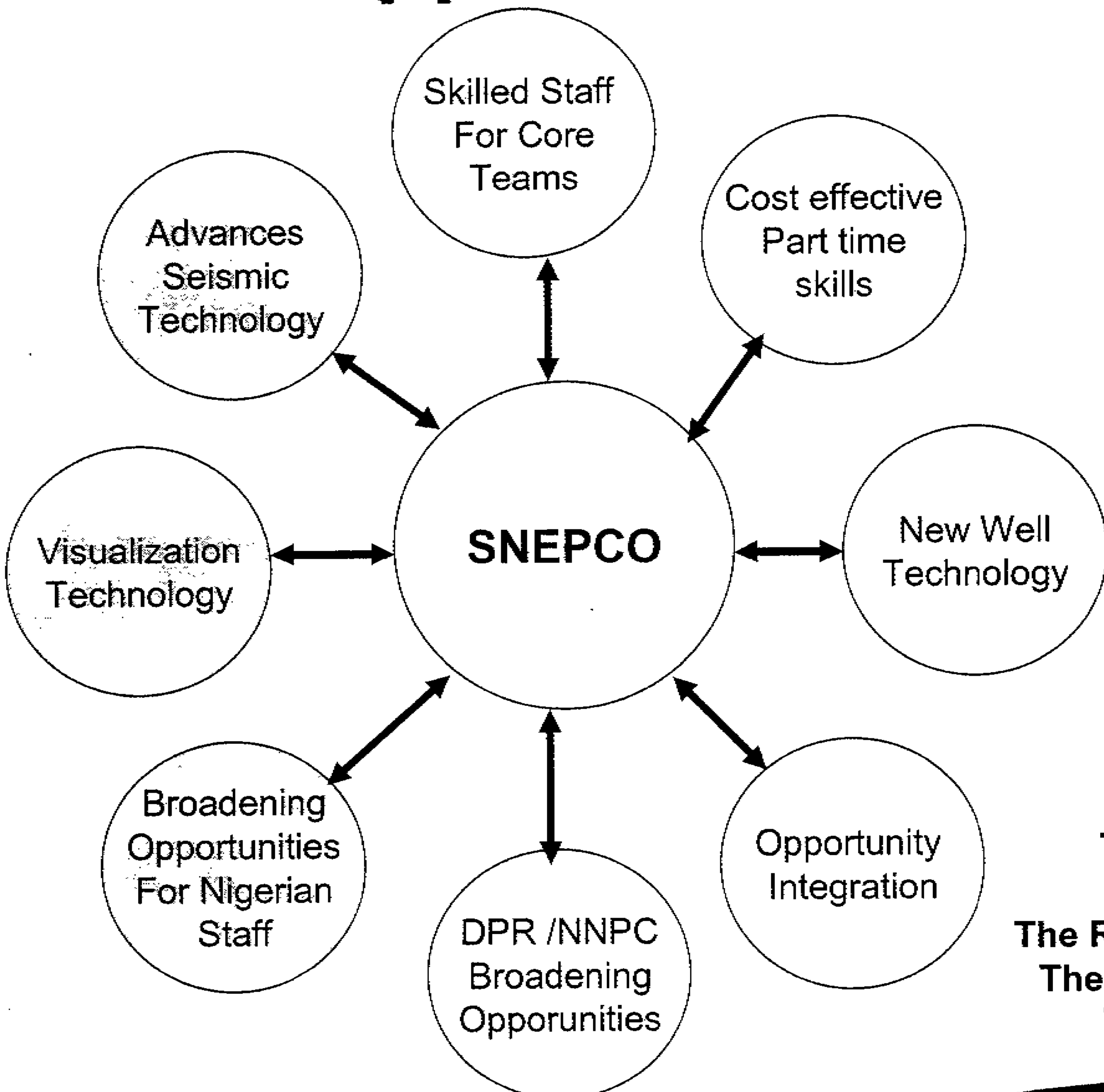
SNEPCO Opportunities with SDS



The Right Problem!
The Right skills!
The Right Global Experience!
The Right OU Partnership!
The Right location!

Value Proposition: Skills & Teams

SDS Self Sustaining Skills

Basin & Play Evaluation
Volume & Risk Assessment
Geology Field Evaluation
Static Reservoir Modeling
Seismic Interpretation
Reservoir Geophysics
Seismic Data Processing
Seismic Data Acquisition
Geochemistry
Basin Modelling & Petroleum Systems
Biostratigraphy
Geo Information Mgmt
Geomatics
Petrophysics
Reservoir Eng
Reservoir Eng Studies
Quantitative Evaluation
Production Technology
Development Planning
Well Engineering

SNEPCO Teams

Niger Delta Team
Geophysics
Geology

Bonga Team
Geophysics
Geology
Reservoir Eng
Production Tech'
Dev' Planning
Well Eng'

Bonga SW Team
Geophysics
Geology
Reservoir Eng
Production Tech'
Well Eng'

Brazil Teams
Exploration
Geophysics
Geology

GOM Teams
Exploration
Geophysics

BC-10
Geophysics
Geology
Reservoir Eng
Produ
Dev'
W

vor Technologies
Geophysics
Geology
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Great White
Geophysics
Geology
eservoir Eng
Prod' Tech'
ev' Planning
Well Eng'

BS-4
Geophysics
Geology
Reservoir Eng
Prod' Tech'
Dev' Planning
Well Eng'

Sharing and Learning

- SDS Provides Key skilled staff to Core Teams
- SDS Provides additional skills to Core Team on a part time basis
- SDS Grows new self sustaining skills
- SDS provides opportunities to up-skill new staff
- SDS provides secondment opportunities for Government staff

Nigerian Staff Within SDS

SDS Skills

Basin & Play Evaluation
Volume & Risk Assessment
Geology Field Evaluation
Static Reservoir Modeling
Seismic Interpretation
Reservoir Geophysics
Seismic Data Processing
Seismic Data Acquisition
Geochemistry
Biostratigraphy
Geo Information Mgmt
Geomatics
Petrophysics
Reservoir Eng
Reservoir Eng Studies
Quantitative Evaluation
Production Technology
Development Planning
Well Engineering

SG1	1
SG2	2
SG3	9
SG4	7
SG5	1

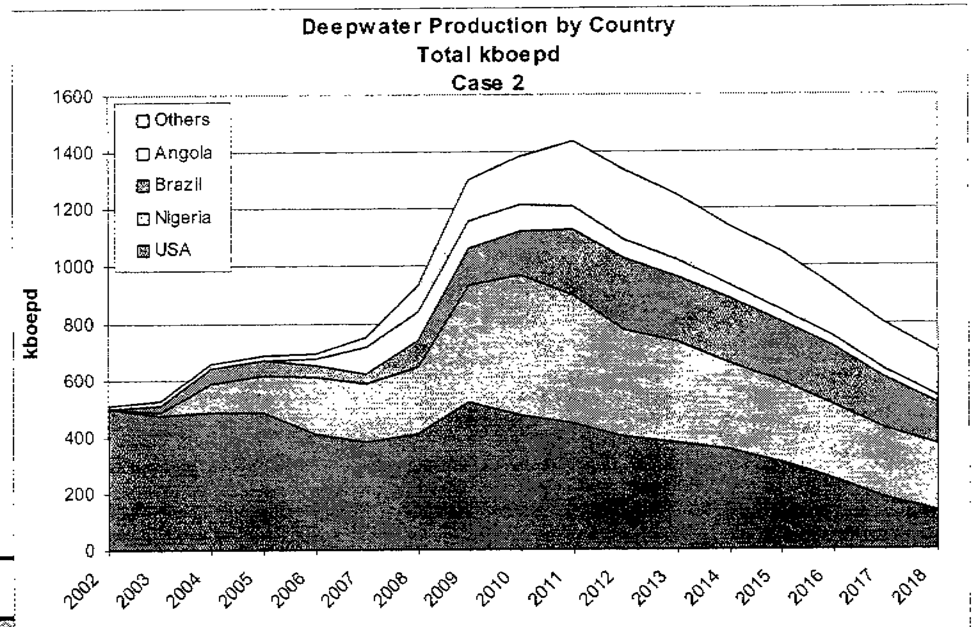
Nigeria Staff

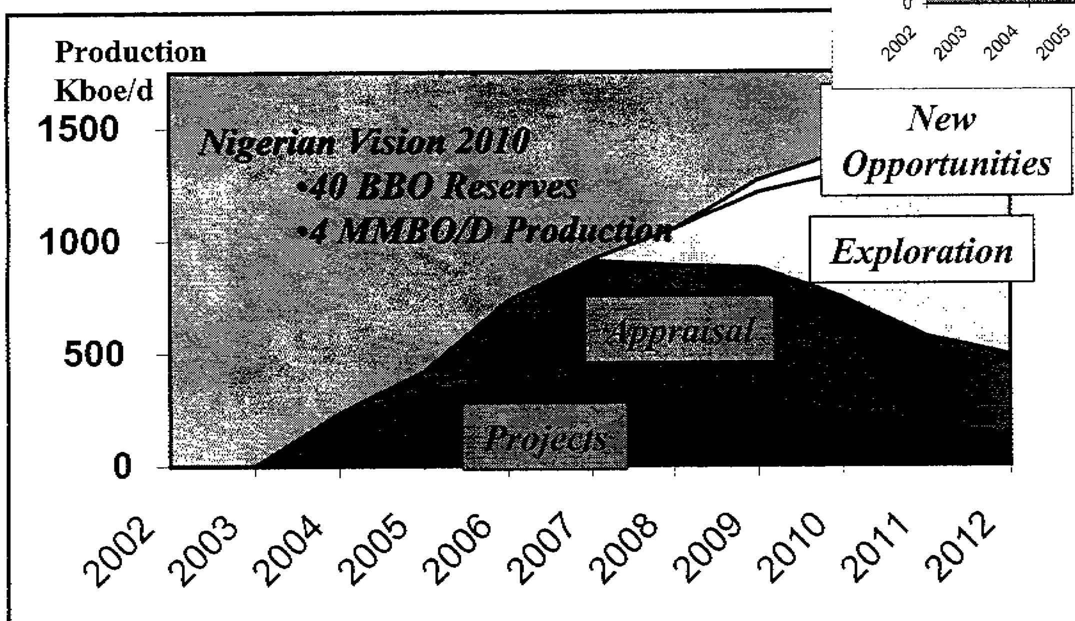
Funmi Ebinwonjumi
Chidi Chukwueke
Akinyemi Akinkunmi
Usman Yahaya Joe
Olusola Adesanya
Ben Anagbogu
Chima Chima
Collins Ibekwe
Lanre Maliki
Tony Nwaozomudoh
Jack Wilkie
Segun Omidele
Tony Agbojo
Emmanuel Enu
Lanre Oladosu
Muyiwa Esho
Chike Nwosu
Chima Okorie
Joshua Oletu
Okwudiri Uzoh

