September 30, 2008

OIL AND GAS DOCKET NO. 08-0249225

THE COMPLAINT OF ICE BROTHERS, INC., DURANGO RESOURCES CORP., AND PITTS ENERGY CO. AGAINST ENSTOR WAHA STORAGE & TRANSPORTATION LP REGARDING ENSTOR'S WATER INJECTION PROJECT UNDER COMMISSION PERMIT NUMBER F-16749, FROST LEASE, WAHA (DELAWARE) FIELD, REEVES COUNTY, TEXAS.

APPEARANCES:

For Complainant Ice Brothers, Inc.
Michael Maloney
Lanny Ice
For Complainants Durango Resources Corp and Pitts Energy Co.
John Soule
Jeff Swanson
Greg Stevens
David Pitts
Keith Masters
John Ely
For Respondent Enstor Waha Storage & Transportation, LP
Michael McElroy
Tom Weber
Stephen Schubarth
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Greg Copeland
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Robert Trentham
Mark Houston
For Railroad Commission of Texas
David Cooney, Office of General Counsel, Special Counsel Section
Mark Henkhaus, Director, District Office - Midland
For Observor Hodge Royalty Owners
Kevin Beiter
For Observor Exxon Mobil Corporation
Tim George

PROPOSAL FOR DECISION
PROCEDURAL HISTORY

COMPLAINT FILED:	September 20, 2006
NOTICE OF HEARING:	October 6, 2006
HEARING DATE:	April 15, 16 & 17, 2008
RECORD CLOSED:	June 5, 2008
HEARD BY:	Mark Helmueller - Hearings Examiner Donna Chandler - Technical Examiner
PROPOSAL FOR DECISION ISSUED:	September 30, 2008

STATEMENT OF THE CASE

Complainants Ice Brothers, Inc.,("Ice") Durango Resources Corp.,("Durango") and Pitts Energy Co. ("Pitts"), request that Enstor Waha Storage and Transportation, L.P.'s ("Enstor") authority to inject saturated brine into the Waha (Delaware) Field under Permit No. F-16749 be cancelled for the failure to provide proper notice of the permit to Ice, and because injection operations from December 2005 through August 2006 negatively impacted producing wells completed within the permitted injection interval. Enstor's permit allows for ten injection wells to each inject 40,000 bpd with a maximum surface injection pressure of 1500 psig. The permitted injection interval is between 4900 and 6700 feet.

Enstor opposes any cancellation, arguing that any alleged problems were resolved when it reentered its injection wells and squeezed off all perforations which can be correlated to the productive formation in the offsetting producing wells. Enstor urges that it should be allowed to conduct interference testing on the reworked wells to determine whether injection can continue without impacting the offsetting wells.

In brief, the evidence indicates that Enstor's injection operations have impacted producing oil and gas wells offsetting Enstor's Waha facility up to 2 ½ miles from the injection wells. The examiners therefore recommend that Enstor's permit be modified to limit the maximum surface injection pressure in the permitted wells. Additionally, the examiners recommend additional permit conditions be adopted related to monitoring and further injection activities by Enstor under the modified permit to avoid any further impact to the offsetting producing wells.

APPLICABLE AUTHORITY

Statewide Rule 46(d)(1), provides in pertinent part:

> An injection well permit may be modified, suspended, or terminated by the commission for just cause after notice and opportunity for hearing, if:
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> (A) a material change of conditions occurs in the operation or completion of

the injection well, or there are material changes in the information originally furnished;

(B) fresh water is likely to be polluted as a result of continued operation of the well;

(C) there are substantial violations of the terms and provisions of the permit or of commission rules;

(D) the applicant has misrepresented any material facts during the permit issuance process;

(E) injected fluids are escaping from the permitted injection zone; or

(F) waste of oil, gas, or geothermal resources is occurring or is likely to occur as a result of the permitted operations.

FIELD INFORMATION AND PERMIT RECORDS

The Delaware formation is a deep water sand depositional environment composed of numerous sand packages interspersed with limestone members. The limestone members can be correlated through the Delaware basin and are used as markers to separate the productive intervals. The Waha (Delaware) Field produces primarily from two formations, the upper sand package identified as the Bell Canyon and a lower sand package identified as the Cherry Canyon. The marker for the top of the Bell Canyon is the Lamar Limestone member. The lowest limestone member in the Bell Canyon is the Hegler Limestone which ranges in thickness throughout the area. The Manzanita limestone member is the marker typically used to define the top of the Cherry Canyon sand package. A schematic showing the Bell Canyon and Cherry Canyon formations which also identifies the limestone members is attached for reference purposes.

