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# E Estimating the economic cost of approval delays

This appendix presents the method used by the Commission to estimate the economic costs associated with approval delays in the upstream petroleum sector. Section E.1 sets out the design. Section E.2 describes the data sources. Section E.3 outlines some limitations of the method and potential areas for further development.

## E.1 Design

Petroleum production can be viewed as a supply process transforming initially unknown oil and gas resources into marketable products through the stages of exploration, development and production. Under this approach, the economics of petroleum supply can be portrayed by the time distribution of cash flows associated with the discovery and operation of an economic field (figure E.1).

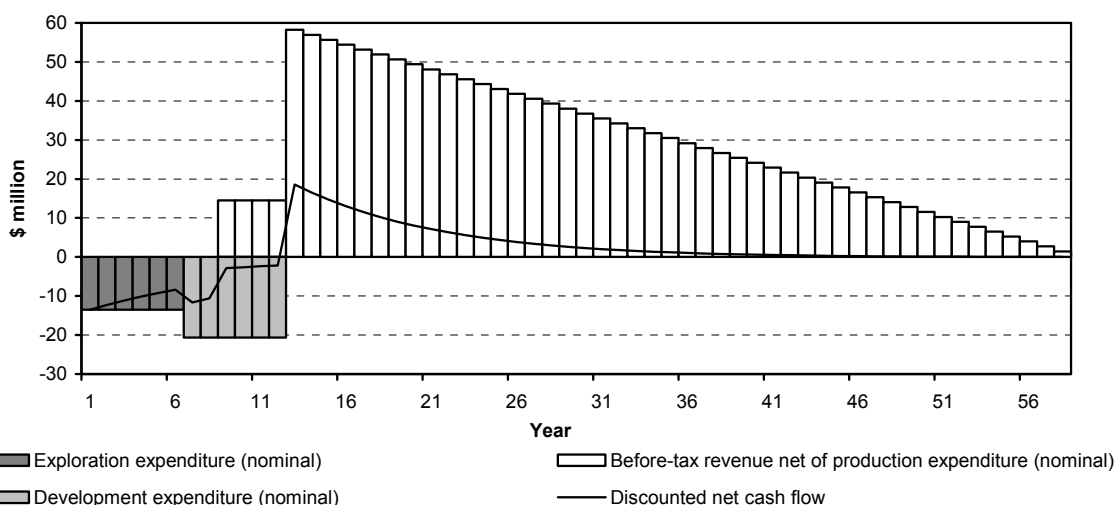
In practice, the value of resource extraction in a project can be assessed from different time perspectives. Specifically:

- the long-term value of exploration is evaluated prior to commencing exploration
- the medium-term value from successful exploration is evaluated from the start of field development, conditional on the exploration outcome.

For this study, the project value was evaluated from a long-term perspective and assuming full information on costs, petroleum prospectivities and output prices. This approach, though not fully consistent with the way petroleum businesses make sequential decisions on capital commitment, enables estimating the net value of an economic field over its entire exploration–development–production cycle.

Cash flows were estimated to represent output values and input costs at different points of time over the petroleum supply process. The evaluation of output values typically combines field-specific prospectivity assessments with petroleum price projections.

**Figure E.1 A stylised representation of cash flows from an economic field**



*Data source:* Commission estimates based on data in Mackenzie and Cai (1993).

Cost estimates were derived for each of the exploration, development and production stages. Exploration costs include expenditures for geological analysis, seismic surveys, drilling exploration and appraisal wells, and related overheads. Development costs include expenditures for drilling development wells, establishing field structures, and constructing pipelines, processing plants and other transmission and storage facilities. Production costs include expenditures for processing and delivering petroleum products, as well as field operating expenses.

All project costs were treated as current expenditures. This is appropriate for variable inputs such as operating expenses and the costs of hiring seismic survey ships. For durable project-specific capital inputs, however, it is a simplification to include the full expenditures as they are incurred.

