Oil Upstream Investments
and
Technology Learning

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Content

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1. Background

The purpose of this Memo is to use experience curve methodology to assess the effect of technology learning on estimates of investments in the upstream oil sector over the period 2001-2030. For the purpose of the analysis the upstream oil sector is defined in Figure 1. The chain has three links: Exploration, Development and Production. Investments are supposed to take place in the first two links of the chain. Learning is assumed to take place independently in the three systems.

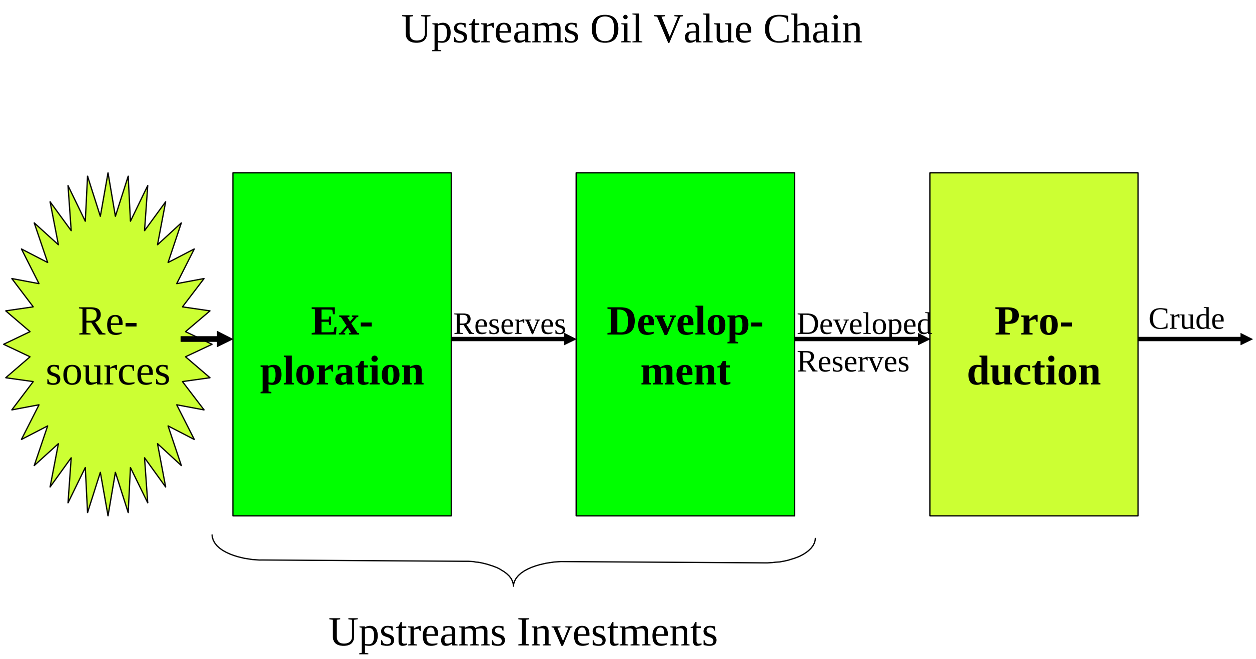

Figure 1. Oil E&P activities.

The demand for Crude oil is taken from the Reference Scenario in WEO2002. Based on WEO2002 and IFP(2003) forecasts for different regions and off-shore productions, global production is then allocated to seven different sources of oil: OPEC-Middle East, OPEC-Rest, On-shore Non-OPEC, Off-shore Shallow Waters, Off-shore Deep Waters, Off-shore Ultra-Deep Waters, and Unconventional Oil. Such allocation is necessary to obtain a hold on technology learning. The need for physical investments to obtain “Reserves” and “Developed

Reserves[1]" is estimated based on R/P-ratios and Yield per Developed Reserve. Possible developments of E&D prices during the 30-year period are then investigated with experience curve methodology building on historical analysis and benchmark progress ratios. Different scenarios for technology learning are developed and it is argued that they together bracket reasonable continuous technology progress.

The experience curve methodology and the model used to estimate physical investments and calculate investment costs are discussed in the next section. Sections 3 and 4 apply the methodology and the model to the two first links in the upstream chain. Section 5 sums up the scenario results.

2. Methodology

Figure 2 depicts the methodology used and the role of the model to obtain physical investments.

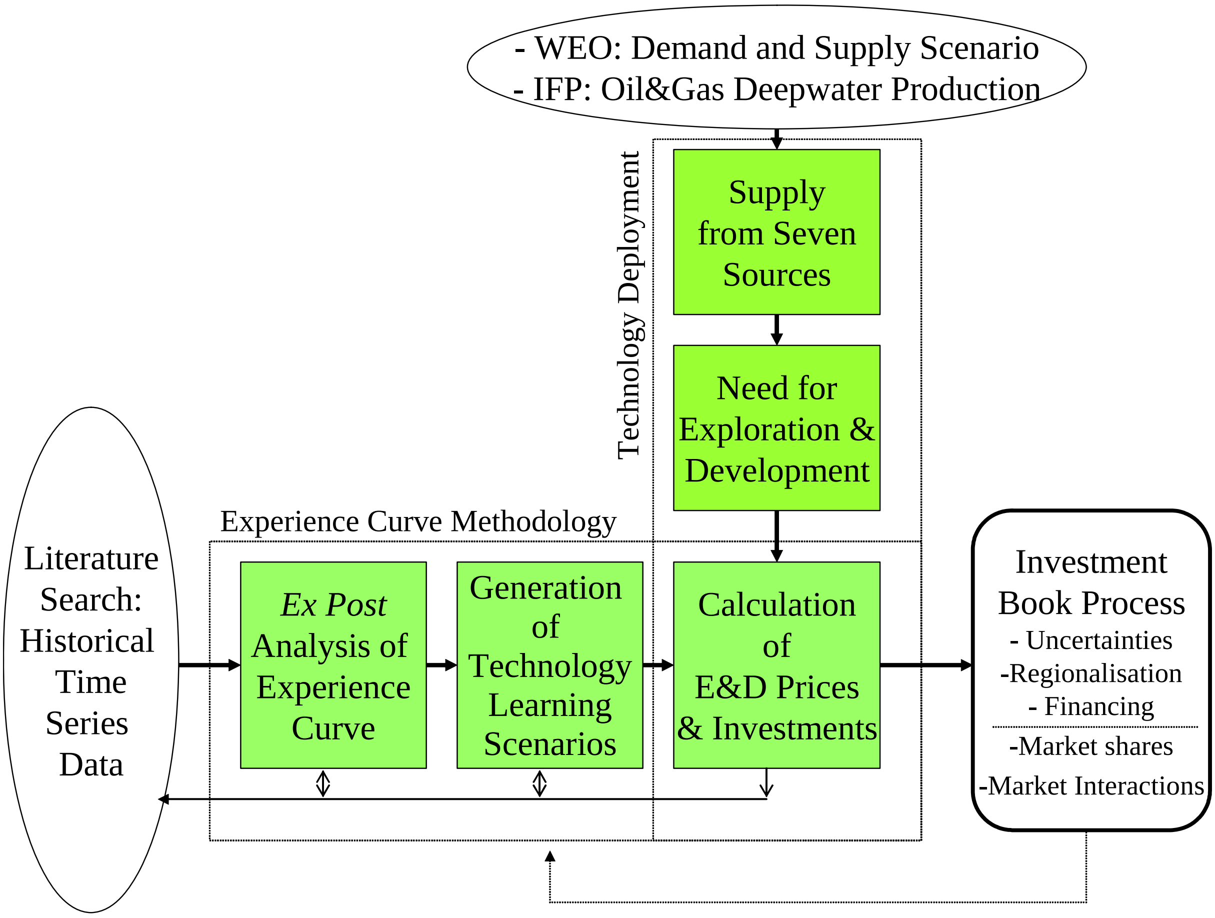

Figure 2. Experience Curve Methodology and calculation of Technology Deployment for Physical Investments in Exploration and Development (TED4FED).

Figure 2 shows that there are two analytical streams that come together in the calculation of F&D prices and total investments. The prices cannot come out of the experience curve stream alone; the logic of the experience curve tells us that prices are generated by market

[1] I will use "Developed Reserves" to denote oil ready for lifting

experience and the amount of market experience in the form of exploration and development is provided by the other analytic stream (Technology Deployment). Both streams are discussed in more detail below.

The major input from this exercise to the Investment book process is estimates on the possible effects of technology learning: “uncertainties in technology progress”. Using a researched methodology to establish these estimates contributes to validating and benchmarking the overall results. However, the analysis could also provide input to discussions on regional distribution of technologies and their financing (“Is learning global or regional?”, “Who will finance learning investments?”) and, further down the road, when revisiting assessments of market shares and interactions (“Will learning substantially change the competition between different technologies and technology chains?”).

2.1 Analytic stream: Experience Curves

2.1.1. Ex-Post Analysis of Experience Curves

The basic methodological points for analysis of historical experience curves are provided in the Memo “Investments in the Mid-stream LNG Chain and Technology Learning”(Wene, 17 March 2003). The LNG-Memo highlights three important standard issues in such analysis:

- *Benchmarking.* The measured progress ratios (or learning rates) should be compared to ratios measured for other technologies. Published data on distribution of progress ratios (Dutton and Thomas, 1984 and McDonald and Schrattenholzer, 2001) leads to a distinction between emerging new technologies (“Dutton-Thomas Technologies”) and grafted technologies.
- *Price-Cost Cycle*. Prices can be observed in the markets, but cost data are usually very difficult to obtain. In equilibrium markets, we expect cost and prices to appear as two parallel lines in a log-log diagram, the ratio indicating profit margins in the industry. The work by the Boston Consulting Group (1968) indicates that there may be price-cost cycles where a period with a low learning rate may be followed by a short period with a very high learning rate. Such shakeouts in prices signal market changes, not to be confused with technical changes.
- *Technology Structural Change.* A fundamental change in technology may appear as a strong sudden increase in learning rate for ***costs.*** One expects that the reduction in cost would show up also in prices, but without other evidence for fundamental technological change, it may be difficult to distinguish from market changes in the price-cost cycle. Additional proofs are required, for instance learning curves for technical properties such as efficiency and bottom-up analysis of the technology.

The analysis of experience curves for exploration and development is complicated by the fact that one of the inputs to the learning system is exhaustible and may not be properly valued in the total input cost. This means time series of cost with changing mix of resources and reserves may be difficult to interpret in the technology learning framework. Figure 3 illustrates this argument. The basic cybernetic model of the experience curve (Wene,1999 and IEA 2000, p.27) assumes that all inputs can be consistently valued in one currency and added together to provide the total cost to produce the output. Figure 3 suggests that the inputs “Oil Resources” and “Reserves” are not properly monetized and not added to the “Monetized Inputs”, which are labour, capital, raw materials and energy.

In discussing Figure 3 it is important to remember that experience curves refer to ***all*** costs that are necessary to produce one unit of output from the learning system. Learning curves on the other hand refer to the use of one special input, e.g., labour or capital, to produce one unit of output. The Boston Consulting Group which introduced this important distinction observes that experience curves include “all of the cost elements which may have a trade-off against each other. This therefore means all costs of every kind required to deliver the product to the ultimate user, including the cost of intangibles which affect perceived value. There is no question that R&D, sales expenses, advertising, overhead, and everything else is included” (p.12). It is important to note that by looking at a learning curve we cannot tell whether improved performance relative to the specific input is due to more efficient use of this input in the learning system or due to the input being substituted for another input, e.g. capital for labour. Such a curve cannot be easily benchmarked against curves for other technologies, because it reflects changes in the environment outside the control of the feedback loop, for instance changes in relative prices of different inputs. A learning curve with a very high learning rate could therefore indicate that the learning system over the observed period was just increasing the share of such uncontrolled inputs that needed less of the monetized inputs to produce a unit of output. To interpret the time series in the technology learning framework requires either that uncontrolled inputs have been constant or ways to correct for the change of such inputs.

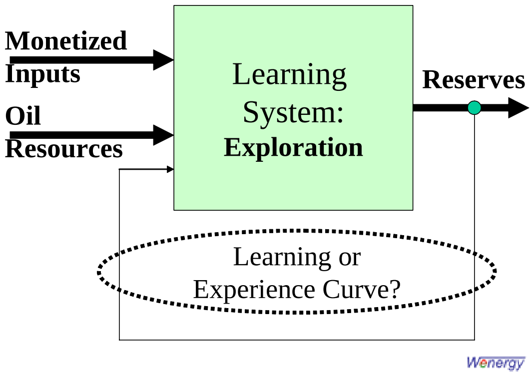

Figure 3A. Learning system for oil Finding

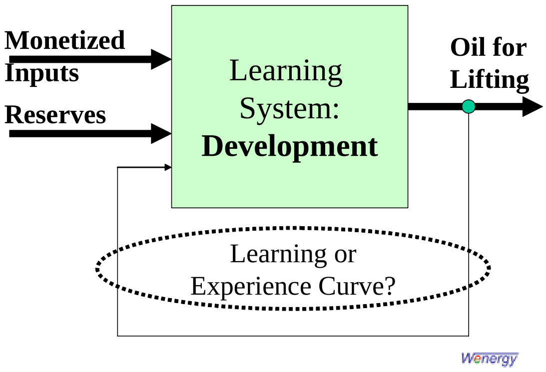

Figure 3B. Learning system for Development

In the terminology of the Boston Consulting Group, the crucial question for “Exploration” is thus whether a plot of reported exploration costs versus cumulative findings represents a learning curve or an experience curve for the exploration learning system. In the first case, the curve reflects both the learning going on within the system and the fact that as a play is being exhausted the finds will be smaller and smaller which should drive up the cost per barrel. There is a trade off between monetized inputs and oil resources. To understand the technology learning that has taken place and make forecast for the future it is necessary to correct for the effect of exhaustion of resources.

However, considering the process leading up to reserves and proven reserves indicates that the interpretation of the observed relation between exploration costs and cumulative findings as a learning curve is *not* correct. Oil resources are indeed given a price, e.g. in the North Sea through an auction process. Oil companies buy the right to make resources into reserves. The question is then if the mechanisms in place to value resources correctly reflect the effect of resources depletion on the need for other inputs to the learning system, i.e., labour, capital, raw materials and energy. For instance, does the outcome of an auction correctly reflect the expectations about the distribution of field sizes? The second question is: do quoted exploration costs include the cost for the right to prospect for oil? If the answers to both these questions are “Yes”, then the observed relation between exploration cost and cumulative findings through exploration represents an experience curve.

Obviously, finding the correct answer to the two questions requires considerable research. For the purpose of this Memo I will argue that the oil industry is a mature and competitive industry which should be able to correctly value its assets. Consequently, I will treat the observed relation between exploration cost and cumulative finding through exploration as a good first approximation to an experience curve for exploration.

For the Development learning system, reserves are the input. Such reserves get a market valuation when they are sold between companies (“reserve acquisition”). However, these costs do not enter into the quoted development cost so we cannot construct an experience curve for Development. The questions are then how much the mix of reserves being developed has changed over the last two decades and how such change would affect the cost for development.

