North American Midstream Infrastructure Through 2035 – A Secure Energy Future

Prepared for the INGAA Foundation

June 28, 2011

Kevin R. Petak
Vice President
ICF International
703-218-2753
kpetak@icfi.com

David Fritsch
Senior Associate
ICF International
703-218-2740
dfritsch@icfi.com

E. Harry Vidas
Vice President
ICF International
703-218-2745
evidas@icfi.com

Disclaimer

This presentation presents views of ICF International. The presentation includes forward-looking statements and projections. ICF has made every reasonable effort to ensure that the information and assumptions on which these statements and projections are based are current, reasonable, and complete. However, a variety of factors could cause actual market results to differ materially from the projections, anticipated results or other expectations expressed in this presentation.

Contents

Study Overview

Study Objectives

- The objective of this study is to estimate future midstream infrastructure requirements, including natural gas, natural gas liquids, and oil infrastructure through 2035.
  - Study is based on a detailed supply/demand outlook for North American energy markets.
  - In the context of this analysis, the midstream includes natural gas gathering, processing, pipeline transportation and storage, and LNG import and export facilities.
  - Bracketing results around a reference case are considered.
  - Provides an update to INGAA Foundation's 2009 infrastructure study.
  - Robust growth in gas production has resulted in more midstream infrastructure development from 2008 through 2010 than the 2009 study had estimated.
  - The study adds NGL and oil infrastructure requirements that were not explicitly considered in the 2009 analysis.
- So, this study has been initiated to more fully consider recent trends and to more fully investigate the impacts of those trends, particularly robust shale gas development, on future infrastructure requirements.

Scope of Work

- This study provides natural gas and liquids infrastructure requirements
  - Provides Regional Supply/Demand Projections Considering Most Current Trends in Gas Markets
  - Provides Well Completion and Production Information for Major Supply Areas
  - Provides Capital Requirements for New Gas Plants and Associated Pipeline Connection Requirements by Region
  - Provides Gas-fired Generation, Gas Use, and Estimates for Number of Gas Power Plants and the Associated Pipeline Connection Requirements by Region
  - Reviews Underground Natural Gas Storage Requirements and Associated Pipeline Connection Requirements by Region
  - Completes Bracketing Case Results on Natural Gas Infrastructure Needs
  - Completes an analysis of NGL and Oil infrastructure Requirements using Production and Well information by Major Supply Area

Summary of Deliverables

- Results of a Reference Case projection of infrastructure requirements and their associated expenditures during the next 25 years
- Projected midstream infrastructure needs from the Reference Case
  - Region requirements for pipelines, storage, gathering, processing, and LNG Facilities
  - Quantification of expenditures and relevant expansion statistics
- Bracketing of infrastructure needs
- Summary PowerPoint Presentation that highlights results of analysis
- Executive Summary style report discussing results

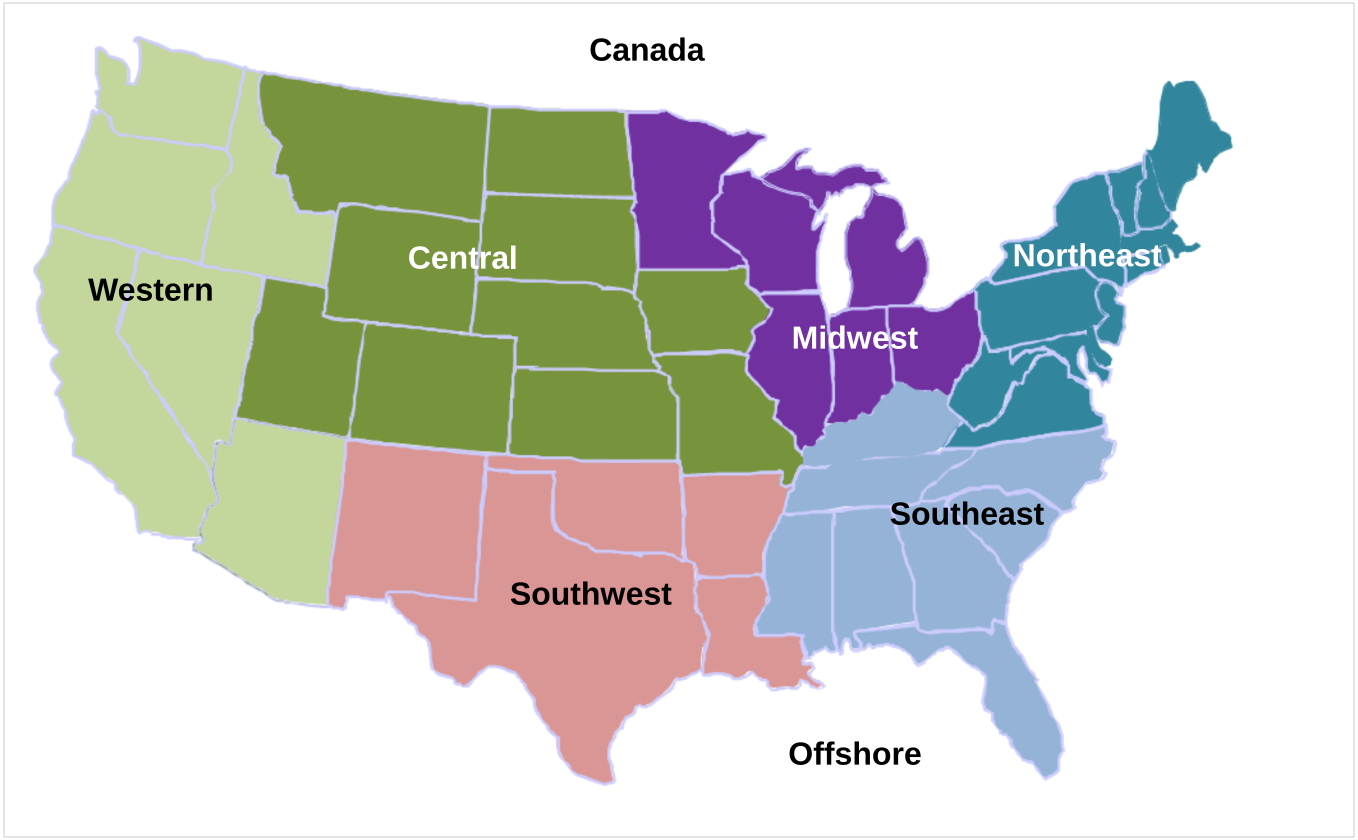
Study Methodology

- Study relies on ICF’s April 2011 Reference Case for projections.
- The case projects market changes over time, more specifically, the amount of gas used by sector and region at gas prices that are computed by ICF’s Gas Market Model (GMM).
  - Changes in power generation gas use are computed, and an estimate for the number of new gas power plants is provided assuming a prototypical plant.
- The case also projects supply development and production growth that occurs at the solved market prices.
  - Production projections from the model are cross-checked with a vintage production analysis that considers number of wells, well recoveries, and representative decline curves to estimate production trends for about 50 different supply areas.
- The modeling also projects the amount of gas transmission capacity that is likely to be developed based on the market and supply dynamics from the GMM.

Study Methodology (continued)

- From incremental gas production and well completions, the incremental amounts of gathering line and processing capacity have been computed.
  - Gathering line estimates have been derived based on the number of wells and considering the first-month and average production from the wells assuming an average feet of line per well.
  - Processing plant capacity is computed based on the average production of wells and the characteristics of the production stream.
    - Number of processing plants is estimated by assuming average plant sizes that are area dependent.
    - The number of laterals needed and the associated pipeline mileage is derived for processing plants.
- Number of laterals and associated pipeline mileage is derived for power plants.
- Horsepower requirements are derived separately for each transmission project.
- Storage capacity is added based on market growth and seasonal price spreads.
- Unit cost measures have been derived for pipeline and gathering ($/inch-mile), horsepower ($/HP), processing capacity ($/MMcfd), and storage ($/Bcf) based on historical expenditure information provided by various sources.
- Unit cost measures are applied to estimate total expenditures for midstream infrastructure.

Study Regions



EIA's pipeline regions with regions added for Offshore Gulf of Mexico, Canada, and Arctic (Alaska and NWT). This is the same regional format as used in the INGAA 2009 Infrastructure Study.

Categories of Pipeline Characterized in Study

- Natural Gas Mainline Pipe
  - New Line – New Greenfield
  - New Line - Extensions
  - Expansion - Looping & Compression
  - Expansion - Compression Only
- Lateral Pipe
  - Power Laterals
  - Storage Field Laterals
  - Gas Plant Laterals
  - Other Laterals (Delivery or receipt area)
- Gathering Pipe
- Natural Gas Liquids (NGL) Mainline Pipe
- Oil Mainline Pipe

Summary of Reference Case Trends

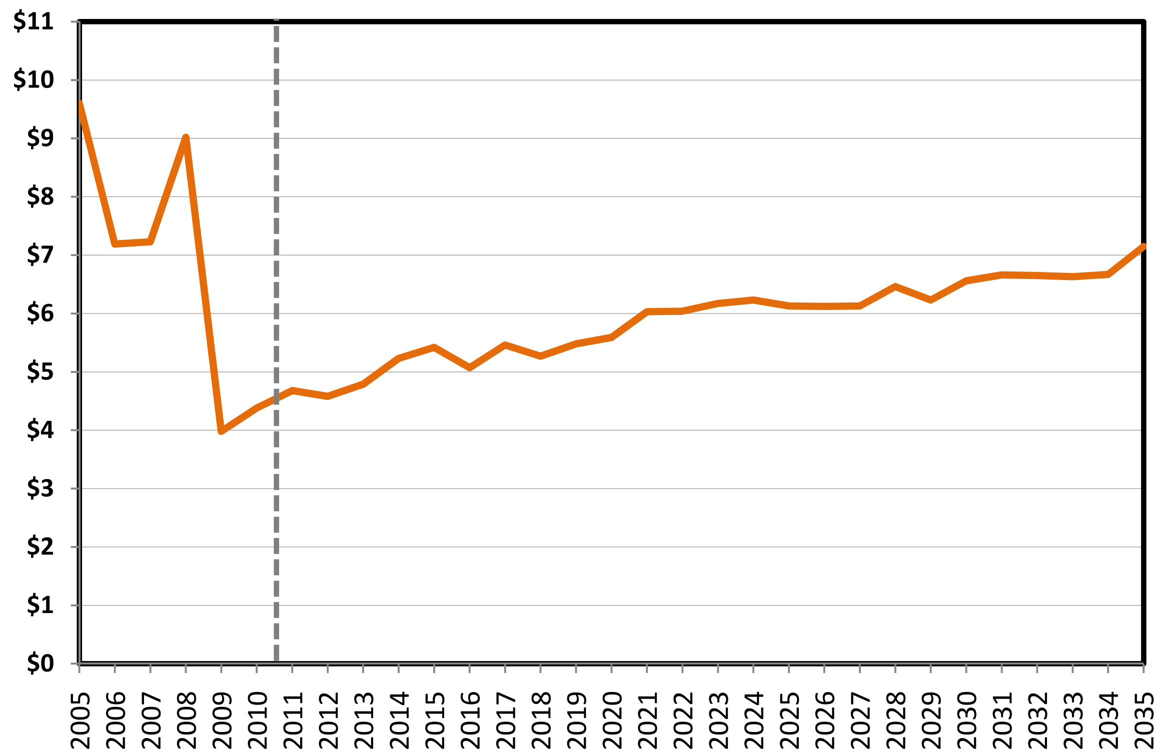
Reference Case Overview

- The ICF April 2011 Reference Case applied as a starting point for this study generally depicts a world in which:
  - Economic growth in the U.S. continues at a rate of 2.8% per year, consistent with the average observed during the past 20 years.
    - U.S. electric load grows at 1.3% per year.
  - Thus, significant growth in gas use occurs, particularly in the power sector where incremental gas-fired generation is required to satisfy the electric load growth.
  - Some other gas uses also increase. For example in Canada, incremental gas is needed for oil sands development in Western Canada and for coal-to-gas plant conversions in Ontario.
  - Continued robust growth in shale gas development makes it possible for the growing market needs to be satisfied.

Projected Natural Gas Price in Reference Case

- The Reference Case projects real gas prices that rise from $4 to between $6 and $7 per MMBtu.
- This price level is sufficiently high to encourage significant gas supply development, but not so high as to significantly limit market growth.
- The gas price is not low enough to motivate significant amounts of gas for coal substitution in the power sector beyond the amounts that are motivated by environmental policies assumed in the projection.

Average Annual Natural Gas Prices at Henry Hub (2010$/MMBtu)



ICF Model Reference Case Compared to the Recently Completed EIA-AEO Reference Case

		ICF Model Reference Case		AEO 2011 Reference Case	
	2010	2020	2035	2020	2035
US Natural Gas Production (Tcf)	21.3	27.5	33.1	23.4	26.3
Net Imports (Canada + Mexico + LNG)	2.7	1.9	0.9	1.9	0.2
US Natural Gas Supply (Tcf)	24.0	29.4	34.0	25.4	26.6
Natural Gas Consumption (Tcf)	23.8	28.9	33.8	25.3	26.6
Natural Gas Power Sector (Tcf)	7.4	10.8	14.8	6.8	7.9
Henry Hub Price (2010$/MMbtu)	$4.38	$5.59	$7.15	$5.15	$7.21

- The ICF case projects significant market growth for natural gas while EIA AEO 2011 projects slower market growth.

ICF's North American Natural Gas Resource Base (Tcf)

ICF INTERNATIONAL

- In total, the U.S. and Canada have almost 4,000 Tcf of resource that can be economically recovered using current exploration and production (E&P) technologies.
  - At current levels of consumption, this is enough resource for about 140 years.
- Over 50% of the assumed resource is shale gas.
- EIA-AEO 2011 Resource Base is 2,552 Tcf for the U.S. compared to ICF's 3,105 Tcf.

U.S. and Canada Natural Gas Resource Base

(Tcf of Economically Recoverable Resource, Assuming Current E&P Technologies)

	Proven Reserves	Unproved Plus Discovered Undeveloped	Total Remaining Resource	Shale Resource[1]
Alaska	7.7	153.6	161.3	0.0
West Coast Onshore	2.3	24.6	27.0	0.3
Rockies & Great Basin	66.7	388.3	454.9	37.9
West Texas	27.6	47.7	75.3	17.5
Gulf Coast Onshore	70.1	684.7	754.8	476.9
Mid-continent	37.0	205.0	241.9	133.9
Eastern Interior [2,3]	18.6	1053.7	1072.3	986.1
Gulf of Mexico	14.0	238.6	252.5	0.0
U.S. Atlantic Offshore	0.0	32.8	32.8	0.0
U.S. Pacific Offshore	0.8	31.7	32.5	0.0
WCSB	60.4	664.0	724.4	508.8
Arctic Canada	0.4	45.0	45.4	0.0
Eastern Canada Onshore	0.4	15.9	16.3	10.3
Eastern Canada Offshore	0.5	71.8	72.3	0.0
Western British Columbia	0.0	10.9	10.9	0.0
US Total	**244.7**	**2,860.6**	**3,105.3**	**1,652.5**
Canada Total	**61.3**	**807.6**	**868.8**	**519.1**
US and Canada Total	**306.0**	**3,668.1**	**3,974.1**	**2,171.6**

1. Shale Resource is a subset of Total Remaining Resource
2. Eastern Interior includes Marcellus, Huron, Utica, and Antrim shale.
3. Reference case assumes drilling levels are constant at today's level over time, reflecting restricted access to the full resource development.

Reference Case Assumptions

- U.S. economy grows at 2.8% per year.
- Oil prices in the U.S. average about $80 per barrel in real terms.
- Demographic trends consistent with trends during past 20 years. U.S. population growth averages about 1% per year.
- Electric load growth averages 1.3% per year.
- ICF's Base Case reflects one plausible outcome of EPA's proposals for major rules that have been drawing the attention of the power industry – these include the Clean Air Transport Rule (for SO_2 and NO_X), air toxics (including mercury), water intake structures and coal combustion residuals (CCR, or ash). It also includes a charge starting in 2018 on CO_2 reflecting the continuing lack of consensus in Congress and the time it may take for direct regulation of CO_2 to be implemented. The case generally leads to retirement and replacement of some coal generating capacity with gas generating capacity.
- Power plant mix: renewables up to meet state RPS's, coal generation down, and other forms of non-gas generation are slightly down. Gas generation grows to fill the gap between electric load and the total amount of generation from other types of generation.
- Adoption of DSM programs and conservation and efficiency trends continue, consistent with recent history.
- CNG vehicles are assumed to be limited to commercial fleets and busses.

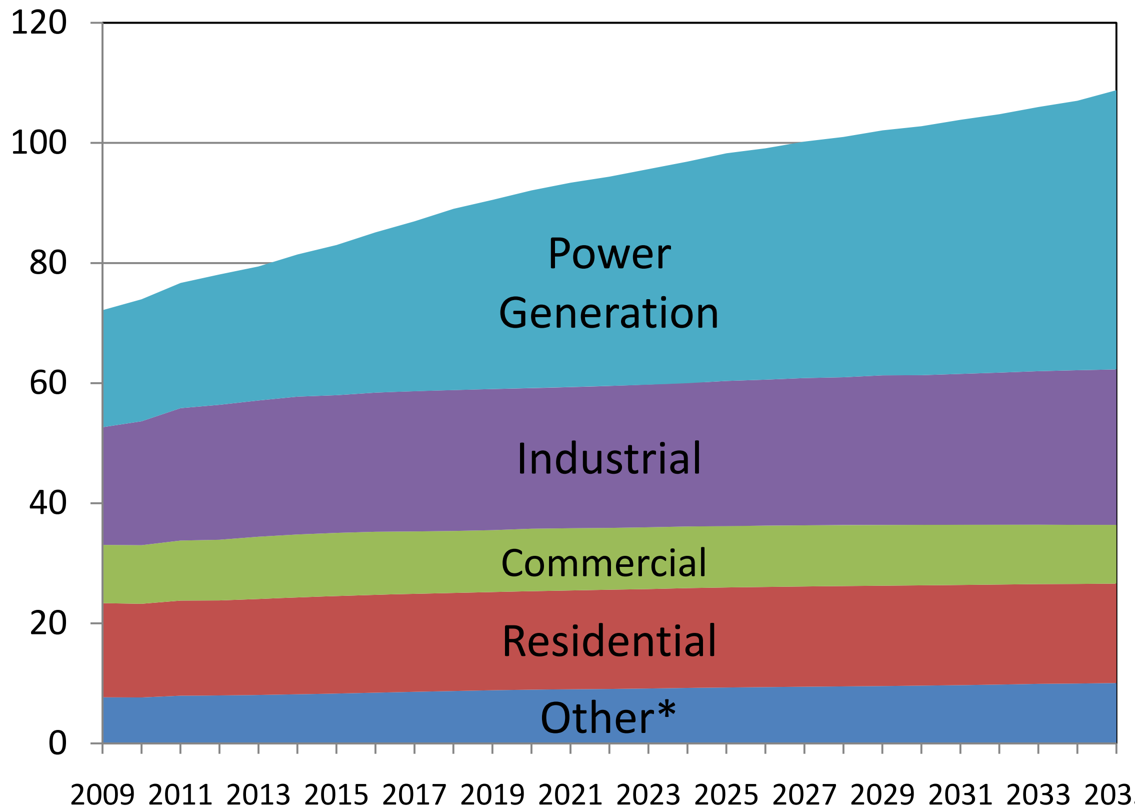
Reference Case Assumptions (continued)

- Weather assumed to be consistent with past 30 year averages.
- Gas supply development is permitted to continue at recently observed activity levels – no significant restrictions on permitting and fracturing beyond current restrictions.
- No significant hurricane disruptions to natural gas supply (20-year average).
- No Arctic projects (specifically no Alaska and Mackenzie Valley gas pipelines).
- Net LNG exports occur only at the Kitimat facility (no net LNG exports from elsewhere in the U.S. and Canada).
- ***Near-term midstream infrastructure development assumed per project announcements. Unplanned projects included when market signals need of capacity, and there are no significant delays in permitting and construction.***

Natural Gas Consumption

- Total gas consumption is projected to increase at a rate of 1.6% per year
  - By 2035, total gas consumption in the U.S. and Canada is projected to approach an average of 110 Bcf per day.
- About 75% of the incremental demand growth is in the power sector.
  - Power sector gas consumption is projected to more than double by 2035.
- In aggregate, very little demand growth occurs in the other sectors.

U.S. and Canadian Gas Consumption (Average Annual Bcfd)



* Other includes lease, plant, and pipeline fuel gas use.

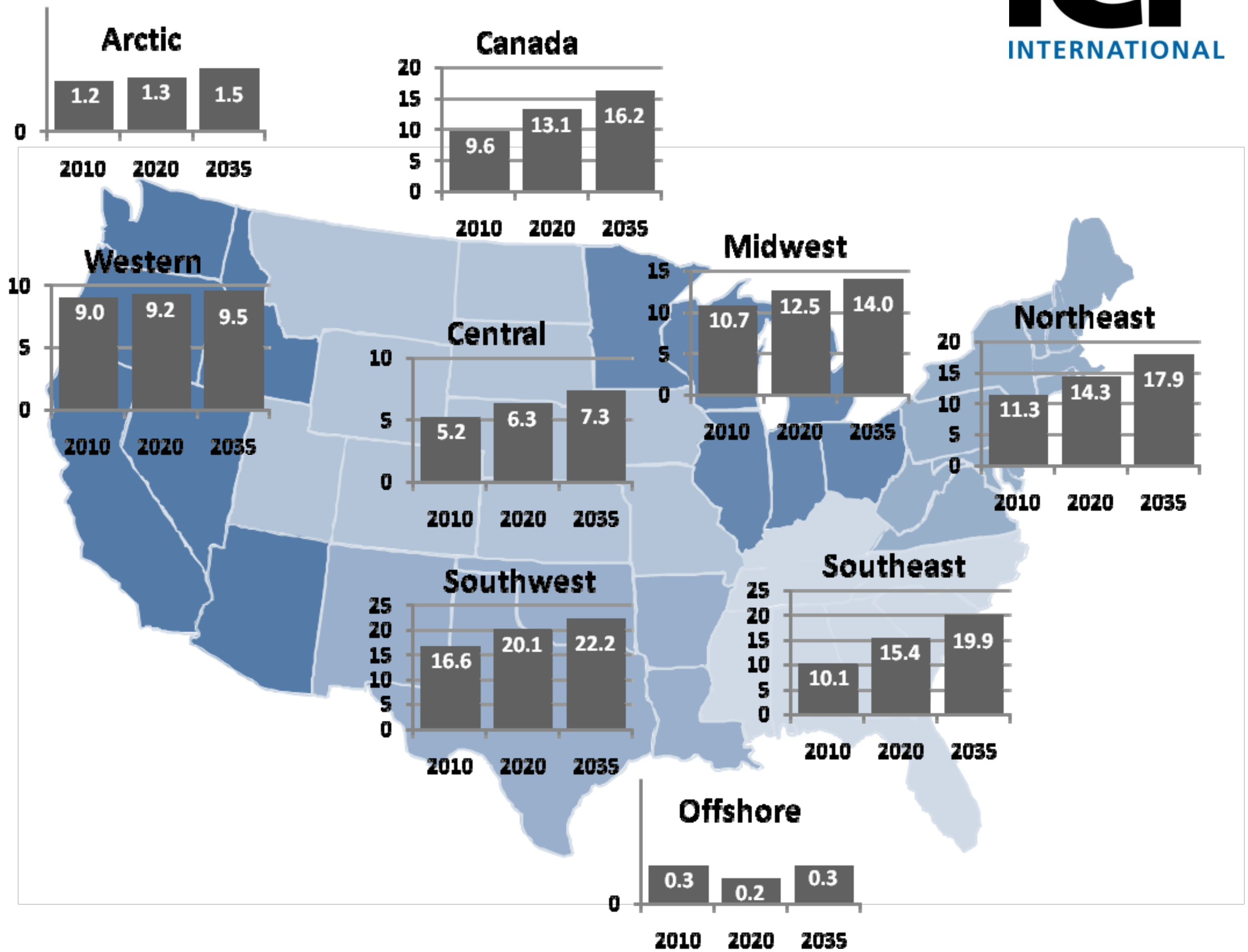
Regional Gas Consumption

- Gas consumption grows by 12.7 Tcf (or 35 Bcfd) by 2035.
- The regions with the greatest increases in gas demand are the Southeast, Northeast, Southwest, and Canada.
- Demand increases are primarily due to power generation growth, but gas demand in extracting oil from oil sands is a significant share of Canada's growth.

	Trillion Cubic Feet					Billion Cubic Feet per day				
	2010	2020	2035	2011 to 2020	2011 to 2035	2010	2020	2035	2011 to 2020	2011 to 2035
Northeast	4.1	5.2	6.5	1.1	2.4	11.3	14.3	17.9	3.0	6.6
Southeast	3.7	5.6	7.3	1.9	3.6	10.1	15.4	19.9	5.3	9.9
Midwest	3.9	4.6	5.1	0.7	1.2	10.7	12.5	14.0	1.8	3.3
Central	1.9	2.3	2.7	0.4	0.8	5.2	6.3	7.3	1.1	2.1
Southwest	6.1	7.3	8.1	1.2	2.0	16.6	20.1	22.2	3.4	5.6
Western	3.3	3.4	3.5	0.1	0.2	9.0	9.2	9.5	0.2	0.6
Offshore	0.1	0.1	0.1	0.0	0.0	0.3	0.2	0.3	0.0	0.0
Arctic	0.4	0.5	0.6	0.0	0.1	1.2	1.3	1.5	0.1	0.3
Canada	3.5	4.8	5.9	1.2	2.4	9.6	13.1	16.2	3.4	6.5
US & Canada	**27.0**	**33.7**	**39.7**	**6.7**	**12.7**	**74.0**	**92.3**	**108.8**	**18.4**	**34.8**

Regional Natural Gas Demand (Bcfd)

- U.S. Demand increases are primarily due to power generation growth.
- Canada 's gas demand growth includes gas used in extracting oil from oil sands.



U.S. Power Generation Capacity (GW)

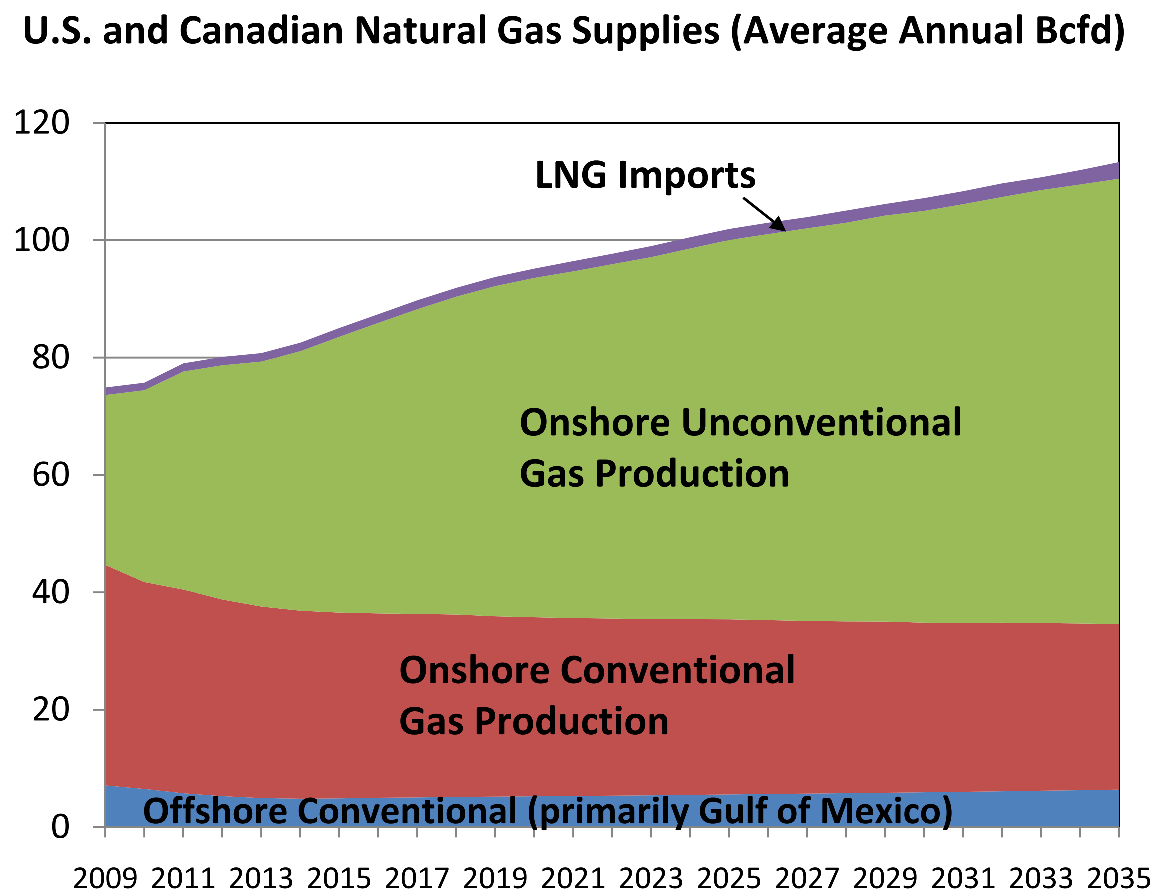
Net Summer Dependable Capacity After Retirements

	2010	2015	2020	2025	2030	2035
Natural Gas	450	463	540	598	647	689
Coal	316	281	260	261	260	270
Nuclear	102	105	105	105	104	90
Hydro	97	97	96	96	96	96
Other	49	102	117	124	171	210
Total	**1014**	**1048**	**1118**	**1184**	**1278**	**1355**

- Gas generating capacity is net up by about 240 GW over the next 25 years.
- Coal capacity net down by over 45 GW.
- Nuclear capacity is down by 12 GW.
- Other types of capacity net up by about 160 GW.

