The Oil Drum
DISCUSSIONS ABOUT ENERGY AND OUR FUTURE

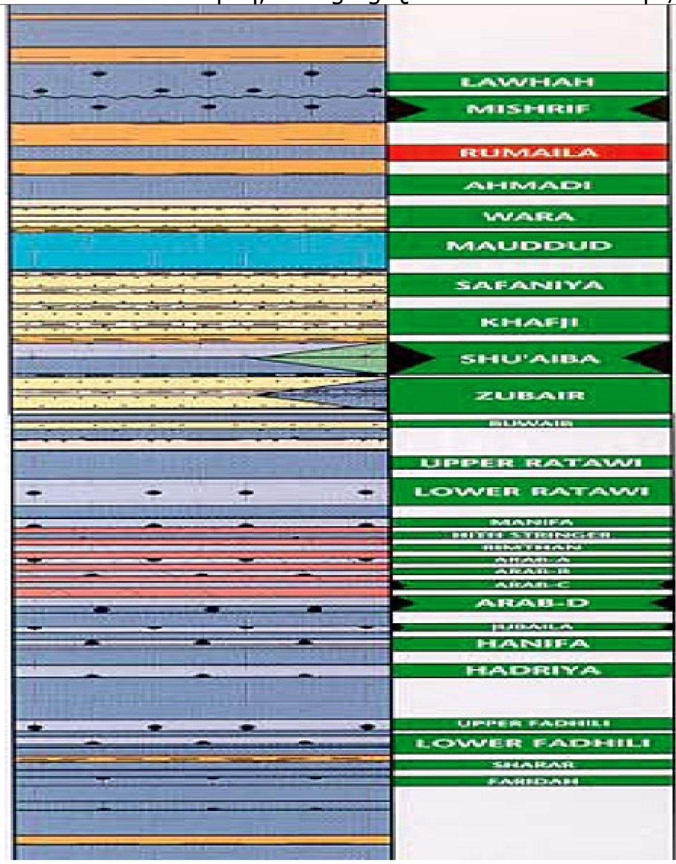
Tech Talk - Production from Abqaiq, an Aging Queen

Posted by Heading Out on April 9, 2012 - 10:57am
Topic: Supply/Production
Tags: abqaiq, arab d, crude oil production, hanifa, mrc, saudi arabia, smartwells
[list all tags]

The topic of rising gas prices is pervasive, and at a breakfast meeting last Monday, Richard Williams, a friend, commented that he had seen some cores from Saudi Arabia, and that they looked so weak, he felt he could put his fist through them. It reminded me of a passage that Glenn Morton had also caught in Ken Deffeyes book "Hubbert's Peak":

> Most massive and nonporous limestones contain textures made by invertebrate animals that ingest sediment and turn out fecal pellets. Usually, the pellets get squished into the mud. Rarely do the fecal pellets themselves form a porous sedimentary rock. In the 1970s, the first native-born Saudi to earn a doctorate in petroleum geology arrived for a year of work at Princeton. I used the occasion to twist Aramco's collective arm for samples from the super-giant Ghawar field. As soon as the samples were ready, I made an appointment with our Saudi visitor to examine together the samples using petrographic microscopes. That morning, I was really excited. Examining the reservoir rock of the world's biggest oil field was for me a thrill bigger than climbing Mount Everest. A small part of the reservoir was dolomite, but most of it turned out to be a fecal-pellet limestone. I had to go home that evening and explain to my family that the reservoir rock in the world's biggest oil field was made of shit.

Such it may be, but it has supplied a form of liquid gold to the world for the past fifty years. Ali Naimi, the Minister for Petroleum and Mineral Resources in Saudi Arabia, had an article in the Financial Times in which he re-iterated that the Kingdom can produce some 12.5 mbd, and that it thus has more than enough in reserve to meet any supply shock that might be reasonably foreseeable at present. (Texas was in the same position and proved its capacity on occasion, before it lost it). There are times when the true size of the Saudi reserve is not fully recognized, as the late Matt Simmons noted in his early presentations on the subject.



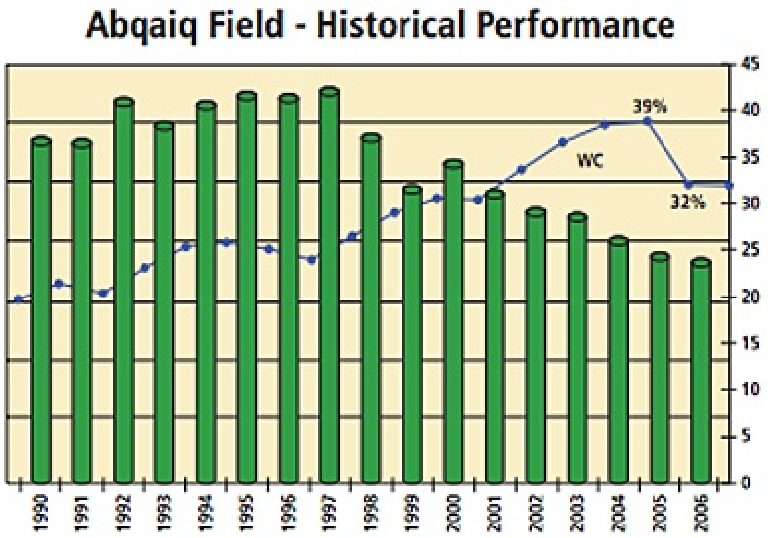
Some of the reservoir rocks found in Saudi Arabia - there are over 300 recognized reservoirs. (Matt Simmons at the CSIS meeting, Feb 2003)

