Time-Dependent Performance Evaluation of Cyclic Injection of Gas Mixtures into Hydraulically-Fractured Wells in Appalachian Sandstones*

Emre Artun[1]

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[1]Middle East Technical University Northern Cyprus Campus (artun@metu.edu)

Abstract

Single-well cyclic gas injection is a promising method to increase recovery from depleted and fractured reservoirs. The process is primarily driven by a diffusion process through the fracture surface, allowing the oil in the matrix to be displaced towards fractures, resulting in improved oil production. The method is attractive because of lower investment requirements as compared with larger field-scale flooding projects. It was previously shown both in the field and through experimental/modeling studies that nitrogen and carbon-dioxide can be used effectively in Appalachian Basin sandstones for cyclic injection in the presence of hydraulic/natural fractures.

In this study, injection of mixtures of nitrogen, carbon-dioxide and methane gases are evaluated using a compositional reservoir model that represents a hydraulically-fractured, stripper production well with characteristics of Appalachian sandstones and a 36-API gravity crude oil sample taken from the Appalachian Basin. By varying process design parameters such as injection rate, injection period, soaking period, economic rate limit and injected gas composition, 5000 simulation runs were completed to assess the applicability of the process. Results were analyzed by defining an economic indicator that takes into account discounted values of incremental oil produced, volume of injected gas, oil price and costs of injected gas for varying project periods between 1 year and 20 years. Among the ranges studied, it was observed that the process would result in a positive net present value for all the cases, up to 6 years of project time. Feasibility beyond 6 years depends on the operational parameters. Keeping the injection rate below 400 MCF/d, injection duration less than 20 days, economic rate limit below 4 STB/d and soaking period greater than 30 days would contribute to the successful application of this process. It was observed that the injected gas composition does not significantly affect the efficiency since each type of gas contributes to the recovery mechanism differently. However, economic analysis favors nitrogen since the cost of generation is lower than other gases. Results were also used to develop a screening model that is based on neural networks that forecasts the efficiency. This model was validated with 500 blind cases, with a correlation coefficient of 0.95. Analysis of this model confirmed previous findings regarding the importance of all operational parameters except gas composition.

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Emre Artun

Petroleum and Natural Gas Engineering

Middle East Technical University, Northern Cyprus Campus

46th Annual Meeting of AAPG Eastern Section

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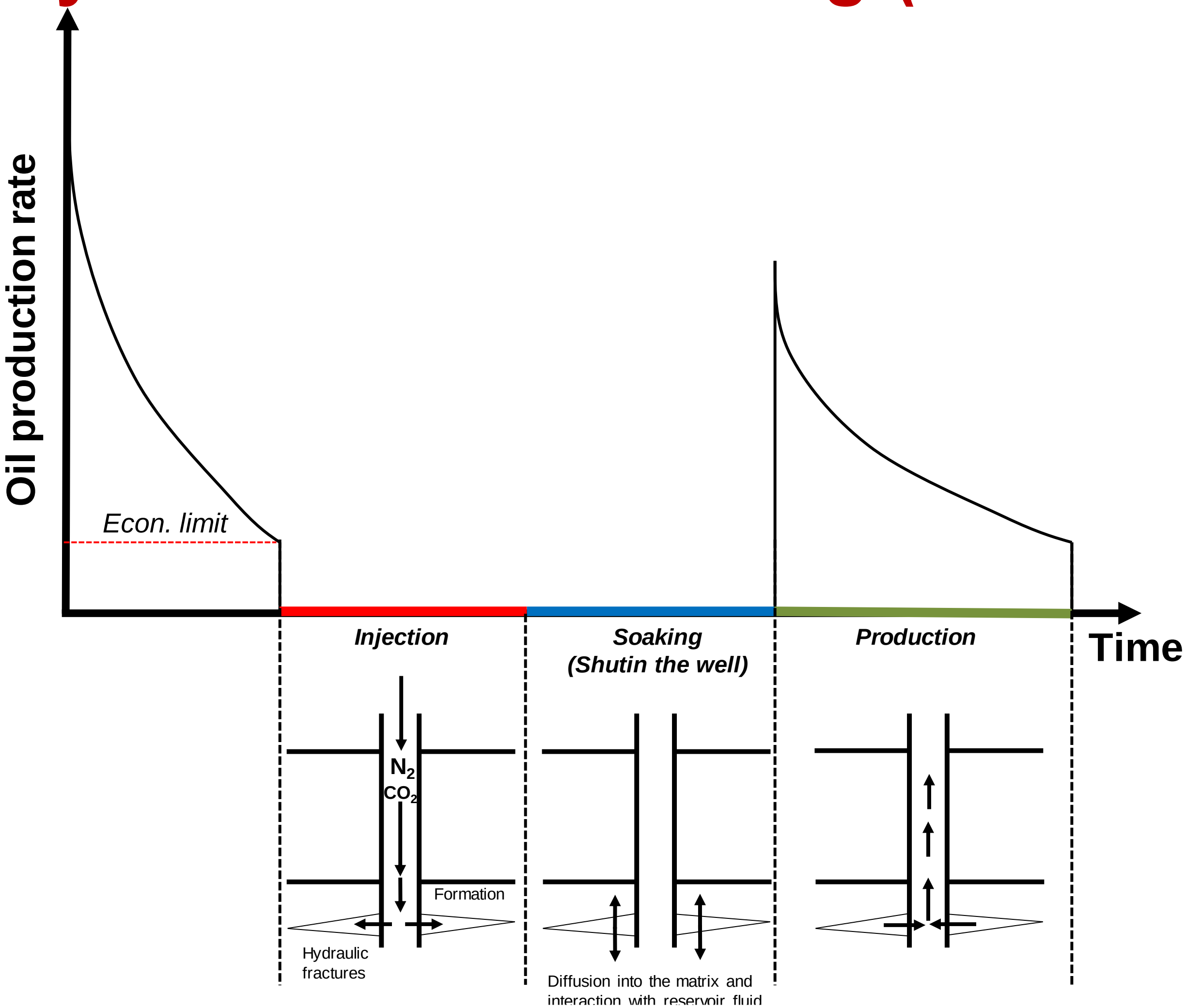
Outline

- Introduction
- Methodology
  - *Modeling*
  - *Experimental Design*
  - *Performance Assessment*
- Results & Discussion
  - *Analysis*
  - *Screening Tool*
- Conclusions

Motivation: Appalachian Basin Sandstones

- Production since early 1900's: Old wells / infrastructure
- Depleted (p < 200 psia)
- Stripper wells ($q \approx$ 1-10 STB/d)
- Secondary recovery: completed
- Hard to justify costly EOR methods
- Hydraulic fractures
- Poorly characterized reservoirs with questionable connectivity between wells

Cyclic Pressure Pulsing (Huff 'n' Puff) with Gas



- Single-well EOR
- Fractured reservoirs (Large surface area for diffusion)
- Various types of gases

Advantages:

- Well-to-well connectivity is not required
- Shorter payback periods

History of Cyclic Pressure Pulsing

- Water: an improved way of waterflooding
  - *Owens and Archer (1966)*
  - *Felsenthal and Ferrell (1967)*

- Natural gas
  - Raza (1971)
  - Shelton & Morris (1973)

- CO_2 for heavy oil
  - Khatib *et al.* (1981): *California*
  - Bardon *et al.* (1986): *Bati Raman, Turkey*
  - Gondiken (1987): *Bati Raman, Turkey*

History of Cyclic Pressure Pulsing

- CO_2/N_2 for light oil (Kentucky/Appalachian Basin)
  - *Miller and Gaudin (2000): naturally fractured reservoirs*
  - *Artun et al. (2010, 2011, 2012): naturally fractured reservoirs*
  - *Artun et al. (2016): hydraulically fractured wells*

- CO_2/natural gas for shale oil reservoirs
  - *Yu et al. (2014)*
  - *Sheng (2013, 2014, 2015)*
  - *Meng et al. (2015)*
  - *Li et al. (2016)*
  - *Zuloaga-Molero (2016)*
  - *Li and Sheng (2017)*

Objectives

- Understanding the applicability of cyclic pressure pulsing with gas mixtures (N_2, CO_2 and CH_4) in hydraulically fractured wells in the Appalachian Basin
- Time-dependent analysis of various operational parameters on their effects on process efficiency
- Development of a data-driven screening tool to estimate the process efficiency given set of operational parameters

Reservoir Modeling → Experimental Design → Performance Analysis → Screening Tool

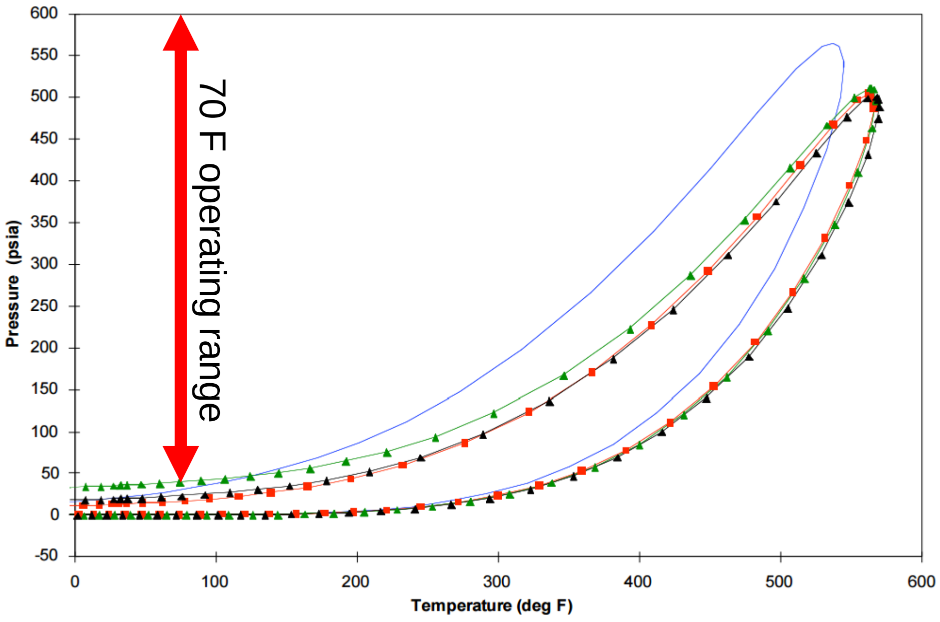
Modeling: Characteristics

- Single-well, compositional, single porosity reservoir model with a Cartesian gridblock system (CMG, 2015)

