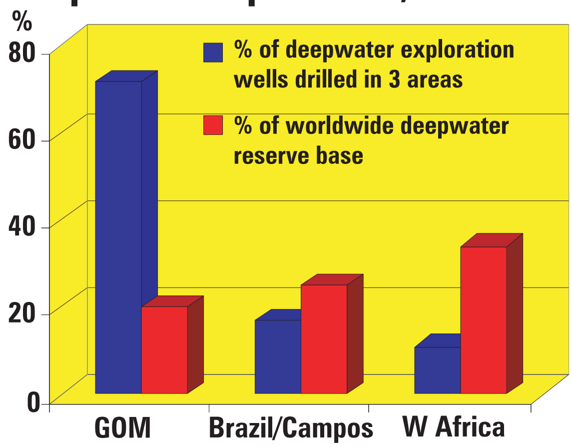
Fiscal regime key to northern deepwater potential

Mike Killalea, Editor & Publisher

WHILE DEEPWATER exploration offshore Norway has languished compared to other markets, sharply declining UK gas supplies coupled with soaring demand could soon change that.

"This supply-demand gap will grow sharply through the next decades," predicted Dr **Andrew Armour**, Exploration Director, **Enterprise Oil**, speaking at IADC Drilling Northern Deepwater, held 31 May-1 June in Stavanger. The event was co-sponsored by **Statoil** and **Smedvig ASA**.

Deepwater exploration, reserves



Source: Enterprise Oil

However, the nation's financial status quo could stand in the way of such development.

Dr Armour blames Norway's tough fiscal regime in large part for the dearth of deepwater exploration in its waters. He explained that the Net Present Value of the same hypothetical deepwater discovery stands much lower in Norway than in other nations, such as Ireland, UK, Italy, US, Angola and Brazil.

A DEEPWATER "MAJOR"

Enterprise Oil is a major deepwater operator. Only **British Gas** and **BHP** rank higher, according to Dr Armour, in terms of deepwater holdings as a share of all reserves.

"We are spending more on deepwater and particularly, ultra-deepwater, than ever before," he said. He defined deepwater as 1,000 m or more, and ultra-deepwater as exceeding 1,500 m.

Dr Armour said that established deepwater areas are rapidly maturing, especially in the Gulf of Mexico and Brazil. This in turn is partially responsible for driving deepwater activity to the north, away from the so-called "Golden Triangle" formed by the Gulf of Mexico, Brazil and the West African coastline.

He observed first that the Gulf of Mexico deepwater success rate stands at just 26% from 450 exploration wells. Gulf of Mexico deepwater wells represent 20% of the current worldwide reserve base.

"This is not an enormous success rate," Dr Armour observed. However, that is not to say the Gulf of Mexico is a deepwater Dead Sea.

Dr Armour explained that a key indicator of the continued viability of a deepwater basin is evidence of "creaming." Creaming occurs when a plot of oil equivalent vs cumulative wells flattens out. "There is little sign of that [in the Gulf of Mexico]," he said, once all bad data are filtered out.

On the other hand, Brazil shows unmistakable signs of creaming after about 50 wells and 12 billion bbl oil equivalent. The Brazilian success rate, though, runs around 41% and the Brazilian deep accounts for 25% of the current worldwide deepwater reserve base, he said. About 110 exploration wells have been drilled.

West Africa boasts a 60% success rate after some 70 wells and accounts for 34% of the current worldwide deepwater reserve base. Creaming curves of the Nigerian and Congolese deepwater basins show no sign of flattening.

On the contrary, the lines appear to be increasing linearly, particularly the Congolese, said Dr Armour.

DEEPWATER FLEET

Kjell Jacobsen, Managing Director of **Smedvig Offshore**, also anticipates increased spending on deepwater projects.

In his 1 June keynote address at IADC Drilling Northern Deepwater 2001, Mr Jacobsen said, "I see a number of signals pointing in the direction of deepwater. I am an optimist in this area."

Mr Jacobsen also pointed to the Norwegian financial structure for the shift in rig ownership from European hands to the US over the last 5 years.

In1995, roughly half the world's floaters were owned by European drilling contractors, according to data collected by **Fearnley Offshore**. Today, 71% belong to US firms. European drillers represent only 17% of floating rigs today.

At one time, as many as 8 Norwegian drilling contractors were operating. Time has whittled that down to 3—**Odfjell**, **Fred Olsen/Dolphin**, and Smedvig. A fourth is **Ocean Rig**, whose rigs are still under construction.

Mr Jacobsen observed that the main reason for this is the inefficiency of the Norwegian capital market. Norwegian companies have more difficulty in raising money than those in the US, he said.

"This is a paradox," Mr Jacobsen said, "since we know that Norway is one of the most capital-rich countries in the world."

The North Sea deepwater rig fleet has now fallen to its lowest level since the mid-1980s, as units have departed for more lucrative drilling markets.

"All the good units are working," remarked **Knut Froystad**, Partner with Fearnley Offshore ASA. "If you look at it, the best units left first."

Of the remaining deepwater rigs, Mr Froystad said, the average rig age is about 23 years, compared to only 10 years for the departing units.

