9

17 Producing, Closed a. What about not producing yet?

18 Copy of spreadsheet?

19 Conflict: rapid reserves maturation vs long-term FID need is an inherent discrepancy that needs to be resolved.

20 Check P85 ~~/~~ Exp'n vs Cump/UR

21 Introduce new criteria:
Proved/Expn Developed and P, E Undev versus
Proved ≡ LKH
CI = pre-production / post production
Economics OK?

22 Project executed/executing: relevant?

23 Criterion < 2 MMbls: could bring lower if we combine several reservoirs?

24 Give recommendations regarding 2004 audit?

Tentative Conclusions

1. Portfolio is far less mature than originally thought / appeared in 1999 (but guidelines have changed also?) | LACK OF INTEGRATED PLAN?
   Rem reserves kept largely unchanged (ie URs inflated?) without real justification by individual field estimates

2. Very good start with inventorisation of reserves / reservoir blocks
   Interesting insight into (lack of) maturity of portfolio

3. Only some 20% of Proved reserves portfolio passes all ~~[illegible]~~ maturity criteria. However, not all of these needed for Proved res (eg 3D seismic)
   Need to re-screen with appropriate partial set of criteria.

4. Need to integrate all criteria: maturity (reservoir, field, project) with those of size and BP status.

5. [illegible]
   for action, e.g. additional data gathering, study + FDP etc; weed out "unknown" projects etc

6. Dev'd R/P = 11 yrs - OK
   Undev'd R/P = 22 yrs - already large?
   Seeking to increase latter may ~~be~~ not be realistic: FIDs on many of these projects may not be until 2011+

"Are getting mature on the creaming curve"

11

(7) REs (oil) generally look favourable.
What is reason for large amount of small
(< 2 MMbl) reservoir blocks? RF?, depletion
size?

(8) Condensate should be accounted for separately
with increasing definition in gas reserves.

(9) Gas forecast / reserves approach seems
largely sound.

(10) "Flares out 2008" seems most immediate
problem to address – No oil or gas
reserves post 2008 if not yet addressed?

(11) Spot market gas is an issue – to be
resolved by updated guidelines.
Approach as in US/ ~~Land~~ Europe land
market ?, ie when we install facs (LNG pll
we can book?

(12) ~~Stuff~~ Proved Res seem overstated
- Can accept maintaining on the books if
action to mature is clearly there
- Do not increase UR (ie reduce reserves)
until portfolio mature – depending on

Check previous points as well?

X Copy of spreadsheet?

Tom v Leenen EPG
Mark Horner DVDir ~~[illegible]~~ SPDC
Chris Finlayson SPDC
Steve Ratcliffe BusDir SPDC
John Hoppe ~~Uitgeest~~ SPDC
Cees van ~~Houten~~ Vijlenhoed CFD

John Pay

Barendregt, Anton AA SIEP-EPB-P

From: Pay, John JR SIEP-EPB-P
Sent: vrijdag 30 mei 2003 12:14
To: Barendregt, Anton AA SIEP-EPB-P
Subject: RE: SPDC Proved Reserves Booking Guidelines

John,
My (preliminary) scribbles/comments
Anton

Anton

this is still not the final draft (which I have not yet seen), but it is close to being final.

The minimum objective (from my point of view) for the rest of the year is to ensure that the base case is safeguarded: namely that oil debookings are limited to an extent by which they offset gas bookings, so that net reserves changes for SPDC in 2003 are close to zero.

My ideal objective would be that SPDC is able to conduct the necessary technical assurance work between now and the end of the year that will enable them to avoid any net debooking of oil reserves, so that there would be no change to oil, an addition to gas and an overall significant contribution in boe terms from SPDC. I have asked them to seriously consider what it would take to achieve this - if the reserves were booked in the past, surely it must be possible to find a way of underpinning them today so that they do not have to be written off... It would be a genuine shame if we were to write off reserves in the area that is the most rich resource base in our portfolio!

Oil Gas Reserves in Nigeria-m...

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-----Original Message-----
From: Barendregt, Anton AA SIEP-EPB-P
Sent: 30 May 2003 12:05
To: Pay, John JR SIEP-EPB-P
Subject: RE: SPDC Proved Reserves Booking Guidelines

John,

Happy to discuss next Tuesday (3rd June). In your message you refer to 'John Hoppe's proposal' - is there a mailable doument that I could have a look at? I agree with you that in setting new rules we should be as reasonable and as objective as possible, leaving no room for subjective interpretation.

Anton

-----Original Message-----
From: Pay, John JR SIEP-EPB-P
Sent: woensdag 28 mei 2003 18:51
To: Barendregt, Anton AA SIEP-EPB-P
Subject: FW: SPDC Proved Reserves Booking Guidelines

Anton

we are strugling to come up with practical guidelines for controlling the proved reserves additions process in Nigeria. I have just had (yet another) discussion with various people on this topic, which as usual seems to have resolved nothing. I would appreciate the opportunity to discuss this again with you next time you are in the office. Meanwhile, please find attached my latest plea for a pragmatic and defensible solution, on which

DEPOSITION EXHIBIT
Barendregt
#24 2/21/07

FOIA Confidential Treatment Requested

RJW00920777

your comments would be most welcome,

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-----Original Message-----
From: Pay, John JR SIEP-EPB-P
Sent: 28 May 2003 18:44
To: Davis, Phil P SEPI-EPG
Cc: Blaha, Michael FMJ SEPI-EPM; Ten Brink, Martin J SEPI-EPG
Subject: SPDC Proved Reserves Booking Guidelines

Phil

following our discussion, I think it helpful to put the following statements down on paper as a means of helping to shape the final guidelines:

1. There is not absolute certainty on how the SEC rules must be interpreted - we have to put our own rules in place and our managers have to be comfortable that they honour the spirit and intent of the SEC rules.

2. The key test is "reasonable certainty" that our disclosed proved reserves will indeed be produced. We must be able to stand up in front of a third party and defend to them that the reserves we have booked reflect a scenario that is certain, within reason, to materialize.

3. This requires that a minimum level of documentary evidence is in place to defend the assertion that reasonable certainty exists. We (in Shell) have translated this into the minimum requirement for technical and commercial project maturity, as documented in our guidelines. The only significant change to these criteria that is currently being contemplated is to link reserves booking for major projects and new field developments to FID, as opposed to VAR 3.

4. In Nigeria, the situation is made more difficult by the fact that the available discovered resources are vastly more than can be accommodated within a reasonable time frame under current OPEC constraints. This is a very unusual situation, requiring some form of "reasonable certainty" test to be applied to the entire Nigeria portfolio. Here I find it difficult to be specific, and depending on one's attitude one can be more or less bullish while still claiming "reasonable certainty" to exist. I suggest that the current ExCom would be unwilling to over stretch proved reserves bookings (but we should test them on this) and therefore some form of blocker needs to be put in place to regulate the pace with which new reserves are added to the portfolio.

5. John Hoppe's suggestion of distinguishing between (1) incremental developments on existing producing assets and (2) new developments requiring significant new infrastructure provides a sensible means of effecting control which maps relatively easily onto the existing guidelines for the rest of the Group. The former would require a relatively lower level of technical definition (VAR 3) than the latter (VAR 4 / FID). This in principle prevents a whole slug of new reserves being booked on the one hand, while allowing the study effort to be varied to bring new reserves in as and when required. if we do have a VARs at all?

6. Allied to this, we need sensible criteria for assessing the commercial maturity of individual projects and of the portfolio as a whole. I think it reasonable to book proved gas reserves in relation to LNG contracts that we have in place and to cover a plausible outlook for domestic gas sales, as suggested by John Hoppe. For oil, there is a whole range of things we might consider. Certainyl individual projects need to be shown to be commercially attractive. However, in addition we need to show that entire portfolio reflects a plausible view of what can be considered certain, within reason, to materialize. I think it would be reasonable to assume that today's level of investment will continue indefinitely and this might be one factor that is taken into consideration in scheduling new developments. Another factor is clearly a plausible outlook for SCiN's share of OPEC quota. However, I feel that we must be careful about how far we extend this into the future. Is it reasonable to book reserves today in relation to developments that will take FID in 2010? Yes, I think so. In 2020? Probably not. In 2030? Almost certainly not. However, I don't know where the cut-off should be and at the end of the day it will be up to our managers (who sign off on the reserves disclosure) to determine where their level of comfort is. Perhaps an approach would be as follows: Hm

That's what worries me

Establish a reasonably certain (i.e relatively conservative) forecast for production and expenditure. Using this as a constraint, schedule each technically mature development and establish when FID would be. (as per BP?)

* Provided we can demonstrate that the technical reserves are there? ** As per BP?

RJW00920778

Allow bookings only for proved reserves where FID will occur within the lifetime of the existing licence.

Such an approach is arbitrary, but it has the advantages that: But allow developed reserves to continue beyond that

a) genuine growth in production can be used as the justification for accelerating FIDs and bringing in more reserves

b) licence extension, when secured, would allow substantial additional reserves to be booked.

c) it would be difficult for a 3rd party to argue that we were being unreasonable.

Other approaches are possible: we could arbitrarily limit reserves to today's production rate times a fixed number of years. This allows us to add reserves every year, and throw more in when we get a genuine and sustainable increase in offtake rate. Does not instill much discipline on details per field?

7. Whatever we do, it must be demonstrably plausible. I think John Hoppe's suggested approach provides enough flexibility at the individual project level that we can then use his suggested criteria as a means of restating reserves bookings, yet in a controlled and reasonable manner.

8. The limiting case, whatever we do, would be our base plan going forward: we should not book proved reserves that exceed what will be delivered by our documented base business plan. To do otherwise would be to clearly violate the principle of reasonable certainty. ✓

Happy to discuss further, but let's try to land on an approach that we can all feel comfortable with. If that means we have to take two or more alternative suggestions to our managers and let them decide, so be it.

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What about SIEP's RRR management process (to avoid major swings from year to year?

Oil & Gas Reserves in Nigeria

Summary

1. Introduction

A moratorium on additional SPDC reserves bookings was introduced in 1999 given concerns that it may not be possible to deliver the ambitious growth programme and produce the current proven reserves volume prior to licence expiry in November 2019. The moratorium was extended to gas in 2001, as domestic gas sales were falling significantly below the forecasts upon which reserves were based. Consequently, it was decided not to book additional reserves when FID was taken on NLNG Trains 4/5 in March 2002, pending an overall review of gas reserves.

Reserves were one of the "Five Critical Issues" identified in November 2002, for which detailed action plans were developed and are now being implemented. This reflected concerns that reserves may be over booked if production and development activity continue to be constrained by factors such as OPEC quota, NNPC funding constraints or executive capacityor if growth in the domestic gas market failed to materialise. Considerable upside was also identified if the licence constraint could be removed, given SPDC's massive resource base and continuing technical success rate in exploration. This note details the main findings of the work carried out under the Critical Issue Plan.

The work concluded that SPDC could book reserves after licence renewal. This was unexpected and was therefore extensively tested, both internally and externally. The conclusions were confirmed and hence this constraint has been dropped in the reserves estimates presented in this note.

The principal remaining constraint on reserves was found to be the technical and commercial maturity of SPDC's underlying resource base. As the interpretation of SEC guidelines[2] has been tightened over the last few years, a detailed review of the resource base was undertaken to determine the volume that currently qualifies as proven reserves. A fundamental review of domestic gas demand was also undertaken as part of a wider EP/GP Gas Strategy Review in order to re-assess gas reserves.

2. Reserves Post Licence Renewal

For external reporting, Group share of reserves (Proved, Proved Developed) is limited to future production within the existing licence or contract period, including any agreed extensions as may be covered by documented evidence.

Recent work has confirmed that both SPDC and SNEPCO have a legal right to licence extensions. In the case of SPDC:

- The Government is obliged to grant a licence renewal under the Petroleum Act, so long as the lease holder has complied with their licence obligations. These obligations are in line with normal business practices and SPDC is therefore unlikely to be found in default.
- Licence renewals have been granted to all JV partners in the past. A relatively low fixed charge has also now been specified for licence renewal (in the past a payment was negotiated).
- Legal opinions were obtained from Group Legal, Nigerian Counsel and Cravaths Swain and Moore . All confirmed a solid legal basis for the lease holder's right to licence extensions.
- A "defence" letter outlining the position was approved by EPG, EPF, and LSEP and has been accepted by KPMG.

In the case of SNEPCO:

- Licence rights under the PSC are vested in NNPC as licence holder, who are obliged under the terms of the PSC to apply for renewals.
- The renewal conditions are as covered by the Petroleum Act, and so essentially identical to those for the SPDC licences.
- If the renewal is granted, either party to the PSC may exercise the option (provided for in the PSC) to extend the PSC term in line with the licence renewal.

3. Application of SEC Guidelines in Nigeria

The SEC Guidelines, as documented in the Group's Petroleum Resource Volume Guidelines, are applied fully in SPDC and SNEPCO. There are no "grey" areas allowing for interpretation. The key elements are as follows:

- Reserves, being future hydrocarbon product available for sale, are tied to **projects**. The aggregated production forecast must be consistent with the reported reserves. This also holds for the 'proved forecast', as defined by the aggregated **'reasonably certain'** amount of hydrocarbons forecast to be produced by the appropriate development/production scenario, duly respecting license duration and overall constraints (e.g. quota).
- For a resource volume to pass from scope for recovery (SFR) to reserves (for internal as well as external reporting) the associated project(s) have to reach both **technical** and **commercial maturity.** This is deemed to be the case when:
  - The Shell shareholder assurance processes have been satisfactorily passed both technically and commercially and no significant issues that could preclude proceeding with the project exist.

- Support to fund the project is reasonably certain (e.g. the project survives the business planning processes of Capital Allocation) and the project forms (or is reasonably certain to form) part of the relevant business plan.
- It should be emphasized that if no Proved reserves can be assigned to a project, then the related petroleum resource volume should be retained as SFR, i.e. there should be no Expectation reserves reported without Proved reserves.

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

➢ For project reserves to enter into the Proved category, **Independent** review and challenge is required (as a control) to preserve integrity of the external disclosures. For major projects such review is routinely executed through the Group's Value Assurance Review process. Note that concept selection (VAR3) must at least have been completed. Applied to all SPDC projects? now FID

Historically, SPDC's reserves have been based on probabilistic estimates of volumes initially-in-place combined with ranges of recovery factors. Projects were only defined, as part of the Field Development Planning process, after many of the reserves volumes were already booked. In recent years Ultimate Recovery Change Reports (URCRs) used to document reserves bookings, have included a description of a "Notional Development Plan" that outlines how the volumes could be produced, but not how they will be produced. Consequently there is now a need to reconcile the booked reserves numbers with the volumes covered by projects in the Business Plan.

Strictly speaking, booked reserves that are not covered by a specific project should be reclassified as SFR. However, it is recognised that project recoveries may change as a project progresses to execution, and new projects may be defined as a result of ongoing work in the Asset Teams. Reclassification should only take place as the result of a thorough re-evaluation of the reserves volumes documented in a URCR. In between such revisions, any variances between the booked ARPR volumes and the Business Plan project volumes should be tracked and reported annually as part of the Hydrocarbon Master Plan. Each variance should be accompanied by a resource maturation plan explaining how and when it will be resolved, either by maturing new development activities, or by re-evaluation and reclassification.

Development projects within SPDC are defined to incorporate activities only from within a single field, but may deliver production from several reservoirs and blocks. Production forecasts associated with each project must be broken down into separate forecasts for each reservoir-block to enable accounting at a level where the correct physical reservoir behaviour can be shown to apply. Proved forecasts are derived from the expectation forecasts by discounting by the ratio between the low ultimate recovery (P85 estimate) and the expectation ultimate recovery of the respective reservoir-blocks. In recent years, all proved developed volumes (i.e. those related to the NFA forecasts) have been taken equal to the expectation forecasts (i.e. undiscounted). Clarification in the latest Group Guidelines recommends that this should only apply to "mature" reservoir-blocks This year, SPDC is re-introducing the concept of **proved blocks** to catalogue those reservoir-blocks that are sufficiently mature to require no discounting. Proved forecasts for all other blocks are discounted from the expectation. Proved blocks are defined to be those with:

➢ Volumetric estimates based on 3D seismic;
➢ Fluid contacts known to "reasonable certainty"; — based on seismic / pressures / logs?
➢ An adequate number and distribution of well penetrations;
➢ Cumulative production in excess of 25% of the estimated ultimate recovery.

The key documentation for a project in SPDC is the Project Proposal Sheet (PPS). This provides a description of a project and all of the information to carry out an economic evaluation. However, more is required to demonstrate a project is technically mature.

➢ For each reservoir-block addressed by a project there must be a demonstrable audit trail for the resource volumes carried in the current ARPR. For some of the older resource volumes reported before the introduction of the URCR reporting system, this may require additional review.
➢ Each PPS must be based on a current Field (re-)Development Plan (FDP), and any changes from the FDP must be documented.
➢ Smaller projects, for which the PPS is based on a "notional" development plan, must be based on a well-established analogue for which there is a current FDP. The basis for the analogy and any deviations must be documented.
➢ Projects in the "Base Plan" contribute to SPDC's proved reserves and therefore must have been subjected to independent review and challenge (as a control) to preserve integrity of the external disclosures. all of them?
  - For major projects (>US$100 million, 100%) such a review will be an externally led VAR3. now FID
  - For minor projects (<US$100 million, 100%) an internal SPDC Corporate Project Review (CPR) should be carried out.
  - Related minor projects producing through shared facilities such that they may mutually affect each others development decisions should be grouped for review purposes, e.g. an infill-drilling project, tie-in of a satellite field through the same facilities, and the installation of associated gas gathering facilities. In many cases the resulting integrated project will then require a full VAR.

> Resource volumes reported in the ARPR, for which there are no mature projects defined, must have a hydrocarbon resource maturation plan documenting how and when projects will be defined, or the resource volumes removed. These will include small volumes "left over" after reconciling project volumes ~~with the ARPR, many of the PAFs~~ and UADs and all of the SFR.

> Resource volumes "missing" from the ARPR, i.e. volumes carried in a PPS for which there are no corresponding volumes reported in the current ARPR must be documented in a URCR during the current year for reporting in the next ARPR at the end of the year.

All projects must be assessed against the Group's profitability criteria as set for the Capital Allocation process. This does not mean the projects must rank and be funded, but they must pass the screening levels to be considered mature. why not?

Assurance of market availability, in addition to having a contract, requires the availability of the infrastructure to transport the product to market. This requires either:

> The project will deliver product into an existing pipeline system having sufficient ullage to handle the full volumes; or

> The project includes the development of the necessary transport infrastructure. FID

Where major new infrastructure is to be built, e.g. for a new offshore field such as in the H-Block, or for a remote onshore field such as Utapate, the project should pass VAR4 to ensure there are no significant issues that could preclude proceeding with the project. Moreover, where the infrastructure component of such a project is dedicated to the project, i.e. is not providing shared capacity for use by other developments, then the project is a true "option", and in order to be reasonably certain of funding by the Group it should take FID before being considered commercially mature.

Much of SPDC's gas reserves are associated gas volumes subject to the same concerns as the corresponding oil volumes. Little non-associated gas has been booked to date, and with the focus on oil, NAG reservoirs have received little attention until recently. Further areas of concern for gas are:

> The commercial maturity of the various projects. In particular the availability of evacuation routes to the designated customers, and contractually bound, realistic, gas demand forecasts to constrain the sales gas supply forecasts. Many of the domestic gas contracts are small GSPAs, effectively renewable indefinitely, and consequently do not provide a clear boundary for the reserves. In such cases the reserves are constrained from the supply side, ensuring only existing supplies and projects in the ~~Base Plan are~~ counted. Previously these forecasts tended to ~~assume continuity of supply by drilling NAG wells~~ as required.

> Data availability. In particular, gas properties from fluid samples, and the reliability of historical gas production volumes. This should be reflected in the range of volumetric uncertainty and the corresponding discount to proved reserves.

> Sufficient supply projects are defined in the Base Plan to cover the full contractual demand for NLNG trains 1-5, but the plan assumes full blow-down of the back-up/swing NAG supplies in Bonny and Soku in the later years [ISSUE BEING OIL RIMS?]. These volumes will be replaced in subsequent Business Plans (2004/2005) by further AG nodal projects that are not yet mature enough to carry in the Base Plan this year. ?

