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Options for Exploiting Gas from West of Scotland

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Research in North Sea Economics has been conducted in the Economics Department since 1973. The present and likely future effects of oil and gas developments on the Scottish economy formed the subject of a long term study undertaken for the Scottish Office. The final report of this study, The Economic Impact of North Sea Oil on Scotland, was published by HMSO in 1978. In more recent years further work has been done on the impact of oil on local economies and on the barriers to entry and characteristics of the supply companies in the offshore oil industry.

The second and longer lasting theme of research has been an analysis of licensing and fiscal regimes applied to petroleum exploitation. Work in this field was initially financed by a major firm of accountants, by British Petroleum, and subsequently by the Shell Grants Committee. Much of this work has involved analysis of fiscal systems in other oil producing countries including Australia, Canada, the United States, Indonesia, Egypt, Nigeria and Malaysia. Because of the continuing interest in the UK fiscal system many papers have been produced on the effects of this regime.

From 1985 to 1987 the Economic and Social Science Research Council financed research on the relationship between oil companies and Governments in the UK, Norway, Denmark and The Netherlands. A main part of this work involved the construction of Monte Carlo simulation models which have been employed to measure the extents to which fiscal systems share in exploration and development risks.

Over the last few years the research has examined the many evolving economic issues generally relating to petroleum investment and related fiscal and regulatory matters. Subjects researched include the economics of incremental investments in mature oil fields, the impact of the Gas Levy on incremental investments in mature gas fields, economic aspects of the CRINE initiative, economics of gas developments and contracts in the new market situation, economic and tax aspects of tariffing, economics of infrastructure cost sharing, the effects of comparative petroleum fiscal systems on incentives to develop fields and undertake new exploration, the oil price responsiveness of the UK petroleum tax system, and the economics of decommissioning, mothballing and re-use of facilities. This work has been financed by a group of oil companies and Scottish Enterprise, Energy

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Options for Exploiting Gas from West of Scotland

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1. Introduction

The first licences for the West of Scotland (WOS) area were granted in 1971-1972 under the 4th Licensing Round. The Clair field was the first to be discovered in the West of Scotland area by BP in block 206/8. Later that year the first gas discovery (Victory) was made in Block 207/1 now operated by Chevron. There were further discoveries but it was not until after the Foinaven discovery in 1992 that development plans were put in place.

Foinaven, Schiehallion, Loyal, and Clair have since been granted development approval and production from WOS commenced in 1997. Foinaven was developed using a leased converted support vessel, Petrojar 1 IV, as an FPSO. Schiehallion has been developed using a new-build FPSO and Loyal is a sub-sea satellite. Clair South is the first fixed platform development in the West of Scotland area.

A new gas pipeline, WOSPS, was given consent in late 2000. This pipeline takes gas from the Foinaven, Schiehallion and Loyal fields to Sullom Voe then onwards to Magnus and St Fergus via the FLAGS pipeline.

Currently these are the only producing fields but there is a substantial number of discoveries and prospects. These discoveries are modestly-sized and the aggregate expected reserves is moderate. There is a mixture of oil fields, gas fields, and fields containing both oil and gas. It is likely that the development and operating costs of these undeveloped fields will be relatively high. One of the problems associated with the fields is their wide geographic dispersion. There is also limited investor alignment among the licensees. Another problem is the limited existing infrastructure, both processing and pipelines, in the area. Other than the WOSPS and the link to it from Clair there is no gas transport infrastructure in the area. There are however, limits to the quantity of gas which the WOSPS pipeline can transport so questions remain regarding how the rest of the known gas in the West of Scotland area can be economically produced and transported to markets. The smaller finds are not viable without an established pipeline into which they could put their gas.

As all these fields are geographically remote from the nearest mainland gas terminal at St Fergus and almost all of them are small in size the aim of this paper is to look at a number of development scenarios which could result in a comprehensive development.

Four comprehensive scenarios were developed as follows:

1. Use of the existing infrastructure both WOS and EOS, with the gas being sent from Magnus to St Fergus. Schiehallion and the Clair Area would act as hubs to minimise the transport costs. Most gas fields would connect to a new platform in the Clair Area because of the relatively shallow water in the Clair area.
2. Use of the Laggan field, which is one of the larger gas fields in the study, as the main hub, with a new communal pipeline linking Laggan to St Fergus either directly, or indirectly via FLAGS, Frigg, or SAGE.
3. Use of the Victory field, which is in relatively shallow water, as the main hub, with a new communal pipeline linking Laggan to St Fergus either directly, or indirectly via FLAGS, Frigg, or SAGE.
4. Use of the Seonaid field, which is in relatively shallow water and slightly closer to St Fergus than the previously mentioned fields, as the main hub with a new communal pipeline linking Laggan to St Fergus either directly, or indirectly via FLAGS, Frigg, or SAGE.

2. Data and Methodology (General)

Cost and production data for the fields already in production or under development were validated by the operators. To these have been added 19 fields in the West of Scotland area and 4 Prospects – Tormore, Tamdhu, Capercaillie and Cardu. The total reserves/recoverable resources amount to just under 3tcf. For these fields the reserves, costs, development concepts and timing of development have been estimated using P50 estimates from a variety of information either in the public domain or by the authors' own calculations. For the scenarios analysed, different development concepts were considered for the fields, including fixed platforms, FPSOs, TLPs, and sub-sea tieback systems. The chosen scheme was determined by cost and reserves considerations. The development cost estimates employed reflect the recent and ongoing cost escalation in the UKCS. Each field's operating costs were modelled based on the accumulated development costs. The annual operating costs attributed to each field ranged from 7% to 23% of accumulated development costs depending on the reserves size and type of development. The average percentage was relatively high at 10.5% because many of the fields are small. The highest of 23% occurred with some leased FPS facilities. For each of the 23 projects the pipeline length was calculated using maps from the DEAL website. Estimates of the pipeline diameters required for each of the fields, the pipeline costs between the different hub fields, and the different landfall or pipeline routes was calculated using information from a variety of sources.

It was assumed that almost all fields would have their own separation facilities and that produced oil would generally be tanker loaded. Where sub-sea developments were involved a processing tariff of 50p/bbl was paid to the receiving field.

As part of the study was to determine how the gas from WOS could be developed and taken to market it was necessary to determine what ullage would be available in the existing pipeline network not only in the WOS area but in the North Sea including the FLAGS, Frigg UK, and SAGE systems. From information in the public domain the various pipeline capacities are known and from the authors' database of sanctioned and future fields (validated by the field operators) estimates were made of the capacity expected to be employed to transport gas in each pipeline. To this was added the volume of gas likely to come from as yet undeveloped technical reserve fields and (modelled) new discoveries[1]. The geographic location of the technical reserves fields gives a good indication of which transport route the fields would choose. The geographic location of new discoveries is less precise, but assumptions can be made regarding the likely route. All of these volumes were aggregated and the total volumes compared with the capacity in each pipeline. The result is the prospective ullage available.

[1] For details of how future production estimates were made see A.G. Kemp and L. Stephen, North Sea Study Occasional Paper No. 98, University of Aberdeen, Department of Economics, May 2005, pp. 52.

Further exploration will take place in the WOS area in the time period under study. It was assumed that the size of the effort from the 22nd and 23rd Licensing Rounds will be greater than over the past decade, partly because of the higher levels of oil and gas prices. An exploration success rate of 15% was assumed with a 42% probability of any find being gas (based on historic experience). Using Monte Carlo analysis 5 gas fields were discovered over the next few years with average reserves of 42mboe (227Bcf with a small quantity of associated oil). The development of these exploration finds could commence in 2008 with the 5th field commencing development in 2016. Because of the many uncertainties these possible discoveries were not included in the economic modelling but are employed to indicate the longer-term total production potential.

First development dates for Alligin and Suilven were as estimated by the operators and the phasing chosen for the other fields was determined in relation to the first development of Laggan which was taken to be sometime in 2006. Where there are sub-hub developments the phasing was arranged such that the fields connecting to the sub-hub field would post-date the hub field's first production. The results have been shown under 2 timing assumptions, namely, (a) Fast-Track and (b) a slower, and probably more realistic, pace of development.

The analysis was based on financial simulation modelling employing the following price scenarios (real 2005).

	Oil Price	**Gas Price**
Base Case	$30/bbl	28p/therm
Low Case	$20/bbl	18p/therm
High Case	$40/bbl	36p/therm

The gas price is that received at St Fergus. The economic results are shown in terms of NPVs at 10% and 15% in real, post-tax terms. The study was undertaken before the announcement by the Chancellor to increase taxation and thus the NPVs reflect CT+SC at 40%.

3. Option 1 – Maximum Use of Existing Infrastructure

This scenario would use Schiehallion and the Clair Area as the main hubs. The Clair Area facilities would need to be enhanced and a new 10km pipeline from the Clair area to the WOSGPS would be required. It is assumed that Suilven, Alligin and 204/23-1 would all link directly to Schiehallion. Solan, 204/28-1 and 205/26a-2 would be tied back to Strathmore, the largest of the 4 fields, and oil would be tanker loaded.

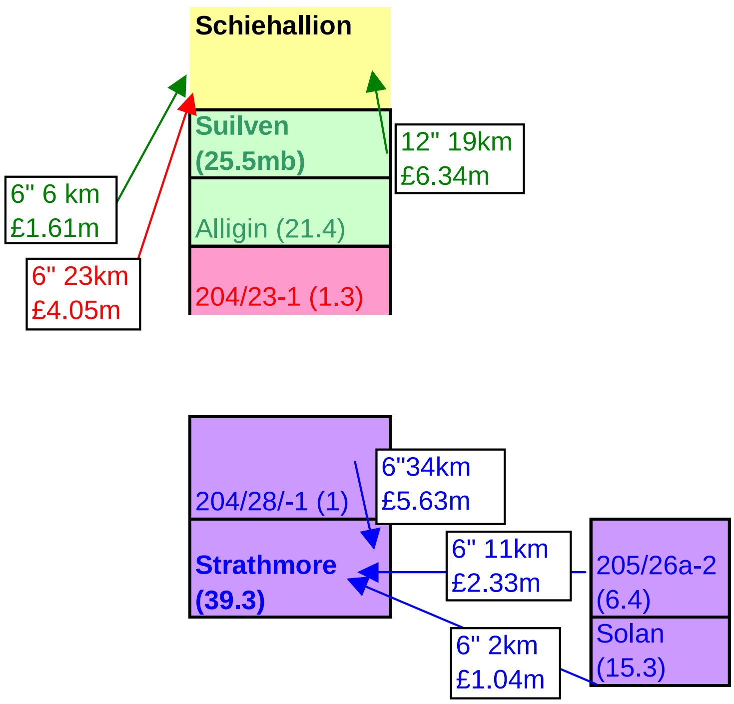
Estimated costs for these fields are shown below in real 2005 prices. Field development costs are split between drilling and other investment. They exclude pipeline costs except where indicated. Tariff costs are added to the operating costs where applicable. The costs shown assume that Strathmore acts as a hub for the 4 field cluster containing 62mmbbls. A TLP is assumed for Strathmore, and each of the fields in the cluster is assumed to pay a tanker loading tariff of £1/bbl and an oil processing tariff of 50p/bbl to Strathmore.

	Reserves mboe	% Gas	First Devex (Fast-Track)	Development Costs $/boe	Capex £m	Drilling £m
Alligin *	21	13%	2008	5.54	36.4	29.47
Suilven *	25	98%	2012	4.62	35.99	29.37
204/23	1	100%	2006	9.46	1.71	5.13
Strathmore	39	0%	2006	8.95	125.05	70.34
205/26	6	0%	2008	9.46	8.34	25.01
Solan	15	0%	2007	8.27	20.42	50.00

** Pipeline costs included*

The field linkages, pipeline distances, assumed pipeline diameters and estimated pipeline costs are shown below. In total the developments would require 48km of wet gas pipeline and 47km of oil pipeline. Block 204/28, Strathmore, 205/26 and Solan being oil only could be developed as a stand-alone cluster.

Chart 1

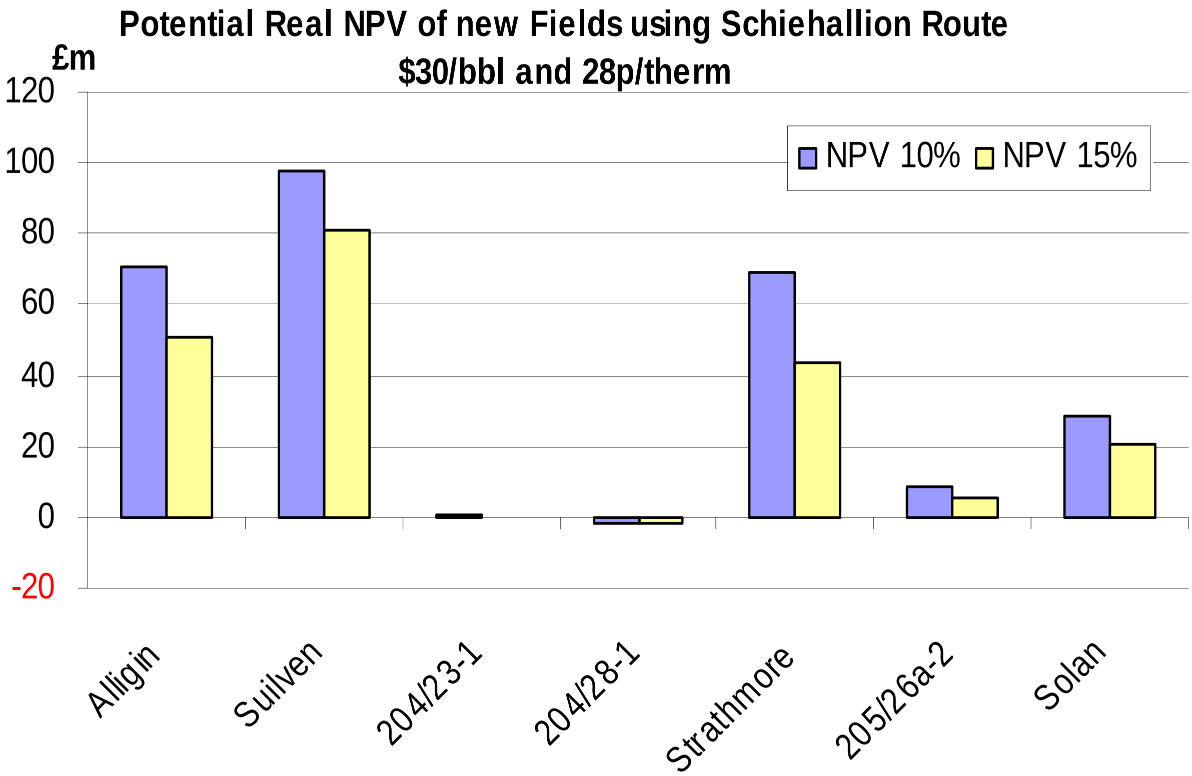


It is assumed that 204/23 pays a gas tariff of 20p/mcf to Schiehallion. Strathmore, Solan, 205/26 and 204/28-1 all pay a tanker loading charge of £1/bbl and Solan and 205/26 pay £0.5/bbl to Strathmore. Block 204/28 also pays £0.5/bbl.

Tariff assumptions for Scenario 1 Schiehallion Route
$30/bbl and 28p/therm

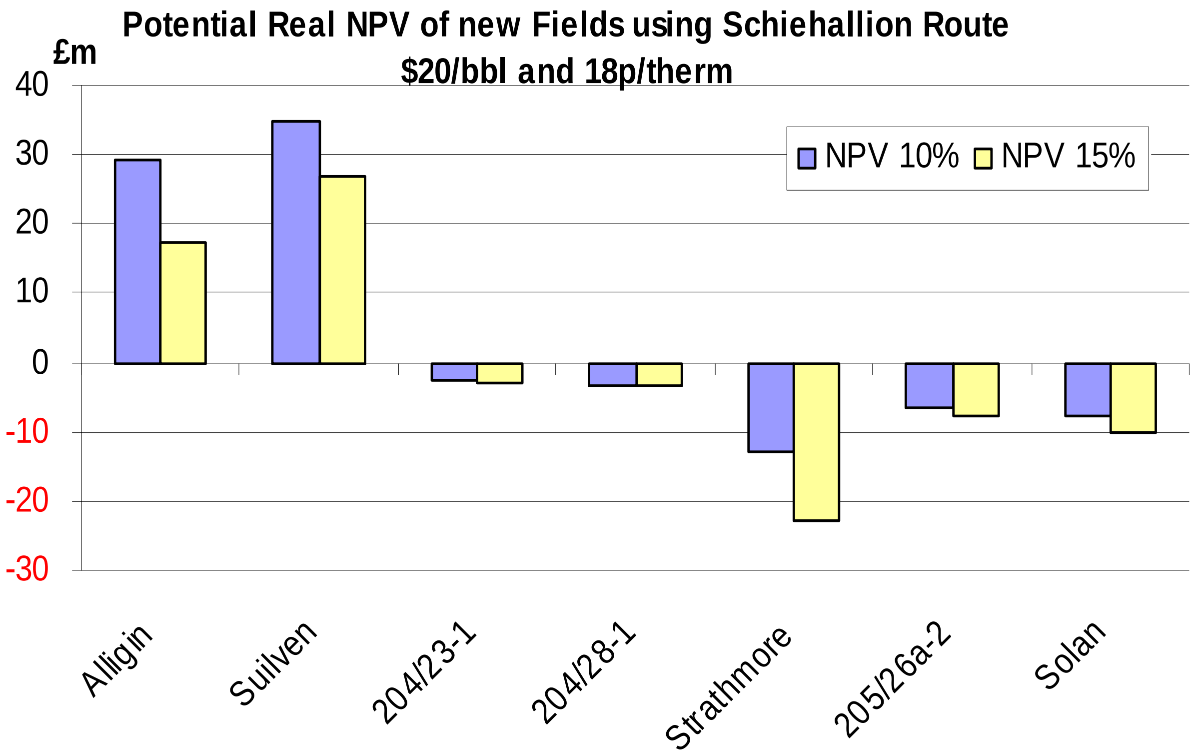
1	£m NPV 10%	NPV 15%	Tariff to Schiehallion	Tariff to Strathmore	Tanker Loading Tariff
Alligin 1	**70.35**	51.14	20p/mcf		£1/bbl
Suilven 1	**97.52**	81.29	20p/mcf		£1/bbl
204/23-1 1	**0.30**	-0.45	20p/mcf		
Strathmore 1	**69.19**	43.35			£1/bbl
204/28-1 1	-1.36	-1.82		50p/bbl	£1/bbl
205/26a-2 1	**8.53**	5.70		50p/bbl	£1/bbl
Solan 1	**28.32**	20.66		50p/bbl	£1/bbl

Chart 2



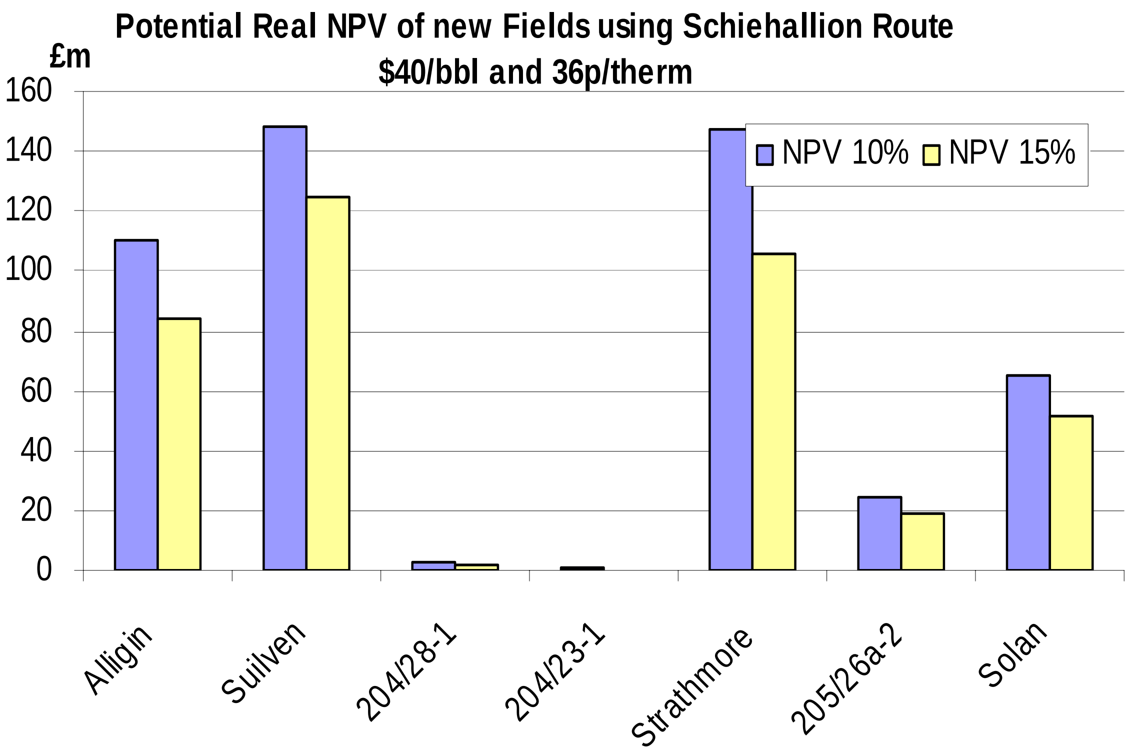
Under the $30, 28p scenario all but one of the projects exhibit positive NPVs, but at the low price level, $20/bbl and 18p/therm, 204/23-1, Strathmore, 204/28-1, 205/26a-2 and Solan all fail the 10% hurdle.

Chart 3



At the high price level, $40/bbl and 36p/therm, all fields pass the 10% hurdle rate.

Chart 4



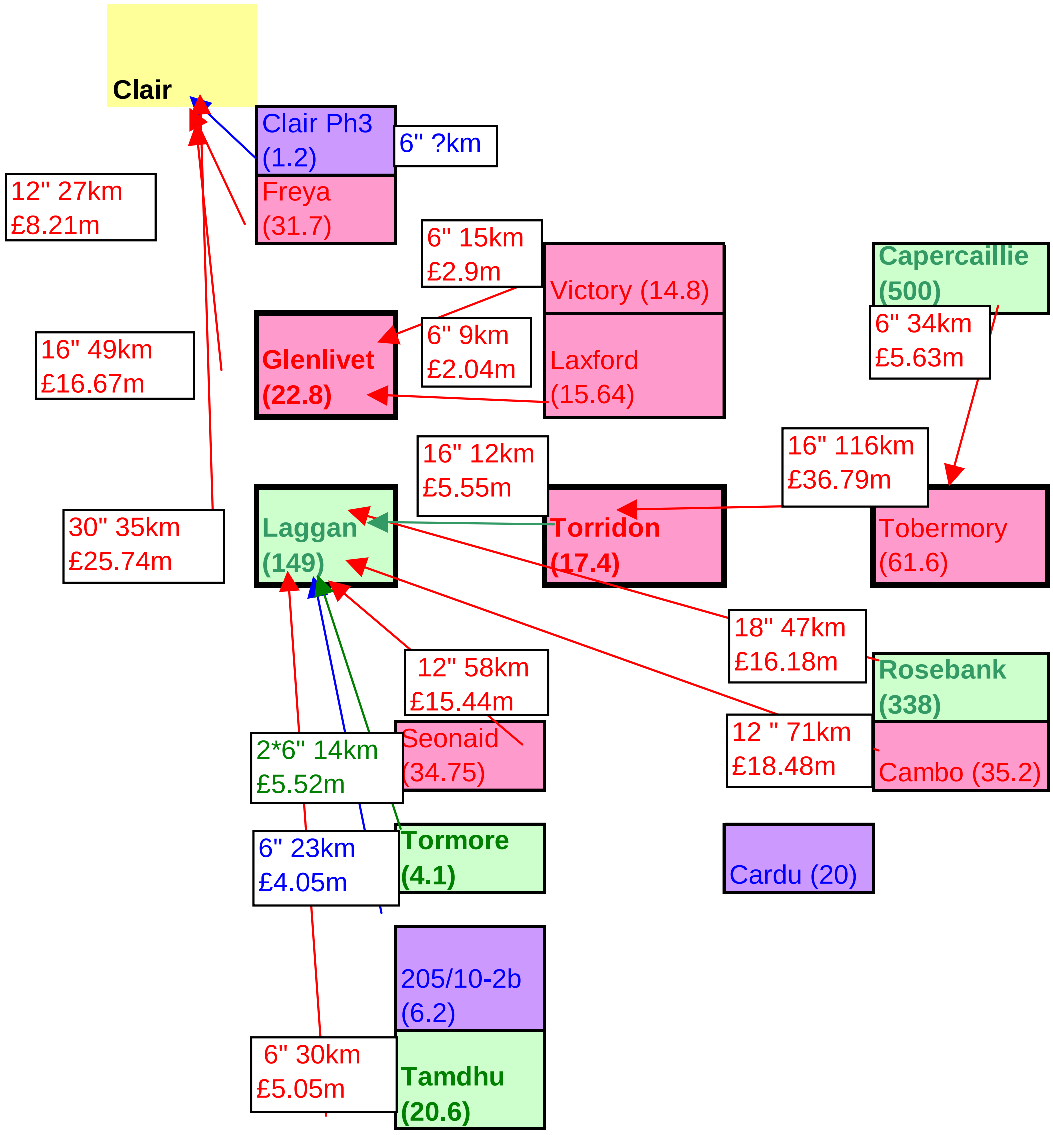
With respect to the other fields in this scenario (Option 1) Victory and Laxford are tied back to Glenlivet. Tamdhu, being oil, is developed independently. Tobermory is linked by pipeline to Torridon (116km). Torridon is linked by pipeline to Laggan (12km away) with a 16” pipeline to accommodate Torridon and Tobermory gas as well. Rosebank is linked by pipeline to Laggan (47km away). Tormore is 14km from Laggan and 205/10-2b is 23km from Laggan. These fields are tied back to Laggan. Seonaid is linked by pipeline to Laggan (58km away) with a 12” gas pipeline to take peak gas of 76mmcf/d. Laggan is 35km from Clair. Rosebank may require a pipeline costing £25.74m.

