Anatomy of a U.S. liquefaction project

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Cautionary statements

Forward-looking statements

The information in this presentation includes "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 fact are forward-looking statements. The words "anticipate," "assume," "believe," "budget," "estimate," "expect," "forecast," "initial," "intend," "may," "model," "plan," "potential," "project," "should," "will," "would," and similar expressions are intended to identify forward-looking statements. The forward-looking statements in this presentation relate to, among other things, future costs, prices, margins, cash flows and other financial results, liquidity and financing, construction of pipelines and other facilities, and other aspects of our business and our prospects and those of other industry participants.

Our forward-looking statements are based on assumptions and analyses made by us in light of our experience and our perception of historical trends, current conditions, expected future developments, and other factors that we believe are appropriate under the circumstances. These statements are subject to numerous known and unknown risks and uncertainties which may cause actual results to be materially different from any future results or performance expressed or implied by the forward-looking statements. These risks and uncertainties include those described in the "Risk Factors" section of our Annual Report on Form 10-K for the fiscal year ended December 31, 2017 filed with the Securities and Exchange Commission (the "SEC") on March 15, 2018 and other filings with the SEC, which are incorporated by reference in this presentation. Many of the forward-looking statements in this presentation relate to events or developments anticipated to occur numerous years in the future, which increases the likelihood that actual results will differ materially from those indicated in such forward-looking statements.

Plans for the PGAP and HGAP projects discussed herein are in the early stages of development and numerous aspects of the projects, such as detailed engineering and permitting, have not commenced. Accordingly, the nature, timing, scope and benefits of those projects may vary significantly from our current plans due to a wide variety of factors, including future changes to the proposals. Although the Driftwood pipeline project is significantly more advanced in terms of engineering, permitting and other factors, its construction, budget and timing are also subject to significant risks and uncertainties.

Projected future cash flows as set forth herein may differ from cash flows determined in accordance with GAAP.

The information on slides 11, 12 and 13 is meant for illustrative purposes only and does not purport to show estimates of actual future financial performance. The information on those slides assumes the completion of certain acquisition, financing and other transactions. Such transactions may not be completed on the assumed terms or at all.

The forward-looking statements made in or in connection with this presentation speak only as of the date hereof. Although we may from time to time voluntarily update our prior forward-looking statements, we disclaim any commitment to do so except as required by securities laws.

