OKLAHOMA GAS & ELECTRIC
McCLAIN FACILITY
UIC CLASS I PERMIT RENEWAL APPLICATION
RESERVOIR MECHANICS

TABLE OF CONTENTS

LIST OF FIGURES

LIST OF TABLES

LIST OF APPENDICES

I. RESERVOIR MECHANICS

After analysis of the local and regional geology near the OG&E McClain LLC facility, injection well flow and pressure models (*DuPont Basic Plume and DuPont Multilayer Pressure*) were run to evaluate the effects of effluent disposal under the conditions requested in this Permit Application. A detailed description of these models can be found in Appendices 1 and 2 of this section.

The DuPont Deepwell models are structured to focus on the key physical mechanisms influencing the system behavior at a particular site. These models permit evaluation of the contribution of each mechanism to the system under consideration. The DuPont Deepwell models are not only understandable, they are also accepted by the U.S. Environmental Protection Agency (EPA) and many state regulatory agencies. Model results are obtained from equations, which provide a clear relationship between the physical mechanisms governing the system response. The ease of understanding these relationships provides the means for technical interaction by a diverse group of interested people.

The OG&E McClain LLC facility has one injection interval, the Pawhuska Sand Injection Interval. (see Attachment B, for a discussion of the Pawhuska Sand.) This interval is the focus of the model simulations. Predicted effects of effluent disposal into the injection interval are modeled for injection time periods of actual historical injection (year-end 2022) and a future term to year-end 2035. A post-closure period of 30 years is also modeled to show the rapid decay in pressure once injection ceases.

I.A. Reservoir Mechanics of the Injection Reservoir

Prior to modeling, an understanding of the regional and local geology is essential. Based upon interpretation of borehole geophysical logs, scout ticket information, and published literature sources, a comprehensive picture of the subsurface geology was developed for the facility. Input parameters required by the flow and containment model are the following.

- Sand and Shale Layers
    - Average Thickness
    - Permeability
    - Porosity

  - Compressibility
- Original formation fluid salinity, viscosity, density
- Original formation pressure
- Layer Dispersion Characteristics

The following sections describe where and how the model input parameters were obtained. Note that the specific model inputs are dependent on the particular model used. The models use different parameter subsets; differentiation between the model inputs is identified in each parameter description section.

I.A.1 Injection Zone Stratigraphy and Lithology

The OG&E McClain LLC injection facility lies in Section 4, Township 9 North, Range 4 West in McClain County, Oklahoma. The structure of the area is characterized by a thick sequence of regionally southwesterly gently dipping sediments and sedimentary rocks. Injection is projected to occur into Pawhuska Sand between average depths of 4,548 feet and 6,790 feet below ground level (see Figure C-1 in Attachment C).

Quarternary alluvium and sands of the Hennessey and Garber-Wellington make up the principal ground-water aquifers in the OG&E McClain LLC facility area. The base of the lowermost underground source of drinking water (USDW) (<10,000 mg/l total dissolved solids (TDS)) occurs at approximately 1,117 feet below ground (1,135 feet kelly bushing (KB) on the Schlumberger Array Induction Imager log). Over 3,075 feet of shale, limestone, and thin sands separate the Injection Zone from the lowermost USDW, with a thick shale Confining Zone (lower Post Oak Formation) overlying the Injection Zone.

I.A.2 Characteristics of the Injection Reservoir

I.A.2.1 Layer Thickness

The *DuPont Basic Plume Model* and *Multilayer Pressure Model* perform two-dimensional computations for horizontal distribution of effluent front boundaries and pressure. They accept one thickness value for each modeled layer. The perforated injection interval sands are identified in Table 1. The table also shows the gross sand thickness (deflection away from the shale baseline) and the net sand thickness (50 percent spontaneous potential deflection).

A total of 502 feet of the 563 feet of net Pawhuska Sand is perforated in the Injection Well. The gross sand within this formation interval was picked at each spontaneous potential deflection away from the shale baseline, and totals 692 feet. The model assigned thickness (*DuPont Multilayer Pressure Model*) to the Pawhuska Sand Injection Interval is 502 feet. This value is approximately 90 percent of the net sand and 73 percent of the gross sand, potentially available for flow.

The *DuPont Basic Plume Model* is capable of considering the effects of injection into thinner sand layers that appear to be more receptive to flow. Therefore, a more conservative approach to layer thickness designation (90 net feet for the receptive interval) is used in that modeling (see Section I.A.7). This is conservative as all the flowmeter/spinner logs show flow over a thicker interval. Where small-scale variations exist, such variations are not expected to materially influence model predictions, since their effects will tend to be averaged out over the larger distance scales. In terms of plume movement, the influences of small-scale variations in layer thickness are implicitly included within the framework of the dispersion parameters (i.e., "multiplying factor" in the *DuPont Basic Plume Model*).

I.A.2.2 Permeability and Transmissivity

Permeability is the capacity of a porous media to transmit fluids. Permeability values for the injection interval sand were determined from core data, Schlumberger Combinable Magnetic Resonance log data, injection/falloff testing of the Test Well, and routine injection/falloff testing of the injection well.

In May - June of 2000, an onsite geologic Test Well was drilled to gather site-specific data (this well is now the Injection Well). Air permeability of whole core Pawhuska Sand samples range from 22.5 to 998 millidarcies. Transmissibility of the Pawhuska Sand interval equals 145.52 darcy-ft from the Schlumberger Combinable Magnetic Resonance tool. Over the 502 feet perforated in the Test Well, an average permeability of 290 millidarcies is calculated from the Schlumberger Combinable Magnetic Resonance tool.

Pressure transient testing (injection/falloff) of the Pawhuska Sand was conducted during initial completion of the well, and subsequently after well development activities. Routine regulatory required testing is performed on an annual basis. The most recent injection/falloff test was conducted on May 2 – 4, 2023 using high-resolution surface gauges. The falloff portion of that test was analyzed using Reservoir Description Services, Inc.'s TRANS II transient analysis software package. TRANS II provides both log-log (multi-rate and derivative type curve) and semi-log (superposition) analyses.

Testing was performed at the completion of re-sleeving operations, as part of the final well certification-testing program. A step-rate injection test was run in order to evaluate the performance of the Injection Well with the new tubulars in place. Injection was conducted in steps between 300 and 700 gallons per minute (gpm), in 100 gpm increments, and at a final injection rate of 820 gpm. Wellhead pressure and injection rate were digitally monitored and recorded. At the completion of the last step-rate injection period, flow to the well was ceased and pressure was allowed to falloff. An analysis of the wellhead pressure decay with time, following shut-in of the well, was analyzed in TRANS II. Results of historical falloff tests are shown in Table 2.

Average permeability of the transient falloff tests conducted in the well is 63 millidarcies. A permeability of 60 millidarcies is assigned to the Pawhuska Sand Injection Interval in the modeling, based on the average permeability and the calibration of the pressure model to flowing bottomhole pressure data (corrected for well skin) gathered from site-specific annual transient reservoir testing (Figure 1). Compared to early reservoir testing results, the 60 millidarcies permeability provides an overall good match between the model and the measured well data.

I.A.2.3 Porosity

Porosity is the ratio of void space in a given volume of rock to the total bulk volume of rock expressed as a percentage. The more porous a rock, the more fluid can be stored in a given rock volume. Porosity for Pawhuska Sand is determined from geophysical well log analysis and site-specific whole core data collected from the Test Well. Porosity of the Pawhuska Sand ranges from 11.3 to 23 percent in the whole core from the Test Well. Table 3 shows a tabulation of the average calculated sand layer porosities derived from open-hole logging of the well. The average porosity of the Upper Sand Unit is approximately 22 percent, and porosity of the Lower Sand Unit is approximately 18 percent.

A conservative value of 18.4 percent is used in the Pawhuska Sand, for both the pressure model and the plume model. Minor variations in porosity are handled in the *DuPont Basic Plume Model* through the use of a "Multiplying Factor" (see Section 1.A.2.6).

I.A.2.4 Temperature

Formation temperature is determined from data recorded during cased-hole logging of the Test Well in July 2001. Recorded temperatures from the differential temperature log were plotted as a function of total depth, and the data were fitted with a regression line. The regression shows a mean surface temperature of 59.0 °F and a gradient of 1.1 °F per 100 feet of depth. The temperature at the top of the perforated injection interval (4,566 feet referenced to the rig kelly bushing) is approximately 109 °F.

I.A.2.5 Compressibility

Compressibility is the change in volume per unit increase in pressure. In a zone that is 100 percent saturated with water the total compressibility is defined as the formation compressibility plus the compressibility of water corrected for water saturation:

$$c_t = c_f + c_w S_w$$

Fluid (water) compressibility (c_w) is built into the program code of the *DuPont Multilayer Pressure Model* as a fixed value of 3.034E^{-06} psi^{-1} after Table 2-5 in Freeze and Cherry (1979). Correlations of pressure and temperature from Amyx et al. (1960) indicated a water compressibility value of approximately 2.95E^{-06} psi^{-1} for the Pawhuska native formation water.

Yale et al. (1993) provide a set of "type curves" for determining formation compressibility in sediments:

$$c_f = A(\sigma - B)^C + D$$

where:

c_f	=	formation compressibility (psi^{-1})
A	=	constant depending on rock type (-2.399 x 10^{-5} for consolidated sands)
B	=	constant depending on rock type (300 for consolidated sands)
C	=	constant depending on rock type (0.0623 for consolidated sands)
D	=	constant depending on rock type (4.308 x 10^{-5} for consolidated sands)
σ	=	effective stress

and:

$$\sigma = K_1\sigma_z - K_2 p_i + K_3(p_i - p)$$

where:

σ	=	effective stress
σ_z	=	overburden stress
K_1	=	constant depending on rock type (0.85 for consolidated sands)
K_2	=	constant depending on rock type (0.80 for consolidated sands)
K_3	=	constant depending on rock type (0.45 for consolidated sands)
p_i	=	original reservoir pressure (psi)
p	=	present reservoir pressure (psi) [assumed to be the original pressure].

Calculating the formation compressibility (c_f) using the consolidated variables and an overburden gradient of 1 psi/ft:

$$c_f = -2.399E\text{-}05 \times (3{,}205 - 300)^{0.0623} + 4.308E\text{-}05$$

$$c_f = 3.65E\text{-}6 \text{ psi}^{-1}$$

Therefore, total compressibility is the combination of the water compressibility ($2.95E^{-06}$ psi^{-1}) and the formation compressibility ($3.65E^{-06}$ psi^{-1}), or a total compressibility of $6.6E^{-06}$ psi^{-1}.

The *DuPont Multilayer Pressure Model* uses the classic "hydrology" definition (Freeze and Cherry, 1979; Lohman, 1979) for compressibility of "alpha", which is related to the rock compressibility as shown below.

$$c_f = \alpha / \phi$$

Since fluid (water) compressibility is built into the program code as $3.034E^{-06}$ psi^{-1}, a value for alpha of $6.7E^{-07}$ psi^{-1} is assigned in the model input file so that the total model compressibility is equal to the total system compressibility of $6.6E^{-06}$ psi^{-1}.

I.A.2.6 Layer Dispersion Characteristics

Dispersivity is a measure of the mechanical dispersion property of a porous material and is defined as a length to describe the ability of media to disperse solutes (Walton, 1985). Dispersivity is a function of both the vertical and lateral permeability variations, and increases with formation heterogeneity. In general, increasing travel distance equates to greater dispersion, and, therefore, higher dispersivities.

