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A Hedonic Study of Drilling Costs for Oil and Gas Wells in Western Canada

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Abstract:

Exploratory and development drilling constitutes an important component of expenditures on non-residential construction in Canada, and particularly in Western Canada, where the majority of activity is located. Therefore, it is important that changes in drilling costs be measured precisely so that changes in the volume of activity can be distinguished from changes in spending due to cost pressures. This paper uses the Well Cost Studies for 1994 and 1995 to perform hedonic cost regressions for Western Canada over this period. It was found that drilling costs increase disproportionately with depth, although the hypothesis that drilling costs increase proportionately with depth could not be rejected. Sour wells are significantly more expensive to drill than sweet wells. The northern part of B.C. and Alberta and the foothills region were found to be the most expensive areas to drill in, southwestern Saskatchewan the least expensive.

Hedonic price indexes for drilling costs were calculated in two ways, first by taking the exponent of the year dummy variable from the regression equation as the index number, and then by calculating a matched-model index for wells, with a predicted 1994 cost being used for 1995 wells with no match in 1994. Both methods yielded comparable results, showing a 1995 increase in direct drilling costs of 5.0% and in drilling and completion costs of between 1.0% and 2.1%.

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A Hedonic Study of Drilling Costs for Oil and Gas Wells in Western Canada

I. Introduction

NAED Drilling Deflator

The annual movement for National Accounts and Environment Division's deflator for exploratory and development drilling, which is also used by Input-Output Division, is obtained from Gary Howe of the Alberta Department of the Treasury, who in turn gets his estimate from Roger Soucy of the Petroleum Services Association of Canada (PSAC). The source of the annual estimate has been the well cost studies commissioned by the PSAC, and produced by Winterhawk Petroleum Consulting Services Ltd of Calgary (hereafter Winterhawk).

Table 1: Comparison of Measures of Oil & Gas Well Drilling Costs

	1990	1991	1992	1993	1994
NAED deflator	118.1	119.1	119.1	122.3	122.4
% change		0.8	0.0	2.7	0.1
Average cost/m.	$369	$370	$322	$383	$351
% change		0.3	-13.0	18.9	-8.4
Average cost/well	$439,207	$452,117	$396,045	$406,546	$406,847
% change		2.9	-12.4	2.7	0.1

Source: internal IOD listing; PSAC's *Midstream '95 Activity Update, May 1995*

As can be seen from Table 1 above, the NAED deflator doesn't match the movement of either average cost per well drilled or average cost per metre drilled, although in 1993 and 1994 it shows the same increases as the unit cost per well and in 1992 it shows only a slightly smaller decrease from the unit cost per well. This is because Mr. Soucy will not always use the movement of the unit cost of wells as the drilling cost measure, but will adjust that estimate if he thinks changes in the mix of wells make its use inappropriate.

The purpose of this paper is to explore how a matched-models or a hedonic approach might be used to obtain an alternative drilling cost deflator using the same data. The hedonic cost approach is also of interest because it permits the testing of hypotheses concerning exploratory and development drilling such as the relationship between drilling costs and depth. To the best of my knowledge, this is the first study that has used this rich source of information to try to find out what is driving the costs of drilling oil and gas wells.

Section II discusses some of the previous literature on the relationship between depth of wells and drilling costs. Section III describes the data contained in the 1994 and 1995 well cost studies on which the empirical work in this paper is based. Section IV describes the hedonic equations themselves and analyses the regression results. Section V discusses how the equations were used to calculate alternative cost indexes for drilling costs and Section VI concludes.

II. Impact of Depth on Drilling Costs

This paper does not deal with offshore wells. Generally the *Well Cost Study* for a given year is limited to onshore wells drilled in Western Canada, although the 1996 study will incorporate offshore wells drilled off the East Coast. The relationship between drilling costs and depth for such offshore wells is much different from onshore wells, firstly, because the costs themselves are much greater whatever the depth drilled to, and secondly, because the depth of water also has an important impact on drilling costs, independent of drilling depth.

Livernois, in his doctoral thesis on oil extraction, assumed that the relationship between drilling depth (D)and drilling cost (C) is of the type:

$$C = \beta_0 D^{\beta_1} \text{ or } \log(C) = \beta_0 + \beta_1 \log(D) \qquad \text{(II.1)}$$

which argues for fitting a double-log equation to the data, as was done in this study.[i] (In equation (1) and those following a well subscript is omitted to reduce the notational burden, but should be understood.) The double-log form has the additional advantage that since both costs and depth are expressed as logarithms, it is unlikely that the assumptions of OLS estimation will be violated due to heteroskedastic disturbances, and in fact the assumption of homoskedasticity was accepted for all equations calculated.[ii] Nevertheless, an interesting followup to this study would involve testing for functional form, here assumed to be double-log.

Franklin M. Fisher, in one of the earliest econometric studies of the oil industry, postulated a relationship between variable drilling costs and depth of the type

$$C = \beta_0 (e^{\beta_1 D} - 1) \qquad \text{(II.2)}$$

which is nonlinear, and cannot be fitted using OLS.[iii] This equation falls out of the following assumed relation between changes in variable costs and depth

$$dC / dD = H + \beta_1 C \qquad \text{(II.3)}$$

where $H>0$ is the limit on marginal cost as it goes to zero. Note that if $H \approx 0$ then the appropriate functional form is semi-log and the cost equation can once again be estimated using OLS.

Returning to (II.1), if $\beta_1 = 0$ then costs are identical for shallow wells and deep wells, depth having no independent influence on costs, and the intercept coefficient β_0 is then simply the geometric mean of the drilling costs for the wells in the sample. Although such a relationship between depth and cost is unrealistic, it is the implicit assumption that SNA makes in basing the movement of the drilling cost deflator on the unit cost for oil and gas wells, even though there are changes in the depth of wells included in the *Well Cost Study* from one year to another.

Generally one would expect β_1 to be close to but in excess of one. If $\beta_1 \approx 1$ then the intercept coefficient β_0 is approximately equal to the drilling cost per metre. However, there are good reasons to believe that drilling costs per metre will increase with depth (i.e. there are diminishing returns to scale with depth), because larger and more expensive rigs are required to drill deeper wells, and these rigs have greater installation costs. Also, it takes more more time to trip in and out of wells the deeper they are (i.e. to hoist pipe out of and return it to the well-bore, when a drill bit is being replaced, a core sample is taken, or for some other reason). Using Fisher's equation (II.2), a positive value for β_1 is consistent with diminishing returns to scale with depth, and this was generally what he found. Livernois is agnostic on the issue, only stating that a reasonable range for the parameter value is from 0.9 to 1.3.[iv]

Adelman and Ward, working with a combined sample of onshore and offshore wells from Louisiana, used two different nonlinear specifications to derive cost equations, taking care to allow for both different intercepts and different interactions with depth for onshore and offshore wells. For both functional forms, costs that vary with depth were found to increase disproportionately with depth, however, the cost per well independent of depth was very substantial. Predicted total cost per metre drilled actually declined with depth over the wells in the sample up to a depth of 1,400 to 2,000 metres and only increased with depth beneath those levels.

