FILLING THE GAP:

HOW CAN UTILITIES ENCOURAGE NEW SUPPLY SOURCES?

by

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Introduction

For the past fifteen years, fuel buyers have been blessed with seemingly endless alternatives for procuring uranium on both a spot and long-term basis. They could choose among large conventional uranium mining companies, major by-product operators, smaller ISL producers, marketing companies for eastern production, trading companies with a variety of inventory supplies, HEU feed, uranium contained in EUP, and other sources. For the last ten years, spot prices have averaged around $10 per pound, with long-term prices either indexed to that level or not a whole lot higher. For much of the last decade, spot prices have been below the production cost of all but the lowest-cost producers.

As one would expect under these trying conditions, supply concentration gradually took over, as uncompetitive companies exited the business. Until recently, the survivors often adopted the “Field of Dreams” approach to new mining projects -- build it and they will come. But the long, grinding period of low market prices that followed the 1996 spike, aided by the looming presence of HEU feed and USEC inventories on the market, began to have an effect on the mentality of the remaining producers. Management became far less willing to fund new projects without firm commitments with a strong projected rate of return. For companies without the internal cash flow to self-finance, Wall Street, banks and other outside source of capital have demonstrated far less inclination to fund nuclear-industry capital projects with long payback periods.

Of even greater concern are the non-financial constraints that may delay or prevent major new sources from being exploited. The McArthur River flood alerted the market to the growing reliance on a smaller number of large projects, and the increased risk exposure that entails. Thus, if supplies are as tight in ten years as is indicated in some scenarios, even the presence of higher market prices may not spur sufficient new supplies in a timely manner.

So now that most U.S. utilities are being granted nuclear plant license extensions that will allow operation well into this century, what is being done to ensure the availability of a diverse and robust nuclear fuel market beyond this decade? Is there anything buyers can do to encourage new project development? Many nuclear operators are now big enough to reconsider strategic investments in supply capability. Some have shown a willingness to do it already – in enrichment, for example, where trade restrictions have sharply increased costs for U.S. utilities and spurred three of them to partner with Urenco to build a new plant in the U.S. While these fall short of actual equity investments, this participation nonetheless indicates strategic thinking and an effort to enhance future competition. Is this trend is likely to increase? Today we will explore the conditions under which we might again see utilities getting involved in uranium production in some manner in the future.

Understanding the Problem

To do this, first it is necessary to examine the future supply situation and determine if we really are facing a serious problem. After all, this is a commodity market, and like all markets, supply will meet demand, the only variable is price, right?

Well, perhaps not. Like any extracted resource, technical and environmental constraints can play a prominent role in the timing of uranium mine development – and political constraints affect uranium more than any other mineral. Canada's Cigar Lake, with its extremely high grade and swampy ground conditions, provides a good example of technical constraints; Australia's Jabiluka, an even larger deposit, is an example of political/environmental constraints at work. What this means is that although rising prices strengthen the business case for opening these new mines, price doesn't always solve other problems that can delay their operation by months or years.

The World Nuclear Association's Market Report issued last month contained some unusually dire warnings for the future supply outlook, and other analysts have commented on this as well over the last few months. Perhaps it is useful to look at the overall supply-demand picture for uranium and apply some assumptions to what the future may hold.

Building the Supply Picture

Using supply data from Ux Consulting, I've prepared a relatively simple chart to try to break down the supply and demand picture out to 2015 (Figure 1). This uses the World Nuclear Association's reference case for world uranium requirements over the next fifteen years. In my view, this reference case is a realistic and perhaps even conservative assumption given the improving prospects for nuclear power growth that we've seen over the last few years. China alone, for example, has brought five units on line since 2000, with three more entering service next year. With improved plant performance, the political issues surrounding climate change, price increases in the natural gas market, and a growing realization of the limitations of non-baseload renewable sources such as wind power, nuclear power stands to gain a much better reputation with both the public and the politicians over the course of this decade. So I don't think this requirements growth is overly optimistic by any means.

Now, let's add in the supply sources, and apply some assumptions to see whether there is a gap, and how severe it might be.