I.A.2.6.1 Multiplying Factor for Advective Dispersion in Basic Plume Model

The *DuPont Basic Plume Model* is an analytical calculation that accounts for the effects of advective dispersion within injection reservoirs by means of a special technique known as the “multiplying factor concept,” introduced by Miller et al. (1986). The "multiplying factor" M is implemented in practice by computationally assigning increased rates of injection to the model, with values that are enhanced by a factor of M (see Appendix 2 of this section). This produces computed plume growth velocities that are also increased by the same factor M. These higher velocities correspond to the lateral speed of travel of the fastest-moving portion of the effluent. Use of the *DuPont Basic Plume Model* combined with the multiplying factor provides a basis for tracking the location of this fastest-moving effluent.

The calculated value for the Multiplying Factor is, in the strictest sense, valid for a geologic setting in which the only nonuniformities present are physical property variations with depth. However, in actual geologic settings properties and thicknesses of the layers may also vary laterally, and the depositional system may exhibit anisotropy to some degree. These effects will tend to increase the predicted extent of the effluent plume. On the other hand, the influence of transverse dispersion perpendicular to the bedding planes (i.e., vertically) will cause constituents of interest to move from higher to lower permeability depth increments within the injection interval, thereby reducing the extent of the effluent plume. This transverse dispersion phenomenon is largely responsible for the transition that takes place from the purely advective dispersion existing in the near-wellbore region, to the Gaussian dispersion, characteristic of the field scale.

For perfectly stratified (layer cake) geological settings in which both the permeability and porosity vary solely with vertical depth through the injection interval, M can be calculated from the following formula (this equation is a simple extension of the earlier relationship developed in

$$M = \frac{(k/\phi)_{\max}}{\frac{1}{h}\int_0^h (k/\phi)\partial z}$$

Miller et al. (1986) for geological systems in which only the permeability varies with depth):

where:

k = permeability at vertical location z

ϕ = porosity at z

h = thickness of the layer.

As can be noted from this formula, the permeability k appears in both the numerator and denominator of the expression. This indicates that the absolute value of the permeability is not important in determining M. Only the variations of the permeability relative to the average value enter into determining M.

Porosity and permeability data for many of the perforated sand intervals in the Pawhuska Sand are available from open-hole logging of the Test Well. The sand layer variability calculation was made for 10 sands across which a Schlumberger Combinable Magnetic Resonance tool was run. The calculation is shown in Table 4.

The calculation shows that the Multiplying Factor "M", based on the geological variability of the perforated sands in the injection interval, is equal to a value of 2.36. This means that the highest K/ϕ product layer (the 4,600-Foot Sand) is 2.36 times the average layer K/ϕ product.

Calculation of M can also be determined from a consideration of conventional longitudinal dispersivity (an alternate methodology), which is discussed in the following descriptive scenario, whereby a single isolated well is injecting into a geologic formation. The equations for combined advective and dispersive transport of constituents of interest in this system have been solved analytically by de Josselin de Jong (in Lau et al., 1959; see also Bear, 1972) for the case of conventional Gaussian dispersion. The approximate analytic solution obtained by de Josselin de Jong is in excellent agreement with the well-known numerical results of Hoopes and Harleman (1967). This analytic solution is represented by:

$$C = 0.5 \text{ erfc}\left(\frac{r-r_o}{\delta}\right)$$

$$\text{with } \delta = \frac{2}{(3)^{1/2}}(\alpha_L r_o)^{1/2}$$

where:

erfc = "complementary error function"

C = relative constituent of concern concentration (normalized to the value in the effluent) at radial distance r from the well

r_o = "nominal" radius of the effluent plume for a uniform formation without dispersion (i.e., calculated with M = 1)

α_L = longitudinal dispersivity

δ = characteristic dispersion distance

The relative concentration used in the modeling, C, is conservatively selected as 1.0×10^{-6} at the plume perimeter. This represents a million-fold reduction (six 9s) in concentration from the point of injection to the calculated plume perimeter. Using the upper-end dispersivity of 117 feet, a relative concentration of 1.0×10^{-6} at the plume perimeter, and substituting these values into the above formulas and solving for the radial location, r (perimeter distance where that concentration is attained), yields:

$$r/r_o = 1 + \left(\frac{2}{\sqrt{3}}\right) * 3.36 * \left(\frac{\alpha_L}{r_o}\right)^{1/2}$$

Solving for the Pawhuska Sand, for a longitudinal dispersivity value of α_L = 105 feet and a "nominal" plume radius of r_o = 3,591 feet (for Pawhuska Sand Injection Interval plume radii with M = 1), the above relationship predicts a ratio of:

$$\frac{r}{r_o} = 1.66$$

This indicates that the radial distance required for injected effluent concentrations to fall below a million-fold reduction (at 10^{-6}) is 1.66 times the nominal radius of the plume. Since the M is a quantity based on volume of effluent injected, the value of M necessary for the *DuPont Basic Plume Model* to predict this same radial distance for the outer boundary of the plume is represented by:

$$M = \left(\frac{r}{r_o} \right)^2 = 2.77$$

An upper-end dispersivity value is assigned to the *DuPont Basic Plume Model*, based on the work of Xu and Eckstein (1995). For the Pawhuska Sand, a nominal plume radius (volumetric plug flow from a point source) at the end of injection at the end of 2035 is determined, assuming that all of the flow entered a conservative 90-foot interval with an average porosity of 18.4 percent. The resulting nominal plume radius of 3,591 feet describes the volumetric displacement of the wastewater [note that if the full perforated interval accepted the wastewater uniformly (i.e., assume 502 feet), the resulting nominal radius would only be 1,521 feet]. An upper-end dispersivity value of 105 feet is assigned in the modeling (via a 2.77 multiplying factor), based on the work of Xu and Eckstein (1995).

I.A.2.7 Wellbore Characteristics

The *DuPont Multilayer Pressure Model* uses a default wellbore skin factor of zero (*i.e.*, no enhancement or pressure drop at the completion). The wellbore skin factor is set at the default value of zero in the model. Therefore, the model is predicting the incremental flowing pressure increase in the formation, which provides a stable point of comparison for future monitoring, since actual wellbore skin conditions vary year to year (see Table 2). All of the calculated flowing bottomhole pressures have been corrected for the pressure drop due to completion skin in order to calculate a sand-face pressure. For the tests conducted from surface, the tubing friction loss is inherent in the overall test computed skin value.

I.A.2.8 Reservoir Fluid Dissolved Solids Content, Viscosity, and Specific Gravity

Formation fluid salinity for the Pawhuska Sand is determined from recovered water samples taken during open-hole logging of the Test Well using the Schlumberger Repeat Formation Tester tool. A sample from the 4,900-Foot Sand in the Upper Sand Unit recovered waters with

130,222-ppm total dissolved solids content from the second chamber (the first chamber contained formation waters diluted with mud filtrate). A second water sample was attempted from the 6,800-Foot Sand in the Lower Sand Unit; however, both chambers appeared to contain formation water diluted with mud filtrate. Therefore, based on the results from the fluid sample taken in the 4,900-Foot Sand, a total dissolved solids concentration of 130,222-ppm is assigned for the native formation waters.

A nomograph, showing viscosity as a function of temperature and fluid content, is used to assign a viscosity of 0.81 centipoise at the top of the perforated injection interval (4,566 feet), which has a temperature of approximately 109 °F.

The specific gravity of the recovered formation fluid samples was also measured. The sample from the 4,900-Foot Sand in the Upper Sand Unit discussed above had a specific gravity value of 1.0746.

I.A.2.9 Initial and Current Static Reservoir Pressure

The *DuPont Multilayer Pressure Model* predicts the incremental pressure increase with time, above the background formation pressure. Therefore, the original formation pressure is used as the reference point so that the incremental pressures above background from the model can be translated to the reservoir depth in the well for future monitoring purposes.

A Schlumberger Repeat Formation Tester was used to obtain a vertical formation pressure profile in Pawhuska Sand in the Test Well. The pressure sets indicate a pressure gradient of approximately 0.414 psi/ft in the Upper Sand Unit and a pressure gradient of approximately 0.438 psi/ft in the Lower Sand Unit.

However, since the current completion in the Injection Well WDW1 is commingled between the Upper Sand Unit and the Lower Sand Unit, the pressure observed in the well is an average of these gradients. Static reservoir pressures were taken in the Test Well prior to performing the June 2000 and August 2001 injection/falloff tests. The perimeter static pressure gradient surveys from these two tests are shown in Table 5.

The two surveys indicate approximately the same static pressure at the top of the Pawhuska Sand. Based on the static pressure surveys, a reference pressure of 1,932.2 psi from the August 2001 survey is assigned to the model reference depth of 4,566 feet. Table 6 gives a summary of the historical injection and static pressures measured at the well during annual testing, since 2002.

I.A.3 Estimation of Fracture Pressure

The fracture gradient for the injection interval sands can be estimated by Eaton's Method, following Moore (1974):

$$FG = \frac{\left(P_{ob} - P_r\right)e}{\left(1 - e\right)} + P_r$$

Where:

FG	=	Fracture Gradient
P_{ob}	=	Overburden Gradient (Figure 11-11 in Moore, 1979)
P_r	=	Reservoir Pressure Gradient (original)
e	=	Poisson's Ratio (Figure 11-12 in Moore, 1979)

For the Pawhuska Injection Interval:

$$FG = \frac{(0.904 - 0.423) * 0.4}{(1 - 0.4)} + 0.423$$

$$= \quad 0.743 \text{ psi/ft}$$

Using the calculated fracture gradient of 0.743 psi/ft, the fracture pressure for the Pawhuska Sand is estimated to equal 3,395 psi at 4,566 feet (top of perforations).

I.A.3.1 Maximum Allowable Surface Injection Pressure Calculation

The surface pressure required to reach the bottom hole fracture pressure is determined by subtracting the hydrostatic head of the wastewater (P_{hydro}) from the bottom hole fracture pressure (discounting any friction losses).

P_{hydro} = ρ x 0.052 x Depth

P_{hydro} = 8.5 x 0.052 x 4,566 = 2,018 psi (weight of wastewater)

Surface Fracture Pressure = P_{frac} - P_{hydro}

Surface Fracture Pressure = 3,395 psi – 2,018 psi

Surface Fracture Pressure = 1,377 psi

The potential surface injection pressure required to fracture the Pawhuska Sand is calculated to be 1,377 psi, assuming no friction losses or completion friction (skin) losses occur in the well.

The maximum allowable surface injection pressure (MASIP) is the maximum surface pressure at which an injection well is allowed to inject fluid into the subsurface.. According to Oklahoma Administrative Code, Subchapter 9 – §252:652-9-1(1)(B), the maximum total pressure gradient (applied injection pressure plus fluid pressure plus allowances for friction pressure loss) shall not exceed 0.65 psi/ft of depth from ground surface to the top of the disposal zone.

