

ENERGY MANAGEMENT BRIEF

Dynamics of Oil and Gas Prices and Implications for the U.S. Economy

An Interview with Roger Ihne and Sampat Prakash from Deloitte's Center for Energy Solutions

Sheridan: Over the last couple of years the price of oil has recovered from its 2009 low while the price of natural gas has continued to decline. As a result, natural gas is quite cheap relative to oil. In terms of energy content, natural gas is about one-fourth the cost of oil. Roger Ihne and Sampat Prakash, from Deloitte's Center for Energy Solutions, have joined John Butler and me to discuss the causes of, and implications from, the relatively cheap natural gas that we are currently enjoying in the United States.

Sampat: Low gas prices are largely due to the fact that the abundance of shale resources in the United States is causing a temporary surplus of natural gas. And, because natural gas is not as easily transportable as crude is, the price of natural gas varies geographically whereas the price of crude reflects a world market.

John: However, although the market for domestically produced gas is very segmented, isn't there a world market for LNG?

Sampat: It's a world market with some differentials based on contracts and shipping laws.

Roger: Let's put it in context though. The amount of gas available for trade across the continents as LNG is only about 10% of the total global natural gas demand of over a hundred trillion cubic feet per year. Also, some nations, such as Japan, have higher needs for natural gas than others, and are currently paying a very high price in today's market. LNG prices in certain markets were traditionally linked to the price of crude oil. Recently, and for differing reasons, we have seen this link being broken. Obviously, the US is a good example where the two are not linked because of the great abundance of shale gas that's come onto the market in a really short period, as well as the fact that oil and natural gas tend to serve different fuel markets. Oil is primarily used for transportation, while natural gas is used primarily for power generation, home heating and fuel for industry.

Sheridan: But worldwide LNG prices are still linked to oil prices.

Roger: Yes, in some instances this is still the case.

Sheridan: Just to clarify, LNG in terms of energy content in, say, Japan is priced very much like oil.

Roger: Yes, LNG in Japan is about fifteen dollars per mmbtu, which is much closer to the BTU value of crude oil.

Sheridan: A few years ago there was a lot of U.S. investment in facilities to import LNG. The current discussion is about the U.S. and Canada exporting LNG. Do you think this is likely?

Sampat: There certainly are a lot of folks that are looking at that right now. The DOE has actually issued an export permit for a few facilities already, but the soonest those would be operational is probably 2016 or 2018. I think Kitimat on the west coast is one that's aiming at something closer to 2016.

Sheridan: Have you looked at the economics of Kitimat and the Lake Charles facility?

Sampat: The Kitimat facility was originally designed to bring gas into Canada but now the flow is expected to be in the reverse direction - from western Canada to the coast - and then shipped as LNG to China primarily, although the gas could go into Japan or Korea as well. From the west coast of Canada there is about a dollar per mmbtu transportation advantage between western Canada and China, versus the shipping coast from Qatar to China. So it's a dollar cheaper to ship it from Canada versus Qatar.

Sheridan: Because we're closer?

Sampat: Yes. Closer and it's easier to get tankers to go back and forth, too.

Roger: To put the economics of exporting LNG from North America in context, let's say the price in Japan is \$15 per MMBTU. The price on the US Gulf Coast is about \$4 per MMBTU. If you assume the liquefaction and transportation costs run from \$3 to \$5, there is clearly a good arbitrage opportunity at the present time.

Sheridan: And then you'd need a lot of capital to do that.

Roger: Okay, but looking at the margin, you're at say \$8.00 in costs, versus a price of \$15. So that leaves a margin of \$7.00 to be able to pay your capital cost, depending upon your view of how long that gap will last.

Sheridan: The capital cost could be \$5 billion, is that about right?

Roger: That depends on what type of facilities are needed and what infrastructure already exist versus what needs to be added.

Sampat: It's a big bet.

Sheridan: Since these are very risky investments, I imagine that companies require very long term contracts to limit their risks prior to making the investments.

Sampat: The gas contracts typically run for long periods of time. From memory, the first wave of contracts was seven, eight, maybe ten years, because people were getting to understand the whole business of LNG. So exactly, people will not commit capital and will not be able to secure funding without long term guarantees. In addition, if you look at what companies are doing off the coast of Australia it demonstrates that this is a very significant bet. In this instance, there is a floating production and liquefaction train being built, the first of this scale in the world. It is about four football fields long. As long as this natural gas field is producing, the floating production facility will be there. If the company needs to move the floating facility because the next major gas opportunity occurs elsewhere, then the floating LNG facility can be repositioned geographically. It provides much more flexibility.

