Natural gas dilemma - Everyone agrees Cook Inlet needs help. No one agrees on how or where to get it.

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Just to get your attention, here's the worst-case scenario: A mid-winter cold snap hits Southcentral Alaska, bringing temperatures of 20 below zero. People from the Matanuska Valley to the Kenai Peninsula turn up their heat in unison, sucking natural gas from the Enstar Natural Gas Co. distribution grid buried beneath the city streets. This network is fed by transmission lines leading back to wells that pump natural gas from underground reservoirs across Cook Inlet. As more people turn up the heat, engineers search for additional molecules of natural gas to manage the increased demand. But the cold doesn't let up. Then, a compressor trips at one of the major gas fields, and the pressure in the pipeline system drops below the threshold needed for making electricity. So the lights go out. System operators worry the drop in pressure allowed air to get into the grid, and federal regulations require them to stop delivering to customers. So the heat goes off.

The bigger problem comes next, though. To revive the system, hundreds of technicians need to go door to door to bring every customer back online one at a time, on top of a long list of other regulatory and technical requirements. It could take weeks or even months, during which time the region would be without heat or power. In winter. In Alaska. Even worse, the underground reservoirs of natural gas could be damaged from disuse, meaning if once the system is restored, it might never be the same again.
For all the issues Alaskans worry about, none threatens as many people with consequences as extreme as this scenario. If it comes to pass, half the population of Alaska would lose heat, and even more would lose power. Industry would be crippled. It's been described as the economic equivalent of the 1964 Good Friday Earthquake.

Like every worst-case scenario, this one requires a lot of things to go wrong all at once. It's unlikely, but it's not impossible. And the chances of it happening increase every year because of the changing nature of natural gas reservoirs in the Cook Inlet basin. In fact, it's come close to happening a few times over the past decade. It came close to happening earlier this year.

On January 3, temperatures dropped to 15 below across Southcentral and the local system pulled harder on the wells and pipelines than ever before. And a compressor did fail, momentarily. In the end, the system prevailed because some things went right and some other things didn't go wrong, **but industry watchers suggest we came within a few hours of a total failure.**

The key to understanding what almost happened is something known in industry jargon as "deliverability"—the measure of how much natural gas can be called upon at any given moment. Having large volumes of natural gas available is important because Southcentral is so dependent on it. Enstar supplies it to almost 350,000 customers. Chugach Electric Association makes 93 percent of its electricity from it. It's pulled from underground fields across the Cook Inlet and sent through transmission pipelines to the local Enstar distribution grid, where it fuels furnaces and stoves. It also travels to plants owned by Chugach and Municipal Light & Power, who use it to run giant turbines that produce electricity for all of Anchorage. Chugach, in turns, sells electricity to smaller utilities in Homer, Seward and the Matanuska Valley, and also sends some power north to Fairbanks.

Deliverability doesn't measure the amount of gas still underground, waiting to be brought to the surface. That's "reserves." According to the state, Cook Inlet produced around 10.1 trillion cubic feet of gas between 1958 and 2006 and still had around 1.7 trillion cubic feet in remaining reserves as of 2007, the most recent figures available. Think of reserves as a giant tank of water, and of deliverability as a fire hose. If the stream on the hose is weak, it doesn't matter how much water is in the tank: The house will burn down.

The Cook Inlet natural gas system is like a living organism connecting your furnace to underground reservoirs. Producers like Marathon, Chevron and ConocoPhillips constantly monitor wells, gauging the amount of gas remaining in each reservoir and the amount of pressure available to help bring that natural gas up to the surface. Buyers like Enstar and Chugach do similar monitoring on their pipelines and power plants. These figures all change constantly. Reservoirs lose pressure as they age, like a deflating balloon, making each new molecule harder to retrieve. The biggest gas fields in the Cook Inlet are more than 40 years old. Cook Inlet just doesn't deliver like it used to.

