APPENDIX XI

Stimulation Plans

APPENDIX XI-1

Stimulation Plan for Minerva South CCS No. 001

Tables

FACILITY INFORMATION

Facility Name: Minerva Facility

Injector Wells: Minerva South CCS Well No. 001 (MS CCS 1)
Minerva South CCS Well No. 002 (MS CCS 2)

Facility Contact: David Cook, CEO
5599 San Felipe St., Ste. 1450, Houston, Texas 77056
(713) 419-6808; dcook@gcscarbon.com

Well Locations: Sec 3, T12S, R13W, Cameron Parish, Louisiana
MS CCS 1 (NAD 1927)
Surface: 30° 02' 34.10"N, 93° 40' 20.63"W
Bottom-Hole: 30° 02' 34.10"N, 93° 40' 20.63"W
MS CCS 2 (NAD 1927)
Surface: 30° 02' 33.84"N, 93° 40' 20.48"W
Bottom-Hole: 30° 02’ 13.74”N, 93° 40' 42.07"W

1 PROPOSED STIMULATION PLAN FOR MS CCS 1

The primary objective of the stimulation process in the Project Minerva injector wells is to improve the permeability of the surrounding formation after the drilling of the wellbore. The damage is typically caused by contact and filtration with drilling fluids. The stimulation process is aimed at enhancing the final conditions of the wellbore by eliminating damage and improving contact of the wellbore with the reservoir.

The drilling plan involves using a drilling fluid (water base or synthetic mud) in the hole section covering confining and injection zones. The objective of the stimulation process is to eliminate either hydrocarbon components and weighting agents, namely calcium carbonate and Barium sulfates, that may stay on the formation's surface in case of any partial losses that occur during drilling operations.

1.1 METHODS

GCS is considering implementing an acidizing treatment to eliminate synthetic mud residues. This treatment has proven to be highly effective for Sandstone formations, as it employs the dissolving power of a multi-acid system to eliminate fines damage and stimulate flow paths outside the near-wellbore formation area. A Sandstone Acid System has been specifically designed to manage hydrogen fluoride (HF) acid generation at depth and to maximize contact of the wellbore with the reservoir.

Software Modeling such as StimVision™ software, or equivalent can be utilized to ensure containment is maintained during the stimulation treatment, and the proposed injection rates are adequate to treat the entire target zone without breaking out of zone or crossing over the fracture pressure.

Once the final fluids vendor is selected, a specific acid system and software modeling system will be reviewed to ensure its application is consistent for this purpose.

1.2 STIMULATION FLUIDS

The proper system(s) should be determined based on the formation fluids samples analysis and formation minerology.

Example of fluid systems to be used in the stimulation of the Minerva wells:

- A Sandstone Acid System for main stimulation fluid to clean up the near wellbore area and to maximize contact with the formation.
- Low concentration hydrochloric (HCl) acid blend, to help “pickle” and pre-treat the wellbore tubulars prior to start of the main treatment, and to displace or “post-flush” the main acid mixture.
- A visco-elastic diverting agent, Divert SP, to aid in chemical diversion of main acid treatment down the target treatment zone. This ensures full coverage of the target zone.
- Particulate diverters, such as Real Acid Divert products. To aid the Divert SP type systems in case of extraordinary leak-off scenarios where the formation permeability is extremely high and extending the vertical coverage of the treatment is important.
- The solvent mixture of mutual solvents and paraffin inhibitors to aid in cleaning the wellbore tubulars of any oil or grease left from the drilling operations such as synthetic mud, casing or tubing connection grease (“pipe dope”), or other additives that were used during drilling or workover operations.

1.3 ADDITIVES

A Sandstone Acid System is mainly composed of HCl and HF acids (Mud Acid), with the addition of non-emulsifiers, corrosion inhibitors, iron ion scale control additives, clay control additives, inhibitor intensifiers, and fines stabilization agents. Water-wetting surfactants are optionally used to help water wet the formation, thus aiding in the recovery of the spent stimulation fluid should that be necessary.

Low concentration HCl acid blend consists of a low loading of raw acid, clay, and fines control additives, non-emulsifiers, iron ion scale control additives and reducing agents, corrosion inhibitors and inhibitor intensifiers, and clay control additives.

