REGION 5

CHICAGO, IL 60604

August 6, 2025

MEMORANDUM

SUBJECT: EPA Alternative Post-Injection Site Care (PISC) Review Memorandum for the Marquis Class VI permit– Permit Number IL-115-6A-0001; Putnam County, IL

FROM: Peter Bergman, ORISE Fellow and Felicia Chase

TO: Well files and Administrative Record, IL-155-6A-0001

Summary

The U.S. Environmental Protection Agency ("EPA" or "Agency") received a permit application from Marquis Carbon Injection, LLC ("Marquis") for a Class VI Underground Injection Control (UIC) well in Illinois. Marquis proposed a Post-Injection Site Care (PISC) timeframe shorter than 50-years and submitted a demonstration in support as required in Section 146.93 (b) of Title 40 of the Code of Federal Regulations (40 C.F.R. § 146.93(b)). EPA conducted an independent review of the proposal to determine whether the requirements of 40 C.F.R. § 146.93(c) had been met. Marquis initially requested an alternative-PISC timeframe of five years but increased it to a request for 12 years as a result of modeling outputs validated by EPA in August of 2024. EPA reviewed all parts of the Marquis application relevant to the PISC as a part of the technical review. Marquis has met the regulatory requirements for an alternative PISC timeframe of 12 years, and EPA concludes that there is substantial evidence that the project will not pose a risk of endangerment to USDWs at the end of the 12-year timeframe as outlined in this memorandum. This memo outlines EPA's review of the 12-year request, citing to the Administrative Record (AR) for its rationale and decision-making, using site-specific data and information in its approval of the 12-year PISC timeframe request.

Overall Summary of Legal Requirements

The PISC and Site Closure Plan is part of a Class VI permit as an attachment. See generally 40 C.F.R. § 146.93. A PISC includes monitoring requirements that apply to "the period after [carbon dioxide] CO_2 injection ceases—but prior to site closure—during which the owner or operator must continue monitoring to ensure [underground sources of drinking water] USDW protection from endangerment." 75 Federal Register (Fed. Reg.) at 77,266; see also 40 C.F.R. § 146.93(a)(1), (b). The "period" is known as the PISC timeframe. See 75 Fed. Reg. at 77,266; 40 C.F.R. § 146.93(a)(1)(v). The Class VI regulations require the PISC timeframe to be "at least 50 years or for the duration of the alternative timeframe approved by [EPA]." 40 C.F.R. § 146.93(b)(1). Under the latter of these options, a permit applicant may submit, and EPA may approve an alternative timeframe for a PISC "if an owner or operator can demonstrate during the permitting process that an alternative post-injection site care timeframe is appropriate and ensures non-endangerment of USDWs." 40 C.F.R. § 146.93(c); see also 40 C.F.R. § 146.93(a)(2)(v). The permit applicant may engage in an iterative process with EPA throughout the permitting process to meet the data and information requirements in the Class VI regulations.

The alternative PISC permitting process begins with the submission of a demonstration by the permit applicant as part of the permit application. 40 C.F.R. § 146.93(c). Under 40 C.F.R. § 146.93(c), an alternative PISC timeframe demonstration must consider and document ten elements (with an eleventh at EPA's discretion). 40 C.F.R. § 146.93(c)(1). The regulations also outline seven criteria (with an eighth at EPA's discretion) that the information submitted as part of the demonstration must meet. 40 C.F.R. § 146.93(c)(2). Prior to approval, EPA must ensure that the permit applicant's demonstration, comprised of information on each of the ten elements in accordance with the requirements for the eight criteria, meets two standards overall: 1) the demonstration must be based on significant site-specific data and information, including data and information collected in the permit application (146.82) and the siting criteria (146.83); and 2) the demonstration must include substantial evidence to support a conclusion that the project will no longer pose a risk of endangerment to USDWs at the end of the PISC timeframe. 40 C.F.R. § 146.93(c). Site-specific data and information collected under these regulatory elements allows EPA to evaluate whether the applicant has demonstrated that the project will not pose a risk of endangerment to USDWs at the conclusion of the alternative PISC timeframe.[1]

EPA may reject a permit applicant's demonstration for a variety of reasons including if the supporting information provided is inadequate, does not support the proposed timeframe, or indicates a risk of endangerment to a USDW, regardless of support for the alternative timeframe from modeling or any single regulatory requirement. See 40 C.F.R. § 146.93(c) (stating that a demonstration must ensure non-endangerment of USDWs). EPA may also provide feedback on and accept revisions to the permit applicant's demonstration as necessary. If EPA is satisfied

[1] Much of the information and data relevant to the alternative PISC timeframe elements are likely to be included elsewhere in a permit applicant's materials. For example, the "results of the computational modeling," which is Element #1, would be contained in a permit applicant's Area of Review submission under 40 C.F.R. § 146.84. A permit applicant may reference other portions of their permit application submissions for information and data relevant to the elements in their alternative PISC timeframe demonstration, but the demonstration needs to explain why the cited information and data supports their proposed PISC timeframe.

that the demonstration addresses all of the required information and "an alternative [PISC] is appropriate and ensures non-endangerment of USDWs" in accordance with 40 C.F.R. § 146.93(c), EPA may ultimately choose to approve the alternative PISC timeframe. Importantly, not all ten elements are weighted equally in an alternative PISC timeframe decision, but rather information to be "considered and documented" in the demonstration. The Agency's approval results in the alternative PISC timeframe's incorporation into a draft permit, which is subject to public participation procedures under 40 C.F.R. Part 124. 40 C.F.R. §§ 146.82(a)(17), 146.84(b)(2)(i), 146.93(a). Importantly, if incorporated into the final permit, the PISC timeframe may be reconsidered at several points in the project lifecycle based on data collection required under the permit to ensure that the period of post closure site care is sufficient to demonstrate protection of USDWs. See 40 C.F.R. §§ 146.93(b)(2) through (4). The initial PISC timeframe is reconsidered and updated as appropriate based upon well construction and collection of well-specific data prior to injection, during operation, after injection ceases, and at site closure. See 40 C.F.R. §§ 146.82(c)(9) and 146.87 (prior to injection), 146.84(b)(2)(i) (during injection), 146.93(a)(2)(ii) (during injection), 146.93(a)(3) (post injection), 146.93(b)(3) (site closure).

Technical Background Summary of the Elements in the Regulations

As explained in the Legal Requirements Section, an alternative PISC timeframe demonstration must consider and document ten elements. 40 C.F.R. § 146.93(c)(1). Overall, those elements must demonstrate that the alternative timeframe ensures non-endangerment of USDWs, i.e., that the project will not pose a risk of endangerment to USDWs after the end of the timeframe. Below is an explanation of each element and how it relates to the PISC timeframe determination.

Element #1: the results of computational modeling performed pursuant to delineation of the area of review (AoR), as required by 40 C.F.R. § 146.93(c)(1)(i). The AoR is "the region surrounding the geologic sequestration project where USDWs may be endangered by the injection activity" absent protective permit conditions. 40 C.F.R. § 146.84(a). For Class VI wells, the AoR is determined by computational modeling that accounts for the physical and chemical properties of all phases of the injected carbon dioxide stream, and is based on available site characterization, monitoring, and operational data. The model defines the predicted subsurface influence of the fluid injection activity. The maximal extent of this influence defines the AoR. The extent of influence includes the area of the pressure front and the area of the CO_2 plume.[2] 40 C.F.R. § 146.81(d). The AoR is set based on whichever influence extends furthest away from

[2] "Pressure front" means the zone of elevated pressure that is created by the injection of carbon dioxide into the subsurface. For the purposes of [subpart H of Part 146], the pressure front of a carbon dioxide plume refers to a zone where there is a pressure differential sufficient to cause the movement of injected fluids or formation fluids into a USDW. 40 C.F.R. § 146.81(d).

the well, meaning that the maximum CO_2 plume is not always synonymous with the AoR outer limit.

In delineating the AoR, it is possible that the maximum size of the pressure front and of the CO_2 plume will not be the same. Since the AoR must encapsulate both "the projected lateral and vertical migration of the carbon dioxide plume . . . until plume movement ceases [and the] pressure differentials sufficient to cause the movement of injected fluids or formation fluids into a USDW [i.e., the pressure front] are no longer present," it must be delineated to the extent of the larger of the two influences when their maximum extents are not the same. 40 C.F.R. 146.84(c)(1).[3]

In order to provide an alternative timeframe, the applicant's demonstration must include site-specific geologic data to be input into the computational model. 40 C.F.R. § 146.84(a). Using these data, the model predicts the growth in three dimensions of the pressure front and CO_2 plume over time until the point at which the maximum extent of both is reached and the AoR is delineated. Put another way, computational modeling and site characterization (Element #7 below) are used to predict the migration of the CO_2 plume until the plume movement reaches its maximum and ceases (Element #3 below) and until the pressure differentials (Element #2 below)[4] sufficient to cause movement of fluids into USDWs are no longer present. 40 C.F.R. § 146.84(c)(1).

The regulation contains requirements for the computational modeling. See 40 C.F.R. § 146.84(c)(1)(i)-(iii). The model relies upon significant site-specific data and information from, inter alia, the other regulatory elements in 40 C.F.R. § 146.93(c), which, among other things, ensure that the model accounts for conditions present in the geology as inputs, outputs, variables, and assumptions. The model is relevant to determining the PISC timeframe because the PISC timeframe should be based on an accurate understanding of the CO_2 plume and the pressure front. At this point, the model results should indicate that the injected CO_2 will be safely stored in the injection zone ad infinitum, ensuring non-endangerment of USDWs.

<u>Element #2</u>: the predicted timeframe for pressure decline within the injection zone and any other zones, such that formation fluids may not be forced into any USDWs; and/or the

[3] The permit applicant must "Predict, using existing site characterization, monitoring and operational data, and computational modeling, the projected lateral and vertical migration of the carbon dioxide plume and formation fluids in the subsurface from the commencement of injection activities until the plume movement ceases, until pressure differentials sufficient to cause the movement of injected fluids or formation fluids into a USDW are no longer present, or until the end of a fixed time period as determined by the Director." 40 C.F.R. 146.84(c)(1).

[4] The pressure differential is the pressure that exists in a given rock formation at a certain point in time during the life of the project (i.e., 5 years into injection, 12 years end of injection, 5 years post injection, etc.) minus the pressure existing in the relevant rock formation naturally.

timeframe for pressure decline to pre-injection pressures, as required by 40 C.F.R. § 146.93(c)(1)(ii). For Class VI wells, the CO_2 is injected at high pressure in order to ensure it is able to travel vertically thousands of feet underground to the targeted injection depth. The pressure in the injection zone is highest at the portion of the well where CO_2 is injected and the pressure spreads in three dimensions in the subsurface injection formation rock. The pressure differential declines with distance from the well. After injection ceases, the pressure within the front dissipates over time. An understanding of the propagation (or expansion) and decline of underground pressure in the geology around the injection well helps predict the maximum extent of the pressure differential and the predicted movement of fluid in the subsurface, including the CO_2 plume (Element #3, below). It is also important to predict the expansion and decline of underground pressure to ensure pressure will not be high enough to cause fluid movement into a USDW. See Proposed Class VI Rule, 73 Fed. Reg. 43492, 43519 (July 26, 2008) (explaining that "[a] record of the pressures in the injection formation can help the owner or operator determine that the injected fluid does not pose endangerment to USDWs."). The predicted pressure decline is relevant to determining the PISC timeframe because it may impact the migration of the CO_2 plume and an accurate understanding of the migration of the CO_2 plume is important in determining an appropriate PISC timeframe. At this point, the model results should indicate that the injected CO_2 will be safely stored in the injection zone ad infinitum, ensuring non-endangerment of USDWs.

<u>Element #3</u>: the predicted rate of CO_2 plume migration within the injection zone and the predicted timeframe for the cessation of migration, as required by 40 C.F.R. § 146.93(c)(1)(iii). The CO_2 plume refers to the extent of the injected CO_2 in the subsurface, which grows in the subsurface during the injection period and may migrate after injection stops due to residual pressure effects (Element #2 above) until equilibrium is attained and migration of the CO_2 plume ceases.[5] A prediction of the migration of the CO_2 in the injection zone is important for many reasons including that a project cannot be approved if there is any indication that CO_2 may migrate outside of the confining zone (Element #7 below) and pose a risk to USDWs (Element #10). The assumed rate of CO_2 plume growth is relevant to determining the adequacy of the PISC timeframe because it will model how quickly the CO_2 plume will migrate. The PISC timeframe must be of sufficient duration to demonstrate that the model is accurately predicting the migration of the CO_2 plume because an accurate prediction of the CO_2 plume migration is important to demonstrate non-endangerment of USDWs. At this point, the model results should indicate that the injected CO_2 will be safely stored in the injection zone ad infinitum, ensuring non-endangerment of USDWs.

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[5] Equilibrium (i.e., a state of physical balance), stabilize (i.e., becomes unlikely to change), and cessation (i.e., being brought to an end) are all terms that can accurately describe or characterize when migration has reached its final or maximum extent (i.e., the end or highest degree to which something can possibly spread).

Introduction to Trapping: Elements 4 through 7 provide information relevant to characterization of the site-specific trapping mechanisms and rates of trapping present at the injection well location. CO_2 trapping occurs when CO_2 is injected into the subsurface for capture and storage. See 75 Fed. Reg. at 77232 (defining trapping). Injected CO_2 accumulates, i.e., becomes trapped, in one area or another due to variations in rock structure and other chemical and physical properties. Depending on the phase and rate of the trapping, discussed below, trapping can prevent migration of the CO_2 plume. Trapping may warrant further evaluation when it is uneven and excessive and occurs next to a fault or conduit because it may allow for unintended fluid movement. See Elements #7-#8 below.

EPA considers the rate of trapping to initially determine how CO_2 will be stored in the injection zone long-term. The initial accuracy of the computational modeling of the AoR (pressure front and plume migration- Elements #1 and #2) may not be accurate if it does not accurately predict the rate of trapping. The model (Element #1) can show the rates of dissolved phase and the mineral phase trapping. The rate of immobile capillary phase trapping is an input for the model. Both are used to ensure the model accurately predicts CO_2 plume migration using site-specific data. The modeling results can demonstrate that trapping will occur at appropriate locations and points in time and uneven excess trapping of CO_2 will not occur within the predicted rates for the immobile capillary phase, dissolved phase, or mineral phase or that if uneven excess trapping is predicted to occur, that it will not result in unintended fluid movement. Trapping is relevant to determining the PISC timeframe because it impacts the CO_2 plume and an accurate understanding of the CO_2 plume is important in determining an appropriate PISC timeframe. In addition, trapping must be considered to confirm that the injected fluid will not move in unintended ways and will remain in the injection zone long term, thus ensuring non-endangerment of USDWs. Elements 4 and 5 are discussed together because of their interrelated nature.