Sheridan: Why do they call them trains?

Sampat: Because it looks like a train; very long process facility.

John: What's the useful life on these trains? For this train off Australia, how many times could you really think about redeploying this asset?

Sampat: That's a great question. A lot of these facilities are being designed so that high wear and tear parts are replaced often, and the larger assets receive ongoing scheduled maintenance. Deepwater drilling rigs are much the same way - the average last year was twenty four, twenty five years old - these are not

young assets. So these large capital assets that can be repositioned provide more strategic flexibility for the investment.

But back to the point— if gas is \$5 in Canada, and you get it to Kitimat and ship and yield a price of let's say over \$10, you can still make money on it.

Sheridan: So taking into account capital costs, it'll give you around a \$1 billion cashflow per year?

Sampat: Depending on where, when and what you build, capital costs can swing quite widely. I think the smart operators, like some of the super-majors, are picking a time to build, then locking in a reasonable contract price and writing a guaranteed rate of return, right? And they can then ride an upside.

Sheridan: The companies developing the LNG terminals lock in the prices that they sell the LNG. Do they also have contracts that lock in the natural gas they buy?

Sampat: Correct. The big producers who also own these assets have an advantage. The operators of a liquefaction plant have to lock in long term sale contracts and work from there to purchase contracts, which they've done. Roger, do you know? Eighty percent plus is what I have heard some of the early exports facilities contemplated and achieved in terms of long term sales contracts.

Roger: Yes, but it is also important to recognize that the capital cost associated with building the floating LNG facility versus converting a regasification plant on the US Gulf Coast are hugely different. Most of the initial liquefaction facilities in the world were built to capitalize on a huge amount of "stranded" gas. In many instances, if the gas was not able to be liquefied and shipped as LNG, it probably would not have been produced, or if it is gas associated with oil production, it would have been flared (burned). So in many cases, the cost of extracting the gas itself was pretty minimal. However, once the capacity gets built up to support the worldwide development of the many natural gas fields that exist today, it could be an interesting dynamic. In looking out thirty years, especially if the shale gas phenomenon we've seen in the US occurs in other places around the world, with a worldwide abundance of gas, you can see where there could be further delinking of natural gas and crude prices and much more of a world market for LNG.

Sheridan: Will LNG will be exported from North America?

Roger: North America, I think it's a given from Canada, and it looks increasingly likely there will be exports from the US since the DOE has approved the export licenses.

Sampat: And you're talking about the next five years. Is that the horizon?

Roger: Yes.

Sampat: Agreed, it's hard to see any exports of scale happening in the next two or three years.

Sheridan: Okay so exporting is one way that we'll see the gap close between natural gas and oil.

Roger: I think we are only talking about US exports of between two and six BCF a day. In the US we currently use about 60 billion cubic feet a day, so at the most maybe five to ten percent of existing demand and/or production.

Sampat: The other twist in Canada is incremental investments in oil sands are more in-situ than mining, and in-situ is very energy intensive. So the other thing we've been looking at for pricing domestic gas is the correlation between increased oil sands production and domestic gas demand.

Sheridan: So the bottom line is, if the disconnect continues there's clearly an opportunity for export of LNG. However, the amount of LNG that will be exported will have a small effect, and isn't nearly large enough to move that gap too much.

Roger: Right, certainly in terms of the natural gas price in the US. According to the models I have seen, it could add about a dime to fifteen cents per MMBTU if we export anywhere from three to six BCF per day.

Sheridan: Let's discuss other possible ways that the gap might close. Honda has a natural gas vehicle they sell and we are seeing the development of electric cars. On the margin if electric cars become more important the extra electricity for those electric cars will come from natural gas. So at least indirectly we can talk about electric cars as natural gas vehicles as well.

Roger: Yes, but we have to be a little careful there. For the demand side of natural gas, by far the largest component is incremental electric generation. And we're talking ten to fifteen billion cubic feet a day of additional demand that will be going into the power sector. That's a huge amount. However, if the entire light duty vehicle fleet in the US converted to natural gas, that would actually double the demand for natural gas overnight. Clearly that isn't feasible. But in spot cases, especially with large trucks and fleets that have defined routes where you could install a fueling station or a natural gas compression station, it's going to make sense. However, the answer for transportation fuels in the future is probably driven more by government policy than any other single factor. One policy is the CAFE (corporate average fuel economy) standards to take the light duty vehicle fleet from about 27 miles per gallon today, to 56 miles per gallon by 2025. In order to do this, the composition of the US light duty vehicle fleet would have to change dramatically. The EIA (Energy Information Agency) estimated what that fleet would look like and one of the surprises is that it increases the amount of diesel fuel that's used in the US more than any other fuel type.

