Oil field mega projects 2004

The future shape and prosperity of the oil industry is determined by the mega projects – those with reserves of over 500mn boe and the potential to produce over 100,000 b/d of oil. Here, *Chris Skrebowski* tabulates and analyses all the mega projects, as well as the key discoveries that could become mega projects at some later date.

This year's listing has been expanded to include all the discoveries of over 500mn boe that are likely to become mega projects but have not yet reached the point of project sanction. Where projects seem certain to be sanctioned they have been included under the most likely start-up year. Those where the uncertainty is greater, or the production date is unknown, have been listed as 'potential projects'.

Examination of our mega projects database shows that, on average, from first discovery to first production is about six years. Where the project time is significantly shortened it is usually because there is some existing infrastructure that can be used in whole or in part. In contrast, where there is an extended delay the underlying cause is either political (Russia, Caspian), challenges in getting egress for production flows (Caspian), or the challenging economics of the production (heavy oil, tar sands).

In sharp contrast to gas, where there are large volumes of stranded reserves, there is a ready market for additional oil flows. The days of large oil companies having substantial reserves banks are largely over. This means that any substantial finds will become development projects in a very limited time, unless actively inhibited by politics or access.

Offshore domination

The listing is overwhelmingly dominated by offshore projects. For onshore projects production builds progressively as wells are drilled or gathering stations installed. In sharp contrast, most offshore projects are pre-drilled – which means that peak production flows are achieved rapidly and are largely determined by the capacity of the facilities. Companies aim to maintain flows from developments close to peak capacity for as long as possible by linking in new accumulations as the original accumulation starts to deplete. A perfect example of this is the Girassol facilities offshore Angola, where Total has just starting flowing the Jasmin field through the Girassol facilities to compensate for the decline from the Girassol field (see p41).

Over the last year (2003) seven mega projects have been brought onstream, with two more due to flow by the end of the year. As seven of the fields were offshore, most of the peak capacity of 1.2mn b/d should be achieved by 2004. In the course of the next 12 months (2004) a further 11 mega projects are due onstream. As most of them are offshore projects it means that most of the peak capacity of 2mn b/d will be flowing by 2005.

New capacity

The year 2005 continues to be the peak year for new mega projects coming onstream. Some 18 projects with a potential peak capacity of 3mn b/d are due onstream in 2005. For 2006 the pace of development eases back a little to 11 projects, with a capacity of around 2mn b/d.

Undoubtedly there will be project slippage – it already looks virtually inevitable that Kashagan will slip into 2007. However, the bottom line is that between 2003 and early 2007 some 8mn b/d of new capacity will have been brought onstream to meet global oil demand growth and to offset the decline in oil production from those areas that are already in decline.

Currently 21.3mn b/d or around a third of the world's oil production is already in decline (see Petroleum Review August 2003), the best estimate of the likely decline rate going forward is about 4%, made up of a typical onshore decline rate of around 3% and an offshore one of around 5%. On the basis of a 4% decline rate for one third of the world's production, global capacity declines by over 1mn b/d each year. Global demand growth is once again expanding at over 1mn b/d. (the IEA's latest estimate is for oil demand of 78.6mn b/d in 2003 and 79.6mn b/d in 2004. Demand in 2002 was 77.3mn b/d).

As a rough calculation, by early 2007 production capacity will have declined by 3-4mn b/d (2004–2006), offset by the 8mn b/d of new capacity – giving up to 4mn b/d of new capacity to meet demand growth of around 3mn b/d. However, this is before the additional capacity created from the development of all the smaller accumulations and the expansion of production in existing fields. In short, supplying global oil demand up to 2007 appears to be well covered and, depending on the timing of new capacity and economic conditions, there may even be periods of relative price weakness.

Problematic future

If we look beyond 2007, however, the outlook becomes rather more problematic. Only three mega projects are so far known for 2007 and a further three for 2008. For 2009 and 2010 only the later stages of existing projects are currently known about. Consequently, the volumes of new production for this period are well below likely requirements.