A more rigorous way of estimating capital input flows is to, first, derive the capital stock as a cumulative sum of investment expenditures and then apply a rental price of capital to that capital stock estimate. Instead, the simplified treatment of capital costs avoids such computational complications involved in capital stock estimation.

An economic field adds value to the economy by generating greater output values than the input costs required over time. To account for the diminishing time value of money, the net present value (NPV) of resource supply was derived by discounting input–output cash flows in future periods with a measure of risk-adjusted cost of capital. In effect, the NPV converts the time distribution of cash flows for a project into an equivalent dollar value at the start of the petroleum supply process.

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For cash-flow discounting, the cost of capital was set equal to an estimate of the weighted average cost of capital (WACC) for the upstream petroleum sector. The estimation of WACC is typically based on a capital asset pricing model with the assumption that debt and equity finance is allocated through complete and perfectly efficient capital markets.

Specifically, it was assumed that project proponents have access to portfolio diversification opportunities that eliminate non-systemic risks associated with individual projects. Under this assumption, the cost of capital comprises a risk-free rate (often proxied by a long-term government bond yield rate) and an equity risk premium reflecting extra returns commensurate with non-diversifiable project risks.

A uniform risk–return profile was assumed for the entire supply process. This enables using a constant WACC. In reality, capital risk tends to be higher in the exploration stage than in the development and production stages.

Algebraically, the NPV formula was expressed as:

$$NPV = \sum_{i=1}^T \frac{R_i - O_i - E_i - D_i}{(1 + c)^{i-1}}$$

where:

$R_i$  = revenue in year  $i$

$O_i$  = production expenditure in year  $i$

$E_i$  = exploration expenditure in year  $i$

$D_i$  = development expenditure in year  $i$

$c$  = weighted average cost of capital

$T$  = project life.

Two types of delay were simulated: (1) delay in the approval of exploration activity; and (2) delay in the approval of development activity after exploration. For each type, a delay was represented by a backward shift in the time distribution of cash flows affected by the approval delay. A zero cash flow was assumed for the delay period, which is an oversimplification — in the real world companies will continue to incur costs during periods of delays.

The economic cost of delay was calculated as the difference between the NPV estimates obtained for the delay scenario and the base case (without the simulated delay). The estimated change in NPV was expressed as a percentage of the base case NPV.

## E.2 Data

The primary data source is a study by Mackenzie and Cai (1993) that sought to evaluate the economics of all petroleum fields discovered in Australia up to 1987. The economics of these projects may be somewhat different from more recent large scale export liquefied natural gas projects. However, it appears that no other up-to-date database is available in published form.

The aggregate data on various expenditure items and production revenues for all economic fields identified were used to derive the corresponding average cash flows per field. These data enable the calculation of total undiscounted cash flows as shown in table E.1.

The time pattern of expenditure and revenue flows was constructed using the relevant cash-flow graph in Mackenzie and Cai (1993, p. 43) as a guide. As depicted in figure E.1:

- exploration expenditure was evenly distributed over a six-year period
- development expenditure was evenly distributed over a six-year period after exploration
- production expenditure was assumed to be a fixed proportion (27 per cent) of production revenue
- net production revenue was diminishingly distributed over a 50-year period, with annual flows tailing off towards a minimal positive net return.

**Table E.1 Key characteristics of an economic field**

<i>Characteristic<sup>a</sup></i>	<i>Unit</i>	<i>Base case</i>
Time period:		
Exploration	years	6
Development (maximum)	years	11 <sup>b</sup>
Production (maximum)	years	50
Undiscounted cash flows:		
Exploration expenditure	\$m	81
Development expenditure	\$m	124
Production expenditure	\$m	538
Production revenue	\$m	1 968
Weighted average cost of capital	%	10

<sup>a</sup> Based on the average characteristics of 184 economic fields. <sup>b</sup> The Commission assumed a period of six years for the development stage.

