Onshore Lower 48 Oil & Gas Supply Submodule (OLOGSS)

Workshop
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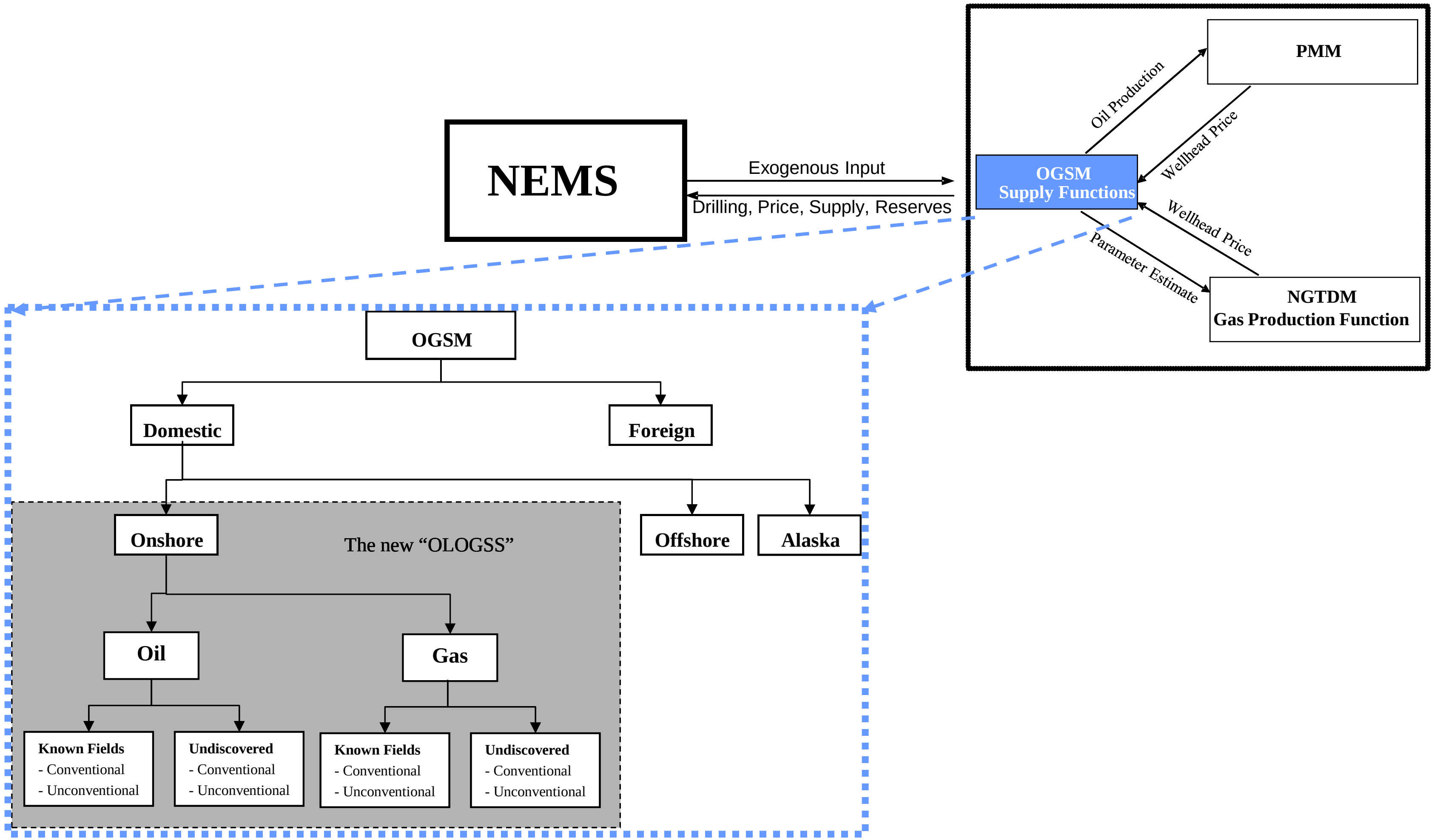
Overview

- OLOGSS methodology overview
- OLOGSS Resources : Oil and Gas
- Enhanced oil recovery
- Shale gas

Interaction of OLOGSS with NEMS



Role OLOGSS within NEMS

- Projects future domestic oil & gas supply
  - production from existing fields/reservoirs
  - reserves growth in existing fields/reservoirs
  - exploration in undiscovered fields/reservoirs

- Development of resources is subject to the following constraints
  - access to resource
  - technology
  - economics
  - infrastructure
    - drilling
    - co_2 availability
    - pipeline
    - others

Capabilities of OLOGSS

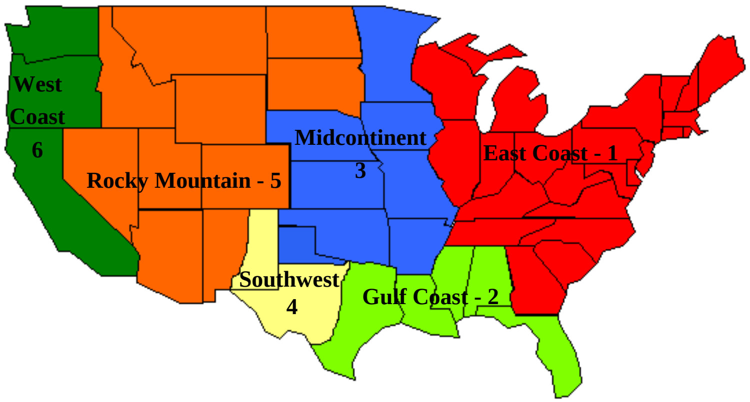
- Model entire oil & gas resource in Lower 48
  - conventional
  - unconventional
    - tight sands
    - gas shale
    - coalbed methane

- Ability to model
  - technology change / improvements
  - land access issues
  - legislative policy issues (royalty relief, tax credits, etc…)

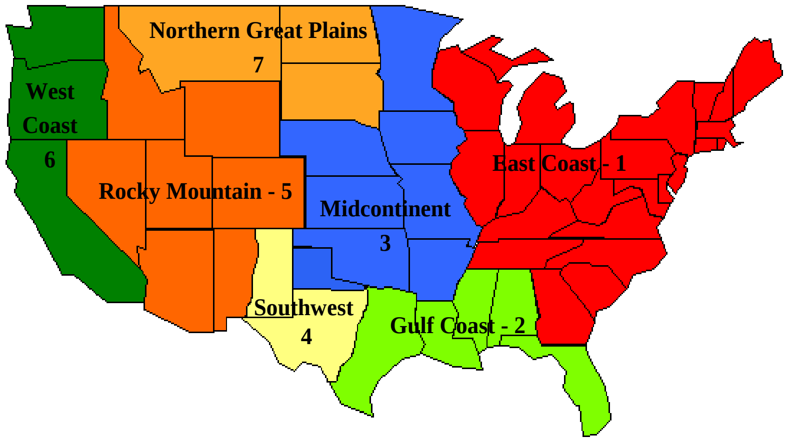
- Ability to address more policy and financial issues that affect the profitability of oil and natural gas drilling than with current module

OGSM/OLOGSS regions

Onshore OGSM Regions

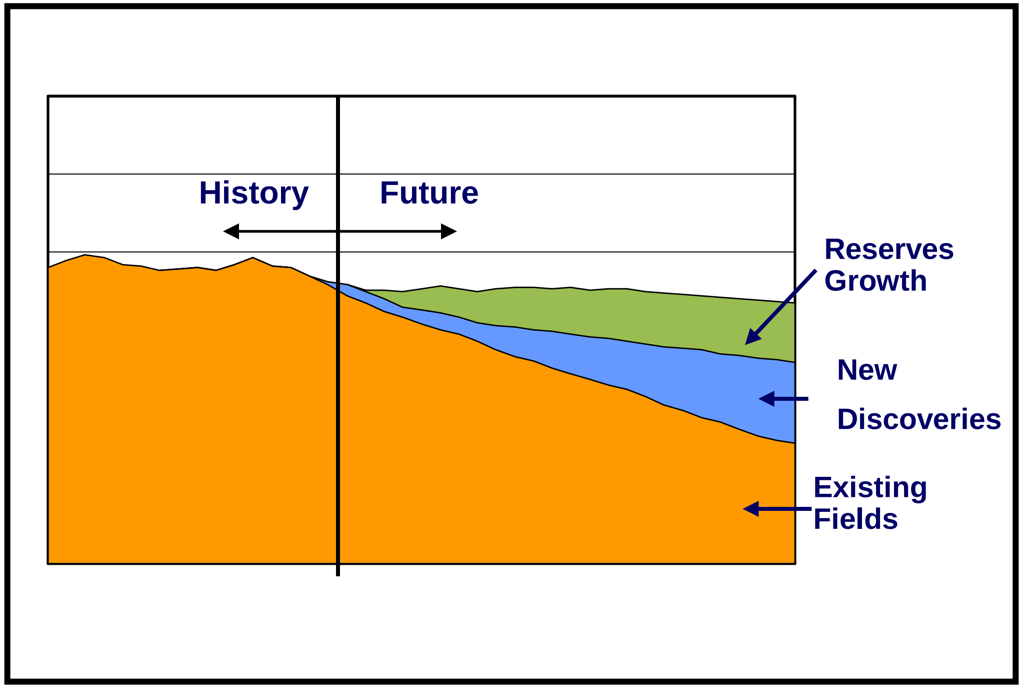


OLOGSS Regions



Three phases of future production

- Existing production
  - from currently producing oil & gas fields
- Reserves growth
  - ASR / EOR
  - infill drilling
- Undiscovered resource



