Faroes Exploration License 004

Remaining Hydrocarbon Potential

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1 Executive Summary

This document provides a review of the remaining hydrocarbon potential of Faroes Exploration License 004. It documents the evaluations leading up to the application for the license, the drilling of the Svinøy well and the subsequent re-evaluation of the remaining hydrocarbon potential of this license. The remaining hydrocarbon potential of Faroes License 004 is described by referring to the play risk model.

There is a proven, working petroleum system in License 004 and there is evidence to indicate that the hydrocarbon discovered has typing from a mixed middle Jurassic-upper Jurassic source system similar to that observed elsewhere in the Faroes-Shetland Basin.

The poor quality oil sample recovered in the 6004/12-1 (Svinøy) core indicates that the T35 sandstone comprises a hydrocarbon migration pathway. The T10 oil discovery by the 6004/16-1Z (Marjun) well is a potential play-opening discovery and has shown that there are hydrocarbons at different stratigraphic levels to the West of Shetland (WoS) field reservoirs. There is also evidence to indicate that a regional seal exists between the T10 and T38-T34 plays.

Nevertheless, there is some evidence to signify sediment provenance to Faroes Exploration License 004 from a westerly source. This has significant implications for seal competency, trap development and reservoir presence.

Bright seismic amplitudes have been used as lithology indicators (reservoir presence) with some degree of success. However, there is a high degree of uncertainty in the use of amplitudes as a fluid indicator.

Reservoir quality in License 004 fluctuates widely with good porosity, permeability and net to gross characteristics in the T38 – T34 focus interval and poor characteristics in the T10 interval. Reservoir deliverability is highly variable in all sequences (T38-T10). Significantly, in the T10 hydrocarbon bearing interval reservoir quality and subsequently deliverability is extremely poor culminating in the low commercial viability of any discovery.

To conclude, the elements of the play risk model enabled a full re-evaluation of the remaining hydrocarbon potential of Faroes License 004. The majority of prospects identified in License 004 required a stratigraphic element to form the trap. This trapping mechanism relied heavily on top, bottom and lateral seals which have a historically low probability of success. The absence of a seal in License 004 and the subsequent absence of a valid trapping mechanism have proven to be the critical risks for prospect failure in the license area.

The conclusion is that the remaining hydrocarbon potential of License 004 is considered to be very low with volumetrically minor, high risk prospects remaining.

2 Introduction

Faroese Exploration Licence 004 was awarded during the First Faroes Licensing Round in August 2000 (see figures 1a and 1b). BP Amoco Exploration (Faroes) Limited (100% operator) applied for two, six year Exploration Licences on the Bordøy and Bordøy Satellite Application Areas illustrated in figure 1.

BP Amoco Exploration Faroes Ltd was awarded the operatorship (100%), of blocks 6005/15, 6004/11 and 6004/12 in the original Bordøy application area. Shell then farmed into the License in June 2001 resulting in following equity split; BP 66.67% (operator) Shell 33.33%.

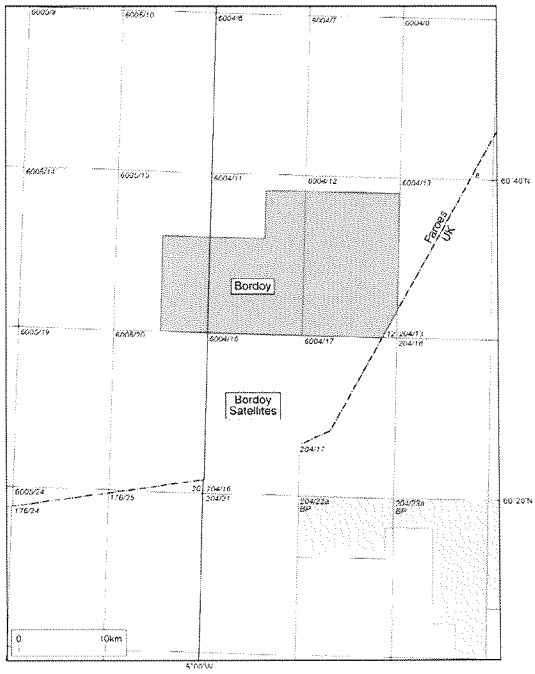


Figure 1a: BP Faroes Exploration License 004 Application

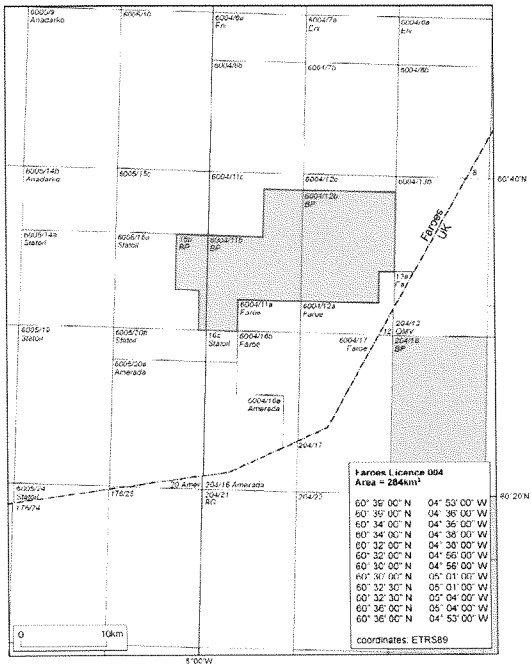


Figure 1b: BP Faroes Exploration License 004 Award

3 License History

3.1 The Application

BP Amoco Exploration (Faroes) Limited (100% operator) applied for two, six year Exploration Licences on the Bordøy and Bordøy Satellite application areas illustrated in figure 2. The Bordøy License area incorporated Faroese blocks 6005/15, 6004/11 and 6004/12. The Bordøy Satellite area application was contingent on the award of the Bordøy License area and included blocks 6005/20 and 6004/16. BP believed that the six year licence period was sufficient to effectively explore and appraise the area.

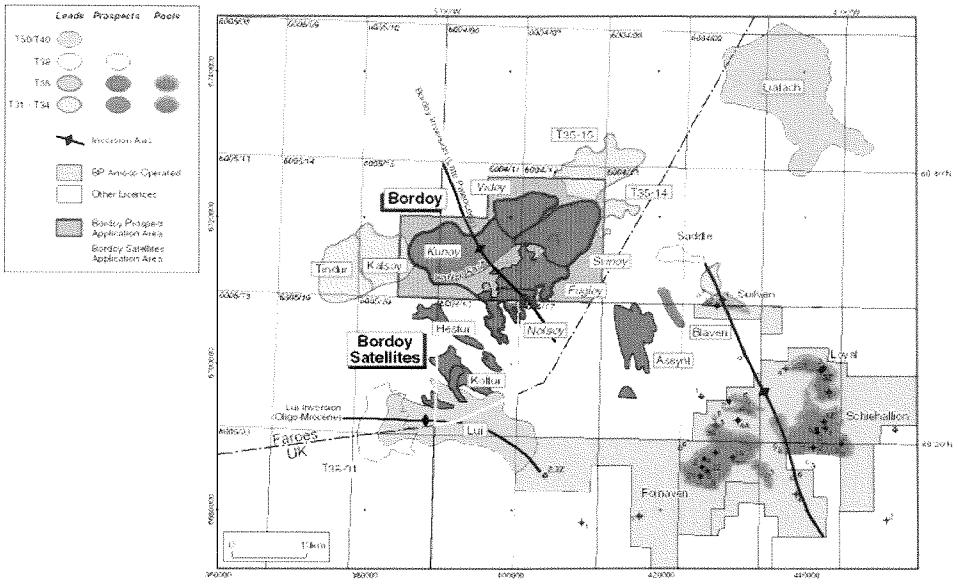


Figure 2: Bordoy and Bordoy Satellite application areas. (Source BP)

Work Programme

The work programme was three wells on the Bordøy Licence area and one firm well on the Bordøy Satellites (Koltur prospect) Licence, contingent on the award of the Bordøy Licence. The wells were planned to fully penetrate the Paleocene target interval, with the option of deepening two wells to test the full Tertiary section at depths ranging from ca. 2500 to 4200mss.

BP Exploration (Faroes) Limited agreed to provide Environmental Impact Assessments prior to each well, and any other associated activity would be undertaken in accordance with relevant Faroese legislation and existing BP Amoco environmental policies.

Participation

BP Amoco Exploration (Faroes) Limited also agreed to fund a project with the Faroese electricity company, SEV, to investigate the options for the BP provision of low sulphur clean fuels for electricity generation (14.4 million DKK/$2million).

Furthermore BP Amoco Exploration Faroes Ltd agreed to fund a feasibility study for establishing a permanent fibre optic telecommunications link between the Faroe Islands and Shetland, UK (7.2 million DKK/$1 million) and undertake a Strategic Business Review of the Faroes/UK Atlantic margin area to baseline the impact of the industry on aspects of the economy, environment and socio-environmental conditions (1.08 million DKK/$0.15 million).

BP Amoco Exploration Faroes Ltd also offered opportunities for developing local industry competence through the use of local services where possible and the training and employment of local personnel on appropriate activities (7.2 million DKK/$1 million). BP Amoco Exploration Faroes Ltd also arranged to second two people, nominated by the Faroese authorities, to work for two years in BPA's offices in Dyce, Aberdeen; to work in a variety of business units to gain first hand experience of working for a major oil and gas company. (This is in addition to the above).

The proposed work programme for the Bordøy Licence application area was as follows:

- 1 exploration well on the Svinøy segment, to test T35 and T34 levels.
- 1 exploration well on the Vidøy segment, drilled to test T35 and T34 levels, with a possibility of deepening to base Tertiary.
- 1 exploration well on the Kunøy segment, drilled to test the T34 level, with a possibility of deepening to base Tertiary.

In the event of exploration success, three segments would be drilled in the following order:

1. Svinøy: Primary test of the T35 reservoir target, TD in the lower T30's.
2. Vidøy: A cross-fault extension of Svinøy and a test of the down-dip extension of the deeper T34 Kunøy segment. It will also test the stratigraphy to base Tertiary.
3. Kunøy: Crestal T35 test and will possibly be deepened to base Tertiary, dependant on the results of Pre-Stack Depth Migration (PSDM) seismic reprocessing

In the event of early failure three independent tests will be made from Svinøy, Kunøy, Nolsøy or Fugløy. In the event of early success, was planned to reshoot 3D seismic over all or part of the application area, in order to optimally appraise and develop the discoveries.

The proposed work programme for the Bordøy Satellites Licence application area was for a single exploration well on the T35 Koltur prospect, which was contingent on the award of the Bordøy Licence area. In the event of Koltur success, BP would appraise the Hestur and Nolsøy prospects. In the event of failure no further activity would be anticipated.

3.2 The Award

The Faroes 1st Round Licence 004 was awarded to BP Amoco Exploration Faroes Ltd on August 17th 2000, for a six year term. Shell gained 33.33% equity in the licence in June 2001.

The commitment work programme comprised three wells (Svinøy, Kunøy, and Vidøy): a full fold, fully migrated 3D seismic acquisition over the licence area; Faroes participation projects in support of education and industry to a total value of DKK 40 million; and DKK 1.5m/year contribution to the SINDRI programme.

3.3 License Key Events

The first well was drilled on the Svinøy prospect in 3rd Quarter 2001 and was suspended with minor shows after experiencing difficulties removing the wellhead during abandonment. Abandonment was completed in November 2002 and environmental compliance was acknowledged by the HFS in September 2003.

197 km2 of 3D seismic over 004 was acquired by Agip in 2001 and obtained through a trade agreement. The Faeroese Petroleum Ministry recognized this as partial fulfilment of the 3D requirement. In July, 2003 the JFS granted a waiver of the remaining 3D conditioned upon completion of a 610 sq km, 3D, pre-stack depth migration.

The technical efforts in 2003 included evaluating other opportunities for fulfilling the remaining well commitments; finalizing and delivering the 2002 long-offset, 2D seismic; a re-evaluation of the petroleum system incorporating new well results; a gravity/magnetics study to validate Kunøy and Vidøy; monitoring of key new wells in the Faroes-Shetland basin; and attempting lithology calibration and prediction over the License.

In late 2004 BP, as operator of Faroese Exploration License 004, approached the Faroese Petroleum Administration (OFS), on behalf of the partnership (BP/Shell) with a proposal to transfer the two remaining drilling commitments (Vidøy and Kunøy) on License 004 to a single well commitment on Exploration License 007.

The rationale behind the approach was based on the partnership's belief that the results of the first well on License 004 had changed the perception of the hydrocarbon prospectivity of the Licence to a degree that it had become more attractive and economically sound to allocate the commitments of the License to other parts of the Faroese license area. There were no longer valid prospects at Vidøy and Kunøy on License 004.

The Faroese Petroleum Administration (OFS) approved the transfer in November 2005.

Technical efforts in 2005 concentrated on detailed location assurance for the proposed well transfer and outline well planning and cost forecasting. The subsequent granting of approval from the Faroese Minister of Trade and Industry was received in October 2005 on the condition that:

The Licensees, BP Amoco Exploration (Faroes) Limited and Shell U.K. Limited, agree to enter into L007 with Anadarko and take on the firm commitment for Licence 007 as specified in the enclosed draft Annexes 2B and 3B of Licence 007.

The Licensees submit a final report on the remaining hydrocarbon potential of the relinquished area.

Furthermore, a site survey was commenced during the summer months but was cancelled due to harsh weather conditions encountered on site. A pore pressure evaluation was also completed for the proposed well location (see Cox, D.J, 2005). 2D depth migration seismic processing tests were also undertaken.

3.4 Participation

The 004 License award required BP Amoco Exploration Faroes (Ltd) participating in projects in support of education and industry to a total value of DKK 40 million as well as DKK 1.5m/year contribution to the SINDRI programme until the end of the six year License term in 2007.

The transfer of License 004 to License 007 does not include the transfer of any obligations regarding BPA's commitment to participation in education and industry and the aforementioned obligations will remain until the end of the original six year 004 License term at the end of 2007.

As at the end of 2005 BP and Shell had spent DKK 27,144,739 million on Faroese Participation, of which DKK 8.326.512, DKK 2.223.558, DKK 4.682.179, DKK 6.536.766 and DKK 5.375.724 were spent in 2001, 2002, 2003, 2004 and 2005 respectively.

During 2006 BP and Shell will focus their efforts on finding attractive projects to sponsor and they intend to spend approximately DKK 5,8 million on Faroes Participation during 2006. This leaves DKK 7,055,261 from the original participation commitment to be allocated in 2007.

4 License Evaluation at Time of Application

4.1 Prospectivity Summary

All the elements required of a working petroleum system were thought to be present in the Licence application area to deliver significant oil accumulations:

Pre-drill of the 6004/12-1, 1Z Svinøy well, the primary reservoir targets were the T34-T35 sandstones deposited by turbidite flows in a deep marine setting. Significantly, the pre-drill BP Amoco view was that sandstone deposition took place within channelised systems on a low angle ramp, fed from an uplifted Scottish Massif (Shetland Platform) to the south-east. These reservoirs were thought to be directly analogous to those currently producing oil in the UKCS Quadrant 204 Foinaven, Schiehallion and Loyal fields.

All the reservoirs were thought to sit beneath the basal T36 sequence which was thought to provide a regionally extensive top seal across the basin. In addition, local intra-sequence seals were also thought to be present and able to provide effective seals at a prospect level. The most likely hydrocarbon charge at the time of application was considered to be oil. Two significant charges of oil were identified, the first in the Eocene and the second in the Oligo-Miocene. Both charge events post-date the initial formation of the traps; the second charge offers the possibility of a late 'top-up' to the traps following post Paleocene structural modification.

The Bordøy Licence application area covers a T38/T40 inversion anticline which has been modified by post Late Eocene subsidence and basin inversion. The structural geometries formed during T38/T40 inversion were considered key to hydrocarbon trap formation at Paleocene T34-T35 levels, in particular, E-W extensional faults, SW-NE strike-slip faults and associated 'pop-up' structural highs, and inversion of structurally low areas containing reservoir sands to enhance the extent of stratigraphic traps.

The Bordøy area was the core of BPA's application. The Bordøy Prospect comprised five reservoir segments within a T38/T40 inversion structure - at Upper T35 (Svinøy and Vidøy), Lower T35 (Nolsøy) and T34 (Kunøy and Fugløy) levels. Total mean oil reserves within this Licence application area were 392 Million Sm3. (unrisked) at an average risk of 0.29 (1 in 3.4) which gave a risked reserves outcome of 114 Million Sm3. Individual segment risks range from 0.42 (1 in 2.4) to 0.23 (1 in 4.3).

All the prospects and prospect segments were thought to combine both structural and stratigraphic trapping elements which were believed to have been mapped in detail on 3D seismic data. Some generic risks remained on reservoir effectiveness and charge which were only addressed by drilling the 6004/12-1, 1Z Svinøy well. Despite these generic risks, BP Amoco had been able to reduce segment risks down to low levels through the application of BPA 's proprietary seismic technology, experience and detailed understanding of the petroleum system in the UKCS Quadrant 204.

4.2 Available Datasets

4.2.1 2D Seismic Database

BP Amoco has an exhaustive 2D database in the Faroe-Shetland Basin, dating back to the earliest phase of exploration in the 1970's. The database was primarily targeted at the definition and delineation of structural targets along the basin margins of the Faroe-Shetland Basin, such as the Rona Ridge and Judd High. The database led to the discoveries of Clair, Strathmore and Victory which all appeared as large areal closures on relatively sparse 2D grids. The success rate of exploration wells drilled on 2D seismic data however has been poor in comparison to other areas of the United Kingdom Continental Shelf (UKCS).

The database used for the Faroes License 004 exploration acreage evaluation consisted of surveys acquired post-1984, to ensure that imaging was of sufficient quality to allow a reasonable sequence based interpretation. Over 39,000 line kilometers of data formed the basis for the regional evaluation covering the Faroe-Shetland Basin and its margins. The same data were also provided regional tie lines from 3D surveys into unlicensed/undrilled acreage and provided well ties between 3D seismic surveys or into areas of sparse 3D coverage.

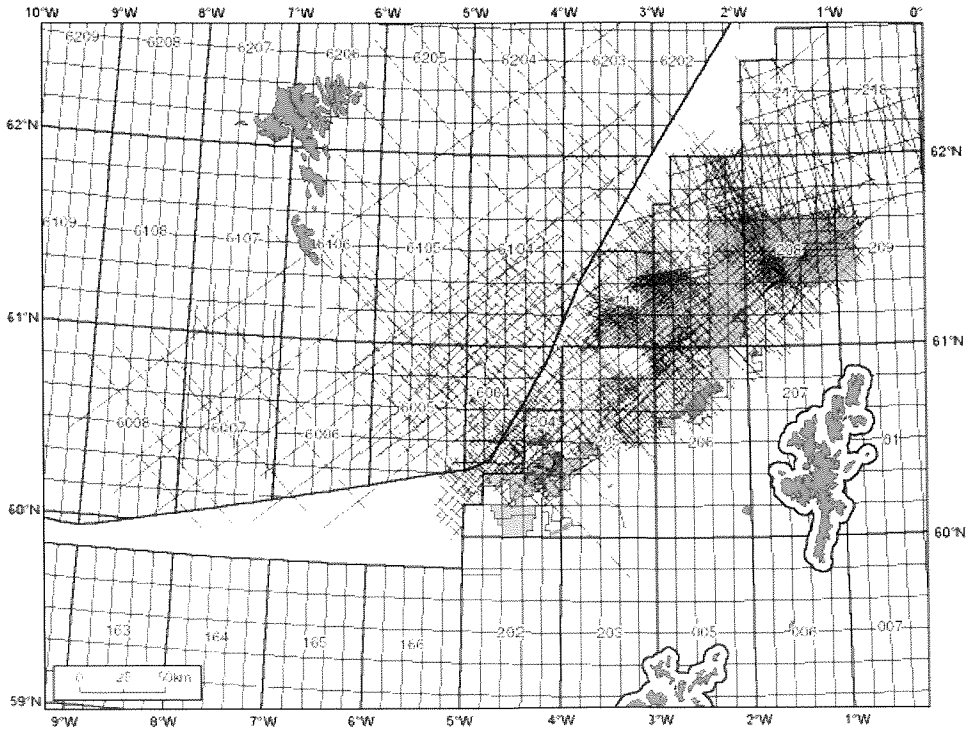


Figure 3: BP 2D seismic coverage in the Foinaven Basin (Source BP)

4.2.2 3D Seismic Database

A combination of entitlements provided BP Amoco with extensive coverage of the Faroe-Shetland Basin by 3D seismic data. This blanket coverage was instrumental in focusing the area of interest and provided a wealth of information in contrast to earlier acreage licensing rounds, where much reliance was placed upon 2D seismic data.

