STATE OF NEW MEXICO
ENERGY, MINERALS AND NATURAL RESOURCES DEPARTMENT
OIL CONSERVATION COMMISSION

APPLICATION OF GOODNIGHT MIDSTREAM PERMIAN LLC FOR APPROVAL OF A SALTWATER DISPOSAL WELL, LEA COUNTY, NEW MEXICO — **CASE NO. 24123**

APPLICATIONS OF GOODNIGHT MIDSTREAM PERMIAN LLC FOR APPROVAL OF SALTWATER DISPOSAL WELLS, LEA COUNTY, NEW MEXICO — **CASE NOS. 23614-23617**

APPLICATION OF GOODNIGHT MIDSTREAM PERMIAN, LLC TO AMEND ORDER NO. R-22026/SWD-2403 TO INCREASE THE APPROVED INJECTION RATE IN ITS ANDRE DAWSON SWD #1, LEA COUNTY, NEW MEXICO — **CASE NO. 23775**

APPLICATIONS OF EMPIRE NEW MEXICO LLC TO REVOKE INJECTION AUTHORITY, LEA COUNTY, NEW MEXICO — **CASE NOS. 24018-24020, 24025**

EMPIRE NEW MEXICO LLC'S MOTION TO REQUIRE MODIFICATION OF THE OIL CONSERVATION DIVISION'S IMPLEMENTATION DECISION

Empire New Mexico, LLC ("Empire") moves the Oil Conservation Commission ("OCC" or "Commission") to require the Oil Conservation Division ("OCD" or "Division") to modify the Division's Implementation of OCC Orders 24004 and 24004-A ("Implementation Decision") in accordance with the requirements of OCC Order Nos. 24004 and 24004-A (collectively "Orders").[1] As demonstrated below, OCD's Implementation Decision fails to protect Empire's correlative rights or prevent waste within the Eunice Monument South Unit ("EMSU") and consequently does not comport with the Orders. Indeed, the Implementation Decision effectively

[1] A copy of the January 15, 2026 Implementation Decision is attached as Exh. A.

nullifies many of the Commission's findings and unreasonably benefits Goodnight Midstream Permian, LLC ("Goodnight") to the detriment of Empire. Specifically, the Implementation Decision improperly allows Goodnight's injection to continue unfettered until Empire commences active CO_2 injection and denies Empire the flexibility to determine the most appropriate method to demonstrate recoverability of the San Andres Residual Oil Zone ("ROZ") within the EMSU. Accordingly, the Commission should direct OCD to revise its Implementation Decision by: (1) requiring Goodnight to cease injection now; and (2) allowing Empire flexibility to determine the most appropriate type of pilot project to demonstrate recoverability of the ROZ.

I. BACKGROUND

a. OCC Procedural History

This matter involves Goodnight's and Empire's applications regarding Goodnight's current and proposed injection into Empire's EMSU. Following eighteen days of testimony, the OCC entered its Order Denying Goodnight's Applications & Partially Granting/Partially Denying Empire's Applications (OCC Order R-24004), on September 12, 2025 ("September Order").

The September Order denied Goodnight's Applications to drill new disposal wells in Case No. 241234 (Piazza), Case No. 23614 (Gooden), Case No. 23615 (Hernandez), Case No. 23616 (Hodges), and Case No. 23617 (Seaver). Additionally, the September Order denied Goodnight's application to increase injection into the existing Dawson well in Case No. 23775. Finally, the September Order suspended permits associated with Goodnight's injection wells in Case No. 24018 (Dawson), Case No. 24019 (Banks), Case No. 24020 (Sosa), and Case No. 24025 (Ryno) (collectively, Dawson, Banks, Sosa and Ryno are the "Suspended Wells").

In reaching its decision to deny Goodnight's applications and order the suspension of injection into the Suspended Wells, OCC made, among others, the following findings:

- **The Commission finds that there was substantial evidence presented at the hearing to establish the existence of a ROZ in the Grayburg and San Andres, especially the core analysis evidence**.[2]

- **Based on the 1984 Commission Order, Empire has the exclusive rights to produce the ROZ in the EMSU**.[3]

- The Unit Agreement gives Empire the "**exclusive right**, privilege and duty of exercising any and all rights of the parties hereto including surface rights which are necessary or convenient for prospecting for, producing, storing, allocating and distributing the Unitized Substances are hereby delegated to and shall be exercised by the Unit Operator."[4]

- Empire purchased the EMSU to continue the current extraction of oil from the Grayburg formation **but also to start a new project to extract oil from the San Andres formation via a CO_2 flood as part of an Enhanced Oil Recovery (EOR) project**.[5]

- Based on the 1984 Commission Order, **Empire has the exclusive rights to decide how to best extract oil in the EMSU**.[6]

- **The injection of hundreds of thousands of barrels a day conflicts with Empire's exclusive rights to extract oil in the EMSU**[.][7]

- **Empire DID adduce substantial evidence of the possibility of FUTURE impairment of correlative rights or waste in the EMSU**.[8]

- Empire's witness, Dr. Buchwalter, built a model and the model shows to a reasonable degree that **water is moving from the San Andres into the Grayburg**.[9]

[2] September Order, II. B. (emphasis in original).

[3] *Id.* at II.A. (emphasis in original)

[4] *Id.* at ¶ 18 (emphasis added).

[5] *Id.* at ¶ 26 (emphasis added).

[6] *Id.* at ¶ 27 (emphasis added).

[7] *Id.* at ¶¶ 40-41 (emphasis added)

[8] *Id.* at III. A. (emphasis in original).

[9] *Id.* at ¶ 47 (emphasis added).

Following entry of the September Order, Goodnight and Empire each filed a motion for re-hearing. The OCC issued an order granting a limited rehearing in the above matters on October 17, 2025, to consider two questions of law:

> 1. Does the Commission have the legal authority to suspend existing Goodnight's injection wells in order to provide Empire with the opportunity to establish the CO_2 EOR pilot project, given that there was insufficient evidence presented at hearing to prove whether the ROZ [Residual Oil Zone] is recoverable?
>
> 2. Does Commission Order R-24004 provide OCD [Oil Conservation Division] with discretion in managing the suspension of existing Goodnight injection wells and to provide Empire the opportunity to establish a CO_2 EOR pilot project?

After considering the briefing of the parties, and having held oral argument on November 13, 2025, the Commission issued an Amended Order Denying Goodnight's Applications & Partially Granting/Partially Denying Empire's Applications, OCC Order R-24004-A, on December 17, 2025 ("December Order").

In its December Order, the OCC upheld its determinations and findings in the September Order and ultimately determined the Commission can order the suspension of water injection into a ROZ. This includes suspension to allow Empire to plan and execute an EOR pilot project to determine recoverability of the ROZ.[10] Additionally, the OCC confirmed that OCD can and should manage suspension of Goodnight's injection "in order to" facilitate the EOR pilot project granted by the Commission.[11]

Additionally, the Commission reiterated its conclusion that "New Mexico law authorizes the Commission to allow companies to have an opportunity to pursue oil discoveries so the oil is

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[10] December Order, heading for Rehearing Issue II.

[11] *Id.* at ¶ 1 (citing NMSA 1978, Section 70-2-11 and September Order, ¶ 38).

not left wasted or untapped underground."[12] The Commission also acknowledged that Goodnight and Rice's arguments at rehearing surrounding the Commission's authority to prevent waste hinged on a "crucial misinterpretation of the Commission's September Order" as "the Commission did not find sufficient evidence presented at hearing to prove that the ROZ is **not** recoverable."[13]

The Commission further confirmed it "**recognized a realistic possibility that the ROZ could contain oil that could be both physically and economically recovered**" and therefore, by way of entry of the September Order, suspended Goodnight's injection into the Suspended Wells and granted Empire the opportunity to establish a CO_2 EOR pilot project "for the purpose of ascertaining the recoverability of the ROZ."[14] Lastly, the Commission stated:

> The Commission has already determined that the only practical way to prove for certain, whether there might be recoverable hydrocarbons in this ROZ, is to conduct a CO_2 enhanced oil recovery pilot project, because recovery "is site-specific and is based on the conditions at the EMSU." And the Commission has also already found, as a technical matter, that a CO_2 EOR pilot cannot be successfully performed while wastewater is being disposed into the same region.[15]

b. OCD Implementation

OCD provided the parties with its Implementation Decision on January 15, 2026.[16] The Implementation Decision only limits Goodnight's injection once the CO_2 project is active; requires Empire to seek the Division's authorization to permanently amend the order approving the current waterflood project within the EMSU, Order No. R-7766 ("Waterflood Order"); and requires

[12] *Id.*

[13] *Id.* at ¶ 11 (emphasis in original).

[14] *Id.* at ¶ 13 (citing September Order at ¶ 61, Heading E) (emphasis added).

[15] *Id.* at ¶ 18 (internal citations omitted).

[16] *See* Implementation Decision, Exh. A.

Empire to implement a multi-well pattern CO_2 flood. To that end, the Division has required Empire to take the following steps:[17]

1. Submit a hearing application to the OCD requesting to establish a CO_2 EOR, this submittal must include:

    a. Summarize the scope for the project including the area of the pilot project within the existing EOR project and the proposed use of existing wells or development of new wells.
    b. C-108 application for each proposed injection including the AOR reviews for each well.
    c. Request the use of CO_2 including anticipated maximum surface injection pressures for each fluid (CO_2, water, produced gas)
    d. Corrosion plan for well construction, well monitoring and a procedure for how mechanical issues will be mitigated.
    e. H2S contingency plan (if applicable)
    f. Notice as required for Division hearings
    g. Planned or existing infrastructure supporting the injection and production
    h. Anticipated schedules for development of key items of the CO_2 EOR pilot project
    i. The division will review the applications to ensure compliance with OCD's rules and regulations

2. If the Division grants an order for the CO_2 EOR

    a. Empire will ensure Goodnight is provided notice of an approved order.

3. Empire will provide an infrastructure implementation plan with a detailed schedule for tie-ins.

4. Empire must then submit identified C-101s, change of plans for existing wells or new wells APDs

    a. The division will review the applications to ensure compliance with the CO_2 EOR order and the OCD's rules and regulations.

5. The operator will provide OCD and Goodnight with a 30-day notice when they mobilize to drill or work over the proposed wells.

[17] Order No. R-7766 approved the initial waterflood project within the EMSU. The Waterflood Order has been amended three times (R-7766-A; R-7766-B; and R-7766-C).

6. Empire will provide Goodnight and the OCD a 90-day "activation notice" of their anticipated commencement of the CO_2 flood. Commencement is identified as the first CO_2 injection and production. Empire will provide Goodnight and OCD notice of any extended delays.[18]

The Division has imposed a one-year deadline for Empire to complete Requirement No. 1 and an 18-month deadline for Empire to complete Requirement No. 4.[19] While Goodnight will have 60 days to shut in its Suspended Wells, that 60-day period does not begin to run until Empire completes the steps identified above.

On February 18, 2026, Empire sent a letter to the Division outlining its concerns with the Implementation Decision.[20] Specifically, Empire pointed out that while Goodnight will have 60 days to shut in its Suspended Wells, that 60-day period does not begin to run until Empire completes the steps identified above.[21] As a result, Goodnight's injection will continue unfettered despite the Commission's recognition that Empire has exclusive rights within the EMSU[22] and that Goodnight's operations conflict with Empire's exclusive rights and are causing waste within the EMSU.[23] Moreover, the Implementation Decision requires Empire to amend the Waterflood Order and implement a full-scale CO_2 flood within the EMSU rather than conduct a pilot project. As a matter of efficiency, economy, and resources, Empire requested that the OCD reconsider these requirements.

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[18] Implementation Decision, Exh. A, at 1-2.

[19] *Id.* at 2.

[20] Letter from Counsel for Empire to OCD Deputy Director (Feb. 18, 2026), attached as Exh. B.

[21] *Id.* at 3.

[22] September Order at ¶¶ 40-41.

[23] *Id.* at ¶ III.A.

On February 27, 2026, by letter response, the OCD declined to modify its Implementation Decision.[24] In the response, OCD stated that it "possesses the authority to address Goodnight's injection and Empire's proposed EOR pilot project as OCD sees fit under the circumstances."[25] OCD further maintained that even a pilot project necessitated the same steps and requirements as a full-scale CO_2 flood within the EMSU and that any modification of the Implementation Decision would violate applicable rules and regulations.[26] Empire disagrees. For the reasons discussed below, the Implementation Decision does not prevent waste or protect correlative rights in accordance with the requirements of OCC Orders 24004 and 24004-A, and the Commission should direct OCD to revise the plan accordingly.

II. ARGUMENT

a. The Implementation Decision fails to protect Empire's correlative rights within the EMSU such that it can proceed with a CO_2 pilot project.

As discussed above, the Commission's Orders recognize that: Empire has the exclusive rights to decide how to best extract oil in the EMSU;[27] the injection of hundreds of thousands of barrels of wastewater each day conflicts with Empire's exclusive rights to extract oil;[28] Empire adduced substantial evidence of the possibility of future impairment of correlative rights or waste in the EMSU;[29] and water is moving from the San Andres into the Grayburg.[30] Despite these findings, the Implementation Decision allows Goodnight's injection to continue unabated *until*

[24] Letter from OCD Assistant General Counsel to Counsel for Empire (Feb. 27. 2026), attached as Exh. C.

[25] *Id.* at 1.

[26] *Id.* at 5-6.

[27] *Id.* at ¶ 27 (emphasis added).

[28] *Id.* at ¶¶ 40-41 (emphasis added)

[29] *Id.* at III. A. (emphasis in original).

[30] *Id.* at ¶ 47.

Empire commences CO_2 injection. Thus, the Implementation Decision fails to protect Empire's correlative rights within its currently producing Grayburg interval and also impedes Empire's ability to effectively proceed with a CO_2 pilot project by impacting the reservoir pressure.[31] In this regard, the Division's Implementation Decision renders meaningless the Commission's findings regarding Empire's correlative rights within the EMSU. For these reasons, Empire requests that the Commission amend the Implementation Decision by requiring Goodnight to cease injection now rather than when Empire commences CO_2 injection.

b. The Implementation Decision improperly requires Empire to amend the Waterflood Order rather than implement a pilot project.

As discussed above, the Division's Implementation Decision requires Empire to amend the Waterflood Order rather than implement a pilot project. In the context of enhanced oil recovery, a pilot project is typically a small-scale testing phase conducted before implementation of a full EOR project. Essentially, the pilot project permits the operator to run a small, short-term trial to determine if a full-scale project is viable. On the other hand, an EOR project seeks to maximize oil recovery over an entire field, long-term. Here, the Commission very clearly grants Empire the opportunity to establish a ***CO_2 EOR pilot project*** to ascertain the recoverability of the ROZ lying beneath the EMSU. Upon completion of the CO_2 EOR pilot project, Empire can then apply to implement an EOR project covering the entirety of the EMSU. Empire should not be required to amend the Waterflood Order prior to implementing the pilot project.

[31] 04/09 Tr. 156:19 – 158:13; 04/11 Tr. 43:7-25.

c. The Commission should direct the Division to modify its Implementation Decision to allow Empire flexibility and latitude to demonstrate recoverability of the ROZ within the three-year timeframe set by the Commission.

Given the tight three-year timeline and the narrow scope of the pilot project, i.e., demonstrating recoverability of the ROZ, Empire requests that the Commission require the Division to modify its Implementation Decision to allow Empire the flexibility to successfully plan and execute a true pilot project, rather than a full-fledged EOR project. More specifically, Empire requests the ability to pursue either a Huff-and-Puff project or a CO_2 injection project that would involve a multi-well pattern. The Commission has previously approved Huff and Puff projects via C-103 forms.[32] Due to the small-scale, short-term nature of an EOR pilot project, Empire believes a C-103 form, rather than a C-108, may be more appropriate for the establishment of such a project, and more efficient for the Division and its proceedings necessarily related to same. CO_2 Huff and Puff projects have been widely utilized to prove the viability of CO_2 injection in areas where CO_2 infrastructure is not available.[33] The Implementation Decision should be modified to allow Empire to utilize this lower-cost option to demonstrate oil can be mobilized from the ROZ using CO_2 without the need to hold a hearing, amend the Waterflood Order, or submit a C-108 form. This modification would align with the Division's requirements for other Huff and Puff projects.

If the Huff and Puff project results are inconclusive, or if Empire deems appropriate, the Implementation Decision should allow Empire the flexibility to pursue some other method for Empire's pilot project, such as a multi-pattern CO_2 injection pilot. At that point, Empire would

[32] Form C-103, Central Vacuum Unit No. 097, APD No. 30-025-03076, attached as Exhibit D.

[33] Hiroaki Koga, et al., *Field Experiences: CO_2 HuffnPuff Test at the Minami-Aga Depleted Onshore Oil Field in Japan*, SPE-222757-MS (Nov. 2024), attached as Exhibit E; D. Halinda, et al., *CO2 Huff and Puff Injection Operation Overview in Jatibarang Field Lessons Learned from a Successful Case Study in Mature Oil Field*, SPE-216175-MS (Oct. 2023), attached as Exhibit F; Giang The Ha, et al., *Design & Implementation of CO2 Huff-n-Puff Operation in a Vietnam Offshore Field*, SPE 161835 (Nov. 2012), attached as Exhibit G.

file a hearing application and any requisite C-108 form as outlined in the existing Implementation Decision. However, the Division's current requirements do not allow Empire flexibility in developing a pilot project within the three-year period that would minimize both costs and regulatory burden. To be clear, Empire is not requesting an exemption from OCD's regulations and requirements; however, the Implementation Decision imposes requirements and steps that may ultimately be unnecessary based on the type of project developed by Empire. The Division should be directed to revise its Implementation Decision accordingly.

In addition, because Empire intends to establish a pilot project rather than a full-scale EOR project, it should not be required to submit an infrastructure implementation plan with a detailed schedule for tie-ins in accordance with OCD's Requirement No. 3. Empire would provide an infrastructure implementation plan with a detailed schedule for tie-ins after completion of the pilot project, and upon Empire's application to implement a full-scale CO_2 EOR project. Until then, the information is premature and unnecessary.

The Division's Requirement No. 5 requires Empire to provide OCD and Goodnight with 30-days' notice when it mobilizes to drill or work over the proposed wells. Instead, Empire proposes to notify Goodnight when Empire submits its application to OCD. Given the narrow timeframe imposed by the Implementation Decision, Empire intends to commence work immediately upon approval. Requiring otherwise would delay progress and impede Empire's ability to commence the pilot project in a timely manner.

Finally, Requirement No. 6 references a "CO_2 flood" rather than a pilot project. This language should be amended to refer to a pilot project. Commencement of the pilot project would be identified as the first injection of CO_2.

III. CONCLUSION

The Division's Implementation Decision fails to protect correlative rights or prevent waste within the EMSU and therefore contravenes the Commission's findings and determinations in OCC Order Nos. 24004 and 24004-A. Accordingly, Empire respectfully requests that the Commission direct OCD to modify its Implementation Decision to: (1) require Goodnight to cease injection now – rather than once Empire commences CO_2 injection; and (2) allow Empire the flexibility to demonstrate ROZ recoverability through either a Huff and Puff project or a CO_2 multi-pattern flood.

Respectfully submitted,

By: */s/ Dana S. Hardy*

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CERTIFICATE OF SERVICE

I hereby certify that a true and correct copy of the foregoing was served upon the following counsel of record by electronic mail on March 24, 2026.

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Oil Conservation Division

Implementation of OCC Orders 24004 and 24004-A

January 15, 2026

Greetings,

In accordance with OCC orders 24004 and 24004-A (Orders), OCD is providing the below directions on the execution of the Orders requiring the suspension of Goodnights injection in the area to facilitate a pilot CO2 EOR project by Empire. These directions were created taking the OCC findings and orders into account. In accordance with the findings these directions will allow Empire to plan and execute a timely pilot project and will ensure produced water is not being injected once that pilot project is active. In consideration of the findings OCD is determining "**active CO2 flood**" is the physical injection and withdrawal of fluids into the formation. Be advised this letter does not alleviate either party of general compliance with OCD's rules and regulations throughout compliance of these directions.

