Improved Natural Gas Extraction as a Strategy for Reducing Climate Impacts of Transportation

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Agenda

- Technology Description
- LCA Boundaries
- Natural Gas Modeling Framework
- Co-product Management
- GHG Results
- Role of Reduced Extraction Emissions

Favorable resource and technology characteristics drive commercialization of GTL

- **Technological and economic advantages**
  - Can use growing domestic resource base of natural gas
  - Upgrades economic value of natural gas by converting it to transportation fuels
  - Feedstock and product infrastructure are already in place
- **Commercial development has matured in last decade**
  - Two GTL projects in Qatar came online
  - Two domestic projects have been proposed (in Louisiana and Northeast U.S.)[1, 2]

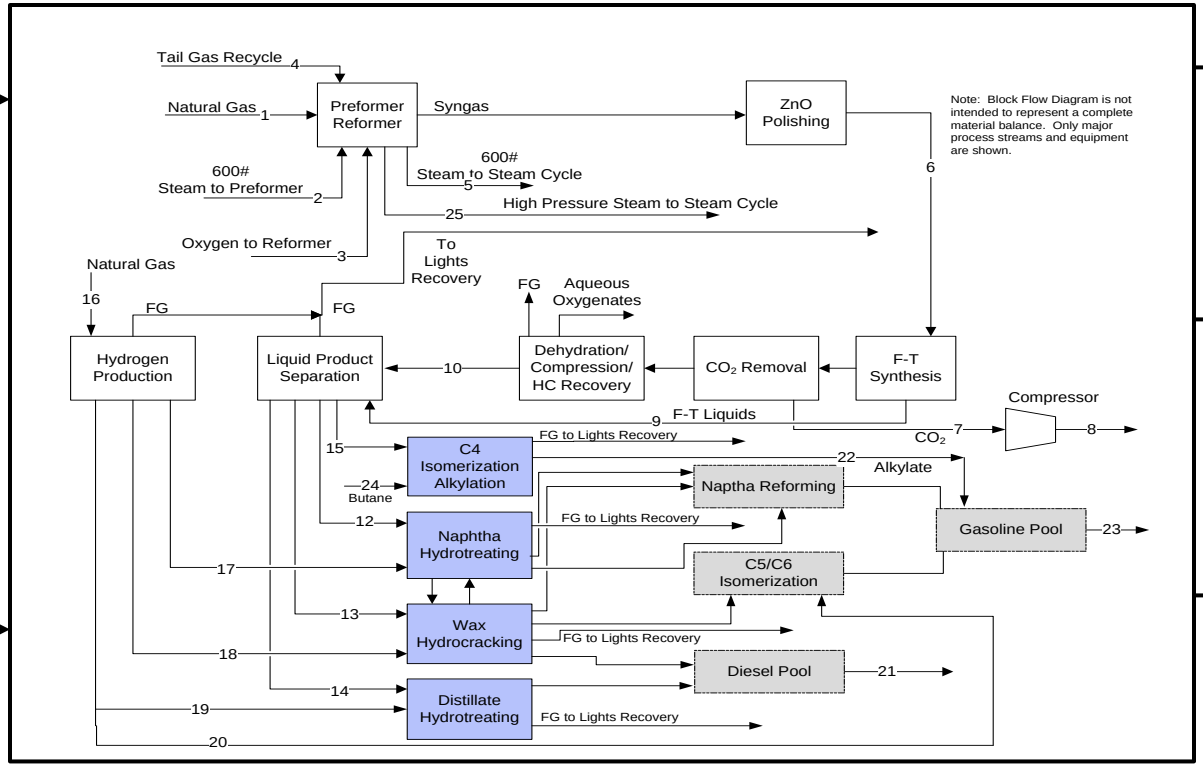
[1] *Office of the Governor Bobby Jindal: State of Louisiana. (2011). Gov. Jindal Announces Sasol Selected Calcasieu Parish as Location for Potential $8-10 Billion Gas-to-Liquids Complex. Retrieved on November 28, 2012, from http://gov.louisiana.gov/index.cfm?md=newsroom&tmp=detail&articleID=3022.*

[2] *Oil products plant considers adding GTL capacity. (n.d.). Oil and Gas Journal, 110, 14.*

GTL is one example of the advanced energy technologies that NETL researches

Natural Gas
423,745 MMBtu/day (9,374 ton/day)

Butane
499 tons/day (used for gasoline blending)