In writing about the oil production from the most active drilling sites in the United States, the last post noted that there are thousands of wells being drilled in the Bakken and Eagle Ford regions, and that they average less than 100 bd of production. Consider that there are about 100 rigs in Saudi Arabia, and that in 2010 they drilled some 386 wells in a country that had a total of 2,880 producing wells in 2010, not counting the 527 wells in the Saudi:Kuwait Neutral Zone. (In perspective, there are roughly a million producing wells around the world). Those wells produced roughly 8.1 mbd on average in 2010, or an average of 2,800 barrels a day. (OPEC Annual Statistical Review 2010:2011).

However, even the most massive of reservoirs must begin to run out of crude over time, and that has been an area of concern, particularly in the older fields perhaps best exemplified by the adjacent fields of Abqaiq and Ghawar. The first well at Abqaiq was spudded in August 1940, not that much later than the first oil wells at Dammam. At that time, the company now known as Aramco had 3,229 Saudi employees, 363 Americans, and 121 other nationalities working to produce some 15 kbd.

Location of Abqaiq relative to Dammam – the red line (derived from [Joules Burn's post]) shows roughly the center-line and linear extent of the field.

The EIA reported in their last [Country Analysis] brief that in 2010, Abqaiq was still producing at 400,000 bd, but that the available reserves for the field had been depleted by 74%. Times have changed from those early days, however, and (as the late Matt Simmons noted in 2008) all the 40,000 to 60,000 bd wells that existed in Abqaiq have long stopped producing at that rate, and the average has fallen by an order of magnitude.



Historic production from Abqaiq including water cut ([Abduldayem et al])

I am going to append an abbreviated and slightly modified description that I gave in an earlier post at this point, because in the next couple of posts, understanding a little of the technology is going to be helpful. It begins with a simple model, and does not get very complicated.

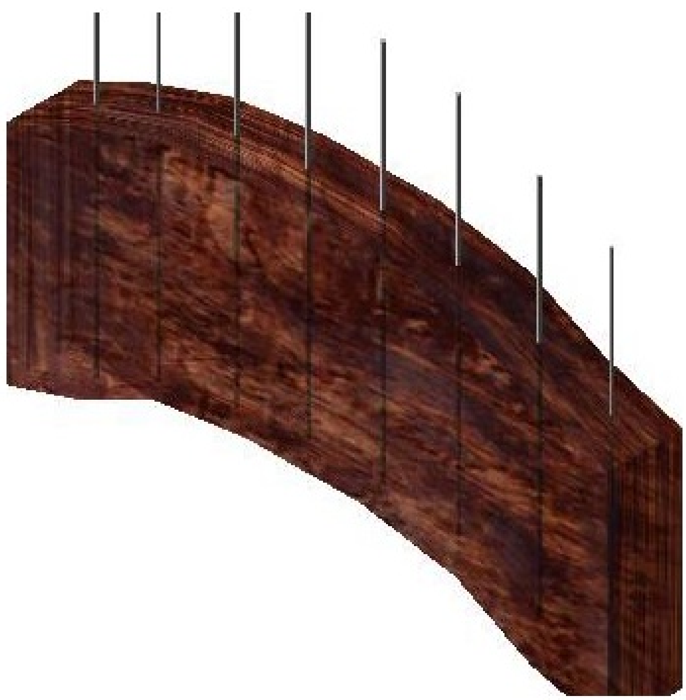
. . . .

Assume that there is a layer of rock that is 300 ft thick, five miles wide and thirty miles long. This has, over time, been folded in the middle, so that it now has trapped oil within all the pores of the rock. And, for the sake of discussion, let's assume that it has a porosity of 20%. This gives a very rough initial approximation to the conditions of the Arab D horizons at Abqaiq.

Doing the arithmetic - 300 x 5 x 5280 x 30 x 5280 = 1,254,528,000,000 cu.ft. At 20% porosity, this means that some 250,905,600,000 cu. ft. are not rock, and in this case are going to be full of fluid. This is equivalent to 1,876,773,888,000 gallons or 44,685,092,571 barrels of oil. This is, roughly 45 billion barrels of oil. That's how much is there, or the oil initially in place. (We're neglecting for now any water that is also in the rock).

This is a relatively light oil (API gravity 37 deg) that flows through the cracks in the rock quite easily. There are a lot of these fractures, and it doesn't stick to the rock that tightly, so the assumption is made that production can get out some 50% of the original oil in place. So, at this point we can say that the ultimate resource recovery (URR) is going to be 22.5 billion barrels.

