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Economic Assumptions and Feasibility of Marginal Offshore Field

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ABSTRACT

The economic analysis involved cash flow modeling, project profitability analysis, project sensitivity analysis and risk modeling using available and generally accepted economic, financial and technical data about the Mid Norwegian Shelf in the Voring Basin operating environment. The economic analysis is based on Norwegian fiscal policies. The produced oil will be sold free on board (FOB). The cash flow was created based on Norwegian tax regime of 50% Special tax and 28% corporation tax and an inflation rate of 3%.

There is a great deal of uncertainty as to whether oil and gas production in the Voring Basin would occur, and if production does occur, it is even more difficult to predict the timing and magnitude of exploration, development, and production activities. This study assumes that development would occur given certain price and cost assumptions and that there will be no major regulatory impediments or delays to Mid Norwegian Shelf in the Voring Basin development. As with any other large industrial development, there could also be social and environmental considerations associated with offshore oil and gas development. This study is only focused on the economic effects of Mid Norwegian Shelf in the Voring Basin development.

Key words: Offshore, Oil fields, Oil and gas, Voring basin

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1. INTRODUCTION
OVERVIEW OF THE ECONOMIC ENVIRONMENT

The O-Field location is in the Mid Norwegian Shelf in the Voring Basin with Block reference 6306/3. This region is generally considered as a gas prone province having a remaining commercial reserve of 1936mmbbls liquid and 21974bcf gas; hence, infrastructure development has modelled this assumption. Some recently drilled wells have struck oil in the cretaceous reservoir and this has opened up new oil play in the province. Geological knowledge of the Mid Norwegian Shelf is still relatively limited, although exploration activities in the area has accelerated since the acreage award in the fifteenth licensing round in 1996. These have led to significant discoveries being made notably that of Ormen Lange, and companies have high expectations that further exploration will prove successful.

There are no export oil pipelines to shore from any of the producing fields in the area. Oil is produced and processed using an FPSO with the assumption of being sold Free on Board, FOB and transported by a shuttle tanker. The gas is disposed through the Asgard gas pipeline about 26km from the O-Field.

