Cheniere Energy

June 2014

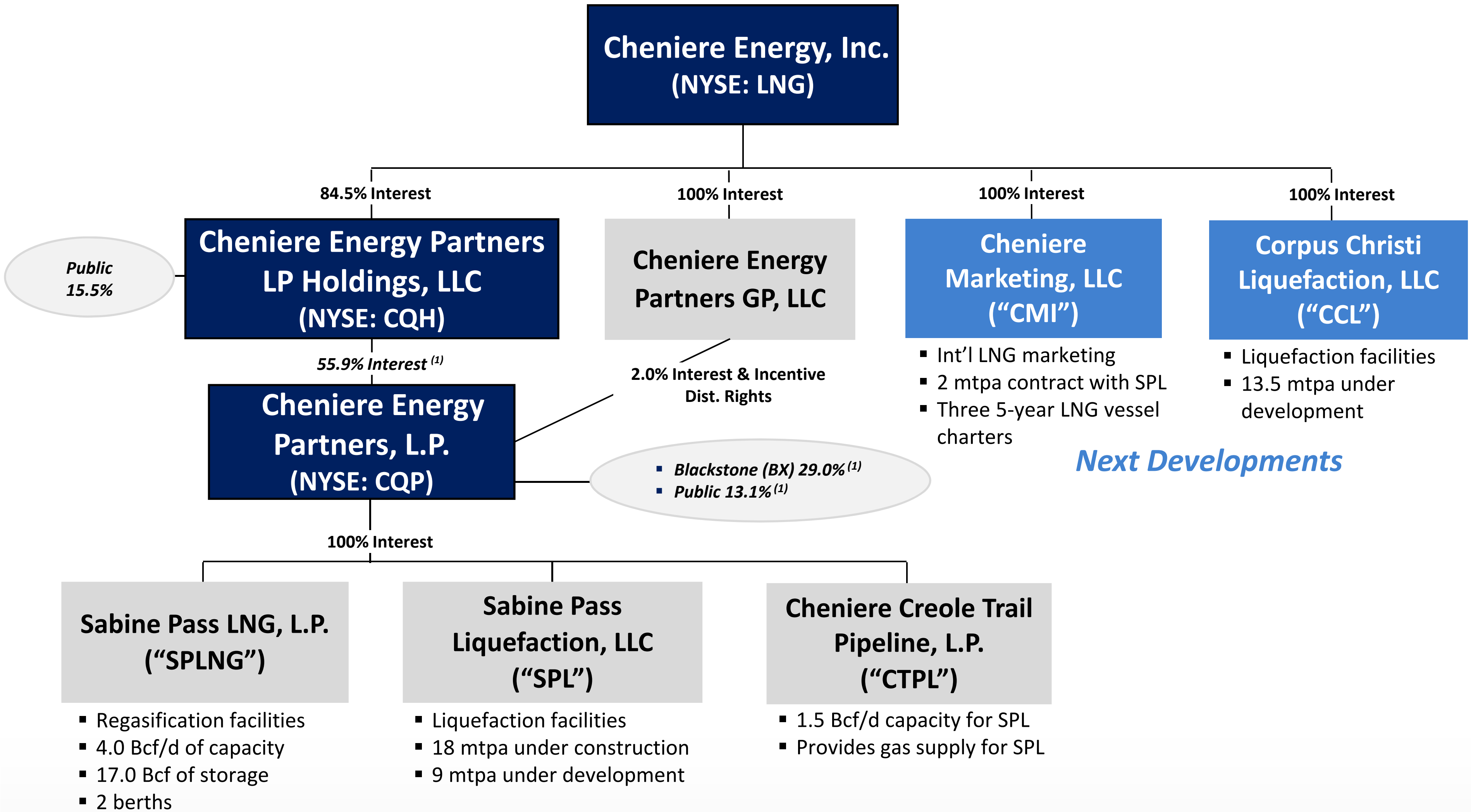
Forward Looking Statements

This presentation contains certain statements that are, or may be deemed to be, "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. All statements, other than statements of historical facts, included herein are "forward-looking statements." Included among "forward-looking statements" are, among other things:

- statements regarding the ability of Cheniere Energy Partners, L.P. to pay distributions to its unitholders or Cheniere Energy Partners LP Holdings, LLC to pay dividends to its shareholders;
- statements regarding Cheniere Energy Inc.'s, Cheniere Energy Partners LP Holdings, LLC's or Cheniere Energy Partners, L.P.'s expected receipt of cash distributions from their respective subsidiaries;
- statements that Cheniere Energy Partners, L.P. expects to commence or complete construction of its proposed liquefaction facilities, or any expansions thereof, by certain dates or at all;
- statements that Cheniere Energy, Inc. expects to commence or complete construction of its proposed liquefaction facilities or other projects by certain dates or at all;
- statements regarding future levels of domestic and international natural gas production, supply or consumption or future levels of liquefied natural gas ("LNG") imports into or exports from North America and other countries worldwide, regardless of the source of such information, or the transportation or demand for and prices related to natural gas, LNG or other hydrocarbon products;
- statements regarding any financing transactions or arrangements, or ability to enter into such transactions;
- statements relating to the construction of our natural gas liquefaction trains ("Trains"), or modifications to the Creole Trail Pipeline, including statements concerning the engagement of any engineering, procurement and construction ("EPC") contractor or other contractor and the anticipated terms and provisions of any agreement with any EPC or other contractor, and anticipated costs related thereto;
- statements regarding any agreement to be entered into or performed substantially in the future, including any revenues anticipated to be received and the anticipated timing thereof, and statements regarding the amounts of total LNG regasification, liquefaction or storage capacities that are, or may become, subject to contracts;
- statements regarding counterparties to our commercial contracts, construction contracts and other contracts;
- statements regarding our planned construction of additional Trains, including the financing of such Trains;
- statements that our Trains, when completed, will have certain characteristics, including amounts of liquefaction capacities;
- statements regarding any business strategy, our strengths, our business and operation plans or any other plans, forecasts, projections or objectives, including anticipated revenues and capital expenditures and EBITDA, any or all of which are subject to change;
- statements regarding projections of revenues, expenses, earnings or losses, working capital or other financial items;
- statements regarding legislative, governmental, regulatory, administrative or other public body actions, approvals, requirements, permits, applications, filings, investigations, proceedings or decisions;
- statements regarding our anticipated LNG and natural gas marketing activities; and
- any other statements that relate to non-historical or future information.

These forward-looking statements are often identified by the use of terms and phrases such as "achieve," "anticipate," "believe," "contemplate," "develop," "estimate," "example," "expect," "forecast," "opportunities," "plan," "potential," "project," "propose," "subject to," "strategy," and similar terms and phrases, or by use of future tense. Although we believe that the expectations reflected in these forward-looking statements are reasonable, they do involve assumptions, risks and uncertainties, and these expectations may prove to be incorrect. You should not place undue reliance on these forward-looking statements, which speak only as of the date of this presentation. Our actual results could differ materially from those anticipated in these forward-looking statements as a result of a variety of factors, including those discussed in "Risk Factors" in the Cheniere Energy, Inc., Cheniere Energy Partners, L.P. and Cheniere Energy Partners LP Holdings, LLC Annual Reports on Form 10-K filed with the SEC on February 21, 2014, which are incorporated by reference into this presentation. All forward-looking statements attributable to us or persons acting on our behalf are expressly qualified in their entirety by these "Risk Factors". These forward-looking statements are made as of the date of this presentation, and other than as required under the securities laws, we undertake no obligation to publicly update or revise any forward-looking statements.

Summary Organizational Structure



(1) Current ownership interest. As Class B units accrete Blackstone will increase its ownership percentage, and the public and CQH will have reduced ownership percentages. See Slide 37.

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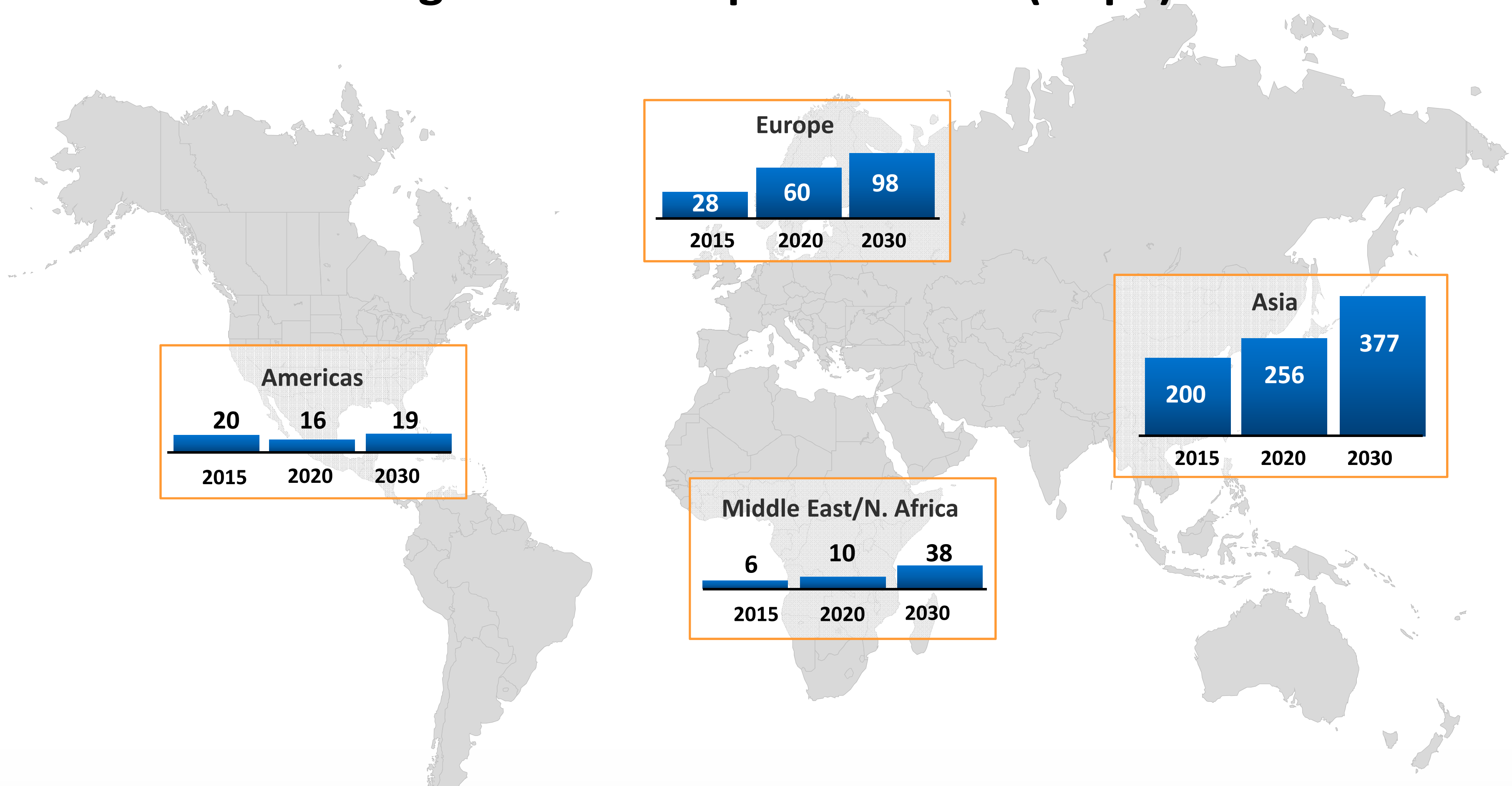
Projected Global LNG Demand Growth

Regional LNG Import Outlook (mtpa)



Global demand is forecast to grow from 236 mtpa (~32 Bcf/d) in 2012 to 532 mtpa (~71 Bcf/d) in 2030
~4.6% CAGR equivalent to ~16 mtpa average growth per year (~three 5 mtpa trains)