First we will add existing western production centers, dominated by Canada and Australia, and including central and southern Africa and the U.S. I'm using the current projected levels of production at existing mines, and in a moment we'll deal with expansions that might be justified given higher market prices. Next we'll add nonwestern sources of mined uranium. This is mainly comprised of Kazak and Uzbek ISL production, along with ongoing conventional production in Russia and some newer Russian ISL development. Since we are counting worldwide reactor demand, the fact that Russia no longer exports its U_3O_8 to western markets is immaterial. This section also assumes moderate increases at existing Kazak operations, along with supply from the Cameco and Cogema ISL joint ventures at Inkai and Moynkum, respectively.

Next we will add non-produced material. This is dominated by the HEU feed. Some assumptions must be made here about the future sale of material currently stockpiled by Russia because of U.S. quota limitations – I've assumed the majority of it becomes available as prices rise and the quota increases, except for what is thought to be required for additional HEU blending. I'll deal with so-called HEU-2 in a moment.

This section also includes re-enriched tails, MOX and reprocessed uranium, sales from USEC's inventory, and future sales of DOE inventories and U.S. HEU. These are not an insignificant volume, but is unlikely to be growing to a great degree over the forecast period. The energy bill currently being debated in Congress will address government inventory sales, but in any event these are likely to be small and may not kick in for three to five more years.

So here we are -- a gap of more than 50 million pounds per year by 2010. Now let's assume that a rising price stimulates both increases at existing facilities as well as the development of new mines.

First, at some price probably above today's level, output from certain existing mines could be increased. The most significant of these would be an expansion of Olympic Dam, although it's important to note that the copper market will be the primary determinant for this expansion. Next would be another four to six million pounds from McArthur River. One can expect, however, that the flood problem Cameco encountered last spring may well discourage them from pushing the limits of this operation. Third, there is the possible expansion of Namibia's Rössing open-pit mine, an issue which is currently in front of Rio Tinto management to decide. But even if that expansion occurs, it is really more of an extension of existing supply rather than a significant net increase. I've also allowed for a doubling of South African production, although that is more likely to be gold-driven and as far as I know is not being contemplated at present.

With regards to new mines, clearly this is dominated by a few major deposits. Cigar Lake is the closest to commercial operation, and I would expect it to come to market in the next few years depending on market prices. But as noted above, there are some technical concerns with a method of mining that is relatively unproven on a commercial scale. I've also added Honeymoon in Australia, the small in-situ operation that apparently only lacks funding at this point – we'll assume that a slightly stronger market can overcome this constraint. Beyond 2010, a few other major deposits become available – Jabiluka in 2011, and possibly Cogema's Midwest Lake. But Jabiluka is only a replacement for Ranger, and Midwest may not have a good milling option because of

Cigar Lake. So although neither of these large operations are guaranteed, I've included them anyway to be optimistic.

Now the situation looks like this. As you can see, there is still a significant shortfall. Hence the importance of HEU-2. If we add a follow-on HEU deal at the current levels, beginning in 2014, we get this picture. Still not meeting demand, but important nonetheless.

Now, I've worked with the Russians for many years in various capacities, but I'm as uncertain as anyone regarding the possibility of an HEU-2. My gut says that a deal will be forthcoming, mainly because of the large contribution such an arrangement makes to the Russian budget in general and to Minatom's defense-conversion activities in particular. I believe the nonproliferation aims of the U.S. combined with the economic benefits to Russia will overcome any opposition.

However, I could be wrong. Russian representatives have been cautioning the market not to take this source for granted. I do know that the Russians are not happy about subsidizing USEC with their HEU, especially now that the price they receive has dropped about $10 per SWU. Nor are they happy about the ongoing Commerce Department limitations, and the fact that the U.S. is not actually down-blending its own HEU. At the same time, economic progress in Russia, while still occurring in fits and starts, is moving at an impressive pace, and exports of natural gas to Europe are a major source of export revenue. Perhaps in ten years the economic drivers for selling HEU will not be as pressing. Moreover, if Russia's reactor program expands more rapidly than the country's uranium mining capabilities, then HEU may first be reserved for internal Russian reactor needs. So the overall message here is that HEU-2 is needed, and we should support its entry, but we had better be prepared to live without it or with a smaller volume than currently available.

