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

Re: THE APPLICATION OF	)	**Disposal Injection Order No. 34A**
Marathon Oil Company for	)	**Docket No. DIO-09-01**
modification of Disposal Injection	)	**Sterling Formation**
Order 34 to expand the approved	)	**Kenai Unit Well 12-17**
waste disposal injection interval in	)	
the Sterling Formation in the Kenai	)	**May 27, 2009**
Unit Well 12-17, Section 17, T4N,	)	
R11W, S.M.	)	
	)	

IT APPEARING THAT:

1. Alaska Oil and Gas Conservation Commission (Commission) regulation 20 AAC 25.252 provides the authority to issue an order governing underground injection of Class II oil field wastes. The Commission issued Disposal Injection Order 34 (DIO 34) on November 20, 2008 for Kenai Unit (KU) 12-17 (KU 12-17), operated by Marathon Oil Company (Marathon).

2. The Commission issued administrative approval DIO 34.001 on December 17, 2008 clarifying the fluids eligible for Class II waste disposal in KU 12-17.

3. By application dated March 23, 2009, Marathon requested the Commission amend DIO 34 by expanding the approved underground disposal injection zone in KU 12-17. Marathon also requested an alternate schedule for submitting the annual disposal injection report.

4. Notice of opportunity for a public hearing was published in the ANCHORAGE DAILY NEWS on March 26, 2009, in the PENINSULA CLARION on March 29, 2009, on the State of Alaska Online Notices on March 25, 2009, and on the Commission's Web site on March 25, 2009, in accordance with 20 AAC 25.540. The scheduled hearing date was May 4, 2009.

5. The Commission did not receive any comments, protests or requests for a public hearing.

6. The public hearing was vacated on April 21, 2009.

7. The information submitted by Marathon; the findings, conclusions and administrative record for DIO 34; and public well history records are the basis for this amended order.

FINDINGS:

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

   KU 12-17 is an existing well directionally drilled in June-July 2008 to a total depth of 6585 feet measured depth (MD), which is equivalent to 5786 feet true vertical depth (TVD). The bottom hole location for KU 12-17 is in Section 17, Township 4N, Range 11W, Seward Meridian (2823 feet from north line, 163 feet from east line). The surface location is on the Marathon-operated 41-18 drill site within the Kenai Gas Field in Section 18, Township 4N, Range 11W (848 feet from north line, 742 feet from east line). The plat included with Marathon's application shows the location of all wells within a ¼-mile radius of KU 12-17.

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

   Marathon is the only operator within a ¼-mile radius of the proposed disposal well. Surface owners within a ¼-mile radius of KU 12-17 are Salamatof Native Corporation and Cook Inlet Regional Corporation. All surface owners were notified by letter regarding the proposed injection using KU 12-17 according to the "Affidavit of Notice to Surface Owners and Operators" provided by Marathon.

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

   The Sterling Formation consists of thick, sandy, meandering stream bar deposits alternating with coals and shales. Sterling B1 and B2 intervals as shown on Figures 5 and 5A of Marathon's original application are the intended injection zone, from 4002 feet to 4147 feet TVD. Porosity and permeability in the disposal interval range up to 28 percent and 1000 millidarcies, respectively. The disposal injection zone is within the aquifer exemption area defined by EPA in 40 CFR 147.102(b)(1)(iii). Marathon perforated the Sterling B2 interval in KU 12-17 from 4110 feet to 4140 feet TVD for primary waste disposal injection. A coal layer from 3919 feet to 3926 feet TVD is identified by Marathon as providing upper confinement for injected fluids. Interpreted cross sections indicate the upper confining layer is laterally continuous across the Kenai Gas Field.

   Commercial gas accumulations are in the Sterling Formation in other parts of the KU. In the section of the Sterling penetrated by KU 12-17, all intervals but the deepest—*i.e.*, Sterling Pool 6—are water wet. Gas storage in Sterling Pool 6 is isolated from the shallower Sterling B1 and B2 disposal injection intervals by laterally continuous coal, silt and shale layers.

