Prices set firm, despite massive new capacity

Over the last two years Petroleum Review *has regularly updated its listing of the upcoming so-called 'megaprojects'. The aim of the listing is to attempt to answer the question as to whether sufficient oil is being developed to meet likely requirements going forward, writes* Chris Skrebowski.

This latest update – based on public sources of information – identifies a total of 16.65mn b/d of new capacity due onstream by 2010. This, in turn, is made up of 6.34mn b/d of incremental Opec capacity and 10.31mn b/d of non-Opec capacity additions (see p2 for basis of tabulation). This is directly comparable with the 16.5mn b/d identified by the consultant CERA in its recent report. However, CERA's happy conclusion that potentially price depressing excess supply was about to emerge does not appear to take project slippage and depletion fully into account and, therefore, appears highly optimistic.

Experience shows that between 10% and 20% of projects slip from one year to the next. As no company intends this to happen and there is no way it can be anticipated, the only way to deal with it is to continuously update the database. A recent example of this phenomenon is the BP-operated Thunder Horse project, where, following storm damage to the platform, start-up has moved from late 2005 to 1H2006. Project slippage does not mean that the capacity is lost, but merely postponed. This, however, will reduce the actual capacity increments each year going forward. The exact magnitude cannot be determined in advance – although 10% to 20% would be a reasonable rule of thumb.

Depletion modelling

Depletion is relatively difficult to model, but must be taken into account when determining future capacity additions. It is possible, and useful, to identify three sub-categories, or types, of depletion.

Type I depletion – is the normal loss of capacity in an oil field as production from wells in one field run down and are offset by new wells or increased production from other existing wells in the field. There is only limited public data available, apart from the North Sea, where decline rates of between 5% and 15% are reported and are typical of the main decline phase. The North Sea also shows that a proportion of the region's fields are able to finally stabilise production at about 10% of peak flows. There have also been reports (not fully corroborated) of 7% declines in Iranian fields and 6% declines in Saudi fields. Offshore fields, which, because of their economics require high flow rates and much more rapid and intensive development, tend to have the most rapid decline rates – often as much

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Project	Location	Operator	Oil peak flows (kb/d)	Gas peak flows (mn cf/d)	Reserves (mn b)	Partners and shareholdings
Onstream 2005						
Opec countries						
Bab North East	Abu Dhabi onshore	ADCO	+90 (2005)			ADCO 100%
Bonga	Nigeria OML 118	Shell	225	170	600	Shell 55%, ExxonMobil 20%, Total 12.5%, Agip 12.5%
Darkhovin Ph1	Iran	Eni/Naftiran	55			Eni 60% (on behalf of NIOC), Naftiran Intertrade (NICO) 40%
Northern fields incr.	Kuwait	KOC	+300			
Nowruz expansion	Iran expansion	Shell	+90			Shell buy-back from NIOC
Soroush expansion	Iran expansion	Shell	+100			Shell buy-back from NIOC
Non-Opec countries						
ACG magastructure Ph1	Azerbaijan	BP	+300 (2006)		6,000+	BP 34.14%, Unocal 10.28%, Socar 10%, Inpex 10%, Statoil 8.56%, ExxonMobil 8%
(Azeri-Chirag-Guneshli)	(Central Azeri)					TPAO 6.75%, Devon 5.62%, Itochu 3.92%, Delta Hess 2.72%
Adar Yale fields	Sudan	CNPC	250 (2006)			
Angostura Ph1	Trinidad	BHP Billiton	60 (2005)		300	BHP Billiton 45%, Total 30%, Talisman Energy 25%
Barracuda (25°API)	Brazil (Campos)	Petrobras	150 (2005)		770	Petrobras 100%
Baobab	Ivory Coast	CNR	65 (2006)	25		CNR 57.61%, Svenska Petroleum 27.39%, Petroci Overseas 10%, Petroci Holdings 5%
Caratinga (24° API)	Brazil (Campos)	Petrobras	150 (2005)		330	Petrobras 100%
Clair South	West of Shetland	BP	60 (2006)	15	250	BP 28.6%, ConocoPhillips 24%, Chevron 19.4%, Shell 18.7%, Amerada 9.3%
Kizomba B	Angola	ExxonMobil	250 (2005)		1,000	ExxonMobil 40%, BP 26.66%, Eni 20%, Statoil 13.33%
Kristin	Norway	Statoil	126 (cond)	530	220 (cond)	ExxonMobil 11%?
Mad Dog	Gulf of Mexico	BP	80	40	250 boe	BP 60.5%, BHP Billiton 23.9%, Unocal 15.6%
Mutineer-Exeter (Cnvr Basin)	NW Australia	Santos	85 (2006)	3	61	Santos 33.3977%, Kufpec 33.4023%, Nippon Oil 25.0%, Woodside 8.20%
Prirazlomnoye	Russia Siberia	Gazprom/Statoil	155 (2010)		610	Gazprom ?, Rosneft?
Sakhalin I (Chayvo field)	Russian Far East	ExxonMobil	250 (2006)	1,000	2,300	Exxon NG 30%, Sakhalin O&G 30%, ONGC Videsh 20%,SakhMNG 11.5%, RB-Astra 8.5%
Salym fields	Khanty-Mansiisk	Shell/Evikhon	120 (2009)		800	Salym Petroleum Development NV (SPD): Shell 50%, OAO Evikhon 50%
Sanha(cond),						