Commission proration schedule and production reporting records show there are currently 62 wells carried in the Waha (Delaware) Field. Total production from the field in 2007 was 22,767 barrels of oil/condensate and 293,868 MCF of natural gas.

On November 19, 2004, Enstor applied for a permit to inject a maximum capacity of 400,000 barrels of brine per day into the Waha (Delaware) Field (including both the Bell Canyon and Cherry Canyon) through 10 injection wells, each with a daily capacity of 40,000 barrels. The maximum permitted injection pressure was 1500 psig. All 10 wells were to be drilled on a single 640 acre section. The permitted injection interval is between 4900 and 6700 feet.

Enstor's injection project was needed to dispose of saturated brine which was being used to solution mine caverns into the Salado formation for the purpose of a gas storage facility being built on the section. An estimated 225 million barrels of saturated brine would be injected into the formation over the projected life of the project.

As required under Statewide Rule 46, notice of the application was provided to operators of wells within ½ mile of the proposed injection wells. The operators included Pitts and Durango, but not Ice, as Ice's closest producing well was located more than ½ mile from the nearest injection well. No protests were received and the application was administratively approved on January 3, 2005.

COMMISSION INSPECTIONS AND TESTIMONY

In response to a complaint from Durango, the Commission's District Office inspected Well Nos. 1 and 2A on the Brown, G. (36015) Lease on August 23 and 24, 2006. The inspection confirmed that wells were not producing. The wells exhibited pressure at the surface at the time of the inspection. The inspector observed water which tested at 135,200 ppm chlorides flowing from the backside of the surface casing at Well No. 1. A follow up inspection on September 5, 2006 noted that a bridge plug set immediately above the uppermost perforations in Well No. 1 had eliminated the source of the water. A report prepared by District Director Mark Henkhaus concluded that the source of the water flow in Well No. 1 was the Bell Canyon formation.

Director Henkhaus also attended a step-rate test conducted by Enstor on February 19, 2008 for the Waha/Frost Well 7D and prepared a report, including an annotated pressure chart which is attached to the proposal for decision for reference purposes. The test commenced with an initial rate of 1 bpm and initial pressure of 650 psi. Pressure and volume were ramped up to 28 bpm and 1150 psi. At that point, a hard shut down was initiated. Pressure dropped immediately upon ceasing pumping to 550 psi. The report notes that the pressure drop suggests that frac pressure had been exceeded at the initiation of the test. Frac closure was observed at 550 psi. After closure, formation pressure declined slowly via "leakoff" as expected.

Director Henkhaus testified at the hearing that as a result of the initial investigation in 2006, he concluded Enstor's injection operations were responsible for watering out the offsetting producing wells. After reviewing the step rate test data he was provided and generating a pressure chart based on that data, he determined that the initial step rate test started at levels above the fracture gradient for the Delaware formation.

COMPLAINANTS' POSITIONS

Complainants contend that Enstor's injection of saturated brine into the Bell Canyon and Cherry Canyon formations fractured the reservoir. The injection of 30 million barrels of brine between December 2005 and October 2006 resulted in the lateral migration of fluids to producing wells at least 2 ½ miles away both to the southeast and northwest of Enstor's proposed storage facility. A map showing the Enstor facility with its injection wells and the surrounding wells operated by Ice, Durango and Pitts is attached for reference purposes.

Complainants jointly argue that Enstor's operations caused the problems experienced in their wells. Supporting evidence for this argument includes the correlation in time between Enstor's operations and problems in the producing wells, the presence of perforations outside of the permitted interval in Enstor's wells, pressure changes in wells, increased water production, and increased scaling and corrosion. Complainants also urge that the problem cannot be remedied by isolating the injection interval to the Cherry Canyon formation because: 1) there are producing wells completed in the Cherry Canyon; and, 2) evidence indicates that Enstor's injection operations have already created fracture pathways between the Cherry Canyon and Bell Canyon formation.

Durango claims it lost two producing oil wells completed in the Bell Canyon formation, Well Nos. 1 and 2A on its Brown, G. (36015) Lease. These two wells are located on the northeast 160 acres of Section 9. This section offsets the Enstor facility to the south. Durango claims its mineral lease terminated as a result of the lost production.

