White Rose Development Plan Amendment
Production Volume Increase
Supplemental Information

November 2006

Husky Document No. WR-DVG-RP-0010

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1.0 Introduction

On September 29, 2006, Husky Energy submitted an Amendment to its White Rose Development Plan, **White Rose Development Plan Amendment – Production Volume Increase** (WR-RP-00187) to the Canada – Newfoundland and Labrador Offshore Petroleum Board (C-NLOPB).

Following submission of the Development Plan Amendment, the C-NLOPB conducted a Completeness Review and on October 26, 2006 issued a request for additional information (C-NLOPB File:8010) (Husky Reference No. 003979508). This supplemental report addresses the request for additional information received from the C-NLOPB.

2.0 Supplemental Information

The following supplemental information is provided using the same numbering scheme as that used in the request for further information received from the C-NLOPB on October 26, 2006. The specific request from the C-NLOPB is shown in bold text.

1. **A listing of all reports and data used by the proponent in the preparation of the Application.**

   Following is a list of reports and data used in the preparation of the Development Plan Amendment:

   SeaRose FPSO - Performance Test - July / August 2006 Final Test Report (WR-DVG-RP-0005). 2006. Prepared by Husky Energy.

   SeaRose FPSO - Performance Test - Main Power Generators - Final Test Report (WR-DVG-RP-0006). 2006. Report prepared for Husky Energy by Aker Kvaerner, Cahill, SCN-Lavalin.

   SeaRose Debottlenecking Study (WR-DVG-RP-0001). 2006 Report prepared for Husky Energy by SGS Canada.

   SeaRose FPSO MPG Gas Turbine Offshore Site Performance Testing August 2006 WR-DVG-RP-0004. 2006. Report prepared for Husky Energy by MSE Consultants Ltd.

   White Rose Field Development Sea Rose Metering for 140,000 bbls/d Case (WR-DVG-RP-0003). 2006. Report prepared for Husky Energy by SGS Canada.

   Sea Rose FPSO Piping Vibration Risk Assessment. (NSOX0046/1 Rev 0). 2006. Report prepared for Husky Energy by Acoustics and Vibrations Group, Bureau Veritas, Hampshire, UK.

   Reference to the following reports was made in Section 8.0 of the Development Plan Amendment. The reports have been re-issued as a result of the higher production rate and offloading frequency.

Quantitative Risk Analysis (QRA) (WR-HSE-RP-0003). 2006. Report prepared for Husky Energy by W.S. Atkins, Glasgow, Scotland.

Temporary Refuge Impairment Analysis (TRIA) (WR-HSE-RP-0004) 2006. Report prepared for Husky Energy by W.S. Atkins, Glasgow, Scotland.

Fire Risk Analysis (FRA) (WR-HSE-RP-0009) 2006. Report prepared for Husky Energy by W.S. Atkins, Glasgow, Scotland.

Inert Gas Dispersion Analysis (WR-HSE-RP-0014) 2006. Report prepared for Husky Energy by W.S. Atkins, Glasgow, Scotland.

Ship Collision Risk Analysis (WR-HSE-RP-0021) 2006. Report prepared for Husky Energy by W.S. Atkins, Glasgow, Scotland.

Cargo Pump Room Explosion Analysis (WR-HSE-RP-0062) 2006. Report prepared for Husky Energy by W.S. Atkins, Glasgow, Scotland.

2. **Section 6.0, Figure 6.1 notes the current development region. It is observed that Block 6, which was proposed for development in the Approved Development Plan, is not proposed for development in the Application. If this is correct it should be stated and the reason for no longer pursuing development should be noted.**

   The development of Block 6 was contemplated in the original White Rose Development Plan. However, with the drilling of the F-04 and F-04z wells in 2003, a greater understanding of the seismic interpretation into Block 6 was realized. The potential for reserves in Block 6 has decreased significantly as a result of this information because a level of fault seal not seen in the South Avalon Pool would be required for there to be any appreciable amount of hydrocarbons present. Therefore, development wells into Block 6 are not currently planned.

3. **Section 6.2 Petrophysics: The following should be provided for the wells drilled since the original development plan submission:**

   a. **the methods used to adjust core analysis data to reflect subsurface conditions;**

   b. **assumptions and methods used in interpreting log data, including water resistivity values, porosity and permeability relationships;**

   c. **cut-off criteria used to estimate net pays; and**

   d. **procedures to calibrate logs and to calculate porosity, permeability and water saturation.**

   Reservoir Porosity and K_Air Permeability
   Overburden Compaction Factor

   Standard core analysis may incorporate systematic errors in porosity because these values are measured at low pressure (e.g. 2758 Kpa), which lead to an over-estimation of porosity. At surface conditions pore volumes tend to expand with the decrease in confining pressure. Additional core analysis was undertaken to correct for the overburden.

Porosity and permeability measurements were taken on thirteen core plugs from WhiteRose A-17 and N-30. This work was carried out by Hycal Laboratories as a supplement to special core analysis work. The measurements were taken using CMS-300 equipment. Measurements were taken using a series of increasing pressures intended to simulate and span reservoir pressures existing in the White Rose Field.

The resulting data series have been trended to extract equations. These equations link the decrease in reservoir porosity and permeability to an increase to overburden or reservoir-equivalent pressures, and to the original porosity and permeability in each sample. These equations provide the basis for adjusting all "as measured" lab porosities and permeabilities to those representing the same rock under reservoir conditions.

Work Method

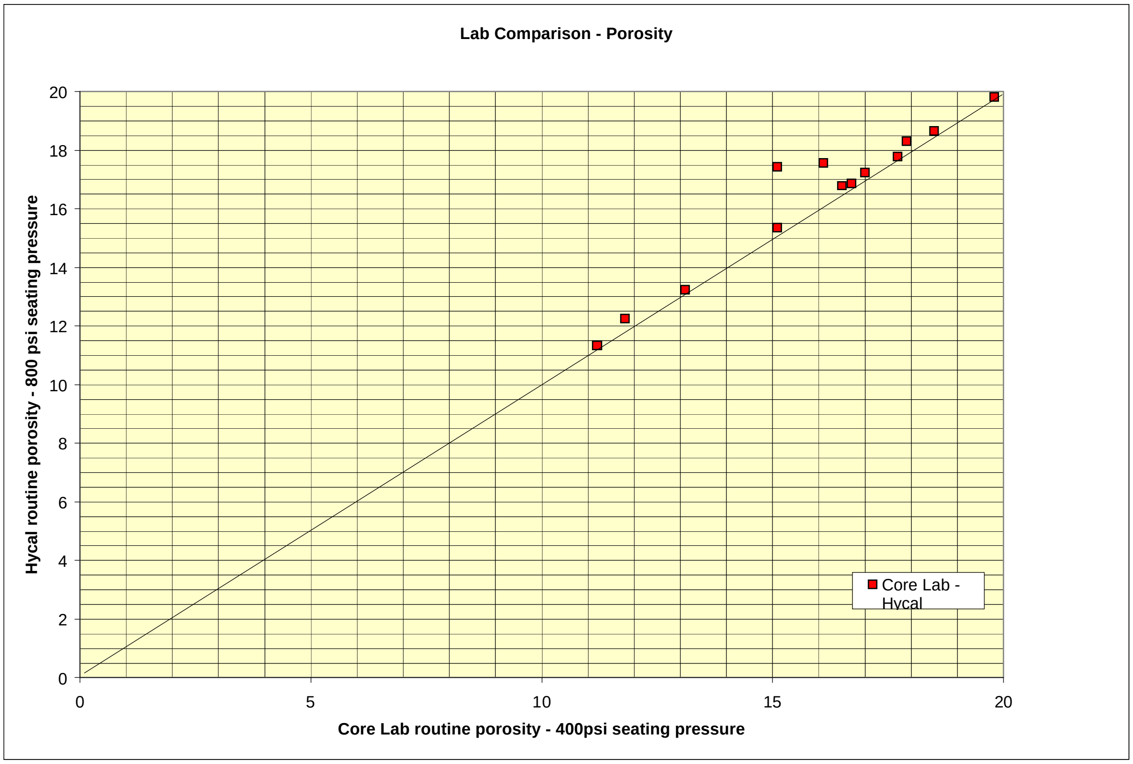
Hycal measured the porosity and permeability for each plug at requested overburden pressures of 800, 1740, 3480, 5370 and 7250 psi (Table 2.1). Rock and pore volume varied, plug by plug and acted to reduce this pressure by a small amount. These overburden pressures were converted to kPa. The overburden pressures applied for the permeability calculations are different than those applied for the porosity calculations.

