Assessment of a Potential Second Injection Well Site in the Paradox Valley Unit Saline Water Disposal Project

The Bureau of Reclamation Paradox Valley Unit

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1.0 QUESTIONS TO THE CONSULTANT REVIEW BOARD

1. Are existing studies adequate to determine the feasibility and optimum location of a second injection well?

In the narrow interpretation of this question put to the CRB, the response is: No; existing studies are inadequate, more work is needed to carry out the selection process of a second Bureau of Reclamation Paradox Valley Unit (PVU) injection well site. In this report, the CRB will outline a number of methods of more precisely delineating the geoscience and engineering needs to carry out such a selection process.

With respect to the broader view of saline water management in the Paradox Valley, which the CRB was encouraged to consider despite it not being explicitly defined in the remit, the CRB wishes to clearly state that alternatives such as evaporation ponds and land use, pumping or diverting fresh groundwater to reduce deep saline dissolution rates, solar desalination to generate fresher water, or some optimized combination of these alternatives, should be fully evaluated by the BoR with view to reducing the continued injection rate demands on PVU #1 well. At the same time, the CRB wishes to clearly state that these alternatives are outside the domain of our expertise, and other experts must be consulted for these evaluations.

With respect to the optimum location of a second well, there is not yet enough information quantifying the large-scale injection efficacy of the first well as the pressure data and shut-in and build-up pressure response have not been fully analyzed. Once these data are analyzed, there will exist a sounder basis to move forward on the possible selection of a site for a second PVU injection well.

2. Regarding the technical criteria considered by the existing studies for evaluating second injection well sites:

a. Are the identified criteria appropriate and sufficient?

Not entirely. The CRM has several comments in this regard:

- There remains substantial uncertainty about the location of the faults that subdivide the Leadville Formation into discrete blocks. Given that the Leadville Formation is the primary stratum for injection of the saline fluid, its spatial disposition and petrophysical properties should be further clarified before any major decisions are made. There have been advances in a number of technical areas in the last 25 years, and new methods of analysis and evaluation are possible. A brief list is included here.
    - Greatly improved behind-the-casing wireline geophysical logs to assess the near-wellbore environment now exist and could be deployed in PVU #1 during any upcoming intervention to characterize the Leadville and other formations.
    - Better wireline geophysical logs in general are available for open-hole logging if any regional wells (Union Well, Conoco Well) are to be re-entered.
    - Better quantitative petrophysical methods exist for core and drill cuttings. If drill cuttings and core are still available from the original well, consideration should be given to more in-depth study of those materials.
    - There exist gravity and magnetic surface surveys methods that can help extend the value of the existing seismic and borehole information (see comments in

Appendices) and help identify superior targets for the trajectory of a second well or a Union Well side-track.

- The previous studies did not include the microseismic evolution that is now known and been tracked for several decades. Potentially, this information, in combination with the approaches delineated above and in the responses to Questions 4 and 5, may substantially clarify the knowledge of the geological disposition and pressurization of adjacent blocks that may be injection candidates.
    - There should be an evaluation as to whether there is sufficient quality surface microseismic data to use in an inverse mode to increase the details of the seismic velocity models at depth, and this may aid in re-evaluation of the existing information.
    - The spatial and magnitude evolution of the microseismic data should be assessed in terms of the probability of lengthy flow paths (distant pressurization phenomena). In other words, is there a possibility of quantitatively linking the induced seismicity distant from PVU #1 to a regional increase in pressure in the strata?
    - The more sophisticated mathematical methods available today may increase the value of a re-analysis of existing seismic data, but only if these data are enhanced through the addition of supplementary data such as a tomographic analysis of the microseismic data, and perhaps some new seismic information such as Vertical Seismic Profiling (VSP) data near the PVU #1 well.
- Of great importance is the additional stratigraphic and reservoir data that could become available through the workover of PVU #1 and the re-entry of the Union 1-0-30 well (if this is a possibility). If these data are carefully collected and analyzed (VSP data and microseismic data), the stratigraphic structures in the vicinity of these wells will be clarified, and there may even be the possibility of identifying zones of higher porosity and permeability in the surrounding region.

b. Is their relative importance identified and correctly evaluated?

In general, the value of the previous studies is considered to be high, as the general geological disposition and formation properties are well-defined and the analysis and interpretations are solid. However, those studies did not have the microseismic data and the years of well performance information available to them. These sources of information must be accommodated in the site selection process, as suggested elsewhere.

- There remains substantial uncertainty about the location of the faults that subdivide the Leadville Formation into discrete blocks that may or may not be hydraulically connected. Given that the Leadville is the primary formation for injection of the saline fluid, its spatial disposition and petrophysical properties should be clarified before any major decisions are made. There have been advances in a number of technical areas in the last 25 years, and new methods of analysis and evaluation are possible (see the partial list above). The integration of several approaches (seismic, borehole geophysical, magnetic, gravimetry, core analysis) should provide a degree of synergy in delineating the disposition and characteristics of the Leadville Formation at depth.

c. Should additional or alternative criteria be considered?

The criteria for choosing a second well are related as to whether it is actually needed if additional disposal capacity can be accommodated by evaporation ponds or by a workover of the existing well. This is discussed in greater detail in the pages that follow.

d. Are the existing geologic and geophysical studies adequate to reasonably characterize the local geologic structure?

To a considerable degree, yes. That is, the CRB accepts the geological model that exists, and within reasonable limits the geological model is adequate for most purposes because the lateral variability (spatial inhomogeneity) of the strata such as the Leadville Formation is so large that refining the details of the lithostratigraphic disposition to reduce uncertainty may prove to be prohibitively expensive. Nevertheless, in this report we have outlined several methods that can be used opportunistically during a well intervention that could help refine the local geologic structure with view to decision making for the location of a second site. These methods are discussed in greater detail below.

e. Do existing seismic reflection data provide sufficient resolution and areal coverage?

No they do not. However, for various reasons, it is unlikely that this situation can be improved from additional surface surveys because of the difficulty of obtaining high resolution data in this area (topography, salt…). In other words, the seismic interpretation is poor, but not likely to be significantly improved purely by acquiring additional seismic data from surface surveys. If a higher resolution velocity model could be generated by analyzing the travel times from VSP surveys using a wellbore, or tomographic analysis of the microseismic data, it is probable that existing seismic data could be refined to give better control on fault locations, fault throw, and depths in the region of the VSP wellbore.

f. Does information from existing wells provide sufficient stratigraphic control for interpreting the subsurface geologic structure?

In some regions it is adequate, but the poor quality seismic data and the proven inhomogeneity mean it is difficult to interpolate between widely spaced wells, many of which did not penetrate the target formation (Leadville Formation). In other areas, such as the region around the locus of recent microseismic activity to the northeast of the Paradox Valley, there are simply no wells and the seismic data interpretation thus remains largely unconstrained, with too elevated a level of uncertainty to be confident in the details of the stratigraphic interpretation. In this regard, and given the relatively modest additional cost:

- In the workover of PVU #1, a walk-away VSP is strongly recommended, and a microseismic monitoring period within the wellbore should be considered.
- If the option of a second well is chosen, the use of magnetic surveys and gravity surveys will help refine the geo-model before siting the second well completion zone (whether it is a deviated well, a side-track from an existing well, or a totally new site).
- The use of the Union 1-0-30 Well for a walk-away VSP in several directions can refine the seismo-stratigraphic model.

g. Have characteristics of potential reservoir formations adequately been considered, such as ultimate capacity, fracture and flow properties, pressure limits, and availability of suitable confining layers?

No, and recommendations have been made to reduce the uncertainty in the possible reservoir parameters, including detailed well pressure fall-off analysis to examine the evolution of the reservoir parameters and other factors. Furthermore, induced microseismic data suggest that the bounds of pressurization in the subsurface is increasing in areas where previously it was thought that there was no pressure communication, therefore the “effective” reservoir area (volume) may be increasing with injection and pressurization.

3. Do the existing studies and documentation adequately consider the feasibility of drilling and maintaining the structural integrity of a second injection well? Have available technologies been considered fully, such as directional drilling, horizontal drilling, or methods for drilling and completing a well through thick sections of salt?