   Gas storage injection in the Kenai Gas Field occurs into Sterling Pool 6. KU 12-17 penetrated the Sterling Pool 6 at a depth of 4706 feet TVD. The gas storage injection zone is isolated from the Sterling B1 and B2 intervals by laterally continuous coal, silt, and shale layers as well as well construction (casing and cement). Marathon identifies the specific lower confinement for the Sterling B1 and B2 intervals as being from 4150 feet to 4203 feet TVD. Structure maps provided by Marathon indicate there are no transmissive faults in the vicinity of Drillsite 41-18 at the depths that correlate to the injection zone and confining layers.

Included in Marathon's application for amendment was a request to approve a maximum disposal zone defined by modeling the fracture extension assuming no confining layers. Marathon reports that the extreme case model (no confining layers) would result in fracture extension within the interval 3600 feet to 4150 feet TVD. Marathon's application requests the approved disposal zone be 3500 feet to 4400 feet TVD.

4. Evaluation of Confining Zones (20 AAC 25.252(c)(9))

Marathon's application for DIO 34 relied on the recent fracture model updates for waste disposal wells KU 11-17 and KU 24-07RD (which, also located on the 41-18 drill site, dispose into the Sterling Formation). The KU 11-17 and KU 24-07RD model updates evaluated a range of factors to determine the sensitivity of those factors to fracture dimensions. Historical performance data (*i.e.*, rate, pressure, and fluid composition data) for the KU 11-17 and KU 24-07RD disposal injection wells were also used in the model updates to estimate fracture geometry for an injected volume of up to 2 million barrels. Marathon reported that similar rock and fluid properties allow these well fracture model updates to predict fracture behavior for KU 12-17. The KU fracture model updates are in the Commission's files.

For DIO 34, Marathon predicted a fracture height of 200 feet, growing into the Sterling B1 interval, and a half-length of 4,000 feet as the most likely case based on the fracture model updates and nearby waste injection performance in the Sterling Formation. The modeling predictions indicate neither the upper nor lower confining layers would be penetrated because of the planned injection operations in KU 12-17. Additional evidence that the confining layers would be effective barriers includes the historic injection in the Sterling Formation within the KU 11-17, KU 14-4, KU 24-07, and KU 24-07RD wells.

More rigorous fracture simulations specific to KU 12-17 were performed at Marathon's initiative using actual well and formation data gathered during drilling and completion activities, including well log and step-rate test results. Simulations evaluated fracture geometry using stress profiles representing different confining layers. A worst case scenario involving no confining layers was also evaluated to determine the maximum possible fracture growth.

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

By regulation (*i.e.*, 40 CFR 147.102(b)(1)(iii)), EPA has exempted those portions of aquifers below 1300 feet TVD in the Kenai Gas Field. As additional confirmation that the water below 1300 feet TVD is not fresh water, Marathon provided the water analysis for a Sterling Formation water sample taken from KU 14-6 indicating total dissolved solids greater than 10,000 mg/l.

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

Log data from KU 12-17 are on file with the Commission.

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

KU 12-17 was drilled to be a Class II waste disposal injector. The well was directionally drilled south to a depth of 5786 feet TVD (6585 feet MD); constructed with 20-inch conductor casing set at 189 feet TVD, 10-3/4-inch surface casing set at 1492 feet TVD, and 7-5/8-inch production casing set at 5786 feet TVD; and plugged back to 5682 feet TVD. The injection completion consists of 4.5-inch injection tubing run to 3896 feet TVD and a permanent packer installed at 3865 feet TVD, thereby establishing the Sterling Formation as the intended zone for underground injection control (UIC) Class II disposal.

The surface casing is cemented from shoe depth to the surface. The production casing is constructed with sufficient cement to cover from total depth to 2517 feet TVD.

A cement bond log was run in KU 12-17 to evaluate the cement placement and bond integrity of the casing string isolating the planned injection zone. Marathon evaluated the 7-5/8-inch casing interval with a cement bond log from 5680 feet to 2373 feet TVD. An estimated cement top of 2586 feet TVD with good to excellent cement bond is interpreted from the log data. Cement bond appears to be excellent throughout, above and below the proposed Sterling B1 and B2 injection intervals. The interpreted top of the cement is approximately 360 feet above the top of the upper confining zone.