Pitts contends it lost its Barber No. 9 Well, a gas well located in the southeast corner of its Barber, W.T. Lease because it pressured up and watered out. Pitts urges that this was caused by Enstor's injection operations. Pitts identified the Barber No. 9 as its closest well to the Enstor facility along the northwest to southeast trend affected by Enstor's injection operations. The Barber No. 9 Well is completed in both the Bell Canyon and Cherry Canyon formations in which Enstor was injecting its saturated brine.

Pitts claims producing wells completed in the Bell Canyon and Cherry Canyon formations on the Frost, J. Lease, Trees, J.C. Estate et al, Lease, Trees, J.C. Estate et al, A Lease, Barber, W.T. Lease, Ligon, S.E. Lease, and Ligon, S.E. A Lease experienced increased water volumes as a result of Enstor's injection operations. Pitts reports that its daily water production increased from 1500 bwpd to 2500 bpwd after Enstor began injecting in December 2005. Pitts further claims production of oil decreased over 10% daily from 110 BOPD to 91 BOPD. Gas production has been cut from 883mcf/d to 492 mcf/d.

Ice contends it has permanently lost three wells, Well Nos. 1, 2A and 4A on its Hodge Unit, a 1440 acre unit on Sections 8, 17 and 18 which adjoins the Enstor facility to the east and southeast. These three wells are the closest to the Enstor facility following a northwest to southeast trendline. Ice also believes its remaining six gas wells on the Hodge Unit have been affected and are threatened by any additional injection All of the wells are completed in the Bell Canyon formation.

Ice also urges that it should have been provided with notice as a potentially affected party when Enstor filed its permit application. While Ice's wells were more than a ½ mile from any of the proposed injection wells, Ice believes it should have been considered an affected party in light of the requested pressures and total volume of saturated brine Enstor was requesting to inject into a producing formation.

The complainants' jointly argue that Enstor's own reservoir study prior to approval of its project, and the step rate test performed in February 2008 confirm that the injection operations

fractured the Delaware formation. Complainants' expert, John Ely, testified that it is well known that the fracture gradient for the Delaware formation is less than .6 psi/ft. Ely opined that the step rate test confirmed this general knowledge.

Complainants urge that Enstor knew of the reservoir characteristics regarding the low fracture gradient and deliberately disposed of its brine at pressures which would propagate fracturing. Complainants believe this intentional fracturing was necessary to dispose of the massive volumes of brine which would result from the solution mining of the storage caverns.

Ely also testified that the injection operations between December 2005 and October 2006 have created vertical fractures between the Bell Canyon and Cherry Canyon intervals. Ely opined that any shale streaks or limestone were discontinuous and would not have created a barrier between the two intervals, including the Hegler Limestone located at the base of the Bell Canyon formation. Complainants specifically point out that Enstor's spinner surveys show 99% of the injected brine was into perforations in the Cherry Canyon formation. However, wells completed in only the Bell Canyon experienced problems. Complainants therefore contend that any workover of the injection wells to squeeze off perforations into the Bell Canyon would not prevent an adverse impact from the injection of an additional 140 million barrels of saturated brine in the Cherry Canyon interval.

Complainants also argued that the characteristics of the water are consistent with water produced from the Capitan Reef formation, the source water for Enstor's injection project. Capitan Reef water is high in sulfate concentration, whereas Delaware produced water is not. Complainants provided documentation and test results to confirm that the sulfate concentrations have increased in their wells. This increase has reportedly resulted in more frequent problems with scaling and corrosion. Complainants are now treating their wells with microbial inhibitors, a treatment which was not previously required.

ENSTOR'S POSITION

Enstor argues that its past injection operations are irrelevant and that the only issue before the Commission currently is whether it should be allowed to test its injection wells because they have been reconfigured. Enstor immediately began investigating complainants' allegations that its brine injection was affecting their wells when it was advised of the issue. In October 2006 it shut down its injection operations. Enstor has spent more than $15 million in investigating and responding to the complaints. Enstor asserts that it is necessary to perform injectivity tests to determine whether the recompletion of its injection wells has eliminated any possible impact of the injection operations on the offsetting producing wells.

Enstor performed workovers on all five of its currently permitted injection wells to confine injection to the Cherry Canyon formation. In addition to squeezing off any perforations into the Bell

Canyon, Enstor also reconfigured its injection profile in the Cherry Canyon to close off the perforations at the top of the formation. Enstor urges that the recompletion provides a further buffer between the injection interval and the Bell Canyon formation.