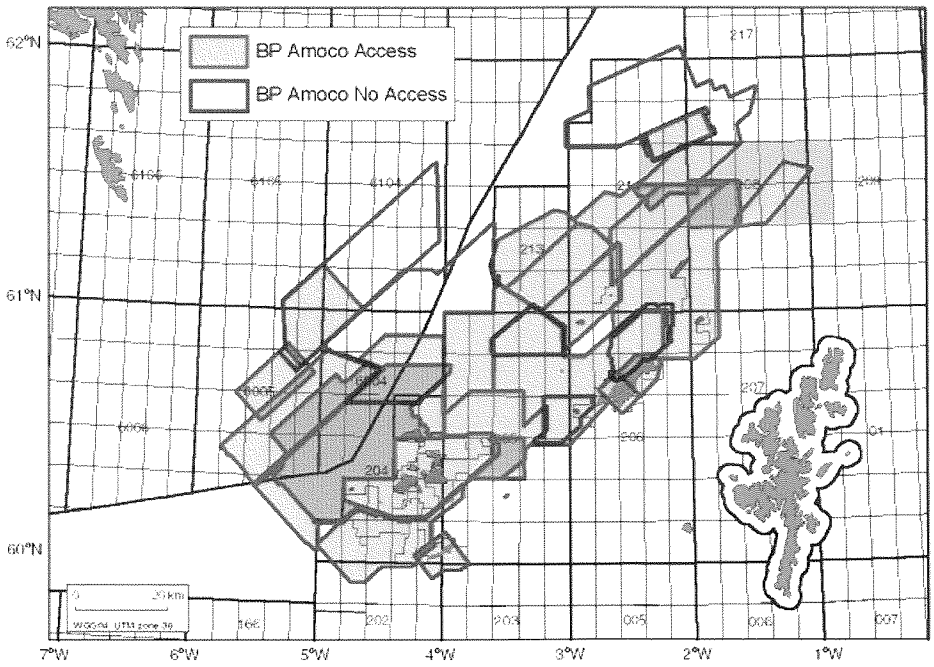


Figure 4: BP 3D seismic coverage in the Foinaven Basin. (Source BP)

BP Amoco created a new high quality 3D seismic data-set over the Foinaven Basin. This new dataset was critical in accurately describing and de-risking the Paleocene prospectivity. The final migrated data-set combined data from four vintages of seismic acquisition across the UKCS Quadrant 204 and UK/Faroes undesignated acreage. These include both the BP Amoco proprietary UKCS Quadrant 204 data and the 1996/1997 Veritas and PGS acquired 'spec' surveys. Combining these surveys allowed regional sequence mapping and prospect description to be done in a consistent manner, and directly tied in to the producing Foinaven and Schiehallion fields. This was done by ensuring the best possible merge of the 4 separate surveys, applying processes that retained consistent amplitude and phase across the whole area of interest, and by applying extensive processing knowledge throughout the pre-and-post stack processing sequence.

The work was done by the in-house processing team, with staff, software and hardware contracted from the experienced seismic contractor CGG (Companie Generale de Geophysique). Seismic traverses from the original and reprocessed volumes emphasised the increased resolution, continuity and amplitude integrity for both regional mapping and prospect description seen on the 1999 data.

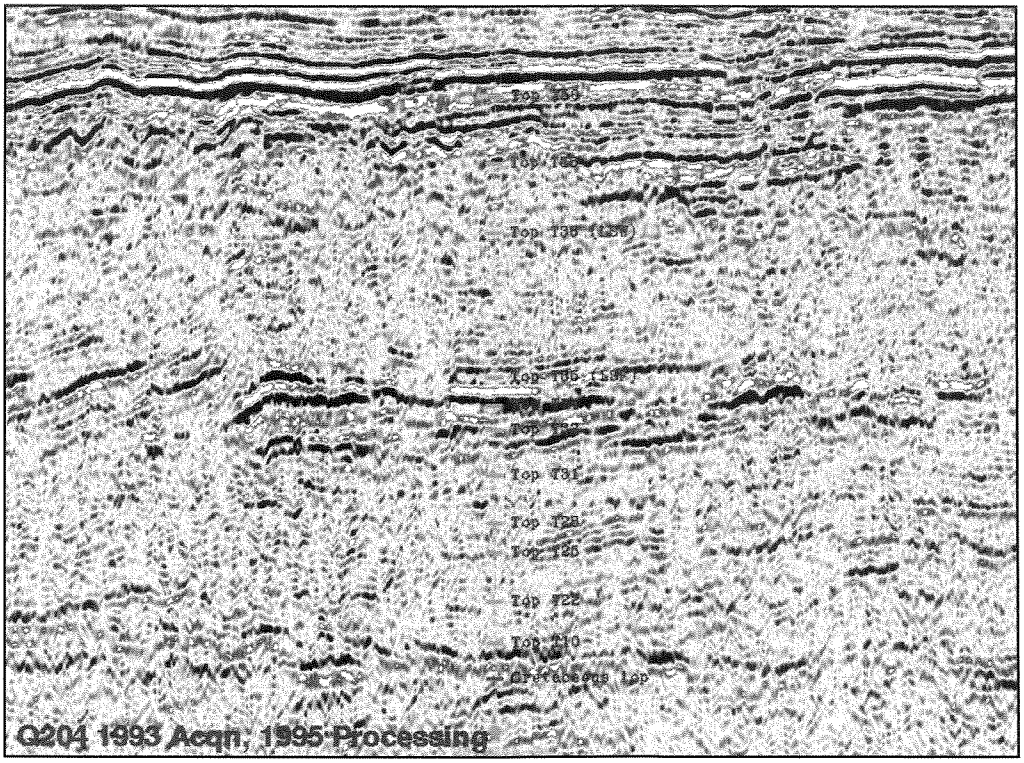


Figure 5a : Foinaven strike line showing Quadrant 204 1993 acquisition data before 1999 reprocessing

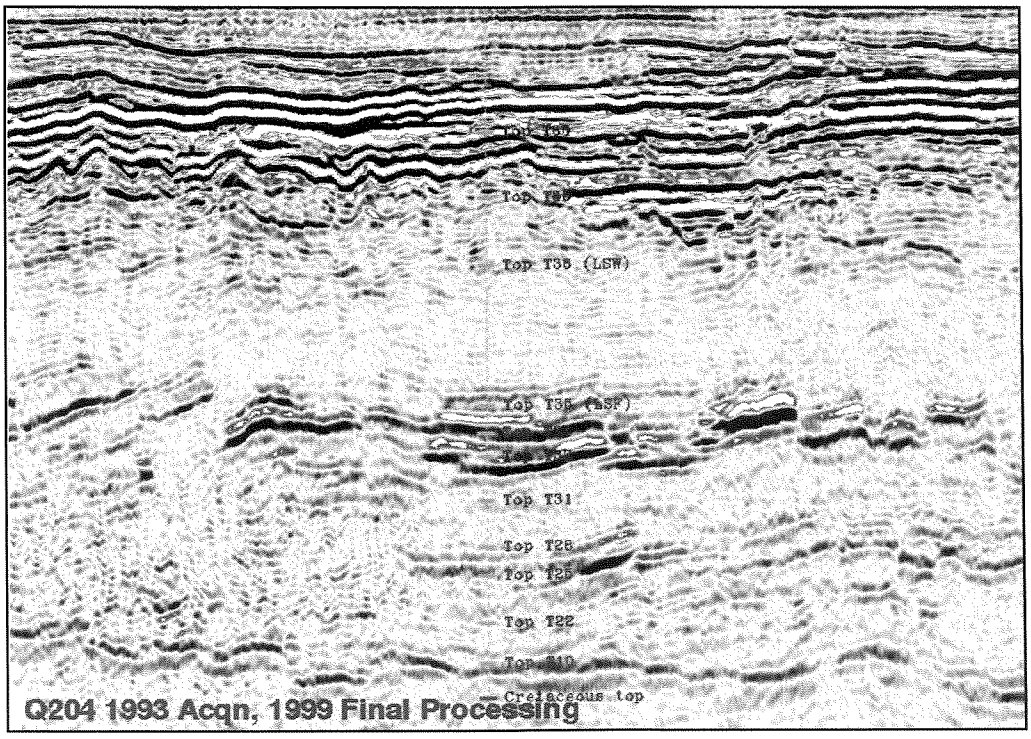


Figure 5b : Foinaven strike-line showing Quadrant 204 1993 acquisition data after 1999 reprocessing

Figure 5b illustrates a clear improvement in continuity, fault resolution and amplitude over the previous 1995 version of a Foinaven strike line shown in figure 5a.

In addition to the delivery of a high quality zero phase full offset migration, BP Amoco created AVO analysis volumes (using the restricted angle stacking technique) and a 3D velocity volume for depth conversion and sequence velocity analysis. AVO volumes were an important part of the prospect de-risking process. Figure 5 shows an AVO volume illustrated on a Foinaven dip-line. The brightening that occurs on the oil filled sand event when comparing the Far offset volume to the Near offset volume.

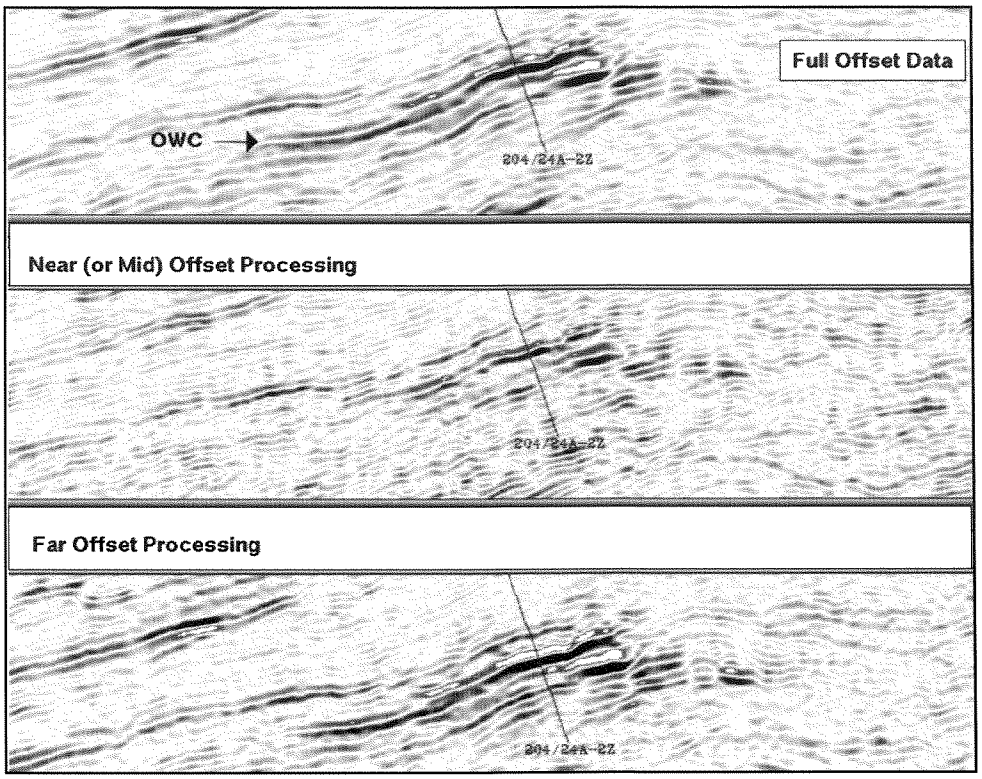


Figure 6: AVO volumes illustrated on Foinaven dip line. (Source BP)

Further to these direct reprocessing products, BP Amoco also created Acoustic Impedance (AI) Inversion volumes. These data-sets, as with the AVO volumes, played a part in improving prospect risk reduction. BP Amoco developed a proprietary technique for AI inversion that is highly appropriate to inverting a large area of seismic data with only limited or areally restricted well data ties. The technique is faster and more efficient than conventional approaches.

There were, however, a number of remaining issues around seismic quality, such as acquisition coverage and quality, data-set edges and areas of shallow basalt overburden. Mapping suggested that a thin feather edge of basalts within the late Paleocene extended over a significant part of the Foinaven Basin, and could cause significant problems with seismic imaging in that area. BP Amoco consequently carried out a full pre-stack depth migration (PSDM), where a more accurate model of the depth/velocity field was built in an iterative manner, which was then input into a high quality imaging algorithm on the pre-stack data-set. BP Amoco reprocessed a 240 square kilometre swathe of data using CGG's depth migration capability in the first quarter of year 2000.

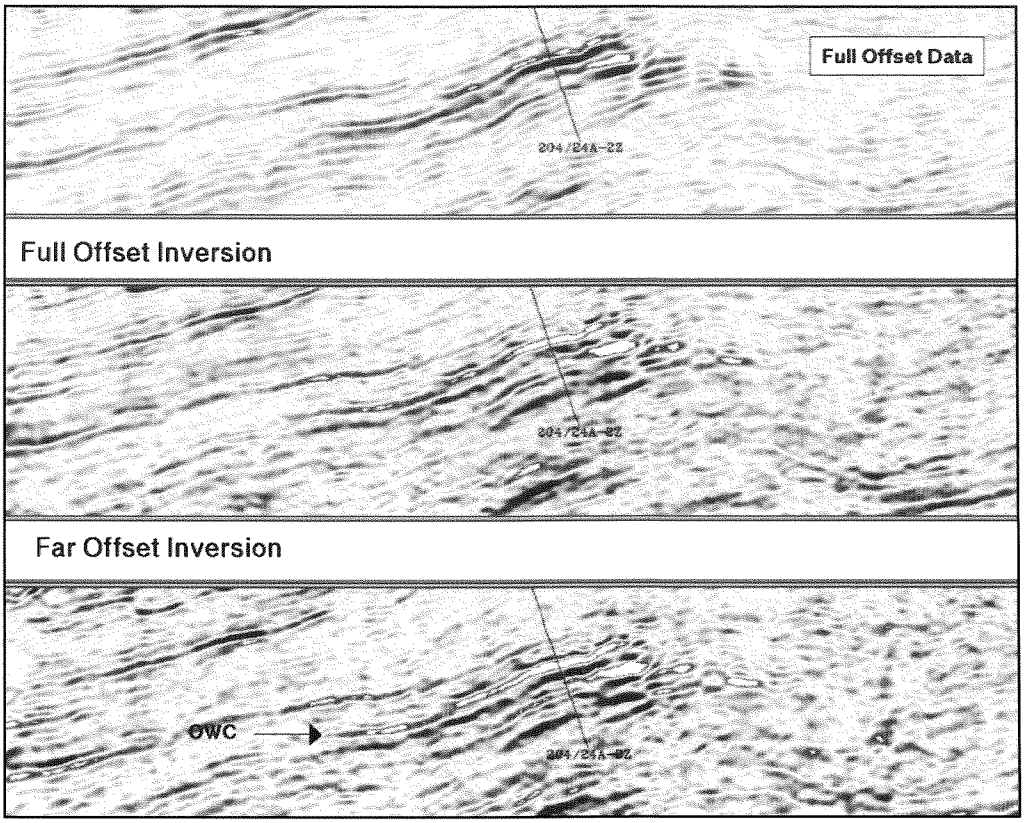


Figure 7: Inverted impedance volumes illustrated on Foinaven dip line. (Source BP)

4.3 Seismic Analysis

4.2.3 Rock Physics: Calibration to Seismic Response

One of the keys to successful exploration in the Foinaven Basin was the integration of seismic amplitudes with the acoustic properties of the rocks revealed in data from nearby wells. A detailed understanding of the subsurface controls on the seismic response enabled BP Amoco to achieve a step change in exploration risk reduction in allowing the identification of those prospects which had the lowest risk.

BP Amoco analysis of the well data revealed that the principal controls of the seismic response to the subsurface to be; sediment provenance, diagenetic history, depth of burial effects on rock modulii and biodegradation depth controlling fluid visibility.

The various different channel entry points to the Foinaven Basin are fed by sediments of different provenance. Sediments derived from the southern entry point tend to be depositionally more shaley than those derived from the south east entry point. The higher initial clay content has slowed the rate of compaction diagenesis and consequently porosity at any given depth below mud line is higher in the sediments of the south channel than those of south east provenance.

The different diagenetic histories have given rise to different trends in the rock modulii. Trend curves for elastic impedance with depth for shales are compared to sands pore-filled variously with brine, oil and gas. Seismic reflectivity and consequently hydrocarbon visibility is dependent upon there being a difference between the hydrocarbon filled sand and the brine sand/shale background.

Oil sands have lower impedance than shales and gas sands have yet lower impedance again. As depth increases the difference between hydrocarbon filled sand and shales decreases until the point where there is no contrast. This is the Direct Hydrocarbon Indicator (DHI) basement. DHI basement is reached for gas at a slightly greater depth than for oil. DHI basement for both hydrocarbon phases is deeper for sands derived from the southern channel entry than for the south east derived sediments. Hydrocarbons may well exist below the DHI basement depth but confidence in the reliability of seismic anomalies indicating the presence of hydrocarbons is very low.

The final DHI susceptibility factor is the depth of the hydrocarbon reservoir with respect to the biodegradation depth. The bacteria responsible for degrading oil to tar cannot survive at temperatures greater than 75°C. Oils throughout the Foinaven sub-basin reservoir at temperatures lower than the critical isotherm are all partially biodegraded and become supersaturated at low Gas Oil Ratios (GOR). oils at temperatures greater than 75°C appear not to be degraded and are undersaturated (have no gas cap).

4.2.4 Seismic Response: Bright Amplitudes & AVO Analysis

The known rock properties predict the amplitudes of the stacked seismic data as well as the Amplitude Variation with Offset (AVO) measured from incident angle limited stacks and from pre-stack data.

Stack amplitudes and AVO response from both hydrocarbon and brine saturated rocks encountered in wells throughout the UKCS Quadrant 204 area have been examined in both synthetic and real seismic data. These examinations revealed that while amplitude and AVO response varies between the various reservoirs, consistent trends exist. The observed trends can be utilised to significantly reduce the risk in differentiating the seismic responses for brine saturated and hydrocarbon saturated rocks and to a lesser extent, the seismic responses for gaseous and liquid hydrocarbon accumulations.

The trends in stack amplitudes, as identified from data across the UKCS Quadrant 204 area, indicated a consistency in both space and time (or depth). Large negative amplitudes, indicating a decrease in acoustic impedance, which conform to structure are observed to be direct hydrocarbon indicators (DHIs).

