Financial Risk Inherent in Oil Fracking

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Adam Smith and Karl Marx

The central economic problem associated with Marxism is that production is based on quotas. In the Soviet Union, quotas were determined by Gosplan where prices were arbitrary with little or no association with costs. Gosplan-administered prices allowed a Soviet company to have a checking account to pay for supplies and wages and deposit receipts. If prices generated a negative cash flow, the company received an injection of cash to keep it solvent (100% subsidized). If by chance funds were accumulating in the checking account, the excess was removed (100% taxed). Obviously there was no incentive to be efficient. Moreover without prices related to costs, Marxist society was robbed of a vital signal of when and where to invest in new capacity. A capitalist society operates on profits which do provide an incentive to be efficient. And if price is primarily set by supply and demand, then it becomes a vital signal of when and where capital should be employed to expand productive capacity.

In the World of Adam Smith

My first exposure to the free market was probably in the freest market of them all: shipping. Tanker rates are extremely sensitive to the relationship between supply and demand both globally and locally. In a global setting where supply exceeds demand and rates are low, a shortage of capacity at a particular load area would cause a spike in local rates. This then becomes a signal for tanker owners to divert their vessels to earn a higher return, which they do. Rates remain high until enough tankers show up for supply to again exceed demand, suppressing rates. While higher rates indicate that ships are in short supply, they do not let owners know the degree of the shortage. Owners have no idea how many ships are needed. They learn “how many” when too many show up at the load area. Even if owners knew how many ships were needed, which they don’t, too many owners would deploy their vessels to fill that need in a race to be first. Despite this weakness, the “invisible hand” of price assures that the distribution of tankers is responsive to fluctuations in global oil movements with no external assistance whatsoever.

After graduating with a MBA in 1971, my first civilian job was in the planning division of a shipping company. The planning division was composed of three individuals, two recently hired graduates as analysts with no previous experience in shipping, and our supervisor. Our first assignment was to answer the question whether the shipping company, active in both dry bulk carriers (iron ore, coal, grain) and tankers, should order a very large crude carrier (VLCC). Typical VLCCs were about 250,000 deadweight tons (dwt) meaning they could carry crude oil cargoes of about 240,000 tons. The two of us took different tacks to address this issue.

Late 1960s and early 1970s was a time of rapidly expanding demand for VLCCs because of growing oil demand in Europe and Japan, and most importantly, the transition of the US from self-sufficiency to import dependency. Having rapidly exhausted available supplies from nearby sources in South America and West Africa, most of the incremental demand for crude oil was from far-off Middle East. This gave an enormous impetus to VLCC demand. Rates rose as demand absorbed supply igniting an ordering spree for new vessels when rates cleared that necessary to financially support building a new vessel.

There were two chief constraints on how many vessels can be ordered. One is available financing. If banks are acting conservatively, they would require a multi-year charter (preferably 5 years) from a creditworthy charterer such as a major oil company. Then the constraint, under these circumstances, would be the availability of suitable charters. The second constraint is the capacity of the world’s shipyards to build

VLCCs. This constraint becomes controlling when shipyards accept orders with nothing more than a down payment, which they are tempted to do when rates are high. With high rates, shipyards perceive that there will be little difficulty for owners to attract permanent financing to fund the sequence of payments while the vessel is under construction. Shipyards are hesitant to start construction of a vessel without an owner lining up permanent financing such as a commercial bank loan or government supported shipyard credit.

There were two VLCC (business) cycles in the years prior to our being hired. In both cases, when rates rose, owners collectively ordered too many VLCCs. There is a saying in shipping that if there is a need for one new vessel, ten owners will order it. When the VLCCs were delivered after a lapse of 1-2 years after placing their orders, the market was flooded with excess capacity causing a rate collapse, cessation of further orders, and financial distress for those who were too aggressive in ordering new capacity. But bad times did not last long because the underlying demand for VLCCs was rapidly expanding absorbing excess capacity. We were then in the third VLCC cycle. Rates were very high and rising higher. My co-worker, an economist working towards his doctorate, looked at the previous VLCC cycles and noted that the number of VLCCs already on order far, far exceeded the total of the previous two cycles. Shipyard capacity in the interim had been vastly expanded as part of the economic development of Japan (and other nations) to foster employment and exports. Now the fondest dreams of owners to increase the size of their fleets could be accommodated. Based on his analysis of the size of the existing order book compared to past levels, he concluded that the company should not order any tankers.

My approach was different. I calculated the crude oil growth rates necessary in key consuming areas to absorb VLCCs already on order. Even allowing for further growth in oil consumption, which was already at historically high levels, and taking into account the exponential effect oil growth had on tanker demand emanating from the Middle East, more than enough tankers were on order to fulfill record oil growth for years to come. My conclusion was not to order any tankers.

So what happened when the president of the shipping company got off the plane in Japan after reading our two reports? He immediately made a down payment for three ULCCs – ultra large crude carriers of 350,000 dwt – the largest at that time – which represented a mammoth expansion of the company's tanker fleet. Why? He was mesmerized by VLCC rates being so high that an investment in a new vessel with a 20-year life could be recouped during its first year of operation. The problem was that the president did not have these three vessels immediately available to be employed in a peak market. He would have to wait three years before the shipyard, already stuffed with orders, could get around to building his vessels. By that time the peak market, by historical standards, would have been long gone.

It turned out that his orders were among the last to be placed. Shortly after his return to the US, the 1973 oil crisis struck and cheap oil was gone forever. Oil consumption collapsed along with demand for existing vessels. Not only did this mean that tankers operating without oil company charters were left bereft of revenue sufficient to sustain operations, but it also meant that all those VLCCs on order were no longer needed. With no subsequent recovery in oil demand, the VLCC market went into a prolonged two-decade-long depression. VLCCs delivered after the crisis without underlying charters were not to see a single day's profitable operation before they were scrapped. For some, scrapping occurred immediately upon delivery. The shipping company the two of us worked for was eventually liquidated even with the modification of the ULCC orders to smaller sized tankers, which also were not needed. Luckily for us we found other jobs.

What did I learn? Price is a reliable signal of when to add capacity, but price does not tell you how much capacity to add. We invariably add too much capacity because those responsible for making investment decisions believe that high prices will last forever: no end to the good times. Unfortunately their fondest dreams can be realized by the eagerness of banks to finance capacity expansions when profits bloom. Forecasts aid and abet this behavior by supporting the contention that high prices will invariably last long enough to economically justify further capacity expansions. I've seen this story repeated over and over for industry after industry. While Marxism doesn't work – that has been clearly demonstrated – the free market is flawed because there are no controls over capacity expansion condemning industries to the ups and downs, the booms and busts, of the business cycle.

There seems to be no exceptions that I can think of other than monopolistic control over the market. In the world of oil, this was accomplished by Rockefeller's control over the refining industry. After Rockefeller, the mantle of controlling oil prices passed to a cartel of major oil companies headed by Shell Oil that parceled out geographic spheres of influence among major oil companies limiting competition. When that failed, control of oil prices passed to the Texas Railroad Commission that authorized the output for all oil wells in Texas and Oklahoma. The Texas Railroad Commission lost control of price via production quotas in the early 1970s when it was forced to authorize full production of all wells under its jurisdiction to meet demand. Shortly after, the 1973 oil crisis struck and OPEC gained the upper hand. OPEC mimicked the Texas Railroad Commission of influencing price by controlling volume. Rockefeller, Shell, and the Texas Railroad Commission succeeded in keeping stable (and low) oil prices, but OPEC was not interested in low prices. Rockefeller failed when he could no longer control global refining capacity; Shell Oil cartel and Texas Railroad Commission failed because they could not control non-cartel oil production.