Element #4: a description of the site-specific processes that will result in CO_2 trapping including immobilization by capillary trapping, dissolution, and mineralization at the site, as required by 40 C.F.R. § 146.93(c)(1)(iv) and Element #5: the predicted rate of CO_2 trapping in the immobile capillary phase, dissolved phase, and/or mineral phase, as required by 40 C.F.R. § 146.93(c)(1)(v).

The site-specific processes that will result in trapping are: (1) Structural trapping by a low permeability rock layer (confining zone) above and sometimes below and/or around the injection zone, or by fault displacement (Element #7), (2) immobile capillary, also known as residual or formation trapping, trapping of the CO_2 in the physical pore space of the injection zone rock formation, (3) dissolved trapping, a type of geochemical trapping by the dissolution of CO_2 in fluids (usually brine) in the pore space of the injection zone rock, and (4) mineral trapping, a type of geochemical trapping by incorporation of the CO_2 into the formation of new minerals in the pore space of the injection zone rock through chemical processes (Elements #4, #5, and #6).

Structural trapping is demonstrated by satisfying Element #7 and as such, is discussed further in that section below. Confining zones (physical trapping barriers) are low permeability rock formations, which are often made of shale, limestone, or dolomite.

Elements #4 and #5 involve the characteristics of capillary trapping (immobile capillary trapping phase), CO_2 dissolution (dissolved phase) and mineralization (mineral phase) that occur in the pore space of the injection zone formations.

Immobile capillary trapping (sometimes referred to as residual trapping) is a physical process by which the CO_2 occupies a pore space. Residual CO_2 is left behind for permanent storage in the pore spaces of a rock formation as the CO_2 gains buoyancy and migrates to other available pore spaces. Capillary trapping is a force present in all rock pore spaces that causes CO_2 to occupy the interstice prior to it dissolving in the next phase. The dissolved phase of trapping refers to when the CO_2 interacts with the formation fluid to create an aqueous solution. Mineralization refers to when CO_2 combines with existing minerals in the injection zone chemically to create new minerals.

Generally, due to the geology in Region 5, the injection zone rock formations have available pore space to allow the injected CO_2 to be absorbed. They are often comprised of sandstone or other rock types with secondary porosity (small vugs, cavities, or fractures) that are of higher permeability with ample pore space. These rock types also have properties that allow the injected fluid to occupy pore space within the injection zone formation as intended. The physical and geochemical properties of the pore spaces in the injection zone rock will trap CO_2 by mostly capillary at first, then mostly by dissolution, and then mostly by mineralization over time.

By accounting for trapping, the model shows the impact trapping will have on the migration of the CO_2 plume to ensure that the CO_2 plume will no longer pose a risk of endangerment to USDWs at the end of the PISC timeframe. Then, through the collection of monitoring and operational data, the site-specific trapping and the PISC timeframe can be confirmed prior to EPA approval of site closure.

<u>Element #6</u>: results of laboratory analyses, research studies, and/or field or site-specific studies to verify the information required in 40 C.F.R. § 146.93(c)(1)(iv) and (v) (Elements #4 and #5 above). The permit applicant must provide references of research conducted and the sources and studies used to verify the information that was used to input trapping mechanisms and rates to the computational model for Elements #4 and #5 above. Permit applicants may also provide site-specific data from an existing borehole (one type is a test hole) to establish site-

specific geochemical, petrological (the properties of a type of rock), and geological (the properties of the larger group of rock formations) characteristics. The accuracy of trapping data is relevant to determining the PISC timeframe because trapping impacts the migration of the CO_2 plume and an estimation of the migration of the CO_2 plume is important in determining an appropriate PISC timeframe. In addition, trapping must be considered to confirm that the injected fluid will not move in unintended ways and will remain in the injection zone long term, thus ensuring non-endangerment of USDWs. Any research used to verify trapping characteristics assists in the preparation of the permit application and EPA's evaluation of the trapping information provided.

<u>Element #7</u>: a characterization of the confining zone, including a demonstration that it is free of transmissive faults, fractures, and micro-factures and of appropriate thickness, permeability, and integrity to impede fluid movement, as required by 40 C.F.R. § 146.93(c)(1)(vii). A characterization of the confining zone is relevant to determining an alternative PISC timeframe because it affects the computational modeling results (Element #1 above) in at least two ways. First, the modeling must input or account for the characteristics of the confining zones because CO_2 moves differently in different rock formations. See EPA, UIC Program Class VI Area of Review Evaluation and Corrective Action Guidance, at 31 (May 2013) ("Class VI AoR Guidance"). Second, site-specific rock characteristic data of the confining zone must be input so that the model will assess whether the confining zone is adequate to protect USDWs long-term. As the Class VI Rule explains, "[t]he confining system [Element #7] should be of sufficient regional thickness and lateral extent to contain the entire CO_2 plume [Element #3] and associated pressure front [Element #2] under the confining system following the plume's maximum lateral expansion [as modeled]." 73 Fed. Reg. at 43505. The model should corroborate the other data concerning the confining zone. A characterization of the confining zone must be considered to confirm that the injected fluid will not move beyond the confining zone and will remain in the injection zone long term, thus ensuring non-endangerment of USDWs.

<u>Element #8</u>: the presence of potential conduits for fluid movement including planned injection wells and project monitoring wells associated with the proposed geologic sequestration project or any other projects in proximity to the predicted/modeled, final extent of the carbon dioxide plume and area of elevated pressure, as required by 40 C.F.R. § 146.93(c)(1)(viii). EPA evaluates the presence of potential conduits to determine whether there are any pathways that could allow the CO_2 plume to migrate in an unintended way and endanger USDWs. Conduits for fluid movement typically occur in three scenarios. First, faults in the rock formations can create potential conduits for fluid movement. 73 Fed. Reg. at 43505. Second, wells that penetrate the confining zone can create conduits for fluid movement. 73 Fed. Reg. at 43515. The first two of these scenarios are addressed in Element #7 above and Element #9 below.

Under the third scenario, injection and monitoring wells associated with the project are intended to allow fluid movement into the well from the injection zone by design in order to collect and analyze samples that are representative of the fluid in the formation. 73 Fed. Reg. at 43503. Fluid movement is necessary during the operating life of the wells (i.e., the wells acting as conduits for the intentional act of injecting CO_2 and additional project monitoring wells to oversee such injection). See EPA, UIC Program Class VI Well Plugging, Post-Injection Site Care, Site Closure Guidance, at xi (2016) ("Class VI PISC Guidance") (definition of well plugging). So, while there is a potential conduit for fluid movement in the third scenario, the intentional fluid movement during the operating life of the wells is not a risk to USDWs. Unintended fluid movement during operation is mitigated by the proper construction and operating parameters in concert with the approved Testing and Monitoring Plan, especially mechanical integrity testing. See 40 C.F.R. §§ 146.86; 146.88. Unintended fluid movement could also occur through the wells when operation ceases. To address the concern of unintended fluid movement post-injection, wells are plugged, meaning that the conduits are closed. See Class VI PISC Guidance at ii ("After injection ceases at a Class VI [geologic sequestration] GS project, the injection well must be plugged to ensure that the well does not become a conduit for fluid movement into USDWs."). The permit applicant is required to submit a Plugging and Abandonment Plan to address these potential conduits.

Potential conduits for fluid movement are relevant to determining the PISC timeframe because conduits could impact the migration of the CO_2 plume and an accurate understanding of the migration of the CO_2 plume is important in determining an appropriate PISC timeframe. In addition, fluid conduits must be considered to confirm that the injected fluid will not move in unintended ways and will remain in the injection zone long term, thus ensuring non-endangerment of USDWs.

<u>Element #9</u>: A description of the well construction and an assessment of the quality of plugs of all abandoned wells within the AoR, as required by 40 C.F.R. § 146.93(c)(1)(ix). See also 40 C.F.R. § 146.86 (Class VI well construction requirements). Unplugged or improperly plugged wells can act as fluid conduits that might endanger USDWs. See Class VI PISC Guidance at 1. Under 40 C.F.R. § 146.82(a)(4), a permit application must include "[a] tabulation of all wells within the area of review which penetrate the injection or confining zone. Such data must include a description of each well's type, construction, date drilled, location, depth, record of plugging and/or completion, and any additional information the Director may require." In addition, 40 C.F.R. § 146.84(c)(2) requires permit applicants to "identify all penetrations, including active and abandoned wells and underground mines, in the area of review that may penetrate the confining zone(s). Provide a description of each well's type, construction, date drilled, location, depth, record of plugging and/or completion, and any additional information the Director may require." An assessment of abandoned wells within the AoR is relevant to determining the PISC timeframe because the movement of the CO_2 plume may be affected by the presence of penetrations (such as improperly plugged wells) that could serve as potential conduits for fluid movement and an accurate understanding of the migration of the CO_2 plume is important in determining an appropriate PISC timeframe. In addition, the condition of abandoned wells must

be considered to confirm that the injected fluid will not move in unintended ways and will remain in the injection zone long term, thus ensuring non-endangerment of USDWs.

Element #10: the distance between the injection zone and the nearest USDWs above and/or below the injection zone, as required by 40 C.F.R. § 146.93(c)(1)(x). Among other things, an understanding of the distance from the injection zone to the nearest USDW is necessary to evaluate how pressure will behave from the top of the injection zone to the bottom of the confining zone.

The regulations contain an eleventh element that allows the Director to require "additional site-specific factors." 40 C.F.R. § 146.93(c)(1)(xi).

Summary of the Criteria in the Regulations

As explained in the Legal Requirements Section, the information submitted as part of an alternative PISC timeframe demonstration to meet the above elements must meet seven criteria. The regulations provide discretion for EPA to establish additional criteria. 40 C.F.R. § 146.93(c)(2). These criteria help ensure the presentation of well-supported and documented data and analysis underlying the ten elements and thus that EPA can rely upon the information provided for the ten elements. These criteria are:

1. Tests and analyses are accurate, reproducible, and meet established quality assurance standards
2. Use of appropriate estimation techniques or EPA-certified test protocols
3. Predictive models are tailored to site conditions, composition of the carbon dioxide stream, and injection and site conditions over the life of the geologic sequestration project
4. Calibration of predictive models using existing information where sufficient data are available
5. Use reasonably conservative values and modeling assumptions and disclosed to the Director whenever values are estimated on the basis of known, historical information instead of site-specific measurements
6. An analysis must be performed to identify and assess aspects of the alternative post-injection site care timeframe demonstration that contribute significantly to uncertainty. The owner or operator must conduct sensitivity analyses to determine the effect that significant uncertainty may contribute to the modeling demonstration
7. Must have an approved quality assurance and quality control plan that addresses all aspects of the demonstration
8. Any additional criteria EPA requires

Factual Background

In Marquis' initial Class VI permit application submitted to EPA in May of 2022, Marquis proposed an injection period of five years and an alternative PISC timeframe of five years. The primary basis for this proposal was Marquis' first computational model which indicated that the injection zone pressure would decline to near pre-injection levels in fewer than five years after injection ceases (9.0 Post-Injection Site Care Plan at Figure 9-1 (April 2022) A.R. #4). Marquis submitted a revised PISC Plan in June 2022; however, the proposed injection and PISC timeframes were unchanged.

In August 2023, Marquis submitted a second revised PISC Plan wherein they proposed an injection period of six years and a PISC timeframe of 10 years (9.5 Alternative Post Injection Site Care Timeframe Revised (July 2023) A.R. #507). Marquis updated its modeling and provided an updated figure which showed the injection zone pressure returning to near pre-injection levels in fewer than 10 years following the cessation of injection (A.R. #507 at Figure 9-1 Revised).

As part of EPA's technical review and after considering Marquis' PISC submission, EPA issued a Request for Additional Information (RAI) to Marquis on July 22, 2024, regarding questions about the proposed PISC timeframe, among other items.[6] Specifically, EPA had residual questions about the proposed 10-year alternative timeframe due to noticeable plume growth following the end of the proposed 10-year PISC period as shown in Figure 9-3 Revised in the second revision of the PISC Plan. (Section 9.0 Post-Injection Site Care and Site Closure Plan REV 2 at Figure 9-3 Revised (July 2023) A.R. #506). In the RAI, EPA asked Marquis to explain why the plume continued to expand despite the decline of the pressure differential (RAI.PlansTechRev at Question 2.a (July 2024) A.R. #673).

In its August 22, 2024 response to EPA's RAI, Marquis clarified that that plume expansion was calculated by overlaying polygons of the CO_2 at different time intervals (20240822_Marquis Response RAI5 at Response 2.a (August 2024) A.R. # 1156). Figure 2-32: Hydrogeologic velocity of the carbon dioxide plume following injection (below) describes the plume expansion plateau at 12 years post-injection, i.e., trends at a rate of 0.01 mi^2 per year. (Section 2.0 AoR and Corrective Action Plan at Figure 2-32 (August 2024) A.R. #964). Next the buoyancy process will cause the injected CO_2 to move into available spaces in the injection zone causing pooling at the injection-confining zone boundary in a mushroom pattern (A.R. # 1156 at Response 2.a). This

[6] As EPA's Class VI website explains, "[t]h[e] [technical review] involves a thorough review of all application materials and an ongoing dialogue with the applicant to understand the proposed project and ensure that it will be constructed and operated in a manner that will not endanger USDWs. This is accomplished through an ongoing dialogue between the applicant and the permitting authority." See Class VI - Wells used for Geologic Sequestration of Carbon Dioxide, U.S. EPA, https://www.epa.gov/uic/class-vi-wells-used-geologic-sequestration-carbon-dioxide#ClassVI_PermittingProcess.

structural redistribution of CO_2 has been modeled to result in a more normalized vertical plume with minimal horizontal expansion (A.R. #1156 at Figures 9-3(b) and 9-3(c)).