Future oil field projects with a peak production capacity of over 75,000 b/d

Project	Location	Operator	Oil peak flows (kb/d)	Gas peak flows (mn cf/d)	Reserves (mn b)	Partners and shareholdings
Bomboco(crude)	Angola	Chevron	100 boe (2007)			Sonangol 41%, Chevron 39.2%, Total 10%, Eni 9.8%
White Rose	Eastern Canada	Husky Oil	90 (2006)		230	Husky Oil 72.5%, Petro-Canada 27.5%
Onstream 2006						
Opec countries						
Bu Hasa development	Abu Dhabi	ADCO	180			ADCO 100%
Darkhovin Ph2	Iran	Eni/Naftiran	+160			Eni 60% (on behalf of NIOC), Naftiran Intertrade (NICO) 40%
Erha	Nigeria (OPL 209)	ExxonMobil	165		500	ExxonMobil 56.25%, Shell 43.75%
Ghawar Haradh Ph3	Saudi onshore	Saudi Aramco	+300			Saudi Aramco 100%
NEAD project****	NE Abu Dhabi	ADNOC	+110			ADNOC 100%?
Non-Opec countries						
ACG megastructure Ph2	Azerbaijan	BP	+500 (2008)		6,000+	See under Ph1 in 2005
Albacora Leste	Brazil	Petrobras	180 (2006)		700mn boe	Petrobras 90%, Repsol 10%
Atlantis	Gulf of Mexico	BP	150		675 boe	BP 56%, BHP 44%
Benguela-Belize (BBLT1)	Angola	Chevron	100 (2007)		400	Chevron 31%, Agip 20%,Total 20%,Sonangol 20%, Galp 9%
Buzzard	UKCS	Nexen	200 (200720/08)		550	Encana 43%, Intrepid Energy 30%, BG Group 22%, Edinburgh Oil & Gas 5%
Cachalote	Brazil	Petrobras			800	
Chinguetti Ph1	Mauritania offshore	Woodside	75		123	Woodside 53.85%, Hardman Res 21.6%, Roc Oil 3.69, Premier 9.23%, BG 11.63%
Dalia	Angola	Total	240		1,600	Total 40%, BP 16.67 %, Statoil 13.33%, ExxonMobil 20%
Enfield (+Laverda/Vincent)	Australia NW Shelf	Woodside	100	363		Woodside Petroleum 60%, Mitsui 40%
Golfinho Module I	Brazil (Espirito Santo)	Petrobras	100 (2007)	450		Petrobras 100%
Jubarte 1	Brazil (B60 Santos)	Petrobras	60 (2005)		540	Petrobras 100%?
Roncador II	Brazil	Petrobras	145 (2008)		2,700 (tot)	Petrobras 100%
Surmont (heavy oil by SAGD)	Canada, N Alberta	ConocoPhillips	100 (2012)		?	ConocoPhillips 50%, Total 50%
Syncrude Ph3	Canada, Athabasca	Canadian Oil Sands	100			Canadian Oil Sands 32%, Imperial Oil 25%, Petro-Canada 12%, Nexen ?%, others?%
Tengiz/Kololev expansion*	Kazakhstan	Chevron	298 to 450+	100	7,000	Chevron 50%, ExxonMobil 25%, KazMunaiGaz 20%, LukArco 5%
Thunder Horse (inc North)	Gulf of Mexico	BP	250 (2008)	200	1,500 boe	BP 75%, ExxonMobil 25%
Onstream 2007						
Opec countries						
Abu Hadriya/Khursaniyah/Fadhili	Saudi onshore	Saudi Aramco	+500	250	4,500; 500; 950	Saudi Aramco 100%
Azadegan (south part)***	onshore Iran	Inspex	260 (2012)		2,500–3,000	Pedco 25%, Japanese interests 75% (Inspex, Japex , JNOC , Tomen)
Bonga South + Aparo	Nigeria (OML 118)	Shell and Chevron	250		1,000	Shell 55%, ExxonMobil 20%, Total 12.5%, Eni 12.5%
Corocoro Ph1	Venezuela offshore	ConocoPhillips	75		450	ConocoPhillips 32.5%, PdVSA 35%, Eni 26%, Opic 6.5%
Non-Opec countries						
Golfinho Module II (28-40°API)	Brazil (Espirito Santo)	Petrobras	100 (2007/2008)		450	Petrobras 100%
