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Department of Communications, Marine and Natural Resources
Beggars Bush, Haddington Road, Dublin 4, Ireland
Tel: +353 (0)1 678 2000 | **Fax:** +353 (0)1 678 2619 | **Email:** padadmin@dcmnr.gov.ie
www.pad.ie

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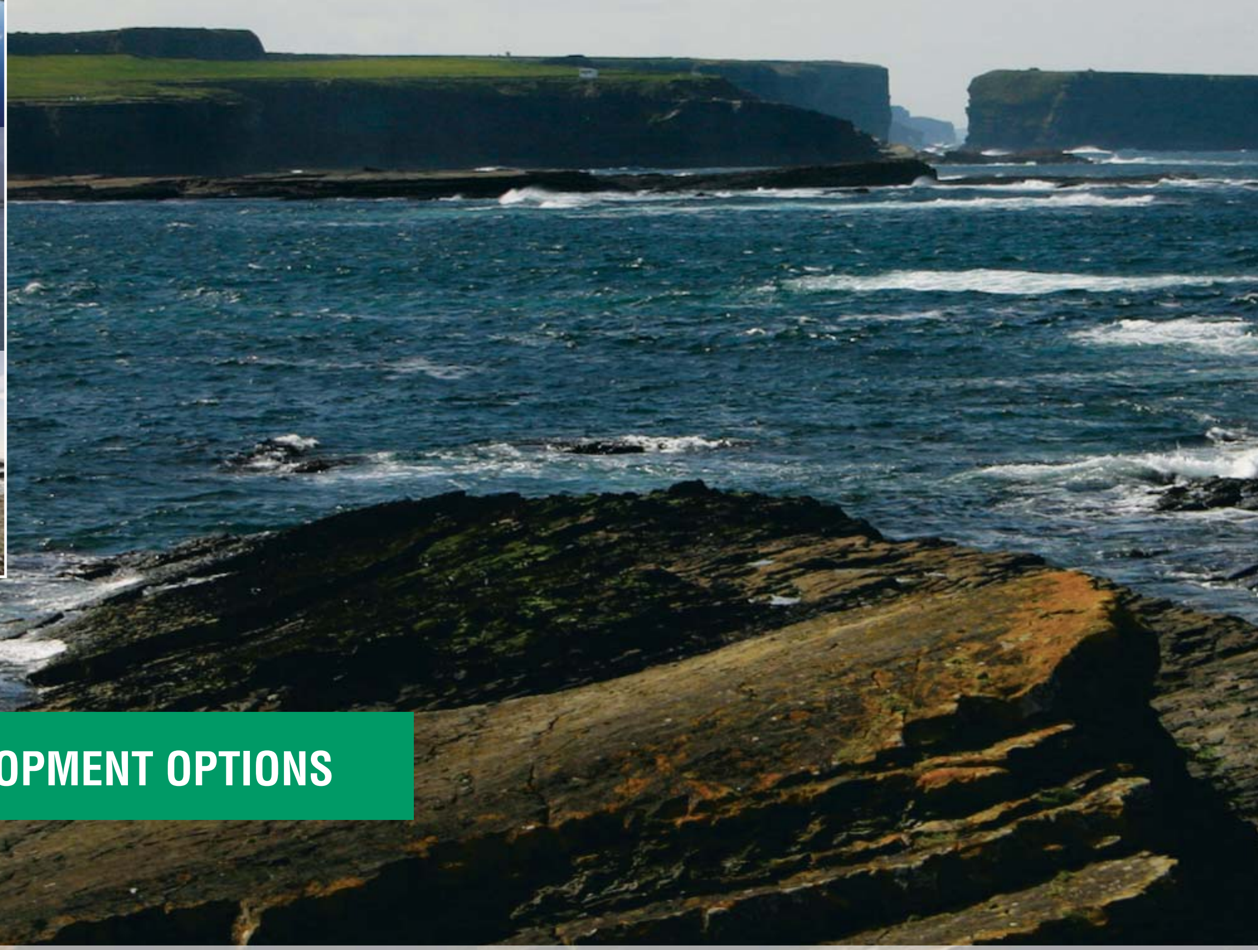

FIELD DEVELOPMENT OPTIONS

Petroleum Affairs Division
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Ireland's Atlantic basins are under-explored but contain a number of proven and emerging play types with potential for field developments in water depths ranging from 500 to 2,500 metres.