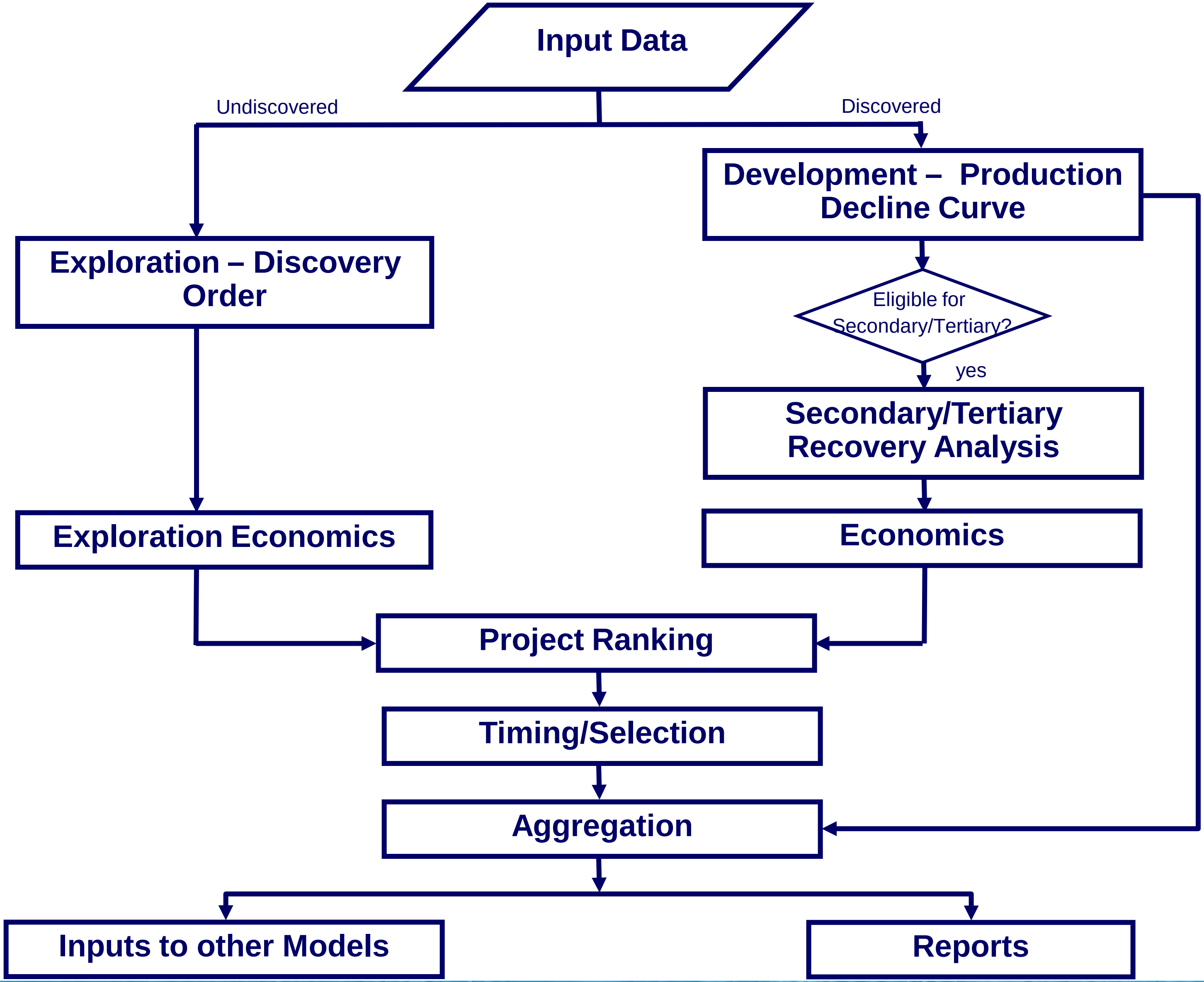
Processes modeled

Crude oil	Natural gas
• Water flooding	• Conventional/water drive
• Polymer flooding	• Tight gas
• Steam flooding	• Coalbed methane
• CO_2 flooding	• Shale gas
• Infill drilling	
• Profile modification	
• Horizontal drilling	

Primary model levers

- Technology levers
  - value of all levers
  - implementation & market penetration curves
  - interaction of technologies
- Economic levers
  - ROR
  - Risk
- Resource access parameters

OLOGSS overview

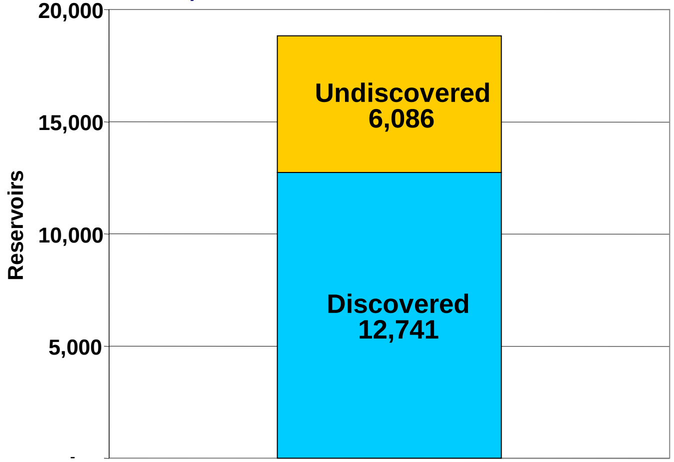


Resource development constraints

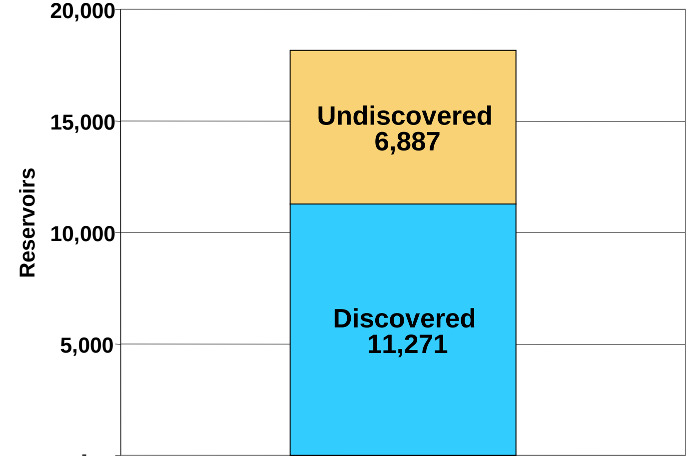
- Constraints will be used for future development of various resources
  - drilling
    - number of rigs
    - depth rating
  - capital constraints
    - E&P capital
    - others
  - co_2 availability – natural and industrial sources
  - access to land – federal/state
  - natural gas demand
  - others to be defined

