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**Note for File**

Managing the EP legacy issues

Introduction

During the last 1.5 years the technical competence and overall integrity of the EP business within Shell has been questioned both internally and externally, most prominently through lowering of the production growth target in August/September 2001 and due to a deteriorating proved reserves replacement ratio. Providing credible explanations for these issues proved near impossible given the disconnects between external promises/expectations and the reality of the state of the business.

As the new CEO of the business, which I relish and believe passionately in, this period has been extremely frustrating and uncomfortable, perhaps even more so with the emergence of stricter disclosure rules following the various corporate scandals in 2001/2202.

The initial "due diligence"

Significant issues emerged during the initial due diligence phase mid 2001, concurrently with the development of the 2002 business plan.

Obviously care was taken not to jump to conclusions too hastingly whilst also recognising the human element of rubbishing everything your pre-decessor has done (we are very good at this within Shell!). Also, how pessimistic are business plans?:

- Suddenly a lot of "dirty washings were thrown into the kitchen sink", I was literally trying not to disappear under water (something to do with previous management style?)
- Past business successes, e.g. build-up of LNG business, growth in North Sea, in Oman and in US GoM, provided confidence on future ability (reflected also in high PoS for new entries and finding upsides!)
- Several new countries were opening for business and created optimism in ability to establish new legacy positions (e.g. Saudi, Iran).
- Mature field declines were still poorly understood in 1997-1999 given concurrent infill drilling and aggressive implementation of new technology (e.g. horizontals)
- First globalisation effort in EP in 1998/1999 (Shell Oil integration, Volume 1 and 2 business planning process) were a success
- Transformation in 95/96 had left severe marks in EP (loss of functional stewardship/excellence) and would take time to correct and would eventually deliver bottomline results.

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A decision was made to safeguard the Group's reputation as good as possible, thereby "blaming" underdelivery to either on "standard acceptable" factors (e.g. project delays in Nigeria) or on external factors (oil price, market).

The actual gaps between external promises in Sept. 2001 and reality were significant and created the "EP in the box" storyline internally.

Primary focus has been on "self-help" activities to improve the long-term fundamentals of EP under the Performance/Portfolio/People umbrella:

- Deliver challenging 2002 production and cost targets and external commitments
- Launch global exploration to ensure focus on quality and on delivery
- Launch EP-projects to ensure global standards/excellence on projects
- Launch T&OE to re-focus on core business of technical competence, standards and performance
- Execute bolt-on acquisitions to fill portfolio gaps with high synergy potential (e.g. Enterprise, Rockies, Draugen)
- Delivery of key new developments (Kashagan, Sakhalin, etc.)
- Focus on Oman, UK and Nigeria (avoidable underperformance)
- Develop comprehensive people programme (eXp)
- Move towards new operating model in EP

The deeper understanding

A full understanding of the gaps between external promises and reality is important to ensure learning for the future.

Attached provides the overall perspective which emerged after several uncomfortable Excom sessions.

Some of the causes are very serious also as the positive external (or even internal) portrayal would lead to a false sense of security and optimism within EP and the Group whilst in reality:

- Portfolio weaknesses could only be hidden for so long (constraints on reserves growth and on development opportunities; real RRR and production growth promises were not compatible)
- Execution weaknesses would emerge from early "hype" on exploration successes, on technology and on new business creation (e.g. subsequent "disappearance" of Kudu/Sunrise FLNG, Brasil "slowed" maturing, Iran new business).
- Lack of attention on core operational business would backfire (e.g. UK, Oman, Nigeria)
- Staff energy/motivation in EP was not high (following the required business process appeared sometimes more important than bottomline delivery, leaders without proven trackrecord, organisation very inward focused).

Bottomline was that both reserves replacement and production growth were inflated:

- Aggressive/premature reserves bookings provided impression of higher growth rate than realistically possible
- Bottoms-up production forecasts (before adding of strategic options) after realistic risk-downgrading (based on past experience on engineering optimism on project start-ups/plateau rate and build-ups) only gave 1-2% aai on production growth compared to 3-5% promises.

Where next?

The year 2003 provides the opportunity to be transparent about the true state of the business and to be humble about some of the failures as well:

- Underlying RRR issues (need more than organic growth, early bookings now leading to high unit F&D costs and undermining credibility/competence)
- Underlying performance issues (mature field declines, new reserves access challenges, production growth and Nigeria exposure level) (need to be more transparent)

whilst at the same time:

- Show the robust fundamentals
  - Legacy assets that competitors "would die for"
  - Conservative and longduring strengths (technology, staff, geographic/political diversity of portfolio)
  - Competitive factors (staff, portfolio, capability of sweating assets)
- Show improvement areas
  - Internal synergy/productivity delivery (new operating model)
  - Long-term reserves and ROACE
  - EP delivery machine
  - Leadership positions (vs. competition) and scale/materiality

The 2002 Bushiness Plan for 2003/2004 contains a significant stretch in order to stay as close as possible to external commitments:

- Continue underlying unit cost reduction at 3% aad ($ 300 mln plus unidentified cost savings banked)
- Continue 3% production growth, although "watered down" (capable of i.s.o. direct promise) (approx. 20/80 forecast rather than 50/50 i.e. 20% chance of delivery probably reducing further when going to 2005 onwards given general decline uncertainty and high Nigeria dependence)
- Recover to 13%+ ROACE in 2004 to get Group ROACE within range (taking credit for above plus $ 1 bln divestment at year-end and 0.5% ROACE uplift from tax, both in 2003/2004)
- 5-year average RRR to remain above 100% (plan only delivers 60-80% organically).

As a consequence there is no safety margin in external commitments and a requirement to deliver a plan with PoS << 50%.

Notwithstanding the above, it is currently planned to portray an upbeat perspective of the business, supported by a very focused high-energy improvement drive as set in motion more than a year ago.
Commencing an internal "witch-hunt" with negative consequences for the Group reputation and requiring tremendous energy that would distract from the improvement drive, is not seen to be productive nor beneficial for the Group in these uncertain times.
For future reference it was however considered prudent to record the issues and provide the context for the decision as taken.
The concerns around the "caught in the box" dilemma and stretch in the EP business plan have been flagged at the highest level in the company, but obviously "transmitted" in a careful fashion as not to compromise/undermine the previous leadership. The severity and magnitude of the EP legacy issues may therefore not have been fully appreciated.
Also, a generally excellent performance (operationally and strategically) from EP in 2002 have masked the issues somewhat.

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12-02-2004 15:11 P.04/04

V00030276

# "EP in the Box"

## Understanding the thinking/behaviour that led to external promises made

**What we do and don't do as leaders...**

**Why?**

**1)EP leadership not adequately connected with the coal face (includes Excom)**
- ExCom too remote in governance mode
- deep understanding of OU performance not there (e.g Oman, Nigeria)
- optimism on delivery/capability
- many initiatives but lost focus on core business delivery/performance (e.g. T&OE)
- no recognition of old vs new EP margins/returns including large focus on MRH to exclusion of other (smaller but more profitable) opportunities and exploration gaps not addressed
- denial on portfolio gaps (e.g. North America)
- EP not globalised,no global mindset around people
- no control on people movement apart from LC opportunistic selections/on a what is available basis mostly
- lack of nurturing of specialist talent (e.g. play-making explorers, carbonate reservoir modellers) so they become generalists
- various staff progresses to senior level without proven track record
- resource skills/shortages
- historical successes provided false sense of security

**2) unchallenged EP CEC campaign to make everything look as good as possible (1999/2001)**
- fear of challenge culture
- aggressive/premature reserves bookings (topdown instructions)
- technology "hype" (RtL/STV) before results
- new country access "hype" (also under-resourced), not realised
- exploration successes pumped up (vintage years!)
- flaws in aspired portfolio (not debated and not communicated through senior management), leading to lack of focus on NA and attempt on WEL
- expectations raised prematurely (SURE,FLNG for Kudu & Sunrise,Brasil discoveries,Sakhalin,Zapo, RtL results)
- blindspots in terms of real competitive position within the energy industry and in terms of portfolio (NA gas, US exposure)
- hoping "rock in the pond" through M&A would allow new beginning
- no "feel" for operational performance

**Choices we make as a management team**

**Why?**

**3) not adequately addressing dilemma of growth vs return (competitors set lower ROACE hurdle and were able to move)**
- 5% growth and 15% ROACE @$14/bbl flawed

**4) pre-occupied internally with 2001 roadmap**
- whilst the competitive environment changed drastically around us (including development portfolios)

**5) Moved towards more autonomy in OU's to drive accountability**
- created fragmented processes and systems and large overhead structure
- lack of a global perspective with strong role of OU scorecards and over-emphasis on asset team

**How we predict/ react to external events. Is this related to items above?**

**Why?**

**6) improving competitors through consolidation**
- no consistent vision for EP, or explicit competitive "niche" against these new competitors
- lack of knowledge of "who we are" and overly internally focussed

**7) external factors that slowed down do-ability tc get access/dealflow in MRH countries and slowed down gas monetisation (market growth reduction)**
- however, false optimism ignored these realities

**8) joining the "dot-com hype" on growth targets and on generally raising external expectations**

WvdV January 2003

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**Unknown**

| | |
|---|---|
| **From:** | Pay, John JR SIEP-EPB-P |
| **Sent:** | 04 December 2002 17:26 |
| **To:** | Van De Vijver, Walter SI-MGDWV |
| **Cc:** | Brass, Lorin LL SIEP-EPB |
| **Subject:** | RE: Reserves "clean-up" |

The current outlook for Potential Reserves Exposure is attached.

It would be defensible to leave all bookings intact (refer to comments on each one), with the possible exception of Enterprise. Audits are still in progress and I intend to put recommendations forward for management determination once they are complete.

Removing all items from the attached list would reduce Proved Reserves Additions for 2002 to ca. 750 million boe (Proved RRR = 50%, including Enterprise and Kashagan). I am working on the assumption that this is not something we want to do, but it would have the advantage of removing these issues once and for all. The timing seems opportune.

. -NG, our review this year identified only two major bookings that are not yet covered by contract: Gorgon (already covered in the attached table) plus 130 million boe in Brunei that rely on extension of supply contracts to BLNG (beyond 2015, I believe). I think it safe to say we have "reasonable certainty" that the latter will be committed in due course and therefore the booking is secure.

We do have some precedence for reversing major bookings: in 1991 we debooked 430 million boe of post-licence reserves in Abu Dhabi that we had booked in 1987.

Draft PRE
ıtalogue end-2002.Z

John Pay
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-----Original Message-----

| | |
|---|---|
| **From:** | Van De Vijver, Walter SI-MGDWV |
| **Sent:** | 04 December 2002 17:13 |
| **To:** | Pay, John JR SIEP-EPB-P |
| **Cc:** | Brass, Lorin LL SIEP-EPB |
| **Subject:** | Reserves "clean-up" |

John,

We want to improve the integrity of our reserves base and achieve full compliance with SEC reporting requirements.
As a result we are taking "hits" this year on Bonga,Ehra etc.
Based on what we know today,what will we still have left in our books by 1/1/2003 that is considered questionable by the auditors or that we
should correct this year?
Obviously we want to link with expecation reserves also.
I know from an earlier note that you did flag some fo the legacies that were being worked out.

Easy to clarify?



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- Gorgon
- Ormen Lange
- non-contracted LNG?
- Brunei?

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Potential Reserves Exposure Catalogue (Draft end-2002 dated 4 December 2002)

| Asset (Year booked) | Proved mln boe | Exp'n mln boe | Comment |
|---|---|---|---|
| Australia Gorgon (1997) | 557 | 785 | Booked in 1997 in anticipation of imminent FID, subsequently deferred indefinitely by the downturn in Asian economies and the consequent reduction in demand for LNG. It is inevitable that a resource of this magnitude will be developed eventually. |
| SNEPCO | | | It is assumed that 133 million boe of potentially overstated proved reserves will be debooked at 31.12.2002 (SEC Reserves Audit recommendation). |
| Angola Block 18 | | | 55 mln boe proved reserves removed from the catalogue in November 2002 following successful reserves audit. |
| Norway Ormen Lange (1999, 2000) | 109 | 186 | Reserves have been partially booked ahead of VAR3 and FID, whilst it appears that there are issues that could prevent it proceeding. De-booking will be considered only when and if it becomes clear that development definitely will not proceed. FID planned in 2003 or 2004. |
| Enterprise (acquired 2002) | ca. 136 | ca. 267 | Certain elements of the portfolio may not satisfy minimum requirements for project maturity (Italy Tempa Rossa, Norway Skarv Area, possibly elements of KMOC). Audits are in progress. |
| Netherlands, Waddenzee (Various) | 26 | 37 | Government-enforced moratorium on Waddenzee drilling, due to environmental concerns, could ultimately prevent development from proceeding. NAM field codes MGT, NES, LWO, VHZ (VHN?) |
| Brunei legacy (Various) | 20 | ca. 30 | Historical reserves bookings that can no longer be supported are inventorized and actively managed. It is expected that the remaining balance will be reduced to zero over the next two or three years, in consultation with national regulatory authorities. |
| Total | 848 | 1305 | |
| Shell reserves, 31.12.2001 | 19100 | 31800 | Excluding AOSP |

Expectation Reserves include post-licence volumes.

In addition, reserves in some OUs might be at risk if planned production rate increases do not materialize. The OUs most affected are SPDC Nigeria and Abu Dhabi. Furthermore, Oman PDO must sustain current production rates throughout the remaining lifetime of the licence to ensure production of the booked proved reserves.

The SEC provides no specific guidance on reserves disclosure for "novel" contract structures. Shell currently has four bookings in this category amounting to 768 and 993 million boe proved and expectation reserves respectively at 31.12.2001. The contracts are: the Venezuela service agreement, Iran buy-back contract, Oman Gisco and the booking of NGL reserves in connection with interests in Abu Dhabi GASCO.

Note: this inventory captures proved reserves bookings that are fully justified at present but which could come under threat of debooking if, for example, the SEC further clarifies its rules to imply that more conservatism should be applied by Form 20-F registrants.



TT 000479

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Presentation Item: Sponsored by MGDWV

24 SEP 2002

# NOTE TO CMD

## EP - Delivery through Globalisation

Date : 24th September

FROM : MGDWV

TO : CMD

In order to achieve its external promises and effectively compete against its supermajor rivals, Shell EP needs to accelerate the globalisation of its business. Building on a suite of global initiatives started in Q4 2001; Technical & Operational Excellence, Global Exploration and HR, Major Projects and SAP, EP intends to capture further value in the global business through:

- Implementing the recommendations of the Cost FRD carried out in 2002, focuses on simplified processes and internal synergy consolidation capture;
- Making changes to the current Operating Model to improve accountability and enforce standardization of global processes from the top;
- Accelerate actions to upgrade the EP portfolio; and
- Focus on enhancing the EP Investment Case as presented to the external market.

Although any one action alone will not improve performance in all the external metrics, it is believed that the above will achieve the targeted $500Mln-$800Mln cost savings, and place Shell EP in a better position to balance maintaining returns from "strongholds" with the speed necessary to win new business in an increasingly globalised competitive environment.

The attached note addresses the current weaknesses, gaps and related forward action and should be seen in the context of a business that generally is sound and competitive but cannot forego identified self-help opportunities to maximize forward value and on learning over the last 5 years.

MGDWV

18-09-2002

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# Note to CMD

## EP - Delivery through Globalisation


### Summary

Shell EP's competition with its peers now focuses on meeting and exceeding the market's expectations for cost savings, production growth, portfolio replenishment, and winning access to new business. Transparent and material differences in these dimensions are more critical to sustained market confidence than ever, but increasingly difficult to establish.

It has become apparent that unless the EP business leverages a truly global approach, it will not be able to keep up on key performance metrics let alone outperform the competition. Moreover, sustained simultaneous delivery on all four of our key promises (on ROACE, Production, Cost Reduction, Reserves Replacement) will likely not be possible.

As a consequence, EP needs to accelerate the globalisation of its business , which includes:

- **Full implementation of PPP (People, Performance, Portfolio) actions that are already underway; T&OE, Major Projects, Global HR, SAP, Global Exploration.**
- **Seeking further internal synergy consolidation benefits ($500Mln annual opex savings as per Cost FRD) by moving to standard global processes through global deliverability with transparent top down accountability and linkage with OUs**
- **Improving the quality of the global portfolio through a structured programme of swaps and active pursuit of asset and potentially corporate acquisitions.**
- **Step-change in quality and appropriateness of our IR story – setting and managing an external agenda to optimise the market impact of our operational achievements and performance improvements.**
- **Implementing a single global EP Scorecard that much better aligns with the key performance metrics and that is an integral part of reward mechanisms across a much broader range of EP staff.**

The implementation of these proposals will be a significant challenge for the global EP business. However, we are convinced that there is no alternative but to deliver on all of them to obtain the synergies from global operations and impress on the broader stakeholder community the seriousness of our commitment.