2. DEVELOPMENT OPTIONS

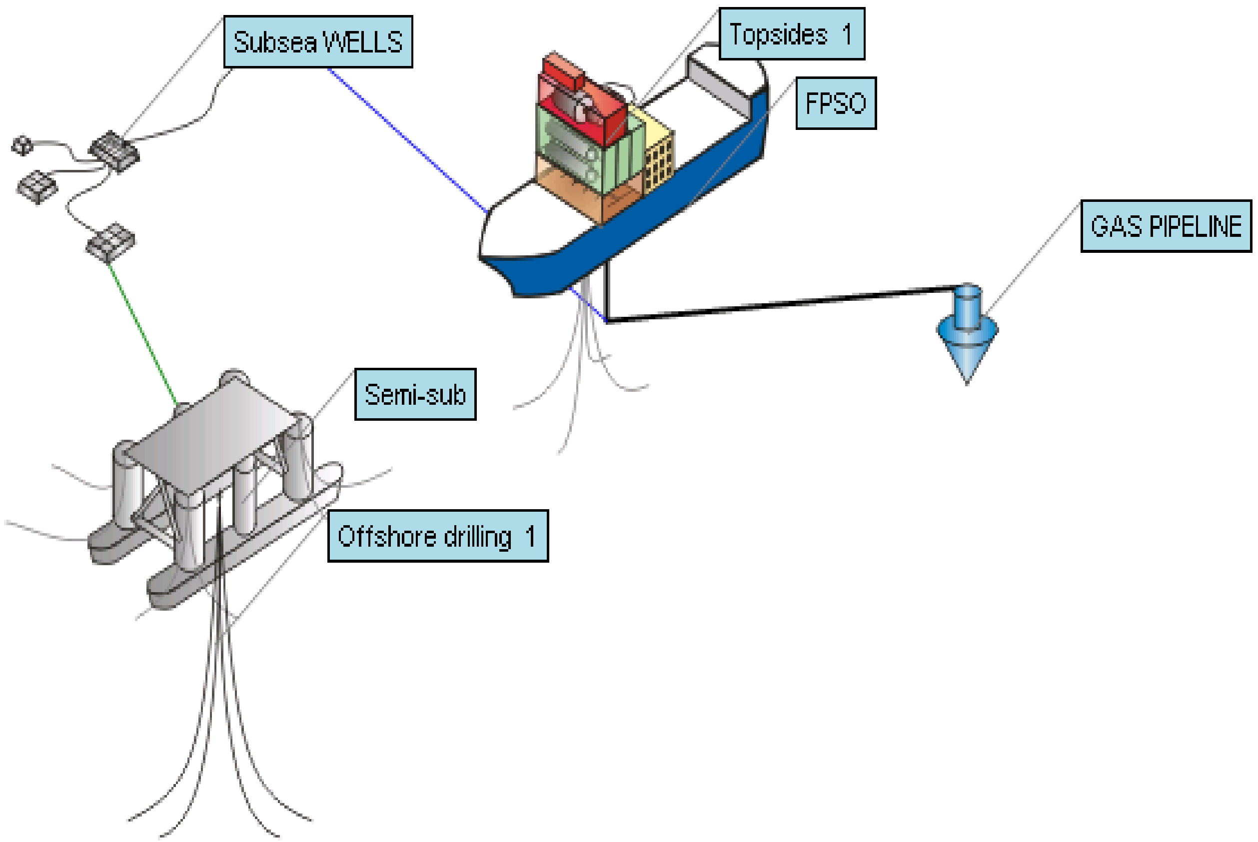

Figure 1: Development option plan of O-field

DEVT OPTION	NPV	IRR	PIR	NPVI
	CADm			
LEASE FPSO + LEASE SEMISUB	623.41	82%	10.27	5.93
BUILD FPSO + LEASE SEMISUB	448.23	27%	1.76	0.80
BUILD FPSO + BUILD SEMISUB	318.02	18%	1.00	0.33

Table 1: comparison of the development options

2.1 Cash Flow Modelling

A cash flow modelling of all the production options are carried out to determine the long term profitability of the project and which option gives a better outcome i.e. higher NPV and NPVI. Base assumptions were made to guide in getting reasonable input parameters used in building the base case model. These assumptions are:

Inflation: a price inflation of 3% is used for the cash flow model. This is based on the forecasted Norwegian inflation rate, which is expected to be 3% in the medium and long term.

Oil and Gas Price: a base assumption of $40/barrel constant money of the day, MOD, is adopted as suggested by Julian Fennema. Otherwise, the oil price based on the Wood Mackenzie forecast is US$59/bbl in 2010, US$69.11/bbl in 2011, US$72.83/bbl in 2012, and escalating at 2.0% per annum from the beginning of 2013 onwards. The gas price is based on the Wood Mackenzie$_2$ forecast of US$7.23/mcf in 2010, US$8.19/mcf in 2011, US$9.05/mcf in 2012 and US$9.38/mcf, escalating at 2.0% per annum from the beginning of 2014 onwards.

Production Profile: The base case of the production profile is from the result obtained from the Eclipse Reservoir Simulation Model of the inner part of the field with known parameters.

Opex and Tariff: the operating cost is made up of annual lease cost for FPSO, tariff on gas pipeline usage and CO_2 and NO_x tax, operating personnel cost, inspection and maintenance cost, logistics and consumable cost, well costs and insurance cost. The base case for the FPSO lease cost is gotten by comparing and taking average of FPSO lease costs for fields with similar recoverable reserve and production.

Capex: The Capex of this project is dependent on the option with the least capital charge and consequently highest profitability. It includes cost of production drilling, cost of subsea wells and cost of pipelines. For this field we considered the following development options:

Vol.5, pp.7-15, December 2018

- Lease FPSO for production, lease semi submersible rig for drilling operations and sell oil Free on Board (FOB) and Subsea wells.
- Build FPSO for production, lease semi submersible rig for drilling operations and sell oil Free on Board (FOB).
- Build FPSO for production, build semi submersible rig for drilling operations and sell oil Free on Board (FOB) and Subsea wells.

A review of these options with respect to profitability is illustrated in Table 1.