A mechanical integrity test (MIT) was performed on December 16, 2008, as required by the Commission prior to commencing injection. A second MIT will be performed after injection commences for the first time; this MIT must be witnessed by the Commission. Marathon will continuously monitor wellhead pressures using a supervisory-controlled automated data acquisition system and daily visual inspections and pressure recordings. Additionally, Marathon states that annual due diligence reviews will be performed for all active slurry injection on the 41-18 drill site; the reviews will evaluate pressure trend data and fracture modeling update results.

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

KU 12-17 will be the third active waste disposal well on the KU 41-18 drill site injecting into the Sterling Formation; there are another three active waste disposal wells within the Kenai Gas Field (2 Kenai Gas Field waste disposal wells are plugged and abandoned). Marathon intends to use KU 12-17 to dispose of drilling, production, completion, workover and other Class II wastes originating from exploration and development well activities on the Kenai Peninsula in a manner and to an extent that is similar to the use of the other KU 41-18 drill site waste disposal wells. Marathon projects the injection volume into KU 12-17 could exceed 1,000,000 barrels of Class II wastes over the expected life of the field. Marathon expects the injection rate to average 1000 barrels per day (with a maximum injection rate of 7200 barrels per day), with rates of up to 5 barrels per minute. The expected performance is less than the injection performance used in fracture modeling for this project.

No compatibility concerns relating to injected fluids and in-situ formation fluids have been identified by Marathon although Marathon has already injected more than 6.5 million barrels of Class II wastes into the KU disposal wells.

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

Marathon estimates that the average surface injection pressure will be 1600 psig. The maximum surface injection pressure is limited by the 3000 psig working pressure of the injection pump, which is equipped with a 2400 psig pressure safety relief system.

10. Mechanical Condition of Wells Penetrating the Disposal Zone Within ¼-Mile of KU 12-17 (20 AAC 25.252(c)(12))

No wells penetrate the Sterling Formation within a ¼-mile radius of KU 12-17. The fracture modeling results provided with the original injection order application led the Commission to request a larger area of review—*i.e.*, a radius equivalent to the 4000-foot fracture half-length around the proposed disposal well—to evaluate the mechanical condition of wells penetrating the disposal zone. Eleven wells were identified: 8 wells within the Kenai Unit (KU 11-17, KU 14-8, KU 24-7, KU 24-7RD, KU 41-18, KU 41-18X, KU 41-19, and KU 44-18); and 3 wells within the Kenai Beluga Unit (KBU 13-8, KBU 24-7X, and KBU 33-7). Marathon indicated the cement and casing in each of the wells appear to be adequate to prevent the movement of injected fluids outside of the disposal zone.

Fracture simulations were performed using the actual well data and test results from drilling and completing KU 12-17. Marathon ran several fracture propagation scenarios using stress profile, barrier, and batch volume injection parameters that are more specific to the proposed disposal operations than those that were considered in connection with DIO 34. The more rigorous modeling supports a smaller area of review than the one used for DIO 34.

CONCLUSIONS:

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

2. The expected Sterling Formation disposal zone is approximately 145 feet thick. Expected upper confinement will be provided by a 50-foot shale and coal sequence that is shown on structural cross sections derived from logging data to be laterally continuous across the field. Expected lower confinement of injected fluids will be provided by a coal, shale and siltstone interval that is also laterally continuous across the field. No significant faults are in the vicinity of the proposed operations. Past injection operations into Sterling B1 and B2 intervals in active disposal injection wells located on the KU 41-18 drill site show the confining layers are effective barriers to fluid movement.

   Based on the modeled and actual injection rates in nearby waste disposal injectors operating analogously to what is planned for KU 12-17, the Commission concluded in DIO 34 that reasonable grounds exist to find that waste fluids will be contained within the proposed disposal zone by the lithologies above and below the Sterling B1 and B2 intervals, cement isolation of the wellbore, and operating conditions.

3. Kenai Gas Field aquifers below 1300 feet TVD are exempted by EPA as underground sources of drinking water for Class II injection activities. *See* 40 CFR 147.102(b)(1)(iii). Also, the total dissolved solids content of the water within Sterling B1 and B2 intervals exceeds 10,000 mg/l.

