STATEMENT OF BASIS
ANETH UNIT PHASE III
CLASS IIR AREA PERMIT
RESOLUTE NATURAL RESOURCES COMPANY

U.S. Environmental Protection Agency, Region IX (EPA)
Underground Injection Control (UIC) Permit NN208000006
Aneth Unit Area Permit Phase III Class IIR Injection Wells
San Juan County, Utah

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BACKGROUND INFORMATION

Resolute Natural Resources Company ("Applicant") has applied to US EPA Region IX for a UIC area permit for the Phase III project area in the Aneth Unit. The permit will authorize the permittee to drill, convert, and operate Class IIR water/carbon dioxide (CO_2) injection wells located on Navajo Nation land within the Phase III project area of the Aneth Unit for the purpose of enhanced oil recovery in the Paradox Formation. The Phase III project area is depicted on the two Area of

Review (AOR) maps in Appendix E of the permit. Thirty-two (32) existing injection wells are located within the Phase III project area and are identified in the Listing of Existing Injection Wells within the Phase III Project Area in Appendix E. The applicant proposes to inject an average of 500 barrels of produced water per day (BWPD) and an average of 1, 400 thousand cubic feet per day (MCFPD) of CO_2 on an alternating schedule and average well basis. The maximum proposed injection rates are 3,000 BWPD and 5,000 MCFPD of CO_2 per well and the proposed maximum wellhead injection pressure is 2,750 psig for water and 2,980 psig for CO_2 injection. The maximum allowable injection pressure will be set at the proposed maximum injection pressures since the surface parting pressure of the Paradox Formation exceeds 3,000 psig in the Greater Aneth Field.

Resolute's permit application is administratively complete and EPA has completed its technical review of the application. The EPA has decided to approve this permit, pending public review and comment, and is now issuing a Draft Permit. If approved, the permit will be issued for a period of twenty (20) years, unless the permit is terminated or modified for reasonable cause (40 CFR §§144.39, 144.40, and 144.41). The permit will be reviewed by EPA every five years.

The source of injection fluids will be CO_2 from the McElmo Dome Field located approximately 30 miles northeast of the Aneth Unit and saltwater produced in association with oil and gas production from Paradox Formation oil wells operated by Resolute in the Aneth Unit. The typical gas content of the recycled injected gas in mole percent is 72.6 % CO_2, 1.58 % nitrogen (N_2), 15.4 % methane, 0.0312% H_2S and the balance is other hydrocarbon gases. The average total dissolved solids (TDS) content of injection water is approximately 103,800 milligrams per litre (mg/l), based on fluid analyses of water from the Aneth Unit water injection plant. The water will be injected into the Paradox Formation, at a depth of approximately 5,200 to 6,000 feet in vertical wellbores, also containing TDS of approximately 103,800 mg/l based on the analysis of formation water produced from the Paradox Formation in the Aneth Unit oil wells. The injection intervals in future horizontal boreholes in multilateral wells are authorized from a depth of approximately 5,100 feet to 6,000 feet True Vertical Depth (TVD), which includes the lower Honaker Trail Formation, located just above and adjoining the Paradox Formation.

The injection zone is overlain by an average of 850 feet of carbonates, mudstones, shales, and fine-grained siliciclastics between the upper casing window and the top of the Honaker Trail formation and approximately 2,800 feet of shales, siltstones, sandstones, and evaporites in the Permian section, providing multiple confining layers to the overall permitted injection zone at 5,100 feet to 6,000 feet. The lowermost underground source of drinking water (USDW) is the Navajo Aquifer, the base of which is located at a depth that varies between 1,316 and 1,770 feet in the Aneth Unit Phase III area, with an average depth of 1470 feet.

The Applicant has notified all interested parties within the Area of Review, which includes the local landowners, land-users, Navajo Nation, Bureau of Land Management, Bureau of Indian Affairs, and the State of Utah.

The Applicant has also requested an area permit from Navajo Nation EPA (NNEPA) for drilling, conversion, and operation of Class IIR injection wells in the Aneth Unit. The permit has not yet been issued, but injection is allowed to continue by a temporary authorization issued by NNEPA, pending issuance of the area permit.

This Statement of Basis describes the specific permit conditions and the basis for those conditions under authority of the Underground Injection Control (UIC) regulations and the UIC provisions of the Safe Drinking Water Act.

BRIEF SUMMARY OF PART II. SPECIFIC PERMIT CONDITIONS

SECTION A. WELL CONSTRUCTION

1. Casing and Cementing

Construction details of existing injection wells are incorporated into the permit and typical wellbore schematic diagrams are included in Appendix C of the permit. Wells are cased and cemented to prevent the movement of injection fluids into a USDW. Surface casing is typically 13-3/8 inches in diameter and set at approximately 100 to 500 feet in depth and cemented to the surface. Intermediate casing, where used, is typically 8-5/8 or 9-5/8 inches in diameter and set at approximately 1,100 to1,600 feet in depth and cemented to surface. Intermediate casing extends to a depth below the lowermost USDW in most wells. In wells where intermediate casing was not installed, long string casing was usually cemented to the surface to protect USDWs from fluid inflow. Long string casing is typically 4-1/2 or 5-1/2 inches in diameter and is set through the Paradox Formation injection zone and cemented from the casing shoe upward to a depth that ensures isolation of the injection fluids from USDWs, located approximately 3,600 feet above the injection interval. Tubing is typically 2-7/8 inches in diameter and is set in a packer located within 100 feet of the perforated interval in the injection zone. The tubing/packer assembly provides another layer of protection from inflow of injected fluids into the USDWs.