Porosity	0.1
Thickness, ft	50
Initial pressure, psia	50
Drainage area, acres	10
Water saturation	0.5
Oil saturation	0.5

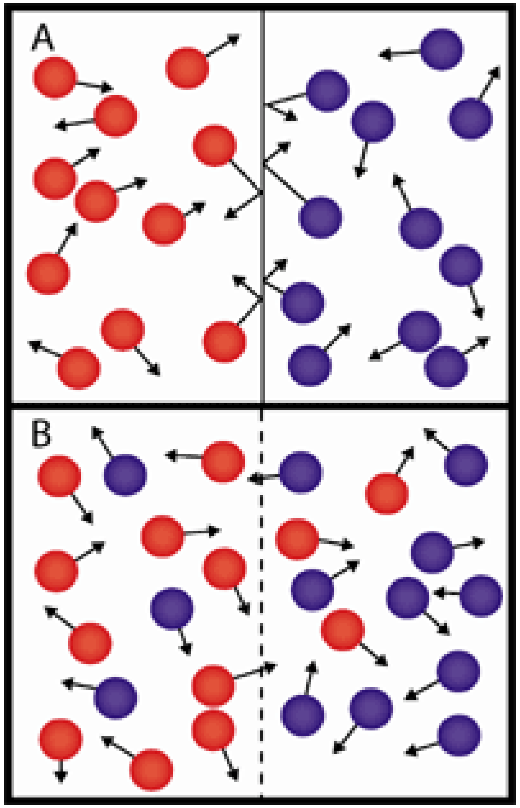
Fluid model:
Mid-Continent (light) crude oil
36º API Gravity
(Abboud, 2005; Farias and Watson, 2006)

Appalachian Basin sandstones
Duda et al., 1967
Boswell et al., 1993



Modeling: Diffusion

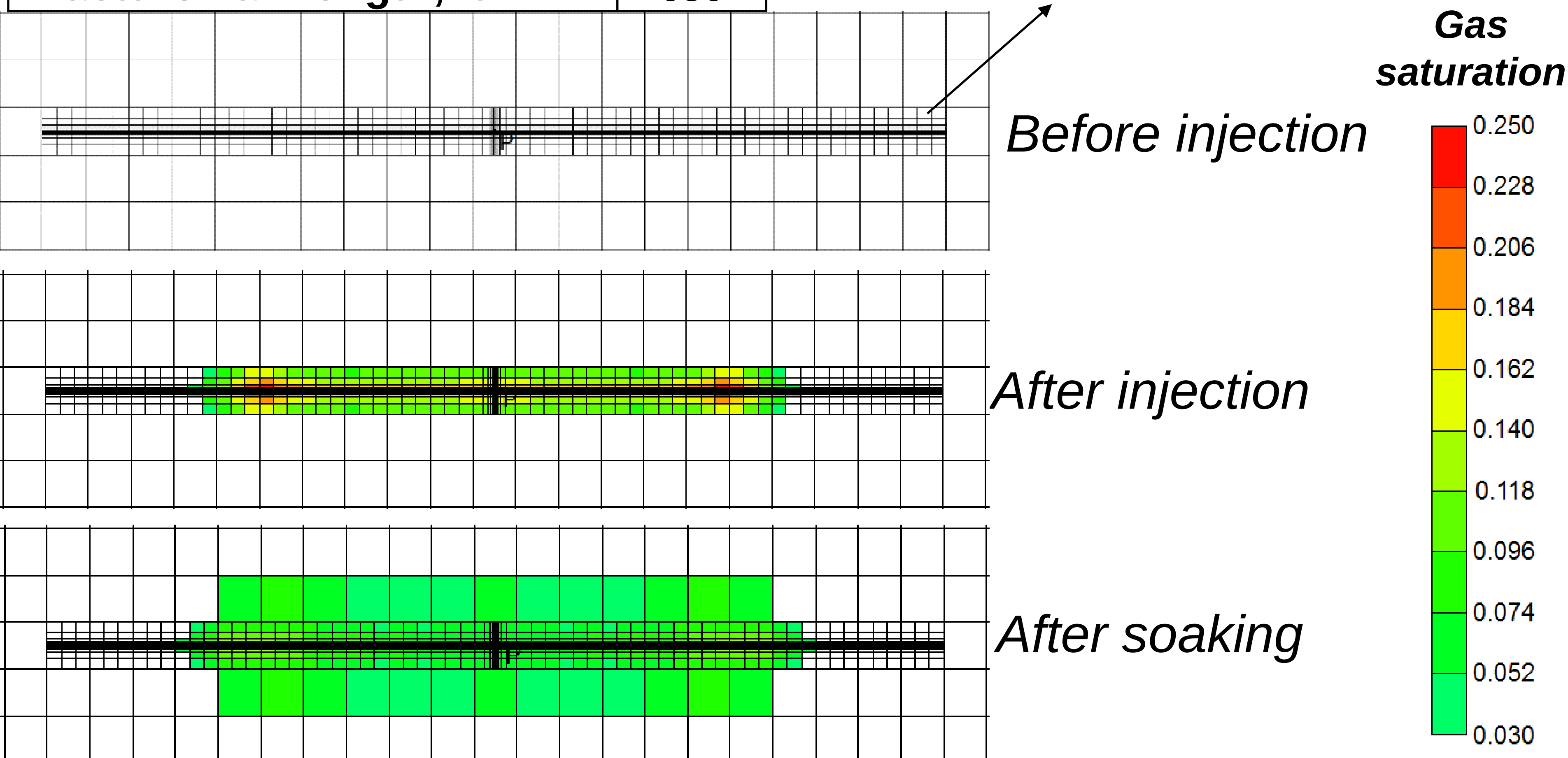
- Sigmund correlation (Sigmund, 1976) for molecular diffusion option is activated for N_2, CO_2, and CH_4
- A diffusion coefficient of **0.001 cm^2/sec** is used for gas diffusion in reservoir conditions which was determined and validated based on:
  - *Chapman-Enskog binary-diffusion theory (Marrero and Mason, 1972)*
  - *Literature (Silva and Belery, 1989)*



Modeling: Hydraulic Fracture

Fracture width, ft	0.05
Fracture permeability, md	5000
Fracture half-length, ft	650

- *Hydraulic fracture represented with a high-permeability streak*
- *Local-grid refinement to capture flow in matrix-fracture interface*



Experimental Design

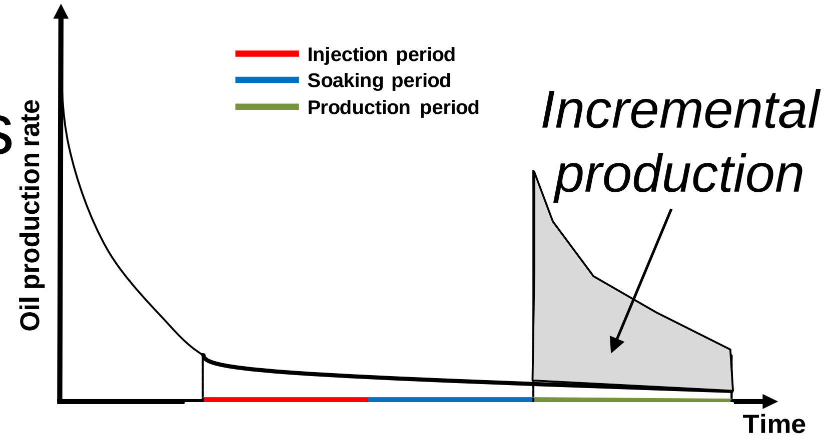
- 9,000 cases were randomly-generated using the combination of input parameters, honoring uniform distribution of all parameters

Parameter	Min	Max
Inj. rate, MCF/d	100	1000
Inj. period, days	5	50
Soak. period, days	5	50
Cycle limit, STB/d	1	10
C (CO_2), %	0	100
C (N_2), %	0	100
C (CH_4), %	0	100

$$\sum_{k=1}^{3} C_k = 100\%$$

Performance Assesment

- Two key performance indicators for income/costs are incorporated for 20 years of project length:



  – Present value of incremental volume of oil produced

$$N_{\mathrm{pio}} = \sum_{n=1}^{20} \frac{\mathrm{N_{pin}}}{(1+i)^n}$$

  – Present value of cumulative volume of gas injected

$$G_{\mathrm{i0}} = \sum_{n=1}^{20} \frac{G_{\mathrm{in}}}{(1+i)^n}$$

Discounted utilization efficiency $\rightarrow$ $E_c = \dfrac{N_{\mathrm{pio}}}{G_{\mathrm{io}}}$ STB/MCF

Performance Assesment

- Dimensionless economic efficiency:

$$E_{ce} = E_c \times \frac{Oil\ price}{Gas\ price}$$

Gas price:

N_2 : \$1.5 /MCF
CH_4 : \$2.6 /MCF
CO_2 : \$2.5 /MCF

If $E_{ce} > 1$ then NPV > 0

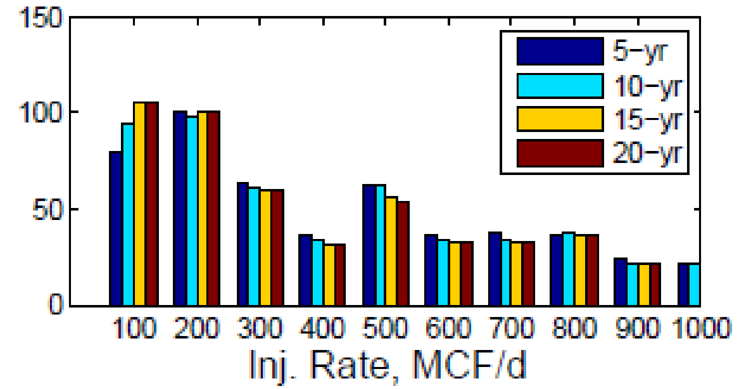
If $E_{ce} < 1$ then NPV < 0

Source for gas price:

CH_4: 2-year average for Henry Hub natural gas price (EIA, 2017)
N_2: Based on polymeric membrane unit reported (Miller and Gaudin, 2000)
CO_2: Overall market conditions reported (NETL, 2010)

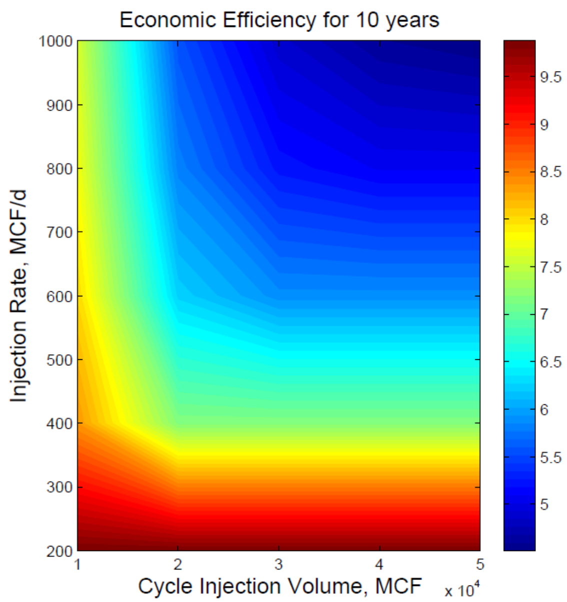
Analysis Methods

Efficiency and economic efficiency parameters are analyzed by considering the following two groups:



1. Top 500 Cases:

Number of occurrences of each variable within the top 500 efficiency values obtained (best cases)



2. All Cases:

Mapping average efficiency values obtained from the combination of 2 related variables

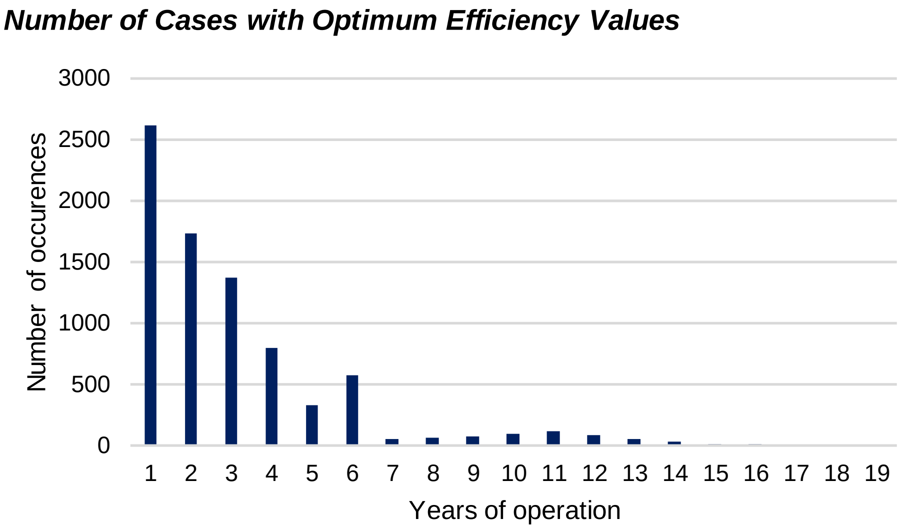
Overall Analysis

- All cases resulted in positive incremental recoveries except

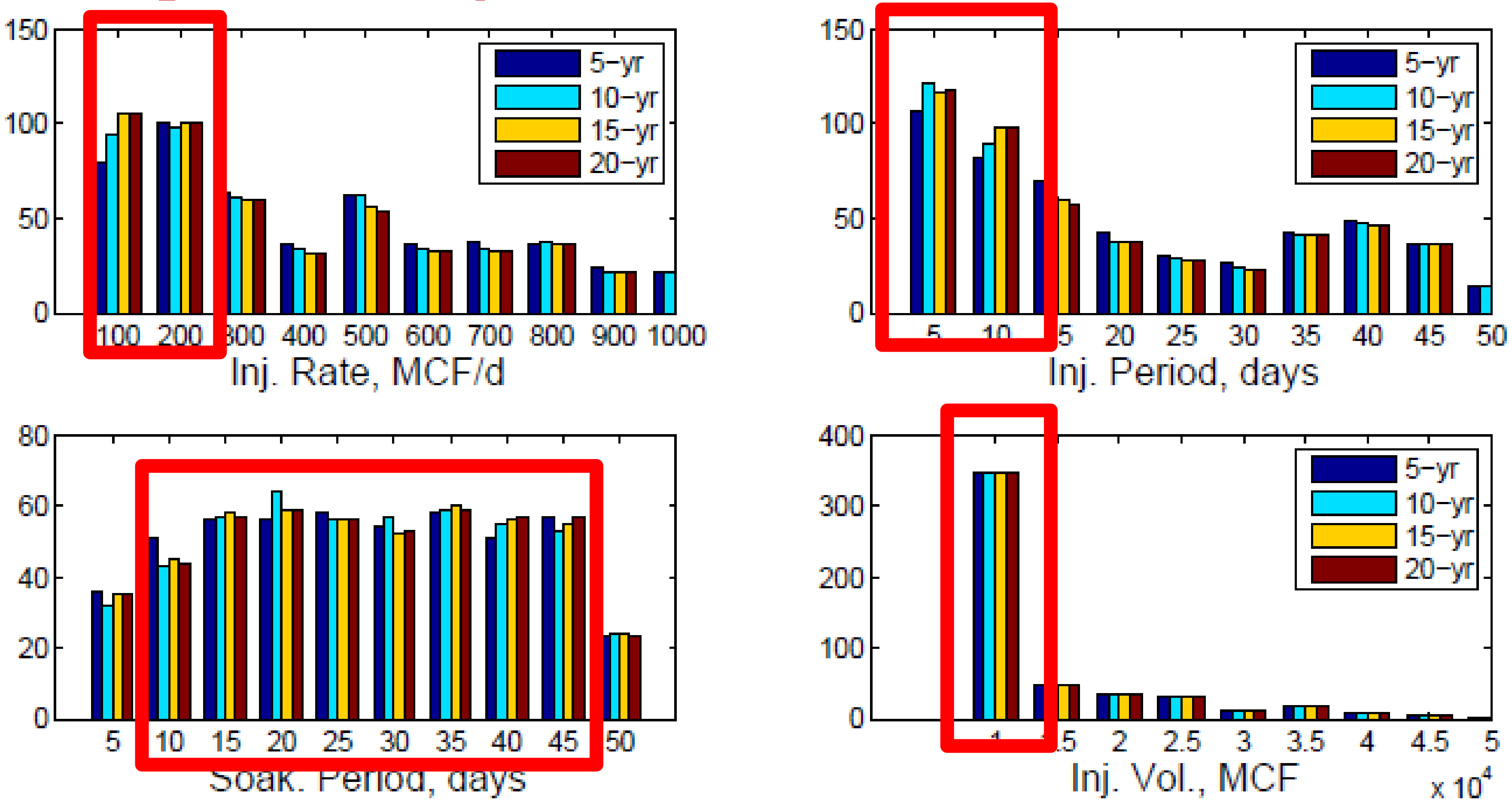
4 cases with negative incremental recoveries during the 1st year only with common characteristics:

  - Soaking Period > 45 days
  - Injection rate > 270 MCF/d
  - Injection Period > 44 days
  - Injected volume per cycle > 10,000 MCF/d

- Throughout the 20-year projects highest efficiencies are mostly observed within the first 6 years
- Beyond 6 years the efficiency generally decreases