No, the existing studies do not have all of the relevant data (fracture gradients, borehole breakouts, velocity data for all wells, drilling logs, etc.). However:

- We believe that with modern drilling methods there are no serious barriers to drilling any reasonable well profile from the existing well, from an offset site such as the Union 1-0-30 Well, or from a new, more remote site, even involving drilling through great thicknesses of salt (see comments in Appendices).
- Existing drilling methods should be able to achieve target depths in substantially less time and with lower risk than methods of 30 years ago.
- If the additional studies detailed below succeed in identifying a favored target for a second well or for a deviated borehole from an existing legacy well, such as the Union 1-0-30 Well nearby the PVU injection well, the CRB sees no technical barriers of any kind that would prevent drilling and completion of a wellbore adequate for saline water injection.

Nevertheless, before a decision is made to drill another well, assuming that additional injection capacity is deemed necessary or assuming that the injection pressure limits will be soon exceeded, the CRM recommends that the option of increasing the injection pressure limit in PVU #1 by perhaps 1000 psi be seriously evaluated:

- This would effectively extend the life of the well for a number of years, given current behavior.
- There is a reasonable possibility that the increased pressures will have favorable flow capacity effects on the available flow paths by increasing the transmissivity of fractures and faults because of increased pore pressures and lowered effective stresses.

Injection is already taking place at pressures above the fracture pressure, and the thermal shrinkage effects in the near wellbore region are probably aiding in the process of injection by causing increases in the aperture and hence flow capacity in the local wellbore region (several thousand feet). Along with an increase in the injection pressure, it is almost certain that there will be an increase in induced seismicity. The BoR must assess this probability in the context of the local community, but the CRB believes that the induced seismicity of itself will not impair the existing wellbore.

The CRB suggests that there is a series of explicit steps that should be undertaken to arrive at a more informed decision. Specifically:

- We recommend that a careful study of the pressure build-up and fall-off behavior history of the current well be executed to evaluate whether the gradual pressure-build up is indeed a far-field pressurization process, or is more related to near-field flow impairment processes that might be rectified more economically.
- Based on the results of the long-term behavior of the well region response recommended above, we recommend that the BoR then evaluate the potential of a full workover of PVU #1 to re-establish flow communication within the wellbore with all of the perforated zones in the vertical sequence below the Paradox salt that have potential to accept flow. Because of the nature of the flow paths at depth (fracture dominated) and the compartmentalization of the reservoirs at depth (sealing and leaky-fault bounded), it is important to assure that full flow communication be established with all potential zones below the salt (Leadville and upper PreCambrian strata). A workover will include:
  - Assessment of well integrity to see if there is a possibility of evaluating whether there is any significant current leakage of saline injectant upward behind the casing of the well.
  - Assessment of current wellbore state (plugged zones, squeezed zones, shear displacement generating dogleg…).
  - Execution of behind-the-casing logs in sections of the production casing where it is considered appropriate and valuable to assess the strata or any changes in the near-wellbore environment.
  - Spinner flow surveys to assess where injection is occurring.
  - Clean out of bottom-hole junk and evaluating scale conditions. The CRB believe that injection is only taking place into the upper Leadville Formation at the present time because of junk and the accumulation of material in the bottom of the production casing. If opening up the lower horizons opens new flow paths, the well injection capacity may be sustained while the rate of pressure increase is reduced somewhat.
  - A walk-away VSP (Vertical Seismic Profile) should be performed when PVU #1 is available. (See additional discussion below.)
  - Evaluating whether formation stimulation treatment and additional perforations should be carried out to re-establish or guarantee injectivity in all appropriate zones (behind-the-casing logs will help this assessment).
  - If considered desirable, and this must be assessed by experts once the workover process is partially underway, it is feasible to increase the injectivity of the PVU #1 through hydraulic fracture stimulation and the placement of high strength proppant. (Of course, if the well testing and analyses clearly demonstrate that the pressure increase is because of far-field pressurization at the reservoir scale, this step will help only marginally.)
  - An additional approach is to recomplete the PVU #1 well with an inclined section directed in an appropriate azimuthal direction so as to intersect a greater length

of permeable rock, and perhaps to intersect an adjacent block (such as to the northeast or to the southwest) that remains partially hydraulically isolated.

4. If existing studies are found to be inadequate, what additional studies should be considered, and what are their likely relative benefits and costs?

Please refer to the recommendations listed above, and to the additional recommendations and discussions in the text that follows here and later in the report.

As mentioned in the responses to previous questions, the CRB noted that there exists substantial uncertainty in terms of the geological model, the specific dispositions of target injection strata, and the state of those strata in terms of petrophysical and mechanical properties. The following actions are intended to reduce this uncertainty in the quest for a good second well location and completion interval selection.

- After the actions suggested above with respect to the existing well are carried out, followed by a full re-evaluation performed to see whether a second injection well is still necessary, it is recommended that the nearby Union Well be re-entered for the following activities:
  - Assess whether inter-formational leaking of saline injectant is taking place through the Union Well pathway (up or around the casing or in the damaged rock zone surrounding the wellbore).
  - Carry out a walk-away VSP in several directions from as deep in the well as possible, assuming it is possible to reach the original depth.
  - Evaluate whether the Union Well could be re-habilitated and re-completed as a second injection well.
    - If yes, it is necessary to evaluate the use of the Union Well as a deviated injection well accessing a region of the surrounding rock mass that is currently not experiencing significant effects from the PVU #1 injection activity, and could take a sufficient volume of saline injectant. It is estimated that the lateral off-set would be on the order of a half-mile if an adjacent block is to be accessed.
    - If yes and it is deemed that adjacent blocks are already subjected to pressure increases (as evidenced by microseismic assessment and well assessment), a sidetrack from the Union Well involving a horizontal well segment to access the strata in the vicinity of Conoco well (under the middle of the salt diapir) should be considered.
    - If no, and drilling an entirely new second well is considered to be the best alternative, the Union Well should be converted into a monitor well for pressures in several horizons (e.g. above the salt) as well as installation of geophysical instrumentation (e.g. downhole accelerometers) to more precisely delineate the locations and evolution of induced seismicity.
    - If no, and if there is evidence that the Union Well is a conduit for saline injectant migration into other zones, this situation should be rectified by an appropriately executed sealing program, in conjunction with the pressure and sensor installation recommended above.

- Assume that the Union Well is deemed not suitable for use as a kick-off point for another saline water injection well and that it is still necessary to choose a different bottom-hole location for the second well. This decision will be facilitated by the refined stratigraphic model that will be developed by the walk-away VSP, and also by several months (6-12 months) of microseismic data to be collected during continued injection into PVU #1. These additional data will prove of great value in deciding where to place the completed zone of the injection well because they will more clearly delineate the fault block structure and give additional insight as to the pressure condition of the surrounding blocks.

These issues should be assessed and examined for an appropriate forward-looking time frame. For example, surface evaporation ponds are likely to be permanent (+50 years), and the impact on the local community and land use over that time frame must be assessed. Similarly, if groundwater re-direction and management are used, the time line must be evaluated. Finally, we note that induced seismicity will continue, and appears to be manageable, but the BoR geophysical personnel should continue to perform forward-looking probabilistic analyses of the evolution of seismicity magnitude and location.

5. Are there other issues, opportunities, or concerns the CRB believes are appropriate to raise concerning the determination of an optimum location for a second injection well?

Elsewhere in this document, the CRB raises a number of questions that should be answered if possible, recognizing that there will always remain a considerable degree of uncertainty because of natural geological inhomogeneity and spatial variability. The answers to these questions may affect somewhat a site decision, or at least clarify the current conditions.

A number of recommendations to move this decision-making process forward are made. More specifically, the CRB recommends gathering additional information during the course of these investigations in order to refine the existing stratigraphic model (depths, thicknesses, fault throws, etc.). Fulfilling these recommendations will provide more information upon which to make decisions. However, without drilling, a degree of uncertainty will remain concerning:

- The porosity and permeability of the Leadville Formation and underlying strata that may have been taking some of the injected saline water.
- The thickness of the Leadville and underlying strata.
- The local salt thickness in areas where it is known to be thin or draped over fault structures. In some areas, it is possible that the salt is absent.
- The condition of the adjacent faults and their roles as hydraulic seals or conduits for the more distant migration of the saline injectant
- The volume of contacted “reservoir” that will be achieved by a particular trajectory.
- And many other factors…

Even with drilling, it is challenging to extrapolate the data laterally a great distance because of the poor quality of the seismic interpretations. Thus, there will always be a substantial residual uncertainty level, no matter what actions are taken to reduce the general uncertainty level.