For OPEC or any cartel to work, its members must be willing to cut production when price weakens. Under OPEC, the only major swing producer was Saudi Arabia. In 2015 Saudi Arabia gave up its role to cut production for the benefit of others and increased production to regain its historical market share. This should not be looked at as a monument of permanence. There may come a day when Saudi Arabia becomes more concerned over price than market share.

Is There Such a Thing as Stable Oil Prices?

A simulation was created to analyze the challenges faced by an oil cartel managing volume to control price.[1] The simulation involved an oil cartel whose output is large enough to affect global prices. The cartel desires to maximize its revenue over the long haul. Maximizing price does maximize revenue in the short haul, but not for the long haul. Maintaining high prices has long term consequences on cartel volume, which ultimately affects revenue. A high oil price:

- Puts a drag on economic activity reducing energy consumption;
- Induces energy users to switch from oil to natural gas or coal or alternative energy sources reducing oil demand;
- Incentivizes motor vehicle owners to consider alternative fuels or hybrid models or smaller sized vehicles with improved mileage and to drive less miles, reducing gasoline demand;
- Creates an incentive for non-cartel owners to upgrade existing oil production facilities and invest in new capital projects increasing oil output.

The combination of lower crude oil growth, better maintenance of existing production capacity, and, most importantly, investments in new incremental sources of oil by non-cartel producers reduces the market for the oil cartel. Eventually supply exceeds demand and prices fall. A low oil price:

- Diverts money away from buying oil to buying goods and services that enhance economic activity, which encourages energy consumption;
- Acts as an incentive to buy larger-sized motor vehicles that get less gasoline mileage and encourage people to drive greater distances, increasing gasoline consumption;
- Discourages other forms of conservation and encourages more wasteful or excessive levels of energy consumption (e.g. flying cargoes of flowers from New Zealand to Europe and US);
- Provides little incentive to maintain oil flow in existing wells and to drill new wells.

These are the classic economic conditions for creating cyclicality in a free market – high prices increase supply and suppress demand and low prices increase demand and suppress supply. Similar to prices for other businesses and industries operating in a competitive environment, oil prices cycle between extremes depending how supply lines up with demand plus the perception by buyers and sellers to a possible change to that relationship.

The Simulation Model

Oil Cartel Controlling Price

In the simulation, the oil cartel does not issue an edict to control price. The control mechanism is indirect through production volume as it influences inventory. If production volume is too high in relation to demand, inventory begins to climb. Oil consumers in a world of plentiful inventory play one competing producer off another to obtain their supplies for the lowest possible price. The oil market reacts to excess inventory by price discounting. At some point, the cartel is forced to cut prices to remain competitive.

Falling prices tend to increase demand, but low prices also cut back on maintenance of wells and drilling for new oil, both of which adversely affect future oil production. Rising demand coupled with declining supply causes demand to exceed supply, leading to inventory drawdowns. As inventories fall, oil consumers lose their negotiating strength. Now it is the turn of the oil producers to play one competing consumer off another to obtain the highest possible price for what has become a scarce resource. As the cartel reacts to falling inventories by increasing prices, a corrective reaction sets in. Higher oil prices adversely affect economic activity depressing energy consumption. Oil consumers reduce wasteful consumption and tend to buy fuel-efficient smaller-sized motor vehicles and drive less. Non-cartel oil producers spend money to increase production from their existing wells and make investments to bring on new production. What happens to oil prices with all this Yin and Yang, thesis and antithesis, ups and downs of a classic business cycle? Can the oil cartel adjust production to guide prices that would maximize their long term revenue? Figure 1 is a large segment of the simulation spreadsheet.

Figure 1 – Simulation Spreadsheet

	B	C	D	E	F	G	H	I	J	K	L	M	N	O
2										Production		Inventory	Months	
3				Global	Demand	Non-Cartel	%	Cartel	Total	less	Inventory	as % of	of	Cartel
4	Year	Price	% Change	Demand	Growth	Production	Growth	Production	Production	Demand	10000	Demand	Inventory	Revenue
5	0	$ 100.00		85,000		60,000	0.0%	25,000	85,000	-	10,000	11.8%	1.4	$2,500,000
6	1	$ 100.00	29%	85,850	1.0%	60,000	0.0%	30,000	90,000	4,150	14,150	16.5%	2.0	$2,585,000
7	2	$ 128.80	25%	86,709	1.0%	60,000	0.0%	40,000	100,000	13,292	27,442	31.6%	3.8	$3,440,003
8	3	$ 150.00	12%	86,489	-0.3%	60,000	0.0%	30,000	90,000	3,511	30,953	35.8%	4.3	$3,973,309
9	4	$ 150.00	9%	85,194	-1.5%	60,000	1.1%	17,000	77,000	(8,194)	22,759	26.7%	3.2	$3,779,034
10	5	$ 150.00	16%	83,918	-1.5%	60,640	2.0%	33,000	93,640	9,722	32,481	38.7%	4.6	$3,491,728

Oil prices per barrel in column C are determined by the percent change in column D, which is a function of the level of inventory in column N. Global demand starts out at 85,000 barrels (bbls) per day and climbs or shrinks by the percentage change entries in column F, which is a function of price in column C with a lag of one year. As price climbs from $100 to $150 per barrel, the highest permissible level, annual demand growth shrinks from 1% to -1.5%. Non-cartel production starts at 60,000 bbls per day and is a function of price in column C. As price increases, percent growth for non-cartel oil production maxes out at 2% for oil at $150 per barrel with a two-year delay between investing in new wells and their coming on stream. Cartel production in column I, which is determined by Evolver, maximizes aggregate revenue in column O. Column J totals cartel and non-cartel production and column K is the amount of production over demand, which is reflected in inventory in column L. Column M expresses inventory as a percentage of annual demand and column N in terms of months of inventory on hand. Cartel revenue is in column O.

Caveats

It is not that the model is difficult to build; the challenge is in assessing relationships. The relationship between inventory and price changes can be constructed using historical data as a guide, but historical data does not provide complete coverage over the entire spectrum of possibilities. More distressing, historical data do not reflect the current or future relationship between inventory and price changes. Expert opinions may have to be sought. Thus there is a significant degree of uncertainty as to the exact relationship between price changes and inventory levels as well as other relationships assumed in the model.

Investments have to be continually made in existing oil production facilities to maintain oil flow. Without these investments, oil production declines as oil fields are depleted. These investments are made during times of high oil prices and may not be economically justified at low oil prices. Moreover the higher the oil price, the greater is the incentive to explore and develop new oil fields. Several issues complicate the relationship between oil prices and new production. One is that there is a two-year hiatus between the decision to invest in developing a new oil field and its coming on stream (for deep water offshore fields, the hiatus may be over 10 years). Thus high oil prices do not immediately result in new oil field production. Revenues can be maximized in the short term by restricting cartel output since the repercussions of a shrinking oil market and expanding production are not immediately felt.

Another element of uncertainty is the difficulty to project the future output of an oil field under development. Sometimes production from a new field disappoints its investors. Other times it proves to be a bonanza, perhaps leading to other major discoveries. New oil fields, once developed, don’t disappear. The “mistake” of having too high of an oil price for too long a period of time spurs development of new oil fields, which may be in excess of future demand. This cannot be undone during times of low oil prices. Oil fields developed in northern Alaska (North Slope) and in North Sea were started when oil prices were high in the late 1970s and early 1980s. Oil prices collapsing in the mid-1980s did not stem production: once in production, always in production. Unlike conventional wells, fracked oil wells have a short life of about 3-4 years. Cessation of new fracked wells means a fairly rapid depletion in fracked oil production, which is sure to impact oil prices within a shorter time frame. It also makes investments in fracked wells more risky than conventional wells in that the probability of a strong market reoccurring after it has weakened is much reduced for an asset with a productive life of not more than four years compared to one that has a productive life of 20-30 years.

