STEP RATE/INJECTIVITY TEST DOCUMENTATION

Windy Hill Water Company
P.O. Box 18283
Denver, Colorado 80218

September 30, 2015

Re: Maximum Injection Pressure Request
Windy Hill #3-17D, API: 05-087-008145
NESE Section 17-T3N-R55W
Morgan County, Colorado

Mr. Stewart Ellsworth
Engineering Manager
Colorado Oil & Gas Conservation Commission
1120 Lincoln Street, Suite #801
Denver, Colorado 80202

Please find the analysis of injection testing in the above referenced well. The analysis in the Power Point has been prepared by Geostock US (Houston) in September 2015. Based on the analysis provided, we request assignment of a maximum wellhead operating pressure of 2700 psia.

During the course of injection testing, even when pumping at relatively high rates, we were unable to establish a traditional break-over in the curve to establish the fracture gradient. This is due to the under pressured nature of the reservoir at this location, tested at 0.228 psi/ft

As noted in the analysis, the surface pressure is estimated as 2700 psia using a 0.6 psi/ft fracture gradient. This assumes a skin factor of 20 and 5-1/2" tubing.

We are available to meet to discuss this in greater detail as your schedule will allow.

Respectfully Submitted

9/30

F. Lee Robinson
Vice President

GEOSTOCK ENTREPOSE

Windy Hill Field

WINDY HILL WELL 3-17D WATER INJECTION PERFORMANCE

M J Rickard

Introduction

Windy Hill Gas Storage LLC (Windy Hill) has commissioned Geostock US LLC (Geostock) to estimate the water injection performance of the Windy Hill 3-17D well (API 05-087-08145), Morgan County, Colorado.

Windy Hill is in the process of converting the well to a Class II E & P Disposal well under Colorado OGCC Rules.

No reliable Step Rate Injection Pressure test data is available. A maximum surface injection pressure is estimated from known and measured parameters assuming a default fracture gradient of 0.60 psi/ft (Exhibit 1).

Conclusions

For well Windy Hill 3-17D, using the recognized and well established reservoir engineering technique of nodal systems analysis the following conclusions can be drawn:

- At an assumed fracture gradient of 0.60 psi/ft the maximum WHP is estimated to be 2700 psia (Figures 4 and 7)
- At same conditions the BHP (Pwf) is estimated to be 3100 psia (Figures 5 and 7).
- At same conditions the maximum injection rate is estimated to be 75,000 BWPD (Figures 6 and 7).
- If the well completion is kept perfectly undamaged (s = 0), at a WHP of 0 psig, an injection rate of 44,700 BWPD is achievable (Table 1, Case 1).

Analysis Methodology

The water injection performance of the Windy Hill 3-17D well is estimated using the well established nodal systems analysis technique (Exhibit 2 from Brown, 1984).

In reservoir engineering nodal analysis refers to a technique where a flow relationship into a point (node) in a flow system is solved simultaneously with a flow relationship out of the node to determine the flow rate and pressure at the node. In this case the node is at the bottom of the well opposite the perforations.

For a given fluid the inflow relationship is a function of the wellhead pressure, the tubing size, the tubing roughness (or other parameters required for the tubing correlation used) and the well depth etc.

Analysis Methodology

For a given fluid the outflow relationship is a function of the wellbore diameter, the skin factor (amount of near wellbore damage causing pressure losses at the sand face), the permeability-thickness, reservoir temperature, the reservoir heterogeneity, the reservoir size and proximity of the well to the reservoir boundaries etc.

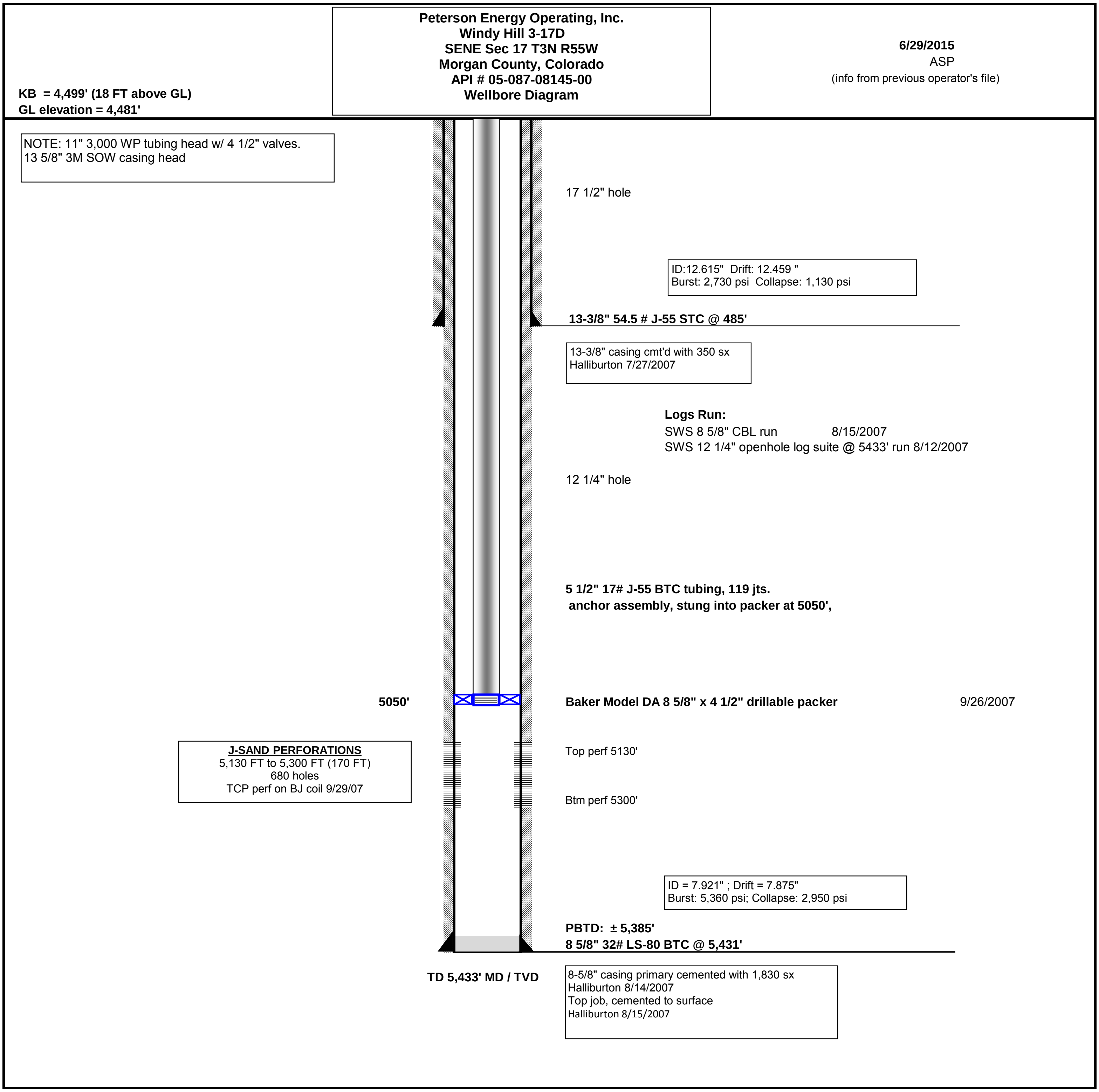
The inflow and outflow relationships are generally plotted on a pressure versus flow rate chart and the intersection point (sometimes called the solution point) gives the estimated pressure and flow rate for the given reservoir and well completion conditions (Figure 3 for example).

Key Inflow Parameters and Assumptions

- Single phase liquid model.
- The wellhead injection pressure will vary and is one of the variables of the analysis.
- Most of the inflow parameters are related to the well completion configuration (Figure 1). For example:

  - Tubing size of 5-1/2 in, 17 lb/ft.
  - Mid perforation depth of 5215’