January's cold snap highlighted the problem. With temperatures averaging 11 below zero, the Cook Inlet basin delivered around 440 million cubic feet of natural gas. On Feb. 3, 1999, a day with even colder temperatures, the basin delivered 763 million cubic feet of natural gas. That's a 42 percent decline over the course of a decade. And the pace is increasing. Over the past two years, deliverability has declined around 21 percent.

The problem of declining deliverability is widely acknowledged by the industry. Enstar, the electric companies and the gas producers all talk about it publicly. At an industry conference in Anchorage last November, Steve Wright, the manager of Chevron's assets in Alaska, said that the four largest Cook Inlet gas fields delivered around 14 billion cubic feet in January 2004, but less than 9 billion cubic feet in September 2008. Wright said Cook Inlet deliverability is falling at a rate of 8 to 14 percent, depending on how you slice it, a trend line he said is "quite alarming for all residents in the Anchorage bowl."

Tony Izzo, the former head of Enstar and now a local consultant, explained it this way to the Anchorage Assembly last November: "We're only as strong as the weakest link in the energy infrastructure and the weakest link right now is deliverability."

The problem isn't a lack of solutions. It's an abundance of them.

The debate going on right now among producers, utilities, regulators and the government is about the best way to solve this problem, knowing on the one hand that time is of the essence and on the other hand that Alaska will be stuck with its decision for decades. The solutions fall into two general categories: bolstering Cook Inlet or supplementing it.

Bolstering Cook Inlet means getting the basin to do more. One way is by artificially increasing the pressure of the natural gas using compressors, allowing a smaller amount of gas to flow with the ease of larger quantities. But while these compressors alleviate the problem, they don't solve it entirely. On occasion, a compressor can fail suddenly, or "trip," for several hours, causing drops in pressure. A compressor at the Beluga River field, one of the largest and oldest in the region, has tripped at least 12 times since being installed in April 2007, according to two area companies that depend on the unit.

Another way to improve deliverability is to decrease the need for natural gas by making power plants that run better, retrofitting buildings to be more efficient and training customers to conserve. "This isn't always about the supply side. It's the demand side also," Carri Lockhart, Alaska production manager for Marathon, said in late March.

Another way to improve deliverability is have gas available any time. This means increasing storage. One of the primary challenges for heating Alaska is managing the extreme swings between summer and winter demand. Storage facilities allow producers to pull natural gas from the ground at a more measured pace from month to month, limiting stress on the reservoirs. Enstar could then use extra gas produced during the summer to meet increased demand in the winter. Storage facilities are expensive, though.

Enstar estimates that the investments needed to offset declines in gas supplies anticipated in 2011 would cost somewhere in the neighborhood of $25 million to $100 million.

In addition to a few traditional storage facilities across the Cook Inlet, there is also a major makeshift storage unit already in operation. It's a 42-year-old facility in Nikiski that super-chills natural gas into a liquid state and loads it onto barges that sail across the Pacific Ocean to feed power companies in Tokyo. This facility, owned jointly by ConocoPhillips and Marathon, frustrates some state lawmakers, who cannot reconcile shipping natural gas to Asia while business leaders complain about declining supplies and looming shortfalls in Alaska. In early May, three Anchorage-area Democratic senators—Bill Wielechowski, Johnny Ellis and Bettye Davis—asked the Palin administration to require Cook Inlet producers to sell gas to Alaska utilities before shipping it to Asia.

But the senators also acknowledged one of the key benefits of the plant: It's viewed by many as being the last line of defense against system failure. During cold snaps, natural gas is diverted from the plant into the local grid. These diversions have kept the system afloat several times over the past decade, but like the rest of the system, the plant has less natural gas is flowing through it each year. During the 1999 cold snap, the plant held 224 million cubic feet of natural gas. During the cold snap this year, it held only 40 million cubic feet.

This plant is the only export facility of its kind in the country and every so often the owners of it must return to the federal government to get renewed permission to ship domestic gas overseas. This export license was set to expire this year, but the companies got it extended to 2011 with the backing of the Palin administration. In return for its support, the administration told ConocoPhillips and Marathon to drill new wells in aging fields. The goal was to increase deliverability, just as two straws suck faster than one straw. The companies followed through, but haven't released the results yet. And Marathon has already said it plans to drill half as many wells this year as last year.