Greater Plutonio (6 fields)	Angola block 18	BP	240		800	BP 50%, Shell 50%
Kikeh	Malaysia, off Sabah	Murphy Oil	120 (2009)		530	Murphy 80%, Petronas Carigali 20%
Lobito-Tombuco (BBLT 2)	Angola	Chevron	+100 (2008)		400+	Chevron 31%, Agip 20%,Total 20%,Sonangol 20%, Galp 9%
Long Lake (tar sands)	Canada, N Alberta	Nexen	70		1,900	Nexen 50%, OPTI Canada 50%
Mangala and Aishwariya	India, onshore Rajastan	Cairn Energy	80–100		600	Cairn Energy 70%, ONGC 30%
Peng Lai Ph2	China, Bohai Bay PL19-3	ConocoPhillips	190 (2009)		800	CNOOC 51%, ConocoPhillips 49%
Polvo (BM-C-8)	Brazil (Campos)	Devon Energy	50		50mn b+	Devon Energy 60%, SK Corporation 40%
Roncador III	Brazil	Petrobras	145 (2008)		2,700 (tot)	Petrobras 100%
Rosa (t'back to Girassol)	Angola block 17	Total	250, net+40		300	Total 40%, Esso 20%, BP 16.67%, Statoil 13.33%, Norsk Hydro 10%
Sakhalin 2	Russian Far East	Shell	+120			
Vankorskoye 2 fields	Russia Siberia	Shell/TFE PSA	216		900	
Onstream 2008						
Opec countries						
Agbami	Nigeria OPL 216, 217	Chevron	250 (2008)		800	Chevron 68.15%, Petrobras 13%, Statoil 18.85%
Akpo	Nigeria OML 130	Elf Nigeria (Total)	225 boe		590	Total 24%, NNPC %, Petrobras %, Sapetro %
Banyu Urip (Cepu block)	Indonesia offshore	ExxonMobil	170	20	700 in block	Under negotiation
Block 208 El Merk fields	Algeria	Anadarko	100			
Shaybah and Central fields expn	Saudi onshore	Saudi Aramco	+300			
Non-Opec countries						
ACG magastructure Ph3??	Azerbaijan	BP	+400 (2009)		5,400	See under Ph1 in 2005
Frade	Brazil	Chevron	110 (2007)		300	Chevron 42.5%, Petrobras, Nissho Iwai
Horizon Ph1 (tar sand)	Canada	CNR	110		3,300	CNR ???
Kashagan Ph1	Kazakh Caspian	Agip (Eni)	450 (2009)	1,500	10,000 (tot)	Eni/Total/ ExxonMobil/Shell 18.52% each, ConocoPhillips 9.26%, Inspex 8.33%,KMG 8.33%
Kizomba C (Mondo,Saxi,Batuq)	Angola	ExxonMobil	125		1,000	ExxonMobil 40%, BP 26.66%, Eni 20%, Statoil 13.33%
Marlim Leste	Brazil (Campos)	Petrobras	180 (2008)	6mn cm/d	150	Petrobras 100%
Marlim Sul III	Brazil	Petrobras	100		2,679 boe (tot)	Petrobras 100%
Moho-Bilondo	Congo (Haute Mer)	Total	90			Total 53.5%, Chevron 31.5%, Societe Nationale de Petroles du Congo (SNPC) 15%
Su Tu Trang (White Lion)15-1	Vietnam, Cuu Long	ConocoPhillips	100?		220	Petrovietnam 50%, ConocoPhillips 23.25%, KNOC 14.25%, SK Corp 9%, Geopetrol 3.5%
Shenzi	Gulf of Mexico	BHP Billiton	100			BHP Billiton ?%, BP ?%
Tahiti	Gulf of Mexico	Chevron	125	70	500mn boe	Chevron 58%, Statoil 25%,Shell 17%
Onstream 2009						
Opec countries						
Al Shaheen expansion	Qatar offshore	Maersk Oil	+210			
Corocoro Ph2	Venezuela offshore	ConocoPhillips	+45		450	ConocoPhillips 50%, PdVSA 24%, Eni 26%
Khurais	Saudi onshore	Saudi Aramco	1,200		3,000	Saudi Aramco 100%
Qatar GTL (Ph1)	Qatar	Qatar Shell Gas	70 (cond)	800		Qatar Petroleum?%, Shell ?%

