STATE OF ALASKA
ALASKA OIL AND GAS CONSERVATION COMMISSION
333 West 7th Avenue, Suite 100
Anchorage, Alaska 99501

Re: THE APPLICATION OF Buccaneer Alaska Operations, LLC for disposal of Class II oil field wastes by underground injection in the Sterling and Beluga Formations in well Kenai Loop # 3, Section 33, T6N, R11W, S.M. (PTD 2110970)	) Disposal Injection Order No. 38)) Sterling and Beluga Formations) Kenai Loop # 3 Well) Kenai Peninsula Borough, Alaska)) November 28, 2012

IT APPEARING THAT:

1. Buccaneer Alaska Operations, LLC (Buccaneer) requested that the Alaska Oil and Gas Conservation Commission (AOGCC) issue an order authorizing underground disposal of Class II oil field waste fluids into well Kenai Loop #3. Buccaneer's Application for Disposal Injection Order was received by the AOGCC on March 16, 2012.

2. In accordance with 20 AAC 25.540, notice of opportunity for a public hearing was published in the Alaska Journal of Commerce on April 15, 2012. In addition, on April 10, 2012 the AOGCC published that notice of opportunity for public hearing on the State of Alaska Online Public Notices website, on the AOGCC's website, electronically transmitted the notice to all persons on the AOGCC's email distribution list, and mailed printed copies of the notice to all persons on the AOGCC's mailing distribution list. The tentatively scheduled hearing date was May 17, 2012, but the hearing was subsequently rescheduled to May 22, 2012.

3. The AOGCC has authority to issue a disposal injection order. 20 AAC 25.252.

4. The AOGCC held the May 22, 2012 hearing despite not receiving any comments, protests or requests for a public hearing. Buccaneer provided testimony, and the hearing record was left open to allow Buccaneer to respond to questions from the AOGCC.

5. The AOGCC requested clarification of certain items on May 31, 2012. Buccaneer responded on June 5, 2012 with clarifications.

6. The AOGCC requested additional clarification on June 26, 2012. Buccaneer responded on July 5, 2012 with clarifications.

7. The information submitted by Buccaneer and public well history records for Kenai Loop #3 are the basis for this order.

FINDINGS:

1. Location of Adjacent Wells (20 AAC 25.252(c)(1))

   Kenai Loop #3 is a gas development well drilled in 2011 to a total depth of 11,368 feet measured depth (MD), which is equivalent to 11,001' true vertical depth (TVD).[1] The surface location is 3,394 feet from south line and 1,124 feet from west line of Section 33, Township 6N, Range 11W, Seward Meridian (S.M.). The bottom-hole location is 1,597 feet from the south line and 1,458 feet from the west line of Section 33, Township 6N, Range 11W, S.M.

   Kenai Loop #3 was the second well drilled to evaluate gas reserves within the Tyonek Formation of the Kenai Loop Field. The well did not find commercial quantities of natural gas, and it was suspended in accordance with AOGCC regulations in 2011. Nearby gas development well Kenai Loop Kenai Loop #1 was placed on regular production in December 2011. Kenai Loop #1 is the only well that penetrates the proposed injection zone within a ¼-mile radius of Kenai Loop #3.

2. Notification of Operators/Surface Owners (20 AAC 25.252(c)(2) and 20 AAC 25.252(c)(3))

   Buccaneer is the only operator within a ¼-mile radius of the proposed disposal well. Surface property owners within ¼-mile radius of Kenai Loop #3 are State of Alaska, Mental Health Trust, and Cook Inlet Region, Inc., and they were provided copies of the disposal injection order application for Kenai Loop #3.

3. Geological Information on Disposal and Confining Zones (20 AAC 25.252(c)(4))

   The proposed disposal injection operations will affect strata that are assigned to the Sterling Formation and the underlying Beluga Formation.

