CO_2 HUFF-n-PUFF PROCESS
IN A LIGHT OIL
SHALLOW SHELF CARBONATE RESERVOIR

(No. DE-FC22-94BC14986)

QUARTERLY TECHNICAL PROGRESS REPORT

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OBJECTIVES

The principal objective of the Central Vacuum Unit (CVU) CO_2 Huff-n-Puff (H-n-P) project is to determine the feasibility and practicality of the technology in a waterflooded shallow shelf carbonate environment. The results of parametric simulation of the CO_2 H-n-P process, coupled with the CVU reservoir characterization components will be used to determine if this process is technically and economically feasible for field implementation. The technology transfer objective of the project is to disseminate the knowledge gained through an innovative plan in support of the Department of Energy's (DOE) objective of increasing domestic oil production and deferring the abandonment of shallow shelf carbonate (SSC) reservoirs. Tasks associated with this objective are carried out in what is considered a timely effort for near-term goals.

BACKGROUND

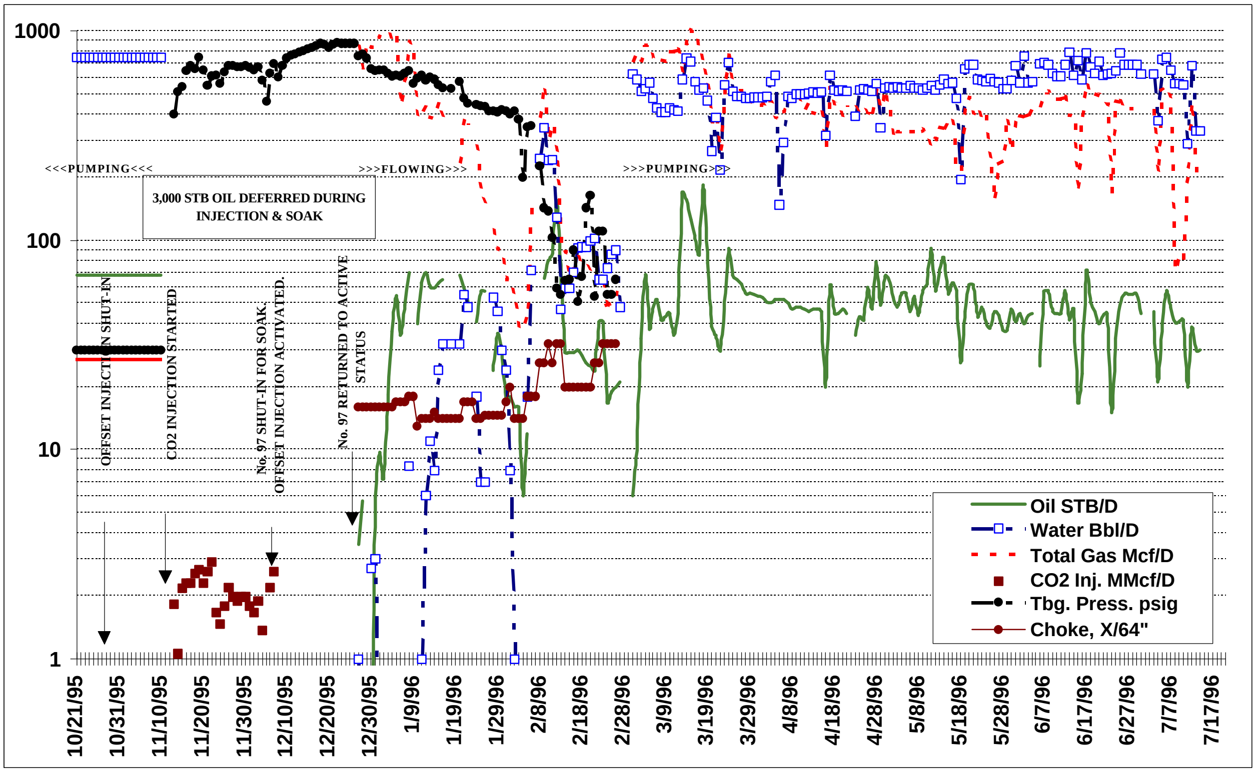
Texaco Exploration and Production Inc's. (TEPI) mid-term plans are to implement a full-scale miscible CO_2 project in the CVU. The economic market precludes acceleration of many such capital intensive projects in many cases. This is a common finding throughout the Permian Basin SSC reservoirs. In theory, it is believed that the "immiscible" CO_2 H-n-P process might bridge these longer-term "miscible" projects with near-term results. A successful implementation would result in near-term production, or revenue, to help offset cash outlays during the initial startup of a miscible flood. The DOE partnership provides some relief to the associated R & D risks, allowing TEPI to evaluate a proven Gulf-coast sandstone technology in a waterflooded carbonate environment. Numerous sites exist for widespread replication of this technology following a successful field demonstration.

