NATURAL GAS MARKET OUTLOOK & FUNDAMENTALS OF LNG BUSINESS

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GAS AND LNG MARKET FUNDAMENTALS ARE STRONG

Gas makes up a rising share of the world's energy mix

- Demand for energy expected to rise by 1.2% a year through 2035, but gas grows faster at 1.6%
- Gas supplies 23.7% of total energy in 2035 (vs. 21.3% in 2011)
- Gas makes up 31% of growth in energy demand through 2035

LNG is the fastest growing part of the gas market

- LNG demand has grown 4x faster than overall gas demand in last decade
- LNG trade expected to grow by as much as 3.8% annually to 2030
- Asia is the prize in terms of demand growth (75+% of total) and pricing

Multiple supply options create downward pressure on pricing – suppliers must compete

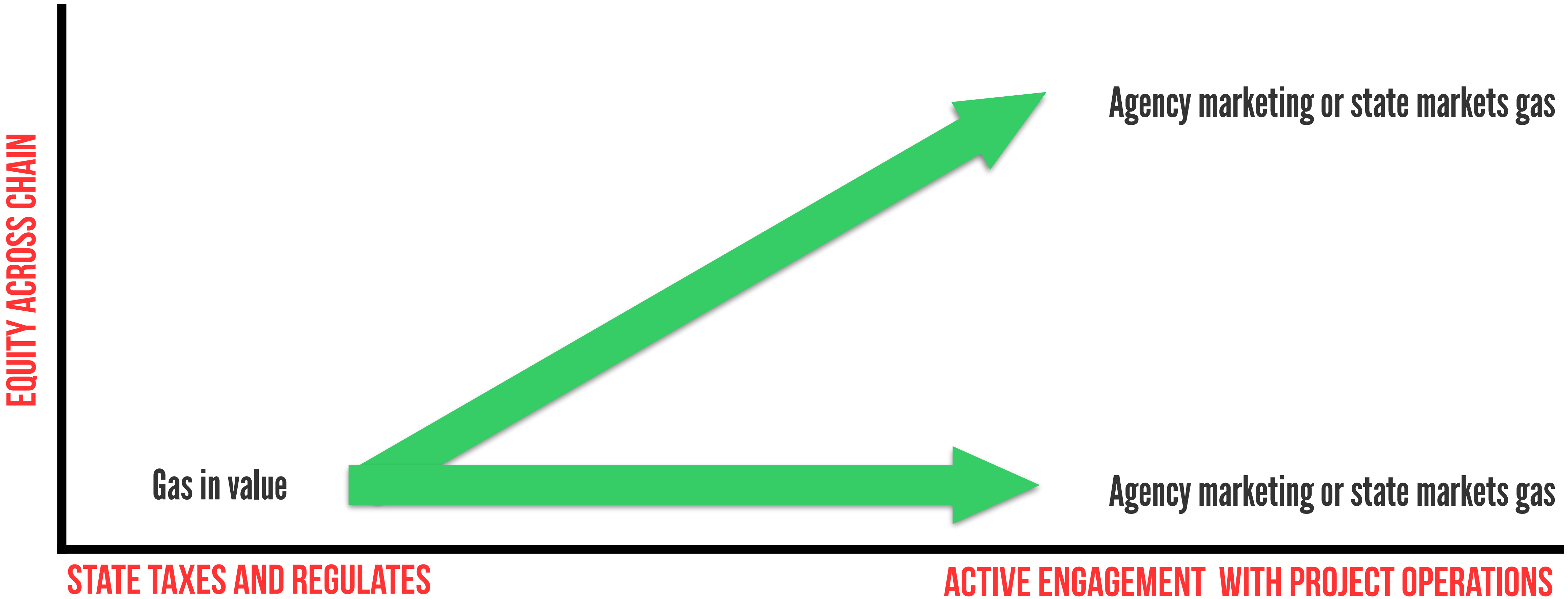
In gas pricing, micro (rather than macro) is still what matters

LNG PROJECTS ARE BIG, COMPLEX AND MULTI-LAYERED

- LNG projects take years (even decades) from first discovery to commercial production
    - They require a large capital commitment upfront—but deliver long-term revenue thereafter
    - No such thing as a "standard" project structure that Alaska can "adopt"
    - Complexity means that value creation and distribution is often a product of negotiation
    - States' participation varies from not at all to fully involved throughout the value chain
    - LNG projects are often used to unlock stranded gas that is also supplied to local markets
- LNG projects face many risks—but have established mechanisms for risk-management and mitigation
    - Third-party finance, marketing integration and pricing bands can reduce exposure/volatility
    - Price review clauses allow counter-parties to provide reprieve to grave imbalances
    - LNG projects tend to be partnerships between many private and state-owned enterprises

ALASKA HAS MANY WAYS TO PARTICIPATE IN LNG PROJECT

- STATE'S GAS
  - GAS IN VALUE: KEY QUESTION IS HOW TO NEGOTIATE A "FAIR" TRANSFER PRICE
  - GAS IN KIND
    - AGENCY MARKETING (COMPANIES SELL GAS ON ALASKA'S BEHALF)
    - STATE MARKETS GAS
      - IN-STATE SALES
      - FOB (BUYERS DO SHIPPING)
      - CIF (ALASKA DOES SHIPPING)



- NATURAL GAS MARKET OUTLOOK
- FUNDAMENTALS OF LNG BUSINESS
- IMPLICATIONS FOR ALASKA
- APPENDICES

ENERGY DEMAND HAS MORE THAN TRIPLED SINCE 1960

Oil provides 31% of total energy and is chiefly a transportation fuel

Coal provides 29%, chiefly for power; gas makes up 21.3% of total energy (of which 40% for power)

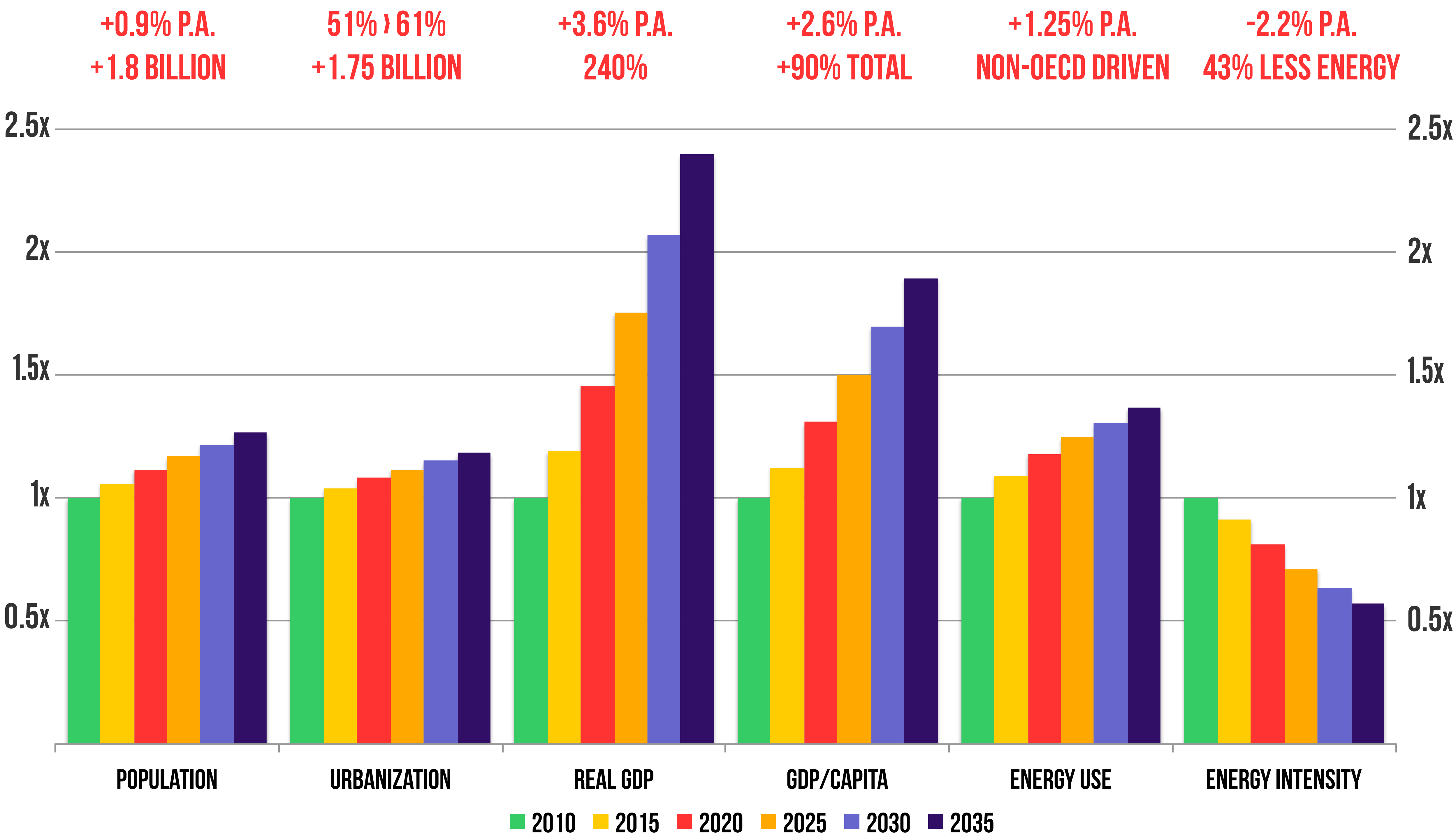
Nuclear and hydro provide a total of 7.5% all in power; biomass (10%) still large in residential use

ENERGY MATRIX IN MMTOE (2011)

	COAL	OIL & PRODUCTS	NATURAL GAS	NUCLEAR	HYDRO	BIOFUELS & WASTE	OTHER	TOTAL
PRIMARY SUPPLY	3,776.1	4,136.0	2,787.0	674.0	300.2	1,312.2	128.1	13,113.4
POWER/HEAT	(2,365.6)	(283.5)	(1,118.2)	(674.0)	(300.2)	(134.6)	2,143.5	(2,732.7)
OTHER TRNSFR	506.8	219.2	288.3	-	-	65.8	383.1	1,463.2
INDUSTRY	728.9	323.2	506.4	-	-	198.2	800.1	2,556.8
TRANSPORT	3.4	2,265.2	92.5	-	-	58.6	25.2	2,444.9
RES/COMM/AGR	132.1	436.1	610.2	-	-	855.0	1,063.1	3,096.4
NON-ENERGY	39.2	608.8	171.4	-	-	-	-	819.4
% TOTAL	28.8%	31.5%	21.3%	5.1%	2.3%	10.0%	1.0%	100%

SOURCE: INTERNATIONAL ENERGY AGENCY, KEY WORLD ENERGY STATISTICS 2013

STRONG FUNDAMENTALS SUPPORT HIGHER ENERGY USE



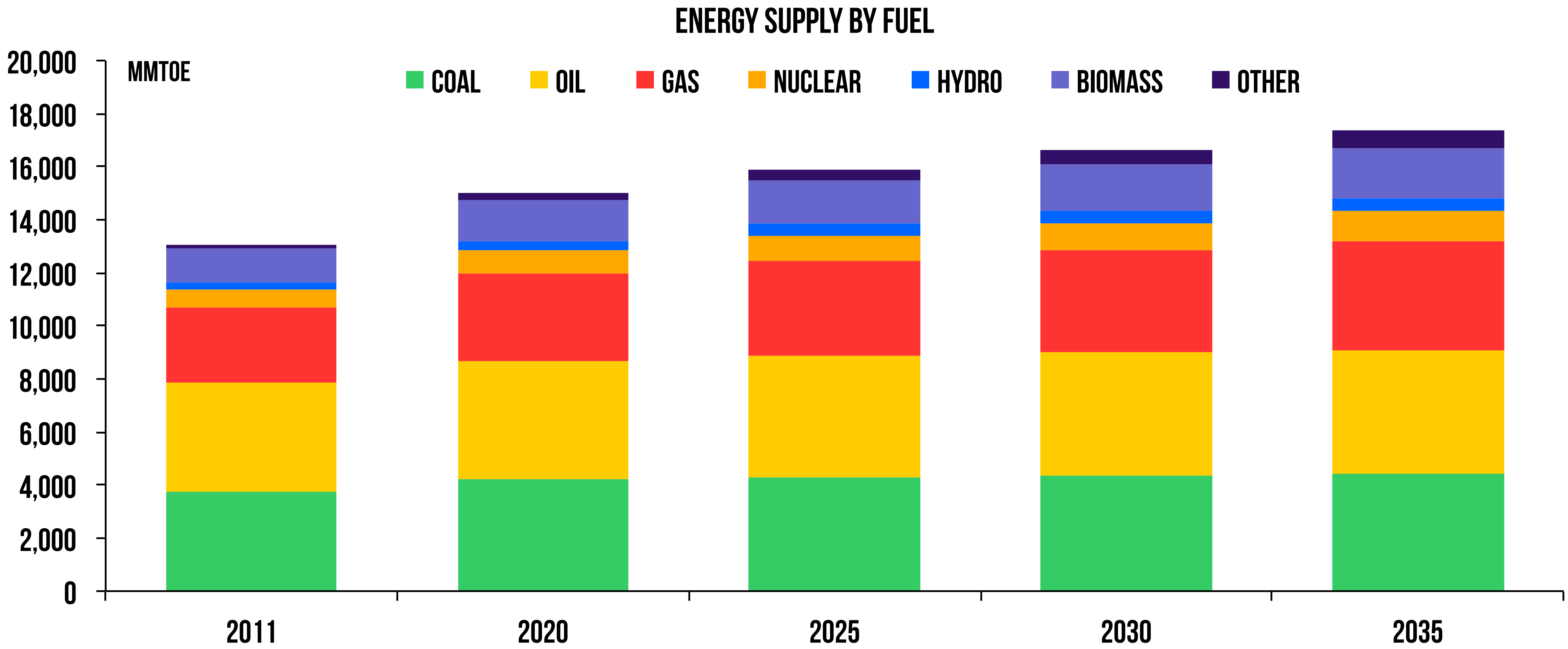
SOURCE: UN POPULATION PROSPECTS (2012); UN, WORLD URBANIZATION PROSPECTS (2011) ; IEA, WORLD ENERGY OUTLOOK; OECD, LONG-TERM GDP PROJECTIONS (JUNE 2013)