Leasing an FPSO seems to be our best option besides its cost benefit; it also has the advantage of being used for production and storage until stored liquid is offloaded into a shuttle tanker. A fixed platform will not be suitable since it will be a permanent structure and it is expensive in this circumstance because the field is marginal it would not be a good idea for any permanent structure as it would attract higher abandonment cost at the end of field life. Besides, the produced oil would require a tie back to an oil pipeline and there are no existing oil pipelines around O-Field. A semi-submersible platform is leased to do the drilling job and the subsea wells are then tied to the FPSO for production while the semi-sub moves away when drilling operations are completed. An FPSO lease rate of \$15.67 Million ($\$_{2001})_1$ per year was used and this rate was converted to the money of the day, MOD, of the appropriate years assuming a price inflation rate of 2.5%. Besides, it is a known fact that FPSOs are better suited for marginal field development in remote locations, such as the O-Field.

Abandonment cost is also another element of the CAPEX. This includes basically the cost of pipeline and well abandonment only since the production unit, FPSO, is leased.

Tax: The base case considered is the upstream taxation of the economic environment, Norway. Upstream petroleum companies in Norway are subject to both the ordinary petroleum tax at the rate of 28% and an additional special tax of 50%. It should also be noted that these taxes are calculated independently of each other.

Discount Rate: A 10% discount rate is employed for the base case and this is also the most likely case for Indy oil. It takes into account the cost of capital and the relevant risk factors applicable in this economic environment, Norway.

Profit to Investment Ration (PIR): PIR for the base case is 11.08. This means that the discount rate margin within which the project is profitable is high.

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NPV: The NPV for the base case is USD 584.6Million (CAD 654.92 Million). This is calculated for the base case with a discount rate of 10%. It should be stated here that this value is highly sensitive to the time of origin.

NPVI: The NPVI for the base case is 6.41.

2.2 Sensitivity Analysis

A sensitivity analysis helps investigate the impact of changes in input parameters of the economics and shows the outcome. For example, the impact of variation in oil price on NPV can be measured by the sensitivity analysis.

