Costs of Aggregate Hydrocarbon Additions

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'Oil Equivalence' is widely used to measure total hydrocarbon activity. Natural gas is converted to oil using a fixed factor, usually based on thermal measurement. In turn, expenditures on oil and gas are divided by such 'oil equivalence' volumes to define unit costs, especially of reserve additions. This approach lacks economic content. We show its implicit assumptions and constraints, and develop an alternative aggregation method using index numbers, with an example.

INTRODUCTION

Typically, investment in petroleum exploration and development yields a joint product: reserves of oil and natural gas. The reserve additions are separable, but the expenditures generating reserve additions cannot be neatly partitioned between the two hydrocarbon sources.

It is not surprising that some way of aggregating the results of exploration and development activity has been sought to relate total effort (cost) to results (reserve additions). The most popular technique has been to convert natural gas to 'oil equivalent' at a fixed ratio based on physical thermal content, or on some fixed value content implied by relative wellhead prices at a given point in time.

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More specifically, 'oil equivalent' is widely used to measure the total hydrocarbons contained in a reservoir, or produced by a company, or within some area, and so forth. Natural gas is used as a proxy for liquids, or vice versa, converting at 5,500 cubic feet per barrel or some other fixed coefficient.[1] Reports in the press, by consulting firms, for example, have used 6:1. Companies have generally stayed close to the 5.5:1 thermal equivalence. But some companies have used 10 mcf per barrel, explicitly called economic equivalence. The market-based foundation for that relation seems to have been a ratio of upstream prices per BTU of oil compared with gas at a time when gas prices per BTU were close to half those for oil.

Using fixed coefficients for aggregation has virtue in terms of consistent reporting, but in an economic context it presents two major problems. First, thermal conversion assumes oil and gas are close thermal substitutes in the marketplace – on the side of demand and also supply. But clearly they are not. Second, relative values of oil and gas change over time.

In what follows, we offer an economic index as an alternative approach to aggregation, one that recognizes changing relative values of oil and gas over time (Section 1). This aggregation technique – the Divisia index – is applied to US reserve and in situ price data from 1982 to year 2002; the results are compared with aggregation using the traditional fixed coefficient measures (Section 2). Concluding remarks are in Section 3.

We find that estimates of aggregated reserve quantities and of unit costs of aggregate reserve additions can be materially affected by the aggregation technique employed. We argue that the Divisia approach is theoretically superior to the usual fixed coefficient methods by allowing for time-varying imperfect substitutability between oil and gas, rather than assuming close substitutability. However, we find empirically that over much of our data period the differences in results by aggregation technique are generally modest.

We first show that adding together oil and gas at a fixed relation makes little sense in economic theory, since oil and gas are only partially interchangeable in respect of either demand or supply. They do compete in some markets, not in others. Any comparison of values per British thermal unit (BTU) is strongly affected by different energy-using apparatus and delivery.

Our alternative approach to aggregation requires input of estimates of the in situ price of oil reserves and of natural gas reserves, separately set by market forces, as they are at the wellhead in terms of flowing production. The time series of reserve prices we employ is based on regression analysis of market transactions relating to the sale of oil and gas reserves in the USA. There is public information on the US national total of gross reserves added in each year. Multiplying these totals by estimated in situ prices imputes an average market value to physical reserve additions. The values of oil and gas reserves

1. DOE *Monthly Energy Review* Appendix Tables A4, A6.

in situ are a surrogate for costs of creating additional oil and gas reserves, namely marginal finding and development costs.

Our next task, the computation of a combined quantity of oil-plus-gas, is dictated by the fact that most hydrocarbon deposits contain recoverable amounts of both. Investment moves toward more profitable deposits and toward that hydrocarbon more valuable to develop. In short, liquids and gas are joint products, in variable proportions, of finding-development investment.

Combining quantities of oil and gas in an economically meaningful way is an index number problem, the topic to which we now turn.