Divert SP typically comprises visco-elastic concentrate, non-emulsifier, gelling breaker additive, and salts.

Particulate diverters are dry particles of various granules or “mesh” sizes that are mixed. This dry mixture is added to the diversion system to enhance its capabilities in very permeable formations.

Solvent mixture, in addition to mutual solvents and paraffin inhibitors, also contains salts and other clay stabilizing additives.

1.4 STIMULATION PROCEDURE REQUIREMENTS

Wellhead injection pressures will be limited such that bottomhole injection pressure does not exceed 90% of the fracture pressure of the injection reservoir to prevent the initiation of fractures or propagation of existing fractures in the confining zone or cause the movement of injection or formation fluids into a USDW. Maximum allowable downhole pressure for each injection interval was determined using a fracture gradient of 0.85 psi/ft and safety factor of 90% (as detailed in Section 7.1.2.1 of the Project Minerva Narrative). The calculated maximum allowable downhole pressures for each completion interval are given in Table XI.1-1 for injector well, MS CCS 1.

The stimulation procedure will take place after successfully running the well completion string and allowing time for the production packer to settle and the well integrity test to be completed. The final formulations for stimulation treatment will be adjusted based on the results of the information of fluid samples recovered in the open hole section across the injection zone.

After the stimulation program has been adjusted and approved by GCS and Louisiana Department of Conservation and Energy (C&E), the next step will be to move the equipment to the injector well location to ensure all safety conditions are met for handling acid and chemicals on site. Pre-job planning would include acid storage and handling containment guidelines to ensure a safe operation.

The procedure will be as follows, depending on the condition of the well:

1. Move pumping equipment, chemicals, and additives to the injector well location.
2. Install and rig-up equipment based on the layout previously approved, and according to established company safety and operations guidelines.
3. Install surface pressure lines with pressure transducers to record and observe the job.
4. Install tubing and pressure tracking equipment on the lines connected to the wellbore annulus.
5. Perform pre-job safety meetings with everyone on site to go over the operation and ensure awareness of all high-risk areas.
6. Pressure test wellhead and surface lines, up to 10% above maximum working pressure resulted on the stimulation job simulation, or 10% under maximum rating of the high-pressure lines. Whichever is agreed upon in pre-job planning.
7. Open the master valve or lateral valve of the production tree, depending on the installation layout. Before opening tree valves, check the pressure inside the well. At this time, the well should be perforated with open intervals' pressure equalized to the reservoir pressure. If necessary, equalize upstream injection line(s) with pressure to

open valves. Follow safety procedures and best practices from the service company during these steps to equalize high pressure lines with service lines.

8. To determine injection pressures during a stimulation job, start with an injection test at a reduced rate to establish injection pressure. Then, gradually increase the pump rate at different rates up to the programmed stimulation pump-rate. This injection test can be conducted with completion fluids, or light brine treated with biocides and clay stabilizing additives.
9. At the end of the test, close Christmas tree valves and release pressure on the surface injection lines. Continue monitoring pressure at well.
10. Once the injection test concludes, adjust the stimulation plan if necessary.
11. Before beginning the stimulation job, it is important to record the well pressure at the Christmas tree. Additionally, prior to opening the Christmas tree valves, it is necessary to equalize the pressure on the upstream injection surface lines once again.
12. During the main treatment, ensure that annular pressure is recorded.
13. Start injection as per pump schedule previously approved by all parties.
14. Maintain injection rate at the pre-approved values to ensure containment and minimize risk of fractures opening during stimulation.
15. In the event of high treatment pressure, reduce rate to stay under fracturing pressure.
16. Flush and displace the treatment as per pumping schedule.
17. Shut-down pumping and monitor pressure fall off, if the well is not on vacuum.
18. Monitor the pressure for at least 15 minutes after shut-down is initiated.
19. Close the well and release the remaining pressure on the surface lines, equalize with flow-back lines.
20. Continue monitoring pressure on the well through gauges installed in the wing valve and annulus.
21. Perform post-job safety meeting to discuss equipment rig-down and any remaining acid neutralization.
22. Rig- down and move out the equipment.