R-24004 findings

> "C. However, the Commission concluded it is premature at present to grant Empire's applications to permanently revoke the injection authority of the existing wells because the **Commission found Empire DID NOT adduce substantial evidence that their correlative rights in the Grayburg are CURRENTLY impaired by Goodnight's injection into the San Andres." (emphasis added)**

R-24004-A findings

> "The Commission reiterates its finding that "[t]o perform a successful CO2 flood, the injection of CO2 and water must be monitored closely and adjustments made based upon design. **Goodnight's SWD [Salt-Water Disposal] wells cannot dispose of water when an active CO2 flood is being performed**" (**emphasis added**)
>
> "The Commission herby concludes that OCD has the authority, and may at its discretion, implement the "suspension" ordered on page 13 of the Commission's September Order "in order to provide Empire with the opportunity to establish the CO2 EOR pilot Project" September Order #3 at page 14. The commission also concludes that the OCD has the authority to impose the suspension ordered by September Order, #3 at page 13, **on any schedule OCD deems necessary "in order to provide Empire the opportunity to establish the CO2 EOR pilot project""** (**emphasis added**)

EXHIBIT A

"The Commission further clarifies that none of the orders in this case preempt any relevant or applicable regulatory requirements for any party. **Empire must follow all relevant and applicable regulations and permitting processes if it chooses to exercise the opportunity the Commission has provided for it to establish a CO2 EOR pilot project."** (**emphasis added**)

Directions for Empire

For a CO2 EOR pilot in EMSU to be established Empire must take the following steps to amend the existing order No. R-7766:

1. Submittal of hearing application from Empire to the OCD requesting to establish a CO2 EOR, this submittal must include:
    a. Summary of scope for the project including the area of the pilot project within the existing EOR project and the proposed use of existing wells or development of new wells.
    b. C-108 application for each proposed injection including the AOR reviews for each well.
    c. Request for the use of CO2 including anticipated maximum surface injection pressures for each fluid (CO2, water, produced gas)
    d. Corrosion plan for well construction, well monitoring and a procedure for how mechanical issues will be mitigated.
    e. H2S contingency plan (if applicable)
    f. Notice as required for Division hearings
    g. Planned or existing infrastructure supporting the injection and production
    h. Anticipated schedules for development of key items of the CO2 EOR pilot project
    i. The division will review the applications to ensure compliance with OCD's rules and regulations
2. If the Division grants an order for the CO2 EOR
    a. Empire will ensure Goodnight is provided notice of an approved order.
3. Empire will provide an infrastructure implementation plan with a detailed schedule for tie-ins.
4. Empire must then submit identified C-101s, change of plans for existing wells or new wells APDs
    a. The division will review the applications to ensure compliance with the CO2 EOR order and the OCD's rules and regulations.
5. The operator will provide OCD and Goodnight with a 30-day notice when they mobilize to drill or work over the proposed wells.
6. Empire will provide Goodnight and the OCD a 90day "activation notice" of their anticipated commencement of the CO2 flood. Commencement is identified as the first CO2 injection and production. Empire will provide Goodnight and OCD notice of any extended delays.

Be advised for the project to be successful Item #1 should be submitted within 12 months and item #4 should be submitted within 18 months from the date of Order #24004-A. If these timelines are not met and communicated with the OCD, OCD may advise the OCC that Empire is not likely to be able to perform an adequate pilot project as allowed by order.

Directions for Goodnight

To ensure there is no injection in the EMSU during the "Active" portion of the implementation of the CO2 EOR pilot Goodnight will perform the following:

- Within 90days of receiving these directions, Goodnight will develop a 60-day shut-in plan and submit it to the Division on how the wells will be shut-in. The plan must include at a minimum:
  - How the wells will be scaled down and shut-in
  - A temporary abandonment (T/A) plan for the wells for an extended shut-in period
    - Goodnight will need to request an exception to the 12-month continuous injection clause of their SWD orders to maintain injection authority as the pilot project proceeds during the T/A period.
  - Curtailment and redirection plan for the produced water
  - A reimplementation plan if the pilot is unsuccessful
  - A long-term plan if the pilot project is successful

Once Goodnight receives the 90 day "activation notice" from Empire they will be required to immediately implement the 60day shut-in plan. This will ensure no injection overlaps with the pilot program. This will provide Empire the opportunity to establish the CO2 flood without offset injection.

Brandon Powell
Deputy Director

Hardy | McLean LLC
ENERGY AND NATURAL RESOURCES ATTORNEYS

February 18, 2026

Via Electronic Mail
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Brandon Powell
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Re: ***Empire New Mexico, LLC's Request to Modify the Division's Implementation of OCC Order Nos. R-24004 and 24004-A***

Dear Deputy Director Powell:

I am writing on behalf of Empire New Mexico, LLC ("Empire") in relation to the New Mexico Oil Conservation Division's ("OCD" or "Division") "Implementation of OCC Orders 24004 and 24004-A" ("Implementation Decision") issued on January 15, 2026. As discussed below, Empire requests that the Division modify the Implementation Decision to allow Empire to establish a CO_2 Enhanced Oil Recovery ("EOR") *pilot project*—rather than a full-scale CO_2 EOR project—within the Eunice Monument South Unit ("EMSU"). Although New Mexico Oil Conservation Commission ("Commission") Order Nos. R-24004 and R-24004-A expressly contemplate a pilot project, the Implementation Decision requires Empire to amend the EMSU in its entirety and engage in a full-scale CO_2 EOR project. In this regard, the Implementation Decision contravenes the Commission's orders, fails to protect correlative rights and prevent waste, and should be amended.

As the Division is aware, this matter involves applications filed by Goodnight Midstream Permian, LLC ("Goodnight") and Empire regarding Goodnight's current and proposed injection into the EMSU. Following the hearing, the Commission entered its Order Denying Goodnight's Applications & Partially Granting/Partially Denying Empire's Applications (Order No. R-24004), on September 12, 2025 ("September Order").

The September Order denied Goodnight's applications to drill new disposal wells in Case No. 24123 (Piazza), Case No. 23614 (Gooden), Case No. 23615 (Hernandez), Case No. 23616 (Hodges), and Case No. 23617 (Seaver). Additionally, the September Order denied Goodnight's application to increase injection in the existing Dawson well in Case No. 23775. Finally, the

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EXHIBIT B

September Order suspended permits associated with Goodnight's injection wells in Case No. 24018 (Dawson), Case No. 24019 (Banks), Case No. 24020 (Sosa), and Case No. 24025 (Ryno) (collectively, Dawson, Banks, Sosa and Ryno are the "Suspended Wells").

Following entry of the September Order, Goodnight and Empire each filed a motion for rehearing. The Commission issued an order granting a limited rehearing in the above matters on October 17, 2025, to consider two questions of law:

1. Does the Commission have the legal authority to suspend existing Goodnight's injection wells in order to provide Empire with the opportunity to establish the CO_2 EOR pilot project, given that there was insufficient evidence presented at hearing to prove whether the ROZ [Residual Oil Zone] is recoverable?

2. Does Commission Order R-24004 provide OCD [Oil Conservation Division] with discretion in managing the suspension of existing Goodnight injection wells and to provide Empire the opportunity to establish a CO_2 EOR pilot project?

After considering briefing of the parties, and having held oral argument on November 13, 2025, the Commission issued an Amended Order Denying Goodnight's Applications & Partially Granting/Partially Denying Empire's Applications, Order R-24004-A, on December 17, 2025 ("December Order").

In its December Order, the Commission upheld its orders and findings in the September Order and ultimately determined the Commission can order the suspension of water injection into a ROZ. This includes suspension to allow Empire an opportunity to establish an EOR pilot project to determine recoverability.[1] Additionally, the Commission confirmed that the Division can and should manage suspension of Goodnight's injection to facilitate the EOR pilot project.[2]

In the Implementation Decision, the Division directed Empire to take the following steps to amend Order No. R-7766[3]:

1. Submittal of hearing application from Empire to the OCD requesting to establish a CO_2 EOR, this submittal must include:

    a. Summary of scope for the project including the area of the pilot project within the existing EOR project and the proposed use of existing wells or development of new wells.
    b. C-108 application for each proposed injection including the AOR reviews for each well.
    c. Request for the use of CO_2 including anticipated maximum surface injection pressures for each fluid (CO_2, water, produced gas)

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[1] *See* December Order, heading for Rehearing Issue I.
[2] *See* December Order, heading for Rehearing Issue II.
[3] Order No. R-7766 ("Waterflood Order") approved the initial waterflood project to commence within the EMSU. The Waterflood Order has been amended three times (R-7766-A; R-7766-B; and R-7766-C).

d. Corrosion plan for well construction, well monitoring and a procedure for how mechanical issues will be mitigated.
e. H_2S contingency plan (if applicable)
f. Notice as required for Division hearings
g. Planned or existing infrastructure supporting the injection and production
h. Anticipated schedules for development of key items of the CO_2 EOR pilot project
i. The division will review the applications to ensure compliance with OCD's rules and regulations

2. If the Division grants an order for the CO_2 EOR, Empire will ensure Goodnight is provided notice of an approved order.

3. Empire will provide an infrastructure implementation plan with a detailed schedule for tie-ins.

4. Empire must then submit identified C-101s, change of plans for existing wells or new wells APDs

   a. The division will review the applications to ensure compliance with the CO_2 EOR order and the OCD's rules and regulations.

5. The operator will provide OCD and Goodnight with a 30-day notice when they mobilize to drill or work over the proposed wells.

6. Empire will provide Goodnight and the OCD a 90-day "activation notice" of their anticipated commencement of the CO_2 flood. Commencement is identified as the first CO_2 injection and production. Empire will provide Goodnight and OCD notice of any extended delays.[4]

The Division has imposed a one-year deadline for Empire to complete Requirement No. 1 and an 18-month deadline for Empire to complete Requirement No. 4.[5] While Goodnight will have 60 days to shut in its Suspended Wells, that 60-day period does not begin to run until Empire completes the steps identified above. As a result, Goodnight's injection will continue unfettered despite the Commission's recognition that Empire has exclusive rights within the EMSU[6] and that Goodnight's operations conflict with Empire's exclusive rights and are causing waste within the EMSU.[7] As discussed below, Empire requests that the Division modify the Implementation Decision to comport with the language and intent of Order Nos. R-24004 and R-24004-A.

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[4] Implementation Decision at 1-2.
[5] *Id.* at 2.
[6] September Order at ¶¶ 40-41.
[7] September Order at ¶ III.A.

The Implementation Decision requires Empire to amend the Waterflood Order and implement a full-scale CO_2 flood within the EMSU rather than conduct a pilot project. Given the three-year timeline and the narrow scope of the pilot project—demonstrating recoverability of the ROZ—Empire should be permitted to pursue a pilot project without amending the Waterflood Order. Empire would only plan to amend the Waterflood Order if and when the pilot project is successful. Further, Empire requests that the Division reconsider its Implementation Decision to tailor its plan to a true pilot project, rather than a full-fledged EOR project.

In the context of enhanced oil recovery, a pilot project is typically a small-scale testing phase conducted before implementation of a full EOR project. Essentially, the pilot project permits the operator to run a small, short-term trial to determine if a full-scale project is viable. On the other hand, an EOR project seeks to maximize oil recovery over an entire field, long-term. Here, the Commission very clearly grants Empire the opportunity to establish a ***CO_2 EOR pilot project*** to ascertain the recoverability of the ROZ lying beneath the EMSU. Upon completion of the CO_2 EOR pilot project, Empire can then apply to implement an EOR project covering the entirety of the ROZ within the EMSU.

Requirement No. 1 directs Empire to submit a hearing application for approval of a CO_2 EOR project along with nine items that would typically be submitted when an operator seeks approval of a CO_2 EOR project. However, in accordance with Orders No. R-24004 and R-24004-A, Empire only intends to implement a CO_2 EOR ***pilot project*** within the EMSU. Although Empire would submit the required information should it decide to amend the Waterflood Order and establish a full-scale CO_2 EOR project, it should not be required to do so to establish a pilot project.

Empire's engineers are examining potential methods for the CO_2 pilot project and are determining which wells would serve best for the method selected. By way of example, an existing well within the EMSU could be utilized for a huff-n-puff recovery method. In that instance, a C-103 form—rather than a C-108—should be sufficient and would allow Empire the opportunity to comply with the three-year limited period afforded by the Commission. Any injection related to the pilot project would be short-term and test for oil production in the San Andres ROZ. Therefore, the information included in a C-108 form should not be necessary.

Additionally, since Empire intends to establish a pilot project rather than a full-scale EOR project, Requirement No. 3 is premature. Empire would provide an infrastructure implementation plan with a detailed schedule for tie-ins after completion of the pilot project, and upon Empire's application to implement a full-scale CO_2 EOR project. Until then, the information is premature and unnecessary. Requirement No. 3 also appears duplicative of Requirement No. 1(g).

Requirement No. 4, which requires Empire to submit C-101s for existing wells or new wells, is similarly premature. Empire should not be required to amend its existing well permits, or obtain new permits, until the pilot project is complete. The Implementation Decision's requirement that Empire provide new C-101s within 18 months of Order No. R-24004-A is particularly problematic because the pilot project will not be complete by that date.

Requirement No. 5 requires Empire to provide OCD and Goodnight with 30-days' notice when it mobilizes to drill or work over the proposed wells. Instead, Empire proposes to notify Goodnight when Empire submits C-103s to OCD. Given the narrow timeframe imposed by Order

Nos. R-24004 and R-24004-A, Empire would intend to commence work immediately once a C-103 is approved. Requiring otherwise would delay progress and impede Empire's ability to commence the pilot project in a timely manner.

Finally, Requirement No. 6 references a "CO_2 flood" rather than a pilot project. This language should be amended to refer to a pilot project. Commencement of the pilot project would be identified as the first injection of CO_2.

In summary, Empire requests that the Division amend its Implementation Decision to allow Empire to proceed with a CO_2 EOR pilot project in accordance with Order Nos. R-24004 and R-24004-A rather than a full-scale CO_2 EOR project that includes amending the EMSU. The Implementation Decision contravenes the Commission's orders and limits Empire's ability to establish recoverability of the ROZ within the prescribed deadlines.

Empire respectfully requests that the Division respond to this request by February 25, 2026 so that Empire can determine how to best proceed. Thank you for your attention to this matter.

Very truly yours,

/s/ Dana S. Hardy
Dana S. Hardy

cc: (via electronic mail)
Albert Chang
Phillip Goetze
Christopher Moander
Adam Rankin
Matthew Beck
Miguel Suazo

State of New Mexico
Energy, Minerals and Natural Resources Department

Michelle Lujan-Grisham
Governor

Erin Taylor
Acting Cabinet Secretary

Ben Shelton
Deputy Secretary

Albert C.S. Chang
Division Director
Oil Conservation Division

February 27, 2026

Dana Hardy
Hardy McLean
125 Lincoln Avenue
Suite 223
Santa Fe, NM 87501
dhardy@hardymclean.com

RE: Empire of New Mexico, LLC's Request to Modify the Division's Implementation of OCC Order Nos. R-24004 and R-24004-A.

Dear Ms. Hardy,

OCD is receipt of your letter concerning the above, dated February 18, 2026. After review and analysis of your letter and the underlying OCC Orders, OCD politely declines the opportunity to modify its Implementation Order. In support of OCD's declination, OCD provides the following response.

As a prefatory matter, the OCC provided the OCD with guidance as to its role in the conflict between Goodnight and Empire in OCC Order No. R-24004-A (***emphasis added***):

> "24. The Commission hereby concludes that **OCD has the authority, and may at its discretion, implement the "suspension" ordered on page 13 of the Commission's September Order "in order to provide Empire with the opportunity to establish the CO2 EOR pilot project."** September Order, §3 at page 13. The commission also concludes that the **OCD has the authority to impose the suspension ordered by September Order, #3 at page 13, on any schedule OCD deems necessary "in order to provide Empire with the opportunity to establish the CO2 EOR pilot project."** *Id.*"

OCD contends that it, *via* OCC Order No.R-24004-A, the Oil and Gas Act, and OCD's own regulations, possesses the authority to address Goodnight's injection and Empire's proposed EOR pilot project as OCD sees fit under the circumstances.

Empire begins its requests concerning OCD's Implementation Order by reiterating the OCC's findings in OCC Order No. R-24004, namely that Empire has exclusive rights in the EMSU and

EXHIBIT C

Goodnight's injection practices interfere with that right. OCD agrees that OCC Order No. R-24004 says precisely that. However, Empire appears to overlook that the OCC "may at its discretion, implement the "suspension" orders on Page 13 of the Commission's September Order "in order to provide Empire with the opportunity to establish the CO2 EOR pilot project." OCD's position is that there is no conflict between OCC Order Nos. R-24004 and R-24004-A.

> *"Order Nos. R-24004 and R-24004-A expressly contemplate a pilot project, the Implementation Decision requires Empire to amend the EMSU in its entirety and engage in a full-scale CO2 EOR project. In this regard, the Implementation Decision contravenes the Commission's orders, fails to protect correlative rights and prevent waste, and should be amended."*

The scope of the amendment to the current EOR order R-7766 is Empire's to propose, in order to meet the OCC's requirement and is expressly considered in Item #1(a) of OCD's implementation letter. OCD did not determine the scope of Empire's proposed EOR pilot project nor the scale of the proposed project. Injection into a formation for EOR requires a permit/order pursuant to 19.15.26.8.A(1)(b) NMAC no matter the size, because there is currently a statutory EOR order for operation in this project area with defined injection fluids and pressures and OCD cannot administratively change the existing order. Therefore, an amended order is required. Also see findings in OCC Order No. R-24004-A. ¶ 25: "The Commission further clarifies that none of the orders in this case preempt any relevant or applicable regulatory requirements for any party. **Empire must follow all relevant and applicable regulations and permitting processes if it chooses to exercise the opportunity the Commission has provided for it to establish a CO2 EOR pilot project." (*emphasis added*)"**

> *"In its December Order, the Commission upheld its orders and findings in the September Order and ultimately determined the Commission can order the suspension of water injection into a ROZ. This includes suspension to allow Empire an opportunity to establish an EOR pilot project to determine recoverability. Additionally, the Commission confirmed that the Division can and should manage suspension of Goodnight's injection to facilitate the EOR pilot project."*

OCD sees this as a statement and does not see a request or question. As part of the Division's implementation letter, OCD addressed how to "manage suspension of Goodnight's injection to facilitate the EOR pilot project." OCD's implementation letter is not vague and provides a clear roadmap for Empire.

> *"The Division has imposed a one-year deadline for Empire to complete Requirement No. 1 and an 18-month deadline for Empire to complete Requirement No. 4. While Goodnight will have 60 days to shut in its Suspended Wells, that 60-day period does not begin to run until Empire completes the steps identified above. As a result, Goodnight's injection will continue unfettered despite the Commission's recognition that Empire has exclusive rights within the EMSU and that Goodnight's operations conflict with Empire's exclusive rights and are causing waste within the EMSU. As discussed below, Empire requests that the*

State of New Mexico
Energy, Minerals and Natural Resources Department

Division modify the Implementation Decision to comport with the language and intent of Order Nos. R-24004 and R-24004-A."

"Requirement No. 1 directs Empire to submit a hearing application for approval of a CO2 EOR project along with nine items that would typically be submitted when an operator seeks approval of a CO2 EOR project. However, in accordance with Orders No. R-24004 and R-24004-A, Empire only intends to implement a CO2 EOR ***pilot project*** within the EMSU. Although Empire would submit the required information should it decide to amend the Waterflood Order and establish a full-scale CO2 EOR project, it should not be required to do so to establish a pilot project."

OCD reminds Empire of the following Commission finding in OCC Order No. R-24004, § (C), which OCD reiterated in its implementation letter:

"C. However, the Commission concluded it is premature at present to grant Empire's applications to permanently revoke the injection authority of the existing wells because the **Commission found Empire DID NOT adduce substantial evidence that their correlative rights in the Grayburg are CURRENTLY impaired by Goodnight's injection into the San Andres." (emphasis added)"** The commission determined there was not evidence of impairment by Goodnight current actions only that injection must be suspended so the production and injection would not overlap. See findings in R-24004-A also provided in the letter **"Goodnight's SWD [Salt-Water Disposal] wells cannot dispose of water when an active CO2 flood is being performed"** (**emphasis added**)." OCD also notes here that Empire alleges that it "should not be required" to file a hearing application for approval of Empire's purported EOR pilot project, but fails to provide any support for this claim. "

"The Implementation Decision requires Empire to amend the Waterflood Order and implement a full-scale CO2 flood within the EMSU rather than conduct a pilot project. Given the three-year timeline and the narrow scope of the pilot project—demonstrating recoverability of the ROZ—Empire should be permitted to pursue a pilot project without amending the Waterflood Order. Empire would only plan to amend the Waterflood Order if and when the pilot project is successful. Further, Empire requests that the Division reconsider its Implementation Decision to tailor its plan to a true pilot project, rather than a full-fledged EOR project."