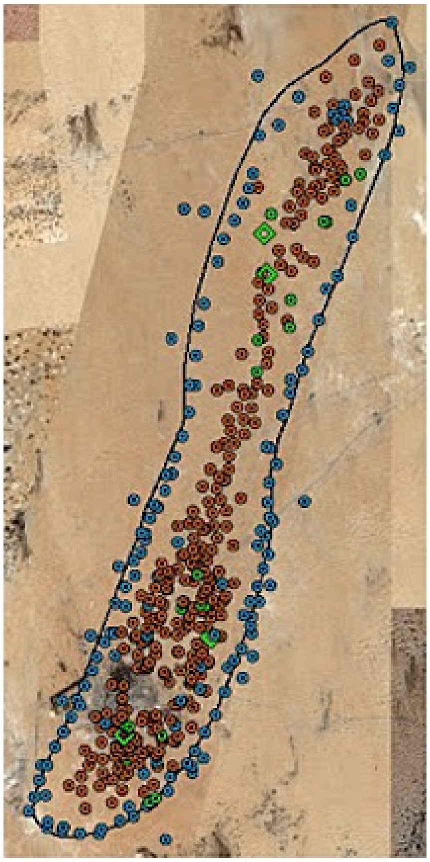
When production began, vertical wells were drilled a quarter of a mile apart. Consider, therefore, a one-quarter-mile section of the reservoir, taken along the length. If the slice is five miles long, then it has 20 wells set along the section, so that each well will pull the oil out of a box that extends out one-eighth of a mile laterally from the well, out toward the next. The total recoverable oil for each well is roughly 10 million barrels, or 30,000 barrels per foot of the oil well in the reservoir.



Showing location of wells quarter-mile apart and in a quarter-mile thick slice along the reservoir. The rock thickness is exaggerated and this is not to scale.

The rate at which the oil flows into the well is related to the difference in pressure between the oil in the rock and the fluid in the well, the frictional resistance of the rock to the oil flow through it, and the length of the well that is exposed to the rock. Let us assume that the rock resistance remains the same, and that production varies directly with changes in the pressure difference and the length of the exposure. And let us start by assuming that the well produces 3,000 barrels of oil a day (i.e. 10 barrels per foot of well exposed to the rock). Then, in the course of a year, the well will produce one million barrels of oil.

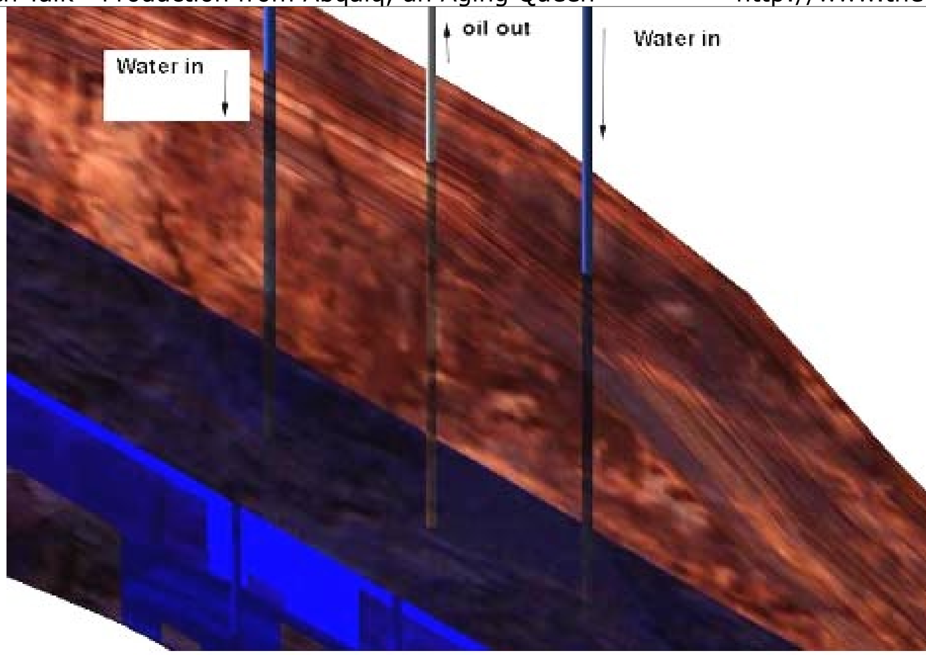
After production begins, however, the volume coming out of the well will, if nothing else is done, begin to decline. This is because as the oil leaves the reservoir, so the pressure on the oil reduces, and with a lower driving force, the flow slows down. To counteract the loss in pressure through the fluid loss, water can be added to the reservoir. This was initially achieved by adding water wells around individual production wells, but this was later changed so that the water is, instead, fed to wells around the perimeter of the field. Joules Burn showed how these were laid out at Abqaiq in an earlier post.



Water injection wells (blue) around the perimeter of Abqaiq, with production wells in red and green.

