Comstock Resources (CRK): Undrilled Value

April 27th, 2026

The market is pricing Comstock Resources as a leveraged commodity survivor, one bad quarter away from distress. However, in reality, CRK’s balance sheet is stronger than it seems on the surface and the company is the lowest-cost natural gas operator in the United States sitting on roughly 70 Tcf of drilling inventory directly in the path of the largest structural gas demand surge in American history. LNG exports, coal-to-gas switching, AI and data center load growth, and industrial reshoring are all hitting at once. When demand and supply imbalances allow for prices to increase CRK is the best positioned company in the country to take advantage of the situation, especially now that their stock is down 30% year to date.

This is a bet that the market has failed to value a 70 Tcf reserve inventory at anything beyond strip pricing at the exact moment structural demand is set to outstrip supply by a factor of three. Because gas prices are way lower than historically, the company is being priced on reserves they can actually extract profitably at this current price, but assuming prices go up, as they should given the imbalance of demand and supply, their PV10 reserves should skyrocket. CRK's cost structure lets it print cash at prices where its competitors struggle to break even, and the demand inflection makes those prices inevitable. The asymmetry is in the gap between what the reserves are worth on the strip and what they are worth in the world that is actually arriving.

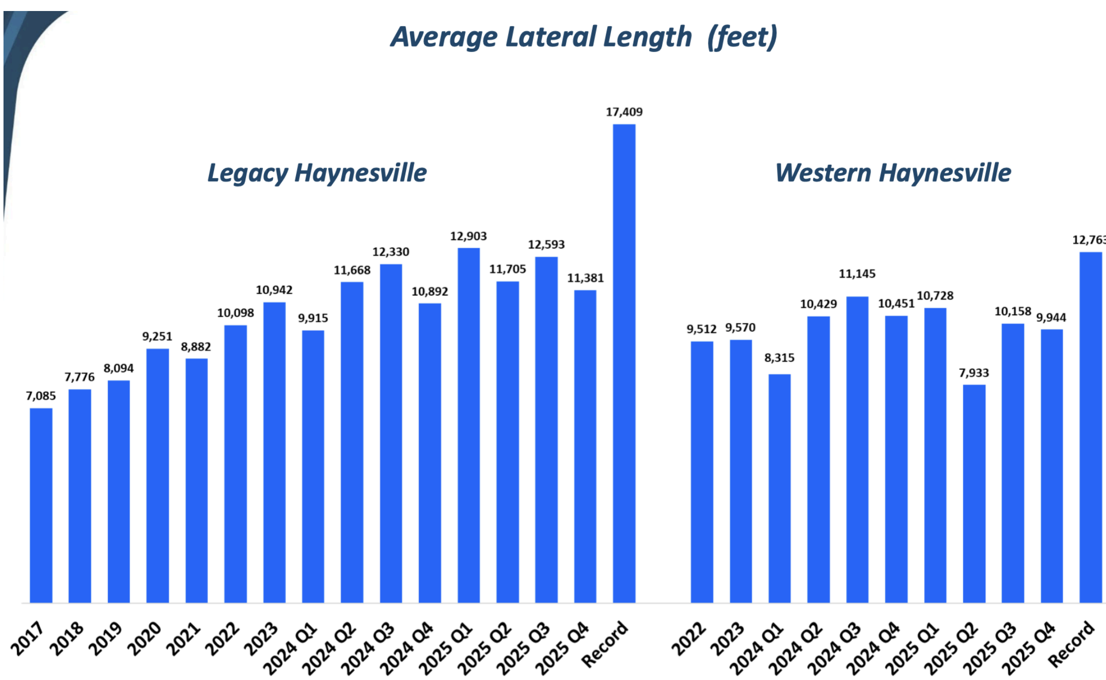
What Comstock Does

Comstock Resources is a(n) (almost) pure-play natural gas producer. The company drills and fracks horizontal wells across two contiguous regions of the Haynesville Shale, one in East Texas, the other in Northwest Louisiana, extracting dry gas (almost entirely methane, no oil, no liquids) from rock roughly two miles below the surface. Once the gas flows to the wellhead, it moves through gathering pipelines to processing facilities and then into the interstate pipeline system, where CRK sells it to utilities, industrial end-users, LNG export terminals along the Gulf Coast, and third-party marketers who resell into the broader market.

The Haynesville sits directly adjacent to the Gulf Coast LNG corridor, with delivery locations such as Sabine Pass, Cameron, Freeport, Plaquemines, and Golden Pass, which means CRK's molecules have the shortest possible journey from wellhead to export tanker. That proximity is one of the structural advantages that makes their cost position so low compared to other companies.

The Haynesville, the Marcellus, the Permian source rocks have hydrocarbons in enormous volumes, trapped in microscopic pores, but the rock does not let them move. So companies like Comstock Resources drill a conventional vertical well into shale and essentially nothing comes out. Fracking, high-pressure water and sand into shale rock to crack it open and hold the cracks propped so the trapped gas can flow out, paired with horizontal drilling, is the technique that solves this problem and it is what has made this whole operation possible in the first place.

The rig drills straight down 8,000 to 12,000 feet in the Haynesville, casing and cementing the wellbore to isolate it from groundwater above. At target depth, the bit curves from vertical to horizontal and drills laterally through the shale with modern Haynesville laterals running 10,000 to 15,000 feet, nearly three miles of pipe running lengthwise through a rock layer only 200 to 300 feet thick. Instead of piercing the reservoir at a point, you run a pipe through it.



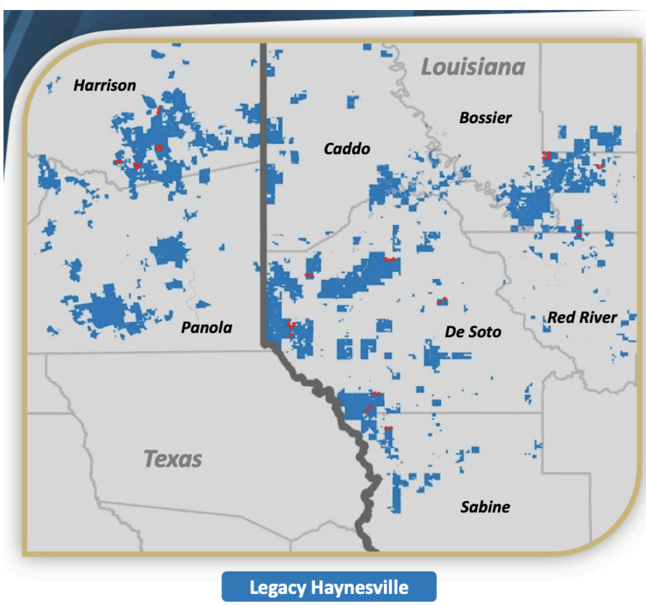
CRK holds about 1.07 million net acres across the Haynesville/Bossier play, making it the largest acreage position in the basin, roughly 520,000 in the legacy core (East Texas /

Northwest Louisiana) and another ~550,000 in the Western Haynesville extension they are currently delineating. Against a total productive Haynesville footprint of 3.5 to 4 million acres across all operators, that puts CRK at 25–30% of the productive play, the biggest in the region. CRK doesn't just have low costs on a few good wells, it has low costs across the largest contiguous position in the basin that sits closest to the Gulf Coast demand.

<u>Legacy Haynesville Operations</u>

This is CRK's bread-and-butter. 917 drilling locations in the core Haynesville Shale, spanning East Texas and Northwest Louisiana, with the acreage the company has been developing for years, with geology that is thoroughly understood and execution risk that is effectively priced out. Average EUR runs 13.95 Bcf per well. Multiply across the location count and the legacy position alone contributes roughly 12.8 Tcf of drilling inventory.

The production profile is steady rather than spectacular: ~1.2 Bcfe/d on a full-year 2025 average, with 47 wells to drill and 48 to sales in 2026. The legacy Haynesville is not the growth story — it is the cash flow engine that funds everything else. It cleans up the balance sheet. It pays for Western Haynesville appraisal and development. It is the reason CRK can afford to be patient on the pieces of the portfolio that actually compound.

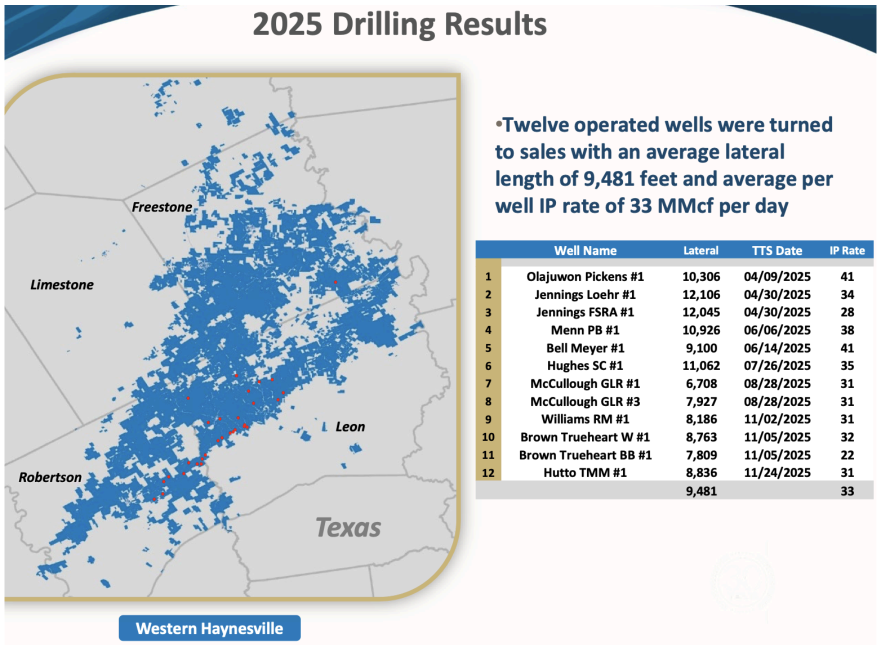


	Well Name	Lateral	TTS Date	IP Rate
1	CRK 19-18 #1	10,028	02/01/2025	24
2	CRK 19-18 #2	9,841	02/01/2025	26
3	Griffith 2-35-26 #1	14,931	02/14/2025	18
4	Griffith 2-35-26 #2	15,164	02/14/2025	24
5	Griffith 2-35-26 #3	14,634	02/14/2025	37
6	BSMC LA 4-9 #1	9,866	03/08/2025	24
7	BSMC LA 4-9-16 #3	14,861	03/15/2025	23
8	Sanders #1	17,409	03/19/2025	24
9	Blocker #2	13,374	03/19/2025	24
10	Harrison #3	11,976	03/20/2025	16
11	Harrison #4	9,252	03/20/2025	18
12	Legacy 10-3 #1	9,836	04/10/2025	25
13	Legacy 10-3 #2	9,602	04/10/2025	24
14	MLJ LLC 6-7 #1	9,776	05/14/2025	25
15	MLJ LLC 6-7 #2	9,691	05/14/2025	24
16	MLJ LLC 6-7 #3	9,578	05/14/2025	26
17	MLJ LLC 6-7 #4	9,821	05/14/2025	26
18	Cates 2-35 #1	9,673	06/09/2025	26
19	Cates 2-35 #2	9,510	06/09/2025	26
20	Talbert 30-31-6 #1	14,014	07/12/2025	29
21	Talbert 30-31-6 #2	15,023	07/12/2025	28
22	Owen GMB #2	14,806	09/11/2025	24
23	Thanos TA #1	14,662	09/11/2025	24
24	Owen GMB #1	15,190	09/11/2025	24
25	Roberts 26-23 HU #1	11,453	09/19/2025	26
26	Roberts 23-14 HC #1	9,923	09/19/2025	25
27	Nation 23-14 #1	9,895	09/20/2025	30
28	Nation 23-14 #2	9,931	09/20/2025	30
29	Sustainable Forests 25 #1	4,968	11/21/2025	22
30	Sustainable Forests 25 HU #2	9,537	11/21/2025	33
31	Lawson 26-35 #1	7,613	12/13/2025	26
32	Lawson 26-35-2 #1	15,466	12/13/2025	37
33	Blocker Gill #1	13,321	12/22/2025	22
34	Blocker Gill #2	13,096	12/22/2025	19
35	Blocker Gill #3	13,093	12/22/2025	20
		11,738		25

<u>Western Haynesville Operations</u>

This is CRK's next big bet for the future. Western Haynesville has around ~535,000 acres in Central-East Texas, a geological extension of the Haynesville into deeper, hotter, higher-pressure rock that was effectively unexplored five years ago. Management now estimates 99 Tcf of resource potential across the play, with 2,559 net well locations and a per-well EUR of 22-32 Bcf, significantly above the core legacy wells. On a drilling inventory basis, the Western Haynesville alone contributes 57 Tcf, most of the bulk of the 70 Tcf total projected.

The horseshoe well design is expected to cut lateral costs by roughly 35%, pushing new Western Haynesville wells costs toward $1.60–$1.70/Mcf all-in. At the corporate level, CRK replaced 229% of 2025 production through drilling at a finding cost of $1.02/Mcfe



	Well Name	Lateral	TTS Date	IP Rate
1	Olajuwon Pickens #1	10,306	04/09/2025	41
2	Jennings Loehr #1	12,106	04/30/2025	34
3	Jennings FSRA #1	12,045	04/30/2025	28
4	Menn PB #1	10,926	06/06/2025	38
5	Bell Meyer #1	9,100	06/14/2025	41
6	Hughes SC #1	11,062	07/26/2025	35
7	McCullough GLR #1	6,708	08/28/2025	31
8	McCullough GLR #3	7,927	08/28/2025	31
9	Williams RM #1	8,186	11/02/2025	31
10	Brown Trueheart W #1	8,763	11/05/2025	32
11	Brown Trueheart BB #1	7,809	11/05/2025	22
12	Hutto TMM #1	8,836	11/24/2025	31
		9,481		33

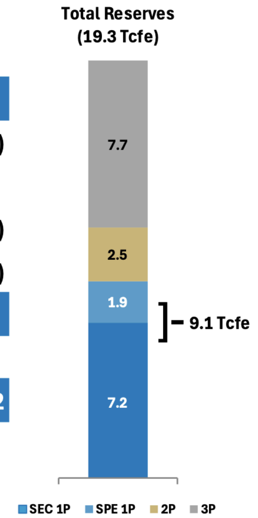
A 229% reserve replacement ratio means that for every 1 Bcfe CRK produced in 2025, they added 2.29 Bcfe of new proved reserves. CRK produced ~450 Bcf of gas and added roughly 1.03 Tcfe back, more than doubling what they depleted. However, the most exciting part is that they did all of that through drilling, not through acquisition, meaning the reserve growth came from their own operational execution rather than financial engineering.