Roles in SDS

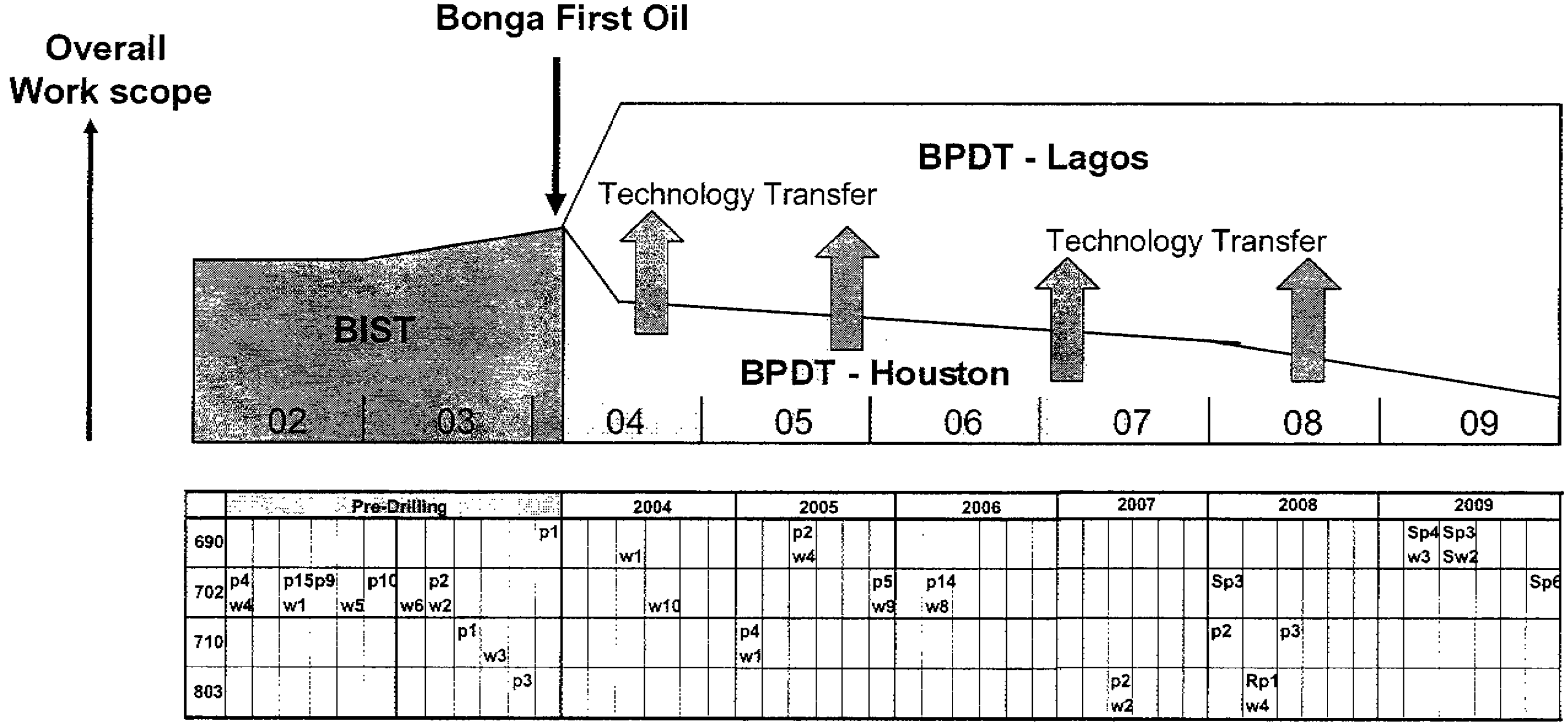
Exploration Team Leader
Basin Eval' & Stratigraphic team
Bonga Integrated Studies team
SEPCO (Production)
Bonga Southwest
Niger Delta team
Bolia Integrated team
Bolia Subsurface Coordinator
Doro Team Leader
Quantitative Eval' & Seismic tech'
Doro Integrated Team
Brazil BC-10 Subsurface Coordinator
Gulf of Mexico Development Planning
Petrophysics & Staff Dev' Advisor

Nigerian Value Creation from Deepwater





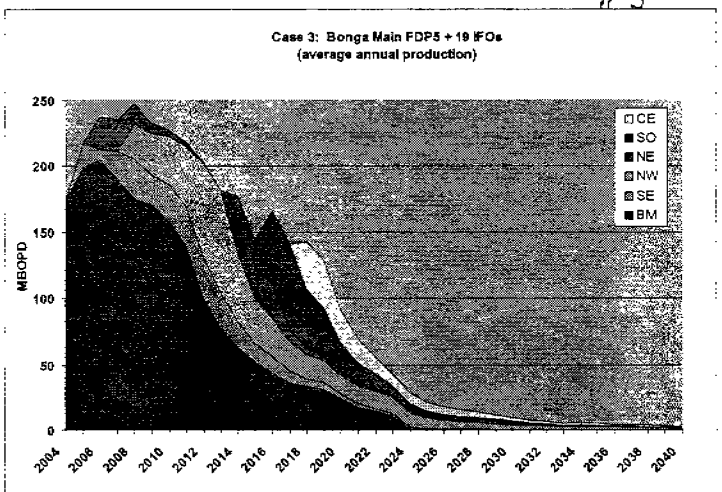
Bonga Technology Transfer



Field Development Plans	FDP Rev. 6	FDP Rev. 7	FDP Rev. 8
Team Leader Based in	Houston	Lagos	Lagos
Primary Responsibility	BIST	BPDT - Houston	BPDT - Lagos
Support Responsibility		BPDT - Lagos	BPDT - Houston

BDPT	– Bonga Production Development team
BIST	– Bonga Integrated Study Team

Technology Transfer: Bonga In Field Opportunity



BONGA In Field Opportunity

Additional volume 500-600 MM bbls

No. of Wells – ca 60

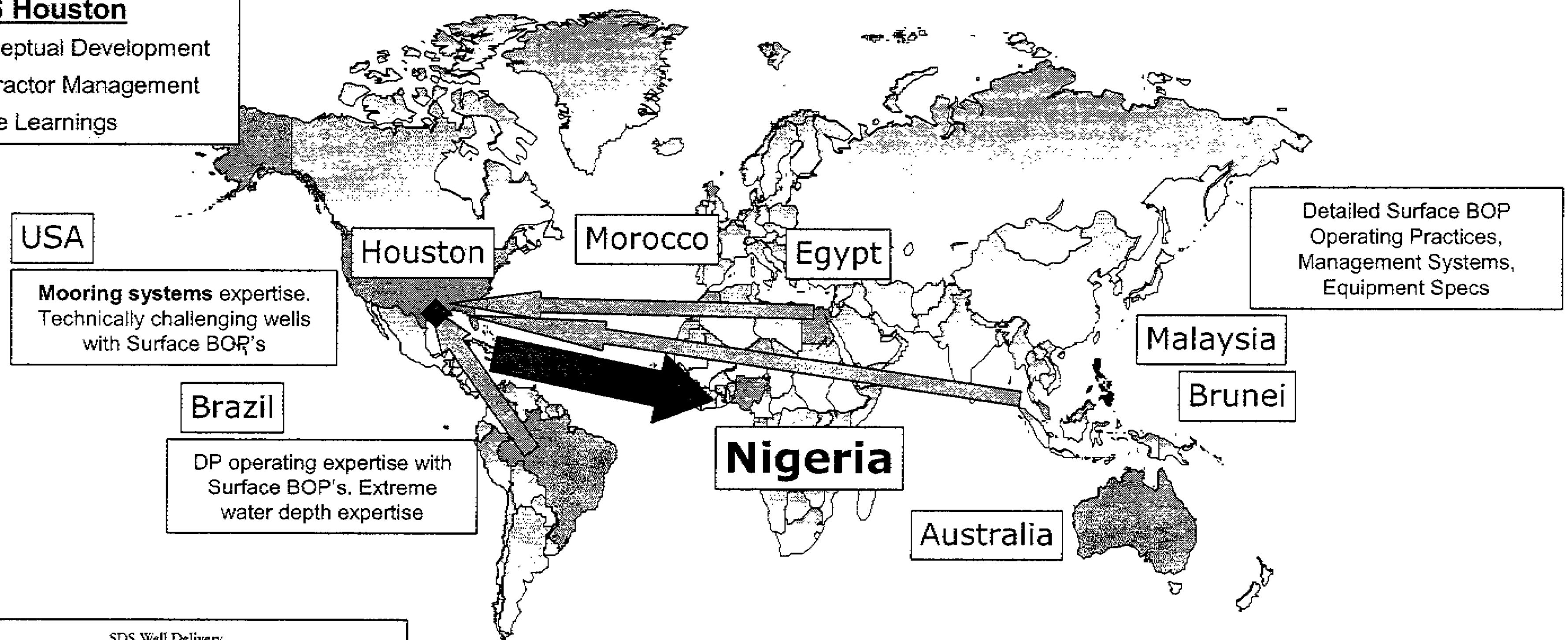
Additional Capex - $2m Bln

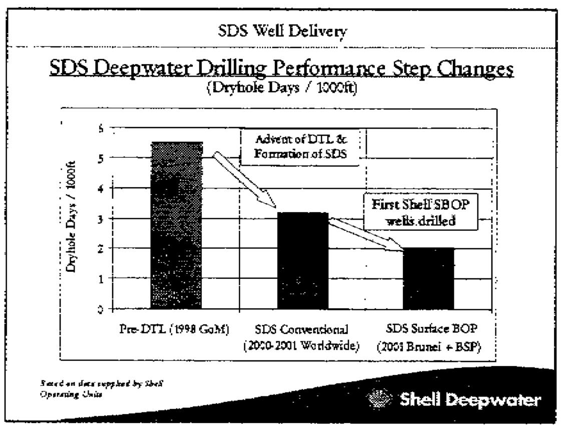
UTC < Bonga

NPV $ 500-600 MM

Technology Transfer: Surface BOP's

SDS Houston
Conceptual Development
Contractor Management
Share Learnings





BONGA SW Opportunity

Development Wells With Surface BOP's

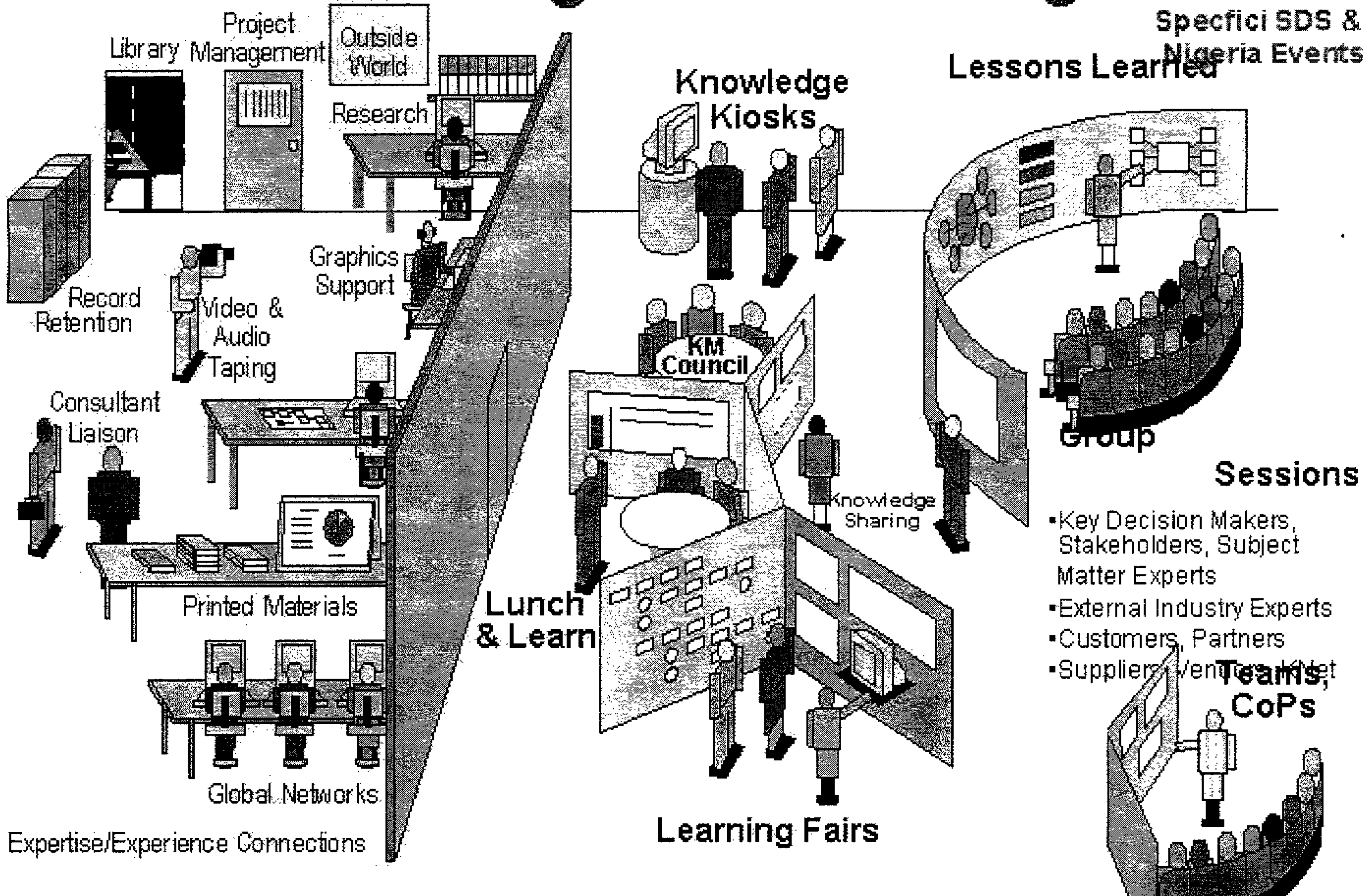
No. of Wells - 45 {22 Prod / 23 Injectors}

Costs of 45 Development Wells - $765MM

Savings of 15 –20% per well by the use of Surface BOP's on Development Wells.