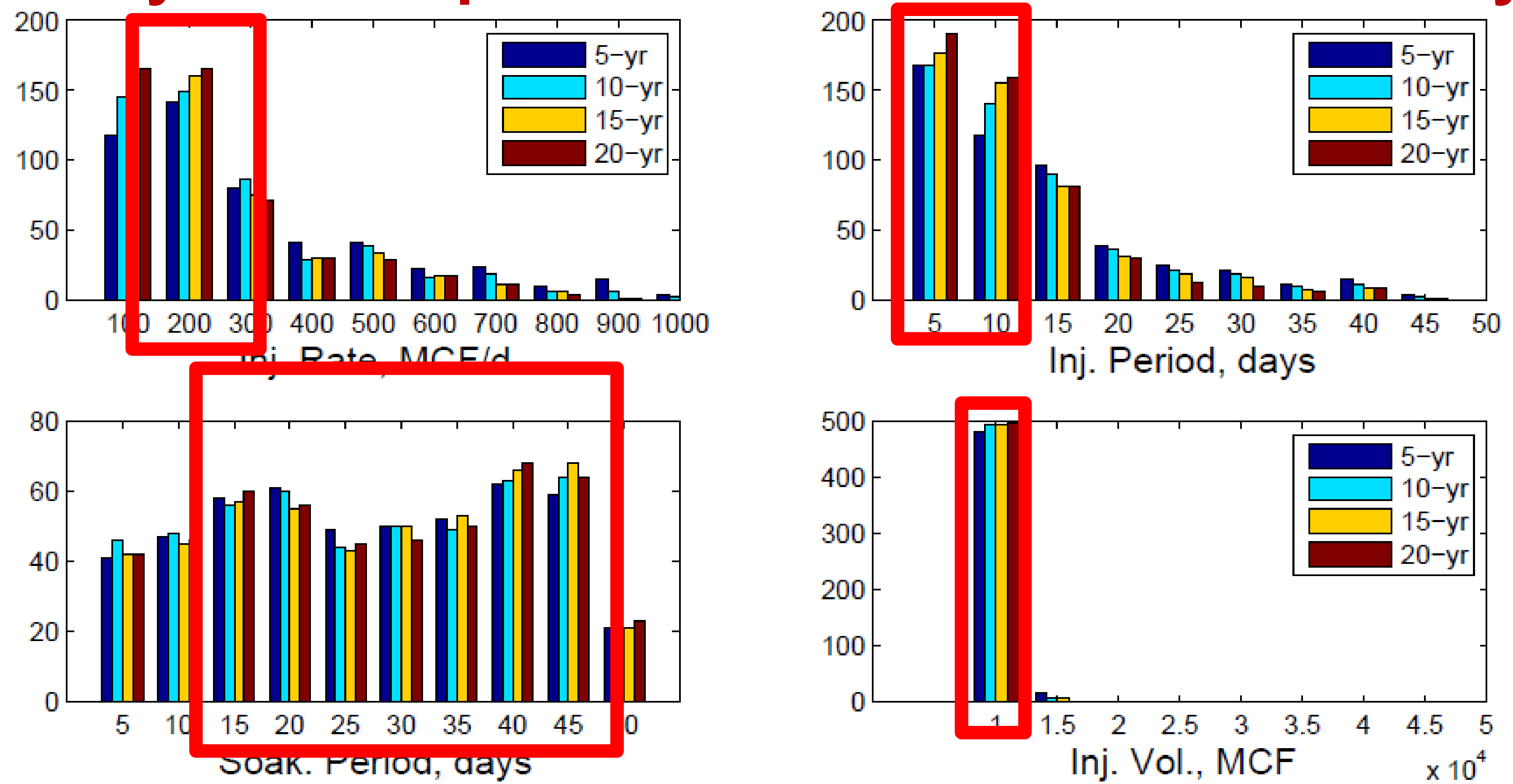
Analysis of Top 500 Cases: Utilization Efficiency



- Inj. rate.: < 200 MCF/d
- Soaking period: 15-45 days

- Inj. period: < 10 days
- Inj. Vol.: 15,000 MCF/cycle

Analysis of Top 500 Cases: Economic Efficiency



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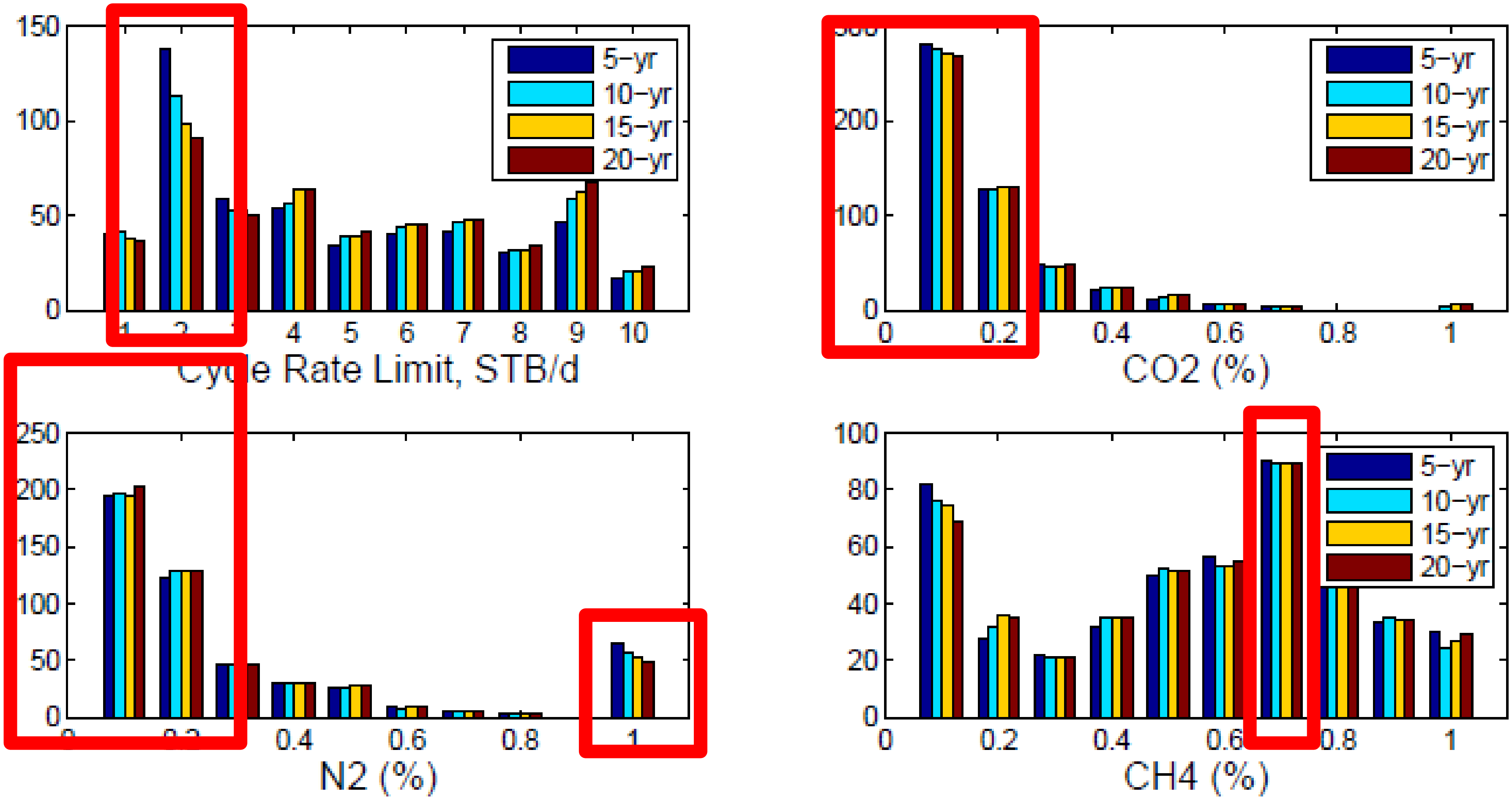
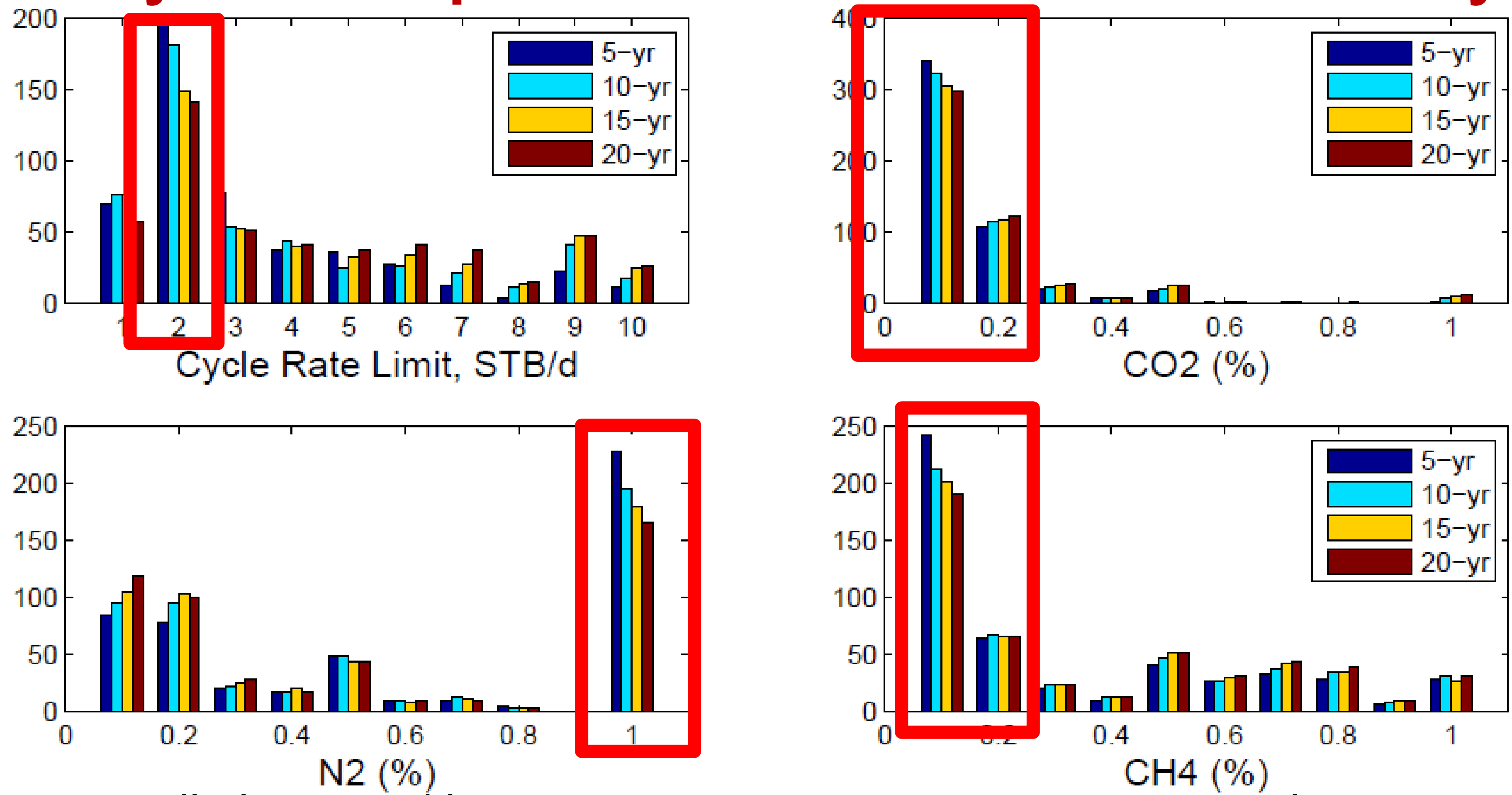
Analysis of Top 500 Cases: Utilization Efficiency