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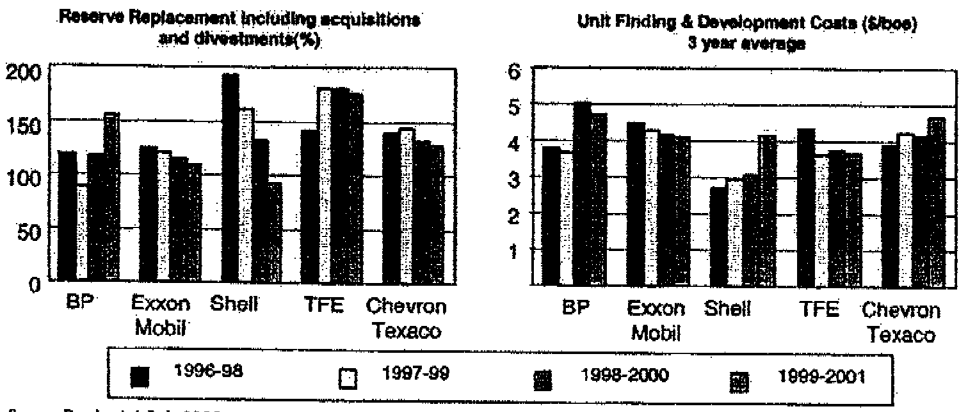
## Context

For the supermajors, traditional advantages of lower costs or higher profitability need more effective global leverage. Against some of the traditional performance metrics, which receive a lot of external profile, Shell is losing ground against these competitors (figure 1).

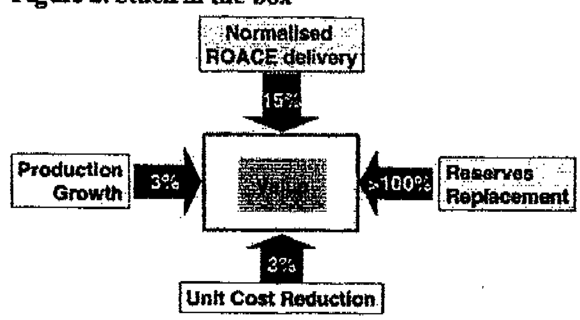
**Figure 1**




*Source: Prudential, July 2002*

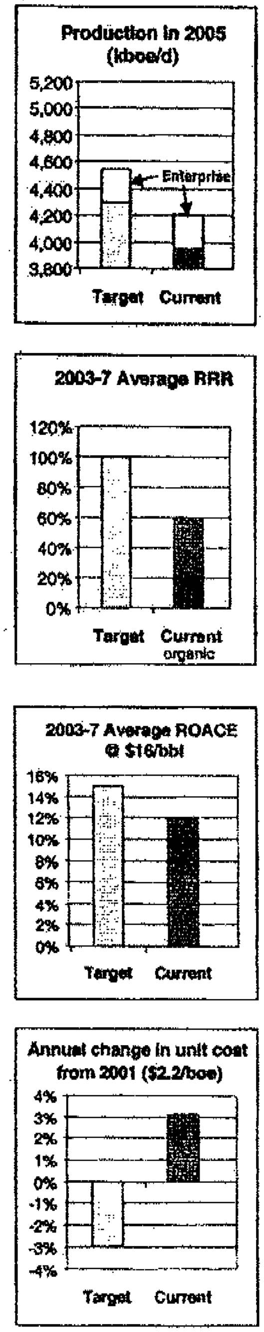
To fulfil market expectations, EP aims to deliver against a suite of external promises. In practice, given EP's portfolio, these criteria can only be met for so long. EP finds itself caught in a box, struggling to deliver on all fronts simultaneously (figure 2).

**Figure 2: Stuck in the box**




The delivery challenges are externally visible (portfolio funnel, production growth, RRR, F&D unit costs) and even in the short term, EP risks entering a "negative spiral" by failing to deliver against these challenging external promises. Market confidence will only be improved with demonstrably "smart" medium term portfolio refreshment and/or positive trends on key indicators. We believe this requires **demonstrable commitment to running EP as a global business** – we can no longer afford the luxury and competitive disadvantage of structural and process inefficiencies inherent in the current OU structure.

**Figure 3 EP Plan 2002**




Note: Unit costs data shown here are operating cost son an OA basis, is cot underlying unit cost upon which the external commitment has been made: this is currently being evaluated

## Meeting our Promises on Profitability and Growth

The first draft of the 2002 Business Plan (figure 3) confirms our concerns:

- Increasingly rapid decline in major producing areas with diminishing infill development opportunities;
- Shortage of major new development projects and lack of material exploration success to feed medium term growth. 3% production growth is unlikely to be achieved organically on the Shell & Enterprise combined portfolio;
- False optimism on the pace and penetration of MRH opportunities providing the EP "hubs of the future";
- Project over-expenditures (e.g. AOSP, Nigeria, USA); and
- Unit operating costs not trending to meet the 3% underlying reduction

The forward challenge for EP is both around portfolio refreshment and around performance improvement. Work is ongoing to improve the key metrics in our 2002 Business Plan.

There are increasing concerns around the revitalisation of "old and tired" strongholds that still can and should be delivering more to the bottom line and the perception exists that the "right people are not in the right place" to be adding most value to EP.

In 2002, a number of actions centred on Shell EPs' Performance, Portfolio and People are being implemented under the title "The Quiet Revolution" to realise these improvements. These include the proposed evolution of the EP Operating Model.

## Actions – 1: Portfolio, Performance, People (PPP) 1999-2002

With the introduction of global capital allocation, global strategy setting and understanding of the global portfolio, EP has been moving since 1999 progressively to a more global organisation and global operating model. In early 2002, the launch of major drives has been specifically designed to harness the expertise of the company's global people resource, improve performance and high-grade the portfolio. The focus areas include Technical and Operational

Excellence, Major Project Delivery, appointing a Head for Global Exploration, and development of global HR and M&A processes.

Progress is being made: the Enterprise acquisition was a truly global M&A deal; there is ongoing refreshment of the exploration prospect portfolio (GoM lease sales, Nigeria, Brunei); operational problems have been overcome through global leverage of knowledge; deliberate moves are being made to take the lead in major strategic projects (China E2W, Sakhalin) and active relationship management of "new" partners is ongoing.

**Figure 4 How to raise the game: PPP Actions**

| Portfolio | [redacted] | [redacted] |
|---|---|---|
| Clear Aspired portfolio and active upgrading<br>Winning the Big Bets – through a global approach to NBD and M&A<br>Bringing the Big Tickets onstream<br>Realising Nigeria<br>Innovative Technology & Gas Solutions | [redacted] | [redacted] |

These, and the ongoing elements of the PPP action plan, are summarised in figure 4.

In late 2002, key areas of ExCom focus are:

- Winning the Big Bets and delivering the Big Tickets - the new business opportunities and major projects pre-FID that are of global significance to the Shell Group;
- Early negotiation of licence extensions to enhance reserve replacement;
- E-X-P, the suite of People products including Competence Based Progression, Batched Open Resourcing and better Leadership Development.

Concentrating on the specific challenge of operating costs, a Cost FRD in 2002 has identified potential synergistic savings of $500mln and a suite of actions (see Attachment 1 for details).

One of the specific recommendations was to rationalise the portfolio to gain operating cost synergies, but this is just one part of a wider suite of actions to rejuvenate the portfolio.

**Actions – 2: Further Portfolio Actions 2002-2003**

Despite actions being taken on critical aspects of EP portfolio, performance and people, it is unlikely that organic growth will be sufficient to compete effectively over the next 5 years. Hence, further acquisitions and targeting of material new business opportunities will be necessary although we must be aware that these may negatively impact short term ROACE (particularly at a normalised $16/bbl reference price). To improve the portfolio, we plan to:

- Commence a programme of swaps and cash divestments of OUs/assets that are currently underperforming. This will improve ROACE, reduce operating costs, generate cash and free up/ re-focus scarce staff resources;
- Develop and implement plans to address assets/OUs which are currently outside the EP Aspired Portfolio;
- Active pursuit of asset and potentially corporate acquisitions, coupled with more aggressive chasing of new business opportunities (e.g. through leverage of very senior management with NOC resource holders).

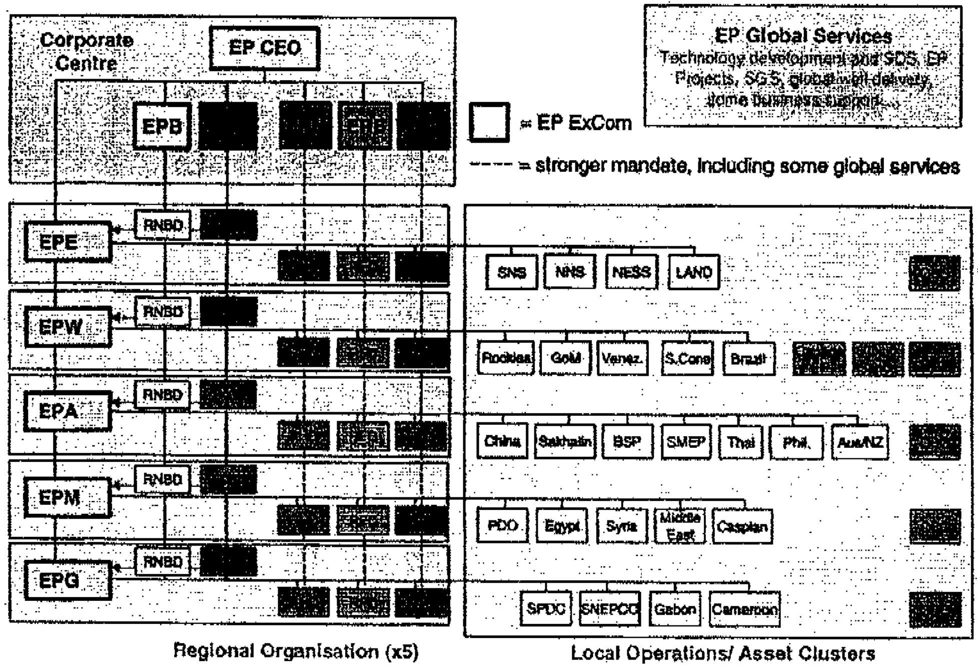
To ensure we realise the full synergies identified in the Cost FRD, and realise these portfolio actions, EP needs to move to a further level of global efficiency and effectiveness. Only by this can EP achieve the optimisation of returns from "strongholds", the optimal allocation of resources, and become sufficiently nimble to win new business opportunities.

**Actions – 3: Further Globalisation of EP 2002-2003**

The next stage in Globalising EP is through strengthening of key global processes and the mandate for their application. In essence this is about enforcing **Standardisation** from the top, **Sharing** best practices, improving **Speed** of decision-making and **Simplifying** organisational and governance structures.

Changes to the current model have been worked by the EP Excom, and can be characterised by a revised, globally focused but regionally distributed operating model in place by the end of 2003 (see figure 5).

**Figure 5 Evolving EP Operating Model**

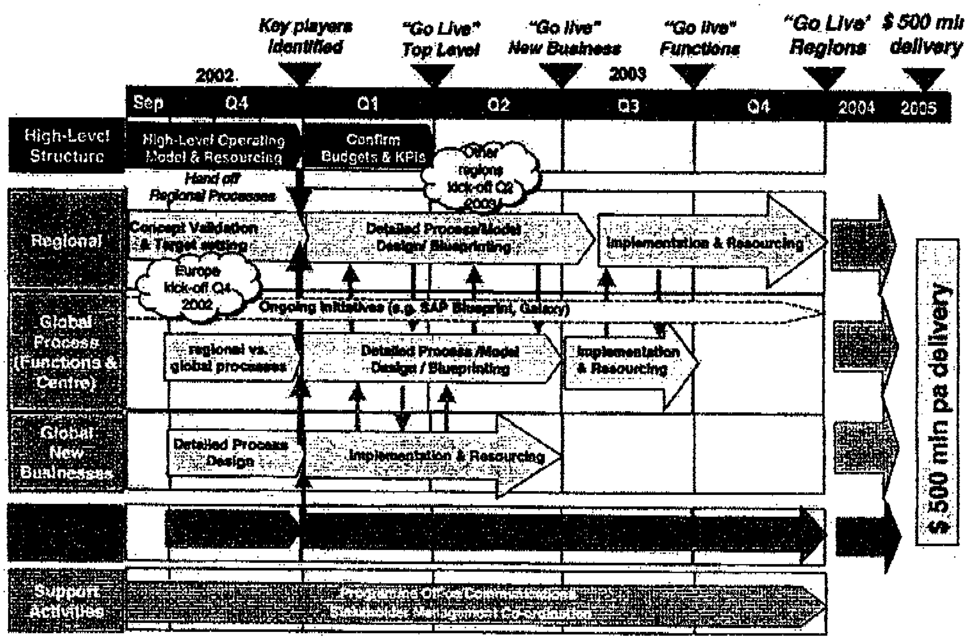



RBDs will assume an executive role over their respective regions. The functional governance of the operation of the business will be strengthened by an increase in mandate of the technical and non-technical support ExCom directors.

The model moves away from operating units based on national boundaries and on large EP Centres in The Hague and Houston; instead we will have a smaller number (say 4 to 6 in total) of trans-national or regional units, global Exploration and New Business Development businesses and a significantly smaller, more governance-focused EP Centre.

The new operating model will introduced in a phased manner , driven by firstly globalising processes, followed by delivery vehicles ( New Business, Functions, Regions) as shown in figure 6.

**Figure 6. Implementation Schedule**




The leadership of EP will be aligned through revised scorecard metrics and wider sharing of the overall EP performance. A new EP Global Scorecard will be in place for 2003.

The detailed implications of HR aspects for the new model will be shared with MDC in November.

This evolution of the EP Operating Model will have the following benefits:

- strongly enforce the application of common global processes, practices and tools for all significant pieces of business. As a consequence, staff will be more flexibly deployable;
- demonstrate technical and operational excellence in all aspects of EP business and will be a low underlying unit operating cost operator, when normalized for portfolio mix.
- benefit from economies of scale and reduced duplication in the provision of technical and non-technical support to core operations and new development activities;
- achieve even greater focus and alignment on Exploration and new business development;

- have a much reduced corporate centre comprising; functional governance staff and a small number of truly global service providers. Other service provision currently centrally supplied will be supplied regionally.
- lines of control will be shortened and better hard-wiring of information flow will be achieved;
- concentrate its portfolio in line with the EP Aspired Portfolio;
- make more effective and selective use of the premium expatriate resource and ultimately will reduce the total numbers of expatriates.
- provide an attractive EVP meeting the aspirations of the demographically changing EP workforce whilst satisfying the EP business needs.
- maintain focus on the importance of local stakeholder engagement.

Equally there are some risks that must be recognised and managed:

- potential for disruption of core business;
- misalignment of staff within EP on the objectives of the changes;
- concern amongst JV partners and government stakeholders of our motives, and undermining of their respective interests at the expense of optimising Shell interests.

**Actions – 4: Regaining Investor (and Employee) Confidence**

Since mid 2001, market confidence in Group performance has been weakened through concerns over unsustainability of cost cutting, downgrading of volume growth projections, and effectiveness of cultural change. More frequent direct comparisons with BP, as the alternative British energy stock, and ExxonMobil, as the world's largest supermajor, have been and remain unfavourable. The relative performance of EP is crucial to overall market confidence in the Group; hence EP must not only *make* but also effectively *market* its step changes in performance and portfolio improvement (see Attachment 2 – The EP Investment Case)

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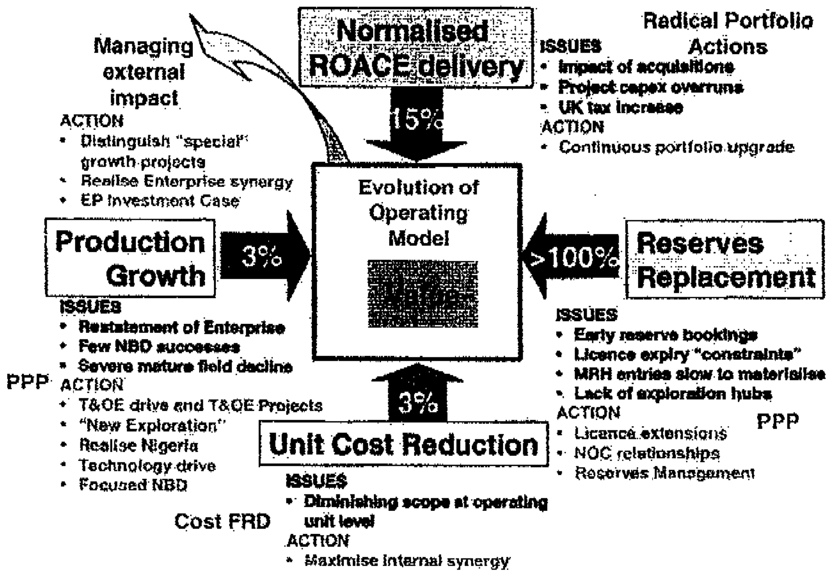
## Summary

Although it is difficult to identify actions that will simultaneously improve EP's position on all of the key metrics that box us in (see figure 7), inaction is not an option. We need to return to the basics of the business, which excels competitively and can credibly explain our forward delivery metrics. Ultimately all actions should be gauged on the basis of impact on value and, indeed, TSR rather than merely improvement in one of four metrics.

**Figure 7: Summary of issues and actions**




Hence, EP proposes to proceed with:

- Full implementation of PPP actions that are already underway.
- Rapid implementation of the Cost FRD recommendations, including the evolution of the Operating Model. Changes to the overall high-level model will be effected by Q1 2003 with the complete operating model becoming fully effective by 1/1/2004.
- Radical actions to improve the quality of the global portfolio
- Focussed efforts on the EP Investment Case; to better manage our external impact.

All of this will need to be firmed up in a definitive roadmap for EP following the finalisation of the 2002 Plan. Timely updates will be provided on any key changes (e.g. the new Europe organisation).