Oil and gas resources in OLOGSS
37,000 oil and gas reservoirs

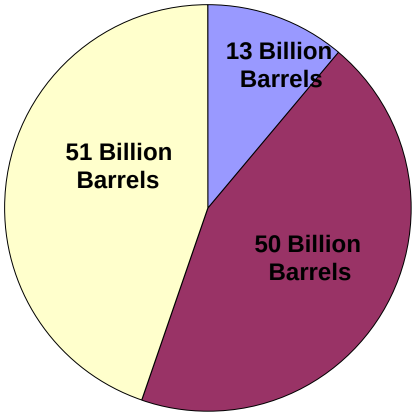
18,827 Oil Reservoirs



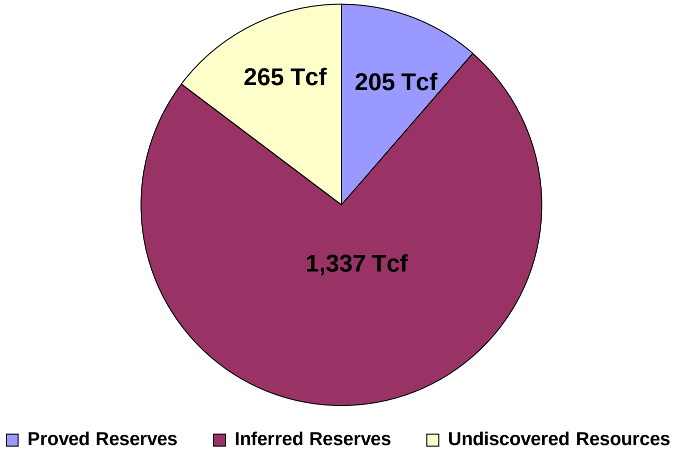
18,158 Gas Reservoirs



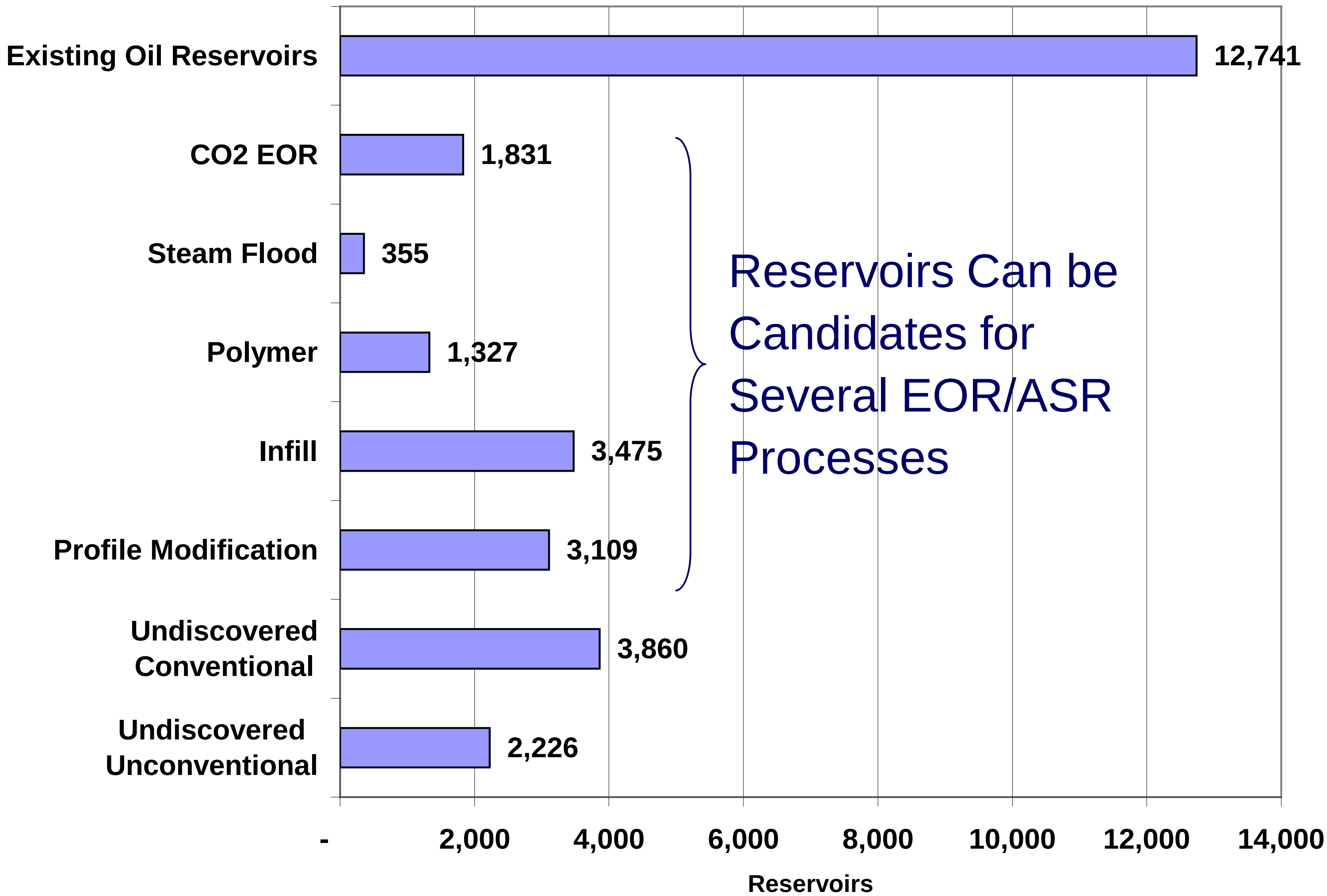
114 Billion Barrels of Oil



1,807 Tcf of Gas



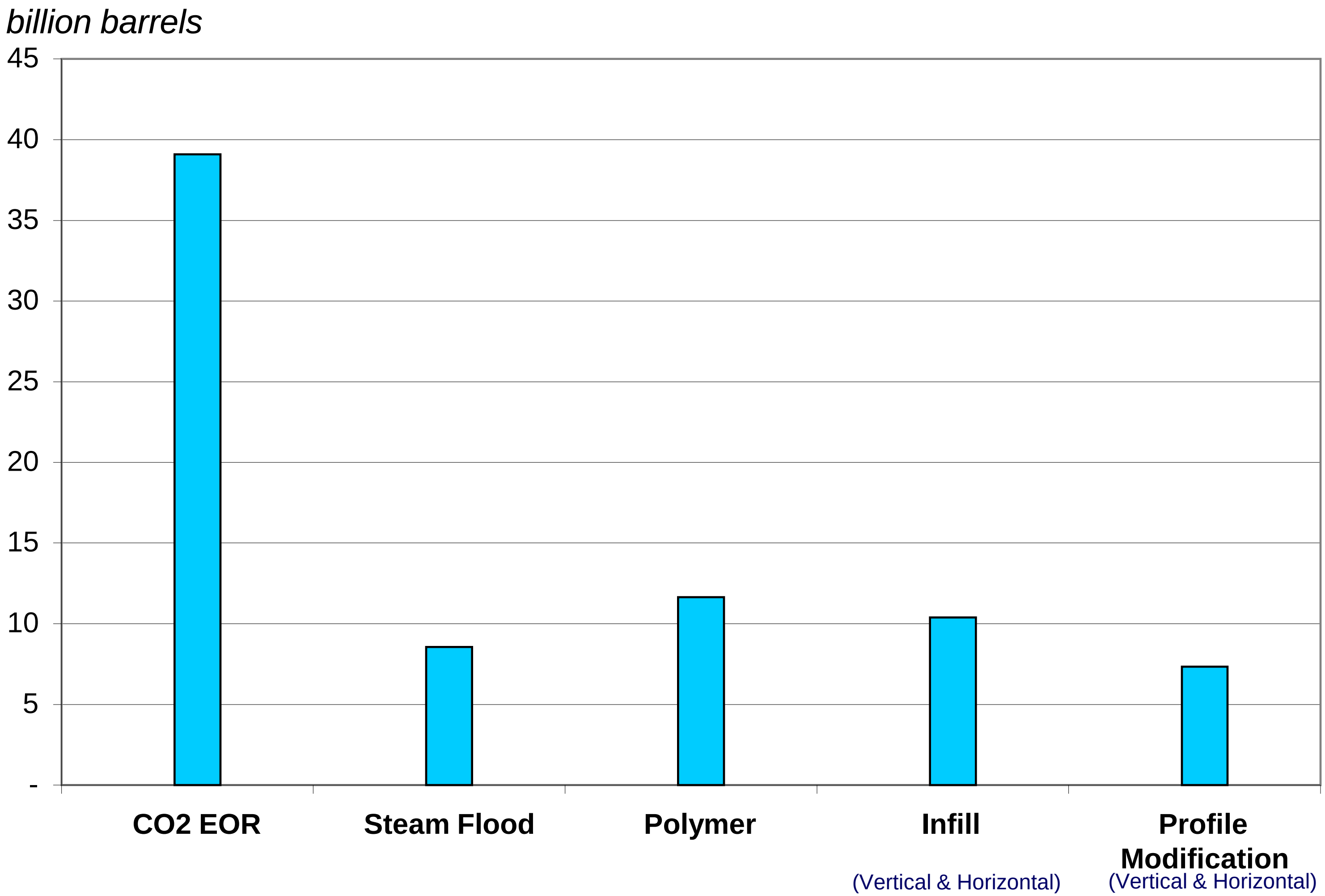
Categories of oil reservoirs in OLOGSS



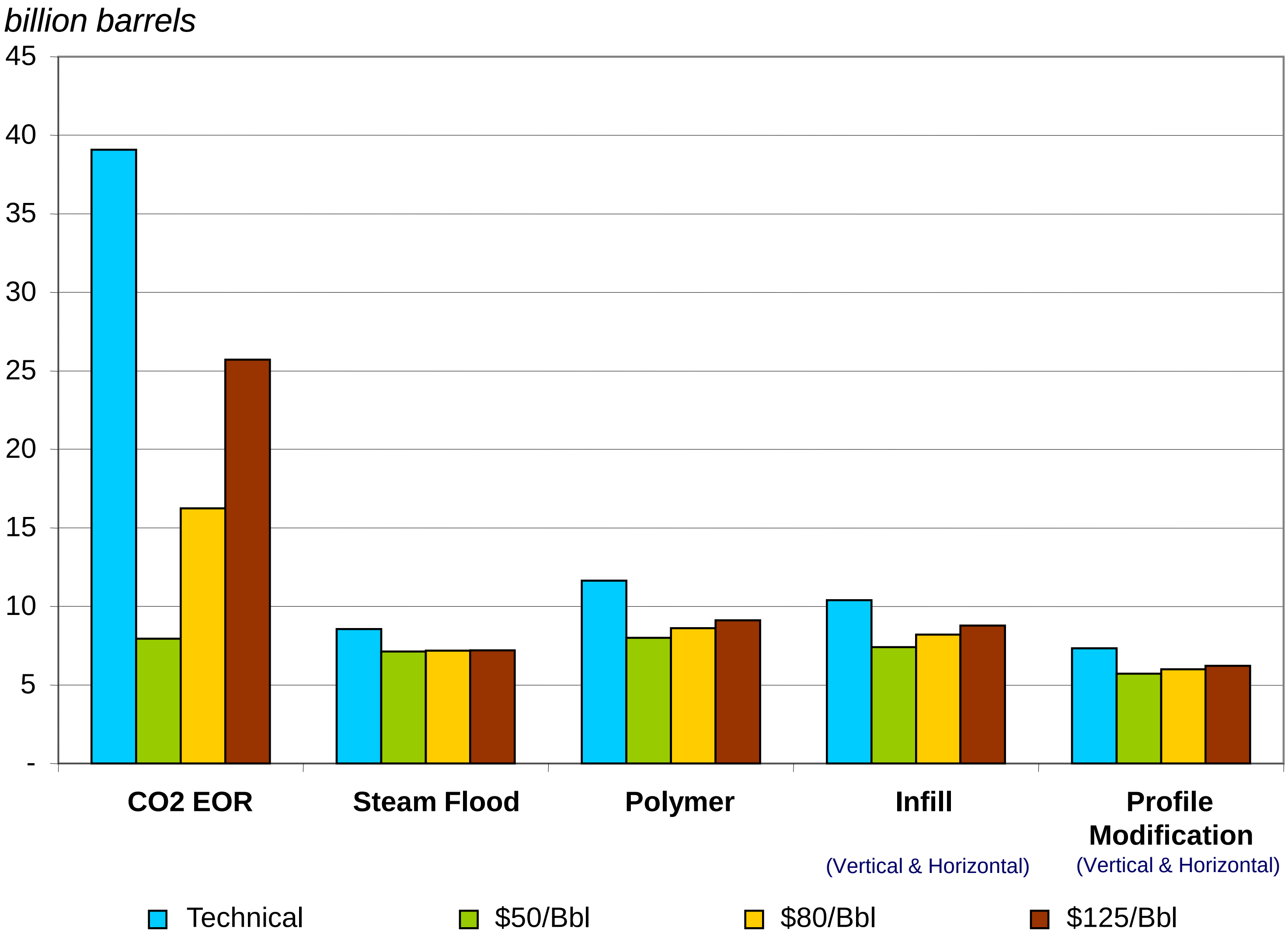
Enhanced oil recovery

- Resources
  - CO_2 Flooding
  - Steam Flooding
  - Polymer Flooding
  - Profile Modification
- AEO2011 production projections
- CO_2 EOR sensitivities