Natural Gas Supply

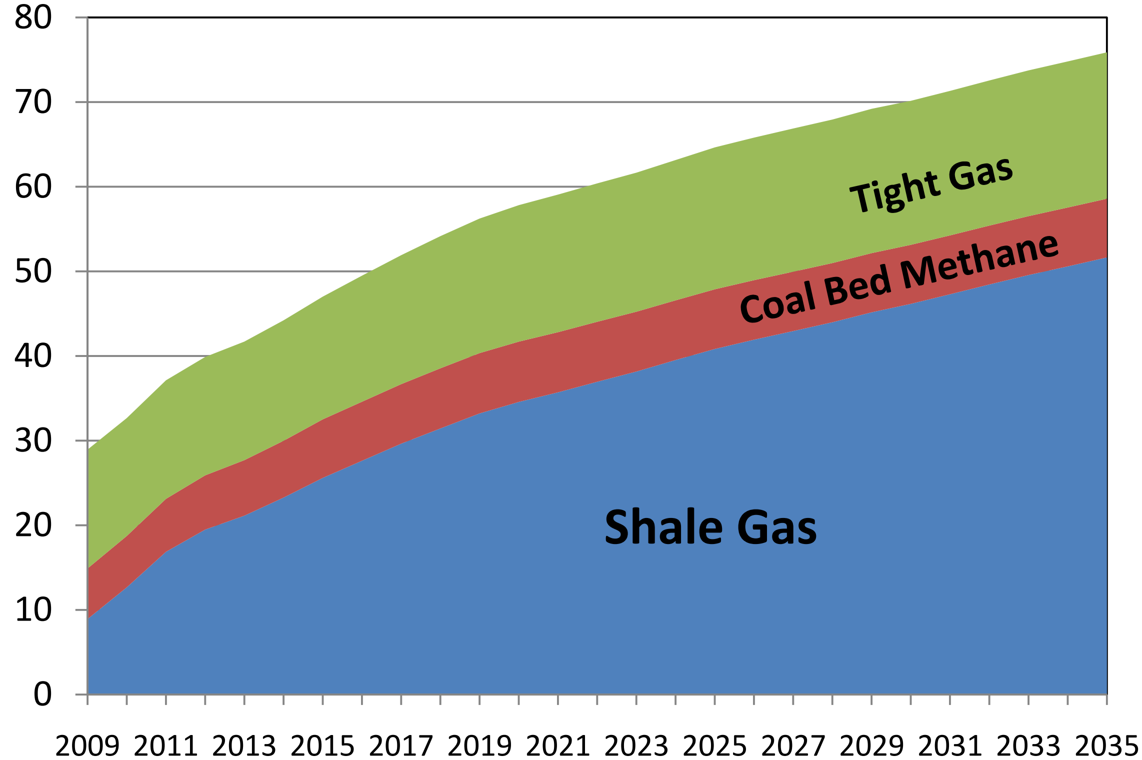
- Onshore conventional and offshore gas production continues to decline, while unconventional production grows robustly.
- Unconventional production comprises two-thirds of the total supply by 2035.



Unconventional Gas Production

- Unconventional gas production increases by over 40 Bcfd between 2010 and 2035.
- Over 90% of the increase in unconventional gas production is due to increases in shale gas.

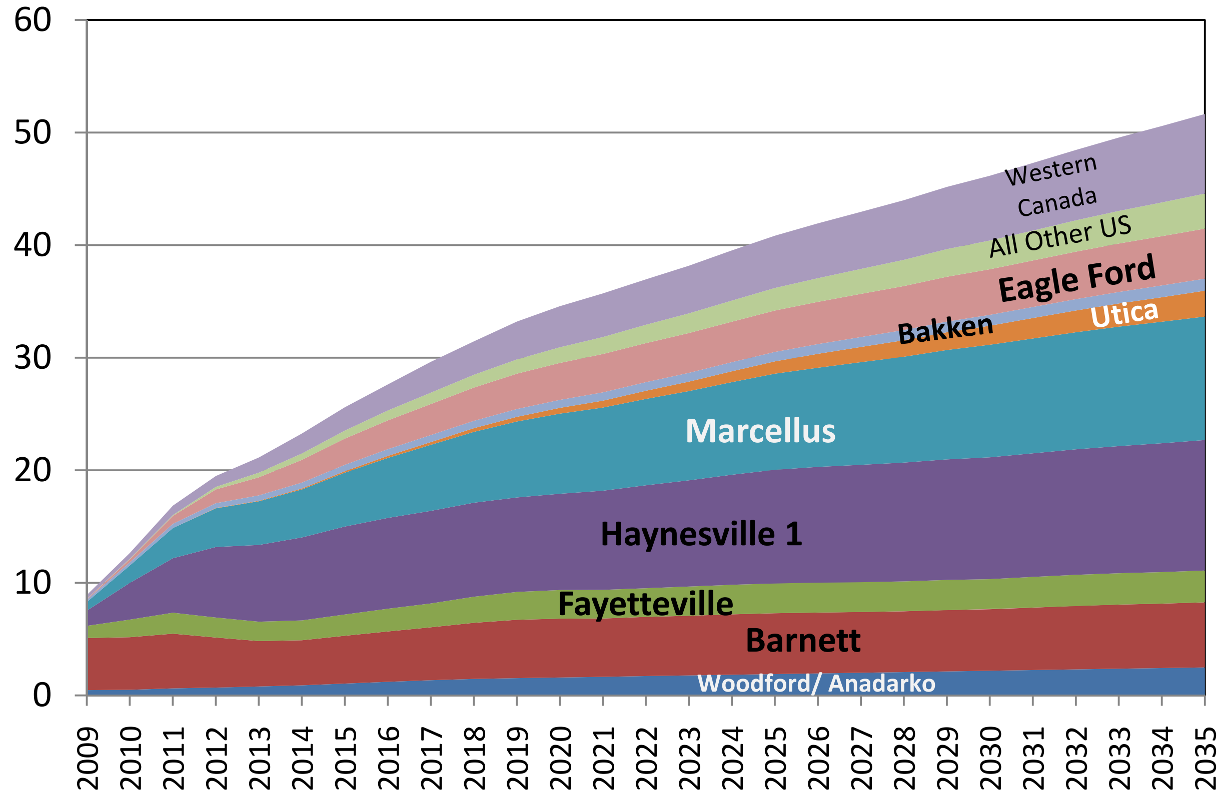
U.S. and Canadian Unconventional Gas Production (Average Annual Bcfd)



Shale Gas Production

- The shale gas plays are among the fastest growing production areas worldwide.
- Total U.S. and Canada shale gas production is expected to increase from about 13 Bcfd in 2010 to 52 Bcfd by 2035.
- Barnett has been under development for 10 years, while development of Eagle Ford began in 2009.
- The strength of the shale plays was evident during the recession, when development continued despite relatively low natural gas prices.

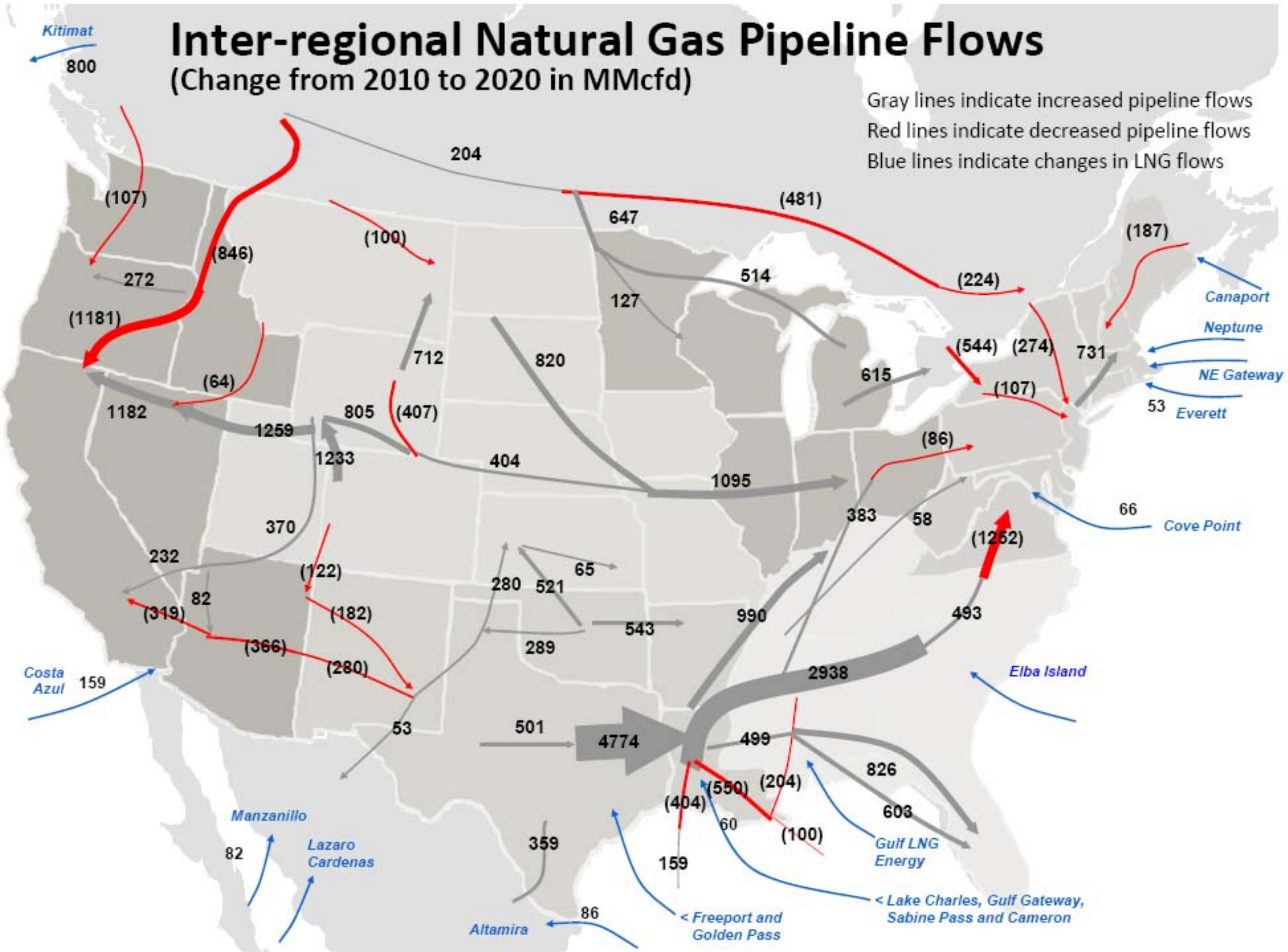
U.S. and Canadian Shale Gas Production (Average Annual Bcfd)



[1] Haynesville values shown here include production from other shales in the vicinity, e.g., the Bossier Shale.

Projected Changes in Gas Flows (2010 – 2020)

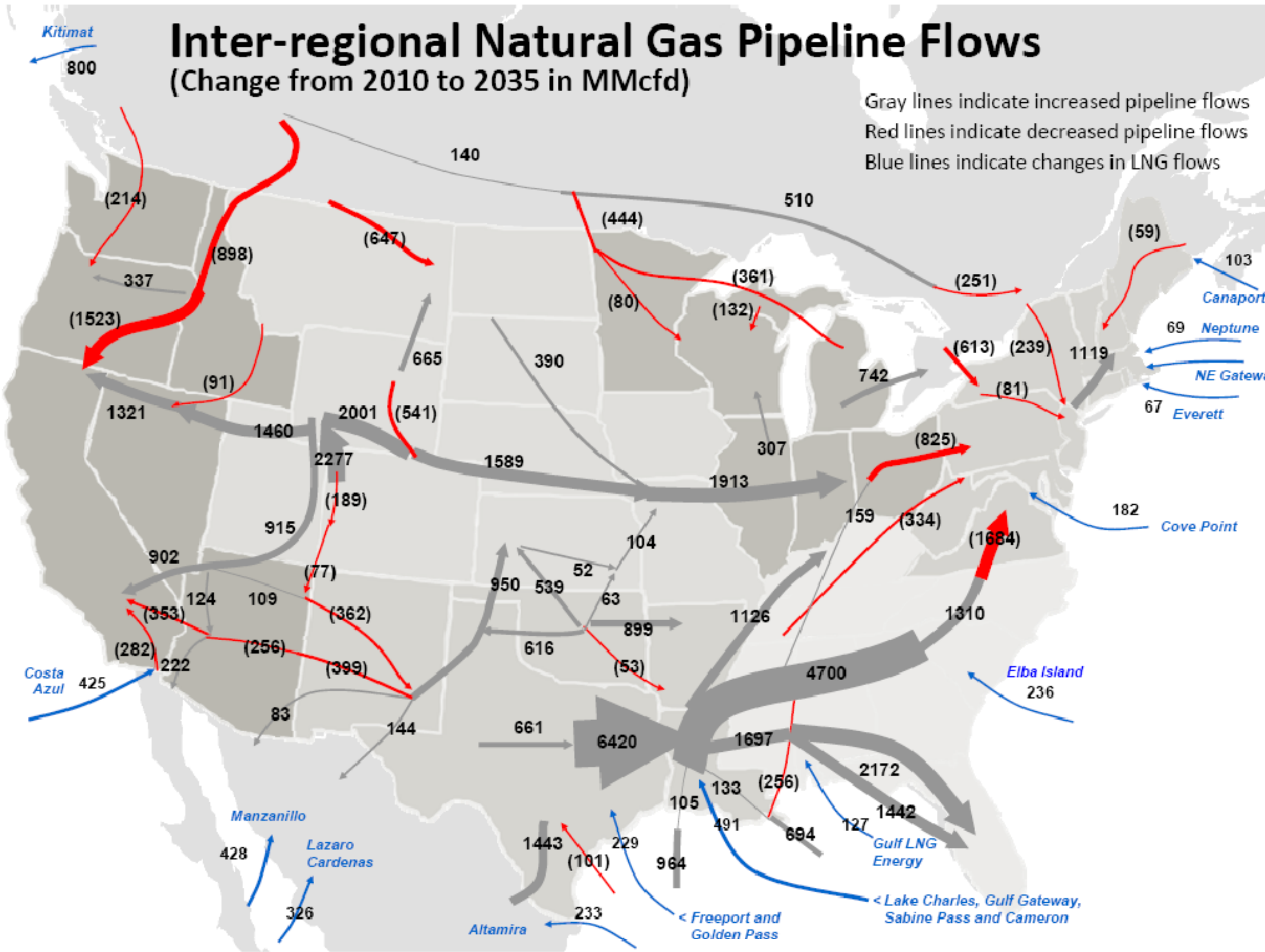
- Increases in flows from the Gulf Coast to the Southeast are due to increases in Mid-continent shale gas production.
- REX Pipeline enables increasing flow from the Rocky Mountains eastward.
- Marcellus gas production growth displaces gas flows into the Northeast U.S. (Shifts within the Northeast are not depicted on this interregional flow map).
- Declining conventional production in Alberta and increasing gas consumption for oil sands development causes flows from Western Canada to decline.



Note that this map does not generally show intra-regional pipeline expansions such as those that occur in the Marcellus shale production area.

Projected Changes in Gas Flows (2010 – 2035)

- Substantial increases in flows continue to occur out of the Mid-continent shales and the Rocky Mountain producing basins.
- Marcellus gas production growth continues to displace gas flows into the Northeast U.S. (Shifts within the Northeast are not depicted on this interregional flow map).
- Flows on TCPL to eastern markets recover slightly, but remain down in the longer term.



Note that this map does not show generally intra-regional pipeline expansions such as those that occur within the Marcellus shale production area.

Summary of Key Market Trends in the Reference Case (Tcf)

U.S. and Canada	2010	2020	2035	% Change 2010 to 2020	% Change 2010 to 2035
Gas Consumption	27.0	33.6	39.7	24%	47%
Gas Use in Power Generation	7.4	12.0	17.0	62%	129%
Gas Production	27.2	34.2	40.3	26%	48%
Conventional Onshore Gas Production	12.9	11.1	10.3	-14%	-20%
Unconventional Onshore Gas Production	11.9	21.1	27.7	77%	132%
Offshore Production	2.4	1.9	2.3	-21%	-2%
Shale Gas Production	4.6	12.6	18.9	274%	308%
Net LNG Imports	0.5	0.6	1.0	20%	120%
Net Exports to Mexico	0.3	0.5	1.1	66%	245%

Variables that Impact Projected Market Growth

ICF INTERNATIONAL

- While the reference case makes reasonable "middle-of-the-road" assumptions for each variable, there are alternate assumptions that could affect the projection for market growth.
- Some variables are potential "Big Market Movers", for which a change in assumption would create significantly more or less incremental market growth.
- Other variables are "Smaller Market Movers", which would have less (but still significant) impacts on incremental growth.

	Big Market Movers	Smaller Market Movers
More Market Growth	• NG passenger vehicles • NG trucks • Increased economic growth • Increased electricity demand growth • Increased LNG exports • Reduced coal-fired capacity • Gas-to-liquids • Arctic gas • Reduced nuclear capacity	• Oil-to-gas conversions • Increased industrial production • Increased population growth • Increased Alberta oil sands production • Increased conversions of industrial boilers • Increased R/C customer growth • Decreased R/C efficiency gains • Higher oil prices • Natural gas hydrates
Less Market Growth	• Limits on hydraulic fracturing • Reduced economic growth • Reduced electricity demand growth • Increased coal-fired capacity • Increased nuclear capacity	• Modest Appalachia drilling constraints • Increased shale production costs • Rockies access restrictions • GOM offshore access restrictions • Decreased industrial production • Decreased population growth • Decreased R/C customer growth • Increased R/C efficiency gains • Lower oil prices

Base Case

Big Market Movers

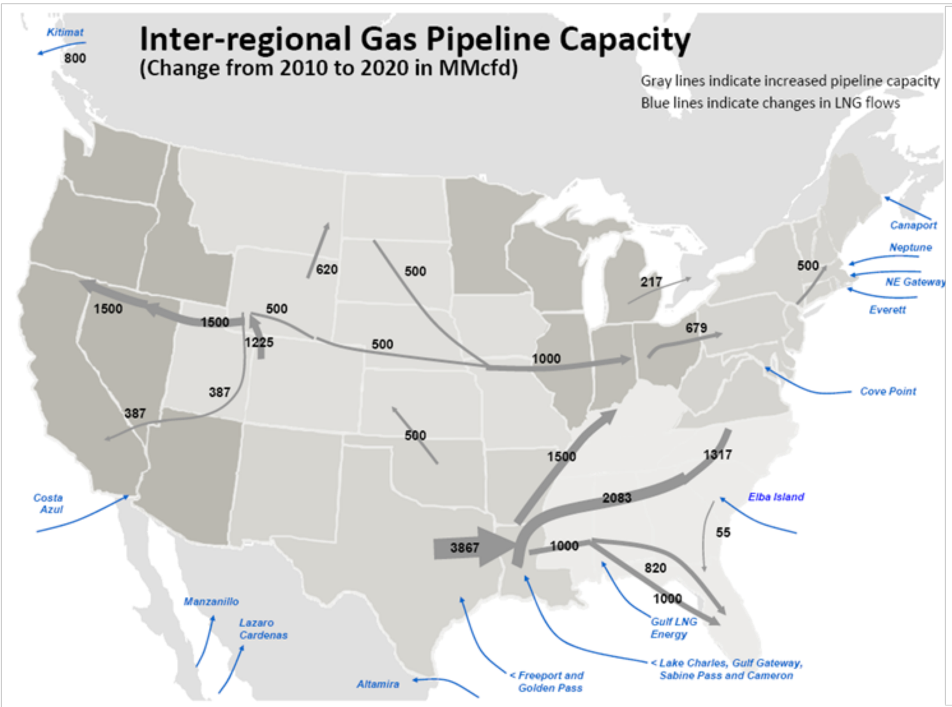
- **Natural gas passenger vehicles** – a potentially huge new market for natural gas.
- **Natural gas trucks** – smaller than the passenger vehicle market, but still significant.
- **Limits on hydraulic fracturing** – new regulations placing limitations on hydraulic fracturing could have significant negative impact on U.S. gas production.
- **Economic growth** – increased or decreased GDP growth in the economy would have wide ranging impacts on gas markets.
- **Electricity demand growth** – the power sector is the source of most of the projected incremental demand growth, so this is a key variable.
- **LNG exports** – growing U.S. shale gas production may make LNG exports an attractive option for both producers and overseas consumers.
- **Coal-fired capacity** – changes in environmental policies could result in increased or reduced capacity.
- **Nuclear capacity** – if units are not retired or retired early and if new units are built.
- **Gas-to-liquids** – another potential demand market for growing natural gas production.
- **Arctic gas** – developing Alaska and Mackenzie Delta gas could add significant incremental supplies to the North American market.

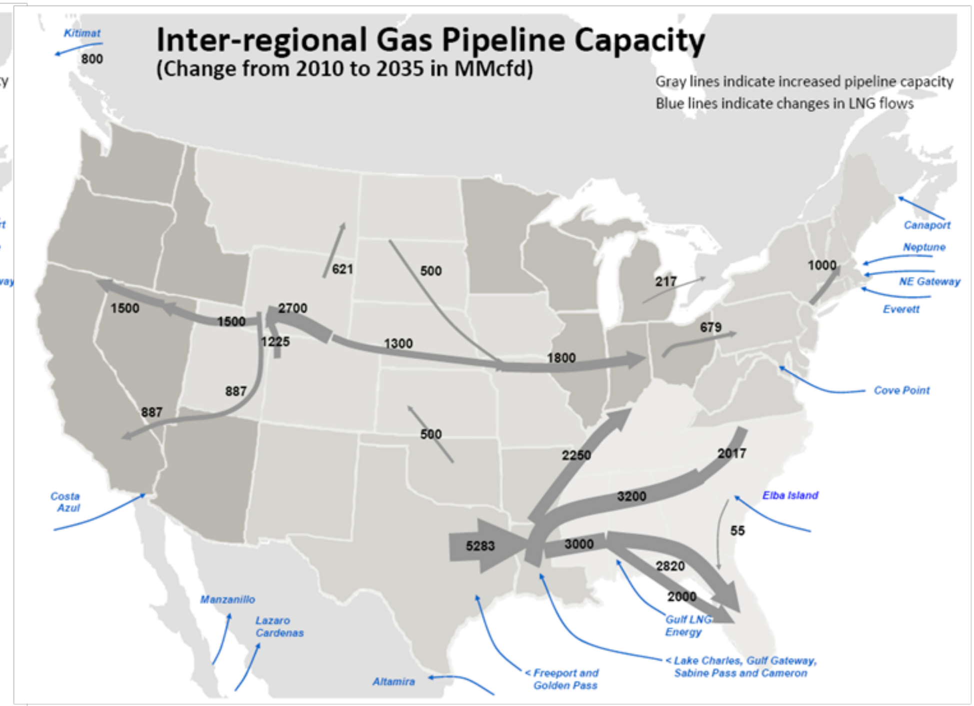
Smaller Market Movers

- **Oil-to-gas conversions** – high fuel oil prices may encourage additional conversions by residential and commercial consumers to convert heaters, boilers, and other equipment from oil to natural gas.
- **Industrial production** – compared to GDP growth, changes in industrial production growth would have a smaller, but still significant, impact on gas markets.
- **Population growth** - while not necessarily a major driver of market growth, the population growth rate may also impact economic activity. Regional shifts of population and immigration policy could also introduce uncertainty on gas market growth.
- **Increased conversions of industrial boilers** – an increase in the number of coal-fired boilers that convert to natural gas would have an impact on this subset of total industrial gas demand.
- **Residential/Commercial customer growth** – changes in the number of R/C customer additions would affect demand growth, but are somewhat offset by end-use efficiency gains.
- **Residential/Commercial end-use efficiency** – per customer gas use has been declining, but the rate of decline could be faster or slower in the future.
- **Alberta oil sands** – producing oil from the oil sands requires significant quantities of natural gas, so accelerating production growth would increase gas demand.
- **Increased shale production costs** – even if drilling activity is not expressly limited, new regulations that increase costs of shale drilling could limit market growth.
- **Modest Appalachia drilling constraints** – constraints on drilling activity in Appalachia, such as a limit on new permits, would limit production growth from Marcellus and Utica shale.
- **Rockies access restrictions** – additional access restriction in the Rockies would hamper supply development in this key growth region.
- **Gulf of Mexico offshore access restrictions** – while offshore production is not expected to grow, production could decline significantly if deep water drilling does not return to pre-2010 levels or is impaired by regulations.
- **Natural gas hydrates** – while a potentially huge supply source, gas hydrate production is not currently technically or commercially competitive.
- **Oil Prices** – higher or lower oil prices are expected to have relatively little impact on gas market growth.

Midstream Infrastructure Requirements for Natural Gas

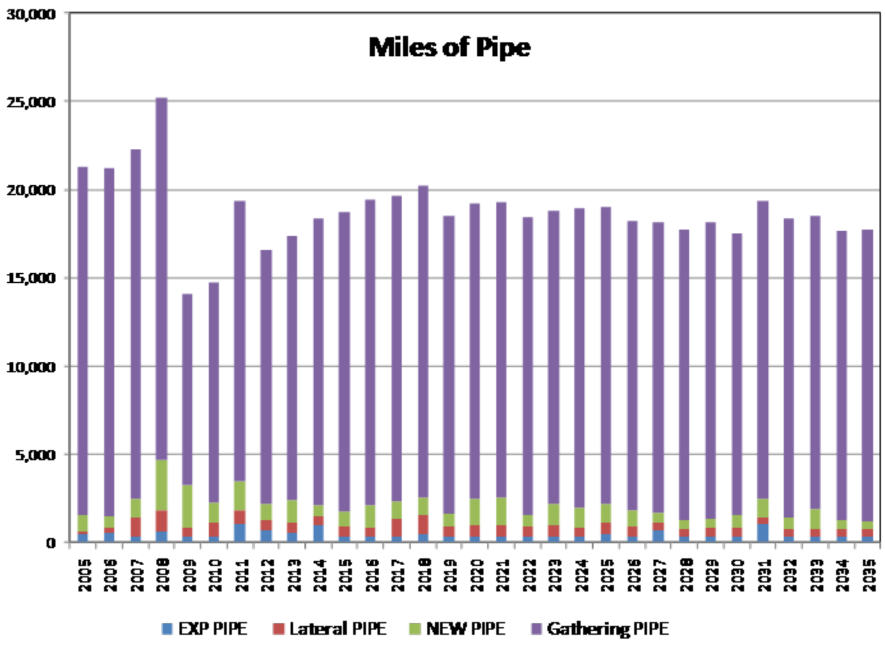
Interregional Pipeline Expansions

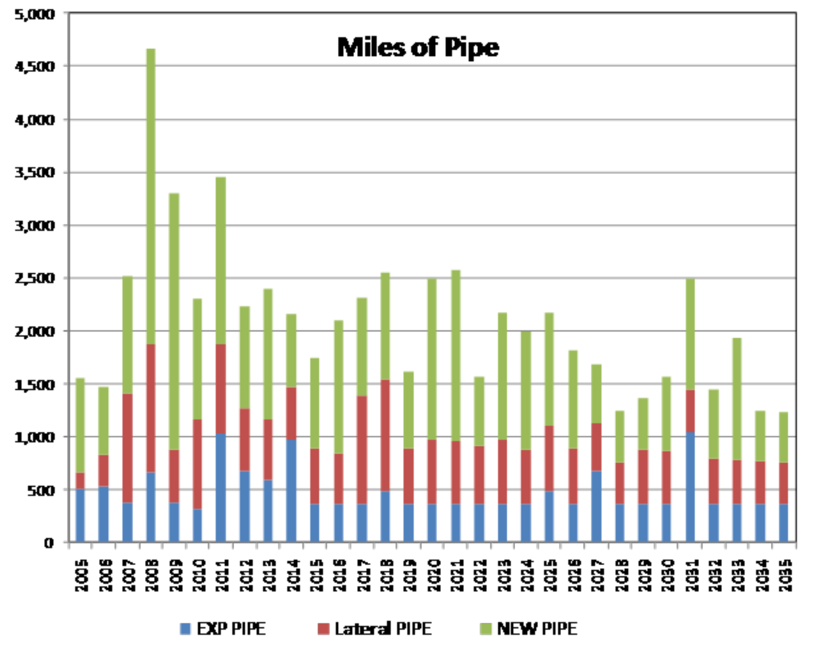




- Roughly 29 Bcfd of incremental pipeline capacity is built from 2011 to 2020 and from 2021 to 2035 an additional 14 Bcfd is built. A total of 43 Bcfd of incremental pipeline is needed to accommodate increasing gas supply that is necessary to satisfy market needs over time. Note that these maps do not generally show intra-regional pipeline expansions such as those that occur within the Marcellus shale production area.