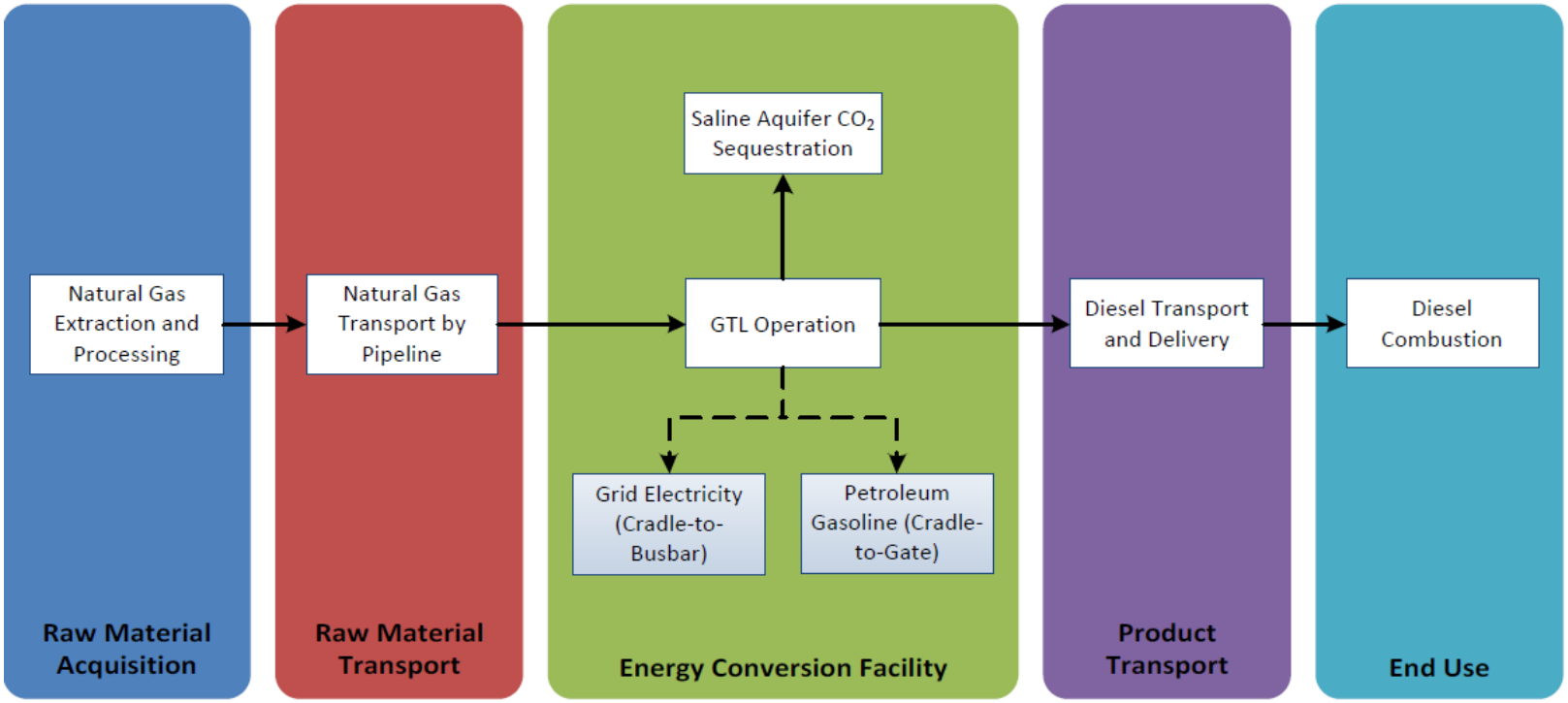
Diesel
34,543 bbl/day

Gasoline
15,460 bbl/day

Electricity
40.8 MW (979 MWh/day)

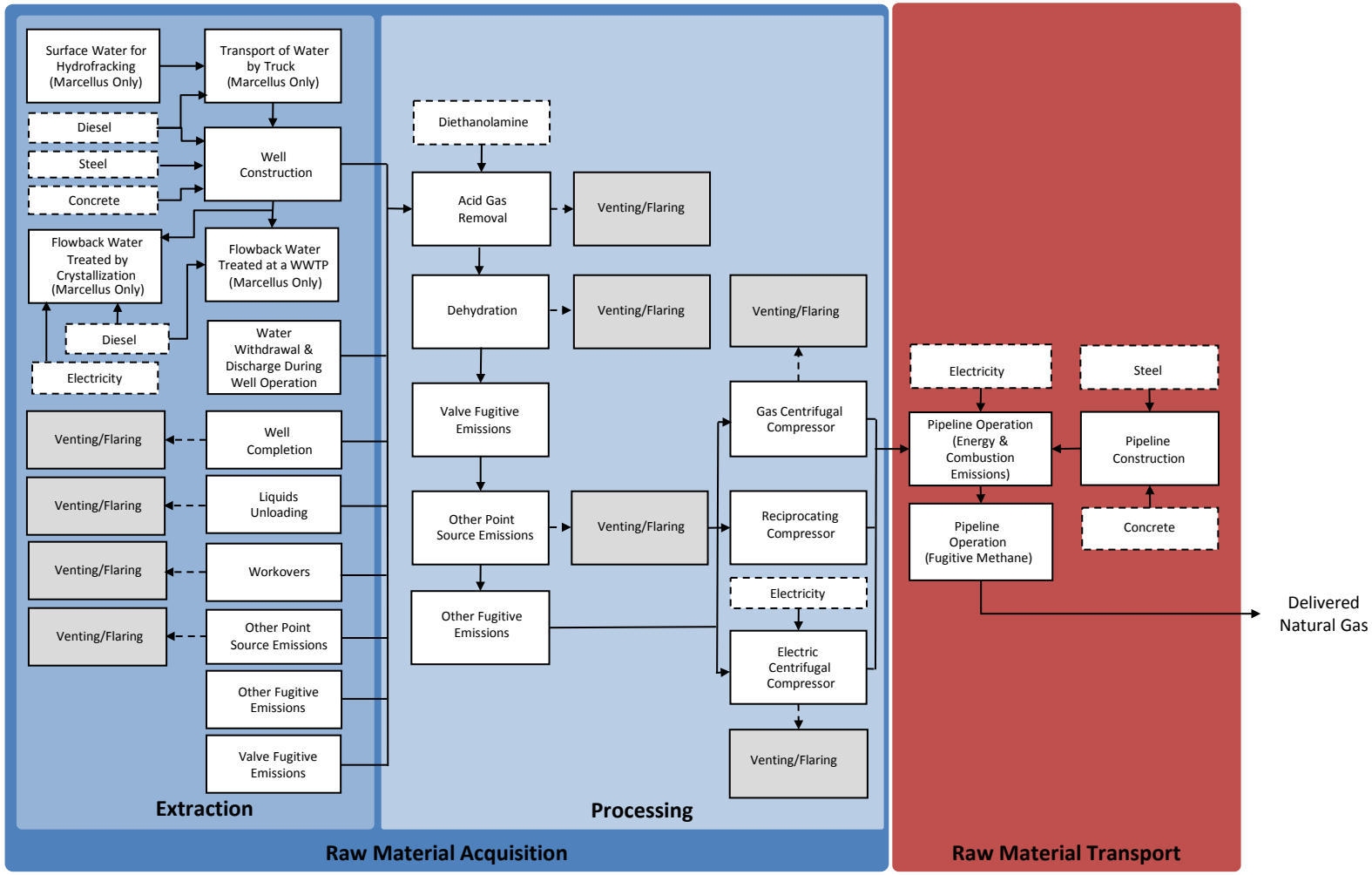
- Catalytic reforming converts natural gas to synthesis gas
- Steam methane reforming increases hydrogen content in synthesis gas
- Liquid synthesis in low-temperature, slurry-bed Fischer-Tropsch reactor with cobalt catalyst
- 93% of CO_2 is captured for sequestration (1,532 tons CO_2/day)