These plugs have previously been measured by Core Laboratories under routine or lab conditions, but Core Lab routinely uses 400 psi seating pressure. The Core Lab values of porosity and permeability were added to Table 2.1 to see whether the values were in the right range, and whether there was any systematic difference between the "routine" values reported by Core Lab and Hycal (Figure 2.1).

These systematic differences in methodology were found to exist. The Hycal porosities and permeabilities measured at 800psi were higher than the Core Lab values measured on the same plugs at a lower seating pressure of 400psi.

Table 2.1 Hycal and Core Lab Measurements

Sample I.D.	Depth	Requested Overburden psi	Act. Overbur. During Pore Vol psi	kpa	Pore Volume cc	Porosity 1 %	Act. OverBur. During Perm psi	kpa	Air Perm md
Core Lab Value	**29**		**400**	2758		**17.7**	**400**	2758	**96.8**
880803	29	800	746	5143.67	12.6111	17.78	896	6177.92	117.32
880803	29	1740	1610	11100.95	12.4305	17.57	1756	12107.62	116.51
880803	29	3480	3318	22877.61	12.2852	17.4	3463	23877.385	113.83
880803	29	5370	5153	35529.935	12.1806	17.28	5306	36584.87	111.83
880803	29	7250	6989	48189.155	12.112	17.2	7151	49306.145	110.41



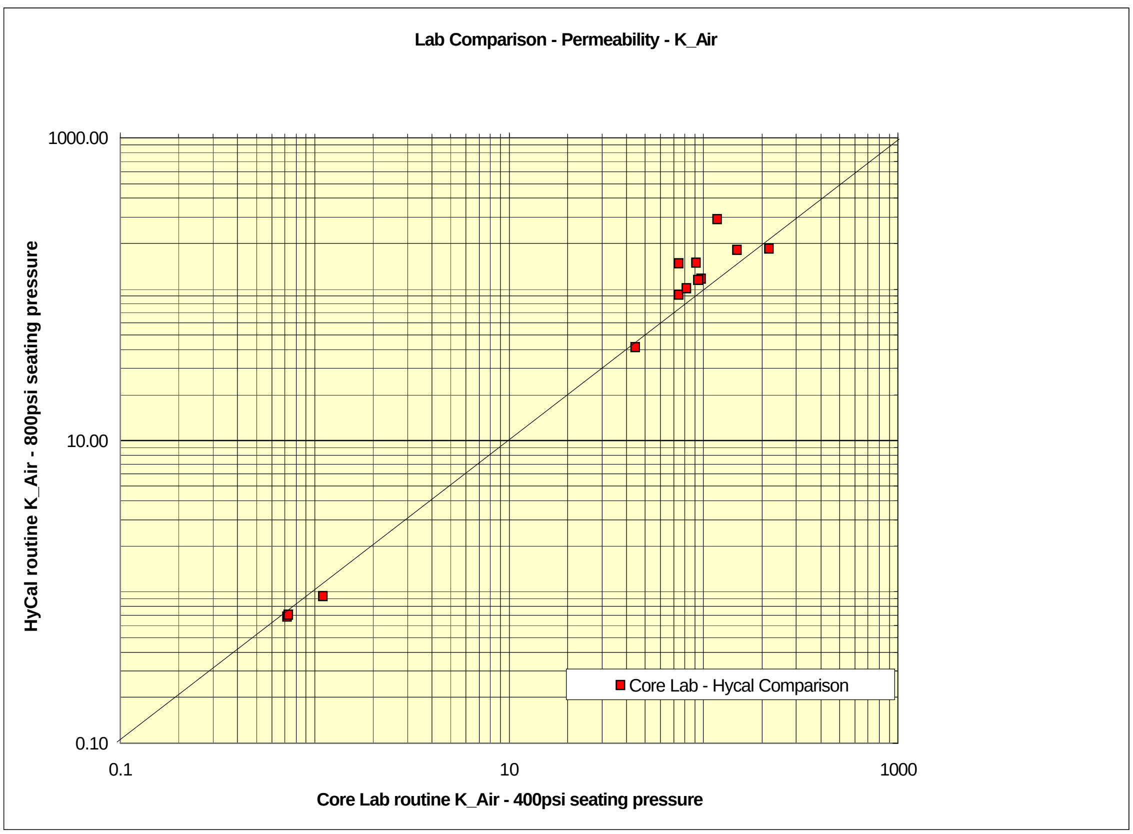


Figure 2.1 Core Lab - Hycal Comparison

Overburden Correction

Core porosity and permeability at low pressure versus core porosity and permeability at simulated overburden pressure is shown in Figures 2.2 and 2.3.

Core porosity measurements measured under laboratory conditions when applying 400psi or 2758kPa seating pressure (CoreLab practice) should be adjusted using the following equation:

$$f\,@30.000Kpa = 1.0191(f\,@2758Kpa) - 0.8695$$

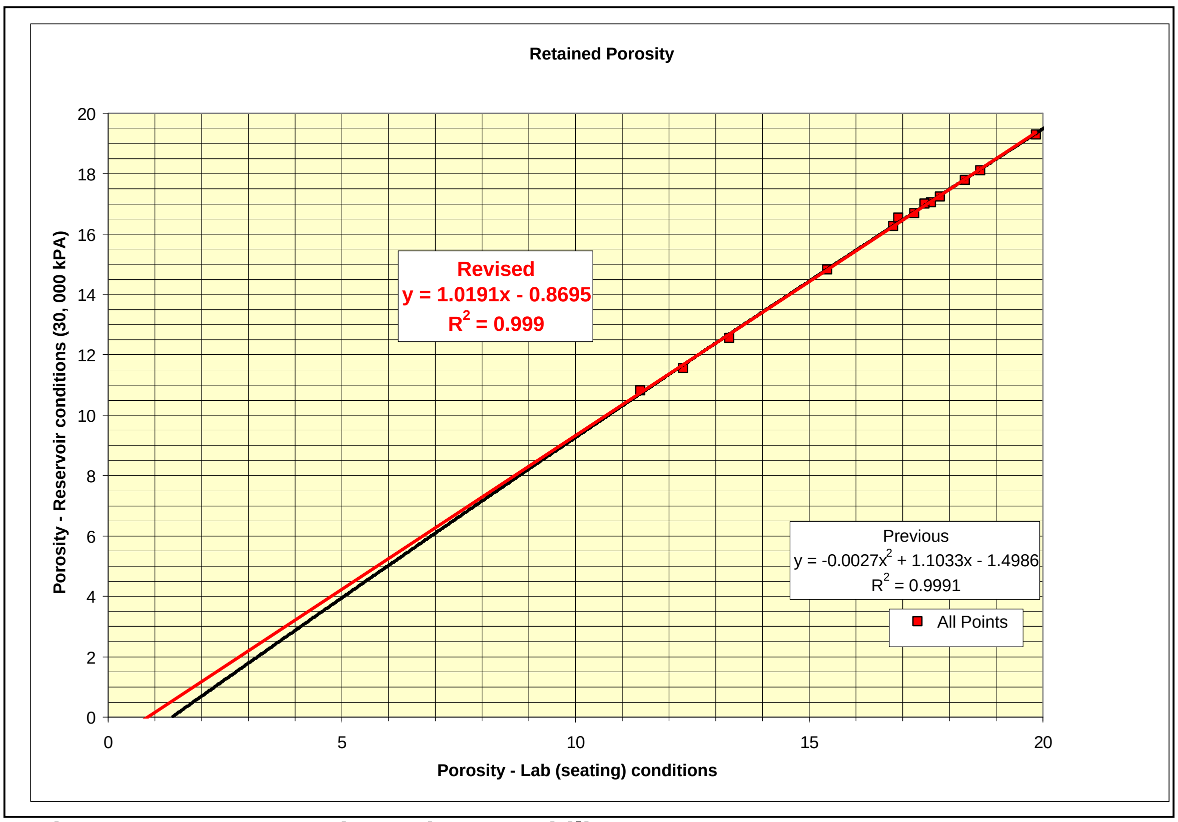


Figure 2.2 Core Porosity and Permeability at Low Pressure

For the 13 samples analyzed the reservoir porosity averaged 96.5% of laboratory values.

Core permeability measurements measured under laboratory conditions when applying 400psi or 2758kPa seating pressure (CoreLab practice) should be adjusted using the following equation:

$$K\,@\,30,000\;Kpa = 0.7088\,(K\,@\,2758\;Kpa)^{1.0442}$$

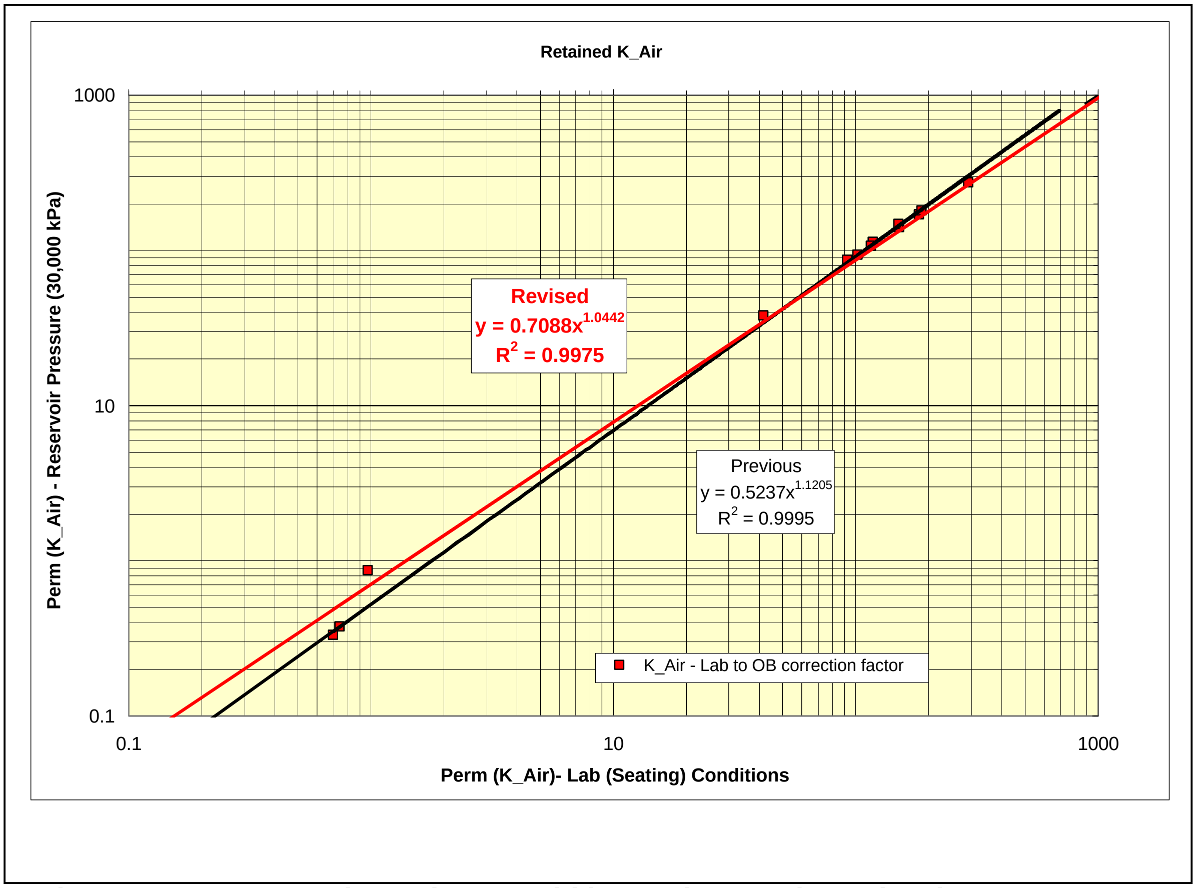


Figure 2.3 Core Porosity and Permeability at Simulated Overburden Pressure

For the 13 samples measured, the reservoir permeability averages 87.2% of laboratory values.

Methods used in the Petrophysics of the White Rose Field
Permeability calculation

For all the wells in the White Rose Field that have core, Figure 2.4 illustrates the core porosity-permeability relationship.