FIGURE 1

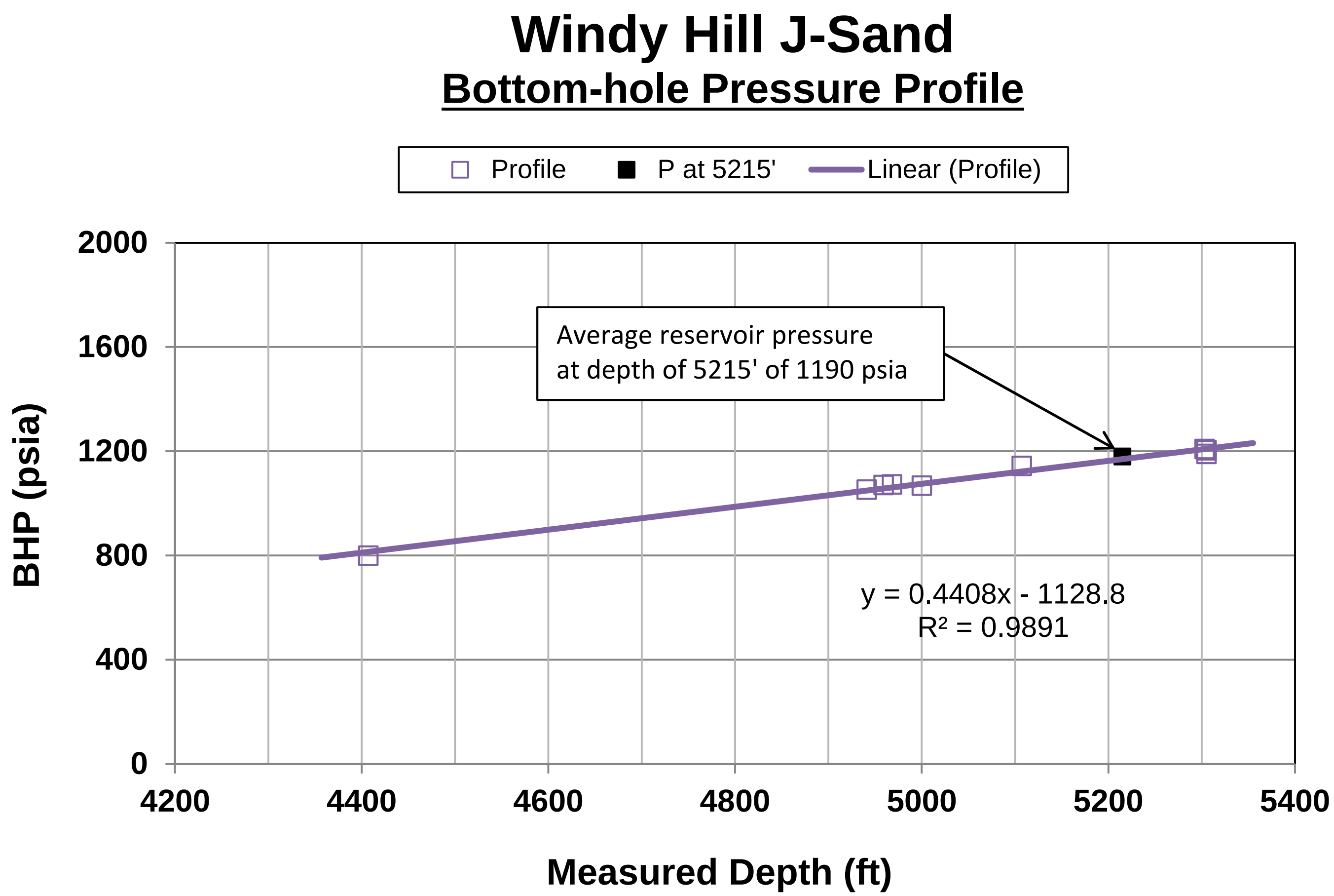

Peterson Energy Operating, Inc.
Windy Hill 3-17D
SENE Sec 17 T3N R55W
Morgan County, Colorado
API # 05-087-08145-00
Wellbore Diagram
KB = 4,499' (18 FT above GL)
GL elevation = 4,481'
6/29/2015
ASP
(info from previous operator's file)
NOTE: 11" 3,000 WP tubing head w/ 4 1/2" valves.
13 5/8" 3M SOW casing head
17 1/2" hole
ID:12.615" Drift: 12.459 "
Burst: 2,730 psi Collapse: 1,130 psi
13-3/8" 54.5 # J-55 STC @ 485'
13-3/8" casing cmt'd with 350 sx
Halliburton 7/27/2007
Logs Run:
SWS 8 5/8" CBL run 8/15/2007
SWS 12 1/4" openhole log suite @ 5433' run 8/12/2007
12 1/4" hole
5 1/2" 17# J-55 BTC tubing, 119 jts.
anchor assembly, stung into packer at 5050',
5050'
Baker Model DA 8 5/8" x 4 1/2" drillable packer
9/26/2007
J-SAND PERFORATIONS
5,130 FT to 5,300 FT (170 FT)
680 holes
TCP perf on BJ coil 9/29/07
Top perf 5130'
Btm perf 5300'
ID = 7.921" ; Drift = 7.875"
Burst: 5,360 psi; Collapse: 2,950 psi
PBTD: ± 5,385'
8 5/8" 32# LS-80 BTC @ 5,431'
TD 5,433' MD / TVD
8-5/8" casing primary cemented with 1,830 sx
Halliburton 8/14/2007
Top job, cemented to surface
Halliburton 8/15/2007

Key Outflow Parameters and Assumptions

- Darcy flow model.
- The reservoir pressure of the J-sand aquifer is 1190 psia at a depth of 5215’ based on multiple surveys (Figure 2). The pressure gradient is subnormal at approximately 0.228 psi/ft.
- The J-sand aquifer is large and outcrops to the east where discharge can occur and the reservoir is essentially infinite acting (Belitz & Bredehoeft, 1988).
- The permeability-thickness is estimated to be 115,000 md-ft based on a well test conducted in December 2007 (Exhibit 3).
- The current wellbore damage (skin factor) is not known and sensitivity of the pressures to this variable is included in the analysis.

Figure 2: J-Sand Reservoir Pressure Profile

GEOSTOCK ENTREPOSE



Nodal Analysis Results

- The nodal analysis results, presented as injection rate versus Pwf, are given in Table 1 and Figure 3 (range of results sometimes called the operating envelope).
- These results are plotted as follows:

  - WHP versus Injection Rate (Figure 4)

  - BHP (Pwf) versus Injection Rate (Figure 5)

  - BHP Gradient versus Injection Rate (Figure 6)
- At the reservoir and well completion conditions given, these plots are used to estimate the flow rate and pressures at a default fracture gradient of 0.6 psi/ft.

Nodal Analysis Results

- **Figure 7 shows the final operating conditions for the well at a BHP based on a default fracture gradient of 0.60 psi/ft.**