And as this graph indicates, without an HEU-2 deal the market could be short 50 million pounds per year. Other than the new projects I mentioned earlier, there is very little in the exploration and development pipeline in the way of major new deposits that could meet this shortfall. I don't want to appear alarmist, but the problem may even go beyond price – the very availability of material on a timely basis could, under certain circumstances, be in question. The last time the market saw anything like this was in the mid-1970s.

The Era of Scarcity

So let's take a short trip back to 1979 to see how utilities coped with the problem (or perception) of uranium scarcity. Only a small group of people in this room were in the industry then, but it was widely believed that there was not enough known uranium reserves to supply rapidly growing nuclear programs around the world. For those of you on the procurement side, imagine being a buyer in a market that looked like this (Figure 2).

Since I was still in high school at the time, to get a better feel for this period I dug up a speech by one of my old Nuexco colleagues, George White, from March 1979. In this presentation, he described the then-widespread practice of utilities directly participating in uranium mining or exploration activities. These ranged from grass-roots exploration programs, where utilities actually employed exploration staff and conducted drilling operations, to the outright purchase of full-blown production facilities. One of the most common mechanisms was the joint development venture, wherein a utility could earn a position in a known deposit based on the level of its financial contribution to the development of the project.

Here are just a few examples of the more than forty utilities that participated in programs like this (Figure 3):

- TVA had its own exploration program, as well as joint ventures with United Nuclear and Mobil Oil;

- Exelon predecessor Commonwealth Edison purchased Cotter Corporation and its Colorado mines. It was just a few years ago that Exelon finally sold the company. In addition to Cotter, Commonwealth had a JV with Getty Oil;

- NMC predecessors Consumers Power and Wisconsin Public Service formed wholly owned subsidiaries to explore for and produce uranium;

- Niagara Mohawk owned 50% of the Clay West ISL operation in Texas;

- Baltimore Gas & Electric funded an exploration program with Intercontinental Energy of Texas, and PG&E advanced more than $12 million to the same producer for a different project;

- Long Island Lighting financed a mine/mill project with Bokum Resources. While the mill was built, the mine never was commissioned – but then again, neither was LILCO’s fully completed Shoreham reactor.

U.S. utilities were not the only ones to enter into these arrangements – Swiss utilities partnered with Energy Fuels, European and Japanese utilities still own shares in ERA, Enusa owns shares of mines in Niger in addition to once having its own mine in Spain, and Korean and Taiwan utilities owned minority shares in U.S. deposits. Many of these positions have been relinquished, but a few remain – for example, Tokyo Electric Power maintains its a five-percent share of Cigar Lake.

The reason most of these projects were closed, sold or written off, of course, is graphically illustrated in the next slide (Figure 4) – the huge decline in prices associated with overproduction and the cancellation of hundreds of planned units worldwide. In hindsight, most of these utility ventures were not particularly successful, considering how uranium would soon become so abundant and cheap for such a long time. A lot of money was lost on these projects, many that never produced a pound of uranium. However, it is also useful to consider the comments that Commonwealth's former head of fuel procurement, George Rifakes, made some years ago. He said that the point of the Cotter purchase was not to obtain the cheapest uranium, but rather to ensure some supply and put a cap on what price they would pay. Such was the concern in a market where the price could go from $6 to $40 per pound in a matter of a year or so. Or as George White noted in 1979, it was the utilities "whose needs were so large that they felt it necessary to increase their security of supply by involving themselves directly in exploration and development," companies like TVA and Commonwealth. That is an interesting point to consider in light of the utility consolidation of the last five years, which has created mega-operators like Exelon and Entergy.

Could This Happen Again?

Now I'm certainly not suggesting that prices are on their way back to $40 per pound. But how likely is it that we will see utilities getting involved in production in the future? Today, most utility executives would say that it is very unlikely -- utility management is not sufficiently interested in fuel supply and in any event wouldn't pursue non-core activities. But such comments made today are based on the current paradigm, where uranium supplies are more than adequate and relatively low priced. A severe shock could change some of those preconceptions.

