The depletion of Abqaiq

Posted by Heading Out on August 20, 2006 - 11:52pm
Topic: Supply/Production
Tags: abqaiq, depletion, horizontal wells, peak oil, waterflood [list all tags]

This is the third post on the life of a large oilfield, after first looking at a very idealized outline of how a major field might be developed, in the second post I gave some of the events that happened at Abqaiq, which is one of the great oilfields of Saudi Arabia, and which approximated my model. What I would like to try now is to explain some of the reasons that the reality is quite a bit different from the ideal, and some of the geological factors that make the considerable difference between the two.

To begin, Abqaiq, like most giant fields, has been around for a long time, and when it was first developed, by a relatively small group during the Second World War, there were many other things going on that limited development so that it took 4 years to go from drilling the first well to the fifth. Technology was not nearly as advanced as it is now, and the wells were spaced considerably further apart than the spacing I placed mine at in the model. Further while I had estimated the OIP as being some 62 billion barrels, based on porosity, in reality the number was half that. I am grateful that both westexas and plucky underdog had the reasons for this.

One is the water saturation (original water in the rock - which I had neglected) and the other is the Oil Formation Volume Factor. To allow PUD to explain

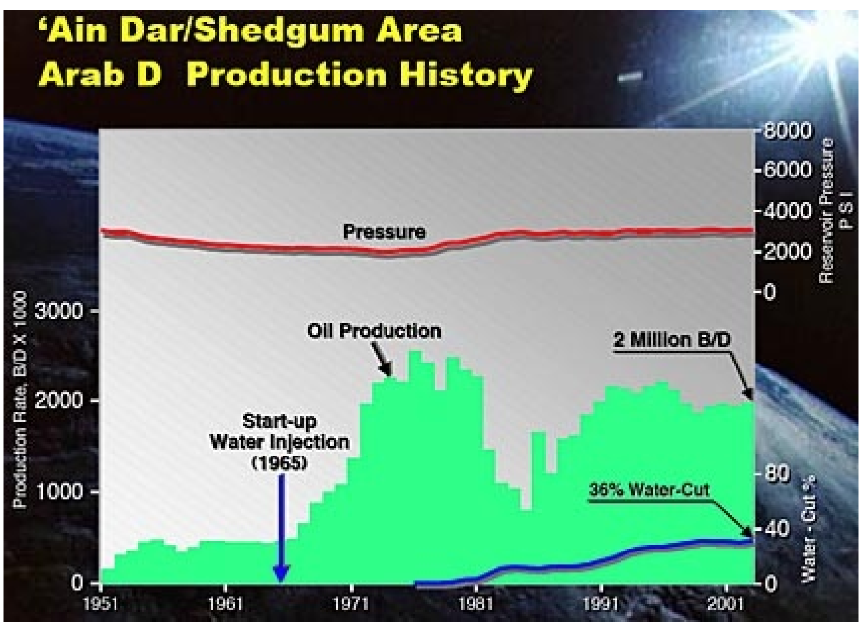
> There are several possible reasons, but the most likely is what is known as Oil Formation Volume Factor (FVF for short, mathematical symbol capital B subscript little O). Basically, oil takes up more space in the reservoir than it does on the surface. The main reason for this is that oil in the reservoir contains large amounts of dissolved gas - possibly 1000 or 2000 cubic feet of gas per barrel of oil (say up to 300 cubic metres of gas per cubic metre of oil).
>
> The gas molecules are small and fit in between the oil molecules, but oil with gas in solution is less dense and the oil simply takes up more space. Add to that the fact that the oil is up to 100 degrees Kelvin hotter at depth, so bigger, and then take off a little volume to allow for the high pressure downstairs, and you end up with Bo = 1.4; so for every barrel of oil you produce at surface you need to inject 1.4 barrels to replace what you are taking out.
>
> 1.4 is a very typical oil FVF - it can vary from 1.15 or so up to maybe 1.6 or 1.7, depending on a number of factors, principally the quantity of dissolved gas.