(Joules Burn)

If the water enters the reservoir beneath the oil, then it will fill holes left as the oil leaves and maintain pressure in the oil. The oil flow will not drop as fast, and production rates will increase (note that when this was done at Berri, it took a field that was producing at 155 kbd in 1971 and raised production to 800 kbd in 1976 when production peaked).

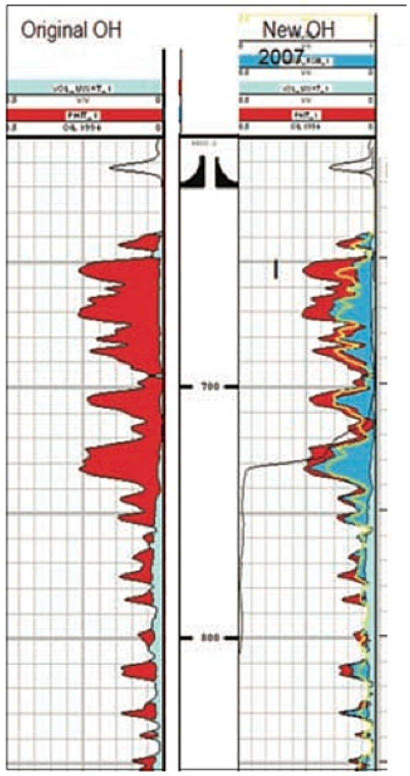


Initial pattern of water flood, adjacent wells flood under the producing central well

Production per well will not return to peak values, however, and it will continue to decline with time. To explain why, return to the model calculation. If four million barrels have been removed from the well, then as the water fills the void left beneath the oil and compresses the fluid back to the original pressure (we're neglecting the gas issue for now), it will now only occupy 60% of the original space, or the top 180 ft of the reservoir. With the same driving pressure, we will now only get 60% of our original flow, because the length of the well exposed to the rock has been reduced (and flow is related to length and pressure).

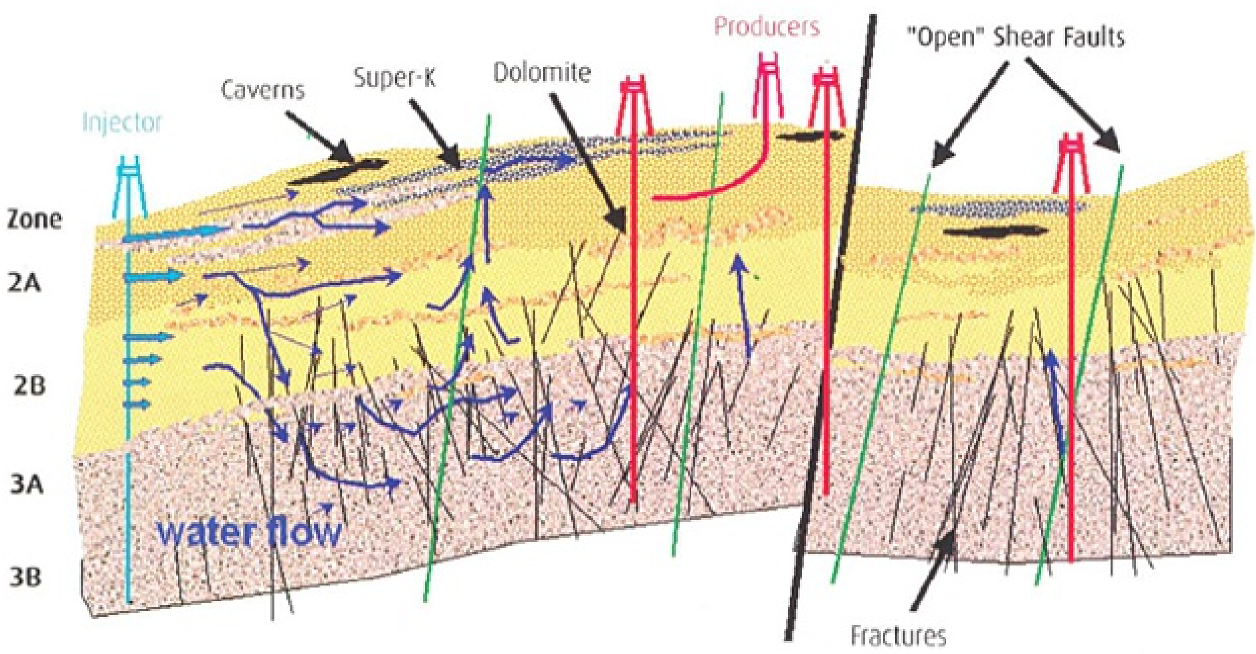
This decline in production will continue each year since the flow will decline as the length of exposed well in the rock gets smaller, with the water rising up behind the oil. For example, assume that in the next year the well will produce at 1,800 bd (10 barrels/day/ft), then at the end of that year it will have delivered (simplifying) 650,000 bd of oil, and so the volume of oil will be reduced by (roughly) 11% of the 6 million barrels that were left, and so the following year, the production will come from only 160 ft of the reservoir, and at the same reservoir pressure, the flow will be reduced because of the shorter exposed length. And the flow will accordingly also be reduced by 11%, assuming that the overall area remains the same. (Some folks might call this depletion, and it is the decline in production with time).

