5 UGS Development Scenarios

5.1 UGS input data

5.1.1 UGS subsurface realizations

As described in the history match section, the range of subsurface realisations was changed with respect to Phase 2. This was done to focus on the possible effects of aquifer presence on the needed cushion and working gas volumes and on well-productivity. Also, the models were refined in the Upper Rotliegend (ROSLU), where the future horizontal wells in Block-2 are planned. This was done to better reflect the changes in permeability with respect to depth below top reservoir. The ALT5 fault variation, which increases the volume of Block2 compared with the MAIN block, was taken along for the low productivity realisations, see Table 5-1.

		Top	Aqf	Comp	fault	xtra bfls	v-prod	h-prod
LowCushion	BGM_InterA_dismid_alt2_bell050_LowCushion	N uplift	yes	high+irrevers	alt2		base	base/high
HighProd	BGM_InterA_dismid_alt2_bell080	N uplift	no	base	alt2		high	high
LowVProd	BGM_InterB_dismid_alt5_bell033	0.4	no	base	alt5		low	base/low
BaseProp	BGM_InterB_dismid_alt2_bell050	0.4	no	base	alt2		base	base/high
Base	BGM_InterA_dismid_alt2_bell050	N uplift	no	base	alt2		base	base/high
LowHprod	BGM_HighP_alt5_bfls	1.0	no	base	alt5	yes	base	low

Table 5-1 Main phase 4 subsurface realizations.

5.1.2 UGS offtake scenario

Based on Phase2, the LARGE offtake scenario, with 9 5/8" Tbg instead of 7 5/8" was chosen in order to reduce the number of wells in the MAIN block from 15 to 9, see **[deleted text because of confidentiality]**

For Block-2, 5 horizontal wells with the maximum Tbg-size of 7 5/8" are needed in the base case.

[deleted text because of confidentiality]

Table 5-2 Possible offtake scenario's from Phase 2 with Phase 4 base case.

Compared to Phase 2, the operating pressure was changed from 145 bar (full) to 133 bar and 95 bar (empty) to 88 bar, thus decreasing the needed amount of cushion gas from 6.1 to ca 5.5 Bscm, as well as the amount of working gas, from 3.9 to ca 3.4 Bscm. The duration of the UGS-cycles was changed from 60 days for both production and injection to 72 days (production) and 88 days (injection). The number of cycles per year was increased from 1 to 2, which had a significant effect on the pressure-equilibration (resulting in capacity-losses) that takes place when the UGS is not used. The UGS parameters for the Phase 4 base case are listed in Table 5-3. The average production rate is ca 50 MMsm3/d during production and ca 40 MM sm3/d during the injection cycle, which means average production rates of ca 4 MMsm3/d for the vertical wells and 2.5 MMsm3/d for the horizontals. While the pressures and cycle durations were defined by TAQA, the volumes result from the straight P/Z behaviour. The pressure constraint for the main fault is the maximum pressure difference seen historically and was imposed by TNO.

[deleted text because of confidentiality]

Table 5-3 UGS parameters Phase 4 base case (INTERA_DISMID_ALT2_BELL050), no aquifer.

5.1.3 Cushion / working gas injection scheme

The pressure in Bergermeer has been increased from ca 9 to 11 bar in the MAIN compartment with the Summer Injection Test of 2007. In the BGM-7 block, the pressure has remained ca 25 bar. With the first UGS-wells planned to be drilled in 2010, the only wells available for injection in the field until 2011 are the existing BGM-wells. It is planned the existing wells will get new 5.5" Tbg's in 2009, some wells will receive workover in order to clean-out the reservoir section. The cushion and working gas injection scheme that was used for the UGS realisations in Eclipse is:

- 2009 Pres ca 12 / 25 bar
- 2010 Pres ca 15 bar – Injected 0.1 Bscm – 184 days – THP 65 bar
- 2011 Pres ca 35 bar – Injected 1.1 Bscm – 184 days – THP 65 bar
- 2012 Pres ca 88 bar – Injected 4.1 Bscm – 184 days – THP 160 bar (compression)
- 2013 Pres ca 133 bar – Injected 3.5 Bscm – 92 days – THP 160 bar
- Winter 2013 / 2014 is first production period (72 days – THP 30 bar)
- Summer 2014 first short injection period of 88 days

5.1.4 UGS well parameters

The base case model has 9 vertical wells planned in the MAIN compartment with 9 5/8" Tbg's. In the BGM-7 compartment (Block-2) 5 horizontal wells will be needed, all with 7 5/8" Tbg's. For details on the well-specifications, like casing and completion design is referred to the Bergermeer Basis of Well-Design report, Drilling & Completion FEED [3]. It is noted that for some subsurface realisations, the number of wells drilled for each block is slightly different, 8 in the MAIN block and 6 horizontals in Block-2. This is due to the alternative continuation of the main dividing fault between the 2 blocks (ALT5) vs. the continuation of the fault in the base case (ALT2). The lift curves that were used in the model include the latest changes in well-design according to the FEED study. The values that were used for mechanical and non-Darcy skin are also based on the well-design analysis done for the FEED. The skin-values for the vertical UGS wells are high as they will be completed with internal gravelpack for sand-control. The horizontal-completions are planned with cemented and perforated liners. No detailed studies were done on the horizontal well-length or the minimum depth above GWC, these values were based on analogue data. A summary of the UGS-well parameters is given below:

<u>Vertical UGS wells (VPROP)</u>

- Skin = 20
- D = 10 [MMsm3/d]$^{-1}$
- Rw = 0.2159 m (8.5" OH)
- Max. well-depth: 50 m above initial GWC (2180 m tvdss)
- THP contraint 30 / 160 bar production / injection
- Erosional constraint 5 MM sm3/d

<u>Horizontal UGS wells (HPROP)</u>

- Skin = 10
- D = 2 [MMsm3/d]$^{-1}$
- Rw = 0.1556 m (6 1/8" OH)
- Horizontal section-length = 500 m
- Max. well-depth: 27 m above initial GWC (2200 m tvdss)
- THP contraint 30 / 160 bar production / injection
- Erosional constraint 3.2 MM sm3/d

The skin-values for the existing BGM-wells were based on average values found by interpretation of the well-tests. These are S = 0 for all wells and D = 20 [MMsm3/d]$^{-1}$ for BGM-1 and BGM-5, D = 10 for BGM-2, BGM-6A and BGM-8A and D = 0 for BGM-7, see Table 2.5 of the Phase 2 report [1].

5.2 UGS modeling results Phase 4

5.2.1 UGS characteristics

The modeling results are characterised by several parameters. The cushion and working gas volumes are given for the different subsurface scenarios accompanied by the resulting reservoir pressures around the well. This is done to indicate how much hysteresis is in the model: the local deviation of the BHP-pressure from the average reservoir pressure. At the end of an injection cycle the pressure around the horizontal wells in Block-2 could be some 40 bar higher than the reservoir pressure in the north of that same block. Hysteresis is expected to be less in the MAIN block, ca 20 bar between the wells in the south and the northernmost part. Other hysteresis and non-straight P/Z behaviour are given by looking at the pressure vs. volume plots, see section 5.5 on hysteresis and non-tank behaviour. The average cycle imbalance is caused by some UGS production wells not meeting the target rate at the end of a production cycle. Although group control was used to even out productivity-differences between the wells, this imbalance could not be avoided. It is a sign that the used subsurface models are on the pessimistic side for the proposed cycle-duration combined with the UGS-specifications. At a later stage of this phase, the minimum UGS reservoir pressure was lowered from 88 to 77 bar, thus changing the cushion and working gas volumes, see Table 5-5.

			BELL080	HighP	BELL033	LOWCUSHION	BELL050
Blk I	Cushion volume	[1e9 scm]	3.842	3.276	3.396	3.651	3.941
	Working volume	[1e9 scm]	2.615	2.304	2.305	2.515	2.553
Blk II	Cushion volume	[1e9 scm]	1.545	2.141	2.108	0.904	1.536
	Working volume	[1e9 scm]	0.849	1.173	1.085	0.835	0.821
Blk I	Well Pressure Max	[bar]	139.4	137.7	138.9	139.8	140.1
	Well Pressure Min	[bar]	71.4	82.3	81.8	72.9	74.3
	End-prod rest dp	[bar]	2.3	1.9	2.1	2.3	2.2
	End-Inj rest dp	[bar]	1.6	1.2	1.3	1.5	1.5
	Non-straight p	[bar]	3.0	1.8	2.1	2.9	3.0
Blk II	Well Pressure Max	[bar]	142.1	148.4	148.7	152.7	145.9
	Well Pressure Min	[bar]	66.7	80.8	66.0	63.3	64.3
	End-prod rest dp	[bar]	4.1	3.6	4.7	4.0	3.9
	End-Inj rest dp	[bar]	3.0	2.8	3.5	2.9	2.9
	Non-straight p	[bar]	5.1	4.0	5.6	4.6	4.9
Blk I	Workvol/Cushion		0.680	0.703	0.679	0.689	0.648
	Dp	[bar]	67.9	55.4	57.0	66.9	65.8
	Dp/Workvol	[bar/1e9sc	26.0	24.0	24.8	26.6	25.8
	Dp/Workvol/Cushion	[bar]	99.8	78.8	84.1	97.1	101.6
Blk II	Workvol/Cushion		0.549	0.548	0.515	0.924	0.534
	Dp	[bar]	75.4	67.6	82.7	89.4	81.6
	Dp/Workvol	[bar/1e9sc	88.9	57.6	76.2	107.0	99.4
	Dp/Workvol/Cushion	[bar]	137.2	123.3	160.6	96.8	152.7
Total Cushion Volume		[1e9 scm]	5.387	5.417	5.504	4.555	5.477
Total Working Gas		[1e9 scm]	3.463	3.477	3.389	3.350	3.373
Workvol/Cushion		[1e9 scm]	0.643	0.642	0.616	0.735	0.616
Average Cycle Imbalance (Vol)		[1e9 scm]	0.023	0.034	0.076	0.091	0.080
Average Cycle Imbalance (Pressure)		[bar]	0.449	0.158	1.011	1.299	1.031

Table 5-4 **Summary of UGS modeling results of the 88/133 UGS scenario. End-prod rest dP is the pressure loss in the 8 days between end of production and start of injection. End-inj dP likewise after injection. The pressures are taken from the gridblocks around the wellbores and are thus different from the average reservoir pressure, see also Figure 5-1.**

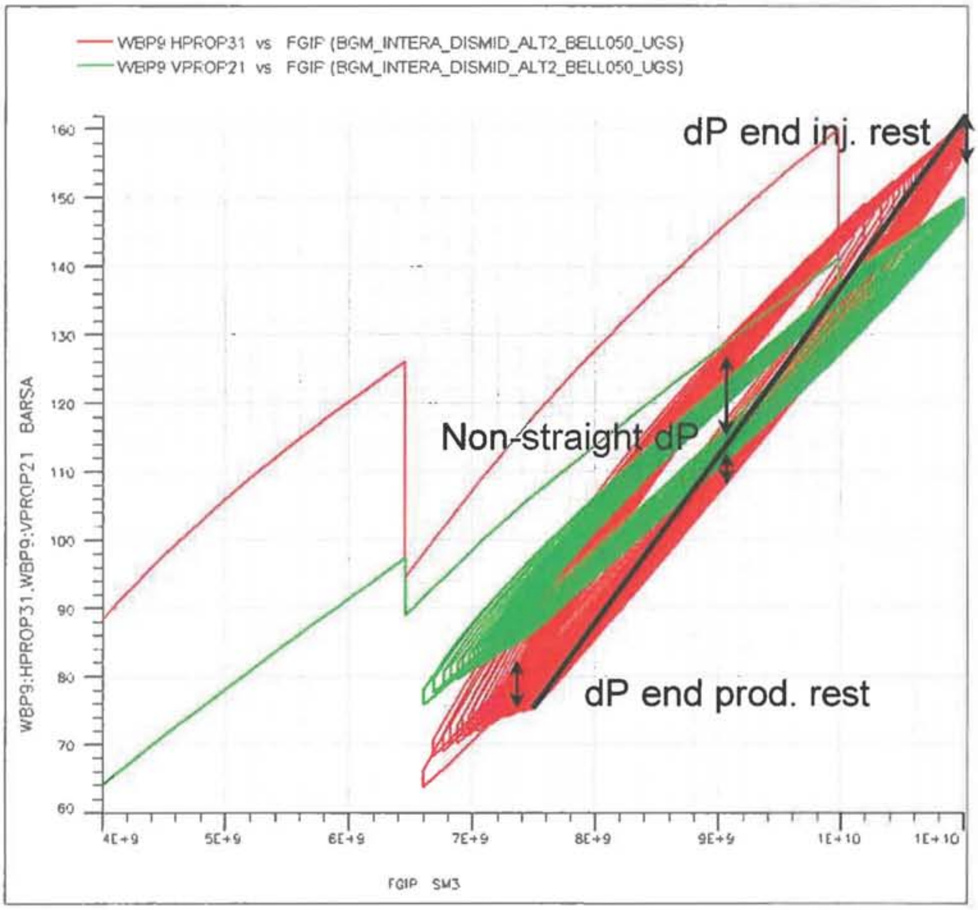

Figure 5-1 **Pressure vs. inventory plot per BGM-block. The dP between the production and injection cycles is caused by pressure-equilibration of the reservoir. The non-straight pressure is the average of the dP between straight and production, resp injection. The 40 consecutive UGS-cycles do not totally overlap due to a small production-injection imbalance.**

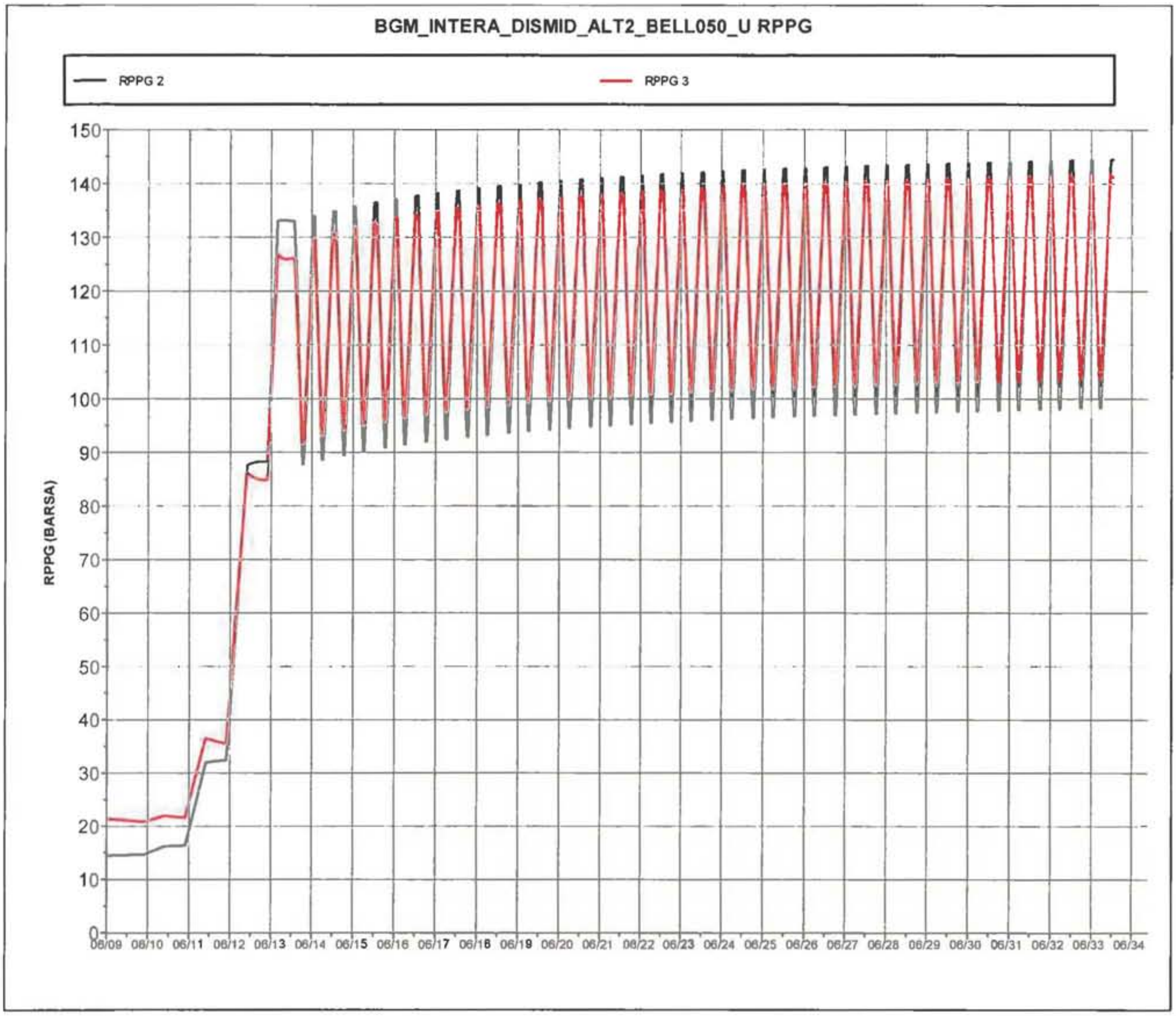

Figure 5-2 **Average reservoir pressure vs. time for base case UGS realisation (INTERA_BELL050). RPPG2 (black) is MAIN block, RPPG3 (red) is block-2. Cushion volume 5.5 Bscm, working gas 3.4 Bscm, 20 year forecast, 40 UGS cycles, 2 cycles per year with 72/88 day production/injection and rest periods between the cycles of ca 1 week.**

Run: BGM_INTERA_DISMID_ALT2_BELL050_UGS.RSM			
Blk I	Cushion volume	3.941	[1e9 scm]
Blk I	Working volume	2.553	[1e9 scm]
Blk I	*Cushion volume 77/133*	*3.365*	[1e9 scm]
Blk I	*Working volume 77/133*	*3.094*	[1e9 scm]
Blk II	Cushion volume	1.535	[1e9 scm]
Blk II	Working volume	0.821	[1e9 scm]
Blk II	*Cushion volume 77/133*	*1.218*	[1e9 scm]
Blk II	*Working volume 77/133*	*1.136*	[1e9 scm]
Blk I	Well Pressure Max	140.2	[bar]
Blk I	Well Pressure Min	74.5	[bar]
Blk I	End-prod rest dp	2.2	[bar]
Blk I	End-Inj rest dp	1.6	[bar]
Blk I	Non-straight p	2.9	[bar]
Blk II	Well Pressure Max	144.9	[bar]
Blk II	Well Pressure Min	64.2	[bar]
Blk II	End-prod rest dp	4.0	[bar]
Blk II	End-Inj rest dp	2.8	[bar]
Blk II	Non-straight p	4.6	[bar]
Blk I	Workvol/Cushion	0.648	[1]
Blk I	Dp/Workvol/Cushion	101.5	[bar]
Blk II	Workvol/Cushion	0.535	[1]
Blk II	Dp/Workvol/Cushion	150.9	[bar]
Total Cushion Volume		5.476	[1e9 scm]
Total Working Gas		3.374	[1e9 scm]
Workvol/Cushion		0.616	[1e9 scm]
Total Cushion volume 77/133		*4.583*	*[1e9 scm]*
Total Working volume 77/133		*4.230*	*[1e9 scm]*
Workvol/Cushion		*0.923*	*[1e9 scm]*
Average Cycle Imbalance/Vol		0.081	[1e9 scm]
Average Cycle Imbalance/Pressure		1.074	[bar]

Table 5-5 Cushion and working gas volumes for alternate pressure scenario (133 – 77 bar), base case subsurface model (INTERA_ALT2_BELL050).

