message-----

> From: McKay, Aidan A.

> Sent: 04 December 2001 15:14

> To: Gardy, D.; Bell, John J.; Powell, Ceri C.M.; Thorkildsen, Alf A.

> Cc: Brass, Lorin L.L.

> Subject: RE: Production forecast

>

>

> Dominique,

> Only just got to this one. Great question....

>

> Q. Will a real world tragic event in any way influence the

> stories we are telling investors.....?

> A. Depends on the degree of truth in the stories being told.....?

>

> Remember Pinocchio....!

>

> Aidan

>

> -----Original Message-----

> From: Gardy, Dominique D SIEP-EPF

> Sent: 04 December 2001 08:53

> To: Bell, John J SIEP-EPB-P; McKay, Aidan A SIEP-EPB-P;

> Powell, Ceri CM

> SIEP-EPB-B; Thorkildsen, Alf A SIEP-EPF

> Cc: Brass, Lorin LL SIEP-EPB; Gardy, Dominique D SIEP-EPF

> Subject: Production forecast

>

>

> All,

>

> We said at the EP September presentation to analysts that our 3 %

> production growth forecast did not reflect the potential

> impact of post

- > 11.09.
- >
- > What would be our answer to the 2 questions:
- > \*How do you see the impact of the post 11.09 on the world environment
- > and the EP business?
- > \*Since you have not changed your production forecast it means
- > that post
- > 11.09 should not impact your business:why?,
- >
- > To prepare for these answers a list of what could be impacted in our
- > business would be useful to have.
- >
- > AidanJohn,Ceri:can you work out answers to this with
- > Alf.....Would like
- > to get something by Wednesday closing.
- >
- > Thanks.
- >
- >
- >
- >
- > Dominique Gardy
- > CFO Exploration and Production
- > Shell International Exploration and Production B.V.
- > Carel van Bylandtlaan 30, Postbus 663, 2501 CR The Hague, The
- > Netherlands
- >
- > Tel: +31 070 3777499 7499Email:
- > Internet: <http://www.shell.com/eandp-en>
- >
- >