W van de Vijver, MGDWV,
18 September 2002

## Unknown

| | |
|---|---|
| **From:** | Copper, Femke F SI-MGDSEC |
| **Sent:** | 18 March 2003 12:19 |
| **To:** | Watts, Philip B SI-MGDPW; Van der Veer, Jeroen J SI-MGDJV; Skinner, Paul PD SI-MGDPS; Brinded, Malcolm A SI-MGDMB |
| **Cc:** | Boynton, Judith G SI-FN; Ruddock, Keith KA SI-DCS; Van De Vijver, Walter SI-MGDWV |
| **Subject:** | Reformatted version visit Oman 15-16 March 2003 |

Send on behalf of Walter van de Vijver.

Reformatted version.

Colleagues,

I had an useful two-day visit to Oman with the objective to carry out another "healthcheck" on PDO and to meet relevant staff/stakeholders.
Below is a brief summary of my visit, key highlights:

- PDO is making progress under the leadership of John Malcolm but still has a long way to go to restore organisational capacity and to have robust technical development/recovery plans.
- Atmosphere with the variety of government stakeholders remain tense given the extent of issues (PDO production, government LNG train (GTP), lack of transparency, reward scheme and license extension, ethane extraction to develop downstream industry). Shell "is expected" to demonstrate long-term commitment to Oman by making concessions on return structure and scale whilst understanding they need Shell's assistance and need to progress GTP and license extension discussions. License extension discussions expected to start after completion of current GTP discussions.

<u>PDO</u>

- Current production is some 730,000 b/d and is still sliding downwards with some signs that attention to core processes are helping.
- Focus on 2003/2004 production is resulting in potential budget overruns (opex 20 % and capex 10 %) which need to dealt with urgently.
- The new SAP system is somehow not delivering the tight controls on annual budgets (more biased towards contract controls and not aligned with accountability coding for annual budgets?!) and this could become the next exposure if not dealt with head-on (also links to learning that need to be worked through the various OU's).
- Scale of operations is growing, already have 30 drilling rigs and 15 hoists operating whilst needing to get ready for next wave of activity linked to additional water injection to re-build production volumes. The conventional delivery model used for the well engineering/well services activity is not sustainable and will require novel outsourcing models.
- Link of development funding to reserves growth is not very transparent (acceleration activities dominate?),need to get back to tight management on drilling sequences supplemented with continuous demonstration of increased capital efficiency (incl. $/ft, etc.).This year we need to pro-actively focus on key development plans to justify year-end reserves bookings.
- Waterflood studies (largely delivered through external support from John Darley's technology organisations) are progressing to plan but will need to be translated in executing plans with clear focus on prioritised activities (biased towards North Oman and towards extensions rather than new floods initially) and simple implementation plans with minimal interfaces and maximal ownership by the asset teams. Waterfloods should be possible at good VIR's and low UTC's
($ 3-5/bbl).
- Several "big ticket" items are starting to mature (Harweel cluster in South Oman, Mukhaizna development, Qarn Alam thermal development), we will need to start deciding how well some of these will compete for funding and how we want to ensure delivery with using relevant parts of our new global operating model. We now have some 2.2 billion oil-in-place in the Harweel cluster and notwithstanding the challenging nature of the deep sour gas/crude and the need for miscible floods to ensure high recovery, we need to get this developed asap.
- Exploration is getting steeply on the creaming curve on the oil side (only material scope appears to be in Harweel area) but also needs to find new material gas given the very strong appetite of the government to develop their downstream business locally (aluminum smelters, cracker, etc.) to stimulate employment. Overall MSV left is some 750 MMbo and 7 Tcf of gas (100 %) with staffwork ongoing to better define scope and forward strategy by early 2004.





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- Asset integrity is getting more attention (mainly corrosion and sand related) but is still not adequately coordinated across the company. Pro-active operational management is needed with support "systems" to reduce deferments.
- Resourcing the business is still very difficult notwithstanding progress made. Better packaging and pre-planning is needed to get Shell staff through the employment committee whilst nurturing the new wave of high-caliber Omani staff. Local study center has to be the answer to get more of the work being done at location (such as in Syria etc.).
- Tremendous workscope for the support activity provided for Government Gas (we have service agreement only, no production/reserves) given the expansion plans and operational pressures (new train, OLNG 1/2 de-bottlenecking supplies, ethane extraction, mercury removal, liquid yields/heating value).
- Take-up of new technology remains very good.

<u>OLNG</u>

- Briefly connected with MD and with Train 3 (GTP) negotiation team. A lot of tension and frustration all around given some of the non-standard processes.
- To allow commitment whilst details still had to be worked at a later stage (e.g. shipping, upside sharing, offtake details).

<u>Government</u>

- Met Macki (Minister of National Economy/Finance) and the new under-secretary of MOG (ministry of Oil and Gas), oil minister was on leave.
- Positive impression about the under-secretary, will help our interfaces all-round. Wanted to work with Shell and was awaiting "instructions" to start license discussions (team to be named soon)
- Macki:
    - Friendly discussion
    - He carefully "planted" questions around "outsourcing" some fields/activities and about our progress on Mukhaizna (competing offer by Oxy with government). He did not wanted to have the discussion on license extension notwithstanding references to HM audience by Phil.
    - Highly interested in general progress in PDO.
    - Extensive friendly discussion about situation in Middle East and potential implications.
    - Very concerned about pushback from PDO on do-ability of ethane extraction to allow Dow plus others to develop downstream business. This project was flagged to Mark Moody-Stuart during his recent visit and has already being "sold" by Macki to HM as feasible and hence strongly supported by HM. Linked to OOC but worked behind the scene and with low-key input from PDO's government gas support team. This will require active management also as the project links directly to reserves availability in the country with GTP commitments and overall gas heating values. We do not want underdeliver on gas as well as on oil!

Kind regards,

Femke Copper
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Discussion Item: Sponsored by MGDWV

22 JUL 2003

Note for Discussion

EP RESERVES OUTLOOK

The attached note provides an update of the proved reserves additions and reserves replacement ratio (RRR) for the year to date and the latest estimate (LE) for end year position. You will appreciate that there remain significant uncertainties on the full year RRR.

In summary, the LE for 2003 is an organic RRR of 72% and a headline RRR (including A&D) of 59%. Both numbers exclude the 45% Minority Interest (MI) in Sakhalin. Adding back MI would increase the above numbers by 22%. A further 8% is being targeted from the Athabasca Oil Sands Project.

There are a number of sensitivities remaining, which also have been highlighted in the note.

The issue of RRR is receiving a very high level of attention. Given the external profile we should not disclose the very confidential information contained in the note.

MGDWV, 17/07/2003

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Van der Vijver
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2/1/07

HAG00043389

## Note for Discussion

## Reserves Outlook

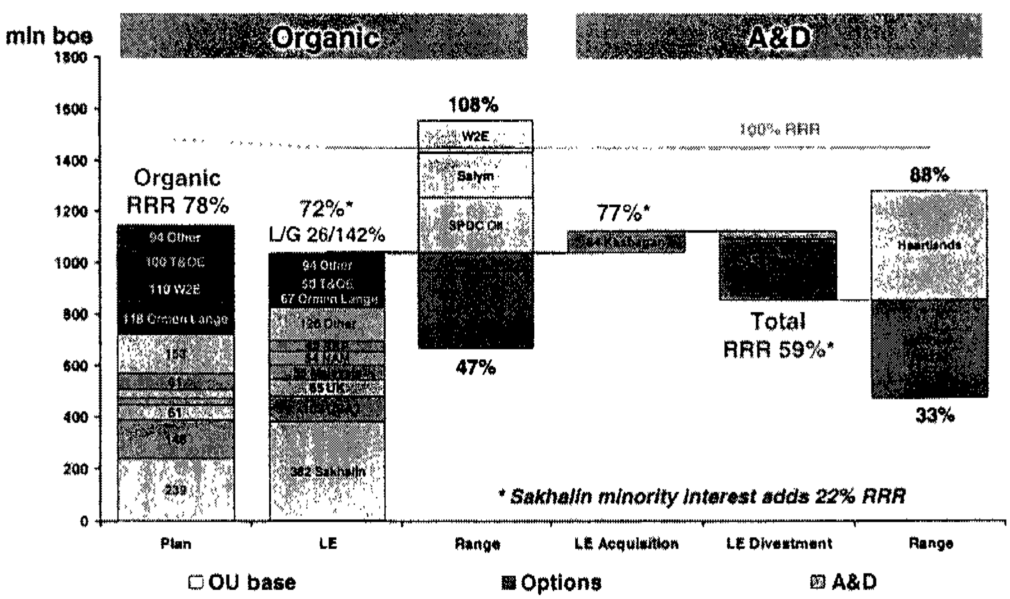
This note summarizes the Latest Estimate (L.E.) for reserves additions in 2003 and the outlook for the plan period (2004 – 2008). Uncertainties in the 2003 L.E. in 2003 are discussed, together with the opportunities that have been identified for improving performance. The latest Potential Reserves Exposure Catalogue is also presented for consideration.

### 2003 RRR Latest Estimate

The Latest Estimate for proved reserves replacement ratio (RRR) in 2003 is as follows:

| **Proved RRR 2003** | **Minority** | **Interests** |
|---|---|---|
| **Liquids : Gas : Total** | **Included** | **Excluded** |
| Total | **81%** | **59%** |
| Total excluding Divestments | **99%** | **77%** |
| Organic (i.e. excluding Acquisition and Divestment) | 38% : 184% : **94%** | 26% : 142% : **72%** |

In reviewing the year-end proved reserves disclosures, the market will focus on the Organic RRR (94%). It is possible that analysts will ignore the major contribution from the Sakhalin Minority Interests and so the corresponding figures (72% Organic RRR) should also be highlighted when describing performance. The breakdown of the L.E. excluding Minority Interests is illustrated below, with further detail in Appendix A.




In addition, Shell Canada expects to increase proved reserves for the Athabasca Oil Sands Project by 120 million bbl (93 million bbl excluding Minority Interests). These resource do not qualify as petroleum reserves under the SEC rules, but their inclusion would add 8% RRR (6% RRR ex-MI) to the figures listed above.

HAG00043390

Key observations on the 2003 RRR L.E. are:

- Organic RRR in 2001 and 2002 was 52% and 50% respectively. The business faces a severe continuing challenge to meet the target of 100% Organic RRR in 2003, especially when the effect of the Sakhalin 45% Minority Interest is excluded.

- Following several years of healthy liquids (Oil & NGL) RRR performance and poor gas performance, the situation for 2003 is reversed. Including the 2003 L.E. figures, the 3-year average organic RRR (ex-MI) will be some 53% for liquids, 61% for gas and 56% overall (5-yr averages are 84%, 62% and 77% respectively).

- Firm divestments will reduce reserves by some 280 million boe, offset by firm acquisitions of some 80 million boe (please refer to Appendix A for A&D details). This will draw the total RRR performance in 2003 below 60% (ex-MI), or further if additional divestments are secured in the remainder of the year.

**Uncertainties in the 2003 Latest Estimate**

- The 2003 L.E. provides a total of 1038 million boe organic proved reserves additions (excluding Minority Interests), of which approximately 590 mln boe can be considered firm at this stage. Key elements in the L.E. that are not yet firm are:

| | |
|---|---|
| 140 mln boe | Sakhalin, negotiations for sales contracts scheduled to reach binding Heads of Agreement by end-2003. |
| ±50 mln boe | Groningen field review: long-term recovery: study in progress. |
| 67 mln boe | Ormen Lange, FID expected in Q4 2003, possible slippage to 2004. |

- The Plan included reserves bookings for the China West to East pipeline project. This has been removed from the L.E. following concerns about progress towards PSC agreement (now reflected as an upside).

- Furthermore the Plan included a significant portion of notional gains for T&OE activities and other unspecified gains. The main focus for T&OE in terms of reserves is on the water flood theme that has the potential to add significant reserves in the medium to long-term as the underlying investment opportunities are matured and funded. The short-term gains that were included in the plan for 2003 related mainly to the anticipated outcome of Realize the Limit and Volumes to Value reviews – any such gains are absorbed into the individual Asset Holders Latest Estimates as the year progresses.

Confidential

## Opportunities to Improve 2003 Performance

Appendix B provides the current reserves Opportunities Catalogue. Specifically for 2003 the following main observations can be made:

- FID on West Salym (licence issues permitting) would enable some 180 mln boe proved reserves additions, increased slightly if Upper Salym re-entry is included. Long-term average organic RRR would be improved if this booking could be secured in 2003 and any Heartlands-related activity deferred until 2004 (see below).

- A review of SPDC Nigeria proved reserves is ongoing. It appears that a significant portion of the oil portfolio lacks the necessary level of technical and commercial maturity. Plans are being developed to ensure that these exposures are addressed over the short term (with a target of full compliance by 1.1.2005), but nevertheless in the L.E. it is assumed that up to 220 million bbl of oil reserves will need to be debooked in 2003. The debooking would be offset by planned gas additions (mainly for NLNG Trains 4 and 5), leaving SPDC effectively neutral in the L.E. An upside exists if the oil debookings could be avoided– work is ongoing to determine the feasibility of this (e.g. through the definition of plans to underpin the entire portfolio within the next one or two years). A reserves audit will take place in August.

- A review of Oman (PDO) proved reserves is in progress and a reserves audit is planned for later in the year. It is expected that these reviews will conclude that the current proved reserves are somewhat aggressive, but any pressure to debook should be offset by the securing of rights to a licence extension beyond 2012. At this stage it is assumed that the net effect will be close to zero, although a net increase in reserves pursuant to licence extension is a possibility.

- A poll of the regions and asset holders was recently conducted to identify additional short-term organic opportunities. This yielded only some 60 – 90 million boe that realistically can be delivered in 2003, mainly through reprioritization of work schedules to accelerate bookings planned for 2004. These gains are being worked and are seen as underpinning the "unspecified" elements of the plan and current L.E. Following a similar exercise last year, it is now clear that the existing portfolio is finely tuned on reserves and there are very few remaining opportunities to increase bookings at a higher rate than is already planned. Focus will nevertheless be maintained to ensure that bookings continue to be maximized within the latitude of the SEC regulations. The introduction of region reserves challenge sessions in Q3 will help in this respect.

- The effect of planned divestments (Marlowe) could be offset if Heartlands were to be secured in 2003 (approximately 425 million boe acquired, although securing the deal in 2003 would reduce organic reserves additions for Salym by half – see above).

## Potential Reserves Exposure Catalogue

The Potential Reserves Exposure Catalogue has been updated (Appendix C). Of the Group's 19350 million boe proved reserves, some 1040 million boe (5%) is currently considered to be potentially at risk. The inventory was significantly reduced since the end of 2002 due to the divestment of KMOC. However, this was more than offset by the addition of 300 million boe with respect to the "Lowest Known Hydrocarbon" (LKH) issue that has been raised by the SEC. This issue arose recently as part of the SEC's enquiry into the industry's reserves booking practices, which was been in progress since October 2002. The SEC proposes an interpretation of the LKH rule that is significantly more restrictive than is commonly applied in the industry and this alternative interpretation is currently being challenged by Shell.

Gorgon remains the largest single potential exposure (560 million boe).

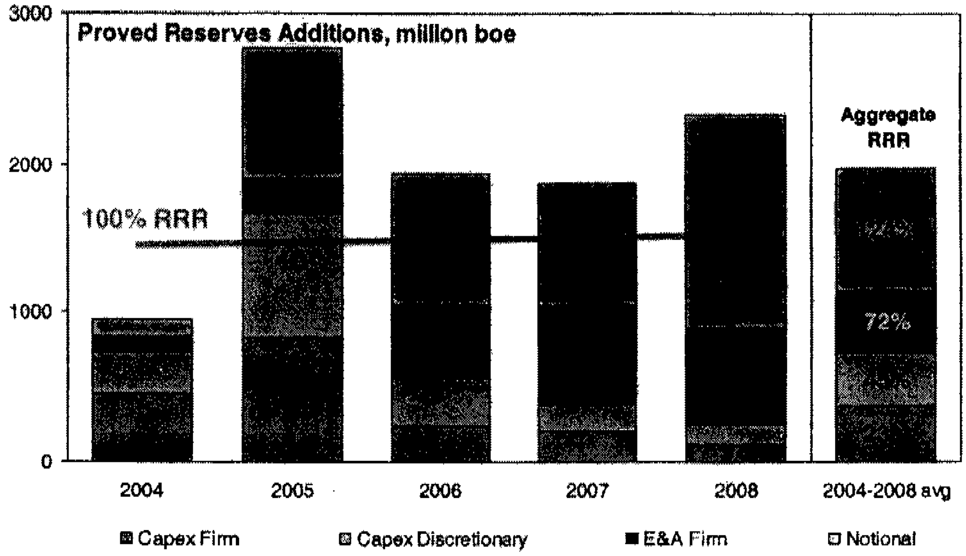
At this stage, no action in relation to entries in the Catalogue is recommended.

It should be noted that the total potential exposure listed in Appendix C is broadly offset by the potential to include gas fuel and flare volumes in external reserves disclosures. There is no specific guidance from the SEC on the inclusion or otherwise of these volumes. Shell's practice has evolved from the principle that reserves disclosures should reflect volumes that will eventually be sold. BP appears to apply the same principle.

Conversely, ExxonMobil and ConocoPhillips openly include fuel and flare in their reserves disclosures, whilst statements in the reports of TotalFinaElf and ChevronTexaco imply that they also do. Therefore a change to Shell's disclosure practice could be justified on the grounds of ensuring alignment with (most of) our major competitors. The potential addition has yet to be precisely quantified, but it is expected to be in the order of 1 billion boe and therefore on a scale that would make its inclusion an attractive option to offset any action that is taken with respect to the Potential Reserves Exposure Catalogue as a whole.