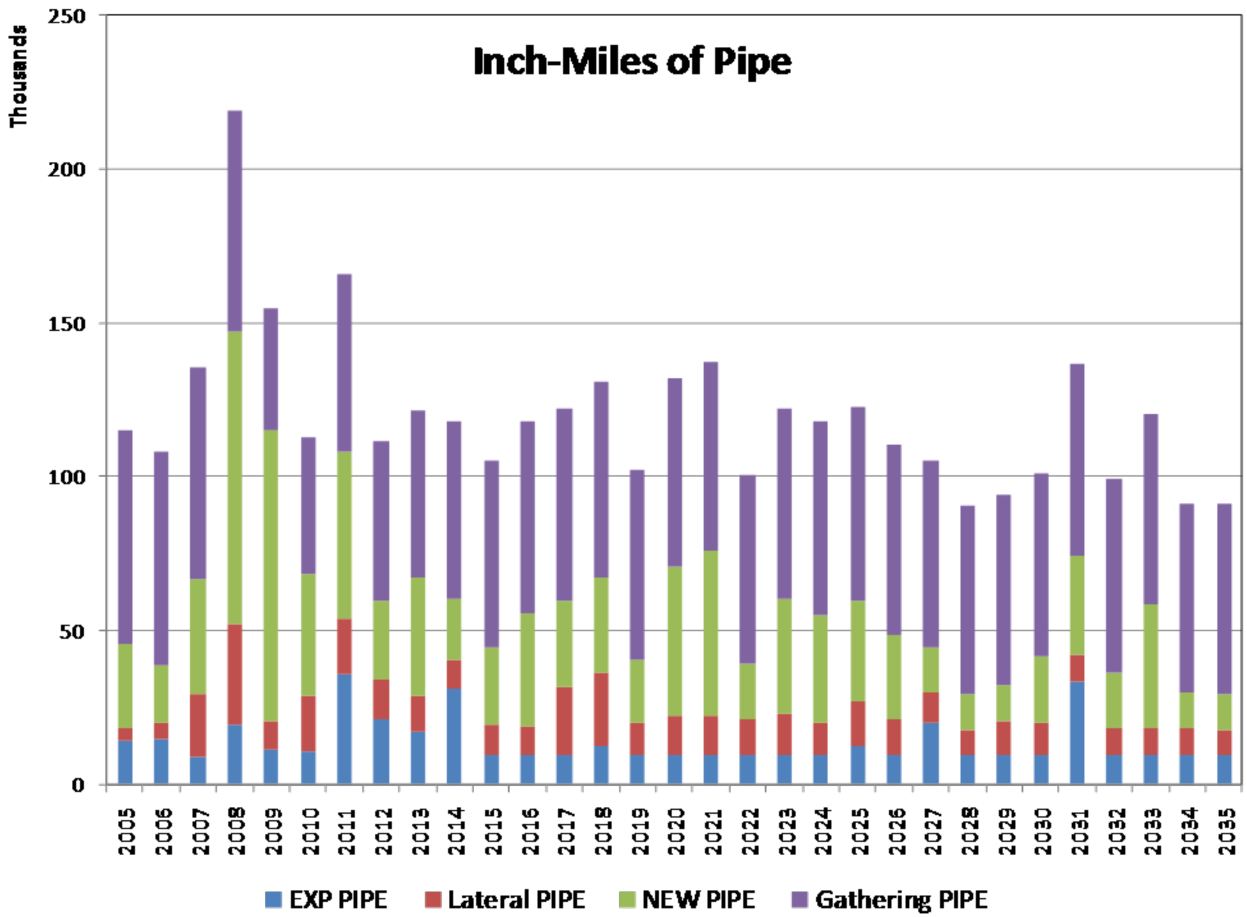
Miles of New Pipeline Added





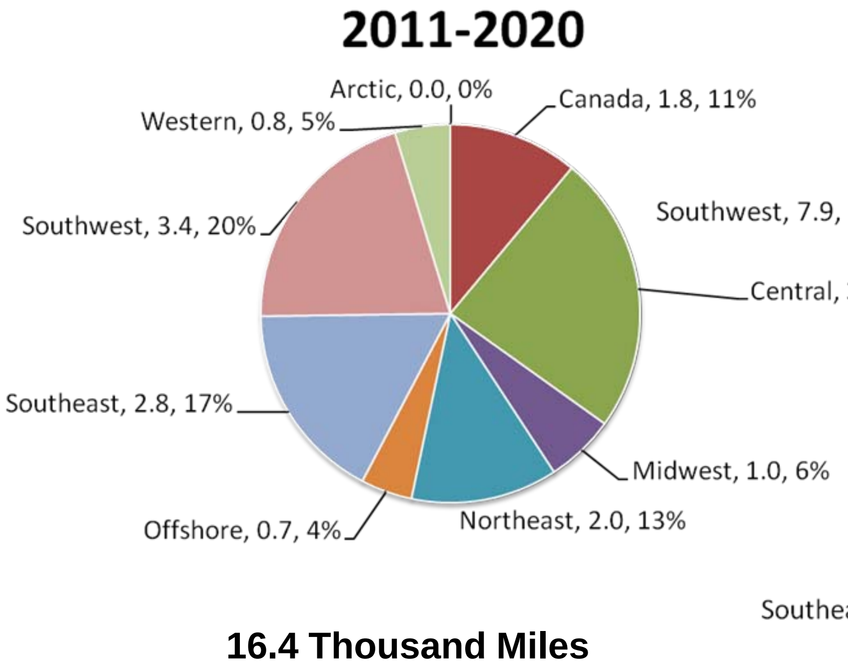
- Most new pipe (about 16,500 miles) is gathering line, which is generally smaller diameter pipe that is planned for and financed as part of upstream project development.
- An average of almost 2,000 miles of new transmission line are added each year, which is well within the range of recent years.. Roughly 1,400 miles per year are mainline miles, while about 600 miles per year are for lateral connections to power plants, processing plants, and other facilities.

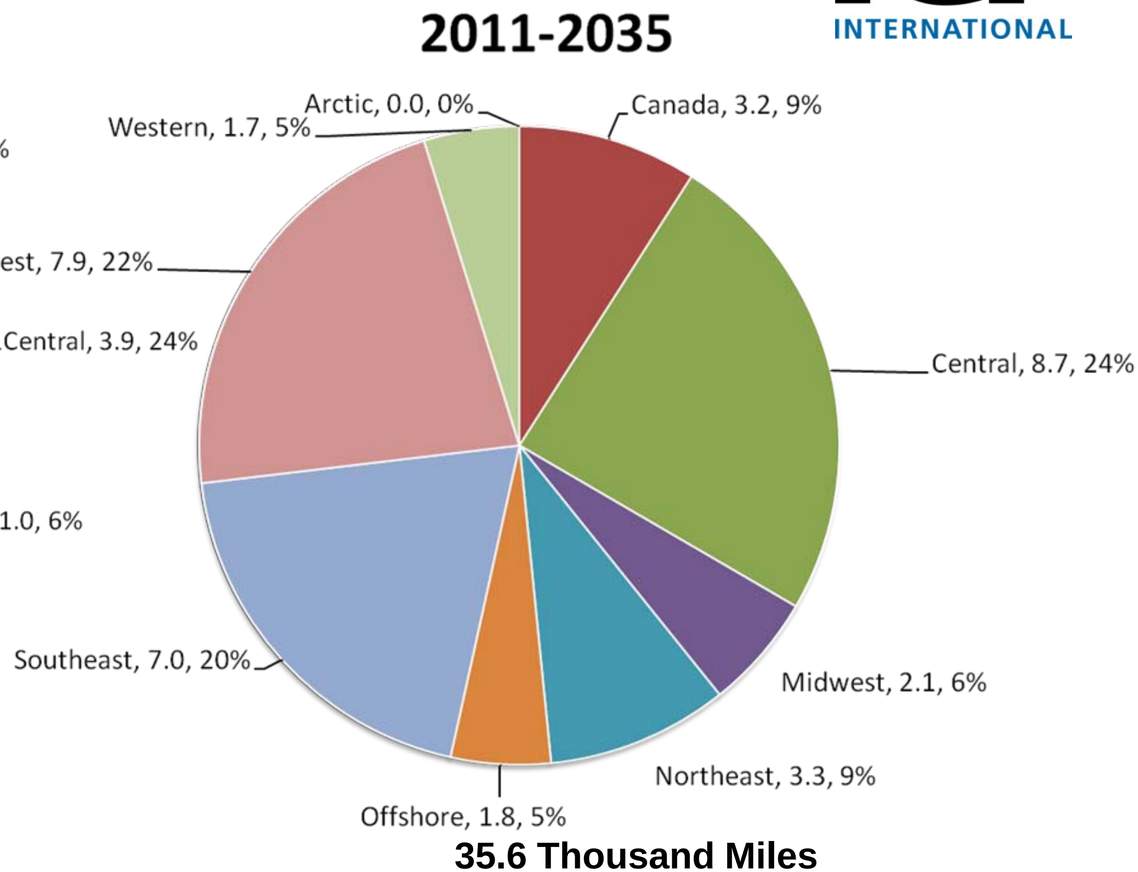
Inch-Miles of New Pipeline Added



- On an inch mile basis, about 110,000 inch-miles of lines are added each year, breaking out as:
  - Approximately 40,000 inch-miles of transmission line.
  - Approximately 60,000 inch-miles of gathering line.
  - Approximately 10,000 inch-miles of laterals from processing plants and to power plants.

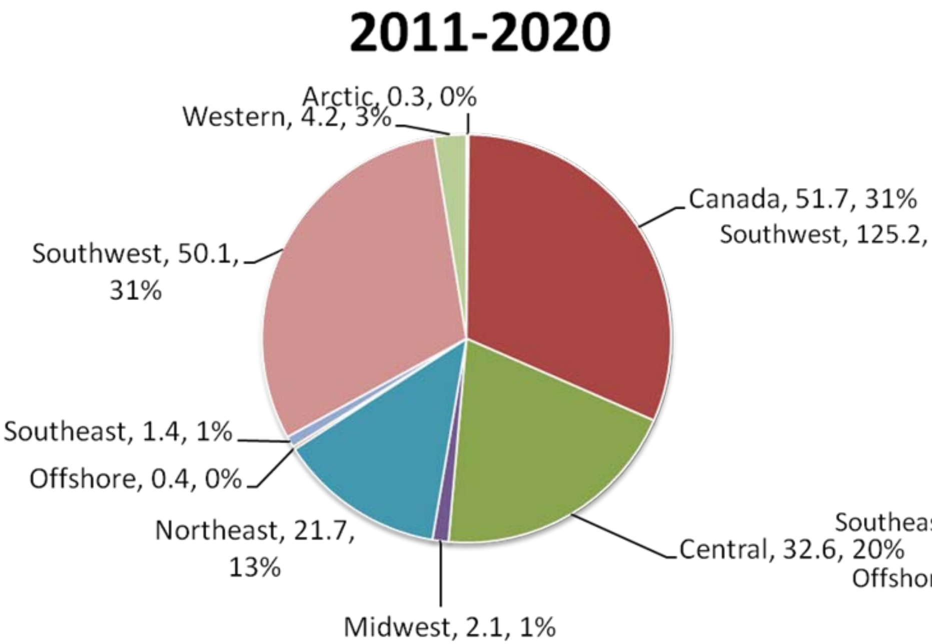
Miles of Transmission Mainline (Excluding Laterals) By Region (1000 Miles)



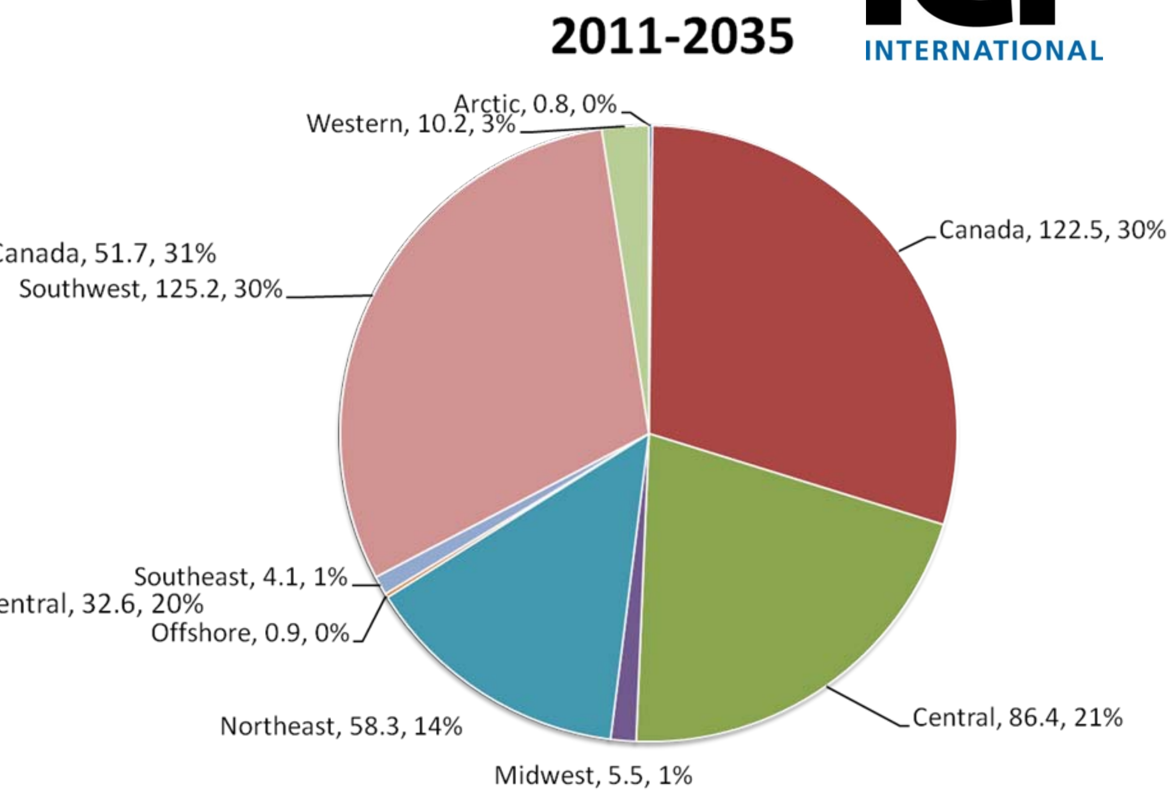


- The Central region which includes the Rocky Mountains gets the largest share of the new transmission pipe, followed closely by the Southwest and Southeast regions. Much of the new mainline capacity is required to make transport of growing shale gas production possible.

Miles of Gathering Pipe By Region (1000 Miles)



165 Thousand Miles



414 Thousand Miles

- Over 30 percent of new gathering line will be concentrated in the Southwest, but other areas where shale gas production is growing like the Northeast (Marcellus shale) and Canada (Montney and Horn River shales) also require significant amounts of new gathering lines.

Miles of Laterals Needed to Hook-Up New Gas Power Plants

- Almost 600 laterals and about 8,500 miles of new gas delivery capability to new gas power plants will be needed over the next 25 years.

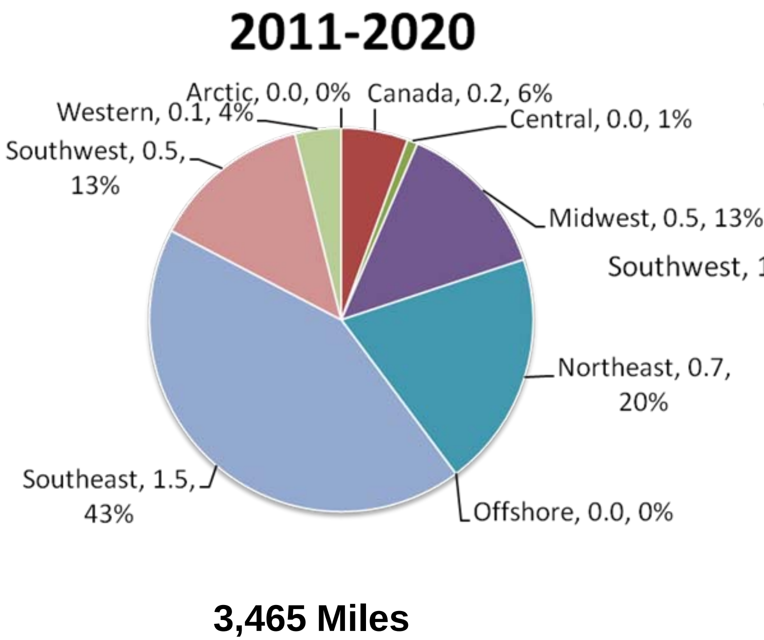
Cumulative Additions from 2010

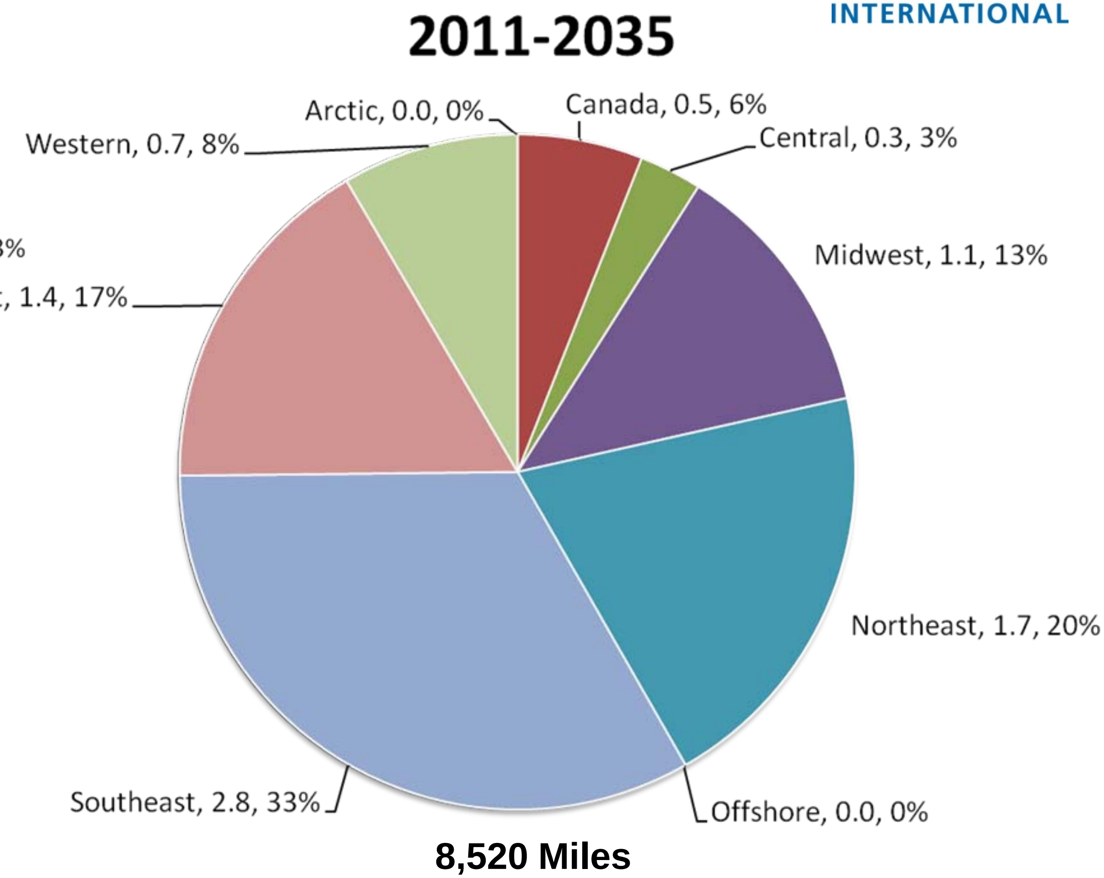
	New Gas Builds (GW)	Plant Connections	Miles of Laterals
2015	28	67	1,005
2020	112	231	3,465
2025	174	362	5,430
2030	227	475	7,125
2035	276	568	8,520

Assumes 15 Miles of 24” pipeline per plant.

Note: Upstream mainline capacity to support service to these laterals is included In the transmission mainline slide.

Miles of Laterals to Gas Power Plants





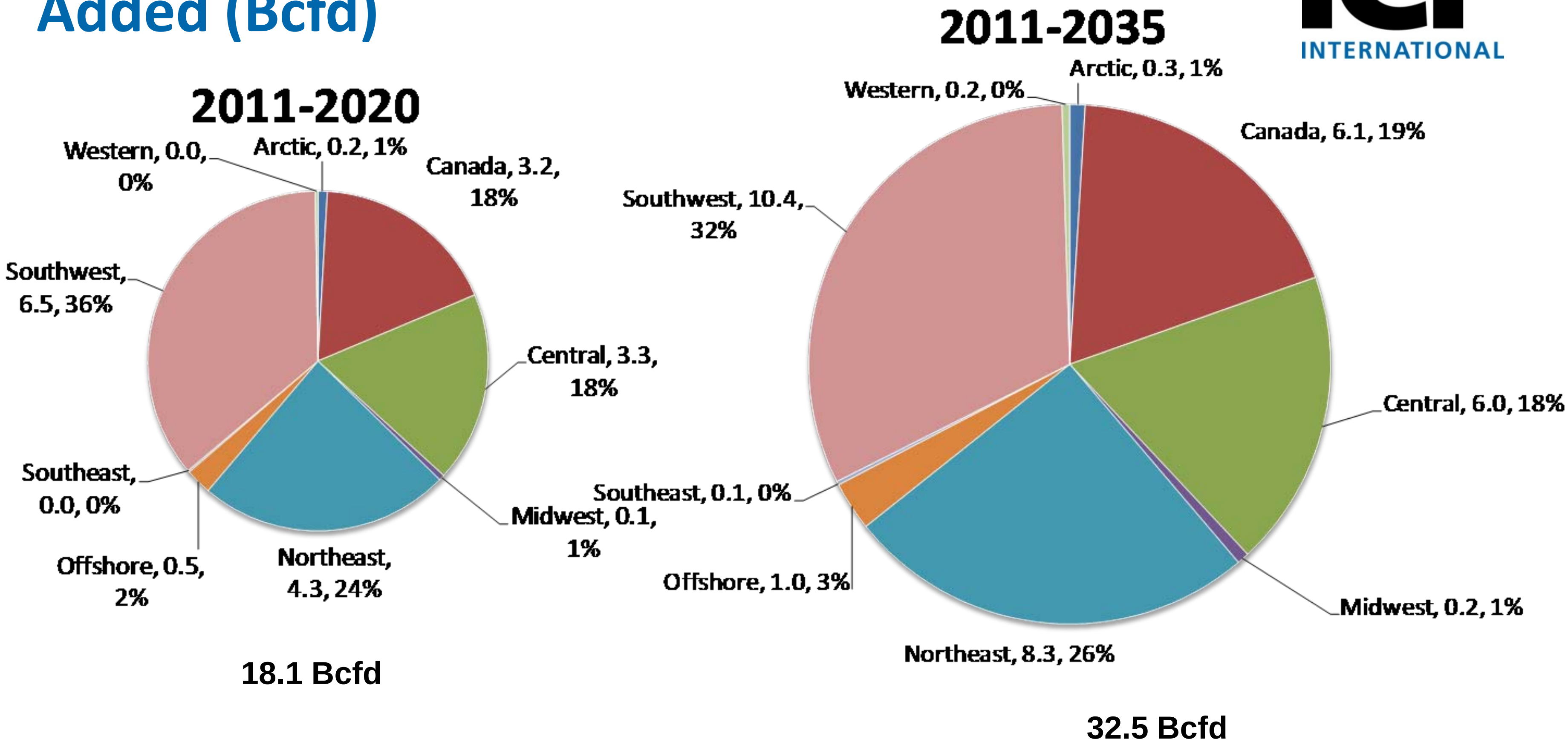
- Regionally, gas power plant additions and their associated pipeline laterals are concentrated in the southern part of the continent, with the Southeast and Southwest accounting for half of the new builds.

Gas Processing Plant Additions

Cumulative from 2010	Change in Gas Production (Tcf)	Change in Gas Production (Bcfd)	New Plants Added	Additional Gas Plant Capacity (Bcfd)	Gas Plant Expenditures Billions 2010$
2015	3.3	9.1	81	10.4	$7.1
2020	7.0	19.2	137	18.1	$12.4
2025	9.3	25.6	175	23.1	$15.8
2030	11.2	30.5	207	27.7	$18.9
2035	13.2	36.0	238	32.5	$21.2

- Large production growth in natural gas from shale formations and previously unproduced frontier areas will require additional gas plant infrastructure over what is simply needed to maintain existing production levels.
- Roughly 240 new processing plants with over 32 Bcfd of processing capability is needed to process much of the incremental gas production occurring over the next 25 years. Capital costs of the new processing plants will exceed $20 billion.

Regional Gas Processing Plant Capacity Added (Bcfd)

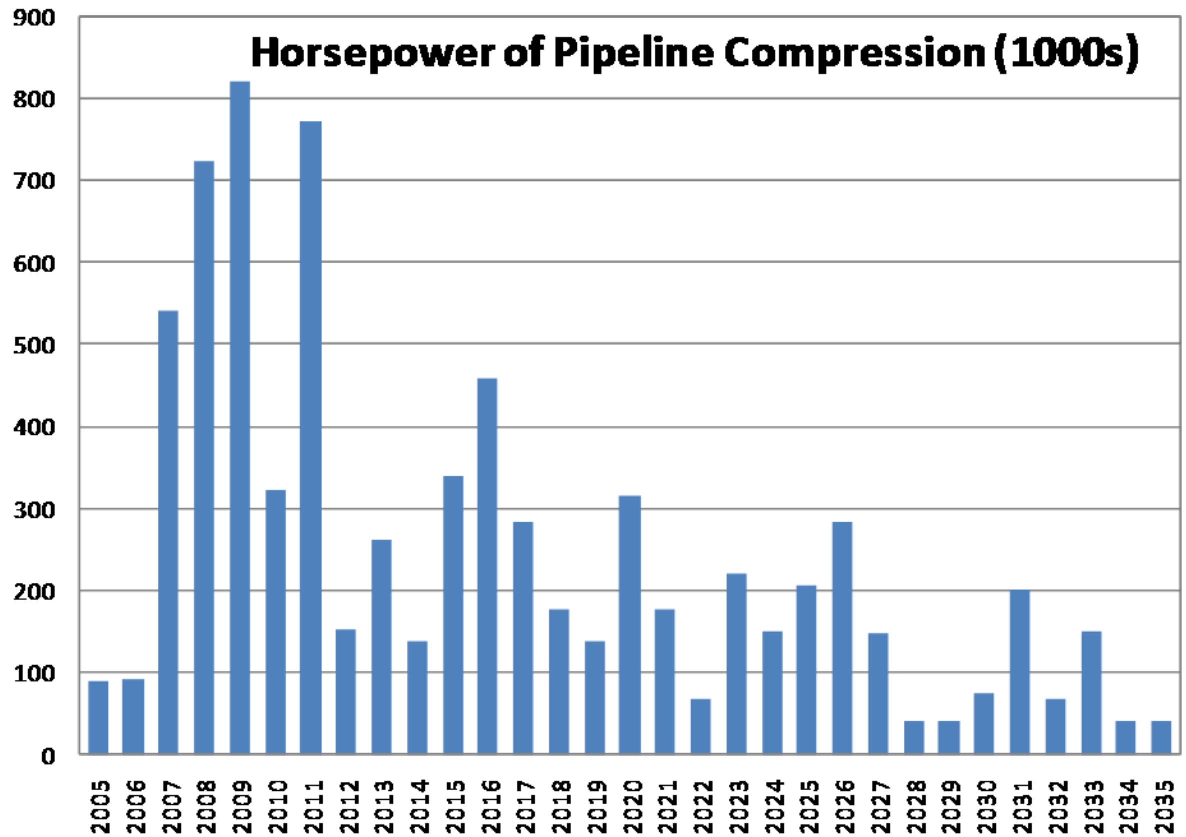


- A large portion of the new processing plant capacity is added in the Southwest where production is growing in a number of shale formations. However, changes in production elsewhere, for example in the Marcellus in the Northeast and in the Horn River and Montney shales in Western Canada also yield significant growth in processing plant requirements.