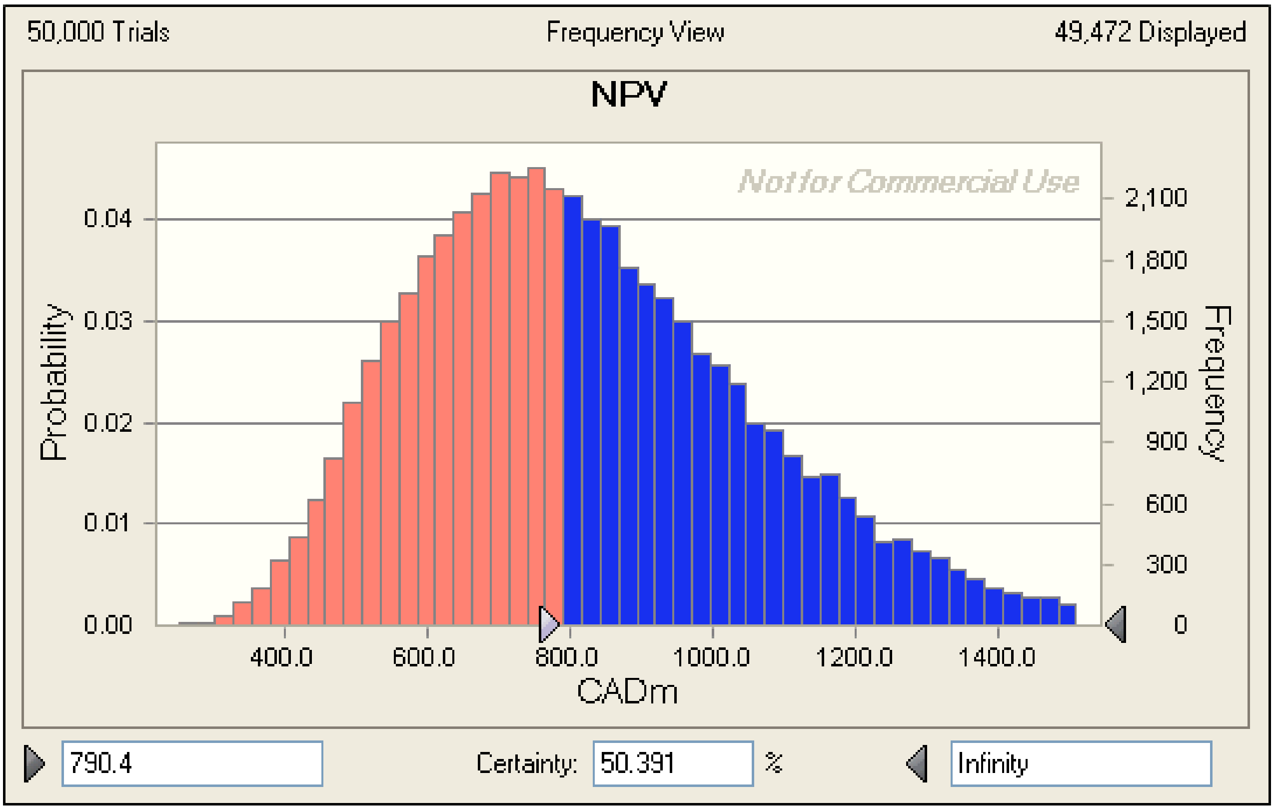

Figure 2: Frequency of NPV

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Vol.5, pp.7-15, December 2018