Managing three risks

Construction

Site selection and execution

Basin

Adequate natural gas supply

Basis

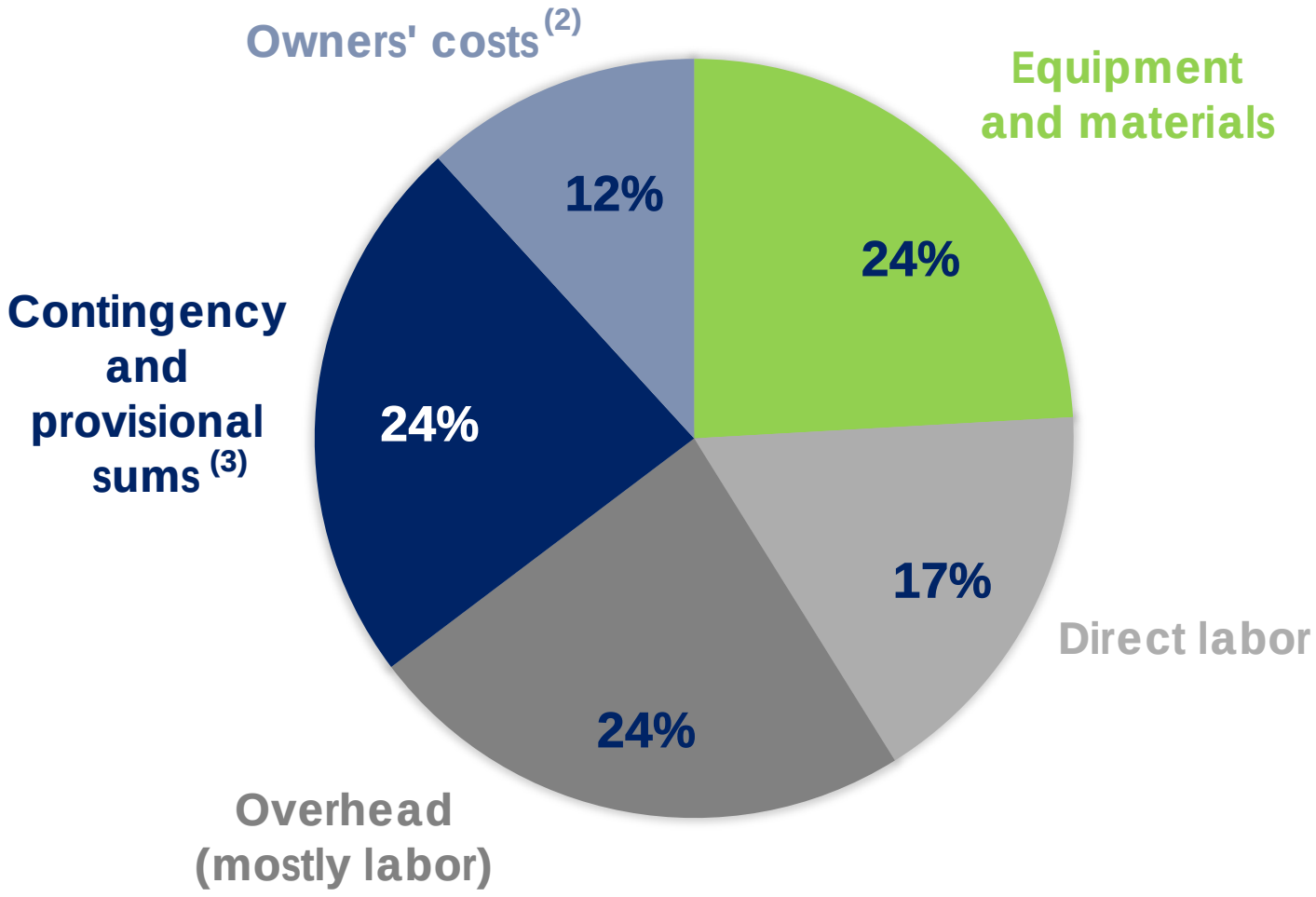
Reliable access to pipelines

Successful projects require a sophisticated strategy to manage complex risks

Site characteristics determine long-run costs

- Access to **pipeline infrastructure**
- Access to **power** and water
- Support from **local communities**
- **Site size** over 1,000 acres
- **Insulation** from surge, wind, and local populations
- **Berth** over 45’ depth with access to high seas

Construction budget breakdown(1)



Notes: (1) Based on Driftwood LNG full development.
(2) Includes additional contingency by developer and staffing prior to commencement of operations.
(3) Provisional sum includes escalation factor for inflation, insurance, foreign exchange, and other costs.

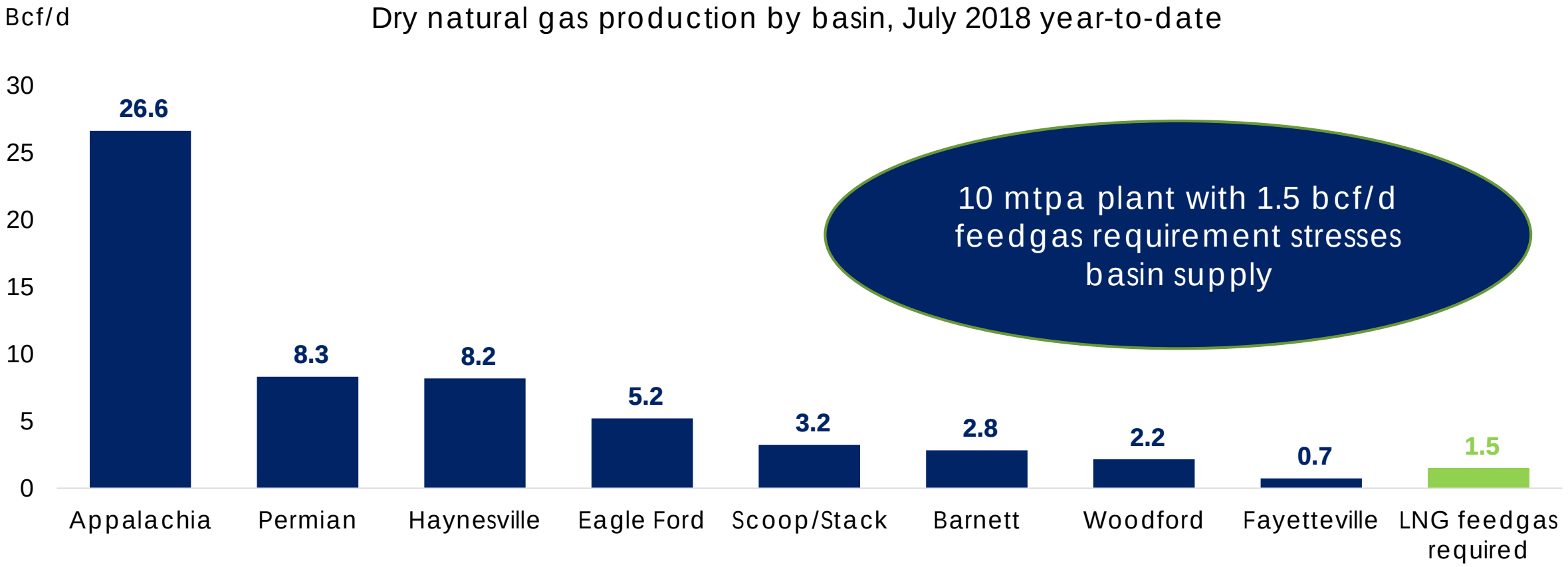
Corpus Christi LNG and Driftwood LNG examples