The temporal variations in stacked amplitudes are diagnostic of possible changes in fluid content in a reservoir. The magnitude of the stacked amplitude decreases when the pore fill changes from hydrocarbon to water at the water contact. Identification of such a change and a corresponding conformance with structure strongly implies the presence of hydrocarbons.

The sources of large negative amplitudes are many, and identifying which are actually indicative of the presence of hydrocarbons is critical and requires additional information. This information may be extracted from the pre-stack data by either comparing sub-stacks created by stacking the data over two or more limited ranges of incidence angle (angle stacks), or by converting the pre-stack amplitude information to constituent intercept and gradient form through least squares inversion and analysing the components. Angle stack comparisons are generally performed by taking the difference between the stacks over ranges of small angles and over ranges of larger angles.

It is generally accepted that the difference is a measure of the overall amount of change of amplitude. Since it is commonly recognised that the reflectivity from a shale/hydrocarbon sand interface is greater than reflectivity from a shale/brine sand, identification of maxima in the difference volume, and conformance of the difference with structure, provides significant reduction to the risk of finding hydrocarbons.

Further analysis of AVO responses comes in the form of pre-stack intercept-v-gradient or B0-v-B1 cross-plotting. The decomposition of offset-variant reflectivity into constituent intercept/gradient components provides a method for identifying not only the increase in amplitude but also the rate of change of amplitude. It is commonly accepted that the gradient, or rate of change of amplitude, is directly related to the change in Poisson's ratio in the rocks, which is

turn is related to the change in the ratio of the P- and S-wave velocities (Vp/Vs) in the rock.

One source of anomalous variations in Vp and Vs is the presence of hydrocarbons in the rock, since the hydrocarbons cause a decrease in Vp at the top of a reservoir but may cause an anomalous increase in Vs at the reservoir top, thus lowering the Vp/Vs ratio. The anomalous change in Vp/Vs, then, introduces an anomalous amplitude gradient. Identification of this gradient, and its conformance with structure, offers a clear reduction to exploration risk.

The decomposition of reflectivity into its constituent parts also permits the identification of anomalous intercept (zero offset) magnitudes. The intercept is a direct measure of the change in acoustic impedance (AI). Hydrocarbons introduce larger reductions in AI than brine, so identification of anomalous impedance changes is often an indication of the presence of hydrocarbons.

A common method for analysis of the intercept (B0) and gradient (B1) pairs is to cross plot the two quantities and, from the cross plot, identify anomalous points that predict hydrocarbon accumulations that are temporally and spatially consistent. The least squares inversion procedure with which the intercept and gradient are commonly computed also allows for the computation of other AVO attributes, such as the fractional change in Vp and Vs, according to various forms of the linearized Zoeppritz equations. AVO attributes, such as intercept and gradient and fractional changes in Vp and Vs, are very useful parameters when data volumes permit viewing and analysis either in cross plot or in unison.

Analysis of the parameters can be simplified through linear combinations of them. For example, it is possible to combine either the intercept and gradient or the fractional changes in velocity (after certain assumptions) to form a representation of the difference between P- and S-wave reflectivity, which is a true fluid indicator.

4.3 License 004 Reserves Base at Time of Application

The total Bordøy and Bordøy Satellite Prospect pre-drill mean reserves base within the application areas was ca. 474 Million Sm3 with an average risk of 0.30, giving a mean risked reserve base of ca. 141 Million Sm3 (see Table 1). The reserves were calculated by applying a 35% recovery factor to the entire mapped oil-in-place.

The Bordøy and Bordøy Satellite reserves represent the ultimate recoverable reserves of the prospects. It was anticipated that growth from the core reserves to the whole prospect reserves would occur following establishment of successful production from the core development area.

	Block	Name	Status	Sequence	Area (km2)	Trap Type	STOIIP Mean (MMm3)	Reserves Mean (MMm3)	Core Area Reserves Mean (MMm3)	Water Depth	Depth to crest	PoS
Bordoy prospect	6004/12	Svinoy		UT35	63	Struct/Strat	260	92	56	1050	2070	0.42
		Vidoy		UT35	46	Struct/Strat	160	58	47	1050	2300	0.33
		Kunoy		T34	70	Struct/Strat	490	171	71	1000	2300	0.25
	6004/12	Fugloy		T34	27	Struct/Strat	80	28	19	1050	2600	0.27
Bordoy Satelittes	6004/17	Koltur		LT35	26	Struct/Strat	130	46	24	900	1600	0.34
	6004/17	Hestur		LT35	12	Struct/Strat	47	16	9	950	1800	0.28
	6004/17	Nolsoy		LT35	59	Struct/Strat	180	63	38	1050	1850	0.23
Leads	6004/16	Lui		T50	132	4-way dip	350	120		950	450	0.21
		T38-01		LT38	52	Strat	128	45		1050	850	0.19
		T35-15		LT35	57	Struct/Strat	202	71		1100	2650	0.19
		T35-14		LT35	18	Struct/Strat	43	15		1100	2400	0.2
	6005/15	Kalsoy		T34	48	Struct/Strat	372	130		1050	2350	0.13
		Tindur		T34/T35	17	4-way dip	88	31		1050	2325	0.22

Table 1: Pre-drill prospects volumetric summary & risk (Source BP)

The core prospect reserves are calculated by including only those compartments where producer recovery of ca. 3.2 Million Sm3 (20 mmbbls) was confidently predicted. This was achieved using seismic amplitude and coherency technology, benchmarked against Foinaven and Schiehallion oil production experience. The total core prospect mean reserves base within the application areas was ca. 259 Million Sm3 at an average risk of 0.30, giving a mean risked reserve base of ca. 76 Million Sm3 (see Table 1).

5 Pre-Application Petroleum System Play Risk Assessment

5.1 Charge

BP Amoco's proprietary database and extensive subsurface interpretation experience in the Foinaven Basin gave it a leading edge for the understanding of the Faroes sector Paleocene play system. An understanding of the play system in the Paleocene of the Foinaven Basin was considered an essential tool for the more detailed identification of prospects in the Basin, particularly as the Paleocene play system in the Faroes sector of the Foinaven Basin is the direct extension of the UKCS Quadrant 204 play system, of which BP Amoco has significant experience.

When considering the charge element of the play risk, BP Amoco envisaged that charge to T35 sands in the UK sector would most probably occur via, variably localised, leakage from underlying T34 carriers. The charging of the main T31-35 prospect trends in the Faroese sector was considered to be the simpler case of dominantly vertical migration through Cretaceous and Early Paleocene muddy sequences with relatively local lateral migration in T30's carriers.

5.2 Source Rock Description

In consideration of the source element of the play risk, BP Amoco's experience in the Foinaven Basin and access to an extensive geochemical database (oils and sediments), analysis of the data showed that a world-class Jurassic, dual source rock system provides giant volume oil and gas charge in the Foinaven Basin. Also, calibrated fluid flow and compositional modelling suggests that T31-35 Prospects in the Faroese sector of the Foinaven Basin would charged with saturated, single phase oil, with bubble point GOR's in the range 190-320m3/m3 and FVF's of 1.8-2.1.

The shallower T38-T50 prospects were thought to be more prone to significant gas caps (10-50%), much lower bubble point GOR's (<180m3/m3) and also significant leakage and biodegradation risks (latter with associated oil quality deterioration). BP Amoco also analysed oils data from UKCS Quadrants 204 to 214 and showed that there have been two or more episodes of low-high maturity petroleum charge. Also, fluid flow modelling, thermal stress and fluid inclusion data suggest a mid-late Eocene and Oligo-Miocene timing for these episodes in the UKCS Quadrant 204-205 area.

Finally, migration mapping suggests that the sub-T34 carriers to be critical to the success of charging the giant UKCS Q204-205 fields, involving significant lateral migration from kitchens in the west and north-west Foinaven Basin.

5.3 Reservoir Quality

5.3.1 Reservoir Presence

Nine Paleocene plays are recognised in the Foinaven Basin of which two, involving T34 and T35 slope fan sands in structural/stratigraphic traps, are the most prospective in the Faroes sector.

The Paleocene is split into seismic sequences (with 'T' prefixes) which are unique to BP Amoco and are constrained by well, biostratigraphic and seismic data. The geometry of the deep basin structure is defined by seismic data and potential field modelling while individual sequence structure maps of the Paleocene are derived directly from seismic mapping.

The integration of the extensive UKCS Quadrant 204 well database with the seismic amplitudes derived from detailed sequence mapping enabled the areal interpretation of sequence depositional environments and hence the distribution of reservoir sands. Confidence in amplitude calibration was sufficiently advanced to result in a very low risk for reservoir presence throughout the Paleocene of the Foinaven Basin.

It is important to note, however, that the most prospective reservoirs in the Upper T35 sequence in the Faroes undesignated area had not been penetrated by any wells prior to BP Amoco acquiring the Faroese acreage in 2000 and individual well deliverability was unknown. As a consequence, an element of reservoir effectiveness play risk was deemed to exist and this was incorporated into all prospect risking calculations. However some trends emerge using data from above and below the UT35 which lead BP Amoco to an expectation that Upper T35 was expected to behave in a similar manner to all the other turbidite sands in the Foinaven Basin from T10 to T38.

5.3.2 Reservoir Effectiveness

Depth of sediment burial beneath sea bed has a direct correlation to reservoir porosity and permeability. The detailed relationships controlling reservoir effectiveness were derived from BP Amoco extensive exploration and development database in UKCS Quadrant 204 field areas. Whilst the effect of depth can be predicted within a range, the actual reservoir behaviour in the Faroes sector of the Foinaven Basin was unproven and carried a distinct play risk.

Prediction of the reservoir quality and effectiveness in the Faroes undesignated acreage was based upon BP Amoco's understanding of the presence of the sands from Gross Depositional Environment (GDE) maps and how those sands were expected to perform in a dynamic sense as potential producing fields. BP Amoco had acquired comprehensive wireline data and a total of approximately 2100 m of core in the BP Amoco operated wells through all the major reservoir units of the Tertiary.

The substantial core database indicated that reservoir effectiveness is controlled by two major factors:-

- Sediment provenance - channel entry point
- Present day depth below sea bed - overburden compaction.

Interpretation of the data highlighted that the following conclusions; that the depth of 2500mbml is regarded as economic basement and that there is an excellent correlation between core and Nuclear Magnetic Resonance (NMR) over a wide range of permeabilities. These conclusions enabled BP Amoco to infill the lower part of the permeability/depth trend with a high degree of confidence. As a result, those prospects mapped shallower than 2500m bml were expected to show increasing viable flow rates.

5.4 Seal

Confidence in the presence and effectiveness of top seals is derived from their detailed seismic character and from observations from proven accumulations in the UKCS Quadrant 204 area. Up-dip seal against small faults is an important proven trapping element in the Foinaven Basin and is well constrained by proven examples. Stratigraphic lateral seals are effective as minor trapping components but carry irreducible prospect risk

Top seal Common Risk Segment (CRS) maps were made for each of the key Tertiary sequences using the Gross Depositional Environment maps (GDE's) and, in some cases, additional windowed Root Mean Square (RMS) amplitude maps. The top seal play risk for the T36 sequence was thought to be predominantly low, with Lower T38 slope mudstones providing a competent top seal over much of the Faroes undesignated acreage. There was a band of moderate top seal risk along the T36 offlap/onlap edge, where the overlying mud prone T38 shelf was thought to have facilitated some vertical leakage. There was also a small area of high risk which lay around the southern entry point where the overlying T38 fan sands may have compromised the top seal.

Further into the Faroes acreage, the potential widespread development of T36 slope fan sands resulted in an overall moderate top seal play risk pre-drill. However, further work at this level, looking at windowed RMS amplitude attributes in the T36 section immediately overlying the Upper T35, indicated that in some areas the risk could be reduced. On reservoir Amplitude Variation with Offset (AVO) maps the area around the Svinøy prospect appeared very bright, which, pre-drill was interpreted to be caused by the effect of the T38-T36 shale directly above the reservoir interval.

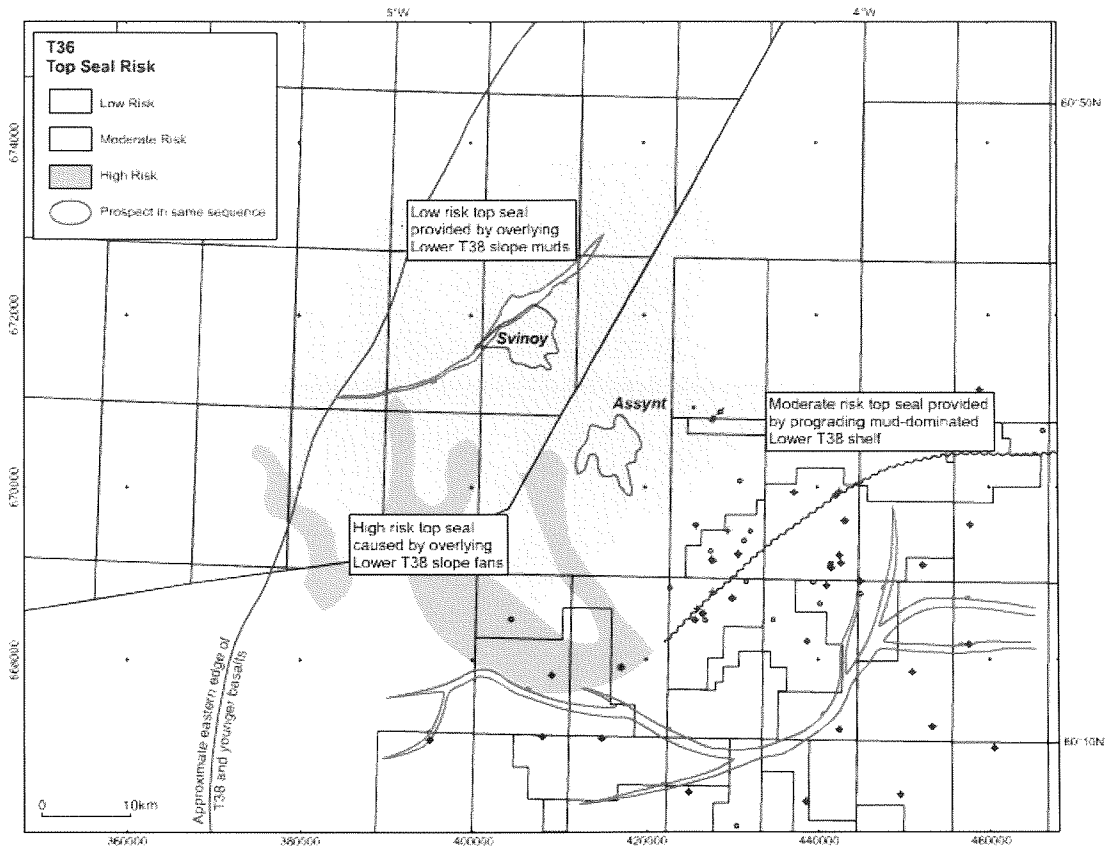


Figure 8: T36 sequence top seal risk map (Source BP)

5.5 Trap

The Bordøy prospect is a late Paleocene T38/T40 inversion anticline which is cross-cut by a strike-slip fault system (the 'Canisp' fault. Three key reservoir sandstone intervals were identified within the structure at T34, Lower T35 and Upper T35 sequences beneath the predicted lower T36 regional seal. Detailed mapping of the reprocessed 3D seismic data allowed the reservoirs to be mapped as distinct prospect segments (See Table 1).

The late Paleocene T38/T40 structural event was identified as a key controlling factor on the distribution of trapped hydrocarbons in the Paleocene basin. The inversion created a number of structural elements which are important components in creating hydrocarbon traps in the Paleocene. These elements include; moderate wavelength (5-20km) inversion anticlines, antithetic east-west extensional faults, which were a key trapping component for the fields in the Faroes acreage prospects, and strike-slip faults oriented approximately NE-SW (e.g. the Canisp system) and NW-SE (e.g. the Westray system).

These faults likely reflect reactivation of older, deeper structural trends. Divergence between the T38/T40 stress field and the actual orientation of the deeper trends has created local transpressional pop-ups and transtensional graben systems.

Subtle inversion of earlier T30 depocentres whilst leaving adjacent mud dominated areas structurally low, thus creating the potential for stratigraphic traping components such as those observed in the Schiehallion and Foinaven field in UKCS Quadrant 204.

Pre-drill it was thought that the traps had then been modified by a combination of post-Paleocene subsidence into the Faroe-Shetland channel and long wavelength (>50km) inversion of the basin from the late Eocene through to the to Miocene. These structural events created the obvious large scale structure of the basin such as the Lui anticline, modified the pre-existing late Paleocene trap geometries, and controlled the migration pattern of any very late charge and remigration of earlier charged hydrocarbons.

6 Pre-Drill Prospect Inventory

An extensive and thorough prospect evaluation exercise was undertaken on the Faroese sector of the Foinaven Basin Paleocene fairway. A specifically designed workflow was used to evaluate the prospectivity from the sub-regional mapping scale down to the specific prospect details, including reservoir deliverability. The workflow addressed critical issues for prospect success with the aim of reducing risk as much as possible.

The prospect evaluation identified a single prospect area, the Bordøy Prospect, with a cluster of segments that had the highest chance of finding hydrocarbons in the Faroes sector of the Foinaven Basin. The prospect area was contained within the late Paleocene Bordøy inversion and comprised individual submarine fan channel sand complexes in the Upper and Lower T35 and T34 sequences. Although the inversion had no significant present day expression, its timing, soon after reservoir deposition and early enough to catch an initial oil charge, made it highly prospective.

A series of Bordøy Satellite prospects were also identified on the southern margin, all in the Lower T35 sequence. These prospects were believed to have a similar chance of success but were more dispersed and had lower reserves density. Away from the inversion, less prospective (Leads) were recognised in a variety of sequences. The Bordøy segments were considered to be directly analogous to prospects in the Foinaven Basin.

The prospects identified on the Bordøy Prospect and Bordøy Satellite Prospect License areas are shown in figure 9. A full listing of the Bordøy Prospect and Bordøy Satellite area opportunities inventory is shown in table 1.