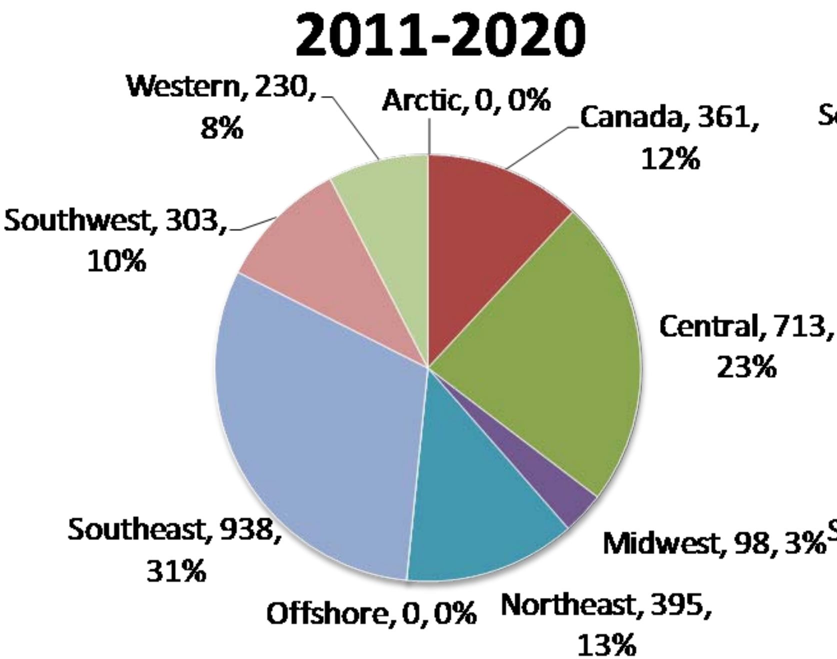
Pipeline Compression Additions

Horsepower Added Each Year

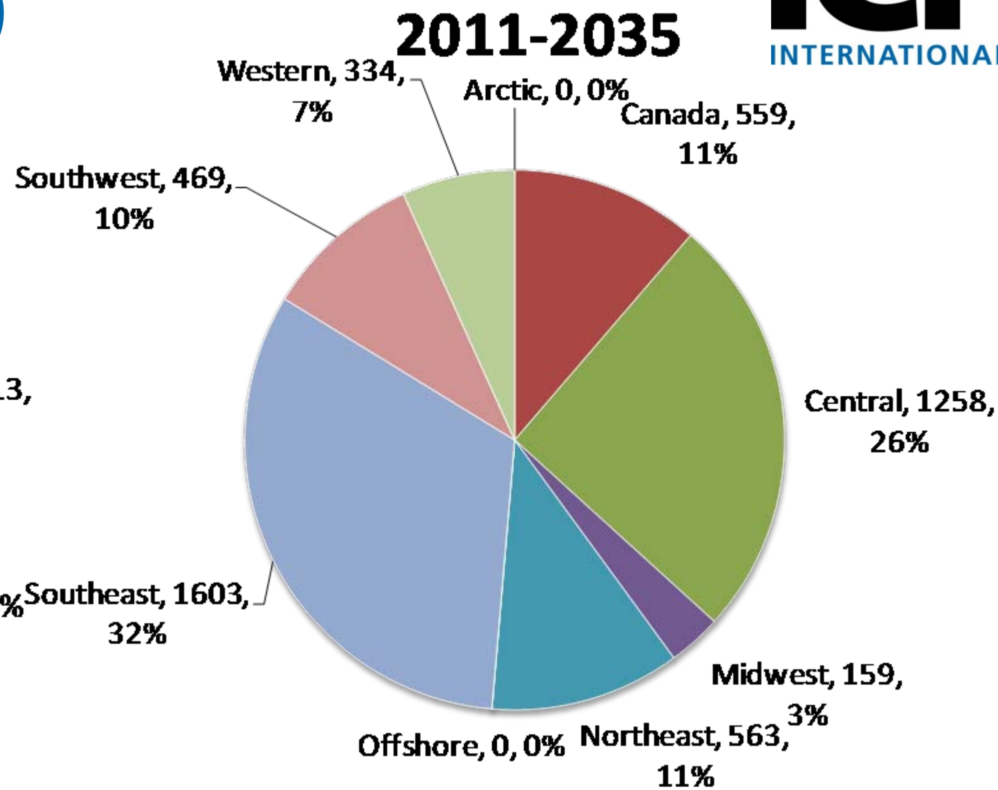
- An average of 200,000 Horsepower of compression per year is added over the next 25 years.



Regional Breakout for Added Pipeline Compression (1000 HP)



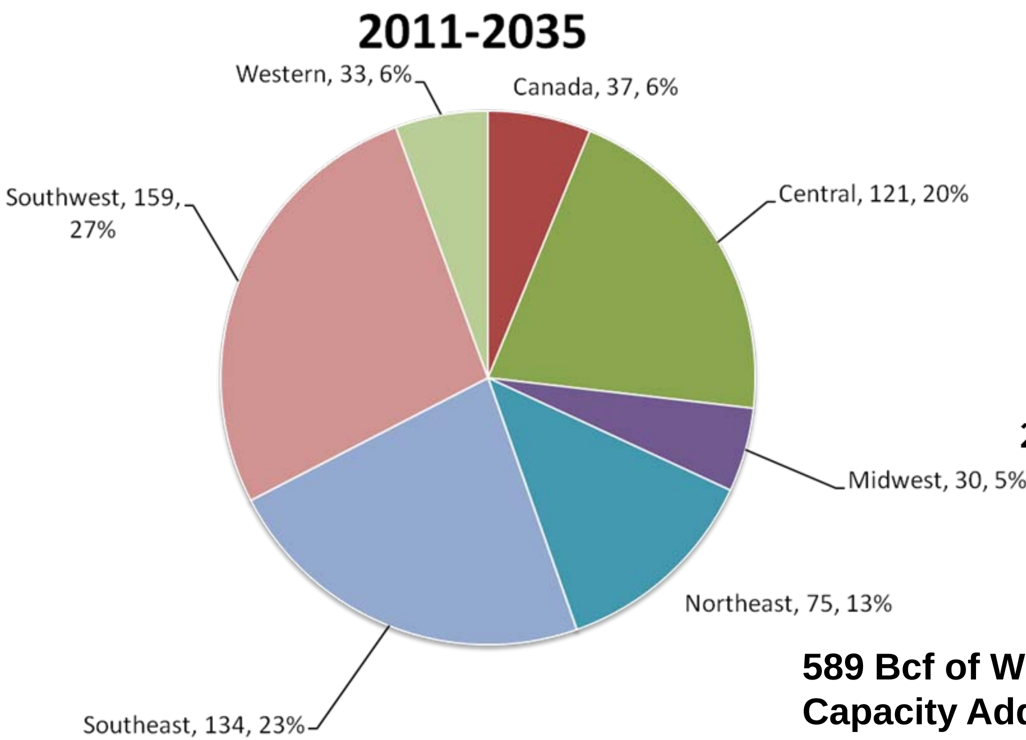
3,039 Thousand Horsepower

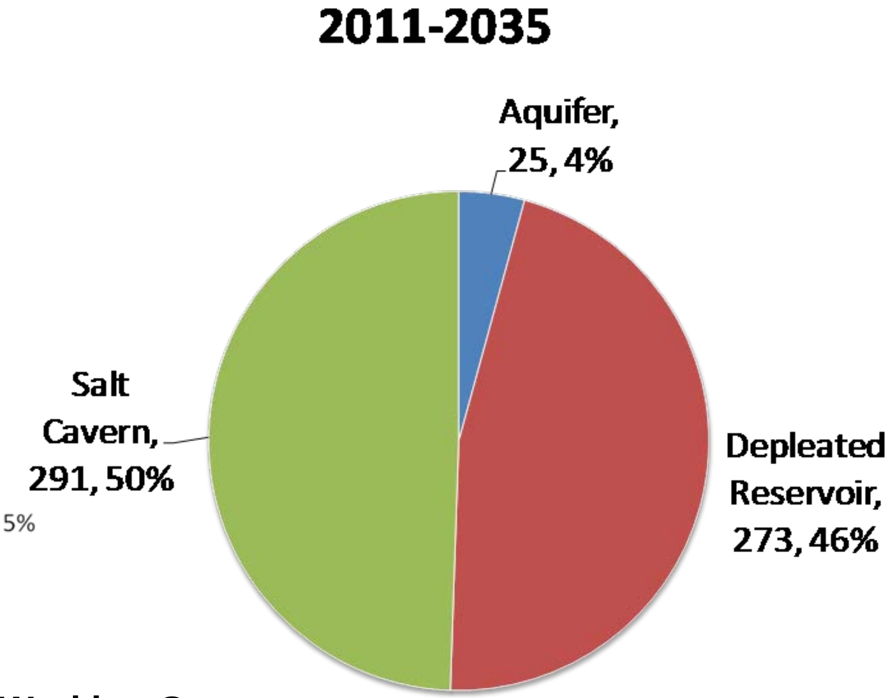


4,946 Thousand Horsepower

- Many regions have significant compression additions as pipelines are enhanced in a number of locations.

Underground Gas Storage Additions By Region and Storage Field Type (Bcf)





589 Bcf of Working Gas Capacity Additions

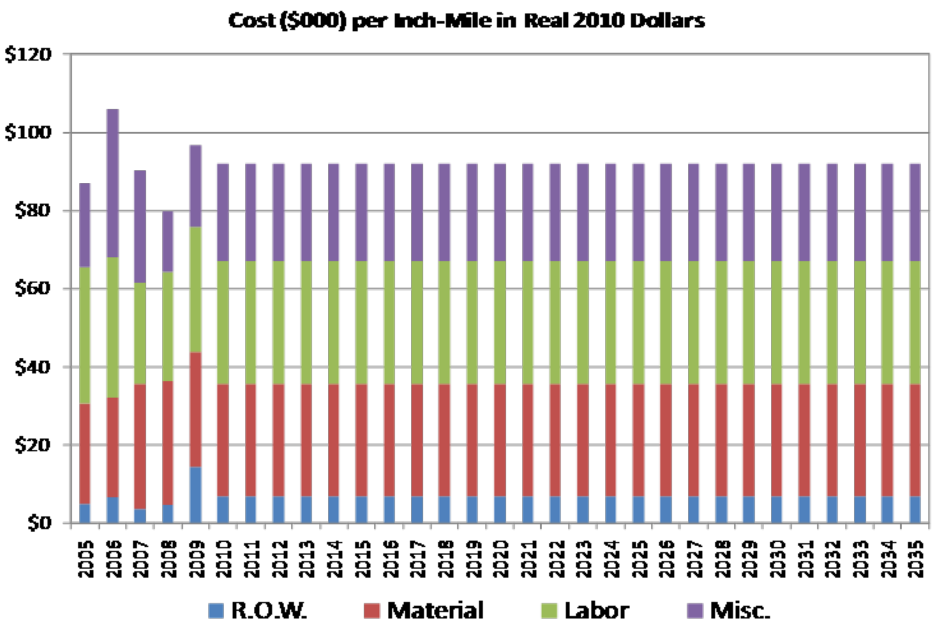
- Almost 600 Bcf of new gas storage capacity will be needed during the next 25 years. Much of the new capacity will be needed to “park” growing gas supplies until the market needs the supplies as load changes across seasons and across days. Storage additions are regionally widespread.

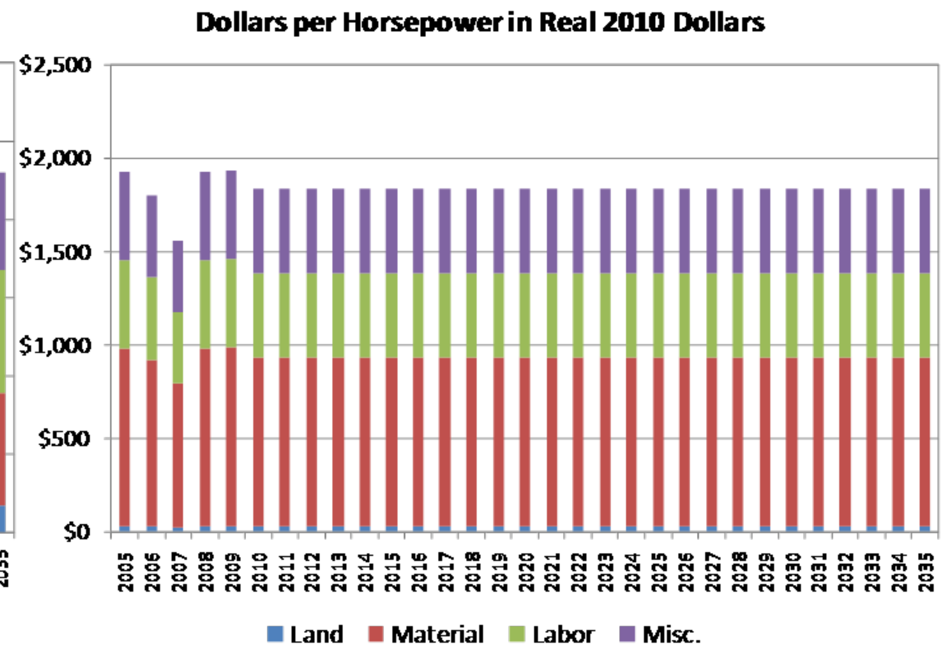
Summary of Incremental Gas Infrastructure Added in the Reference Case (cumulative)

	2011 to 2020	2011 to 2035	Average Annual
Inter-regional Pipeline Capacity (Bcfd)	29	43	1.7
Miles of Transmission Mainline (1000s)	16.4	35.6	1.4
Miles of Laterals to/from Power Plants, Storage Fields and Processing Plants (1000s)	6.6	13.9	0.6
Miles of Gathering Line (1000s)	165	414	16.5
Inch-Miles of Transmission Mainline (1000s)	491	1,043	42
Inch-Miles of Laterals to/from Power Plants, Storage Fields and Processing Plants (1000s)	142	304	12
Inch-Miles of Gathering Line (1000s)	592	1,518	61
Compression for Pipelines (1000 HP)	3,039	4,946	197
Gas Storage (Bcf Working Gas)	NA	589	24
Processing Capacity (Bcfd)	18.1	32.5	1.3

Costs for All Pipelines and Compression/Pumping

All Costs Reported in 2010 Dollars



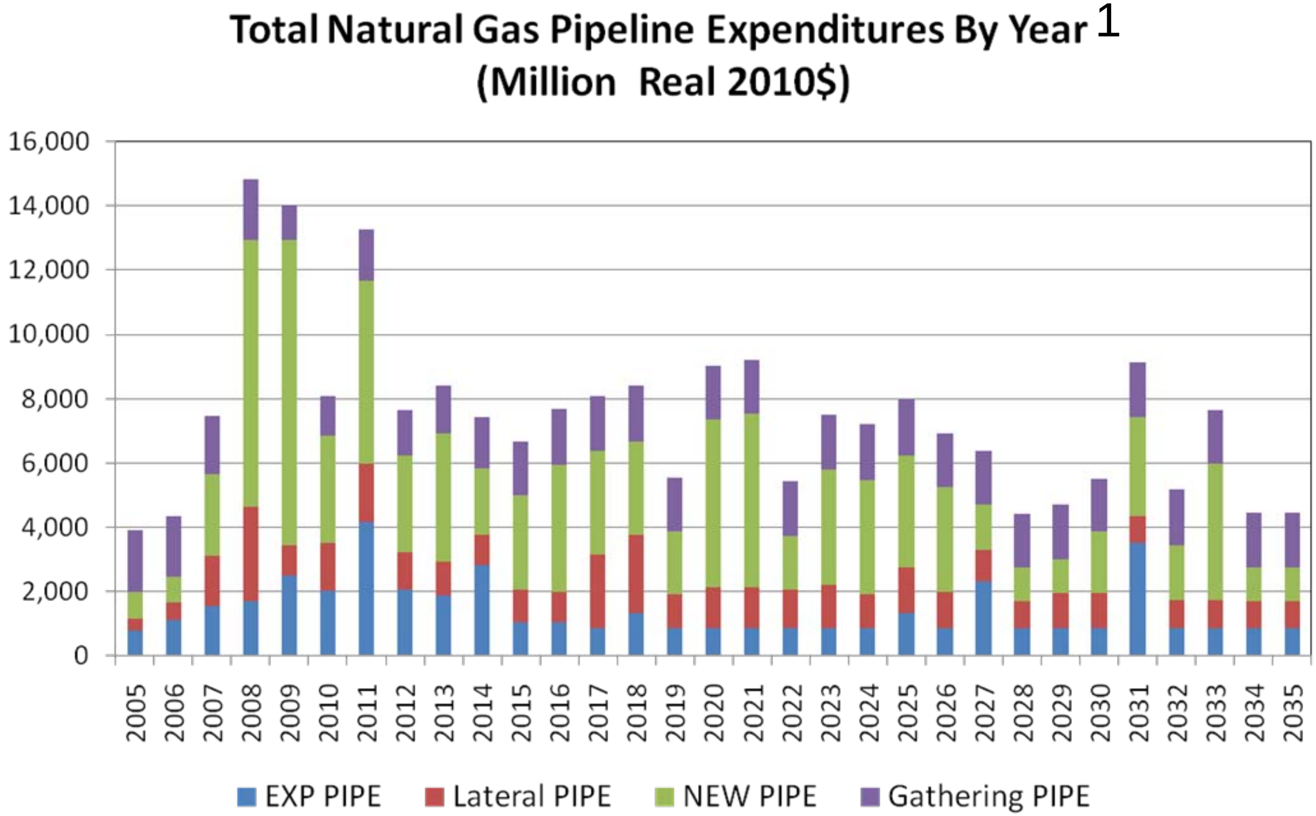


- Projected costs of pipelines and compression on a real dollar per inch-mile and a real dollar per horsepower basis.
- Pipeline costs are assumed to remain constant at about $90,000 per inch-mile in real 2010$.
- Compression costs are assumed to remain constant at about $1,800 per HP in real 2010$.

Capital Expenditures for New Gas Pipeline

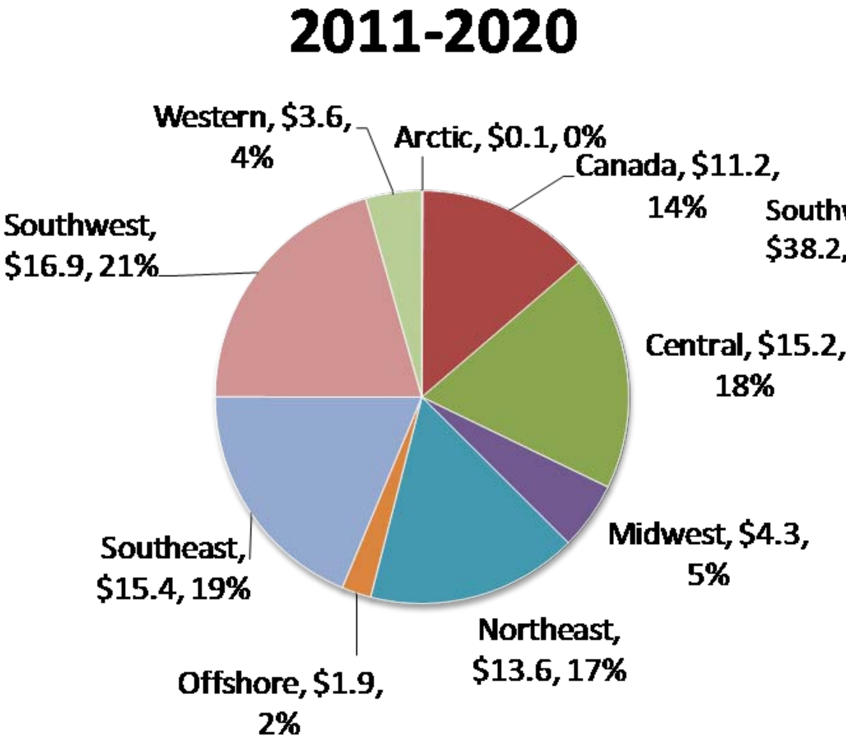
Million dollars (Real 2010$) Spent Each Year, Including the Cost of Compression

- Between 2005 and 2010, pipeline expenditures averaged $8.8 Billion per year in real 2010 dollars.
- Annual pipeline expenditures are projected to be between $4 and $13 billion per year between 2011 and 2035.
- Of the $178 billion of projected investment between 2011 and 2035, roughly 50 percent is for new transmission lines.
- Capital expenditures for the new pipeline infrastructure projected here average about $7 billion per year in real 2010 dollars.
- If upstream gathering lines are excluded, average annual capital expenditures for new pipeline are $5.5 billion per year in real 2010 dollars.

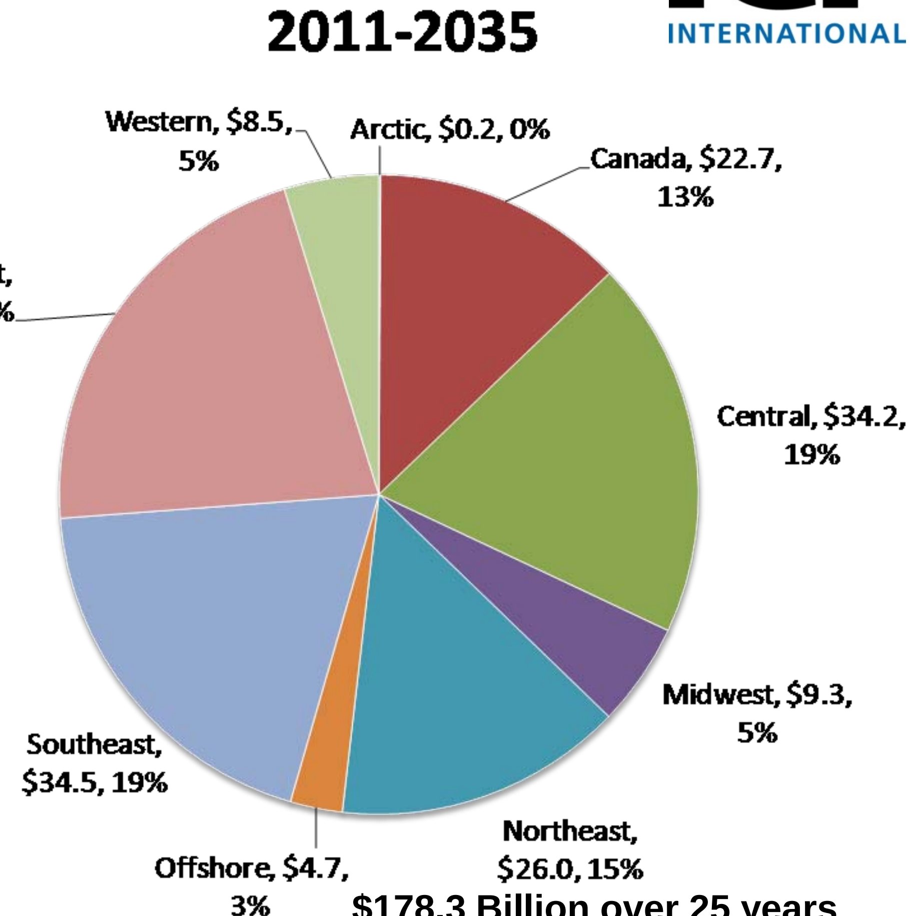


1. Pipeline project costs are represented in the year the project enters service. While in actuality, pipeline investment costs are generally spread over one or more years leading up to a project entering service.

Regional Breakout for Accumulated Capital Expenditures for New Gas Pipeline Capacity



$82.3 Billion over 10 years

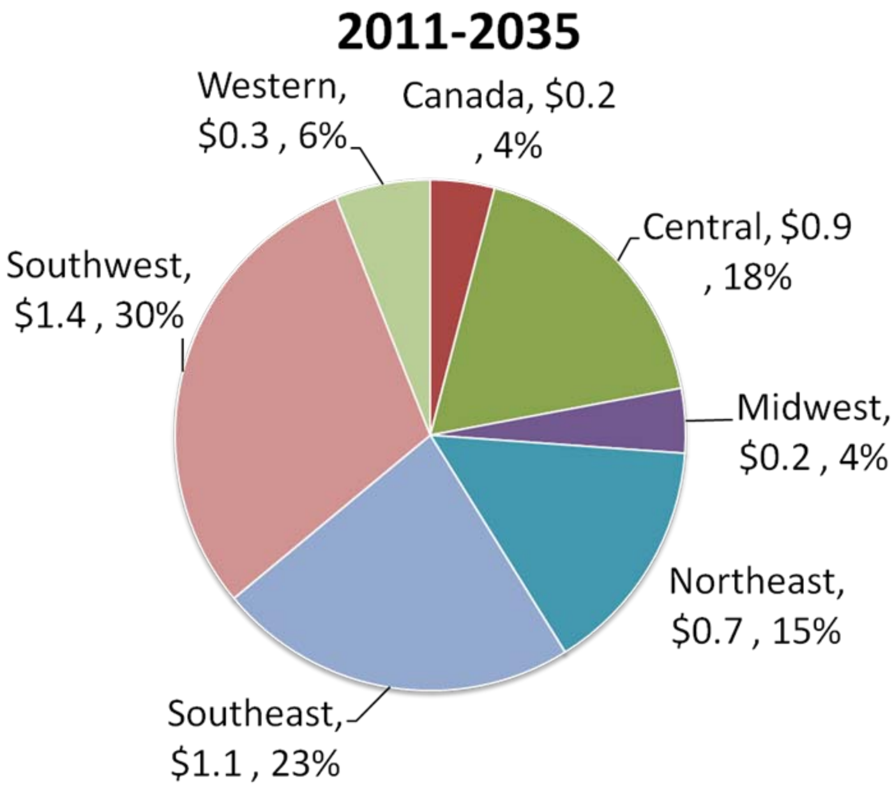


$178.3 Billion over 25 years

- The largest investment in new pipelines occurs in the supply areas of the Southwest and Central regions, followed closely by the Southeast and Northeast which are demand regions with access to growing supply.

Expenditures for New Gas Storage Capacity

All Values in Real 2010 Dollars



$4.8 Billion over 25 years

Regional Comparison of Costs (Index =1.0)

Region	Factor
Canada	0.88
Central	1.03
Midwest	0.77
Northeast	1.83
Southeast	1.10
Southwest	1.18
Western	0.93
Grand Total	1.00

Storage Costs for 2008-09 in Millions of 2010$ per Bcf of Working Gas Capacity

Field Type	Expansion	New
Salt Cavern	$8.7	$10.9
Depleted Reservoir	$6.3	$8.6
Aquifer	$14.2	$17.2

Cost for gas storage projects are flat in real 2010 dollars per Bcf of Working Gas Capacity. Excludes pipeline connection cost.

- Capital expenditures for new gas storage capacity total nearly $5 billion over the next 25 years.