With the size of SPDC's portfolio, not all projects can be accommodated within a five-year programme period due to funding and other resource constraints. It is important to distinguish incremental projects in existing fields that are reasonably certain to be funded by the Group and Partners at some time, probably soon after the five-years, from new developments that can be truly said to be optional and therefore not reasonably certain to receive funding. The former category of projects are candidates to be included in the Base Plan.

4. Review of SPDC Resource Base 15.33?

SPDC currently carries 16.57 billion barrels (100%) of expectation oil reserves in the following categories:

MMbbl, 100%	Proved Blocks	Unproved Blocks	Total	
Developed	1,971	626	2,597	1.625 Proved
Undeveloped in Base Plan	1,931	3,132	5,063	9.018 Proved
Undeveloped, not in Base Plan	1,962	2,207	4,169	
Closed-in Fields (e.g. Ogoni Area, Utapate)	-	1,627	1,627	to be SFR
Partially-Appraised Fields/ Unappraised Discoveries (PAF/UAD)	-	3,113	3,113	
Total				

Here, "Base Plan" is defined to be those projects carried in last year's Business Plan plus the critical T4/5 gas supply projects being matured in Soku and Gbaran/Ubie this year.

Of these volumes, only the first two categories carry corresponding proved volumes. The other three categories do not, and therefore should be carried as SFR not reserves. A case could probably be made that the bulk of reserves in the third category, "Undeveloped, not in Base Plan", should be retained as expectation reserves on the basis that they represent incremental developments within existing developed fields. However, this will require further work to review their project definitions and maturity. Possibly part of the PAFs & UADs could be similarly justified as satellite developments tying in to existing fields. The remaining 4 to 5 billion barrels should really be down-graded to SFR, with little prospect of adequate studies in the near future to mature, or in many cases even define their development projects. i.e. need separate accounting of Proved and Expl.

Besides the impact on the Group's internally reported volumes, it would be difficult not to reflect such a change in the volumes reported to Government. These are reported under the Nigerian National Standard (NNS) format based on the 1987 SPE definitions of Proved, Probable and Possible volumes. Moving expectation reserves to SFR would require a corresponding move from probable (P2) to possible (P3). This would undoubtedly have a knock-on effect on our position with regard to the Reserves Addition Bonus, particularly in the light of the ongoing legal dispute.

There would also be a consequence for Exploration, in that most newly discovered volumes could only be booked as discovered SFR. The only reserves would be for early hook-ups, and then not necessarily in the year of discovery. Moving SFR to reserves would require a Field Development Plan and commitment to development sometime later.

Projects in the Base Plan, which hence carry proved reserves, have been reviewed against the criteria for technical maturity (see section 3 above: audit trail for ARPR volumes; PPS clearly linked to a current FDP). All projects in the Base Plan have passed economic screening against the Capital Allocation criteria, and are being proposed for funding. They are therefore deemed commercially mature. Projects are either mature or not, there is no "in-between". Projects that are not mature [which ones are these; the options?]will have maturation plans prepared by the end of June 2003 leading to full maturity for next year's Business Plan (by 30th April 2004 at the latest).

Projects have also been reviewed to establish whether or not they have been subject to independent review and challenge of the selected concepts (passed VAR3 or equivalent). Again there is no "grey" area, they have either passed or not. Where further independent review is required, this will be scheduled as part of the projects' maturation plans.

A comparison of the expectation Base Plan forecast using the criteria discussed above with that of last year's Business Plan is presented in figure 1. The NFA forecasts for drainage points producing from fields with no associated gas gathering or other gas solution in the Base Plan have been truncated from 1/1/2008 to comply with flares-out. A breakdown of the latest estimate of proved oil volumes compared with those as booked at 1.1.2003 is presented in Table 1, and the changes summarized in figure 2. ~~to ease~~ Shell share?

The overall net reduction is 75 Million m3 (471 MMbbl?). An overall reduction of 150.34 million m^3 within the current licence period is partially offset by an additional 75.35 million m^3 post licence. The bulk of the reduction within the licence period, 132.78 million m^3, results from including only the Base Plan projects. Other changes are relatively small:

- -4.40 million m^3 for the reintroduction of discounting proved developed volumes in unproved blocks;
- -7.77 million m^3 for closing in NFA production from 2008 where there is no associated gas gathering or alternative solution to achieve flares out;
- -5.02 million m^3 for the postponement of EA phase 2.

Most of the volumes that are technically and commercially mature have been subject to external review, but roughly one third of LE volumes at 1.1.2004 require further work to either demonstrate they are sufficiently mature, or mature them further. Of these exposures, 28.38 million m^3 are mature, but have not been externally reviewed, while 81.55 million m^3 have not been demonstrated to be mature.

A number of projects currently excluded from the base plan are being matured and will achieve VAR3 by late 2003 or during 2004. These could be included in the base plan beyond the five year programme period on the grounds that they enable continued production from existing assets post-flares out in 2008 and develop incremental reserves in existing assets. They would be carried as exposures at 1.1.2004, but with clear plans in place to mature the volumes by 1.1.2005. Volumes are as follows:

Otumara	9.35 mln m^3	VAR3 October 2003
Akri-Oguta	11.38 mln m^3	VAR3 November 2003
Remaining Ubie	4.34 mln m^3	VAR3 July 2003
Land Area - West	6.63 mln m^3	AGG has VAR4 but project is currently on hold. Oroni-Uzere fields take VAR3 in June 2003; Aferolo fields take VAR3 in November 2003.
Nun River	8.94 mln m^3	VAR3 currently planned for July 2005.

why?

The combined volume of 40.64 million m^3 would reduce the shortfall to 34.35 million m^3 (216 MMbbl).

5. Review of Gas Forecasts

Volumes for NLNG are based on the various train DCQs and premised 338 stream days per year. Demand forecasts are run out to the expiry of the basic contract terms for each train:

- Trains 1 & 2 basic term expires 30/9/2021
- Train 3 basic term expires 30/9/2023
- Trains 4 & 5 basic term expires 30/9/2026

demonstrated?

No discounting from expectation to proved has been applied as supply plans include sufficient NAG swing capacity to guarantee meeting demand. Bonga gas production (9.28 milliard m^3, 100%) has been excluded from the demand volumes to determine SPDC supply volumes. No provision has been made for further volumes from Bonga. These should be offset from the train 6 bookings expected next year.

Domestic gas volumes are also based on the latest demand forecasts. These have been reduced from last year to include only those volumes for which there are firm contracts in place. Gas supplies to NEPA's power stations (Egbin, Delta, Sapele and Afam), Ewekoro/Shagamu cement factories and DSC Aladja are based on GSPAs between SPDC and NGC:

- Utorogu, ACQ 66 Bcf/yr end date 2008;
- Oben, ACQ 14.7 Bcf/yr end date 2012;
- Sapele, ACQ 24 Bcf/yr end date 2007;
- Afam/Obigbo North, ACQ 31.85 Bcf/yr end date 2016.

There is a direct GSPA between SPDC and NEPA for Ughelli East, ACQ 21.9 Bcf/yr expired but under re-negotiation.

A GSPA exists to supply gas from Alakiri to NGC for delivery to NAFCON's fertiliser plant (ACQ 17.5 Bscf/yr). This contract expires in 2008 but has similar extension provisions to the other GSPAs. NAFCON has been dormant since mid-1999 due to plant breakdown. Forecast gas sales to this customer are based on expected reactivation of the fertilizer plant to its existing capacity and extension of the GSPA beyond current contract life. However, for the purposes of proved reserves, reactivation of the plant has been excluded.

Although a GSPA has never been executed for gas supply to ALSCON, negotiation had been ongoing since the early 1990's and there is an interim agreement with NGC to supply gas from Alakiri and Obigbo. This allowed ALSCON to start commissioning their plant, build up consumption to 30 MMscf/d before the plant shut down in 2000 for lack of working capital. Current demand of about 10 MMscf/d is for utilities only. The forecast shows a restart of the plant in 2006, building up to 102 MMscf/d in 2008. However, for the purposes of proved reserves, restart of the plant has been excluded.

The smaller customers have direct GSPAs with SPDC with various end dates.

All above GSPAs are not tied to field depletion and all have provisions for extension on the basis of mutually acceptable terms. Extension of these GSPAs has been assumed based on historical connection to SPDC's gas sources and the limited scope for other suppliers to deliver gas more competitively to most of these customers than SPDC could. In the West, the forecast has made allowance for Chevron's share of the gas supplies.

Work is still in progress on the supply side, particularly the existing small NAG plants, to determine the technical lifetime of these supplies. At this stage all domestic gas volumes have been cut-off at the old licence boundary of 30th November 2019 as used for previous bookings. It may be possible to extend some volumes beyond that date once the work has been completed later this year.

The increase in gas supply to the Afam power station has been excluded for the purposes of proved reserves. Although the project is "committed" and being progressed on a fast-track, at this stage the upstream project definition is barely at the VAR2 stage. By the end of the year VAR3 will have been taken, and it may be possible to include the volumes. Similarly the increases in ALSCON and NAFCON demand may become bookable if we get firmer indications that they will indeed increase their take. Where to?

Although a Letter of Intent has already been signed for the West African Gas Pipeline, there is currently no firm supply project identified to provide additional gas in the Western division. This may mature sufficiently during the year to allow booking at 1.1.2004.

A breakdown of the latest estimate of proved gas volumes compared with those as booked at 1.1.2003 is presented in Table 2.

Shell share

The overall net increase is 37.5 75 Milliard sm3 ~~(xx boe)~~. The changes are summarised in figure 3. The reductions in domestic gas volumes (14.478 mrd m^3, Shell share) and removal of WAGP volumes (4.180 mrd m^3, Shell share) are more than offset by the new NLNG bookings (56.202 mrd m^3, Shell share). Potential upsides from the reintroduction of WAGP, and the Afam power station, ALSCON and NAFCON increases could add a further 4.180, 6.708, 3.739 and 1.661 mrd m^3, Shell share respectively.

6. Current Reserves Position – SPDC

The overall position for SPDC is summarized in figure 4. The currently defined Base Plan includes a number of projects requiring further maturation to be fully compliant with the SEC and Group guidelines. However, studies are in progress to achieve compliance. Moreover, there are a number of projects currently excluded from the Base Plan, which are essentially no less mature and also being studied (Otumara, Akri-Oguta, Remainder of Uble, Land Area

West, Nun River, Afam Power gas supply including ALSCON & NAFCON increase, WAGP gas supply). These should be moved within the Base Plan. Criteria for inclusion are:

- Project addresses further development within an existing field or fields, and supports continued production beyond flares-out in 2008.
- Studies are in progress leading to full maturity in time for next year's Business Plan and would result in re-booking next year if de-booked this year.
- Gas market availability is confirmed.

This results in a bottom line of **2930 MMboe**, Shell share, approximately the same as would result from continuing the moratorium for one more year (1.1.2003 volumes less 2003 production giving an LE of 2921 MMboe). There is an overall shift of about 320 MMboe from oil to gas, but this is all proved undeveloped.

[Indicate the equivalent numbers if we follow's Daljit's suggestion ref leaving the option projects out of the base plan]

With the upside projects included (otherwise some NFA production is lost from flares-out in 2008), proved developed oil volumes decrease only slightly by 8 MMbbl, Shell share. This reflects the relatively low drilling activity during 2003, which does not quite replace production. Movements between fields may have some impact on depreciation calculations, but these should be small.

A **proved reserves audit** is planned for early August 2003. This will provide the acid-test for SPDC's numbers.

7. Current Reserves Position - SNEPCO

SNEPCO's reserves were subjected to an external reserves auditor review last year (Houston, Sept. 2002). All evaluation techniques and resulting data for external disclosure strictly conform to the SEC Guidelines.

- Proven volumes for the SEC are booked only for those projects where FID has been awarded (OML118, OPL209 and OPL219). For each of the fields, Shell entitlement (i.e. not working interest) is given.
- Of the current proven volumes, none are foreseen to be produced beyond the licence period. The only volumes projected beyond the licence period are SFR. However, licence will become an issue in the future:
  - As producing assets are developed and produced, maturing further proved volumes towards the technical expectation;
  - For OPL219 where a conversion to an OML is being pursued, and first production is now possibly delayed.
- Apart from a fraction of the associated gas from Bonga where firm gathering plans are in place, all gas (and NGLs from the gas) are currently booked as SFR-un-commercial. No PSC terms are in place for the gas. There is likely to be more gas to come from Bonga, but as yet no firm plans are published for when and how much. This needs to be taken into account in SPDC's future gas bookings to ensure no double counting of the NLNG volumes. The gas volumes currently booked for Bonga are best left on the books rather than de-booked and then re-booked later; provided PSC terms are being negotiated before start-up.

SNEPCO as at 1.1.2003, Shell entitlement

	Oil million m^3	Gas milliard sm^3	
Bonga	48.27	2.553	(9.28, 100%)
Erha (operated by ExxonMobil)	21.35	-	Gas reinjected
Abo (operated by Agip)	4.21	-	Gas reinjected
Total	73.83	2.553	

Plans are in place to book a further 3.47 million m^3 for the ExxonMobil operated Bosi Field (oil only) for 1.1.2004. As with Abo and Ehra, all gas will be re-injected and no reserves are carried.

8. Recommendations [for issues within SPDC control, i.e. most, we should present these as action plans rather than recommendations]

For SPDC:

- Seek EXCOM acceptance of the level of exposures we will carry until volumes are fully matured.
- Prepare maturation plans for all exposed projects by the end of June 2003. These will include realistic timing and resource requirements to allow them to be ranked. A small "hit squad" working with each of the Asset Teams will tackle the top-ranked volumes, and there will be an education and awareness campaign at all levels to get things right up-front for new volumes.
- Establish a formal resource maturation process in line with the current T&OE efforts to address the wider issues of compliance with the Group Guidelines for internal reporting. The "what" and "how" is fairly well established, but we are lacking common tools and data systems, and need to more clearly define roles and responsibilities.
- Broaden our LE tracking (quarterly) to address a wider range of resource categories and resource volume maturity (only expectation volumes at the moment, and then without any measure of maturity).

- Further investigate the position with regard to booked expectation reserves not covered by any projects, and the implications of reclassification of volumes as SFR.

SNEPCO is in good compliance with the Group and SEC guidelines. The only exposure being the small volume of Bonga gas reserves. The only recommendation here is:

- Ensure that negotiation of PSC terms for the gas take place during this year or early next.

---

[1] SPDC Onshore Oil Reserves, EPG Note for Information, January 2000

[2] Petroleum Resource Volume Guidelines, Resource Classification and Value Realisation, EP 2002-1100, SIEP EPB-P, April 2002

- ~~We're likely to have oodles of reserves now - let's debook whatever is not according to guidelines and keep only what we can support~~
- Accept that we shouldn't book any decreases (provisionally) this year
- BP is paramount - extrapolations consistency beyond that must be consistent with it, e.g. - same investment level, forecasts
- Capital allocation should in principle cover all of the portfolio.

Table 1 - SPDC Oil & Condensate, million m³, Shell share

	Within current licence period	Post-licence	Total
Booked at 2003[1]			
Onshore (30% Shell share)	360.18	-	360.18
Shallow Offshore (30%)	1.56	-	1.56
Shallow Offshore (77.14%)	42.95	-	42.95
Total booked at 1.1.2003	**404.69**	-	**404.69**
Expected production during 2003[2]			
Onshore (30% Shell share)	15.15	-	15.15
Shallow Offshore (30%)	0.17	-	0.17
Shallow Offshore (77.14%)	2.13	-	2.13
Total expected production during 2003	**17.45**	-	**17.45**
Reference position at 1.1.2004			
Onshore (30% Shell share)	345.03	-	345.03
Shallow Offshore (30%)	1.39	-	1.39
Shallow Offshore (77.14%)	40.82	-	40.82
Total reference position at 1.1.2004	**387.24**	-	**387.24**
Base Plan 2003			
Developed	104.42	25.34	129.76
Fully mature	57.57	14.89	72.46
Exposures			
No external challenge	19.46	9.02	28.48
Technically immature	55.45	26.10	81.55
Total exposures	74.91	35.12	110.03
Total Base Plan 2003	**236.90**	**75.35**	**312.25**
Change w.r.t. reference position	-150.34	+75.35	-74.99
Upsides [3]			
Otumara			9.35
Akri-Oguta			11.38
Remaining Ubie			4.34
Land Area – West			6.63
Nun River			8.94
Total upsides			40.64

1) *Minor revisions to production data compared with 17th January 2003 submission.*
2) *Based on 2002 Business Plan forecast.*
3) *Includes 7.77 mln m³ restored to proved developed by providing AGG facilities for NFA production.*

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NOTE – 18 Nov, 1999 **CONFIDENTIAL**

From:	Anton Barendregt	Group Reserves Auditor, SEPIV
To:	Linda Cook	Director, SEPIV
	Steve Ollerearnshaw	Managing Director, PDO / GISCO
Copy:	Abdulla Lamki	Deputy Managing Director, PDO
	Kees Ruitenbeek	Director Corporate Affairs, PDO
	Vince Holtham	Planning and Economics Manager, PDO
	Said al-Abri	Reserves Reporting Coordinator, PDO
	Niel O'Neill	Discipline Head, Reservoir Engineering, PDO
	(circulation)	EPS-FX: Gardy, Renard
	(circulation)	EPB-P: Platenkamp, van Dorp, Aalbers
	Charles Watson	Business Advisor, SIEP (EPM)
	Egbert Eeftink	Director, KPMG Accountants NV
	Stephen L. Johnson	PriceWaterhouseCoopers

SEC PROVED RESERVES AUDIT - PETROLEUM DEVELOPMENT (OMAN) and GISCO

23-27 October 1999

I have audited the proved reserves statements of PDO / GISCO for the year 1998 and the processes that were followed in their preparation. These statements present the externally reported Proved and Proved Developed Reserves as at 31 December 1998 together with a summary of the changes in Proved Reserves during 1998.

The audit followed the procedures laid down in the "Petroleum Resource Volume Guidelines, EP 98-1100/1101" (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 audit took the form of detailed discussions about the reserves reporting process with PDO / GISCO staff and brief technical reviews with PDO staff of some of the major oil and gas fields. Total booked reserves (Proved, Group share) were 134 10^6 m3, of which 100 10^6 m3 was reported as developed.

The audit found that PDO / GISCO follow well prescribed procedures in their annual reserves reporting process and that there were no deficiencies in these procedures or their application. Particular commendation was made of the well organised system of end-year reserves reporting, which ensures a sound technical basis and a rigorous consistency and auditability between reserves reported to SEPIV and those documented in the annual ARPR.

The most significant comment concerns the generally conservative nature of individual fields' proved and proved developed reserves estimates. However, any scope for increase in externally reported reserves is offset by the fact that the expiration of the production licence in 2012 (within which reported volumes have to be demonstrably producible) has not been properly accounted for. The net result is that reported Proved Developed entitlements are likely to be some 15% overstated, whilst the Total Proved entitlement reserves are probably of the right magnitude. As the 2012 date draws nearer, the cut-off effect will become more pronounced and it should therefore receive proper attention in future submissions.

The audit finding is that the PDO / GISCO statements fairly represent the Group entitlements to Proved Reserves at the end of 1998. The 1998 changes in the Proved Reserves during 1998 can be fully reconciled from the documents at hand. The overall opinion from the audit regarding the state of PDO / GISCO's 1998 Proved Reserves submission, taking account of the thorough technical work underlying the estimates, as reflected in Attachment 4, is therefore <u>good</u>.

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

A.A. Barendregt

Attachments 1, 2, 3

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DEPOSITION EXHIBIT
Barendregt
#25 2/22/07

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Attachment 1

SEC PROVED RESERVES AUDIT - PDO / GISCO, 23-27 Oct 1999

MAIN OBSERVATIONS

1. The audit covered the combined reserves submission by PDO and GISCO (Gas Investment and Services Co). The reserves submitted by PDO related exclusively to the oil fields in the PDO-held concession, in which the net Group interest is 85% of the private shareholders' share of 40%, or a net 34%. No Group entitlement exists to any gas or condensate reserves although PDO can apply any associated gas that it produces for its own use. The private shareholders (PSH) have no title to any gas or liquids from NAG gas reservoirs within the PDO licence, but there is an agreed (in principle, but not exercised) purchase right by the PSH under the new GISCO / Oman LNG contract. This allows NGL and NAG reserves to be assessed and booked by the PSH. Calculation is complex and is essentially determined by translating forecast PSH profits into gas/NGL volumes through agreed NGL/gas price formulae. Separate sheets (within the same submission) have been supplied for oil (PDO equity) and NGL/gas (GISCO Purchase Right) volumes. This is accepted because the three streams are mutually exclusive in the submissions and do not give rise to confusion.