**Outlook for 2004 – 2008**

The following overview of reserves additions is based on the Capital Allocation data set that is being used currently to prepare the 2003 Business Plan. As such, it is consistent with Group guidance on short to medium-term capital and exploration expenditure constraints. It includes dilution of Sakhalin to 51% Shell equity, but excludes the corresponding Minority Interest share of reserves.




The outlook is fundamentally unchanged from the 2002 Business Plan, with 2004 remaining very weak. Whilst in principle it appears possible to achieve 100%+ RRR in the later plan period years, many of the gains rely on delivery of plan elements that at this stage are only notionally defined (including a large contribution from reserves that have yet to be discovered).

The firm elements of the plan (i.e. excluding the Notional tranche illustrated above) deliver approximately some 72% RRR over the plan period, a significant improvement over the 2002 business plan (58% 2003 – 2007) due largely to the retention of a higher equity interest in Sakhalin (40% was previously assumed) and through the inclusion of Qatar SMDS in the "Discretionary" tranche. The major Capex-funded contributors are:

| Project | Equity | Category | Year | Proved Reserves Additions |
|---|---|---|---|---|
| Sakhalin | 51% | Capex Firm | 2004 – 2007 | 1040 million boe |
| Qatar SMDS | 70% | Discretionary | 2005 | 690 |
| Rockies (Pinedale) | 50% | Discretionary | 2004 – 2008 | 260 |
| Kashagan | 20% | Discretionary | 2005 | 190 |

## Appendix A: 2003 Proved Reserves Additions Latest Estimate

**Latest Estimate, Proved Reserves Additions**

End June 2003

| Million Boe | ↑↓ | Proved Reserves Additions | | | Reserves Replacement Ratio | |
|---|---|---|---|---|---|---|
| | | Plan | LE | Delta | Plan, % | LE, % |
| Production | | 1478 | 1449 | -29 | | |
| Organic Excluding Minority Interests | | | | | | |
| Sakhalin | Assume booking on firm HOAs. Taiwan deferred. | 239 | 382 | 143 | 16.2 | 26.3 |
| USA | Rockies additions likely to be delayed | 148 | 102 | -46 | 10.0 | 7.0 |
| UK | Various minor | 61 | 65 | 4 | 4.1 | 4.5 |
| Malaysia | BDO licence extension | 26 | 55 | 28 | 1.8 | 3.8 |
| Netherlands | Groningen Field Review offset by other field debookings | 35 | 54 | 18 | 2.4 | 3.7 |
| Brunei (BSP) | LE down vs. Plan due to acceleration of bookings into 2002 | 61 | 42 | -19 | 4.1 | 2.9 |
| New Zealand | Pohokura and Maui revisions | 6 | 24 | 18 | 0.4 | 1.7 |
| Denmark | Various minor | 30 | 23 | -7 | 2.0 | 1.6 |
| Nigeria SNEPCO | Bolia | 23 | 22 | -1 | 1.5 | 1.5 |
| Gabon | New Rabi PSC | 10 | 19 | 9 | 0.7 | 1.3 |
| Venezuela | | | 18 | 18 | | 1.3 |
| Oman (PDO) | Portfolio review in progress | 15 | 15 | | 1.0 | 1.0 |
| Nigeria SPDC | Assumes oil write-downs offset by T4/6 gas additions | | 13 | 13 | | 0.9 |
| Germany | | 10 | 10 | | 0.7 | 0.7 |
| Syria | | 18 | 9 | -9 | 1.2 | 0.6 |
| Egypt | | 7 | 7 | | 0.5 | 0.5 |
| Norway | | 6 | 6 | | 0.4 | 0.4 |
| Cameroon | | 4 | 4 | | 0.3 | 0.3 |
| Brunei (SDB) | Maharaja Lela South well cancelled | 15 | 3 | -12 | 1.0 | 0.2 |
| Australia (SDA) | | 2 | 2 | | 0.1 | 0.1 |
| Kazakhstan | | 1 | 1 | 0 | 0.1 | 0.1 |
| China | | 1 | 1 | | 0.1 | 0.1 |
| Italy | | 6 | | -6 | 0.4 | |
| Argentina | | 1 | -3 | -3 | 0.0 | -0.2 |
| Oman (GISCO) | Anticipated PSC effect | | -21 | -21 | | -1.4 |
| Thailand | | | -26 | -26 | | -1.8 |
| **OU Options** | | | | | | |
| Ormen Lange | Compression FID deferred | 118 | 67 | -51 | 8.0 | 4.6 |
| China W2E | Assume slipped into 2004 or cancelled | 110 | | -110 | 7.5 | |
| T&OE | Target wound down through year - gains assumed to be incorporated in OU LEs. | 100 | 50 | -50 | 6.8 | 3.4 |
| Other Notional | Unspecified opportunities | 94 | 94 | | 6.4 | 6.5 |
| Total Organic Excluding Minority Interests | | 1146 | 1036 | -109 | 78 | 72 |
| A&D | | | | | | |
| Acquisition | | | | | | |
| Kazakhstan | Kashaagan pre-emption | | 84 | 84 | | 5.8 |
| Divestment | | | | | | |
| Australia (SDA) | Farm out (China deal) | | -30 | -30 | | -2.1 |
| Marlowe: | | | | | | |
| UK | | | -30 | -30 | | -2.1 |
| Russia KMOC | | | -118 | -118 | | -8.1 |
| USA | | | -90 | -90 | | -6.2 |
| Total A&D | | | -184 | -184 | | -13 |
| Total Organic + A&D | | 1146 | 854 | -292 | 78 | 59 |
| Total Organic & Acquisition | | 1146 | 1122 | -25 | 78 | 77 |
| Minority Interests | | | | | | |
| Russia Sakhalin | 45% Mitsubishi and Mitsui | | 312 | 312 | | 21.6 |
| Total Organic + A&D | Including Minority Interests | 1146 | 1166 | 20 | 78 | 80 |

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## Appendix B: Reserves Opportunities Catalogue (July 2003)

| Project | Shell Equity | FID | PRA[1] | RRR[2] | Note |
|---|---|---|---|---|---|
| **Licence Extensions (expiry year)** | | | | | |
| Abu Dhabi ADCO (oil) (2014) | 9.5% | 2010 | 820 | 55% | |
| Abu Dhabi GASCO (NGL) (2008) | 15% | 2005 | 100 | 7% | In Base Case |
| Venezuela (2013) | 100% | 2004 | 400 | 25% | [3] |
| Denmark (2012) | 46% | 2005 | 100 | 7% | [4] |
| Malaysia (2012+) | Various | 2012+ | 90 | 6% | |
| Syria (2014) | 64% | 2004 | 10 | 1% | |
| Oman PDO (2012) | 34% | 2004 | 0 | 0% | [5] |
| Brunei (2003) | 50% | 2003 | 0 | 0% | [6] |
| **Big Tickets and Strategic Options** | | | | | |
| **Risked (unrisked in parentheses) proved reserves additions 2003 - 2008** | | | | | |
| **Development** | | | | | |
| Sakhalin | 51% ex-MI | 2003 | 1420 (1420) | 95% | |
| Pinedale | 50% | 2004+ | 280 (280) | 20% | |
| Salym | 50% | 2003 | 270 (270) | 20% | |
| Bonga incremental | 55% | 2004/5 | 240 (270) | 15% | |
| Kashagan | 20% | 2003/6 | 190 (190) | 10% | |
| Gulf of Mexico | Various | Various | 160 (160) | 10% | |
| Doro FLNG | 33% | 2006 | 139 (350) | 10% | |
| Sunrise | 27% | 2005 | 127 (300) | 9% | |
| **Exploration and Appraisal (cut-off at 150 mln boe risked proved reserves additions potential)** | | | | | |
| Gulf of Mexico – all prospects | Various | | 780 (1980) | 50% | |
| USA Coalbed methane | 100% | | 214 (430) | 15% | |
| Kazakhstan | 20 – 60% | | 193 (485) | 10% | |
| Brazil | Various | | 364 (1430) | 25% | |
| Nigeria SNEPCO | Various | | 233 (1170) | 15% | |
| UK | Various | | 200 (880) | 15% | |
| **New Business / Strategic Options:** | | | | | |
| SURE | 100% | 2008 | 911 (2980) | 60% | [7] |
| Qatar SMDS | 70% | 2005 | 690 (1150) | 45% | |
| Russia Heartlands | 50% | 2003 | 425 (425) | 30% | A&D |
| Iran SMDS | 75% | 2005 | 396 (1070) | 25% | |
| Russia Zapolyarnoye Neocomian | 50% | 2005 | 380 (1090) | 25% | |
| Libya all opportunities | 30 – 100% | | 337 (3390) | 20% | |
| Iraq Halfayah farm-in | 55% | 2005 | 253 (1010) | 15% | A&D |
| Abu Dhabi Whale | 14% | 2003 | 210 (420) | 15% | A&D |
| Iran LNG | 50% | 2004/7 | 176 (780) | 10% | |
| Iraq Bin-Umr farm-in | 20% | 2005 | 146 (580) | 10% | A&D |
| Kuwait OSA | 50% | 2004 | 103 (410) | 7% | organic? [8] |
| Venezuela LNG | 30% | 2006 | 94 (240) | 6% | |

1 **Approximate** Proved Reserves Additions, million boe, Shell share

2 **Approximate** contribution to Proved Reserves Replacement Ratio if all the reserves quoted were booked in a single year.

3 Several opportunities exist to expand and extend current business in Venezuela, with a potential reserves impact over time of some 2.4 bln boe. The estimate reflected here corresponds approximately to extension of the existing service agreement beyond 2012.

4 Not under Shell control: negotiation to be conducted exclusively by Concessionaires (A.P. Moller).

5 Within –licence reserves may contain exposures. Substantial post-licence reserves potential exists, but this will depend on the pace of project maturation. At this stage it is assumed that extension will lead to no immediate net additional reserves booking.

6 Reserves already booked assuming that BSP's rights to two 15-year licence extensions will be exercised. Any reserves upside would be in relation to the negotiation of further extensions beyond the 30-year window, but this may be offset by potential equity reduction in the first two 15-year extensions.

7 May not qualify for conventional petroleum reserves disclosure – treat similar to AOSP project.

8 Cash-based Service Agreement with little exposure to oil price. Reserves bookings rights need to be confirmed.

## Appendix C: Potential Reserves Exposure Catalogue (July 2003)

Revisions since end-2002 are shown as either ~~struck through~~ or underlined

| Asset (Year booked) | Proved mln boe | Exp'n mln boe | Comment |
|---|---|---|---|
| Australia Gorgon (1997) | 557 | 785 | Booked in 1997 in anticipation of imminent FID, subsequently deferred indefinitely by the downturn in Asian economies and the consequent reduction in demand for LNG. It is inevitable that a resource of this magnitude will be developed eventually. 2003 CA submission addresses "unrisked" proved reserves of only 427 mln boe; consider revising booking down to this level for consistency with internal business planning. |
| Norway Ormen Lange (1999, 2000) | 109 | 186 | Reserves were partially booked ahead of VAR3 and FID, whilst it appears that there are issues that could prevent it proceeding. De-booking will be considered only when and if it becomes clear that development definitely will not proceed. FID is planned in Q4 2003. |
| Italy Tempa Rossa (acquired 2002, Enterprise) | 25 | 34 | Phase I reserves were retained at 31.12.2002 on the assumption that the project will reach FID imminently. If FID is not certain to be taken by end 2004, reserves should be debooked at 31.12.2003. Discussions are ongoing with the Italian authorities and it is currently viewed as "certain" that FID will occur in 2004. |
| Russia KMOC (acquired 2002, Enterprise) | ~~±100~~ 0 | ~~±300~~ 0 | ~~Associated company. No data to audit: retain Ryder Scott Proved Reserves assessment. Significant elements of the KMOC portfolio are understood not to be associated with approved development projects and may be difficult to commercialize.~~ Assets divested during 2003. |
| Netherlands, Waddenzee (Various) | 26 | 37 | Government-enforced moratorium on Waddenzee drilling, due to environmental concerns, could ultimately prevent development from proceeding. NAM field codes MGT, NES, LWO, VHZ (VHN?) |
| Brunei legacy (Various) | 20 | ca. 30 | Historical reserves bookings that can no longer be supported are inventorized and actively managed. It is expected that the remaining balance will be reduced to zero by end-2004, in consultation with national regulatory authorities. |
| Pending: SEC Enquiry | ±300 | 0 | Exposure if SEC interpretation of Lowest Known Hydrocarbon (LKH) is used. |
| **Total** | **1037** | **1072** | |
| **Shell reserves, 31.12.2002** | **19347** | **32848** | **Excluding AOSP** |

Expectation Reserves include post-licence volumes.

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In addition, the following threats are presented by ongoing production constraints or by tightening of the SEC rules (or Shell's interpretation thereof):

| Asset | Proved mln boe | Exp'n mln boe | Comment |
|---|---|---|---|
| **Production constraints:** | | | |
| Oman PDO | up to 450 | | Up to half of PDO's within licence proved reserves of 907 mln boe relies on delivery of major new development projects to combat decline of production from existing assets. Securing rights to post-2012 production would alleviate any potential exposure. |
| Abu Dhabi | up to 117 | | OPEC quota constraint. Exposure calculation is based on the assumption that actual 2002 production rate will continue throughout the remaining lifetime of the licence (to 2014). |
| Nigeria SPDC | ~~up to 600~~ | | ~~Effect of OPEC quota prior to licence expiry in 2019.~~ Resolved in January 2003; enforceable right to licence extension exists under Nigerian law. |
| **Technical and Commercial Maturity:** | | | |
| Nigeria SPDC | ca 220 | | Potentially exposed due to lack of audit trail and / or demonstration of maturity; plan in place to address exposures prior to recommencement of new reserves bookings, perhaps in 2005. |
| **PSC entitlement:** Exposure created by the use of Reference Price ($16/bbl) instead of year-end price ($28.66/bbl). Any exposure would be offset partially by an increase in reserves at higher oil price due to extension of the economic lifetime of fields in tax/royalty concessions. Inclusion of tax paid on behalf of Shell by NOCs would also help to offset any exposure. | | | |
| Oman Gisco | 98 | | |
| Iran | 48 | | |
| Malaysia | 47 | | |
| Russia (Sakhalin Holding) | 23 | | |
| Syria | 23 | | |
| Nigeria (SNEPCO) | 21 | | |
| Egypt | 17 | | |
| Kazakhstan | 10 | | |
| Philippines | 6 | | |
| Bangladesh | 2 | | |
| **Total, PSC** | 296 | | |
| **"Novel Contracts":** for information only: no potential exposure, although there may be a requirement in future to disclose separately and / or clarify the bookings in external disclosures. | | | |
| Venezuela Risk OSA | 222 | 358 | |
| Oman GISCO | 186 | 186 | |
| Iran buy-back | 97 | 97 | |
| Brazil Merluza OSA | 28 | 28 | |
| **Total, Novel Contracts** | 533 | 669 | |

Expectation Reserves include post-licence volumes.

Information Item: Sponsored By MGDWV

01 SEP 2003

**Note for Information**

**Group Audit Committee Briefing on Reserves Accounting Guidelines and Procedures**

Please find attached the Note for Information on Group Audit Committee Briefing on Reserves Accounting Guidelines and Procedures

It is the intention to present this to the GAC in October next.

In the mean time we will get to the bottom of the "Fuel and Flare" issue. It appears that RD/ST&T are the only companies reducing their proved reserves by approximately 3% to reflect own use and flaring.

"POTENTIAL EXPOSURE" SOME LOOK LIKE THEY SHOULD BE DEBOOKED

MGDWV, 28/08/2003

000115

EXHIBIT
Van der Vijver
30
2/1/07

FOIA Confidential Treatment Requested
LON00010114

Note for Information

## Group Audit Committee Briefing on Reserves Accounting Guidelines and Procedures

This note summarizes (1) EP's response to the reserves accounting recommendations in the Group Reserves Auditor's 2002 report, and (2) changes that have been made to the reserves accounting guidelines. In addition it (3) describes the status of correspondence with the Securities and Exchange Commission (SEC) on matters relating to proved reserves disclosures and (4) discusses areas of potential concern over Shell's (and, generally, industry's) interpretation of the SEC regulations.

The Sarbanes-Oxley Act of 2002 provides for an increased level of corporate accountability for compliance with the applicable disclosure regulations of the SEC. In response to this, it is appropriate that internal procedures covering all aspects of the Group's financial disclosures are reviewed and that measures are in place for ensuring continued compliance in future. Items (1) and in particular (2) of this Note describe measures that have been introduced in relation to proved reserves disclosures. They enhance the level of corporate control of the reserves accounting process, providing further assurance to EP and Group management of compliance with the applicable regulations. As such, they are designed to improve the transparency and consistency of the Group's external disclosures and to ensure that procedures are in place to regularly review compliance in future.

An overview of the current corporate controls on proved reserves accounting can be found in Attachment 1.

### 1. Group Reserves Auditor's 2002 Report

In his review of the Group's proved reserves at 31 December 2002, the Group Reserves Auditor made eight recommendations for the improvement of reserves accounting guidelines and procedures. All eight recommendations have been accepted by the EP Executive and have been implemented. Please refer to Attachment 2 for detail, the main points of which may be summarized as follows:

- Reserves bookings for major projects will be linked to Final Investment Decision (FID) or other public demonstration of commitment to proceed with the project. In addition the guidelines have been revised to require that, as a minimum, gas reserves that rely on the creation of access to market (e.g. LNG) must be underpinned by binding Heads of Agreement for sales contracts.
- Regional reserves challenge sessions will be introduced, starting in 2003, with the objective of endorsing or otherwise challenging material proved reserves changes that are proposed by the Asset Holders.