As stated above, injection into a formation for an EOR pilot project requires a permit pursuant to 19.15.26.8.A(1)(b) NMAC no matter the size. The scope of the amendment is Empire's to propose. Empire may wish to review ¶ 25 of OCC Order No. R-24004-A (again reiterated in OCD's implementation letter): "The Commission further clarifies that none of the orders in this case preempt any relevant or applicable regulatory requirements for any party. **Empire must follow all relevant and applicable regulations and permitting processes if it chooses to exercise the**

opportunity the Commission has provided for it to establish a CO2 EOR pilot project." (***emphasis added***)"

> *"In the context of enhanced oil recovery, a pilot project is typically a small-scale testing phase conducted before implementation of a full EOR project. Essentially, the pilot project permits the operator to run a small, short-term trial to determine if a full-scale project is viable. On the other hand, an EOR project seeks to maximize oil recovery over an entire field, long-term. Here, the Commission very clearly grants Empire the opportunity to establish a* ***CO2 EOR pilot project*** *to ascertain the recoverability of the ROZ lying beneath the EMSU. Upon completion of the CO2 EOR pilot project, Empire can then apply to implement an EOR project covering the entirety of the ROZ within the EMSU."*

OCD addressed this request above.

> *"Requirement No. 1 directs Empire to submit a hearing application for approval of a CO2 EOR project along with nine items that would typically be submitted when an operator seeks approval of a CO2 EOR project. However, in accordance with Orders No. R-24004 and R-24004- A, Empire only intends to implement a CO2 EOR* ***pilot project*** *within the EMSU. Although Empire would submit the required information should it decide to amend the Waterflood Order and establish a full-scale CO2 EOR project, it should not be required to do so to establish a pilot project."*

OCD addressed this request above.

> *"Empire's engineers are examining potential methods for the CO2 pilot project and are determining which wells would serve best for the method selected. By way of example, an existing well within the EMSU could be utilized for a huff-n-puff recovery method. In that instance, a C- 103 form—rather than a C-108—should be sufficient and would allow Empire the opportunity to comply with the three-year limited period afforded by the Commission. Any injection related to the pilot project would be short-term and test for oil production in the San Andres ROZ. Therefore, the information included in a C-108 form should not be necessary."*

Please see OCD's response to this request above regarding the permitting process. "Huff-n-Puff" or other technology or techniques would be part of the application pursuant to the implementation letter Item #1(a).

> *"Additionally, since Empire intends to establish a pilot project rather than a full-scale EOR project, Requirement No. 3 is premature. Empire would provide an infrastructure implementation plan with a detailed schedule for tie-ins after completion of the pilot project, and upon Empire's application to implement a full-scale CO2 EOR project. Until then, the information is premature and unnecessary. Requirement No. 3 also appears duplicative of Requirement No. 1(g)."*

State of New Mexico
Energy, Minerals and Natural Resources Department

To show recoverability, OCD assumes sustained volumes of CO2 may be needed. If this is going to be accomplished by vehicle, please provide that as part of the application.

> *"Requirement No. 4, which requires Empire to submit C-101s for existing wells or new wells, is similarly premature. Empire should not be required to amend its existing well permits, or obtain new permits, until the pilot project is complete. The Implementation Decision's requirement that Empire provide new C-101s within 18 months of Order No. R-24004-A is particularly problematic because the pilot project will not be complete by that date."*

OCD is unclear as to how the injection of CO_2 will occur if empire does not intend to utilize a new or existing well. Wells are permitted for a specific purpose, thus if Empire intends to use existing wells, permits for those wells will need to be modified.

> *"Requirement No. 5 requires Empire to provide OCD and Goodnight with 30-days' notice when it mobilizes to drill or work over the proposed wells. Instead, Empire proposes to notify Goodnight when Empire submits C-103s to OCD. Given the narrow timeframe imposed by Order Nos. R-24004 and R-24004-A, Empire would intend to commence work immediately once a C- 103 is approved. Requiring otherwise would delay progress and impede Empire's ability to commence the pilot project in a timely manner."*

Submitting a form to OCD does not ensure the requested form will be approved, or that the work will be performed timely. Therefore, OCD maintains the original #5 requirement which requires that Empire provide a 30-day notice of work mobilization.

> *"Finally, Requirement No. 6 references a "CO2 flood" rather than a pilot project. This language should be amended to refer to a pilot project. Commencement of the pilot project would be identified as the first injection of CO2."*

See answers to this request above.

> *"In summary, Empire requests that the Division amend its Implementation Decision to allow Empire to proceed with a CO2 EOR pilot project in accordance with Order Nos. R-24004 and R- 24004-A rather than a full-scale CO2 EOR project that includes amending the EMSU. The Implementation Decision contravenes the Commission's orders and limits Empire's ability to establish recoverability of the ROZ within the prescribed deadlines."*

As provided above, OCD maintains that its implementation letter does not contravene OCC Order Nos. R-24004 and R-24004-A. Were OCD to indulge Empire's demands regarding the permitting process outlined in the implementation order, OCD would violate its own rules, requirements, and obligations under OCD's delegation of authority from the EPA and the Safe Drinking Water Act.

State of New Mexico
Energy, Minerals and Natural Resources Department

As such, OCD expects Empire to comply with the implementation letter and timeframes if they continue to explore the CO_2 EOR pilot project.

Should Empire wish to discuss the above, or other, matters, please let us know.

Regards,

Christopher Moander Digitally signed by Christopher Moander Date: 2026.03.03 10:04:51 -07'00'

Chris Moander
Assistant General Counsel
New Mexico Oil Conservation Division

1220 South St. Francis Drive ▪ Santa Fe, New Mexico 87505
Phone (505) 476-3441 ▪ www.emnrd.nm.gov/ocd/

11/8/95 approx 11:10

Central Vacuum Unit #097
30-025-03076

Approval from Jerry Sexton
(NMOCD District Supervisor)

Hollice Clay

Texaco

C Vut 97-C

Pkr & P.T.
for CO_2 Inj
6-18-32

P.T. 11:00 11/9/95

11/9/95 - Temp test per
Jerry - no special
order - as they have
received verbal
permission from Santa Fe

EXHIBIT D

Submit 3 copies to Appropriate District Office

State of New Mexico
Energ .nerals and Natural Resources Department

Form C-103
Revised 1-1-89

DISTRICT I
P.O. Box 1980, Hobbs, NM 88240
DISTRICT II
P.O. Box Drawer DD, Artesia, NM 88210
DISTRICT III
1000 Rio Brazos Rd., Aztec, NM 87410

OIL CONSERVATION DIVISION

P.O. Box 2088
Santa Fe, New Mexico 87504-2088

WELL API NO. 30-025-~~20754~~ 03076

5. Indicate Type of Lease: STATE ☒ FEE ☐

6. State Oil / Gas Lease No. B-1113-1

SUNDRY NOTICES AND REPORTS ON WELL
(DO NOT USE THIS FORM FOR PROPOSALS TO DRILL OR TO DEEPEN OR PLUG BACK TO A DIFFERENT RESERVOIR. USE "APPLICATION FOR PERMIT (FORM C-101) FOR SUCH PROPOSALS.)

7. Lease Name or Unit Agreement Name: CENTRAL VACUUM UNIT

1. Type of Well: OIL WELL ☒ GAS WELL ☐ OTHER

2. Name of Operator: TEXACO EXPLORATION & PRODUCTION INC.

8. Well No. 97

3. Address of Operator: P.O. BOX 730, HOBBS, NM 88240

9. Pool Name or Wildcat: VACUUM GRAYBURG SAN ANDRES

4. Well Location
Unit Letter C 660 Feet From The NORTH Line and 1810 Feet From The WEST Line
Section 6 Township 18S Range 35E NMPM LEA COUNTY

10. Elevation (Show whether DF, RKB, RT,GR, etc.) 3989' DF

11. Check Appropriate Box to Indicate Nature of Notice, Report, or Other Data

NOTICE OF INTENTION TO:				SUBSEQUENT REPORT OF:			
PERFORM REMEDIAL WORK	☐	PLUG AND ABANDON	☐	REMEDIAL WORK	☐	ALTERING CASING	☐
TEMPORARILY ABANDON	☐	CHANGE PLANS	☐	COMMENCE DRILLING OPERATION	☐	PLUG AND ABANDONMENT	☐
PULL OR ALTER CASING	☐			CASING TEST AND CEMENT JOB	☐		
OTHER:			☐	OTHER: BEGAN CO2 HUFF & PUFF PROJECT			☒

12. Describe Proposed or Completed Operations (Clearly state all pertinent details, and give pertinent dates, including estimated date of starting any proposed work) SEE RULE 1103.

11/9/95

TOH W/ PRODUCTION EQUIPMENT. TIH W/ INJECTION PACKER & SET @ 4013'. TSTD BACKSIDE TO 500 PSI, HELD OK.

TSTD CASING WITH INJECTION PACKER SET @ 4013' AS PER NMOCD GUIDELINES TO 540# FOR 30 MIN, HELD OK.

(ORIGINAL CHART SENT TO NMOCD, COPY OF CHART ON BACK)

11/14/95

BEGAN INJECTION OF CO2 INTO WELL

INJECTION RATE OF 1700 MCFPD OF CO2 @ 771 PSI TUBING PRESSURE.

(INTERNAL TEPI STATUS REMAINS PM)

RECEIVED
NOV 2 0 1995

Submit 3 copies to Appropriate District Office

DISTRICT I
P.O. Box 1980, Hobbs, NM 88240
DISTRICT II
P.O. Box Drawer DD, Artesia, NM 88210
DISTRICT III
1000 Rio Brazos Rd., Aztec, NM 87410

State of New Mexico
Energy, Minerals and Natural Resources Department

OIL CONSERVATION DIVISION

P.O. Box 2088
Santa Fe, New Mexico 87504-2088

Form C-103
Revised 1-1-89

WELL API NO. 30-025-~~20754~~ 03076

5. Indicate Type of Lease STATE ☒ FEE ☐

6. State Oil / Gas Lease No. B-1113-1

SUNDRY NOTICES AND REPORTS ON WELL
(DO NOT USE THIS FORM FOR PROPOSALS TO DRILL OR TO DEEPEN OR PLUG BACK TO A DIFFERENT RESERVOIR. USE "APPLICATION FOR PERMIT (FORM C-101) FOR SUCH PROPOSALS.)

7. Lease Name or Unit Agreement Name: CENTRAL VACUUM UNIT

1. Type of Well: OIL WELL ☒ GAS WELL ☐ OTHER

2. Name of Operator: TEXACO EXPLORATION & PRODUCTION INC

8. Well No. 97

3. Address of Operator: P.O. BOX 730, HOBBS, NM 88240

9. Pool Name or Wildcat: VACUUM GRAYBURG SAN ANDRES

4. Well Location
Unit Letter C : 660 Feet From The NORTH Line and 1810 Feet From The WEST Line
Section 6 Township 18S Range 35E NMPM LEA COUNTY

10. Elevation (Show whether DF, RKB, RT,GR, etc.) 3989' DF

11. Check Appropriate Box to Indicate Nature of Notice, Report, or Other Data

NOTICE OF INTENTION TO:				SUBSEQUENT REPORT OF:			
PERFORM REMEDIAL WORK	☐	PLUG AND ABANDON	☐	REMEDIAL WORK	☐	ALTERING CASING	☐
TEMPORARILY ABANDON	☐	CHANGE PLANS	☐	COMMENCE DRILLING OPERATION	☐	PLUG AND ABANDONMENT	☐
PULL OR ALTER CASING	☐			CASING TEST AND CEMENT JOB	☐		
OTHER:			☐	OTHER: start CO2 flowback for Huff-n-Puff			☒

12. Describe Proposed or Completed Operations (Clearly state all pertinent details, and give pertinent dates, including estimated date of starting any proposed work) SEE RULE 1103.

12-08-95: Last C02 injection. Averaged 2.1 MMcfpd at 675#. Total volume 50 mmcf. Shut in for "soak" period.

12-27-95: Start flowback on 12/64" choke at 646# FTP.

Society of Petroleum Engineers

SPE-222757-MS

Field Experiences: CO_2 HuffnPuff Test at the Minami-Aga Depleted Onshore Oil Field in Japan

Hiroaki Koga and Takashi Akai, Japan Organization for Metals and Energy Security, Tokyo, Japan; Yudai Kayamoto and Toshinori Nakashima, INPEX Corporation, Tokyo, Japan

This paper was prepared for presentation at the ADIPEC held in Abu Dhabi, UAE, 4 – 7 November, 2024.

Abstract

A huff‘n’puff CO_2 injection test was conducted in a depleted onshore oil field in Japan. This pilot test was conducted to evaluate the effectiveness of CO_2-enhanced oil recovery, assess the technical validity of various monitoring tools used for detecting CO_2 behavior in the reservoir, and gain operational experience with CO_2 injection.

The pilot test was conducted in a newly drilled well. Extensive geological information, including wireline logging and core sample acquisition, was collected before the pilot test and used to characterize the pilot test area and design the test procedures. Approximately 100 tons of high-purity CO_2 purchased from industry was transported to the site via trucks and injected into the newly drilled test well.

CO_2 injection last two days, during which a pump and heater at the site were used to maintain CO_2 in a dense liquid phase at the well-head condition. The well was then left to a soaking period for 23 days before being brought back into production for 5 days. A clear increase in oil production rate was observed after CO_2 injection. In addition, a production logging tool and a pulsed neutron reservoir saturation tool revealed the CO_2 flow paths and areas of residual oil remobilization.

This study presents the pilot test results, including the injection and production profiles, in situ CO_2 monitoring with wireline tools, and evaluation of well deliverability based on pressure transient analysis at each test sequence.

Introduction

Japan Organization for Metals and Energy Security (JOGMEC) and INPEX Corporation conducted the huff‘n’puff CO_2 injection test in the Minami-Aga onshore oil field in Japan. This pilot test aimed to evaluate the effectiveness of CO_2-enhanced oil recovery (CO_2-EOR), assess the technical validity of various monitoring tools for detecting CO_2 behavior in the reservoir, and gain operational experience with CO_2 injection.

Huff‘n’puff is a well-established single-well treatment consisting of CO_2 injection, soaking, and flowback. During the CO_2 injection stage, the remaining oil in a region near the wellbore comes into contact

EXHIBIT E

with injected CO_2, causing the oil to swell and lowering its viscosity and interfacial tension. Typically, CO_2 injection is followed by a soaking period to ensure contact between reservoir crude oil and CO_2. The well is then returned to production (Monger and Coma, 1988).

Because huff'n'puff operations using a single well require a relatively small amount of CO_2 compared to inter-well CO_2 flooding (Haskin and Alston, 1989; Halinda *et al.*, 2023), we decided to conduct a CO_2 huff'n'puff test as a field trial to evaluate the effect of enhanced oil recovery in this field.

During the test, we employed several wellbore monitoring tools to evaluate the performance of the test, such as a production logging tool to identify CO_2-flowing intervals and a pulsed neutron reservoir saturation tool to monitor the saturation of fluid in the near-wellbore region.

This study is organized as follows. We begin with an introduction to the Minami-Aga oil field, which includes reservoir descriptions based on newly acquired geological information at the test well. This is followed by the details of huff'n'puff operations. Next, we discuss the data obtained during the test, including the injection and production profiles. Lastly, we discuss the interpretation of the test based on the monitoring data acquired during the test.

Reservoir descriptions

The Minami-Aga onshore oil field, located in Niigata Prefecture, was discovered in November 1964. Full-scale development commenced in August 1965, reaching peak oil production of ~690 kL/d (~4,300 bbl/d) in the late 1960s. Production then continued at a reduced rate to manage a rapid decline in reservoir pressure until production ceased in November 2020. To date, ~30 wells have been completed as producers in the field (Figure 1).

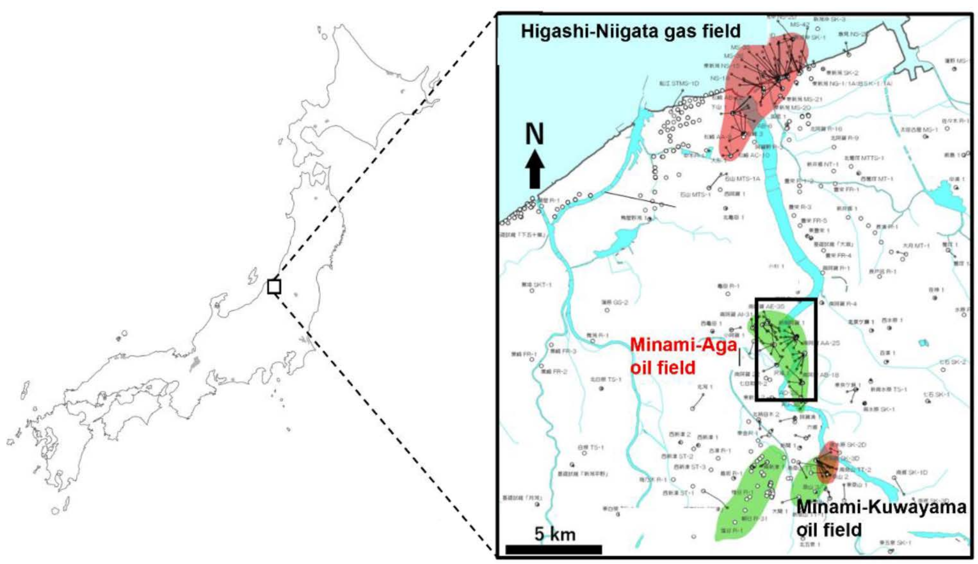

Figure 1—Location of the Minami-Aga oil field.

The oil-bearing horizon is a tuffaceous conglomerate and/or sandstone in the upper part of the Shiiya Formation at a depth of approximately ~2,200 m. The reservoir has a steep dip and pinches out to the west, forming a stratigraphic trap. The initial oil–water contact was interpreted at a depth of 2,250 m and is rising toward a shallow depth owing to strong aquifer brine invasion. The crude oil has a gravity of ~36°API, classifying it as light to medium quality.

The reservoir thickness increases toward the east, reaching ~30 m in the center of the reservoir. The depositional environment is interpreted as turbidite deposition flowing from the south to the north of the field. As a result of this sediment supply, cores obtained show low-permeability siltstone of less than 1 mD to massive conglomerate sandstone with high permeability of several hundred mD, indicating highly heterogeneous reservoir properties.

Petrophysical characteristics at the newly drilled pilot test well were interpreted using wireline logs and core data covering the overlaying caprock section to the underburden interval (Figure 2). The Shiiya Formation (the reservoir formation) was identified between 2,040 and 2,068 mSSTVD (meter subsea true vertical depth), providing a gross thickness of 28 m. The average reservoir porosity was 18%. The permeability of the reservoir was mainly characterized using core data measured from extensive sampling locations, ranging from <0.1 mD to hundreds of mD, resulting in a permeability thickness of 860 mD*m (with an average permeability of ~30 mD).

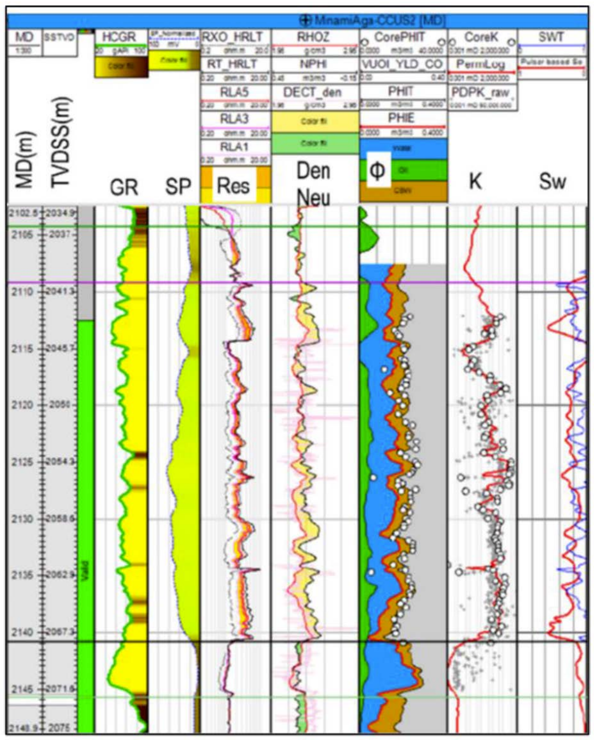

Figure 2—Petrophysical properties observed at the newly drilled test well. A reservoir section with a thickness of 28 m showed a permeability thickness of 860 mD*m and an average porosity of 18%.

Huff'n'puff test operations

A single-well huff'n'puff test involving pre-injection flow, CO_2 injection, soaking, and post-injection flow was conducted at CCUS-2 from September to November 2023. The operational sequence of the test is summarized in Table 1. The test began with the perforation of the newly drilled well, followed by a clean-up flow period to clear the wellbore vicinity and evaluate pre-injection conditions. Following the clean-up flow, pre-injection conditions were evaluated using pressure build-up (PBU) data and pulsed neutron saturation logging (Hereafter, we refer to Pulsar). Approximately 100 tons of CO_2 were injected over two days, during which a production logging tool (PLT) was run. After CO_2 injection, pressure fall-off (PFO) and Pulsar data acquisition evaluated postinjection conditions. After the CO_2 injection, the well was allowed to soak for 23 days (October 22 to November 14) before production for 5 days. Lastly, the test was completed with PFO and Pulsar data acquisition to evaluate post-flowback conditions.