CRK spent roughly $1.05 billion of drilling capex to add 1.03 Tcfe of reserves, every thousand cubic feet equivalent cost about a dollar to put on the balance sheet. For context, Haynesville peer finding costs typically run $1.20–$1.50/Mcfe and some struggle to stay under $2.00. On a delivered-cost basis, CRK at $1.02 is elite.

This is where the market's framing breaks down most visibly. The Western Haynesville is treated as speculative, an unproven extension of a known play, priced accordingly. The operational data says otherwise. A 99 Tcf inventory management estimate, a 229% reserve replacement ratio, and a finding cost that sits below $1.10/Mcfe do not describe a speculative asset, this is an asset that is being systematically de-risked, well by well, at a pace the market has not caught up to.

- **Spent $1,055 million in 2025 to add 1 Tcfe of Proved Reserves achieving all in finding costs of $1.02 per Mcfe.**
- **Replaced 229% of 2025 production.**

	Bcfe
Proved Reserves as of 12/31/24	**7,023**
Production	(450)
Drilling Additions	1,069
Revisions	(39)
Divestitures	(419)
Proved Reserves as of 12/31/25	**7,184**
PV 10 Value (billion $) at NYMEX Gas Price	**$5.2**



A Gas Moat

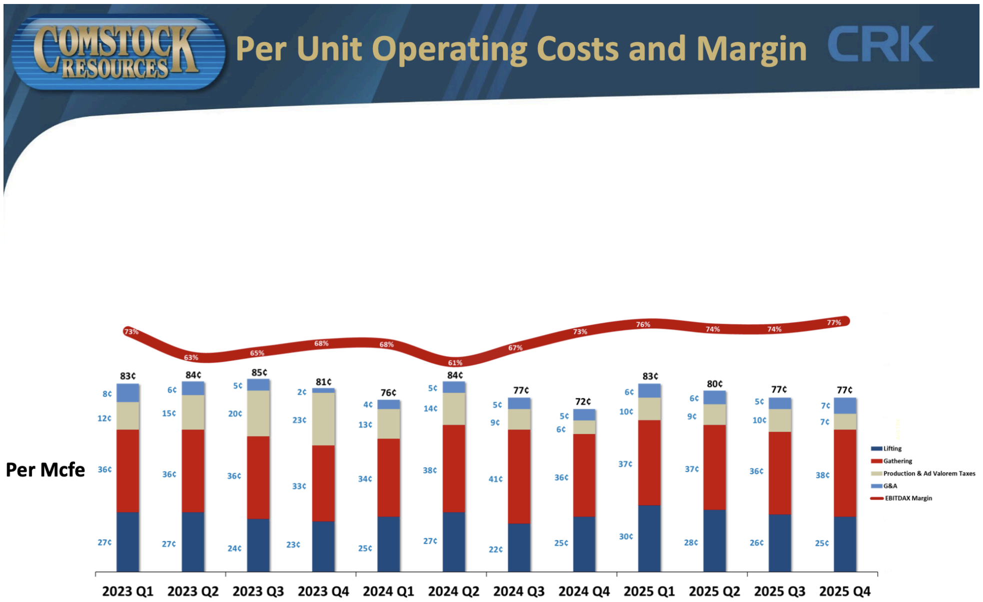
The Moat

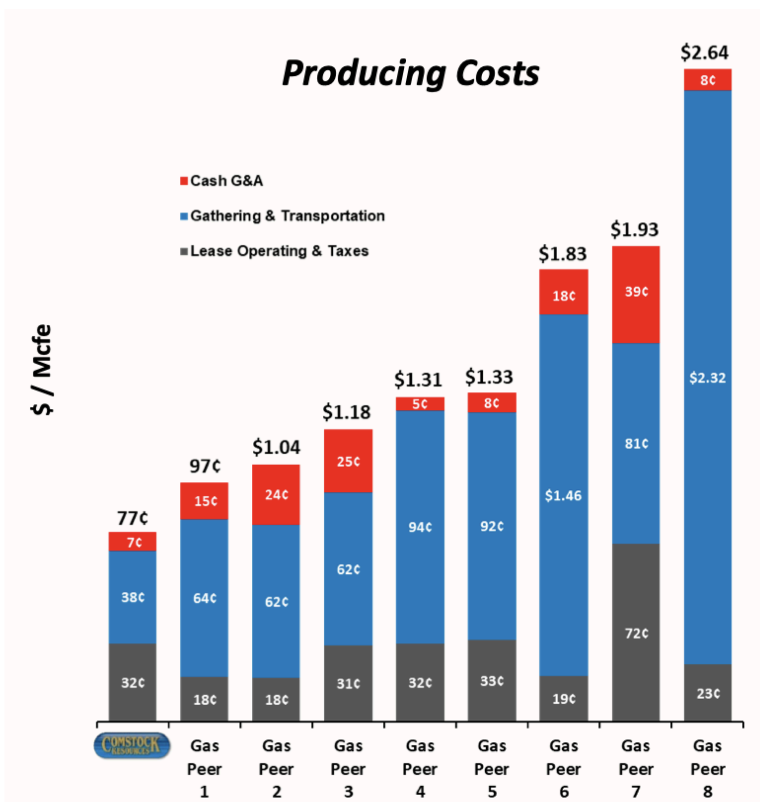
An E&P company does not have a brand moat, a network effect, or switching costs, natural gas is a commodity. So when trying to understand whether an E&P producer has a moat the question is not “does it have pricing power” like a consumer-facing company would, the question becomes “can this company produce at a cost its competitors cannot match, at a scale that matters, in a location that captures the demand?” For CRK, the answer on all three is yes and the three reinforce each other.

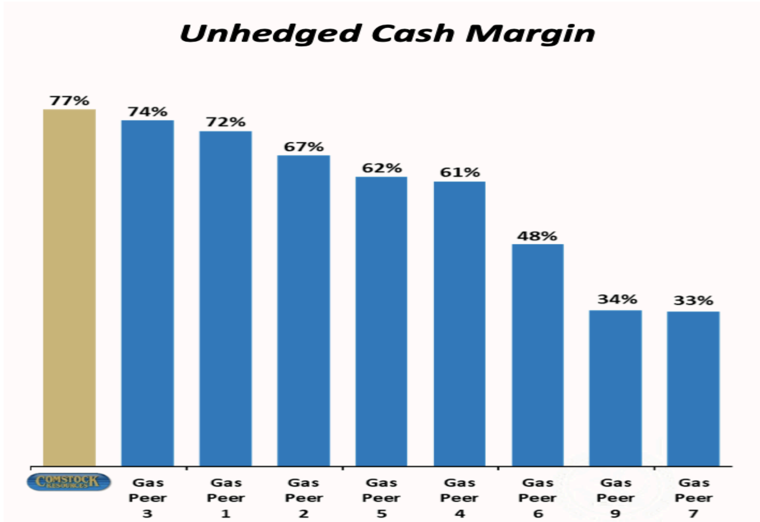
<u>Pillar one: the cost structure</u>

CRK's all-in cost is $1.87/Mcf. That figure breaks down into operating cost of $0.85/Mcf — lease operating expense ($0.26), gathering ($0.36), taxes ($0.17), G&A ($0.06) — plus blended development cost of $1.02/Mcf across the legacy and Western Haynesville acreage. At $5 gas, CRK earns a $3.13/Mcf pre-tax margin. At $4 gas, $2.13. At $3 gas, still $1.13 — which means CRK makes money at price points where meaningful slices of the industry are drilling at a loss or shutting rigs in. The company is structurally profitable in environments that force its competitors to retrench.

That cost position is not replicable by writing a check. It is a function of geology (the Haynesville is thick, high-pressure, and gas-saturated — the rock does more of the work), acreage quality (the best cores of the basin were consolidated years ago), and execution (hundreds of wells drilled, the recipe optimized). The horseshoe well design — a U-shaped lateral that lets a single surface location drain two sections of acreage — takes another 35% off lateral costs and pushes new Western Haynesville wells toward $1.60–$1.70/Mcf all-in. The cost structure is not static; it is still compressing.

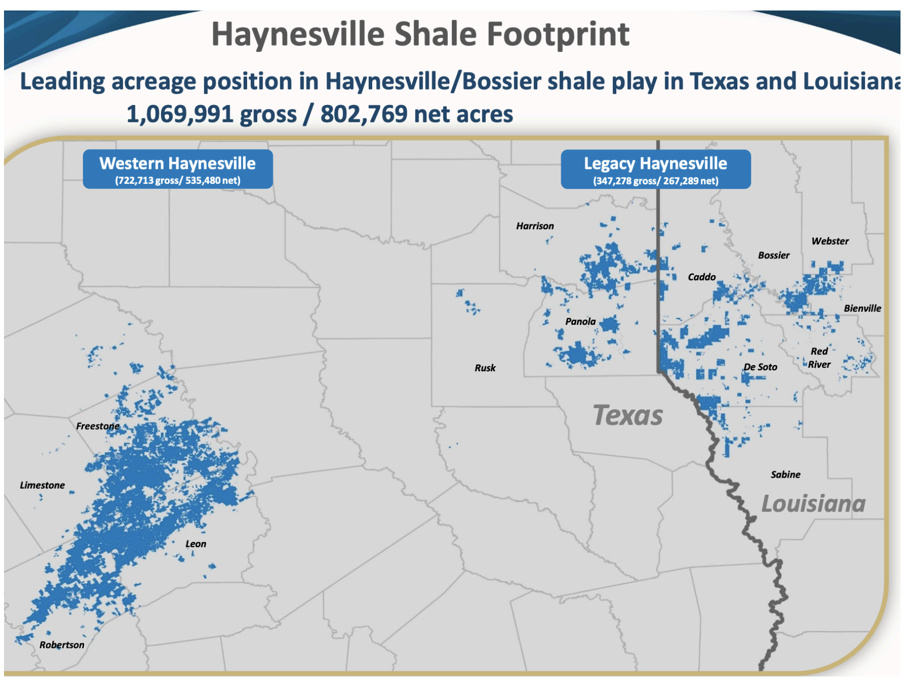


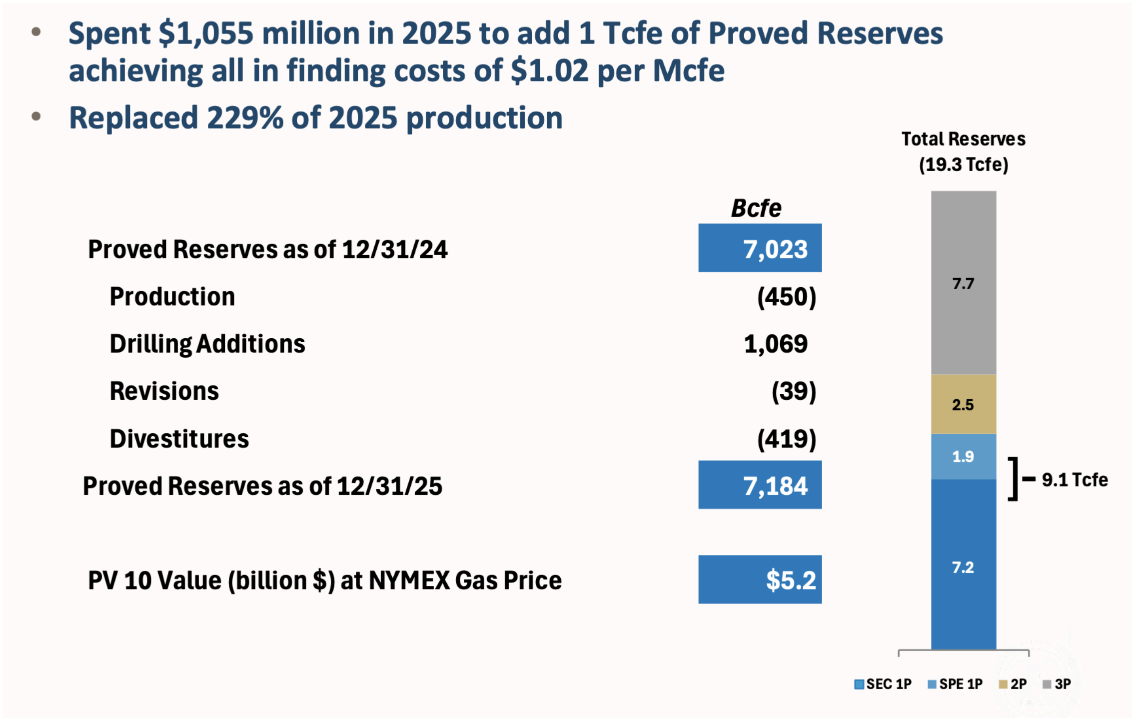




Pillar two: reserves and acreage at scale

As mentioned before, CRK holds ~1.07 million net acres, around 25–30% of the productive Haynesville, making it the single largest holder in the basin. What matters for unit economics and for their moat is that scale turns a per-well advantage into a durable one, as a competitor could match CRK on one well, but no competitor can match it for fifteen-plus years of drilling inventory at the same cost structure. That runway is what lets the cost advantage compound rather than get arbitraged away after only a few years of drilling, and Comstock's inventory allows them to explore gas for a cheap price for many years to come.





The acreage isn't just large, it's good. Management estimates 99 Tcf of resource across the Western Haynesville alone, with 2,559 net drilling locations and per-well EURs tracking toward 22–32 Bcf, a 40–100% uplift over the legacy basin average of 16 Bcf. The rock is thicker, more pressured, and more gas-saturated than anywhere else in the play, which means every well drains more gas for the same dollar of development cost.

A large, productive position still has to be converted into economic reserves, and this is where the story closes the loop. CRK replaced 229% of 2025 production through drilling at a finding cost of $1.02/Mcfe, adding 2.29 Bcfe back for every 1 Bcfe produced, at roughly a dollar per thousand cubic feet. This expansion of productive reserves is the signature of an E&P that is at the top of the operational game that could drill at this pace for decades without degrading the inventory.

But here is the part that matters most for valuation: that 99 Tcf figure does not appear on CRK's financial statements. On the proved reserve line of the 10-K, investors see 7.0 Tcfe. The gap between those two numbers is undisclosed gas, and understanding why requires understanding how the SEC forces E&Ps to report reserves.