On August 21, 2024, Marquis submitted a third revised alternative PISC timeframe demonstration that increased the proposed PISC timeframe to 12 years. Modeling demonstrated that the injection zone pressure returns to a less than 1% difference than pre-injection levels within 12 years post-injection (9.0 Post-Injection Site Closure Plan (August 2024) A.R. #908). Also, as stated above, the model showed that the expansion of the plume will plateau by this time. Given the model design and based upon Marquis' responses and resubmissions, EPA agreed that its questions were addressed. As such, EPA independently evaluated the applicant's revised demonstration for an alternative PISC timeframe of 12 years in accordance with the 40 C.F.R. § 146.93(c) and other UIC implementing regulations, as applicable.

<u>Analysis of Marquis' Alternative PISC Timeframe Demonstration</u>

This Analysis is organized into four parts. In Part I, EPA identifies and evaluates the information and data that Marquis considered and documented in its alternative PISC timeframe demonstration for the ten required regulatory elements. Part II provides EPA's conclusion that Marquis' demonstration is based on significant site-specific data and information, including data and information collected in the permit application and the siting criteria. Part III includes EPA's finding that the information submitted in Marquis' demonstration meets the quality-control regulatory criteria. Part IV is EPA's ultimate determination that Marquis' demonstration includes substantial evidence to support a conclusion that the project will no longer pose a risk of endangerment to USDWs at the end of the proposed 12-year timeframe.

<u>Part I: Ten Elements</u>

EPA has determined that Marquis' alternative PISC timeframe demonstration considered and documented ten elements. 40 C.F.R. § 146.93(c)(1). Overall, those elements must demonstrate that the alternative timeframe of 12 years ensures non-endangerment of USDWs, i.e., that the project will no longer pose a risk of endangerment to USDWs at the end of 12 years post-injection. Below is a discussion of the information that Marquis considered, documented, and submitted to EPA and in turn, that EPA reviewed regarding each element.

Element #1: the results of the computational modeling performed for the Area of Review (AoR) as required by 40 C.F.R. § 146.93(c)(1)(i).

As stated above, the results of the computational model demonstrated that the injection zone pressure will return to a less than 1% difference from pre-injection levels within 12 years post-injection. The model used for the Marquis project was a static earth model (SEM) based on

Schlumberger Petrel® modeling software. The SEM is a three-dimensional geocellular model that represents petrophysical properties within the stratigraphic formation intended for CO_2 storage, as well as the overlying confining layer. The model incorporated site-specific data for the injection and confining zones from MCI MW 1. Gathering geologic information at the project site allowed the model to account for local heterogeneity, proposed operating conditions, and potential migration pathways. See 40 C.F.R. § 146.84(c)(1). There are no local natural or artificial migration pathways in the AoR, as explained in Elements #8 and 9. The results of the computational model are shown in Figures 9-3. Section 2 of the permit application explains that the critical pressure threshold for the model was about 10 PSI and explains the method used to derive this threshold. (A.R. #964).

Sensitivity analyses were performed using varying porosity and permeability values to test how differing porosity-permeability relationships would impact on model results. In addition to the base case, high-high, high-low, low-high and low-low cases were run. Other sensitivity analyses included temperature, flowrate, and vertical permeability. The parameters and results of these tests are summarized in Table 2-11. Among all cases, the size and shape of the plume extent is similar to the base case.

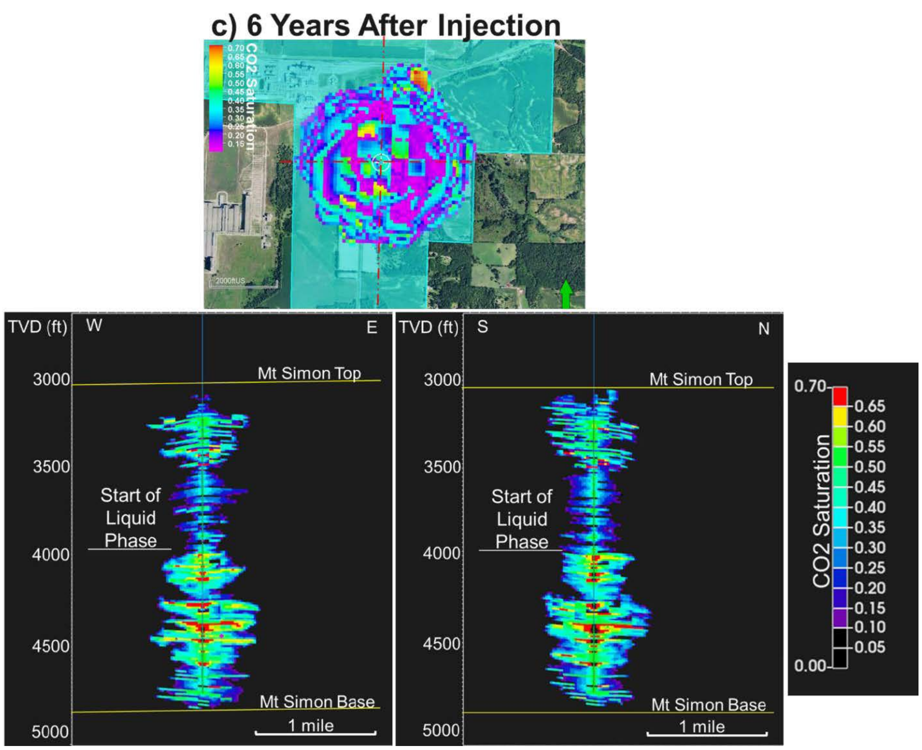


Figure 9-3: Cross-sections of the carbon dioxide plume extent at the end of the 6-year injection period (9.0 Post-Injection Site Closure Plan (February 2025), A.R. #1535).

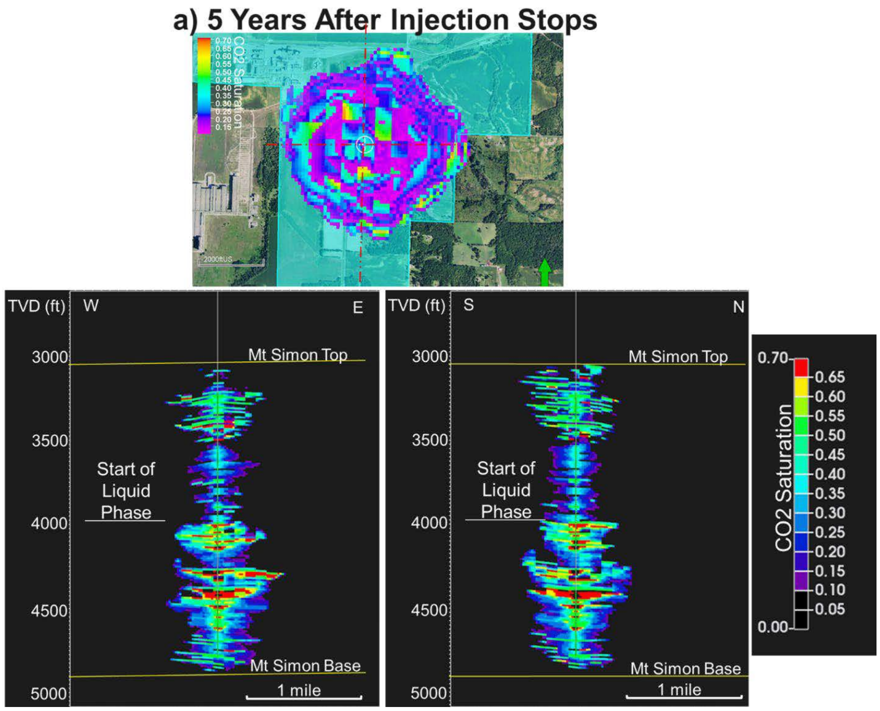


Figure 9-3(a): Cross-sections of the carbon dioxide plume extent 5 years post injection #1535).

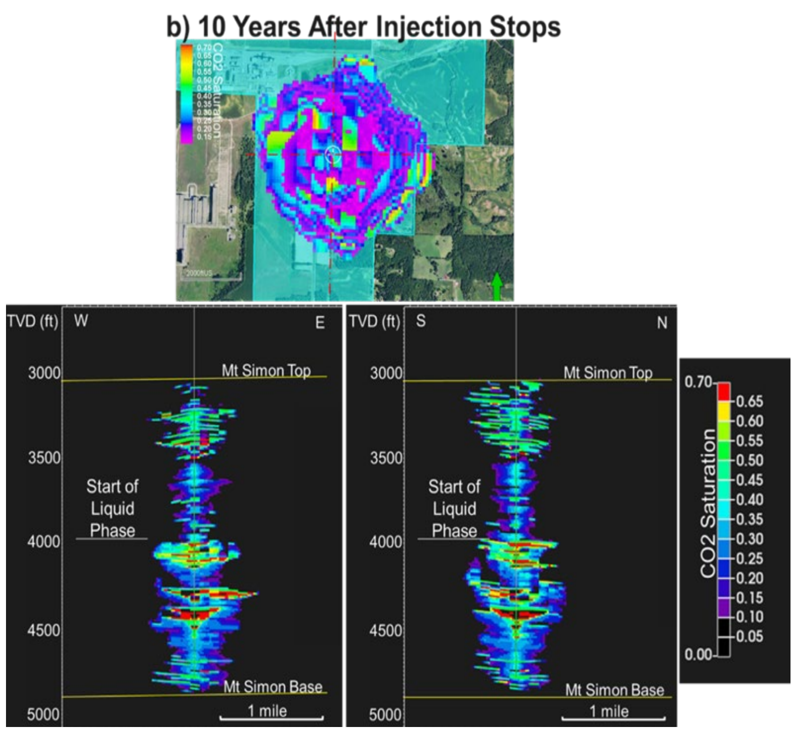


Figure 9-3(b): Cross-sections of the carbon dioxide plume extent 10 years post injection (A.R. #1535).

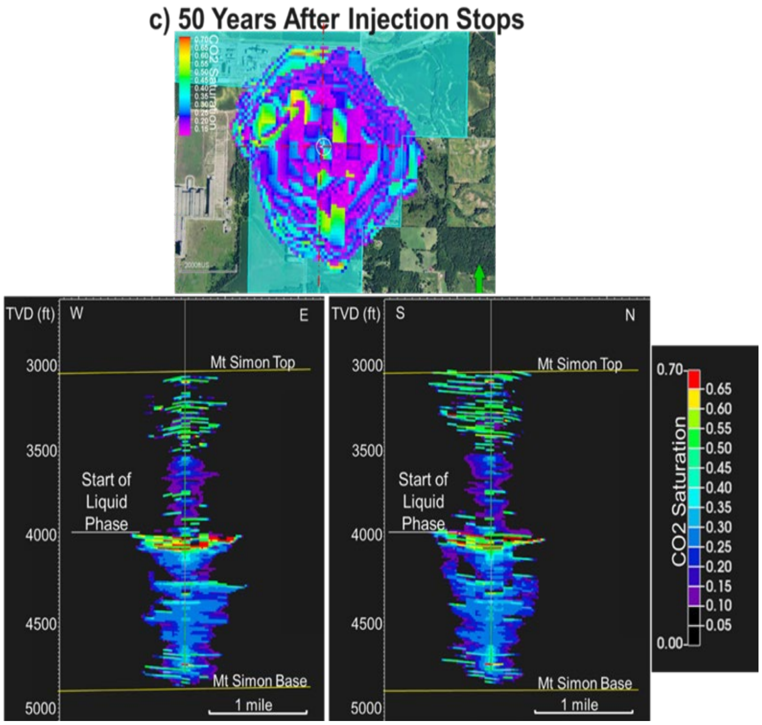


Figure 9-3(c): Cross-sections of the carbon dioxide plume extent 50 years post injection (A.R. #1535).

Case #	Case Name	Altered Parameter	Value of Altered Parameter
BASE	Plume Model	NA	Wellhead Temperature: 105°F Wellhead Pressure: 1,370 psi Porosity: 7.9% Permeability: 79.9 mD Vertical Perm: 1%-20% (Dependent on flow facies) Rate: 1.5 tonnes/year
1	High Porosity High Permeability "High High case"	Porosity/Permeability Transform	Average Porosity: 8.7%, Average Horizontal Permeability: 169.2 mD
2	High Porosity Low Permeability "High Low case"		Average Porosity: 8.7%, Average Horizontal Permeability: 31.5 mD
3	Low Porosity High Permeability "Low High case"		Average Porosity: 6.9%, Average Horizontal Permeability: 111.1 mD
4	Low Porosity Low Permeability "Low Low case"		Average Porosity: 6.9%, Average Horizontal Permeability: 19.8 mD
5	High Vertical Permeability	Vertical to Horizontal Permeability Ratio	0.7%-50% based on flow facies type
6	Low Vertical Permeability		0.1%-0.4% based on flow facies type
7	93.2 °F Wellhead Temperature	Wellhead Temperature	93.2 °F
8	115 °F Wellhead Temperature		115 °F
9	Reduced Rate to 600,000 tonnes/year	CO_2 Injection Rate	600,000 tonnes/year

Table 2-11: The parameters used in the ten cases (including the base case) of the sensitivity analysis (A.R. #964).

Case	Time to Plume Sensitivity Boundary (yr)	Average Yearly Mass Rate (MMt/year)	Cumulative CO2 (MMt)
Plume Model	6	1.5	9
High Porosity Low Permeability	10	1.2	11.9
High Porosity High Permeability	5	1.5	7.5
Low Porosity High Permeability	3	1.5	4.5
Low Porosity Low Permeability	4	0.9	3.5
High Side Vertical Permeability	6	1.5	9
Low Side Vertical Permeability	4	1.4	5.6
93.2 °F Wellhead Temperature	6	1.5	9
115 °F Wellhead Temperature	12	0.3	3.75
Reduced Rate to 600,000 tonnes/year	12	0.6	7.2

Table 2-20: Summary of Sensitivity Cases Results (A.R. #964)

The model showed that the expansion of the plume will plateau by the end of the alternative-PISC timeframe. Furthermore, the AoR was delineated using the pressure front, as the pressure front is larger than the plume extent under all scenarios. EPA has verified that the computational modeling performed demonstrates that the injectate will stabilize and injection zone pressures will decrease soon after injection ends. The model included trapping rates that supported the plume migration results (Section 9.0 PISC and Site Closure Plan (August 2024) A.R. #1542). EPA agrees with the model's inputs, outputs, variables, and assumptions.