Table 1—Operational sequence of the huff'n'puff test.

	Date	Duration (days)
Perforation	9/18 ~ 9/21	3
Clean-up flow	9/30 ~ 10/2	2
Pressure build up	10/3	
Pulsar-1[*1]	10/11	
CO2 injection including PLT[*2]	10/20 ~ 10/22	2
Pressure fall off	10/23	
Pulsar-2	10/24	
Flowback	11/14 ~ 11/19	5
Pressure build up	11/20	
Pulsar-3	11/21	

[*1] Pulsed nuetron logging

[*2] Production logging tool

The test equipment prepared at the test site is shown in Figure 3. We used high-purity CO_2 purchased from an industry located 80 km from the test site. The CO_2 was transported by an 8-ton truck. The CO_2 was delivered (by truck) to a booster pump and then to a main pump. The flowline from the main pump to the well head was heated with an electric heater. An N_2 lift unit and a separator were also set up for fluid production (clean-up and flowback).

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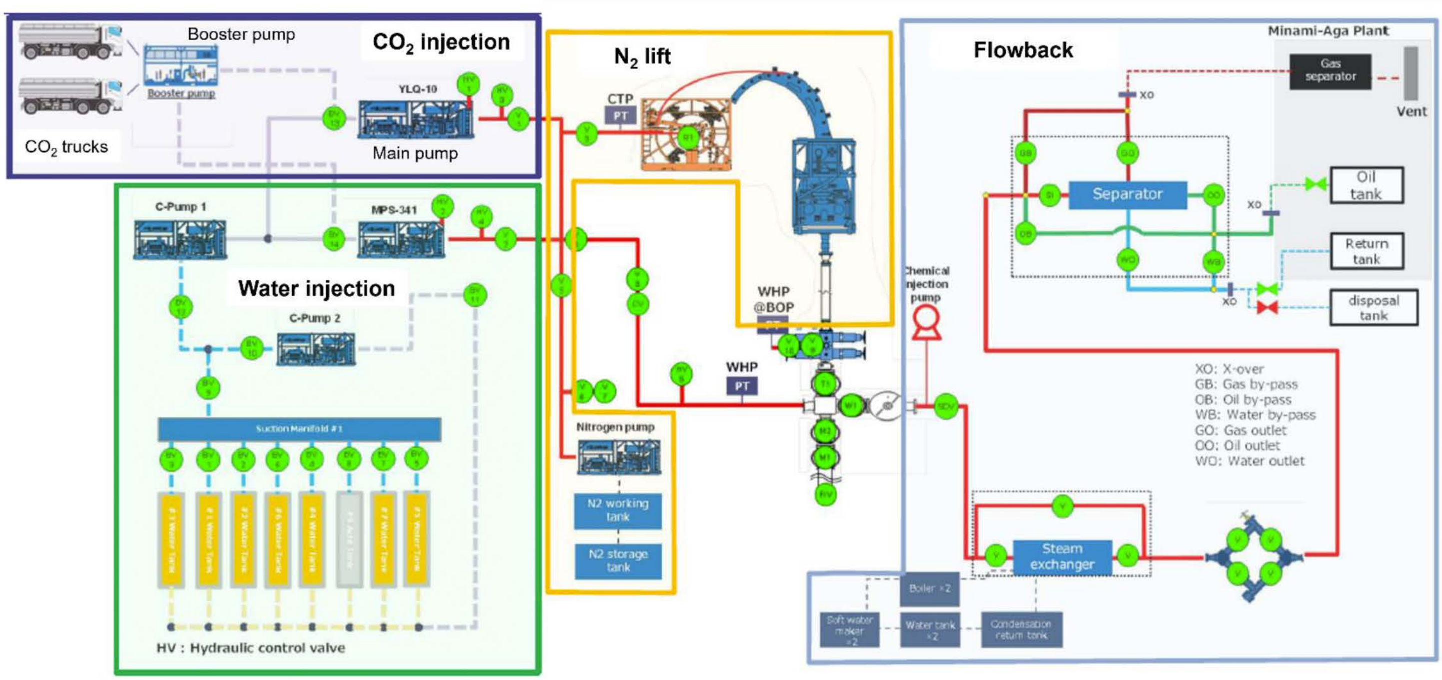

Figure 3—Test equipment at the test site composed of a CO_2 injection unit, a water injection unit, an N_2 lift unit, and a flowback unit.

Figure 4 shows the pressure and temperature during CO_2 injection from the well head to the bottom hole. CO_2 was maintained in a liquid phase at the well head with a pressure of ~800 psi and temperature of ~10°C using the main pump and electric heater. At the bottom hole, the pressure and temperature were ~2,700 psi and 95°C, meaning a super-critical phase. Data from the PLT during injection suggest a transition from liquid to super-critical CO_2 occurred at a depth of ~600 mMD (meter measured depth).

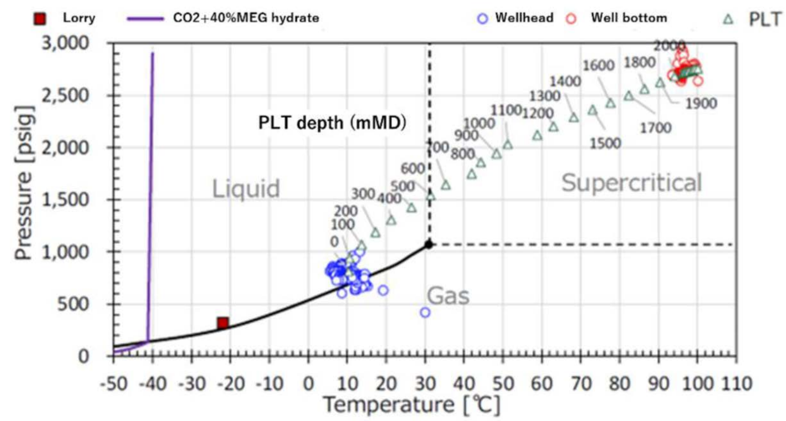

Figure 4—CO_2 Pressure (*P*) and temperature (*T*) phase diagram during CO_2 injection. Blue circles indicate *P* and *T* at the well head, while red circles indicate *P* and *T* at the bottom-hole condition. Triangles indicate *P* and *T* in the wellbore obtained from PLT during CO_2 injection. Numbers beside each triangle denote the PLT depth.

Pressure and temperature as a function of measured depth obtained with PLT during CO_2 injection are shown in Figure 5. The wellbore pressure and temperature profiles were simulated using the commercial pipe-flow simulator (Pipesim provided by SLB), employing the EoS model by Span and Wagner. The simulated pressure and temperature profiles matched the observed profiles well without any significant tuning.

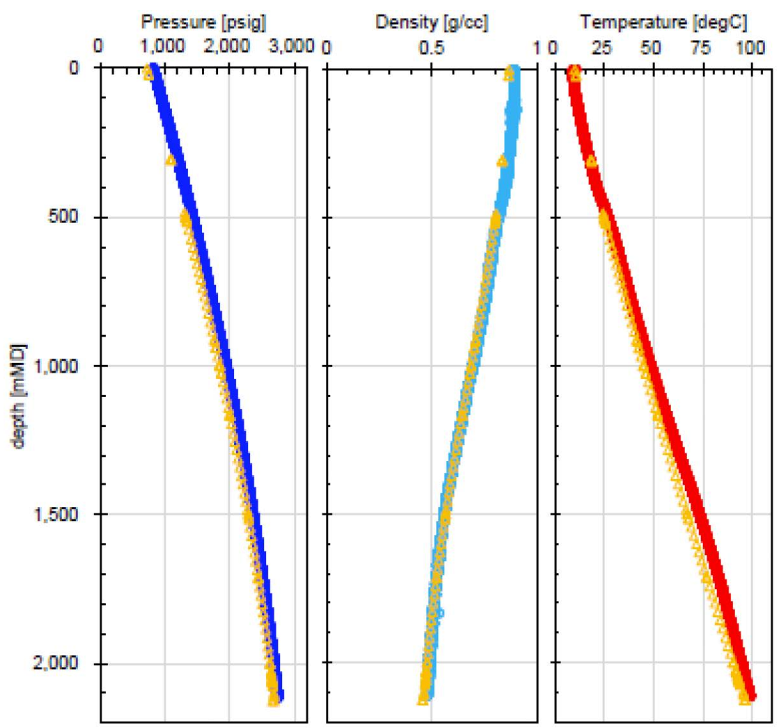

Figure 5—Pressure and temperature as a function of measured depth obtained with PLT during CO_2 injection. Blue, light-blue, and red represent observed pressure, fluid density, and temperature, respectively, while yellow triangles represent those obtained from simulations.

Results

CO_2 injection

Approximately 100 tons of CO_2 were injected over two days. Figure 6 shows the observed profiles during CO_2 injection. The injection rate ranged from 40 to 75 T/D, averaging 53 T/D. Throughout the injection period, well-head pressure and temperature were maintained at 300 psi and 10°C, respectively, ensuring smooth injection at the bottom hole, where pressure and temperature were ~2,700 psi and 95°C. Well-head and bottom-hole pressures initially increased and then decreased as the injection progressed. Injectivity (injection rate divided by differential pressure) during injection remained relatively stable at an average of 0.23 T/D/psi with slight increase in a later period of the injection (after October 22 00:00). This slight increase in injectivity was likely due to improve in effective gas permeability as the near wellbore gas saturation increased.

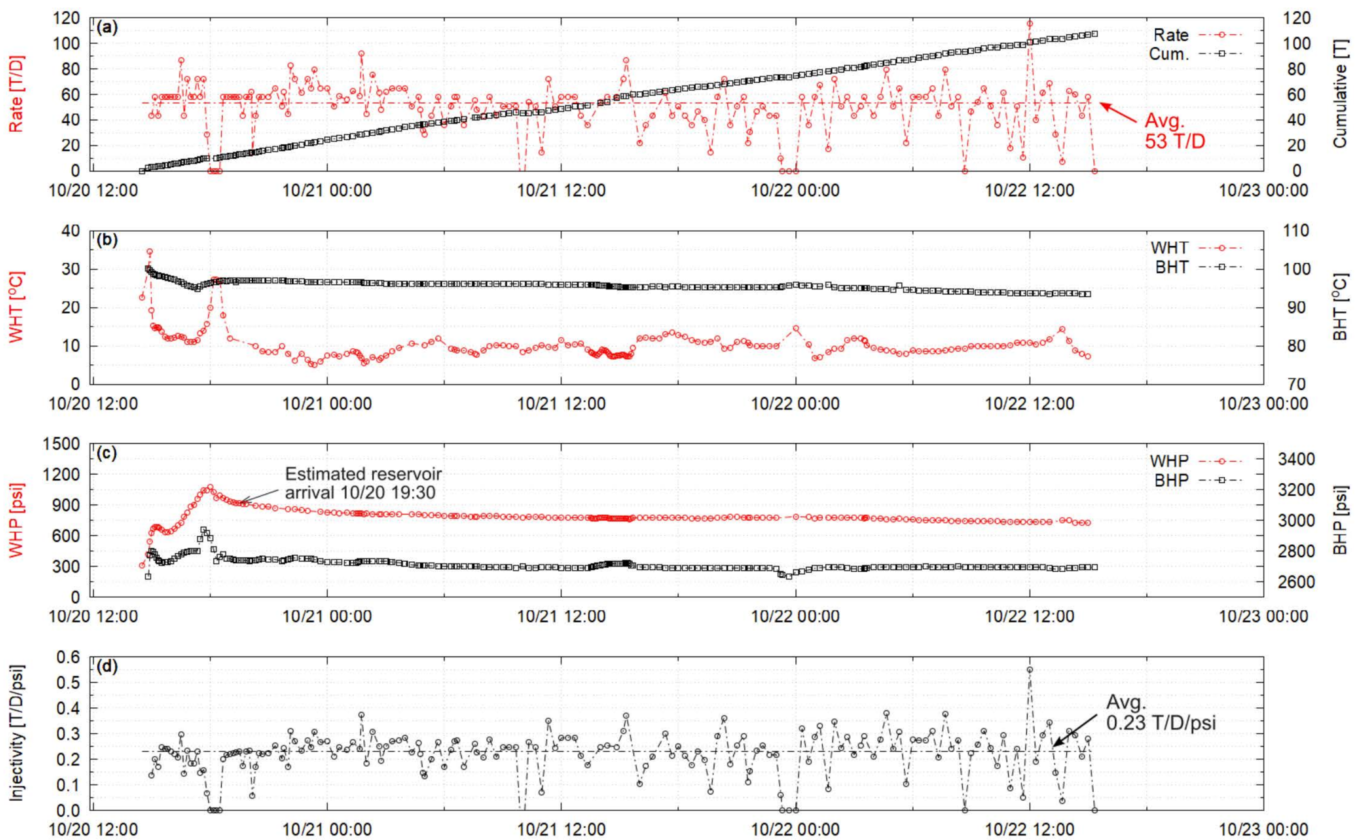

Figure 6—CO_2 injection profile. (a) CO_2 injection rate and cumulative total. (b) Well head and bottom-hole temperature. (c) Well head and bottom-hole pressure. (d) Injectivity index.

Flowback

The comparison of production performance between clean-up flow (pre-injection) and flowback (post-injection) is shown in Figure 7. The left column shows the performance of clean-up flow (pre-injection), while the right column shows the performance of flowback (post-injection).

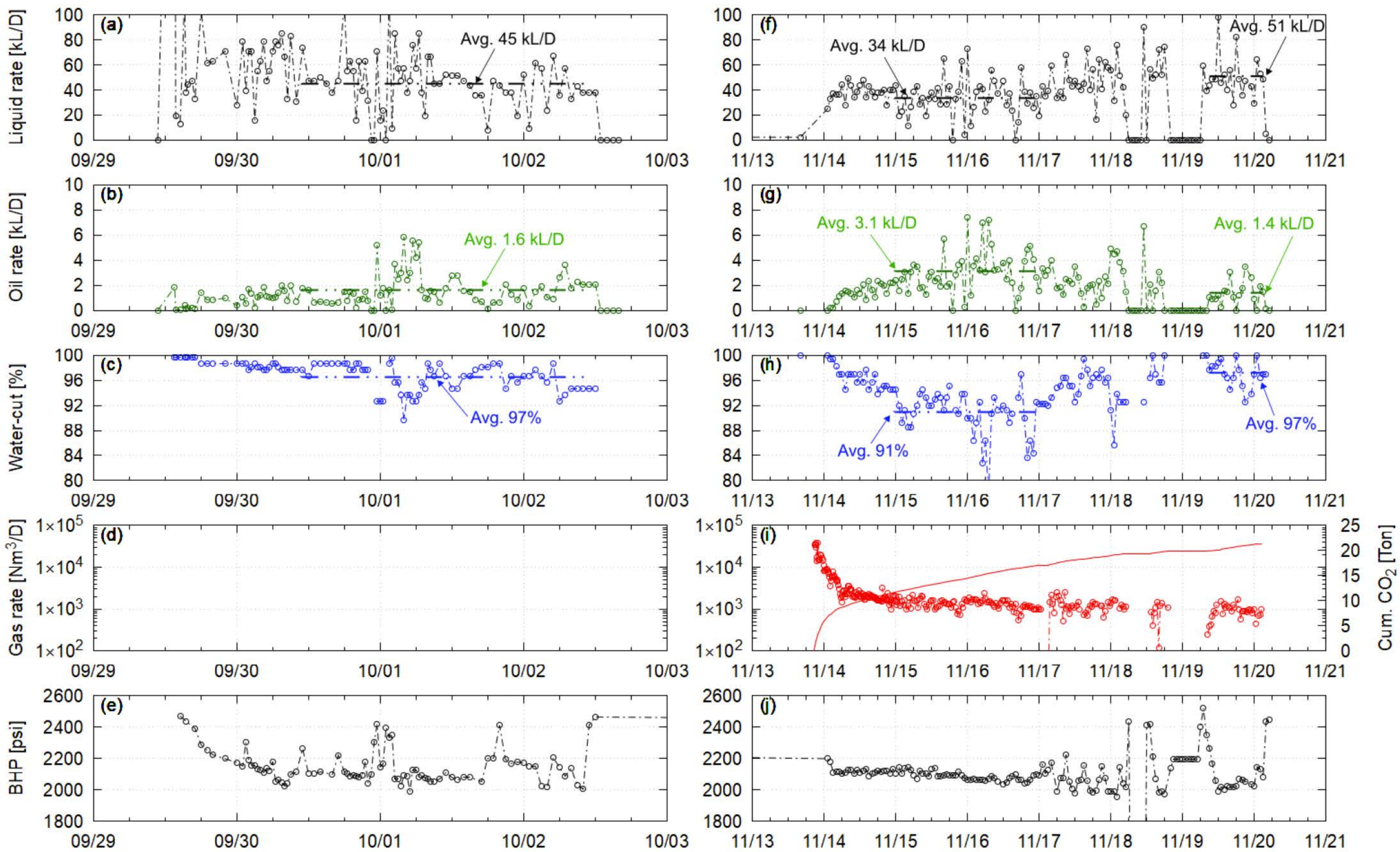

Figure 7—Production profile during clean-up flow before CO_2 injection (a–e) and flowback after CO_2 injection (f–j). The figures, from top to bottom, show liquid rate, oil rate, water cut, gas production rate, and bottom-hole pressure.

During clean-up flow (pre-injection), the test well exhibited a high water cut of ~97%. The liquid production rate averaged 45 kL/D (last 48 h after flow stabilization) at a bottom-hole pressure of ~2,100 psi. This liquid rate slightly decreased to 34 kL/D at the beginning of flowback (post-injection) owing to a high gas production rate. The oil rate increased from 1.6 to 3.1 kL/D (almost doubling), while the water cut decreased to 91% at the beginning of the flowback. After 5 days of flowback, both the oil rate and water cut returned to their pre-injection levels. At the beginning of flowback, the well produced a notable gas rate (>10^4 Nm^3/D), mostly of CO_2, which rapidly decreased to around 10^3 Nm^3/D and continued at this rate until the end of the flowback period. Consequently, ~20 tons of CO_2 were recovered, representing ~20% of the injected CO_2.

Identification of flowing intervals

To identify CO_2-flowing layers, we analyzed the results from PLT and Pulsar logging, as shown in Figure 8. The flow contribution from PLT aligned with the distribution of absolute permeability. Approximately 50% of the injected CO_2 entered a layer with the highest permeability of ~180 mD located at a depth of ~2,125 mMD. The remaining CO_2 flowed into other layers, as detected by near-wellbore saturation interpreted from Pulsar logging (Figure 8d).

We discuss the change in fluid saturation near the wellbore reservoir fluid during the huff 'n' puff test. Figure 9(c) shows changes in CO_2 saturation after CO_2 injection and flowback using data from Pulsar 2 and Pulsar 3 in Table 1. Yellow hatching highlights the reduction in CO_2 saturation after flowback. We observe that the higher the initial gas saturation, the higher the remaining CO_2 saturation, and these layers correspond to high permeability layers where CO_2 preferentially flows. Figure 9(d) shows the change in oil saturation before and after CO_2 injection (black and red in the figure, respectively) obtained from Pulsar 1 and Pulsar 2 in Table 1. The oil saturation before the CO_2 injection was ~20%, close to residual oil saturation, as indicated by high water cut during clean-up flow. After CO_2 injection, this oil saturation further reduced to low levels (red line), indicating remobilization of residual oil owing to CO_2 injection. This remobilization of oil is consistent with the observed increase in oil rate during flowback (post-injection).

