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Potential New Uses for Old Gas Fields: Sequestration of Carbon Dioxide

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Abstract

Although the reality and significance of global warming remain controversial, advanced planning for all contingencies would be advantageous to operators. One approach under consideration by the U.S. Department of Energy and the international community that has the potential to reduce rate of increase of atmospheric carbon dioxide (CO₂) concentrations is to capture CO₂ from industrial point sources and inject it into the subsurface (geologic sequestration). This approach is especially attractive in cases where sequestration provides economic benefits (lower overall costs), such as accelerated gas production, increased ultimate recoveries, and new revenue streams for mature reservoirs.

Carbon sequestration with enhanced gas recovery accelerates production in mature gas reservoirs because CO₂, which is denser than methane, settles at the gas-water interface and displaces remaining methane. Such displacement reenergizes the reservoir and increases ultimate recovery. Another approach, sequestration at the gas-oil contact, might accelerate production of a gas cap otherwise kept in place as pressure support for maximizing oil production. Both techniques are being evaluated through modeling of CO₂ and CH₄ flow and transport processes. Additionally, mature gas reservoirs ready for abandonment but with infrastructure still in place represent a high-volume, low-cost sequestration option, especially when they are situated near a CO₂ source such as a fossil-fuel-burning power plant or chemical plant.

These sequestration options are particularly applicable in the Gulf Coast region, where many CO₂ sources lie near reservoirs. Further evaluation and increased operator interest could provide the U.S. with early sequestration approaches, if necessary, while simultaneously reenergizing Gulf Coast reservoirs.

Introduction

Potential Impact of Climate-Change Concerns on Hydrocarbon Producers

About 85% of U.S. energy comes from combustion of fossil fuels. On the basis of current economic factors, these fuels are expected to continue to dominate energy sources well into the 21st century. Greenhouse gases, volumetrically dominated by carbon dioxide (CO₂) generated by energy uses (electricity generation, transportation, etc.), are an unavoidable byproduct of this process. In response to evidence suggesting a link between CO₂ emissions and global warming, the U.S. Department of Energy (DOE) has sponsored research into technologies that might reduce CO₂ emissions into the atmosphere.

Why should geologists and oil and gas companies be interested in these activities? One of the potential solutions is capturing CO₂ from power plant and refinery emissions and injecting it into the subsurface, thereby sequestering the gas. Likely subsurface targets include brine-bearing formations that regionally underlie fresh-water aquifers, brine-bearing formations adjacent to or under existing oil and gas reservoirs, abandoned or mature oil and gas reservoirs, and unminable coal beds (enhanced coalbed methane production). The bulk of these options involve settings familiar to, and of economic interest to, geologists and oil and gas companies.

Sequestration Approaches

For CO₂ to be injected into the subsurface there must be (1) extraction of the CO₂ from the waste stream and drying in order to avoid compression costs of the nitrogen and oxygen and equipment

being corroded by water vapor, (2) compression to conditions above the critical point, and (3) injection through one or more well bores into the target horizon(s). A typical sequestration project's life span might be 30 years or more. During this time, the CO₂ as a supercritical fluid will displace fluids or gases in a large area around the injection well, and the pressure within the subsurface injection horizon will increase over a much larger area. We expect, over time, that the bubble of supercritical CO₂ will migrate under the influence of gravity, and the pressure, over extended periods of time, will decrease as CO₂ dissolves into the fluid or gas and as water, oil, gas, or CO₂ slowly leaks from the injection horizon into lateral or overlying lower pressure zones.

In producing oil and gas reservoirs, possible techniques include (1) enhanced oil recovery (EOR), tested in many types of reservoirs and widely in use in West Texas carbonate reservoirs; (2) carbon sequestration with enhanced gas recovery (CSEGR), in which CO₂ is injected into mature gas reservoirs for pressure support and to improve recovery efficiency; and (3) sequestration at the gas-oil contact (SGOC), a method being evaluated that might allow simultaneous production of the oil leg and gas cap, thereby accelerating cash flow from new or producing fields. Other techniques being evaluated, such as enhanced coalbed methane production through carbon sequestration, are not discussed here.

With support from DOE, the Bureau of Economic Geology (BEG), in conjunction with Lawrence Berkeley National Laboratory (LBNL), has been evaluating technologies that might be successfully applied in the Texas Gulf Coast. The upper Texas Gulf Coast around Houston, Texas, is one of the areas where U.S. CO₂ emissions to the atmosphere are concentrated because of a combination of electric power generation and industrial activity. Within a 7-county area (16,700 km²) centered on Houston, Texas (Fig. 1), 10 power plants released an estimated 32 million metric tons of CO₂ in 1996. In addition, more than 100 chemical manufacturing plants and refineries in the same area continue to release an unknown additional volume of CO₂. This area also contains an extensive existing infrastructure of oil and gas fields that might be used to facilitate sequestration (Fig. 1). A pilot project to inject minor amounts of CO₂ into a brine-bearing upper Frio Formation sandstone within an existing oil and gas field and closely monitor surface and subsurface response is currently in the planning stages.

The following sections will summarize concepts behind CSEGR and SGOC. The sections will also underscore potential benefits to the oil and gas community, supporting future investigations.

Carbon Sequestration with Enhanced Gas Recovery

Although the idea of injecting CO₂ into existing natural gas reservoirs for purposes of sequestration has been around for more than 10 years (van der Burgt et al., 1992; Koide et al., 1993) and subsequent analyses support the feasibility of the approach (Blok et al., 1997; Oldenburg et al., 2001), CSEGR has yet to be tested in the field. Perhaps it is partly because of the lack of perceived economic benefits and partly because of the concern about mixing of CO₂ with, and subsequent quality degradation of, the native gas (primarily methane—CH₄). Oldenburg et al. (2001) and Oldenburg and Benson (2001) used rigorous mathematical models to evaluate the influence on mature gas reservoirs of CO₂ injection and concluded that mixing may be controlled through various injection strategies (e.g., injecting dense CO₂ low in the formation while producing lighter CH₄ from high in the formation). In all cases modeled to date, CO₂-free methane could be produced from realistic reservoirs for periods of 1 year to more than 5 years.