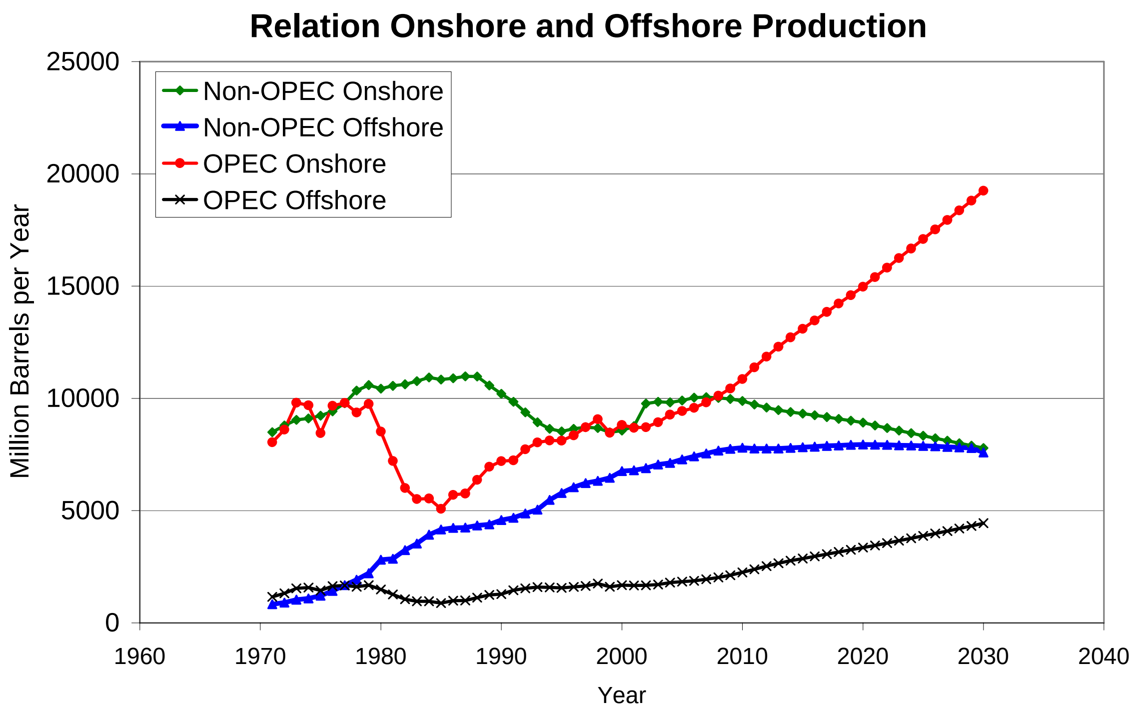

Figure 4. Onshore and Offshore production 1971- 2002 and EAD forecast for the period 2003-2030.

Figure 4 shows how Onshore and Offshore oil productions have changed over the last three decades. For Non-OPEC production the ratio of onshore/offshore decreased from 3.7 in 1980 to 1.3 in 2000. The mix of reserves being developed outside OPEC probably changed even more drastically, considering the build up of offshore capacity during the period. A further indication that development resources outside OPEC was mainly allocated to offshore activities is the fact that onshore production fell by 20% between 1988 and 1995. The ratio of onshore/offshore production within OPEC was almost constant during the same period, going from 5.7 in 1980, 6.1 in 1985 to 5.2 in 2000.

One can ask what the changing mix meant for development cost. Figure 5 shows cost data for Angola and Brazil from the PEPS database. The data shows that going from onshore to offshore production increases development cost, although the increase for shallow waters is not too drastic.[2] However, it is important to remember that PEPS cost data reflects cost levels *today*, after a considerable learning for off-shore activities has taken place. The 7 Majors report development cost around 7 US$(1999)/bbl (Smith 1999) in 1985 falling to 3 US$(1999)/bbl in 1999. I have tentatively entered a cost line for 1985 assuming that this cost refers mainly to development of reserves offshore in shallow waters. Such interpretation of the reported data is supported by Figure 4, and the observation that most development resources in the time period 1980-2000 went into offshore fields.

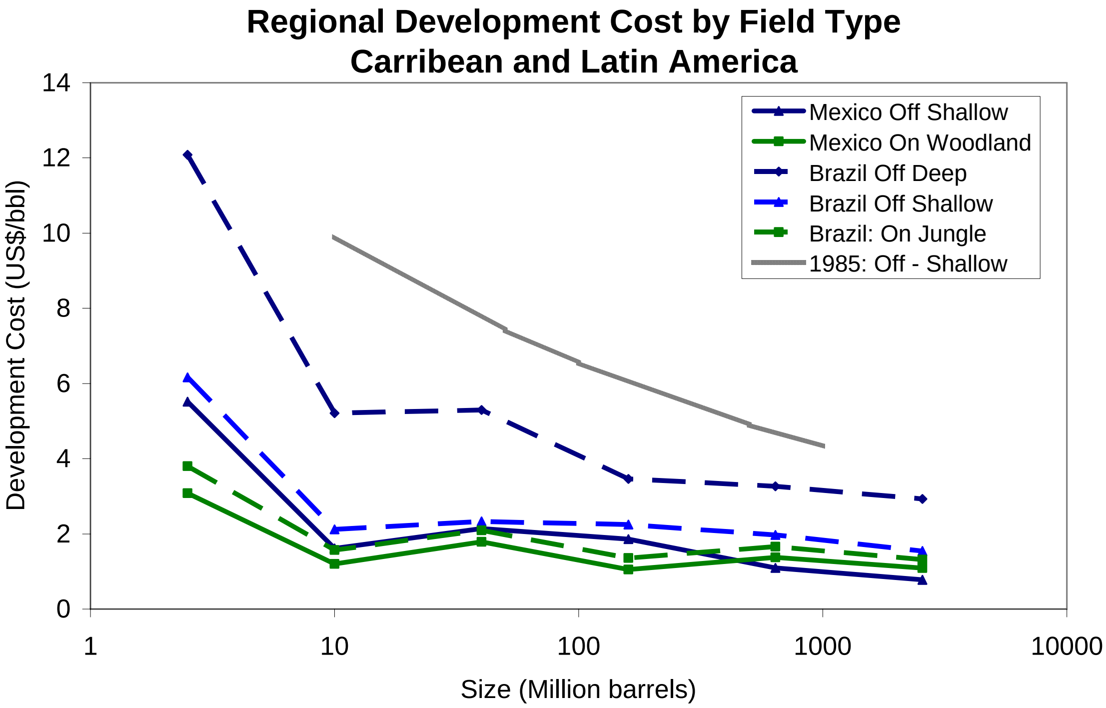

Figure 5. Economies of scale for fields in Caribbean and Latin America (PEPS Database). (Mexico=full lines, Brazil=dashed lines, 1985 Shallow water=shadow line)

I will base the analysis for development cost in the following section on the hypothesis that reported developing cost for NON-OPEC production for the last two decades mainly reflects the transformation of the cost curve for developing reserves in shallow waters from the position in the 80s to the position given by the PEPS database today. Time series provides a learning curve for development, but the hypothesis provides means to assess the influence of uncontrolled inputs. Changing mix of developed reserves can influence the learning rate in two ways:

- *Regional differences*. Specific costs differ considerably between regions. E.g., oil price turbulence in the 80s may have made oil companies change their development portfolios reducing investments in more expensive regions. This increases the observed learning rate, but does not reflect improved technology learning.

[2] Entering data for the North Sea would increase the difference between onshore/offshore, but not change the thrust of the following argument.

Conversely, specific cost may be reduced through learning and thus open up new regions which earlier were considered too expensive. This effect reduces the observed learning rate, thus making technology learning appear less effective.

- *Field size*. Figure 5 shows that specific costs depend on field size. Developing starts with the larger fields, however, as costs are reduced through learning smaller fields become cost-efficient. Real technology progress is made, but its full impact is not reflected in the average development costs.

It is in principle possible to estimate the influence from the two factors. This would, however, require research beyond the scope of this Memo. If our analysis of reported time series would indicate results inexplicable with our benchmarking procedures it is necessary to return to these issues. However, we will continue on the assumption that the effect of the changing mix of reserves on the observed learning rates evens out and that the observed rate reflects technology learning.

2.1.2. Generation of Technology Learning Scenarios

We will use the same scenario approach as in the LNG-Memo (Wene, 17 March 2003) to bracket reasonable outcomes of continuous technology progress for the estimates of future investment costs. The Delphi scenario is renamed “No visible effect”. The technology learning scenarios are:

- *No Visible Effect*: Specific costs remain constant over the whole period, i.e., learning rate is 0%, meaning that there is no visible effect of learning over the period 2000-2030.
- *Dutton-Thomas*: technology learning characterised by a learning rate of 18%, which is the most probable value in the Dutton and Thomas (1985) distribution.
- *Grafted*: technology learning characterised by the low learning rate in the second peak in the distribution presented by McDonald and Schrattenholzer (2001). I consider this emblematic for a technology grafted to an existing well-established technology.
- *Ex Post*: technology learning characterised by the learning rate observed in the ex post analysis. As these learning rates are very high, I consider this as a technology optimistic scenario where the sustainability of such high rates must be scrutinised.

Ideally, the ex post analysis should make it possible for us to decide whether the technology should be characterized as “new” or “grafted”, thus reducing the span of scenarios that need to be considered. However, the approximations discussed in the previous section introduce uncertainties and the measured curves indicate influence of technology and market structural changes. Although a Dutton-Thomas scenario seems most probable, the other two scenarios are necessary to bracket the outcome of technology learning.

The scenario “No visible effect” provides a benchmark for the EAD estimates. It could be interpreted as meaning that the effects of resource exhaustion and technology learning even out. However, there is no indication in the data from the last two decades that this has happened.

2.1.3. Calculation of Prices and Investment

The analytical stream for technology deployment provides information about the physical investments in exploration and development. From this information and the scenario assumptions on technology learning parameters it is possible to calculate prices (specific costs) for Exploration and Development and then the total investments. A spreadsheet model is developed to allocate supply and calculate physical investments in exploration and development for seven different sources: OPEC-Middle East, OPEC-Rest, and Non-OPEC On-shore, Off-shore Shallow, Off-shore Deep Water, Off-shore Ultra-Deep Water, and Unconventional.[3] The two first steps of the model for **Te**chnology **D**eployment for **F**inding **& D**evelopment (TED4FED) are described in the sections 2.2.1 and 2.2.2. We describe here the calculation of prices from technology scenario parameters.

I assume two basic technologies, one for Exploration and one for Development for the six sources of conventional oil. Each basic technology is assumed similar for all the sources and the learning is global. This means that deployment for Exploration and Development, respectively, is summed and a cumulative global deployment is calculated. The specific cost for the basic technology may differ for the six sources, reflecting regional differences. But the yearly cost reduction is the same based on the cumulative global deployment.

For offshore activities, TED4FED provides the option of splitting investment costs in two components: one referring to the base technology with global learning and one specific to the offshore source with independent learning. Independent learning means that the cost reductions for the offshore component are based only on the cumulative deployment of this component. For shallow-water sources the added cost is small, but ultra-deep water technologies are expected to initially carry a large extra cost. In this Memo we assume the same learning rates for all technologies within a scenario, but one can imagine scenario variations with different learning rates for the add-on technologies. Notice, that the same learning rate does *not* mean that all technologies reduce their cost at the same rate! The component specific to ultra-deep water technology will have a very small entry value in 2000 for the cumulative implementation of this technology, which means that cost reductions will come very quickly as this technology is being deployed.

The assumptions used can certainly be contested, but they are the simplest ones and reflect the data available. The model can certainly be refined. The basic technologies are both based on recent breakthrough in seismic data management and interpretation and off-shore technologies have many common elements not reflected in our assumptions. The model does not consider field extensions separately neither enhanced recovery, which is a very important method of increasing reserves. But the present model seems satisfactory for assessing uncertainties in investment estimates.

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[3] The terminology follows the distinctions made in the industry:
shallow water: production in water depths until 500 m
deep water: production in water depths between 500 m and 1500 m
ultra-deep water: production in water depths larger than 1500 m

2.2. *Analytic Stream: Technology Deployment (TED4FED)*

2.2.1. *Supply from seven sources*

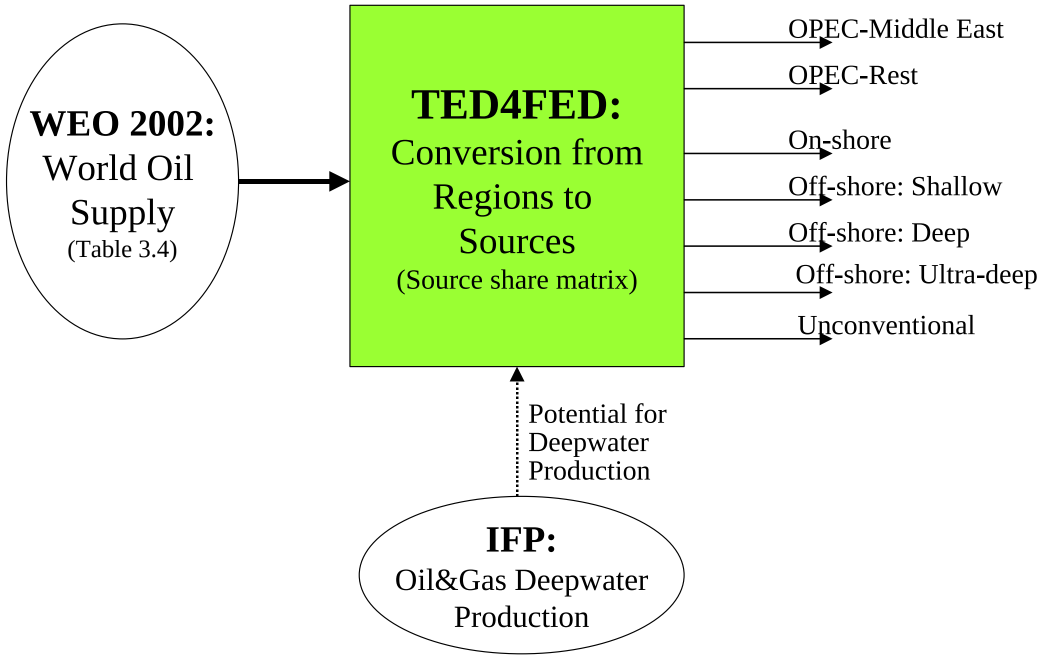

Figure 6. First step in the analysis of technology deployment

Figure 6 shows the first step in the analysis of technology deployed for finding and development of oil reserves. Input is the projections for oil supply from different world regions until 2030 in World Energy Outlook 2003 (WEO 2003). The model uses a matrix for the share of the different sources in the regional supply. The split between non-OPEC on-shore and off-shore oil is crucial, as well as the split between shallow, deepwater and ultra-deepwater in off-shore production. The ratio between onshore and offshore production in different regions are taken from EAD projections (Cattier 2003). The projection for deepwater production from Institut Français du Pétrole (IFP 2003) is used to guide the assumptions on deepwater and ultra-deepwater productions. Figure 7 shows the production from different sources in the period 2000-2030.

2.2.2. *Need for exploration and development*

In the present version physical investments in exploration and development are triggered by Reserve/Production ratios (R/P-ratios) and Yields per developed reserve, respectively. The target values or norms for these parameters are given for each source separately. When actual values become smaller than the regional norms for R/P or smaller than the norms for Yields, exploration and development activities are triggered to restore values for R/P and for Yields to the norms. For old established regions with large R/P and small Yields, this results in a step-wise onset of investments which probably is unrealistic. It is possible to modify the simulation of investment decisions assuming that a part of the industry will start to make investments as the norms are approached, this part growing the closer the region comes to the target values. This smoothes the on-set of investments, however, the assumptions on the share of industry that will act pre-emptively are ad-hoc.