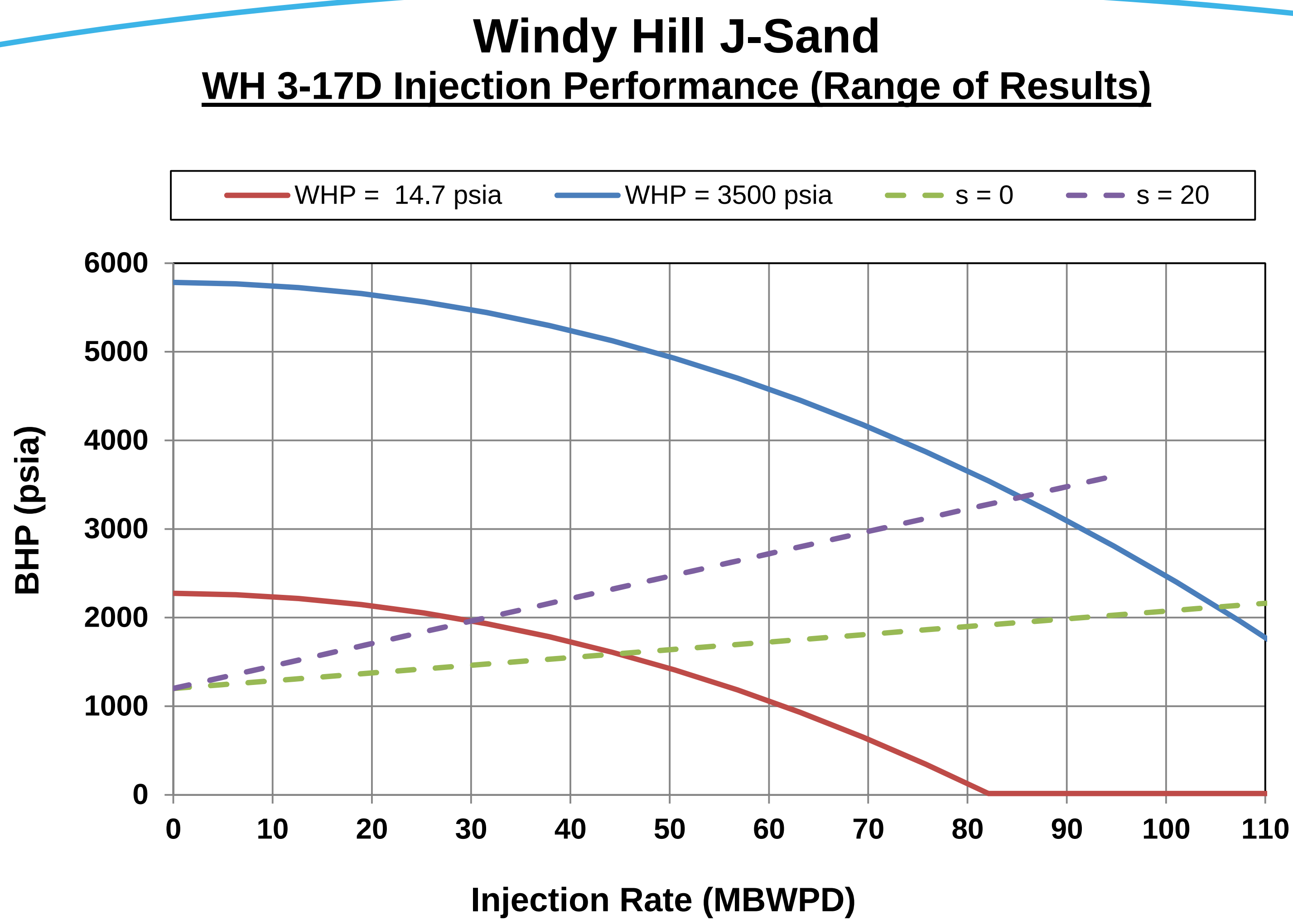
Table 1: Analysis Results

Windy Hill J-Sand

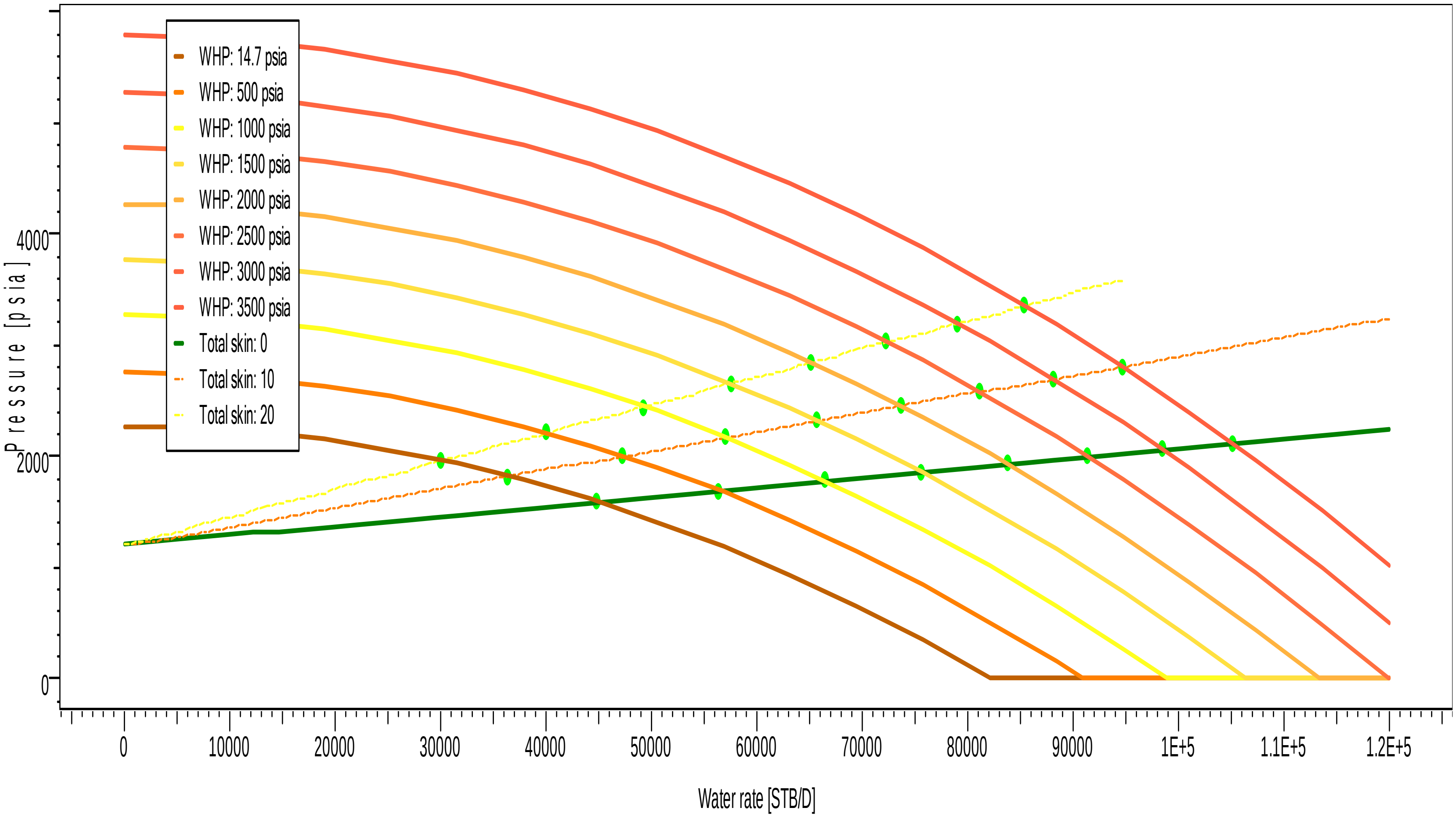
Windy Hill 3-17D Injection Performance Estimates

Case	WH Pressure (psia)	BH Pressure (psia)	Pressure Gadient (psi/ft)	Skin Factor (#)	Injection Flow Rate (BWPD)
1	14.7	1592	0.31	0.0	44782
2	500	1692	0.32	0.0	56312
3	1000	1781	0.34	0.0	66448
4	1500	1860	0.36	0.0	75532
5	2000	1932	0.37	0.0	83729
6	2500	1998	0.38	0.0	91328
7	3000	2060	0.40	0.0	98444
8	3500	2119	0.41	0.0	105140
9	14.7	1820	0.35	10.0	36342
10	500	2005	0.38	10.0	47199
11	1000	2172	0.42	10.0	57008
12	1500	2320	0.44	10.0	65696
13	2000	2456	0.47	10.0	73686
14	2500	2582	0.50	10.0	81116
15	3000	2700	0.52	10.0	88079
16	3500	2812	0.54	10.0	94660
17	14.7	1961	0.38	20.0	30011
18	500	2215	0.42	20.0	40016
19	1000	2447	0.47	20.0	49184
20	1500	2657	0.51	20.0	57502
21	2000	2850	0.55	20.0	65134
22	2500	3030	0.58	20.0	72266
23	3000	3200	0.61	20.0	78984
24	3500	3360	0.64	20.0	85356

Figure 3: Results Range (Operating Envelope)



Nodal Analysis Plot from Software (Basis of Figure 3)



