Optimal Development of the North Sea's Oil Fields – the reply

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We consider that Wall *et al*'s technical criticisms of our monograph are irrelevant or ill-confused. Their volumetric analytic method is inadequate and their approach to the platform/wells location question conflicts with oil industry views. On the economic aspects, Wall *et al* avoid the central issue we considered – on how to resolve company–government conflict – and instead take up an issue – on the overall speed of North Sea development – which we did not discuss. We show, moreover, how this criticism of our study is largely unsubstantiated personal opinion and, as such, unworthy of consideration, even if many of Wall *et al*'s arguments were not erroneous.

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Wall *et al* have produced a critique[1] of our monograph on the optimal development of the North Sea's oilfields[2] which totally ignores the essential theme of the study. This is that government and company interests in the development of large, off-shore oilfields are different, but that, despite this, governments have both the opportunity and the option to modify the economic environment within which the companies must operate. The companies can thus be persuaded to act in the nation's best interest, without the modification adversely affecting their commercial interests. Even if the severe criticisms of our work presented by Wall *et al* were correct (and we do not believe this to be the case), this essential point which has emerged from our research remains valid.

The critique is in two distinct parts – on reservoir calculations and engineering aspects, and on the economics. This division of the article is one of its main weaknesses, for the engineering and economic aspects of off-shore optimal development decisions are so interrelated that it is impossible, as we tried to show in our monograph, to deal separately with the issues involved. Indeed, it seems to be the absence of early and sufficiently comprehensive economic components in evaluations of an oilfield's recoverable reserves (particularly viewed from the national viewpoint rather than that of the company which has discovered the reservoir) that has already led to production plans for North Sea fields which appear to be far from optimal from the British taxpayer's point of view. In as far as our monograph appears to have stimulated interest by the UK Department of Energy in the national aspects of the economics of reservoir development (to complement its existing technical interest in reservoir engineering), perhaps we may already fairly claim a useful result from our efforts to hypothesize nationally optimal development approaches to North Sea oil production.[3] Nevertheless, notwithstanding the symbiotic relationship between the engineering and economic aspects of North Sea oilfield development in the context of important national as well as company interests, we are obliged in this rejoinder to react to the separate – and apparently independent — efforts of Wall and Wilson on engineering and Jones on economics.

Engineering aspects

On the size of reservoirs

Wall *et al* point out that we consulted with experts in the field of analysis outside our direct technical competence – the field of reservoir engineering. Indeed we did, and we wonder why Professor Wall, one of the experts consulted, has changed his opinion so

[1] C.G. Wall, D.C. Wilson and W. Jones, 'Optimal Development of the North Sea's Oil Fields – the criticisms', *Energy Policy*, Vol 5, No 4, 1977, pp 284-294.
[2] P.R. Odell and K.E. Rosing, *Optimal Development of the North Sea's Oil Fields: A Study in Divergent Government and Company Interests and their Reconciliation*, Kogan Page, London, 1976.
[3] Professor Odell has been appointed as a consultant to the UK Department of Energy to study and report on this.

radically since he reviewed an earlier draft of our work and discussed it with us at length. On that occasion he expressed general approval of our methods, and while raising detailed points, such as issues of 'over drilling', his opinion on the work as a whole was that 'a more sophisticated model of the reservoir would change the results by only about five per cent'.[4] We are left pondering what changes in circumstances and/or what external pressures could have produced Wall's remarkable *volte-face.*

$(1\text{-}S_wB)$?

Wall *et al* assert that much of our alleged error in our volumetric calculations on reservoir size is due to a mistake in the term $(1\text{-}S_wB)$ in the equation we used for estimating oil in place.[5] This is impossible, for we use no such term *anywhere* in our monograph. Much of the credibility of the argument against us collapses simply because of this falsification of our work. Where we do use a similar term, $(1\text{-}B_{oi}S_{w_i})$, we clearly state, in our definition of terms, that $B_{oi}S_{w_i}$ represents a single estimate representing two pieces of data which are not available to the public.[6] As we use an estimate for this term, it is self-evident that no mathematical manipulation of the term is possible – or indeed involved. The long and tedious explanation[7] as to why we should have divided rather than multiplied is therefore splendidly irrelevant.

Measuring the bulk volume of a reservoir

Wall *et al* challenge our calculations of the volumes of oil in place and of oil recoverable from the reservoirs. They state that it is 'impossible for his [Odell and Rosing's] model to generate production figures greater than the company estimates'.[8] They fail, however, to present any evidence to justify their categorical statement. Unfortunately, Wall *et al* are again mistaken, for our model *is* able to produce higher recoverable reserves and higher production figures than those reported by the companies, because the bulk volumes of the reservoirs which we calculate from the evidence publicly available is greater than those indicated by the operators.[9] Their failure lies in their simple acceptance, without 'the most elementary of routine checks',[10] of the volumes announced by the companies for their fields.