		LOWCUSHIONY	LOWCUSHIONX	REVERS	LOWCUSHION	LOWCUSHIONZ	
Blk I	Cushion volume	4.950	4.963	3.657	3.662	4.910	[1e9 scm]
Blk I	Working volume	2.616	2.613	2.493	2.503	2.620	[1e9 scm]
Blk I	*Cushion volume 77/133*	*3.204*	*3.125*	*3.276*	*3.218*	*3.220*	[1e9 scm]
Blk I	*Working volume 77/133*	*3.160*	*3.080*	*2.813*	*2.879*	*3.174*	[1e9 scm]
Blk II	Cushion volume	1.385	1.371	0.933	0.909	1.424	[1e9 scm]
Blk II	Working volume	0.794	0.796	0.822	0.831	0.790	[1e9 scm]
Blk II	*Cushion volume 77/133*	*0.861*	*0.841*	*0.835*	*0.792*	*0.925*	[1e9 scm]
Blk II	*Working volume 77/133*	*1.028*	*0.983*	*0.948*	*0.924*	*1.082*	[1e9 scm]
Blk I	Well Pressure Max	159.6	161.5	138.1	140.1	158.1	[bar]
Blk I	Well Pressure Min	95.2	96.1	71.3	72.5	93.9	[bar]
Blk I	End-prod rest dp	2.3	2.3	2.2	2.3	2.3	[bar]
Blk I	End-Inj rest dp	1.6	1.6	1.6	1.6	1.6	[bar]
Blk I	Non-straight p	2.5	2.5	2.9	2.9	2.5	[bar]
Blk II	Well Pressure Max	161.0	165.1	147.2	151.3	156.2	[bar]
Blk II	Well Pressure Min	84.1	84.5	61.8	63.0	81.9	[bar]
Blk II	End-prod rest dp	4.5	4.7	3.8	4.1	4.2	[bar]
Blk II	End-Inj rest dp	2.8	2.9	2.7	2.8	2.6	[bar]
Blk II	Non-straight p	3.7	4.0	4.3	4.3	3.4	[bar]
Blk I	Workvol/Cushion	0.528	0.527	0.682	0.683	0.534	
Blk I	Dp/Workvol/Cushion	121.7	124.1	98.0	99.0	120.2	[bar]
Blk II	Workvol/Cushion	0.573	0.581	0.881	0.914	0.554	
Blk II	Dp/Workvol/Cushion	134.1	138.6	96.9	96.6	134.0	[bar]
Total Cushion Volume		6.334	6.334	4.591	4.571	6.334	[1e9 scm]
Total Working Gas		3.410	3.410	3.315	3.334	3.410	[1e9 scm]
Workvol/Cushion		0.538	0.538	0.722	0.729	0.538	
Total Cushion volume 77/133		*4.065*	*3.966*	*4.110*	*4.010*	*4.145*	*[1e9 scm]*
Total Working volume 77/133		*4.188*	*4.063*	*3.761*	*3.803*	*4.256*	*[1e9 scm]*
Workvol/Cushion		*1.030*	*1.024*	*0.915*	*0.948*	*1.027*	
Average Cycle Imbalance/Vol		-0.063	-0.063	0.108	0.095	-0.063	[1e9 scm]
Average Cycle Imbalance/Pressure		-1.182	-0.985	1.542	1.439	-1.126	[bar]

Table 5-6 Summary of aquifer sensitivities UGS modeling.

5.2.2 UGS GWC behaviour

The GWC behavior was observed at the location of the existing wells BGM-1 and BGM-7. It is observed that after initially pushing back the water in both the MAIN and BGM-7 compartments, the GWC increases again, but behaves differently in both blocks. The MAIN block, which has the highest permeability, shows contact swings in the order of a few meters. Block-2 shows more violent swings, caused by a combination of tilting and coning, but they are below 2200 m, the depth at which the horizontal wells are planned.

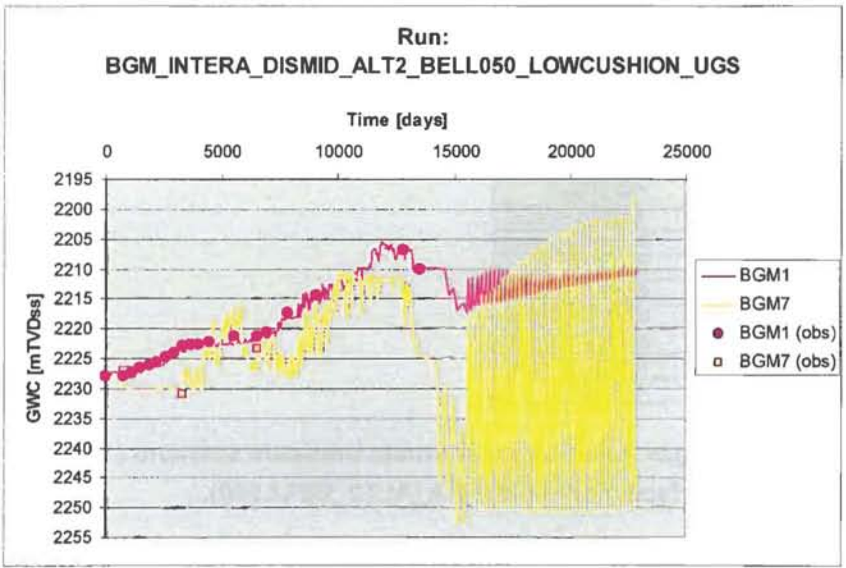

Figure 5-3 **GWC behaviour UGS vs. HM of aquifer scenario INTERA_BELL050_LOWCUSHION. The GWC in BLOCK2 is actually pushed deeper than in the base case, but GWC-rise is higher in later cycles.**

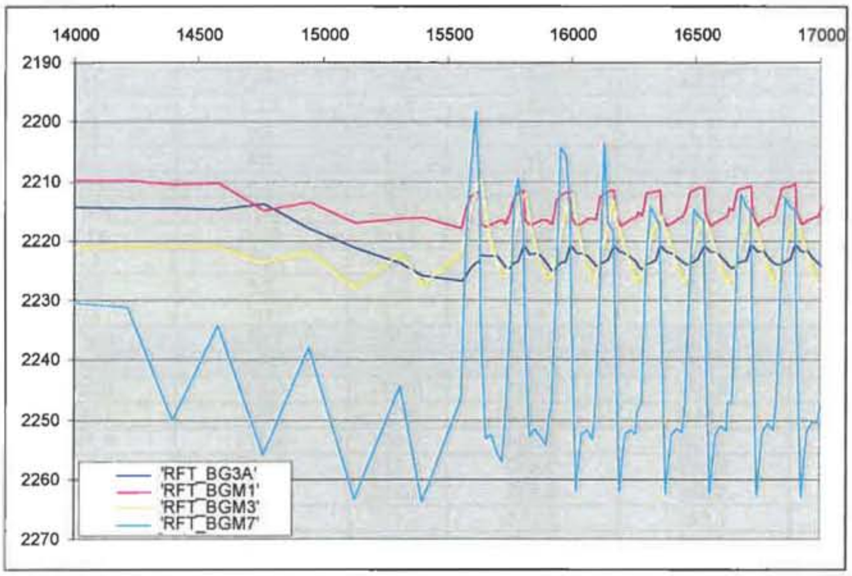

Figure 5-4 **GWC behaviour base case (INTERA_BELL050) at BGM-1, BGM3, BGM-3A and BGM-7 well-locations. Only BGM-7 is used in the UGS, BGM-3A is planned as water injector. In the ALT2 case BGM3 is in block1, in the ALT5 case, BGM3 is in block-2.**

5.3 Well trajectory planning

Six new horizontal wells and 9 vertical wells were planned in order to facilitate the different subsurface scenarios of the BGM UGS. As discussed, the number of wells follow from a combination of subsurface reasoning, surface constraints and economics **[deleted text because of confidentiality]**

The placement of future UGS wells was guided by several constraints (the last one is new compared to phase 2):

- Minimum well KH
- Distance to surface facilities
- Minimum distance of 200 m to bounding faults

In the notional phase 2 tracks, the northernmost well in Block-2 was located some 4 km lateral from the BGM-1 site. Also some wells were too close below the Top ROSLU. It was tested that the KH of some of the phase2 horizontal wells were likely below the 30.000 mDm target (HPROP12/13). The new horizontal wells were therefore replaced in the structural high in the western flank of Block-2, see Figure 5-8. Because of the increased distance to Top ROSLU, the KH increased dramatically and the horizontal well-section length could be decreased to ca 300m. The performance estimate for the wells is discussed in more detail in section 5.4.

Later, an extra complication was introduced by the fact that TNO advised on a safety margin for the distance of the wells to the bounding faults in the field. According to seismicity studies, this distance should be minimum 200m in order to avoid the risk of fault-reactivation triggered by the low temperature of the injection gas. As further away from the flank the Top ROSLU comes in deeper and consequently the permeability is lower, the wells needed to be repositioned with more north-south orientation and extended in length to the original 500m, see Figure 5-9.

If we compare the well placement for the current structure maps (Figure 5-9; the 'InterB' placement looks very similar) with the placement on the base structure (cf. the cross-section in Figure 5-11), we can see that the risk for the well placement appears limited. The main difference is the dip of the structure towards the western boundary fault, i.e. the main difference is the depth below top structure at the wells' toe. Comparing against the original seismic input enforces the conclusion that the relative toe depth is the key uncertainty (Figure 5-10). Taking the 'bell' profile into account, this can lead to a significant permeability reduction or, to be exact, uncertainty.

If we would show the wells on the low case top structure, we would see that they are not all actually penetrating it. However, the volume multiplier needed for a low case structure map model is so large (section 2.2) that it is deemed unlikely. Since no detailed geoscience investigation into likely distributions of top structure uncertainty has been done, we emphasize again that the volumetric match (which is *overall*) cannot be taken as a very strong argument for top structure risk predictor (which requires *local* accuracy). The non-penetration of the reservoir by the BGM9 well can serve as an illustration here (Figure 5-13).

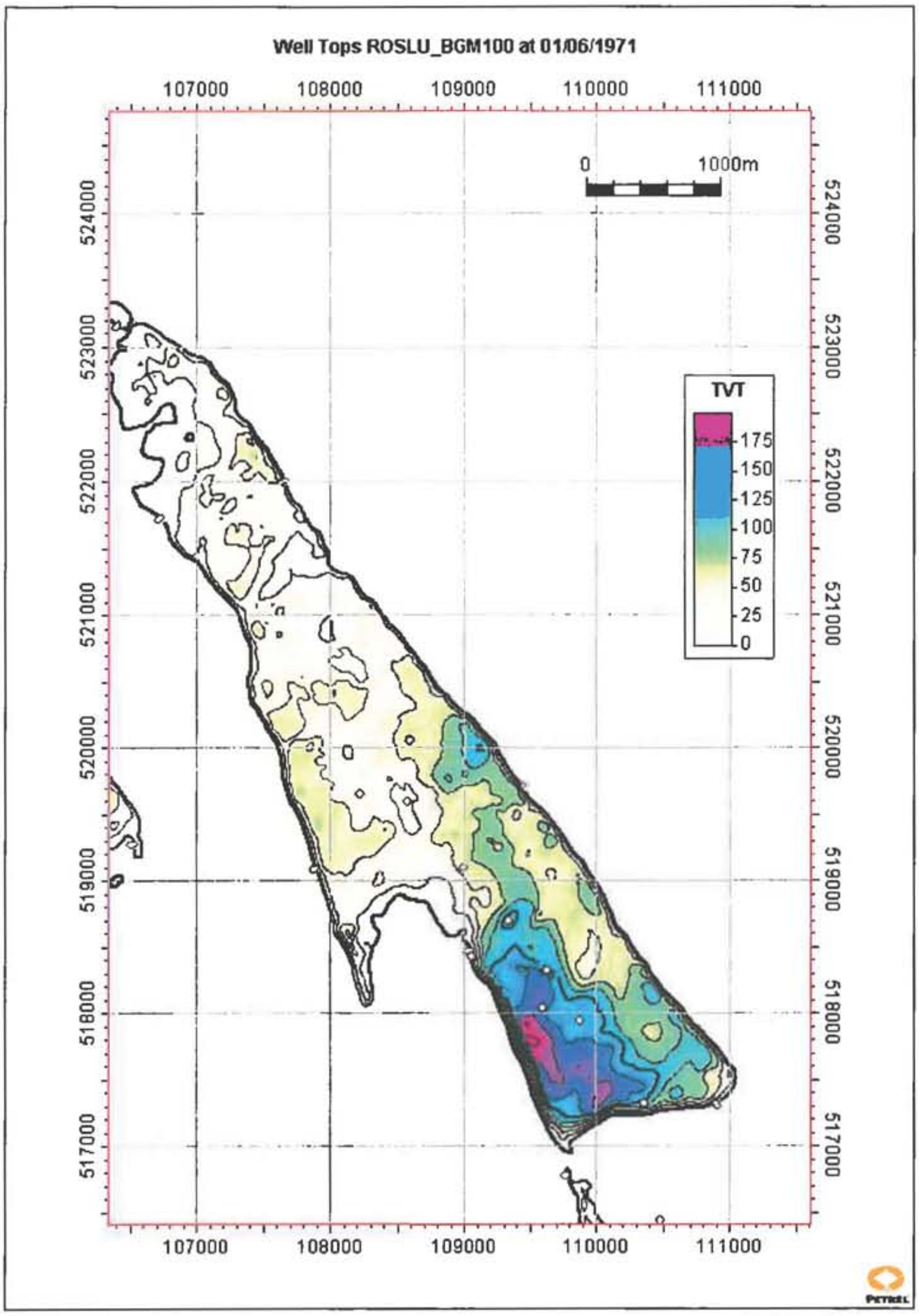

Figure 5-5 **Net reservoir height map between top ROSLU and original GWC at 2227 m, phase 2 base case (DISMIDHIGHKV_BELL050), which means the top is not uplifted to include seismic uncertainty of the INTERA/INTERB cases as used for phase 4.**

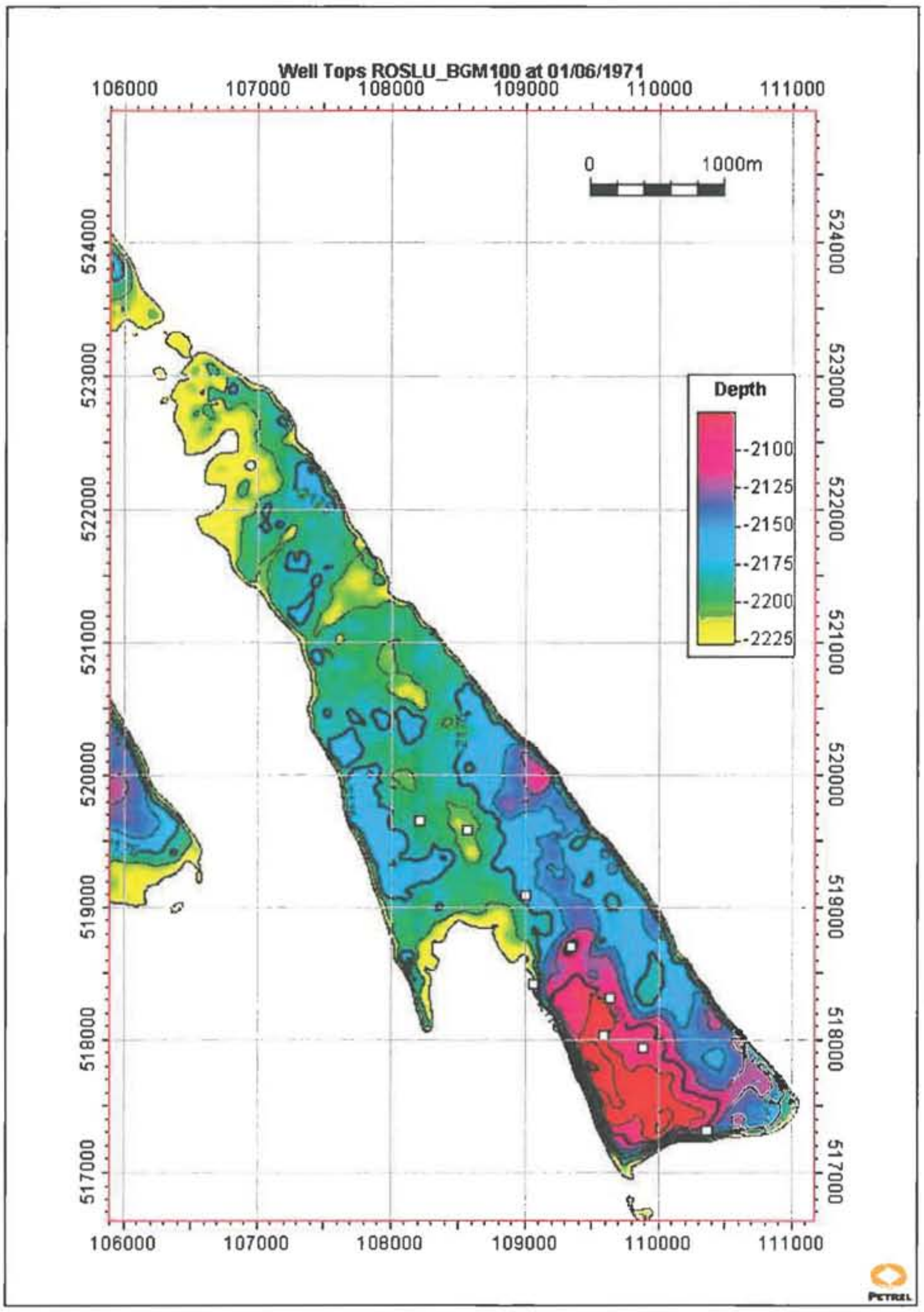

Figure 5-6 **Depth of top ROSLU of the phase 2 model, DISMIDHIGHKV_BELL050 (colour scale limited to 2227 m). The top is not uplifted to include seismic uncertainty of the INTERA/INTERB cases as used for phase 4, which was later done to leave out the volume multiplier.**

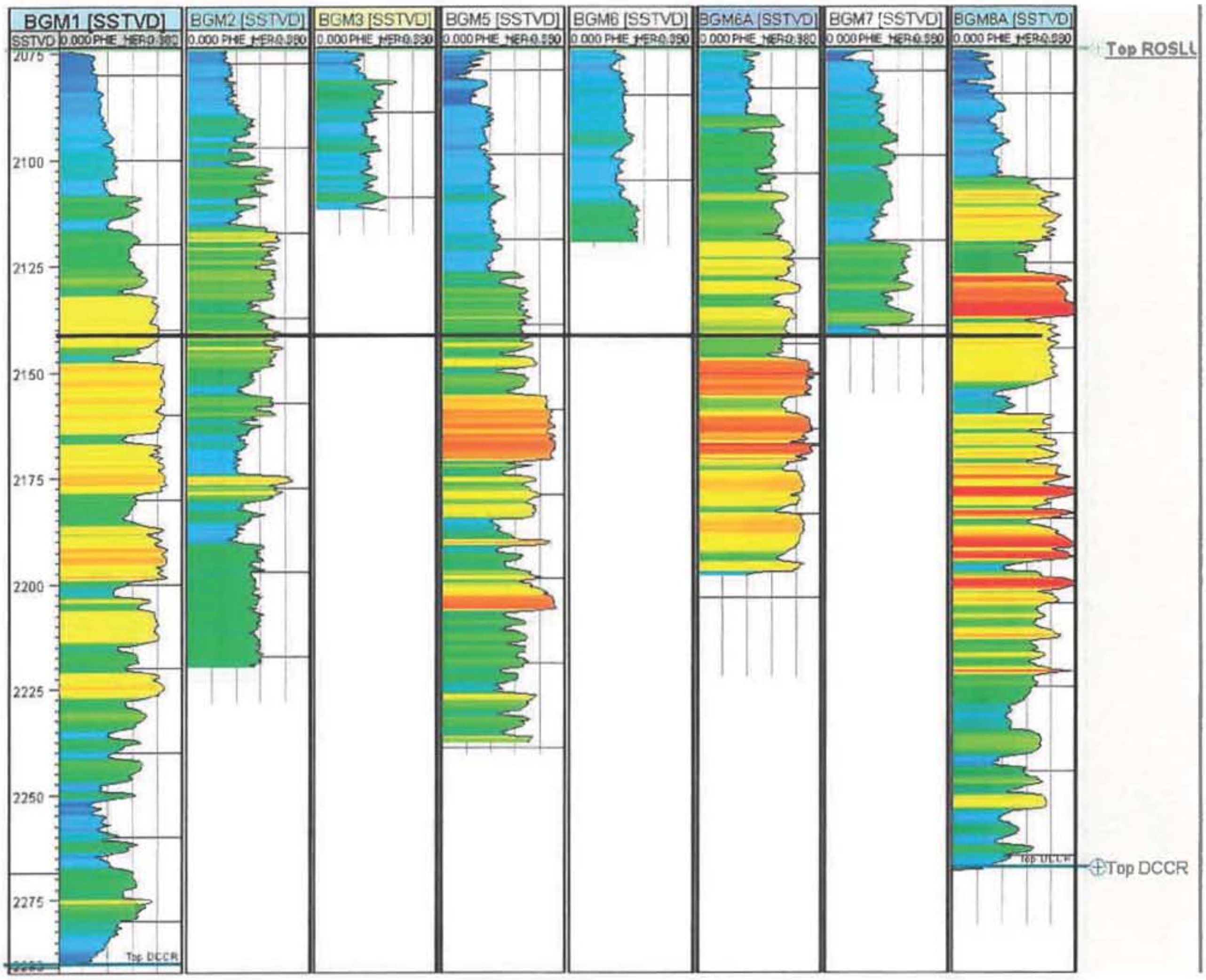

Figure 5-7 **BGM-porosity logs. Wells flattened on TopROSLU. TVDss scale shown for BGM1 only, other wells have same relative scale.**

