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Simple mathematics - The Saudi reserves, GOSPs and water injection

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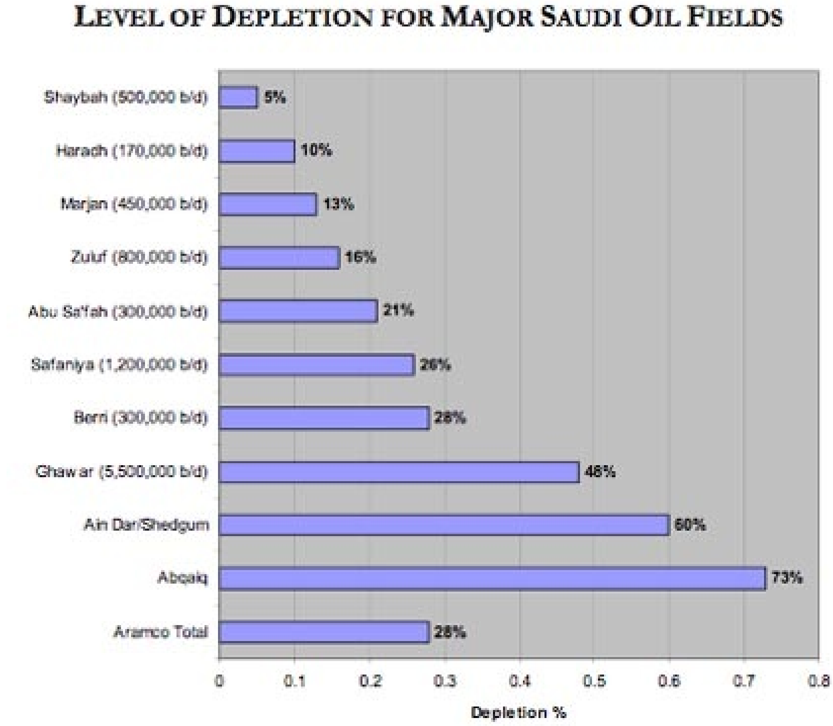
I thought that, with the indulgence of the more technically qualified of the commentators, I might take a little time to explain in my own way, some of the many issues that were debated here at TOD over the past week. So, this post is going to be a little bit of a simplified technical explanation of some of those issues--and I will try to bring in some of the comments explaining the issues that appeared somewhat far down the list in our comment threads as well.

But first there was an interesting piece of data that I hadn't seriously noted until I saw the article. It relates to the actual size of the reserves that remain in Saudi Arabia, a subject I usually shy away from since production rates are more interesting. However, given the numbers it is worth consideration and debate as to what these particular values mean.

Just recently there was a Conference on National Oil Companies that was held at Rice University. And given the recent debate that we have had on these pages relating to Saudi reserves, I looked up the pdf paper on Saudi Aramco . Those that have been reading some of the debate might therefore be as intrigued as I was to read the comment on Saudi individual field reserves.

> Although Saudi Arabia has approximately 80 oil and gas fields, more than half of its oil reserves are contained in only eight giant fields in the Eastern Province in the northeast part of the kingdom. These eight fields include Ghawar (the world's largest oil field, with estimated remaining reserves of 70 billion barrels) and Safaniya (the world's largest offshore oilfield, with estimated reserves of 60 billion barrels). Ghawar's main producing structures are, from north to south: Ain Dar, Shedgum, Uthmaniyah, Hawiyah, and Haradh. Ghawar alone accounts for about half of Saudi Arabia's total oil production capacity. The six other fields with substantive reserves are: Abqaiq (17 billion barrels); Shaybah (14 billion barrels); Berri (11 billion barrels); Manifa (11 billion barrels); Zuluf (8 billion barrels); and Abu Sa'afa (6 billion barrels).
> (Source - "Saudi Arabia," Arab Oil & Gas Directory 2005 (Paris: Arab Petroleum Research Center, 2005), 372.)

