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Shale gas reservoir treatment by a CO_2-based technology

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Outlines

- Shale gas storage mechanism
- Shale gas production obstacles
- CO_2 for enhanced shale gas recovery
- Modeling approach
- Barnett Shale
- Eagle Ford Shale
- Marcellus Shale
- Conclusion

Shale Gas Storage Mechanism

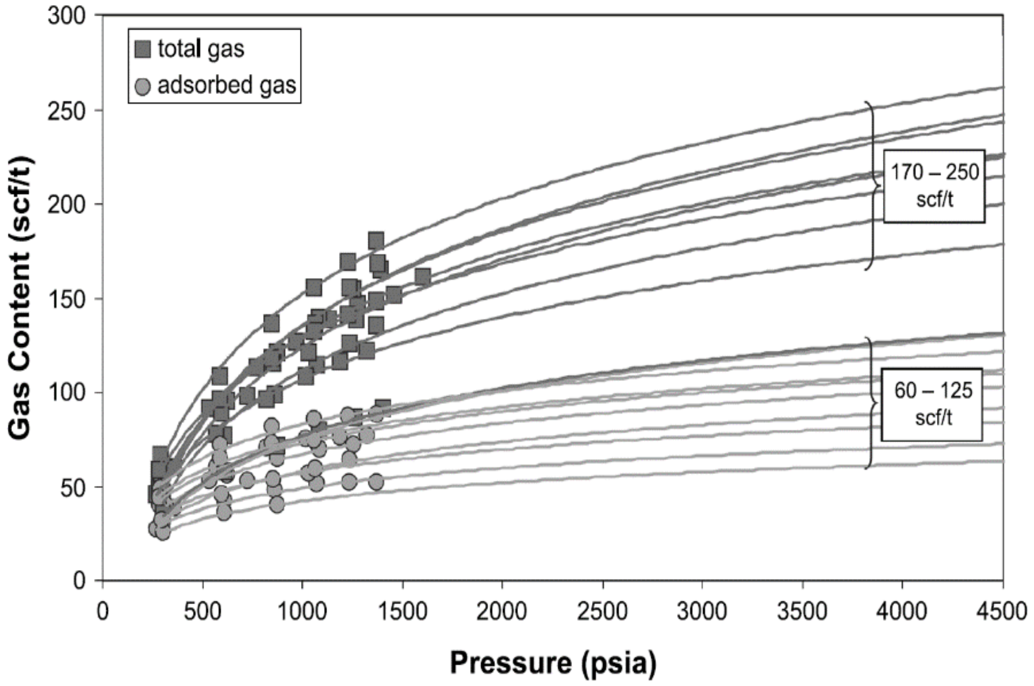
Shale gas storage mechanism

- Natural gas is mainly stored as free gas and adsorbed gas in shale

$$G_{st} = G_f + G_a + G_{so} + G_{sw}$$

- Gas sorption is characterized by Langmuir model
- Due to constraint of reservoir pressure, sorbed gas is hard to recover

$$G_a = V_L \frac{P}{P + P_L}$$



Total gas and adsorbed gas content in the Barnett Shale

Free gas and adsorbed gas fractions in some representative shale plays in the U.S.

Play	Source	Free gas fraction	Adsorbed gas fraction
Barnett	thermogenic	~50%-65%	~35%-50%
Marcellus	thermogenic	~50%	~50%
Fayetteville	thermogenic	~40%	~60%
Woodford	thermogenic	~54%	~46%
Lewis	thermogenic	~40%	~60%
Ohio	thermogenic	~50%	~50%
New Albany	mixed	~50%	~50%
Antrim	biogenic	~30%	~70%