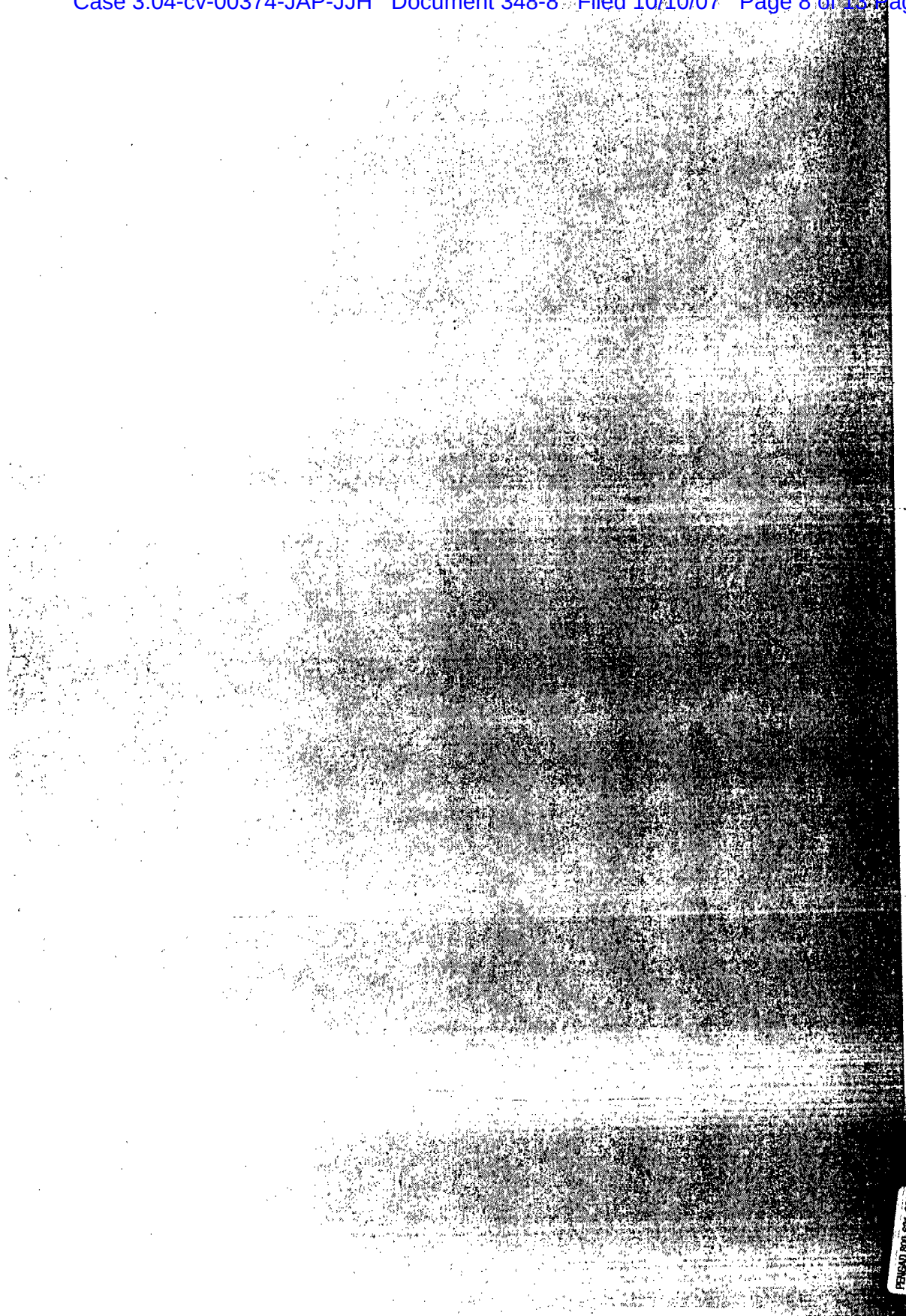


EXHIBIT 10  
10  
Gandy

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**Excom Meeting**  
**4 February 2002**  
**Note for Discussion**  
**Proved Reserves Replacement 2001**

**Achievements**

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

- ◆ The total barrel of oil equivalent proved hydrocarbon reserves replacement ratio (HC-RRR) in 2001 is 74%. (2000 69%). The three years average proved HC-RRR is 67% (2000 102%, excluding AOSP) and the three years average proved developed HC-RRR is 79% (down from 109% in 2000)
- ◆ The numbers above include a 6% contribution resulting from the Sakhalin consolidation.
- ◆ For 2001 the target RRR in the EP scorecard was 79% excluding A&D, or an addition of 1120 mln boe at target production. The actual addition was 710 mln boe, or 52% RRR at actual production, well below the scorecard target (range 50-110%). Performance by Region (DRAFT) is as follows:

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

- ◆ The Options Proved Reserves target for 2001 consisted of Salym and NA Gas
- ◆ In EPN the negative revisions from Canada and Aera and the overall disappointing results from the UK were balanced by upward revisions in the Netherlands and Denmark and large first bookings in the USA
- ◆ In EPM results are suffering mainly from Gisco, Egypt (Obaiyed revised FDP) and PDO where new bookings are not likely to occur in the medium term.
- ◆ In EPA China (no booking in Changbei) and Brunei (legacy debookings) were outweighed by positive bookings in Malaysia and Woodside
- ◆ In EPG SNEPCO (Bonga SW) and Brazil (despite 6 discoveries) could not book reserves, only to be compensated by gas additions in SPDC and revisions in Venezuela

**Issues**

- ◆ SPDC, PDO and Abu Dhabi, representing 18% of EP's production, cannot book reserves for the foreseeable future as it is doubtful that the already booked reserves can be produced within the remaining license period. The reserves exposure in these OUs is over 1 bln bbls, and sensitive to OPEC constraint.
- ◆ Major new projects are very slow to book (particular gas related and MRH) and much of the 2002 RRR depends on it (Kudu, NLNG 4/5, Whale).