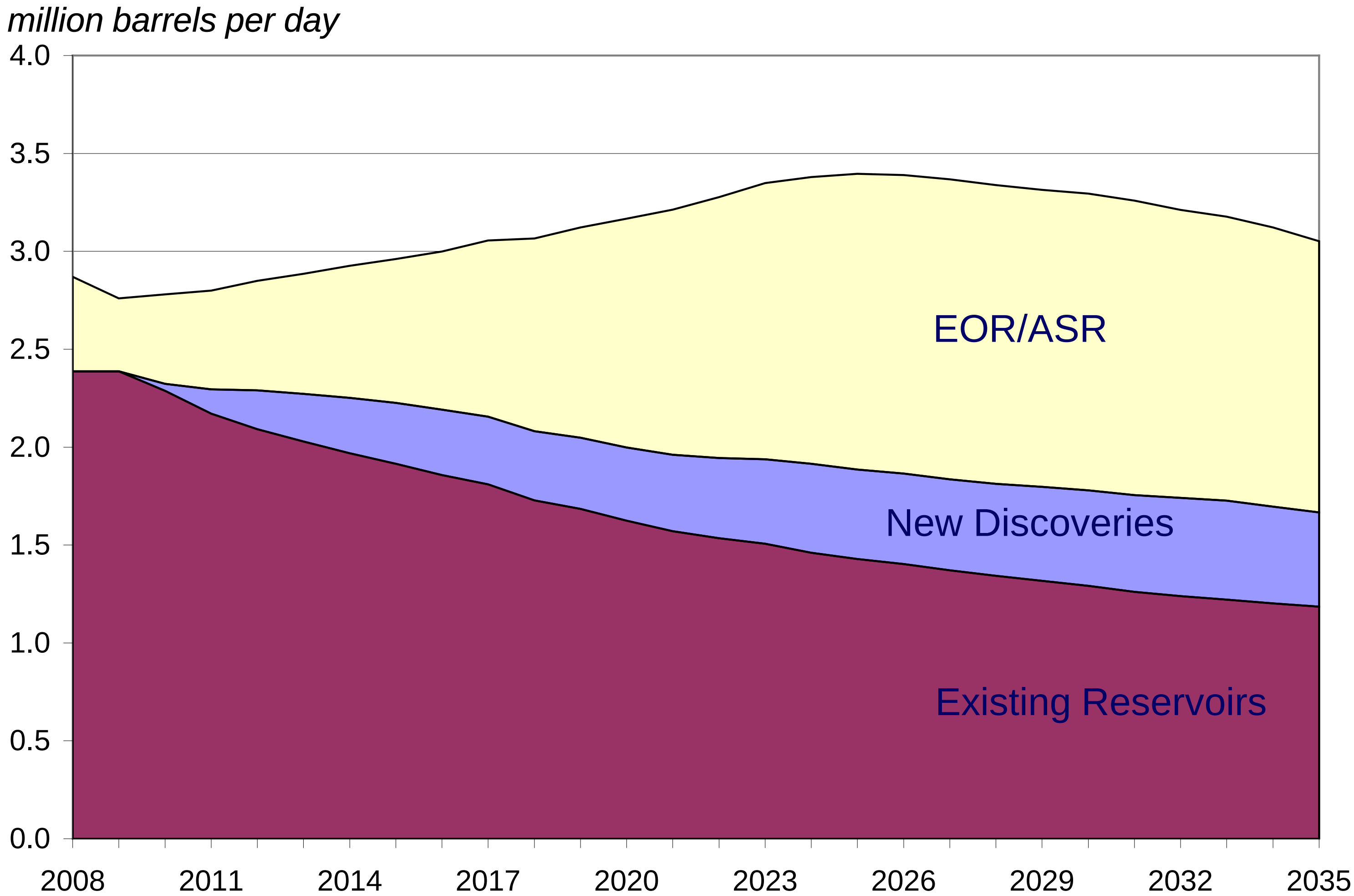
Technical production for EOR/ASR



Technical and economic production for EOR/ASR

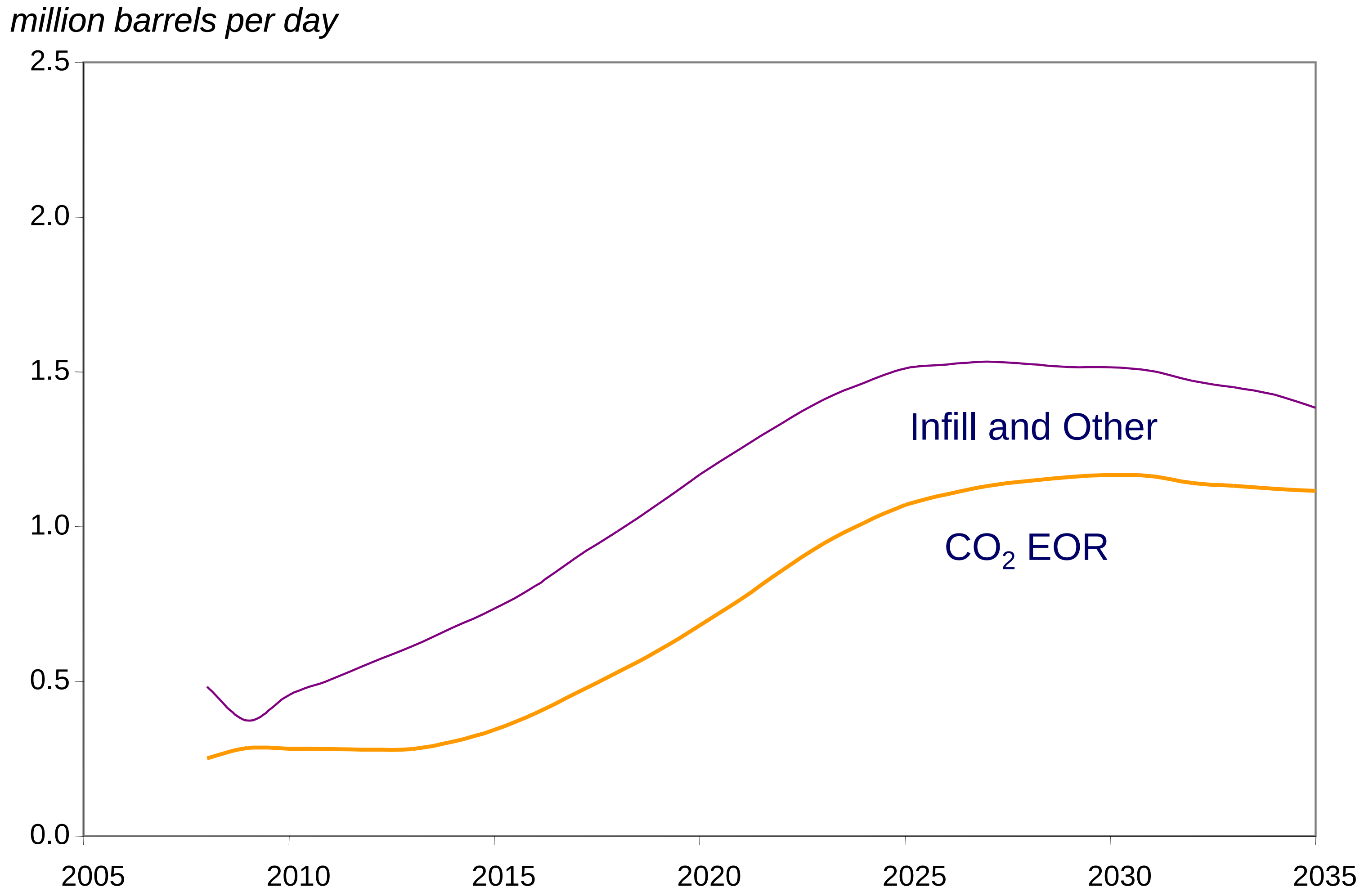


Onshore crude oil production - reference case



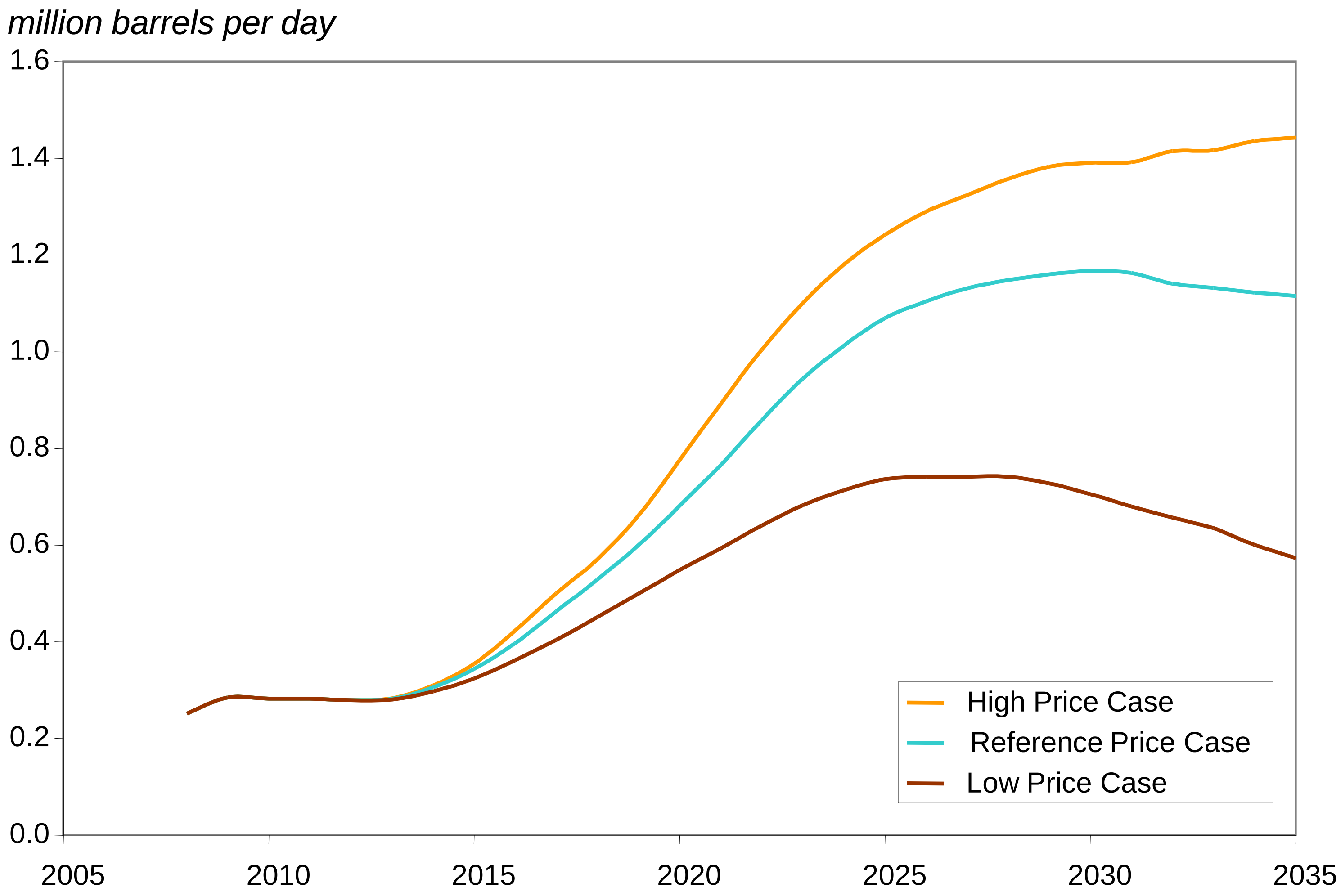
Source: EIA Annual Energy Outlook 2011

Components of EOR/ASR production - reference case



Source: EIA Annual Energy Outlook 2011

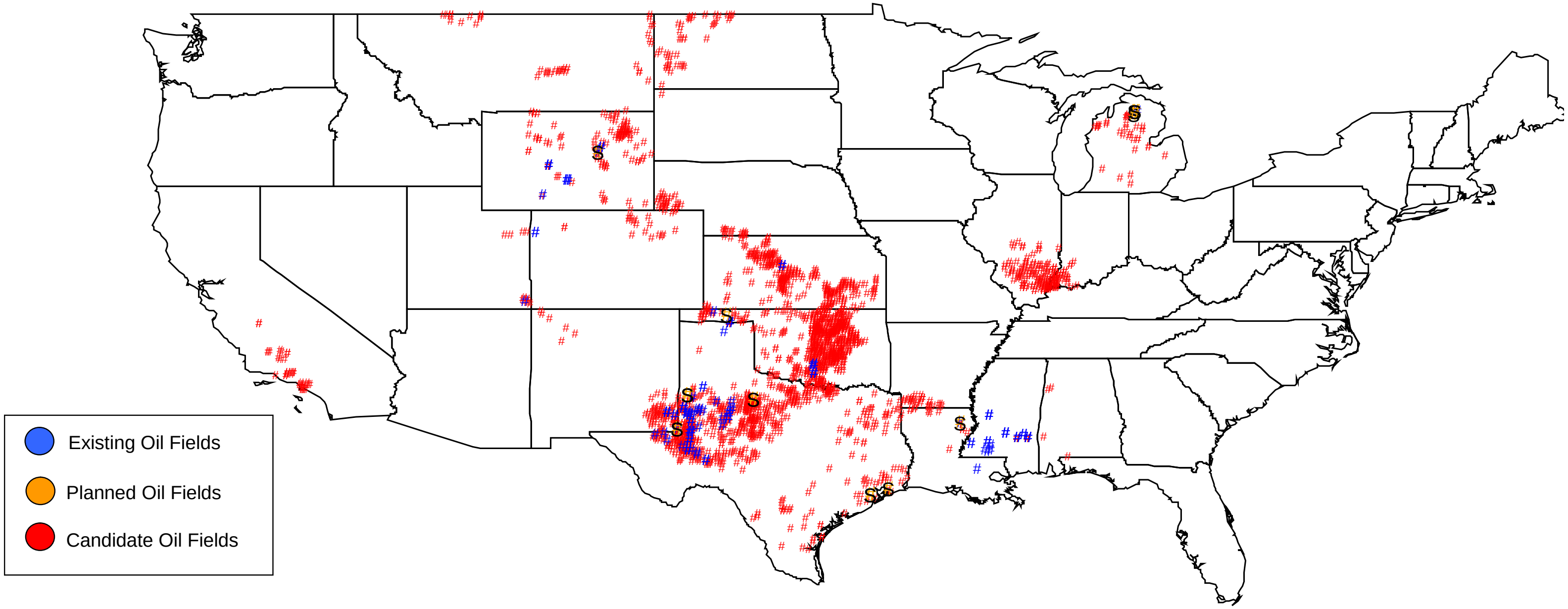
Total EOR production



Source: EIA Annual Energy Outlook 2011

Oil fields currently employing CO_2 EOR

Category	Field Count
Active	113
Planned	12
Candidates	2,235



Sources of CO_2

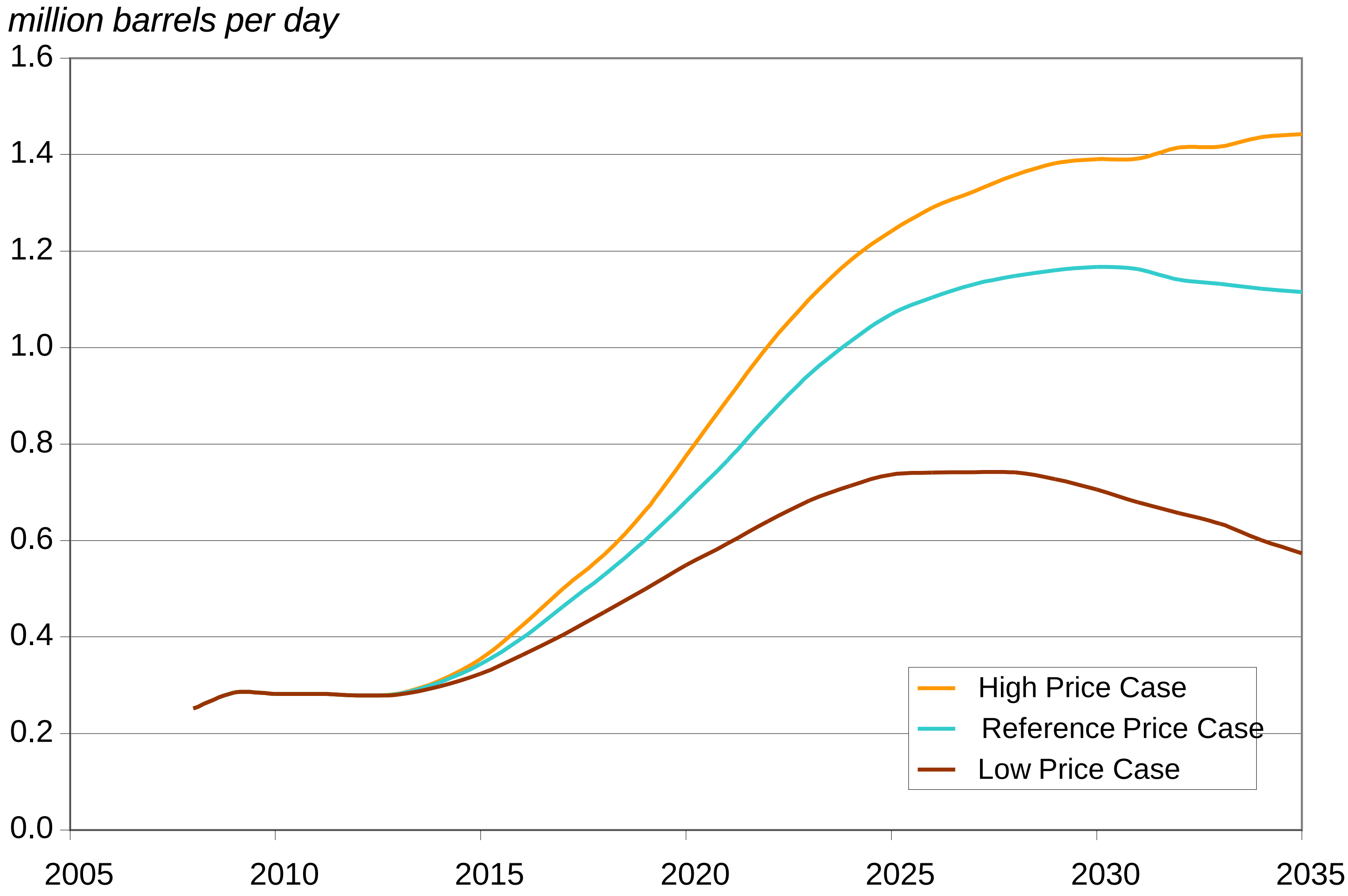
- Natural

- Anthropogenic
  - Hydrogen Plants
  - Ammonia Plants
  - Ethanol Plants
  - Cement Plants
  - Refineries
  - Power Plants
  - Natural Gas Processing Plants
  - Coal-to-liquids Plants

CO_2 availability assumption

Source Type	Infrastructure Development (years)	Market Acceptance (years)	Ultimate Market Acceptance	Maximum CO_2 Volumes (million tons)	Average Carbon Capture & Transportation (within Region) Cost ($/ton)
Ammonia Plants	2	10	100%	4.5	31
Natural Gas Processing	2	10	100%	10.9	27
Ethanol Plants	4	10	100%	18.4	33
Hydrogen Plants	4	10	100%	0.2	37
Refineries	4	10	100%	16.7	29
Cement Plants	7	10	100%	21.6	70
Fossil Fuel Plants	12	10	100%	1,209.0	100
Coal-to-Liquids	Determined by the Petroleum Market Module			77.2	27