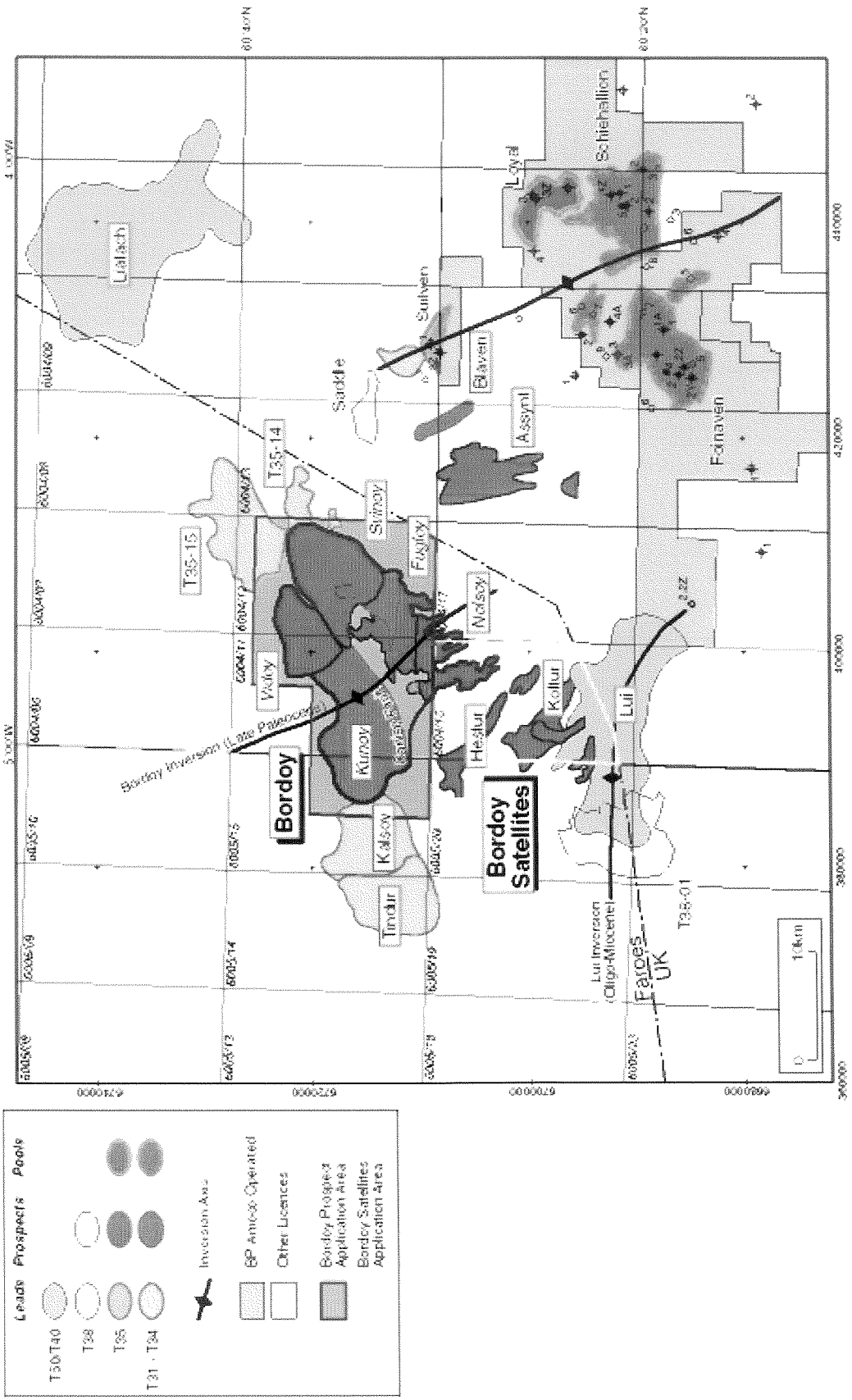


Figure 9: Faroes License 004 Prospects Inventory. (Source BP)

6.1 Bordøy Prospects

The principal segments of the Bordøy Prospect are at Upper 35 and T34 levels. The segments were defined using seismic character and direct hydrocarbon indicators incorporating BP Amoco's experience from Foinaven Basin analogues. In general they have more than one level of pay and potentially high productivity sweet spot core areas can be recognised through direct comparison with Foinaven and Schiehallion. The Upper T35 segments which straddle the Canisp fault are: Svinøy and Vidøy. The T34 segments are Kunøy which partially underlies Vidøy, and Fugløy which partially underlies Svinøy.

The Bordøy Prospect is a late Paleocene T38/T40 inversion anticline which is cross-cut by a strike-slip fault system (the 'Canisp' fault). Three key reservoir sandstone intervals are identified within the structure at T34, Lower T35 and Upper T35 sequences beneath the lower T36 regional seal.

Detailed mapping of the reprocessed 3D seismic data has allowed these reservoirs to be mapped as distinct prospect segments. A pre-drill reserves summary of each Bordøy Prospect segments is shown in Table 1.

The Bordøy Satellite prospects do not lie in Faroese Exploration License 004 and consequently are not discussed in further detail here. The Bordøy Prospects and key play elements are discussed in more detail in the following sections.

6.1.1 Bordøy Prospects Summary

The Svinøy upper T35 segment of the Bordøy Prospect comprised two stacked reservoir units of upper T35 Paleocene turbidite sandstone in a combined stratigraphic/structural trap. Top seal was believed to be provided by basal T36 mudstone.

The segment trap was a northerly dipping anticlinal nose which relied on updip seal to the south along an east-west trending fault system and lateral seal to the west and east, believed to be provided by slope mudstone as mapped on seismic. The east-west fault system was thought to have provided the updip seal to the underlying Fugløy segment, which, in common with the Svinøy, had what was believed to be a high confidence seismic direct indicator in the form of a Hydrocarbon-Water Contact (HWC). This system was then considered to extend eastwards into UKCS Quadrant 204 where it provides the updip seal to the Suilven discovery.

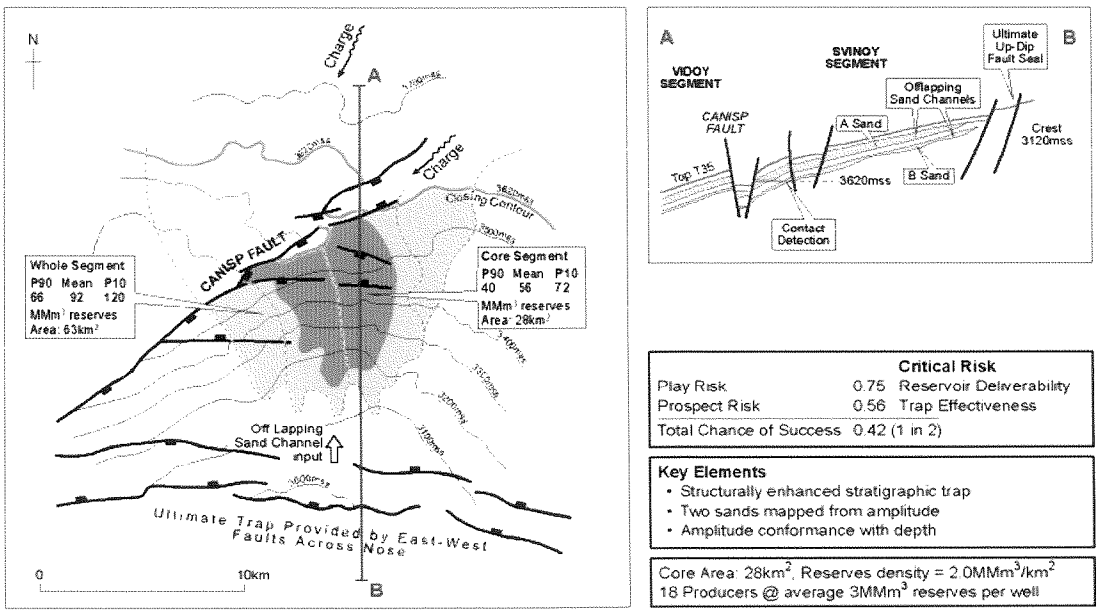


Figure 10: Bordoy Prospect Svinoy segment summary. (Source BP)

The reservoir units were interpreted to be deposited within channelised scours into the mudstone slope which were thought to be analogous to fields in the UKCS Quadrant 204. Slope mudstones are known to provide an effective lateral seal in UKCS Quadrant 204 and were thought to be confidently mapped using seismic amplitude and coherency data in the Bordøy Prospects area. Trap effectiveness was therefore considered likely.

The downdip extent of the segment was determined by the seismic amplitude response which showed significant dimming beneath 3620mss. The dimming corresponded to a spill point out of the structure which was believed to be controlled by leakage to the north through a relay zone in the Canisp fault system.

The northerly dipping structure was created during post Balder subsidence of the Faroes-Shetland trough and was thought to have been modified by post late

Eocene inversion. The anticlinal nose was believed to have formed during T38/T40 transtension in the hangingwall of the Canisp fault to the north.

Hydrocarbon charge from the Jurassic source rocks was thought to have occurred from Late Eocene onwards, probably from directly beneath the Canisp High area, driven by burial in the Eocene-Oligocene. The most likely hydrocarbon phase was expected to be oil.

The reservoir was believed to be confidently mapped, using the existing seismic stratigraphy, at the top of the Upper T35 sequence by tie into the Suilven wells (e.g. 205/19-8Z) and the down-dip Foinaven wells (e.g. 204/24a-6). From the pre-drill play analysis, reservoir and top seal presence were expected at all levels.

The reservoir was mapped as two stacked trough-peak pairs on seismic data, but with a strong leading peak (see figure 11). This seismic response was explained as two stacked acoustically soft oil-filled reservoir sands overlain by an acoustically hard top. Whilst many areas of the UKCS Quadrant 204 fields have a simple trough-peak seismic response, there are several areas where the more complex peak-trough-peak response is developed and is proven to contain oil. In UKCS Quadrant 204, the overlying acoustically hard response is generated from a calcite cemented mudstone interval in the top seal. Isotope studies indicate that the calcite originated from methogenic bacteria.

The segment carried some play risk on reservoir effectiveness, largely because the mapped reservoir units are 25 km from sparse well control within the south sediment entry system. In a success case, given the depth of burial of the prospect at c.2150-2650mSS, reservoir quality was expected to be moderate, with porosity of c.17-25% and permeability in the range 150-500mD.

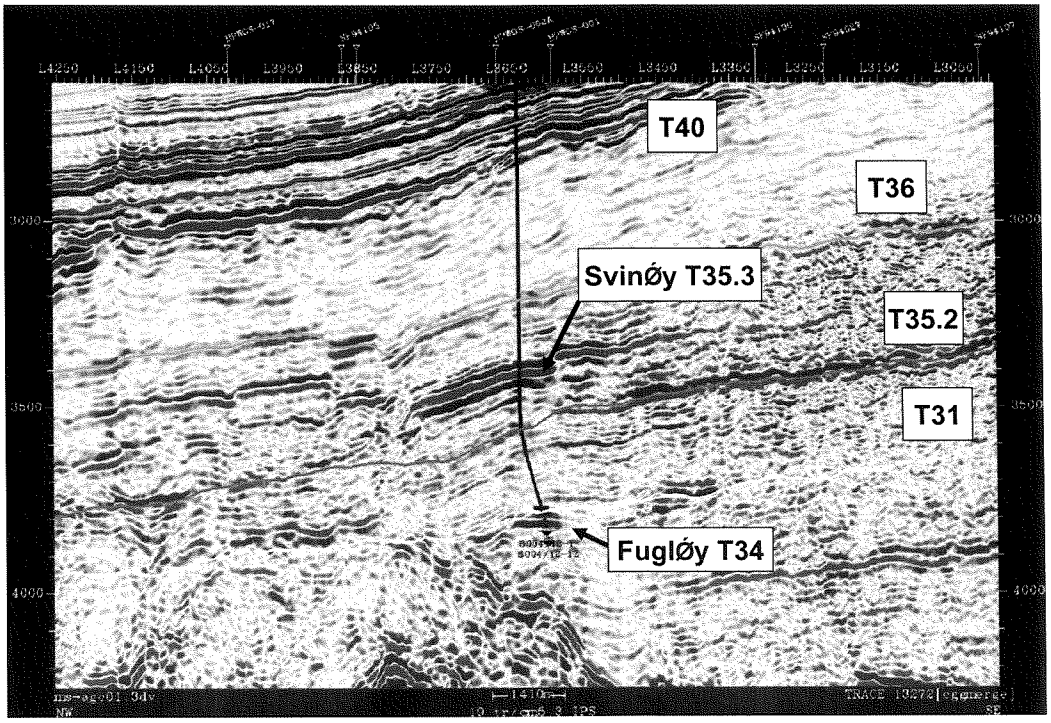


Figure 11: Svinoy T35.3 and Fugloy T34 seismic trough peak pair responses.

Building on the production learning from the UKCS Quadrant 204 fields, the segment was sub-divided into a number of compartments using both the north-south oriented channel complexes reservoir amplitude map and the east-west faults top reservoir coherency map.

The whole segment reserves were 92 mm cu. m (576 mmbbls) which assumed a 35% recovery factor across the entire prospect area.

Within these compartments a core area ('sweet spot') was defined with mean reserves of 53 mm cu. m (335 mmbbls). This core area comprises compartments with areas greater than 2 sq. km within the thickest channels where reserves/producer of c. 3.2 mm cu. m (c.20mmbbls) would be expected. This area was defined by mapping the pattern of channels and faults using seismic amplitude and coherency data

6.1.2 Bordøy Prospects (Vidøy)

The Vidøy segment comprised two stacked reservoir units of upper T35 Paleocene turbidite sandstone in a combined stratigraphic/structural trap. Top seal was expected to be provided by the basal T36 mudstone. The segment trap was a combination of fault seal along a SE bounding fault system, updip stratigraphic sand pinch-out to the west and dip to the north and east.

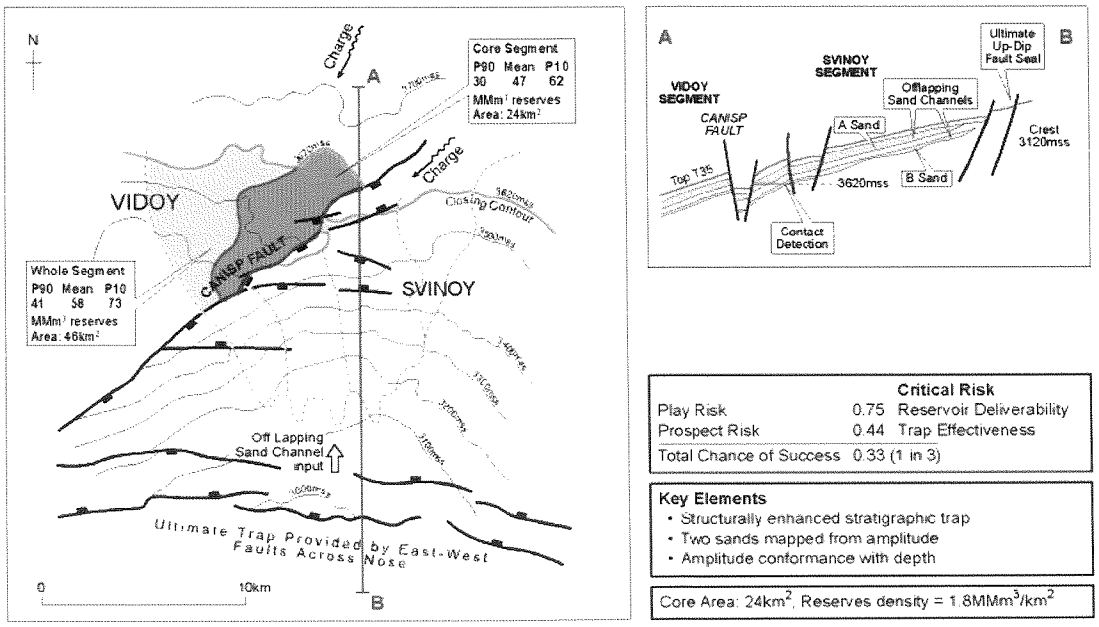


Figure 12: Bordoy Prospect Vidoy segment summary. (Source BP)

The key structural elements were formed during T38/T40 basin inversion and associated dextral strike-slip movement along the Canisp fault system with an associated transtensional low developed in the hangingwall and pop-up on the footwall block. The structure was then slightly modified during later during post Balder subsidence of the Faroes-Shetland trough and post late Eocene basin inversion.

The reservoir is thrown against the lower T36 sequence across the south-east bounding fault system. The lower T36 package was thought to be most likely mudstone dominated and provided the regional top seal, which was interpreted to be confirmed by seismic coherency slices. Some sand to sand juxtaposition across the fault system could not be ruled out. However, given the amount of throw on the fault and the interpreted mud dominated lithology of the T36 interval, by analogy with the UKCS Quadrant 204 fields, fault plane seal was considered likely. Overall, trap effectiveness was considered likely.

The reservoir units were deposited within channelised scours into the mudstone slope and is analogous to fields in the UKCS Quadrant 204. These slope mudstone were expected to provide an effective lateral seal and were confidently mapped using the existing seismic stratigraphy, seismic amplitude and coherency data.

The downdip extent of the segment is determined by the seismic amplitude response which shows significant dimming beneath 3620mSS. This dimming may correspond to a spill point out of the structure to the north-east, though a possible gas chimney has also been identified at this proposed oil-water contact. The proposed oil-water contact was also consistent with the contact identified in the downthrown Upper T35 Svinøy Segment, the two segments being linked through a relay in the Canisp fault system.

As with the Svinøy segment hydrocarbon charge was expected to be from the Jurassic source rocks. This probably occurred from late Eocene onwards, and from directly beneath the Canisp High area, driven by burial in the Eocene-Oligocene. The most likely hydrocarbon phase was thought to be oil.

The reservoir was also believed to be confidently mapped, using the existing seismic stratigraphy, at the top of the Upper T35 sequence by tie into the Suilven wells (e.g. 205/19-8Z) and the down-dip Foinaven wells (e.g. 204/24a-6). From the play analysis, reservoir and top seal presence were expected at all levels.

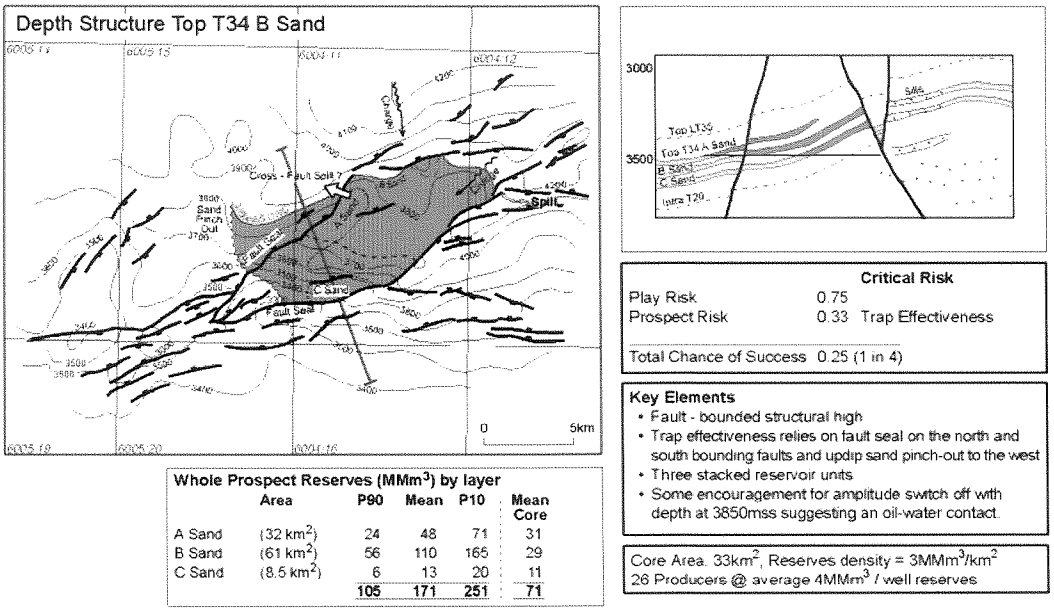
The reservoir was mapped as two stacked trough-peak pairs on seismic data, but with a strong leading peak. Prior to the drilling of the 6004/12-1, 1Z Svinøy well, this seismic response was interpreted as two stacked acoustically soft oil-filled reservoir sands overlain by an acoustically hard top. Whilst many areas of the UKCS Quadrant 204 fields have a simple trough-peak seismic response, there are several areas where the more complex peak-trough-peak response is developed and is proven to contain oil. In UKCS Quadrant 204, the overlying acoustically hard response is generated from a calcite cemented mudstone interval in the top seal. Isotope studies indicate that the calcite originated from methogenic bacteria.