GTL LCA boundaries include upstream and downstream activities



- Functional unit of 1 MJ of combusted diesel or gasoline (diesel shown here)
- Upstream natural gas is based on a detailed model
- GTL co-products are managed with displacement

NETL's NG model is a network of flexible processes



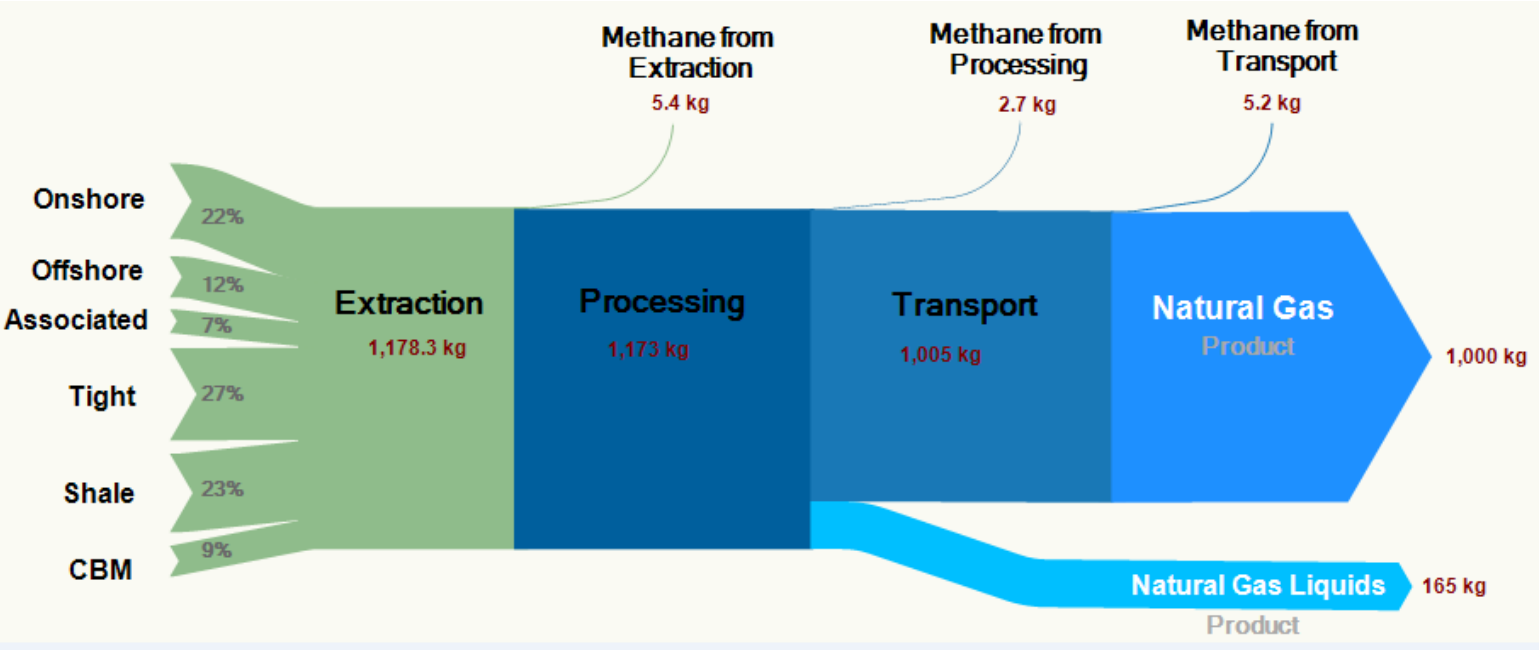
- Over 20 unique unit processes
- Bottom-up engineering calculations instead of top-down data
- Tunable to any natural gas extraction technology

