Welltest Analysis of PNA-GT-06-S3

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Summary

- The PNA-GT-06-S3 production welltest started on 08-08-2019 and included two-rate production periods of 2.6 and 1.8 hours and two build-up periods of 1.2 and 0.3 hours. The water-production rates varied between 100 and 350 m^3/hr with a cumulative production of 1416 m^3.
- The maximum drawdown achieved was some 20.2 bar at an offtake of 352 m^3/hr during flow period 2. The average PI of the well is some 17 m3/hr/bar. The post-test reservoir pressure of the producing Delft sandstone derived from the final build-up is 214.2 bar at the top screen (2075 m TVD).
- All pressures and temperatures are measured with the ESP sensors. No accurate deep gauge was used for this welltest. Data available from regional Delft reservoir wells were used to correct the data for the cooling of the water column between ESP and the top reservoir. Noises from the motor, flow turbulence and also severe flow fluctuation affect the accuracy of the interpretation. Nevertheless, The ESP pressures were adjusted to the reservoir condition and the pressure-transient analysis could be interpreted as expected. A reasonable pressure matching was achieved with a reservoir model. The result of this test is consistent with the welltest results of PNA-GT-05-S1.
- The resulting permeability estimate is about 350 mD and total skin is about 8.5. It is also possible to match the data with a combination of a higher permeability (max 450 mD) and a higher skin factor (around 12). This high skin factor is a possible indication of a resistance over the sand exclusion screens, friction in the casing or formation damage due to drilling mud. No rate-dependent skin could be obtained due to fluctuation in the flow rate and a continuous clean-up. This estimated permeability is based on a reservoir net thickness of 163 m and a temperature of 74°C.
- Based on the petrophysical evaluation, the net thickness of the Delft sandstone in this well is estimated to be 193 m, using a net/gross value of 0.78 for 249 m gross thickness. Only a part of the reservoir is screened. The entire screened section of the reservoir (215 m TVD) contributes to flow with an NTG of 0.76, results in a net thickness of 163 m.
- Extrapolation of the temperature recorded by the bottom gauge during both flow periods indicates a final stabilized temperature of 73.2°C of the produced water corresponding to a geothermal gradient of 3.1°C /100m, assuming 15°C surface temperature.
- The shut-in periods were very short, and no reservoir boundary could be interpreted from the build-up data. In general, the following recommendations are proposed for future production-test design:
    - In general, downhole gauges are strongly recommended. In case of an ESP gauge, it is recommended to install the gauge at least 15 m below the ESP to minimize the ESP heat effect. An accurate ESP installation depth is important.
    - The final production-test rate should be long enough (at least for 4-8 hours) and at a **constant rate.** Maintaining a constant rate at the final flow period is important for build-up analysis. The total water production should certainly not exceed the available storage capacity, possibly requiring a lower rate for the final flow period.
    - Water-quality testing should be done during the flow periods (especially by sampling during the latter half of the test). Surface fluid sampling, with an extra choke at surface to increase pressure, should be carried out at the end of the second flow period. This will ensure an undisturbed transient production (of at least 4 hours) before the shut in.
    - The water samples can provide a visual record of the cleaning of the well during the production test.
    - The final build-up period should be long enough (at least 24 hours). A long build-up period will enable us to spot possible flow barriers in the reservoir. The well should remain untouched during this BU period.
    - It is recommended to perform an interference measurement during the test of the second well of the doublet. It is cheap but can give valuable information for the analysis of the future project performance.

Results of Welltests

Table 1- Data for test interpretation- All depths from Ground level (RT was 8.1m above GL)

Data for test interpretation	Value	Dimension
Well name	PNA-GT-06-S3	
Well location: X Coordinates Y Coordinates	 88781,798 448498,242	 RD RD
Aquifer top (Delft Sandstone)	2894 2051	m (MD) m (TVD)
Aquifer base (Delft Sandstone)	3335 2301	m (MD) m (TVD)
Aquifer thickness	250	m (TVD)
Aquifer Net/Gross (NTG)	78	%
Average aquifer porosity	19	%
Formation water salinity (TDS)	100000?	ppm
Average initial reservoir pressure	214.2	bar @ 2075 m TVD
Stabilized temperature of produced water	73.2	ºC
Temperature gradient	3.1	°C/100m
Casing 24“	94	m (TVD)
Casing 13 3/8”	845	m (TVD)
Casing 9 5/8”	1974	m (TVD)
Borehole diameter at aquifer	8 1/2	inch
Top production interval / screen	2938 2075	m (MD) m (TVD)
Base production interval / screen	3317 2291	m (MD) m (TVD)
Screen resistance	n.a.	bar
Pump location	487 487	m (MD) m (TVD)
Shallow gauge location	n.a	m (MD) m (TVD)
Deep wireline gauge location	n.a.	m (MD) m (TVD)

Table 2- measurement sequence during the production test

Welltest sequence		
Step	Final /stabilized Pump frequency (HZ)	Final /stabilized Flow Rate (m^3/hr)
Flow 1	51	312
Flow 2	56	352

Table 3- Welltest interpretation results

Welltest interpretation results		
Skin	7.1	-
kH	57	Dm (darcy-meter)
Assumed H	163	m
k	350	mD
Productivity Index (PI)	17	m^3/hr/bar

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1 Introduction

The doublet is producing in the community of Pijnacker-Nootdorp and in the province of Zuid-Holland and as a part of the Delft concession. The doublet consists of wells PNA -GT-05-S1 (Pijnacker -05, producer) and PNA -GT-06-S3 (Pijnacker -05, injector). This report describes the analysis of the production test in the geothermal well, PNA -GT-06-S3.

Well PNA -GT-06-S3 was drilled and tested in August 2018. It was produced with an ESP pump, installed in a hole on 8 ⅝" tubing to 487 m (bullnose depth), from the Delft sandstone with a net-sand thickness of 163 m covered. The well was production tested from 08/08/2019 10:00 to 13:53 followed by a very short shut-in period. There was no deep down-hole gauge measurement. The pressure and temperature data were recorded at the ESP-hanging depth.

2 Recorded Production-Test Data

2.1 Data Standards

- The used coordinate system is Rijksdriehoeksmeting / Netherlands New"
- Presented parameters are in metric unit
- Pressure data are absolute values

2.2 Overview of Data Supplied

The following data were supplied by the Leon Ammerlaan:

- All drilling documents including EOWR
- Gamma Ray well log
- Rig Survey and Well Schematic
- ESP pressure and temperature data, Clean out data (Flowrate vs time)

2.2.1 Pressure and rate

The well was produced from the Delft sandstones, 2075-2291 mTVS, covered by sand exclusion screens. The total screened net sand thickness is estimated at 163 m, see appendix A.1 for the gamma-ray well log data.