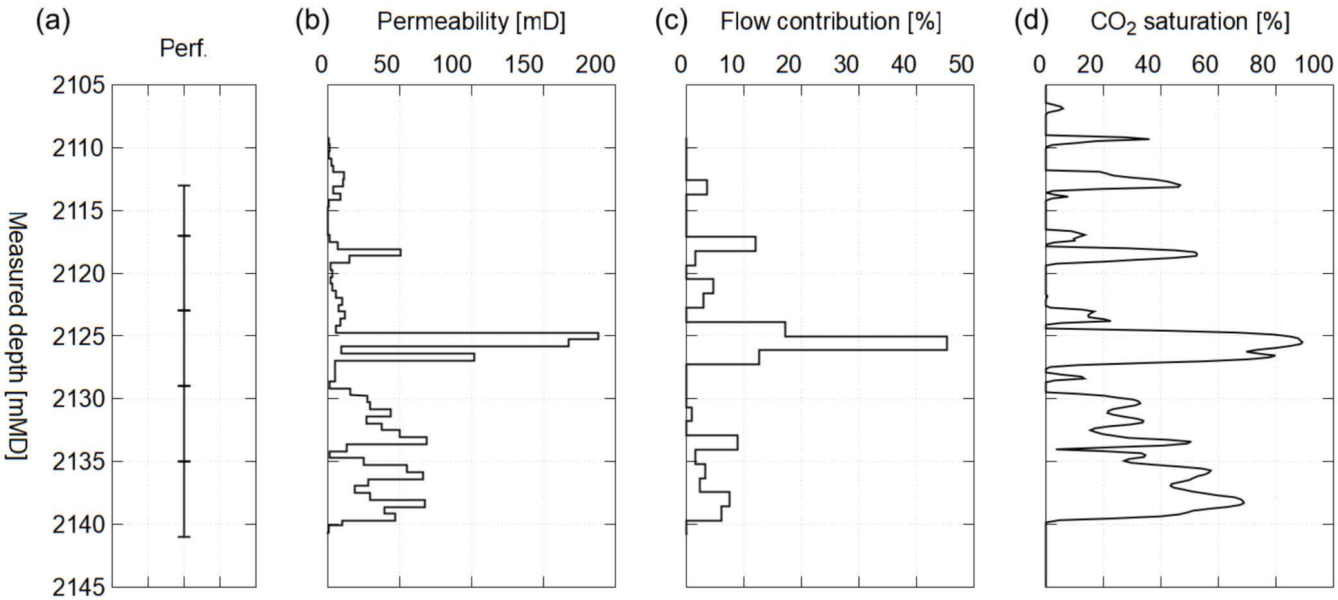

Figure 8—CO_2 flowing layers identified using PLT and Pulsar logging. (a) Perforation interval. (b) Distribution of absolute permeability. (c) Flow contribution determined from PLT. (d) CO_2 saturation determined from Pulsar logging.

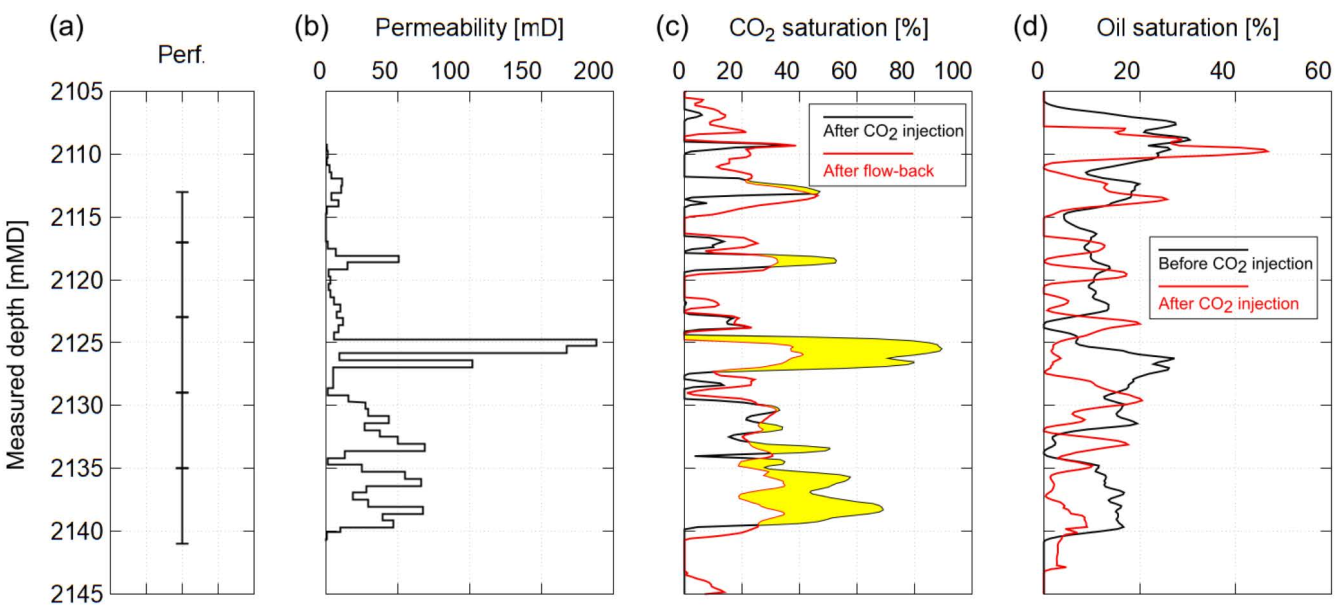

Figure 9—Change in fluid saturation in the near-wellbore region. (a) Perforation interval. (b) Distribution of absolute permeability. (c) CO_2 saturation after CO_2 injection (Pulsar-2; Table 1) and after flowback (Pulsar-3; Table 1). (d) Oil saturation before CO_2 injection (Pulsar-1; Table 1) and after CO_2 injection (Pulsar-2; Table 1).

Furthermore, we compare the CO_2 saturation observed after CO_2 injection with that observed after flowback (Figure 10). The former condition is close to maximum CO_2 saturation, while the latter condition is close to residual saturation condition. Maximum and residual saturations are known to follow the Land correlation derived from core measurements:

$$S_{gr} = \frac{S_{gmax}}{1 + C\frac{S_{gmax}}{1 - S_{wc}}},$$

Where S_{gr} is the residual gas saturation; S_{gmax} is the maximum gas saturation; S_{wc} is the connate water saturation; and C is the Land constant. Literature suggests C ranges from 0.7 to 2.0 based on Berea sandstone experiments (Krevor *et al.*, 2015). Our results obtained from field data are consistent with those of previous core measurement studies.

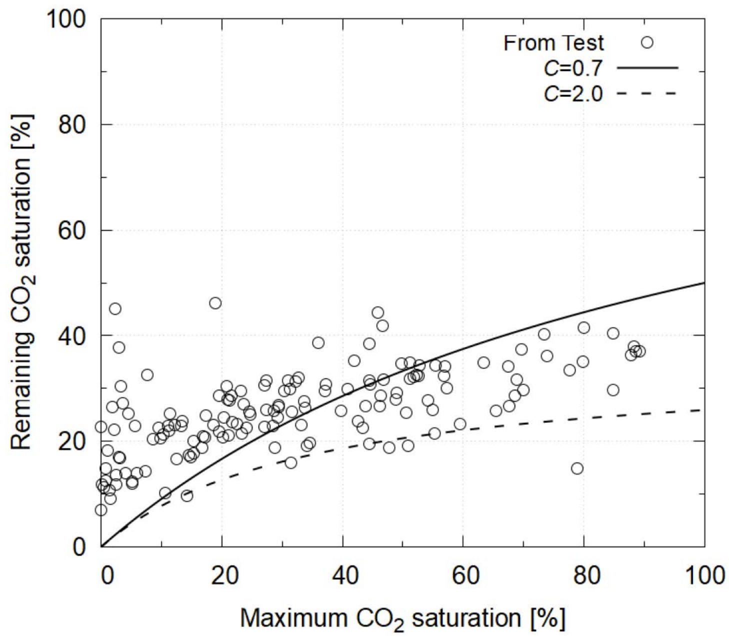

Figure 10—Cross plot of maximum CO_2 saturation (Pulsar 2; Table 1) versus minimum CO_2 saturation (Pulsar-3; Table 1) observed during the huff 'n' puff test.

Pressure transient analysis

The change in well flow capacity during the huff 'n' puff test was investigated by interpreting pressure transient data obtained from each event (Table 1), with results summarized in Table 2. Although there are several possible interpretations for determining well flow capacity, one of the possible interpretations is shown here.

Table 2—Summary of pressure transient analysis.

	Petrophysics	After clean-up flow (PBU[*1])	After CO2 injection (PFO[*2])	After flow-back (PBU)
Remarks	Determined from extensive core permeability measurements.	PBU after clean-up flow at a water-cut of ~97%, suggesting high water saturation in the reservoir.	PFO after ~100 T CO2 injection, at which near wellbore was filled with injected CO2.	PBU after flow-back at a water-cut of ~97%, suggesting high water saturation in the reservoir.
Flow capacity [mD*m]	860	178	96	178
Skin [-]	N/A	15.2	0.2	10.6
Relative permeability [-]	N/A	0.21 (Krw)	0.11 (Krg)	0.21 (Krw)

The flow capacity and skin factor derived from pressure transient analysis of the PBU after the clean-up flow were 178 mD*m and 15.2, respectively. Compared to the flow capacity estimated from absolute permeability in petrophysical interpretation, the water relative permeability during the clean-up flow was estimated at 0.21, close to the residual oil condition measured on cores. The high skin factor, indicative of near-wellbore damage, is attributed to insufficient clean-up flow.

The flow capacity and skin factor derived from pressure transient analysis of the PFO after the CO_2 injection were 96 mD*m and 0.2, respectively. This analysis used a radial composite model, assuming CO_2 in the near-wellbore region with higher mobility and brine in the outer region with lower mobility. In fact, we observed clear change in mobility in the derivative plot of the PFO data. From the result, the gas relative permeability was estimated to be 0.11.

Lastly, PBU analysis after flowback showed a flow capacity equal to that after clean-up flow, but the skin factor improved from +15.2 to +10.6. This implies that after 5 days of flowback, well deliverability returned to pre-injection levels with a slight improvement in the near-wellbore damage.

Conclusions

The huff‘n’puff test was successfully completed as planned without any safety incidents. The following conclusions can be drawn from the test:

CO_2 was maintained in a dense liquid phase at the well-head condition using a pump and heater, transitioning to a super-critical phase at a depth of ~600 mMD in the wellbore, as observed with PLT and characterized with commercial pipe-flow software, Pipesim.

The injectivity of the pilot test well remained stable at 0.23 T/D/psi with a slight increase in a later period of the injection.

An increase in oil rate by a factor of ~2 and a decrease in water cut by 6% were observed during flowback after CO_2 injection, indicating a clear enhanced oil recovery effect owing to CO_2 injection. The layers in which CO_2 flowed, i.e., residual oil was remobilized, were identified using PLT and Pulsar logging. These layers corresponded to the high permeability layers, as identified via petrophysical characterization before the test.

The maximum CO_2 saturation just after CO_2 injection and minimum CO_2 saturation after flowback, determined from Pulsar logging during the test, aligned with the Land correlation commonly observed in the laboratory studies.

Pressure transient analysis throughout the operations showed a qualitatively reasonable change in well deliverability.

Acknowledgment

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CO2 Huff and Puff Injection Operation Overview in Jatibarang Field Lessons Learned from a Successful Case Study in Mature Oil Field

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Abstract

The objective of this paper is to provide an overview of the CO2 Huff and Puff injection operation in the mature Jatibarang field, Indonesia, and share the lessons learned from a successful case study. The scope of this paper includes the project preparation, implementation, and troubleshooting. The aim is to provide insights into the key factors that contributed to the success of the project and to identify potential challenges and their solutions. The paper will present a comprehensive review of the CO2 Huff and Puff injection process, start from the design of the injection plan and the monitoring and evaluation of the injection process. The methods, procedures, and process used in the project will be discussed, including the selection of candidate wells, the injectivity test, the CO2 injection rate, and the well performance evaluation. The paper will also highlight the challenges faced during the implementation of the project and the solutions adopted.

The results of the CO2 Huff and Puff injection operation in the Jatibarang field are promising, with an oil production rate increase of up to 86% with minimum operational difficulties. The successful implementation of CO2 Huff and Puff injection operation in Jatibarang Field was mainly attributed to the good operation procedure that prioritized safety and efficiency. With careful planning and intensive discussion conducted to identify potential risks and minimize operational difficulties, the operation was able to run smoothly, with minimal issues and zero HSE incidents. One of the key challenges that CO2 injection operations usually face is the risk of pipe blockage due to CO2 freezing. Fortunately, no such incidents occurred during the operation. Continuous monitoring of the injection process and fluid properties managed to ensure that the CO2 remained in gas phase in surface and supercritical state in the bottom hole throughout the operation. In conclusion, the success of the CO2 Huff and Puff injection operation in Jatibarang Field was due to the careful preparation and execution of a well-designed operation procedure. The operation demonstrated that with the right approach, the potential risks and challenges associated with the project can be mitigated.

This paper will present novel information on the implementation of CO2 Huff and Puff injection in a mature oil field in Indonesia. The lessons learned and the best practices identified in this project can be of benefit to the petroleum industry, particularly for those dealing with mature oil fields. The paper will

EXHIBIT F

also provide insights into the design of the injection plan and the monitoring and evaluation of the injection process, which can be useful for future CO2 Huff and Puff injection projects.

Introduction

Indonesia's efforts toward decarbonization have been progressing since July 2021 when it announced its "Indonesia Long-term Strategy 2050 for Low Carbon and Climate Resilience," aiming to achieve carbon neutrality by 2060. This commitment aligns with the Paris Agreement (2015), a global treaty to combat climate change that aims to keep the global temperature rise well below 2 degrees Celsius above pre-industrial levels. To achieve this goal, Indonesia is committed to participating in overcome significant challenges, starting from investing in clean energy technologies, improving energy efficiency, and shifting away from fossil fuels to reduce carbon emission. As part of Indonesia's efforts to reduce carbon emissions, Pertamina has been at the forefront of implementing Carbon Capture, Utilization, and Storage (CCUS) programs in its oil and gas fields. CCUS technology is an essential component of the transition toward a low-carbon economy as it helps capture carbon dioxide emissions from industrial processes and stores them safely underground, preventing them from being released into the atmosphere and contributing to climate change.

The Jatibarang Field, located in Indonesia, has become a successful example of the practical application of CCUS technology. It stands as the first field where Pertamina has implemented CCUS, marking a significant milestone in the country's decarbonization journey. It has become a prime example of successful implementation of Carbon Capture, Utilization, and Storage (CCUS) technology through a collaborative effort between Pertamina, PEP, and JOGMEC (Japan Organization for Metals and Energy Security). The collaborative effort between these institutions is a clear demonstration of the importance of working together towards a common goal by facilitating knowledge transfer and overcoming technical barriers to develop new technologies that can contribute to achieving Indonesia's decarbonization goals. Through this partnership, Pertamina, PEP, and JOGMEC were able to develop and implement the CO2 injection project in the Jatibarang Field as a prime example of the collaboration's success, showcasing how it promotes sustainable energy production and reduce the country's carbon footprint.

Case Study

The Jatibarang Field is an onshore field discovered in 1968 and located in West Java (Figure 1), The field is currently operated by PEP (Pertamina EP) Region 2, a subsidiary of Pertamina, the Indonesian state-owned oil and gas company. To enhance oil recovery and investigate the potential of CO2 storage, the CO2 Huff and Puff test was conducted to acquire data that demonstrate and verify the effect of CO2 EOR and CO2 storage in the subsurface formations of depleted oil and gas fields. Notably, this project marked a significant milestone for Pertamina and PEP as it was the first time they implemented CO2 injection technology in an oil and gas field in Indonesia. This project provides valuable data and validation for the application of EOR technology at full scale in the Jatibarang Field. The findings and insights obtained from this project are likely to have far-reaching implications for the future implementation of CO2-based EOR and carbon storage strategies in other oil and gas fields in Indonesia and beyond.

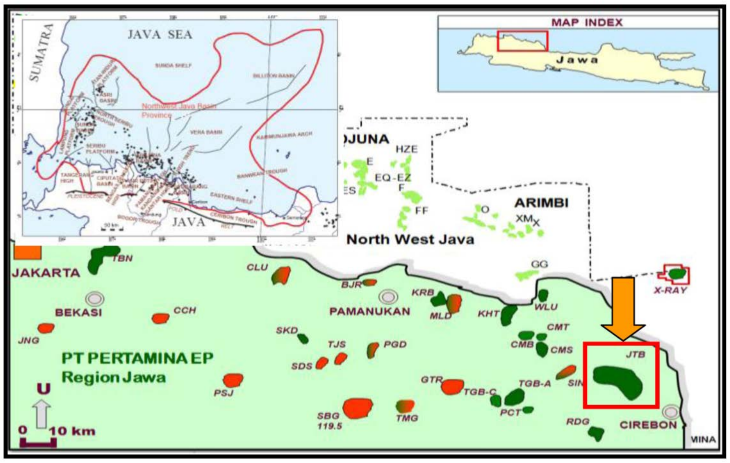

Figure 1—Jatibarang Field Overview.

The CO2 Huff and Puff injection process is a proven well-established technique used for enhanced oil recovery (EOR) and has been widely applied in mature oil fields worldwide. This process is particularly valuable in revitalizing aging oil reservoirs and maximizing their production potential. The fundamental principle of the CO2 Huff and Puff process involves injecting carbon dioxide (CO2) into the depleted oil reservoir. Once injected, the CO2 disperses throughout the porous rock formations and interacts with the residual oil, facilitating its mobility and reducing its viscosity. This phase of injection is commonly referred to as the "Huff" phase.

Following the injection stage, the reservoir is allowed to undergo a soaking or maturation period. During this time, the CO2 interacts with the remaining oil, leading to swelling of the oil and consequent pressure buildup in the reservoir. This pressure increase helps displace the oil and forces it towards the production wells. The duration of this stage depends on several factors, such as the reservoir characteristics, CO2 injection rate, and the volume of the reservoir. The final stage of the process is called the "puffing" phase. During this step, the pressure nearby the well will be decreased as the well is being opened. The pressure drop between well and reservoir will help to mobilize the oil and drive it towards the well. The CO2 and oil mixture are then produced back and separated on the surface. (Figure 2).

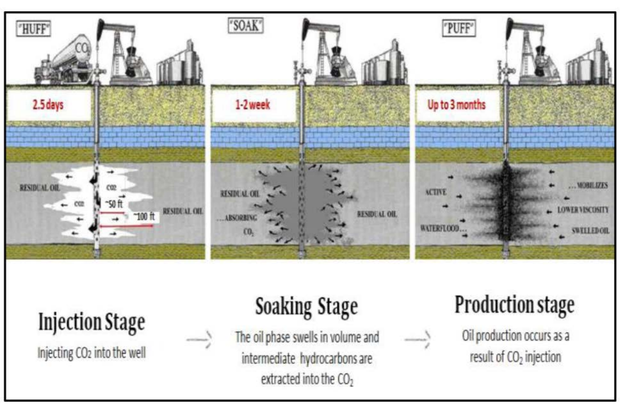

Figure 2—Huff & Puff CO2 Injection General Schematic

Throughout this process, various parameters such as changes in reservoir pressure, temperature, and fluid saturation are continuously monitored to assess the effectiveness of CO2 injection and the potential for CO2 storage. This monitoring is critical to optimize the process and maximize oil recovery while minimizing the environmental impact of the CO2 injection.

As well objectively as a first step towards full scale, the decision to opt for the Huff & Puff method is primarily driven by its lower CO_2 requirements compared to a full-scale injection project. By using smaller amounts of CO_2, the associated costs are significantly reduced, making it a more financially feasible option for the early stages of implementation. Additionally, the simplified execution process of the Huff & Puff method makes it more manageable and less complex from an operational standpoint. Workflow mechanism for the execution of the CO_2 injection Huff & Puff from the operational point of view in brief detail shown in Figure 5.

After going through the process of simulation and technical study, it was pre-defined that the treatment parameters will be as below:

Table 1—Treatment Parameters

Parameters	Design Value
Injected CO_2 volume	200-250 Ton (including injectivity volume)
Number of Cycles	1 cycle (continuous pumping, 24 hr operation)
Soaking time	14 days
Treatment Pressure	Max 1000 psi on surface
Injection Temperature	20-25 deg C
CO_2 phase during injection	Gas or Liq-Gas
Injection rate	80-100 Ton/Day (unit for Liq CO_2 inlet)

The treatment pressure is a critical parameter that requires close monitoring during the CO_2 Huff and Puff injection process, especially in the context of the Jatibarang case. One of the primary concerns in this regard is the limitation imposed by the bottomhole fracturing pressure of the reservoir. This pressure threshold must be carefully managed and prevented from being exceeded during the injection process to avoid the creation of unintended injection pathways and to ensure the overall effectiveness of the CO_2 injection.

For optimum oil recovery, the injection pressure is anticipated to reach the minimum miscibility pressure (MMP) at certain conditions during the CO_2 injection process. At MMP, injection gas stream becomes miscible with the reservoir crude oil to form a single phase through dynamic mass transfer interactions between reservoir crude oil and injected gas. At this point, the injected CO_2 can dissolve into the crude oil, reducing its viscosity and improving its mobility, thus increasing the amount of oil that can be recovered. However, a critical consideration in the Jatibarang oil reservoir is that its MMP is significantly higher than the fracture pressure of the reservoir. Therefore, it becomes imperative to design the treatment pressure below the MMP. By keeping the treatment pressure below the MMP, the risk of fracturing the reservoir is mitigated, ensuring that the injection process remains safe and efficient.