- Rate limit: 2 STB/d
- N_2: Low concentration is better but cases with 100% also exist
- CO_2: Low concentration
- CH_4: Variable, 70% optimum

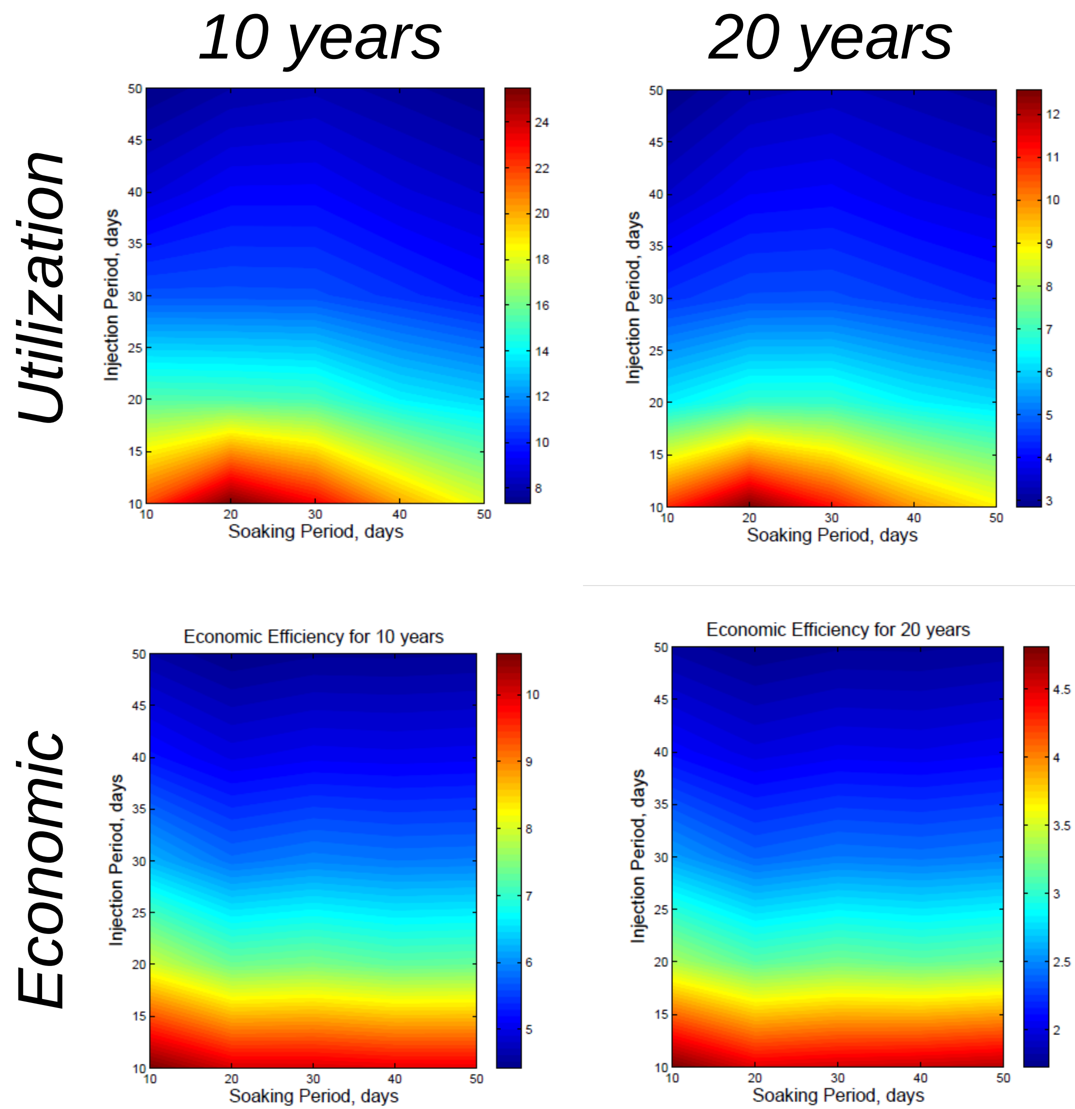
Analysis of Top 500 Cases: Economic Efficiency



- Rate limit: 2 STB/d
- N_2: High concentration is better (economic considerations)
- CO_2: Low concentration
- CH_4: Low concentration

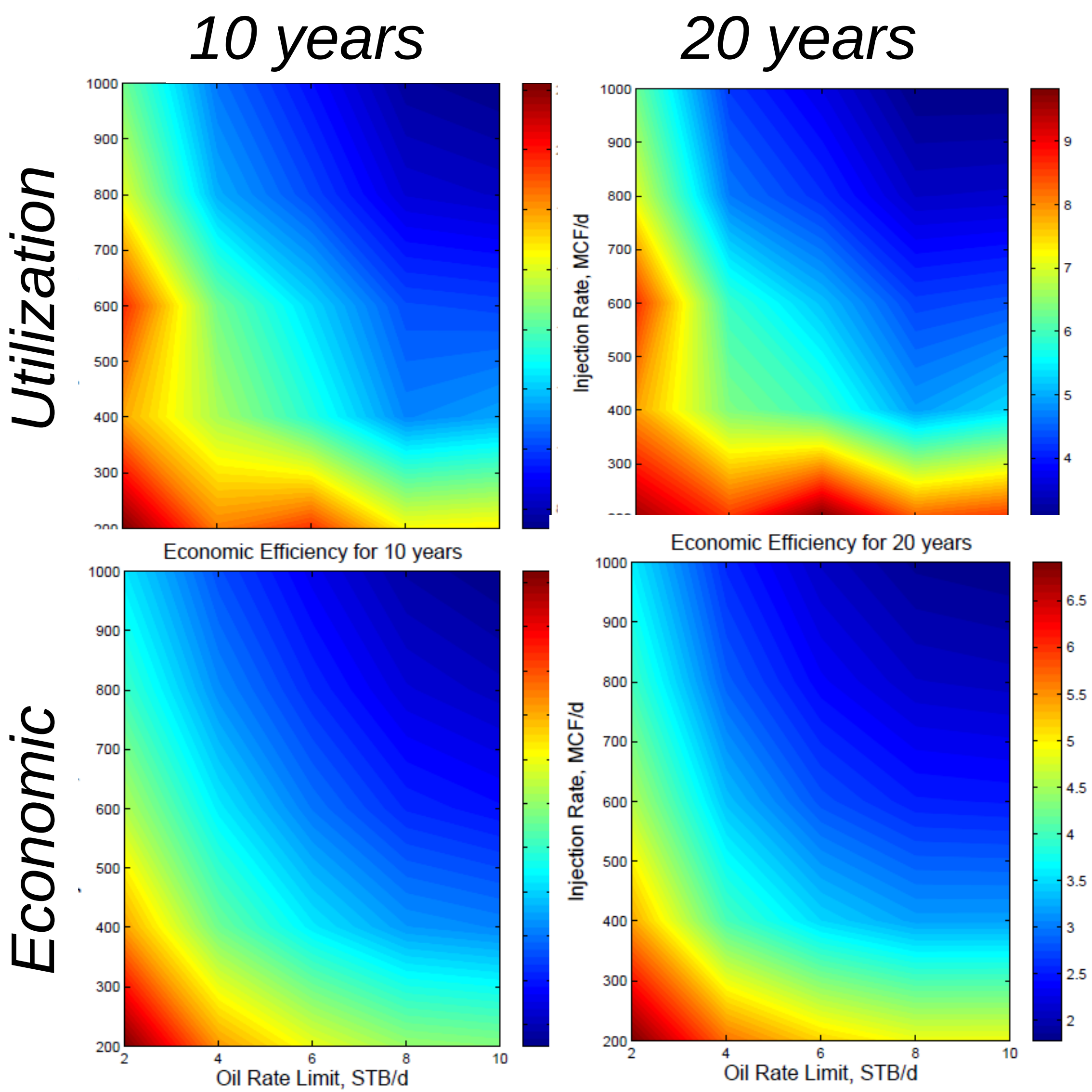
Analysis of All Cases: Injection & Soaking Period

- For volumetric utilization, soaking period of 20 days is the optimum duration
- When economics is considered, effects of soaking becomes less critical
- Injection duration should be short; if soaking is longer, it is better to keep injection duration even shorter
- Project duration does not affect these observations