As the big players expand old fields, several smaller companies believe there are still undiscovered reservoirs in Cook Inlet. But companies both large and small say they have little incentive to drill in Cook Inlet because they can't get a competitive price for gas.

Which gets to the heart of a decades-long debate: What is Cook Inlet gas really worth?

The hearing room of the Legislative Information Office in Anchorage was nearly packed on the afternoon of November 25, 2008, two days before Thanksgiving. Small business owners filled the front rows, followed by regulators and public advocates, and executives from Enstar, Chugach, ConocoPhillips and Marathon. It was a hearing before the Senate Judiciary Committee called by its chair, Senator Hollis French. French had recently received an email from Adam Galindo, vice president of Taco Loco in Anchorage. French paraphrased the message: "They're saying I'm not going to have gas in a month. I make tacos for a living. How am I supposed to figure out where to get a gas supply?"

Local gas supplier Aurora Power Resources had announced plans to drop around 400 commercial customers, effective December 1. Enstar offered to supply those customers, but only through the end of the year. Enstar couldn't legally offer service in 2009, it said, because regulations prohibited the company from adding customers if it didn't already have gas under contract to meet the additional demand. Enstar said it didn't have the gas.

The business owners understood they were collateral damage in a larger battle. "There's an old saying in Africa about how when elephants fight only the grass gets tromped, and that's kind of where I feel I am today," said Mike Gordon, owner of the bar Chilkoot Charlie's. Enstar agreed, but said the fight was bigger and longer than most people realized. "We feel like we are the grass underneath the elephants, also," Dan Dieckgraeff, the manager of rates and regulatory affairs for Enstar, said during testimony.

Enstar had been trying to get more gas supplies for years. In fact, for the six months prior to the November hearing, Enstar had been knee-deep in filings to convince state regulators to let it buy gas from Marathon and ConocoPhillips. And just a few weeks before the hearing, on Halloween, the regulators agreed, but only on the condition that Enstar negotiate a different price for the gas. The regulators told Enstar to make the changes to the contracts by December 1.

This scene would be unlikely anywhere in the United States except Alaska, because the natural gas market in Cook Inlet is fundamentally different than the rest of the country. The Lower 48 gas market is highly liquid, meaning there are many buyers looking for the best deal and many sellers competing against each other to offer the best deal. As a result, prices constantly change as buyers leave one supplier for another, as sellers try to out-price their competitors, as explorers find new reservoirs and as pipeline builders make more efficient connections. The price at any given time is called the spot market.

There has never been a spot market for natural gas in Alaska. The prolific gas fields in the Cook Inlet were found by accident in the 1950s and 1960s, the consequence of early oil exploration. Unable to sell this gas on the world market, companies signed long contracts with Anchorage-area utilities, supplying the region with relatively cheap natural gas at a stable price. Over the decades since, though, these original contracts expired and, after negotiations, were replaced with new, usually more expensive contracts, leading to steadily increasing gas and electricity bills throughout the region (although still typically below Lower 48 prices). (ML&P charges less for electricity than Chugach because ML&P bought a share of the Beluga gas field in the 1990s.) These overlapping and leap-frogging contracts means there is no spot market for natural gas in Alaska. Instead, producers and local utilities negotiate supply contracts, which state regulators either approve or reject.

Enstar currently has five supply contracts, each running for different lengths of time, each supplying a different amount of gas for a different price. Enstar combines these contracts to arrive at an average cost for all the gas it buys. This number is the centerpiece of your monthly Enstar bill, and the reason that bill has nearly tripled since 1998. But Enstar doesn't actually profit from that increase. The price of gas is a pass-through cost: You pay Enstar, and Enstar in turn pays the producers, like ConocoPhillips, Marathon or Chevron.