1. AN ECONOMIC INDEX APPROACH

Energy is only used in conjunction with some form of energy using equipment. Hence, the demand for energy is derived from the demand for the services provided by energy using equipment, not for itself. Consumers generally do not buy BTUs, producers do not sell BTUs.[2] Yet it is commonplace for energy aggregates to be expressed as BTUs. This exercise can be useful as an accounting yardstick, but lacks economic meaning. It ignores the fact that energy sources differ in quality. Even with universal competitive markets, energy prices per BTU would vary among energy types by reflecting different attributes such as end use served, weight, cleanliness, conversion costs, safety, ease of storage and the like.

The sequence and content of our discussion below in large measure follows that in Berndt (1978, pp. 238-48) but is confined to crude oil and natural gas. If only heat content mattered, and oil and gas were closely substitutable, oil and gas prices for the end user indeed would be much the same per BTU. But this is far from the case. Differences in end user BTU prices of oil and gas show that consumers value oil and gas on more qualities than heat content.

Thus, in 2001 oil delivered for power generation in the US cost $4.45 per million BTU, and gas cost $3.92 per million. But oil exiting a refinery as (a) motor gasoline cost $7.09 cents per million BTU; (b) aviation gas, $10.47; (c) home heating oil, $5.45; (d) diesel fuel, $5.65 cents.[3] In other words, much or most of the value in a barrel of oil lay in the light products into which it was refined. These values change up and down, and one year's relations may be very different from the year before and the year after. This market complexity is inescapable. Oil and gas equivalence at any fixed rate adds confusion.

Downstream differences reverberate upstream and can be amplified or compressed by differences in transportation costs per BTU. Natural gas is more

2. However, most natural gas purchase prices are calibrated with BTU content, reflecting a predominance of sales for space heating and boiler use.

3. DOE *Monthly Energy Review*, Tables 9.4, 9.10, and A2.

expensive to transport on a BTU basis than oil. Hence if downstream oil prices (expressed in terms of BTUs) exceeded natural gas, the difference back in the field would be magnified, and vice versa if downstream natural gas prices exceeded oil.

Variations in oil and gas BTU prices across time and across locations demonstrate that oil and gas are far from close thermal substitutes in the market place. It follows that any aggregation of oil and gas quantities using BTU conversion factors fails to capture market valuation by end users: BTU based aggregates lack economic substance.

In the context of oil and gas supply, the economic index number approach to this problem would be to weight quantities of oil and gas in a way that would reflect their respective relative marginal cost (supply price) per unit measured. In competitive markets, prices would equal marginal costs and respective upstream prices would measure the relative unit worth of oil and gas.[4]

Certainly, petroleum markets (as with most markets) do not match the perfectly competitive standard. Nevertheless, deregulation in North America has been pervasive and crude oil and natural gas prices – whether for production or reserves – during the last two decades or so provide reasonable approximations to suitable index weights.

How might oil and gas prices be incorporated in index number formulae that seek to aggregate quantities? If the price were for a unit of production at the wellhead, then the corresponding quantity would be production; if the price were in situ, the corresponding quantity would be reserves. Whether expressed as production or reserves, call the quantity of oil and natural gas at time t $Q_{o,t}$ barrels and $Q_{g,t}$ mcf respectively, with corresponding prices $P_{o,t}$ per barrel and $P_{g,t}$ per mcf; each price can be deflated by a suitable price index to express prices in real terms. Total expenditure on oil or gas, EXP_t, is the product of the respective prices and quantities:

$$EXP_t = Q_{o,t}\, P_{o,t} + Q_{g,t}\, P_{g,t} \tag{1}$$

If the price of oil were adopted as a numeraire, one way of constructing an oil and gas quantity index, QE_t, would be to weight the respective quantities by the relative prices:

$$QE_t = Q_{o,t} + (P_{g,t} / P_{o,t})\, Q_{g,t} \tag{2}$$

4. With imperfect competition, the weights would best reflect the marginal physical revenue product.

According to (2), one unit of oil is equivalent to ($P_{g,t}/P_{o,t}$) units of gas.[5] If the BTU prices of oil and gas were the same and oil and gas quantities were expressed in BTUs, then the relative price would be unity and expression (2), the aggregate quantity index, would indeed be the simple BTU sum of the two commodities. *An economic aggregate of oil and gas supply would only be identical with a BTU aggregate if BTU prices (or costs) were the same and oil and gas were perfectly substitutable.* Such parity pricing and substitutability is a special case that seldom holds. But to the extent that the relative prices of oil and gas do measure consumer preferences, expression (2) is clearly preferable to BTU summation.