Attachment: External Auditors Report on end 2001 Proved Reserves

Excom Note 4-2-2002 Proved Res Repl 01.doc 1

31/01/02

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NOTE – 30 January 2002

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From: Anton A. Barendregt Group Reserves Auditor, SIEP EPB-GRA  
 To: Lorin Brass Director, EP Business Development, SIEP EPB  
 Copy: Walter van de Vijver EP Chief Executive Officer, SIEP  
 Dominique Gardy Chief Finance Officer, SIEP EPF  
 Excom Members SIEP EPA, EPB-X, EPG, EPM, EPN, EPT, EP-HR  
 John Bell Vice Pres. Strategy, Planning, Portfolio and Economics, SIEP EPB-P  
 Han van Delden Partner, KPMG Accountants NV  
 Stephen L. Johnson PriceWaterhouseCoopers

REVIEW OF GROUP END-2001 PROVED OIL AND GAS RESERVES SUMMARY PREPARATION

In accordance with prescribed US FASB accounting principles, SIEP staff have prepared a summary of Group equity proved and proved developed oil and gas reserves for the year 2001. The summary (Att. 3) forms part of the supplementary information that will be presented in the 2001 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 Group 'Petroleum Resource Volumes Guidelines' which in turn are based on (but not identical to) the FASB definitions. Shell Canada's submissions are subject to their own procedures and reviews.

The end-2001 Group share Proved Reserves is summarised in the following table. The figures include the Canadian oil sands reserves (reportable as mining reserves) and the minority reserves in some consolidated companies (together 150 mln m3oe\*).

Oil mln m3 Gas bln m3	1.1.2001 Proved Tot'l	2001 Prod'n	1.1.2002 Proved Tot'l	Repl.Ratio (RR) Tot'l	1.1.2001 Proved Dev'd	1.1.2002 Proved Dev'd	Rep. Ratio Dev'd
Oil+NGL	1646	129	1601	65%	711	689	83%
Gas	1593	93	1580	86%	737	729	91%
Total Oil Equivalent *	3189	219	3132	74%	1425	1394	86%

\* 1 mln m3 oil equivalent (1 m3oe) = 1.03 bln sm3 of gas

I have reviewed the process of preparing the above summary of proved and proved developed oil and gas reserves in as far as these relate to companies outside Canada. This review included, where possible, a verification of the appropriateness of major reserves changes. The most significant conclusions are as follows:

A first time booking for the Bonga SW field (SNEPCO Nigeria) was not accepted by EPB-P staff because the proposed volumes (21 mln m3oe) were technically not mature and did not fulfil present reserves guidelines. This view is fully supported. Further reserves additions in Angola block 18 (where marginal reserves were booked for the first time last year) were also disallowed by EPB-P because the project is economically still marginal, while gas disposal could become a show stopper. This view is also supported. Without any material change in this latter project, reserves may need to be de-booked next year.

Group reserves guidelines have been reviewed against industry practice during 1998 and this has resulted in a 200 mln m3oe increase in Group share Proved reserves in mature fields in recent years. However, recent clarifications of FASB reserves guidelines by the US Security and Exchange Commission (SEC) have shown that current Group reserves practice regarding the first-time booking of Proved reserves in new fields is in some cases too lenient. The Group guidelines should be reviewed. First time bookings should be aligned closer with SEC guidance and industry practice and they should be allowed only for firm projects with technical maturity and full economic viability.

The widespread use of reserves targets in score cards affecting variable pay is seen to affect the objectivity of staff in some OUs when proposing reserves additions. Reserves coordination staff in EPB-P have been alert to this and have successfully met the challenges with which they were faced. However, a shift in score card emphasis from reserves booking to successfully meeting project milestones is recommended.