Parameters allow scenario and uncertainty analysis

Property (Units)		Onshore	Associated	Offshore	Tight Gas	Barnett Shale	Marcellus Shale	CBM
Natural Gas Source								
Contribution to 2010 U.S. Domestic Supply		22%	6.6%	12%	27%	21%	2.5%	9.4%
Average Production Rate (Mcf /day)	low	46	85	1,960	77	192	201	73
	expected	66	121	2,800	110	274	297	105
	high	86	157	3,641	143	356	450	136
Expected EUR (Estimated Ultimate Recovery) (BCF)		0.72	1.32	30.7	1.20	3.00	3.25	1.15
Natural Gas Extraction Well								
Flaring Rate (%)		51% (41 - 61%)			15% (12 - 18%)			
Well Completion (Mcf natural gas/episode)		47			3,600	9,000	9,000	49.6
Well Workover (Mcf natural gas/episode)		3.1			3,600	9,000	9,000	49.6
Lifetime Well Workovers (Episodes/well)		1.1			0.3			
Liquid Unloading (Mcf natural gas/episode)		3.57	n/a	3.57	n/a	n/a	n/a	n/a
Lifetime Liquid Unloadings (Episodes/well)		930	n/a	930	n/a	n/a	n/a	n/a
Valve Emissions, Fugitive (lb CH_4/Mcf natural gas)		0.11		0.0001	0.11			
Other Sources, Point Source (lb CH_4/Mcf natural gas)		0.003		0.002	0.003			
Other Sources, Fugitive (lb CH_4/Mcf natural gas)		0.043		0.01	0.043			

- Natural gas extraction parameters include expected values and uncertainty ranges
- Emission factors for unconventional wells and liquid unloading recently updated based on EPA revisions
- Similar parameterization approach used for processing and transport

NETL's NG model allows calculation of upstream methane emissions



- 13.4 kg CH_4 emissions per 1,000 kg of delivered natural gas and 165 kg NGL
- Applying mass allocation between co-products translates to a 1.26% loss of CH_4 per unit of delivered natural gas
- Comparable to results of a recent 190-well study completed by University of Texas[1] (both studies show ~0.5% extraction loss)

[1] Allen, David T., et al. "Measurements of methane emissions at natural gas production sites in the United States." *Proceedings of the National Academy of Sciences* (2013): 201304880.

Co-product management is necessary to calculate LCA results for individual GTL products

- Allocation?
  - Mass allocation not possible with electricity as a co-product
  - Economic allocation is possible, but costs are relative and societal values reflected by prices do not necessary indicate relative environmental burdens of co-products
  - Energy allocation is possible, but *useful* energy in a unit of fuel is different than *useful* energy in a unit of electricity
- Displacement?
  - Large scale energy systems can affect demand for competing products
  - Unlike allocation, which severs links between GTL co-products and the energy market, displacement considers broader consequences of co-production

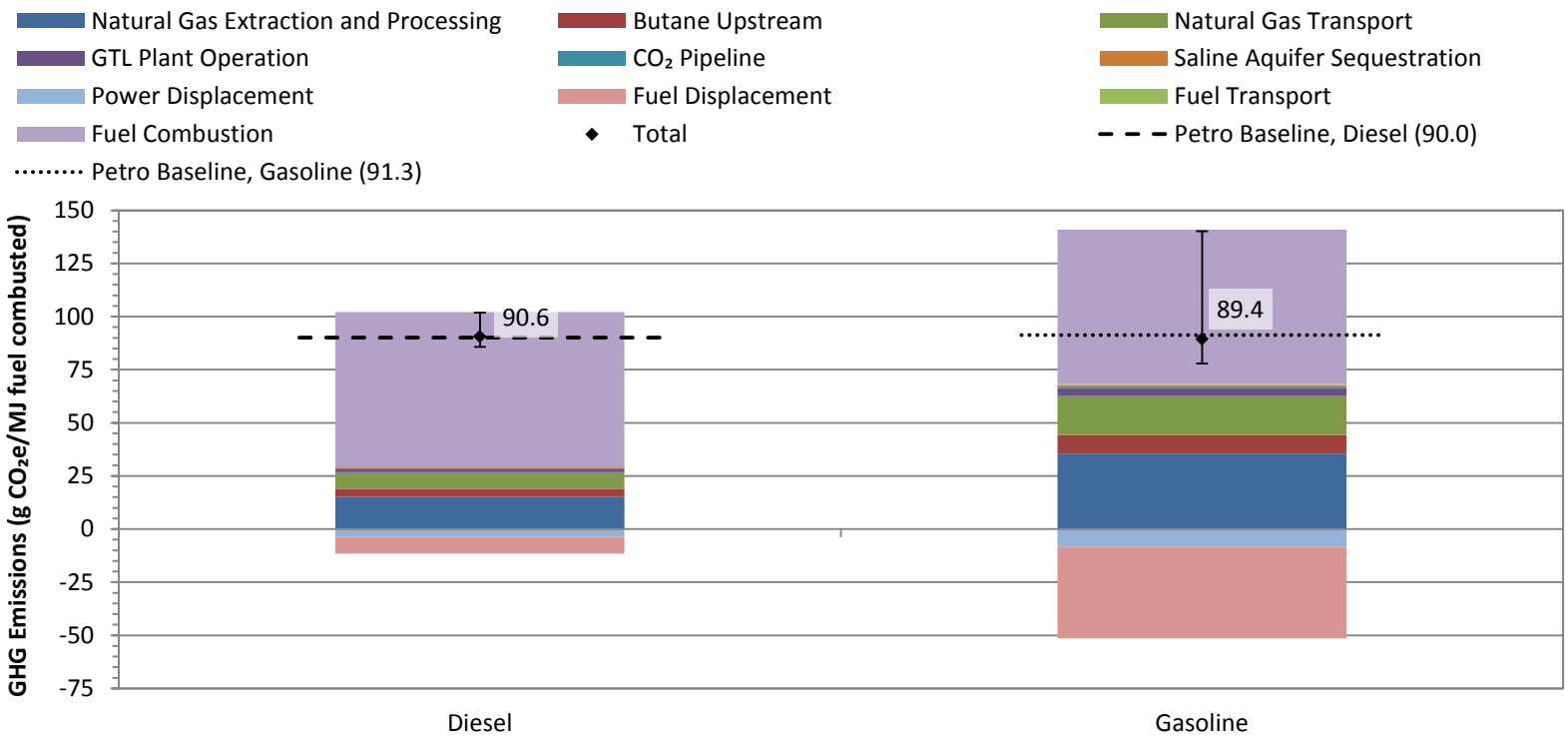
Displacement is more appropriate than allocation for this analysis because the scale of the GTL system will affect conventional routes to fuel production.