However, expression (2) is itself restrictive, treating one unit of oil as substitutable with ($P_{g,t}/P_{o,t}$) units of gas. Such strict proportionality of substitution is unlikely. A preferred indexing technique would be a more general one. Berndt mentions the Cobb-Douglas index (Berndt, 1978, p245), but points out that it assumes substitution possibilities and expenditure shares are constant. These restrictions are not attractive. More promising are general index number formulae based on the classic work of Fisher (1922), notably developed by Diewert, who especially emphasized the discrete approximation to the continuous Divisia index (Diewert, 1976).

The most noteworthy properties that aggregate indices should satisfy are that they be single valued, separable and homothetic. Single valued means that for a given set of prices and quantities there is a unique solution for the aggregate quantity index. Separability is the requirement that buyer or seller preferences among the aggregated quantities be independent of the other quantities that lie outside the aggregated set. Homotheticity requires that when all components of the aggregate increase by a constant factor, the aggregate index also increases (at least within a small range of component changes).[6]

Divisia indices incorporate these desirable properties. Theoretically, Divisia indices are defined in terms of differential equations in continuous time, where the rate of change in the aggregate quantity index is the (instant) expenditure weighted sum of the rate of change of each component. Practical applications require approximation. Laspeyres, Paasche and (Fisher) Ideal indices can all approximate true Divisia indices over small price changes.[7] The Tornquist or Fisher discrete approximation we use is a good discrete approximation over larger price changes. The weights used for discrete time intervals are arithmetic averages of expenditure shares in two adjacent periods, and the continuous rate of change in quantities is approximated by differences

5. Note that if the same deflator applied to both oil and gas prices (as would be normal), then the price ratio would be invariant as to whether prices were expressed in nominal or real terms.

6. A special case of this would be constant returns to scale: the aggregate index would vary by the same (constant) as the components.

7. The Fisher "Ideal" index in effect is the geometric mean of Laspeyres weights and Paasche weights.

between one year and the next. Diewart (1976) has shown that the discrete Divisia index permits varying substitution possibilities without imposing parameter restrictions.

Divisia indices are chain linked, not binary. A binary index of values between two time periods depends only on information at the beginning and end of a period of time. Chain linked indices depend on the path taken by prices and quantities during the interval. Divisia indices are also invariant to base year normalization.

In our case of two commodities, oil and gas, a Divisia index for an aggregated quantity, QE_t at time t, would be derived from the expression:

$$\ln QE_t - \ln QE_{t-1} = a_{o,t}(\ln Q_{o,t} - \ln Q_{o,t-1}) + a_{g,t}(\ln Q_{g,t} - \ln Q_{g,t-1}) \qquad (3)$$

where the a's are average expenditure shares for adjacent years, namely:

$$a_{o,t} = 1/2\ (w_{o,t} + w_{o,t-1}) \text{ where } w_{o,t} = Q_{o,t}\, P_{o,t} \,/\, EXP_t \qquad (4)$$

The expressions for $a_{g,t}$ and $w_{g,t}$ are analogous (in the two commodity case, of course $w_{g,t}$ is $1 - w_{o,t}$ and $a_{g,t}$ is $1 - a_{o,t}$). The expenditure shares typically will vary over time; supply prices enter the index via the expenditure share weights. Note that the antilog of equation (3) is the ratio of the aggregate quantities in successive periods. Calculations of changes in Divisia quantities are invariant to whether prices are expressed in real or nominal terms, as long as the same deflator applies to each price component.