Enstor believes that a possible explanation for the water intrusion into the offsetting wells is the presence of mechanical pathways, i.e., improperly plugged wells completed in the Bell Canyon formation. This explanation is based on Enstor's re-entry into two plugged offsetting wells, the Frost Cleveland Gas Unit No. 1 and No. 2. Enstor's investigation found in both wells, the plugs and cement were not encountered at the locations reported on the Commission Form W-3 (Plugging Report), and in some instances were missing entirely. Additionally, Enstor found damaged casing, poor cement, voids, channeling behind pipe and an open DV tool. Enstor replugged the wells to include cement across the entire Cherry Canyon interval. Enstor claims that injectivity tests will confirm whether these mechanical pathways and limited injection in the Bell Canyon formation were the cause of the water intrusion in the offsetting wells. Enstor will closely observe any tests with a network of 20 monitor wells. This will prevent any potential harm to the neighboring wells.

Enstor admits that its past injection operations may have fractured the injection interval. However, it asserts that Commission rules do not prohibit fracturing as long as it is confined to the injection interval. Enstor's geologist testified that the Hegler Limestone member at the bottom of the Bell Canyon interval is a condensed or tight 40 feet thick formation that would confine any fracturing to the Cherry Canyon interval in the reworked injection wells. Additionally, Enstor's geologist also opines that the Cherry Canyon is an ideal injection interval as it is 1,000 feet thick and extends over an area greater than 10,000 square miles.

Enstor opines that there is no vertical communication between the Cherry Canyon and Bell Canyon formations which resulted from its prior injection operations. As previously noted, Enstor first argues that there are several limestone members, most notably the Hegler Limestone, which act as barriers to vertical flow. Enstor also asserts that pressure data from Enstor's injection wells further demonstrates that no out of zone fracturing has occurred. Enstor observes that the six injection wells continue to exhibit different pressures after being shut in for more than eighteen months. Enstor interprets this data as evidence that the various Cherry Canyon sands are not in communication with each other or with the Bell Canyon sands through vertical fracturing.

Enstor also urges that the microseismic studies performed during the step rate test further demonstrate that there has been no vertical fracturing allowing communication between the Cherry Canyon and Bell Canyon formations. The microseismic study observed 38 microseismic events during and immediately following the step rate test. All of the microseismic events were contained within the Cherry Canyon formation.

Enstor also notes that the calculation of fracture gradients based on pressures observed during injection operations are consistent with the fracture gradient determined from the February step rate test. Enstor believes this undermines Complainants' contention that its initial injection

operations caused fracturing which migrated horizontally through a larger area and migrated vertically through any of the limestone members.

In sum, Enstor urges: 1) it has a valid permit; 2) complainants failed to demonstrate that future injection operations pose any threat to their offsetting wells; and 3) injectivity tests should be allowed to go forward because the fluids will be confined to the permitted injection zone. Enstor contends the Commission should not take any action with respect to the prior injection operations in light of the changed circumstances since it voluntarily shut down operations in October 2006, and reconfigured its injection wells

EXAMINERS' OPINION

The examiners recommend Enstor's permit be modified. It is undisputed that injection at the permitted rate and pressure would exceed the fracture gradient of the Waha (Delaware) Field in both the Bell Canyon and Cherry Canyon formations as shown by the results of the step rate test conducted in February 2008. Enstor asserts that this fact is irrelevant as long as any fracturing is limited to the injection interval. In other words, Enstor argues that horizontal fracturing within zone is permitted but vertical fracturing out of zone is prohibited for injection operations. This position is contrary to current regulatory structure used by the Commission's Underground Injection Control program. Additionally, the cases and prior Commission decisions cited by Enstor do not support a departure from the longstanding accepted Commission standard precluding injection at pressures or rates which would exceed the fracture gradient in the injection interval.

The evidence also demonstrates that Enstor's prior injection operations resulted in vertical fracturing which brought the Bell Canyon and Cherry Canyon intervals into communication. As Enstor's microseismic study shows, the reconfiguration of Enstor's injection wells to the lowest sands in the Cherry Canyon interval does not eliminate the problem because it does not address the vertical pathways caused by its prior injection operations. Additionally, Enstor's opinion that communication between the Bell Canyon and Cherry Canyon is the result of mechanical pathways, i.e. improperly plugged wells, is not plausible in light of the evidence that vertical fracturing occurred and likely included any limestone intervals in the formations.