000116

## 2. Petroleum Resource Volume Guidelines and Administration Procedure

The internal guidelines for proved reserves reporting are reviewed annually to ensure continuing compliance with the SEC regulations. In the 2003 edition (EP 2003-1100, currently in drafting), the following key revisions have been made:

- Major projects: trigger for reserves bookings: see (1) above.
- Gas sales contracts: see also (1) above.
- "New contracts": the criteria for booking reserves in relation to new contract structures (i.e. those that are not traditional tax / royalty licences or Production Sharing Contracts) have been clarified. The change will bring the guidelines into line with actual practice as documented in the 1996 Group Audit Review of reserves disclosures for Venezuela and Oman GISCO.
- No changes to the guidelines have been made in relation to matters that are currently the subject of correspondence with the SEC (please refer to (3) below).

The full inventory of documents that describe and / or control procedures for proved reserves estimation and disclosure is as follows:

**EP 2003-1100** — **"Petroleum Resource Volume Guidelines: Resource Classification and Value Realisation"**: updated annually: 2003 edition in draft for publication in September.

This describes the petroleum resource volume classification system and the rules and guidelines that are to be followed in the estimation of all such volumes, including proved reserves.

**EP 2003-1101** — **"Petroleum resource volumes submission requirements for internal and external reporting"**: updated annually: 2003 edition in draft for publication in October.

This describes the manner and format in which petroleum resource volumes, and in particular changes to said volumes, are to be reported annually by all Asset Holders.

**EP 2003-1102** — **"Guide for the Administration of Proved Reserves and Production for External Disclosure"**: updated when required: 2003 edition issued in July 2003.

This describes the controls that are in place to assure the accuracy of the external proved reserves disclosures and their compliance with SEC rules.

EP 2003-1102 is an update to a similar document that was first published in 1986 and which was revised in 1996. The key change that has been incorporated in the 2003 update is the introduction of a "Reserves Committee" to provide further assurance on the quality and integrity of the Group's external proved reserves disclosures.

The Reserves Committee consists of the following permanent members:

- EP Chief Financial Officer (EPF)
- EP Corporate Support Director (EPS)
- EP Director Shell Technology (EPT)
- EP Hydrocarbon Resource Coordinator (EPS-P)
- SI Deputy Group Controller (FCG)

In addition, the Group Reserves Auditor attends the Reserves Committee in an advisory role.

The Reserves Committee reports to the EP Chief Executive Officer and the other members of the EP Executive on all procedural matters concerning the disclosure of proved reserves. In this context, its duties include, but are not limited to:

- To understand, challenge and ultimately to authorize on behalf of the EP Chief Executive Officer the proved reserves figures that are disclosed externally, together with any explanation thereof that is to be published.
- At least annually, to review internal procedures (as described in EP 2003-1102) and the Petroleum Resource Volume Guidelines (EP 2003-1100) with a view to determining the need for revision and to direct such revisions where necessary.
- To coordinate relevant correspondence with the United States Securities and Exchange Commission on behalf of the Group Controller.
- To maintain an interface with the external Group Auditors.
- To monitor action taken by Regions/Asset Holders or by the EP organization as a whole in response to Group Reserves Auditor recommendations and to inform the external Group Auditors accordingly.
- To assist in the resolution of disagreements between authorizers of proved reserves at different levels in the EP organization.

Furthermore, EP 2003-1102 provides for the introduction of annual regional reserves challenges sessions, in which the material proposed changes to proved reserves volumes will be reviewed in advance of year-end for compliance with the Group guidelines.

### 3. SEC Enquiry

In October 2002, the SEC began an enquiry into practices surrounding the disclosure of proved reserves in the Gulf of Mexico. The enquiry was conducted through correspondence with individual companies and it appears to have encompassed virtually all companies owning subsurface assets in the Gulf of Mexico. The initial focus was on the booking of proved reserves in the absence of a production flow test.

Correspondence is still ongoing and, in a total of four rounds to date, the SEC has broadened the scope of its enquiry beyond the Gulf of Mexico and has introduced several additional areas of focus. The four most important issues are:

#### (a) Production Flow Test

The initial focus of the enquiry was on the following SEC rule:

> *"Reservoirs are considered proved if economic producibility is supported by either actual production or conclusive formation test."*

The SEC indicated its view that a full production flow test is required in order to meet the "conclusive formation test" criterion. It is understood that the overwhelming response from the industry (including Shell) was to reject this interpretation, citing the fact that core, log, pressure and fluid sample data, properly calibrated with reference to analogue reservoirs, has been viewed widely as meeting the "conclusive formation test" criterion for many years now. The SEC appears to have partially accepted this view: in a recent web bulletin it acknowledged the use of analogue data, although commenting that the analogue reservoir must be within the same field. This is still a more strict interpretation than is applied in the industry, where reference is commonly made to similar reservoirs in other nearby fields.

#### (b) Trigger for proved reserves booking

The SEC requested comments on its views concerning the type of criteria that it expects to see in relation to demonstration of commitment ("reasonable certainty") to proceed with a development project. These criteria included:

> "*the approved application for the setting of a platform...*", and
>
> for reserves that would be developed by sub-sea tie back: "*evidence of flow line construction or platform modification...*"

In a previous round of correspondence Shell had already advised the SEC, in broad terms, of the criteria that are used internally for establishing the existence of "reasonable certainty" that a development will proceed. These criteria, which are understood to be broadly comparable with those adopted by other companies in the industry, are substantially less stringent than the SEC appears to require. Shell responded to the SEC with the view that "*such a strict interpretation would go substantially beyond the intent of the proved reserves definitions regarding 'reasonable certainty'*". To date no further comment on this issue has been received from the SEC.

**(c) Reserves entitlements for Production Sharing Contracts (PSCs)**

The SEC expressed its view that FAS 19[1] requires reserves entitlement for PSCs to be disclosed separately (i.e. as a separate line item) from other reserves. After review of FAS 19, supported by reference to external legal counsel (Cravath, Swain and Moore), Shell's long-standing view was confirmed: FAS 19 does not provide any requirements for the separate disclosure of reserves that would extend to include PSCs. This view was communicated to the SEC, with no response yet having been received.

Informal discussion with industry colleagues suggests that (1) the SEC did not communicate its views to all companies that have PSCs in their portfolios (raising the unfortunate possibility that the SEC's views are being communicated selectively and not universally to the industry) and (2) Shell's interpretation of FAS 19 appears to be shared by at least two major competitors. In addition to the latter point, it is observed that none of Shell's major competitors discloses PSC reserves separately.

**(d) Lowest Known Hydrocarbon (LKH)**

Recently the SEC has indicated to Shell its view that the Lowest Known Hydrocarbon (LKH) as defined by drilling (and logging) must constrain the part of any reservoir for which proved reserves are booked. This view seems to run against the original FASB definition, which stipulates the above condition only "in the absence of information on fluid contacts". Hence it runs contrary to Shell's (and the industry's) established practice of interpreting "information on fluid contacts" to include indirect observations such as pressure-depth cross plots and, in some cases, 3D seismic data.

If the SEC were to insist on the adoption of its revised interpretation, an exposure of some 300 mln boe in Shell's 2002 proved reserves disclosure would be created, equating to approximately 1.5% of Shell's total proved reserves. This exposure would erode over time as further drilling and production performance information is gathered on the subject reservoirs.

As with the PSC issue (see (c) above), it appears that the SEC's views on this matter have been communicated selectively and not universally to all registrants. It is understood that the SEC has advised at least one major competitor that it has concluded its correspondence with them and that the LKH issue was not raised during the course of its correspondence with that company. It is also known that while correspondence continues with another, this issue has not yet been raised with them. In both cases it is understood that the companies would share Shell's reservations concerning the SEC's interpretation.

Shell has challenged the SEC's interpretation of the LKH criterion, on the grounds that it is not in line with either (1) the spirit or intent of the SEC rules, (2) the views of the SEC's own staff members, as published previously or (3) long-standing, established industry practice. Recently Shell staff visited the SEC offices in

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[1] United States Financial Accounting Standards Board (FASB), Statement of Financial Accounting Standards number 19 (FAS 19).

Washington DC with the objective of reinforcing these points. The SEC expressed considerable interest in Shell's views (for the purpose of learning, not enforcement) but did not concede any ground on the interpretation of its rules.

WHO WENT? WHO WAS THERE FROM SEC

As follow-up, Shell is preparing to contribute to an industry-wide challenge of the SEC's interpretation through such means as consultation between the SEC and the Society of Petroleum Engineers' (SPE) Reserves Committee (on which Shell has one member) and through a workshop between the SEC and industry that is organized in October each year by the Society of Petroleum Evaluation Engineers (SPEE).

## 4. Possible areas of non-compliance with SEC regulations

On several key points the SEC regulations on proved reserves are vague or are not explicit, leaving room for interpretation and a consequent risk that some practices might be deemed to be against the spirit and intent of the regulations if subjected to external scrutiny. The problem of interpretation is not unique to Shell – it is clear that many registrants experience similar problems in determining (1) whether a right to disclose reserves exists, under certain circumstances, and (2) the basis upon which reserves should be estimated. Evidence for this comes from the many interpretive responses that have been provided to industry questions by the SEC staff and from discussions at the SPEE workshops (see (3) above).

The main areas of potential concern at present are summarized below, with the current potential reserves exposures being listed in Attachment 3:

- **Trigger for booking reserves:**
  See 3(b) above. The move towards booking reserves for major projects at FID should bring Shell into line with industry practice, although some exposure will remain pending FID on projects for which reserves have already been booked.

- **Definition of the "proved area":**
  The extent to which the reservoir has been "proved up" away from well control is subject to interpretation outside the United States or in any situation where the concept of a "legal well spacing" does not apply. Shell's practices are believed to be broadly consistent with the rest of industry. See also 3(d) above.

- **Production Sharing Contract (PSC) entitlement:**
  Shell reports reserves on the basis of economic entitlement, as opposed to working interest share, in line with industry practice and SEC preference. However, Shell uses its internal oil and gas reference prices in this calculation, rather than the year-end price preferred by the SEC. At least one major competitor is known to take a similar approach. This practice could be deemed to overstate reserves at times of high actual oil price, but the effects are offset by a corresponding understatement of reserves in tax/royalty concessions. Furthermore, unlike some competitors, Shell does not currently include reserves

in some PSCs in relation to tax that is paid on its behalf by the National Oil Company.

- **Non-traditional contracts:**
  Over the last few years Shell has taken interests in novel contract structures for which the SEC regulations provide little, if any, direct guidance on how reserves entitlements should be treated. In the interests of informing the investor in a meaningful way, honouring the spirit and intent of the SEC regulations, reserves are calculated and disclosed analogous to the economic entitlement method that is used for PSCs. Competitors are understood to adopt similar approaches.

- **Royalties:**
  Outside the US, the SEC regulations permit net production (and reserves) to be disclosed inclusive of royalty "if more appropriate" than exclusive of royalty. This is interpreted to mean that royalty taken in kind must be excluded, but royalty taken in cash may be included. Practice is believed to be aligned with competitors, but no hard details of competitor practices in general are available.

- **Post-licence entitlements:**
  Shell discloses reserves beyond the current term of licences and concessions when (1) an agreement for extension or renewal is in place or (2) the regulatory authorities have a track record of granting renewals or extensions "as a matter of course" (the latter condition being supported by SEC guidance). In some cases consideration may be given to recognizing post-licence reserves when the licensee has a legally enforceable right to extension or renewal. The recent problems experienced by BP in booking reserves in Russia may relate to a lack of "reasonable certainty" concerning licence extension, and the situation for Shell's intended reserves disclosures in Russia is currently under review.

Much, if not all, of the potential exposure arising from interpretation of the factors listed above is offset by Shell's practice of not disclosing reserves in relation to gas production that is consumed on site as fuel or (incidental) flaring and venting. Shell's approach seems to have been based on interpretation of the original SEC regulations, introduced in Accounting Series Release number 257, dated December 1978. This stipulated the requirement to disclose (1) proved reserves and (2) production "as sold". Shell took the view that the "as sold" condition applies both to the production and reserves figures (the latter being the sum of the former for future years). In fact these two issues seem to be viewed separately by the SEC, and it is expected that reserves are disclosed "as produced", whereas production "as sold" must be disclosed in addition for comparison. A review of competitor practices indicates that most include fuel and (possibly) at least some flare gas in their reserves disclosures (with the notable possible exception of BP), and a further review is in progress to examine the implications of changing Shell's reporting practice.

## Reserves Accounting: Overview

An overview of responsibilities for controlling the annual proved reserves disclosures is presented below, in approximately the correct chronological sequence:

| | |
|---|---|
| Asset teams | Prepare estimates based on Group Guidelines (EP 2003-1100). |
| Asset Holder / Region Reserves Focal Point | Assists asset teams in preparing estimates and collates information for submission to EP Hydrocarbon Resource Coordinator |
| Regional Challenge process | Senior technical experts in Region verify compliance of annual proved reserves changes with Group Guidelines |
| Asset Holder / Regional Technical Management | Authorize estimates as having been prepared in compliance with Group Guidelines. |
| EP Hydrocarbon Resource Coordinator | Collates information submitted by Regions / Asset Holders, clarifies and challenges where necessary, prepares information in correct format for external disclosure. |
| Group Reserves Auditor | In conjunction with Group External Auditors, reviews information submitted by Regions / Asset Holders, clarifies and challenges where necessary, verifies correct transcription of information for external disclosure by EP Hydrocarbon Resource Coordinator. |
| Reserves Committee | Reviews information to be externally disclosed, clarifies and challenges where necessary, and ultimately endorses (EPF and EPS, who also provide a Letter of Comfort to the Group External Auditors certifying that the disclosures comply with the applicable SEC regulations). |

In support of this annual process are the following additional control and review responsibilities:

| | |
|---|---|
| Group Reserves Auditor | Periodic audits of Asset Holder reserves accounting procedures, verifying that same are compliant with Group Guidelines. |
| Reserves Committee | Annual review of Group Guidelines for continuing compliance with SEC regulations and FASB disclosure requirements, taking into account (any) new SEC guidance, Group Reserves Auditor recommendations and issues arising from recent disclosures. |
| EP Hydrocarbon Resource Coordinator | Updates Group Guidelines where and when necessary in accordance with Reserves Committee direction. Disseminates same to Asset Holders. |
| Asset Holder / Regional Technical Management | Ensures that procedures in place locally for proved reserves estimation are in accordance with Group Guidelines. |
| Asset Holder / Regional Reserves Focal Points | Disseminate Group Guidelines locally, support management in assuring that appropriate procedures are in place, support asset teams in preparation of proved reserves estimates. |

The financial aspects of external reserves disclosures (notably the agreement of production figures with disclosed sales volumes and the information used in preparing the Standardized Measure of Discounted Cash Flow) are subject to similar approvals by Asset Holder / Region Finance Management.

**Reserves: 2002 Group Reserves Auditor Report**

This note summarizes the actions that have been taken or that are planned in response to the reserves accounting recommendations made by the Group Reserves Auditor in his report on the Group's proved reserves disclosures as at the end of 2002.

In summary, all the recommendations of the Group Reserves Auditor have been accepted and action has been taken. The specific recommendations are reproduced below, with action summarized in each case.

1. *Maintain the present vigilance regarding the continued booking of Proved reserves volumes with poor justification, as highlighted in [the Group Reserves Auditor's] report and re-consider the booking of these volumes as appropriate.*

   Action: The procedure for administering proved reserves information for external disclosure has been updated and is documented in report EP 2003-1102: "*Guide for the Administration of External Disclosure of Proved Reserves and Production*" in line with changes to the EP Proved Reserves Management procedure that were introduced in 2002 (the previous update was made in 1996). The principal revision has been to establish a Reserves Committee which will report to the EP Executive. It will oversee the integrity of all aspects of the external proved reserves disclosures and the procedures by which they are administered.

   Vigilance and the integrity of reserves bookings will be maintained and further improved by the establishment of the Reserves Committee and by actions taken with respect to other recommendations (e.g. 2 and 4 below). The EP Hydrocarbon Resource Co-ordinator ("HRC") will continue to maintain a Potential Reserves Exposure Catalogue, first compiled in 2002, and bring this forward for consideration by the Reserves Committee at least twice per year (in July and October).

2. *Consider a further tightening of conditions under which first-time booking of major project reserves can be allowed by Group reserves guidelines. The prime condition should be a clear public commitment by the Group that development will be undertaken. This could be FID, but also a Declaration of Commerciality if the latter is sufficiently binding.*

   Action: The recommendation is accepted. The guidelines for the estimation and reporting of proved reserves are updated annually. The 2003 edition (EP 2003-1100: "*Petroleum Resource Volume Guidelines: Resource Classification and Value Realisation*") is currently being drafted for publication in September 2003. It will include a modification of the criteria for booking reserves for all major projects (not only "first-time bookings") in line with this recommendation.

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3. *Maintain and, if necessary, increase EP ExCom's attention to the preservation of the integrity of OU reserves bookings in the light of the potential threat emanating from reserves addition targets in score cards.*

   Action: The potential threat from scorecard targets is well understood and was taken into account when changes to the EP Proved Reserves Management procedure were considered in 2002. As well as the vigilance of the EP Hydrocarbon Resource Coordination function and the attention of EP Executive members to the figures disclosed, further controls have been introduced through the introduction of regional reserves challenge sessions (see (4) below) and through the establishment of a Reserves Committee (see (1) above). The Reserves Committee includes three EP Executive members and it has the duty to authorize the proved reserves figures for external disclosure and to assist in the resolution of disputes within the EP organization concerning proved reserves estimates. Disputes related to score card items would fall into the latter category. Please refer to EP 2003-1102 for further information.