   Upper confinement for the proposed injection interval consists of numerous, laterally continuous tuffaceous claystone and siltstone layers and thin coal seams that lie within the Sterling Formation between 3,065' MD / TVD and 3,980' MD (3,961' TVD), a total true vertical thickness of 896'. Fracture-arrest and additional upper confinement will be provided by several laterally persistent, tuffaceous siltstone, claystone and thin coal layers that lie within the Beluga Formation between 5,453' and 5,720' MD (5,289' and 5,530' TVD), an interval that is 241 true vertical feet thick.

   Buccaneer's planned injection interval lies in the Beluga Formation between 5,721' and 7,025' MD (5,531' and 6,704' TVD), an interval that is 1,173 true vertical feet thick. Such a large interval is requested because, in this portion of the Cook Inlet Basin, Beluga Formation sediments were deposited by a network of small meandering and anastomosing rivers and streams that cut through a silt-and clay-rich alluvial plain. In this area, the Beluga Formation typically has a low net-sand-to-gross-thickness ratio and a low median permeability because of abundant diagenetic clay.

   The proposed injection interval contains several thin layers of fluvial sandstone. Laboratory measurements performed on nine rotary sidewall cores from these layers yielded a median

[1] Unless otherwise indicated, all depth- and thickness-related footages presented herein refer to the Kenai Loop #3 well.

porosity of 21% (range: 1.9% to 29.1%) and a median permeability of 1 millidarcy (abbreviated as md; range: 0.001 md to 128 md). Buccaneer conducted two drill stem tests within the proposed injection interval. One test recovered formation water. The second test did not flow.

Lower confinement and fracture arrest will be provided by laterally continuous layers of tuffaceous claystone, siltstone and thin coal seams that are common between 7,026' and 7,539' MD (6,705' and 7,191' TVD), an interval within the Beluga Formation that is 486 true vertical feet thick. Additional lower confinement for injected fluids will be provided by Beluga Formation tuffaceous siltstone, claystone and coal layers that lie between 7,539' and 8,554' MD (7,191' and 8,193' TVD), a total true vertical feet thickness of 1,002'.

Maps provided by the operator do not display any faults within the confining intervals or the injection interval within the affected area.

4. Evaluation of Fluid Confinement (20 AAC 25.252(c)(9))

Buccaneer's application for a disposal injection order suggests Kenai Loop #3 could serve as a central Class II waste disposal injection facility supporting onshore and offshore oil and gas development activities in the Cook Inlet area.

Disposal injection of drilling mud and slurried cuttings will require pressure sufficient to fracture the Beluga Formation. In support of fracture modeling, Buccaneer evaluated drilling and production wastes generated from the Cook Inlet area to determine a range of expected fluid densities. Buccaneer also evaluated rock properties from well data collected during the drilling of Kenai Loop wells #1 and #3.

Buccaneer's fracture modeling effort addressed injected fluid densities, and rates and pressures for both expected and extreme injection conditions. Modeling predicts a radially-fractured zone of influence (*i.e.*, waste plume area) – dependent on volume of injection and rock properties within the injection zone – that may extend as much as 1,600 feet laterally from the well and as much as 40 feet above and below the perforated interval. The only well penetrating this area – Kenai Loop #1 – has sufficient mechanical integrity to prevent the migration of fluids from the proposed injection zone.

The potential 1,600-foot lateral fracture extent renders a ¼-mile area of review around Kenai Loop #3 too small for evaluating the worst-case scenario. Extending the area of review to ½-mile radius around Kenai Loop #3 accommodates the worst case lateral fracture, but does not add any additional wells for evaluation. Future wells within ½-mile must be constructed to ensure they do not serve as a conduit for fluid migration from the disposal zone.

5. Aquifer Exemption (20 AAC 25.252(c)(11)); Standard Laboratory Water Analysis of the Formation (20 AAC 25.252(c)(10))

Buccaneer applied for a Freshwater Aquifer Exemption (Aquifer Exemption Order No. 15, abbreviated as AEO 15) simultaneous to the application for this disposal injection order, received by the AOGCC on March 16, 2012.