Preliminary modeling suggests that CSEGR can increase ultimate recoveries more than fivefold in very mature gas reservoirs relative to no-stimulation cases. This increase occurs because the denser and more viscous injected CO₂ displaces the methane toward producing wells, improving sweep efficiency, and prevents further water encroachment, preventing typical losses to residual saturation in the invaded zone.

Figures 2 and 3 show the density and viscosity, respectively, of CO₂ and CH₄ as a function of pressure at three different supercritical temperatures. At 40° C, the density of CO₂ is gaslike below 60 bars, whereas above approximately 100 bars it is liquidlike. Viscosity of CO₂, although larger than that of CH₄, is always gaslike at reservoir conditions. Pressures in depleted gas reservoirs are commonly 20 to 50 bars, whereas initial reservoir conditions commonly exceed 60 bars. Note that in most conditions, CO₂ is several times denser and more viscous than CH₄ and that although this difference increases with increasing pressure, it decreases under increasing temperature. An extension

of the TOUGH2 integral finite difference code, called EOS7C (Oldenburg and Benson, 2001; Oldenburg et al., 2001), considers five mass components (water, brine, CO₂, gas tracer, and CH₄) and can simulate nonisothermal multiphase and multicomponent flow. It incorporates a Peng-Robinson equation of state to handle real gas properties across the ranges of temperature and pressure common in reservoir conditions. Viscosities and solubilities of gas components are calculated, allowing evaluation of solubility trapping by connate water. The code is capable of two- and three-dimensional simulations, including gas-water-contact movement and water-drive conditions.

Initial runs have used conditions typical of a very mature gas reservoir (discovery date, 1936) in Rio Vista field of the Sacramento Basin, California, to demonstrate sequestration capabilities of a source-sink pair (electric generation facility and mature gas reservoir), but the conditions modeled are directly applicable to Gulf Coast reservoirs as well. Simulated conditions included 10 years of CO₂ injection with both subsequent (scenario I) and simultaneous (scenario II) CH₄ production. The model (Fig. 4) assumed a flat water table in a homogeneous sandstone reservoir dipping at 0.78°. The model is a 1-km-wide strip of reservoir sandstone 100 m thick and 6,600 m long, with an injection well downdip and the production well updip. Grid blocks, parallel to the sand-body boundaries, were 200 m long, 5 m high, and 1 km wide.

Figure 5 shows CO₂ mass fraction in the gas phase and gas velocity in scenario I after 10 years of production followed by 2 and 10 years of CH₄ production. The plume tends to settle initially along the gas-water contact and only mildly cones upward toward the production well with time. Figure 6 shows the resulting reservoir pressure and produced gas fraction for both scenarios, and Figure 7 shows the decline curve for both cases. Careful attention to gas concentrations in the produced well in Figure 6 indicates that, if the 10-year delay in production for scenario I is accounted for, there is earlier CO₂ contamination in the produced stream for scenario I. There is, however, also higher initial CH₄ production rate and very little decline in rates for scenario I. CH₄ production for scenarios I and II compared with that of a no-stimulation base case is 540% and more than 770%, respectively. It should be noted that subsequent model runs with statistically generated heterogeneity (Oldenburg and Benson, 2002) indicate that permeability heterogeneity tends to accelerate CO₂ breakthrough to

adjacent wells. Further modeling with specific reservoir heterogeneity may be required to evaluate reservoir-specific responses.

No economic cutoffs were applied to the model results related to maximum allowable CO₂ concentration in the production stream, nor was the time value of money incorporated. The model suggests, though, that CSEGR can significantly increase ultimate recoveries through repressurization, improved aerial sweep efficiency, and potentially less loss to residual saturation because of water influx.

Sequestration at the Gas-Oil Contact

In the method where carbon is sequestered at the gas-oil contact, CO₂ is injected in a liquidlike state into a producing oil reservoir (Fig. 9), potentially allowing simultaneous production of the oil column and gas cap while maintaining reservoir pressure. This approach is a good one because (1) it may have the potential to reduce sequestration costs significantly because of its anticipated value-added end use; (2) it would be linked through an existing infrastructure with refineries that contain some already-separated CO₂ streams and can, therefore, be rapidly deployed prior to maturation of lower cost separation technologies currently in development; (3) it would ensure long-term isolation of CO₂ with low environmental risk; and (4) it would make use of oil and gas reservoirs for which techniques of verifying gross storage volumes are well developed. Verification allows tracking of total greenhouse gas volumes actually sequestered.

The SGOC method differs from enhanced oil recovery (EOR) techniques in that it focuses on accelerating the production of associated gas. For sequestration purposes, this method may be superior to EOR because CO₂ cycling may be minimized and storage capacity for CO₂ maximized. Numerical modeling of the CO₂/methane/oil system under simplified and realistic reservoir conditions is still needed to determine the range of conditions under which mixing of CO₂ with gas will be minimized. As discussed earlier, however, for CSEGR modeling already accomplished, it is clear that higher-pressure conditions minimize CO₂-CH₄ mixing, suggesting that this approach might favor gas-cap reservoirs in their early stages of development.

Approach

Normal production of oil decreases reservoir pressure and causes exsolution of gas dissolved in the oil. This process creates two compounding problems for oil recovery: (1) the resulting pressure drop reduces the energy available to drive the oil to producing wells and (2) the simultaneous increase of free gas within the pore network reduces the relative permeability to oil (that is, the ability of the oil to flow physically through the pores). This problem is traditionally ameliorated if the original gas cap is left in place (the production of which would further reduce pressures) and if produced water and/or gas is injected. The result is that production and use of the gas, increasingly important resources, are delayed until near the end of the life cycle of the reservoir, when recovery of oil reaches an economic limit. Consumers are thus denied access to an increasingly valuable commodity, and the time value of money erodes the worth of the total field resource.