Even if the normal mega project development period of around six years was foreshortened to four years a mega project sanctioned now would be unlikely to be onstream by 2008. There are clearly enough known developments – listed as the 23 potential developments – to plug the gap. However, of these 23 developments 11 are in Opec countries and 10 in Russia, leaving just Shell's Great White discovery in the Gulf of Mexico and PetroVietnam's block 09-03 discovery in the Cuu Long Basin as yet-to-be sanctioned non-Opec, non-FSU projects.

Project	Location	Operator	Oil Peak Flows (kb/d)	Gas Peak Flows mn cf/d	Reserves mn/b	Partners and shareholdings
Onstream 2003						
Amenam/Kpono	Nigeria	Total	125 (04)			Elf Nigeria 30.4%, NNPC ??, Mobil Nigeria ??
Bijupura-Salema	Brazil	Shell	70 (03)		170 boe	Shell 80%, Petrobras 20%
Doba fields	Chad onshore	ExxonMobil	250		1000	ExxonMobil 40%, Petronas 35%, ChevronTexaco 25%
Grane	Norway	ExxonMobil	200 (05)			ExxonMobil 26%
Karachaganak PhII	Kazakhstan (onshore)	Eni and BG	200 (04)	1,400	2,400 (liqs)	Eni 32.5%, British Gas 32.5%, ChevronTexaco 20%, Lukoil 15%
Muskeg River (Tarsand)	Canada Athabasca	Shell	130 (03)			Shell Canada 60%, Chevron Canada 20%, Western Oil Sands 20%
Nakika	GoM	Shell	100	425	300 boe	Shell 50%, BP 50%
Soroush/Nowruz	Iran expansion	Shell	130			
Zafiro S'th'n, Exp Area	Equatorial Guinea	ExxonMobil	110		150	ExxonMobil(MEG) 71.25%, Devon Energy 23.75%, Equat Guinea Govt 5%
Onstream 2004						
Albacora Leste	Brazil	Petrobras	180 (09)		1507 boe	Petrobras 90%, Repsol 10%
Banyu Urip (Cepu block)	Indonesia Offshore	ExxonMobil	165		2000 in block	ExxonMobil 90%
Bayu-Undan Phase1 (liqds)	ZOCA	ConocoPhillips	200			ConocoPhillips 63%,
Bonga (OML 118)	Nigeria	Shell	225	170	600	Shell 55%, ExxonMobil 20%, TFE 12.5%, ENI 12.5%
Caofedian	China Bohai Gulf	Kerr McGee	100			Kerr McGee
Elephant NC-174	Libya onshore	Eni	150 (06)		760	Libya's NOC 50%, Eni 33.34%,Korean Consortium 16.66%
Kizomba A	Angola	ExxonMobil	250		1000 boe	ExxonMobil 40%, BP 26.66%, Eni 20%, Statoil 13.33%
Marco Polo	GoM	Anadarko	100		180	Anadarko??
Marlim Sul II	Brazil	Petrobras	180		2679 boe (tot)	Petrobras 100%
Priobskoye	Russia Siberia	Yukos	550		4000	
Roncador II	Brazil	Petrobras	140 (08)		2000 boe (tot)	Petrobras 100%
Onstream 2005						