Let's not forget that utilities, to this day, do participate to varying degrees in the supply infrastructure for other fuels. Duke Energy, for example, owns natural gas gathering pipelines through a joint venture with Phillips Petroleum, and also owns transmission pipelines and storage facilities. Other utilities invest in coal transportation and loading facilities. And although it does not represent an equity investment, three U.S. utilities are partners in the LES venture and are presumably signing contracts that go beyond normal arm's-length relationships, all in an effort to jump-start an operation that will enhance long-term supply security and procurement alternatives for enrichment. In other words, the LES project is evidence that utilities will get strategically involved in supply when necessary to enhance competition.

One major reason why we are unlikely to see significant utility ownership of production is the effect of supplier concentration. Now that just four western companies control about 90% of western production, these large diversified companies generate sufficient cash flow to internally fund the exploitation of new reserves. So Cameco, Cogema, Rio Tinto and Western Mining are not as likely to sell equity in various projects to utilities to fund their development. Instead, they use their own sources of capital – internally generated cash flow, revolving lines of bank credit, and equity in the form of their own stock (Cogema excepted). For these companies, then, the decision whether to invest $50 to $200 million in a new mine or mill depends on their projected internal rate of return and competing opportunities for the invested capital. As you can imagine, a company as large and diversified in mining as Rio Tinto has many competing demands on its capital resources. And it all boils down to the expected profitability of a new uranium mine compared to other opportunities. Hence the often-stated refrain that market prices need to be sustainably higher to justify these investments.

Nonetheless, if an Exelon or Entergy approached one of these companies and offered a $100 million investment to take a portion of a new mine's output for twenty years, even these large mining companies might consider laying off some of the development risk and taking on a minority partner. And there will be other situations where utilities could play a more crucial role on the investment side. For producers that are not so large, going to the financial markets to source capital can be far more difficult these days. This is certainly true on the debt side, where banks and other lenders are increasingly shying away from long-term capital projects, even when secured by so-called "bankable" contracts. The economics have to be very attractive to allow a relatively short payback on the funds – even a producer with $10 per pound costs and $14 contracts would not likely get access to bank funds – that differential may have to be on the order of contract prices almost twice the level of production costs to attract lenders. That leaves the equity markets, and you may have noticed those have not been so welcoming in the last few years, either. Hence, producers like Southern Cross are stuck on the sidelines until funds become available to begin the project.

So it is possible that, under the right circumstances, utilities could find it of interest to invest their own capital in a new production source. Market prices would probably have to be higher than now, of course, and some of the expected mines or sources might have to be in jeopardy before management could be convinced. But stranger things have happened in this industry, and I don't think we can rule out such activities in the future.

And of course, short of taking equity positions, there are other strategic moves that buyers could make to help ensure adequate future uranium supplies. This matrix is an attempt to model some of these different mechanisms according to risk, cost and strategic value (Figure 5).

Arm's length contract – Obviously this is the dominant relationship now, and involves virtually no risk for buyers. In the past, ordinary contracts with dependable buyers were often "bankable;" that is, the supplier could borrow from a lender using the assigned contract as collateral. This practice is becoming more difficult, however, as capital markets shy away from these projects unless the payback period is very short.

"Enhanced" contract – This refers to a contract that goes beyond the commercial norm, terms that might not be the best available in the market, but help the buyer achieve a different goal. For example, LES is likely to employ this technique for the National Enrichment Facility. Partners Exelon, Entergy and Duke have reportedly executed purchase contracts for up to 50% of the plant's output that will enable LES to borrow a portion of the funds needed to construct the plant. While I have no inside knowledge, I would expect that these contracts are longer in duration, and perhaps lower in flexibilities, than a currently available arm's-length enrichment contract. But of course, this is to be expected given that the utilities are trying to induce new supply capability.

While we are on the topic of enrichment, from all indications USEC is exploring several types of participation for the American Centrifuge. These might include borrowing against bankable contracts, of which the recently announced Exelon contract extension could be a significant example, as well as other partnership arrangements with buyers. For example, USEC management has reportedly visited Japanese utilities looking for financial cooperation, perhaps in the form of advanced-payment schemes, that would help with the financing. And joint ventures are also possible.

