SCA HW1 - CaLNG

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February 2026

1 Question 1: Optimal Contract Parameters

Using 5,000 simulated demand scenarios for each configuration, we evaluated combinations of total LNG purchased and peak pipeline intake. The optimal pair that minimises expected seasonal utility cost is:

- **Optimal total LNG purchased:** 900 MMcf
- **Optimal peak intake from pipeline:** 180 MMcf

This configuration yields the lowest expected total utility cost across all simulated scenarios.

2 Question 2: Cost Plots

Next, we plot the mean cost across 5,000 simulated seasons with a ± 1 standard deviation band.

2.1 Cost vs total LNG purchased (peak intake fixed at optimum)

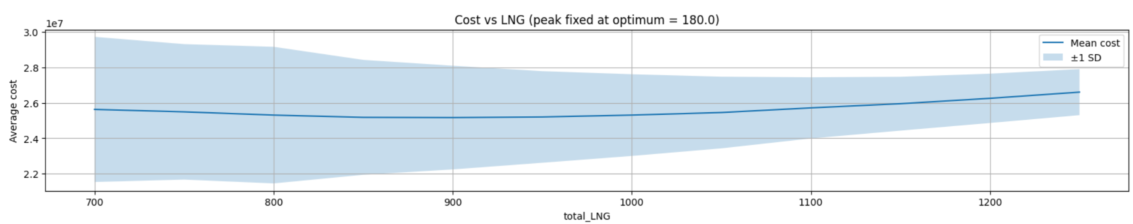

Figure 1: Average seasonal utility cost vs total LNG purchased, with peak pipeline intake fixed at its optimal value (180). Shaded band represents one standard deviation across 5,000 simulation draws.

2.2 Cost vs peak pipeline intake (total LNG fixed at optimum)

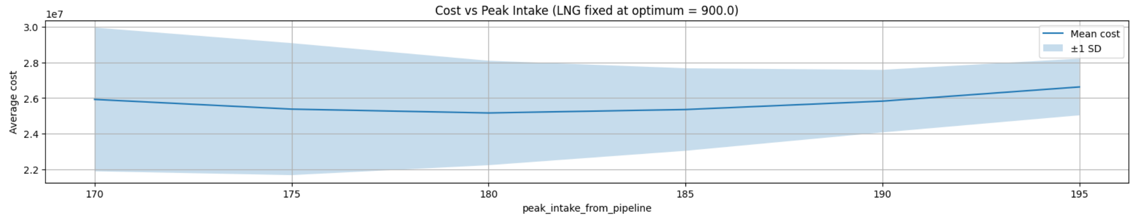

Figure 2: Average seasonal utility cost vs peak pipeline intake, with total LNG purchased fixed at its optimal value (900). Shaded band represents ± 1 standard deviation across 5,000 simulation draws.

3 Question 3: Take-or-Pay Contract Assessment

Based on the simulation results, it makes sense for a utility company to sign a take-or-pay contract with CaLNG.

Across 5,000 Monte Carlo demand simulations per scenario, the cost-minimizing contract occurs at a total LNG purchase of 900 MMcf and a peak pipeline intake of 180 MMcf. At this optimum, the expected seasonal utility cost is approximately \$25.18 million, representing an expected savings of approximately \$6.46 million relative to the pipeline-only baseline.

Although the take-or-pay structure requires the utility to pay for the full contracted LNG volume regardless of actual usage, the optimization still selects a substantial LNG commitment. This indicates that the avoided costs from high pipeline spot prices during peak-demand periods exceed the expected cost of unused LNG in lower-demand seasons.

The contract also reduces risk. Under a pipeline-only procurement strategy, the standard deviation of seasonal cost is approximately \$6.22 million, reflecting high exposure to demand spikes and the exponential pipeline price function. At the optimal take-or-pay contract, the standard deviation falls to approximately \$3.19 million, representing a reduction in cost variability of nearly 50%. By capping pipeline intake on high-demand days, LNG limits the impact of extreme price realizations and acts as an effective hedge against price volatility.

Therefore, for utilities facing uncertain demand and convex pipeline pricing, a take-or-pay contract with CaLNG is justified on both expected-cost and risk-reduction grounds.

4 Question 4: Supply Chain Design by Utility Size

In this model, the best supply chain setup depends on how often a utility is pushed into the steep part of the pipeline price curve, which happens when daily demand exceeds the peak pipeline intake limit.

For a utility with relatively limited peak exposure, most demand can be served through the pipeline at stable prices. In this case, the added cost and complexity of local LNG storage provide little benefit, and an on-demand supply structure is sufficient without meaningfully increasing cost or risk.

For a utility that experiences larger or more frequent demand spikes, local LNG storage or guaranteed LNG availability becomes more valuable. The simulation results show that using LNG to cap pipeline intake during high-demand periods lowers both expected seasonal cost and cost variability. Having LNG available in advance allows the utility to avoid the most expensive pipeline price outcomes.

Overall, within this analysis, utilities with greater exposure to peak-demand pricing benefit from supply chain structures that include local storage or assured LNG supply, while utilities with lower peak exposure can rely on on-demand delivery with minimal loss of efficiency.

5 Question 5: Risks Faced by CaLNG

Based on the analysis, CaLNG faces three main risks.

First, CaLNG is exposed to demand risk. The benefit of LNG in the model comes from covering peak-demand days. In lower-demand seasons, utilities may not fully use contracted LNG volumes, which weakens the appeal of take-or-pay style contracts.

Second, CaLNG faces risk when it comes to pricing. The value of LNG depends on the steep increase in pipeline prices at high intake levels. If pipeline pricing becomes less convex, the cost advantage of LNG during peak periods is reduced.

Third, CaLNG faces operational risk. The model assumes LNG is available whenever pipeline intake is capped. Any disruption to LNG availability during peak-demand periods would reduce its effectiveness as a substitute for regular pipeline gas.