As a shipping company, Enstar makes money from the amount of natural gas it sells, not from the price. In other words, the company makes the same amount of money if it sells a unit of gas at $1 or $2 or $1,000. Enstar also claims that the cost to deliver that gas has dropped when adjusted for inflation (although the company recently asked regulators to up those delivery rates for the first time since 1984). It also likes to claim that it actually makes less money when prices go up, because customers tend to cut back.

Those original long-term contracts worked as long as the companies didn't need to drill new wells, but as the fields aged, those old wells slowed down and deliverability declined. Faced with the prospect of drilling new wells, the companies said the price of gas in Alaska didn't justify the expense of looking for more of it. Why should we spend money looking for gas in the Cook Inlet, the companies argued, when it's cheaper to look for gas in Wyoming or Louisiana, and we can get a higher price for whatever we find?

Without a spot market, though, no one can agree on what the "right" price should be.

For at least the past decade, producers, utilities and regulators have tried to find the perfect index, a way to use prices around the country to approximate a price for Alaska. For instance, since Anchorage is around 50 miles from its source of natural gas, maybe the local price should be based on prices in Texas or Colorado, areas with nearby natural gas production. Or, maybe, because Alaska is cold and icy, the price should be higher.

Just like any act of translation, indexes are imperfect. Some Enstar contracts are indexed to Lower 48 crude oil prices over the previous summer. Oil prices hit record highs last summer, peaking near $150 a barrel, and so in turn Enstar rates jumped 22 percent this year. Because the index only covered the summer months, Enstar's rates didn't drop when oil prices tanked last fall, but its rates will drop next year (unless oil spikes again).

Another Enstar contract, signed with Unocal in 2001, is tied to Henry Hub, a place in Louisiana where around 13 different pipelines connect. All those connections make Henry Hub very liquid, which is why it's considered to be an accurate snapshot of the national marketplace. This Henry Hub-based contract cuts both ways. Imagine if natural gas in Anchorage simply matched the Henry Hub price: last summer we would have paid more than $13 per thousand cubic feet of gas, double the actual price. But right now, we would be paying $4.25, about half our current rate. During regulatory hearings over the contract, Unocal said companies needed to start looking for new gas fields in the Cook Inlet. "The contracts you've approved in the past are traditional supply contracts. This is an exploration contract. Traditional supply contracts involve the sale of gas that already exists. It's there. An exploration contract is a contract where you have to go out and you have to find it," the company testified. The Public Advocate, a section of the state Department of Law that argues the side of the people during regulatory cases, said the proposed contract didn't guarantee the higher price would be used only for "new" gas. Under the terms of the contract, Unocal could charge Henry Hub for existing gas, too.

Some insist this is exactly what happened, comparing the price consumers paid for gas under the Unocal contract with the price under other contracts. "This pricing difference under the American Henry Hub is the principal reason for the increased cost of gas supply to ratepayers in Cook Inlet. Enstar's consumers have paid Unocal $184 million more, or about $850 per customer, under what was presented as an exploration contract," Commissioner Kate Giard of the Regulatory Commission of Alaska wrote on February 27, in a statement she called the "Reader's Digest" version of Cook Inlet pricing story.

The Regulatory Commission of Alaska, or the RCA, is an independent branch of state government charged with approving gas supply contracts in Alaska. The RCA approved the 2001 contract, but hasn't approved another major contract since. In 2005, Enstar brought forward a contract with Marathon called APL-5. This contract also used Henry Hub, which Enstar said would help address "serious supply problems in Southcentral Alaska." The Public Advocate again stepped in, saying Enstar's primary concern was locking down a reliable supply of gas. "It will pay virtually any price to get its supply because its costs are passed through," the Public Advocate said. The RCA ultimately rejected APL-5. Still looking to fill holes in its portfolio, Enstar introduced APL-6 in April 2008, a pair of contracts: one with Marathon and another with ConocoPhillips.

ConocoPhillips and Marathon did not participate as parties in the case, saying only that prices in Alaska needed to increase to compete with prices around the country. The RCA agreed, but only if the producers could prove that production costs in Alaska were also higher. The producers didn't provide regulators with concrete figures for drilling costs in the Cook Inlet compared with other parts of the country. Without those, the RCA said it couldn't consider the cost argument, citing a 35-year-old State Supreme Court decision saying the RCA can't make decisions based on "bald assertion." They need hard data.