Channeling Shell worldwide deepwater experience to add further value to Nigerian operations.

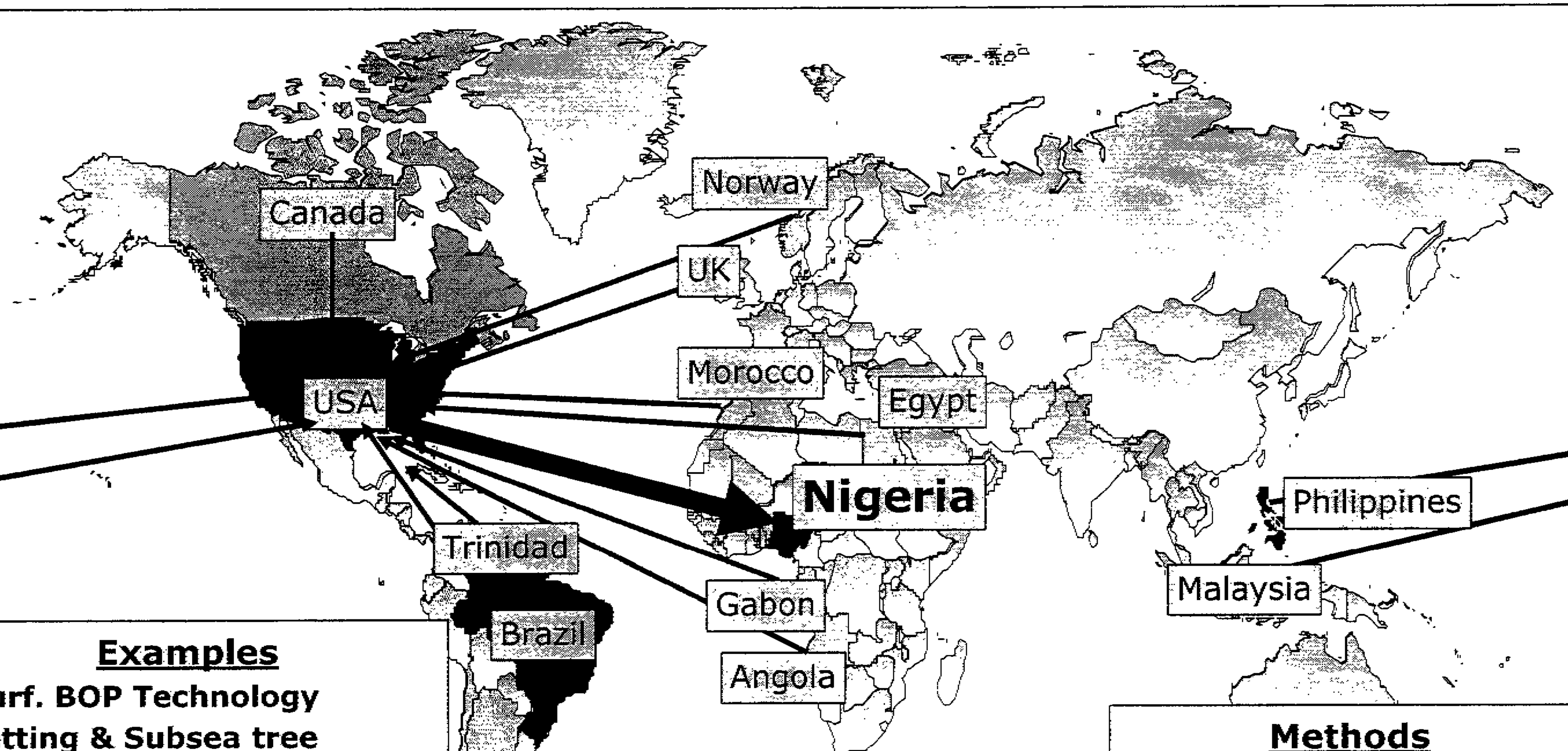
Learning & Networking



"Back Office" Support

"Front Office" Support

SDS-WDU: Global Leverage of Knowledge Transfer



Examples

- Surf. BOP Technology
- Jetting & Subsea tree installation knowledge
- Expert Skill Pool for Int. Deployment
- Development of Nigerian Staff
- Completions Experience
- SMART Wells & Multilaterals
- Lateral Learning
- Drilling The Limit

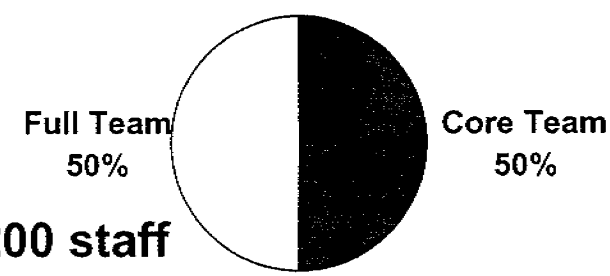
Methods

- Livelink, HDI & Wells Global Network.
- SDS Conferences
- Staff Transfer
- Expert Peer Reviews
- Shell Research & Contractor Liaison

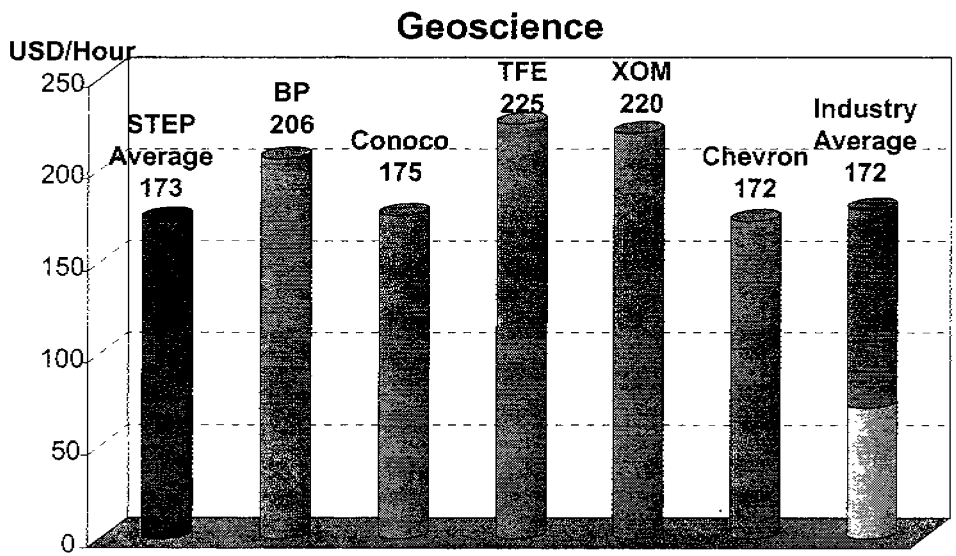
SNEPCO Service $ in SDS

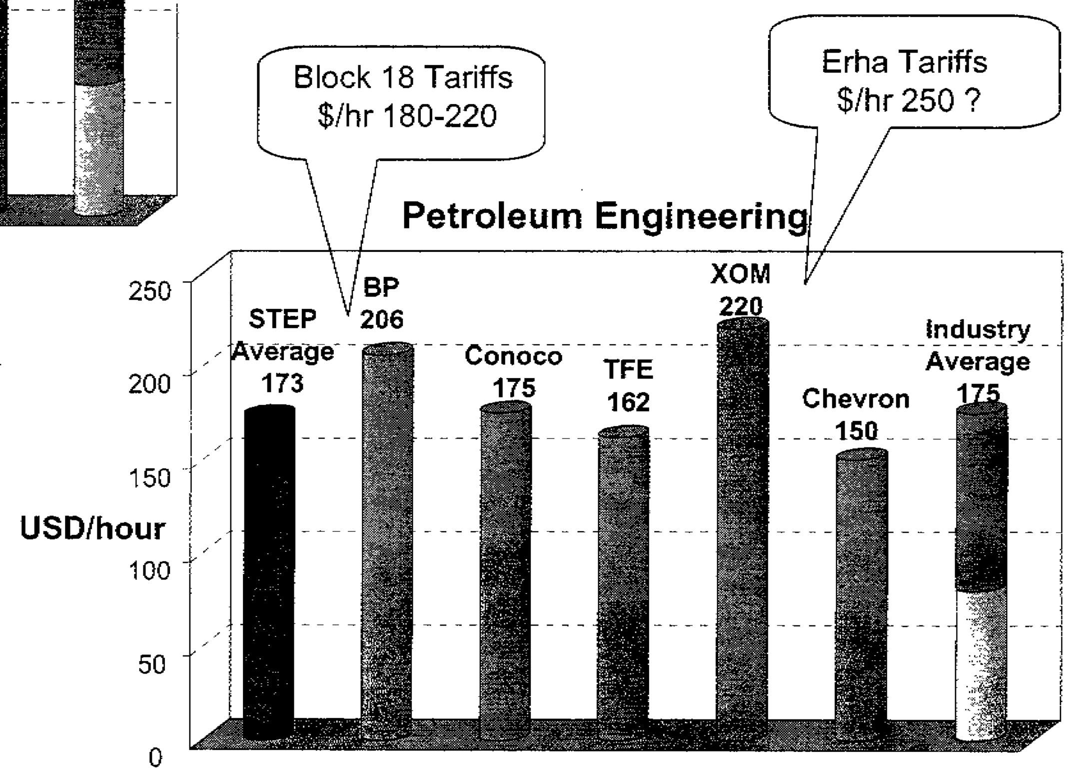
- **Value of SNEPCO Services in 2002** **$ 33 MM**
- **Major Development Projects (63%)**
  - Bonga
  - Bonga SW
- **Currently status** **$ 25.8 MM**
  - Staff Time $ 23 MM
  - Travel $ 0.8 MM
  - 3rd Party $ 0.8 MM
  - Materials $ 0.3 MM
  - Training $ 0.9 MM

- **$23 MM equivalent to ca 100 full time staff**
- **Based on on core team to extended team ratio of 0.5**
  - **$23MM buys access to a full team of ca 200 staff**



Tariff Benchmarking

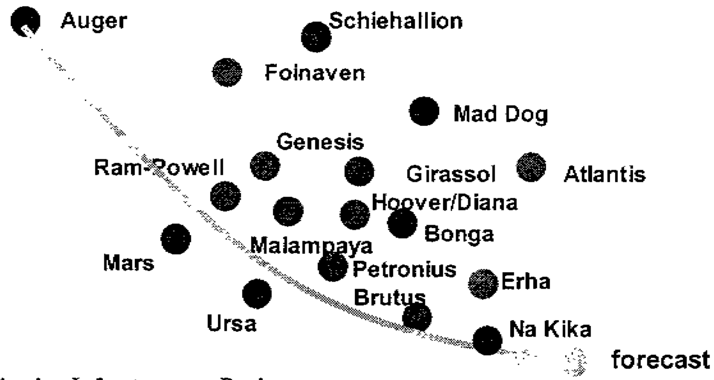




Summary

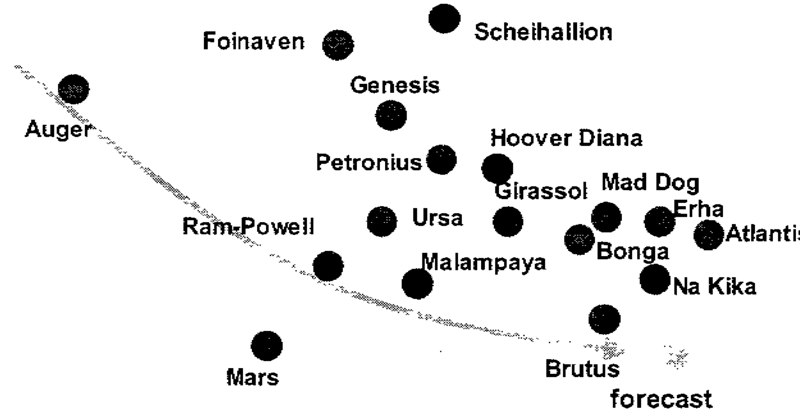
- Industry average with STEP Internal Overhead is at a slightly higher tariff rate @ USD 179/hour
- STEP average is the second lowest among the Big 5 companies