The segment carried some play risk on reservoir effectiveness, largely because the mapped reservoir units were 25-30 km from sparse well control within the south Quadrant 204 sediment entry system. In the success case, given the depth of burial of the segment at c.2150-2650mSS, reservoir quality was expected to be moderate, with porosity of c.17-25% and permeability in the range 150-500mD.

The whole segment reserves were 58 mm cu. m (367 mmbbls) and assumed a 35% recovery factor across the entire segment area. Building on the production learning from the UKCS Quadrant 204 fields, a core area ('sweet spot') is defined with mean reserves of 47 mm cu. m (296 mmbbls). The core area comprises compartments with areas >2 sq. km within the thickest channels where reserves/producer of c.20mmbbls can be expected. This area has been defined by mapping the pattern of channels and faults using seismic amplitude and coherency data.

6.1.3 Bordøy Prospects (Kunøy)

The Kunøy segment comprised three stacked reservoir units of T34 Paleocene turbidite sandstone in a fault bounded horst block. Top seal was interpreted to be provided by the basal T35 mudstone. The segment was defined by 3D seismic mapping of amplitude anomalies - the A, B and C sands, of which the B sand was the most areally extensive.



Whole Prospect Reserves (MMm³) by layer

	Area	P90	Mean	P10	Mean Core
A Sand	(32 km²)	24	48	71	31
B Sand	(61 km²)	56	110	165	29
C Sand	(8.5 km²)	6	13	20	11
		105	171	251	71

Figure 13: Bordoy Prospect Kunoy segment summary. (Source BP)

The trap relied on seal across the south bounding Canisp fault, updip stratigraphic seal to the west and structural dip to the north and east. By analogy with the UKCS Quadrant 204 fields, given the large throw on the south-bounding Canisp fault (>50m), fault seal was considered probable. Potential gas chimneys were mapped along the faults system; similar gas chimneys were also mapped at the crest of the Schiehallion and Foinaven fields.

The segment is located near the crest of the broad N-S oriented Bordøy T38/T40 inversion anticline. The structure formed during dextral shear along the SW-NE Canisp fault which created the Kunøy segment as a transpressional 'pop-up' in the footwall to the Canisp fault, together with coeval transtensional east-west faulting in the hangingwall. The structure was further modified by post late Eocene inversion.

Detailed structural mapping on 3D seismic data clearly demonstrated that the throw on the south bounding Canisp fault system diminished to the west where it comprised a number of en echelon extensional E-W faults. Given the small offset on these faults, it was considered unlikely that they would provide an effective updip seal. As a result, a stratigraphic trap updip to the west was required to seal the mapped T34 reservoir units.

At a segment level, confidence was derived for reservoir presence and an updip stratigraphic seal to the west from sequence isopaching which showed that the Kunøy segment represented a local lower Paleocene (T10-T34) isopach thick. The isopach thick was controlled by the pre-existing Cretaceous basin topography and was largely infilled and overstepped during deposition of the T30 sequence which demonstrated thinning onto the western and eastern flanks of the embayment. This sequence thinning and associated sand pinch-out formed the western limit of the Kunøy reservoir and the updip trap. The T30 sand pinch-out associated with sequence thinning was directly analogous to the eastern limit and trap to the T31 reservoir in the UK Quadrant 204, Schiehallion field.

The downdip extent of the segment was determined by the seismic amplitude response which showed significant dimming beneath 3850mSS. The dimming corresponded to a mapped spill point out of the structure across a relay in the south-bounding Canisp fault system.

Hydrocarbon charge from the Jurassic source rocks probably occurred from the Eocene onwards, probably from directly beneath the Bordoy T40 inversion, driven by burial in the Eocene-Oligocene. The most likely hydrocarbon phase was thought to be oil.

Given the distance from well control, and the difficulty of tying across the Canisp fault, the exact stratigraphic age was uncertain but likely to be no older than T31 and no younger than T35. From the play analysis, reservoir and top seal presence were deemed possible at all levels.

The reservoir was mapped as three stacked trough-peak pairs on seismic data at T34 level. The segment sat beneath the feather edge of the basalt flows. The effect of the basalt was to reduce the energy and frequency response of the seismic compared with the basalt free areas to the south. These effects were areally variable depending on the thickness and roughness of the Balder basalt layer. Despite the basalt overburden, a number of key observations of the seismic data indicate that the mapped events most likely represented sands, and not poorly imaged sills:

The large number of sills intruded into the Paleocene and deeper layers in the area clearly demonstrated that the seismic data was correctly phased (i.e. +/-c.30o). Seismic energy extractions from the pre-Paleocene demonstrate that sills and dykes were well imaged beneath the Kunoy segment and therefore that the T34 events were unlikely to represent poorly imaged sills. Two localised sills within the T34 Kunoy interval itself which act as a 'benchmark' for the seismic response.

The seismic response at target level was variable across the segment, and could be broadly divided into two areas:

- An updip westerly area with up to three stacked trough-over-peak pairs (i.e. soft sand in hard mudstone) seismic response with a variably developed, moderate-weak leading peak which may represent a cemented shale over the top of the sandstone intervals.
- A downdip easterly area with a moderate-strong leading peak and moderate-weak trailing peak. This leading peak may be explained by a strongly developed cemented unit in the overlying mudstone. A relative hardening of the sandstone seismic response with increased depth of burial (i.e. >2,500m below mud line) may also be a contributing factor to this change of seismic character.

The segment carried some play risk on reservoir effectiveness, largely because the mapped reservoir units are a 30 km from sparse well control and because of the depth of burial of the segment (2,220-2,700m below mud line). The updip, western part of the segment is at a depth of c.2,200-2,500m below mud line and has a good probability of yielding effective reservoir. The downdip, eastern part of the segment is at a depth of c.2,500-2,800m below mud line and has a higher risk of yielding effective reservoir.

In a success case, reservoir quality was expected to be moderate, with porosity of c.18-25% and permeability in the range 50-500mD. However, because of the relatively thick, stacked nature of the reservoirs, particularly in the west of the segment, reservoir productivity was expected to be good. The whole segment reserves were 171 million m3 (1082 mmbbls) and assumed a 35% recovery factor across the entire segment area.

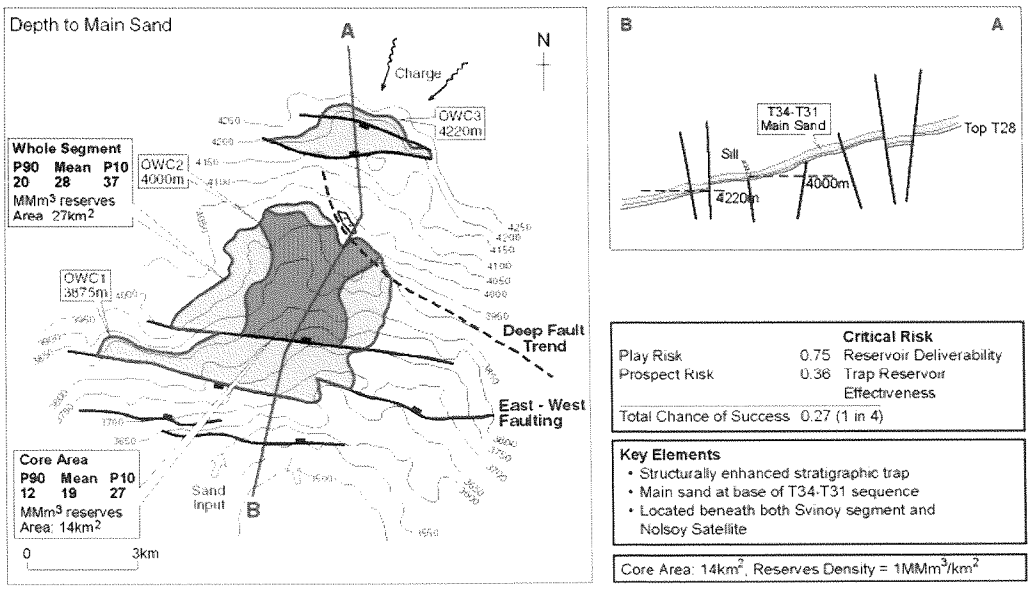


Figure 14: Bordoy Prospect Fugloy segment summary. (Source BP)

6.1.4 Bordøy Prospects (Fugløy)

Fugloy comprises early T34 to T31 sequence slope turbidites in a combination structural/ stratigraphic trap. The prospect is located beneath the lower risk and large volume Svinøy segment and the smaller Nolsøy 'satellite' prospect.

The prospect was defined by three trapping elements:

- Up-dip seal to the S provided by significant E-W faulting. Two key faults form a graben geometry, which also provides the ultimate up-dip seal on a number of shallower prospects in the area.
- Lateral seal was thought to be provided by channel margins/pinch-out on the depositional slope to the east.
- The extent of down-dip hydrocarbons is defined by amplitude shut-off at three levels, each of which describes a distinct depth closure against the three key trapping faults.

The main reservoir sand section was in the lower T30's sequence, sitting immediately above the Top T20's sequence boundary. It was characterised by a single trough-peak event that had the indicative signature of hydrocarbon filled sand. The trap relied on T31 to T34 shales for both top and lateral. Late and middle Jurassic source rocks provided the charge system. Further discreet sands appeared to be present within the T31 to T34 sequence above the main prospect which may have resulted in a significant volumetric up-side.

The risk reduction techniques that combine observations of soft kick, depth conformance and a hint of AVO response suggested that the trap presence, and to some extent effectiveness, were relatively low risk. However, the depth to target of between 2600 to 3100m below sea-bed provided a serious problem in that porosity and permeabilities were expected to be relatively poor, and possibly even below economic threshold (<20% porosity and low 100's mD permeability).

Seismic coherency, on the other hand, mapped relatively continuous and well connected sands. At the time, no other T34 to T31 sequence prospects had been identified that could correlate to the main sand in this prospect, hence this may be a somewhat unique event within the depositional history of the basin, with a rock property trend that has no equivalent within the known and drilled stratigraphic section in UKCS Quadrant 204. Although this promoted the potential for upside from an unusual rock property trend, reservoir effectiveness and deliverability remained the key prospect risks.

7 Well Results

7.1 Svínøy/Fugløy (6004/12- 1,1Z)

Well 6004/12-1 (Svínøy) was plugged and abandoned having encountered oil and gas shows, with operations completed by 5th October 2001 after 75 days.

Three key reservoir sandstone intervals were identified within the structure mapped from seismic amplitude responses. The primary target was the Upper T35 'A' Sand (Svínøy Prospect), in a combined stratigraphic/structural trap, with secondary targets at Lower T35 'B' Sand (Nolsøy equivalent) and T31 (Fugløy equivalent) sequences beneath the lower T36 regional seal. BP made an operational decision following the failure of the primary Upper T35 target to deviate the well to target the higher amplitudes of the secondary T34 target. The T35 Svínøy sidetrack well encountered 5m of gas pay (SG 30%-50%) at 4213mtvdss, in T34 reservoir sands, in the deviated well section. The Svinøy sidetrack (6004/12-1Z) well failed to find hydrocarbons in the T35 as no valid trap exists for the Svínøy 'A' and 'B' sands.

The well did encounter 114m of good quality reservoir sand across Svínøy in 'A' and 'B' Sand intervals. It is high Net to Gross (N:G), high porosity (23%-25%), and comparable to Foinaven and Schiehallion reservoirs (see figure 15). The reservoir is at a higher stratigraphic level than predicted, most likely lower T36. Charge exists, with evidence of a dual system similar in character to the West of Shetland (WoS). A poor quality oil sample from core indicates typing from a mixed middle and upper Jurassic source system. Svinøy reservoir sands are believed to be a hydrocarbon migration pathway.

The Svínøy sidetrack well encountered 5m of gas pay (SG 30%-50%) at 4213mtvdss, in T34 reservoir sands, in the deviated well section (see figure 16). The sands were identified from seismic amplitudes and comprise a down dip extension of the T34 Fugløy prospect. The T34 reservoir section comprises 35m of clean, porous sands (15%-20% porosity) encased in tightly cemented T34 sandstones (5%-7% porosities). The well TD is at 4586m in tightly cemented T28 sandstones. The primary failure mode for the prospect was the lack of top, bottom and lateral seal as none were present. In addition, the misinterpretation of seismic amplitudes and anomalous lithologies gave false AVO's.

The T38-T36 section (2532-3109m tvdss) is sand and not shale as predicted pre-drill and the T36 sand amplitudes suggest a south-south west sediment system extends over Svínøy rather than a shale seal. Reservoir Characterisation Instrument (RCI) pressure data from top T38 to lower T35 suggests a hydrostatic gradient (0.45 psia) from top to base with no pressure break across the pre-drill T36 predicted seal. In addition, the amplitude response, used to define the prospect pre-drill, does not correspond to hydrocarbon filled reservoir and therefore cannot be used to define the trap. Svínøy's amplitude variation with offset (AVO) response is now believed to be the result of the large impedance contrast between the basal T36 tuff and the 'A' Sands.

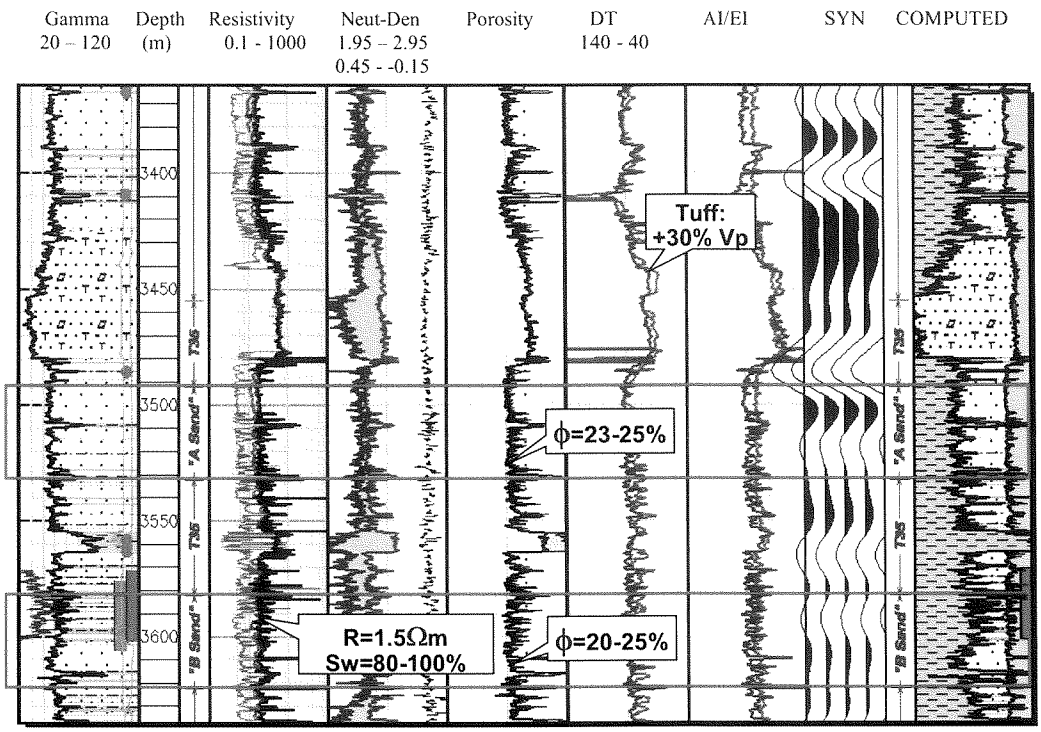


Figure 15: Svinoy T35 'A' & 'B' sand reservoir interval CPI (Source BP)

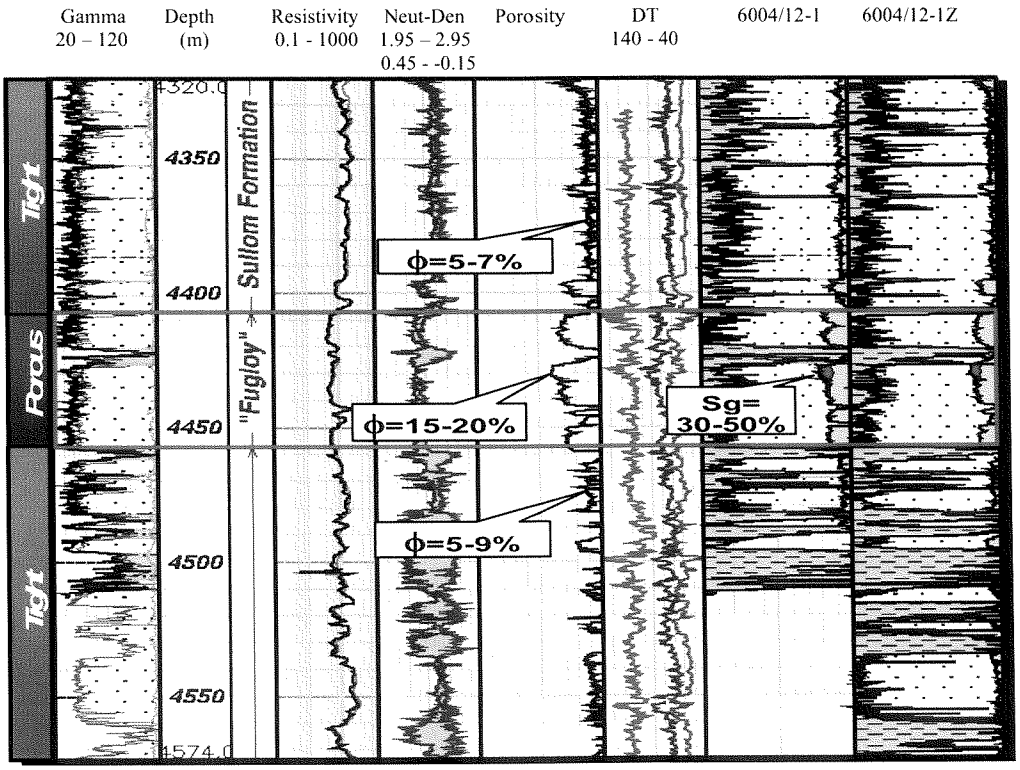


Figure 16: Svinoy T34 'Fugloy' sand reservoir interval CPI (Source BP)

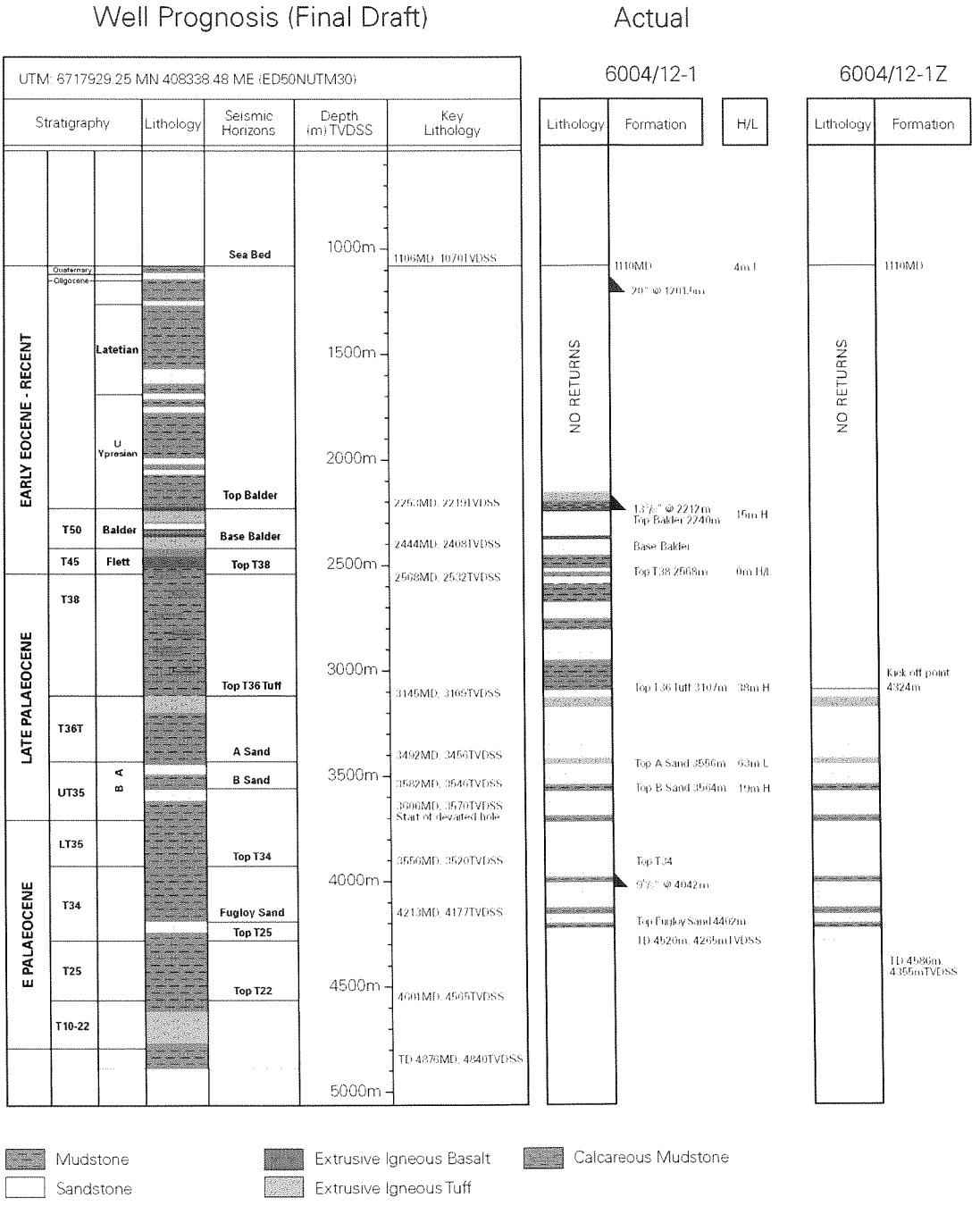


Figure 17: Prognosed vs. actual lithology & horizon tops.