Improved technology affects the relationship between present oil prices and future addition to oil production. For instance, developing oil fields in the North Sea during the late 1970s/early 1980s presented a challenge of drilling production wells in 1,000-foot water with 100-foot waves and 100-knot gales. This was accomplished by building gigantic “ocean scrapers” on shore that were towed, tipped, and lowered into place. These 1,000-foot plus “ocean scrapers” resting on the ocean bottom and extending above the ocean surface numbered among the world’s tallest and costliest structures. Today technological advances in three-dimensional seismology have significantly cut the cost of developing new fields by reducing the chance of drilling a dry hole. Far less costly floating production platforms drilling wells from the ocean surface eliminate the need for “ocean scrapers” and have been successfully employed in waters ten times deeper. Horizontal drilling significantly extends the area (reach) that can be served by a floating oil production platform along with productivity gains in drilling speed and well depth. Floating production platforms remain on station until the oil field is depleted. They are reusable and can be moved to another oil field whereas “ocean scrapers” are fixed and must be abandoned or, worse yet, dismantled when an oil field is depleted.

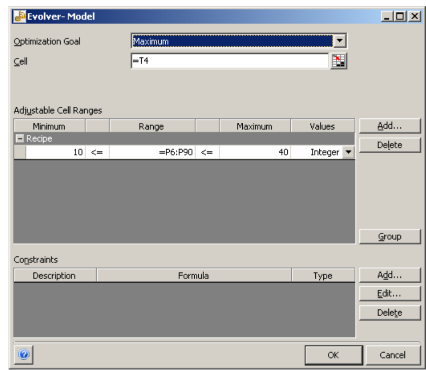
In oil fracking, there are no exploration costs and no dry holes because wells are drilled in specific geological formations that cover wide areas of entire states. But knowing where to drill is still vital information as there are sub-areas within these formations where fracked oil well productivity is higher. The breakeven price for oil fracking is falling from lower capital costs, shorter completion times, higher output volume, and longer productive life. This reduces the inherent risk in oil fracking projects and enhances their prospects.

Final Steps in Formulating the Simulation

The completed cash flow model needs a few more steps to get ready for Evolver to determine the optimal production for the cartel oil.

Figure 2 – Remainder of Simulation Spreadsheet and Evolver Menu

	Q	R	S	T
3	Negative	Excess		Objective
4	Inventory	Inventory		=SUM(O5:O90)-1000*T8-100*T12
5	=IF(L5<0,-100*L5,0)	=IF(L5>J5,L5-J5,0)		
6	=IF(L6<0,-100*L6,0)	=IF(L6>J6,L6-J6,0)		Total Negative
7	=IF(L7<0,-100*L7,0)	=IF(L7>J7,L7-J7,0)		Inventory
8	=IF(L8<0,-100*L8,0)	=IF(L8>J8,L8-J8,0)		=SUM(Q5:Q90)
9	=IF(L9<0,-100*L9,0)	=IF(L9>J9,L9-J9,0)		
10	=IF(L10<0,-100*L10,0)	=IF(L10>J10,L10-J1(		Excess
11	=IF(L11<0,-100*L11,0)	=IF(L11>J11,L11-J11		Inventory
12	=IF(L12<0,-100*L12,0)	=IF(L12>J12,L12-J1z		=SUM(R5:R90)

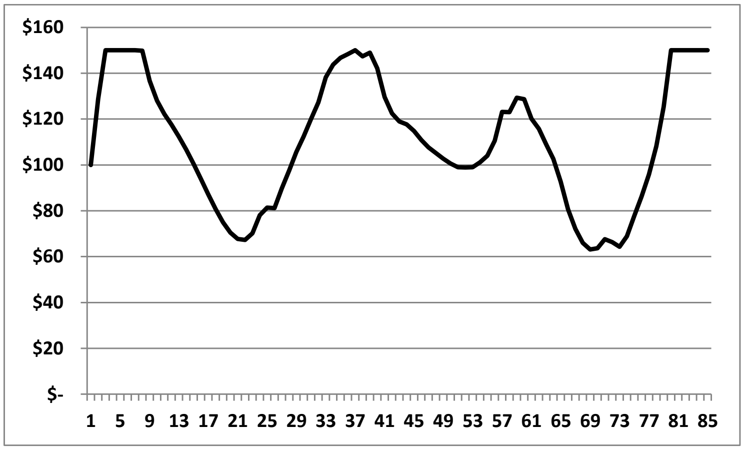


Negative inventory is to be avoided – column Q contains 100 times negative inventory expressed as a positive value. Excess inventory is also to be avoided – column R keeps track of those times when inventory exceeds annual global demand recording the excess inventory. Objective cell T4 maximizes aggregate cartel revenue in column O less two punitive charges: 1000 times the total of column Q that already has a punitive charge of 100 times negative inventory and 100 times the sum of excess inventory in column R. The objective is to maximize cell T4 by varying the adjustable cells in column P between integer values of 10 and 40, which represent cartel production between 10,000 and 40,000 barrels per day in column I. Actual cartel production starts out at 60,000 barrels per day and after that fills the gap between total oil demand and non-cartel production net of the indicated cycling. The simulation covers 85 years and the solution was interesting to watch as Evolver worked with 85 variables where each could take on 30 distinct values.

Results of the Evolver Optimization Run

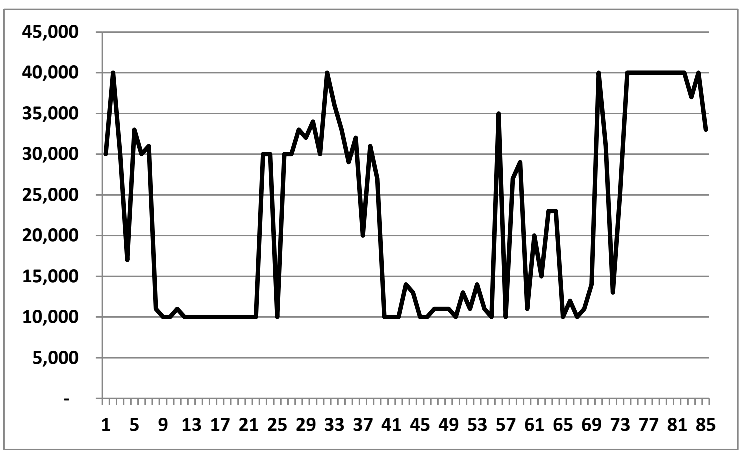
In this mythical world, oil prices cycled between the lowest and highest price permitted with short periods of stability during price reversals seen in Figure 3.

Figure 3 – Fluctuations in Oil Prices



We can now answer the question whether oil prices can be stabilized under a cartel that controls volume to influence price: the short answer is No! Even to keep prices within the extreme bounds in Figure 3, the variable portion of cartel oil production cycles between the permissible limits of 10,000 and 40,000 barrels per day (bpd) in Figure 4.