The possible development costs for the fields and prospects under this development scenario are given below. A TLP is assumed for Laggan.

	Reserves mboe	% Gas	First Devex (Fast-Track)	Assumed Development Costs $/boe	Capex £m	Drilling £m
Clair Ph3	1	0.00%	2006	9.46	1.58	4.73
Victory	15	100.00%	2008	8.27	19.72	48.29
Freya	32	100.00%	2007	7.05	49.94	74.22
Laxford	16	100.00%	2008	8.27	20.84	51.03
Torridon	17	100.00%	2008	9.6	38	54.68
Seonaid	35	100.00%	2007	6.83	60.25	71.62
Tobermory	62	100.00%	2008	5.9	137.34	64.57
Glenlivet	23	100.00%	2008	7.47	34.22	60.4
205/10-2b	6	0.00%	2008	9.46	8.13	24.4
Rosebank	338	26.00%	2007	6.5	585.87	634.69
Cambo	35	100.00%	2008	6.84	61.22	72.54
Laggan	149	84.00%	2006	5.29	342.29	96.52
Tormore PROSPECT	4	40.00%	2008	9.46	5.38	16.13
Tamdhu PROSPECT	21	40.00%	2008	9.84	52.08	60.72
Capercaillie PROSPECT	500	5.00%	2007	6.5	1029.17	776.39
Cardu PROSPECT	20	0.00%	2008	8.27	34.01	57.9

The field linkages, pipeline distances, assumed pipeline diameters and assumed pipeline costs are shown below. In total the Clair links would require 517km of gas pipelines and 37km of oil pipelines.

Chart 5



In the modelling Laggan, Tormore, Tamdhu, 205/10-2b, Cardu and Capercaillie pay a tanker loading charge of £1/bbl and Tormore and 205/10-2b pay an oil processing tariff of £0.5/bbl to Laggan. The tariffing arrangements for the other fields are shown below.

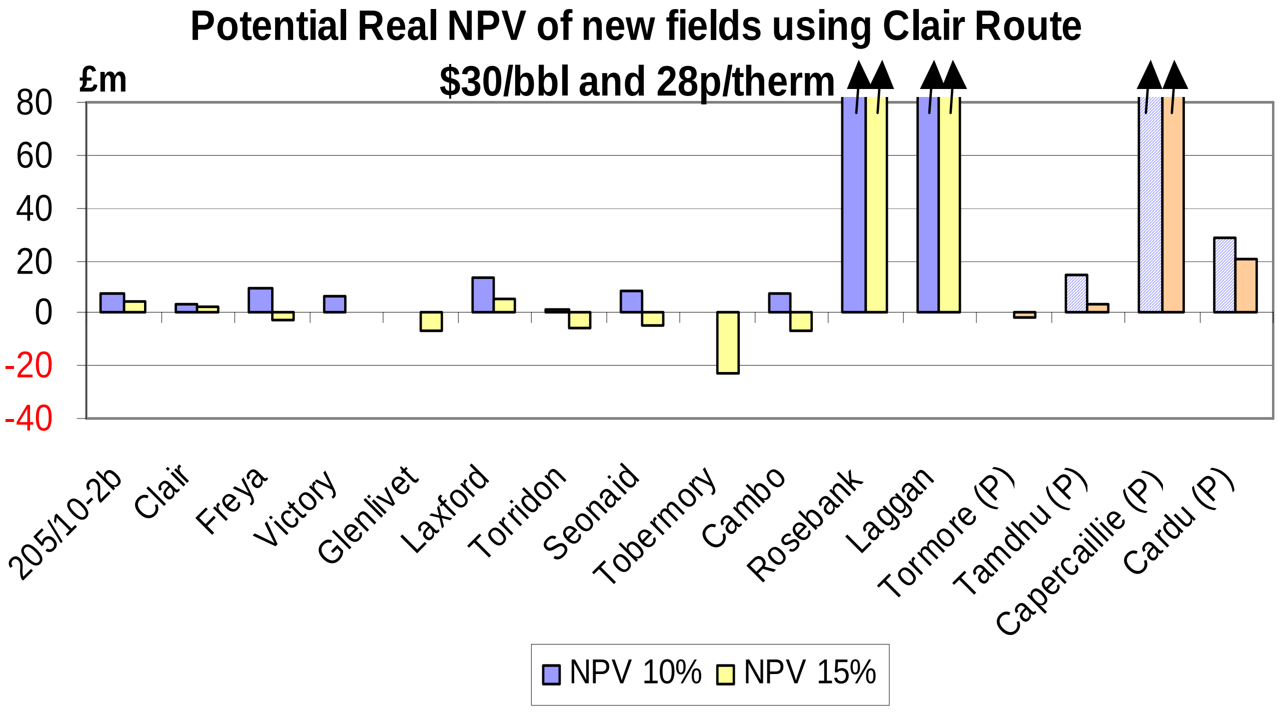
To get the gas to the mainland market it is initially assumed that the gas can proceed from Magnus to FLAGS and then to St. Fergus. The owners of communal pipelines are assumed to require tariffs from user fields which are high enough to produce a return on the incremental pipeline cost of at least 10% in real, post-tax terms. In this Scenario it is also assumed that Magnus receives a tariff of 5p/mcf and FLAGS receives a tariff of 10p/mcf. A tariff of 20p/mcf to the Clair Area gives a 10% return on the incremental platform and pipeline costs provided that these incremental costs amount to no more than £242m. For the Laggan sub-hub field a tariff of 2.4p/mcf gives a 10% return on the incremental costs. A tariff of 9p/mcf would give Glenlivet a 10% return on the incremental pipeline cost but, to act as a sub-hub field whilst paying higher tariffs, it requires a tariff of 12p/mcf to pass the 10% hurdle rate. A tariff of 1.5p/mcf is enough to give Torridon a 10% return on the incremental pipeline costs, but to pass the 10% hurdle rate with the higher tariff levels payable it requires a tariff of 18p/mcf.

Tariff assumptions for Scenario 1 Clair Route
$30/bbl and 28p/therm

	£m NPV 10%	NPV 15%	Tariff to Clair	Tariff to Glenlivet	Tariff to Torridon	Tariff to Tobermory	Tariff to Laggan	Tariff to Magnus	Tariff to FLAGS	Tanker Loading Tariff
205/10-2b	**7.21**	4.46					50p/bbl			£1/bbl
Clair Ph3	**3.09**	2.34								
Freya	**9.11**	-3.12	20p/mcf					5p/mcf	10p/mcf	
Victory	**5.99**	-0.10	20p/mcf	12p/mcf				5p/mcf	10p/mcf	
Glenlivet	**0.30**	-6.50	20p/mcf					5p/mcf	10p/mcf	
Laxford	**13.28**	5.22	20p/mcf	12p/mcf				5p/mcf	10p/mcf	
Torridon	**0.91**	-5.84	20p/mcf				3p/mcf	5p/mcf	10p/mcf	
Seonaid	**8.30**	-5.09	20p/mcf				3p/mcf	5p/mcf	10p/mcf	
Laggan	**266.26**	152.60	20p/mcf					5p/mcf	10p/mcf	£1/bbl
Tobermory	**0.01**	-22.67	20p/mcf		18p/mcf		3p/mcf	5p/mcf	10p/mcf	
Cambo	**6.96**	-6.66	20p/mcf				3p/mcf	5p/mcf	10p/mcf	
Rosebank	**636.02**	383.66	20p/mcf				3p/mcf	5p/mcf	10p/mcf	£1/bbl
Tormore Prospect	**0.48**	-1.24	20p/mcf				3p/mcf 50p/bbl	5p/mcf	10p/mcf	£1/bbl
Tamdhu Prospect	**14.45**	3.52	20p/mcf				3p/mcf	5p/mcf	10p/mcf	£1/bbl
Capercaillie Prospect	**719.05**	349.98	20p/mcf		18p/mcf	15p/mcf	3p/mcf	5p/mcf	10p/mcf	£1/bbl
Cardu Prospect	**28.18**	20.23								£1/bbl

The resulting NPVs under the $30, 28p scenario are shown in Chart 6. All projects have positive NPVs at 10% but several fail at 15%.

Chart 6



Under the $40, 36p case all projects have positive NPVs at 15% (Chart 7).

Chart 7

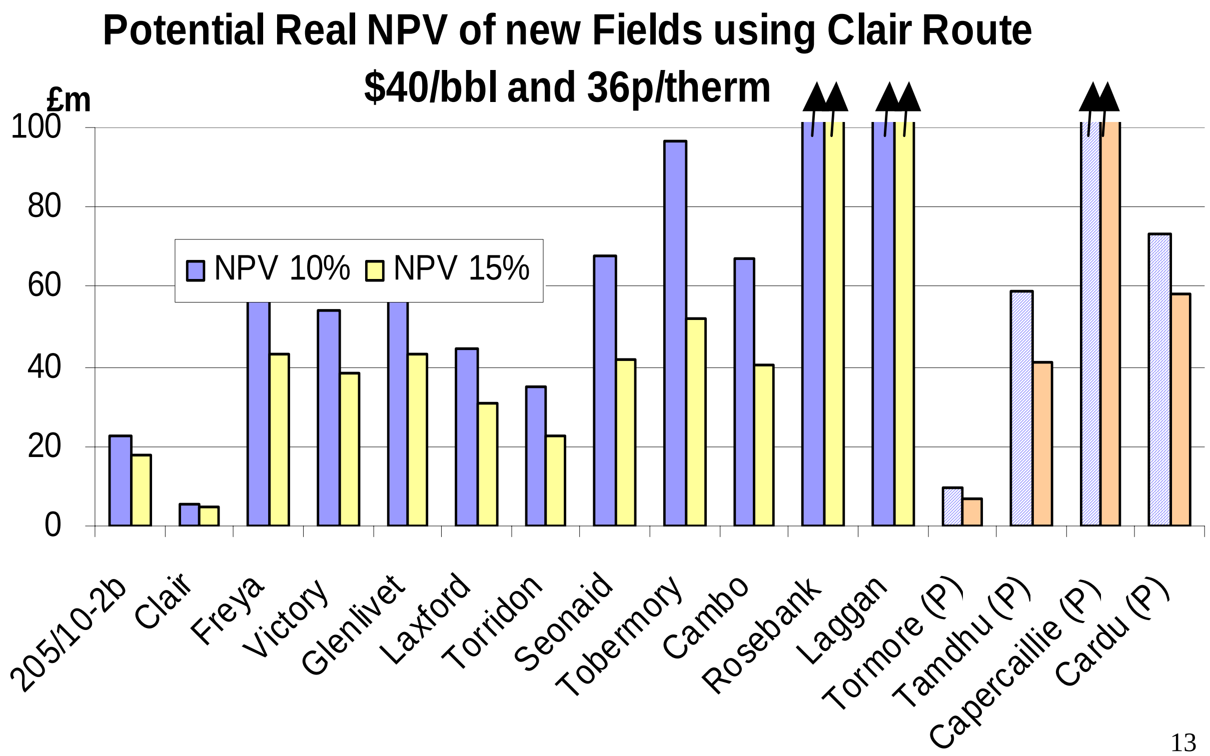


Chart 8

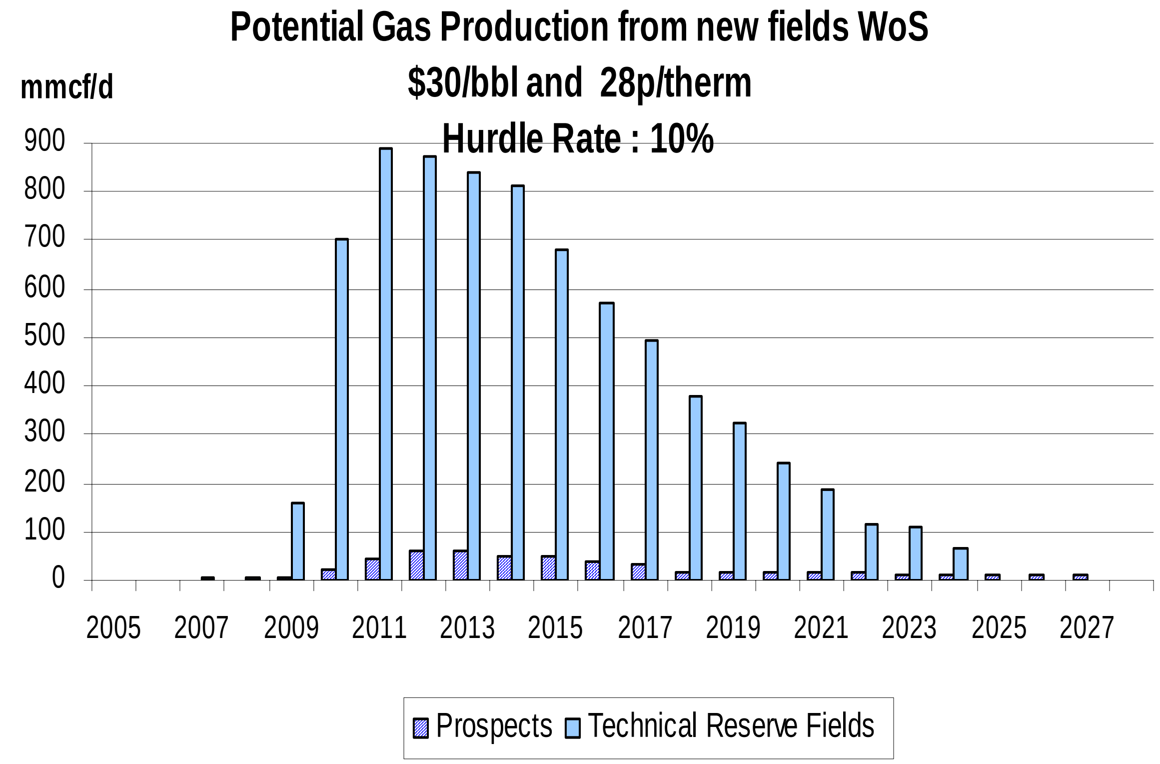


Chart 9

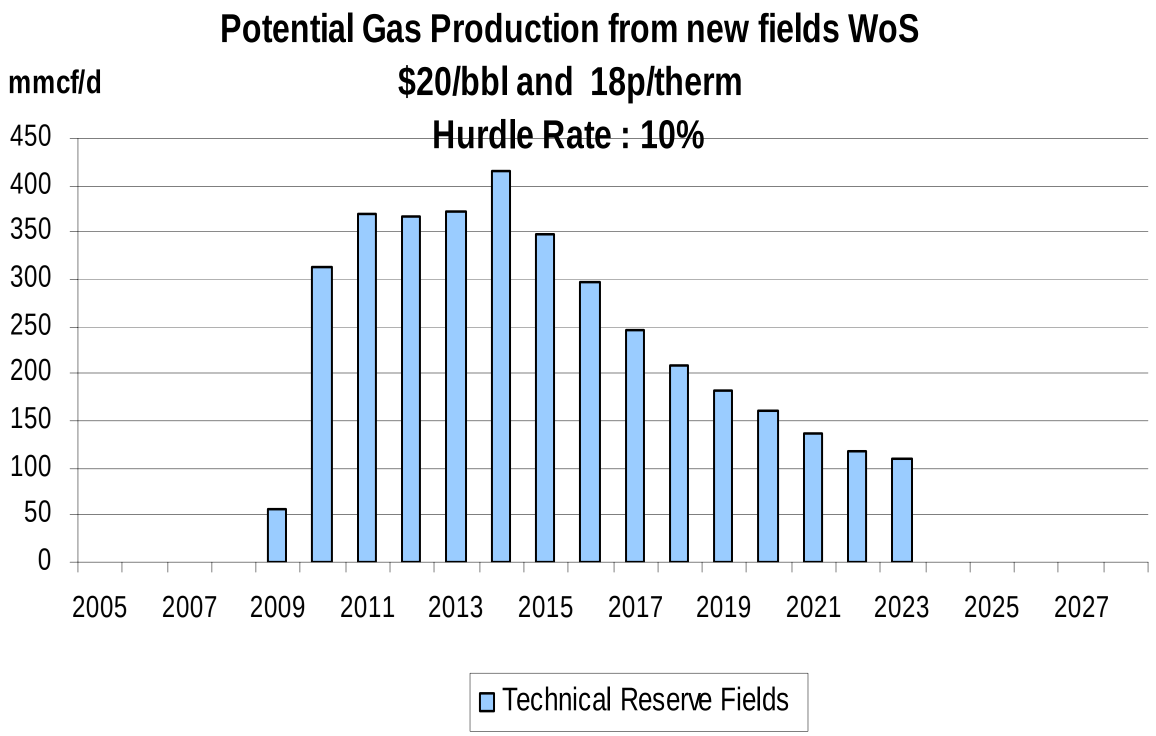
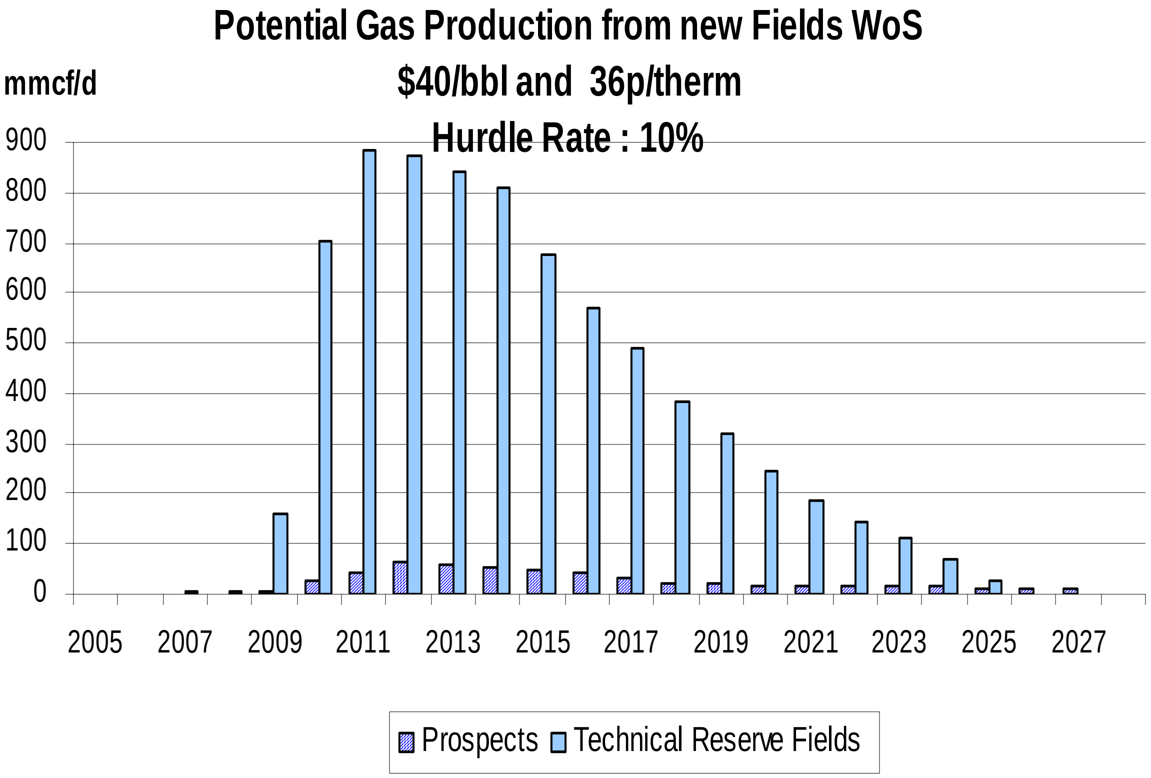
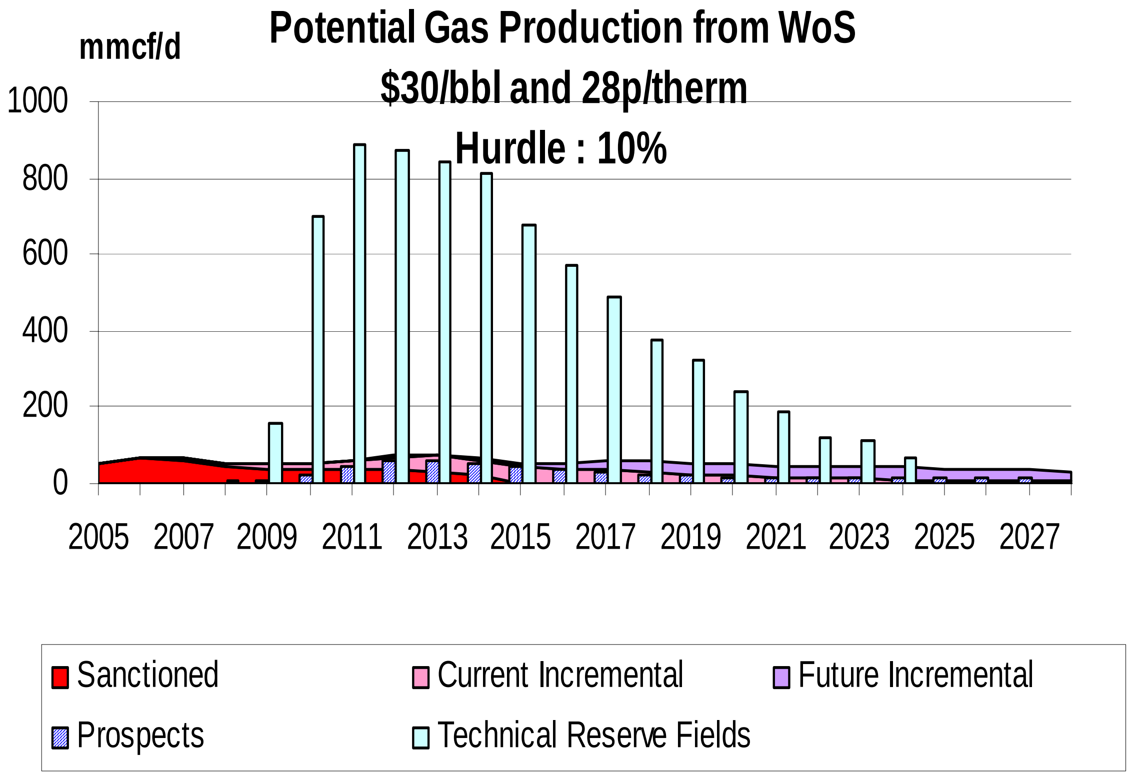


Chart 10



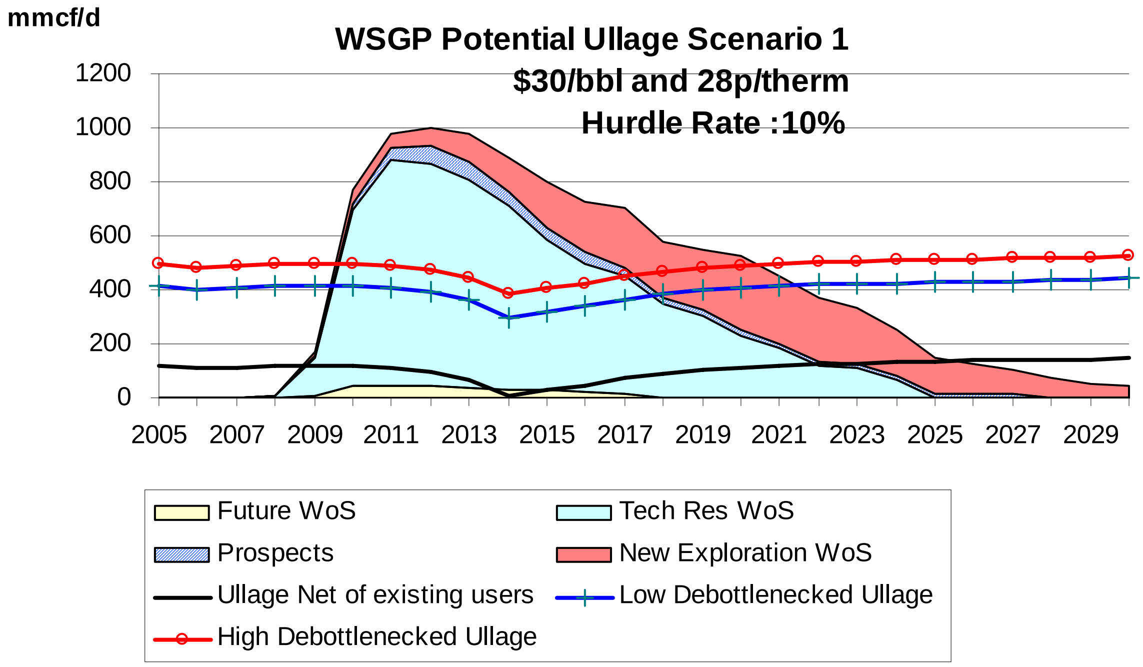
The potential gas production from new fields under the different prices in shown in Charts 8, 9 and 10. Production from new fields is large compared with that from already sanctioned ones and potential incremental production relating to the latter. This is seen from Chart 11.