Paul G. Bradley in his study on Alberta natural gas wells decomposed drilling costs into contractor and non-contractor costs. Three different equations were estimated, with depth as the sole explanatory variable in each. For contractor costs, daily rental rates were modelled using a linear equation, and drilling days using a quadratic equation. Bradley's results indicate that daily rental rates increase less than proportionately with depth, while drilling days increase less than proportionately with depth initially, but disproportionately for wells deeper than 880 metres. Consequently, contractor costs per metre start increasing after about 690 metres. Non-contractor costs associated with depth were modelled using Fisher's equation (1), and increase disproportionately with depth for all wells, however total non-contractor costs per metre are only increasing for wells deeper than 2,000 metres. Finally, total drilling costs per metre increase only for wells deeper than 1,750 metres, which is within the 1,400 to 2,000 metre range indicated by Adelman and Ward's equation.

A recent CERI study provides the only empirical cost estimates I have been able to find for horizontal wells. In 1993 dollars, the study estimates a linear relationship between cost and depth in metres for vertical wells[v]:

$$C = 163{,}300 + 139.2 * D \qquad \text{(II.4)}$$

and a similar equation relating cost to depth and the length in metres of the horizontal segment of the well for a new-drill horizontal (*L*):

$$C = 1.25*[163,300 + 139.2*(D + L)] \quad \text{(II.5)}$$

Finally, for a re-entry horizontal, the cost equation used is:

$$C = 2.50*[44,100 + 41.6*(D + L)] \quad \text{(II.6)}$$

In equations (5) and (6) *D* stands for the total vertical depth of the horizontal well and not the depth of the well at the kick-off point.

A report of the National Energy Board states that "at present, a typical horizontal well costs somewhat less than two corresponding vertical wells, while a horizontal re-entry well costs approximately the same as a new vertical well"[vi]. Using the above equations and the Petroleum Recovery Institute's standardized horizontal well length of 501 metres, a new-drill horizontal well 1,000 metres deep costs 1.54 times as much as a vertical well drilled to the same depth, and a horizontal re-entry well costs 0.88 times as much as a new vertical well, or in line with the NEB statement. If the depth of the typical well is kept constant, while the horizontal well length is increased, the cost ratio rises substantially: a new-drill horizontal well 700 metres long costs 1.65 times as much as a vertical well drilled to the same depth.

III. Data

The data used come from the *Well Cost Study* for 1994 and 1995. These studies have been conducted every year by Winterhawk for the PSAC from 1982 forward, except for 1988 and 1992. The original 1982 study covered only British Columbia and Alberta. All other studies have included wells from all four provinces of Western Canada.

Drilling Areas

The *Well Cost Study* divides Western Canada into 12 areas for the purpose of sampling wells. (See the attached map from the 1995 edition. The circles indicate wells in the 1995 sample; the squares are for urban centres.) These areas do not correspond to the 10 standard Potter-Liddle areas, which have been used in other studies of the Canadian petroleum industry, for example, Uhler and Eglington[1986]. The Potter-Liddle areas were considered quite unacceptable for a study of drilling costs since the same area may contain wells that are drilled to 300 metres and wells that are drilled to 5,500 metres.

The 12 areas of the *Well Cost Study* were not defined by geological formations or plays, because the same play, if it covers a large area, may have quite different drilling costs from one area to another. The Cardium play, which contains the huge Pembina field, is found in central Alberta but also in Alberta's northern foothills, where it is much more expensive to drill.

Instead, areas were defined more according to whether their wells were shallow or deep, and whether they contained light or medium crude oil, heavy crude oil or gas.
For example, area 1 contains mostly deep wells with sour gas, area 2 is also mostly sour gas and there is a lot of seasonal drilling in this area, area 3 is mostly sweet gas and area 4 is mostly wells for heavy oils.

It is possible to cross-classify wells by geographic area and geological formation but this could quickly become unwieldy. Uhler and Eglington note that for Alberta alone cross-classification of the Potter-Liddle areas with areas based on geological horizons yields a potential 100 areas.[vii] One of the tasks of the present study is to establish if geological horizon seems to explain drilling costs independently of geographical area or other variables such as drilling depth.

Table 2: Breakdown of Areas for the Well Cost Study 1994 and 1995 by Province

Area	B.C.	Alta	Sask.	Man.
1	x(95)	x		
2		x		
3		x		
4		x	x(94)	
5		x		
6		x		
7		x		
8	x			
9			x	
10			x	
11			x	
12				x

x indicates that part of a particular province belongs to the designated area.

The areas have not been delineated the same way from 1982 forward, and have been altered slightly even from 1994 to 1995. The areas used in the *Well Cost Study 1994* and the *Well Cost Study 1995* do not cross provincial boundaries except for area 1 in 1995 and area 4 in 1994 (see Table 2 above). Area 1 as defined by the 1995 study is mainly in Alberta (it includes Banff and Jasper National Parks) but extends into eastern B.C., taking in part of what was area 8 in the 1994 study. The effect of the change is to reallocate the very deep and expensive Sukunka well from area 8 to area 1, a logical change since in 1994 the only well surveyed in area 1 was the Jumping Pound West well, with the highest cost of any well in the sample. There was no other well in the 1994 study that was even half so expensive as these two. There were no wells surveyed in Saskatchewan in 1994 for area 4 so its change in definition did not change the area code of any wells in the sample.

Directional and Horizontal Wells

The data on wells drilled comes from the *Daily Oil Bulletin.* Winterhawk chooses one or more wells from an area based on scatterplots of all wells drilled within an area against their depth in metres and the number of days over which they were drilled (which is highly correlated with costs), with some consideration of other variables. Generally, Winterhawk tries to sample wells that are representative of their areas, or at least wells that are not outliers, but they also try to obtain a representative sample of wells for Western Canada as a whole. For example, in 1994 there were 129 re-entry horizontal wells drilled in all of Western Canada, so this is hardly a typical well in any area. Nevertheless a re-entry horizontal well was sampled in area 5 since they are a significant and growing part of drilling activity in Western Canada.

The horizontal wells sampled were chosen in areas where there is substantial horizontal drilling activity. The re-entry horizontal well is in central Alberta, where a lot of the re-entry horizontals have been drilled. The other three horizontal wells are in Saskatchewan, where the formations are conducive to horizontal drilling, that is, flat and relatively unfaulted. By contrast, many of the oil-bearing areas of Alberta are hilly and heavily faulted, so that when one drills horizontally one may easily drill out of the oil-bearing formation, and they are also often friable, which makes drilling difficult. Also, there is not much pinchout in Saskatchewan, whereas there is a lot of it in Alberta.[viii]

Horizontal wells can be used as injection wells or production wells. In fact, one enhanced oil recovery process, steam-assisted gravity drainage, involves the use of a horizontal injection well placed in a formation just above a horizontal production well.[ix] They can therefore be very useful in increasing the recovery rate for heavy oil reserves, which account for most of Saskatchewan's resource base.