TEPI concluded all of the Tasks associated with the First Budget Period by October, 1995. The DOE approved the TEPI continuation application. Budget Period No. 2 is in progress. Initial injection of CO_2 began in November, and after a short shut-in period for the soak, the well was returned to production in late December, 1995. Monitoring the results of the first demonstration continued through mid-year. This report, as did the previous report, covers TEPI's efforts at history matching the results of the field demonstration. Costs and economics of the work are presented. The majority of effort during the fourth quarter has revolved around the selection of a new project site and refinement of the demonstration design and well selection.

SUMMARY of TECHNICAL PROGRESS

FIELD DEMONSTRATION:

Results/Continued Monitoring. CVU No. 97 was returned to active status under flowing conditions on December 27, 1995. Flowing tubing pressure averaged 631 psig with choke settings between 13/64 in. and 18/64 in. Initially, production averaged 901 Mscf/Day. Gas production could not exceed 1,000 Mscf/D due to disposal limitations. No appreciable water production was seen initially. As expected, the water production slowly returned to the pre-demonstration rates. Compositional analyses of the gas stream shows that early gas rates were at 94 mole-% CO_2. Late-time production has been steady around 70 mole-% CO_2. Liquid hydrocarbon production was initially too small to measure and began increasing on the third day. Samples are being collected and retained. The fluid was initially a transparent straw color (41^{o}API), suggesting that lighter hydrocarbons are being effected (or paraffins & asphaltenes are being left behind). The well is currently producing the field normal 38^{o}API crude. The well had achieved a 70 BOPD rate by the tenth net day of flow-back (average pre-demonstration was 68 BOPD). Production has been quite volatile. The well initially flowed on various choke settings, but eventually loaded up. An ESP was run into the wellbore in early March, 1996. Following some minor operational problems, the well peaked at 184 BOPD. However, production has declined rather sharply following this peak. Approximately 100% of the injected CO_2 volume has been produced. The well continues to produce rather high gas volumes, therefore, the accuracy of either the test volumes, laboratory analysis, or a combination of both are suspect. One notable benefit to date is a reduced volume of water production which has a strong impact on lifting costs. **T**he field demonstration history through mid-July, 1996 has been provided in the following graph. Subsequent to the daily frequency of testing shown in this graph, the well is now being tested monthly. The well has continued on a steady decline and is producing approximately 35 BOPD as of the date of this report.

