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The Rice World Gas Trade Model: A Discussion of Reference Case Results

prepared by:

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The Rice World Gas Trade Model

The RWGTM

- The Rice World Gas Trade Model (RWGTM) has been developed to examine potential futures for global natural gas, and to quantify the impacts of geopolitical influences on the development of a global natural gas market.
- The model predicts regional prices, regional supplies and demands and inter-regional flows.
- Regions are defined at the country and sub-country level, with extensive representation of transportation infrastructure
- The model is non-stochastic, but it allows analysis of many different scenarios. Geopolitical influences can alter otherwise economic outcomes
- The model is constructed using the *MarketBuilder* software from Deloitte MarketPoint, Inc.
  - Dynamic spatial general equilibrium linked through time by Hotelling-type optimization of resource extraction
  - Capacity expansions are determined by current *and* future prices along with capital costs of expansion, operating and maintenance costs of new and existing capacity, and revenues resulting from future outputs and prices.

The RWGTM: Demand

- Over 290 regions.
  - Regional detail is dependent on data availability and existing infrastructure.
- Demand is estimated directly for US…
  - United States (residential, commercial, power and industrial sectors)
    - Sub-state detail is substantial (for example, 10 regions in Texas) and is based on data from the Economic Census and the location of power plants.
    - Demand functions estimated using longitudinal state level data.
    - WECC infrastructure and demand detail defined by CEC for CEC Reference Case.

Commercial

$$\ln q_{com,i,t} = \alpha_i - 0.154 \ln p_{ng,i,t} + 0.039 \ln p_{ho,i,t} + 0.160 \ln y_t + 0.290 \ln hdd_{i,t} - 0.033 \ln cdd_{i,t} + 0.176 \ln pop_{i,t} + 0.758 \ln q_{com,i,t-1}$$

Residential

$$\ln q_{res,i,t} = \alpha_i - 0.201 \ln p_{ng,i,t} + 0.049 \ln p_{ho,i,t} + 0.117 \ln y_t + 0.405 \ln hdd_{i,t} - 0.007 \ln cdd_{i,t} + 0.312 \ln pop_{i,t} + 0.683 \ln q_{res,i,t-1}$$

Industrial

$$\ln q_{ind,i,t} = \alpha_i - 0.071 \ln p_{ng,i,t} + 0.330 \ln manuf_{i,t} + 0.202 \ln hdd_{i,t} + 0.047 \ln cdd_{i,t} + 0.780 \ln q_{ind,i,t-1}$$

Power Generation

$$\ln q_{pwr,i,t} = \alpha_i - 0.442 \ln p_{ng,i,t} + 0.238 \ln p_{fo,i,t} + 0.102 \ln p_{coal,i,t} + 1.089 \ln elecgen_{i,t} - 0.189 \ln renew_{i,t}$$
$$- 0.511 \ln hdd_{i,t} + 0.339 \ln cdd_{i,t} + 0.716 \ln q_{pwr,i,t-1}$$

The RWGTM: Demand (cont.)

- … but demand is estimated indirectly for RoW.
  - Rest of World (Power Gen, Direct Use, EOR)
    - Energy intensity is estimated as a function of per capita income and energy price using panel data for over 70 countries from 1970-2007.

Energy Intensity

$$\ln\left(\frac{E}{Y}\right)_{i,t} = \alpha_i - 0.086\ln y_{i,t} - 0.012\ln p_{i,t} + 0.834\ln\left(\frac{E}{Y}\right)_{i,t-1}$$

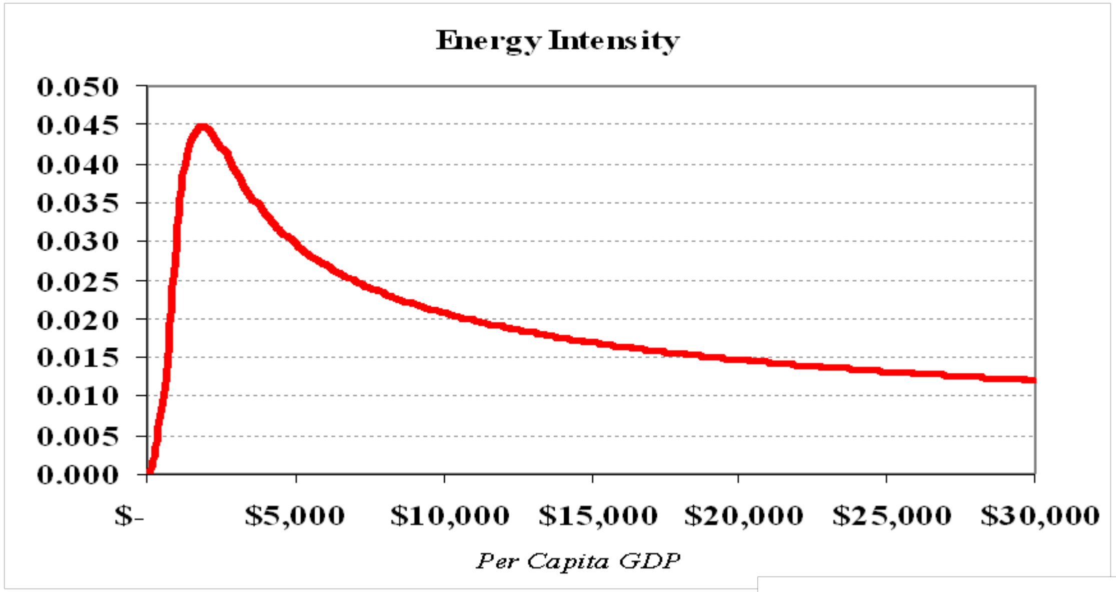
- Natural gas share is estimated as a function of GDP per capita, own price, oil price, installed thermal capacity, and the extent to which the country imports energy

Natural Gas Share

$$\ln\left(\ln\theta_{ng,i,t}\right) = \alpha_i + 0.068\ln\left(\frac{E}{Y}\right)_{i,t} + 0.043\ln p_{ng,i,t} - 0.028\ln p_{oil,i,t} - 0.041\ln thermcap_t + 0.098\ln entrade_{i,t} + 0.767\ln\left(\ln\theta_{ng,i,t}\right)$$

Note, the natural gas share equation is in double log form, which bounds the share between 0 and 1 (when forecasting). The sign of the estimated coefficients are opposite the sign of the elasticity. In fact, the own price elasticity is given as: $\varepsilon_{\theta,p} = 0.043\ln\theta_{ng,i,t}$. So, the price elasticity is decreasing in natural gas share, ranging between -3.064 and -0.049 across all countries. This feature captures rigidities associated with capital deployment.

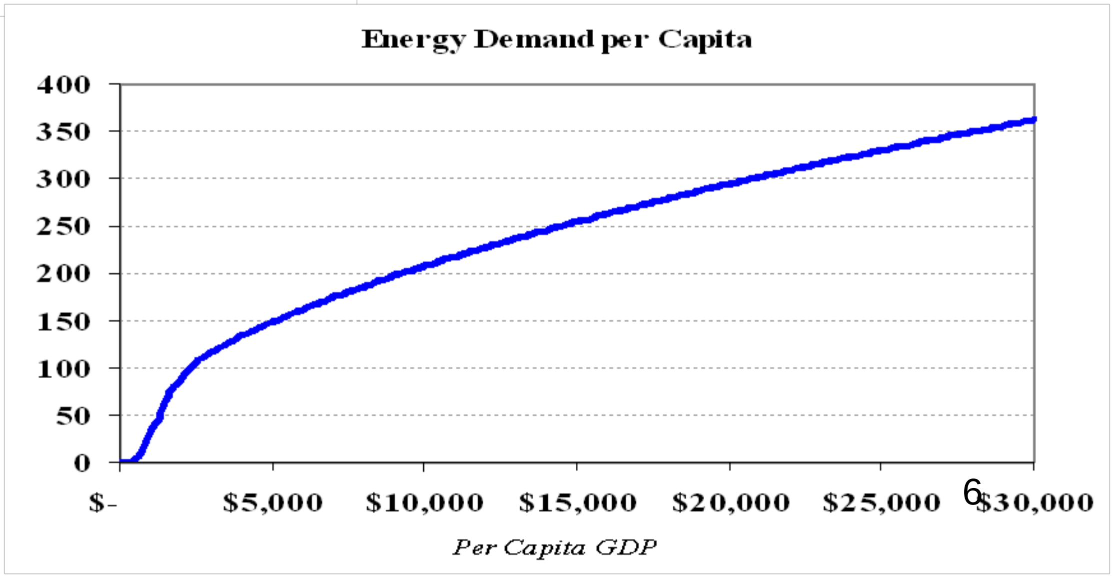
The RWGTM: Demand (cont.)



The estimated relationship between energy intensity and per capita GDP reveals that energy intensity generally decreases with rising incomes (see Medlock and Soligo, *Energy Journal* 2001)

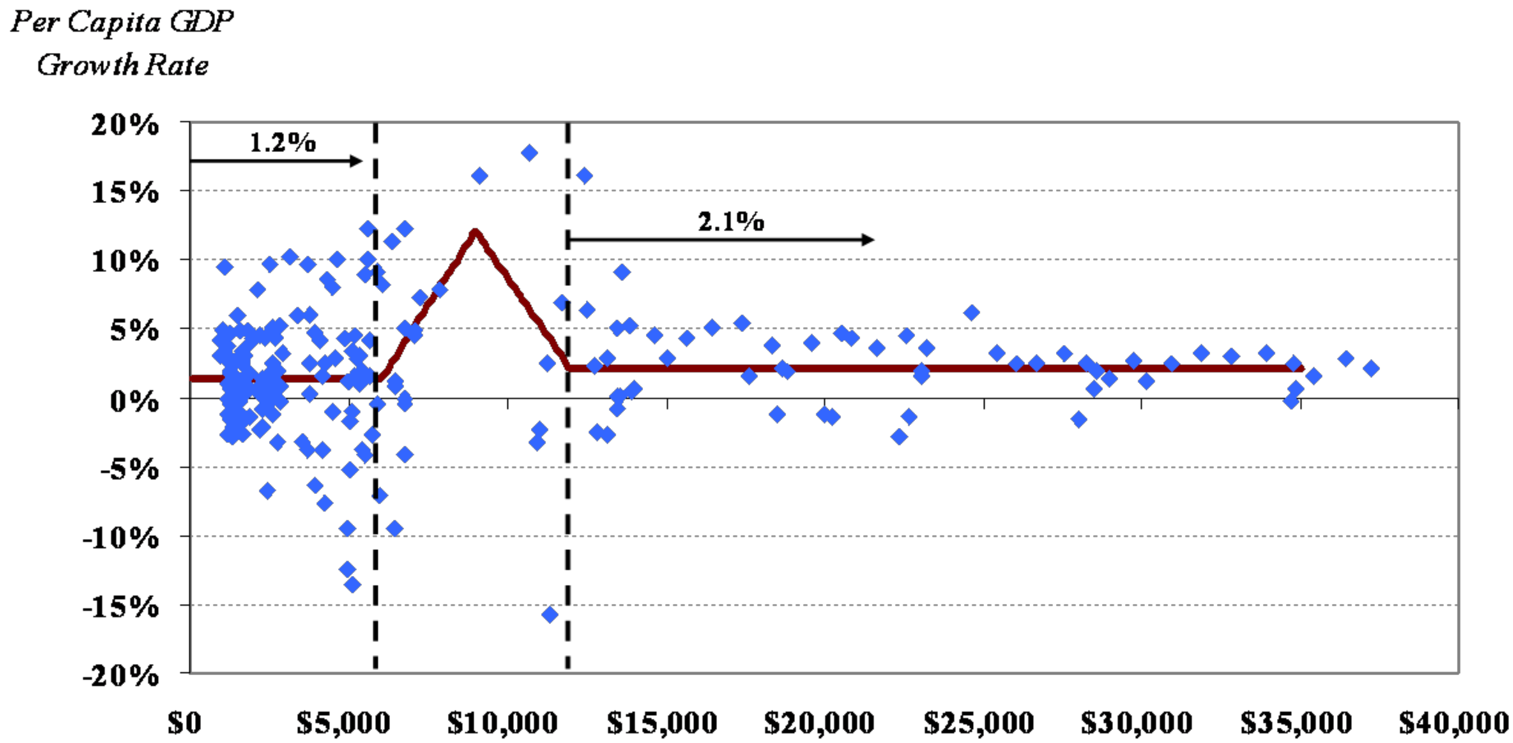
The graphic indicates a path for a generic country. The level of energy intensity for individual countries will vary depending on a number of factors, but each will exhibit a similar pattern.