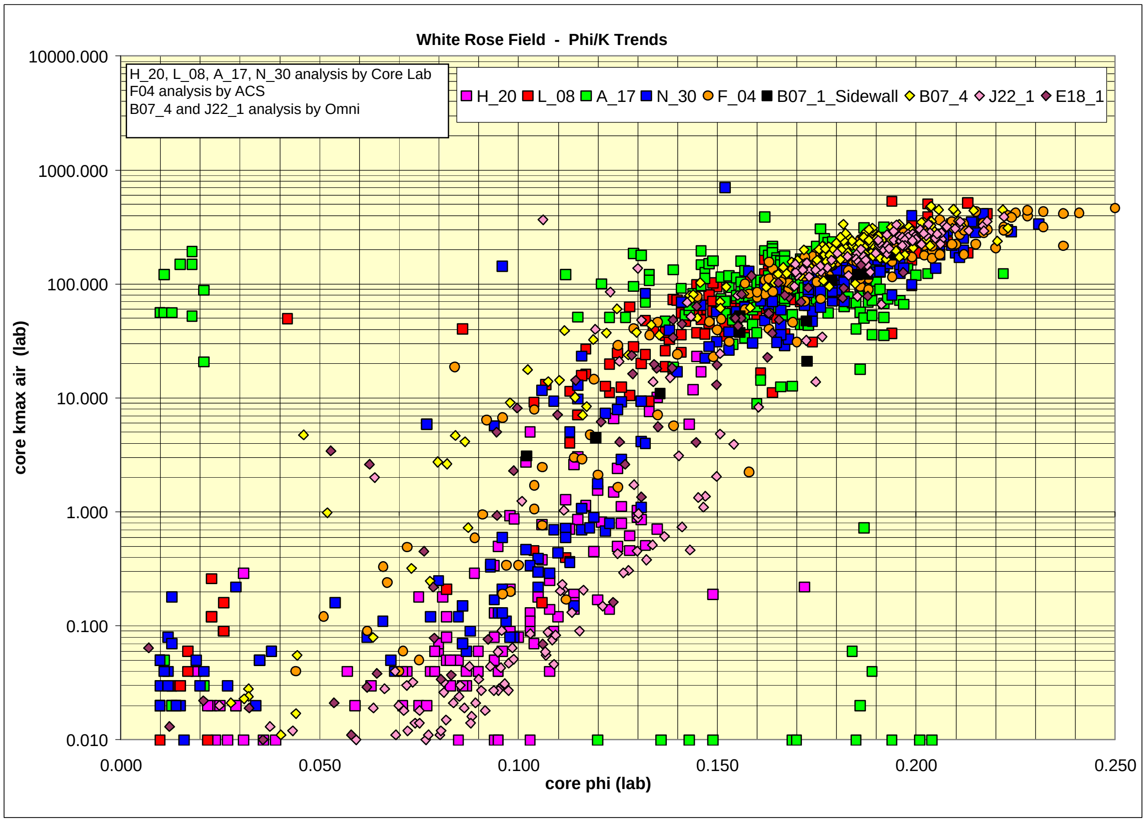


Figure 2.4 Core Porosity-Permeability Relationship for White Rose Wells

Husky's standard practice is to correct the core porosity and permeability for the over-burden pressure and link the core permeability with other attributes such as porosity and depositional facies.

On Figure 2.5 the porosity-permeability relationship shows two different trends: one mainly for the better laminated sand (colored in blue) and the second trend for the bioturbated sand facies (colored in green). The generated permeability from the porosity and given deposition facies assignment is illustrated in the following equations:

For shale, bioturbated sand, calcite:

$$k = 10^{\left(-2.1890 + 0.567\phi + 84.1\phi^{2} + 656.31\phi^{3}\right)}$$

For laminated sand:

$$k = 10^{\left(-2.301 + 40.02\phi - 84.056\phi^{2}\right)}$$

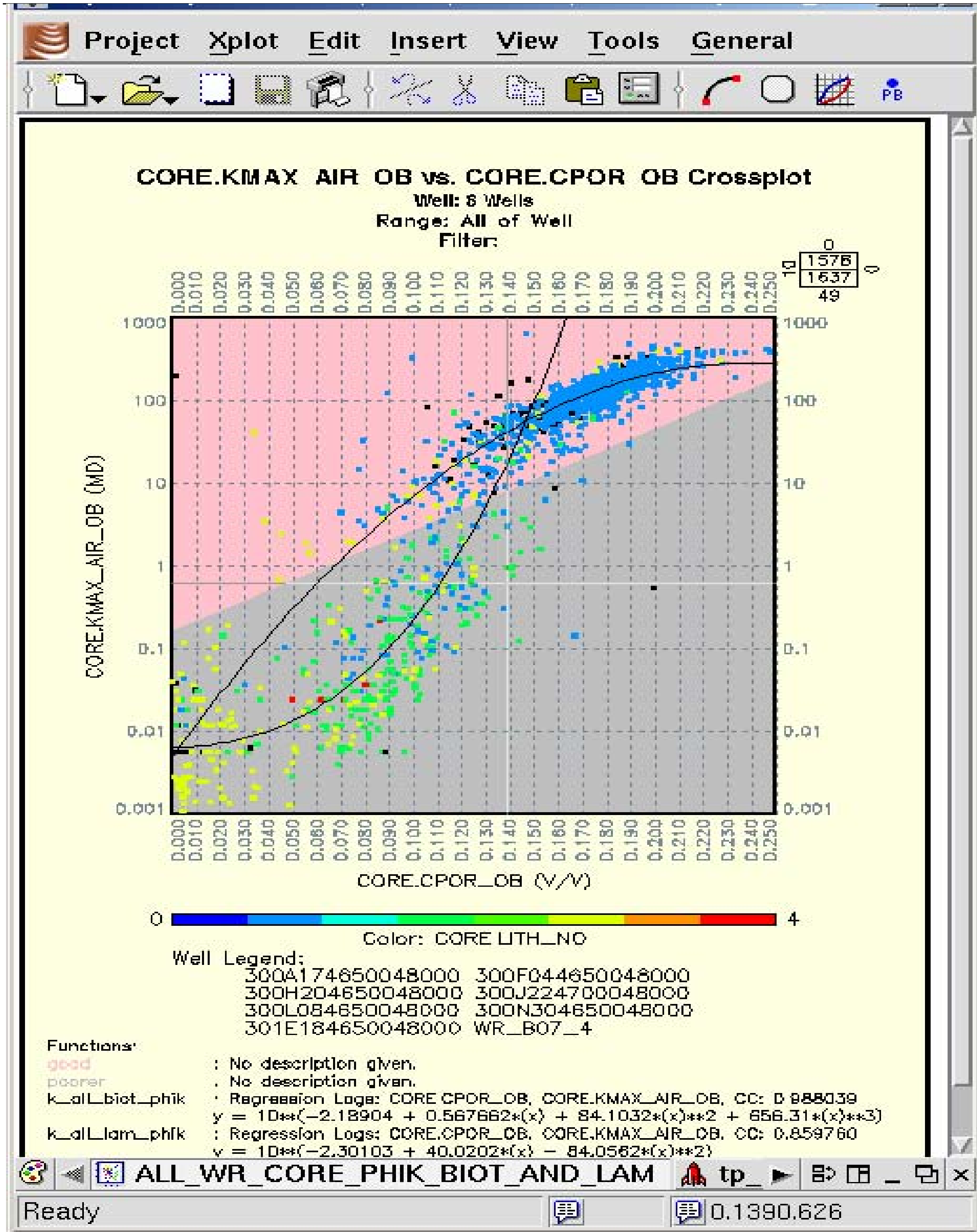


Figure 2.5 Porosity-Permeability Relationship

Formation Water Resistivity

The water salinity was determined using the modular dynamic tester water samples gathered in the well L-08. The samples were obtained using the optical fluid analyzer and resistivity measurement to minimize the mud filtrate contamination.