Wall *et al* explain quite clearly the normal text-book method of volumetrically estimating oil in place and recoverable reserves, which presumably is used by their former colleagues in the oil companies. But they omit one important point in their summary of that methodology – the method used to convert planimetered areas to volumes. Craft and Hawkins cover this point very clearly.[11]

This method, however, inevitably results in underestimation of the bulk volume, as demonstrated in Figure 1. Our method[12] (Figure 2) provides a more accurate estimate of the true overall volume of the reservoir rock, though it should be noted that there is still an error because it is necessary to assume that each area A in Figure 2 is equal to the corresponding area B. This is not true, but the error introduced is very small and the error is, moreover, distributed both positively and negatively around the true value so that, in the field overall, the net error is likely to be of little significance.

Compared with this accurate method of measurement, Wall *et al* chose to employ an inherently less accurate method in which, as shown, there is an inevitable underestimation of the bulk volume. The degree of their conservatism will be a function of the configuration of

[4] Discussions held on 10 June 1976 on Odell and Rosing, 'Optimal development of large North Sea oil fields', *Series A Working Papers No 76-8,* Economic Geography Institute, Rotterdam, 1976; see also the acknowledgment in Odell and Rosing, *op cit,* Ref 2, p 9.
[5] Wall *et al, op cit,* Ref 1, p 286, lines 43-46.
[6] Odell and Rosing, *op cit,* Ref 2, p 62.
[7] Wall *et al, op cit,* Ref 1, pp 285-287.
[8] *Ibid,* p 285, paragraph 4.
[9] *Ibid,* p 285, Table 1.
[10] *Ibid,* p 284, paragraph 4.
[11] B.C. Craft and M.F. Hawkins, *Applied Petroleum Engineering,* Prentice Hall, Englewood Cliffs, NJ, 1959. The method involves measuring the area contained within each contour interval of producing sands. The area within the lowest contour is then multiplied by its height above the water–oil contact line. The area lying in each successively higher contour is multiplied by the contour interval to give a series of bulk volumes. Finally these are added to give the total bulk volume (see Craft and Hawkins, pp 27-28).
[12] We divided the surface of the field into small hexagons, identified the mid-point of each of these, and interpolated from the contour information the average height of each hexagon across the field (see Odell and Rosing, *op cit,* Ref 2, pp 60-61). The volume of each hexagonally shaped column was calculated by multiplying its height above the oil–water contact level by the area of the hexagon. This gives the volume of oil-bearing sands in that column, and the summation of the values of all columns is thus the estimate of the total volume of the reservoir sands.