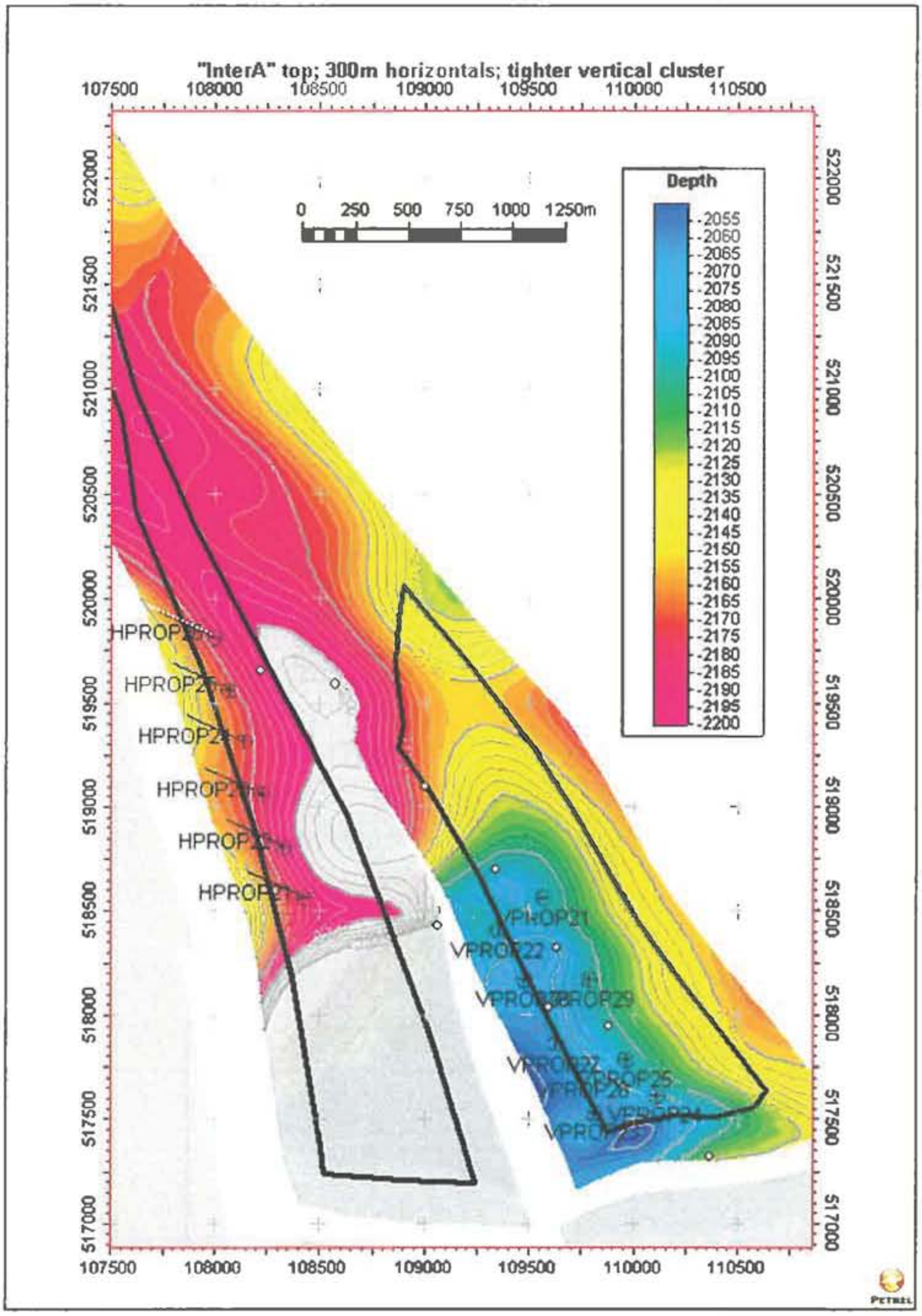

Figure 5-8 **Intermediate phase 4 well-planning plotted on 'InterA' Top ROSLU-map with 5 m contours. Lower boundary is 2200 m tvdss (depth of horizontal wells). The horizontal wells cross the 200m distance to the fault (black line) and had to be re-orientated.**

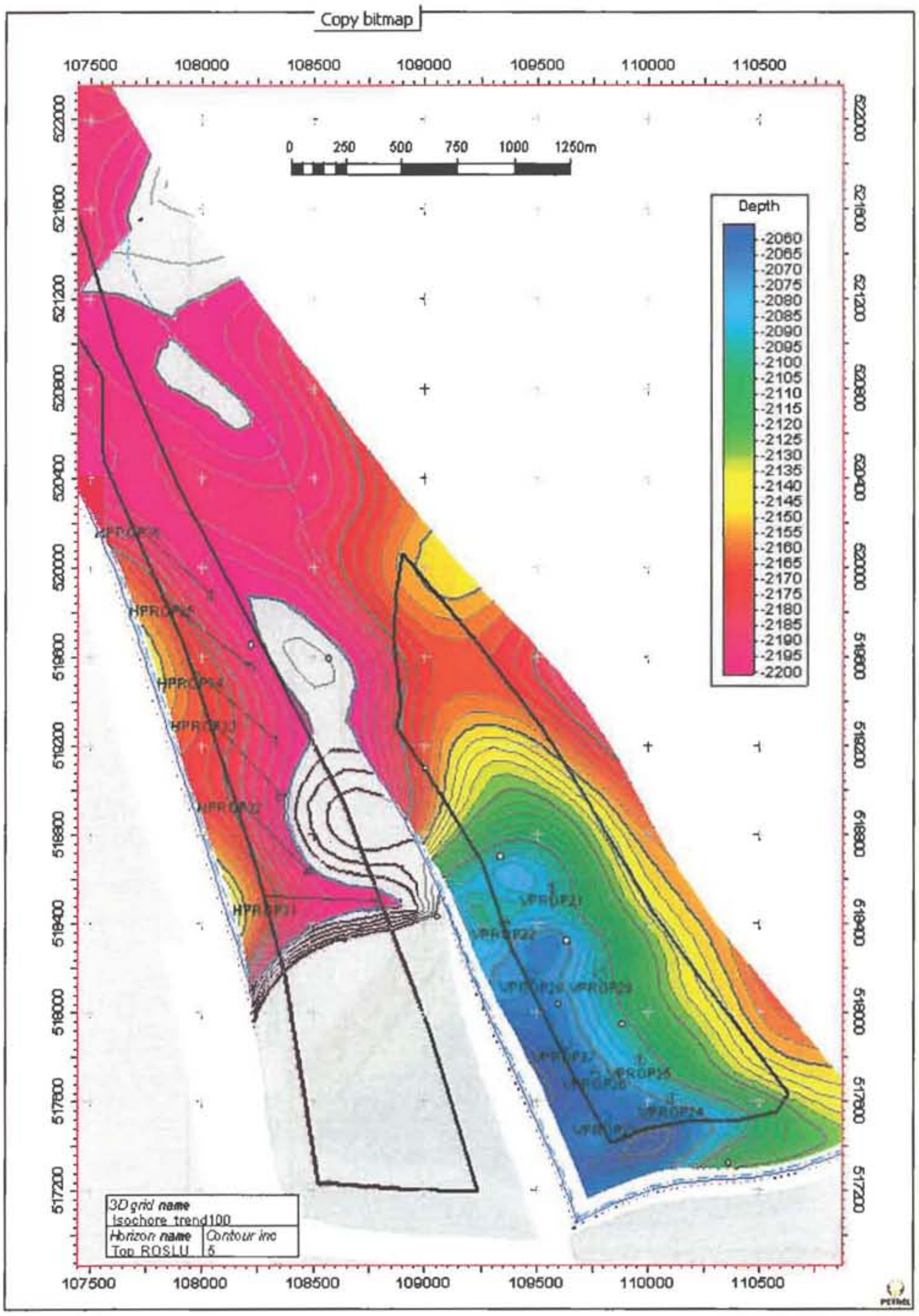

Figure 5-9 **Phase 4 well-planning plotted on 'InterA' Top ROSLU-map with 5 m contours. The blue solid line indicates 'InterA' at 2200 m, almost coinciding with the 2200 m contour in this structure. (Cf. Figure 5-10.) [This top structure map is the one that was used in phases 1 & 2 for the base case; the current phase 4 horizons are shallower to get a volumetric match, see section 2.2. As emphasized there, the fact that the phase 4 horizons match the *overall* volumes better should not be read as implying that *locally* the shallower structure maps necessarily give a better prediction.]**

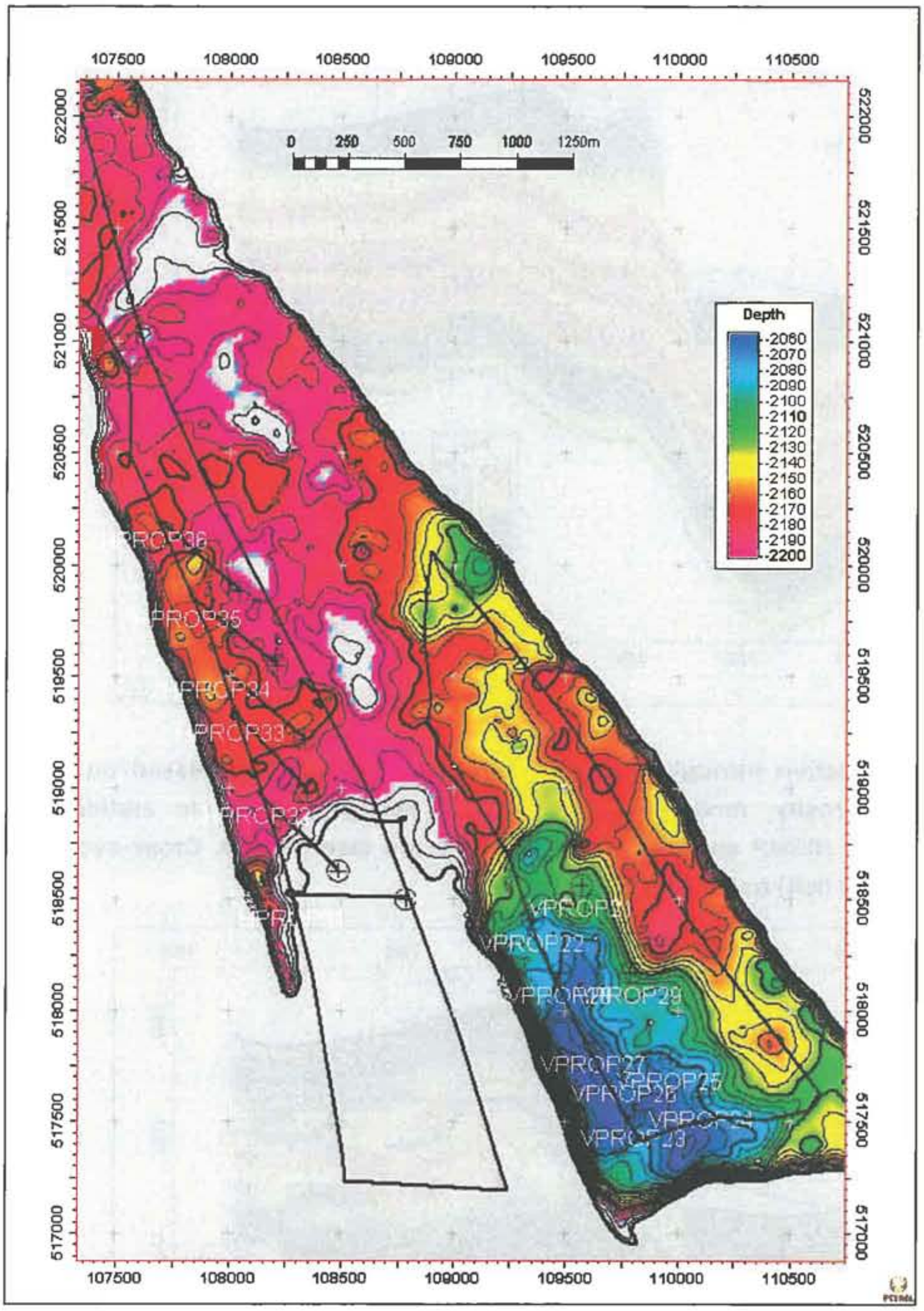

Figure 5-10 **Same well pattern as Figure 5-9, but now on the seismic input base case top map.**

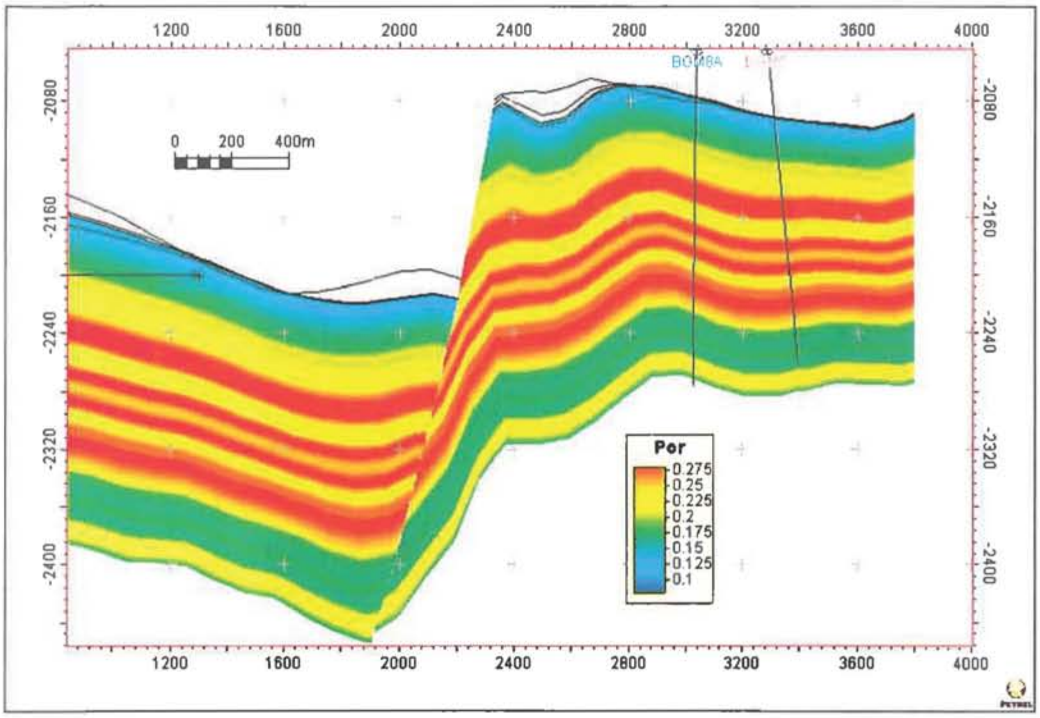

Figure 5-11 **Cross-section through proposed UGS well HPROP34 displayed on BGM1 core porosity, model INTERA, vertical exaggeration 5. In addition the INTERB, HIGHP and base case horizons are also plotted. Cross-section is from NW (left) to SE (right).**

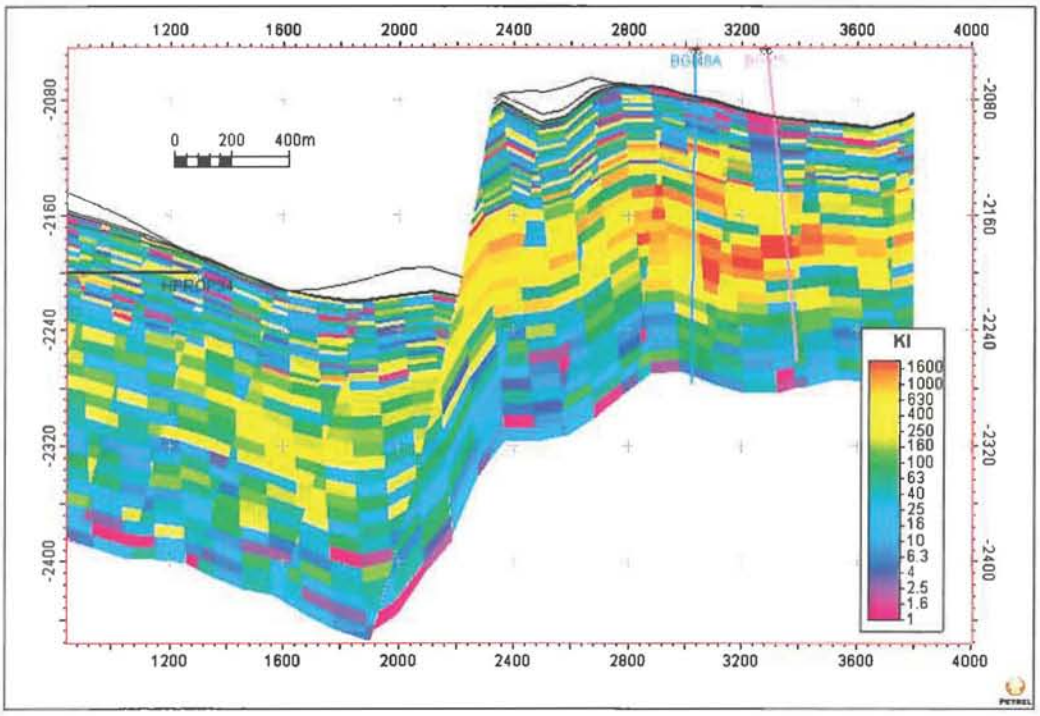

Figure 5-12 **Cross-section through proposed UGS well HPROP34 displayed on INTERA_BELL050 permeability, vertical exaggeration 5. In addition the INTERB, HIGHP case and base case horizons are also plotted. Cross-section is from NW (left) to SE (right).**

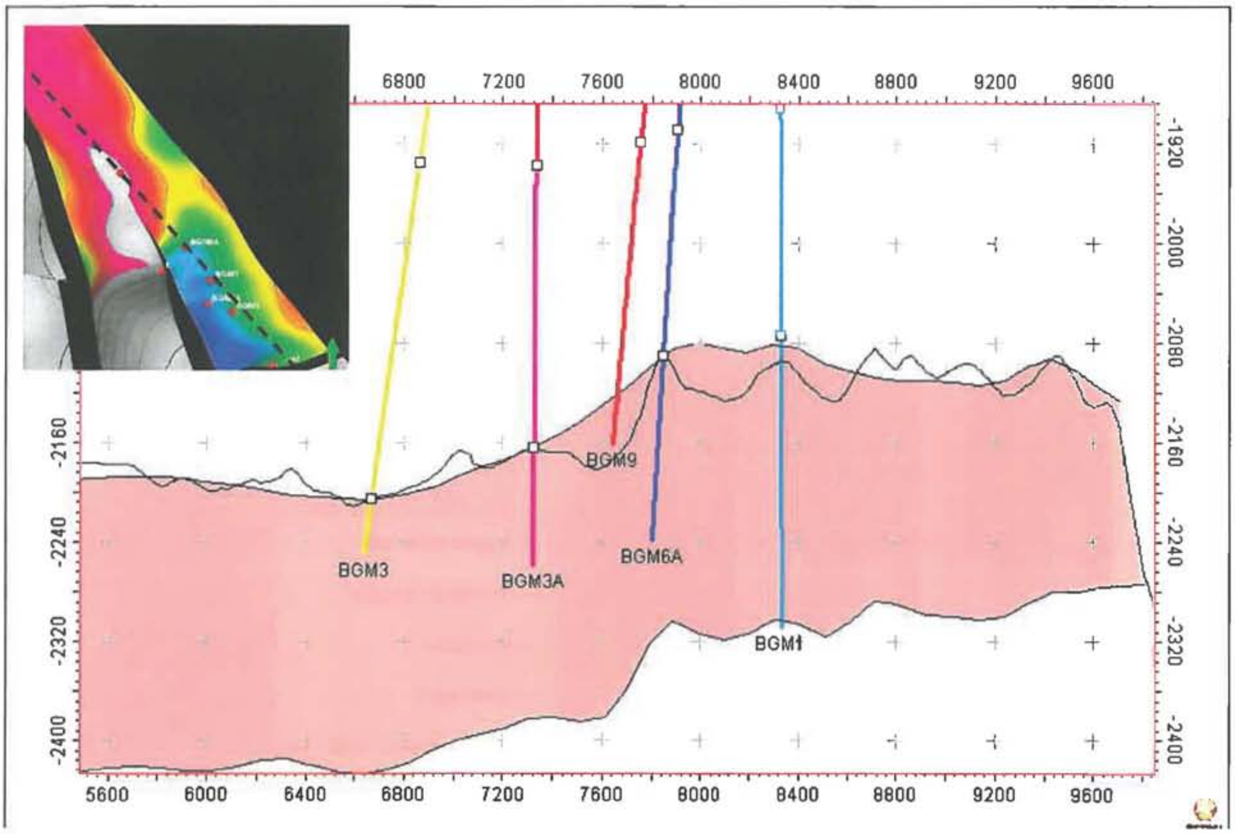

Figure 5-13 NW/SE intersection (see inset). The well BGM9, between BGM6A and BGM-3A, does not penetrate the Rotliegend reservoir zone, as an illustration of the magnitude & areal length scale of top structure uncertainty. Shown is the seismic top (black) and the current model ('IntercaseB', pink), which due to smoothing & gridding resolution (100m) cannot honour this non-penetration. Also plotted are the ROSLU and ZEZ3G tops. Possibly in this case the structure reflects the impact of a fault corresponding to the 'BaffleN' in the model (Figure 4-3). [The BGM1 well is not exactly in the plane of the intersection, hence the apparent non-matching of tops.]