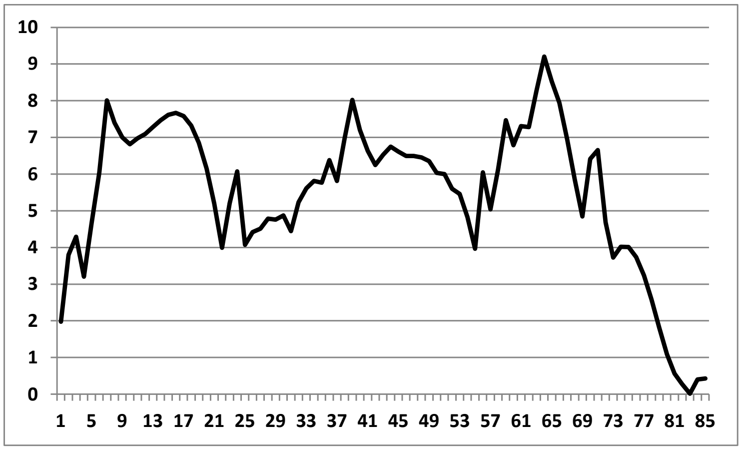
Figure 4 – Fluctuations in Cartel Oil Output



This is entirely unrealistic – OPEC production does not cycle between such extremes. Thus the cartel has its work cut out to "manage" price with volume with an eye on maximizing aggregate revenue.

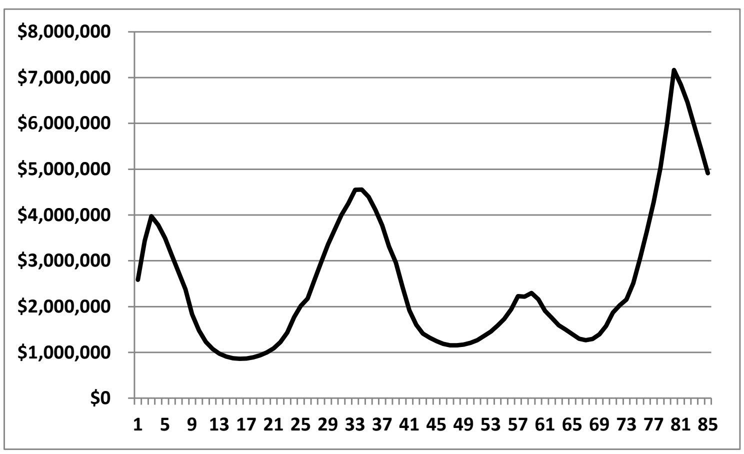
Inventory in terms of months of annual demand remained within 4-7 months for the most part seen in Figure 5. The dive to zero at the end of the period is Evolver maximizing revenue – the period of analysis probably should not extend beyond 70 years to avoid this end-play.

Figure 5 – Fluctuation in Oil Inventory



Cartel revenue in Figure 6 also oscillates considerably between high and low priced crude accompanied with large swings in production.

Figure 6 – Cartel Revenue Oscillations



Again, the revenue spike at the end is Evolver attempting to maximize aggregate revenue by liquidating inventory. This attempt by Evolver to maximize revenues with a high price of oil near the end of the time horizon should be ignored. Thus in setting up a spreadsheet, extra years should be added beyond the desired time horizon to eliminate end-game moves by an optimization program.

While this model cannot be used to model reality as relationships were arbitrarily assumed, the conclusion of the model is still pertinent. The oil cartel has its hands full in attempting to maximize revenues by controlling market price via production quotas. Expanding or cutting back on production affects supply and consequently inventories, which, in turn, affects price. It takes a major shift in cartel volume to affect a price change sufficient in magnitude to influence supply and demand because the immediate impact is relatively small. But once a trend is set in motion, it is difficult to change its direction by steering the ship of oil with a rudder tied to production that indirectly influences price.

History of Oil Prices

Other than the very beginning of the oil industry, prices were low in today's dollars up to 1973. Figure 7 is the history of oil prices since 1973 in constant 2015 dollars.[2]

Figure 7 – Annual Average Oil Prices in $ per Barrel

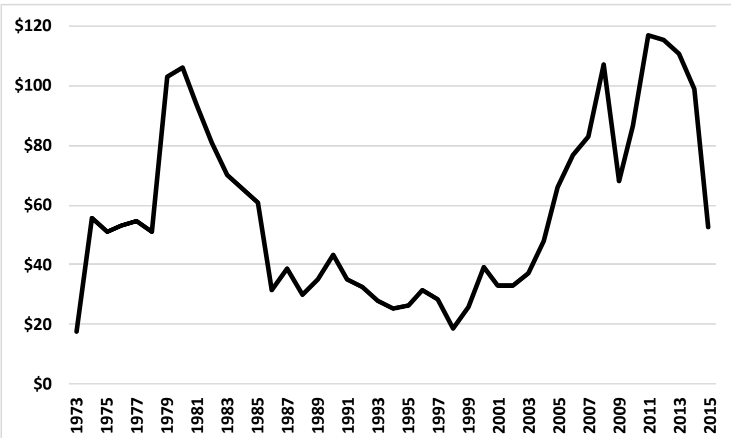


Table 1 shows the periods of high, intermediate, and low prices. High prices are greater than $80 per barrel, low prices are less than $40 per barrel, and intermediate prices are between the two. One can argue about these demarcations. They were chosen because oil fracking costs have been reduced and productivity of fracked wells have been improved to the point where it is felt that sustained prices above $80 per barrel can turn the industry on – that is, begin fracking new wells in earnest. A price of $80-$100 encourages expansion of Canadian oil sand production and development of deep oil fields. A price of $100 per barrel or more is necessary to keep OPEC nations financially solvent to cover the cost of government-assumed societal responsibilities. Prices falling below $80 per barrel stops drilling of new fracked oil wells along with developing new deep oil fields and Canadian oil sand projects and puts OPEC nations in a financial bind. Table 1 also includes the inputs for triangle probability distributions for price and years duration for each market environment.

Table 1 – Demarcation of Market Environments

Market Environment	Years	Duration (# Years)	Triangle Distribution Parameters for Oil Prices Low, Most Likely, High	Triangle Distribution Parameters for Duration Low, Most Likely, High
High >$80/bbl			$80, $100, $120	3, 5, 7
	1979-1982	4		
	2007-2008	2		
	2010-2014	5		
Medium $40-$80/bbl			$40, $60, $80	1, 3, 6
	1974-1978	5		
	1983-1985	3		
	1990	1		
	2004-2006	3		
	2009	1		
	2015-2016	2		
Low <$40/bbl			$25, $35, $40	3, 7, 12
	1973	1		
	1986-1989	4		
	1991-2003	12		

We can use Table 1 to judge the ability of OPEC to maintain high oil prices. With the exception of one year (1990), there was a seventeen-year slump in oil prices where OPEC was seemingly unable to cut production enough to sustain higher prices.

Establishing an $80 per Barrel Breakeven Price

Spreadsheet FrackedOil sets up a simulation to model oil fracking wells with the objective of maximizing revenue by varying the percentage of debt to support financing. But before that can be done, it is necessary to design the parameters of a "standard" fracked well to have an $80 per barrel breakeven price, which is derived in Figure 8.