We note that the current distribution of induced seismicity is distant from the sparse population centers in the Paradox Valley, and this is considered desirable; injection sites that would increase the induced seismicity level near to populated areas should be down-graded in terms of suitability.

We emphasize that induced seismicity will continue for several reasons:

- Pressurization of volumes of rock at a distance because of the low porosity and the relative incompressibility of the saline injectant, leading to a decrease in the effective frictional strength of the faults and fractures.
- Stress redistribution on the scale of the pressurized region because of the pore pressure effect.
- Stress redistribution on a smaller scale around the injection well because of the massive cooling (≈100°C) associated with injection of cool saline injectant.   This effect will remain far more local than the pressure and stress effects.

There are a number of ideas that the BoR must evaluate in order to achieve their goal of sustaining the rate at which the saline water is being handled. Some have been alluded to above, but we list them explicitly here for clarity and emphasis.

- Deviated and horizontal trajectories from existing wellbores are likely to be considerably less costly than new wells. Furthermore, they may, by virtue of their contact length, access additional fault blocks positively with regard to rates and slowing of pressurization.
- If the rate must be slowed down to keep injection pressure constant (i.e. regional pressurization effects) and an increase in the injection pressure is not possible, it is likely that a continued slowing of the rate will take place. This will be slow enough that the excess saline fluid can be handled by evaporation ponds that are slowly increased in area with time.
- It may be possible through groundwater management using shallow wells at the surface to reduce the amount of saline brine coming into the system through re-direction and interception (see comments in Appendices).
    - A designed row of groundwater wells can be installed not only to pump saline water, as at present, but to inject fresh water to create barriers to flow through the reduction of hydraulic head. The current system increases the hydraulic head and, in the long-term, increases the flow rate by increasing the magnitude of the sink, and therefore contributes to the dissolution rate of the salt at depth. If the gradient and rate can be diminished by such a groundwater management strategy, it could mean less saline water to inject.
    - This could potentially be done sequentially at a rate that could keep up with the rate of injection capacity loss in PVU #1, delaying the time at which additional deep drilling activity is needed.
    - The possibility of this approach to reduce the flux and therefore reduce the demands on PVU #1 would require a detailed hydrogeological study of the paradox valley to the northwest of the Dolores River, including modeling to allow sensitivity analyses and impact assessment.

1.1. Additional Comments

There is a possibility to achieve lower second-well costs through the use of new casing materials such as carbon-fiber reinforced plastics instead of hyper-expensive metal alloys. Similarly, BoR should seek ways of reducing surface facilities costs and avoiding duplication of surface facilities, such as locating a second well-head nearby so that short-distance pipelining of pressurized brine can be used, and so on.

In terms of scale and time, the PVU #1 represents a unique and valuable long-term experiment related to earth stresses, waste disposal, induced seismicity, well management and control of seismicity, and so on. Some of the potential benefits of looking upon the BoR activity as a major applied science project include:

- There is large social and scientific value in using the Unit's activities to train highly qualified personnel for the scientific community.
- The work undertaken to date and the use of the microseismic sources to refine the analyses can lead directly to a far more sophisticated geophysics/geoscience model of the Paradox Valley system.
- Furthermore, this study could become a case study of geoscience use, and in the future new seismic methods and modeling methods that are developed could be field tested in the Paradox Valley system, either through direct field use or through re-analysis of an unparalleled data set.
- Continuation of the PVU and continuing to collect detailed pressure response data and microseismic response, while refining the geological model, will be a major contribution to geosciences because there has never been, to our knowledge, such a detailed data collection and evaluation process in an interesting practical example before, over such a long time period.
- The long-term PVU data can serve as a template and case history of great value, with ramifications for other areas such as enhanced geothermal systems, deep toxic waste disposal, deep process water disposal microseismicity (e.g. recent issues with microseismicity at Ohio and Oklahoma water disposal wells), CO_2 sequestration, and other geoscience and georisk issues.
- The CRB suggests that the PVU consider undertaking more explicit cooperation with appropriate research organizations (Lawrence Berkeley National Laboratories) and universities to leverage the value of the PVU data and long-term analyses.

2.0 GENERAL ISSUES

The presence or absence of the Leadville Formation itself is uncertain at a scale of kilometers because of lack of well control and the inability to get better-quality surface seismic data and therefore more adequate interpretations. Also, there is a lack of knowledge of the porosity and permeability conditions of the Leadville Formation and the underlying strata (including the Pre-Cambrian schist) at a scale of 100's of meters, or even the variability between the fault blocks. This may be significantly improved with better seismic data from VSP and microseismic modeling. This uncertainty and spatial variability is evidenced by the large differences in porosity between the Union 1-0-30 well and the PVU #1 well, demonstrating that there is great uncertainty and lateral heterogeneity in these vital parameters. Furthermore, the Leadville is well-known for karstic features, and it is not at all clear how widespread karst features are in the region, and if these features are unequivocally higher permeability zones or not. If higher resolution seismic models could be developed using VSP and microseismic data, it is possible that adjacent fault blocks could be better characterized for injection purposes.

The implications of the lateral variability and heterogeneity, for various reasons (fault proximity, matrix vs. fracture flow…), are:

- There will always be substantial uncertainty in important parameters (porosity, permeability, compressibility) no matter what type and amount of data are available,
- Additional geophysical data will constrain, but not eliminate all of the uncertainty, and,
- It is too expensive to drill additional wells merely for the acquisition of additional stratigraphic data to constrain a second well location.

The injection pressure buildup with time at PVU #1 that has been clearly described and seen in the pressure-time plots, as well as the change in the slope of the pressure buildup with time, can be affected by a number of factors, including the following:

- The far-field drainage boundary condition of the Leadville Formation at the scale of 10s of kilometers.
- The porosity and compressibility of the rocks which are in hydraulic connectivity with the PVU #1 well, as well as the nature of the permeability (matrix porosity dominated or fracture dominated)
- The spatial intensity of the natural fractures from place-to-place, and whether these natural fractures in the Leadville Formation and deeper strata are vertically continuous at the scale of meters to 10 meters. For example, it could be that the areas near the faults are well-fractured, but the rock mass in the regions between faults is far less intensely fractured.
- The temperature effects ($\Delta T = -180°F$) in the intermediate field of PVU #1 , which will have caused stress and fracture aperture changes, which in turn have likely affected the permeability, and therefore the pressure distribution in the intermediate and far field regions.
- An increase in pressure can also change the value of the permeability by allowing fracture aperture increases or decreases (a poroelastic effect).
- The far-field pressurization effects at distances on the order of the distances of remote injection-induced seismicity, which will in turn reflect the differences in the distribution of permeability and porosity.
- The degree of hydraulic connectivity that exists between the Leadville and the Pre-Cambrian basement schist and intervening strata, and the ratio of large-scale vertical to horizontal permeability in this section.
- Any potential change in the sealing characteristics of the bounding faults as the bottom hole pressures continue to slowly rise and as the temperature effects in the near-vicinity of the PVU #1 well propagate outward. (Is the recent outward migration of seismicity evidence of loss of vertical seal of a well? Or is it evidence that the bounding faults are starting to leak with the higher pressure, or have changed effective stress or increased permeability from the small shearing events – the microseismic events?)

Clearly, there will remain a **strong residual uncertainty** in the site assessment criteria quantification no matter what data are collected, thus a semi-quantitative cost-benefit approach must be implemented to assess what actions are the most likely to reduce uncertainty incrementally and sequentially in a series of logical steps.

Perhaps the most important technical activity the BoR can do at the present time is to develop a comprehensive ROAD MAP, based in part on this report and on input from the experienced professionals of the BoR. It is recommended that a 4'×8' white board with multi-colored sticky tabs be used for this purpose, with planning meetings to develop the road map.

3.0 MAJOR RECOMMENDATIONS

The remit of the CRBM in this PVU study was to assess whether the information available was sufficient to choose and site a second well. During discussions, and because of a somewhat broader interpretation of the remit, the CRM has attempted to answer the basic question and recommend actions to be taken to rectify deficiencies. However, the CRB believes that it is appropriate to point out other options and to identify ideas that may be of more general interest to the entire evaluation process being undertaken by the BoR.

The BoR should consier the evaluation of options such as groundwater management and the use of solar evaporation ponds to see if non-drilling possibilities exist for achieving the desired saline fluid disposal rates with time as the primary PVU #1 well loses rate capacity because of pressure limitations. Also, the possibility of an increased pressure limit should be investigated, although it is almost certain that this would be associated with a rise in the microseismic activity. If these alternatives are deemed unsuitable for cost, environmental, or social reasons, a second well possibility should be investigated further.