Source: Wood Mackenzie

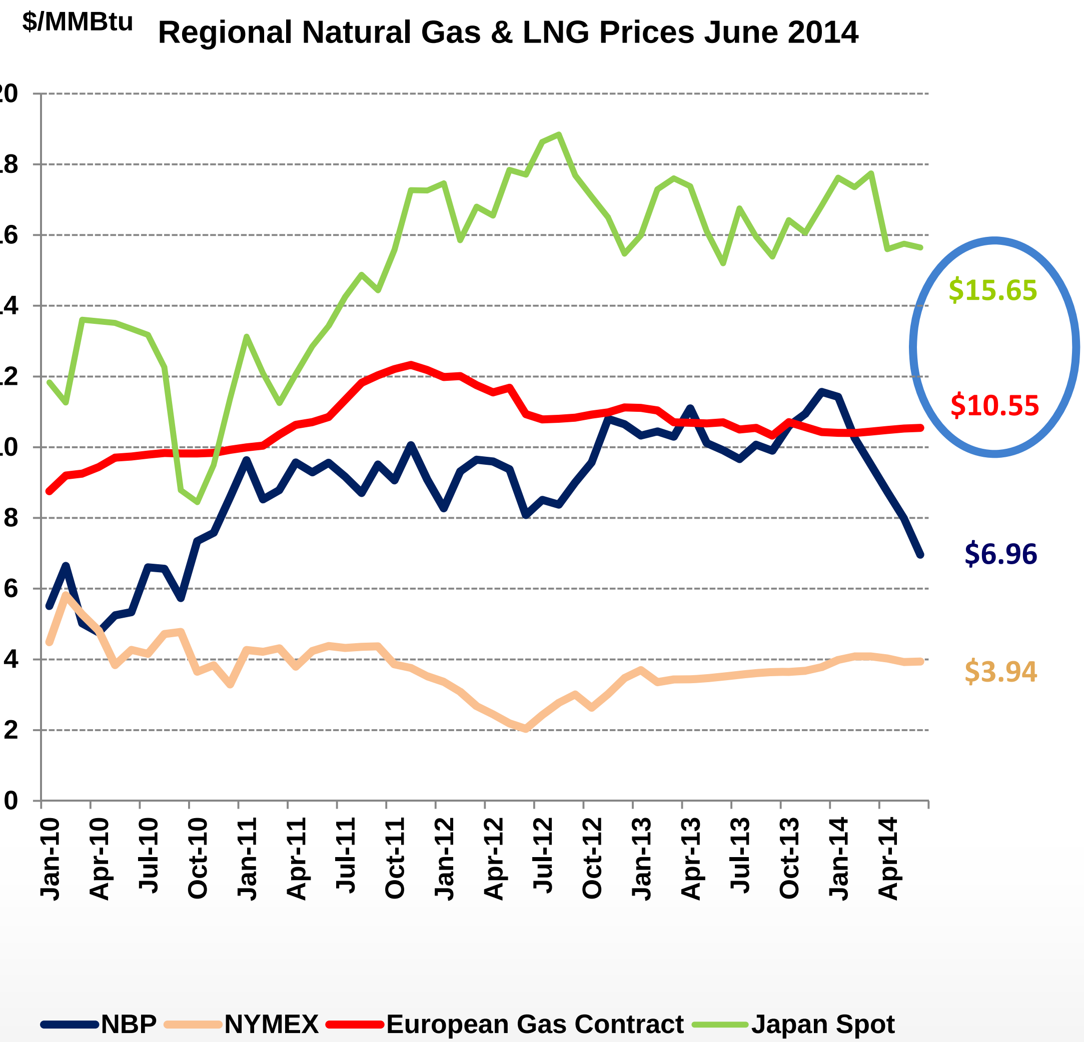
2013 Q4 Data

Cheniere's LNG Export Facilities Offer Attractive Pricing for Global LNG Buyers

Worldwide LNG Prices = 11% to 15% of Crude Oil

Example Prices
Henry Hub: $4.00 / MMBtu
Brent Crude: $100 / Barrel

($/MMBtu)	Americas	Europe	Asia
LNG Cost (1)	$ 4.60	$ 4.60	$ 4.60
Liquefaction Fee	3.50	3.50	3.50
Shipping	0.50	1.00	3.00
Delivered Cost	$ 8.60	$ 9.10	$11.10
	@ 15%	@ 12%	@ 15%
LNG Price (% Crude)	15.00	12.00	15.00
Net Difference	**$ 6.40**	**$ 2.90**	**$ 3.90**



(1) LNG Cost is calculated as 115% of Henry Hub price.

Source: Pira, Cheniere Research estimates

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Cheniere Liquefaction Projects

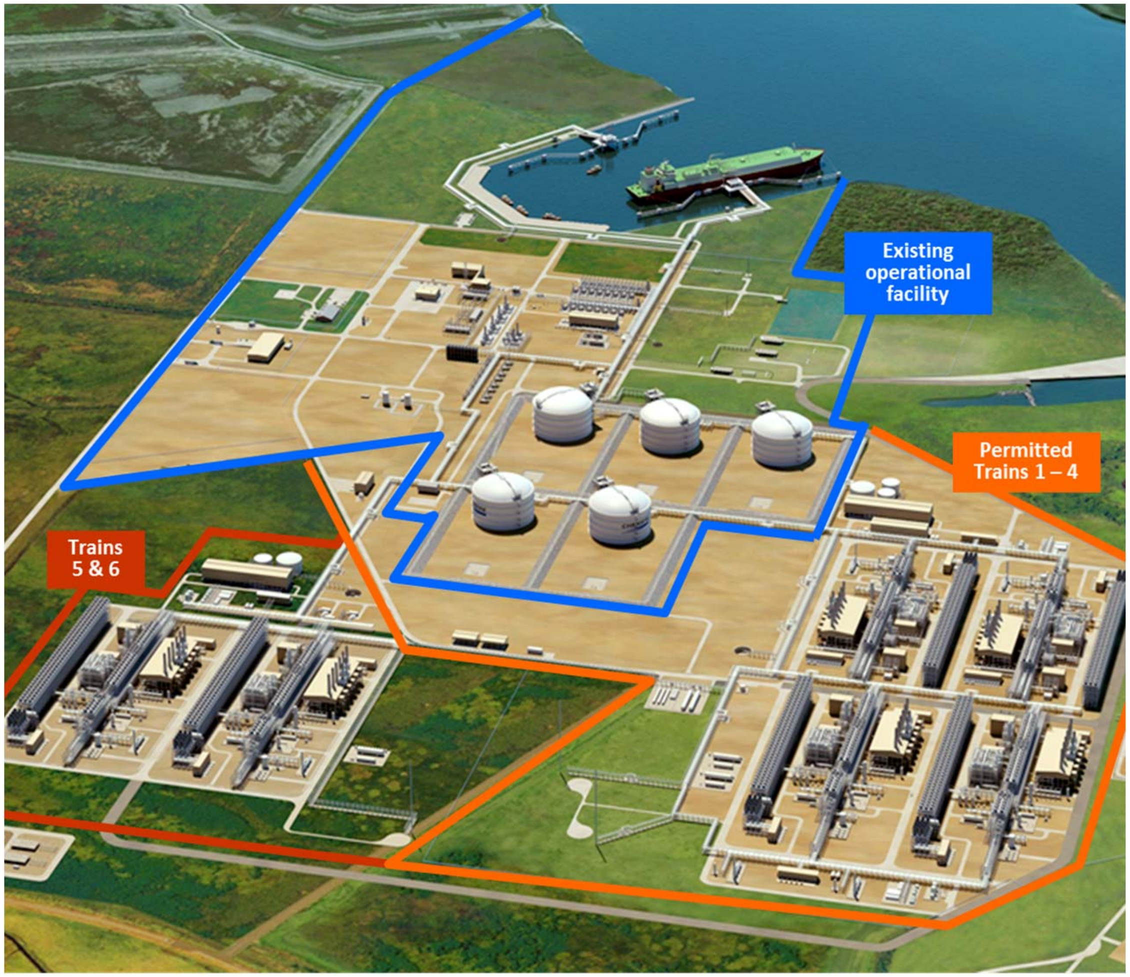
9 Trains, ~$31B investment, ~40.5 MTPA LNG Exports (~5.5Bcf/d)

	Sabine Pass T1-4	Corpus Christi T1-2	Sabine Pass T5-6	Corpus Christi T3
Estimated Cost[1]	$12B	$10B	$6B	$3B
Volume (MTPA)	18.0	9.0	9.0	4.5
3rd Party Contracts to date (MTPA)	16.0	3.8	3.75	-
Development Stage	Under Construction	FID Expected 1Q 2015	Permitting/ Commercializing	Permitting/ Commercializing
First LNG	2015	2018/19	2018/19	2019

(1) Includes financing cost estimates

Brownfield LNG Export Project: Sabine Pass Liquefaction

Utilizes Existing Assets, Trains 1-4 Fully Contracted, Under Construction



Design production capacity is expected to be ~4.5 mtpa per train, using ConocoPhillips' Optimized Cascade® Process

Current Facility

- ~1,000 acres in Cameron Parish, LA
- 40 ft ship channel 3.7 miles from coast
- 2 berths; 4 dedicated tugs
- 5 LNG storage tanks (~17 Bcfe of storage)
- 5.3 Bcf/d of pipeline interconnection

Liquefaction Trains 1 & 2 – Fully Contracted

- Lump Sum Turnkey EPC contract w/ Bechtel
- Total EPC contract price ~$4.0 billion
- Overall project ~65% complete (as of 4/30/2014)
- Operations estimated late 2015/2016

Liquefaction Trains 3 & 4 – Fully Contracted

- Lump Sum Turnkey EPC contract w/ Bechtel
- Total EPC contract price ~$3.8 billion
- Construction commenced in May 2013
- Overall project ~30% complete (as of 4/30/2014)
- Operations estimated 2016/2017

Liquefaction Expansion - Trains 5 & 6

- Bechtel commenced preliminary engineering
- Permitting initiated February 2013
- FERC scheduling notice received May 2014

Significant infrastructure in place including storage, marine and pipeline interconnection facilities; pipeline quality natural gas to be sourced from U.S. pipeline network

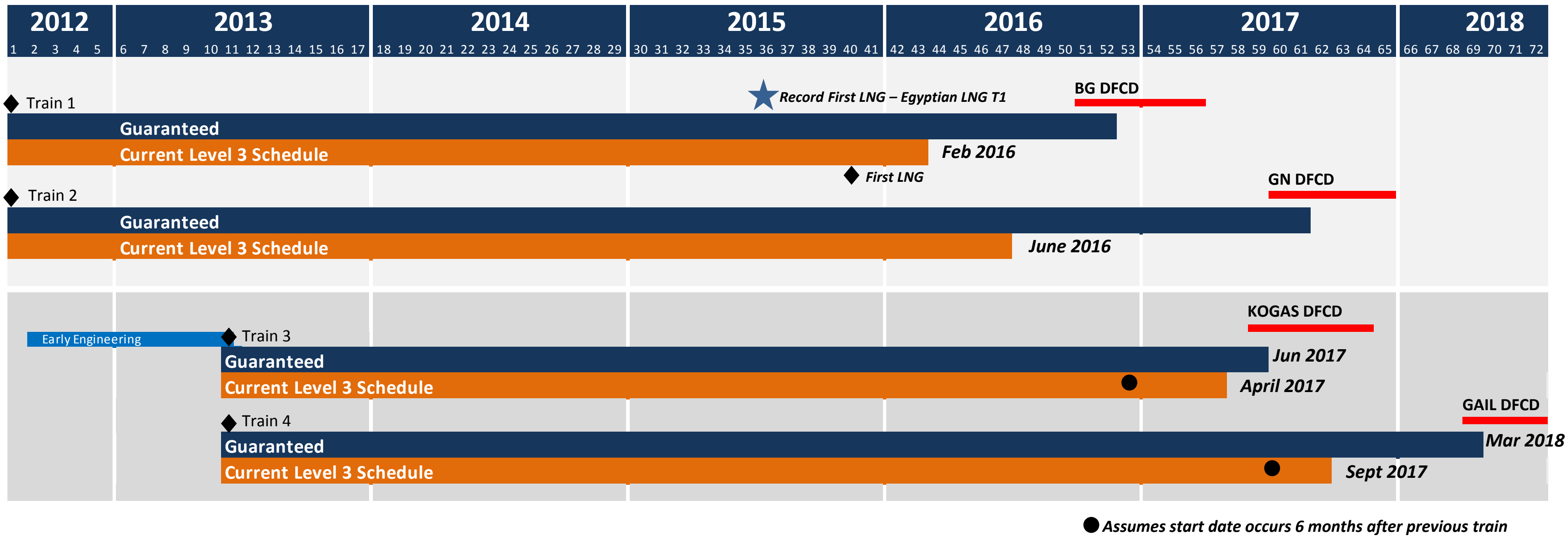
LNG Sale and Purchase Agreements (SPAs)
Sabine Pass Liquefaction