The paper also gives 2004 depletion rates for the various fields, using the same numbers that have been quoted from the CSIS debate between Matt Simmons and Saudi Arabia.



Now what is interesting is that if you take the depletion amounts that Aramco report, say 73% for Abqaiq, and you look at how much has been produced, in this case about 8.5 billion barrels, then what is left is the reserve. This is not complicated arithmetic – it comes out to 8.5 x 27 / 73 = 3.1 billion barrels. So when we are told that Abqaiq has 17 billion barrels left (which is more than it started out with) it seems not unreasonable to ask where ? It becomes more logical to suggest that the numbers that Aramco have been citing, such as those given above, were the reserve size anticipated when the field was developed, rather than that remaining in this point in time.

Because, by their own numbers, there is less than 3 billion barrels left. The same arguments, as I recently noted, also apply to Northern Ain Dar and probably most of the other fields. For Ain Dar my very rough initial calculation suggested that they were 70% depleted, a calculation made some 3 years after Aramco had said that they were 60% depleted, and with an assumed 2% a year consumption of the remaining oil since that time.

(The conference papers look as though they deserve more study, since they also cover China, Brazil, Russia, Nigeria, Norway, Iraq, Iran, Indonesia, and Venezuela.)

OK, let me now wander a little nervously into the debate on Ain Dar, and the production potential for the next few years from that field. I am going to try and be a little simplistic in my descriptions, but will try and note that as I go along.

The northern parts of the Ghawar oilfield is, as [Stuart and Euan have illustrated], a little like a mountain range, in that it is higher in the center, and falls away on either side, however, the slope of the sides is much more like that of the beach down on the coast, than it appears in the pictures, because of the way that the scales of the pictures have been drawn. And one of the major points of discussion last week was exactly where on that beach we were standing, and how deep the tide had already become. When the field was first developed vertical wells were sunk down through the roughly 200 ft thick layer of oil bearing rock, and, under the pressure at which the oil was confined, flow rates of up to 15,000 bd per well were achieved.

However, as the oil flowed into the well, so the pressure confining the remaining oil within the rock also began to reduce, lowering the rate at which the oil was produced. In order to keep the pressure up, Aramco then began to inject water into the rock, hoping in this way to replace the oil being removed, and thus keep up the pressure.

Originally they did this by injecting water into wells that surrounded a production well, creating a localized stability, but they soon realized that this was not efficient, and so they switched to injecting water into the wells that were on the outer edge of the field, adding the water at the bottom of the well so that it flowed under the remaining oil in the field, helping to remain at pressure, so that it would continue to flow into the well, and displacing some of the oil as the water penetrated the rock.

Picture shows water flowing horizontally into the rock from the injector well, despite some easier paths through the rock that would carry it selectively higher, if not controlled.

(And as a small technical point I believe there is a slight erroneous assumption in the paper that started the whole Ain Dar discussion – when using seawater as an injected fluid it will enter the rock at a lower temperature, and cool the rock and oil in the vicinity. Since the ability of water to interact with the oil:rock interface is temperature dependent – see among other things the post on the oil sands , assuming that the residual oil behavior around an injection well is equivalent to that in the reservoir is not necessarily correct.)

Now it depends on how easily the water will flow into the rock and how the relative cracks and fractures are in the rock, as to where this water will go. If the bedding planes and fractures are relatively horizontal (as in the picture) then the water will flow out relatively smoothly under the oil filling in the voids and holding the pressure. That is the case here, in general, and so the pressure in the oil reservoir was relatively well maintained, and the production pressure was maintained to hold the pressure, and keep the flow going to the well. (If the cracks run more upwards or vertically then the water would not get very far from the well but would give a column of water rather than a sheet – more on that later).