Authority to Inject at Pressures Known to Fracture the Injection Interval

Enstor's claim that the Commission previously permitted injection operations in a productive interval at pressures known to be greater than the fracture gradient for the formation is unsupported by any of the decisions cited. Further it is contrary to the Commission's regulatory framework for underground injection control.

The Commission's Underground Injection Control Manual includes a technical discussion section related to injection pressure issues. The discussion specifically notes:

Statewide Rules 9 and 46 both require that injected fluids remain confined to the

> authorized injection/disposal interval. The technical review of the proposed injection pressure verifies that the injection pressure does not exceed the formation fracture gradient and that the existing casing cement is adequate to ensure that injected fluids are confined to the proposed injection zone.
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> ***
>
> If you are requesting an injection pressure higher than the 1/2 psi per foot of depth to the top of the injection/disposal interval, you will need to run a Fracture Step Rate Test (FSRT) to demonstrate that the requested injection pressure is below the fracture gradient for the injection zone.
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> ***
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> The highest injection pressure justified by the FSRT will be the last data point set just below the fracture pressure. Note that this may be significantly lower than the fracture pressure depending on how the "steps" were chosen.

The Commission's Underground Injection Control manual establishes a standard maximum permitted surface injection pressure of .5 psig/ft. When combined with the estimated pressure created by the weight of the fluid column of .5 psig/ft, the standard maximum surface pressure presumes that the fracture gradient of the injection interval will be 1 psig/ft. However, if evidence becomes available to the Commission that the fracture gradient is less than the standard maximum surface injection pressure, the Commission can and has modified the maximum permitted injection pressure. This was most recently seen in the modification of the multiplier for injection into shallow formations (above 2000 feet) in the Barnett Shale trend. After being provided with step rate tests from operators, as well as the occurrence of several breakouts and other incidents, the Commission modified the multiplier to .25 psig/ft for injection and disposal into that formation. Similar modifications have been made in the Gulf Coast area where fracture gradients of shallow disposal intervals are less than the standard of .5 psig/ft.

Additionally, the Underground Injection Control manual specifically prohibits injection at pressures or rates which would exceed the fracture gradient of the injection interval. This can be seen in the Step Rate Test Guidelines set forth in the manual:

> A fracture step rate test is a method used to accurately measure the fracture pressure of a given formation. A fracture step rate test must demonstrate that formation fracturing will not occur at the proposed injection pressure.

It is a basic principle of petroleum engineering to presume the movement of fluids in a radial flow pattern surrounding a well bore. In the technical evaluation of injection and disposal well applications, the Commission's areal review relies on this basic principle. When injection pressures

exceed the fracture gradient for the formation, one can no longer rely upon a radial flow pattern to predict any fluid movement, because fluid movement will then be influenced by the propagation of a fracture system in the formation.

The two Commission decisions referenced by Enstor[1] can be distinguished from the instant case as both of those decisions involved waterflooding to facilitate secondary recovery operations. Those two cases, Oil & Gas Docket No. 8-96,609: *Application of Chevron, U.S.A., Inc. to Amend Authority to Inject Fluid Into a Reservoir Productive of Oil or Gas Under UIC Project No. F-1460 for the J.T. McElroy Cons. & Crier McElroy Leases, in the McElroy Field, Crane and Upton Counties, Texas* (Final Order Entered December 16, 1991) and Oil & Gas Docket No. 8-93,603: *Application of Shenandoah Oil, Inc. (I) and Wilton Oil Company for Maximum Injection Pressures of 2,100 for the Injection Wells Permitted in Project No. F-1702 and F-1703 in the Wentz (Clearfork) Field) Pecos County, Texas* (Final Order Entered January 15, 1990) were both unprotested applications related to existing waterflooding operations. In both cases the increased pressures were necessary to prevent abandonment of secondary recovery operations in areas where waterflooding was ineffective. Additionally, in these two cases, any threat of premature water breakthrough in producing wells due to the injection at higher pressures would have been to the applicants' wells in the waterflood project. Both of these facts are important distinctions from the current case. Enstor's injection operations are not a waterflood project, but are more accurately characterized as disposal operations unrelated to secondary recovery operations. Further, the risks of early water breakthrough were not to Enstor's wells, but to the producing wells operated by complainants.