CO₂ injected at the gas-oil contact of a reservoir could act as a substitute for pressure support, thereby allowing simultaneous production of oil *and* gas. Above and beyond this benefit, we anticipate that the process will improve displacement efficiency of both oil and gas phases, resulting in increased ultimate recovery of both oil and gas. Although injection of CO₂ strictly for pressure support may have been considered in the past, the prohibitive cost of the large volumes of CO₂ needed for pressure support prevented detailed evaluation of this approach.

It is possible that under a future emissions-trading program, disposal of waste CO₂ would have some economic value to refiners, thereby lowering the cost of CO₂ that could be used in SGOC. Preliminary investigations indicate that sources of fairly pure CO₂ already exist within the oil- and gas-gathering and refining infrastructure. Significant volumes of CO₂ are separated at gas-gathering/treatment facilities, and CO₂ is also produced at ammonia and methane reformers, among other processes, at refining and petrochemical plants. These sources could be used for initial projects in the near future, before other separation technologies mature.

For some sequestration methods, transportation of CO₂ from source to sequestration site represents a large cost (Holtz and others, 1998). Pipeline construction and rights-of-way purchase represent significant parts of pipeline costs, and permitting may be a barrier in some areas. In the

Texas Gulf Coast, however, most CO₂ sources lie within an existing grid of established pipelines, potentially significantly decreasing costs and delays associated with pipeline construction.

Low Environmental Risks with Established Verification Techniques

Oil reservoirs present an ideal low-risk sequestration target because subsurface conditions are known, existing wells can provide infrastructure for injection and monitoring, and production has created low-pressure volumes that may be able to accept more CO₂ than undisturbed, hydrostatically pressured formations can. An additional advantage of CO₂ injection into oil reservoirs having gas caps is their proven low risk—the reservoir top seal, having retained methane molecules over geologic time, would most likely retain the slightly larger and less buoyant CO₂ molecule (Bachu, 2001).

Sequestered volumes can be documented by using well-established and highly accurate mass-balance methods developed by the petroleum industry to monitor the economic value of in-place oil and gas resources. These methods quantify the volume of oil and gas originally in place and track changes in producible volumes as reservoir management techniques, such as injection of water or gas, are applied during the life of the field. Subsurface behavior of fluids and gases is well understood through theoretical and practical study, and data regarding storage volumes (porosity), fluid flow (permeability, reservoir heterogeneity), and pressure/temperature conditions are provided by the large number of wells drilled for production and management of the resource. The combination of these factors means that reliable documentation of sequestered volumes is easier in established oil and gas reservoirs than in other subsurface settings.

Saturation and thickness of the injected CO₂ phase can be monitored using cased-hole geophysical logging (for example, the carbon-oxygen log), as well as using other evolving techniques. The large number of well bores allows for the application of these techniques to overlying units to ensure that CO₂ is not breaching the seal and migrating vertically. Because the surface area of most fields is not populated or commercially developed, surface monitoring of soil and air is relatively easy.

Economic Impact

The SGOC technique accelerates and maximizes domestic production of gas, a high-demand, low-emissions fuel that currently supplies one-quarter of the nation's energy needs (Tinker and Kim, 2000). Our evaluation of Energy Information Administration (EIA) data and National Petroleum Council (NPC) reports indicates that future increases in gas-fired electricity generation will exacerbate rapid rises in gas prices and imports. Gas consumption is forecast to increase from 22 trillion cubic feet (Tcf) in 1998 to 31 Tcf in 2015 (National Petroleum Council, 1999) as a result of increased economic growth and environmental concerns that favor gas over oil and coal for energy production. In particular, approximately 50 percent of the gas-demand growth would be for electricity generation (National Petroleum Council, 1999). On the production side of the equation, optimistic forecasts predict an increase from 19 Tcf in 1999 to 26 Tcf by 2015 for the lower 48 states. This shortfall in supply relative to demand is expected to come from imports, mainly from Canada. Acceleration of domestic gas production resulting from SGOC would positively impact both growing trade deficits and overall domestic economic health.

Conclusions

The economic and regulatory future of geologic sequestration is uncertain. The potential impact of these issues on Gulf Coast oil and gas interests is, however, significant, and warrants investigation. Various EOR projects in Gulf Coast reservoirs using CO₂ or flue gas have yielded uneconomical results under the current economic climate. However, a policy change that assigns value to the disposal of CO₂ could dramatically reverse these conditions, making CO₂ affordable to oil and gas operators. A multitude of new projects could result, ranging from EOR, CSEGR, and SGOC to conversion of wet or abandoned intervals into disposal operations, and these projects could apply to fields in all stages of the life cycle from newly discovered to nearly abandoned.

Early collaborative experiments are in progress to evaluate all aspects from mathematical modeling to pilot-scale field experiments. Continued investigation will most likely reveal the need for more field sites along the Gulf Coast for various types and scales of experiments. Joint efforts by

operators, academic and research institutions, and service companies may be needed to determine the most viable approaches, techniques, and tools to inject, monitor, and successfully sequester greenhouse gases.