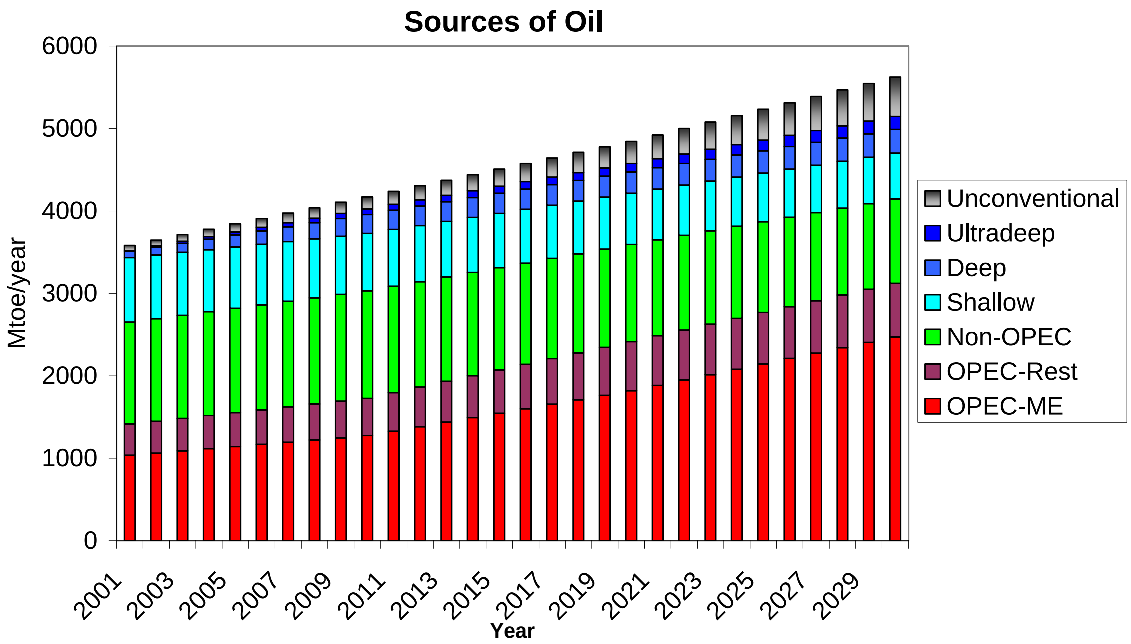

Figure 7. Sources of oil in the period 2001-2030.

It is fairly easy to modify the model to follow externally given paths for R/P-ratios and Yields. However, it is important that such paths are consistent with both regional supply projections and projections of the source share matrix in the previous step of TED4FED. I feel the externally given paths may reduce the flexibility of the model and make computations more complex. I therefore use the existing formulation and try to reproduce projected R/P and Yield paths.

Annex 1 proves information about the assumptions made for the target values of R/P and Yields. It also compares values for R/P obtained by TED4FED for the 30 years period with the corresponding values from the EAD analysis. The conclusion is that the simple target approach of TED4FED can reproduce the EAD values well enough for the purpose of this Memo.

3. Exploration

3.1 Ex post Analysis of Experience Curves

Figure 8 indicates the rapid introduction of new technologies for oil and gas exploration. Especially the 1960s saw new technologies being used to gather and analyse seismic data, following the first wave of mainframe solid state computers. Figure 8 only shows the picture between 1950-1980. After the 2D-seismic with introduction of the common depth point in 1960s came the 3D seismic in the 90s. The story about the 3D seismic is told by Albertin et al. (2002) and reflects the leap in computing power and computer availability that started in the late 1980s with the large-scale launching of micro-computers.

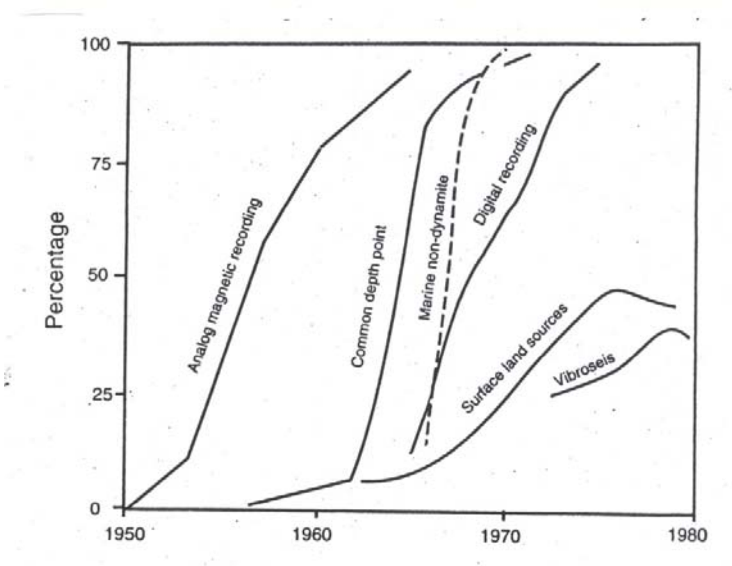

Figure 8. Percentage of United States seismic activity in exploration accounted for by various techniques (Cleveland and Kaufmann, 1997)

Figure 9 shows the cumulative use since 1964 of 2D and 3D seismic techniques for new wildcats (note that scales are logarithmic). Compared to the take-off in the 90s, the growth in use of 2D until 1980 appears rather sluggish. This probably reflects the fact that computing on main frame computers was rather expensive, but still an average line of 10,000 km was covered per year. The price hike after the Iranian crises 1979 saw major activities starting with even a first pioneering use of 3D technology, but all this stopped after the drastic price cuts in 1985/86. The take-off for both technologies comes in 1990. Total area covered by 3D techniques goes from about 5000 km2 in 1990 to 1.5 million km2 in 2001.

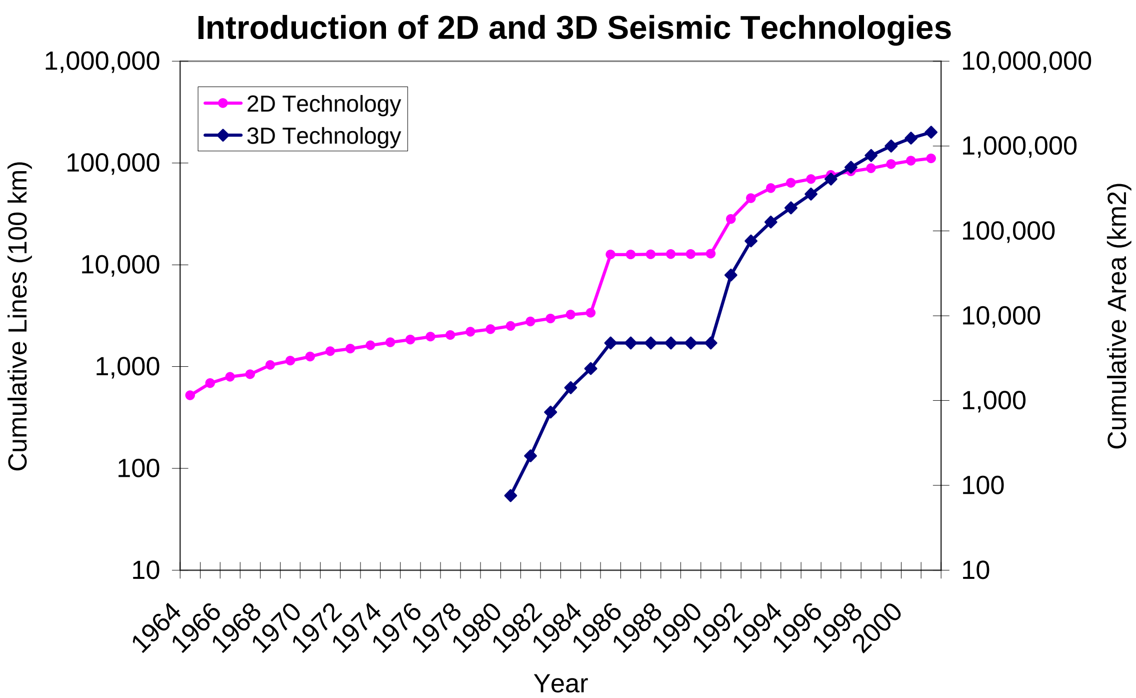

Figure 9. Use of 2D and 3D seismic technology for new wildcats. Scales are logarithmic. (Data from PEPS)

From studying the history of seismic activities we could thus expect technology structural change in the experience curves in 1960s and in the beginning of 1990s. The boom and bust of the oil market in the 80s can also be expected to leave traces in finding costs. In fact shakeout behaviour has been observed for Enhanced Oil Recovery, see Figure 10. The possibility of both technology changes and price-cost cycles must be taken into account when interpreting finding costs for the last 10-15 years. For forecasting one would like to have cost data over a much larger time period in order to isolate the influences of major changes in technologies and in price-cost cycles. However, I have not been able to find cost data before 1985. We could search for other indicators which express technical performance and for which there are much longer time series. One such indicator is wildcat performance. In the following we discuss technology structural changes based on the observations in Figures 11 and 12. A learning curve analysis of wildcat performance is made in appendix 2.

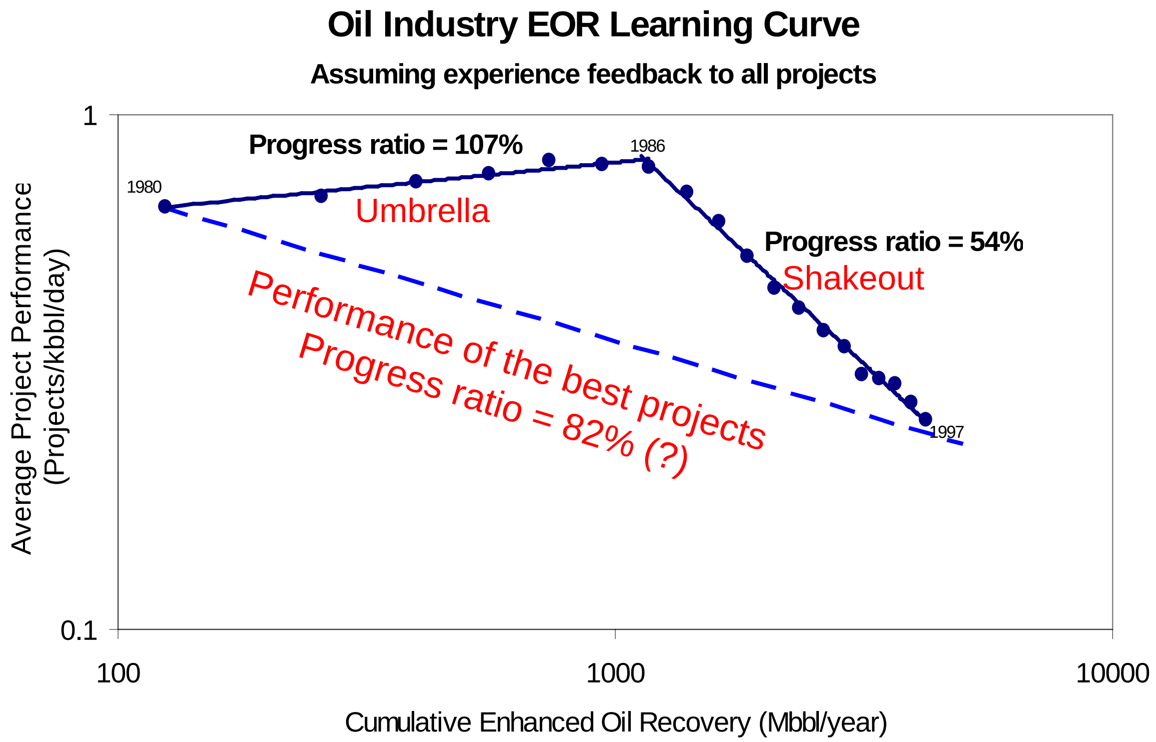

Figure 10. Learning curve for enhanced oil recovery 1980-1997, showing the shakeout in project performance as oil prices fell from over 30 US$/barrel down to under 10 US$/barrel in 1986 (Data from Implementing Agreement on Enhanced Oil Recovery)

The performance of wildcats in the U.S. is tabulated since 1947 (API, 2002) and for areas outside of USA, data are available since 1964 (PEPS) for offshore activities and since 1980 for onshore activities. To be consistent with the learning curve analysis in Appendix 2, Figure 11 shows the number of wildcats needed to make one strike ("Wildcats/successful wildcat"). Wildcats performances are quite different between the two areas.

US data are characterized by a flat performance ratio for the period 1947-1968. After 1968 there is a steep improvement in performance; before 1968 about 10 wildcats had to be bored to make one strike, but in the beginning of 1980s on 5-6 wildcats were necessary to make one strike. However, the number of wild-cats then rises to 7-8 around 1985 but from 1989 there is another steep improvement in performance and at the beginning of the 21st century only 2-3 wildcats are necessary for one strike. Areas out side of USA show none of those structures. In offshore findings about four wildcats are needed for one strike and the performance increase slowly but continuously to 2.5-3 wildcats per successful wildcat around 2000. At the beginning of the 21st century wildcats performance are the same inside and outside USA.

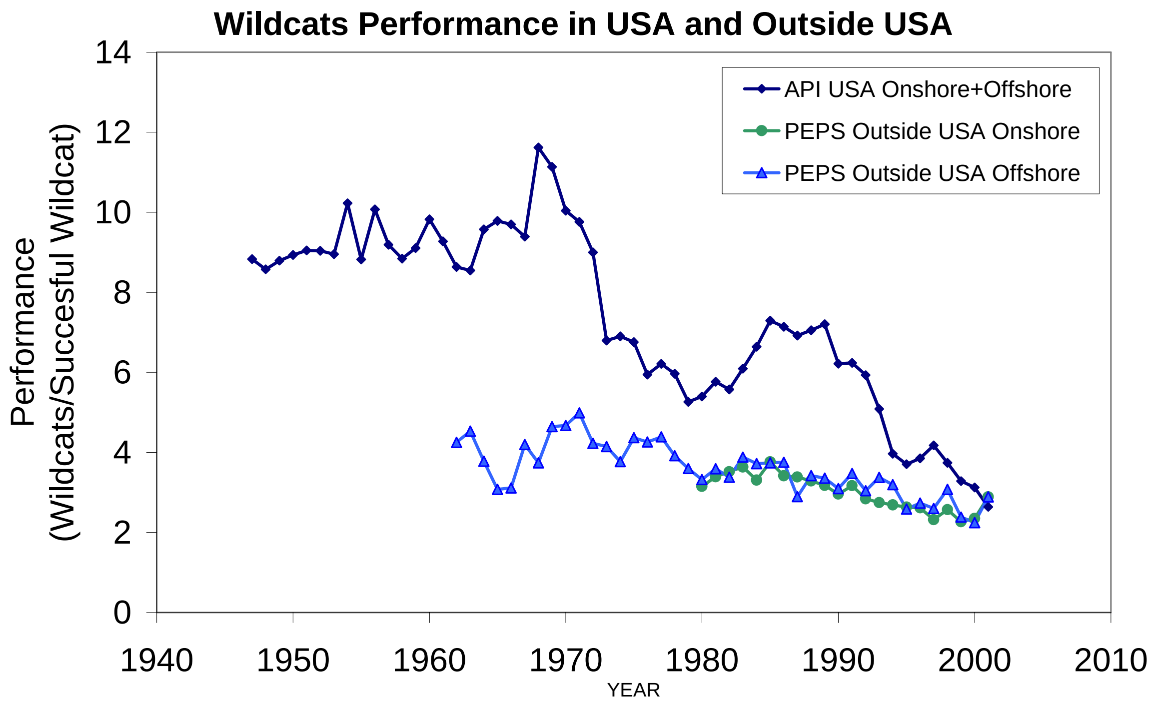

Figure 11. Wildcats performance. More than 90% of US wildcats are onshore.