Co-product displacement requires modeling decisions about type and extent of displacement

- **Diesel as functional unit**
  - GTL gasoline displaces conventional petroleum gasoline
  - GTL electricity displaces average power produced by the U.S. electricity grid
- **Gasoline as functional unit**
  - GTL diesel displaces conventional petroleum diesel
  - GTL electricity displaces average power produced by the U.S. electricity grid
- **Displacement value is inversely proportional to LCA result**
  - Low displacement corresponds to *high* LCA result
  - High displacement corresponds to *low* LCA result

Co-Product	Low Value	Expected Value	High Value
Electricity	AEO 2035 U.S. Grid Mix (671 kg CO_2e/MWh)	U.S. Grid Mix (707 kg CO_2e/MWh)	Fleet Coal (1,161 kg CO_2e/MWh)
Diesel	No Displacement	100% Displacement of Diesel from Imported Crude Mix	100% Displacement of Diesel from Imported Crude Mix
Gasoline	No Displacement	100% Displacement of Gasoline from Imported Crude Mix	100% Displacement of Gasoline from Imported Crude Mix

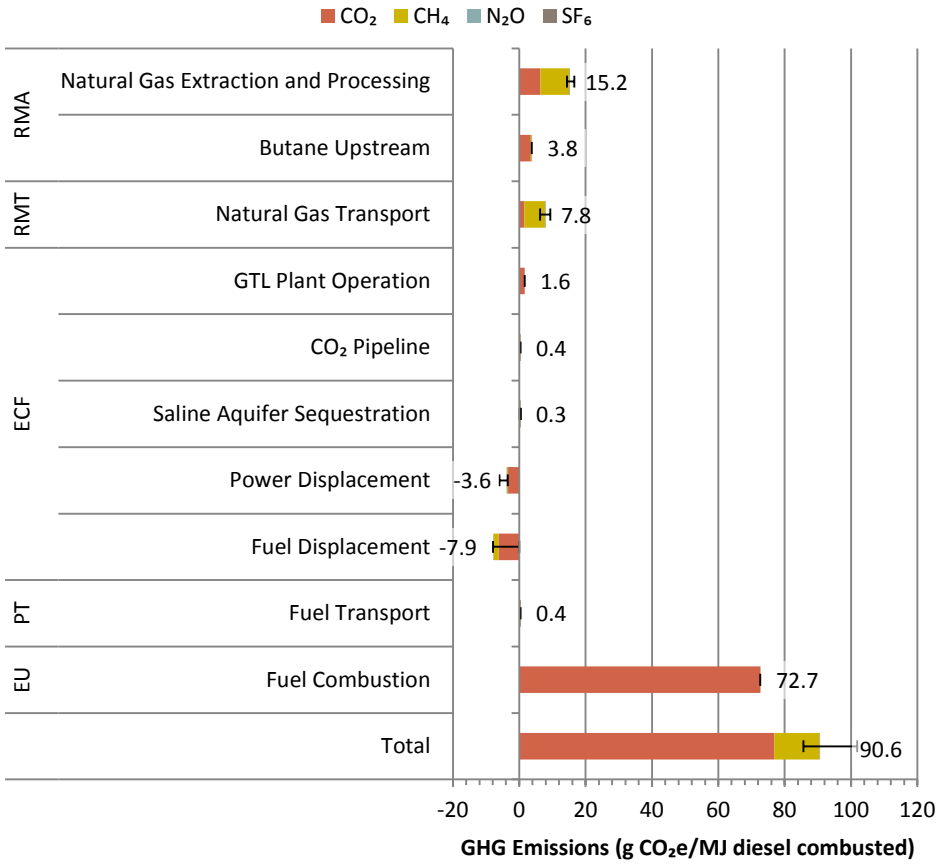
GTL GHG results are comparable to NETL's petroleum baseline