Awareness of Group and SEC reserves booking guidelines was seen to be less than desirable at senior levels in OUs and in support functions in the centre (RBDs, SDS, SEPTAR). This should be improved by issuing appropriate high level guideline summaries, organisation of workshops etc.

After some corrections, very good correspondence was obtained between annual production volumes as reported through the separate Finance (Ceres) and SIEP reserves systems. Both of these are reported (separately) in the Group annual report.

During 2001 I made Reserves Audit visits to a total of seven Group OUs. Audit opinions on these varied between 'satisfactory' and 'good'. As far as observed, most audit recommendations appear to have been followed in this year's submissions.

The overall finding from the audit visits and from the end-year review in SIEP is that the SIEP statements fairly represent the Group entitlements to Proved Reserves at the end of 2001. There is a possibility of a minor overstatement of Group Proved reserves in some fields where historically booked reserves are not fully in line with recent SEC guidance. However, this overstatement is likely to be offset by reserves in areas where current Proved reserves are probably too conservative (e.g. Brunei). The 2001 changes in the Proved Reserves can be fully reconciled from the individual OU submissions.

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



A.A. Barendregt

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Attachments 1-7

- Attachment 1 Main Observations End-2001 Reserves
- Attachment 2 Significant Reserves Changes
- Attachment 3 Group Proved Reserves Summaries
- Attachment 4 Production Reconciliation Ceres vs. Reserves Submissions
- Attachment 5 Proved Reserves Maturity – by OU
- Attachment 6 Main Observations 2001 Reserves Audits
- Attachment 7 Reserves Audit Plan 2002

## REVIEW OF GROUP END-2001 PROVED OIL AND GAS RESERVES SUMMARY PREPARATION

## MAIN OBSERVATIONS

## 1. Reserves Summary

The 1.1.2002 Group Share Proved Reserves can be summarised as follows:

Oil mln m3 Gas bin m3	1.1.2001 Proved Tot'l	2001 Prod'n	1.1.2002 Proved Tot'l	Repl.Ratio Total	1.1.2001 Proved Dev'd	1.1.2002 Proved Dev'd	Repl.Ratio Dev'd
Oil+NGL	1646	129	1601	65%	711	689	83%
Gas	1593	93	1580	86%	737	729	91%
Total Oil Equivalent*	3189	219	3132	74%	1425	1394	86%
Canada Oil sands	95		95				
Minority reserves	48		55				
Net Group m3oe	3046		2982				

\* 1 mln m3oe = 1 mln m3 oil equivalent = 1.03 bin sm3 of gas

The Replacement Ratios mentioned above are with respect to total Group share reserves, i.e. including the Canadian oil sands and Minority reserves.

A full overview of end-2001 Proved and Proved Developed Reserves is presented in Attachment 3.1-2.

## 2. Significant reserves changes

Significant reserves changes during 2001 were as follows:

Acquisition of assets from Fletcher Challenge Energy led to Group share reserves increases in New Zealand (+35 mln m3oe) and Brunei (+5 mln m3oe). In the USA, the Pinedale (Rocky Mountain) gas acquisition added 10 mln m3oe. This was partly offset by a net divestment in Pakistan (-3 mln m3oe) and by a revision of the Oman Gisco gas processing agreement (-16 mln m3oe).

Technical reviews led to reserves additions in the Netherlands (+23 mln m3oe), in the USA (+24 mln m3oe), in Denmark (+11 mln m3oe) and in Sakhalin (+3 mln m3oe), whilst reductions were seen in New Zealand (-11 mln m3oe), Canada (-9 mln m3oe) and Egypt (-5 mln m3oe). New fields were booked in the USA (+10 mln m3oe) and Brunei (+5 mln m3oe). New field developments added developed reserves in the USA (+26 mln m3oe), Australia (+21 mln m3oe), SPDC (+17 mln m3oe of gas and NGL), Philippines (+13 mln m3oe) and Iran (+6 mln m3oe).