Table 2.2 indicates the values obtained for each sample. At 25°C, the resistivities varied from a low of 0.212 to a high 0.565 ohm-m. Sample number 208 was used because this sample indicated the lowest PH, above 7.

Table 2.2 Values from Formation Water Testing

Sample #	Sample Depth	Sample Tritium Conc	Mud Tritium Conc	Sample Tritium Contam	Contam Sample Rw@25	Contam Sample Conc	Sample pH	Mud Salinity	Corrected Formation Salinity PPM	Corrected Formation Resistivity Rw @ 25
	(m)	(pCi/ml)	(pCi/ml)	(%)	(ohm-m)	(ppm)		(ppm)	(ppm)	(ohm-m)
199	3047	10874	42345	25.7	0.135	47,100	8	133,267	17,327	0.339
311	3047	10294	42345	24.3	0.156	39,960	8	133,267	9,992	0.565
315	3047	9722	42345	23.0	0.144	43,746	8	133,267	17,068	0.344
208	3094.5	2853	38058	7.5	0.171	36,000	7.7	133,267	28,118	0.218
233	3094.5	2870	38058	7.5	0.167	36,972	7.8	133,267	29,118	0.212
248	3094.5	2970	38058	7.8	0.173	35,500	7.9	133,267	27,225	0.224

Note: The Rw used for the Avalon field study was 0.218 @ 25°C, 0.082 @ Formation Temperature of 100°C, which is 28,118 NaCl equivalent.

Electrical Properties M and N

Special core analyses were undertaken using core from L08 to determine the correct cementation exponent “m” and saturation exponent “n” to be used in determining water saturation using the log evaluation software.

The reported average values for M and N, using an ‘a’=1 are:

The Cementation exponent M=1.78
The Saturation exponent N=1.86

By knowing the M and N values it will be easy for the petrophysicist to use the Pickett Plot in the water leg to determine the formation water resistivity.

Application of Cut-offs

The cut-offs used for the study of the White Rose field are:

Reservoir Cut-offs:
Porosity cut-off 10%
Permeability cut-off 3md
Shale volume cut-off 30%

Pay Cut-offs
Porosity cut-off 10%
Permeability cut-off 3md
Shale volume cut-off 30%
Water saturation cut-off 50%

4. **Section 6.4 Field Peak Rate Sensitivities: In addition to the figures reference the following should also be provided for each case examined in tabular format: forecasts of the production and/or injection of oil, gas and water, on an annual basis for the field.**

Tables 2.3 to 2.5 summarize the cumulative oil, gas and water production volumes on an annual basis for each of the rate sensitivity case considered utilizing both the sealing fault and non-sealing fault scenarios. As stated in Section 6.3.4 of the Development Plan Amendment, the sealing fault scenario is the preferred Base-Case predictive model for the field, and provides a good match to the production history and advised-production rates for the field. The non-sealing fault scenario was run to evaluate the sensitivity of fault-seal, and it's potential influence on field production. In this regard, the non-sealing scenario should be considered in the context of a "hypothetical / upside case" since the model was not constrained by the field advised-production rates. As a result, the production volumes for the sealing and non-sealing scenarios are slightly different.

Tables 2.6 and 2.7 summarize the anticipated field Water injection volumes for each rate sensitivity case evaluated by the sealing and non-sealing fault scenarios. The quantity of water injected is controlled by the voidage replacement and bottomhole flowing pressure constraints imposed by the ECLIPSE reservoir simulation model.

Table 2.8 summarizes the Gas Injection Volumes anticipated for each of the rate sensitivity cases evaluated. It is important to note that the quantity of gas available for injection (and likewise the quantity of gas injection) is dependent upon a number of factors/variables such as quantity of gas produced, quantity of fuel-gas usage, quantity of gas flared, gas-lift requirements, and overall compression system availability. Furthermore, these factors/variables are subject to change with time. For this reason, Table 2.8 presents the gas injection volumes for each rate-sensitivity cases evaluated but does not distinguish between the sealing / non-sealing scenarios.

Table 2.9 summarizes the typical gas-lift rates anticipated for the White Rose Field. The quantity of gas-lift-gas will be dependent upon individual well parameters (ie. water cut, timing of water breakthrough) and overall field production / injection constraints which will necessitate optimization of the gas-lift system at a future date. For this reason, Table 2.9 summarizes the "typical" gas lift rates for the White Rose field, but does not distinguish between the rate-sensitivity cases or the fault-seal scenarios.

Table 2.3 Field Oil Water and Gas Production Volumes for 15,900 Sm³/d Case

Month-Year	Sealing Fault Scenario 15,900 Sm³/d Case			Non-Sealing Fault Scenario 15,900 Sm³/d Case		
	Field Oil Cumulative Sm³	Field Water Cumulative Sm³	Field Gas Cumulative 1000 Sm³	Field Oil Cumulative Sm³	Field Water Cumulative Sm³	Field Gas Cumulative 1000 Sm³
Dec-05	390,387	607	52,293	555,000	866	74,514
Dec-06	5,507,277	8,798	772,603	5,611,700	8,910	799,994
Dec-07	11,310,777	25,964	1,674,378	11,415,200	20,974	1,702,745
Dec-08	17,130,176	309,401	2,765,351	17,234,600	126,287	2,733,760
Dec-09	22,563,862	1,753,426	4,066,370	23,038,100	1,014,219	3,985,553
Dec-10	26,804,948	4,869,248	5,282,902	28,235,548	3,806,470	5,398,273
Dec-11	29,817,548	9,253,129	6,133,107	31,344,022	7,746,823	6,318,691
Dec-12	31,869,856	14,308,429	6,780,962	33,284,872	12,449,355	6,979,624
Dec-13	33,377,132	19,851,586	7,323,887	34,695,828	17,728,610	7,518,041
Dec-14	34,566,348	25,799,482	7,793,330	35,807,664	23,480,162	7,985,162
Dec-15	35,531,408	32,010,882	8,204,697	36,725,732	29,624,762	8,405,791
Dec-16	36,348,016	38,408,424	8,577,034	37,503,808	36,140,232	8,793,202
Dec-17	37,048,644	44,935,704	8,918,829	38,162,968	42,890,820	9,148,463
Dec-18	37,657,944	51,602,432	9,234,355	38,729,784	49,920,284	9,473,975
Dec-19	38,206,272	58,548,876	9,534,278	39,225,488	57,187,700	9,775,460
Dec-20	38,698,124	65,725,164	9,815,687	39,665,200	64,654,144	10,057,081
Dec-21	39,137,636	72,990,904	10,073,971	40,058,008	72,287,808	10,319,256