2. The Omani Government are keen to see an expansion of the country's reserves base and have awarded PDO a reserves addition bonus for every barrel of additional reserves in existing fields agreed with the Government. Extensive study work is undertaken by PDO to justify reserves additions through further infill drilling (most of it through horizontal wells) and through a continuing effort of new technology solutions and cost reduction, in an attempt to keep infill drilling costs at their current low level of $2-3/bl. A well established process of reserves approval is in place, involving proper documentation of the basis for the reserves addition, followed by meetings with Ministry staff. Main focus of these efforts are the 30-year field reserves, but proved estimates are now also updated and recorded in the documentation. The latter was one of the recommendations of the previous reserves audit in 1995.

3. The audit found that PDO follow well prescribed procedures in their annual reserves reporting process and that there were no deficiencies in these procedures or their application. Particular commendation can be made of the well organised system of end-year reserves reporting, which ensures rigorous consistency and full auditability between reserves reported to SEPIV and those documented in the annual ARPR. The latter document contains exclusively 100% field figures and includes in-place and reserves estimates for the NAG gas fields. Whilst full audit trails are in place for all updates of any significance, it was noted that some minor updates, e.g. those adjusting too low proved estimates when the latter are being overtaken by production, are handled by brief notes for file, which are not always referenced in the text.

4. Many STOIIP probabilistic estimates tend to be based on static well data only. No account seems to be taken of available performance /material balance evidence. Total oil recovery estimates tend to be based on probabilistic combinations of RF ranges from simulation studies and static STOIIP estimates for each reservoir. No probabilistic addition of reservoirs within fields is made. The result is that many proved total recoveries are low in comparison with the field's maturity (see also Fig. 1).

5. Proved developed reserves for each field are calculated as the minimum of either expectation developed reserves or proved total reserves. Because of the conservative nature of the latter, that value tends to prevail. In line with Group guidelines, proved developed reserves should be made equal to expectation developed reserves for mature fields. Many fields have a ratio of Np/UR in excess of 40% (see Fig.1). The area can therefore be classed as mature.

6. The PDO production licence expires on 24th June 2012. There is at present no legal right to extension. Total proved reserves in the 1998 reserves submission have been postulated to be producible within that period. This was done through a forecast at current plateau level, cut off at the point where production exceeds total field proved reserves (in 2007). This forecast cannot be seen as realistic.

7. For the proved developed reserves no proper assessment has been made of the volumes actually producible within the licence period. It was noted that the expectation NFA (no further activity) forecast shows a licence producible volume (100% field) of only 255 10^6 m3, i.e. less than the 295 10^6 m3 currently carried for proved developed reserves.

8. It is noted that in the 1998 reserves submission for internal reporting a figure of 632 10^6 m3 (100%) is reported as the expectation volume producible within licence, together with a figure of 752 10^6 m3 for total fields' 30-year expectation reserves. The volume producible within licence cannot be correct as the forecast on which it is based contains a significant slice of volumes that are presently classified as SFR.

9. Gisco's NGL and gas entitlements have been properly derived from an extensive spreadsheet including anticipated sales, developments and operating costs and resulting cash flows and profits. NGL and gas entitlements are calculated from this through an agreed price formula.

10. Proper gas GHV measurements exist for the fields dedicated to the Omani government gas grid and the Gisco contract. The reserves-weighted average of all gas fields is calculated as 1064 Btu/scf (with individual fields varying between 956 and 1137 Btu/scf, see Fig.2). A different average may be appropriate, dependent on which fields can actually be considered as dedicated to the gas contract. Either way, the appropriate average seems to exceed the 1025 Btu/scf implied in the 1998 submission, see Att. 2.4.

Recommendations:

1. Investigate ways of adjusting the proved reserves estimates in mature fields where this can be justified by performance. Some suggestions are given in Attachment 3.
2. At a PDO corporate level, proper allowance should be made for the licence expiry in 2012 in the end-year submission of proved and proved developed reserves. This will probably need documentation in a separate note for file outside (or as an attachment to) the ARPR. Suggestions are also given in Attachment 3.
3. Ensure that the properly calculated average gas GHV is used in the conversion to normalised gas volumes (9500 kCal/m3) in the annual submission.
4. Ensure that minor reserves changes are also referenced in the ARPR text.

Attachment 2.1

SEC RESERVES AUDIT - VOLUMES RECONCILIATION
Oman, 23-27 Oct 99

Oil / NGL / Gas Reserves as at 31.12.98

Area / field	Exp'n HIIP 10^6 sm3/ 10^9 sm3	Proven HIIP 10^6 sm3/ 10^9 sm3	Cum. Prod 10^6 sm3/ 10^9 sm3	Proved Rem. Recov. Dev. 10^6 sm3/ 10^9 sm3	Proved Rem. Recov. Tot'l 10^6 sm3/ 10^9 sm3	RF Dev. %	RF Tot'l %	PSH share Dev. 10^6 sm3/ 10^9 sm3	PSH share Tot'l 10^6 sm3/ 10^9 sm3	Within Licence & comtd Dev. 10^6 sm3/ 10^9 sm3	Within Licence & comtd Tot'l 10^6 sm3/ 10^9 sm3	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	1998 Subm'n Tot'l 10^6 sm3/ 10^9 sm3
Oil																
PDO Fields GISCO contract (NAG fields)	7870.79	5925.52	878.18	294.77	394.36	19.8%	21.5%			294.77	394.36	34.0%	100.22	134.08		
Total Oil	7870.79	5925.52	878.18	294.77	394.36	19.8%	21.5%			294.77	394.36	34.0%	100.22	134.08	100.22	134.09
NGL																
PDO Fields GISCO contract (NAG fields)	283.40	191.17	0.62	0.00	70.50	0.3%	37.2%	0.00	32.34	0.00	32.34	100.0%	0.00	32.34		
Total NGL	283.40	191.17	0.62	0.00	70.50	0.3%	37.2%	0.00	32.34	0.00	32.34	100.0%	0.00	32.34	0.00	32.34
Gas																
PDO Fields GISCO contract (NAG fields)	1176.751	877.583	45.398	0.000	525.224	5.2%	65.0%	0.000	59.321	0.000	59.321	100.0%	1.000	59.321		
Total Gas (Bscf / 10^9 sm3) (10^9 Nm3)	1176.751	877.583	45.398	0.000	525.224	5.2%	65.0%	0.000	59.321	0.000	59.321	100.0%	1.000	59.321	0.000	59.321

Audit Trail:

Total HIIPs from ARPR/RISRES
Cum.Prod. from ARPR/RISRES
Oil Prov.Dev Res from spreadsheet

All field proved oil reserves are postulated to be producible within licence by cutting off exp'n forecast at proved volumes

Gas/NGL Priv.ShareHolders (PSH) share from economic model

Shell share in GISCO venture is 85%; Group accounting rules require 100% to be reported (consolidated Co.)

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Attachment 2.2

SEC RESERVES AUDIT - VOLUMES RECONCILIATION
Oman, 23-27 Oct 99

Oil Reserves Changes 1998 (100%, 10^6m3)

Field	Prov.Res. 1.1.98	Revisons/ Reclasins Guidelines	Revisons/ Reclasins Economic	Revisons/ Reclasins Other	Revisons/ Reclasins Total	Improved Recovery	Extens./ Discov's	Purchase in-place	Sales in-place	New Devel'd. Reserves	Product'n 1998	Prov.Res 31.12.98	Shell Equity Share % 1997	Shell Equity Share % 1998	Net Shell Equity 1.1.98 (10^6 m3)	Net Shell Equity 31.12.98 (10^6 m3)	Comments
Proved Total Reserves																	
PDO Fields GISCO contract (NAG fields)	391.84				35.00	9.49	8.52				48.48	394.36	34.00%	34.00%	133.23	134.08	Field reviews as per ARPR; 9.5 10^6 m3 improved recovery from Fahud (Natih-E NW)
Tot'l Prov.Res (10^6 m3)	391.84	0.00	0.00	0.00	35.00	9.49	8.52	0.00	0.00		48.48	394.36	34.00%	34.00%	133.23	134.08	
Proved Developed Reserves																	
PDO Fields GISCO contract (NAG fields)	227.38				115.87					?	48.48	294.77	34.00%	34.00%	77.31	100.22	
Prov.Dev.Resvs 10^6 m3	227.38	0.00	0.00	0.00	115.87	0.00	0.00	0.00	0.00	0.00	48.48	294.77	34.00%	34.00%	77.31	100.22	
Net Group Equity Prov.Dev. Res Prov Tot'l Res 10^6 m3	77.31 133.23				39.40 11.90	3.23	2.22				16.48 16.48	100.22 134.08					
1998 Submission Prov.Dev.Res Prov.Tot'l Res 10^6 m3	77.31 133.22				11.82	3.23	2.22				16.50	100.22 134.08					

Audit Trail:

1.1.98 ProvRes 391.84 10^6 m3 =
1221.76 (1.1.98 oil PUR) - 878.18 (1.1.98 oil cumprod) + 48.26 (1998 oil prod)
1998 Revisions (35.00 10^6 m3) includes 0.22 10^6 m3 allowance
for 1998 condensate prod'n from Saih Rawl and Barik (no entitlement reserves)

1998 Production includes 0.22 10^6 m3 condensate
from Saih Rawl / Barik pre-Gisco contract start.

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Attachment 2.3

SEC RESERVES AUDIT - VOLUMES RECONCILIATION

Oman, 23-27 Oct 99

NGL Reserves Changes 1998 (100%, 10^6 m3)

Field	Prov.Res. 1.1.98	Revisons/ Reclasins Guidelines	Revisons/ Reclasins Economic	Revisons/ Reclasins Other	Revisons/ Reclasins Total	Improved Recovery	Extens./ Discov's	Purchase In-place	Sales in-place	New Devel'd Reserves	Product'n 1998	Prov.Res 31.12.98	Shell Equity Share % 1997	Shell Equity Share % 1998	Net Shell Equity 1.1.98 (10^6 m3)	Net Shell Equity 31.12.98 (10^6 m3)	Comments
Proved Total Reserves																	
PDO Fields GISCO contract (NAG fields)	32.12				0.22						0.00	32.34	100.00%	100.00%	32.12	32.34	Minor revision due to changes in Gisco devml cost profile
Tot'l Prov.Res 10^6 m3	32.12	0.00	0.00	0.00	0.22	0.00	0.00	0.00	0.00		0.00	32.34	100.00%	100.00%	32.12	32.34	
Proved Developed Reserves																	
PDO Fields GISCO contract (NAG fields)	0.00										0.00	0.00	100.00%	100.00%	0.00	0.00	
Prov.Dev.Resvs 10^6 m3	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	100.00%	100.00%	0.00	0.00	
Net Group Equity Prov.Dev. Res Prov Tot'l Res 10^6 m3	0.00 32.12				0.00 0.22						0.00 0.00	0.00 32.34					
1998 Submission Prov.Dev.Res Prov.Tot'l Res 10^6 m3	0.00 32.12				0.22						0.00	0.00 32.34					

Audit Trail: Full match

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Attachment 2.4

SEC RESERVES AUDIT - VOLUMES RECONCILIATION

Oman, 23-27 Oct 99

Gas Reserves Changes 1998 (100%, 10^9 sm3)

Field	Prov.Res. 1.1.98	Revisions/ Reclassns Guidelines	Revisions/ Reclassns Economic	Revisions/ Reclassns Other	Revisions/ Reclassns Total	Improved Recovery	Extens./ Discov's	Purchase in-place	Sales in-place	New Devel'd Reserves	Product'n 1998	Prov.Res 31.12.98	Shell Equity Share % 1997	Shell Equity Share % 1998	Net Shell Equity 1.1.98 (10^9sm3)	Net Shell Equity 31.12.98 (10^9sm3)	Comments
Proved Total Reserves																	
PDO Fields GISCO contract (NAG fields)	11.434				47.887						0.000	59.321	100.00%	100.00%	11.434	59.321	Revision due to changes in GISCO contract assumptions (gas price)
Tot'l Prov.Res 10^9 sm3	11.434	0.000	0.000	0.000	47.887	0.000	0.000	0.000	0.000		0.000	59.321	100.00%	100.00%	11.434	59.321	
Proved Developed Reserves																	
PDO Fields GISCO contract (NAG fields)	0.000										0.000	0.000	100.00%	100.00%	0.000	0.000	
Prov.Dev.Resvs 10^9 sm3	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000		0.000	0.000	100.00%	100.00%	0.000	0.000	
Net Group Equity Prov.Dev. Res Prov Tot'l Res 10^9 sm3	0.000 11.434				0.000 47.887						0.000 0.000	0.000 59.321					
1998 Submission Prov.Dev.Res Prov.Tot'l Res 10^9 sm3	0.000 11.434				47.887						0.000	0.000 59.321					
Net Group Equity Prov.Dev. Res Prov Tot'l Res 10^9 Nm3 @ 9500 kCal/Nm3	0.000 10.977				0.000 45.971						0.000 0.000	0.000 56.948					
1998 Submission Prov.Dev.Res Prov.Tot'l Res 10^9 Nm3 @ 9500 kCal/Nm3	0.000 10.977				45.971						0.000	0.000 56.948					

GHV used: 1024.80 Btu/scf

Conversion factors used by PDO/GISCO:
1 sm3 = 0.948 Nm3 (if GHV=9500 kcal/Nm3 or 1012 Btu/scf))
1 sm3 = 0.960 Nm3 (for GHV=9620 kcal/Nm3 or 1024.8 Btu/scf))

Audit Trail: Full match for sm3 volumes.
GHV implied in conversion to Nm3 volumes seems too low (1028 iso 1064 Btu/scf)

Attachment 3

SEC PROVED RESERVES AUDIT - PDO / GISCO, 23-27 Oct 1999

SOME SUGGESTED PROCEDURES FOR RESERVES BOOKING

Raising individual fields' proven volumes:

1. For mature fields (e.g. with cumulative productions of 40% of expectation UR or more), separate deterministic assessment of developed and undeveloped recoverables through simulation modelling often becomes more appropriate than conventional probabilistic estimates of ultimate recovery. This is in line with the need for a gradual shift from volumetric to performance based reserves estimates as the fields mature, see Group guidelines SIEP 98-1100, p.15.
2. For proved developed reserves, Group guidelines (p.14) state that these can be made equal to expectation developed reserves 'for mature fields', provided the relevant portion of the field can be considered 'proven' with regard to fluid contacts and fault delineations. In the Oman environment, where reservoirs tend to be generally 'proven', but more complex than in many other areas, a suitable criterion for 'maturity' could be Np > 0.4*expnUR.
3. For proved undeveloped recoverables, a multiple scenario modelling approach should ideally be followed. To some extent this is already being applied for many fields in PDO. It is suggested that STOIIP uncertainties (if still present and significant) could be included in these scenarios. In any event, an attempt should be made to calibrate low (and high) STOIIP estimates against field performance.
4. Consider the appropriateness of probabilistic addition of reservoirs within fields. For reservoirs that cannot be seen as fully independent, some partial probabilistic dependency could be adopted, if its quantification can be properly assessed and justified.

Taking account of production licence expiry

1. For proved developed reserves it is suggested to take the <u>corporate</u> expectation NFA forecast, proportionally downgraded to take account of the ratio between proved developed reserves (compounded from individual field estimates as suggested above) and expectation developed reserves. The proper way to do this downgrading is to transform the forecast vs. time into a rate vs. cumulative production forecast, shrink the horizontal axis in proportion to the proved vs. expectation reserves and re-expand into a time-based forecast. This should leave the production rate in the initial year of the forecast more or less unchanged. The downgraded forecast can then be cut off at the appropriate date (24th June 2012).
2. For proved total reserves a similar approach is suggested by taking the corporate expectation forecast for developed and undeveloped reserves (but excluding volumes that are presently classed as SFR!) and by following a similar downgrading as above to reflect the ratio between proved and expectation total reserves. The expectation forecast itself should of course be used for assessing the expectation volumes producible within licence (see submission for internal reporting).
3. It can be argued that simply taking the corporate forecast after deduction of the SFR slice is somewhat conservative. In reality, if no SFR would be maturing to reserves in the coming years, it would be likely that development of the present undeveloped reserves portfolio would be accelerated. Allowance could be made manually for this, but the only rigorous way would be to revert to the individual project forecasts and re-schedule those. Care should be taken that the SFR forecast itself should be similarly adjusted, to reflect the fact that acceleration of reserves within licence (under a ceiling-constrained production scenario) should cause a backout of SFR volumes beyond licence expiry.

Figure 1 - Proved/Expn reserves ratio vs Field Maturity

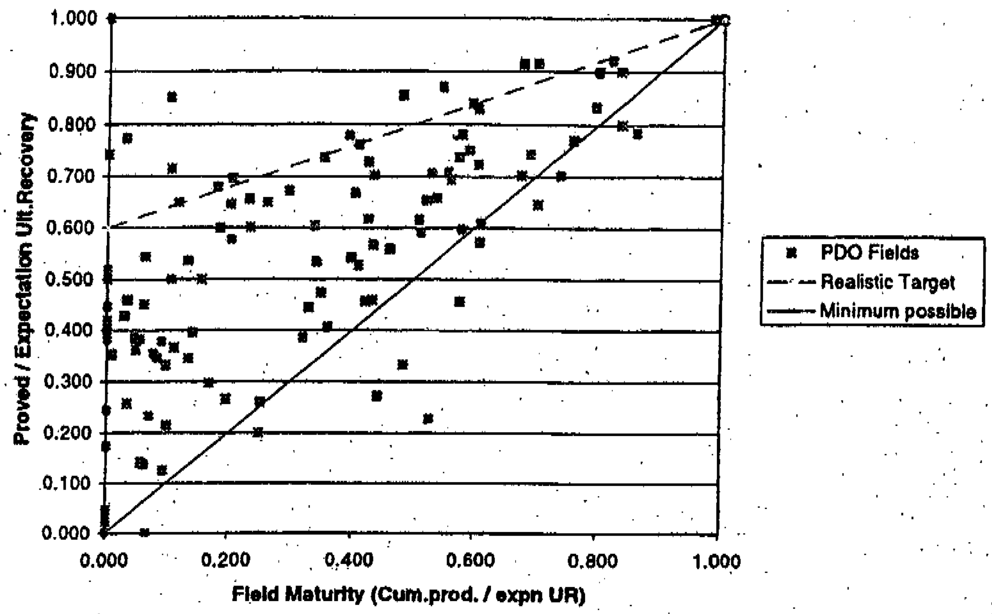

Figure 2 - PDO Expectation Gas Reserves, 1.1.99

Field	Expectation Reserves bcm	Tcf	HHV	HHV*Reserves		
Barik-Bk	57.511	2.034923	1137	65390		
Saih Rawl-	228.195	8.074269	1102	251471		
Saih Nihay	37.571	1.329382	1083	40689		
Saih Rawl-	139.187	4.924881	1005	139883		
Saih Nihay	38.701	1.369365	1027	39746		
Saih Nihay	8.691	0.307515	1016	8830		
Central O	509.856	18.04034		546009	Average weighted heating val	1071 btu/scf
					Reserves equivalent	19320 10exp12 btu
Yibal Natl	75.846	2.683674	1061	80473		
SN-Shuaib	21.978	0.777652	998	21934		
Makarem	17.565	0.621506	956	16792		
Burhaan V	3.296	0.116623	1118	3685		
Burhaan V	8.336	0.294954	1050	8753		
Other	127.021	4.494409		131637	Average weighted heating val	1036 btu/scf
					Reserves equivalent	4658 10exp12 btu
Central +	636.877	22.53475		677646	Average weighted heating val	1064 btu/scf
					Reserves equivalent	23977 10exp12 btu
Total Oman		25.9				

CHECKLIST SEC RESERVES AUDIT
Oman, 23-27 Oct 1999

Attachment 4

COMPANY: PDO and GISCO, Oman AREA / FIELD: Total area

Dimensions:

	100% Field volumes	
1.1.99 Proved Oil Reserves	394	10^6 m3
1.1.99 Proved Developed Oil Reserves	295	10^6 m3
1998 Oil Production	48	10^6 m3
	132	10^3 m3/d
1.1.99 Proved Gas (NAG) Reserves	525	10^9 Sm3
1.1.99 Proved Developed Gas (NAG) Reserves	0	10^9 Sm3
1998 Gas (NAG) Production	0	10^9 Sm3
	0	10^6 Sm3/d
Number of fields in area	113	
Number of wells drilled / in production	2200 / 750	

	Audit criteria	Result	Comments
1	TECHNICAL MATURITY		
1.01	Is 3D seismic available and used for the field(s) in question?	+	Coverage is virtually complete for the discovered fields.
1.02	Is pre-SDM available and used (when relevant)?	+	Pre-SDM is used in areas with high relief and/or salt domes. Other state-of-the-art techniques (amplitude mapping, buried geophones, cross-well seismic) are used as appropriate.
1.03	Is well log data quantity and quality adequate?	+	Full suites of logs and cores are taken in initial wells and development wells as appropriate.
1.04	Is well data coverage adequate?	+	Most fields require relatively dense well spacing patterns
1.05	Has a 'proved area' been defined (lowest known fluid contact, no major/sealing faults) and is it realistic?	+	Fluid contacts tend to be well known in developed areas; unappraised areas are suitably discounted
1.06	Is reservoir producibility supported by production tests or other evidence?	+	Production tests are a standard part of data gathering in successful exploration / appraisal wells.
1.07	Is there a proper volumetric estimate?	+	All discovered fields have a proper volumetric estimate which is regularly updated as new data becomes available.
1.08	Is a static model available / adequate?	+	The larger fields / reservoirs, particularly those with more complex geology, have proper geological models.
1.09	Is a dynamic model available / adequate?	+	Proper simulation models (full field or often multiple sectors) are used for the larger reservoirs.
1.10	Is a history match available / adequate?	+	History matches are updated regularly, often annually.
1.11	Is the recovery factor for proved reserves realistic?	+	Proved reserves RF (as fraction of proved STOIIP) is equal to expn RF (some 21%). SFR volumes up to an RF of 29% are recognised and a continuous effort is made to improve recoveries through reduced well costs and new technology.
1.12	Are developed reserves based on existing wells, completions and facilities, or do they require only minor costs (<10% project cost) to be hooked up?	+	Expectation developed reserves are based on proper NFA (no further activity) forecasts and/or full well performance reviews. No specific forecast is made for proved reserves, which are derived somewaht conservatively from expectation developed reserves (see also 3.07).
1.13	Has/have (a) development project(s) been defined for undeveloped reserves or can it/they be defined?	+	All expectation reserves updates are discussed with the Omani Government who require them to be supported by proper reservoir modelling and forecasts.
1.14	Is/are the project(s) technically mature or is further data gathering necessary?	+	Projects generally consist of infill drilling of wells (many of them now horizontal). Water and/or gas injection projects are also well established.
1.15	Is/are there (an) auditable development project plan(s) with costs, benefits and economics?	+	New projects and/or wells are subjected to proper evaluation and screening.
1.16	Are improved recovery estimates based on a successful pilot or analogue or are they otherwise supportable?	+	Water- and gas injection are well established recovery methods in the PDO environment.
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; Most drilling activities in the next few years have UTCs of $2-3/bl. All new field developments are required to fulfill the appropriate screening criteria.
2.02	Is/are the project(s) economically viable (meeting Group Scr. Crit. over range of possible future scenarios / low case reserves)?	+	See above.
2.03	Has/have the project(s) been approved by Shareholders?	+	Development activities are approved on an annual basis by shareholders.
2.04	Have the latest Group Screening / Reference Criteria been used?	+	Yes.
2.05	Are assumed prices and costs RT (or justified if not)?	+	Yes
2.06	Is project financing available or can it reasonably be expected to be available?	+	Yes, although some projects may from time to time be deferred.
2.07	Are developed reserves actually in production?	+	Yes
2.08	Have all gas proved reserves been contracted to sales?	+	Yes (see also 4.05)
2.09	If not, can they reasonably be expected to be sold in existing markets and through existing facilities?	N.A.	

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

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CHECKLIST SEC RESERVES AUDIT
Oman, 23-27 Oct 1999

Attachment 4

2.10	If neither, can they reasonably be expected to be developed and sold in a future market?	N.A.	
3	**REASONABLE CERTAINTY**		
3.01	Is the uncertainty range of volumetric parameters and STOIIP estimates adequate?	O	Many STOIIP probabilistic estimates tend to be based on static well data only. No account is taken of performance /material balance evidence.
3.02	Is the uncertainty range of total recovery adequate?	O	Total oil recovery estimates tend to be based on probabilistic combinations of RF ranges from simulation studies and static STOIIP estimates. The result is that many proved total recoveries are low in comparison with the field's maturity (see also Fig. 1).
3.03	Is the uncertainty range of developed recovery adequate?	O	Proved developed reserves for each field are calculated as the minimum of either expectation developed reserves or proved total reserves. Because of the conservative nature of the latter, that value tends to prevail. In line with Group guidelines, proved developed reserves should be made equal to expectation developed reserves for mature fields (see also 3.07). However, the impact of this apparent conservatism is nullified by the constraint that reserves must be producible within licence (see 4.01).
3.04	Have market / production constraint uncertainties been taken into account?	+	In line with Government directives, PDO oil offtake is constrained to 6.5% of expectation reserves per annum. The resulting ceiling of some 825 kb/d has been incorporated in all relevant production forecasts.
3.05	What is ratio of field(s) cum.prod. / proved total recovery?		Many fields (together some 85% of Ultimate Recovery) have a ratio of Np/UR in excess of 40% (see Fig.1). The area can therefore be classed as mature.
3.06	Can the field(s) be considered mature?		Yes, see above.
3.07	Are proved (developed and total) reserves benchmarked against expectation reserves for 'proved areas' when field(s) are mature (deterministic approach)?	O	No, a more conservative approach is taken (see 3.03, but also 4.01).
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?	O	No; This should be considered.
3.10	Is any assumed dependency in probabilistic addition appropriate?	N.A.	
4	**GROUP SHARE CALCULATION**		
4.01	Are proved and proved developed reserves producible within the licence period (or its extension if there is a legal right)?	X	The PDO production licence expires on 24th June 2012. There is at present no legal right to extension. Total proved reserves are postulated to be producible within that period through a forecast at current plateau level, cut off at the point where production exceeds total field proved reserves (in 2007). This forecast cannot be seen as realistic. No assessment is made of the proved developed reserves producible within the licence period. The expectation NFA forecast shows a licence producible volume of 255 10^6 m3, i.e. less than the 295 10^6 m3 currently carried for proved developed reserves. In the 1998 submission for internal reporting, 632 10^6 m3 (100%) is given as the expectation volume producible within licence, together with 752 10^6 m3 for total fields' 30-year expectation reserves. The first of these figures cannot be correct as the forecast on which it is based contains a significant slice of volumes that are presently classified as SFR.
4.02	Are proved and proved developed reserves producible within production ceilings / constraints etc.?	+	All relevant forecasts do take account of the 825 kb/d production ceiling (see 3.04).
4.03	Is the hydrocarbons Equity share calculated properly?	+	Yes. For oil, the Shell equity is 85% of the Private shareholders' 40% share of the venture. Net Group share for oil is thus 34%. For gas and NGL, see 4.04 below.
4.04	Is the hydrocarbons PSC entitlement share (net cost oil + profit oil only) calculated properly?	N.A.	

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

CHECKLIST SEC RESERVES AUDIT
Oman, 23-27 Oct 1999

Attachment 4

4.05	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?	+	Although the private shareholders (PSH) have no title to any gas or liquids from NAG gas reservoirs within the PDO licence, there is an agreed (in principle, but not exercised) purchase right by PSH under the new GISCO / Oman LNG contract. This allows NGL and NAG reserves to be booked by the PSH. Calculation is complex and is essentially determined by translating forecast PSH profits by agreed NGL/gas price formulae.
4.06	Are royalties in cash (legally or customarily) counted as reserves?	+	Royalties are paid in cash and are not deducted from reserves bookings.
4.07	Are royalties in kind excluded from reserves?	N.A.	
4.08	Are volumes received as fees in kind (e.g. for infrastructure use by third parties) excluded?	N.A.	A small third party stream (from Oxy) is handled and paid for in cash. Associated volumes are excluded reserves and production.
4.09	Has Group under-or overlift been accounted for?	N.A.	Partner liftings are administered downstream, i.e after fiscalisation of production
4.10	Have separate submissions been made for Equity, Entitlement and Purchase Right volumes?	O	Separate sheets (within the same submission) have been supplied for oil (equity) and NGL/gas (Purchase Right) volumes. This is accepted because the three streams are mutually exclusive in the submissions and do not give rise to confusion.
5	**AUDIT TRAILS**		
5.01	Are proved and proved developed reserves estimates up-to date?	+	A reserves addition bonus of $0.15/bl is awarded by the Omani Government. This is a strong incentive for PDO to keep reserves estimates up to date and to agree new values when justified, particularly where previous estimates have tended to be conservative.
5.02	Can reported net Group equity reserves be reconciled with individual field reserves estimates?	+	Annual reserves submissions are prepared at the same time as PDO's annual ARPR document. Both are fully consistent (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.)?	+	For oil: forecasts, where used, are appropriate (see 3.04, 4.02). For NGL/gas: reserves are based on current best estimates of gas markets demand.
5.04	Can reserve changes be reconciled with individual field changes and are they reported in the appropriate categories?	+	Yes, full reconciliation is possible, see Atts 2.2-2.4.
5.05	Are technical reports available describing reasons and justifications for new reserves estimates in sufficient detail?	+	All reserves updates need discussion and agreement with the Omani Government. A detailed report (now also adressing proved reserves) is a standard requirement in this process. Trivial updates, e.g. upgrading too low proved estimates when these are being overtaken by production, are handled by a brief note for file.
5.06	Are reports numbered / indexed properly and is there a central library where copies are kept?	+	All reports are indexed properly and master copies are kept in a central location.
5.07	Is the annual reserves submission supported by a sufficiently detailed summary note explaining the reserves changes (classified in revisons, extensions, sales-in-place etc) per field, with references to detailed reports as appropriate?	+	A concise summary ARPR document is issued annually, together with a detailed supplement giving individual field details.
5.08	Are data bases containing historic submissions' data and current reserves status (e.g. RISRES) in place and accessible?	+	A RISRES data base is kept up to date and frozen copies of previous ARPRs' data are archived.
5.09	Do these data bases also contain references to detailed reports?	+	Yes, references are included in RISRES as well as the ARPR document.
6	**CONSISTENCY WITH FINANCIAL REPORTING**		
6.01	Are proved and proved developed reserves based on fiscalised volumes under sales conditions?	+	Yes; Oil volumes are properly fiscalised. NGL/gas volumes are based on currently anticipated net sales.
6.02	Are oil, NGLs and sales gas reported in their appropriate categories?	+	Yes; NGLs from the Gisco contract are in fact spiked into the main PDO crude stream, but in view of their special status vav Group entitlement their separate booking is fully justified. A minor exception existed in the advance test production from two gas wells destined for the Gisco contract. PDO was allowed to keep the condensate during the 1-2 year test period (ended in June 1999 with the commencement of deliveries under the Gisco contract). Appropriate allowance has been made for this under the oil reserves, see Att 2.2.
6.03	Are own use, fuel, losses etc excluded?	+	Yes, see 6.01.

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CHECKLIST SEC RESERVES AUDIT
Oman, 23-27 Oct 1999

Attachment 4

6.04	Are gas GHVs properly measured for sales gas conditions and accounted for in reserves submissions?	O	Proper HHV measurements exist for the fields dedicated to the Oman government gas grid and the Gisco contract. Their reserves-weighted average is calculated as 1064 Btu/scf (with individual fields varying between 956 and 1137 Btu/scf). This does not seem to match with the 1025 Btu/scf implied in the 1998 submission, see Att. 2.4.
6.05	Are reported proved developed reserves consistent with those used for asset depreciation in Group Accounts?	N.A.	Asset depreciation is done through a fixed percientage profile over 5 years, both for tax purposes and (by exception) for Group Accounts. Hence, no account is taken of proved developed reserves.
6.06	Are annual Oil+NGL production volumes in reserves submissions consistent with Upstream production 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]?	+	Yes.
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 (GroupCy net NG sales) + 3598 (Assoc.Cy NG sales), corrected for 1404+4796 (Gas purchases) and 4100+4510+4575+0873 (Trade, other Sales and Transfers)?	N.A.	Gisco's NGL and gas entitlements have been derived from profits via an agreed price formula. Hence, once contract deliveries have started (June 1999), produced and delivered volumes will not necessarily match those deemed to be 'sold' by Gisco (and deducted from future entitlements).
7	OVERALL		
7.01	If Group guidelines should not or not completely have been followed, are results still reasonable / overstated / understated?	O	Proved developed oil reserves for individual fields (30 yrs) are too conservative, but the SEC reported value is probably some 15% too high because no proper account has been taken of volumes realistically producible within licence. Total proved oil reserves are similarly conservative on an individual field basis. However, little account has been taken of the volumes actually producible within licence and the correct value may well be comparable to the value presently reported. NGL and gas reserves have been properly accounted for.
7.02	Do the reported proved and proved developed reserves estimates give a reasonably accurate reflection of shareholder value?	+	On the basis of the above, PDO/Gisco's statement of proved and proved developed reserves can be considered to give a fair reflection of shareholder value. However, proper account must be taken of volumes producible within licence in future submissions, since this becomes more important as the 2012 date moves nearer.

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LON00010741

DRAFT NOTE – 3 Nov 2003 **CONFIDENTIAL**

From:	Anton A. Barendregt	Group Reserves Auditor, SIEP – EPF - GRA
To:	Frank Coopman	Chief Financial Officer, SIEP – EPF
	John Bell	Corporate Support Director, SIEP – EPS
	John Malcolm	MD, PDO
	Andy Wood	General Manager, Shell Representative Office, Oman
Copy:	Abdulla Lamki	Deputy Managing Director, PDO
	Stuart Clayton	Head, Economics, Technology & Planning, PDO
	Stuart Evans	
	Fatima Kharusi	Finance Director, PDO
	Guy Jansens	Controller, PDO
	Lynda Armstrong	Exploration Director, PDO
	(circulation)	SIEP – EPS-P: Hans Bakker, John Pay
	Andrew Vaughan	Technical Director, SEPI – EPM
	René Zwanepol	Finance Director, SEPI – EPM
	Ken Marnoch	Internal Auditor EP, SI-FSAR, The Hague
	Han van Delden	Partner, KPMG Accountants NV
	Brian Puffer	PriceWaterhouseCoopers

SEC PROVED RESERVES AUDIT - PDO (OMAN), 25-28 Oct 2003

I have audited the Proved Reserves submissions of Petroleum Development Oman (PDO) for the year 2002 and the processes that were followed in their preparation. These submissions present the PDO contribution to the Group's externally reported Proved and Proved Developed Reserves and their associated changes as at 31 December 2002.

Total Group share Proved Reserves booked by PDO at the end of 2002 were 144 mln m3 of oil. This represents some 5% of total Group share Proved Reserves on an oil-equivalent basis. Proved reserves replacement ratio for PDO over 2002 was –19%.

The last previous SEC proved reserves audit for PDO was carried out in 1999. This current audit verified the PDO procedures against those laid down in the "Petroleum Resource Volume Guidelines, SIEP 2002-1100/1101" (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 the reserves reporting process with PDO staff. Emphasis was placed on the procedures and methods followed and less on detailed individual field estimates.

The audit found that PDO's Group share proved developed reserves are largely reasonable, but that the proved total reserves are currently overstated by some 40%. The reason for this was partly the progressive tightening of Group reserves guidelines (following SEC guidance), but more fundamentally that proved reserves had not been reviewed and reduced in the light of recent downturns in oil production rates. The technical maturity of the projects associated with proved undeveloped reserves had also been eroded through lack of medium- to long-term field development planning work. PDO have recognised this and have embarked on an aggressive study programme to address the maturation of these projects. A foreseen extension to the current production licence agreement with the Government during 2004 may provide some relief from the necessary de-booking of the overstated volumes.

The audit recommendation is that the present erroneous volumes be continued unchanged per 1.1.2004 (reduced by 2004 production), but that a properly based portfolio of proved reserves should be submitted by 1.1.2005. The overall opinion on the state of PDO's 1.1.2003 Proved Reserves submission, taking account of the audit's findings (see Attachment 3), is <u>unsatisfactory</u>. Improvements have been set in motion.

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

DEPOSITION EXHIBIT
Barendregt
#26 2/22/07

FOIA Confidential
Treatment Requested

VIJVER 2233

V00240172

A.A. Barendregt

Attachments 1, 2, 3

VIJVER 2234

V00240173

Attachment 1

SEC PROVED RESERVES AUDIT - PDO and GISCO 25-28 Oct 2003

MAIN OBSERVATIONS

1. **PDO** are the operator in a land-based concession in the Oman interior. Shareholders in PDO are the Oman Government (60%) and the 'private shareholders' (Shell, BP and Partex). Shell holds 85% of the private shareholders' share of 40% and has thus title to 34% of the PDO produced crude. PDO are free to use produced gas for own use and for re-injection where needed, but the Oman Government has exclusive title to the exported gas. Hence, no gas reserves are carried by PDO. The current production licence started in 1967 and ends on 24th June 2012.

   A separate agreement has been concluded between Shell, Total and Partex with the Oman Government regarding processing and further export of the associated and non-associated gas produced from PDO fields. This gas plant has been funded jointly between the co-venturers and the Oman Government and in recognition of this funding each of the co-venturers receives an annual fee, which is translated back into entitlement volumes for gas and NGL. This operation, administered by **GISCO**, is not addressed in this audit report.

   PDO projects are in principle approved by the PDO board. The Group Capital Allocation system has little influence on these decisions. The verbal statement was made that many of the latest projects might not have passed the stringent Group criteria. Previous UTC levels were at some $4/bl, but these have risen in recent years and the current outlook is that these may rise further to levels up to $10/bl.

2. **PDO production levels** have climbed gradually from 200 Mb/d in the early 1970's to a plateau of 850 Mb/d in the late 1990's. A relatively steep decline has set in since 2000 and current production is at some 700 Mb/d. The fundamental reason for the decline is the progressing maturity of the many producing fields, as evidenced by increasing water cuts and, to a lesser extent, increasing GORs. The first signs of field decline had been countered by an aggressive drilling campaign, including many horizontal wells, which has helped to maintain the earlier plateau production level. Decline, or at least production at lower levels, has now been accepted by PDO (and the shareholders) as inevitable, although further development options are still pursued vigorously.

   At the request of the Oman Government, PDO have committed a team from SIEP-EPT to carry out a comprehensive review of the STOIIPs and reserves of the PDO operated fields (the **STOIIP and Reserves Review Team**, or RSST). This review was in the final stages of completion during the audit. Preliminary conclusions by the RSST were that PDO's STOIIP estimates could largely be confirmed and that current reserves estimates were generally in line with field performance, with the exception of Yibal, Marmul and Qam Alam. Expectation reserves in these fields were concluded to be overstated by some 100 MMstb out of a total expectation reserves base of some 730 MMstb as at 1.1.2003. The RSST also noted that the great majority of the projects associated with the undeveloped reserves were not properly defined (i.e. passed VAR3) and that some were notional to very notional.

   The auditor is indebted to the RSST for sharing their preliminary conclusions with him. The review was found to be highly opportune and it provided a firm basis for the audit's findings.

3. **The characteristics of the PDO fields** tend to be complex in nature. The predominant reservoirs in the northern part of the concession are the Natih and Shuaiba carbonates, which are generally tight and which show varying degrees of fracturing. The predominant reservoirs in the South are the Haima and Al Khlata sandstones. The latter is of glacial origin and has been deposited onto the heavily scoured and eroded Haima sands. It tends to be highly heterogeneous, showing poor to excellent permeabilities.

   The oil in these reservoirs varies from medium-light to heavy quality, with generally low GORs. Coupled with generally poor aquifer activity, this means that reservoir energy tends to be low and that pressure maintenance methods of recovery have to be applied. Water injection is used most widely, but gas injection under gas-oil gravity drainage has been implemented successfully in the steeply dipping Fahud field. Steam and polymer injection have been tried with varying success in the Marmul field in the South. A steam injection pilot has been in progress for several years in the heavily fractured Qam Alam field and a field wide application is now planned. Injection of gas alternated by water (WAG) is seen as a possible further recovery mechanism. Horizontal wells have been used quite successfully and these have led to significantly improved field rates and, in many cases, improved recoveries.