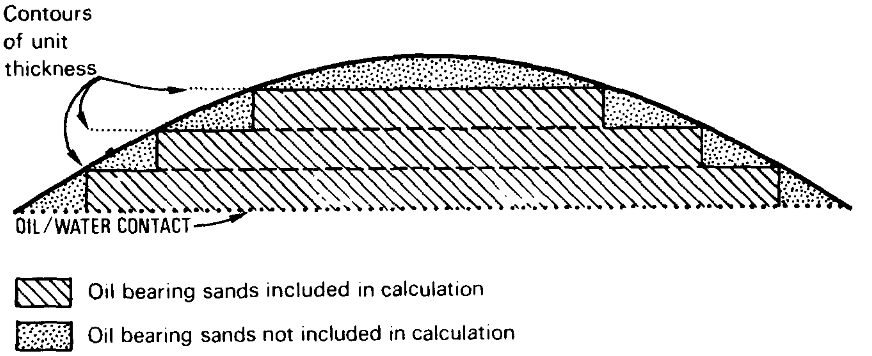

Figure 1. Area of oil-bearing sands calculated by planimetry

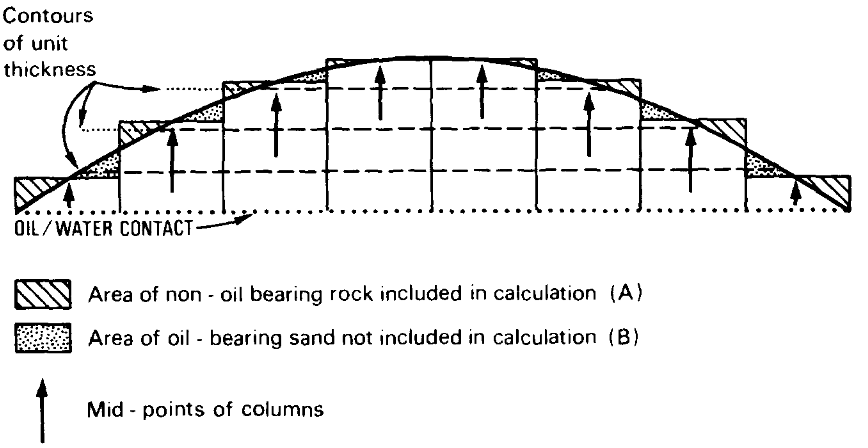

Figure 2. Area of oil-bearing sands calculated by interpolated column heights

the reservoir (in its three dimensions) and of the contour interval chosen for the calculations. The interpolation method must always produce higher estimates of reservoir sand volume (and of stocktank oil in place and of recoverable oil, when using identical porosity and permeability characteristics) than the methods used by Wall *et al* and by the oil companies (if they indeed use the methods described by our critics), simply because our method more faithfully represents reality. The differences for the Forties field are shown below.

Volumetric calculations for the Forties field

Table 1 shows volumetric calculations for the Forties field calculated in four different ways. Comparison of columns 3 and 4 indicates the significant magnitude (about 17% in this case) of the inevitable underestimate obtained by using Wall *et al's* method, while the values which they quote (column 1) are another 19% less than those in column 3. This latter difference may well arise because of the introduction at this stage of a variable (not publicly available) in the calculations of the volume of *producing* sands, ie the specific ratio of net to gross volume of producing sands in the particular reservoir. As indicated above, there was (and is) no publicly available information on the net:gross sand ratio for the Forties field.[13] Although we mentioned the importance of this variable in reservoir calculations,[14] we were unable to incorporate it specifically in our analysis. Various allowances were made in our monograph calculations for factors reducing the producibility of the reservoir, including the net:gross

[13] BP could not or would not give us such information.
[14] Odell and Rosing, *op cit*, Ref 2, pp 60, 66, and 107.

Table 1. Volumetric analysis of the Forties field

	Wall *et al* from BP	Wall *et al* from Odell and Rosing	Odell and Rosing following Wall *et al's* directions[a]	Odell and Rosing's true volume method[b]
Volume of sands (million m^3)	(3729)[c]	(5377)[c]	4755	5751
Stock tank oil in place (million bbl)	4400	6345	5611	6786
Recoverable reserves (million bbl)	1800	2538	2244	2714

[a] Based on the planimetered contours. Our planimetry was done on a Science Accessories Corporation Model GP/3 backing up an IMLAC PDS/4 digitizing table with a resolution of 0·05 mm. A scale of 1 in corresponding to 1·43 miles was used, and the calculations were performed by systems software on the Hewlett-Packard 2200 system which backs up the SAC-GP/3. A video display was generated and used to verify the accuracy of the line trace. Areas should be accurate to ± 1·7%.

[b] The 'true volume' calculations consisted of generating a full three dimensional view of the field via the equipment described above, and integrating the volume.

[c] Calculated from figures in the lines below.

ratio, but if we are now correct in assuming that Wall *et al's* 19% reduction (the difference between columns 1 and 3 in Table 1) is entirely due to the difference between gross and net sands' volume, then we have overestimated the size of the recoverable reserves by about 12%.[15]

Nevertheless, even if we accept that Figure 8-13 in our monograph[16] overstates the values by *at most* 12%, so that each curve in that graph should be lowered by at most that amount, the shape of the curve is not affected and the argument presented remains unaltered by the minor recalculation necessary to adjust our reservoir size calculations to take full note of the non-producing sands in the Forties field.

On producing an oilfield

Wall *et al* argue that the more intensive field development schemes we investigated inevitably mean over-drilling and over-investment, and they imply that the less intensive field development schemes will, in any case, produce as much oil. The crucial point is the spatial coverage of a field which can be achieved by a specific number of wells and platforms. We have discussed this point with other reservoir engineers,[17] and they agree with our interpretation of terms such as 'average well spacing' and 'platform draw areas'. We took these to define the portion of a field which can be depleted by wells drilled by deviated drilling from platforms, given that there is a 'normal draw area per well' in respect of the volume of the sands that can thus be depleted in an economically relevant time period.

This is entirely different from simply drilling more wells in areas which can already be served by existing wells, as Wall *et al* imply we suggested – and which they indicated would mean a repetition of earlier 'mistakes' in depleting reservoirs in the USA. In the context of the North Sea's development, their reference to previous US experience is totally fallacious. That experience related to developments for which oilfield management was primitive, and where regimes of pressure maintenance were established only near the end of the fields' lives because of ownership problems as well as undeveloped technology. In those circumstances there was over-drilling and over-exploitation of reservoirs, leading to low ultimate recovery rates. Such experience is entirely irrelevant to the managerial, physical and

[15] Note, however, that Wall *et al* seem to be happy to accept a figure which underestimates the size of the reservoir by no less than 17%. We would argue that their presentation is much more seriously in error in its volumetric calculations than was our original overestimate.