IEA FORECASTS ENERGY TO GROW AT 1.2% BY 2035

Gas accounts for 31% of energy growth (1.6% annual growth); share of total energy from 21.3% to 23.7%

Coal plateaus in the 2020s and its share of total energy shrinks to 25.5% (vs. 28.8% in 2010)

Percent of fossil fuels declines from 81.6% in 2010 to 76% in 2035



SOURCE: US ENERGY INFORMATION ADMINISTRATION, INTERNATIONAL ENERGY OUTLOOK (JULY 2013)

GAS UNITS AND CONVERSIONS

bbl	barrel (oil)	1 bbl = 6 thousand cubic feet (6 mcf)
$/bbl	dollars per barrel (oil)	$6/bbl = $1/mcf ≃ $1/mmbtu
mmbtu	million British thermal units	$1/mmbtu ≃ $1/mcf
mmcf/d	million cubic feet per day	1,000 mmcf/d = 7.8 mmtpa = 10.3 bcm/yr
bcf/d	billion cubic feet per day	1 bcf/d = 7.8 mmtpa = 10.3 bcm/yr
bcm	billion cubic meters	1 bcm/y = 0.73 mmtpa = 96.7 mmcf/d
mmtpa	million tons per annum (LNG)	1 mmtpa = 1.37 bcm = 48.37 bcf/y = 132 mmcf/d
mmtoe	million tons of oil equivalent	1 mmtoe = 1.11 bcm = 39.2 bcf = 107.4 mmcf/d

ONLY 30% OF GLOBAL GAS IS TRADED (VS. 64% OF OIL)

Europe and Asia are deficit regions (71% of imports); FSU is the largest surplus region (26% of exports)

North America is the biggest producer (27% of global) and consumer (27% of global); it is in small deficit

68% of gas trade by pipeline; 32% as liquefied natural gas (LNG)

REGIONAL BALANCES (2012) IN BCF/D

	PRODUCTION		EXPORTS		IMPORTS		NET	DEMAND	
	BCF/D	%	BCF/D	%	BCF/D	%	BCF/D	BCF/D	%
N. AMERICA	86.5	27%	12.5	13%	13.6	14%	-1.0	87.5	27%
S. AMERICA	17.1	5%	4.0	4%	3.1	3%	0.9	15.9	5%
EUROPE	25.5	8%	19.9	20%	43.2	43%	-23.3	48.0	15%
FSU	74.4	23%	26.1	26%	8.9	9%	17.2	56.5	18%
MIDDLE EAST	52.9	16%	15.4	15%	3.3	3%	12.1	39.7	12%
AFRICA	20.9	6%	9.7	10%	0.6	1%	9.1	11.8	4%
ASIA PACIFIC	47.3	15%	12.4	12%	27.3	27%	-15.0	60.3	19%
TOTAL	324.6	100%	99.9	100%	99.9	100%	0.0	319.8	100%

SOURCE: BP STATISTICAL REVIEW OF WORLD ENERGY (JUNE 2013)

MORE THAN HALF (58%) OF GAS TRADE WITHIN REGIONS

Intra-regional trade patterns

- Intra-European trade accounts for 19.5% of the volumes traded internationally
- Intra-North America and Intra-Asia Pacific make up another 12.5% each
- Intra-FSU trade makes up 9% of total trade, mostly originating from Russia

Inter-regional trade patterns

- Trade from FSU to Europe is the largest inter-regional trade route (13% of global)
- Middle East and Africa into Europe almost as big (10.3% of global trade)
- Middle East to Asia (9%) and FSU to Asia (3.5%) other major routes

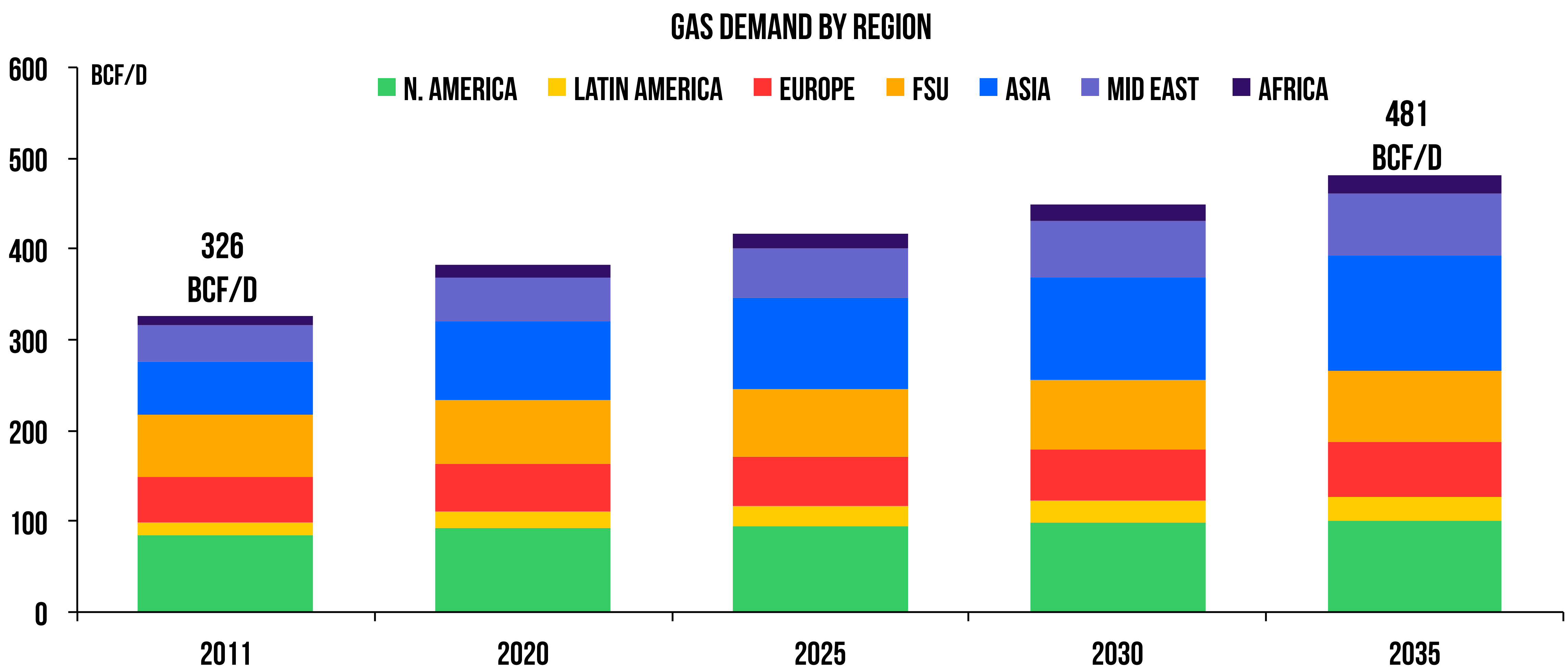
SOURCE: BP STATISTICAL REVIEW OF WORLD ENERGY (JUNE 2013)

IEA PUTS GAS DEMAND GROWTH AT 1.6% THROUGH 2035

OECD accounts for 18% of demand growth; non-OECD 82%

Asia accounts for 44% of incremental demand; Middle East follows by 19.5%

OECD North America grows faster than OECD Europe / OECD Asia due to cheaper gas prices



SOURCE: INTERNATIONAL ENERGY AGENCY, WORLD ENERGY OUTLOOK 2013 (NOVEMBER 2013)

LNG MARKET WAS 31.7 BCF/D IN 2012

Middle East is largest surplus region (+12.3 bcf/d); Asia is largest deficit region (-11.5 bcf/d)

Around 70% of LNG went to Asia and 21% to Europe

South America and Middle East are recent importers (since 2008); they took in 6% of demand in 2012

Middle East (40%) and Asia Pacific (33.2%) were the largest suppliers of LNG

Africa is the next largest supplier (Algeria, Nigeria, Eq. Guinea, Egypt) with 16.5% of exports

LNG IMPORTS AND EXPORTS IN 2012

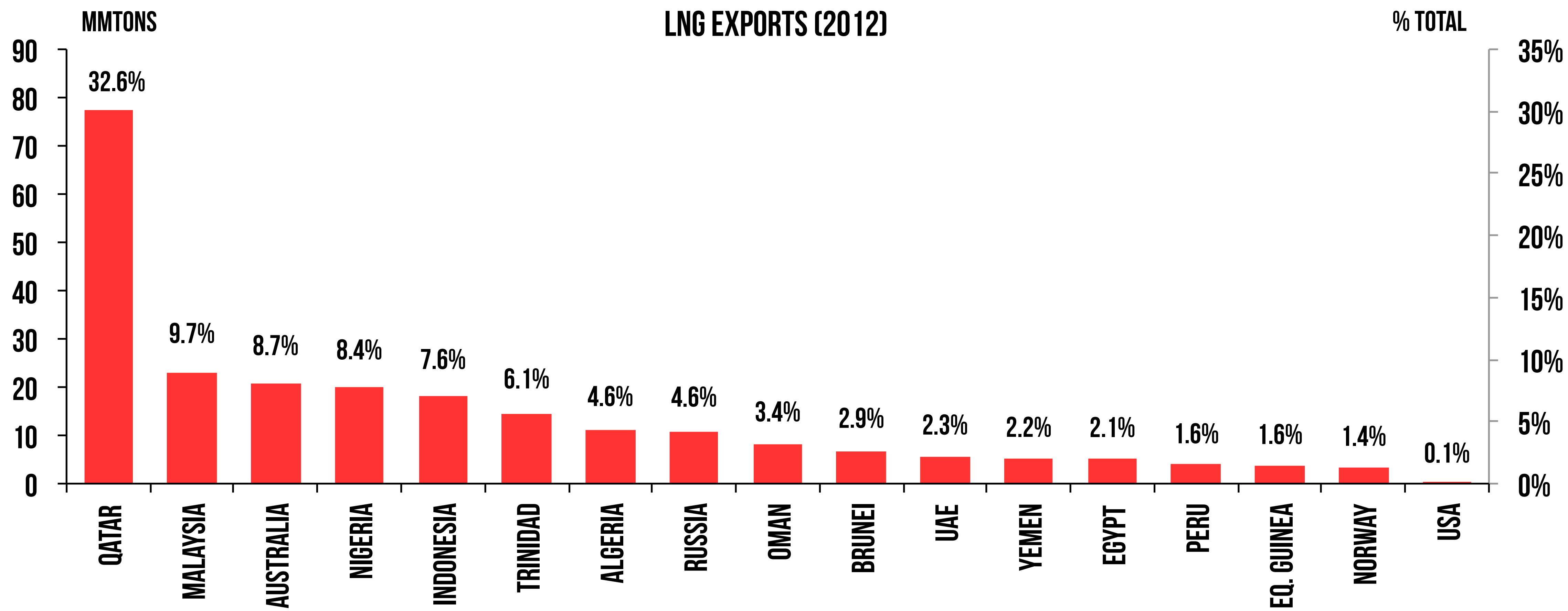
	IMPORTS		EXPORTS		NET
	BCF/D	% TOTAL	BCF/D	% TOTAL	BCF/D
MIDDLE EAST	0.4	1.4%	12.7	40.1%	12.3
AFRICA	0.0	0.0%	5.2	16.5%	5.2
S. & C. AMERICA	1.5	4.6%	2.4	7.6%	0.9
N. AMERICA	1.1	3.5%	0.1	0.2%	-1.0
EUROPE	6.7	21.1%	0.8	2.4%	-5.9
ASIA PACIFIC	22.0	69.3%	10.5	33.2%	-11.5
TOTAL	31.7	100%	31.7	100%	0.0