From a drilling standpoint, it is critical to determine the proposed bottom-hole location so that a detailed drilling prognosis could be developed. Because of directional drilling capabilities that are widely available, the surface wellhead location does not need to correspond to the bottom-hole location. Once the appropriate geological and geophysical conditions have been determined and led to a bottom-hole site selection (or a list of potential sites), then the drilling and completion engineering team can determine surface drilling location. This decision would be based on topography, geology, and operational considerations such as use of the current well site for a second well because of facilities proximity, etc.

The ideal case would be to be able to either save the current wellbore, re-enter a nearby old wellbore and directionally drill out from there, or build a new wellbore very close to the current well. This would shorten any distance from the existing pump station and minimize the environmental footprint of a new pump station. This would save an enormous amount of funding as a new facility with attendant material property costs would not need to be built.

4.0 THUS, THE CRB BELIEVES THAT THE OPTIONS FOR A SECOND INJECTION SITE, IF DEEMED NECESSARY, SHOULD BE PURSUED AS FOLLOWS:

4.1. Option 1

First, the existing well should be subjected to assessment and a workover if it is found that there is near-wellbore flow impairment, and it should be cleaned to bottom and re-tested for injection capacity (the CRB believe injection is only occurring in the top of the Leadville Formation). There is a reasonable probability that this will stop the pressurization, or at least reduce the pressure build-up rate, as long as additional porosity and interconnected permeability can be encountered in the Lower Leadville and the Pre-Cambrian strata. During the workover, precise seismic information can be collected to refine the geological model. Probably the most economical approach is to execute walk-away VSP (vertical seismic profiling) in several radial directions before finalizing the workover.

During a workover, a period of microseismic monitoring in the well should be considered, although this means that injection cannot take place during the period of monitoring. This can be integrated with the VSP survey, which is an active seismic method, rather than a passive method. Typically, a set of hydrophones or wall-locking triaxial geophones can be installed in a down-hole mode in the lower part of the wellbore. These are then used to collect VSP data and are left in the borehole for a period of a week or more to passively collect the waveform data from the regional microseismic emissions that are taking place. The spatial resolution and frequency content of the received microseismic signals are substantially superior to ground-surface based geophones. This permits a high detail stratigraphic interpretation, and the availability of high resolution microseismic data can be combined with the VSP and the existing seismic data to give a more detailed geological model of the region around PVU #1. The basic reason that a high quality interpretation will be possible is, first, the combination of several data streams (conventional surface microseismic data, VSP, conventional surface seismic data and the down-hole microseismic data), and second, the availability of data from depth so that the effects of the intervening strata and the attenuation of the signals are reduced.

Note that as part of other Options below, the CRB also advises that consideration be given to better system characterization using these methods.

4.2. Option 2

If a second well is indeed needed, and the Union 1-0-30 well can be successfully re-entered, it can be used to kick-off a deviated well at a depth of perhaps 8000′-9000′, most likely in the NE or the south-east directions, and the design of this deviated well section, as well as its completion strategy, should be to intersect the more permeable zones and to enter into at least one, perhaps two, fault delineated blocks to provide additional injection capacity. There must also be a VSP executed from this well before it is deviated, and perhaps a prolonged period of microseismic monitoring as well, to help choose the optimum trajectory for the deviated wellbore and the best locations for perforations. Under exceptional conditions, depending upon need, it will be also possible to drill more than one lateral branch, perhaps into different fault blocks, so as to increase the injection capacity of the well. If this well cannot be re-used, it should be instrumented for pressure and for microseismic monitoring measurements to help understand the flow and stress evolution in the region. Note that two or three pressure measurement sites, perhaps in the Precambrian, in the Upper Leadville, and in the strata above the thin Paradox Salt, would be highly valuable in constraining any reservoir or seismic modeling in the futures, and aid in the microseismic data interpretation as well.

4.3. Option 3

If the Union well cannot be re-used, and a second well is deemed necessary, we recommend it be drilled relatively close to the existing PUV #1 well and deviated laterally to intersect the most appropriate fault blocks and high permeability zones as delineated by the additional investigation activities that have been recommended. This means the well drilling and wellhead can be located close to existing facilities, create a lower level of disturbance in the region, and be easier to manage. Note that the additional VSP seismic data and an improved velocity model from a detailed inversion of the microseismic data (velocity structure and quality tomographic reconstruction) can be used to enhance the existing surface seismic data as well, giving a far more precise delineation of the subsurface structure details, perhaps even identifying zones of better flow properties. As stated above, such a well could be completed with more than one lateral branch to increase its access to different zones and fault-delineated blocks that are not in full hydraulic connectivity.

4.4. Option 4

Although the exotic alloys and the completion of the current PVU #1 well may make such a choice a bit more problematic (and this may be the subject of a technical evaluation in the future), it is also possible to use the current well to install an additional lateral branch that is deviated to intersect adjacent fault blocks that are currently not penetrated by the vertical well. This option, although listed as OPTION 4, is not meant to be an inferior option to the two previous ones, providing that the suspension of the well for the requisite time can be accommodated, because the capabilities for deviation and drilling of horizontal sections at great distance have advanced tremendously in the last 15 years. For example, it is possible, after cleaning the well to bottom, to install a lateral branch 3000′ long to intersect the more permeable zones in the Upper Leadville Formation in the fault block to the northeast (this is not a recommendation, merely an example option), thus increasing the injection capacity of the well, that is, decreasing the rate of pressure build-up.

4.5. Option 5

If these options are deemed not to be suitable, the next options should be pursued, although they are considered far less desirable:

1. Examine other plugged and abandoned wells in the region for possible re-entry and use, including the possibility of deepening the existing wellbore, drilling a deviated well from an intermediate depth, and horizontal section installation for the injection portion to increase injectivity (increase in the injection capacity at a given pressure). For example, the Conoco well drilled to the northeast of the PVU #1 well is a possibility for re-entry and installation of a second well, but it is likely that that borehole has experienced salt closure and cannot be re-entered easily. Clearly, a more general economic evaluation will be part of the BoR examination of alternatives.
2. Choose an entirely new site some distance away from the existing site. This alternative carries advantages and deficiencies. Advantages include the possibility of accessing more highly favorable injection intervals; disadvantages include additional costs for surface facilities.

5.0 ANCILLARY RECOMMENDATIONS AND COMMENTS

1. Evaluate the current well extremely carefully before spending a great deal of capital on choosing a second well site (if other options are deemed unsuitable). Some of the issues are:
    a. Is injection brine actually getting into the lower strata below the upper part of the Leadville Formation? Are the strata vertically connected hydraulically? What is the volumetric sweep efficiency in the porous and permeable interval? Is flow concentrated along the fault planes where more fractures in the rock would be

expected, or is flow more uniform? The CRM recognizes that complete answers to all of these questions will not be achieved, but some indication of the flow paths and conditions at depth will facilitate the decision making process for a potential second injection site.

   b. Would the well pressurization rate stabilize or increase more slowly if a full well cleanout and intervention were performed, including the possibility of hydraulic fracture stimulation with aggressive propping?
   c. What would be the magnitude of the benefit in cleaning, reperforating, acidizing, hydraulic fracturing, or otherwise stimulating the PVU #1 well?
   d. Is a short radius horizontal section drilled within the Leadville likely to improve the injectivity sufficient to reduce the rate of wellhead injection pressure increase?