In order to assist oil companies in their evaluations of the region, we have modelled the economic viability of various field development concepts in each of the four Atlantic basins: the Rockall Basin with water depths varying from 1,000m to 4,000m, the North Porcupine Basin where the water depth reaches 2,000m, the South Porcupine Basin with water depths of up to 2,500m and finally the Slyne/Erris/Donegal Basins where the water depth varies from 150m to 1,500m.

Although the region has a highly variable climate and experiences some of the harshest conditions in the world, these are similar to the extremes experienced in other deep water regions where the ability to drill and produce from water depths of 2,600m is now proven and being further developed to move into even deeper water.

The field development options described are for illustration only and the economic valuations are based on assumptions which are considered valid for scoping purposes at the time of writing. The report includes full details of the assumptions used.

	1A	1B	1C	1D	2A	2B	3A	3B	3C	3D
Location	Rockall			S Porcupine Goban	North Porcupine		Slyne/Erris/Donegal			
WD (m)	2,500	2,500	2,500	2,500	1,000	1,000	500	500	500	500
Oil (mmbbl)	424		750		125					
Gas		1tcf		2tcf sweet gas		1tcf gas/cond	1tcf gas/cond	1tcf dry gas	500bcf sweet gas	250bcf sweet gas
Scheme	subsea wells, FPSO	subsea wells, shallow water platform	subsea wells, manifold, FPSO	subsea wells, manifold, platform	subsea wells, FPSO	subsea wells, manifold	subsea wells, manifold	subsea wells, manifold	subsea wells, manifold	subsea wells, manifold
	1,388	1,214	2137	1448	1,001	795	524	524	449	262
Wells	18P + 7WI	8P	32P + 13WI	13P	8P + 3WI	9P	9P	9P	8P	4P
IRR	36%	10%	40%	23%	11%	43%	61%	61%	56%	33%

IRR @$35/bbl oil, $4/mmBtu gas *P = production* *WI = water injection*

Field 1A – This was found to meet all the economic hurdles with payback period of approximately seven years across an oil price spread of US $25-45/bbl.

Field 1B – This requires gas prices of around $5.6/mmBtu to be even marginally economic. These fields are candidates for the application of offshore gas to liquid conversion, as yet this is unproven in such conditions, but could significantly reduce the Capex for development and increase IRR from 10% to 27%.

Field 1C – This was found to meet all the economic hurdles with payback period of approximately five years across an oil price spread of US $25-45/bbl.

Field 1D – This requires gas prices above $3.2/mmBtu to be economic.

Field 2A – Oil fields of this size in deep water are shown to be uneconomic to marginal as standalone developments across the oil price range of $25-$45/bbl. This example illustrates the lower boundary for deep water stand-alone developments and the opportunities for tying marginal fields into host facilities.

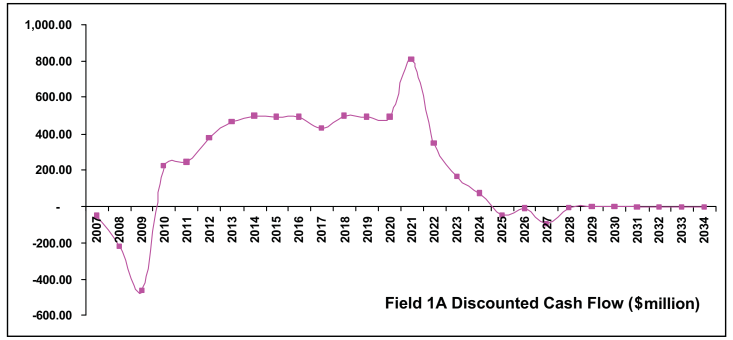
Field 2B – Even with a long tieback and associated cost, the development option was found to be viable under all gas prices above $3.2/mmBtu.

Fields 3A and 3B – These were selected as a dry gas and a gas/condensate field each of 1tcf. Both fields were found to robustly meet the economic indicators at all gas prices above $2.4/mmBtu, but even so, may struggle to match alternate investment opportunities on the basis of stringent payback periods.

Field 3C – This was found to robustly meet the economic indicators at all gas prices above $3.2/mmBtu.

Field 3D – This was found to be economic as a stand alone development at gas prices above $4/mmBtu based on capital efficiency indicators. Below $4/mmBtu, the Field would be economic if tied back as a satellite development to a Field providing the infrastructure.

Rockall Basin Oil Field 1A



The Rockall Basin is a steep-sided channel with water depths ranging from 1,000-1,500m in the northeast to 3,500-4,000m in the southwest. There is some evidence of seabed geohazards from slope failures that may impact on the foundations of fixed facilities.