Advanced payments – This is a concept that has been employed in the past. A buyer could sign a contract requiring a series of advanced payments that are paid back in material (uranium or SWU), with interest, when the new facility is in operation. This can present some accounting challenges for regulated utilities, but is otherwise a relatively low-risk activity given the proper security protections. It is quite possible that USEC will approach customers with this concept for the American Centrifuge.

Exploration funding – As noted, this was common in the 1970s, but seems less likely in today’s context. Although exploration expenditures by producers are at all-time lows, utility funding of this activity doesn’t really help them much, because the lead time between discovery and exploitation of an orebody is now so long – often twenty years or more.

Equity interest/Joint Venture – This could well be employed in the cases of smaller, undercapitalized producers such as Southern Cross for Honeymoon, URI with Vasquez, or WM Mining for Dornod in Mongolia. As equity investments, these are likely to entail a higher degree of risk of loss compared to secured advanced payments – the analogy is that it’s better to be a bondholder rather than a stockholder in the case of bankruptcy.

Wholly Owned Production Facility – The size of the investment and the managerial requirements associated with this option make it appear rather unlikely in the future. However, it may depend on future utility consolidation. Perhaps a utility operating twenty-five or thirty reactors would find it prudent to bring a portion of its supplies in house.

Conclusion

In conclusion, most now agree we are headed into a period of great uncertainty in terms of future fuel supplies. What has been abundant and cheap may now become far less so in another ten years. This may require utilities to reevaluate their procurement strategies and take a more active role in stimulating new production. Whether this will result in utilities again partnering with producers to encourage new supply remains to be seen. However, those who may be certain this will never happen again could be confronted with a whole new reality in five to ten years.