7.2 Longan. Statoil, 6005/15-1 (BP Amoco, Kalsøy Lead)

The Statoil-operated Longan well was plugged and abandoned as a dry hole. The Longan well was spudded in July 2001 and reached TD at 4026m MDBRT (-3993.5m TVDss) on the 17th September in the T20 sequence. The well was designed to test the T34-T21 interval in the Vaila Formation. The primary target interval contained dolerite sills, siliceous, non-calcareous breccias and basaltic sills.

The mode of failure was the lack of seal and reservoir presence due to the misinterpretation of seismic amplitudes. The reservoir was mapped as two stacked trough-peak pairs on seismic data, but with a moderate, locally strong leading peak. This seismic response was interpreted as two stacked acoustically soft oil-filled reservoir sands overlain by an acoustically hard top and not a dolerite sill.

The Longan well drilled BP Amoco's Kalsøy lead, which was risked with a chance of success (CoS) of 0.13 or 1 in 8. However, an alternative interpretation of the strong amplitudes observed in the Kalsøy segment was that the observed strong amplitudes represented sills which are relatively poorly imaged beneath the feather edge of the Balder basalt flows. This interpretation was supported by tomographic analysis of seismic stacking velocities from trial 2D pre-stack depth migration processing and seismic energy extractions from the pre-Paleocene. The well confirmed this interpretation.

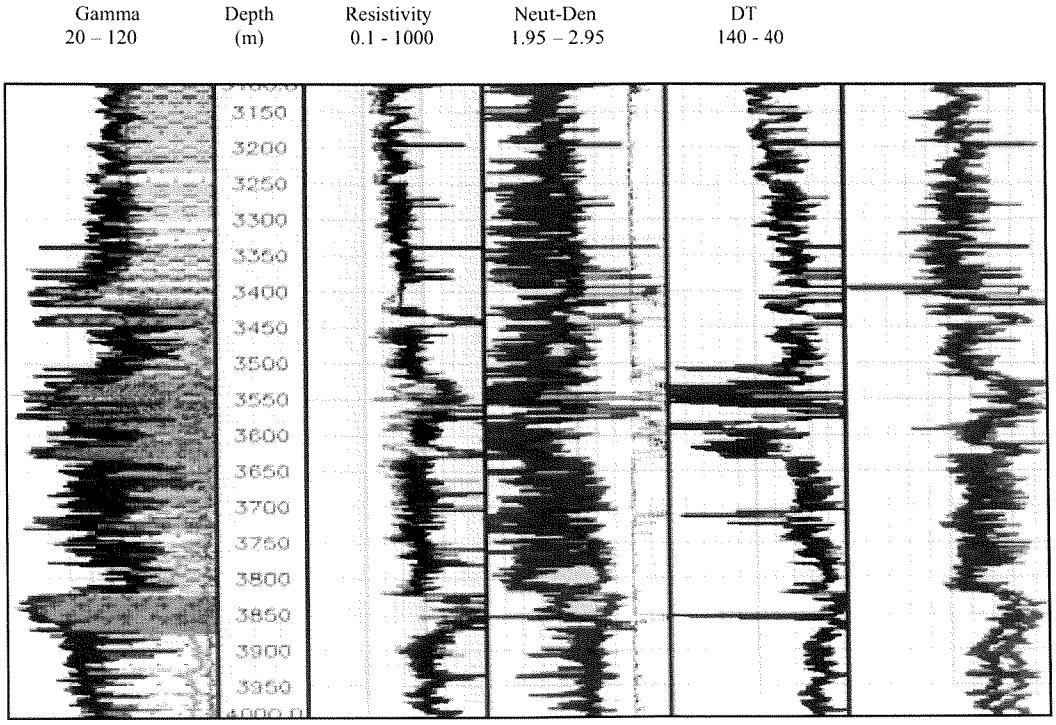


Figure18: Longan T34-T21 target interval CPI

7.3 Marjun. Amerada Hess, 6004/16-1Z (BP Amoco, Lui Lead)

The Amerada Hess-operated Marjun well was plugged and abandoned as an oil and gas discovery. The Marjun well was spudded in September 2001 and reached TD at 4274m MDBRT (-4245m TVDss) in November 2001 in the T10 sequence. The well was designed to test four intervals and encountered oil in T10 sands of the Sullom Formation with an Oil Water Contact (OWC) observed at 4225.4m MDBRT (-4196.9m TVDss).

The well encountered 170 metres gross hydrocarbon column in the Late Palaeocene T10 sequence, with 66 metres of net pay. There is a small gas column over light oil. The average reservoir parameters showed a net to gross of 60%, porosities between 11% - 16% and low permeabilities between 0.3mD and 4.0mD. It is thought that the hydrocarbon volume in place, if the feature is filled to structural spill, would be some 100mmboe.

The Marjun well drilled BP Amoco's T50 (Balder) Lui Lead, which was risked with a chance of success (CoS) of 0.21 or 1 in 4.7 at the T50 level. The mode of failure at the T50 level was no evidence of migration into the Lui structure or the development of a top seal. However, despite no apparent amplitude anomaly (dim pay) or AVO at T10 level oil was discovered and a potential deep T10 play opened with the well indicating a regional seal between the T10 and T35 plays. However, given the reservoir parameters, particularly permeability, it is unlikely that any accumulations would be economically developable.

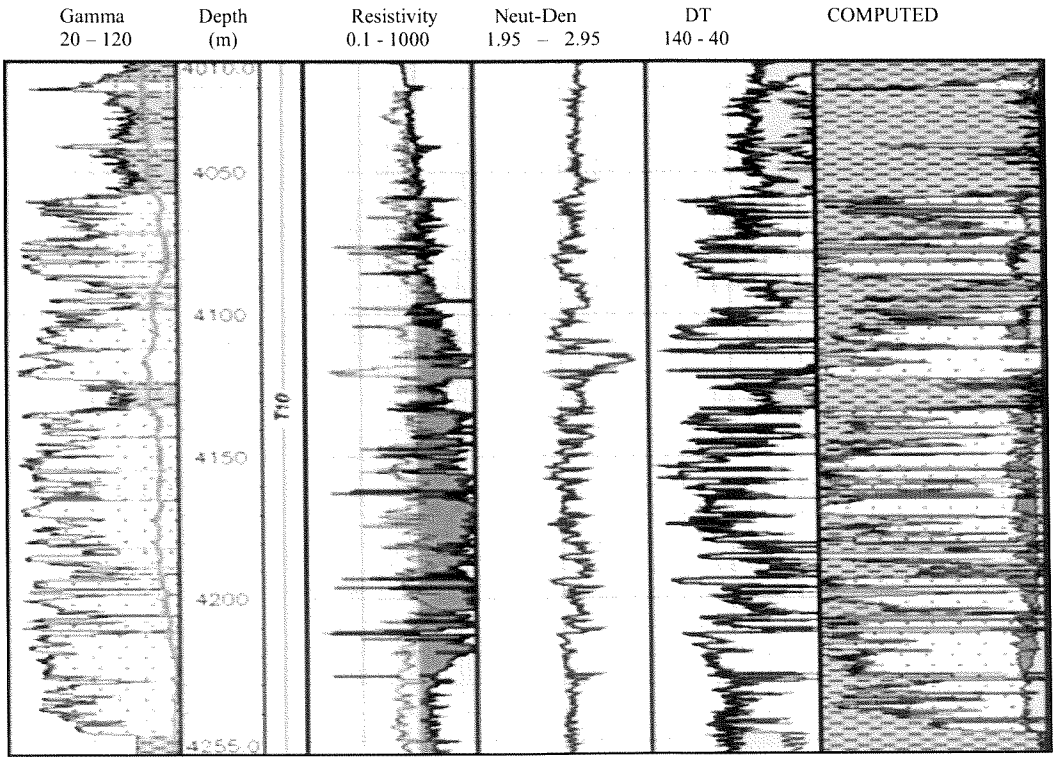


Figure 19: Marjun T10 reservoir interval CPI (Source BP)

7.4 Marimas. ENI, 6004/17-1 (BP Amoco, Fugløy & Nolsøy Prospects)

The ENI-operated Marimas well was plugged and abandoned as a dry hole. The Marimas well spudded in June 2003 and reached TD at 3847m MDBRT (-3821.8m TVDss) on the 29th July in the T20 sequence. The well was designed to test three independent closures at T38 (Pippin), T35.2 (Marimas) and T31 (Galadriel).

The Marimas well drilled BP Amoco's LT35 Nolsøy Prospect, which was risked with a chance of success (CoS) of 0.23 or 1 in 4.3 at the LT35 level. The primary failure mode for the prospect was the lack of top, bottom and lateral seal as none were present. In addition, the misinterpretation of seismic amplitudes and anomalous lithologies gave false AVO's.

Significantly, the reservoir is at a higher stratigraphic level than predicted, most likely lower T36 and not T35. Notably, the basal T36 tuff encountered in the well had only previously been seen in the Svinøy well penetration in the Foinaven sub-basin. It has subsequently been penetrated in the 204/17-1 (North Fleet) well.

The amplitude response, used to define the prospect pre-drill, does not correspond to hydrocarbon filled reservoir and therefore cannot be used to define the trap. Nolsøy's amplitude variation with offset (AVO) response is now believed to be the result of the large impedance contrast between the basal T36 tuff and the 'A' Sands.

8 Faroese Exploration License 004 Play Risk Review

8.1 Overview

Pre-Drill Risk

Following the drilling of a number of wells in the Faroes sector of the Foinaven Basin, a much fuller understanding of the key play risks has been reached. Extensive analysis of all aspects of the Svinoy well results has taken place (documented elsewhere). An overview of the key petroleum system, play risks within Faroese Exploration License 004 is presented below followed by a more detailed analysis of the individual key play risk elements.

Following the drilling of the 6004/12-1 well and geological sidetrack (6004/12-1Z) it is possible to revise the key components of the pre-drill risk element analysis.

Pre-drill, risk (see figure 20) was recognised in one area for evaluation, trap, which had a secondary aspect in the form of the amplitude variation with offset (AVO) and direct hydrocarbon indicator's (DHI's) used to define the trap. The trap definition was identified as the critical risk. Seal risk was seen as low with the interpretation of the T38-T36 sequence as a shale directly above the reservoir interval. There was no risk associated with source rock presence and potential charge as the Foinaven basin is a proven hydrocarbon system.

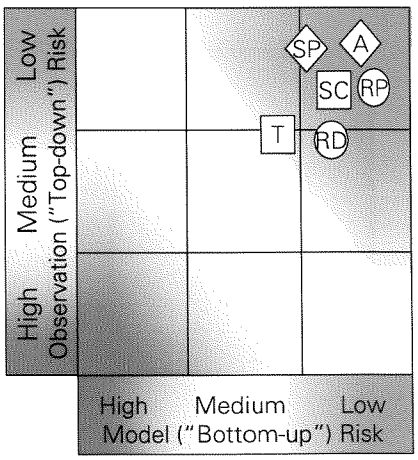


Figure 20: Faroes License 004 Pre-drill TDBU Faroes Risk Matrix

T	Container / **Trap** Presence	SP	**Source Presence**	RP	**Reservoir Presence**
SC	**Seal** Presence/ **Column**	A	Charge **Access**	RD	**Reservoir Deliverability**

Post Drill Risk

Post drill, risk (see figure 21) is identified in three key areas: trap, seal and reservoir deliverability. The seal presence is a major risk. The observed DHI's do not correspond to a known seal are caused by the presence of anomalous lithologies (tuffs) and do not correspond to a sealing mudstone. The AVO response at Svinøy and Marimas (Nolsøy) is now believed to be the result of the large impedance contrast between the previously unseen basal T36 tuff and the primary T35 Reservoir, 'A' Sands.

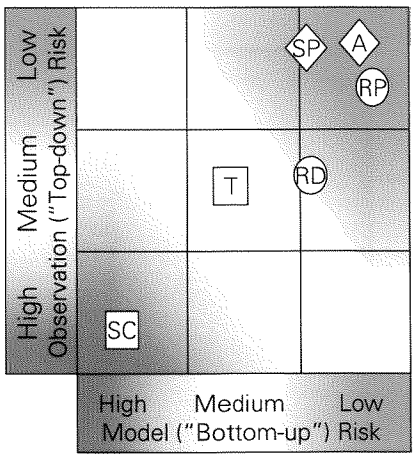


Figure 21: Faroes License 004 Post-drill TDBU Faroes Risk Matrix

T	Container / **Trap** Presence	SP	**Source Presence**	RP	**Reservoir Presence**
SC	**Seal** Presence/ **Column**	A	Charge **Access**	RD	**Reservoir Deliverability**

There are also different rock properties that those observed in the West of Shetland (WoS). The seismic response thought to be explained by two stacked acoustically soft oil-filled reservoir sands overlain by a hard top, as observed elsewhere in the WoS is actually the acoustic impedance contrast between a previously unseen, anomalous basal tuff horizon and reservoir sands. The critical risk identified post drill however, is the absence of the T36 shale seal and the presence of the 'anomalous' basal T36 tuff which causes the AVO response.

Reservoir deliverability is also a significant risk. The reservoir interval sands encountered in the Faroes license areas show widely varying quality. The T34-T35 reservoir sands encountered in the Svinøy well have excellent net to gross and porosity (23%-25%), but the permeability ranges from poor to very good (1-764mD). The T10 reservoir sand encountered in the Marjun (Lui) well also have excellent net to gross (60%), but poor porosity (11%-16%) and very poor permeability (0.3mD – 4.0mD).

8.2 Source/Charge

The Foinaven and the greater Faroe-Shetland Basin contain two penetrated and fully characterized source rocks:-

- Late Jurassic (J60-70) Kimmeridge Clay Formation – this is a world class source rock, equivalent to the Kimmeridge Clay source rock in the North Sea which has resourced billions bbls of petroleum. In this basin, the formation is a diachronous transgressive/overstepping marine system with variable land plant influence on the kerogen to yield variably low-moderate wax oils.
- Middle Jurassic (J30-40) Heather Formation equivalent – brackish/lagoonal/nearshore system dominated by land plant input into the kerogen yielding variably moderate to high wax oils.

The relatively few well penetrations of source facies in the late and, particularly, the middle Jurassic sections tend to be concentrated in the eastern part of the basin. The westernmost penetration of (in this case immature) late Jurassic source rocks is in 204/15-2 with >200m of high-Total Organic Content (TOC), very oil-prone section on the northern part of the Westray Ridge in the Suilven structure.

Biomarker analysis of source rock extracts has shown that 28-30 bisnorhopane (a biomarker associated with sulphur-oxidising bacterial mats) occurs in the Kimmeridge Clay organic-rich sediments but NOT in the middle Jurassic. Therefore the amount of this biomarker which occurs in the oils (relative to C30 Hopane) can be used to estimate the relative contribution from the Late and middle Jurassic source rocks. Geochemical analysis of solvent extracts of oil-stained core and side wall core from 6004/12-1 T31-35 have proven the western extent of the same working mature dual-source rock system in the Foinaven Basin (Figure 22).

The same system is also evident from oil-stained T10-28 sediments in the Amerada Hess well 6004/16-1. The combination of source rock analytical information and the occurrence of oils sourced from this dual Jurassic source rock system shows that the petroleum system is active throughout the Foinaven Sub-Basin.