Sheridan: So you're not foreseeing a big move away from oil and an increase in demand for natural gas for transportation?

Roger: Oh we see a huge change in technology, but it's largely a guess as to which technologies will be the ultimate winners. There are so many wildcards.

Sampat: One more thing, let's mention flex fuels where there's an exciting new trend, which is the CNG and gasoline engine. It'd run both or either.

Sheridan: Is anyone actually selling a car like that?

Sampat: Absolutely, Chevy Tahoe has it. Executives at some O&G companies drive these. The inconvenience is that there are currently only a few CNG fueling stations in many cities. But the next wave of technology would make it possible to not just go one or the other, but to use both in some kind of variable volume. So think of flex fuel cars that can use ethanol as a 10% or a 12% or an E85. And if you could do the same with natural gas and gasoline, it would give you that flexibility. So some interesting new trends there.

Sheridan: What is the price premium for a Chevy Tahoe that can run on both CNG and gasoline?

Sampat: It's quite heavy. Right now it's not an economic choice. It's a choice you make largely to make a statement. But at some stage those technologies will become economic.

Roger: It's the regulations that are really driving many decisions. The other mandate that's important is the renewable fuel standard. This year thirteen billion gallons of bio-based fuels are mandated to be blended into the fuel supply in the US. This is supposed to almost triple to 36 billion gallons by 2022. This mandate could drive a number of decisions that are not based on fundamental economics.

Roger: A lot of moving parts and I don't think anyone knows what the answer is but, within twenty years the conventional gasoline cars we drive today could very well represent a minority of the fleet.

Sheridan: If these regulatory changes, the CAFE standards, are going to lower the demand for oil, increase the demand for natural gas, to what extent is that going to close the price gap?

Roger: Well, oil's price is determined in a world market so look at long term prices for oil. If you assume 1-2% demand growth a year worldwide, that is an appetite for oil that is unlikely to bring any relief to world prices.

Sheridan: So we're not saying the oil prices are going to go down, but if these other things increase the demand for natural gas, will that raise the natural gas prices from \$4 to \$8 in ten years, for example?

Sampat: Here's the thing. Drilling and production costs have been on a downward curve for gas. The big guys have gone into the fray, several of the super-majors are bringing additional discipline and scale into what is essentially a production process. The view we're hearing is that they expect to keep pushing the costs down. However, one of the biggest variables is water. That's a huge variable.

Roger: And regulation.

Sampat: Sorry, yes, water and regulation. Not the same thing, but water in all its forms: access to water, reuse of water, regulatory environment around water, etc.

Roger: The real key is as Sampat said, what's going to be the cost in the future for producing shale gas? The cost curves for extracting natural gas in each of the basins around the US are all different, so you produce the lowest cost first, and then you move to the higher cost. Unless we are able to lower these cost curves, within ten years, we could end up importing higher cost LNG, so we'll be back at a much higher price for natural gas. However, to the extent that we're successful in driving down the cost of producing shale gas through innovation and the larger players entering the business, then all of a sudden the model changes and we will not be importing the gas and prices will remain relative low in the US.

Sampat: Right. That's the bet.

Roger: We've already seen a dramatic reduction in the cost of producing shale gas, but the unknown thing is regulation and the cost associated with that. For example, Pennsylvania is considering a proposal to add a \$160,000 per well as an additional tax/fees. Obviously, this adds to the cost of producing the shale gas.

Sheridan: I also heard the drilling costs are increasing.

Roger: One independent producer whom I spoke to recently said he used to drill nothing but gas wells, but he is switching to oil wells, in order to make money because of the higher relative price of oil. He was blaming it on the increase in service costs, not the low gas prices. Because of higher service costs, he said drilling costs have doubled from \$2.5 million to \$5 million a well. The demand for rigs is outpacing supply because of all the shale gas drilling, as well as high oil prices, which have stimulated drilling in

North America for oil. This has resulted in higher service costs across the board for drilling either gas or oil wells.

Sampat: It depends on who you are however, because we know of an entity where over half the drilling fleet is horizontally integrated—so they use their internal capacity first and can manage that cost issue much better. The little guys will get squeezed, you know, it's the inevitable consolidation of business.