~20 mtpa "take-or-pay" style commercial agreements
~$2.9B annual fixed fee revenue for 20 years

	BG GROUP BG Gulf Coast LNG	gasNatural fenosa Gas Natural Fenosa	KOGAS Korea Gas Corporation	GAIL GAIL (India) Limited	TOTAL Total Gas & Power N.A. (6)	centrica Centrica plc (6)
Annual Contract Quantity (MMBtu)	286,500,000 (1)	182,500,000	182,500,000	182,500,000	104,750,000 (1)	91,250,000
Annual Fixed Fees (2)	~$723 MM (3)	~$454 MM	~$548 MM	~$548 MM	~$314 MM	~$274 MM
Fixed Fees $/MMBtu (2)	$2.25 - $3.00	$2.49	$3.00	$3.00	$3.00	$3.00
LNG Cost	115% of HH	115% of HH	115% of HH	115% of HH	115% of HH	115% of HH
Term of Contract (4)	20 years	20 years	20 years	20 years	20 years	20 years
Guarantor	BG Energy Holdings Ltd.	Gas Natural SDG S.A.	N/A	N/A	Total S.A.	N/A
Corporate / Guarantor Credit Rating (5)	A-/A2/A-	BBB/Baa2/BBB+	A+/A1/AA-	NR/Baa2/BBB-	AA-/Aa1/AA	A-/A3/A-
Fee During Force Majeure	Up to 24 months	Up to 24 months	N/A	N/A	N/A	N/A
Contract Start	Train 1 + additional volumes with Trains 2,3,4	Train 2	Train 3	Train 4	Train 5	Train 5

(1) BG has agreed to purchase 182,500,000 MMBtu, 36,500,000 MMBtu, 34,000,000 MMBtu and 33,500,000 MMBtu of LNG volumes annually upon the commencement of operations of Trains 1, 2, 3 and 4, respectively. Total has agreed to purchase 91,250,000 MMBtu of LNG volumes annually plus 13,400,000 MMBtu of seasonal LNG volumes upon the commencement of Train 5 operations.
(2) A portion of the fee is subject to inflation, approximately 15% for BG Group, 13.6% for Gas Natural Fenosa, 15% for KOGAS and GAIL (India) Ltd and 11.5% for Total and Centrica.
(3) Following commercial in service date of Train 4. BG will provide annual fixed fees of approximately $520 million during Trains 1-2 operations and an additional $203 million once Trains 3-4 are operational.
(4) SPAs have a 20 year term with the right to extend up to an additional 10 years. Gas Natural Fenosa has an extension right up to an additional 12 years in certain circumstances.
(5) Ratings are provided by S&P/Moody's/Fitch and subject to change, suspension or withdrawal at anytime and are not a recommendation to buy, hold or sell any security.
(6) Conditions precedent must be satisfied by June 30, 2015 or either party can terminate. CPs include financing, regulatory approvals and positive final investment decision.

SPL Construction Completion Schedules Trains 1-4



- **Current plan estimates Train 1 operational in 40 months from NTP**
  - Bechtel schedule bonus provides incentive for early delivery
  - Bechtel's record delivery was Egyptian LNG train 1, delivered in 36 months from NTP
- **Notice to Proceed for Trains 3&4 issued to Bechtel in May 2013**
- **Trains expected to come on-line on a 6-9 month staggered basis**

Note: See "Forward Looking Statements" slide.

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Aerial View of SPL Construction – April 2014

Corpus Christi Liquefaction Project

Design production capacity is expected to be ~4.5 mtpa per train, using ConocoPhillips' Optimized Cascade® Process

Proposed 3 Train Facility

- >1,000 acres owned and/or controlled
- 2 berths, 3 LNG storage tanks (~10.1 Bcfe of storage)

Key Project Attributes

- 45 ft. ship channel 13.7 miles from coast
- Protected berth
- Premier Site Conditions
  - Established industrial zone
  - Elevated site protects from storm surge
  - Soils do not require piles
  - Local labor, infrastructure & utilities
  - 23-mile 48" pipeline interconnected to several inter- and intrastate pipelines

Project Update

- Lump Sum Turnkey contracts signed with Bechtel
  - Stage 1: ~$7.1B includes 2 Trains, 2 tanks, 1 berth
  - Stage 2: ~$2.4B includes 1 Train, 1 tanks, 1 berth
- SPAs signed covering ~5.3 mtpa at a fixed fee of $3.50/MMBtu
- Anticipate FID on Stage 1 in early 2015
- First LNG expected 2018

Advanced commercialization

LNG Sale and Purchase Agreements (SPAs)
Corpus Christi Liquefaction

SPA progress: ~5.3 mtpa "take-or-pay" style commercial agreements
~$965MM annual fixed fee revenue for 20 years

	PT Pertamina (Persero)	Endesa S.A.	Iberdrola S.A.	Gas Natural Fenosa
Annual Contract Quantity (TBtu)	39.68	117.32	39.68	78.22
Annual Fixed Fees (1)	~$139 MM	~$411 MM	~$139 MM	~$274 MM
Fixed Fees $/MMBtu (1)	$3.50	$3.50	$3.50	$3.50
LNG Cost	115% of HH	115% of HH	115% of HH	115% of HH
Term of Contract (2)	20 years	20 years	20 years	20 years
Guarantor	N/A	N/A	N/A	Gas Natural SDG S.A.
Guarantor/Corporate Credit Rating (3)	BB+/Baa3/BBB-	BBB/Baa2/BBB+	BBB/Baa1/BBB+	BBB/Baa2/BBB+
Contract Start(4)(5)	Train 1	Train 1	Train 2	Train 2

(1) 11.5% of the fee is subject to inflation for Pertamina; 14% for Endesa, Iberdrola, and Gas Natural Fenosa
(2) SPA has a 20 year term with the right to extend up to an additional 10 years.
(3) Ratings are provided by S&P/Moody's/Fitch and subject to change, suspension or withdrawal at anytime and are not a recommendation to buy, hold or sell any security.
(4) Conditions precedent must be satisfied by December 31, 2014 (Pertamina) or June 30, 2015 (Endesa, Iberdrola, Gas Natural Fenosa) or either party can terminate. CPs include financing, regulatory approvals and positive final investment decision.
(5) If FID is reached on Sabine Pass T6 prior to Corpus Christi T1, Pertamina contract will transfer to Sabine Pass T6 with identical terms.

Regulatory Approvals Needed for Corpus Christi and SPL Trains 5-6

Scheduling Notices received for both Corpus Christi and SPL Trains 5-6

- **Corpus Christi Trains 1-3**
  - **FERC**: Scheduling Notice received 2/2014, final EIS expected October 8, 2014, 90-day federal authorization decision deadline January 6, 2015
  - **DOE**: Received FTA authorization in 10/2012
  - **DOE**: Non-FTA authorization is pending

- **SPL Trains 5-6**
  - **FERC:** Scheduling Notice received 5/2014, final EA expected August 1, 2014, 90-day federal authorization decision deadline October 30, 2014
  - **DOE**: Received FTA authorization for Total and Centrica SPAs in 7/2013, received FTA authorization for Train 6 in 1/2014
  - **DOE:** Non-FTA authorization is pending

FERC Applications Filed for Liquefaction Projects

LNG Export Projects	Pre-filing Date	Application Date	FERC Scheduling Notice Issued	EIS / EA	Scheduled Date for EIS or EA	Rec'd Approval
Sabine Pass Liquefaction T1-4	July 26, 2010	January 31, 2011		EA		✓
Corpus Christi Liquefaction	December 13, 2011	August 31, 2012	February 12, 2014	EIS	October 8, 2014	
Freeport LNG	December 23, 2010	August 31, 2012	January 6, 2014	EIS	June 16, 2014	
Cameron LNG	April 30, 2012	December 10, 2012	November 21, 2013	EIS	April 30, 2014	✓
Dominion Cove Point LNG	June 1, 2012	April 1, 2013	March 12, 2014	EA	May 15, 2014	
Jordan Cove Energy	February 29, 2012	May 22, 2013		EIS		
Oregon LNG	July 3, 2012	June 7, 2013		EIS		
Sabine Pass Liquefaction T5-6	February 27, 2013	September 30, 2013	May 30, 2014	EA	August 1, 2014	
Excelerate	November 5, 2012	February 6, 2014		EIS		
Southern LNG	December 5, 2012	March 10, 2014		EA		
Lake Charles LNG	March 30, 2012	March 25, 2014		EIS		
Magnolia LNG	March 20, 2013	April 30, 2014		EIS		

- Corpus Christi received FERC scheduling notice on February 12, 2014; FERC approval expected 2014/2015
- SPL received FERC scheduling notice on May 30, 2014; FERC approval expected 2014/2015

Note: National Environmental Policy Act (NEPA) empowers FERC as the lead Federal agency to prepare an Environmental Impact Statement in cooperation with other state and federal agencies

Timeline & Milestones

Milestone	Target Date: SPL T1-2	SPL T3-4	Corpus Christi	SPL T5-6
Initiate permitting process (FERC & DOE)	✓	✓	✓	✓
Commercial agreements	✓	✓	T1/T2: 5.3 mtpa 2014	T5 ✓ T6: 2014
EPC contract	✓	✓	✓	2015
Financing commitments	✓	✓	2014	2015
Regulatory approvals	✓	✓	2014/15	2014/15
Issue Notice to Proceed	✓	✓	2015	2015
Commence operations (1)	2015/16	2016/17	2018/19	2018/19

(1) Each Train of the respective projects is expected to commence operations approximately six to nine months after the previous train.

Note: See "Forward Looking Statements" slide.