($ billions)	Corpus Christi LNG			Driftwood LNG
	T1-2	T3	T1-3	Plants 1-3
Capacity (mtpa)	9.0	4.5	13.5	16.5
— EPC	$7.8	$2.4	$ 10.2	$ 10.3
— Pipeline	$0.4	$0.0	$ 0.4	$ 1.5(1)
— Owners' cost & contingency(2)	$1.4	$0.5	$ 1.9	$ 2.4
Total cost	**$9.6**	**$2.9**	**$12.5**	**$ 14.2**
Unlevered cost ($ per tonne)	**$1,070**	**$645**	**$925**	**$860**

- **Does not include G&A to manage the project**
- **Cost of financing is ~$300-$400 per tonne**
- **Delays cost $150 per tonne per year**

Source: Cheniere Analyst Day presentation (2018) and Tellurian analysis.
Notes: (1) Includes approximately $0.4 billion in costs for additional compression on Driftwood pipeline in 3-plant case.
(2) For Corpus Christi LNG, combined owners' costs and contingency from page 18 of Cheniere Analyst Day presentation. For Driftwood LNG, includes owners' costs and Tellurian costs presented on slide 12.

LNG projects require supply optionality



Source: IHS, DrillingInfo, EIA, Tellurian analysis.

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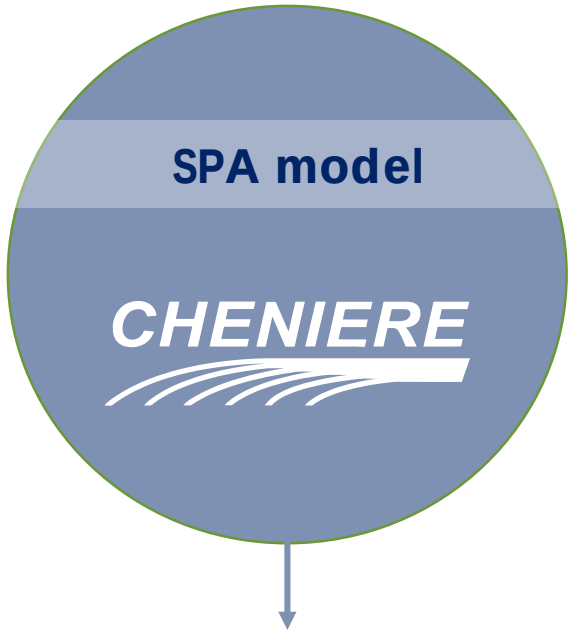
Owning pipeline infrastructure mitigates basis risk

Can you reach your selected basin? For how long?

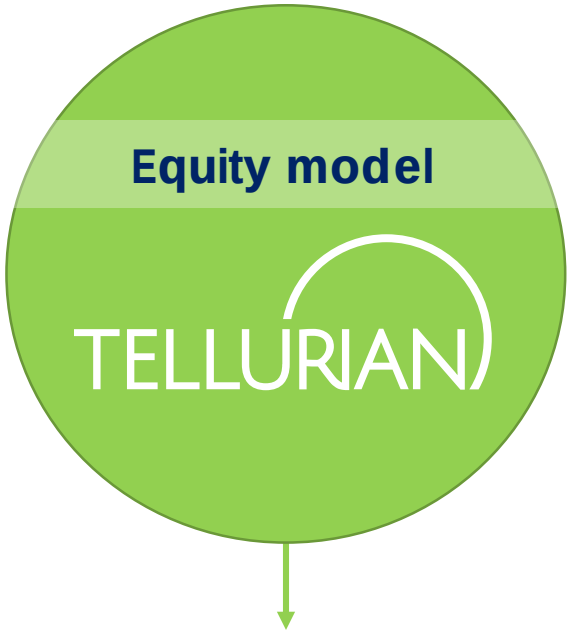
Customer incurs risk

Competition between customers for pipeline access leads to **hidden costs** and higher cost of LNG on the water