ACG magastructure	Azerbaijan	BP	1000 (11)		5300	ExxonMobil 8%
Barracuda-Caratinga	Brazil	Petrobras	273 (06)		1778 boe	Petrobras 100%
Bonga South	Nigeria	Shell	250		1000	Shell 55%, ExxonMobil 20%, TFE 12.5%, ENI 12.5%
Corocoro Phase 1	Venezuela offshore	ConocoPhillips	50		240	ConocoPhillips 50%, PDVSA 50%
Erha	Nigeria	ExxonMobil	150		500	ExxonMobil 56.25%, Shell 43.75%
Frade	Brazil	ChevronTexaco	110 (05)		836 boe	ChevronTexaco?? Petrobras??
Greater Angostura Ph I	Trinidad	BHP Billiton	80		up to 300	BHP Billiton 45%, TotalFinaElf 30%, Talisman Energy 25%
Holstein	GoM	BP	100	290	500-1000 boe	BP 50%, Shell 50%
Jubarte+Cachalote?	Brazil B60 Santos	Petrobras	60+50?		600+300? boe	
Mad Dog	GoM	BP	100	290	up to 800 b	BP 63.56%, Unocal 25%, BHP 11.44% ??
Marlim Leste	Brazil	Petrobras	100 (07)		?	Petrobras 100%
NEAD project	NE Abu Dhabi	Adnoc	110			
Prirazlomnoye	Russia Siberia	Gazprom/Rosneft	150 (10)		600	
Roncador III	Brazil	Petrobras	145 (08)		2000 boe (tot)	Petrobras 100%
Sakhalin I	Russian Far East	ExxonMobil	250		2300	ExxonMobil 30%, SOGDC 30%, ONGC 20%, Russian Co's 20%
Salym fields-W,Upp,Vade	Khanty-Mansiisk	Shell/Evikhon	120 (09)		600	Salym Petroleum Development NV (SPD) 50% Shell, 50% OAO Evikhon $1billion project
Thunder Horse (inc. Nth)	GoM	BP	250	200	1500 boe	BP 75%, ExxonMobil 25%
White Rose	Eastern Canada	Husky Oil	100		230	Husky Oil
Onstream 2006						
Atlantis	GoM	BP	150		675boe+200b	BP 56%, BHP 44%
Agbami	Nigeria	ChevronTexaco	225		1000	ChevronTexaco 59%, Statoil 15% ??
Benguela-Belize (BBLT1)	Angola	ChevronTexaco	100		400	ChevronTexaco 31%, Agip 20%,Total 20%,Sonangol 20%, Galp 9%
Bu Hasa development proj.	Abu Dhabi	Adco	250			
Buzzard	UKCS	Encana	180 (07)		400	Encana 43%, Intrepid Energy 30%, BG Group 22%, Edinburgh Oil & Gas 5%
Dalia	Angola	Total	240		1600	TotalFina Elf 40%, BP 16.67 %, Statoil 13.33%, ExxonMobil 20%
Enfield	Australia NW Shelf	Woodside	100		363	Woodside Petroleum 100%
Kashagan Ph1	Kazakh Caspian	Agip (Eni)	450	1,500	9,000	Agip/Total/ ExxonMobil/Shell 20.37%, ConocoPhillips 10.19%, Inspex 8.33%
Kizomba B	Angola	ExxonMobil	250		1000	ExxonMobil 40%, BP 26.66%, Eni 20%, Statoil 13.33%
Marlim Sul III	Brazil	Petrobras	100 (07)		2679 boe (tot)	Petrobras 100%
Tengiz expansion*	Kazakhstan	ChevronTexaco	200 to 450		7,000	ChevronTexaco 50%, ExxonMobil 25%, KazMunaiGaz 20%, LukArco 5%