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Cheniere Marketing

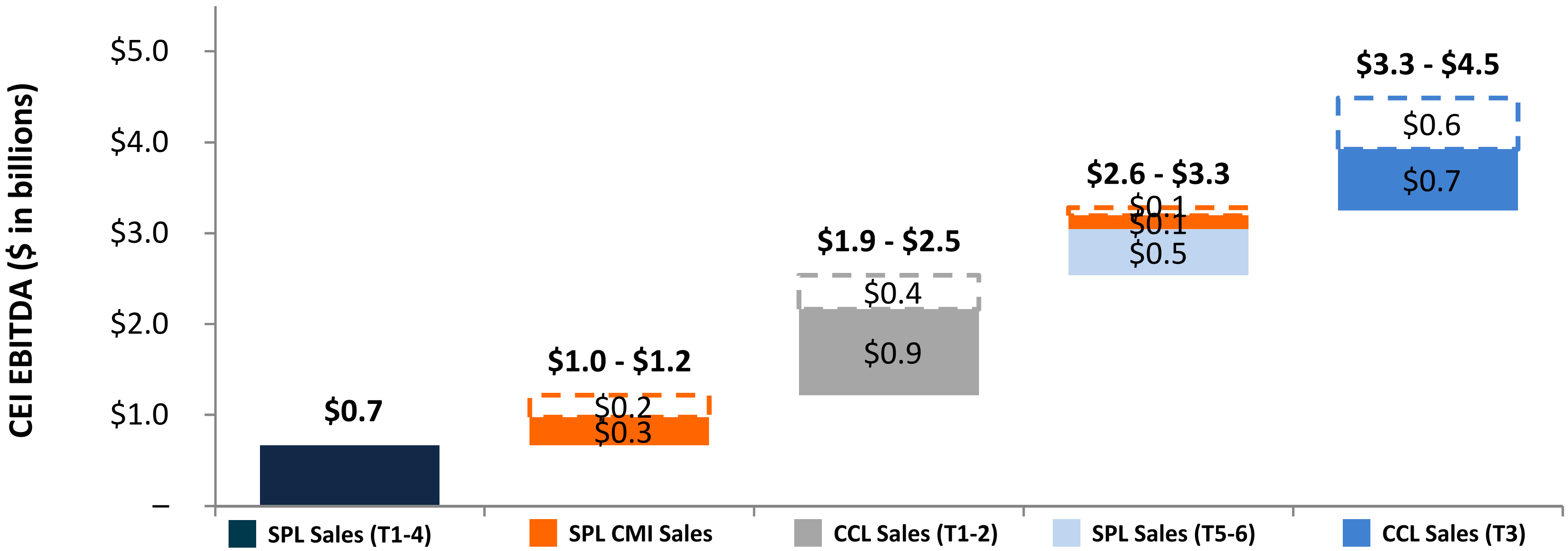
Cheniere developing platform for LNG sale opportunities to international markets

- International LNG marketing operation
- Professional staff based in London, Houston and Santiago
- SPA with SPL for 2 mtpa LNG volumes (equivalent of 104,000,000 MMBtu)
- Chartered three LNG vessels for deliveries in 2015 and 2016
- Developing complementary, high-value markets through small-scale asset investments
- Scale up for > 5 mtpa including LNG purchases from Cheniere terminals and other places
- Staffing, systems, and processes are underway and on schedule

Financial Estimates

Estimated CEI EBITDA Build Up

SPL Trains 1-6 and CCL Trains 1-3



Cumulative build up

Number of trains	**4 trains**	**4 trains**	**6 trains**	**8 trains**	**9 trains**
Nameplate capacity	**18.0 MTPA**	**18.0 MTPA**	**27.0 MTPA**	**36.0 MTPA**	**40.5 MTPA**
Long term SPA volumes	**16.0 MTPA**	**16.0 MTPA**	**22.0 MTPA**	**27.8 MTPA(1)**	**27.8 MTPA(1)**
Short / medium term LNG sales	**0 MTPA**	**1.6 MTPA**	**4.0 MTPA**	**6.6 MTPA(1)**	**10.2 MTPA(1)**
Assumed LNG gross margin	**NA**			**$4.00 - $7.00/MMBtu**	
CEI debt balance (unconsolidated)	**No debt**	**No debt**	**~$2 billion**	**~$2 billion**	**~$4 billion**

Note: EBITDA is a non-GAAP measure. EBITDA is computed as total revenues less non-cash deferred revenues, operating expenses, assumed commissioning costs and state and local taxes. It does not include depreciation expenses and certain non-operating items. Because we have not forecasted depreciation expense and non-operating items, we have not made any forecast of net income, which would be the most directly comparable financial measure under generally accepted accounting principles, or GAAP, and we are unable to reconcile differences between forecasts of EBITDA and net income. EBITDA has limitations as an analytical tool and should not be considered in isolation or in lieu of an analysis of our results as reported under GAAP, and should be evaluated only on a supplementary basis.

(1) Assumes 4.0 MTPA sold at $3.50/MMBtu on Train 6 and split evenly across long term and short / medium term sales.

Potential Financial Profile of CEI

Cheniere development of ~41 MTPA of US liquefaction capacity (9 trains) leads to

- EBITDA of $3.3 - $4.5 billion(1) (unconsolidated)
- CEI level debt of ~$4 billion (unconsolidated)
- CEI share count of 238.1 million as of March 31, 2014

(1) Depending on CMI's financial performance, CEI will become a corporate tax payer after its NOLs are fully exhausted starting in either 2020 or 2021 with a ~20-25% effective tax rate on pre-tax equity cash flow.

CQP Forecasted Distributable Cash Flows

CQP estimated distributable cash flows *($ in millions)*	Trains 1-4	Trains 1-6
SPLNG distributable cash flow	$370	$380
SPL distributable cash flow	1,400	2,260
CTPL distributable cash flow	30	30
CQP expenses	(15)	(15)
Estimated total distributable cash flow	**$1,785**	**$2,655**
Estimated distributable cash flow to		
General Partner	$350	$750
CQH(1)	700	870
Public and BX units	735	1,035
Estimated range of DCF per unit(2)	**$3.00 - $3.10**	**$3.80 - $3.90**

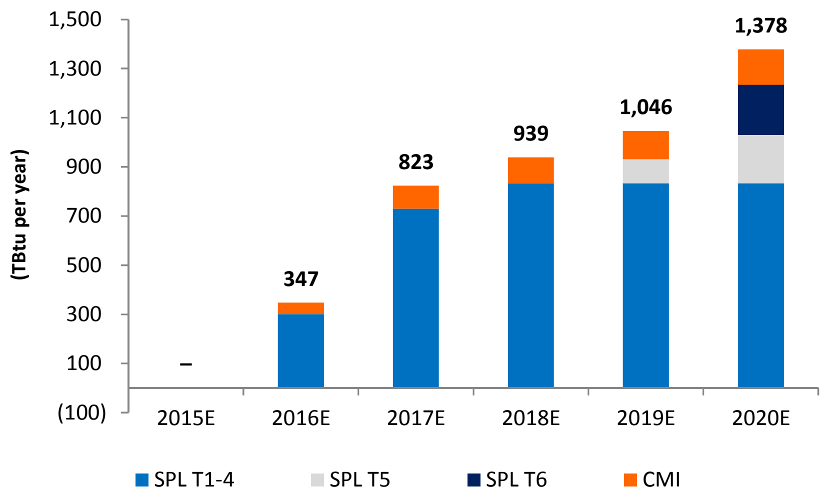
Note: Assumes conversion of all subordinated units and early conversion of Class B units at Trains 2 COD to common units and assumes ~269 million of public and Blackstone common units, ~227 million CQH common units and 2% General Partner interest and IDRs held by Cheniere.
Estimates represent a summary of internal forecasts, are based on current assumptions and are subject to change. Actual performance may differ materially from, and there is no plan to update, the forecast. See "Forward Looking Statements" slide.

(1) Depending on the number of liquefaction trains at SPL, CQH will become a corporate tax payer after its NOLs are fully exhausted starting in either 2019 or 2020 with a ~20-25% effective tax rate on pre-tax cash flow.

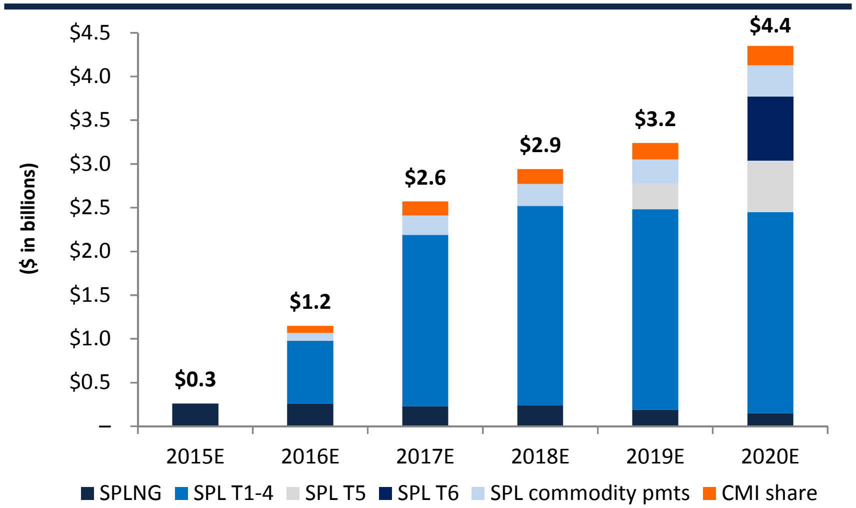
(2) Assumes CMI sells 2.2 MTPA (SPL Trains 1-4: 80% of 2 MTPA, plus SPL Train 5: 80% of 0.75 MTPA) on SPL Trains 1-5 at $4.00 - $7.00/MMBtu margin, net of expenses including shipping.

CQP Outlook – Visible Future Growth

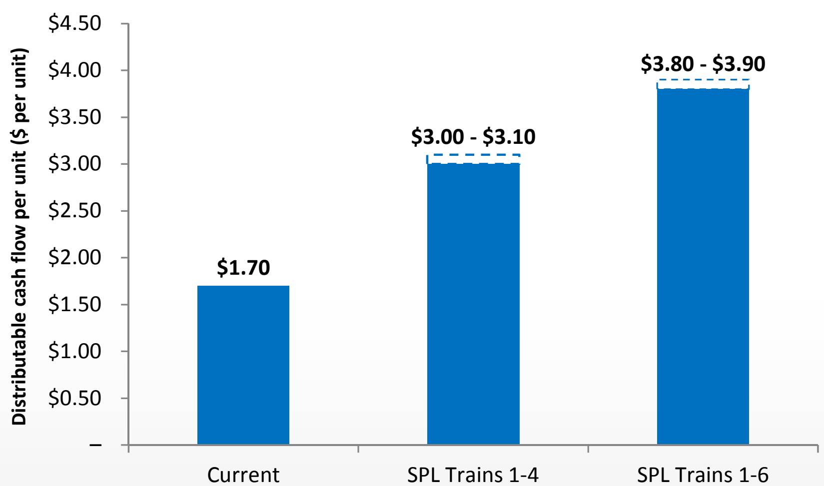
Estimated LNG export volumes



Estimated CQP revenues



Estimated CQP distributable cash flow per unit



Note: Estimates represent a summary of internal forecasts, are based on current assumptions and are subject to change. Actual performance may differ materially from, and there is no plan to update, the forecast. See “Forward Looking Statements” slide.

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Financial Strength

Demonstrated ability to raise capital, multiple options available

As of March 31, 2014	CQP	Other Cheniere Energy, Inc.	Consolidated CEI
Unrestricted cash and equivalents	$ 0	$915	$915
Restricted cash and securities	826	24	850
Current & long-term debt	$6,578	$ 0	$6,578

- **Since 2010, Cheniere has executed $15B+ in corporate and project level financings**
  - ~$5.0B in equity capital
  - ~$10.5B in debt capital
- **Multiple sources of capital available**
  - CQH
  - Bond markets
  - Bank markets

Cheniere's Debt Summary

As of June 2014

($ in millions)

- **Cheniere Energy, Inc. (NYSE: LNG)** — *No Debt*
  - **Cheniere Energy Partners LP Holdings, LLC (NYSE: CQH)** — *No Debt*
  - **Corpus Christi Liquefaction, LLC**
  - **CQP GP (& IDRs)**
  - **Cheniere Marketing, LLC**
    - **Cheniere Energy Partners, L.P. (NYSE: CQP)** (owned by Cheniere Energy Partners LP Holdings, LLC and CQP GP)
      - **Sabine Pass LNG, L.P. (SPLNG)**
        - Sr Secured Notes
          - $1,666 due 2016 (7.50%)
          - $420 due 2020 (6.50%)
        - Total TUA (1 Bcf/d)
        - Chevron TUA (1 Bcf/d)
        - SPL TUA (2 Bcf/d)
      - **Creole Trail Pipeline (CTPL)**
        - $400 Term Loan due 2017 (L+325)
        - SPL Firm Transport (1.5 Bcf/d)
      - **Sabine Pass Liquefaction, LLC (SPL)**
        - Trains 1-4 Debt
          - $2,703 Credit Facilities due 2020 (1)
          - $2,000 Notes due 2021 (5.625%)
          - $1,000 Notes due 2022 (6.250%)
          - $1,500 Notes due 2023 (5.625%)
          - $2,000 Notes due 2024 (5.750%)
        - BG SPA (286.5 million MMBtu / yr)
        - Gas Natural SPA (182.5 million MMBtu / yr)
        - KOGAS SPA (182.5 million MMBtu / yr)
        - GAIL SPA (182.5 million MMBtu / yr)
        - Total SPA (104.8 million MMBtu / yr)
        - Centrica SPA (91.3 million MMBtu / yr)
        - CMI SPA (up to 104 million MMBtu / yr)

(1) Includes $2,016 million term loan facility, $495 million Republic of Korea ("ROK") covered facility and $192 million ROK direct facility. Interest on the term loan facility is L+300 during construction and steps up to L+325 during operation. Under the ROK credit facilities, interest includes L+300 on the direct portion and L+230 on the covered portion during construction and operation. In addition, SPL will pay 100 bps for insurance/guarantee premiums on any drawn amounts under the covered tranches. These Credit Facilities mature on the earlier of May 28, 2020 or the second anniversary of Train 4 completion date.