MASIP = (Depth x 0.65 psi/ft) – P_{hydro} + $P_{friction}$

$P_{friction}$ = 50 psi [calculated using a friction loss (pressure drop) calculator for Newtonian fluid flow through clean 6 5/8-inch tubing (ID = 5.761 inches) at 530 gpm]

MASIP = (4,566 ft. x 0.65 psi/ft) – 2,018 psi + 50 psi

MASIP = 1,000 psi

The MASIP allowed by Oklahoma Department of Environmental Quality (ODEQ) regulations (1,000 psi) is less than the calculated pressure required to fracture the formation from the surface (1,388 psi). Therefore, a maximum allowable surface injection pressure of 1,000 psi is requested for Injection Well WDW1 (Table 6), per Oklahoma Administrative Code, Subchapter 9 – §252:652-9-1(1)(B).

I.A.4 Prediction of Reservoir Pressure Increase

I.A.4.1 The DuPont Multilayer Pressure Model

Whenever effluent is injected into a subsurface geological formation, the pressure within the receiving reservoir will increase. This pressure increase will be greatest at the well, and will decrease with distance away from the injection site. After injection has ceased, the pressure will rapidly diminish, and approach its value before injection.

The *DuPont Multilayer Pressure Model* is used to determine the pressure distribution within the injection reservoir. Complete documentation of this model is presented in Appendix 1 of this section. The model is an extension of an earlier treatment presented by Miller, et al., (1986) that is based on the Theis (1935) equation. The model discounts the ability of the aquiclude layers to compressively store fluids, which provides a conservative upper bound to the pressures modeled within the injection reservoir. The pressure model is set up as a single-layer simulation of injection into the Pawhuska Sand. The *DuPont Multilayer Pressure Model* requires four layers as a minimum, consisting of an alternating sequence of impermeable (odd numbered layers) and permeable (even numbered layers) units. The base of the bottom layer is a “no flow” boundary, which does not allow a leak-off of pressure or fluid from the system. The Pawhuska Sand is set up as the bottom layer (Layer 4) in the four-layer *DuPont Multilayer Pressure Model*; therefore, it is confined from below.

The Pawhuska Sand is assigned a thickness of 502 feet, a permeability of 60 millidarcies (md), and a fluid viscosity of 0.81 centipoise (cp). Therefore, the model transmissibility (permeability-thickness/ viscosity) is conservative compared to the calculated transmissibility of 44,000 md-ft/cp, determined from the February 4 - 9, 2002, injection/falloff test. An average porosity of 18.4 percent (thickness weighted average over the perforated interval) is also used in the model. An “alpha” value of $6.60E^{-07}$ psi^{-1} is assigned to the Pawhuska Sand so that the total system compressibility (formation compressibility plus water compressibility) value of $6.60E^{-06}$ psi^{-1} is also matched. The overlying shale layer is assigned a vertical permeability of $1.0E^{-12}$ darcies and a minimum porosity (1 percent), rendering it impermeable. Therefore, Pawhuska Sand is essentially a “confined” unit in the model, allowing no leak-off or exchange of pressure or fluid above or below the modeled unit. The single-layer model set-up for the Pawhuska Sand used in the simulation is shown in Table 7.

I.A.4.2 Modeled Injection Rate

For this Permit Application, modeling of injection at the OG&E McClain LLC facility considered two time frames: historical injection to year-end 2022 and maximum injection through year-end 2035. Additionally, a post-closure period of 30 years is also modeled. Projected injection is modeled on a yearly time step. Modeling considers the most conservative case, which assumes that Injection Well WDW1 will inject at the maximum-modeled rate of 530 gpm for the entire projected time period through year-end 2035. The injection rate used in the pressure model simulation run for the OG&E McClain LLC facility is shown in Table 8. It is anticipated that the injection well will be operated at rates closer to the recent average injection rates closer to 11 gpm (volumetric annual average); therefore, use of the maximum requested rate for modeling is conservative.

I.A.4.3 Modeled Injection Interval Transmissibilities

Model predicted formation pressure increase due to injection is directly proportional to the assigned transmissibility (kh/μ) value used for that interval. Calculated injection reservoir transmissibility from the model inputs (thickness x permeability/viscosity) is shown in Table 10. The modeled value of 37,185 md-ft/cp is more conservative than the transmissibility calculated from the February 2002 injection/falloff test that followed selective acid stimulation of the 4,800-Foot and 4,900-Foot Sands. This value is lower than that determined from the step-rate injection/ falloff test on February 25, 2002.

I.A.4.4 Pressure Model Results

Model runs for the Pawhuska Injection Interval is made to predict lateral pressure distributions for the historical injection period and for a future term to year-end 2035 at the Maximum Injection Rate of 530 gpm. The DuPont Multilayer Model run files for the Pawhuska Sand consist of:

Injection Rate (gpm)	Filename	Comment
530	oge_maxcase_530_60md.rcv	Master job input deck and run file
	oge_maxcase_530_60md.prm	Model parameter dimension file

These model input files for the pressure simulations are contained in Appendix 3.

The DuPont Multilayer Model output files for the Pawhuska Sand consist of:

Model Rate	Filename	Comment
Maximum Rate (530 gpm)	oge_maxcase_530_60md.sum	Master job run summary output file
	oge_maxcase_530_60md.pinj	Pressure increase at injection well output file
	oge_maxcase_530_60md.pmon	Pressure increase at artificial penetrations output file
	oge_maxcase_530_60md.pcnt	Areal pressure distribution plot file – End of Historical (2022) and 2035

*These output files for the pressure simulations are also contained in Appendix 3.

Results of the pressure simulation are based on the *DuPont Multilayer Pressure Model* run. A summary of the pressure increases at the Injection Well and at the 2.0-mile radius Area of Review Boundary is tabulated in Table 10.

Figure 2 graphically shows the modeled incremental predicted pressure increase (year-end values) with time in the Pawhuska Sand at the Injection Well. Note that the incremental pressure increase in the model has been translated to a wellbore pressure at the reference depth of 4,566 feet using the reference initial pressure of 1,932 psi (right graph axis).

Figure 3 presents the distribution in incremental pressure increase away from the Injection Well at the end of the historical injection period (year-end 2022). Injection pressure is highest at the point of injection and decreases away from the point of injection. Incremental pressure increase at the 2.0-mile radius Area of Review is 14 psi. Figure 4 presents the distribution in incremental pressure increase away from the Injection Well at the end of the modeled injection period (year-end 2035) using maximum injection rates over the projected time period. Injection pressure is highest at the point of injection (852 psi) and decreases away from the point of injection. Incremental pressure increase at the 2.0-mile radius Area of Review is 138 psi.

I.A.4.5 Pressure Recovery

The *DuPont Multilayer Pressure Model* simulation run also is used to predict the post-injection pressure recovery back towards initial formation pressures for a period of 30 years after injection is modeled to cease at year-end 2035. The results of the modeling for the maximum injection rate (530 gpm) indicate that pressure recovery will begin immediately in the injection reservoir, with a rapid decrease in the formation pressure within the first year after injection is modeled to cease (no Cone of Influence within the first year). Pressure recovery is projected to continue asymptotically, with formation pressure returning to approximate background pressure after 30 years (see Figure 2). Results indicate that pressure in the injection reservoir sands will equilibrate rapidly within the Area of Review, and the driving force needed for potential vertical movement of formation water or effluent from an injection interval into an adjacent layer will dissipate rapidly.

I.A.5 Determination of the Cone of Influence

The methodology used for calculating the Cone of Influence in this Permit Application is based on the underlying assumption that in the absence of naturally occurring, vertically transmissive conduits (faults and fractures) between the injection interval and USDW (such as at the OG&E McClain LLC facility site), the only potential pathway between the injection zone and USDW is through an artificial penetration (active or inactive oil and gas well(s)). In order to pose a potential threat to a USDW (i.e., pressure buildup from injection sufficient to drive fluids into a USDW), the pressure increase in the injection interval would have to be greater than the pressure necessary to displace the material residing within the borehole. This pressure necessary to displace the material residing within the borehole is defined as the allowable buildup pressure. Therefore, the Cone of Influence is defined as the area within which injection interval pressures are greater than this allowable buildup pressure.

A static mud column exerts pressure. For an abandoned well to be a pathway for fluid movement, the pressures acting on the static mud column must be greater than the static mud column pressure. In a static fluid column, the gel strength of the mud must also be considered.

In this case, for upward fluid movement to begin, original formation pressure (P_f) plus the pressure due to injection (P_i) must be greater than the static fluid column pressure plus the gel strength of the mud. This relationship is based on a simple balance of forces (Davis, 1986):

$$P_f + P_i > P_s + P_g$$

where:

P_f = original formation pressure (psi)

P_i = formation pressure increase due to injection (psi)

P_s = static fluid column pressure (psi)

P_g = gel strength pressure (psi)

Therefore, pressure increase due to injection must be greater than static fluid column pressure minus original formation pressure:

$$P_i > P_s + P_g - P_f$$

In an artificial penetration filled with drilling mud, the gel strength of the mud must also be considered. In this case, for upward fluid movement to begin, the original formation pressure (P_f) plus the pressure due to injection (P_i) must be greater than the static fluid column pressure plus the gel strength of the mud. This relationship is based on this simple balance of forces (Davis, 1986):

$$P_f + P_i > P_s + P_g$$

where:

P_f = original formation pressure (psig)

P_i = formation pressure increase due to injection (psi)

P_s = static fluid column pressure (psig)

P_g = gel strength pressure (psi)

Therefore, the pressure increase due to injection must be greater than static fluid column pressure plus the pressure due to gel strength minus original formation pressure, demonstrated as follows:

$$P_i > P_s + P_g - P_f$$

The initial step in calculating the allowable buildup pressure (cone of influence) for the Pawhuska injection reservoir at the OG&E McClain LLC facility involved determining the maximum pressure buildup gradient. This gradient is derived by first calculating the mud column gradient from the very conservative 8.9-lb/gal mud (lightest drilling mud weight used for wells in the area) and subtracting from it the original formation pressure gradient of the injection interval sand.

In iteration, the maximum pressure buildup gradient is calculated by subtracting the original formation pressure gradient from the 8.9-lb/gal mud column gradient, as is demonstrated for the Pawhuska by the following:

0.052 x 8.9 lb./gal = 0.463 psi/ft	(mud column gradient, modified from Barker, 1981)
	0.052 is a conversion factor and has units of gal/ft-in^2
-0.425 psi/ft	[average formation pressure gradient from ground level (4,566 foot depth – 18 feet) from August 2001 static survey]
0.038 psi/ft	(maximum pressure buildup gradient, based on 8.9-lb/gal mud)

Thus, 0.038 psi/ft is the maximum pressure buildup gradient allowed in the Pawhuska Sand prior to possible fluid movement. Multiplying the maximum pressure buildup gradient by the depth to the injection reservoir (4,548 feet below ground at the Injection Well) yields the allowable pressure buildup (172.8 psi), due to the mud column pressure.

However, as an additional measure of conservatism, a 50-foot fallback of the mud column from the surface is utilized in the calculation. This 50-foot fallback in the assumed mud column reduces the allowable buildup pressure due to the mud column from the calculated 172.8 psi, to a more conservative allowable buildup pressure value of 149.5 psi.