Element #2: the predicted timeframe for pressure decline within the injection zone and any other zones, such that formation fluids may not be forced into any USDWs; and/or the timeframe for pressure decline to pre-injection pressures as required by 40 C.F.R. § 146.93(c)(1)(ii).

Marquis conducted critical pressure (the pressure required to cause fluid movement) calculations using EPA methodology to determine the extent and impact that the pressure front has on AoR determination.

Although the pressure front is largest at the end of injection, the pressure increase within the injection zone will peak immediately after injection begins before declining slightly. However, the injection zone pressure will remain largely stagnant – as well as staying below 90% of the formation fracture pressure – during operation. Based on the model, the areal extent of the pressure front and the pressure differential in the injection zone shrink rapidly after the 6-year injection period. 12 years after injection ceases, modeling predicts the pressure in the injection zone will decrease to pre-injection levels. That is, the pressure differential is expected to be less than 1% (9.0 Post-Injection Site Closure Plan (February 2025) A.R. #1535 at Figures 9-1(a) and 9-1(b)). Since there is naturally existing pressure within the injection zone, a pressure differential less than 1% is not directly attributable to the injection pressure front.

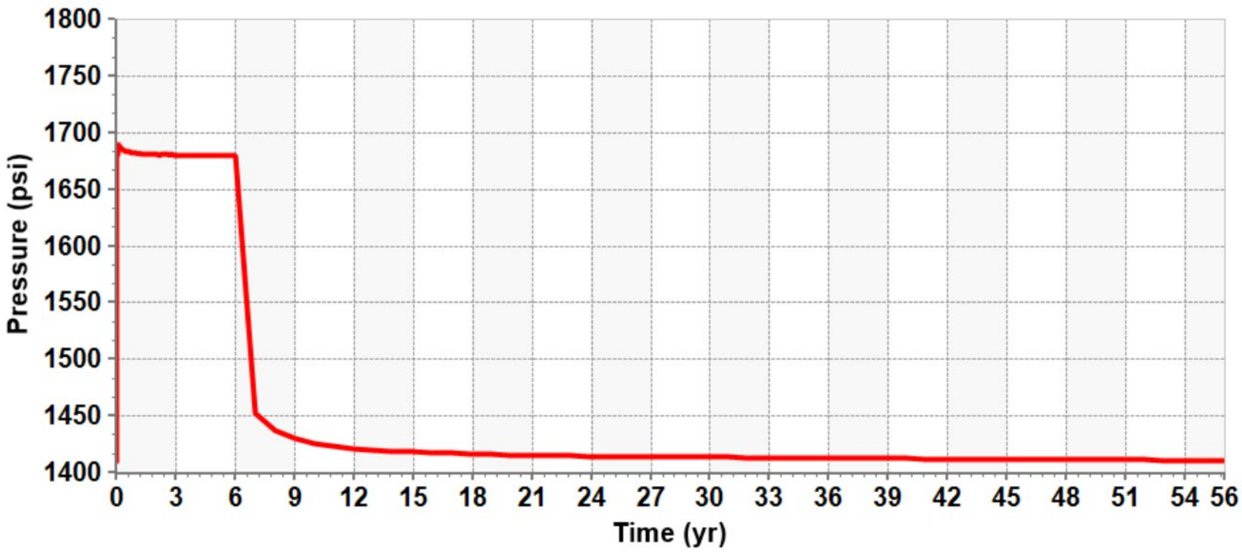


Figure 9-1(a): Pressure at Well Block/Cell Including Initial Time Step for the 6-year injection phase and a post injection period of 50 years (A.R. #1535).

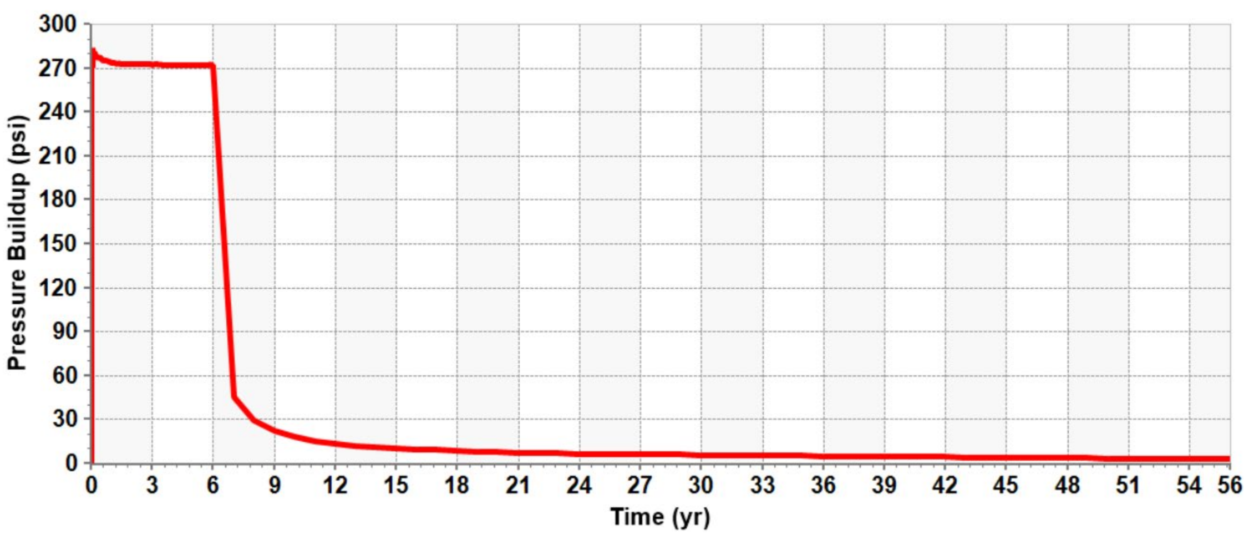


Figure 9-1(b): Pressure Buildup at Injection Well Block/Cell Including Initial Time Step for the 6-year injection phase and a post injection period of 50 years (A.R. #1535).

Marquis also provided figures showing the modeled evolution and maximum extent of the pressure front, accounting for trapping over the life of the project. Specifically, at years 4 and 6 of injection, and years 1, 5, and 10 after injection ends (A.R. #1535 at Figures 9-4 and 9-5). As seen in Figure 9-5, the pressure front will almost entirely disappear 10 years after injection stops. The Alt-PISC Timeframe for Marquis is 12 years, meaning the pressure front at the time of site closure will be even smaller than as shown in the figure. Figures 2-101, 2-101(b), 2-101(c), 2-103 and 2-104 also demonstrate the same information. (A.R. #964).

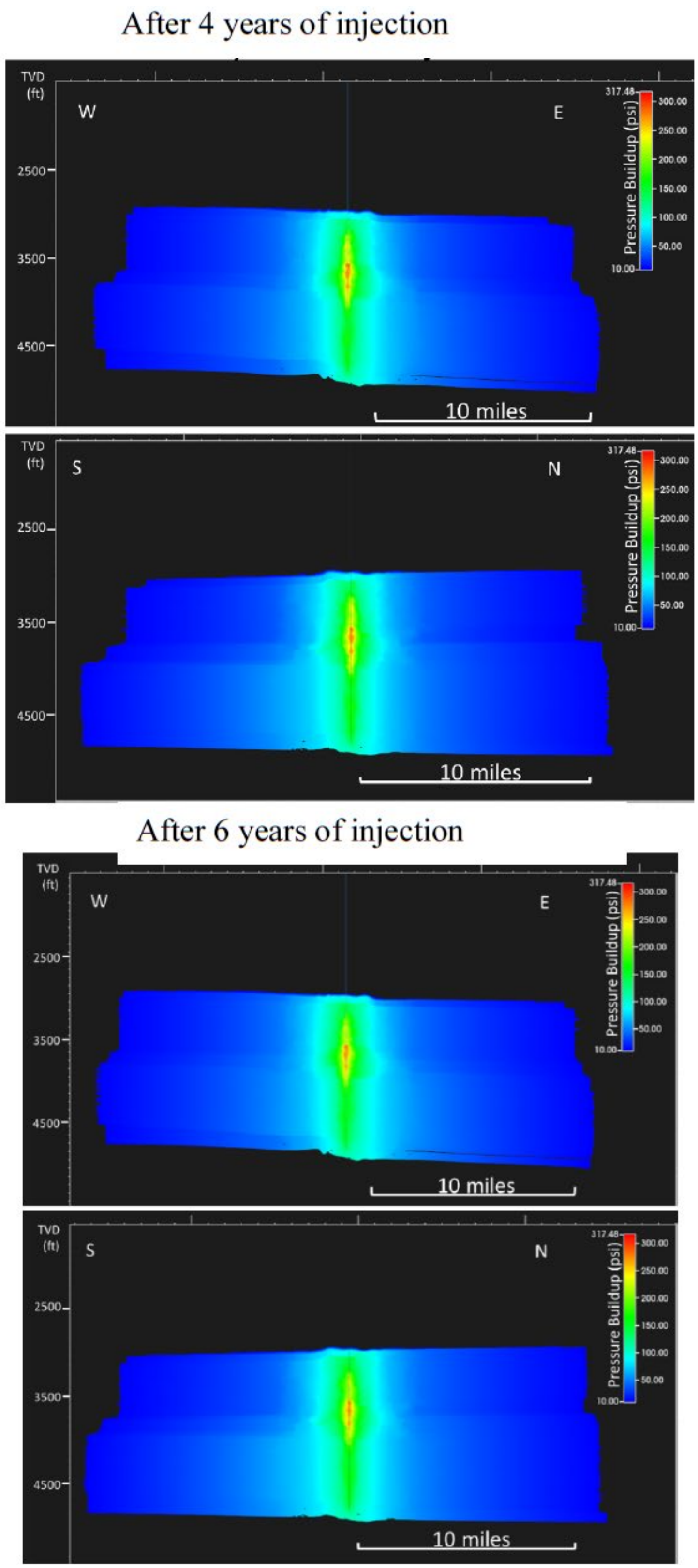


Figure 9-4: Predicted pressure plume development at years 4, 6 of injection (A.R. #1535).

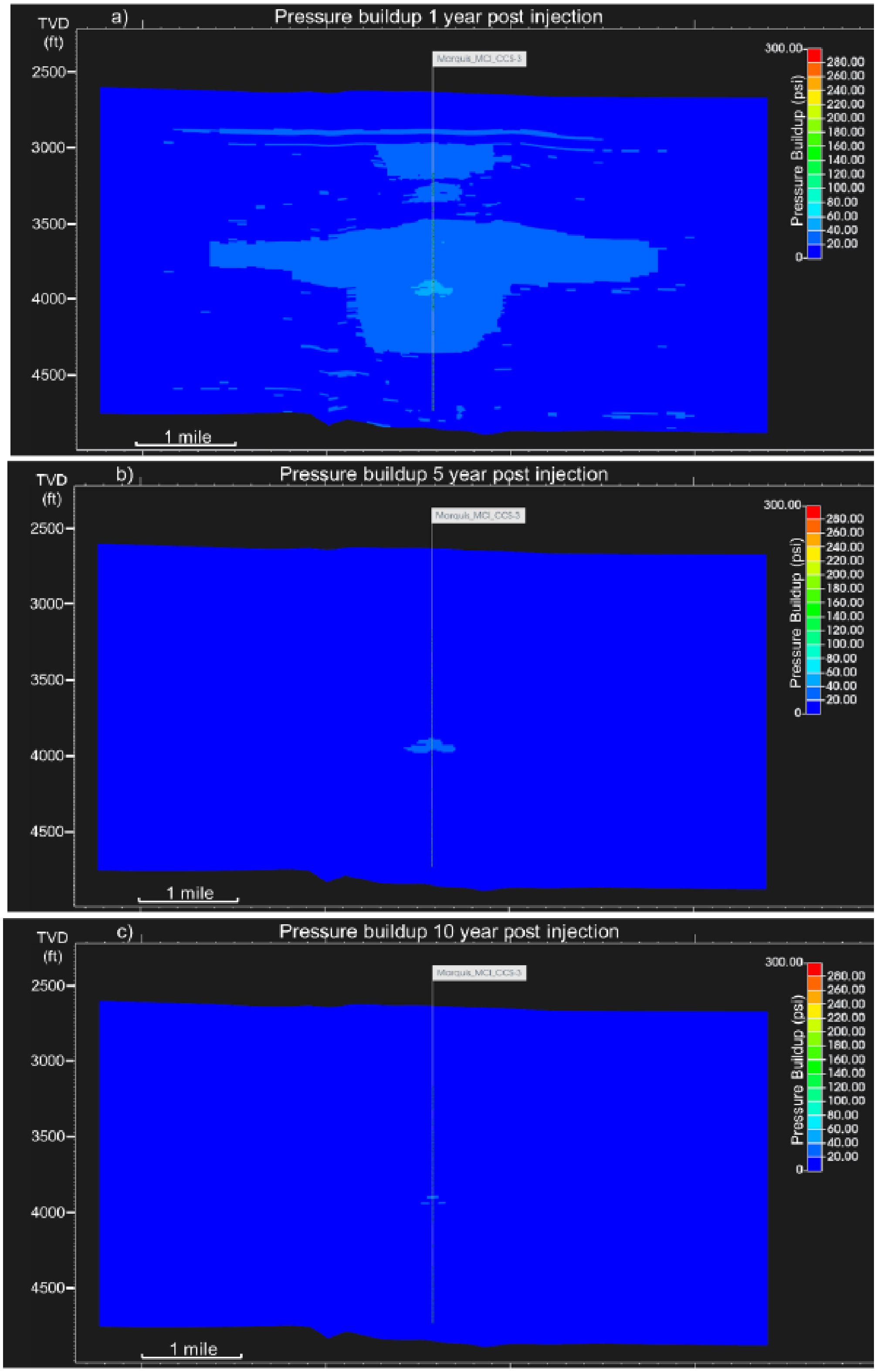
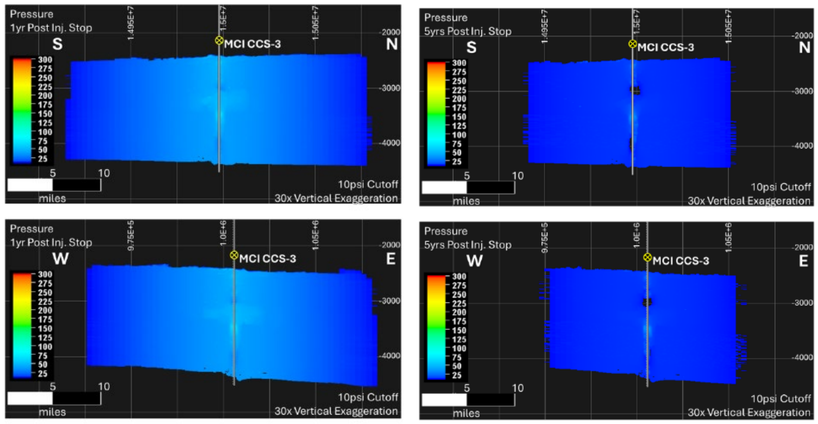


Figure 9-5: Predicted pressure plume development /dissipation at years 1, 5, and 10 post injection (A.R. #1535).