A standard laboratory analysis of Beluga Formation water is not available. However, a formation water sample was recovered during drill-stem testing within the planned disposal interval. Onsite analysis of that water sample yielded a measurement of 6,000 mg/l chlorides.[2] Based on well log calculations, Buccaneer concludes that the total dissolved solids (TDS) concentration of formation waters within proposed disposal interval is greater than 3,000 mg/l. Using similar methods, the AOGCC calculated TDS concentrations ranging from 6,500 to 8,500 mg/l for the proposed disposal interval and the associated confining intervals.[3]

6. Well Logs (20 AAC 25.252(c)(5))

   Log data from Kenai Loop #3 are on file with the AOGCC. In their application, Buccaneer provided a type log that illustrates the proposed injection and confining zones.

7. Demonstration of Mechanical Integrity and Disposal Zone Isolation (20 AAC 25.252(c)(6))

   Kenai Loop #3 is constructed as follows: 16-inch conductor casing driven to 120 feet MD (120 feet TVD); 10-3/4-inch surface casing set at 3,027 feet MD (3,060 feet TVD); 7-5/8-inch intermediate casing set at 8,330 feet MD (7,969 feet TVD); and 4.5-inch liner installed from 8,100 feet MD to 11,362 feet MD (7,631 feet to 11,001 feet TVD). The well's plug-back depth is 6,375 feet MD (6,116 feet TVD). Buccaneer will perform a well workover to set up Kenai Loop #3 for disposal injection. Work will include drilling out the uppermost abandonment plug to expose existing perforations in the Beluga Formation at 6,435 feet to 6,450 feet MD (6,170 feet to 6,183 feet TVD) and 6,950 feet to 6,960 ft MD (6,634 feet to 6,643 feet TVD). The injection completion will consist of 3.5-inch tubing and a permanent packer installed at 5,500 feet MD (5,331 feet TVD). An alternate setting depth for the injection packer was approved by AOGCC (Sundry No. 312-100; May 14, 2012) as part of reconfiguring the well for disposal injection.

   Buccaneer reports that the 7-5/8-inch casing is cemented from the casing shoe to 4,850 feet MD (4,548 feet TVD), providing an estimated 1,585 feet of annular cement above the upper most injection perforations. Cement bonding in the 7-5/8-inch casing section opposite the injection and confining layers was evaluated with a cement bond log. The reported cement top of 5,000 feet MD (3,925 feet TVD) was calculated from the volume of cement pumped and an assessment of the cement placement operation.

   Buccaneer commits to performing mechanical integrity tests of the tubing and tubing-casing annulus (including packer) as part of the workover operations before injection commences. Additional baseline assessments and subsequent evaluations will be necessary to confirm the well has the proper mechanical integrity for disposal injection as proposed.

8. Disposal Fluid Type, Composition, Source, Volume, and Compatibility with Disposal Zone (20 AAC 25.252(c)(7))

   Buccaneer requests approval to dispose of drilling, production, completion, workover wastes, and other associated wastes that are intrinsically derived from primary field operations. The volume of wastes to be injected into Kenai Loop #3 could be as much as 1,135,000 barrels of

[2] Kenai Loop #3, Daily Drilling Report, October 25, 2011, in AOGCC Well History File No. 211-097 (all information from this well are currently held confidential; the scheduled public release date is November 25, 2013)

[3] AOGCC's calculation techniques are compatible with EPA Guidance Document "Survey of Methods to Determine Total Dissolved Solids Concentrations" (EPA LOE Contract No. 68-03-3416, Work Assignment No. 1-0-13, KEDA Project No. 30-956, October 1988, Revised October 1989).

Class II wastes over the expected life of the well. Buccaneer expects daily injection volumes of 155 barrels with excursions up to approximately 1,000 barrels, rates up to 4 barrels per minute, and slurry densities up to 10.5 pounds per gallon. Fracture modeling evaluated several conservative slurry injection scenarios, including: a single 2,500-barrel batch injected at 6 barrels per minute; and injecting 155 barrels per day at a rate of 3 barrels per minute for 5 years. Buccaneer states that injected slurry will not penetrate the upper or lower confining layers based on the slurry fracture modeling, nor will it intersect any well penetrating the injection zone.