5.4 Well productivity estimates from static model

As discussed in phase 2, the performance of the block-II horizontals is critical for the operation of the UGS. In this section we will try to get an estimate of their productivity from static considerations, i.e. outside of the Petrel/Eclipse realizations we work with.

Given the analysis we have done earlier (section 2.3) we can estimate a permeability as a function of the distance from the top of the reservoir. Moreover, for every given top structure, we can compute this distance from the top along the proposed. Combining this, we can compute the KH for the proposed horizontals.

Since there is some spread in the data (Figure 5-14), we can see that the estimates show a large spread both as a function of the vertical permeability trend uncertainty (Figure 5-15) and the top structure uncertainty (Figure 5-16). Therefore we can conclude from this analysis that the uncertainty on the permeabilities seen by these wells is at least a factor 3-6.

It should be noted that we did not model that the permeabilities in the model deteriorate towards the faults (damage zone), which is likely to be the case.

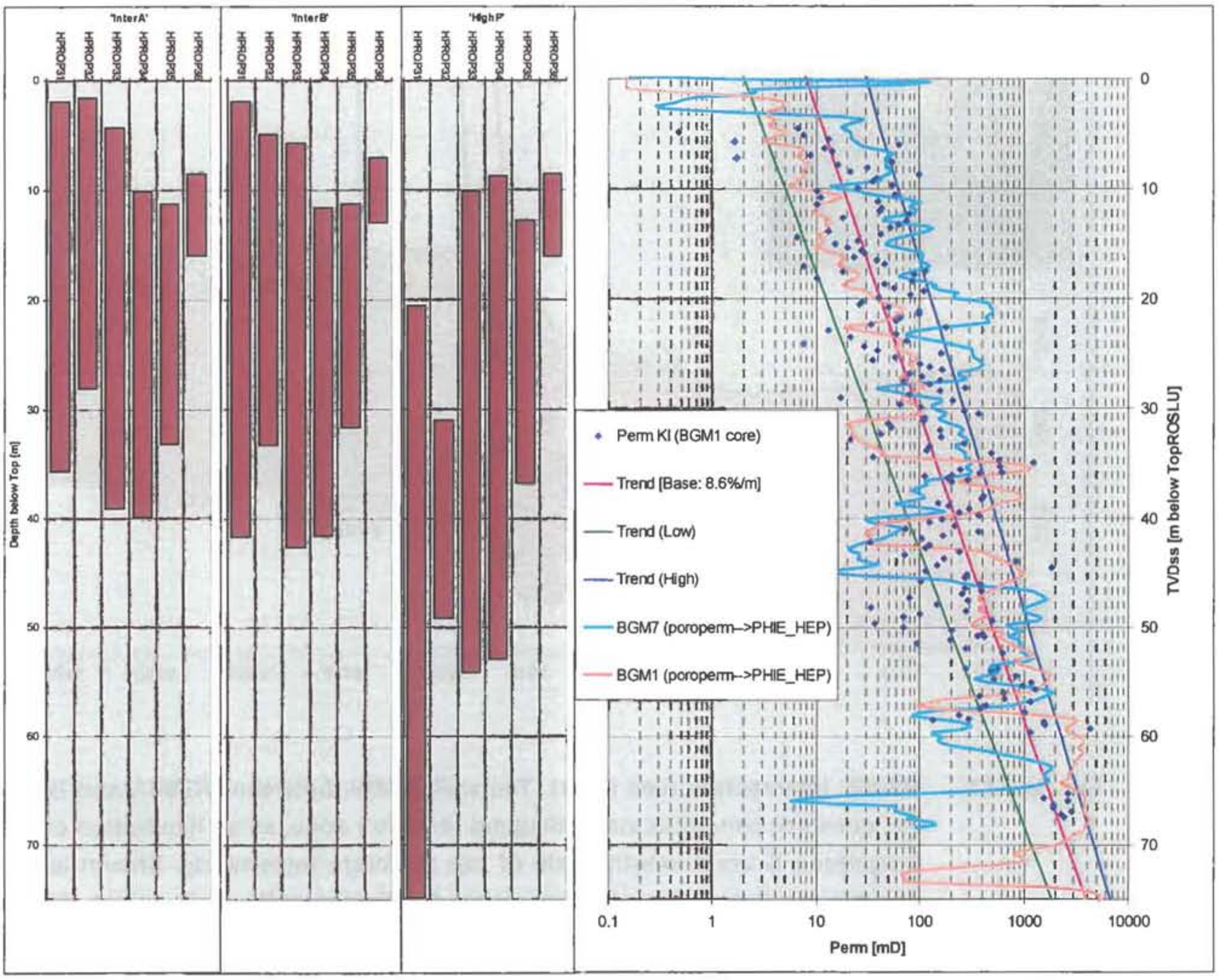

Figure 5-14 **Vertical location of the proposed horizontals HPROP31..36 for the three top structures used ('InterA', 'InterB', 'High', respectively). The RHS plot shows the core porosity trend (Figure 2-5) along with poroperm-based permeability logs for both BGM1 and BGM7. The scatter in the data suggests a range of trends: poor (green), base (purple; same as Figure 2-5) and high (blue). The latter seems to match BGM7 best, which is closest to the HPROP wells.**

'Intera'				Base				Low				High			
Well	Length	First Depth	Last Depth	First Perm	Last Perm	Average perm (linear)	Kh (linear)	First Perm	Last Perm	Average perm (linear)	Kh (linear)	First Perm	Last Perm	Average perm (linear)	Kh (linear)
	[m]	[m]	[m]	[mD]	[mD]	[mD]	[mD m]	[mD]	[mD]	[mD]	[mD m]	[mD]	[mD]	[mD]	[mD m]
HPROP31	500	1.91	35.69	9	153	51	2.57E+04	2	52	16	8.02E+03	35	393	147	7.37E+04
HPROP32	500	1.62	28.08	9	81	33	1.66E+04	2	26	10	4.89E+03	34	227	102	5.08E+04
HPROP33	500	4.27	39.11	11	203	66	3.32E+04	3	71	21	1.07E+04	41	503	184	9.21E+04
HPROP34	500	10.07	39.83	18	214	80	3.99E+04	5	75	26	1.29E+04	62	529	218	1.09E+05
HPROP35	500	11.23	33.24	20	125	58	2.88E+04	6	41	18	8.94E+03	68	330	165	8.27E+04
HPROP36	500	8.48	16.03	16	30	22	1.12E+04	4	9	6	3.13E+03	55	95	74	3.68E+04

Table 5-7 Static trend based estimates for the HPROP KH's in the 'InterA' top structure.

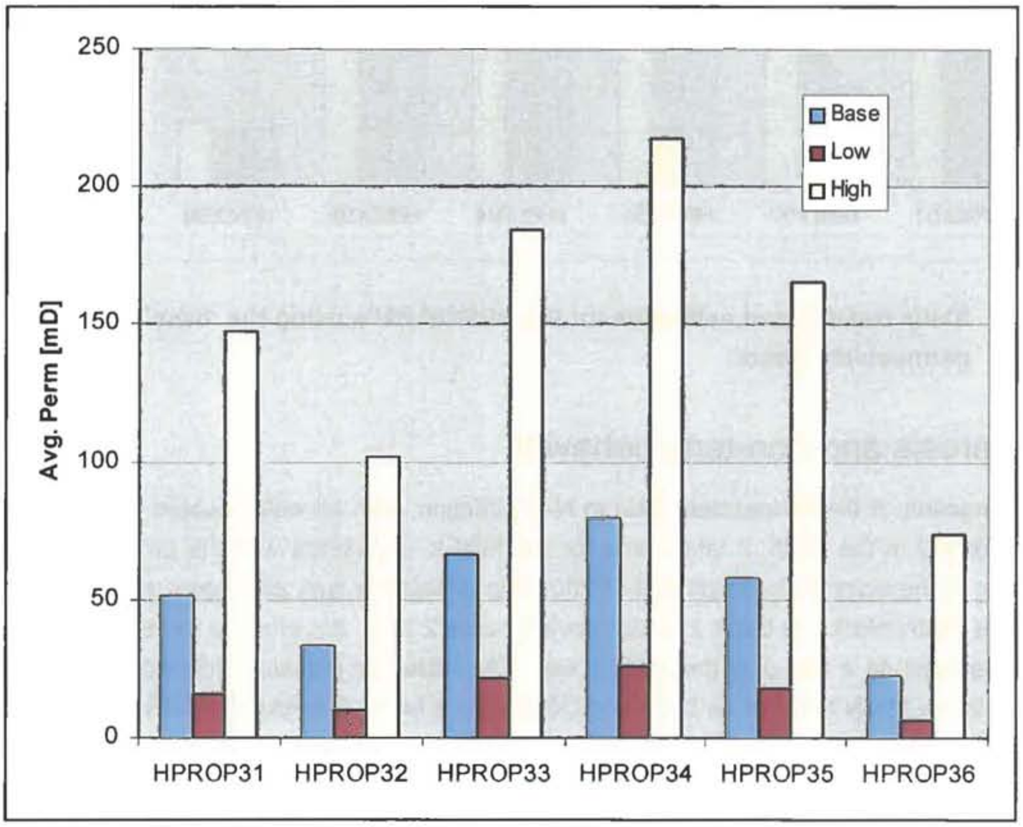

Figure 5-15 Static trend based estimates for the HPROP KH's in the 'InterA' top structure.

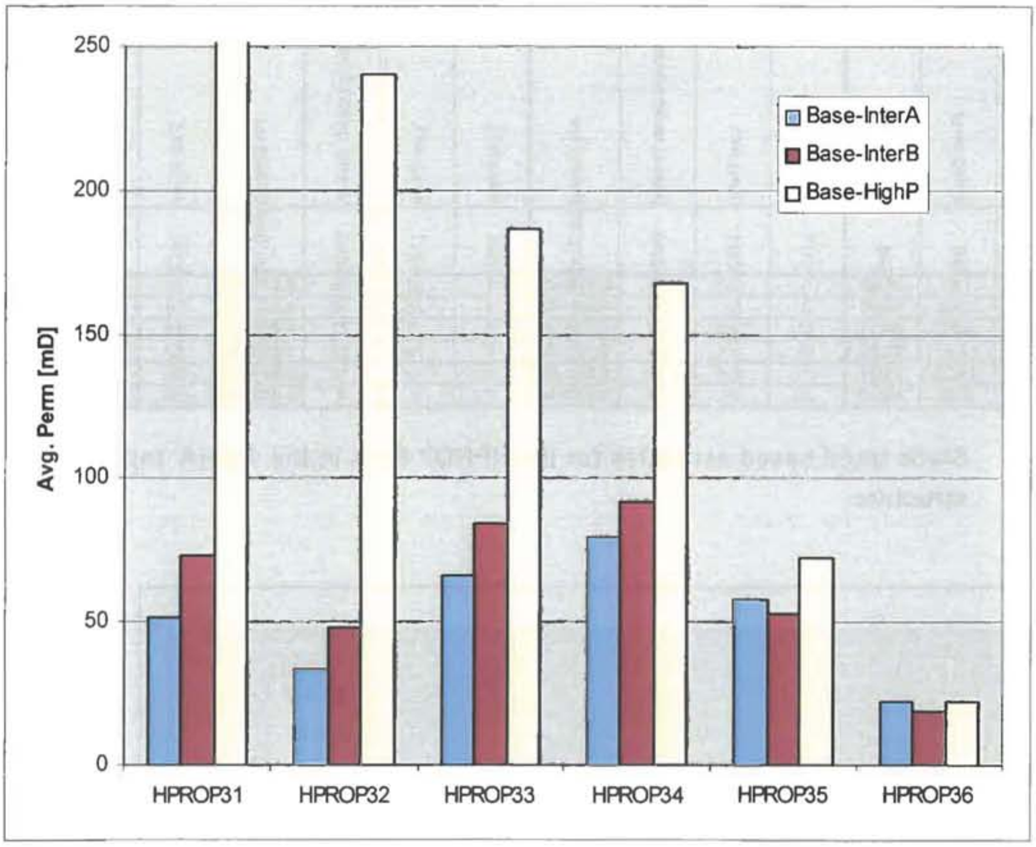

Figure 5-16 Static trend based estimates for the HPROP KH's using the 'base' vertical permeability trend.

5.5 Hysteresis and non-tank behavior

Due to the elongation of the Bergermeer field in N-S direction, with all wells located in the south and low permeability in the north, it takes time for the field to equilibrate with the projected UGS operating rates. In the summer injection test of 2007 this imbalance was also seen and explained by baffles in the MAIN block. In block 2, which covers some 2 km2, the effect is more severe, but can not be measured as it has only the BGM-7 well. The historical pressure differential over the northern baffle in the MAIN block of ca 3 bar is multiplied by a factor 5 during the UGS phase. Also the GWC is influenced by the presence of baffles, see section 5.2.2.

Figure 5-17 shows the pressure distribution at the end of a production and injection cycle. The plot was not corrected for height differences, but these are small (a few bar) for a gas at these pressures. The internal pressure gradient at the end of a production cycle is ca 65 bar in block-2 and ca 30 bar and in the MAIN block. As the injection takes place over a longer period, the rates are lower and the pressure gradients after injection are lower: ca 40 bar in block-2 and 20 bar in block-1.

Although the average pressure between the two blocks was minimised to adhere to the 20 bar constraint (seismicity, see section 5.1.2), it can be seen in the plots that along the fault, the local pressure differences are more than 20 bar. The difference is highest at the southern end, where there is less juxtaposition between the two blocks; towards the north, where the fault is actually subseismic, the pressure difference goes to zero. It is therefore important to realize that the well pressure difference is not always an accurate indicator of the across-fault pressure difference, all the more since the precise location of the fault is not known. The design and implementation of an *operational monitoring* strategy to monitor/maintain this pressure difference between the blocks, will require care.

Some typical pressure-gas-inventory plots are also given; see Figure 5-24, Figure 5-25 and Figure 5-26.

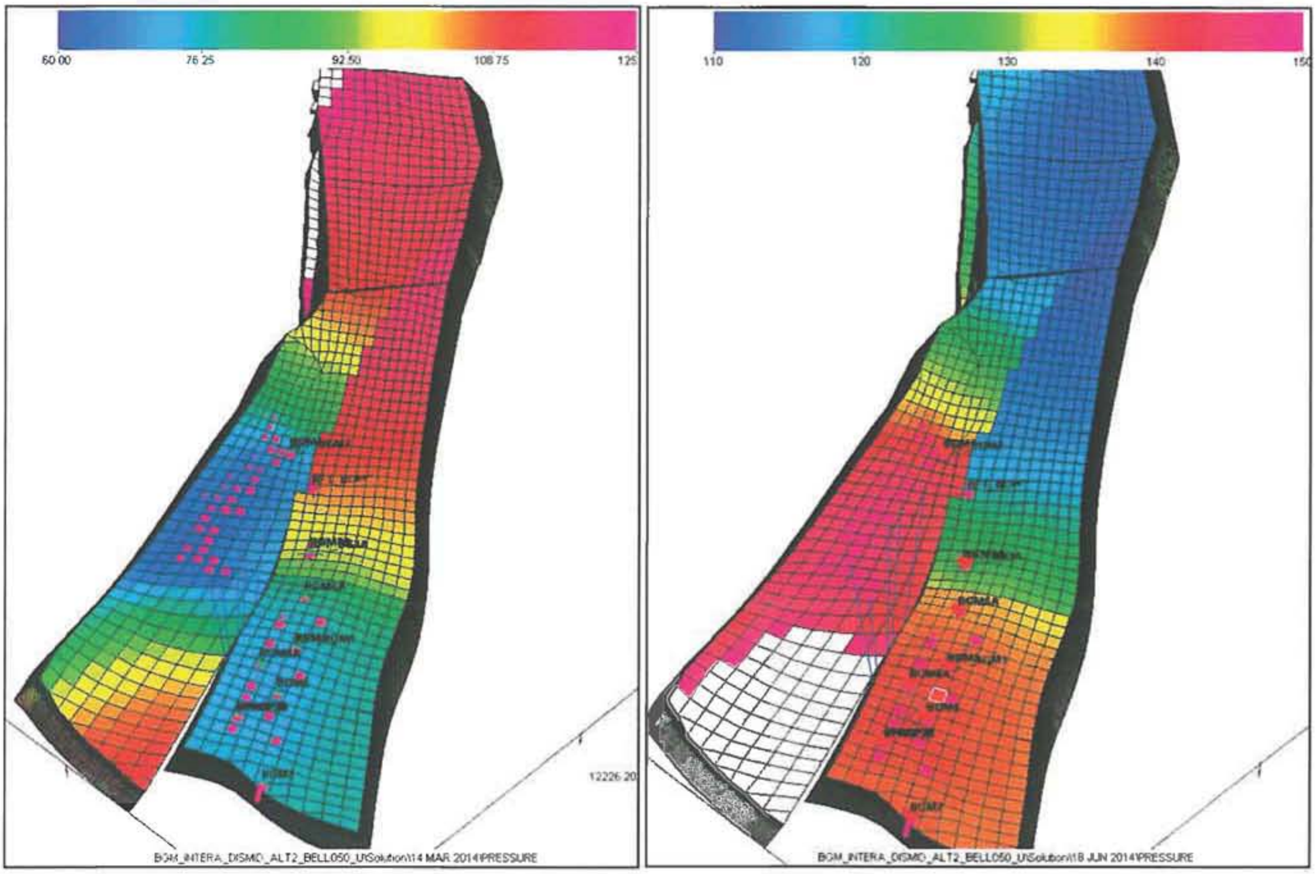

Figure 5-17 P_res of base case 'INTERA_BELL050_ALT2' end of production cycle (left) and injection cycle (right). When interpreting this graph it should be remembered that the height of the HC column greatly varies across the structure. Thus the south-eastern (block I) area is much higher than the northern end of the field. In other words, the visual appearance of this plot can be misleading w.r.t. the volumetric importance of the various areas.