[16] Odell and Rosing, *op cit*, Ref 2, p 96.

[17] We have now discussed this point fully with petroleum geologists and reservoir engineers in both the US and the Canadian Geological Surveys. These offices are intensively involved in off-shore assessment and development regulation. *Without exception* these experts in the application of Wall *et al's* discipline to offshore conditions reject Wall *et al's* view and agree with ours. (Discussions held on 24 March 1977, Office of Energy Resources, Reston, Virginia, and on 19 July 1977, Office of Non-Renewable Resources, Ottawa, Ontario.)

technological conditions that prevail in the North Sea province.

There is also a major difference, in economic terms, between the development of onshore and offshore fields. In developing an onshore field a company is committed only to the cost of drilling each well (or perhaps a small group of wells) in turn. In deep-water offshore developments (as in the North Sea), the company has to commit itself to the cost of installing a platform from which to drill, the cost of which is virtually the same whether it is used for one well or for 27 as in the Forties field. This 'lumpiness' in the investment required for developing an off-shore field creates a very different economic environment. Indeed, it dictates a different set of considerations for evaluating the physical development process.

The spatial coverage problem

We maintain that the spatial coverage of an offshore field achieved using the production system initially determined for installation is one of the most critical variables in the production regime for that field. Increasing the portion of the field covered by platforms (by adding platforms to the production system) will normally increase the economically recoverable reserves of a field: when what is 'economic' depends upon the timing of production.

This is clearly recognized by oil companies. Chevron, for example, have announced that the addition of a third platform to the producing system they are to install on the Ninian field increases the recoverable reserves of that field from 850 million bbl to 1100 million bbl.[18] This must be due mainly to the fact that the portion of the field which can be covered by the platforms to be placed on the field has been increased. There is no other change which could account for the magnitude of increase in the reserves' estimates. A recent report on the Ninian field has been even more specific both on the additional platform and the additional wells on the field:

> The planned development scheme for the Ninian Field in October 1975 included two platforms, one in the central and one in the southern portion of the field. Because the reservoir is more narrow in the northern portion, *the use of a third platform has been evaluated based on the economics of recovering more oil in less time* ... There have been several changes in the [production] limiting factors since the last report, causing significantly higher maximum production rates. Tubing size has been increased ... the capacity of the oil processing facilities was increased and *five more wells are added to the Northern platform* ... These changes resulted in a faster production rate build-up and much higher maximum daily rates of oil production.[19]

Amoco has made much the same point in writing to us about various possible production schemes for draining a hypothetical field. Figure 3 was appended to the following Amoco description of the economics of recovering the reserves of a field with various faults:

> It shows the existence of faults serving to rule out a natural water drive ... In an effort to enjoy higher recovery through water flooding, the operator would seek to inject water into the reservoir but ... the result would be limited by the number of available well slots (on the platform) and the ability of the operator accurately to identify and locate the various fault traps and to penetrate them with both an injection well and one or more producing wells (thus the undrained areas on the field as shown). This illustrates the not uncommon situation whereby a field which *almost* justified two platforms at the outset but which was developed initially with only one platform ... this would in effect rule out the possibility of the second platform at a later date ... for by locating the first platform right in the middle of

[18] Reported in *The Economist*, 5 February 1977, p 90.
[19] LASMO's share offer document, July 1977 (authors' italics).