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Appendix

Operating Assets

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Contracted Capacity at SPLNG
Third Party Terminal Use Agreements (TUAs)

Long-term, 20 year "take-or-pay" style commercial contracts
~$253MM annual fixed fee revenue

	TOTAL Total Gas & Power N.A.	Chevron Chevron U.S.A. Inc.
Capacity	1.0 Bcf/d	1.0 Bcf/d
Fees (1)		
Reservation Fee (2)	$0.28/MMBTU	$0.28/MMBTU
Opex Fee (3)	$0.04/MMBTU	$0.04/MMBTU
Full-Year Payments	$124 million	$129 million
Term	20 years	20 years
Guarantor	Total S.A.	Chevron Corp.
Guarantor Credit Rating **	Aa1/AA	Aa1/AA
Payment Start Date	April 1, 2009	July 1, 2009

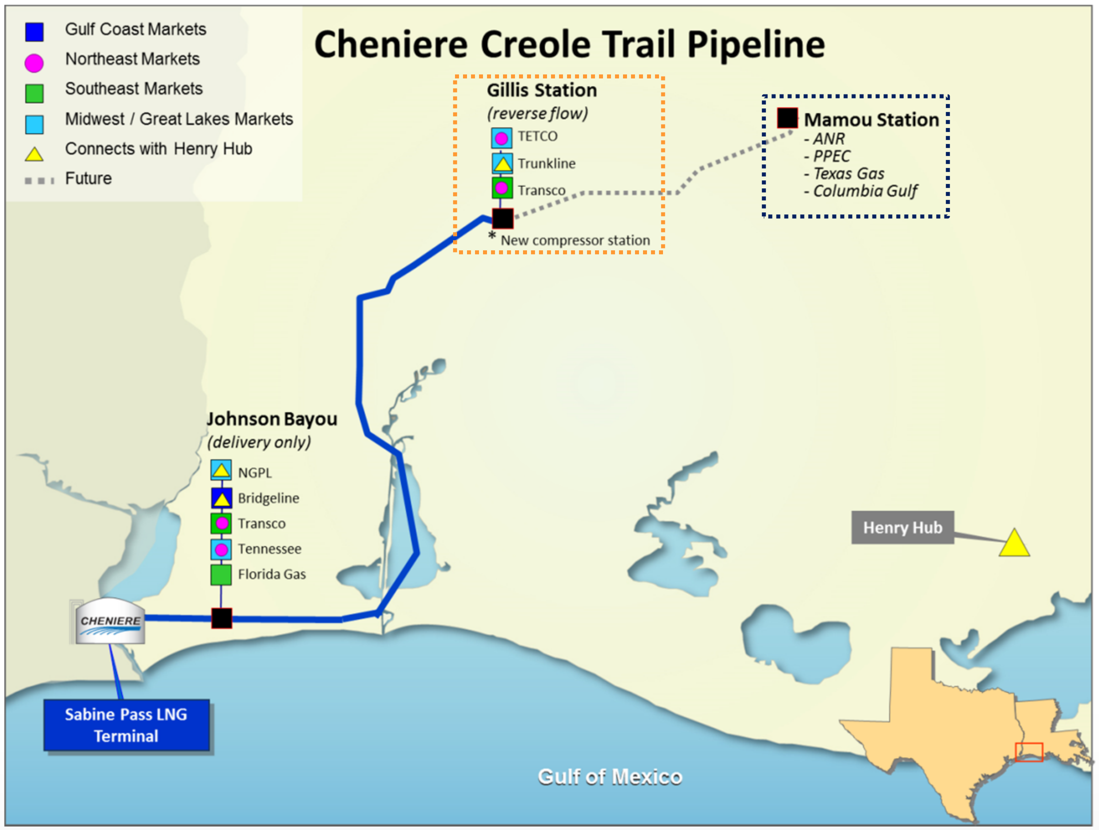
(1) Fees do not vary with the actual quantity of LNG processed; tax reimbursement not included in the fees.
(2) No inflation adjustments.
(3) Subject to annual inflation adjustment.

Note: Termination Conditions – (a) force majeure of 18 months or (b) unable to satisfy customer delivery requirements of ~192MMbtu in a 12-month period, 15 cargoes over 90 days or 50 cargoes in a 12-month period. In the case of force majeure, the customers are required to pay their capacity reservation fees for the initial 18 months.

**Ratings may be changed, suspended or withdrawn at anytime and are not a recommendation to buy, hold or sell any security.

Creole Trail Pipeline

- In May 2013, Cheniere Partners acquired CTPL from Cheniere Energy, Inc. for $480MM, and following the sale CTPL secured a $400 million senior secured term loan facility
- CTPL is fully contracted with expected annual revenue of ~$80MM expected to commence with Train 1 operations



Modification to reverse flow   Potential expansion for Trains 5&6

Current Facility

- Receipt capacity from SPLNG: 2.0 Bcf/d
- Diameter: 42-inch; Length: 94 miles
- Delivery Points: NGPL, Transco, TGPL, FGT, Bridgeline, Tetco, Trunkline
- No compression

Pipeline Modifications

- Delivery capacity to SPLNG: 1.5 Bcf/d
- Receipt points: TETCO, Trunkline, Transco
- One new compressor station with four new units
- Two new meter stations
- Modify existing meter stations
- Est ~$100MM capital cost
- Design and procurement near completion (>95%)
- Modifications commenced 4Q2013
- Est in-service: 4Q2014

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LSTK EPC Contract with Bechtel
Minimize Construction Costs and Risks

Why Bechtel?

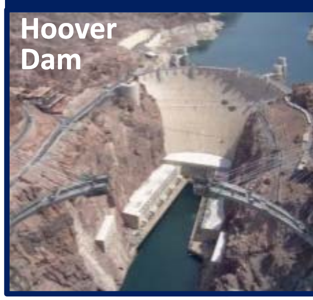
Proven construction contractor
- Founded in 1898 and headquarted in San Francisco
- Received 35+ industry awards since 2009
- Named the Top US Construction Contractor for the last 15 consecutive years by Engineering News Record

Industry leading experience and results
- Have participated in 23,000 projects in 140 nations and seven continents (average of 200 projects per year)
- Built ConocoPhillips Petroleum Kenai liquefaction plan in 1969

Leading LNG Construction Contractor
- Constructed one third of the world's liquefaction facilities (more than any other contractor)
- Designed and/or constructed LNG facilities using ConocoPhillips' Optimized Cascade® technology in Angola, Australia, Egypt, Equitorial Guinea and Trinidad
- 5 liquefaction projects in the last decade, 4 currently underway all using the ConocoPhillips' Optimized Cascade® Process

Bechtel was the EPC contractor for the regasification project at the Pass LNG terminal, which was constructed on time and on budget

Notable Other Non-LNG Projects

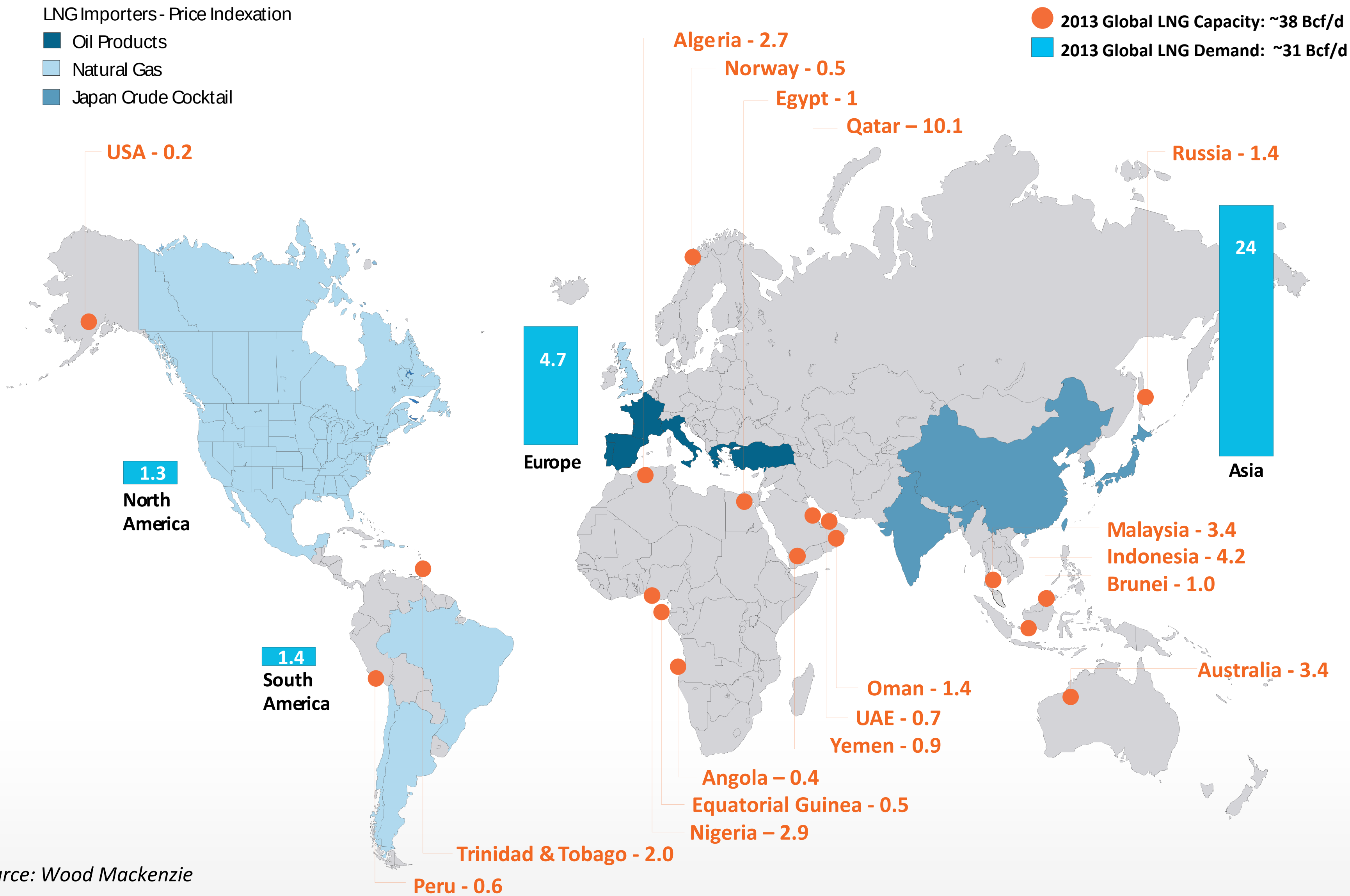


Key Competitive and Cost Advantages

- Existing SPLNG infrastructure provides significant cost advantages (jetty, pipeline, control room, ~17 Bcf storage tanks, etc.)
- Economies of scale from building multiple trains
- Easy access to the Gulf Coast labor pool where we have strong labor relations
- Established marine and road access provide easy delivery of materials
- Duplicating Sabine Pass LNG Train Design at Corpus Christi

Source: Bechtel.