The forecast path for energy intensity is then multiplied by the projected GDP per capita to reveal a forecast path for per capita energy demand. Population projections are then taken from the UN median case to reveal total energy demand.



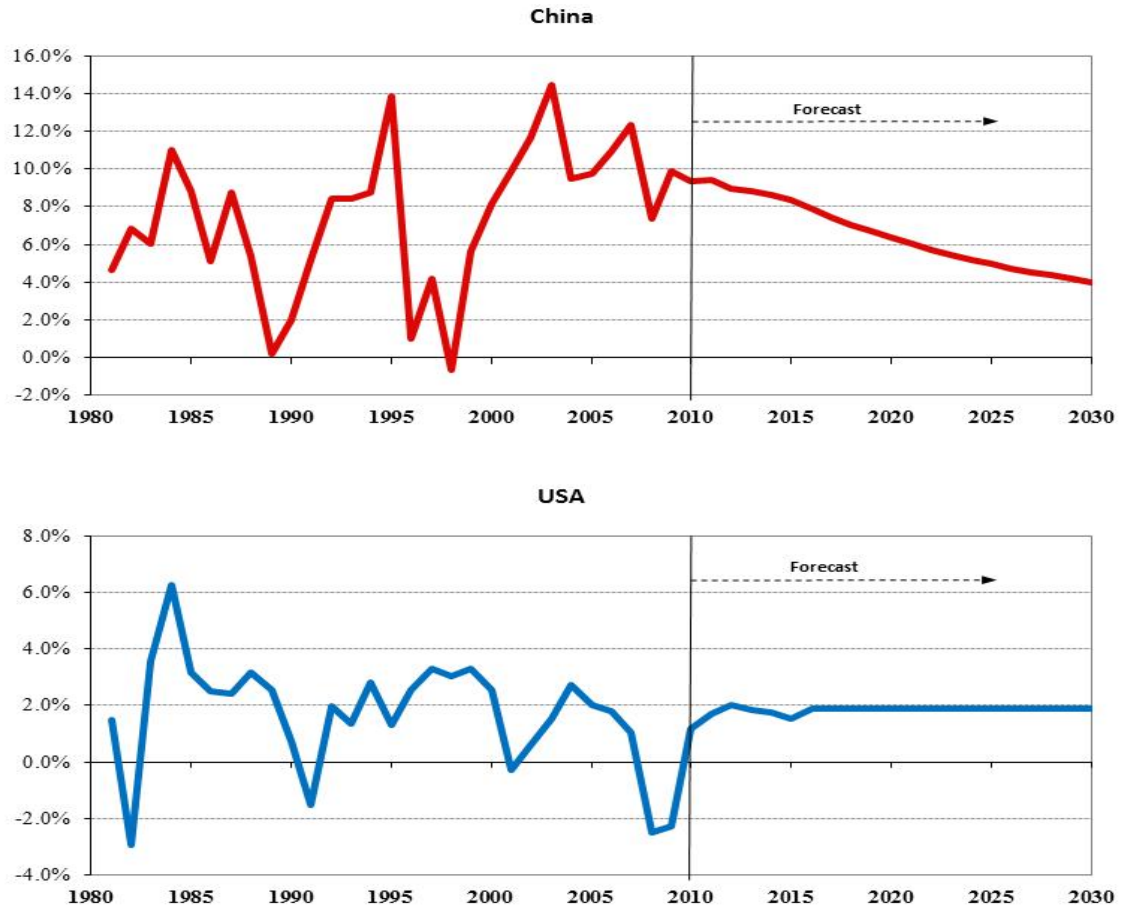
The RWGTM: Demand (cont.)

- Economic growth is based on conditional convergence a long run growth path that is based on historical US and UK growth rates (dating back into the 1800s) at various levels of per capita income. The long run growth path is estimated using a piecewise linear spline knot regression.
- Countries converge to the long run growth path at a rate estimated using an unbalanced panel across all countries spanning multiple years.



The RWGTM: Demand (cont.)

- Recent economic and financial crisis is incorporated. We use the IMF economic outlook for growth through 2015 for all countries. Beyond 2015, growth is governed by the model of conditional convergence. All GDP estimates are in $2005PPP.



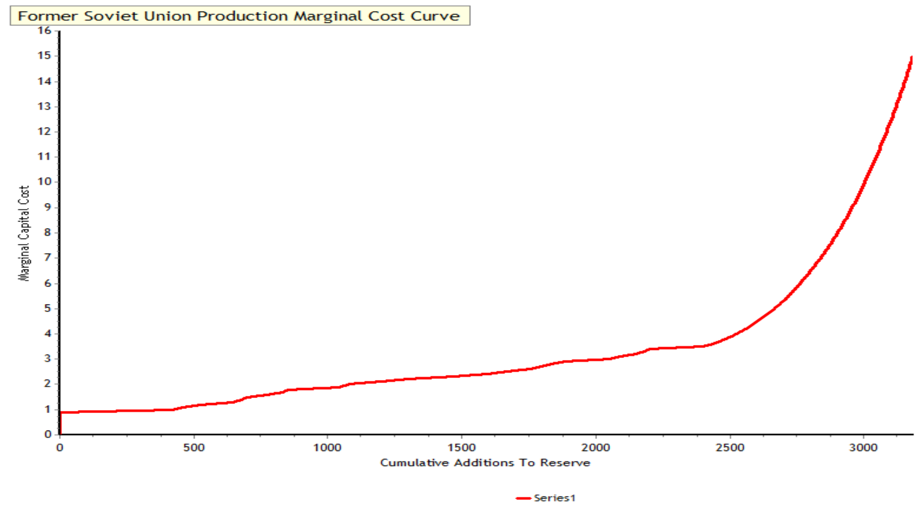
Note, the graphics depict real growth of per capita GDP in PPP terms. These growth estimates will differ from growth estimates of GDP per capita converted using nominal exchange rates to the extent the PPP exchange rate changes. Accordingly, in PPP terms, Chinese per capita income in roughly 60% of US per capita income by 2030, compared to 28% currently. This results due to the conditional convergence feature of the long run growth model.

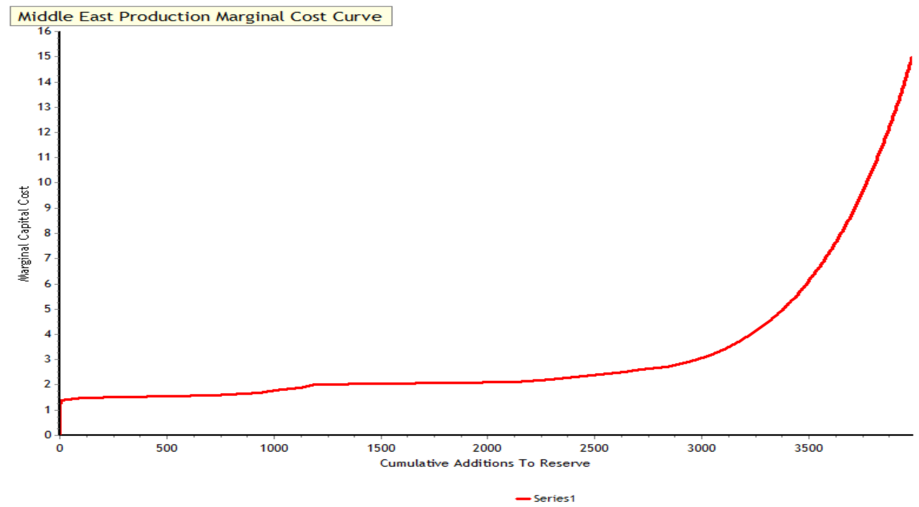
The RWGTM: Supply

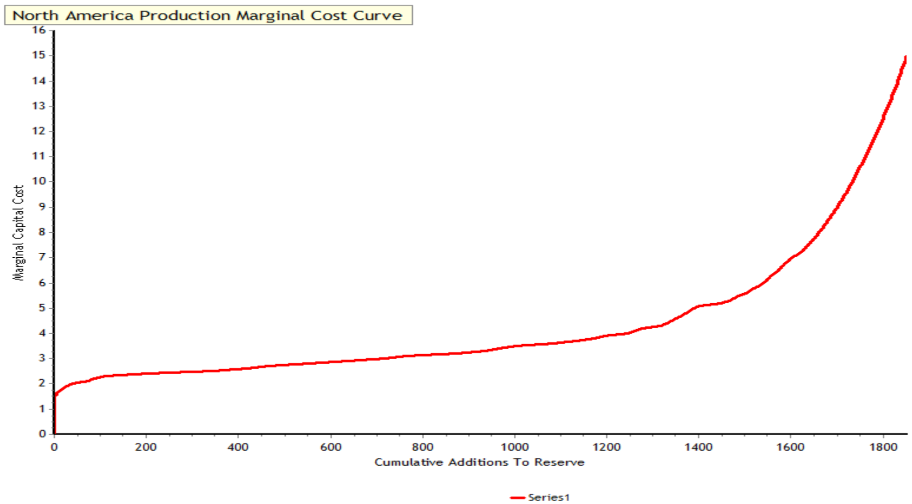
- Over 135 regions
- Natural gas resources are represented as...
  - Conventional, CBM and Shale in North America, China, Europe and Australia, and conventional gas deposits in the rest of the world. Recent ARI assessment of shale around the world is being studied for incorporation.
- ... in three categories
  - proved reserves (Oil & Gas Journal estimates)
  - growth in known reserves (P-50 USGS and NPC 2003 estimates)
  - undiscovered resource (P-50 USGS and NPC 2003 estimates)
    - Note: resource assessments are supplemented by regional offices if available.
- North American cost-of-supply estimates are econometrically related to play-level geological characteristics and applied globally to generate costs for all regions of the world.
  - Long run costs increase with depletion.
  - Short run adjustment costs limit the “rush to drill” phenomenon.
  - We allow technological change to reduce mining costs longer term

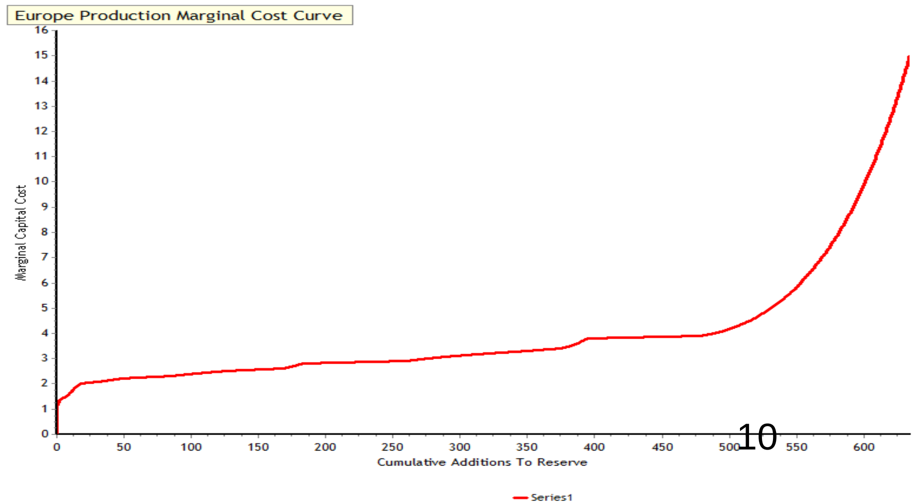
The RWGTM: Supply (cont.)

- Selected examples: Regional marginal cost of supply curves…









The RWGTM: Infrastructure

- Required return on investment varies by region and type of project (using ICRG and World Bank data)
- Detailed transportation network
  - Pipelines aggregated into corridors where appropriate.
  - Capital costs based on analysis of over 100 pipeline projects relating project cost to various factors.
  - Tariffs based on posted data, where available, and rate-of-return recovery.
  - LNG is represented as a hub-and-spoke network, reflecting the assumption that capacity swaps will occur when profitable.
  - LNG shipping rates based on lease rates and voyage time.
- For all capital investments in both the upstream and midstream, we allow for existing and potential pipeline links, then “let the model decide” optimal current and future capacity utilization.
- For detailed information please see Peter Hartley and Kenneth B Medlock III, “The Baker Institute World Gas Trade Model” in *The Geopolitics of Natural Gas*, ed. Jaffe, Amy, David Victor and Mark Hayes, Cambridge University Press (2006).