Chart 11



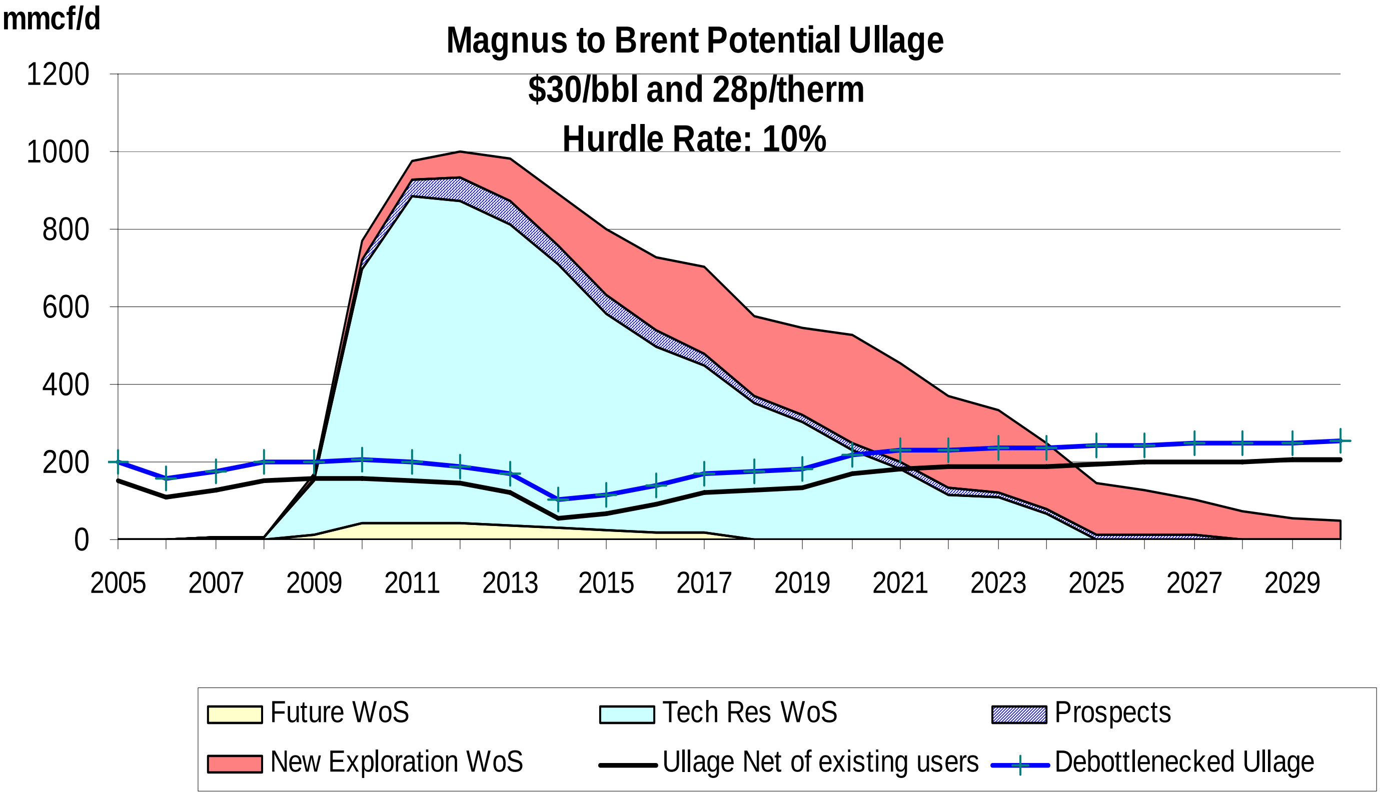
There are considerable ullage problems for WOS gas. The problems arise with the WSGP, the Magnus to Brent link, and the FLAGS pipeline itself. The ullages likely to be available in the different systems are shown in Charts 12, 13, and 14.

Chart 12



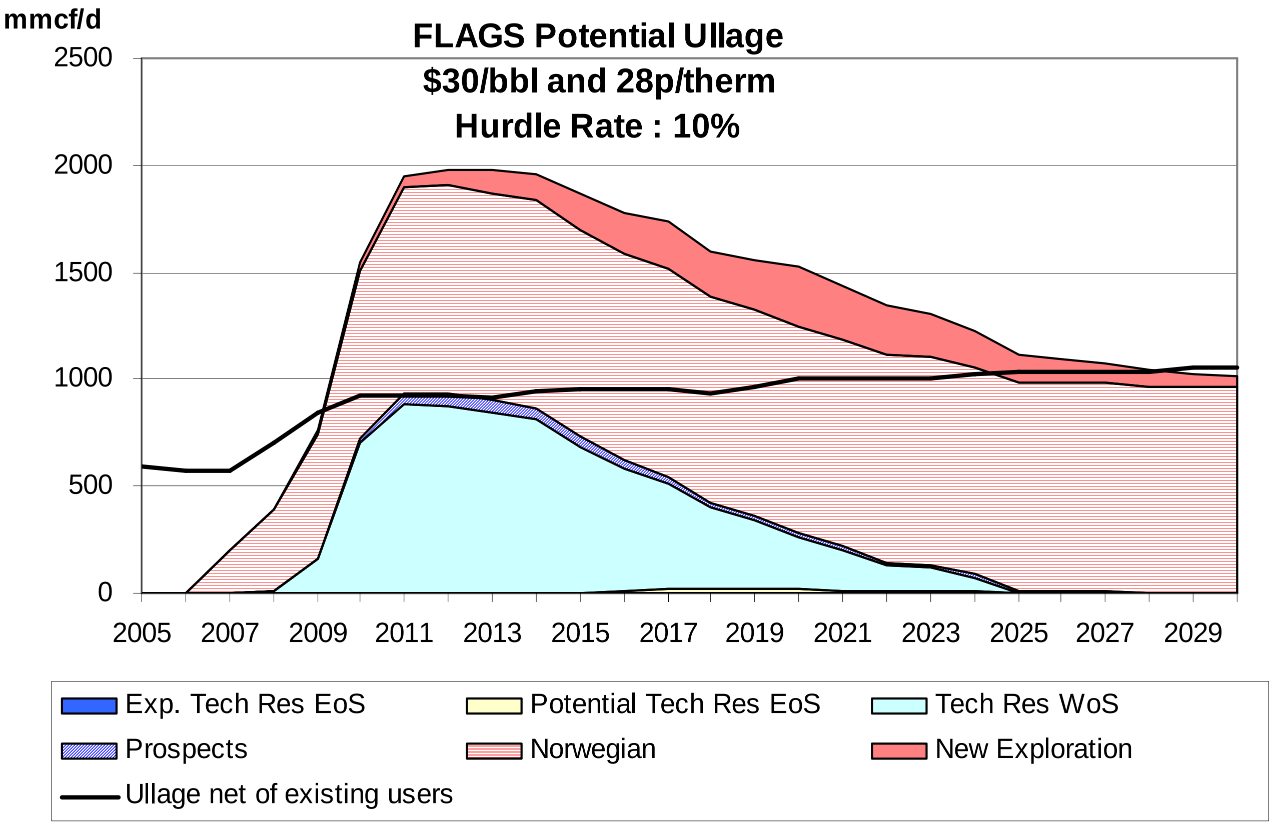
For the WSGP system it is seen (Chart 12) that the ullage, net of existing users from fields already sanctioned or under development, is small. This pipeline could have its capacity increased by de-bottlenecking schemes. However, even if the project for a high level of de-bottlenecking goes ahead the pipeline will still lack the capacity to take all the gas from the technical reserves fields in the WOS area. This is seen from Chart 12.

Chart 13



The lack of capacity problem is even more apparent when the potential ullage in the Magnus to Brent link is considered. This is shown in Chart 13.

Chart 14



The prospective position with respect to ullage in the FLAGS system is shown in Chart 14. Much depends on what volumes of Norwegian gas are transported through this system. Information on what quantity of Norway gas is likely to be transported in the FLAGS pipeline shown in Chart 14 comes from a variety of sources in the public domain. There is a serious danger that Norwegian gas could utilise the ullage before gas from WOS becomes available.

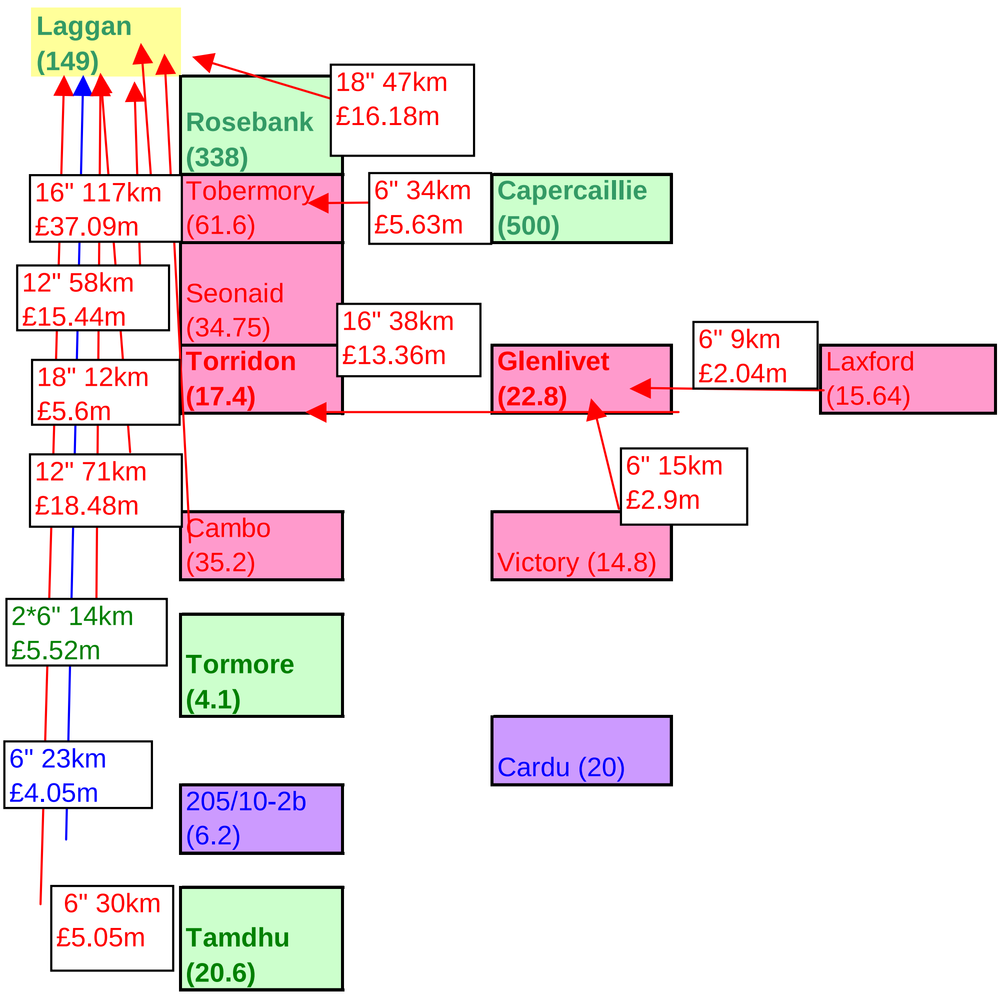
The general conclusion is that, because of the prospective ullage problem a comprehensive development of gas from the WOS area in the medium-term based on use of existing infrastructure is rendered very problematic.

4. Option 2 – Laggan as Hub

a) Scenario 2A – Laggan Direct to St. Fergus, Lower Tariff Case

This scenario uses Schiehallion, Clair, and Laggan as hub fields. The fields linking with Schiehallion would be the same as under Option 1 and the fields with oil only would again be developed independently as a cluster. Freya and Clair Ph 3 would be tied back Clair. Freya to Clair would require a 27km 12" gas pipeline (£8.21m) and the development costs would be as in Scenario 1.

Chart 15



The fields linked to Laggan are shown in Chart 15. In Scenario 2A it is assumed that Laggan is linked directly by pipeline to St Fergus. This communal 30” 385km pipeline would cost £262m (real 2005). Other fields would pay tariff to Laggan and the sub-hub fields.

Rosebank, Tobermory, Seonaid, and Torridon may all be directly linked by pipeline to Laggan as would Cambo and Tamdhu. Tormore and 205/10-2b may be tied back to Laggan. Rosebank is 47km from Laggan. Capercaillie is linked to Tobermory by pipeline. Tobermory is 117km from Laggan and a 16” pipe would be more than adequate to take Tobermory and Capercaillie gas. Seonaid is 58km from Laggan and a 12” gas pipeline is required. Laxford could be linked to Glenlivet by a 6” 9km pipeline. Victory would be linked to Glenlivet by a 15km 6” gas line and Glenlivet could be linked to Torridon by a 16” 38km gas pipeline. Torridon would then require an 18” 12km gas pipeline to Laggan. Cambo could be linked by a 71km pipeline to Laggan. In total this scenario would require 445km of gas pipelines and 47km of oil pipeline.

Possible development costs for Laggan are different from Scenario 1 but those of the other fields remain the same. However, the inter-field pipeline costs do differ. The Laggan development would again be a TLP but, as the hub field, there would be extra costs. The totals are shown below. They exclude the cost of the communal pipeline to St. Fergus.

	Reserves mboe	Development Cost $/boe	Capex £m	Drill £m
Laggan	149.28	6.82	469.1	96.52

If Laggan becomes a hub field and the owners also develop the communal pipeline to St. Fergus there would be a considerable increase in pipeline costs. On a stand-alone basis an 18" pipeline could cost £118.37m, but a 30" pipeline could cost £261.92m. To achieve a return of 10% on the extra pipeline costs Laggan would need to charge a tariff of around 17.715p/mcf. With this scenario Torridon would become one of the sub-hub fields. Torridon itself requires a 6" pipeline to Laggan which would cost £2.47m. Torridon as a sub-hub would require an 18" pipeline costing £5.6m. To achieve a return of 10% on the extra pipeline cost Torridon would have to charge a tariff of about 2p/mcf, but at this tariff it would fail as a sub-hub, and Glenlivet, Victory and Laxford gas could be stranded. For Torridon to pass the minimum hurdle rate and operate work as a sub-hub field it would have to charge a tariff of at least 12p/mcf.

Glenlivet would also become a sub-hub field. Glenlivet needs a 6" pipeline to Torridon for its own use (costing £6.2m), but as a sub-hub it requires a 16" pipeline costing £13.36m. To achieve a return of 10% on the extra pipeline cost Glenlivet would have to charge a tariff of 7.1p/mcf. If the tariff to Laggan was 17.715p/mcf, and the tariff to Torridon were 12p/mcf, the Glenlivet field only just passes the hurdle rate at 10%. Tobermory also acts as a sub-hub in this scenario and requires a 16" pipeline.

Tariff assumptions for Scenario 2A Laggan Route
$30/bbl and 28p/therm

2A	£m NPV 10%	NPV 15%	Tariff to Laggan	Tariff to Torridon	Tariff to Glenlivet	Tariff to Tobermory	Tanker Loading Tariff
205/10-2b	7.21	4.46	50p/bbl				£1/bbl
Clair Ph3	3.09	2.34					
Freya	9.11	-3.12					
Victory	8.43	1.94	17.715p/mcf	12p/mcf	10p/mcf		
Glenlivet	3.63	-3.46	17.715p/mcf	12p/mcf			
Laxford	15.88	7.38	17.715p/mcf	12p/mcf	10p/mcf		
Torridon	0.78	-5.17	17.715p/mcf				
Seonaid	22.00	5.68	17.715p/mcf				
Laggan SF	186.92	57.94					£1/bbl
Tobermory	40.04	8.23	17.715p/mcf				
Cambo	20.82	4.24	17.715p/mcf				
Rosebank	665.21	405.20	17.715p/mcf				£1/bbl
Tormore Prospect	1.23	-0.61	17.715p/mcf 50p/bbl				£1/bbl
Tamdhu Prospect	18.20	6.64	17.715p/mcf				£1/bbl
Capercaillie Prospect	734.91	360.98	17.715p/mcf			5p/mcf	£1/bbl
Cardu Prospect	28.18	20.23					£1/bbl

Chart 16

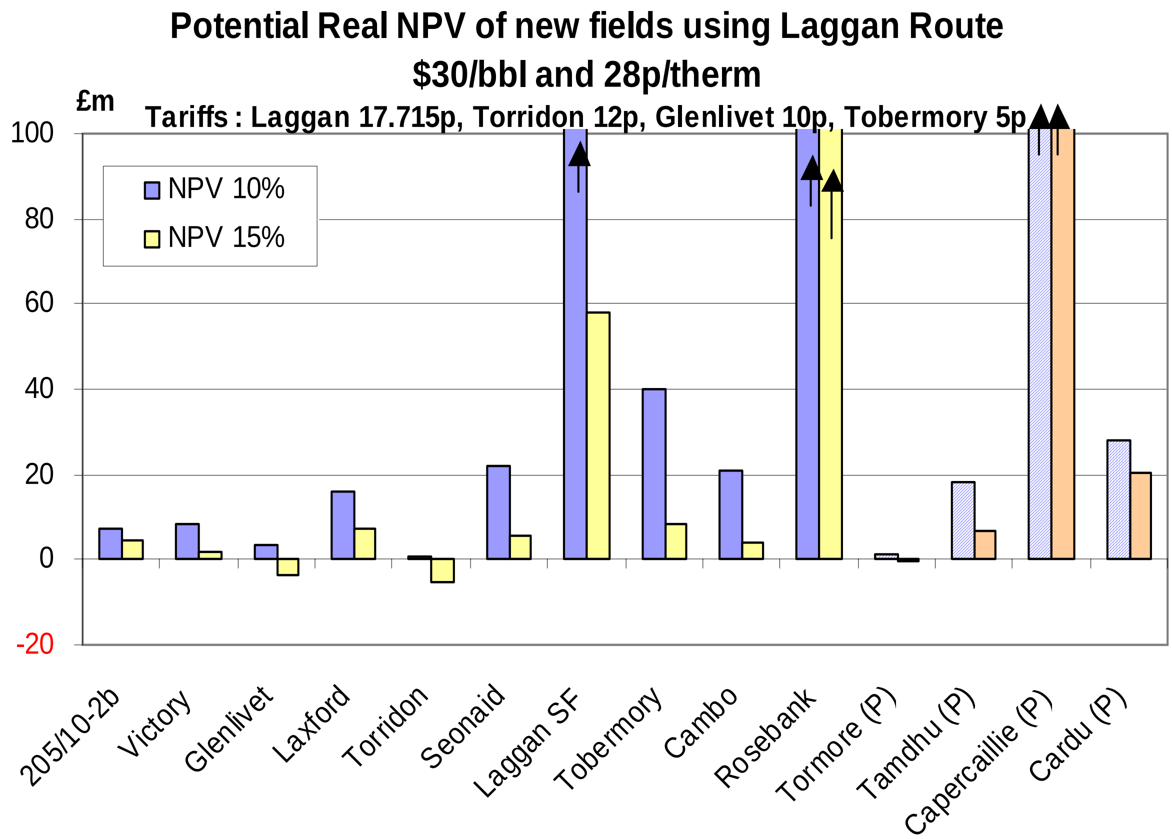
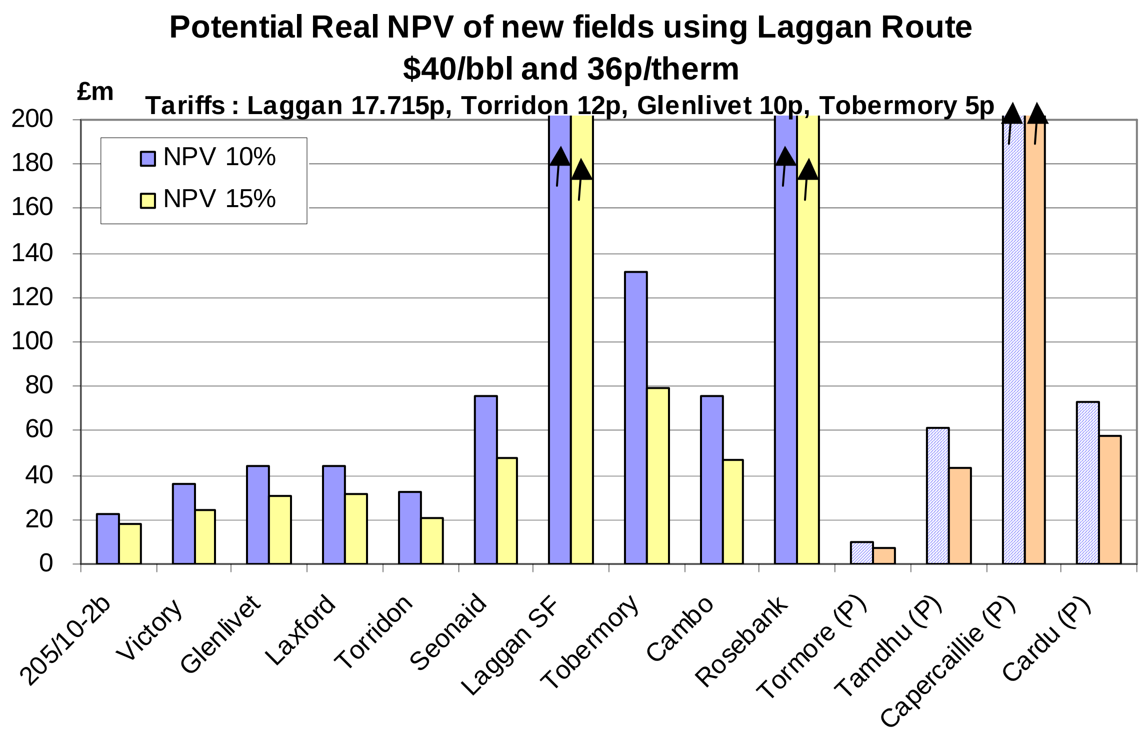


Chart 17



The results of the modelling of Scenario 2A (Charts 16 and 17) indicate that all fields have the 10% hurdle under the $30, 28p case but the NPVs are often quite small. Several fields fail the 15% hurdle. Under the $40, 36p case all NPVs are positive, but the values are often modest.

b) Scenario 2B – Laggan Direct to St. Fergus, Higher Tariff

Although Laggan and the sub-hub fields do receive a 10% return on their incremental pipeline costs, given the risks of this Scenario a higher rate of return may be required. A case was thus examined where the tariff to Laggan was increased to 20p/mcf. The results are shown in Charts 18 and 19.

Tariff assumptions for Scenario 2B Laggan Route
$30/bbl and 28p/therm

2B	£m NPV 10%	NPV 15%	Tariff to Laggan	Tariff to Torridon	Tariff to Glenlivet	Tariff to Tobermory	Tanker Loading Tariff
205/10-2b	7.21	4.46	50p/bbl				£1/bbl
Clair Ph3	3.09	2.34					
Freya	9.11	-3.12					
Victory	4.99	-0.94	20p/mcf	15p/mcf	15p/mcf		
Glenlivet	4.35	-2.85	20p/mcf	15p/mcf			
Laxford	12.21	4.33	20p/mcf	15p/mcf	15p/mcf		
Torridon	3.65	-2.73	20p/mcf				
Seonaid	20.45	4.46	20p/mcf				
Laggan SF	198.99	66.71					£1/bbl
Tobermory	39.07	7.45	20p/mcf				
Cambo	19.26	3.02	20p/mcf				
Rosebank	661.92	402.77	20p/mcf				£1/bbl
Tormore Prospect	1.15	-0.68	20p/mcf 50p/bbl				£1/bbl
Tamdhu Prospect	17.77	6.29	20p/mcf				£1/bbl
Capercaillie Prospect	732.52	359.32	20p/mcf			10p/mcf	£1/bbl
Cardu Prospect	28.18	20.23					£1/bbl

Chart 18

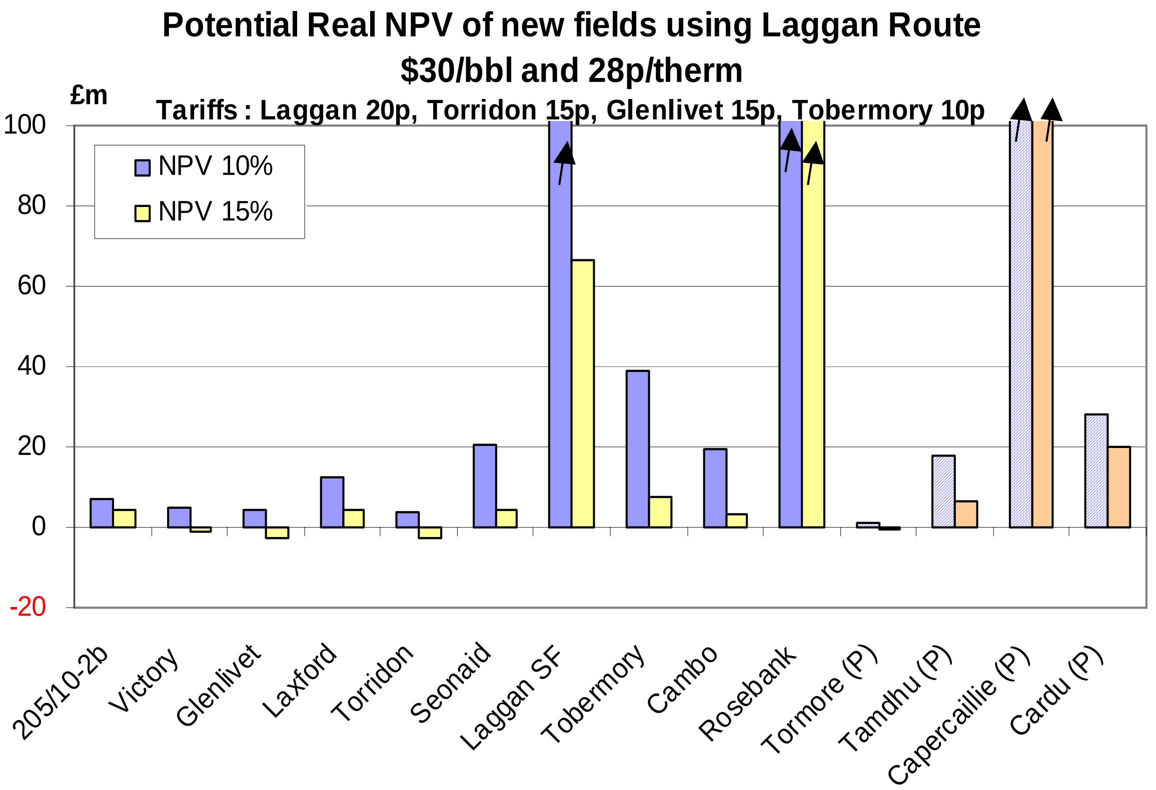
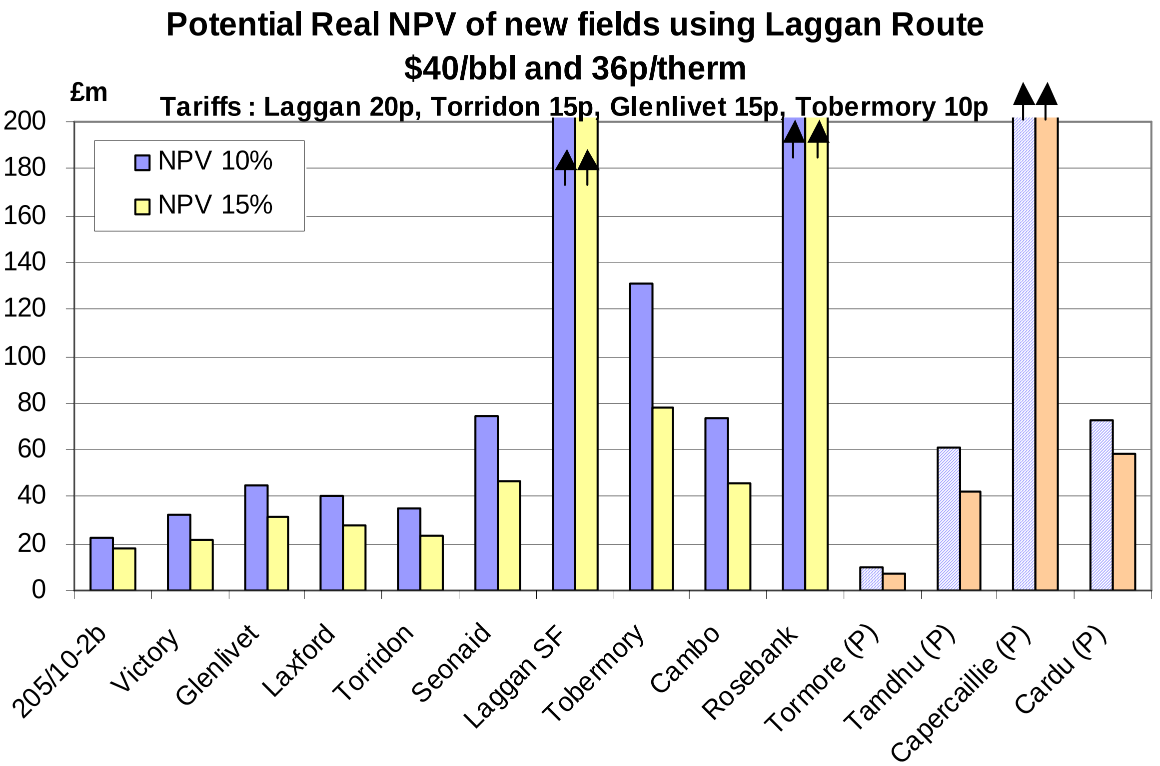


Chart 19



It is seen that at the $30, 28p price scenario the NPVs at 10% are all positive but several are very small. The proposed tax changes will, of course, render them even smaller. Under the $40, 36p case NPVs are significantly improved. All but one have NPVs at 15% of at least £20 million.