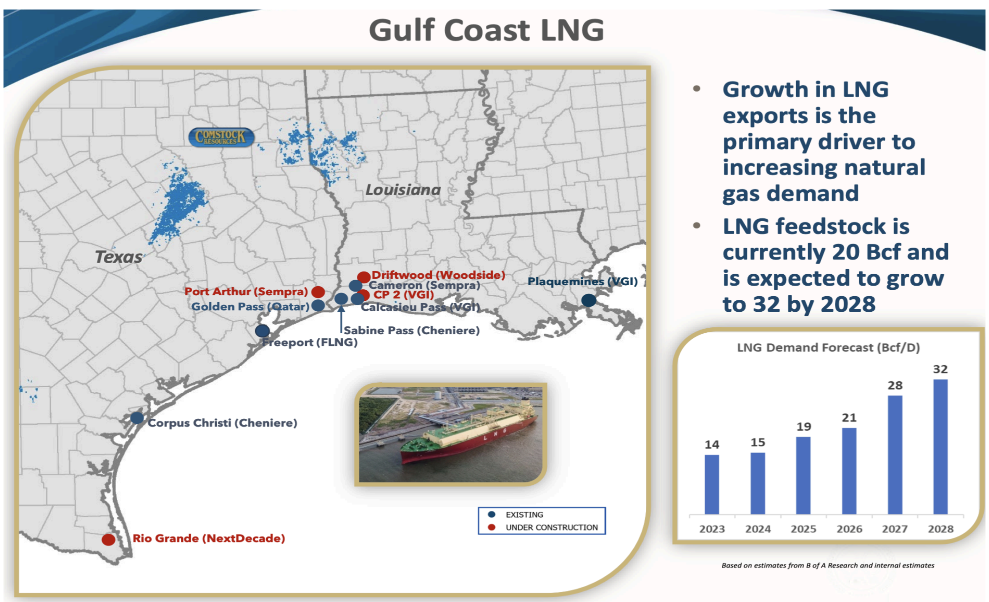
Under SEC rules a company can only book "proved reserves" that meet a narrow legal test. The resource must be recoverable with "reasonable certainty" using existing technology, developed within five years, an economic at a trailing 12-month average commodity price. If gas is averaging $3/Mcf on the SEC's trailing benchmark and a well needs $3.25/Mcf to break even, the gas stays in the ground on paper, regardless of whether it physically exists or whether management knows it will eventually be produced at higher prices.

Gas prices rise and as drilling progresses, the accounting framework starts to catch up with the geology. Proved reserves migrate from "contingent" to "proved" as more wells get drilled (which proves up surrounding acreage), and higher prices lower the economic threshold for which resources qualify.

This is already happening, as we saw in the Q4 2025 release already showed a PV-10 lift to $7.0 Tcfe from the prior year's 6.0 Tcfe, entirely through drilling and price revisions, before the LNG and data center demand wave meaningfully hits realized prices. As prices rise, as we will discuss soon, their Tcf will skyrocket alongside their balance sheet.

Pillar three: proximity to the demand

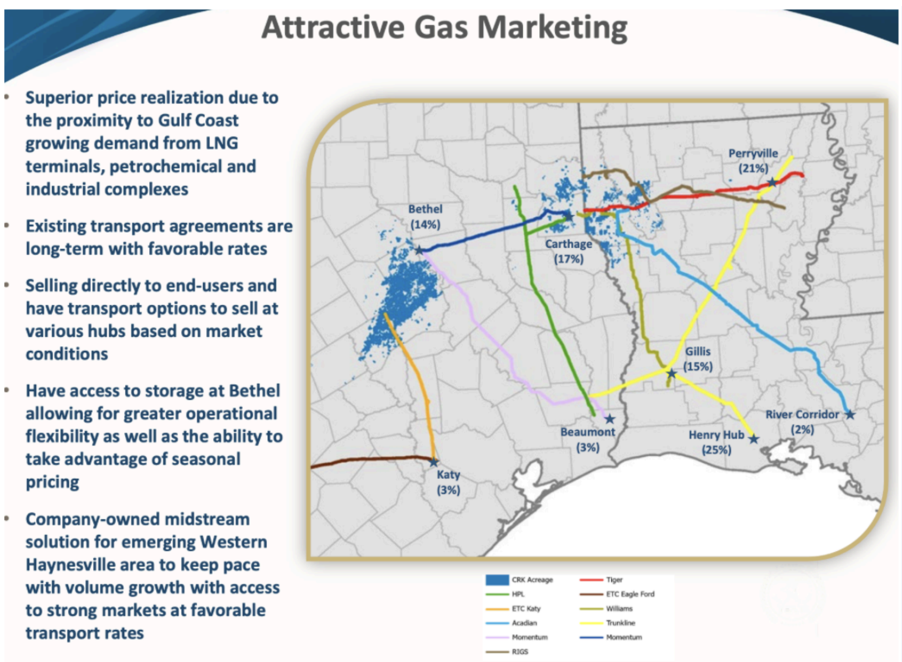
CRK sits in the one basin in America where the cost structure, the reserve base, and the demand geography all align. The Haynesville is roughly 200 miles from the Gulf Coast LNG corridor, compared to Appalachia's far larger reserve base sits 1,200+ miles away and pays $0.80+/Mcf to get there, while Permian gas is a byproduct of oil drilling with no ability to match gas demand. CRK’s proximity to the midstream system of gas distribution and geographical location compared to the Coast allow the company to have a great competitive advantage.



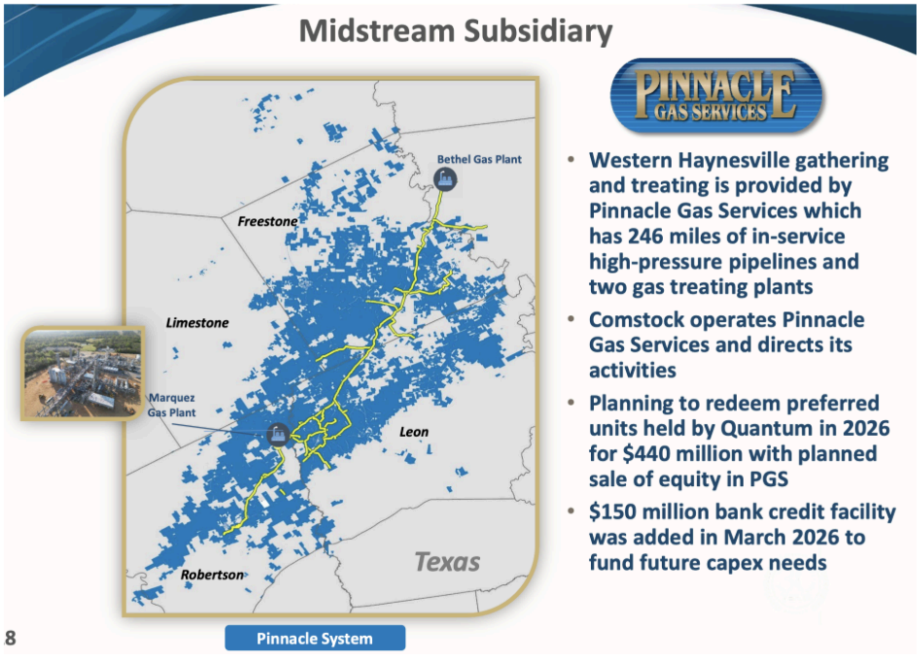
The strongest single demand driver for U.S. natural gas over the next five years is Gulf Coast LNG export capacity, and CRK sits directly in its path. LNG gas demand was 20 Bcf/d in 2025 and is projected to grow to 32 Bcf/d by 2028, driven by a series of terminals going online. Every one of those terminals sits on the Texas or Louisiana Gulf Coast, within a few hundred miles of CRK's acreage. Appalachian producers have lower wellhead costs but pay $0.80+/Mcf to move gas to the Gulf while CRK's molecules travel the shortest path to the largest demand source in American energy, and the proximity shows up directly in realized prices. In Q4 2025, CRK's basis differential to Henry Hub, the price gap between a regional hub and the national benchmark, was just $0.26 compared to Appalachian hubs that trade at structural $0.50–1.00

discounts because Comstock has an easier way of reaching the trade hubs. This is a structural cost advantage that non-Haneysville players will likely never have, and with Comstock being the largest producer there, they will benefit the most.

The company currently sells into seven major regional hubs, Henry Hub (25%), Perryville (21%), Carthage (17%), Gillis (15%), Bethel (14%), with smaller volumes at Katy, Beaumont, and River Corridor. CRK can route volumes to wherever pricing is most attractive on a given day, take advantage of seasonal Bethel storage (waiting for winter prices for higher margins if necessary), and sell directly to end-users rather than through intermediary marketers. On any given day, Carthage might trade at a $0.10 premium to Henry Hub while Perryville trades at a $0.15 discount. CRK's transport flexibility across seven hubs means they can nominate volumes to wherever netback is highest, capturing arbitrage that single-hub producers cannot. The moat is having the pipeline and contract architecture to monetize that proximity.



The pure-play E&P model is to produce gas and hand it off to a third-party midstream company at the wellhead, paying gathering and treating fees that show up as a cost line. CRK has vertically integrated into midstream through Pinnacle Gas Services, a company-owned subsidiary operating 246 miles of high-pressure pipelines and two gas treating plants (Bethel and Marquez) across the Western Haynesville footprint. Every Mcf CRK produces in the play is gathered and treated on CRK-owned infrastructure, which means the $0.36/Mcf gathering line in the cost stack is going to a subsidiary rather than a third-party tariff, further improving their cost advantage.



Finally, NextEra Energy selected Western Haynesville as the site for a $16 billion, 5.2 GW natural gas-fired power generation hub in Anderson County, Texas, a project selected by the US Department of Commerce as a strategic infrastructure priority. The facility will serve as a data center and advanced manufacturing load, drawing up to 1 Bcf/d of CRK gas by 2031, fed directly through Pinnacle's system and CRK's Bethel transmission infrastructure. This is the pinnacle of what the proximity argument enables, a 1 Bcf/d end-user, built physically on top of the reserve base, sourcing gas through CRK-owned midstream, with no third-party intermediation and no delivered-cost competition from Appalachia or the Permian.

The market prices CRK as a commodity producer facing strip pricing. The reality is a company with anchor end-user demand being built on top of its acreage.

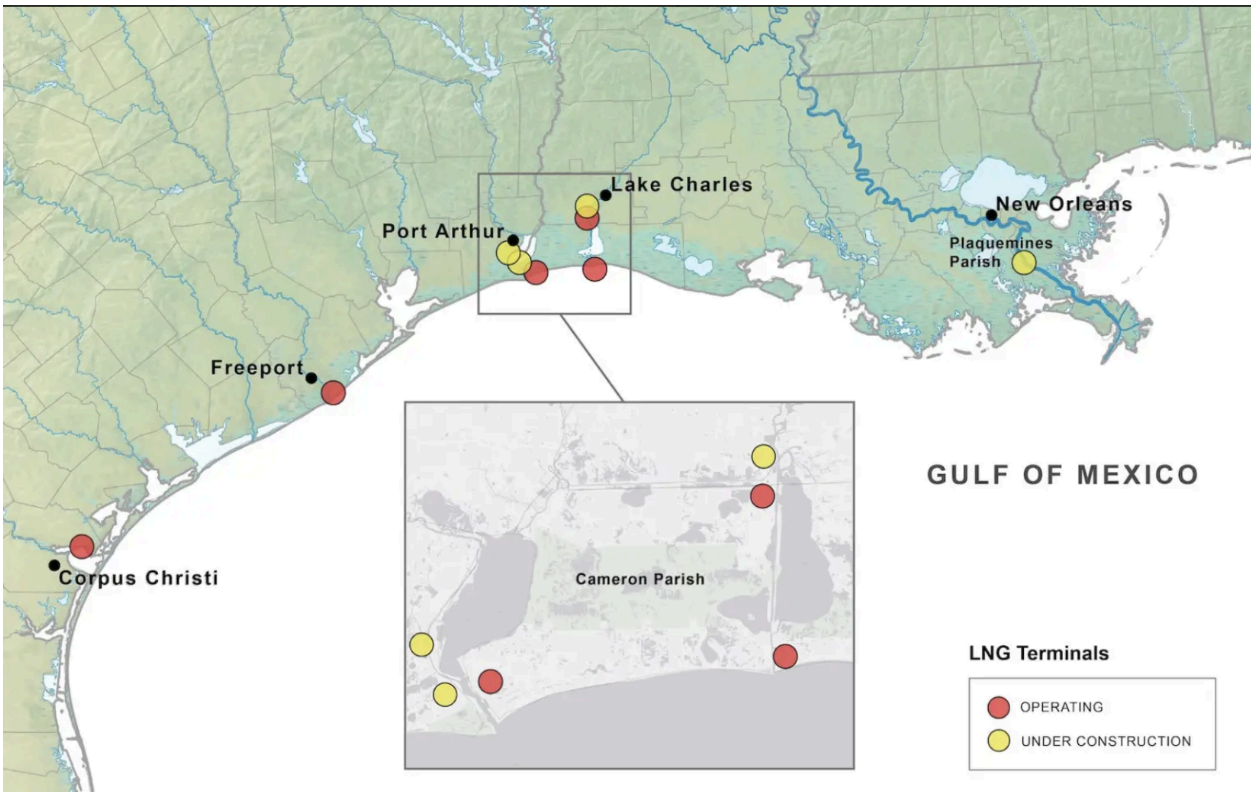
Each pillar alone would be valuable. Together they compound. Low cost gives CRK the margin to survive any price environment, scale turns that survival into fifteen-plus years of compounding drilling opportunities and proximity ensures those molecules get captured by the demand wave at the lowest delivered cost in the industry. The moat is that every structural force driving natural gas demand on U.S. natural gas over the next decade arrives at CRK's doorstep first and at the lowest marginal cost.

Demand and Supply imbalance

Demand Boost from multiple sources

<u>LNG buildout</u>

The U.S. LNG export complex is in the middle of the largest demand buildout in North American gas history. Peak export capacity exited 2025 at 17–18 Bcf/d and is on track to cross 19+ Bcf/d during 2026, with EIA projecting exports to grow another ~30% by 2027. The centerpiece is Golden Pass LNG, which achieved first production from Train 1 on March 30, 2026; Train 1 alone will ramp to ~800–850 MMcf/d of feedgas in Q2 2026, and Trains 2 and 3 follow in 2027. Full-year operations at Plaquemines and the ramp of Corpus Christi Stage 3 layer on another ~2+ Bcf/d of pull. Critically, this is already contracted under 15–20 year take-or-pay agreements, financed, and physically under construction. This type of contract means that demand will be pulled regardless of spot Henry Hub sentiment.