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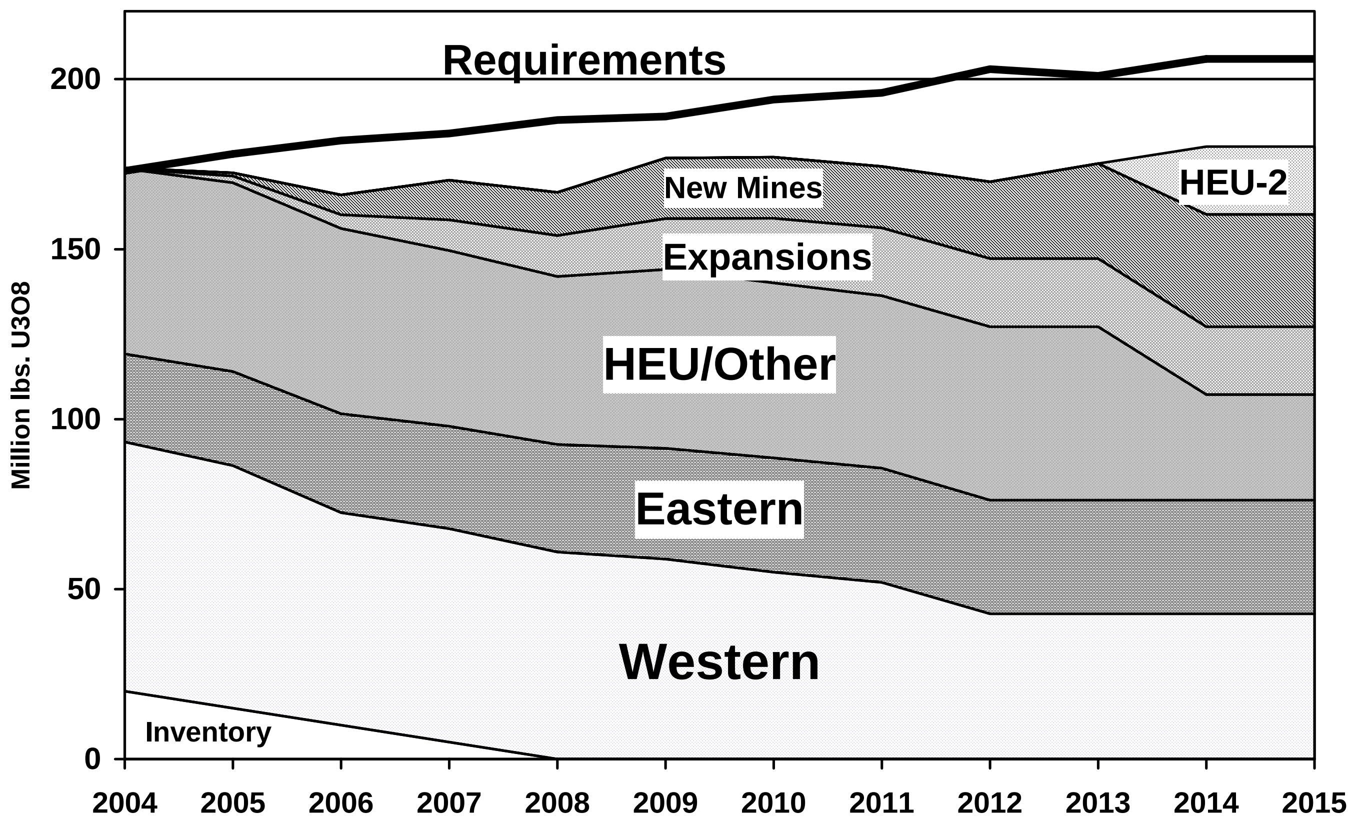
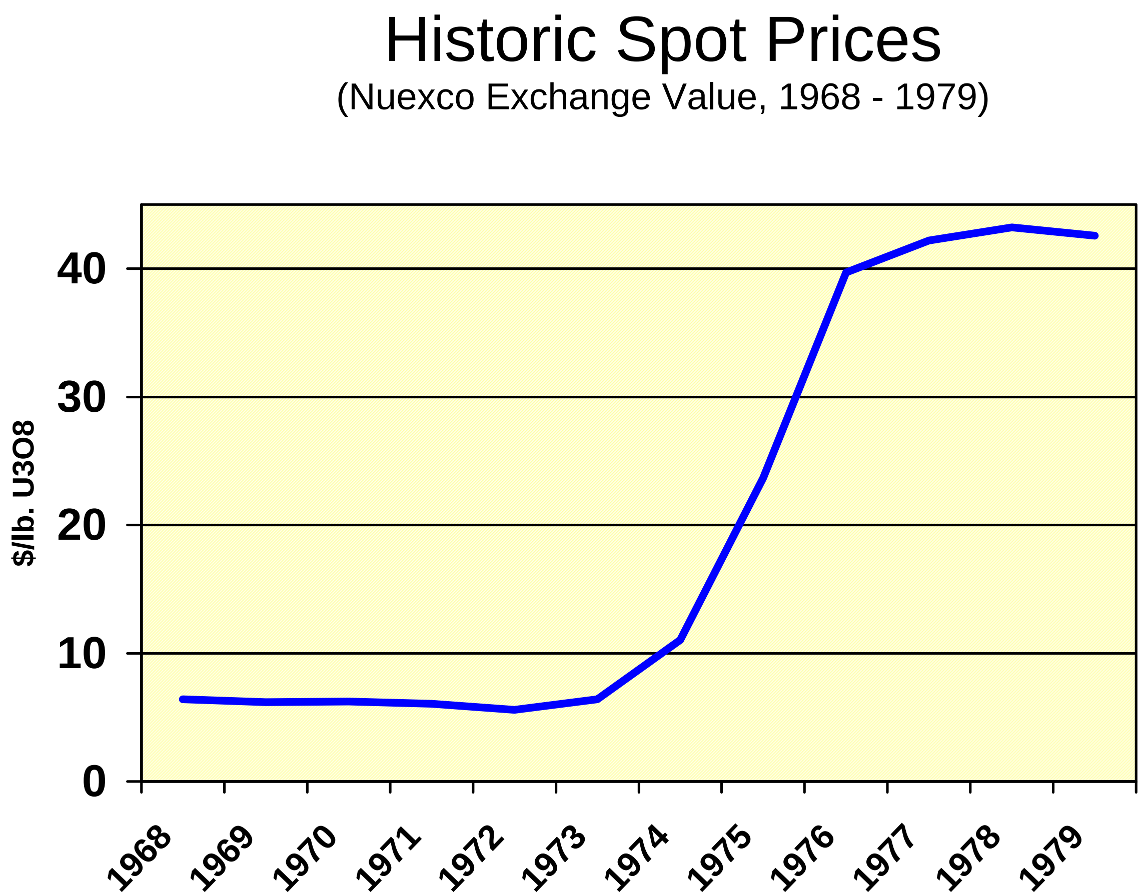
Figure 1