Shell Deepwater Development
Cost/Unit Capacity Index and Production

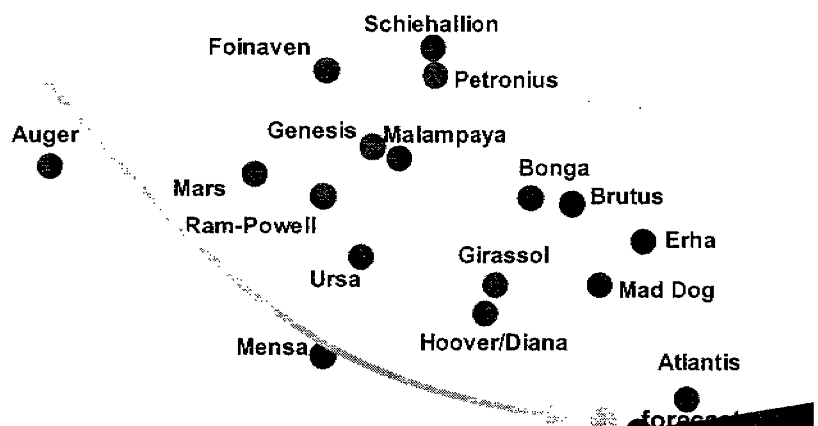


Criteria - Infrastructure Projects
Water Depth >1500 ft
Reserves >150 MM boe
Onstream <12/1/2001

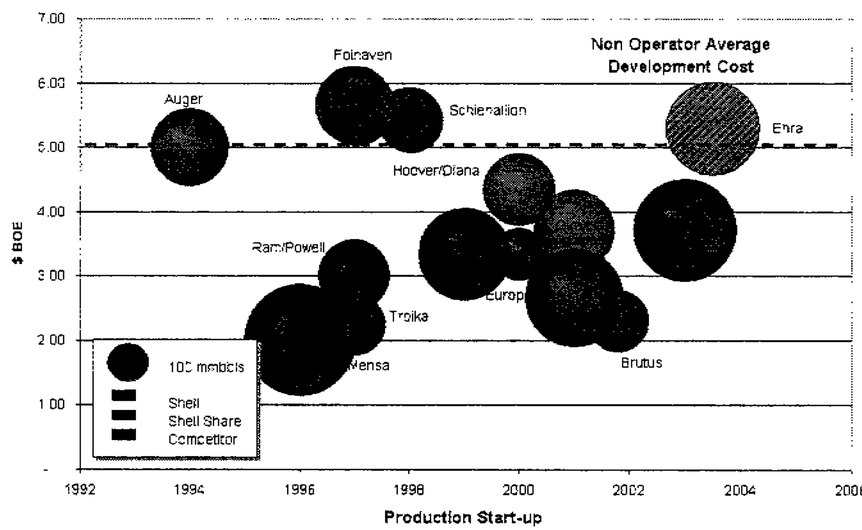
Shell Deepwater Development
Unit Development Cost



Shell Deepwater Development
Water Depth vs Project Approval



Deepwater Unit Development Cost and Reserves



SDS /SIEP Finance Controls

- Cost Recovery Analysis
  - Monthly (SDS)
  - Quarterly (QBR)
  - Yearly (STEP)
- Yearly External Audit (KPMG)
  - KPMG 1996-2000
  - KPMG Audit Feb 2002 (for year 2000)

We have been been requested by SIEP to confirm (for the year 2000) that the stipulated services should be provided at cost and that the billings to affiliates of SIEP are designed to recover only actual costs incurred by SIEP

"no matter came to our attention that caused us to believe that the accounting policies and procedures in SIEP are not in accordance with the "at cost policies and procedures"

KPMG

Auditors' statement regarding the application of at cost accounting policies and procedures within Shell International Exploration and Production B.V. for the year 2000

We have been requested by the management of Shell International Exploration and Production B.V. ("SIEP") to confirm, based on our audit work in respect of the 2000 annual accounts, the correct application within SIEP for the year 2000 of the accounting policies and procedures that stipulate that services should be provided at cost (the "at cost accounting policies and procedures") and that the billing process and procedures of billings to affiliates of SIEP[1] (under the terms of the E&P services agreements) including, but not limited to direct charge activities, is (are) designed to fully recover only actual costs incurred by SIEP.

As statutory auditors of SIEP we have audited the 2000 annual accounts of SIEP. These annual accounts, as well as the correct application of the "at cost" policies and procedures, are the responsibility of SIEP's management. Our responsibility is to issue an opinion on the annual accounts based on our audit. We confirm having issued an unqualified opinion dated 3 December 2001 on the 2000 annual accounts.

In performing our audit we have evaluated the application of the "at cost accounting policies and procedures" that were relevant for purposes of our audit of 2000 annual accounts. This evaluation was based on interviews and an examination, on a test basis, of the application of SIEP's accounting policies and procedures to specific transactions. We have performed limited tests on specific charges to individual cost sharers in line with the above-mentioned accounting policies and procedures.

Based on our audit of the 2000 annual accounts, no matter came to our attention that would cause us to believe that the accounting policies and procedures used within SIEP were not applied in all material respects in accordance with the "at cost accounting policies and procedures".

The Hague, 20 February 2002

KPMG Accountants N.V.

Ref.: J. van Delden

[1] Note: Shell Nigeria Exploration and Production Company Limited is one of the affiliate companies of SIEP and has entered into an E&P services agreement (as amended) which stipulates the "at cost" accounting policies and procedures are applicable.

NAPIMS & DPR Value Proposition

- **Seconded Staff**
  - **Bonga Team**
    - 2001 DPR, S.A. Adenle, C,N, Ameachi, C.I. Otiji
    - 2001 NNPC, V.S. Ewetuya
    - 2002 NNPC:M.K Kyari, C.U. Ailemen, G. Chuku
    - 2002 DPR , O.S Bajomo
  - **Bonga SW Team**
    - Lemmy Ugbaje, NNPC (BSW – 2 Well Test Analysis)
    - Jidi Adetola, NNPC (Net San prediction project)

    Rotating
    - Innocent G. Etotok / Ikeke Akabekwa, DPR (Topsides)
    - Sylvester Njoku / Emma Ogunka, DPR (Hull/Risers/Topsides)
    - James Ojo / Sani Hassan, DPR (subsurface)
    - Ifeany Animan / Auwal Sarki, DPR (HSE)
  - **Bolia Team**
    - Mohammed Alaku
  - **Doro Team**
    - Mr Oyawoye (2001) / Mr Ogunnbi (2003)
  - **Bonga Team**
    - Mr Balogum DPR
    - Mr Bajomo DPR

Continuous Involvement

- 4-6 DPR/NNPC staff on assignment of 2-3 months each year for the last 3 years

Opportunities for Assignments

Further opportunities exist are welcomed by SDS

Structuring the role and tasks are very important

Specific training & mentoring roles within SDS

SDS Affiliate Services Summary

Note for Information

From : EPM

To : EP Excom

PDO Programme and Budget 2003

Following detailed review at the mid-October Technical Shareholder Meeting, the PDO Board approved PDO's proposed Production Programme 2003 last week.

As previously flagged in Excom, as a consequence of PDO's planning process being aligned with the Government's timetable rather than Shell's, the Programme differs from PDO's Volume 2 submission *(n.b. the "new" numbers were included in advance in the Excom presentation of 7 October and incorporated into the EP BP).* Whilst the production target for 2003 remains unchanged at 703kb/d annual average, the total capital expenditure proposed is higher than the Volume 2 submission, and exceeds the 2003 ceiling advised in the Capital Allocation Investment Letter by $66million Shell share. The additional funds are required both to support projects needed to deliver the 703kb/d, and for the early phases of projects that deliver production in later years, as PDO strives to rebuild production to at least 800kb/d by 2007. There is little option for Shell other than to be seen to be supportive of PDO's programme and to do all it can to rectify the production problems in PDO. To do otherwise would throw the Government's fiscal position into turmoil were oil prices to fall below $20/b, and severely damage our position as we move ever closer to concession and net reward discussions.

Whilst we have approved the 2003 budget proposed by PDO in full, the Board has also introduced the requirement for a quarterly review of PDO's progress against the key elements of their Business Plan. As a self-funded associated company PDO is not required to provide 502s/503s, but the new reviews will also require that PDO submits "502 style" investment proposals for all major projects for shareholder review. This increased rigour will provide substantially greater clarity to those elements of the plan that are, at present, rather sketchily defined -- including demonstration of the economic robustness of new project proposals for all shareholders and confidence that the associated technical risks have been understood and addressed. The greater transparency will be essential to support PDO's 2003 capital allocation submission which, until new concession/reward terms are negotiated, are unlikely to rank if judged solely against the usual screening criteria. The reviews also introduce the opportunity for rigorous challenge on the cost efficiency of other capital-intensive elements of the programme, such as drilling, where efficiency assumptions are declining substantially, despite the application of drilling the limit.

These new reviews are also, in part, a response to an evident expectation from Government that Shell, as Technical Adviser, should provide regular and structured assurance that PDO is on track to recovery, as well as appropriate intervention/collaboration to ensure implementation. This will also call for more focus in the support that Shell provides to PDO in the technical arena, whether for technology or for the provision of services. John Darley will be assisting me in 'managing' this during interactions in the quarterly sessions, where technical governance aspects will be addressed specifically. Our prime focus will be to maximise the value of Shell input through coordinated input of Shell expertise from outside of PDO into key PDO activities. To ensure that this is brought to bear most effectively we have decided to appoint Dan Antheunis, Vice President SEPTAR, to be the lead person on the Shell side to coordinate our efforts in agreed technical focus areas.

The other area where Government is looking for improved performance is in the provision of seasoned professional staff according to PDO's needs. Considerable progress has been made over recent months, particularly in filling the PE and WE establishment, and there is now clarity as to what is expected through the remainder of 2002 and 2003. I am encouraged that the recently improved focus is now bringing together the processes that will enable us to deliver.

Din Megat
6 November 2002

EXHIBIT
Darley 14
11/17/06

Attachment: CMD Note for Information - Oman Exploration and Development budget 2003

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NOTE FOR INFORMATION
OMAN – PDO OIL CAPITAL EXPENDITURE 2003

This note for information has been prepared for the attention of the CMD[1] before the 2003 Oil Development Programme is presented to the PDO Board for approval on 29th October 2002. The capital expenditure in respect of the Upstream LNG Development is not included here, as it has already been approved by the CMD and the SPCO Board in June 1996. In addition, Domestic Gas capital expenditure is excluded as this is funded 100% by the Government.

Summary

The disappointing decline in PDO production experienced during the second half of 2001 has continued through 2002. The latest estimate for annual average production stands at 771 kb/d, compared with 831 kb/d in 2001 - well short of the 815 kb/d target. By the end of Q1-2002 it became evident that production problems, and their underlying causes, were more severe than previously understood. The contributors to the poor production performance are many, complex and inter-related. The strong drive towards unit costs ($3.45/boe) adopted in 1998/99 for example meant PDO got into a vicious cycle of short-term solutions to try meet the target of producing 850,000 b/d, with studies and investment for sustainability, for instance in new water flood facilities, was deferred. Hence when the 'short term solutions' of the recent past (principally horizontal drilling) failed, compounded by subsurface surprises in some fields, there were just insufficient projects to fill the gaps.

Whilst the changes proposed in PDO's "Oil Production Recovery & Business Improvement Plan", issued Q4-2001, remained relevant they were insufficient to deliver the aspired oil production recovery and more fundamental changes were found to be required. A re-organization of the asset teams in May (reduced from 6 to 2, each led by a line Director) was followed by three fundamental initiatives:

- *Portfolio Review* (with Septar): to review the robustness of the hydrocarbon resource base underpinning the base forecast, segment the diverse portfolio of fields into opportunity themes, and propose strategic development opportunities
- *6 FRDs*: to improve understanding of underlying problems and further develop strategic thrusts that will significantly add to PDOs medium term production. The FRDs addressed Well and Reservoir Management; Waterfloods; Near Field Exploration; Well Delivery; Engineering Manpower; and People Motivation.
- *Manpower Review*: to determine the resource requirements to support PDO's 2003 Programme - both to implement the recommendations of the Portfolio review and FRD, and revisiting the way work is organised in PDO and how staff, contractors and technology are applied to deliver business results.

This work has confirmed that with 50 billion barrels of STOIIP (of which only 6 billion has been produced) black oil production at sustainable rates of at least 800kb/d are achievable in the future - but recovery to that level will take time. PDO has captured the aspiration to recover performance in the vision statement to '*sustainably deliver 800 kb/d by 2007 utilising the full potential of our people*'.