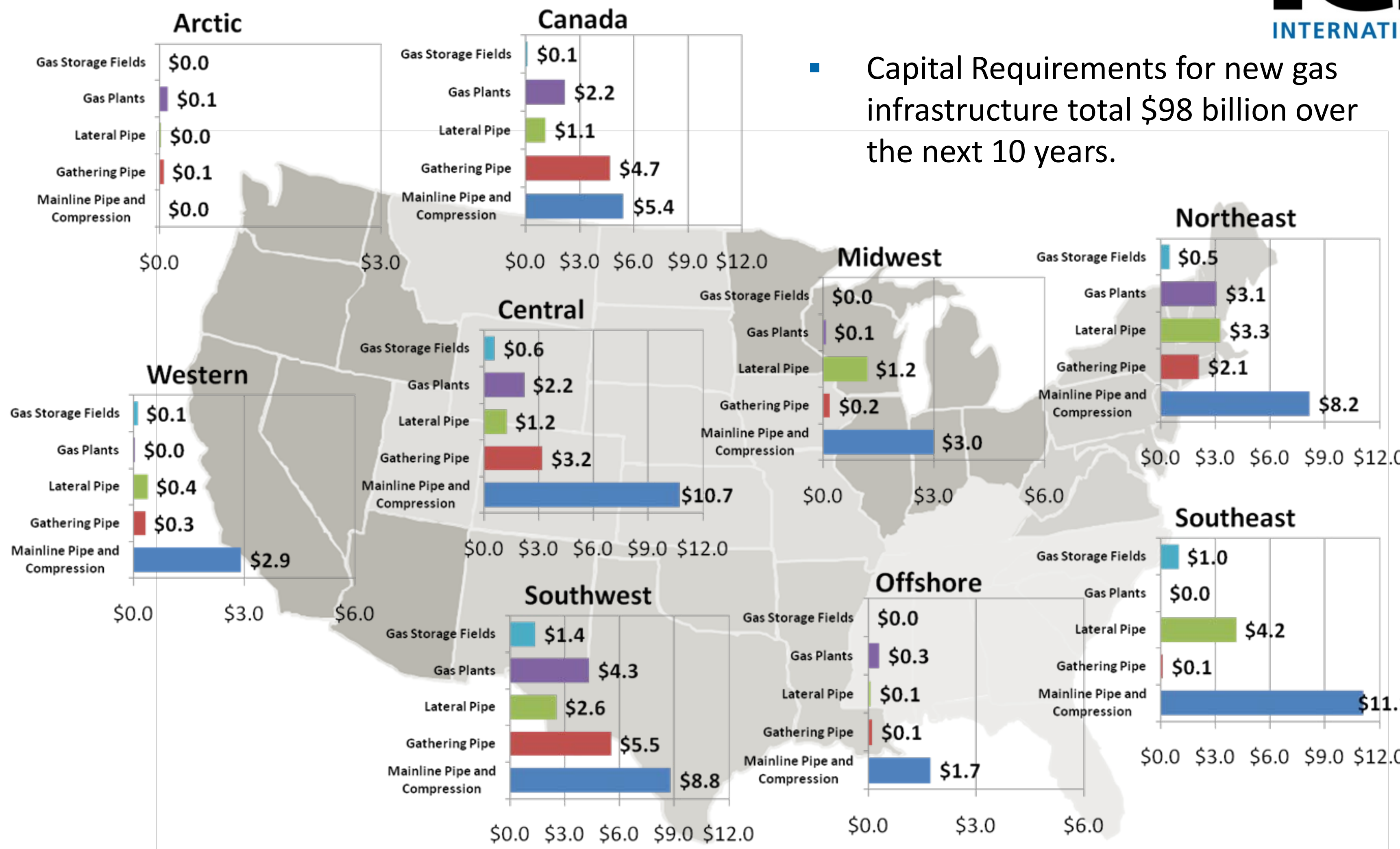
Natural Gas Infrastructure Capital Requirements (Billions of 2010$)

Natural Gas Infrastructure Capital Requirements (Billions of 2010$)	2011 to 2020	2011 to 2035	Average Annual Expenditures
Gas Transmission Mainline	$46.2	$97.7	$3.9
Laterals to/from Power Plants, Gas Storage and Processing Plants	$14.0	$29.8	$1.2
Gathering Line	$16.3	$41.7	$1.7
Gas Pipeline Compression	$5.6	$9.1	$0.3
Gas Storage Fields	$3.6	$4.8	$0.2
Gas Processing Capacity	$12.4	$22.1	$0.9
Total Gas Capital Requirements	$98.1	$205.2	$8.2

- Recent historical trends have matched or surpassed the average annual expenditures shown here.

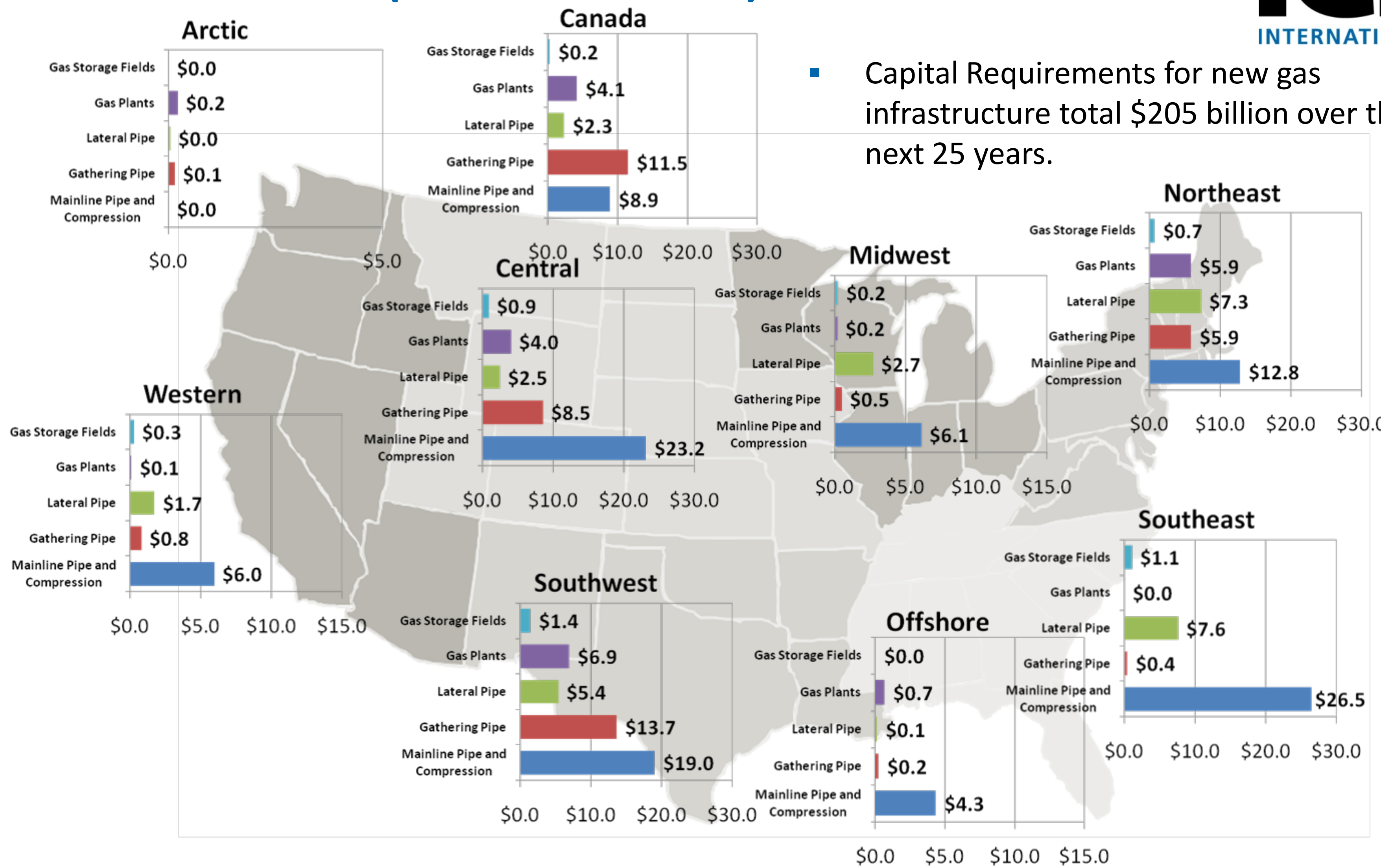
Regional Gas Infrastructure Capital Requirements for 2011 to 2020 (Billions of 2010$)

- Capital Requirements for new gas infrastructure total $98 billion over the next 10 years.



Regional Gas Infrastructure Capital Requirements for 2011 to 2035 (Billions of 2010$)

- Capital Requirements for new gas infrastructure total $205 billion over the next 25 years.



Results for Midstream Infrastructure Requirements for Oil and Natural Gas Liquids

(See Appendix A for Details of the Oil and NGL Projection)

Premises for NGL Infrastructure Analysis

- Refinery production of Ethane, Propane, and Butane is unchanged over time.
- Natural gas plant liquids are produced as a function of natural gas production trends and gas composition. The natural gas-oil price ratio is assumed to remain low enough to make ethane extraction economic for all new gas supplies.
- Demand for propane and butane grows by 1 percent per year in US and Canada. Any excess propane and butane is exported. Since exports occur mostly from the Gulf Coast, pipeline infrastructure needs would be the same as if Gulf Coast refineries/petrochem demand increased to sop up Propane/Butane supplies (and exports are zero).
- All of the incremental ethane production is used for ethylene cracking. Regional pattern of demand is same as in 2010. An alternative premise would be to assume that ethylene crackers are built in or near the Appalachian Basin (and less NGL pipeline would be needed).
- All pentanes+ increases are used in US and Canadian refineries.
- Seasonal variability is not considered in the flows. To the extent that US East supplies own propane/butane, local underground LPG storage may have to be built. Otherwise Midcon/Gulf storage may be utilized (with a increase in pipeline flows back and forth)

U.S. and Canada Oil Production Growth

- Oil production is projected to increase by 1.7 percent annually through 2035. The largest areas of production growth include Western Canada and the north eastern Rocky Mountains.
- Nearly all of Canada's oil production growth comes from increases of bitumen and synthetic crude production from oil sands which will account for over 85 percent of western Canada oil production in 2035 (versus 65 percent in 2010).
- The Rocky Mountains have several areas where oil production is projected to grow significantly, i.e., by 925 MBpd. These include the Bakken and Three Forks shale formations in North Dakota and Montana, the Niobrara shale formation in Denver, Powder River, and Green River basins of Wyoming, Colorado and Utah.
- Oil production is also projected to grow significantly from the Eagle Ford shale of South Texas, the Avalon, Bone Springs and Wolfberry plays (West Texas) the Utica shale (Ohio, Pennsylvania and West Virginia), and other tight oil plays.
- Production from all forms of "tight" oil (oil shales and associated low permeability carbonates and sands) is projected to reach 2,386 MBpd of crude oil and condensate by 2035.

Premises for Crude Oil Infrastructure Analysis

- Demand for crude oil at US refineries would follow slowly declining trajectory in EIA's AEO. Canadian crude runs would stay constant at 2010 levels.
- Runs within each PADD or Canadian province would not change dramatically from 2010 levels. In other words, regional trade in products would not shift. This premise avoids the issue of having to build new or expand existing refinery capacity. However, refinery upgrades due to changing crude slates may be needed.
- <u>Another premise is that North America would use its own crude first, so all increases in North American crude oil production will back out imports</u>.
- These assumptions mean that due to decline in AK crude production, West Coast refineries need to get more crude supplies from Canada or the Rockies. The case results presented here assume that crude comes from WCSB via pipeline to western British Columbia and ships to California from there.
- Alternative configurations are possible in which CA imports more oil and WCSB oil is exported. This would likely reduce infrastructure changes.
- Transport of oil from wellhead to pipeline/rail terminals is assumed to be predominantly by truck, so no estimate is made for the capital cost of new oil gathering line.

NGL and Oil Infrastructure Capital Requirements

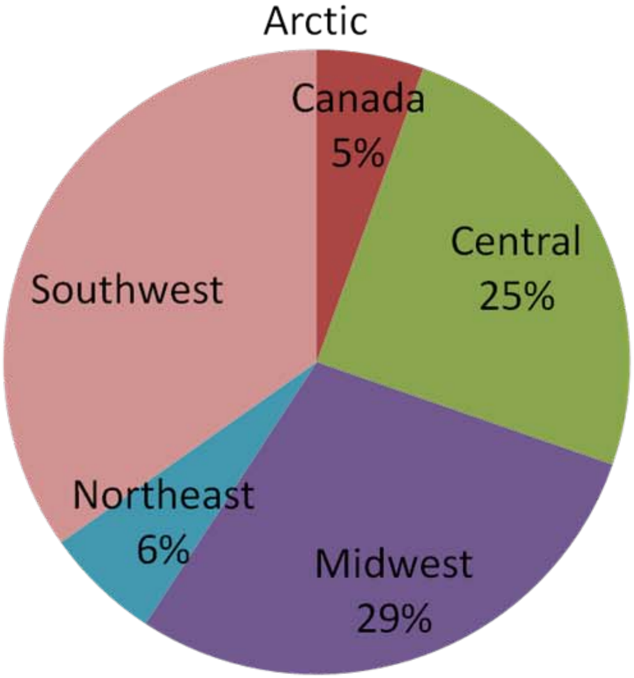
ICF INTERNATIONAL

NGL Pipeline Infrastructure	2011-20	2011-35	Average Annual
Miles of Transmission Mainline (1000s)	10.6	12.5	0.5
Cost of Transmission Mainline (Billions 2010$)	$12.3	$14.5	$0.6
Oil Pipeline Infrastructure	**2011-20**	**2011-35**	**Average Annual**
Miles of Transmission Mainline (1000s)	13.0	19.3	0.8
Cost of Transmission Mainline (Billions 2010$)	$19.6	$31.4	$1.3
NGL and Oil Pipeline Infrastructure	**2011-20**	**2010-35**	**Average Annual**
Miles of Transmission Mainline (1000s)	23.6	31.8	1.3
Cost of Transmission Mainline (Billions 2010$)	$31.9	$45.9	$1.8

Regional NGL Pipeline Expenditures

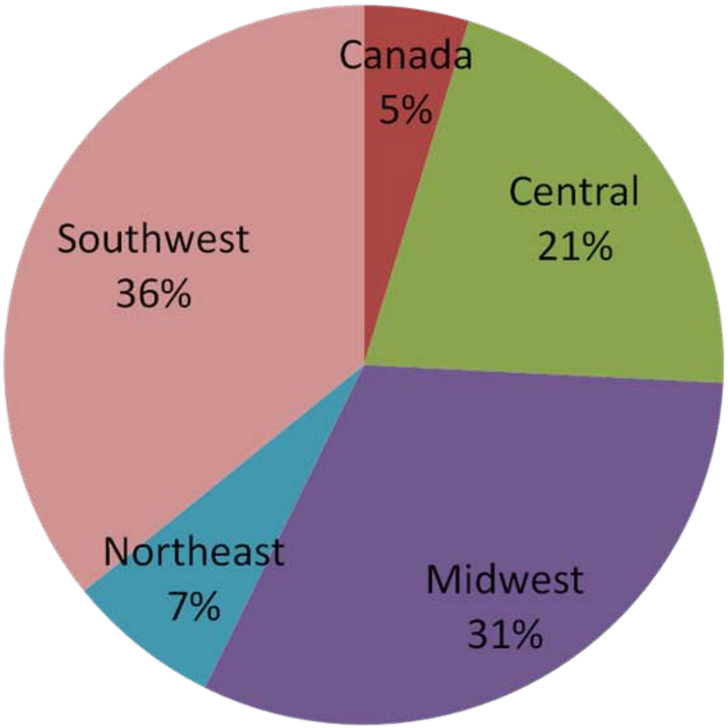
Total Expenditures, 2011-20 (Billions of 2010$):

$12.3



NGL Pipeline Expenditures, 2011-35 (Billions of 2010$):

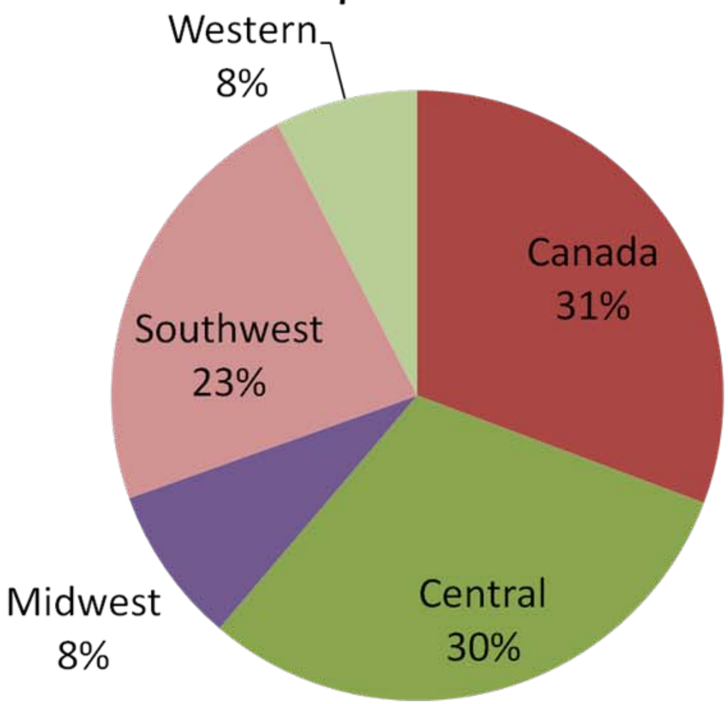
$14.5



Regional Oil Pipeline Expenditures

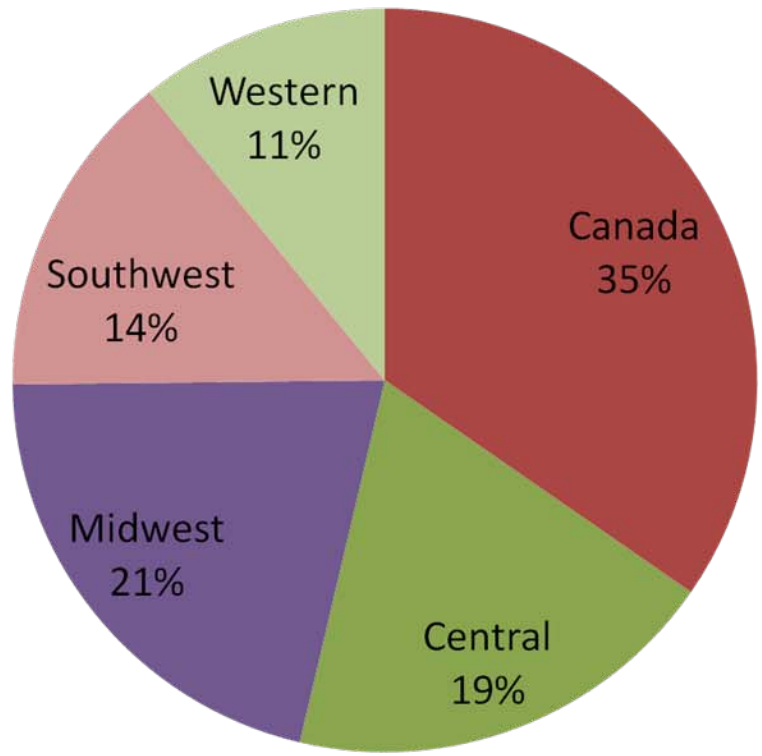
Total Expenditures, 2011-20 (Billions of 2010$):

$19.6



Oil Pipeline Expenditures, 2011-35 (Billions of 2010$):

$31.4

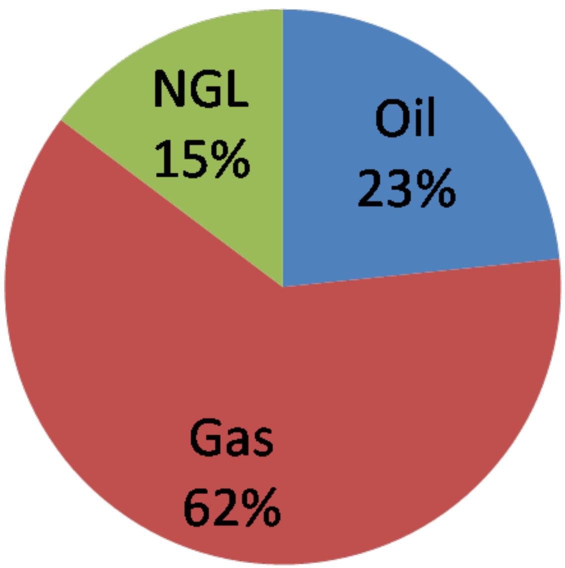


Oil and NGL Infrastructure Needs

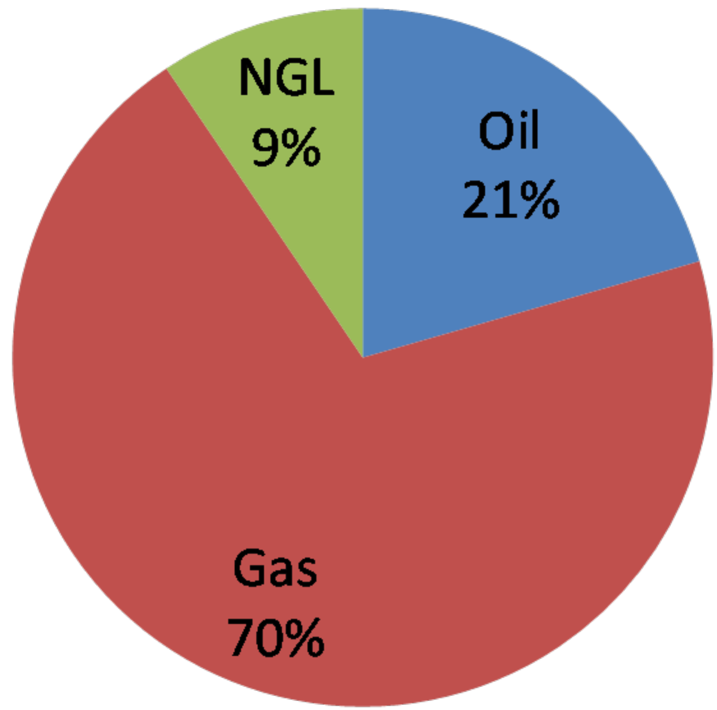
- The oil and gas industry will need to invest roughly $50 Billion (2010$) over the next 25 years in pipeline infrastructure for the transport of oil and NGLs to consumers of these products. This is in addition to the $205 Billion dollar investment by this industry in natural gas transport, processing, and storage.
- Oil and NGL infrastructure will require over 30 thousand miles and 500 thousand inch-miles over the next 25 years. The average pipe size is approximately 16 inch diameter, where oil pipelines are generally larger than the average and NGL pipelines smaller than the average.
- Comparing oil and NGL infrastructure needs with natural gas for a total oil and gas industry view, the inch-miles of oil and NGL pipelines are roughly one-third of the mainline required by the industry through 2035, and through 2020 the share for liquids pipelines is about 40 percent.
- Investment in both oil and gas mainlines is projected to be over $150 Billion dollars through 2035 or approximately $6 Billion dollars per year, of which roughly one-third is for oil and natural gas liquids.

Oil and NGL Share of Total Oil and Gas Mainline Transmission Expenditures

Main Line Expenditures, 2011-20
(Billions of 2010$)
$83.8



Main Line Expenditures, 2011-35
(Billions of 2010$)
$152.8



- New pipelines for Oil and NGL growth represent 30 to 40 percent of all mainline expenditures in the combined projection.

Cost of Infrastructure Added in the Combined Natural Gas and Liquids Reference Case
(Billions of 2010$)

Cost of Infrastructure Added in the Combined Natural Gas and Liquids Reference Case (Billions of 2010$)	2011 to 2020	2011 to 2035	Average Annual Expenditures
Gas Transmission Mainline	$46.2	$97.7	$3.9
Laterals to/from Power Plants, Gas Storage and Processing Plants	$14.0	$29.8	$1.2
Gathering Line	$16.3	$41.7	$1.7
Gas Pipeline Compression	$5.6	$9.1	$0.3
Gas Storage Fields	$3.6	$4.8	$0.2
Gas Processing Capacity	$12.4	$22.1	$0.9
Sub-Total of Gas Capital Requirements	$98.1	$205.2	$8.2
Oil Transmission	$19.6	$31.4	$1.3
NGL Transmission	$12.3	$14.5	$0.6
Total Gas and Liquids Capital Expenditure	$130.0	$251.1	$10.0

Summary and Conclusions

Summary of Key Market Trends in the Reference Case (Tcf)

U.S. and Canada	2010	2020	2035	% Change 2010 to 2020	% Change 2010 to 2035
Gas Consumption	27.0	33.6	39.7	24%	47%
Gas Use in Power Generation	7.4	12.0	17.0	62%	129%
Gas Production	27.2	34.2	40.3	26%	48%
Conventional Onshore Gas Production	12.9	11.1	10.3	-14%	-20%
Unconventional Onshore Gas Production	11.9	21.1	27.7	77%	132%
Offshore Production	2.4	1.9	2.3	-21%	-2%
Shale Gas Production	4.6	12.6	18.9	274%	308%
Net LNG Imports	0.5	0.6	1.0	20%	120%
Net Exports to Mexico	0.3	0.5	1.1	66%	245%

Summary of Incremental Gas Infrastructure Added in the Reference Case (cumulative)

	2011 to 2020	2011 to 2035	Average Annual
Inter-regional Pipeline Capacity (Bcfd)	29	43	1.7
Miles of Transmission Mainline (1000s)	16.4	35.6	1.4
Miles of Laterals to/from Power Plants, Storage Fields and Processing Plants (1000s)	6.6	13.9	0.6
Miles of Gathering Line (1000s)	165	414	16.5
Inch-Miles of Transmission Mainline (1000s)	491	1,043	42
Inch-Miles of Laterals to/from Power Plants, Storage Fields and Processing Plants (1000s)	142	304	12
Inch-Miles of Gathering Line (1000s)	592	1,518	61
Compression for Pipelines (1000 HP)	3,039	4,946	197
Gas Storage (Bcf Working Gas)	NA	589	24
Processing Capacity (Bcfd)	18.1	32.5	1.3
Inch-Miles of Oil & NGL Mainline (1000s)	341	519	21

Cost of Infrastructure Added in the Combined Natural Gas and Liquids Reference Case (Billions of 2010$)

Cost of Infrastructure Added in the Combined Natural Gas and Liquids Reference Case (Billions of 2010$)	2011 to 2020	2011 to 2035	Average Annual Expenditures
Gas Transmission Mainline	$46.2	$97.7	$3.9
Laterals to/from Power Plants, Gas Storage and Processing Plants	$14.0	$29.8	$1.2
Gathering Line	$16.3	$41.7	$1.7
Gas Pipeline Compression	$5.6	$9.1	$0.3
Gas Storage Fields	$3.6	$4.8	$0.2
Gas Processing Capacity	$12.4	$22.1	$0.9
Sub-Total of Gas Capital Requirements	$98.1	$205.2	$8.2
Oil Transmission	$19.6	$31.4	$1.3
NGL Transmission	$12.3	$14.5	$0.6
Total Gas and Liquids Capital Expenditure	$130.0	$251.1	$10.0

Conclusions

- The ICF Reference Case projects significant gas market growth, particularly in the power sector where gas use doubles over the next 25 years.
- Significant infrastructure will be needed to support growing long run demand in many regions including the Southeast, Northeast, Southwest and Canada.
- The case also projects significant supply development and growth in gas production, primarily from shale resources. Producers are also likely to develop shale plays with large quantities of oil and natural gas liquids, which have needs for new pipeline infrastructure in addition for those required for natural gas.
- Key to this projection are gas prices that rise from $4 per MMBtu in real terms to between $6 and $7 per MMBtu in the longer-term. This gas price level is sufficiently high to foster the development of incremental gas supplies while not so high as to significantly limit market growth.
- The ICF Reference Case represents a “middle of the road” case where a variety of variables could change and result in more or less gas market growth.

Conclusions (continued)

- Midstream infrastructure development in the environment projected in the reference case is relatively robust. From 2010 through 2035:
  - Approximately 43 Bcfd of new transmission capability.
  - Approximately 1,400 miles per year of new gas transmission mainline.
  - Approximately 550 miles per year of new laterals to/from power plants, processing facilities, and storage fields.
  - Approximately 16,500 miles per year of new gathering line.
  - Approximately 1.3 Bcfd per year of new processing capability.
  - Almost 25 Bcf per year of new working gas capacity.
  - About 200,000 HP per year for pipeline compression.
  - Over 5 MMBpd of new oil transmission capacity.
  - Approximately 800 miles per year of new oil transmission line.
  - About 2 MMBpd of new NGL transmission capacity.
  - Approximately 500 miles per year of new NGL transmission line.