Enstor has not established that Commission approval of maximum injection pressure is limited to the impact on the confining interval. The two decisions cited are distinguished from this matter. Accordingly, the maximum surface pressure permitted for Enstor's injection operations should be limited to an amount less than the demonstrated fracture gradient of the injection interval.

The maximum surface injection pressure can be determined from the undisputed testimony about the results of the step-rate test. The step rate test shows a fracture gradient of .578 psi/f, which is equivalent to 3410 psi at 5900 feet, the depth of the injection interval in the modified wells. The hydrostatic head of 9.5 ppg fluid (a weight typical for saturated brine) is calculated at 3050 psi. Subtracting the hydrostatic head from the calculated pressure to open the formation yields a maximum surface pressure of less than 360 psi. The examiners therefore recommend that Permit F-16749 be modified to allow for a maximum surface injection pressure of 300 psi.

The examiners also recommend permit provisions requiring Enstor to maintain monitoring

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[1]Enstor also cited four proposals for decision issued for disposal wells in 2005 and 2006 to support its position that the Commission has issued permits for wells at pressures exceeding the fracture gradient of the disposal interval. Enstor specifically notes language that the injection pressure "will not fracture the overlying rock" as support for its position. The examiners note that in each of the four dockets referenced, maximum surface injection pressures were limited to either the standard amount .5 psig/f contemplated in the Underground Injection Control Manual or the modified maximum pressure of .25 psig/f applied to shallow disposal zones in Wise County.

wells at its facility and provide the data collected from the monitoring wells to the Commission's District Office in Midland, and the Oil & Gas Division, Technical Permitting Section in Austin. Monitoring wells are currently in place as a result of Enstor's investigation and corrective measures. Because Enstor has already drilled five injection wells, one of which has been plugged, and has the authority to drill up to 10 wells, active monitoring is necessary through the existing network of monitoring wells to ensure that any further injection does not impact the offsetting producing wells.

Recompletion of the Injection Wells has not Eliminated the Threat to the Producing Wells

The step rate test was performed on a well which Enstor recompleted to squeeze off perforations in the Bell Canyon and the uppermost sands in the Cherry Canyon. Enstor argues that it should be allowed to test the recompletion of the well. Enstor's argument centers on the theory that the injection operations between December 2005 and October 2006 did not cause any vertical fractures which brought the Bell Canyon and Cherry Canyon formations into communication. This no vertical fracturing theory rests on two primary assumptions: 1) improperly plugged wells were potential mechanical pathways which allowed communication between the two formations, and 2) limestone members in between the perforated intervals in the Bell Canyon producing wells and the perforated injection interval of Enstor's wells confined any fracturing to the injection interval.

Enstor identified three plugged wells as candidates to support its potential mechanical pathway assumption: the Frost Cleveland Gas Unit Well No. 1, the J. Frost No. 2; the Pitts Energy Trees A-10. Enstor reentered two of the wells, the Frost Cleveland and J. Frost. In reentry of the wells they found several discrepancies from the reported plugging, however, Enstor's own expert could not definitively state that either well provided a mechanical pathway to facilitate communication between the Bell Canyon and Cherry Canyon.

Enstor did not re-enter the Trees A-10. Enstor further acknowledges that the total depth of the Trees A-10 as reported on Commission records does not significantly penetrate into the Cherry Canyon formation. However, Enstor expressed concern that the total depth of the well may not be reported accurately. Enstor did not point to the existence of any documentation to support this suspicion. In the absence of any evidence to support that the total depth reported for the Trees A-10 is not accurate, any opinion that the well "might" be deeper than reported is pure speculation.

The Trees A-10 well is the only plugged wellbore between Enstor's injection wells and Pitts' producing wells. It is therefore essential to Enstor's mechanical pathway theory. However in the absence of any demonstrative evidence to support the speculation of Enstor's expert on inaccuracies in the reported total depth of the well, it cannot be concluded that the well acted as a conduit between the Bell Canyon and Cherry Canyon formations. This essentially invalidates Enstor's mechanical pathway theory.

The examiners also believe the evidence undermines Enstor's claim that limestone members will act as impenetrable barriers to flow between the Bell Canyon and Cherry Canyon formations. Enstor's injection operations between December 2005 and October 2006 were not limited to the lower Cherry Canyon but included injection into the uppermost sands. Enstor's microseismic analysis concluded that even during the limited period of the test, fracture propagation was observed in a 600 foot vertical interval. While Enstor urges that all fracturing remained in the Cherry Canyon, it is clear that limestone members in the Cherry Canyon were fractured even during the short testing in February 2008.