One of the reasons that this is a simplified explanation is that the water does not fully displace the oil, but only some of it, and thus there will be some oil left that can be recovered later in the process. This can be illustrated by looking at open hole (OH) well logs from a survey done in the region which shows the relative quantities of oil, (red) and water (blue) over the reservoir column before and after the water flood - the well was shut-in prior to 2007.



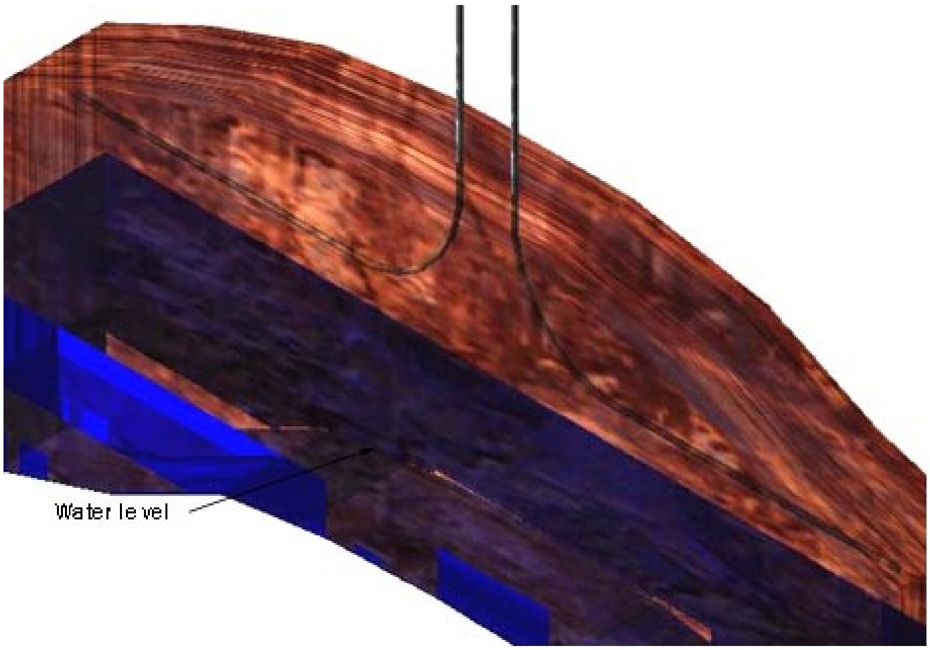
Open hole surveys of a water-flooded well, before and and after production, showing as a function of depth, the relative oil (red) and water(blue) content. ([Mark Ma et al](#))

There are ways in which the relative penetration of the water through the formation can be controlled, so that more of the oil is initially moved and less is left in place. This requires detailed knowledge of the reservoir, and knowing where zones of high permeability exist that can otherwise allow water to bypass oil. (These are the Super K layers shown below, as well as the fractures).



Reservoir characterization (Saudi Aramco via Matt Simmons 040224)

In order to overcome the problem of declining production over time, and as the water flood rises up the well, the alternative (which has not been around that long) is to drill the wells horizontally. These wells can be drilled over the full two-and-a-quarter miles from the center out to the edge of the reservoir, and just two would have the same exposed length in the reservoir as forty of the original wells. Now the exposed length to the oil stays the same, and at a constant pressure (held through water injection) production from the horizontal wells may reach 18,000 barrels of oil a day.



Water flood under horizontal wells, in this ideal case the water is fed from the outside of the reservoir and rises as a steady horizontal lift over time - until it reaches the wells.

When horizontal wells were introduced (1992), the field had already been in production for decades. Thus, while horizontal well technology allowed some gain in daily production, the rate of oil removal still had to be controlled in order to maximize overall total recovery. And thus, from time to time, the field was “rested.” In addition, over the years, smart well technology has been introduced, with isolating valves located along the horizontal section of the well, so that should water break through at one section, this can be shut off from the rest of the well, which can then continue to produce.

As the technology improved over the life of the field, oil was found in an additional mile of rock to either side of the zone that had been initially identified and the field extended about seven miles longer than originally anticipated. However, with the new additions, and as the field finally began to play out, it turned out that the average thickness of the carbonate grainstone was only 240 ft. Repeating the calculation changes the estimate of the original oil in place to be some 62 billion barrels. This change in reserves as the field is developed is not uncommon in oil fields, and is one of the ways in which reserves grow, often quite significantly, after the field has started to be developed.

(The above exemplary numbers, other than the geometric size of the field and its porosity and depth, were invented to illustrate the developments of the technology that have been applied to that field). The oil has a 36deg API, with a gas/oil ratio of 860 cf/barrel. (It is also sour). The rock permeability is 400 millidarcies in the Arab D formation (this info is from "Twilight").

The first well at Abqaiq was spudded in [August 1940](). It began production at 9,720 bd in [October 1940](), but had to be temporarily shut-in the following February because of the adjacent war.