2. Pressure-time analysis on PVU #1 pressure build-up data and the pressure fall-off data dating back from the beginning of injection and done on all the high quality data since that time must be carried out to try and answer the following questions:
   a. Is there a strong mechanical skin effect that has, over time, developed in the near (10 m) and intermediate (100 m) regions around the wellbore?
   b. Can the presence of the purportedly sealing faults striking NW-SE and located to the NE and SW of PVU #1 be identified and verified as sealing lateral barriers (no-flow boundaries) in the Δp-Δt analyses over time (from 1991 to 2012)?
   c. Has the flow regime evolved over time from radial flow (early in the PVU #1 history) to linear flow (later in the records) confined between the bounding faults?
3. The wellbore should be carefully profiled to detect any casing deformation. Apparently, the last profiling was carried out in 2001, and a new profile acquisition will require well shut down and tubing pulling to carry out these tasks. Furthermore, it will likely be necessary to do a live-well intervention under the circumstances because it takes too much time for the wellhead pressure to drop to zero (A $CaCl_2$ kill fluid, very cheap, can likely be used). A live well intervention (workover) is more expensive than doing an intervention in a well that has been killed, but it may be preferable to the use of a kill fluid of high density. The CRB notes that the risks associated with a possible surface spill of brine during a well intervention are small because the safety and environmental consequences of such a spill are minor.
   a. Is there merit to executing a spinner survey in the wellbore to find out which perforations are open (under injection conditions)? This will indicate in which perforation intervals the formation is taking the fluid, and how much. Knowing the injection profile will give insight into the potential injectivity of a second well, which could, for example, help decide where to place a horizontal well injection section to achieve maximum efficacy.
   b. Is there any ellipticity in the production casing developed through the Paradox Salt interval above the Leadville? Early detection of ellipticity that is continuing to develop and may eventually impair PUV #1 would mean that mitigation actions could be planned in advance, to coincide with a shut-down period. Furthermore, if such an effect is detected, it may have implications for the design of a potential second injection well.
   c. Is there any shear distortion indicating slip along any bedding plane interface between lithologies?

   d. Is there any other distortion of connections or casing that would indicate that the hydraulic integrity of the cased wellbore could be impaired in the future (10-20 years)?
   e. Does a cement bond log of the production casing show good bond integrity?
   f. Is there merit to obtaining a temperature profile in PVU #1 after a period of non-injection, or has the wellbore region been cooled so much that no ΔT response will be seen in a reasonable time frame?
   g. Are there any other behind-the-casing logs that would be valuable to run (gamma, density log, neutron porosity, acoustic log…)?
   h. Is there merit to a VSP run at the time that a major well intervention would take place (see Seismic Analysis Section)?
   i. Should advantage be taken of the intervention to assess other issues such as the corrosion state of the Hastalloy and the CYS 95 casing, the presence of any scale or other debris, etc.?
4. Microseismic Analyses
   a. We recommend that the BoR consider installing a high-T wall-locking triaxial borehole accelerometer array into the PVU #1 well to collect the decay of microseismic activity as the pressure gradually equilibrates soon after commencement of a shut-in period.
   b. We recommend that other near-by well locations be evaluated for the possible installation of a down-hole accelerometer array. This evaluation can extend to any well, not just wells penetrating the Paradox salt. A vertical array will provide a great deal of constraints on the depth locations of the microseismic events, and also aid in tomographic velocity model optimization for the region.
   c. The seismologists should provide images that allow the assessment of the time and space migration of the microseismicity, tied to the stratigraphy as much as possible. Pseudo 3-D images with microseism magnitude (size of bubble) location and time (color coded) could be developed.
5. Analysis of Other Wellbores, Other Oilfields
   a. Lisbon Oilfield, where there exist far more detailed structural data and geological studies, should be examined to see if there are geological analogues that would be useful to the task of 2nd well site selection.
   b. Consideration should be given to opening Union 1-0-30 for the following reasons:
      i. To guarantee that the Union 1-0-30 Well is providing a hydraulic seal between the Leadville and the strata above the Paradox salt seal. Has the salt totally closed the borehole?
      ii. To assess the temperature change and the stress state in the Leadville Formation around the PVU #1 injection well so that a data point is provided to help constrain any reservoir modeling or other calculations.
      iii. To see if there has been any borehole deformation or other evidence of salt mobilization that would indicate concern for a second well location.
      iv. To provide a location for possible installation of pressure monitoring at depth (perhaps in several horizons, again constraining the reservoir modeling and the microseismic interpretation).

v. To obtain a quality velocity model in the well to improve the location analysis of the microseismic data.
vi. To provide a site for the installation of a string of borehole accelerometers for refining the microseismic interpretation and tomographic velocity model. Such an installation would also be highly valuable if a walk-away VSP were ever performed in the PVU #1 well.
vii. To assess the condition of the Union 1-0-30 Well as a potential well from which a deviated wellbore could be installed to provide a second injection site.

c. Drilling logs and records of the nearest offset wells (at least the Union 1-0-30 and the Conoco wells, perhaps also the Chicago 1) should be examined for any evidence of lost circulation, drilling problems, or other information that could be valuable to assess conditions at depth and the approach to future drilling at a selected site.

6. Seismic Reflection and Refraction Analysis
    a. Seismic reprocessing of existing data is not likely to provide significant additional value and is not recommended at this time.
    b. Given the rugged topography, a high-resolution 3-D seismic survey carried out from the surface in the area surrounding PVU #1 is not likely to give a great deal of additional structural information, and would be expensive.
    c. Given the lack of holes NE of the salt diapir, there is little merit to executing high-quality surface seismic surveys in that region because of the lack of a calibration wellbore to formation tops, and the lack of a wellbore-calibrated velocity model.
    d. Thus, at the present time, we do not recommend any additional re-analysis of the currently available surface seismic data, nor do we recommend new seismic surveys carried out at the surface. (This does not apply to down-hole seismic data acquisition approaches.)
    e. We do recommend that the potentially high value of a radial “walk-away” vertical seismic profiling (VSP) be considered during the period when a shut-down or a remediation of PVU #1 takes place. In particular, locating the cross-cutting strike-slip faults with greater precision in the NW-SE directions, or the locations of the normal faults in the directions to the SW and NE of the PVU #1 well can be achieved with a quality VSP survey.
    f. We recommend a walk-away VSP be undertaken if the Union 1-0-30 well is re-entered, to further refine the seismic interpretation.
    g. We recommend considering that when the PUV #1 well is re-entered for a workover, a microseismic wall-locking string be lowered into the base of the hole and the microseismic activity be recorded for some time as the regional pressures dissipate. With a number of wall-locking 3-D geophones in place, the locations and characteristics of the microseismic activity in the vicinity will, in combination with the surface microseismic data, be able to be analyzed with great precision, and this can increase the reliability of the velocity model for the vicinity of the well.
    h. Similarly, if the Union 1-0-30 well is successfully re-entered, we recommend that a VSP be performed as soon as the well is cleaned to depth.

  i. Similarly, the Union well, immediately after the VSP, if it is not going to be used for a second injection wellbore, should be instrumented with a wall-locking 3-D geophone string for monitoring while injection is taking place in the PVU #1 well, for the same reasons as delineated above.
  j. If it is deemed that the Union well is suitable for use for drilling an offset deviated well, a decision will have to be made at that time whether it is economically justifiable to instrument the well with downhole microseismic sensors for a period of time before returning to the well for continued drilling. In other words, the value of the additional refinement of the seismic stratigraphic model and the possibility of identifying regions of higher porosity and permeability in the vicinity must be weighed against the additional rig mobilization costs.

7. Microgravimetric and Aeromagnetic Surveys
    a. Gravimetric techniques could provide more detail on the distribution of salt because of the sharp density contrasts between salt and the other lithologies at depth.
    b. Aeromagnetic data would provide better constraints on the locations and throw of the faults at depth.
    c. We have not done a cost-benefit estimate for these or other related geophysics methods; they should be evaluated for cost-benefit in the context of refinement of the geological models for site selection for the second well.
8. Reservoir Calculations
    a. We recommend that a simple volume balance model be developed to study (estimate) the lateral extent of the zone that has been invaded by injected brine. Inputs to this model would be average porosity, location of assumed sealing faults (and hence areal extent of fluid displacements), displacement efficiency of the invading fluid, assumptions as to the vertical extent of the sweep, and so on.
    b. We recommend some simple convective heat transfer calculations to estimate the volume of rock that might have been cooled because of the lower temperature of the injection water. This can then be compared to the assumed thickness of the Leadville formation that is taking brine, and a few simple thermoelastic calculations can be done.
    c. Although at this stage of assessment it is not a strong recommendation, we suggest that the BoR consider commissioning a geomechanics simulation expert to carry out some preliminary (first-order) calculations of the changes in the poroelastic stress field arising from the increased pressure and the convective-conductive heat transfer effects around PVU #1, assuming that the BoR injection block is sealed to the NE and SW by bounding faults and that pressure transmission and flow is dominantly to the NW and SE. Although this will be a rough model, it may, in combination with the microseismic data and with the refined stratigraphic model from the VSP, microgravity survey, and other activity, give insight to the changes taking place in the stress fields and therefore the evolution of the microseismic activity.
    d. Request an opinion of a reservoir engineer as to the feasibility of a simple (single-phase flow) reservoir simulation of the PVU #1 injection geo-system at depth. This should be a relatively simple problem except that there are no pressure data outside of the PVU #1 well to constrain the analysis.