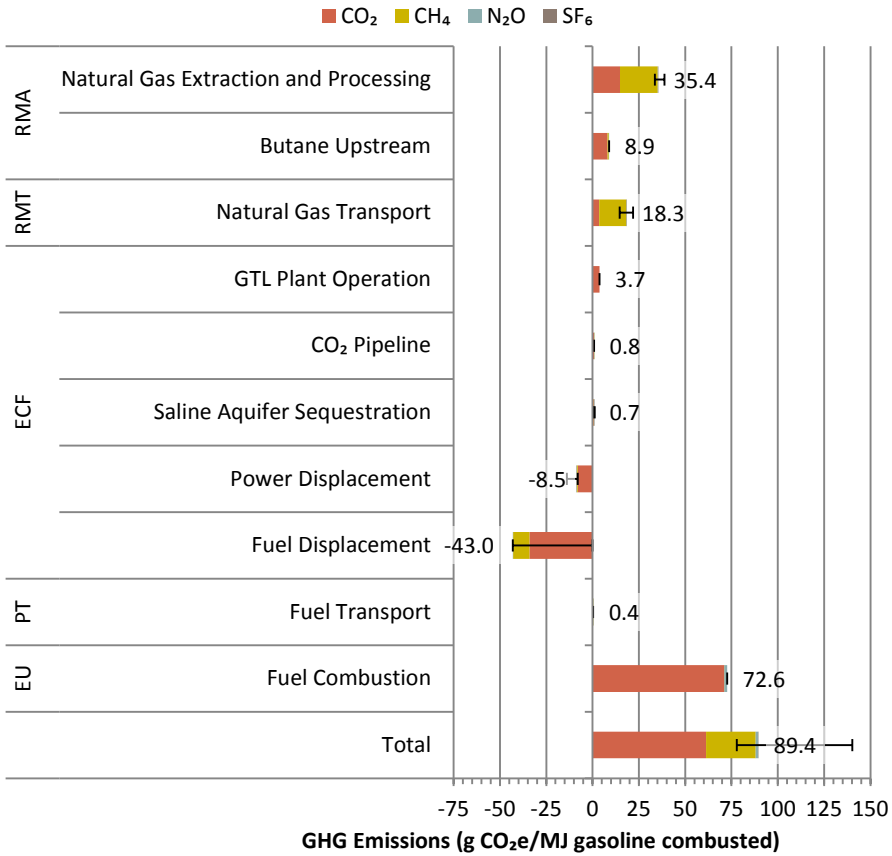
- NETL's petroleum baseline is basis for Renewable Fuel Standards (RFS)
- Expected life cycle GHG emissions from GTL fuels are close to petroleum baseline
- Uncertainty straddles petroleum baseline
- Fuel combustion is largest GHG contributor, but upstream natural gas matters too

Detailed results point to key contributors

Diesel



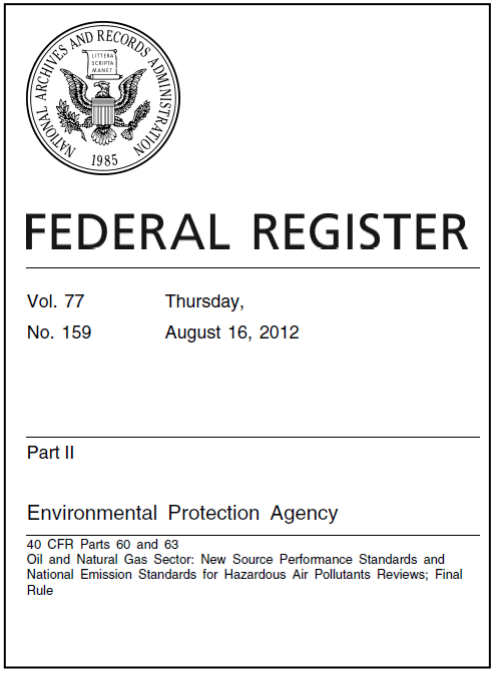
Gasoline



- Displacement uncertainty is larger when gasoline is functional unit because GTL plant is optimized for diesel production
- Fuel combustion may be largest GHG contributor, but methane emissions from upstream natural gas represent greatest opportunity for improvement

EPA New Source Performance Standards (NSPS) regulate VOC emissions from the oil and gas sector

- **Final Oil & Gas Sector NSPS rule under CAA established August 16, 2012**
- **Methane is a key component of the VOC category for the oil and gas sector**
- **Reduces emissions from some processes by as much as 95%**
  - Well completions and workovers
  - Centrifugal compressors
  - Reciprocating compressors
  - Storage tanks
  - Pneumatic controllers
- **Does not regulate all upstream natural gas processes**
  - Liquid unloading
  - Pipeline transmission