SOURCE: BP STATISTICAL REVIEW OF WORLD ENERGY (JUNE 2013)

QATAR IS BY FAR LARGEST LNG EXPORTER (32.6% TOTAL)

Five countries (Qatar, Malaysia, Australia, Nigeria, Indonesia, Trinidad) make up 73% of supply

Russia, Peru, and Yemen have all started to export after 2008. Angola started exports in 2013



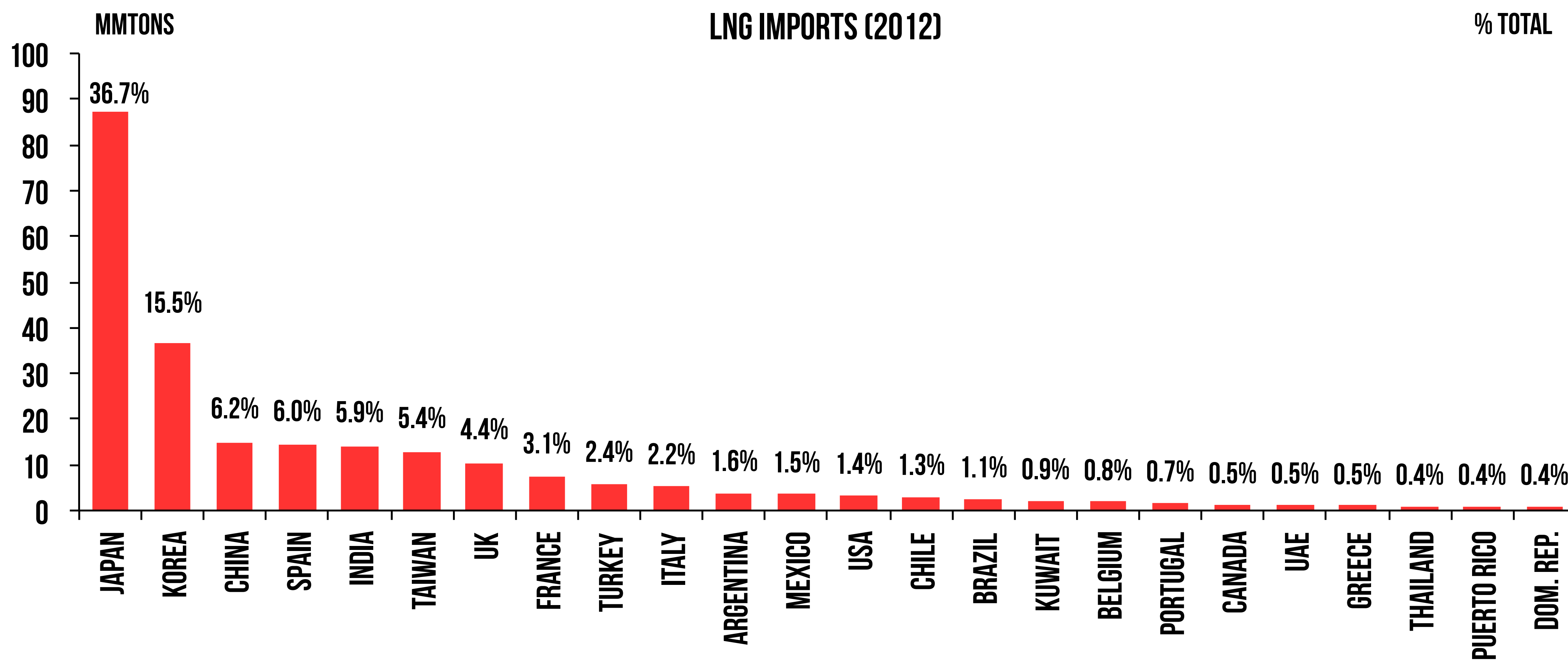
SOURCE: INTERNATIONAL GAS UNION, WORLD LNG REPORT 2013 (JUNE 2013)

LNG DEMAND CONCENTRATED AMONG FEW BUYERS

Two markets (Japan and Korea) account for 50% of demand

Six countries (Japan, Korea, China, Spain, India, Taiwan) make up 75% of demand

15 countries import less than 2% of global demand each – but more and more countries importing LNG



SOURCE: INTERNATIONAL GAS UNION, WORLD LNG REPORT 2013 (JUNE 2013)

LNG DEMAND TO GROW 3.8% A YEAR TO 2030

Asia has been and remains the dominant market for LNG and accounts for 75+% of demand growth

Demand for LNG in Americas flat; shale shrinks N. America's needs but S. America grows

Europe flat through 2020 but growth thereafter driven by resource maturity

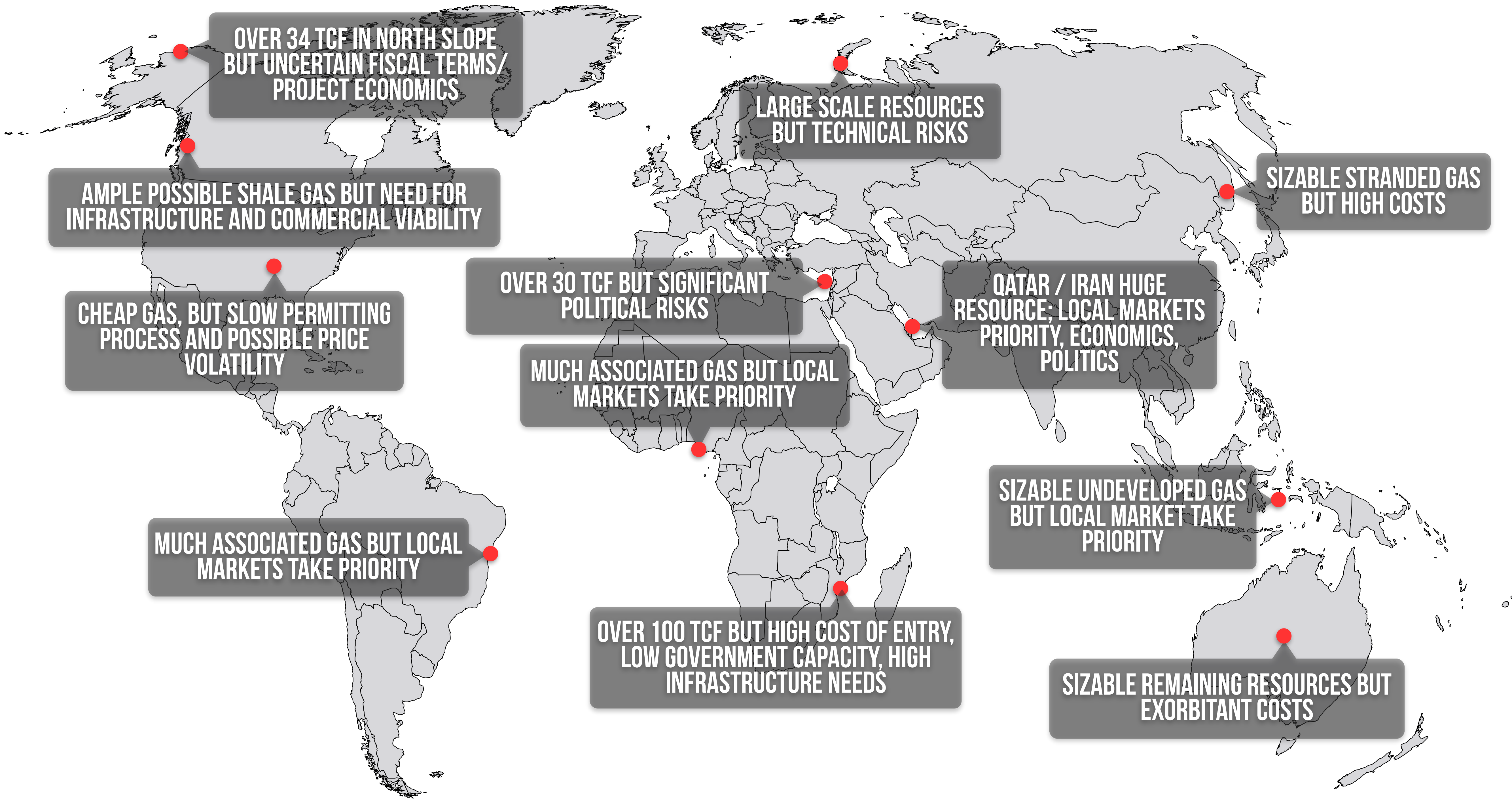
Middle East and Africa fastest growing markets but volumetrically make bigger impact post 2020

LNG IMPORTS IN MMTPA

	2010	2015	2020	2030	Δ: 10-30	Δ: 10-30
AMERICAS	21	20	16	19	-2	-0.3%
EUROPE	64	28	60	98	34	6.5%
MID EAST/AFRICA	3	6	10	38	35	9.7%
ASIA	129	200	256	377	248	3.2%
TOTAL	217	254	342	532	315	3.8%

SOURCE: WOOD MACKENZIE LNG FORECAST (DATA FROM CHENIERE IR PRESENTATION IN JANUARY 2014)

MANY POSSIBLE SUPPLIERS, MANY RISKS TO MANAGE



GAS PRICING STRUCTURES HIGHLY VARIABLE

Gas pricing can be either cost-plus or market netback

Gas is usually priced in any of four alternative ways; some deals could include a mixture of all four

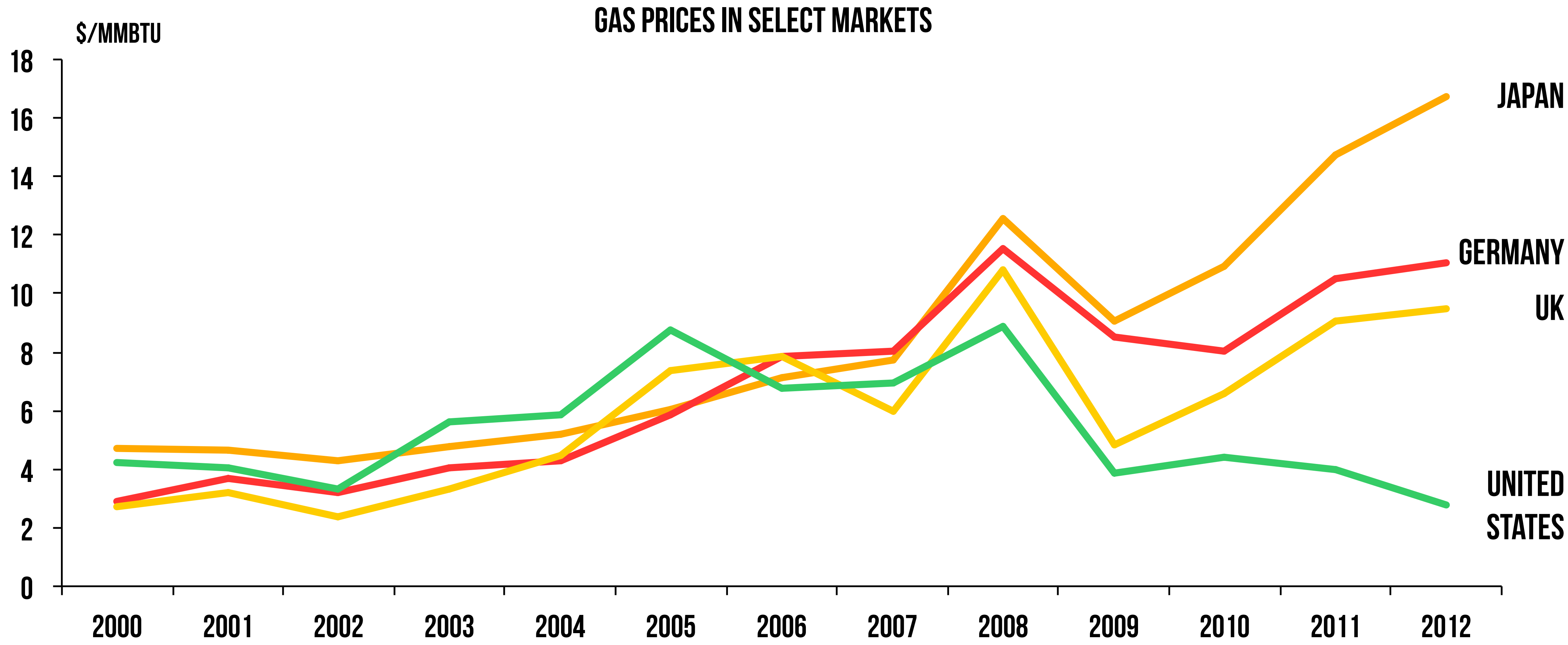
MARKET-BASED (HUBS)	Pricing references a marker; e.g. Henry Hub in the United States or National Balancing Point (NBP) in the United Kingdom
ALTERNATIVE FUELS (E.G. OIL, OIL PRODUCTS, COAL)	Pricing references a competing fuel to retain competitiveness of gas; e.g. LNG into Japan priced against Japan Customs Cleared (JCC) price; pipe gas in Europe vs. HFO/diesel
END-PRODUCTS (E.G. ELECTRICITY, CHEMICALS)	Pricing references a final product price; e.g. EOG in Trinidad sells gas to local consumers at a price linked to exported methanol/ammonia
FLAT RATE	The price negotiated does not reference any external marker, except perhaps inflation; e.g. The Alba gas field in Equatorial Guinea sells to the LNG and a methanol plant at a flat rate