Sixteen (16) of the existing injection wells in the Phase III project area were not cased and cemented to be fully protective of USDWs. Annular cement in those wells does not extend from total depth to the base of the USDWs, which leaves them vulnerable to possible fluid movement in the casing/wellbore annulus. Those wells will require remedial cementing during casing repairs or when they are plugged and abandoned if casing repairs are not required before P&A operations occur.

The permittee will be required to provide notice and submit drilling and construction plans for proposed new and converted injection wells in advance of drilling or converting injection wells. Surface or intermediate casing in newly drilled wells will be set and cemented to a depth of at least 50 feet below the base of USDWs unless the cement placement in the long string casing/wellbore annulus is from the casing shoe to the surface or at least to a depth that is a minimum of 100 feet above the surface of intermediate casing shoe and is verified by a cement bond log. This construction design will ensure that USDWs are protected from the possible inflow of injection and formation fluids as long as mechanical integrity is maintained in the well. Advance notice of casing and cementing operations will be given to the Director so that an EPA representative may arrange to be present to monitor those operations.

2. Formation Logging and Testing

Average injection zone pressure must be measured and reported to the EPA on an annual basis. A step-rate injectivity test may be required for the determination of formation fracture pressure if the applicant seeks to exceed the maximum allowable injection pressure during the life of the wells. Advance notice will be given to the Director of any logging and testing operations so that an EPA representative may arrange to be present to monitor those operations. Proposed logging and testing procedure are subject to EPA review and approval. A cement bond log will be run from plug-back total depth to the surface in newly drilled wells.

3. Monitoring Devices

The Applicant is required to install pressure gauges or FIP (female) fittings with cut-off valves to allow an inspector to obtain injection pressure measurements. A flowmeter shall be installed for measuring flow rates and cumulative volumes injected and a sampling tap shall be installed on the injection pump discharge line for the purpose of periodically obtaining representative samples of the injection fluid. Casing and tubing pressures will be monitored at the surface on a weekly basis by means of pressure/vacuum gauges.

SECTION B. CORRECTIVE ACTION

The permit will be issued based on corrective action considerations associated with the proposed AOR. Corrective actions are not required as a condition of injection operations since all of the existing wells within the AOR are constructed or plugged and abandoned to prevent movement of injection fluids into USDWs. However, any wellbores that lack sufficient intermediate string casing and/or cement in the long string casing/wellbore annulus to isolate the Navajo Aquifer (lowermost USDW) from potential fluid movement will require remedial cementing when casing leaks are detected or when the well is plugged and abandoned. A total of thirty-two (32) wells in the AOR have known deficiencies in the casing and cement placement and will require remedial cementing if a casing leak is detected during operations or mechanical integrity testing. If casing leaks do not occur, remedial cementing will be required when the wells are plugged and abandoned.

SECTION C. WELL OPERATION

1. Mechanical Integrity

A mechanical integrity test (MIT) of the casing, tubing, and packer will be conducted prior to commencement of injection in newly constructed or converted wells and prior to the resumption of injection operations following remedial operations in a well and periodically in each injection well as described below. The purpose of this test is to ensure there are no significant leaks in the tubing, packer, and casing. The standard MIT procedure requires applying a pressure at least equal to the maximum allowable injection pressure in the tubing/casing annulus for thirty (30) minutes with no more than 5% change in pressure. A differential of at least three hundred (300) psig between the tubing and tubing/casing annulus will be maintained throughout the test. Demonstrations of mechanical integrity of the injection tubing and casing will be required every five (5) years and within thirty (30) days after any workovers or alterations of the wellbore, prior to resuming injection. An alternative to the standard MIT is to apply a pressure of at least 1,000 psig and perform the MIT every three (3) years, which is the operator's preferred alternative for injection wells in the Greater Aneth Field.

If a loss of mechanical integrity occurs, the Permittee is required to terminate injection operations immediately and notify EPA of the failure and plans to take corrective action. Notice is required within twenty-four (24) hours and a written report is required within five days of the occurrence. Remedial action to restore mechanical integrity or plug and abandon the well must be completed within six months of the occurrence unless deferral for reasonable cause is requested by the Permittee and is approved by EPA.

2. Injection Interval

Injection will be permitted for the lower Honaker Trail and Paradox Formations in the approximate subsurface interval of 5,100 to 6,000 feet in future horizontal wells. Currently, there are no existing or proposed horizontal wells in the Phase III project area The actual depths in each proposed well will be determined by the depths to the upper casing windows in the lower Honaker Trail Formation in horizontal wells and to the base of the Paradox Formation in all wells. The Desert Creek and Ismay members of the Paradox Formation are expected to take most if not all of the injected fluids since the lower Honaker Trail Formation is a confining layer. The injection interval in vertical wells is limited to the Paradox Formation. Any proposed change of injection formation or enlargement of these intervals would require a permit modification, subject to public notice, comment and appeal if considered a major modification of the injection interval.