4. *Consider a tightening of the control on reserves changes by introducing regional reserves audit teams which are to carry out annual reserves audits with OUs and which have the power to approve / disallow OU proposed reserves changes.*

   Action: Regional reserves challenge sessions are to be introduced commencing in 2003. They will take place in September or October each year, this timing being selected on the basis that it is sufficiently late in the year to allow a meaningful consideration of the proved reserves changes for the year, whilst being early enough to allow such consideration to take place in advance of discussions with partners, co-venturers and host government representatives.

   The challenge session in each region will be attended by senior technical professionals drawn from the region. They will review material proposed changes for compliance with the Petroleum Resource Volume Guidelines and, hence, with the SEC rules. In principle, each session will be attended either by the EP Hydrocarbon Resource Coordinator or the Group Reserves Auditor and by a representative of another region (to promote the adoption of common standards globally). The sessions will ensure an appropriate level of peer review of the proposed changes. This may result in the proposed changes being withdrawn, deferred, modified, considered sound or referred to EP management for determination. The outcome of the sessions, including recommendations and any matters requiring consideration by EP management, will be reviewed subsequently by the Reserves Committee (see (1) above).

   For 2003, whilst the EP organization is still in a transition phase, it is possible that challenge sessions will be held in only three of the five regions (EPE, EPA and EPW), with the other two commencing in 2004 (EPM and EPG).

5. *Re-evaluate the effect of using PSV oil prices instead of end-year oil prices on PSC and other reserves bookings at regular (bi- or tri-yearly) intervals.*

**Comment:** This recommendation stems from the SEC requirement that proved reserves be evaluated with reference to conditions applicable as at the date of the estimate, i.e. 31st December each year. This includes product prices. In fact proved reserves are calculated using the prevailing Group reference price.

For PSCs, reserves entitlement is inversely proportional to oil and gas price, whilst in tax/royalty licences there is a positive (or neutral) correlation. Consequently the effects of changes in oil and gas price on reserves for these two types of contract oppose each other, tending to limit the degree to which EP's total proved reserves figure is dependent on product price. That being the case, it is convenient to evaluate proved reserves at a single set of reference price conditions that can be linked readily to assumptions that are made for the purpose of business planning. Indeed, it is viewed as highly desirable to maintain such a link, since the use of two different price assumptions, and hence two different "proved reserves" estimates, could lead to confusion and hence erosion of the integrity of the external proved reserves disclosures. There are also logistical reasons related to the process of estimating reserves which make it highly desirable (and even necessary) to determine reference oil and gas prices well in advance of the end of the year.

For PSCs the difference between reserves entitlement at the reference price compared with the year-end price is collected every year as part of the reserves reporting exercise.

Capturing reliable and comprehensive data on the corresponding effects for tax/royalty licences is significantly more difficult and time-consuming. It was last attempted in 2000, and it is planned to repeat the exercise in 2003. Tri-annual frequency appears to strike a good balance between the effort expended and the need to periodically check that the two effects on reserves are broadly equal and opposite.

Only in the event that a material discrepancy arises between the total reserves bookable according to the reference price assumption, compared with actual year-end pricing, would a change to the current reporting practice be considered.

Action: The recommendation will be implemented at three-yearly intervals, the next to occur when the 31.12.2003 reserves estimates are filed by the Asset Holders.

6. *Ensure that OUs, in particular PDO and SPDC, prepare proper composite production forecasts (built up from realistic individual field forecasts, both Proved and Expectation) demonstrating the reasonable certainty that Proved reserves can be produced within current licence durations. The annual forecast rates should not exceed those presented as the Base Plan in the latest Business Plan.*

   Action: This matter is being addressed with the companies mentioned, both of which will be subjected to audit by the Group Reserves Auditor in 2003. The 2003 edition of the Petroleum Resource Volume Guidelines (EP 2003-1100) will stress this point.

7. *Challenge OUs with regard to their submissions of estimates of amounts by which Proved reserves should rise if there were no licence duration constraints.*

   Comment: External disclosures of proved reserves must respect the constraints imposed by licence durations and therefore the estimates of "post-licence" reserves do not influence Shell's external disclosures. Nevertheless, this information is of use not only for determining the reward associated with licence extension or renewal, but also in judging the reasonableness of the overall proved reserves estimate in relation to the expectation reserves estimate. In the 31.12.2002 reserves submission, several OUs reflected substantial changes to their estimates of post-licence reserves compared with the previous year, prompting this comment from the Group Reserves Auditor.

   Action: This matter has been addressed with the OUs concerned and, with relatively minor exceptions, the estimates registered at 31.12.2002 have been confirmed as correctly reflecting the OUs' current views. The 2003 edition of the Petroleum Resource Volume Guidelines (EP 2003-1100) will stress the importance of ensuring accuracy in this information and will clarify the intention behind capturing the data.

8. *Include guidelines with respect to appropriate methods of proved and Expectation forecasting in the next edition of the Group reserves guidelines.*

   Action: The 2003 edition of the Petroleum Resource Volume Guidelines (EP 2003-1100) will include appropriate guidance.

Appendix C: Potential Reserves Exposure Catalogue (July 2003)

| Asset (Year booked) | Proved mln boe | Exp'n mln boe | Comment |
|---|---|---|---|
| Australia Gorgon (1997) | 557 | 785 | Booked in 1997 in anticipation of imminent FID, subsequently deferred indefinitely by the downturn in Asian economies and the consequent reduction in demand for LNG. It is inevitable that a resource of this magnitude will be developed eventually. |
| Norway Ormen Lange (1999, 2000) | 109 | 186 | Reserves were partially booked ahead of VAR3 and FID, whilst it appears that there are issues that could prevent it proceeding. De-booking will be considered only when and if it becomes clear that development definitely will not proceed. FID is planned in Q4 2003. |
| Italy Tempa Rossa (acquired 2002, Enterprise) | 25 | 34 | Phase 1 reserves were retained at 31.12.2002 on the assumption that the project will reach FID imminently. If FID is not certain to be taken by end 2004, reserves should be debooked at 31.12.2003. Discussions are ongoing with the Italian authorities and it is currently viewed as "certain" that FID will occur in 2004. |
| Netherlands, Waddenzee (Various) | 26 | 37 | Government-enforced moratorium on Waddenzee drilling, due to environmental concerns, could ultimately prevent development from proceeding. NAM field codes MGT, NES, LWO, VHZ (VHN?) |
| Brunei legacy (Various) | 20 | ca. 30 | Historical reserves bookings that can no longer be supported are inventorized and actively managed. It is expected that the remaining balance will be reduced to zero by end-2004, in consultation with national regulatory authorities. |
| Pending: SEC Enquiry | ±300 | 0 | Exposure if SEC interpretation of Lowest Known Hydrocarbon (LKH) is used. |
| Total | 1037 | 1072 | |
| Shell reserves, 31.12.2002 | 19347 | 32848 | Excluding Athabasca Oil Sands Project (AOSP) |

Expectation Reserves include post-licence volumes.

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In addition, the following threats are presented by ongoing production constraints or by tightening of the SEC rules (or Shell's interpretation thereof):

| Asset | Proved mln boe | Exp'n mln boe | Comment |
|---|---|---|---|
| **Production constraints:** | | | |
| Oman PDO | up to 450 | | Up to half of PDO's within licence proved reserves of 907 mln boe relies on delivery of major new development projects to combat decline of production from existing assets. Securing rights to post-2012 production would alleviate any potential exposure. |
| Abu Dhabi | up to 117 | | OPEC quota constraint. Exposure calculation is based on the assumption that actual 2002 production rate will continue throughout the remaining lifetime of the licence (to 2014). |
| **Technical and Commercial Maturity:** | | | |
| Nigeria SPDC | ca.220 | | Potentially exposed due to lack of audit trail and / or demonstration of maturity: plan in place to address exposures prior to recommencement of new reserves bookings, perhaps in 2005. |
| **PSC entitlement:** Exposure created by the use of Reference Price ($16/bbl) instead of year-end price ($28.66/bbl). Any exposure would be offset partially by an increase in reserves at higher oil price due to extension of the economic lifetime of fields in tax/royalty concessions. Inclusion of tax paid on behalf of Shell by NOCs would also help to offset any exposure. | | | |
| Oman Gisco | 98 | | |
| Iran | 48 | | |
| Malaysia | 47 | | |
| Russia (Sakhalin Holding) | 23 | | |
| Syria | 23 | | |
| Nigeria (SNEPCO) | 21 | | |
| Egypt | 17 | | |
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| Oman GISCO | 186 | 186 | |
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Expectation Reserves include post-licence volumes.

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Ewart, Pauline M SI-MGDPW

**From:** Van De Vijver, Walter SI-MGDWV
**Sent:** 09 November 2003 11:17
**To:** Watts, Philip B SI-MGDPW
**Subject:** FW: LKH

Phil,

Reference our discussion on reserves on monday 3/11,please find attached the summary on LKH.
The issue of LKH is not just a US issue (perhaps you were implying something there?).
I am becoming sick and tired about lying about the extent of our reserves issues and the downward revisions that need to be done because of far too aggressive/optimistic bookings in the past ,aside from the embarrassment of having booked reserves prematurely.
Regards,
Walter

-----Original Message-----
**From:** Bell, John J SIEP-EPS
**Sent:** 06 November 2003 11:20
**To:** Van De Vijver, Walter SI-MGDWV
**Cc:** Pay, John JR SIEP-EPS-P; Coopman, Frank F SIEP-EPF
**Subject:** LKH

LKH Slide.ppt
(Compressed)

Walter,

You asked for details of our exposure to the LKH issue. The attached is from John Pay. Happy to discuss further if needed.

John will join the EPLF tomorrow to help facilitate the discussion on the acceleration of reserves bookings. He will sit in the GRoup with the RTDs and EPT to assist in assessing ideas and providing data.

John.

000002

[redacted]

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# LKH Exposures at 1.1.2003

| MMboe | Total | Dev | Undev |
|---|---|---|---|
| Brunei | 87 | 1 | 86 |
| USA | 72 | 20 | 52 |
| SNEPCO | 36 | 0 | 36 |
| Sakhalin (ex MI) | 26 | 5 | 21 |
| Canada | 11 | 0 | 11 |
| Denmark / Norway | 10 | 5 | 5 |
| **Total** | **242** | **31** | **211** |

- 24 other OUs indicated zero or negligible exposure
- 3 other OUs were unable to quantify without detailed review, but exposures are not expected to be severe.

- SEC has stated its view that reserves below Lowest Known (Logged) Hydrocarbon do not qualify as proved until sufficient performance history available to confirm higher volume.
- Private correspondence - issue not raised directly with main competitors (but supported by general public SEC statements)
- Exposures mainly in immature fields / undeveloped reserves.
- Exposure will erode over time as performance history builds.
- Current plan is manage exposure rather than debook.
- Debooking, if required, could be offset by adding Fuel to disclosed reserves.

**EPS**

000003

## Unknown

**From:** Coopman, Frank F SIEP-EPF
**Sent:** 24 November 2003 06:50
**To:** Lau, David DNP SIEP-EPF-CT
**Cc:** Bouchla, Souli C SIEP-EPS-D
**Subject:** FW: 2003 RRR Review

**Importance:** High

We need a telcon today..........(you , me)

-----Original Message-----
**From:** Van De Vijver, Walter SI-MGDWV
**Sent:** 23 November 2003 15:50
**To:** Pay, John JR SIEP-EPS-P
**Cc:** Bell, John J SIEP-EPS; Coopman, Frank F SIEP-EPF
**Subject:** RE: 2003 RRR Review
**Importance:** High

John,

I want to have a proper EP view before Conference (3/12/03) how we should manage reserves going forward.
I would prefer to re-state our 1/1/03 reserves and de-book all remaining legacies to allow for a clean start as of 1/1/03 with a healthy organic reserves replacement for 2003 and later years, better reflecting the true health of our business.
This would imply de-bookings on Oman,Nigeria plus perhaps some of the other items that are unlikely will be finally matured in 04/05 (ie Waddenzee,Gorgon,...).
This is a very sensitive issue particularly when we will look at the arguments for doing so:

- stricter SEC guidelines (but could this lead to a fall-out from the SEC?)
- linkage with our reputattion to be conservative?
- are their sound technical arguments that would not make us look technical incompetent and would not hamper the outlook for EP?

I have asked Frank to work the disclosure/SEC issues.
I still find it amazing to compare the 99 and the 03 audit write-ups for Nigeria and for Oman.We better categorise the differences
to have a logical explanation.
I trust there are also exposures wrt previously received reserves bonus fees.

Regards,
Walter

-----Original Message-----
**From:** Pay, John JR SIEP-EPS-P
**Sent:** 17 November 2003 13:16
**To:** Van De Vijver, Walter SI-MGDWV
**Cc:** Bell, John J SIEP-EPS; Coopman, Frank F SIEP-EPF; Darley, John J SIEP-EPT; Percival, Iain IDR SIEP-EPT-OE-HL
**Subject:** RE: 2003 RRR Review

The latest reports are (PDO only draft at this stage): Both "Unsatisfactory":

<< File: SPDC03-Rept.doc (Compressed) >> << File: PDO03-Covnt.doc (Compressed) >>

The previous ones, both from 1999, are as follows: "Satisfactory" and "Good" respectively, although comments were made in both cases about the (lack of) audit trail in support of the disclosed figures:

<< File: SPDCovnt.doc (Compressed) >> << File: OmnCovnt.doc (Compressed) >>

The audits were conducted with reference to the 1998 and 2002 editions of the Petroleum Resource Volume Guidelines. In 1998 the criteria for project technical and commercial maturity were somewhat more relaxed than now. Whereas now reserves should in principle be post-FID (major projects) or at least post-VAR-3 (lesser projects),

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in 1998 the criteria were as indicated below. Key points that now are subject to much more stringent interpretation are highlighted in red. The increased stringency stems both from SEC guidance and from the desire to ensure that reserves bookings are tied more closely to investment decisions. Furthermore, the 1998 guidelines continued to endorse the use of probabilistic (p85) proved reserves estimates. The emphasis is now on deterministic techniques which tend to yield lower estimates in immature fields.

**1998: Technical and Commercial Maturity**

The classification scheme uses a project's technical and commercial maturity as the primary criteria to distinguish between reserves and scope for recovery (SFR). Resource volumes can be classified as reserves only if the associated project that will result in production of those volumes is considered to be technically mature and commercially viable. If it cannot, the resource volumes should be classified as SFR. SFR needs an activity (e.g. exploration appraisal, field trial, gas market development, etc) to achieve technical maturity and commercial viability. Secondary technical and commercial distinctions (between proved and unproved techniques SFR and between commercial and non-commercial SFR) further identify resource volumes at various stages in the life cycle.

*Project Basis*

Technical and commercial maturity reflects the status of remaining uncertainties in the assessment of the optimal development project and its associated recovery. A project is any proposed or notional modification of the wells, the production facilities and/or the production policy, aimed at changing the company's sales product forecast. It can also be a modification of the company's share in a venture (purchase/ sales-in-place, unitisation, new terms). The generic term 'project' is also used to describe a group of (sometimes alternative) projects, each with a certain chance of realisation, depending on the results of further data gathering. In that case, the project NPV is replaced by the Expected Monetary Value (or EMV, see Appendix 6).

*Technically Mature*

For a project to be **technically mature**, information on the resource volume, including its level of uncertainty, is such that an optimal project can be defined with an auditable project development plan, based on a resource and development scenario description, with drilling/engineering cost estimates, a production forecast and economics. The plan may be notional or it may be an analogy of other projects based on similar resources. However, there should be a reasonable expectation that a firm development plan can be matured with time. Projects do not have to have a completed development plan.

*Commercially Mature*

A **commercially mature** project is commercially viable over a sufficiently large portion of the range of possible scenarios that reflect the remaining resource uncertainties. The definition of what constitutes "a sufficiently large portion" may vary from case to case and could for example require the project NPV for the low reserves scenario to be positive for appropriate commercial criteria. It is also likely to include an assessment of the capital exposure in case of project failure due to adverse resource realisations. The selected range of scenarios should be documented and auditable.

A scenario is **commercially viable** if the NPV is expected to be positive under the applicable terms and conditions for the acreage and for the current advised Group reference criteria for commerciality (Reference 9).

A project is **economically viable** if the expected NPV under the applicable terms and conditions for the acreage exceeds the separately advised Group project screening criteria or if the project has already been approved by shareholders. Projects generally have to demonstrate economic viability in order to obtain investment approval. However, economic viability or formal project approval is not required for a project to be considered commercially mature. Reserves may be booked before project approval is sought.

