STATE OF OHIO
DEPARTMENT OF NATURAL RESOURCES
DIVISION OF OIL AND GAS RESOURCES MANAGEMENT

In re the Matter of the Application of	:	
Gulfport Energy Corporation for	:	
Unit Operation	:	Application Date: March 15, 2016
	:	Supplemental Date: July 5, 2016
Hogston C Unit	:	

PREPARED TESTIMONY OF DANNY WATSON, P.E.
ON BEHALF OF GULFPORT ENERGY CORPORATION

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Date: July 5, 2016

Exhibit 4

PREPARED DIRECT TESTIMONY OF DANNY WATSON, P.E.

Q1. Please introduce yourself.

A1. My name is Danny Watson and my business address is 14313 N. May, Oklahoma City, Oklahoma 73134. I am the Resource Development Manager for Gulfport Energy Corporation.

Q2. What is the purpose of your testimony today?

A2. I am testifying in support of the Application of Gulfport Energy Corporation for Unit Operation filed with respect to the Hogston C Unit, consisting of fifty-nine (59) separate tracts of land totaling approximately 576.511 acres in Belmont County, Ohio. My testimony addresses the following: (1) unit operations for the Hogston C Unit are reasonably necessary to increase substantially the recovery of oil and gas and (2) the value of the estimated additional recovery due to unit operations exceeds the estimated additional costs.

Q3. Can you summarize your educational experience for me?

A3. I hold a Bachelors of Science in Petroleum Engineering from West Virginia University.

Q4. Are you a member of any professional associations?

A4. I am a member of The Society of Petroleum Engineers.

Q5. Do you hold a professional licensure?

A5. I am a registered Professional Engineer in the state of Oklahoma.

Q6. How long have you been a Reservoir Engineer for Gulfport?

A6. Two years.

Q7. What other work experiences have you had?

A7. With over 7 years of experience, I have worked for Marshall Miller & Associates as a Reservoir Engineer, Chesapeake Energy as a Completions/Production Engineer, and Gulfport Energy as a Reservoir Engineer and in my current role as Resource Development Manager.

Q8. What does being a reservoir engineer entail?

A8. I perform reserve evaluations estimating reserves and recoveries. I analyze the economics and risk assessment of developmental wells and projects. I calculate how many hydrocarbons are believed to exist or remain on Gulfport properties as well as how much we can economically expect to produce.

Q9. How do you do that?

A9. There are several methods available such as volumetric analysis, utilizing analogous offset production, and decline-curve analysis that can be used to make projections about how much hydrocarbon exists and how much can be produced. Geologic data, drilling and fracturing techniques, and costs are considered to estimate economics.

Q10. Did you perform any calculations to support Gulfport's application for unitization for the proposed Hogston C Unit?

A10. Yes, I did.

Q11. And did you perform those calculations yourself, or did someone assist you?

A11. I performed the calculations myself.

Q12. What sort of calculations were you asked to perform?

A12. Under the current un-unitized acreage, Gulfport would be unable to drill any horizontal wells when considering the 500 feet limit of the unleased parcels. If the acreage were approved for full development, Gulfport would be able to drill 2 horizontal wells (approximately 9,882' average lateral length) from a single pad in an adjacent unit. I estimated the reserves for each scenario in this two-well unit.

Q13. Why horizontal wells?

A13. The vast majority of unconventional shale reservoirs cannot be produced at economic flow rates and do not produce economic volumes of oil and gas without the use of horizontal drilling and the assistance of stimulation treatments like hydraulic fracturing. This largely explains why Utica Shale exploration and production in Ohio is a recent development. The permeability of shale formations, including the Utica formation, is extremely low. In order for hydrocarbons found in the shale reservoir to flow at economic rates, the surface area open to flow must be maximized. Thus far, horizontal multi-stage, hydraulically-fractured wells are the most efficient way that the oil and gas industry has been able to maximize the surface area exposed to the reservoir for flow purposes.

Q14. How are horizontal wells drilled?

A14. Horizontal drilling is the process of drilling down vertically to a point commonly referred to as the kickoff point, and then gradually turning the wellbore to drill and place the wellbore in the desired hydrocarbon bearing formation – in this case, the Utica shale – horizontally in order to maximize the areal contact of the reservoir. This technology, along with hydraulically fracturing the formation, is required to economically develop unconventional resources like shale gas formations.

Q15. How deep is the desired hydrocarbon bearing formation that you are referring to?