Future oil field projects with a peak production capacity of over 75,000 b/d

Project	Location	Operator	Oil peak flows (kb/d)	Gas peak flows (mn cf/d)	Reserves (mn b)	Partners and shareholdings
Non-Opec countries						
Karachaganak Ph3 & 4	Kazakhstan	Eni and BG	+200?			Eni 32.5%, British Gas 32.5%, Chevron 20%, Lukoil 15%
Marlim Sul III (FPSO P56)		Brazil	Petrobras	100		
Marlim Sul IV (Semi tba)		Brazil	Petrobras	100		
New Canadian tar pit	Canada,, Athabasca	Imperial Oil	100			Imperial Oil ?%, ExxonMobil ?%
Onstream 2010						
Opec countries						
Usan/Ukot/Tongo	Nigeria (OPL 222)	Elf Nigeria (Total)	150		480+	Elf Nigeria 20%, Chevron 30%, ExxonMobil 30%, Nexen 20%
Non-Opec countries						
Jubarte 2	Brazil B60 Santos	Petrobras	60 (2005)		540	Petrobras 100%?
Kashagan Ph2	Kazakh Caspian	Agip (Eni)	+450 (2012)	1,500	10,000 (tot)	Eni/Total/ ExxonMobil/Shell 18.52% each, ConocoPhillips 9.26%, Inspex 8.33%,KMG 8.33%
Roncador IV (FPSO P54)	Brazil	Petrobras	150			
Uvatskoye	Russia Siberia	TNK-BP	200			
Onstream 2011						
Opec countries						
Qatar GTL (Ph2)	Qatar	Qatar Shell Gas	70 (cond)			Qatar Petroleum?%, Shell ?%
Onstream 2012						
Non-Opec countries						
Horizon Ph2 (tar sands)	Canada	CNR	+122		3,300	CNR ???
Kashagan Ph3	Kazakh Caspian	Agip (Eni)	+300 (2015)	1,500	10,000 (tot)	Agip/Total/ ExxonMobil/Shell 20.37%, ConocoPhillips 10.19%, Inspex 8.33%
Potential Projects						
Opec countries						
Ahwaz Bangestan devs	onshore Iran	Pedco?	+150			
Arash	Iran, in Gulf	NIOC			683 boe	
Azadegan (Northern part)***	onshore Iran	NIOC/?	400		2,500–3,000	
Hamrin	Iraq onshore (South)	SOC				
Manifa (Arab Heavy)	Saudi offshore	Saudi Aramco	300			Saudi Aramco 100%
Majnoon	Iraq onshore	SOC	360		12,100	
Minagish EOR project	Kuwait onshore	KOC	100			
Nuayyim (Arab Super Light)	Saudi onshore	Saudi Aramco	75		250	Saudi Aramco 100%
Northern Fields 'Project Kuwait'	Kuwait onshore	KOC/?	+450			
Ramin	Iran, near Ahwaz	NIOC			1,500	
Sincor II	Venezuela	Total	180			
Subbah-Luhais	Iraq onshore (South)	SOC				
Su Tu Nau (Brown Lion)	Vietnam block 15-1	ConocoPhillips				PetroVietnam 50%, ConocoPhillips 23.3%, KNOC 14.2%, SK Corp 9%, Geopetrol 3.5%
Tomoporo (23° API)	Venezuela	PdVSA	250?		1,000	PdVSA, but private investors to 49%
Upper Zakum redevelopment		Abu Dhabi	ExxonMobil	+650?		ExxonMobil to 28%
Yadavaran (Khushk, Hosseinieh)	Iran onshore	NIOC/Sinopec	300	1,500+		Nioc 80%, ONGC 20%
West Qurna Ph2	Iraq onshore	SOC	650		11,300	