The reserves increase of +23 mln m3oe in the Netherlands was booked in the Groningen field. Field performance over the last ten years had allowed gradual increases in Proved developed reserves, but total Proved reserves were maintained unchanged. Booked undeveloped reserves (e.g. as a result of very low pressure compression) became thus indefensibly low and this has now been rectified.

Further maturing of gas utilisation and development in SPDC (Nigeria) is allowing gradual increases in Proved developed and total gas reserves. Proved condensate (NGL) reserves do also increase, but these have to be largely offset by corresponding reductions in Proved oil reserves because of the overall constraint in offtake rate and licence duration (see also below).

A tabulation of these and some other changes is given in Attachment 2.

## 3. Shell Canada's Athabasca Oil Sands

The 95 mln m3 oil volumes from Shell Canada's Athabasca Oil Sands Project (AOSP) are not strictly oil and gas reserves as defined by the US Securities and Exchange Commission (SEC). Hence, they will be excluded from the Group's submission of Proved oil and gas reserves to the SEC. They are also mentioned separately in the Group Annual Report.

## 4. Angola block 18

A total of five discoveries were made in the Angola block 18 area during 1999 and 2000. Preliminary economics showed development to be marginal to unattractive and the 1.1.2001 booking of Proved reserves could only be justified through a notional small scale creaming project in the two largest accumulations. One further appraisal well and sidetrack during 2001 allowed in principle an increase in these reserves by an enlargement of the 'proved area'. However, a VAR3 review in December 2001 showed project economics still to be 'marginal at best', while the continued lack of a viable gas disposal solution was seen as a potential show stopper. Hence, a further increase in reserves was not accepted by EPB-P and the possibility was recognised that, without further changes, the project reserves may have to be de-booked next year. This view is also supported.

## 5. SNEPCO fields

A significant increase in Proved reserves (+19 mln m3 oil, +2 bin sm3 gas) was proposed by SNEPCO (Nigeria) through a first time booking of reserves in their new discovered Bonga SW field (one discovery well in 2001). After a review of the available evidence and following advice from the Group Reserves Auditor and SNEPCO's Reserves Manager, the reserves coordination function in SIEP EPB-P has declined to accept this proposal. Considerations were that the project is still immature (failed a VAR2 in Sept 2001) and is not properly defined (no dynamic simulation studies, well targets, forecasts or cost estimates), while its development is uncertain (other fields could be developed in its stead). In addition,

the seismic response is generally of insufficient quality to support a large enough area as (SEC defined) 'proved area' on which to base Proved reserves. This view is fully supported.

It was furthermore noted that SNEPCO, upon seeing the Bonga SW reserves addition not accepted, withdrew a negative correction to Bonga Main reserves (-2 mln sm<sup>3</sup> oil, -2 bln sm<sup>3</sup> gas), emanating from a 2001 study which showed these volumes to be non-productive within the prevailing PSC licence. In addition, the technical basis for the reserves in the Erha field, at its first time booking in 1999, was said by SNEPCO staff to be of lower quality than that for Bonga SW. A SEC reserves audit is planned for 2003. Advancement of this audit is being considered.

#### 6. Production licence duration constraints

Externally reported Proved and Proved Developed Reserves need to be confined to those volumes producible within the duration of current production licences, or their extensions if there is a right to extend. With progressing maturity, a number of OUs are seeing their possibilities for increasing Proved Reserves severely curtailed because any increase in field volumes cannot be produced within (generally constrained) future offtake profiles and licence durations. With ongoing annual production, these OUs will in fact see their remaining Proved reserves decline in future years until either offtake rates can be increased or until licence extensions have been agreed with Authorities. OUs most affected by this are SPDC (Nigeria), Shell Abu Dhabi and PDO (Oman) and, to a lesser extent, Malaysia, Syria, Denmark and Venezuela. At present, some 300 mln m<sup>3</sup>oe Proved field volumes (10% of the Group Proved Reserves portfolio) are reported by OUs as being non-productive within existing licences.