Developer incurs risk

Developer consolidates pipeline transport, but still **a price taker** for transportation services; developer only has 5% of Henry Hub price to pay for transport



Own the infrastructure

True **cost control** and **transparency** from owning and managing pipeline transportation

Basis: challenges for SPA and tolling model

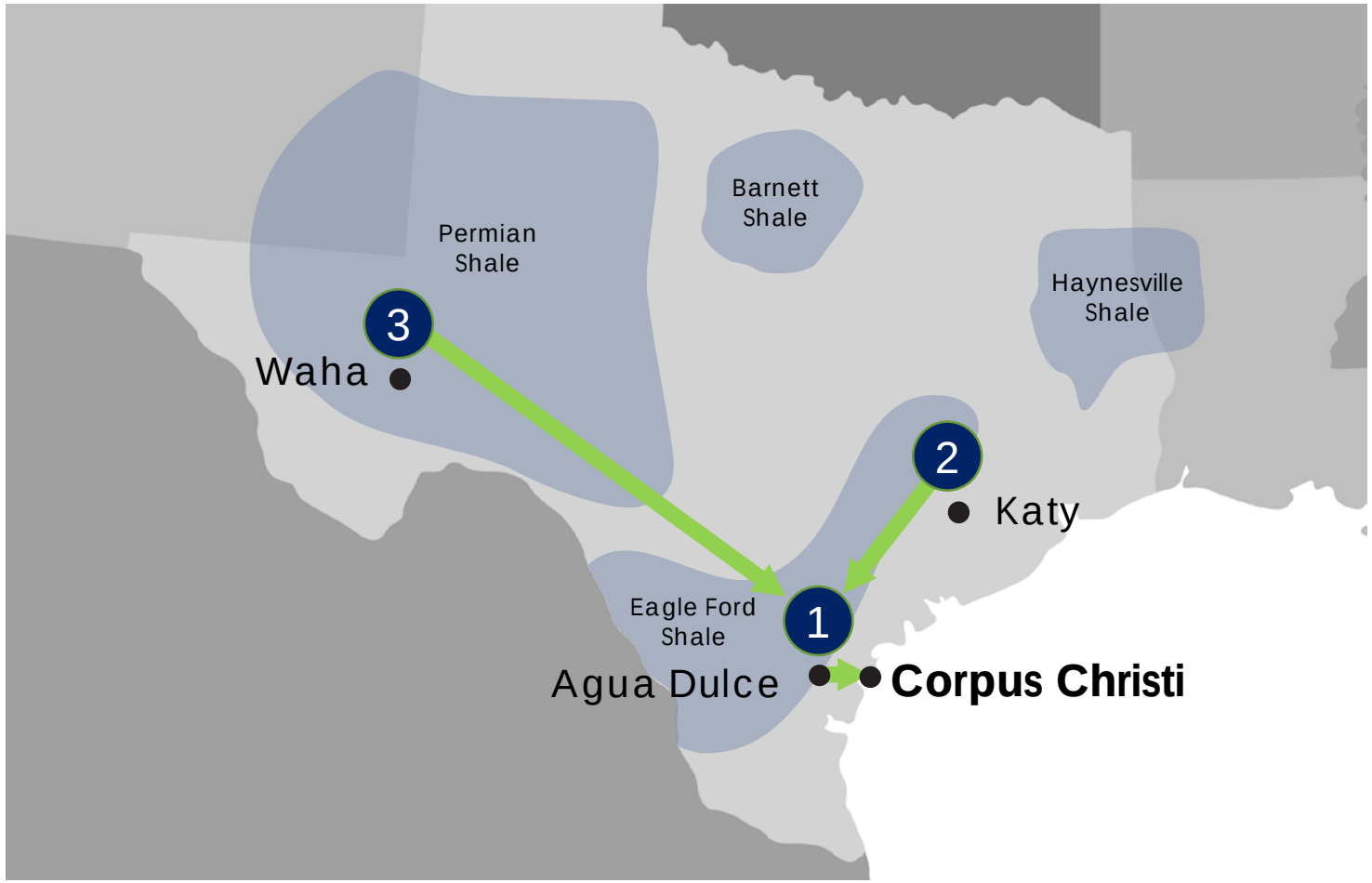
Corpus Christi example: low-cost gas from basin can become expensive on the wrong pipeline