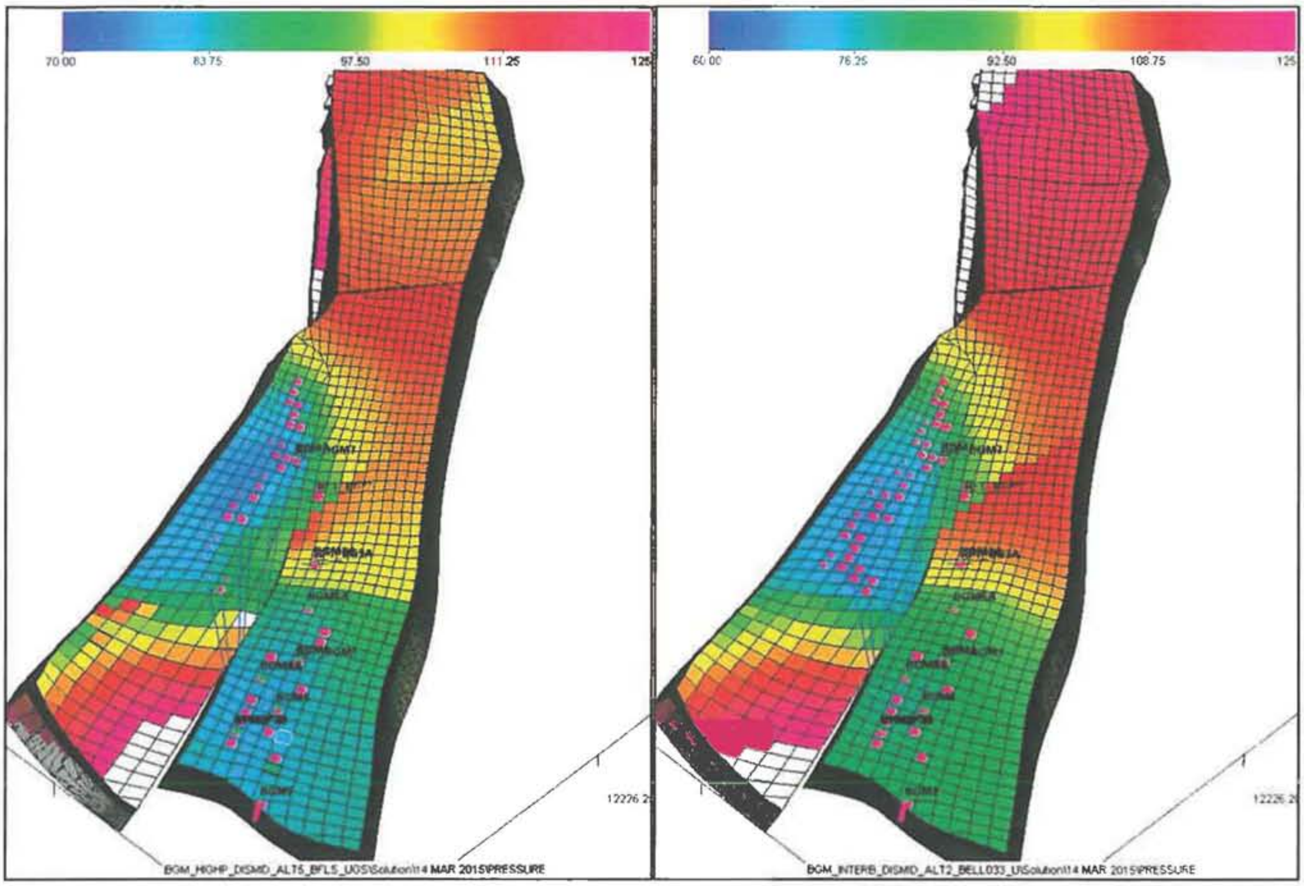

Figure 5-18 P_reservoir low horizontal productivity case 'HIGHP_ALT5_BFLS' (left) and low vertical productivity case 'INTERB_BELL033_ALT5' (right) at the end of production cycle.

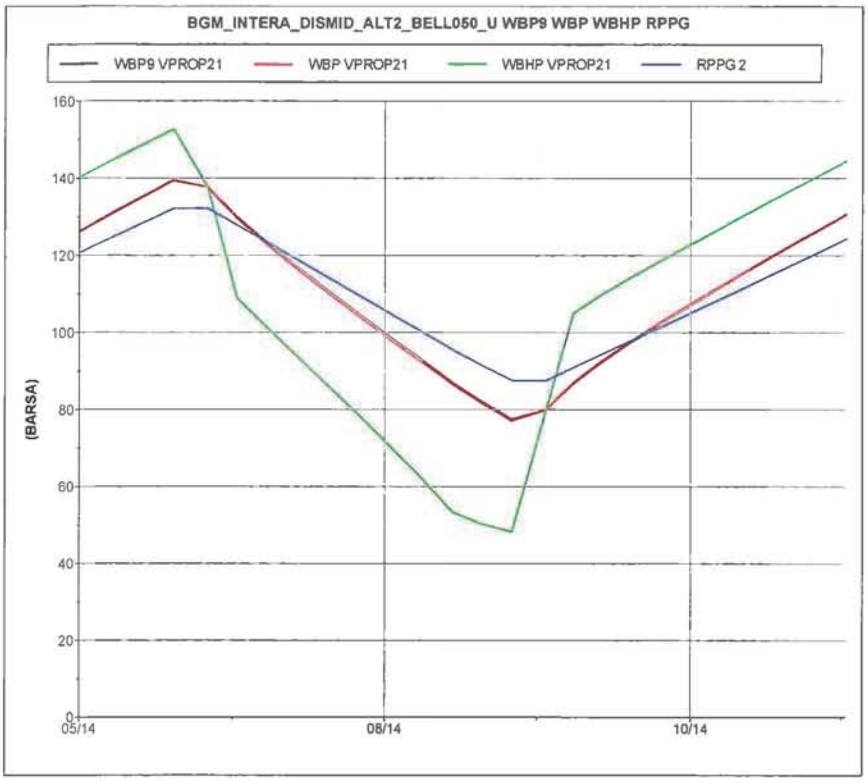

Figure 5-19 **Relationship between WBHP (wellbore pressure), WBP9 (pressure in connected and surrounding gridblocks and RPPG (reservoir pressure) for vertical UGS well (in block I), base case INTERA_BELL050. The skin for a vertical well is 20 (section 5.1.4).**

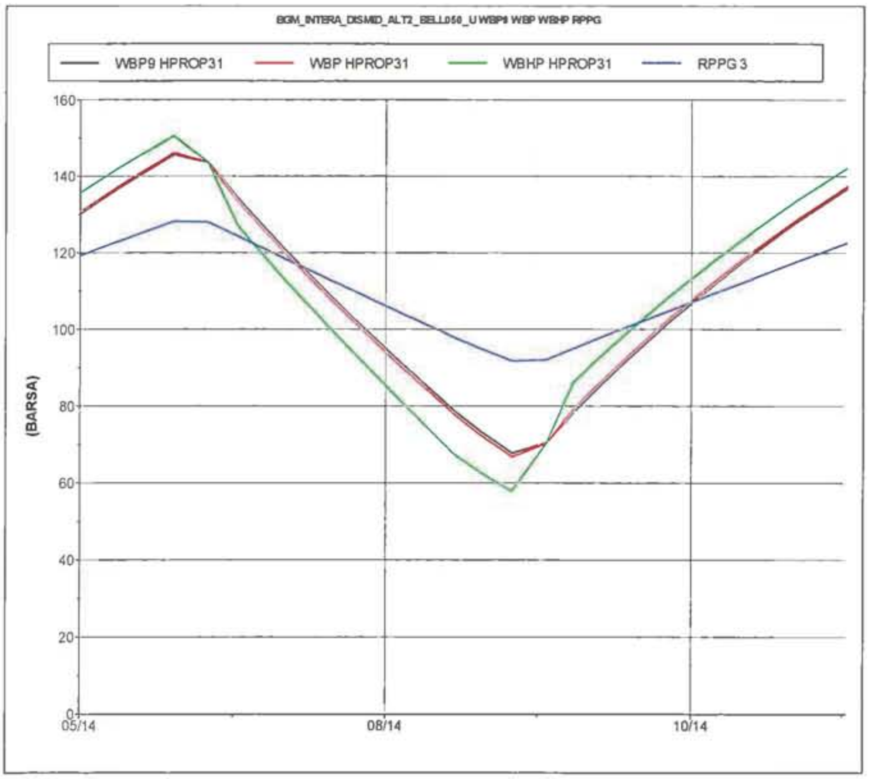

Figure 5-20 **Differences between WBHP, WBP9 en WBP for horizontal well in Block-II, base case INTERA_BELL050. The skin for a horizontal well is 10 (section 5.1.4).**

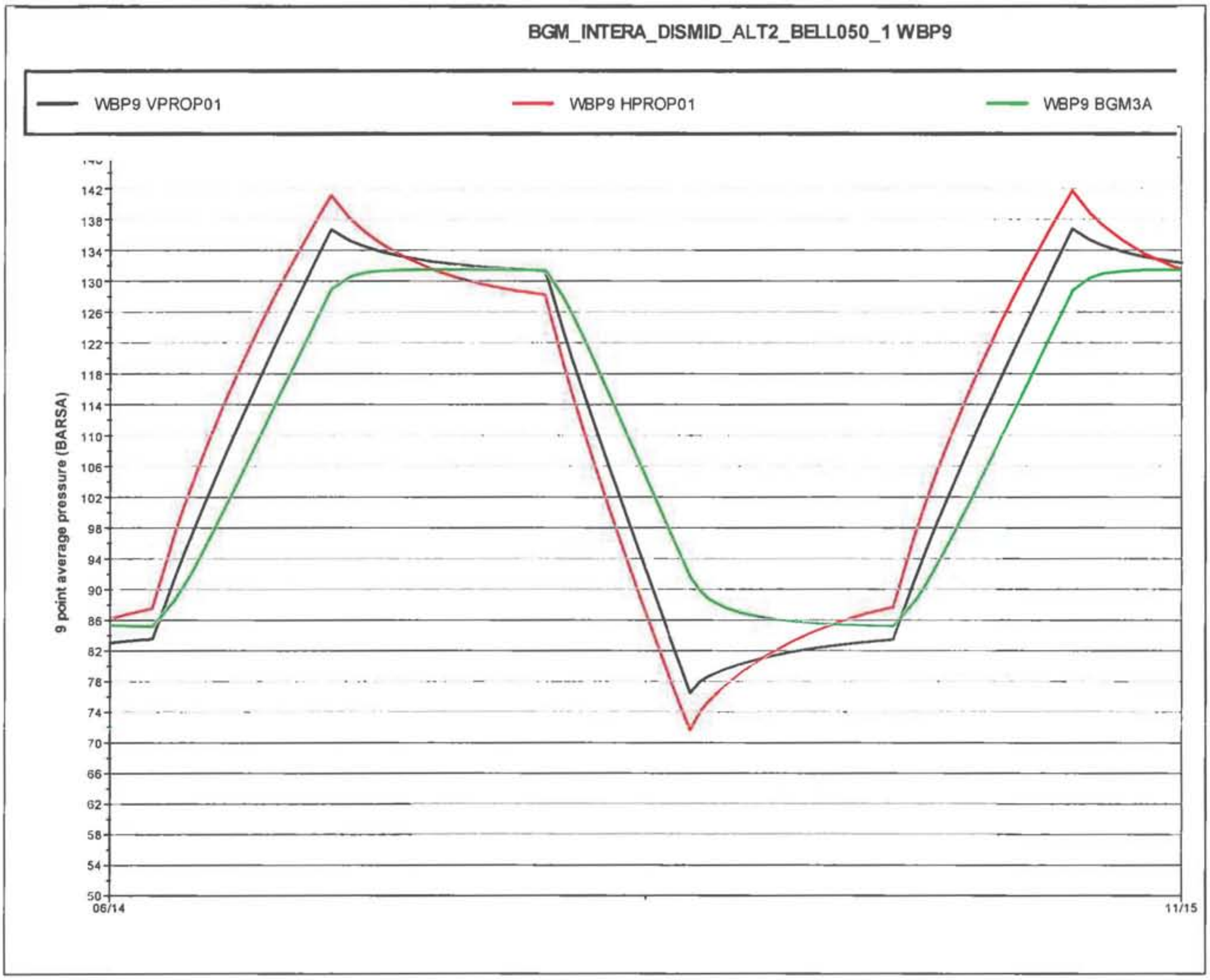

Figure 5-21 **Capacity losses in UGS with 1 production/injection cycle per year, rest periods of 90 days. Result is ca 4 bar loss in MAIN block, up to 16 bar loss after end of production cycle in the BGM-7 block.**

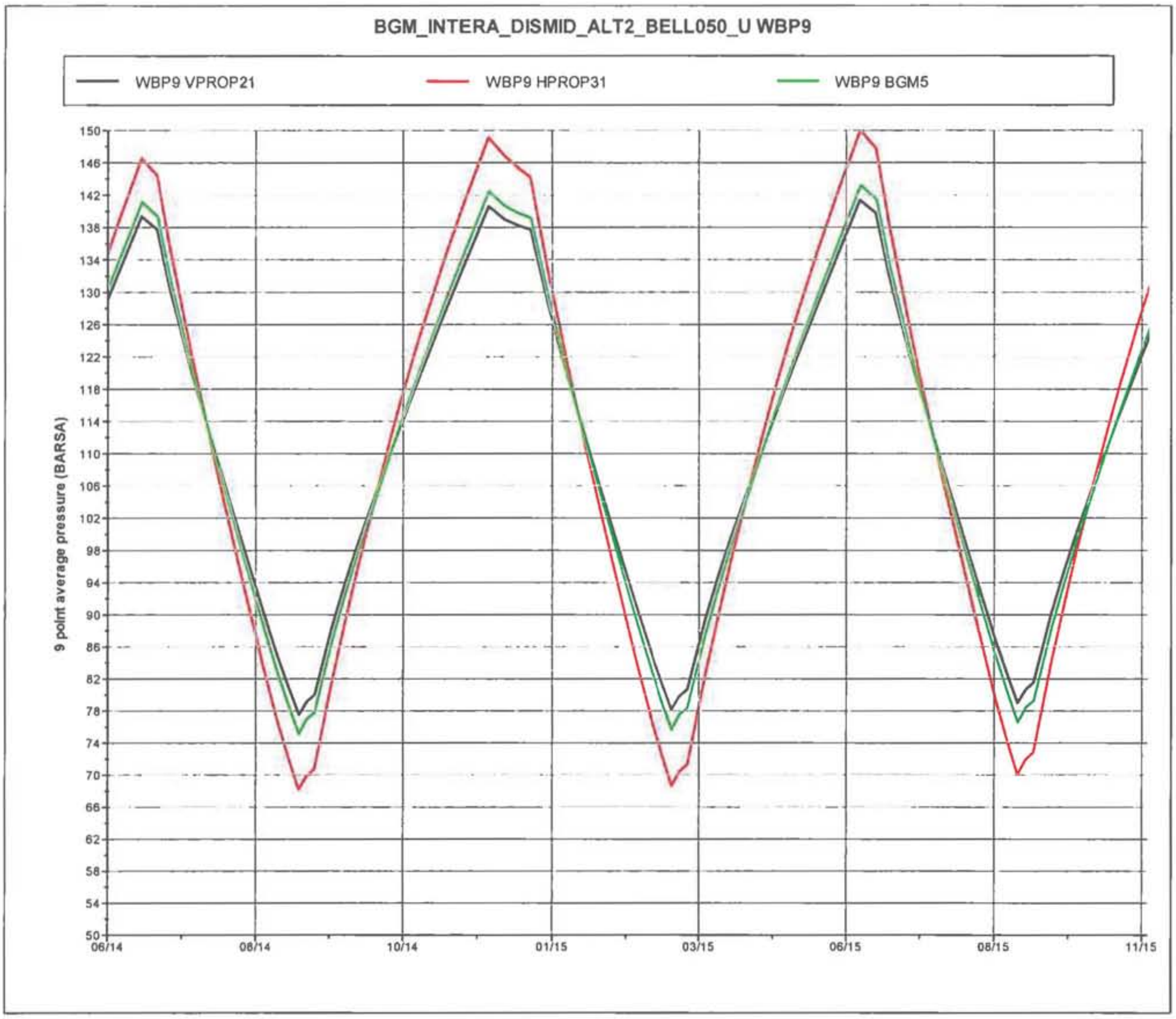

Figure 5-22 **Capacity losses in UGS with 2 production/injection cycles per year, rest periods of 8 days. Result is only 2 bar loss in MAIN block, up to 4 bar loss after end of injection cycle in the BGM-7 block.**

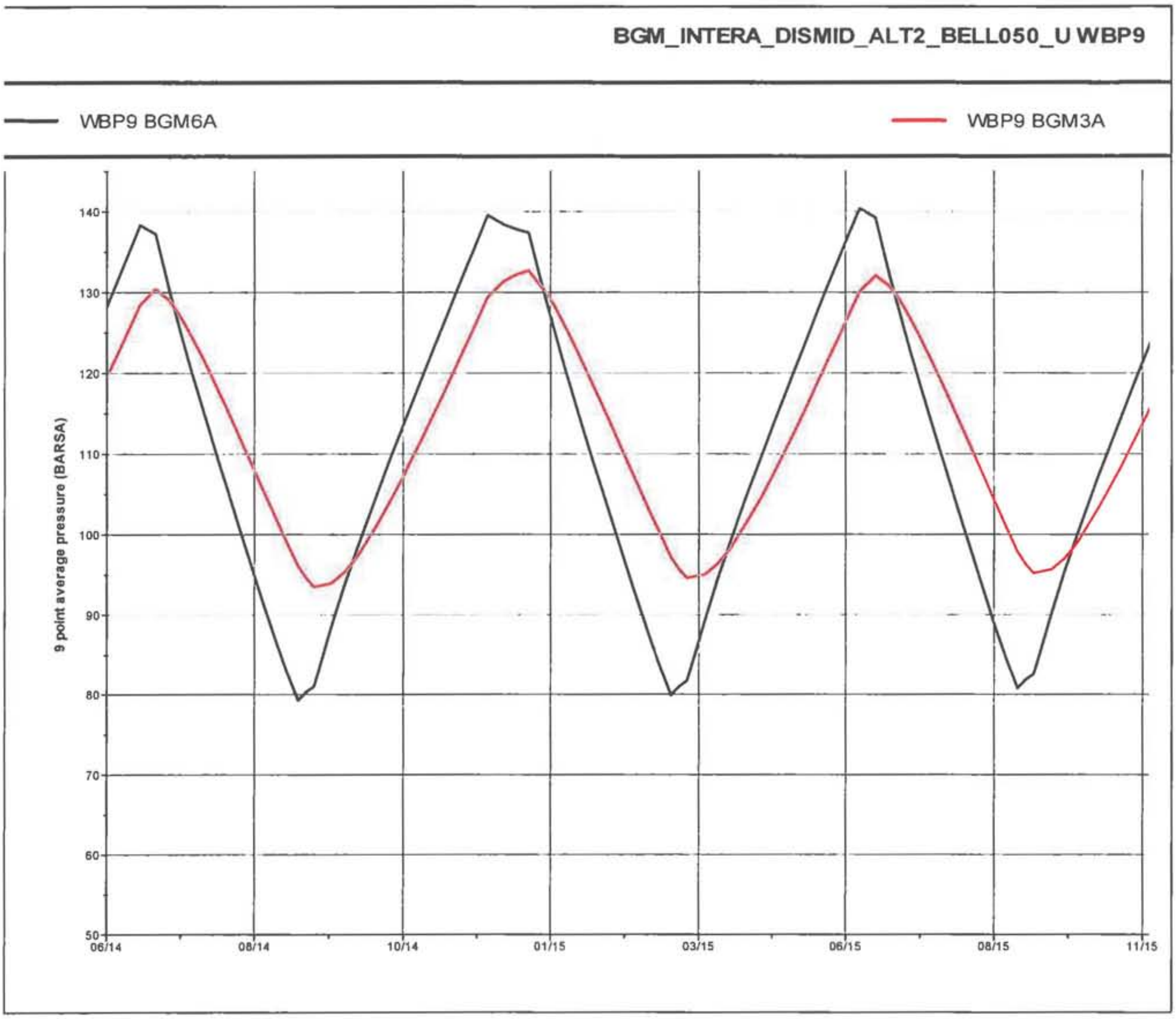

Figure 5-23 **Pressure difference over northern baffle in MAIN block. The historical dP of ca 3 bar between BGM-6A and BGM-3A is increased to ca 15 bar during the UGS period, a multiplication of factor 5. The pressure plotted is well 9-gridblock-average pressures 'WBP9'.**