CO_2 EOR production

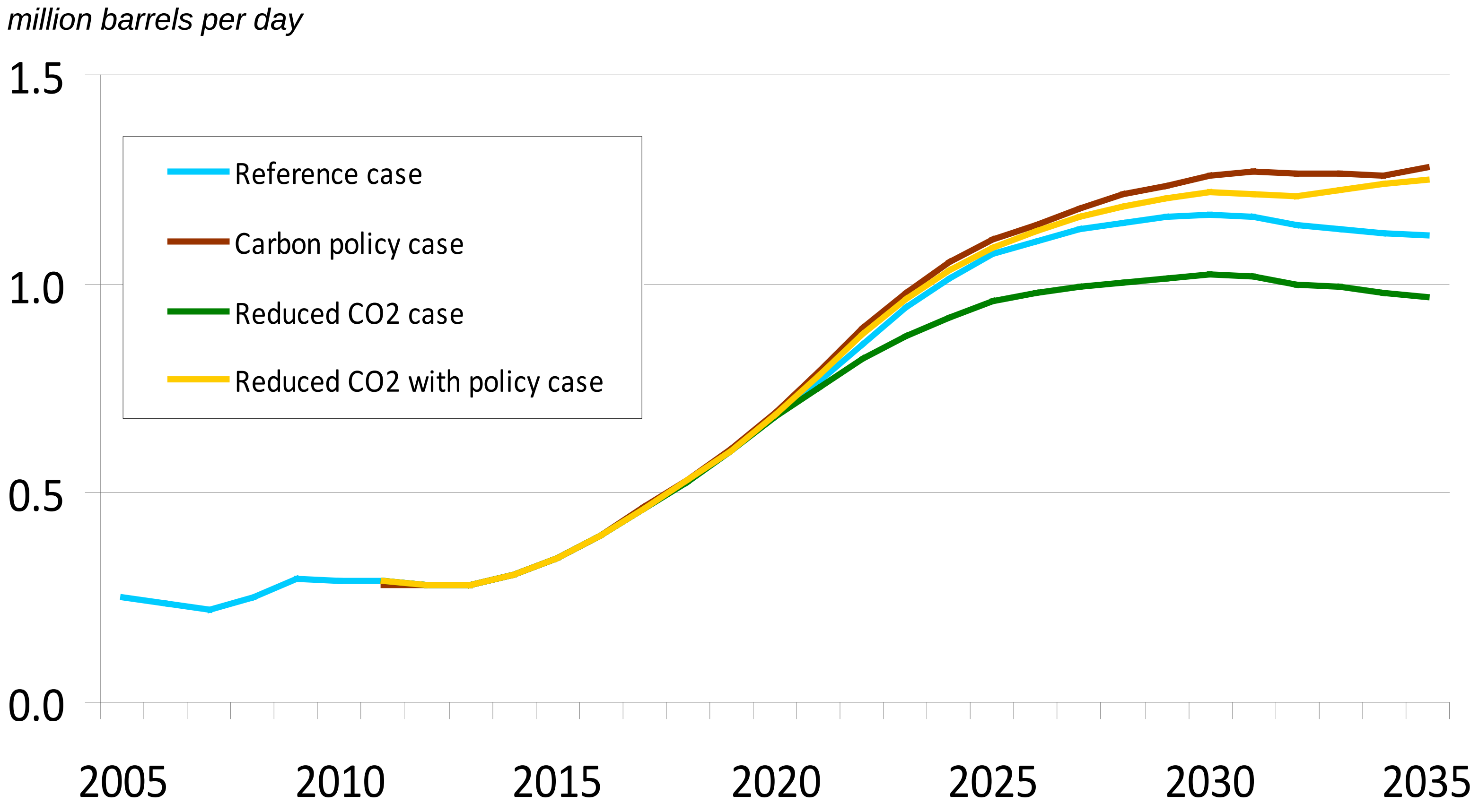


Source: EIA Annual Energy Outlook 2011

Alternative cases

- Reference case
  - no CO_2 tax
  - high proportion of high purity industrial CO_2 streams can be purchased by oil producers
- Carbon Policy case
  - CO_2 tax: rises from $25/ton in 2013 to $77/ton in 2035
  - oil producers receive CO_2 at reduced rates as quantity captured increases
- Reduced CO_2 cases
  - reduction in amount of anthropogenic CO_2 available to oil producers
- Reduced CO_2 with Carbon Policy case
  - same carbon tax as in Carbon Policy case