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Part II

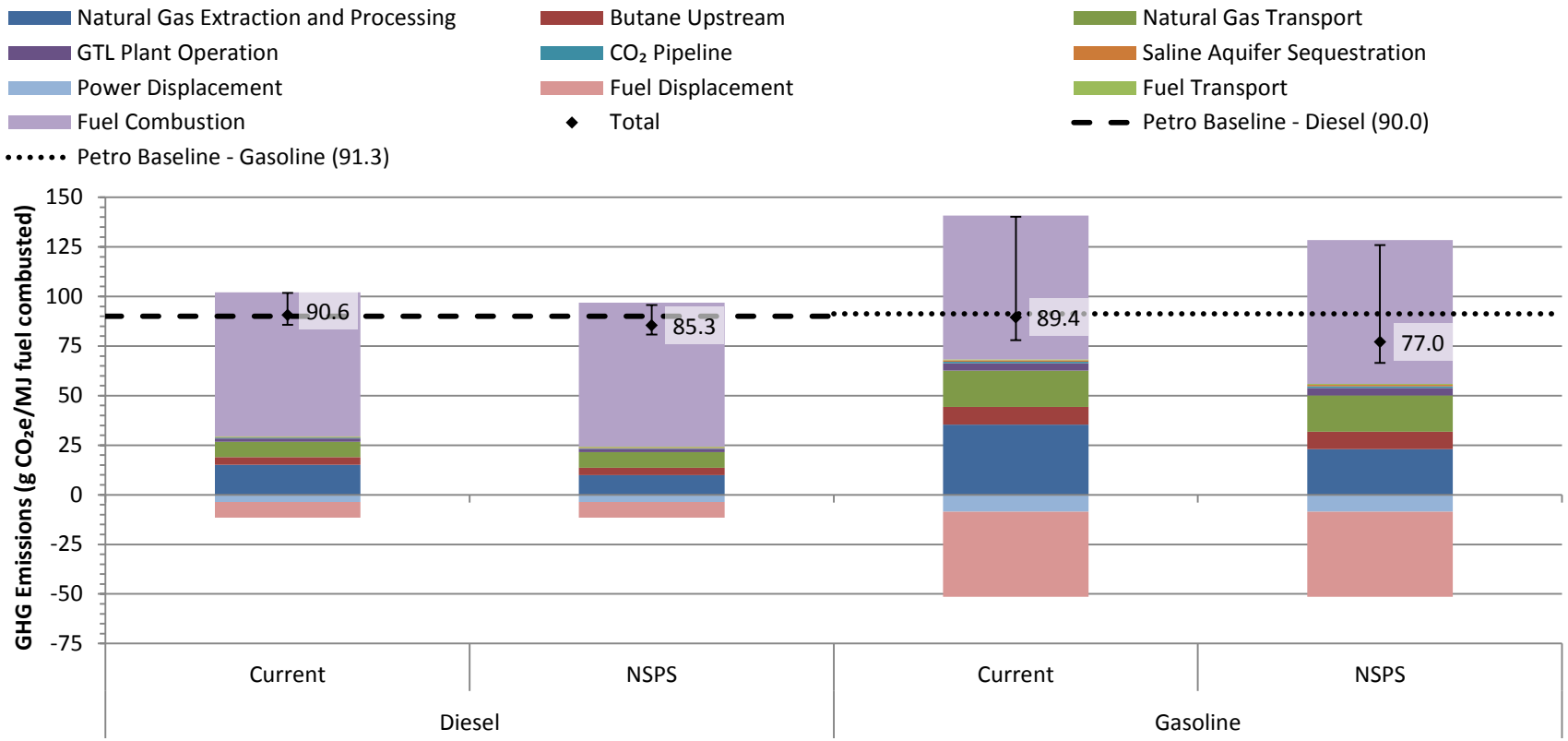
Environmental Protection Agency

40 CFR Parts 60 and 63
Oil and Natural Gas Sector: New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants Reviews; Final Rule

NETL's parameterized modeling approach can estimate the GHG changes caused by NSPS

- **Reduced emission completions (RECs) for unconventional wells**
  - Can reduce unconventional completion emissions by 95% (NSPS, 2012)
  - New completion and workover emission factor = 9,000*(100% - 95%)
    = 450 Mcf natural gas/episode
  - A higher extraction flaring rate is also expected for RECs, so increase unconventional flaring rate from 15% to 51%
- **Replacement of compressor wet seals with dry seals**
  - Can reduce centrifugal compressor CH_4 emissions 95% (NSPS, 2012)
  - New emission factor for centrifugal compressors (at processing site)
    = 0.0069 kg CH_4/kg natural gas compressed * (100% - 95%)
    = 0.00035 kg CH_4/kg natural gas compressed
- **Routine replacement of compressor rod packings**
  - Can reduce reciprocating compressor CH_4 emissions 95% (NSPS, 2012)
  - New emission factor for reciprocating compressors (at processing site)
    = 0.0306 kg CH_4/kg natural gas combusted * (100% - 95%)
    = 0.00153 kg CH_4/kg natural gas combusted
- **Replacement of pneumatic controllers**
  - High bleed controllers have leak rates of 6 - 42 scf/hr (EPA, 2006b)
  - Low bleed controllers have leak rates less than 6 scf/hr and are used by offshore gas wells (EPA, 2006b)
  - New emission factor for onshore conventional and unconventional valves = existing emission factor for offshore valves = 0.0001 lb CH_4/Mcf

NSPS implementation significantly reduces life cycle GHG emissions from GTL fuels



- GTL diesel GHG emissions are reduced by 5.8%
- GTL gasoline GHG emissions are reduced by 13.9%
- Expected values are below baseline, but uncertainty still straddles baseline
- NSPS reduces upstream CH_4 losses from 1.26% to 0.83% (CH_4 emissions per unit of delivered natural gas)

Conclusions and Recommendations

- Life cycle GHG emissions from GTL fuels are competitive with those from petroleum fuels
- Combustion of produced fuel is greatest contributor to life cycle GHG emissions, but does not present opportunities for GHG reductions
- Tighter regulations on natural gas extraction can make GHG emissions from GTL fuels lower than those from petroleum fuels, but there is uncertainty
- Co-product management contributes to uncertainty, with greatest uncertainty when gasoline is the functional unit

Full report available at www.netl.doe.gov/energy-analyses (Analysis of Natural Gas-to-Liquid Transportation Fuels via Fischer-Tropsch, September 2013)