The discrete Divisia index defined by (3) treats the percentage change in the aggregate oil and gas quantity index as the weighted average of the percentage change in the individual quantities of oil and gas, where the weights are two period moving average cost shares. If the cost shares were constant – which is seldom – the discrete Divisia index would collapse to a Cobb-Douglas index.

When quantities of both oil and gas increase between adjacent periods, the Divisia quantity given by (3) will also increase (the homotheticity property). Suppose the percentage growth in the quantity of oil were matched by the same percentage decline in the gas quantity. As long as the weighted average expenditure share for oil exceeded that for gas, the Divisia quantity would rise. But whether that inequality would hold depends on what happens to prices. A decline in gas quantities would tend, other things equal, to reduce gas expenditure shares. But it is conceivable that an increase in the price of gas could be such as to reduce Divisia quantities, even though the quantity of oil may have increased. Hence a change in Divisia quantities is dependent not only on underlying changes in the quantities of its components, but also on what has happened to relative prices. Decomposing the sources of change in a Divisia index is not straightforward.

The Divisia index has been used extensively in energy demand analysis, aggregating over different energy types. However, Berndt has rightly cautioned that aggregate energy indexing may be difficult to interpret and not well defined, although the economic theory of aggregation does provide a rigorous framework (Berndt, 1978, p.248).

Below we apply these ideas to data on US oil and gas reserve additions for the period 1982 to 2002, in conjunction with corresponding estimates of in situ prices. We shall show how quantity and price (cost) information over a period of time may be employed using the Divisia technique to provide a quantity index of reserve additions for comparison with corresponding quantity indices using a fixed coefficient approach. We relate these quantity indices to changes in expenditures to see whether aggregate costs are rising or falling, and to what extent.

2. APPLICATION TO US DATA, 1982-2002

The formula to aggregate oil and gas quantity index of reserves using the Divisia approximation given by expression (3) above yields the change in the index between two adjacent periods. The calculation can be repeated for other adjacent periods, providing a chained index. Computation requires information on reserve additions and corresponding market prices.

Data on reserve addition volumes measured in barrels of liquids and cubic feet of natural gas are normally unambiguous, although consistency of reserve definition is a perennial issue. Development investment related to reserve additions is more troublesome. As mentioned earlier, oil and gas reserves are normally joint products. But sometimes natural gas found with oil is not marketable. Here oil related costs would become less ambiguous, by default. Conversely, the yield of light oil (condensate) found with natural gas could be so lean as to make recovery uneconomic, enabling gas costs to be identified. However, this is not the norm. Moreover, finding costs are not only joint between oil and gas but may also be joint across discoveries.

This is where information on oil and gas reserve prices – in situ prices – is valuable. A market price of reserves would measure the marginal cost or supply price of reserves. We rely here on estimates of in situ prices of oil and gas from Adelman and Watkins (2003).[8]

Another dimension is that crude oils differ in quality – especially in terms of gravity – as do the constituents of natural gas. These factors lead to value differences. Our data are not sufficiently finely tuned to adjust for variations in these characteristics. Instead, in what follows we treat the

8. These estimates focus on transactions involving proven reserves, to avoid uncertainties associated with purchase of undeveloped reserves.

respective volumes of crude oil and natural gas reserve additions as possessing average characteristics throughout.

To contrast and compare aggregation techniques, we create three sets of *aggregated* annual oil and natural gas reserve additions, using official US reserve data for the period 1982-2002. Two sets are calculated by converting natural gas to 'oil equivalent' employing fixed conversion factors of 5.5 mcf per barrel and 10 mcf per barrel respectively. Recall that the 5.5 coefficient represents conversion on a thermal basis, and is hereafter referred to as *thermal conversion*. The coefficient of 10 is one that has been used by some in industry (see earlier) to represent a wellhead oil price per BTU close to double that for natural gas implicit in thermal value. It is analogous to expression (2) above, although the ratio is fixed, not time varying. Hereafter it is called *price ratio conversion*. The third set uses the Divisia index method (see equation (3)).