One of the horizontal wells in the 1995 study is also an underbalanced well. Underbalanced drilling is a technology developed in western Canada, generally but not invariably used in drilling horizontal wells, which substantially increases drilling costs but can also dramatically improve the recovery rates from a formation.

For directional and horizontal wells there is a distinction between the depth of a well (DEPTH) and the metres drilled, which are identical for vertical wells. Directional wells are drilled at a controlled angle from the vertical plane. Horizontal wells, as the name suggests, at some depth are drilled at a right angle, or almost so, to the vertical plane.[x] For both types of wells, the total metres drilled for a well exceeds its total vertical depth. For example, the underbalanced horizontal well in Weyburn, Saskatchewan used in the 1995 study, was drilled for 2,500 metres but only to a vertical depth of 1,400 metres.

In the *Well Cost Study* the same directional well is to be found in both annual samples, costed assuming that it is one of four such wells drilled from a single drilling pad. Many of the cost components, including rig transport and road and site preparation are reduced when several wells are drilled from a single pad, since these costs are shared between all the wells in the pad. A single directional well is more expensive to drill in terms of cost per metre than a single vertical well, but this is not necessarily the case for a pad-mounted directional well. In fact, the directional well in the *Well Cost Study* has a lower cost per metre drilled than the comparable non-directional well from the same area with the same vertical depth, whether one considers drilling costs only, or total drilling and completion costs.

The horizontal wells in the sample consist of six new-drills and two re-entries. A horizontal re-entry is "an older vertical well re-entered and extended horizontally".[xi] There are more of these wells being drilled every year in Western Canada, since they permit improved recovery rates from existing oil fields.

The re-entry horizontal well in the 1995 sample was drilled from a 1,750m depth in an existing vertical well for an additional 250m. This took the well to a vertical depth of 1,850 metres, or 100 metres vertically downward from the starting point. From this one could calculate that if drilled in a straight line the horizontal well would have been drilled at an angle of 66.4° from the vertical.

By definition, a horizontal well is drilled at an angle of not less than 80 ° from the vertical plane[xii], but it curves smoothly over a horizontal distance of 15 to 600 metres before it continues in a straight line at a horizontal or near-horizontal angle. Since the radius of curvature on a horizontal well is variable from one well to another, there is no way of knowing given the total vertical depth and the metres drilled value alone what were the actual number of metres drilled from the kick-off point (the point at which the well departs from the vertical plane). A lower bound on that number is the difference between the total number of metres drilled and the total vertical depth. This is 200 metres for the re-entry horizontal in the 1995 sample, 50 metres less than the actual value. For the re-entry horizontal well in the 1994 sample, there is no indication what were the actual number of metres drilled past the kick-off point (the variable denoted by L in equations (5) and (6) below). In future editions of the *Well Cost Study*, Winterhawk should try to specify this parameter for any horizontal in the sample, new-drill or re-entry.

Geological Epochs

The wells can be grouped according to their geological epoch, which is a common distinction made in economic analysis of the petroleum industry. The age of an oil-bearing formation is distinct from, but positively correlated with the depth of drilling. This relationship is, however, not uniform. For example, the Devonian stratum is about 300 metres thick, but it tilts upwards from west to east so a well to an oil-bearing Devonian formation in British Columbia might be 3,400 metres deep, while a similar well in eastern Alberta might be only 2,600 metres deep.

The relevant epochs are, from earliest to most recent:

1. Devonian,

2. Carboniferous,
3. Permian,
4. Triassic,
5. Jurassic,
6. Cretaceous.

These epochs can be subdivided, and some of them are known under different names. For example, the Manitoba Energy and Mines Department indicates that the Bakken formation belongs to the Mississippian epoch rather than to the early Carboniferous.[xiii] The naming of the epochs shown above conforms to the usage of the Geological Survey of Canada.

Smaller firms tend to drill in the Cretaceous formation, which tends to be lower profit but also lower risk than the deeper formations. The highest rents on resources probably come from the Devonian deposits, which are typically reef structures, very porous and under high pressure. At the same time, the massive capital investment required to drill to these deposits means that only larger companies are likely to drill to them.

The well cost studies specify the formation, but not the geological epoch, to which a well belongs. The assignment of epochs to the wells based on their formations was part of the work of this paper, and was based mainly on tables for the Western Canadian Sedimentary Basin found in Conn and Christie[1988].

IV. Regression Equations: Methodology and Results

Equations Estimated

The most general form of a hedonic cost equation for drilling oil and gas wells is

$$F(C_j; Q_{1j}, Q_{2j}, \ldots, Q_{mj}, u_j) = 0 \qquad \text{(IV.1)}$$

where C, the drilling cost, is the dependent variable, the Qs are the cost-determining explanatory variables, and u is the disturbance term, all for the jth well drilled. The equations estimated in this study were all estimated according to a single simple variant of that overall relation, specifically:

$$\ln(C_j) = \beta_0 + \beta_1 \ln(D_j) + \beta_2 SOUR_j + \ldots + u_j \qquad \text{(IV.2)}$$

where D_j stands for the depth of the jth well, and $SOUR_j$ indicates the first of several dummy variables that help to explain cost variation, in this case, depending on whether or not a well is drilled to sour oil or gas.

Cost equation (IV.2) conforms to the double-log functional form, so that the regression coefficient β_1 indicates the percent increase in costs with a 1% increase in drilling depth. By specifying the other explanatory variables as dummy variables the assumption is that the identical cost-to-depth relationship exists in all types of oil and gas wells, except that costs will shift up by the same percentage at all depths going from say a sweet gas well to a sour gas well or from a well drilled to a Cretaceous pool to one drilled to a Jurassic pool. It is of course possible that the value of the depth parameter for sour gas wells is different from that for sweet gas wells, i.e. that separate equations are appropriate for the two types of wells. In some cases, the assumption of common parameter values for subsets of the population of oil wells defined by dummy variables was formally tested, but not in every case.

The double-log functional form selected is arbitrary; a more careful analysis might establish another functional form as superior. In some of the equations for non-vertical wells a second continuous explanatory variable is used, but it enters the equation linearly, so the double-log functional form is not consistently used.

These are cost equations and take account of different technologies only from the viewpoint of costs, without regard to the advantages entailed in terms of increasing recovery rates from a reservoir and so forth. For proper measurement of productivity change, it cannot be otherwise. If one adjusted the costs of say, an underbalanced horizontal well for the improvement in recovery expected over a comparable vertical well, then any increase in output for the oil and gas industry due to the introduction of underbalanced horizontal wells would be attributed to an increase in capital inputs, rather than to an improvement in technology.

Separate equations were estimated for

1. the drilling subtotal of costs,
2. total drilling and completion costs.