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POTENTIAL NEW USES FOR OLD GAS FIELDS: SEQUESTRATION OF CARBON DIOXIDE

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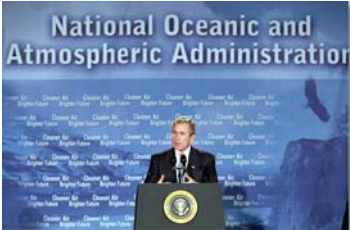


AGENDA

- **Overview of sequestration issues**
- **Application in oil and gas fields**
- **Enhanced gas recovery**
- **Pressure maintenance**
- **Wet intervals**
- **Summary**

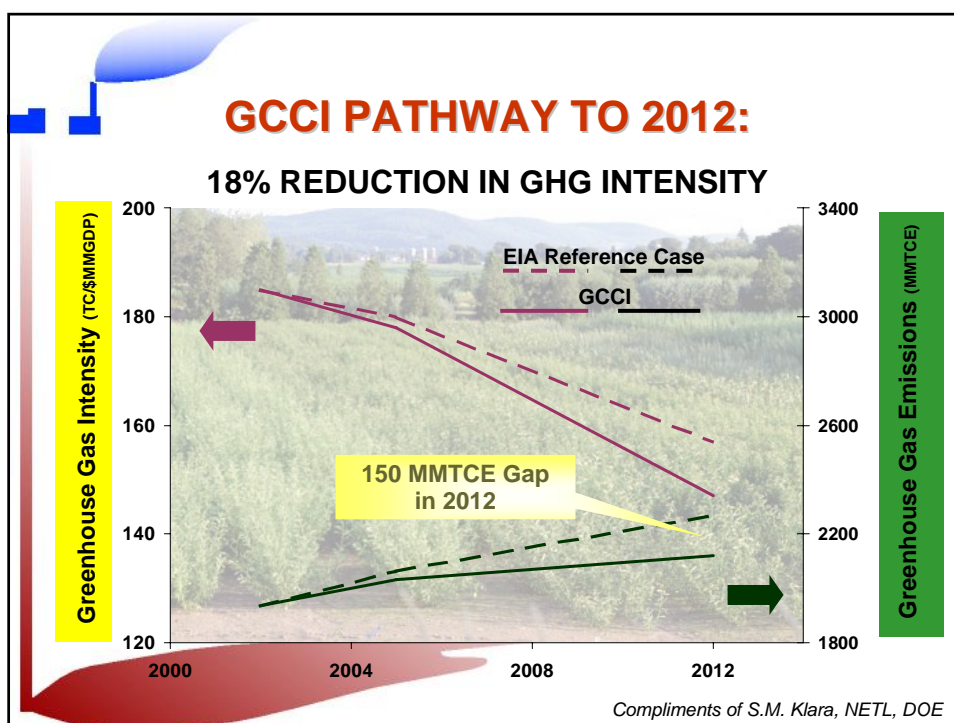
GLOBAL CLIMATE CHANGE INITIATIVE

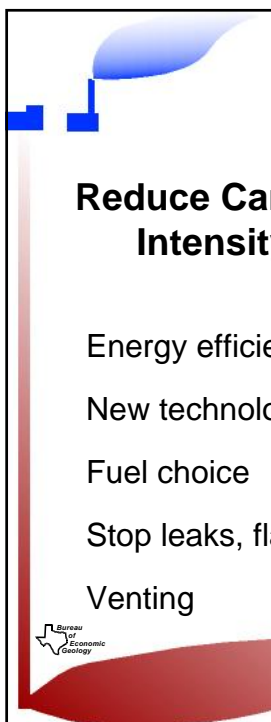
- “Today, I’m announcing a new environmental approach . . .”
- “We must foster economic growth in ways that protect our environment”
- “. . . set path to slow GHG emissions, and as science justifies - stop and then reverse that growth”