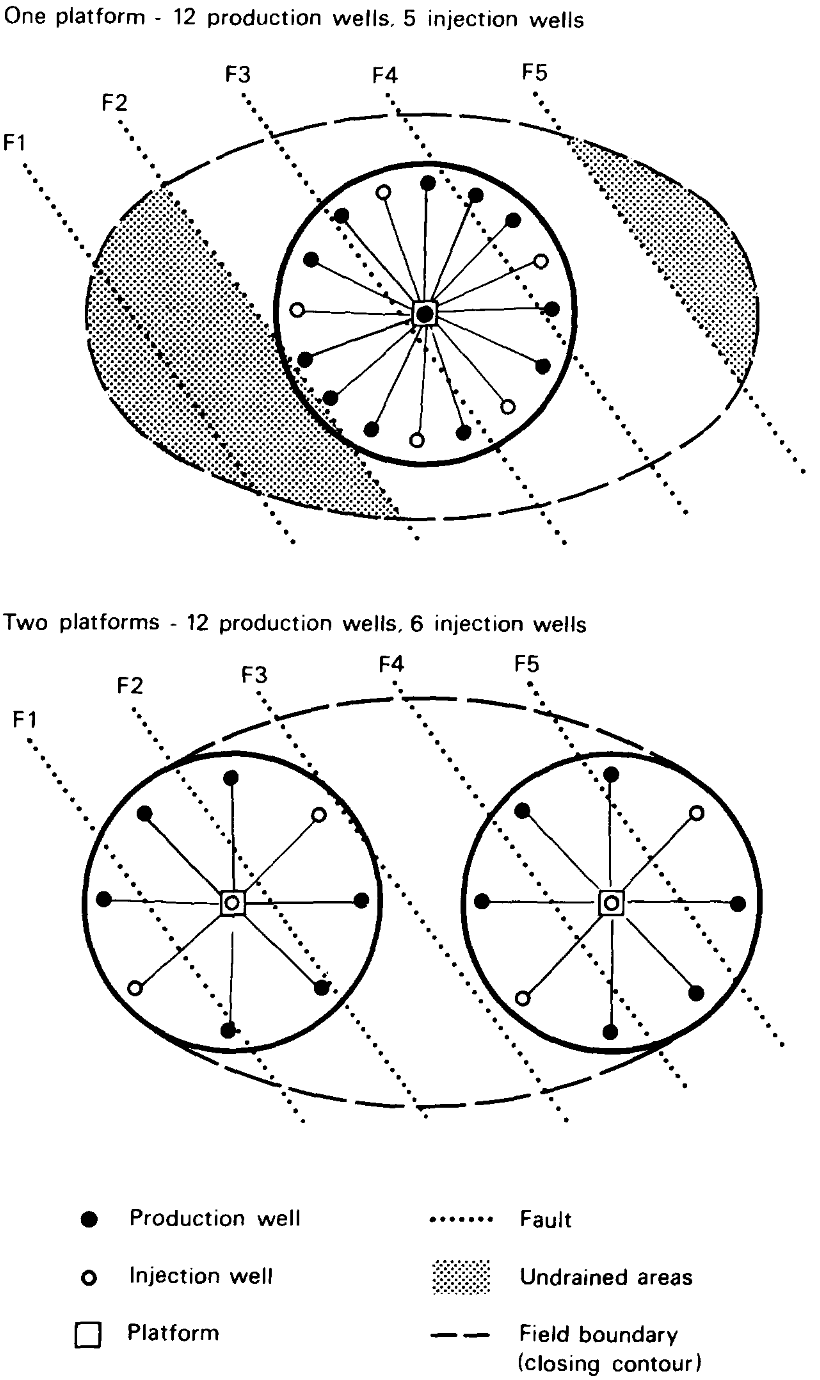

Figure 3. Recoverable reserve (economic) as determined by fault pattern and/or initial development scheme

the deposit none of the edge areas in this are big enough to support a second platform. With better economics (higher prices, lower taxes?) at the outset, two platforms towards the extremes of the field area might have been justified by a higher reserve.[20]

From this description of the physical characteristics of off-shore reservoirs and the economics of their producing systems, Amoco (as with Chevron) seems to think that more platforms and more wells give more coverage and more recoverable reserves.

The technical literature contains many oblique references to this

[20] Letter from AMOCO (UK) Ltd to the authors, July 1975.

central problem of spatial coverage. The exploration director of CFP is reported by *Noroil* as saying that 'Alwyn's oil reserves were insufficient to warrant the use of several production platforms, but a single platform would not be capable of bringing out enough oil from the field'.[21]

Finally, it also seems worth recording that in our discussions with British Petroleum on the spatial coverage problem, there was such interest in the analytical methodology we were talking about that BP's spokesman suggested that we should be given – in confidence – the necessary reservoir data on a field, which at that time (February 1976) had not been publicly announced, to see what solution we could reach in respect of the economics of its producibility by one, two or more platform systems. Again, the company concerned appeared to think that the spatial coverage problem is one of importance in determining recoverable reserves over economically relevant time periods.[22]

Other criticisms

We have identified the major errors, misunderstandings and misleading elements in the engineering part of Wall *et al's* article. There are other points in their criticism which seem irrelevant, inconsistent or mistaken.

Wall *et al* state that we recommend direct government investment for developing a field[23] – this is not so. What we do recommend is a more flexible governmental policy for fields being developed, modifying the economic environment within which the companies operate, to encourage a more complete development of the field which would still be profitable to the operating company. At present, inflexible government policy on royalties and taxes leads companies to plan the development that is likely to maximize their profits after tax – with the tax being taken as a fixed element in their cost evaluations.[24] This approach appears to limit the total planned recovery from a field to less than that which is technically recoverable. In one of our examples, the mechanism investigated for engendering governmental encouragement of the field's development was direct investment, but other strategies, such as modified taxation policy and loan guarantees, to achieve optimal development of a field, were also presented.