The procedure we follow below is to first outline the basic data employed. Next we compare changes in quantities derived from the three aggregation techniques. We then relate these changes to total estimated expenditures on oil and gas reserve additions. This enables us to estimate and compare unit costs relating to the three sets of aggregated reserve additions.

The Data

The basic data used in making these calculations are shown in Table 1. For aggregation of quantities using fixed coefficients, only gross reserve additions (columns (2) and (4)) are relevant. Calculation of rates of growth in Divisia quantities requires in situ price data (columns (3) and (5)) as well as reserve additions. The prices drawn from Adelman and Watkins (2003) are nominal (not inflation adjusted) prices.[9] In the context of this analysis they represent the supply price of proven gross reserve additions – a surrogate for marginal finding plus development costs.

Fluctuations in the in situ price series we use reflect not only changes in amounts paid over time, but also changes in the mix of transactions among years. Variations in mix include the effect of location and differences in the constituents of the reserves that change hands.[10] The estimated in situ values are also subject to stochastic error. The confidence intervals that surround the estimates of reserve prices we employ could yield corresponding confidence bands for the Divisia indices. This further embellishment is omitted since it is not crucial to our focus on comparing different aggregation techniques.

9. Recall our earlier comment that a Divisia quantity index is invariant to whether prices are in nominal or real terms if the same deflator applies to both commodities.

10. Ideally we would wish to control for these elements, but lack of information precludes that.

Table 1. Basic Data

1 *Year*	2 *Volumes of Oil Reserve Additions (mmbbls)*	3 *Insitu Price of Oil ($/bbl)*	4 *Volumes of Gas Reserve Additions (bcf)*	5 *Insitu Price of Natural Gas ($/mcf)*	6 *Total Expenditures ($million)*
1982	2256	7.13	17288	0.36	22267
1983	4302	3.37	14253	0.64	23660
1984	4266	6.95	14409	0.86	42092
1985	4076	7.74	11891	0.52	37766
1986	2405	5.10	13827	0.96	25598
1987	3969	4.40	11739	1.02	29503
1988	3225	5.69	22085	0.99	40116
1989	2524	4.61	16075	0.88	25738
1990	2807	3.64	19463	0.90	27724
1991	1572	4.44	14918	0.87	19946
1992	2269	4.14	15376	0.82	22038
1993	2110	3.54	15189	0.87	20714
1994	2507	2.90	19744	0.77	22412
1995	3127	3.81	19275	0.60	23559
1996	3113	3.67	20189	0.69	25307
1997	3681	5.01	19960	0.93	37015
1998	863	2.85	15538	0.62	12049
1999	3961	3.59	22293	0.67	29233
2000	3520	3.55	29240	0.75	34377
2001	2854	4.21	25812	1.68	55297
2002	2991	5.74	22839	0.88	37232

Sources: Columns 2, 4: DOE,: *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves, 2002 Annual Report*, Table 1; 2002 from DOE release. Columns 3, 5: Adelman and Watkins (2003, Table B-2a); column 6 = col 2 x col 3 + col 4 x col 5.

Expenditures on reserve additions are the sum of the imputed value of oil and natural gas reserve additions (column (6), Table 1). Imputed oil reserve expenditures are the product of oil reserve additions and the estimated in situ price of oil reserves; imputed gas reserve expenditures are the product of gas reserve additions and the in situ price of gas reserves. Total imputed expenditures are unaffected by aggregation technique.