6.0 QUESTIONS OF INTEREST

These ancillary questions are related to various issues arising in the evaluation of options for the second well location in the Paradox Valley Unit.

1. Is the current metallurgy appropriate for the brine and Temperature conditions (80 ppm H_2S)? Is there a cheaper metallurgy that would suffice? The cost savings would be substantial. Some years ago, the USDoE (NPTO) had a research project on development of reinforced plastic casing. More recently, the development of carbon fiber-reinforced composites (such as the material used to build the body of the Boeing Dreamliner) has advanced to a state where the strength of a casing should be fully sufficient for deep downhole use.
2. How long would it take for the PVU #1 well-head pressure (with the injection brine in the hole) to be equilibrated to a hydrostatic condition at the wellhead (i.e. to achieve a dead well condition.)? It is not necessary to wait until this fully happens, it will be sufficient to do a careful analysis of the pressure decay after a shut-in for several days or weeks (a well-test expert should be consulted in this regard). Understanding the pressure response of the far-field and how it affects the microseismic activity level (magnitude, frequency, location, and motion) may give quantitative insight as to the propagation of the pressurized region. Is this information valuable enough to warrant a shut-down of PVU #1 for a period of (for example) three weeks while carefully monitoring the pressure decay and the alterations in the microseismic response? (This is a question for geophysicists, and as scientists as well as engineers, the CRB points out that the PVU is turning out to be one of the truly stellar long-term geomechanical-geophysical experiments in the history of these disciplines.)
3. Have the microseismic data been analyzed using tomographic techniques to refine the 3D velocity model? This would in turn refine the microseismic locations. Could high-quality walk-away VSP data and microseismic data collected using a string of borehole geophones in the wells (PVU or Union wells) be combined to refine the velocity model sufficiently so as to give more precise locations for the general microseismic data in the vicinity of PVU #1. Then, with this refined velocity model and a reanalysis of all of the microseismic data, perhaps we might be able to achieve some insight into the following questions:
    a. Can we identify whether adjacent faults are sealing or non-sealing through the migration of microseismic activity over time?
    b. Can we refine the location and throw of the faults so that more guidance to future drilling can be given?
    c. Can we locate zones of higher permeability (porosity) through detained analysis of the seismic attributes of a superior seismic model (e.g. zones of higher permeability are likely associated with higher attenuation coefficients)?
    d. Can the enhanced data guide the decision to drill a deviated wellbore section to the NE (toward the Conoco well, under the salt diapir) or to the SE, to intersect new fault blocks?
4. In terms of water treatment, is there any real merit to filtering down to 3 μm particle size? Can the wellbore region take the small amounts of 3-25 μm fines with no loss of injectivity?

Do the well drop-off and build-up analyses that have been recommended have anything to say in this regard? If we are injecting above fracturing pressure at depth in any case, are the natural fractures which are generally believed to be the flow conduits being blocked in the intermediate region (> 100 feet beyond the perforations) or in the far field (>1000 feet beyond the perforations)? It seems reasonable that some increase in injection pressure, if allowed, could resolve any potential for blockage of the natural fractures by the fines. It is also possible that the thermoelastic cooling of the rock because of the cool injectant will open the natural flow conduits even further, so that the fines migration is dispersed deep onto the formations where it has no deleterious effect on the flow.

5. Do we have any constraints whatsoever on how far the distinct plume of injection brine has travelled (not the pressure wave, just the physical brine) and if it has channeled (very likely) and dominantly followed the more permeable (naturally fractured) path we would expect near the faults? This path has always been assumed to be in the NW-SE directions, given the fault structures and the stratigraphy.

Appendix A. Delineation of Salt and Basement Faults using Gravity and Magnetics

Delineation of Salt and Basement Faults using Gravity and Magnetics

Salt in the Paradox Formation is less dense and basement rocks are denser than sedimentary rocks in Paradox Valley (**Figure A1**). Gravity data can be used to delineate the size, depth, and shape of the Paradox Valley Salt Ridge and basement faults with significant offsets. The largest contribution to anomalous gravity is due to the low density Paradox Valley Salt Anticline. Using a horizontal cylinder as a first order approximation the Paradox Valley Salt Anticline should produce a negative gravity anomaly of 15 mGals with a wavelength of more than 12 km. The near vertical salt walls depicted in **Figure A1** would produce a wider anomaly than predicted by a horizontal cylinder.

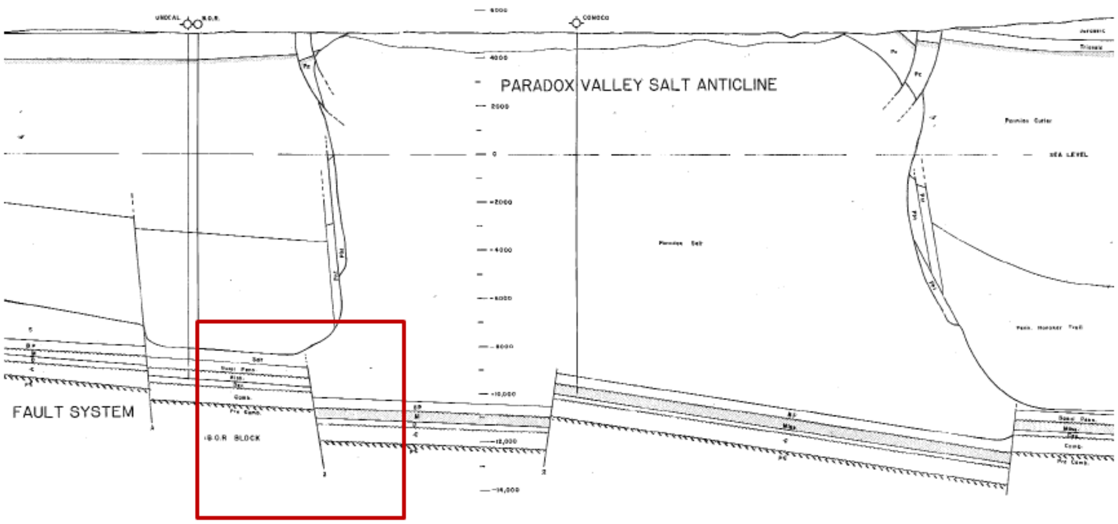

Figure A1. West to East cross-section across Paradox Valley. Modified from Figure 20 in Technical Memorandum No. 86-68330-2012-27. Red box indicates normal fault used in gravity modeling.

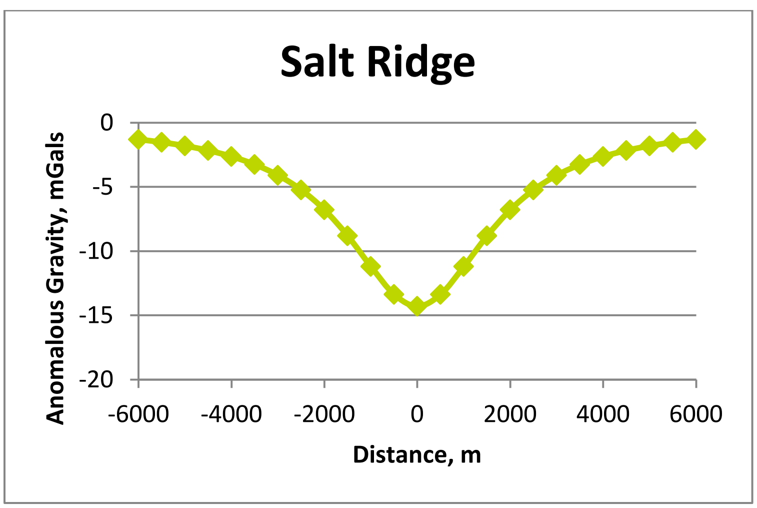

Figure A2. Gravity anomaly for a salt ridge approximated by a horizontal cylinder with a radius of 1.8 km, buried 50 m beneath the surface and a density contrast between salt and surrounding sediments of 0.2 g/cm^3.