Analysis of All Cases: Rate Limit & Inj. Rate

- Optimum injection rate:
  < 200 MCF/d
- Optimum rate limit:
  2 STB/d
- More pronounced when economics is considered
- Project duration does not affect these observations



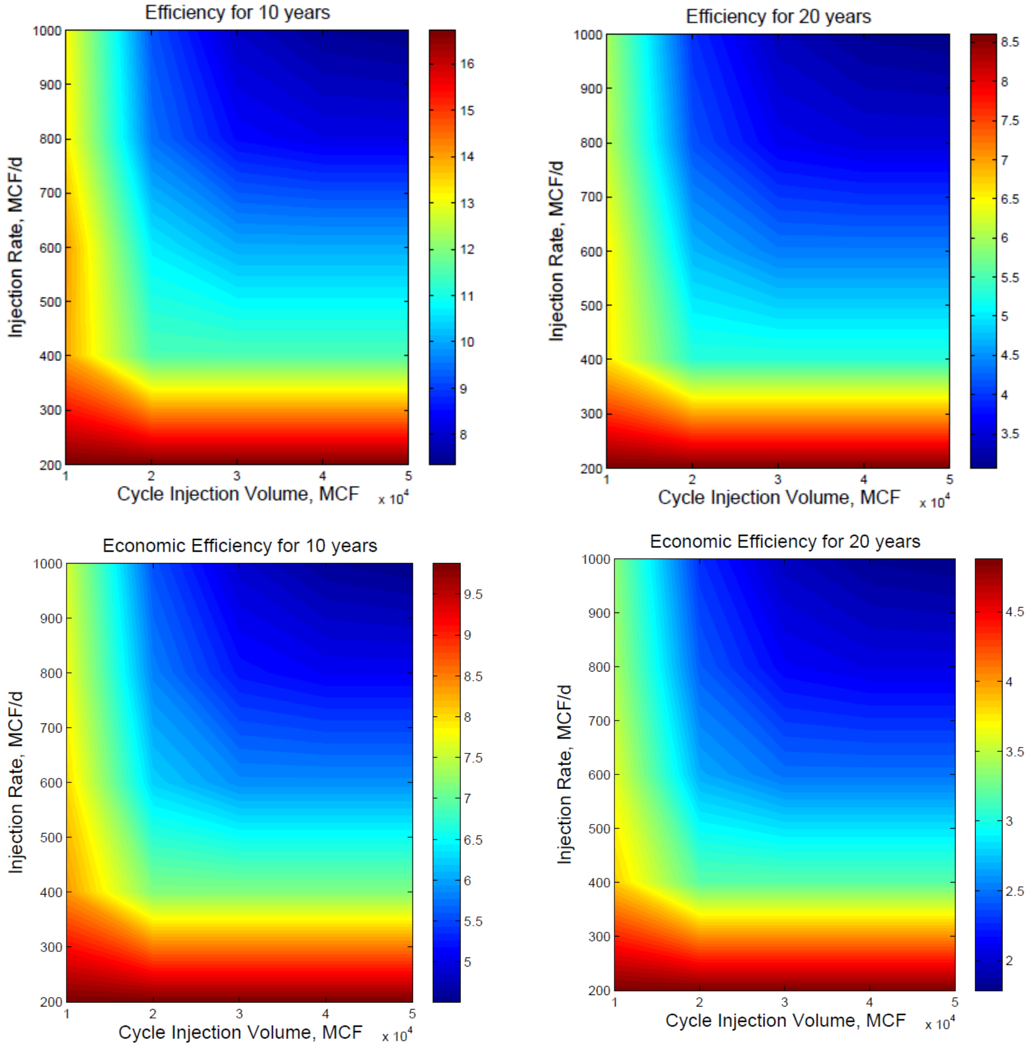
Analysis of All Cases: Injection Rate & Volume

- Injection rate has a larger effect than injection volume
- As long as the injection rate is low <200 MCF/d, the efficiency gets maximum regardless of injection volume

10 years *20 years*

Utilization

Economic



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Presenter: Emre Artun

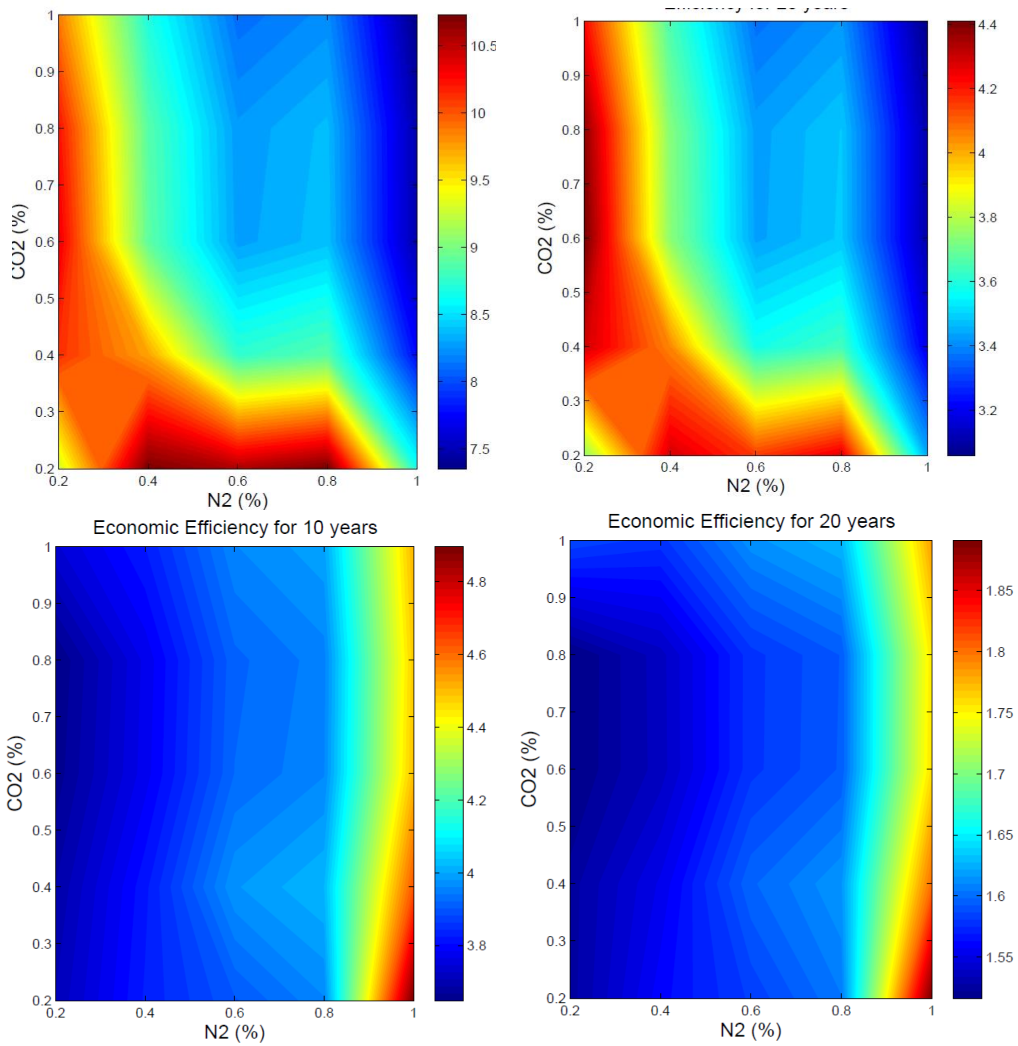
Analysis of All Cases: Composition CO_2 & N_2

- CO_2 is effective when volumetric efficiency is considered, and benefits of N_2 are not very visible
- Economic efficiency strongly favors N_2 over CO_2