The CO_2 Huff and Puff injection test conducted in the Jatibarang Field was a comprehensive and well-monitored effort spanning six months. Throughout this period, CO_2 was injected into two oil wells within the reservoir, and extensive production data was collected for analysis. The test aimed to evaluate the impact of CO_2 injection on oil recovery and determine the overall effectiveness of the Huff and Puff CO_2 injection method. The results of the implementation were encouraging, showing positive outcomes for the oil production from the two wells. On average, the oil production increased significantly, with a remarkable up to 86% improvement compared to the pre-injection production levels (as depicted in figure 3) indicating the success of the CO_2 Huff and Puff injection process in improving oil recovery from the Jatibarang Field reservoir.

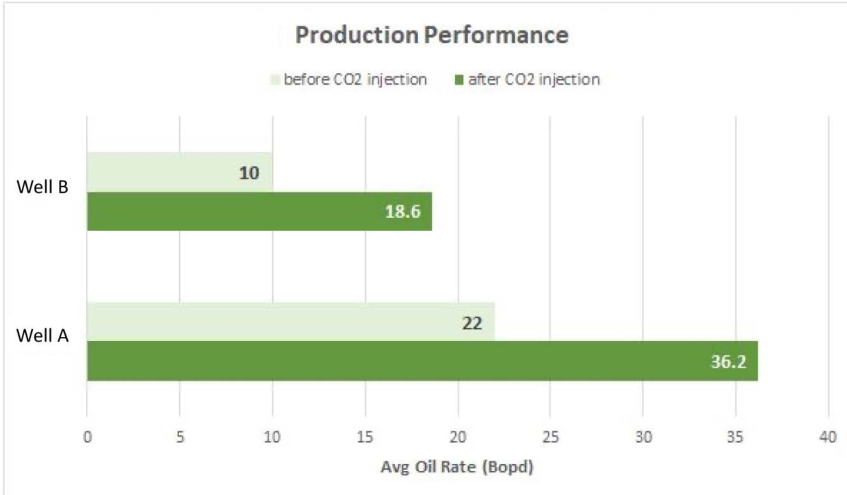

Figure 3—Huff & Puff Production Performance

Continuous monitoring and data collection and analysis are being carried out from the two wells after the Huff and Puff CO_2 Injection has been performed. This post-injection monitoring is of utmost importance as it enables the assessment of the long-term effectiveness of the injection process. It helps to gauge the sustainability of the increased oil production and evaluate any potential variations or changes in the reservoir's behavior over time.

The ongoing monitoring and data analysis also serve the purpose of identifying any potential risks or issues that may arise during the post-injection phase. By closely examining the data, experts can detect any unintended consequences or adverse impacts resulting from the CO_2 injection. Early detection of such issues allows for timely intervention and corrective measures, ensuring the safety and efficiency of the reservoir.

Operational Overview

The huff and puff CO_2 injection operation was performed in a rigless condition, which offers several advantages. By eliminating the need for drilling rigs, the operation becomes more cost-effective, environmentally friendly, and reduces potential risks associated with rig-based operations. To execute the CO_2 injection process, a nearby CO_2 extraction plant located in Subang city served as the primary source of CO_2. This extraction plant captures CO_2 gas from nearby Subang gas field.

The distance between the Jatibarang oil field, where the CO_2 injection took place, and the Subang CO_2 extraction plant was approximately 180 km. While having a nearby CO_2 source is advantageous, transporting CO_2 over such a significant distance presents logistical challenges. Since no pipeline was lied down for the operation, it relied on iso tank trucks to transport CO_2. These trucks proved to be a reliable solution for transporting CO_2 over long distances, ensuring the huff & puff operation could have a continuous supply of CO_2 throughout the injection stage.

Maintaining non-stop 24-hour operation in the huff and puff CO_2 injection process was crucial for maximizing its effectiveness and economic benefits. To achieve this, careful scheduling and coordination of iso tank trucks were paramount. The schedule had to consider transportation time from the Subang plant to the Jatibarang field, potential traffic or logistical challenges along the route, and the capacity of the iso tank trucks. Any delay or interruption in CO_2 supply could result in downtime for the operation, leading to reduced oil production and financial losses.

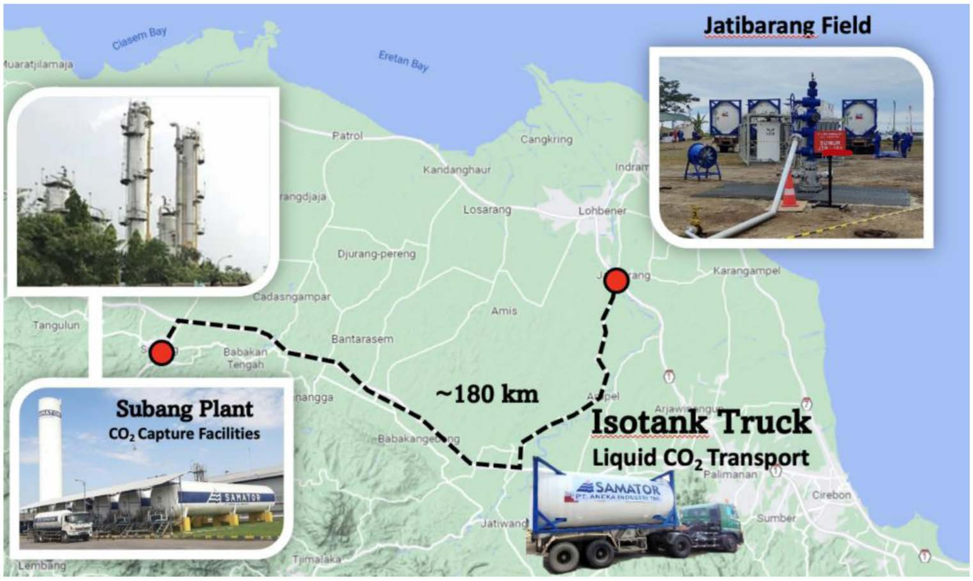

Figure 4—Operation Overview.

The CO2 Huff & Puff operational workflow involves several essential steps that are crucial for the successful implementation of the CO2 injection process. The workflow can be broken down into four main phases as below Figure 5:

1. Pre-Work CO2 Huff & Puff Operation, this line would include all the operation related with rig and well intervention before CO2 injection, this operation will include but not limited to:

   a. Well Intervention, operation that in general would be covered here are consists of: remedial cementing (squeeze operation), re-perforation existing interval and/or perforation targeted interval
   b. Logging Services, specifically to perform initial reservoir saturation validation before CO2 Huff & Puff injection, in addition to this operation if in the well intervention operation require remedial cementing then validation of the cementing bond log quality would be mandatory to be performed with the logging tool
   c. Artificial Lift Dismantling, in the case of the well is using any artificial lift method then pre-work operation would require to perform rig operation to dismantle the existing pump on the injected well
   d. Coiled Tubing Services, various operations prior to CO2 Huff & Puff injection could be performed either as contingency or main pre-work operation such as unload dry well target, drill out cement after remedial cementing operation.
2. CO2 Injection Period, detail of this line of operation been described as above Figure 3. In addition to this operation, injectivity test performed prior to the main injection with objective to initiate CO2 injection to the targeted interval within several attempt of the CO2 injection rate to validate the reservoir response, especially the response of the pressure during CO2 injection.
3. Soaking Period, detail of this line of operation been described as above Figure 3 with additional information to be monitored during soaking period specifically are tubing pressure (wellhead pressure) and annulus pressure. Pressure build up in the tubing pressure could be further analyze with the pressure transient analysis, and with early time period validation of the possible skin value after CO2 injection could be resulted. Presence of the annulus monitoring during soaking period would validate well integrity in which annulus pressure monitoring supposed to be remain constant.

4. Put on Production Period, detail of this line of operation been described as above Figure 3, this period will be preceded with the intervention operation of running saturation logging tool post CO2 injection. Then continue with several main operation during monitoring period that must be considered, with several important aspects are early production facilities (EPF) to monitor post CO2 injection productivity rate as well the sampling point to analyze the gas compositional - properties, water analyses and oil compositional - properties from the wells.

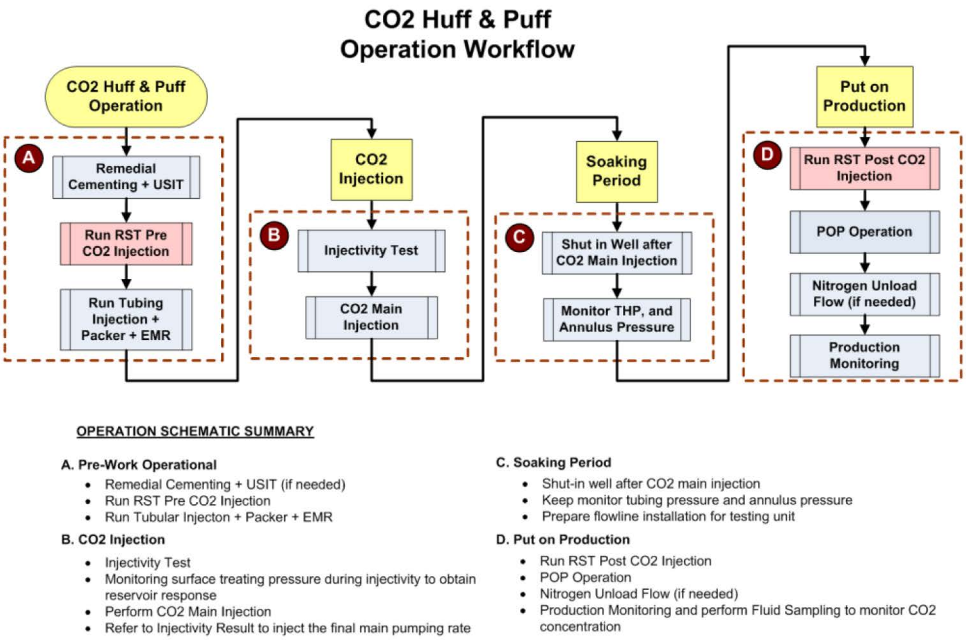

Figure 5—CO2 Huff & Puff Operational Workflow

Lesson Learned

During the Huff & Puff process, CO2 gas is injected into the reservoir and the CO2 interacts with the remaining oil, leading to swelling of the oil and consequent pressure buildup in the reservoir. A notable decrease in the oil's API gravity was observed, dropping from 37° to 28° API before it went back again to the normal oil API after 100 days due to limited CO2 injection volume. The API gravity is a measure of an oil's density compared to water; lower values indicate heavier oils, while higher values indicate lighter oils. Therefore, the decrease in API gravity suggested that the oil became heavier after the Huff & Puff Injection.

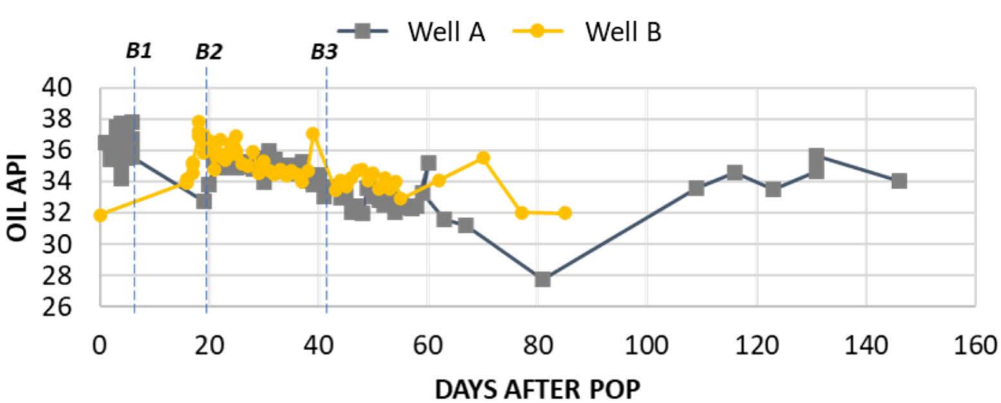

Figure 6—Oil Samples Analysis

The reason behind this change in API gravity was attributed to the behavior of previously immobile heavier hydrocarbon components within the reservoir. With the introduction of dissolved CO2, these heavier components started to swell. This swelling phenomenon made them more mobile and accessible for extraction. Additionally, the dissolved CO2 caused a decrease in the viscosity of the heavier hydrocarbon components. Lower viscosity allows the oil to flow more easily, making it easier to extract from the reservoir during the production process. However, despite the individual heavier hydrocarbon components becoming more mobile and resulting in lower viscosity, the overall API value of the total oil decreased after the Huff & Puff Injection. It was due to the heavier oil mixed with the lighter oil already present in the reservoir. The increased presence of heavier oil in the mixture contributed to the drop in the API gravity of the produced oil.

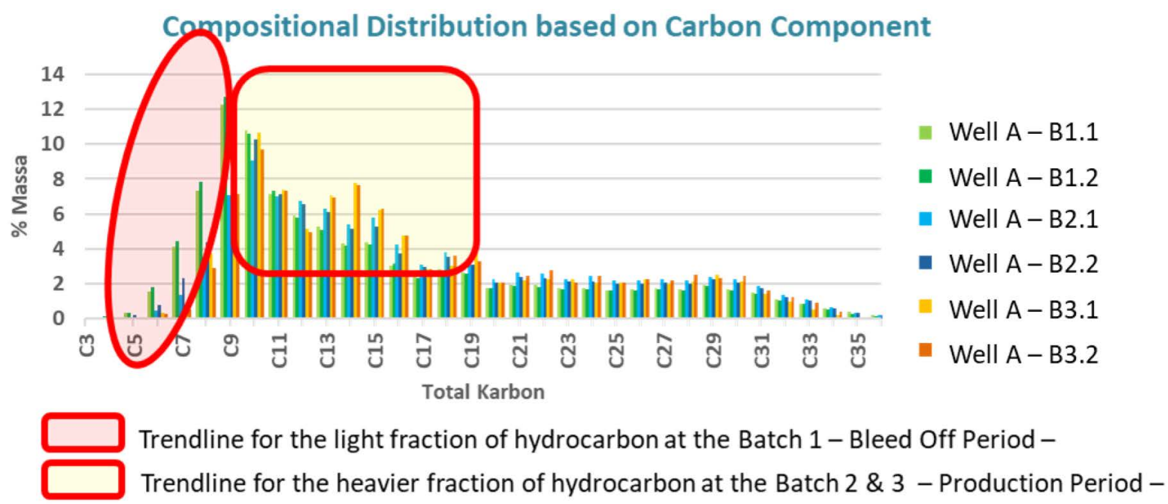

Figure 7—Oil Composition Lab Test Result

To gain a deeper understanding of the changes caused by the Huff & Puff Injection, an analysis of the oil composition was conducted using three batches of oil sample taken in different period post Huff & Puff CO2 injection: Batch 1 (B1), Batch 2 (B2), and Batch 3 (B3). The results confirmed that after the injection process, there was a higher concentration of C10 to C19 hydrocarbon components in B2 and B3 compared to the lighter oil composition observed during the early production phase (B1). This finding supported the notion that the heavier hydrocarbon components, which were previously immobile, were now actively participating in the oil production process and contributing to the increased oil output. Nevertheless, the overall impact of the injection was positive, as it effectively enhanced the oil recovery process by mobilizing previously trapped heavier hydrocarbons, leading to a more productive reservoir and increased oil yield.

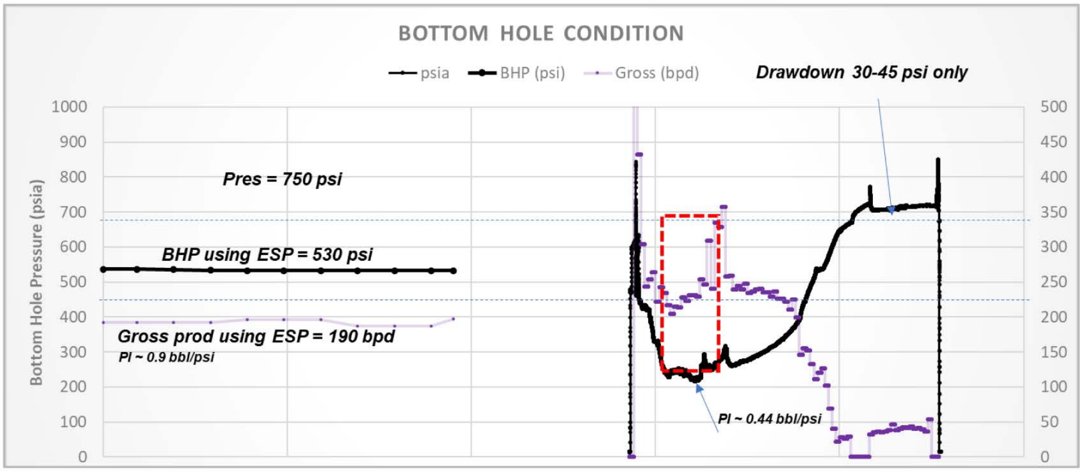

Figure 8—Huff & Puff Production Performance

By analyzing both electromagnetic resonance (EMR) data and production data obtained after the CO2 injection,a significant decrease in the productivity index (PI) following the injection of CO2 into the reservoir. A decrease in PI by up to −50% sfrom 0.9 bbl/psi to 0.44 bl/psi suggests a considerable decline in the productivity of the reservoir. The sharp decline in the PI after CO2 injection raises important questions and necessitates further investigation. This negative impact on the PI could be attributed to various factors associated with CO2 injection, such as reservoir fluid interactions, mineral precipitation, or changes in the reservoir's physical properties.

A study by Kaszuba et al. highlights a significant issue associated with the injection of supercritical CO2 into the reservoir - desiccation of the aqueous phase. When supercritical CO2 comes into contact with the reservoir's brine (water phase), it acts as a powerful desiccant, effectively removing moisture from the brine and creating a relatively dry environment. As a result, the lack of water in the brine leads to the precipitation of salts and scaling within the reservoir. The formation of scales and salts poses a serious problem as it can impede the injectivity of CO2, hindering its efficient injection into the reservoir.

In carbonate formations, two major minerals, calcium carbonate (CaCO3) and sodium chloride (NaCl), play a significant role in porosity and permeability reduction. When CO2 is injected in a dry state into the reservoir, it comes into contact with the brine, leading to the partial dissolution of water (H2O) in the dense CO2. Under high injection rates, significant amounts of water can transfer to the CO2 phase, resulting in the concentration of aqueous species in the brine. It also induces an increase in pH levels and raises the concentration of chloride ions (Cl−) in the brine due to desiccation. These changes in the brine chemistry facilitate the formation of CaCO3 and NaCl precipitates, leading to clogging and reduction in the reservoir's porosity and permeability. Moreover, scale occurrence was also found inside tubing up to 250 meters from perforation interval as shown in figure 7.

Figure 9—Scale Occurrence Inside Tubing

The Huff and Puff method has been extensively researched in various studies to investigate the effectiveness of the Huff and Puff method and to develop optimization strategies for the technique (Cheng et al, 2018; Luo et al, 2021; Zhu et al, 2019). In overall, the extensive research conducted on the Huff and Puff method demonstrates the potential of this technique for increasing oil recovery rates in depleted oil reservoirs. By optimizing injection parameters and combining the method with other EOR techniques, the effectiveness of the Huff and Puff method can be further enhanced.