Early development was slow, but began to pick up as the conflict moved further away.

> If the expansion of 1936 had struck some of them as a period of hectic confusion, this 1944 expansion struck them as bedlam. Their goal by the end of 1945, they were told from San Francisco, was 550,000 barrels a day, nearly 25 times what they were turning out now in their standby operation, and much more than the capacity of their existing wells. There would have to be a massive drilling program involving perhaps 20 strings of tools, and drilling that many oil wells meant developing adequate water supplies both at Abqaiq and at Qatif, where they had been instructed to put down a wildcat. . . . . By 13 June, too, Phil McConnell had entirely shut down the Abqaiq field after completing No. 5, and had diverted his entire Drilling Department to Ras Tanura.

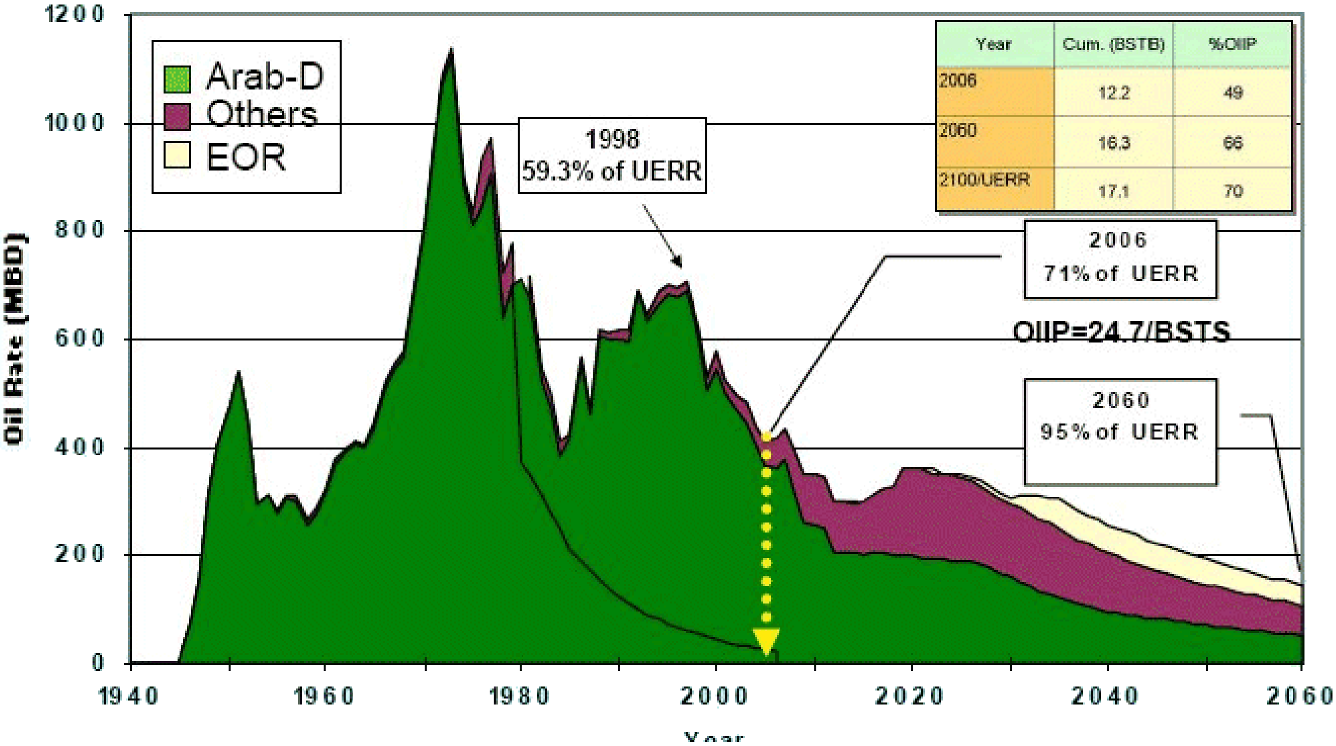
By 1962, only 72 wells had been drilled in the field. At the same time the gas was being extracted with the oil, and 50% of it was being used. Most of it was pumped back underground to maintain pressure and in some cases it was mixed with LPG (liquefied petroleum gas), and this helped dilute and increase the flow of oil from the reservoir. (But sometimes it did not work). It was used in the Ain Dar part of the Ghawar field and right next door to Abqaiq. But in 1982 the gas was collected for sale abroad.

By 1972, Aramco was drilling a well at the rate of 1 every 2.1 days. Shortly thereafter, Abqaiq peaked at 1,094,062 bd. In the area of Abqaiq, there were four drilling rigs and five workover rigs in the period around 1977, as the field fell back to a production of less than 800,000 bd. By 1981, production was down to 652,000 bd. In the mid-80's it was partially shut-in, and flow was reduced to 200,000 bd as demand declined.