Additionally, a minimum gel pressure is determined using a conservative value of 20-lb/100 sq. ft. for the gel strength and a borehole radius of 9-inches (largest borehole, to be conservative). The pressure due to gel strength (G) in an open borehole can be calculated from the following equation:

$$P_g = \frac{0.00333 \text{ x } G \text{ x } h}{d}$$

where:

P_g	=	pressure due to gel strength (psi)
G	=	gel strength (pounds per 100 square feet [lb./100 ft.^{2}])
h	=	depth to the injection reservoir from the 50 foot fallback (ft.)
d	=	borehole diameter (in.)
0.00333	=	conversion factor

For a cased hole, pressure due to gel strength (G) can be calculated from the following:

$$P_g = \frac{0.00333 \text{ x } G \text{ x } h}{d_b \text{ - } d_c}$$

where:

P_g	=	pressure due to gel strength (psi)
G	=	gel strength (lb./100 ft.^{2})
h	=	depth to the injection reservoir from the 50-foot fallback (ft.)
d_b	=	borehole diameter (in.)
d_c	=	outside casing diameter (in.)

Multiplying the minimum gel strength by the depth to the injection reservoir (considering a conservative 50-foot fallback in the mud column) and dividing by the maximum borehole diameter yields the additive pressure buildup of 33.3 psi (measured from ground level) due to gel strength of the mud column.

The Cone of Influence allowable pressure buildup for the Pawhuska Sand at the Injection Well is the sum total of the incremental pressure buildup of 33.3 psi due to gel strength and the incremental pressure buildup due to the differential weight of the mud column of 149.5 psi, or 182.8 psi. The Cone of Influence value of 182.8 psi is shown as the red isopressure contour on Figure 4. Note that the Cone of Influence is contained within the 2.0-mile radius Area of Review. Figure 5 presents a cross-sectional view of the of the maximum pressure increase with distance away from the injection well at the end of maximum injection at year-end 2035. The figures also show the Cone of Influence allowable pressure buildup value of 182.8 psi. Figure 2 shows that there will no longer be a Cone of Influence in the Area of Review within the first post-closure year.

It is important to note that the current calculations of Area of Review are very conservative and contain significant, additional safety factors. The additional safety factors include the actual weight of the mud in the borehole, the actual gel strength of the drilling mud, and borehole closure, which have not been included in the conservative assessment.

I.A.6 Justification of Plume Geometry

In a purely homogeneous geological formation, the interface between the effluent and formation fluid will advance laterally as a sharp vertical front. This front will take the shape of a right circular cylinder for the case of a single isolated well. The diameter of the circle will be determined strictly by geometric considerations, involving the total volume of the injected effluent, and the height and porosity of the formation. Such a plume is referred to as an ideal circular plume.

Horizontal variations in formation thickness and permeability can affect the lateral extent of effluent transport. Large sudden changes in these parameters can be included explicitly in model calculations, using image well techniques, or through the use of the multiplying factor (see Section 1.A.2.6).

For multiple-well injection sites, methods of analyzing injected effluent transport in purely homogeneous geological formations have been available for many decades, based on work in the petroleum field. The standard approach involves a two-part process. First, determine the lateral velocity distribution within the injection formation at any time using solutions provided by potential flow theory. Second, integrate the time-dependent kinematic equations relating the calculated velocity distribution to the motion of the interfacial front between the injected effluent and formation fluid.

The first step takes advantage of the well-known mathematical analogy between fluid flow in porous media and ideal potential flow of inviscid fluids. This mathematical analogy permits the determination of the velocity distribution in an injection formation directly from the previously established solution to the same problem in potential flow theory.

The second part of the modeling process involves the use of the velocities determined by the mathematical equations to calculate the time-dependent motion of the front between the injected effluent and formation fluid. This is accomplished mathematically by introducing a set of fictitious tracer particles around the circumference of each plume in the *DuPont Basic Plume Model*, and calculating the trajectory of these particles as time progresses. A separate set of tracer particles is employed for each well. Because the model automatically conserves mass, these tracer particles remain situated on the outer perimeter of the individual plumes for all times.

A variety of different forms of horizontal variation can occur, but two of the most common are (a) gradual changes in permeability, and (b) sudden changes, such as a flow barrier. If a sudden change is known to exist, its effects can be modeled directly, using image well methods, as discussed previously. Gradual trends have less of an influence on effluent transport, but are more difficult to model precisely. However, one can obtain a worst-case estimate of their effects simply by approximating these variations as equivalent sudden changes. Other types of horizontal variations that may be present can be handled through the use of the multiplying factor to provide a margin of safety in predicting an upper bound to the maximum lateral extent of the injected effluent.

At the OG&E McClain LLC facility, plume geometry is only influenced by dispersion. Dispersion is handled in the model through the "multiplying factor" described in Section 1.A.2.6, which results in a modeled plume size greater than that which would be predicted using pure plug flow.

I.A.7 Extent of the Waste Plume

I.A.7.1 The DuPont Basic Plume Model

During injection, the movement of effluent within the injection reservoirs is dominated by the volumetric growth of the individual plume and related displacement of the formation fluid away from the well. Effluent plume growth during injection is modeled in this Permit Application using the *DuPont Basic Plume Model*.

This model was introduced in Miller, et al., (1986). Model documentation is presented in Appendix 2. The *DuPont Basic Plume Model* calculates the time-dependent lateral movement of the plumes emanating from the wells at an injection site. The model can handle the effects of multiple well interactions, but that feature is not required in the case this site. The model is set up as a single layer calculation, which discounts the vertical exchange of fluids between geologic strata.

The plume model is set up as a single-layer simulation of injection into the Pawhuska Sand. The *DuPont Basic Plume Model* does not allow a leak-off of pressure or fluid from the system. The Pawhuska Sand is assigned a conservative thickness of 90 feet (502 feet of sand is perforated in the Test Well) and an average porosity of 18.4 percent.

The Multiplying Factor is set at a value of 2.77, which simulates a dispersivity of 117 feet and results in the plume perimeter being defined as a million-fold reduction in concentration. The single-layer model set-up used in the simulation is in Table 12.

I.A.7.2 Modeled Injection Rate

For this Permit Application, modeling of injection at NRG McClain LLC facility considered two time frames: historical injection through year end 2022 and maximum injection through year-end 2035. Projected injection is modeled using the Maximum Injection Rate (530 gpm).

It is conservatively assumed that the modeled well injects at the modeled rate for the site for the full projected time period. The injection rates used in the model simulations runs for the OG&E McClain LLC facility are shown in Table 14.

The Multiplying Factor enhances the injection rate as a multiplier; therefore, the effective modeled future injection rate in the Pawhuska Sand is 1,468 gpm through year end 2035. This rate is modeled for the full duration to year-end 2035 after the historical injection period.

I.A.7.3 Plume Model Results

Two model simulations for the Pawhuska Injection Interval were made to predict the plume perimeter (million-fold reduction in concentration) at the end of the historical injection period (year-end 2022) and through year-end 2035. The simulation is run using the Maximum Injection Rate of 530 gpm and a Multiplying Factor of 2.77.

The *DuPont Basic Plume Model* run files for the Pawhuska Sand consist of:

Injection Rate (gpm)	Filename	Comment
530	oge_plume_MAX.rcv	Master job input deck and run file
	oge_plume_MAX.prm	Model parameter dimension file
	oge_plume_MAX.inj	Layer properties and injection rate file

These input model files for the plume simulation are contained in Appendix 4.

The *DuPont Basic Plume Model* output file for the Pawhuska Sand consists of:

Injection Rate (gpm)	Filename	Comment
530	oge_plume_MAX.plt	Areal plume perimeter plot file – end of each year

The plume plot output file for the simulation is also contained in Appendix 4.

The time dependent horizontal distribution of injected effluent (plume geometry) is presented in the following section. The results are obtained from the prediction of the *DuPont Basic Plume Model*.

I.A.7.3.1 Horizontal Extent

The projected maximum horizontal extent of the injected effluent plume (at the million-fold reduction in concentration) in the Pawhuska Sand Injection Interval at year-end 2035 will not exceed a radius of 5,979 feet, using Maximum Injection Rate of 530 gpm and a Multiplying Factor of 2.77.

The time dependent horizontal extent of the plume at the end of the historical injection period (2022) and at year-end 2035 are shown in Figures 6 and 7, respectively. The modeled plumes are contained within the 2.0-mile radius Area of Review boundary through the end of the model time period (year-end 2035). Radial distance from the point of injection at each time period is shown in Table 15.

REFERENCES

Amyx, J. W., Bass, D. M., and Whiting, R. L., 1960, Petroleum Reservoir Engineering: McGraw-Hill Book Company, New York, New York, p. 63.

Barker, S. E., 1981, Determining the Area of Review for Industrial Waste Disposal Wells: Masters Thesis, The University of Texas at Austin, Austin, Texas, 146 p.

Bear, J., 1972, Dynamics of Fluids in Porous Media: Elsevier, New York, New York.

Davis, K. E., 1986, Factors affecting the area of review for hazardous waste disposal wells: Proceedings of the International Symposium on Subsurface Injection of Liquid Wastes, New Orleans, National Water Well Association, Dublin, Ohio, p. 148-194.

Freeze, R. A. and Cherry, J. A., 1979, Groundwater: Prentice-Hall, Inc., Inglewood Cliffs, New Jersey, 604 p.

Hoopes, J. A., and Harleman, D. R. F., 1967, Dispersion and radial flow from a recharge zone: Journal of Geophysical Research, v. 72.

Lau, L. K., Kaufman, W. J., and Todd, D. K., 1959, Dispersion of a water tracer in radial laminar flow through homogenous porous media: Hydraulic Lab., University of California, Berkley, California.

Lohman, S. W., 1979, Groundwater Hydraulics; Geological Survey Professional Paper 708, United States Government Printing Office, Washington, DC., 70 p.

Miller, C., Fisher, T. A. II, Clark, J. E., Porter, W., Hales, C. H. Tilton, J. R., 1986, Flow and containment of injected waste: Proceedings of the International Symposium Subsurface Injection of Liquid Wastes, New Orleans, National Water Well Assc., Dublin, Ohio, p. 520-559.

Moore, P. L., 1974, Drilling Practices Manual: PennWell Books, Tulsa, Oklahoma.

Theis, C. V., 1935, The relation between the lowering of the piezometric surface and the rate and duration of discharge of a well using groundwater storage: Trans. Amer. Geophys. Union, v.2, p. 519-534.

Walton, W. C., 1985, Practical Aspects of Groundwater Modeling: National Water Well Association, Worthington, Ohio.

Xu, M., and Eckstein, Y., 1995, Use of weighted least squares method in evaluation of the relationship between dispersivity and field scale: Groundwater, pp. 905-908.

Yale, D. P., Nabor, G. W., Russell, J. A., Pham, H. D., and Yousef, M., 1993, Application of variable formation compressibility for improved reservoir analysis: Society of Petroleum Engineers, Society Petroleum Engineers Paper 26647, Houston, Texas, p. 435-450.