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[1] The PDO oil investment programme is not addressed by normal Group capital budget procedures, as PDO is an associate company (34% Group equity interest) and remuneration of the private shareholders (POHOL, 85% Shell) is dependant on a Net Reward scheme rather than conventional corporate economics.

HAG00161604

To achieve this vision PDO must transform from a company focused on primary and infill drilling to intensive reservoir management, and successful pursuit of secondary and tertiary recovery. Medium and long-term oil in PDO will be delivered from waterflood and EOR projects underpinned by well and reservoir management as a way of life. In the short-term exploration will be refocused on near field exploration delivering rapid hook up production.

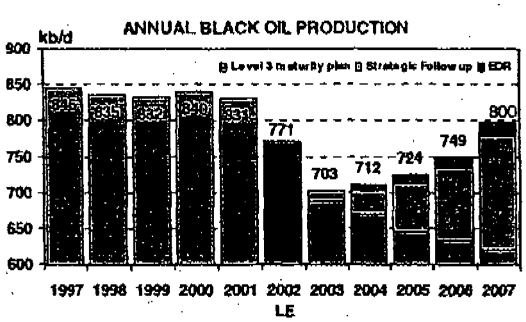
This shift demands changes in capabilities and priorities, and considerable additional competent resources to prepare and mature sufficient opportunities to restore robustness to the production programme. The Government ambition of 'full Omanisation' by 2007 will undoubtedly have to be revisited. Bringing forward the more expensive IOR/EOR programme compared to earlier plans results in substantially higher expenditure over the production period than previously forecast and a higher level of uncertainty and risk.

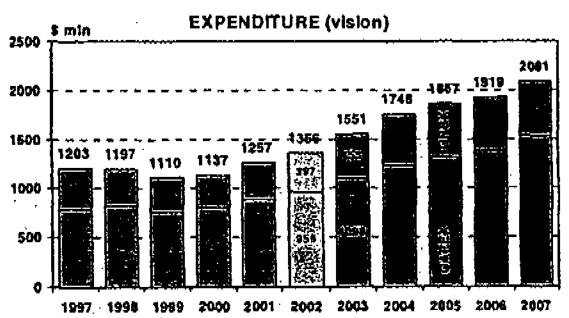
Shell has given full commitment to Government to make all necessary efforts to help PDO deliver on their recovery targets. Our reputation and future standing in Oman (and also in pursuing new business opportunities in the region) is closely linked to making rapid progress to improve the situation, and ensuring success will be crucial as we move into concession renewal discussions.

As a consequence of the current production difficulties and the change in the nature of the investments required, Shell's returns from PDO are lower than in the past for the remaining duration of the current net reward agreement (expiring in 2004) and if extrapolated with similar terms thereafter. It is therefore the intention, with support also indicated by the Government, to start concession extension discussions whilst reviewing the net reward terms post-2004, as soon as possible.

Programme Objectives

Whilst PDO's black oil development plans for the 2003-2007 programme period are in line with the vision of restoring production to 800 kb/d by 2007, they show a significant shortfall compared to last years programme which projected 830kb/d through to 2005, rising to 850 kb/d thereafter. Significantly, the programme will not fulfill the Government desire to restore production above 800,000 b/d much earlier than 2007.





The oil production to meet the vision is illustrated below – highlighting the considerable contribution anticipated from, first waterflood projects and, later, EOR. The degree of maturity of these opportunities is variable and considerable work is required to develop implementation plans to deliver this promise. Over the next six

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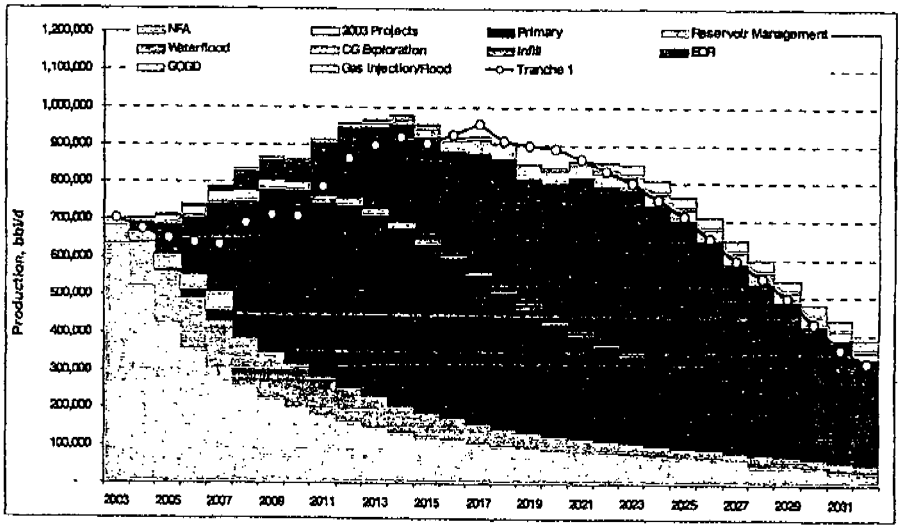
months the level of definition will be deepened and opportunities ranked and prioritised to reduce the level of uncertainty both on the production and the cost side. The longer-term profile will be flattened to deliver an 800kb/d plateau that incorporates a balanced portfolio designed to deliver primarily at lowest cost, but also maintaining the necessary strategic investments in early EOR opportunities that will build experience and knowledge for the future. The Programme will demand a significant increase in organisational capability over the plan period, provided not only by increases in staff numbers but also substantial improvements in the competence development of current staff.

Through the Programme period this "vision scenario" sees the future growth IOR and EOR projects kicking-off on their earliest technical start dates. As such, any earlier recovery to 800kb/d will depend on implementation schedules that consider PDO taking on "new ways of working" that might achieve significant reductions in lead time for major projects, and identification of new opportunities and redefined developments that can deliver early oil. Further deepening of the Portfolio Review work will permit a considered view on whether, beyond the Programme Period, production levels above the 800kb/d are achievable and sustainable.



Capital Expenditure

The five-year programme is anticipated to require a total capital investment of some $6,500 mln (100% venture basis). Proposed PDO capital investment for 2003 is $1,075 mln, made up of $150 mln exploration expenditure, $819 mln to fund the asset development plan, $106 mln for first phase EOR projects, and $23 mln for strategic follow-up projects (successful exploration in Central Gharif will require on a risked basis $11 mln to ensure rapid follow-up and a further $12 mln is expected to be required to fund metering and testing equipment to implement well & reservoir management FRD recommendations).

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	PB 2003 CAPEX					
NON EOR	2002	2003	2004	2005	2006	2007
Development	608	624	648	753	770	640
Exploration	147	150	150	150	150	150
Infrastructure	52	52	59	64	59	57
Integrity	47	61	97	107	84	68
Other	38	43	48	46	43	40
Safety_Env.	23	40	29	22	22	25
NON EOR Sub Total	915	969	1032	1142	1128	980
EOR						
Development	45	104	94	72	84	151
Infrastructure	0	2	2	0	0	0
Other	0	0	1	0	0	1
EOR Sub Total	45	106	97	72	84	151
SubTotal	959	1075	1128	1214	1222	1132
Strategic Follow-Up (Risked)	0	23	102	100	152	394
Total PDO Vision Forecast	959	1098	1230	1314	1374	1526

Shell share of the 2003 capital expenditure is $365.5 mln with the following split between exploration and production capex:

2003 Capital Expenditure US$ mln

	100%	*Shell share Capital (34%)*
Exploration: - oil - Government gas	 117.9 32*	 **40.1** **10.9***
Production	925.1	**314.5**
Total	**1075**	**365.5**

* gas exploration drilling is 34% funded by Shell but immediately recovered from Government one month later and is not capitalised.

It is clear that some elements of PDO's proposed programme, in particular the IOR and EOR projects, require further work to firm up capital expenditure requirements. From a Shell perspective, the overall expenditure level will have to be accommodated within the constraints of the EP Business Plan, and there remains scope for vigorous challenge of the proposed costs in some core areas of the business.

Notwithstanding these uncertainties, the PDO proposal is recommended for Shell support, on the basis of demonstrating full commitment and support for PDO's recovery to aspired production levels. This support, which is offered through Board approval of the 2003 Programme, will be tempered with a firm challenge to PDO to deliver targeted cost savings, both as project definitions are sharpened, and in major cost centers such as drilling where the full benefits of SCL/RTL initiatives are yet to be realised.

It will be recommended to the Board to consider withholding approval of funding in specified areas requiring further definition until the necessary supporting work is complete. This requirement will be proposed as part of a strengthened formal (quarterly) review of PDO's progress against all key Business Plan targets. The approach is likely to appeal to Government who, with the pressure of reduced oil revenues and increased costs, are also looking for improved capex control and efficiency - and for Shell to visibly accept a greater degree of responsibility for PDO performance.

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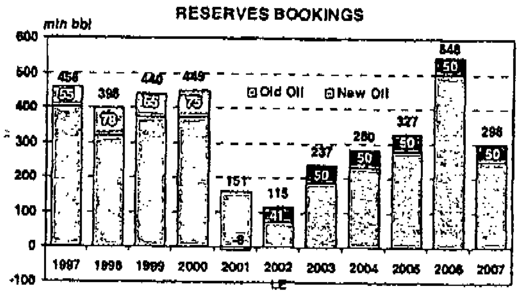
Reserves

The reserves booking plan through the Programme Period shows a downward trend in the volumes to be booked. This is fundamentally a reflection on the substantial tightening of the process by which reserves are booked, in reaction to the apparent difficulty over recent years converting booked reserves to production. Nevertheless, ensuring that future reserves bookings at least replace annual production remains a shared aspiration for both Government and PSH, and a basic requirement to ensure the future health of PDO. Studies plans will be set to ensure that, on average, this target is met. The current 5-year maturation plan anticipates booking 1.7bln bbl compared to the 1.34 bln bbl of reserves produced.



Remuneration

Oil remuneration for the private shareholders is based on a Net Reward formula that has two components:

(a) a production component equivalent to 5% of the net margin (gross oil revenues minus oil costs) and,

(b) a reserves component related to the number of barrels of "old oil" (additions to existing fields) and "new oil" added to the ultimate recovery.

Anticipated results, based on Volume 2 capital investment ceiling of $347 mln and production level of 703 kb/d, are as follows.

	Net Income	Cash Flow	(Oil)
	US$ million MOD	US$ million MOD	ROACE %
2002 LE	256	138	43%
2003 Plan	196	179	48%

For 2002, an oil price of $21.3/b has been assumed. This is the average of actuals to end July and $20 for the remainder of the year. Oil price of $20/b is assumed for 2003.

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EP EXCOM
Minutes of meeting held in The Hague
11th November 2002

EP Excom Members Present

Walter van de Vijver – Chairman, Matthias Bichsel, Lorin Brass, Linda Cook, Frank Coopman, John Darley, Carol Dubnicki, Dominique Gardy, Din Megat, Bob Sprague and Brian Ward.

Curtis Frasier attended as Secretary.

1. Staff Planning

Notes of the discussion to be circulated under separate cover.

2. Minutes of the meeting of 28th October and Highlights

- Need to show where we stand on the scorecard. **Action: Brass**
- The next step in the "close the gaps" process is identifying the actions necessary to actually deliver.
- Dominique updated the Excom on the latest developments in the West to East pipeline project, noting particularly concerns regarding IOC alignment.
- Project Thistle is scheduled for the Excom meeting of 25th November. **Action: Ward**
- An update on Omalanga was requested. **Action: Ward**
- A joint SDPC/EPG workshop had been conducted in Noordwijk to develop plans to address four critical issues in Nigeria. The results of this workshop would be shared with Excom. **Action: Ward**
- The Bonga hull was scheduled to leave Rotterdam today, weather and tides permitting.
- Need details/information regarding Kashagan for Walter's telecon later this week. **Action: Megat**

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3. Hydrocarbon Reserves Outlook

John Pay presented the current outlook for reserve replacement in 2002 and 2003. He noted particularly the impact of: (i) the Enterprise acquisition, (ii) license extensions, (iii) Big Tickets and Strategic Options, and (iv) T&OE opportunities.

Reserves issues in Nigeria continued to be a matter of concern. Brian Ward noted certain issues raised in the recent reserves audit of SNEPCo.

Lorin Brass told the Excom that, consistent with the agreed approach on this subject, developments and updates would be brought to Excom on a regular and ongoing basis.