These results for the predicted timeframe for pressure decline are for the base case of the model. Marquis performed a sensitivity analysis in addition to the base case. From this sensitivity analysis, EPA evaluated the effects of different input parameters in the model (cases) on the timeframe for pressure decline. Pressure decline in the injection zone was similar in the sensitivity cases as it was in the base case (A.R. #964).

In addition to demonstrating the pressure decline over time, Marquis conducted critical pressure evaluations. The critical pressure is the pressure value used to delineate the edge of the AoR. The critical pressure that Marquis calculated using EPA's equation is 10.76 psi (Appendix U, A.R. #514). This critical pressure was rounded down to 10 psi in the model, which is slightly more conservative than the original value of 10.76 psi. The fracture pressure was calculated using site-specific data taken from MCI MW 1. Minifrac tests yielded a fracture gradient of 0.76 psi/ft. Using this data, the maximum injection pressure (MIP) was calculated to be 2,206 psi, which is 90% of the Mt. Simon fracture pressure (A.R. #964). Limiting the MIP to 90% of the formation's fracture pressure accounts for uncertainty and further protects USDWs. As seen in Figure 9-1(a), injection zone pressure is expected to be at least several hundred psi below this value for the entire life of the project (A.R. #1535).

After considering 40 C.F.R. § 146.84, EPA agrees with the model's inputs, outputs, variables, and assumptions, and the results of the model are valid using the site-specific data. The pressure decline has been accurately defined. Marquis has demonstrated that formation fluids will not be forced into USDWs due to the elevated pressure.

Therefore, EPA determines that Element #2 has been considered and documented as part of the demonstration for a 12-year alternative PISC timeframe.

Element #3: the predicted rate of CO_2 plume migration within the injection zone as required by 40 C.F.R. § 146.93(c)(1)(iii).

The CO_2 plume as predicted by the model is largely static at 12 years post-injection and beyond (A.R. #1535 at Figures 9-3, 9-3(a), 9-3(b), and 9-3(c)). Specifically, at the end of the proposed PISC timeframe, the rate of plume expansion is minimal: 0.01 mi^2/yr. After injection ends, a decrease in injection zone pressure and increase in CO_2 trapping slow plume expansion (A.R. #964 at Figure 2-32).

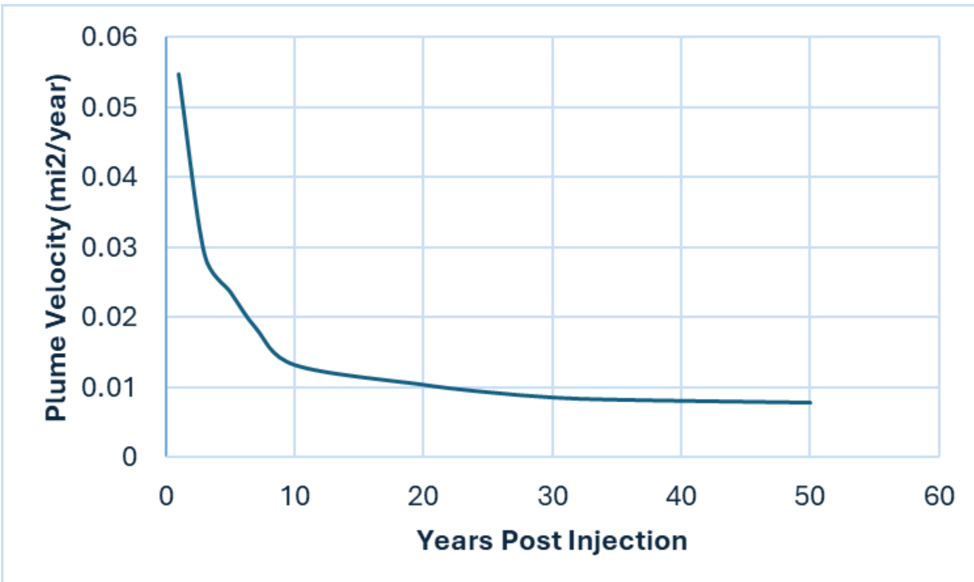


Figure 2-32: Hydrogeologic velocity of the carbon dioxide plume following injection (A.R. #964).

Variation in injection zone porosity and permeability could affect CO_2 migration. However, the sensitivity analyses discussed above account for this uncertainty. Under all sensitivity cases, plume growth declines quickly following the end of injection, and the injectate remains trapped by the confining zone. All the model iterations also demonstrate that the plume extent will be very small compared to the AoR. The large buffer between the edge of the plume and the edge of the AoR provided further justification that the entirety of the plume will be properly monitored. Therefore, based upon EPA's review, the model was correctly run to depict the rate of CO_2 plume migration over time.

EPA has determined that Element #3 has been considered and documented appropriately as part of the demonstration for a 12-year alternative PISC timeframe.

Element #4: a description of the site-specific processes that would result in CO_2 trapping including immobilization by capillary trapping, dissolution, and mineralization at the site as required by 40 C.F.R. § 146.93(c)(1)(iv).

Marquis provided an assessment of the site-specific processes that will result in trapping at this project and provided a description and explanation of these processes. Trapping reduces CO_2 migration and was assessed as a part of the computational modeling. The computational model accounted for trapping using site-specific data and information collected from MCI MW 1. (40 C.F.R. § 146.82(a)(6) requires applicants to baseline geochemical data on the subsurface.) The site-specific processes that will result in trapping are both physical and geochemical, and they are documented in the Alt-PISC timeframe demonstration, AoR, Geology Memo, and this memorandum [A.R. #1535, 964, and 1682].

The physical processes that result in trapping are the properties of the rock formations, such as permeability and pore space, and how they impact the ability of the fluid to flow or migrate through the rock formations. The model shows that these processes will result in two types of trapping—structural or stratigraphic trapping and immobile capillary phase trapping.

The Eau Claire formation is composed of shale, siltstone, sandstone, and minor dolomite in the upper formation. The low permeability and very limited pore space in the confining layer result in structural trapping. That is, the injectate is physically blocked from migrating upward. There is an interval of sandstone at the base of the Eau Claire Formation called the Elmhurst Sandstone Member that is more permeable, but above it is an over 300-foot-thick shale formation that will ensure migration does not occur above the confining zone. In addition, the trapping model accounted for the Elmhurst. Trapping due to the confining zone is discussed further in Element #7.

In contrast, the injection zone formation (the Mt. Simon) for the Marquis project has high permeability because it is comprised primarily of more porous rock such as sandstone. This is not conducive to structural trapping, instead allowing for the intended fluid movement of the injected CO_2. Relatedly, as injected CO_2 flows through one available pore space in the injection zone formation to another open pore space, some residual CO_2 is left behind in the previous pore space. Immobile capillary trapping (also known as residual trapping) refers to the amount of CO_2 that remains behind in a pore space once the CO_2 fills the space and then moves into the next available pore space. The trapping models show that the high permeability and porosity of the Mt. Simon will allow for saturation and result in immobile capillary trapping over time and the migration of the fluid will decrease in the injection zone formation over time, as intended. The saturation of the injectate within the pore spaces will change fluid movement in the injection zone. This is discussed more in Element #5 below because it is part of immobile capillary trapping.

The site-specific geochemical processes that will result in trapping at the Marquis project are the properties of the rock formations in the injection zone that will allow for dissolution. Dissolved trapping will occur through the dissolution of CO_2 into the native formation fluids (brine) in the pore space of Mt. Simon injection zone formation, eventually becoming a part of the rock formation (see the paragraph on mineralization below). Solubility is a function of pressure, temperature, and salinity. The pressure, temperature, and salinity of the Mt. Simon injection zone formation allow for dissolution trapping of CO_2. Dissolution trapping in the injection zone decreases the migration of the fluid over time, as intended.

Mineralization refers to when elements in the injection zone chemically react with the CO_2 to create new minerals (primarily clay). Mineralization occurs over centuries to millennia and is, thus, not relevant to this project. (Note: the regulations require predicted rates of the dissolved phase and/or the mineral phase.) Marquis did not evaluate mineralization and offered that "Mineralization is unlikely to play a significant role as a major trapping mechanism for the project" (A.R. #1535 at p. 29).

EPA has determined that Element #4 has been considered and documented appropriately as part of the demonstration for a 12-year alternative PISC timeframe.

Element #5: the predicted rate of CO_2 trapping in the immobile capillary phase, dissolved phase, and/or mineral phase as required by 40 C.F.R. § 146.93(c)(1)(v).

Marquis' alternative PISC timeframe demonstration included predicted rates of CO_2 trapping in the immobile capillary phase and dissolved phase. Per EPA's review, Figure 9-9 demonstrates carbon dioxide will be trapped, and migration of carbon dioxide will slow over time at various rates dependent on the type of trapping processes (9.0 Post-Injection Site Closure Plan, A.R. #1542 at Figure 9-9 and A.R. #964 at Figure 2-40). The full site-specific model (with geologic heterogeneities included) was run by incorporating solubility and residual trapping modules during injection and post-injection conditions to predict/estimate (1) the total CO_2 in the system, (2) CO_2 dissolved in brine (i.e. dissolved phase), (3) CO_2 residually trapped in brine during injection (i.e. immobile capillary phase), and (4) structurally trapped CO_2 as a percentage of total CO_2 moles. This is illustrated in Figure 9-9 below, which was pulled from A.R. #1535. Marquis modeled trapping for 56 years, 6 years of injection and 50 years post-injection to facilitate comparison between a standard and an alternative PISC timeframe. (Note: In Figures 9-9 and 2-40, large amounts of injected CO_2 are labeled as "free." This means that the CO_2 is not geochemically trapped. However, it is still physically trapped by the confining zone.) Specifically, by year 12 post-injection 9×10^{10} moles of CO_2 will be immobilized (5×10^{10} due to immobile capillary trapping and 4×10^{10} due to dissolved trapping).[7] The injected CO_2 that is not subject to immobile capillary and dissolved trapping will remain confined to the injection zone due to structural trapping. The model shows that with the given trapping rates, the CO_2 plume migration will stabilize by year 12 post-injection (see Element #3 above), which EPA verified as acceptable through model computations.

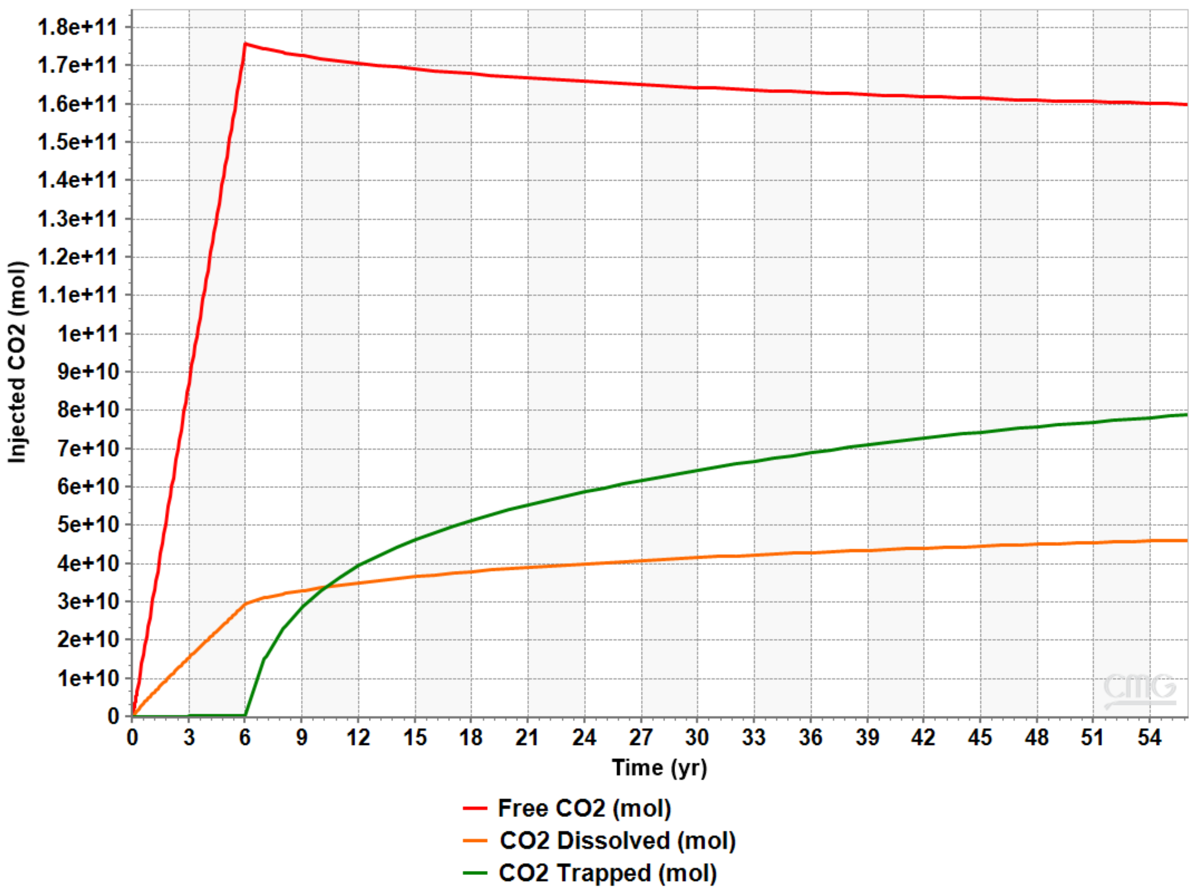


Figure 9-9: CO_2 dissolved in brine, CO_2 residually trapped in brine during injection, and free CO_2 as a percentage of total CO_2 moles injected during the injection and post-injection periods (A.R. #1535).