*President Bush
February 14, 2002*


Compliments of H.D. Guthrie, NETL, DOE

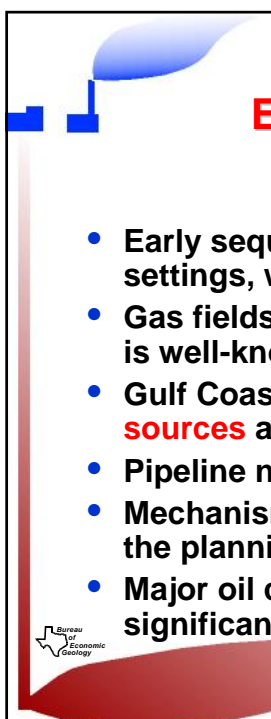



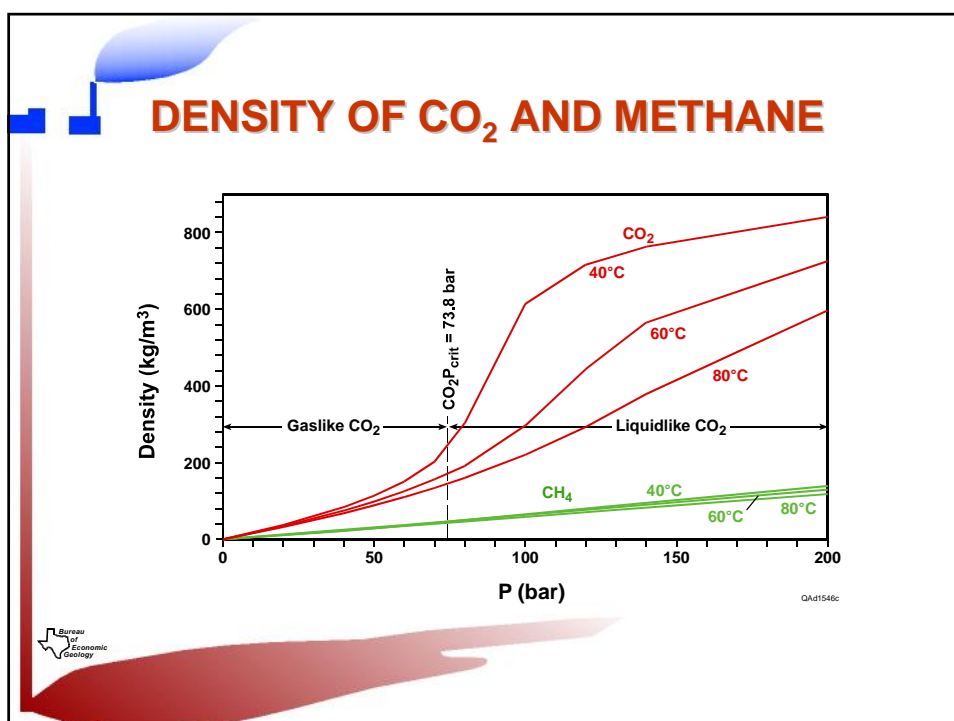
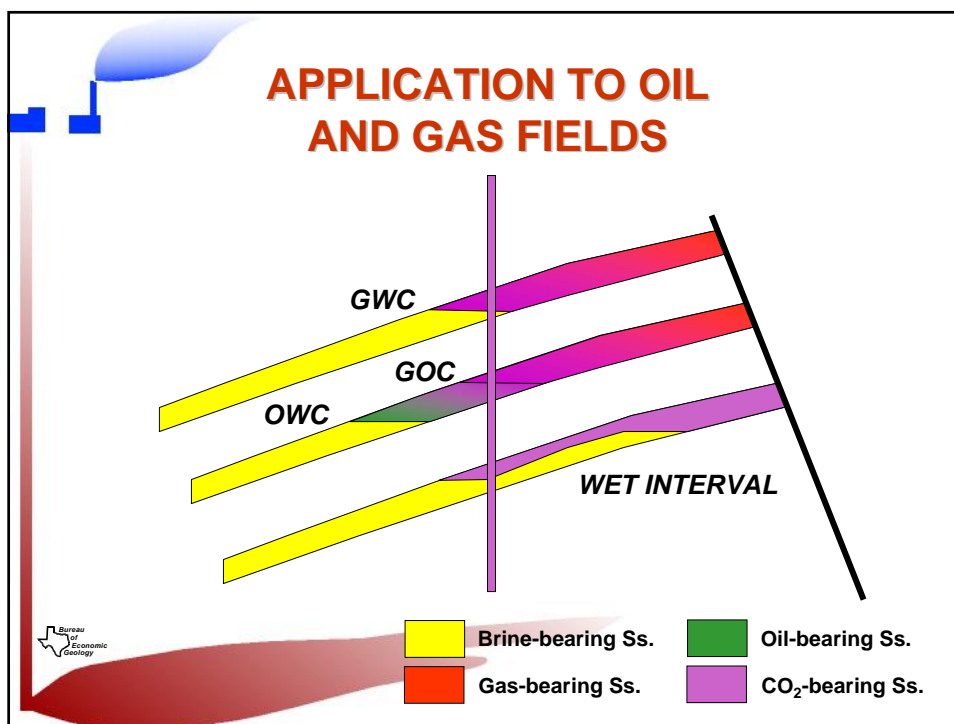


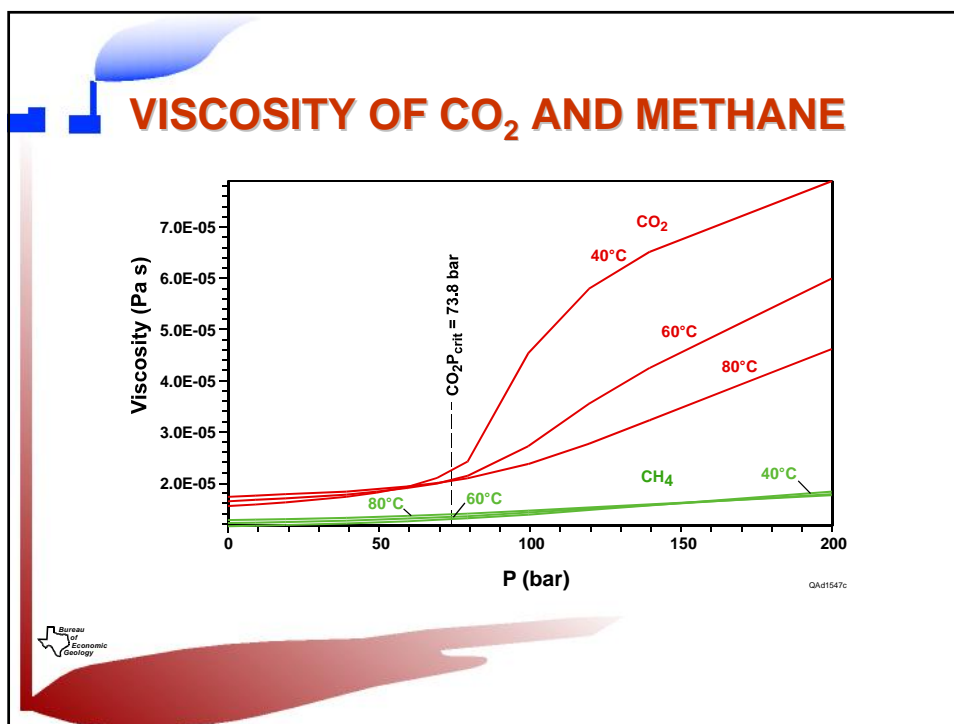
THE OPTIONS

Reduce Carbon Intensity	Sequester	
	<u>Disposal</u>	<u>Value-Added</u>
Energy efficiency	Saline aquifers	EOR
New technology	Deep oceans	EGR
Fuel choice	Biomass	ECBM
Stop leaks, flares		
Venting		