4. Strategic notes for Discussion

4.1 Global Scorecard

Lorin Brass reviewed the proposed EP Global Scorecard for 2003. He noted that the proposed scorecard had been simplified significantly in comparison to the previous years and told the Excom that the new format was intended to articulate EP's direction and priorities in delivering targets in 2003. The scorecard is expected to be a key tool for engaging staff and further driving the behaviors and actions required to deliver against Plan and meet external promises.

Excom agreed that the items referred to as "Deliverables" were better described as "Milestones" and that delivery of 12 or more of the 15 identified should constitute "outstanding" performance (with 6 as threshold and 9 as target).

It was agreed that the structure and high-level metrics of the scorecard could be shared, while the detail (including Milestone identification) should remain confidential at this time.

4.2 Big Bets / Big Tickets / Regrets

Lorin Brass presented the latest update of the three Businesss Development Funnels (Brownfield, A&D and Exploration), as well as the "Big Bets" and "Big Tickets". He also presented a chart showing the timeline for FID and first production for the Brownfield projects.

A review of the Heartlands Project was scheduled for 3rd December and the results will be presented to Excom on 9th December. **Action: Brass**

4.3 Project Marlowe

Lorin Brass reported on the status of Project Marlowe. He told the Excom that the Project screening process had identified 16 preliminary candidates for potential divestment/swap. From this list, 6 had been selected based on considerations of related regrets and doability. Each of these had been included in the EP plan for 2003-2007.

It was noted that the key metric in this exercise is high book value.

Lorin told the Excom that work on bringing this down to the asset level continued and it was hoped that this detail would be ready for presentation to Excom at the meeting scheduled for 25th November. **Action: Brass**

4.4 Southern Cone Strategy

Bob Sprague summarized the status of the GP/EP Southern Cone Business.

The prospects for successful conclusion of Project Miranda were considered remote, and it was determined that this effort should now be discontinued.

Excom supported the portfolio rationalization, as proposed in the note.

5. Managing the Business notes for Discussion

5.1 EP Solutions Organization

John Darley proposed the creation of an EP Solutions organization. This organization would be a product of alignment between SDS and SepTAR (GIS cluster) to provide full life cycle solutions for the exploration, appraisal, development and production of hydrocarbons.

The Excom requested that the proposal be shown in the context of the total organization redesign. **Action: Darley**

5.2 EP Global Well Delivery Organization

John Darley proposed the creation of an EP Global Well Delivery organization, by combining the SDS Well Delivery unit and SEPTAR's WEDO team. He told the Excom that this new organization would be equipped to provide competitive well delivery performance to those organizations which lack the volume of work to develop such capability themselves.

As with the EP Solutions proposal, The Excom requested that this proposal be shown in the context of the total organization redesign. **Action: Darley**

5.3 EP Projects

Excom endorsement was requested for the enhancement of processes relating to: (i) business planning & decision review processes, (ii) Value Assurance Reviews, and (iii) capital allocation exercises.

Concern was expressed on the issues of: (i) alternative compensation tools, and (ii) global procurement and contracting. **Action: Darley and Coopman**

It must be clear that, within these processes, EPT-P serve in the role of service provider and not as a business director or project manager.

Subject to the above, the proposal was supported.

5.4 Malaysia: BDO extension mandate

Excom endorsement was requested for a mandate to negotiate a 20 year extension of equity in the Baram Delta Operation's PSC.

- Supported.

5.5 EPLF Agenda

A draft of the proposed agenda for the December EPLF was tabled. A number of changes were suggested. Lorin to discuss changes with Ceri Powell. **Action: Brass**

6. Presentations

6.1 Sure Strategy – Plan of Execution

Steve Mut presented current strategy for SURE and developments to date. He reminded the Excom that SURE had been launched based on its potential impact on reserves, unrisked production and portfolio value. A significant investment had been expended and significant learning's had been achieved. He then reviewed the technological developments and described the current portfolio focus.

A revised plan for the execution of SURE was the presented. Steve told the Excom that the revised plan entailed a significant reduction in the cost both for 2003 and for the total cost to first commercial FID relative to the plan used as the basis of the Capital Allocation submission in June.

Management of environmental issues has always been a critical element of SURE development. This was seen as a global issue, beyond a local project consideration. From the beginning, it was considered essential that there be a sustainable development case and a story to go with it.

In reply to a question, Steve told the Excom that, from a technical/quality standpoint, Venezuela/Orinoco was preferred to Canadian options.

The question of a potential joint venture with ChevronTexaco was discussed. The critical question was: "what do they bring to a project?" At this time, the feeling within SURE was "not enough". However, partnering options should be further developed and explored.

Excom supported the revised plan.

6.2 New Operating Model for EP

John Bell presented the proposed details of Change Programme, in terms of scope, schedule, accountability, and savings targets. He then reviewed the design of the proposed Programme Office, in terms of role, composition, tasks, cost, and timing/communication. He said success would require the following from the EP Excom and the CEO: (i) cooperative working, (ii) sharing of information, (iii) involvement is key decision making, meetings and activities, (iv) proactive challenge with "Big Rules", (v) team-play and display of expected leadership behaviors and (vi) regular air-time and steerage.

It was noted that it was not too early for HR to be thinking creatively about the way forward. Carol reported that this was already underway, with a meeting of regional HR managers scheduled for later this week in The Hague.

7. Notes for Excom Information

7.1 Shell/ExxonMobil EP Tax Rate Comparison 2001

- It was queried whether Shell Canada data could be made available. **Action: Sprague**

7.2 EPA Capex Options for 2003

- Noted.

7.3 Brunei: Champion West Phase 2 GBP

- Noted

7.4 Australia: Sunrise/FLNG Project – Update and Way Forward

- Noted.

7.5 USA: SEPCo Dorado Prospect & Development

- The timing of submittals from the USA continues to be unsatisfactory. **Action: Sprague**

7.6 USA: SEPCo Mars Basin Differential

Excom supported a requested mandate to fix the differential between West Texas Intermediate and Mars Blend crude at targeted levels for approximately 25% of SEPCo's Mars Blend production.

7.7 USA: SEPCo Plains Divestment Update

- Noted.

7.8 USA: SEPCo Fairway Field Working Interest Acquisition

Bob Sprague reported that BP had withdrawn the interest based on a relative lack of interest/competition.

7.9 Greenhouse Gas Emissions - Q3 and YTD Performance for EP

- Noted.

7.10 Stena Tay Update

- Keep the rig occupied in South America drilling for Shell and others remains the preferred sequence scenario. Noted.

7.11 Brazil: SBEP Revised Deepwater Program GBP

- Noted.

7.12 Shell E and P Offshore Services (Seapos) - Stena Tay under-recovery GPB

- Noted.

7.13 USA: Project Martini

- Noted.

7.14 Production in EP Business Plan 2002

- Noted.

7.15 Iraq Scenarios and Way Forward

- Noted.

(Lorin Brass, Linda Cook, Carol Dubnicki and Bob Sprague did not participate in consideration of this item.)

7.16 Kuwait Partnering Update

Not ready to concede operatorship to ChevronTexaco at this time.

7.17 Libya Country Strategy

- Noted.

(Lorin Brass, Linda Cook, Carol Dubnicki and Bob Sprague did not participate in consideration of this item.)

7.18 Oman: PDO Programme and Budget 2003

- Noted.

7.19 Pecten Cameroon Company Hydrocarbon Forward Sale

- Noted.

7.20 EP/GP Projects - Cost Split

Further progress on this will require agreement between the CEOs of the businesses.

7.21 Morocco: Enterprise Interest - Group Restructuring Proposal

- Noted.

7.22 Expex Latest Estimate 2002

- Noted.

8. Any Other Business

It was suggested that a running update on capex options and their progress, be maintained and distributed regularly to Excom. **Action: Coopman**

ROYAL DUTCH/SHELL GROUP OF COMPANIES

STRATEGY PRESENTATION
Exploration and Production
Gas & Power

WALTER van de VIJVER
Group Managing Director

MATTHIAS BICHSEL, Director, Exploration

JOHN DARLEY
Director, Global EP Technology

LINDA COOK
Chief Executive Officer, Gas & Power

MALCOLM BRINDED
Group Managing Director

9:00 a.m.
Thursday, March 27, 2003
New York, New York

This document was prepared by ETX Corporation

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11/17/06

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WELCOME

MR. WALTER van de VIJVER, Group Managing Director: Good morning, ladies and gentlemen. Welcome to the Exploration and Production and Gas & Power strategy presentation. You have all seen this slide before, the disclaimer, so I will not read it to you.

I am joined here by my colleague, Linda Cook, the CEO of Gas & Power, who will do the Gas & Power presentation. She will be joined by Malcolm Brinded, who will take over from Linda in the middle of this year as the CEO of Gas & Power. For the Exploration and Production presentation I will joined by John Darley, our head of technology, and by Matthias Bichsel, who is head of exploration, to give you a little of the story. Today is all about deepening the story on Gas & Power we had on February 6.

OVERVIEW

MR. van de VIJVER: What do we want from EP and Gas & Power? We want more of it; we want to grow it. If you look at our current portfolio, about half our capital employed is tied up in EP and Gas & Power, but it generates about three-quarters of our earnings. Therefore, at the same time we strive to disproportionately grow EP and Gas & Power, about three-quarters of our investment level overall as a Group, which is about $12 billion, goes into Gas & Power so we can invest beyond depreciation and actually grow this business. It is very important for the future of the Group overall is why we are here today.

Just a reminder of the Group financial framework we showed you on February 6. Everything you hear today is consistent with that framework. On our returns targets we are getting back in the range in the short term, while at the same time investing in the future to insure we have the long-term value delivery and flow to the shareholders. Another thing we hope you will see throughout this day of presentations is the view of our portfolio with the continuous balance between the short term, and medium term and the long term. We are very much focused on getting back in the range of 13 percent to 15 percent, while at the same time executing all the projects that will deliver medium-term growth and then creating new legacy positions for the future. You will see this again and again throughout the whole presentation.

Another thing we want to drive home today, and I hope we will be successful, is how very passionate we are about this business. We do feel we have the strongest and most balanced portfolio among our peers. We also feel, particularly when you look at the combination of EP and Gas & Power, that we are the absolute industry leader. That is not only when it comes our the resource volume—the highest among our peers—but also how we monetize that and have the overall value chain of technologies, costs and operational excellence that will deliver the value, not only today but also in the long term, in earnings and real, hard dollars. It is essential to get the message about our leading-edge portfolio across.

EP—PORTFOLIO AND PERFORMANCE

MR. van de VIJVER: Let's start with the Exploration and Production story. We believe our portfolio is second to none, looking at it on a global scale. The whole strategy of EP is focused around our existing business, in particular on areas we call our "heartlands." The heartlands are geographically spread over the globe, and we will focus on them today. These heartlands are also about leveraging leadership positions and growing them in the future. At the same time we will have the separate drive to build the long-term legacy positions that will deliver the value for many decades to come. We will drill down into the portfolio to give you a more inside look at the strength in that portfolio.

First, let's look at the portfolio from a reserves perspective on a global scale when it comes to distribution. On the Shell side we have a very balanced geographical spread in our reserves. It is interesting to note that we all know where we want to grow our businesses, and you will see we are already present in many of these areas. Our competitors are still trying to grow in areas where we have been for many years. It is important to see that in perspective.

You should also recognize that we are by far the largest operator in the world. These are real data looking at where Shell operates and where we have a strong role, bringing our operational excellence to the table to the many areas of the world where we operate. It is a very large scale that brings true capability to leverage technology, leverages our overall cost structure and the staff capabilities you need to operate, not only in the North Sea and Gulf of Mexico, but in other areas of the world. We feel very strongly about our leadership position.

Another thing that should come out more clearly is the comparison around returns. We see a lot of comparisons of returns around the EP business and Shell versus our competitors, but people ignore how things are grouped in the portfolio. This is the like-for-like comparison looking at returns. This takes the EP business as we define it, as well as the Gas & Power business minus the power segment, and combines those two. We call that the midstream and LNG business with our EP business to reflect Shell returns. Compare that with ExxonMobil where we deduct from their results their power results in China. And with BP we take the totality of EP and Gas & Power because we cannot take out their power side.

This is the true story over the period 2000 to 2002. It is important to highlight here that this is with an average price environment of $26 Brent and $3.90 Henry Hub. It is a high-priced environment and we are still as competitive. There is always the issue around exposure in the U.S. and so on. You see that even in these high-priced environments we are very competitive when it comes to returns.