* 2023 image

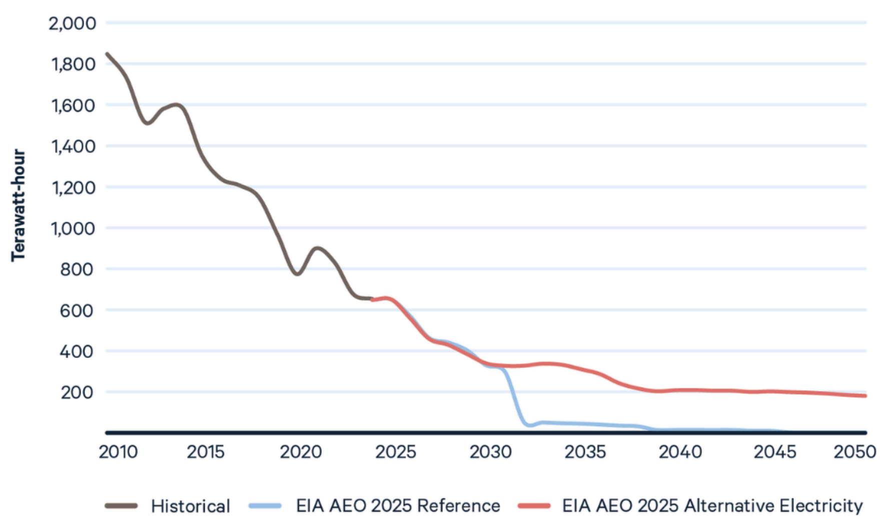
For CRK specifically, this is a geographic and geological coincidence that is very hard to replicate. The Haynesville sits in the backyard of every major Gulf Coast liquefaction facility, making its gas the cheapest molecule physically capable of reaching the LNG corridor, a premium already visible in Gulf Coast basis and in real-time flows being redirected out of Transco and Tennessee Gas into Golden Pass. As the largest pure-play Haynesville operator, CRK is the cleanest public-equity expression of that structural pull, with infrastructure and acreage quality both sized to deliver into it.

By 2029, U.S. export capacity is expected to nearly double and other projections are translating this growth to roughly 10–13 Bcf/d of new demand over the next five years.

Coal transition

The U.S. Energy Information Administration's Annual Energy Outlook 2025 projects electricity generation from coal will decline almost 50% from 2024 levels by 2030, and 93% by 2035. YEs, it is this crazy of a decline. The U.S. coal fleet is in structural decline, but the pace and direction of that retirement curve is being completely reshaped by data-center load growth. EPA's power-plant rule reinforces the trajectory, with plants committing to retire by 2032 facing no new requirements, those committing to 2039 must cut emissions 16% by 2032, and anything past that requires 90%-capture of emitted carbon, which is economically untenable for most of the fleet. Utilities have postponed 15 already-announced coal retirements, and the Department of Energy issued multiple emergency declarations in 2025 halting the retirement of eight coal units totaling more than 17 GW, showing an interesting contrast between the necessity of increasing energy supply and the interest in shutting down coal-sourced energy plants. But even at a slower retirement cadence, every megawatt that does come offline, and regardless of new energy demand they still are coming offline, must be backfilled and this is a great opportunity for gas.

Figure 1. Projections of US Coal-Fired Electricity Generation Through 2050



Using a conservative 150 MMcf/d of incremental gas demand per 1 GW of retired coal, the 3.0–5.2 GW of expected 2026 retirements alone translates to 200–400 MMcf/d of new structural gas burn. To build this substitution path, more than 100 GW of new gas-fired generation has been announced in the last few years, most online before 2030, and 55–65 GW of new grid-scale gas capacity is now expected in the U.S. from 2025 to 2030. Assuming that around 69 GW of coal capacity will be retired by 2030 and given the rule of thumb of 0.15 Bcf/d of new gas demand, that's roughly 10 Bcf/d of new power-sector demand by 2030

<u>AI and Data Center Power</u>

Data centers consume enormous amounts of energy because they are effectively industrial-scale computing factories that run 24/7 and have been fundamentally reshaped by AI.

A single modern AI training chip (like an NVIDIA H100) draws around 700 watts, and hyperscalers now pack them into racks that pull 40–100+ kilowatts each, ten to twenty times the density of a traditional enterprise rack. Training a frontier large language model can require tens of thousands of these chips running in parallel for weeks, and once deployed, AI inference workloads keep the chips busy around the clock rather than idling between tasks. On top of the compute itself, every watt used by a chip generates heat that has to be removed, so roughly 30–40% of a data center's total power goes to cooling, humidity control, and power conditioning. Multiply that by campuses that now exceed 500 MW, with single sites approaching 1 GW, the scale of a nuclear reactor, and it becomes clear why a handful of AI data centers can move the needle on an entire state's electricity demand, and why reliable, dispatchable gas-fired power has become the default way to feed them.

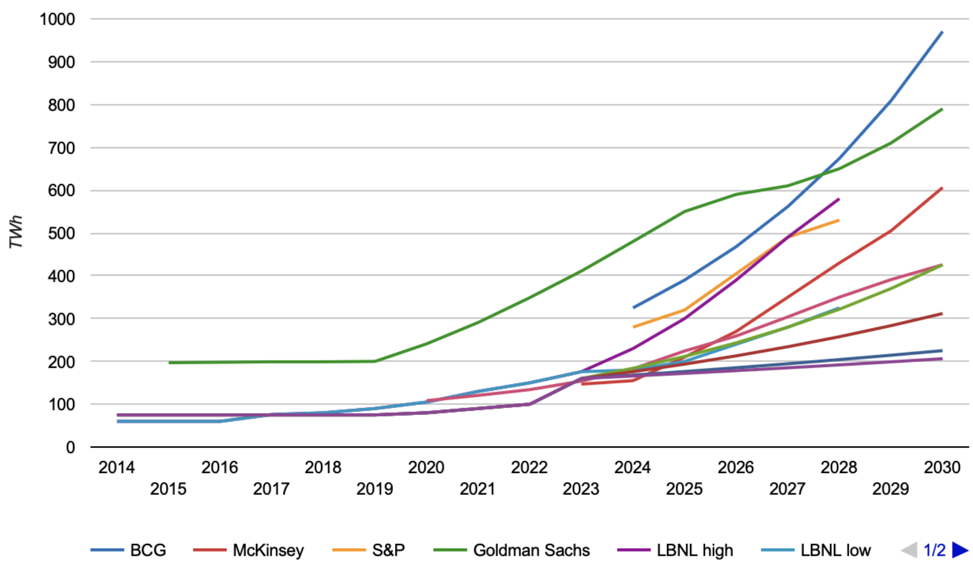
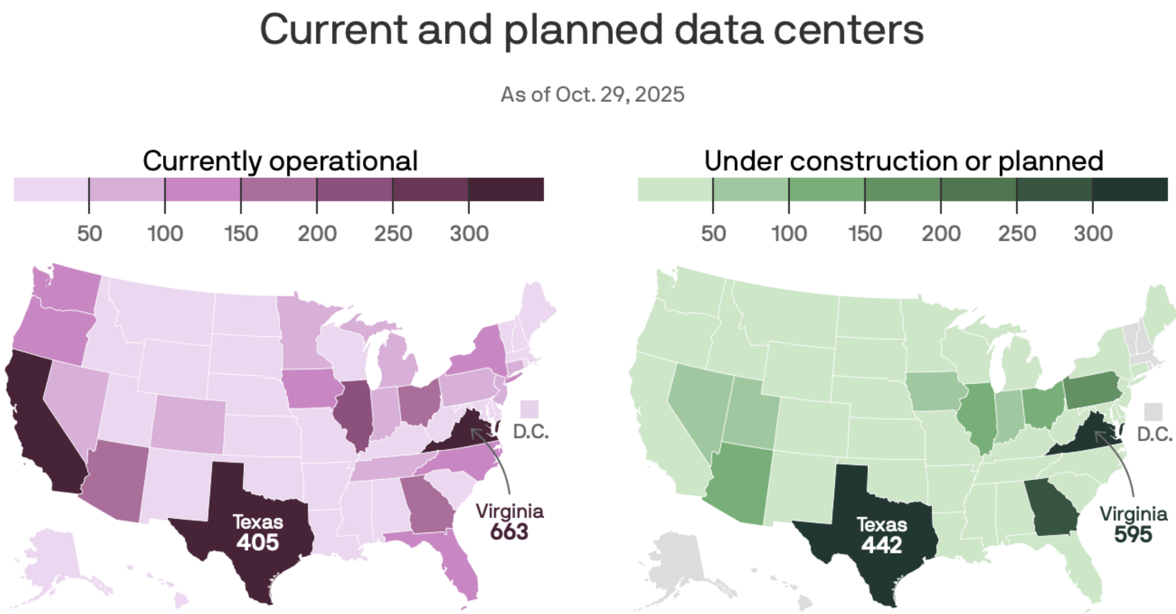


Figure 1: US Centers Electricity Consumption by Different Sources 2014-2030

As discussed earlier, the Power Generation Hub announced in March 2026 is the clearest expression of this strategy as a growth tailwind for Comstock. This is a $16 billion, up-to-5.2 GW gas-fired facility developed with NextEra Energy, with Comstock supplying feedgas that ramps toward nearly 1 Bcf/d by 2031. CRK has locked in a direct, contracted path from the wellhead to large-load customers (data centers and advanced manufacturing), bypassing the wholesale pipeline grid and the basis volatility that comes with it. Beyond this massive project, Texas is now one of the fastest-growing data-center markets in the U.S., with 405 currently operational and another 442 under construction or planned, nearly matching Virginia's build pipeline and putting CRK's Western Haynesville acreage right next to the center of demand.Very few U.S. gas producers have that kind of structural placement into the single fastest-growing source of domestic power demand.



Beyond that, the Transco and Tennessee Gas reach the Mid-Atlantic and Northeast regions, allowing them to sell gas to the data centers in Virginia, the Southern Natural Gas serves Georgia and the Carolinas, serving the growing data center hub near Atlanta, and westbound capacity connects to Texas and Midwest load, serving Texas, as mentioned before. They're in a prime position to capture this growth in Texas but also around the country.

Running the math on the latest data center forecasts confirms the gas pull is bigger than the market consensus. McKinsey now pegs U.S. data center capacity growth at 70–80 GW by 2030, BCG sees 60–90 GW over 2023–2030 plus an 80 GW gap between reliable round-the-clock generation and what's needed. A modern combined-cycle gas plant running at high utilization burns roughly 0.15 Bcf/d per 1 GW of capacity.

Taking the middle of that forecast range, about 80 GW of new data center capacity by 2030, with roughly 60% backfilled by gas works out to 7 Bcf/d of incremental gas demand by 2030. A low case (60 GW, 50% gas) lands at 4.5 Bcf/d, a high case (90 GW, 70% gas) at 9.5 Bcf/d, and Goldman's 1,350 TWh global forecast implies gas pull in the 10–12 Bcf/d range. Net-net, the recent data center numbers point to 6–10 Bcf/d of incremental gas demand by 2030.

The Supply Side: Why It Can't Keep Up

<u>Competitors' drilling guidance</u>

The most telling evidence that supply will stay tight is in the 2026 guidance decks the four largest U.S. gas producers have just put in front of investors. Combined, EQT, Expand Energy, Coterra, and Antero account for roughly a quarter of all U.S. gas production, and none of them are responding to higher prices by stepping hard on the accelerator. Taken together, their 2026 plans imply combined year-over-year growth of only about 1.0–1.5 Bcf/d across the four companies, a fraction of what the LNG and data-center demand curve needs.

EQT is the largest pure-play gas producer in the country, and its 2026 guidance is the clearest signal of how restrained the industry has become. The company expects total 2026 sales volume of 2,275–2,375 Bcfe, which works out to roughly 6.25–6.50 Bcfe/d on an average basis, effectively flat-to-modestly-up versus 2025. Growth capex is just $580–$640 million, and the 2026 program calls for turning in line only 125–150 net wells. Crucially, most of EQT's strategic spend is going into infrastructure rather than new drilling, meaning that the country's biggest gas producer is prioritizing debottlenecking existing molecules over aggressive new-well growth.

Expand Energy, the product of the 2024 Chesapeake-Southwestern merger, is the country's other true gas giant, and its 2026 outlook leans just as heavily on discipline. The company guides to roughly 7.5 Bcfe/d of production in 2026 on about $2.85 billion of capex, with Haynesville volumes explicitly "maintained at fourth-quarter 2025 levels", with little change from prior production. Management has framed 2026 as a year to "deliver higher volumes with less capital" and to "grow free cash flow," not a year to flood the market with incredibly high capex expenses. Notably, Expand did build roughly 300 MMcf/d of Haynesville productive capacity in the back half of 2025 by running up to 15 rigs, but that capacity is being held as a buffer, not released, which is precisely the behavior you see when operators expect prices to move higher, which means that supply should stay constrained until further notice.

Coterra'2026 guidance frames natural gas production at 2,775–2,975 MMcf/d, roughly 2.8–3.0 Bcf/d, on a total capex of $2.175–$2.325 billion, meaning production will be actually flat-to-slightly-down year-over-year, even though capex is ticking up from roughly $2.0 billion in 2025. In other words, Coterra is spending ~10% more capital to produce essentially the same amount of gas, which is the clearest possible signal that incremental barrels are getting more expensive and that management sees no reason to chase volume growth at today's strip. It reinforces the "prudent patience" framing that higher spending is going to sustain production and fund Permian activity, not to add meaningful gas supply to the market. The striking number is that about 68% of their capex is going to the Permian, with only 16% dedicated to the Marcellus, and as explained before Permian gas is largely connected to oil E&P. If oil prices drop, as the EIA predicts, this Permian production could flatten and actually not materialize into actual natural gas supply increases.

Antero is the most growth-oriented of the big four, largely because of its 2025 acquisition of HG Energy, which added scale and dry-gas exposure. Full-year 2026 production is guided to roughly 4.1 Bcfe/d, which translates to 0.3–0.4 Bcfe/d of year-over-year growth, meaningful for a single operator but tiny against a demand backdrop measured in tens of Bcf/d.

<u>Rig Count Dynamics</u>

The clearest evidence that supply isn't catching up lives in the rig count itself, as Haynesville rig count peaked at 75 active rigs in late 2022, when Henry Hub was running above $6/MMBtu and producers were racing to grow but as of mid-February 2026, the basin has only 52 gas-directed rigs working, roughly 30% below the 2022 peak, even with gas prices recovering to a forecast $4.31/MMBtu for 2026 versus $3.52/MMBtu in 2025.

The reason is a cultural shift across the industry toward capital discipline and Comstock Resources offers a clean illustration of what that looks like in practice. For 2026, CRK is budgeting roughly $1.4–$1.5 billion in D&C capex plus another $100–$150 million for Western Haynesville midstream, and plans to run just nine rigs as well as selling half of them. Management's stated priorities are reducing Western Haynesville drilling costs by about $300 per lateral foot and rebuilding production efficiently rather than chasing volume at any cost. After drilling 52 operated wells in 2025, the 2026 program is a measured ramp, not a land grab. That mindset is broadly shared across the basin's major operators, which is why the rig fleet isn't snapping back even as the price deck improves.

<u>The Supply Response Lag: 12–24 Months the Market Doesn't Have</u>

Even if every Haynesville operator decided tomorrow to aggressively grow, the physics of shale development imposes a long lag before new production actually reaches the market. Permitting, pad construction, drilling, completion, and tie-in to takeaway infrastructure typically consume 12 to 24 months from the initial capital decision to first production. The EIA's own modeling reflects this as even with higher prices baked in, the agency forecasts Haynesville production to grow just 1.2 Bcf/d in 2026 and 1.6 Bcf/d in 2027 even though forecasts for gas prices are overwhelmingly upwards facing. Those are meaningful gains, but they are paced against an incremental demand ramp from LNG export trains and AI-driven data center power loads that are arriving right now so the timing mismatch represents a demand inflections hit on a six-to-twelve month horizon, while supply inflections take two to three times as long to materialize. This gap will force prices higher until supply can catch up.