Global LNG Supply & Demand



Source: Wood Mackenzie

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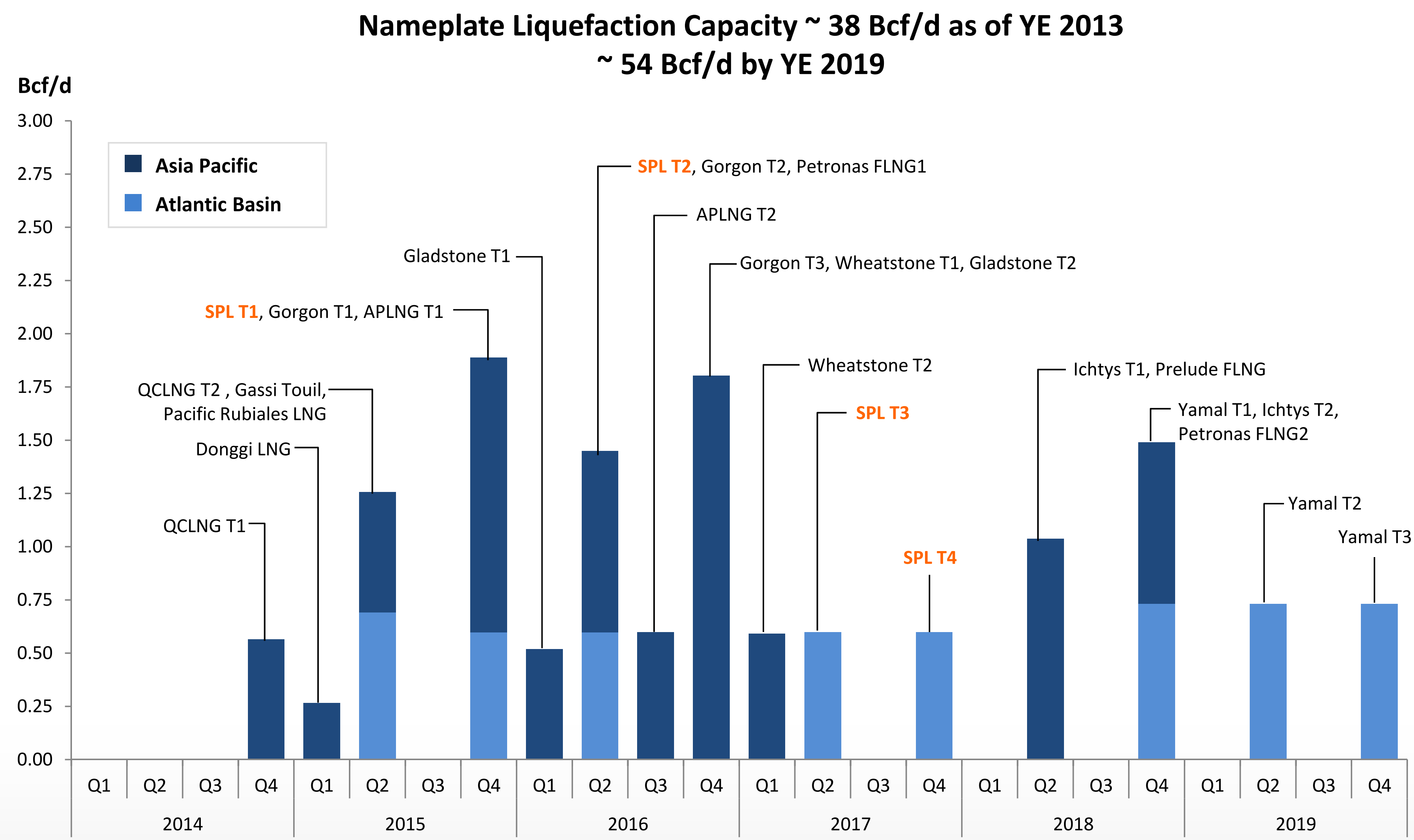
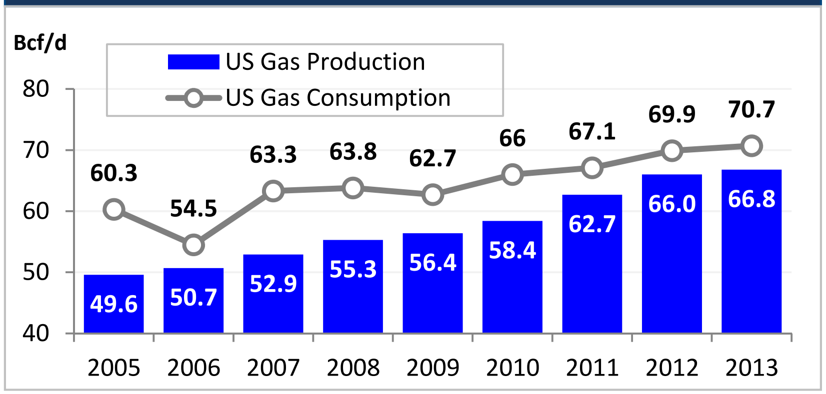
Firm Liquefaction Capacity Additions (Bcf/d)



Source: Cheniere Research

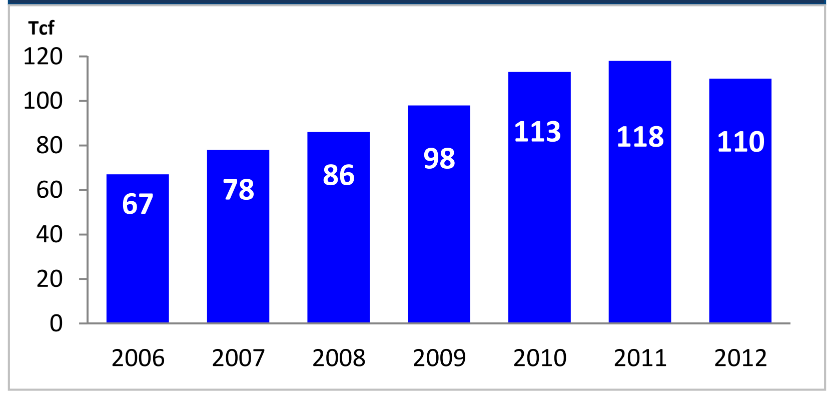
U.S. Natural Gas Markets

US Gas Consumptions vs. Production



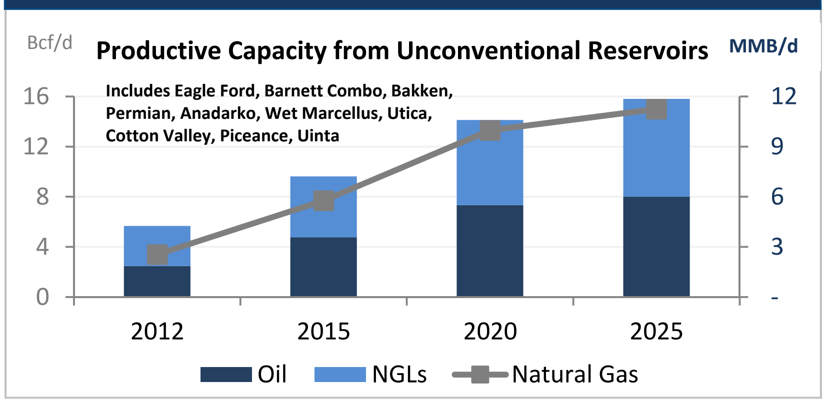
Source: EIA Apr 2014 STEO

US Proved Non-Producing Reserves



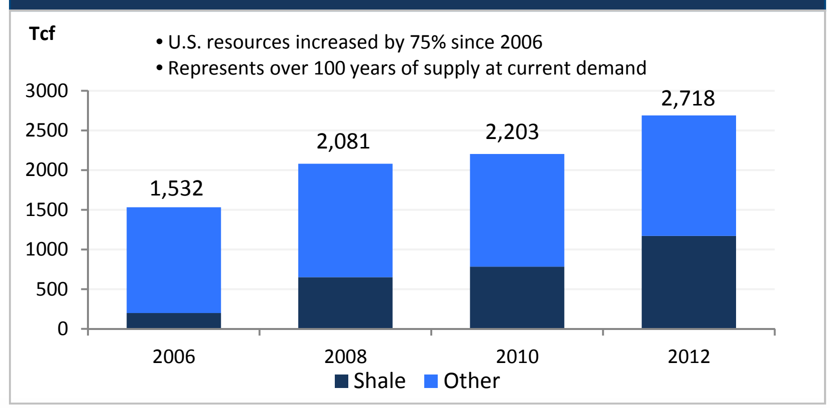
Source: EIA, US Crude Oil, Natural Gas and Natural Gas Liquids Proved Reserves, 2012.

Productive Capacity from Unconventional Reservoirs



Source: Advanced Resource Intl; Cheniere Research.

US Natural Gas Resources



Source: Potential Gas Committee, 2013; EIA, Natural Gas Proved Reserves, 2010

- **Current market fundamentals in the U.S. – increased production, increased natural gas reserves and lackluster increase in natural gas demand – have created an opportunity to expand into exports – benefitting U.S. economy, creating jobs and reducing balance of trade deficit**

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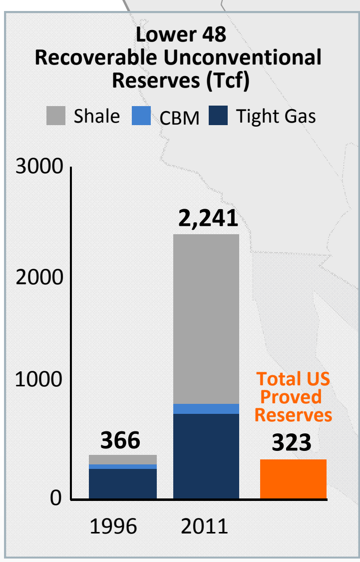
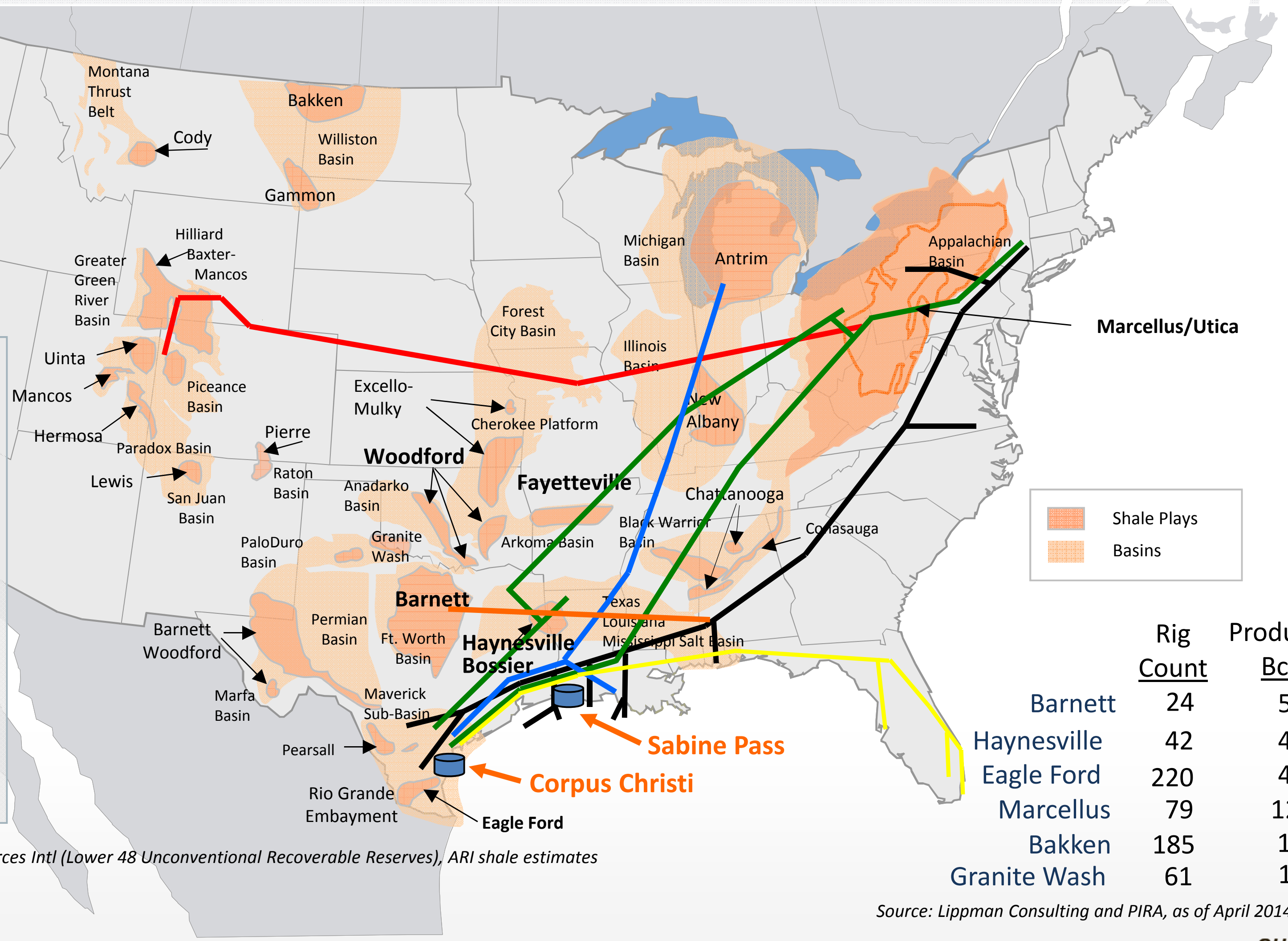
Strategically Located – Extensive Market Access to Gas