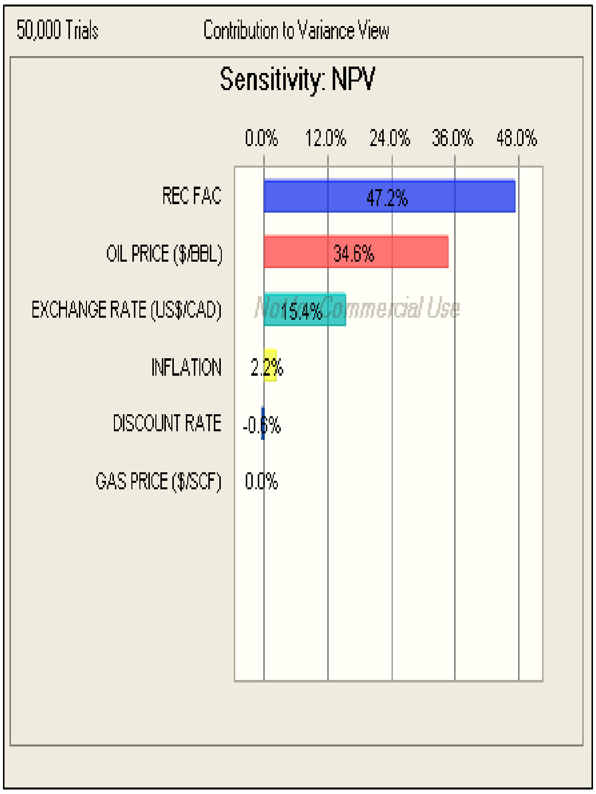

Figure 3: Sensitivity NPV

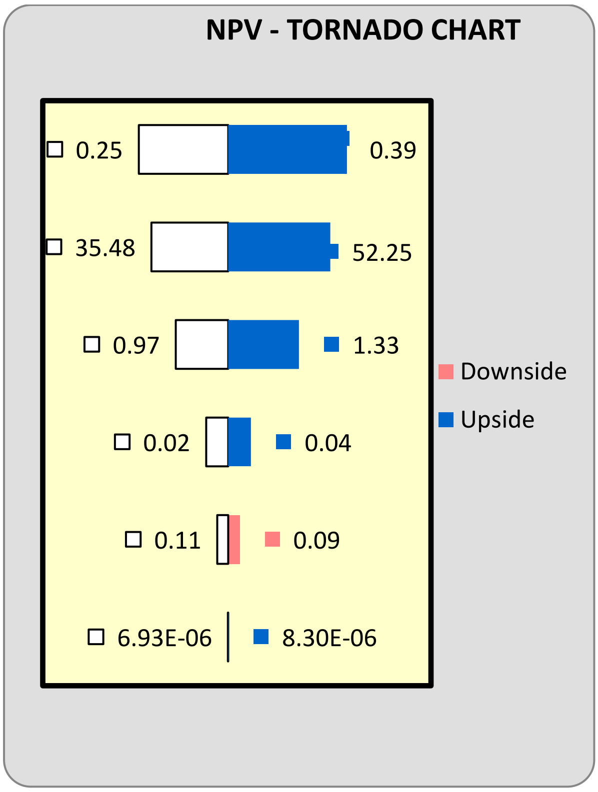

Figure 4: NPV- TORNADO Chart

	NPV			Input		
Variable	*Downside*	*Upside*	*Range*	*Downside*	*Upside*	*Base Case*
REC FAC	597.9	1026.6	428.7	0.25	0.39	0.31
OIL PRICE ($/BBL)	623.9	992.6	368.7	35.48	52.25	42.68
EXCHANGE RATE (US$/CAD)	674.1	927.8	253.8	0.97	1.33	1.12
INFLATION	736.8	829.1	92.3	0.02	0.04	0.03
DISCOUNT RATE	805.6	759.6	46.0	0.09	0.11	0.10
GAS PRICE ($/SCF)	782.2	782.2	0.0	6.93E-06	8.30E-06	7.50E-06

Table 2: illustrates the justification for the variation from base case

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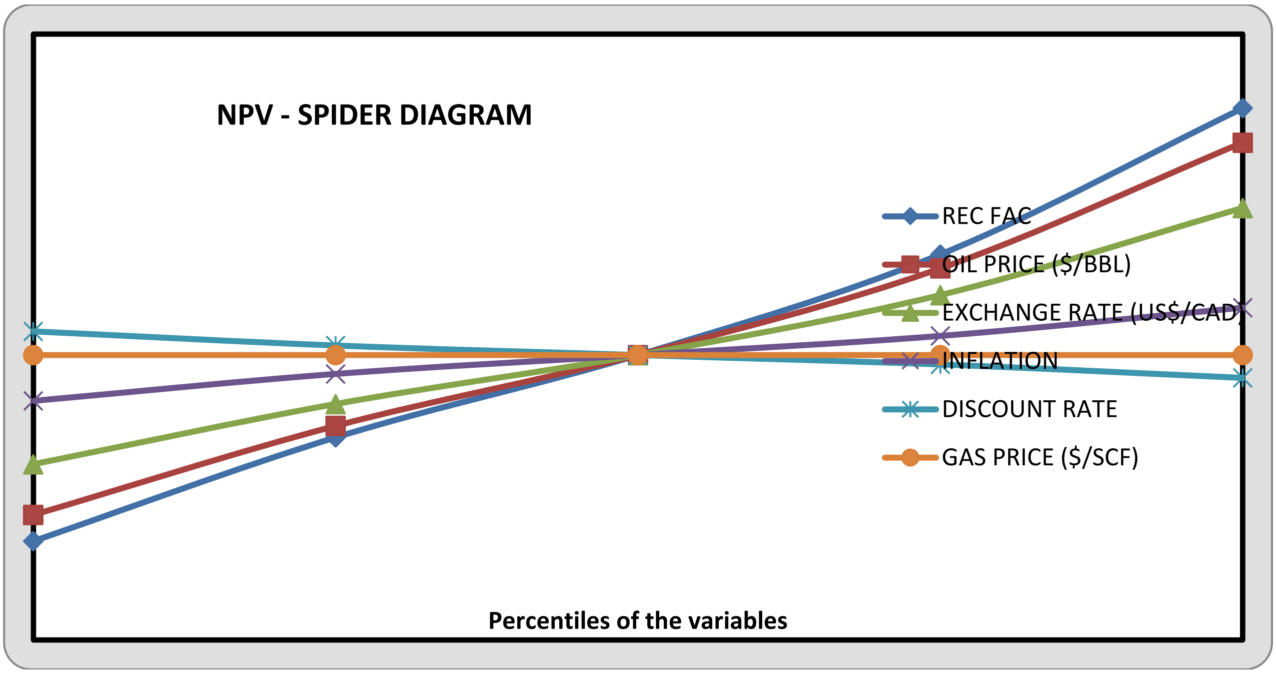