"Typically when someone comes forward with a contract, they come forward and they say, 'Trust me, I need this price.' But there's no evidence to back it up," Commissioner Anthony Price said during an RCA meeting in March. "So when people come and just state that they need a price and don't produce any evidence, what are we to do?"

A major complication in this ongoing price war is that the RCA regulates gas buyers like Enstar and Chugach, but not gas sellers like ConocoPhillips, Marathon and Chevron. This turns Enstar and Chugach into middlemen forced to manage the demands of industry against the demands of regulators. In the 2008 rate case, for instance, Enstar negotiated contracts with ConocoPhillips and Marathon. Then the RCA rejected those contracts and proposed a price cap based on an index of North American prices. Enstar brought the proposal to the producers, who in turn rejected it. Ultimately, Enstar used a legal loophole to buy the gas it needed. If it hadn't, those 400 businesses would have been left in the cold.

Some people complain the RCA is overly focused on price instead of supply: worrying about consumers getting a good rate, but not about whether they will even have gas to buy in the future. One of those people is Dave Harbour, a former RCA commissioner who wanted to approve the 2005 APL-5 contract and whose term expired before the RCA began considering the newer APL-6 contracts. Over the past six months, Harbour has spoken publicly several times about the gas situation in Cook Inlet, including a February 23, 2009 speech before a group of local energy economists where he praised the decision to approve the 2001 contract, but criticized the recent rejections. “The 2001 gas supply agreement with Union Oil Company was properly approved by a wiser commission concerned about price and near and long term supply for citizens,” Harbour said. “In their more recent APL-5 and APL-6 decisions, the majority of Commissioners have mistakenly concluded that their change in regulatory policy should result in an immediate improvement in prices and not adversely affect private investment decisions and results.”

During the 2008 Enstar rate case, Natural Resources Commissioner Tom Irwin wrote to the RCA, saying, “Long-term solutions must reflect the cost to find and develop the new resources that will be required to meet the public demand for gas supply.” Commissioner Kate Giard replied, saying Irwin’s comment reflected “a disappointing lack of awareness of recent RCA case history” because the producers said production costs didn’t matter; what mattered was establishing a price that made companies want to invest in Cook Inlet. “It is elementary that knowing the cost to produce gas is necessary to truly hit the bulls-eye in setting gas prices,” Giard wrote. “We have been denied this information.”

Giard said if the Department of Natural Resources wanted to guarantee that regulators would consider production costs in future cases over natural gas supply contracts, it could require companies to provide that information as part of the lease agreements governing mineral development on State lands. She said the legislature could go one step further by passing laws that require production costs to be a factor in setting prices. “Without the DNR or the Legislature taking positive action, no gas price will be accurate,” she wrote.

Despite the hours of legislative testimony this year devoted to natural gas in Alaska, not one lawmaker proposed changes to the way the RCA considers gas supply contracts.

This gridlock isn’t just affecting big companies. It’s also influencing the search for new gas supplies in the Cook Inlet. Even with talks of looming gas shortfalls in the Cook Inlet—which should create a paradise for gas sellers—the small Houston-based company Escopeta Oil suggested in recent state filings that it preferred to look for oil rather than gas at a prospect in the waters south of Tyonek called Kitchen Lights. Even if Escopeta made a big find of gas, it couldn’t be completely sure it could sell it into the local market. A small company from Denver called Armstrong Oil and Gas found gas last summer after drilling a well on southern Kenai Peninsula, following up on a prospect north of Homer first explored nearly 45 years ago. This past March, Armstrong told the RCA it couldn’t justify developing the prospect without knowing it could make a decent profit. If Armstrong provides production cost data and gets the RCA to approve a supply contract, it could change the dynamic of buying and selling natural gas in Southcentral Alaska.