In previous cycles, the market had a shock absorber for exactly this kind of gap. DUCs, drilled but uncompleted wells, where the vertical and horizontal drilling is done, but the fracking (completion) hasn't happened yet, which can be brought online in weeks rather than years because the most expensive part (drilling) is already done. That buffer has essentially been exhausted, and according to the EIA's Drilling Productivity Report, total DUC inventory across all seven major U.S. shale basins sat at roughly 1,566 wells in March 2026, a level that's been grinding lower for years after peaking near 8,800 in mid-2020.

The Haynesville specifically has been running near multi-year lows, having drawn its DUC count down through the 2023–2024 period to support production while rigs were idled. With the cupboard bare, operators can no longer "complete their way out" of a tight market, meaning every new Bcf/d of supply now has to come from a fresh dribrilling cycle, which snaps us right back into the 12–24 month lag problem.

<u>Permian Associated Gas: The Other Supply Engine Is Throttling Back</u>

Over the past several years, much of the country's incremental gas supply has come as a byproduct from Permian oil drilling rather than from targeted gas basins like the Haynesville.

However, Permian gas production averaged a record 27.6 Bcf/d in 2025 and is forecast by the EIA to reach 29.0 Bcf/d in 2026. The key difference is that for 2027, the EIA projects Permian gas growth to slow to just 0.6 Bcf/d, while Haynesville steps up to 1.6 Bcf/d to become the largest contributor to U.S. gas growth, meaning supply will be severely constrained now that one of the major US basins is not producing as much.

The reason for this sharp decline is oil economics, as the EIA's forecast has WTI falling from roughly $65/bbl in 2025 to around $52/bbl in 2026, and at those prices, operators are cutting oil rigs, which means less associated gas comes along for free. For this part of the gas extraction math, gas prices don’t matter for E&P as much as oil prices do, since that is what they’re in the Permian to extract.

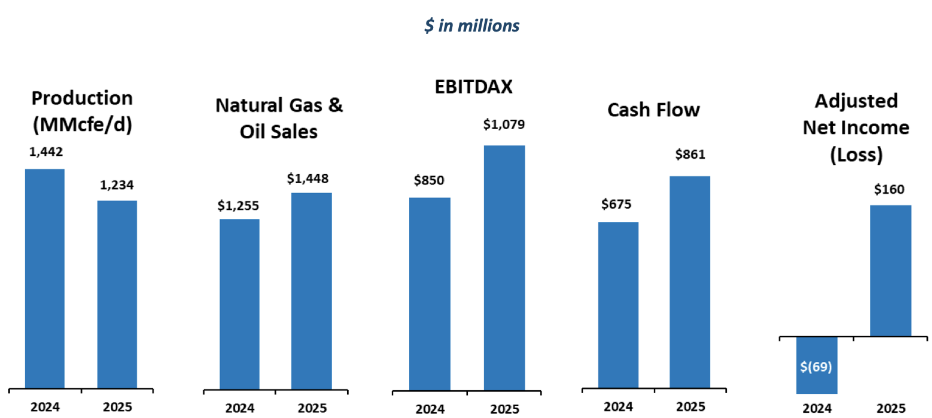
<u>The 3x Gap: A Structural Deficit, Not a Cyclical Blip</u>

Stack the pieces together and the math is striking: roughly 30.3 Bcf/d of incremental demand chasing just 9.7 Bcf/d of incremental supply. Structural deficits in commodity markets will, of course, produce an unique outcome,a price-spike window that disproportionately rewards the producers best positioned to deliver volumes into it.

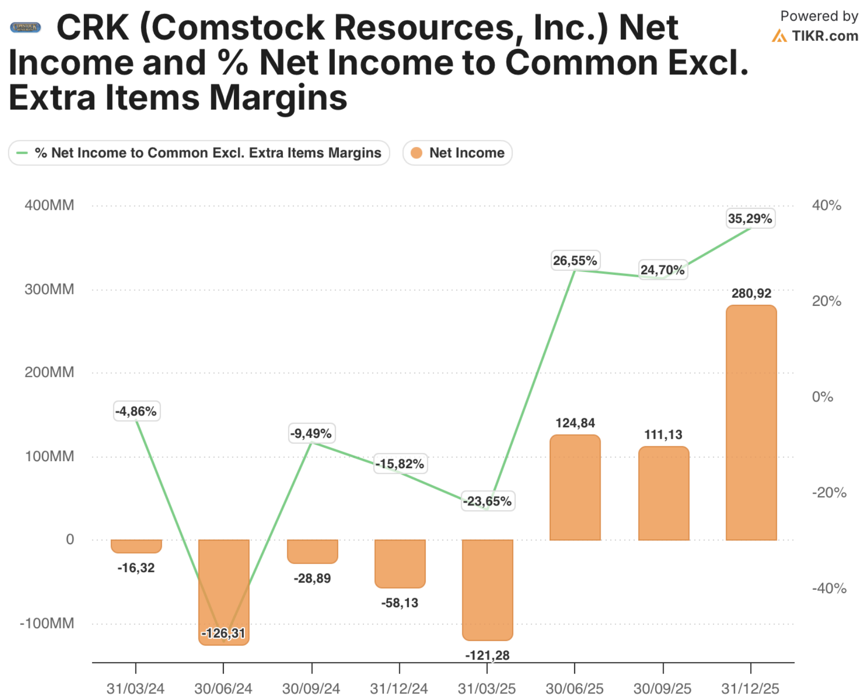
For a pure-play Haynesville operator like CRK, sitting on a reserve base that grew from 3.8 Tcfe to 7.0 Tcfe year-over-year at the end of 2025, with nine rigs running and a multi-year Western Haynesville inventory in front of it, that window is exactly what will realize the value for the stock.

2025 Results

Comstock closed 2025 with natural gas and oil sales of $1.4 billion and generated $861 million of operating cash flow, a strong result in what was otherwise a depressed-price year. Reported net income came in at $420 million ($1.43 per diluted share), though the headline figure was heavily influenced by a $291.9 million pre-tax gain on the Shelby Trough asset sale, meaning that on an adjusted basis, net income was $160 million, or $0.54 per share.



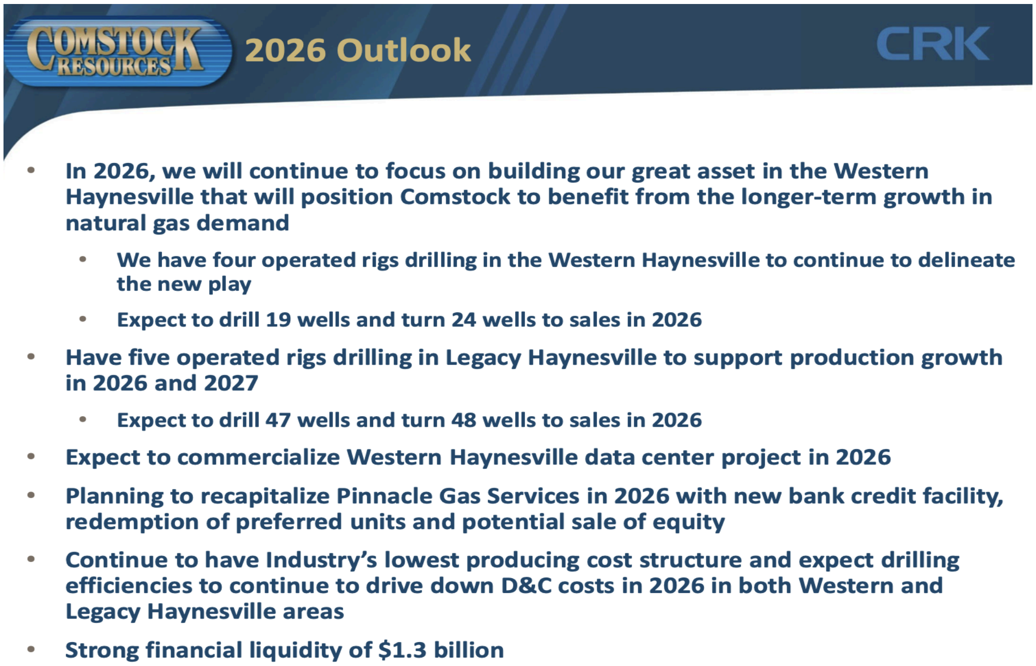
Full-year production averaged 1.2 Bcfe/d, down roughly 14% year-over-year, but this decline was deliberate, not a performance miss as management actively curtailed volumes through a soft-price window in 2024–early 2025, choosing to defer production into a tighter market rather than sell molecules at the bottom of the cycle.



All-in production costs were just $0.77/Mcfe (broken down as $0.38 gathering & transportation, $0.25 LOE, $0.07 production taxes, and $0.07 cash G&A), keeping Comstock structurally low on the Haynesville cost curve. Net, Q4 demonstrated exactly the operating leverage thesis: modestly higher realized prices plus tight costs translated into meaningfully expanded margins, setting up a strong jump-off point for the 2026 ramp.

The combination of reduced volumes, disciplined spending, and $445 million of total divestitures (including the Shelby Trough transaction) allowed the company to enter 2026 with a materially stronger balance sheet than it had a year earlier, and with its Western Haynesville appraisal program further de-risked.

For 2026, Comstock is guiding full-year production of 1.25–1,4 Bcfe/d, roughly 3–5% growth over 2025. The drilling program calls for 66 wells spud and roughly 72 wells turned to sales, in line with what management said about taking opportunities to sell wells in Western Haneysville, supported by nine rigs and a capex budget of $1.4–$1.5 billion. The Western Haynesville is explicitly moving into multi-pad development mode, a shift from the appraisal-driven cadence of 2024–2025 that should drive per-well cost reductions and more consistent production additions as 2026 progresses. This is overall a strong guidance for next year, especially as the company goes into Q1 with a balance sheet stronger than ever and with a production ready to capitalize on henry hub gains.



Debt and Reserve Risk: Overblown Concerns

<u>Concern 1: $3.17B in Debt Looks Dangerous</u>

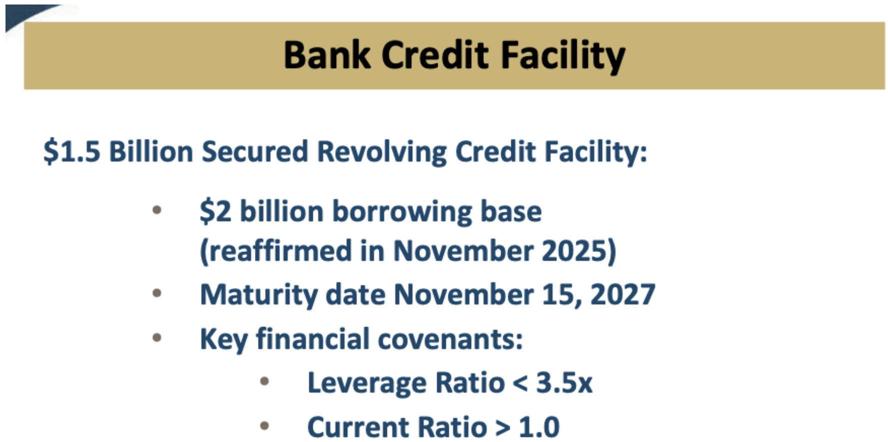
On the surface, the balance sheet looks scary, as they have roughly $3.17 billion of total debt against only $19 million of cash as of year-end, the optics of an overleveraged E&P one downturn away from distress. What the surface doesn't say is that Comstock runs a $1.5 billion secured revolving credit facility, reaffirmed in April 2025 against a $2 billion borrowing base and extending to November 2027, with roughly $939 million of availability still undrawn. Layer in the Shelby Trough divestiture that closed in December 2025 for $417 million in net proceeds, with 100% earmarked for debt reduction, and pro forma liquidity comes in near $1.4 billion.

The following table summarizes Comstock's principal amount of debt as of December 31, 2025 by year of maturity:

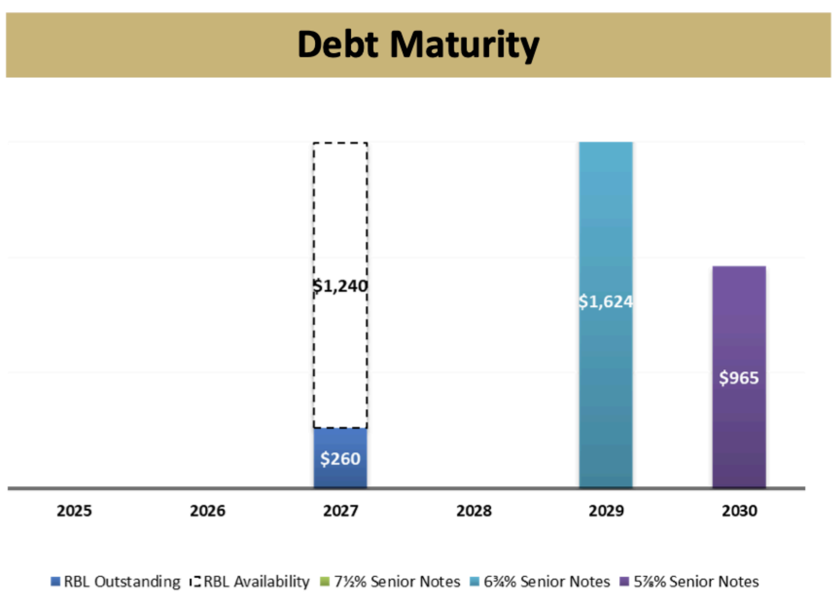
	2026	2027	2028	2029	2030	Total
				(In thousands)		
Bank Credit Facility....................	$ —	$ 260,000	$ —	$ —	$ —	$ 260,000
6.75% Senior Notes due 2029	—	—	—	1,623,880	—	1,623,880
5.875% Senior Notes due 2030 ..	—	—	—	—	965,000	965,000
	$ —	$ 260,000	$ —	$ 1,623,880	$ 965,000	$ 2,848,880

Beyond the aggregate number being less daunting than it looks, the near-term calendar is genuinely benign as there are no bond maturities in either 2026 or 2028, and the only 2027 obligation is the $260M drawn balance on the $1.5B revolver, which is a routine facility-extension event rather than a cash paydown. The December 2025 Shelby Trough sale is enough to retire that revolver balance outright and still leave room for opportunistic tenders on longer-dated paper at discounts to par, a strong sign of management moving in the right direction on retirement of older bonds. Beyond that, the next real bond wall isn't until March