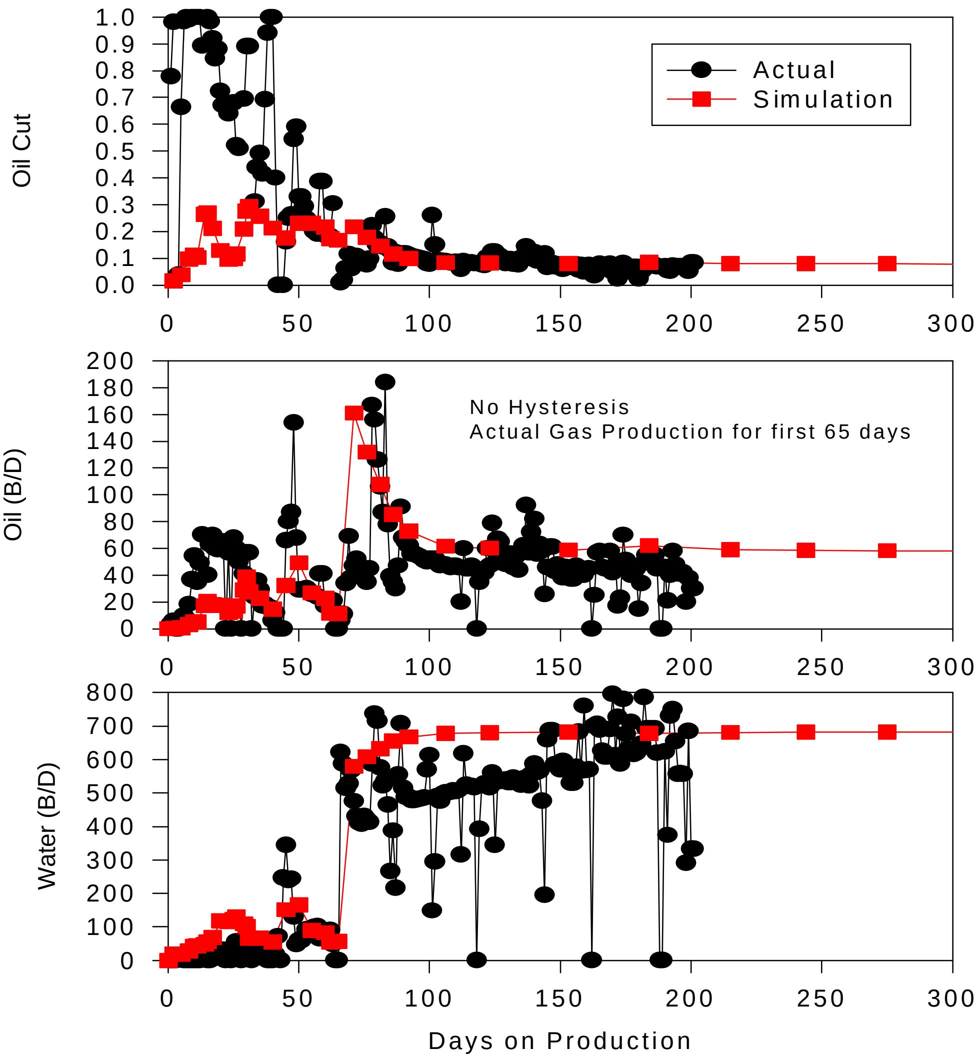


It is noteworthy to point out that although production expectations have not been achieved at this specific test site, there was a period that experienced a favorable reduction in operating expenses. During the injection, soak and flowing periods there were no electrical costs. Electrical load was also significantly reduced during the initial pumping period when water rates were 33% below pre-demonstration levels. Although there are a few signs of paraffin buildup and scaling, the lower than forecast oil production result is felt to be due to a lack of gas trapping in the matrix since nearly 100% of the injected CO_2 volume was recovered. However, the metered gas volumes shown in the chart above are in question since early May. The metering accuracy is suspect for periods shortly after installation of the production equipment. The well continues to produce a 40% CO_2 gas stream as of the end of 1996.

SITE-SPECIFIC SIMULATION:

History Match. The need for model refinement was demonstrated by the differences between predictions and early results (injection rates, pressures, & production). Monitoring of the CVU field demonstration continues on a reduced test frequency. Sufficient data was gathered for a meaningful attempt at history matching. The mechanisms investigated during the parametric simulation were incorporated as warranted. The history matching exercise was completed during the third quarter of 1996. The pursuit of a second demonstration site is being weighed with findings developed during the history matching.

A reasonably close history match was obtained by limiting the gas production during the first 65 days of production to the actual gas production rate experienced in the field test. The gas hysteresis (i.e., the gas trapping mechanism) was also eliminated. The following figure shows the history match with the limitations on the initial gas rate.