Table XI.1-1 Maximum Allowable Downhole Pressures for Minerva South CCS Well No. 001

Completion Interval	Completion Zone	Completion Interval Elevation Corresponding to Pressure		Thickness	Fracture Gradient	Maximum Allowable Downhole Pressure
		Top (ft TVD)	Bottom (ft TVD)	(ft)	(psi/ft)	(psig)
3 *(Upside)*	Frio 0.5 & Frio 1	9,194	9,494	300	0.85	7,033
2	Frio 4	9,736	9,896	160	0.85	7,448
1	Frio 5	9,996	10,056	161	0.85	7,647

APPENDIX XI-2

Stimulation Plan for Minerva South CCS No. 002

Tables

FACILITY INFORMATION

Facility Name: Minerva Facility

Injector Wells: Minerva South CCS Well No. 001 (MS CCS 1)
Minerva South CCS Well No. 002 (MS CCS 2)

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Well Locations: Sec 3, T12S, R13W, Cameron Parish, Louisiana
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MS CCS 2 (NAD 1927)
Surface: 30° 02' 33.84"N, 93° 40' 20.48"W
Bottom-Hole: 30° 02’ 13.74”N, 93° 40' 42.07"W

1 PROPOSED STIMULATION PLAN FOR MS CCS 2

The primary objective of the stimulation process in the Project Minerva injector wells is to improve the permeability of the surrounding formation after the drilling of the wellbore. The damage is typically caused by contact and filtration with drilling fluids. The stimulation process is aimed at enhancing the final conditions of the wellbore by eliminating damage and improving contact of the wellbore with the reservoir.

The drilling plan involves using a drilling fluid (water base or synthetic mud) in the hole section covering confining and injection zones. The objective of the stimulation process is to eliminate either hydrocarbon components and weighting agents, namely calcium carbonate and Barium sulfates, that may stay on the formation's surface in case of any partial losses that occur during drilling operations.

1.1 METHODS

GCS is considering implementing an acidizing treatment to eliminate synthetic mud residues. This treatment has proven to be highly effective for Sandstone formations, as it employs the dissolving power of a multi-acid system to eliminate fines damage and stimulate flow paths outside the near-wellbore formation area. A Sandstone Acid System has been specifically designed to manage hydrogen fluoride (HF) acid generation at depth and to maximize contact of the wellbore with the reservoir.

Software Modeling such as StimVision™ software, or equivalent can be utilized to ensure containment is maintained during the stimulation treatment, and the proposed injection rates are adequate to treat the entire target zone without breaking out of zone or crossing over the fracture pressure.

Once the final fluids vendor is selected, a specific acid system and software modeling system will be reviewed to ensure its application is consistent for this purpose.

1.2 STIMULATON FLUIDS

The proper system(s) should be determined based on the formation fluids samples analysis and formation minerology.

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- A visco-elastic diverting agent, Divert SP, to aid in chemical diversion of main acid treatment down the target treatment zone. This ensures full coverage of the target zone.
- Particulate diverters, such as Real Acid Divert products. To aid the Divert SP type systems in case of extraordinary leak-off scenarios where the formation permeability is extremely high and extending the vertical coverage of the treatment is important.
- The solvent mixture of mutual solvents and paraffin inhibitors to aid in cleaning the wellbore tubulars of any oil or grease left from the drilling operations such as synthetic mud, casing or tubing connection grease (“pipe dope”), or other additives that were used during drilling or workover operations.

1.3 ADDITIVES

A Sandstone Acid System is mainly composed of HCl and HF acids (Mud Acid), with the addition of non-emulsifiers, corrosion inhibitors, iron ion scale control additives, clay control additives, inhibitor intensifiers, and fines stabilization agents. Water-wetting surfactants are optionally used to help water wet the formation, thus aiding in the recovery of the spent stimulation fluid should that be necessary.

Low concentration HCl acid blend consists of a low loading of raw acid, clay, and fines control additives, non-emulsifiers, iron ion scale control additives and reducing agents, corrosion inhibitors and inhibitor intensifiers, and clay control additives.

Divert SP typically comprises visco-elastic concentrate, non-emulsifier, gelling breaker additive, and salts.