Laggan need not be linked directly to St Fergus, it may connect to Alwyn North, to the Frigg MCPO1, to SAGE, or to a FLAGS tee. Estimated pipeline costs are as follows (£m 2005).

Laggan to	St Fergus	MCPO1	Alwyn North	FLAGS	Sage	Magnus
24"	207.42	151.41	135.94	122.61	172.75	127.94
30"	261.92	191.01	171.5	154.63	218.06	161.38

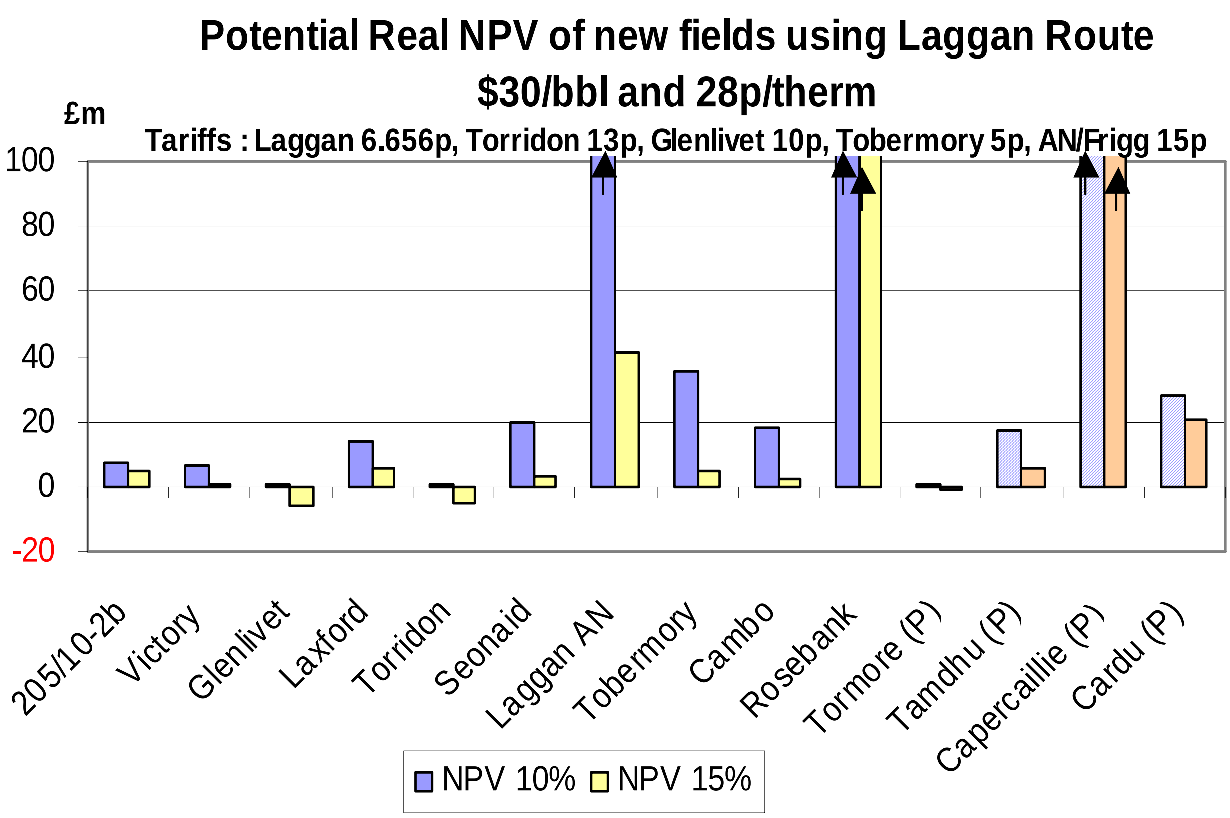
c) Scenario 2C – Laggan to Alwyn North then Frigg UK to St. Fergus

Under this Scenario the communal pipeline from Laggan goes to North Alwyn and then to St. Fergus via Frigg UK. To receive a 10% return on the incremental pipeline costs to Alwyn North, Laggan needs to charge a tariff of 6.645p/mcf. Scenario 2C is a low tariff one where all hub fields receive a return of at least 10% on their incremental costs, including the Laggan owners of the pipeline to North Alwyn, and Alwyn North/Frigg share a tariff of 15p/mcf.

Tariff assumptions for Scenario 2C Laggan Route
$30/bbl and 28p/therm

2C	£m NPV 10%	NPV 15%	Tariff to Laggan	Tariff to Torridon	Tariff to Glenlivet	Tariff to Tobermory	Alwyn North /Frigg	Tanker Loading Tariff
205/10-2b	7.21	4.46	50p/bbl					£1/bbl
Clair Ph3	3.09	2.34						
Freya	9.11	-3.12						
Victory	6.78	0.56	6.656p/mcf	13p/mcf	10p/mcf		15p/mcf	
Glenlivet	0.90	-5.76	6.656p/mcf	13p/mcf			15p/mcf	
Laxford	14.12	5.91	6.656p/mcf	13p/mcf	10p/mcf		15p/mcf	
Torridon	0.45	-5.44	6.656p/mcf				15p/mcf	
Seonaid	19.34	3.59	6.656p/mcf				15p/mcf	
Laggan TLP AN	150.12	41.00					15p/mcf	£1/bbl
Tobermory	35.56	4.78	6.656p/mcf				15p/mcf	
Cambo	18.13	2.13	6.656p/mcf				15p/mcf	
Rosebank	659.54	401.01	6.656p/mcf				15p/mcf	£1/bbl
Tormore Prospect	1.09	-0.73	6.656p/mcf 50p/bbl				15p/mcf	£1/bbl
Tamdhu Prospect	17.47	6.04	6.656p/mcf				15p/mcf	£1/bbl
Capercaillie Prospect	733.62	360.09	6.656p/mcf			5p/mcf	15p/mcf	£1/bbl
Cardu Prospect	28.18	20.23						£1/bbl

Chart 20



It is seen that the NPVs at 10% are all positive under the $30, 28p case, but they are often very small and will become smaller still if the tax proposals are enacted.

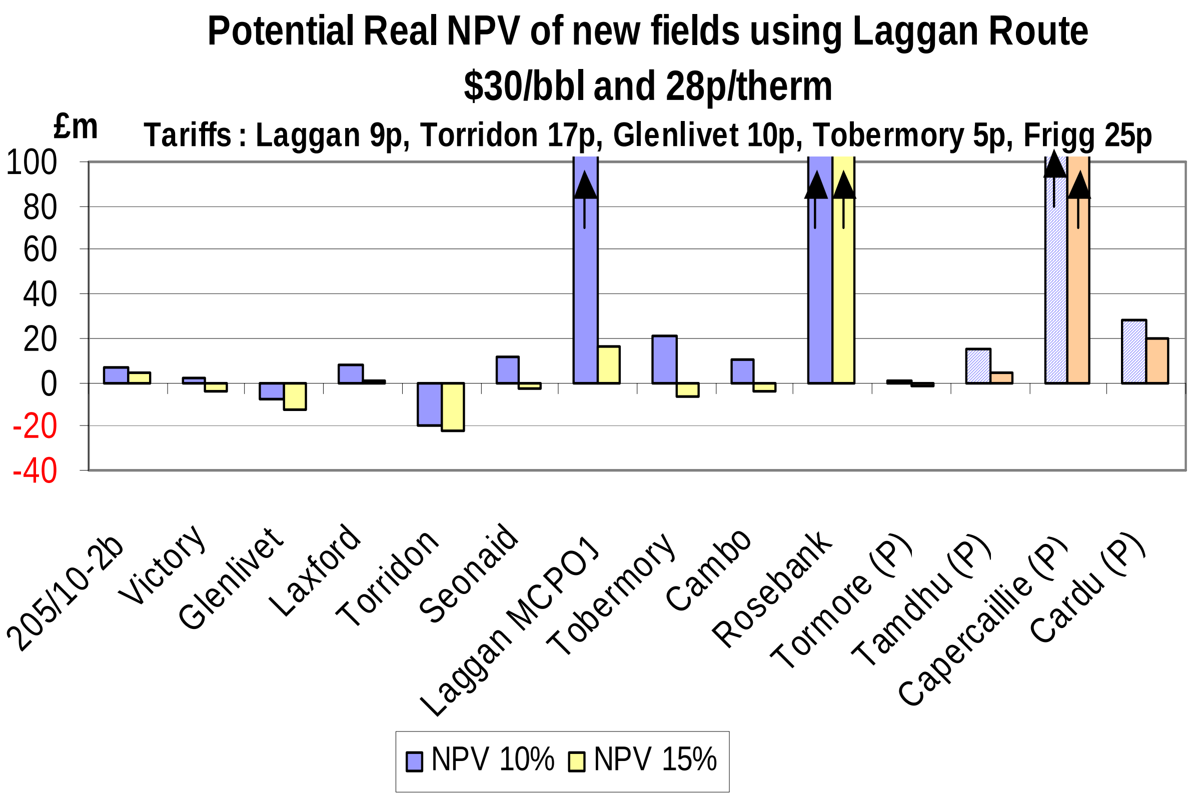
d) Scenario 2D – Laggan to MCPO1 and then to St. Fergus

Under this Scenario the communal pipeline from Laggan goes to MCPO1 and the gas then goes to St. Fergus. In this case a tariff of 9p/mcf gives a 10% real return on the incremental pipeline costs and a larger tariff of 25p/mcf is paid to the Frigg owners. Under the $30, 28p price scenario even if the tariff to Torridon in increased to 17p/mcf when it must itself pay the higher tariff levels, it fails the 10% hurdle rate. Glenlivet also fails the 10% hurdle rate when the tariffs it must pay are increased. As Glenlivet fails the hurdle rate, Victory and Laxford gas are stranded. Without the Glenlivet, Victory, and Laxford tariffs, and after paying higher tariffs, Torridon also fails the hurdle rate. Laggan would then receive no tariffs from Torridon, Glenlivet or the stranded fields, and, while the 9p/mcf tariff should have given Laggan a 10% return on the incremental pipeline costs the 10% is not achieved when this cluster of fields fails to pay tariffs. This Scenario is thus not viable.

Tariff assumptions for Scenario 2D Laggan Route
$30/bbl and 28p/therm

2D	NPV 10%	NPV 15%	Tariff to Laggan	Tariff to Torridon	Tariff to Glenlivet	Tariff to Tobermory	Tariff to Frigg	Tanker Loading Tariff
205/10-2b	7.21	4.46	50p/bbl					£1/bbl
Clair Ph3	3.09	2.34						
Freya	9.11	-3.12						
Victory	1.31	-4.02	9p/mcf	17p/mcf	10p/mcf		25p/mcf	
Glenlivet	-7.11	-12.49	9p/mcf	17p/mcf			25p/mcf	
Laxford	8.27	1.07	9p/mcf	17p/mcf	10p/mcf		25p/mcf	
Torridon	-19.10	-21.94	9p/mcf				25p/mcf	
Seonaid	11.00	-2.96	9p/mcf				25p/mcf	
Laggan TLP MCPO1	120.16	16.72					25p/mcf	£1/bbl
Tobermory	21.55	-6.03	9p/mcf				25p/mcf	
Cambo	9.69	-4.51	9p/mcf				25p/mcf	
Rosebank	641.77	387.91	9p/mcf				25p/mcf	£1/bbl
Tormore Prospect	0.63	-1.11	9p/mcf 50p/bbl				25p/mcf	£1/bbl
Tamdhu Prospect	15.19	4.13	9p/mcf				25p/mcf	£1/bbl
Capercaillie Prospect	729.57	357.27	9p/mcf			5p/mcf	25p/mcf	£1/bbl
Cardu Prospect	28.18	20.23						£1/bbl

Chart 21



e) Scenario 2E – Laggan to SAGE and gas on to St. Fergus

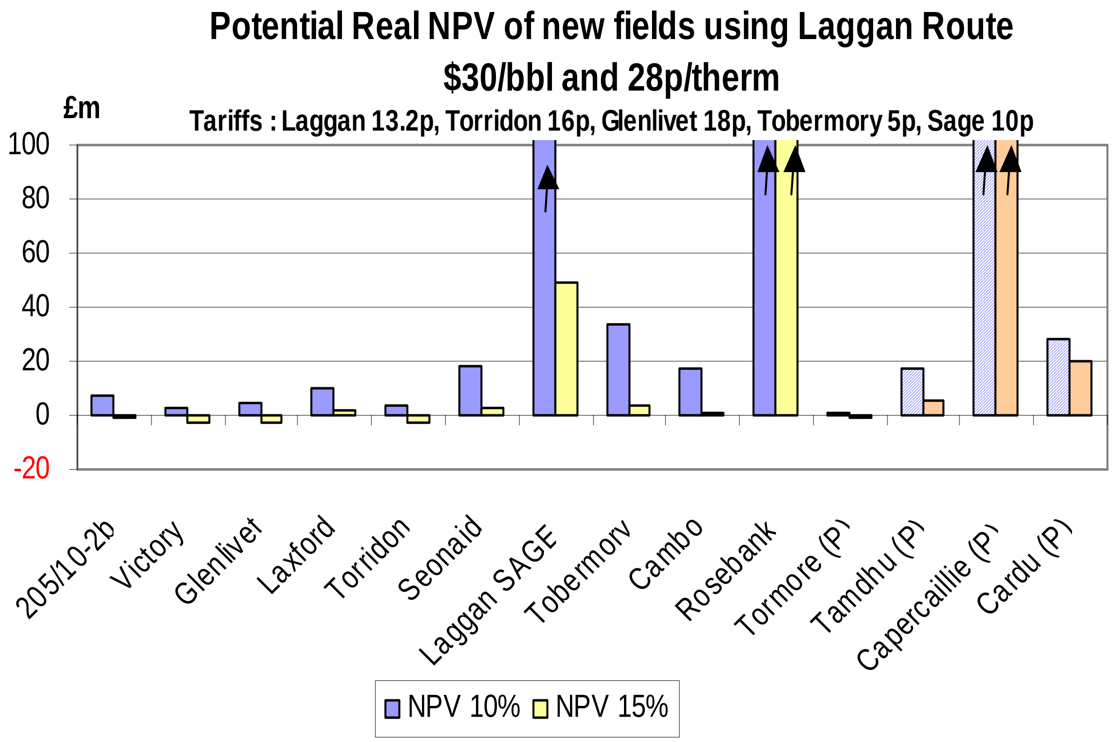
Another possibility is that Laggan may link to the SAGE pipeline. Because of the long distance and thus high cost of the pipeline Laggan would require a tariff of 13.2p/mcf to receive a 10% return on the incremental pipeline costs. In this case a relatively low tariff of 10p/mcf is paid to the SAGE licensees.

Tariff assumptions for Scenario 2E Laggan Route
$30/bbl and 28p/therm

2E	NPV 10%	NPV 15%	Tariff to Laggan	Tariff to Torridon	Tariff to Glenlivet	Tariff to Tobermory	SAGE	Tanker Loading Tariff
205/10-2b	7.21	4.46	50p/bbl					£1/bbl
Clair Ph3	3.09	2.34						
Freya	9.11	-3.12						
Victory	**2.58**	-2.95	13.2p/mcf	16p/mcf	18p/mcf		10p/mcf	
Glenlivet	**4.26**	-2.92	13.2p/mcf	16p/mcf			10p/mcf	
Laxford	**9.63**	**2.19**	13.2p/mcf	16p/mcf	18p/mcf		10p/mcf	
Torridon	**3.60**	-2.77	13.2p/mcf				10p/mcf	
Seonaid	**18.29**	2.77	13.2p/mcf				10p/mcf	
Laggan TLP SAGE	168.31	49.17					10p/mcf	£1/bbl
Tobermory	**33.81**	3.43	13.2p/mcf				10p/mcf	
Cambo	**17.07**	1.30	13.2p/mcf				10p/mcf	
Rosebank	**657.32**	399.37	13.2p/mcf				10p/mcf	£1/bbl
Tormore Prospect	**1.03**	-0.78	13.2p/mcf 50p/bbl				10p/mcf	£1/bbl
Tamdhu Prospect	**17.18**	5.80	13.2p/mcf				10p/mcf	£1/bbl
Capercaillie Prospect	**733.11**	359.73	13.2p/mcf			5p/mcf	10p/mcf	£1/bbl
Cardu Prospect	28.18	20.23						£1/bbl

In this Scenario it is seen that the fields have positive but generally very small NPVs at 10% under the $30/28p price case. The tax proposals reduce the returns further.

Chart 22



f) Scenario 2F – Laggan to FLAGS (tie-in) then to St. Fergus

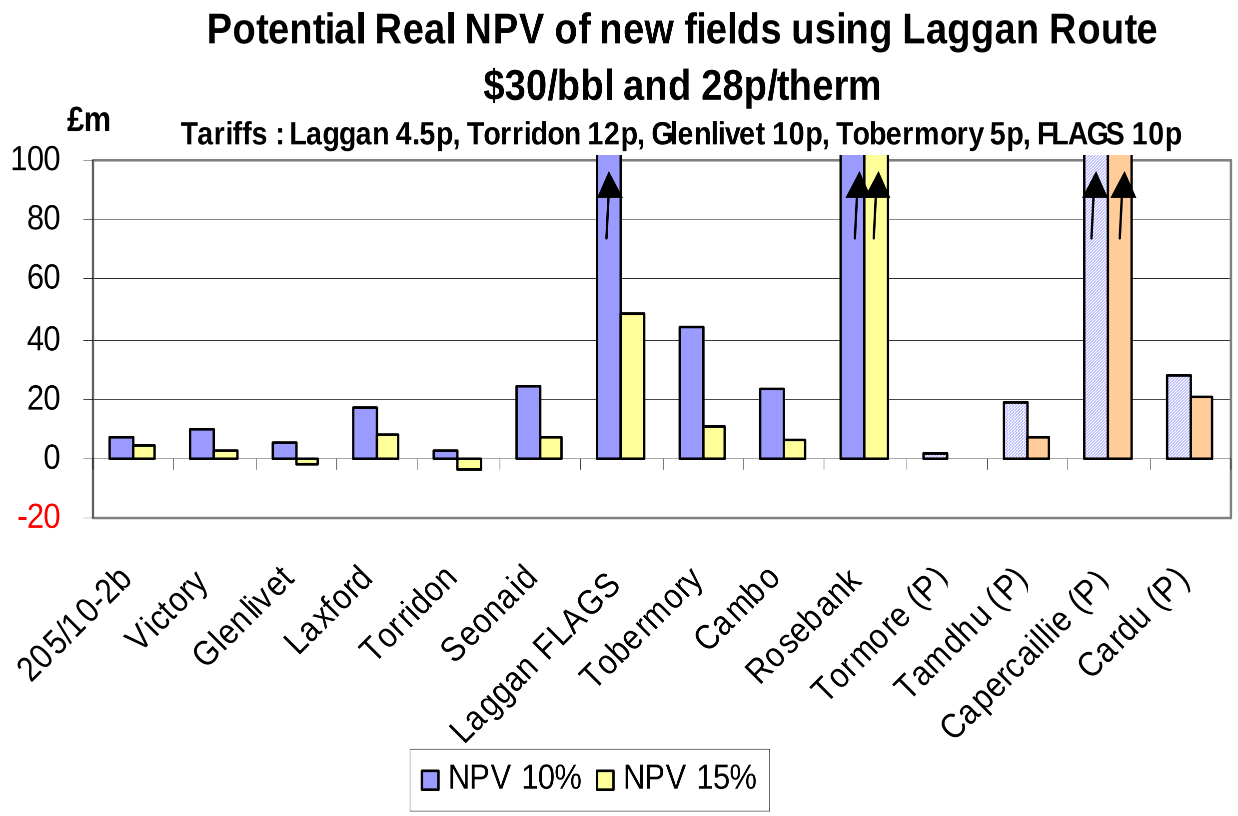
A further possibility is that the pipeline from Laggan may tie-in directly to the FLAGS pipeline. In this case then a tariff of 4.5p/mcf gives a 10% return on the incremental pipeline costs of the Laggan licensees.

Tariff assumptions for Scenario 2F Laggan Route
$30/bbl and 28p/therm

2F	NPV 10%	NPV 15%	Tariff to Laggan	Tariff to Torridon	Tariff to Glenlivet	Tariff to Tobermory	Tariff to FLAGS	Tanker Loading Tariff
205/10-2b	7.21	4.46	50p/bbl					£1/bbl
Clair Ph3	3.09	2.34						
Freya	9.11	-3.12						
Victory	9.51	2.84	4.5p/mcf	12p/mcf	10p/mcf		10p/mcf	
Glenlivet	5.27	-2.09	4.5p/mcf	12p/mcf			10p/mcf	
Laxford	17.03	8.33	4.5p/mcf	12p/mcf	10p/mcf		10p/mcf	
Torridon	2.21	-3.94	4.5p/mcf				10p/mcf	
Seonaid	24.17	7.38	4.5p/mcf				10p/mcf	
Laggan TLP FLAGS	158.35	48.74					10p/mcf	£1/bbl
Tobermory	43.69	11.05	4.5p/mcf				10p/mcf	
Cambo	23.02	5.97	4.5p/mcf				10p/mcf	
Rosebank	669.84	408.61	4.5p/mcf				10p/mcf	£1/bbl
Tormore Prospect	1.35	-0.51	4.5p/mcf 50p/bbl				10p/mcf	£1/bbl
Tamdhu Prospect	18.79	7.14	4.5p/mcf				10p/mcf	£1/bbl
Capercaillie Prospect	735.97	361.72	4.5p/mcf			5p/mcf	10p/mcf	£1/bbl
Cardu Prospect	28.18	20.23						£1/bbl

In this Scenario it is seen that not only do all fields receive a return of at least 10% on the incremental pipeline costs but the NPVs at 10% of the fields themselves are positive, albeit often very small. The size of the tariffs are very small, however, the asset owners may feel that higher ones are necessary to reflect the costs and risks.