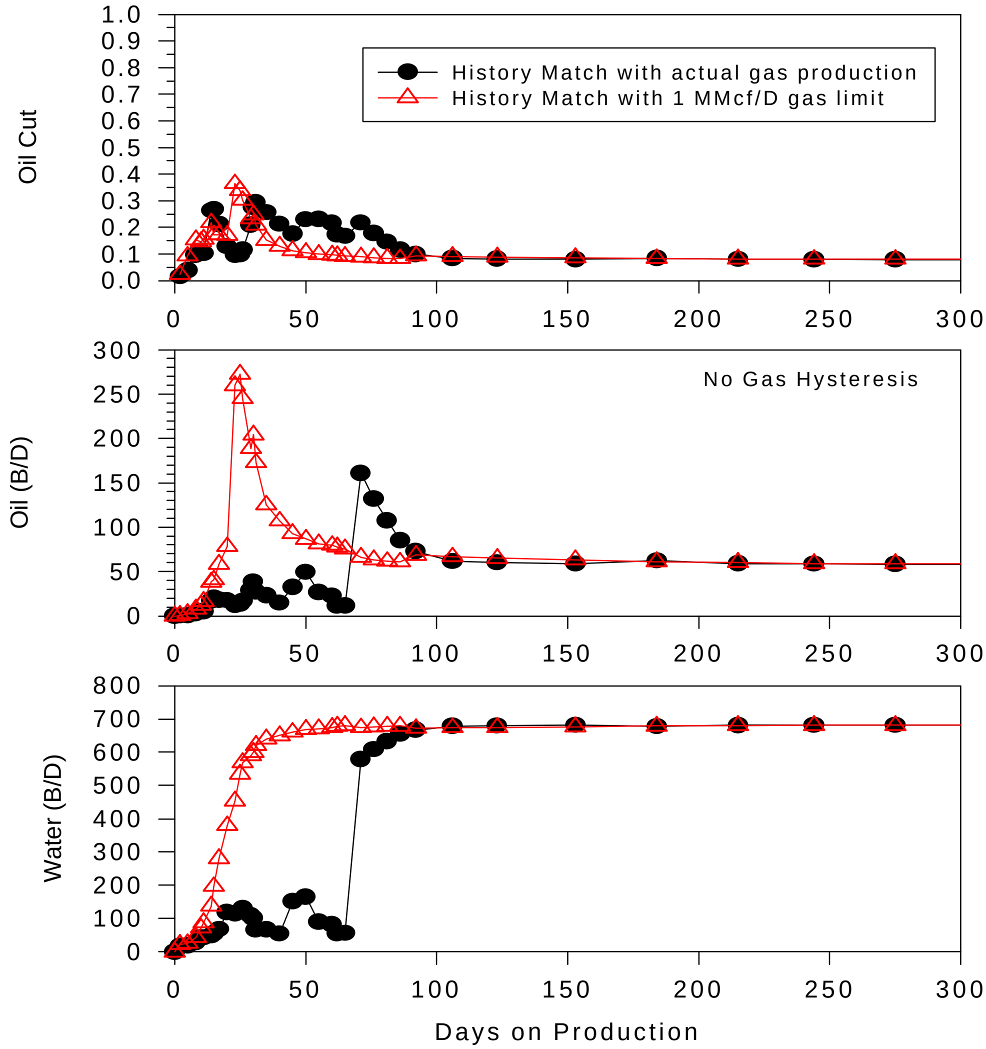
Comparison of Actual Performance and the Site-Specific Prediction. The two main difference between the the predicted performance and the actual performance of the Huff-n-Puff were an apparent absence of gas trapping and lower than predicted production rates. A crucial difference between the actual test and the predicted performance was that the total liquid (oil + water) production rates were much lower for the actual test when the well was flowing. The rates were less than the rates prior to the demonstration and needed to be compensated for in the simulation. The liquid production rate in the simulation was reduced indirectly by placing a limitation on the gas production. For the original site-specific prediction (discussed in previous reports), the well was controlled in the simulation model to maintain the same liquid (oil + water) production rate after the Huff-n-Puff as before, and the gas production was not allowed to exceed 1,000 Mscf/D. There was anticipated to be an actual field limitation of 1,000 Mscf/D on gas production (the limitation on gas production in the early production period was due to disposal issues). However, in the actual field test, both the initial total liquid production rates and the gas production rates were much less than in the prediction. The gas production was initially around 1,000 Mscf/D, but it rapidly declined and became less than 100 Mscf/D before the pump was put back in the well. This was the result of flowing the well, which ultimately loaded up with liquids. The lower early liquid production rates were matched in the simulation model by limiting the simulated gas production rates to the actual gas production rates for the first 65 days the well was placed back on production.