Table 2. Aggregated Oil and Gas Reserve Additions Indexed to 1982

1 *Year*	2 *Divisia Index*	3 *BOE Index Thermal Conversion Factor*	4 *BOE Index Price Ratio Conversion Factor*
1982	1.00	1.00	1.00
1983	1.44	1.28	1.44
1984	1.44	1.28	1.43
1985	1.33	1.16	1.32
1986	0.99	0.91	0.95
1987	1.20	1.13	1.29
1988	1.45	1.34	1.36
1989	1.09	1.01	1.04
1990	1.28	1.18	1.19
1991	0.88	0.79	0.77
1992	1.03	0.94	0.96
1993	0.99	0.90	0.91
1994	1.25	1.13	1.12
1995	1.35	1.23	1.27
1996	1.38	1.26	1.29
1997	1.49	1.35	1.42
1998	0.76	0.68	0.61
1999	1.63	1.48	1.55
2000	1.81	1.64	1.62
2001	1.56	1.40	1.36
2002	1.46	1.32	1.32

Quantity Comparisons

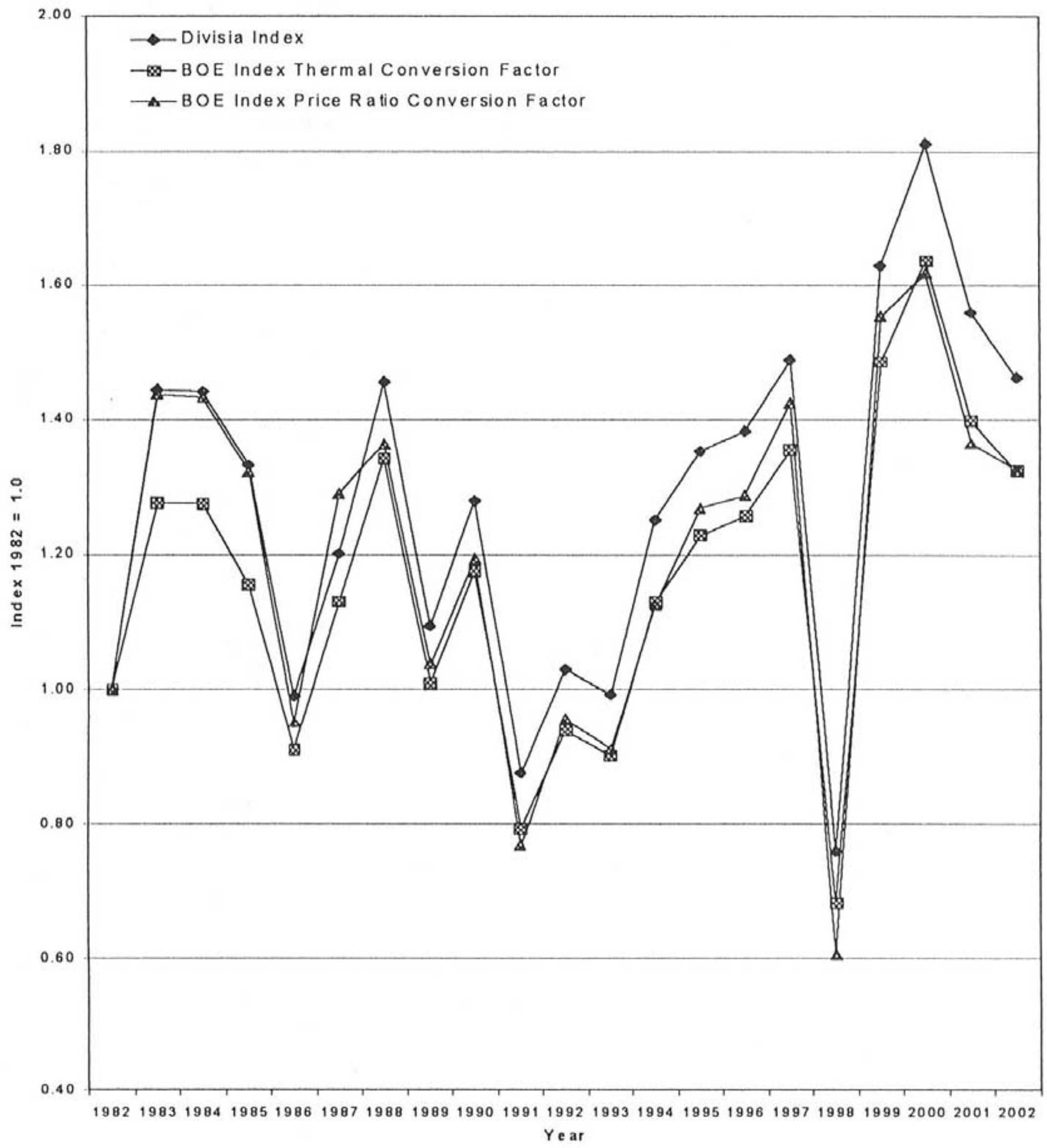
Table 2 shows the quantities of aggregate reserve additions indexed to base 1982 for the three techniques: Divisia, BOE thermal conversion (5.5), and BOE fixed price conversion (10.0). The numbers are plotted in Figure 1. The ratios of the Divisia reserve quantity index to that for the thermal index, and to that for the price ratio index, are shown in Table 3.