Enstor's high volume continuous injection operations over an 11 month time period at pressures exceeding the fracture gradient of the formation is significant to the issue of communication between the Cherry Canyon and Bell Canyon intervals. As shown by the spinner surveys, approximately 30 million barrels of brine were injected into the Cherry Canyon between December 2005 and October 2006. This resulted in the lateral migration of fluids to producing wells at least 13,000 feet (2 ½ miles) away to the southeast and northwest of Enstor's storage facility.

CONCLUSION

The examiners conclude from the evidence and testimony submitted at the hearing, as well as the physical observations reported by the District Office in September 2006, that Enstor's injection operations between December 2005 and October 2006 affected the producing wells operated by complainants. The injection of an additional 140 million barrels of saturated brine in the Cherry Canyon interval at pressures greater than the fracture gradient of the injection interval will pose a threat to the producing wells operated by Complainants which in turn may lead to the waste of oil and natural gas. The examiners therefore conclude that no further testing should be permitted at the pressures and volumes specified in the original permit. Additionally, the permit should be modified to limit surface injection pressure to 300 psig. Finally, Enstor shall be required to monitor the impact of any further injection through its network of existing monitoring wells.

Based on the record in this Docket, the examiners recommend adoption of the following Findings of Fact and Conclusions of Law.

FINDINGS OF FACT

1. Notice of Hearing was provided to the parties through their attorneys of record who attended the proceedings and presented evidence.

2. Enstor Waha Storage and Transportation, L.P. ("Enstor") is the operator of an Underground

Gas Storage Facility on its Waha Frost Lease in Reeves County, Texas. A permit was issued for this facility in Oil and Gas Docket No. 08-0242525, pursuant to a Final Order entered on September 7, 2005. The storage caverns for the facility are created through solution mining in the Salado salt formation.

3. On January 3, 2005, Permit No. F-16749 was issued to Enstor allowing it to inject a maximum capacity of 400,000 barrels of brine per day into the Waha (Delaware) Field (including both the Bell Canyon and Cherry Canyon formations) through 10 injection wells, each with a daily capacity of 40,000 barrels.

    a. The maximum permitted injection pressure was 1500 psig.

    b. All 10 wells were to be drilled on a single 640 acre section.

    c. The permitted injection interval is between 4900 and 6700 feet.

    d. Notice was provided to all operators of producing wells within ½ mile from the nearest injection well.

    e. No protests were received and the application was administratively approved.

4. Between December 2005 and October 2006, Enstor injected approximately 30 million barrels of saturated brine into the Waha (Delaware) Field through five of its injection wells.

5. Commission proration schedules and production reporting records show there are currently 62 wells carried in the Waha (Delaware) Field. Total production from the field in 2007 was 22,767 barrels of oil/condensate and 293,868 MCF of natural gas.

6. Complainants Ice Brothers, Inc.,("Ice") Durango Resources Corp.,("Durango") and Pitts Energy Co. ("Pitts") all operate producing oil and gas wells completed in the Waha (Delaware) Field on properties adjacent to Enstor's underground storage facility.

7. Two producing oil wells operated by Durango completed in the Bell Canyon formation, Well Nos. 1 and 2A on its Brown, G. (36015) Lease were watered out after Enstor commenced injection operations.

    a. The two wells are located on the northeast 160 acres of Section 9. This section offsets the Enstor facility to the south.

    b. The Commission's Midland District Office inspected Well Nos. 1 and 2A on the Brown, G. (36015) Lease on August 23 and 24, 2006.

    c. The District Office inspection confirmed that wells were not producing.

d. The wells exhibited pressure at the surface at the time of the inspection.

e. The inspector observed water which tested at 135,200 ppm chlorides flowing from the backside of the surface casing at Well No. 1.

f. A follow up inspection on September 5, 2006 noted that a bridge plug set immediately above the uppermost perforations in Well No. 1 had eliminated the source of the water.

8. Pitts Barber No. 9 Well, a gas well located in the southeast corner of its Barber, W.T. Lease pressured up and watered out after Enstor's commenced injection operations.

a. The Barber No. 9 is Pitts' closest well to the Enstor facility.

b. The Barber No. 9 Well is completed in both the Bell Canyon and Cherry Canyon formations in which Enstor was injecting its saturated brine.