Injected fluids are expected to be compatible with the lithology and resident water of the injection zone based on operating experience and performance (*e.g.*, pressures, rates, and volumes) of numerous disposal injection wells in surrounding fields that have the same receiving formation—the Beluga Formation—as proposed for Kenai Loop #3. There have been no reported compatibility issues associated with disposal injection into the Beluga Formation at other fields in the Cook Inlet area.

9. Estimated Injection Pressures (20 AAC 25.252(c)(8))

   Buccaneer estimates that the average surface injection pressure will be between 1,800 psig and 3,000 psig. The maximum surface injection pressure could reach 6,000 psig if sporadic plugging of perforations or fracture flow channels occurs.

10. Mechanical Condition of Wells Penetrating the Disposal Zone Within a ¼-Mile Radius of Kenai Loop #3 (20 AAC 25.252(c)(12))

    Kenai Loop #1 is the only well to penetrate the proposed disposal injection zone within ¼-mile radius of Kenai Loop #3. Well construction records show that both the proposed injection well and producing well Kenai Loop #1 are cased and cemented to prevent the movement of injected fluids beyond the well's confinement zones. Records documenting the drilling, casing, cementing, and testing of these wells are in the AOGCC's files.

CONCLUSIONS:

1. The 20 AAC 25.252 requirements for approval of an underground disposal application are met.

2. Kenai Loop #3 was drilled as a gas exploration well, but it did not find commercial quantities of gas.

3. Buccaneer's planned injection interval in Kenai Loop #3 lies in the Beluga Formation between 5,721' (5,531' TVD) and 7,025' (6,704' TVD), an interval that is about 1,173 true vertical feet thick. This large interval is necessary because, in this portion of the Cook Inlet Basin, the Beluga Formation displays a low net-sand-to-gross-thickness ratio and low permeability.

4. Upper confinement will be provided by 896 true vertical feet of laterally continuous tuffaceous claystone and siltstone layers and thin coal seams within the Sterling Formation. Fracture-arrest and additional upper confinement will be provided by 241 true vertical feet of tuffaceous siltstone, claystone layers and thin coal seams within the underlying Beluga Formation.

5. Lower confinement and fracture arrest will be provided by 486 true vertical feet of laterally continuous layers of Beluga Formation tuffaceous claystone, siltstone and thin coal seams. Additional lower confinement will be provided by 1,002 true vertical feet of tuffaceous siltstone, claystone layers and thin coal seams.

6. No significant faults are present near area that will be affected by the proposed injection operations.

7. TDS content of formation water within the proposed injection and confining intervals is greater than 3,000 mg/l and less than 10,000 mg/l. AEO 15 (Corrected)—issued by the AOGCC on November 28, 2012—exempts aquifers occurring in the Sterling and Beluga Formations that are stratigraphically equivalent to, and lie within a radius of ½ mile of, the interval from 3,980 to 7,539 feet MD in well Kenai Loop #3.

8. No compatibility concerns relating to the injected fluids and in-situ formation fluids have been identified in connection with the injection of a similar waste fluid streams into the Beluga Formation at other locations within the Cook Inlet Basin.

9. Fracture modeling indicates that disposed waste fluids will be contained within the receiving interval by confining lithologies, cement isolation of the well bore, and planned operating conditions. Modeling of the most extreme injection conditions predicts that fractures will not penetrate the upper confining zone, or breach the lower confining zone. Within the predicted fracture geometry for the most extreme injection conditions modeled, Kenai Loop #1 is the only penetration. Sufficient mechanical integrity has been demonstrated in Kenai Loop #1 to prevent the migration of fluids from the proposed injection zone. The adequacy of mechanical integrity for new wells constructed within the worst-case predicted fracture geometry surrounding Kenai Loop #3 will be assessed in each well's permit to drill to ensure injected fluids remain confined to the intended receiving interval.