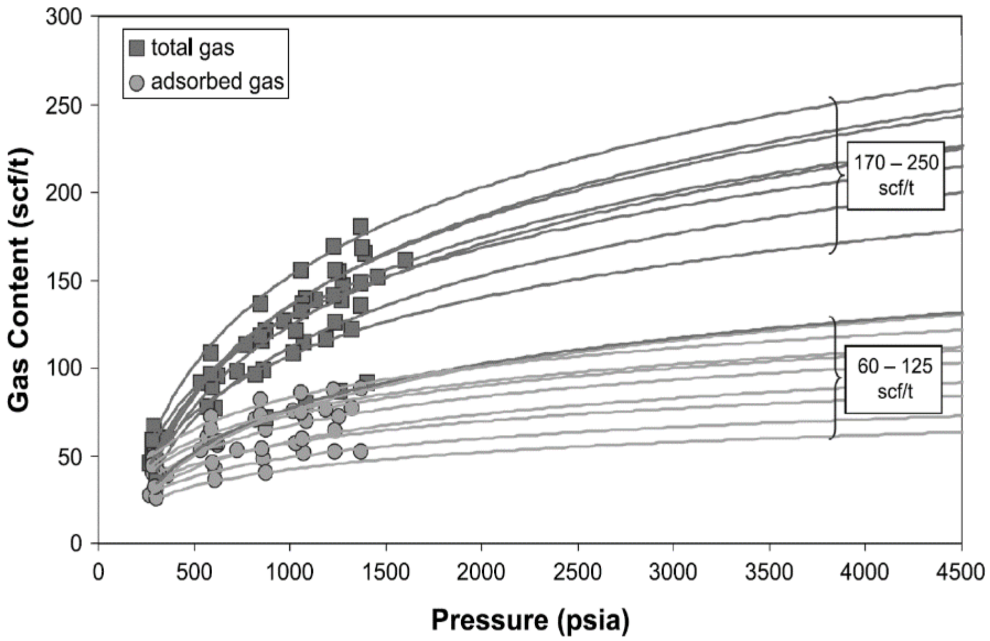
Pei, et al., 2015, Shale gas reservoir treatment by a CO2-based technology, in *Natural Gas Science and Engineering*

Shale Gas Production Obstacles

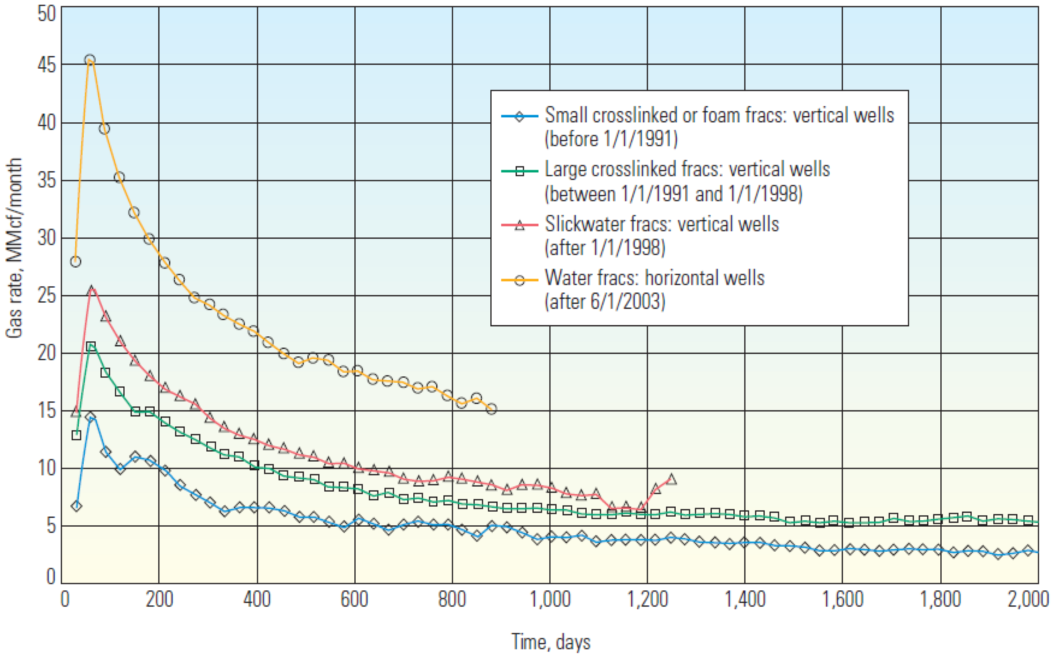
Shale gas production involves three main processes: depletion of free gas in fractures, depletion of free gas in matrix pores, and desorption of sorbed gas