NO SUCH THING AS A "GLOBAL GAS" PRICE

There has always been a major disparity between regional prices

In 2012, Henry Hub in the United States averaged $2.76/MMBtu; the price in Japan was $16.75/MMBtu

European pricing was somewhere in the middle: $9.46/MMBtu in the UK to $11.03/MMBtu in Germany



SOURCE: BP STATISTICAL REVIEW OF WORLD ENERGY (JUNE 2013)

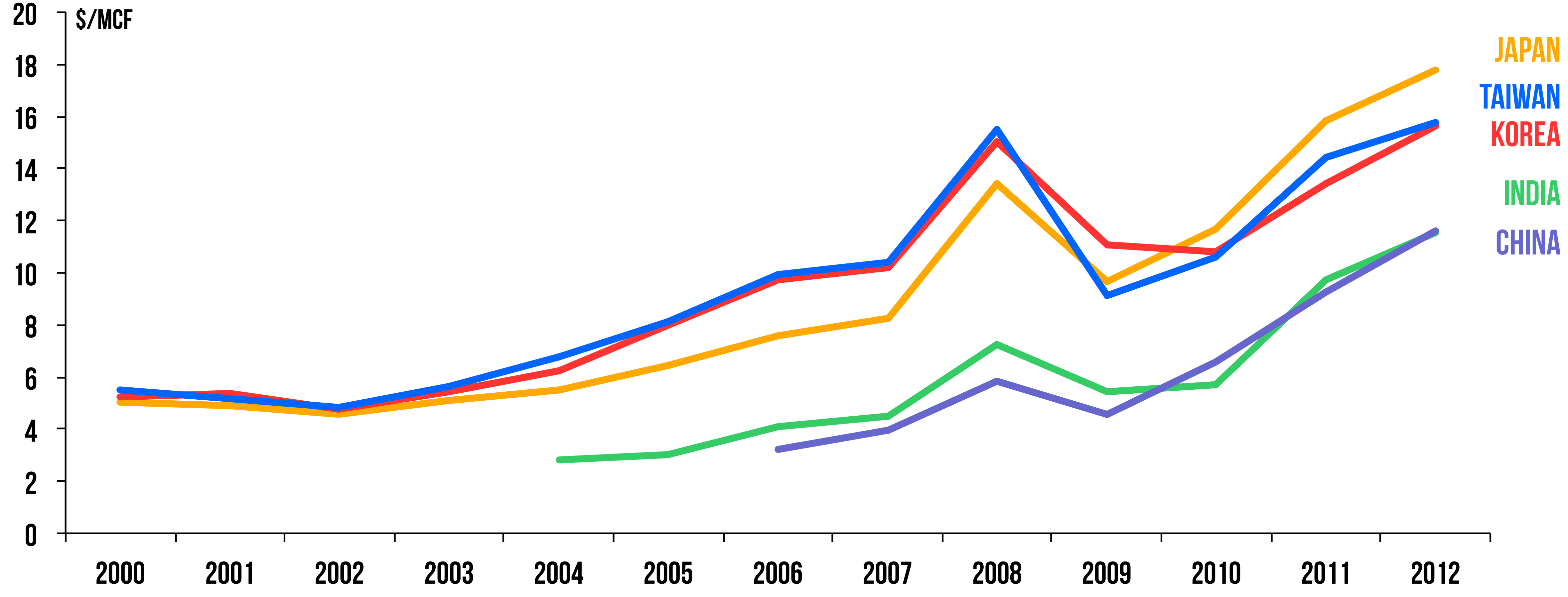
NO SUCH THING EVEN AS AN "ASIAN" GAS PRICE

LNG prices in Asia ranged from $17.81/mcf on average in Japan to $11.52/mcf on average in China

China and India have cheaper average prices due to some lower priced contracts signed in early 2000s

From 2003 to 2008, Japan had lower prices than Korea and Taiwan; since 2010, it has had higher prices

GAS PRICES IN SELECT MARKETS



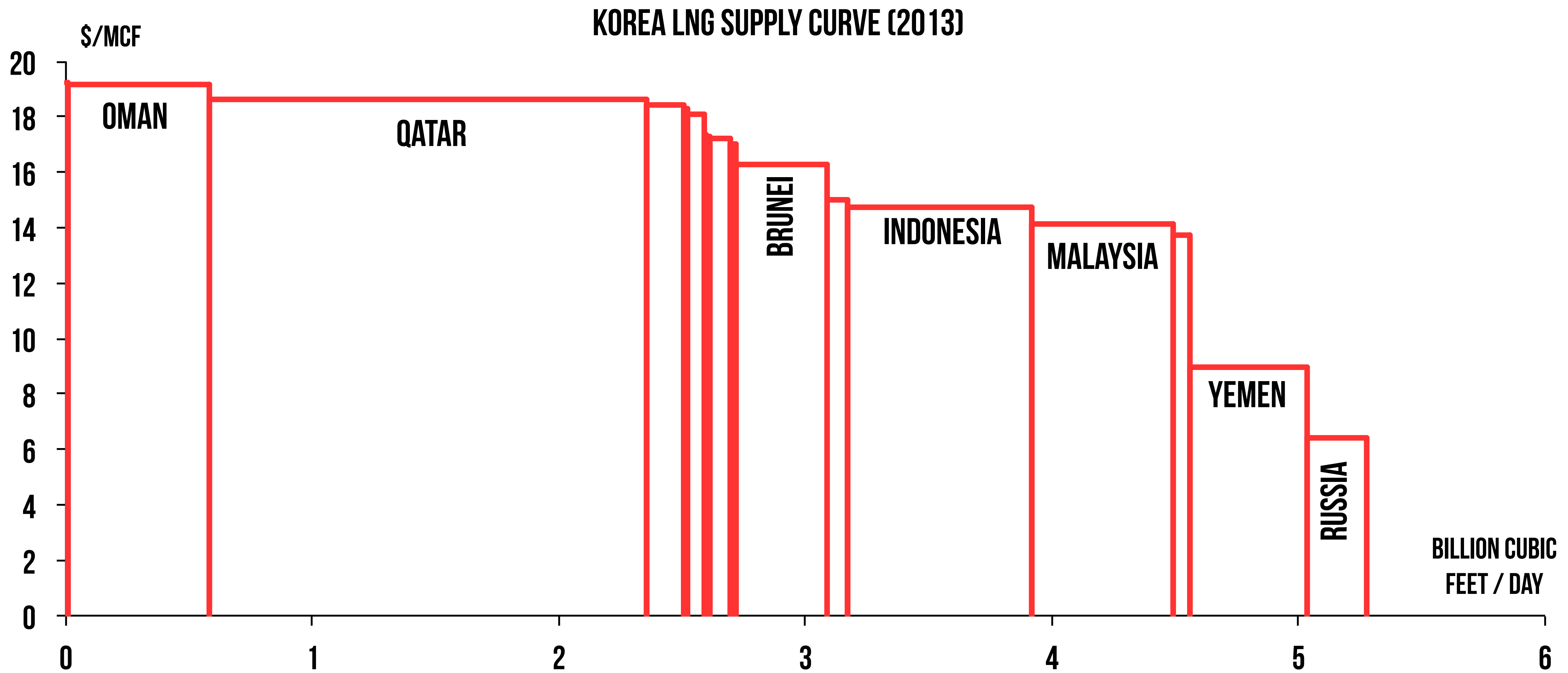
SOURCE: NATIONAL STATISTICAL AGENCIES, BP STATISTICAL REVIEW OF WORLD ENERGY (JUNE 2013)

PRICING CAN VARY EVEN WITHIN COUNTRIES

For example, Korea paid $15.88/mcf for LNG in 2013

But bilateral prices ranged from $19.25/mcf (Norway) to $6.40/mcf (Russia)

Individual contract terms can matter more than the destination country in general



SOURCE: KOREA INTERNATIONAL TRADE ASSOCIATION (KITA), HTTP://KITA.ORG (ACCESSED JANUARY 2014)

GAS PRICING IS UNDERGOING FUNDAMENTAL CHANGES

Gas pricing tends to go through cycles

- Surplus: prices tend to fall to the marginal cost of supply (cost-plus): $8-12/MMBtu
- Shortage: prices move to cost of alternative fuels or demand destruction (netback): $16-18/MMBtu
- Timing is everything – but pricing formulae can change
- Current market conditions pushing pricing towards cost-plus (e.g. US Gulf Coast)

LNG pricing post 2020 will be driven by:

- How quickly will proposed projects move forward (turning possible supply into real supply)?
- The strategies of importers: will they create new supply and not renew old contracts?
- How will existing suppliers (e.g. Qatar) respond? Will they try to undercut new suppliers?
- How quickly will gas hubs develop (e.g. Singapore, Tokyo)?

GAS AND LNG MARKET FUNDAMENTALS ARE STRONG

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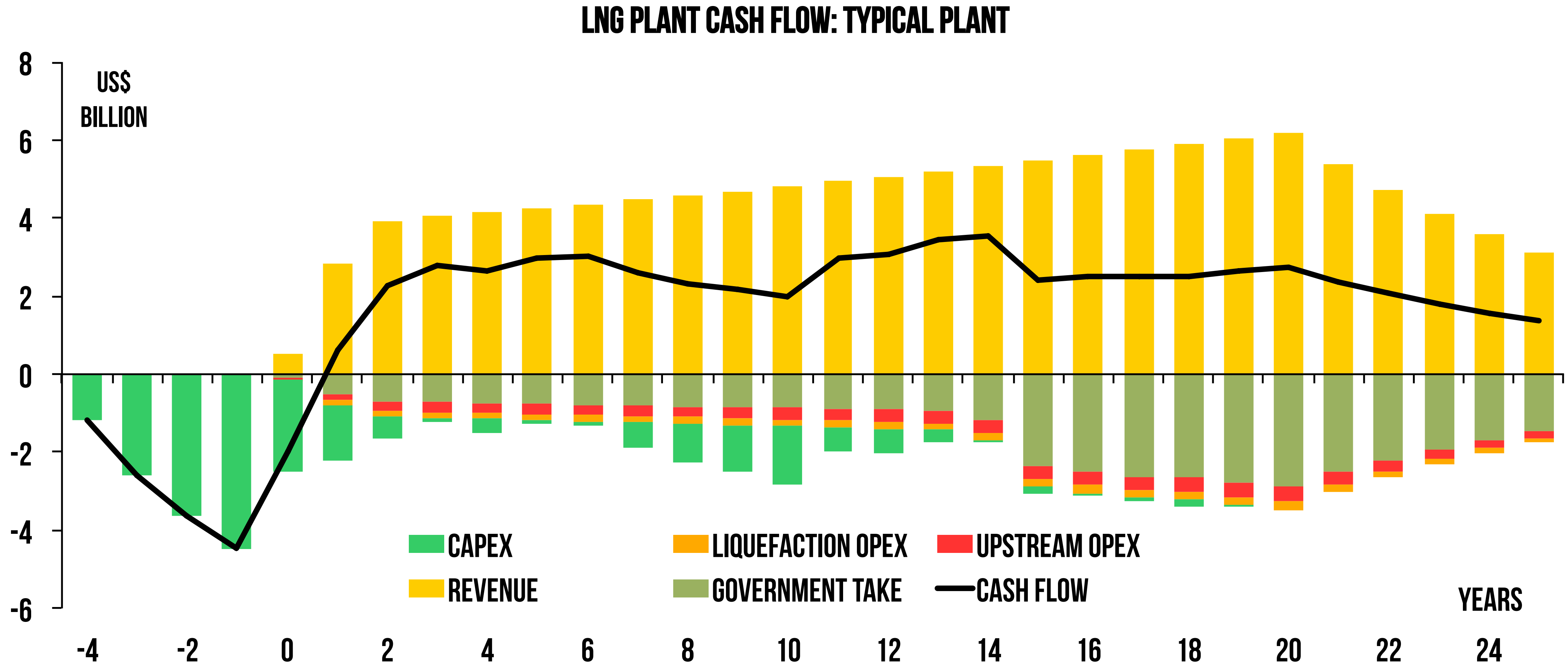
BIG, UPFRONT INVESTMENT, LONG-TERM REVENUE

LNG projects take 4-5 years to build but run for 20-50 years with low maintenance / upkeep costs

Majority of LNG projects have been expanded and/or taken gas from new fields

Subpar rate of return tends to be bigger risk than outright "losing money"