According to Wall *et al* our definition of the drainage area of wells is arbitrary.[25] This is untrue, however, for we assigned the well drainage areas either on the basis of information on this variable as published by the appropriate operating company (for Forties and Montrose), or from estimates we made from the indirect evidence in the literature (in the case of the Piper Field).[26]

Wall *et al* state that the term $(1-S_w)/B$ can be estimated from published data, and state that our incorrect estimates of it are responsible for the 'error' in our calculations of recoverable oil.[27] For the Forties field we have an estimate which is certainly within the error of the value they give (0·70 compared with 0·67). In the case of Montrose, it would appear that they have misinterpreted our statement of the term. The factor they quote from our study should not be 0·65, but 1·00 – 0·65 = 0·35; this again is well within the error of the term, which they give as 0·30. They do not mention our estimate for the Piper field – why not? Is our estimate again accurate within the error of the (still publicly unknown) value estimated by the

[21] *Noroil*, Vol 4, No 10, October 1976, p 80.
[22] Discussions between BP and the authors, February 1976.
[23] Wall *et al*, *op cit*, Ref 1, p 284, line 24.
[24] More strictly speaking, the production system selected is the one that enables the company concerned to achieve the minimum acceptable rate of return on investment – in the light of all competing opportunities.
[25] Wall *et al*, *op cit*, Ref 1, p 287, lines 29-30.
[26] Odell and Rosing, *op cit*, Ref 2, pp 77, 107, and 131.
[27] Wall *et al*, *op cit*, Ref 1, p 286, lines 41-42, p 287, lines 29-30, and p 289, lines 5-6.

operating company? They then fault *us* because the operating companies have, on producing the reservoirs, discovered that they are producing better than their estimates of $(1\text{-}S_w)/B$ led them to expect.[28] Our model had to be calibrated from the data as published by the operators up to the summer of 1976, and it was within the framework of this data that we tried to simulate the information environment within which the companies' production decisions were made. If it has now been demonstrated that fewer wells are necessary to produce certain quantities of oil than the companies originally estimated, then the average well spacing could have been greater than they originally expected. This revised view of the situation is *totally external* to our work, and if there has to be criticism of production estimates then it has to be of those made by the operators. It cannot be criticism of our work, which could only be based on what the companies had publicly reported at the time we were attempting to simulate the fields' development. With better data we could have more effectively calibrated our model.

Wall *et al's* general approach on reservoir engineering

One aspect of Wall *et al's* criticism of our study is in one way more important than all the substantive matters with which we have dealt above. There are no citations or literature references in the engineering section of their article.* For example, they do not cite the publication(s) which contain the information from which $(1-S_w)/B$ can be calculated. They expect the reader simply to accept that such publications exist. Nor do they provide any citation or other indication of the performance of their calculations, but merely present the reader with the result.

The principle basis of the scientific method is replicability, but as Wall *et al* do not produce the evidence on which they base their work, it is impossible for another scholar to duplicate or analyse the bases of their criticism. The reader is continually expected to accept statements for which there is no collaborative evidence. This approach would seem to violate the most basic principle of publishing in any academic discipline, including, we are sure, their own discipline of reservoir engineering. Their closest approximation of a citation is 'BP estimate',[29] expressed in various ways. Other esoteric items of factual knowledge lack even this sort of prosaic reference!

We are criticized for our lack of academic rigour,[30] but we at least give the reader the opportunity of verifying or of refuting our results, through explanation, accreditation and citation – that is, by adhering to the rules of academic publishing. Wall *et al's* article comprises only unsubstantiated personal opinion. For this reason alone their paper is unworthy of consideration even had we not shown that many of their arguments are erroneous or false.

Economic aspects

We can agree on one item in the economics section of Wall *et al's* article – their final comment that public attention and debate in respect of the economics of North Sea oil need to be stimulated. This was the prime motivation to publish our monograph which, we concluded, 'may perhaps have indicated an approach which can achieve the reconciliation of the conflicting interest of state and oil companies'.[31] However, Wall *et al's* contribution to this important

* *Editor's note:* We included a reference to Odell and Rosing's monograph in Wall *et al's* article after this rejoinder by Odell and Rosing was completed and submitted to us.

[28] *Ibid*, p 288, lines 36-48.
[29] *Ibid*, p 288, line 39.
[30] *Ibid*, pp 284, 294.
[31] Odell and Rosing, *op cit*, Ref 2, p 174.

debate is entirely negative, and its somewhat intemperate tone smacks more of the familiar propaganda that 'what is right for the companies must be right for the community' than it does of any wish to continue the search for the truth.