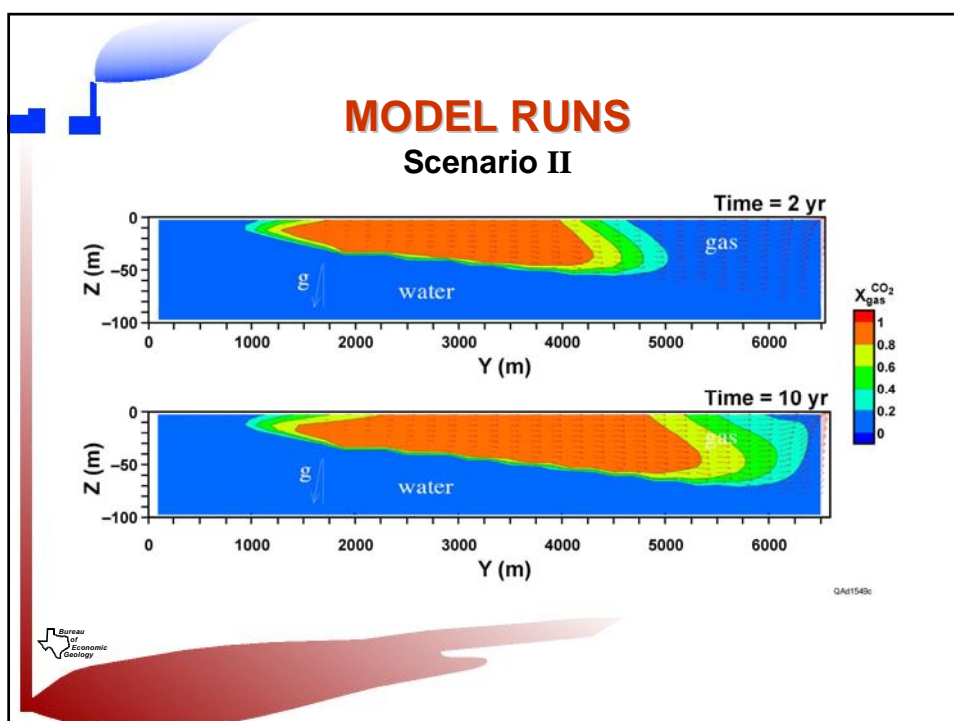
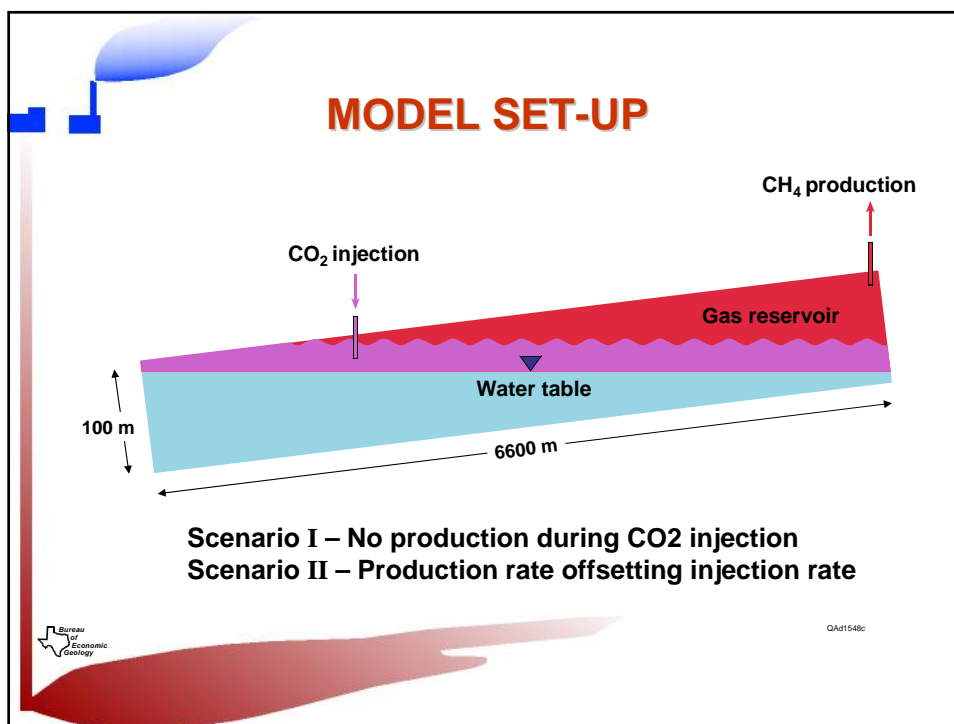