Challenges in shale gas production:

1. High water consumption
2. Formation damage (clay swelling)
3. Fast drop of production
4. Low production of single well
5. High-density well drilling

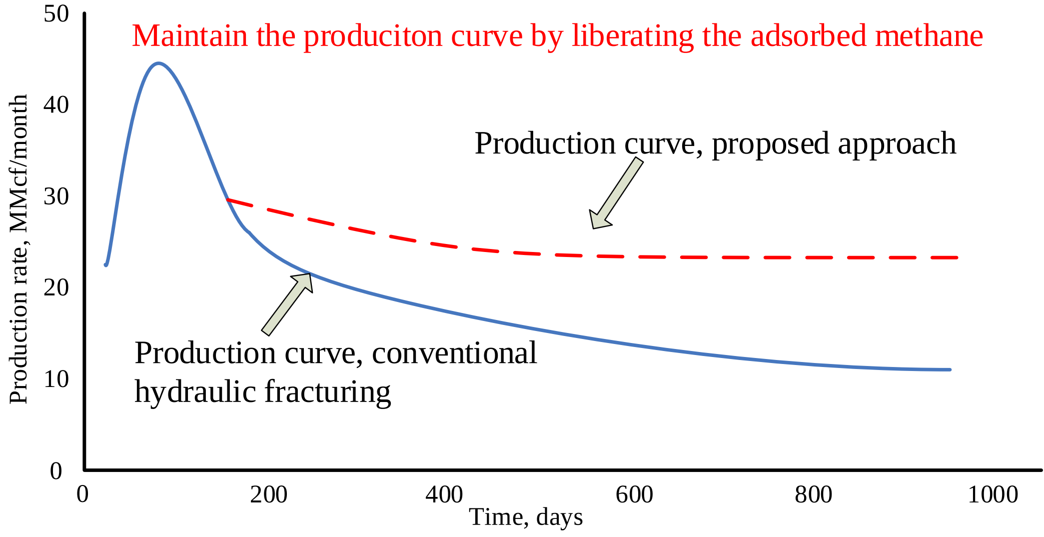


Typical gas decline curves of Barnett Shale



CO_2 for Enhanced Shale Gas Recovery

- Organic surface of shale has a higher affinity for CO_2 than CH_4
- Selectivity of CO_2 over methane varies from 2 to higher than 5 at various temperatures and pressures
- Use CO_2 as a displacing fluid
- Similar to enhanced coal bed methane recovery
- Reservoir damage free, boost production
- A large CCUS market and storage capacity for CO_2



Modeling Approach and Assumption

- Case study for Barnett, Marcellus and Eagle Ford shales.
- The reservoir had been stimulated.
- CO_2-EGR was applied after the steep drop stage in primary recovery.
- CO_2 injection wells and natural gas production wells were arrayed next to each other.
- The reservoir pressure was maintained at an approximately constant level during CO_2 injection.
- Gas adsorption in the rock followed the Langmuir monolayer adsorption theory.
- Extended Langmuir isotherm for binary gas sorption.

Modeling Approach and Assumptions

- Extended Langmuir isotherm for binary gas sorption: $$G_{a,i} = \frac{V_{L,i}\dfrac{P_i}{P_{L,i}}}{1+\sum_j \dfrac{P_j}{P_{L,j}}}$$