The learning curve analysis in Appendix 2 shows that the time series for USA are consistent with two technology structural changes: the first starting at the end of the 60s and the second occurring around 1990. This is in line with the analysis from Cleveland and Kaufmann (1997), Albertin et al. (2002) and the PEPS data on deployment of 2D and 3D technology. The increase in wildcats required per successful wildcat 1980-1985 can be interpreted as an oil market effect; the strong increase in oil prices made oil executives more willing to take risks. Except for a slight knee at 1985 in the curve for onshore activities, the learning curves for areas outside USA show none of these features. Assuming a technology structural change in oil exploration starting in 1989 provides a learning rate for wildcats in USA of 23% but only 8% for wildcats outside of USA. This requires an explanation.

Contrary to an experience curve analysis, the learning curve analysis does not provide control over other inputs to the learning system. A possible (and probable) explanation is that "oil resources" provide quite different inputs to the learning system inside and outside USA. Figure 12 shows that the first finds offshore outside of USA in the 1960s had an average size of 1 billion barrels. During the 90s, the average size of a find in North America was about 10 million barrels. USA was the dominating player in North America during this period. One could thus argue that the difference is due to the fact that large fields are easier to find than the remaining small fields in onshore USA, but technology progress makes it easier and easier to find the small fields, equalising the plays ("it was easier to find an iron rod than in needle in a haystack, but now-a-days technology takes away the difference"). In this picture, the continuous reduction in field size outside the U.S. has to a considerable degree balanced out the improvements in technology.

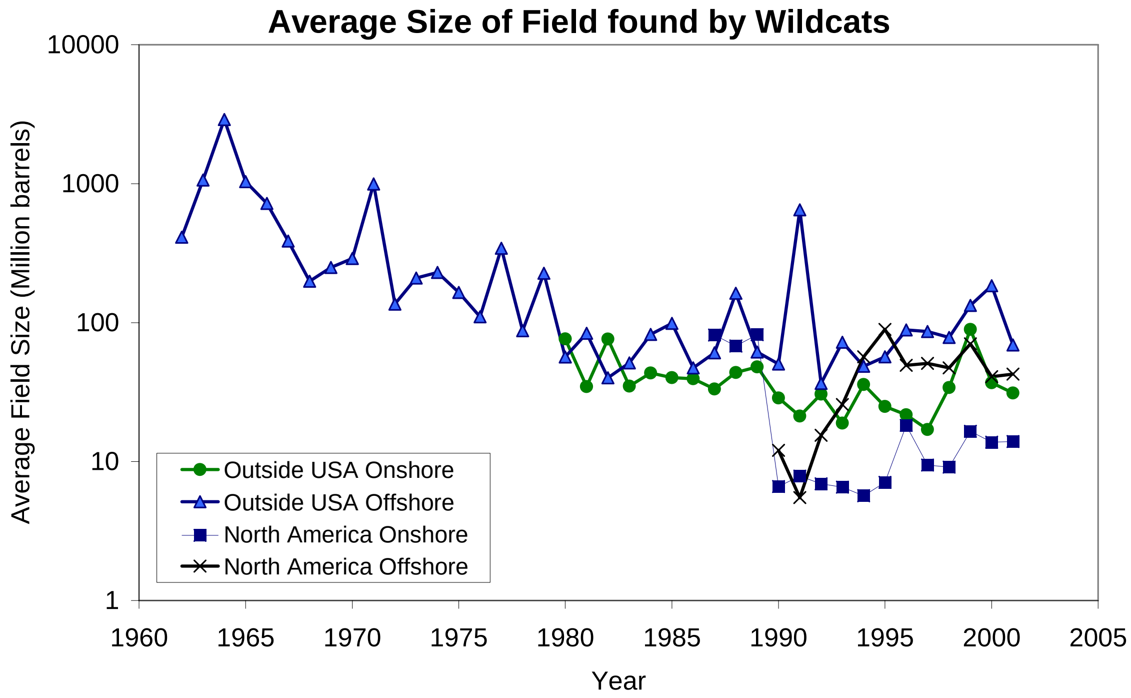

Figure 12. Size of new fields outside and inside USA (data from PEPS)

Data on average finding size in the 60s and 70s in USA are required to show that resource depletion is the explanation for the different behaviour of wildcats. My conclusion is that the hypothesis of a structural change in exploration technology around 1990 seems quite probable, and is the main theme in the following analysis. However, our choice of technology scenarios must reflect that this hypothesis requires further tests and that there may be other important factors explaining the behaviour of exploration costs, such as field size and oil price.

Figure 13 shows the experience curve analysis of the five years average *finding* costs in the period 1985 to 1999 reported for the 7 majors by Smith (2001). It is not clear what "finding" implies in the paper, but considering the fairly high values given by Smith, I will treat the data as indicative for exploration cost (i.e., excluding revisions and EOR). Based on the previous analysis, the analysis consists of three steps. In the first step, finding costs are plotted versus cumulative additions through exploration for the seven majors since 1968, assuming a technology structural change at the end of the 60s. This places the learning rate at 76%, which is completely outside the observations reported by Dutton and Thomas (1984) and McDonald and Schrattenholzer (2001). I consider this learning rate as indicating either a very strong shakeout on the market for exploration or a technology structural change. As an intermediate step, finding costs are plotted versus cumulative findings since 1985, i.e. the start of the time series. We observe a knee in the curve at 1989, i.e., at about the time for the takeoff for 2D and 3D technologies and the onset of the strong improvement on performance for US wildcats. In the third step the findings cost are plotted versus cumulative findings since 1989 providing a learning rate of 28%.

The start of the technology structural change is not well defined by the data. According to PEPS, the precise year of takeoff for 2D and 3D technologies is 1991. Moving the entry point for technology change to 1991 would improve the fit to the data points and provide a learning rate of 35%, which is at the lower end of the distributions reported by Dutton and Thomas(1984) and McDonald and Schrattenholzer(2001). Considering possible uncertainties in databases and reports I would like to err on the conservative side and will use the value of 28% as the result of the ex post analysis of the 7 Majors finding cost.

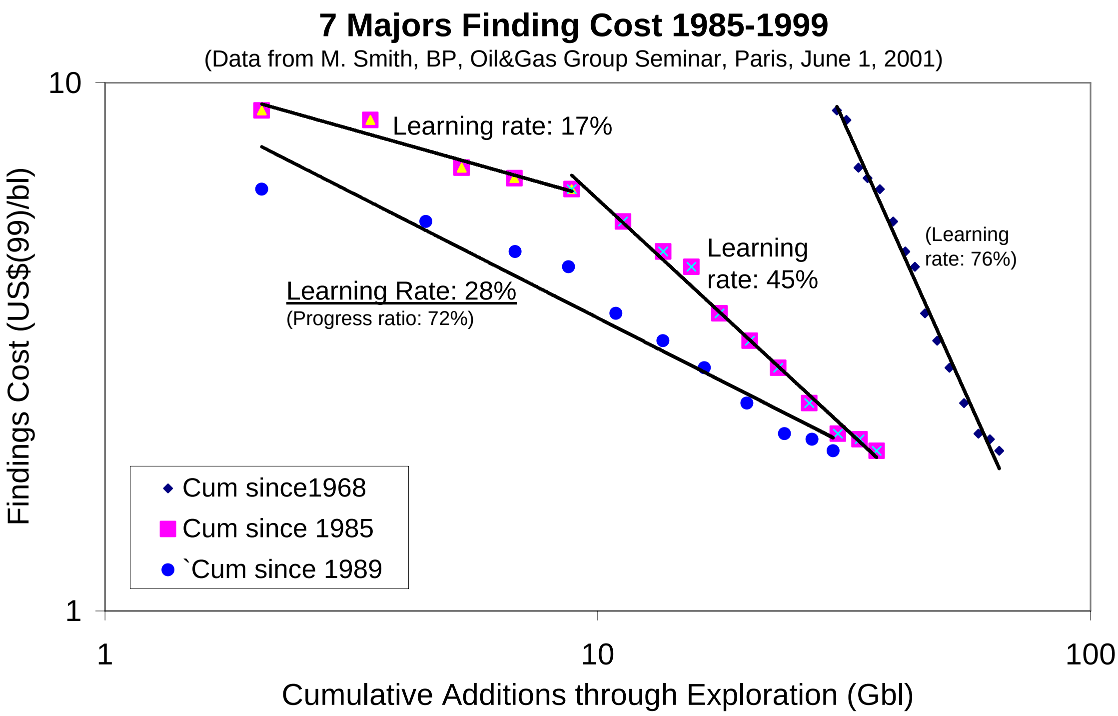

Figure 13. Finding Experience Curve for the 7 Majors

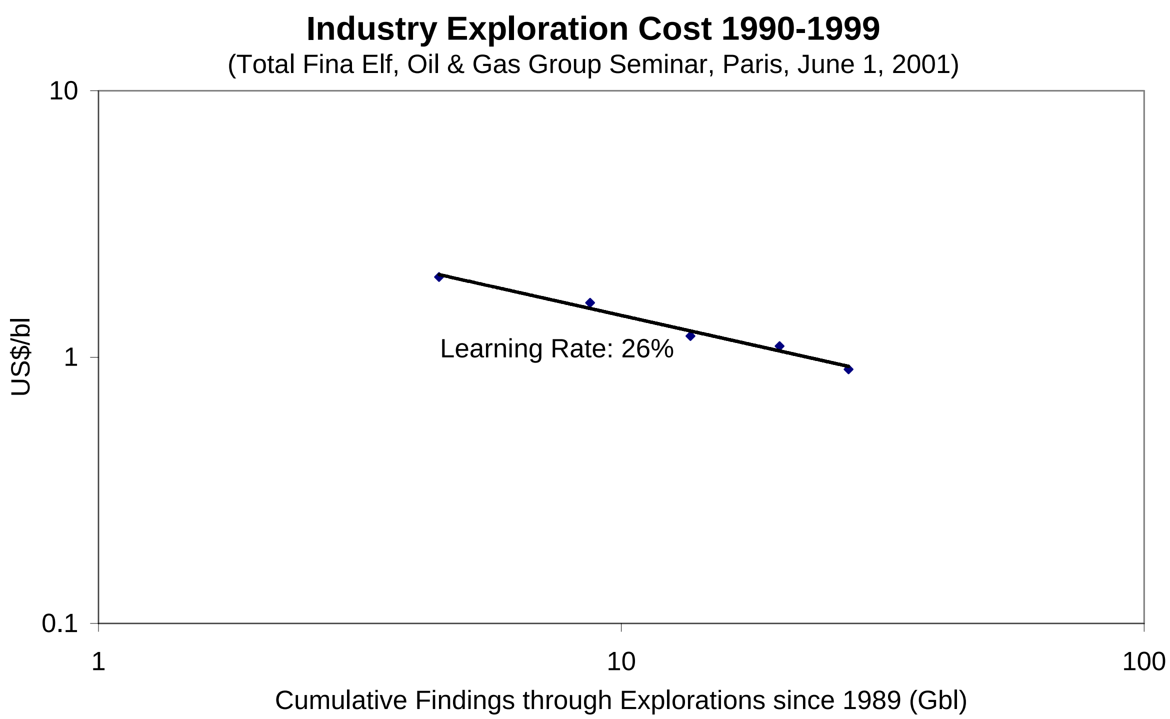

Figure 14. Exploration Cost according to Total Fina Elf (2001) and Delaytermoz and Lecourtier (2001).

Figure 14 shows the analysis of exploration cost for 1990-1999 reported by TotalFinaElf (2001) and Delaytermoz and Lecourtier (2001). Following the result of the earlier analysis, their cost data are plotted versus cumulative findings through exploration since 1989. The resulting experience curve has a learning rate of 26%, which agrees very well with the analysis of the data from Smith (2001).

Smith(2001), TotalFinaElf(2001), Delaytermoz and Lecourtier(2001) agree on learning rates, but not on the cost levels, in fact the costs provided by TotalFinaElf and Delaytermoz and Lecoutrier are more than 50% lower than the finding costs reported by Smith(2001). For 1999 Smith gives 2 US$/bl while TotalFinaElf7Delaytermoz and Lecoutrier gives 0.9 US$/bl. Another source indicates 1.5 US$/bloe for oil and gas exploration (Andersen 2001). The differences in cost level illustrate the difficulties in comparing time series without very detailed information about how they are constructed. However, the usefulness for our purpose is that they express the same trend in the industry expressed through similar learning rates.

3.2. Generation of technology scenarios

Our ex post analysis indicates that as a basic assumption we could treat exploration technology as a Dutton-Thomas technology with an entry point in 1989, meaning that cumulative findings should be counted from that year. However, the difference between wildcats in US and outside US is not fully understood. We cannot rule out that the strong decrease in finding costs are due to other factors than technology, e.g., oil market prices or the value of the probability of large fields not being properly monetized. The behaviour of the learning curve for wildcats outside of the U.S. is characteristic for grafted technologies. The basic assumption has to be balanced with a more pessimistic alternative assuming that the underlying and sustainable real cost decrease follows an experience curve with a learning rate of 5%.

All scenarios assume a technology structural change in 1989, meaning that in calculating cost reductions it is assumed that deployment of the technology starts in 1989. For the technology with global learning the cumulative deployment at the model entry point in 2001 is equal to *all* reserve additions between 1989 and 2000. For the source specific technologies the cumulative deployments in 2001 are discoveries between 1989 until 2000 made in shallow, deep and ultradeep waters, respectively.

Considering the uncertainty in cost at the entry point in 2001 for the different sources, we will work with two different set of *cost assumptions* for each of the technology scenarios. The two sets of cost assumptions differ only for the cost of offshore activities. One scenario will emulate as closely as possible the EAD assumptions which have a much higher regional resolution than what is possible with TED4FED but do not distinguish between different offshore sources. In the “EAD” cost scenario there is no specific learning for the three offshore sources and they have the same (average) specific cost.

The learning parameters proposed for the four technology learning scenarios are given in Table 1 and the two sets of assumptions for the cost of technologies in 2001 in Table 2.

Table 1. Exploration: Parameters for the Technology Learning Scenarios

Scenario	*No visible Effect*	*Dutton-Tomas Most probable*	*Grafted Pessimist*	*Ex Post Optimist*
Learning rate (Progress ratio)	0%(100%).	18%(82%)	5%(95%)	28%(72%)
Technology for	*Global Learning*	*Shallow Water*	*Deep Water*	*Ultradeep Water*
Cumulative Findings through Exploration since 1989 (billion barrels)	170	44	5.3	0.3

Table 2. Exploration: Technology Cost in 2001

	EAD Cost		**TED4FED Cost**	
	Global Learning (US$/bl)	Specific Source (US$/bl)	Global Learning (US$/bl)	Specific Source (US$/bl)
Source				
OPEC-ME	0.15		0.15	
OPEC-Rest	1.30		1.30	
Onshore Non-OPEC	1.56		1.56	
Offshore Shallow	1.71	0	1.70	0
Offshore Deep	1.71	0	1.70	0.5
Offshore Ultradeep	1.71	0	1.70	1.0

3.3. Investments in Exploration

We have four different technology learning scenarios, each calculated with two sets of cost assumptions, altogether eight cases. I provide the results in the form of four figures.

Figure 15 and 16 shows yearly investments as calculated by TED4FED. Figure 15 shows the results for the “No visible Effects” scenario calculated with the EAD cost assumptions. This case serves as a benchmark for the estimates made by EAD. Figure 16 shows the results for the “Dutton-Thomas” scenario calculated with the TED4FED cost assumptions. The author of this Memo considers this scenario as the most likely one.