Conclusions (continued)

- Expenditures for the incremental infrastructure projected here are significant but similar to those observed in recent years.:
  - Over $251 billion (Real 2010$) or about $10 billion per year of total capital expenditures are required over the next 25 years for the combined natural gas and liquids outlook.
  - $3.9 billion, or almost 40 percent of this amount is required for new or expanded gas mainline capacity.
  - $1.2 billion per year required for laterals.
  - $1.7 billion per year needed for gathering lines.
  - $0.9 billion per year required for processing plants.
  - $1.3 billion per year for new oil pipelines.
  - $0.6 billion per year for new NGL pipelines.
  - Pipeline compression and storage fields account for the remainder of the capital requirements.
- Roughly one-third of the mainline infrastructure requirement will be for oil and natural gas liquids pipelines.
- The future environment for market growth and supply development hinges on a number of key assumptions, many of which are uncertain.

Appendix A: Details from Midstream Infrastructure Requirements for Oil and Natural Gas Liquids

Recent US Ethylene Feedstock Inputs, Approximate Byproduct Ratios

Average (July - December 2010)	
US Ethylene Feed Slate (1,000 bpd)	
Ethane	932.3
Propane	302.7
n-Butane	41.9
Naptha, Gas Oil	311.3
Total	1,588.1
Ethylene from US Steam Crackers (billion pound per month)	
LPG Crackers	1.59
Multi-feed	2.81
Total	4.40
Co-product Propylene from US Steam Crackers (billion pounds per month)	
LPG FEEDS	0.392
NGO FEEDS	0.365
Total	0.757

	Output by Weight for Each Ethylene Cracker Feedstock			
	Ethane	Propane	Butane	Naptha
Ethylene	0.841	0.420	0.378	0.242
Propylene	0.029	0.174	0.194	0.126
Butylene	0.015	0.019	0.049	0.148
Butadiene	0.008	0.010	0.029	0.040
Hydrogen	0.044	0.028	0.025	0.016
Methane	0.056	0.339	0.276	0.241
Gasoline	0.008	0.010	0.049	0.178
Gas Oil	0.000	0.000	0.000	0.010
Total Output Products	1.000	1.000	1.000	1.000
Theoretical bbl/tonne Ethylene	21.01	29.44	28.84	34.74

Source: Petral Consulting; Oil and Gas Journal, March 7 2011 and ICF estimates.

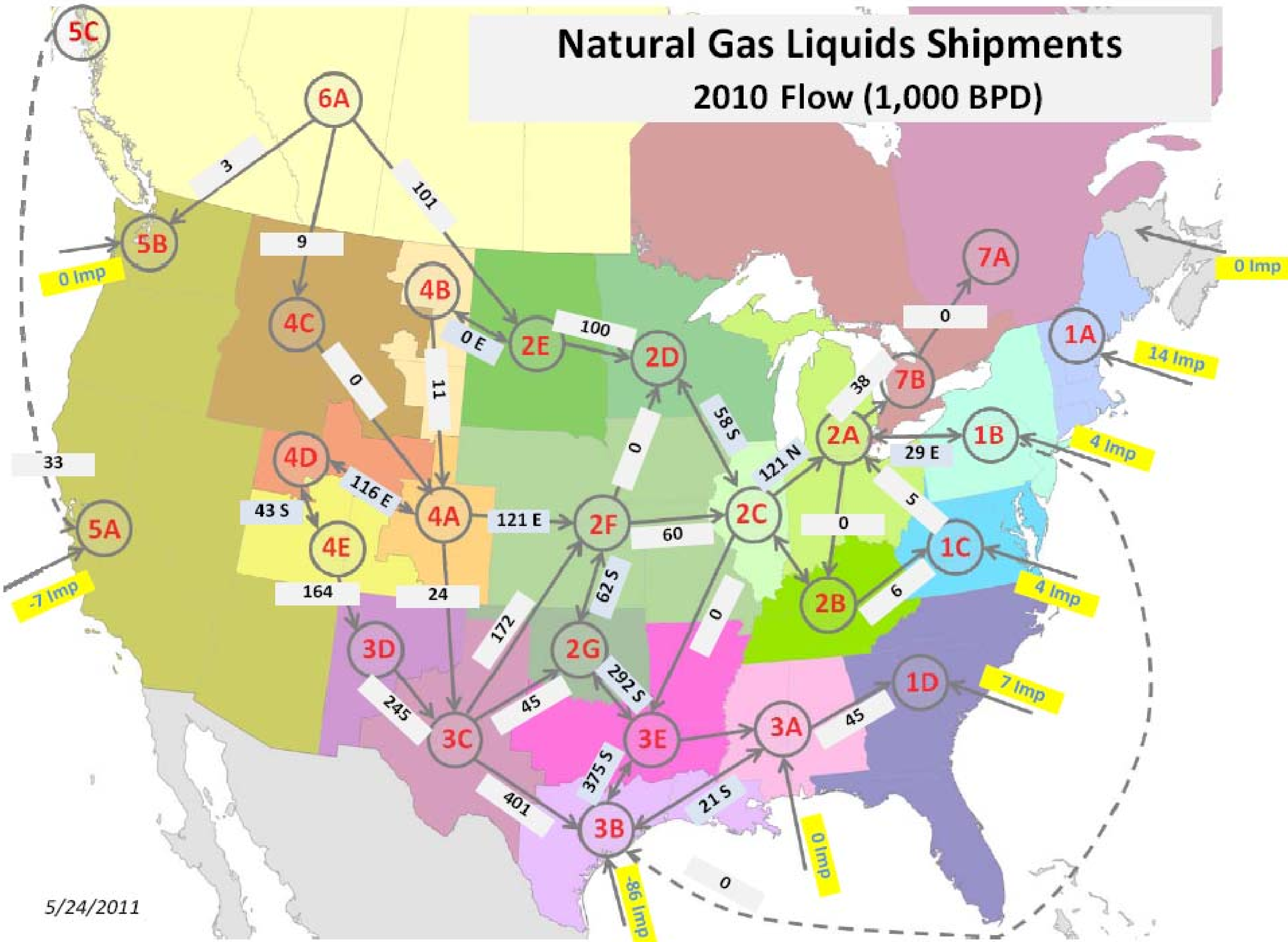
Overall North American NGL Balances (bpd)

	2010	2015	2020	2025	2030	2035	% p.a. 2010 to 2035
Ethane NGP Production	1,073,254	1,286,366	1,509,740	1,646,562	1,772,061	1,899,042	2.3%
Ethane Refinery Production	20,367	20,367	20,367	20,367	20,367	20,367	0.0%
Ethane Consumption (US+Can)	1,093,621	1,306,733	1,530,107	1,666,929	1,792,428	1,919,409	2.3%
Net Imports (Exports)	0	0	0	0	0	0	0.0%
Propane NGP Production	674,042	793,754	910,722	985,608	1,053,689	1,122,359	2.1%
Propane Refinery Production	619,607	619,607	619,607	619,607	619,607	619,607	0.0%
Propane Consumption (US+Can)	1,223,755	1,286,179	1,351,787	1,420,742	1,493,214	1,569,383	1.0%
Net Imports (Exports)	-69,894	-127,182	-178,542	-184,473	-180,082	-172,582	3.7%
Butane Production	411,859	470,184	525,141	559,164	588,972	620,947	1.7%
Butane Refinery Production	130,866	130,866	130,866	130,866	130,866	130,866	0.0%
Butane Consumption (US+Can)	543,813	571,553	600,708	631,350	663,555	697,403	1.0%
Net Imports (Exports)	1,088	-29,497	-55,299	-58,679	-56,282	-54,409	0.0%
Pentanes+ Production	416,664	481,917	536,267	567,211	594,147	623,334	1.6%
Pentanes+ Refinery Production	-17,710	-17,710	-17,710	-17,710	-17,710	-17,710	0.0%
Pentanes+ Consumption (US+Can)	390,376	455,629	509,979	540,924	567,859	597,046	1.7%
Net Imports (Exports)	-8,578	-8,578	-8,578	-8,578	-8,578	-8,578	0.0%
All NGPL Production	2,575,820	3,032,221	3,481,870	3,758,544	4,008,869	4,265,681	2.0%
All Refinery Production	753,130	753,130	753,130	753,130	753,130	753,130	0.0%
All Consumption (US+Can)	3,251,566	3,620,095	3,992,582	4,259,944	4,517,057	4,783,241	1.6%
Net Imports (Exports)	-77,384	-165,257	-242,418	-251,730	-244,942	-235,570	4.6%

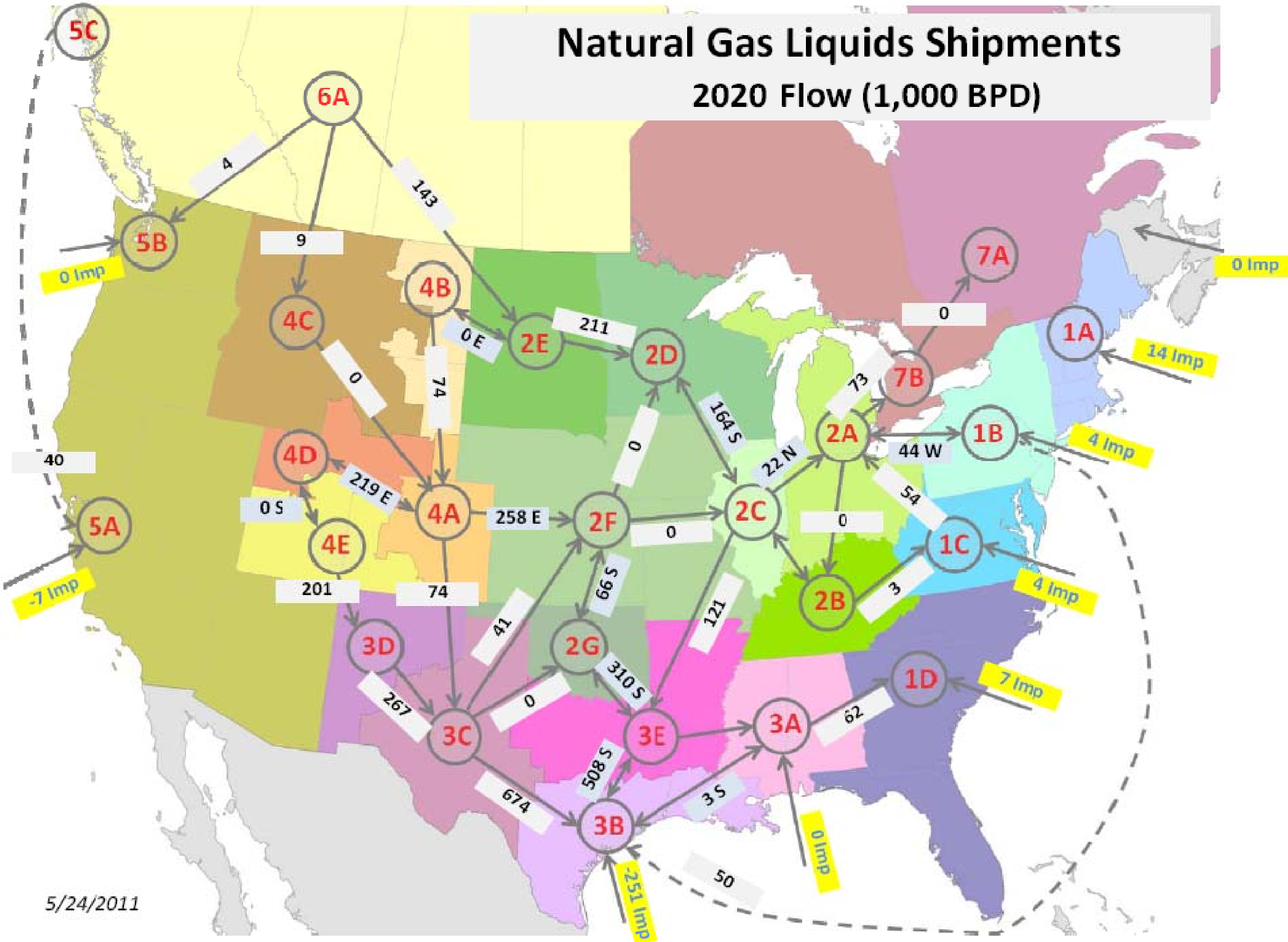
Regional All Gas Plant Liquids Production Trends (bpd)

Node Name	Node Number	2010	2015	2020	2025	2030	2035	% p.a. 2010 to 2035
New England	1A	0	0	0	0	0	0	
Mid-Atlantic	1B	3,137	82,357	143,213	183,948	225,312	255,525	19.2%
DE-MD-VA-WV	1C	20,959	47,581	68,645	83,310	98,154	109,312	6.8%
South Atlantic	1D	0	0	3	41	70	117	
MI IN OH	2A	6,023	10,865	28,133	51,499	74,905	99,075	11.9%
KY TN	2B	6,173	5,912	5,809	5,801	5,613	5,501	-0.5%
Illinois	2C	65,548	64,001	63,718	63,327	62,968	62,705	-0.2%
Upper Midwest (MN WI)	2D	0	0	0	0	0	0	
North and South Dakota	2E	19,633	68,804	91,742	111,953	132,865	150,181	8.5%
Central Plains (NE KS IA MO)	2F	51,610	38,321	33,716	30,248	27,506	27,778	-2.4%
Oklahoma - Cushing	2G	211,059	241,427	273,443	300,653	320,431	335,835	1.9%
AL MS	3A	65,197	64,449	65,257	65,921	66,434	67,274	0.1%
Gulf Coast Texas and Louisiana	3B	373,875	490,277	584,571	628,330	663,390	698,402	2.5%
West Texas and NM Permian	3C	431,726	448,875	473,155	486,174	499,952	520,037	0.7%
North New Mexico	3D	84,914	76,143	67,418	58,776	50,515	42,681	-2.7%
Northeast Texas, North LA, Ark	3E	256,641	274,512	276,339	285,870	288,286	291,585	0.5%
Eastern Rockies (DJB)	4A	26,722	41,915	54,799	64,912	74,108	82,850	4.6%
Baker - Powder River	4B	15,920	55,380	80,284	96,483	111,411	124,357	8.6%
Billings	4C	12,244	10,781	10,274	9,546	9,014	8,870	-1.3%
Salt Lake City - Green River	4D	162,576	185,781	223,664	237,183	250,029	266,978	2.0%
Southwestern Rockies	4E	127,881	148,204	217,700	255,281	287,262	322,910	3.8%
Western U.S.	5A	27,703	25,037	22,124	24,173	26,961	31,268	0.5%
Pacific Northwest	5B	0	0	0	0	0	0	
Alaska	5C	31,607	34,755	37,636	39,998	42,145	44,402	1.4%
Western Canada	6A	567,579	609,850	653,095	667,780	683,987	710,170	0.9%
Montreal	7A	0	-99	40	246	458	777	
Sarnia	7B	7,092	7,092	7,092	7,092	7,092	7,092	0.0%
Sum Gas Plant Liquids		**2,575,820**	**3,032,221**	**3,481,870**	**3,758,544**	**4,008,869**	**4,265,681**	**2.0%**

Major NGL Flow Patterns 2010

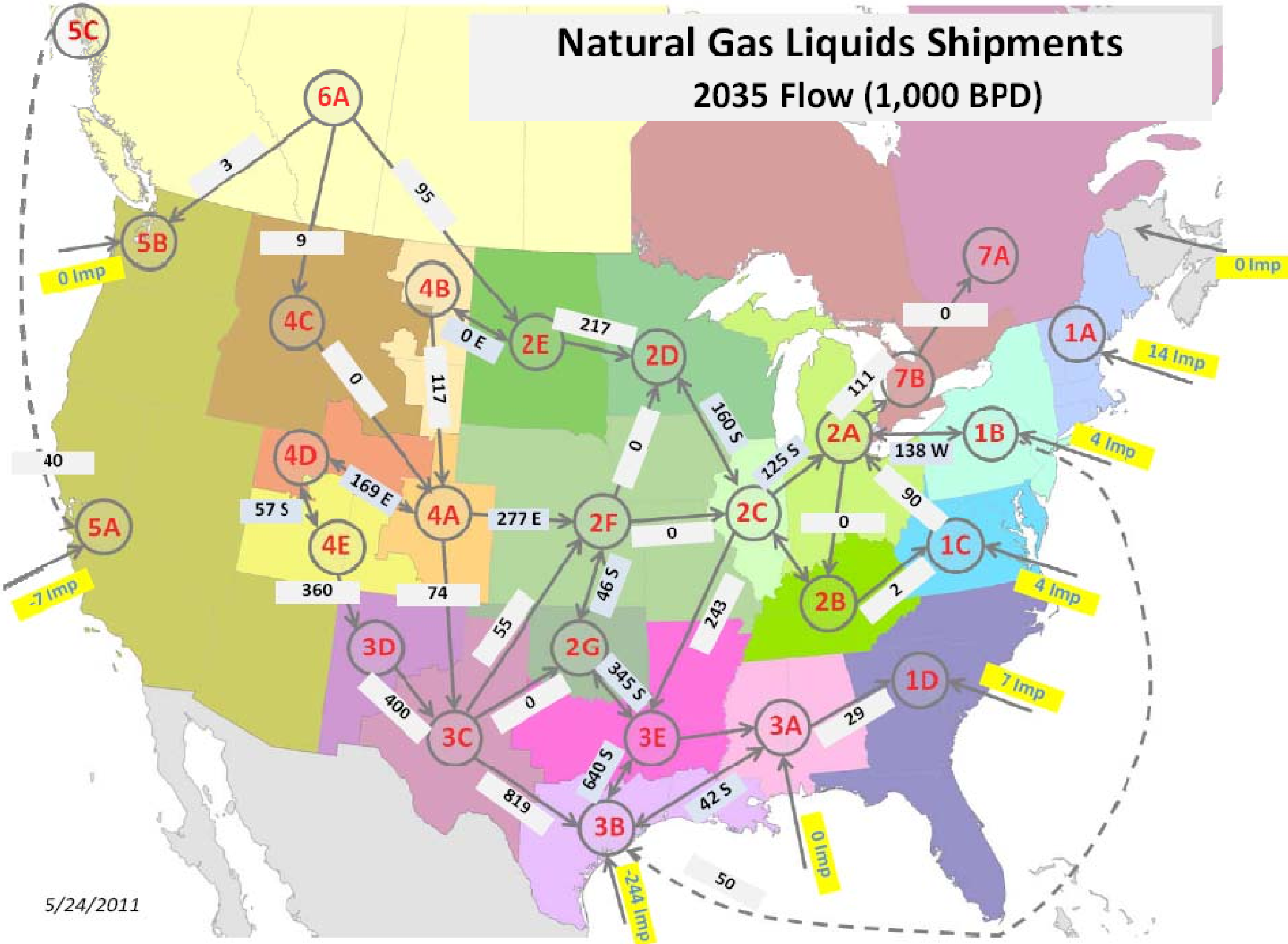


Major NGL Flow Patterns 2020

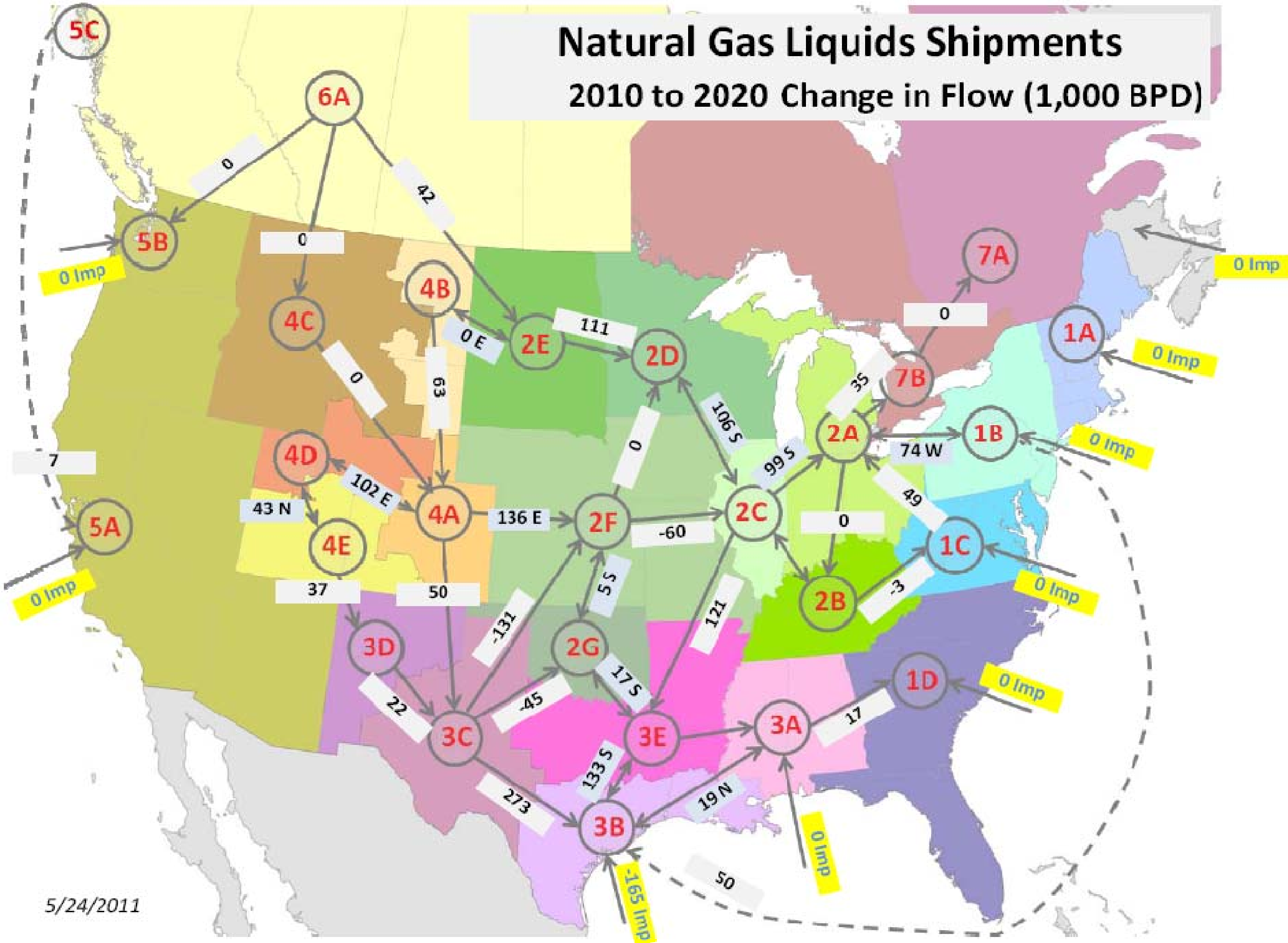


ICF INTERNATIONAL

Major NGL Flow Patterns 2035

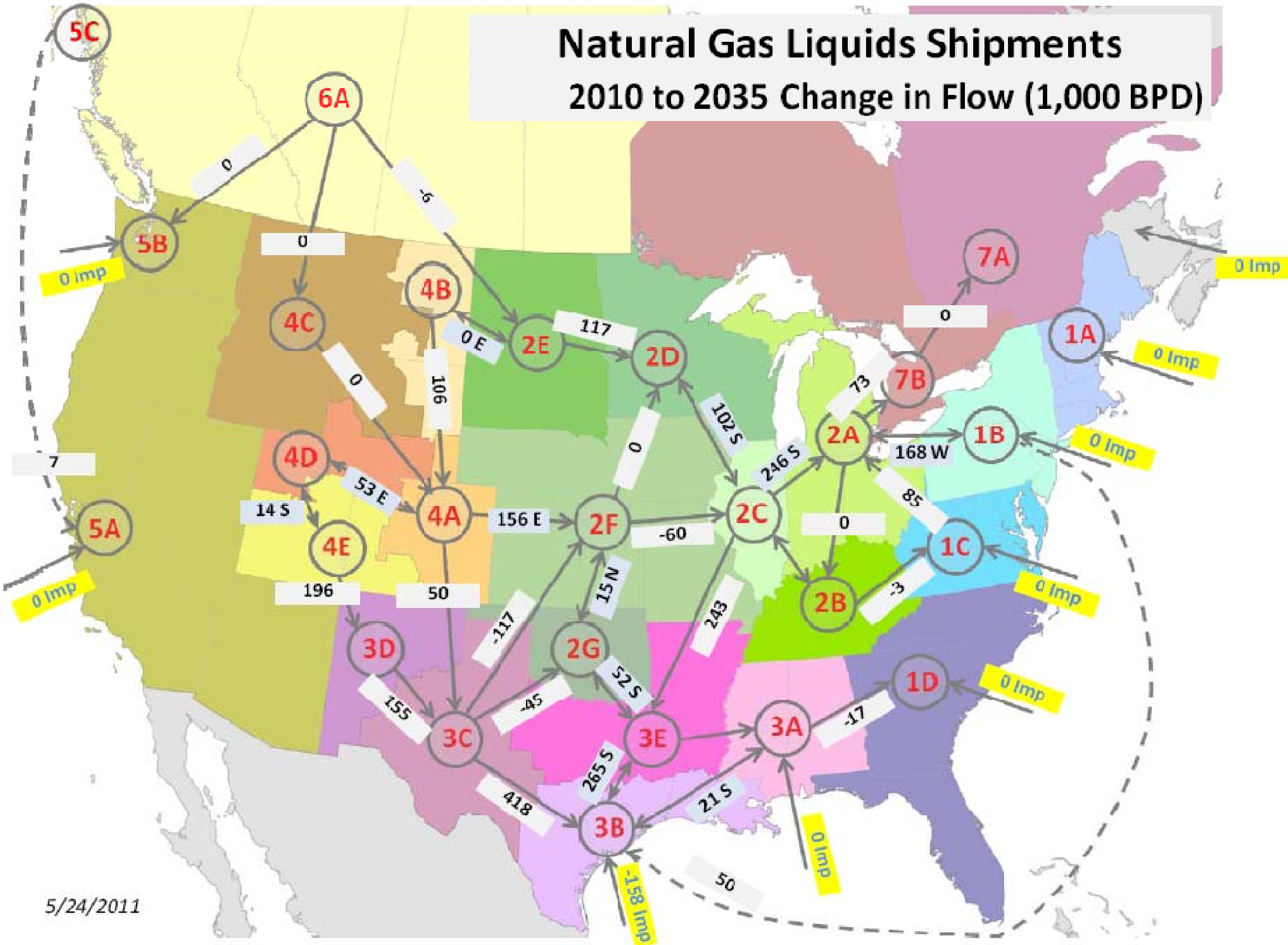


Major NGL Change in Flow Patterns



INTERNATIONAL

Major NGL Change in Flow Patterns



NGL Pipeline Infrastructure

- A significant number of pipeline expansions and new pipelines are under development to accommodate growing NGL production. Many of these projects are in areas like the Gulf Coast, West Texas, and Oklahoma, which have a significant amount of existing pipeline infrastructure. Rapid growth in emerging shale and tight gas formations like the Eagle Ford or Granite Wash, is putting a strain on existing infrastructure, and creating a need for expansions.
- Other areas that will need new pipeline capacity for NGLs, both in the short and the long term, are the frontier shale plays like Marcellus, Utica, Bakken, and Niobrara. These liquids rich plays do not have much existing capacity and will require significant investment. Roughly 80 percent of the new NGL infrastructure requirements will be in these areas.
- This projection builds roughly 2 million barrels per day of new natural gas liquids transmission lines between 2010 and 2035.