**John Pay**
Group Hydrocarbon Resource Coordinator
Shell International Exploration and Production B.V.
Shell Exploration & Production International Centre
Kessler Park 1, 2288 GS,
PO Box 60, 2280 AB,
RIJSWIJK-ZH,
The Netherlands

**Tel:** +31 (70) 447 2547 **Other Tel:** +31 (0)6 5252 1964
**Email:** john.pay@shell.com
**Internet:** http://www.shell.com/eandp-en

NOTE – 30 Sept 2003

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2003 AUDIT "unsatisfactory" due to project immaturity.

| | | |
|---|---|---|
| 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 |
| | Chris Finlayson | Managing Director, SPDC |
| Copy: | Mark Comer | Development Director, SPDC |
| | Steve Ratcliffe | Business Director, SPDC |
| | Cees Uijlenhoed | Finance Director, SPDC |
| | Promise Egele | Petroleum Engineering Manager, SPDC |
| | John Hoppe | Head, Reservoir Engineering, SPDC |
| | (circulation) | SIEP – EPS-P: Hans Bakker, John Pay |
| | Tom van Leenen | Technical Director, Europe & Africa Region, SEPI – EPG |
| | Martin ten Brink | Finance Director, Europe & Africa Region, SEPI – EPG |
| | Ken Marnoch | Internal Auditor EP, SI-FSAR, The Hague |
| | Han van Delden | Partner, KPMG Accountants NV (2x) |
| | Brian Puffer | PriceWaterhouseCoopers |

**PROVED RESERVES PROCESS AUDIT - SPDC (NIGERIA), 18-19 Sept 2003**

I have audited the processes underlying the Proved Reserves submissions of SPDC for the year 2002 and the current measures undertaken by SPDC to introduce improvements in these processes. The reserves submissions present the SPDC contribution to the Group's externally reported Proved and Proved Developed Reserves and associated changes as at 31 December 2002.

Total Group share Proved Reserves booked by SPDC at the end of 2002 were 404 mln m3 of Oil+NGL and 85 bln sm3 of gas. This represents some 16% of total Group share Proved Reserves on an oil-equivalent basis. Proved reserves replacement ratios for SPDC over 2002 were -6% for oil+NGL and -55% for gas.

The last previous SEC proved reserves audit for SPDC was carried out in 1999. This current audit is a partial audit of reserves reporting processes only (in The Hague), replacing a full audit, which has been deferred to 2004. The audit took the form of presentations and detailed discussions about the reserves reporting process with a small selection of SPDC staff.

The audit found that SPDC's portfolio of proved oil reserves estimates appears far less mature than during the last (1999) reserves audit. One important reason for this is that the Group guidelines for Proved reserves have been tightened considerably with respect to the need for properly defined FDPs and the passing of either VAR3 or FID hurdles. It was also found that SPDC's annual proved oil reserves submissions during the years 1999-2002 have been 'managed' as a total sum only, without taking heed of the underlying individual field estimates.

SPDC have realised these shortcomings and have taken steps to set up a full inventory of oil project forecasts and reserves with the ultimate aim of obtaining complete consistency between the reserves data base, Capital Allocation / Business Plan volumes and end-year reserves submissions. By end this year it should be possible to have a good overview of the maturity of the project portfolio, in terms of development hurdles passed or to be passed. Under the present circumstances there can be no doubt that the portfolio of proved oil reserves per 1.1.2003 has been overstated due to insufficient maturity in the underlying future projects. The precise correction that will be needed per 1.1.2004 will depend on further evaluations to be undertaken by SPDC during the remainder of 2003.

The audit finding is therefore that the present status of SPDC's proved oil reserves is <u>unsatisfactory</u>. Efforts are underway to address this situation. Proved gas reserves at 1.1.2003 appeared insufficiently founded on firm contracts but this will now be corrected with the commitment to a fourth and a fifth LNG train.

It must be realised that the scope for increasing SPDC proved oil reserves beyond present (inflated) levels is probably limited. The reason is that many projects will not be required until the next decade. It seems unlikely that these projects will be matured in the next few years (VAR3 or FID), which means that proved reserves for these cannot yet be booked.

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

A.A. Barendregt

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2/1/07

Attachments 1, 2, 3

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RJW00770717

Attachment 1

PROVED RESERVES PROCESS AUDIT - SPDC, 18-19 Sept 2003

MAIN OBSERVATIONS

1. **SPDC's portfolio of proved oil reserves** estimates appears **far less mature** than during the last (1999) reserves audit. The two main reasons for this are:
- The Group guidelines for Proved reserves have been tightened considerably with respect to the need for properly defined FDPs and the passing of either VAR3 or FID hurdles,
- SPDC's annual proved oil reserves submissions during the years 1999-2002 have been 'managed' largely by keeping the sum of oil and condensate recoveries constant and by presenting declining reserves through subtraction of annual production only, without taking heed of the underlying individual field estimates.

The latter approach did also not take sufficient account of the fact that realised offtake rates during 1999-2002 remained well below those originally planned (due to OPEC quota's, local community disturbances etc), while future planned rates (up to a doubling of offtake over a period of some 5-7 years) proved unrealistic due to investment level restrictions. With the perceived end-of-licence in 2019 this meant that considerable volumes of proved reserves would be produced after that date and thus became unbookable. This was not reflected in the reported estimates.

This approach would have amounted to a serious loss of integrity of SPDC's proved reserves submissions. However, the integrity loss was reduced significantly by the realisation by SPDC during 2002 that Nigerian law does provide for a right to extend production licences and that such extensions have been granted without any serious hindrances in the past. Thus, any shortfalls in current or future production levels would no longer have any effect on producible volumes within-licence, and therefore not on bookable proved reserves.

However, the above does not imply that all of SPDC's currently (1.1.2003) reported reserves are sound.

2. To date, SPDC have maintained **three separate sources of proved reserves estimates:**
- The annual reserves submissions ('managed' separately, as described above),
- The ARPR reserves volumes data base, built up from individual reservoir estimates,
- The annual Capital Allocation / Business Plan ('CA/BP') submissions, which provide production forecasts and proved and expectation reserves estimates for developed fields and future projects.

Consistency between these three sources has been incomplete at best and, in the case of the annual reserves submissions, it was allowed to deteriorate further. SPDC have now realised this and steps have recently been taken to bring the three in closer alignment, aiming for full alignment in the course of 2004. This is strongly supported.

3. The approach taken by SPDC (with assistance by SIEP EPT-OE-VAS) has been to link the inventories of **CA/BP project data with individual reservoir data through a large combined spreadsheet.** The reservoir data was obtained directly from the Petroleum Engineering field teams, not from the ARPR, whose current volumes are seen as less reliable in many cases.

This spreadsheet was enhanced by the addition of a set of criteria checks, which give a reflection of the technical maturity of each of the reservoirs plus the maturity of their their development planning and reserves estimates. These checks relate e.g. to the appraisal status and general knowledge of the reservoirs, but also to the passing of development hurdles and to the potential for community disturbances (see Att. 2). These criteria checks should provide significant insight into the appropriateness of SPDC's proved reserves submissions and they are strongly supported.

A number of the criteria checks coincide with necessary conditions for booking proved reserves, in accordance with the most recent (2003) Reserves guidelines. These are highlighted in Att. 2. A first pass run through the spreadsheet data seemed to indicate that only 44% of proved developed reserves and not more than 7% of proved undeveloped reserves fulfil the criteria for proved reserves. It is likely that these percentages are too low. There are still a considerable number of 'empty' entries in the spreadsheet and these should be completed before end year. However, there is a strong indication that in particular the undeveloped proved reserves estimates have not kept pace with the increased requirements for booking such reserves as defined in the recent Group guidelines. The most significant of these is that the associated development projects must have passed either VAR3 (for small brownfield projects) or FID (for new field and major projects).

It is noted that the availability of 3D seismic (one of the spreadsheet criteria) is not strictly a necessary condition for booking proved reserves. However, it is unlikely that fields without modern seismic will have passed recent VAR2/3 reviews and/or FID.

The insertion of two additional criteria would be useful. There should be a check to indicate whether the proved volumes are consistent with 'known' fluid levels (from logs and/or pressures) as this is one of the key requirements for proved reserves ('proved area'). In addition, the inclusion of the intended year of start of development would allow a better assessment of the imminence (or otherwise) of the various development activities. The insertion of both criteria into the spreadsheet is recommended.

4. **The incomplete alignment between CA/BP and individual field forecasts** and plans implies that not all fields and reservoirs carrying reserves are taken up into the CA/BP, nor are all CA/BP forecasts tied into specific fields. Both of these 'orphaned' forecasts and reserves are at present included into the spreadsheet. It is possible that they may overlap to some extent and that their addition is not strictly valid. In any event, both groups should be eliminated from the spreadsheet (and indeed from the CA/BP data). SPDC have recognised this and are aiming towards full alignment between CA/BP and reserves data in the course of 2004. This is fully supported.

5. There are some obvious redundancies in the spreadsheet's criteria. This provides scope for **automatic checking for consistency** of the various entries. Examples are:
   - Brown-field developments must have developed reserves / production in the same field,
   - New field developments must have no developed reserves and zero production,
   - Productivity is always proven if cumulative production is >0, etc.

   Use should be made of these redundancies to enhance the quality and robustness of the spreadsheet entries.

6. To provide better insight into the maturity of SPDC's proved oil reserves portfolio it is suggested that, following completion and validation of all spreadsheet entries, a distinction is made into **seven categories of proved oil reserves:**
   A Proper proved developed reserves
   B Proved developed reserves in reservoirs without properly defined 'proved areas'
   C Proper proved undeveloped reserves
   D Reservoirs / projects that are likely to pass VAR3/FID in the next 2 years
   E Reservoirs / projects that are likely to pass VAR3/FID between 2 and 5 years from now,
   F Reservoirs / projects that are likely to pass VAR3/FID more than 5 years from now,
   G Reservoirs / projects that fall into none of the above and hence are completely immature.

   It is possible that a slightly different set of reserves categories may be more descriptive of the portfolio's maturity spectrum. This should be discussed between SPDC and SIEP EPS-P when the spreadsheet data set is complete (early December?). The proved (and expectation) oil reserves volumes for each of the categories should be reported in a table format similar to that presented in the lower half of Attachment 2.

7. With a few exceptions for the more mature fields, the proved reservoir and field reserves are largely based on probabilistic volumetric estimates. Although the **ratio between proved and expectation reserves** should show an increasing trend with field maturity (i.e. with the ratio between cumulative production and expectation ultimate recovery), this trend is not apparent in the current field data, see Attachments 3.1-3.4. In particular it is noted that:
   - P/E ratios for developed oil reserves are generally lower than for undeveloped oil reserves (the reverse is expected) and they do rarely show an increasing trend with field maturity,
   - The P/E ratios for undeveloped gas reserves are close to 1 in many fields, including some immature ones; this cannot give a proper reflection of remaining uncertainties.

   It is suggested that plots as presented in Att. 3 are used to verify the appropriateness of proved vs. expectation estimates.

8. During the presentations it was mentioned by SPDC that a large amount of the reservoir/project proved oil reserves showed **volumes below 2 MMstb per reservoir** (100%). Their combined volume was said to amount to some 30-50% of total proved oil reserves. The reason for this could not be made clear during the audit. SPDC should investigate whether this is due to inappropriate conservatism in the estimates, to genuine end-of-life maturity ('scraping the barrel') or to the small size of the many (>3000) reservoirs. The subject should be addressed during the 2004 Proved Reserves Audit.

9. **SPDC's gas reserves** are in principle based on committed volumes to date. A gas strategy is in place. Booked reserves volumes at 1.1.2003 included contracted volumes for NLNG trains 1-3 (all now operating), a 42 bln sm3 allowance for the DomGas-East project and a small (notional) allowance of 4 bln sm3 for the West Africa Gas Pipeline (all volumes Shell share). The latter two projects' volumes have not been secured by contract yet and are at this stage uncertain. These will be reduced / debooked per 1.1.2004. On the other hand, volumes for NLNG trains 4 and 5 have now been secured and these will allow an increase of some 54 bln sm3 in proved reserves, while a modest commitment for the DomGas West project will allow booking of 16 bln sm3 of gas. The net increase by 1.1.2004 could be some 30 bln sm3 Shell share. The precise status of contractual commitments for all these volumes was not discussed in detail during this audit and this should be addressed more fully during the 2004 audit.

10. As for further future gas reserves volume bookings, there is the potential problem that future **NLNG sales** may be more **on a spotmarket basis** rather than a firm long term gas sales contract. This brings the NLNG marketing closer to that of a mature gas market, similar to land based markets in the USA and Europe. Present reserves guidelines still require firm sales commitments for LNG gas reserves volumes, although gas volumes into existing (mature) gas markets can be booked without such commitments. It is suggested that

the next (Sept 2003) guidelines should be revised in such a manner that 'existing markets' are defined more precisely and may include mature LNG markets.

11. **SPDC's condensate reserves** (associated with non-associated gas (NAG) production, have been 'managed' in conjunction with the oil reserves, i.e. their combined volume was made to increase with the annual liquids production, without a specific link to actual field volumes. This kept condensate/LNG reserves artificially low and the link with actual field volumes should be re-established. SPDC condensate reserves should therefore be based fully on foreseen (and committed) NAG field gas sales and should be administered fully separately from the oil reserves.

12. The Nigerian authorities are now vigorously pursuing a **'flares out' policy, to be reached by 2008**. This means that Associated Gas Gathering ('AGG') plans must be in place for each of the major processing centres and their associated fields, and that implementation must be assured by 2008 before the associated post-2008 oil forecasts (and hence reserves) can be accepted as proved. SPDC have rightly included this criterion into their spreadsheet. Current improved modelling runs (and field gas measurements) indicate that GOR trends may rise more slowly than originally thought. In addition, there are continuing delays in the on-stream dates of new oil projects. There is said to be sufficient NAG capacity in initial years to take up the shortfall.

13. In summary, **the way forward for SPDC's oil, condensate and gas reserves** booking per 1.1.2004 is suggested to be as follows:
    - Proved gas reserves can be booked as per plan, i.e. for NLNG trains 1-5 and appropriate, committed volumes for domestic gas,
    - Proved condensate reserves should be evaluated in line with foreseen NAG sales and should be administered to their full (proved!) extent, independently from oil reserves,
    - Proved oil reserves are at present overstated and a reduction in 1.1.2004 proved oil reserves will probably be necessary. The precise value of the reduction cannot be assessed at this stage as it will depend on SPDC's evaluation of the maturity spectrum of their portfolio by early December. At the least, all volumes in category G (fully immature or undefined, see 6 above) and probably those in category F (long term projects) will need to be removed from the proved reserves portfolio.

14. A fundamental consideration is that the Reserves / Production ('R/P') ratio for SPDC's proved reserves submission per 1.1.2003 is 11 years for developed reserves and 22 years for undeveloped reserves. Both these ratios are considerably in excess of the Group average, which are 6 and 7 years respectively. To some extent this reflects the present constraints to SPDC's current and future offtake rates. However, it also suggests that **the scope for a further increase in SPDC's proved reserves is rather tenuous**. Many of the presently foreseen developments are not required until well into the next decade, even at a favourable upturn in offtake levels (an increase from 0.8 MMb/d to 1.4 MMb/d in 100% SPDC offtake levels is assumed by 2009). Also, some projects need to be delayed because they require ullage in presently fully utilised facilities. This means that investment decisions (VAR3/4's and FID's) for these projects are not likely to be taken in the near future and hence, that proved reserves for these activities cannot properly be booked at this stage.

**Recommendations**

1. Verify and complete all entries in the SPDC reserves/ projects spreadsheet such that a proper scan of the maturity of the reserves portfolio can be made.
2. Add (and complete) two additional maturity criteria to the spreadsheet:
   - Confirmation that proved reserves are consistent with 'known' fluid levels (logs and/or pressures)
   - The intended year of start of development.
3. Use should be made of data redundancies to verify and enhance the quality and robustness of the spreadsheet entries.
4. The proved and expectation oil reserves volumes for each of the seven suggested (or somewhat modified) reserves categories should be reported in a table format similar to that presented in the lower half of Attachment 2.
5. SPDC condensate reserves should be based on foreseen (and committed) NAG field gas sales and should be administered fully separately from the oil reserves.
6. Proved oil reserves per 1.1.2004 should exclude all volumes in category G (fully immature or undefined, see 6 above) and probably those in category F (long term projects). This should be reviewed jointly with SIEP EPS-P.
7. Plots as presented in Att. 3 should be used to verify the appropriateness of proved vs. expectation estimates.

8. The 2004 audit should specifically look at:
   - The status of the maturity of future projects in SPDC's portfolio and the effect that this will have on bookable proved reserves,
   - The reason why small (<2 MMbl) reservoir reserves volumes occur in a large majority of cases,
   - The precise status of gas contractual sales commitments,
   - The reasons for the low Proved/Expectation reserves ratios in many fields (Att. 3).

   These issues are already covered by the general Reserves Audit Terms of Reference, but in the case of SPDC reserves they require particular attention.

9. The (Sept 2003) Group reserves guidelines should be revised in such a manner that 'existing markets' are defined more precisely and may include mature LNG markets (action: SIEP EPS-P).