And while the rest of Saudi production continued to grow, in 1988 it had 550 wells in production; by 1990 Abqaig had only 47 flowing wells, and by 2002 had dropped to 500,000 bd. It is currently 73% depleted, according to Aramco in 2004 and 74% according to the EIA . Horizontal wells were introduced in 1992, and maximum reservoir contact (MRC) wells with 15,000 ft of contact have been extensively used. Since 2004, Aramco has also gone back into “dead” wells with perhaps 10 ft of remaining oil and run short laterals (up to 1,000 ft long) across the top of the reservoir to gain that additional production. These typically produced around 1,000 bd for six months before water breakthrough. By combining those into MRC layouts, production could be increased to 4-5,000 bd and held for a year before watering out.

Now, beyond this point there are some conflicting numbers. Let me just list some of the information that is out there.

In the 50 years since discovery, it yielded 7.5 billion barrels of oil.

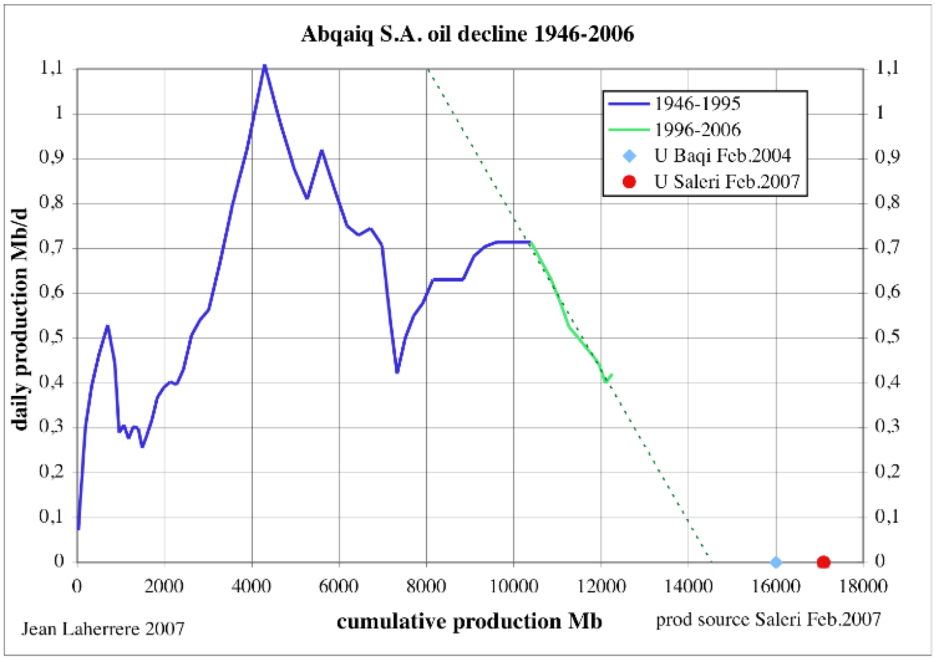


Abqaiq production history from Saleri via [Joules Burn](#)

The [EIA](#) considers that Abqaiq has 17 billion barrels of proven reserves. This is in contrast with the recent "World Energy Outlook 2005", which projected - through 2004 - that Abqaiq had 5.5 billion barrels remaining, and had produced some 13 billion. It uses IHS data for its projections. (But it got the start date wrong as well).

From that data, quoted by [Jean Laherrere](#), one can estimate the total oil contained in the field. Using their anticipated total of 19 billion barrels, and that this is considered to have a recovery factor of 60%, indicates that the overall oil in place is about 31 billion barrels. This is about half of the theoretical prediction I had made, using total volume and porosity, but given the variations in geology over the region, that the field has about 50% of the oil that the general assumption predicted is not bad.

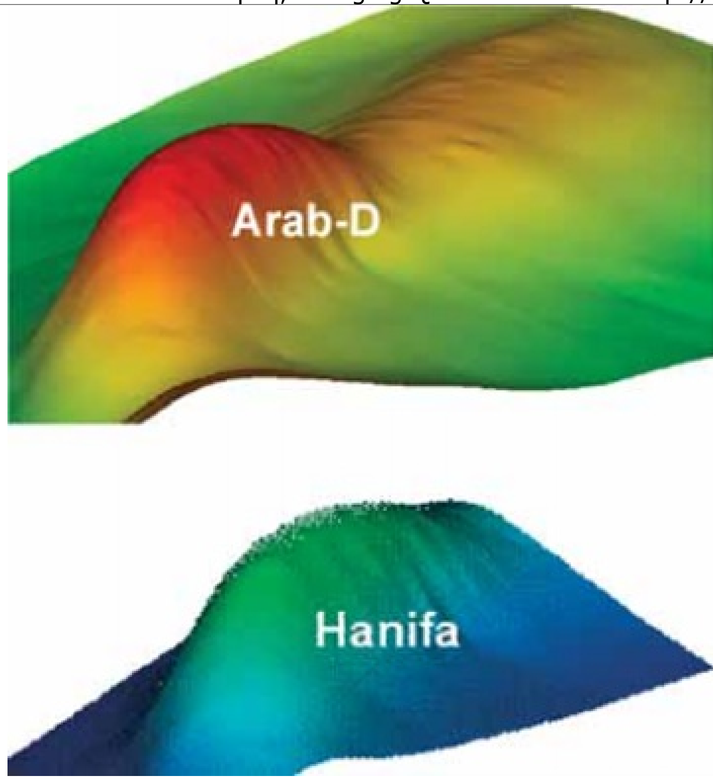
However, using the Aramco statement that the field is 73% depleted implies that the total oil that can be recovered from the field is around 11 - 12 billion barrels, which is in line with an HL projection created by Jean Laherrere.