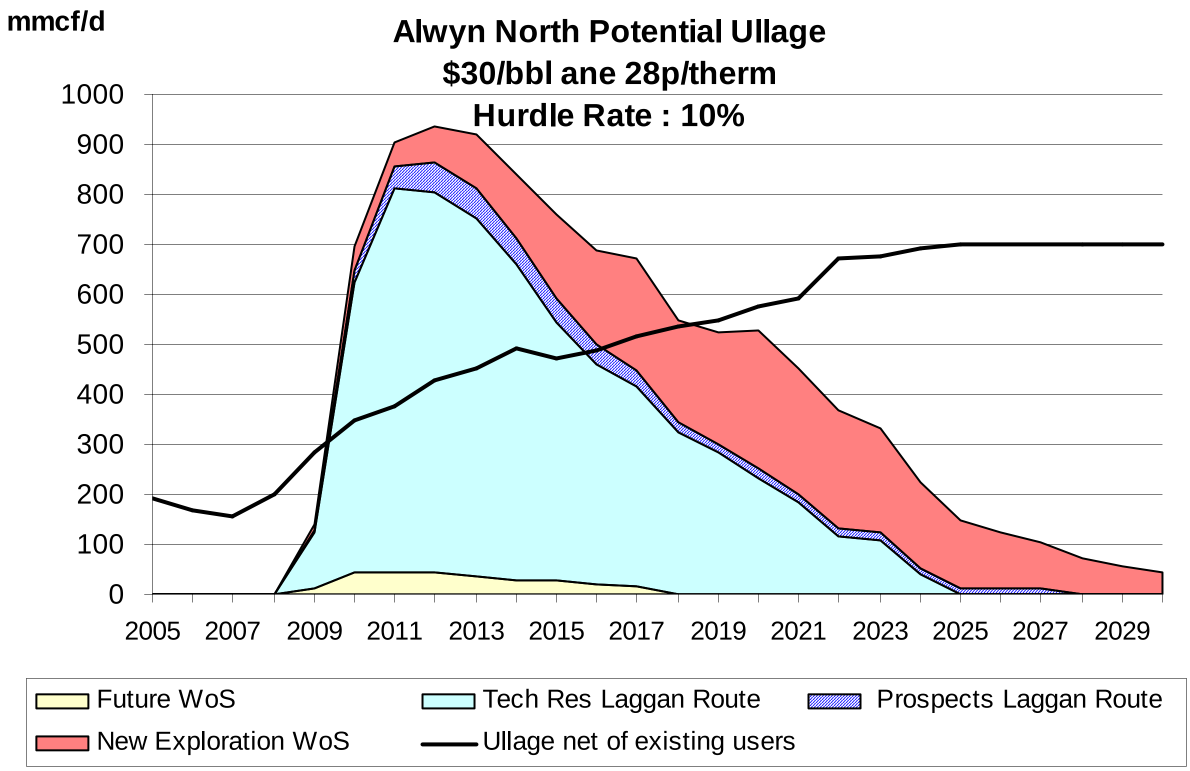
Chart 23



g) <u>The Ullage Problem at North Alwyn, Frigg UK, and SAGE</u>

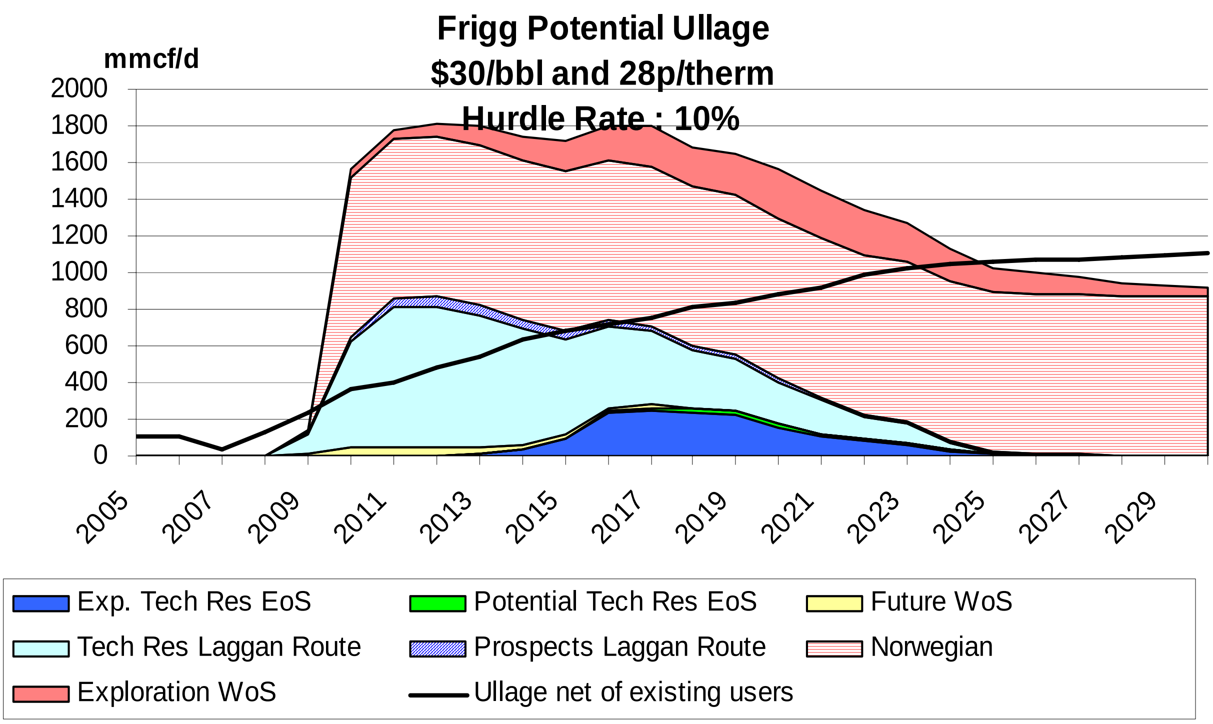
The ullage issue was investigated with respect to Scenarios 2D, 2E, and 2F. The potential ullage after taking account of the volumes from existing users was calculated. The likely volumes not only from WOS but also from EOS (and from Norway in the case of Frigg UK) were also estimated. The resulting available ullage is seen in Charts 24, 25 and 26.

Chart 24



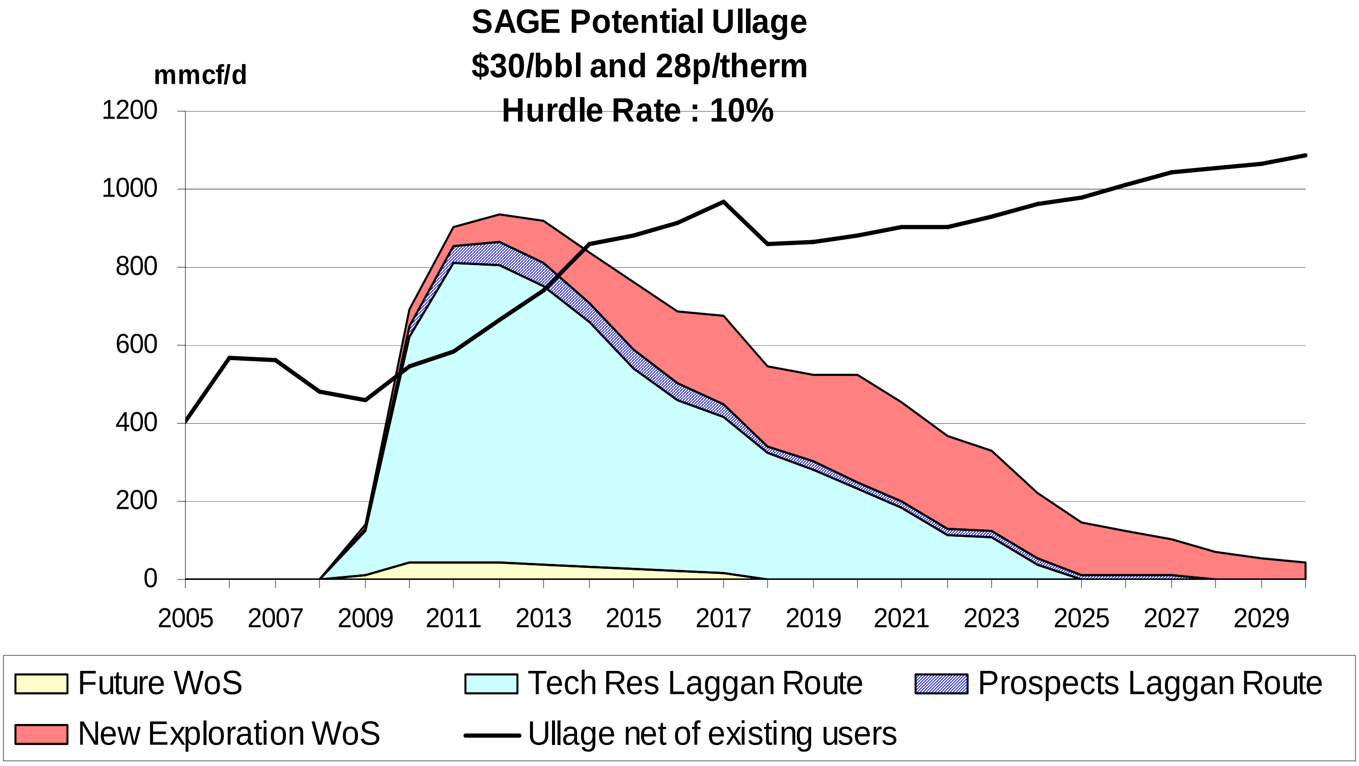
It is clear from Chart 24 that the Alwyn North pipeline link to Frigg does not have enough capacity to transport the WOS gas fields using the Laggan route.

Chart 25



From Chart 25 it is seen that even without the potential Norwegian imports, the Frigg pipeline does not have the capacity to accept all the WOS gas via the Laggan route until after 2010.

Chart 26



The SAGE pipeline has much more prospective available capacity and has enough to accept a considerable amount of WOS gas via the Laggan route. With delays in the implementation of the WOS projects there would be enough capacity available. The problem with this Scenario relates to the high pipeline cost.

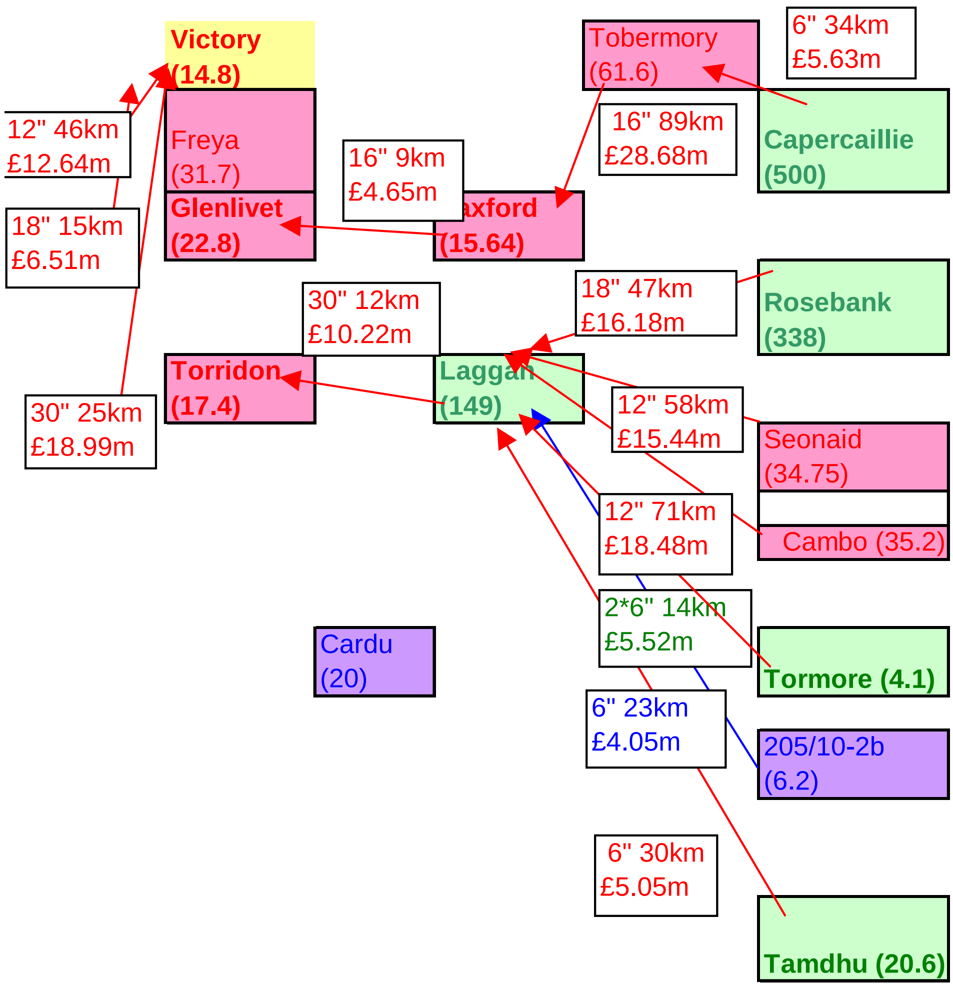
It was clearly shown above (Chart 14) that FLAGS could not take the WOS gas if there are imports from Norway on the scale indicated.

5. Option 3 – Victory as Hub

a) Scenario 3A – Victory as Hub with Modest Tariffs

This scenario would use Schiehallion, Clair, and Victory as hubs. The fields linking with Schiehallion would be the same us with the other scenarios. The linkages of the fields to Victory are shown in Chart 27.

Chart 27



Victory is in relatively shallow water. This represents the case for considering it as a hub. The interfield network of pipelines and sub-hubs would be different and there would need to be a dramatic increase in the Victory facilities before it could act as a hub. The development costs for Laggan would be reduced if Victory became the hub field. The cost estimates are as follows:

	Reserves mboe	Development Cost $/boe	Capex £m	Drill £m
Laggan	149.28	5.01	318.99	96.52
Victory	14	n/a	132.6	48.29

Freya, Glenlivet and Torridon could be linked directly by pipeline to Victory. Freya would require a 12", 46km pipeline.

Capercaillie would again link to Tobermory which could be linked to Laxford by an 89km pipeline. Laxford would require a 9km pipeline to link to Glenlivet. Glenlivet is 15km from Victory. Cambo could be linked to Laggan by a 12" 71 km pipeline. Laggan would require a 30" 12km pipeline to link to Torridon. Torridon is 25km from Victory. At least 450km of gas pipelines would be required.

The cost of a communal 30% pipeline to St. Fergus is estimated at £259.22m. To achieve a return of 10% on the extra pipeline costs Victory would need to charge a tariff of around 18.9p/mcf, but this does not take any account of the extra field development costs required. In fact Victory requires a tariff of 27.7p/mcf to achieve a 10% field return on the incremental costs and pass the 10% field development hurdle rate. This case is shown in Chart 28.

Under this scenario Glenlivet would become one of the sub-hub fields. Glenlivet needs a 6" pipeline to Victory for its own use costing, £2.9m but as a sub-hub field it requires an 18" pipeline costing £6.51m. To achieve a return of 10% on the extra pipeline cost Glenlivet would have to charge a tariff of at least 1.4p/mcf.

Laxford would also become a sub-hub field. Laxford needs a 6" pipeline to Glenlivet for its own use costing £2.04m, but as a sub-hub field it requires a 16" pipeline costing £4.65m. To achieve a return of 10% on the extra pipeline cost Laxford would have to charge a tariff of at least 1.3p/mcf. Tobermory also acts as a sub-hub in this scenario, requiring a 16" pipeline.

Torridon would also become one of the sub-hub fields. It requires a 6" pipeline to Victory which could cost £4.34m. Torridon as a sub-hub would require a 30" pipeline costing £18.99m. To achieve a return of 10% on the extra pipeline cost Torridon would have to charge a tariff of 2.07p/mcf, but at this tariff Torridon would fail economically, and Glenlivet, Victory and Laxford gas could be stranded. For Torridon to pass the hurdle rate and work as a sub-hub field it would have to charge a tariff of at least 6p/mcf.

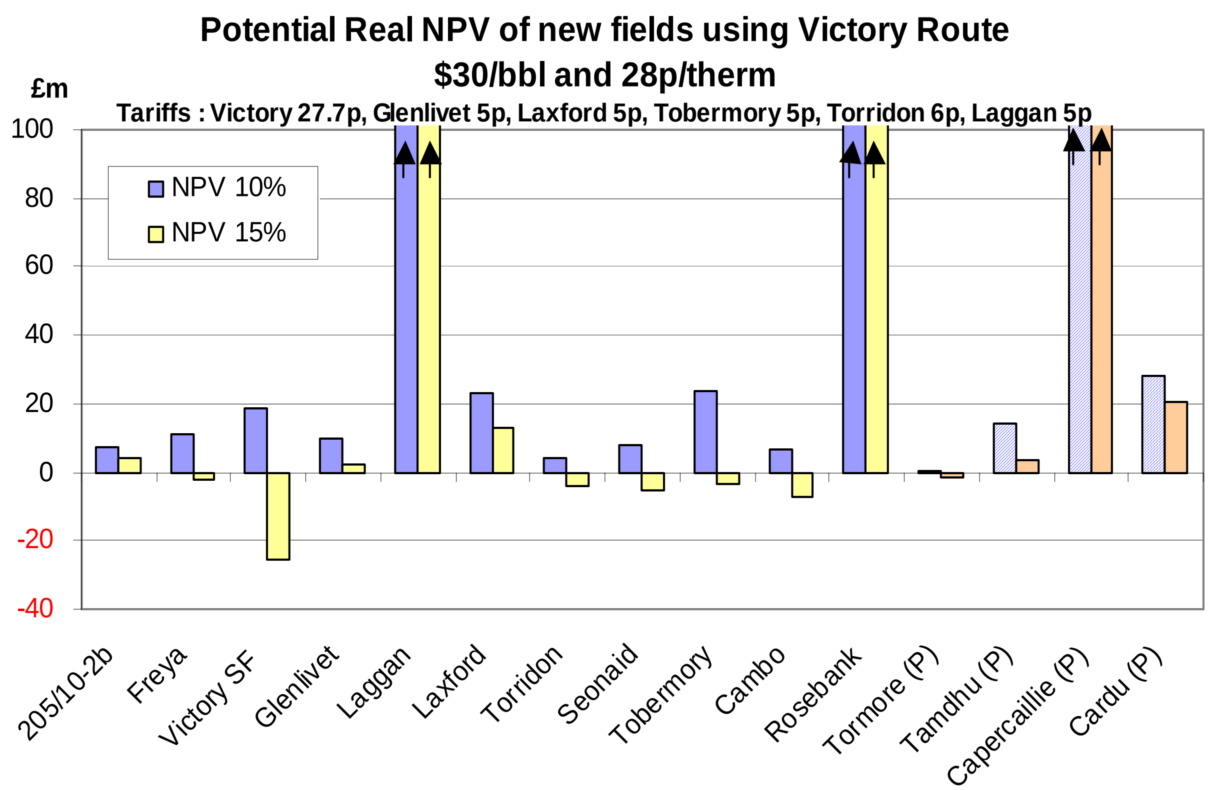
Laggan would also become a sub-hub field. As a sub-hub field it requires a 30" pipeline costing £10.22m. To achieve a return of 10% on the extra pipeline cost Laggan would have to charge a tariff of 1.3p/mcf.

It is seen from Chart 28 that under the $30, 28p price case and the indicated tariffs all fields have positive NPVs at 10%. But several, including Victory as hub, have negative NPVs at 15%.

Tariff assumptions for Scenario 3A Victory Route
$30/bbl and 28p/therm

3A	£m NPV 10%	NPV 15%	Tariff to Victory	Tariff to Glenlivet	Tariff to Laxford	Tariff to Tobermory	Tariff to Torridon	Tariff to Laggan	Tanker Loading Tariff
205/10-2b	7.21	4.46						50p/bbl	£1/bbl
Clair Ph3	3.09	2.34							
Freya	10.93	-2.18	27.7p/mcf						
Victory to St Fergus	18.89	-25.76							
Glenlivet	9.85	2.06	27.7p/mcf						
Laxford	23.25	12.96	27.7p/mcf	5p/mcf					
Torridon	3.98	-3.97	27.7p/mcf						
Seonaid	7.83	-5.46	27.7p/mcf				6p/mcf	5p/mcf	
Laggan	296.17	178.13	27.7p/mcf				6p/mcf		£1/bbl
Tobermory	23.66	-3.16	27.7p/mcf	5p/mcf	5p/mcf				
Cambo	6.48	-7.03	27.7p/mcf				6p/mcf	5p/mcf	
Rosebank	635.01	382.92	27.7p/mcf				6p/mcf	5p/mcf	£1/bbl
Tormore Prospect	0.46	-1.26	27.7p/mcf				6p/mcf	5p/mcf 50p/bbl	£1/bbl
Tamdhu Prospect	14.32	3.41	27.7p/mcf				6p/mcf	5p/mcf	£1/bbl
Capercaillie Prospect	728.35	356.43	27.7p/mcf	5p/mcf	5p/mcf	5p/mcf			£1/bbl
Cardu Prospect	28.18	20.23							£1/bbl

Chart 28



b) Scenario 3B – Victory as Hub with Higher Tariffs

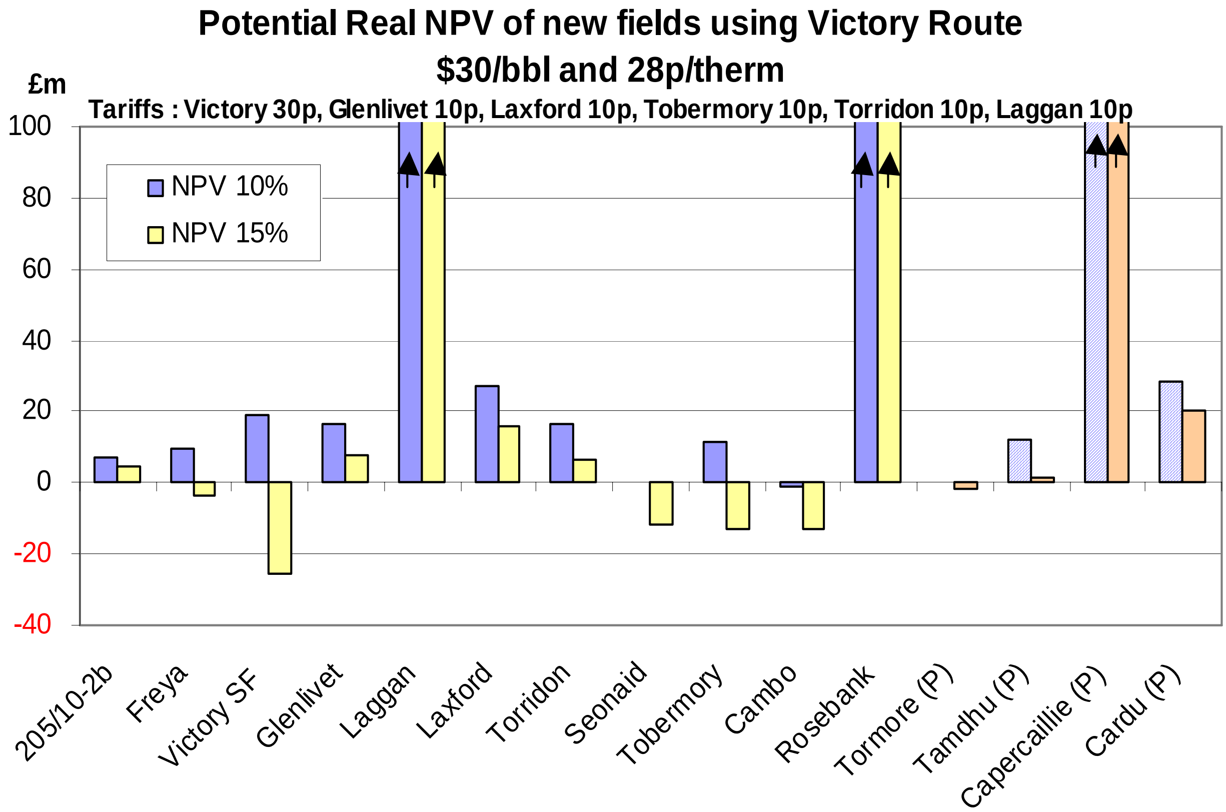
The resulting NPVs with higher tariffs are shown below.

Tariff assumptions for Scenario 3B Victory Route
$30/bbl and 28p/therm

3B	£m NPV 10%	NPV 15%	Tariff Victory	toTariff Glenlivet	toTariff Laxford	toTariff Tobermory	toTariff Torridon	toTariff Laggan	Tanker toLoading Tariff
205/10-2b	7.21	4.46						50p/bbl	£1/bbl
Clair Ph3	3.09	2.34							
Freya	9.51	-3.29	30p/mcf						
Victory to St Fergus	18.78	-25.58							
Glenlivet	16.58	7.45	30p/mcf						
Laxford	27.43	16.13	30p/mcf	10p/mcf					
Torridon	16.48	6.37	30p/mcf						
Seonaid	0.20	-11.45	30p/mcf				10p/mcf	10p/mcf	
Laggan	291.37	174.68	30p/mcf				10p/mcf		£1/bbl
Tobermory	11.33	-12.71	30p/mcf	10p/mcf	10p/mcf				
Cambo	-1.25	-13.10	30p/mcf				10p/mcf	10p/mcf	
Rosebank	618.74	370.92	30p/mcf				10p/mcf	10p/mcf	£1/bbl
Tormore Prospect	0.00	-1.65	30p/mcf				10p/mcf	10p/mcf 50p/bbl	£1/bbl
Tamdhu Prospect	12.23	1.67	30p/mcf				10p/mcf	10p/mcf	£1/bbl
Capercaillie Prospect	722.67	352.49	30p/mcf	10p/mcf	10p/mcf	10p/mcf			£1/bbl
Cardu Prospect	28.18	20.23							£1/bbl

It was felt that a case with higher tariffs should be examined given the risk involved for the asset owners. A case where the Victory owners received a tariff of 30p/mcf and other sub-hub assets owners received one of 20p/mcf was examined. The results are shown in Chart 29.

Chart 29



The results show that all but one of the fields have positive NPVs at 10% under the $30, 28p case, but Victory, the hub, has a negative NPV at 15%. The general conclusion is that this Scenario is very unlikely to be viable.

In principle a communal pipeline from Victory could go to MCPO1, North Alwyn, FLAGS or SAGE. The comparative pipeline costs are shown below (£m).