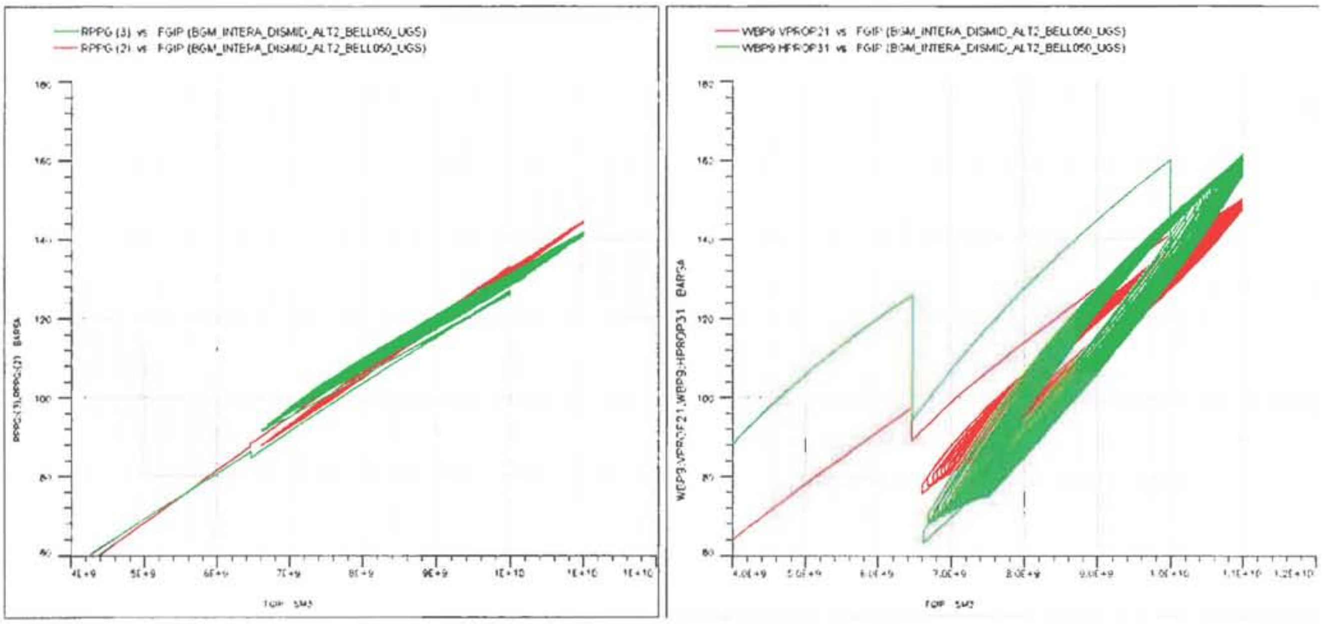

Figure 5-24 **Comparison of non-tank behaviour in block averages pressure 'RPPG' (left) and well 9-gridblock-average pressures 'WBP9' (right). RPPG2=MAIN, RPPG3=BLOCK-2, red=block-I, green=block-II) vs. UGS gas-in-place.**

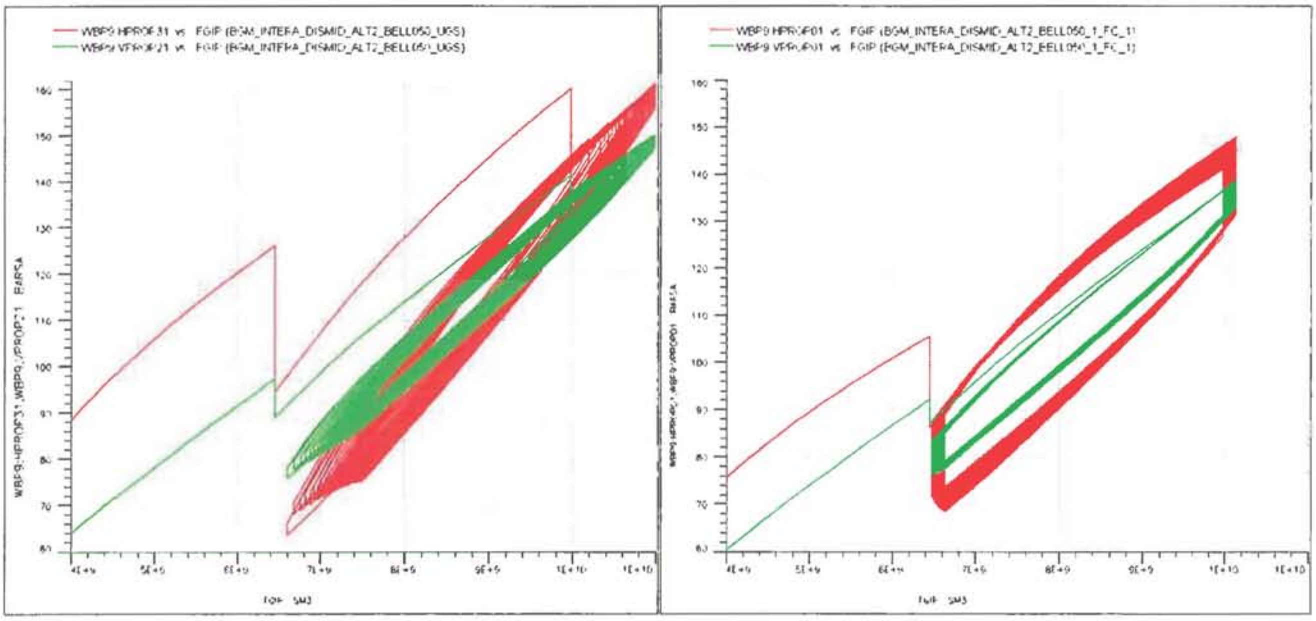

Figure 5-25 **Comparison of non-tank behaviour in well 9-gridblock-average pressures 'WBP9' between base case 'INTERA' 2 with cycles per year (left) and with 1 cycle (right).**

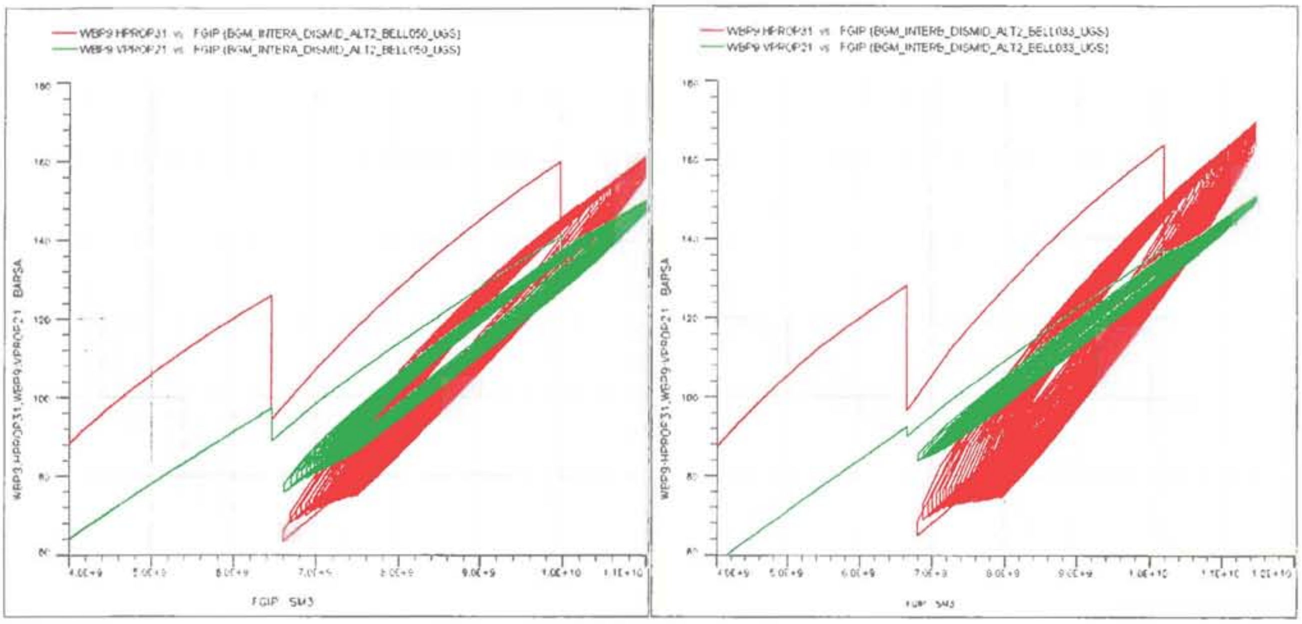

Figure 5-26 **Comparison of non-tank behaviour in well 9-gridblock-average pressures 'WBP9' between base case 'INTERA_BELL050' with ALT2 (left) and low vertical productivity model 'INTERB_BELL033' with ALT5 (right).**

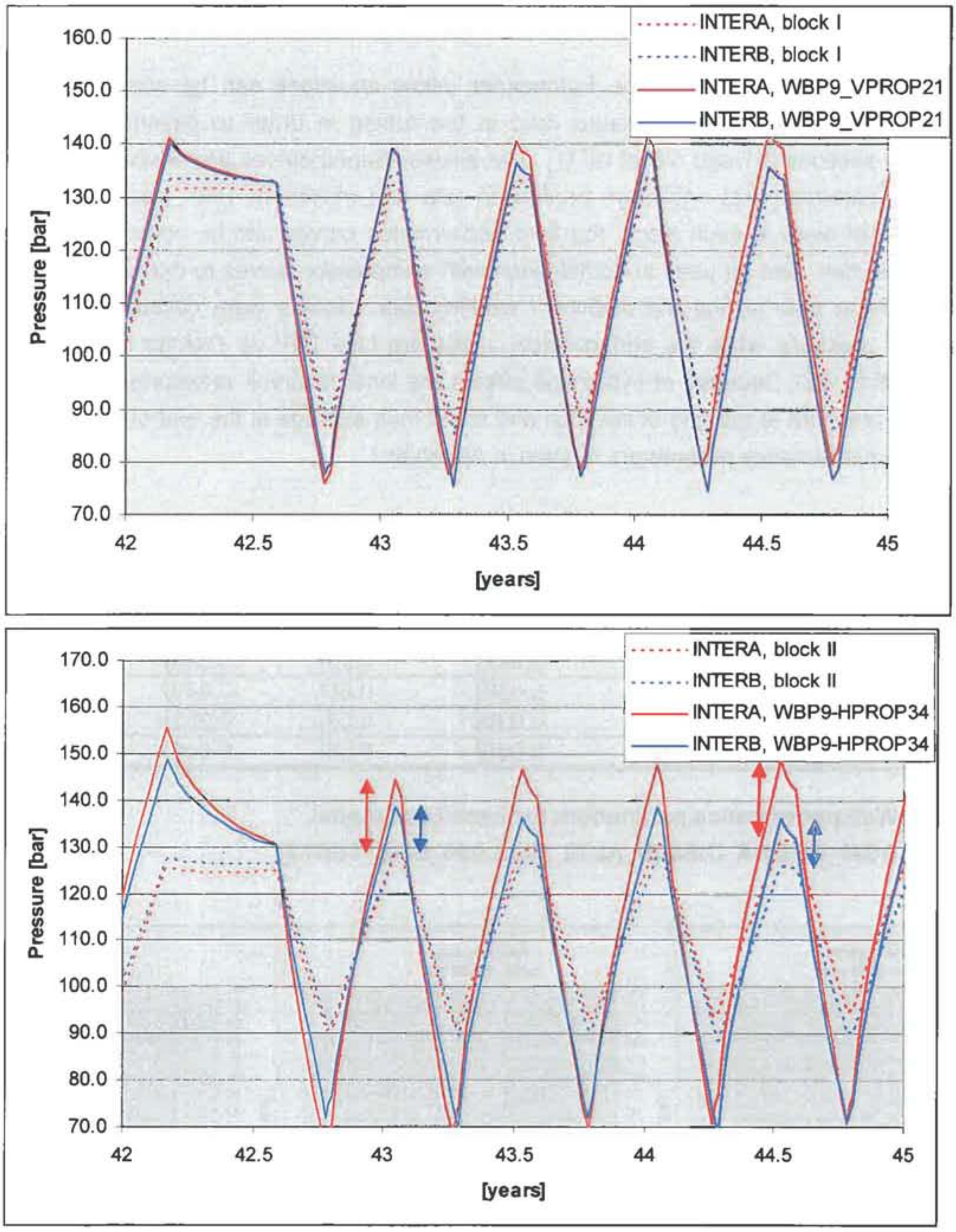

Figure 5-27 Effect of top structure on hysteretic behaviour. Plotted is an 'InterA' run (red) vs. 'InterB' run (blue). Dashed lines are block average pressures 'FPPG', full lines are 9-gridblock well average pressures 'WBP9'. The top plot shows block I, the bottom one block II. Clearly, the 'InterA' run (with more volume in the N, Figure 2-3), has more hysteresis in block II (approx. 15 bar vs. 10 bar). [The UGS rates are not identical in their relationship to the different block volumes, hence a small discrepancy in the absolute pressure levels. Also note that e.g. the relative sizes of the blocks are different in the two runs, so that certain other parameters, in particular the intra-field fault transmissibility multiplier, are different as well.]

5.6 UGS capacity curves

As described in the phase 2 report, the Forcheimer inflow equations can be combined with standard outflow equations for the pressure drop in the tubing in order to describe the well performance, see sections 3.1 and 5.6 of ref [1]. The ellipse-shaped curves are described by the well-performance parameters at maximum production rate and maximum THP, see Table 5-8. Using the number of wells in each block, the field performance curves can be constructed, see Figure 5-28. These can then be used in combination with compressor curves to optimise surface facilities. Important to note is that the cushion / working gas volumes were calculated for the average reservoir pressure, while the performance curves are give THP vs. rate for the average production / injection well. Because of hysteresis effects the local reservoir pressures are higher than the average pressure at the end of injection and lower than average at the end of production. A summary of the performance parameters is given in Appendix I.

	MAIN_BGM		BGM7_HOR		MAIN_VERT	
	Qlim/THPlim	THPlim/Pres	Qlim/THPlim	THPlim/Pres	Qlim/THPlim	THPlim/Pres
Prod 88	0.022	0.88	0.038	0.86	0.049	0.86
Inj 88	0.022	0.88	0.039	0.88	0.050	0.82
Prod 110	0.023	0.88	0.042	0.86	0.053	0.86
Inj 110	0.022	0.87	0.039	0.86	0.049	0.81
Prod 133	0.022	0.88	0.039	0.86	0.051	0.85
Inj 133	0.022	0.87	0.038	0.86	0.046	0.81

Table 5-8 Well performance parameters for base case model BGM_INTERA_DISMID_ALT2_BELL050_UGS_TESTS.

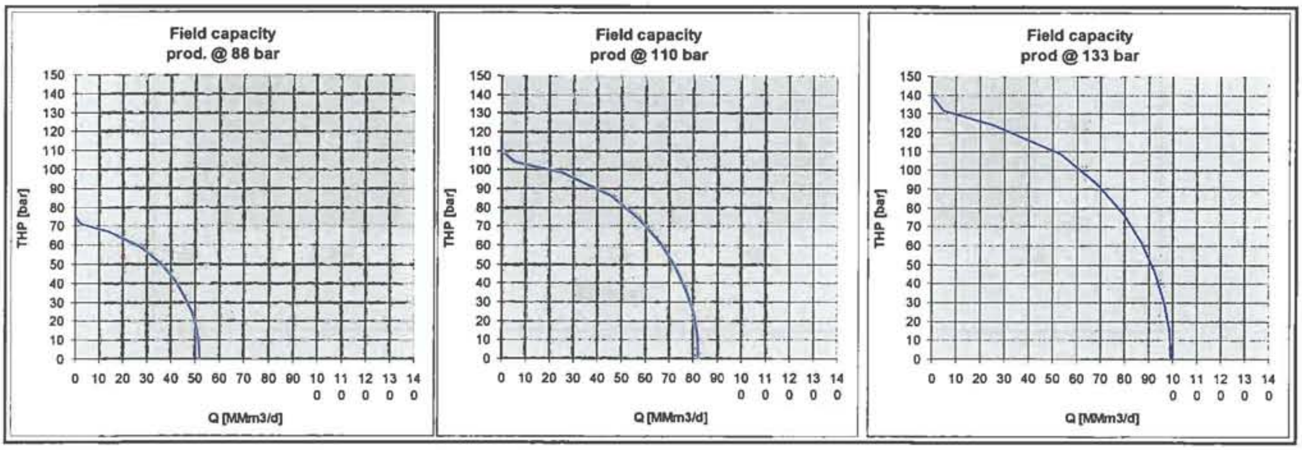

Figure 5-28 Field capacity curves for UGS production cycle at 88, 110 and 133 bar, model BGM_INTERA_DISMID_ALT2_BELL050.

5.7 Water disposal BGM-3A

From well test reports, a historical WGR for condensed water between 1 and 10 m3/MMm3 can be deduced, see Figure 5-29. This does not take into account the possible production of free water in the reservoir. At lower pressures, the gas is able to hold more water than at higher pressures. At 133 bar, the condensed WGR is ca 4-5 m3/MMm3 and at 88 bar it is ca 6-7 m3/MMm3, based on correlation charts from McKetta & Wehe [7]. Two corrections should be made for the expected WGR during UGS operations, which are a salinity correction and adjustment for the temperature of the injection gas. As the contribution of these effects is not known exactly, it suffices to say that the condensed water WGR values quoted above are considered conservative. These effects, together with the drying out of the near-wellbore region could be modeled in Eclipse with an extra license and compositional model set-up for water. It was decided not to carry out compositional modeling; instead TAQA carried out near wellbore modeling.

Taking into account the production of some free water, it was requested to test the water injection of ca 500 m3/d in well BGM-3A during the UGS cycles. This equated to a WGR of 10m3/MMm3 at a production rate of 50 MMsm3/d. Based on model INTERA_BELL050 it was found that:

- The injected water flows downwards in western/northern direction towards the aquifer
- No water is produced in any of the UGS wells
- The impact on UGS behaviour could not be found

The same was repeated with a WGR 20 m3/MMm3, with the same results. It is noted that BGM-3A is located in the north of the MAIN block at a much deeper location than the vertical UGS-wells. Also a baffle was found during HM-ing between BGM-3A and BGM-6A that reduces the transmissibility to the south.

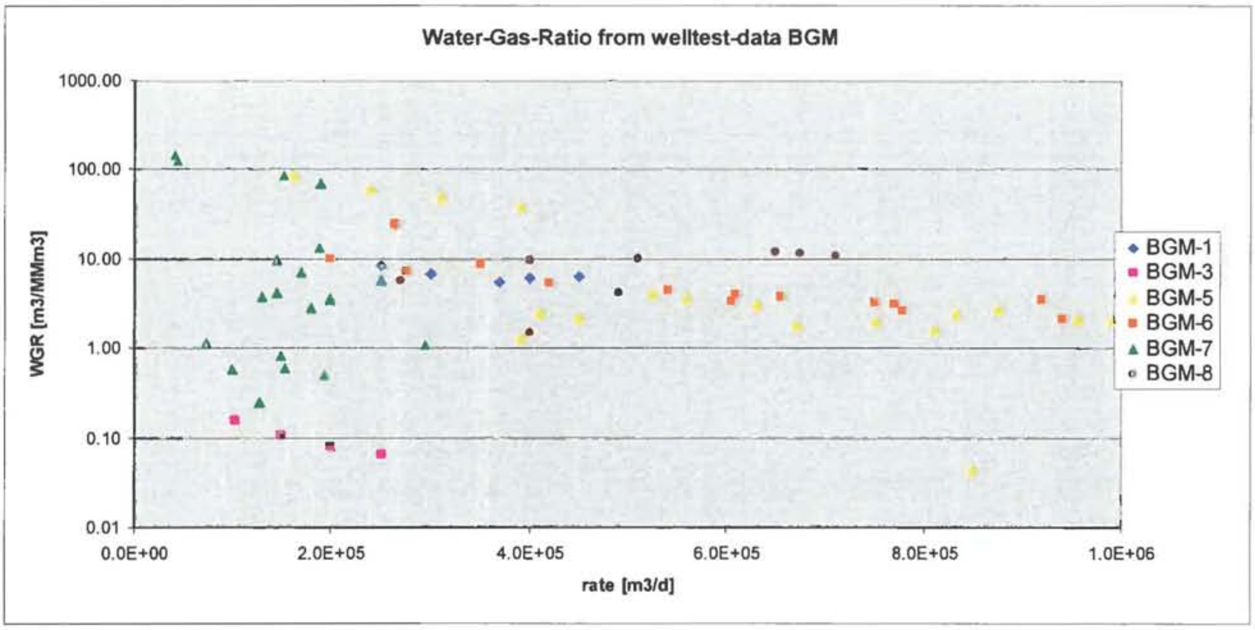

Figure 5-29 Historical WGR found during well tests in Bergermeer-wells. The higher values are found at lower rates, which shows the well was not properly cleaned out.