Reservoir fluid was produced with an Electric Submersible pump (ESP). The water production rates frequently varied between 100 and 350 m^3/hr with a cumulative production of 1416 m^3.

An ESP was run on 8 5/8" tubing at 487 mTVD. The pressure and temperatures were recorded at the ESP depth. No deep downhole gauge was installed in the well. Therefore, the pressure data have been affected by the cooling of the water (and therefore, the pressure) inside the well. There are also large noises in the ESP pressures that affect the accuracy of the analysis.

The original recorded pressures and temperature are shown in Figure 1. Extrapolation of the recorded temperature during flow periods indicates a final stabilized temperature in the range of 73 to 74°C, corresponding to a temperature gradient of 3.1°C/100m (with T = gradient × depth + 15).

To analyze the pressure at the reservoir depth, the recorded pressure data need to be corrected for the changing weight of the 1588 m water column between ESP and reservoir. Proper pressure correction is important during the shut-in periods when the well temperature can be dropped significantly. Here the temperature drop is not significant and is over 8°C.

The ESP-pressure recordings were extrapolated to the top screen depth at 2075 mTVD in order to correct for the cooling of the water column within the wellbore, and depth gradient. The extrapolation to downhole pressure was done by means of a function derived from the test data of other Delft reservoir wells.

Equation 1-The extrapolation to downhole pressure

$$\Delta p \text{ (bar)} = C_1 \times L \times \{\rho_w + C_a \times (T_{max} - T_{top}) - C_b \times (T_{max} - T_{top})^2\}$$

Where,

C_1 =0.000098063 if pressure in bar

L is the m TVD difference to the top reservoir

$C_a = 0.4931$ and $C_b = 0.003$
T_{max} is the maximum recorded temperature in °C
T_{top} is the current temperature at the recorded depth

The water density ρ_w was estimated based on the regional data, water salinity, and reservoir temperature and pressure. Water density is estimated to be 1085 kg/m^3, with a salinity of 100 kg/m^3 NaCl equivalent, using the curves presented in Appendix A.3.

Figure 2 shows the adjusted pressure data recorded by the ESP.

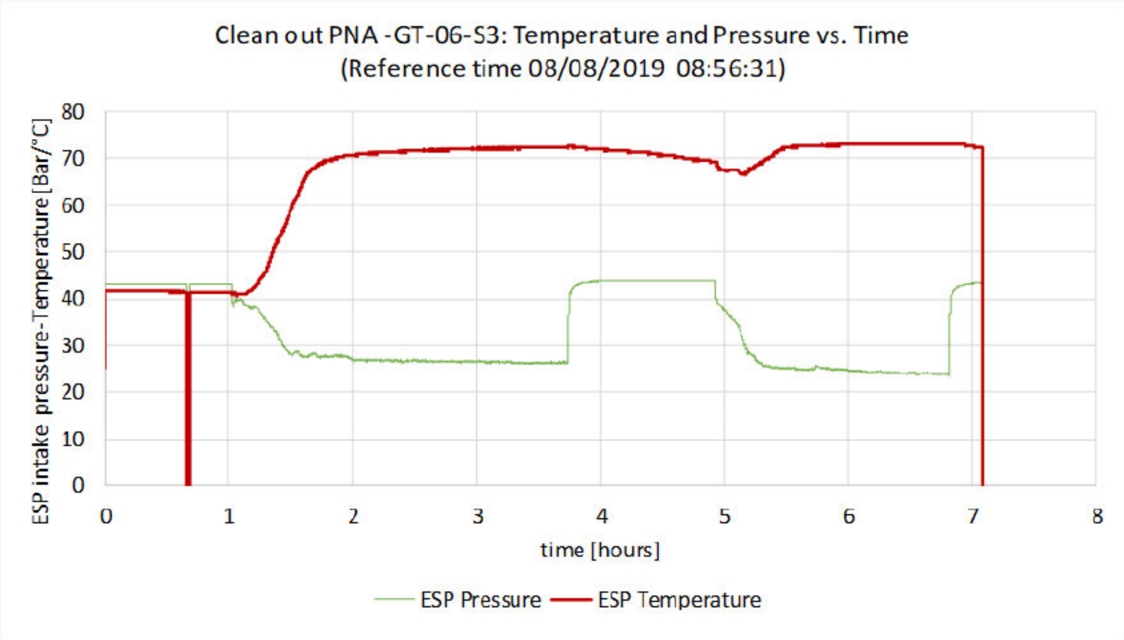


Figure 1 – Original recorded pressure data without adjustment

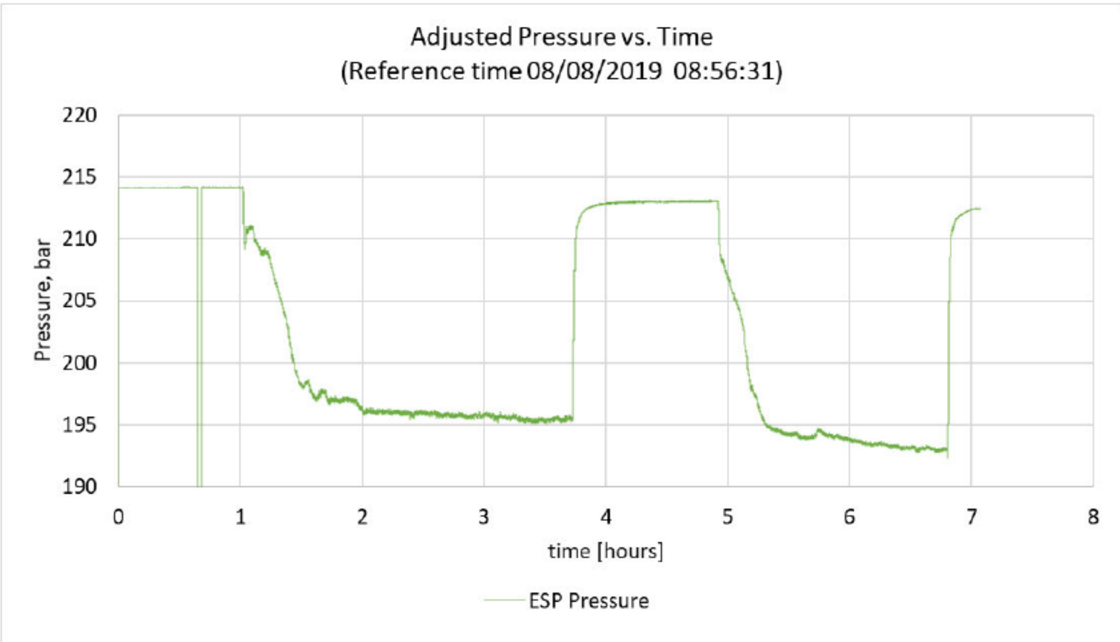


Figure 2 – Adjusted recorded pressure to a datum depth of 2075 mTVD (top screen)