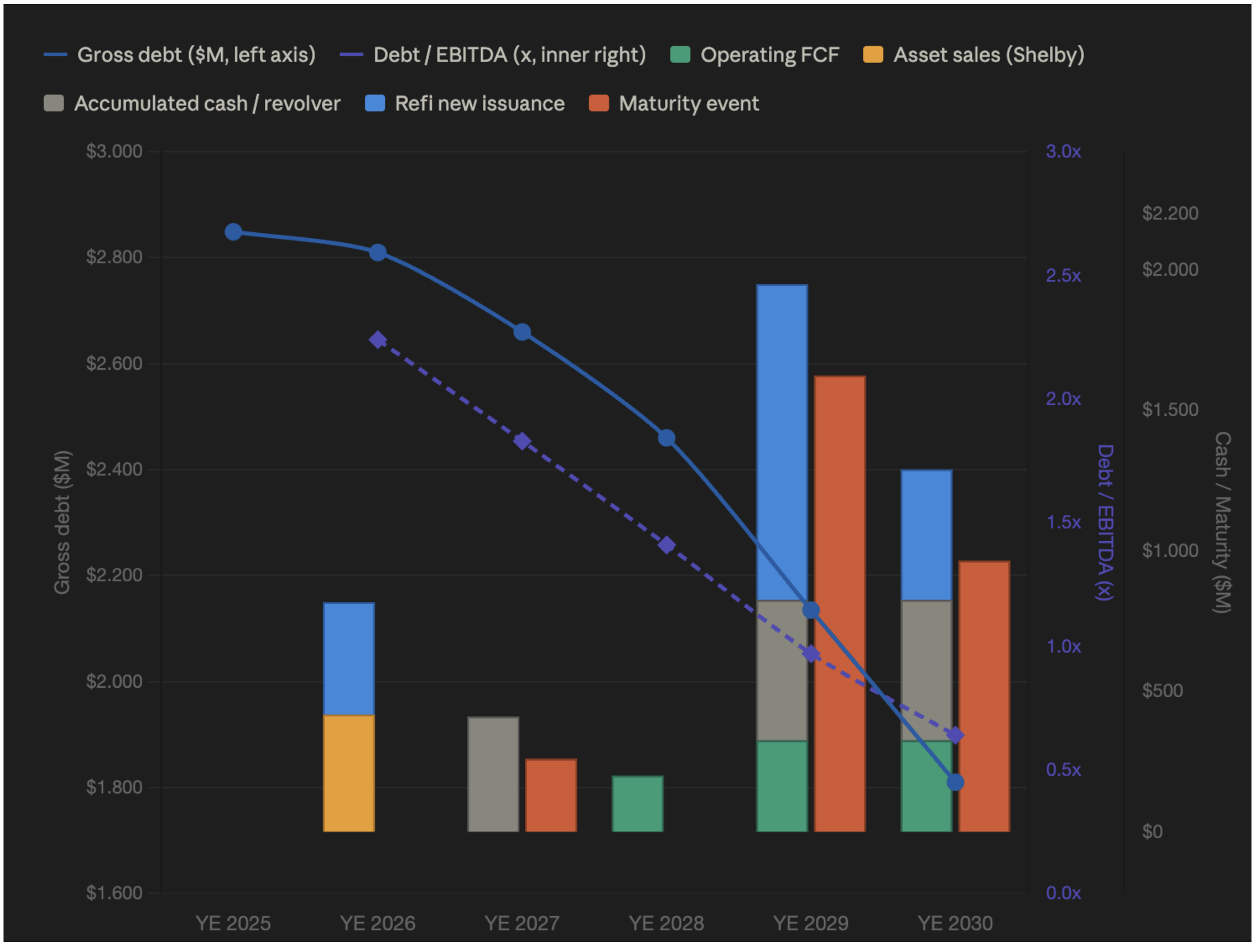
2029 followed by $965M of 5.875% notes in January 2030. That gives Comstock three full years to generate cumulative free cash flow into a structurally tightening gas market before the next meaningful tranche needs to be dealt with. The debt math looks a lot less threatening when the only 2027 item is a routine revolver recast and the next real bond wall is four years out, well after the gas-demand inflection has played out.



Even if free cash flow underperforms the base case Comstock has a demonstrated second lever in asset monetization that the Shelby Trough sale just proved out. That December 2025 transaction generated $417M of net proceeds for non-core acreage earmarked 100% for debt reduction, and it happened in a market where buyers were already aggressively stepping into Haynesville-area assets with private-equity-backed E&Ps, Aethon, and midstream-adjacent sponsors have all been active, and the bid for proven, delineated gas acreage has only strengthened as LNG and data-center demand pull has become consensus.



CRK's remaining footprint plus substantial midstream infrastructure gives management multiple additional packages that could be monetized without impairing the core growth engine, whether through outright sales, DrillCo-style JVs, midstream minority stakes, or volumetric production payments. With the next bond wall not hitting until March 2029, there is no scenario where Comstock is forced to transact under duress, meaning that management has three to four years to opportunistically time any asset sale into receptive markets, which is exactly what the Shelby Trough transaction demonstrated they are both willing and able to do.



2026: Maturity-Free Runway, $2,810M Ending Debt No bond maturities. Unlevered FCF of -$349M means revolver funds the capex gap while Shelby Trough proceeds clear the year-end 2025 revolver draw.

2027: Revolver Recast + $50M Extra Paydown, $2,660M Ending Debt The $260M revolver matures in November and gets recast into a larger, lower-priced facility against a stronger balance sheet. $50M of surplus cash applied to opportunistic open-market purchases of the '29s at any discount to par.

2028: Clean Calendar + $100M Extra Paydown, $2,460M Ending Debt Unlevered FCF of +$353M funds $200M of gross paydown, $100M scheduled plus $100M of incremental open-market activity on the '29s.

2029: $1,624M Maturity + $125M Extra Paydown, $2,135M Ending Debt Unlevered FCF of +$724M handles the March 2029 tranche with more cash and a smaller refi tranche than the base case. Net paydown of $325M - $200M scheduled plus $125M incremental. .

2030: $965M Maturity + $125M Extra Paydown, $1,810M Ending Debt Unlevered FCF of +$1,294M addresses the final tranche. $325M of net paydown, meaning $200M scheduled plus $125M incremental. The January 2030 maturity is handled with ~$500M cash + revolver.

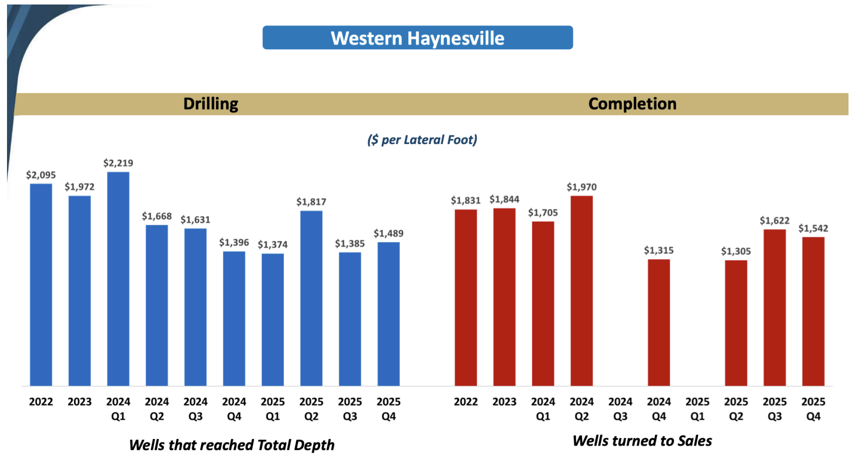
* The model assumes a total of $400M in projected opportunistic liability management throughout the 5 years coming from excess FCF being used to pay down debt, which offsets $400M of scheduled paydown to keep gross debt roughly flat while compressing the coupon stack. There is no open tender today but the assumption rests on management's demonstrated track record (2021 $1.25B tender retiring the 2025/2026 notes, April 2024 $400M add-on cleaning up the remaining 2026 stub). This would make sense if the company would like to keep a clean Debt/EBITDA ratio by 2030 while still have around $300M of FCF over these years to return to shareholders.

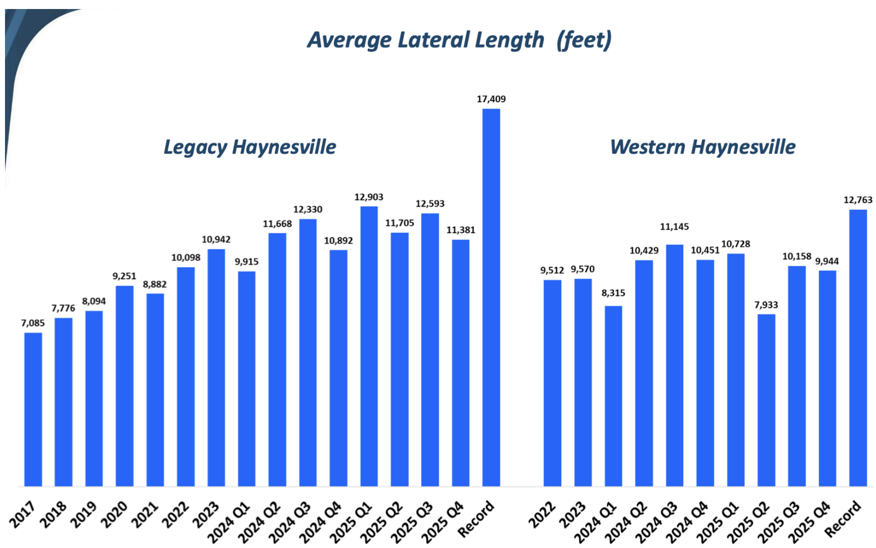
<u>Concern 2: Western Haynesville Is Unproven</u>

Market skeptics still frame the Western Haynesville as a speculative exploration play with $27–$30 million per-well costs, but the data tells a different story, the story of how Comstock and partner now drilled 17 Western Haynesville wildcats across a 535,000 net-acre position, and those wells have averaged 946 MMcf of production per 1,000 lateral feet, a remarkably consistent result across wells ranging from five to 29 months of production history, with cumulative production already exceeding 112 Bcf.

Management's inventory framework is also more conservative than critics give it credit for, since Comstock's 2,559-well count excludes short laterals entirely, meaning the company is underwriting its development plan only against full-length laterals even though shorter sticks will inevitably be drilled as pad development fills in around existing wells. With 24 Western Haynesville wells scheduled to turn in line in 2026 (double the 12 turned in 2025) and the program explicitly moving to multi-pad development mode, the play is already proven as a successful venture and now the question becomes how quickly then can develop this further.

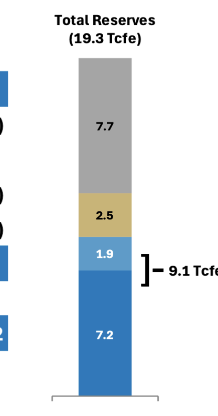
As we will address in the valuation section of this report, the Western Haynesville inventory reserve is massive and could sustain the future of this company for the foreseeable future, and investors, too conservative about its feasibility, are discounting its valuation when analyzing the company. As gas prices rise in the next few years, as discussed before, the actual PV10 reserves, what CRK actually can show on their presentations to investors, will skyrocket and, with it, fears of losing money with Western Haynesville will disappear.





- **Spent $1,055 million in 2025 to add 1 Tcfe of Proved Reserves achieving all in finding costs of $1.02 per Mcfe.**
- **Replaced 229% of 2025 production.**

	Bcfe
Proved Reserves as of 12/31/24	**7,023**
Production	**(450)**
Drilling Additions	**1,069**
Revisions	**(39)**
Divestitures	**(419)**
Proved Reserves as of 12/31/25	**7,184**
PV 10 Value (billion $) at NYMEX Gas Price	**$5.2**



The Bottom Line on Market Pessimism

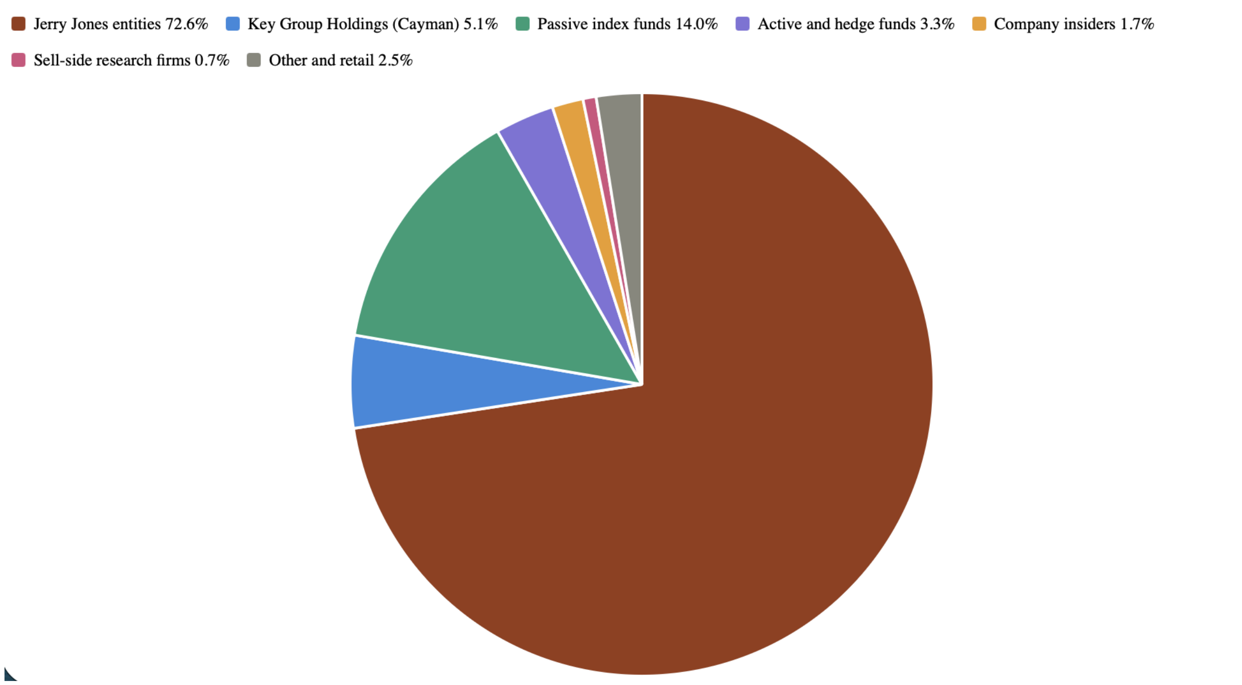
The debt concern is being solved in real time through the Shelby Trough proceeds, revolver headroom, and a targeted tender for the future payable notes. The Western Haynesville concern misreads a delineated and increasingly repeatable play as an exploration gamble. And the broader skepticism on gas demand is still being anchored to the 2020–2024 oversupply psychology that the current LNG and data-center demand cycle has structurally broken.