Figure 5: NPV Spider Diagram for percentiles of the variables

Variable	*10.0%*	*30.0%*	*50.0%*	*70.0%*	*90.0%*
REC FAC	597.9	700.6	782.2	881.8	1026.6
OIL PRICE ($/BBL)	623.9	712.0	782.2	867.9	992.6
EXCHANGE RATE (US$/CAD)	674.1	733.7	782.2	841.6	927.8
INFLATION	736.8	763.5	782.2	801.1	829.1
DISCOUNT RATE	805.6	791.6	782.2	772.8	759.6
GAS PRICE ($/SCF)	782.2	782.2	782.2	782.2	782.2

Table 2: NPV sensitivity analysis with discount percentage

3. Results & Discussion of Sensitivity Result

It is seen that the Recovery factor has the highest impact on the NPV. Moreover, this can be attributed to the very high uncertainty due to the geology of the field and consequently the under-detailed reservoir characteristics. We plan to acquire more information in the cause of production of the field and therefore reduce accompanied uncertainties.

Other factors with significant impact on the project NPV include tax rate and fiscal regime, oil price and exchange rate. From the sensitivity analysis, it can be seen that the CAPEX and OPEX have little impact on the NPV. Gas production from the field is very small and is mostly used to fuel the FPSO. Thus, the impact of its variation is negligible.

3.1 Financing and Risk Management Consideration

The O-Field is a marginal field and has significant risks in its development assumptions. The following approaches were used to mitigate the risks involved:

Lease Contract: The drilling will be done by a leased Semi-submersible platform, the production and storage is by a leased FPSO. This approach ensures that the project does not tie down Indy oil's capital, as this field is both marginal and with lots of uncertainties. Leasing will also significantly reduce the Maximum capital outlay and ultimately increase the PIR and NPVI. Another benefit of the lease contract is that it eliminates the risk of being stuck with capital-intensive investments if the estimated recoverable reserve is less than estimated.

Others: From the outcome of the sensitivity analysis and the fact that the recovery factor seems to be a key NPV constraint, thus it is recommended that further information gathering should be done to reduce the risk created by this uncertainty. This can be in the form of carrying out history matching; refining the reservoir simulation model and carrying out further geological studies to better understand the fault and fracture system.

4. RECOMMENDATION AND CONCLUSION

Indy oil is a Canadian company with high interest in mature assets. It implements an upstream strategy based on an aggressive international expansion aim to reach a better global spread. This has been boosted by the acquisition of Bow Valley in 1994, Arakis Energy in 1998, Lundin Oil in 2001, and other companies, thus gaining a portfolio of assets in the UK and a presence in Algeria, Indonesia, Sudan, Malaysia, Papua New Guinea and Vietnam amongst other places. The O-Field is in mid-Norwegian shelf, an area with much potential for Indy oil due. Some recently drilled wells have struck oil in the cretaceous reservoir and this has opened up new oil play in the province. This also provides future "hub and spoke" and exploitation potentials for the Company. It replicates Indy oil's success in the UK. On the Global Upstream Portfolio for Indy oil, Norway is classified as core development area. The O-Field emphasizes this as it presents the company with potentials in the area of pipeline development, as there are currently no oil pipelines to shore facilities in the area. The base case analysis for the O-Field produces an IRR of 82%, which is far above the average IRR of 50% for new projects in Indy oil. The Capital expenditure is US$ 587.99 with an estimated return on capital of 10.27 for every dollar invested. The development option of leasing the FPSO and Semi sub was to reduce the risk of capital exposure and free up capital for alternative investments. This project provides an opportunity of the company to have a controlling stake in this asset and even provides future opportunities in line with the company's strategy of achieving a better global spread. Details of the base case anticipated profitability is shown below.

DEVT OPTION	NPV CADm	IRR	PIR	NPVI
LEASE FPSO + LEASE SEMISUB	623.41	82%	10.27	5.93
BUILD FPSO + LEASE SEMISUB	448.23	27%	1.76	0.80
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Table 3: Illustrates the development option with respect to profitability

This study describes and quantifies the potential economic benefits to O Field located in the Mid Norwegian Shelf in the Voring Basin.The findings of this study are not predictions of the future for Voring Basin, but rather they describe a reasonable approach that one might expect for Offshore Field development. The findings also provide a basis for thinking about potential actions that state and local governments, industry, and other stakeholders might undertake to deal most effectively with the effects that do occur.

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