The only published data implies the potential for oil & gas shows. No infrastructure exists within the Rockall Basin, but when the Corrib gas field is developed this will include a new onshore gas terminal at Bellanaboy Bridge.

Field 1A is assumed to be an oil field with Standard Tank Oil Initially In Place (STOIIP) of 650mmbls. The recovery rate is assumed to be 40% with peak production rate of 110,000bopd. It is assumed that the oil is similar to that tested on Connemara, i.e. 32-38º API crude. It is noted that in geologically-similar Eastern Canada, some oil is heavy, e.g. Ben Nevis is 19-21º API; if this were repeated in Field 1A, then flow assurance issues would need to be fully assessed. Water depth at the field is 2,500m.

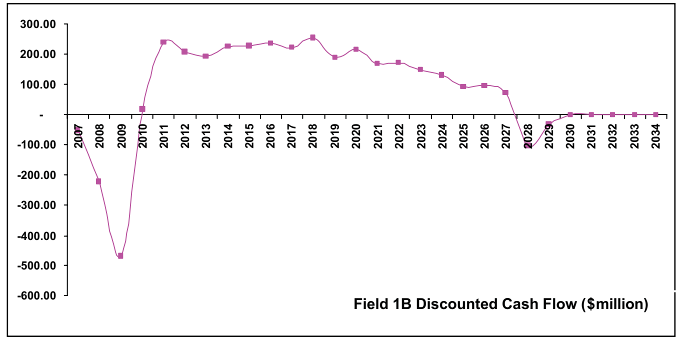
This development scenario was found to meet all the economic hurdles with payback period of approximately seven years across an oil price spread of $25-45/bbl. (The 'spike' in discounted net cash flow in 2021 is due to the drilling of water injection wells.)

Development Parameter	
Field	Oil
Reserves	425mmbls recoverable 35º - API
Production	121,000bopd
Field life	17 years
Wells	Up to 18 producing wells + 7 WI
Water Depth	2,500m
Facilities	Subsea wells tied back to production manifold, flexible line to riser base, hybrid risers to FPSO which has 10 days production storage, offloading by dedicated shuttle tanker.

Element	Capex
Subtotal	$1,168,413,000
Contingency	$220,040,000
Total	$1,388,453,000
Tanker	$185,312,000
Floater	$150,072,000
Drilling 1	$295,507,000
Drilling 2	$322,538,000
Subsea 1	$220,395,000
Subsea 2	$214,629,000
Total	$1,388,453,000

Oil Price at Start Production	$45/bbl	$35/bbl	$25/bbl
NPV @10% - $million	1846	1712	1577
IRR	38%	36%	35%
NPV/NPCe	3.0	2.8	2.5
Payback - years	6.7	6.51	6.35

Rockall Basin Gas Field 1B



Field 1B is a dry gas field with initial gas in place of 1tcf, a recovery rate of 70% and condensate of 1bbls/mmscf. The pipeline to shore would be routed allowing flexibility in the event of seafloor geohazards and slope instability. It is assumed booster compression will be required early in the field life to ensure adequate flow pressures.

In this case, the field development would not pass the hurdle rates at gas prices below $5.6/mmBtu and would struggle to match alternate investment opportunities.

Development Parameter	
Field	Gas
Reserves	1tcf sweet gas
Production	264 mmscf/d
Field life	18 years
Wells	Up to 8 producing wells
Water Depth	2,500m
Facilities	Subsea wells tied back to production manifold, pipeline to a new booster platform built in < 500m water with 450mm scf/d 24" 320 km export pipeline back to an onshore terminal adjacent to Corib.

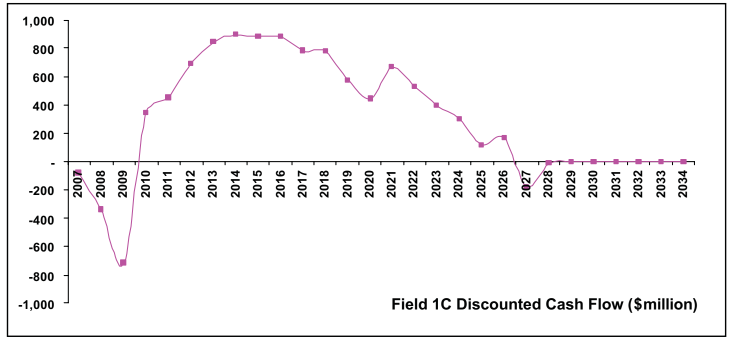
Element	Capex
Subtotal	$1,053,298,000
Contingency	$160,578,000
Total	$1,213,876,000
Jacket	$121,367,000
Topside	$100,732,000
Pipeline	$687,466,000
Drilling	$217,862,000
Subsea	$86,447,000
Total	$1,213,876,000