CO_2 EOR production

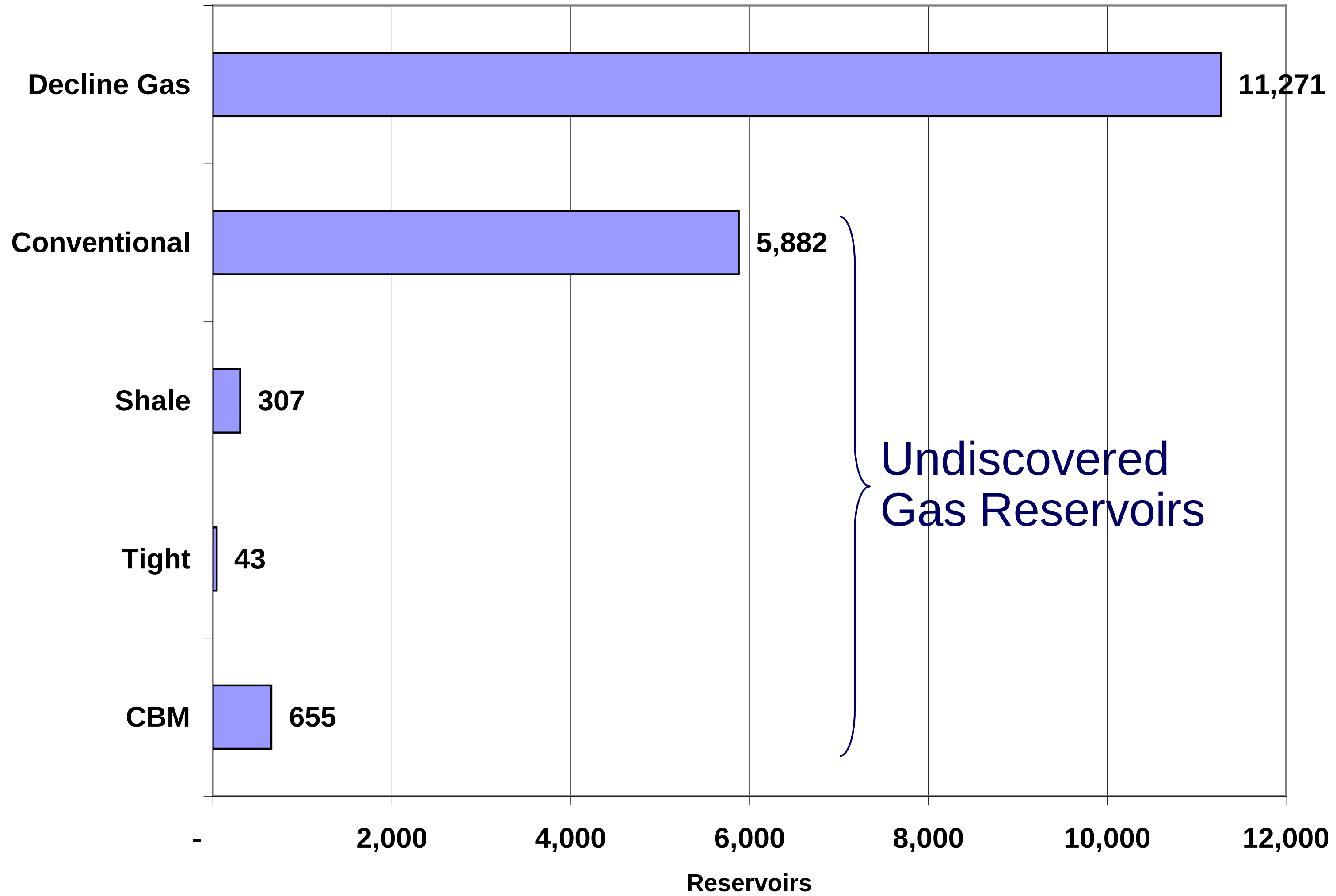


Source: EIA Annual Energy Outlook 2011

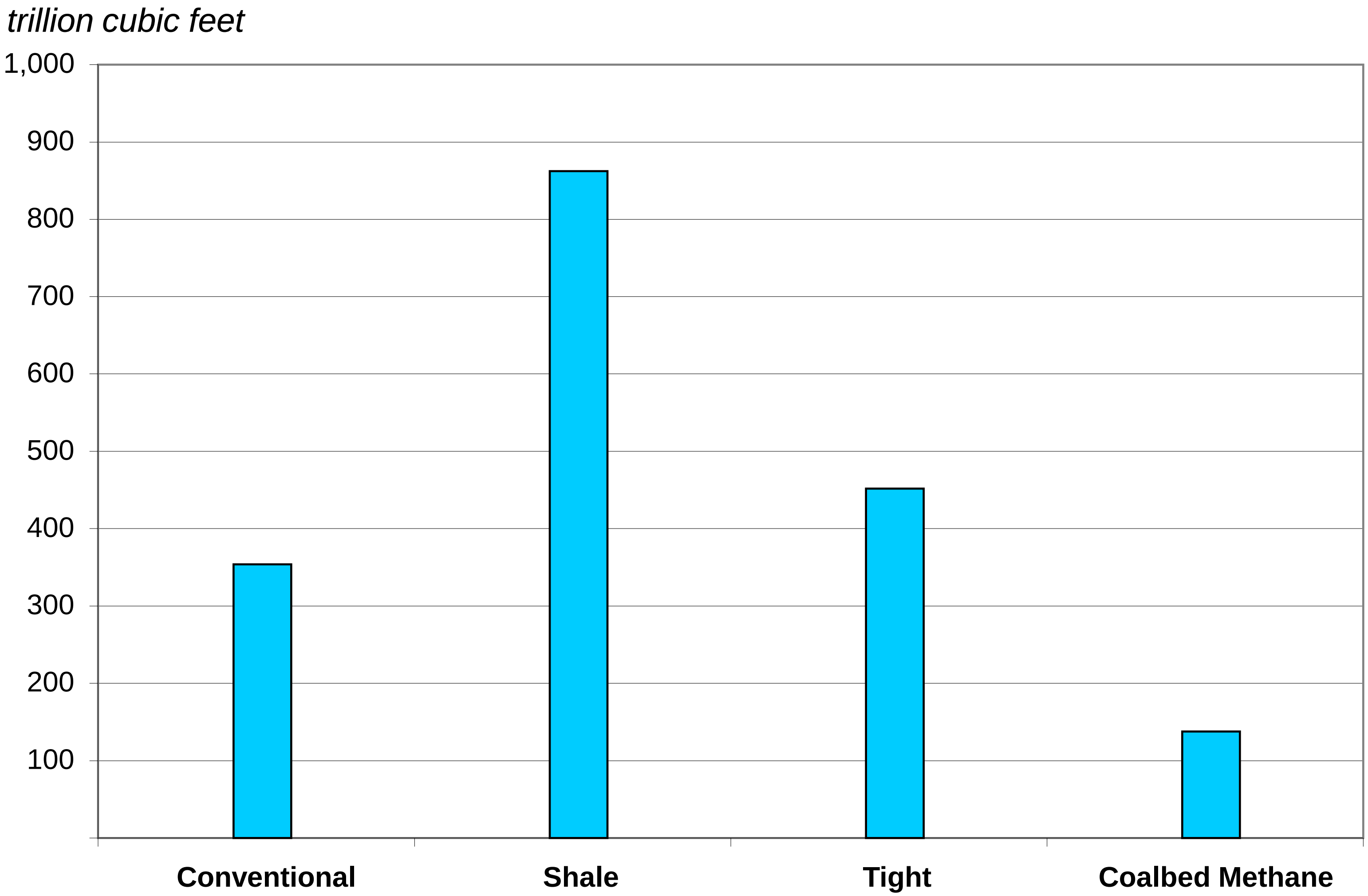
Natural gas projections in OLOGSS

- OLOGSS Gas Resources
- Components of Projections
- Shale Gas Analysis

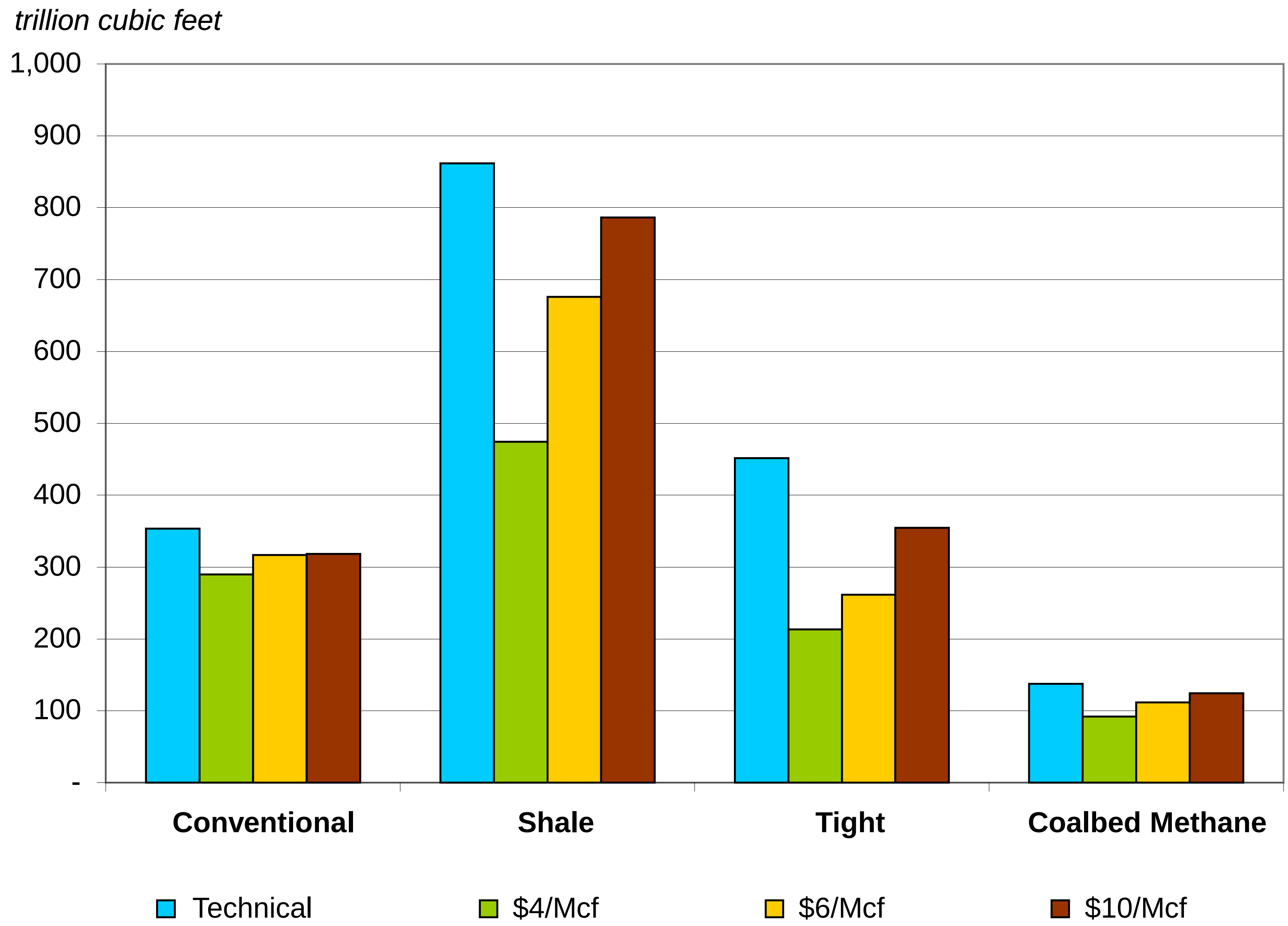
Gas reservoirs by classification



Technical production for natural gas



Technical and economic production for natural gas



Shale gas

- Uncertainties
- Resource assumptions
- Sensitivities

Shale gas uncertainties

- Considerable shale play/formation heterogeneity
- Shale productive capability is largely untested
- Long-term decline and recovery rates are unknown
- Producers maximize rates of return (ROR), not resource recovery
- Recovery rates depend on gas prices and production costs
- Re-fracturing potential is unknown
- Public information bias creates expectations that overstate “typical” shale gas well recovery and profitability

Within a shale formation, the following attributes will vary:

- Depth
- Formation thickness
- Pore space
- Pore pressure
- Carbon content → absorbed gas
- Thermal maturity
- Clay content (more clay → shorter fracture length and/or higher fracturing cost)

Lower 48 technically recoverable unproved shale gas resources

trillion cubic feet

Region	AEO2011	AEO2010
Northeast	473	73
Gulf Coast	105	90
Midcontinent	63	51
Southwest	87	60
Rocky Mountain	58	22
West Coast	41	51
Lower 48 Total	827	347

Technically recoverable unproved shale gas resources

billion cubic feet

Region	Basin	Play	AEO2011	AEO2010
Northeast	Appalachian	Marcellus – Developing	177,931	47,504
		Marcellus – Undeveloped	232,443	--
		Devonian - Big Sandy Central	6,490	3,428
		Devonian - Big Sandy Extension	940	2,247
		Devonian - Greater Siltstone	8,463	2,133
		Devonian - Low Thermal Maturity	13,534	4,015
	Illinois	Devonian - Cincinnati Arch	1,435	1,106
		New Albany	10,947	2,998
	Michigan	Antrim	20,512	9,738
Gulf Coast	TX-LA-MS Salt	Haynesville	80,023	71,974
	Western Gulf Coast	Eagle Ford	20,807	18,344
	Black Warrior	Floyd-Neal/Conasauga	4,465	--
Midcontinent	Arkoma	Fayetteville – Central	29,505	26,056
		Fayetteville – West	4,639	3,476
	Anadarko	Woodford – Western	19,771	15,503
		Woodford – Central	8,664	5,945
Southwest	Fort Worth	Barnett – Core	34,923	29,454
		Barnett – Extension	19,732	16,399
	Permian	Barnett-Woodford	32,152	13,690
Rocky Mountain	Greater Green River	Hilliard-Baxter-Mancos	3,770	17,790
	San Juan	Lewis	11,638	
	Uinta	Mancos	21,021	
	Williston	Shallow Niobrara	6,757	3,831
	Undiscovered		14,626	--
West Coast	Undiscovered		41,356	50,870

U.S. Geological Survey (USGS) shale gas resource assessment uncertainty

Summary statistics for the 20 USGS shale assessment units:

F95/mean natural gas volume ratio:

- Arithmetic average = 51 percent
- Gas volume weighted average = 58 percent

F5/mean natural gas volume ratio:

- Arithmetic average = 164 percent
- Gas volume weighted average = 153 percent

USGS resource estimate range supports the +/- 50 percent shale gas case variance.

AEO2011 shale gas resource determinants

The key determinants of the AEO2011 technically recoverable shale gas resource base are:

(1) the estimated ultimately recovery (EUR) per well, and

(2) the formation acreage from which natural gas can be produced.

Shale gas cases were created by varying the reference case resource EUR and recovery factors by +/- 50%, which is consistent with USGS 95 and 5 percent probability range.

Shale cases are meant to be illustrative of the shale gas resource uncertainty and do not represent confidence intervals or expected probability distributions.

High shale gas cases

- **High EUR case**. The estimated ultimately recovery (EUR) per shale gas well is assumed to be 50 percent higher than in the AEO2011 Reference case. Well spacing remains unchanged. Each well is recovering 50% more gas from the same acreage. The formation's productive acreage remains unchanged.

- **High Recovery case.** Fifty percent (50%) more natural gas can be recovered from the shale formation than in the Reference case, with 50 percent more productive acreage. The EUR per well is unchanged. Fifty percent (50%) more wells would be drilled to fully recover the shale gas in each play.

- In both cases, the technically recoverable **unproved** shale gas resource potential increases from 827 Tcf to 1,230 Tcf.

Low shale gas cases

- **Low EUR case**. The estimated ultimately recovery (EUR) per shale gas well is assumed to be 50 percent lower than in the AEO2011 Reference case. Well spacing remains unchanged. Each well is recovering 50% less gas from the same acreage. The formation's productive acreage remains unchanged.

- **Low Recovery case.** Fifty percent (50%) less natural gas can be recovered from the shale formation than in the Reference case, with 50 percent less productive acreage. The EUR per well is unchanged. Fifty percent (50%) less wells would be drilled to fully recover the shale gas in each play.

- In both cases, the technically recoverable **unproved** shale gas resource potential decreases from 827 Tcf to 423 Tcf.