Jerry Jones as a Safeguard

Most Americans know Jerry Jones as the billionaire owner of the Dallas Cowboys, but before he ever bought an NFL franchise he was an oil and gas operator. His original fortune came from a series of wildcat plays in Arkansas and Oklahoma in the 1970s and 1980s, and his private company Arkoma Production has remained an active E&P vehicle for more than four decades. He is, in a literal sense, an oilman with a football team — not the other way around — which is why his conviction on a specific gas basin carries weight that a casual celebrity investor's never would.

As of April 2026, Jerry Jones owns 72.6% of Comstock Resources making him by far the dominant economic stakeholder and the single most important variable in any credit analysis of the company.

CRK ownership breakdown: Jerry Jones 72.6%, institutional and other holders 27.4%



The Jones family's involvement began when he exchanged the Bakken oil assets of his private firm, Arkoma, for $620 million of Comstock stock, taking his ownership to roughly 84% at the time and establishing the template that has defined every subsequent support event.

A year later, Jones wrote a personal $475 million check as part of the $2.2 billion Covey Park acquisition, the transformational transaction that made Comstock the largest operator in the Haynesville basin.

In March 2024, Jones entities purchased 12.5 million newly issued CRK shares at for total proceeds of $100.5 million, a direct capital injection during a weak-price environment that lifted his stake from roughly 65% to 67% and, more importantly, was priced at a level most outside investors were unwilling to commit capital at.

Further open-market purchases and convertible note conversions have since compounded his position to approximately 71% of shares outstanding, reinforcing that every major Jones-related transaction over the past eight years has moved in the same direction — more capital into Comstock, never out.

In August 2024, Jones purchased an additional 13.4 million shares for roughly $137.5 million, a transaction notable both for its size and its direction, meaning that in an environment where an owner of his scale could easily have been trimmed to diversify, he added.

With a Forbes-estimated net worth of approximately $19.8 billion, CRK represents a material but manageable share of Jones's wealth, which is precisely why the backstop argument works. He has the capacity to inject further capital without threatening his own balance sheet, meaning a liquidity support decision is a business judgment, not a bet-the-house choice.

Jones has publicly described the Western Haynesville as having "$100 billion in potential present value," and in a Wall Street Journal interview stated he "is ready to inject more cash if needed," predicting the play will become "one of the two or three top-ranked sources of gas in the United States."

Jones, just based off his personal wealth and clear interest in the company's future, retains the practical ability to take CRK private, inject fresh equity at distressed prices, or broker a sale to a larger integrated producer, all paths that are unavailable to minority-held E&Ps and that sit in the background as tail protection for CRK shareholders. This differential of having a "guaranteur" backing a company is a further signal that Comstock's current debt pile is not as big of a problem as investors seem to believe.

9. Critical Risks

Risk 1: LNG Delays or Outages

The bull case for Henry Hub from 2026 onward rests heavily on roughly 12 Bcf/d of new LNG export capacity coming online and any of these projects can slip. Trains 2 and 3 of Golden Pass have already dealt with contractor bankruptcy issues, and new greenfield projects historically arrive 9–18 months later than their announced in-service dates. If that happens here, the demand call on US supply simply shifts out by a year or two rather than disappearing, the gas needs to go somewhere, and with 600+ million tonnes of global LNG demand already contracted through 2035, the pull on the Gulf Coast eventually materializes.

For CRK, a slipped LNG timeline means realized prices drift in the $3.50 range through 2026 and early 2027 instead of ramping immediately, which pushes the deleveraging and FCF inflection out by 12–24 months. This would mean that FCF generation would be significantly hurt and target prices would be slashed significantly, but the future opportunity still makes it so that the upside will be still on the horizon.

DEMAND GROWTH (Annual Incremental, Bcf/d)						
LNG exports (Golden Pass, Plaquemines, Corpus, Rio Grande)				4,5	5,5	2,0
Coal-to-gas substitution (~0.15 Bcf/d per 1 GW retired)		0,3	0,5	1,5	3,0	4,7
AI / Data center baseload gas demand		0,5	1,0	1,5	2,0	2,0
Industrial / Residential / Commercial growth		0,2	0,3	0,3	0,3	0,2
Total annual incremental demand		**1,0**	**1,8**	**7,8**	**10,8**	**8,9**
Cumulative incremental demand (vs 2025)		**1,0**	**2,8**	**10,6**	**21,4**	**30,3**

SUPPLY GROWTH (Annual Incremental, Bcf/d)						
Haynesville (CRK + peers, price-sensitive)		0,8	1,0	1,2	1,3	1,2
Appalachia (Marcellus/Utica, pipeline-constrained)		0,2	0,3	0,3	0,4	0,3
Permian associated gas (oil-drilling dependent)		0,3	0,3	0,3	0,2	0,2
Other basins (Eagle Ford, Bakken, Rockies, Anadarko)		0,2	0,3	0,3	0,3	0,3
Total annual incremental supply		**1,5**	**1,9**	**2,1**	**2,2**	**2,0**
Cumulative incremental supply (vs 2025)		**1,5**	**3,4**	**5,5**	**7,7**	**9,7**
MARKET BALANCE & PRICE DERIVATION						
Cumulative net tightness (Demand - Supply)		**(0,5)**	**(0,6)**	**5,1**	**13,7**	**20,6**
Equilibrium Henry Hub price ($/MMBtu)	$3,53					
Price sensitivity ($/MMBtu per 1 Bcf/d tightness)	**$0,15**					
Henry Hub price forecast ($/MMBtu)		**$3,46**	**$3,44**	**$4,30**	**$5,59**	**$6,62**
Less: CRK Haynesville basis differential ($/Mcf)	($0,25)					
CRK realized gas price ($/Mcf)		**$3,21**	**$3,19**	**$4,05**	**$5,34**	**$6,37**

<u>Risk 2: AI Power Demand Overhyped</u>

The DeepSeek moment earlier this year is the cleanest example, a new model architecture wiped out consensus assumptions about how much compute each unit of useful AI output requires, and the market re-priced data-center-linked utilities within days. If a similar efficiency leap removes 3–6 Bcf/d of forecasted power demand, the thesis still works since the gap between 2030 US gas demand and pre-LNG baseline supply would narrow from 32+ Bcf/d to 26 Bcf/d, which is still one of the largest structural demand shifts the industry has ever absorbed.

Even if AI energy demand expectations gets cut in half, the other gas demand drivers, such as LNG and transition from coal to gas, are sufficient to drive the pricing environment CRK needs.

DEMAND GROWTH (Annual Incremental, Bcf/d)						
LNG exports (Golden Pass, Plaquemines, Corpus, Rio Grande)		2,0	3,0	2,5	2,5	2,0
Coal-to-gas substitution (~0.15 Bcf/d per 1 GW retired)		0,3	0,5	1,5	3,0	4,7
AI / Data center baseload gas demand		0,3	0,5	0,8	1,0	1,0
Industrial / Residential / Commercial growth		0,2	0,3	0,3	0,3	0,2
Total annual incremental demand		**2,8**	**4,3**	**5,1**	**6,8**	**7,9**
Cumulative incremental demand (vs 2025)		**2,8**	**7,1**	**12,1**	**18,9**	**26,8**

MARKET BALANCE & PRICE DERIVATION						
Cumulative net tightness (Demand - Supply)		1,3	3,7	6,6	11,2	17,1
Equilibrium Henry Hub price ($/MMBtu)	$3,53					
Price sensitivity ($/MMBtu per 1 Bcf/d tightness)	**$0,15**					
Henry Hub price forecast ($/MMBtu)		**$3,72**	**$4,08**	**$4,52**	**$5,21**	**$6,10**
Less: CRK Haynesville basis differential ($/Mcf)	($0,25)					
CRK realized gas price ($/Mcf)		**$3,47**	**$3,83**	**$4,27**	**$4,96**	**$5,85**

Natural Gas	2024	2025
Natural gas price at Henry Hub (dollars per million Btu)	2.19	3.53

Risk 3: Supply Increases Much Faster Than Expected

The honest biggest threat to the bull case is that American producers do exactly what they've always done, which is respond to higher prices by drilling more wells faster than anyone expected. The shale era has repeatedly proven that when natural gas climbs into the $4 handle, Haynesville and Appalachian operators can add meaningful production within a few quarters, and a growing pool of private producers behind them is happy to add rigs the moment the strip signals it's worth the risk. If that response comes in 50% stronger than the base case predicts, instead of gas settling into the $5 zone by around 2027, it probably hovers somewhere in the high-$3s to low-$4s, which is comfortably profitable territory for most companies, including and especially CRK, but nothing like the windfall the bull case needs. The FCF ramp that drives the deleveraging story still happens, just more slowly and less dramatically.

The important thing, though, is what this scenario means for the investment itself rather than for the model. In a world where gas prices settle around $3.75 rather than climbing to $5, marginal producers elsewhere end up earning very little while CRK still generates cash, still pays down debt, still quietly compounds. And because the stock today already trades near the value implied by a $3 gas world, that scenario leaves the current quote roughly where it is rather than punishing it further. The downside was absorbed before you got here; what's at stake if supply surprises is the shape and tempo of the upside, not whether it shows up at all. The thesis becomes a slower-burning version of itself, but the floor the stock is sitting on doesn't move much.

SUPPLY GROWTH (Annual Incremental, Bcf/d)						
Haynesville (CRK + peers, price-sensitive)		1,2	1,5	1,8	2,0	1,8
Appalachia (Marcellus/Utica, pipeline-constrained)		0,3	0,5	0,5	0,6	0,5
Permian associated gas (oil-drilling dependent)		0,5	0,5	0,5	0,3	0,3
Other basins (Eagle Ford, Bakken, Rockies, Anadarko)		0,3	0,5	0,5	0,5	0,5
Total annual incremental supply		**2,3**	**2,9**	**3,2**	**3,3**	**3,0**
Cumulative incremental supply (vs 2025)		**2,3**	**5,1**	**8,3**	**11,6**	**14,6**
MARKET BALANCE & PRICE DERIVATION						
Cumulative net tightness (Demand - Supply)		**0,5**	**2,0**	**3,9**	**7,4**	**12,3**

MARKET BALANCE & PRICE DERIVATION							
Cumulative net tightness (Demand - Supply)		0,5	2,0	3,9	7,4	12,3	P
		Natural Gas					
Equilibrium Henry Hub price ($/MMBtu)	$3,53						2
Price sensitivity ($/MMBtu per 1 Bcf/d tightness)	$0,15		2024	2025			C
		Natural gas price at Henry Hub (dollars per million Btu)	2.19	3.53			
Henry Hub price forecast ($/MMBtu)		**$3,61**	**$3,82**	**$4,11**	**$4,63**	**$5,37**	H
Less: CRK Haynesville basis differential ($/Mcf)	($0,25)						Q
CRK realized gas price ($/Mcf)		**$3,36**	**$3,57**	**$3,86**	**$4,38**	**$5,12**	F

Red Flag Triggers (Position Review)

- Gas Price Collapse: Henry Hub below $2.50 for two consecutive quarters
- LNG Demand Miss: Golden Pass Train 1 delays beyond Q3 2026; new FIDs cancelled
- Jones Sells: Any material insider selling by Jones entities

Valuation

Gas Price | Demand Wall Hits a Stalled Supply Response

Assumption: Henry Hub rises from $3.68 in 2026 to $5.59 by 2030, anchored to EIA STEO's $3.53 equilibrium for 2025–26 and lifted by a structural supply-demand deficit.

MARKET BALANCE & PRICE DERIVATION						
Cumulative net tightness (Demand - Supply)		1,3	3,7	6,6	11,2	17,1
		Natural Gas				
Equilibrium Henry Hub price ($/MMBtu)	$3,53					
Price sensitivity ($/MMBtu per 1 Bcf/d tightness)	$0,15		2024	2025		
		Natural gas price at Henry Hub (dollars per million Btu)	2.19	3.53		
Henry Hub price forecast ($/MMBtu)		**$3,72**	**$4,08**	**$4,52**	**$5,21**	**$6,10**
Less: CRK Haynesville basis differential ($/Mcf)	($0,25)					
CRK realized gas price ($/Mcf)		**$3,47**	**$3,83**	**$4,27**	**$4,96**	**$5,85**

The entire thesis turns on a simple imbalance between supply and demand for gas in the US for the next few years. Hence, the entire DCF and reserve value estimation are very much anchored to how I perceive the price of gas changing. I anchor the 2026 price to EIA's STEO equilibrium ($3.53/MMBtu) and layer on $0.15/MMBtu of price response per Bcf/d of cumulative tightness, a sensitivity calibrated to the 2022 winter spike and the shape of the Haynesville cost curve, and deliberately below what the last cycle delivered.

That produces a Henry Hub path of $3.68 → $3.97 → $4.34 → $4.90 → $5.59 across 2026–2030. CRK realizes this at roughly HH minus $0.22/Mcf on its Gulf-proximate basis, much cheaper than their competitors in the Appalachian basin or even in western Texas.

1. PRODUCTION PROFILE							
2026E production (Bcfe/d)	1,33						C
Production growth (YoY)	2,0%						F
Production (Bcfe/d)		1,33	1,35	1,38	1,41	1,43	
Annual production (Bcfe)		484	493	503	513	523	
2. PRICING & HEDGE BOOK OVERLAY							
Henry Hub spot ($/MMBtu)		$3,72	$4,08	$4,52	$5,21	$6,10	F
CRK realized spot (post-basis, $/Mcf)		$3,47	$3,83	$4,27	$4,96	$5,85	H
% of production hedged		35,0%	20,0%	15,0%	5,0%	-	C
Hedge strike price ($/Mcf)		$3,75	$4,00	$4,25	$4,50	-	T
Blended realized price ($/Mcf)		**$3,57**	**$3,86**	**$4,27**	**$4,94**	**$5,85**	(
3. REVENUE ($mm)							
Gas & oil sales (post-hedge)		$1.725	$1.905	$2.147	$2.534	$3.060	

CRK's realized price climbs from $3.56/Mcf to $5.37/Mcf as the price of gas scales up throughout this period. Something to note is that I only take into account CRK's booked hedges for this math, which, because they're not yet hedged for the latter years, also improves their realized price.

Capex | Ramp Taper as Western Haynesville Matures

Assumption: Total capex declines from $1.26B in 2026 to $965M in 2030 (-24%), with the shape driven by D&C moderation and the front-loaded Pinnacle midstream build.

D&C capex tapers from $1.175B to $900M over the five years as the Western Haynesville multi-pad program transitions from exploration-heavy development to repeatable pad manufacturing, while midstream capex drops from $88M to $65M as Pinnacle's core gathering spine completes in 2026-27.

Debt Reduction | $600M Cumulative Paydown, Supported by Asset-Sale Optionality

Ending debt falls from $2,810M to $2,210M across 2026–2030 via a $400M refi of the 2026 revolver draw plus $500M of discretionary paydown drawn from FCF, with additional deleveraging capacity from non-core asset sales similar to last year's $700M Pinnacle JV (see debt section for full funding walk).