Permitting the well to produce at a gas rate of 1,000 Mscf/D (drawing down the wellbore fluid level), increased the oil recovered during the simulated Huff-n-Puff. About 3,000 STB of incremental oil was recovered during the production period under the 1000 Mscf/D limitation scenario compared to no incremental oil when the gas production rate was reduced to match actual gas production in the demonstration site. However, the incremental oil under the 1,000 Mscf/D limitation is still only enough to compensate for deferred production during the CO_2 injection and soak phases. The site-specific simulation, suggesting that a high gas rate during production increases oil recovery, is consistent with previous parametric simulations that indicated incremental oil during the production phase was increased when the gas production limitation was removed. Permitting the well to produce at higher gas rates should increase the oil recovered during the Huff-n-Puff, but it is not expected to compensate for more than the oil deferred during the CO_2 injection and soak phases unless a trapped gas saturation is anticipated. The following figure shows the difference between the history match simulation with the actual gas production rates and the history match case with one change. The change, involving a limitation on the gas production rates during the first 65 days, was removed and the well was permitted to produce at a gas rate of up to 1,000 Mscf/D. When the gas limitation was removed the oil response was improved. This suggests not limiting gas production during a Huff-n-Puff.

If the well had been drawn down, higher total liquid rates would have likely been achieved. In addition, if the total liquid production rates in the actual test had been close to those in the prediction, there would probably have been a large oil spike in production. After the pump was put back in, the liquid rate in the demonstration site did increase to pre-Huff-n-Puff levels, and the oil rate did spike up for a few days. The oil-cut stayed above the pre-Huff-n-Puff level for a period of time after the pump was put back in.

In many Huff-n-Puffs that have been described as successful in the literature, the total liquid production rate increased although the steady oil-cut did not increase. These previous reports of increased total liquid may simply reflect a cleanup of perforations or the wellbore, whereas this demonstration utilized a wellbore that had been cleaned out several months earlier--eliminating the unknown variable.

The following figure shows how the history match is changed when the gas production rates are permitted to increase to 1,000 Mcf/D. The oil response is improved. This suggests not limiting gas production during a Huff-n-Puff.