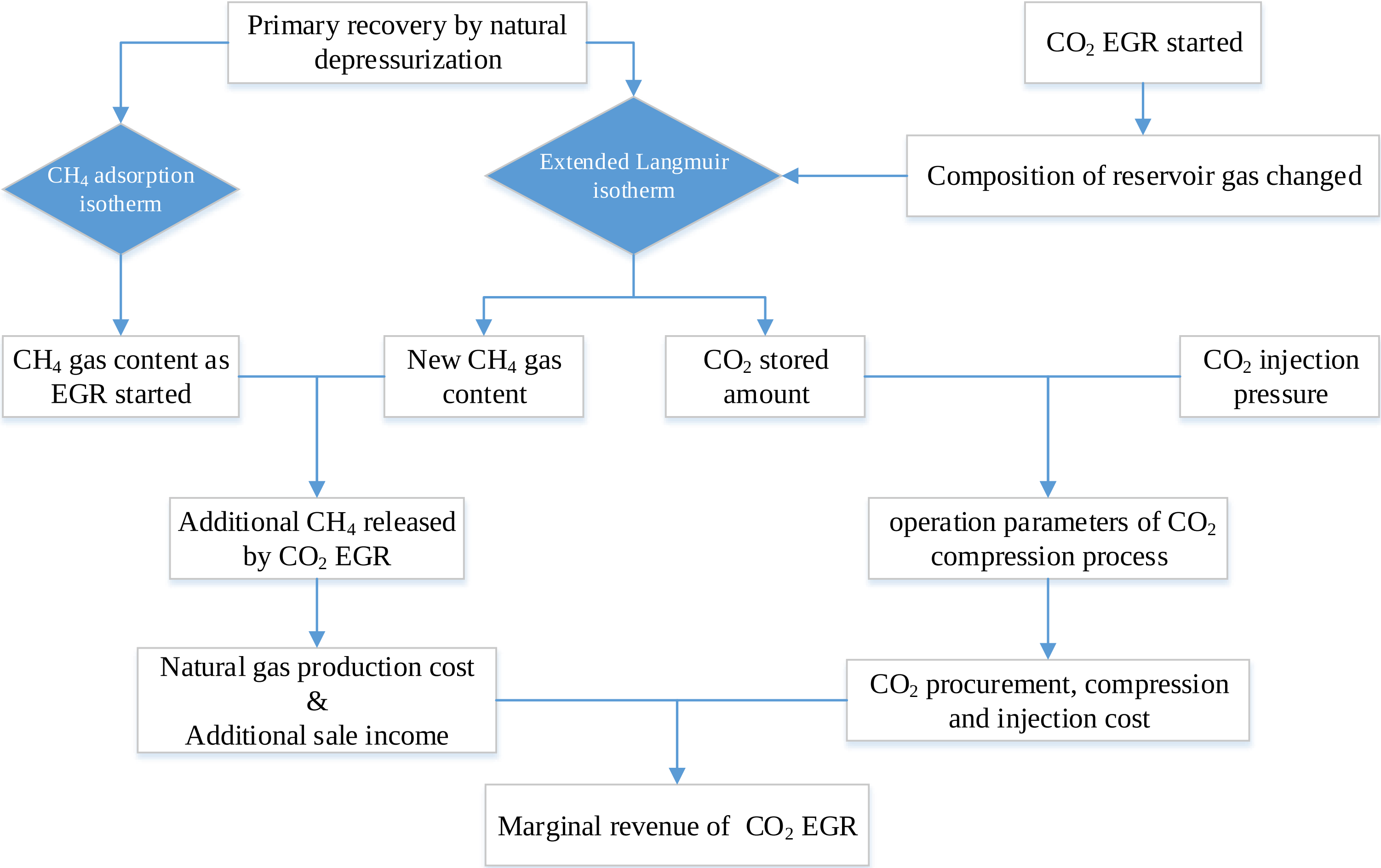
- Selectivity ratio: $$\alpha = \frac{\left(\dfrac{V_{L,i}}{P_{L,i}}\right)}{\left(\dfrac{V_{L,j}}{P_{L,j}}\right)}$$

- The amount of CH_4 liberated through CO_2 injection: $$\Delta G_{CH4} = G_{CH4,0} - G_{a,CH4}$$

- ratio of production (R_{prd}) is defined as a parameter to represent how many volumes of CO_2 must be injected to liberate one unit volume of CH_4:

$$R_{prd} = \frac{\Delta G_{CO2}}{\Delta G_{CH4}}$$

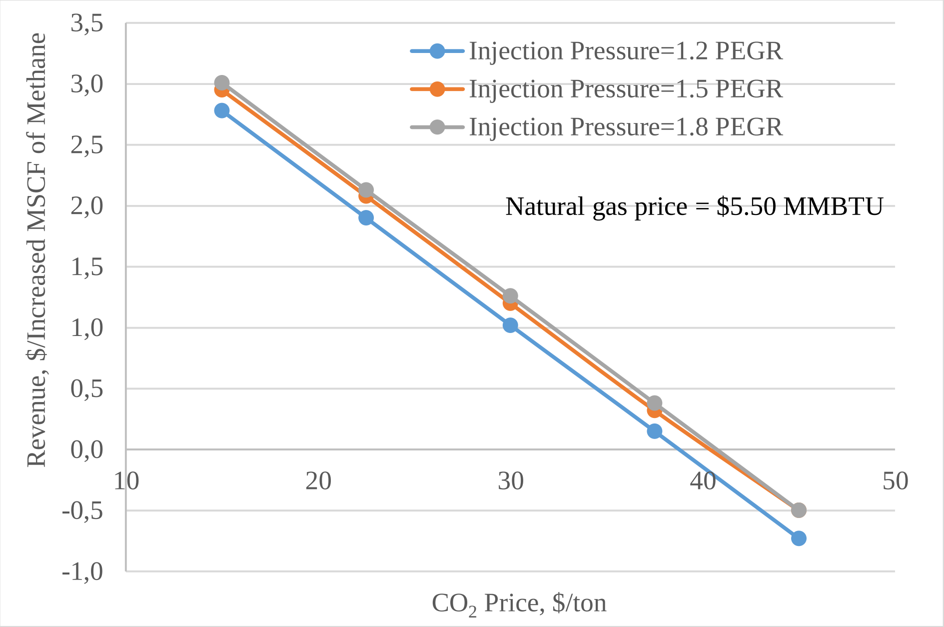
Modeling Approach and Assumptions



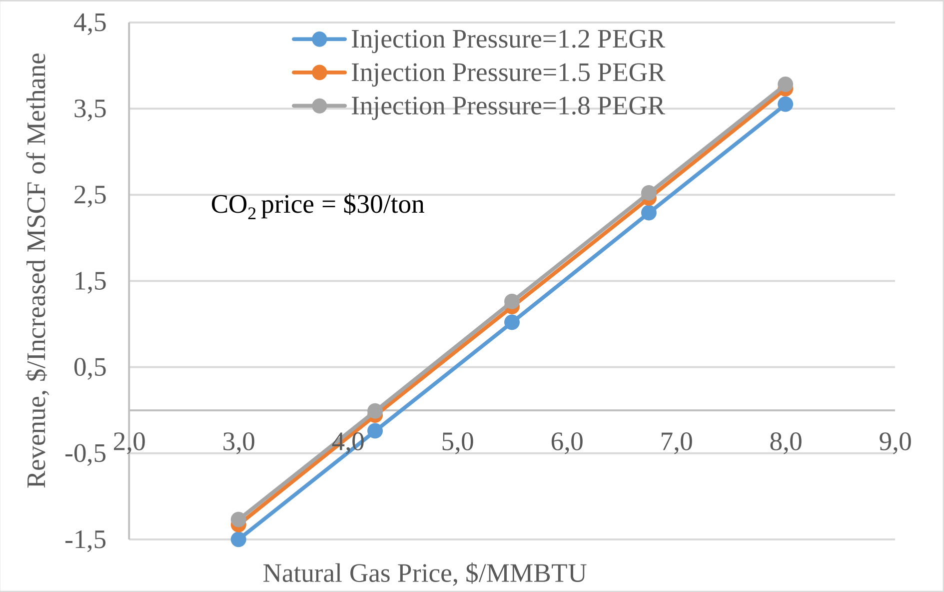
Barnett Shale

Reservoir depth, D	7,000	ft
Pay zone thickness, h	300	ft
Original reservoir pressure, P_0	3,800	psi
Reservoir temperature, T	640	ºR
Horizontal permeability in fracture, K_H	0.25	mD
Permeability anisotropy, I_{ani}	71	
Primary recovery year, $t_{primary}$	5	years
Reservoir external pressure during EGS, P_{EGR}	3,400	psi