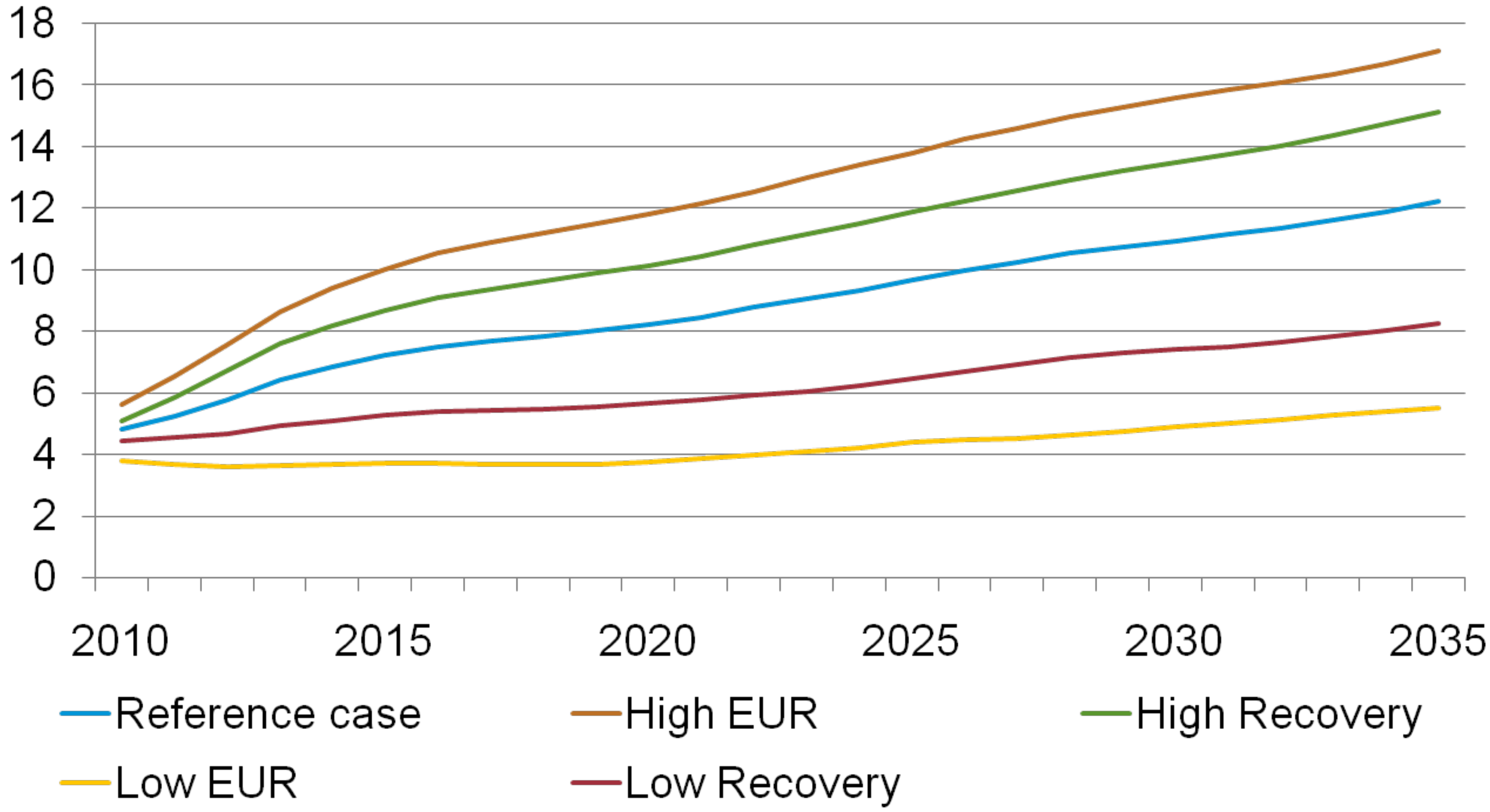
Implications of shale gas cases

- **High/Low EUR cases** vary the cost of producing shale gas on a per unit basis by varying the volume of gas that can be recovered from a well at a fixed capital cost per well. These cases exhibit the greatest variability in gas prices, consumption, and supply.

- **High/Low recovery cases** vary the area of the shale gas resource endowment, but do not affect the cost of producing gas within the productive area. Gas prices increase as the less expensive shale gas formations are depleted first. These cases exhibit less variability in gas prices, consumption, and supply.

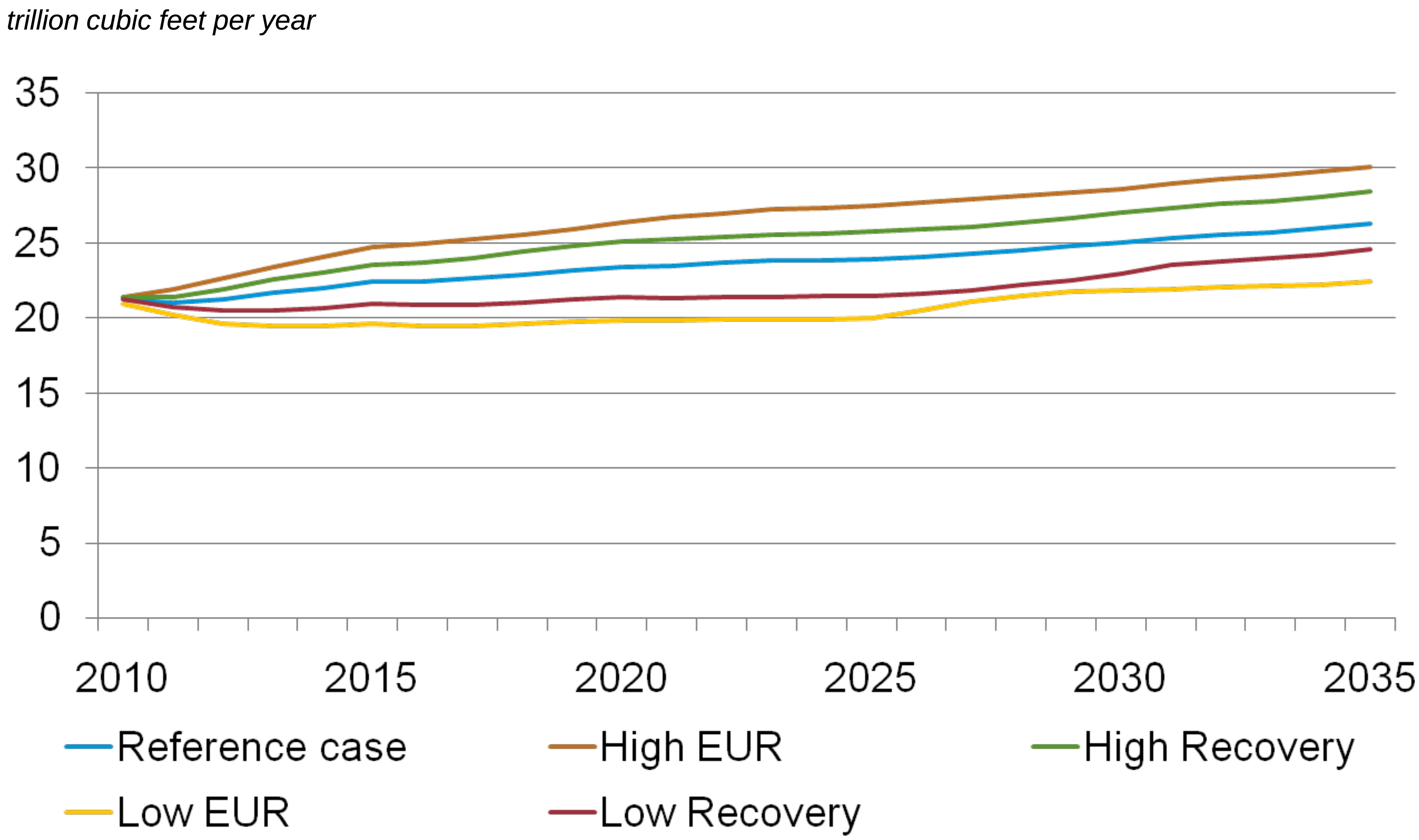
Shale gas production

trillion cubic feet per year



Source: EIA Annual Energy Outlook 2011

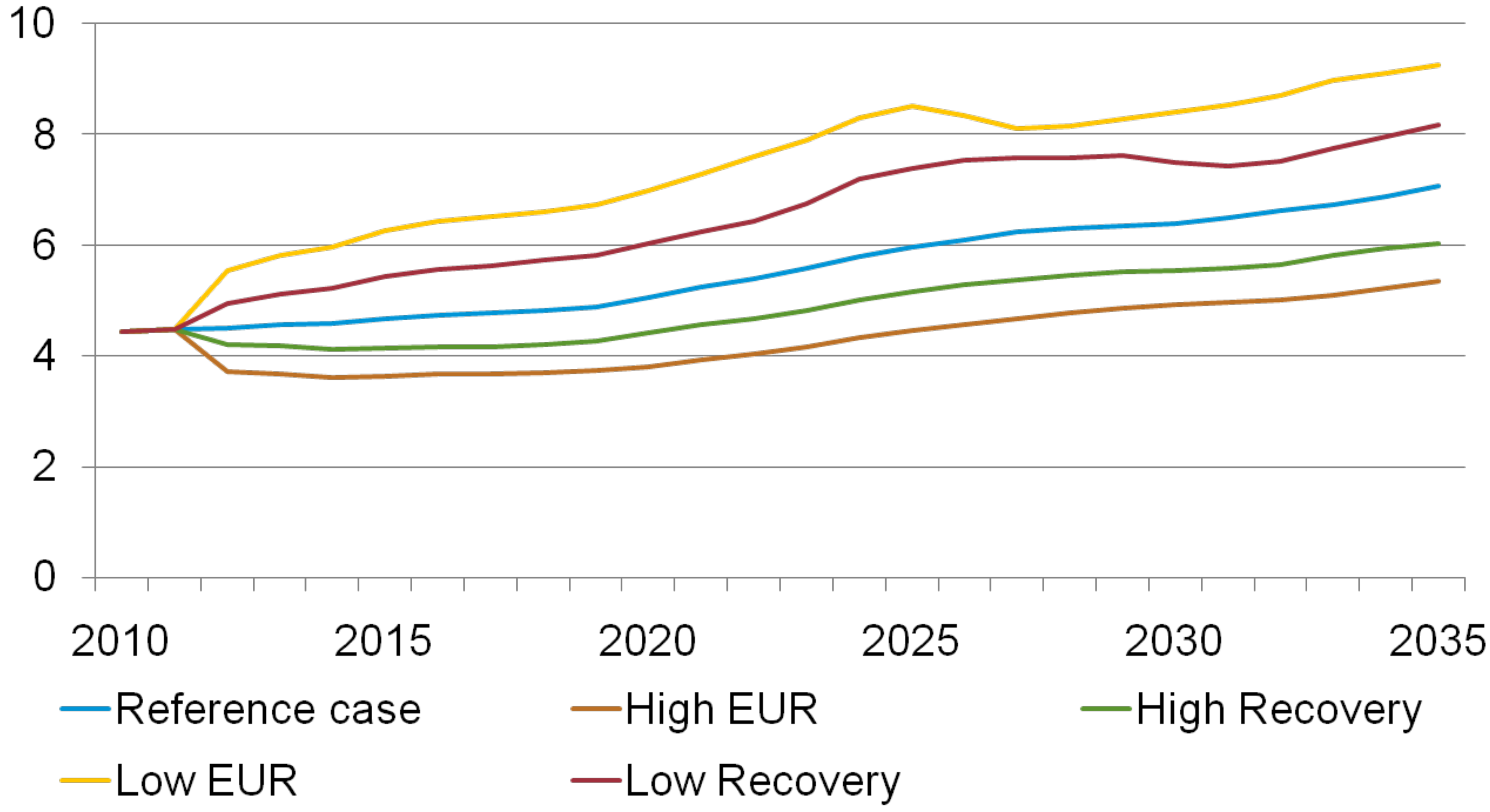
Total natural gas production



Source: EIA Annual Energy Outlook 2011

Henry Hub spot natural gas prices

dollars per million Btu in 2009 constant dollars



Source: EIA Annual Energy Outlook 2011

For more information

U.S. Energy Information Administration home page | www.eia.gov

Annual Energy Outlook 2011 | www.eia.gov/aeo

Short-Term Energy Outlook | www.eia.gov/steo

Oil and Gas Supply Module Documentation | www.eia.gov/analysis/model-documentation.cfm

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