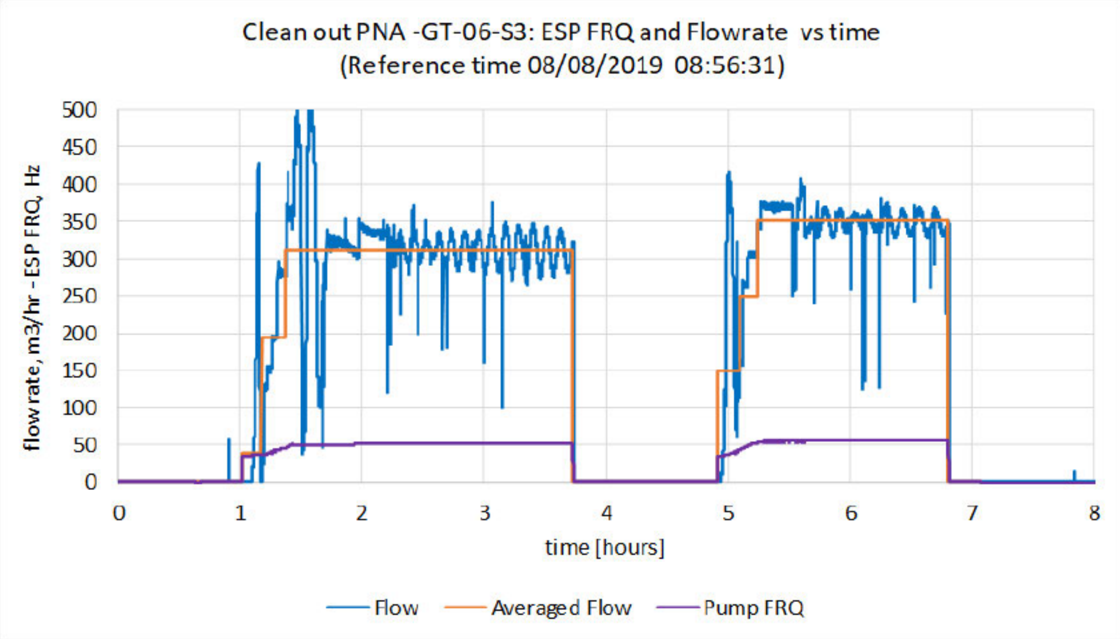


Figure 3 – Recorded flow rates and the averaged flow rate per flow stages

Figure 3 shows the flow rates recorded by the flow meters at surface. For the feasibility of the interpretation, the averaged flow rates per flow stages were also calculated, as summarized in Table 4. The time stamp of the flow periods was synchronized with the responded pressure. The total produced volume of water during the production test was close to 1416 m³. The bottomhole pressure at the end of each flow period and productivity indices are also shown in Table 4. The average PI of the well is some 17 m³/hr/bar.

The maximum drawdown achieved was some 20.2 bar at an offtake of 352 m³/hr during flow period 2. The large dataset points within the gauges were reduced using a combination of time and resolution filters. An arithmetic filter for flow periods, and a logarithmic filter for shut-in periods were used. Figure 4 shows the filtered data used for the analysis.

As can be seen, no stable flow can be achieved during the production test. This affect the accuracy of the interpretation. In general, fluctuations in flow rate before shut-in (at each flow period) should be avoided. All information about the past rate history of a well is "stored" in the pressure profile in the reservoir at the instance of shut-in. During the build-up, the well "sees" the flow rate history in reverse. Stabilizing the well at a constant rate before testing is an important part of a pressure build-up test. Although, in principle, either a drawdown (flow period) or a build-up (shut-in period) will reveal the reservoir characteristics, the build-up response is 'cleaner' than the drawdown data, which can be adversely affected by even a slight instability in the flow rate.

Both shut-in periods are extremely short. It should also be noted that early shut-in data are affected by the wellbore storage effect and cannot represent the reservoir characteristics. A long build-up period (at least 24 hrs, preferably 48 hrs) will enable us to spot possible flow barriers in the reservoir.

Table 4: Summary of production test sequence and average rates.

Start of Event	Start time		Effective duration	Rate		Volume	Bottomhole pressure	Productivity Index
	(Days)	(Hours)	(Hours)	(m³/d)	(m³/hr)	(m³)	(bar)	m³/hr/bar
Flow 1	08-08-2019	10.00	2.6		312	794	195.3	16.6
BU 1	08-08-2019	12.40	1.2	0	0	0	213.1	n.a.
Flow 2	08-08-2019	13:53	1.8		352	622	192.3	17.0
BU 2	08-08-2019	15:45	0.3	0	0	0	212.5	a.a.
				Total volume:		1416		

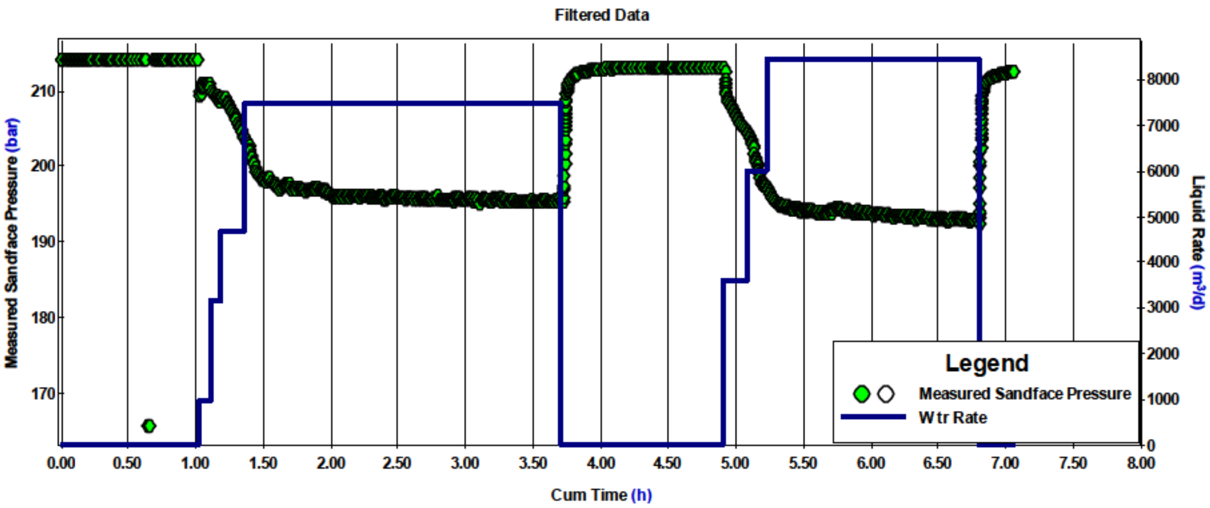


Figure 4: Filtered pressure data (extrapolated to reservoir depth) and flow rates as function of time.