The detailed criticisms

Our capital costs estimates did not disregard inflation, as Wall *et al* claimed. We did not consider that anyone could fail to recognize the need for incorporating rising prices into the costs of North Sea installations, so we did not think it necessary to spell this out. However, it can clearly be seen to be incorporated in our inputs, for example in Table 7–1[32] which shows capital costs of the various platforms on the Forties field. Early-period installations (including pipeline costs) are each about $300 million (a figure based on the published data for platform installation in 1975–6). For the fifth, sixth and seventh platforms (in the systems with a larger number of platforms, so involving platforms which are built and installed up to several years later than the early ones), the capital costs per platform range from $450 to $535 million.

We chose three specific cases dealing with the future price of oil and inflation rate. Our base case, with 10% per annum inflation and a $12.50 per barrel oil price in 1975 rising by $0.50 cents per annum, is not a prophecy – it is the kind of reasonable guess that all investors have to make about the future behaviour of the economic system relevant to their interests. In early discussions of our work with British Petroleum, we found that these figures for inflation rate and price of oil were close to their best guesses for movements in the two variables. Since then (1975), the two variables have, indeed, moved roughly in line with these base case figures. The assumption that running costs increase proportionately more quickly than oil price is, of course, related partly to the fact that the former is a function of rising British costs (with its higher than average inflation) while the latter is a reflection of OPEC's reaction to the overall change in international price levels.[33]

We stated specifically[34] that there are many sophisticated theorems for finding the right discount rate to evaluate past, present and future revenue and expenditure flows. This, of course, is necessary so that one can realistically model the way a company looks at the opportunity cost of its investment in general, as well as the way in which it takes into account the 'specific risk' of developing the North Sea's potential. The method we chose was certainly not related to the Dow Jones or the *Financial Times* indexes, as Wall *et al* seem to imply, but was related to the *unique* circumstances of the alternative investment decisions that can be taken for developing North Sea oilfields. At the time that the development decision on a field has to be taken, the availability of information on the existence and recoverability of oil varies *spatially* (because of the limited nature of the field exploration programme that can be undertaken in the evaluation stage). In such circumstances, a company can only equate the commercial validity of the most certain, the less certain, and the least certain flows of oil from the field (by means of possible alternative production systems) by varying the discount rate it uses for measuring the return on geographically discrete 'lumps' of investment. These separate 'lumps' then aggregate in different ways to define a series of systems of varying cost and of varying productivity.

[32] *Ibid*, p 72.
[33] Moreover, we tested the impact of varying the rate of inflation in the range 3-15% per annum in the case of the Piper field. This sensitivity analysis (carried out on no fewer than 7 variables and on a worst case/best case combination) was described in Chapter 11 of our study. As Figure 11-2 shows (Odell and Rosing, *op cit*, Ref 2, p 162), the results were very insensitive to variations in inflation rate.
[34] Odell and Rosing, *op cit*, Ref 2, p 71.

As Wall *et al* point out, the oil company may undertake a variety of projects, all with independent risks. However, rather than risk averaging – which implies taking on some high risk projects – the company selects those projects with a high potential pay-off. Varying the discount rates to include the increasing risk in developing a field more intensively allows the study of these alternatives.

The literature on the choice of discount rates did not appear to us to have considered this situation, and the cases quoted by Wall *et al* are quite irrelevant. We are still very much open to persuasion on the methodology we used (and on the appropriate way to combine the discount rates for different platforms in the same system – for which, incidentally, our most extensive range for various platform systems was 15–26·5%, not 15–45% as Wall *et al* erroneously indicated) but the criticisms here are entirely unhelpful and mistaken. Wall *et al* simply forgot – or failed to understand – that we are dealing with alternatives of 1, 2, 3, ... N platform systems, and not with incremental additions to a single system. We did, incidentally, also test the sensitivity of variation in the relative risk assessment by about 20% around the base case value. This resulted in changes in the present values of the two- and three-platform systems on the Piper field (the inputs for which were used for the sensitivity analysis), but it did not alter the shape of the curves.[35]

Wall *et al* consider that we chose a 'wrong' figure for the cost of government borrowing. They use the extraordinary argument that because we worked in dollars we should have related the test discount rate to the cost of government borrowing in the US capital market.[36] Any such calculation would, in the circumstances of 1975–76 (when we did the work), also have had to take near-future expectations of adverse changes in the $/£ exchange rate into account. This is exactly the same variable that was then expressed, through the financial market, by the difference at that time between the 12% government borrowing rate in the UK and lower borrowing rates in the USA.