Figure 8 – Economic Analysis of $80/bbl Breakeven Price

	A	B	C	D
32		Output	Price $/bbl	Cash flow
33	Years	200,000	$60	-$9,961,615
34	1	40%	$4,800,000	$4,800,000
35	2	30%	$3,600,000	$3,600,000
36	3	20%	$2,400,000	$2,400,000
37	4	10%	$1,200,000	$1,200,000

The well is assumed to have a four-year life with the percent of annual output given in column B along with the aggregate lifetime output of 200,000 barrels. While the breakeven price per barrel of oil is about $80 per barrel, an owner of a fracked well does not see this price. Transportation of fracked oil is very expensive as there are generally no major crude pipelines passing close to oil fracking areas and building permanent pipelines to wells with a short life time of four or less years would be quite expensive. Oil from fracked wells are gathered by local pipelines and shipped by truck to existing crude oil pipelines or to rail heads for transport by railroad tank cars to the nation's refineries. It is estimated that transportation along with the variable cost of operating a well plus some contribution to fixed costs consumes $20/bbl, over half being logistical costs. Thus an owner of a fracked well actually sees $60/bbl when the market price is $80/bbl at major refining centers. Figure 8 is the solution of What If Analysis. The parameters are a fracked well costing $10 million producing a total of 200,000 barrels over its four-year lifetime with 40% of its total production the first year, 30% the second, 20% the third, and 10% the fourth, will breakeven with a net price of $60/bbl, which corresponds to a market price of $80/bbl. The breakeven price includes a 10% discount factor. One could argue that perhaps the breakeven price should have a discount rate of 0%, but most wells have associated debt and thus there has to be some return built into the breakeven rate in order to pay interest on the debt. While the breakeven price can vary considerably for each well, verification that $80/bbl or more as the industry breakeven price was the cessation of drilling new fracked wells when crude prices fell below $80/bbl.

Figure 9 shows that the simulation starts out with a strong market with the subsequent market being intermediate then low then intermediate then high again. Duration in column B is determined by triangle distributions whose parameters are listed in Table 1. Column C cumulates these durations, which are incorporated in the simulation to determine market conditions for each year of an iteration.

Figure 9 – Spreadsheet Showing Market Condition and Duration

	A	B	C
2	Market		
3	1-Low		
4	2-Medium	Duration	Cumulative
5	3-High	in Years	Years
6	3	6	6
7	2	6	12
8	1	9	21
9	2	4	25
10	3	5	30
11	2	4	34
12	1	10	44

Since each iteration starts with a strong market, this creates a period of zero cash flows in the simulation from the end of the first period of high oil prices and the subsequent intermediate-weak-intermediate market environments before a strong market emerges again. This interim exceeds the four-year life for the last wells drilled. This "dead" period occurs in about the same timeframe for all iterations. While this could be "fixed" by having the first market condition randomly determined, it would not affect the conclusions of a simulation. The benefit of setting the spreadsheet up this way clearly demonstrates the risk of fracked wells over conventional wells. A concern whose only assets are fracked wells may well experience extensive periods of no activity and no revenue. This is hardly a mark of an on-going concern. Figure 10 shows the spreadsheet for the first five years.

Figure 10 – Spreadsheet Showing Simulation for the First Five Years

	E	F	G	H	I	J	K	L
1			Equity	25.0%		Debt Repayment		0.29523
2								
3			Total Cash Flow	$ (25,000)	$ 30,458	$ 52,416	$ 40,045	$ 42,003
4			Cum Cash	$ (25,000)	$ 5,458	$ 57,874	$ 97,918	$ 139,921
5								
6	Ending Cum Cash Position		Year	1	2	3	4	5
7	$106,668			3	3	3	3	3
8								
9	Min Cash Flow		Oil Price	$ 113	$ 117	$ 98	$ 106	$ 105
10	($34,684)							
11			Expansion					
12	Min Cum Cash Position		of Wells	10	10	5	10	10
13	($25,000)							
14			Year 1		10	10	10	10
15	Years Neg Cum Cash		Investment	$ 100,000				
16	1		Equity	$ 25,000				
17			Debt	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000
18	Total Wells		Debt Payments		$ 22,142	$ 22,142	$ 22,142	$ 22,142
19	85							
20			Revenue		$ 77,600	$ 46,800	$ 34,400	$ 17,000
21	Objective Cell							
22	$106,668		Cash Flow	$ (25,000)	$ 55,458	$ 24,658	$ 12,258	$ (5,142)

Cell H1 contains the equity investment for all fracked wells. Cell L1 is the capital charge to be placed on the debt portion of the financing for a four-year loan at 7% interest. This capital charge, derived by the PMT function, is applied against the loan amount and is sufficient to both pay off the loan in four years and provide 7% interest on the amount outstanding. Row 3 is the cash flow over 35 years and row 4 accumulates annual cash flows. Row 7 starting at column H is the market condition reflected in column C. Oil price in row 9 is determined by triangle probability distributions whose parameters for the applicable market condition are contained in Table 1.

Expansion of capital capacity in any year follows the rule that ten wells will be authorized to be built if oil prices are above $100 per barrel and 5 wells if oil prices are between $80 and $100 per barrel and none if oil prices are below $80 per barrel. Ten wells are the presumed maximum capacity of the owner to increase capacity. Five wells reflect reluctance of financial institutions to support new wells when oil prices approach breakeven. Since $80 per barrel is the minimum oil price in a strong market, either 5 or 10 wells will be authorized to be built in the first year and for each of the subsequent years of a strong market. Wells are completed one year after authorization and have a production life of four years.

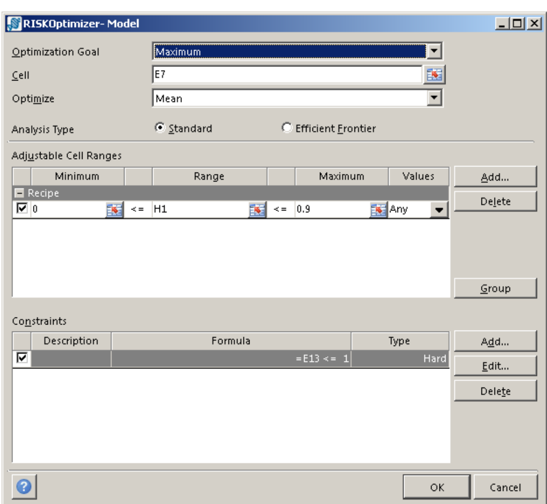
The financial analysis starts in row 14. The number of wells authorized for construction in year 1 in cell H12 is repeated in cells I14:L14 in order that the year 1 financial results are “replicable” for the remaining 34 years. The investment in cell H15 is the number of wells multiplied by $10 million expressed as thousands of dollars. Equity is assumed to be 25% of the investment. Debt is investment less equity and is repeated in cells I17:K17, again for ease of replication. Debt payments is the capital charge applied against the amount of debt. Revenue in row 20 is the price of oil less $20 per barrel for logistic and variable costs plus a contribution to overhead expenses multiplied by the step-downs in production volume. Cash flow in row 22 is revenue less equity and operating costs. The financial analysis of year 1 is replicated for year 2 and so forth for 35 years of financial results. The ending cumulative cash position after 35 years is in cell E7, the minimum cash flow over the 35-year span of the simulation is in cell E10, the minimum cumulative cash position over the 35-year span is in cell E13, the number of years when the cumulative cash position is negative (COUNTIF function) is in cell E16. The minimum number is 1 since the first year starts with a negative value for the cumulative cash position from the initial equity investment. The total number of wells drilled is in cell E19 and the objective function, to be covered shortly, is in cell E22. Figure 11 shows the first three years of the simulation.