LNG PROJECTS MOVE ON MANY PARALLEL FRONTS

Upstream	Delineate resource base, certify reserves, define production plan
Midstream	Define pipeline path, secure right-of-way, environmental permits
Liquefaction	Define project size, processing / gas quality, project structure
Shipping	Decide whether to own, lease or outsource shipping to buyers
Marketing	Define commercialization plan, secure buyers, sign contracts
Financing	Define financing plan, secure in-house and third-party lending
Permitting	Secure permits to construct facility, export gas

Partners conduct front-end engineering and design studies (pre-FEED and FEED)

They then sign engineering, procurement and construction (EPC) contracts

Construction starts with final investment decision (FID); usually less than 10% of CAPEX spent before FID

PRICING	Pricing will refer to some alternative fuel (usually crude oil or oil products) and/or a gas marker (e.g. Henry Hub, NBP in the United Kingdom, etc.)
DURATION & START	For new projects, contracts are usually 15-20 years. Contracts will also specific start date (month / year)
DESTINATION CLAUSES	Destination clauses, which restrict which markets the LNG can be sold at, are increasingly out of favor—and are illegal in Europe. However, producers dislike when their gas is resold to third parties without any upside to them. LNG in Atlantic Basin is generally destination-free, Qatari equity marketed gas is flexible, and Pacific LNG has territorial restrictions.
VOLUME QUANTITY & FLEXIBILITY	Contracts are typically take-or-pay: buyers can typically buy 10-20% more or less of their annual take-or-pay volumes—but they have to pay for LNG whether they lift it or not.
SCHEDULE & LOGISTICS	Estimated schedule for delivering cargoes (e.g. seasonality patterns) and logistics for delivery (e.g. tanker size)
GAS QUALITY	Specifications for gas, including any treatment of liquids
PROFIT SHARING	Some contracts allow the original seller to share the profit in case a cargo is diverted from its original source, but such provisions are illegal in Europe (they are considered to inhibit competition)
NON-COMPLIANCE	Penalties can involve non-delivery, delays, off-spec gas (different gas quality)
RENEGOTIATION	Most contracts will allow price reviews every 3-4 years but usually within a band. Most contracts will also allow a one-time review clauses for extraordinary circumstances. Arbitration is usually required when parties cannot agree
TITLE TRANSFER	Specification of when the LNG transfers ownership from buyer to seller (e.g. FOB, CIF, DES)

LNG EXPORTS OFTEN LINKED TO DOMESTIC GAS SALES

LNG projects could either seek to scale up existing producing assets or may unlock stranded gas

In cases where there is no existing production, LNG exports often serve as foundation for a local market

The prospect of exports often incentivizes further exploration that benefits local and export markets

Some jurisdictions (Indonesia, Western Australia) have explicit domestic gas reservation policies

Examples

Angola LNG will deliver 125 mmcf/d to the local market

Bintulu LNG (Malaysia) makes possible gas consumption in the remote areas of Sarawak (east Malaysia)

Donggi Senoro LNG (Indonesia) will couple exports with sales to local ammonia and power plants

North West Shelf (Australia) started to supply local market 5 years before exports started (1984 / 1989)

Yemen LNG sources gas from gas Marib Area—1 tcf of 9.15 has been allocated to local market

SOURCES: COMPANY PRESS RELEASES AND INDUSTRY PRESS

INTEGRATED PROJECTS DISTRIBUTE VALUE INTERNALLY

Same companies own upstream and midstream—value driven by sales price (FOB/CIF)

Distribution of value between upstream and midstream is an internal transfer question

Transfer price may or may not be public

	UPSTREAM	LIQUEFACTION	SALES
ALGERIA	Gas produced across Algeria Piped to shore	Sonatrach 100% owned facilities FOB: $11.50/mcf	Various LNG SPAs & direct marketing
QATAR	Gas produced from the North Field Varying ownerships	Qatargas & RasGas Varying ownerships FOB: $11.36/mcf	LNG pricing ranging from China: $20 North America >$3
RUSSIA	Gas produced and piped across Sakhalin Island (500 miles of pipe)	Sakhalin-2 LNG project Both trains same ownership FOB: $6.18/mcf	Various SPAs Japan (76%): $15.40 Korea (20%): $8.10

INTERNAL TRANSACTION | THIRD-PARTY TRANSACTION

SOURCE: COMPANY FINANCIAL REPORTS AND COUNTRY IMPORT STATISTICS

INFRASTRUCTURE OWNER DRIVES PRICING

Infrastructure owner buys gas and sells LNG—value in differential between upstream and downstream

FOB price does not need to be linked to upstream price (e.g. Equatorial Guinea)

Upstream price can be netback (e.g. Malaysia LNG) or cost-plus (e.g. Sabine Pass)

	UPSTREAM	LIQUEFACTION	SALES
EQ. GUINEA	Noble Energy: Alba Field 235 mmcf/d (2012) % sold to LNG $0.25/MMBtu	Marathon-Operated: EG LNG T1 90% * Henry Hub linked FOB price: $2.57 FOB cost: under $1	BG Group LNG Sales to Japan (76%): $18.65 Korea (10%): $15.04 Taiwan: (5%): $20.38
MALAYSIA	Murphy Oil: SK 309 and SK 311 174 mmcf/d (2012) 50% * LNG export price $7.50/mcf	PETRONAS: Malaysia LNG Oil-linked pricing Various contracts (mostly cif) FOB: $15.64	LNG Sales to Japan (62%): $19.07 Korea (18%): $11.69 Taiwan: (12%): $19.11
SABINE PASS	No single supplier Gas sourced from the market Henry Hub prompt month in 2013 $3.73/MMBtu	Cheniere Energy: Sabine Pass 16-18 mmtpa 115% * Henry Hub + $2.25 to $3 FOB: $6.54 to $7.29	LNG SPAs BG Group, Gas Natural Fenosa GAIL, KOGAS Companies can resell LNG for any price

INTERNAL TRANSACTION | THIRD-PARTY TRANSACTION

SOURCE: COMPANY FINANCIAL REPORTS AND COUNTRY IMPORT STATISTICS

LNG AKIN TO PIPELINE: PAY A FEE TO USE FACILITY

In a tolling structure, the supplier or buys pays the liquefaction owner a usage fee

The infrastructure owner takes no ownership of the gas

The relevant pricing is between supplier and buyer; infrastructure owner is “irrelevant”

	UPSTREAM	LIQUEFACTION	SALES
EGYPTIAN LNG	BG Group (50%) and PETRONAS (50%) West Delta Deep Marine Conduct SPAs with off-takers Pay liquefaction plant a fee	T1: BG 35.5%, PETRONAS 35.5% EGPC 12% EGAS 12%, GDF SUEZ 5% T2: BG 38%, PETRONAS 38% EGPC 12% EGAS 12%	Train 1 sales 100% to GDF SUEZ Train 2 sales 100% to BG Group
TRINIDAD	Various suppliers e.g. BG and partners 28.9% of gas supply Pay liquefaction plant a fee (est. $1/mcf) Upstream pricing is netback from FOB	T4 : BP 38%, BG 29%, Shell 22%, NGC 11% FOB price (est. $5.16/mcf)	Off-take proportional to gas supply Some suppliers may sell gas FOB Henry Hub pricing and profit sharing e.g. Japan ($13.63/mcf)
CAMERON	No single supplier Gas sourced from the market	Sempra 50.2% Mitsubishi 16.6% Mitsui 16.6% GDF SUEZ 16.6%	Mitsubishi, Mitsui and GDF SUEZ Pay LNG facility a tolling fee They also procure their own gas

SOURCE: COMPANY FINANCIAL REPORTS AND COUNTRY IMPORT STATISTICS

INTERNAL TRANSACTION | THIRD-PARTY TRANSACTION

THERE IS NO "RIGHT" PROJECT STRUCTURE

Type of resource base is often a major driver (size of initial resource, expansion potential, new fields)

The partners risk appetite and desire to commit capital is another main driver

Expansion prospects and competitive landscape is a third driver (# of companies that could supply gas)

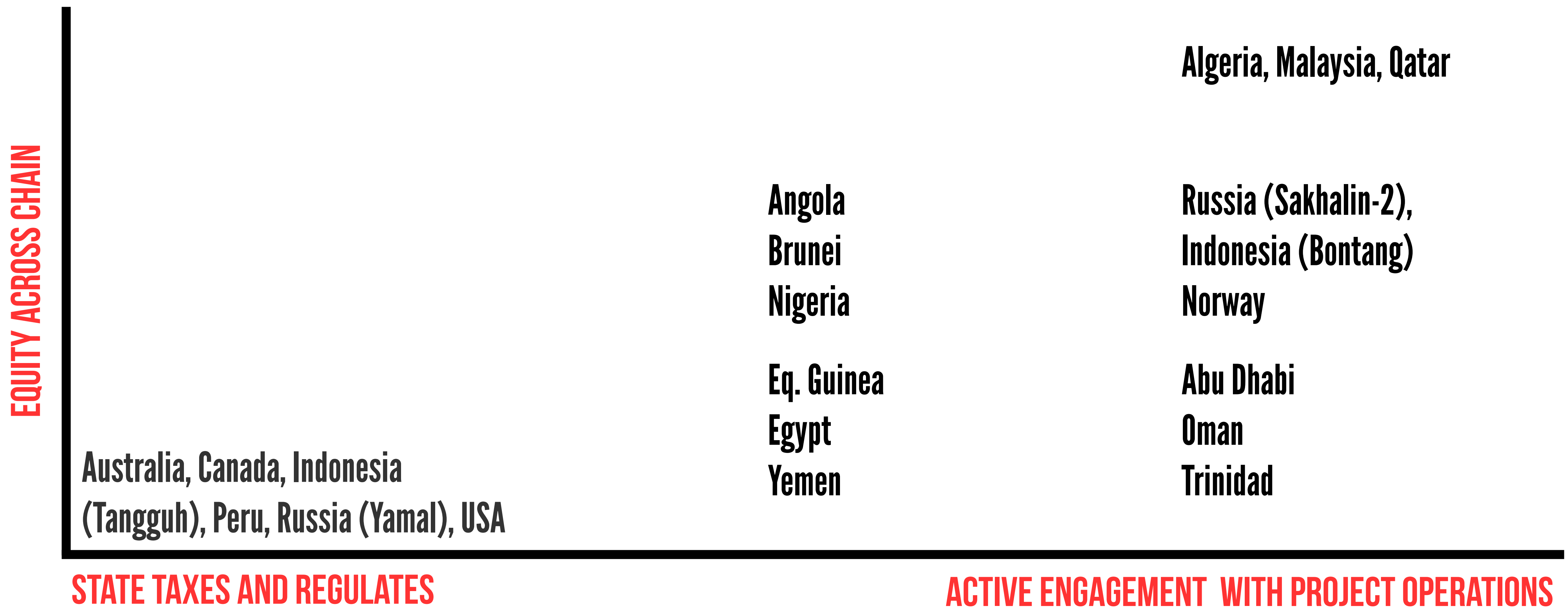
	ADVANTAGES	DISADVANTAGES
INTEGRATED	Integrated plants are simple—the only relevant point is the sales price to the off-take	Integrated projects work when there is high partner alignment, a steady (not variable) source of gas and where all partners are equally interested in any expansions
MERCHANT	Project can accommodate new supply sources. Especially useful to allow companies varying participation along the chain and to enable projects to tap new resources	Multiple transaction points can cause tensions and/or delays in the project.
TOLLING	Very adaptable and able to accomodate changes in upstream supply. Easily scalable.	Setting tolling fee can be a challenge, particularly in cases where the upstream players have a bias towards using their own supplies

STATE PARTICIPATION IN LNG PROJECTS VARIES GREATLY

Several states take no equity stake in LNG projects—they merely regulate and tax

Most countries have some equity—but their involvement varies from passive to very active

Equity stakes are held through national oil companies—Brunei and Norway (Petoro) are exceptions



SOURCE: OWNERSHIP FROM GIIGNL, THE LNG INDUSTRY IN 2012, HTTP://WWW.GIIGNL.ORG/SITES/DEFAULT/FILES/PUBLICATION/GIIGNL_THE_LNG_INDUSTRY_2012.PDF

LNG TAKES TIME, OFTEN DECADES FROM FIRST DISCOVERY

LNG projects are big, complex, multi-stakeholder agreements and they often take years to put together

Challenges include offtake, capital, permits, partner commitment, or overcoming technical problems

Several existing projects were stuck for a long-period of time in the planning phase

Examples

The Camisea complex (Peru) discovered in early 1980s, online in 2004 and exported LNG in 2010

The Gorgon gas field (Australia) discovered in 1981 with LNG exports starting in 2015

North Field (Qatar) was discovered in 1971, but LNG exports started in 1996

Shtokman (Russia) discovered in 1988, but still lacks a development path

Snøhvit (Norway) was discovered in 1984 and LNG started in 2007

Atlantic LNG (Trinidad) project first mulled in 1970s, then again early 1980s; first LNG started in 1999