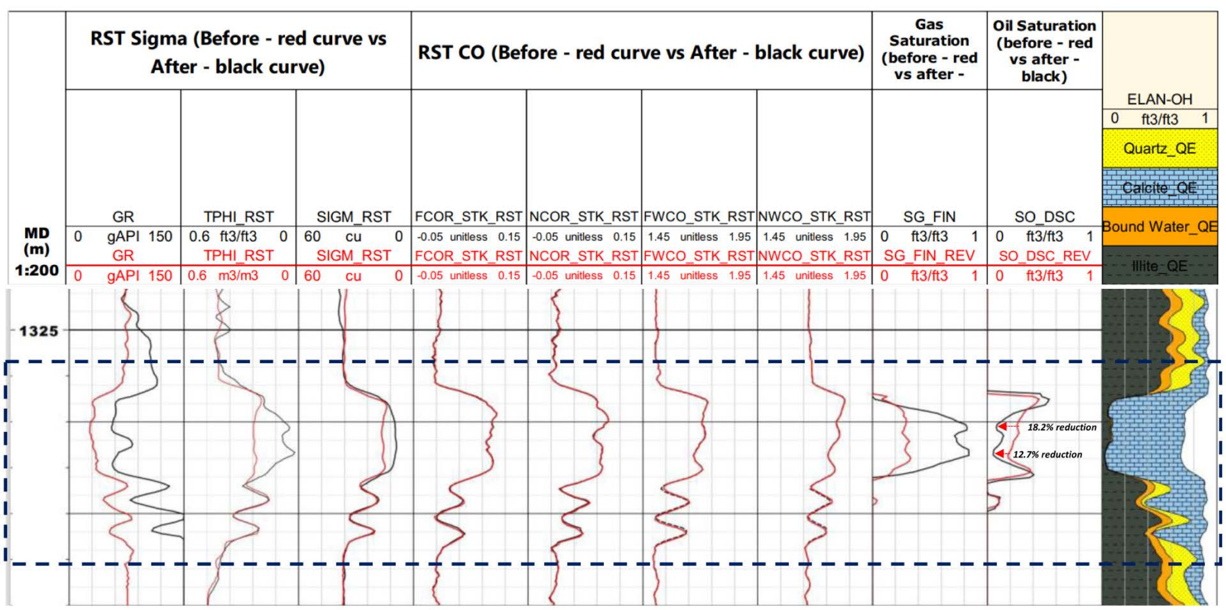

Figure 10—RST Survey Result

Before and after the huff and puff CO2 injection, Reservoir Saturation Tool (RST) measurements were conducted to evaluate the changes in fluid saturation within the reservoir. The RST is a crucial tool used in the oil and gas industry to assess the distribution of different fluids in the subsurface reservoir. By performing RST both before and after the CO2 injection process, engineers and geologists aimed to gain valuable insights into how the reservoir fluids interacted with CO2 and how this interaction affected the fluid saturation within the reservoir. The primary objective behind conducting RST measurements before and after the huff and puff CO_2 injection was to understand the impact of CO_2 on fluid saturation in the reservoir. It is crucial to understand how CO_2 interacts with the reservoir fluids and how this process affects the distribution and displacement of oil and gas within the rock formations.

The results of the RST measurements revealed that the huff and puff CO_2 injection process led to a substantial reduction phenomena in oil saturation within the reservoir. Comparing the fluid saturation levels before and after the CO_2 injection, it was observed that the oil saturation decreased by an impressive value between 12 to 18%. This reduction in oil saturation indicates that the injected CO_2 effectively displaced and replaced some of the oil in the porous rock formations. Such a finding is highly encouraging as it demonstrates the potential of CO_2 injection as an efficient method for enhancing oil recovery and simultaneously sequestering carbon dioxide.

Correspondingly, a considerable increase in gas saturation within the reservoir was recorded indicating that the gas saturation levels surged by up to 50% after the CO_2 injection. This phenomenon can be attributed to the CO_2 occupying most of the pore volume in the rock formations. As CO_2 is injected into the reservoir, it displaces not only oil but also some of the existing gas and water present in the pore spaces.

When considering the economics analysis of CO_2 Huff and Puff in relation to enhanced oil recovery (EOR), additional factors come into play. EOR involves injecting CO_2 into oil reservoirs with the beneficial parameter objectively at the full field scale to increase oil production, but for the CO_2 injection Huff & Puff would need to be treated differently as initial phase and different objective to be achieved as proof of concept need to be applied despite the project cost would be implied in marginal result.

Several parameter for the cost analysis for the CO_2 Injection Huff & Puff considerations for this case study would be:

1. Pre-Work CO_2 Huff & Puff operational cost, as described in the Figure 5
2. Cost of the CO_2 equipment services (Figure 11), which consists of the all designated equipment for CO_2 injection with main technical requirement of the services would be CO_2 resistant material proven.
3. Cost of CO_2 consumables materials in the form of liquid cryogenic that be pumped in the reservoir as well the cost of the transportation (Figure 4).
4. Monitoring Production equipment services (Figure 12, Figure 13), as described in the Figure 5

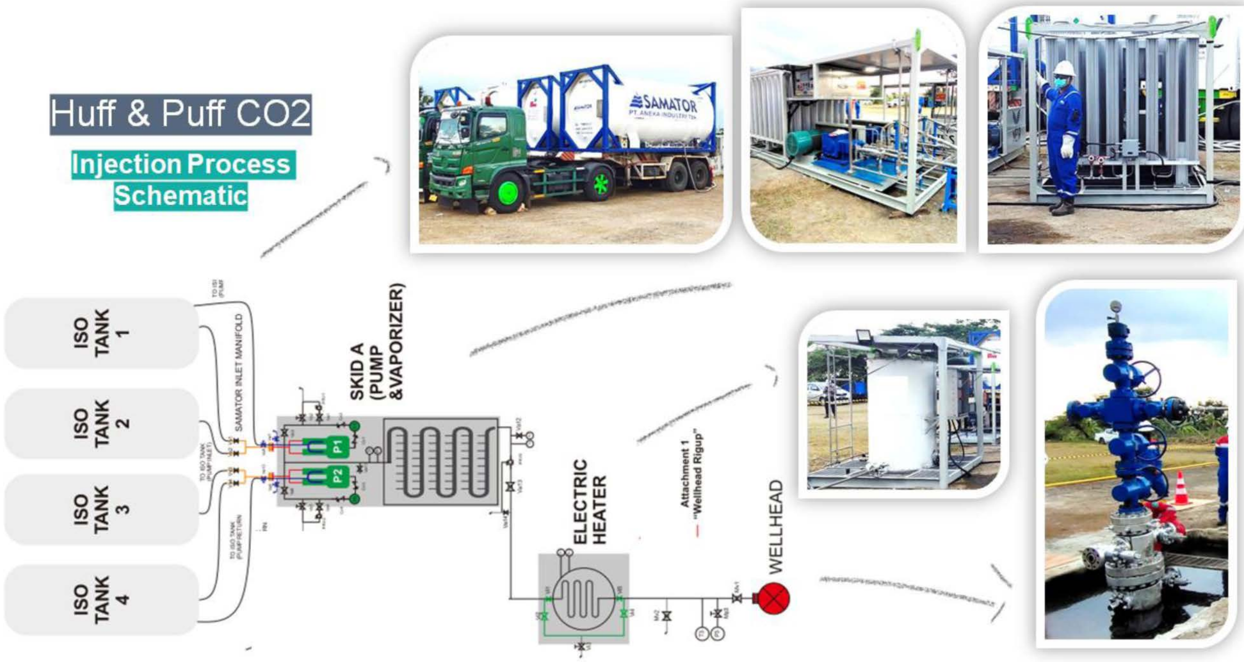

Figure 11—CO2 Injection Equipment Services

Figure 12—Production Monitoring Services

Figure 13—Sampling Analysis

Equipment set up as well the requirement for the injection operation was being engineered design to meet the requirement design of the CO2 Huff & Puff in Jatibarang Field, which has been describe in Table 1. Operationally the execution performed smoothly with average total duration of the operation days of ten (10) days include set-up equipment and on-site equipment engine check. The operation executed as rigless onshore operation, while most of the pre-work operational consisted of uninstall artificial lift equipment, and pre-CO2 injection saturation logging, as detail shown in Figure 3.

Early production facility was used in the post injection monitoring with the specification of the three (3) phase separator, that objectively to separate the flowback liquid and gas from the well during production (puff) period. Flare pit as well be prepared on location as the mitigation plan while the oil production was still consisted of high concentration of CO2 that production facility could not yet be able to handle it in the gathering station. Return liquid tank will be vacuumed in frequent basis to temporarily store the oil production and deliver the oil to the gathering station afterward.

Conclusions

- The successful implementation of Huff and Puff CO2 Injection on 2 (two) wells in Jatibarang Field indicates that the technology is feasible and effective in enhancing oil recovery in the field. The injection process was carried out according to the planned target, which suggests that the project was well-planned and executed.
- This project is an important milestone for Indonesia's oil and gas industry which provides valuable data for the implementation of EOR technology at full scale in Indonesia supporting the country's efforts towards achieving carbon neutrality by 2060 by implementing CO2 injection as part of the CCUS process.
- Reservoir characterization resulted in several interesting analysis that were showed during the CO2 injection, post injection analysis and during post injection production monitoring. Which conclusively showed that positive indication after the CO2 injection that supported with qualitative and quantitative analysis.
- The collaboration between Pertamina and PHE Region 2 also involved knowledge sharing and technology transfer providing valuable insight and experience to improve their capabilities and competitiveness which is important for the development of the oil and gas industry in Indonesia.

- The success of the collaboration between Pertamina, PHE Region 2, and JOGMEC in the Huff and Puff CO2 Injection project demonstrates the potential for further collaboration between national and international companies in the Indonesian oil and gas industry. This collaboration can lead to the development of new technologies, increased efficiency, and sustainable development of the industry, which is crucial for Indonesia's energy security and economic growth.
- Operationally speaking for the implementation of the CO2 Injection with Huff & Puff method in Jatibarang field executed in a safely way by delivering process with a very detail and careful consideration, preceded with pre-work operation until production monitoring period. This would as well need to consider external operation – transportation for consumables materials.
- Jatibarang field is proven has potential to implement CO2 injection in the future as part of Production Enhancement and CCUS, and also feasible to be extended to the Pilot Test Stage (inter-well).

Abbreviations

URTI : Upstream Research Technology & Innovation
PHE : Pertamina Hulu Energy
PEP : Pertamina Exploration Production
JOGMEC : Japan Organization for Metals and Energy Security
EOR : Enhanced Oil Recovery
CCS : Carbon Capture, and Storage
CCUS : Carbon Capture, Utilization, and Storage
JSA : Joint Study Agreement
MMP : Minimum Miscible Pressure
EPF : Early Production Facility
CA : Confidentiality Agreement
POP : Put on Production
EMR : Electromagnetic Resonance
RST : Reservoir Saturation Tool
PI : Productivity Index

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Design & Implementation of CO2 Huff-n-Puff Operation in a Vietnam Offshore Field

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Abstract

The Carbon Dioxide Enhanced Oil Recovery (CO2 EOR) application to the offshore oil field in Vietnam has been investigated through an international joint study scheme between Japan and Vietnam since 2007 and a preliminary study for potential CO2 EOR application indicated feasibility to some extent. To reduce and mitigate technical uncertainties/risks in the field scale EOR implementation, in May 2011, a CO2 EOR pilot test was executed in a sandstone reservoir of Rang Dong oil field, offshore Vietnam.

The test was designed to be conducted as a single-well test, and generally called CO2 Huff-n-Puff. Major field operations included test string installation, pre-CO2 injection flow, CO2 injection (ca. 111 metric tonnes) and post-CO2 injection flow. Whole operation was performed satisfactorily with all objectives achieved. During the test, clear increment of oil rate and reduction of water cut were observed after CO2 injection as well as oil composition change. The contrast of CO2 injectivity and oil saturation change in the reservoir was confirmed by saturation logs, etc.

Being the first CO2 EOR application in Southeast Asia and also offshore application worldwide is rarely reported, the operational gained is especially valuable. This paper is to describe the process of engineering design, planning, onshore preparation and field execution leading to the success of the project[1].

Introduction

Rang Dong oil field is located approximately 135km offshore from Vung Tau, Vietnam. The field has been producing oil since 1998 from two major reservoirs, fractured granite Basement (BM) reservoir and Lower Miocene (LM) sandstone reservoir.

From 2007 to 2010, a study of CO2 EOR application for sandstone reservoir in Rang Dong field had been implemented. The study result indicated that more than 32 million barrels of additional oil would be recovered; however it will require huge investment for construction of CO2 supply infrastructure, CO2 separation/ recovery, and the modification of existing production facilities, etc. Therefore, CO2 Huff-n-Puff was selected as the first step preparing for field scale CO2 EOR application in the future. CO2 Huff-n-Puff is basically a well stimulation technique in one well, which composes mainly three stages i.e., 1) Inject CO2 into a single producing well [Huff], 2) Shut in the well to allow CO2 to dissipate and dissolve, and 3) Produce the well back [Puff].

Selection of test well was one of critical issues for a successful pilot test in terms of reservoir quality to secure good CO2 injectivity and high reservoir pressure to achieve minimum miscible pressure (MMP) as defined from the study[2] during CO2 injection. The selected test well was an oil producer of BM reservoir, which had well path penetrating LM reservoir at shallower section. The BM reservoir of the well was no longer producing oil and under schedule for sidetracking. Therefore, it was proposed to perforate 9-5/8" casing of the well to access LM reservoir for CO2 Huff-n-Puff test. **Fig.1** is the schematic of test well.

The entire project was carried out on the jack-up rig supported by CO2 workboat, working simultaneously on a wellhead platform (WHP) connected to a central production complex of Rang Dong field. During whole test, oil production from this field was maintained normally through production facility in this central production complex. The operation procedure is summarized as below.

1) Recover existing production tubing. Set cement plugs to P&A the BM reservoir.
2) Perforate 9-5/8" casing on wireline casing gun to access LM section.

EXHIBIT G

3) Install test string and surface testing equipment.
4) Flow the well to clean-up and establish base production rate (pre - CO2 injection flow).
5) Shut-in the well and run reservoir saturation tool, RST logging #1.
6) Inject approximate 100 metric tonnes (MT) of CO2 [Huff] from CO2 pumping vessel.
7) Shut-in the well for CO2 soak and RST logging #2 to evaluate fluid saturation changes at the wellbore.
8) Open the well (post- CO2 injection flow) [Puff].
9) Kill well and recover the test string.

Based on the reservoir simulation design, injection volume of CO2 is optimized to 100MT as minimum volume to sweep the oil near wellbore; the soaking duration is theoretically a time required for mixture and reaction between injected CO2 and reservoir oil and it is minimized to two (2) days including 1 day for RST logging after CO2 injection; the duration for post-CO2 injection flow [Puff] is minimized to four (4) days as a minimum duration to monitor production performance.

Equipment Considerations

Being the first CO2 EOR application in the region, a number of challenges were encountered in design stage, which were caused by:

1. Unconventional workscope.
2. Limited offshore experience worldwide.
3. Simultaneous operation with production activity.
4. Short time of preparation.

The following sections describe the key considerations and mitigations that led to the success of the project.

Test string

The locally available downhole DST tool e.g., packer, gauge carrier, reversing valve, slip joint, etc provide only 2.25" inside diameter (ID) whereas min ID of test string must allow 3.375" outside diameter (OD) logging tool to run through. Therefore, the new concept of test string was established to use 4-1/2" tubing and downhole completion equipment with min 3.813" ID to make the logging operation become feasible. Additionally, a 5-1/8" big-bore flowhead – an uppermost item of the test string was also mobilized from oversea to satisfy the min ID requirement.

Tubing stress analysis: The liquid CO2 was stored in insulated tanks at temperature of -24degC and saturation pressure of 250psig. Depending on wellhead injection pressure, the temperature of injected CO2 will change, and may be as low as approximately -20degC at the wellhead if the heater was not used or it did not work during CO2 injection accidentally. A combination of the thermal contraction and high bottom-hole injection pressure (max. 5,000psig) was considered the worst case for stress analysis. Sensitivity analysis with various wellhead injection pressures and CO2 discharge temperature was performed. The analysis result indicated a polished bore receptacle (PBR) was not necessary, however, for the purpose of retrieving the test string at the end of the test the PBR was finally integrated.

Downhole wireless pressure gauges: According to CO2 injection simulation, bottom-hole pressure during CO2 injection had to be maintained above MMP of 2,950psig and below anticipated fracturing pressure of 5,000psig. To serve for this requirement, the real-time acoustic pressure gauges were prepared. In principle, it allows acquiring real-time pressure and temperature data from downhole gauges without a conventional wireline deployment, therefore, the on-site well test engineer would be able to monitor downhole pressure and adjust the pumping rate accordingly. The real-time monitoring system also allowed controlling drawdown to minimize the risk of sand production during well flowing, as well as optimize the shut-in time for pressure build-up.

As result of above considerations, the string included 4-1/2" 15.5# PH6 tubing as major part; and disappearing plug (for setting packer), hydraulic-set packer, PBR, wireless gauge mandrel, Surface-Controlled Subsurface Safety Valve (SCSSV), and flowhead as downhole completion equipment. The well schematic during CO2 Huff-n-Puff is shown in the **Fig.2**.

Material selection

The corrosive agent in LM reservoir fluid of Rang Dong field is negligible; however once injected, CO2 is present in the wellbore and may cause two issues concerning the integrity of downhole and surface equipment

- First, with inherent nature, CO2 acts as corrosive agent to metallic components in the presence of water.
- Second, CO2 is a major contributor to explosive decompression damage to elastomeric parts of equipment. The seals can be damaged in forms of blisters, splitting, and cracks.

The downhole completion equipment: Metallurgy study was carried out to evaluate the corrosion level, then to select the most suitable metallurgy for completion equipment. The study was based on the anticipated well condition that CO2 concentration from 90% to 50% during 4 days of post-injection flow and bottom hole flowing pressure at around 2,000psig. As result of metallurgy study, corrosion level was not expected to be severe in such a short time of service, L80 13Cr was then selected.

To mitigate the risk of damaging elastomeric parts of completion equipment in case of unexpected rapid depressurization of CO2 - rich gas, all elastomeric part was selected to be resistant to explosive decompression. In addition, the guideline for bleeding off operation after CO2 injection was also given to avoid any sudden depressurizations.

The tubing: Although it also exposes to CO2-rich fluid, the corrosion effect is not critical like completion equipment because the tubing can tolerate the metal loss better than completion equipment while still maintaining its integrity. Another consideration is a short time service i.e., within 10 days after CO2 injection; the 4-1/2" 15.5# T-95 PH-6 tubing was then selected. In order to control the quality of rental tubing (e.g. wall thickness, structural defects), the EMI (Electro-Magnetic Inspection) was carried out on full length of every tubing joints. The result of wall thickness was also used to determine the metal loss on the tubing by comparing wall thickness before and after the job, that would be a good reference for future use.

The surface testing equipment: The plan was to use specialized piping and elbows instead of Coflexip for the upstream flowline (to connect flowhead to choke manifold) as countermeasure to mitigate the concerns during post-CO2 injection flow as aforementioned. Like downhole equipment, seals/ packing of surface standard testing equipment were changed to the material which was resistant to explosive decompression damage.

Burning CO2-rich gas

As result of reservoir simulation, the CO2 concentration was expected very high (up to 90%) in early days of "Puff" operation, there was a serious concern on burning CO2-rich gas and oil since the combustion experiments and worldwide experience showed that burning efficiency strongly decreases at CO2 concentration over 40%. The low efficiency of burning process could lead to several risks for offshore operation:

- Unburned hydrocarbon gas accumulates around the jack-up rig and adjacent production facility that may cause fire or explosion.
- Sea pollution by oil spill.

In land well testing operation, the CO2-rich gas is commonly cold-vented to the surrounding area; however, this practice is not applicable for offshore operation, especially where the complex of existing production platform is around. The solution was to modify the standard burner booms by introducing an additional gas line from which the hydrocarbon gas, received from adjacent wellhead platform, would dilute the CO2-rich gas at the burner head and assist the burning process. The construction work included:

- Construct 3" pipelines from the wellhead platform production facility to 85ft-boom burners. The burners were installed on both Port and Starboard side for any change in wind direction during the test.
- Install additional gas line with burner head on the standard burner booms.

Those preparatory works were thoroughly planned and implemented in the manner of minimum impact to production operation. The construction of assisting gas line, installing burner booms and commissioning were completed and commissioned successfully prior project commencement when the rig was working on an adjacent well slot of the test well.

CO2 Pumping Equipment

Once the project was conceived in February 2011, the operator contacted all major pumping service companies in Vietnam; however, only one service company was interested in providing this service. A huge amount of works were done within a short period of 3 months to complete pumping design and equipment preparations.

CO2 source and supply: As environmental requirement, the liquid CO2 had to be mobilized locally and no CO2 was imported and many attempts was then made to source out liquid CO2; However, there was no available CO2 source in the South of Vietnam. The liquid CO2 was finally purchased from a fertilizer and chemical company located in the North of Vietnam, approximate 1,800km away from Vung Tau. The liquid CO2 was trucked to the supply base in Vung Tau and transferred to CO2 storage tanks temporarily installed on a workboat. The route of CO2 transportation from the source to Vung Tau then to the field is shown in **Fig.3**.

Although the plan was to inject about 100 MT of CO2, the total amount liquid CO2 of 163MT (99.97% purity) was trucked, including 25MT for equipment function test and 138MT was loaded out offshore. The extra amount was intended to cover, volume loss during transportation, pressure testing, cooling down equipment and dead volume of CO2 storage tanks.

Handle cold liquid CO2: During CO2 pumping, the temperature of injected CO2 could be as low as approximately -20degC at the wellhead as explained earlier. There would be several risks associated with this low temperature.