Table 2.4 Field Oil Water and Gas Production Volumes for 19,875 Sm^3/d Case

Month-Year	Sealing Fault Scenario 19,875 Sm^3/d Case			Non-Sealing Fault Scenario 19,875 Sm^3/d Case		
	Field Oil Cumulative Sm^3	Field Water Cumulative Sm^3	Field Gas Cumulative 1000 Sm^3	Field Oil Cumulative Sm^3	Field Water Cumulative Sm^3	Field Gas Cumulative 1000 Sm^3
Dec-05	390,387	608	52,310	555,000	866	74,514
Dec-06	5,736,067	9,171	806,850	5,954,500	9,447	846,455
Dec-07	12,990,442	43,322	1,961,449	13,208,875	25,370	2,020,159
Dec-08	19,966,886	638,028	3,431,145	20,399,808	273,813	3,461,227
Dec-09	25,257,752	3,086,994	4,961,989	26,331,584	1,967,559	4,972,937
Dec-10	28,881,116	7,578,557	6,129,546	30,128,546	4,988,074	6,056,128
Dec-11	31,254,198	13,001,257	6,959,988	32,368,376	8,814,030	6,779,338
Dec-12	32,888,936	19,020,356	7,620,856	33,954,476	13,370,445	7,349,928
Dec-13	34,110,972	25,447,154	8,169,133	35,169,340	18,491,388	7,827,414
Dec-14	35,079,096	32,190,128	8,641,987	36,160,236	24,069,714	8,247,606
Dec-15	35,882,864	39,194,220	9,061,348	36,996,764	30,014,762	8,631,520
Dec-16	36,566,564	46,424,888	9,435,325	37,717,648	36,327,112	8,988,809
Dec-17	37,158,588	53,807,988	9,769,377	38,333,884	42,846,712	9,317,619
Dec-18	37,683,600	61,383,352	10,074,307	38,872,856	49,700,088	9,622,908
Dec-19	38,150,300	69,030,656	10,345,004	39,343,312	56,737,988	9,906,092
Dec-20	38,568,156	76,710,760	10,589,202	39,762,968	63,991,520	10,171,404
Dec-21	38,939,300	84,334,528	10,811,402	40,138,352	71,389,624	10,418,844

Table 2.5 Field Oil Water and Gas Production Volumes for 22,261 Sm^3/d Case

Month-Year	Sealing Fault Scenario 22,261 Sm^3/d Case			Non-Sealing Fault Scenario 22,261 Sm^3/d Case		
	Field Oil Cumulative Sm^3	Field Water Cumulative Sm^3	Field Gas Cumulative 1000 Sm^3	Field Oil Cumulative Sm^3	Field Water Cumulative Sm^3	Field Gas Cumulative 1000 Sm^3
Dec-05	390,387	608	52,310	555,000	866	74,514
Dec-06	5,736,067	9,171	806,951	5,954,500	9,447	846,461
Dec-07	13,806,067	52,023	2,109,690	13,975,000	27,819	2,163,463
Dec-08	20,706,422	702,660	3,646,536	21,311,196	342,365	3,699,343
Dec-09	25,794,440	3,238,270	5,170,894	26,973,784	2,189,947	5,176,589
Dec-10	29,212,568	7,732,076	6,287,127	30,456,082	5,190,446	6,186,667
Dec-11	31,486,062	13,040,982	7,090,958	32,560,624	8,977,428	6,878,861
Dec-12	33,056,262	18,931,230	7,734,833	34,079,236	13,492,393	7,429,839
Dec-13	34,247,620	25,249,700	8,273,656	35,256,960	18,571,170	7,894,738
Dec-14	35,196,260	31,897,748	8,739,885	36,224,648	24,110,682	8,305,031
Dec-15	35,993,024	38,834,636	9,157,192	37,043,536	30,005,118	8,680,097
Dec-16	36,674,108	46,021,376	9,533,087	37,752,440	36,273,480	9,030,444
Dec-17	37,262,536	53,370,056	9,869,740	38,359,980	42,746,376	9,352,293
Dec-18	37,784,148	60,904,372	10,177,350	38,893,152	49,559,832	9,653,204
Dec-19	38,250,348	68,605,480	10,459,847	39,359,352	56,554,040	9,932,948
Dec-20	38,663,156	76,308,992	10,713,849	39,775,500	63,766,476	10,195,038
Dec-21	39,031,936	83,989,976	10,942,894	40,150,588	71,160,936	10,441,891

Table 2.6 Summary of Field Water Injection for Sealing Fault Scenario

Month/Year	Sealing Fault Scenario 15,900 Sm^3/d Case	Sealing Fault Scenario 19,875 Sm^3/d Case	Sealing Fault Scenario 22,261 Sm^3/d Case
	Field Water Injection Cumulative Sm^3	Field Water Injection Cumulative Sm^3	Field Water Injection Cumulative Sm^3
Dec-05	573,025	573,025	573,025
Dec-06	8,276,458	8,566,814	8,567,249
Dec-07	17,356,886	19,449,809	20,313,022
Dec-08	26,892,116	31,127,457	32,257,416
Dec-09	37,850,076	43,658,452	44,927,993
Dec-10	49,461,596	56,154,444	57,162,903
Dec-11	60,110,016	67,333,527	68,058,011
Dec-12	69,757,240	77,703,406	78,189,632
Dec-13	78,974,056	87,631,444	87,954,614
Dec-14	88,041,696	97,358,570	97,549,408
Dec-15	96,924,608	106,953,116	107,067,852
Dec-16	105,684,290	116,462,850	116,544,500
Dec-17	114,341,940	125,872,822	125,931,650
Dec-18	122,944,360	135,285,916	135,316,212
Dec-19	131,706,310	144,574,316	144,711,580
Dec-20	140,564,720	153,751,676	153,961,428
Dec-21	149,366,560	162,769,508	163,060,228

Table 2.7 Summary of Field Water Injection for Non-Sealing Fault Scenario

Month/Year	Non-Sealing Scenario 15,900 Sm^3/d Case	Non-Sealing Scenario 19,875 Sm^3/d Case	Non-Sealing Scenario 22,261 Sm^3/d Case
	Field Water Injection Cumulative Sm^3	Field Water Injection Cumulative Sm^3	Field Water Injection Cumulative Sm^3
Dec-05	748,273	748,273	748,273
Dec-06	7,832,780	8,296,583	8,296,609
Dec-07	17,046,379	19,199,992	20,110,682
Dec-08	26,650,066	31,094,238	32,462,077
Dec-09	37,619,164	43,387,556	44,486,340
Dec-10	49,881,308	53,548,314	54,167,386
Dec-11	60,105,476	62,470,598	62,872,080
Dec-12	69,397,112	71,111,066	71,373,502
Dec-13	78,488,256	79,716,640	79,873,024
Dec-14	87,552,332	88,391,976	88,461,896
Dec-15	96,646,132	97,133,344	97,120,624
Dec-16	105,830,508	106,003,008	105,924,124
Dec-17	115,010,316	114,889,052	114,748,432
Dec-18	124,261,296	123,904,012	123,711,492
Dec-19	133,582,504	132,966,824	132,724,308
Dec-20	142,974,400	142,106,460	141,824,976
Dec-21	152,445,448	151,331,760	151,048,684

Table 2.8 Summary of Predicted Gas Injection Volumes for each Rate Sensitivity Case Evaluated

