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to J. H. Ramsthaler

from T. W. Lawford T W Lawford

subject ANALYSES OF INTERACTIONS BETWEEN THE 5MW(e) PILOT PLANT AND THE WELLS WHICH SUPPORT IT: GUIDELINES FOR PRESENT & FUTURE DRILLING OPERATIONS - TWL-22-78

This letter summarizes analyses performed on the interactions between the 5 MW(e) Pilot Plant and the wells which support it. These analyses may be used as guidelines upon which to base decisions relative to present and future drilling operations. All of these analyses are based upon well characteristics as we know them today, and many of these characteristics are extrapolated from very short term ~~flow~~ tests. These analyses must, therefore, be considered as scoping studies, but they can serve as guidelines for drilling operations.

Introduction

The effects of production wells and injection wells on the overall system performance are basically independent. Separate studies have been performed which are reported in this letter. The first section considers the production well system. The section discusses the choice among the existing production wells which could be used for plant support; considers the decision on tripple legging of RRGP #5 (a decision made in the past) and gives information regarding future decisions such as the feasibly triple legging of RRGP #4 and/or drilling a new well. The second section considers the injection well system and the trade between raising the injection system pressure and drilling a new well.

An integral part of these studies involves assessment of the economic worth of improvements in plant power output. While for the Raft River Pilot Plant these economic considerations are not the prime considerations, this reasoning does allow for decisions to be made in a manner similar to the way that a utility would be forced to make decisions, if the only justification for the plant was the economic generation of electric power. This adds a dimension of realism to the decision made with regard to the 5MW Raft River Pilot Plant.

Production Well Analyses

Studies concerned with interactions between production wells and the 5 MW(e) Pilot Plant have included: 1) determination of which combination of the existing wells would be the best choice to support the plant; 2) estimation of the effect triple legging RRGP #5 would have on plant performance; and 3) evaluation of other possible present and future drilling options as they will affect plant performance. The study of the existing wells (assuming that RRGP #4 had been deepened) indicated that the best choice among RRGP #1, RRGP #2, RRGP #4, and RRGP #5 was to use #1, #4 and #5 for support of the plant. This choice has been used as a baseline combination for all of the further studies. The question of triple legging RRGP #5 was considered at the time of its completion and the decision was made that there was not enough potential gain to justify the work. The economic worth of other activities, such as triple legging the other production wells and drilling a new well has been established to serve as a guideline for future drilling decisions. The well characteristics used are based on limited data and, so, this work should be considered scoping in nature and subject to revision when more complete data is available.

Data for the individual wells which was used in these studies is given in Table 1. Flow rates and downhole temperatures for wells #1, #2, and #5 are best-estimates of the reservoir engineering group. The assumed well #4 characteristics reflect the facts that it should have a higher flowrate and downhole temperature than well #1 when it is deepened. The well bore heat transfer (temperature loss) was accounted for as a function of flowrate, based on well #1 experimental data. For these studies, a new well was assumed with downhole temperature of 300°F (hotter than any existing wells) and a flowrate equal to that estimated for well #4. It was assumed that triple legging any well would improve its production by 35 percent and not change its downhole temperature.

A baseline combination of existing wells was determined by considering the characteristics of combinations of production wells which have a total flowrate between 80 and 120 percent of the design geothermal fluid flowrate for the pilot plant. Table 2 shows all of these combinations. The temperatures are the average mixed fluid temperatures and do not account for additional temperature losses between the wellhead and the plant. The gross and net plant power outputs are taken to be the arithmatic average of the output at the extreme summer and winter conditions using the floating power concept. The plant performance was determined from computer simulation. On the basis of maximization of the net power output, the combination of well #1, #4, and #5 was chosen as the best performance and is used as the base-line case for further studies. An alternative to #1, #4, and #5 is #1, #2 and #4 with only 4 percent less net output but with 12 percent less flow.