Pipeline allowance is $0.15-$0.20/mmBtu(1)

1 **Ague Dulce to Corpus**
Basis(2): +$0.15/mmBtu
Transport: $0.10/mmBtu
Total: **$0.25/mmBtu**
Insufficient liquidity

2 **Katy to Corpus**
Basis: +$0.15/mmBtu
Transport(3): $0.40-$0.50/mmBtu
Total(4): **$0.60/mmBtu**

3 **Waha to Corpus**
Basis: -$1.00/mmBtu
Transport(5): $0.60-$0.70/mmBtu
Total(4): **$-0.35/mmBtu**



Sources: Platts Gas Daily July 20, 2018, CME Group, Cheniere Energy public documents, Tellurian analysis.
Notes: (1) Assuming $3.00/mmBtu Henry Hub, 10% fuel, 5% pipeline.
(2) Basis to Henry Hub.
(3) Assumes $0.40/mmBtu full cycle transport costs on pipeline from Waha to Agua Dulce at 100% load factor rate.
(4) Based on midpoint of range of estimated transport costs.
(5) Internal estimates of $0.50/mmBtu to transport gas from Waha to Ague Dulce based on Kinder Morgan's Gulf Coast Express project.

Low-cost LNG is built before the fence line

Basis

Pipeline access and control of infrastructure is key

Illustrative cost inflation

+$1-$2/mmBtu in costs from long-term cost escalation as legacy agreements roll off

Basin

Adequacy and reliability of supply is critical

+$1-$2/mmBtu in long-term cost escalation from exhausting lowest-cost drilling locations in one basin