In all years the Divisia index exceeds the *thermal* index. The differences are some 13-15 per cent initially, but then fall to between six to nine per cent, 1986-1990. From 1990 to 2002 the difference is persistently around 10-12 per cent

Tables 2 and 3 also reveal that in all years bar one the Divisia index is greater than or equal to the *price ratio* index. Initially the difference between these two indices is trivial. For the next ten years beyond 1987, the Divisia index typically exceeds the price ratio index by about seven per cent. Beyond

1997 the comparisons are more erratic, with the Divisa 25 per cent higher in 1998, only five per cent higher in the next year; then ranging from 10-14 per cent.[11]

Figure 1. Aggregated Oil and Gas Reserve Additions Indexed to 1982



11. The respective simple correlation coefficients are high: 0.99 (Divisia and Thermal); 0.97 (Divisia and Price Ratio); 0.97 (Thermal and Price Ratio).

The annual percentage *changes* in these indexed quantities are closely correlated in some years, not in others. Over the 21 years, there is no difference in sign of adjacent year changes between the Divisia and the two fixed coefficient series, but 10 years show marked differences in percentage changes. The annual changes oscillate considerably, as is quite common for reserve additions.

Table 3. Ratio of Divisia Estimates of Aggregated Reserve Additions to BOE Estimates, Referenced to 1982

1 *Year*	2 *Ratio of Divisia Quantity to Thermal Conversion Quantity*	3 *Ratio of Divisia Quantity to Price Ratio Conversion Quantity*
1982	1.00	1.00
1983	1.13	1.00
1984	1.13	1.01
1985	1.15	1.01
1986	1.09	1.04
1987	1.06	0.93
1988	1.08	1.07
1989	1.08	1.06
1990	1.09	1.07
1991	1.10	1.14
1992	1.10	1.08
1993	1.10	1.09
1994	1.11	1.11
1995	1.10	1.07
1996	1.10	1.07
1997	1.10	1.04
1998	1.11	1.25
1999	1.10	1.05
2000	1.11	1.12
2001	1.12	1.14
2002	1.10	1.10

Source: Table 2.

Cost Comparisons

Since total imputed expenditures do not vary by technique, differences in aggregated quantities of reserve additions translate into corresponding variations in unit cost. Hence the heading of the second column of Table 3 could equally be written 'Ratio of thermal index to Divisia index of unit cost' and column 3 to 'Ratio of price ratio index to Divisia index of unit cost'.

The relationships between the Divisia and the two fixed coefficient quantity indices reviewed above, then, are the mirror of those for unit costs. Divisia derived estimates of unit costs are lower than those for thermal aggregation by between six and 15 per cent, 1982-2002, but the difference is stable beyond 1990: a representative figure would be 11 per cent. The Divisia unit costs are much the same as those provided by the price ratio approach until 1987 – this provides theoretical support for the conversion factor used during this period of 10 mcf per barrel – but thereafter Divisia unit costs are between five and 25 per cent lower that costs under price ratio aggregation.