Several options concerning additional drilling have been considered. Table 3 shows possible combinations related to triple legging existing wells and drilling a new well (with the probability of it being hotter than any of the existing wells). Table 3 gives combinations of these possible situations with existing wells. The assumptions for plant inlet temperature and average power output are the same as for Table 2. Because each of these new configurations requires the additional expenditure of money, an economic assessment of the options is useful. The drilling and outfitting costs are taken as: $500,000 for a new production well; $200,000 to triple leg an existing well. The economic benefit of additional net power output is assessed in the following manner: The annual return from selling the additional net power above the base case amount is determined using a price of 50 mills per kWhr and a plant operating factor of 80 percent. The present worth of this amount is determined for both a 5 year period and a 30 year period of power production assuming an interest rate of 8 percent, typical of costs for a public utility. The difference in the present worth of the increase in net output and the additional capital cost over the base case is a measure of the profitability of the venture.

Table 4 summarzies the economic results of the options outlined in Table 3. The additional costs incurred in going from the base case configuration are shown along with the increase in net plant power output over the base case. The present worth of this increase in net output is tabulated for 5 years and 30 years of power production. The final columns are the difference in these quantities to give the net economic gain or loss expressed as present worth.

Consider the first entry in Tabel 4. This represents triple legging of well #5 (an option which was studied when well #5 was completed). If the worth of 5 years of power are considered, the venture shows a net loss. If a 30 year period is considered, a gain is indicated. This option was not pursued, as other options (such as triple legging well #4) appeared more promising.

The most attractive ventures shown in Table 4 are using well #4 and the New well, both triple legged. The next most attractive configurations are: Well #2, #4TL and N and the #1, 4TL and 5. In these comparisons, no account is taken of the possible worth of the wells no longer used for support of the plant.

The results of this analysis are strongly dependent upon the input assumptions, both with respect to well characteristics and economics, that the analysis is based upon. All of the cases considered here are built upon assumed flow and temperature characteristics of well #4, which has not yet been deepened into the production zone. Other cases incorporate well #5, which has not been flow tested, and a projected new well with hypothetical characteristics. It is recommended that these analyses be updated in a step wise manner as additional well data becomes available, first from well #5 and then from well #4, before making decisions on future drilling operations for production wells.

Injection Well Analyses

Unlike production wells which affect the plant performance by altering flow rate and inlet temperature, for a given plant flowrate the injection system changes the plant performance only in that the injection pumping power is changed. The present analysis considers the most recent injectibility data for wells RRGE #3, RRGI #6 and RRGI #7 obtained from the reservoir engineering group. It is realized that these results have been extrapolated from very short term data, however, at this time this is all the data that is available.

The injection well study consisted of considering two baseline systems: Case A) wells RRGI #6 and RRGI #7; and Case B) those two wells with RRGE #3 used as an injection well. If the injection pressure is raised enough either of these systems should have adequate capacity for the fluid to be injected from the power plant. The preliminary data indicates that an injection pressure for Case A of 855 psia is sufficient whereas for Case B 700 psia is high enough. It is possible to achieve these pressures with appropriately sized pumps and auxiliary equipment. It should be noted that the increase in pumping power required (the decrease in net plant output) over the pumping power if the injection pressure is 300 psia is 0.72 MW in Case A and 0.52 MW in Case B.

The injection pressure and, therefore, the injection pumping power can be decreased with the addition of a new injection well. This increase in net output which is caused by the decrease in pumping power can be treated as an equivalent capital cost using the present worth of the annual revenue increase as was done in the production well studies, using the same economic assumptions: Electricity Cost - 50 mills/kW hr, Plant Operating Factor - 80 percent, Interest Rate - 8 percent.

Figure 1 shows the case of adding one new well to Case A to form the injection system for the plant. Incremental cost changes from the baseline of the two existing wells only are shown as they are related to the performance of the new well expressed as a percentage of the capacity (flowrate) of RRGI #6 at the same pressure. The performance of wells RRGE #3 and RRGI #7 are shown on the figure as reference points. The relative well performance is influenced by the wellhead pressure so the points are slightly different on the subsequent figures. System wellhead injection pressure for this new well performance is shown across the top of the curve. The present worth of the increase in net power (resulting from the decrease in injection pressure) is shown for a 5 year and a 30 year period. The change in capital cost of pumps and equipment will be quite small with respect to these values and is, therefore, not shown. The cost of drilling and outfitting an injection well is shown on the figure also. It was taken as $300,000; based on the costs of RRGI #6 and RRGI #7. It is seen that on the basis of increased net power output for 5 years, if the well has a capacity larger than 34 percent of well RRGI #6 (approximately equal to the performance of wells RRGE #3 and RRGI #7), it is advantageous to drill the new well. If the worth of power for 30 years is considered, the breakeven point would be a well with 12 percent of the RRGI #6 capacity. Similar results are indicated for Case B on Figure 2.