Primary Gas Sources for Sabine Pass and Corpus Christi Liquefaction

Conventional Gulf Coast Onshore: Barnett, Haynesville, Bossier, Eagle Ford, Fayetteville, Permian Basin, Anadarko Basin





Source: EIA, April 2014; Advanced Resources Intl (Lower 48 Unconventional Recoverable Reserves), ARI shale estimates updated October 2013

	Rig Count	Production Bcf/d
Barnett	24	5.2
Haynesville	42	4.6
Eagle Ford	220	4.9
Marcellus	79	12.5
Bakken	185	1.1
Granite Wash	61	1.2

Source: Lippman Consulting and PIRA, as of April 2014

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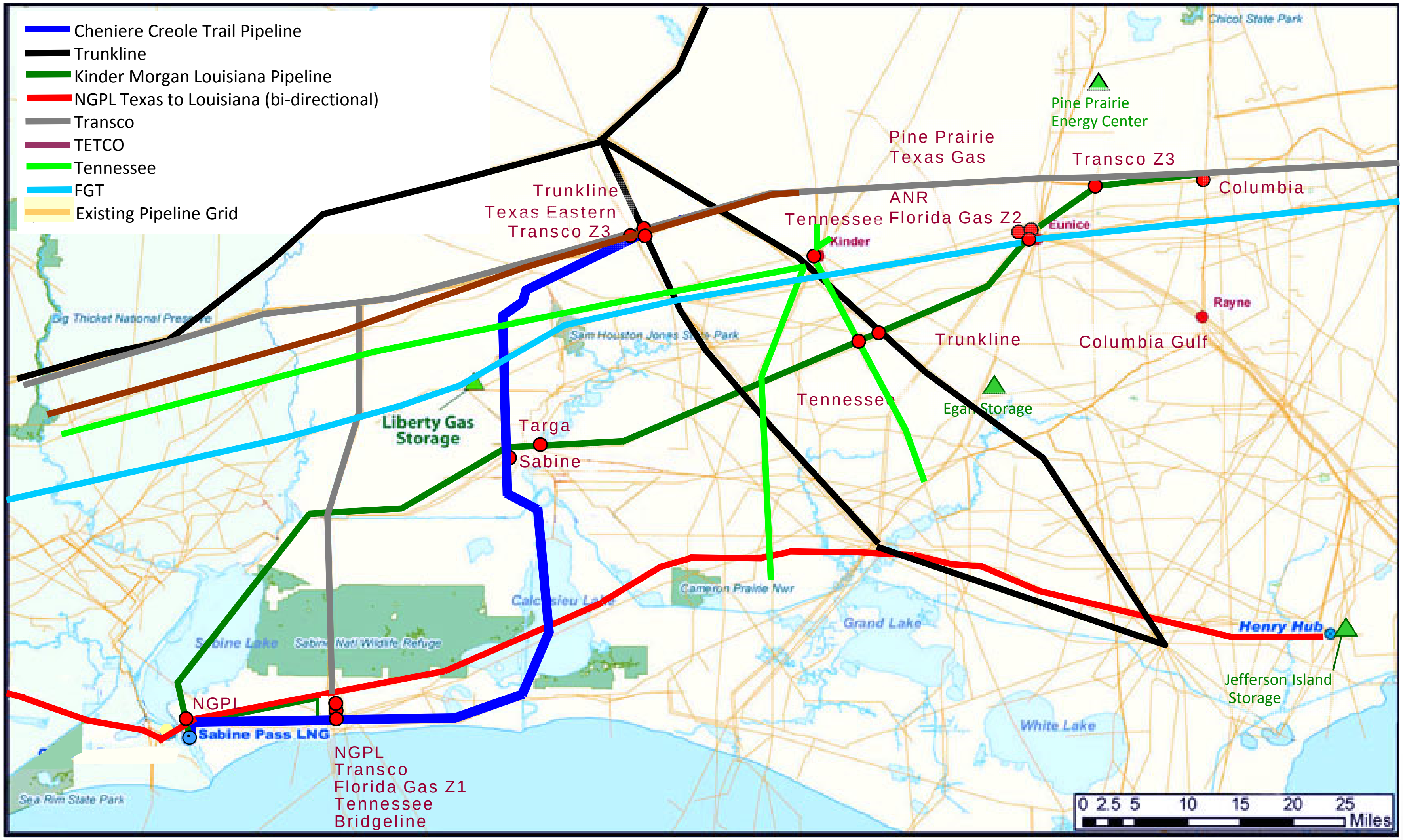
Multiple Local Pipeline Interconnections Provide Several Options for Access to Natural Gas Supply



Source: Cheniere Research

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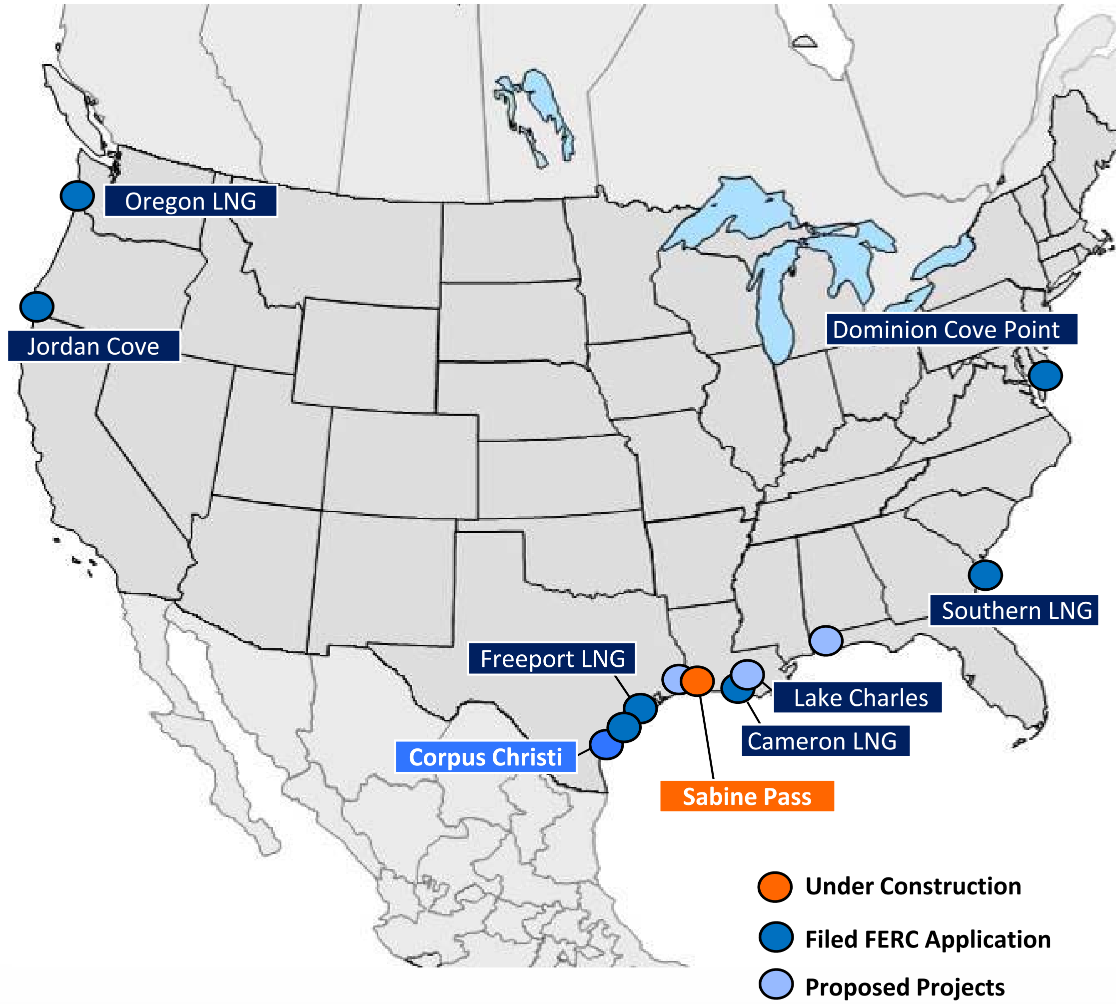
U.S. LNG Export Projects



Company	Quantity (Bcf/d)	DOE	*FERC**	Contracts
Cheniere Sabine Pass T1 – T4	2.2	Fully permitted		Fully Subscribed
Freeport	1.8	FTA + NonFTA	✓	T1-T3
Lake Charles	2.0	FTA + NonFTA	❖	Fully Subscribed
Dominion Cove Point	1.0	FTA + NonFTA	✓	Fully Subscribed
Cameron LNG	1.7	Fully permitted		Fully Subscribed
Jordan Cove	1.2/0.8	FTA + NonFTA	❖	
Oregon LNG	1.25	FTA	❖	
Cheniere Corpus Christi	2.1	FTA	✓	Partially Subscribed
Cheniere Sabine Pass T5 – T6	1.3	FTA	✓	T5 Subscribed
Excelerate	1.3	FTA	❖	
Southern LNG	0.5	FTA	❖	Fully Subscribed
Magnolia LNG	0.5	FTA	❖	Partially Subscribed

Plus other proposed LNG export projects that have not filed a FERC application.

- Application filing = ❖
- FERC scheduling notice issued = ✓

Source: Office of Oil and Gas Global Security and Supply, Office of Fossil Energy, U.S. Department of Energy; U.S. Federal Energy Regulatory Commission; Company releases

CQP: SPLNG (Regas) Estimated Cash Flows

SPLNG estimated cash flows *($ in millions)*	Trains 1-4	Trains 1-6
Total	$130	$130
Chevron	135	135
SPL[1]	295	305
Other	10	15
Total revenues	**$570**	**$585**
Total expenses	(70)	(75)
EBITDA	**$500**	**$510**
Interest expense[2]	(130)	(130)
SPLNG distributable cash flow to CQP	**$370**	**$380**

Note: EBITDA is a non-GAAP measure. EBITDA is computed as total revenues less non-cash deferred revenues, operating expenses, assumed commissioning costs and state and local taxes. It does not include depreciation expenses and certain non-operating items. Because we have not forecasted depreciation expense and non-operating items, we have not made any forecast of net income, which would be the most directly comparable financial measure under generally accepted accounting principles, or GAAP, and we are unable to reconcile differences between forecasts of EBITDA and net income. EBITDA has limitations as an analytical tool and should not be considered in isolation or in lieu of an analysis of our results as reported under GAAP, and should be evaluated only on a supplementary basis.