10 years *20 years*

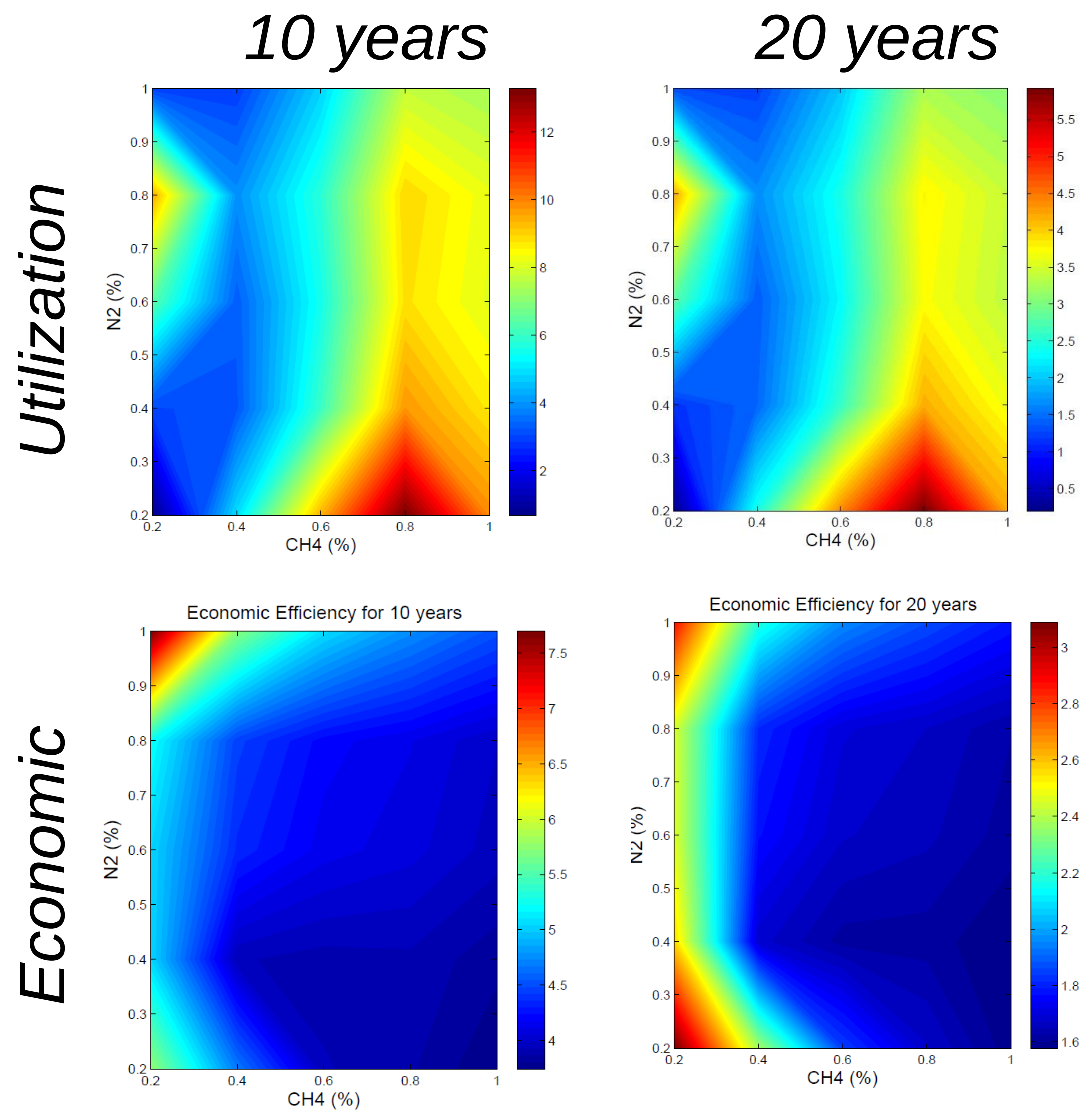
Utilization

Economic



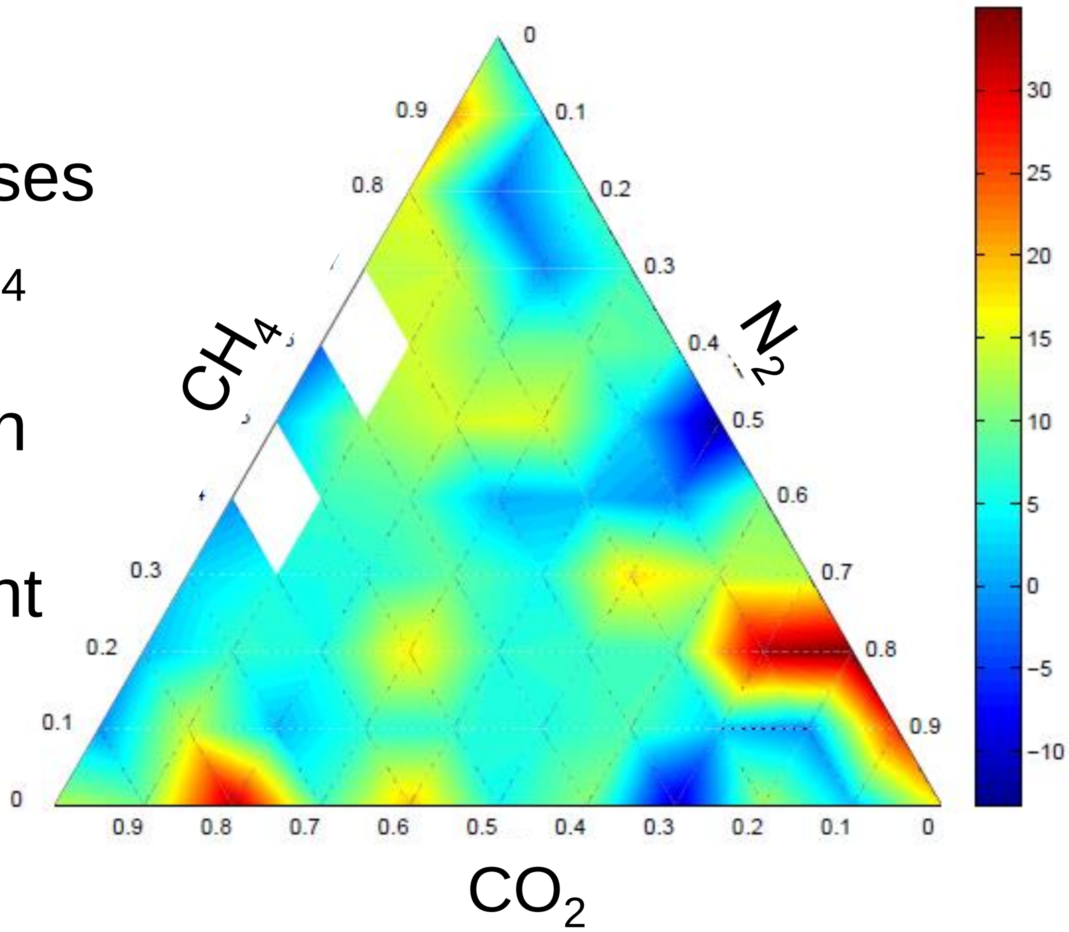
Analysis of All Cases: Composition N_2 & CH_4

- CH_4 is effective when volumetric efficiency is considered, and benefits of N_2 are not very visible
- Economic efficiency strongly favors N_2 over CH_4



Analysis of All Cases: Composition

- Although there are cases with high CO_2 and CH_4 that resulted in high efficiencies, cases with high N_2 (low CO_2 and CH_4) are more frequent

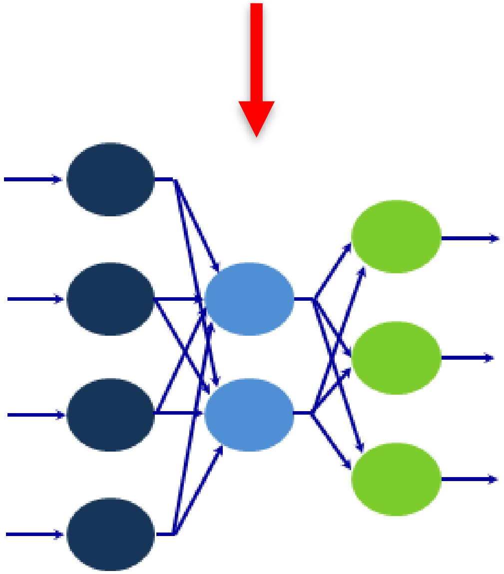


Development of a Screening Tool

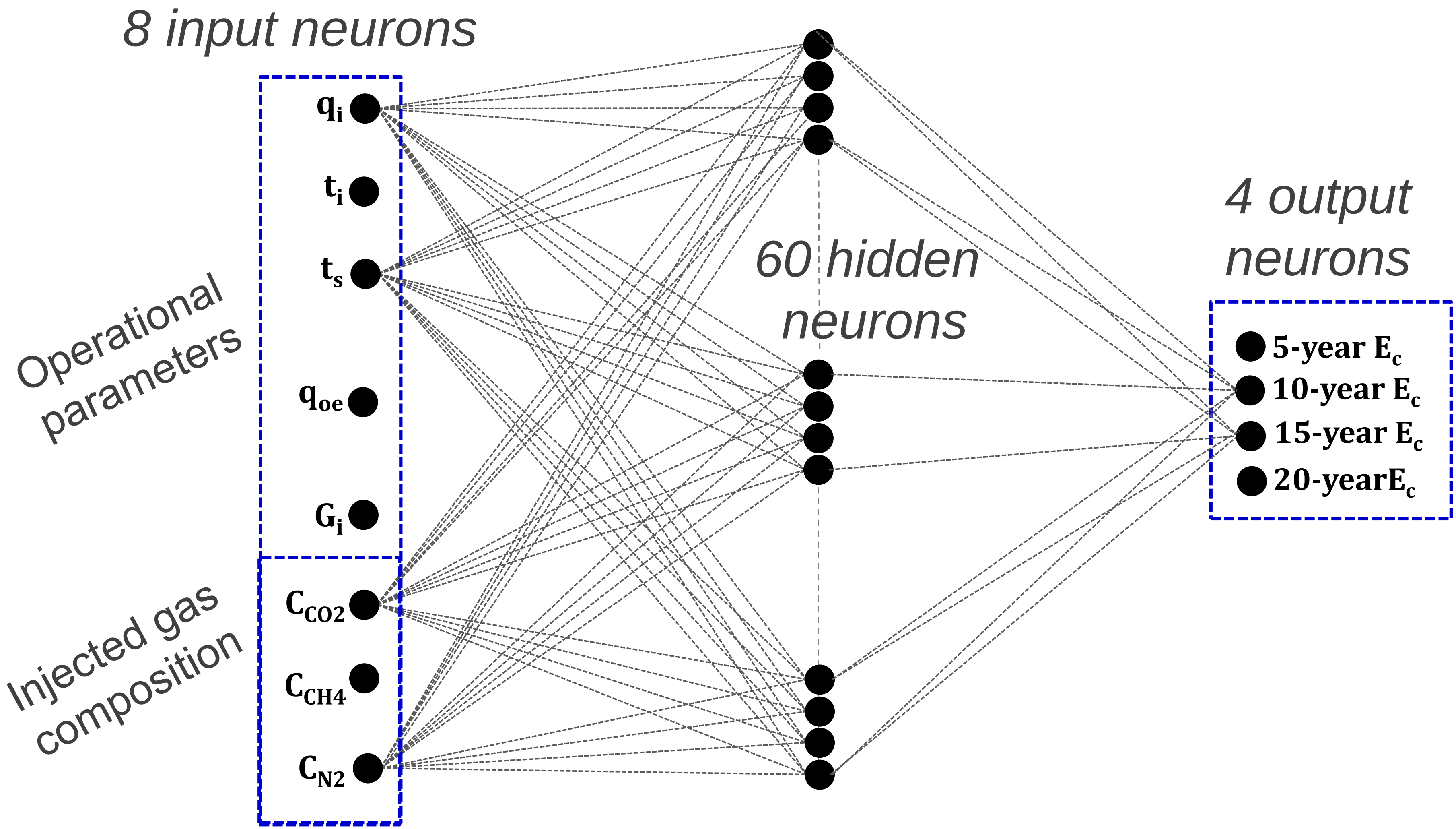
- A screening tool is developed that utilizes neural networks to predict the economic efficiency
- Levenberg-Marquardt backpropagation algorithm is used for training
- The data set is divided as:
  - 70% training set
  - 15% validation set (testing during training)
  - 15% testing set (blind cases that are not shown during training)