CJB:ajw

Attachments:
Tables 1-4
Figures 1 & 2

cc: C. A. Allen
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Table 1

Individual Production Well Characteristics

Well	Flowrate (gpm)	Flowrate (lb/hr)	Downhole Temp. (F) ΔT top of upper production zone	MAX. Wellhead* Temp. (F) E	OBSERVED (obs.)
1	800	373,000	~~286~~ (B)	281- 265-	265 (1)
2	400	186,00	~~277~~ (291) (A)	279-281	279 obs 10/9/78
4**	~~1000~~ 500	~~465,000~~	290 -	285 282	
5	(2000) ~~650~~ 100	~~302,000~~	274 (C)	~~268~~ 265	264
New***	~~1000~~ 500	~~465,000~~	~~300~~ 290-	~~295~~ 282	
Triple-Legged****					
1 TL	1080	503,000	286	282	
4 TL	~~1350~~ 675	~~628,000~~	290	286	
5 TL	~~877~~ 135	~~408,000~~	274	296	
New TL***	~~1350~~ 675	~~628,000~~	~~300~~ 290-	296	

*Wellhead temperatures extrapolated from Well RRGE #1 measured difference between downhole and wellhead temperature as realted to the flowrate.

**Best estimate of RRGP #4 performance when deepened.

***Hypothisized New, hot well (see text).

****Triple legging was assumed to increase the flowrate by 35 percent and not change the downhole temperature.

(1) Temperature declined from 274°F to 265°F when pumping 1010 [illegible] gpm [illegible] 103

(A) LOG OF 6/27/75 @ ~4100 ft. est.

(B) LOG OF 4/6/75 @ 4500 ft

(C) LOGS OF 7/8/78, 9/14/78 @ 4400 ft.

800
400
2000
100

[illegible] 503 gpm

Table 2

Existing Production Well Combinations

Well Combination	Total Flowrate (lb/hr)	Percentage* of Plant Design Flow (%)	Plant Inlet Temp. (F)	Average** Net Power (MW)	Average** Gross Power (MW)
1,4	838,000	80	283	2.74	4.75
1,2,5	861,000	83	274	2.44	4.48
2,4,5	953,000	92	276	2.72	4.94
1,2,4	1,024,000	98	281	3.10	5.34
1,4,5	1,140,000	110	279	3.25	5.64

*Design Flowrate - 1.04×10^6 lb/hr

**Average Power Output taken as arithmatic average of 1% summer and 1% winter conditions.

Table 3

Some Possible Drilling Options

Well Combination	Total Flowrate (lb/hr)	Percentage of Plant Design Flow (%)	Plant Inlet Temp. (F)	Average Net Power (MW)	Average Gross Power (MW)
1,4,5 (base case)	1,140,000	110	279	3.25	5.64
1,4,5TL	1,246,000	120	279	3.38	5.90
1,4TL,5	1,303,000	125	280	3.51	6.09
1,2,4TL	1,187,000	114	282	3.46	5.90
1TL,4TL	1,132,000	109	284	3.48	5.85
4,N	930,000	89	290	3.29	5.39
2,4,N	1,116,000	107	286	3.55	5.90
4TL,N	1,093,000	105	290	3.68	6.01
2,4TL,N	1,279,000	123	287	3.90	6.43
4TL,NTL	1,256,000	121	291	4.06	6.58

Table 4

Economic Results for Drilling Options

Listed in Table 3

Well Combination	Additional Capital Cost	Net Power Increase Over Base Case	Present Worth of Net Power Increase for a Period of:		Net Economic Gain (Loss) from Base Case Expressed as Present Worth	
	(10^3 \$)	(MW)	5 Years (10^3 \$)	30 Years (10^3 \$)	5 Years (10^3 \$)	30 Years (10^3 \$)
1,4,5TL	200	0.13	182	513	(18)	313
1,4TL,5	200	0.26	364	1026	164	826
1,2,4TL	200	0.21	294	828	94	628
1TL,4TL	400	0.23	322	907	(78)	507
4,N	500	0.04	56	158	(444)	(342)
2,4,N	500	0.30	419	1183	(81)	683
4TL,N	700	0.43	602	1696	(98)	996
2,4TL,N	700	0.65	909	2564	209	1864
4TL,NTL	900	0.81	1133	3195	233	2295