4. Commercial gas accumulations are in the Sterling Formation in other parts of the KU. In the section of the Sterling penetrated by KU 12-17, all intervals but the deepest—*i.e.*, Sterling Pool 6—are water wet. Gas storage in Sterling Pool 6 is isolated from the shallower Sterling B1 and B2 disposal injection intervals by laterally continuous coal, silt and shale layers. Therefore, vertical fracture growth will not likely reach Sterling Pool 6.

5. More rigorous fracture simulations were performed using well log data and injectivity test results generated during KU 12-17 well construction. Marathon's March 23, 2009 application for an amended DIO 34 summarized the fracture simulations performed. Included in the more rigorous simulations was an extreme case evaluating fracture growth in the vertical and lateral directions assuming no confining layers. Maximum upward fracture growth depth was determined to be 3500 feet TVD; maximum downward fracture growth depth was determined to be 4150 feet TVD; and maximum lateral fracture propagation was determined to be approximately 1000 feet.

6. In DIO 34, the Commission concurred with Marathon's assessment that the casing, cement placement, and cement quality records indicate that all wells penetrating the disposal zone within an area of review described by a 4000-foot radius around KU 12-17 have sufficient mechanical integrity to prevent the migration of injected fluids outside of the proposed disposal zone. A 4000-foot radius around KU 12-17 was deemed necessary based on information provided with the application for DIO 34. Results of rigorous fracture modeling provided with Marathon's application for an amended DIO 34 (requesting a vertically expanded underground disposal injection zone in KU 12-17) support an area of review defined by a quarter-mile radius around KU 12-17, *i.e.*, a smaller radius than that used for the well integrity reviews and surveillance requirements in DIO 34.

7. Disposal injection operations in KU 12-17 will be conducted at rates and pressures below those estimated to fracture through the confining zones. Therefore, oil field wastes injected into KU 12-17 will be confined to the isolated Sterling B1 and B2 intervals by an upper coal layer at 3919 feet to 3926 feet TVD and lower coal, shale, and siltstone interval from 4150 feet to 4203 feet TVD.

8. Modeling of a fracture growth scenario considering no confining layers reveals a disposal interval of 3600 feet to 4150 feet TVD, according to information provided by Marathon. The Commission agrees with Marathon's analysis that there would be no impact to freshwater or to production and gas storage zones in the case of no confining layers. A coal interval from 4200 feet to 4203 feet TVD is shown in the modeling results provided by Marathon to provide lower confinement for all scenarios evaluated. Therefore, setting the allowed disposal zone to coincide with the findings of an extreme case – 3600 feet to 4200 feet TVD

– will not promote waste, jeopardize the ultimate recovery of hydrocarbons, jeopardize correlative rights, or result in fluid movement into freshwater.

9. There is no basis on which or apparent need to establish a disposal zone that is larger than what is indicated by the extreme case of fracture extension presented by Marathon: *i.e.*, the disposal injection zone does not need to be greater than 3600 feet to 4200 feet TVD.

10. For disposal operations, fluid compatibility in the Sterling B1 and B2 is not a concern. Operating experience and data from disposal injection involving similar materials and performance parameters (*i.e.*, pressures, rates, and volumes) elsewhere within the Kenai Unit Sterling Formation provide an analogy for underground disposal in KU 12-17.

11. Supplemental mechanical integrity demonstrations and the surveillance of injection operations—including 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.

12. Making the first annual performance report due 6 months following the commencement of injection into KU 12-17 will enable Marathon to undertake a more meaningful review of the well's injection performance. Subsequent annual injection performance reports should be provided to the Commission no later than July 1 of each year.

NOW, THEREFORE, IT IS ORDERED THAT disposal injection is authorized into the Sterling Formation within Kenai Unit Well 12-17 subject to each of the following requirements:

RULE 1: Injection Strata for Disposal

The underground disposal of Class II well oil field waste fluids is permitted into the Sterling Formation within KU 12-17 in the interval from 3600 feet to 4200 feet TVD. The Commission may immediately suspend, revoke, or modify this authorization if injected fluids fail to be confined to the approved disposal interval.

RULE 2: Fluids

This authorization is limited to Class II oil field waste fluids generated during drilling, production or workover operations. Included are drilling, completion, and workover fluids; glycol dehydration wastes; drilling mud slurries; tank bottoms; pipe scale (including naturally occurring radioactive material); produced water; precipitation within containment areas; pad storm water retention basins; drum rinsate; equipment wash water; and organic materials that are contaminated with crude oil or natural gas liquids.