2.3 Overview of Software Utilized

IHS WellTest (Fekete), which is one of the technically advanced pressure-transient analysis software packages has been used for this analysis. It has several simple and complex reservoir models, which allows for efficient analysis of pressure data yielding permeability, wellbore skin, drainage area, hydrocarbon-in-place, and stimulation effectiveness.

3 Analysis Method

The pressure-test analysis is carried out by the match of the most appropriate analytical well/reservoir model response with the total test history. In this way, no approximations must be used, as for the model response the flow equations are solved for the reported flow rates. It should be noted that each pressure point measured in a well depends on the total earlier rate history of that well, both in the real reservoir as in the analytical model. Analysis of only one rate period, ignoring the rate history, can thus give only an approximation of the actual reservoir/well parameters.

The average porosity of the formation has been estimated at 19% based on the regional data. The net thickness is 163 m (using a NTG of 76% over screened interval) based on gamma ray log. The water viscosity and water compressibility have been based on the salinity: $\mu_w = 0.465$ cP and $C_w = 3.5 \times 10^{-7}$ 1/kPa respectively. The porosity and total compressibility ($C_w + C_f$) may have to be adjusted once the interference test with the next well is completed.

The standard analysis results in a split of the observed productivity at reservoir depth into the reservoir potential (kh/μ) and an extra flow resistance, the skin, S. This skin is any deviation of the effective wellbore radius, r_w, and it is formation damage of the reservoir, which may be caused by drilling (mud invasion), resistance over the sand exclusion screens, by deposits of evaporates, etc.

Due to the short duration of the build-up pressure data, information about the presence and distance of flow barriers in the reservoir (faults, channel boundaries or sedimentological changes) cannot be obtained.

As no deviated well model is available, a vertical well model has been used, based on the assumption that the flow in the reservoir at some distance from the well will be horizontal and thus the same for a deviated and a vertical well. This is usually a valid assumption, as the vertical permeability is normally lower than the horizontal permeability in unfractured sandstone. The wellbore radius r_w has been set to 0.108 m based on the hole ID of 12.25" as shown in the well schematic (Appendix A.2). In view of the deviation of the well with an average angle of about 56 degrees through the reservoir, the wellbore radius was adjusted to $r_w \times \sqrt{(1+1/\cos\alpha^2)/2} = 0.156$ m, for the analysis with the vertical well model.

The matched-model response for early times usually deviates from the observed pressures. These early build-up pressures are expected to be influenced by water hammer, the latent motor heat of the ESP motor and possibly by cold water fallback. These temporary effects are hard to model in detail and have no impact on the estimation of reservoir properties.

The model response to the test-rate history, including all flow and shut-in periods (even the pre-test flow periods for which no pressure data are available), is obtained by the principle of super-position. The parameters of the model are varied until the difference between model response and observed well response is minimal.

4 Production-Test Interpretation Results

The adjusted ESP pressures have been matched with a vertical no boundary model. The quality of the data and also test-sequences duration do not allow any boundary detection. Figure 5-9 shows the match of the model, both for pressure and for the derivative of the pressure for both shut-in periods. As can be seen in Figure 5, a reasonable match is achieved for the whole test period (history). The mismatch in the early flow periods is due the flow-rate variation and cleaning process, as an average flow rate was used in the interpretation.

The pressure derivative displays more information than the pressure and is therefore used to draw conclusions about the reservoir geometry and the presence of flow barriers.

The early mismatch in the derivative figure is due to wellbore-storage effect including "water-hammer" effect, gas bubbling upwards, cold water moving downwards and the latent heat of the ESP motor. The late build-up points were usually used to estimate reservoir properties and detect any potential boundary.

In view of the uncertainty in temperature correction, ESP pressure noises and the fact that most rates fluctuated somewhat during a fixed ESP frequency period, only a range of possible permeabilities could be established. For future production tests it is recommended to install downhole gauges in the vicinity of the reservoir to be tested.

The resulting permeability estimate for both build-up and also drawdown is about 350 mD. Total skin is about 8.5. It is also possible to match the data with a combination of a higher permeability (max 450 mD) and a high skin factor (around 12). This shows a resistance over the sand exclusion screens, friction in the casing or formation damage due to drilling mud. Note that the shut-in period is too short, and the derivative is too poor to draw any conclusion about possible flow barrier.

As an alternative model, a reservoir model with the Delft total net thickness and partial penetration with the net screen thickness was also modeled. Almost the same results were obtained. In fact, the test duration was not long enough to see the effect of unperforated intervals.