Roger: It's interesting, because even in these highly regulated markets, the free market system tends to work. The best cure for low prices is low prices. And the best cure for high prices is high prices. And indeed we're seeing that play out every day in these markets. Because of the higher prices for oil relative to gas, there is an increasing emphasis by the industry on drilling oil wells and much less for gas.

Sheridan: Can we talk about chemicals for a little bit? Can you describe how the low natural gas prices are affecting the US chemical industry?

Roger: It's transformed it. About five years ago North America was the second highest cost producer of ethylene, which is one of the primary building blocks of the entire chemical industry. Because of the abundance of shale gas, North America has become the second lowest cost producer of ethylene in the world. There's two ways to make ethylene. One is to use oil-based products from the refinery—historically that's produced about 50% of the ethylene in the world. The other way is to use liquids that have been extracted from natural gas when it's processed (natural gas liquids, or "NGLs"). The economics are different, but in the U.S., given the huge difference between the price of oil versus the price for natural gas, the U.S. has a cost advantage to most of the rest of the world because it uses lower cost NGLs as a feedstock to make ethylene. All of a sudden in an industry where they never thought another NGL based ethylene cracker would be built in the United States, we are now the second lowest cost producer in the world. This causes other ripple effects. Ethylene crackers tend to be very large facilities and require large investments, and many companies in this business are looking at whether or not to build a cracker in the US and where to locate it.

John: Are we seeing chemical companies profit?

Roger: Oh yes. Certainly the petrochemical industry is doing quite well. However, because the chemical industry comprises everything from commodity petrochemicals all the way through certain high performance specialty chemicals, it is somewhat hard to generalize.

Sheridan: I went on Yahoo Finance in preparation just to look at stock performance of chemical companies and they didn't seem to be booming. Was I looking at the wrong companies?

Roger: I would look at more of a "pure play" commodity petrochemical producer, with substantial NGL based ethylene operations in the US.

Sheridan: Refining is very similar to the chemical industry. Our refiners are at an advantage relative to overseas refiners because of cheap natural gas, is that correct?

Roger: If that's the only thing you're looking at, then, yes. However, by far the largest cost for a refiner is the oil that it purchases to convert into gasoline and other refined products. Crude oil accounts for over 90% of the total cost of refining, and then the second largest cost traditionally has been energy, primarily in the form of purchased natural gas. As such, low natural gas prices directly benefit refiners in this way.

Sheridan: WTI is twenty dollars a barrel less than Brent and that's a further advantage.

Roger: Definitely. Right now by far the largest advantage is for refineries in the US that have access to WTI crude, or crude oil that is priced based on differentials to the price of WTI.

Sheridan: I guess we have a small amount of crude products that we export now, but it's relatively minor.

Roger: Fifteen percent of total output.

Sheridan: Do you see that amount growing over time?

Roger: Well it's already grown. About five or six years ago, it was very consistent at five percent. And now it's at fifteen percent due to a number of different reasons. One, the US has excess refining capacity. We have seventeen and a half million barrels a day of capacity, but our US domestic demand would only account for about fifteen and a half million barrels. Two, we have strong demand in the developing world, primarily South America, Latin America for refined products, as well as diesel demand in Europe. Mexico has a large demand for gasoline. However these markets will probably dissipate in the future because of the huge investment programs in Brazil and in other places.

Sheridan: Going back to what we talked about earlier, if you look at the big picture, the US is running a huge trade deficit and it looks like cheap natural gas is a natural advantage we need to use to increase exports and refining of chemicals.

Roger: It's going to have a huge impact on petrochemicals, and that should continue. A smaller impact on the refiners, but it also has an impact on any manufacturer that uses a lot of natural gas. So all of a sudden the old paradigm about how we always export or outsource our manufacturing operations to countries that have a competitive advantage, all of a sudden those economics have to be looked at under comparatively low US fuel costs. If you have a manufacturing process that requires a lot of natural gas and you're currently operating overseas facilities with higher gas prices, then if things continue, maybe the next plant you build will be in the US?

Sheridan: It makes the mid west look a lot better.

Roger: It sure does. And the Midwest is really being helped from a refining perspective because of that cheap crude, not only produced domestically, but also imported from Canada. So those economics have changed dramatically and I don't see them changing any time in the short term.



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To learn more about the North American shale gas market, including production, pricing and economic impacts, please see these other articles published by the Deloitte Center for Energy Solutions.

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