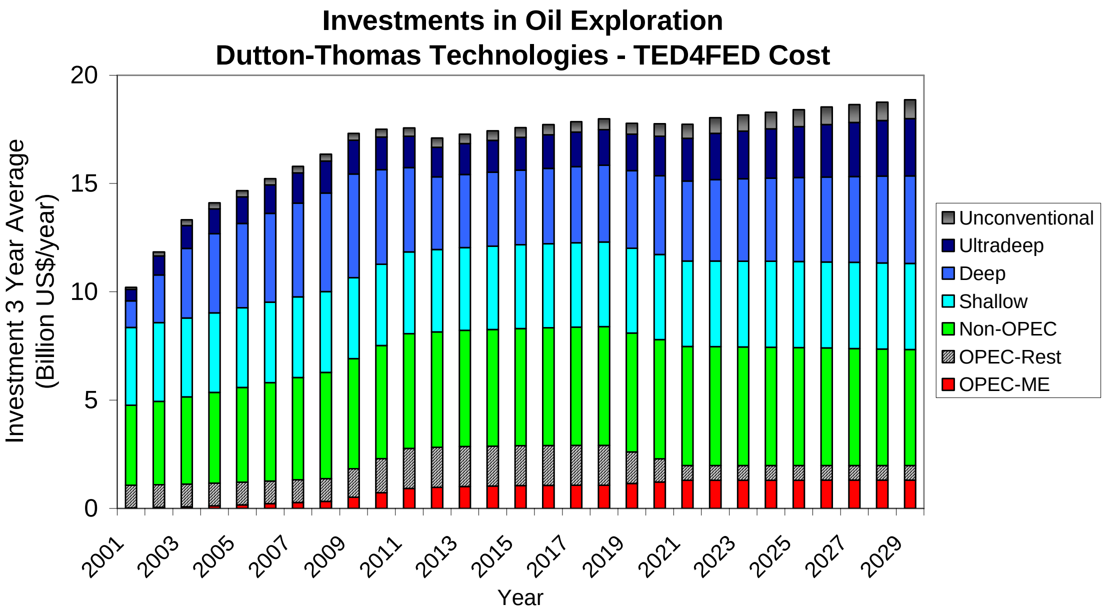

Figure 15. Yearly investments in Exploration assuming 100% progress ratio and EAD costs.

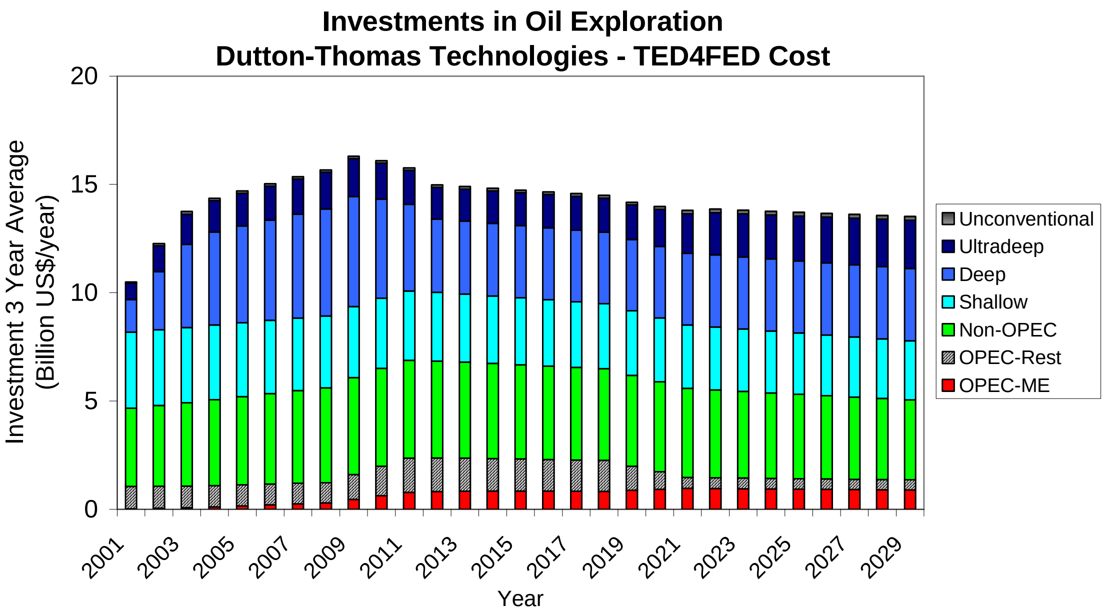

Figure 16. Yearly investments in Exploration assuming 82% progress ratio and TED4FED costs

Both cases show investments for oil exploration of about 10 billion US$ in 2001 growing to over 15 billion US$ in 2010. Andersen(2001) gives capital expenditures of 18 billion US$ for oil *and* gas exploration in 2000 for the 155 oil&gas companies in their survey leading to the discovery of 5.5 billion barrels of oil and 6.2 billion barrels of oil equivalent of natural gas. The allocation of cost between oil and gas discoveries is not straightforward; however, our result seems to be within the error margin.

The strong increase in annual cost until 2010 mainly reflects the expansion in the offshore industry. Between 2000 and 2010, OPEC provides over 60% of the *increase* in demand for conventional oil while offshore oil outside of OPEC provides 25%. Table 2 shows that the cost for exploration in OPEC is much smaller than for offshore fields and the increase of offshore activities has therefore a much larger impact on total investments. It should also be pointed out that there is a strong reduction in R/P for all onshore and shallow-water sources in the EAD oil production scenario which is the base for our technology scenarios. These reduction cushions the cost increase in all the technology scenarios.

Figure 16 shows that we should expect the learning effect to start reducing total costs after 2010. Comparing the two figures we also see that the total cost in the Dutton-Thomas scenario is smaller in 2010 than in the scenario assuming no visible effect, in spite of the fact that the initial costs in 2001 are higher for offshore technologies. One could argue that the resource exhaustion may offset the learning effect, however, our previous discussion indicates that the historical cost data do reflect real cost reductions due to technology learning, and that we can expect the same at least for the specific offshore technologies.

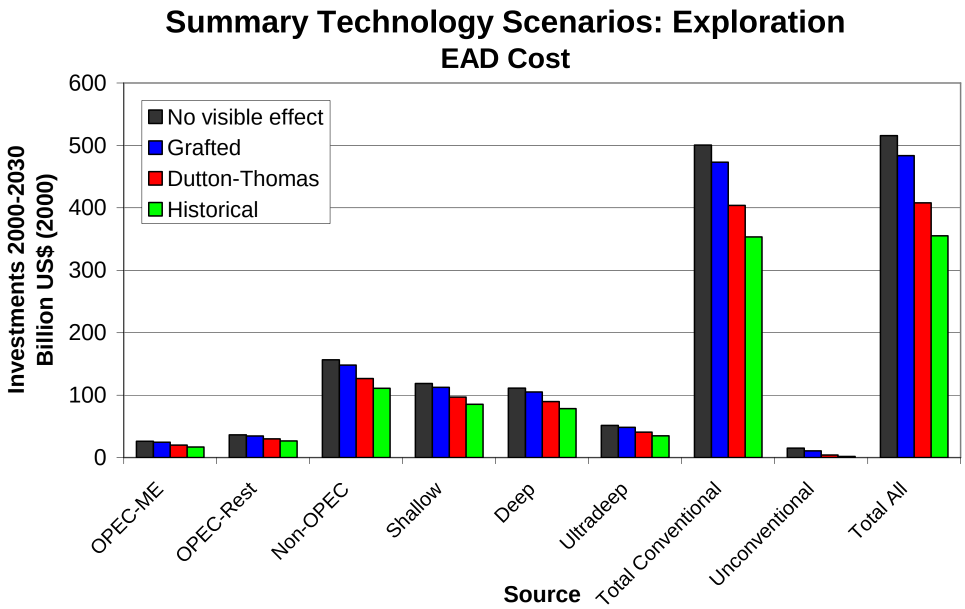

Figure 17. Investments in Exploration 2000-2030 in the technology scenarios calculated with EAD costs.

Figure 17 shows the sum of investments over the 30 year period 2000-2030 calculated with the EAD set of costs. The possible effect of technology learning may be strong; the total investment in conventional sources is 30% lower with historical rate of learning compared to a case with no visible effects.

Figure 18 shows the model results with the TED4FED set of costs. The effect of technology learning is slightly larger; assuming historical rates for learning reduce investments by 35% relative to the case with no visible effect. This is the result of our assumption of cost components specific for deep water exploration, which have much lower values for cumulative deployment in 2001 than the global component and therefore learns faster.

Our analysis thus places the 30 years investments for exploration in the bracket of 350 to 580 billion US$(2000) with a most probable value around 430 billion US$(2000) for exploration of conventional oil resources.

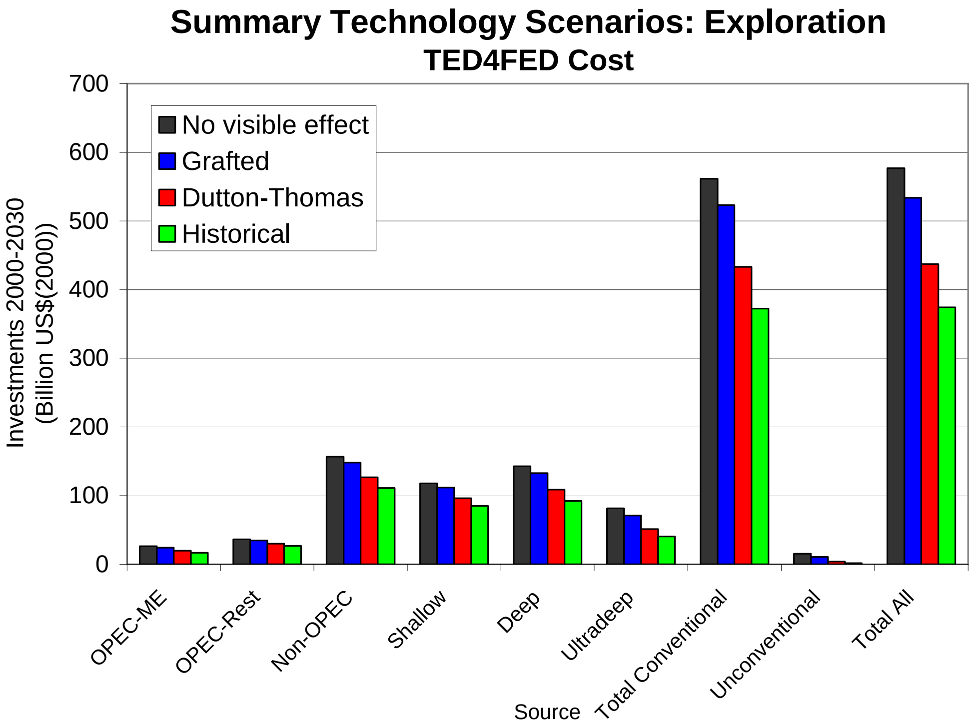

Figure 18. Investments in Exploration 2000-2030 in the technology scenarios calculated with TED4FED costs.

4. Development

4.1. Ex-Post Analysis of Learning Curves

Communication and Information Technology (CIT) development has enabled considerable technology change for development and production. Horizontal, multilateral and deviated wells with logging and measuring when drilling (LWD, MWD) are parts in a large cluster of technologies with a large CIT component. Like for exploring technologies, we can ask if the change has been so thorough that we can analyse learning and experience curves assuming a technology structural change in the second half of the 80s. And if so, did the change produce a Dutton-Thomas or a grafted technology? And is this technology a global technology with global learning, or is it strongly source dependent with learning by source?

In considering exploration, we got some insights from studying the performance of wildcats. So far, I have not been able to find time series of technical performance that could be used to identify the onset of technology structural change. Considering the importance of drilling, a time series with the barrel of oil available per footage of new development wells would be of considerable interest, or even barrel of oil available per new development well. Appendix 3 discusses a substitute, namely development wells/well with oil gas, i.e., the ability to position the development well in the reservoir so that oil or gas become available for producing. I have only data available for USA (API, 2002). The signal from this indicator is, however, weak. It indicates a stepwise improvement in performance starting around 1985. As there is no reduction in performance before 1985, such as was observed for the wildcats, reserve management or improvement in technology rather that market shakeout are the most probable explanations.

Figure 19 shows the analysis of development costs for the seven majors 1985-1999. Recalling the discussion in 2.1.1., we recognise that we observe a learning curve rather than an experience curve, although we expect the learning rate to be indicative for technology learning. There are however, a few other methodological issues.

The correct explanation variable ("x-axis") should be cumulative additions to production capacity given, e.g., in barrels/day. This information is not available, and cumulative production is used instead assuming that each barrel produced requires development to make one additional barrel available for lifting. This is not correct on an annual basis, but in a steady state, it would probably be correct over the fifteen year period considered. However, the period has also seen an increase in bopd[4] per barrel in the ground indicating that physical capacity for production has increased faster than production. This means that the choice of explaining variable may overestimate the learning rate.

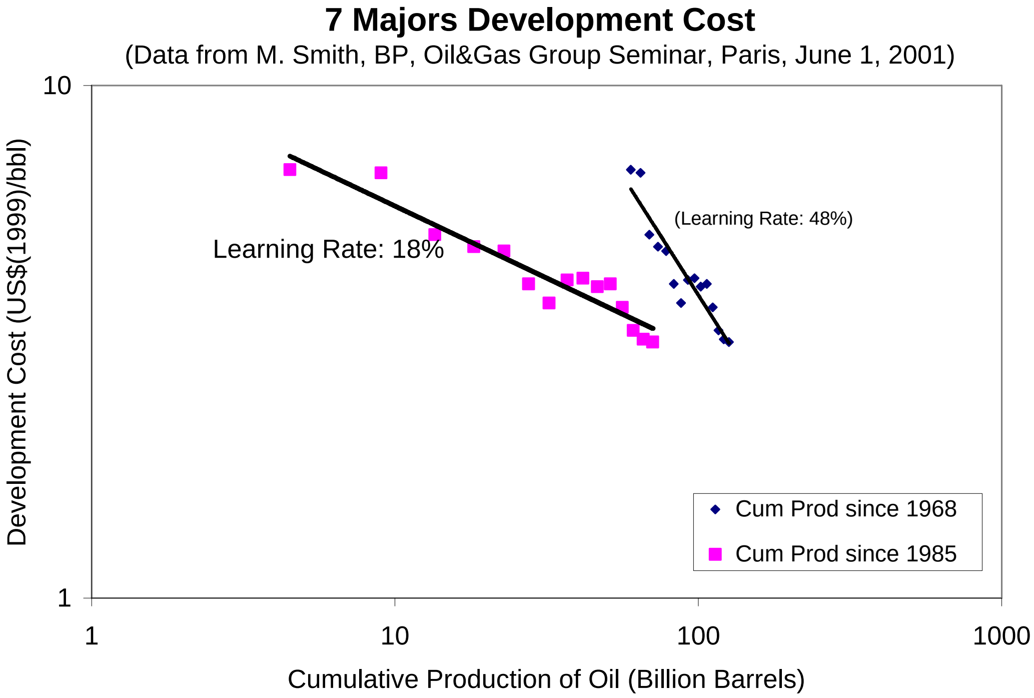

Figure 19. Majors learning curve for development. Note that the diagram only shows capital expenditure for production.

The analysis of the development cost has proceeded in two steps. To initiate the analysis, the reported development costs were plotted against cumulative production from the seven majors since 1968. This gives a learning rate of 48% indicative of a market shakeout or a technology structural change. In the second step, the x-axis is recalibrated to show cumulative production since 1985 following the indication of a possible technology change at this time from the analysis of development wells. The observed learning rate is 18%, i.e., the typical learning rate of a Dutton-Thomas technology. However, the interpretation of the learning curve poses several problems:

[4] bopd = barrel of oil per day

- So far the indications of a technology structural change is weak and must be corroborated with further analysis of technical performance
- A competitive interpretation of the curve is market shakeout. To rule out this possibility a longer time series is necessary
- The choice of explaining variable ("x-axis") may overestimate the observed learning rate as discussed above.
- Influence of changes in the mix of developed reserves as discussed above in section 2.1.1.