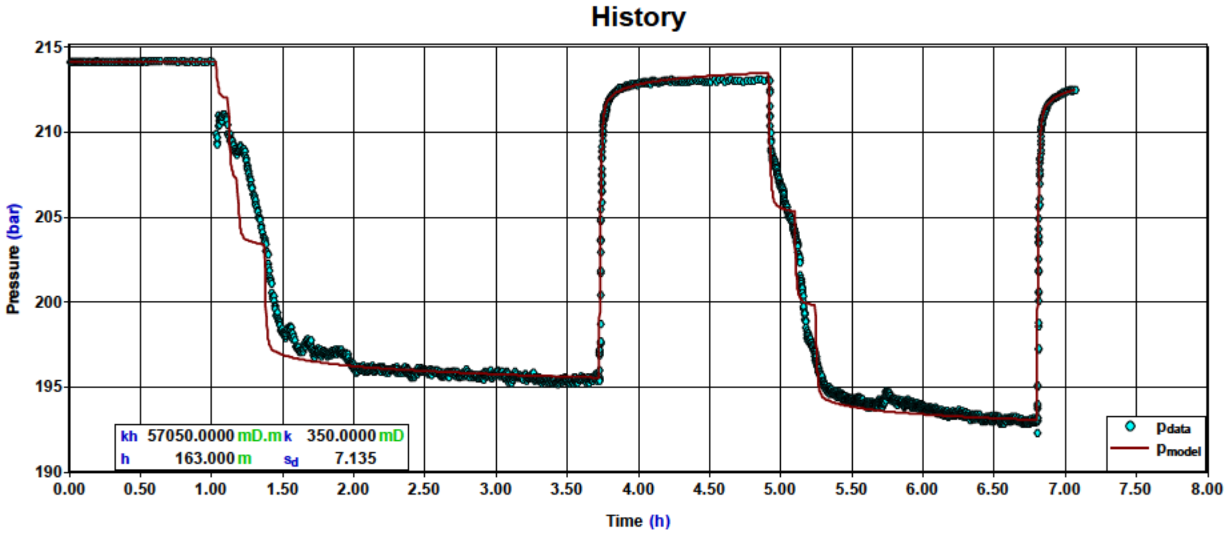


Figure 5 – Pressure match for the entire production well test period

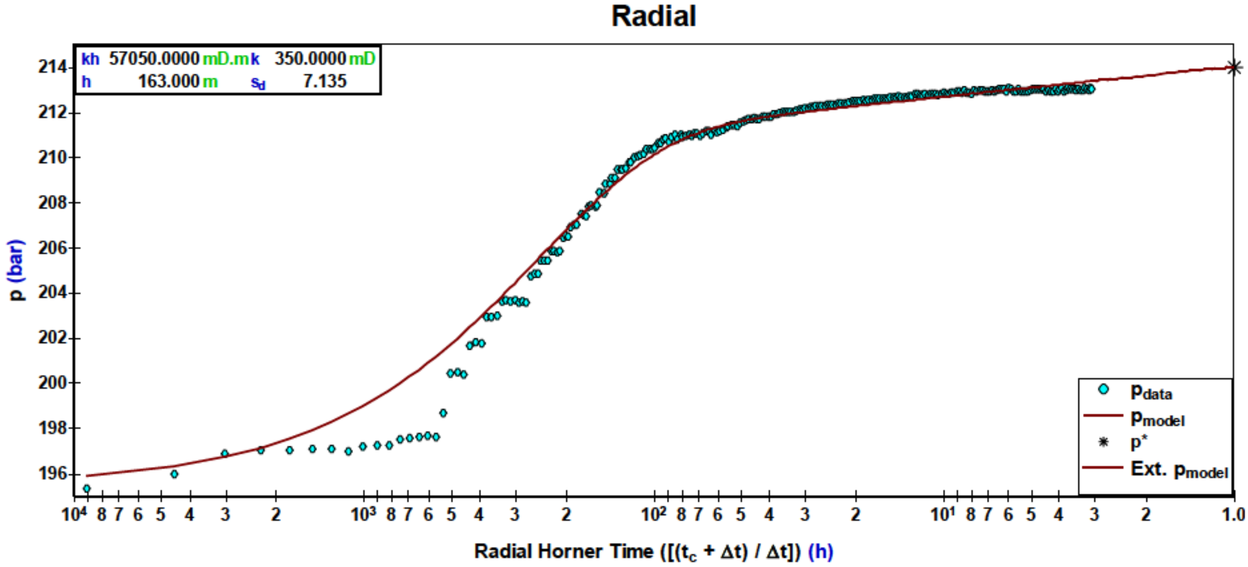


Figure 6 – Horner plot of the first Build-up, comparison of measured and modelled Pressure response vs radial Horner time, showing a good match between the model and the measured data after wellbore storage effect.

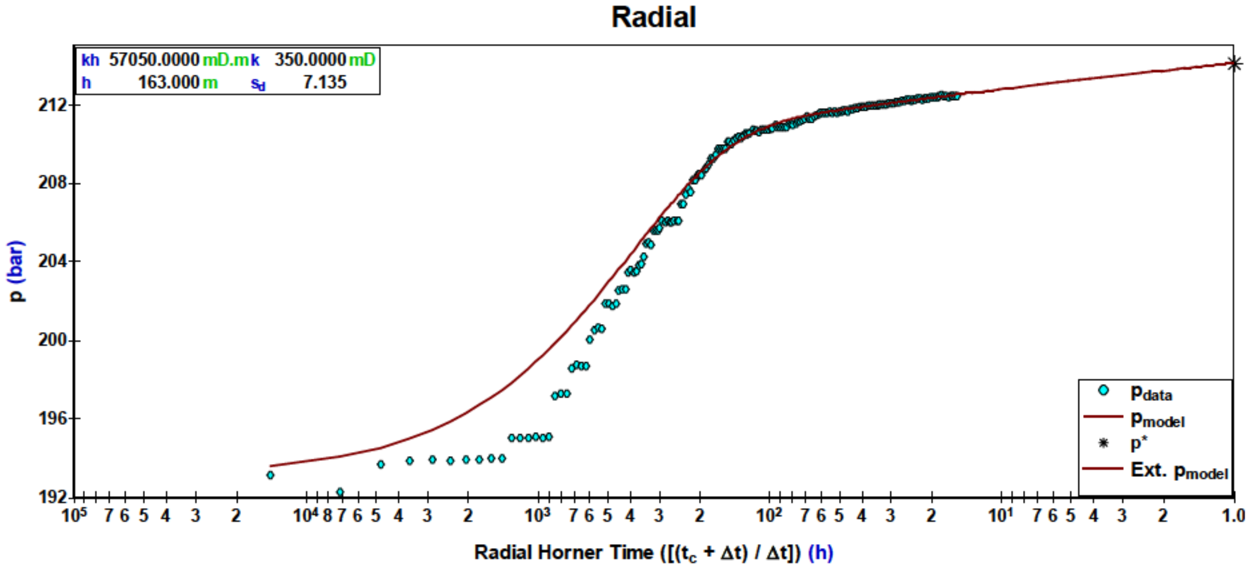


Figure 7 Horner plot of the second Build-up, comparison of measured and modelled Pressure response vs radial Horner time, showing a good match between the model and the measured data after wellbore storage effect.