Gas Price at Start Production	$5.6/mmBtu	$4/mmBtu	$3.2/mmBtu
NPV @10% - $million	614	33	-176
IRR	21%	10%	4%
NPV/NPCe	1	0	2.5
Payback - years	8	17	-

The capital cost of the facility and export pipeline is estimated at $979m. An alternate to the pipeline would be to utilise a gas-to-liquids process for converting the produced gas and offloading by tanker. For an offshore GTL plant capable of handling 200mmscf/d, the US department of Energy has estimated costs as $541m. This represents a potential Capex reduction of $316m, which would significantly increase the capital efficiency rates. The process technology is still unproven for offshore use so that more evaluation would be required before committing to its use on a potential project. The GTL option results are:

Gas Price at Start Production	$5.6/mmBtu	$4/mmBtu	$3.2/mmBtu
NPV @10% - $million	1386	549	131
IRR	45%	27%	14%
NPV/NPCe	4.2	1.6	0.3
Payback - years	5.5	7.4	11.9

Rockall Basin Oil Field 1C



Field 1C Discounted Cash Flow ($million)

Field 1C is a variation of Field 1A and similarly assumed to be an oil field but with Standard Tank Oil Initially in Place (STOIIP) of over 1,000mmbbl. The recovery rate is assumed to be 60% with recoverable reserves of 750mmbbl and peak production rate of 230,000bopd. It is assumed that the oil is similar to that tested on Connemara i.e. 32-38° API crude.

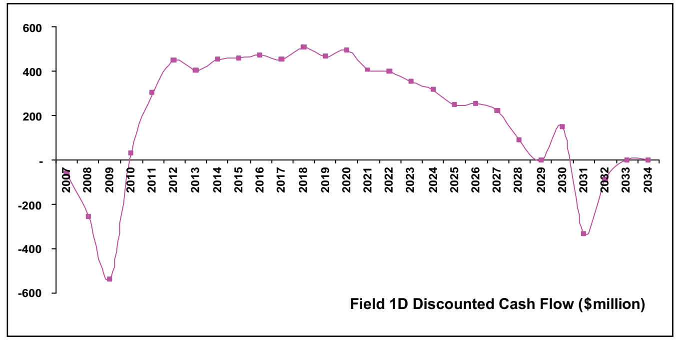
The optimum solution is a series of subsea production and injection wells, tied back to a central manifold by flexible flow lines. The manifold is connected to a riser base by infield flowline, and then by a riser system through the turret of a FPSO fitted out with production and utility systems. The FPSO provides storage for up to ten days production. Offloading is by shuttle tanker to one of a number of reception facilities throughout Europe.

Development Parameter	
Field	Oil
Reserves	750 mmbls recoverable – 35 ° API
Production	230,000bopd
Field life	17 years
Wells	Up to 32 producing wells + 13 WI
Water Depth	2,500m
Facilities	Subsea wells tied back to production manifold, flexible line to riser base, hybrid risers to FPSO which has 10 days production storage, offloading by dedicated shuttle tanker

Element	Capex
Subtotal	$1,798,656,000
Contingency	$338,840,000
Total	$2,137,496,000
Tanker	$187,611,200
Floater	$229,803,200
Drilling 1	$525,640,000
Drilling 2	$552,702,400
Subsea 1	$345,356,800
Subsea 2	$296,382,400
Total	$2,137,496,000

Oil Price at Start Production	$45/bbl	$35/bbl	$25/bbl
NPV @10% - $million	2,977	2,778	2,700
IRR	42%	40%	39%
NPV/NPCe	3.11	2.91	2.92
Payback - years	5.1	6.88	6.78

South Porcupine/Goban Basin Gas Field 1D



Field 1D Discounted Cash Flow ($million)

Field 1D is a variation of Field 1B and similarly assumed to be a dry gas field but with initial gas in place of in excess of 2tcf with recovery rate of 70% and condensate of 5bbls/mmscf. We assume a 24 inch pipeline to shore with a capacity of 450mmscf/d. This option maintains pipeline sizing from Field 1B and hence field life increases with larger reserve quantities. The pipeline length is estimated to be 320km to be routed allowing flexibility in the event of seafloor geohazards and slope instability. The pipeline will land adjacent to the existing Corrib terminal. It is assumed booster compression will be required early in the field life to ensure adequate flow pressures.