SOURCES: COMPANY PRESS RELEASES AND INDUSTRY PRESS; VIKTOR, ET. AL, “NATURAL GAS AND GEOPOLITICS”

PARTNER ALIGNMENT CRUCIAL FOR LNG DEVELOPMENT

Many LNG projects were developed by a different set of companies that first proposed the LNG project

Partners with low portfolio fit and/or risk appetite can slow down project development

Getting new partners is often a precondition for an LNG project to move forward

Examples

ExxonMobil pulled out of Angola LNG; Eni acquired stake soon thereafter

Atlantic LNG (Trinidad) T2-3 needed new shareholding deal as Cabot and NGC did not want to participate

Kitimat LNG (Canada) started off as Apache/EOG, then EnCana joined; now Chevron / Apache (50:50)

PTT (Thailand) acquired Cove Energy to access gas that could supply an LNG project in Mozambique

North Field (Qatar) discovered by Shell; Shell and later BP left; LNG developed by Mobil (now ExxonMobil)

Marathon and McDermott sold out of Sakhalin Energy (Sakhalin-2 LNG in Russia)

SOURCES: COMPANY PRESS RELEASES AND INDUSTRY PRESS; VIKTOR, ET. AL, “NATURAL GAS AND GEOPOLITICS”

PROJECT	SANCTIONED	TARGET DATE	ACTUAL DATE	DELAY	BUDGET BN	COST BN	% OVERRUN
Snøhvit (Norway)	Mar-02	2006	Sep-07	1.5 years	NOK39.50	NOK48.00	21.5%
Egyptian LNG T1	Sep-02	Aug-05	May-05	3 months early	$1.1	on budget	0%
Sakhalin-2 (Russia)	May-03	2007	Mar-09	2 years	$10.0	$22.0	120.0%
Atlantic LNG T4 (Trinidad)	Jun-03	2005	Dec-05	on time	$1.2	on budget	0%
Egyptian LNG T2	Jul-03	Jun-06	Sep-05	9 months early	$0.6	on budget	0%
Equatorial Guinea	Jun-04	Late 2007	May-07	6 months early	$1.5	on budget	0%
North West Shelf (Australia)	Jun-05	2008	Sep-08	on time	AUS$2	AUS$2.6	30.0%
Yemen	Aug-05	Dec-08	Nov-09	1 year	$3.7	$4.5	21.6%
Peru	Jan-07	mid 2010	Jun-10	on time	$3.8	$3.9	2.6%
Pluto	Jun-07	Early 2011	May-12	1.5 years	AUS$11.2	AUS$14.9	33.0%
Skikda LNG (Algeria)	Jun-07	2011	Mar-13	2 years	$2.8	?	?
Angola	Dec-07	Early 2012	Jun-13	1.5-2 years	?	$10.0	?
Gorgon (Australia)	Sep-09	2014	n/a	n/a	$37.0	$54.0	45.9%
Papua New Guinea	Dec-09	2014	n/a	n/a	$15.0	$19.0	26.7%
Queensland Curtis (Australia)	Nov-10	2014	n/a	n/a	$15.0	$20.5	36.7%
Gladstone LNG (Autralia)	Jan-12	2015	n/a	n/a	$16.0	$18.5	15.6%

SOURCE: COMPANY PRESS RELEASES AND INDUSTRY PRESS

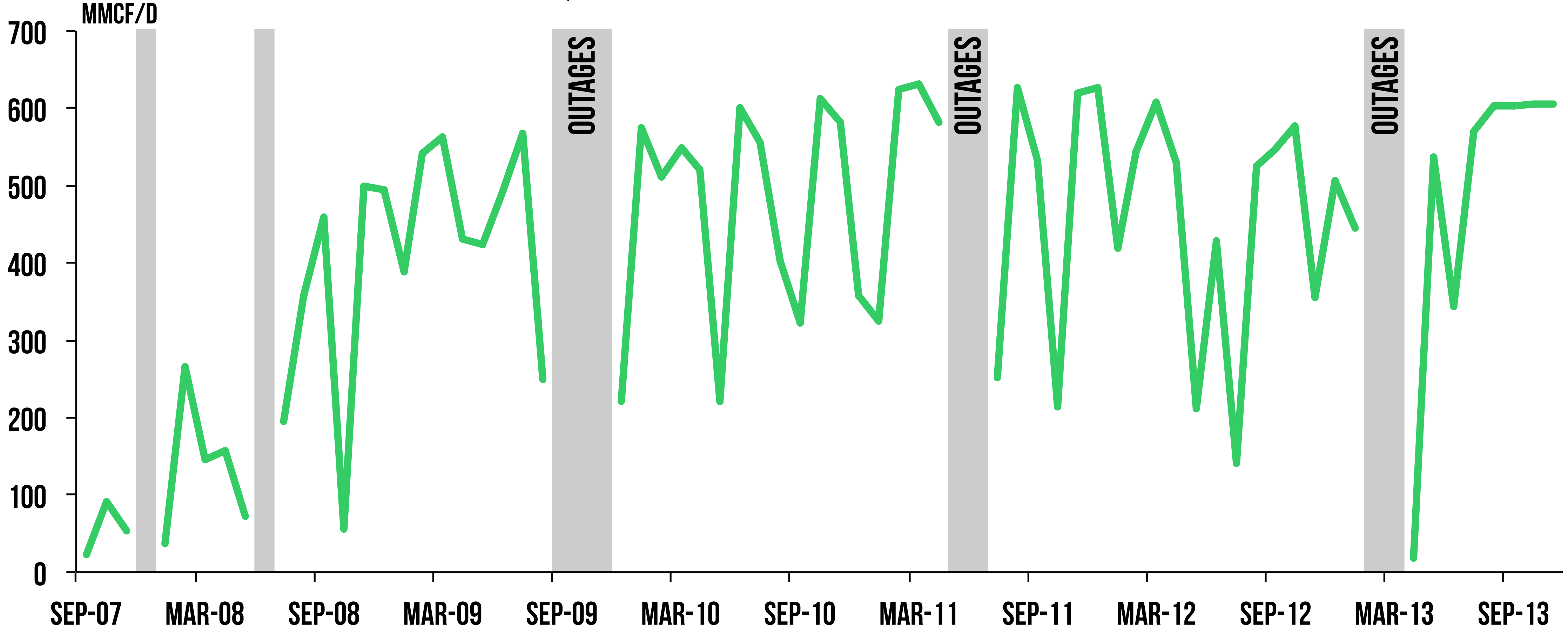
TECHNICAL CHALLENGES CAN LEAD TO FREQUENT OUTAGES

Historically, the LNG industry has operated plants at high utilization rates (85-90%)

However, as projects become more technically complex, outages are a real risk

For example, Snøhvit (Norway) has experienced frequent outages (2-3 months) since start-up in 2007

SNØHVIT LNG PLANT (NORWAY): GAS PRODUCTION



SOURCE: NORWEGIAN PETROLEUM DIRECTORATE, FACTPAGES, PRODUCTION MONTHLY BY FIELD (ACCESSED JANUARY 2014)

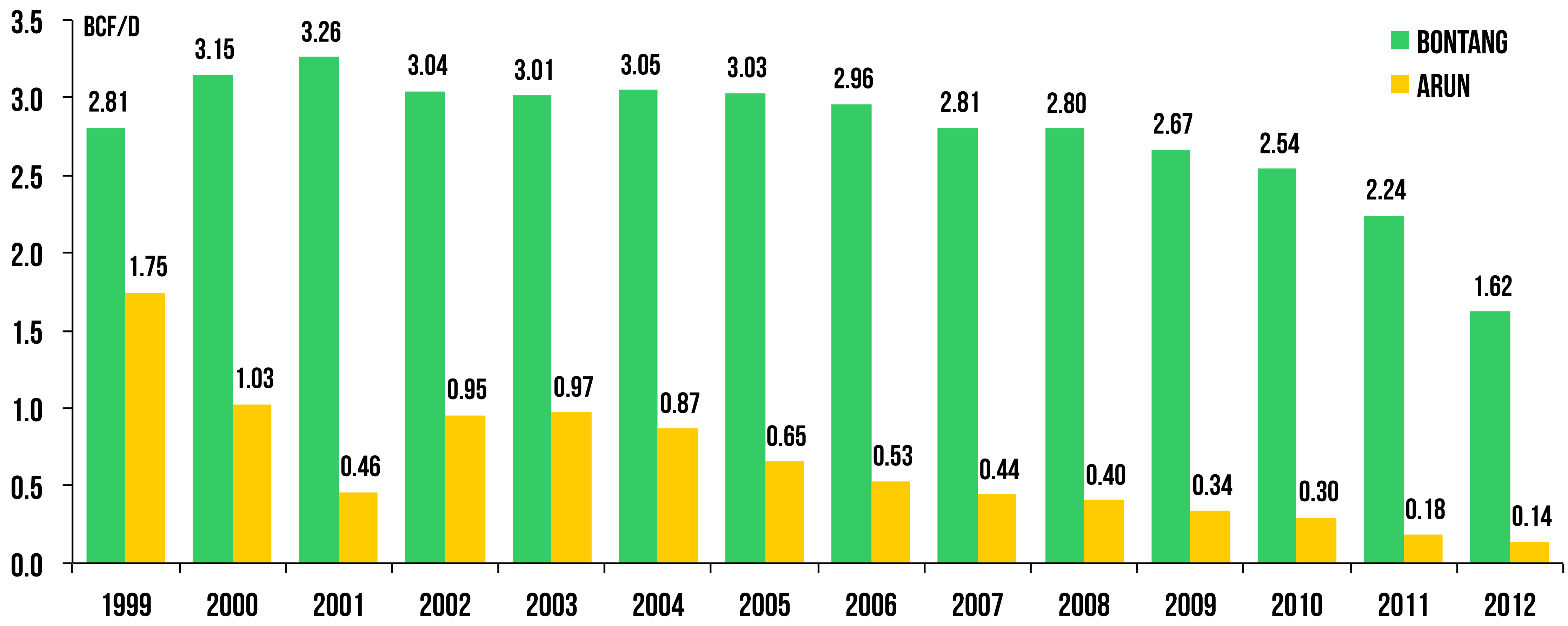
SUPPLYING LOCAL MARKETS CAN DIVERT GAS FROM LNG

Indonesia has seen exports from its oldest facilities (Arun and Bontang) decline over time

At issue is a combination of resource depletion and a need to divert gas to local markets

Arun has been shut down and is being converted to an import terminal

ARUN AND BONTANG LNG PLANTS (INDONESIA): GAS EXPORTS



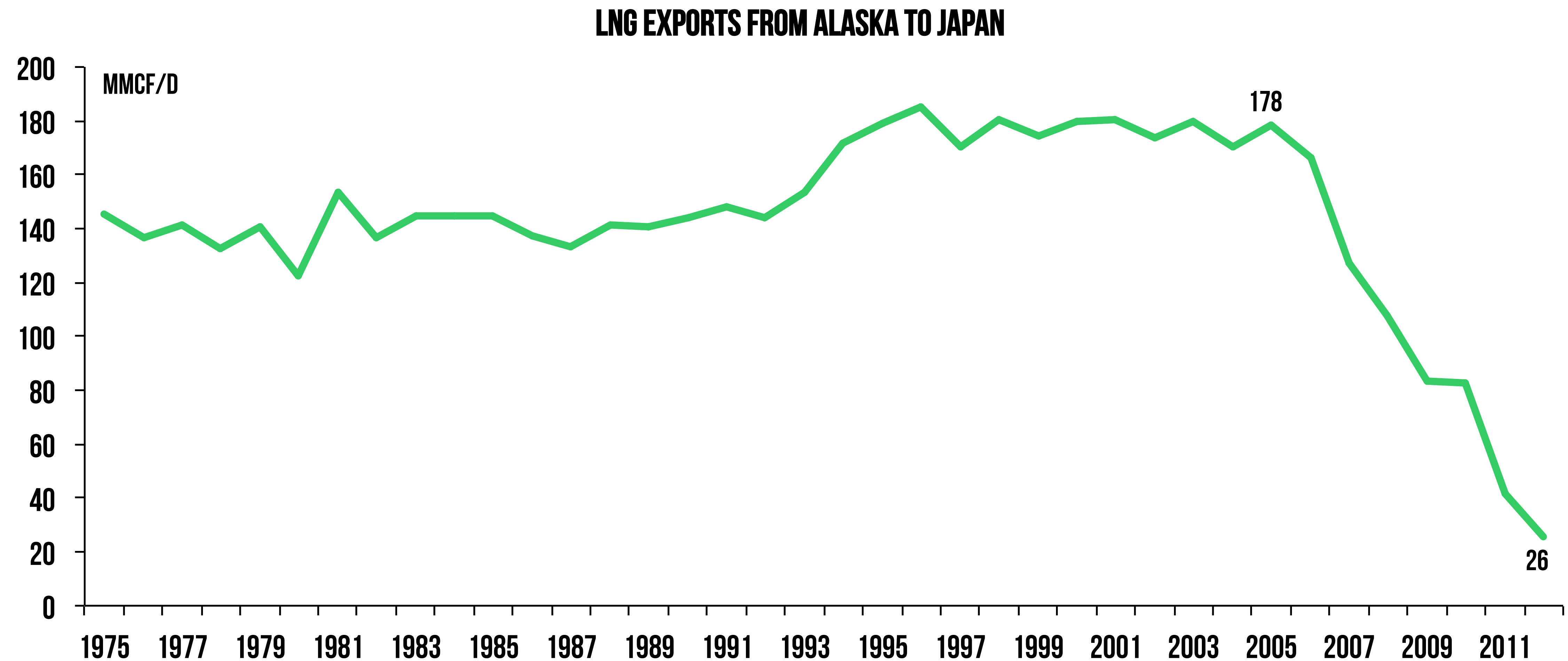
SOURCES: PENGKAJIAN ENERGI UNIVERSITAS INDONESIA, INDONESIA ENERGY OUTLOOK & STATISTICS 2006, MINISTRY OF ENERGY AND NATURAL RESOURCES, “STATISTIK GAS BUMI 2012”