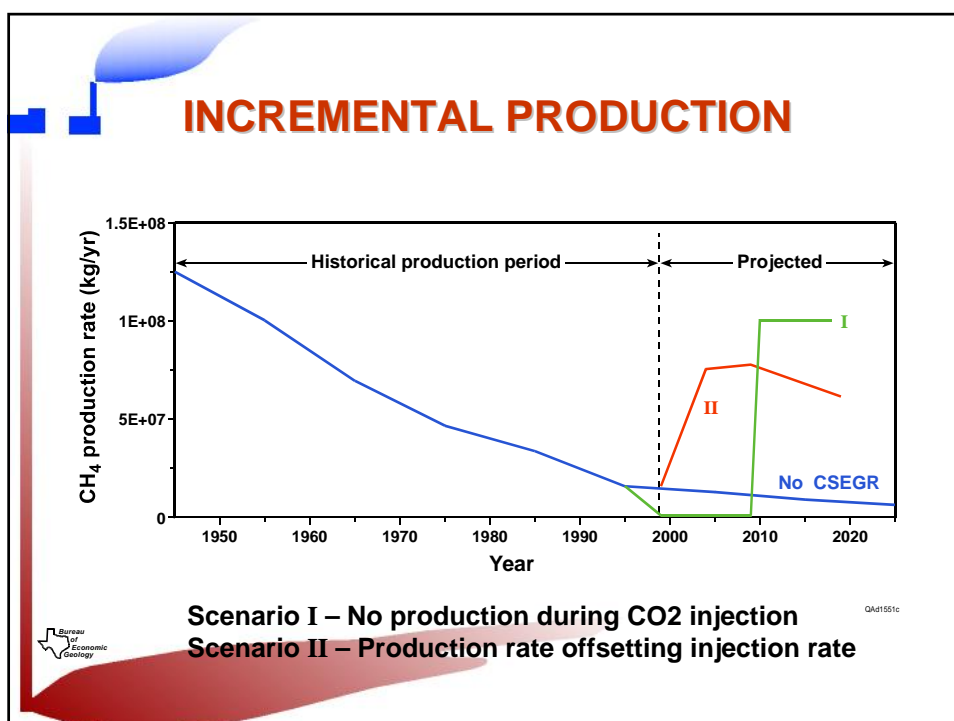
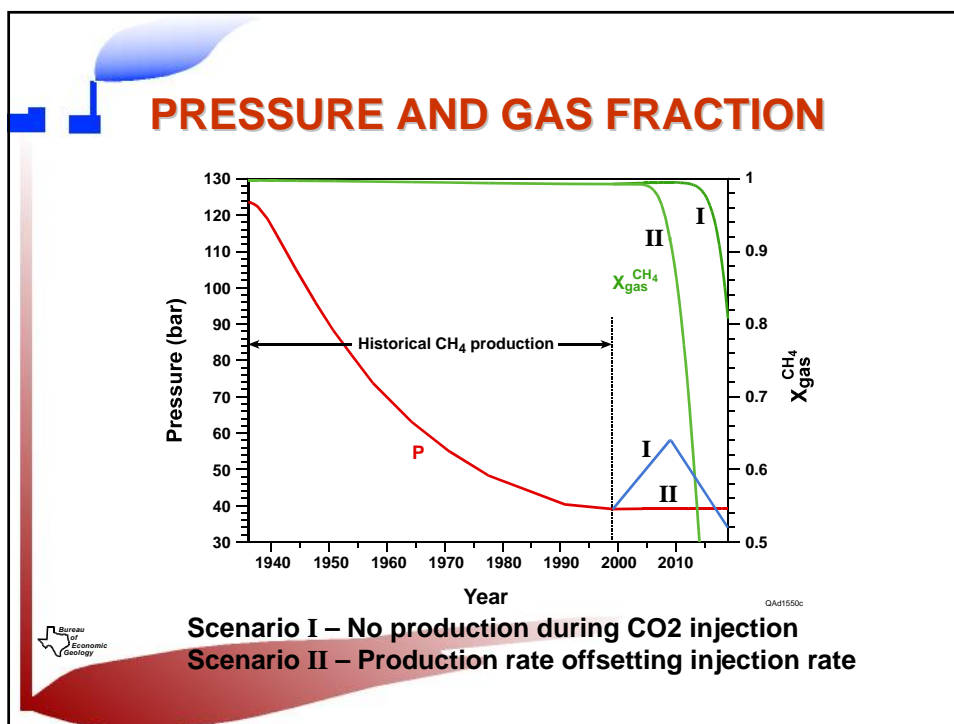
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- ## ECONOMIC REALITIES
- Early sequestration will be in value-added settings, where geographically available
 - Gas fields: distributed volumes where subsurface is well-known
 - Gulf Coast represents a combination of many **CO₂ sources** and **high-injectivity intervals**
 - Pipeline networks provide deliverability
 - Mechanisms to address emissions credits are in the planning stages
 - Major oil companies have demonstrated significant interest in geologic sequestration
- 





- ### AGENDA
- Overview of sequestration issues
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 - **Enhanced gas recovery**
 - Pressure maintenance
 - Wet intervals
 - Summary
- Bureau of Economic Geology





CSEGR: OUTSTANDING ISSUES

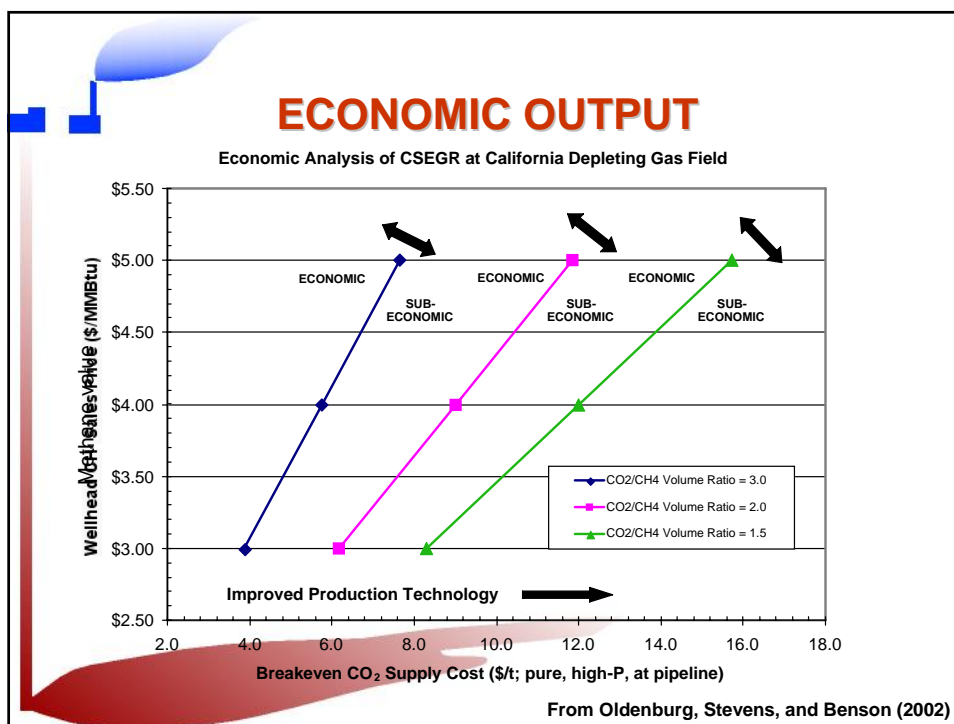
- Economic Feasibility
- Field Testing

• Economic feasibility evaluated by Oldenburg, Stevens*, and Benson (2002) using example from California's largest gas reservoir

* Advanced Resources International, Inc.