Source: Mackenzie and Cai (1993).

The WACC was set equal to 10 per cent, following Mackenzie and Cai (1993). In a more recent study, Antill and Arnott (2002) considered it reasonable to estimate the WACC for upstream petroleum businesses at around 8 per cent to 9 per cent.

Unsurprisingly, sensitivity tests confirm that the economic cost of approval delay increases as the WACC increases (table E.2). For a delay in exploration approval, changing the WACC within a reasonable range would have a small effect on the estimated NPV reduction. By comparison, the choice of WACC has a larger effect on the cost estimate of a delay in development approval. This higher sensitivity reflects increased significance of the WACC in discounting delayed revenue flows after exploration costs have already been incurred.

**Table E.2 Sensitivity tests for different values of the weighted average cost of capital**

<i>Weighted average cost of capital</i>	<i>One-year delay in exploration approval</i>	<i>One-year delay in development approval</i>
%	% of NPV <sup>a</sup>	% of NPV <sup>a</sup>
8	-7.4	-11.4
9	-8.3	-14.3
10	-9.1	-18.4

<sup>a</sup> Net present value.

Source: Commission estimates.

### **E.3 Potential for further development**

The Commission has sought to produce indicative estimates of delay costs for plausible scenarios by using readily accessible data in conjunction with credible assumptions. Therefore, the approach has been kept relatively simple. However, several data and design issues arguably limit the scope and amount of detail. Addressing such issues is likely to offer possibilities for improved evaluation of the impact of approval delays on the sector. Specifically, potential improvements identified include:

- using up-to-date and disaggregated cash-flow data
- enriching the structure with additional variables
- modifications to account for regulatory risk and uncertainty.

The current aggregate cash-flow pattern of the sector may have changed from that applied in this study for two reasons. First, there have been considerable relative price and cost changes over the past two decades or so. Second, a number of recent discoveries and projects — particularly those in the North West Shelf — have

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increased the economic significance of gas production relative to oil production and, in so doing, have greatly increased the capital costs involved (given the relatively expensive nature of export liquefied natural gas plants).

The accuracy of the cost estimation can be improved by using cash-flow data that reflect present cost structures and revenue potentials of all prospective and operating petroleum fields in Australia. Such data updating will provide a better representation of the ‘relativity’ between various cost and revenue variables, which is a crucial determinant of the cost estimates expressed in percentage terms.

Applying the approach to individual basins, instead of their aggregation as in this study, is another way to produce more accurate cost estimates. This could help capture variations in the cost structure and petroleum prospectivity between onshore and offshore operations across different basins. Using this approach, it is also possible to produce cost estimates for individual jurisdictions.

Additional variables could be introduced to enrich the descriptive and information structure. Incorporating details on taxation arrangements could improve the analysis relating to investment returns and government revenues. The impact of compliance costs, which has been omitted, could be analysed through adding relevant cost variables. Further, simulation results could become more accurate if decommissioning expenditures were included.

A key limitation of the present approach is related to its assumption of full information. This means that the estimated economic cost does not account for the adverse impact of approval delay on increased uncertainty and constrained flexibility for responding to market changes facing businesses.

It appears feasible to modify the approach in two ways to estimate the economic cost associated with increased regulatory risk and uncertainty. A risk premium could be incorporated in the WACC to account for the possibility that regulatory outcomes might be worse than expected or worse than the *status quo* from an industry perspective.

Alternatively, a real-option approach could be used to estimate economic costs associated with regulatory constraints that impede businesses from capturing market opportunities. In estimating such costs, the focus would be on the curtailment of upside potential amid uncertainty. Although uncertainty typically involves both upside and downside potential, downside risk can typically be managed by creating and exercising investment options based on incremental information gathering — as in the case of petroleum exploration and development. Regulatory delays and other compliance burdens diminish the probability of benefiting from such options, resulting in welfare losses to business and the community.