Amethyste, Kappa Engineering, 2015

Figure 4: WHP versus Injection Rate

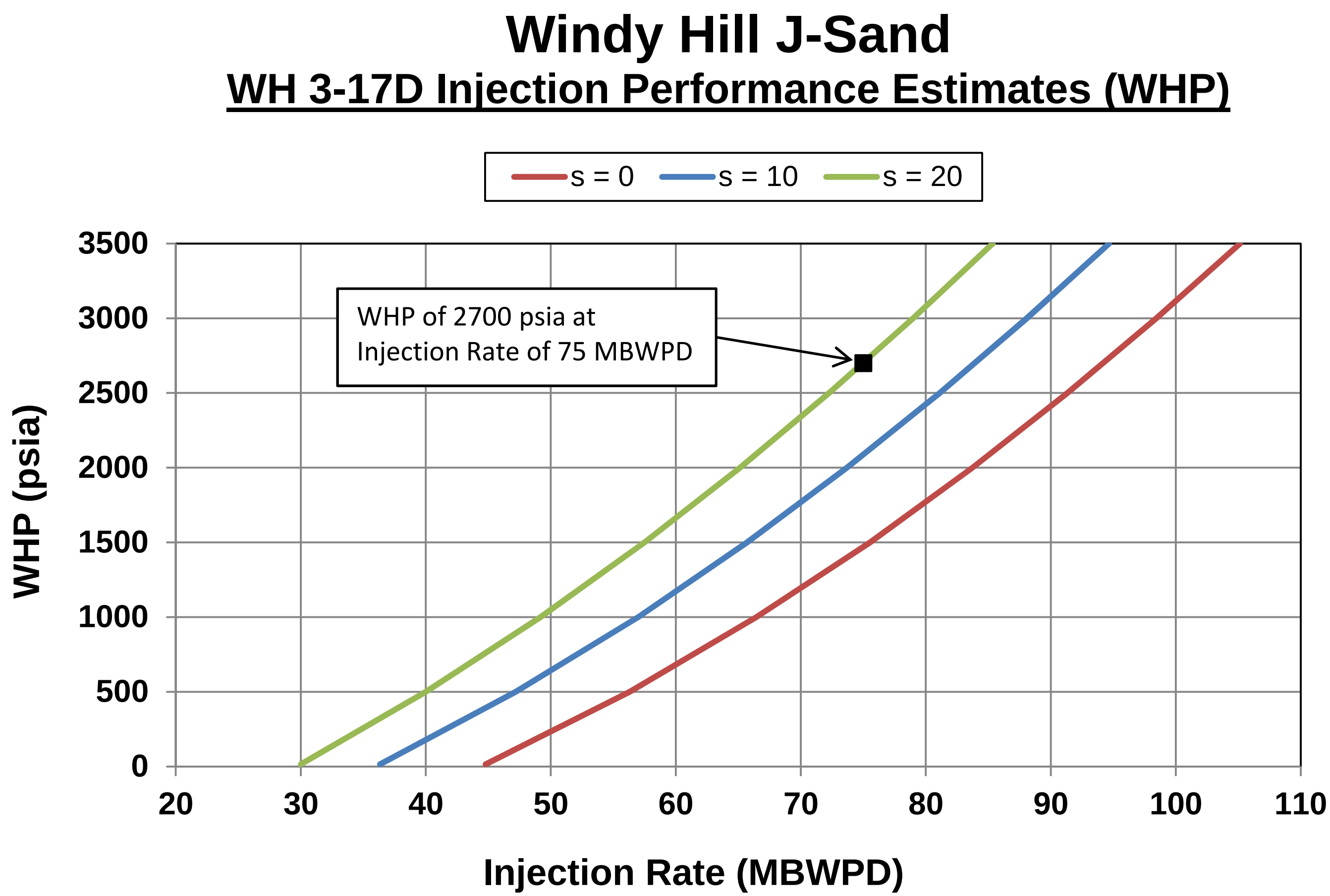


Figure 5: BHP versus Injection Rate

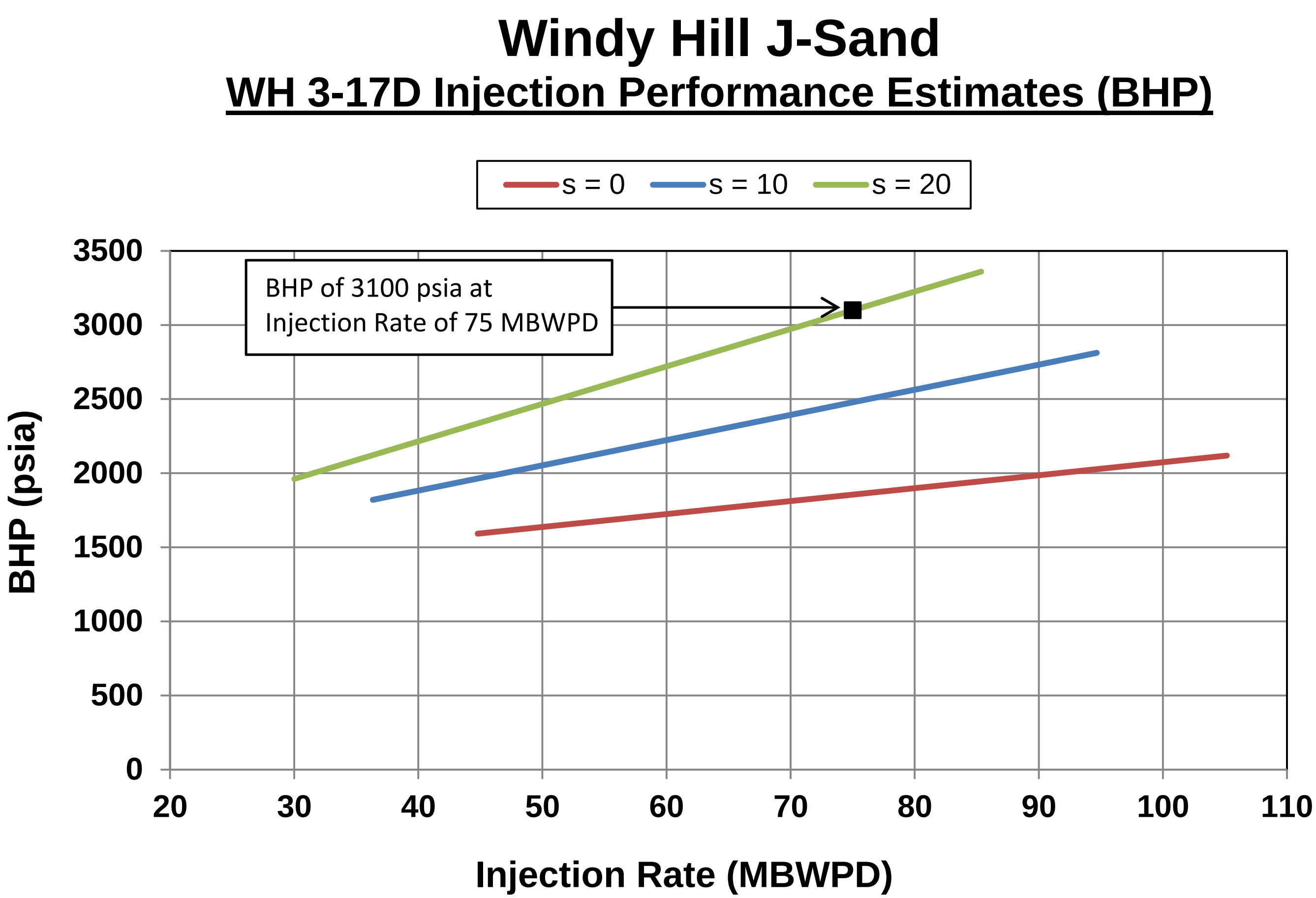
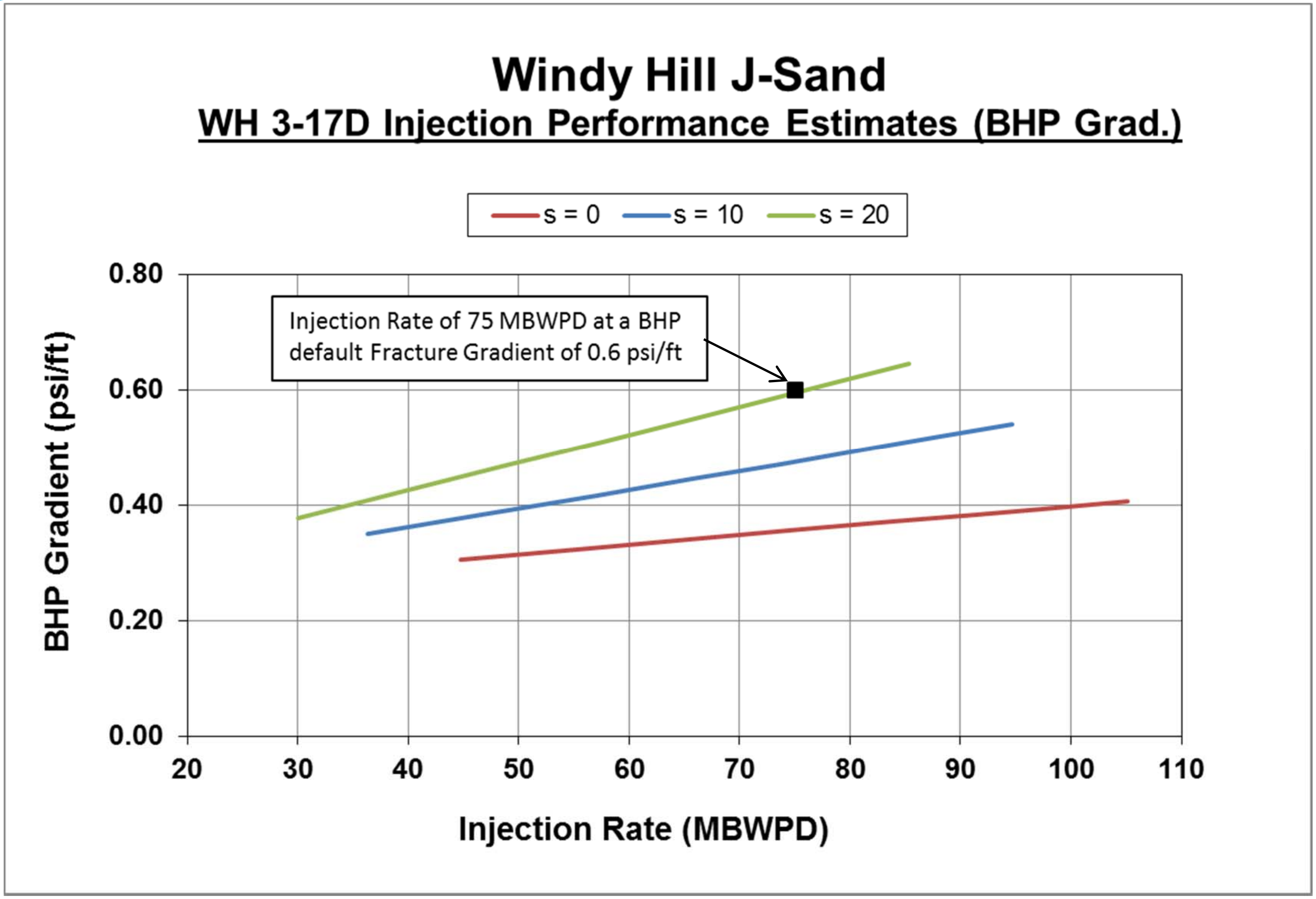


Figure 6: BHP Gradient versus Injection Rate



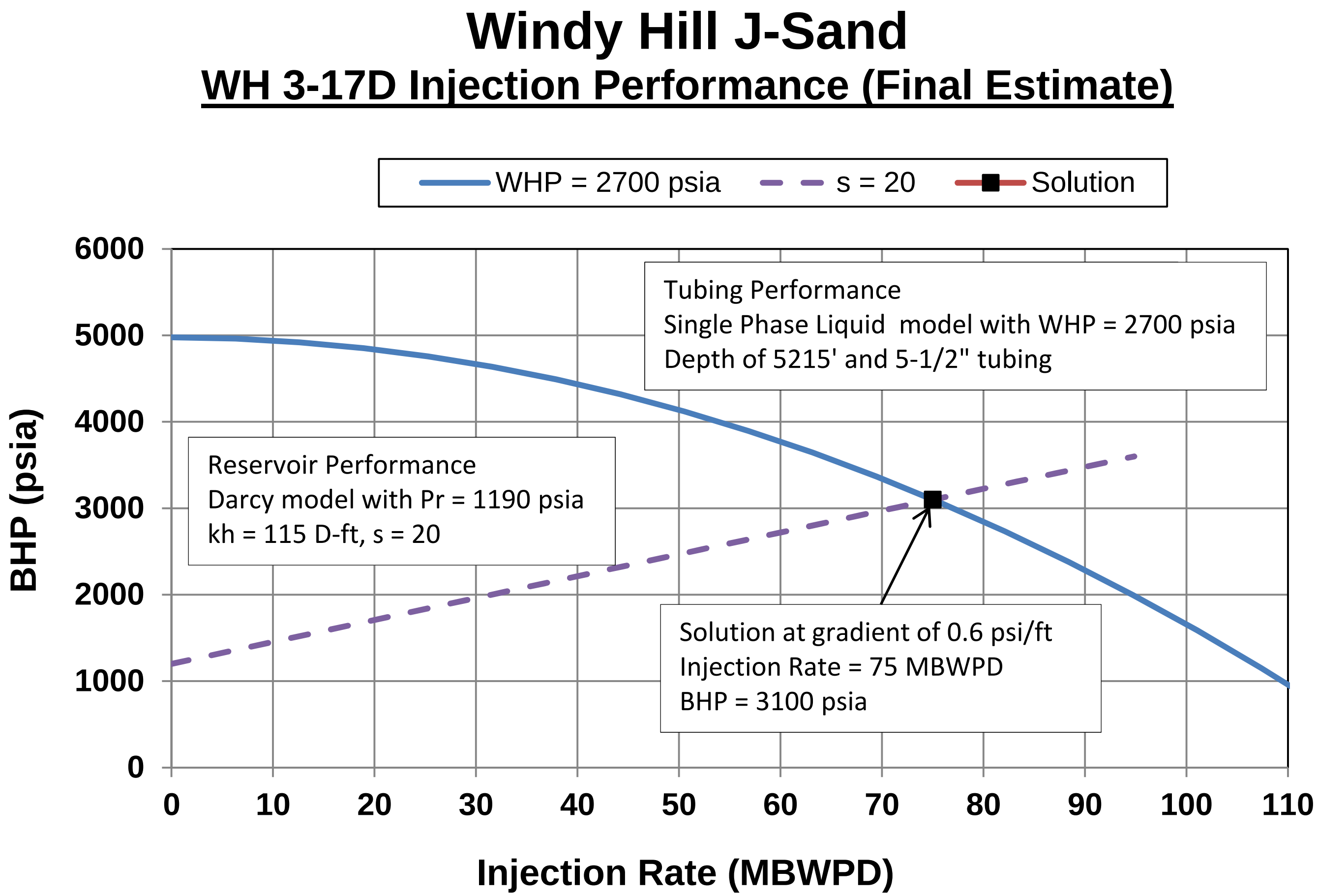
Maximum Injection Rate and Pressure Estimates

- At the time of pressure testing the well was found to be badly damaged with skin factors in the range of 120 – 140 (Exhibit 3). The well will likely require clean-up or reperforating prior to commencing water injection.
- It is understood that during water disposal the water will be filtered to 10 microns. This will plug some of the smaller pore-throats and cause some formation damage assumed to stabilize at a skin factor (s) of 20.
- From Figure 6 at an assumed fracture gradient of 0.60 psi/ft and s = 20 the maximum injection rate is estimated to be 75,000 BWPD.

Maximum Injection Rate and Pressure Estimates

- From Figure 5 at an injection rate of 75,000 BWPD and s = 20 the maximum BHP (Pwf) is estimated to be 3100 psia. (Cross-check: 3100 psia at depth of 5215' gives a pressure gradient of 0.594 psi/ft)
- From Figure 4 at an injection rate of 75,000 BWPD and s = 20 the maximum WHP is estimated to be 2700 psia.
- The analysis was then rerun with all the same assumptions at the specific WHP of 2700 psia to cross-check the results. Figure 7 shows an annotated plot of the operating conditions at the default fracture gradient of approximately 0.6 psi/ft.