The equation for the drilling subtotal of costs can be considered as an equation for exploratory drilling costs, since most exploratory wells are dry holes and are not completed. The equation for total drilling and completion costs can then be considered as an equation for development drilling.

Given this framework, all directional wells and horizontal wells were excluded from the sample for the drilling subtotal regressions, since these are invariably development wells. However, for other purposes it would be interesting to calculate equations for the drilling cost subtotal that would include other types of wells besides vertical wells, and this would make a useful extension of the present study.

For the total costs equation, the observation set initially included all vertical wells and directional wells. It was later restricted to exclude directional wells, and expanded to include horizontal wells.

Choice of Explanatory Variables

A dummy was included for gas wells, with the intercept representing oil wells, and sour oil or gas wells, with the intercept representing sweet oil or gas wells. There was no attempt to test for interaction effects, to see if, for example, sour gas wells were more expensive to drill but not sour oil wells. One would expect sour wells to be more expensive to drill than sweet wells, and they are certainly more dangerous to drill, since exposure to hydrogen sulphide is potentially lethal. Like many dummy variables, this is one that arguably could be or should be respecified as a continuous variable, for instance by introducing the hydrogen sulphide content of the petroleum in a reservoir to which a development well is drilled as a variable. However, the *Well Cost Study* only tells us whether the well is sweet or sour.

There were 11 area dummies in the stepwise regression, based on the area definitions of the 1995 *Well Cost Study* rather than the slightly different definitions of the 1994 study. Area 12 (southwestern Manitoba) was the omitted dummy at the start of the stepwise procedure.

There were no observations in either year for wells drilled to Permian formations so dummy variables represented the Devonian, Triassic, Jurassic and Cretaceous epochs, with the Carboniferous epoch represented by the intercept term. The Carboniferous was the omitted dummy in the stepwise regression because area 12 (Manitoba) was the omitted area dummy and the Manitoba oil-bearing formations are Carboniferous. If all area and epoch dummies had been included in the final equation, then the intercept would have represented the cost of drilling a sweet oil well in southwestern Manitoba.

The depth and drilling-to-depth ratio variables, the only non-dichotomous explanatory variables used in the cost equations, are discussed below (see "Modelling of Total Metres Drilled").

Weighting of Individual Observations and Adjustment for Outliers

Ideally, one would reweight the observations in the two samples to make them more representative of exploratory and development drilling respectively, but for these initial estimates, no attempt was made to do so. Table 3 shows the actual provincial distribution of exploratory and development drilling within Western Canada in 1994, as compared to the values from the *1994 Well Cost Study* used in regression equations for the drilling subtotal and total costs. What stands out in Table 3 is that British Columbia has a much more important share of exploratory drilling expenditures than development drilling, while the opposite is true for Saskatchewan and Manitoba. British Columbia is overweighted in both equations, mainly due to a single influential observation (the Sukunka gas well), causing Alberta to be underweighted in all equations and Saskatchewan to be underweighted in the total cost equations. Manitoba is overweighted in all equations, as is almost inevitable in a sample of this size (there is only one Manitoba well priced for the *Well Cost Study*).

Some observations frequently showed up as outliers in the regression equations, where an outlier is defined as an observation with a studentized residual that is significant at the 5% or 1% level. The Brazeau River well, the deepest well in the 1995 sample, generally had its costs significantly underpredicted, which suggests that the impact of depth on costs is more substantial than the equations indicate, at least for very deep wells. For an earlier specification that omitted any epoch dummies, the Brazeau River observation was excluded as an outlier only to find that another observation had now become an outlier based on the same criterion. When it was omitted a third observation became an outlier. This was an exercise reminiscent of Peer Gynt stripping off the layers of an onion to search for its inner core, only to find that it is all layers and no core.

Table 3: Exploratory and Development Drilling Expenditures in Western Canada, 1994 (in millions of dollars)

	Exploratory			Development		
	Value	%	WCS %	Value	%	WCS %
British Columbia	353.3	17.6	29.0	296.1	8.3	24.0
Alberta	1,550.9	77.2	67.2	2,763.5	77.8	68.0
Saskatchewan	101.8	5.1	2.8	473.0	13.3	6.9
Manitoba	3.5	0.2	1.0	19.8	0.6	1.1
Western Canada	2,009.5	100.0	100.0	3,552.4	100.0	100.0

Finally, no observations were discarded from the regressions as outliers. This was partly to preserve degrees of freedom, stretched to the limit as it was, but mainly because Winterhawk Consultants had carefully chosen these wells based on scatterplots of all wells as representative of their areas, so it would seem counterproductive to delete any of them from the sample. An additional consideration was that the outlying values were invariably for Alberta wells, and their deletion from the sample would have left an unweighted sample very badly underrepresenting the main province for drilling activity.

The Jenner well, found in both the 1994 and 1995 samples, was completed with a coiled tubing unit rather than a conventional service rig, which is perhaps why its costs were substantially underpredicted in every equation. Perhaps a dummy variable should have been assigned to this type of well, but there was only one well of this kind in each year's sample.

Analysis of Covariance

Table 4 shows the results of the principal equations tested. Standard errors are shown in brackets beneath the coefficient values. In all equations, the drilling costs were expressed as logarithms.

Stepwise regressions were calculated first for a drilling subtotal equation based on vertical wells only and a total costs equation based on vertical and directional wells only. The stepwise procedure chose explanatory variables for the total cost equation using a depth variable defined as metres drilled rather than total vertical depth, which only affected the two observations in the dataset related to pad-mounted directional wells.

Separate regressions for the years 1994 and 1995 were run based on the same variables chosen by the stepwise procedure for the pooled sample and an analysis of covariance indicated that the assumption of unchanged slope coefficients between the two years was acceptable.

An F test run on total cost regressions estimated with and without the two pad-mounted directional wells supported the assumption of common structure for directional and vertical wells. Surprisingly, analysis of covariance also indicated that there was common structure between the new-drill horizontals and the other wells in the sample, so that it was legitimate to calculate a single equation for both. There is no way to calculate separate equations for directional wells, horizontal wells or non-vertical wells because of insufficient observations.

Modelling of Total Metres Drilled

In the first go at modelling the total cost equations that included non-vertical wells, both total vertical distance and metres drilled were included as variables, but this did not give good results. For 55 of the observations the two variables are identical, and for the two directional wells the differences between their values are not great. In a stepwise regression with one of the variables constrained to be included, the other variable will not be chosen. If both are entered, then essentially the value of the depth coefficient is just shared between the depth and total metres drilled variables, so high is the multicollinearity between them.[xiv]

As an alternative, the total metres drilled variable was replaced with an interaction term, which took a zero value for vertical wells, and a value equal to the logarithm of total metres drilled for non-vertical wells (i.e. it was the product of the sum of HZTL and PAD, the horizontal and pad-mounted dummies, and the logarithm of total metres drilled). This had the correct positive sign, but was not statistically significant in the cost equation, probably because of inappropriate scaling. (The zero value for vertical wells would actually correspond, taking its exponent, to one metre drilled.)