It should be pointed out that we are here only looking at capital expenditure for production. The data from Smith (2001) and from Delaytermoz and Lecoutrier (2001) show that the reduction in operating costs are considerably stronger.

In conclusion, we find that the observed learning rate is consistent with a Dutton-Thomas technology. However, our empirical results are considerably less decisive than for Exploration. We have to accept that our ex-post analysis presently leaves open several questions about the starting point for cumulative production, whether observed development costs indicate market shakeout after 1985 or technology structural change, and the use of cumulative production as explaining variable in view of the present trend toward faster recycling of capital for development.

In the following I will choose 1985 as the starting point for a technology structural change and treat "Grafted Technology" and "Dutton-Thomas Technology" as equally probable technology learning scenarios.

4.2. Generation of technology learning scenarios

Our generation of technology scenarios for Development follows the same procedures as for Exploration and with the same rationale as discussed in section 2.1.2. We will work with two sets of costs named "EAD" and "TED4FED". However, the observed learning rate for Development is the same as for a Dutton-Thomas technology, and we will therefore not have a separate Ex Post scenario.

Table 3 provides the learning parameters used in the three technology learning scenarios.

Table 3. Development: Parameters for the Technology Learning Scenarios

Scenario	*No visible Effect*	*Dutton-Tomas*	*Grafted*	*Ex Post*
Learning rate (Progress ratio)	0%(100%).	18%(82%)	5%(95%)	N.A.
Technology for	*Global Learning*	*Shallow Water*	*Deep Water*	*Ultradeep Water*
Cumulative Production 1985-2000 (billion barrels)	349	69	4	0.3

The costs for the offshore technologies used in the TED4FED set of costs are derived from the analysis of representative countries in the PEPS database. Figure 20 shows the cost as a function of field size for onshore, shallow water and deep water fields from this analysis. I have not found any estimates for ultradeep fields in the database and the curve for such fields is derived by extrapolation. The (red) line crossing the four curves shows the size of the fields corresponding to the respective costs assumed in the TED4FED set.

In the sense discussed in IEA(2000) and IEA(2003), the large fields in deep and ultradeep water act as *niche markets* for the deep and ultradeep water technology. The new and initially expensive technologies can be used for these large fields where the cost per barrel can still be carried by the market. As the companies learn to bring down the cost for deployment, smaller and smaller fields can be opened up; i.e., technology learning shifts the whole curve downwards in Figure 20 and the field sizes permitting exploitation moves to the left in the diagram. Cost time series may show little cost reductions although technology learning is in reality the necessary prerequisite for continuing the exploitation and obtaining the large volumes. We have already discussed this methodological issue in the empirical analysis of historical data above and now it appears again for the modeller. An obvious modelling solution is to introduce assumptions on the distribution of field size, but TED4FED does not yet have this option. Our solution here is to consider this effect taken care of through the scenarios. For the purpose of bracketing uncertainty from technology learning, this solution is satisfactory. However, a niche market analysis for emerging deep water technology would require much more sophisticated treatment of field sizes.

Table 4 gives the set of costs used for “EAD” and “TED4FED” cases.

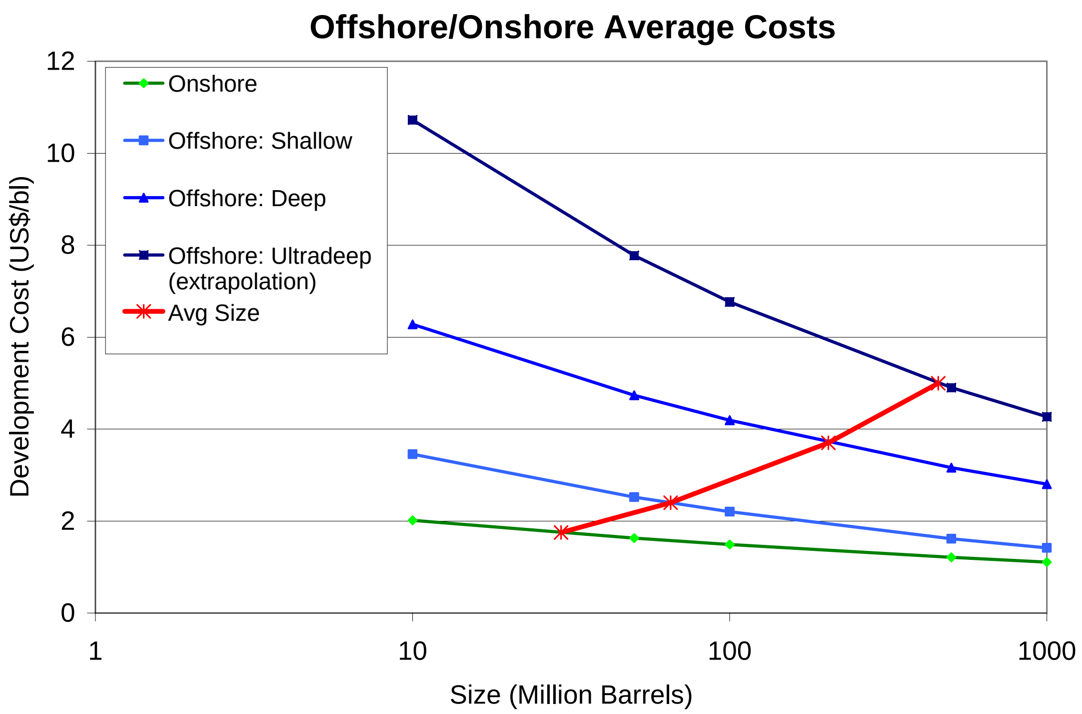

Figure 20. TED4FED assumptions on offshore costs for Development

Table 4. Development: Technology Cost in 2001

	EAD Cost		TED4FED Cost	
	Global Learning (US$/bl)	Specific Source (US$/bl)	Global Learning (US$/bl)	Specific Source (US$/bl)
Source				
OPEC-ME	0.84		0.84	
OPEC-Rest	1.75		1.75	
Onshore Non-OPEC	1.75		1.75	
Offshore Shallow	2.88	0	2.40	0
Offshore Deep	2.88	0	2.40	1.30
Offshore Ultradeep	2.88	0	2.40	2.60

4.3. Investments in Development

We have three different technology learning scenarios, each calculated with two sets of cost assumptions, altogether six cases. I provide the results in the form of five figures.

Figure 21, 22 and 23 show yearly investments as calculated by TED4FED. Figure 21 shows the results for the "No visible Effects" scenario calculated with the EAD cost assumptions in Table 4. This case serves as a benchmark for the estimates made by EAD. Figure 22 shows the results for the "Grafted Technologies" and Figure 23 for the "Dutton-Thomas" scenarios calculated with the TED4FED cost assumptions in Table 4. The author of this Memo considers these two scenarios as equally likely.

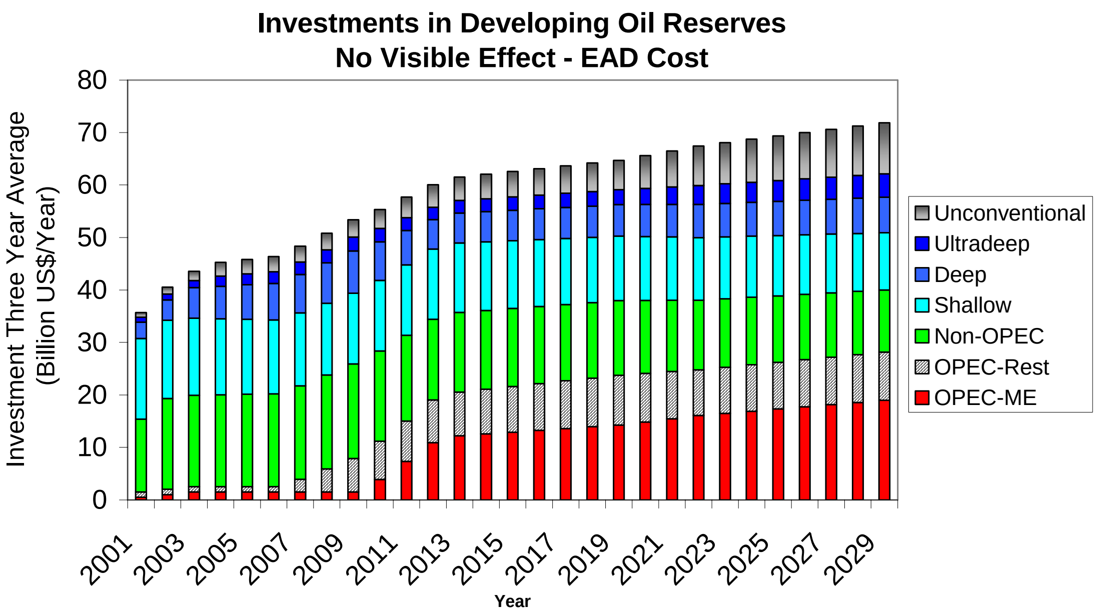

Figure 21. Yearly investments in Development assuming 100% progress ratio and EAD costs.

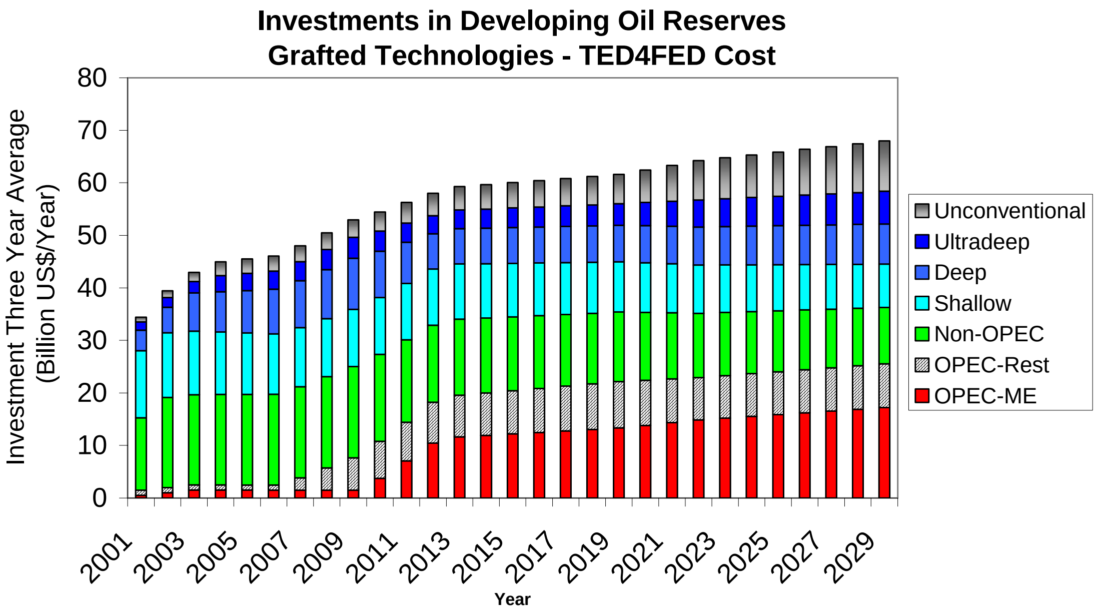

Figure 22. Yearly investments in Development assuming 95% progress ratio and TED4FED costs.

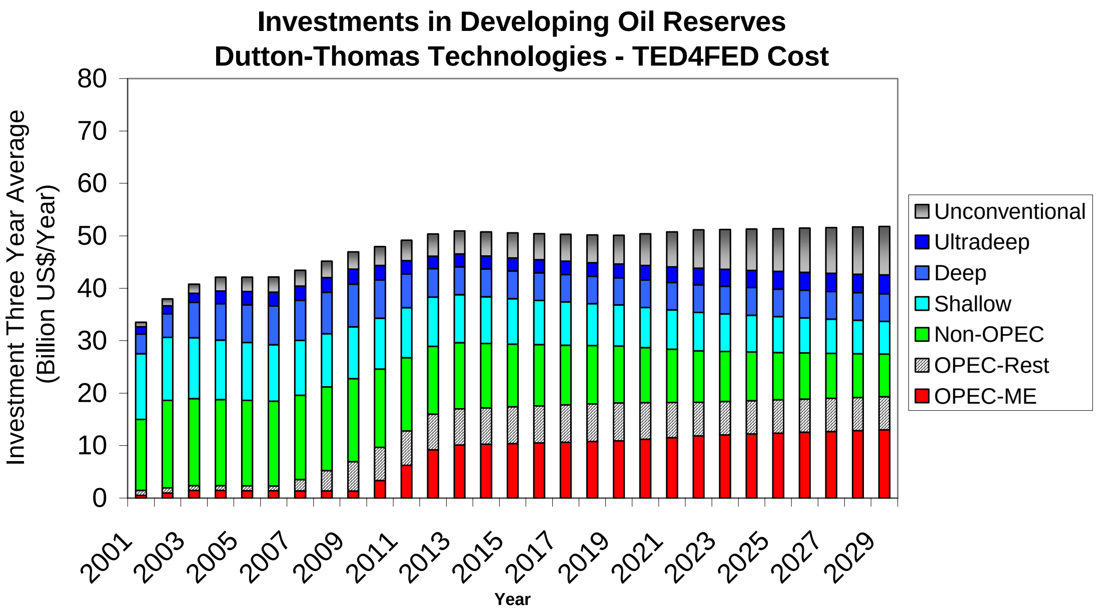

Figure 23. Yearly investments in Development assuming 82% progress ratio and TED4FED costs.

In the absence of technology learning yearly investments increase from about 35 US$/year to 70 US$/year in 2030 (Figure 21). Three factors explain this increase: the increase in consumption from 75 to 120 million bbl/day, the expansion of the deep water production until 2010, and finally the need for new investments in capacity in OPEC-ME. Following the analysis in EIA(1996), the TED4FED assumes that the yields of the developed fields in the Middle East are fairly low and that these yields can be increased by fairly small investments. By 2010, this slack in yield has been used up and full cost reinvestments are necessary.

The effect of technology learning is evident in Figures 22 and 23 but not as strong as for Exploration. With a 5% learning rate (progress rate 95%), the need for investments are reduced by 10% at the end of the period. In the Dutton-Thomas scenario, yearly investments remains constant after 2015 and are actually reduced for conventional oil sources.

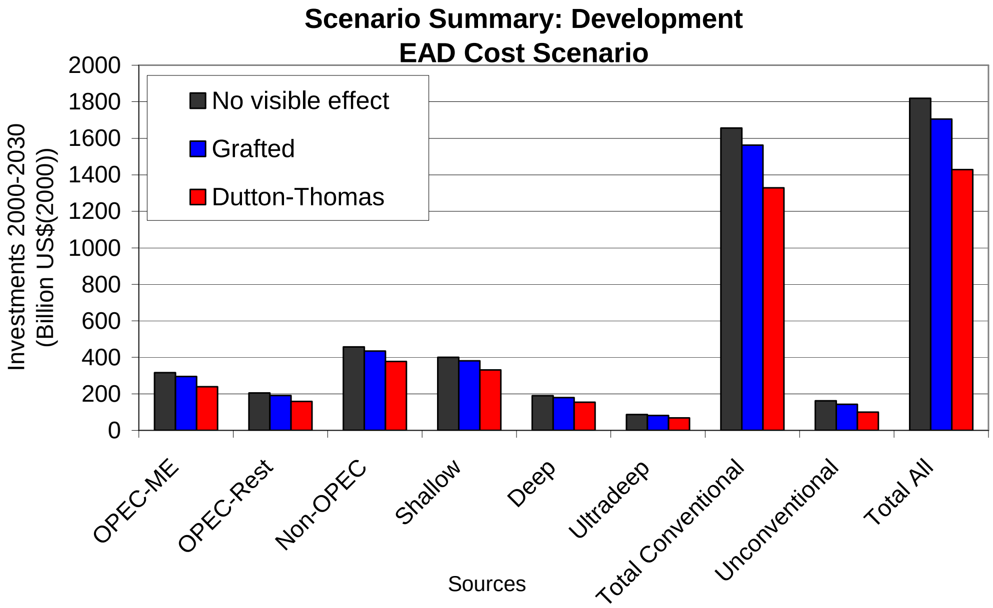

Figure 24. Investments in Development 2000-2030 in the technology scenarios calculated with EAD costs.