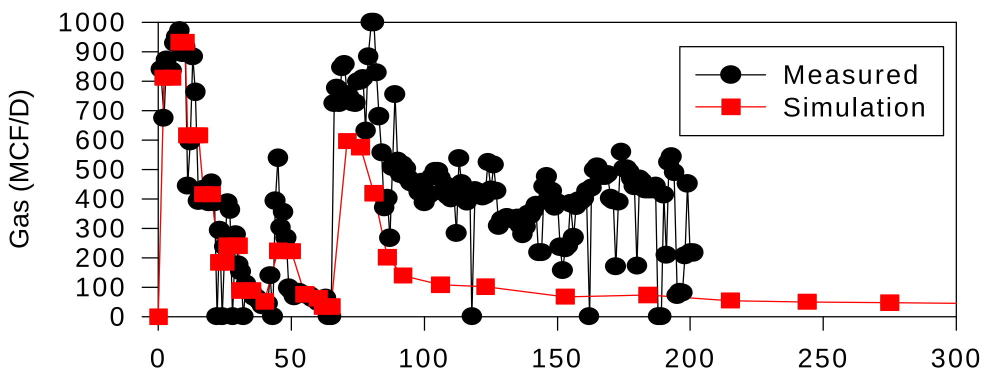


If gas trapping occurred during the demonstration it was short-lived since nearly 100% of the injected CO_2 volume was produced. This was the main mechanism required in theory to provide the improved oil recovery profile developed in the parametric and site specific simulations. Earlier reports detailed the need for a trapped gas saturation. It is theorized that the water production was able to dissolve the trapped gas saturation, or the reservoir is not amenable to gas trapping. The simulation predictions (and history matching) do not include dissolved gas in the water fraction. Although this is known to occur on a limited basis, it could not be adequately simulated with the software which was used due to computational instabilities. Additionally, it is possible that gas trapping cannot occur in this specific reservoir. This might be due to pore throat size, porosity-type, lithologic characteristics, or a combination of these that are not currently understood.

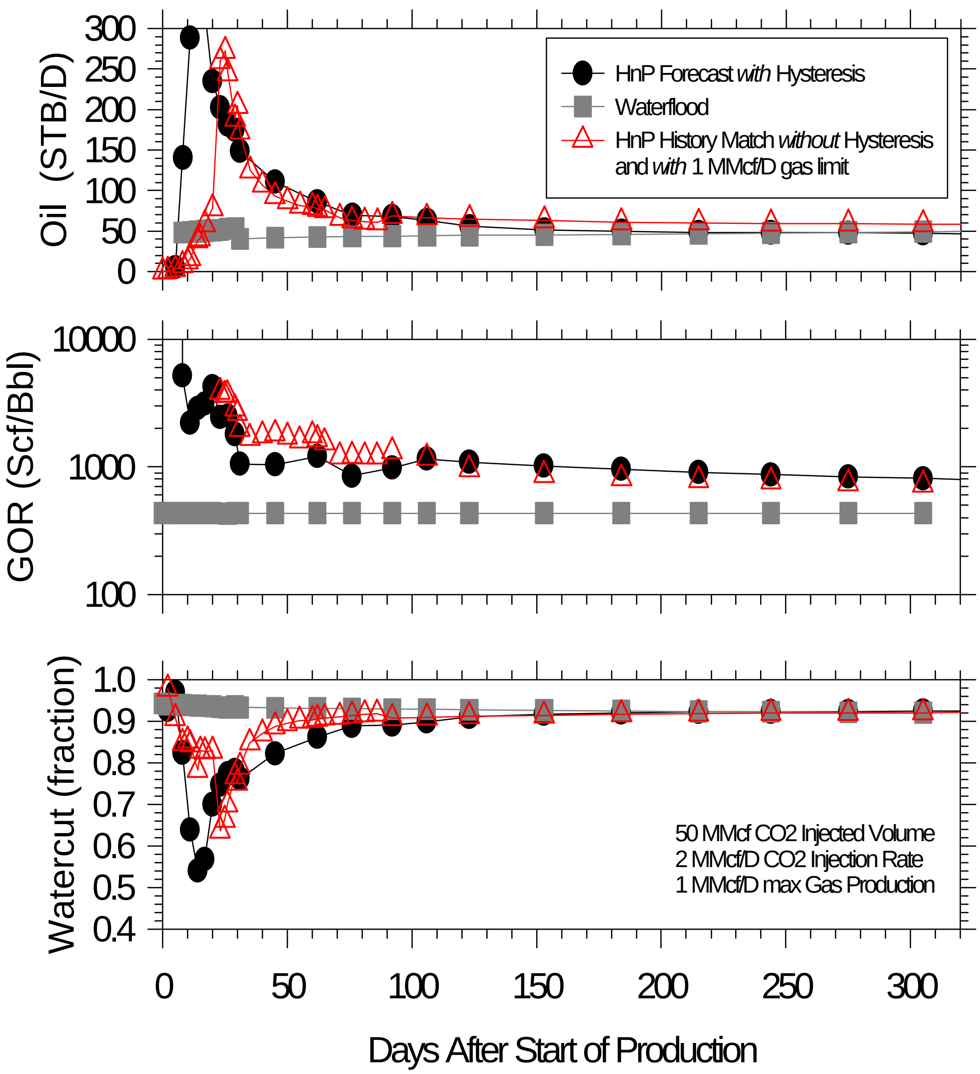
It is interesting to note that near-wellbore gas trapping of CO_2 has been cited as one possible cause of reduced injectivity following Water-Alternating-Gas (WAG) injection methods employed in most miscible CO_2 floods. The offset East Vacuum Grayburg San Andres Unit miscible CO_2 flood operated by Phillips is one of the few Permian Basin CO_2 floods that has not experienced any appreciable reduction in injectivity during 11 years of WAG operations even though many of the other shallow shelf carbonate reservoirs experience 30 to 50 percent reductions in water injectivity following the introduction of CO_2 to the reservoirs. If it can be inferred that reduced injectivity in WAG operations is related to gas trapping, then Vacuum field is not a good candidate for further testing of the Huff-n-Puff technology. Oxy has been experimenting with Huff-n-Puff technology in the Welch field of West Texas. Oxy's Huff-n-Puff results have been favorable enough to expand their program. An offset miscible CO_2 flood within the Welch field experienced reduced injectivity in WAG operations. This suggests that the technology should be applied to another reservoir that has documented WAG injectivity reductions. This option is being pursued. The Huff-n-Puff technology might become a valuable indicator of potential injection rates when designing a miscible CO_2 flood. Injectivity is one of the main parameters affecting the economics of these large scale projects. The failure of the Huff-n-Puff might indicate favorable expectations of injection, whereas a positive response may suggest injectivity reductions--thus the need for the parallel implementation of the Huff-n-Puff technology.