My involvement in this project stems from a previous study on the incorporation of resources in estimates of multifactor productivity for the oil and gas industry. The depth of an oil or gas pool is one of the fundamental quality attributes to be considered in determining its quality as a resource input of the extraction activity, so it seemed essential to keep total vertical depth as an explanatory variable. The basic thread is that with depletion of our petroleum reserves, Canada will rely more for oil and gas on deeper wells, whose drilling costs will be greater, and therefore, because of depreciation charges and other charges arising out of increased capital costs, the real value added per cubic metre of petroleum extracted will be smaller.

What one would like then is some measure of the additional effort involved in drilling a non-vertical well to a certain depth, and an obvious choice would be the drilling-to-depth ratio (DDR), defined as:

DDR = TMD / D (IV.3)

where TMD is total metres drilled. The advantage of this variable is that it is appropriate to both directional and horizontal wells, assuming, as analysis of covariance with small sample sizes would lead us to believe, that it is appropriate to model drilling costs for vertical and non-vertical wells in the same equation. In the total cost equations, the DDR variable itself was used rather than its logarithm, which is equal to the difference in the logarithms of total metres drilled and total vertical depth. Thus the cost equation, ignoring other explanatory variables, would look like this:

$$\ln(C) = \beta_0 + \beta_1 \ln(D) + \beta_2 (TMD / D) \text{ or}$$

$$C = e^{\beta_0} D^{\beta_1} e^{\beta_2 (TMD/D)} \qquad \text{(IV.4)}$$

Equation (7) is an awkward hybrid of the semi-log and double-log functional forms. If the logarithm of DDR were the explanatory variable, we would have

$$\ln(C) = \beta_0 + \beta_1 \ln(D) + \beta_2 \ln(TMD / D) \text{ or}$$

$$C = e^{\beta_0} D^{\beta_1} (TMD / D)^{\beta_2} \qquad \text{(IV.5)}$$

which is a cleaner looking formulation.

For this initial study, choice of functional form was not the principal focus of concern, but for cost equation (2) in Table 4 the logarithm of the drilling-to-depth ratio was also tested as an explanatory variable, and it made virtually no difference to the outcome.

Equation for Vertical and Directional Wells

For equation (2), which included vertical wells and directional wells, it was not possible to introduce a dummy variable PAD for pad-mounted directional wells because for this particular dataset PAD is a linear combination of the intercept and DDR variables.[xv] The dummy variable by itself would have little explanatory power; it was never introduced by the stepwise procedure into any equation during the modelling process.

For equation (2), the coefficient for DDR implies that the cost of drilling a directional well 1040 metres to a total vertical depth of 900 metres is

$$e^{0.390147*(1040/900-1)} = e^{.060689533}$$

which amounts to a cost premium of 6.3% over a vertical well drilled to the same depth. Although the coefficient for DDR is not statistically significant even at the 20% level of significance, its parameter value appears to be plausible. As it happens, there is a vertical well drilled to a depth of 900 metres in the same area as the directional well that is also part of the well cost studies. The cost premium for the directional well over the vertical well is 6.4% in 1994 and 3.6% in 1995, which brackets the cost premium indicated by equation (II.6).

Equations for Horizontal Wells

Although it was not intended to reexamine model selection for the total costs equation with the introduction of non-vertical wells, the dummy for southeastern Saskatchewan, Area11 was dropped from the equations including horizontal wells. Significant at the 5% level in the total cost equations (1) and (2), which omitted horizontals, it was not even significant at the 15% level in the equations that included horizontals. (The entry criterion for a variable in the stepwise procedure is that its coefficient must be significant at least at the 15% level.) This is hardly surprising, since the Area11 dummy had a negative coefficient based on two vertical wells, and three of the six new-drill horizontals added to the dataset are in area 11.

Equations (3)(a) and (3)(b) showing the values for the horizontal dummy in the equations containing only new-drill horizontals are included for completeness. Note that in equation (3)(b), the coefficient of the horizontal dummy implies that costs are 72% higher for horizontal wells than for vertical or directional wells drilled to the same depth, which is consistent with the NEB's belief that a horizontal well costs slightly less than two vertical wells drilled to the same depth. However the hypothesis that the value of the horizontal dummy is exactly equal to 2.0 is rejected using a t test at the 5% level of significance.

The condition number of the matrix of explanatory variables for equation (3)(b) indicates a high degree of multicollinearity between the horizontal dummy HZTL and the drilling-to-depth ratio, DDR. Since the horizontal dummy is not statistically significant it was dropped from the equation, giving equation (3)(c). This is the best of the four equations including horizontals in terms of its coefficient of correlation adjusted for degrees of freedom (RB2).

The coefficient for DDR in (3)(c) is significant at the 1% level. Its value of 0.900794 implies that the cost of drilling a new horizontal well for 2500 metres to a total vertical depth of 1400 metres is

$$e^{0.900794*(2500/1400-1)} = e^{0.7077667}$$

Table 4: OLS Regressions for 1994-95 Well Costs

	Drilling Costs	Total Drilling and Completion Costs					
	(1)	(1)	(2)	(3)(a)	(3)(b)	(3)(c)	(4)
Intercept	4.6069	5.4513	5.0611	5.6166	5.0198	4.6471	4.6513
	(0.5360)	(0.3647)	(0.8435)	(0.3724)	(0.5641)	(0.3872)	(0.3830)
Year95	0.01715	0.007847	0.007812	-0.01303	-0.01148	-0.00962	-0.00823
	(0.0505)	(0.0411)	(0.0399)	(0.0399)	(0.0395)	(0.0394)	(0.0384)
Log(depth)	1.0833	1.0379	1.0379	1.0132	1.0180	1.0217	1.0216
	(0.0704)	(0.0513)	(0.0507)	(0.0525)	(0.0522)	(0.0519)	(0.0514)
DDR			0.3901		0.5559	0.9008	0.8967
			(0.7148)		(0.3973)	(0.1190)	(0.1159)
Area1	1.2622	1.1456	1.1456	1.1311	1.1314	1.1325	1.1331
	(0.1413)	(0.1283)	(0.1268)	(0.1331)	(0.1319)	(0.1317)	(0.1304)
Area3	-0.1854	-0.1227	-0.1227	-0.10815	-0.1009	-0.0994	-0.0997
	(0.0810)	(0.0645)	(0.0637)	(0.0646)	(0.0642)	(0.0641)	(0.0635)
Area6	0.7336	0.3496	0.3496	0.3420	0.3535	0.3584	0.3579
	(0.1587)	(0.1243)	(0.1229)	(0.1276)	(0.1267)	(0.1264)	(0.1252)
Area7	0.4375	0.3560	0.3560	0.3603	0.3679	0.3703	0.3701
	(0.0795)	(0.0617)	(0.0609)	(0.0621)	(0.0618)	(0.0617)	(0.0611)
Area8	0.3440	0.2200	0.2200	0.2377	0.2297	0.2321	0.2330
	(0.1220)	(0.1273)	(0.1259)	(0.1223)	(0.1213)	(0.1211)	(0.1199)
Area10	-0.5879	-0.3770	-0.3770	-0.3671	-0.3590	-0.3567	-0.3571
	(0.0907)	(0.0731)	(0.0723)	(0.0739)	(0.0734)	(0.0732)	(0.0725)
Area11	-0.3641	-0.2282	-0.2282				
	(0.1448)	(0.1123)	(0.1111)				
Sour	0.4146	0.3227	0.3227	0.3594	0.3592	0.3563	0.3559
	(0.1041)	(0.0866)	(0.0856)	(0.0887)	(0.0879)	(0.0877)	(0.0868)
Gas	0.1550						
	(0.0579)						
Triassic		0.1417	0.1417	0.1692	0.1717	0.1705	0.1701
		(0.0985)	(0.0974)	(0.1014)	(0.1004)	(0.1003)	(0.0993)
Cretaceous	-0.1239						
	(0.0726)						
Horizontal				0.5421	0.2197		
				(0.0731)	(0.2415)		
Re-entry							-0.4959
							(0.1333)
n	55	55	57	63	63	63	65
R2	0.9755	0.9781	0.9782	0.9736	0.9746	0.9742	0.9744
RB2	0.9693	0.9725	0.9722	0.9679	0.9685	0.9686	0.9685
DW	2.371	2.194	2.196	2.260	2.256	2.244	2.286