The general issues

The first of these is the differential between private and public money and between private and public risk in investment decisions. Wall *et al* seem to believe that the world's financial markets are perfectly competitive with no institutional, geographical, or political constraints. Thus, all parties have an identical opportunity cost of capital in all circumstances, with variations only over time as the 'invisible hand' tugs the strings of the puppet actors up and down. Wall *et al* must surely be aware of the fallacy of this too simplistic view of the operation of the international financing system. Opportunity costs vary even between international companies, because there are constraints that are peculiar to some decision makers but not to others (a factor we described in our analysis of the Piper field, which is being developed by a consortium of companies whose economic behaviour is, and must be, very different from that of BP, the sole developer of the Forties field). They vary even more between companies which operate internationally and those with purely national interests. They vary most between major international oil companies (with their ability to rank their investment priorities against opportunities existing in many countries and in many circumstances) and national governments (whose investment

[35] *Ibid*, Figure 4, p 164.
[36] We used this mode of expression simply because this is the way costs and prices in the oil industry are usually expressed.

opportunities are limited, by and large, to developments in their own national territories).

In the North Sea the oil companies can (and must) test the validity of their additional investment opportunity against alternative claims for their money provided by investment opportunities in the Gulf of Mexico, the Gulf of Thailand, or the North West Australian Shelf, or against opportunities for investing in coal mines in South Africa, open-cast coal mining in Sumatra, or shale oil developments in the USA. Given such a plethora of investment opportunities, a minimum internal rate of return of 25% is demanded for all lumps of investment by such companies and, in present circumstances, the minimum acceptable rate may be as high as 40%. The UK government, on the other hand, does not have many chances to invest in ventures with high rates of return. Even if they were available, any UK government would also have to consider their employment, balance of payments, social welfare, and political and strategic implications. The public would not wish its security and future to be put at stake by a government deciding that investment in 'candy floss' production, with a possible rate of return of 20% is 'better' for the country than investment in off-shore oil, deep-mined coal, or nuclear power stations from which 20% returns are more difficult to generate. Our study showed that the UK government can make acceptable 'rates of return' on 'investing' money in the North Sea, if it can persuade companies to push the development of an oilfield beyond the strictly commercial limit (when 'acceptable' is defined as a rate which exceeds its costs of medium-term borrowing). Such opportunities for government interests in oil developments do appear to be more favourable than most current alternatives open to the government in other parts of the energy sector of the economy. For example, nuclear power stations barely 'pay out' with a 9–10% cost, and, from calculations we have made recently, it seems that the *best* that can be expected from the investment of over £400 million in the Selby coalfield is a return of 15·3%. This would hardly be an investment opportunity of interest to any international oil company, but would Wall *et al* suggest that it should not, therefore, be undertaken, given what they and all of us know about the uncertainties of the world's energy supply in the 1980s and the 1990s. Such considerations mean that there must be investment *now* in energy producing potential by any government with the longer-term interests of the nation at heart.

We are also taken to task by Wall *et al* on the question of speed of development of the UK's oil resources for allegedly advocating their accelerated production. We did no such thing, but indeed dealt specifically with the issue in Chapter 5 on 'Policy implications':

> We ... accept that a country may wish to prevent the discovery or the development of a field or fields because it wishes to save the potential reserves for the future.[37]

This is an issue which can perhaps be resolved by the 'full cost–benefit analysis of government policy' which Wall *et al* say is needed. But our study was not directly concerned with that issue. Instead, we tried to evaluate the significance of contrasting rates of production from individual fields, and we showed how the government can benefit by getting more oil more quickly out of each field in return for creating conditions in which the most intensive and extensive production system is also profitable enough for the oil company concerned. If it does this with *each* field which is to be

[37] Odell and Rosing, *op cit*, Ref 2, p 54.

developed, then the government *enhances*, rather than reduces, its opportunities to consider the question of the overall 'best' rate at which the North Sea's reserves should be produced. If one or more field(s) can be developed so as to produce 20% or 50% more oil over the next 15 years, and this higher rate of production then satisfies the government's evaluated need of the total amount of oil the country 'ought' to produce, then the potential for oil production from other fields can be saved for the future. If, on the other hand, each company decides for itself what part of a reservoir it shall develop only in relation to a rate of return which it finds acceptable *vis-à-vis* alternative opportunities, then the country risks having all its lowest production cost fields only half-depleted in the short term, so opening up dangers for the supply and price of oil in the UK over the longer term. There is a real conflict of interest here which can only be avoided by the reconciliation which remains to be worked out between government and companies for the benefit of the society at large. The issue is important – perhaps even critical – to the UK's development strategy, and we hope the debate will be continued.