- First, cold CO2 may cause brittle cracking to the test string.
- Second, such low temperature is beyond the temperature limit of seal/elastomer parts of some well completion components such as flowhead and SCSSV located at shallow depth where geothermal heat was not sufficient to heat up equipment against cold CO2 being injected.
- Third, ice plug may be formed inside tubing if cold CO2 is in contact with water present inside the tubing leading to restriction to pumping operation.

Increasing CO2 temperature became crucial to the integrity of downhole equipment and pumping operation. However, heating liquid CO2 is not common task in the region; therefore heating equipment was not readily available in the contractor's equipment package. Many attempts were made to source out the suitable heater; the steam-heat exchanger was finally selected with some modifications to make it workable at low temperature.

Equipment function test: Upon arrival of CO2 pumping equipment to Vung Tau, the equipment was setup in an open yard for function testing, aimed to verify all pumping equipment was functioning properly and adequate to perform planned well treatment. Layout of CO2 equipment during function test at open yard is shown in **Fig.4**.

One of the most important parameter was the performance of steam-heat exchanger at various pumping rate and stimulated wellhead pressure. The function test was successfully performed with consumption of 25MT liquid CO2. The conclusions of the function test were as followings.

- Entire CO2 pumping package including the data acquisition system worked properly and accurately.
- Steam generator and heat exchanger capacity were adequate to heat up CO2 to required temperature.

Installation of CO2 pumping equipment: Initially, a site survey was carried out on the jack-up rig to examine whether all CO2 and testing equipment could be accommodated on the rig in term of deck space and deck loading for two objectives: 1) save cost for chartering a dedicated workboat and 2) mitigate the risk of wait-on-weather with CO2 workboat.

As the result of the rig survey, it was not able to spot both testing gears and CO2 pumping equipment on the rig due to limited deck space, therefore, a DP2 vessel with ca. 500m2 deck was sourced out to serve as a workboat. The CO2 equipment package which mainly consisted of 8 insulated CO2 storage tanks, CO2 booster pump, 2 triplex fluid pumps, steam generator, heat exchanger, Coflexip, data cabin, and N2 tank/ converter was installed on the work boat as shown in **Fig. 5**. Whole operation including equipment setup, sea fastening and CO2 transfer took approximate 4 days. In total, 138MT of liquid CO2 were equally loaded into 8 CO2 storage tanks on the workboat.

Offshore Execution

Well preparations

The operation commenced with tubing recovery in the existing BM producer, then a hundred meter of cement plug was set to isolate BM reservoir. The wellbore was then circulated clean and displaced with completion fluid 1.07sg filtered KCl brine. Two 7” HSD 12spf 135/45deg phasing casing guns with PJO HMX charges were run on wireline to perforate 8m of 9-5/8” casing interval. Test string was run and packer was set successfully. Concurrently, surface testing equipment was spotted, rigged up, and prepared for well opening.

Huff-n-Puff Operation

Pre-CO2 injection flow: The well was flowed to clean-up and to get original production data with representative fluid samples for later comparison with post-CO2 injection flow. The coiled tubing was run and kick-off the well by Nitrogen lift before the well could flow naturally with oil rate of 900-1,000bpd and water cut of 50-60% at 40/64” choke size.

Well fluid (oil/ gas/ water) samples were continuously taken for onsite compositional analysis in order to obtain a baseline of fluid properties before CO2 injection. The oil and gas composition were analyzed to C36+ and C12+ respectively by gas chromatography every 3 hours. The water compositional analyses were done by titration method using chemical apparatus. In total, the actual quantity of onsite compostional analysis during pre-CO2 injection flow were 8 for oil, 8 for gas 24 for water.

After 26 hours flowing, the well was shut-in at choke manifolds after confirming thestable flow was achieved. The RST logging #1 was run on wireline to evaluate original reservoir fluid saturation before CO2 injection.

CO2 injection [Huff]: Upon completion of RST logging #1, the work boat approached the rig and Coflexip hose was picked up from work boat and landed on Coflexip hanger installed on the rig. After connecting Coflexip hose to 2” treating iron run from Coflexip hanger to the flowhead on rig floor, the entire surface treating line from the workboat to flowhead was tested to 5,000psia with Glycol. Pumping operation was then carried out smoothly at stable pump rate of 1.65bpm and calculated bottom-hole rate of 2.3bpm at desired bottom hole treating pressure. Maximum treating pressure was 2,131psia and 4,060psia at surface and bottom hole, respectively. The heat exchanger worked perfectly and delivered desired CO2 discharge temperature, i.e. 12-15degC. The casing/ tubing annulus surface pressure was continuously monitored from workboat and drill floor during CO2 injection and the integrity of the test string appeared good throughout the operation. Pumping data during CO2 injection is shown in **Fig.6**.

During pumping operation, the CO2 injection rate, pressure and temperature were continuously measured at upstream and downstream heat exchanger. The CO2 mass was then independently calculated and the results agreed within 1% accuracy. Totally, 111.2 MT was delivered to the wellbore after 7 hours pumping, followed by pumping N2 to displace CO2 inside the tubing further down to the reservoir. The well was then shut-in for CO2 soaking and the RST log to obtain the changes in fluid saturation after CO2 injection.

Post-CO2 injection flow [Puff]: Considering enough CO2 soaking time was achieved after 45 hours shut-in, the well was opened at small choke in order to eliminate the explosive decompression damage to elastomer of downhole equipment, and also to facilitate the burning process for CO2-rich gas by adding hydrocarbon gas from wellhead platform. The choke size was increased stepwise to 40/64” finally and kept flowing for 48 hours as planned. The CO2 concentration, as expected, was 97% at beginning and gradually reduced to 10% at the end of post-CO2 injection flow. The assisting hydrocarbon gas was maintained at 2-7MMscfd that effectively burned CO2-rich well fluid without any critical safety and environmental issues as illustrated in Fig.7.

In comparison with pre-CO2 injection flow at the same choke size 40/64”, oil rate was measured at 1,400-1600bpd i.e., 1.6-times increase with zero water cut in the first 24 hours, which was believed due to the effect of CO2 EOR. The production performance in pre-CO2 injection and post-CO2 injection flow is shown in **Fig.8**.

Well fluid (oil/ gas/ water) samples were taken and analyzed at much higher frequency i.e., every 30 minutes compared to pre-CO2 injection flow. In total, the actual quantities of onsite analysis during post-CO2 injection flow were 184 for oil, 184 for gas and 46 for water. A huge amount of dead oil sample was also taken every 15 minutes for future validation.

At the end of post-CO2 injection flow, a memory production logging (MPLT) was conducted on slickline to determine flow contribution from two perforation intervals, followed by downhole sampling with two samples successfully taken. As the result of encouraging oil rate during the test, the decision was made to convert the well into oil producer. The test string was unstung from the PBR. A production tubing string was then run in hole, Xmas tree was nippled up and the well was tied in wellhead platform factility for long term oil production.

Conclusions

- The first offshore CO2 EOR Huff-n-Puff operation was successfully performed in safe and effective manner. The success of the operation was contributed by thorough design, preparation and implementation including equipments specially designed and constructed.
- The integrity of test string was maintained throughout the test. The full length EMI on all tubing joints after the service indicated negligible loss of wall thickness. Logging operation was carried out smoothly through the big-bore test string. The downhole real-time acoustic gauge worked effectively in providing continuous downhole pressure temperature data.
- Good and stable CO2 injectivity at desired bottom hole treating pressure was achieved. The design concept and execution procedure for an offshore liquid CO2 pumping was established including selection of suitable CO2 pumping equipment, dedicated work boat, pumping simulations and function testing.
- All flowing parameters were acquired during well flowback. The increased oil production and reduction of water cut was confirmed in CO2-post injection flow. The effect of CO2 injection was successfully confirmed by production profile and numerical well model calculations[3].
- The CO2-rich gas was effectively burned by application of assisting hydrocarbon gas via the gas line temporarily constructed.
- Following the success of this project, an inter-well CO2 EOR pilot test has been considered as the next step before the field scale application.

Acknowledgements

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Unit Coversion Factors

lb x 2.204622E+03 = mt
degC x 1.8 + 32 = degF
in. x 2.54E + 00 = cm
ft x 3.28084E + 00 = m
bbl x 1.58987E - 01 = m3
Pa x 6.894757E + 03 = psi

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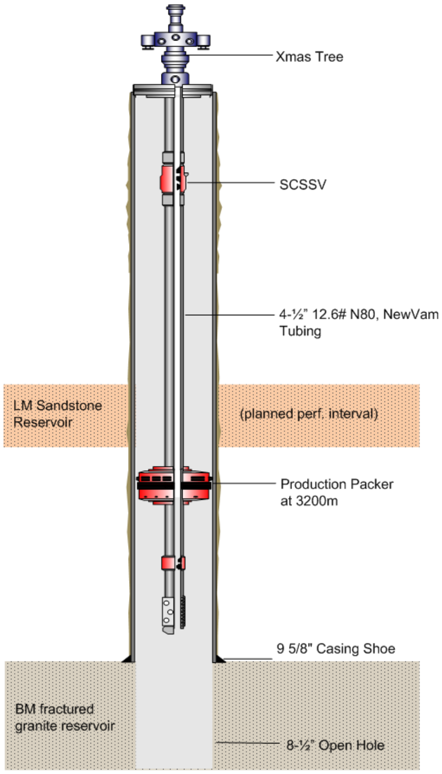

Fig.1 – Schematic of existing BM oil producer

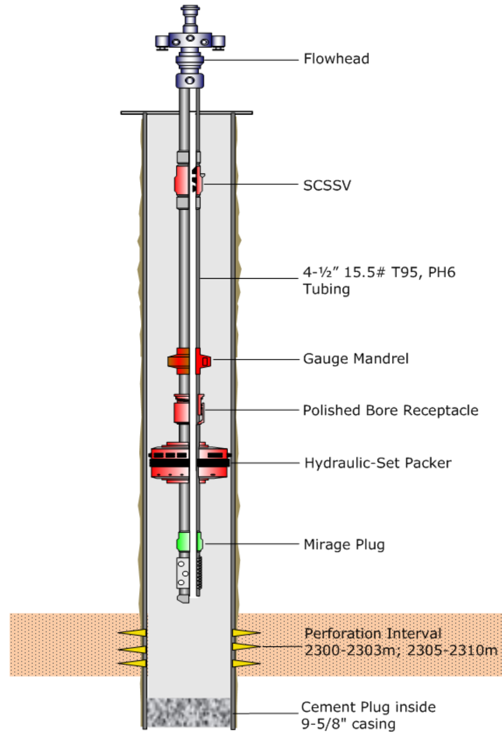

Fig.2 – Well schematic during CO2 Huff-n-Puff

Fig.3 – Route of CO2 from the source to the field

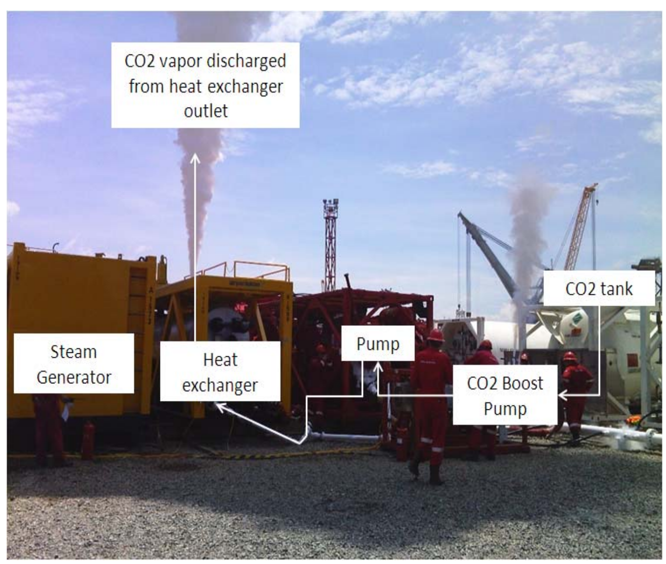

Fig.4 – Layout of CO2 equipment for function testing

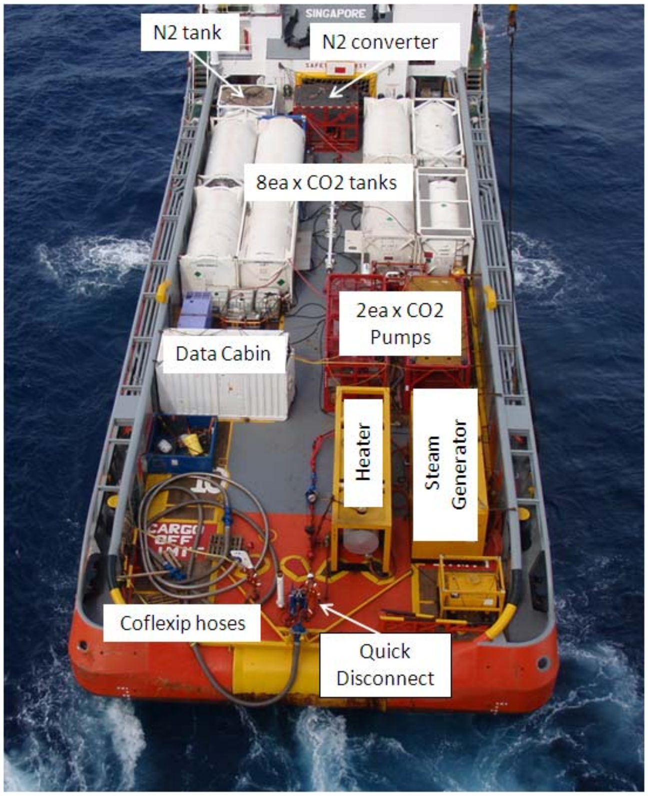

Fig.5 – Layout of the CO2 equipment on the work boat

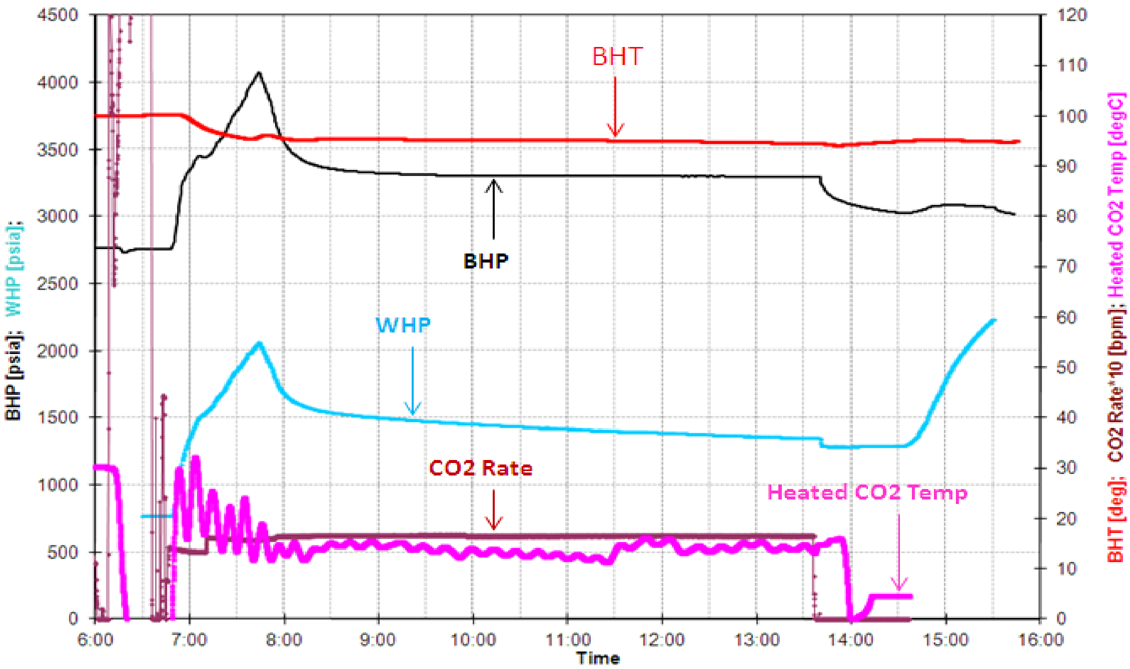

Fig.6 – Pumping data during CO2 injection

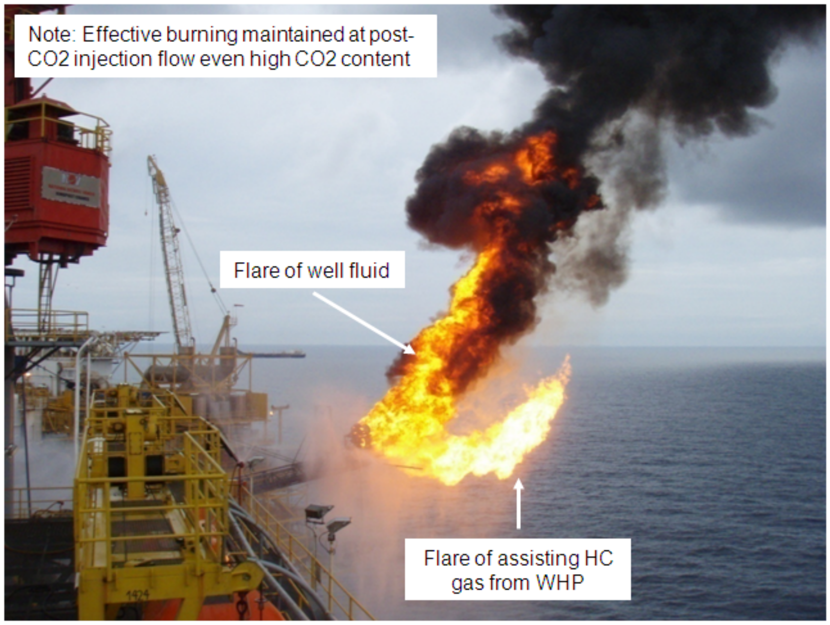

Fig.7 – Burning CO2-rich well fluid

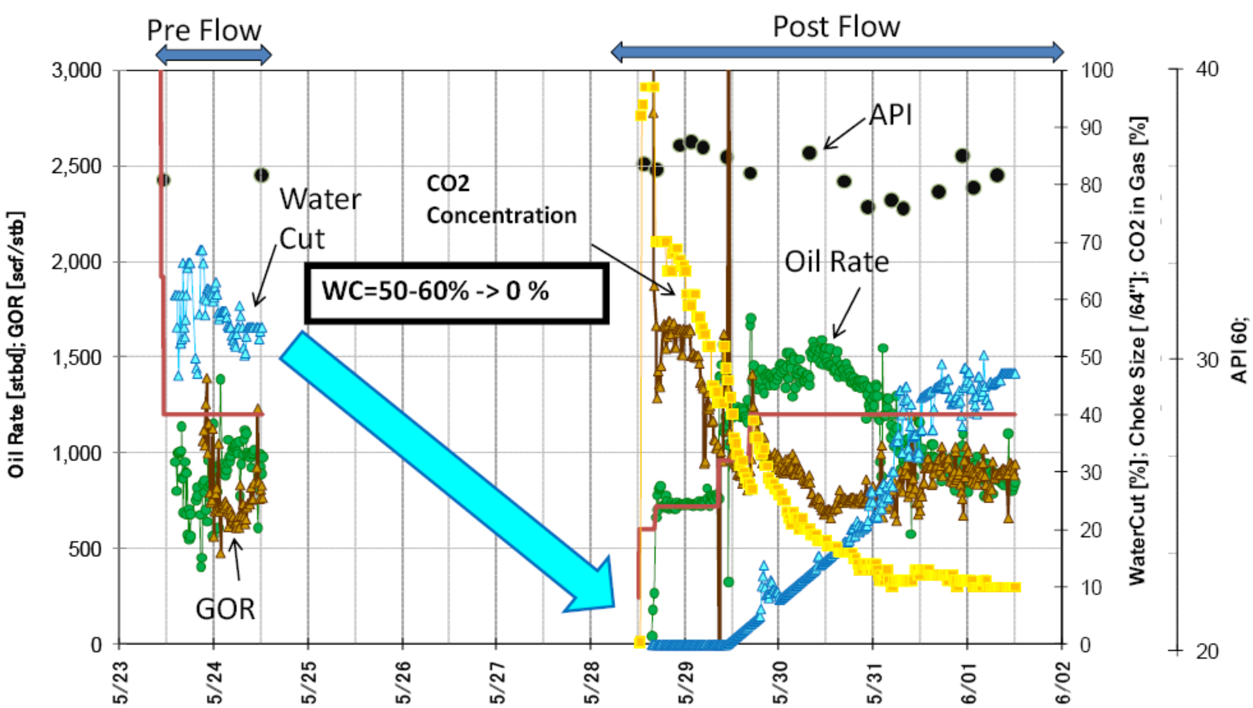

Fig.8 – Production performances in Pre-CO2 injection and Post-CO2 injection flow