In year 2002, relative to 1982, the unit cost of aggregate oil and gas reserve additions under the Divisia approach is estimated as 1.14, those for both the thermal conversion and price ratio conversion series is 1.26. In this year, then, Divisia estimated unit costs of reserve additions are some 10 per cent below those estimated using both fixed coefficient techniques of aggregation.[12]

Digest

Estimates of unit costs of aggregate reserve additions can be affected by the aggregation technique employed. In the US since 1982 the conventional thermal conversion factor generally produced estimates of unit costs around 10 per cent higher than the Divisia technique. The other technique of aggregation tested, using a fixed price ratio, produced results much the same as the Divisia until the late 1980s; beyond then, unit costs exceed those under the Divisia by varying degrees. We observe that application over an extended period of any fixed ratio of oil to gas values will tend to be falsified so that a flexible scheme like Divisia is preferable, if the available data permit implementation. A recent trend towards higher natural gas field prices versus oil prices – which can be expected to affect reserve values – would not be accommodated by any fixed coefficient methodology.

By avoiding distortion of aggregate cost our methodology guards against exaggerating or underestimating costs of reserve additions and drawing false conclusions about industry profitability. A tendency to overestimate aggregate costs under traditional methods implies corresponding underestimation of corporate profitability and larger upward shifts in aggregate reserve supply curves than may actually have occurred. We caution, however, that these conclusions are sensitive to estimates of in situ prices employed. Moreover, the representative degree of cost exaggeration over the period examined (1982-2002) of around 10 per cent is modest.

12. It so happens that in 2002 the ratio of natural gas reserve additions to crude oil reserve additions, measured in their natural units, is the same as in 1982. Hence the quantity or cost index for 2002 to base 1982 is invariant to the conversion factor.

The only published paper of which we are aware that deals specifically with the oil equivalence issue is Lohrenz (1998). His 'equivalent barrels' were calculated by using a range of conversion factors, from 2 mcf per barrel to 15 mcf per barrel. He regressed equity values plus debt of independent oil and gas companies[13] on 'equivalent barrels' for the period 1992-1996. The conversion factor that maximized the degree of fit and minimised the standard error was found to be 5 to 6 mcf per barrel. He did not argue, however, that this demonstrated 'thermal' validity.

3. CONCLUSIONS

Costs of finding new reserves cannot be neatly partitioned between oil and gas, since such costs are typically joint. This feature has led to attempts to define costs of oil and gas reserve additions by dividing expenditures by some kind of aggregate quantity.

The aggregation technique preferred by industry, the investment community and governments has been to translate gas to oil 'equivalent' by using a fixed physical thermal conversion factor or a factor intended to express some fixed BTU price equivalence. These manipulations create economic fictions.

The economic validity of a thermal conversion factor rests on oil and gas being close substitutes over most end uses. Differences in BTU prices of oil and natural gas, upstream and downstream, demonstrate the assumption is false. A fixed value related ratio is also false when relative prices fluctuate over time.

A preferable aggregation technique is one that embraces changes in economic information, such as the Divisia approach. It has been widely used in the analysis of energy demand. It can also be applied to aggregating energy supply.

Comparisons of shifts in apparent unit costs of aggregated oil and gas reserve additions in the United States, 1982-2002, show that different techniques of aggregation can lead to noticeable variations in results. But the typical difference is modest, with Divisia aggregation generally yielding quantities about 10 per cent higher, and thus unit costs about 10 per cent lower, than aggregation based in thermal content. The direction of this result, however, is not a general property of the Divisia method – it follows the data.

The Divisia technique is preferable to a fixed coefficient approach, whether based on thermal properties or on something else. However, if past relationships continue, a rule of thumb would be that unit costs for aggregate oil and gas volumes derived using thermal conversion should be reduced by around 10 per cent.

13. He argued that most of the assets of the companies he selected were reserves, so that the coefficient attached to the reserve volume would estimate the in situ reserve value.

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