Overall North American Crude Oil and Lease Condensate Balances (bpd)

	2010	2015	2020	2025	2030	2035
Production	8,346,583	9,238,937	10,621,826	11,382,251	12,024,555	12,741,672
Imports	7,782,546	6,630,456	5,106,754	4,155,596	3,425,162	2,845,953
Refinery Runs	16,129,129	15,869,394	15,728,580	15,537,847	15,449,716	15,587,625

US Liquid Fuels Supply and Disposition from AEO (million barrels per day, unless otherwise noted)							
Supply and Disposition	2010	2015	2020	2025	2030	2035	%ch p.a.
Crude Oil							
Domestic Crude Production 1/	5.43	5.72	6.05	5.80	5.82	5.73	0.26%
Alaska	0.61	0.49	0.42	0.41	0.27	0.39	-1.92%
Lower 48 States	4.82	5.23	5.63	5.39	5.55	5.34	0.48%
Net Imports	9.17	8.81	8.34	8.40	8.29	8.52	-0.20%
Gross Imports	9.21	8.84	8.38	8.43	8.32	8.55	-0.20%
Exports	0.04	0.03	0.03	0.03	0.03	0.03	-1.31%
Other Crude Supply 2/	0.01	0.00	0.00	0.00	0.00	0.00	- -
Total Crude Supply (US Refinery Runs)	**14.61**	**14.53**	**14.39**	**14.20**	**14.11**	**14.24**	**-0.02%**
Other Petroleum Supply	**3.36**	**4.39**	**4.35**	**4.41**	**4.39**	**4.43**	**1%**
Natural Gas Plant Liquids	1.96	2.22	2.37	2.63	2.74	2.90	1.6%
Net Product Imports	0.37	1.17	0.97	0.84	0.77	0.66	-0.5%
Gross Refined Product Imports 3/	0.97	1.06	0.98	0.94	0.93	0.85	-1.5%
Unfinished Oil Imports	0.62	0.80	0.78	0.76	0.75	0.77	0.5%
Blending Component Imports	0.70	0.81	0.81	0.80	0.81	0.84	0.6%
Exports	1.92	1.51	1.61	1.65	1.71	1.80	-0.2%
Refinery Processing Gain 4/	1.03	1.00	1.01	0.93	0.88	0.87	-0.5%
Product Stock Withdrawal	0.00	0.00	0.00	0.00	0.00	0.00	- -
Other Non-petroleum Supply	**1.01**	**1.40**	**1.85**	**2.33**	**2.86**	**3.30**	**6%**
Supply from Renewable Sources	0.89	1.12	1.44	1.89	2.31	2.56	4.8%
Ethanol	0.86	1.01	1.29	1.57	1.76	1.82	3.6%
Domestic Production	0.86	0.95	1.18	1.41	1.52	1.56	3.0%
Net Imports	0.00	0.06	0.11	0.16	0.23	0.26	12.2%
Biodiesel	0.02	0.09	0.10	0.12	0.13	0.13	7.1%
Domestic Production	0.03	0.09	0.10	0.12	0.13	0.13	5.2%
Net Imports	-0.01	0.00	0.00	0.00	0.00	0.00	- -
Other Biomass-derived Liquids 5/	0.00	0.02	0.05	0.20	0.42	0.62	- -
Liquids from Gas	0.00	0.00	0.00	0.00	0.00	0.00	- -
Liquids from Coal	0.00	0.05	0.07	0.13	0.29	0.47	- -
Other 6/	0.12	0.24	0.34	0.31	0.27	0.27	6.6%
Total Primary Supply 7/	**18.97**	**20.32**	**20.59**	**20.94**	**21.36**	**21.97**	**0.62%**
Liquid Fuels Consumption							
by Fuel							
Liquefied Petroleum Gases	2.13	2.32	2.34	2.33	2.26	2.19	0.1%
E85 8/	0.00	0.01	0.22	0.60	0.83	0.83	26.2%
Motor Gasoline 9/	9.02	9.40	9.18	8.89	8.94	9.31	0.1%
Jet Fuel 10/	1.40	1.55	1.62	1.68	1.72	1.75	0.9%
Distillate Fuel Oil 11/	3.73	4.14	4.33	4.49	4.66	4.87	1.1%
of which: Diesel	3.24	3.68	3.90	4.09	4.28	4.51	1.4%
Residual Fuel Oil	0.53	0.59	0.60	0.61	0.61	0.62	0.7%
Other 12/	2.16	2.45	2.41	2.38	2.37	2.41	0.4%
by Sector							
Residential and Commercial	1.00	0.95	0.91	0.88	0.86	0.85	-0.8%
Industrial 13/	4.37	5.00	4.98	4.94	4.84	4.80	0.5%
Transportation	13.74	14.31	14.60	14.95	15.47	16.11	0.6%
Electric Power 14/	0.20	0.19	0.20	0.21	0.21	0.21	0.8%
Total	**18.98**	**20.45**	**20.69**	**20.98**	**21.39**	**21.97**	**1%**

US Crude Oil and Petroleum Liquids Balance from AEO (Million Barrels per day)

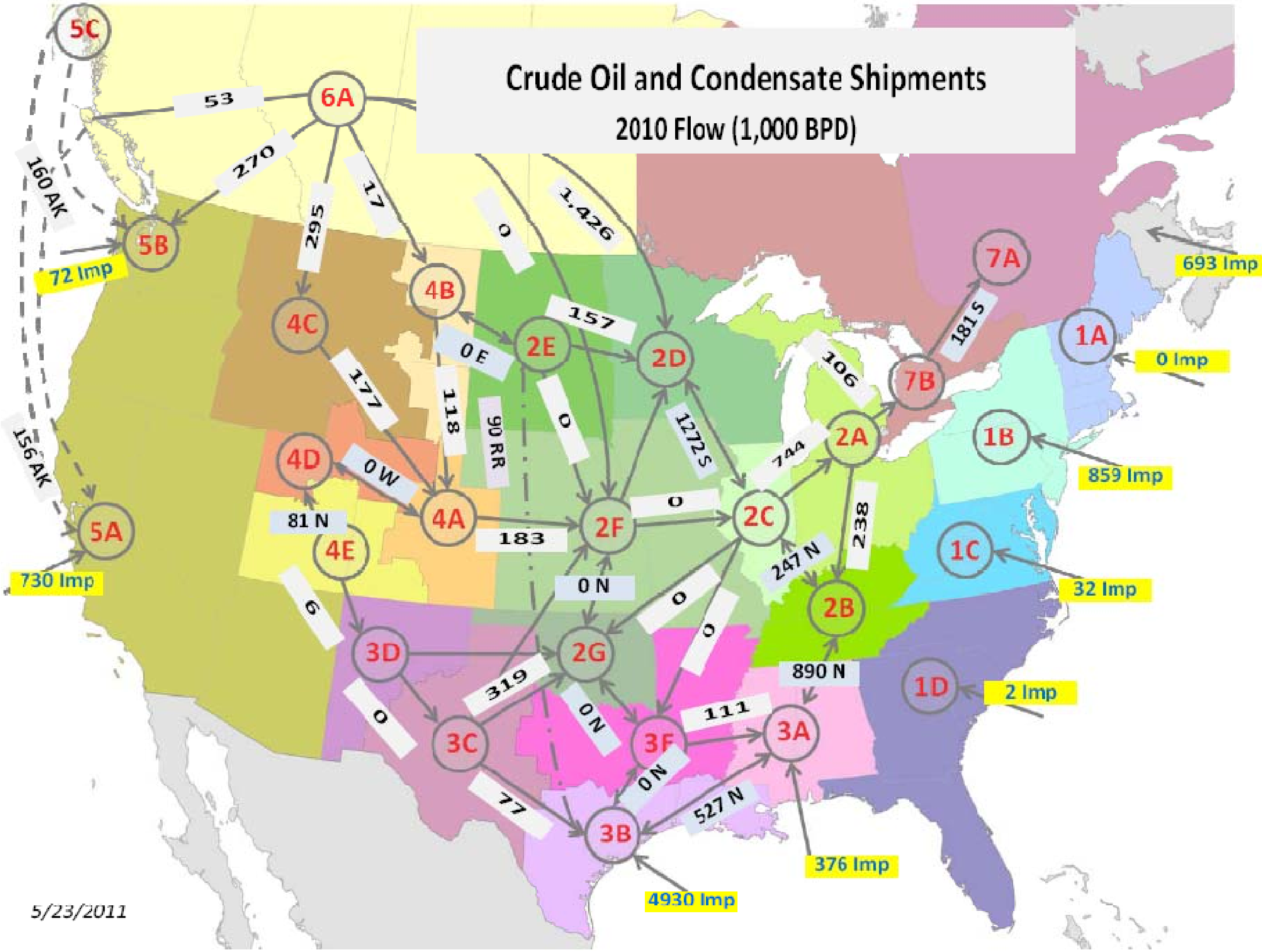
Only AEO data used for this study is refinery runs.

Regional Crude & Condensate Production Trends (bpd)

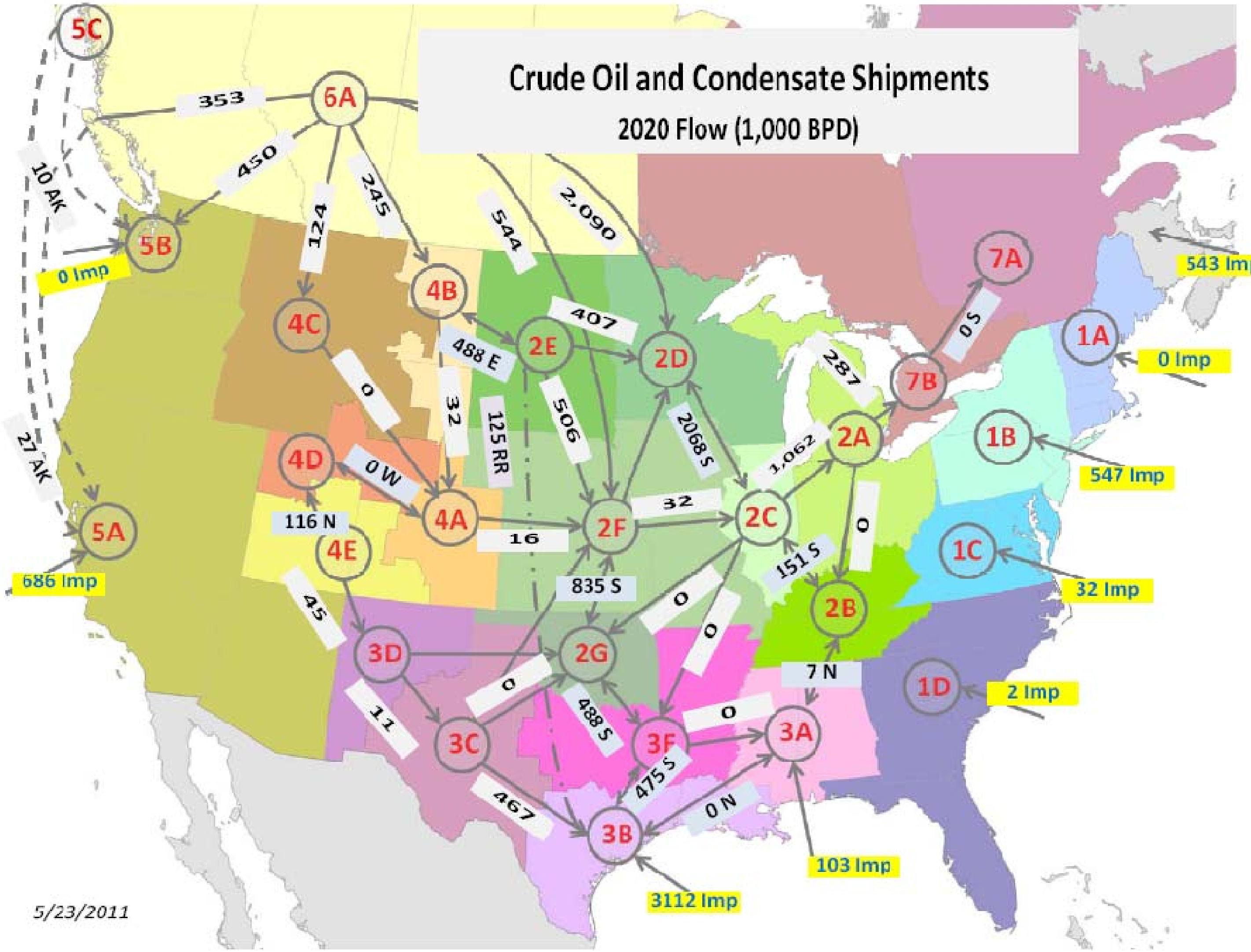
Node Name	Node Number	2010	2015	2020	2025	2030	2035	% p.a. 2010 to 2035
New England	1A	-	-	-	-	-	-	
Mid-Atlantic	1B	10,400	21,860	36,956	50,607	62,842	73,522	8.1%
DE-MD-VA-WV	1C	5,333	10,177	17,210	23,836	29,736	34,972	7.8%
South Atlantic	1D	4,747	5,523	6,040	6,182	6,157	6,319	1.2%
MI IN OH	2A	38,320	57,984	102,189	145,184	182,530	217,243	51.9%
KY TN	2B	7,250	7,003	6,810	6,748	6,668	6,625	-0.4%
Illinois	2C	24,373	20,165	21,661	20,003	17,819	16,131	-1.6%
Upper Midwest (MN WI)	2D	-	-	-	-	-	-	
North and South Dakota	2E	304,346	542,072	607,925	660,390	714,703	764,363	3.8%
Central Plains (NE KS IA MO)	2F	115,304	124,990	138,972	139,482	132,473	137,605	0.7%
Oklahoma - Cushing	2G	183,711	169,473	155,763	148,397	140,226	132,426	-1.3%
AL MS	3A	84,106	97,858	107,013	109,533	109,090	111,948	1.2%
Gulf Coast Texas and Louisiana	3B	2,015,476	1,789,262	2,084,271	2,197,059	2,364,903	2,526,463	0.9%
West Texas and NM Permian	3C	971,189	1,096,044	1,126,817	1,102,549	1,067,352	1,043,087	0.3%
North New Mexico	3D	6,814	7,167	6,211	4,728	3,095	1,477	-5.9%
Northeast Texas, North LA, Ark	3E	163,884	130,203	118,298	112,216	99,571	88,966	-2.4%
Eastern Rockies (DJB)	4A	54,753	126,662	170,255	198,380	221,022	240,990	6.1%
Baker - Powder River	4B	100,569	217,503	275,216	316,358	349,741	379,234	5.5%
Billings	4C	64,753	61,489	58,668	55,506	52,674	51,116	-0.9%
Salt Lake City - Green River	4D	48,826	39,017	55,427	51,852	57,314	68,232	1.3%
Southwestern Rockies	4E	87,005	127,176	160,851	161,945	167,164	173,058	2.8%
Western U.S.	5A	621,428	562,775	455,765	438,774	430,012	464,526	-1.2%
Pacific Northwest	5B	-	-	-	-	-	-	
Alaska	5C	599,353	481,070	407,200	397,020	260,500	378,691	-1.8%
Western Canada	6A	2,550,283	3,312,979	4,295,167	4,845,639	5,374,428	5,664,033	3.2%
Montreal	7A	282,892	229,018	205,673	188,395	173,067	159,177	-2.3%
Sarnia	7B	1,468	1,468	1,468	1,468	1,468	1,468	0.0%
Sum US & Can. Crude and Condensate		8,346,583	9,238,937	10,621,826	11,382,251	12,024,555	12,741,672	1.7%

Major Crude & Condensate Flow Patterns 2010

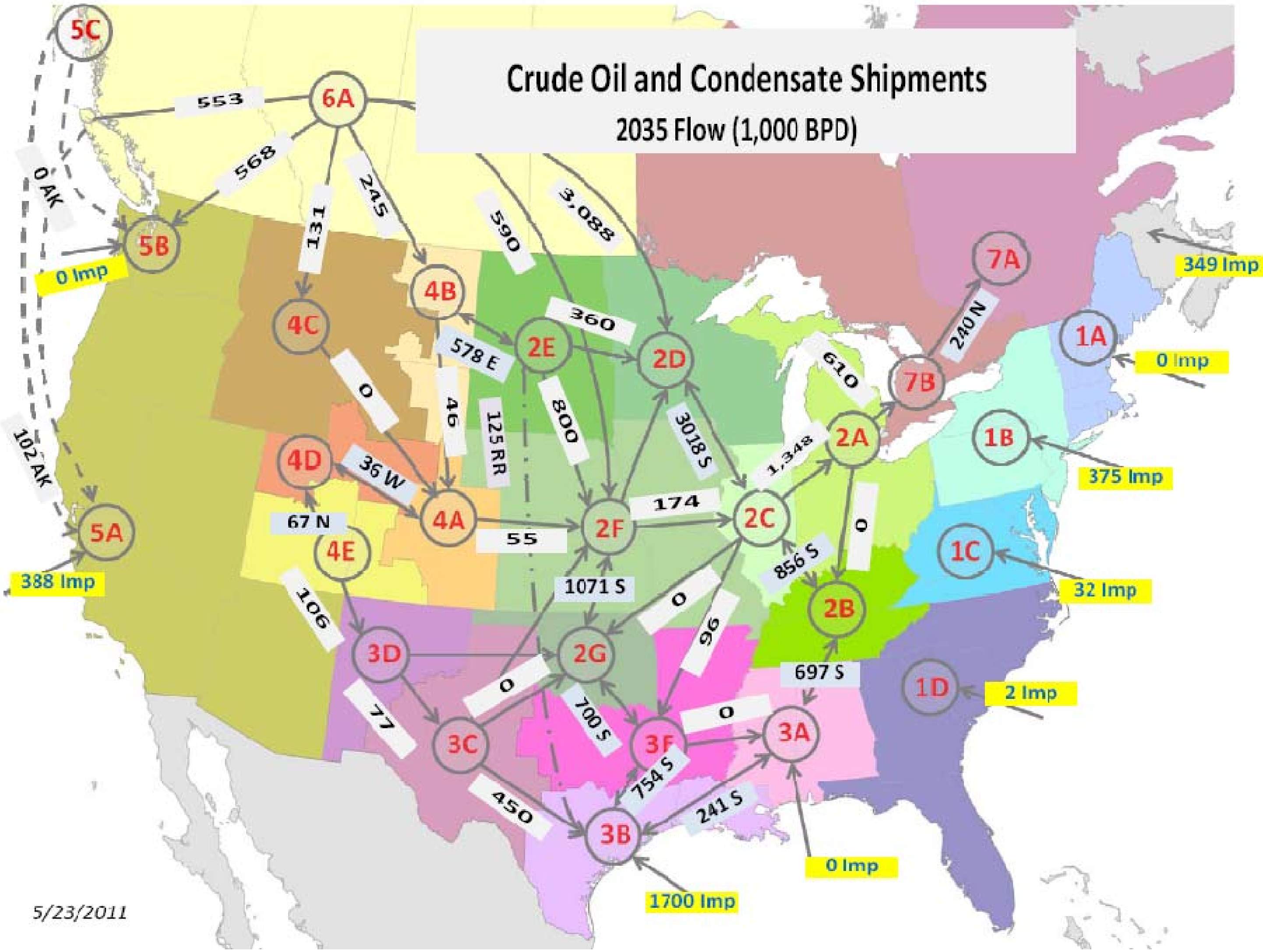
ICF INTERNATIONAL



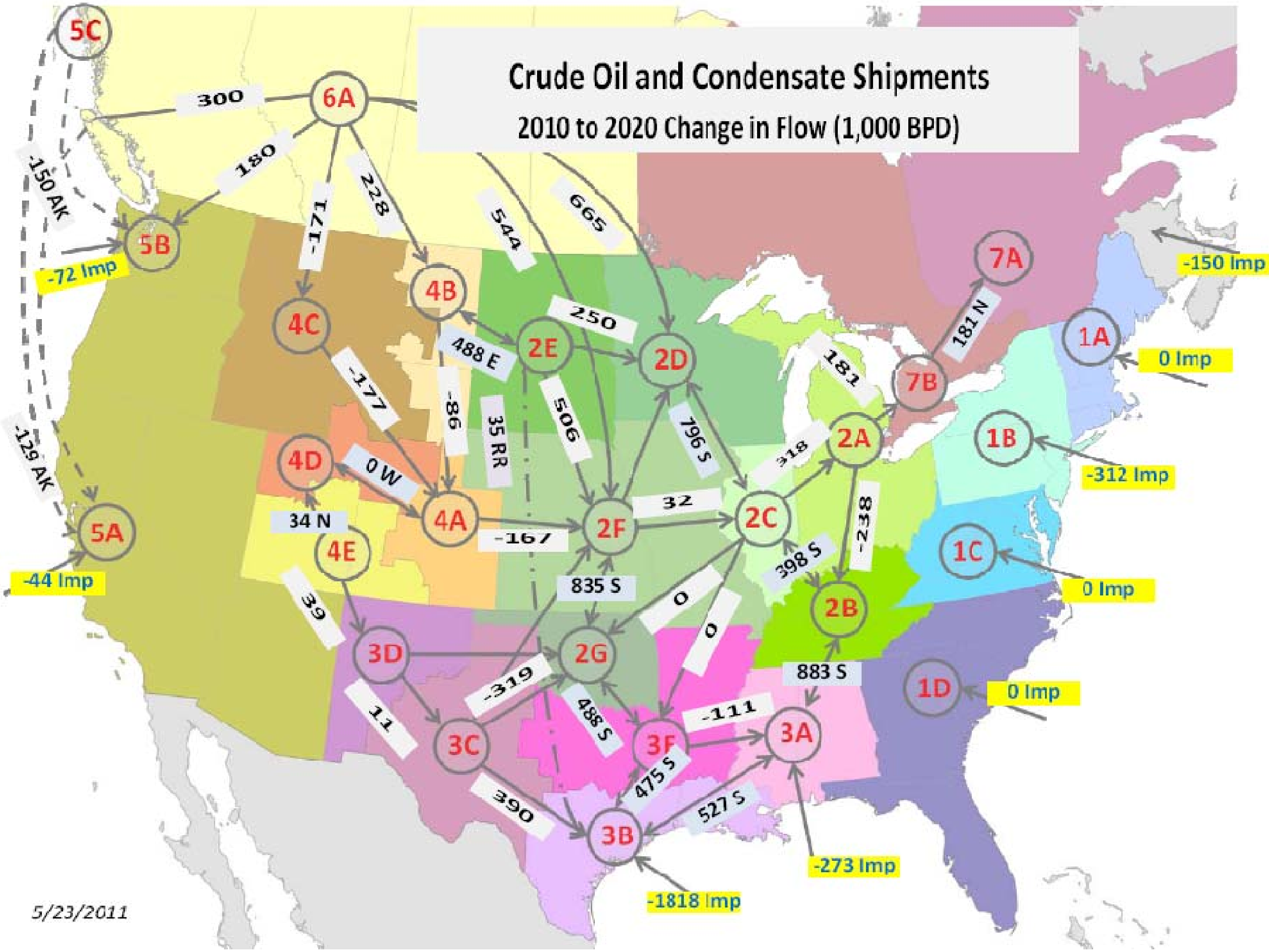
Major Crude & Condensate Flow Patterns 2020



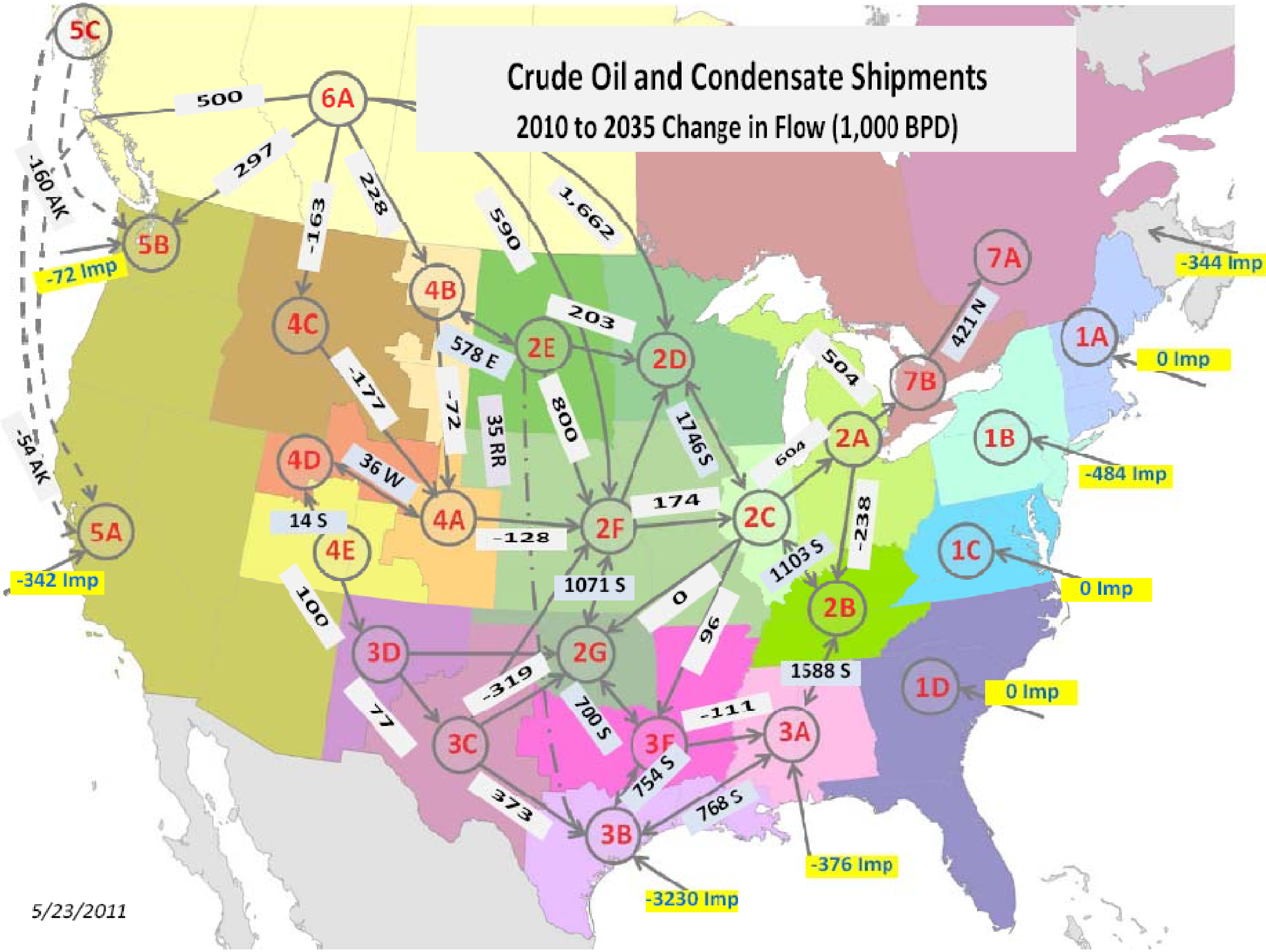
Major Crude & Condensate Flow Patterns 2035



Major Crude & Condensate Change in Flow



Major Crude & Condensate Change in Flow



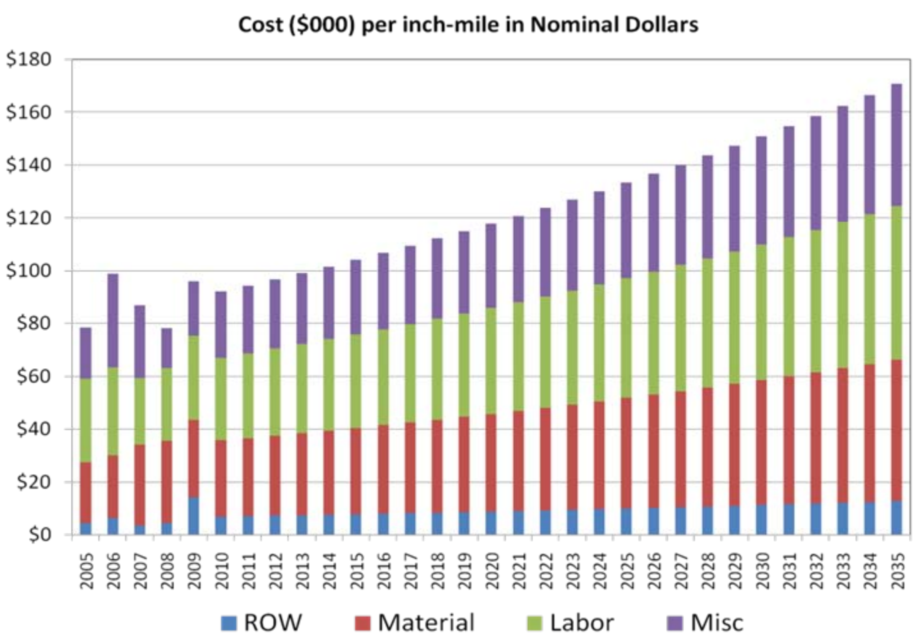
Oil Pipeline Infrastructure

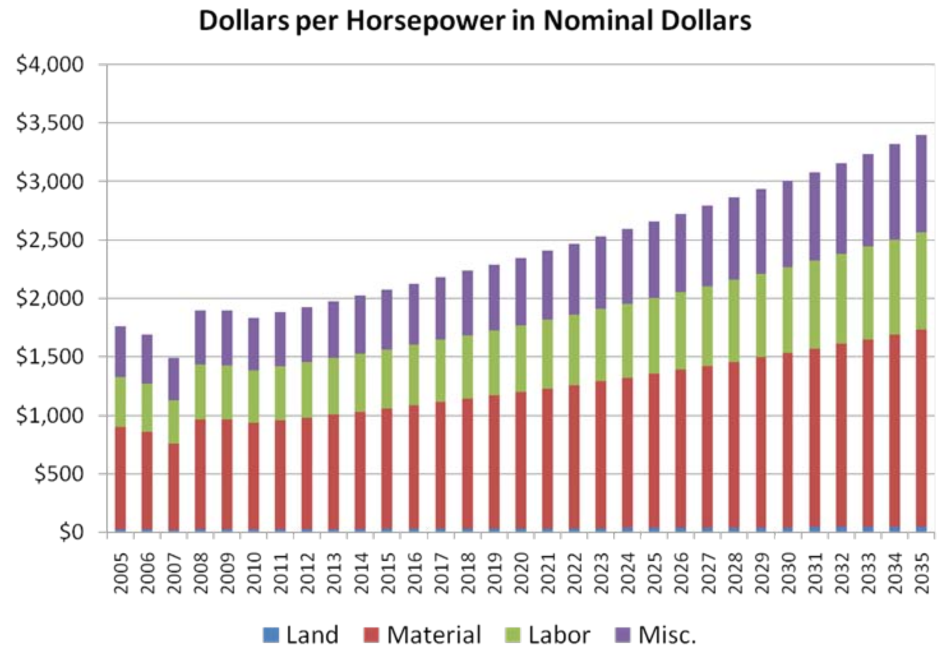
- The current trend of building new pipelines to deliver oil from Western Canada to the refineries of the Central US and Gulf Coast is expected to continue.
- The two Keystone projects (the first is complete and the second Keystone XL is waiting final approval in the US to begin construction in 2012) will increase capacity from western Canada by 1.3 Million Barrels per day and should accommodate the growth for the next 10 to 20 years.
- Significant pipe capacity is also built to the Pacific Coast to facilitate exports from ports in British Columbia.
- Additional oil pipeline capacity is also built out of the Rockies, but no where near the amount needed from western Canada.
- Over 5 Million Barrels per Day of new oil transmission capacity will be required between 2010 and 2035, in addition to reversing capacity on some existing oil pipes where changes in supply sources affect oil movement patterns.