TABLE 1
SAND LAYER DESIGNATIONS AND THICKNESS

SAND LAYER	GROSS THICKNESS (FEET)	NET THICKNESS* (FEET)	PERFORATED THICKNESS (FEET)
4,600-ft Sand	38	34	30
4,700-ft Sand	78	67	67
4,800-ft Sand	82	70	60
4,900-ft Sand	44	35	35
5,100-ft Sand	20	16	10
5,200-ft sand	52	45	25
6,200-ft Sand	110	90	85
6,300-ft Sand	33	20	20
6,400-ft Sand	115	100	100
6,620-ft Sand	14	10	7
6,700-ft Sand	43	28	23
6,800-ft Sand	63	48	40
	692	563	502

* 50% of the spontaneous potential deflection

TABLE 2

SUMMARY OF HISTORICAL INJECTION/FALLOFF TESTS

TEST	TRANSMISSIBILITY (MD-FT/CP)	FORMATION THICKNESS (FEET)	VISCOSITY (CENTIPOISE)	PERMEABILITY (MILLIDARCIES)	SKIN
08/02/2001	38,976	502	0.81	62.9	-1.39
02/09/2002	44,000	502	0.81	71.0	-1.79
02/25/2002*	52,504	502	0.81	84.7	0.30**
04/24/2003*	53,111	502	0.81	64.78	1.6
04/27/2004*	54,070	502	0.81	87.2	1.22
04/23/2005*	53,055	502	0.81	65	0.91
04/23/2006*	53,652	502	0.81	65	1.33
05/08/2007*	46,043	502	0.81	56	-0.24
05/13/2008	44,120	502	0.81	71.2	1.226
05/12/2009	43,662	502	0.81	70.45	2.72
05/19/2010	33,808	502	0.81	54.55	0.41
05/02/2011	31,254	502	0.81	50.43	0.895
05/16/2012	40,569.04	502	0.81	65.460	2.86
06/19/2013	33,590.62	502	0.81	54.2	1.42
05/15/2014	30,054.73	502	0.81	48.5	1.244
05/28/2015	36,738.96	502	0.81	59.28	3.030
05/11/2016	35,635.8	502	0.81	57.5	3.48
05/11/2017	34,086.42	502	0.81	55.0	2.62
05/16/2018	31,018.64	502	0.81	50.05	2.170
05/02/2019	32,779.42	502	0.81	52.9	2.850
06/10/2020	37,185.19	502	0.81	60	4.22
05/04/2021	35,945.68	502	0.81	58	3.98
05/04/2022	49,344.74	502	0.81	79.6	8.24
05/03/2023	36,416.69	502	0.81	58.76	4.765

*Note-Transmissibility & permeability updated for corrected test flow rates (see 2008 Bottomhole Pressure Falloff Test Report.
** Note – since surface gauge was used, skin includes both completion efficiency and tubing friction loss.

TABLE 3
AVERAGE SAND LAYER POROSITY

SAND LAYER	PERFORATED THICKNESS (FEET)	AVERAGE LOG POROSITY* (PERCENT)	POROSITY – THICKNESS
4,600-Ft Sand	30	23	6.9
4,700-ft Sand	67	21	14.3
4,800-ft Sand	60	23	13.9
4,900-ft Sand	35	22	7.8
5,100-t Sand	10	19	1.9
5,200-ft sand	25	20	4.9
6,200-ft Sand	85	20	16.8
6,300-ft Sand	20	20	4.0
6,400-ft Sand	100	18	18.5
6,620-ft Sand	7	20	1.4
6,700-ft Sand	23	19	4.4
6,800-ft Sand	40	20	7.9
	502	Total ϕ*h =	102.5
		Average =	20.4

*Density porosity log

TABLE 4
SAND LAYER GEOLOGICAL MULTIPLYING FACTOR

Sand	Perforated Thickness (ft)	Incremental CMR K*H (d-ft)	Sand K*H (d-ft)	CMR Sand Permeability (md)	CMR Sand Porosity (%)	K/ϕ
4,600-Ft	30	145.52	27.46	915.3	22.1	4,144.0
4,700-Ft	67	118.06	20.31	303.1	20.3	1,492.9
4,800-Ft	60	97.75	27.85	464.2	20.7	2,238.3
4,900-Ft	35	69.9	11.28	322.3	21.2	1,521.9
5,200-Ft	25	58.62	5.89	235.6	18.4	1,277.6
6,200-Ft	70	52.73	10.91	155.9	18.7	834.2
6,300-Ft	20	41.82	3.3	165.0	19.2	859.6
6,400-Ft	100	38.52	8.13	81.3	16.8	484.0
6,700-Ft	23	30.39	3.96	172.2	18.6	925.8
6,800-Ft	40	26.43	26.43	660.8	17.6	3,763.7

Maximum K/ϕ =	4,144.0
Average K/ϕ =	1,754.2
Multiplying Factor =	2.36

TABLE 5
STATIC PRESSURE GRADIENT SURVEYS

DEPTH (FT)	PSIA 06/27/2000 PRESSURE (PSI)	INTERVAL COLUMN GRADIENT PSI/FT	DEPTH (FT)	PSIA 08/02/2001 PRESSURE (PSI)	INTERVAL COLUMN GRADIENT PSI/FT
0	0		0	53.5	
4,560	1,940.1	0.425	1,000	470.2	0.417
4,950	2,114.5	0.447	2,000	897.4	0.427
5,250	2,254.6	0.467	3,000	1,328.4	0.431
6,150	2,677.8	0.470	4,000	1,760.3	0.432
6,808	2,975.0	0.452	4,960	2,167.4	0.424
Gradient Average =		0.452	Gradient Average =		0.426
Bottom Gradient =		0.447	Bottom Gradient =		0.424
Pressure at 4,566 Feet =		1,928.1	Pressure at 4,566 Feet =		1,932.2
Gradient at 4,566 Feet =		0.422	Gradient at 4,566 Feet =		0.423
*Pre-injection static pressure gradient surveys, note that reference is to kelly bushing + 18 feet above ground level					

TABLE 6

SUMMARY OF HISTORICAL INJECTION AND STATIC PRESSURES

Test Date	Flowing BHP at Datum Depth (psig)	Delta Pressure due to Skin (psi)	Skin adj FBHP at Datum Depth (psig)	Static Pressure at Gauge Depth (psig)	Static Pressure at Datum Depth (psig)
08/02/2001	3,416.41	0	3,416.41	2,167.40	2,000.319
02/09/2002	2,910.49	22	2,888.49	3,008.43	2,049.396
04/25/2003	2,447.16	91	2,356.16	2,192.60	2,024.812
04/28/2004	2,910.49	127	2,783.49	2,241.61	2,059.078
04/25/2005	2,910.49	55.35	2,855.14	2,250.71	2,082.126
04/25/2006	2,910.49	79	2,831.49	2,278.61	2,087.670
05/10/2007	2,618.56	0	2,618.56	2,308.04	2,125.896
05/14/2008	2,759.00	85	2,674.00	174.33	2,150.406
05/07/2009	2,720.62	142	2,578.62	167.48	2,143.556
05/21/2010	2,782.03	29.82	2,752.21	231.80	2,207.876
05/06/2011	2,759.35	65.95	2,693.40	157.50	2,148.276
05/16/2012	2,726.48	172	2,554.48	129.14	2,105.216
07/21/2013	2,605.75	96	2,509.75	2,202.59	2,020.082
05/16/2014	2,708.34	101	2,607.34	27.75	2,018.526
05/29/2015	2,730.57	200	2,530.57	54.40	2,045.176
05/12/2016	2,701.36	215	2,486.36	49.03	2,039.806
05/12/2017	2,675.41	177	2,498.41	21.03	2,011.806
05/15/2018	2,694.76	162	2,532.76	12.03	2,002.806
05/03/2019	2,691.93	198	2,493.93	2.44	1,993.216
06/11/2020	2,657.22	248	2,409.22	0.00	1,990.776
05/04/2021	2,646.64	241	2,405.64	2,125.62	1,943.880
05/05/2022	2,675.39	365	2,310.39	1.51	1,983.154
05/04/2023	2,651.87	254	2,397.87	15.63	1,997.274
Note-since surface gauge was used, skin includes both completion efficiency and tubing friction loss					

TABLE 7
MAXIMUM REQUESTED SURFACE INJECTION PRESSURE

INJECTION INTERVAL	MAXIMUM REQUESTED SURFACE INJECTION PRESSURE
Pawhuska Sand	1,000 psi

TABLE 8
DUPONT MULTILAYER PRESSURE MODEL INPUT PARAMETERS

Model Layer	Model Interval	Thickness (feet)	Porosity (percent)	Permeability (darcy)	Viscosity (cp)	Compressibility (psi-1)
1	Containment Shale Layer	100	1.0	1.0E-14	1.0	8.00E-06
2	Permeable Sand	100	20.0	0.500	1.0	5.26E-07
3	Containment Shale Layer	100	1.0	1.0E-14	1.0	8.00E-06
4	Pawhuska Sand	502	18.4	0.060	0.81	6.60E-07

TABLE 9

DUPONT MULTILAYER PRESSURE MODEL INJECTION RATE

SAND	RATE MODELED (GPM)
Pawhuska Sand	530

TABLE 10

DUPONT MULTILAYER PRESSURE MODEL TRANSMISSIBILITY

SAND	MODEL TRANSMISSIBILITY (md-ft/cp)
Pawhuska Sand	37,185

TABLE 11
DUPONT MULTILAYER PRESSURE MODEL - PRESSURE DISTRIBUTION RESULTS

Injection Rate (gpm)	LOCATION	END OF HISTORICAL INJECTION PERIOD (PSI)	YEAR END 2035 (MAXIMUM INJECTION) (PSI)
530	Injection Well WDW1	29.5	852
	2-Mile AOR Boundary	14	138

The modeling results of the pressure build-up for each year modeled can be found in Appendix 3 The files are designated with the suffix ".sum".

TABLE 12
CALCULATED RADIUS OF THE CONE OF INFLUENCE FROM THE PROPOSED INJECTION WELL

INJECTION RATE (gpm)	INJECTION INTERVAL	RADIUS OF CONE OF INFLUENCE AT YEAR 10 (YE2035) (Feet)
530	Pawhuska	5,360

TABLE 13
DUPONT BASIC PLUME MODEL INPUT PARAMETERS

MODEL LAYER	MODEL INTERVAL	THICKNESS (FEET)	POROSITY (PERCENT)	DISPERSIVITY (FEET)	MULTIPLYING FACTOR
1	Pawhuska Sand	90	18.4	117	2.77

TABLE 14

DUPONT BASIC PLUME MODEL INJECTION RATE

INJECTION INTERVAL	RATE MODELED (GPM)	EFFECTIVE RATE MODELED (GPM)*
Pawhuska Injection Interval	530	1,468