The gas content at Abqaiq was 860 cf/barrel. As I mentioned yesterday this was initially re-injected, but more recently has been collected and sold. (The GOSP - gas oil separation plants that are located in or near the oil fields are used for this and at one time Abqaig had eleven of these).

In regard to the spacing, I don't have access to the actual numbers but can do the following: If the surface area is 7 x 37= 259 sq miles and the maximum number of producing wells was 72, then each well was draining, on average some 3.6 sq. miles, or the wells, were about 1.9 miles apart. Making a SWAG on this being the number of wells at peak would indicate that the individual well production rate, at the time, was 1,092,064/72 = 15,000 bd. This seems somewhat consistent with production in later years. At peak, Abqaig produced about 0.4 billion barrels a year. (Incidentally in Ghawar the initial spacing was 2 km, with individual well drainage areas of up to 5 sq. miles, and subsequently this was changed to 1 km, so that these initial numbers may not be that far out.

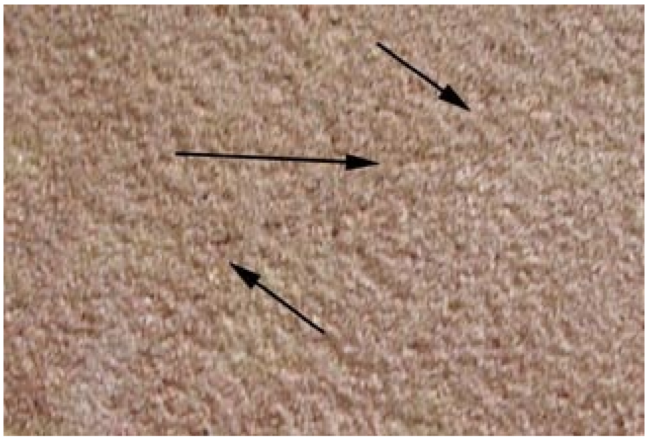
The real size of the volume that can be recovered from the field is a matter of some debate, and it is not completely clear how much has been extracted so far. If the IHS numbers from the past are used, then the field has produced a total of some 8.2 billion barrels and if we accept the Aramco view (given at the CSIS meeting) that some 78% of the oil that it is possible to recover has been, then this suggests that Jean Laherrere's view that it has a total available of 12 billion is highly optimistic. Roughly, it means that it can potentially recover another 2.3 billion barrels of oil. It is currently producing at a rate of around 434,000 bd, or 0.16 billion barrels a year, which means that, without an annual decline in production rate, it would last for another 14 years. In this regard however, it is worth noting that the IHS analysis changed from 2004 to 2005 in downrating the overall recovery factor for Abqaiq from an anticipated 72% to 60%. Of the oilfields listed it was the closest to being emptied, and is the only one for which the overall recovery factor has been dropped.

Matt Simmons in "Twilight" quotes Greg Croft in that the productivity index at Abqaiq is 110 barrels/day per psi differential across the well. Thus if they were retaining 1,000 psi at the well then to produce 15,000 bd they would need to hold 26,500 psi pressure in the formation. While I don't have data from Abqaiq, we can, again look at nearby Ghawar both for the pressure, and to see what happened to it as the field began to deplete.



Note that they began water injection in 1965, and that oil production here peaked in the late 1970's. (For those who don't know Ain Dar/Shedgum is one of the older, and most produced, parts of the Ghawar oil field.) The slide, which also comes from the Aramco presentation as CSIS in refutation of Matt Simmons, also shows that about the time that production was peaking, so water started to appear in significant quantities in the wells, and has grown to a greater percentage of the take, since that time.

The arrival of water at the production wells is where it becomes increasingly a technical challenge to maintain production from the field. Much of the reason for this has to do with permeability and more specifically relative permeability. As I pointed out in that post, a very narrow crack in a rock can take all the flow, stranding the fluid on either side of it. For those who never saw it, here is the picture I showed.