Month-Year	Cumulative Gas Injection Volume (1000 Sm^3)	Cumulative Gas Injection Volume (1000 Sm^3)	Cumulative Gas Injection Volume (1000 Sm^3)
	(15,900 Sm^3/d Case)	(19,875 Sm^3/d Case)	(22,261 Sm^3/d Case)
Dec-05	0	0	0
Dec-06	479,625	498,828	498,865
Dec-07	1,245,585	1,512,493	1,643,626
Dec-08	2,190,361	2,840,420	3,050,214
Dec-09	3,360,889	4,134,005	4,253,588
Dec-10	4,388,387	4,725,289	4,778,096
Dec-11	4,862,978	5,030,984	5,061,994
Dec-12	5,120,294	5,224,762	5,245,248
Dec-13	5,285,733	5,356,912	5,371,096
Dec-14	5,399,829	5,449,820	5,459,557
Dec-15	5,480,192	5,515,536	5,522,451
Dec-16	5,537,350	5,562,346	5,567,443
Dec-17	5,577,911	5,595,755	5,599,476
Dec-18	5,606,857	5,619,668	5,622,349
Dec-19	5,627,566	5,636,808	5,638,647
Dec-20	5,642,476	5,649,109	5,650,372
Dec-21	5,653,135	5,657,891	5,658,820

Table 2.9 Typical Gas-lift Rate for White Rose Field

Month-Year	Typical Field Gas Lift Rate (Sm^3/d)
Dec-05	0
Dec-06	0
Dec-07	0
Dec-08	0
Dec-09	575,000
Dec-10	850,000
Dec-11	1,000,000
Dec-12	1,050,000
Dec-13	1,150,000
Dec-14	1,200,000
Dec-15	1,250,000
Dec-16	1,250,000
Dec-17	1,250,000
Dec-18	1,300,000
Dec-19	1,400,000
Dec-20	1,400,000
Dec-21	1,400,000

5. **The drilling schedule for all planned wells should be provided.**

The proposed drilling schedule for the remaining wells for the South Avalon Development are indicated in Table 2.10

Table 2.10 Remaining South Avalon Development Wells to be Drilled

Well Name	Drill Centre	Well Type	Estimated Spud/ Re-entry Date
E-18 7	Central	Water Injector	Q4 2006
E-18 8	Central	Producer	Q4 2006
J-22 2	Northern	Gas Injector	Q2 2007

6. **There is no discussion of the analysis of the relief blow down system. That is, the capacity of this system to handle increased volumes of gas, the capacity of individual PSV valves on various pieces of equipment. This is also something the CA will be reviewing, but there is no discussion in the application. In addition, there is no discussion of the analysis of erosion in the pipe work because of increased flow rates. There is also the possibility of issues around corrosion because of increased flow. We will require some discussion of the studies undertaken to address these issues.**

With the exception of the oil stream processing, it is Husky's intention to operate the plant within the existing Total Liquids limit of 33,000 m^3/d. Further work will be completed in the future but at this stage, the intent is to displace water capacity with crude oil.

For clarity the operating case under consideration is summarized in Table 2.11.

Table 2.11 Base Case and Dry Oil Case

Fluids	Base Case	Dry Oil Case	Comments
Oil Flow Rate bbls/d [m^3/d]	100,000 [15,900]	140,000 [22,261]	
Gas mmscf/d [sm3/d]	150 [$4.2x10^6$]	150 [$4.2x10^6$]	• Includes Fuel Gas & Lift Gas • Gas injection rate will reduce as head requirement increases
Lift Gas mmscf/d [sm3/d]	42 [$1.6x10^6$]	39 [$1.1x10^6$]	• Limit per glory hole of $1.19x10^6$ sm3/d
Water Injection bbls/d [m^3/d]	189,000 each Glory Hole [30,000 / Glory Hole]	219,000 Total [35,000]	• Limit of 44,000 m^3/d
Produced Water Handling bbls/d [m^3/d]	176,400 bwpd [28,000 m^3/d]	104,000 bwpd [16,500 m³/d]	• Maximum water capacity within total liquid limit
Total Liquids bbls/d [m^3/d)	207,900 [33,000]	143,000 [22,700]	

Relief & Blowdown System

Relief System

The relief valves on the HP Separator, 33-PSV-1105 A/B/C/D are sized for the blocked outlet case. For the increased oil rates, the installed capacity is sufficient. The valves require no modification.

The relief valves on the LP Separator, 330PSV-1312 A/B/C/D are also sized for the blocked outlet case. Preliminary calculations have been carried out and it was concluded that:

- Installed capacity of relief valves are adequate to relieve a liquid rate of 177,148 bopd (28,168 m^3/d) and hence suitable for the proposed 140,000 bopd (22,261 m^3/d) service.
- Piping pressure losses are within the 3% limits recommended by API 520/521 during maximum possible flow through the PSV's.

Detailed calculations are now in progress to identify the ultimate capacity of the valves and piping using rigorous Vapour Liquid Equilibrium (VLE) methods.

Flare System

The following design cases sized the flare system. Cases marked with an asterisk **(*)** are impacted by changes in production rates.

HP Flare Tip	Emergency blowdown/ continuous flaring off HP Separator and blowdown of compression train*****
LP Flare Tip	Continuous flaring off LP and MP Separators *****
HP Cold Flare Header	Emergency blowdown
HP Warm Flare Header	HP Separator blocked outlet PSV relief *****
LP Warm Flare Header	LP Separator blocked outlet PSV relief *****
HP Flare	Emergency Blowdown
LP Flare	Emergency Blowdown

1. HP Flare Tip

The design profile under review has maximum gas rates within the original design capacity – hence no impact.

2. LP Flare Tip

Increasing oil flow may increase gas evolution in LP and MP Separators and hence peak continual flaring rates. Technical Query (TQ) 0796 addressed the capacity of the LP flare tip versus capacity of control valves to flare. The recommendations from this TQ (to install stops to limit opening of LP and MP valves to flare) will be implemented prior to increasing production over 125,000 bopd (19,875 m^3/d).

3. Warm HP Header

The existing HP Separator PSVs can adequately relieve the revised production during blocked outlet. The PSV rated flow will remain the same and therefore the HP Flare header will not be impacted.

4. LP Flare Header

The PSV's on the LP Separator are suitably sized for the 140,000 bopd (22,261 m^3/d) case. Based upon the detailed VLE approach, the limiting capacity of the LP Flare Header will also be determined.

5. Relieving Cases – Impact on existing Flare & KO Drums

Study work for the relieving scenarios associated with increased oil production is currently in progress. Husky continues to progress the evaluation of the relieving scenarios for the 140,000 bbl/d (22,261 m^3/d) dry oil case and it is expected that this will be concluded in the first quarter 2007. Any consequential improvements or additional process safeguarding will be implemented prior to increasing oil production in the summer of 2007.

Husky is also evaluating whether there may be a requirement for production limitation during flaring (relating to excess radiation).

Results from the study work will be submitted and agreed with the Certifying Authority. It is anticipated that the Certifying Authority will provide a conditional release pending completion of actions required for facility output of 140,000 bbls/d (22,261 m^3/d).

Corrosion and Erosion

As outlined above, with the exception of the oil stream processing, the plant will be operated within the existing Total Liquids limit of 33,000 m^3/d.

The performance of the HP Separator will not be impacted as this unit is a two-phase separator, with the total fluid rate and overall gas rate remaining within design values.

The MP and LP Separator total fluid handling also remains within design limits with the exception that the crude oil outlet from the LP Separator is increased above the original design in order to process 140,000 bbls/d (22,261 m^3/d). The impact of this increased oil flow on piping velocity is discussed in the following sections.