The RWGTM: Infrastructure (cont.)

- A brief focus on LNG costs
  - These are generally generic with regard to region.

Sample Capital Cost for Liquefaction			
	Capex ($/mcf)	Capex ($/ton)	
Australia	12.8934	$	620.2
Australia (Queensland)	9.0988	$	437.7
Atlantic	7.7854	$	374.5
Pacific	9.0988	$	437.7
Middle East	8.4784	$	407.8
Arctic	18.2287	$	876.8

- A facility must earn a minimum return to capital prior to the model choosing to build it. Hence, construction is based on current *and* future prices, as well as construction costs and financial parameters defining things such as tax rates and the required rates of return to debt and equity.

Contracts and Other Major Assumptions

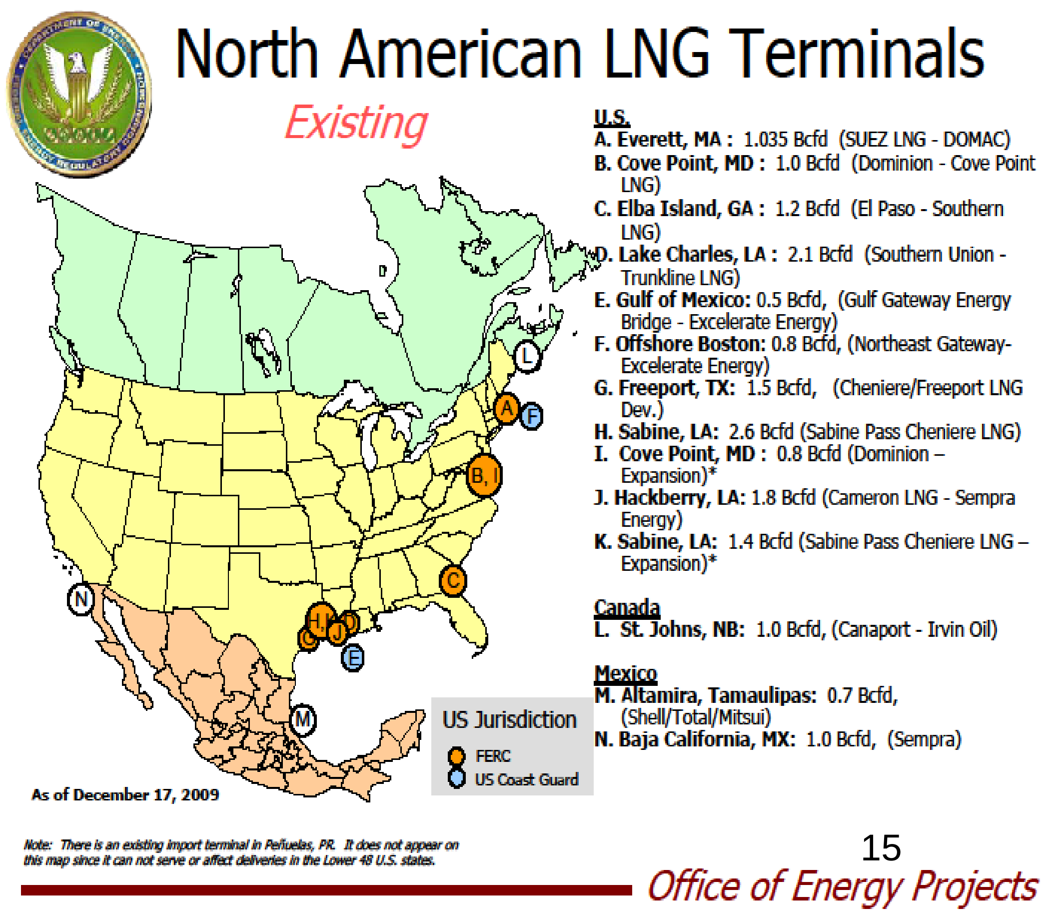
- LNG contract data obtained from Petroleum Economist is included in the RWGTM. This has the effect of imposing first mover advantage. Contracts can be swapped if they are out of the money.
- The list below captures some of the major assumptions regarding timing and availability for various infrastructure investments in the RWGTM.

North America	**Middle East**
LNG availability from North AK to 2020	Iraq gas available in 2020
LNG availability from L48 to 2016 at LA/MD	No Iran LNG until post 2030
No LNG to CA/WC/FL/DE/NY	No Iran PLs to Europe, India
No Offshore OCS outside West and Central GoM	
No PL from FL to Cuba	**FSU**
No PL from MX to Cuba	Nordstream available in 2014, Southstream and other available in 2017
No PL from MX to Cent Am	Turkmenistan to China via Kazakhstan
	Trans-Caspian available in 2018
South America	Nabucco available in 2015
Venezuela LNG available in 2030	
Venezuela to Trinidad PLs available in 2030	**Europe and NE Asia**
No Venezuela PLs to Brazil	No PLs to Korea
Suriname LNG available in 2030	
	India
Africa	No Iran PL
Restrain growth in Angola, Egypt, Libya, Sudan to begin in 2020	No Afghan PL
	No Pakistan PL

A Note on Shale in the RWGTM

A Paradigm Shift

- The view of natural gas has changed dramatically in only 10 years
  - Most predictions were for a dramatic increase in LNG imports to North America and Europe.
  - Today, growth opportunities for LNG developers are seen in primarily in Asia.
- Many investments were made to expand LNG potential to North America in particular
  - At one point, 47 terminals were in the permitting phase.
  - Since 2000, 2 terminals were re-commissioned and expanded (Cove Point and Elba); 9 others were constructed.
  - In 2000, import capacity was just over 2 bcfd; It now stands at just over 17.4 bcfd.
  - By 2012, it could reach 20 bcfd.
- A similar story in Europe
  - In 2000, capacity was just over 7 bcfd; It is now over 14.5 bcfd.
  - By 2012, it could exceed 17 bcfd.
- Shale gas developments have since turned expectations upside-down



Defining the Resource

- It is an incorrect representation to simply characterize recent estimates of shale gas in North America as “reserves”. It is important to understand what these assessments are actually estimating.
- Shale gas GIP numbers are large. *Cost* and *technology* define accessibility.
- **We use estimates of technically recoverable resource and define development cost curves for each assessment.**

Resource in Place

Resource endowment. Lots of uncertainty, but we can never get beyond this ultimate number.

Technically Recoverable Resource

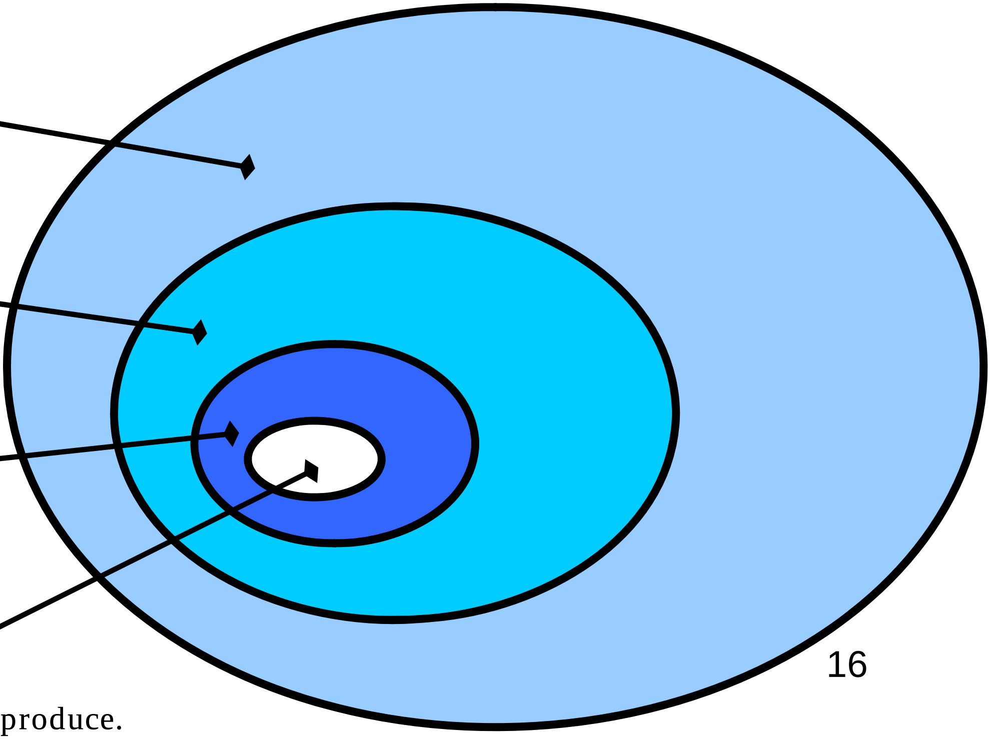
This is the number that is being assessed. Lots of uncertainty, but experience has shown this number generally grows over time.

Economically Recoverable Resource

This will grow with decreasing costs and rising prices, but is bound by technology.

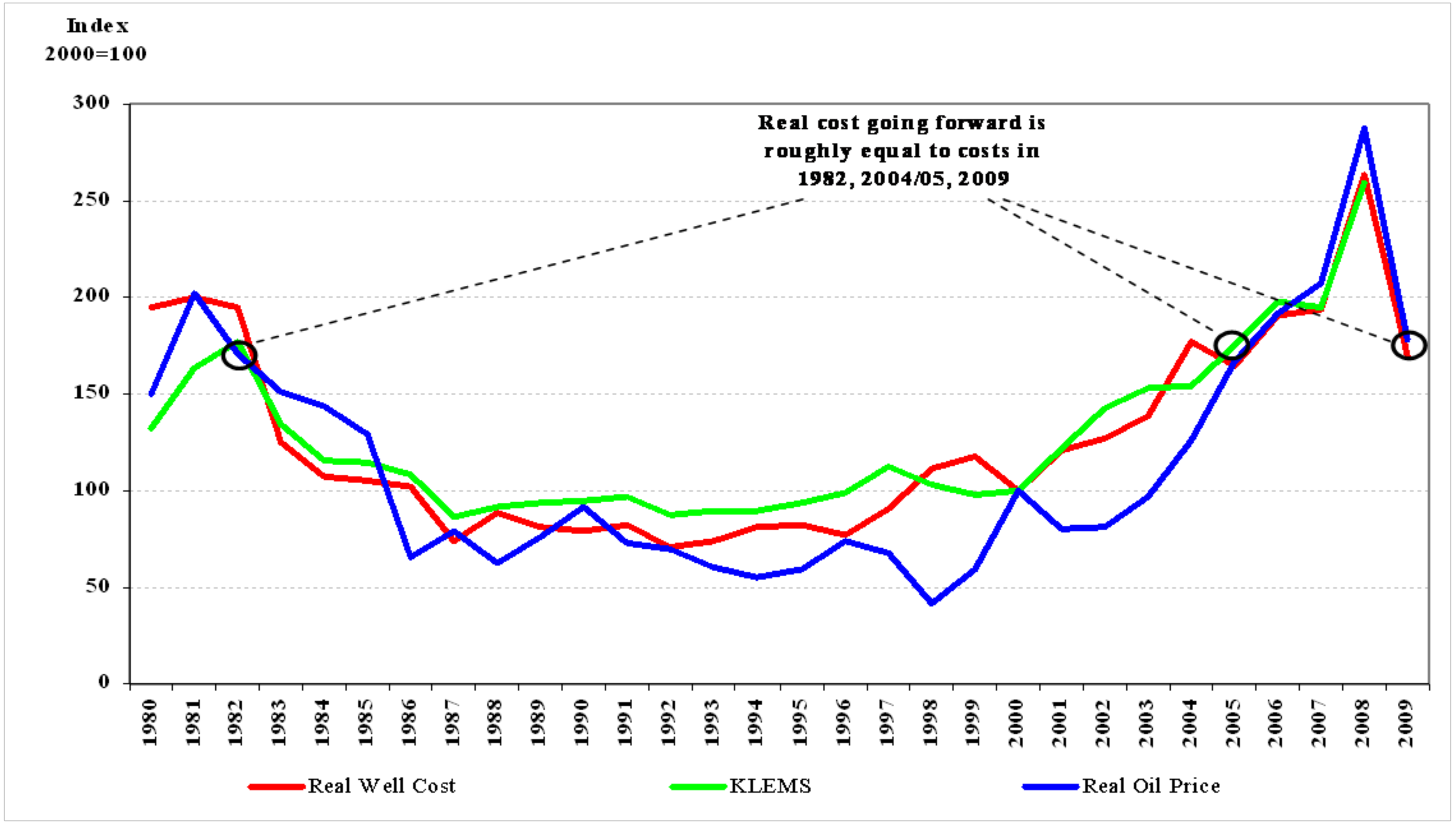
Proved Reserves

Connected and ready to produce.