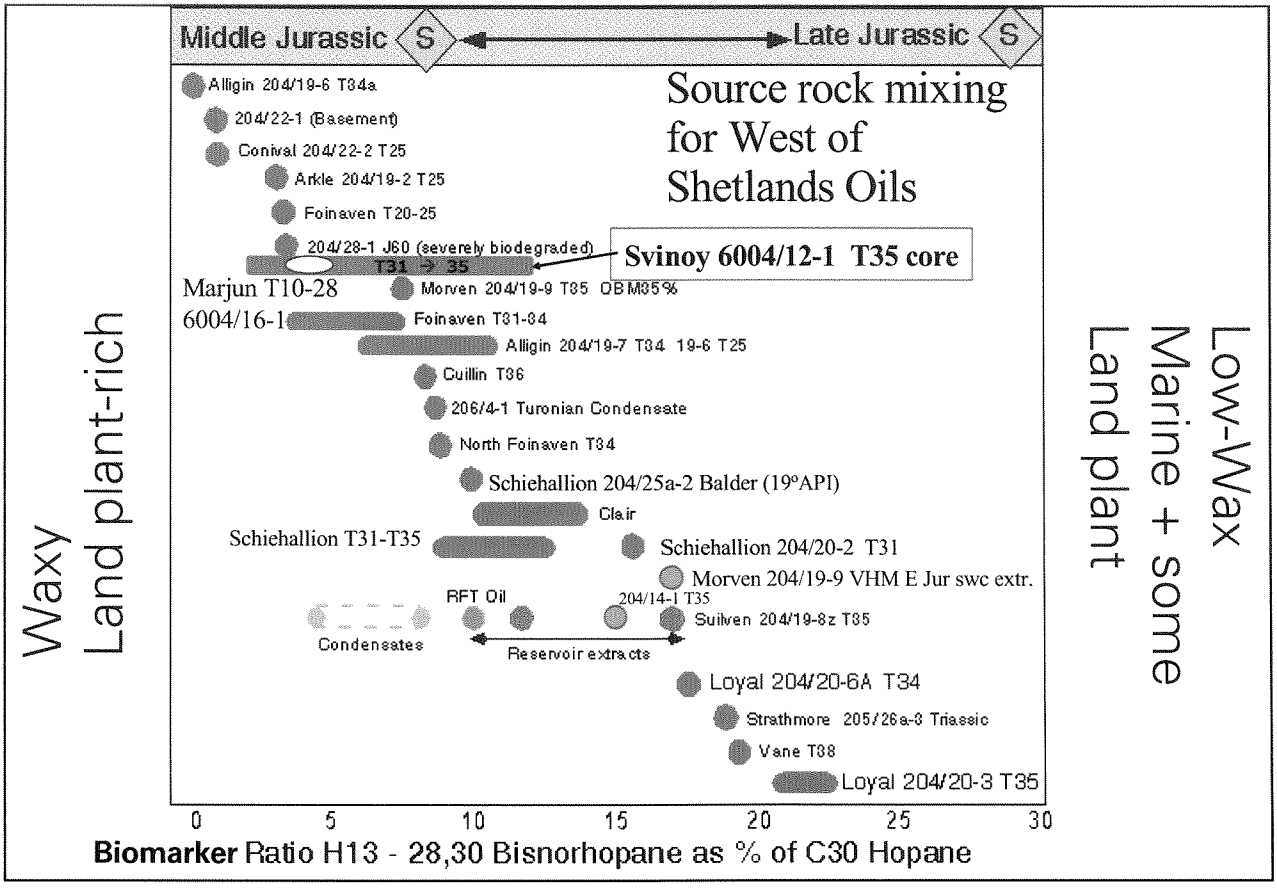


Figure 22: Foinaven Sub-Basin source rocks from fluids. (Source BP)

8.2.1 Maturity

The highly oil-prone middle and late Jurassic source rocks in the Foinaven Basin require heating to about 110-120°C to generate and expel significant volumes of oil. Heating depends on burial and heat flow/prevailing geothermal gradient. The most likely deep basin structure and geometry of the top source rock system, requires significant vertical migration to charge Tertiary carriers.

Depth to the top of the source system (base Cretaceous/top Jurassic) is not mappable on current seismic. Therefore 3D gravity modelling (Longacre, M. 2003) and base Cretaceous well penetrations in the Foinaven Sub-Basin were used to obtain a very approximate depth to top source (Figure 23). However, uncertainty on this estimated depth increases away from the Quadrant 204 well control area.

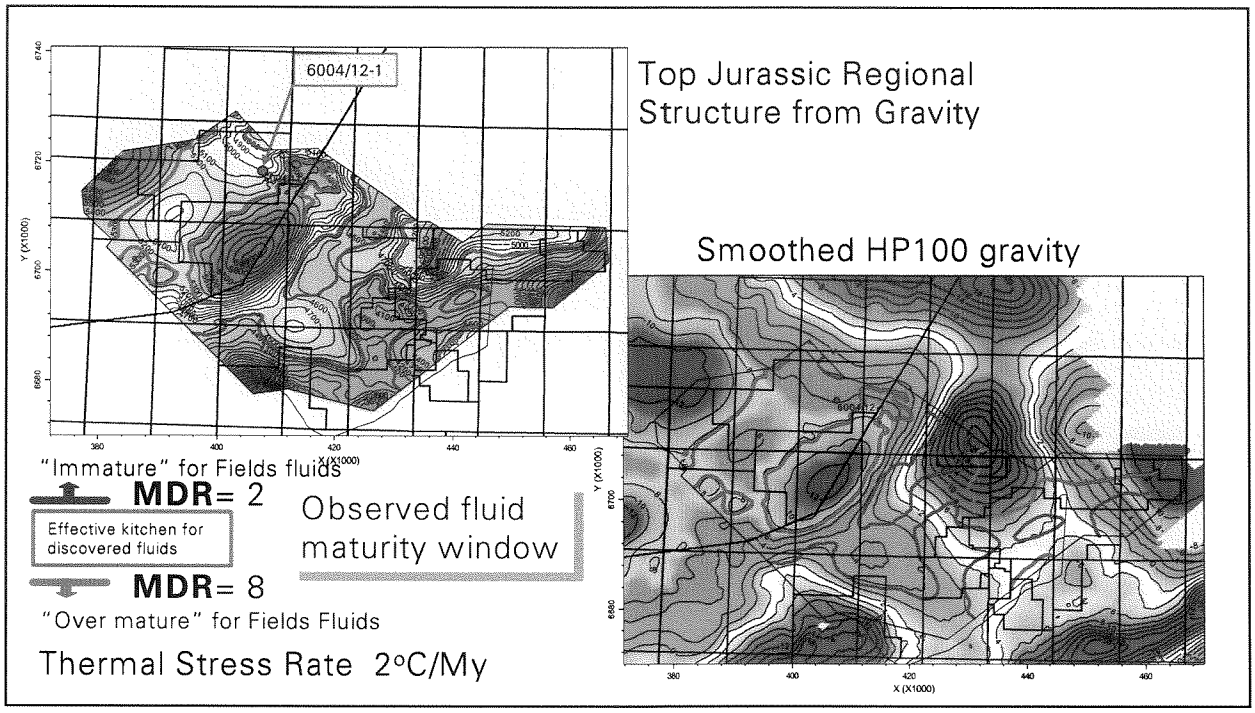


Figure 23: Svinoy *effective* hydrocarbon source kitchen. (Source BP)

Additionally, biomarker maturity data from the abundant West of Shetland oils geochemical database constrains the likely expulsion temperature window (Figure 24). Using the current geothermal gradient, the gravity-derived base Cretaceous depth estimate and the oils biomarker data, the distribution of the effective source kitchen is shown in Figure 24. Basin modelling suggests that the most likely time of migration is Eocene-Oligocene.

Hydrocarbons in Core

The T35 core from 6004/12-1 is heavily oil stained and the well has shows throughout the T35 section. The oil saturation and morphology of the stain in the cores (see figure 26) is strongly suggestive of a migration pathway rather than a failed accumulation. Biomarker data show that the oil in the core is a moderate maturity oil, with a likely density equivalence of >25° API . Biomarker maturity data show that the T31 received a slightly more mature charge than the T35, suggesting a later charge (Figure 25). The oil is clearly correlatable to the dual Jurassic source system seen in the Quadrant 204 development area and very similar to fluids from the Schiehallion Field (Figure 25).

Figure 24 also shows that the fluids are the result of multiple charge, again very consistent with the Quadrant 204 area. The first period of charge was highly biodegraded i.e. migration through the carrier when it was cold (probably <<50°C) and shallow. This was "topped-up" by a later, volumetrically much more significant charge which only shows evidence of mild biodegradation i.e. when the carrier was hotter and closer to its maximum burial depth. The biomarker data also suggest some phase effects consistent with a higher Gas Oil Ratio (GOR) fluid also moving through the carrier – in the Quadrant 204 area oils this is evident in the light hydrocarbons segment of the chromatograms which are typically lost during core handling and subsequent solvent extraction.

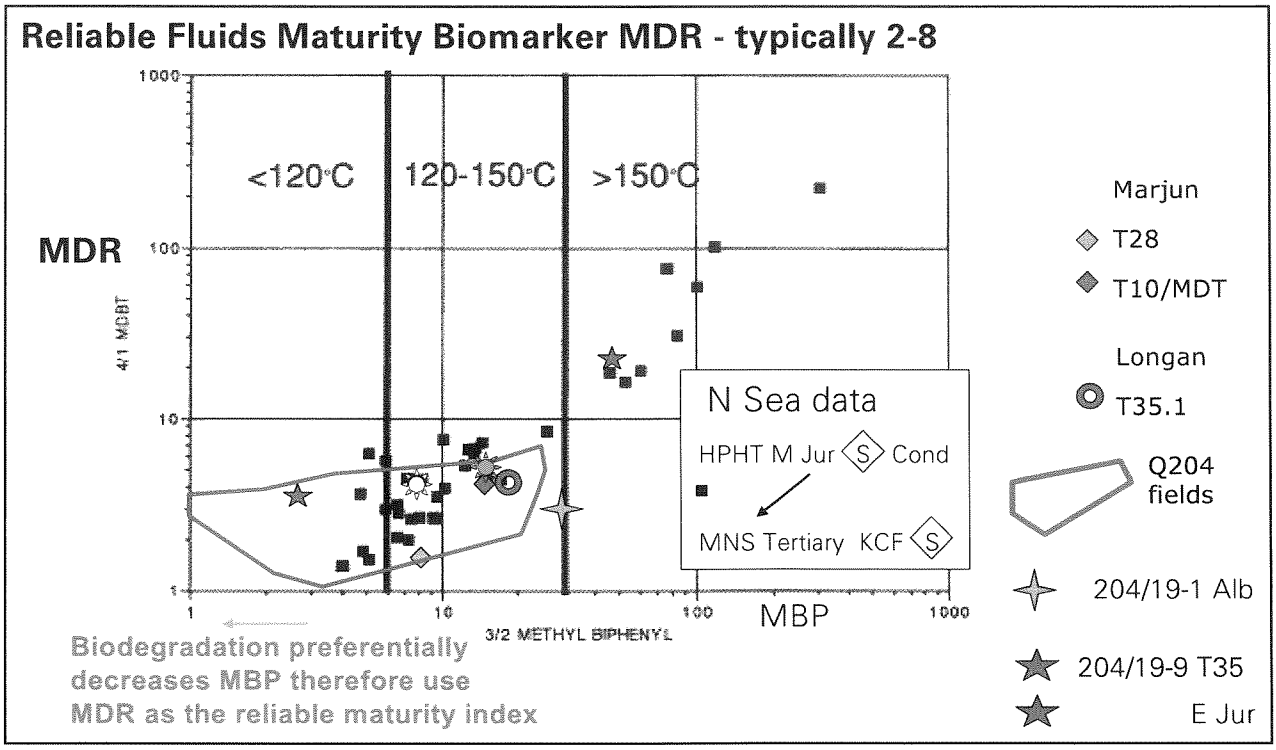


Figure 24: Faroes-Shetland Basin fluids maturity. (Source BP)

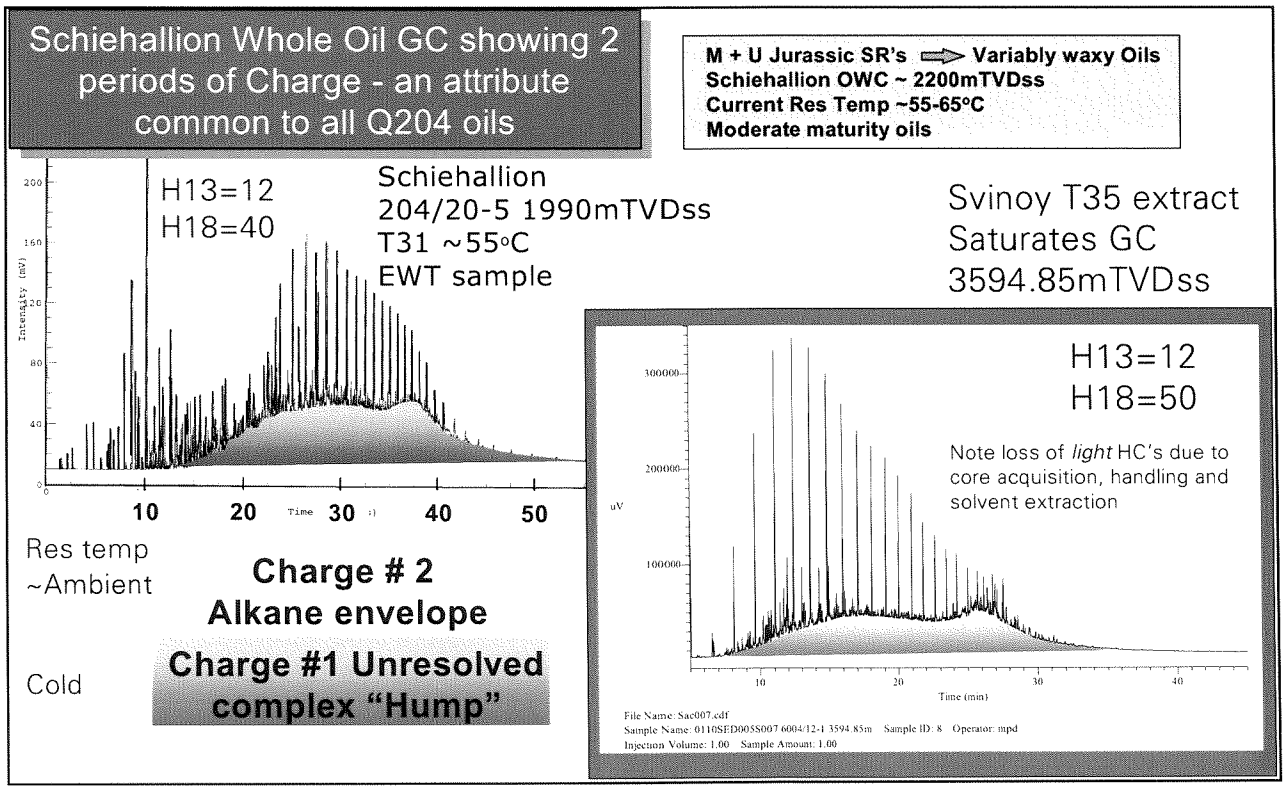


Figure 25: Faroes-Shetland Basin Fluids – Charge Periods. (Source BP)

8.3 Reservoir Quality

8.3.1 Reservoir Presence

The pre-drill prediction for reservoir presence versus the actual encountered reservoir is shown in figure 17. Pre-drill a mud dominated slope incised by sand-filled channels was assumed which continued into the basin; this is analogous to UKCS Quadrant 204. However, post drill an abundance of reservoir quality sand was found to be present which consequently decreases the chance of an effective seal being present.

No log-calculated commercial or non-commercial hydrocarbons are present in the 'A' Sand and 'B' Sand reservoir intervals (Figure 15). Water saturation calculations were computed for clean sand resistivities ranging from 1.5-2.1 ohm-m, total porosities of 19-25%, formation water salinity of 18k ppm, and m=n=1.8 to 2.0. Water saturations of 100% for each potential sandstone reservoir interval corroborated wellsite observations of no movable liquid or gas hydrocarbons within the T35 Sandstones. Oil stain and millimetre-scale oil shows on the core surface (see figure 26 below) are preferentially associated with relatively higher permeability intervals. Combined with the lack of any pressure seals in the well, this low-saturation, residual oil is most likely to be associated with a hydrocarbon migration pathway. The location of the cored interval is shown on figure 15.

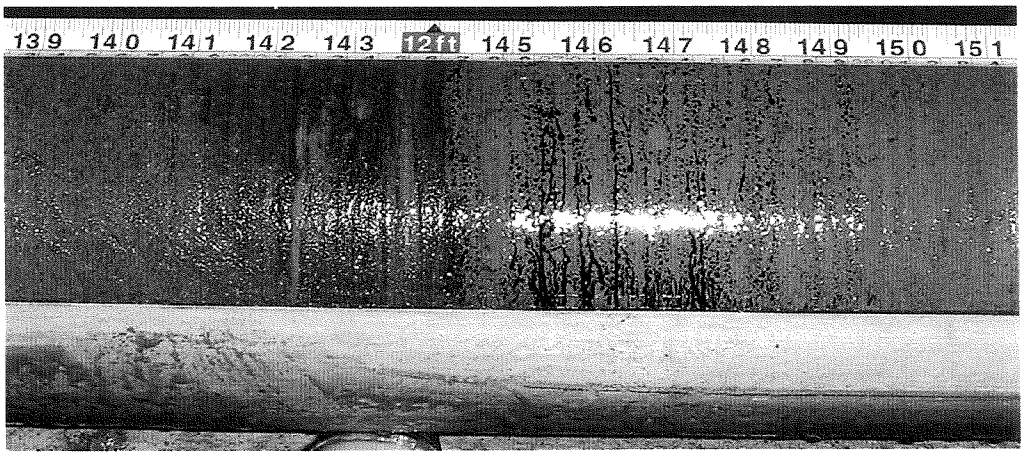


Figure 26: Svinoy T35 'B' sand cored interval oil shows (Source BP)

Strong seismic trough-peak amplitudes were generated by a 35-meter localized increase in sand porosity enhanced with some apparent low gas saturations. A preliminary calculation of up to 5.0m net pay over the interval 4428-4435m MD (Figure 16) follows from an increase in Logging While Drilling (LWD) density porosity from 17.5 to 20.0% with resistivities from 5-7 ohm-m. This results in 7.0m MD (5.0m TVD) with porosity > 15%, Vshale < 70%, and Sw from 51-64%, as well as a neutron-density crossover indicating probable gas. Rigsite chromatography likewise showed a significant increase in background gas over the interval 4430-4440m MD (average gas 1-2%, average 1.6 %, [C1 8000-15000 ppm, C2 200-300ppm]).

The apparent live, non-residual 5m gas column ranges from Sg (Gas Saturation) 30-50% under the m (Cementation Factor), n (Saturation Exponent), and Rw (Resistivity of Formation Water) values seen in analogous T34/T35 Foinaven/Schiehallion/Loyal reservoirs, generally ranging from m/n/1.8 to m/n/2.0. The resistivity of formation water (Rw) trends from the T38/T36/T35/UT34 Svinøy reservoirs suggest a single water salinity (18k ppm), which is not inconsistent with the lack of pressure seals (RCI data) seen in the previous hole section.

The exact composition of the apparent hydrocarbons (gas/light oil, biogenic/thermogenic) and its impact on the seismic response is currently unknown, but is critical to understanding the remaining prospectivity of the region.

8.3.2 Reservoir Effectiveness

Reservoir quality in the T38-to-T35 sequences was generally better than predicted, however, pervasive diagenesis caused by calcareous and siliceous cements effects the lower LT35-to-T31 section. Previously believed to be related to mineral-rich waters associated with the fault plane, the extensive diagenesis suggests a more sub-regional event whose cause and extent is currently being addressed. Cuttings are very poor and predominantly rock flour, although with moderate to very significant amounts of calcite and siliceous cements. Additional authigenic minerals may also be identified from the analysis of sidewall cores.

A notable exception to this trend is the T34 Fugløy Sand itself, which lies on the same porosity-depth trend as the upper T38/T36/T35 Sands. This interval may have been shielded from the cement-rich waters by a lensing of the bounding shales or with the addition of porosity-preserving (chloritic) clays.

Porosity/Permeability: T35 'A' & 'B' Sands

Two principal porosity domains are evident in the Svinøy well (see figure 27). Sandstones above c.3700m md (i.e. Sequences T35.3, T36, T38 and T45) yield porosities of >15% (typically 20-27%), whilst the more deeply buried sandstones yield porosities of <15%, commonly 9% (T31-T34.2). In this deeper section, it is only at the Fugløy level (c.4409m md) that sandstones of potential reservoir calibre are encountered. Whilst very good porosities are characteristic of the T35-T45 sandstones, Routine Core Analysis (RCA) data demonstrates that permeability is more variable, with permeabilities typically ranging from poor to very good (1-764mD).

Sandstones that are pervasively cemented by carbonate and tuffs or sandstones with tuffaceous affinities (T36 tuffaceous and volcaniclastic sandstones) do not support, or never had, a macropore network and cluster at the lower end of the porosity-permeability spectrum (Ø <15%, Kh <2mD). In contrast to the T34 Fugløy Sands, the T35 'A' and 'B' sands have higher than prognosed porosities of 23%-25%, in a high net to gross interval of 114m; this is comparable to the Foinaven and Schiehallion reservoirs. The diagenetic occurrence of chlorites in the T35 reservoir sequence has resulted in some preservation of porosity.