The oilcut in the actual Huff-n-Puff was very high, better than 0.90 for a period of time. The predicted oilcut did not reach such high levels. The high oilcut could not be achieved in the simulation. Although the oilcut was very high, the actual oil rate was quite small in this period--as was water production. The capability of accurately measuring these small volumes may have an influence on the calculated oilcut in the initial production period. It is also possible that water relative permeability curve hysteresis may be required to limit the water production in the simulation. This option is not available in the commercial simulator used. If the total liquid production rate in the actual test during the flowing period had been close to that in the prediction, there would have been a large oil spike in production. After the pump was put back in, the liquid rate in the demonstration site did increase to pre-Huff-n-Puff levels, and the oil rate did spike up for a few days. The oilcut stayed above the pre-Huff-n-Puff level for a period of time after the pump was put back in.

The simulation also suggests that an error in the measured gas production rate may have occurred shortly after the pump was put back in. The metered volumes plateaued after the 100th day rather than continuing to decline. Metered gas volumes from the demonstration site also suggest recovery was 40% higher than the volume injected. The following figure compares the measured and simulated gas production for the history match.



The following figure compares the site-specific prediction with the history match case in which the gas production rate was permitted to reach 1000 Mcf/D. The site-specific forecast also had a 1000 Mcf/D gas production limitation. The main difference between these two cases is that the forecast had gas trapping (i.e., gas hysteresis) while the history match case did not. The absence of the residual gas saturation delays and reduces the predicted oil production.



The history matching efforts validate the decision to not attempt any more Huff-n-Puffs at CVU. In addition to requirements about a trapped gas saturation, there appears a "rate" requirement for a successful H-n-P which cannot be tolerated due to disposal limitations at CVU. If the total liquid production rate during the H-n-P cannot be maintained at the same level (or least a high fraction) of the pre-H-n-P level, then the H-n-P will not be successful because the oil rate will be too small (even though the oil cut might be improved). If this CVU well is typical, a successful H-n-P may not be possible for a well which must be converted from pumping status to flowing status and back again. The liquid production rate during the flowing period would be too low. This work suggests that improved rates may be possible if higher gas volume production equipment can be utilized.