Victory to	St Fergus	MCPO1	Alwyn North	FLAGS	Sage
24"	205.29	144.48	109.27	116.74	165.82
30"	259.22	182.30	137.76	147.21	209.29

As with the Laggan-based Scenarios cases were developed for those based on Victory. They are not shown here because it was felt that the returns available to the owners of Victory for accepting the increased development and transportation risks were likely to be inadequate. The general conclusion is that all the Scenarios with Victory as hub are unlikely to be viable.

6 Option 4 - Seonaid as Hub

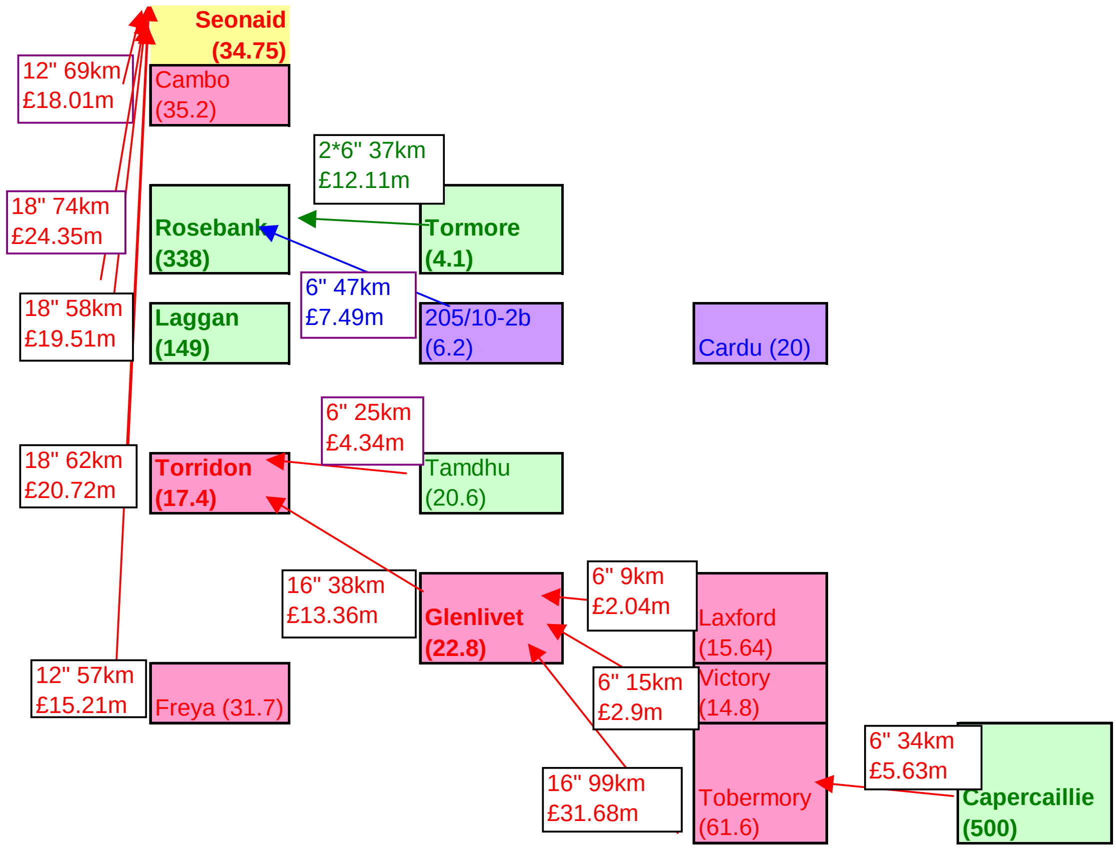
a) Scenario 4A – Seonaid as Hub and Modest Tariffs

This scenario would use Schiehallion, Clair and Seonaid as hubs. The fields linking with Schiehallion would be the same us with the other scenarios.

As a hub Seonaid's costs would also increase substantially (see table below) and there would be a different configuration of inter-field pipelines with different sub-hubs. The configuration is shown in Chart 30.

	Reserves mboe	Assumed Development Cost $/boe	Capex £m	Drill £m
Seonaid	34.75	10.37	128.61	71.62

Chart 30



If Seonaid became a hub field there would be a considerable increase not only in development costs but in pipeline costs to St Fergus. A 30” pipeline would cost £225.48m plus the increase in development costs. To achieve a return of 10% on the extra pipeline costs Seonaid would need to charge a tariff of around 13.22p/mcf, but this does not take any account of the extra development costs. To achieve a 10% return on the incremental pipeline <u>and</u> development costs Seonaid would have to charge a tariff of 23p/mcf.

With this scenario Rosebank would become one of the sub-hub fields and requires an 18” pipeline.

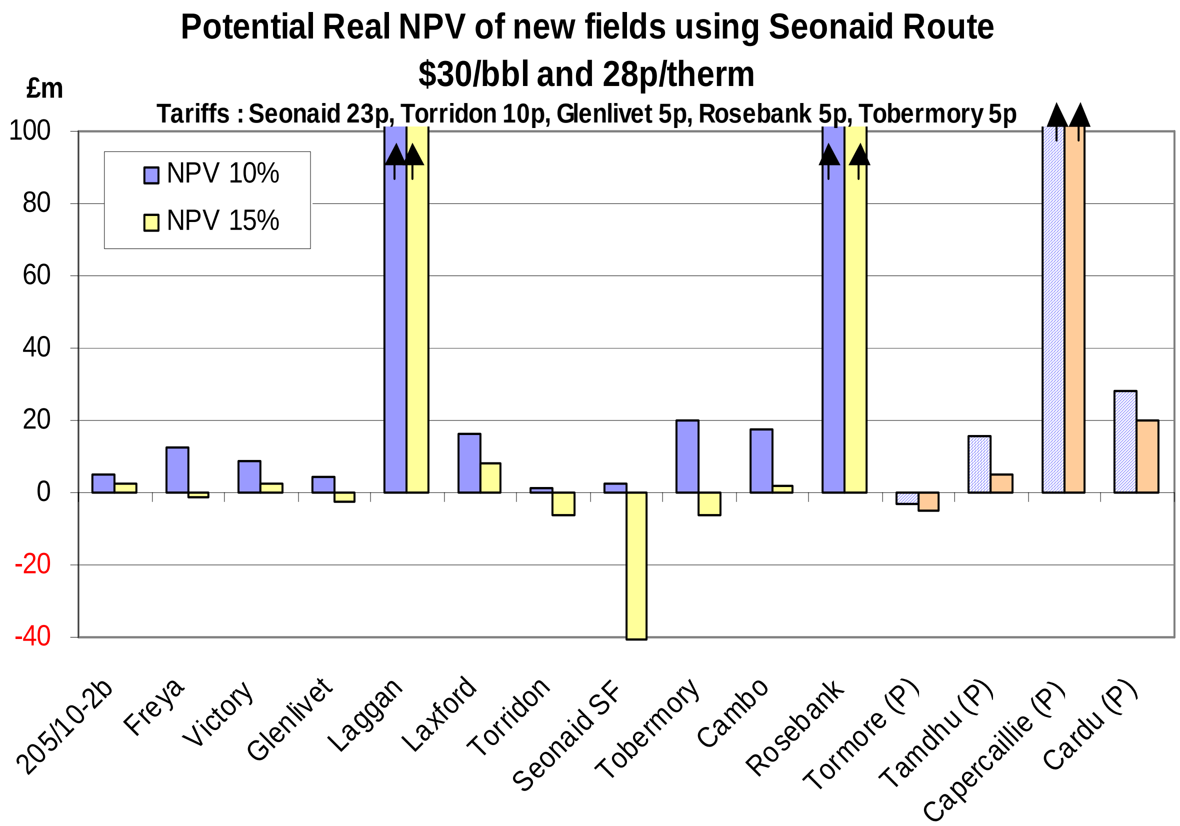
Under this scenario Torridon would become one of the sub-hub fields. Torridon needs a 6” pipeline to Seonaid for its own use costing £9.64m but as a sub-hub field it requires an 18” pipeline costing £20.72m. To achieve a return of 10% on the extra pipeline cost Torridon would have to charge a tariff of 2.7p/mcf. However, with this tariff it fails the economic hurdle rate, and so Tamdhu, Glenlivet, Laxford, Victory, Tobermory and Capercaillie gas would be stranded. For viability Torridon needs a tariff of at least 10p/mcf.

With this scenario Glenlivet would also become one of the sub-hub fields. Glenlivet needs a 6” pipeline to Torridon for its own use costing £6.2m, but as a sub-hub field it requires a 16” pipeline costing £13.36m. To achieve a return of 10% on the extra pipeline cost Glenlivet would have to charge a tariff of 2.4p/mcf. Tobermory also acts as a sub-hub in this scenario, and requires a 16” pipeline for its own use.

Tariff assumptions for Scenario 4A Seonaid Route
$30/bbl and 28p/therm

4A	NPV 10%	NPV 15%	Tariff to Seonaid	Tariff to Torridon	Tariff to Glenlivet	Tariff to Tobermory	Tariff to Rosebank	Tanker Loading Tariff
205/10-2b	5.06	2.32					50p/bbl	£1/bbl
Clair Ph3	3.09	2.34						
Freya	12.27	-1.41	23p/mcf					
Victory	9.00	2.42	23p/mcf	10p/mcf	5p/mcf			
Glenlivet	4.68	-2.81	23p/mcf	10p/mcf				
Laxford	16.49	7.89	23p/mcf	10p/mcf	5p/mcf			
Torridon	1.54	-6.21	23p/mcf					
Seonaid to SF	2.45	-40.43						
Laggan	297.31	177.80	23p/mcf					£1/bbl
Tobermory	20.29	-6.36	23p/mcf	10p/mcf	5p/mcf			
Cambo	17.49	1.68	23p/mcf					
Rosebank	654.31	396.44	23p/mcf					£1/bbl
Tormore Prospect	-3.29	-5.04	23p/mcf				5p/mcf 50p/bbl	£1/bbl
Tamdhu Prospect	15.82	4.73	23p/mcf	10p/mcf				£1/bbl
Capercaillie Prospect	728.25	356.36	23p/mcf	10p/mcf	5p/mcf	5p/mcf		£1/bbl
Cardu Prospect	28.18	20.23						£1/bbl

Chart 31



The results are shown in Charts 31. It is seen that all fields except Tormore pass the 10% hurdle rate and obtain at least 10% on their incremental costs. The size of the NPV to Seonaid is very small and becomes substantially negative at 15% discount rate. This casts much doubt on the viability of this Scenario.

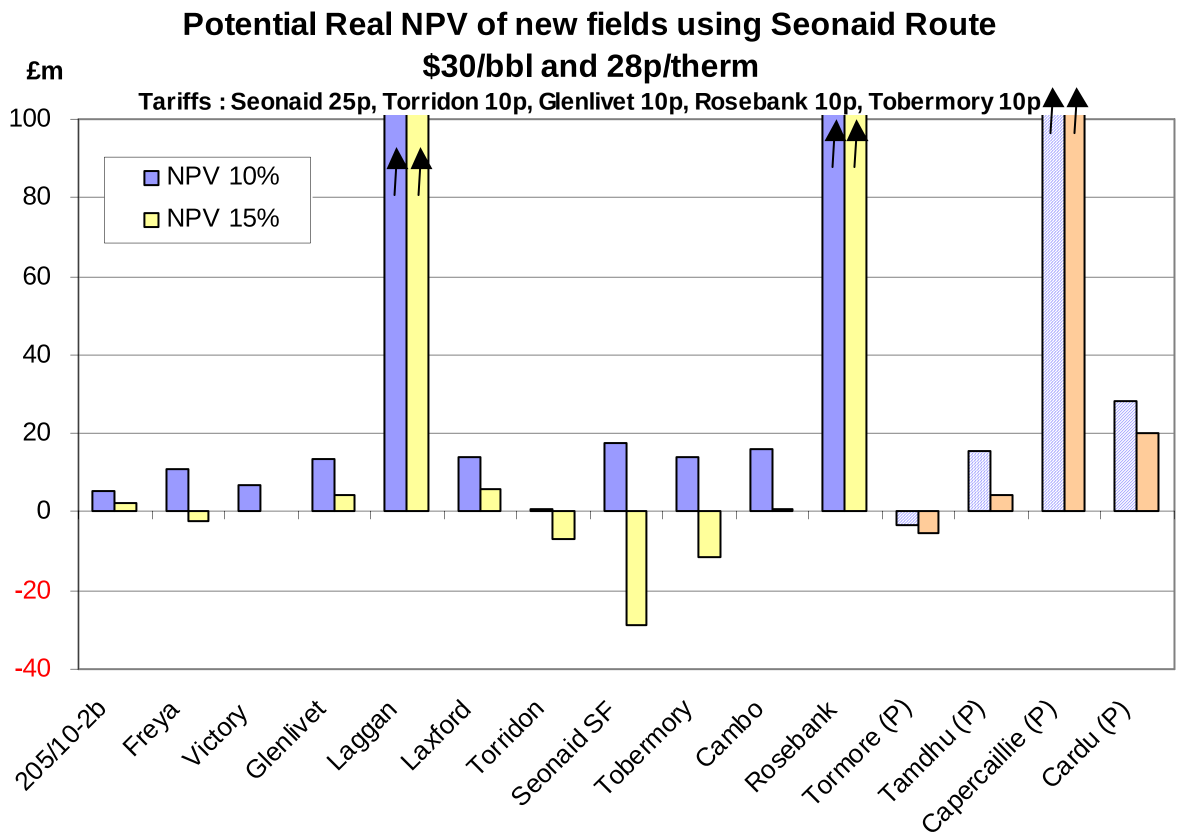
<u>b) Scenario 4B – Seonaid as Hub with Higher Tariffs.</u>

Given the risks on the asset owners a case with higher tariffs was considered. Accordingly, one where the Seonaid owners received 25p/mcf and other sub-hub owners 10p/mcf was examined. The results are shown in Chart 32 for the $30, 28p case. While all fields bar one have positive NPVs at 10%, the size of the returns to Seonaid are still very modest given the risks and at 15% discount rate the NPV becomes substantially negative.

Tariff assumptions for Scenario 4B Seonaid Route
$30/bbl and 28p/therm

4B	NPV 10%	NPV 15%	Tariff to Seonaid	Tariff to Torridon	Tariff to Glenlivet	Tariff to Tobermory	Tariff to Rosebank	Tanker Loading Tariff
205/10-2b	5.06	2.32					50p/bbl	£1/bbl
Clair Ph3	3.09	2.34						
Freya	11.04	-2.38	25p/mcf					
Victory	6.66	0.46	25p/mcf	10p/mcf	10p/mcf			
Glenlivet	13.23	4.10	25p/mcf	10p/mcf				
Laxford	13.99	5.81	25p/mcf	10p/mcf	10p/mcf			
Torridon	0.76	-6.86	25p/mcf					
Seonaid to SF	17.53	-28.85						
Laggan	293.35	174.94	25p/mcf					£1/bbl
Tobermory	13.97	-11.26	25p/mcf	10p/mcf	10p/mcf			
Cambo	16.13	0.61	25p/mcf					
Rosebank	651.43	394.32	25p/mcf					£1/bbl
Tormore Prospect	-3.55	-5.26	25p/mcf				10p/mcf 50p/bbl	£1/bbl
Tamdhu Prospect	15.45	4.43	25p/mcf	10p/mcf				£1/bbl
Capercaillie Prospect	724.31	353.63	25p/mcf	10p/mcf	10p/mcf	10p/mcf		£1/bbl
Cardu Prospect	28.18	20.23						£1/bbl

Chart 32



In principle a communal pipeline from Seonaid could go to MCPO1, North Alwyn, FLAGS or SAGE. The calculated costs are shown below. Calculations were made of the resulting returns but are not shown here. The general conclusion is that, given the costs and risks to the Seonaid licensees, the option of the Seonaid hub is very unlikely to be viable.

			£m			
Seonaid	St Fergus	MCPO1	Alwyn North	FLAGS	Sage	Magnus
24"	178.62	133.28	139.68	105.54	152.48	145.01
30"	225.48	168.13	176.22	133.04	192.42	182.97

7. Rephasing of WOS Field Developments

The above analysis was based on fast-track field developments. The question of whether the ullage problem might be less if development was slower (and probably more realistic) was examined. The comparative timings are shown below.

First Development	Fast Track	Rephased
Clair PH 3	2006	2007
Victory	2008	2010
Freya	2007	2010
Laxford	2008	2010
Torridon	2008	2010
Seonaid	2007	2010
Tobermory	2008	2010
Glenlivet	2008	2010
205/10-2b	2008	2009
Tormore	2008	2010
Tamdhu	2008	2010
Rosebank	2007	2008
Cambo	2008	2012
Capercaillie	2007	2009
Cardu	2008	2012
Laggan	2006	2006

With constant real prices and costs rephasing would not generally change the individual field NPVs to the base year of first development. Where a field is a tariff receiver, however, there would be some change in the NPV attained if there is a lag in the timing of the tariff revenues received.

Two cases have been analysed with the above slower pace of development, namely Scenario 1 (use of existing infrastructure) and Scenario 2A (Laggan route). There is very little difference between the 2 rephased cases. The results of the modelling are shown in Charts 33 and 34.

Chart 33

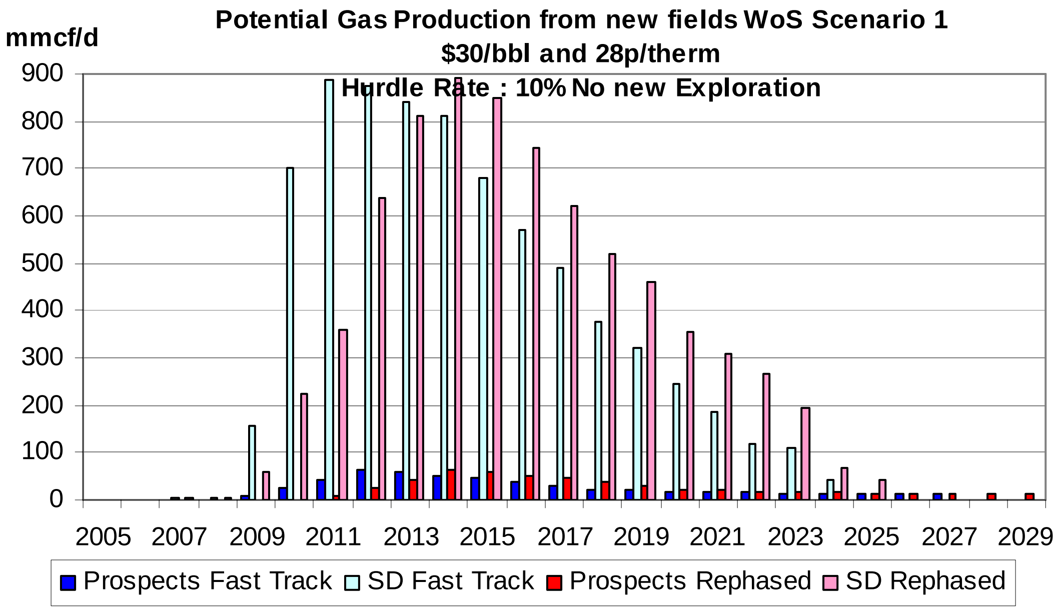
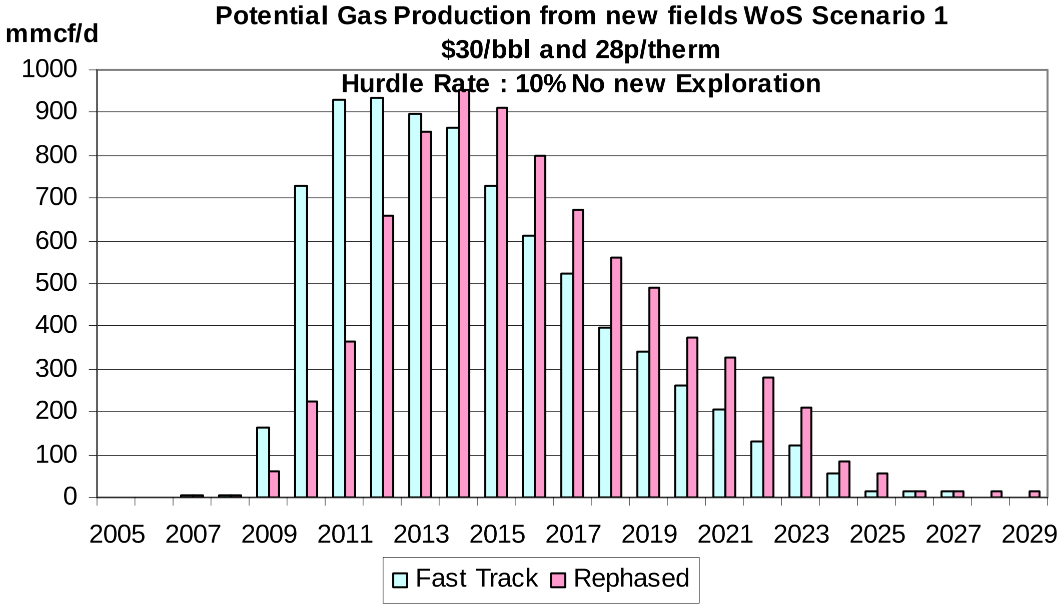


Chart 34



The ullage problem is shown for the rephrased Scenario 1 in Charts 35 and 36. The peak has shifted but the ullage problem with the WSGPS and the Magnus to Brent link remains.

Chart 35

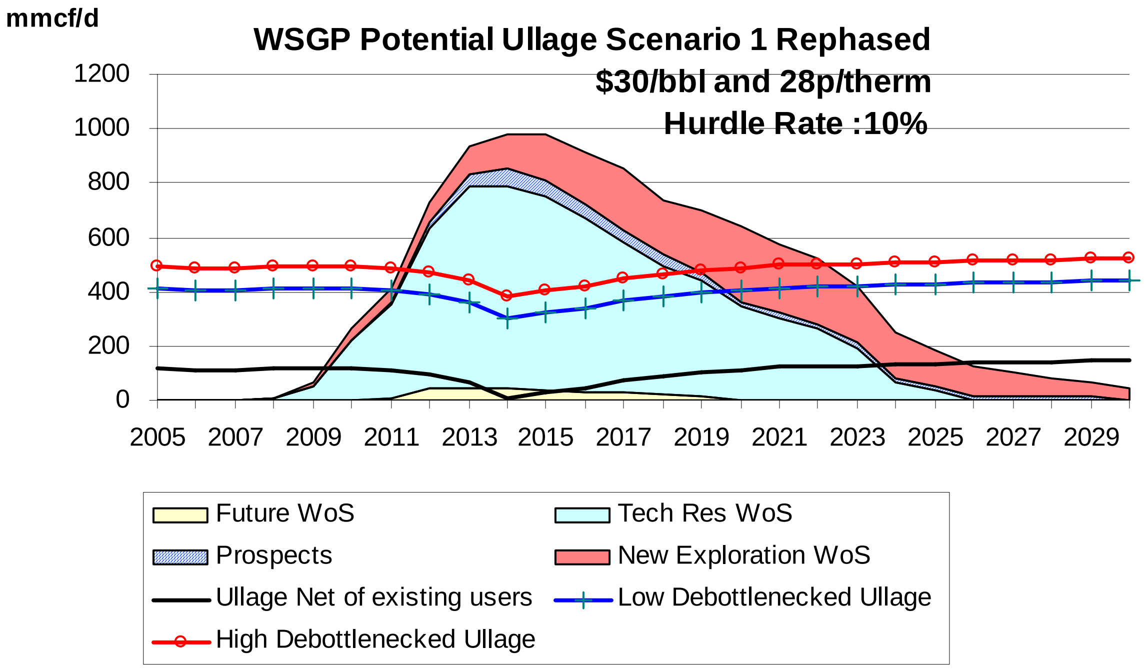
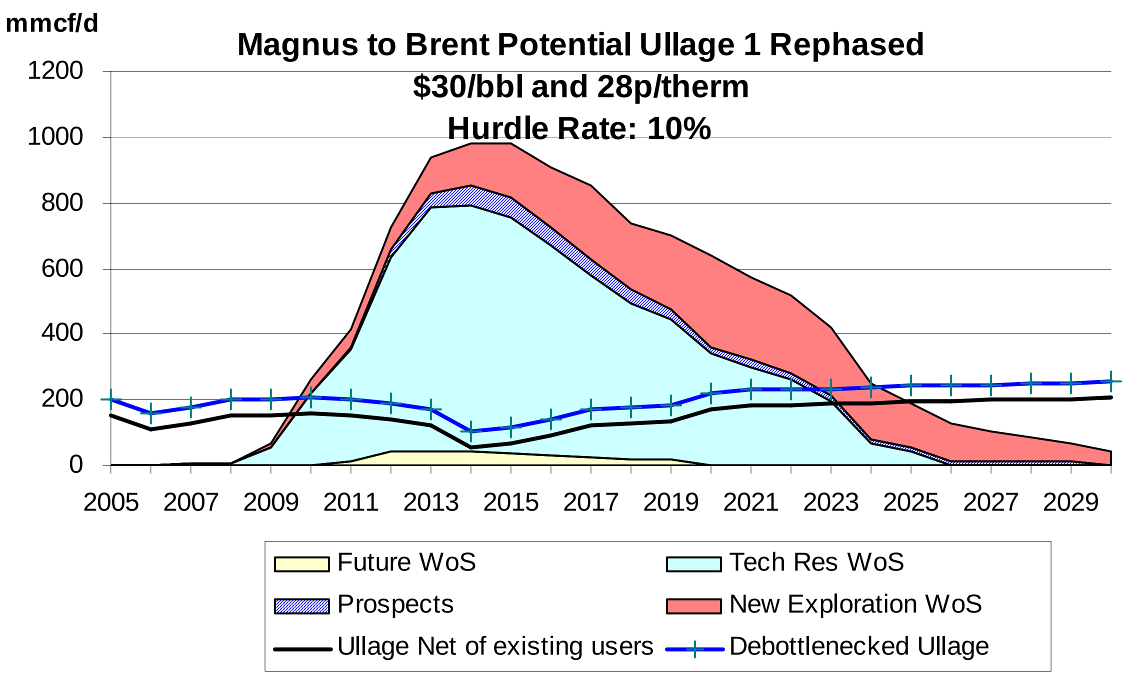
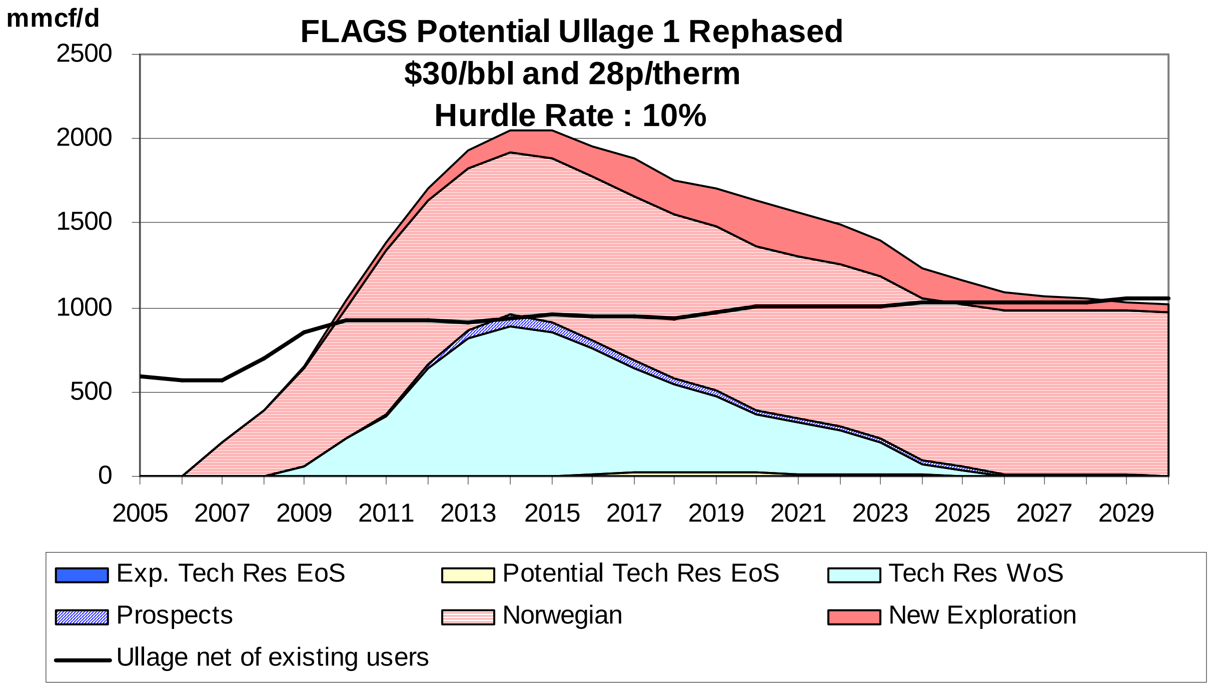


Chart 36



The FLAGS ullage problem (Chart 37) also remains. In fact the problem may be worse when the technical reserve fields are rephased because the FLAGS owners are likely to attempt to use the capacity and the gas will most likely be obtained from Norway.