(1) excluding directional and horizontal wells
(2) including directional wells
(3) including directional and horizontal wells, re-entry horizontals excepted
(4) all wells, including re-entry horizontals
DDR=drilling-to-depth ratio

which amounts to a cost premium of 102.9% over a vertical well drilled to the same depth. This is reasonably close, but somewhat larger than the cost premium predicted by the NEB study, which would be somewhere under 100%. Note that the *1995 Well Cost Study* provides an actual cost ratio for this comparison between an underbalanced horizontal and a vertical well in southwestern Saskatchewan. The actual cost ratio of 1.87 suggests that the DDR coefficient in (3) may be too large. Also, equation (3)(c) pertains to directional wells in addition to horizontal wells; recalculating the cost premium for the directional well from the previous section gives:

$$e^{0.900794*(1040/900-1)} = e^{0.14012}$$

or a cost premium of 15.0%, which looks to be too high. Recall that the actual cost premium for a directional well over a horizontal well from the *1994 Well Cost Study* was 6.4%, and a little more than half of that in 1995.

Equation for New-Drill and Re-entry Horizontals

A test on common structure between all other wells and the re-entry horizontals indicated that the re-entry horizontals did not have the same structure as the other wells. However, the addition of a dummy for re-entry horizontals rectified this, and a second F test accepted the null hypothesis that the re-entry horizontals shared common slope parameters with the other wells in the sample.

The value of the re-entry coefficient is consistent with a 39.1% discount on re-entry horizontals compared to new-drill horizontals since

$$e^{-0.4959} = 0.60902254$$

The cost of drilling a re-entry horizontal 2000 metres to a total vertical depth of 1850 metres would be about 1.45 times greater than drilling a vertical well to the same depth, since

$$e^{-0.4959} \times e^{0.896(2000/1850)} = 0.6090 \times 2.3853 = 1.4526$$

This is a very substantial cost premium compared to a vertical well, when the NEB document quoted above postulated virtually no cost premium for comparable wells. Since the coefficient of the re-entry dummy is significant at the 1% level with the correct negative sign, and the coefficient of the DDR variable is also significant at the 1% level, one can reject the hypothesis that there is no cost premium for re-entry horizontals over vertical wells.

There are only two re-entry horizontals in the sample, but the PRI equations discussed above were framed for a re-entry horizontal with a horizontal span of 501 metres (the re-entry-to-horizontal cost ratio would increase substantially for a given vertical depth with any increase in the length of the horizontal span); the 1995 well must have had a horizontal span in the 500-metre range, and the 1994 well had a horizontal span of just 250 metres.

Analysis of Coefficient Values

In all of the equations, the depth coefficient was greater than one, consistent with increasing drilling costs per metre with deeper wells. However, the coefficient values are always close to one. In no case would the hypothesis that the depth coefficient equals one be rejected at even the 10% level of significance. As one might expect, the depth coefficient is larger in the drilling subtotal equation than in any of the equations for total costs; a t-test rejects the hypothesis that the coefficient equals one at the 25% level of significance. A doubling in depth for a well would entail a 12% increase in drilling cost per metre.

For the equations based on total costs, the depth coefficient varies between 1.018 and 1.038, with the higher value corresponding to the equation that excludes horizontal wells. This is as expected, since horizontal wells are generally more expensive in terms of drilling cost per metre than other wells (three of the six most expensive wells in the 1995 sample are new-drill horizontals), and it may not be appropriate to include horizontals in the same equation with vertical wells. A depth coefficient of 1.0138 implies that a doubling in depth for a well would entail a 1.9% increase in total drilling and completion costs per metre.

Note that for all equations, the depth coefficients fit easily into the range of 0.9 to 1.3 postulated by Livernois, in fact they all fit within the much more restrictive range of 1.01 to 1.09. They do not, if taken at face value, offer much help in explaining the perceived productivity decline in the oil and gas industry in the 1970s and 1980s. Any increase in the depth of wells over those years was gradual, and was not continuous from year to year. The muted response of drilling costs to such increases is insufficient to explain a large part of the industry's falling productivity during that period.

None of the epoch dummy variables seemed to explain much of the variation in drilling costs. The Cretaceous dummy was barely accepted for the drilling costs model; it carries the correct sign, since the Cretaceous pools tend to be shallower and cheaper to drill into than other pools.

The Triassic dummy was accepted for the total costs model with a positive sign, as would be expected since it is an early epoch, and wells to Triassic strata are therefore generally deeper and more costly to drill. According to equation (1) in Table 4 for the total costs model, total drilling costs would be about 15% higher for a well drilled to a Triassic strata than to another strata. As can be seen from the standard error in brackets beneath the coefficient, the Triassic dummy is not statistically significant at the 5% or even the 10% level. (The stepwise procedure will keep a variable in the model if it is only significant at the 15% level.) In some of the subsequent equations for total costs, the Triassic dummy was not even significant at the 15% level, but it was kept in the model since it was always significant at least at the 20% level.

In the drilling costs equation, the Carboniferous dummy represents a different intercept from the one defined for all lower strata, but in the total drilling costs equation, the Triassic dummy represents a different intercept from the one defined for both lower strata (Devonian and Carboniferous) and upper strata (Jurassic and Cretaceous). The Triassic dummy would not be included without the presence of the Sukunka well in both samples. It was the most costly well in the 1995 sample and the next most costly in the 1994 sample, after Jumping Pound West, a Carboniferous well.