[7] The rate of trapping is expressed in moles of CO_2 per year (mol/yr). One mole of CO_2 is 6×10^{23} molecules.

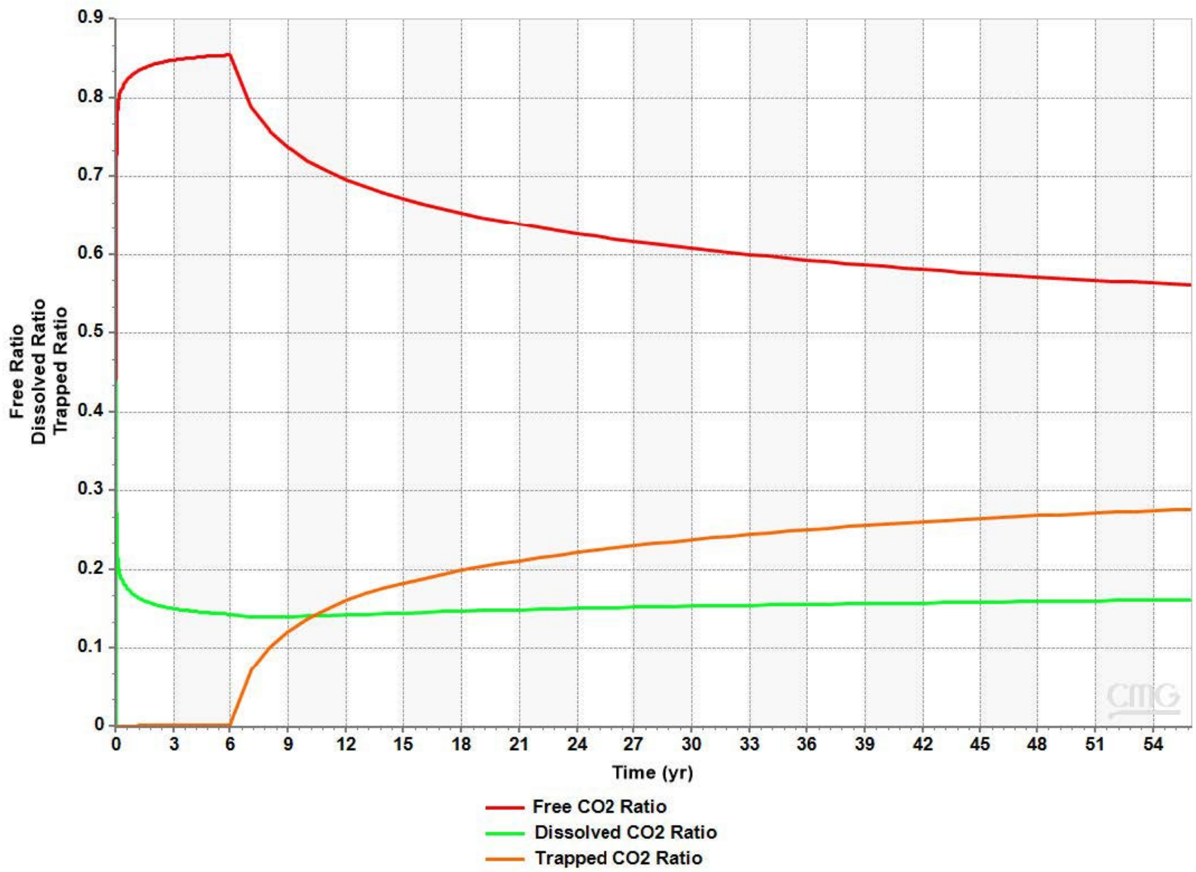


Figure 2-40: Ratios of free, dissolved, and trapped CO_2 to total CO_2 injected during and post injection (A.R. #964 at Figure 2-40).

These predicted rates of trapping at year 12 post-injection show sufficient decline in the migration of the CO2 plume that when considered alongside the decline in the pressure front demonstrate non-endangerment of USDWs.

Marquis' alternative PISC timeframe demonstration included site-specific data for the confining and injection formations of the project when determining the potential for structural or stratigraphic trapping at the project. Structural trapping is a primary trapping process that occurs during injection and storage due to the site-specific physical properties of the formations. Those properties for the Eau Claire Formation are the fact that it consists primarily of shale and acts as a confining layer. The physical properties of the Mt. Simon, which is primarily sandstone, provide ample pore space for storage.

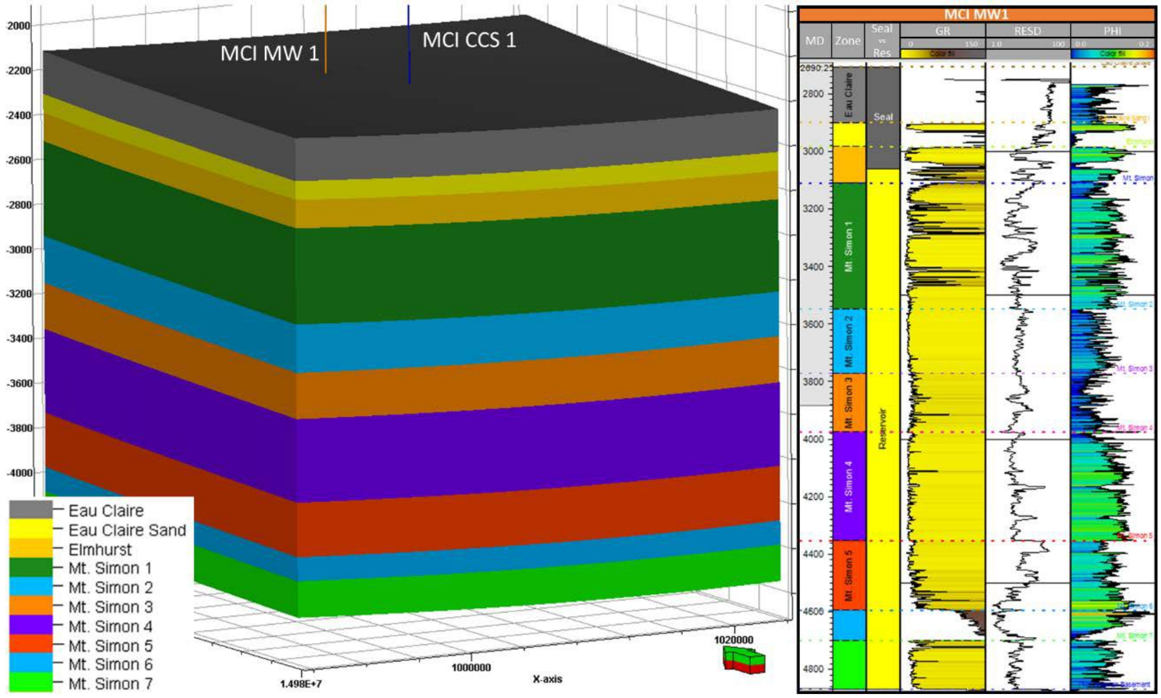


Figure 2-16: Model Zones and corresponding gamma ray, resistivity, and porosity logs. The Mt. Simon layers are considered reservoir, while the upper Elmhurst and Eau Claire shale act as the seal (A.R. #964).

The Mt. Simon is heterogeneous, meaning it is largely composed of sandstone, but does contain other rock types. As demonstrated via the site-specific data, there will be some less porous space in the Mt. Simon that will cause CO_2 to not be trapped at the same rate as in sandstone. However, the model shows the percentage of CO_2 that is not physically trapped by the sandstone will continue to reduce over time. See A.R. #1542 at Figure 9.3.

Next the computational model shows that the physical trapping process will continue via the Immobile Capillary (also known as Residual Trapping) phase wherein porosity is the main site-specific property that will result in trapping. The model shows that fluid will travel in the pore space of the Mt. Simon, with the CO_2 moving – via buoyancy or other forces – from saturated pores to less saturated pores. As this happens, some residual CO_2 remains in the previous pore space. This is the immobile capillary trapping process. The predicted rate of the immobile capillary trapping phase is relative to saturation and permeability. As saturation varies over time and space, the rate of immobile capillary trapping will also vary. A Land Model was used to predict the amount of CO_2 trapped this way.[8] In the model, the maximum residual gas saturation was 0.3. That is, the maximum residually trapped saturation will be 30% of pore volume. Typical values for maximum residual gas saturation are 0.3 to 0.4.[9,10] Due to the

[8] Land, C.S., 1968. Calculation of imbibition relative permeability for two-and three-phase flow from rock properties. *Society of Petroleum Engineers Journal*, *8*(02), pp.149-156.

[9] Computer Modelling Group, 2022, GEM Compositional & Unconventional Simulator User Guide. Calgary, Alberta.

[10] Burnside, N.M. and Naylor, M., 2014. Review and implications of relative permeability of CO2/brine systems and residual trapping of CO2. *International Journal of greenhouse gas control*, *23*, pp.1-11.

thickness and permeability variations of the Mt. Simon Sandstone, significant amounts of CO_2 can be residually trapped. Residual CO_2 trapping increases during the post-injection time period. Per Figure 2-40, 20% of the injected CO_2 will be residually trapped at year 18 (6-years of injection and 12-years post injection). (A.R. #964).

The geochemical trapping process introduces the dissolved phase (also known as dissolution or solubility trapping), which is demonstrated by the Marquis' use of Henry's solubility model. This model uses a constant determined by pressure, temperature, and salinity as published by Harvey (1996).[11] The model calculates the fugacity/partition coefficients for soluble CO_2 in aqueous phase using Li & Ngheim (1986) method.[12] Per Figure 2-40, 15% of the injected CO_2 will be trapped via dissolution at the end of the alt-PISC timeframe (year 18). (A.R. #964).

The site-specific trapping model predicts that the CO_2 will move and interact within the intended injection zone in a manner that will prevent endangerment to USDWs. Based upon EPA evaluation of Element #5, all of the modeled and simulated trapping mechanisms (capillary or formation trapping, dissolved trapping, and mineral trapping) will occur within the AoR at suitable rates to permanently store the injected CO_2. The predicted rates of trapping at year 12 post-injection show sufficient decline in the migration of the CO_2 plume to, when considered alongside the decline in the pressure front, demonstrate non-endangerment of USDWs.

EPA has determined that Element #5 has been considered and documented appropriately as part of the demonstration for a 12-year alternative PISC timeframe.

Element #6: the research used to verify the information required in 40 C.F.R. § 146.93(c)(1)(iv) and (v) (elements #4 and #5 above).

The equations and models used to verify the trapping information come from reputable scientific literature and are industry standards that have been validated over time. Marquis summarized many of these sources in its demonstration (A.R. #1535), reproduced below:

- Duan and Sun (2003) developed a thermodynamic model for the solubility of CO_2 in pure water and aqueous solutions.[13]

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[11] Harvey, A.H., 1996. Semiempirical correlation for Henry's constants over large temperature ranges. *AIChE journal*, *42*(5), pp.1491-1494.

[12] Li YK, Nghiem LX. Phase equilibria of oil, gas and water/brine mixtures from a cubic equation of state and Henry's law. The Canadian Journal of Chemical Engineering 64(3):486-96(1986).

[13] Duan, Z. and Sun, R., 2003. An improved model calculating CO2 solubility in pure water and aqueous NaCl solutions from 273 to 533 K and from 0 to 2000 bar. *Chemical geology*, *193*(3-4), pp.257-271.

- Razipechikolaee et al., 2013 shows the CMG solubility model using Henry's law is in good agreement with the Duan and Sun model under different pressure and temperature conditions.[14]
- The amount of CO_2 residually trapped in the aquifer due to relative permeability hysteresis is determined by the Land Model. Linear Land's equation is used in the simulator for modeling hysteresis in relative permeability (CMG-GEM,2022, Land, 1968).[9] The input parameters that control the amount of trapped gas are the relative permeability curves to estimate Land model's parameters depending on CO_2 saturation at each time step and maximum residual gas saturation (relative permeability curve provided in Section 2.1.4 (Constitutive Relationships and Other Rock Properties) of Area of Review and Corrective Action Plan (A.R. #964).
- As mentioned, one of the parameters that controls the amount of trapped gas by relative permeability hysteresis is the maximum residual gas saturation, which is a function of the formation pore structure (Raziperchikolaee et al., 2013).[13]

EPA found Element #6 to be satisfied in that the research studies used to verify Marquis' trapping information and relied upon in Marquis' trapping evaluation are all valid, scientific studies that supported Marquis' conclusions. Additionally, data will be collected from the injection and monitoring wells before, during, and after operations to verify the computational models (A.R. #1535).

Element #7: a characterization of the confining zone, including a demonstration that it is free of transmissive faults, fractures, and micro-factures and of appropriate thickness, permeability and integrity to impede fluid movement as required by 40 C.F.R. § 146.93(c)(1)(vii).

Marquis gathered site-specific data on all geologic formations from the surface to the injection zone from MCI MW 1. The primary confining zone is the 400-foot-thick Eau Claire formation. It is composed of shale, siltstone, sandstone, and minor dolomite in the upper formation. Unlike the porous and permeable injection zone, the Eau Claire is significantly less permeable and, therefore, prevents the movement of CO_2 through it. There is an interval of sandstone at the base called the Elmhurst Sandstone Member that is more permeable, but above that interval is an over 300-foot-thick shale upper formation that will ensure migration does not occur above the confining zone. The sample cores provided and reviewed confirm that the Eau Claire consists of shale and indicate that it is a sufficient seal. (A.R. #964 at p. 16). Data taken from the injection well, MCI CCS 3, will be used to confirm and supplement the models before and during operation (A.R. #1535 at p. 30 and 5.0 Pre-operational Testing Plan, A.R. #1309).

[14] Raziperchikolaee, S., Alvarado, V. and Yin, S., 2013. Effect of hydraulic fracturing on long-term storage of CO2 in stimulated saline aquifers. *Applied energy*, *102*, pp.1091-1104.

Seismic surveys conducted indicated that there is no faulting and fracturing in the confining zone that will obstruct its ability to impede fluid movement. 2D and 3D seismic surveys were completed in 2021 and 2022, respectively, and found a lack of faulting at the site. The results of the seismic surveys were implemented into the static earth model (A.R. #1535).

Values directly measured or calculated from the MCI MW 1 stratigraphic test well were input into the predictive model. Classification of the rock column into different environments of deposition along with distributions of porosity and permeability were used to model porosity and permeability in the Eau Claire Shale and Mount Simon Sandstone (Figure 2-18). Other parameters used in the model based on values from the MCI MW 1 well include compressibility, capillary pressure, formation brine geochemistry, temperature at depth, pore pressure gradient, and fracture gradient (A.R. #964).