Another thing to recognize is the volatility of our results as part of the market prices for our commodities. We have a portfolio that is very robust against oil price volatility. You see that on the left-hand side of the chart. This is because we have a very large part of our portfolio, like the world outside the U.S., on the gas side where contracts are either long term or are tied to LNG where there is a time lag until prices come through. So we are very capable of absorbing these price differences and are less exposed than our competitors. On top of that, we have 16 percent of our portfolio on fixed margin. The other side of the equation, currently 10 percent of our volume is exposed to OPEC—always a sensitive issue. If we look forward to 2007, the prediction is that number will double. It is still modest in comparison to our total portfolio.

Let's go to reserves. I know there has been a bit of a debate on reserves and I will try to be open and transparent around where we feel we are on the reserve side. On the left side is a combination of proved and probable reserves—PP reserves. That is how we plan our business; this is used for our normal internal business planning. You see very healthy growth here, and this health growth gave a replacement on the PP of almost 44 percent in the last five years. Recognize that this is just PP—it does not include all the scope volumes that go above there some of our competitors show. This is purely the PP volume.

If you look at our proved reserves, again you can see the trend relative to our competition. You see we strongly believe you should not look at these measures on a short-term basis, but on a longer-term basis at 5 percent or 10 percent when the differences between us and the competition are not that stark. You should also recognize that when we look at our reserve replacement, for the last couple of years we have been struggling to replace reserves around the gas side. It is the gas side where we already have the strongest reserve base of our competitors. On top of that, we know the lumpiness of that measure will only come through if you look at it for a long-enough period, with some of these truly major projects we have in the development phase. That is the story around reserve replacement.

The good thing about reserve replacement, if you look at the total Shell portfolio again, is the growth of our reserves over the various geographies we operate in and our ability to grow that reserve base while at the same time growing production. We are organically growing that production and at the same time growing our overall reserve base over the various areas.

Allow me to give a little tutorial on reserve replacements, because it is such an important issue. I will end by giving you some comments around the 2003 outlook. If we look at the total life cycle around reserves, this is the story. The message we want to get across is if you do not take the simple measure of unit finding and development cost over a long-enough period, you will have a totally flawed perspective of the real strength of the business.

Look at the metrics you can use to track resource development. We all know you start with exploration and prospects. You have undiscovered scope, then you go into your exploration appraisal cycle and you have discoveries. There are metrics around the exploration business that are often expressed in unit finding costs. They are out there, but not easily benchmarked; they very much depend on what you assign as the numerator and denominator when it comes to the numbers.

On the Shell side when we talk about unit finding costs, we apply basic SEC discipline around what we call "discovered volumes." That is what a particular well actually encounters in oil and does not take the full scope yet, since that will mature through appraisal and the final investment decision. That is why we talk about dollar per barrel on average, on unit finding costs, while at the same time you could talk far lower numbers if you looked at the total scope of some of our discoveries. We try to be very disciplined as part of that whole chain of discipline on SEC guidelines.

Another area that is a measure of the success of the business is around unit development cost. We think that is a very variable measure because it tries to depict the amount of money you spent on development and the production capital expenditure directly linked to the movement of developed, proved reserves. It is a bit more difficult to get out of the published numbers, but it is a true like-for-like comparison between expenditure and actual reserves. As you know, that is the great difficulty with unit finding and development costs, because people can put whatever range of numbers they would like in both categories.

If you actually start operating, you have a unit operating cost. We feel you need to look holistically at the total reserve cycle and all these metrics to give you a real feel for the strength of the portfolio and how these things move across it.

Here you see the comparison on unit development cost and adjusted production cost, based on a variety of external data as you see in the footnote. Key here is the competitive position of Shell versus the competition. Being the lowest in development costs and adjusted production costs all links directly to our capital efficiency where technology plays a major role, and is also linked to our technical and operational excellence when it comes to delivering the goodies on a day-to-day basis. The key element ultimately is what translates to the bottom line, whatever metrics you talk about.

Going forward, that depicts how we see both our cash and noncash costs that translate into our unit earnings. You see here both operating costs with ongoing trends, and you know our commitment on a 3 percent underlying unit cost reduction for 2003 and 2004. You see here the reduction on DD&A, which to an extent is also linked to the conservative depreciation we did on the Enterprise acquisition. That is why you see the DD&A coming down going forward. Overall you see the trend averages around $8 per boe. So whatever metrics we talk about in unit finding and development cost, because the numerator and denominator are out of sync and you can start looking backwards rather than forward, what really matters is what comes through to your bottom line. There we have a positive trend going forward.

Before I go, I do want to make some comments on reserve replacements for 2003, knowing you will ask questions on it—and that is good, because we do like questions. There are quite a few things happening you will hear about later today on the gas side that could have a major impact on our reserve replacements for 2003. This is where all these projects—whether they are activities ongoing in the U.S. with onshore gas, or activities ongoing in the North Sea like an Ormen Lange, or the issues around Sakhalin defining the projects that will supply Train 4 and Train 5 in Nigeria—all those will come to pass as part of making those decisions that will impact our 2003 reserve replacements. I hope you get additional comfort that things are moving forward on the gas side after the last couple of years; at the same time, as we keep reminding you, don't just look at the individual year-to-year replacements.

Now let's start drilling down into our portfolio. We have a very balanced portfolio and we like to show you where the investment on that portfolio is going and why. Thirty percent of our investment still goes into our existing businesses, which are very focused around our heartlands; another 30 percent goes into growing the heartlands; and then we have about 30 percent linked to building these new legacy positions; and almost 10 percent around the discoveries, bringing them to reality. This is very balanced and centered around how we spent that $7 billion to $8 billion of capital expenditure.

Let's start with our heartlands. This is a very important part of our portfolio and I would like to spend some time today talking about things we normally do not talk about. Maybe we take their value to our overall portfolio too much for granted. I will drill down further on Europe and on Brunei and Malaysia, as just two examples of the strength of our portfolio.

Also at this time I will comment on some other areas. We have a lot of pressure around Oman with the current decline, after a very long successful buildup. We are going through a transition there and we are very optimistic about the future. I think it is important to recognize that in Oman, just on the oil side, we are playing with a massive portfolio. It has about 50 billion barrels of oil originally in place. To date we have only produced 13 percent of that. There is enormous potential still left in Oman. In the U.S. we have the leadership in unit earnings, as we have said in the past. I will come back later to Nigeria. Let's go into Malaysia, Brunei and Northwest Europe.

It is important to realize why we spend 30 percent of our money in these existing heartlands overall—because we made an average return of 40 percent ROACE on them. That is why we still like that business so much.

Looking at Europe, irrespective of some of the stories you might hear from competitors, it is very important to us and will continue to be important for a long time in the future. With all the stories about production decline, here is our outlook on production in Europe—still strong and stable with lots of opportunities. The other thing to recognize is that 40 percent of our overall EP earnings come out of Europe.

Let's have a look at the map on Europe and the North Sea. We currently have operations in Norway, Denmark, The Netherlands and the U.K., and we are developing things on offshore Ireland. Key here are a couple of things: We are the absolute cost leader in the North Sea. You don't have to believe our numbers; that is what Mackenzie confirms after very extensive benchmarking. We are number one in the central North Sea and number three in the southern North Sea. We still have many opportunities out there that will offset the decline in some of the more mature areas. We have lots of ongoing activities. We still see potential in the Atlantic margin, going all the way from Ireland to Norway, and we had an extremely exciting discovery, Dooish, at offshore Ireland. In the next couple of months we will be further appraised on this development.

There are a lot of key projects there, but also some little examples. You can see Nelson Oil Production on the right-hand side. We took over that operation from Enterprise.. Guess what? In a very short time frame we were able to turn around the decline and actually build production again. Through applying our skills on execution and waterflood—managing the water—we are able to see a lot of life in a mature asset in the North Sea.

That is all I will say about Enterprise. Enterprise has disappeared into our portfolio. It is performing extremely well. We stick to all the synergy promises we made in February. There is future value potential there. You can imagine with Enterprise having delivered more than $1 billion, we are smiling all the way to the bank.

We have a very strong position in Europe, but we will go further. We are now putting up the next generation of management processes around EP Europe to manage it as a single entity. We see enormous potential there, not only for cost takeout, but also for value creation. We will finally break down the barriers between those various assets. We will be able to use standardized processes that will speed up learning and transfer of technologies. We see a lot of value creation coinciding with all the liberalization taking place in the European gas market. This is much like an alliance we want to do on the gas side, which Linda will cover. It is all about positioning ourselves for the future, seeing a lot of value creation and finally taking the next step of looking at Europe. It will be very important for a long time into the future.

Let's look at some areas we do not talk about too much in Shell where we have very dominant positions and long-standing relationships with governments. They are Malaysia, Sarawak and Brunei. We have been there for a long time—Malaysia nearly 100 years and Brunei over 50 years. Amazingly enough, this is still a growing business. We continue to reinvent ourselves. We see continued growth with the scope we have in Sabah in the deepwater. Last year they reached a production record. If we look at areas around

Sarawak, last year they had liquid records coinciding with LNG volumes. We are at the startup of Train 3 and will continue to grow volume. This is a very important business with very high value for Shell overall.

Brunei is a typical example. Last year Brunei reached a production record. Brunei currently has more reserves than it had 20 years ago. That is the real strength of Shell—being able to apply all the leading-edge technologies. John Darley will show an example of how we still see the value in these very so-called mature areas that will be heartlands for a long time in the future.

Let's go through the next stage of growing our heartlands and highlighting why there is still so much growth for the deepwater. I don't think anyone dares contest our leadership in deepwater. This is not just talk, but actually doing and delivering in deepwater. It is a very competitive area and very important. We have been investing there for a long time, as you know, starting in the Gulf of Mexico. We still see enormous potential going forward.

Here is an example of our deepwater leadership. Mars Basin, one of the so-called mature deepwater assets in the Gulf of Mexico, last year delivered over $600 million of net income to our bottom line. Not a lot of people have these kinds of assets. Mars has been able to surprise us year after year in capability and potential. We had to adjust the facilities going forward, as you see on the step chart on the Mars TLP. There is still a lot potential left in Mars. Mars Basin overall has about five billion barrels of oil in place. At the same time we are still exploring and appraising in that area. This is where the Deimos discovery was made, and we are currently appraising that. That has high potential. Don't forget, we will only start waterflooding the Mars field in 2004—just the second stage of development. There is still a lot of scope left.

Let's go to Nigeria. We all know the misery around Nigeria at this time, but let's put it into context. We have a massive operation and potential in Nigeria. This is the only area in West Africa where there is an integrated solution on both maximizing oil and gas reserves in the country. As you know, Shell has been instrumental in creating that integrated gas and oil company in Nigeria. Irrespective of all the troubles we have had in our western division over the last couple of weeks, we are still able to supply all the gas needs after the startup of the third train on Nigerian LNG.

We have that flexibility in our portfolio to do so. We have a very nice portfolio because these are all very big material assets. That is what this map shows—all the individual assets with over half a billion barrels of oil in place. We are now still in the buildup phase on our EA facility offshore Nigeria. It is doing about 60,000 barrels a day, so it is all going according to plan. It is a very successful operation with the right balance between onshore and offshore, the right balance in exposure, and still has lots of potential.

On our gas portfolio, this is the spread of our overall gas reserves across the world, which translates into an R/P of 15.5 years. We have a very strong position in Asia Pacific as the leader there. We are very strong in Africa and the Middle East. You will note scope for recovery is quite a thin sliver in North America. It does not make sense in a lot of these areas to find more reserves. You have to align it with monetizing your reserves, so you have to look at these things in context. You know the size of Europe when we sit on these assets around the [indistinguishable] of fuel to The Netherlands, which has huge potential for the future. I think we all recognize that the bars in America are a little thin.

Let's go to the last stage of building new positions. We are trying to give you a feeling for how we carefully balance our funding to create some of these long-term positions that will deliver value. It is very geographically spread risk-wise over the globe in the places we want to be, like key areas around the Althabasca oil sands. As you know, they are now in the final stage of commissioning a startup and have now successfully commissioned the Scotsford upgrader, so that is all in train to start. In Brazil deepwater, again Shell has so far discovered close to four billion barrels of oil in place. It is now in the process of commercializing those resources, knowing we are the strongest international oil company in the deepwater of Brazil after Petrobras. We have already talked about West Africa. In the Middle East there are still many select areas for growth. The Caspian in Russia is very much centered around Sakhalin. We have talked to you about China before.