Because of the inclusion of these epoch dummies, it is unlikely that the depth coefficient is overestimated, since one would expect the Triassic dummy to explain higher drilling and completion costs for Triassic wells that might otherwise be attributed to their depth, and the Cretaceous dummy to explain lower drilling costs for Cretaceous wells that might otherwise be attributed to their being shallow. The dummies were nevertheless tested for and included if significant because there may be other reasons why drilling costs would be higher in one formation than another. Not having the background knowledge to accept or reject the role of these dummies in the cost equations, I included them wherever the stepwise procedure indicated appropriate.

The same applies to the area dummies, since, as mentioned, the area boundaries were defined partly in terms of whether they contained deep or shallow pools. These dummies had a much more important impact on the cost equations than the epoch dummies, since they were often significant at the 1% level in the equations. All of the areas for British Columbia and northern Alberta and the foothills region were identified as high-cost areas (Area1, Area6, Area7 and Area8), while southwestern Saskatchewan (Area10) is identified as a low-cost area. The most expensive area to drill in by far was area 1; its coefficient in the drilling subtotal equation of 1.2622 implies that this area was 3.5 times more expensive to drill in than other areas. Since the two wells drilled into this area were both deep wells (the Sukunka well was the second deepest well in the 1995 sample), it may be that the equations have attributed some of the higher cost of these wells due to depth to the area in which they occur.

Note that the intercept term corresponds to the Manitoba region (area 11), the only area without a dummy variable in the initial stepwise procedure, plus all of those areas whose dummies were not selected by the stepwise procedure, specifically, areas 4, 5 and 9, and, for equations including horizontal wells, area 11. The intercept term thus corresponds to wells drilled in central Alberta and Saskatchewan, except for the foothills region, Manitoba, and, for the horizontal equations, southeastern Saskatchewan.

The dummy for gas wells in the equation for drilling costs only was significant at the 1% level, and its coefficient indicated that gas wells were 16.9% more expensive to drill than oil wells after other factors were taken into consideration. The collinearity diagnostics indicated a high degree of multicollinearity between the gas dummy and the depth variable, not surprisingly, since there are only four wells in the sample deeper than 3,000 metres, and they are all sour gas wells.

The dummy for sour oil or gas wells was signficant at the 1% level in all equations. The results shown in Table 4 indicate a 51% cost premium for sour wells in terms of drilling costs only, and a 38% to 43% cost premium in terms of total costs, with the equations including horizontal wells generating the higher values for the premium. Sour wells definitely do impose additional costs on producers, but multicollinearity may be responsible for making this premium appear larger than it is. Equation (1) based on total costs had substantial multicollinearity between the intercept, depth variable and the sour dummy.

There was no attempt to test for interaction effects between variables in this study, an exercise that degrees of freedom problems would probably render unrewarding in any case. Thus there was no attempt made to see if a sour gas dummy might have more explanatory power than separate sour and gas dummies. The Sylvan Lake well, which is sour oil, had its costs substantially overpredicted in most equations, and for the most part the other sour oil wells in the sample also had their costs overpredicted.

V. Hedonic Price Indexes for Drilling and Completion Costs

There are many different ways of calculating price indexes that make some use of hedonic regression analysis. In this study, analysis of covariance supported the use of a dummy variable for the year 1995 to measure cost change for that year. The limited number of degrees of freedom very much discouraged a characteristics approach to calculating the hedonic price index or any other approach not based on dummy variables. So only two methods were used to calculate the indexes, both using dummies:

1. the direct approach, taking the exponent of the coefficient of the 1995 dummy as the index number,
2. the composite approach, taking the geometric mean of the ratio of costs for the same wells in 1994 and 1995, using a predicted 1994 cost for any 1995 well that was not also part of the survey in 1994.

Since the hedonic equations used a year dummy, the characteristics approach would in any case degenerate to the direct approach. More precisely, the ratio of the geometric mean of the predicted values for 1995 compared to 1994 would equal the exponent of the value of the dummy for 1995.

There were 32 wells in the 1994 sample and one more in the 1995 sample, so the version of the composite approach used gives a slightly lower weight to the matched-model part of the index than would an implementation that instead of looking for a match in 1994 for all 1995 wells, looked for a match in 1995 for all 1994 wells.

The composite index is calculated based on geometric means for compatibility with the direct index. Because the dependent variables in the cost regressions are logs of costs, the dummy variable is consistent with a price index number based on geometric means of costs. In fact if the matrix of explanatory variables were limited to an intercept and the year 1995 dummy variable, the exponent of the coefficient of the year dummy would be identical with a geometric mean index of costs.

Figure 5 of the *1995 Well Cost Study* shows comparisons of costs of wells common to the 1994 and 1995 studies; the pairings shown there were used in calculating the matched-pairs index and the composite index. Some wells from earlier years were not recosted in 1995; they are only similar enough to wells drilled in 1995 to establish a match. The actual 1994 costs were adjusted for the differences in depth drilled based on the depth coefficient from one of the hedonic equations. For the Kaybob matched pair it was also necessary to reduce the cost of the 1994 sour gas well for comparison with the 1995 sweet gas well, and to increase costs by 13% since the 1994 well was drilled to a Cretaceous formation, and the 1995 well to a Jurassic formation.

Table 5: Hedonic and Matched-Models Cost Indexes for Oil and Gas Wells, 1995 (1994=1.000)

	Drilling Costs	Total Drilling and Completion Costs					
	(1)	(1)	(2)	(3)(a)	(3)(b)	(3)(c)	(4)
Direct Approach	1.017	1.008	1.008	0.987	0.989	0.990	0.992
Composite Approach	105.0		1.012				1.010
Matched-Models Index	1.050						1.021

For the total costs composite index, the re-entry horizontal well from the 1995 sample was matched to its counterpart in the 1994 sample. Here the actual 1994 cost of the re-entry horizontal had to be boosted because it represented a sweet oil well and the 1995 well is a sour oil well, which had a significant impact not only on this price relative, but on the entire composite index. In addition to an adjustment for depth, there was an adjustment for the different drilling-to-depth ratios of the two wells. For purposes of comparison, the adjustment was done using first coefficients from equation (3) in Table 4, then with coefficients from equation (4) in Table 4. The former estimate is incorporated in the first composite index shown in Table 5, the latter estimate in the other composite index, whose 1994 costs were adjusted using the coefficients of equation (4), which incorporates both new-drill and re-entry horizontals, throughout.

There were three unmatched vertical wells. For the composite index of drilling costs only, their cost movements were proxied by the direct-approach hedonic index for drilling costs only. For the composite index of drilling and completion costs, their cost movements and those of two horizontal wells were proxied first by the direct-approach hedonic index based on equation (2), then by the index based on equation (4).