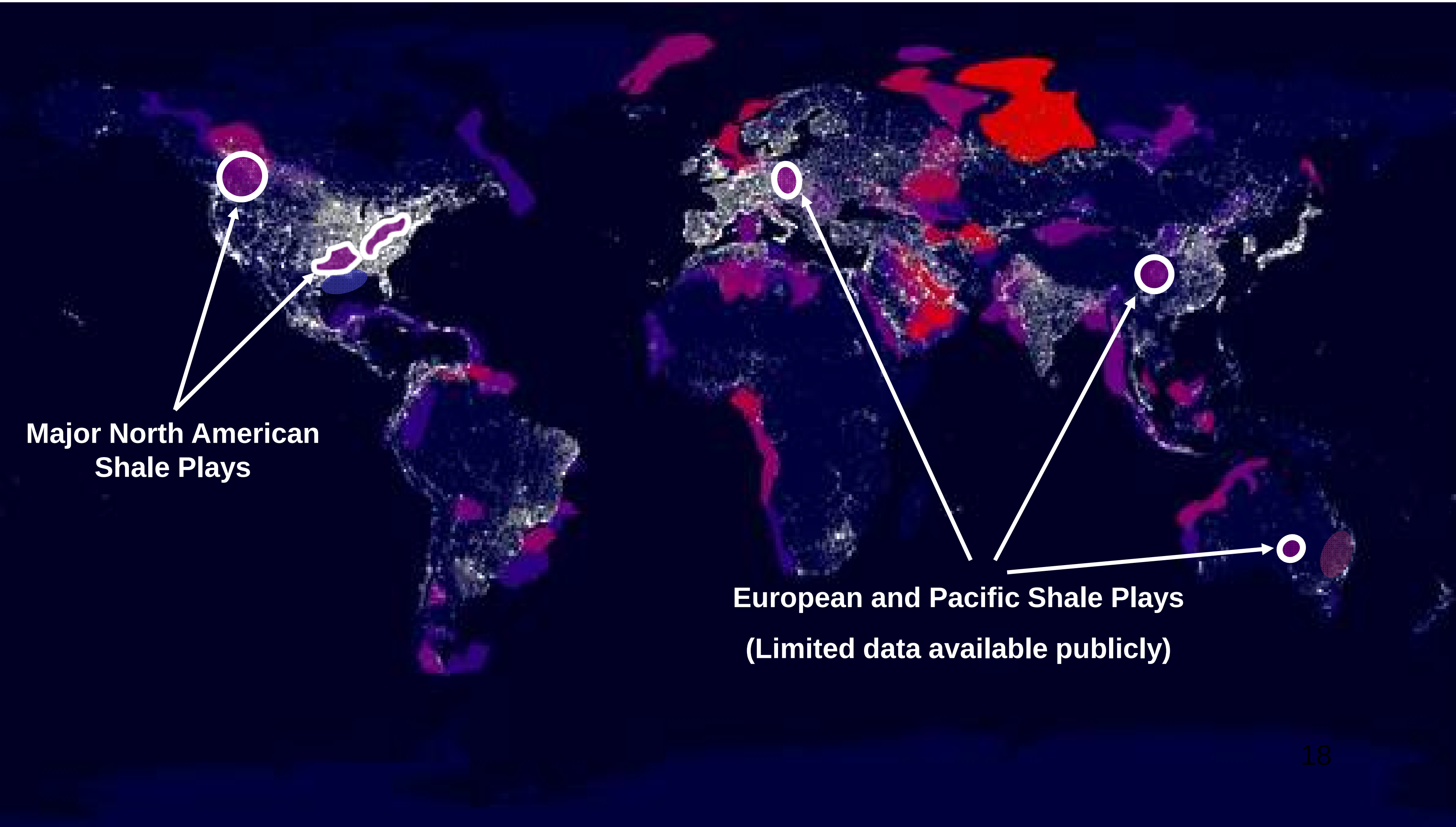


A Comment on Development Costs and Treatment in the RWGTM

- We often discuss the concept of "breakeven" in well development, but it is important to put this into context...
- The cost environment is critical to understanding what prices will be. For example, F&D costs in the 1990s yield long run prices in the $3-$4 range.

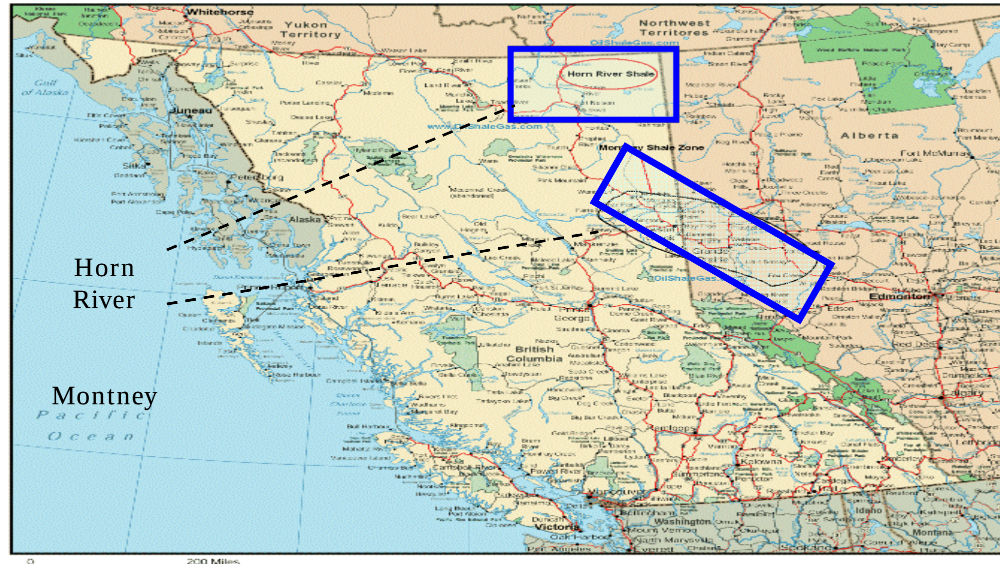


Shale is everywhere, and it has significant implications for global energy markets



North American Shale Gas

- Shale is distributed in many locations, some traditional producing areas but others are in the heart of market areas.
- Supply potential in BC, in particular, has pushed the idea of LNG exports targeting the Asian market
  - Asia is an oil-indexed market.
  - Competing projects include pipelines from Russia and the Caspian States, as well as LNG from other locations.
  - BC is a basis disadvantaged market, but selling to Asia could provide much more value to developers.
- For those regions not accustomed to seeing robust natural gas development, regulatory conflicts are being realized.



Source: Energy Information Administration based on data from various published studies
Updated: May 28, 2009

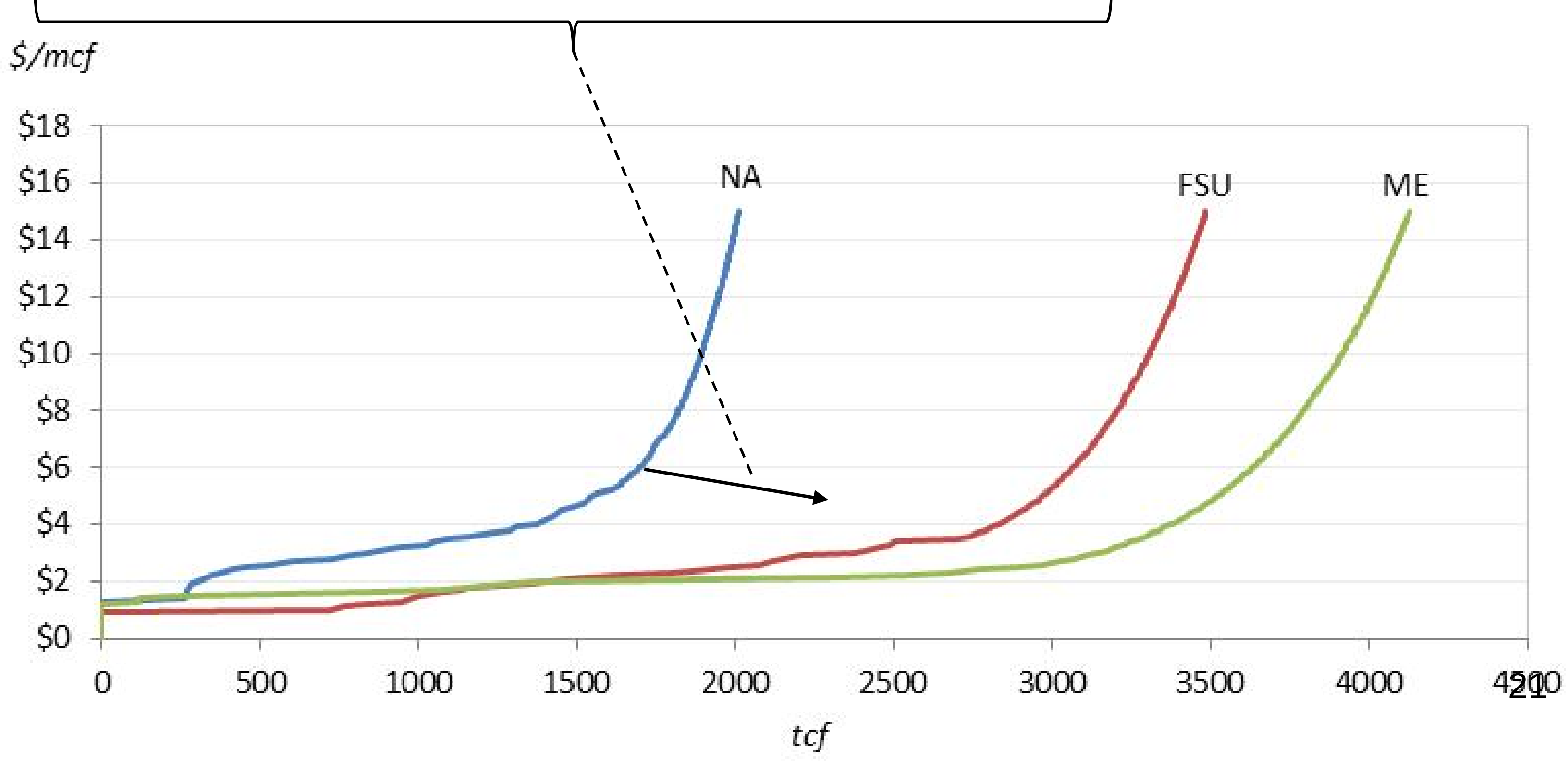
North American Shale (cont.)

- In 2003, the NPC used an assessment of 38 tcf of technically recoverable shale gas in its study of the North American gas market.
- In 2005, most estimates placed the resource at about 140 tcf.
- Recent estimates are much higher
  - (2008) Navigant Consulting, Inc. estimated a mean of about 520 tcf.
  - (2009) Estimate from PGC over 680 tcf.
  - (2010) ARI estimate of over 1000 tcf.
- Resource assessment is large. Our work at BIPP indicates a technically recoverable resource of 686 tcf.
- Point: We learn more as time passes!