A15. It depends on the well being drilled, but for the proposed Hogston C Unit, it is likely to be approximately 9,605' TVD (true vertical depth) based on data gathered from an offset that was recently drilled.

Q16. Is horizontal drilling common in the oil and gas industry?

A16. Yes. The oil and gas industry has been drilling horizontal wells for many years. Also, hydraulic fracturing has been used in the oil and gas industry for more than seventy years. The combination of hydraulic fracturing and horizontal drilling is what is allowing shale formations like the Utica to finally be developed.

Q17. Is it fair to say, then, that horizontal wells are the predominant method used to develop shale formations like the Utica today?

A17. Yes.

Q18. Turning specifically to the Hogston C Unit, have you made an estimate of the production you anticipate from the proposed unit's operations?

A18. Yes, I have evaluated and estimated the production potential from the Utica formation in the Hogston C Unit and believe that the gross production from unitized operations, as proposed in this application, if successful, could be as much as 47.5 BCF of gas.

Q19. How did you make those estimates?

A19. From analogy of offset Utica horizontal wells and from decline-curve analysis. There are horizontal Utica wells located within approximately two miles of the proposed unit that I believe have similar characteristics in terms of fluid type and production profile; therefore, data from those wells were used in my calculations.

Q20. Once you had that data from the other Utica shale wells, what did you do with it?

A20. I used actual production data from those wells to develop an average Utica production profile or "type curve" using decline-curve analysis. With all wells, production and pressure is highest at the onset and gradually decreases to a point where production cannot be sustained without some degree of additional stimulation. These declines can be plotted and, for wells within the same formation, tend to exhibit similar characteristics. In the type curve process, data from the first day of production for all the wells are all aligned, and the production volumes are then averaged. This will produce the average production profile of the wells included in the type curve. A mathematical expression is then used to match the existing production and forecast the future production that is expected to be produced from the well. This is referred to as "decline-curve analysis." Type curves are routinely used in the industry to estimate reserves.

Q21. I see that you've qualified your calculations as an estimate. Does that mean that you cannot calculate the production from these wells ahead of time with mathematical certainty?

A21. Yes, that is correct. The ultimate recovery of a well cannot be known until it has produced its last drop, which will not be for many years. However, we have established production and test data in the area.

Q22. In your professional opinion, would it be economic to develop the Hogston C Unit using traditional vertical drilling?

A22. No. These unconventional reservoirs cannot be produced at economic flow rates or do not produce economic volumes of oil and gas without the use of horizontal drilling and the assistance of stimulation treatments. This largely explains why the Utica Shale had not been developed prior to the recent horizontal activity in Ohio.

Q23. Are the estimates that you made based on good engineering practices and accepted methods in the industry?

A23. Yes.

Q24. Do you have the calculations you performed?

A24. Yes. The summary of my calculations are attached to this prepared testimony as Exhibit "DW-1"

Q25. Can you summarize what your calculations show?

A25. Yes. First, I looked at the economics of non-unitization. In this case, Gulfport has to avoid the unleased parcels and, as a result, will not be able to drill any economical wells.

Q26. Did you also estimate what could be recovered if operations in this area are unitized, as is being proposed by this application?

A26. Yes. In that case, Gulfport does not have to avoid the unleased parcels, and Gulfport is able to fully develop the unit with two horizontal laterals. The Hogston C, A and B laterals would measure approximately 9,894' and 9,870', respectively.

Q27. Can you summarize what those calculations show?

A27. Yes. Gulfport cannot economically develop the acreage under the non-unitized scenario; therefore, no gas will be produced. If unitization occurs, Gulfport will be able to produce approximate 47.5 bcf of gas over the productive life of the two wells.

Q28. Is the unitized recovery due solely to being able to drill beneath the currently unleased parcels?

A28. No. The oil and gas from those unleased parcels accounts for part of the increase, but the majority of the increase is from what would otherwise be stranded reserves that would not be produced unless the Division approves the unitization application for full unit operation. That oil and gas would forever be left behind if not produced through unit operation by these wells. Drilling an additional well or wells to try to recover those stranded reserves is simply not economically feasible.

Q29. Let's shift our focus to the economic calculations for this project. Have you made an estimate of the economics of the proposed development of the Hogston C Unit?

A29. Yes

Q30. Would you walk us through your economic evaluation, beginning with your estimate of the anticipated revenue stream from the Hogston C Unit development?