World Supply and Demand, 2004 - 2015



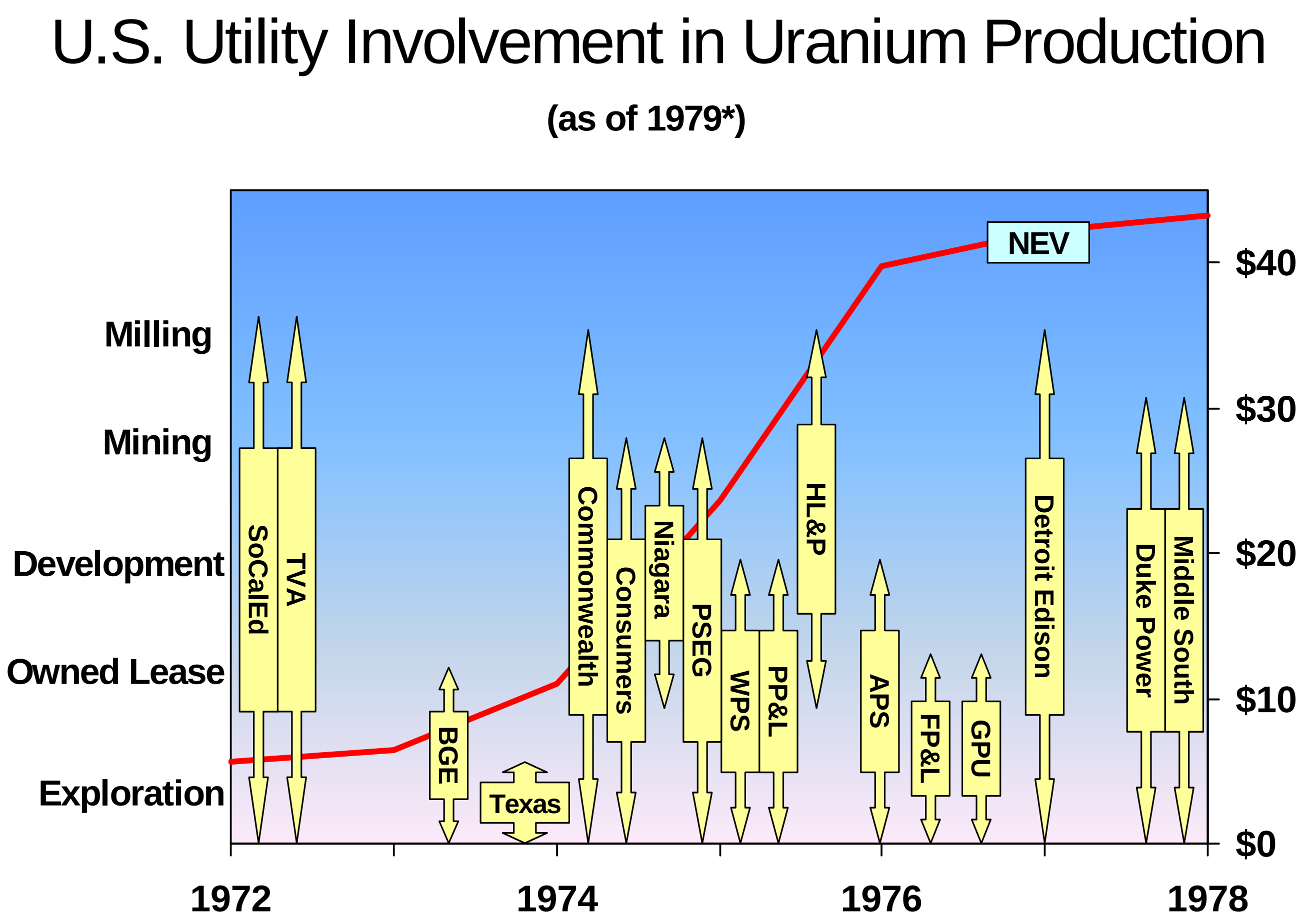
Source: Ux Consulting Company; World Nuclear Association