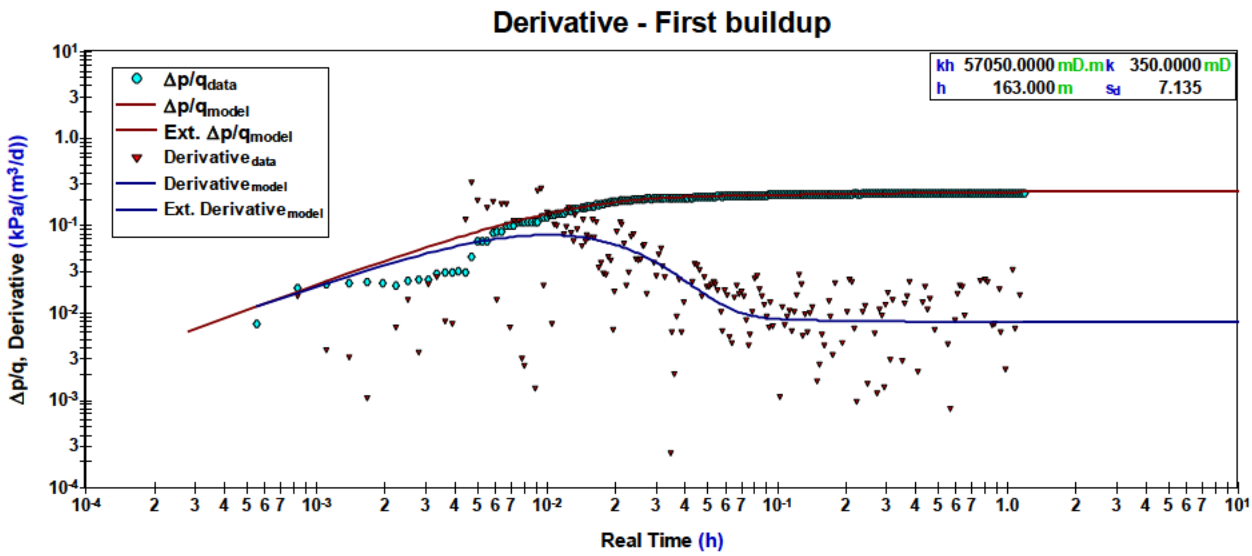


Figure 8 - Comparison of measured and modelled Pressure and pressure derivative response vs radial time for the first build-up, showing a match between the model and the measured data after wellbore storage effect.

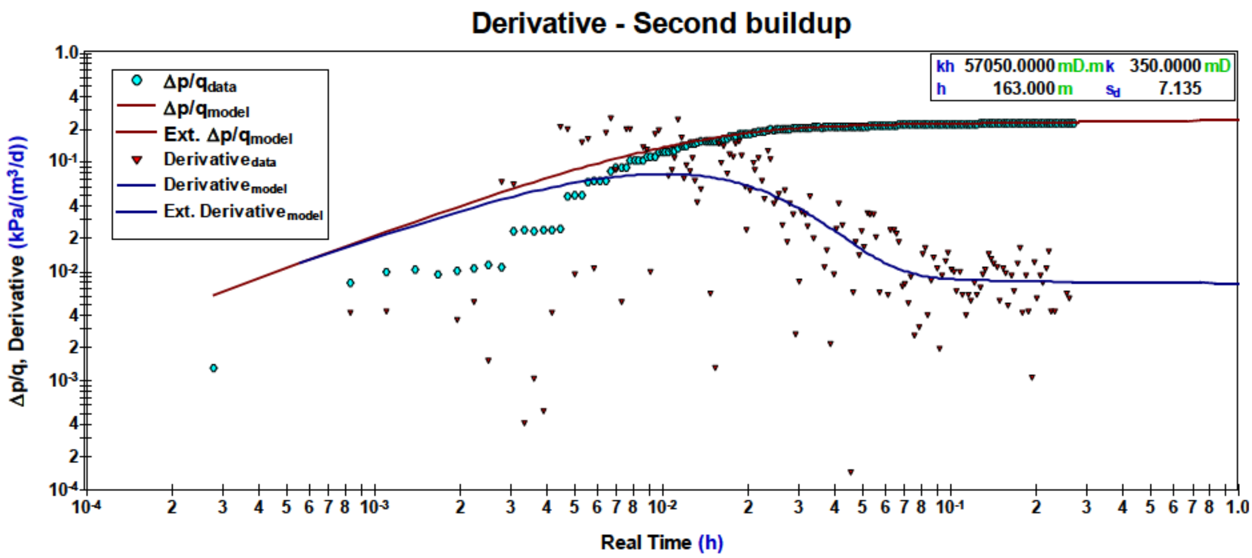


Figure 9 - Comparison of measured and modelled Pressure and pressure derivative response vs radial time for the second build-up, showing a match between the model and the measured data after wellbore storage effect.

5 Conclusions and Recommendations

The PNA-GT-06-S3 production welltest has been successful in establishing an estimate of reservoir permeability of about 350 mD and demonstrates that there is a relatively high skin factor (7) with possible formation damage. Given the uncertainties in required temperature corrections, production rates, ESP noises, etc, the permeability is considered to range between 350 and 450 mD.

The observed total net screened sand thickness is 163 m. The reservoir pressure (214.2 bar) and temperature (73.2 °C) are in line with expectations. The PI of the well is 17 m^3/hr/bar.

The shut-in periods were very short, and no reservoir boundary could be interpreted from the build-up data. In general, the following recommendation are proposed for the future production test design:

- The final production-test rate should be long enough (2-3 times as long as the previous rates) and at a **constant rate.** Maintaining a constant rate at final flow period is important for the build-up analysis.

- Water-quality testing should be done during the flow periods (especially by sampling during the latter half of the test). Surface fluid sampling, with an extra choke at surface to increase pressure, should be carried out at the end of the second flow period. This will ensure an undisturbed transient production (of at least 4 hours) before the shut in.

- The water samples can supply a visual record of the cleaning of the well during the production test.