Particulate diverters are dry particles of various granules or “mesh” sizes that are mixed. This dry mixture is added to the diversion system to enhance its capabilities in very permeable formations.

Solvent mixture, in addition to mutual solvents and paraffin inhibitors, also contains salts and other clay stabilizing additives.

1.4 STIMULATION PROCEDURE REQUIREMENTS

Wellhead injection pressures will be limited such that bottomhole injection pressure does not exceed 90% of the fracture pressure of the injection reservoir to prevent the initiation of fractures or propagation of existing fractures in the confining zone or cause the movement of injection or formation fluids into a USDW. Maximum allowable downhole pressure for each injection interval was determined using a fracture gradient of 0.85 psi/ft and safety factor of 90% (as detailed in Section 7.1.2.1 of the Project Minerva Narrative). The calculated maximum allowable downhole pressures for each stage are given in Table XI.2-1 for injector well, MS CCS 2.

The stimulation procedure will take place after successfully running the well completion string and allowing time for the production packer to settle and the well integrity test to be completed. The final formulations for stimulation treatment will be adjusted based on the results of the information of fluid samples recovered in the open hole section across the injection zone.

After the stimulation program has been adjusted and approved by GCS and Louisiana Department of Conservation and Energy (C&E), the next step will be to move the equipment to the injector well location to ensure all safety conditions are met for handling acid and chemicals on site. Pre-job planning would include acid storage and handling containment guidelines to ensure a safe operation.

The procedure will be as follows, depending on the condition of the well:

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4. Install tubing and pressure tracking equipment on the lines connected to the wellbore annulus.
5. Perform pre-job safety meetings with everyone on site to go over the operation and ensure awareness of all high-risk areas.
6. Pressure test wellhead and surface lines, up to 10% above maximum working pressure resulted on the stimulation job simulation, or 10% under maximum rating of the high-pressure lines. Whichever is agreed upon in pre-job planning.
7. Open the master valve or lateral valve of the production tree, depending on the installation layout. Before opening tree valves, check the pressure inside the well. At this time, the well should be perforated with open intervals' pressure equalized to the reservoir pressure. If necessary, equalize upstream injection line(s) with pressure to

open valves. Follow safety procedures and best practices from the service company during these steps to equalize high pressure lines with service lines.

8. To determine injection pressures during a stimulation job, start with an injection test at a reduced rate to establish injection pressure. Then, gradually increase the pump rate at different rates up to the programmed stimulation pump-rate. This injection test can be conducted with completion fluids, or light brine treated with biocides and clay stabilizing additives.
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11. Before beginning the stimulation job, it is important to record the well pressure at the Christmas tree. Additionally, prior to opening the Christmas tree valves, it is necessary to equalize the pressure on the upstream injection surface lines once again.
12. During the main treatment, ensure that annular pressure is recorded.
13. Start injection as per pump schedule previously approved by all parties.
14. Maintain injection rate at the pre-approved values to ensure containment and minimize risk of fractures opening during stimulation.
15. In the event of high treatment pressure, reduce rate to stay under fracturing pressure.
16. Flush and displace the treatment as per pumping schedule.
17. Shut-down pumping and monitor pressure fall off, if the well is not on vacuum.
18. Monitor the pressure for at least 15 minutes after shut-down.
19. Close the well and release the remaining pressure on the surface lines, equalize with flow-back lines.
20. Continue monitoring pressure on the well through gauges installed in the wing valve and annulus.
21. Perform post-job safety meeting to discuss equipment rig-down and any remaining acid neutralization.
22. Rig- down and move out the equipment.

Table XI.2-1 Maximum Allowable Downhole Pressures for Minerva South CCS Well No. 002

Completion Interval	Completion Zone	Completion Interval Elevation Corresponding to Pressure		Thickness	Fracture Gradient	Maximum Allowable Downhole Pressure
		Top (ft TVD)	Bottom (ft TVD)	(ft)	(psi/ft)	(psig)
3 *(Upside)*	Frio 0.5 & Frio 1	9,041	9,350	309	0.85	6,916
2	Frio 4	9,593	9,770	177	0.85	7,339
1	Frio 5	9,870	9,930	60	0.85	7,551