COST & ECONOMIC CONSIDERATIONS:

The actual costs associated with the field demonstration components of the project are included in the following Table under the heading, *No. 1 (Pumped)*. There were a number of non-recurring charges identified that would not be included if a second site was chosen at CVU for another demonstration. Additionally, the volume of CO_2 would not be as large; reducing pump time. The soak period would also be scaled back somewhat. This second option is depicted in the Table as *No. 2 (Pumped)*. The cost of a second site at CVU would be about half the cost of the first site. As originally hypothesized, the largest benefit of this technology would come from coupling it to a miscible CO_2 flood; having pipeline CO_2 available as the project was implemented and expanded. This last scenario is included in the Table as *No. 2 (Piped)*. The availability of pipeline CO_2 makes a significant impact on the cost of the demonstration. The piped CO_2 scenario would cost about one-quarter of the first demonstration.

Field Demonstration Costs

($M)

DEMONSTRATION	No. 1 (Pumped)	No. 2 (Pumped)	No. 2 (Piped)
Deferred Production, Days	43	20	20
Test Separator	34.2	0	0
CO2 Commodity/ Transport/Pump	142.3	79	19
Wireline	5.9	6	6
Downhole*	19.5	15	15
Surface**	42.8	20	20
New Tbg.	15.6	0	0
In-Line Heater	6	0	0
Misc.	17.8	10	10
TOTAL:	284.1	130	70
DOE Share (45%)	127.8	58.5	31.5
CVU Share (55%)	156.2	71.5	38.5

* Pulling Unit, etc.
**Contract labor, welding, transport, etc.

The final Table shows some simple relationships depicting the basic economics of the Huff-n-Puff demonstration along with the two options previously discussed. The same naming convention is applied. In addition to some non-recurring items the field demonstration costs were heavily influenced by the cost of delivering and pumping the CO_2. As can be seen in the following Table, the planned CO_2 volume would not likely be as large for a second demonstration. This directly impacts the amount of deferred production.

The project becomes more attractive if pipeline CO_2 is available. Assuming an $18.00/STB sales price for crude oil, the necessary volume of recovery to reach a pseudo-break-even point is calculated. The cost reductions available for the *No. 2 (Piped)* case begin to look encouraging. The CO_2 utilization in this case looks reasonable at 6.4 Mscf/STB--similar to miscible CO_2 flooding cases. The recovery for the *No. 2 (Piped)* case are similar to expectations derived from the compositional simulations when a trapped gas saturation develops in the near wellbore vicinity.

Field Demonstration Economics

[back of the napkin]

DEMONSTRATION	No. 1 (Pumped)	No. 2 (Pumped)	No. 2 (Piped)
CO2 Vol., MMscf	50	25	25
CO2 Cost, $/Mscf	2.85	3.16	0.76
Deferred Production, STB	2924	1360	1360
TOTAL Cost, $M	284.1	130	70
Equiv. Bbl's @ $18/STB	15800	7200	3900
Breakeven Utilization, Mcf/STB	3.2	3.5	6.4

Additional benefits that are not accounted for in this simplistic review were noted. First, even though recoveries in this demonstration accounted for only the deferred production, there were reduced electrical requirements during the injection, soak and flow period. Secondly, there were reduced water handling requirements for an extended period of time. These benefits, coupled with the potential to recover additional oil suggest further investigation is warranted if the technology is applied to a reservoir amiable to gas trapping.

REFERENCES/PUBLICATIONS

The Petroleum Recovery Research Center continues to provide updates on the project in its quarterly newsletter. In addition, the Petroleum Technology Transfer Counsel, a joint venture between the Independent Producers Association of America (IPAA) and DOE is providing complete quarterly and annual Technical Reports on an Industry Bulletin Board called GO-TECH. This is allowing a more timely dissemination of information to interested parties.