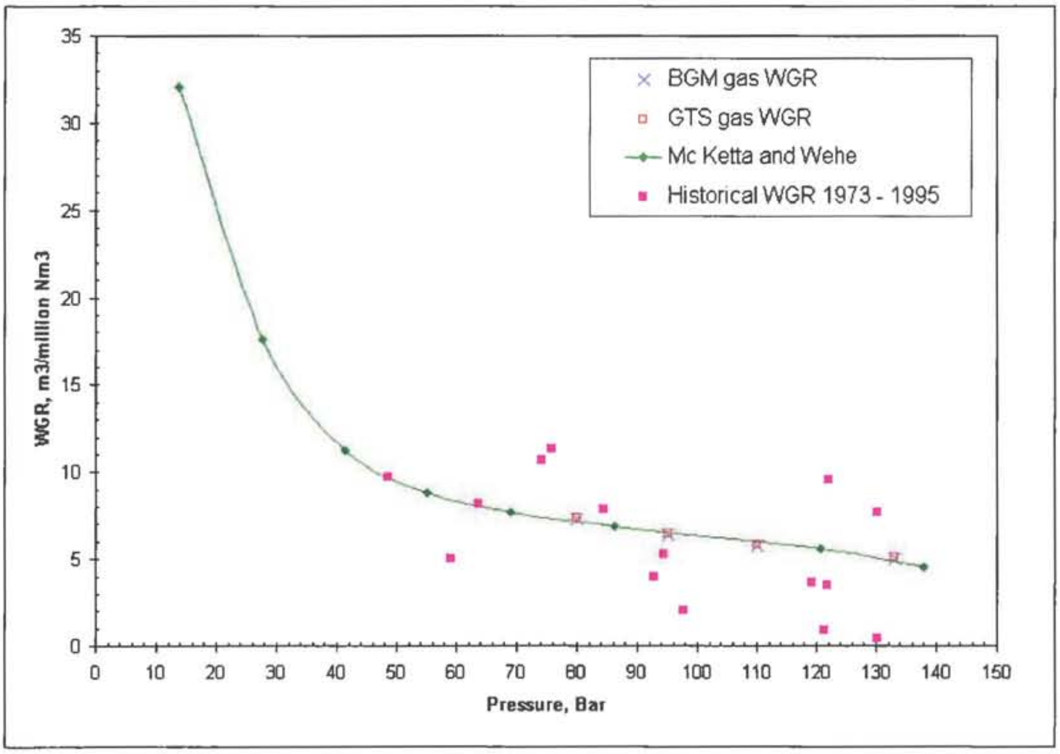

Figure 5-30 **Comparison of historical WGR with expected values for UGS storage pressures, based on correlation charts from McKetta&Wehe [7].**

6 Conclusions and Recommendations

The Bergermeer field has been studied in this phase in more detail with special focus on well placement and dynamic behavior during future UGS operations. The most important well tests were explicitly modeled with the dynamic UGS model and the geological uncertainty was more precisely captured. Introducing a more uplifted top ROSLU reservoir, new models were explicitly created in accordance with the volume seen by the depletion history (P/Z-plot). The gridding in the uppermost part of the reservoir was refined in order to better facilitate the planning of horizontal wells in block-2. The new 200 m constraint imposed by TNO between the UGS wells and interpreted faults in Bergermeer was taken into account. Conclusions from the phase-4 reservoir modeling study are:

- range in welltest permeabilities overlap permeabilities needed for history match
- low permeable streaks, as evidenced by BGM-7 welltests, are present in the block-2 but are probably of limited extent and can be breached when higher pressure differentials are imposed
- permeability in the main UGS area is suitable for development with vertical wells, 9 5/8" tbg
- due to combination of limited permeability and height, the western BGM block is to be developed with horizontal wells and 7 5/8" tbg
- difference in <u>average</u> reservoir pressure across the main fault can be balanced by placement of 9 vertical wells in block-1 and 5 horizontal wells in block-2 in the base case
- due to hysteresis effects during UGS operations, <u>local</u> pressure differences over the fault can be greater than 20 bar
- small internal pressure differences in the main block caused by baffles are blown up by ca factor 5 during UGS operations, e.g. over baffle_north the historic dP of ca 3 bar becomes ca 15 bar with the projected UGS cycling rates
- due to the location of the wells in the south of the field, pressure losses are expected when the UGS switches from production to injection or vice-versa; these can be up to 16 bar for block-2 when the UGS is not used for 90 days, but total equilibration takes even longer
- historical pressures and GWC measurements indicate Bergermeer is a closed system
- presence of a small aquifer can not be ruled out, possibly reducing the amount of cushion gas required
- the dynamic models shows that the GWC is pushed back with injection of the cushion gas, during the UGS-cycles the swings in GWC around the wells are up to 5 m for block-1 and up to 50 m for block-2 (but still below 2200 m tvdss, where the horizontal wells are located)

The main uncertainties are:

- position of the main fault extension between UGS main and western compartment
- compartment volume distribution between main and block-2
- depth control of top ROSLU horizon in western block and in the north of the main block (north of BGM6A)
- reservoir quality above the GWC in the western block, which is strongly dependent on depth of top ROSLU

Recommendations:

- monitoring of pressures during cushion gas injection to confirm heterogeneities in main block and transmissibility of main fault
- monitoring of pressures in Groet (GRT-1) to confirm closed system at pressure differentials higher than 35 bar seen historically between Bergermeer and Groet
- reduce seismic uncertainty of the top ROSLU by seismic reprocessing (PSDM)
- re-evaluate seismic interpretation of 'spill-point' between BGM and GRT, dynamically simulated with 'fault_at_spill', w.r.t. location of top reservoir in the north of Bergermeer and the volume-multiplier needed for the phase 2 models to acquire the correct Bergermeer GIIP
- devise operational monitoring strategy to maintain pressure difference between the two blocks

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[13] From a TNO report, 2008, conclusions communicated by Taqa

7 Appendix I

7.1 Welltest modeling statistics

Model	Inp. Run	Modifications	Match Quality	
			DD's	log-log
BAG25_ALT5_DISMIDHIGHKV_BELL_050/BAG25_ALT2_DISMIDHIGHKV_BELL050_ALT_BGM1_86_RADFIN5_A.DATA	base	WDFACCOR 1.6, z=3-9, WBS 350		
BAG25_ALT5_DISMIDHIGHKV_BELL_050/BAG25_ALT2_DISMIDHIGHKV_BELL050_ALT_BGM1_86_RADFIN5_B.DATA	base	WDFACCOR 1.6, z=8-9 (KH18000), WBS 100		
BAG25_ALT5_DISMIDHIGHKV_BELL_050/BAG25_ALT2_DISMIDHIGHKV_BELL050_ALT_BGM1_86_RADFIN5_C.DATA	base	WDFACCOR 1.6, z=9-10 (KH 26000), WBS 100		
BAG25_ALT5_DISMIDHIGHKV_BELL_050/BAG25_ALT2_DISMIDHIGHKV_BELL050_ALT_BGM1_86_RADFIN5_D.DATA	base	WDFACCOR 1.6, z=7-9 (KH21500), WBS 100		
BAG25_ALT5_DISMIDHIGHKV_BELL_050/BAG25_ALT2_DISMIDHIGHKV_BELL050_ALT_BGM1_86_RADFIN5_E.DATA	base	WDFAC 2.7, z=7-9 (KH21500), WBS 100		
BAG25_ALT5_DISMIDHIGHKV_BELL_050/BAG25_ALT2_DISMIDHIGHKV_BELL050_ALT_BGM1_86_RADFIN5_F.DATA	base	WDFAC 3.1, z=7-9 (KH21500), WBS 100	OK	
BAG25_ALT5_DISMIDHIGHKV_BELL_050/BAG25_ALT2_DISMIDHIGHKV_BELL050_ALT_BGM1_86_RADFIN5_G.DATA	base	WDFAC 3.1, z=7-8 (KH14592), PERMMULT 1.47, WBS 100		
BAG25_ALT5_DISMIDHIGHKV_BELL_050/BAG25_ALT2_DISMIDHIGHKV_BELL050_ALT_BGM1_86_RADFIN5_F_THETA.	base	WDFAC 3.1, z=7-9 (KH21500), WBS 100	OK	

Table 7-1 Statistics welltest modeling BGM-1 1986.

Model	Inp. Run	Modifications	Match Quality	
			DD's	log-log
BAG25_ALT5_DISMIDHIGHKV_BELL_050/BAG25_ALT2_DISMIDHIGHKV_BELL050_ALT_BGM1_86_RADFIN5_A.DATA	base	WDFACCOR 1.6, z=3-9, WBS 350		
BAG25_ALT5_DISMIDHIGHKV_BELL_050/BAG25_ALT2_DISMIDHIGHKV_BELL050_ALT_BGM1_86_RADFIN5_B.DATA	base	WDFACCOR 1.6, z=8-9 (KH18000), WBS 100		
BAG25_ALT5_DISMIDHIGHKV_BELL_050/BAG25_ALT2_DISMIDHIGHKV_BELL050_ALT_BGM1_86_RADFIN5_C.DATA	base	WDFACCOR 1.6, z=9-10 (KH 26000), WBS 100		
BAG25_ALT5_DISMIDHIGHKV_BELL_050/BAG25_ALT2_DISMIDHIGHKV_BELL050_ALT_BGM1_86_RADFIN5_D.DATA	base	WDFACCOR 1.6, z=7-9 (KH21500), WBS 100		
BAG25_ALT5_DISMIDHIGHKV_BELL_050/BAG25_ALT2_DISMIDHIGHKV_BELL050_ALT_BGM1_86_RADFIN5_E.DATA	base	WDFAC 2.7, z=7-9 (KH21500), WBS 100		
BAG25_ALT5_DISMIDHIGHKV_BELL_050/BAG25_ALT2_DISMIDHIGHKV_BELL050_ALT_BGM1_86_RADFIN5_F.DATA	base	WDFAC 3.1, z=7-9 (KH21500), WBS 100		OK
BAG25_ALT5_DISMIDHIGHKV_BELL_050/BAG25_ALT2_DISMIDHIGHKV_BELL050_ALT_BGM1_86_RADFIN5_G.DATA	base	WDFAC 3.1, z=7-8 (KH14592), PERMMULT 1.47, WBS 100		
BAG25_ALT5_DISMIDHIGHKV_BELL_050/BAG25_ALT2_DISMIDHIGHKV_BELL050_ALT_BGM1_86_RADFIN5_F_THETA.DATA	base	WDFAC 3.1, z=7-9 (KH21500), WBS 100		OK

Table 7-2 Statistics welltest modeling BGM-1 1997.

Model	Inp. Run	Modifications	Match Quality	
			DD/multirate	BU
BGM_INTERA_DISMID_ALT2_BELL050_ECLIPSE100/BGM_INTERA_DISMID_ALT2_BELL050_BGM7_94_RADFIN5_B4.DATA	base		Too opt	Too opt
BGM_INTERA_DISMID_ALT2_BELL080_ECLIPSE100/BGM_INTERA_DISMID_ALT2_BELL080_BGM7_94_RADFIN5_B4.DATA	bell080		Too opt	Too opt
BGM_INTERB_DISMID_ALT5_BELL033_ECLIPSE100/BGM_INTERB_DISMID_ALT5_BELL033_BGM7_94_RADFIN5_B4.DATA	bell030		OK?	Too opt
BGM_HIGHP_DISMID_ALT5_BFLS_ECLIPSE100/BGM_HIGHP_DISMID_ALT5_BFLS_BGM7_94_RADFIN5_B4.DATA	highp		Too opt	Too opt
BGM_INTERA_DISMID_ALT2_BELL050_ECLIPSE100/BGM_INTERA_DISMID_ALT2_BELL050_BGM7_94_RADFIN5_X4.DATA	base	perm*0.2 in 9x9x21 box	Too pess	OK?
BGM_INTERA_DISMID_ALT2_BELL050_ECLIPSE100/BGM_INTERA_DISMID_ALT2_BELL050_BGM7_94_RADFIN5_W4.DATA	base	WDFAC = 15e-6	OK	Too opt
BGM_INTERA_DISMID_ALT2_BELL050_ECLIPSE100/BGM_INTERA_DISMID_ALT2_BELL050_BGM7_94_RADFIN5_Y4.DATA	base	perm*0.5 in 9x9x21 box, again 0.5 in 1x1x22 box	Too pess	Two 'plateaus' on either side

Table 7-3 Statistics welltest modeling BGM-7 1994.

Model	Inp. Run	Modifications	Match Quality	
			DD/multirate	BU
BGM_INTERA_DISMID_ALT2_BELL050_ECLIPSE100/BGM_INTERA_DISMID_ALT2_BELL050_BGM7_94_RADFIN5_B4.DATA	base		Too opt	Too opt
BGM_INTERA_DISMID_ALT2_BELL050_ECLIPSE100/BGM_INTERA_DISMID_ALT2_BELL050_BGM7_94_RADFIN5_W4.DATA	base	WDFAC = 10e-6	Slightly too opt	Too opt

Table 7-4 Statistics welltest modeling BGM-7 1997.

Model	Inp. Run	Modifications	Match Quality	
			DD's	log-log
BAG25_ALT2_DISMIDHIGHKV_ECLIPSE100_WDF_BFLS4/BAG25_ALT2_DISMIDHIGHKV_WDF_BFLS4_RADFIN5_A.DATA	base phase2	SKIN 0 , WDFACCOR 1.6e-6, WBS 370, Perm 525 av	too low	
BAG25_ALT2_DISMIDHIGHKV_ECLIPSE100_WDF_BFLS4/BAG25_ALT2_DISMIDHIGHKV_WDF_BFLS4_RADFIN5_B.DATA	base phase2	SKIN 0 , WDFACCOR 1.6e-6, WBS 370, Perm 410 av	too low	
BAG25_ALT2_DISMIDHIGHKV_ECLIPSE100_WDF_BFLS4/BAG25_ALT2_DISMIDHIGHKV_WDF_BFLS4_RADFIN5_C.DATA	base phase2	SKIN 0 , WDFACCOR 2.7e-6, WBS 370, Perm 410 av	OK	
BAG25_ALT2_DISMIDHIGHKV_ECLIPSE100_WDF_BFLS4/BAG25_ALT2_DISMIDHIGHKV_WDF_BFLS4_RADFIN5_D.DATA	base phase2	SKIN 0 , WDFACCOR 2.7e-6, WBS 370, Perm 410 av, permz (k=9) = 0	too low	
BAG25_ALT2_DISMIDHIGHKV_ECLIPSE100_WDF_BFLS4/BAG25_ALT2_DISMIDHIGHKV_WDF_BFLS4_RADFIN5_E.DATA	base phase2	SKIN 0 , WDFACCOR 2.7e-6, WBS 370, Perm 410 av, permx * 0.5 (k=10-25) for 3*3 cells	too high	
BAG25_ALT2_DISMIDHIGHKV_ECLIPSE100_WDF_BFLS4/BAG25_ALT2_DISMIDHIGHKV_WDF_BFLS4_RADFIN5_F.DATA	base phase2	SKIN 0 , WDFACCOR 2.7e-6, WBS 370, Perm 410 av, permx * 0.5 (k=10-25) for 9*9 cells	too high	
BAG25_ALT2_DISMIDHIGHKV_BELL050_ALT_ECLIPSE100/BAG25_ALT2_DISMIDHIGHKV_BELL_050_ALT_RADFIN5_A.DATA	intermediate base phase4	WDFACCOR 1.6e-6, SKIN 0, KH 24005 mDm, LGR open z=17-72	too low	
BAG25_ALT2_DISMIDHIGHKV_BELL050_ALT_ECLIPSE100/BAG25_ALT2_DISMIDHIGHKV_BELL_050_ALT_RADFIN5_B.DATA	intermediate base phase4	WDFACCOR 2.7e-6, SKIN 0, KH 24005 mDm, LGR open z=17-72	OK	
BAG25_ALT2_DISMIDHIGHKV_BELL050_ALT_ECLIPSE100/BAG25_ALT2_DISMIDHIGHKV_BELL_050_ALT_RADFIN5_C.DATA	intermediate base phase4	WDFAC 2.3e-6, SKIN 0, KH 24005 mDm, LGR open z=17-72	OK	
BAG25_ALT2_DISMIDHIGHKV_BELL033_ALT_ECLIPSE100/BAG25_ALT2_DISMIDHIGHKV_BELL_033_ALT_RADFIN5_WD3.DATA	intermediate low phase4	WDFACCOR 9e-6, SKIN 0, LGR open z=17-72	too high	
BAG25_ALT2_DISMIDHIGHKV_BELL033_ALT_ECLIPSE100/BAG25_ALT2_DISMIDHIGHKV_BELL_033_ALT_RADFIN5.DATA	intermediate low phase4	WDFACCOR 1.6e-6, SKIN 0, LGR open z=17-72	too high	
BAG25_ALT2_DISMIDHIGHKV_BELL033_ALT_ECLIPSE100/BAG25_ALT2_DISMIDHIGHKV_BELL_033_ALT_RADFIN5_B.DATA	intermediate low phase4	WDFACCOR 0e-6, SKIN 0, LGR open z=17-72	too low	
BAG25_ALT2_DISMIDHIGHKV_BELL033_ALT_ECLIPSE100/BAG25_ALT2_DISMIDHIGHKV_BELL_033_ALT_RADFIN5_c.DATA	intermediate low phase4	WDFACCOR 0e-6, SKIN 0, LGR open z=17-72, KH MULT 278-->350 mD	too low	
BAG25_ALT2_DISMIDHIGHKV_BELL033_ALT_ECLIPSE100/BAG25_ALT2_DISMIDHIGHKV_BELL_033_ALT_RADFIN5_D.DATA	intermediate low phase4	WDFACCOR 1.6e-6, SKIN 0, LGR open z=17-72, KH MULT 350-->400 mD	too low	
BAG25_ALT2_DISMIDHIGHKV_BELL033_ALT_ECLIPSE100/BAG25_ALT2_DISMIDHIGHKV_BELL_033_ALT_RADFIN5_E.DATA	intermediate low phase4	WDFACCOR 4e-6, SKIN 0, LGR open z=17-72, KH MULT 350-->400 mD	almost OK	
BAG25_ALT2_DISMIDHIGHKV_BELL033_ALT_ECLIPSE100/BAG25_ALT2_DISMIDHIGHKV_BELL_033_ALT_RADFIN5_F.DATA	intermediate low phase4	WDFACCOR 4e-6, SKIN 0, LGR open z=17-72, KH MULT 350-->400 mD, WBS 350 m3	OK	
BAG25_ALT2_DISMIDHIGHKV_BELL033_ALT_ECLIPSE100/BAG25_ALT2_DISMIDHIGHKV_BELL_033_ALT_RADFIN5_F_KH1.DAT	intermediate low phase4	WDFACCOR 4e-6, SKIN 0, LGR open z=17-72, K 278 mD, K below perfs *2	too high	
BAG25_ALT2_DISMIDHIGHKV_BELL033_ALT_ECLIPSE100/BAG25_ALT2_DISMIDHIGHKV_BELL_033_ALT_RADFIN5_F_KH2.DAT	intermediate low phase4	WDFACCOR 4e-6, SKIN 0, LGR open z=17-72, K 278-->400 mD, K below perfs *2	OK	
BAG25_ALT2_DISMIDHIGHKV_BELL033_ALT_ECLIPSE100/BAG25_ALT2_DISMIDHIGHKV_BELL_033_ALT_RADFIN5_G.DATA	intermediate low phase4	WDFACCOR 4e-6, SKIN 0, LGR open z=17-72, KH MULT 350-->400 mD, WBS 350, VDFLOW 10	too low	
BAG25_ALT2_DISMIDHIGHKV_BELL033_ALT_ECLIPSE100/BAG25_ALT2_DISMIDHIGHKV_BELL_033_ALT_RADFIN5_H.DATA	intermediate low phase4	WDFACCOR 4e-6, SKIN 0, LGR open z=17-72, KH MULT 350-->400 mD, WBS 350, VDFLOW 0	too high	
BAG25_ALT2_DISMIDHIGHKV_BELL033_ALT_ECLIPSE100/BAG25_ALT2_DISMIDHIGHKV_BELL_033_ALT_RADFIN5_I.DATA	intermediate low phase4	WDFACCOR 4e-6, SKIN 0, LGR open z=17-56, KH 400 mD	OK	
BAG25_ALT2_CONTMID_ECLIPSE100_WDFACCOR/BAG25_ALT5_CONTMID_RADFIN5_A.DATA	intermediate low phase4	no k-mult, WDFACCOR 1.6e-6	too low	barrier needed
BAG25_ALT2_CONTMID_ECLIPSE100_WDFACCOR/BAG25_ALT5_CONTMID_RADFIN5_B.DATA	intermediate phase4	no k-mult, WDFACCOR 5.5e-6	OK	barrier needed
BAG25_ALT2_CONTMID_ECLIPSE100_WDFACCOR/BAG25_ALT5_CONTMID_RADFIN5_C.DATA	intermediate phase4	no k-mult, k(z=9)=0 (below perfs), WDFACCOR 1.6e-6	too low	OK
BAG25_ALT2_CONTMID_ECLIPSE100_WDFACCOR/BAG25_ALT5_CONTMID_RADFIN5_D.DATA	intermediate phase4	no k-mult, k(z=9)=0 (below perfs), WDFACCOR 5.2e-6	OK	OK
BAG25_ALT2_CONTMID_ECLIPSE100_WDFACCOR/BAG25_ALT5_CONTMID_RADFIN5_E.DATA	intermediate phase4	no k-mult, k(z=10-25) *0.5 (below perfs), WDFACCOR 5.2e-6	too little	barrier needed
BAG25_ALT2_CONTMID_ECLIPSE100_WDFACCOR/BAG25_ALT5_CONTMID_RADFIN5_F.DATA	intermediate phase4	no k-mult, k(z=3-9) *0.5 (below perfs), WDFACCOR 5.2e-6	too much	barrier needed
BAG25_ALT2_CONTMID_ECLIPSE100_WDFACCOR/BAG25_ALT5_CONTMID_RADFIN5_G.DATA	intermediate phase4	no k-mult, k(z=3-9) *0.5 (below perfs) 9*9 cells around well, WDFACCOR 5.2e-6	too much	barrier needed
BAG25_ALT2_CONTMID_ECLIPSE100_WDFACCOR/BAG25_ALT5_CONTMID_RADFIN5_H.DATA	intermediate phase4	no k-mult, k(z=3-9) *0.1 (below perfs) 9*9 cells around well, WDFACCOR 5.2e-6	too little	barrier needed
BAG25_ALT2_CONTMID_ECLIPSE100_WDFACCOR/BAG25_ALT5_CONTMID_RADFIN5_I.DATA	intermediate phase4	no k-mult, k(z=3-9) *0.01 (below perfs) 9*9 cells around well, WDFACCOR 5.2e-6	OK	OK
BGM_INTERA_DISMID_ALT2_BELL050_ECLIPSE100_REALLY_FINAL/BGM_INTERA_DISMID_ALT2_BELL050_RADFIN5_A.DATA	base	WDFAC 2.5, SKIN -0.3, WRONG COMPDAT	OK	
BGM_INTERA_DISMID_ALT2_BELL050_ECLIPSE100_REALLY_FINAL/BGM_INTERA_DISMID_ALT2_BELL050_RADFIN5_B.DATA	base	WDFAC 2.5, SKIN -0.3	Too opt	
BGM_INTERA_DISMID_ALT2_BELL050_ECLIPSE100_REALLY_FINAL/BGM_INTERA_DISMID_ALT2_BELL050_RADFIN5_C.DATA	base	WDFAC 14, Skin 0, WBOREVOL 350 sm3	OK	