Corrosion

No significant changes in composition, pressure and temperatures are envisaged in either liquid or gas, hence there will be no impact on existing corrosion rates of materials as installed.

Erosion and Vibration

With the increased production scenario a number of Crude Oil lines that exceed API recommended velocity criteria have been identified. These are further detailed in Appendix A. While the velocity in the crude oil lines exceeds the API criteria, the velocities remain within the NORSOK guidelines. The exception to meeting the NORSOK criteria is the crude oil cooler bypass, however this is not open in the normal operating case and will only be fully open in the event of a process upset.

Since the increased oil production is above the Base Case 100,000 bbl/d (15,900 m^3/d), as a mitigating measure, an erosional monitoring program has already been initiated on the particular lines as part of the asset integrity monitoring. This monitoring program will remain in place until such times as the crude oil flow rate returns to the original Base Case flow rate of 100,000 bbl/d (15,900 m^3/d).

Although the API RP14E is a recommended practice, the RQF process will be used as a query process to ensure a common interpretation of the regulations. An RQF will be raised, submitted to the Certifying Authority for concurrence by December 15, 2006, and to the C-NLOPB for approval.

7. **The Application appears to indicate that the maximum produced water (PW) discharge rate will be less than the 30,000 m3 maximum assessed in the WR Comprehensive Study Report (see, for example, Figure 6.25 on page 98, that appears to indicate a maximum discharge of approximately 23,000 m3/d). This being the case, there is no requirement for additional environmental assessment related to PW discharges. However, the maximum anticipated PW discharge rate is not state explicitly in the Application and this should be clarified.**

Based upon predictions from the ECLIPSE reservoir simulation model, the maximum anticipated produced water discharge rate for the White Rose South Avalon Pool is approximately 22,000 m^3/d.

The C-NLOPB also asked for the following information (not numbered):

- **A copy of the most recent seismic cube**.

This information will be provided to the C-NLOPB under the conditions outlined in the letter sent to Mr. Wayne Chipman on November 9, 2006 (Husky Ref. No. HUS-CPB-WR-LTR-00308).

- **A digital copy of WBHP, WHP and build-up extrapolated pressure that was used in the history match process.**

This information has been provided to the C-NLOPB in electronic format on the CD accompanying this report.

- **The prorated oil production and water injection rates used, covering the first seven months of production data with a cutoff date of June 13, 2006.**

This information has been provided to the C-NLOPB in electronic format on the CD accompanying this report.

Appendix A – Increased Capacity Impact on Piping

Piping

For each of the lines between the LP Separator and the cargo tanks the increased velocity corresponding to 140,000 bbl/d (22,261 m^3/d) was calculated and evaluated against the original design philosophy. Current design data was extracted from the linelist WR-P-30-B-SC-00001 rev Z1 and prorated from the current 100,000 bbl/d (15,900 m^3/d) to 140,000 bbl/d (22,261 m^3/d), with the exception of the cargo tank lines, whose maximum flowrate was extracted from the P&ID. The limits of the investigation are clouded in Figure 1, with the lines exceeding the velocity requirement highlighted in magenta (ref. Calculation 1A007-006). The lines that exceed the API RP14E velocity criteria are also tabulated in Table 1.

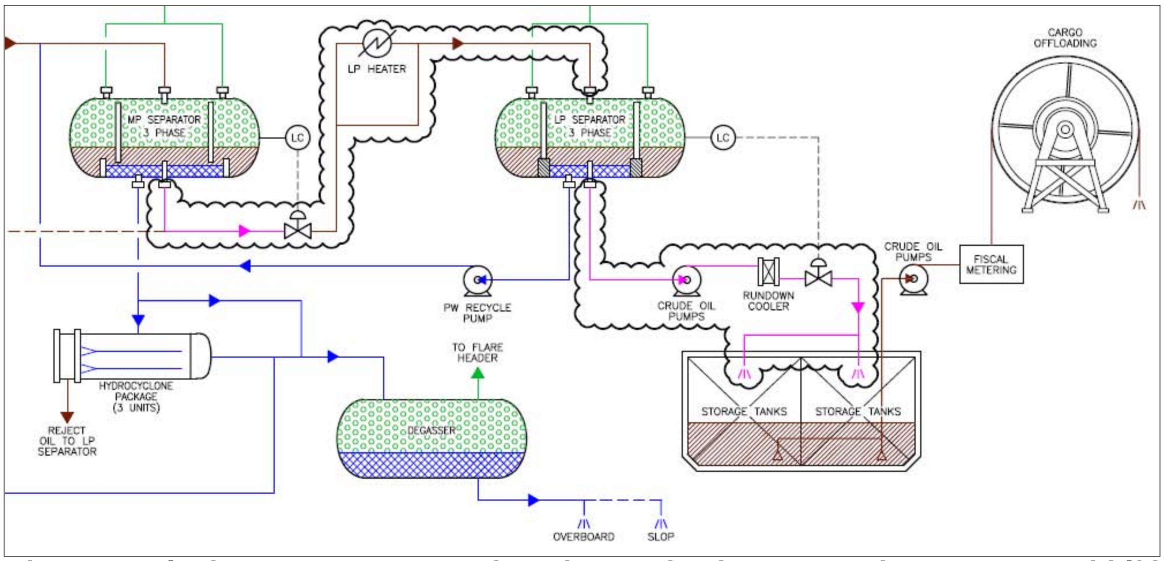


Figure 1 Velocity Concern Imposed on the Crude Lines Operating at 140, 000 bbl/d (22,261 m^3/d)

Table 1 Crude Oil Lines that Exceed the API RP14E Velocity Criteria

Line	Service	Material	NORSOK Guidelines	API Limiting Velocity, m/s	Actual Velocity, m/s
P-16-P-33015-AD1	Crude pump suction manifold	CS*		1.8	2.3
P-8-P-33120-AD1	Pump min. flow header	CS	6.0	4.6	5.2
P-10-P-33027-AD1	Crude oil pump discharge manifold	CS	6.0	4.6	5.4
P-10-P-33032-AD1	Cooler inlet	CS	6.0	4.6	5.4
P-10-P-33033-AD1	Cooler inlet	CS	6.0	4.6	5.4
P-10-P-33034-AD1	Cooler outlet	CS	6.0	4.6	5.4
P-10-P-33035-AD1	Cooler outlet	CS	6.0	4.6	5.4
P-8-P-33036-AD1	Cooler bypass	CS	6.0	4.6	8.5
10" CS STPY 440	10" section of cargo piping	CS	6.0	4.6	6.0

* carbon steel

These velocities occur under normal conditions. Operating of control valves will typically increase flow rate by 20 to 40%. The lines highlighted in Table 1 require further investigation because the high velocities introduce the potential for vibration-induced fatigue and erosion to occur. Specifically, a risk review will be completed followed by development of a crude rundown lines inspection plan and subsequent erosion inspections on the affected lines.

To determine if excess pressure loss would be introduced into the system by the additional 40% capacity, the pressure drop was modeled from the LP Separators, through the crude oil pumps and heaters to the crude rundown valve (ref. Calculation 1A007-003). The pressure drop increase is marginal and will not impede the cargo delivery rate or capacity. There is no evidence to suggest that the pressure at any point in the pump supply line will drop below the oil vapor pressure, therefore cavitation is not predicted.