FEEDSTOCK MATURITY CAN LEAD TO RAPID DECLINE

Kenai was the second LNG project in the world and it supplied Japan continuously since 1969

As production matured, however, exports faced a precipitous decline: from 2007 to 2012 fell 25% a year

Matching the production profile to LNG sales contracts is essential to mitigate any penalties



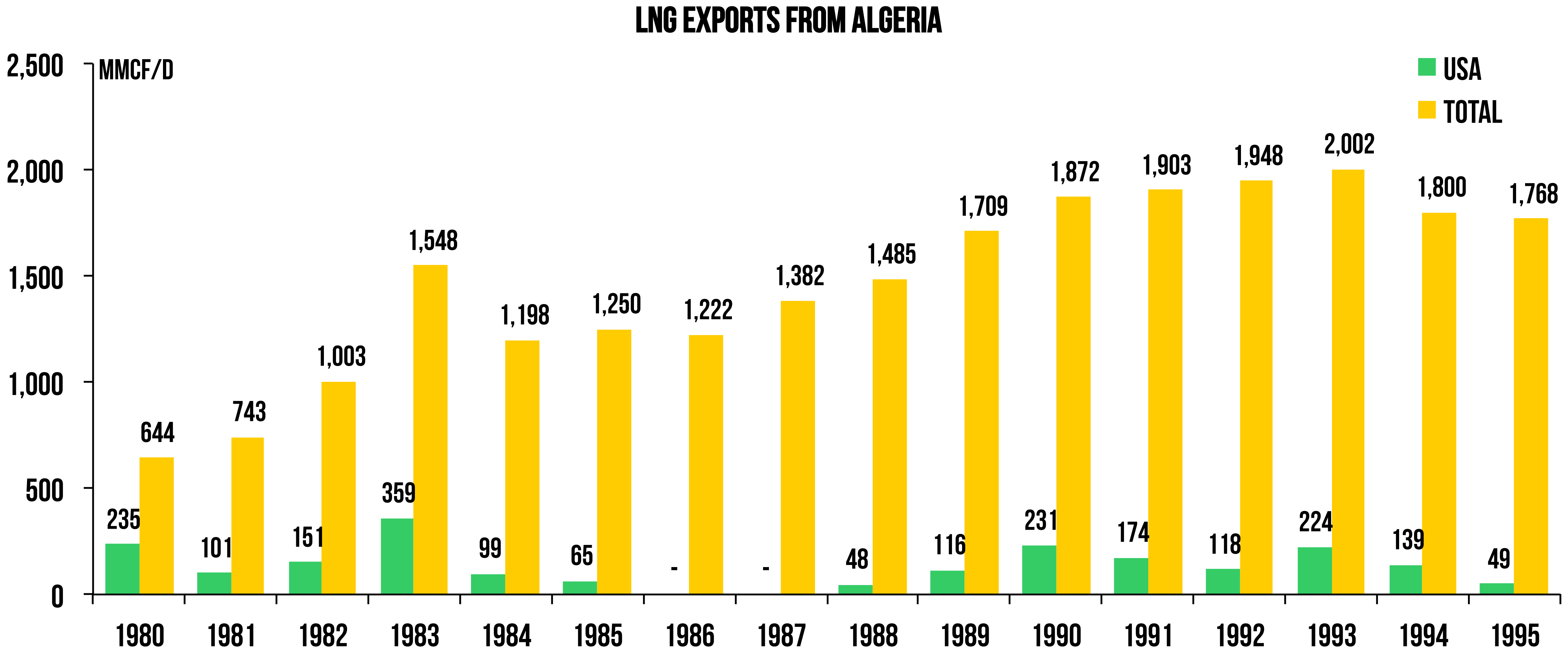
SOURCE: US ENERGY INFORMATION ADMINISTRATION,ALASKA LIQUEFIED NATURAL GAS EXPORTS TO JAPAN (ACCESSED JANUARY 2014)

DEMAND SHOCK LED TO OUTPUT LOSSES— BUT LONG AGO

Algeria experienced two waves of LNG output contraction in the 1980s and early 1990s

Both were driven by declines in demand for Algerian LNG from the United States (and, less so, France)

But the depth of the current LNG market has meant that producers face price but not output risk



SOURCES: US ENERGY INFORMATION ADMINISTRATION,U.S. LNG IMPORTS FROM ALGERIA (ACCESSED JANUARY 2014), MINISTÈRE DE L'ENERGIE ET DES MINES, ENERGY BALANCE 1980-2004

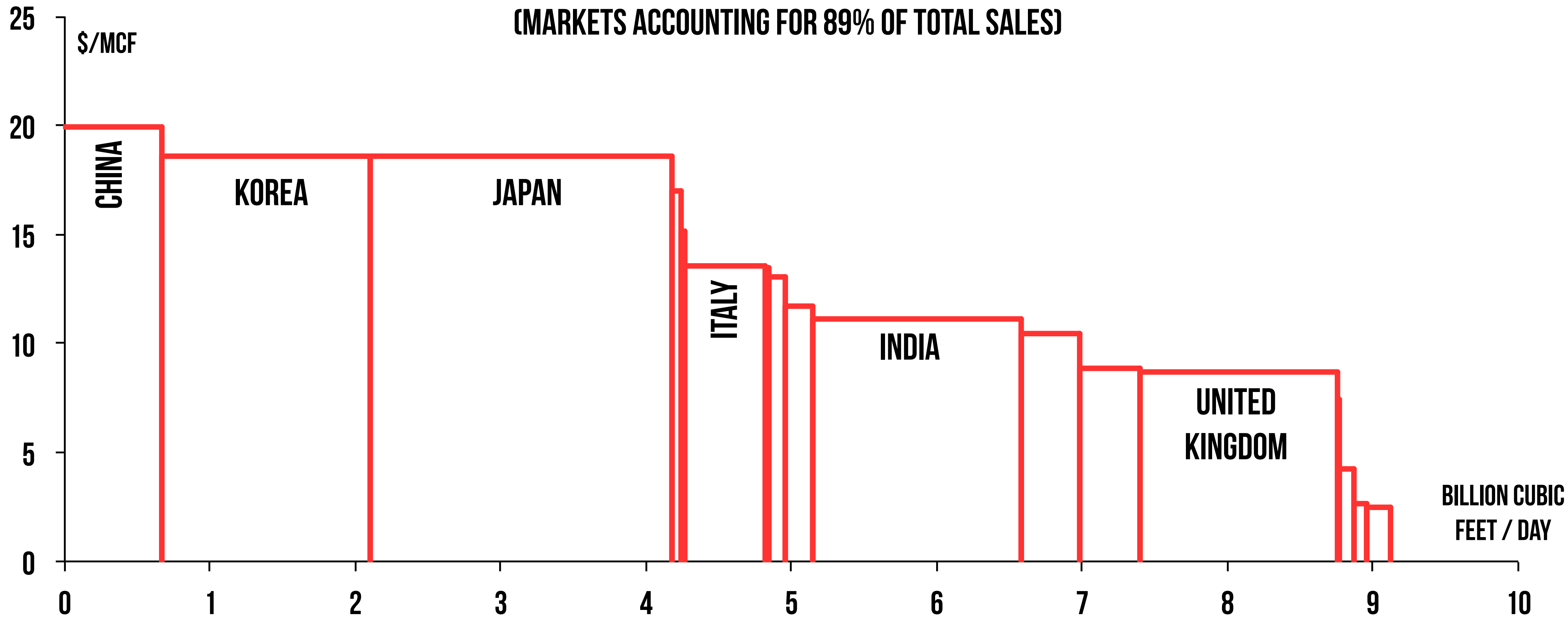
PRICE RISK MORE IMPORTANT THAN VOLUME RISK

Market fundamentals affect price rather than volume (2012 utilization was over 100%)

Qatar earns vastly different prices across markets: $20/mcf in China to sub-$3/mcf in North America

Lower prices reflect contracts linked to low benchmarks (e.g. Belgium) or LNG "pushed into" markets

QATAR: LNG PRICE CURVE (2012)
(MARKETS ACCOUNTING FOR 89% OF TOTAL SALES)



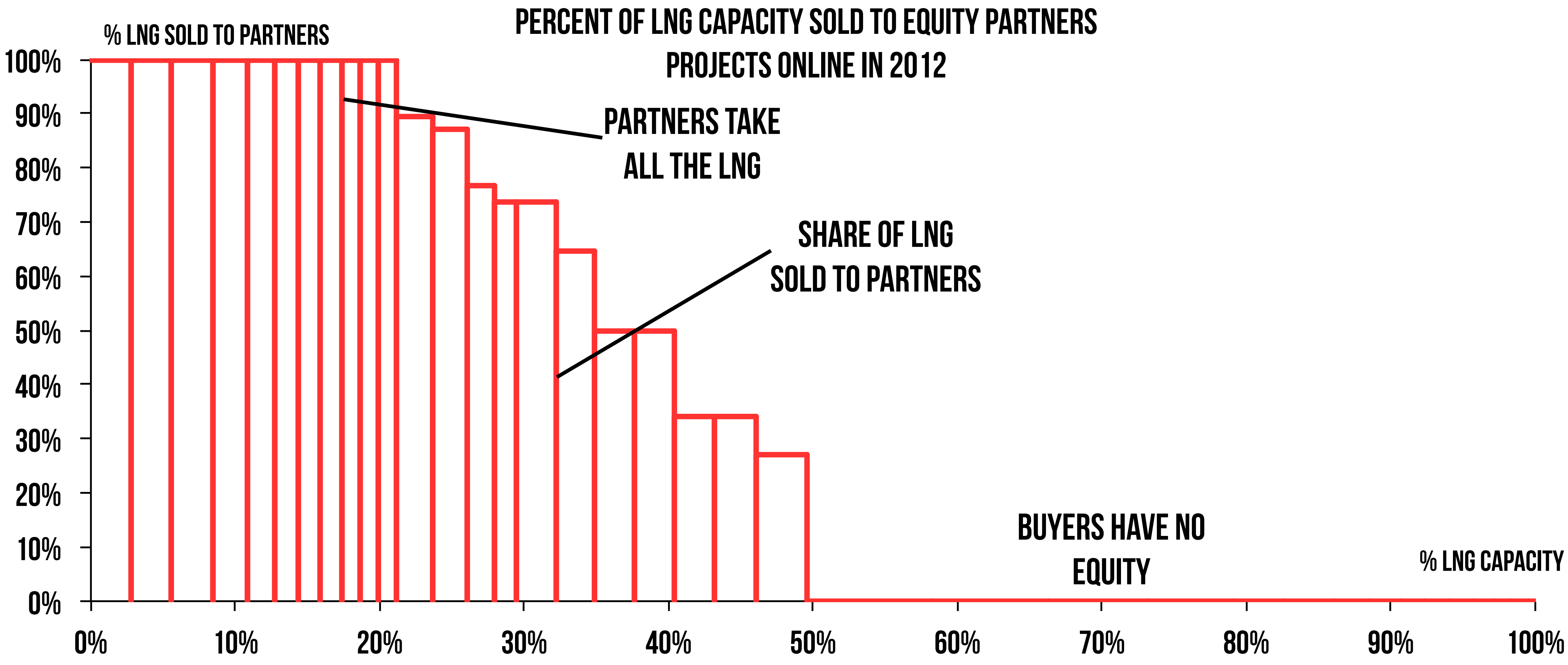
SOURCES: INTERNATIONAL GAS UNION, WORLD LNG REPORT 2013 (JUNE 2013), UN COMTRADE DATABASE (ACCESSED JANUARY 2014)

BUYERS OFTEN TAKE EQUITY | PARTNERS OFF-TAKE LNG

In half of the world's LNG capacity, a share of the LNG is sold to equity partners

Such deals can mitigate risk by aligning supplier-buyer interests (e.g. output shortfall)