Figure 11 – Spreadsheet Layout for First Three Years

	G	H	I	J	K	L	M	N
6	Year	1	2	3	4	5	6	7
7		3	3	3	3	3	2	2
8								
9	Oil Price	$ 113	$ 117	$ 98	$ 106	$ 105	$ 66	$ 51
10								
11	Expansion							
12	of Wells	10	10	5	10	10	0	0
13								
14	Year 1		10	10	10	10		
15	Investment	$ 100,000						
16	Equity	$ 25,000						
17	Debt	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000		
18	Debt Payments		$ 22,142	$ 22,142	$ 22,142	$ 22,142		
19								
20	Revenue		$ 77,600	$ 46,800	$ 34,400	$ 17,000		
21								
22	Cash Flow	$ (25,000)	$ 55,458	$ 24,658	$ 12,258	$ (5,142)		
23								
24	Year 2			10	10	10	10	
25	Investment		$ 100,000					
26	Equity		$ 25,000					
27	Debt		$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	
28	Debt Payments			$ 22,142	$ 22,142	$ 22,142	$ 22,142	
29								
30	Revenue			$ 62,400	$ 51,600	$ 34,000	$ 9,200	
31								
32	Cash Flow		$ (25,000)	$ 40,258	$ 29,458	$ 11,858	$ (12,942)	
33								
34	Year 3				5	5	5	5
35	Investment			$ 50,000				
36	Equity			$ 12,500				
37	Debt			$ 37,500	$ 37,500	$ 37,500	$ 37,500	$ 37,500
38	Debt Payments				$ 11,071	$ 11,071	$ 11,071	$ 11,071
39								
40	Revenue				$ 34,400	$ 25,500	$ 9,200	$ 3,100
41								
42	Cash Flow			$ (12,500)	$ 23,329	$ 14,429	$ (1,871)	$ (7,971)

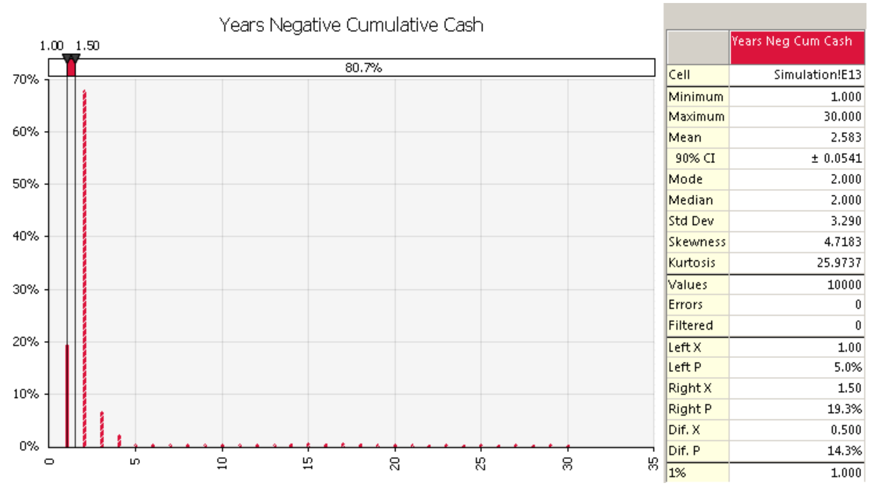
Figure 12 is the initial RISKOptimizer menu.

Figure 12 – RISKOptimizer Menu



The objective is to maximize cell E7, the cumulative cash position in year 35, by varying H1, the percentage of equity, between 0 and 90% with the hard constraint that the number of years of cumulative cash positions in E13 must be 1(the first year starts out with a negative cash flow). The RISKOptimizer solution is an equity portion of 24.7%. Figure 13 is number of years out of 35 years of operation when there is a negative cumulative cash position.

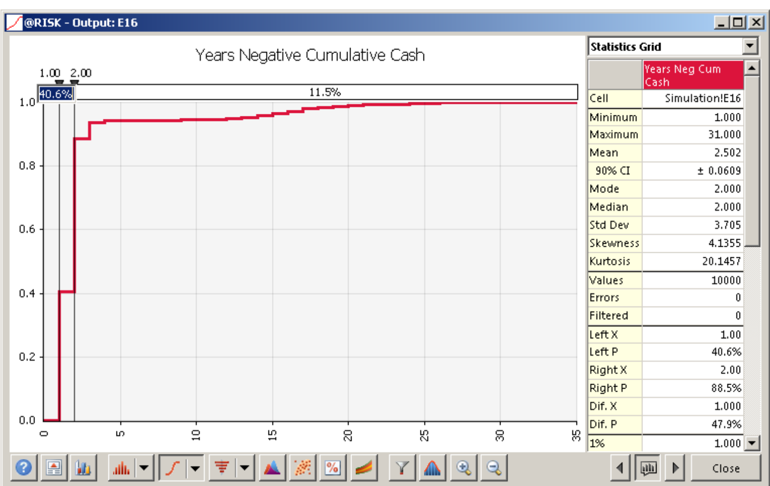
Figure 13 – Years of Negative Cumulative Cash



There is an 80.7% chance that the number of occurrences of a negative cumulative cash position will be more than 1. How can that be when there is a hard constraint that the number should not exceed 1? The reason for this is that during optimization, a hard constraint eliminates any iteration that exceeds a constraint value. But when a simulation is run on the resulting optimal values, the hard constraint is no longer operable. Thus there may be iterations of a simulation based on optimal values with more than one negative cumulative cash position.

As an alternative to a hard constraint, a soft constraint in the form of a punitive charge was incorporated in the model. The spreadsheet was modified to add an objective cell in E22 to maximize cell E7 accompanied with a punitive charge of $10,000 times the number of negative cumulative cash positions exceeding 1: =E7-10000*(E13-1). RISKOptimizer was rerun with this change and the result was a reduction in the equity to 20.7% and a reduction in the probability of occurrences of negative cash positions above 1 shown in Figure 14.

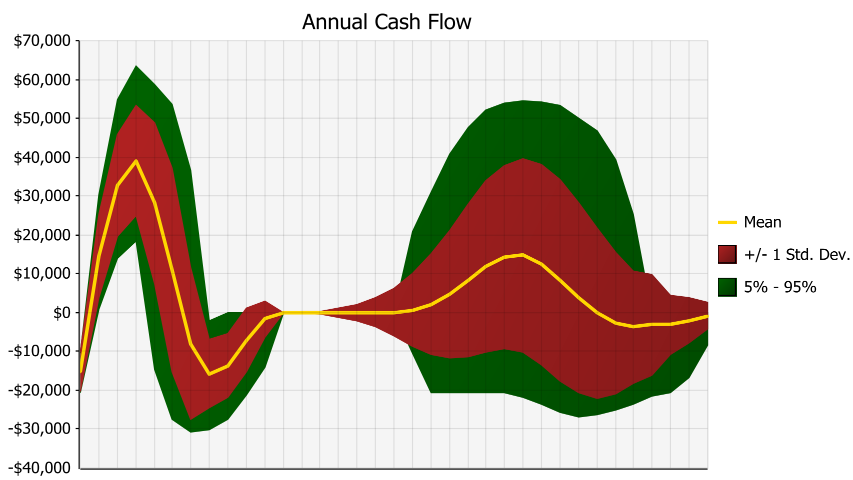
Figure 14 – Revised Years of Negative Cumulative Cash



This is the cumulative ascending probability distribution. Changing a hard constraint to a soft constraint involving a punitive charge reduced the chance of the number of years of negative cumulative cash positions being over 1 year from 80% to 60% (40.6% for 1 or less), 11.5% for greater than 2 occurrences, and therefore 47.9% chance for 2 occurrences (remember that a value of 1 is acceptable as it represents the initial equity investment).