Inj. rate, MCF/d	Inj. period, days	Soak. period, days	Prod. period, months
60	15	20	12
82	20	12	7
76	25	18	9
90	14	34	7
66	34	16	20
⋮	⋮	⋮	⋮
100	22	36	16

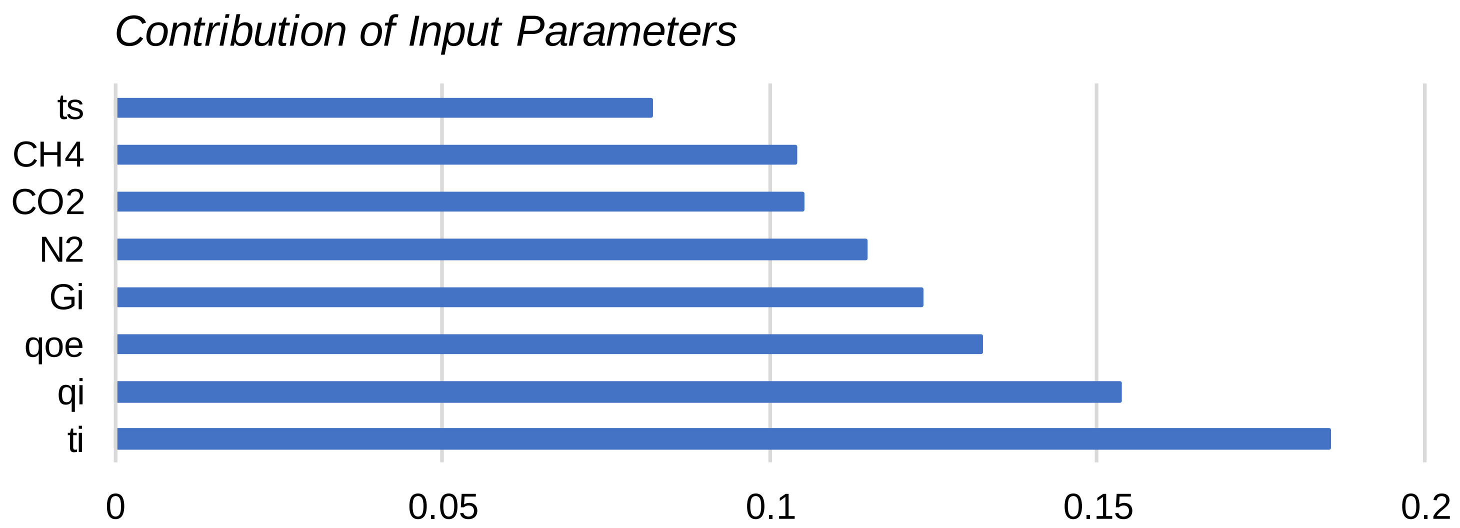
500 cases



Structure of the Screening Model



Analysis of Weights After Training

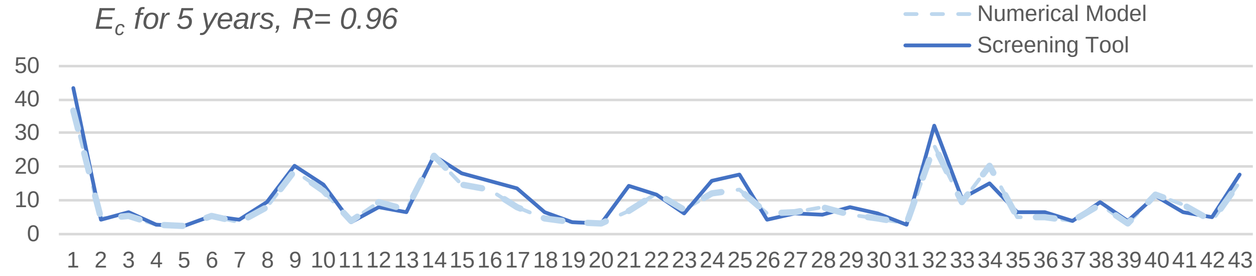


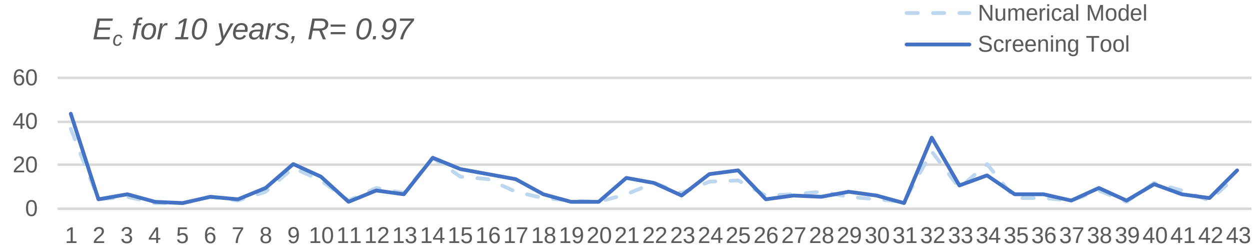
- Injection length, volume, rate and cycle rate limit are more important parameters that affect the efficiency
- Soaking period is the least important parameter
- Gas composition is not very important, N_2 is more critical than other two gases

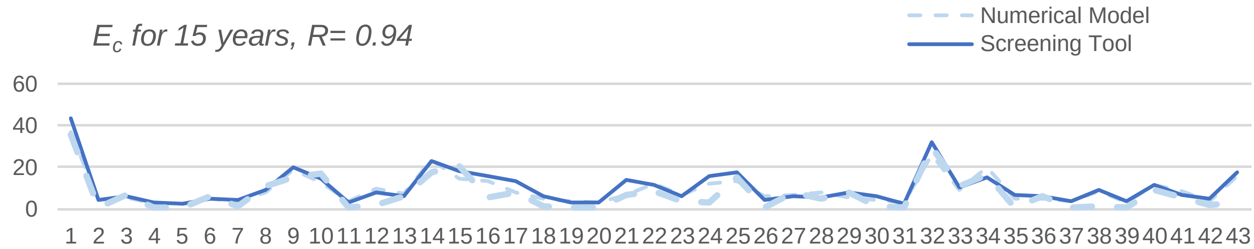
Accuracy of the Screening Model

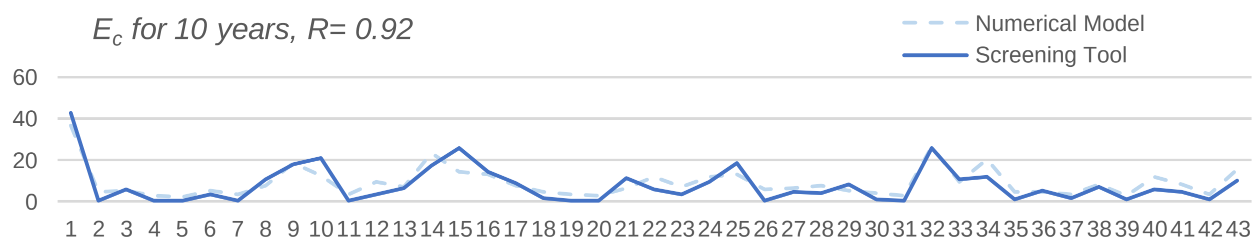
Given operational parameters and injected gas composition as inputs:

- Efficiencies after 5, 10, 15 and 20 years are predicted with a correlation coefficient of **0.95 on average** by the neural-network based screening tool
- Visual analysis also indicates accurate estimations









Conclusions

- Cyclic pressure pulsing with gas mixtures of CH_4, N_2 and CO_2: an effective and feasible EOR method in hydraulically fractured wells, in reservoirs similar to the Appalachian Basin sandstones
  - *All cases within the ranges of parameters studied resulted in positive incremental oil recovery beyond 1 year*
  - *Short-term (1 to 6 years) yielded maximum efficiency*

- Type of gases may result in different results, but high concentrations of N_2 is favorable when economic considerations are taken into account (lower cost)

- A neural-network based screening tool is constructed
  - *Economic efficiency at different years with an average correlation coefficient of 0.95*

Conclusions

- Soaking period doesn't affect the efficiency significantly but 15-45 days is the optimum range
  - *Trade-off between pressure dissipation and effective diffusion*

- Injection rate and time are more important than the total volume, low rates (<200 MCF/d) and short durations (10 days) are generally preferable
  - *Hydraulic fractures: limited surface area for diffusion*

- Production limit rate must be optimized: 2 STB/d is optimum
  - *< 2 STB/d, not sufficient energy in the reservoir*
  - *> 2 STB/d, high base recovery, low incremental recovery*

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Thank you…

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