$$R_{prd} = 2.04$$



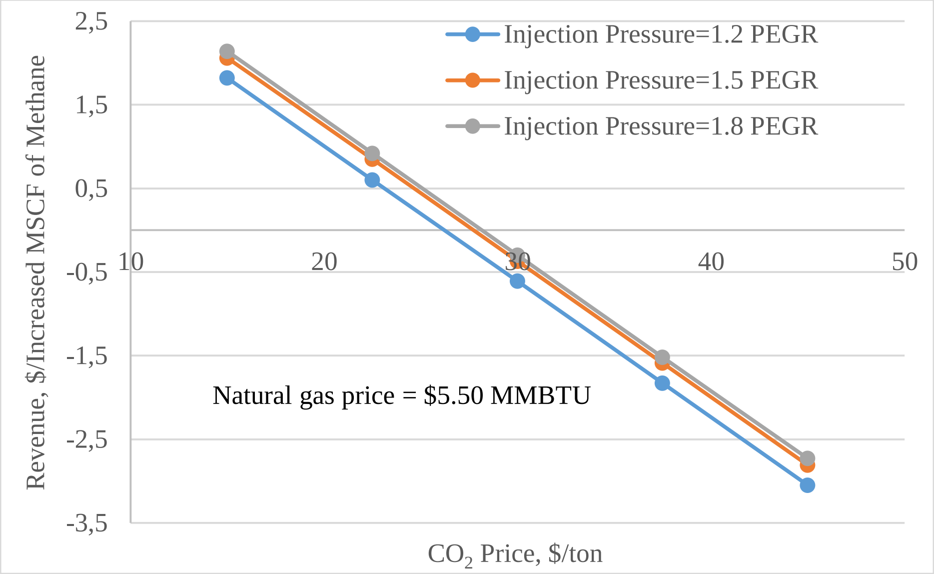
Inj. Pre. Ratio	CO_2 price	Production cost of CH_4	CH_4 well	CO_2 well	CO_2 compressor	CO_2 purchase
	$/ton	$/increased MSCF CH_4	Share %	Share %	Share %	Share %
1.2	15.0	2.78	7%	20%	9%	63%
1.5	15.0	2.61	7%	16%	9%	67%
1.8	15.0	2.55	7%	15%	10%	69%
1.2	22.5	3.66	5%	16%	7%	72%
1.5	22.5	3.48	5%	12%	7%	76%
1.8	22.5	3.43	5%	11%	7%	77%
1.2	30.0	4.54	4%	13%	6%	77%
1.5	30.0	4.36	4%	10%	6%	80%
1.8	30.0	4.30	4%	9%	6%	82%
1.2	37.5	5.42	4%	10%	5%	81%
1.5	37.5	5.24	4%	8%	5%	84%
1.8	37.5	5.18	3%	7%	5%	85%
1.2	45.0	6.29	3%	9%	4%	84%
1.5	45.0	6.12	3%	7%	4%	86%
1.8	45.0	6.06	3%	6%	4%	87%