10. Supplemental mechanical integrity demonstrations and the surveillance of injection operations—including baseline and subsequent temperature surveys, monitoring of injection performance (*i.e.*, pressures and rates), and analyses of the data for indications of anomalous events—are appropriate to ensure that waste fluids remain within the disposal interval.

11. Actual performance information gained during drilling, injection and remedial well operations must be monitored during the life of the disposal project to ensure appropriate operation of the field. A requirement for formal review of the disposal injection performance every five years will ensure the findings, conclusions, and rules of this order remain valid.

NOW, THEREFORE, IT IS ORDERED THAT disposal injection is authorized into the Beluga Formation within well Kenai Loop #3 subject to each of the following requirements:

RULE 1: Injection Strata for Disposal

The underground disposal of Class II oil field waste fluids is permitted into the Beluga Formation within Kenai Loop #3 in the interval from 5,721 feet to 7,025 feet MD (5,531 feet to 6,704 feet TVD). The AOGCC may immediately suspend, revoke, or modify this authorization if injected fluids are not confined by the upper and lower confining zones.

RULE 2: Authorized Fluids

This authorization is limited to Class II oil field waste fluids generated during drilling, production, workover, or abandonment operations, specifically:

> Drilling fluids; drill cuttings; well workover fluids; stimulation fluids and solids; produced water; rig wash water; formation materials; naturally occurring radioactive materials; scale; tracer materials; glycol dehydration; reserve pit fluids; chemicals used in the well or for production processing at the surface (in direct contact with produced fluids); and precipitation accumulating in drilling and production impoundment areas.

Administrative action under Rule 8 of this order is required prior to initiating commercial Class II disposal injection in Kenai Loop #3.

RULE 3: Injection Rate and Pressure

Injection pressures must be maintained such that the injected fluids do not fracture the confining intervals or migrate out of the approved injection stratum. Disposal injection is authorized at (a) rates that do not exceed 4 barrels per minute and (b) wellhead injection pressures that do not exceed 6,000 psig.

RULE 4: Demonstration of Mechanical Integrity

The mechanical integrity of Kenai Loop #3 must be demonstrated before injection begins and before returning the well to service following a workover affecting mechanical integrity. An AOGCC-witnessed mechanical integrity test must be performed after injection is commenced for the first time in Kenai Loop #3, to be scheduled when injection conditions (temperature, pressure, rate, etc.) have stabilized. Subsequent mechanical integrity tests must be performed at least once every two years after the date of the first AOGCC-witnessed test. Mechanical integrity tests must be conducted in accordance with AOGCC Industry Guidance Bulletin No. 10-02, "Mechanical Integrity Testing" and done to a test pressure equal to the maximum anticipated surface injection pressure. The AOGCC must be notified at least 24 hours in advance of each such test to enable a representative to witness the test. The results of all mechanical integrity demonstrations and Buccaneer's interpretation of those results shall be provided to the AOGCC within seven (7) days of completing the test.

RULE 5: Well Integrity Failure and Confinement

Whenever any pressure communication, leakage or lack of injection zone isolation is indicated by injection rate, operating pressure observation, test, survey, log, or any other evidence, the Operator shall notify the AOGCC within 24 hours and submit a plan of corrective action on a Form 10-403 for AOGCC approval. The Operator shall immediately shut in the well if continued operation would be unsafe or threaten contamination of freshwater, or if so directed by the AOGCC. A monthly report of daily tubing and casing annuli pressures and injection rates must be provided to the AOGCC for Kenai Loop #3 if the well indicates any well integrity failure or lack of injection zone isolation.

RULE 6: Surveillance

The operator shall run a baseline temperature log and perform a baseline step-rate test prior to initial injection. A subsequent temperature log must be run one month after injection begins to delineate the receiving zone of the injected fluids. Surface pressures and rates must be monitored continuously during injection for any indications of anomalous conditions. Results of daily wellhead pressure observations in Kenai Loop #3 must be documented and available to the AOGCC upon request. The conduct of subsequent temperature surveys or other surveillance logging (*e.g.*, water flow; acoustic) will be based on the results of the initial and follow-up temperature surveys and injection performance monitoring data.