For a proper estimation of Proved reserves (which have to fulfil the criterion of 'reasonable certainty') it is important that OUs faced with the above constraints make realistic assumptions regarding their future production profiles. The selected build-up and plateau levels should preferably be in line with base case Business Plan assumptions and with profiles used for the SEC 'Standardized Measure' submission. In addition, post-plateau tail-end profiles should be technically defensible. It is noted that PDO still maintain a 850 kb/d plateau in their forecast, in spite of recent problems in maintaining that production level. SPDC seem to have included LNG trains 4&5 in their condensate forecast, while the associated gas reserves have not yet been included in gas reserves because of lack of market definition.

At present, the Group reserves guidelines do not provide any guidance about what assumptions to take for future forecasts in these cases. This should be rectified. Following that, the assumed forecasts should be reviewed with the OUs concerned.

During this year's reserves submission and accumulation process, the critical information about OU assumed production profiles could in some cases only be made available to the auditor after repeated requests and in a late stage, thus leaving insufficient time for a comprehensive review. This should be remedied in future submissions by ensuring that full life cycle production profiles are requested from and made available by OUs in an early stage.

#### 7. Group Guidelines – mature fields

Group Guidelines for externally reported Proved reserves (Ref. 3) have historically been somewhat different from Proved reserves definitions as applied by the oil industry (Refs. 1, 2). The reason for this was that the Group have long based their Proved reserves estimates on probabilistic methods, using the 85% confidence level criterion. This was found to lead to too conservative estimates in mature fields (in comparison with industry practice) and the guidelines were therefore changed for these fields in 1998. The updated guidelines prescribe that, in mature fields, externally reported Proved and Proved Developed Reserves should be brought closer to, or made equal to Expectation Reserves. Significant Group share Proved Reserves additions (+200 mln m<sup>3</sup>oe) have thus been booked by many OUs between 1998 and 2000.

A method of visualising the relative positions of OUs is through plotting the ratio between Proved and Expectation reserves versus average OU maturity. The latter is defined as cumulative production as a fraction of total life cycle Expectation Ultimate Recovery. Plots showing the OU positions for Developed and Undeveloped Oil+NGL and Gas reserves are presented in Attachments 5.1-5.2. From this it can be seen that most mature OUs show Proved / Expectation ratios close to 1 for their developed and undeveloped reserves. Most notable exceptions are:

- BSP, where Proved reserves have to be agreed with the Government (a reserves audit is planned for 2002),
- SEPCo, where undeveloped proved reserves are depressed because of low SEC proved areas in Pinedale, Brutus and Mars
- BEB, who tend to maintain unrealistically high Expectation reserves (much of it to be SFR),
- Expro UK, where uncertainties in undeveloped reserves are large in Schiehallion and some tight gas fields.

#### 8. Group Guidelines – first time booking of new fields

Group guidelines for fields at the other end of the maturity spectrum, i.e. new discoveries, have historically been less well defined. Probabilistic P85 estimates were generally used (which for sparsely appraised fields tended to be larger than the SEC guidelines allowed), but there was often no clarity as to the appropriate moment when first-time booking of reserves could be made. This situation improved somewhat in 1993 when the requirement for technical and commercial maturity was first introduced in the Group reserves guidelines. This was later strengthened by adding the requirement that large or frontier projects should 'in principle' first pass a VAR review (preferably VAR3 – Concept Selection) before any reserves could be booked. Large projects of a downstream nature (e.g. LNG plants), which would not be subjected to a VAR review, would 'in principle' need to wait until FID.

The experience since the introduction of these new guidelines has been that the large established OUs (SEPCo, Shell UK Expro, NAM) tended to follow these guidelines, generally deferring first time bookings for new fields until at least a proper Development Plan had been prepared and commercial viability had been assured. The approach followed by smaller OUs and SDS has in some cases been more aggressive, even to the point where technically and/or commercially immature projects, some of those not even passing VAR2 or VAR3 reviews, were put forward as reserves. The main drive behind this appears to be a lack of awareness or indeed a disregard for the guidelines, coupled with a strong drive from score card reserves targets.