The pore system character and geological controls on reservoir quality are strongly governed by the depositional texture (grain size, sorting, ductile abundance) and sandstones provenance. Tuffaceous and volcaniclastic sandstones lack effective macropore networks due to widespread precipitation of analcime and/or calcite.

Furthermore, although the other T36 sandstones have loosely packed fabrics and retain a moderately connected macropore network, their reservoir potential is reduced by the presence of potentially swelling chlorite-smectite clays. This is illustrated by the reduced permeabilities observed in core (see figure 28). Precipitation of grain-coating chlorite in the T35.3 sandstones appears to have prevented widespread quartz cementation and limited compaction and therefore these sandstones have moderately well to well-connected primary macropore-dominated pore networks.

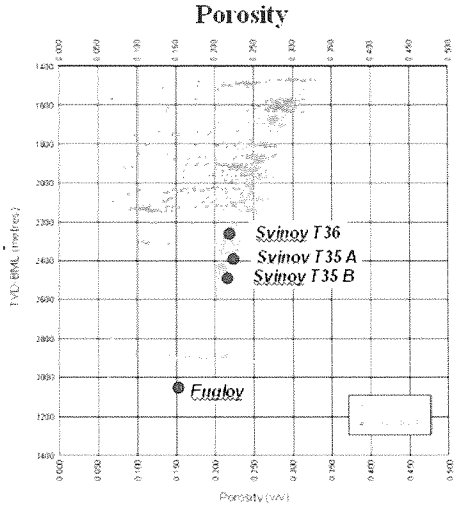


Figure 27: Foinaven Basin offset wells porosity versus depth plot

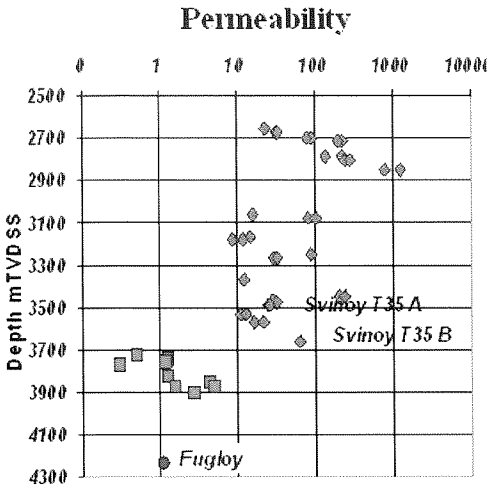


Figure 28: Foinaven Basin offset wells permeability versus depth plot

Porosity/Permeability: T34 Fugloy Sands

The porosity and permeability of the Svinøy deeper sands (T34-T28, Fugløy), are illustrated in figures 27 and 28 above. The porosity values recorded in the T34 reservoir interval, which encountered 35m of clean porous sands, were 15% - 20%. However, the reservoir interval was encased in tightly cemented T34 sandstones with porosities of 5% - 7%.

The substantial diagenesis encountered in Svinøy deeper sands (T34-T28) is a combination of quartz overgrowths and calcite cement, facilitated by a drop in porosity-preserving chlorites. There are also a relatively high proportion of authigenic minerals which may have been introduced through the local Canisp fault system. Significantly, the fault was drilled through by the original 6004/12-1 Svinøy wellbore and the observed high amplitudes associated with the T34 occur directly beneath the fault which supports the conclusion that authigenic minerals may have been introduced through the Canisp fault system. The presence of authigenic minerals and high degree of diagenesis encountered at this depth have also had a detrimental effect on permeability with values in the order of one millidarcy.

8.4 Trap/Seal

The top seal play risk for the T36 sequence was thought to be predominantly low, with Lower T38 slope mudstones providing a competent top seal over much of the Faroese Exploration License 004 area. On the reservoir amplitude variation with offset (AVO) map the area around the Svinøy prospect is very bright, which was interpreted to be caused by the effect of the T38-T36 shale directly above the reservoir interval.

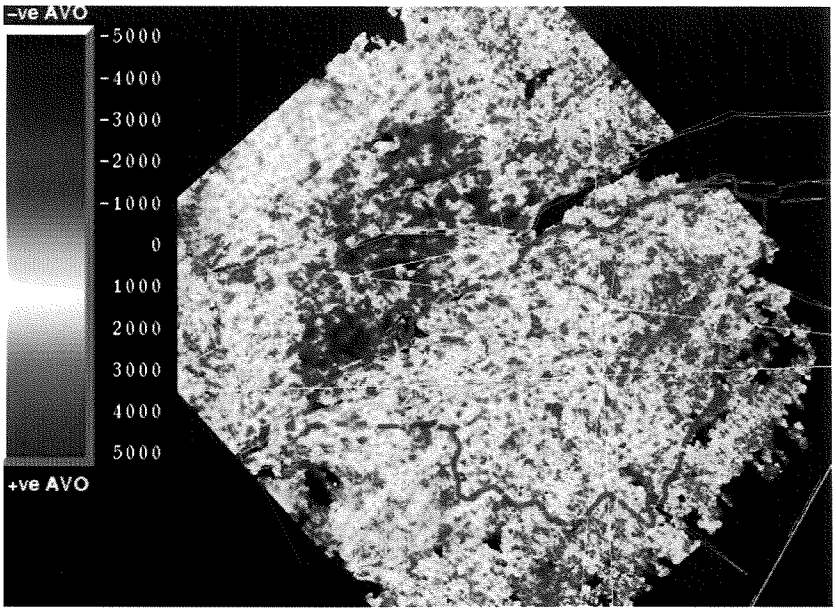


Figure 29: Svinoy T36 reservoir offset acoustic impedance map (Source BP)

Post well evaluation has shown that the DHI's provide a false AVO which is caused by the presence of anomalous lithologies, in this instance the basal T36 tuff. Notably, the basal T36 tuff encountered in the well had not previously been seen in any other well penetration in the Foinaven sub-basin. Only latterly has the basal tuff been penetrated in the 6004/17-1 (Marimas) and 204/17-1 (North Fleet) wells.

Svínøy's AVO response is now believed to be the result of the large impedance contrast between the basal T36 tuff and the 'A' Sands. There are also different rock properties that those observed in the West of Shetland (WoS). The critical risk identified post drill however, is the absence of the T36 shale seal and the presence of the 'anomolous' basal T36 tuff which causes the AVO response.

9 Remaining Hydrocarbon Prospectivity of License 004

From the original prospect inventory identified at the time of the BP Amoco license application in 2000, two segments of the Bordøy area remain untested.

In Faroese Exploration License 004 the Vidøy (UT35) and Kunøy (LT35-T34) segments remain undrilled. Both segments are dependent with similar structural settings as discussed in section 5.1. Prospectivity at some key stratigraphic levels has been eliminated by drilling. However, a number of prospects at other, less important, stratigraphic levels remain. These however carry relatively high risks and are volumetrically (risked reserves) minor. They are documented below with reference to Table 2.

	Block	Name	Status	Sequence	Area (km2)	Trap Type	STOIIP Mean (MMm3)	Reserves Mean (MMm3)	Core Area Reserves Mean (MMm3)	Water Depth	Depth to crest	PoS
Bordoy prospect	6004/12	Svinoy	Drilled	UT35	63	Struct/Strat	260	92	56	1050	2070	
		Vidoy		UT35	46	Struct/Strat	160	58	47	1050	2300	0.14
		Kunoy		T34	70	Struct/Strat	490	171	71	1000	2300	0.02
	6004/12	Fuglov	Drilled	T34	27	Struct/Strat	80	28	19	1050	2600	
Bordoy Satelittes	6004/17	Koltur		LT35	26	Struct/Strat	130	46	24	900	1600	?
	6004/17	Hestur		LT35	12	Struct/Strat	47	16	9	950	1800	?
	6004/17	Nolsoy	Drilled	LT35	59	Struct/Strat	180	63	38	1050	1850	
Leads	6004/16	Lui	Drilled	T50	132	4-way dip	350	120		950	450	
		T38-01		LT38	52	Strat	128	45		1050	850	?
		T35-15		LT35	57	Struct/Strat	202	71		1100	2650	?
		T35-14		LT35	18	Struct/Strat	43	15		1100	2400	?
	6005/15	Kalsoy	Drilled	T34	48	Struct/Strat	372	130		1050	2350	
		Tindur		T34/T35	17	4-way dip	88	31		1050	2325	?

Table 2: Volumetric Summary & Risked Reserves of Remaining License 004 Prospects (Source BP)

9.1 Vidøy (UT35)

The significant risks for the Vidøy segment reflect the results of the Svinøy well. The trap, top, bottom and lateral updip seal elements of the segment were not present in the Svinøy well and as a result do not exist in the Vidøy segment.

In consideration of the individual play elements the key risk for the Vidøy segment is top seal as the basal T36 mudstone was not present in the Svinøy well. As a result there is no viable trap for the Vidøy segment. The results of the Svinøy well indicate reservoir sand is present and that the quality was better than predicted, although there are still concerns regarding deliverability due to the effects of pervasive diagenesis in the deeper (LT35-T31) section. The Svinøy well also demonstrates that there is a hydrocarbon source and that there is charge access but without a seal and trap the Vidøy segment is a high risk low value opportunity.

The segment is an amplitude defined UT35 stratigraphic trap. Significantly, Svinøy and Marimas (Nolsøy) were also amplitude defined stratigraphic traps, and post well evaluations have proven that the misinterpreted DHI's observed at the well locations in conjunction with anomalous lithologies, provides a false AVO. The false AVO is caused by the previously unseen basal T36 tuff. Svinøy and Marimas (Nolsøy) AVO responses are now believed to be the result of the large impedance contrast between the basal T36 tuff and the 'A' Sands.

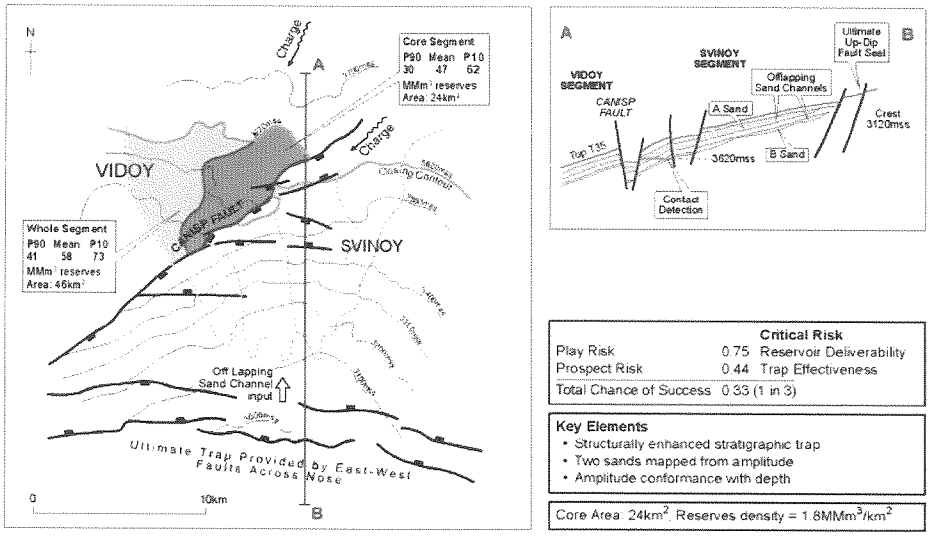
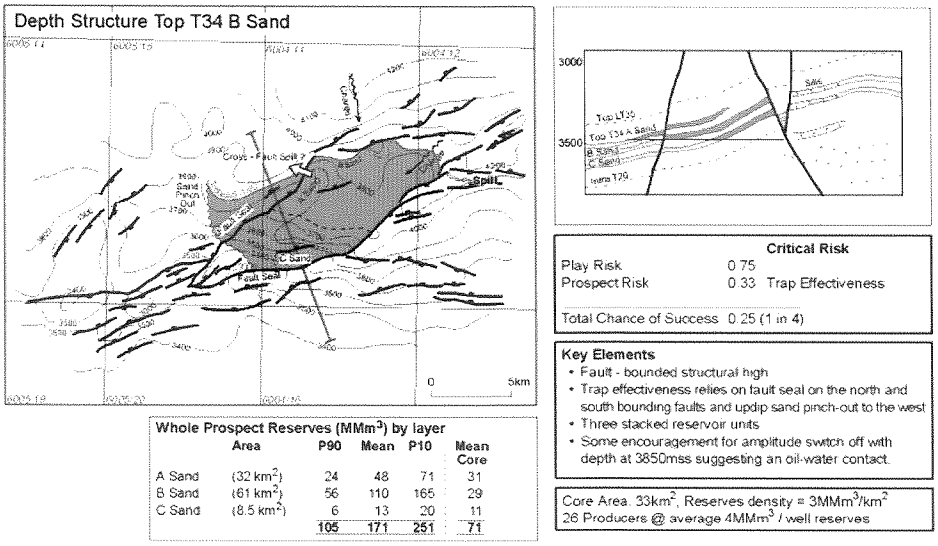


Figure 30: Vidoy segment summary. (Source BP)

9.2 Kunøy (LT35-T34)

The significant risks for the Kunøy segment also reflect the results of the Svinøy and Longan wells. The key risk following the post well evaluation of the Longan (Kalsøy) well is reservoir presence, as Longan encountered dolerite sills and not reservoir sands. In addition, there is also a significant risk of top, bottom and lateral seal failure given the absence of seal and subsequently trap at the Svinøy location.

In consideration of the individual play elements the key risk for the Kunøy segment is top seal as the basal T35 mudstone was not present in the Svinøy or Longan wells. As a result there is no viable trap for the Kunøy segment. The results of the Longan well indicated that there is a significant risk on reservoir presence as the predicted reservoir interval comprised dolerite sills. The Svinøy well demonstrates that there is a hydrocarbon source and that there is charge access but without a seal, trap and a significant risk on reservoir presence the Kunøy segment is a high risk low value opportunity.



Whole Prospect Reserves (MMm³) by layer

	Area	P90	Mean	P10	Mean Core
A Sand	(32 km²)	24	48	71	31
B Sand	(61 km²)	56	110	165	29
C Sand	(8.5 km²)	6	13	20	11
		105	171	251	71

Figure 31: Kunoy segment summary. (Source BP)

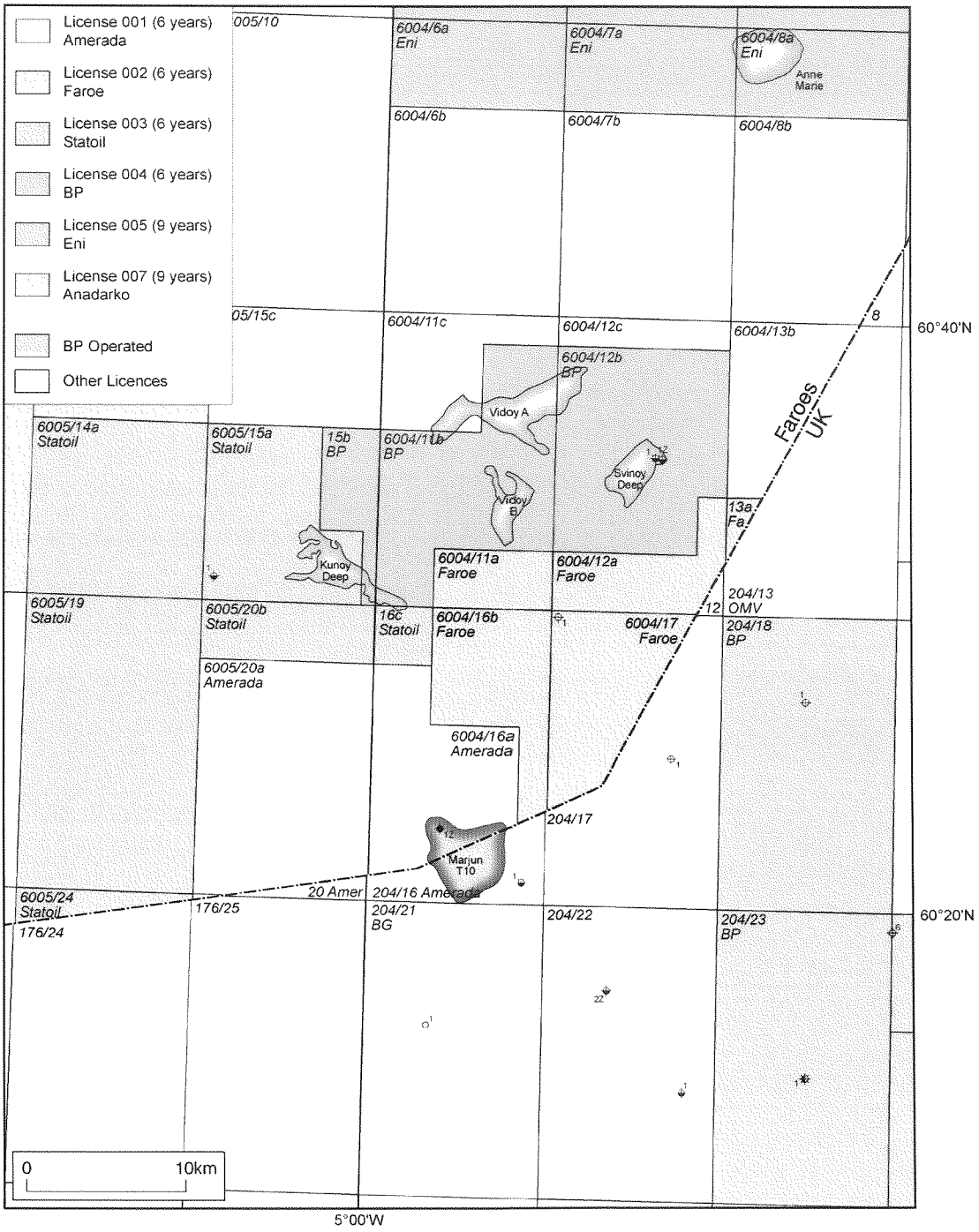


Figure 32: Faroese Exploration License 004 remaining pools & prospects (Source BP)

10 Conclusions

The remaining hydrocarbon potential of Faroes License 004 is described by referring to the play risk model.

The drilling of the 6004/12-1, 1Z (Svinøy) and 6004/16-1Z (Marjun) wells has proven that a working petroleum system has been discovered in the Faroes. There is evidence to suggest that the hydrocarbon discovered has typing from a mixed middle Jurassic, upper Jurassic source system similar to that observed elsewhere in the Faroe-Shetland Basin.

Bright seismic amplitudes can be used as lithology indicators with some degree of success. There is however a high degree of uncertainty in the use of amplitudes as a fluid indicator. There is some evidence to suggest sediment provenance to the Foinaven Basin from a westerly source. This has implications for reservoir presence and seal competency.

Reservoir deliverability has been shown to be variable with good porosity, permeability and net to gross characteristics in the T38 – T34 focus interval despite pervasive diagenesis caused by calcareous and siliceous cements and chloritic clays preserving porosity in the T34 interval. However, in the T10 hydrocarbon bearing interval reservoir quality is poor resulting in low commercial viability.

Significantly, the majority of prospects identified pre-drill in the Faroes License 004 required a stratigraphic element to the trap which relied heavily on top, bottom and lateral seals which have a historically low probability of success. The absence of a valid trap and the absence of a valid seal has proven to be the key risk of prospect failure in License 004.

The remaining hydrocarbon potential of License 004 is considered to be very low with volumetrically minor, high risk prospects remaining.

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