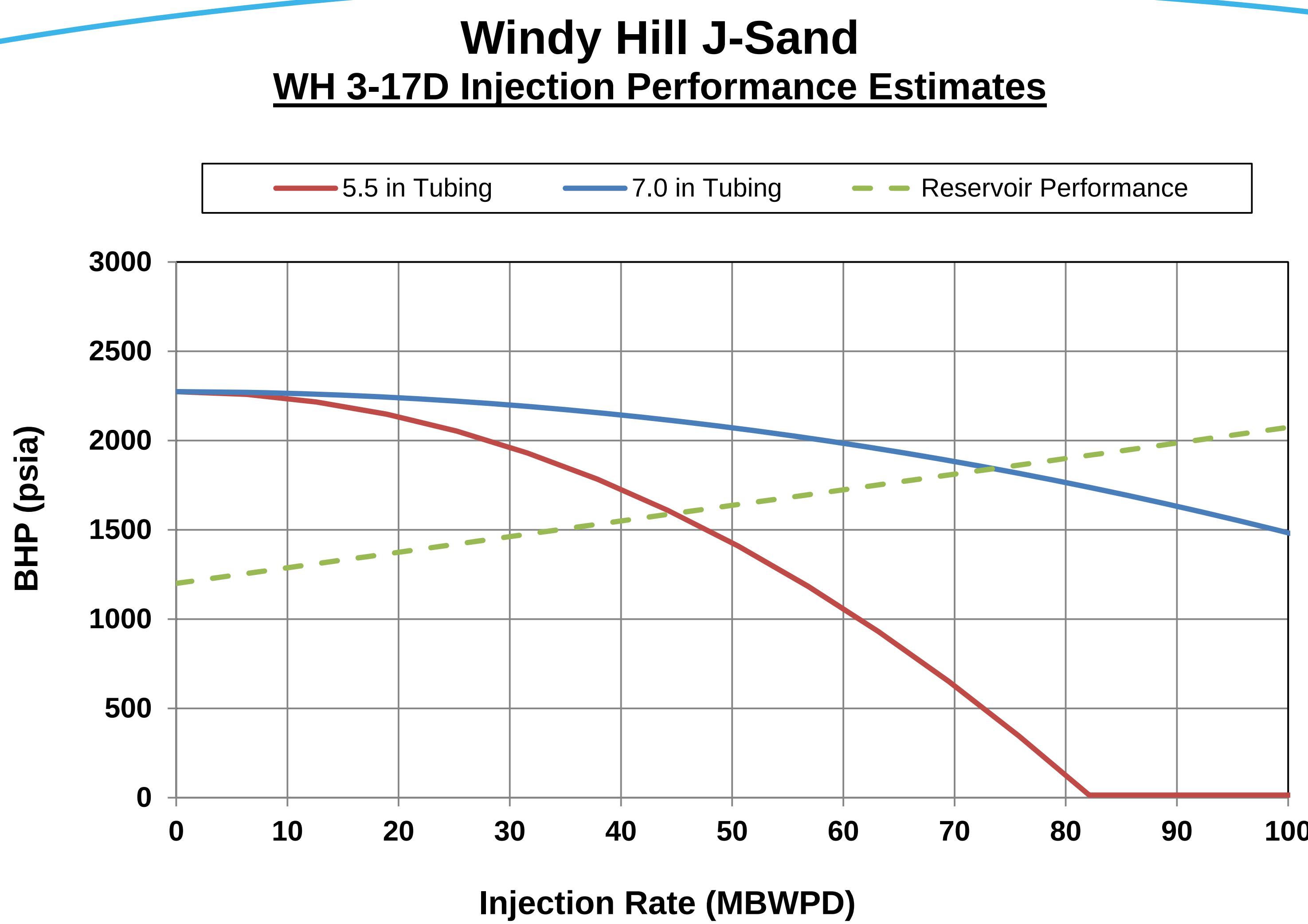
Figure 7: Final Operating Conditions at Default Fracture Grad. of 0.6 psi/ft



Sensitivity to Tubing Size

- Figure 3 shows that for the tubing, Pwf declines markedly as injection rate increases and this is due to the frictional pressure losses. These would be significantly reduced with a larger tubing size and Figure 8 shows the impact of 7 in tubing rather than the currently installed 5-1/2 in tubing.
- Under these conditions it can be seen that injection rates improve for the same WHP.

Figure 8: Sensitivity to Tubing Size



COLORADO
Oil & Gas Conservation Commission
Department of Natural Resources

ENGINEERING UNIT
CLASS II UNDERGROUND INJECTION CONTROL WELLS

COGCC permits and regulates Class II Underground Injection Control ("UIC") wells. Class II wells are used specifically to inject oil and gas exploration and production waste for disposal, and for enhanced oil recovery through injection of water, gas, or other substances.

The COGCC Class II UIC permit process involves the review and approval of:

- Well construction;
- Isolation of ground water aquifers;
- Maximum injection pressure;
- Maximum injection volume;
- Injection zone water quality; and
- Potential for seismicity.

Well Construction and Isolation

Injection wells must utilize a well construction method of cemented surface casing and production casing, which isolates and prevents fluid flow between injection zones and Underground Sources of Drinking Water ("USDWs"). To verify this isolation, the COGCC reviews all relevant information, including:

- Hydrogeologic studies;
- Colorado Division of Water Resources water well information; and
- COGCC's geophysical well log database.

This information is used in conjunction with specific formation and well construction data submitted by the injection well operator, including resistivity and cement bond geophysical logs, to ensure that:

- The surface casing is set below all fresh water zones used as a water supply; and
- The placement and quality of production casing cement allows for adequate isolation of the injection zone and USDWs, including fresh water zones that are not currently being used as a water supply.

The geophysical logs are also used to determine the injection zone thickness and porosity, which confirms that the bounding shale zones are thick enough to provide zonal isolation.

Maximum Injection Pressure and Volume

Maximum surface injection pressure is calculated based on a default fracture pressure gradient of 0.6 pounds per square foot (“psi”) of depth. The operator may elect to conduct a Step Rate Injection Test to determine whether a higher injection zone fracture gradient exists. From the resulting fracture gradient, the COGCC designates a maximum surface injection pressure at the operator’s requested injection rate as a condition of permit approval. The COGCC’s policy is to keep injection pressures below the fracture gradient, which is uniquely defined for each injection well, in order to minimize the potential for seismic events related to fluid injection.

The COGCC calculates a maximum injection volume, based on thickness and porosity from the log data. By COGCC policy, the injection volume calculation is restricted to a one-quarter mile radius. This restriction is intended to constrain the total volume of injected fluids during the life of the injection well.

Seismicity Review

The UIC permit review also includes a review for seismicity. This was previously performed by the Colorado Geological Survey (“CGS”) but is currently performed by a former CGS staff member now working for the COGCC. The seismic review uses CGS geologic maps, the United States Geological Survey earthquake database, and area-specific knowledge to assess seismic potential. If historical seismicity has been identified in the vicinity of a proposed Class II UIC well, COGCC requires an operator to define the seismicity potential and the proximity to faults through geologic and geophysical data prior to any permit approval.

Water Analysis

Injection permits are only approved if water analyses from the injection zones show an acceptable level of total dissolved solids or an Aquifer Exemption is required. If the total dissolved solids are between 3,000 and 10,000 milligrams per liter, then a request for an Aquifer Exemption is sent to the U.S. Environmental Protection Agency and Colorado Department of Public Health and Environment. An Aquifer Exemption will only be granted if the injection zone: 1) is not currently a source of drinking water, and 2) is unlikely to become one, because it is or may be a hydrocarbon producing interval, is too deep to be economically or technically practical, or currently has more than 10,000 milligrams per liter of total dissolved solids.

Mechanical Integrity Test

Finally, the well must pass a Mechanical Integrity Test ("MIT") after it has been set up in the final injection configuration. The MIT assures that any leaking fluids from the injection tubing, which conveys fluid from the surface to the injection zone and past the packer, or the packer, which separates the injection zone from the tubing-casing annulus, are contained within the tubing-casing annulus.

4.3 INJECTION WELLS

Nodal systems analysis can be applied to both water and gas injection wells in order to determine optimum injection rates, correct tubing sizes, and completion techniques, and as a diagnostic tool.

4.31 WATER INJECTION WELLS

4.311 INTRODUCTION

There are numerous wells that are being used to inject water for waterflood purposes or as water disposal wells. The proper design of these wells is very important economically because new wells may be required to inject the objective water rates. In other cases, some producing or abandoned wells may be converted to injection wells.

After a period of time, these wells generally start showing a decrease in injection rate, principally because of partial plugging near the wellbore. Therefore, provision is made to backwash many of these wells. This is generally done by installing gas-lift valves and producing the well in a normal production manner until it has cleaned up properly and will again take water as an injection well.

If this well is completed in an unconsolidated sand, it may also have to be gravel packed in order to backwash properly without excessive sand production. Therefore, it is not unusual to find a gravel-packed water injection well. This must be properly designed to permit water injection at the objective rate as well as to permit proper backwashing at sometimes rather high differentials to remove those deposits, particles, etc., that have reduced the injection rates.

4.312 DESIGN PROCEDURE FOR A STANDARD WATER INJECTION WELL

(1) Prepare the IPR curve in the normal manner by making use of Darcy's Law:

$$q_{inj} = \frac{7.08 \times 10^{-3} k_w h (\Delta P)}{\bar{\mu}_w \bar{B}_w (\ln r_e/r_w - 3/4 + S)}$$

where:

k_w = md
h = ft
q = b/d
μ_w = cp

This equation appears the same as Darcy's law for flow into the wellbore except that ΔP must be added to the average reservoir pressure. An injection productivity index can be calculated; then, the equation appears as follows:

$$q_{inj} = J_{inj}\, \Delta P$$

This is a linear relationship for single-phase water flow. Assume values of ΔP and calculate the corresponding rates. Then, plot q vs ($P_r + \Delta P$). Obtain a figure similar to Figure 4.50.

The fracture pressure should not be exceeded, and this point is noted in Figure 4.50. If the fracture gradient for a particular well is not known, it can be estimated; it seldom exceeds a gradient of 0.8 psi/ft and is more likely to be on the order of 0.7 psi/ft. That is, the fracture gradient for a normal well can be estimated to be (0.7) (10,000) = 7,000 psi for a 10,000-ft well.