A30. During the reserve estimation process, not only were the ultimate reserve numbers estimated, but the production profile of the reservoir hydrocarbons over time was also developed. The production profile and a price scenario were used to develop the revenues that are expected from the proposed unit's development.

Q31. What do you mean when you say "production profile over time of the reservoir hydrocarbons," and why is it important?

A31. I am referring to the actual production we expect on a daily or monthly basis for the well's entire life. This is important when doing an economic evaluation in which revenue from future production is discounted in order to obtain the net present value and rate of return for the specific project.

Q32. What price scenario did you use?

A32. A six-year forward strip price for May 31, 2016 was used. This is the market's current view of what gas and oil prices will be in the future and are not guaranteed to be the price received for the produced hydrocarbons from the Hogston C Unit. I have attached those figures as Exhibit "DW-2".

Q33. What about anticipated capital and operating expenses?

A33. Capital and operating expenses were incorporated as well. The total estimated capital is based on the anticipated capital costs for both the drilling and completion processes. The basis for this estimate comes from recent costs we have experienced with our Utica formation development in the state of Ohio. These costs were adjusted to correspond to the respective lateral length of each lateral within the proposed unit. Incorporated in the analysis are both fixed and variable cost estimates.

Q34. Based on this information and your professional judgment, does the value of the estimated recovery from the operations proposed for the Hogston C Unit exceed its estimated costs?

A34. Yes. The total estimated cost of developing the Hogston C Unit is approximately $21.6 million. Undiscounted Net Cash Flow is $58.3 million and using a 10% discount rate, the net present value is approximately $19.8 million.

Q35. In your professional opinion, do you believe that the proposed unit operations for the Hogston C Unit are reasonably necessary to increase substantially the ultimate recovery of oil and gas from the unit area?

A35. Yes. It is my professional opinion that unit operations are reasonably necessary to increase substantially the ultimate recovery of oil and gas from the unit area. This area would not be able to be fully developed without unit operations. Further, unit operation will protect the correlative rights of all of the mineral owners by effectively and efficiently draining all of the reserves, eliminating any waste of mineral resources associated with stranded reserves. There is no doubt in my mind that unit operation will substantially increase the ultimate recovery of oil and gas from this unit area.

Q36. In your professional opinion, does the value of increased recovery attributable to unit operations exceed the estimated additional costs of unit operation?

A36. Yes. To increase the exposure to the reservoir and produce the maximum amount of hydrocarbons, placing horizontal wells across the entire proposed unit is ideal. This limits the capital cost by limiting the number of required surface locations and wells and maximizes the production from the proposed unit's operations. Without the proposed unit operations, we would not be able to fully develop this area. As indicated above, the estimated development of the proposed unit would require $21.6 million in capital, and would have an undiscounted net cash flow of $58.3 million and a net present value discounted at 10% per annum of approximately $19.8 million. Thus, the value of the increased recovery significantly outweighs the increased cost of unitized operation. Financially, it makes sense to operate as a unit.

Q37. And your opinions are based on your education and professional experience?

A37. Yes.

Q38. Does this conclude your testimony?

A38. Yes.

EXHIBIT "DW-1"

HOGSTON C UNIT

Lateral Length and Capital				
Well Name	Unit Lateral Length (ft)	Unit Dev. Cost (M$)	Non-Unit Lat. Length (ft)	Non-Unit Dev . Cost (M$)
HOGSTON C A	9,894	10,828	0	0
HOGSTON C B	9,870	10,812	0	0
TOTAL	19,764	21,640	0	0

Reserve and Economic Summary		
	Full Dev. Totals	Partial Dev. Totals
Gross Condensate (MBbls.)	0	0
Gross Residue Gas (Bcf)	47.5	0.0
Equivalent EUR (Bcfe)	47.5	0.0
Undis. Net Cash Flow (M$)	58,292	0
PV 10% (M$)	19,835	0

EXHIBIT "DW-2"

STRIP PRICES AS OF MAY 31, 2016

DATE	OIL PRICE $/BBL.	GAS PRICE $/MCF
July-Dec 2016	50.80	2.53
Jan-Dec 2017	51.90	3.00
Jan-Dec 2018	52.68	3.03
Jan-Dec 2019	53.98	3.05
Jan-Dec 2020	55.29	3.13
Jan-Dec 2021	56.45	3.27
To Life	58.35	3.60