ATTACHMENT 2 - SPDC – SPREADSHEET CRITERIA FOR PROVED OIL RESERVES

| Criterion (as included in SPDC's integrated reserves spreadsheet) | Proved Dev'd Resvs | | Proved Undev'd Resvs | | | | | Comment |
|---|---|---|---|---|---|---|---|---|
| | Prov Resvs OK | 'Proved area' not OK | Prov Resvs OK | Resvr OK FID <2 yr | Resvr OK FID 2-5 yr | Resvr OK FID >5 yr | Im-mature resvrs and projects | |
| 3D Seismic available? | | | | | | | | |
| OWC defined? | | | | | | | | |
| *No Proved volumes below LKH or OWC from pressures?* | + | X | + | + | + | + | | |
| Productivity proven? | + | + | + | + | + | + | | |
| Property appraised? | + | X | + | + | + | + | | |
| Near / far from existing infrastructure? | | | | | | | Remainder | Not relevant if VIR OK? |
| AGG plans defined? | + | + | + | + | + | + | | Needed for all post-'flares out' (2008) reserves |
| Community disturbance non-critical? | + | + | + | + | + | + | | |
| Facilities not vandalised? | + | + | + | + | + | + | | |
| VAR2 passed recently? | | | + | + | + | + | | |
| VAR3 passed (if brown-field)? | | | + | | | | | |
| FID passed (if new field)? | | | + | | | | | |
| Project executed / executing? | + | + | | | | | | |
| In production now (or shortly)? | + | + | | | | | | |
| VIR / economics OK? | | | + | + | + | + | | Only used for 'Unplanned' at present – should be inserted for all undeveloped reserves! |
| Volume < 2 MMstb (100%)? | | | + | + | + | + | | Crude screening only – should be replaced by VIR/economics-check |
| *Intended year of project's start of execution* | | | | ≤2005 | 2006-2009 | ≥2010 | | |
| CA/BP 'Developed' | + | + | X | X | X | X | | Prov Dev must be in CA/BP 'Developed' |
| CA/BP 'Base' | X | X | + | + | + | X | | Prov Undev must be in 'Base' if pre-2010, otherwise in 'Options' |
| CA/BP 'Options' | X | X | + | X | X | + | | |
| CA/BP Unplanned? | X | X | X | X | X | X | | All proved reserves projects must be in CA/BP! |
| CA/BP 'Not known'? | X | X | X | X | X | X | | All CA/BP projects must be 'known' |

*In italics* Criteria not yet in spreadsheet!
+: Necessary criterion (must be 'Yes')
blank: Not needed
X: Not allowed (must be 'No')

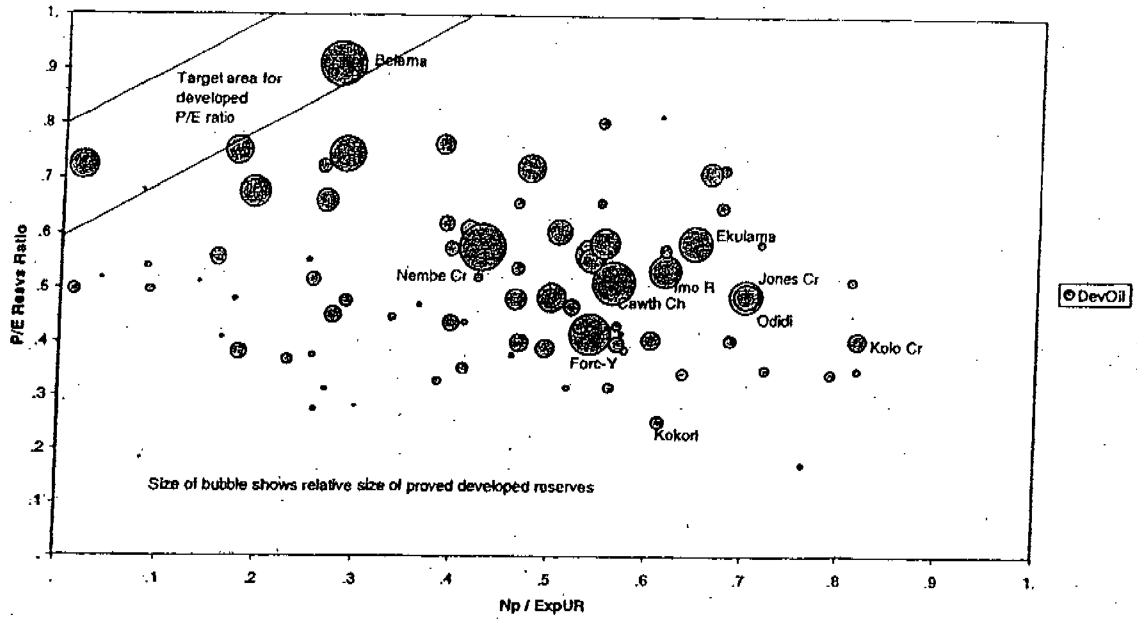
**SPDC Group share oil reserves volumes (MMstb) as per data base Sept 2003**

| | Proved Dev'd Resvs | % of booked resvs | Proved Undev'd Resvs | % of booked resvs | Proved Total Resvs | % of booked resvs |
|---|---|---|---|---|---|---|
| **In CA/BP, fulfilling proved reserves requirements** | 377 | 44% | 125 | 7% | 502 | 20% |
| In CA/BP, not fulfilling requirements | 319 | 37% | 1325 | 79% | 1644 | 65% |
| In CA/BP, 'Unknown' reservoirs | 178 | 21% | 198 | 12% | 376 | 15% |
| Not in CA/BP, 'known' reservoirs ('Unplanned') | | | 590 | 35% | 590 | 23% |
| Total in data base | 874 | 102% | 2238 | 134% | 3112 | 123% |
| **Total actually booked 1.1.2003** | 854 | 100% | 1670 | 100% | 2524 | 100% |

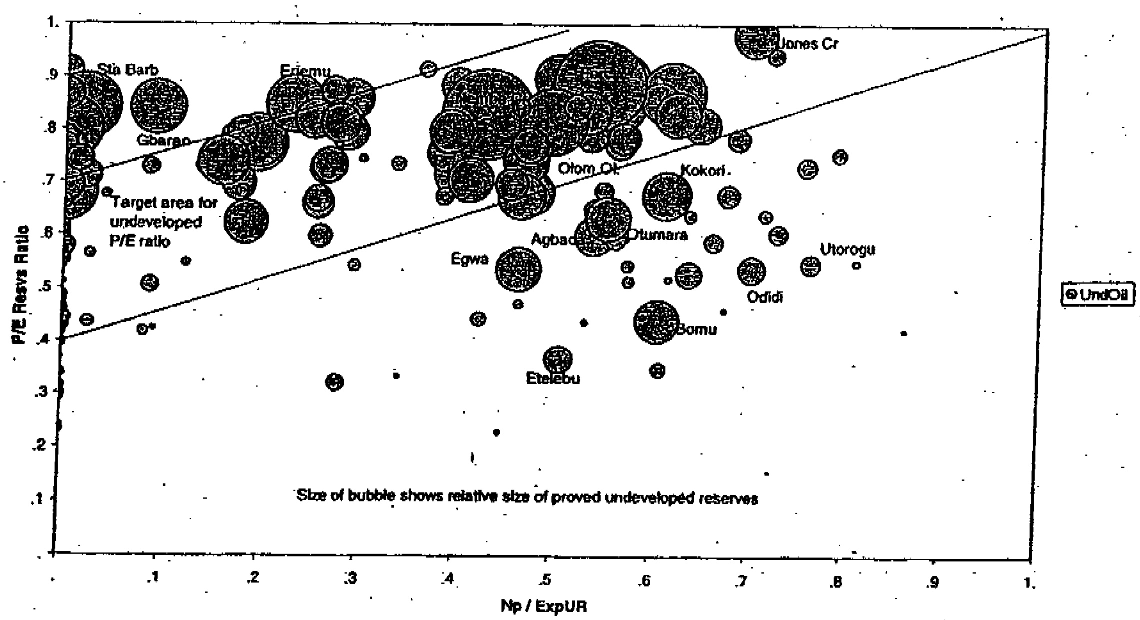
Note: 'Unknown' and 'Unplanned' volumes may overlap – addition is not strictly valid!

Attachment 3.1

SPDC - OIL DEVELOPED PROVED / EXPECTATION RESERVES 1.1.2003

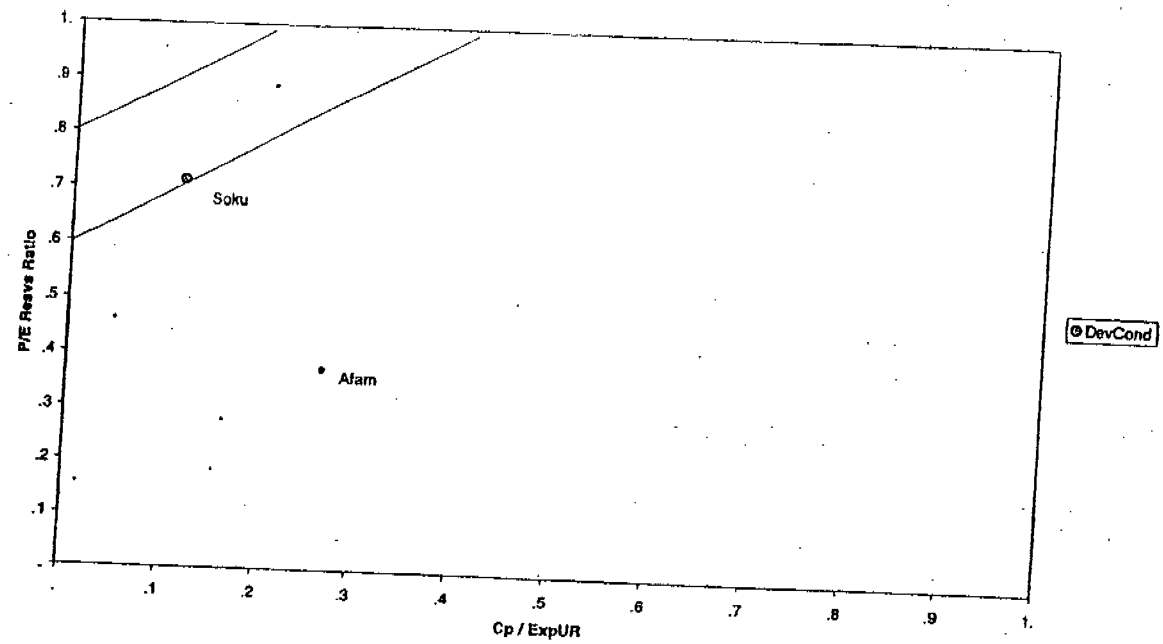



SPDC - OIL UNDEVELOPED PROVED / EXPECTATION RESERVES 1.1.2003

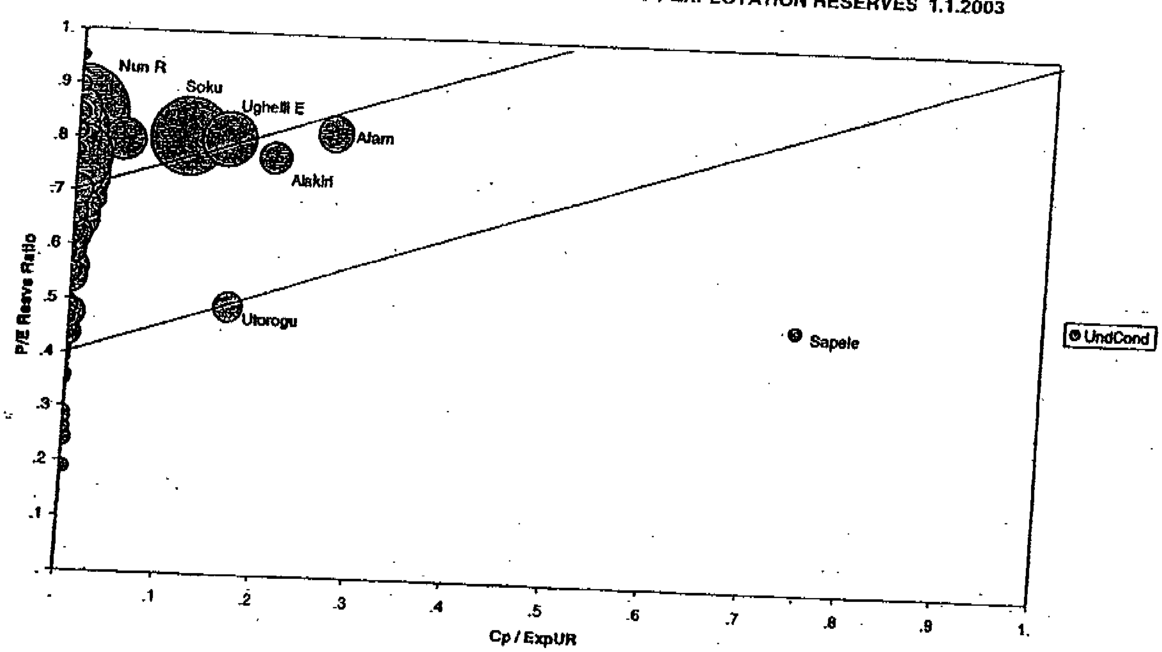


Attachment 3.2

SPDC - CONDENSATE DEVELOPED PROVED / EXPECTATION RESERVES 1.1.2003

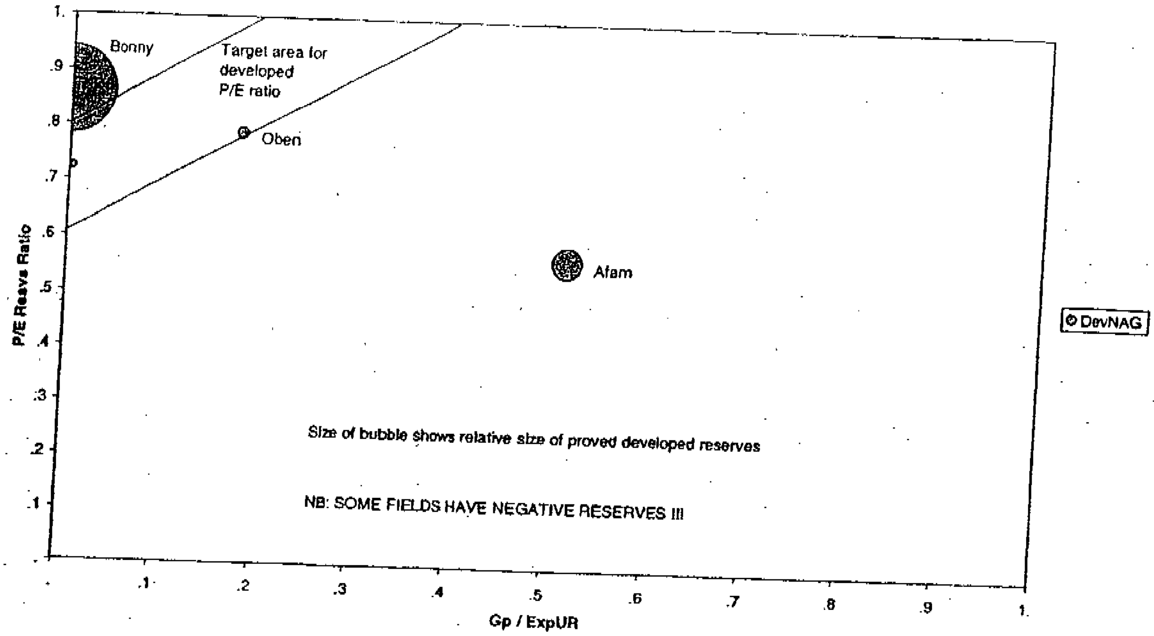



SPDC - CONDENSATE UNDEVELOPED PROVED / EXPECTATION RESERVES 1.1.2003

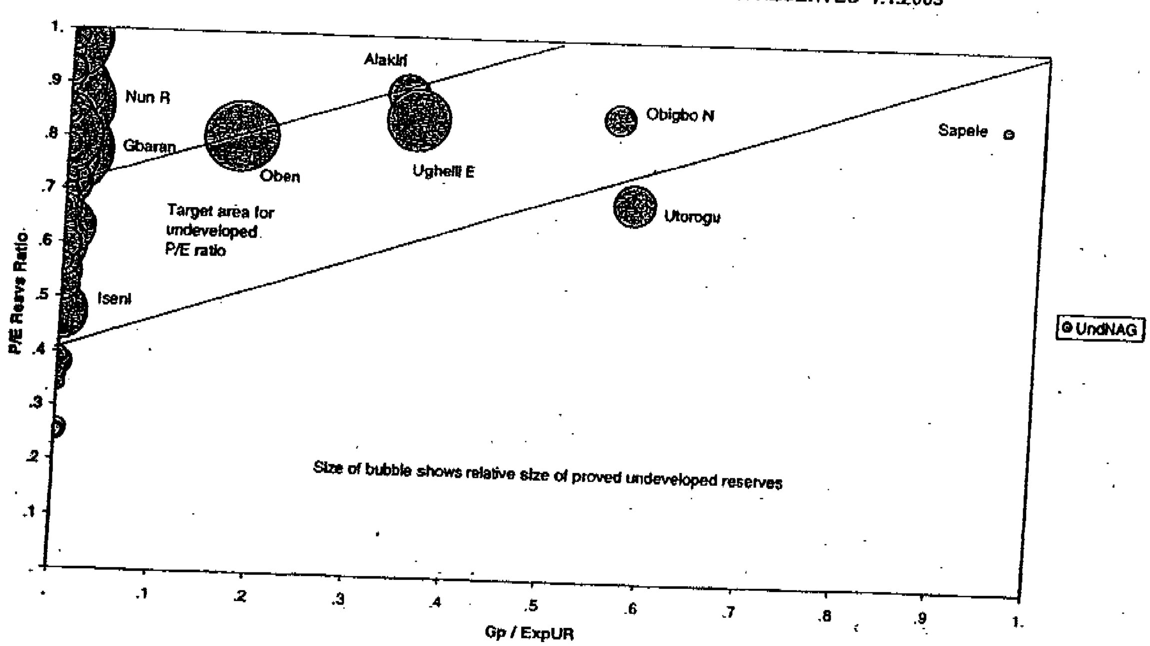


Attachment 3.4

SPDC - NAG DEVELOPED PROVED / EXPECTATION RESERVES 1.1.2003




SPDC - NAG UNDEVELOPED PROVED / EXPECTATION RESERVES 1.1.2003



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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 |
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**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 unsatisfactory. Improvements have been set in motion.

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

A.A. Barendregt

EXHIBIT
Van der Vijver
134
2/1/07

Attachments 1, 2, 3

RJW00950013

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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 Qarn 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 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.

   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.