Estimates represent a summary of internal forecasts, are based on current assumptions and are subject to change. Actual performance may differ materially from, and there is no plan to update, the forecast. See "Forward Looking Statements" slide.

(1) Includes export fees.

(2) Assumes $2.1 billion of debt outstanding at a weighted average interest rate of 6.3%.

CQP: SPL Estimated Cash Flows

SPL estimated cash flows *($ in millions)*	Trains 1-4	Trains 1-6
Trains 1-4 (BG, Gas Natural, KOGAS, GAIL)	$2,300	$2,300
Train 5 (Total, Centrica)	–	590
Train 6 customer[1]	–	730
CMI[2]	170	220
Commodity payments, net[3]	250	360
Total revenues	**$2,720**	**$4,200**
O&M and Management fees	(170)	(270)
Maintenance capex	(90)	(140)
SPLNG / Total TUA	(330)	(440)
Pipeline costs	(160)	(230)
Total expenses	**($750)**	**($1,080)**
EBITDA	**$1,970**	**$3,120**
Interest expense[4]	(570)	(860)
SPL distributable cash flow to CQP	**$1,400**	**$2,260**

Note: EBITDA is a non-GAAP measure. EBITDA is computed as total revenues less non-cash deferred revenues, operating expenses, assumed commissioning costs and state and local taxes. It does not include depreciation expenses and certain non-operating items. Because we have not forecasted depreciation expense and non-operating items, we have not made any forecast of net income, which would be the most directly comparable financial measure under generally accepted accounting principles, or GAAP, and we are unable to reconcile differences between forecasts of EBITDA and net income. EBITDA has limitations as an analytical tool and should not be considered in isolation or in lieu of an analysis of our results as reported under GAAP, and should be evaluated only on a supplementary basis. Estimates represent a summary of internal forecasts, are based on current assumptions and are subject to change. Actual performance may differ materially from, and there is no plan to update, the forecast. See “Forward Looking Statements” slide.

(1) Assumes 4.0 MTPA sold at $3.50/MMBtu on Train 6.
(2) Assumes CMI sells 2.2 MTPA (SPL Trains 1-4: 80% of 2 MTPA, plus SPL Train 5: 80% of 0.75 MTPA) on SPL Trains 1-5 at $7.00/MMBtu margin, net of expenses including shipping.
(3) Assumes $5.00/MMBtu natural gas price and that Offtakers lift 100% of their full contractual entitlement. Amounts are net of estimated natural gas to be used for the liquefaction process.
(4) SPL Trains 1-4 assume consolidated debt of ~$9.4 billion with weighted average interest rate of ~6.2%. SPL Trains 1-6 assume consolidated debt of ~$14.0 billion with weighted average interest rate of ~6.2%.

CCL Estimated Cash Flows

Trains 1-3

CCL estimated cash flows

($ in millions)	**CCL Trains 1-2**	**CCL Trains 1-3**
Long term SPAs	$1,110	$1,110
Short / medium term LNG sales[1]	500 - 880	1,250 - 2,190
Commodity payments, net[2]	160	230
Total CCL revenues	**$2,150**	**$3,530**
Plant O&M	(250)	(320)
Plant maintenance capex	(70)	(100)
Pipeline costs (primary plant and upstream pipelines)	(130)	(180)
Total CCL expenses	**($450)**	**($600)**
CCL EBITDA	**$1,320 - $1,700**	**$2,000 - $2,930**
Less: Project-level interest expense[3]	(380)	(380)
CCL distributable cash flow to CEI	**$940 - $1,320**	**$1,620 - $2,550**

Note: EBITDA is a non-GAAP measure. EBITDA is computed as total revenues less non-cash deferred revenues, operating expenses, assumed commissioning costs and state and local taxes. It does not include depreciation expenses and certain non-operating items. Because we have not forecasted depreciation expense and non-operating items, we have not made any forecast of net income, which would be the most directly comparable financial measure under generally accepted accounting principles, or GAAP, and we are unable to reconcile differences between forecasts of EBITDA and net income. EBITDA has limitations as an analytical tool and should not be considered in isolation or in lieu of an analysis of our results as reported under GAAP, and should be evaluated only on a supplementary basis.

(1) Assumes CCL sells 2.4 MTPA (80% of 3.0 MTPA) on Trains 1-2 and 3.6 MTPA (80% of 4.5 MTPA) on Train 3 at $4.00 - $7.00/MMBtu margin, net of expenses including shipping, in the short / medium term market.

(2) Assumes $5.00/MMBtu natural gas price and that Offtakers lift 100% of their full contractual entitlement. Amounts are net of estimated natural gas to be used for the liquefaction process.

(3) Assumes debt at CCL of $6 billion at 6.25%.

Cheniere Marketing SPA
Estimated Annual Gross Profit from 2 mtpa

Volumes		
LNG Loaded Sabine Pass (Tbtu)		104
LNG Delivered DES (Tbtu)		98
Cash Flows		
Sales		
Total Revenue ($MM)	$	1,466
Expenses		
LNG purchase from Sabine		(598)
Vessel Charter Costs		(92)
Port and Canal Costs		(25)
Incremental Vessel Charters		(37)
Financing Costs		(7)
Gross Profit ($MM)	**$**	**707**
Gross Profit ($/MMBtu)	**$**	**6.80**

Assumptions

- $5 Henry Hub Price
- $15 LNG sales price, delivered at terminal
- 6% loss of gas on the vessel
- Cheniere vessels: $84,000 per day average charter rate
- Port / Canal costs: $900,000 per voyage
- 1 incremental vessel needed at $100,000 per day
- Financing costs: $250,000 per cargo for LCs at L+250

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Cheniere Marketing SPA
Estimated Annual Gross Profit from 2 mtpa - Sensitivities

$MM Gross Profit at Varying Prices

Henry Hub Price, $/MMBtu	LNG Sales Price, $/MMBtu: $10.00	$15.00	$20.00
$4.00	$338	$827	$1,316
$5.00	$219	$707	$1,196
$6.00	$99	$588	$1,077

Gross Profit per MMBtu at Varying Prices

Henry Hub Price, $/MMBtu	LNG Sales Price, $/MMBtu: $10.00	$15.00	$20.00
$4.00	$3.25	$7.95	$12.65
$5.00	$2.10	$6.80	$11.50
$6.00	$0.95	$5.65	$10.35

Observations

- The intrinsic value of 104 million MMBtu of LNG from Sabine Pass is ~$700 million
- Trading activity could add an additional 10-25% extrinsic value
- A 10% change in the LNG sales price causes a 21% change in the gross margin
- A 10% change in the Henry Hub Price causes an 8% change in the gross margin

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Conversion of Class B and Subordinated Units

Class B Units:

- **Mandatory conversion**: within 90 days of the substantial completion of Train 3
- **Optional conversion by a Class B unitholder** may occur at any of the following times:
  - After 83 months from issuance of EPC notice to proceed
  - Prior to the record date for a quarter in which sufficient cash from operating surplus is generated to distribute $0.425 to all outstanding common units and the common units to be issued upon conversion
  - Thirty (30) days prior to the mandatory conversion date
  - Within a 30-day period prior to a significant event or a dissolution

Subordinated Units:

- Subordinated units will convert into common units on a one-for-one basis, provided that there are no cumulative common unit arrearages, and either of the below distribution hurdles is met:
  - For three consecutive, non-overlapping four-quarter periods, the distribution paid from "Adjusted Operating Surplus"(1) to all outstanding units(2) equals or exceeds $0.425 per quarter
  - For four consecutive quarters, the distribution paid from "Contracted Adjusted Operating Surplus"(1) to all outstanding units(2) equals or exceeds $0.638 per quarter

(1) As defined in CQP's partnership agreement.
(2) Includes all outstanding common units (assuming conversion of all Class B units), subordinated units and any other outstanding units that are senior or equal in right of distribution to the subordinated units.

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Pro Forma CQP Ownership

(in millions)	CEI	CQH[3]	Blackstone	Public	Total
Common units [1]		12.0		45.1	57.1
Class B units [1]		45.3	100.0		145.3
Subordinated units [1]		135.4			135.4
General Partner @ 2%	6.9				6.9
	6.9	192.7	100.0	45.1	344.7
Percent of total (as of 12/31/13)	2%	55.9%	29.0%	13.1%	100.0%
Pro forma accretion YE2016	9.4	231.7	182.9	45.1	469.1
Percent of total (pro forma YE2016)	2%	49.4%	39.0%	9.6%	100.0%

- Current common unit annualized distribution expected to be $1.70/unit [2]
- Class B units accrete 3.5% quarterly until converted into common units

(1) Unit amounts are current units outstanding, including Blackstone's total investment of $1.5B but excluding accretion of Class B Units.
(2) Currently, CQP is paying distributions on the common units and the applicable 2% distribution to the GP.
(3) CQH is a subsidiary of Cheniere, of which Cheniere owns ~84.5%.

Note: The above represents a summary of internal forecasts, are based on current assumptions and are subject to change. Actual performance may differ materially from, and there is no plan to update, the forecast. See "Forward Looking Statements" slide.


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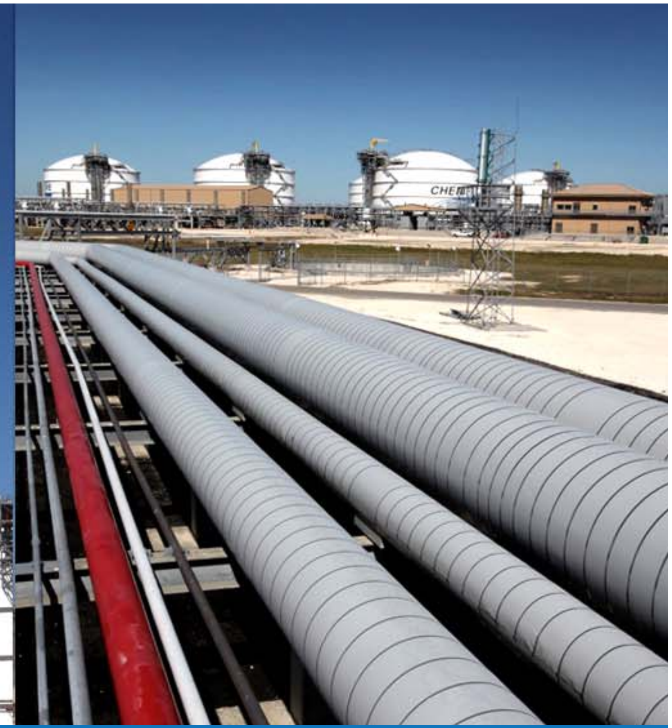


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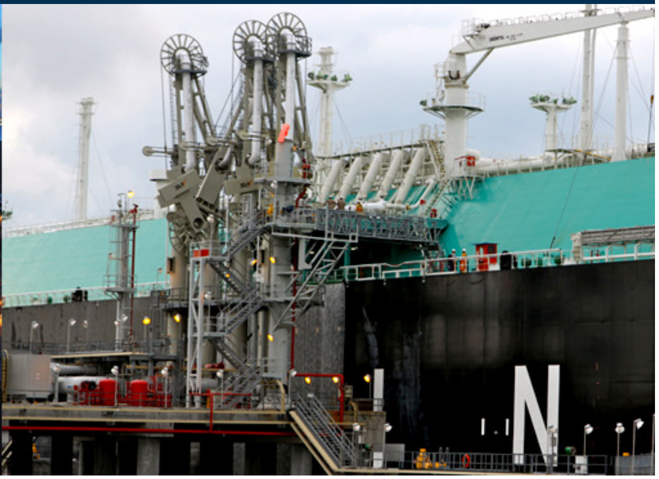

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