This shows some of those world-class projects coming through. Here is a picture of Althabasca. Again, recognize that Sakhalin is one step in a major development we are pursuing with $10 billion of overall investment, for a position that will be there for decades to come. We are currently in the final stages of setting up all the elements, including the marketing, which Linda will cover, to take it to the final investment decision. It is the same with Kashagan—there are a lot of activity happening now to arrive at the final awarding of the contract and get this development going.

Here are some more near-term things. Bonga FPSO will be the biggest offshore FPSO in Nigeria. The topsides are put on in the U.K. and will sail from there around September, moving slowly south to be installed in Nigeria for startup in April next year. Bijupira Salema is another present we got from Enterprise. We came in late in that project's development but were able to apply our skills in project management to accelerate the startup from September to three months earlier in July. Again that effectively shows our strength in overall project management.

With that, I will hand it over to Matthias for a deeper look into our exploration portfolio.

EP PORTFOLIO—GLOBAL EXPLORATION

MR. MATTHIAS BICHSEL, Director, Exploration: Thank you, Walter, and good morning, ladies and gentlemen. By choice we have the strategy of pursuing two distinctly different types of exploration. They are at different stages of the hydrocarbon life cycle and require quite different skills to be successful. Near field exploration, addressing by its very nature the smaller volumes but the high unit-value barrels, is in support of our production in the heartlands. To be good at it one has to have a deep understanding of the interaction of geology and geophysics in a particular area. Conversely, exploring for new hubs requires an outstanding skill in understanding the hydrocarbon systems of the world. Obviously this type of exploration is in support of our growth in the heartlands as well as building our new positions, since it addresses the larger volumes.

In the second half of the 1990s and into the early part of this decade we have spent a lot of effort on near field exploration in terms of money, and in particular, manpower. In late 2001 at the presentation on the EP strategy, we indicated to you we would shift the focus of exploration towards the new-hub type exploration. Now we are drilling more "big cats," as we call our material opportunities, than we were in the past.

Let me say a few words on the performance of exploration. We are very proud of our near field exploration track record with its high success rate. That success rate allows us to design our exploration wares as producers, which in turn enables us to shorten the cycle time between exploration and first oil to capture maximum value. To give you one example, the Gulf of Mexico last year had a success rate of over 80 percent. From this activity in 2003 we are producing 30,000 oil equivalent today, and that is increasing over time. You can imagine the value we have created through that activity. We are replicating that as a success across the world.

Our strategy to move to new hub-type exploration is paying off, as you can see on this slide that shows the discoveries we made last year in this category. These discoveries range from the Gulf of Mexico, where we have participated in all the big discoveries that industry has made, into Ireland—Walter already talked about Dooish—and over into the Far East and also in West Africa, where we are very successful. A study done by Deutsche Bank looking at the equity resources discovered in 2002 in giant discoveries—they have used a cutoff of 300 million barrels—compares Shell very favorably with the competition.

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Exploration is there to underpin growth. The exploration discoveries are fueling the development opportunity funnel that is graphically represented on this slide. We have a very strong near field exploration performance, as I mentioned, close to its production. That is on purpose. We have a just-in-time approach to near field exploration, just in time as it becomes available. There is no point in drilling these wells too early; that would destroy value. At the same time, once again this picture underpins our shift of strategy and proves the new strategy of moving to new hub-type exploration is showing traction. We have more of those discoveries now populating this funnel and moving forward to production. It is clear that 2002 discoveries in particular require more work, appraisal drilling and studies to nail down the exact plan—when they come on stream and how we will develop them.

Ultimately exploration is all about creating value. This is a study conducted by Wood Mackenzie looking at the value added through organic exploration and appraisal activities over the period 1996 to 2002. It puts us squarely in the number-one position. That same study indicates that we are top tier in the finding costs, as Walter mentioned.

That was all about the past; we need to replicate that success into the future. We require a few ingredients. One is to have a portfolio of opportunities. Our acreage position is second to none, but that is not a static picture. We are continually rejuvenating our portfolio. Last year, for instance, we farmed out over 50 positions and relinquished 113 blocks. At the same time last year we acquired acreage in nine countries, excluding the acquisition of Enterprise. That keeps our portfolio rejuvenated, renewed and allows us to high grade the drilling opportunities.

I realize, of course, that having a portfolio per se has no value. The value lies in the capability to unlock that portfolio, to turn it into volumes and to transform that into cash. Shell has that inherent strength, a strength we have honed over years of successful exploration. Decade by decade, as this example of Oman will show you, we have found more plays that in turn generated over 100 oil fields currently on production, with more to come. All that massive oil in place present in Oman that we are working has been found by exploration—it is pure organic exploration success. We are replicating that capability and success across the world.

Allow me to sum up. We have an exploration strategy that makes sense, supporting both production and the growth in the heartlands, as well as in the new positions. We have a track record we can be proud of and a portfolio we know how to unlock. A nice example to illustrate that is deepwater. Walter already mentioned our leadership position in that. We pioneered deepwater exploration in the Gulf of Mexico in the 1980s. We learned the ropes, built up the skills and developed the technology. We take that capability and leverage it across and into northwest European Atlantic margin, into deepwater Nigeria, into Brazil and into the basins of northwest Borneo.

Now in this century we are taking it a step further. We are building our positions in undrilled frontier basins, such as Morocco deepwater and the ultra deepwater in the Nile delta, and at the moment we are finalizing the negotiations on the terms of a large deepwater acreage tract in Tanzania. This position together with our heartlands will deliver a sustained stream of new production to Shell from exploration.

Thank you very much. I will hand over to John Darley, who will talk about technology.

EP STRATEGY—TECHNICAL EXCELLENCE

MR. JOHN DARLEY, Director, Global Exploration and Production Technology: Thank you, Matthias. Good morning, ladies and gentlemen. In the next few minutes I would like to explain how technology adds value to the EP portfolio and how our technology strategy adds value to the short and the medium, and positions us for the longer term. Our targets are very clear: to drive down unit costs both in operating and capital investment; to grow opportunities for production; to look at new ways to leverage the assets in our heartlands, and I will come back to that; to maximize the ultimate recovery, and we heard examples of how recoveries over time continue to grow through new technology; and finally to position us for the longer term, because we are looking outwards, particularly in R&D, at the technologies we will need five or 10-plus years out.

I do not have time this morning to cover the full spectrum of our technology, so I will focus on three areas. I will look at well technology and why we give that focus. I will look at imaging the subsurface and how that generates opportunities to defer some of the declines we see in mature fields; and I will look at the integration, particularly in the concept of smart fields, and show how each of these elements add value to the portfolio.

Let's start with the well arena. Why do we look at well technology and why is this important to us? Of that $7 billion to $8 billion annual investment we make in capital spend, something like 25 percent to 30 percent finds its way back into drilling and completion of wells. On the left-hand side of the chart you can see the performance in the Gulf of Mexico in driving down the time to complete or finalize the drilling phase, the complete subsea wells, taken at the period from 70 to 80 days down to about 20 days. The significance of this is very clear. An offshore drilling rig in the deepwater Gulf of Mexico will cost anything upwards of $100,000 a day. The ability to drive down completion times and therefore costs of these wells is instrumental in maximizing the volume.

On the other side of the chart you see an example of productivity improvement in well design. This is talking about big bore wells. We look both at the well bore itself as well as the completion technology in the reservoir. This example shows production of 70,000 barrels a day from this technology during 2002. Some of these techniques use our proprietary invention of expandable tubular technology, which you may have seen in the press. This allows us to run pipe in the bore hole and expand it in situ.

Last year we successfully demonstrated what we call the monoDiameter well. The monoDiameter well has the capability to run from top to bottom a uniform diameter well bore. This is a major breakthrough in well design. Traditionally wells are drilled with a very large surface pipe that concertinas down to a very small size. That approach in itself is somewhat is somewhat inefficient in terms of the large pipe at the surface leading to only a very small conduit at the total depth. The monoDiameter concept, the ability to run top-to-bottom expandable and sequentially expandable tubular pipes, allows us to achieve both more productivity from the well and a significant cost reduction in that we remove a lot of the weight constraints of drilling wells, and are able particularly in deepwater to use generation III rigs at perhaps a cost of $60,000 a day instead of a generation V rig up to $200,000 a day. Again that cost is coming from efficiency improvement. This monoDiameter technology is proprietary from ourselves. It has been licensed and worked in joint ventures as part of our technology strategy to bring the technology to our own asset base very quickly.

The speed of deployment of technology for us is a key differentiator. Across the full spectrum of technologies, we cannot have the same focus, but we can identify we really need to be the lead player. We have identified four technologies. One we call 4D seismic technology, the ability to understand in the reservoir the oil and gas displacement process or recovery process in the subsurface. The technology of under-balanced drilling, which is not a Shell technology but one we recognized and believed would add a lot of value to a special focused implementation approach. I have mentioned expandable technology already, and the whole arena of smart wells.

Our focus here is to take teams able to take learning from one side of the world to the other. Our globally deployed implementation teams are focused on working with our asset base with our operating units around the world to apply a technology, to benefit from the value of that technology and take the learning and replicate it elsewhere. It is an extremely successful program. You can see our market penetration or global market share of these technologies in 2002. You can see the value we added to the totality of Shell's business—a material contribution to our business in 2002.

The next slide is not in your pack, but this shows the 4D seismic and the way the process works in identifying displacement in the subsurface. This is an image from the Tern Field in the North Sea. Through advanced seismic imaging we have the ability to see where oil has been recovered and where it has been displaced by the water. The lightly colored blues going to the reds are areas that originally contained oil. The red lines are the wells where they either inject water or produce the oil. The brightly colored areas are those areas of remaining oil. We can then identify where we need to put additional wells or how to fine tune the injection of production programs to manage the reservoir process.

The next shows how that works in the Dragon Field in Norway. Here you can see the original decline from Dragon was predicted in 2002 or so. By running a sequential number of time-lapsed seismic interpretation runs, we were able to manage that reservoir and drill the wells needed to further decline away from plateau, hold the plateau for a longer period and increase ultimate recovery. This is a clear example of the benefit of this technology.

Walter already mentioned Brunei and our ability to manage the hydrocarbon resource base over many years. The reservoirs in Brunei are rather complex. We have something like 3,000 different reservoir compartmentalizations in that part of the world. The picture here depicts what that might look like. The red areas in the cross-section are individual pockets of oil. The pockets of oil are underlying a green gas zone. The challenge is how to most effectively tap into each of those individual pockets of oil. Traditionally we would have drilled a number of vertical wells that would have tapped the oil, and produced that oil in very small pockets. That is often not economical.

We approached this challenge differently by drilling what we call a "snake well", which is steered through the drilling process into the individual pockets of oil and gas.

That steering technology is coupled with an expandable technology that allows us to expand the casing in situ. The numbers refer to the control systems run into wells. Those control systems allow us to then selectively produce each of those layers or pockets of oil, so from one well we can tap this total array of potential producible hydrocarbons. You can see the value. The gain is immediately obvious in terms of production and ultimate recovery. Technologies of this type allow Brunei and other of our heartland areas to continue to grow reserves despite a very mature production history.

The technology of smart wells is already being applied in the United States in the NaKika Field, Gulf of Mexico. That field will come on stream later this year. It will be the deepest water development in the Gulf of Mexico, again pushing forward our leadership for being a water depth of 2,300 meters. Smart well technology is a key factor to enable us to recover oil and gas from six discrete fields, which otherwise would not be economic. The NaKika uses smart well technology in the same way we use it in Brunei.

Taking the technologies and integrating them is the key to gathering volume in the longer term. The picture here is a bit of a schematic of what we call the smart field value loop—the ability to sense in the reservoir the displacement process; to measure the pressure and the effectiveness of oil and gas production; to model that capability in real time; to select the options for future developments; and again in real time use telemetry, robotics and advanced, non-traditional oil field capabilities to maximize volume. We believe, and are not alone in that belief, that real value will be generated from smart field applications in the coming years. K&G [ed. query] Energy Research Associates have similar large numbers. We believe we need to be a player in elements of this and certainly a player in the integration of technologies that brings them together to capture the maximum value.

I hope I have been able to show you in this brief glimpse some of our strategy around technology. It is, first, the identification of what we really need to maximize