Based upon EPA's review of the data presented by Marquis, the confining zone is free of faults, fractures, and micro-fractures, and is of appropriate thickness, permeability, and integrity to impede fluid movement. This characterization of the confining zone formation supports Marquis's proposed 12-year PISC timeframe because it confirms the modeling appropriately incorporated a confining layer that will prevent vertical fluid movement.

EPA agrees that the confining zone is of appropriate thickness, permeability, and integrity. EPA also determines that Element #7 has been considered and documented appropriately as part of the demonstration for a 12-year alternative PISC timeframe.

For more information on the characterization of the confining zone, see EPA's Geology Memorandum, A.R. #1610.

Element #8: the presence of potential conduits for fluid movement including planned injection wells and project monitoring wells associated with the proposed geologic sequestration project or any other projects in proximity to the predicted/modeled, final extent of the carbon dioxide plume and area of elevated pressure as required by 40 C.F.R. § 146.93(c)(1)(viii).

As discussed in Element #7, vertical migration of injectate is restricted due to the absence of geological conduits within the AoR. A tabulation of wells that penetrate the confining zone was submitted as a part of the application (A.R. #964 at Section 2.5.1). There are wells that penetrate the Eau Claire, but all except one only penetrate the top 56 feet of it, so they are not conduits for injection fluid movement (A.R. #964 at Section 2.5.1). The only non-project well that completely penetrates the confining zone is the J&L Well. This well was properly plugged and abandoned in 2013 (Appendix W, A.R. #1490) so it is not a potential conduit for fluid movement either.

Furthermore, the extent of the CO_2 plume is much smaller than the AoR, being only about 1 mile in diameter. Only the injection well and one of the monitoring wells (MCI MW 2) will penetrate the confining zone within the modeled plume extent (A.R. #1535 at Section 9.5.6 and Figure 9-2). Wells constructed as a part of the project will also not serve as conduits other than that which is intentionally designed and controlled as part of operation to allow for injection and monitoring operations. The injection and monitoring wells will be plugged at the end of project. The wells will be tested for mechanical integrity, and temperature and pulsed neutron capture logs will be recorded before their plugging. (A.R. #1535). The EPA confirmed in its review that the plugging plans are appropriate under industry standards and meet the regulatory requirements such that none of the wells will act as conduits for unintended fluid movement. The construction of the wells is discussed in Element #9 below.

After considering the information submitted, EPA agrees with the methodology used to identify conduits of potential fluid movement. Furthermore, based upon the results of the computational modeling at no point does the CO_2 plume nor mobilized fluids reach any known conduits that could pose of a risk of endangerment to USDWs. The potential conduits for fluid movement evaluation supports Marquis' proposed 12-year PISC timeframe.

EPA determines that Element #8 has been considered and documented appropriately as part of the demonstration for a 12-year alternative PISC timeframe.

Element #9: A description of the well construction and an assessment of the quality of plugs of all abandoned wells within the AoR required by 40 C.F.R. § 146.93(c)(1)(ix). See also 40 C.F.R. § 146.86 (Class VI well construction requirements).

The UIC regulations have specific requirements for Class VI well construction. (See 40 C.F.R. § 146.86). EPA reviewed the construction specifications for the injection wells and monitoring wells along with their respective plugging and abandonment plans and finds the requirements are met. (See EPA Construction Memo A.R. # 1681). The regulations require that the injection and monitoring wells will be made with industry standard materials, as well as corrosion-resistant materials where contact with injectate may occur. This ensures that the well will be constructed in a manner sustainable for both the injection period and PISC timeframe, and that mechanical integrity is maintained throughout the life of the project (4.0 Injection Well Construction Plan (February 2025), A.R. #1571). MCI CW 2 will be constructed in a similar manner to the injection well, using materials that are more corrosion resistant than standard steel and will therefore decrease the risk of fluid migration. The plume will not extend to the location of MCI MW 1, and therefore the lower portion of its long-string casing and tubing should not come into contact with injection fluid (Section 7.0 Testing and Monitoring Plan (February 2025), A.R. #1519). See also EPA's Construction memo (A.R. # 1681).

Additionally, the draft permit requires all wells to have mechanical integrity tests conducted to ensure that the wells retain their constructed characteristics. The draft permit also requires that the wells will be properly plugged with cement compatible with Class VI projects following injection (8.0 Injection Well Plugging Plan (January 2025), A.R. #1528). The well construction design authorized by the permit requires that the wells meet the standards of American Petroleum Institute, American Society for Testing and Materials (ASTM) International, or comparable standards acceptable to the Region and must be constructed of corrosion resistant, compatible materials that completely seal the CO_2 within the injection zone. See draft Permit at Section I and Att. H. Based on the construction and plugging information provided and the draft permit conditions, the wells will not allow unintended fluid movement that could pose a risk to a USDW during injection, after injection, or post site closure.

As stated in Element #8 above, Marquis identified all wells within the AoR, including abandoned wells. The J&L Well was properly plugged and abandoned in 2013 (Appendix W, A.R. #1490). The remaining wells in the AoR do not pose a migration risk as they do not fully penetrate the confining zone (A.R. #1535 at Section 9.5.6). The well construction and plugging of the wells within the AoR support Marquis' proposed 12-year PISC timeframe because the CO_2 plume will not be able to travel outside of the injection zone through any of these conduits, confirming that the model assumptions and predictions about conduits are reliable.

EPA determines that Element #9 has been considered and documented appropriately as part of the demonstration for a 12-year alternative PISC timeframe.

Element #10: the distance between the injection zone and the nearest USDWs above and/or below the injection zone as required by 40 C.F.R. § 146.93(c)(1)(x).

Marquis constructed the stratigraphic test well MCI MW 1 to gather geologic data. Marquis has properly identified all geologic formations from the ground surface to below the proposed injection zone. At the project site, the lowermost (nearest above the injection zone) USDW is the Gunter Sandstone, which has a total dissolved solids (TDS) of 665 mg/L. The base of the Gunter Sandstone is 914 ft above the top of the Mt. Simon injection zone. As explained above, the primary confining layer is in between. There are no potential conduits that would allow for vertical migration through the confining zone to the lowermost USDW. There are no USDWs beneath the injection zone (A.R. #1535 at Section 9.5.7 Figure 9-6 Revised).

After considering the information submitted, EPA agrees with the geologic interpretation offered by Marquis. EPA determines that Element #10 has been considered and documented appropriately as part of the demonstration for a 12-year alternative PISC timeframe.

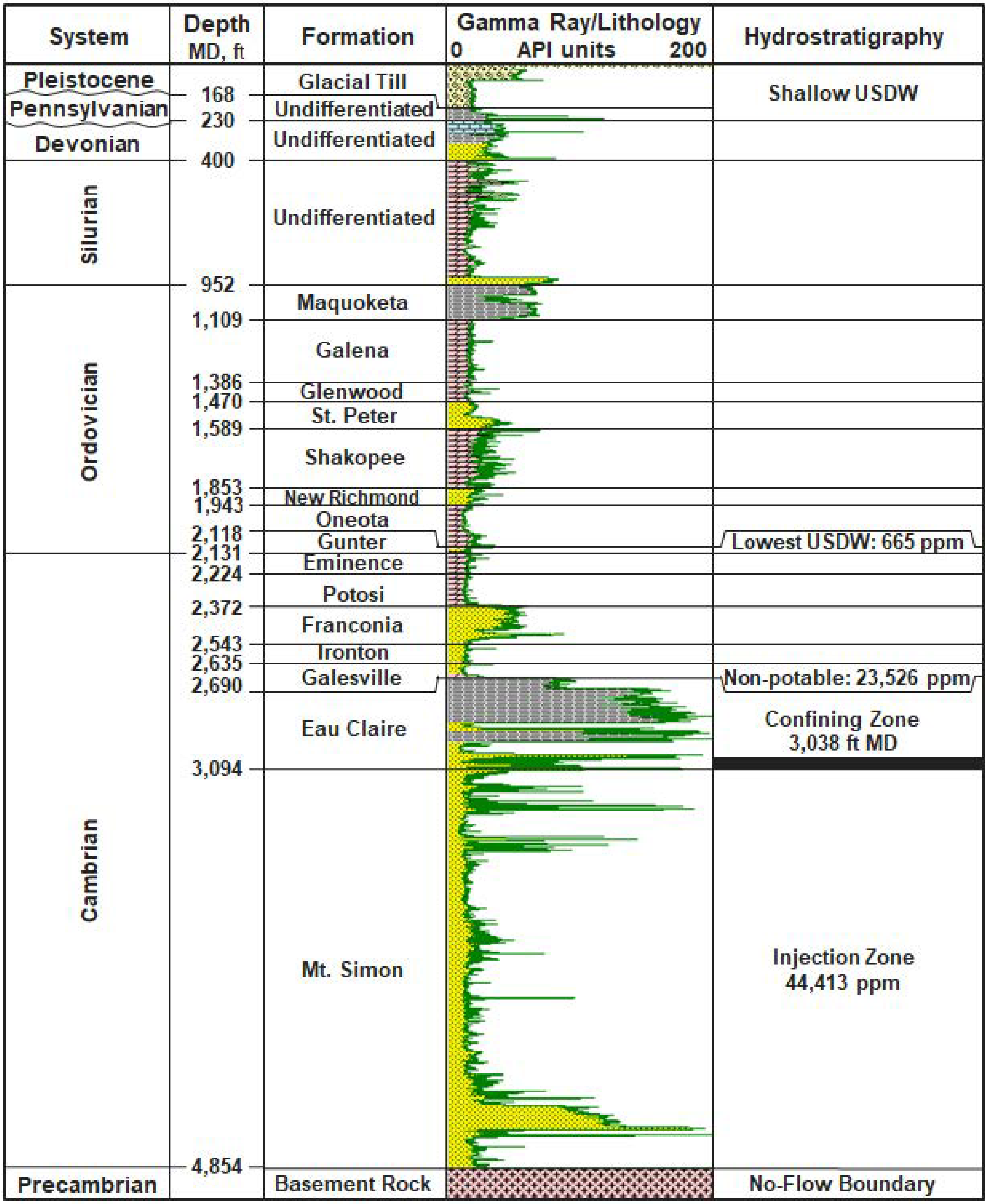

Figure 9-6 Revised: Stratigraphic column from MCI MW 1 well located at the Marquis (A.R. #1535).

Part II: Significant site-specific Information

EPA concludes that Marquis' alternative PISC demonstration is based on significant site-specific data and information, including data and information collected pursuant to the permit application (146.82) and the siting criteria (146.83). 40 C.F.R. § 146.93(c). Specifically, the siting criteria require:

(1) An injection zone(s) of sufficient areal extent, thickness, porosity, and permeability to receive the total anticipated volume of the carbon dioxide stream;
(2) Confining zone(s) free of transmissive faults or fractures and of sufficient areal extent and integrity to contain the injected carbon dioxide stream and displaced formation fluids and allow injection at proposed maximum pressures and volumes without initiating or propagating fractures in the confining zone(s). 40 C.F.R. § 146.83(a).

To help generate site-specific data, Marquis drilled a test well called MCI MW 1 well. This well is located in the same geographic column of rock formations as the proposed injection well. EPA has determined in its review that the MCI MW 1 test well generated site-specific data under 40 C.F.R. § 146.93(c), and that Marquis used said data in its alternative PISC timeframe demonstration regarding the elements under 40 C.F.R. § 146.93(c)(i)-(x). For example, whole cores, sidewall cores, fluid samples, and well logs (e.g., elemental neutron, gamma ray, resistivity, and porosity logs) were obtained from this well to characterize the geology at the proposed injection well site. Section 1.0 Project Narrative at Section 1.2.4 (February 2025), A.R. #1561). Core samples and well logs obtained from the MCI MW 1 well were used to determine the lithology of geologic units at depth and to divide the Eau Claire Shale and Mt Simon Sandstone into different environments of deposition. Further information on the site characterization can be found in the Project Narrative and AoR and Corrective Action Plans (Section 1.0 Project Narrative, A.R. #1561 and A.R. #964). A vClay log was used to divide the rock into three categories: clean sand, dirty sand, and shale. Once the Eau Claire Shale and Mount Simon Sandstone had been divided into different facies, a porosity log was used to determine the distributions of porosity values within each facies. (A.R. #1561 at Figure 1-12). Permeability values for rock units were calculated from porosity values using porosity-permeability transform functions and compared against permeability values measured in the lab using core samples from the MCI MW 1 well. The geochemistry of the site was determined from analyzing fluid samples obtained from the MCI MW 1 well (A.R. #1561).

The fracture pressure was determined via minifrac tests conducted in the Eau Claire and Mt. Simon formations at various depths. The result of these tests was a fracture gradient of 0.76 psi/ft (A.R. #1561). Porosity and permeability were also measured at the site. To account for uncertainty, sensitivity analyses were performed, as discussed in Element #1. Based on its evaluation of these site-specific data, EPA concludes that the injection zone is capable to receive the full amount of injected carbon dioxide, the confining zone will contain it, and artificial fracturing will not occur. Marquis' 12-year PISC timeframe is sufficient to characterize the CO_2 plume and pressure front growth over time. See 40 C.F.R. § 146.83(a)(1).

Marquis' alternative PISC timeframe demonstration is also based on the site-specific data and information considered regarding the siting criteria for the confining zone. This information and how it was used in the demonstration is discussed in Elements #2 and #7 above. See 40 C.F.R. § 146.83(a)(2).

Under the siting criteria, EPA may also require applicants to "identify and characterize additional zones that will impede vertical fluid movement, are free of faults and fractures that may interfere with containment, allow for pressure dissipation, and provide additional opportunities for monitoring, mitigation, and remediation." See 40 C.F.R. § 146.83(b). Marquis collected voluminous site-specific data and information on numerous rock formation layers from the surface through to the basement rock, as discussed in Element #7 above. For example, extensive data was collected on the characteristics of the rock formations in the injection and confining zones, including their geophysical and geochemical properties (A.R. #1561 and A.R. #964). Also discussed in Element #7 are the 2D and 3D seismic surveys taken at the site.