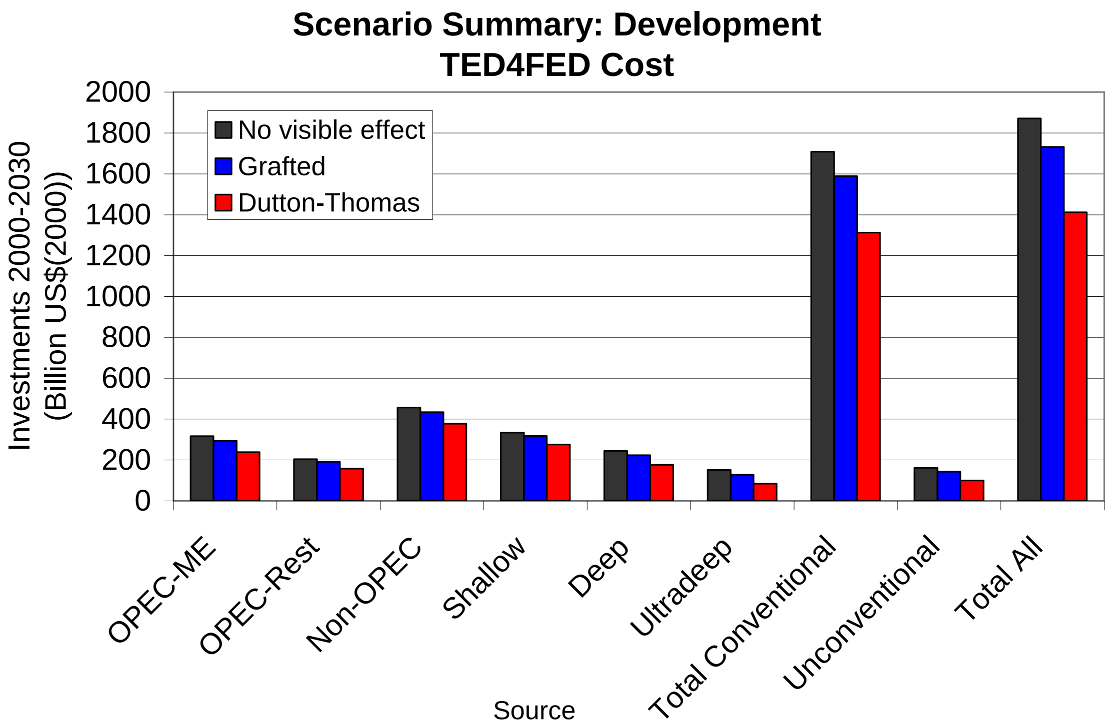

Figure 25. Investments in Development 2000-2030 in the technology scenarios calculated with EAD costs.

Figures 24 and 25 show the sum of investments over the 30 years period 2000-2030 calculated with the EAD and the TED4FED sets of costs, respectively. Dutton-Thomas scenarios reduce the total investments by 20% and 25% relative to investments in a scenario with No Visible Effect of technology learning. Notice that investments in *developing* shallow water fields are larger than for deep water fields, but investments in *exploration* in Figure 18 are larger for the deep water fields. The development of R/P ratio explains this difference (see Appendix 1). The large 2001 R/P values for shallow water fields makes it possible to produce more from the shallow fields than what is discovered. For the expanding deep water production, more has to be discovered than what is produced in the period in order to hold a R/P ratio of about 8. For production, we have not assumed any such “slack” in the yield from shallow water fields and the costs here reflects more closely the total production.

Our analysis places the 30 years investments for development of conventional oil resources in the bracket of 1300 to 1700 billion US$(2000).

5. Summary and Conclusions

Figures 26 and 27 summarize the TED4FED results for Exploration and Development. The total investments over the 30 years period from 2000 to 2030 are estimated to be between 1700 and 2300 billion US$ for conventional oil production.

Our investigation of technology learning indicates a major technology take off for *Exploration* at the end of 1980s or the very beginning of 1990s. I have placed the technology structural change in 1989. The most spectacular effects of this change have already happened, however, the effect on costs will still be considerable during the analysed period. Analysis of cost time series indicates historical learning rates for the global exploration technology in excess of average values for new technologies; i.e., more than 18%. I argue that a scenario with 18% learning rate (“Dutton Thomas Technology”) provides the most probable result and using the historical values also for the future may be overly optimistic.

For *Development*, the historical analysis yields much more ambiguous results. There are indications of a technology structural change around 1985 but confirmation of such a technology take off requires more investigations. Placing a change in 1985 provides sensible learning rates for cost time series, namely 18%, but interpretation is not straightforward. Analysis of reported costs can only provide a learning curve, i.e., cost reduction may be influenced by a changing mix of reserves and this mix is not properly monetised. The model calculations are based on a technology structural change in 1985. I argue that the uncertainties in the analysis make scenarios with learning rates of 5% and 18% (“Grafted Technologies” and “Dutton Thomas Technologies”) equally probable, in spite of the measured value of 18% from historical data.

The present analysis of Development meets the requirement for this Memo, that is to assess the effects of technology learning on investment estimates. However, investments in Development are more than ¾ of total upstreams investments. The importance of Development cost motivates further analysis of historical data if the purpose is to go beyond just understanding the uncertainty in investment estimates. *Niche market analysis of deep water technologies* is an example where experience and learning curve analysis would provide important insights but which requires more detailed understanding of historical data. Such an analysis would also require a much wider scope including operating costs.

The calculations for this Memo were made by the model TED4FED (Technology Deployment for Finding and Development). This model distinguishes between cost components subject to global learning and cost components specific to offshore activities. The reason is that the effects of technology learning may still be very large for the emerging deep water technologies. In fact they may be as spectacular as observed for the global technology in the 80s and 90s. For the purpose of this Memo, the split between the global and source specific components were made from an aggregate analysis and extrapolation of cost information in a database used in the industry (PEPS). More detailed work, e.g., niche market analysis, would require deeper analysis of offshore technologies.

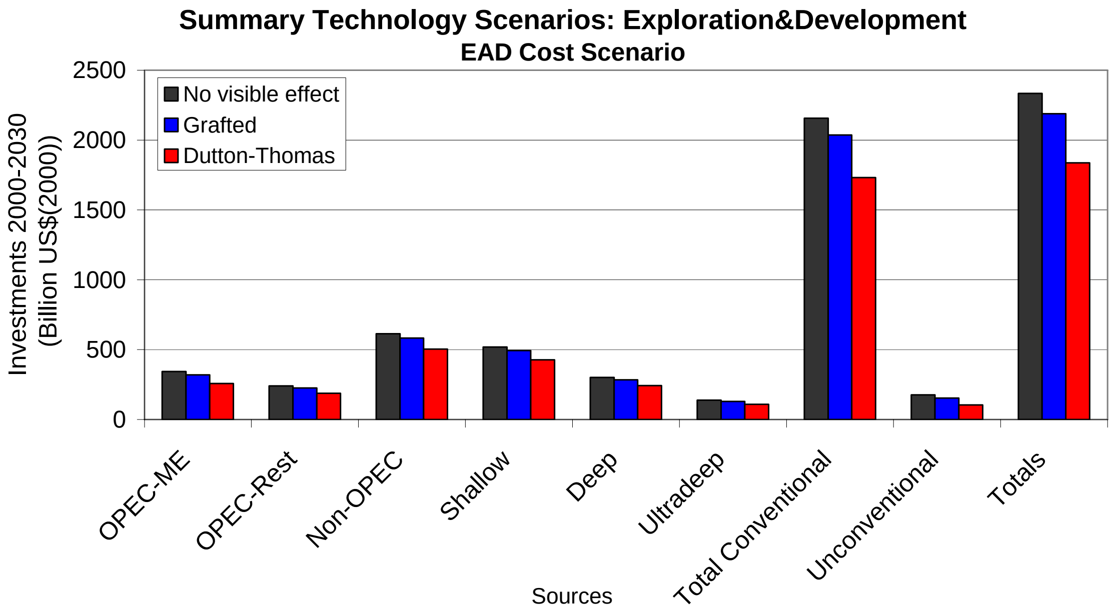

Figure 26 . Total investments in Exploration and Development calculates with EAD cost.

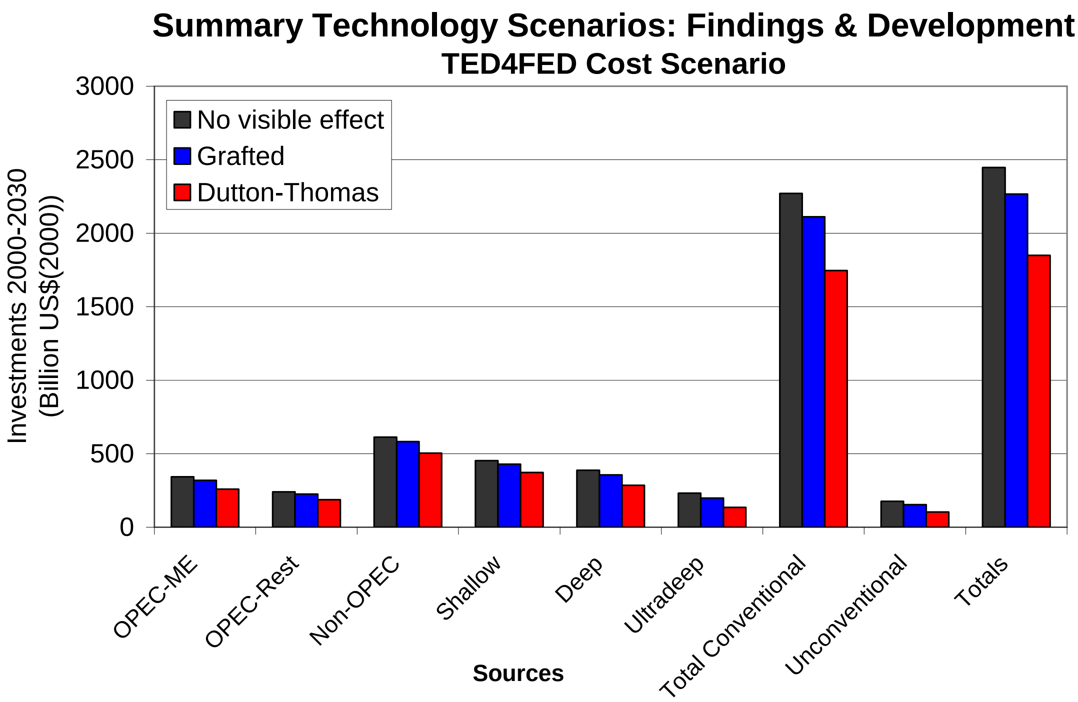

Figure 27. Total investments in Exploration and Development calculated with TED4FED cost

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APPENDIX 1:
R/P and Yields in TED4FED

Table A1 provides the target values for R/P and Yields for developed reserves used in TED4FED. If original R/P or yields are different from the target values, the model provides a smooth path from the original value to the target value. Figure A1.1 and A1.2 show how this work in the different region and also demonstrate how TED4FED follows the R/P ratios in EAD oil scenario.

Table A1.

Source	R/P (year)	Yields (bpd/MMbbl)
OPEC-ME	18	375
OPEC-REST	13	375
Non-OPEC		
Onshore	10	375
Shallow	8	375
Deep	8	376
Ultradeep	8	375

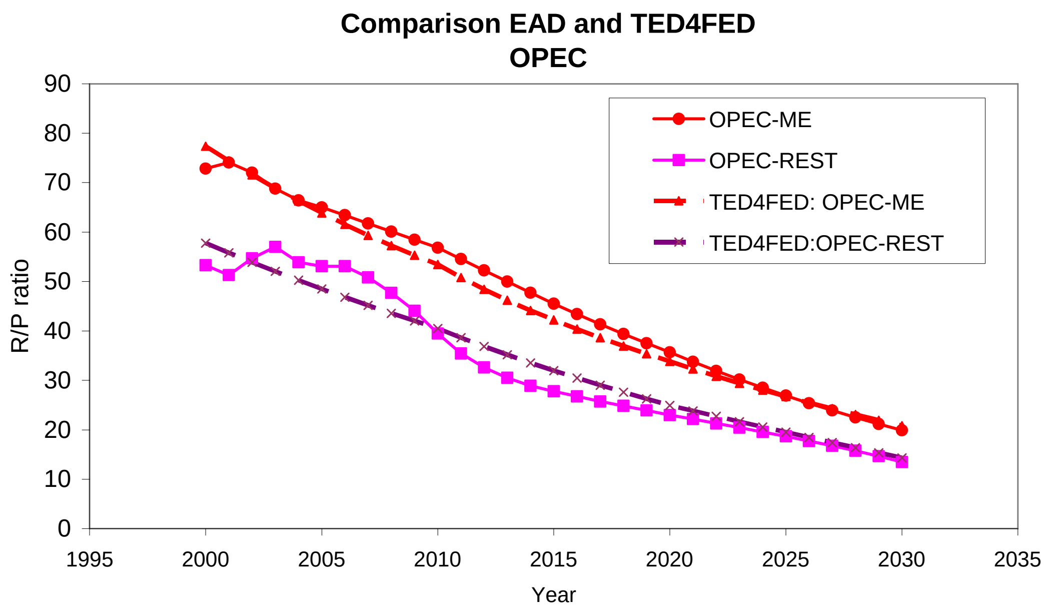


Figure A1.1. R/P in OPEC regions.

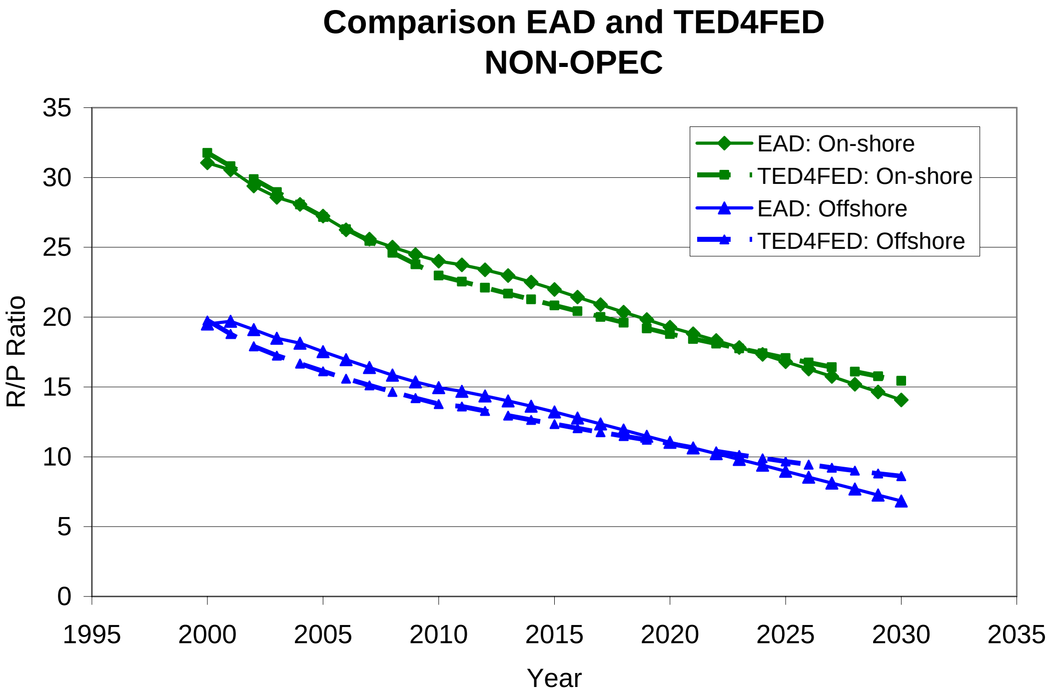


Figure A1.2. R/P in Non-OPEC regions.