The eligibility of other fluids for Class II waste disposal injection will be considered by the Commission on a case-by-case basis upon application by the operator.

RULE 3: Injection Rate and Pressure

Disposal injection is authorized at (a) rates that do not exceed 5 barrels per minute and (b) surface pressures that do not exceed 2400 psig.

RULE 4: Demonstration of Mechanical Integrity

The mechanical integrity of KU 12-17 must be demonstrated before injection begins and before returning the well to service following a workover affecting mechanical integrity. A Commission-witnessed mechanical integrity test must be performed after injection is commenced for the first time in KU 12-17; that test must 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 Commission-witnessed test. The Commission must be notified at least 24 hours in advance of each such test to enable a representative to witness the test. Unless an alternate means is approved by the Commission, mechanical integrity must be demonstrated by a tubing/casing annulus pressure test that meets the following conditions: (1) pressure of either 1,500 psig or 0.25 psi/ft. multiplied by the vertical depth of the packer, whichever is greater is applied; (2) the test shows stabilizing pressure; and (3) pressure does not change more than 10 percent during a 30-minute period. The results of all mechanical integrity demonstrations and Marathon's interpretation of those results shall be provided to the Commission and be readily available for Commission inspection.

RULE 5: Well Integrity Failure and Confinement

Whenever any pressure communication, leakage or lack of injection zone isolation is indicated by the injection rate, an operating pressure observation, a test, a survey, a log, or any other evidence, the operator shall notify the Commission by the next business day and submit a plan of corrective action on Form 10-403 for Commission 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 Commission. A monthly report of daily tubing and casing annuli pressures and injection rates must be provided to the Commission for KU 12-17 indicating 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 KU 12-17 must be documented and available to the Commission upon request. The requirement to perform 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 Commission by July 1 of each year. The report shall include data sufficient to characterize the disposal operation; it shall include, among other information, the following: injection and annuli pressures (daily average, maximum and minimum); fluid volumes injected (disposal and clean fluid sweeps); injection rates; an assessment of fracture geometry; a description of any anomalous injection results; and a calculated zone of influence for the injection fluids. The initial injection performance report may be delayed to include 6 months of data if injection commences after February 1.

Wellhead pressures shall be monitored daily and maintained for KU 41-18 drill site wells penetrating the disposal zone within an area of review described by a quarter-mile radius around

KU 12-17. Pressure records shall be made available for inspection upon Commission request. The annual surveillance report shall include for each of these KU 41-18 drill site wells a summary wellhead pressure plot and an assessment of the well's mechanical integrity.

RULE 7: Notification of Improper Class II Injection

The operator must immediately notify the Commission if it learns of any improper Class II injection. Complying with the notification requirements of any local, state or federal agency remains the operator's responsibility.

RULE 8: Administrative Action

Unless notice and public hearing are otherwise required, the Commission may administratively waive or amend any rule stated above as long as the change does not promote waste, jeopardize the ultimate recovery of hydrocarbons, or jeopardize correlative rights, is based on sound engineering and geoscience principles, and will not result in fluid movement outside of the authorized injection zone.

RULE 9: Compliance

All operations must be conducted in accordance with the requirements of this order, AS 31.05, and (unless specifically superseded by Commission order) 20 AAC 25. Any noncompliance may result in the suspension, revocation, or modification of this authorization.

ENTERED at Anchorage, Alaska, and dated May 27, 2009.

Daniel T. Seamount, Jr., Chair
Alaska Oil and Gas Conservation Commission

Cathy P. Foerster, Commissioner
Alaska Oil and Gas Conservation Commission

John K. Norman, Commissioner
Alaska Oil and Gas Conservation Commission

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 Commission grants for good cause shown, a person affected by it may file with the Commission 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 Commission 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 Commission 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 Commission mails, **OR 30** days if the Commission 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 Commission 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 Commission, and it may be appealed to superior court. That appeal **MUST** be filed within **33** days after the date on which the Commission mails, **OR 30** days if the Commission 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 Commission 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.