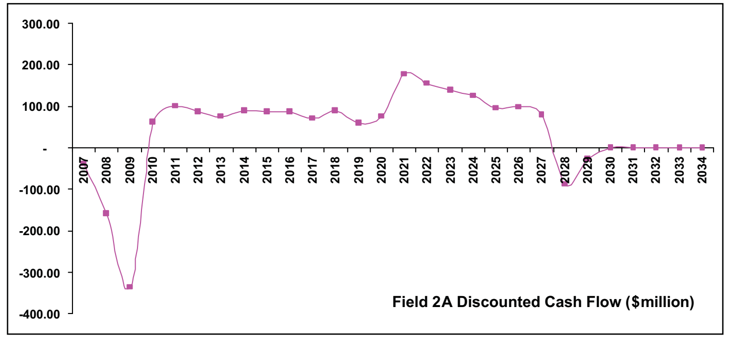
The optimum solution would appear to be a combination of subsea wells tied back to a central production manifold. The manifold would be connected via a pipe-in-pipe to a fixed platform some 150-200km from the field and in shallower water. The fixed platform would act as a booster platform to control pipeline temperature and pressure and chemical injection to control hydrate formation. The fixed platform would then be connected by pipeline to a land based gas terminal.

Development Parameter	
Field	Gas
Reserves	2tcf sweet gas
Production	490 mmscf/d
Field life	21 years
Wells	Up to 13 producing wells
Water Depth	2,500m
Facilities	Subsea wells tied back to production manifold, pipeline to a new booster platform built in <500m water with export pipeline back to an onshore terminal

Element	Capex
Subtotal	$1,261,840,000
Contingency	$186,756,800
Total	$1,448,596,800
Jacket	$121,366,400
Topside	$271,571,200
Pipeline	$687,464,000
Drilling	$217,860,800
Subsea	$150,334,400
Total	$1,448,596,800

Gas Price at Start Production	$5.6/mmBtu	$4/mmBtu	$3.2/mmBtu
NPV @10% - $million	1,864	938	475
IRR	32%	23%	17%
NPV/NPCe	2.6	1.29	0.64
Payback - years	6.1	8.4	10.52

North Porcupine Basin Oil Field 2A



Field 2A Discounted Cash Flow ($million)

The North Porcupine is a north-south trending deep water area with water depths ranging from 350m to 1,700m. There is no evidence of specific seabed geohazards that may impact on the foundations of facilities.

There is potential for sulphur-free sweet light crudes with API gravities of 32-41° API. Additionally the potential for gas exists.

No significant infrastructure exists, but when the Corrib gas field is developed in the nearby Slyne/Erris/Donegal region, this will include an export pipeline to a new gas terminal at Bellanaboy Bridge.

Field 2A is an oil field with STOIIP of 250mmbbls and recovery of 50% oil. Individual well flow rates are taken as 1,500-5,000bopd. The distance to shore is 240km. Water depth at the field is 1,000m.

There are a number of feasible options for this field, one of which is to utilise a Spar or Semi-submersible with a pipeline tied back to a storage facility at Bantry Bay, from which the crude could be transferred to VLCC for transport to processing plants. If Bantry Bay could not be utilised, an FPSO option with shuttle tanker would be an alternative.

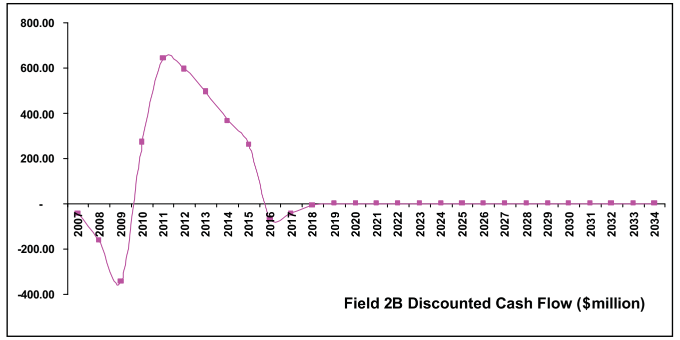
In this case, the field development would not pass the hurdle rates at the high oil price. To be economic it would require a tieback to an existing facility which would reduce the Capex from $1,078m to around $474m although there would be additional operating tariffs added into the Opex. Alternately, increasing the minimum recoverable reserves above 250mmbbls may significantly improve the financial assessment.