Basement faults will produce gravity anomalies that are smaller in amplitude(less than 1 mGal) and larger in wavelength than the salt anticline because the anomalous mass (difference in mass between basement rocks and an equivalent volume of sedimentary rocks) is smaller and the depth to anomalous mass is deeper. However, they should still be detectible with modern gravimeters. **Figure A3** shows the anomalous gravity associated with the normal fault to the east of the PVU Well (red box in **Figure A1**) approximated as two horizontal semi-infinite sheets. In this first order approximation, the anomalous mass thickness is the vertical offset on the fault (500 meters) and the difference in density between basement rocks in the up thrown block and the salt in the down thrown block (0.5 g/cm^3). Gravity on the up thrown side is higher than on the down thrown side as the dense basement rocks are closer to the surface. The normal fault directly underneath the Paradox Valley Salt Ridge (to the east of the red box in **Figure A1**) would produce an anomalous gravity profile that is the mirror image of **Figure A3**. The asymmetry in the anomalous gravity profile (difference in amplitude/wavelength) in **Figure A3** is due to the fault dipping at 75 degrees rather than vertical.

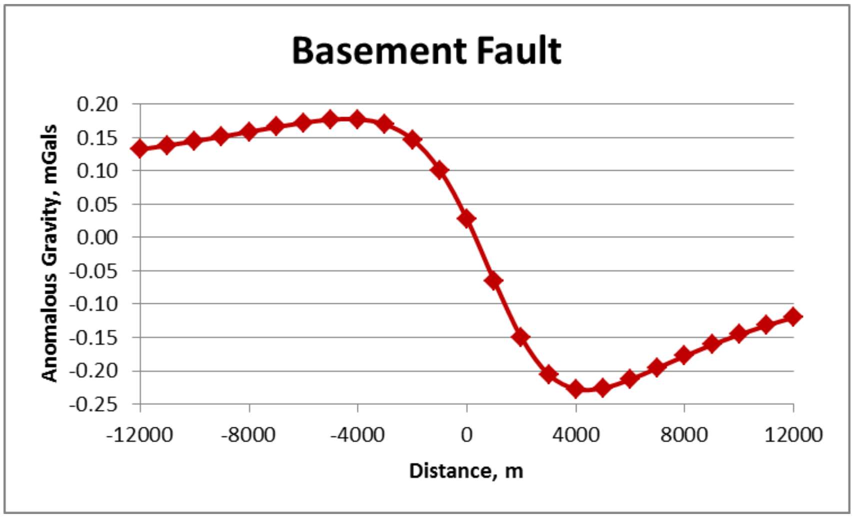

Figure A3. Gravity anomaly due to normal fault east of PVU Well (red box in Figure A1) approximated by two semi-infinite horizontal sheets offset vertically by 500 m at an angle of 75 degrees. Downthrown sheet is 4500 m below the surface. Density contrast between sheets and surrounding sediments is 0.5 g/cm^3.

The magnetic susceptibility of basement rocks is higher than sediments or salt. Thus, offset of basement rocks along faults should also produce a magnetic anomaly similar to the gravity anomaly in **Figure A3** (magnetic highs over up thrown blocks and magnetic lows over down thrown blocks).

Appendix B. Hydrogeology

Hydrogeology

Shallow groundwater flow (upper 500 ft) in Paradox Valley due to topographically driven recharge occurs in Quaternary Alluvium, Triassic age sandstones of the Chinle and Meonkopi Formations and caprock overlying the Paradox member (salt) of the Hermosa Group (Konikow and Bedinger, 1978). Recharge of freshwater occurs from infiltration of precipitation (snow and rain), surface and subsurface runoff from valley walls and mountain flanks as well as infiltration from irrigation fields and ditches. Flow direction is downward from the edges of the valley towards the axis of the valley and then along the valley axis towards the Dolores River (**Figure B1**). As freshwater moves downward through the caprock it dissolves salt from the Paradox member creating brine at depth. The western side of the valley has a thick freshwater wedge whereas only a thin layer of freshwater overlies brine in the eastern side of the valley. This difference is believed to be due to the greater depth of the salt/caprock interface on the western side of the valley. Discharge of the groundwater/brine occurs adjacent to the Dolores River. Piezometers located near the Dolores River indicate the hydraulic potential increases with depth (Konikow and Bedinger, 1978) which is consistent with upward groundwater discharge.

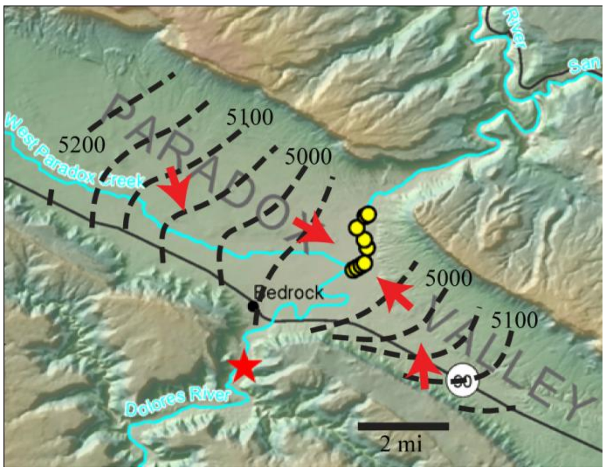

Figure B1. Estimated water table configuration for part of the Paradox Valley. Modified from Konikow and Bedinger (1978). Brine extraction wells are shown as yellow circles. PVU Injection Well is red star. Contours are in feet. Red arrows show approximate direction of groundwater flow.

The great depth, limited reservoir quality (porosity and permeability) or poor water quality (saline) of older (pre-Paradox member) aquifers in the region make them unsuitable for development as a water resource (Hite and Lohman, 1973). Of these older aquifers, the best reservoir is the Mississippi Leadville Formation. The quality of this carbonate aquifer is highly variable because of uplift and erosion, karst, dolomitization, fracturing, and sealing faults (Bremkamp and Harr, 1988). Early Pennsylvanian weathering and erosion reduced the thickness of the Leadville Formation on structural highs. In some areas, the entire Mississippian section has been removed. In addition, infilling of karst porosity in the upper Leadville with shale and clay during this period significantly reduced matrix porosity and permeability. The best effective porosity exists in dolomitized zones immediately underlying the karst interval. Porosity estimates from sonic logs and core sample range from 3 percent to greater than 10 percent although the thickness of > 10 percent porosity zones is limited. Porosity and permeability has been enhanced by fractures within the dolomitized zone. Open fractures and hairline fractures are visible in core taken from the PVU Well. Prior to PVU injection, the Leadville Formation was hydrostatically pressured (~.438 psi/ft). The lateral extent of the Leadville reservoir is limited by faulting which truncates Leadville against Paradox Formation.

The underlying Devonian and Cambrian Formations have limited porosity (< 5 percent) and do not have fracture enhanced permeability. For example, core porosity for the McCraken and Ignacio sandstones in the Shell Wray Mesa No. 1 well are less than 3.5 percent and permeability is less than 0.1 mD (Bremkamp and Harr, 1988). In contrast, the well tests in the PVU Well indicate that the Leadville formation has an average permeability of approximately 20 mD in the fractured intervals when fluid is injected at fracture pressures.

Finally, the upper most Precambrian has significant fracture porosity and permeability and is a secondary reservoir for brine disposal.

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Appendix C. Drilling and Completion Issues

Drilling and Completion Issues[1]

Drilling and Completing In and Through Salt Zones.

Drilling and completing in and through salt zones has become an important aspect of oil and gas operations. There are massive salt sections throughout the US Gulf of Mexico region, North Dakota, and offshore Brazil. Some of the most significant oil accumulations recently discovered are amongst salt domes and under massive salt layers. This is especially true in the Atlantic Ocean off of Brazil where multi-billion barrel oil fields have been discovered (sub salt zones). This success has led the oil and gas industry to find and invent ways to mitigate salt issues while drilling, completing, and producing these wells

Issues with respect to drilling through salts are many. These include the plastic flow salts undergo when an open well bore unloads an area of stress allowing the salt to “flow” into the well bore. These salt flows have been known to shear thick drill collars in half. The salt can also contaminate a drilling fluid and cement to such an extent as to detrimentally affect their useful properties.

The rate of salt movement is based on many factors. These include the type of salt and its crystalline structure and size, the inclusion of water, the tectonic stress field, burial depth, types and mixtures of salts, impurities in the salt (i.e. clays), and the geothermal temperature. In addition, should the tectonic stresses be non-uniform or the bore hole within the salt not be circular, non-uniform loading, known as “point loading”, will rapidly lead to casing failure or even drill string failure in rapidly changing environments.