Future oilfield projects with a peak production capacity of over 100,000 b/d

continued overleaf...

Project	Location	Operator	Oil Peak Flows (kb/d)	Gas Peak Flows mn cf/d	Reserves mn/b	Partners and shareholdings
Onstream 2007						
Lobito-Tombuco (BBLT 2)	Angola	ChevronTexaco	100 (09)		400	ChevronTexaco 31%, Agip 20%,Total 20%,Sonangol 20%, Galp 9%
Platina/Plutonio	Angola	BP	220		800	BP 50%, Shell 50%
Tahiti	GoM	ChevronTexaco	150?		700mn boe	ChevronTexaco 58%, Encana 25%,Shell 17%
Onstream 2008						
Kizomba C	Angola	ExxonMobil	250		1000	ExxonMobil 40%, BP 26.66%, Eni 20%, Statoil 13.33%
Marlim Sul IV	Brazil	Petrobras	120 (07)		2679 boe (tot)	Petrobras 100%
Kashagan Ph2	Kazakh Caspian	Agip (Eni)	900	1,500	9,000	Agip/Total/ ExxonMobil/Shell 20.37%, ConocoPhillips 10.19%, Inspex 8.33%
Onstream 2009						
Karachaganak Ph III & IV	Kazakhstan					
Onstream 2010						
Kashagan Ph3	Kazakh Caspian	Agip (Eni)	1,200	1,500	9,000	Agip/Total/ ExxonMobil/Shell 20.37%, ConocoPhillips 10.19%, Inspex 8.33%
Potential Projects						
Ahwaz Bangestan Devs	onshore Iran	NIOC/?	350			
Akpo	Deepwater Nigeria	S. Atlantic Pet.			625 boe	
Arash	Iran in Gulf	NIOC			683 boe	
Azadegan	onshore Iran	NIOC/?	100		2.5-3.5bn b	
Block 09-03	Vietnam Cuu Long Bas	Petrovietnam	100+?		300-400	
Ghawar Haradh Phase 2	Saudi Arabia onshore	Saudi Aramco	300			
Great White	GoM	Shell			500 boe	
Kharyaga	Russia Siberia	Total PSA			5200	
Khvalynskoye	Russian Caspian	Lukoil			627 boe	
Kirkuk Khurmala Dome Dev.	Iraq onshore	NOC	100			
Kushk	Iran	NIOC			1,000 boe	
Lungu	China Tarim Basin	Petrochina			500	
Majnoon	Iraq onshore	SOC	360			
Northern Fields Project	Kuwait	KOC/?	400			
Northern Territories 4flds	Russia Siberia	ConocoPhillips			1000	
Qatif field expansion	Saudi Arabia	Saudi Aramco	500			
Talanskoye	Russia Siberia	Being auctioned			832	
Val Gamburtsev	Russia Siberia	Yukos/Sibneft			600	
Vankorskoye	Russia Siberia	Shell/TFE PSA			900	
Verkhnechonsknoye	Eastern Siberia	TNK-BP?			1500	
Yuri Korchagin	Russian Caspian	Lukoil			879 boe	
Yuzhno-Shapinskoye	Russia Siberia	SeverTek			500	Lukoil Fortum
West Qurna Phase 2	Iraq onshore	SOC	650			

Future oilfield projects with a peak production capacity of over 100,000 b/d

Whether this skewing of future projects to Russia/FSU and Opec is seen as a curiosity or a concern largely depends on the degree to which western interests coincide with those of Russia and Opec. To date Opec has tended to favour prices rather higher than than western interests would prefer while the importance of oil exports to the Russian and FSU economies would suggest that they too would favour higher prices.

In terms of future production capacity the largest single unknown is the speed at which Iraq's production capacity can be restored and then expanded. The potential is certainly there (see Petroleum Review, July 2003) but the rate at which it can be developed is currently unknowable.

Although it is too early to be wholly certain there is mounting evidence that the discovery rate for major oil fields with reserves of over 500mn boe has fallen dramatically over recent years. IHS Energy, on a map of recent discoveries it supplies to its clients, records 28 discoveries of over 500mn boe in the three years 2000, 2001 and 2002. However, 16 of the discoveries were in 2000, eight in 2001 and just three in 2002. Broken down by discovery type this gives:

- 2000: 6 oil/gas finds, 7 gas/condensate finds, 3 gas finds;
- 2001: 2 oil/gas finds, 4 gas/condensate finds and 2 gas finds;
- 2002: 2 oil/gas finds (Shell's Great White and Petrobras' Jubarte) and 1 gas find.

This rapid decline in recent large discoveries may the explanation for why there are so few mega projects six years later, ie 2007-2008. A lack of recent discovery has also been seen in Russia, where IHS Energy records reserves replacement ratios of 17% in the last five years and 14% in the last ten years. Even Opec seems to be having difficulty replacing reserves with a replacement ratio of just 18.2% in 2002 (see Petroleum Review, November 2003).

The conclusion to be drawn appears to be that for the next four years a flood of new production is set to hit the market. Whether the volume and timing is of a magnitude that significantly depresses prices remains to be seen and will largely depend on whether existing flows are maintained and whether the sort of unpredictable events such as the production restrictions seen in Venezuela, Iraq and Nigeria over the last 12 months remain a feature of the market ●

While every effort has been made to esure that the data in the table is correct, if readers are able to fill in gaps or have better information the Editor would be very please to hear from them. Please contact: **cs@energyinst.org.uk**