The site-specific data and information collected pursuant to the permit application requirements in 40 C.F.R. § 146.82 are discussed elsewhere in this memo and in the administrative record. They include site-specific data and information for the AoR (Element #1), any faults or wells within the AoR (Elements #7 and #9), information on the structure and properties of the injection zone and overlying formations (Element #7), seismicity (A.R. #1561 and 1682), USDWs within the AoR (Element #10), and well construction (Element #9).

In addition to the site-specific data and information collected as part of the permit application and the siting criteria, there are references to further site-specific information and data that Marquis utilized in several of the sections above discussing the ten elements. Element #4 describes the site-specific processes that Marquis identified that will result in trapping. Element #5 describes the trapping phases that will occur at the site and the model outputs based on the site-specific geology. Element #7 describes the assessment of the site-specific geology that was performed, including an analysis of faults and fractures based on information concerning the site-specific geology. Element #8 describes how conduits for fluid movement were assessed for this site and the site-specific plugging plans. Element #9 recognizes the construction specifications designed for this site and the assessment of other wells within the AoR specific to this site. Element #10 identifies the site-specific USDWs. Furthermore, the injection and confining zones are laterally continuous across the AoR and beyond. Marquis confirmed this by correlating data from MCI MW 1 and nearby regional wells, regional cross sections, and seismic surveys (A.R. #1561).

Therefore, EPA has determined that MCI MW 1 and seismic surveys have generated site-specific data and information under 40 C.F.R. § 146.93(c). Marquis used this site-specific data and information in its alternative PISC timeframe demonstration, as required by 40 C.F.R. § 146.93(c)(i)-(x).

Part III: Eight Criteria

As explained in the Legal Requirements Section, the information submitted as part of Marquis' alternative PISC timeframe demonstration must meet eight criteria. 40 C.F.R. § 146.93(c)(2). After considering all the information and data submitted as part of Marquis' demonstration, EPA found that the information supporting the 12-year PISC timeframe meets all eight criteria, as explained below:

1. Tests are accurate, reproducible, and meet quality assurance standards

Analyses and tests used to support the alternative PISC demonstration are accurate, reproducible, and performed in accordance with established quality assurance standards. Physical and chemical properties of the geologic units at the site were measured using industry standard methods. Specific analytical methods can be found in Table 9-3 (A.R. #1535, at Table 9-3). Analyses of the geologic units are reproducible and were able to be tested for accuracy. Properties of the Eau Claire Shale and Mount Simon Sandstone were obtained from measurements of 8 whole cores, 29 sidewall cores, multiple well log test types, and 8 dynamic formation tests. Well logs collected by Marquis included gamma ray, resistivity, porosity, elemental neutron, X-ray diffraction (XRD), and X-ray fluorescence (XRF) logs. The results of each individual log were compared against other logs to check for accuracy. For example, the lithologies of the Eau Claire shale and Mount Simon Sandstone were determined from an elemental neutron log and compared to the determined lithologies from core samples and XRD and XRF logs (A.R. #1561). Interpreted properties of the geologic units from well logs could be checked against core samples in the lab. Permeability values of the Eau Claire Shale and Mount Simon Sandstone were calculated from measured porosity values using porosity-permeability transform function, and these values were consistent with direct lab measurements of permeability from core samples. Relative permeability curves measured from samples in the lab were also found to be consistent with permeability curves obtained from analysis of core samples at the Illinois Biocarbon Decatur Project, which is 99 miles away from the proposed Marquis well site and within the Illinois Basin (A.R. #964).

Parameters	Analytical Methods	Alternate Analytical Method (Note 1)
Cations: Na, Ca, Mg, Ba, Sr, Fe, and K	ASTM D1976	EPA Method 6020
Cations: Sr	ASTM D1976	EPA Method 6010
Anions: Cl, Br, SO_4	ASTM D4327	EPA Method 300
pH	ASTM D1293	Standard Method (SM) 4500H
Alkalinity	ASTM D3875	SM 2320B
Total Dissolved Solids (TDS)	ASTM D5907	SM 2540C
Density	ASTM D4052	SM 2710F
Dissolved Inorganic Carbon	ASTM D513-11	SM 5310C
Conductivity/Resistivity	ASTM D1125	SM 2510B
Stable Isotopes of C, O, and H	CRDS Laser H Isotope Ratio Mass Spectrometry (IRMS) for C	(Note 1)
Carbon-14	Accelerator Mass Spectrometry (AMS)	(Note 1)
Note: 1. If another alternative analytical method(s) is considered, prior approval will be obtained from the UIC Director.		

Table 9-3: Summary of analytical and field parameters for ground water samples (A.R. #1535).

The modeling of the predicted CO_2 plume is reproducible, as the values for the input parameters, details on the modeling software, and equations used within the model were provided by Marquis in the application. It is possible to re-run the predictive model using these data. During the sensitivity analysis of the model, Marquis ran 10 different test cases of the model with differing input parameters and SEM realizations. Equations used to calculate model parameter values are also reproducible. These equations include calculations of permeability based on porosity and maximum injection pressure based on fracture pressure gradient and depth (A.R. #1561).

2. Use of appropriate or EPA-certified test protocols where available

Marquis has listed testing methodology in the Quality Assurance and Surveillance Plan. Marquis used a static earth model (SEM) created in Schlumberger Petrel modeling software, which was used as a framework for dynamic reservoir modeling (DRM) in CMG-GEM to model the injection of CO_2. The methods used in computational modeling of the injected CO_2 plume demonstrate that the geologic, chemical, and physical properties of the site are appropriate (A.R. #964).

3. Predictive models are appropriate and tailored to site conditions and composition of the CO_2 stream, composition of the carbon dioxide stream, and injection and site conditions over the life of the geologic sequestration project

The predictive model used to determine the future extent of the CO_2 plume over time is tailored to site conditions. See Part II above for discussion on the extensive collection and review of site-specific data and information that was used to tailor the models to site conditions. Marquis collected geological information from the onsite test well (MCI MW 1) through core samples and geophysical logging. This information was used to determine the model layers and thicknesses. Porosity and permeability data was also obtained from the test well to input those values in the computational model. Marquis collected site specific data on the geology from the MCI MW 1 deep characterization well to generate inputs for the predictive model. Whole cores, sidewall cores, fluid samples, and well logs (e.g., elemental neutron, gamma ray, resistivity, and porosity logs) were obtained from this well to characterize the geology at the proposed injection well site. Core samples and well logs obtained from the MCI MW 1 well were used to determine the lithology of geologic units at depth and to divide the Eau Claire Shale and Mount Simon Sandstone into different environments of deposition (A.R. #1561 at Figure 1-10). A vClay log was used to divide the rock into three categories: clean sand, dirty sand, and shale (A.R. #1561 at Section 1.2.4). Once the Eau Claire Shale and Mount Simon Sandstone had been divided into different facies, a porosity log was used to determine the distributions of porosity values within each facies (A.R. #1561 at Figure 1-12). Permeability values for rock units were calculated from porosity values using porosity-permeability transform functions and compared against permeability values measured in the lab using core samples from MCI MW 1 (A.R. #1561 at Section 1.2.4 and Section 1.2.10). The geochemistry of the site was determined from analyzing fluid samples obtained from the MCI MW 1 well. (A.R. #1561 at Section 1.2.8).

Values directly measured or calculated from the MCI MW 1 stratigraphic test well were input into the predictive model. Classification of the rock column into different environments of deposition along with distributions of porosity and permeability were used to model porosity and permeability in the Eau Claire Shale and Mount Simon Sandstone (A.R. #964 at Figure 2-18). Other parameters used in the model based on values from the MCI MW 1 well include compressibility, capillary pressure, formation brine geochemistry, temperature at depth, pore pressure gradient, and fracture gradient (A.R. #964 at Section 2.1.5, Section 2.1.6, Section 2.1.8, and Section 2.1.10).

The model is also tailored to the composition of the CO_2 stream. The anticipated physical properties of CO_2 stream are included in Table 1-14, and the anticipated composition of the CO_2 stream is included in Table 1-3 (A.R. #1561). The fluid properties of the injected CO_2 stream were modeled using the anticipated physical properties of the CO_2 stream, such as temperature and pressure (A.R. #964).

4. Calibration of predictive models using existing information where sufficient data are available

The predictive models Marquis used were calibrated. To calibrate a predictive model, you essentially adjust its output probabilities to better align with the actual observed outcomes by using a separate validation dataset, typically through methods like histogram binning, Platt scaling (logistic regression), or isotonic regression, where you essentially fit a new function to the model's predictions to correct for any systematic biases in probability estimations, ultimately aiming to create a calibration curve that closely follows the diagonal line representing perfect calibration; this is often visualized through a calibration plot where the x-axis shows the predicted probabilities and the y-axis shows the actual event rate within probability bins.

Marquis used a static earth model (SEM) created in Schlumberger Petrel modeling software, which was used as a framework for dynamic reservoir modeling (DRM) in CMG-GEM to model the injection of CO_2 (A.R. #964 at Section 2.1.1). The methods used in computational modeling of the injected CO_2 plume and used to measure the geologic, chemical, and physical properties of the site are appropriate and the calibration is certified.

5. Use reasonably conservative values and assumptions and disclose to the Director whenever values are estimated on the basis of known, historical information instead of site-specific measurements

The model Marquis used to predict the plume of injected CO_2 incorporated reasonably conservative values and assumptions. The maximum annual injection rate and maximum surface and bottom hole injection pressures were used in the computational model (A.R. #1561 at Section 1.7.1). As these are the maximum values possible during operation of the well, actual injection rate and pressure will be less than or equal to the modeled values, which produced a conservative model output. High and low estimates for porosity, permeability, temperature, and injection rate were used as input parameters in multiple runs of the model as part of the sensitivity analysis (A.R. #964 at Section 2.3).

6. An analysis must be performed to identify and assess aspects of the alternative post-injection site care timeframe demonstration that contribute significantly to uncertainty. The owner or operator must conduct sensitivity analyses to determine the effect that significant uncertainty may contribute to the modeling demonstration

Marquis performed a sensitivity analysis to supplement the modeling of the projected CO_2 plume to account for uncertainty in the model parameters. Parameters included within this sensitivity analysis are horizontal and vertical permeability and porosity, well head temperature, and flow rate. Combinations of high and low values for permeability and porosity were input into the model (A.R. #1535). The range of porosity and permeability values used in the sensitivity analysis cover a broad range of possible values resulting from different proportions of sedimentary facies within depositional environments. For example, to calculate high porosity and permeability, Marquis assumed rock layers deposited in dune paleoenvironments were comprised of 100% clean sands, and to calculate low porosity and permeability, Marquis assumed rock layers deposited in dune paleoenvironments were comprised of 80% “clean sand”, 10% “dirty sand”, and 10% “shale” (A.R. #964 at Table 2-12). Marquis provided a list of the 10 cases used for the sensitivity analysis in Table 2-11 and Figure 9-7 (A.R. #964).

The resulting model outputs showing the predicted areal extent of the CO_2 plume 50 years post-injection are shown in Table 2-11 and Figure 9-8 in the Alt-PISC timeframe demonstration (A.R. #1535). The sensitivity analysis covers a wide range of possible values for multiple model parameters and accounts for uncertainty in the modeling. These upper bounds of the ranges of possibilities are unlikely to represent actual conditions but are included for a comprehensive model computation. Differences are seen post injection where the lower vertical permeability case shows the least or no post-injection movement, while the higher vertical permeability case shows more post-injection movement especially in the south direction. Regardless, this still demonstrates via plume model predictions that CO_2 is being captured in the Mt. Simon as designed under high porosity and high permeability conditions.

7. Must have an approved quality assurance and quality control plan that addressed all aspects of the demonstration

EPA approved Marquis’ quality assurance and quality control plan. The quality assurance and quality control plan is contained within Appendix 7.A: Quality Assurance and Surveillance Plan. The approved QASP applies to the entire Marquis project, including the PISC and Site Closure plan, and addresses all aspects of the demonstration (7.A Quality Assurance and Surveillance Plan (November 2024), A.R. #1524).

8. Any additional criteria EPA requires

EPA did not require any additional criteria for the demonstration.

Part IV: No Risk of Endangerment Conclusion

After considering all the information submitted as part of Marquis’ alternative PISC demonstration and in the remainder of the administrative record, EPA has concluded it is based on significant site-specific data and information provided via the application documents, submissions to RAIs, technical discussions with applicant, and siting criteria, as required by 40 C.F.R. § 146.93(c). Marquis’ alternative PISC timeframe demonstration (A.R. #1542) includes substantial evidence to support a conclusion that the project will not pose a risk of endangerment to USDWs at the end of the 12-year timeframe.

To summarize from the ten elements above, some of the most important ways in which the site-specific data and information in the demonstration supports a 12-year alternative PISC timeframe and addressed risk to USDWs are as follows: the computational modeling (Element #1) demonstrated that the CO_2 plume (Element #2) will stabilize by year 12 of the PISC timeframe and that the pressure front (Element #3) will dissipate to native levels by year 12 of the PISC timeframe. The modeling shows that the site-specific processes that will occur in the Mt. Simon injection zone will result in appropriate trapping of the injected CO_2 to ensure uniform capture, storage, and movement of the CO_2 (Elements #4-6). There is significant separation (approximately 963 feet) between the top of the injection zone (Mt. Simon) and the bottom of the lowest/nearest USDW (Gunter Sandstone) (Element #10), including the Eau Claire confining layer located in between, which is of appropriate thickness, permeability, and integrity to prevent vertical migration of the CO_2 plume at year 12 post-injection and beyond (Element #7) and is free of fractures and faults (Element #7) that could provide a pathway for fluid movement into a USDW (Element #8). The only abandoned well within the AOR (J&L Well) has been appropriately plugged (Element #9). The construction of the injection well (MCI CCS 3) will ensure CO_2 injection occurs only at depth within the Mt. Simon injection zone (Element #9). The plugging plans will ensure that the wells associated with the project do not become potential conduits for fluid movement post-injection (Element #8). In totality, information and data related to all the elements demonstrate that the Marquis project will not pose a risk of endangerment to USDWs after the 12-year PISC timeframe.

Based on the substantial evidence contained in the administrative record and described herein, Marquis has demonstrated to EPA's satisfaction that the project will not pose a risk of endangerment to USDWs at the end of the 12-year alternative PISC timeframe. Therefore, EPA will incorporate a 12-year PISC timeframe in the Marquis permit. This is done with the understanding that the PISC timeframe can be modified by EPA if necessary as operational and monitoring data is acquired.