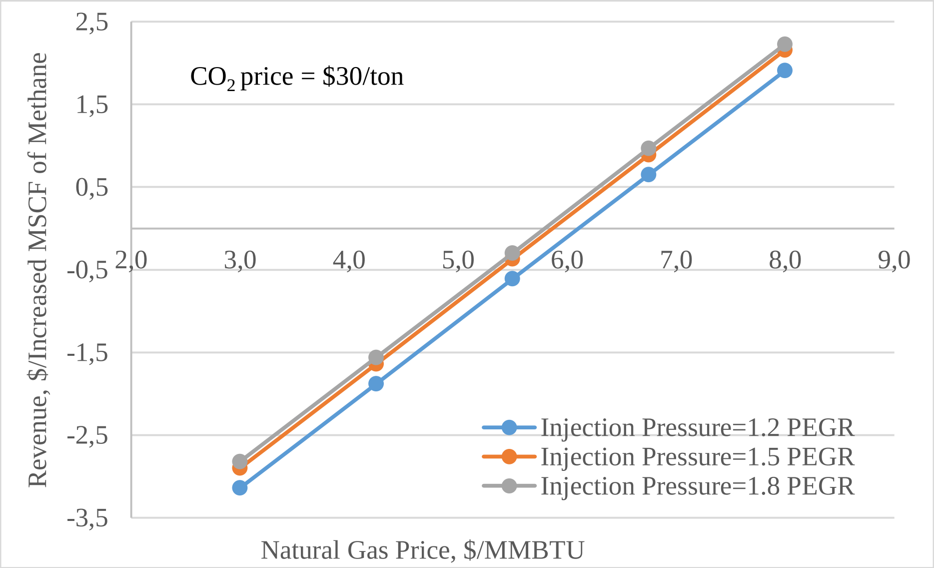
Eagle Ford Shale

Reservoir depth, D	9,000	ft
Pay zone thickness, h	200	ft
Original reservoir pressure, P_0	6,400	psi
Reservoir temperature, T	715	ºR
Horizontal permeability in fracture, K_H	0.25	mD
Permeability anisotropy, I_{ani}	71	
Primary recovery year, $t_{primary}$	5	years
Reservoir external pressure during EGS, P_{EGR}	3,000	psi

$$R_{prd} = 2.88$$



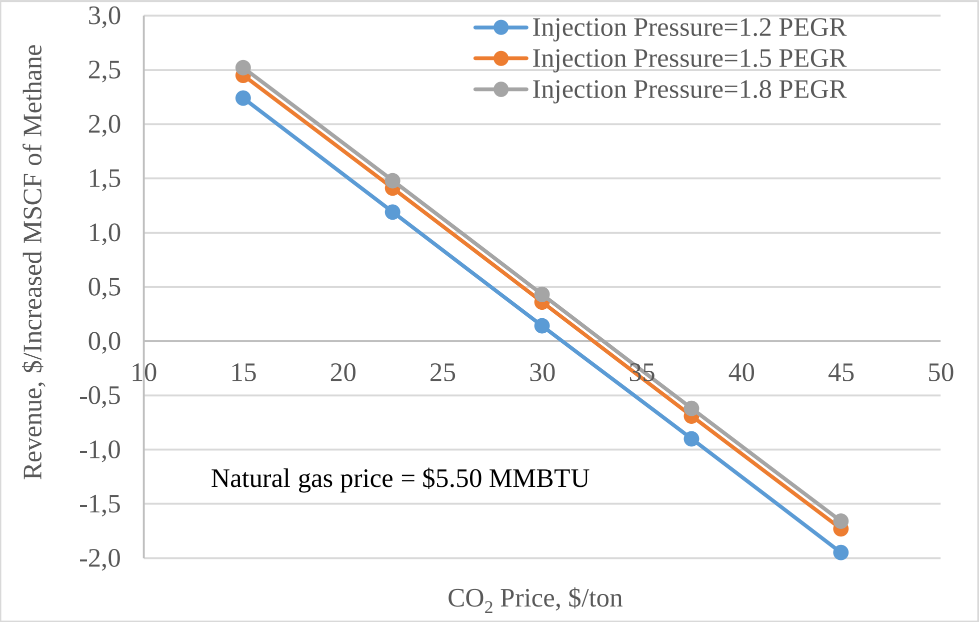
Inj. Pre. Ratio	CO_2 price	Prod. cost of CH_4	CH_4 well	CO_2 well	CO_2 compressor	CO_2 purchase
	\$/ton	\$/increased MSCF CH_4	Share %	Share %	Share %	Share %
1.2	15.0	3.74	6%	21%	8%	65%
1.5	15.0	3.50	5%	16%	8%	70%
1.8	15.0	3.42	5%	15%	9%	71%
1.2	22.5	4.96	4%	16%	6%	74%
1.5	22.5	4.71	4%	12%	6%	78%
1.8	22.5	4.64	4%	11%	6%	79%
1.2	30.0	6.17	3%	13%	5%	79%
1.5	30.0	5.93	3%	10%	5%	82%
1.8	30.0	5.86	3%	9%	5%	83%
1.2	37.5	7.39	3%	11%	4%	82%
1.5	37.5	7.15	3%	8%	4%	85%
1.8	37.5	7.08	3%	7%	4%	86%
1.2	45.0	8.61	2%	9%	4%	85%
1.5	45.0	8.37	2%	7%	4%	87%
1.8	45.0	8.29	2%	6%	4%	88%