6. DEBT SCHEDULE & INTEREST EXPENSE ($mm)						
Beginning debt balance		$2.810	$2.810	$2.660	$2.460	$2.135
Scheduled principal paydown		$400	$150	$200	$325	$325
Refinancing / new issuance		$400	-	-	-	-
Ending debt balance		**$2.810**	**$2.660**	**$2.460**	**$2.135**	**$1.810**
Blended interest rate	6,8%					
Interest expense (avg balance x rate)		$191	$186	$174	$156	$134

Cost Structure | Fixed-Cost Base Translates Gas Price Directly Into FCF

Assumption: Operating cost holds at $1/Mcfe against a rising realized price, producing ~10pp of EBITDA margin expansion from 78% to 86% by 2030. The $1/Mcfe is a conservative number compared to their current $0.78 cost structure.

CRK's unit economics are what make the price thesis actually compound. Operating cost is $0.78/Mcfe all-in, LOE of $0.26, gathering $0.36, production tax $0.17, and G&A $0.06, and it is largely fixed on a per-unit basis because Haynesville pad drilling is a manufacturing process where efficiency gains (longer laterals, multi-well pads) offset service-cost.

D&A runs $1.35/Mcfe and interest falls from $191M to $157M as debt is retired and they refinance future notes on favorable terms.

With operating cost flat and realized price climbing from $3.56 to $5.37/Mcf, revenue compounds from $1.72B to $2.81B (+63%) while EBITDA runs from $1.35B to $2.40B (+79%), showing their successful operating process.

4. OPERATING COSTS ($mm)						
LOE, gathering, prod tax, G&A ($/Mcfe)	$1,00					
Total operating costs		$484	$493	$503	$513	$523
Operating EBITDA		**$1.241**	**$1.412**	**$1.644**	**$2.021**	**$2.536**
EBITDA margin		72,0%	74,1%	76,6%	79,7%	82,9%

<u>Reserves | Risked NAV Across the 1P/2P/3P Stack</u>

This is where the optionality lives and most of Comstock's valuation upside lives. The SEC 10-K discloses 7.0 Tcfe of proved (1P) reserves, which we split into PDP+PDNP (already producing) and PUD (proved undeveloped, must be drilled within 5 years at current prices per SEC rules).

CRK's reserves disclosure is brutally leveraged to the SEC reference price because the same Haynesville footprint was worth $15.5B in 2022 at $6.36/Mcf and just $1.6B in 2024 at $1.84/Mcf, a 9x swing on identical rock, driven by margin compression on producing wells and PUD locations flipping in and out of the proved category as economics cross the threshold. SEC reserves rules force CRK to mark its proved book at backward-looking prices, so the same Haynesville rock can disappear from disclosure and reappear with multi-billion-dollar swings in reported reserve values meaning the market's view of CRK's terminal value and optionality is mechanically a function of where gas prices have been, not where they're going, and that lag is exactly the inefficiency our thesis is positioned to exploit.

It's like if Apple's Terminal Value exit multiple was dictated by its Iphone software and not perception of the company's future. CRK has one of the largest gas reserves in the country, and once the company reports these values as attainable in their reports investor perception of valuation will skyrocket.

Beyond proved reserves, CRK's Western Haynesville position sits on 75 Tcfe of gross probable and possible resource per management's investor-day disclosures, which the SPE-PRMS framework categorizes as 2P (probable, 50% confidence of recovery) and 3P (possible, 10% confidence of recovery). I valued each category separately with recovery-factor haircuts reflecting the underlying geological and timing risk as well as extraction costs and profitability given gas prices.

Category	Gross (Tcfe)	Recovery	Risked Net (Tcfe)	Margin ($/Mcfe)	Life (yrs)	PV @ 10.5% ($mm)
P1a Proved Developed (PDP + PDNP)	2,87	90,0%	2,58	$3,43	4	$4.630
P1b Proved Undeveloped (PUD)	4,13	85,0%	3,51	$2,41	7	$3.275
P1 Proved Total (1P)	**7,00**		**6,09**			**$7.905**
P2 Probable Reserves	15,00	50,0%	7,50	$2,91	15	$4.061
P3 Possible Reserves	60,00	15,0%	9,00	$3,41	20	$3.246
3P Total (Proved + Probable + Possible)	**82,00**		**22,59**			**$15.212**

The **90% recovery factor on PDP+PDNP** reflects that these wells are already flowing — the only residual risk is minor completion work on PDNP wells, and industry precedent on producing Haynesville assets supports haircuts in the 85–95% range.

PUD gets 85%, this is the SEC proved-reserves standard is already a high-confidence bar (reasonable certainty of recovery using existing technology under current economic conditions abd gas prices), but we haircut modestly for execution risk and gas price volatility risk given the 5-year development clock.

P2 gets 50%, the standard SPE-PRMS benchmark for probable reserves, which are defined as "more likely than not to be recoverable" (50% confidence). CRK's 15 Tcfe probable is largely Western Haynesville acreage with confirmed stratigraphy but fewer delineation wells than proved and the 50% haircut is the industry-convention midpoint and matches what acquirers have historically paid for similar resource in A&D transactions.

P3 gets 15%, consistent with SPE-PRMS possible-reserve convention (P10 — "may be recoverable under favorable conditions"). The 60 Tcfe gross figure reflects CRK's acreage-derived estimate of ultimate Western Haynesville potential based on operated + observed well results extrapolated across the deeper, higher-risk northern extent of the play. A 15% haircut is deliberately conservative, it treats 85% of the resource as either uneconomic, geologically uncertain, or too long-dated to credit, allowing the valuation to reflect uncertainty about the company’s future. However, considering Comstock’s massive acreage P3 value still boosts up their valuation, even at this incredible haircut, which reflects the company’s ability to prosper into the future which the market doesn’t seem to consider at all.

RESERVE CATEGORY FRAMEWORK

Category	Gross Resource (Tcfe)	Recovery Factor	Risked Net (Tcfe)	Realized Price ($/Mcf)	Margin ($/Mcfe)	Mid-life Years	PV @ 10.5% ($mm)
P1a Proved Developed (PDP + PDNP)	2,87	90,0%	2,58	$4,47	$3,62	3	**$5.412**
P1b Proved Undeveloped (PUD)	4,13	85,0%	3,51	$4,47	$2,60	5	**$4.328**
P1 Proved Total (1P)	**7,00**		**6,09**				**$9.740**
P2 Probable Reserves	15,00	50,0%	7,50	$4,47	$2,60	15	**$3.407**
P3 Possible Reserves	60,00	15,0%	9,00	$4,47	$2,60	20	**$2.482**

SUM-OF-PARTS NAV BUILD ($mm)			
Component	**Value ($mm)**		**Weighted ($mm)**
PV of 2026-2030 explicit FCF (DCF sheet)			$905
P1 reserves NAV (less 5-yr DCF overlap)			$9.740
P2 reserves NAV (probable)			$3.407
P3 reserves NAV (possible / optionality)			$2.482
NAV Enterprise Value			**$16.533**
Less: Net debt (end 2030, post-paydown)			$1.810
NAV Equity Value			**$14.723**
Diluted shares (end 2030E, mm)	300,9		
			$48,93

SCENARIO-BLENDED PRICE TARGET			
Scenario	**iplied Share Pri**	**Probability**	**Weighted ($/sh)**
Bear: DCF + minimal P1 credit (no P2/P3)	$16,41	25,0%	$4,10
Base: Risk-weighted NAV (sum-of-parts above)	$48,93	50,0%	$24,46
Bull: DCF + full P1 + full P2 + 30% P3	$28,59	20,0%	$5,72
Tail: Full P1 + P2 + P3 (3P NAV)	$34,36	5,0%	$1,72
Sum of weights (should = 100%)		**100,0%**	
PROBABILITY-WEIGHTED PRICE TARGET ($/sh)			**$36,00**

Valuing CRK any other way would mean pretending we know exactly how the next 5 years plays out, which gas price prevails, how fast LNG and data centers ramp, whether Western Haynesville ultimately reclassifies into proved, and the truth is nobody does, including management.

By sizing what the business is worth in each of four plausible futures (a bearish world where prices mean-revert and the resource base gets no credit, a base case where the supply-demand thesis plays out, a bull case with a tighter market, and a tail where the structural supercycle materializes and P3 is given some serious attention from management and investors) and then weighting each by how likely it actually is, the framework forces honesty about what we're underwriting and surfaces what really matters: even the bear case clears today's share price, and the probability-weighted target of $36.00 comes out roughly double the current quote without needing the bull or tail outcomes to do the heavy lifting.

That asymmetry is the whole reason this trade is worth taking, and it only becomes visible when you stop forecasting a single answer and start pricing the distribution.

Hedging Analysis: EQT pair-trade

First, I looked at how much correlation there was between Comstock and other pure play gas stocks as well as correlation to gas futures itself. The goal here is to find another pure-play company that would do less well than CRK if gas prices go up but would do even worse than CRK if gas prices stay stable or go down. I want to capture the alpha from CRK's better cost structure, ability to profit from the LNG boom, large but mispriced reserve inventory and its stronger than assumed balance sheet, while isolating the risks of macroeconomic tensions and gas prices volatility.

Tier	Ticker	Corr 5Y	Corr 3Y	Corr 1Y	Corr 3M	Vol
TIER A · BEST PEER HEDGES						
A	RRC	0.78	0.76	0.67	0.76	33%
A	AR	0.77	0.75	0.64	0.79	39%
A	EQT	0.76	0.76	0.70	0.75	33%
A	EXE	0.72	0.75	0.69	0.65	32%
TIER B · DECENT HEDGES						
B	CTRA	0.68	0.63	0.48	0.53	30%
B	XOP	0.66	0.61	0.50	0.66	27%
B	CNX	0.66	0.61	0.56	0.59	30%
B	GPOR	0.66	0.66	0.69	0.67	34%
TIER C · WEAK HEDGES						
C	OVV, MTDR, XLE, BOIL, UNG, KMI, WMB	0.53–0.57	—	—	—	—
C	PR, APA, DVN, FANG, OXY, COP	0.46–0.52	—	—	—	—

RRC wouldn't make sense as the short because it's the lowest-cost operator in the Marcellus basin (though this is largely affected by their oil and LNG processing exposure) and roughly 30% NGL-weighted, so its margin actually expands when oil and propane prices rally, the opposite of what you want from a short paired against a pure-gas long. AR has the same problem amplified since they have around 35% NGL exposure plus its own integrated midstream (Antero Midstream) means a short on AR is really a short on gas, NGLs, and their infrastructure all at once, which dilutes the gas-price isolation that makes the CRK long work (though CRK has a small exposure to midstream this is much less representative to their firm than AR's). Together, both names sit in the same Appalachian basin as EQT and share the pipeline-bottleneck thesis, but their NGL kicker means the short loses money exactly when oil and gas prices both rise, which is precisely the macro state where CRK is supposed to print.

EQT is the cleanest single-name short for a long-CRK pair trade given that Its correlation profile is the steadiest in the gas-pure-play complex across the timeframes analyzed, versus RRC dipping to 0.67 at 1Y and AR swinging from 0.64 to 0.79 across windows. And EQT is essentially 100% gas. More importantly, the structural setup is the explicit mirror of the CRK bull case.

On cost structure, EQT is lean but not as lean as CRK, where they have have driven operating costs to a record $1.00/Mcfe in Q3 2025, helped meaningfully by the 2024 Equitrans midstream reacquisition, which cut net unit costs ~15% by removing third-party gathering fees. That's competitive industry-wide, but CRK runs at $0.78-0.85/Mcfe, so on a per-unit basis CRK still carries a 20-25% cost advantage despite EQT's much larger scale. Every dollar of gas-price decline compresses EQT's margin faster than CRK's, so the spread widens against EQT in any sell-off.

EQT is the largest Appalachian pure-play (Marcellus + Utica), and CEO Toby Rice has publicly said takeaway capacity has "hit the wall" regarding bottlenecks in transporting this gas out of the region, meaning that EQT realizes Marcellus in-basin pricing, which sits $0.50-1.50/MMBtu below Henry Hub when gas is tight because the gas physically can't leave fast enough. CRK, as explained before, sits a few hundred miles from the Sabine Pass / Plaquemines / Corpus / Rio Grande complex with basis already at -$0.22/Mcf and tightening, meaning that CRK gets the LNG export premium and midstream logistical benefits today while EQT waits until 2028 and pays tolls to get there.

On reserves versus market cap, both stocks look similarly priced on what they have, but what they have is very different. EQT and CRK both trade at roughly the same market cap relative to their proved reserve value PV-10, around 1.3-1.7x, however the story gets more interesting when analyzing the unbooked value.

The clearest evidence shows up in how each company's reserve value moved between the 2022 peak and today. CRK's PV-10 fell from $15.5B in 2022 to $4.5B in 2025, a 71% drop on a

52% drop in gas prices, meaning CRK's reserve value swung roughly 1.4x as hard as the price itself. EQT's PV-10 fell from $50B to $26B over the same window, a 48% drop on a 47% price drop, almost exactly in line. EQT's reserves barely flex with price because Marcellus is a mature, almost fully drilled play, the same wells stay on the books in good years and bad.

This analysis actually points to the reason why the EQT pair trade makes sense when isolating alpha from CRK's reserve valuation: there's nothing left for EQT to discover. EQT has already booked essentially all of its economic resources, about 25 years of drilling inventory, all on the books, all priced into the stock. CRK is the opposite, where only 7 Tcfe of its 80+ Tcfe Western Haynesville resource is on the books today. The other 75 Tcfe sits outside the SEC disclosure, waiting to be added as prices rise and drilling proves it up.

So when gas prices rise, EQT gets a single boost, its existing wells become more valuable. CRK gets two boosts, its existing wells become more valuable *and* a huge chunk of unbooked resources starts moving onto the books. The 2022 → 2025 history already showed CRK's reserves are highly reflexive on the way down and the same reflexivity works in reverse on the way up, but with the additional kicker of Western Haynesville reclassification that EQT simply doesn't have. That's why CRK's reported reserve value should grow much faster than EQT's over the next few years, and that's the catalyst that widens the spread between the two stocks and makes the pair trade work.

This makes EQT an almost perfect hedge to isolate unbooked reserves boost.

If LNG ramps faster than expected, CRK captures it directly while EQT waits on pipelines. If takeaway projects slip on midstream or contractor issues, EQT's basis stays blown out while CRK is unaffected. If gas prices spike, CRK realizes Henry Hub minus 22 cents while EQT gives back a dollar-plus to Marcellus basis, and if prices fall, EQT's higher unit cost compresses margins harder.

Conclusion

CRK at current prices offers an opportunity for a value investor to get exposure to natural gas and the coming energy demand boom as they have great cost structure, logistical benefits, a sea of opportunities through a strong reserve inventory and a stronger than it appears balance sheet to support them along the way.

I will build CRK into a 10% position in my portfolio.