   However, the heterogeneous nature of both the carbonates and the sandstones make good sweep efficiencies a challenging target. The current average recovery factor is some 23% and major fields like Fahud and Natih have recovery factors in this range. The best recoveries are in the 40-50% range (Yibal, Rima, Saih Nihaida). The aspiration by the Oman Government and by PDO is to raise the target recoveries to the latter level for all fields. This will require extraction of the oil from the less permeable portions of the reservoirs, which is counteracted by the many bypass routes (higher permeable 'thief zones' or fractures) that surround these tighter portions.

Many of the PDO fields started production before or during the 1970's and **production declines** are apparent in a number of them. As mentioned, these declines have been countered by an aggressive drilling campaign, and this has helped maintain the PDO plateau production through the 1990's. The many infill wells did not always yield the additional reserves that were aspired. A striking example is seen in the Yibal field, where a massive horizontal infill well campaign did raise production, but now shows a decline towards an ultimate recovery that is not much different from that seen before, see Fig.1. A possible mild arrest of the decline may be evident from recent measurements. The lesson seems to be that many fields will yield additional recoverable volumes, but that they need sufficient time. The prevailing reservoir heterogeneities make gas-oil gravity drainage or induced/spontaneous water imbibition the only realistice option for further recovery. The associated time frames can hardly be accelerated.

4. The RSST have identified that lack of **reservoir understanding** is the single most important bottleneck to production increases and further oil development maturation. Good reservoir understanding requires a reliable and representative 3D reservoir model (first static, then dynamic) and the experience in many other operations in the Group is that the availability of **good 3D seismic** is key to such modelling. Spectacular results have been seen in a number of places making e.g. reservoir character or oil fill clearly visible. Many PDO teams claim that, due to the complex overburden (a number of strong reflective events) and due to the poor acoustic contrast at reservoir level, little use can be made of the available seismic in reservoir characterisation and 3D mapping. This opinion seems to be contradicted by experience in the Rima field, where it has been shown that dedicated re-processing (Cheats and van Gogh filtering) and close cooperation with Exploration Processing can yield much improved results. This should be pursued further to see whether similar results can be obtained in other fields.

5. There is **mis-alignment between individual field proved reserves and the corporate PDO submission.** The root cause for this has been that PDO have historically focused mainly on expectation reserves because these are the subject of intensive discussions with the Oman Government (and also the basis for reserves addition bonuses). Proved reserves estimates for individual fields were prepared but these have hardly been updated and they have now shrunk to unrealistic levels (see 6 below). Because of this, PDO have maintained corporate Group share proved total reserves as an independent entity, not linked to individual field volumes. This approach has not only caused problems with the audit trail but, more seriously, it allowed the Group proved reserves estimate to drift away from realistic levels, see 8 below.

6. **Probabilistic estimates** of STOIIP and ultimate recoveries have been prepared by PDO prior to and in early stages of field development. Recovery factor ranges were obtained from preliminary reservoir modelling. The probabilistic parameter ranges tend still to be based on early well data only, i.e. no adjustment has been made for subsequent dynamic STOIIP and recovery determination from production performance. Hence, the current **proved vs expectation recovery ranges** are too wide for the current stage of field development. The 1999 reserves audit made the same observation. It is therefore disappointing to see that no progress has been made in this respect.

   The conservative nature of the current field proved (P85) recoveries has been further exposed by progressing cumulative production from the fields. With proved and expectation ultimate recoveries fixed, the range between proved and expectation remaining reserves will widen with progressing production. This is clearly visible in Figure 2. Cumulative production has already overtaken proved ultimate recovery in some fields, with the result that these fields now carry negative proved remaining reserves, which is of course impossible. Examples are Rima, Sayyala, Wafra and Runib.

   Group reserves guidelines state clearly that field / reservoir reserves estimates should be made separately for developed (no further activity, or NFA) and undeveloped reserves. The latter must be project based, i.e. they must be associated with clearly identified future development activities (wells, facilities). Estimation of total recoveries based on (largely assumed) recovery factors is archaic and is considered indefensible with the current state of petroleum engineering technology.

   Proved developed reserves should be derived in a deterministic manner, using reservoir model simulations and production trend extrapolations. Proved undeveloped reserves should be evaluated in the same manner, using a low case model realisation. This practice should result in proved undeveloped reserves growing towards expectation levels with progressing field maturity, see Fig. 2.

7. Expectation **developed reserves** are generally, and correctly, derived from well and cluster decline analysis (through Oil Field Manager software) or from reservoir simulation models. The origin of the Group share proved developed estimate was not clear (poor audit trail, see below), but its volume seems broadly in line with the expectation NFA forecast, cut off at the end-of-licence in 2014. This is in accordance with Group guidelines. However, the link between Group share / corporate proved reserves and individual field estimates should be re-established.

8. There is a serious flaw in the corporate **total proved reserves** estimate (and, by implication, in the undeveloped reserves estimate) in that this estimate was not reviewed when the PDO oil production started to decline rapidly from 2000 onwards. Group share reserves should be producible within the current licence period (ending in 2014) and the achievement of production of the stated volumes in that time period has rapidly

become unlikely.

The majority of **undeveloped field reserves** are associated with identified projects. However, many of these are notional or highly notional, while others do not even have a forecast associated with them in the Business Plan. There are of course more mature projects, but many of these are recognised as needing further work or re-work in order to become matured towards the required VAR3 (or FID) level. Even some projects/volumes based on FDPs from the late 1990's, which did pass VAR3 earlier, are now seen as out of date because of subsequent well and field performance. The estimate made by PDO and the SRRT is that 80-90% of the presently identified undeveloped reserves are yet to pass through the VAR3 stage. This means that these volumes do not fulfil present Group and SEC guidelines. It is accepted that the latter have tightened over the last three years (from 'defined' projects to VAR3) and thus further increased the exposure.

The main reason for this regrettable situation is that proper modern static and dynamic modelling has received insufficient attention in PDO in recent years. Much attention was diverted towards short-term activities to provide new well proposals. The situation is now being addressed through an urgent and aggressive study programme.

The Group share total (i.e. undeveloped) reserves booked at 1.1.2003 have thus been seriously overstated. A preliminary estimate by PDO is that of the 907 MMstb (Group share) booked at 1.1.2003, some 400 MMstb are exposed as insufficiently mature according to present Group guidelines.

The impact of this overstatement of reserves is somewhat reduced by the fact that discussions between PDO and the Oman Government towards an extension of the current production licence are currently in progress and that a Heads of Agreement is expected before the end of 2003. A formal extension agreement could then be signed during the first half of 2004. This should bring some 300 MMstb (230 MMstb developed, 70 MMstb undeveloped) into the Group reserves portfolio.

9. It has been noted during the audit that PDO carry a number of projects with **positive expectation reserves but zero proved reserves**. These volumes relate to projects and exploration discoveries, whose development plan is not yet sufficiently mature to merit the booking of proved reserves. The expectation volumes have been agreed with the Oman Government and reserves addition- and exploration bonuses have been received for them. The Group guidelines state clearly that expectation reserves can only be booked if the associated projects fulfil the conditions for proved reserves. If the latter is not the case, the expectation volumes should be booked as SFR. This should be addressed in the forthcoming submission.

10. The **consistency between reserves and Finance** was good. There was full agreement between the 1.1.2003 submissions for reserves and for annual production through Ceres/FIRST, without any corrections being required.

    The verification of the correctness of proved developed and proved total reserves used for UOP asset depletion calculations was not relevant in the case of PDO, because UOP asset depletion has not been applied in the past. The operating agreement stipulates a 40-30-10-10-10% depreciation profile for all capex and this is applied for calculation of the PDO profit margin and for PDO tax returns. Shell Group accounts returns are prepared by Shell Oman Trading (SOMANT) and they do not declare any share in the PDO assets.

    PDO accounts are managed with depreciation through the abovementioned 5-year profile. This is not in accordance with international accounting practices, which require **UOP depletion**, based on proved total and proved developed reserves. This has led to qualifications in external auditor reports, which the Oman Government now want to see removed. Hence, PDO will need to start maintaining proper estimates of individual field proved developed and proved total (i.e. undeveloped) reserves. In view of the current state of PDO's proved reserves estimates (both corporate and by field), PDO have considered it not realistic to start with the new method of UOP accounting per 1.1.2004. A start per 1.1.2005 was seen to be the earliest possible as it would be desirable to avoid major swings in individual field reserves and asset values due to the necessary corrections to be applied during 2004. This view is fully supported.

    Following the implementation of the new method of asset accounting, PDO will be required to re-state their accounts back to 2000. The intention was to do this on the basis of the 1.1.2005 volumes, correcting back only for annual production. The auditor recommendation is to include annual transfers from undeveloped to developed volumes (i.e. development activity) as well, since without this correction the earlier proved developed reserves would become too large.

11. By way of **audit trail**, PDO issue an annual ARPR report, which lists full life cycle (i.e. 30-years) recoverable volumes of oil+condensate (from PDO facilities) and associated gas. The format of the report seems somewhat cumbersome (duplicated data and unnecessary data, e.g. depletion rates, high estimates) and it could benefit from a simplification.

    There is no note or report describing the basis or background for the Group share reserves submission. There is a spreadsheet, but this is not very accessible. Individual field proved reserves in the 1.1.2003 submission are clearly wrong (e.g. larger than expectation volumes and also larger than full-field-life proved reserves). The submission listed changes in the 'Improved Recovery, 'Extensions and Discoveries', and 'Transfers form Undeveloped to Developed' categories, but there was no audit trail to link this back in a quantitative manner to individual fields. The audit trail for PDO's shell share proved reserves is thus extremely poor. Guidelines for a proper audit trail are published on the EPB-P website ('Planning'/'Reserves', to be moved to a new EPS website in due course) and these should be followed. What is needed is a set of tables as presented in Att.2, with a brief note describing the source of the constituent data.

It was noted that there seems to be no effective central PDO library and field teams tend to keep project reports in personal filing cabinets. The RSST reported instances where documents had to be obtained from the Ministry because no copies could be found within PDO, following the temporary abandonment and re-assignment of the Fahud field team. This clearly an undesirable situation and corrective measures should be undertaken.

12. The auditor's suggestion for **the way forward** is as follows:

- In view of the short period left to end-2003, continue booking the present proved developed and proved total Group share reserves volumes in the 1.1.2004 submission, correcting only for 2003 production and for transfers from developed to undeveloped. Total proved reserves replacement ratio should thus be –100%.

- Conclude the production licence extension agreement with the Oman Government during 2004

- Book the proper sum of full life cycle proved developed reserves for all fields and proved undeveloped reserves for all projects fulfilling Group reserves criteria per 1.1.2005. This would require the maturation of at least some 200 MMstb of proved project volumes, to obtain a 100% proved reserves replacement ratio over 2004, see Table 1 below. Group share reserves should be a straight 34% of PDO oil reserves.

- It is suggested to invite the Group Reserves Auditor for a consultation visit towards the end of 2004 to verify with him the status of the of the proved developed and proved undeveloped reserves portfolio.

Group share total proved reserves 1.1.2003 (MMstb)	907
2003 Production	-87
Group share total proved reserves 1.1.2004 (MMstb)	820
Group share total proved reserves 1.1.2004 (MMstb)	820
Overstatement 400 MMstb	-400
Transfer from beyond-licence	+287
New matured proved reserves	+200
2004 Production	-87
Group share total proved reserves 1.1.2005 (MMstb)	820

Table 1 – Progression of PDO Group share proved reserves during 2003 / 2004

Recommendations

1. Pursue the possible improvements in reservoir characterization and modelling that may be obtained from dedicated seismic re-processing (cf Rima).
2. Declare proved developed as equal to expectation developed reserves in fields where there is either a good simulation history match or where there is a well-defined decline rate extrapolation. New fields and reservoirs with neither of these should be assigned a conservative (low case) value for proved developed reserves.
3. Prepare proved and expectation estimates of undeveloped reserves by individual project and by field. Proved estimates should preferably be based on low case simulation model realisations and should be seen to be growing towards expectation levels with progressing field cumulative production. Projects should be ranked according to their maturity, e.g. 'firm' (VAR3/FID), 'mature' (documented FDP), 'possible' (VAR2) etc.
4. Invite the Group Reserves Auditor for a consultation visit towards the end of 2004 to verify the status of Group share proved developed and proved undeveloped reserves.
5. In the re-statement of PDO accounts for years back to 2000, correct the 1.1.2005 volumes back to earlier years by adding annual production and by subtracting annual transfers from undeveloped to developed reserves.
6. Classify projects with expectation reserves but zero proved reserves as SFR in the 1.1.2004 submission.
7. Improve the audit trail for the Group reserves submission by following the guidelines for on the EPB/Planning/Reserves website.
8. Consider the installation of a central library where properly indexed copies of reports and meeting notes (e.g. with the Ministry) can be stored and kept.

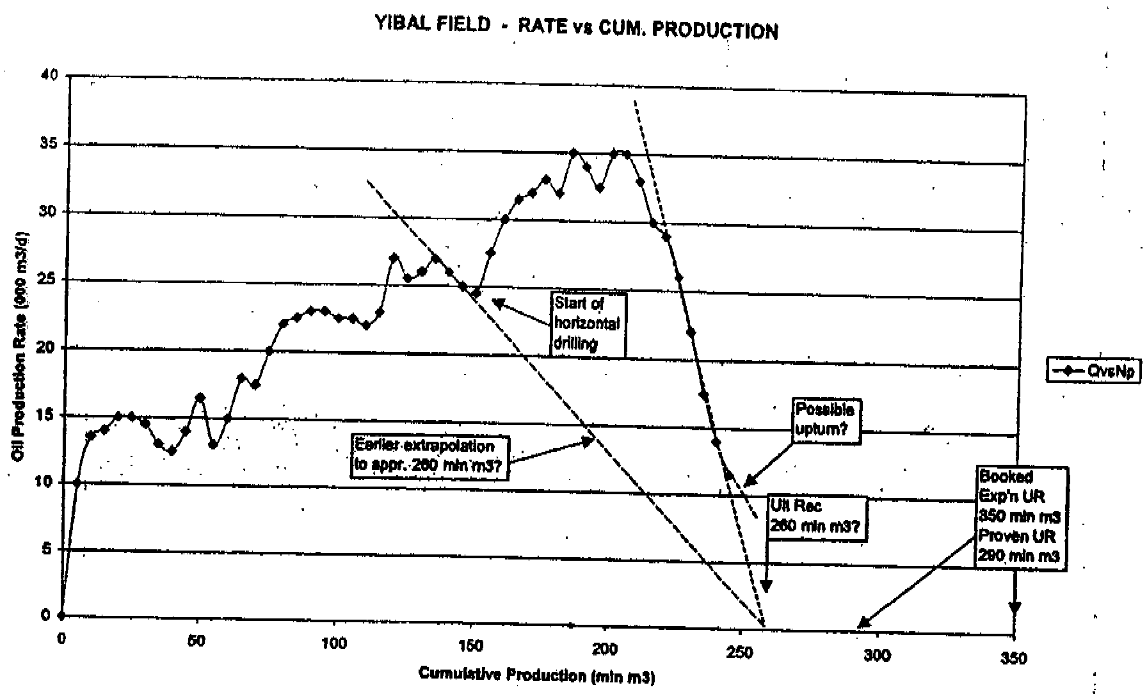

Figure 1 - Yibal field oil rate decline versus cumulative production

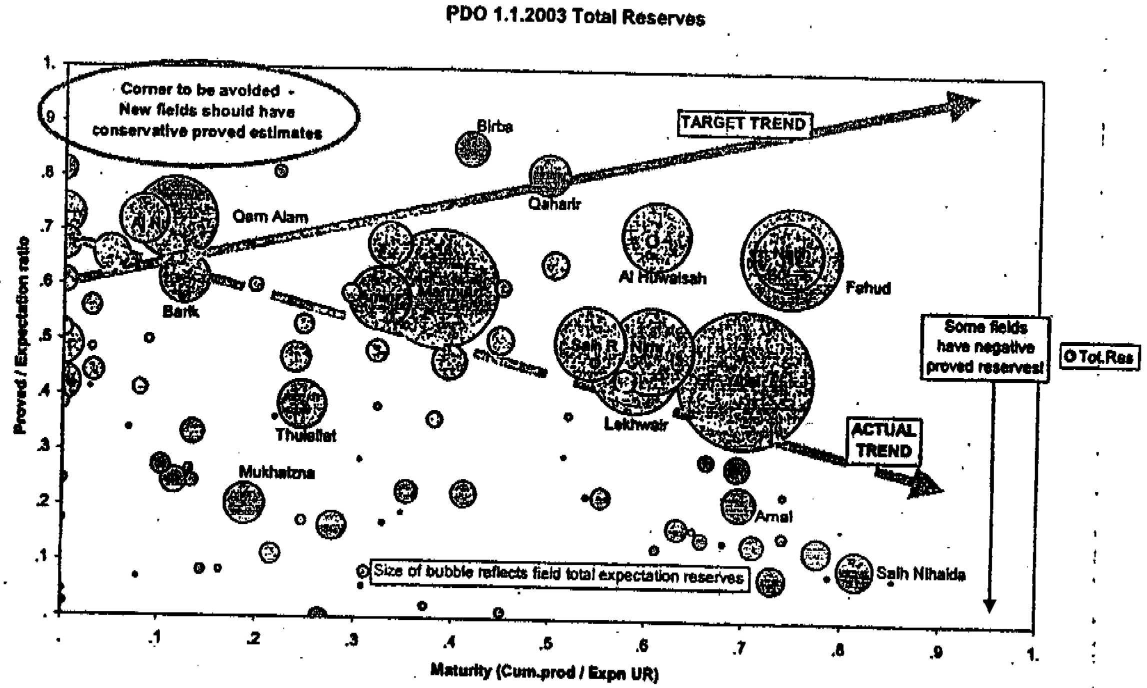

Figure 2 - Ratio of Proved / Expectation Reserves versus progressing field maturity **VIJVER 2239**

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Attachment 2

PDO — Proved Oil / NGL / Gas Reserves as at 1.1.2003

Area / field	Proven HIIP (MMstb / Bscf)	Exp'n HIIP (MMstb / Bscf)	Cum. Prod + Sales 1.1.2003 (MMstb / Bscf)	Proved Rem. Recov. Dev'd (mln m3)	Proved Rem. Recov. Undev (mln m3)	Exp'n Rem. Recov. Tot'l (mln m3)	Maturity (Cum.pr / Exp'n UR) %	Dev. / Tot'l Proved UR %	Prov / Expn Rem %	Proved RF Tot'l %	Exp'n RF Tot'l %
Oil											
YIBAL	557.79	696.12	246.22	10.76	35.39	105.07	70%	68%	44%	61%	50%
FAHUD	845.49	1016.77	166.40	36.59	0.79	56.44	75%	100%	66%	24%	22%
MARMUL	463.11	666.37	49.21	10.91	35.97	70.48	39%	63%	60%	21%	23%
LEKHWAIR	230.75	311.51	67.98	18.28	5.84	47.63	69%	84%	45%	38%	37%
NATIH	414.24	458.39	77.98	16.11	1.78	26.87	74%	98%	67%	23%	23%
HIMR	368.61	426.13	62.93	7.46	12.56	41.09	61%	85%	49%	23%	24%
RIMA	161.46	177.17	74.36	-1.38	0.03	6.84	92%	100%	-20%	45%	46%
AL HUWAISAH	187.70	249.02	42.26	6.52	12.61	27.73	61%	80%	70%	33%	28%
SAIH RAWL	182.82	174.66	36.01	8.71	8.15	29.67	64%	84%	50%	35%	37%
QARN ALAM	185.30	185.80	5.07	0.76	27.30	38.91	12%	10%	72%	20%	24%
Other Fields	2508.29	3638.60	240.78	38.02	85.67	276.44	47%	76%	45%	15%	14%
Total Oil (mln m3)	6058.04	7880.82	1068.17	148.80	225.80	734.86	69%	84%	61%	24%	23%
NGL											
(No NGL reserves carried)							0	0	0	0	0
Total NGL (MMstb)	0.00	0.00	0.00	0.00	0.00	0.00	0	0	0	0	0
Gas (Dry, sales gas volumes)											
(No gas reserves carried)							0	0	0	0	0
Total Gas (Bscf)	0.000	0.000	0.000	0.000	0.000	0.000	0	0	0	0	0

Area / field	Frac'n wrt lic. contd Pr.Dev. %	Frac'n wrt lic. contd Pr.Undv %	Within Licence contd Pr.Dev. (mln m3)	Within Licence contd Pr.Tot'l (mln m3)	Venture Shell share %	Shell Equity Pr.Dev. (10^6 sm3/ 10^9 sm3)	Shell Equity Pr.Tot'l (10^6 sm3/ 10^9 sm3)	1.1.2003 Subm'n Pr.Dev (10^6 sm3/ 10^9 sm3)	1.1.2003 Subm'n Pr.Tot'l (10^6 sm3/ 10^9 sm3)	Prev. Res / Prod Dev. yrs	Prev. Res / Prod Tot yrs
Oil											
YIBAL	400.65%	44.71%	43.12	98.54	34.00%	14.66	20.04			2	9
FAHUD	49.68%	659.52%	18.18	25.00	34.00%	6.18	8.50			10	11
MARMUL	191.08%	79.16%	20.85	49.32	34.00%	7.09	16.77			6	22
LEKHWAIR	133.17%	174.22%	21.66	31.47	34.00%	7.36	10.70			3	4
NATIH	63.01%	125.24%	13.50	15.74	34.00%	4.59	5.35			9	10
HIMR	180.39%	109.34%	13.67	27.35	34.00%	4.65	9.30			2	4
RIMA	266.66%	6382.72%	3.94	6.66	34.00%	1.34	1.92			-1	-1
AL HUWAISAH	79.85%	108.19%	6.21	18.74	34.00%	1.77	6.37			4	11
SAIH RAWL	143.74%	128.12%	9.66	20.08	34.00%	3.28	6.83			3	6
QARN ALAM	94.15%	94.88%	0.71	26.63	34.00%	0.24	9.02			0	316
Other Fields	89.97%	129.57%	34.21	145.21	34.00%	11.63	49.37			2	7
Total Oil (mln m3)	124.07%	106.05%	184.62	424.03	34.00%	62.77	144.17	62.77	144.07	5	8
NGL											
(No NGL reserves carried)			0.00	0.00		0.00	0.00				
Total NGL (MMstb)	0	0	0.00	0.00	0	0.00	0.00	0.00	0.00		
Gas (Dry, sales gas volumes)											
(No gas reserves carried)			0.000	0.000		0.000	0.000				
Total Gas (Bscf)	0	0	0.000	0.000	0	0.000	0.000	0.000	0.000		

Conversion factors used by PDO: 1 m3 = 1 m3; 1 scf = 0.0283 sm3

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

Licence expiry date: 24 June 2012

Audit Trail: Proved developed and undeveloped field volumes (100%) derived from exp' devs Wunder'd volumes, multiplied by proved/exp's total reserves ratio. Disconnect between field volumes in submission and actual field volumes (e.g. within-licence volume exceeds 100% field volume in some cases) Negative proved field reserves in Rima!