Production for Abqaiq (Jean Laherrere)

The above presentation also assumes only production from the upper (Arab D) reservoirs available at Abqaiq. Joules Burn has, however, carried out a detailed analysis looking at additional production that can be achieved from the underlying Hanifa reservoir, which is 450 ft lower, is some 300 ft thick, and has a higher porosity (perhaps 30%). Unfortunately, as he points out, the permeability of the rock is much poorer than that of the Arab D, and thus production has not been as easy from the reservoir, nor can as high an overall yield be anticipated.

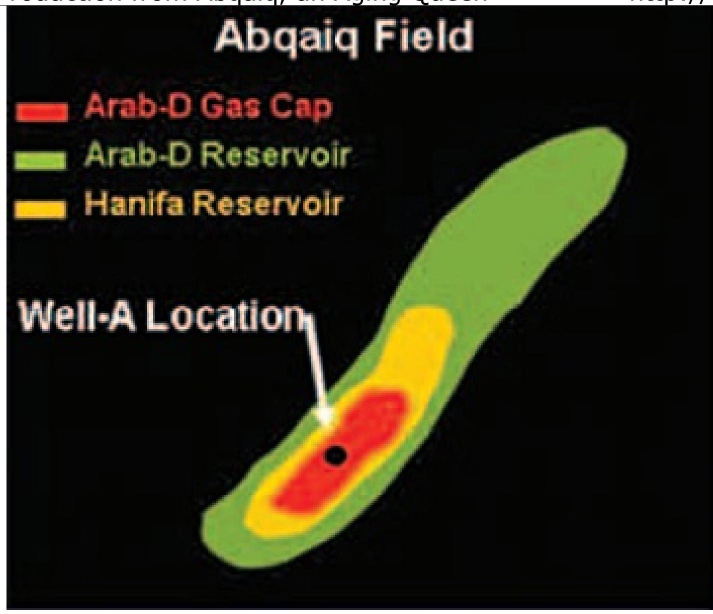
Nevertheless, this explains why production levels of up to 434,000 bd can be achieved. However, while there is a considerable oil resource in the lower reservoir, it is not as extensive as the Arab D.



Relative size and position of the Hanifa reservoir under the Arab D at Abqaiq (Abdulayem et al)

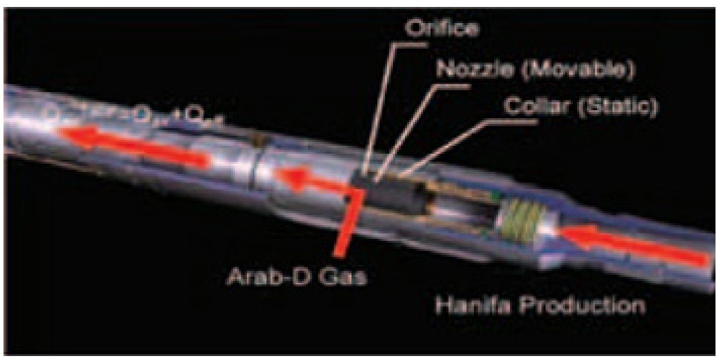
Production from the Hanifa reservoir began in 1954 and was limited, since with a matrix permeability of only 1-2 millidarcies, much of the flow relies on fractures in the rock for production. (The Arab D has a permeability of some 400 millidarcies). Fractures do extend between the two reservoirs and so there has also been some migration of oil up into the overlying reservoir.

As the field has aged, there is some problem in achieving enough pressure in the center (crest) of the field when the water is being injected only at the perimeter. Thus, as the field now enters the latter stages of production, a novel solution to extracting the oil has been tested. It is referred to as a SmartWell technology, and simplistically uses the gas in the gas cap as it enters the well through a choked valve, to create enough suction in the well as to draw the underlying oil into the lower section of the well, and thence be taken with the gas to the surface.



Relative size of the Hanifa reservoir under Abqaiq ([Al-Otaibi et al])

The gas enters the well through side vents and a constriction in the well (the collar) which generates the suction needed.



The use of the gas cap to power production from the Hanifa at Abqaiq ([Al-Otaibi et al])

While the idea is ingenious, the use of the gas cap to draw out the remaining oil from the field does suggest that the age of Abqaiq is coming to a close. Aramco has [recently stated] that, using EOR they anticipated that they may get up to 80% of the recoverable oil, although they are now running at 40% water cut. By 2006, some [60% of the oil] initially in place (OIIP) had been produced. [Joules' post] goes into more detail on the field with a greater discussion of the well patterns and what they mean.