ECONOMIC PARAMETERS

- Interval is high-porosity, high-permeability sandstone at 5,000 ft depth (Rio Vista field)
- 25 injectors (125 MMcfd, 6,500 tons/d)
- 18 producers (peak 45 – 90 MMcfd)
- 8 monitor wells
- 15 years duration
- Costs included mix of new and recompleted wells, pipelines
- Produced gas CO₂ content: 1-5 yrs = 0%, 5-10 yrs = 5%, 10-15 yrs = 25%



BOTTOM LINE

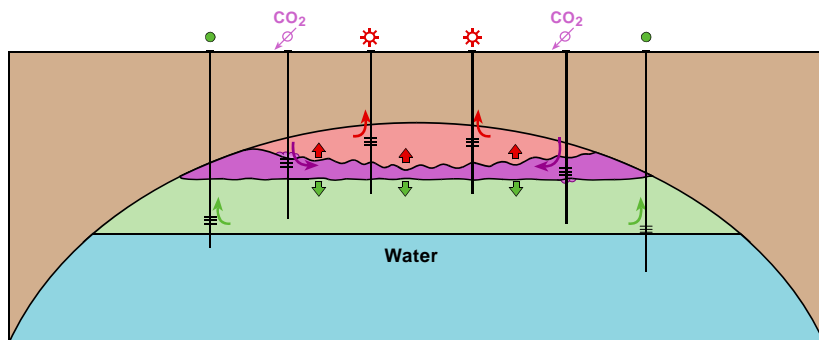
- For CO₂/CH₄ volume ratio = 1.5, need CO₂ cost ~ \$10/t.
- Economics are sensitive to physical processes, specifically CO₂/CH₄ volume ratio, mixing, and breakthrough times.
- Economic feasibility will be reservoir-specific.
- Overall conclusion is that CSEGR will require subsidy under current conditions, but that increases in CH₄ price or decreases in CO₂ supply costs can make CSEGR profitable at a field like Rio Vista.
- Field demonstration project **essential** to realistic assessment in the Gulf Coast

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SEQUESTRATION AT THE GAS-OIL CONTACT



- Producing oil well
- CO2 injection well
- ★ Producing gas well
- ≡ Perforations
- ↗ Flow of gas and oil into wellbore
- ↘ Flow of CO2 into reservoir

QA68550c



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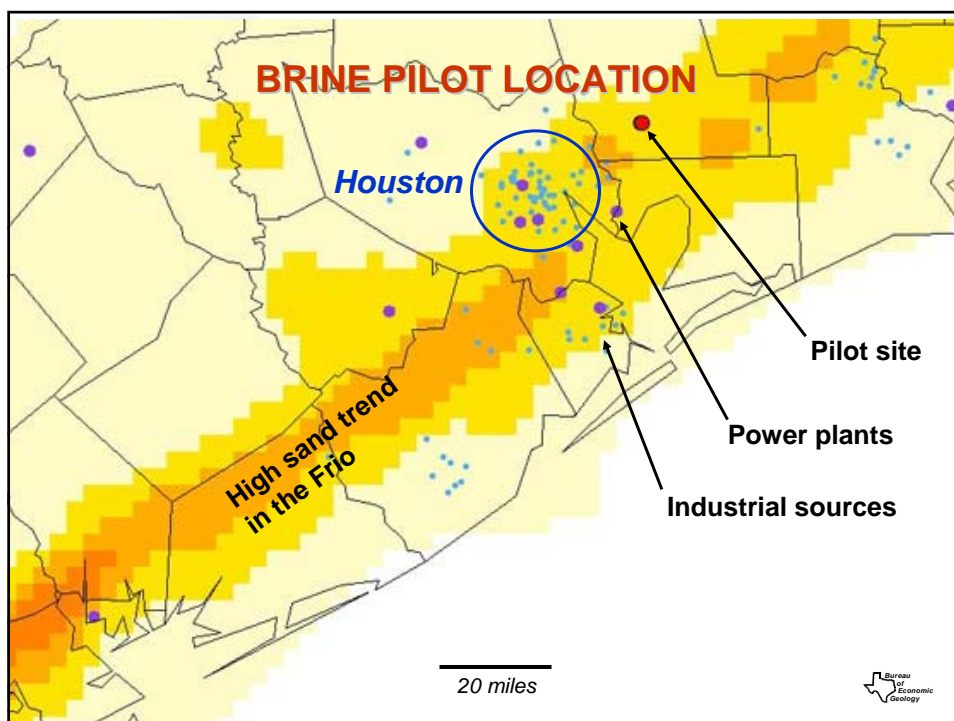
WET INTERVALS

- Increase overall sequestration volume
- Existing subsurface infrastructure
- Existing surface infrastructure (pipelines)
- Abundant subsurface data
- Subsurface activities familiar to local communities and regulators
- U.S. Department of Energy-funded Gulf Coast pilot in permitting stages



BRINE PILOT

- **Purpose:** demonstrate feasibility and monitoring techniques, evaluate model predictions
- **Setting:** salt dome flank, Frio sandstone, 5,000 ft depth.
- **Scope:** < 5,000 tonnes (90 MMcf) over 20 days of injection
- **Monitoring:** tracers, pressure and temperature, logs, seismic



CONCLUSIONS

- Preparations are being made in the event that geologic sequestration becomes necessary
- Sequestration can substantially enhance production from mature gas reservoirs and is economic with low-cost CO₂ supplies
- Sequestration seems a logical option to maintain reservoir pressure and facilitate simultaneous oil and gas production
- Sequestration has the potential to extend field life, increase ultimate recoveries, increase production rates, and add new revenue streams to mature fields.



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