To give an example of the kind of adjustment performed to obtain 1994 costs for 1995 wells, consider the sour gas Brazeau River well introduced in the *1995 Well Cost Study*. It was paired with a considerably deeper sour gas well from the same area, Jumping Pound West (JPW), which was the most costly well in the 1994 sample. The adjustment to the total drilling and completion costs of the Jumping Pound West well to obtain a 1994 cost for the Brazeau River well was done as follows:

$$\begin{aligned}
\text{Cost(Brazeau)}_{1994} \quad &= \text{Cost(JPW)}_{1994} * (\text{Depth(Brazeau)}/(\text{Depth(JPW)})^{1.0216} \\
&= \$4{,}771{,}980 * (3{,}100/3{,}650)^{1.0216} \\
&= \$4{,}771{,}980 * (0.84932)^{1.0216} \\
&= \$4{,}771{,}980 * 0.84632 \\
&= \$4{,}038{,}642
\end{aligned}$$

where the depth exponent used comes from the total costs equation (4) in Table 4. Note that the use of the exponent makes almost no difference to the cost adjustment in this case. If one simply adjusted the 1994 cost for the depth ratio of the two wells the adjusted cost would be $4,052,938, or less than $15,000 larger than the adjusted value used in the composite index.

There were only 16 matched wells in the sample, and three of these were directional or horizontal wells and so were excluded from the drilling costs index. Thus, it is somewhat surprising that the matched-models and composite indexes for drilling costs are identical to four significant digits. The matched-models index for total costs however, shows a cost increase of about 2.1%, as opposed to 1.0% for the composite index.

All composite indexes show higher rates of increase than the corresponding direct approach indexes, although the difference is smaller for the total costs indexes than it is for the indexes for drilling costs only. From Table 4, it can be seen that the coefficients of the year dummy variables have high standard errors. For equation (4), the point estimate is -0.00823, consistent with a price index of 0.992, but adding the standard error takes the price index to 1.031, which is a very substantial increase and in excess of those registered by either composite or matched-models indexes. Thus, the composite index values fall within the limits imposed by even quite narrow confidence intervals around the point estimates for the hedonic indexes, but only unfortunately, because the precision of these estimates is so poor.

The individual cost relatives varied over a substantial range for the composite indexes. For the drilling cost relatives, they range from 93.5 to 128.9 and for the total cost relatives, from 71.1 to 121.9. None of these values would however, be rejected as outliers using established sampling procedures. Provincial indexes for the wells are not shown (the samples they are based on are probably too small for them to be meaningful) but the indexes for drilling costs varied from 99.7 for Manitoba to 108.1 for British Columbia.

Indexes for drilling costs only were consistently and substantially higher than those for total costs whatever the type of index. This suggests a need for separate indexes for exploratory and development drilling, the index for drilling costs only being appropriate to exploratory drilling and the index for drilling and completion costs to development drilling. The differences between the two types of indexes would likely be even more pronounced if the observations were appropriately weighted. The Boyer well near High Level, Alberta had the highest cost relative for both drilling-cost and total-cost indexes, and is in an area where exploratory drilling is more important than in most of Western Canada.

Of the three sets of indexes, the composite-approach hedonic indexes would seem to provide the best indicators of price change, and to be the most consistent with accepted price index practice. There are too few matched models and they are too unrepresentative of drilling activity in western Canada to favour the matched models index, but the composite approach permits some use of matched-model pricing while still incorporating information from other wells in the sample. The use of the direct-approach hedonic indexes cannot be justified, at least not for this set of data, given the high standard errors of the estimates.

One might also argue for a matched-sample approach based on a proportional adjustment of costs for changes in depth, pairs of wells having other differences between them simply being discarded as unmatched. This would be a much simpler way of calculating an index, since there would be no need for econometric modelling, but would likely give similar results to the composite indexes shown in Table 5.

VI. Conclusion

This first attempt to calculate hedonic cost indexes for oil and gas wells has been successful enough to justify its further development. It has generated separate deflators for exploratory and development drilling, something SNA has needed but has never had before. SNA should continue to receive the *Well Cost Study* every year and derive deflators based on manipulation of the data therein rather than depending on PSAC for an estimate, although any estimate received from that source would of course still be of interest.

The effort required in maintaining a *Well Cost Study* database would not be substantial since the number of wells sampled from year to year is always less than 40, and some wells are repeated except for their cost updates from one year to the next. The assignment of geological epochs to each well, which was a tedious task in the present study, could be quickly carried forward now that a correspondence file between names of formations and their epochs has been developed.

More work should be undertaken to determine the appropriate functional form for the hedonic cost regressions. This is potentially an expensive process since some of the candidate functional forms would require use of non-linear least squares for their estimation but is a less onerous task now that there is a better handle on the appropriate explanatory variables for inclusion in the cost equations.

Ideally, both hedonic equations and composite price indexes should have their observations weighted based on exploratory and development drilling estimates for the appropriate years. With less than forty observations in each annual sample, a very expensive well is bound to have an undue influence on simple-weighted estimates, no matter how carefully that sample was chosen. This problem will be more acute when offshore wells are introduced to the sample with the 1996 survey. Also, a self-weighted sample will always overrepresent Manitoba, with only a single well in the survey, which would also tend to overweight sweet oil wells as a category.

In a worst-case scenario, where resource constraints prevent any further modelling of drilling costs, it would still be better to calculate a matched-models index based on data from the well cost studies, with proportional adjustment of costs for changes in drilling depth, which would still allow for separate deflators for exploratory and development drilling, and would give results that would be reasonably close to the preferred hedonic estimates.

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[i] See Livernois[1984], p.135.

[ii] An asymptotic test for heteroskedasticity was employed, using the SPEC option of the REG procedure in SAS. See *SAS User's Guide: Statistics, Version 5 Edition*, p.682.

[iii] See Fisher[1964], p.41-53.

[iv] See Livernois[1984], p.135.

[v] See Chan et al[1994], p.217

[vi] See National Energy Board[1994], p.7-7.

[vii] See Uhler and Eglington[1986], p.5.

[viii] Langenkamp defines pinch-out as "disappearance or 'wedging out' of a porous, permeable formation between two layers of impervious rock; the gradual, vertical 'thinning' of a formation, over a horizontal or a near-horizontal distance, until it disappears".

[ix] See Chan et al. [1994], p.119.

[x] In Chan et al., the definition of a horizontal well adopted is "a well drilled from the surface that penetrates a reservoir at an anle of at least 80°". (See p.123.)

[xi] See PSAC[1995], p.4.

[xii] See Chan et al[1994], Appendix B.2.

[xiii] See *Oil Activity Review 1987*, p.55.

[xiv] The sum of the two coefficients was 1.024313 in an equation identical to 3(a) except for the inclusion of a variable for total metres drilled and a dummy for AREA11, which compares with 1.0132 for total vertical depth in 3(a).

[xv] Specifically, PAD=-6.4286*INTERCEPT+6.4286*DDR, an equation that equals 0 for any vertical well. Generally it would not equal one for all directional wells, but there is only one directional well in each year, and the 1995 well is just the 1994 well with its costs updated, so they both have the same value for the drilling-to-depth ratio, which solution of the equation shows is 0.865.

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