9. Pitts producing wells completed in the Bell Canyon and Cherry Canyon formations on the Frost, J. Lease, Trees, J.C. Estate et al, Lease, Trees, J.C. Estate et al, A Lease, Barber, W.T. Lease, Ligon, S.E. Lease, and Ligon, S.E. A Lease have experienced increased water volumes after Enstor commenced injection operations.

a. Daily water production increased from 1500 BWPD to 2500 BPWD

b. Production of oil decreased over 10% daily from 110 BOPD to 91 BOPD.

c. Gas production was cut from 883mcf/d to 492 mcf/d.

10. Ice permanently lost three wells, Well Nos. 1, 2A and 4A on its Hodge Unit, a 1440 acre unit on Sections 8, 17 and 18 which adjoins the Enstor facility to the east and southeast after Enstor commenced injection operations. All of the wells are completed in the Bell Canyon formation.

11. A Commission witnessed step-rate test conducted by Enstor on February 19, 2008 for the Waha/Frost Well 7D confirmed that maximum surface pressure under Permit F 16749 exceeds the fracture gradient of the injection interval.

a. The step-rate test commenced with an initial rate of 1 bpm and initial pressure of 650 psi. Pressure and volume were ramped up to 28 bpm and 1150 psi. At that point, a hard shut down was initiated.

b. Pressure dropped immediately upon ceasing pumping to 550 psi.

c. Frac closure was observed at 550 psi.

12. The maximum surface pressure used to inject waste fluids into a productive formation may not exceed the fracture gradient of the injection interval.

a. For every application to either inject fluids in a productive reservoir, the Commission conducts an areal review of producing wells within a ½ mile radius of the proposed injection well.

b. The areal review presumes the movement of fluids in a radial flow pattern surrounding a well bore.

c. When injection pressures exceed the fracture gradient for the formation, a radial flow pattern will no longer accurately predict any fluid movement, because fluid movement will then be influenced by the propagation of a fracture system in the formation.

d. The inability to predict the movement of injected fluids in a productive interval may result in the waste of hydrocarbons through early water breakthrough into producing wells.

13. In order to prevent fracturing of the injection interval, the maximum surface pressure for Enstor's injection operations under Permit F 16749 may not exceed 300 psig.

a. The top of the injection interval in the reconfigured wells is approximately 5900 feet.

b. Based on the results of the step rate test, the calculated fracture gradient for the injection interval is .578 psi/f.

c. The injected fluids have an estimated weight of 9.5 ppg.

d. The hydrostatic head of 9.5 ppg fluid is calculated at 3050 psi for a depth of 5900 feet.

e. A fracture gradient of .578 psi/f, is equivalent to 3410 psi for a depth of 5900 feet.

f. Subtracting the calculated pressure created by the hydrostatic head of 3050 psi from the calculated pressure to fracture the injection interval of 3410 psi leaves a

remainder of 360 psi.

g. Maximum surface injection pressure must be less than the calculated pressure necessary to fracture the injection interval.

h. In order to provide an appropriate safety factor, the maximum surface pressure for injection operations should be limited to 300 psig.

14. Monitoring any further injection operations under the modified permit through Enstor's existing network of monitoring wells is necessary to prevent the potential waste of oil and natural gas.

CONCLUSIONS OF LAW

1. Proper notice of hearing was timely given to all persons legally entitled to notice.

2. All things have occurred to give the Commission jurisdiction to decide this matter.

3. Statewide Rule 46 provides for modification of an injection permit where waste of oil, gas, or geothermal resources is occurring or is likely to occur as a result of the permitted operations.

4. Modification of Enstor's injection permit No. F 16749 to limit maximum surface injection pressure to 300 psig is necessary to prevent the waste hydrocarbons.

5. Modification of Enstor's injection permit No. F 16749 to include provisions requiring monitoring of any injection operations through a monitoring well system is necessary to prevent the waste of hydrocarbons.

RECOMMENDATION

The examiners recommend Enstor's permit be modified to limit the maximum surface pressure so that injection operations will not exceed the observed fracture gradient in the injection interval. Additionally, the examiners recommend additional permit conditions be adopted related to monitoring any further injection activities by Enstor under the modified permit to avoid any impact to the offsetting producing wells that would result in the waste of oil and natural gas.

Respectfully submitted,

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