Development Parameter	
Field	Oil
Reserves	125mmbls – 35°API
Production	26,400 bopd
Field life	18 years
Wells	Up to 8 producing wells + 3 WI
Water Depth	1,000m
Facilities	Subsea wells tied back to production manifold, flexible risers tied back to a semi-submersible/spar production unit with tanker offloading or pipeline to Bantry Bay

Element	Capex
Subtotal	$844,064,000
Contingency	$156,490,000
Total	$1,000,554,000
Semi sub	$413,552,000
Floater	$53,013,000
Pipeline	$172,575,000
Drilling 1	$109,634,000
Drilling 2	$137,289,000
Subsea 1	$46,247,000
Subsea 2	$68,245,000
Total	$1,000,554,000

Oil Price at Start Production	$45/bbl	$35/bbl	$25/bbl
NPV @10% - $million	181	62	-8.8
IRR	14%	11%	9%
NPV/NPCe	0.4	0.1	0
Payback - years	14.6	15.7	20.0

North Porcupine Basin Gas/Condensate Field 2B



Field 2B Discounted Cash Flow ($million)

Field 2B is a gas/condensate field with initial reserves of 1tcf, 70% recovery and condensate rates of 1bbl/mmscf. There is no H2S but 0.3% CO2. Gas is exported by a 24 inch pipeline; capacity of 450mmscf/d and a length of 240km back to the existing Corrib terminal.

The selected option is a series of satellite subsea wells tied into a central manifold and control centre and an export pipeline to shore. Pipeline flow assurance will need to be fully assessed including the potential use of subsea booster pumps and possibly a midline booster station.

If pipeline flow assurance proves problematical, the second option would likely be the use of subsea wells tied back to a manifold, which connects to a Mini-TLP. An export pipeline would run from the mini-TLP to the onshore gas reception terminal.

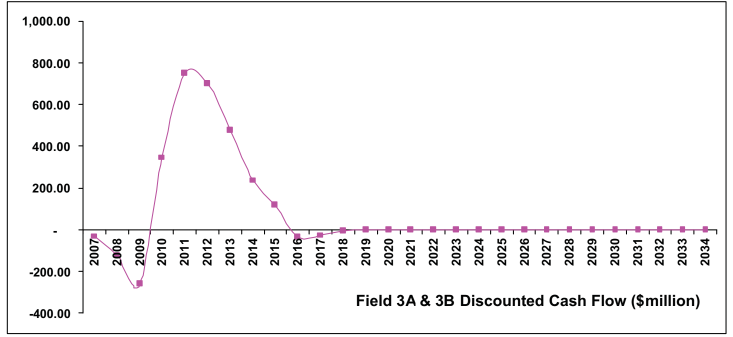
In this case, the field development would pass the hurdle rates at gas prices above $4/mmBtu, but may struggle to match alternate investment opportunities on the basis of payback periods

Development Parameter	
Field	Gas
Reserves	1tcf sour gas 70% recovery
Production	550mmscf/d
Field life	6 years
Wells	Up to 9 producing wells
Water Depth	1.000m
Facilities	Subsea wells tied back to production manifold, with export pipeline 240km back to onshore terminal – may need to incorporate subsea booster pumps.

Element	Capex
Subtotal	$678,801,000
Contingency	$115,759,000
Total	$794,560,000
Semi sub	$460,017,000
Floater	$171,812,000
Subsea 1	$162,730,000
Total	$794,560,000

Gas Price at Start Production	$5.6/mmBtu	$4/mmBtu	$3.2/mmBtu
NPV @10% - $million	1108	674	432
IRR	59%	43%	33%
NPV/NPCe	2.4	1.5	0.9
Payback - years	4.4	5.0	5.6

Slyne/Erris/Donegal Basin Gas/Condensate Fields 3A & 3B



Field 3A & 3B Discounted Cash Flow ($million)

Fields 3A and 3B are gas fields with initial reserves of 1tcf and a recovery rate of 70%; no H2S but 0.3% CO2. In one case, condensate rate is assumed to be 5bbl/mmscf/d; the other case assumes dry gas. Export of gas is by a 24 inch pipeline with capacity of 450mmscf/d and a length of 120km tying back to the Corrib onshore gas terminal.

It is assumed the optimum solution is subsea wells tied back to a manifold from which an export pipeline runs to the Corrib gas terminal or an adjacent facility. Depending on well shut-in pressures, it may be advantageous to incorporate a High Pressure Integrity Protection System to facilitate the use of a lower rated pipeline.