	Mean Technically Recoverable Resource (tcf)	Breakeven Price
Antrim	13.2	$ 5.50
Devonian/Ohio	170.8	
Utica	5.4	$ 6.25
Marcellus	135.4	
Marcellus T1	47.4	$ 4.00
Marcellus T2	43.3	$ 5.25
Marcellus T3	44.7	$ 6.50
NW Ohio	2.7	$ 6.75
Devonian Siltstone and Shale	1.3	$ 6.75
Catskill Sandstones	11.7	$ 6.75
Berea Sandstones	6.8	$ 6.75
Big Sandy (Huron)	6.3	$ 6.00
Nora/Haysi (Huron)	1.2	$ 6.25
New Albany	3.8	$ 7.00
Floyd/Chatanooga	4.3	$ 6.00
Haynesville	105.0	
Haynesville T1	42.0	$ 4.00
Haynesville T2	36.8	$ 5.00
Haynesville T3	26.3	$ 6.25
Fayetteville	36.0	$ 4.25
Woodford Arkoma	8.0	$ 4.50
Woodford Ardmore	4.2	$ 5.75
Barnett	54.0	
Barnett T1	32.2	$ 4.25
Barnett T2	21.8	$ 5.75
Barnett and Woodford	35.4	$ 6.50
Eagle Ford	35.0	$ 4.00
Palo Duro	4.7	$ 6.25
Lewis	10.2	$ 6.25
Bakken	1.8	$ 6.50
Niobrara (incl. Wattenburg)	1.3	$ 6.50
Hilliard/Baxter/Mancos	11.8	$ 6.50
Paradox/Uinta	13.5	$ 6.50
Mowry	8.5	$ 6.50
Horn River	90.0	
Horn River T1	50.0	$ 4.50
Horn River T2	40.0	$ 5.25
Montney	65.0	
Montney T1	25.0	$ 4.75
Montney T2	40.0	$ 5.50
Utica	10.0	$ 6.25
Total US Shale	521.4	
Total Canadian Shale	165.0	
Total North America	686.4	

LNG Exports and North American Resources in a Global Context

- North American resources are large, but must be placed in a global context.
  - FSU and Middle East (pictured for comparison) are larger and generally less costly. However, access and transportation costs make North American resources preferential in the short-to-medium term *in North America*. But, prospects for large scale competition are limited by cost.
  - Cost reductions and higher recoverable resource estimates benefit the US supply picture.



Rest of World Shale Gas

- There is tremendous uncertainty about shale resources outside of North America.
- To be certain, the estimates of resource in place are very large, and location is a premium with regard to prevailing market prices and energy security benefit.
- However, accessibility is critical. Not only do cost and technology matter, but market structure and government policy is equally as important.
  - Arguably, if the current market structure in the United States did not exist, the shale gas boom would not have occurred. This is due to the fact that the small producers who initiated the proof of concept had little to no risk of accessing markets from very small production projects. A market in which capacity rights are not unbundled from facility ownership does not foster entry by small producers.

	Mean Technically Recoverable Resource (tcf)	Breakeven Price
Austria	40.0	$ 5.75
Germany	30.0	$ 5.50
Poland	120.0	$ 5.25
Sweden	30.0	$ 6.00
China	45.0	$ 5.00
Australia	50.0	$ 4.00
Total non-North America	315.0	

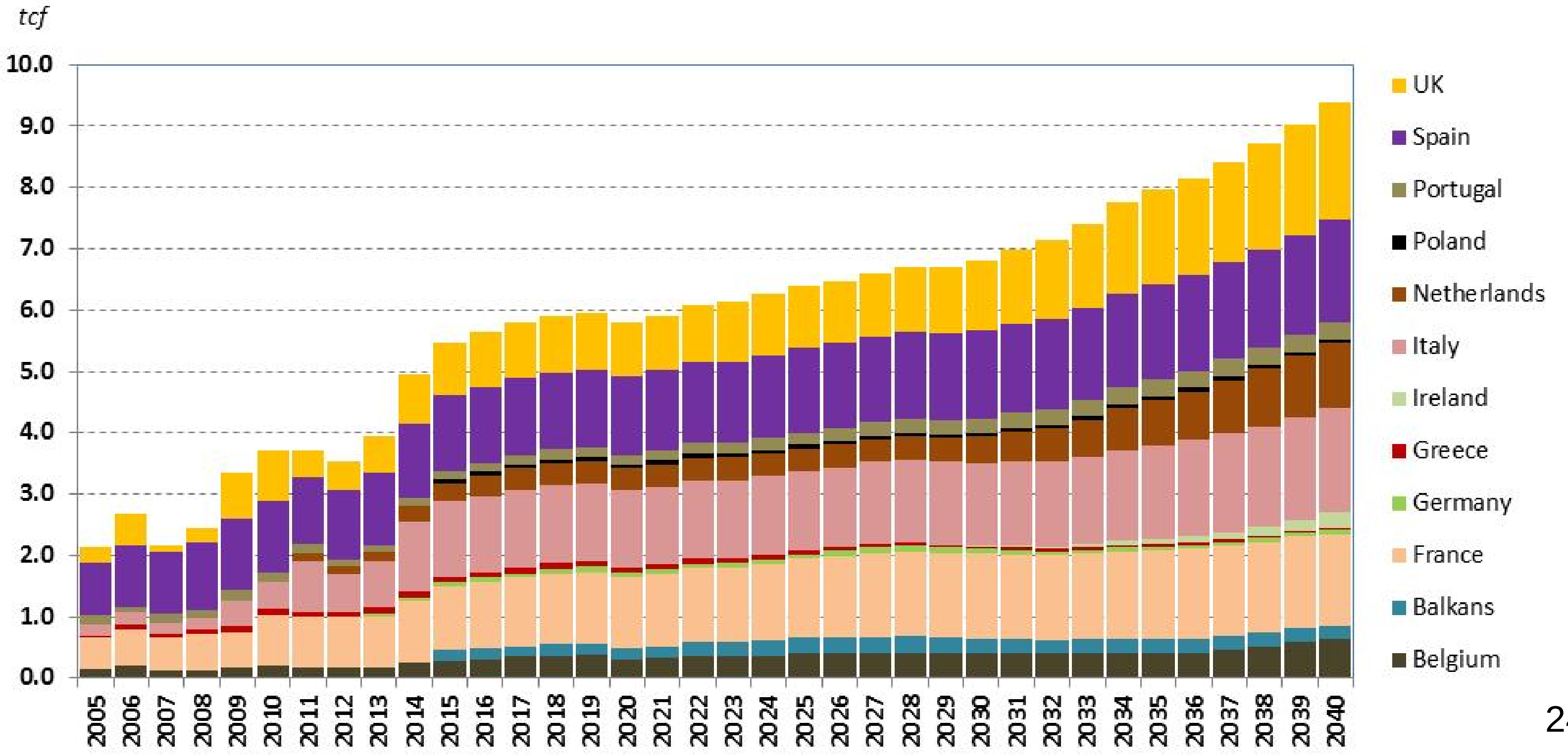
Note, ongoing work will likely add assessments for technically recoverable resource in Croatia, Denmark, France, Hungary, Netherlands, Ukraine, and the United Kingdom. Estimates are currently too preliminary to be presented in this case.

New ARI assessment under review for incorporation into the Reference Case.

Reference Case Results

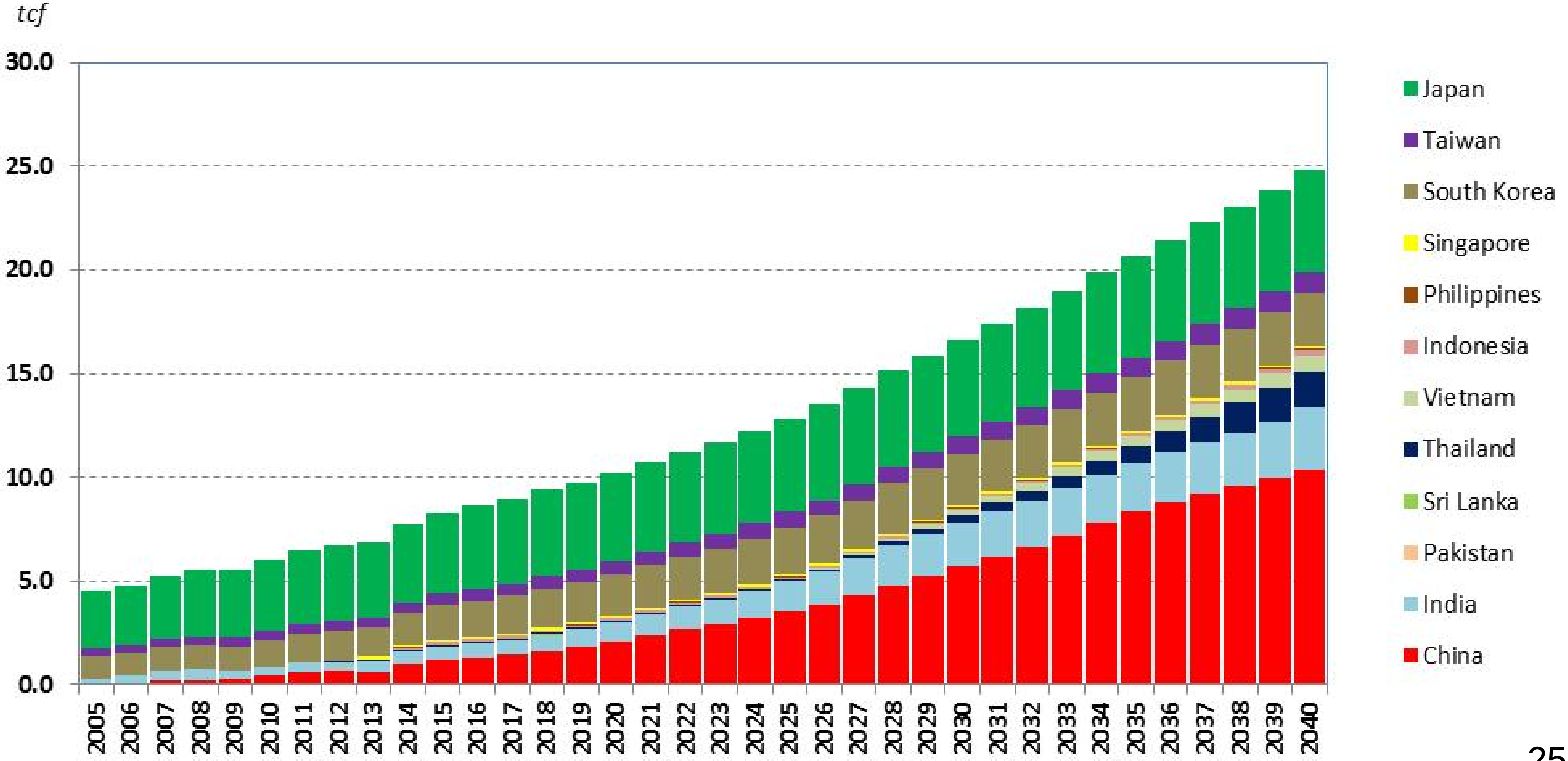
LNG Imports to Europe

- Growth in LNG is an important source of diversification to Europe. Indigenous shale gas opportunities abate this to some extent. However, shale production does not grow as strongly as in North America, so LNG imports in Europe rise.