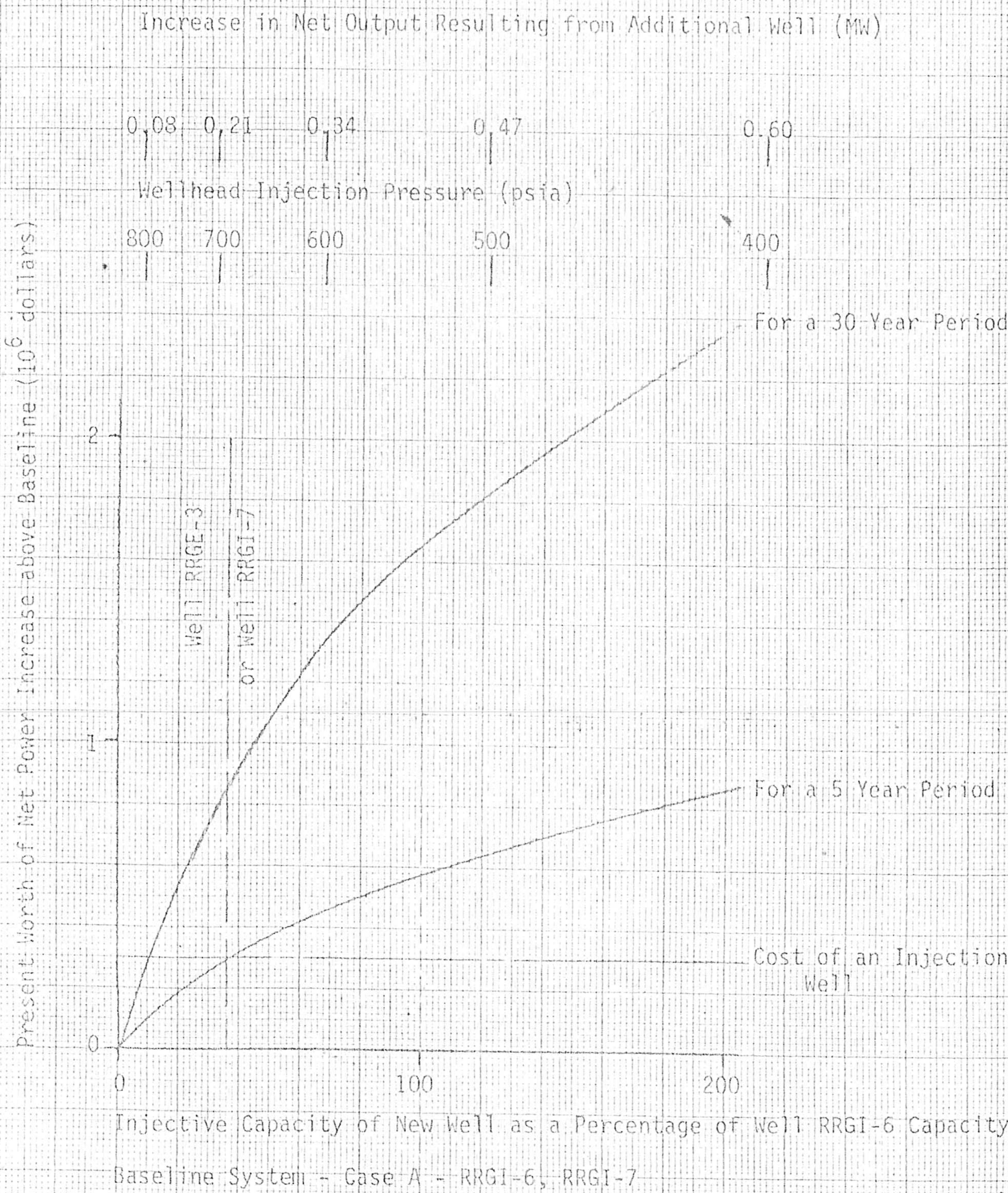

Figure 1. Economic Evaluation of Adding an Additional Well to Case A