Non-Opec countries						
BC-2	Brazil (Campos)	Total				
BS-4	Brazil offshore	Shell				
Block 09-03	Vietnam, Cuu Long	Petrovietnam	100+?		300–400	
Block 18 West (3 fields)	Angola block 18	BP			250–300	
Block 31 Nth E Plutao+3 dev	Angola block 31	BP			500 in block 31	BP 26.67%, ExxonMobil 25%, Sonangol 20%, Statoil 13.33%, Marathon 10%, Total 5%
Block 31 S-Ceres/Palas/Juno	Angola block 31	BP			500 in block 31	BP 26.67%, ExxonMobil 25%, Sonangol 20%, Statoil 13.33%, Marathon 10%, Total 5%
Block 32 Perpetua et al	Angola block 32	Total			4 discoveries	Total 30%, Marathon 30%, Sonangol 20%, ExxonMobil 15% and Petrogal 5%
Fort Hills oil sands	Canada, N Alberta	PetroCanada	190		2,800	Petro-Canada 55%, UTS Energy Corp 30%, Teck Cominco 15%
Great White	Gulf of Mexico	Shell			500–1000 boe	Shell ??
Jeruk	Indonesia, offshore Java	Santos			170 boe	Sampang PSC: Santos 45%, Singapore Petroleum Co (SPC) 40%, Cue Energy 15%
Kebabangan	Malaysia, off Sabah	ConocoPhillips			200–300	Block J: Petronas Carigali 20%, ConocoPhillips 40%,Shell 40%
Kharyaga	Russia Siberia	Total PSA			5,200	
Khvalynskoye	Russian Caspian	Lukoil/KazMgaz			627 boe	
Kirkuk Khurmala Dome	Iraq onshore	NOC	100			
Kizomba D	Angola block 15	ExxonMobil				
Kurmangazy	N Caspian (Russ/Kaz)	Rosneft/KMG	600?		7,000	Rosneft 25%, other Russian 25%, KazMunaiGaz 25%, Total 25% (tbc)
Lungu	China Tarim basin	Petrochina			500	
Marimba Leste (FPS-Semi)	Brazil (Campos)	Petrobras				
Marimba Leste (FSO)	Brazil (Campos)	Petrobras				
Northern Lights oil sands	Canada, N Alberta	Synenco	100			Synenco 60%, Sinopec 40%
Northern Territories 4flds	Russia Timan-Pechora		Lukoil, ConPhillips		990	
Stybarrow	Australia Exmouth basin	BHP Billiton	100		90	BHP Billiton 50%, Woodside Petroleum 50%
Su Tu Vang (Golden Lion) 15-1	Vietnam, Cuu Long	ConocoPhillips	100?		400?	Petrovietnam 50%, ConocoPhillips 23.25%, KNOC 14.25%, SK Corp 9%, Geopetrol 3.5%
Suncor (tar sands)	Canada		100			
Talanskoye	Russia Siberia	Surgutneftegas			832	
Tiof	Mauretania	Woodside			298	
Tsentralnoye block	Russia/Kazakh Caspian	Lukoil/Kazakhoil			3,800	TsentrKaspneftegaz JV : Kazakhoil 50%, Lukoil and Gazprom 50%
Val Gamburtsev	Russia Siberia	Yukos/Sibneft			600	
Verkhnechonskoye	Eastern Siberia	TNK-BP?			1,500	
Yalamo-Samur	Russia/Azeri Caspian	Lukoil			3,750 boe	
Yuri Korchagin	Russian Caspian	Lukoil			879 boe	
Yuzhno-Shapinskoye	Russia Siberia	SeverTek			500	Lukoil Fortum