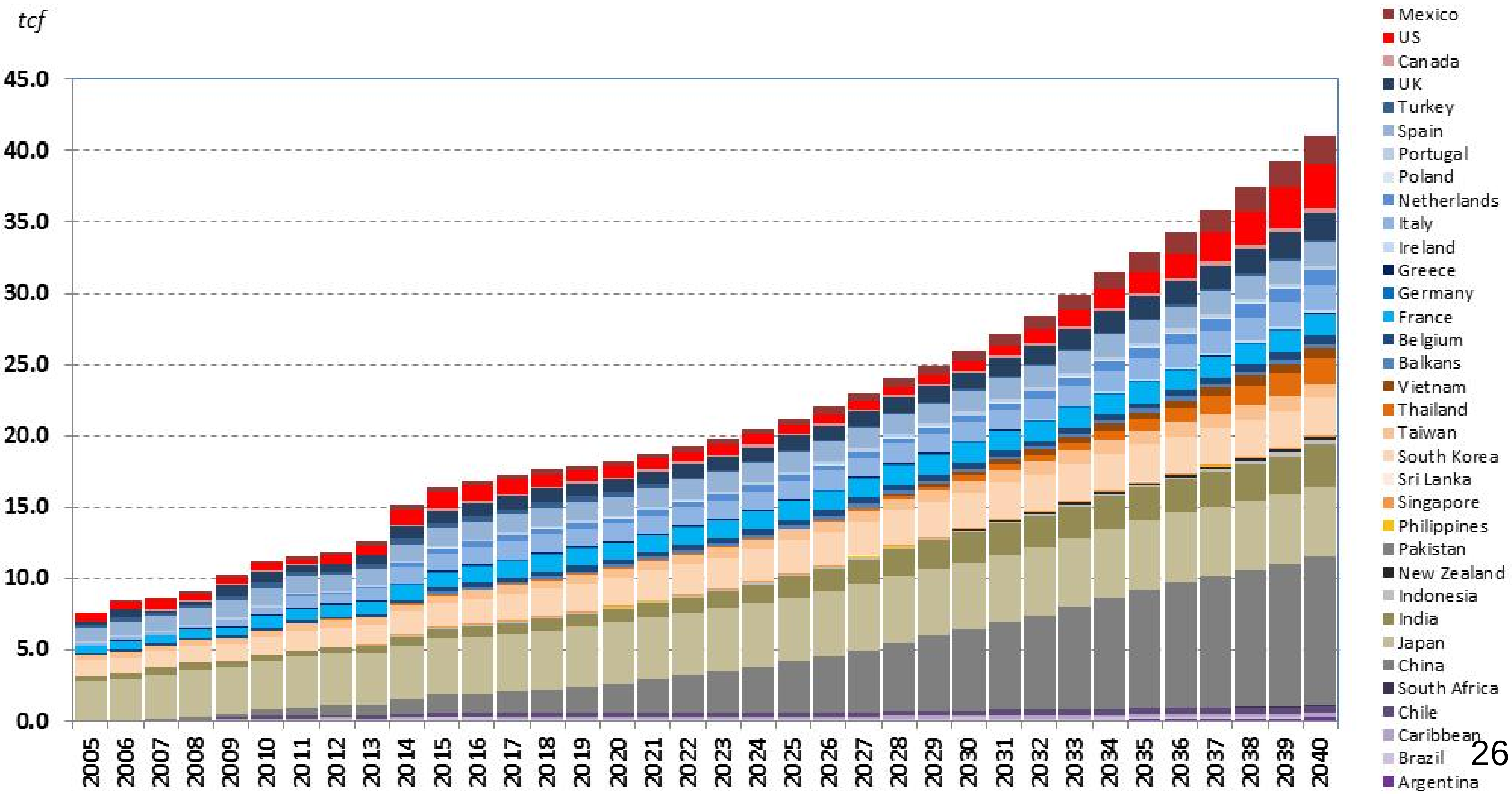
LNG Imports to Asia

- Strong demand growth creates a much needed sink for LNG supplies.
  - China leads in LNG import growth despite growth in pipeline imports and supplies from domestic unconventional sources.



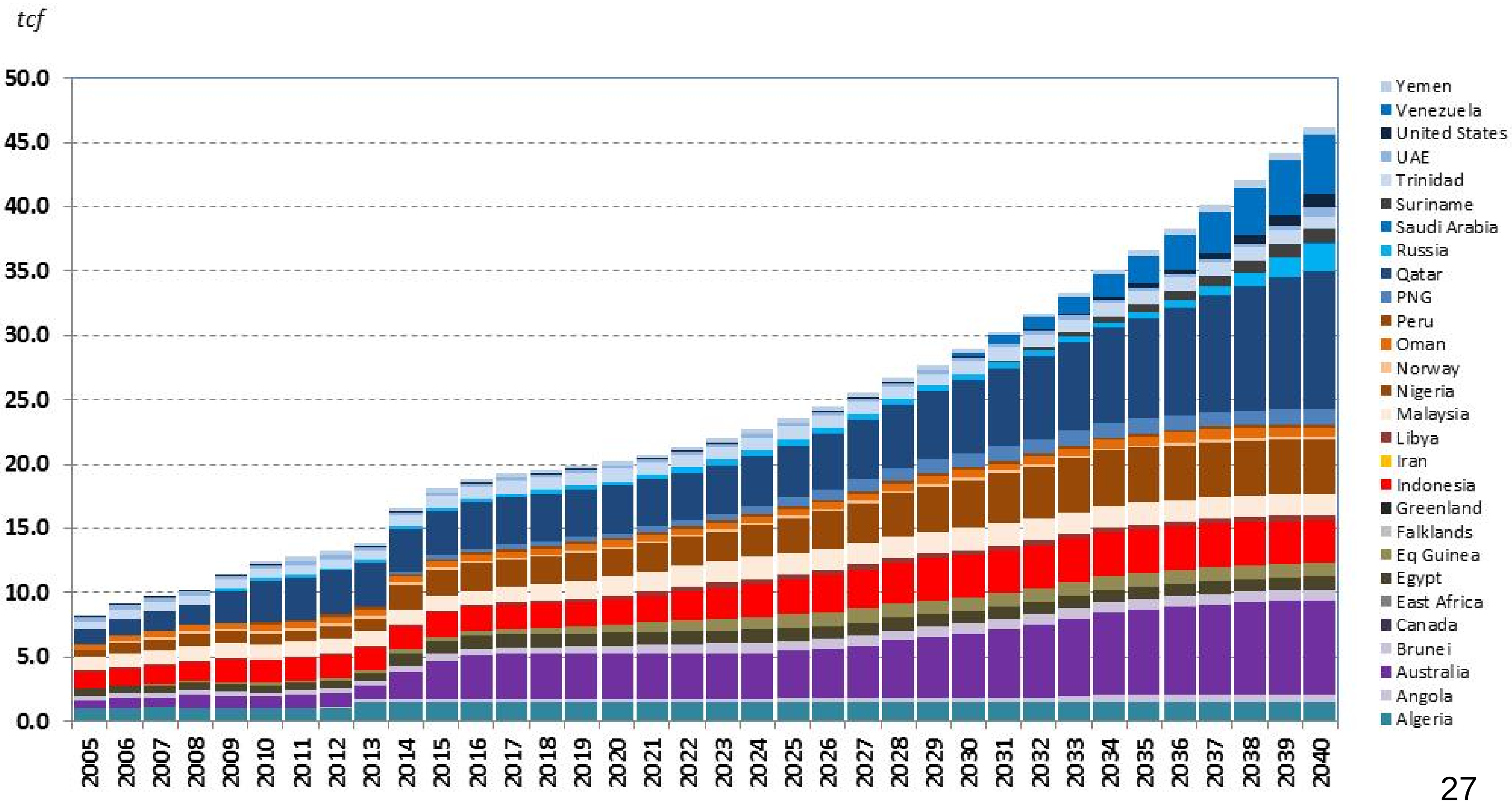
LNG Imports

- Most LNG import growth is in Asia, particularly in China and India. In fact, Asia accounts for over 60% of all LNG imports in 2040.
- The United States remains a minor LNG importers.



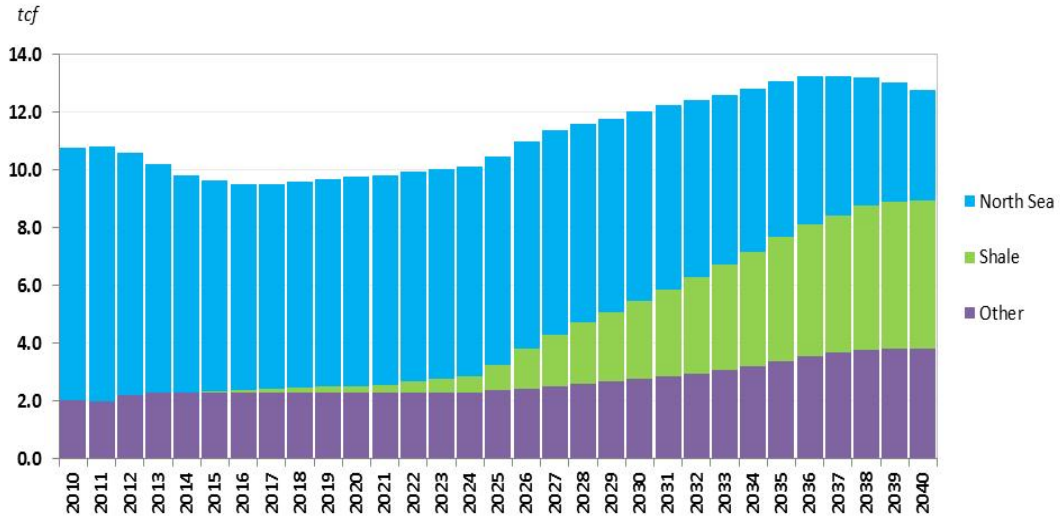
LNG Exports

- Qatar and Australia are the two largest LNG exporters in 2040, and, collectively, account for just under 40% of global *LNG* exports.

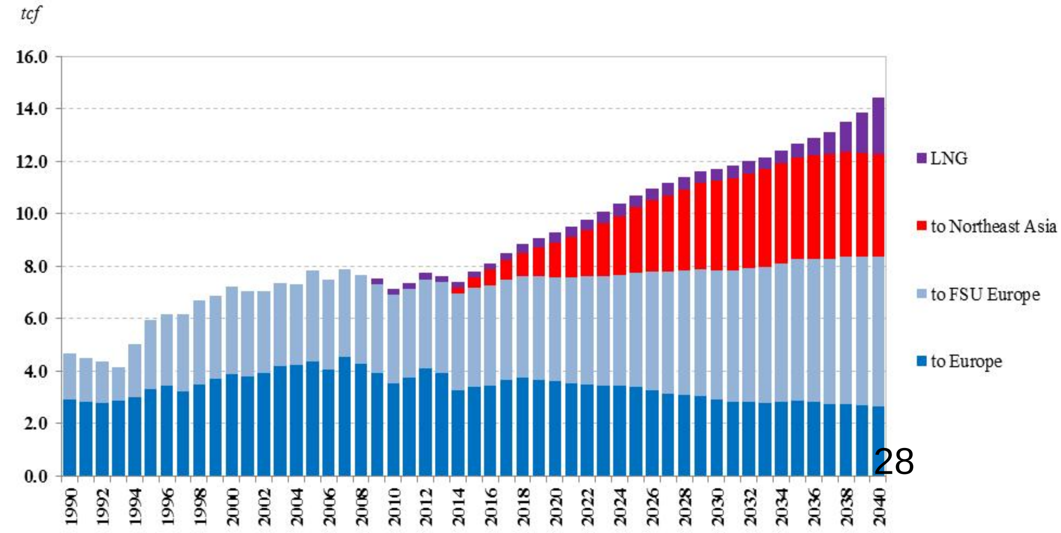


Impact of Shale Production in Europe

- European shale production grows to about 35% of total production by 2040. While not as strong as North America, it does offset the need for increased imports from Russia, North Africa, and LNG.

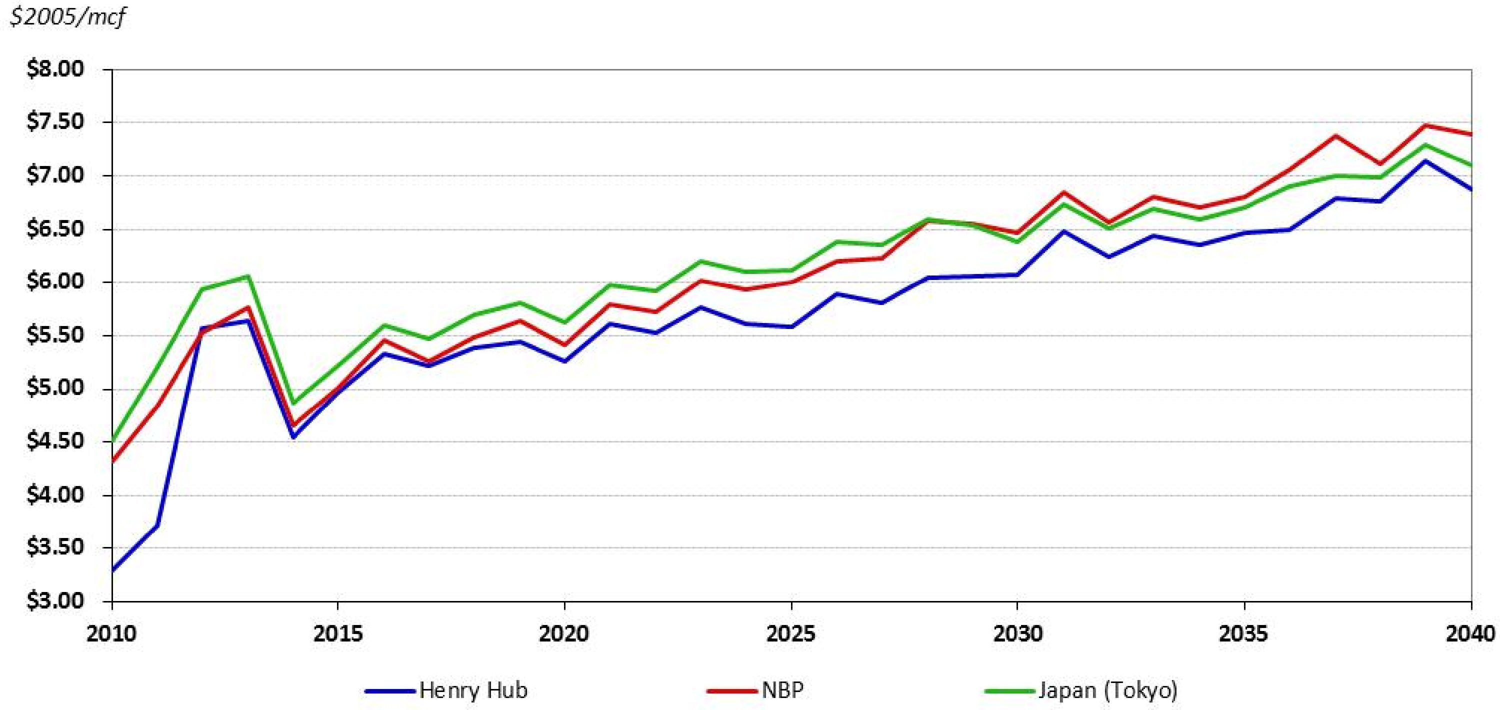


- The impact of shale growth in Europe is tilted toward offsetting Russian imports. In fact, Russian market share in non-FSU Europe declines from 20% currently to 10% by 2040.