I am partial toward soft over hard constraints. With a number of hard constraints, it may be difficult for Evolver to accumulate enough iterations to identify optimal values. With punitive charges, all iterations are employed in the search for optimal values, but some degree of experimentation is necessary to identify the appropriate values for punitive charges. Using the model incorporating punitive charges, cash flows over 35 years in Figure 15 reveal the consequences of always starting an iteration with a strong market. The starting cash position is either $10 or $20 million reflecting the first year investment of 20% X $10 million X 5 or 10 wells.

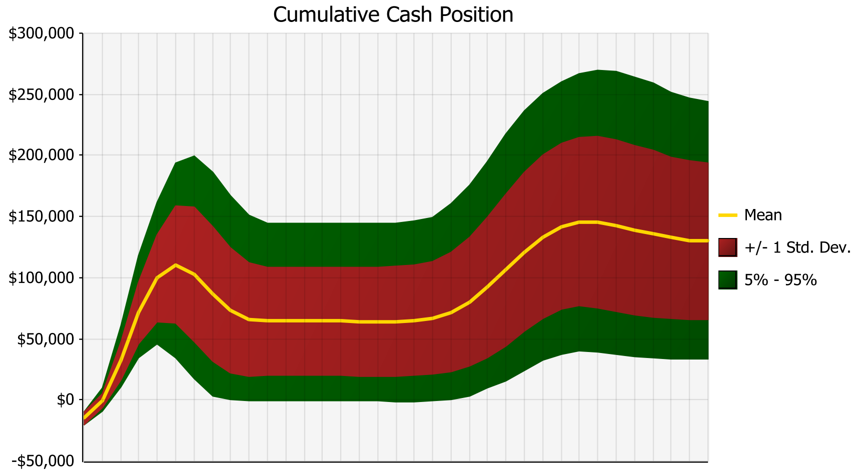
Figure 15 – Cash Flow Over 35 Years



The cash flow is initially positive, but turns negative when oil prices fall below $80 with the start of the intermediate market. Prices falling below breakeven generates negative cash flows for four years after completion of the last set of 5 or 10 wells. After that there is no revenue. A period of zero revenue occurred mostly twice. Once after the completion of the first strong market and then again near the end of the simulation. The timing of the start of the second strong market had enough variation built into its starting year to mask the intensity of periods of zero cash flows; but on individual iterations, they still occur as seen by striking the F9 key in Random mode.

Maximum negative cash flows can be as large as $30 million per year. Generally speaking this is not fatal if the cumulative cash position is large enough to fund the deficits, which it is most of the time as seen in Figure 14. Figure 16 reinforces this point that cumulative cash positions are sufficient to fund a cash outflow most of the time.

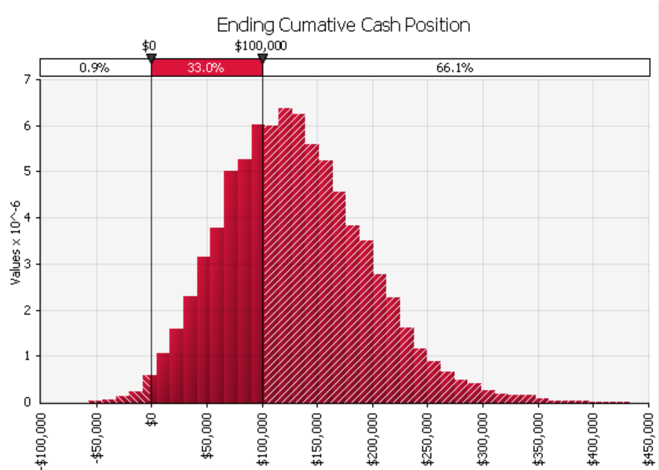
Figure 16 – Cumulative Cash Position Over 35 Years



It appears that other than year 1 where the initial negative cash flow is either $10 or $20 million, the cumulative cash position is positive growing during the initial strong market. It levels off during the subsequent intermediate-weak-intermediate markets when cash flow is zero and then subsequently resumes growing with the start of the next strong market. The cumulative cash position levels off again during the end period of the simulation when cash flow is again zero.

Although it appears that the cumulative cash position is always positive, this is not quite true as the entire band represents 95% of all values. Thus there is a small chance that there may be negative cumulative cash position illustrated in Figure 14. The low probability stretches of negative cumulative cash extending over a number of years are those periods of no revenue that happen to start out with a negative cash position. Figure 17 is the ending cumulative cash position after 35 years of fracking activity.

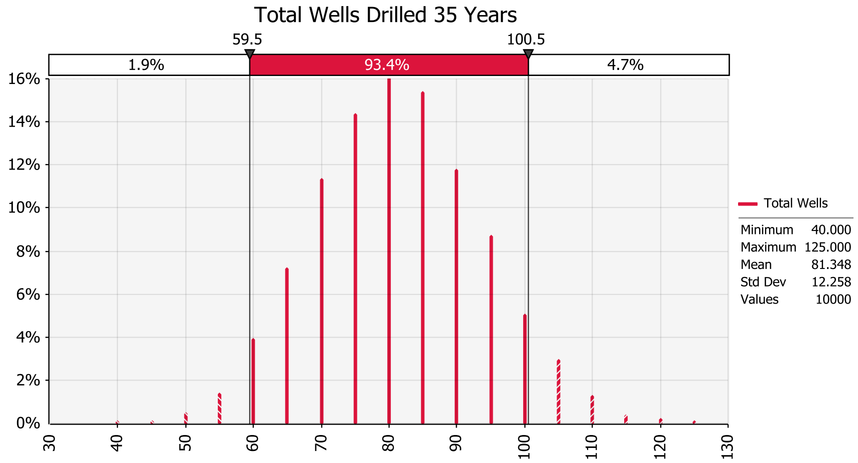
Figure 17 – Ending Cumulative Cash Position



	Ending Cum Cash Position
Cell	Simulation!E7
Minimum	-$56,538.42
Maximum	$433,653.95
Mean	$130,060.88
90% CI	± $1,057.96
Mode	$79,766.21
Median	$125,818.53
Std Dev	$64,313.56
Skewness	0.4182
Kurtosis	3.2395
Values	10000
Errors	0
Filtered	0
Left X	$0
Left P	0.9%
Right X	$100,000
Right P	33.9%
Dif. X	$100,000.00
Dif. P	33.0%
1%	$2,166.21

The initial investment is either 5 or 10 wells costing $50 or $100 million ($50,000 or $100,000). The chance of the ending cumulative cash position being less than $100,000 is 33.9% including a 0.9% chance of being less than zero. The mean is $130 million. The maximum ending cumulative cash position of $433 million reflects a string of short duration weak and intermediate markets coupled with long duration strong markets. Figure 18 is the number of wells drilled over 35 years.

Figure 18 – Total Number Wells Drilled Over 35 years



The total number varies between 40 and 125 wells with an average of 81 wells. There is a 1.9% chance that fewer than 60 wells would be drilled over the 35-year span and 4.7% that they will number over 100. Thus there is a 93.4% chance that the number of wells drilled will be between 60 and 100 wells. As a point of reference, drilling the maximum of 10 wells per year would result in 350 wells, but oil prices prohibit this from happening. The 81 wells represent a total investment of $810 million. The ending cumulative cash position is money free and clear as normal operations amortized the investment in the wells.

Table 2 shows the respective long term returns. If the initial investment is limited to the cash required to drill the wells ($10 or $20 million), then the return on the ending cumulative cash position looks attractive. If the total investment in the initial wells are used for evaluating returns, then the investment is not attractive. Business people often prefer to evaluate investments in terms of a leveraged basis of cash outlay, but financial analysts prefer to evaluate projects on a non-leveraged basis. The choice is an important one in evaluating competing projects.