* with Multiplying Factor

TABLE 15
DUPONT BASIC PLUME MODEL – PLUME DISTRIBUTION RESULTS

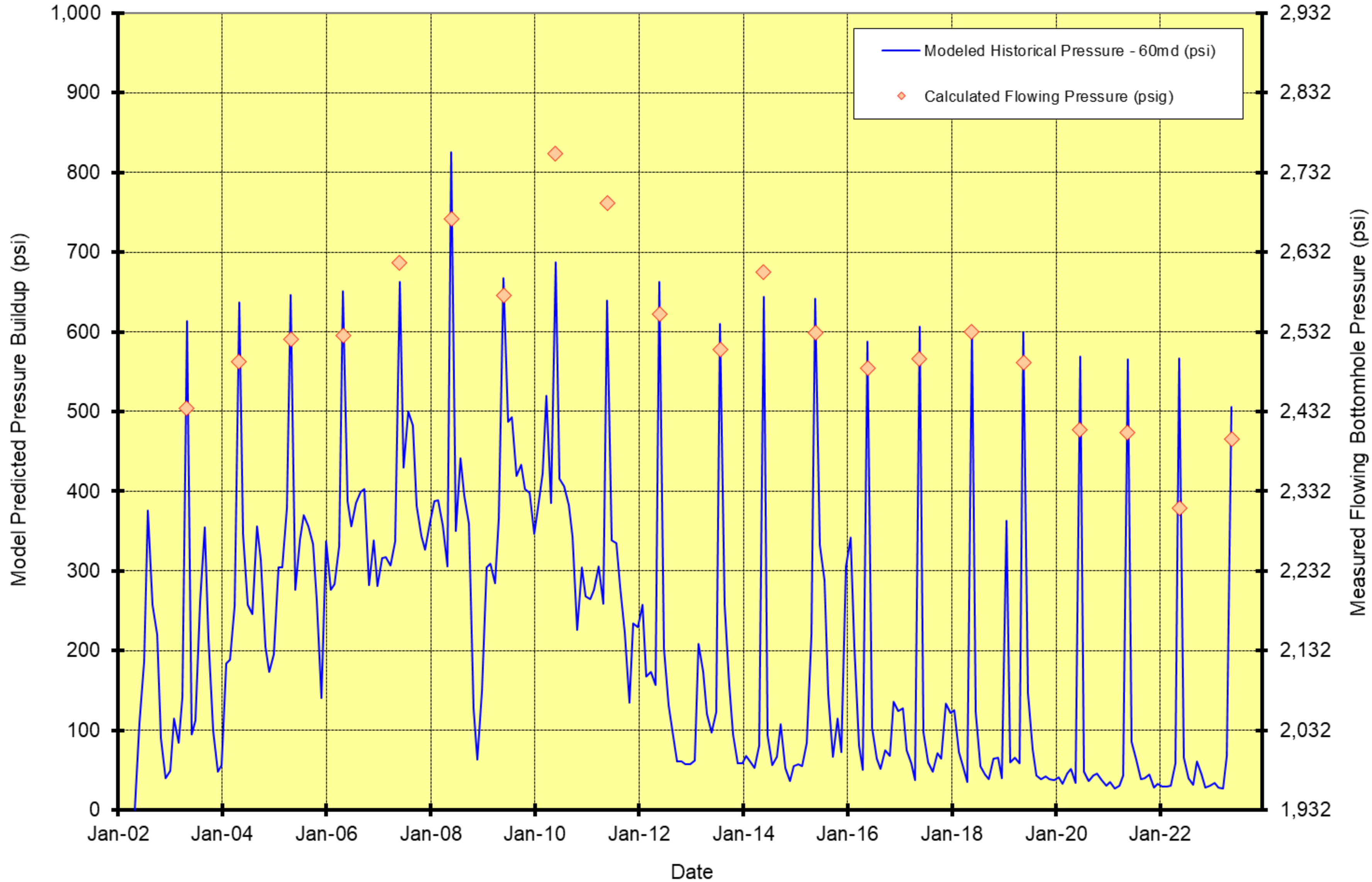
	INJECTION RATE (GPM)	**END OF HISTORICAL INJECTION PERIOD (YE2022) (FEET)**	**END OF MODEL PERIOD (YE2035) (FEET)**
Pawhuska Sand	530	2,991	5,979
The modeling results of the plume perimeter can be found in Appendix 4 .plt File. Note perimeter shown for a million-fold reduction in concentration			

FIGURES

MODELED HISTORICAL PRESSURE COMPARED WITH CALCULATED FLOWING PRESSURE

CLIENT: OG+E

CLIENT INFORMATION: **OGE ENERGY CORP.**
HISTORICAL PRESSURE COMPARED TO CALCULATED FLOWING PRESSURE
MCCLAIN FACILITY - MCCLAIN COUNTY, OK



PROJECT NO:	ILLUSTRATION NO:		REVISION:
230051ONC	-		-
SCALE: NOT TO SCALE	DATE: 08/30/2023	BY: AMZ (GKS)	APPROVED BY: DJC

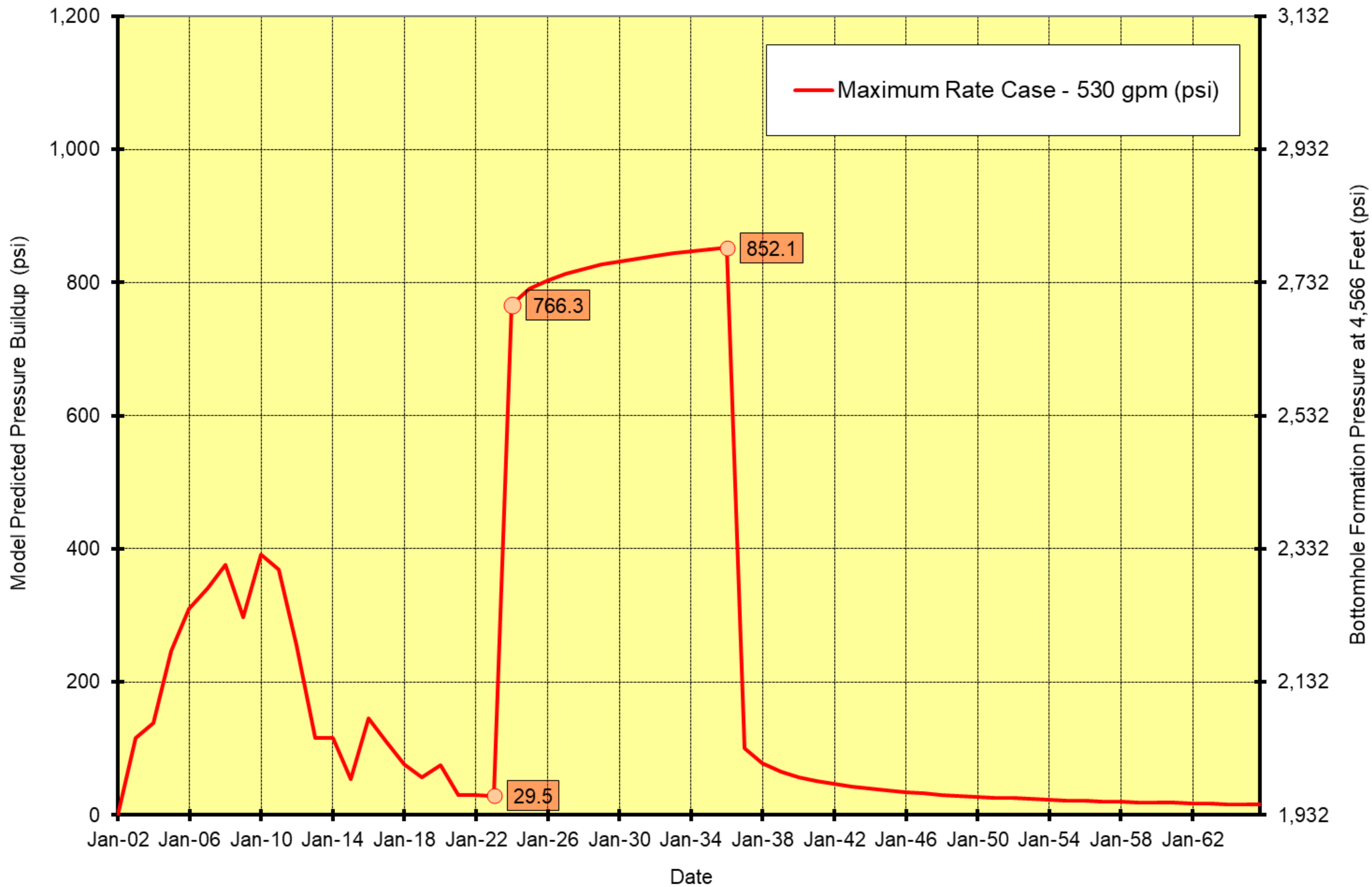
Geostock Sandia

FIGURE 1: Plot of historical pressure increase at Injection Well 1, compared with calculated annual ambient test flowing bottomhole pressures.

PREDICTED OPERATIONAL PRESSURE INCREASE AT WELL 1

CLIENT: OG&E

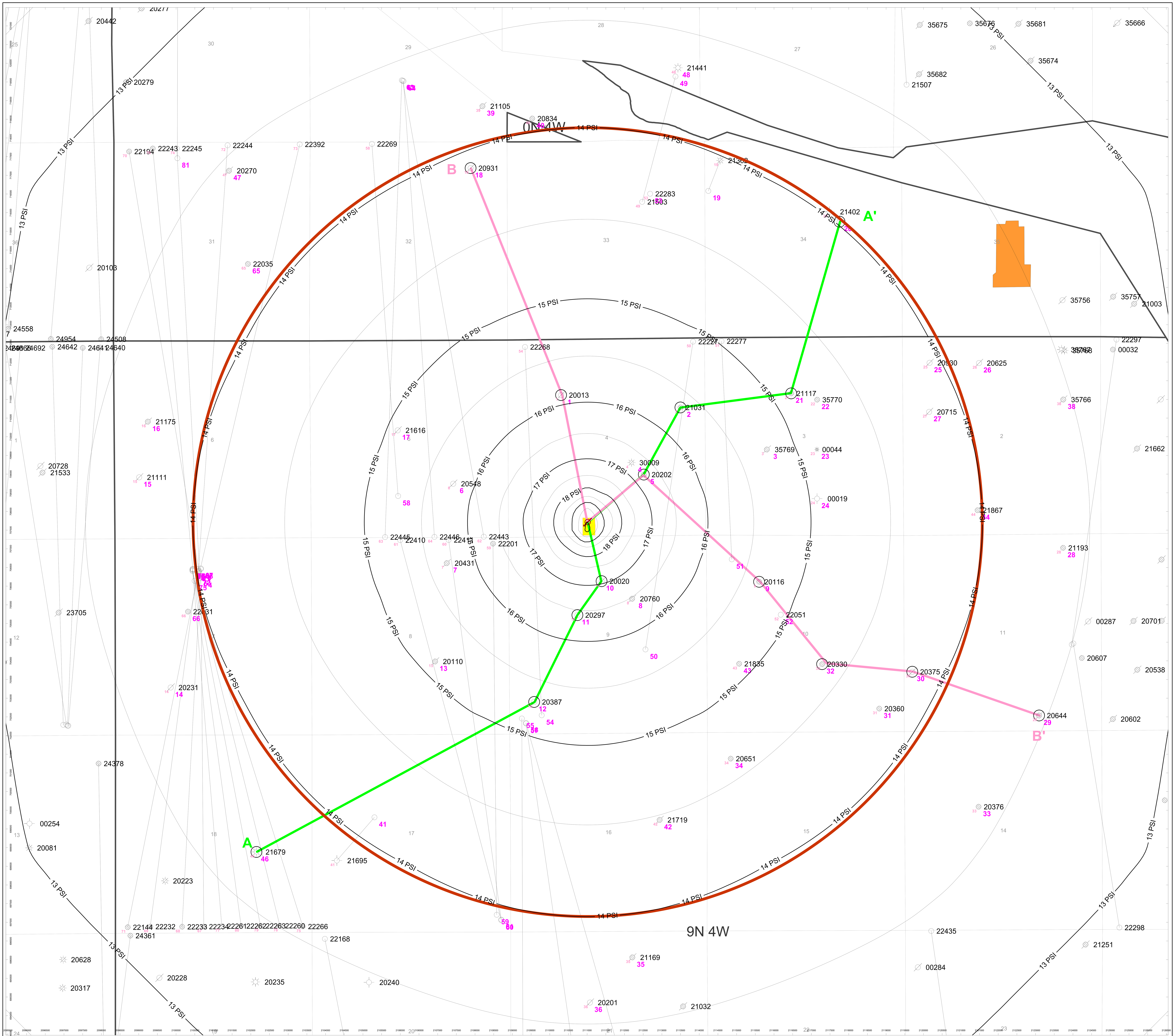
CLIENT INFORMATION: **OGE ENERGY CORP.**
Model Predicted Pressure Buildup at Maximum Rate
MCCLAIN FACILITY - MCCLAIN COUNTY, OK