Buyers get sense of supply security, and these deals often open up the project to third-party financing



SOURCE: BASED ON GIIGNL, THE LNG INDUSTRY IN 2012, HTTP://WWW.GIIGNL.ORG/SITES/DEFAULT/FILES/PUBLICATION/GIIGNL_THE_LNG_INDUSTRY_2012.PDF

PROJECT FINANCE WELL ESTABLISHED IN LNG

IHS estimates that LNG projects raised over $97 billion in third-party financing since 2000

Financing from project sponsors, export credit agencies, multilateral banks and commercial banks

Commercial loans can also secure sovereign guarantees as insurance

The Japan Bank of International Cooperation (JBIC) is the largest single provider of funds

Examples

AP LNG	$5.8 billion	US EXIM, China EXIM, banks
Ichthys	$20 billion	JBIC, Korea and Australia EXIM, banks, sponsors ($4 bn)
Papua New Guinea	$14 billion	Six ECAs and 17 banks, ExxonMobil
Peru	$2.25 billion	IADB, US EXIM, Korea EXIM, IFC, others
Sakhalin-2	$6.4 billion	JBIC, NEXI, banks
Tangguh	$3.5 billion	JBIC, ADB, banks

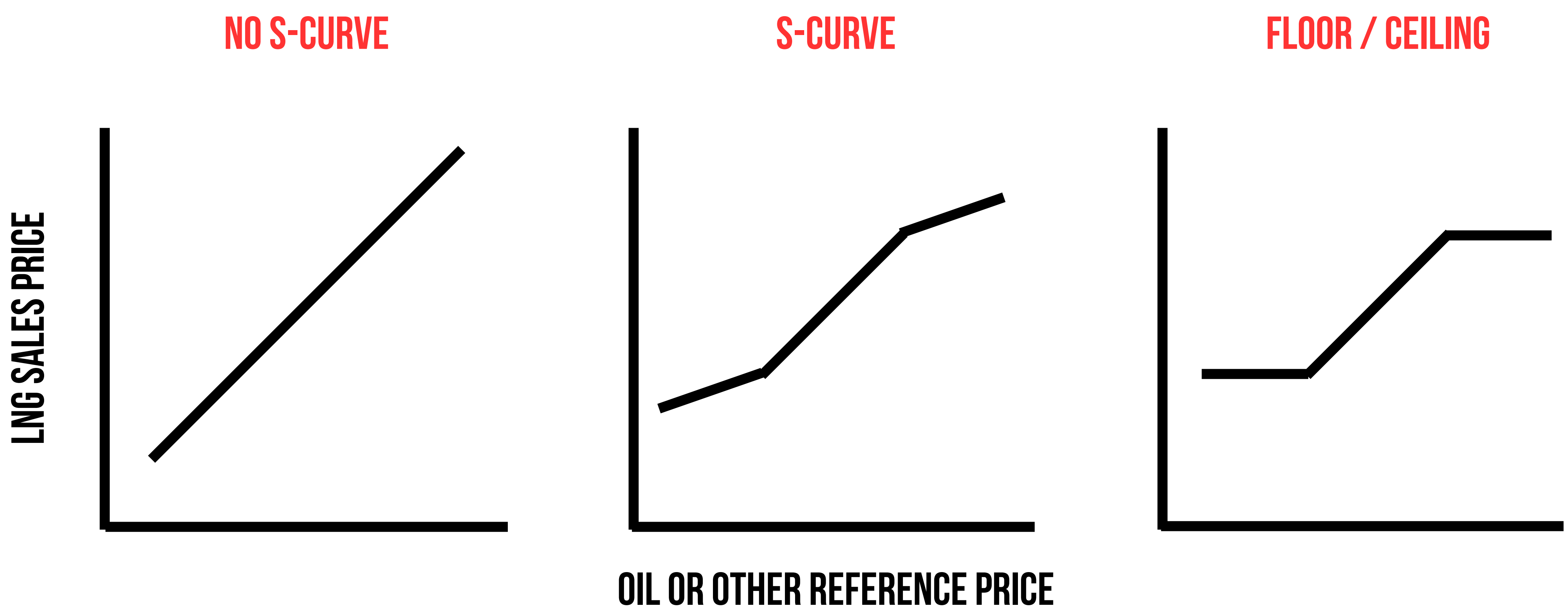
SOURCES: IHS IN LEDESMA, ET. AL, “THE COMMERCIAL AND FINANCING CHALLENGES OF AN INCREASINGLY COMPLEX LNG CHAIN,” LNG 17 (APRIL 2013); INDUSTRY PRESS

PRICING FORMULA CAN REDUCE PRICE VOLATILITY

"S-curves" are clauses that change the relationship between oil and gas above or below thresholds

Instead of a linear link, gas prices do not rise/fall as much if oil prices rise/fall above certain thresholds

They reduce downside risk by forgoing some upside—they can even provide a floor/ceiling on prices



WORST CASE, THERE IS ALWAYS RENEGOTIATION

Most LNG contracts include price review clauses—especially for fundamental / unforeseen changes

Most renegotiations focus on pricing—but European disputes have included volumes (take-or-pay)

Disputes between states and companies usually center on upside that is not flowing back to the state

Examples

BG and its Chilean buyers renegotiated to raise LNG prices

Brunei and Japanese buyers adjusted their price formula—as a result prices tripled from 2007 to 2008

Gas Natural and Atlantic LNG went to arbitration and add a US-based reference price to their contract

RasGas gave a price discount to Edison (Italy) after arbitration settlement ($580 mm in 2012)

Yemen LNG increased its LNG sales prices towards GDF SUEZ, TOTAL, KOGAS

SOURCES: COMPANY PRESS RELEASES AND INDUSTRY PRESS

LNG PROJECTS ARE BIG, COMPLEX AND MULTI-LAYERED

- LNG projects take years (even decades) from first discovery to commercial production
  - They require a large capital commitment upfront—but deliver long-term revenue thereafter
  - No such thing as a "standard" project structure that Alaska can "adopt"
  - Complexity means that value creation and distribution is often a product of negotiation
  - States' participation varies from not at all to fully involved throughout the value chain
  - LNG projects are often used to unlock stranded gas that is also supplied to local markets
- LNG projects face many risks—but have established mechanisms for risk-management and mitigation
  - Third-party finance, marketing integration and pricing bands can reduce exposure/volatility
  - Price review clauses allow counter-parties to provide reprieve to grave imbalances
  - LNG projects tend to be partnerships between many private and state-owned enterprises

- NATURAL GAS MARKET OUTLOOK
- FUNDAMENTALS OF LNG BUSINESS
- IMPLICATIONS FOR ALASKA
- APPENDICES

PATH FORWARD REQUIRES ANSWERS TO KEY QUESTIONS

How should Alaska take its gas share?

Should the state take equity in the project and if so, in what parts of the value chain?

If the state decides to take its gas entitlement in kind, how will it market that gas?

What is the state's appetite for risk, and what type of risk?

What type of risk mitigators will make the state more comfortable about participating in an LNG project?

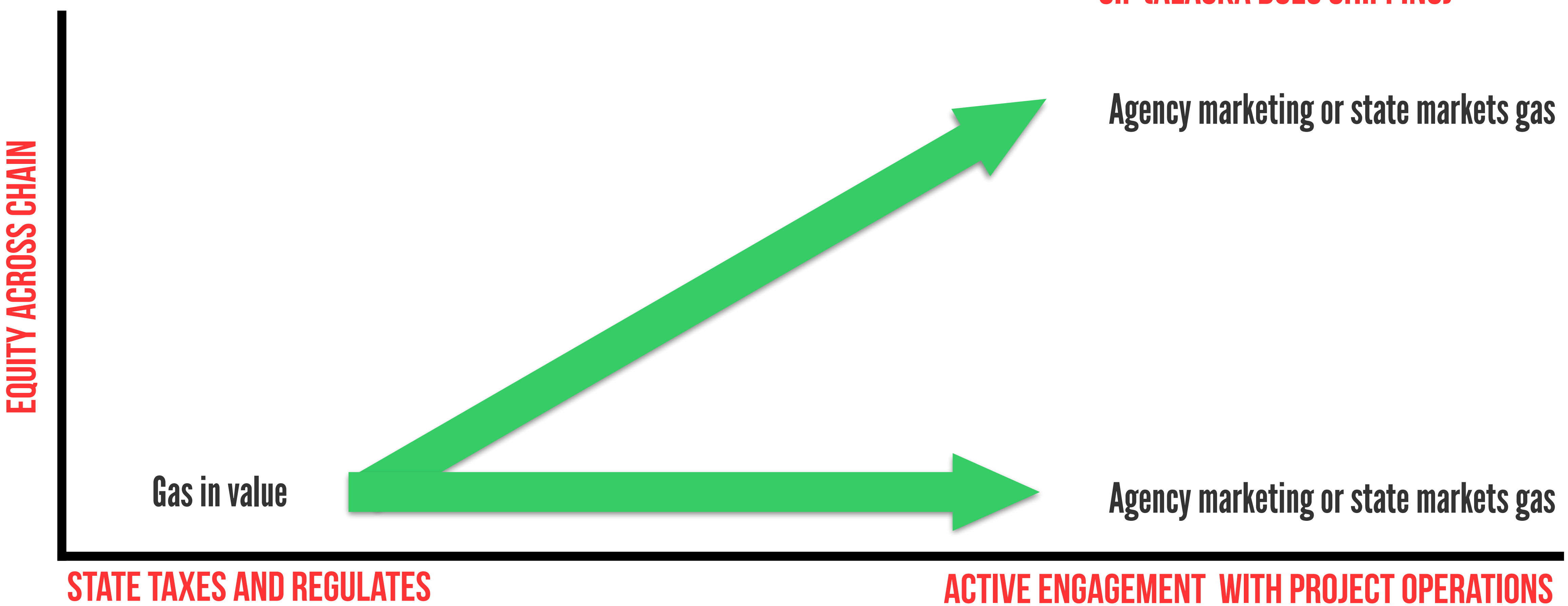
Is the state prepared to forgo some upside in order to be better protected on the downside?

What project structure can expedite development while allowing the project to evolve with time?

What are the state's long-run revenue needs and how might the LNG project help meet those needs?

ALASKA HAS MANY WAYS TO PARTICIPATE IN LNG PROJECT

- STATE'S GAS
  - GAS IN VALUE: KEY QUESTION IS HOW TO NEGOTIATE A "FAIR" TRANSFER PRICE
  - GAS IN KIND
    - AGENCY MARKETING (COMPANIES SELL GAS ON ALASKA'S BEHALF)
    - STATE MARKETS GAS
      - IN-STATE SALES
      - FOB (BUYERS DO SHIPPING)
      - CIF (ALASKA DOES SHIPPING)



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Before co-founding *en*alytica, Janak led the Upstream Analytics team at PFC Energy, focusing on fiscal terms analysis and project economic and financial evaluation, data management and data visualization.

Janak has modeled upstream fiscal terms in all of the world's major hydrocarbon regions, and has built economic and financial models to value prospective acquisition targets and develop strategic portfolio options for a wide range of international and national oil company clients. He has advised Alaska State Legislature for multiple years on reform of oil and gas taxation, providing many hours of expert testimony to Alaska's Senate and House Finance and Resources Committees.

Prior to his work as an energy consultant, Janak advised major minerals industry clients on a range of controversial environmental and social risk issues, from uranium mining through to human rights and climate change. He has advised bankers at Citigroup and policy-makers at the US Treasury Department on the management and mitigation of environmental and social impacts in major projects around the world, and has undertaken macroeconomic research with senior development economists at the World Bank and the Peterson Institute for International Economics.

Janak holds an MA with distinction in international relations and economics from from the Johns Hopkins School of Advanced International Studies (SAIS), and a BA with first-class honors from the University of Adelaide, Australia.

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Nikos Tsafos has a diverse background in the private, public and non-profit sectors. He is currently a founding partner at *en*alytica. In his 7 ½ years with PFC Energy, Nikos advised the world's largest oil and gas companies on some of their most complex and challenging projects; he also played a pivotal role in turning the firm into one of the top natural gas consultancies in the world, with responsibilities that included product design, business development, consulting oversight and research direction.

Prior to PFC Energy, Nikos was at the Center for Strategic and International Studies (CSIS) in Washington, DC where he covered political, economic, and military issues in the Gulf, focused on oil wealth, regime stability and foreign affairs. Before CSIS, he was in the Greek Air Force, and prior to his military service, Nikos worked on channeling investment from Greek ship-owners to Chinese shipyards.

Nikos has also written extensively on the domestic and international dimensions of the Greek debt crisis. His blog (Greek Default Watch) was listed as one of "Europe's Top Economic Blogs" by the Social Europe Journal, and his book "Beyond Debt: The Greek Crisis in Context" was published in March 2013.

Nikos holds a BA with distinction in international relations and economics from Boston University and an MA with distinction in international relations from the Johns Hopkins School of Advanced International Studies (SAIS).

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