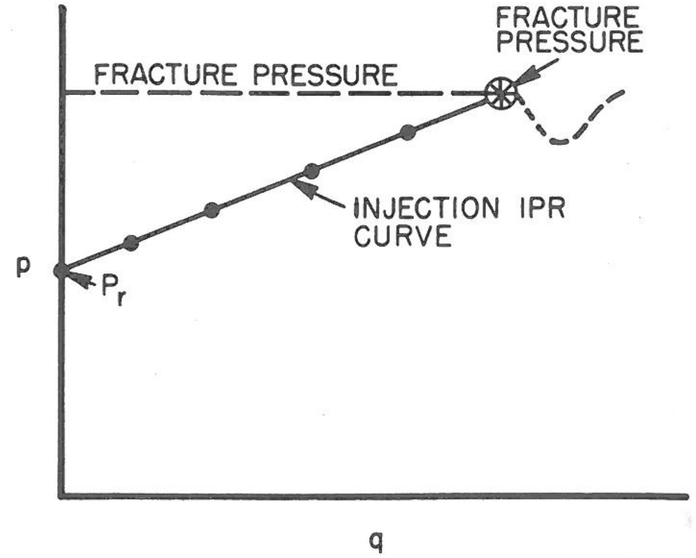


Figure 4.50 Construction of Water Injection IPR Curve

(2) Construct the tubing discharge curves as noted in Figure 4.51. These curves are analogous to the tubing intake curves for a producing well. However, for water injection curves, the friction is subtracted from the elevation component (static gradient). That is, the total pressure at the discharge of the tubing (assumed to be at the center of the perforations) is the elevation component minus the friction component, with acceleration normally being negligible for water flow only. If the tubing is less than two or three joints from the center of the perforated interval, it can be assumed to project to the center of the interval. Less friction will occur in the casing interval as compared to the tubing, and any long length of casing should be properly accounted for. By assuming tubing all the way, a slightly lower pressure and, hence, slightly lower injection rate will be predicted. A typical set of gradient curves for water injection is noted in Figure 4.52, including

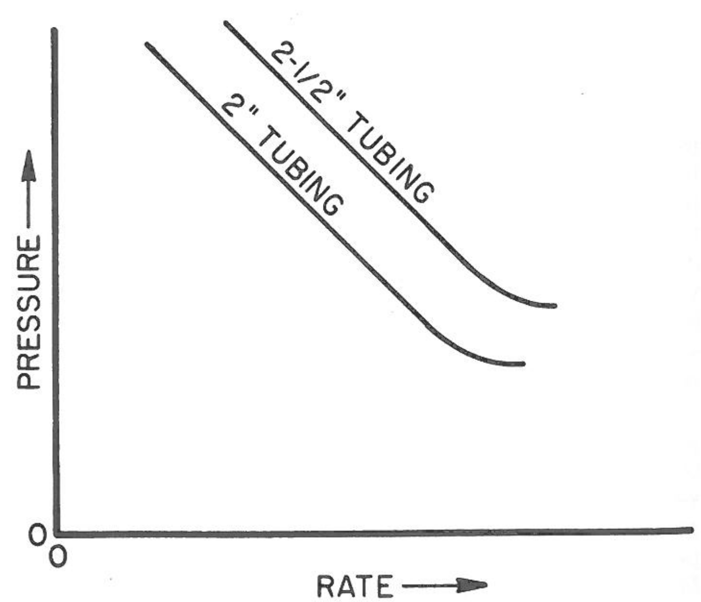


Figure 4.51 Tubing Discharge Curves for Water Injection Well

EXHIBIT 2

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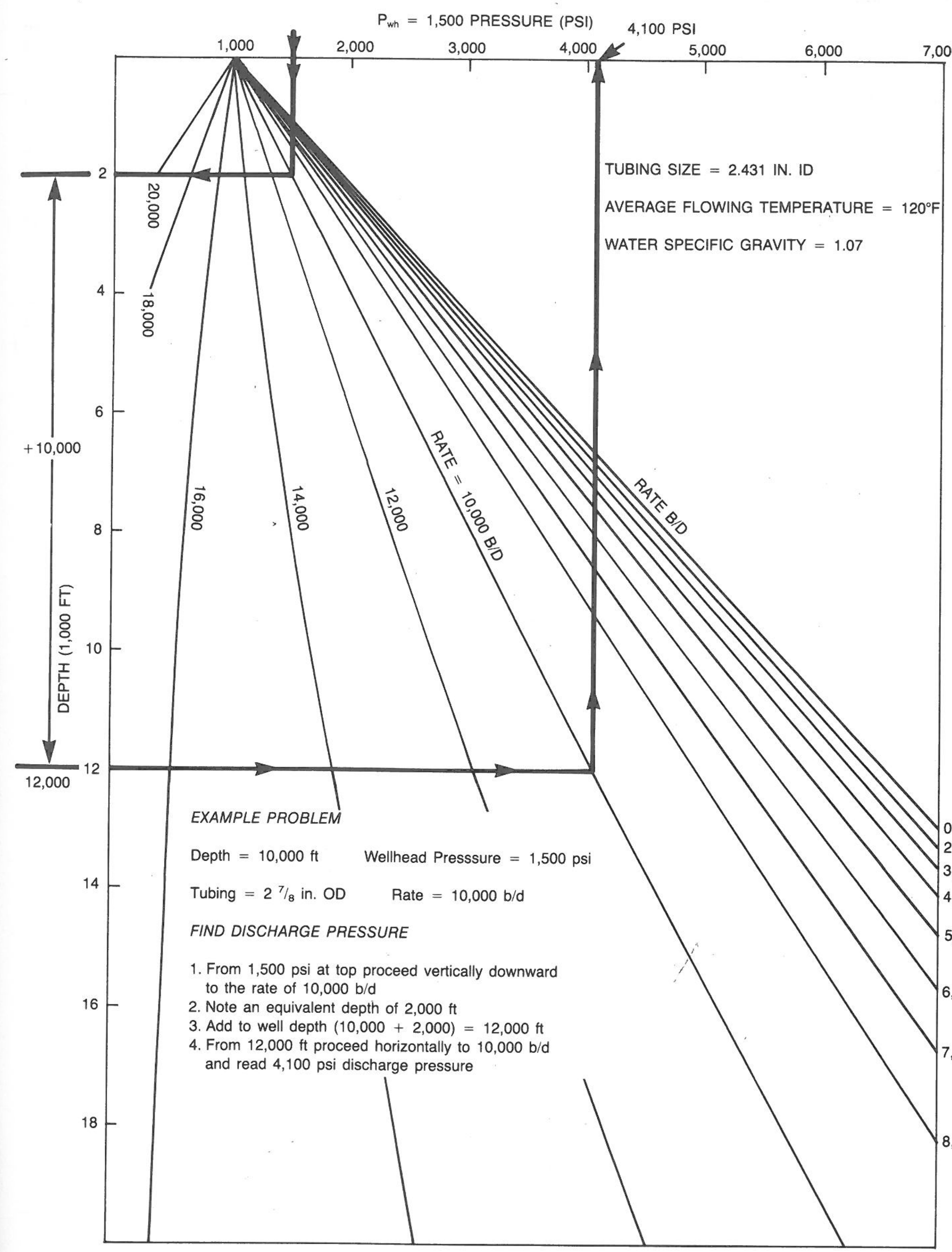


Figure 4.52 Typical Water-Injection Curves with Example Problem

an example problem. A complete set of curves for several tubing sizes can be found in Volume 3b of this textbook series. (Also see Appendix 4.4.)

(3) The injection IPR curves of step 1 and tubing discharge curves of step 2 are combined in the same manner as for a flowing well, as shown in Figure 4.53. The intersection of these curves shows the injection rate possible for this well.

A gravel-packed water injection well can be handled in the same manner as a producing well. The loss across the pack can be included in the IPR curve, or a ΔP plot such as Figure 4.54 can be prepared.

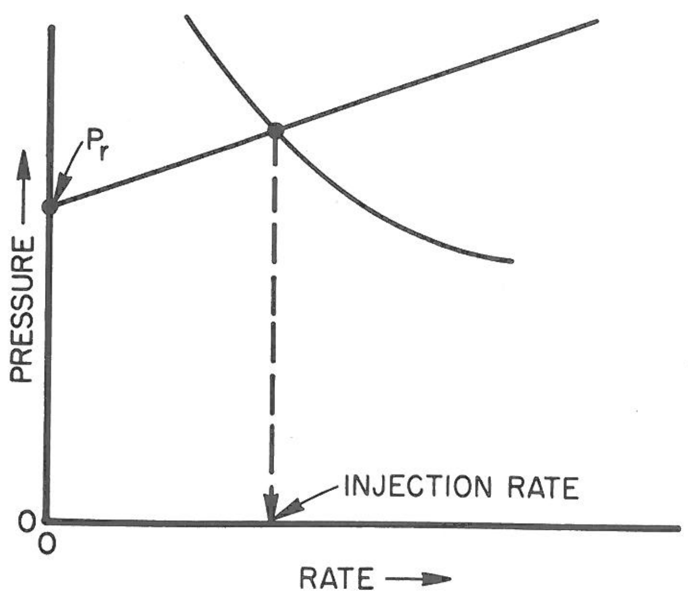


Figure 4.53 Combined IPR and Tubing Discharge Curves for Rate Prediction of Water Injection Well

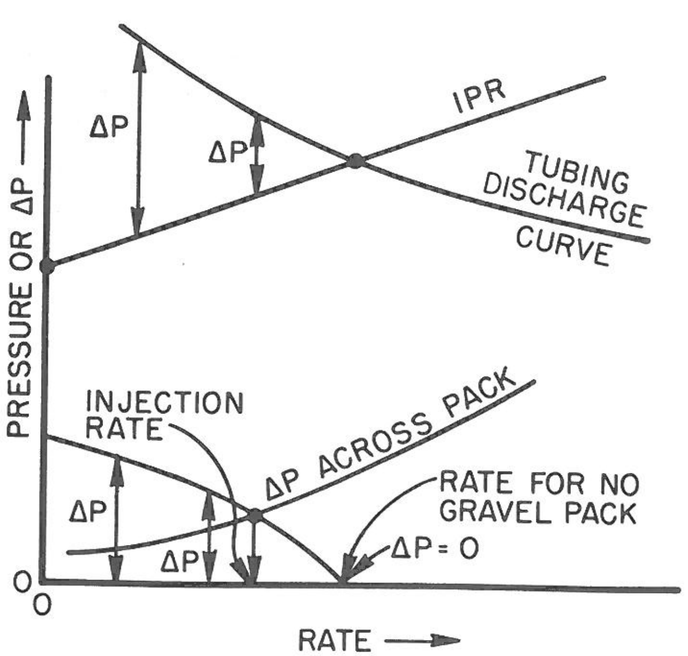


Figure 4.54 Solution for Gravel-Packed Water Injection Well

4.313 EFFECT OF VARIABLES FOR A WATER INJECTION WELL

A nodal systems analysis graph similar to Figure 4.53 can be used to look at the effect of such variables as wellhead pressure, tubing size, injection surface flow-line length, surface injection pump pressure, and perforation shot density for both gravel-packed and non-gravel-packed wells.