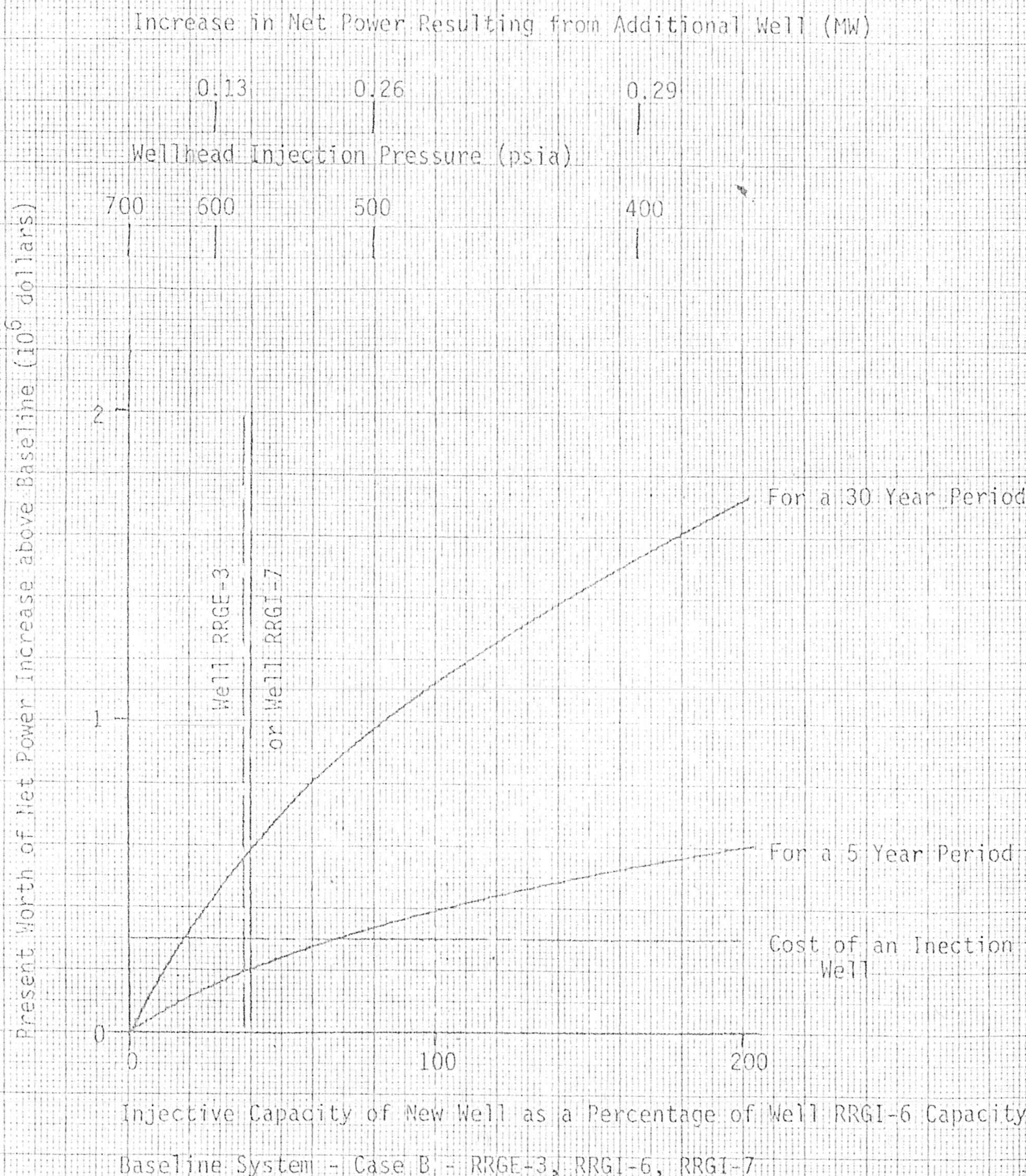

Figure 2. Economic Evaluation of Adding An Additonal Well to Case B