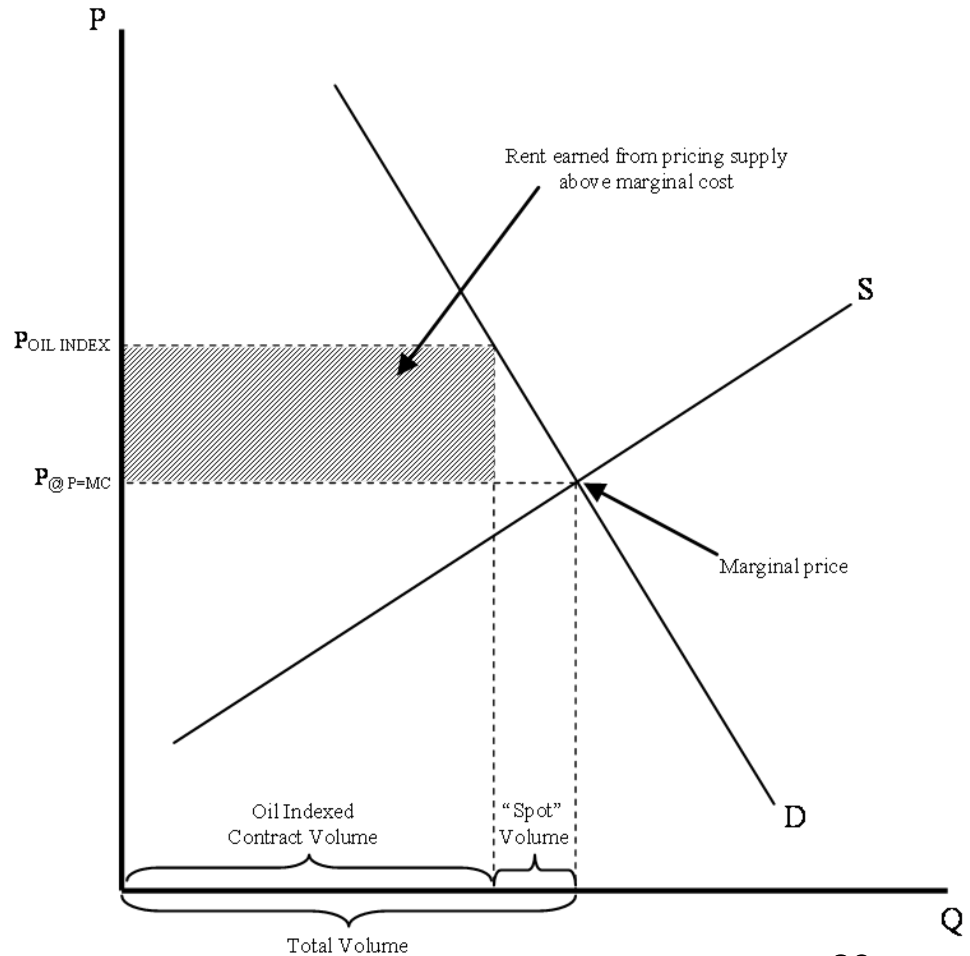
Select Regional Prices

- Prices tend to rise over time as lower cost supplies are depleted.
- Prices tend to move together as LNG growth increasingly connects markets. Note this occurs despite lack of substantial LNG trade into the US because arbitrage *opportunity* forces equilibrium.
- NBP and Tokyo average about $0.50 over Henry Hub longer term. Note this is spot delivery. Contracted flows are priced differently…



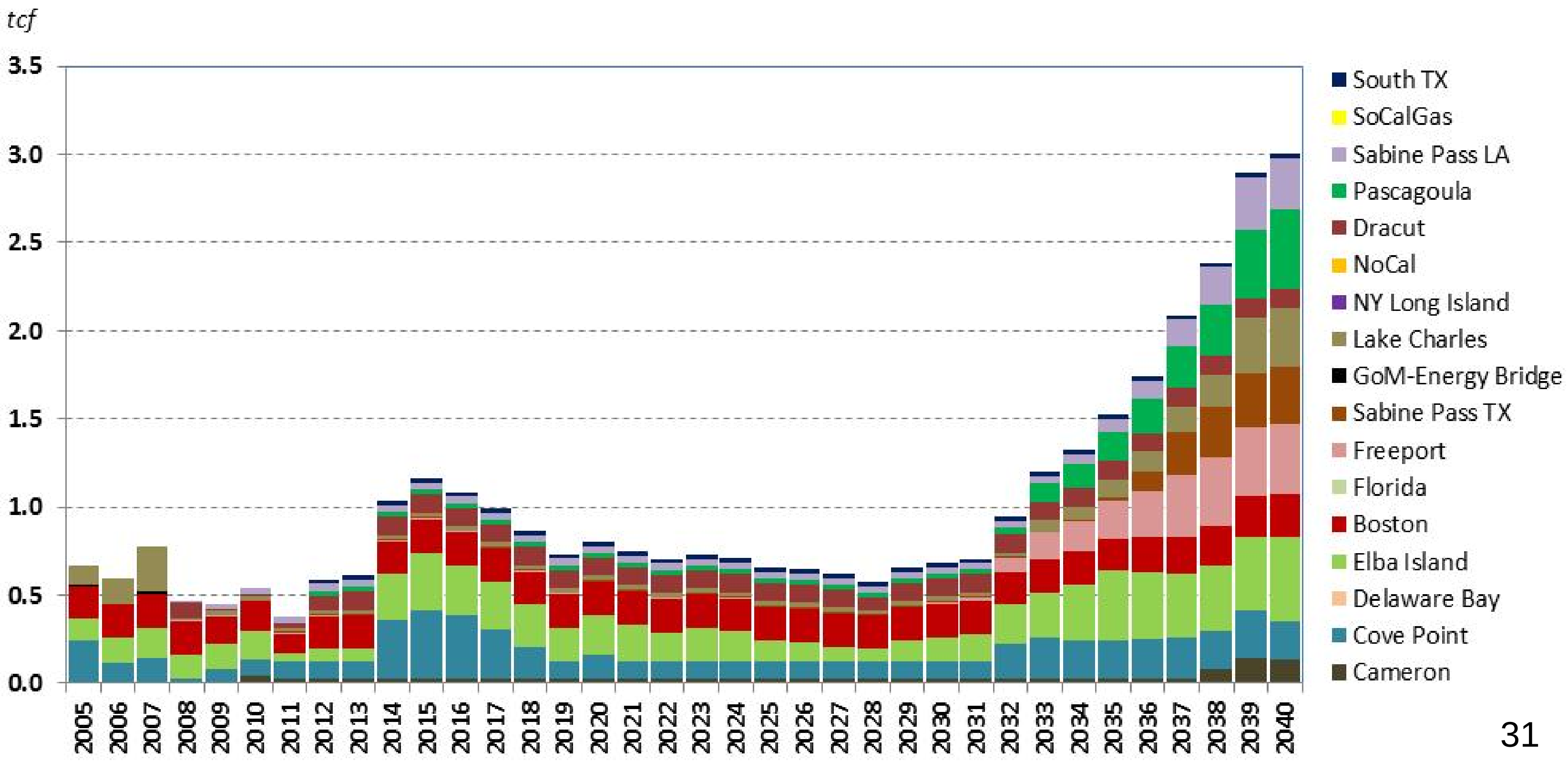
A Comment on the Role of Oil Indexation

- Absent storage and physical liquidity, oil indexation provides an element of price certainty.
- Oil indexation is a form of price discrimination
  - (1) Firm must be able to distinguish consumers and prevent resale.
  - (2) Different consumers have different elasticity of demand.
  - Both conditions are met in Europe and Asia, but not in North America.
    - Lack of transport differentials in Europe is evidence of discrimination.
- Increased ability to trade between suppliers and consumers (physical liquidity) violates condition (1).
  - This will happen in a liberalized market or as LNG trade grows.
- Evidence of a weaker ability to price discriminate is emerging in Europe.
  - Recent changes in contractual terms

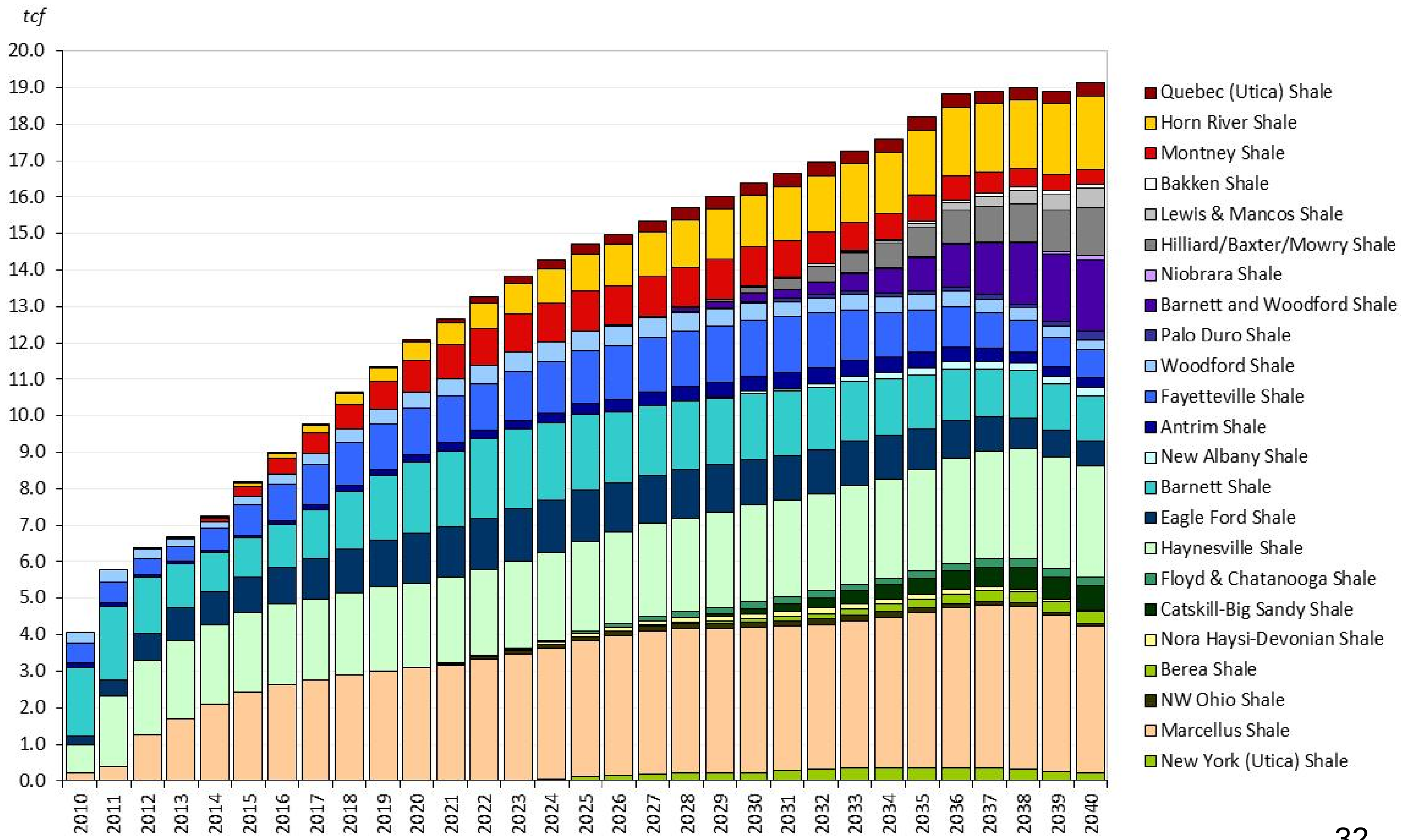


U.S. LNG Imports

- Very low re-gas terminal capacity utilization through the mid-2030s.
- Slight uptick in imports in 2014 due to timing of export capacity and US as a market of last resort.
- LNG imports eventually rise as declines in conventional basins accelerate.