*limited production from 12/2004, Vadelyp 2006; ** 250,000 b/d 2007–2009; *** 5,000mn barrels for field; **** Al Dhabiya, Rumaitha, Shanaget

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as 15%/y. Companies really only suffer the impact of Type 1 depletion when a field is fully drilled up and there is no possibility of offsetting the declines.

However, with the consultant IHS Energy now reporting to various conferences that 90% of known reserves are in production, more and more fields around the world are moving into their decline phase. One estimate is that as much as 70% of the world's producing oil fields are now in decline.

Type II depletion – is when a company, or country, can offset field declines in one part of the country with expansion in another part. Because public data is collected on a national basis, there is only limited data available on Type II depletion – although its magnitude is likely to be the same as for Type I.

Type III depletion –is when a country produces less oil in a year than it did in the previous year. This can be identified quite readily from public production databases (see *Petroleum Review*, August 2004 and August 2005). Type III depletion will increase as additional countries move into decline, but will reduce as the volumes produced by the countries in decline decreases. In 2003, Type III depletion was running at around 1.1mn b/d, but in 2004 it fell back to around 900,000 b/d (significant revisions to production data tend to confuse the picture). Over the next few years a number of countries are likely to move into decline – Denmark, China, Malaysia, Mexico, Brunei and India are the obvious candidates and account for over 12% of global production – so a reasonable working assumption is that Type III depletion will increase, although with something of a saw-tooth profile.

Recent statements by oil companies (*Petroleum Review*, August 2005) have tended to indicate that overall depletion (Types I, II and III) is running at between 4% and 6%. Analysis of recent company production (see p24) tends to confirm that using a 5% figure is a reasonable approximation. Demand growth is subject to quite rapid swings, but appears to average around 2%/y. By combining these various pieces of information, it is possible to determine whether the market will tighten or weaken and whether 'peak oil' is a likely outcome in the period to 2010 (see **Table 2**).

In 2004, effectively all the world's spare capacity was used up in meeting unexpectedly rapid demand growth. It is not at all clear if the world's oil companies can provide an incremental 3mn-plus b/d from all the small, untabulated projects and infill drilling going forward year after year. The world has now reached the point where the volumes lost to depletion are much larger than the levels of likely new demand. This means total increments requred (new demand plus depletion) are running at around 7%/y, while the largest supply increments in 2006 and 2007 are contributing 3.6% and 3.5%.

It would seem most unlikely that small projects and infill drilling could account for the remaining required 3.5%. The inescapable conclusion is that oil prices will have to remain high enough to destroy demand, bringing supply and demand back into balance.

	2004	2005	2006	2007	2008	2009	2010
Oil demand	82.1*	83.5*	85.3*	87.0[+]	88.8[+]	90.5[+]	92.3[+]
Demand increase	2.9	1.4	1.8	1.7	1.8	1.7	1.8
Supply increase**	1.1	2.4	3.1	3.1	2.8	2.8	1.5
Opec	0.3	0.9	0.9	0.9	1.0	1.4	0.9
Non-Opec	0.8	1.5	2.1	2.1	1.8	1.4	0.6
5% depletion	4.1	4.2	4.3	4.4	4.4	4.5	4.6
Extra volume required[++]	2.3	3.2	3.0	3.0	3.4	3.4	4.9

*Source: *International Energy Agency (IEA)* Oil Market Report*, September 2005; **from* Petroleum Review *megaprojects database; [+]calculated on 2% growth; [++]volume required from infill drilling and the small projects not tabulated in the megaprojects database*

Table 2: Oil demand, supply and depletion to 2010 (mn b/d)