We have included in the financial model an additional Capex of $256m to cover a newbuild terminal, adjacent to the existing Corrib terminal and its operating costs. It may be possible to reduce the Capex if it is feasible to add an additional two processing trains and slug catcher into the existing terminal (depending on tariffs charged by the existing terminal operator). The total Capex for this option of $224m, plus terminal cost of $256m, equating to $480m, compared to the estimated total Capex cost for Corrib and the terminal of $800m.

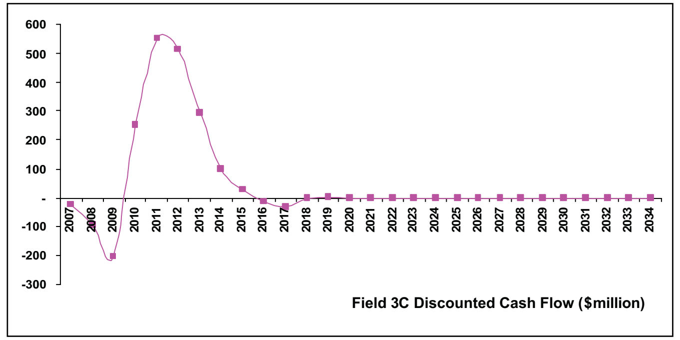
The field development for dry gas is virtually the same as that for wet gas and similarly would pass the hurdle rates at gas prices down to below $2.4/mmBtu, but even so may struggle to match alternate investment opportunities on the basis of stringent payback periods.

Development Parameter	
Field	Gas
Reserves	1tcf gas 70% recovery
Production	670mmscf/d +340bbl/d condensate
Field life	6 years
Wells	Up to 9 producing wells
Water Depth	500m
Facilities	Subsea wells tied back to production manifold, with export pipeline 120km back to onshore terminal.

Element	Capex
Subtotal	$444,845,000
Contingency	$79,253,000
Total	$524,098,000
Drilling	$223,443,000
Pipeline	$154,165,000
Subsea	$146,490,000
Total	$524,098,000

Gas Price at Start Production	$5.6/mmBtu	$4/mmBtu	$3.2/mmBtu
NPV @10% - $million	1284	767	620
IRR	84%	61%	53%
NPV/NPCe	3.8	2.2	1.8
Payback - years	4.4	4.5	5.6

Slyne/Erris/Donegal Basin Gas/Condensate Field 3C



Field 3C Discounted Cash Flow ($million)

Field 3C is a variation of Field 3A and similarly assumed to be a gas/condensate field with smaller initial reserves of 500bcf, 70% recovery, condensate rates of 5 bbl/mmscf. There is no H2S but 0.3% CO2. A 24-inch pipeline exports gas; capacity of 450mmscf/d and a length of 120km back to the existing Corrib terminal. Cost savings could be realised if instead of running the pipeline directly to the onshore terminal it ran to a tie-in point on the main Corrib export line.

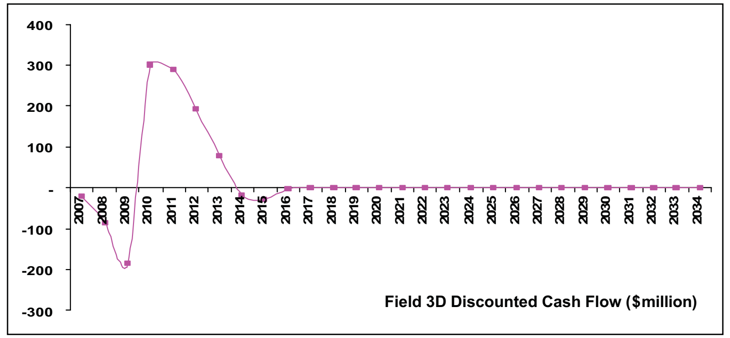
No specific option screening has been undertaken for Field 3A and similarly it is assumed the optimum solution for Field 3C is a series of subsea wells tied back to a manifold from which an export pipeline runs to the Corrib onshore gas terminal or adjacent facility. Depending on well shut-in pressures it may be necessary to incorporate a High Pressure Integrity Protection System (HIPPS) to facilitate the use of a lower rated pipeline.