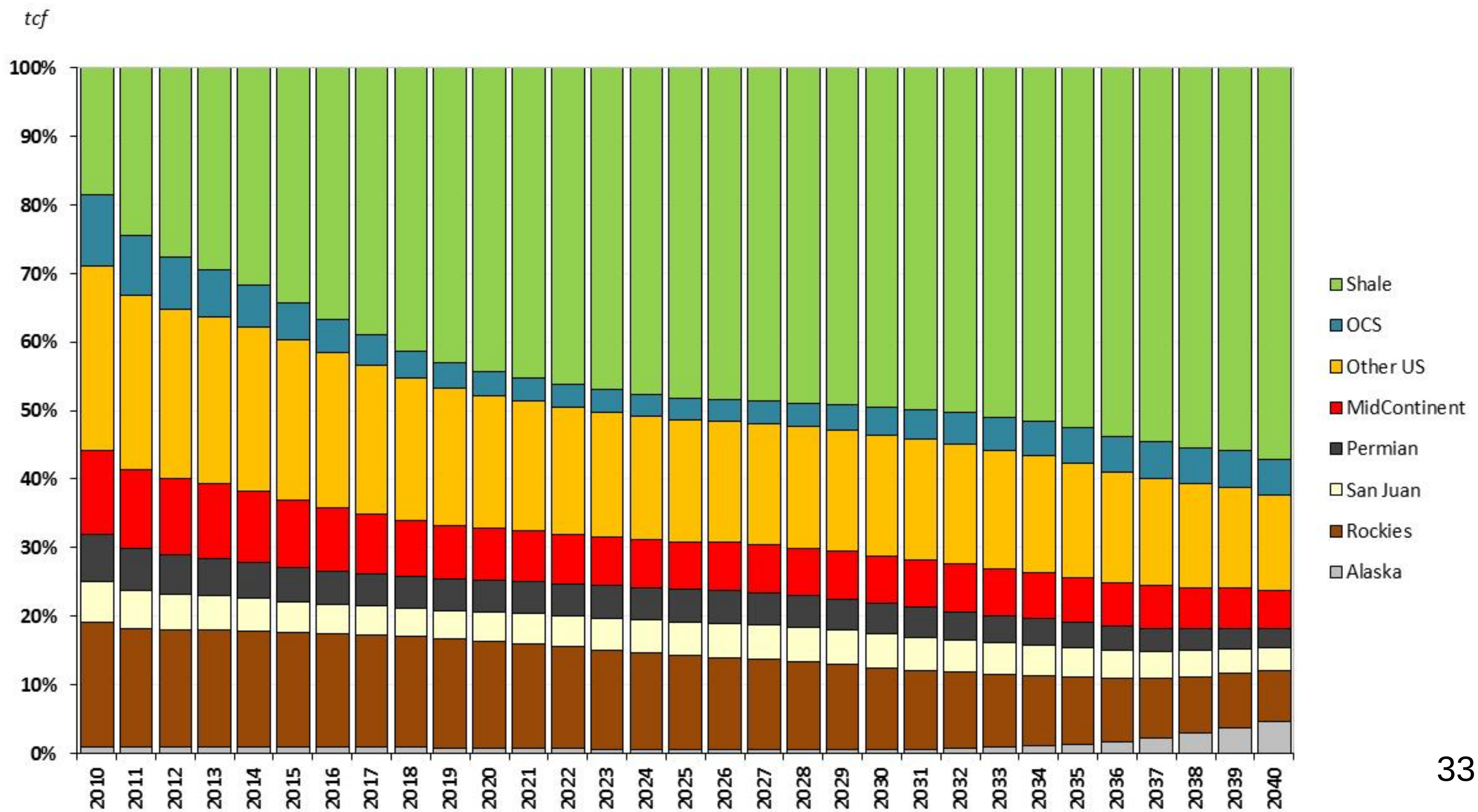


North American Shale Production



Composition of U.S. Production

- US shale production grows to about 50% of total production by early 2030s.
- Canadian shale production grows to about 1/3 of total output by 2040 (not pictured). This offsets declines in other resources as total production remains fairly flat.



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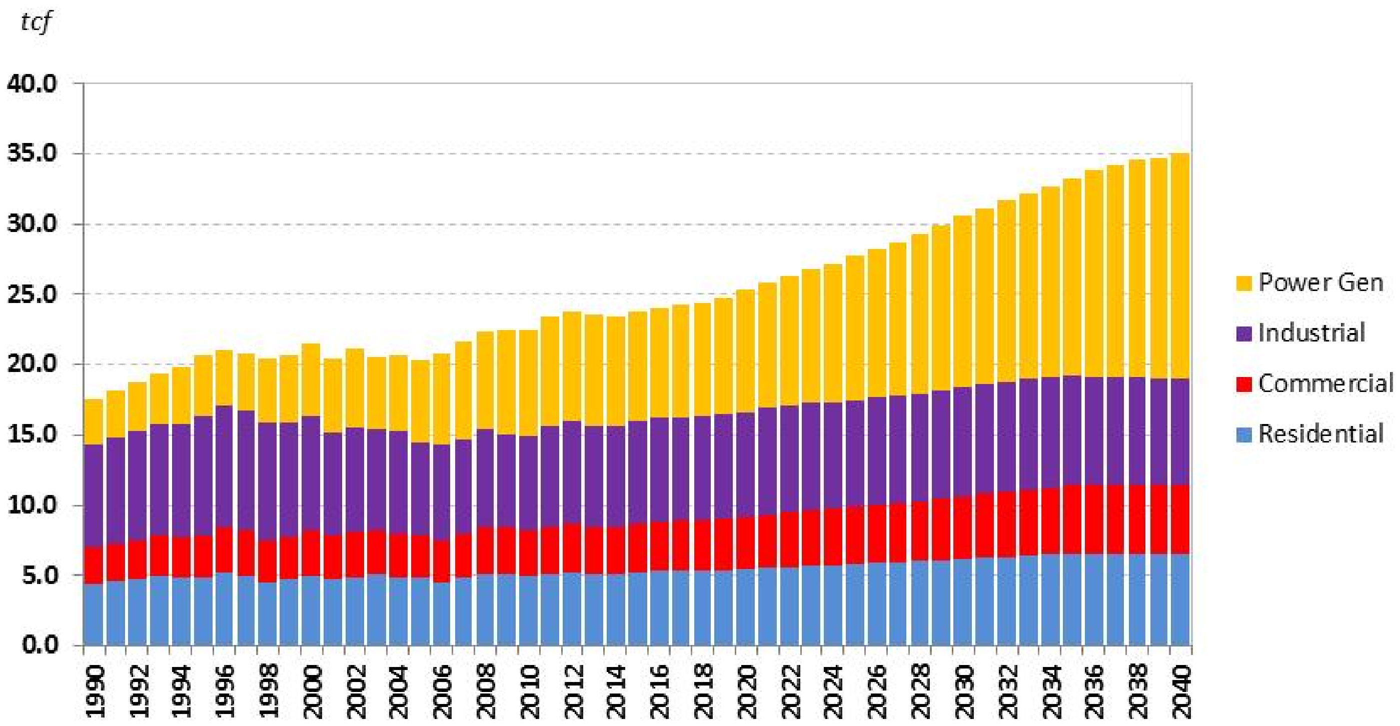
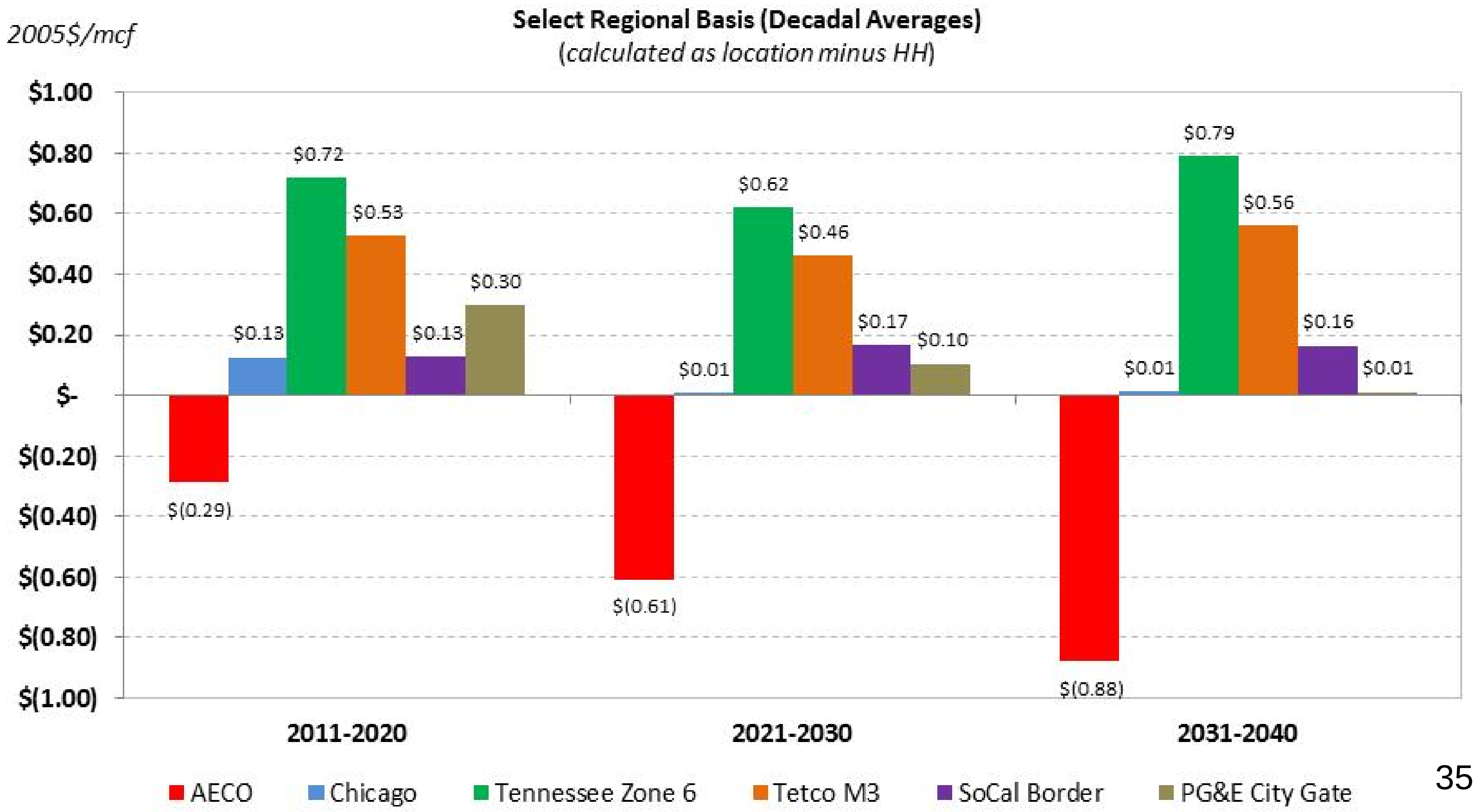
U.S. Demand

- Largely driven by growth in power generation.
- Average annual growth by sector:
  - Power Gen (2010-2040): 2.48%
  - Industrial (2010-2040): 0.36%
  - Residential (2010-2040): 0.84%
  - Commercial (2010-2040): 1.38%



U.S. Regional Pricing

- Shale developments have regional impacts on pricing.
  - AECO weakens as Canadian shale gas is developed. This directly impacts PG&E. SoCal strengthens from flat to HH in 2011.



California Demand

- Based on reference case inputs from 2007 IEPR.
- Average annual growth by sector:
  - Power Gen (2010-2040): 0.89%
  - Industrial (2010-2040): 0.05%
  - Residential (2010-2040): 0.88%
  - Commercial (2010-2040): 1.01%