Figure 2



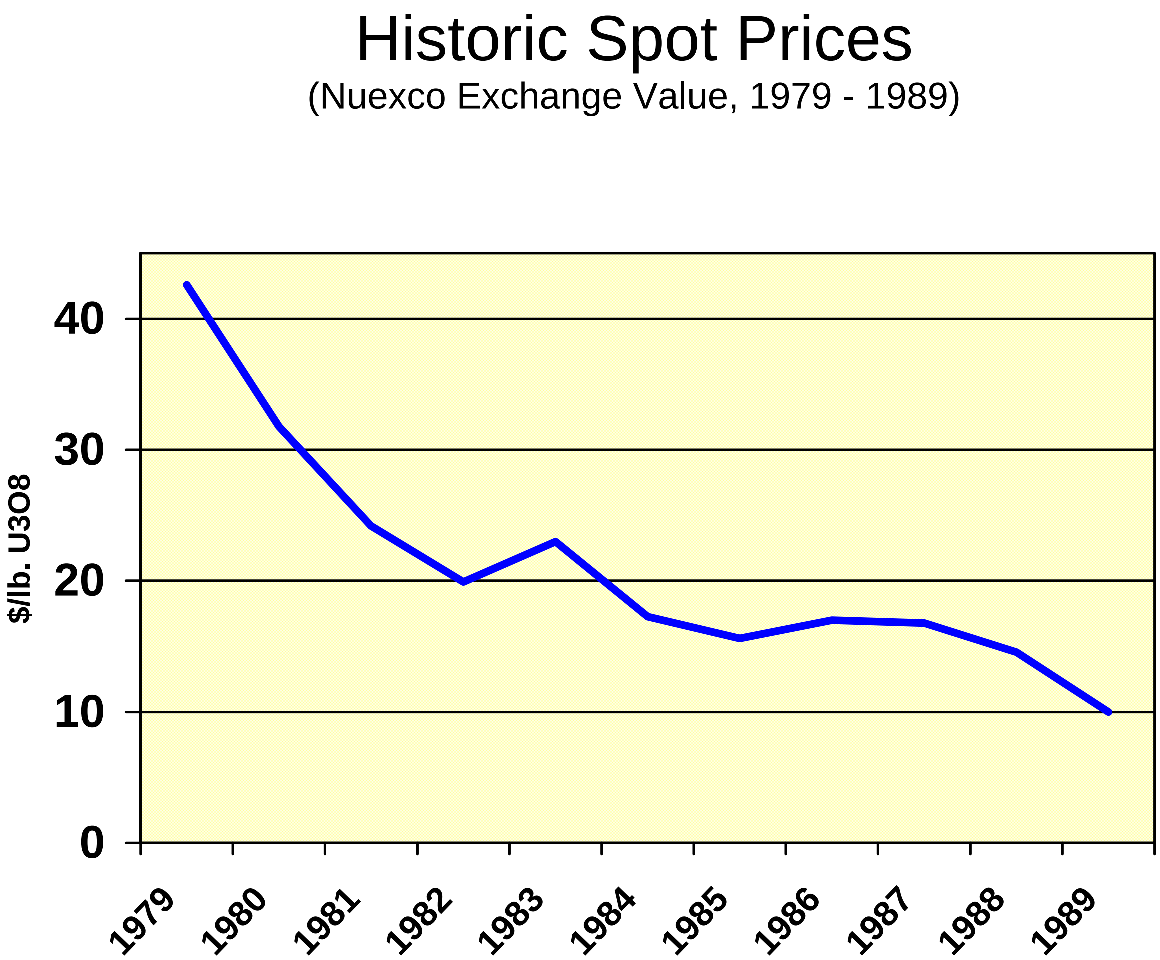
Source: TradeTech

Figure 3



** Adapted from Sullivan and Riedel, IAEA 1979*

Figure 4



Source: TradeTech

Figure 5

Utility-Producer Relationship Matrix