The systems graph can also be used as a diagnostic tool in determining when to backwash or acidize an injection well to increase the injection rate.

(1) *Effect of Surface Injection Wellhead Pressure.* A plot similar to Figure 4.55 can be prepared to show the effect of wellhead injection pressure and to aid in the selection of pump discharge pressure and pump horsepower. This plot is quite easily prepared by assuming various wellhead pressures and determining the corresponding tubing discharge curves.

(2) *Effect of Tubing Sizes.* The effect of tubing sizes can be shown in a plot similar to Figure 4.56. The

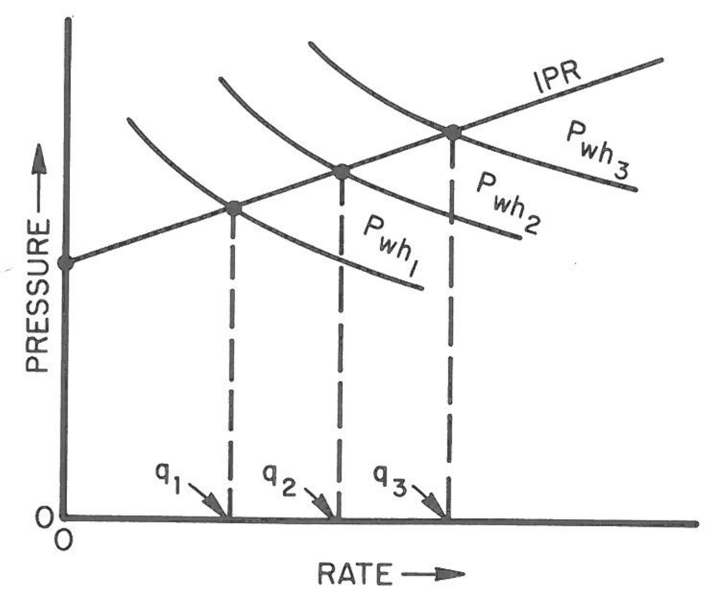


Figure 4.55 Effect of Surface Injection Wellhead Pressure

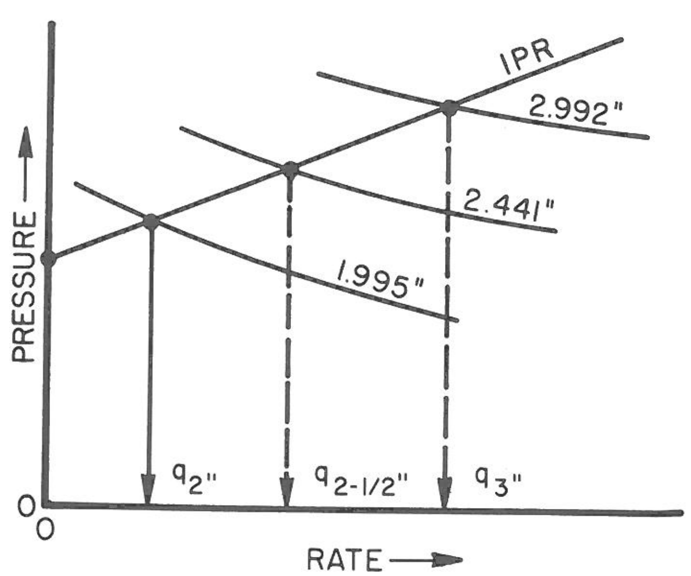


Figure 4.56 Effect of Tubing Sizes on Water Injection Well

correct tubing-size selection can then be made in order to obtain the objective flow rate.

(3) *Effect of Static Reservoir Pressure.* If a waterflood project is started on a depleted reservoir with a relatively low static pressure, the injection rate vs $\bar{P}_r$ may be important; this is noted in Figure 4.57.

Eventually at reservoir fill-up, the original reservoir will be reached or exceeded, depending upon reservoir withdrawals at that time. In order to construct IPR curves during these transient times—that is, until the water bank has reached r_e—an interative procedure could be employed that would properly account for all variables.

(4) *Effect of Flow-line Size.* If a long, small flow line is required to bring the water to the injection well, its effect can be significant in that excessive pressure loss caused by friction will occur in the flow line.

The effect of flow-line sizes could be evaluated in the same manner as for a naturally flowing well by taking the solution point at the wellhead or at the bottom of the well.

The following procedure would be followed for a wellhead pressure solution (see Figure 4.58):

(1) Assume various flow rates.
(2) Starting with the surface pump discharge pressure, determine the wellhead pressure for each assumed rate. This will be just opposite that of a flowing well in that wellhead pressure will be less as the rate increases because of increased frictional losses from the pump to the wellhead.
(3) Plot P_{wh} vs rate as noted in Figure 4.58.
(4) Starting from $\bar{P}_r$, determine the pressure at the center of the wellbore for injecting the various flow rates or read these values from the IPR curves.
(5) Using the pressures of step 4, determine the required wellhead pressure for each rate.
(6) Plot the required wellhead pressures of step 5 on Figure 4.58. The intersection of the curve of step 3 and step 6 gives the injection rate for this well.

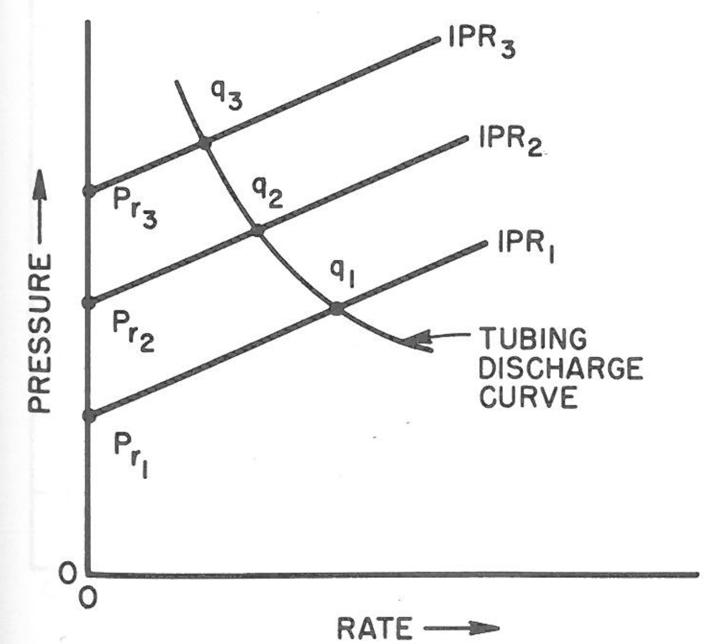


Figure 4.57 Effect of Increase in Static Reservoir Pressure

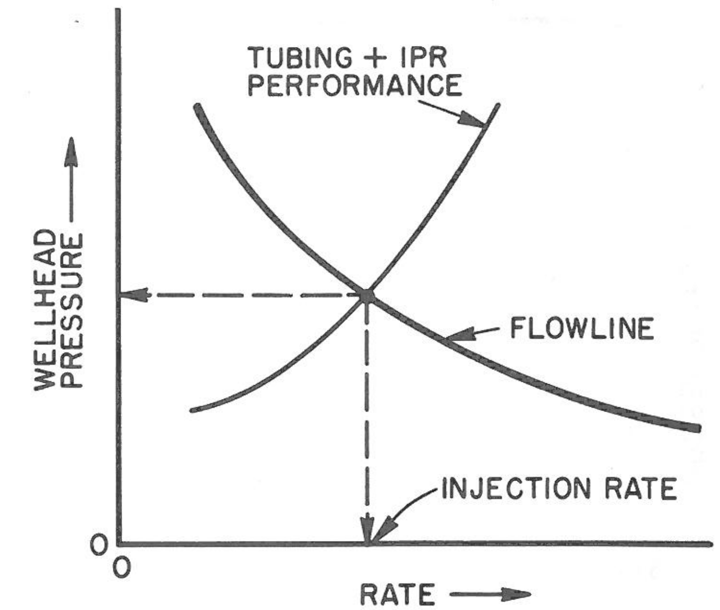


Figure 4.58 Wellhead Solution for Water Injection Well

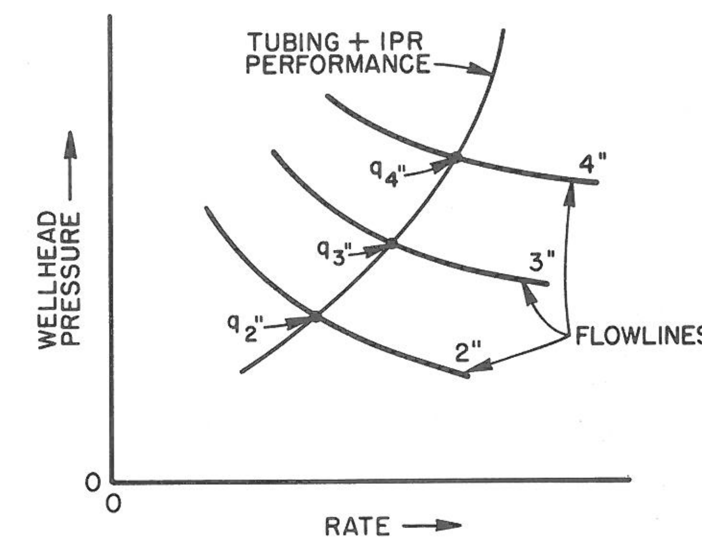


Figure 4.59 Effect of Flow-Line Sizes

The wellhead pressure solution permits the isolation of the flow line from the rest of the system and larger flow lines can be easily evaluated as shown in Figure 4.59.