Salt movement during and after drilling can be challenging. Typically, the larger the bore hole, the more likely the well bore will close in. For example, the hole closure rate is considered to be linearly proportional to the well bore diameter. A hole twice as large as another will close twice as fast as the original bore hole. Higher hydrostatic loading (i.e. heavier mud weights) can slow down, but not stop salt creep. It is important to have an understanding of the rate of salt creep in a given area. The slower the rate, the less difficult the situation. Regardless of the condition, salt will still flow into the well bore. This assumes a uniform tectonic stress field. Should this not be the case, the salt will preferentially flow into the wellbore on one side, leading to significant shear stresses.

The API collapse rating of casing, tubing, and drill pipe presupposes a uniform hydrostatic loading. The methodology for calculating collapse is based on some theoretical but primarily empirical data and does not explicitly take into account casing eccentricity, ovality, or residual stresses. Recent advances in casing design methods show that even small variations in any of these aforementioned conditions lead to drastic reductions in collapse resistance. For example, 9-5/8” 53.5 ppf P110 LTC casing has a collapse resistance of 7,950 psi by API standard. However, using the latest ISO-10400 collapse model based on Tamano’s work with Nippon Steel shows a collapse resistance of 12,810 psi. However, inputting a ±0.02 inch variance into the outside diameter of the pipe (ovality) shows a decrease in collapse resistance to 10,940 psi, almost a 15 percent decrease.

Drilling fluids and cement must be compatible with salt. Typically, these compatible drilling fluids would be either a non-aqueous based fluid (either an oil or synthetic base fluid) or a salt saturated drilling fluid. The issue with both fluids is that if any of the water in either system (and there still exists a little bit of water in oil or synthetic drilling fluids) is under-saturated with salt, then

[1] Authored by Alfred W. Eustes III

dissolution of the salt will occur, leaving a rugose, over-gauged borehole. Since the saturation condition for water is temperature dependent, as the drilling fluid is pumped down hole, the saturation conditions change to higher values. There is a train of thought to use just under-saturated drilling fluids to dissolve any salt creep into the wellbore. This would be miraculous if it could be done precisely; however, this can be managed.

Drilling fluids and cement can pick up salts. If this occurs, the rheological and fluid loss properties change. Typically, adding NaCl salt to a drilling fluid will create flocculation conditions in fresh water based fluid. This means the clays in the fluid are clumping together in “floc cells” leading to serious variations in rheological properties and increasing fluid loss into formations.

The chemistry of the cement must be compatible with the salt. Adding salt will alter the setting time and strength of cements. For example, less than 5 percent NaCl salt in the mix water of cement will accelerate the cement setting time. Conversely, more than 10 percent to saturation of NaCl salt in the mix water can significantly retard the cement setting reaction. However, if under-saturated mix water is used, this mix water will pick up salt from the formation leading to significant variations in setting times, fluid loss and rheological properties, and eventually compressive strengths. Note that saturated KCl mix water will lead to stronger compressive strengths than saturated NaCl mix water. In addition, if the cement picks up more salt (or simply is salt saturated to begin with) and eventually ends up against a non-salt formation, the osmotic forces between the salt laden cement and the non-salt formations could lead to cement degradation.

In a related issue, should the setting time be lengthened, the “window of vulnerability” could be lengthened. This is the time frame in which the solids in the cement no longer contribute to the fluid density because of hydration chemical reactions and yet, is not hard enough to prevent fluid movement through the slurry. If there are formations with high pore pressures exposed to the open hole interval, this loss in hydrostatic loading could lead to cement sheath ‘wormholes” (especially with gas) or even loss of cement sheath all together. A short thickening time helps minimize this time.

Casing design must be rigorous. Typically, if uniform loading is assumed, then an equivalent mud weight external loading of 19.25 ppg (1 psi/ft) is often used. However, this number can be larger by up to 6 ppg in some cases. The use of a high-collapse non-API grade should be considered. Thick wall pipe has been suggested; however, as noted earlier, even thick wall drill collars will not escape damage in some cases. One train of thought is to use multiple casing strings with cement in between each string. The thought is that the collapse resistance is the sum of the two casings. This author has seen no evidence of this allegation and is dubious of this condition without further study.

Regardless of the casing situation, a key to successful casing strings through salts is to have a uniform cement sheath around the wellbore. This means a centralized casing string inside essentially a circular and uniform gauge bore hole. In oil field parlance, this means “gun barrel straight and smooth.” It also means that the cement sheath must be uniformly distributed 360° around the wellbore with 100 percent coverage through the salt zone at the minimum. Any gap will allow non-uniform loading to build and potentially damage the casing.

With time, there is another issue of corrosion. If magnesium bearing salts are presents, the casing may be prone to corrosion. In addition, the cement sheath may degrade with time. Since this is not normally a uniform degradation, the tectonic stresses may be applied to the casing in a non-uniform manner leading to point loading and ultimately, casing failure.

Material Selection

Exotic corrosion resistant alloys (CRA) have been used in the PVU #1. Inconel has been used in the high pressure pump and valve train as well as in the piping to the wellhead. A steel based wellhead internally clad in Inconel is in use. And an entire 5-1/2” casing string of Hastalloy C276 has been used down hole. Each of these CRA’s is useful, do work, and are exceptionally expensive.

Given the current environmental conditions and the time since the original specifications, it is suggested that a new study of the use of the CRA’s be initiated. This study would be useful to either confirm the continued expenditure into the use of CRA’s or if there exists some other materials that may be suitable for PVU conditions. One suggestion to consider would be to look into the use of composite materials. Another possibility is to determine if standard OCTG pipe with modern plastic coating materials would be robust enough to withstand the PVU #1 conditions. If so, this could be a source of considerable savings.

A suggested course of action would be to identify potential materials that have the potential to withstand the environmental conditions and test them. Samples of the identified material could be incorporated into a flow loop built into the flow line from the pumps to the wellhead. With appropriate safety measures in place in case of catastrophic containment failure, the flow could be routed through the flow loop on its way to the wellhead. After a given amount of time, the flow could return to the main line and the samples analyzed for corrosion rates and products. In this manner, potentially significant savings might be identified and implemented. Or, it may show that Hastalloy C276 is the required material. Either way, the answer to the material property needed would be answered.

Directional Drilling

The technology and engineering operational skill in North America to be able to drill a significant distance from the current location directionally exists today. In the Bakken play in North Dakota, wells are routinely drilled down 2.5 km (8,000 feet) and then horizontally for 3 km (10,000 feet). There are extended reach wells[2] (ERD) that have reached 10 km (32,800 feet) at a depth of 1.5 km (5,000 feet). The industry is looking into wells with 12 km (40,000 feet) departures.

A vertical wellbore is considered the least expensive wellbore to drill. However, one is limited to surface conditions. A vertical wellbore will also need the least amount of steel, cement, drilling fluids, and rig power. A directional or horizontal will require more steel, cement, drilling fluids, and rig power than the vertical case as the wellbore is longer for a given vertical depth. In addition, the non-vertical component of the forces in the wellbore can create wellbore instabilities, cuttings transport issues, cementing irregularities, and higher wellbore friction (torque and drag) among other issues. None of these are insurmountable. If an ERD well is desired, then a significant engineering effort will need to be made. Plus, the expense will be significantly higher than a vertical or routine horizontal well. However, long distances from a given location can be achieved.

The use of standard directional drilling equipment (i.e. mud motor and MWD/LWD combination) may be enough to accomplish the needs of the project. However, given the critical nature of uniformity within a salt section, it may be that a Rotary Steerable System (RSS) would be required. RSS’s are well suited to generating uniform boreholes; however, two factors limit them. First, they cannot turn more than about 10° per 100 feet (which may not be an issue depending upon the well

[2] ERD wells are defined as wells with a measured depth to true vertical depth ratio of 2 or greater.

plan) and second, they are quite expensive to use (3 to 4 times as much as a standard mud motor/MWD system)

Appendix D. List of Documents Provided by the BOR for CRB Review

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Meeting Attendees

The following people attended the December 16-19, 2012 CRB meeting No. 1 in Grand Junction, Colorado:

Bureau of Reclamation

- Andy Nicholas
- Chris Wood
- Lisa Block
- Dan Levish
- Vanessa King
- William Yeck

Consultant Review Board

- William Eustes III
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- Maurice Dusseault
- Jeff Nunn

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