Appendix 2:
Learning Curve analysis of Wildcats

We look at a learning system which has new-field wildcats as inputs and oil&gas wells as output.

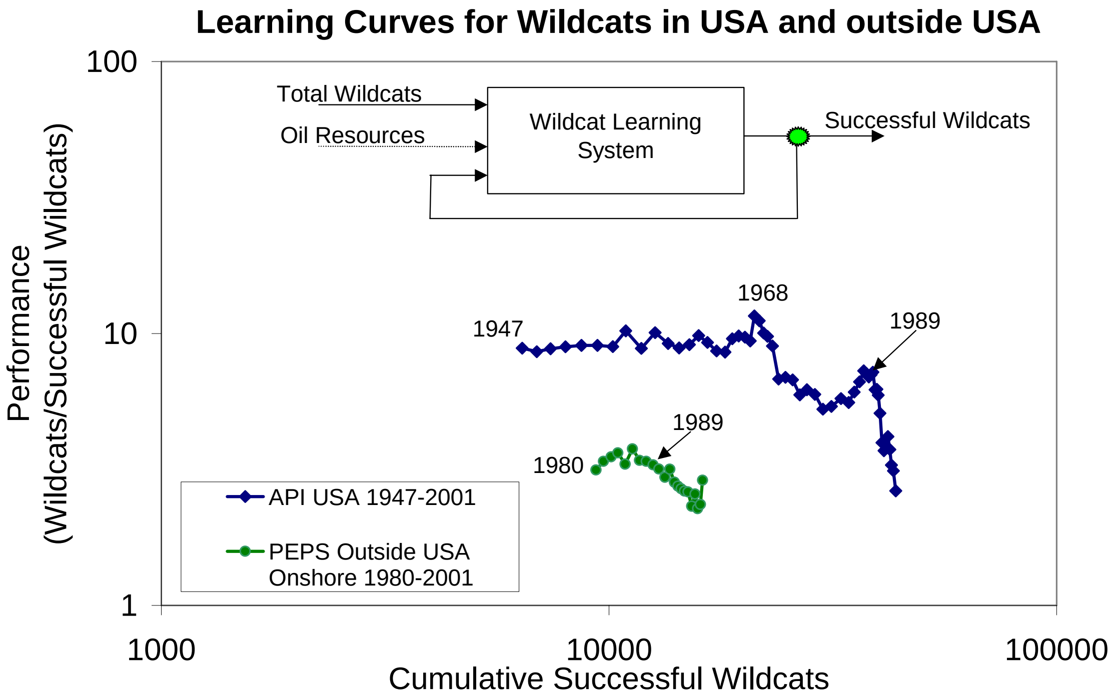
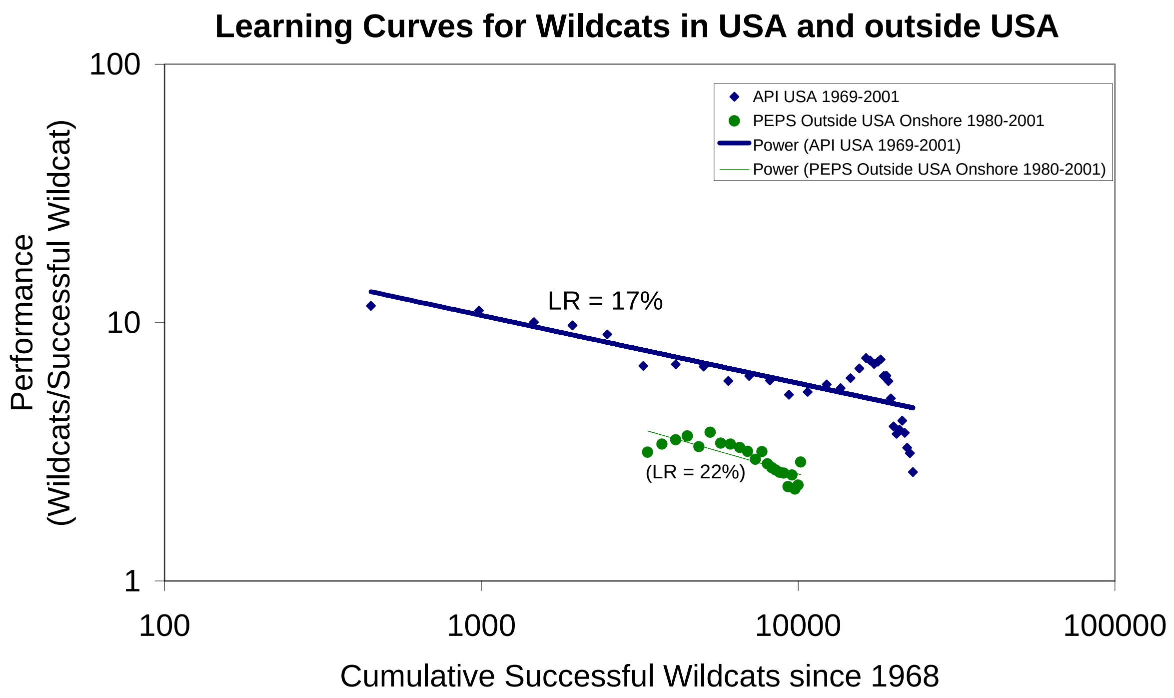


Figure A2.1. US Wildcats learning system

When interpreting Figure A2.1 it is important to remember that we here see a learning curve, we cannot argue that we have control over oil resource input as we did for the exploration costs in section 2.1.1. The effect of resource depletion is unknown. However, the wildcat's performance provides us with a very long time series to identify the effect of technology structural changes. A plausible interpretation of the learning curve for wildcats is that the steep increases in performance after 1968 and after 1989 are due to the technology changes described by Cleveland and Kaufmann (1997) and by Albertin et al.(2002). The increase in wildcats per successful wildcat in the beginning in 1980s is probably an oil market effect. The strong increase in oil price made oil executives more willing to take risks. However, the plateau of the curve between 1985-1989 is somewhat strange. A similar analysis for Enhanced Oil Recovery presented to the oil and gas group (Wene 2001) indicates that for EOR projects the shakeout started in 1986 as expected. We leave for the moment the explanation of the plateau 1985-1989.

Figures A2.2 and A2.3 show the analysis of the technology structural changes starting 1968 and 1989 respectively. The two learning curves have been constructing by setting cumulative successful wildcats to 0 in 1967 and 1988. This probably under-estimates the effect of the change, because the learning system is still using experiences gathered before this time. The learning rates in the cases are 17% and 23% respectively, well within the ranges of both the Dutton and Thomas and the McDonalds and Schrattenholzer distributions. The conclusion from this exercise is that the technical breakthroughs in computing and data gathering totally renewed exploration technology and that for forecasting one could place the entry-point at 1988 and as a first approximation assume 0 cumulative successful wildcats at that point.



FigureA2.2. Wildcats learning system since 1968

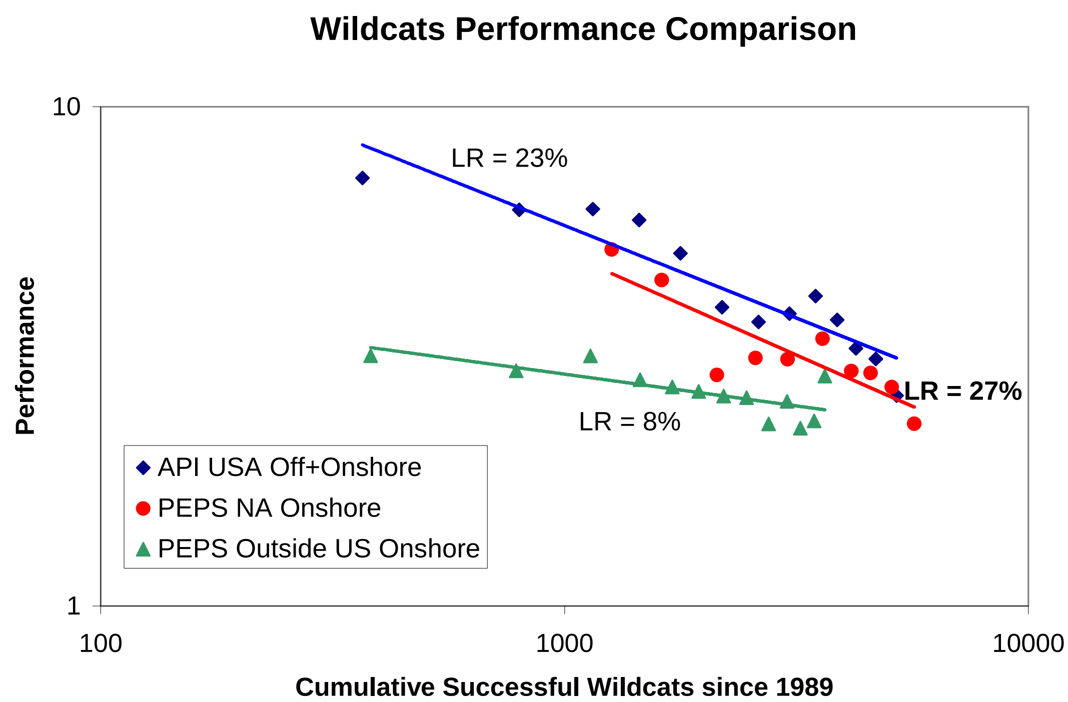


Figure 2.3. US Wildcats learning system since 1989

Appendix 3:
Performance of Development Wells

Figure A3.1 and A3.2 show the same analysis for development wells as for the wildcats in Appendix 2. However, the break in the 80s is much less pronounced and the learning rate for a technology structural change in 1985 is poor. The jury is still out on this one.

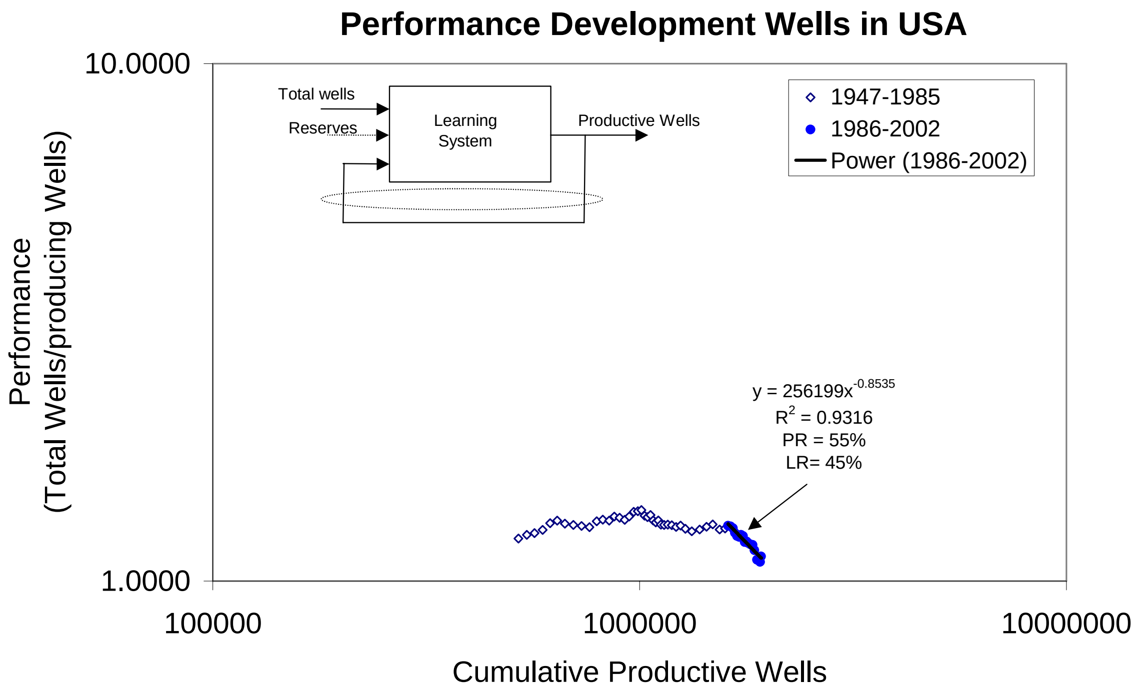


Figure A3.1. Performance of development wells

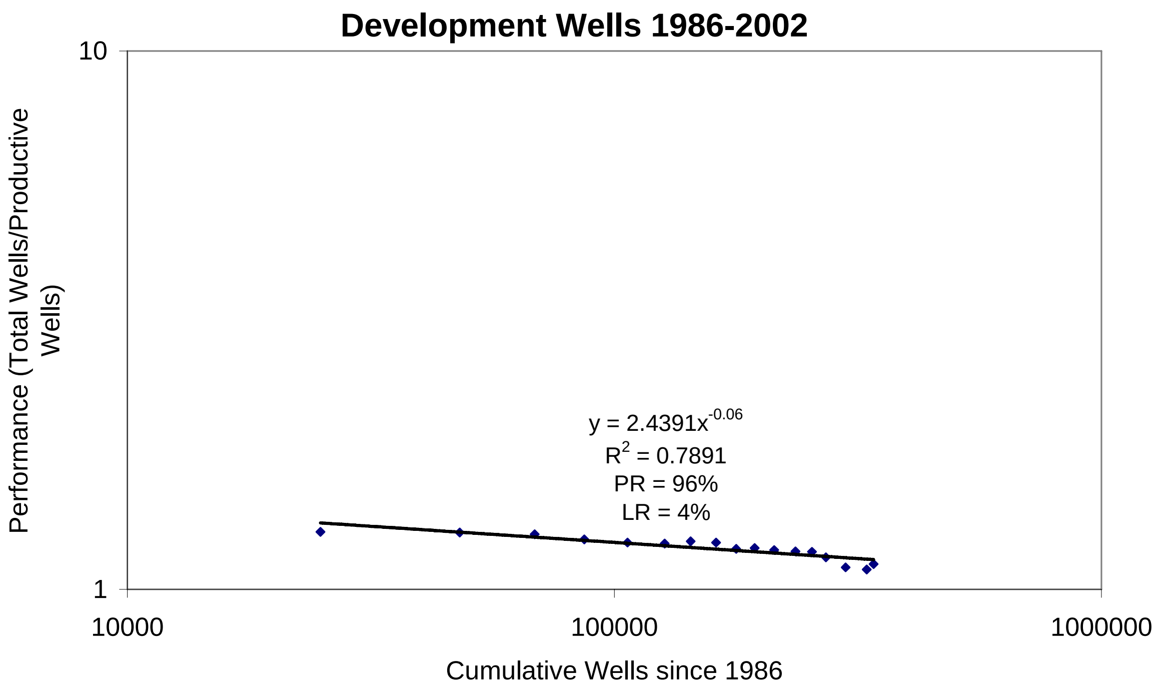


Figure A3.2. Performance of development wells since 1986.