Chart 37



The production profiles for case 2A are shown in Charts 38 and 39.

Chart 38

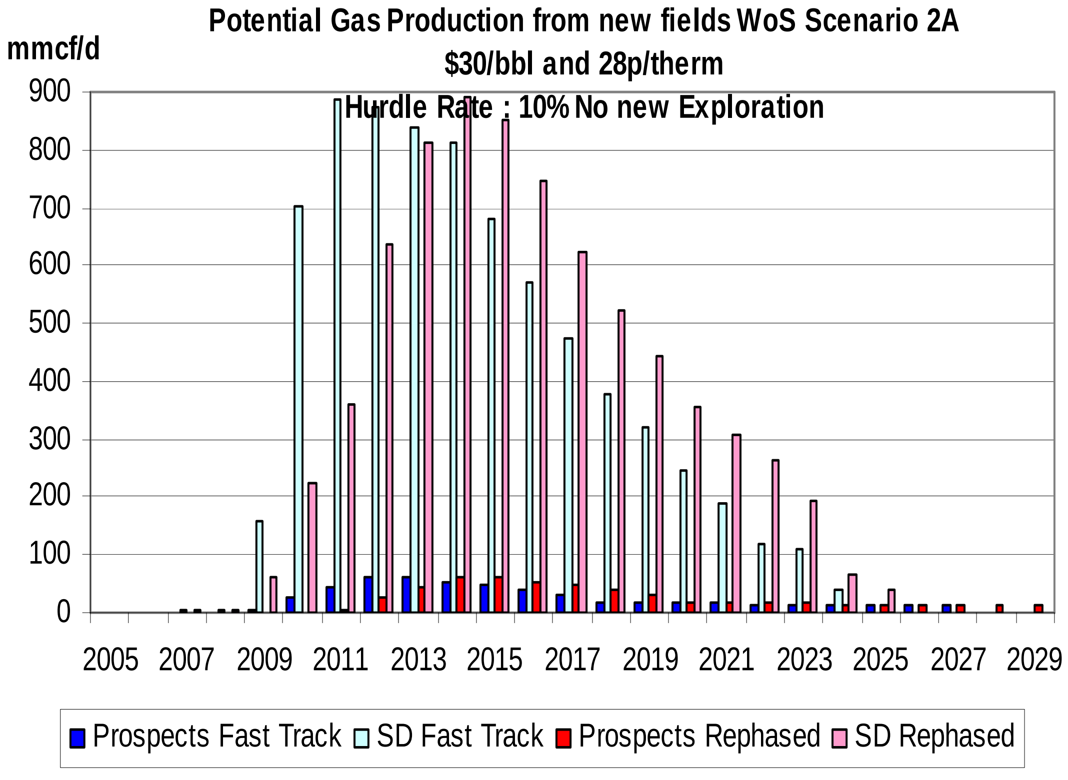
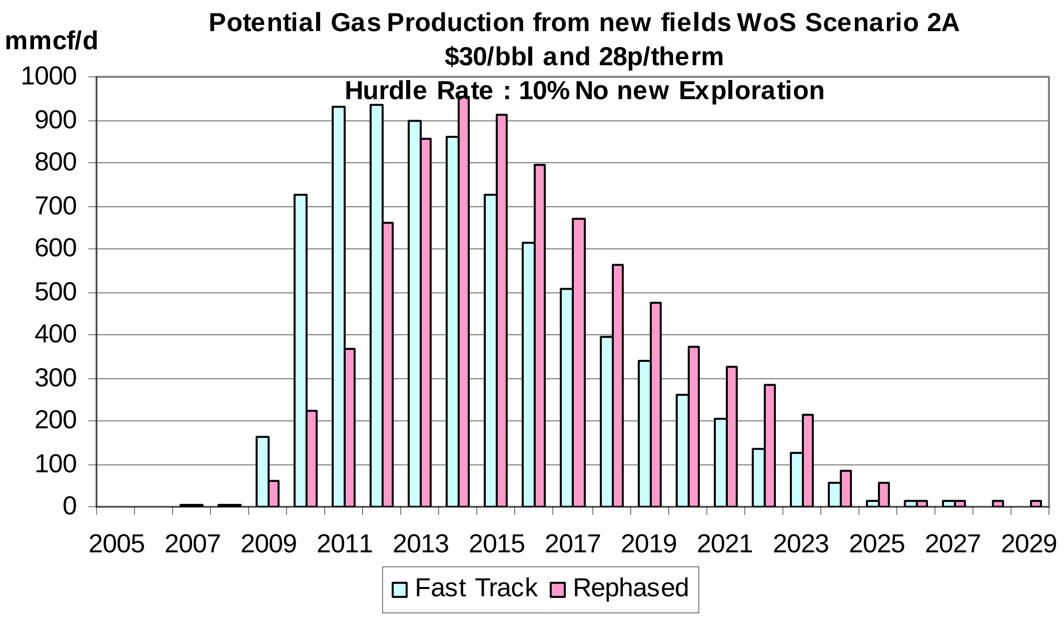
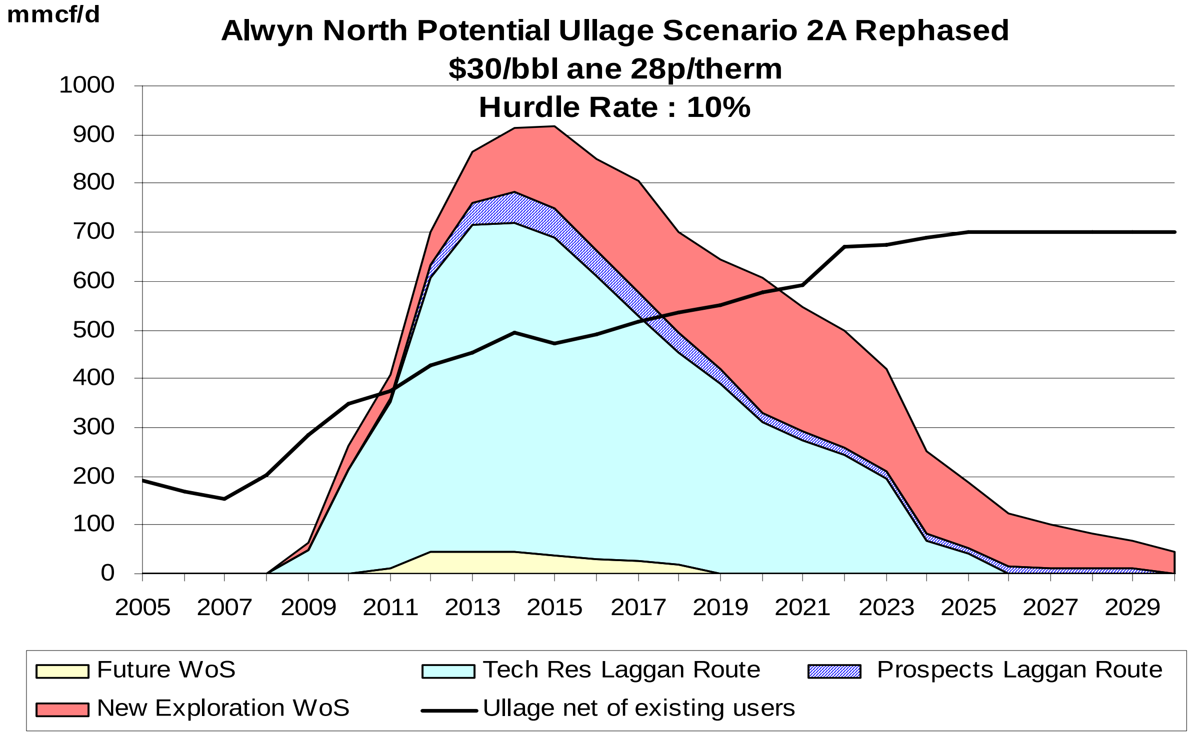


Chart 39



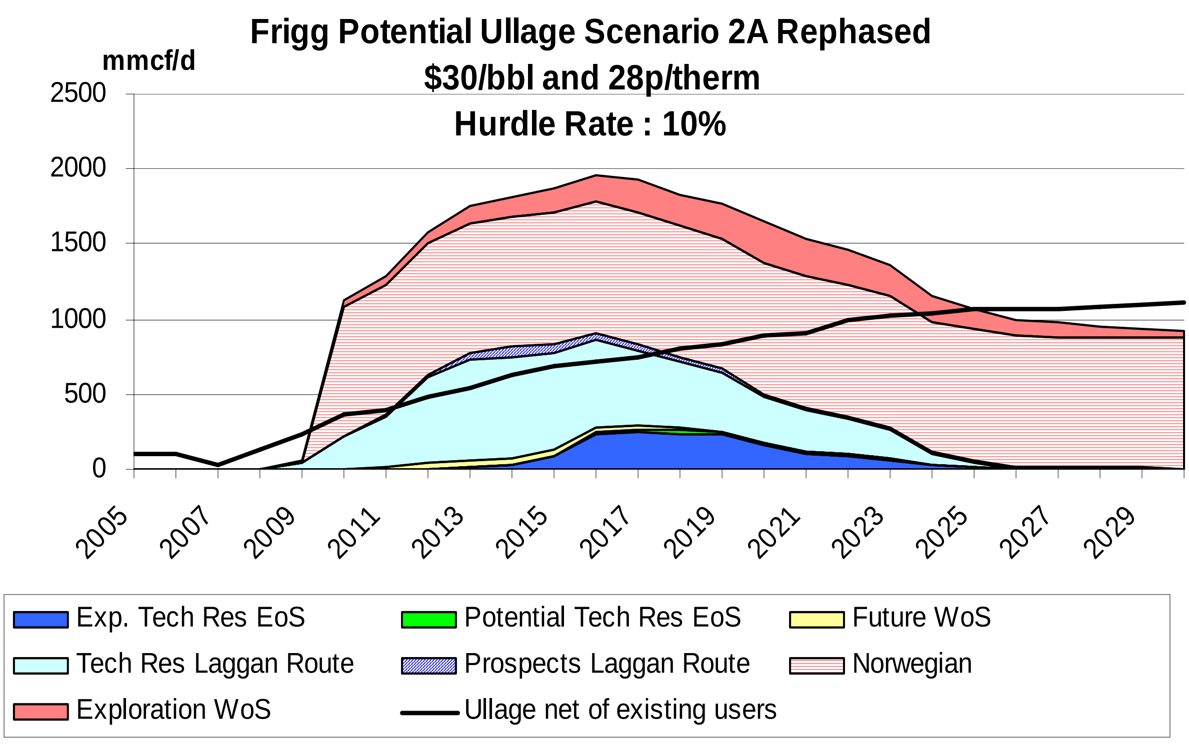
The ullages for the rephased case 2A is shown in Charts 40, 41 and 42.

Chart 40



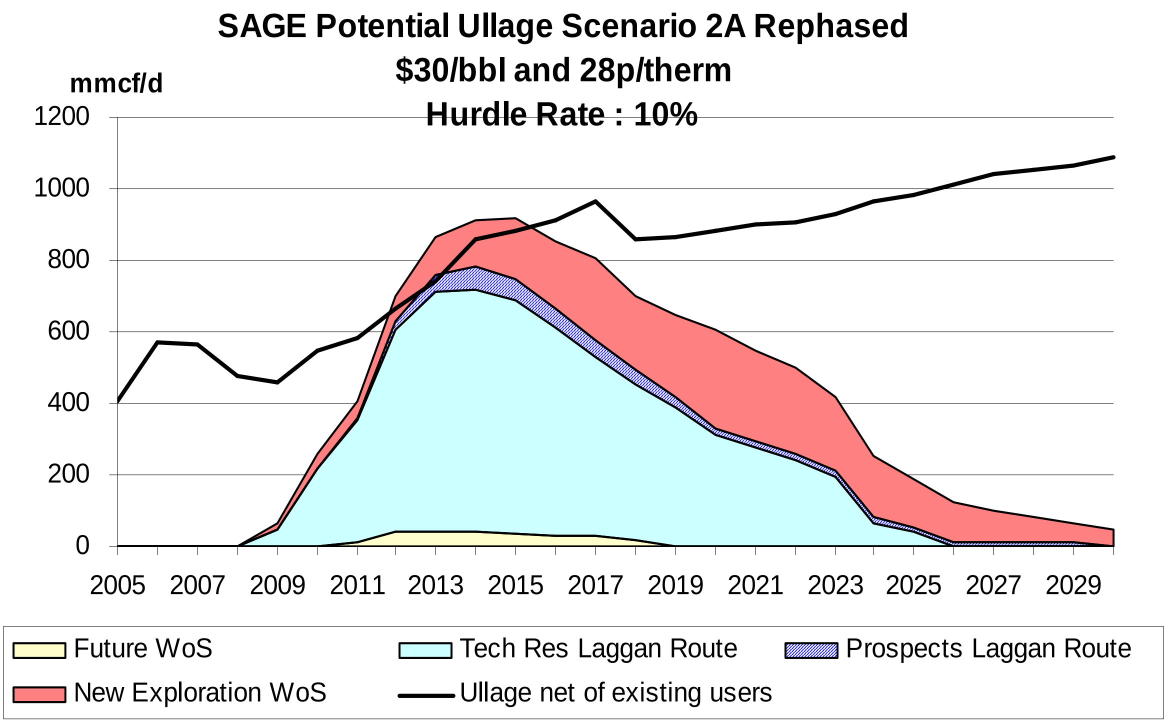
There is still a problem with lack of capacity in the Alwyn North link.

Chart 41



The Frigg ullage problem is greatly reduced, but there is again the possibility that gas from Norway may book the available capacity before the WOS fields are ready.

Chart 42



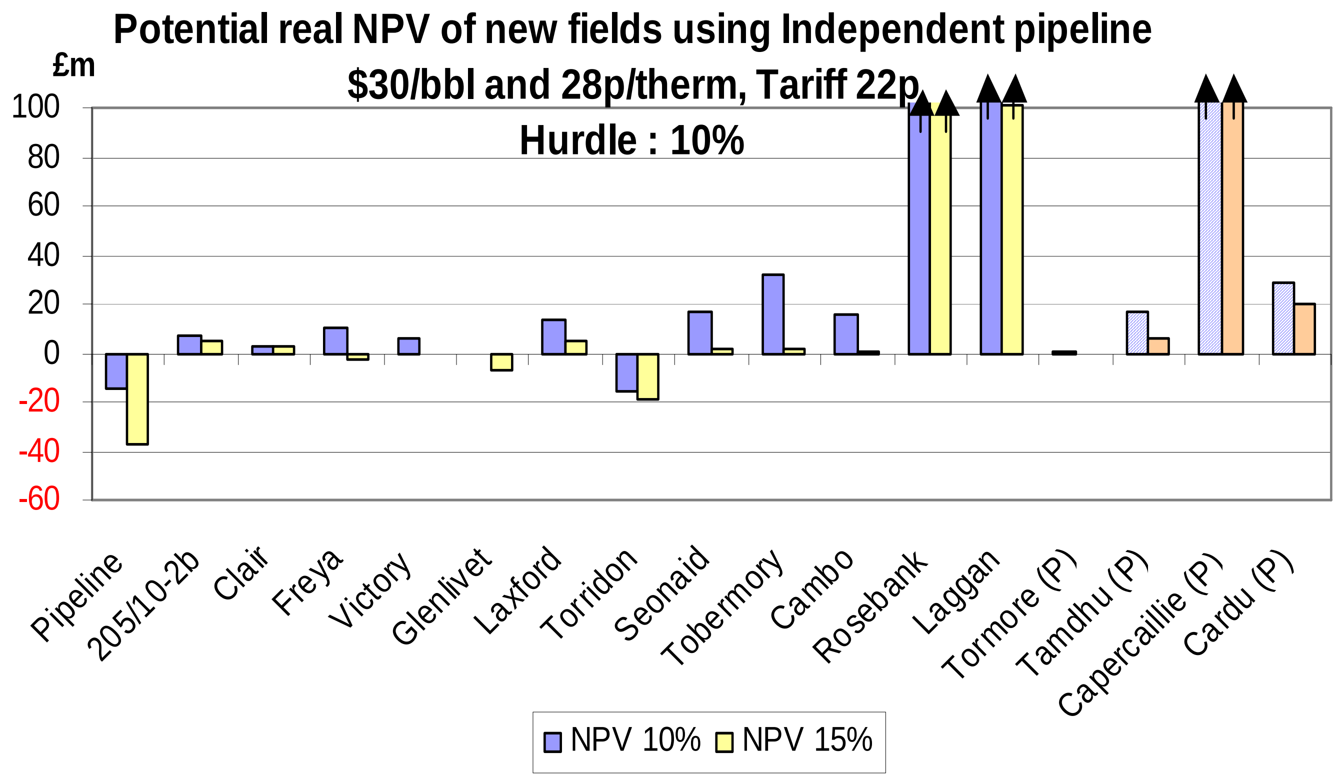
The SAGE route, from the ullage viewpoint, now looks more plausible. However, the route has the disadvantage of distances and it is questionable whether the fields would be willing to pay the SAGE transportation tariff, which lowers the NPV for all of them except Laggan, or take the gas directly to St Fergus via a dedicated pipeline.

8. Independent Communal Pipeline Company

A quite different possibility is that a communal pipeline would be owned and developed by an independent pipeline company i.e. separate from the licensees and engaged only in the transportation business. Such a company would be taxed at 30% with capital allowances on 25% declining balance basis, compared to 40% (and soon to be 50%), with capital allowances on 100% first year basis. It is also possible that an independent company would have a lower cost of capital, though this would depend on fairly secure long-term contracts being agreed with the producers.

The case examined in detail corresponds to Scenario 2A above i.e. the communal pipeline from the Laggan area direct to St. Fergus. A range of possible minimum returns to the independent pipeline company were calculated, namely 12.5%, 10% and 8%, all in real, post-tax terms. (In money-of-the-day terms 8% corresponds to around 10.5%). Under the $30, 28p case it was found that to obtain a 12.5% real, post-tax return a tariff of 22p/mcf would be required if all the fields went ahead. Unfortunately, two fields, Glenlivet and Torridon failed to obtain their minimum acceptable returns, and Victory and Laxford gas would become stranded. In the absence of these fields the NPV at 12.5% real for the independent pipeline becomes negative. The results are shown in Chart 43 and the accompanying table.

Chart 43

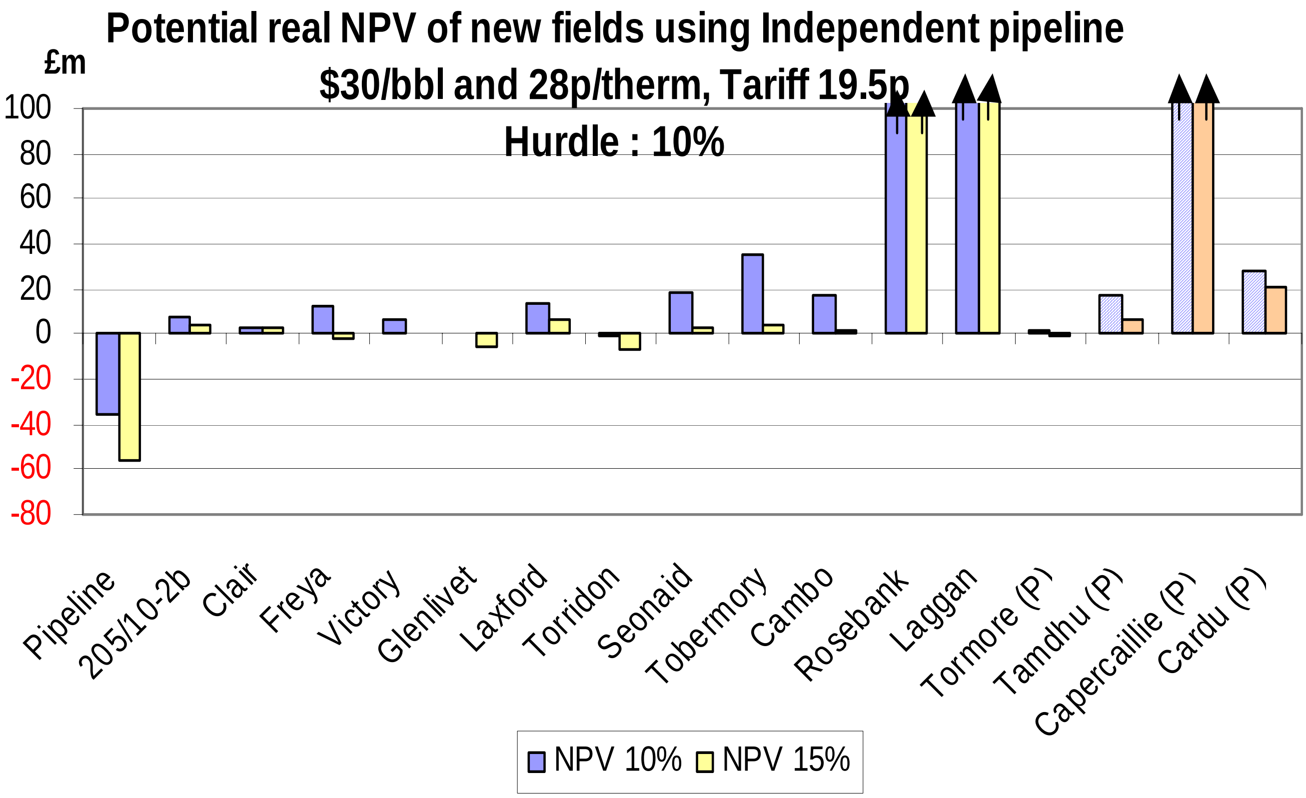


Tariff assumptions for Independent pipeline to St Fergus from Laggan Route
$30/bbl and 28p/therm

Independent	£m NPV 10%	NPV 15%	Tariff Laggan	toTariff Torridon	toTariff Glenlivet	toTariff Tobermory	Tariff toIndependent pipeline	toTanker Loading Tariff
205/10-2b	7.21	4.46	50p/bbl					£1/bbl
Clair Ph3	3.09	2.34						
Freya	10.62	-2.78	3p/mcf				22p/mcf	
Victory	5.99	-0.10	3p/mcf	12p/mcf	10p/mcf		22p/mcf	
Glenlivet	-0.25	-6.72	3p/mcf	12p/mcf			22p/mcf	
Laxford	13.28	5.22	3p/mcf	12p/mcf	10p/mcf		22p/mcf	
Torridon	-15.90	-19.24	3p/mcf				22p/mcf	
Seonaid	17.08	1.81	3p/mcf				22p/mcf	
Laggan	208.46	101.51					22p/mcf	£1/bbl
Tobermory	31.77	1.85	3p/mcf				22p/mcf	
Cambo	15.84	0.33	3p/mcf				22p/mcf	
Rosebank	654.73	397.46	3p/mcf				22p/mcf	£1/bbl
Tormore Prospect	0.96	-0.83	3p/mcf 50p/bbl				22p/mcf	£1/bbl
Tamdhu Prospect	16.85	5.52	3p/mcf				22p/mcf	£1/bbl
Capercaillie Prospect	732.52	359.32	3p/mcf			5p/mcf	22p/mcf	£1/bbl
Cardu Prospect	28.18	20.23						£1/bbl
Pipeline	-14.40	-37.05						

If the minimum required rate of return for the independent pipeline company were 10% in real, post-tax terms a tariff of 19.5p/mcf would be required provided all the fields went ahead. Unfortunately Torridon again fails to meet its minimum return and, with Laxford and Glenlivet gas being stranded as a consequence, the pipeline company has a negative NPV at 10% in real, post-tax terms. The results are shown in Chart 44 and the accompanying table.