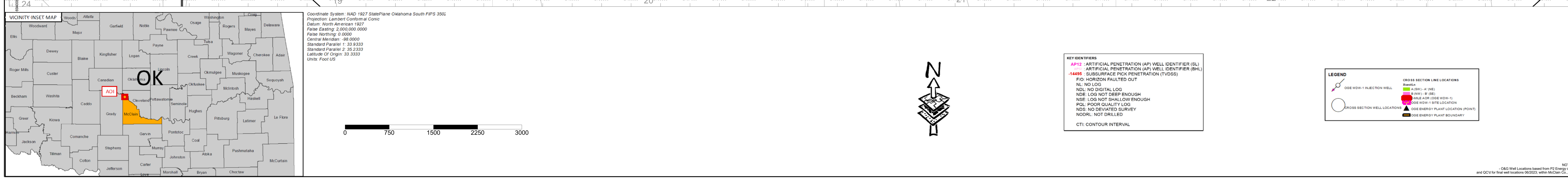


PROJECT NO:	ILLUSTRATION NO:		REVISION:
230051ONC	-		-
SCALE: NOT TO SCALE	DATE: 08/30/2023	BY: AMZ (GKS)	APPROVED BY: DJC

Geostock Sandia

FIGURE 2: Plot of predicted operational pressure increase at WDW 1, through year end 2035 at maximum permitted modeled injection rate (530 gpm). Includes a 30 year post-closure period.





OGE ENERGY CORP.

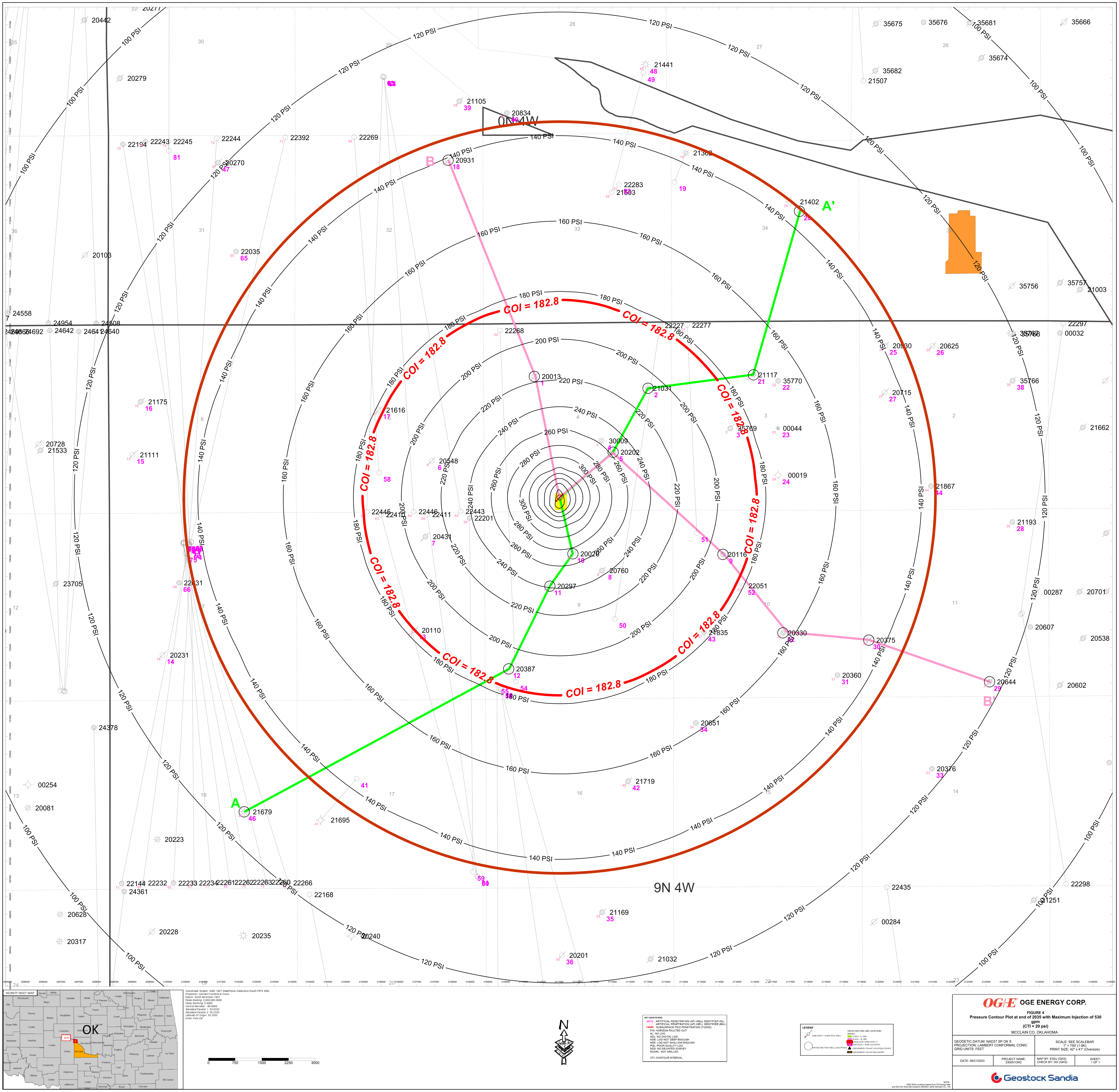
FIGURE 3
Model Predicted Pressure at year-end 2022 with Historical Injection

(CTI = 0.5 psi)
MCCLAIN CO. OKLAHOMA

GEODETIC DATUM: NAD27 SP OK S PROJECTION: LAMBERT CONFORMAL CONIC GRID UNITS: FEET	SCALE: SEE SCALEBAR 1" = 750' (1:9K) PRINT SIZE: 42" x 41" (Oversize)

DATE: 08/21/2023	PROJECT NAME: 230051ONC	MAP BY: ESSJ (GKS) CHECK BY: DG (GKS)	SHEET: 1 OF 1

Geostock Sandia



COI = 182.8
120 PSI
140 PSI
160 PSI
180 PSI
200 PSI
220 PSI
240 PSI
260 PSI
280 PSI
300 PSI
100 PSI
A
A'
B
9N 4W
OK
VICINITY INSET MAP
N
0
750
1500
2250
3000
OGE ENERGY CORP.
FIGURE 4
Pressure Contour Plot at end of 2035 with Maximum Injection of 530 gpm
(CTI = 20 psi)
MCCLAIN CO. OKLAHOMA
GEODETIC DATUM: NAD27 SP OK S
PROJECTION: LAMBERT CONFORMAL CONIC
GRID UNITS: FEET
SCALE: SEE SCALEBAR
1" = 750' (1:9K)
PRINT SIZE: 42" x 41" (Oversize)
DATE: 08/21/2023
PROJECT NAME: 230051ONC
MAP BY: ESSJ (GKS)
CHECK BY: DG (GKS)
SHEET: 1 OF 1
Geostock Sandia

PRESSURE PROFILE YE 2035 WELL 1

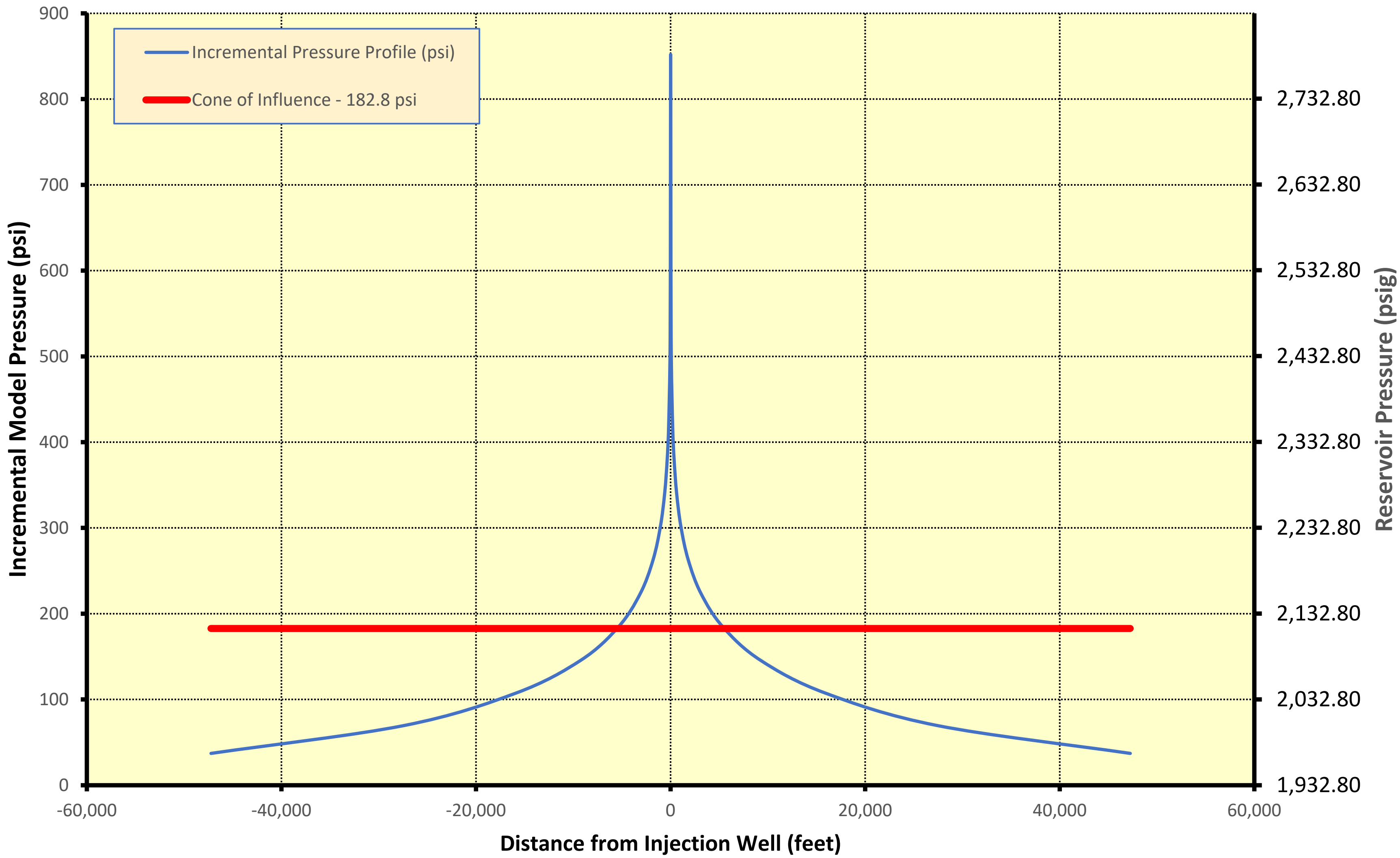
CLIENT:

OG&E

CLIENT INFORMATION:

OGE ENERGY CORP.
Pressure Profile

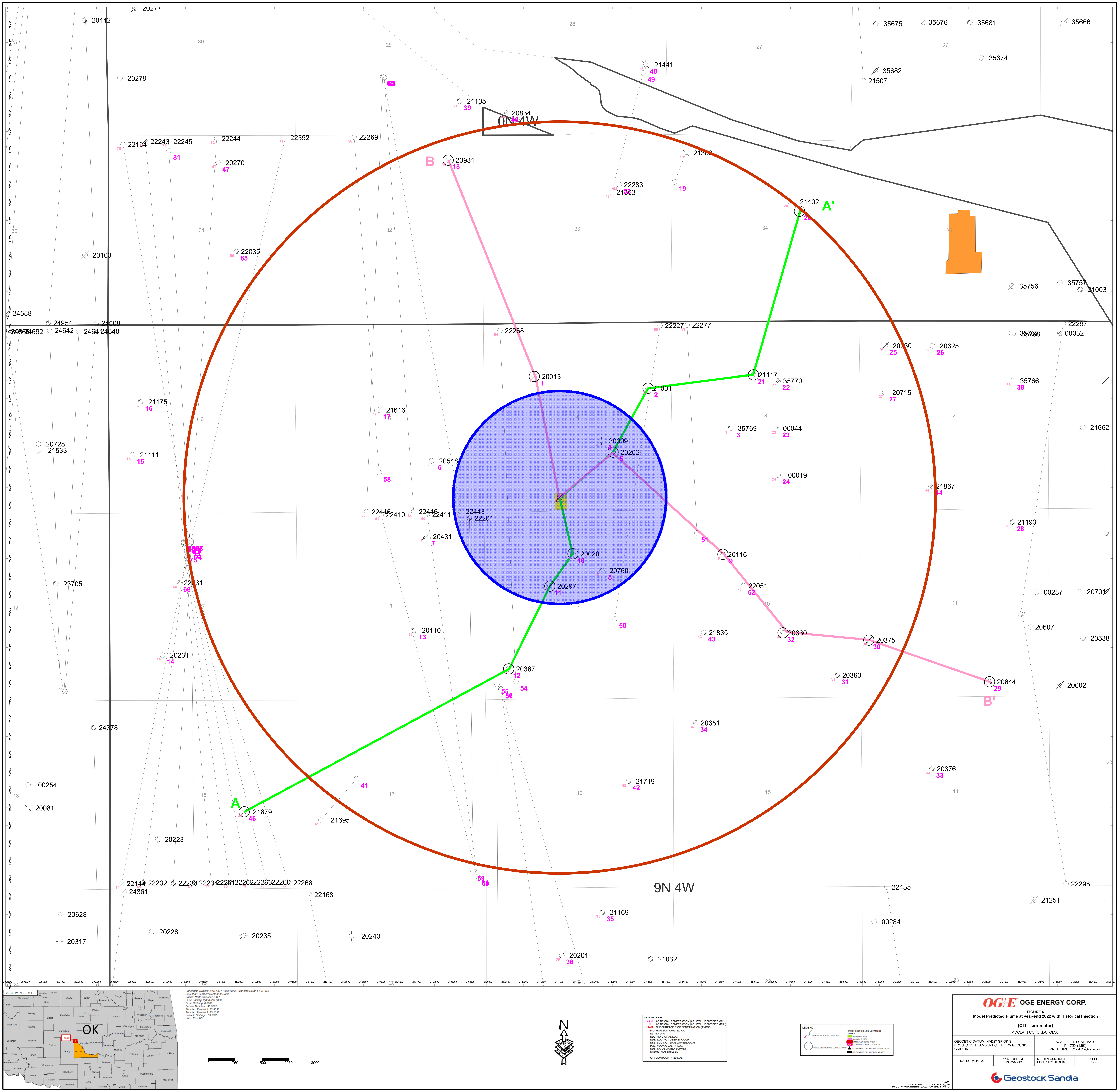
MCCLAIN FACILITY - MCCLAIN COUNTY, OK



PROJECT NO: 230051ONC	ILLUSTRATION NO: -		REVISION: -
SCALE: NOT TO SCALE	DATE: 08/30/2023	BY: AMZ (GKS)	APPROVED BY: DJC

Geostock Sandia

FIGURE 5: Pressure profile at year end 2035 at Maximum Injection Rate (530 gpm)



OGE ENERGY CORP.

FIGURE 6
Model Predicted Plume at year-end 2022 with Historical Injection

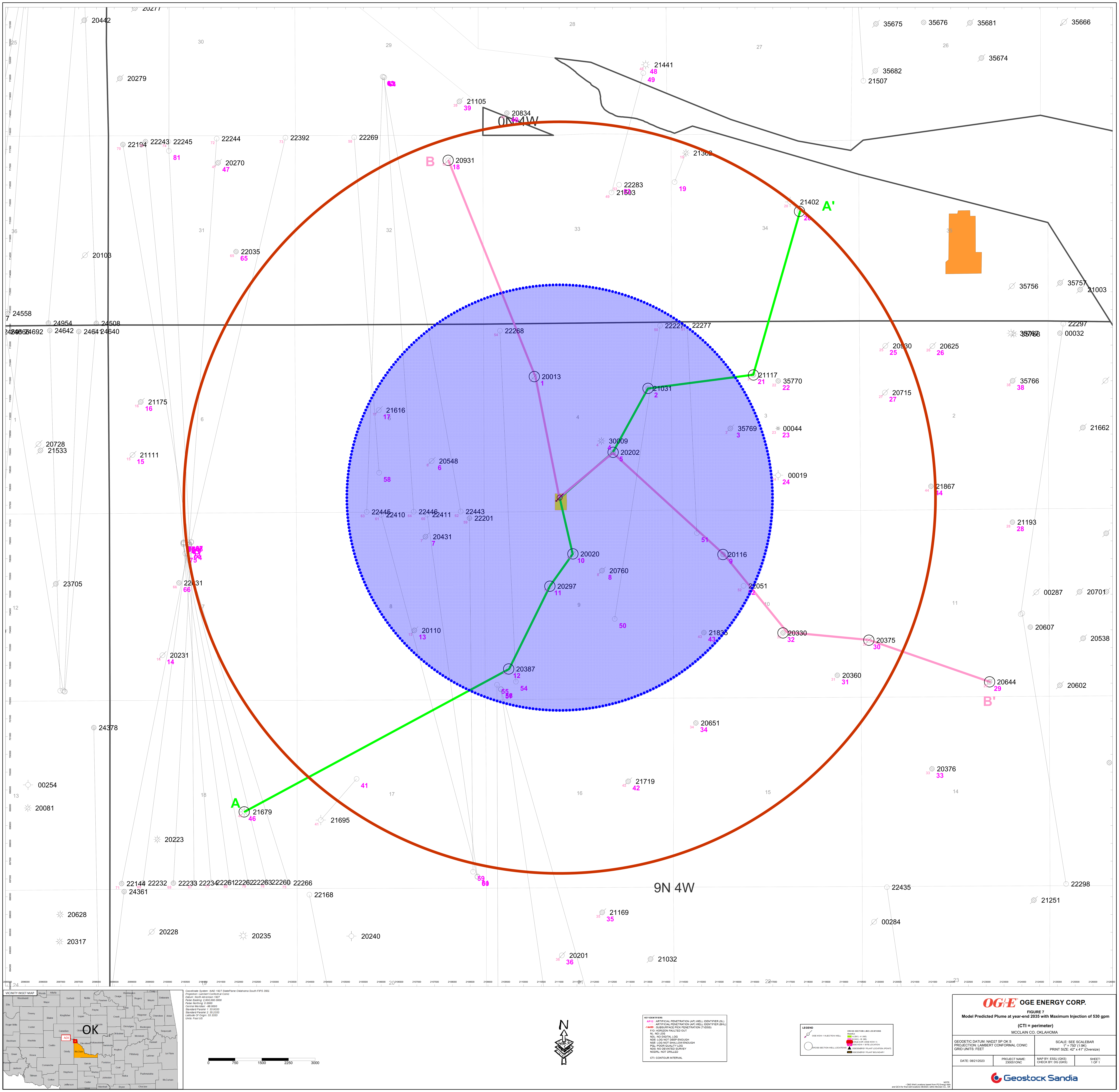
(CTI = perimeter)

MCCLAIN CO. OKLAHOMA

GEODETIC DATUM: NAD27 SP OK S PROJECTION: LAMBERT CONFORMAL CONIC GRID UNITS: FEET	SCALE: SEE SCALEBAR 1" = 750' (1:9K) PRINT SIZE: 42" x 41" (Oversize)

DATE: 08/21/2023	PROJECT NAME: 230051ONC	MAP BY: ESSJ (GKS) CHECK BY: DG (GKS)	SHEET: 1 OF 1

Geostock Sandia



OGE ENERGY CORP.

FIGURE 7
Model Predicted Plume at year-end 2035 with Maximum Injection of 530 gpm

(CTI = perimeter)

MCCLAIN CO. OKLAHOMA

GEODETIC DATUM: NAD27 SP OK S PROJECTION: LAMBERT CONFORMAL CONIC GRID UNITS: FEET	SCALE: SEE SCALEBAR 1" = 750' (1:9K) PRINT SIZE: 42" x 41" (Oversize)

DATE: 08/21/2023	PROJECT NAME: 230051ONC	MAP BY: ESSJ (GKS) CHECK BY: DG (GKS)	SHEET: 1 OF 1

Geostock Sandia

LEGEND

OGE WDW-1 INJECTION WELL

2-MILE AOR (OGE WDW-1)

OGE WDW-1 SITE LOCATION

OGE ENERGY PLANT LOCATION (POINT)

OGE ENERGY PLANT BOUNDARY

APPENDICES

APPENDIX 1
DUPONT MULTILAYER PRESSURE MODEL

APPENDIX 2
DUPONT BASIC PLUME MODEL

Appendix 3

Computer Run and Output Files

DuPont Multilayer Pressure Model

Appendix 3

DuPont Multilayer Pressure Files

Monthly Flowing Calibration Model Files

Appendix 3

DuPont Multilayer Pressure Model

Monthly Flowing Pressure Calibration Input- .RCV File

Appendix 3

DuPont Multilayer Pressure Model

Monthly Flowing Pressure Calibration Input- .PRM File

Appendix 3

DuPont Multilayer Pressure Model

Monthly Flowing Pressure Calibration Output- .SUM File

Appendix 3

DuPont Multilayer Pressure Model Files

Appendix 3

DuPont Multilayer Pressure Model Files
Pressure Model File Input - .RCV

Appendix 3

DuPont Multilayer Pressure Model Files
Pressure Model File Input - .PRM

Appendix 3

DuPont Multilayer Pressure Model Files
Pressure Model File Output - .SUM

Appendix 4

Computer Run and Output Files
DuPont Basic Plume Model

Yearly Plume Files

Appendix 4

DuPont Basic Plume Model

Projected Maximum Plume Input - .RCV File

Appendix 4

DuPont Basic Plume Model

Projected Maximum Plume Input - .PRM File

Appendix 4

DuPont Basic Plume Model

Projected Maximum Plume Output - .INJ File