Table 7-5 Statistics welltest modeling BGM-1 1987.

7.2 UGS performance curve parameters

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Table 7-6 Well performance curve parameters base case 'INTERA_BELL050'.

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Table 7-7 Well performance curve parameters low vertical well productivity case 'INTERB_BELL033'.

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Table 7-8 Well performance curve parameters high productivity case 'INTERA_BELL080'.

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Table 7-9 Well performance curve parameters base case productivity with aquifer 'INTERA_BELL050_LOWCUSHION'.

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Table 7-10 Well performance curve parameters low horizontal well productivity 'HIGHP'.

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Table 7-11 Well performance curve parameters low vertical productivity case 'INTERB_BELL033', with lower skins, see Table 7-13.

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Table 7-12 Well performance curve parameters low vertical productivity case 'INTERB_BELL033', with lower skins, see Table 7-13.

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Table 7-13 Darcy and non-Darcy skin values for LOWSKIN sensitivity runs for performance parameters.

8 Appendix II : PVT-study (Phase 3)

8.1 Composition definition original Bergermeer gas

Objectives

- Determine Bergermeer gas composition after cushion and working gas injection for first storage cycle
- Determine CGR for 1st, 5th, 10 and 15th cycle

Work done

- Composition original Bergermeer gas defined
- Composition storage gas mixture for 1st cycle defined
- Compositional MBAL-model created for CGR forecast up to 2nd cycle

PVT data available

- BGM-1 initial gas composition @ unknown separator conditions
- ALKM-1 condensate composition @ standard conditions
- HICAL gas composition (GTS-grid) for future injection
- Historical condensate SG Bergen concession
- Historical CGR Bergermeer wells, back-allocated from all fields in Bergen concession

Composition	*DATE??*
Component	**Moles**
Nitrogen	**0.970**
Methane	**94.535**
Carbon dioxide	**0.699**
Ethane	**3.048**
Hydrogen sulfide	**0.000**
Propane	**0.444**
i-Butane	**0.086**
n-Butane	**0.079**
i-Pentane	**0.024**
n-Pentane	**0.024**
Hexanes	**0.019**
C7+	**0.072**
Total:	100.000
C7+ Mole Weight	**116**
C7+ Density, g/cc @ 60F	**0.7931**
Gas Gravity	**0.590**
Default C7+ MW	100
Default C7+ Density	0.70

BGM-1 original composition

Component	Wt.%	Mol.%
Nitrogen	0.000	0.000
Hydrogen Sulphide	0.000	0.000
Carbon Dioxide	0.000	0.000
Methane	0.000	0.000
Ethane	0.021	0.111
Propane	0.057	0.187
Isobutane	0.031	0.085
N-Butane	0.113	0.309
Isopentane	0.126	0.277
N-Pentane	0.172	0.378
Cyclopentane	0.021	0.048
Isohexane	0.391	0.739
N-Hexane	0.321	0.591
Methylcyclopentane	0.128	0.241
Benzene	1.007	2.046
Cyclohexane	0.401	0.756
Isoheptane	1.040	1.719
N-Heptane	0.590	0.934
Methylcyclohexane	1.180	1.907
Toluene	0.760	1.309
Isooctane	2.321	3.442
N-Octane	0.970	1.348
Ethylcyclohexane	0.540	0.726
Ethylbenzene	0.283	0.423
Xylene	0.751	1.122
Isononane	3.102	4.068
N-Nonane	1.614	1.997
Isodecane	6.348	7.517
N-Decane	2.701	3.012
Isoundecane	7.293	7.873
N-Undecane	3.861	3.920
Isododecane	6.282	6.165
N-Dodecane	4.367	4.065
Isotridecane	10.331	9.369
N-Tridecane	4.401	3.785
Isotetradecane	9.641	8.052
N-Tetradecane	3.628	2.902
Isopentadecane	7.701	5.932
N-Pentadecane	2.501	1.868
Isohexadecane	4.551	3.253
N-Hexadecane	1.473	1.032
Isoheptadecane	2.892	1.936
N-Heptadecane	0.908	0.599
Isooctadecane	1.407	0.890
N-Octadecane	0.487	0.304
Isononadecane	0.588	0.355
N-Nonadecane	0.281	0.166
Eicosane +	0.423	0.238
Total	100.000	100.000

ALKM-1 liquid composition, 1994

Composition (HICAL gas)

Component	Mol%
Methane	90.507
Ethane	3.516
Propane	0.753
i-Butane	0.086
n-Butane	0.137
i-Pentane	0.031
n-Pentane	0.032
i-Hexane	0.000
n-Hexane	0.004
Benzene	0.000
i-Heptanes	0.000
n-Heptane	0.000
Methylcyclohexane	0.000
Toluene	0.000
n-Octane	0.000
Helium	0.000
Hydrogen	0.000
Nitrogen	4.147
Carbondioxide	0.787
Total	100.000

HICAL composition (injection gas from grid)

Figure 8-1 **Original gas compositions BGM-1, liquid composition ALKM-1 and HICAL injection gas composition.**

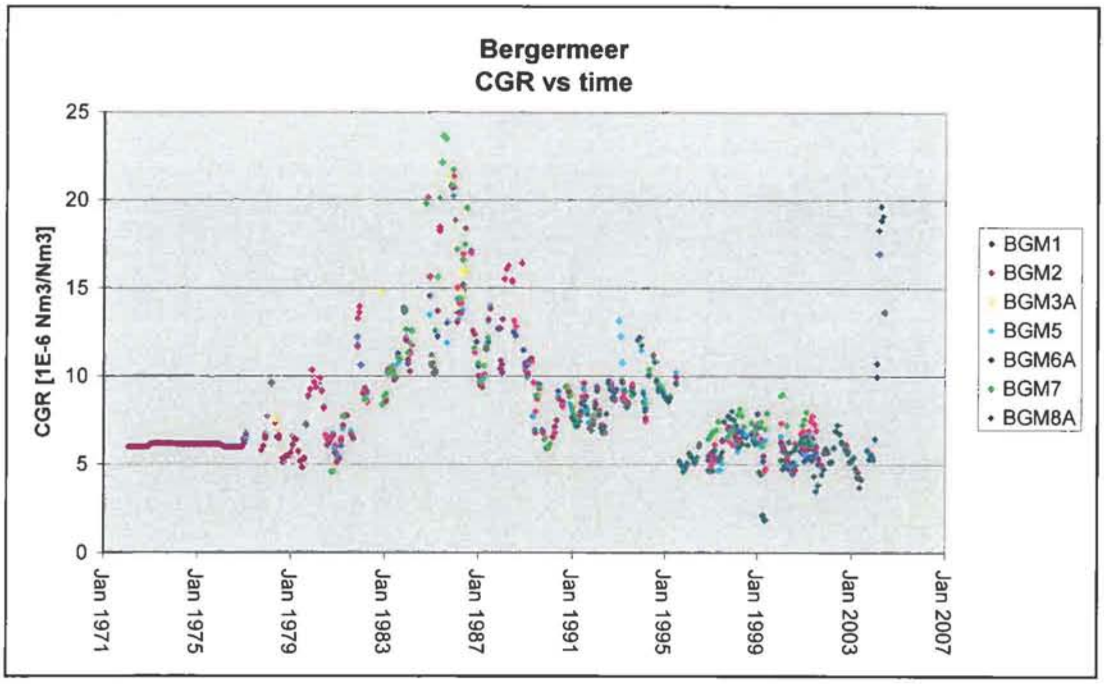

Figure 8-2 **Historical condensate production Bergermeer, back-allocated from gathering station of fields in Bergen concession.**

Historical condensate production Bergermeer

- CGR ratio's Bergen concession back-calculated according to gas-allocation
- First few years unreliable (constant)
- Increase and peak CGR 1986 can not physically be explained by depletion in BGM (could be caused by new fields in concession)
- Measured CGR from well test BGM-1 of 2 stb/MMscf (Aug 1972)
- This corresponds to a CGR of ca 11 m3/MMm3, including vaporized and free condensate

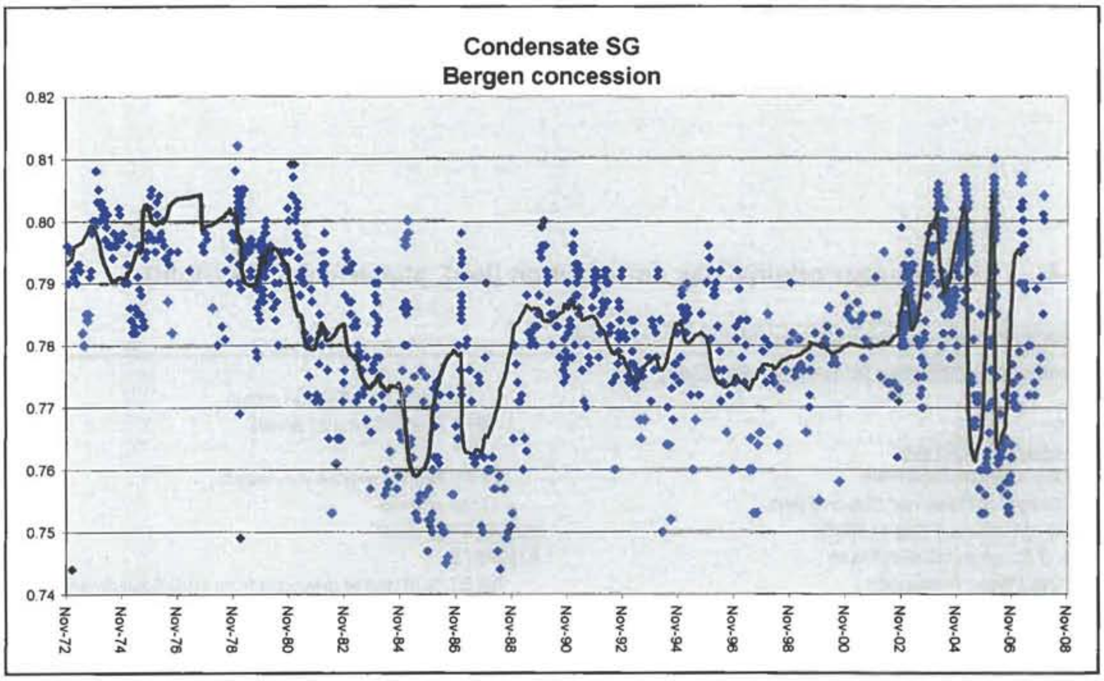

Figure 8-3 Historical condensate SG of fields in Bergen concession, initial SG is ca 0.8, this corresponds to SG 0.8005 (45.26 API of ALKM-1 @ s.c.) mentioned in PVT-report, Amoco, June 1994

Re-creation of original Bergermeer gas in PVTSim

- Calculate theoretical separator liquid BGM-1 using K-values, using the ALKM-1 condensate for distribution of heavy ends and the BGM- separator gas (this is called Calc Sep Liquid)
- Recombine Calc Sep Liquid with BGM-1 separator gas, this resulted in Pdew very close to initial Pres of 227 bara.
- Regress the recombined reservoir gas to the original reservoir conditions and CGR of 11 m3/MMm3 and SG 0.8 to better define the plus fraction properties
- Use K-factors to adjust plus fraction to correct gas/liquid equilibrium ratio

Original Bergermeer gas composition

- Pdew 226 bar / 0.1 bar
- Gas SG 0.59
- Condensate SG 0.809 (43.3 API)
- Total CGR 11 sm3/MMsm3

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Figure 8-4 Bergermeer original gas composition (left), phase envelope (right).

Composition definition UGS gas mixture for 1st cycle

Current Reservoir Conditions - 1st Gas Injection Cycle		
Pressure=	12	bara (from 24-Jun email)
Temperature=	86.1	C (from 24-Jun email)
In-Situ Reservoir Gas Phase		
Gas-in-Place (standard volume)=	1.00	Bsm^3 (from 24-Jun email)
Mole Weight of Reservoir Gas-in-Place	17.24	gm/mol
Density of Reservoir Gas-in-Place	0.0007299	gm/cm^3
Moles of Reservoir Gas-in-Place	**42327273**	
Cum Gas Phase Produced=	94.86	% of gas at dewpoint from CVD Experiment
In-Situ Retrograde Liquid Phase		
Retrograde Liquid-in-Place=	0.04	% of volume at dewpoint from CVD Experiment
in cubic meters at reservoir conditions	**42613**	m^3 (assumes no reservoir liquid production)
Mole Weight of Retrograde Liquid-in-Place	211.09	gm/mol
Density of Retrograde Liquid-in-Place	0.8527	gm/cm^3
Moles of Retrograde Liquid-in-Place	**172134**	
Injection Gas during UGS Cycle		
Gas Volume Injected (full UGS)	9	Bsm^3 (note: 9 Bsm^3 will result in Pr « 133 bar)
Mole Weight of Injection Gas	17.60	gm/mol
Density of Injection Gas at Standard Conditions	0.0007443	gm/cm^3
Moles of Gas Injected	**380707178**	moles of Injection Gas

	Moles	Molar %
Reservoir Gas In-Place at 12 bara	42327273	**10.0016**
Retrograde Liquid In-Place at 12 bara	172134	**0.0407**
Gas Injected at 12 bara	380707178	**89.9578**
Totals	423206585	100.00

Figure 8-5 Mol-fraction distribution of UGS gas mixture at 1st cycle

Definition of storage gas mixture

- Check mol-fraction distribution of gas-mixture: 10% original BGM-gas + 90 % GTS gas, based on current Pres of 12 bar, gas-in-place of 1 Bcm and injection volume of 5.8 Bcm cushion and 3.3 Bcm working gas
- The homogeneous fluid was then subjected to a CVD at reservoir temperature at the pressures indicated in the table below.
- At each CVD point, the produced gas phase was flashed through a surface separator at 6.69 bara and 15.56 C to predict the surface yield. These yields represent the theoretical MAXIMUM yield anticipated during the first UGS injection / production cycle.

Calculated Yields (assuming 100% mixing in the reservoir; Psep = 6.69 bara; Tsep = 15.56 C)

Reservoir Pressure Bara	Surface Yield sm^3/STm^3	Surface Yield $STm^3/MMsm^3$
150	360318	2.78
133	406357	2.46
120	449531	2.22
100	529777	1.89
88	586726	1.70
50	766409	1.30
25	744395	1.34
12	543157	1.84

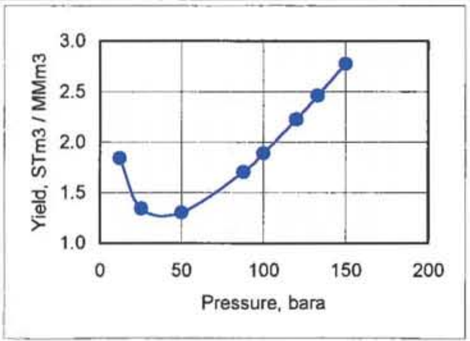

Figure 8-6 Condensate yield (CGR) of BGM UGS given at different initial pressures, e.g. at start of 1st cycle (133 bara), a max. CGR of 2.5 sm3/MMsm3 (0.45 stb/MMscf) is calculated.

Composition storage gas mixture

- 10% BGM gas, 90% HICAL gas
- Gas SG 0.606
- Pdew 256 bar
- Condensate SG 0.881 (29.1 API)
- Total CGR 4.7 sm3/MMsm3

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Figure 8-7 Bergermeer UGS gas composition (left), phase envelope (right).

Assumptions PVTSim

- The fluids (reservoir gas, retrograde liquid and injected gas) mix completely during the storage period between injection and production of the stored gas.
- The original reservoir pressure of 227 bara was at, or above, the gas dewpoint pressure.
- The ALKM-1 atmospheric condensate is representative of the BGM reservoir.
- Separator conditions were not given corresponding to the yields indicated. For this exercise, the separator conditions were calculated based on theoretical equilibrium ratios and composite compositions. As a result, the separator conditions may not accurately represent actual separator conditions.

PVTSim results

- Pdew of storage gas mixture increased from 226 bar (original) to 256 bar due to lower C1-content
- CGR of original BGM-gas, 11 sm3/MMsm3, based on lots of assumptions
- Storage gas-mixture of 2.5 sm3/MMsm3 for first cycle @ 133 bar probably on the high side due to less than 100% mixing
- The CGR for the 1st cycle is considered a maximum as the gas will dry out during subsequent cycles

Remarks

- Many unknowns such as separator conditions of original gas, well test conditions of CGR-test-point, CGR produced in BGM etc, BGM liquid composition
- The remaining retrograde condensate in the reservoir may contribute to surface yields **higher than calculated in this exercise** depending on the location of production and injection wells, but this risk of condensate banking was considered low because UGS-wells will be used both as injector and producer
- Compositional modeling was done in MBAL with compositions calculated with PVTSim to see CGR-development during subsequent UGS cycles, but this stalled due to misallocation of historical liquid production (RF cond.> 100%).