A report evaluating the performance of the disposal operation must be submitted to the AOGCC by April 1 of each year covering injection operations during the previous calendar year. The report shall include data sufficient to characterize the disposal operation, including, among other information, the following: injection and annuli pressures (*i.e.*, daily average, maximum, and minimum pressures); fluid volumes injected (*i.e.*, in disposal and clean fluid sweeps); injection rates; an assessment of the fracture geometry; a description of any anomalous injection results; and a calculated zone of influence for the injected fluids. An assessment of the applicability of the injection order findings, conclusions, and rules based on actual performance shall be included with the annual performance report.

RULE 7: Notification of Improper Class II Injection

Injection of fluids other than those listed in Rule 2 without prior authorization is considered improper Class II injection. Upon discovery of such an event, the operator must immediately notify the AOGCC, provide details of the operation, and propose actions to prevent recurrence. Additionally, notification requirements of any other State or Federal agency remain the operator's responsibility.

If fluids are found to be fracturing through a confining interval or migrating out of the approved injection stratum, the Operator must immediately shut in well. Upon discovery of such an event, the operator must immediately notify the AOGCC, provide details of the operation, and propose actions to prevent recurrence. Injection may not be restarted unless approved by the AOGCC.

RULE 8: Administrative Action

Upon proper application, or its own motion, and unless notice and public hearing is otherwise required, the AOGCC may administratively waive the requirements of any rule stated herein or administratively amend this order as long as the change does not promote waste or jeopardize correlative rights, is based on sound engineering and geoscience principles, and will not result in an increased risk of fluid movement into freshwater or outside of the authorized injection zone.

RULE 9: Compliance

Operations must be conducted in accordance with the requirements of this order, AS 31.05, and (unless specifically superseded by AOGCC order) 20 AAC 25. Noncompliance may result in the suspension, revocation, or modification of this authorization and other penalties.

RULE 10: Reauthorization

The Operator must apply to reauthorize disposal injection at intervals not exceeding five (5) years from the effective date of this Order. The application shall include an assessment of the Order findings, conclusions, and rules taking into account actual injection performance.

DONE at Anchorage, Alaska, and dated November 28, 2012.

Cathy P. Foerster
Chair, Commissioner

Daniel T. Seamount, Jr.
Commissioner

John K. Norman
Commissioner

RECONSIDERATION AND APPEAL NOTICE

As provided in AS 31.05.080(a), within **20** days after written notice of the entry of this order or decision, or such further time as the AOGCC grants for good cause shown, a person affected by it may file with the AOGCC an application for reconsideration of the matter determined by it. If the notice was mailed, then the period of time shall be **23** days. An application for reconsideration must set out the respect in which the order or decision is believed to be erroneous.

The AOGCC shall grant or refuse the application for reconsideration in whole or in part within 10 days after it is filed. Failure to act on it within 10-days is a denial of reconsideration. If the AOGCC denies reconsideration, upon denial, this order or decision and the denial of reconsideration are **FINAL** and may be appealed to superior court. The appeal **MUST** be filed within **33** days after the date on which the AOGCC mails, **OR 30** days if the AOGCC otherwise distributes, the order or decision denying reconsideration, **UNLESS** the denial is by inaction, in which case the appeal **MUST** be filed within **40** days after the date on which the application for reconsideration was filed.

If the AOGCC grants an application for reconsideration, this order or decision does not become final. Rather, the order or decision on reconsideration will be the **FINAL** order or decision of the AOGCC, and it may be appealed to superior court. That appeal **MUST** be filed within **33** days after the date on which the AOGCC mails, **OR 30** days if the AOGCC otherwise distributes, the order or decision on reconsideration. As provided in AS 31.05.080(b), "[t]he questions reviewed on appeal are limited to the questions presented to the AOGCC by the application for reconsideration."

In computing a period of time above, the date of the event or default after which the designated period begins to run is not included in the period; the last day of the period is included, unless it falls on a weekend or state holiday, in which event the period runs until 5:00 p.m. on the next day that does not fall on a weekend or state holiday.