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PDO		Proved Oil Reserves Changes 2002 (100%, mln m3)													
Field	Prov.Res. 1.1.2002	Revisions/ Reclassific	Improved Recovery	Extens / Discov's	Purchase in-place	Sales in-place	New Devel'd Reserves (Transf. Und. to	Productn 2002	Prov.Res 1.1.2003	Shell Equity Share % 1.1.2002	Shell Equity Share % 2002 Prod	Shell Equity Share % 1.1.2003	Net Shell Equity, 1.1.2002 (10^6 m3)	Net Shell Equity 1.1.2003 (10^6 m3)	Comments
Proved Developed Reserves															
YIBAL	15.76	0.00	[redacted]					5.00	10.76	136.22%	34.%	136.22%	21.47	14.66	
FAHUD	40.15	0.00						3.56	35.59	15.89%	34.%	18.88%	6.78	6.18	
MARMUL	13.09	0.00						2.18	10.91	64.97%	34.%	64.97%	8.50	7.09	
LEKHWAIR	21.17	0.00						4.91	16.26	45.28%	34.%	45.28%	9.59	7.36	
NATIH	17.90	0.00						1.79	16.11	28.5%	34.%	28.5%	5.10	4.59	
NIMR	12.05	0.00						4.50	7.55	61.33%	34.%	61.33%	7.39	4.63	
RIMA	0.21	0.00						1.69	-1.39	-97.19%	34.%	-97.19%	-0.20	1.34	
AL HUWAISAH	8.31	0.00						1.79	6.52	27.15%	34.%	27.15%	2.26	1.77	
SAIH RAWL	9.03	0.00						2.32	6.71	48.87%	34.%	48.87%	4.42	3.28	
QARN ALAM	0.84	0.00						0.09	0.75	32.01%	34.%	32.01%	0.27	0.24	
Other Fields	55.04	0.00						17.02	38.02	30.59%	34.%	30.59%	16.84	11.63	
Prov.Dev.Resvs (mln m3)	193.56	0.00 0.00	0.00	0.00	0.00	0.00	0.00	44.76	148.80	42.57%	34.%	42.18%	82.41	62.77	
Proved Undeveloped Reserves															
YIBAL	35.39	0.00					[redacted]		35.39	18.2%	[redacted]	18.2%	6.38	6.38	
FAHUD	0.79	0.00							0.79	291.9%		291.9%	2.32	2.32	
MARMUL	36.97	0.00							36.97	26.91%		26.91%	9.98	9.98	
LEKHWAIR	5.64	0.00							5.64	59.24%		59.24%	3.34	3.34	
NATIH	1.78	0.00							1.78	42.58%		42.58%	0.76	0.76	
NIMR	12.56	0.00							12.56	37.18%		37.18%	4.67	4.67	
RIMA	0.03	0.00							0.03	1830.13%		1830.13%	0.59	0.59	
AL HUWAISAH	12.61	0.00							12.61	38.79%		38.79%	4.80	4.80	
SAIH RAWL	8.15	0.00							8.15	43.56%		43.56%	3.55	3.55	
QARN ALAM	27.30	0.00							27.30	32.18%		32.18%	8.78	8.78	
Other Fields	85.67	0.00							85.67	44.06%		44.06%	37.74	37.74	
Prov.Under.Res (mln m3)	225.80	0.00 0.00	0.00	0.00	0.00	0.00			225.80	36.05%		36.05%	81.40	81.40	
Net Group Equity															
Proved Developed Reserves	82.41	-4.42	[redacted]				0.00	15.22	82.77	62.77					
Proved Total Reserves 10^6 m3	163.81	-4.42	0.00	0.00	0.00	0.00	[redacted]	15.22	144.17	144.17					
											Audit Trail:				
1.1.2003 Submission															
Prov.Dev.Res	65.80	4.32					7.27	15.22	62.77	62.77	My 1.1.2002 field data available/				
Prov.Tot'l Res 10^6 m3	162.30	4.74	6.34	1.49				15.22	144.17	144.17	No audit trail for Transfers undev'd to dev'd, Extensions/Discoveries and Improved Recovery				

Conversion factors used by PDO:
1 m3 = 1 m3
1 scf = 0.0283 sm3

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

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V00240180

NOTE – 29 Nov 2003 **CONFIDENTIAL**

From:	Anton A. Barendregt	Group Reserves Auditor, SIEP – EPF - GRA
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	John Bell	Corporate Support Director, SIEP – EPS
	John Malcolm	Managing Director, PDO
Copy:	Abdulla Lamki	Deputy Managing Director, PDO
	Stuart Clayton	Head, Economics, Technology & Planning, PDO
	Stuart Evans	Petroleum Engineering Value Assurance Manager, PDO
	Fatma Kharusi	Finance Director, PDO
	Guy Janssens	Controller, PDO
	Lynda Armstrong	Exploration Director, PDO
	Dave Kemshell	Corporate Function Discipline Head Reservoir Engineering, PDO
	Said Al Harty	Reserves Coordinator, PDO
	(circulation)	SIEP – EPS-P: Hans Bakker, John Pay
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	Maarten Wetselaar	Finance Director, SEPI – EPM
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	Han van Delden	Partner, KPMG Accountants NV
	Brian Puffer	PriceWaterhouseCoopers

DEPOSITION EXHIBIT
Barendregt
#27 2/22/07

SEC PROVED RESERVES AUDIT - PDO (OMAN), 25-28 Oct 2003

I have audited the Proved Reserves submissions of Petroleum Development Oman (PDO) for the year 2002 and the processes that were followed in their preparation. These submissions present the PDO contribution to the Group's externally reported Proved and Proved Developed Reserves and their associated changes as at 31 December 2002.

Total Group share Proved Reserves booked by PDO at the end of 2002 were 144 mln m3 of oil. This represents some 5% of total Group share Proved Reserves on an oil-equivalent basis. Proved reserves replacement ratio for PDO over 2002 was –19%.

The last previous SEC proved reserves audit for PDO was carried out in 1999. This current audit verified the PDO procedures against those laid down in the "Petroleum Resource Volume Guidelines, SIEP 2002-1100/1101" (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 the reserves reporting process with PDO staff. Emphasis was placed on the procedures and methods followed and less on detailed individual field estimates.

The audit found that PDO's Group share proved developed reserves are largely reasonable, but that some 40% of the submitted proved total reserves at 1.1.2003 do not fulfil present reserves guidelines. The reason for this is partly the progressive tightening of Group reserves guidelines (following SEC guidance), but more fundamentally that submitted proved reserves have not been reviewed and reduced in the light of recent downturns in oil production rates. The technical maturity of the projects associated with proved undeveloped reserves had also been eroded due to lack of medium- and long-term field development planning work. PDO have recognised this and have embarked on an aggressive study programme to address the maturation of the associated projects. An imminent agreement with the Government regarding an extension to the current production licence may provide further (partial) relief from the necessity to de-book the overstated volumes.

In view of the many positive changes foreseen during 2004, the audit suggestion is that the present volumes be continued unchanged per 1.1.2004 (reduced by 2003 production), but that a properly based portfolio of proved reserves should be submitted by 1.1.2005. The overall opinion on the state of PDO's 1.1.2003 Proved Reserves submission, taking account of the audit's findings (see Attachment 3), is <u>unsatisfactory</u>. However, improvements have been set in motion.

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

V00300014

A.A. Barendregt

Attachments 1, 2, 3

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DB 28763

Attachment 1

SEC PROVED RESERVES AUDIT - PDO and GISCO 25-28 Oct 2003

MAIN OBSERVATIONS

1. **PDO** are the operator in a land-based concession in the Oman interior. Shareholders in PDO are the Oman Government (60%) and the 'private shareholders' (Shell, TFE and Partex). Shell holds 85% of the private shareholders' share of 40% and has thus title to 34% of the PDO produced crude. PDO are free to use produced gas for own use and for re-injection where needed, but the Oman Government has exclusive title to the exported gas. Hence, no gas reserves are carried by PDO. The current production licence started in 1967 and ends on 24th June 2012.

   A separate agreement has been concluded between Shell, Total and Partex with the Oman Government regarding processing and further export of the associated and non-associated gas produced from PDO fields. This gas plant has been funded jointly between the co-venturers and the Oman Government and in recognition of this funding each of the co-venturers receives an annual fee, which is translated back into entitlement volumes for gas and NGL. This operation, administered by **GISCO**, is not addressed in this audit report.

   PDO projects are in principle approved by the PDO board. The Group Capital Allocation system has little influence on these decisions. The verbal statement was made that many of the latest projects might not have passed the stringent Group criteria. UTC levels (an important screening tool for the PDO board) have risen above $4/bl in recent years and the current outlook is that these may rise further, up to $10/bl for some projects.

2. **PDO production levels** had climbed gradually from 200 Mb/d in the early 1970's to a plateau of 850 Mb/d in the late 1990's. A relatively steep decline has set in since 2001 and current production is at some 700 Mb/d. The fundamental reason for the decline is the progressing maturity of the many producing fields, as evidenced by increasing water cuts and, to a lesser extent, increasing GORs. The first signs of field decline had been countered by an aggressive drilling campaign, including many horizontal wells, which has helped to maintain the earlier plateau production level. Decline, or at least production at lower levels, has now been accepted as inevitable by PDO (and the shareholders), although further development options are still pursued vigorously.

   Prior to and during Programme Build preparation in 2003, PDO staff recognised that some 900 MMstb (100% volumes) of expectation undeveloped reserves could not be supported by identifiable projects. These volumes were still based on assumed recovery factors, which should be seen as an outdated practice. After initial shareholder resistance, these 'unmatched' volumes have now been moved out of the 30-year Programme Build window. To address the resulting shortfall, Shell committed a team from SIEP-EPT and other sources to carry out a comprehensive review of the STOIIPs and reserves of the PDO operated fields (the **STOIIP and Reserves Review Team**, or SRRT). This review was in the final stages of completion during the audit. Preliminary conclusions by the SRRT were that PDO's STOIIP estimates could largely be confirmed and that the expectation project reserves estimates in the 2003 Programme Build could generally be supported. Some exceptions were still found in Marmul and Yibal, where expectation reserves in these fields were considered to be some 20 mln m3 too high. The SRRT also noted that the great majority of the projects associated with the undeveloped reserves were not properly defined (i.e. passed VAR3) and that some were notional to very notional.

   The auditor is indebted to the SRRT for sharing their preliminary conclusions with him. The review was found to be highly opportune and it provided a firm basis for the audit's findings.

3. **The characteristics of the PDO fields** tend to be complex in nature. The predominant reservoirs in the northern part of the concession are the Natih and Shuaiba carbonates, which are generally tight and which show varying degrees of fracturing. The predominant reservoirs in the South are the Haima and Al Khlata sandstones. The latter is of glacial origin and has been deposited onto the heavily scoured and eroded Haima sands. It tends to be highly heterogeneous, showing poor to excellent permeabilities.

   The oil in these reservoirs varies from medium-light to heavy quality, with generally low GORs. Coupled with generally poor aquifer activity, this means that reservoir energy tends to be low and that pressure maintenance methods of recovery have to be applied. Water injection is used most widely, but gas injection under gas-oil gravity drainage has been implemented successfully in the steeply dipping Fahud field. Steam and polymer injection have been tried with varying success in the Marmul field in the South. A steam injection pilot has been in progress for several years in the heavily fractured Qarn Alam field and a field wide application is now planned. Injection of gas alternated by water (WAG) is seen as a possible further recovery mechanism. Horizontal wells have been used quite successfully and these have led to significantly improved field rates and, in many cases, improved recoveries.

   The heterogeneous nature of both the carbonates and the sandstones make **good sweep efficiencies a challenging target**. The current average recovery factor is some 23% and major fields like Fahud and Natih have recovery factors in this range. The best recoveries are in the 40-50% range (Yibal, Rima, Saih Nihaida).

The aspiration by the Oman Government and by PDO is to raise the target recoveries to the latter level for all fields. This will require extraction of the oil from the less permeable portions of the reservoirs, which is counteracted by the many bypass routes (higher permeable 'thief zones' or fractures) that surround these tighter portions.

Many of the PDO fields started production before or during the 1970's and production declines are apparent in a number of them. As mentioned, these declines have been countered by an aggressive drilling campaign, and this has helped maintain the PDO plateau production through the 1990's. The many infill wells did not always yield the additional reserves that were aspired. A striking example is seen in the Yibal field, where a massive horizontal infill well campaign did raise production, but where the subsequent much steeper decline seems to point towards an ultimate recovery that is not much different from that seen before, see Fig.1. A possible mild arrest of the decline may be evident from recent measurements. The lesson seems to be that many fields will yield additional recoverable volumes, but that they need sufficient time. The prevailing reservoir heterogeneities make gas-oil gravity drainage or induced/spontaneous water imbibition the only realistic option for further recovery. The associated time frames can hardly be accelerated.

4. The SRRT have identified that lack of **reservoir understanding** is the single most important bottleneck to production increases and further oil development maturation. Good reservoir understanding requires a reliable and representative 3D reservoir model (first static, then dynamic) and the experience in many other operations in the Group is that the availability of **good 3D seismic** is key to such modelling. Spectacular results have been seen in a number of other Group operated areas making e.g. reservoir character or oil fill clearly visible. Many teams in the South Oman area to claim that, due to the complex overburden (a number of strong reflective events) and due to the poor acoustic contrast at reservoir level, little use can be made of existing seismic in reservoir characterisation and 3D mapping. This opinion seems to be contradicted by experience in the Rima field, where it has been shown that dedicated re-processing (Cheats and van Gogh filtering) and close cooperation with Exploration Processing can yield much improved results. Further pursuit of this, to see whether similar results can be obtained in other fields, is strongly encouraged and supported.

5. There is **mis-alignment between individual field proved reserves and the corporate PDO submission.** The root cause for this has been that PDO have historically focused mainly on expectation reserves because these are the basis for business planning. Expectation reserves are also the subject of intensive discussions with the Oman Government (and also the basis for reserves addition bonuses!). Proved reserves estimates for individual fields were prepared but these have hardly been updated and they have now shrunk to unrealistic levels (see 6 below). Because of this, PDO have maintained corporate Group share proved total reserves as an independent entity, not linked to individual field volumes. This approach has not only caused problems with the audit trail but, more seriously, it allowed the Group proved reserves estimate to drift away from realistic levels, see 8 below.

6. **Probabilistic estimates** of STOIIP and ultimate recoveries have been prepared by PDO prior to and in early stages of field development. Recovery factor ranges were obtained from preliminary reservoir modelling. Although new well results are incorporated, the probabilistic parameter ranges still seem to reflect early well data only, i.e. little adjustment seems to be made for subsequent dynamic STOIIP and recovery determination from production performance. Hence, the current **proved vs. expectation recovery ranges** in individual fields are too wide for the current stage of field development. The 1999 reserves audit made the same observation. It is therefore disappointing to see that no progress has been made in this respect.

The conservative nature of the current field proved (P85) recoveries has been further exposed by progressing cumulative production from the fields. With proved and expectation ultimate recoveries fixed, the range between proved and expectation remaining reserves will widen with progressing production. This is clearly visible in Figure 2. Cumulative production has already overtaken proved ultimate recovery in some fields, with the result that these fields now carry negative proved remaining reserves, which is of course impossible. Examples are Rima, Sayyala, Wafra and Runib.

Group reserves guidelines state clearly that field / reservoir reserves estimates should be made separately for developed (no further activity, or NFA) and undeveloped reserves. The latter must be project based, i.e. they must be associated with clearly identified future development activities (wells, facilities). Estimation of total recoveries based on (largely assumed) recovery factors is archaic and is considered indefensible with the current state of petroleum engineering technology.

Proved developed reserves should be derived in a deterministic manner, using reservoir model simulations and production trend extrapolations. Proved undeveloped reserves should be evaluated through simulation, using either a low case model realisation or e.g. a specific assessment for infill wells whether they address 'proved areas'. This practice should result in proved undeveloped reserves growing towards expectation levels with progressing field maturity, see Fig. 2.

7. Expectation **developed reserves** are generally, and correctly, derived from well and cluster decline analysis (through Oil Field Manager software) or from reservoir simulation models. The Group share proved developed estimate was derived from the expectation NFA forecast, cut off at the end-of-licence in June 2012. This is in accordance with Group guidelines. However, the link between Group share / corporate proved reserves and individual field estimates should be re-established.

8. There is a serious flaw in the corporate **total proved reserves** estimate (and, by implication, in the undeveloped reserves estimate) in that this estimate was not reviewed when the PDO oil production started to decline rapidly from 2000 onwards. Group share reserves should be producible within the current licence period (ending in 2012) and the achievement of production of the stated volumes in that time period has rapidly become unlikely.

   The majority of the declared corporate **undeveloped field reserves** are associated with identified projects. However, many of these are notional or highly notional. There are of course more mature projects, but many of these are recognised as needing further work or re-work in order to become matured towards the required VAR3 (or FID) level. Even some projects/volumes based on FDPs from the late 1990's, which did pass VAR3 earlier, are now seen as out of date because of subsequent well and field performance. The estimate made by PDO and the SRRT is that 80-90% of the presently identified undeveloped reserves are yet to pass through the VAR3 stage. This means that these volumes do not fulfil present Group and SEC guidelines. It is accepted that the latter have tightened over the last three years (from 'defined' projects to VAR3) and thus further increased the exposure.