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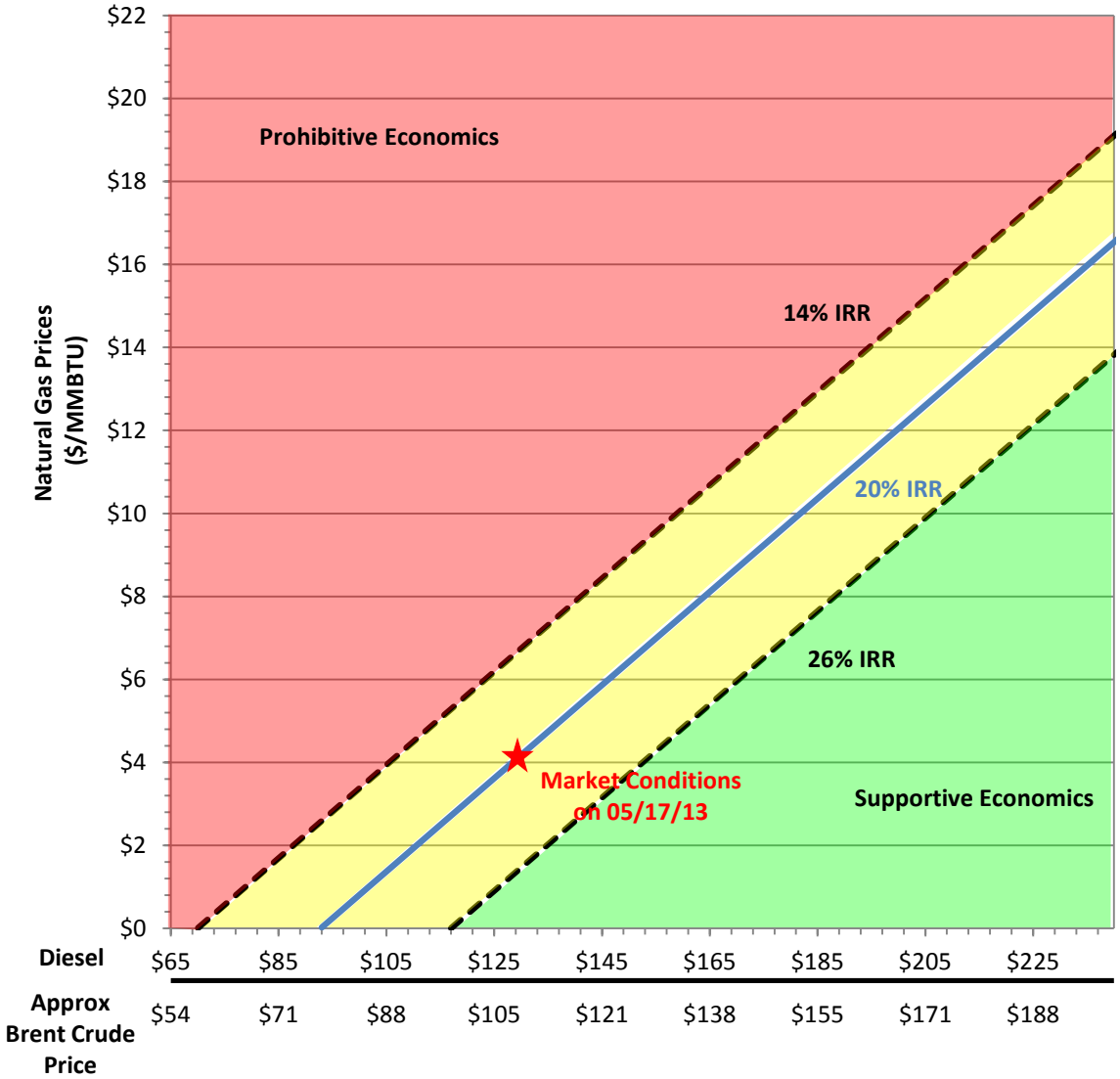
Supporting Material: Cost Parameters

Parameter	Value
Taxes	
Income Tax Rate	38% (Effective 34% Federal, 6% State)
Capital Depreciation	20 years, 150% declining balance
Investment Tax Credit	0%
Tax Holiday	0 years
Analysis Time Periods	
Capital Expenditure Period	5 Years
Operational Period	30 years
Economic Analysis Period (used for IRROE)	35 Years (capital expenditure period plus operational period)
Treatment of Capital Costs	
Capital Cost Escalation During Capital Expenditure Period (nominal annual rate)	3.6%[1]
Distribution of Total Overnight Capital over the Capital Expenditure Period (before escalation)	5-Year Period: 10%, 30%, 25%, 20%, 15%
Working Capital	zero for all parameters
% of Total Overnight Capital that is Depreciated	100% (this assumption introduces a very small error even if a substantial amount of TOC is actually non-depreciable)
Escalation of Operating Revenues and Costs	
RSP, O&M, COE, and Fuel Costs (nominal annual rate)	3.0%
Financing Structure for Commercial Fuels Projects[3]	
Debt % of Total	50.0%
Debt interest rate, %	8.0% (LIBOR + 4.5%)
Equity Percent of Total	50.0%
Required return on equity, %	20.0%
Capital Charge Factor, CCF	0.236
TASC/TOC	1.181

Supporting Material: Cost Analysis



- Envelope of economic viability depends on natural gas and diesel prices as well as returns expected by investors
- Window of viability widens if capital costs can be reduced by leveraging technology development or creating long-term contracts for natural gas