However, for the deeper wells on the outer part of the reservoir, the water level would start to rise. Simply we are going to assume that the rock above the water level produces oil, and that below it produces water. This isn't quite true but it makes it easier to make the point. Let us assume that the well is drilled through 200 ft of rock. Then after the water has been injected for a while the bottom 50 ft is flooded. Now the well is making 50 ft of water and 150 ft of oil. So that the fluid that comes out of the well is 25% water and 75% oil. This is acceptable since, as I mentioned the other day, the fluid flows to a common treatment plant called a Gas Oil Separation Plant (GOSP) that can separate the gas, water and oil into separate flows. It is normally set up to handle a mixture within a certain range. (For the sake of the example let us say 25 – 50% water).

So as the water continues to rise, because the field is rising toward the center of the bow, so more oil wells begin to encounter water in their lower regions and those on the outside of the field see the water content (cut) still going up. Now at some point the water from a well will get to be more than 50%. If the GOSP was just treating that one well then the GOSP would have to be shut down and reconfigured to handle the higher water content. But because the plant is taking oil from a number of wells going upfield the overall average can be kept within the GOSP operating range, and oil can continue to be recovered, as the remaining oil column in the outer wells gets shorter.

However there comes a point when just too much water is coming from too many wells into the GOSP, and at this point Aramco goes into the well, and lowers a plug of concrete down into the well, to seal off the lower portions of the well. Now the producing portion of the well will still shrink, but considers what happens if, for example, the plug had been set 80 ft. below the top of the reservoir rock. The overall production from the well will drop from say 2,000 bd of fluid from the original 200 ft long well, to 800 bd of fluid from the remaining 80 ft. But if the plug has been set at the water line (the oil water contact or OWC) then now the 800 bd will initially be all oil, rather than the flow being 60% water and 40% oil.

The downside to this is that now as the water level rises the percentage water in the mix goes up much more rapidly. A 10-ft rise in water level from 20 to 30 ft changes the water cut from 25% to 37.5%, rather than from 60 to 65% had the well still been 200 ft thick. And so the well will only be useful for a limited time, but that does allow more oil to be recovered.

This is further helped if, as they have started to do in Ain Dar, the wells that are drilled later in the production cycle are drilled horizontally near the crest of the bow-shape. These horizontal wells will produce oil with almost no water, and thus, in balancing these with wells producing say 60% water (and equivalent flows) then the average water cut going into the GOSP would be only 30% and the plant could continue to operate efficiently. (Bear in mind it is set up for a lower as well as an upper water cut level).

Now lets go back to that illustration that I added up near the beginning. You will notice that the rock model has cracks in it that go up through the rock at an angle. These are easier paths for the water to follow, and thus, if proper control is not applied, the water can move more quickly through these than through the rest of the rock. If, at the top of the layer that water reaches a horizontal well, prematurely, it can flow sufficient water into the well that the mix drops below the oil levels needed for economic return. At that point any oil remaining in the rock on either side of the cracks will be lost, as the wells shut down. This is why a skilled level of control is required to manage the movement of the water through the rock, trying to keep the whole OWC relatively horizontal, so as to get the most oil out of the rock.

So far it seems that at both Ain Dar and Abqaiq Aramco have been able to keep this flood under good control for some years as the water has migrated through the field, and the oil has been recovered. However, in the sense that the water is replacing the oil, it should be born in mind that unless there are water breakthroughs, then the arrival at the horizontal wells will be after the remaining targeted recoverable oil has been removed. However, as a precaution, this is why the more recent maximum reservoir contact (MRC) wells have valves in them that can shut off the flow from the lateral branches that sprout off along the length of the horizontal well. In this case, should a lateral start to make a high water cut because of water breakthrough into it, the valve can be closed, and only that flow reduced. This has been found to work.

At last count the recoverable oil still left in Northern Ain Dar amounted, by my calculation, to about 2.4 billion barrels, and so I still suspect that they will be producing from this part of Ghawar for around a decade yet. (Though perhaps not at the same levels). (And then they will go back and pump it, but that is another story).