Chart 44

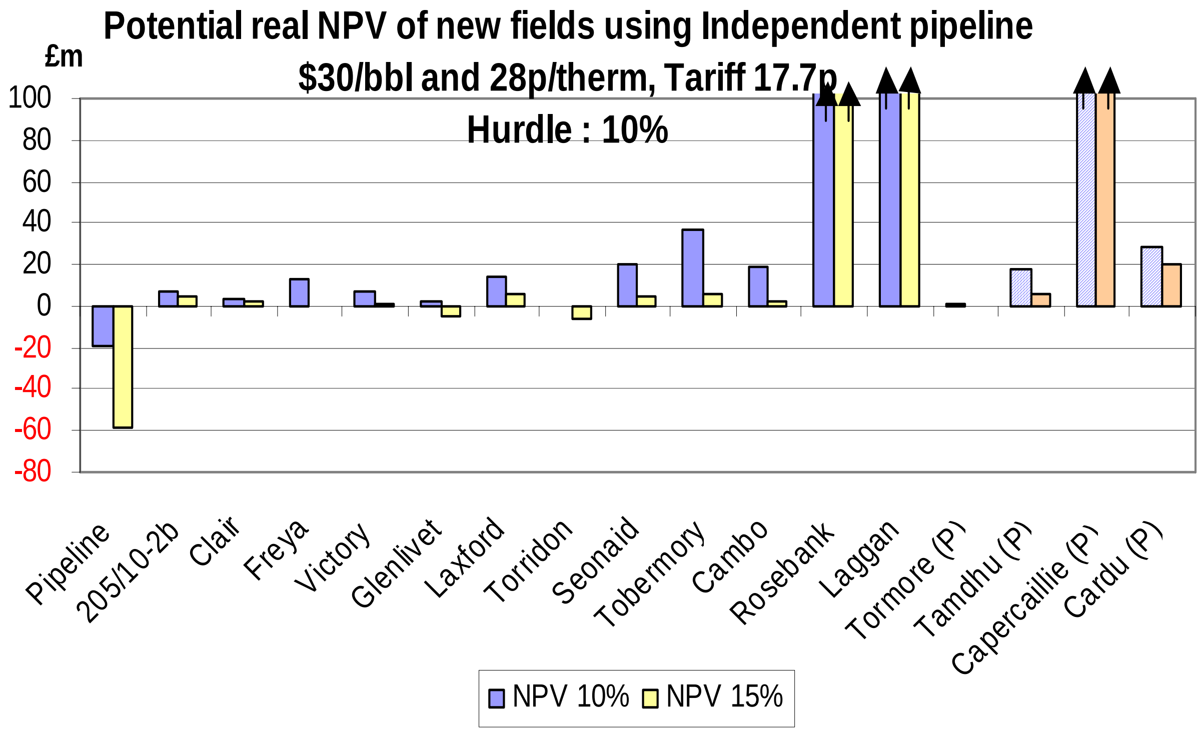


Tariff assumptions for Independent pipeline to St Fergus from Laggan Route $30/bbl and 19.5p/therm

Independent	£m NPV 10%	NPV 15%	Tariff Laggan	toTariff Torridon	toTariff Glenlivet	toTariff Tobermory	Tariff toIndependent pipeline	toTanker Loading Tariff
205/10-2b	7.21	4.46	50p/bbl					£1/bbl
Clair Ph3	3.09	2.34						
Freya	12.16	**-1.58**	3p/mcf				19.5p/mcf	
Victory	6.83	0.60	3p/mcf	12p/mcf	10p/mcf		19.5p/mcf	
Glenlivet	0.98	-5.69	3p/mcf	12p/mcf			19.5p/mcf	
Laxford	14.17	5.96	3p/mcf	12p/mcf	10p/mcf		19.5p/mcf	
Torridon	-1.01	-6.67	3p/mcf				19.5p/mcf	
Seonaid	18.77	3.14	3p/mcf				19.5p/mcf	
Laggan	213.39	105.09					19.5p/mcf	£1/bbl
Tobermory	34.61	4.04	3p/mcf				19.5p/mcf	
Cambo	17.55	1.67	3p/mcf				19.5p/mcf	
Rosebank	658.32	400.12	3p/mcf				19.5p/mcf	£1/bbl
Tormore Prospect	1.06	-0.76	3p/mcf 50p/bbl				19.5p/mcf	£1/bbl
Tamdhu Prospect	17.31	5.91	3p/mcf				19.5p/mcf	£1/bbl
Capercaillie Prospect	733.34	359.89	3p/mcf			5p/mcf	19.5p/mcf	£1/bbl
Cardu Prospect	28.18	20.23						£1/bbl
Pipeline	-35.62	-55.87						

If the minimum acceptable return for the independent pipeline company were 8% real, post-tax (i.e. 10.7% in MOD terms) the tariff required would be 17.7/mcf if all the fields went ahead. In this case all the fields do pass the minimum hurdle. The results are shown in Chart 45 and the accompanying table.

Chart 45

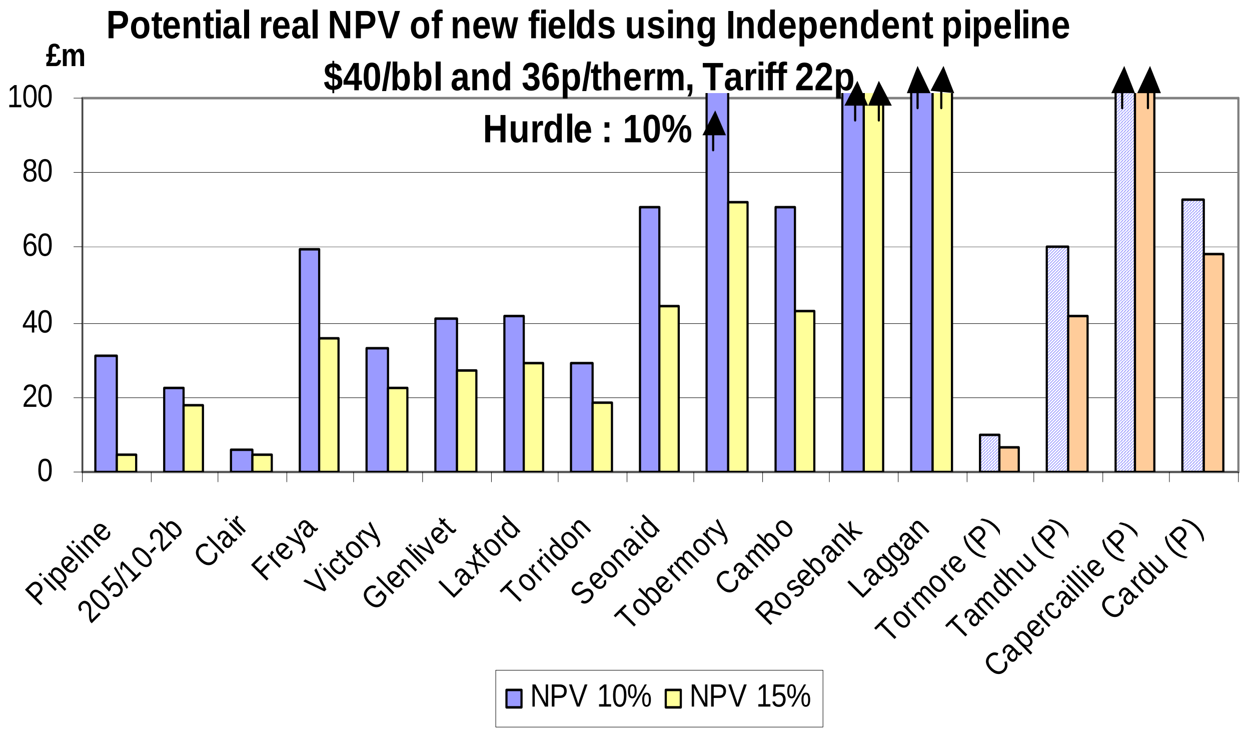


Tariff assumptions for Independent pipeline to St Fergus from Laggan Route $30/bbl and 28p/therm

Independent	NPV 10%	NPV 15%	Tariff Laggan	toTariff Torridon	toTariff Glenlivet	toTariff Tobermory	Tariff toIndependent pipeline	toTanker Loading Tariff
205/10-2b	7.21	4.46	50p/bbl					£1/bbl
Clair Ph3	3.09	2.34						
Freya	13.26	-0.70	3p/mcf				17.7p/mcf	
Victory	7.27	0.97	3p/mcf	12.5p/mcf	10p/mcf		17.7p/mcf	
Glenlivet	1.85	-4.94	3p/mcf	12.5p/mcf			17.7p/mcf	
Laxford	14.64	6.34	3p/mcf	12.5p/mcf	10p/mcf		17.7p/mcf	
Torridon	0.23	-5.62	3p/mcf				17.7p/mcf	
Seonaid	19.98	4.09	3p/mcf				17.7p/mcf	
Laggan	220.85	110.64					17.7p/mcf	£1/bbl
Tobermory	36.65	5.62	3p/mcf				17.7p/mcf	
Cambo	18.78	2.64	3p/mcf				17.7p/mcf	
Rosebank	660.91	402.03	3p/mcf				17.7p/mcf	£1/bbl
Tormore Prospect	1.12	-0.70	3p/mcf 50p/bbl				17.7p/mcf	£1/bbl
Tamdhu Prospect	17.64	6.18	3p/mcf				17.7p/mcf	£1/bbl
Capercaillie Prospect	733.93	360.30	3p/mcf			5p/mcf	17.7p/mcf	£1/bbl
Cardu Prospect	28.18	20.23						£1/bbl
Pipeline	-19.74	-58.59						

It is noteworthy that under the $40, 36p scenario the independent pipeline company can obtain returns of 12.5% in real, post-tax terms with a tariff of 22p/mcf as all the fields pass their minimum hurdle at these oil/gas prices. The results are shown in Chart 46 and the accompanying table.

Chart 46

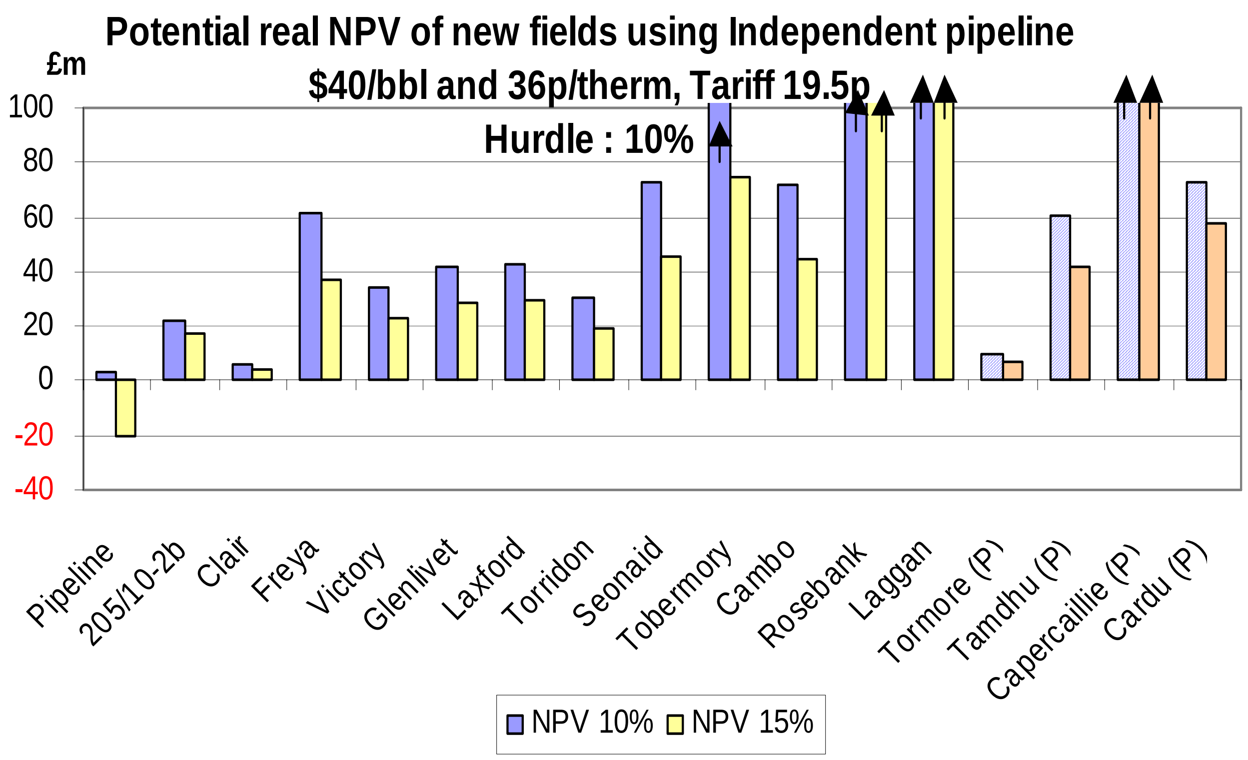


Tariff assumptions for Independent pipeline to St Fergus from Laggan Route $40/bbl and 36p/therm

Independent	£m NPV 10%	NPV 15%	Tariff to Laggan	Tariff to Torridon	Tariff to Glenlivet	Tariff to Tobermory	Tariff to Independent pipeline	Tanker Loading Tariff
205/10-2b	22.35	17.68	50p/bbl					£1/bbl
Clair Ph3	5.64	4.63						
Freya	59.87	35.93	3p/mcf				22p/mcf	
Victory	33.19	22.63	3p/mcf	12p/mcf	10p/mcf		22p/mcf	
Glenlivet	40.73	27.47	3p/mcf	12p/mcf			22p/mcf	
Laxford	41.87	28.94	3p/mcf	12p/mcf	10p/mcf		22p/mcf	
Torridon	29.24	18.59	3p/mcf				22p/mcf	
Seonaid	71.08	44.26	3p/mcf				22p/mcf	
Laggan	412.44	250.84					22p/mcf	£1/bbl
Tobermory	123.41	72.41	3p/mcf				22p/mcf	
Cambo	70.54	43.32	3p/mcf				22p/mcf	
Rosebank	1182.53	787.74	3p/mcf				22p/mcf	£1/bbl
Tormore Prospect	10.01	6.94	3p/mcf 50p/bbl				22p/mcf	£1/bbl
Tamdhu Prospect	59.97	41.68	3p/mcf				22p/mcf	£1/bbl
Capercaillie Prospect	1447.46	862.65	3p/mcf			5p/mcf	22p/mcf	£1/bbl
Cardu Prospect	73.01	58.04						£1/bbl
Pipeline	31.32	4.89						

Similarly, if the minimum return for the independent pipeline were 10% in real, post-tax terms a tariff of 19.5p/mcf would suffice and all the fields would pass their minimum hurdle. The results are shown in Chart 47 and the accompanying table.

Chart 47



Tariff assumptions for Independent pipeline to St Fergus from Laggan Route
$40/bbl and 36p/therm

Independent	£m NPV 10%	NPV 15%	Tariff Laggan	toTariff Torridon	toTariff Glenlivet	toTariff Tobermory	Tariff toIndependent pipeline	toTanker Loading Tariff
205/10-2b	22.35	17.68	50p/bbl					£1/bbl
Clair Ph3	5.64	4.63						
Freya	61.41	37.14	3p/mcf				19.5p/mcf	
Victory	34.05	23.34	3p/mcf	12p/mcf	10p/mcf		19.5p/mcf	
Glenlivet	42.01	28.53	3p/mcf	12p/mcf			19.5p/mcf	
Laxford	42.77	29.68	3p/mcf	12p/mcf	10p/mcf		19.5p/mcf	
Torridon	30.21	19.40	3p/mcf				19.5p/mcf	
Seonaid	72.77	45.58	3p/mcf				19.5p/mcf	
Laggan	417.94	254.77					19.5p/mcf	£1/bbl
Tobermory	126.29	74.62	3p/mcf				19.5p/mcf	
Cambo	72.24	44.66	3p/mcf				19.5p/mcf	
Rosebank	1186.15	790.41	3p/mcf				19.5p/mcf	£1/bbl
Tormore Prospect	10.10	7.02	3p/mcf 50p/bbl				19.5p/mcf	£1/bbl
Tamdhu Prospect	60.44	42.07	3p/mcf				19.5p/mcf	£1/bbl
Capercaillie Prospect	1448.28	863.22	3p/mcf			5p/mcf	19.5p/mcf	£1/bbl
Cardu Prospect	73.01	58.04						£1/bbl
Pipeline	3.41	-20.11						

While the reduced rate of tax payable by an independent pipeline company has some effect it is clear that the viability of the entire activity is very sensitive to the required rate of return of the company and the associated level of tariffs.

9. Summary and Conclusions

This study has examined the economic aspects relating to a possible comprehensive development of the known gas discoveries and prospects for West of Scotland. Nineteen discovered fields and 4 prospects were identified. Some are virtually all gas but others are associated with oil, and some are predominantly oil. The combined gas reserves are estimated at around 3 tcf with the average size being quite small. Given the scattered location of the fields over a large area, and the hostile operating environment, with resulting high unit development costs, the economic exploitation of these reserves represents a considerable challenge. The relatively undeveloped infrastructure of (a) pipelines and (b) processing facilities adds greatly both to the technical and economic challenges. The long distance to a recognised gas market also adds substantially to the challenge.

There is a large range of possible development options. These relate both to the transportation routes and the development schemes. In this study various options relating to the eventual landing of the gas at St. Fergus were examined. These included maximum use of existing infrastructure (including its possible augmentation) both in the WOS and EOS areas. Thus the maximum use of the existing system for Schiehallion to Sullom Voe to Magnus was examined. The use of the existing pipeline systems from Magnus to Brent/FLAGS to St. Fergus was included in the study. In addition the possible further use of North Alywn/Frigg UK, and the SAGE systems were examined. Further, a new pipeline system direct from WOS to St. Fergus was considered.

With respect to the fields in the WOS area various possible development options were examined, including fixed platforms, FPSOs, TLPs, and sub-sea systems. For FPS systems both purchase and lease options were considered. The system which appeared most suitable for the size of reserves, water depth, and location in relation to possible host fields was chosen. Consideration had also to be given to the initial processing of the gas when it was associated with oil. Generally it was assumed that much initial processing would be undertaken on the field. The field development costs reflected the associated costs. Where no pipeline was readily available oil was assumed to be evacuated by tanker loading.

The economic analysis was undertaken by financial simulation modelling backed up by a large field database incorporating key data on production, and development and operating costs for sanctioned fields and those currently under active consideration for development. In addition a less comprehensive database incorporating fields in the technical reserves category was employed. The financial modelling also included possible new discoveries in all areas of the UKCS. From this modelling it was possible to estimate the likely ullage in all the main pipeline systems which might take additional gas from the WOS area. The financial modelling was undertaken for 3 price scenarios namely (a),$20, 18p, (b) $30, 28p, and (c) $40, 36p all in real, 2005 terms. The results for the fields are shown in terms of NPVs at 10% and 15% in post-tax real terms. In MOD terms this corresponds to 12.75%, and 17.875% post-tax at the inflation rate employed. The work was undertaken prior to the Pre-Budget Statement of the Chancellor that the tax would be increased and the results reflect CT + SC at 40%.

With respect to the Scenario involving maximum use of the existing infrastructure enhanced facilities in the Clair Area involving some synergy with the existing facilities were assumed. The relatively shallow water depth was a main consideration here. A new, but short, pipeline link to the existing Schiehallion gas pipeline would also be required. The results of the modelling indicated that, if adequate ullage was available, WOS, EOS and to St. Fergus the fields would generally be marginally acceptable at 10% real discount rate. Several would fail at 15% real discount rate. When the ullage issue was also considered it was found that there was inadequate capacity both in the Schiehallion – Sullom Voe – Magnus pipeline systems and in the system from Magnus to FLAGS to St. Fergus to accommodate the volumes from the fields. This remained the case even when significant augmentation of the WOSGPS, EOSGPS and the Magnus – FLAGS systems were included. With respect to the FLAGS system a major issue is the distinct possibility that substantial volumes of Norwegian gas will use it and pre-empt gas from WOS.

The study then considered the idea of a separate, communal pipeline system emanating from a hub in the WOS area and coming to St. Fergus either directly or via tie-ins to existing pipeline systems, namely at Alwyn North, MCPO1, FLAGS (direct tie-in), and SAGE. The first hub examined was at the Laggan field. This is the largest in terms of reserves. The modelling proceeded on the basis that the Laggan owners would develop the new separate pipeline and change tariffs to all the other fields as users. A working assumption was that the asset owners would require post-tax rate of return of 10% in real terms on any <u>incremental</u> pipeline costs. This assumption would apply to sub-hub owners as well.

The modelling found that under the $30, 28p case it was possible to find combinations of tariffs which left positive NPVs at 10% on the individual fields and satisfied the stated conditions for the asset owners for the system involving a pipeline direct to St. Fergus. But the size of the NPVs was often quite small. Under the $40, 36p case there was some additional margin for the field owners, but the NPVs at 15% were still sometimes unlikely to be acceptable.

When the modelling examined the prospective returns to field and pipeline owners for schemes linking into North Alwyn, MCPO1 and FLAGS it was found that, while there could be reductions in the pipeline costs problems of ullage in the Frigg UK and FLAGS pipelines re-emerged.

The study then examined the possibilities of using Victory and Seonaid as hubs. They were chosen because of their location in relatively shallow water and on transport distance minimisation grounds. But both of these fields have small reserves and their employment as hubs would entail major increases in investment costs. The modelling examined a direct communal pipeline to St. Fergus and the other options discussed above in relation to Laggan as a hub.

It was found that, under the $30, 28p case, while it was possible to find a combination of tariffs which produced positive NPVs for the fields and gave the asset owners a 10% real post-tax return on their incremental costs, the size of the returns to the asst owners was quite modest. Generally they failed to produce 15% real post-tax returns. The downside risks would, therefore, be high and these options were felt to be less attractive than the hub based on Laggan.

The modelling was based on a fast-track pace of development for the gas fields in the WOS area. A case where the pace was rephrased was examined to ascertain whether this would make the use of the existing infrastructure more plausible. Even with a significant rephrasing it was found that the ullage problem was likely to be present. A significant rephrasing of field developments may also make the development of a communal pipeline system more difficult. The asset-owners will have to wait a longer time before receiving tariffs from some of the user fields.

Finally, the idea of an independent communal pipeline system was examined. This would attract tax at 30% with capital allowances on 25% declining balance basis. It is also possible that the cost of capital might be relatively low if substantial long-term contracts were secured. The case examined in detail was a pipeline from Laggan direct to St. Fergus. The modelling indicated that, under the $30, 28p case, the requirement of a 12.5% real post-tax return by the pipeline owner (15.3% in MOD terms) would result in tariffs being such that some of the new fields would become uneconomic at 10% real, post-tax discount rates. The result was that the asset-owner did not achieve his minimum return. A similar result emerged when the required minimum return of the asset owner was 10% in real, post-tax terms (12.75% in MOD terms). When the asset owner's minimum return was 8% in real, post-tax terms (10.7% in MOD terms) it was found that tariffs could be levied which would leave the field owners with positive returns at 10% in real, post-tax terms. Under the $40, 38p price scenario there is distinctly more scope for the achievement of minimum acceptable returns to both field and asset owners.

The overall conclusion is that under the price scenarios likely to be employed by investors the comprehensive development of gas from WOS is only marginally attractive. Substantial extra discoveries would, of course, greatly facilitate development by making the returns to a cluster development and communal pipeline more attractive. If the expected exploration in 2006 and 2007 produced discoveries in the 1-2 tcf range the economic prospects would be greatly enhanced.

The study was conducted before the Pre-Budget Statement announcing that the tax on new fields such as are examined here is to be increased from 40% to 50%, an increase of 25%. This generally reduces the field returns in terms of NPVs by 16.67%. The already marginal returns under the \$30, 28p case become even more marginal. The tax system itself does not cause a positive pre-tax return to become negative after tax. But on a risk basis the chances of a return becoming very small are increased by the proposed tax change. Thus the chance of a project having a chance of an unacceptably low return are increased by the tax change.

The tax increased applies to tariff incomes. This study has shown that the returns to fields are very sensitive to the tariffs which are payable. In many of the Scenarios relatively low tariffs were necessary to ensure that field developments took place. The increase in the tax on tariff income by 25% may cause upward pressure on tariffs by asset owners which could further jeopardise the development of the fields. In this respect there is a further advantage to the independent pipeline company.

The overall conclusion is that the comprehensive development of the gas discoveries in the WOS is very marginal at gas prices likely to be employed for long-term investments. The attainment of a cluster development involving many fields demands a very high degree of cooperation among licensees. Success is also likely to depend on tariffs which do not produce high returns to the asset owners. The proposed tax changes certainly do not help to promote a comprehensive development. Given all the challenges it is possible that piecemeal developments will occur with the economically most attractive fields leading the way using existing infrastructure, while many small fields are left undeveloped for a long time. A comprehensive development is likely to require a combination of strong leadership and initiatives by both Government and industry.