Development Parameter	
Field	Gas
Reserves	500 bcf gas condensate
Production	400 mmscf/d
Field life	6 years
Wells	Up to 8 producing wells
Water Depth	500m
Facilities	Subsea wells tied back to production manifold, with export pipeline 120km back to an onshore terminal

Element	Amount
Subtotal	$382,550,400
Contingency	$66,793,600
Total	$449,344,000
Drilling	$223,441,600
Pipeline	$163,278,400
Subsea	62,624,000
Total	$449,344,000

Gas Price at Start Production	$5.6/mmBtu	$4/mmBtu	$3.2/mmBtu
NPV @10% - $million	827	495	329
IRR	77%	56%	43%
NPV/NPCe	3.1	1.82	1.21
Payback - years	4.19	4.46	4.77

Slyne/Erris/Donegal Basin Gas/Condensate Fields 3D



Field 3D Discounted Cash Flow ($million)

Field 3D is a variation of Field 3A and similarly assumed to be a gas/condensate field with smaller initial reserves of 250bcf, 70% recovery, condensate rates of 5 bbl/mmscf. There is no H2S but 0.3% CO2. A 24-inch pipeline exports gas; capacity of 450mmscf/d and a length of 120km back to the existing Corrib terminal. Cost savings could be realised if instead of running the pipeline directly to the onshore terminal it ran to a tie in point on the main Corrib export line.

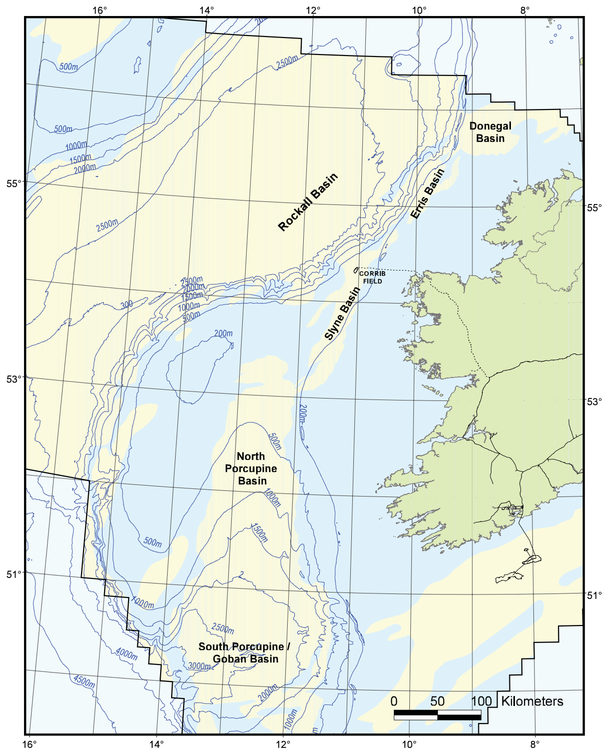
No specific option screening has been undertaken for Field 3A and similarly it is assumed the optimum solution for Field 3D is a series of subsea wells tied back to a manifold from which an export pipeline runs to the Corrib onshore gas terminal or adjacent facility. Depending on well shut-in pressures it may be necessary to incorporate a High Pressure Integrity Protection System (HIPPS) to facilitate the use of a lower rated pipeline.

Development Parameter	
Field	Gas
Reserves	250 bcf gas condensate
Production	232 mmscf/d
Field life	4 years
Wells	Up to 4 producing wells
Water Depth	500m
Facilities	Subsea wells tied back to production manifold, with export pipeline 120km back to an onshore terminal

Element	Capex
Subtotal	$223,703,000
Contingency	$38,669,000
Total	$262,372,000
Drilling	$139,651,000
Pipeline	$96,353,000
Subsea	$26,368,000
Total	$262,372,000

Gas Price at Start Production	$5.6/mmBtu	$4/mmBtu	$3.2/mmBtu
NPV @10% - $million	313	139	53
IRR	56%	33%	19%
NPV/NPCe	1.28	0.57	0.22
Payback - years	4.34	4.88	5.77

KEY MAP



This document summarises the key findings of a report prepared for the PAD in association with the PIP Irish Shelf Petroleum Studies Group (ISPSG) by Douglas-Westwood Limited and the TCS Partnership in February 2006. The full report 'Cost Effective Field Development Study for Atlantic Ireland Basins', PAD Special Publication No 2/06, which includes details of basin attributes, the production systems evaluated and the assumptions used in economics, is available for purchase from:

ISPSG Secretariat
7 Dundrum Business Park
Windy Arbour, Dublin 14

Tel +353 1 296 4667
Fax +353 1 296 4676
E-mail noneill@csa.ie