The arrows point to the thin fracture in the sandstone. And as I commented back then

> I have been on a site where the ground was supposed to be as evenly sized and permeable as this sandstone, if not more. A test was being run in which my hosts had pumped some fluid into the rock. Since they did not get the result they wanted, they dyed the next batch of water a bright color and pumped it into the ground. They then dug a hole over the site, and looked down the side to see the thick colored layer that they expected to find. They needed a magnifying glass, all the fluid (hundreds of gallons) had gone into a single flaw, about the size of the one shown in the two pictures, and none anywhere else.

This is relevant since the rock formation known as Arab D zone 2-B, in which Abqaiq is located has zones of high permeability within it. So that, if water is being injected below the oil:water interface, to increase pressure, if that interface rises to meet one of these highly permeable zones, the water can preferentially flow under the pressure head, to the well.

As water is injected (at greater that production volumes as PUD pointed out) and production increases. The water level also rises with time (as I pointed out in the first post) reducing the length of well that is available for oil production. Now in the example I first gave, to make the point, I had assumed that the oilwell was drawing oil from the entire length of the well in the oil bearing rock. This makes it easier to illustrate oilfield depletion with time. However Aramco would, more likely, use one of their workover rigs and since they had cased the well they would seal the water producing levels and reperforate the well higher up. But before I explsin why that didn/t solve the problem, let me continue with that assumption for just one more paragraph, while I explain "water cut".

In the slide from Aramco above, you can see that the water cut ends up at about 36%. In our 300 ft example when we pressurized the well back, we had 180 ft of oil and 120 ft of water in the well.

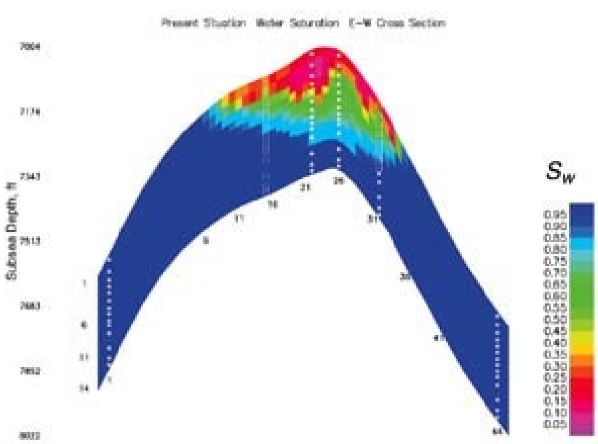
If they both flowed at an equivalent rate then we would get 60% of the fluid coming out as oil, and 40% as water, i.e. we would have a water cut of 40%.

Now unfortunately water flows more easily that oil and so if the hole were left open almost all the fluid would be water, and the well would not produce much oil. Hence the need to seal and reperforate. But this does not, as I said, solve the problem.

If I can make an analogy for the water flow issue, consider that you have a sponge full of lemonade, and you are sucking over the surface to get the lemonade out. Now someone pops a straw through the sponge and leads it down into some cold sour milk that is in the glass under the lemonade.. You don't want to drink the milk, but you do want the lemonade. However if you continue to suck very hard then you will find that the milk flows more easily up through the straw, than the lemonade comes out of the sponge, and so you quit in disgust. There are, however, some controls that can be maintained that don't get as much milk into your mouth. You can, for example, reduce the amount of suction (differential pressure) with which you are sucking on the sponge. One of the problems with doing that is that the amount of suction (or differential pressure) is one of the controls on how far from the well that you can draw oil. So if you drop the pressure differential then you won't get all the oil.

So to reach that oil you can drill more and shallower holes, using computer maps of the fields to work out where, that only go down into the oil layer, and locating them between the wells of the original pattern. Of course, with a relatively uniform water layer rising under the field, and the highly permeable layers being quite common, in most cases you will still find straws sticking up through the sponge, and so you will have to learn to deal, as Aramco has, with a water cut of 35% or more.