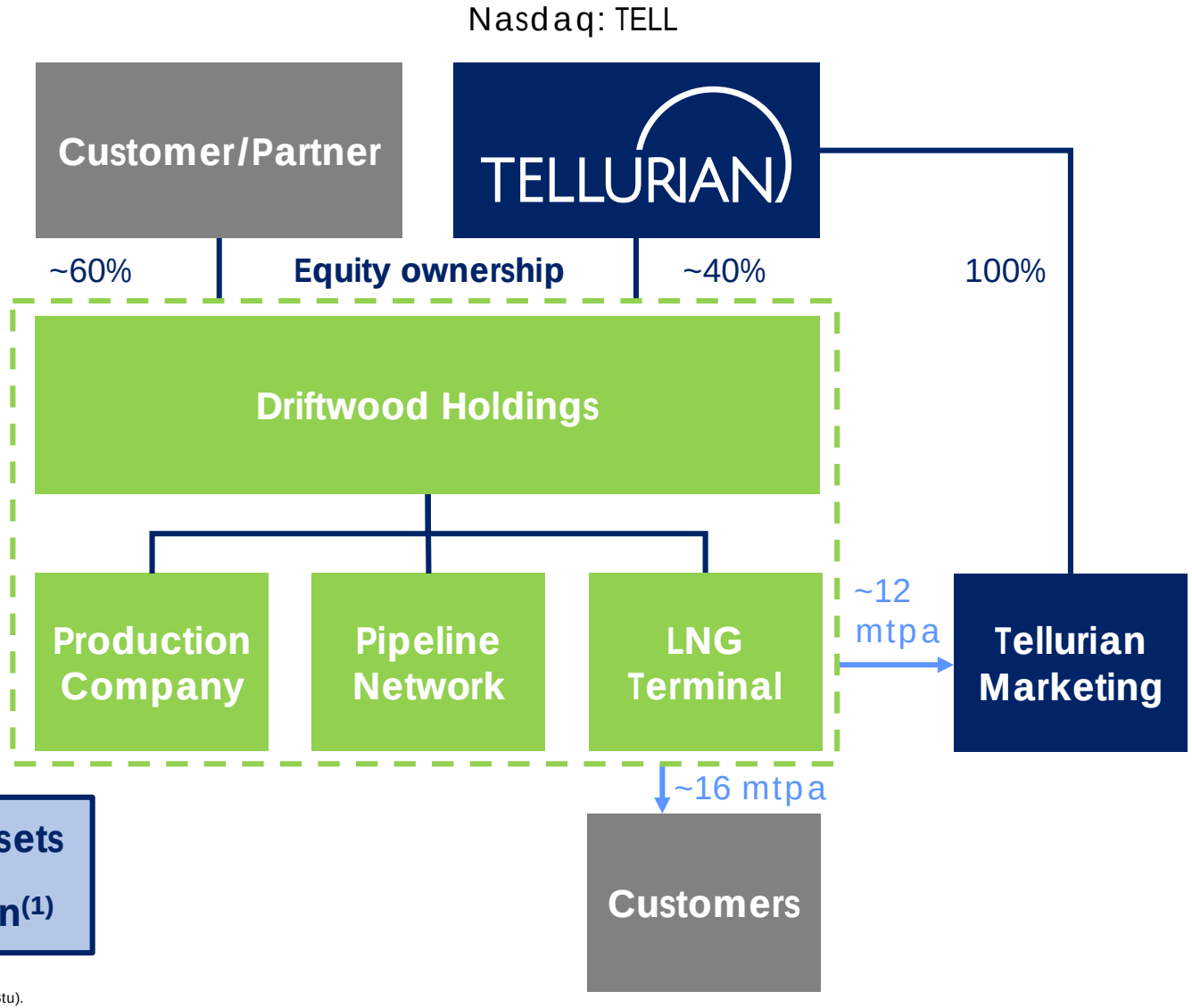
Construction

All-in cost is predictable, but execution and scale matter

+$200-$300 per tonne or $0.40-$0.60/mmBtu cost inflation due to poor execution

Business model

- Tellurian will offer equity interests in Driftwood Holdings
- Driftwood Holdings will consist of a Production Company, a Pipeline Network and an LNG Terminal (~27.6 mtpa)
- **Equity will cost ~$1,500 per tonne**
- Customer/Partner will receive equity LNG at tailgate of Driftwood LNG terminal at cost
- **Variable and operating costs** expected to be **~$3.00/mmBtu FOB** (including maintenance)



- **Tellurian will retain ~12 mtpa and ~40% of the assets**
- **Estimated ~$2 billion annual cash flow to Tellurian(1)**

Note: (1) See slide 13 for levels of annual Tellurian cash flow at various assumed U.S. Gulf Coast netback prices and margins ($/mmBtu).

Driftwood Holdings' financing

	Full development	
Capacity (mtpa)	**27.6**	
Capital investment ($ billions)		
— Liquefaction terminal[1]	$ 15.2	
— Owners' cost[2]	$ 1.9	
— Driftwood pipeline[3]	$ 2.2	
— HGAP *(Haynesville & SCOOP/STACK)*	$ 1.4	
— PGAP *(Permian)*	$ 3.7	
— Upstream *(15 Tcf of Haynesville reserves)*	$ 2.2	
— Tellurian costs[4]	$ 0.9	
Total capital	**$ 27.5**	
— Debt financing[5]	$ (3.5)	
Net Partners' capital	**$ 24.0**	
Transaction price ($ per tonne)	**$1,500**	
Capacity split	**Mtpa**	**%**
— Partner	16.0	*58%*
— Tellurian	11.6	*42%*

Notes: (1) Based on engineering, procurement, and construction agreements executed with Bechtel.
(2) Approximately half of owners' costs represent contingency; the remaining amounts consist of cost estimates related to staffing prior to commissioning, estimated impact of inflation and foreign exchange rates, spare parts and other estimated costs.
(3) Represents the full length of Driftwood pipeline, including estimated compression requirement.
(4) Preliminary estimate of certain costs associated with potential management fee to be paid by Driftwood Holdings to Tellurian and certain transaction costs.
(5) Potential debt facilities to be borrowed by HGAP and PGAP, subject to third-party agreements of each pipeline, or by Driftwood Holdings.

Tellurian margin from retained capacity

	U.S. Gulf Coast netback price ($/mmBtu)		
	$6.00	**$10.00**	**$15.00**
Driftwood LNG, FOB U.S. Gulf Coast	$(3.00)	$(3.00)	$(3.00)
Margin ($/mmBtu)	3.00	7.00	12.00
Retained capacity (mtpa)	11.6	11.6	11.6
Annual Tellurian cash flow ($ millions)(1)	1,810	4,220	7,240

Notes: (1) Annual partner cash flow equals the margin multiplied by 52 mmBtu per tonne assuming full development.