Appendix B: Nominal Dollar Slides

Costs of Pipelines and Compression

All Costs Reported in Nominal Dollars





- Projected costs of pipelines and compression on a nominal dollar per inch-mile and a nominal dollar per horsepower basis start off in 2011 at levels that are consistent with average costs over the prior five years and are projected to rise at a rate that is consistent with inflation (i.e., they are projected to remain constant in real terms).
- Pipeline costs rise from about $90,000 per inch-mile to about 170,000 per inch-mile by 2035.
- Compression costs rise from about $1,700 per HP to about $3,500 per HP by 2035.

Gas Processing Plant Additions

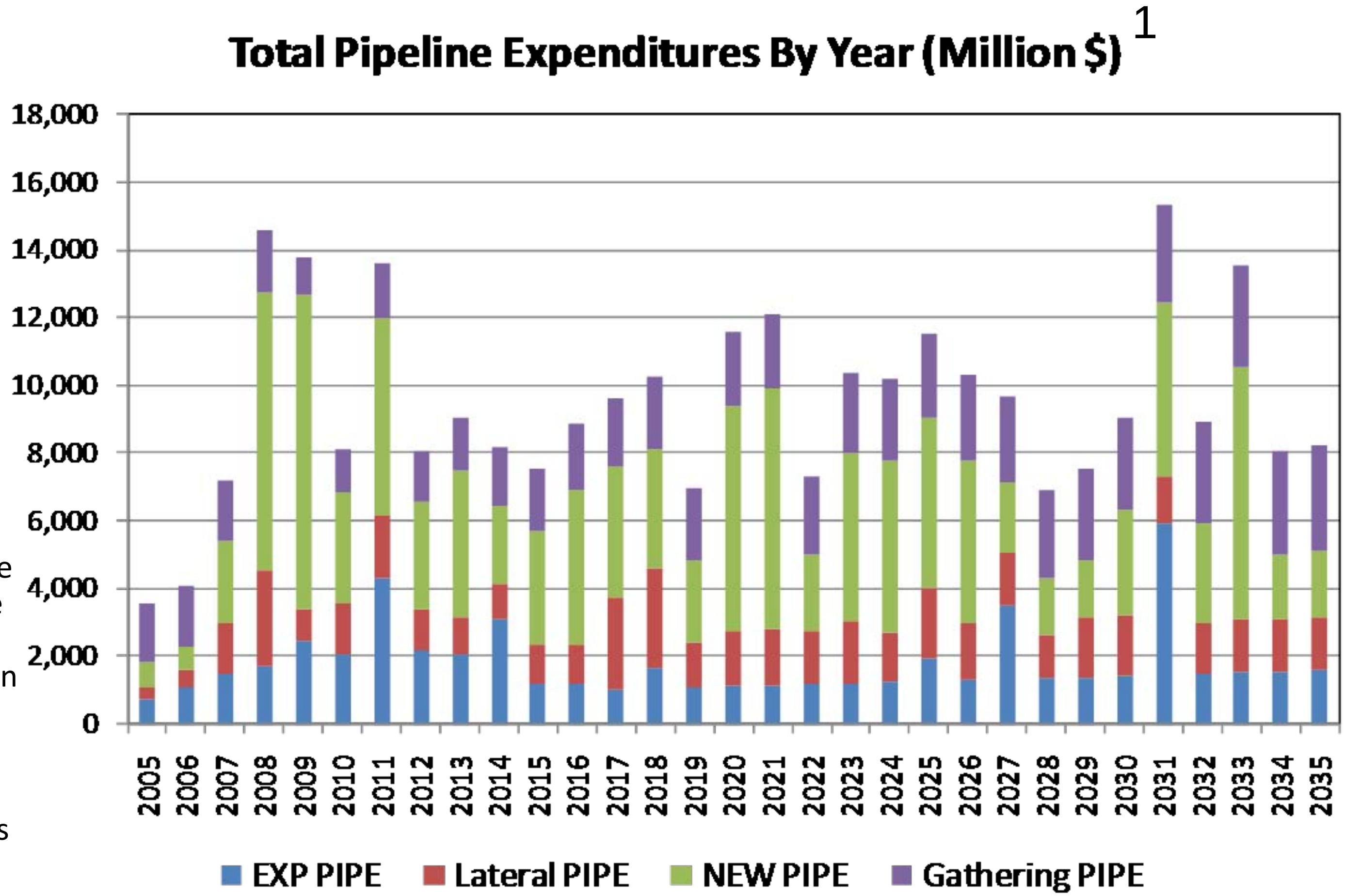
Cumulative from 2010	Change in Gas Production (Tcf)	Change in Gas Production (Bcfd)	New Plants Added	Additional Gas Plant Capacity (Bcfd)	Gas Plant Expenditures Billions $
2015	3.3	9.1	81	10.4	$7.6
2020	7.0	19.2	137	18.1	$14.0
2025	9.3	25.6	175	23.1	$18.8
2030	11.2	30.5	207	27.7	$23.6
2035	13.2	36.0	238	32.5	$29.3

- Roughly 240 new processing plants with over 32 Bcfd of processing capability is needed to process much of the incremental gas production occurring over the next 25 years. Capital costs of the new processing plants almost of $30 billion.
- Large production growth in natural gas from shale formations and previously unproduced frontier areas will require additional gas plant infrastructure over what is simply needed to maintain the existing production levels.

Capital Expenditures for New Pipeline Capacity

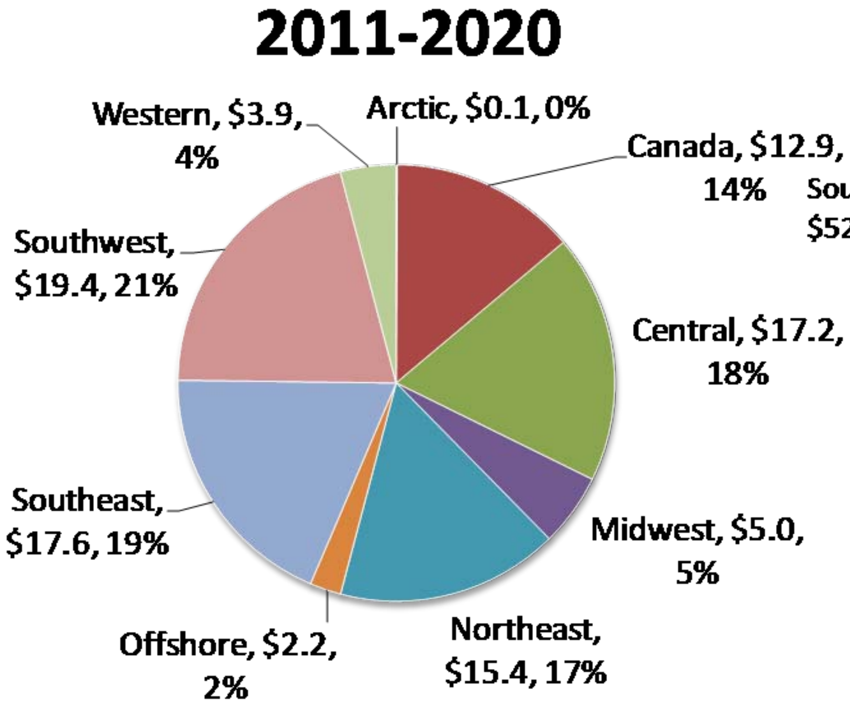
Million dollars (Nominal$) Spent Each Year, Including the Cost of Compression

- Between 2005 and 2010, pipeline expenditures averaged $8.5 Billion per year in nominal dollars.
- Annual pipeline expenditures are projected to be between $7 and $15 billion per year between 2011 and 2035.
- Of the $24 billion of projected investment between 2011 and 2035, roughly 50 percent is for new transmission lines.
- Capital expenditures for the new pipeline infrastructure projected here average about $10 billion per year in nominal dollars.
- If upstream gathering lines are excluded, average annual capital expenditures for new pipeline are $7.4 billion per year in nominal dollars.

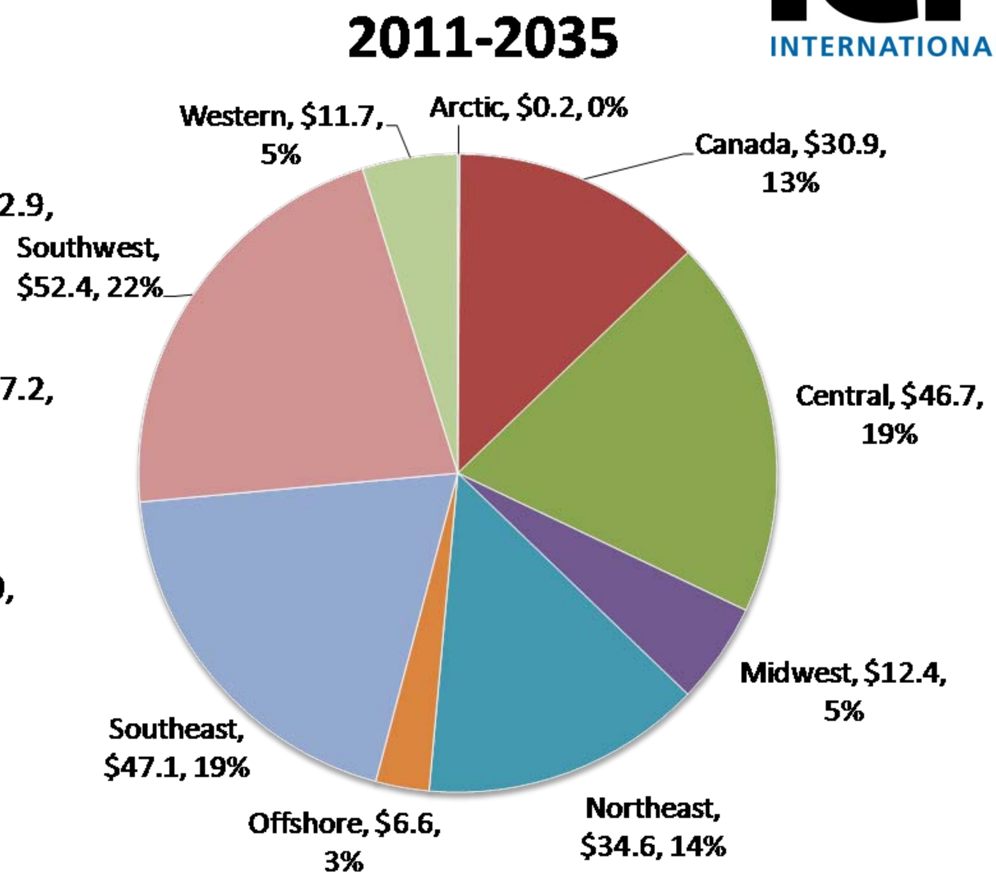


1. Pipeline project costs are represented in the year the project enters service. While in actuality, pipeline investment costs are generally spread over one or more years leading up to a project entering service.

Regional Breakout for Capital Expenditures for New Pipeline Capacity



$93.7Billion over 10 years



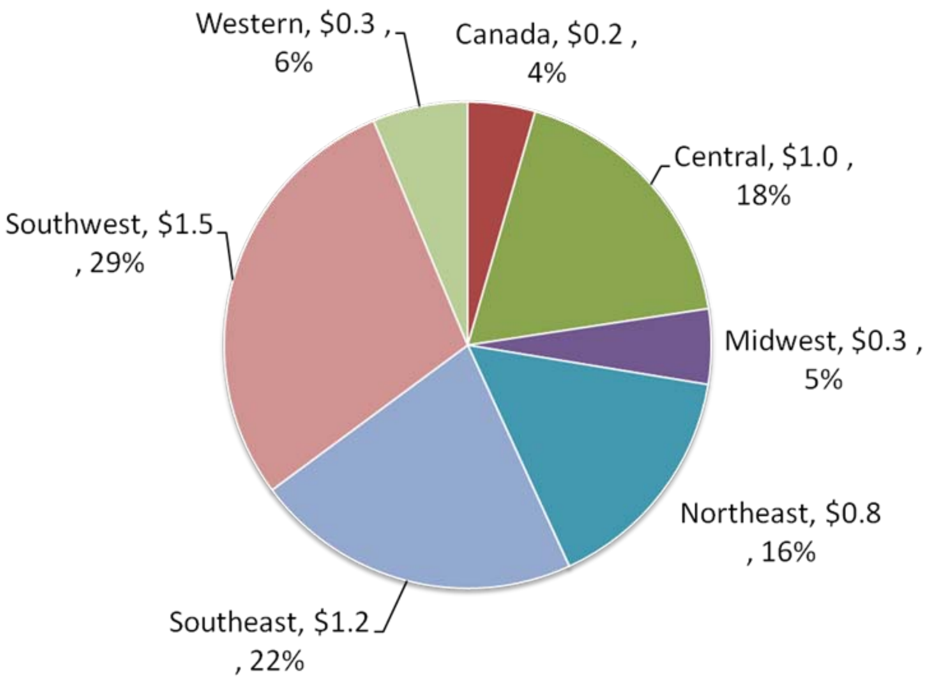
$242.6 Billion over 25 years

- The largest investment in new pipelines occurs in the supply areas of the Southwest and Central, followed closely by the Southeast and Northeast which are demand regions with access to growing supply.

Expenditures for New Gas Storage Capacity

Pie Chart in Nominal Dollars

2011-2035



$5.4 Billion over 25 years

Regional Comparison of Costs (Index =1.0)

Region	Factor
Canada	0.88
Central	1.03
Midwest	0.77
Northeast	1.83
Southeast	1.10
Southwest	1.18
Western	0.93
Grand Total	1.00

Storage Costs for 2008-09 in Millions of Nominal$ per Bcf of Working Gas Capacity

Field Type	Expansion	New
Salt Cavern	$8.5	$10.7
Depleted Reservoir	$6.2	$8.4
Aquifer	$13.9	$16.9

Nominal storage projects cost are escalated at 2.5% per year. Excludes pipeline connection cost.

- Capital expenditures for new gas storage capacity total over $5 billion over the next 25 years.

Natural Gas Infrastructure Capital Requirements from 2010 (Billions of Nominal$)

ICF INTERNATIONAL

	2011 to 2020	2011 to 2035	Average Annual Expenditures
Transmission Mainline	$52.4	$131.9	$5.3
Laterals to/from Power Plants, Gas Storage and Processing Plants	$16.2	$40.5	$1.6
Gathering Line	$18.7	$58.6	$2.3
Pipeline Compression	$6.3	$11.7	$0.5
Gas Storage Fields	$3.9	$5.4	$0.2
Processing Capacity	$14.0	$29.3	$1.2
Total Gas Capital Expenditure	$111.5	$277.4	$11.1

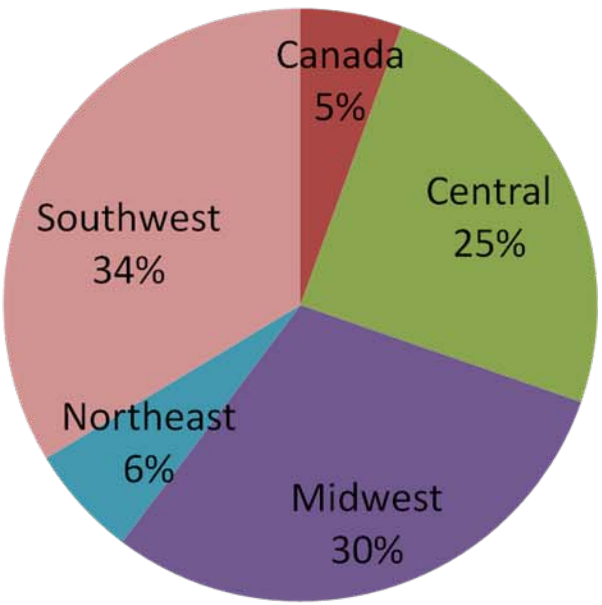
- Recent historical trends have matched or surpassed the average annual expenditures shown here.

Oil Pipeline Infrastructure Added in Reference Case (Cumulative)

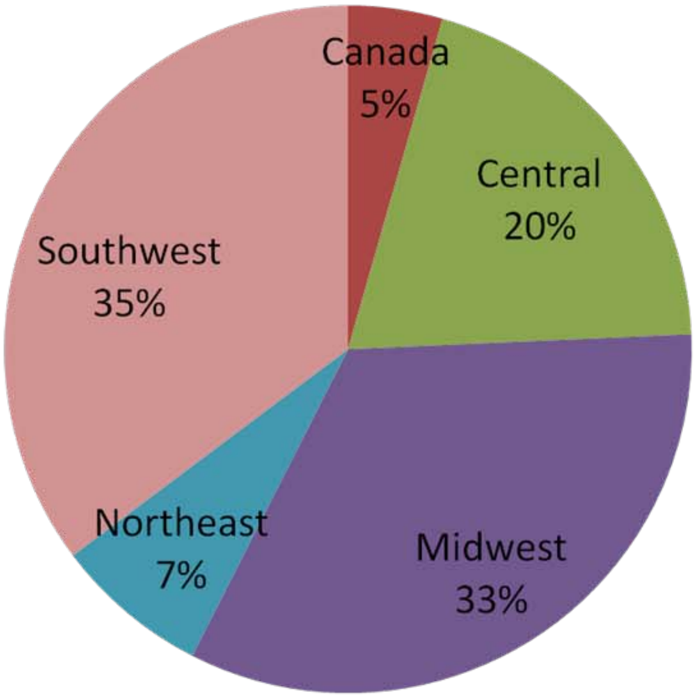
Oil Pipeline Infrastructure	2010-20	2010-35	Average Annual
Miles of Transmission Mainline (1000s)	13.0	19.3	0.8
Cost of Transmission Mainline (Billions $)	$22.5	$42.5	1.7
NGL Pipeline Infrastructure	**2010-20**	**2010-35**	**Average Annual**
Miles of Transmission Mainline (1000s)	10.6	12.5	0.5
Cost of Transmission Mainline (Billions $)	$14.4	$17.9	$0.7
Oil and NGL Pipeline Infrastructure	**2010-20**	**2010-35**	**Average Annual**
Miles of Transmission Mainline (1000s)	23.6	31.8	1.3
Cost of Transmission Mainline (Billions $)	$36.9	$60.4	$2.4

Regional NGL Pipeline Expenditures in Nominal Dollars

Total Expenditures, 2011-20
(Billions of Nominal $):
$14.4

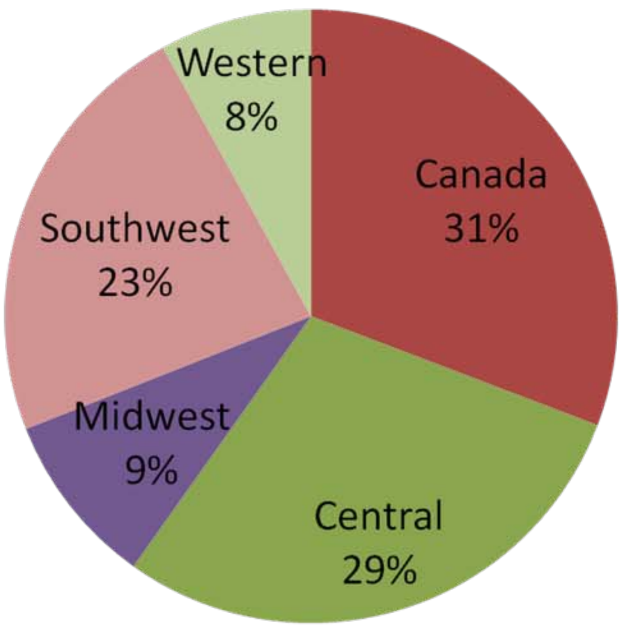


Total Expenditures, 2011-35
(Billions of Nominal $):
$17.9

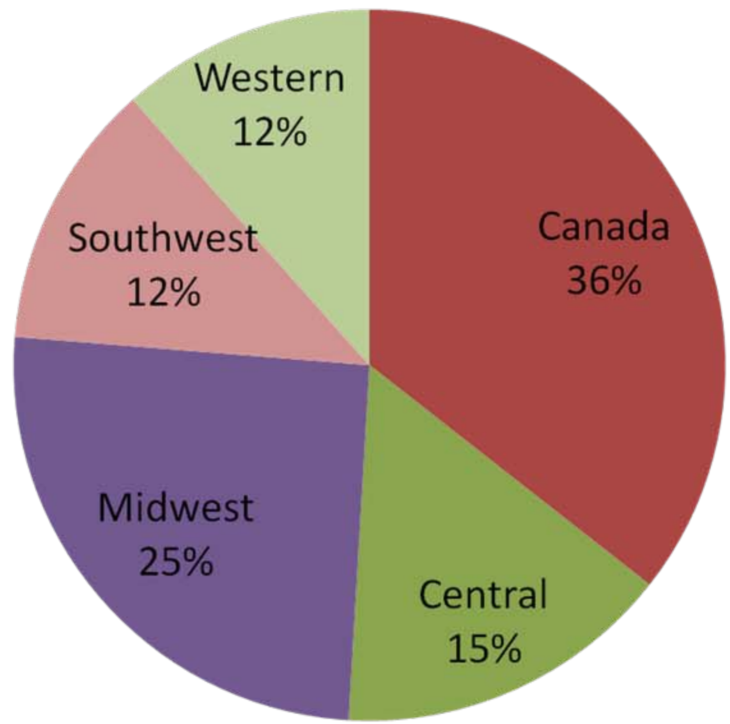


Regional Oil Pipeline Expenditures, in Nominal Dollars

Total Expenditures, 2011-20
(Billions of Nominal $):
$22.5

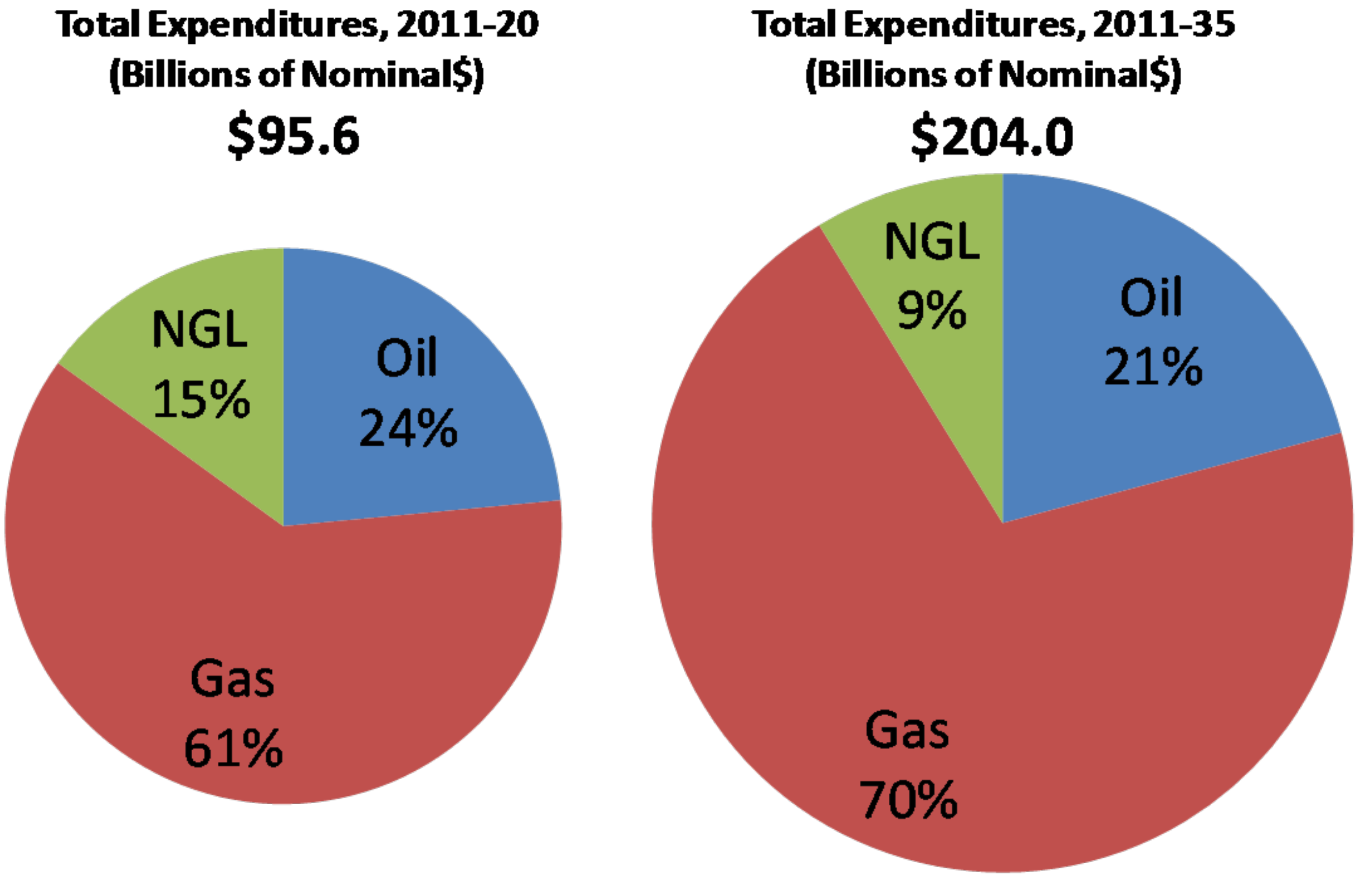


Oil Pipeline Expenditures, 2011-35
(Billions of Nominal $):
$42.5



Oil and NGL Share of Total Gas Infrastructure Cost

Main Line Transmission Expenditures



- New pipelines for Oil and NGL growth are expected to represent 30 to 40 percent of all main transmission line expenditures in the projection.

Cost of Infrastructure Added in the Combined Natural Gas and Liquids Reference Case
(Billions of Nominal$)

Cost of Infrastructure Added in the Combined Natural Gas and Liquids Reference Case (Billions of Nominal$)	2011 to 2020	2011 to 2035	Average Annual Expenditures
Gas Transmission Mainline	$52.4	$131.9	$5.3
Laterals to/from Power Plants, Gas Storage and Processing Plants	$16.2	$40.5	$1.6
Gathering Line	$18.7	$58.6	$2.3
Gas Pipeline Compression	$6.3	$11.7	$0.5
Gas Storage Fields	$3.9	$5.4	$0.2
Gas Processing Capacity	$14.0	$29.3	$1.2
Sub-Total of Gas Capital Requirements	$111.5	$277.4	$11.1
Oil Transmission	$22.5	$42.5	$1.7
NGL Transmission	$14.4	$17.9	$0.7
Total Gas and Liquids Capital Expenditure	$148.4	$337.8	$13.5

North American Midstream Infrastructure Through 2035 –

A Secure Energy Future

Prepared for the INGAA Foundation

June 28, 2011

Kevin R. Petak
Vice President
ICF International
703-218-2753
kpetak@icfi.com

David Fritsch
Senior Associate
ICF International
703-218-2740
dfritsch@icfi.com

E. Harry Vidas
Vice President
ICF International
703-218-2745
evidas@icfi.com