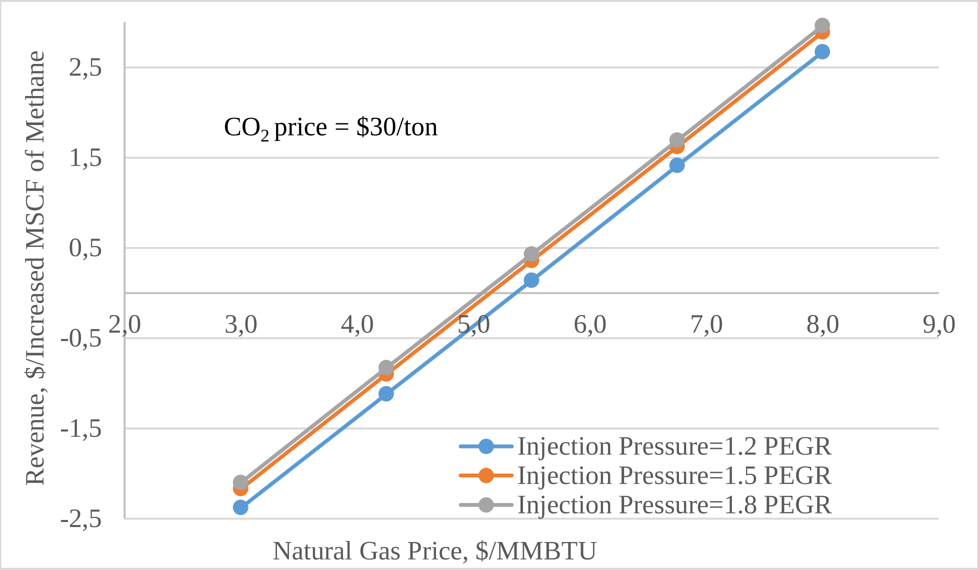
Marcellus shale

Reservoir depth, D	5,000	ft
Pay zone thickness, h	100	ft
Original reservoir pressure, P_0	4,000	psi
Reservoir temperature, T	565	ºR
Horizontal permeability in fracture, K_H	0.25	mD
Permeability anisotropy, I_{ani}	71	
Primary recovery year, $t_{primary}$	5	years
Reservoir external pressure during EGS, P_{EGR}	3,500	psi

$$R_{prd} = 2.46$$



Inj. Pre. Ratio	CO_2 price	Prod. cost of CH_4	CH_4 well	CO_2 well	CO_2 compressor	CO_2 purchase
	$/ton	$/increased MSCF CH_4	Share %	Share %	Share %	Share %
1.2	15.0	3.33	7%	21%	10%	63%
1.5	15.0	3.11	7%	17%	10%	67%
1.8	15.0	3.04	6%	15%	10%	69%
1.2	22.5	4.37	5%	16%	7%	72%
1.5	22.5	4.15	5%	12%	7%	76%
1.8	22.5	4.08	5%	11%	7%	77%
1.2	30.0	5.42	4%	13%	6%	77%
1.5	30.0	5.20	4%	10%	6%	80%
1.8	30.0	5.13	4%	9%	6%	82%
1.2	37.5	6.46	3%	11%	5%	81%
1.5	37.5	6.25	3%	8%	5%	84%
1.8	37.5	6.18	3%	7%	5%	85%
1.2	45.0	7.51	3%	9%	4%	84%
1.5	45.0	7.29	3%	7%	4%	86%
1.8	45.0	7.22	3%	6%	4%	87%



Summary

- Through CO_2 injection during the EGR process, natural gas production will be boosted by the displaced sorbed gas, resulting in benefits of improved single well production and economics, reduced large-scale well drilling, and smaller limited environmental footprints.
- Results of the case study indicate that CO_2 procurement was the biggest cost component for the EGR process, higher than the sum of other cost components.
- Prices of CO_2 and CH_4 were the key factors in determining the profitability of the EGR process.
- The proposed CO_2-EGR process was mostly like to be successful in the Barnett shale since it has the lowest R_{prd} (2.04).
- The R_{prd} value can be used as one of the criteria in assessing the feasibility of CO_2-EGR.

Thank You