   The main reason for this regrettable situation is that proper modern static and dynamic modelling has received insufficient attention in PDO in recent years. Much attention was diverted towards short-term activities to provide new well proposals. The situation is now being addressed through an urgent and aggressive study programme.

   The Group share undeveloped reserves at 1.1.2003 (and hence the total proved reserves) contain therefore a large portion that does not fulfil current Group reserves guidelines. A preliminary estimate made by PDO during 2003 is that of the 907 MMstb (Group share) booked at 1.1.2003, some 400 MMstb are exposed in this manner.

   It is noted that the 907 MMstb submission at 1.1.2003 had been based on SIEP advice, reducing it from a higher value proposed by PDO. This advice was seen as a preliminary correction, pending results of further PDO investigations and the planned 2003 reserves audit. The approach was supported by the Group reserves auditor, but he did express concern in his end-2002 report that PDO's proved reserves were overstated.

   The impact of this effective overstatement of reserves is somewhat reduced by the fact that discussions between PDO and the Oman Government towards an extension of the current production licence are currently in progress and that a Heads of Agreement is expected before the end of 2003. A formal extension agreement could then be signed during the first half of 2004. This should bring some 300 MMstb of mature project reserves (230 MMstb developed, 70 MMstb undeveloped) into the Group reserves portfolio.

9. It was noted during the audit that PDO are proposing to carry a number of projects with **positive expectation reserves but zero proved reserves**. These volumes relate to projects and exploration discoveries, whose development plan is not yet sufficiently mature to merit the booking of proved reserves. The expectation volumes have been agreed with the Oman Government and reserves addition- and exploration bonuses will be received for them. The Group guidelines state clearly that expectation reserves can only be booked if the associated projects fulfil the conditions for proved reserves. If the latter is not the case, the expectation volumes should be booked as SFR.

10. The **consistency between reserves and Finance** was good. There was full agreement between the 1.1.2003 submissions for reserves and for annual production through Ceres/FIRST, without any corrections being required.

    The verification of the correctness of proved developed and proved total reserves used for UOP asset depletion calculations was not relevant in the case of PDO, because UOP asset depletion was not applied in the past. The operating agreement stipulates a 40-30-10-10-10% depreciation profile for all capex and this is applied for calculation of the PDO profit margin and for PDO tax returns. Shell Group accounts returns are prepared by Shell Oman Trading (SOMANT) and they do not declare any share in the PDO assets.

    PDO accounts are declared with asset depreciation through the abovementioned 5-year profile. This is not in accordance with international accounting practices, which require **UOP depletion**, based on proved total and proved developed reserves. This has led to continuing qualifications in external auditor reports (since 1967), which the Oman Government now want to see removed. Hence, PDO will need to start maintaining proper estimates of individual field proved developed and proved total (i.e. undeveloped) reserves. In view of the current state of PDO's proved reserves estimates (both corporate and by field), PDO have considered it not realistic to start with the new method of UOP accounting per 1.1.2004. A start per 1.1.2005 was seen to be the earliest possible as it would be desirable to avoid major swings in individual field reserves and asset values due to the necessary corrections to be applied during 2004. This view is fully supported.

    Following the implementation of the new method of asset accounting, PDO will be required to re-state their accounts back to 2000. The intention was to do this on the basis of the 1.1.2005 volumes, correcting back only for annual production. The auditor recommendation is to include annual transfers from undeveloped to developed volumes (i.e. development activity) as well, since without this correction the earlier proved developed reserves would become too large.

11. By way of **audit trail**, PDO issue an annual ARPR report, which lists full life cycle (i.e. 30-years) recoverable volumes of oil+condensate (from PDO facilities) and associated gas. The format of the report seems

somewhat cumbersome (duplicated data and unnecessary data, e.g. depletion rates, high estimates) and it could benefit from a simplification.

There is no note or report describing the basis or background for the Group share reserves submission. There is a spreadsheet, but this is not very accessible. Individual field proved reserves in the 1.1.2003 submission are clearly wrong (e.g. larger than expectation volumes and also larger than full-field-life proved reserves). The submission listed changes in the 'Improved Recovery, 'Extensions and Discoveries', and 'Transfers form Undeveloped to Developed' categories, but there was no audit trail to link this back in a quantitative manner to individual fields. The audit trail for PDO's Group share proved reserves is thus extremely poor. Guidelines for a proper audit trail are published on the EPB-P website ('Planning'/'Reserves', to be moved to a new EPS website in due course) and these should be followed. What is needed is a set of tables, at field level, with a format as presented in Att.2 and with a brief note describing the source of the constituent data.

It was noted that, whilst there is a central PDO library, field teams tend to keep project reports in personal filing cabinets. The SRRT reported instances where documents had to be obtained from the Ministry because no copies could be found within PDO, following the temporary abandonment and re-assignment of the Fahud field team. This is clearly an undesirable situation and corrective measures should be undertaken.

12. The auditor's suggestion for **the way forward** is as follows:

- In view of the short period left to end-2003, it will not be possible to arrive at a properly defined set of individual field proved reserves that could form a sound basis for the PDO corporate Group share proved reserves booking.

- Assuming that a Heads of Agreement can be obtained with the Oman Government before end 2003 regarding an extension of the PDO production licence, it is argued that the impact of the present reserves overstatement is reduced.

- Hence, it is suggested that the present proved developed and proved total Group share reserves volumes be continued in the 1.1.2004 submission, correcting only for 2003 production and for transfers from developed to undeveloped. Total proved reserves replacement ratio should thus be 0%.

- The proper sum of full life cycle proved developed reserves for all fields and proved undeveloped reserves for all projects fulfilling Group reserves criteria should then be booked per 1.1.2005. This would require the maturation of at least some 200 MMstb of proved project volumes, to obtain a 100% proved reserves replacement ratio over 2004, see Table 1 below. Group share reserves should be a straight 34% of PDO oil reserves.

- It is suggested to invite the Group Reserves Auditor for a consultation visit towards the end of 2004 to verify with him the status of the proved developed and proved undeveloped reserves portfolio.

Group share total proved reserves 1.1.2003 (MMstb)	907
2003 Production	-87
Group share total proved reserves 1.1.2004 (MMstb)	820
Group share total proved reserves 1.1.2004 (MMstb)	820
Overstatement 400 MMstb	-400
Transfer from beyond-licence	+287
New matured proved reserves	+200
2004 Production	-87
Group share total proved reserves 1.1.2005 (MMstb)	820

Table 1 – Possible progression of PDO proved reserves during 2003 / 2004

Recommendations

1. Continue pursuing the possible improvements in reservoir characterization and modelling that may be obtained from dedicated seismic re-processing (cf Rima).

2. Declare proved developed as equal to expectation developed reserves in fields where there is either a good simulation history match or where there is a well-defined decline rate extrapolation. New fields and reservoirs with neither of these should be assigned a conservative (low case) value for proved developed reserves.

3. Prepare proved and expectation estimates of undeveloped reserves by individual project and by field. Proved estimates should preferably be based on low case simulation model realisations and should be seen to be growing towards expectation levels with progressing field cumulative production. Projects should be ranked according to their maturity, e.g. 'firm' (VAR3/FID), 'mature' (documented FDP), 'possible' (VAR2) etc.

4. Invite the Group Reserves Auditor for a consultation visit towards the end of 2004 to verify the status of Group share proved developed and proved undeveloped reserves.

5. In the re-statement of PDO accounts for years back to 2000, correct the 1.1.2005 volumes back to earlier years by adding annual production and by subtracting annual transfers from undeveloped to developed reserves.
6. Classify projects with expectation reserves but zero proved reserves as SFR in the next appropriate submission.
7. Improve the audit trail for the Group reserves submission by following the guidelines for reserves audit trails on the EPB/Planning/Reserves website.
8. Ensure that the central library facilities are fully utilised by all teams, particularly where it relates to proper storing and indexing of copies of all reports and meeting notes (e.g. with the Ministry).

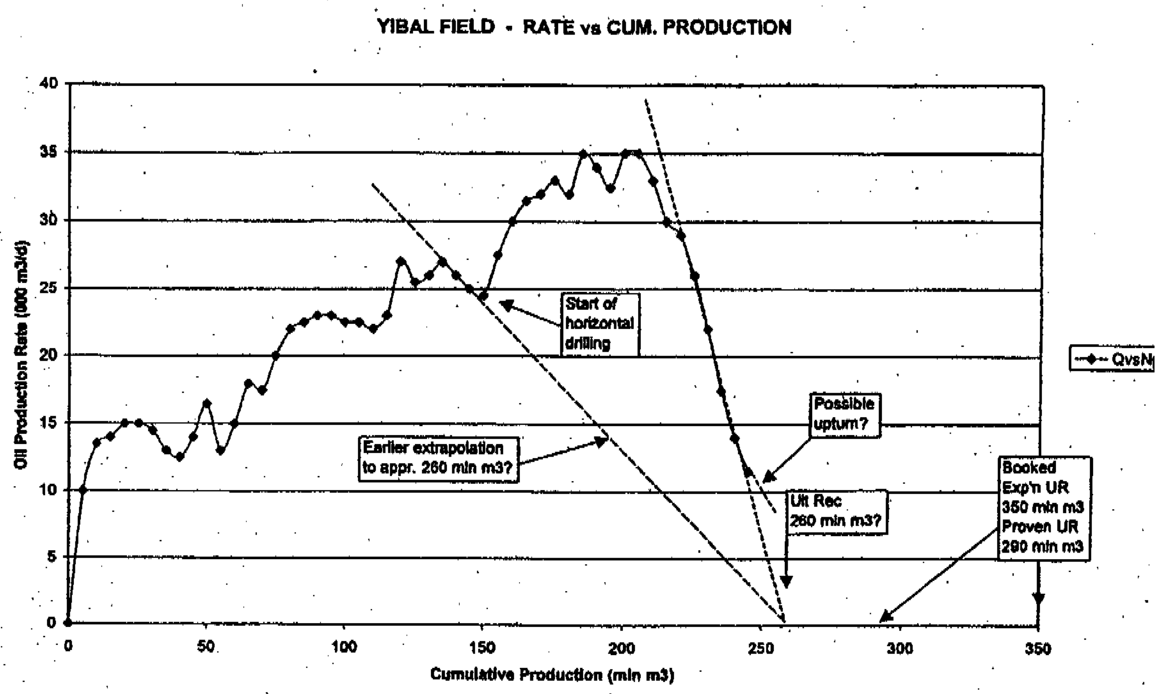

Figure 1 - Yibal field oil rate decline versus cumulative production

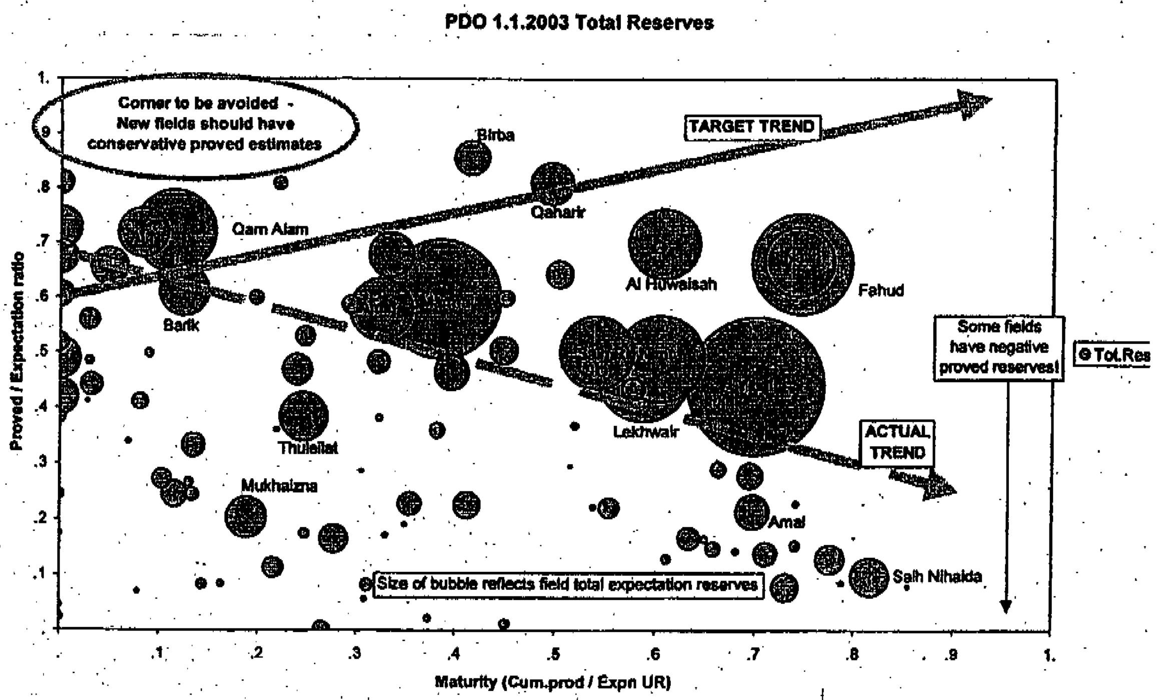

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Figure 2 - Ratio of Proved / Expectation Reserves versus progressing field maturity

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Attachment 2

PDO					Proved Oil / NGL / Gas Reserves as at 1.1.2003																	
Area / field	Proven HIIP	Exp'n HIIP	Cum. Prod + Sales 1.1.2003	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	Prov / Exp'n Rem	Proved RF Tot'l	Exp'n RF Tot'l	Fract'n wrt lic. commit Pr.Dev.	Fract'n wrt lic. commit Pr.Undev	Within Licence commit Pr.Dev.	Within Licence commit Pr.Tot'l	Venture Shell share %	Shell Equity Pr.Dev.	Shell Equity Pr.Tot'l	1.1.2003 Subm'n Pr.Dev	1.1.2003 Subm'n Pr.Tot'l	Prov. Res / Prod Dev.	P R P T
	MMstb / Bscf	MMstb / Bscf	MMstb / Bscf	mln m3	mln m3	mln m3	%	%	%	%	%	%	%	mln m3	mln m3	%	10^6 sm3/ 10^9 sm3	10^6 sm3/ 10^9 sm3	10^6 sm3/ 10^9 sm3	10^6 sm3/ 10^9 sm3	yrs	
Oil																						
YIBAL	667.79	666.12	245.22	10.76	35.39	105.67	70%	68%	44%	51%	50%	400.65%	44.71%	43.12	68.94	34.00%	14.66	20.04			2	
FAHUD	845.49	1016.77	166.40	36.59	0.79	56.44	75%	100%	65%	24%	22%	49.69%	659.52%	18.18	26.00	34.00%	6.18	6.60			10	
MARMUL	483.11	588.37	48.21	10.91	35.97	78.48	38%	63%	60%	21%	23%	191.09%	79.16%	20.85	48.32	34.00%	7.09	16.77			5	
LEKHWAIR	230.75	311.61	67.88	16.26	5.64	47.53	68%	94%	46%	38%	37%	139.17%	174.22%	21.66	31.47	34.00%	7.36	10.70			3	
NATIH	414.24	458.39	77.98	16.11	1.78	26.87	74%	88%	67%	23%	23%	83.81%	125.24%	13.50	15.74	34.00%	4.69	5.35			3	
NIMR	388.81	428.13	62.93	7.55	12.56	41.08	81%	85%	49%	23%	24%	180.38%	109.34%	13.62	27.38	34.00%	4.63	9.30			2	
RIMA	161.46	177.17	74.36	-1.38	0.03	6.64	92%	100%	-20%	45%	45%	-305.06%	5962.72%	3.94	5.65	34.00%	1.34	1.92			-1	
AL HUWAISAH	187.70	248.02	42.35	6.52	12.51	27.23	61%	60%	70%	33%	28%	79.85%	108.19%	5.21	10.74	34.00%	1.77	8.37			4	
SAIH RAWL	142.32	174.85	38.01	6.71	8.16	29.87	54%	84%	60%	35%	37%	143.74%	128.17%	9.65	20.09	34.00%	3.28	6.83			3	
QARN ALAM	165.30	166.68	6.07	0.75	27.30	38.91	12%	18%	72%	20%	24%	94.15%	84.58%	0.71	26.53	34.00%	0.24	9.02			8	3
Other Fields	2509.29	3830.60	240.70	38.02	65.67	276.44	47%	76%	45%	15%	14%	89.97%	129.57%	34.21	145.21	34.00%	11.63	49.37			2	
Total Oil (mln m3)	6065.04	7899.67	1068.17	148.80	226.80	734.66	69%	84%	61%	24%	23%	124.07%	108.03%	184.62	424.08	34.00%	62.77	144.17	62.77	144.17	5	
NGL																						
(No NGL reserves carried)							0	0	0	0	0			0.00	0.00		0.00	0.00				
Total NGL (MMstb)	0.00	0.00	0.00	0.00	0.00	0.00	0	0	0	0	0	0	0	0.00	0.00	0	0.00	0.00	0.00	0.00		
Gas (Dry, sales gas volumes)																						
(No gas reserves carried)							0	0	0	0	0			0.000	0.000		0.000	0.000				
Total Gas (Bscf)	0.000	0.000	0.000	0.000	0.000	0.000	0	0	0	0	0	0	0	0.000	0.000	0	0.000	0.000	0.000	0.000		

Conversion factors used by PDO: 1 m3 = 1 m3; 1 scf = 0.0283 sm3

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

Licence expiry date: 24 June 2012

Audit Trail: Proved developed and undeveloped field volumes (100%) derived from exp' devo'd/undev'd volumes, multiplied by proved/exp'n total reserves ratio.
Disconnect between field volumes in submission and actual field volumes (e.g. within-licence volume exceeds 100% field volume in some cases).
Negative proved field reserves in Rima!