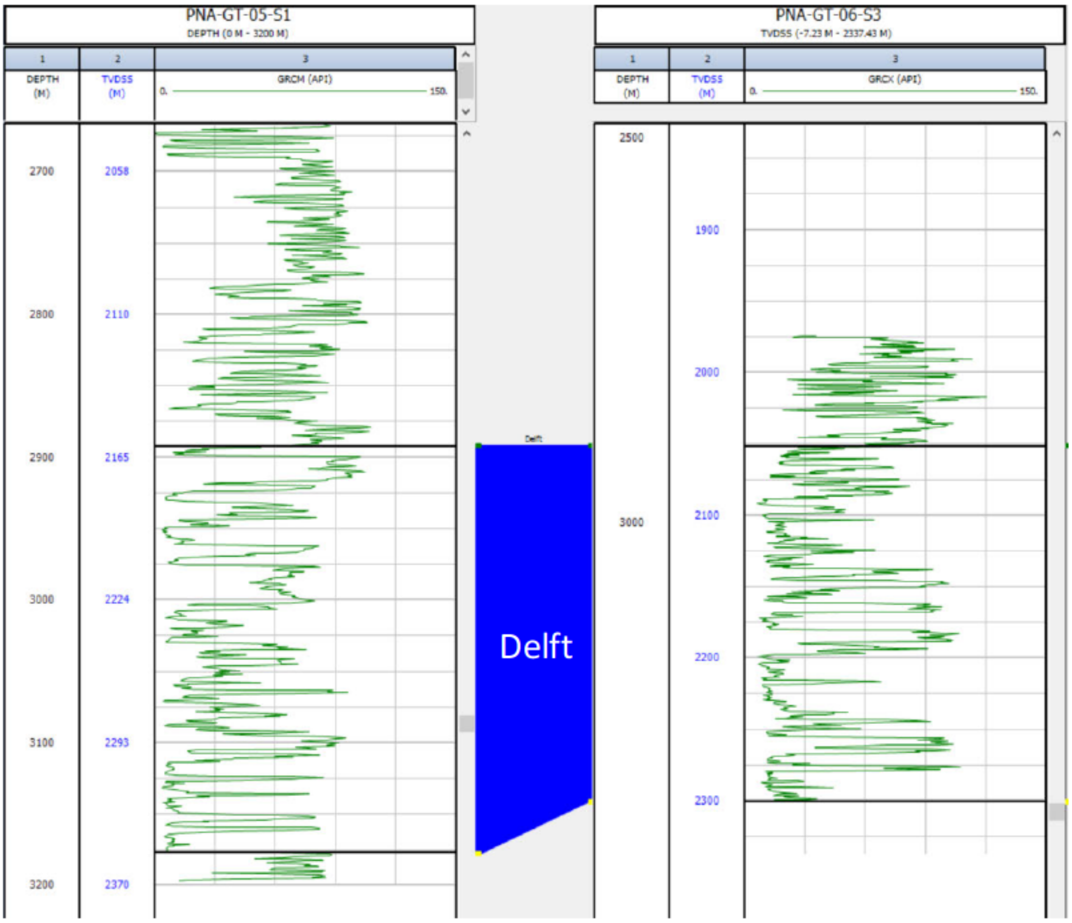
- The final build-up period should be as long as possible. A long build-up period will enable us to spot possible flow barriers in the reservoir.

- In general, downhole gauges are strongly recommended. In a case of an ESP gauge, it is recommended to install the gauge at least 15m below the ESP to minimize the ESP heat effect. An exact ESP installation depth is important.

Appendices

A.1 Net-to-Gross Estimation

N/G whole reservoir



Reservoir averages Delft:

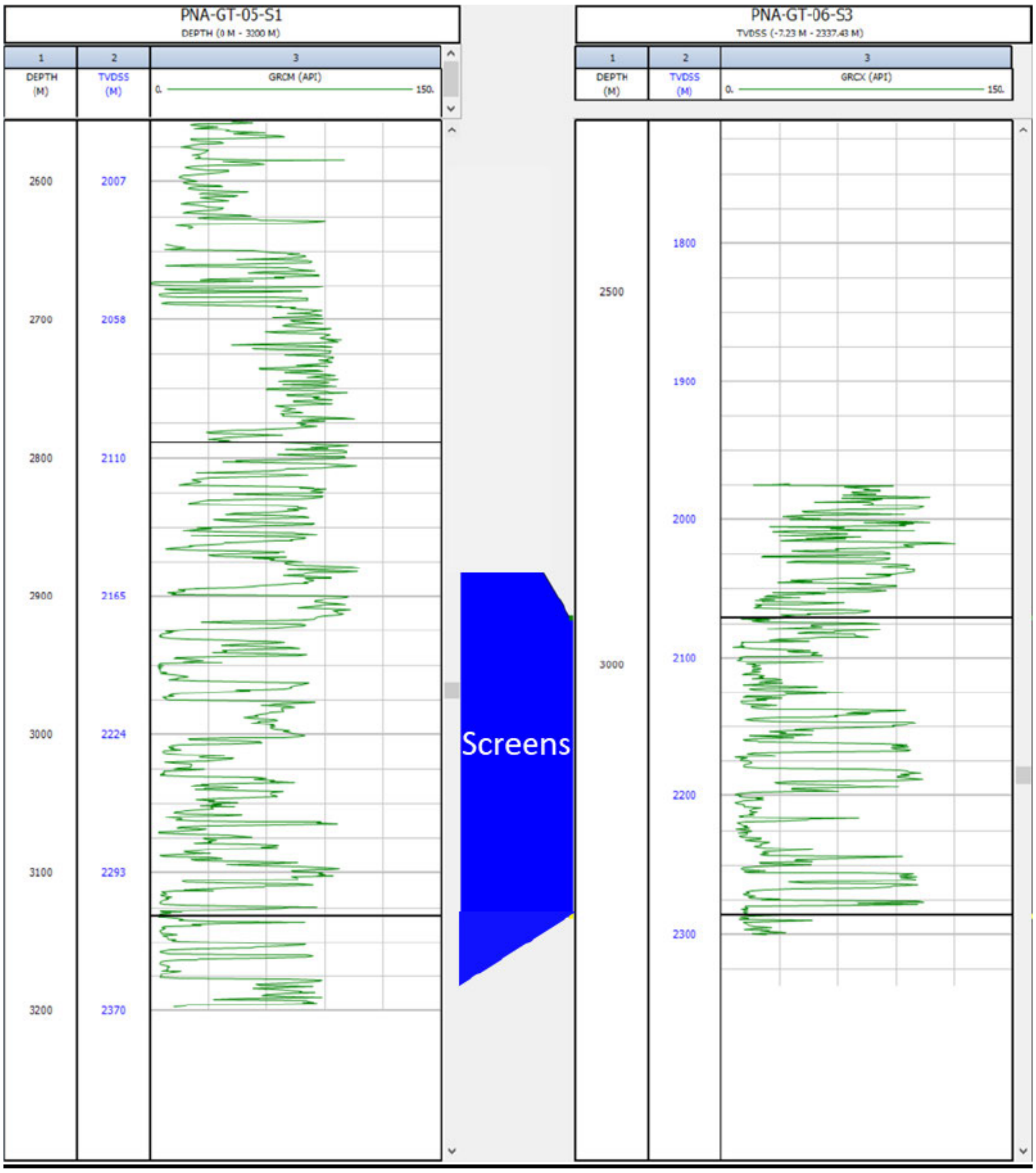
PNA-GT-05-S1:

- Gross: 285 m MD / 191 m TVD
- Net: 179 m MD / 123 m TVD
- N/G: 0.64

PNA-GT-06-S3

- Gross: 438 m MD / 249 m TVD
- Net: 340 m MD / 193 m TVD
- N/G: 0.78

N/G Screens



Reservoir averages interval with screens:

PNA-GT-05-S1:

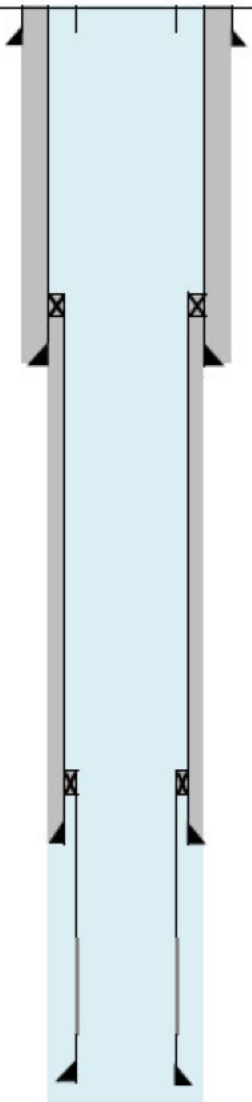
- Gross: 296 m MD / 201 m TVD
- Net: 186 m MD / 126 m TVD
- N/G: 0.63

PNA-GT-06-S3

- Gross: 379 m MD / 215 m TVD
- Net: 287 m MD / 163 m TVD

- N/G: 0.76

A.2 Completion Diagram



Item Description All depths from Ground level (RT was 8,1m above GL)	Wellhead + X-mass tree **PNA- GT- 06- S3**	Depth m tvd	Depth m ah	Hole ID in	Pipe OD in	Collar OD in (nom)	Pipe ID in	Pipe ID in (drift)
9 5/8" 53,5# L80 VAM TOP tubing		87	87	n/a	9 5/8	10,311	8,535	8,500
24" Conductor		94	94	Driven	24,000	24,000	23,000	23,000
16" Hole								
13 3/8" x 9 5/8" Liner Hanger		845	853	Top of liner				
13 3/8", L-80, 72#, VAM TOP Production		906	919	16,000	13,375	14,236	12,347	12,250
12-1/4" Hole								
		1962	2730	Top of liner				
				Window in 9 5/8" casing				
9 5/8" 53.5#, L-80 Production liner, SD, VAM		1974	2752	12 1/4	9 5/8	10,311	8,535	8,500
7" 29#, L-80 Blank joints, VAMTOP		2075	2938	8,500	7	7,644	6,180	6,059
Crossover 6 5/8" to 7"		2075	2938	8,500	7 x 6		5,920	
		2075	2938	*Top 6 5/8" slotted joints*				
8-1/2" Hole								
		2291	3317	*Bottom 6 5/8" slotted joints*				
6-5/8" 24#, L-80 Slotted pipe + blanks, VAGT		2306	3343	8,500	6,625	7,191	5,920	5,795
	TD of well	2310	3349					

A.3 Water-Density-Salinity Chart

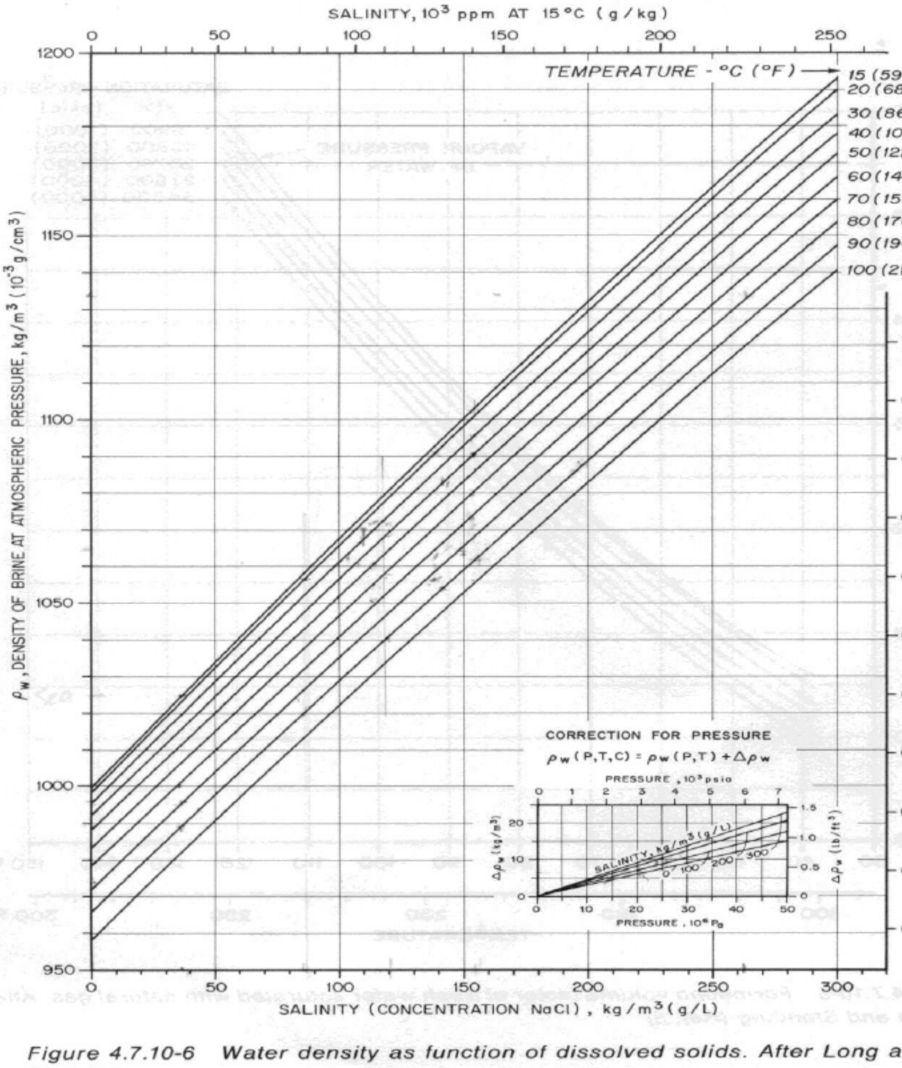


Figure 4.7.10-6 Water density as function of dissolved solids. After Long and Chierici (Ref. 35)