EXAMPLE PROBLEM FOR WATER INJECTION (See Figure 4.60)

Given data:

well depth = 10,000 ft
k = 70 md
h = 30 ft (all perforated)
7⅝-in. casing 9⅞-in. hole 2⅞-in. tubing
T = 190°F
r_e = 2,000 ft
$\bar{P}_r$ = 5,000 psi (at fill-up)

A normal fracture gradient of 0.7 psi/ft is expected. The pump is to be located at the wellsite; hence,

Comments	SWD 3-17D (Relook Sep 2015)
Company Windy Hill Gas Storage LLC Well 3-17D	Field Windy Hill Test Name / # Interference Test

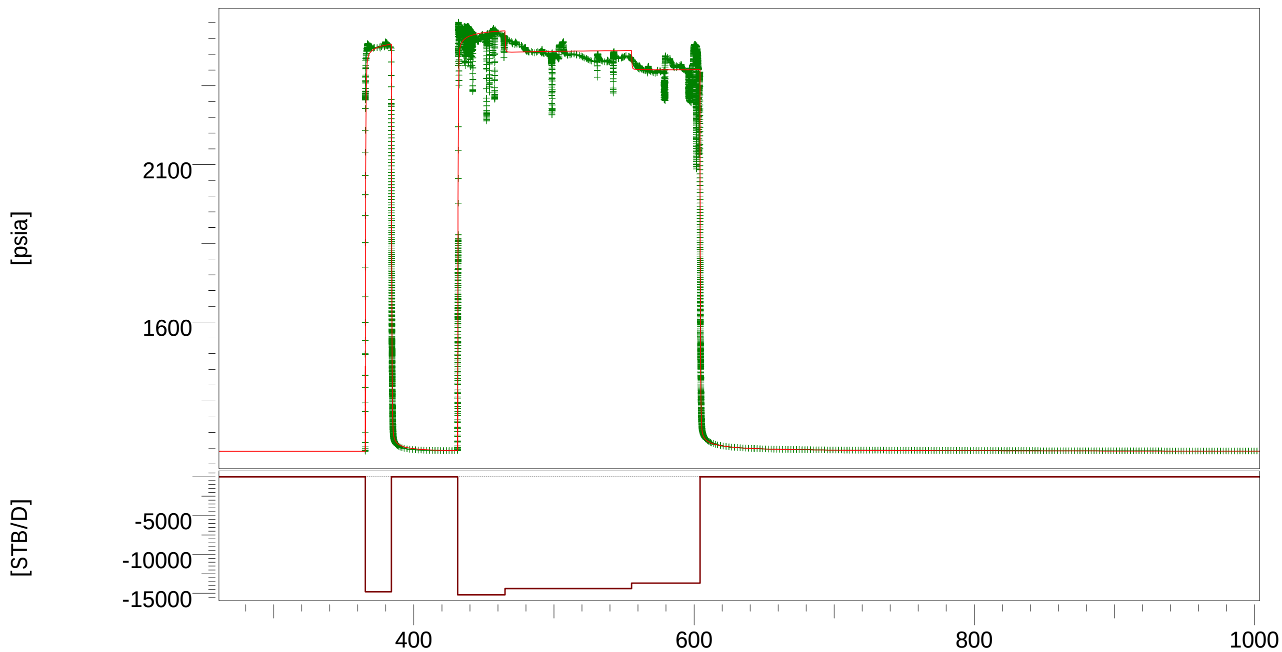
Windy Hill 3-17D Interference Test Analysis

A long-term interference test was conducted in the J-sand (Morgan County. CO) primarily to establish the extent and connectivity of the sand for reservoir modeling purposes, to ensure suitable conditions for simultaneous use of the sand for the cavern mining water source and brine disposal. The mining plan was to source low salinity mining water and dispose of saturated brine into the J-sand.

The interference test used well 3-18WSW as the water source well (ESP installed), 3-17D as the disposal well, and 1-17D as a monitor well, with all wells instrumented with electronic gauges. The main flow of the test was approximately 14,400 BWPD for 173 hours with a 422 hour shut-in period to record the pressure fall-off. This was the longest test conducted on the J-sand so is representative of the largest reservoir volume investigated. Other tests have been conducted but were relatively short and only investigated small local volumes and do not demonstrate a large continuous reservoir volume.

The analysis of 3-17D took account of the interference between the wells. The permeability-thickness of the J-sand was estimated to be approximately 110,000 md-ft and this was supported by other well tests. The total skin factor was high at 140 due to unclean injected water and perforation damage from prior testing. The log-log diagnostic plot clealy shows a negative half slope which is diagnostic of hemi-sphereical flow. The best matches of the data are observed when the open perforation thickness is in the 20' - 30' range. This is normally because the sand has not been fully perforated (partial penetration) but in this case is likely due to plugged perforations. This causes a component of the flow to be vertical and the vertical permeability (kv) is generally lower than the radial permeability (kr). The generated (kv/kr) ratio is given in the results

History plot	Final FO Hemi-spherical flow
Company Windy Hill Gas Storage LLC Well 3-17D	Field Windy Hill Test Name / # Interference Test



Pressure [psia], Liquid Rate [STB/D] vs Time [hr]

Windy Hill SWD #3-17D (W1181 A) fall-off #2

Rate	0 STB/D
Rate change	13700 STB/D
P@dt=0	2391.98 psia
Pi	1190 psia
Smoothing	0.1

Selected Model

Model Option	Standard Model, Other Wells Included
Well	Vertical - Limited entry
Reservoir	Homogeneous
Boundary	Infinite
Top/Bottom	No flow/No flow

Main Model Parameters

TMatch	616 [hr]-1
PMatch	0.141 [psia]-1
C	0.133 bbl/psi
Total Skin	161
k.h, total	1.15E+5 md.ft
k, average	674 md
Pi	1190 psia

Model Parameters

Well & Wellbore parameters (3-17D)

C	0.133 bbl/psi
Skin	113
Geometrical Skin	48
hw	25 ft
Zw	40 ft

Well & Wellbore parameters (Well#2)

C	0.119 bbl/psi
Skin	5.86
Geometrical Skin	48

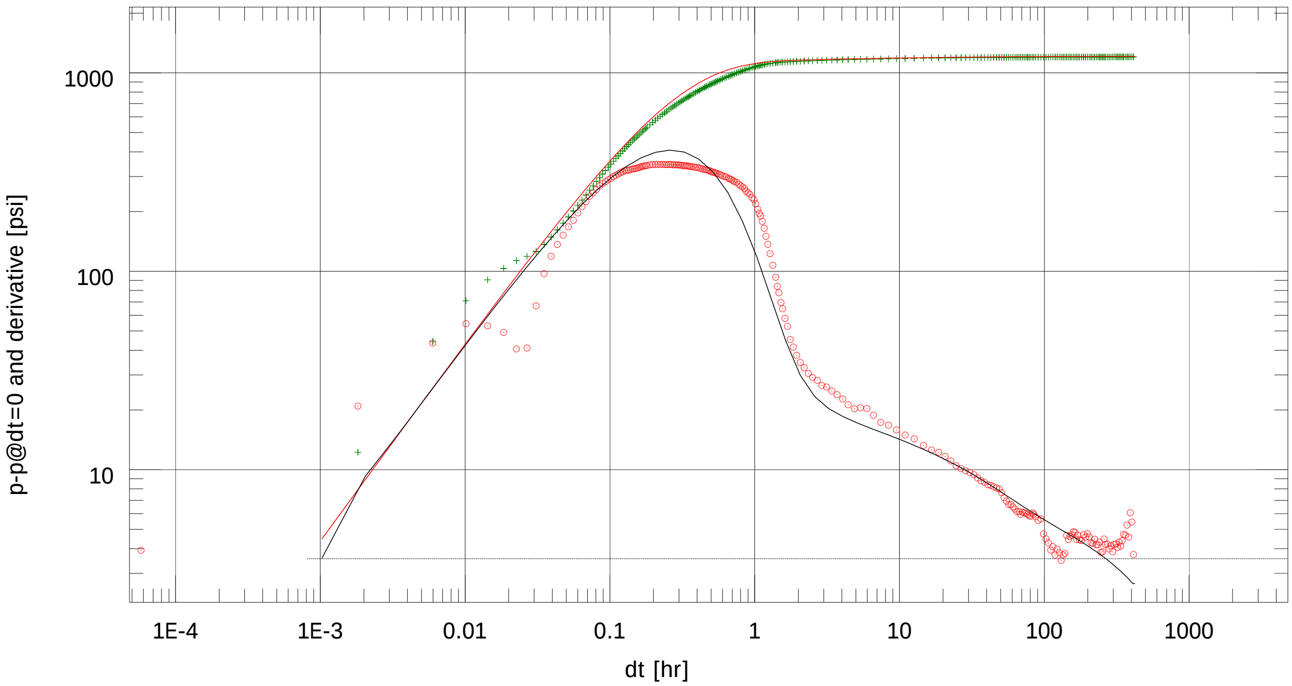
Reservoir & Boundary parameters

h	170 ft
Pi	1190 psia
k.h	1.15E+5 md.ft
k	674 md
kz/kr	3.18E-5

Derived & Secondary Parameters

Rinv	20300 ft
Test. Vol.	9027.38 MMB
Delta P (Total Skin)	1143.55 psi
Delta P (Skin)	802.825 psi
Delta P (Geometrical Skin)	340.724 psi
Delta P Ratio (Total Skin)	0.94446 Fraction

Log-Log plot	Final FO Hemi-spherical flow
Company Windy Hill Gas Storage LLC Well 3-17D	Field Windy Hill Test Name / # Interference Test



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