PDO			Proved Oil Reserves Changes 2002 (100%, mln m3)												
Field	Prov.Res. 1.1.2002	Revisions/ Reclass'ns	Improved Recovery	Extens./ Discov's	Purchase in place	Sales in-place	New Devel'd Reserves (Transf. Und. to	Product'n 2002	Prov.Res 1.1.2003	Shell Equity Share % 1.1.2002	Shell Equity Share % 2002 Prod	Shell Equity Share % 1.1.2003	Net Shell Equity 1.1.2002 (10^6 m3)	Net Shell Equity 1.1.2003 (10^6 m3)	Comments
Proved Developed Reserves															
YIBAL	15.76	0.00						6.00	10.76	136.22%	34.%	136.22%	21.47	14.66	
FAHUD	40.15	0.00						3.56	36.59	16.89%	34.%	16.89%	6.78	6.18	
MARMUL	13.09	0.00						2.18	10.91	64.97%	34.%	64.97%	8.50	7.09	
LEKHWAIR	21.17	0.00						4.91	16.26	45.28%	34.%	45.28%	8.58	7.36	
NATIH	17.90	0.00						1.79	16.11	28.5%	34.%	28.5%	5.10	4.69	
NIMR	12.05	0.00						4.50	7.55	61.33%	34.%	61.33%	7.38	4.63	
RIMA	0.21	0.00						1.59	-1.38	47.19%	34.%	47.19%	-0.20	1.34	
AL HUWAISAH	8.31	0.00						1.79	6.52	27.15%	34.%	27.15%	2.28	1.77	
SAIH RAWL	9.03	0.00						2.32	6.71	48.87%	34.%	48.87%	4.42	3.28	
QARN ALAM	0.84	0.00						0.09	0.75	32.01%	34.%	32.01%	0.27	0.24	
Other Fields	55.04	0.00						17.02	38.02	30.60%	34.%	30.60%	16.84	11.63	
		0.00													
Prov.Dev.Resv (mln m3)	193.56	0.00	0.00	0.00	0.00	0.00	0.00	44.76	148.80	42.67%	34.%	42.18%	82.41	62.77	
Proved Undeveloped Reserves															
YIBAL	35.39	0.00							35.39	18.2%		18.2%	6.38	6.38	
FAHUD	0.79	0.00							0.79	291.9%		291.9%	2.32	2.32	
MARMUL	35.97	0.00							35.97	26.91%		26.91%	9.68	9.68	
LEKHWAIR	5.64	0.00							5.64	59.24%		59.24%	3.34	3.34	
NATIH	1.78	0.00							1.78	42.68%		42.68%	0.76	0.76	
NIMR	12.56	0.00							12.56	37.18%		37.18%	4.67	4.67	
RIMA	0.03	0.00							0.03	1830.13%		1830.13%	0.58	0.58	
AL HUWAISAH	12.51	0.00							12.51	38.70%		38.70%	4.80	4.80	
SAIH RAWL	8.16	0.00							8.16	43.65%		43.65%	3.56	3.56	
QARN ALAM	27.30	0.00							27.30	32.18%		32.18%	8.78	8.78	
Other Fields	65.67	0.00							65.67	44.05%		44.05%	37.74	37.74	
		0.00													
Prov.Undev.Res (mln m3)	226.80	0.00	0.00	0.00	0.00	0.00			225.80	36.05%		36.05%	81.40	81.40	
Net Group Equity															
Proved Developed Reserves	82.41	-4.42					0.00	15.22	62.77	62.77					
Proved Total Reserves	163.81	-4.42	0.00	0.00	0.00	0.00		15.22	144.17	144.17					
10^6 m3												Audit Trail:			
1.1.2003 Submission															
Prov.Dev.Res	65.80	4.52					7.27	15.22	62.77	62.77		No 1.1.2002 field data available!			
Prov.Tot'l Res	162.30	-4.74	8.34	1.49				15.22	144.17	144.17		No audit trail for Transfers undev'd-to-dev'd, Extensions/Discoveries and Improved Recovery!			
10^6 m3															

Conversion factors used by PDO: 1 m3 = 1 m3; 1 scf = 0.0283 sm3

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

Attachment 2.1

..C RESERVES AUDIT - VOLUMES RECONCILIATIO..
PDO 1.1.2003

PDO — Proved Oil / NGL / Gas Reserves as at 1.1.2003

Area / field	Proven HIIP MMstb / Bscf	Exp'n HIIP MMstb / Bscf	Cum. Prod = Sales 1.1.2003 MMstb / Bscf	Proved Rem. Recov. Dev'd mln m3	Proved Rem. Recov. Undev mln m3	Exp'n Rem. Recov. Tot'l mln m3	Maturity (Cum.pr / Exp'n URI %)	Dev. / Tot'l Proved UR. %	Prov / Expn Revs %	Proved RF Tot'l %	Exp'n RF Tot'l %
Oil											
YIBAL	587.79	686.12	248.22	10.76	35.39	105.07	70%	88%	44%	51%	50%
FAHUD	845.49	1016.77	168.40	36.69	0.79	66.44	75%	100%	88%	24%	22%
MARMUL	483.11	566.37	49.21	10.91	35.97	78.48	39%	63%	60%	21%	23%
LEKHWAIR	230.75	311.51	67.98	16.28	5.64	47.63	59%	94%	46%	39%	37%
NATIH	414.24	458.39	77.98	16.11	1.78	26.87	74%	98%	67%	23%	23%
NIMR	368.61	426.13	62.93	7.55	12.56	41.08	61%	85%	49%	23%	24%
RIMA	161.45	177.17	74.36	-1.38	0.03	6.84	92%	100%	-20%	45%	46%
AL HUWAISAH	187.70	248.02	42.25	6.52	12.51	27.23	61%	80%	70%	33%	26%
SAIH RAWL	142.32	174.65	35.01	6.71	8.15	29.67	54%	84%	50%	35%	37%
QARN ALAM	165.30	185.68	5.07	0.75	27.30	38.91	12%	18%	72%	20%	24%
Other Fields	2509.29	3638.60	240.78	36.02	65.67	276.44	47%	76%	45%	15%	14%
Total Oil (mln m3)	6056.04	7899.62	1068.17	148.60	226.80	734.66	59%	64%	51%	24%	23%
NGL											
(No NGL reserves carried)							0	0	0	0	0
Total NGL (MMstb)	0.00	0.00	0.00	0.00	0.00	0.00	0	0	0	0	0
Gas (Dry, sales gas volumes)											
(No gas reserves carried)							0	0	0	0	0
Total Gas (Bscf)	0.000	0.000	0.000	0.000	0.000	0.000	0	0	0	0	0

Area / field	Fract'n w/i lic. comtd Pr.Dev. %	Fract'n w/i lic. comtd Pr.Undv %	Within Licence comtd Pr.Dev. mln m3	Within Licence comtd Pr.Tot'l mln m3	Venture Shell share %	Shell Equity Pr.Dev. 10^6 sm3/ 10^9 sm3	Shell Equity Pr.Tot'l 10^6 sm3/ 10^9 sm3	1.1.2003 Subm'n Pr.Dev 10^6 sm3/ 10^9 sm3	1.1.2003 Subm'n Pr.Tot'l 10^6 sm3/ 10^9 sm3	Prov. Res / Prod Dev. yrs	Prov. Res / Prod Tot'l yrs
Oil											
YIBAL	400.65%	44.71%	43.12	58.94	34.00%	14.66	20.04			2	9
FAHUD	49.88%	858.52%	18.18	25.00	34.00%	6.16	8.50			10	11
MARMUL	191.09%	79.16%	20.85	49.32	34.00%	7.09	16.77			5	22
LEKHWAIR	133.17%	174.22%	21.65	31.47	34.00%	7.36	10.70			3	4
NATIH	83.81%	125.24%	13.50	15.74	34.00%	4.59	5.35			9	10
NIMR	180.38%	109.34%	13.62	27.35	34.00%	4.63	9.30			2	4
RIMA	-285.86%	6382.72%	3.94	5.65	34.00%	1.34	1.92			-1	-1
AL HUWAISAH	79.85%	108.19%	5.21	18.74	34.00%	1.77	6.37			4	11
SAIH RAWL	143.74%	128.12%	9.65	20.09	34.00%	3.28	6.83			3	6
QARN ALAM	94.15%	94.58%	0.71	26.53	34.00%	0.24	9.02			8	318
Other Fields	89.97%	129.57%	34.21	145.21	34.00%	11.63	49.37			2	7
Total Oil (mln m3)	124.07%	106.03%	184.62	424.03	34.00%	62.77	144.17	62.77	144.17	3	8
NGL											
(No NGL reserves carried)			0.00	0.00		0.00	0.00				
Total NGL (MMstb)	0	0	0.00	0.00	0	0.00	0.00	0.00	0.00		
Gas (Dry, sales gas volumes)											
(No gas reserves carried)			0.000	0.000		0.000	0.000				
Total Gas (Bscf)	0	0	0.000	0.000	0	0.000	0.000	0.000	0.000		

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Conversion factors used by PDO:
1 m3 = 1 m3
1scf = 0.0283 sm3

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

Licence expiry date: 24 June 2012

Audit Trail: Proved developed and undeveloped field volumes (100%) derived from exp' devd'd/undev'd volumes, multiplied by proved/exp'n total reserves ratio.
Disconnect between field volumes in submission and actual field volumes (e.g. within-licence volume exceeds 100% field volume in some cases!)
Negative proved field reserves in Rima!

DB 28771

V00300022

DB 28772

SEC RESERVES AUDIT - VOLUMES RECONCILIATION
PDO 1.1.2003

Attachment 2.2

PDO — Proved Oil Reserves Changes 2002 (100%, mln m3)

Field	Prov.Res. 1.1.2002	Revisions/ Reclassns	Improved Recovery	Extens./ Discov's	Purchase in-place	Sales in-place	New Devel'd Reserves (Transf. Und. to Dev)	Productn 2002	Prov.Res 1.1.2003	Shell Equity Share % 1.1.2002	Shell Equity Share % 2002 Prod	Shell Equity Share % 1.1.2003	Net Shell Equity 1.1.2002 (10^6 m3)	Net Shell Equity 1.1.2003 (10^6 m3)	Comments
Proved Developed Reserves															
YIBAL	15.76	0.00						5.00	10.76	136.22%	34.%	136.22%	21.47	14.66	
FAHUD	40.15	0.00						3.56	36.59	16.89%	34.%	16.89%	6.78	6.18	
MARMUL	13.09	0.00						2.18	10.91	64.97%	34.%	64.97%	8.50	7.09	
LEKHWAIR	21.17	0.00						4.91	16.26	45.26%	34.%	45.26%	9.58	7.36	
NATIH	17.90	0.00						1.79	16.11	28.5%	34.%	28.5%	5.10	4.59	
NIMR	12.05	0.00						4.50	7.55	61.33%	34.%	61.33%	7.39	4.63	
RIMA	0.21	0.00						1.59	-1.38	-97.19%	34.%	-97.19%	-0.20	1.34	
AL HUWAISAH	8.31	0.00						1.79	6.52	27.15%	34.%	27.15%	2.26	1.77	
SAIH RAWL	9.03	0.00						2.32	6.71	48.87%	34.%	48.87%	4.42	3.28	
QARN ALAM	0.84	0.00						0.09	0.75	32.01%	34.%	32.01%	0.27	0.24	
Other Fields	55.04	0.00						17.02	38.02	30.59%	34.%	30.59%	16.84	11.63	
Prov.Dev.Resvs (mln m3)	193.56	0.00 0.00	0.00	0.00	0.00	0.00	0.00	44.76	148.80	42.57%	34.%	42.18%	82.41	62.77	
Proved Undeveloped Reserves															
YIBAL	35.39	0.00							35.39	15.2%		15.2%	5.38	5.38	
FAHUD	0.79	0.00							0.79	291.9%		291.9%	2.32	2.32	
MARMUL	35.97	0.00							35.97	26.91%		26.91%	9.68	9.68	
LEKHWAIR	5.64	0.00							5.64	59.24%		59.24%	3.34	3.34	
NATIH	1.78	0.00							1.78	42.58%		42.58%	0.76	0.76	
NIMR	12.56	0.00							12.56	37.18%		37.18%	4.67	4.67	
RIMA	0.03	0.00							0.03	1830.13%		1830.13%	0.58	0.58	
AL HUWAISAH	12.51	0.00							12.51	36.78%		36.78%	4.60	4.60	
SAIH RAWL	8.15	0.00							8.15	43.56%		43.56%	3.55	3.55	
QARN ALAM	27.30	0.00							27.30	32.16%		32.16%	8.78	8.78	
Other Fields	85.67	0.00							85.67	44.05%		44.05%	37.74	37.74	
Prov.Undev.Res (mln m3)	225.80	0.00 0.00	0.00	0.00	0.00	0.00			225.80	36.05%		36.05%	81.40	81.40	
Net Group Equity Proved Developed Reserves 10^6 m3	82.41	-4.42					0.00	15.22	62.77	62.77					
Net Group Equity Proved Total Reserves 10^6 m3	163.81	-4.42	0.00	0.00	0.00	0.00		15.22	144.17	144.17					
1.1.2003 Submission Prov.Dev.Res 10^6 m3	65.80	4.92					7.27	15.22	62.77	62.77					
1.1.2003 Submission Prov.Tot'l Res 10^6 m3	162.30	-4.74	0.34	1.49				15.22	144.17	144.17					

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V00300023

Audit Trail:

No 1.1.2002 field data available!
No audit trail for Transfers undev'd-to-dev'd,
Extensions/Discoveries and Improved Recovery!

Conversion factors used by PDO:
1 m3 = 1 m3
1scf = 0.0283 sm3

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

PDO/Gisco, Oct 2003 **CHECKLIST SEC RESERVES AUDITS** Attachment 3

COMPANY: PDO **AREA / FIELD: ALL FIELDS**

	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 universal over all discovered fields.
1.02	Are seismic processing and interpretation state-of-the-art?	O	Seismic tends to be of poor quality due to strong shallow multiples, surface rugosity and other irregularities, e.g. local sinkholes. Filtering (Cheats, van Gogh) has been applied with mixed success. Results are more promising in one area (Rima cluster) where it is anticipated that good information can be obtained on structure and small scale faulting, but, more importantly on reservoir stratification and perhaps characterisation.
1.03	Is seismic quality used / adequate for proving hydrocarbing bearing areas?	N.A.	Oils tend to be generally heavy and of low GOR. Acoustic contrast with water is small and oil bearing areas cannot be distinguished from seismic.
1.04	Is well data coverage adequate?	+	The majority of fields have been developed by numerous wells, both vertical and horizontal.
1.05	Are fluid levels known?	+	Since seismic and regional aquifer pressures are not reliable for predicting OWCs these tend to be specifically targeted by appraisal wells.
1.06	Are petrophysical well data quality and quantity adequate?	O	Not all wells had full suites of logs during major development drilling phases (GR and resistivity only, no porosity tools). This is a slight hindrance in reservoir characterisation.
1.07	Is reservoir producibility for undeveloped reserves supported by production tests or other evidence?	+	Most fields are now in production. Production tests are carried out in exploration / appraisal wells.
1.08	Are there proper volumetric estimates?	+	Volumetric estimates have been made for all fields. Most date back from the older generation of mapping packages (Zycor, CPS, Supervol). Most of these were coarse layered or coarse gridded. However, the recent (STEP staffed) STOIIP and Reserves Review Team has largely confirmed the validity of these estimates.
1.09	Are representative PVT data available and have they been properly accounted for in the volumetric estimate?	+	Proper sampling and analysis is done for new fields.
1.10	Are gas GHVs measured properly for sales gas conditions and accounted for in reserves submissions?	+	No gas reserves are carried
1.11	Are static models available / adequate?	X	Proper modern static and dynamic modelling has received insufficient attention in recent years. A large volume of booked reserves is based on older and outdated FDPs or on earlier volumetric estimates. This is now being addressed through an urgent study programme. Petrel models are the present standard.
1.12	Are dynamic models available / adequate?	X	See above. MoReS models are now downloaded from Petrel.
1.13	Are history matches available / adequate?	X	History matches are gradually becoming available as models are matured.
1.14	Are the recovery factors for proved reserves realistic?	X	PDO and the STOIIP and Reserves Review Team have concluded that a number of the older (FDP) expectation reserves estimates have been overstated (Yibal, Marmul, Qarn Alam). Individual field proved reserves are still based on old probabilistic volumetrics, in which the margins are much too wide in relation to the field's maturity. As for the booked proved corporate Shell share reserves, these cannot be tied back to realistic proved individual field estimates.
1.15	Are developed reserves based on proper NFA (No Further Activity) forecasts?	+	Expectation developed reserves are based on NFA forecasts - derived from well and cluster decline analysis (through Oil Field Manager software. The origin of the corporate proved developed estimate was not clear, but its volume seems broadly in line with the expectation NFA forecast, cut off at the end-of-licence in 2014.
1.16	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; No behind-pipe reserves are carried.

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

DB 28773
V00300024

PDO/Gisco, Oct 2003 CHECKLIST SEC RESERVES AUDITS Attachment 3

1.17	Have development projects been defined for undeveloped reserves or can they be defined?	X	The majority of undeveloped field reserves are associated with identified projects. However, many of these are notional or highly notional, while others have no forecast associated with them in the Business Plan.
1.18	Are there auditable development project plans with costs, benefits and economics?	X	A large majority of the undeveloped reserves projects are notional, with at best only approximate forecasts and cost estimates.
1.19	Are the projects technically mature or is further data gathering necessary?	X	The majority of projects are recognised as needing further work or re-work in order to become matured. Even many projects/volumes based on FDPs from the late 1990's are now seen as out of date because of subsequent well and field performance.
1.20	Are improved recovery estimates based on a successful pilot or analogue or are they otherwise supportable?	O	There are ample water injection projects in the PDO operated area. This could normally count as a sufficient analogue base for proving further new water injection projects. However, the reservoirs concerned (notably the Al Khlata sandstone and some shallower fractured carbonates) present a high degree of variability and such analogues may not always be representative.
1.21	Have the projects successfully passed a VAR3/VAR4 review or are they otherwise ready for application for funding?	X	PDO and the STOIIP / Reserves Review Team have recognised that 80-90% of the undeveloped reserves are yet to pass through the VAR3 stage. This includes a number of projects that have gone through such a stage in the past but which are now seen to need updating.
1.22	Are the projects firmly planned to go ahead - are there any potential show stoppers?	O	The Oman Government, as the major shareholder, is firmly committed to maximise oil recovery in a manner that is beneficial to them. Only projects with very poor economics would be at risk of not being executed.
2	COMMERCIAL MATURITY		
2.01	Are the projects economically viable (meeting Group Scr. Crit. over range of possible future scenarios / low case reserves)?	O	PDO projects are in principle approved by the PDO board. The Group Capital Allocation system has little influence on these decisions. The verbal statement was made that many projects would not have passed the stringent Group criteria. Previous UTC levels were at some $4/bl, but these have risen in recent years and the current outlook is that these may rise to levels up to $10/bl.
2.02	Have forecasts been cut off when rates become uneconomic?	N.A.	Forecasts are cut off at the end of the current production licence (24th June 2012). This long before production levels have declined below economic production levels.
2.03	Have the latest Group Screening / Reference Criteria been used?	O	See 2.01 above
2.04	Are assumed prices and costs RT (or justified if not)?	O	See 2.01 above
2.05	Is export infrastructure (pipelines, terminals etc) available or, if not, is it firmly planned and fully included in the economics?	+	Most of the export infrastructure is already in place. Any extensions would be included in the relevant 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, see 1.15.
2.08	Have all major gas project reserves been committed or contracted to sales, e.g. through a HOA, GSA?	N.A.	PDO is free to use produced gas for own use and for re-injection where needed, but they have no title to exported gas. Hence, no gas reserves are carried.
2.09	Can smaller gas project reserves reasonably be expected to be sold in existing markets and through existing / firmly planned facilities?	N.A.	
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?	X	STOIIP ranges were evaluated probabilistically after the early static (deterministic) modelling. Parameter ranges tended to take into account well log data only, but no adjustment was made for dynamic STOIIP determination from production performance. Hence these ranges were perhaps defensible at the time of their preparation but they are too wide for the current stage of field development.
3.02	Have 'proved areas' been defined (lowest known fluid contact, 'continuity of production', no major/sealing faults) and are they realistic?	+	Water contact levels are well known and well control tends to be more than adequate.
3.03	Are proved (developed and total) reserves consistent with these 'proved areas'?	+	Yes

DB 28774

V00300025

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

3.04	Is the uncertainty range of developed recovery adequate?	O	Although there is no clear audit trail for the composite proved developed recovery estimate, it appears to align with the expectation NFA forecast within the licence period. This is largely reasonable for a portfolio with the size and maturity of PDO's. Some downward corrections should be made for new developed fields. The composite proved forecast is not linked back to proved estimates for individual fields. The reason is that no such individual field estimates are made.
3.05	Is the uncertainty range of undeveloped recovery adequate?	X	The undeveloped forecast within licence contains a large number of projects that are far from mature and which can therefore not be regarded as proved (or, for that matter as true expectation). The composite proved undeveloped estimate includes a significant number of these immature projects. This is not in accordance with SEC and Group guidelines. As for the developed reserves, the composite proved undeveloped forecast is not linked back to proved estimates for individual fields because no such proved estimates are made.
3.06	Have market / production constraint uncertainties been taken into account?	N.A.	Offtake is at maximum field capacity.
3.07	Is the Group / Region / Asset Holder committed to proceed with development?	+	Yes, see also 1.22.
3.08	What is ratio of field(s) cum.prod. / expectation total recovery?		0.59
3.09	Can the field(s) be considered mature?		On average, yes, although there are numerous small new fields
3.10	Are proved reserves for fields (or other entities used for asset depreciation) added together arithmetically?	+	Yes
3.11	Are proved reserves within fields (or within entities used for asset depreciation) added together probabilistically?	O	Field recovery estimates are now generally made in a deterministic manner. Probabilistic addition is no longer appropriate.
3.12	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?	X	The proved developed reserves align with the expectation NFA forecast, which is appropriate for mature fields. The proved undeveloped reserves are likely to be overstated because they are not fully supported by proved projects.
4.02	Are the forecasts required to demonstrate the above condition consistent with the firm Base Case presented in the latest Business Plan?	X	The proved total estimate is well in excess of the 'Tranche 1' projects forecast from the 2002 Business Plan and similar forecasts from the 2003 Business Plan.
4.03	Is the hydrocarbon Equity share calculated properly (regular production contracts)?	+	The Group share is 34%, which is 85% of the 'private shareholders' share of 40% in the PDO operated fields.
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 are paid in cash and are not deducted from liftings nor reserves bookings.
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 used by third parties) included in reserves? Similarly, are volumes received as fees in kind excluded from reserves?	N.A.	Minor streams of third party crude are exported through PDO pipelines. Fees are paid in cash.
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?	N.A.	No gas reserves are carried
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?	X	The composite total proved reserves within-licence estimate has largely been maintained from previous years, in spite of the growing immaturity of the constituent projects.

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

V00300026

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