He explained that only 5 North Sea-capable deepwater floaters are now available in that region—the DP drillship West Navion, the semi Sovereign Explorer, DP semi Scarebeo 5, semi Transocean Leader and semi Jack Bates.

Of those, he noted that some would depart the region, notably the dual-RamRig-equipped West Navion.

Mr Froystad foresees that high utilization for deepwater units shows no sign of abating. "There will be a very tight supply situation through all of 2002 worldwide," he said. "[For ultra-deepwater rigs], we will see a shortage of units next year."

He forecasts demand for deepwater rigs during 2001-4 at 105 units. Mr Froystad defines depths exceeding 1,000 m as deepwater, and greater than 2,000 m as ultra-deepwater.

The Norwegian analyst predicts that additional new construction will be needed by 2004 at the latest, and that the price tag for a North Sea unit will near US$400 million, which translates to a construction-justifying day rate of $250,000.

Mr Froystad also compared the true costs of conversions vs new builds for deepwater. His study concluded that conversions ran some 67% over budget, compared to 30% for new builds.

As a consequence, conversions were not the bargains they originally appeared, he said.

"If you look at apples and oranges, there's really no savings in doing a conversion," the analyst concluded.

Mr Jacobsen, whose company is committed to deepwater through its investments in the newbuild West Navion drillship and DP semi West Venture, also equipped with a dual RamRig, is an apostle of European readiness to tackle deepwater.

"We risk falling behind," he said. "I think we need to get going in Norway, too."

THE BARENTS SEA

The Barents Sea is the mother of harsh environments, but that has not stopped redoubtable explorationists from exploring its mysteries eagerly. One company, **Norsk Agip**, outlined its Barents program at the recent IADC Drilling Northern Deepwater 2001.

Norsk Agip operates licenses PL229 and PL201 in the Barents Sea, with 25% and 35% interests, respectively. In addition, the company holds interests in other Barents blocks being operated by partners. Norsk Agip holds 27 licenses over 72 blocks in Norway. It is operator in 6 and produces some 96,000 b/d of oil.

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Fearnley Offshore ASA

Bjorn Ellingsen of Norsk Agip detailed his company's Barents work. He noted that exploration was high in the 1980s, but decreased in the 1990s, with the last well drilled in 1994.

Operators were invited to apply for a new round of licenses in 1996. The government feared that without a new round, exploration in the Barents Sea would reach a complete standstill.

Producers were cautioned that they must pay the utmost attention to environmental concerns and fisheries interests. As a consequence, licensees faced some severe constraints, Mr Ellingsen said.

First, exploration drilling in oil-bearing strata was forbidden from 15 Jan until 1 Sept for any portion of block 7122/7, located in PL 229.

Similarly, seismic lines cannot be shot during 15 Jan to 1 May for the same area. This is to avoid any interference with habitat during the summer.

So right off the bat, Norsk Agip's activities were limited basically to the wintertime—the time of harshest conditions. Agip planned to drill 4 exploration wells using the semisubmersible Transocean Arctic.

In addition, the drilling team faced complex meteorological and oceanic conditions. Water depths ranged from 200 m to 400 m, and, given the late autumn/early winter time frame, daylight was severely limited.

An environmental impact study conducted by Agip, Enterprise and **Neste (Fortum)** prior to the 1996 Barents Sea round showed that exploration would pose no significant environmental threat, except in the unlikely event of an accidental discharge from the well.

Several Barents operators joined together in 1998 to form an HSE cooperation group. The HSE group submitted a joint application for consent to use the rig Transocean Arctic and for a discharge permit.

The coalition also prepared a joint environmental risk analysis and emergency preparedness analysis.

Fortunately, Mr Ellingsen said, the 2000-2001 winter season turned out relatively mild. Temperatures never dropped below 2° C and no waiting on weather was suffered.

WELL DESIGN

Operationally, Agip, **Statoil** and **Norsk Hydro** agreed to standardize as much as possible.

For example, a **Vetco** MS-700 wellhead system and 30-in. and 20-in. casings were used by all 3 companies. However, intermediate and final casing varied according to location-specific well design.

The basic rig inventory was supplemented with a rental package of drill pipe, collars, crossover subs and fishing tools. A winterized test package was also installed.

Agip used a low-solids potassium formate brine mud system. The mud system, the Norsk Hydro engineer said, possesses an excellent HSE profile, a good shale stabilizer, high density and low-corrosion potential.

It is also, he said, compatible with reservoir fluids. Limonite replaced barite as the weighting material due to improved heavy metal content.

Mr Ellingsen said the substance performed at least as well as barite, and outperformed it in some cases.

The first well, PL229 7122/7-1, was classed as an oil discovery. Drilled in 382 m of water, the planned TD was 1,524 m TVD, which took 33 days to reach.

Casing program was 30 in. at 454 m, 20 in. at 656 m and 9⅝ in. at 1,032 m.

The second well, which ranked as a gas discovery, was drilled in 190 m of water.

Planned TD on the PL 201 7019/1-1 well was 3,009 m TVD, which took 57 days to drill.

As predicted, the strata were very hard. The casing program was 30 in. at 312 m, 20 in. at 634 m, 9⅝ in. at 1,980 m and 7-in. liner at 2,620 m. Total time on location, including testing, was 62 days. ■