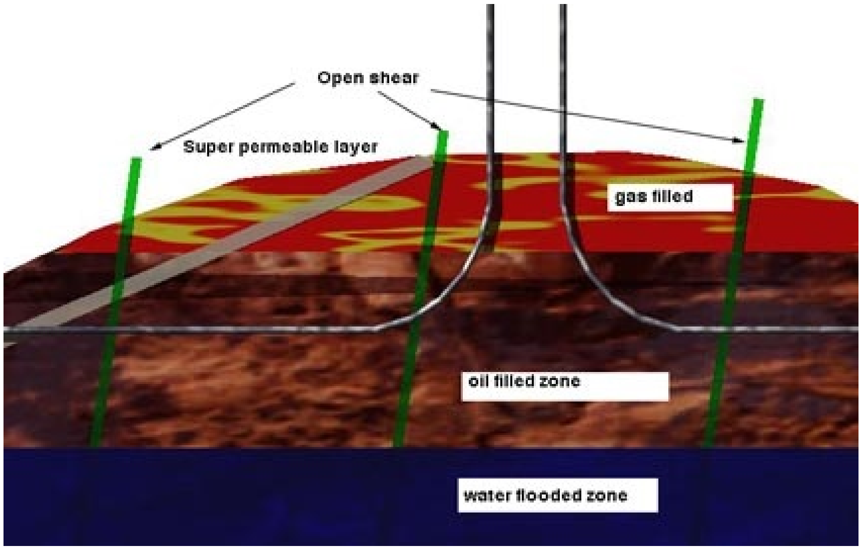
However, let me go back to the picture that I ended with last time



which came from a paper in the Journal of Petroleum Technology and where, by using suitable istrumentation, they had found where the water (deep blue), oil (green) and gas (red) layers were in a relatively depleted section across the reservoir. Now you should be able to see why, by putting long horizontal wells across the field, in its latter days, that one could run the horizontal section through the green zone, and thus continue to get more oil out of the area. Unfortunately, in this zone, because of vertical scale exaggeration, the oil looks thicker than it was - less than 40 ft. (Which anywhere else would be a lot).

(UPDATE: The source paper for the figure above is given [here.](#) It is worth a read because it has on-site photos and a lot more detail about the field than I can get into a post such as this. It also has the results of a horizontal well - which failed shortly after insertion because of water penetration - although it went on to produce 3,000 bd when pumped using multiphase pumping, and accepting the water cut. Note that wells in that region were closed when they reached 70% water cut).

Unfortunately also the highly permeable zones and fractures that run through the rock will also run into the horizontal wells, so that some gas and water will continue to be drawn in, but one can, nevertheless, get more production from the zone than one could before. I can, perhaps illustrate this with a very simplified version of a sketch that Matt Simmons first drew of the geology of the Arabian oil fields.



I have added some of the open shear zones that exist in the field, and one of a number of inclined "super permeable" zones that lie in the field. You can see that as the suction is applied to the horizontal wells, that these provide passage ways to the well from the gas and water filled regions. I have neglected to add the relatively vertical fractures that are also very common within these fields.

In addition (and one of the reasons that the original paper was written) there is another way to go. By drawing the water and oil combination from some of the original wells where the water cut had risen above 75% it was possible to separate as much as 1,000 barrels per well per day of oil from the multiphase flow that came from them. However this is a considerable short-fall from the early production of 15,000 bd/well that the field enjoyed.
At present, as I mentioned, the field is producing at just over 400,000 bd. Wells continue to be drilled to extract the remaining oil, and it is likely that, for a while longer, production may be sustained at around that level. The second last picture in the last post showed that the drop in production at Abqaiq (ABQQ) was running at 2.8%, despite the drilling of more wells, in 2004, which gives a reduction, per year of some 12,000 bd. However that depends on how well water ingress to the horizontal wells can be controlled in the future. Unfortunately I am not that optimistic.

Incidentally I have tried giving this sort of technical explanation in the past, and since it takes a fair amount of words to try and explain the posts are spread over a number of weeks. The posts are as follows, with topic:
Previous posts can be found at::
[the drill]

[using mud]

the derrick

the casing

pressure control

completing the well

flow to the well

working with carbonates

spacing your well

directional drilling 1

directional drilling 2

types of offshore drilling rigs
coalbed methane

workover rigs
As ever, if this is not clear, or if there is disagreement then please feel free to post, and I will try and respond.