Table 2 – Long Term Returns

Initial Investment	Rate of Return over 35 Years	Rate of Return over 35 Years
	Average End Cum Cash Position $130 mm	Maximum End Cum Cash Position $433 mm
Leveraged		
$10 mm	7.6%	11.4%
$20 mm	5.5%	9.2%
Non-leveraged		
$50 mm	2.8%	6.4%
$100 mm	0.8%	4.3%

The probability of achieving the maximum cumulative cash position is very low. If the average cumulative cash position is used for evaluation purposes, then the return is relatively modest if the project is evaluated on a cash investment basis (leveraged). On a non-leveraged basis, the return is quite low.

Interpreting Results

Switching from a hard to a soft constraint had a curious result. With a hard constraint on the number of occurrences of negative cumulative cash positions, maximum revenue could be obtained with equity nearly 25% for financing new wells. The number of negative cumulative cash positions was reduced with a soft constraint, but the degree of equity fell to 20.7%. Thus to reduce risk, leverage was increased, just the opposite of what normally occurs in financial analysis. Why?

Risk was defined as the frequency of negative cumulative cash position. These are associated with making new investments at the start of a strong market environment. If a cumulative cash position is not large enough to sustain the equity investment, then it is counted as a year of a negative cumulative cash position. But the probability can be lessened by relying more heavily on debt, reducing the required equity investment. Thus cutting the number of negative cumulative cash positions can be achieved by increasing the degree of leverage. One may argue that perhaps more leverage should be used, but this detracted from the objective of maximizing revenue.

Managing Risk for an Oil Fracker

This simulation models reality in that owners of fracked wells drill as many wells as possible as long as oil prices are high enough for them to attract necessary capital. Where are the sources of this capital? Financial managers of pension and insurance companies have huge cash reserves that must be invested to cover current and future obligations. In an environment of zero interest rates on government securities, alternative forms of investment have to be sought that do earn a return. This means accepting a higher degree of risk. Investing in fracked wells was very attractive when oil was over $100 per barrel. Now billions of dollars of fracked oil debentures are in danger of default, and some have already defaulted in 2016 with oil prices far below breakeven. This is an unintended consequence of not letting the market set interest rates; that is, forcing interest rates of government securities to near zero levels fuels the search for higher returns fraught with even higher degrees of risk perhaps perpetuating a junk bond bubble.

The simple advice to oil frackers is to cease drilling new wells about 3-4 years before a strong market lapses. Thus the last wells drilled are mostly amortized before oil prices fall. This advice is just as useful as advising to sell a stock when it reaches its historical high. For many individuals, this is the time they are buying the stock, why else would it be at a high? The best advice that can be given is that markets are cyclical no matter how short-term thinking an individual may be. Table 1 and Figure 7 should be burned into a manager's mind. *Good times do not last forever; and bad times seem to last longer*. Moreover, the longer a strong market exists, the higher the probability that it will not last that much longer. Financial institutions buying 10-year debt to finance an asset with a four-year life on the basis of an on-going fracking program should also think about their risk profiles. Investors of tens of billion dollars of debt had a few good years of high returns *on* their principal, now they can worry about the return *of* their principal. If financial institutions were more concerned about risk, maybe the most aggressive dreams for capacity expansion could not have been realized

.

Difficulty of Forecasting

Back in the early 1970s working for the shipping company, I had in my hand all I needed to know to predict an oil crisis. The growth rates I assumed, based on actual rates, would not only make the Middle East the primary source of world oil, but would also tax their capacity to produce oil. Unbeknownst to me at that time, the oil market had already made the transition from a buyers' to a sellers' market. Oil companies had lost control of pricing, but they and the oil producers had not yet realized it. The situation needed only a trigger event for the era of low oil prices to end. I missed this point entirely. I could have written a paper on the "Coming Oil Crisis", but would the *New York Times* or *Wall Street Journal* publish such an outlandish assertion after a century of low oil prices as an Op-Ed article? The trigger event that changed the oil market forever was the Saudi oil embargo of oil shipped to the US and Netherlands for support of Israel during the Yom Kippur War. The resulting shortfall in supply caused oil prices to spike, taking Big Oil and oil producers entirely by surprise. I mention this to demonstrate the difficulty in forecasting prices even for those most immerged in an industry. Unforeseen and unforeseeable events have repeatedly made mish-mash of logically constructed forecasts based on a continuation of existing trends.

I remember when oil prices were at $100 per barrel in the years prior to 2015. A well-known oil expert, after traveling the world talking to oil producers and oil company executives and who knows who else, came to the logically arrived conclusion that $100 per barrel oil was here to stay: it would never end. Why? World oil consumption was rising and incremental oil was mainly from unconventional and costly sources: oil fracking, Canadian oil sands, and deep well drilling in 10,000 foot waters; all of which required $100 per barrel oil to be exploited. Moreover there was every incentive for OPEC to maintain high prices because the cost of free medical, housing, education, and guaranteed income coupled with a huge growth in their populations required high oil prices to prevent societal breakdown. Despite my life-long experience in watching forecasts fail, I bought into this argument hook, line, and sinker. How wrong could I have been? Within a year this forecast was proven to be entirely wrong.

The wild card that brought about lower oil prices far below that to sustain incremental sources of production in the face of growing world oil consumption was Saudi Arabia giving up its role of being a swing producer. Rather they desired to punish Russia for supporting Assad in Syria, to starve Iran of funds to prevent or at least slow down its nuclear weapon development, and last thought of, to bankrupt the US oil fracking industry. All Saudi Arabia had to do to lower prices was open up the oil spigot and flood the market with unneeded oil. The prognosis at this time (summer 2016) is for lower prices for a whole set of logical reasoning built around bloated inventories even in the face of continued growing demand for oil. But low prices may not remain forever if Saudi Arabia believes that it has achieved its objectives or that it is facing societal disruption over cuts in public spending or its record production levels cannot be sustained. This latter point is the basis for those forecasting higher oil prices. But even this forecast is fraught with uncertainty depending on future production in Iraq and Iran where plenty of extra capacity of cheaply produced oil can be developed in a relatively short time. It may be beyond Saudi Arabia’s ability to act on its own volition if, for instance, an outbreak of war between Iran and Saudi Arabia closes the Arabian Gulf to oil exports. Then the frackers will be back in business overnight. Those who invest in the oil industry have a wide assortment of forecasts on oil prices to choose from; one of which may actually turn out to be true. This is what makes investing in oil so challenging.

One Final Observation

If fracking company investment decision makers would only think in terms of the transience and impermanence of business conditions (oil markets), then they would conduct themselves in such a way to always be ready to face a market reversal. This would subdue the overall temptation of gross overexpansion; the pit bull that inevitably turns around and bites its owner. Banks insisting on swaps being arranged to protect revenue of fracked wells for some time into the future was an excellent example of risk mitigation. Simulation can be employed to determine the degree of swap coverage to reduce risk to a manageable level without unduly affecting potential profitability.[3] Unfortunately these swaps were generally too short in duration to provide full coverage for the underlying debentures, but they did delay the onslaught of the vicissitudes of low oil prices on corporate solvency for certain companies. Perhaps the next time around, they will provide adequate coverage for all.

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[1] “An Oil Price Model” (Section 23) in *Energy Risk Modeling*, Palisade, 2013 provides a full description of the simulation model.
[2] *British Petroleum Energy Statistics 2016* can be downloaded from the BP Web site www.bp.com.
[3] “Mitigating Risk with Swaps” (Section 15) in *Energy Risk Modeling*, Palisade, 2013.