3. Injection Pressure Limitation(s)

The applicant proposes a maximum injection pressure of 2,750 psig for water and 2,980 psig for CO_2. The initial maximum allowable injection pressure (MAIP) is set at the proposed maximum allowable injection pressure of 2,750 psig for water and 2,980 psig for CO_2. The formation parting pressure of the Paradox Formation exceeds 3,000 psig, based on the results of step-rate tests conducted in eight (8) McElmo Creek Unit injection wells in 1999, none of which reached the formation parting pressure at 3,000 psig or higher wellhead injection pressures. The maximum injection pressure may be increased above the MAIP only if a valid step-rate test is conducted by the operator and is witnessed and approved by the EPA. Injection pressure shall not exceed the fracture pressure of the injection zone as determined by the EPA from the analysis of step-rate test results.

4. Injection Volume Limitation:

The applicant proposes to inject an average of 500 barrels per day of produced water and an average of 1,400 MCF per day of carbon dioxide (CO_2) on alternating schedule on an average well basis into the Paradox Formation. The maximum proposed injection rates are 3,000 BWPD and 5,000 MCFPD of CO_2 per well, subject to the maximum allowable injection pressures at the wellhead. The injection rates and cumulative volume of water and CO_2 that would be injected into the injection zone over the term of the permit are not relevant to calculation of the area of review in an EOR operation since fluid volumes injected are generally equivalent to fluid volumes withdrawn from the reservoir over the project life.

The storage capacity of the injection zone within the proposed area of review (AOR) is estimated at 480 million barrels, based on injection zone formation properties and thickness determined from wireline log analysis. The proposed AOR boundary is defined by a line that is a distance of one-half (½) mile from the Phase III project area, as depicted on the AOR maps. The storage capacity calculations are based on the area within the AOR (7,500 acres) and the following assumptions and formation properties: a homogeneous injection zone, average effective porosity of 10.0 %, residual water, oil, and CO_2 saturation of 50 %, and net thickness of 165 feet. The storage capacity is not an important consideration for enhanced recovery wells, however, since volumes injected are generally equivalent to volumes of fluids produced from the reservoir. Injection fluids should therefore be contained within the AOR and reservoir pressure build-up effects should be minimal and localized at the injection wells within the AOR.

The potential for migration of formation fluids out of the injection zone and into USDWs will be quite low because reservoir pressure build-up will be limited by withdrawals of formation fluids from production wells. Furthermore, all wellbores that penetrate the injection zone within the AOR are cased and cemented to prevent migration of injected fluids into USDWs. In addition, there are no known faults or fractures that would allow migration of fluids into USDWs within the proposed AOR. Endangerment of USDWs due to pressure build-up and migration of injected and formation fluids is therefore highly unlikely. Formation pressure in the injection zone will be monitored annually during the term of the permit, and corrective actions will be taken if pressure build-up may endanger USDWs. The injection rate and volume will be limited only to the extent that the maximum allowable injection pressure is not exceeded and reservoir pressure does not increase to a level that could cause movement of fluids into USDWs in wellbores within the AOR.

SECTION D - MONITORING, RECORD KEEPING, AND REPORTING OF RESULTS

The Applicant is required to sample and analyze the gas and water quality of the injected fluids at annual intervals and whenever the source of the injection fluid changes. Water samples shall be analyzed for TDS, major ions, pH, specific conductivity, specific gravity, and viscosity. Measurements of the injection pressure, annulus pressure, injection rate, and cumulative volume must be observed weekly and recorded at least once per month. The Applicant is required to submit an Annual Monitoring Report to the EPA summarizing the monitoring of injection rates, volumes, pressures, and injected fluid, and any major changes in the characteristics or sources of injected fluid. Static fluid levels and/or pressures will be measured and will be reported to the EPA on an annual basis.

SECTION E - PLUGGING AND ABANDONMENT

The EPA has reviewed the typical plugging and abandonment (P&A) plans submitted by the applicant. The P&A plans are incorporated into the permit as Appendix A. **The current estimated cost of plugging and abandoning the wells must be provided and approved prior to issuance of the final permit**, and will be reviewed periodically to ensure that the P&A cost estimate remains current and accurate. The plugging plans and procedures will be reviewed prior to commencement of plugging operations to ensure that the wells are abandoned in a manner that protects USDWs.

SECTION F - FINANCIAL RESPONSIBILITY

The Applicant must furnish an acceptable financial instrument prior to issuance of the final permit, sufficient to guarantee current costs of plugging and abandoning the subject wells in the event the Applicant fails to properly plug and abandon the wells, whenever that may become necessary. The EPA shall be the specified beneficiary of the aforementioned financial instruments. The EPA will review and may require updating of the financial responsibility mechanism periodically as plugging and abandonment costs increase, wells are added, or as other circumstances may require.