Another potential turning point on the horizon comes from the second largest buyer in the region. On May 12, Chugach submitted its first long-term supply contract in more than two decades to the RCA, an agreement to buy around 66 billion cubic feet of natural gas from ConocoPhillips through the end of 2016. The price of that gas is based on an index of five producing regions in Texas, Louisiana and Oklahoma, similar to the approach the RCA suggested last year, but the producers, including ConocoPhillips, ultimately refused.

Chugach wants the RCA to approve the contract by November 30.

Meanwhile, the RCA is looking at ways to resolve the pricing problem, including the possibility of creating a standard contract to alleviate the uncertainty facing producers and utilities. Everyone agrees pricing must be reconciled, regardless of the future of Cook Inlet. Declining deliverability can be fixed by replacing Cook Inlet gas with North Slope gas, but new gas still need a price and there still won’t be a spot market. Even fuel from proposed renewable energy projects—like wind and geothermal—will need a price.

With all those headaches, it makes sense that Enstar is interested in looking beyond Cook Inlet for natural gas. Without new supply contracts, Enstar faces a shortfall in 2011. Even with new contracts, Enstar is projecting regional demand will outpace Cook Inlet supplies by 2015. This is the argument for supplementing Cook Inlet, rather than just bolstering it.

It’s long been assumed the North Slope would eventually provide relief to Southcentral in the form of a major gas pipeline running from Prudhoe Bay to Outside markets. Along the route of this big pipeline, take off points would allow Alaska communities to tap the pipeline for local use. In March 2008, though, Enstar signaled its impatience with this game plan, saying it was looking into building a “smaller” pipeline to bring a northern natural gas supply directly into Anchorage, without worrying about hitching local needs onto a project bound for Outside markets. This project is now called the “bullet line.”

“We need gas sooner rather than later,” Colleen Starring, Enstar’s regional vice president, told an industry group in May 2008. “If there were another discovery in the Inlet that’s great, but we can’t wait for that to happen.”

Every pipeline needs a supply. Enstar is focused on the Gubik Complex, a series of natural gas fields dotting the northern foothills of the Brooks Range. Government drilling crews discovered Gubik in the early 1950s and entrepreneurs in Fairbanks at the time looked at developing the field, but decided the numbers didn’t pan out. Anadarko Petroleum Co., a large exploration company out of Houston, arrived in the area in 1998, picking up more than 3 million acres in leases. The company drilled its first Gubik wells in early 2008, and returned to drill more wells this year. The program is unprecedented. All previous gas discoveries in northern Alaska have been accidents, or byproducts of the search for oil. Never before has a company specifically targeted gas in northern Alaska.

The reason for that is simple: there is no way to sell natural gas from northern Alaska, because there is no way to get that natural gas to market. For that reason, many saw Anadarko’s decision to spend tens of millions of dollars looking for gas it can’t currently sell as the company showing faith in various efforts to build a big pipeline, including the Alaska Gasline Inducement Act, or AGIA, Governor Sarah Palin’s 2007 effort to move the project along. Since Anadarko began exploring the region, two competing projects have emerged, the TransCanada effort under AGIA and the Denali project outside of AGIA.

Enstar’s bullet line intrigues Anadarko. It gives the company an alternative if the big pipeline fails or gets delayed. Also, the bullet line offers a financial incentive. Cook Inlet producers currently get a tax break for gas they sell within Alaska. In November 2007, state lawmakers extended that break to the rest of the state, meaning Anadarko would pay lower taxes if it ships its gas through a bullet line, rather than through a big pipeline.

While Enstar looks at this direct bullet line from northern Alaska, other groups continue to pursue the original plan for Anchorage: a spur coming off the proposed big pipeline.

A spur line has an advantage over a bullet line: it’s cheaper. It’s cheaper for several reasons. First, it’s shorter. A bullet line would need to be 800 miles or longer to stretch from northern fields to Anchorage, while a spur would be around 460 miles long.

Second, the spur line is cheaper because it takes advantage of economies of scale on the big pipeline. Market prices like Henry Hub only represent the cost of the actual commodity of gas, not the additional cost to move it from fields to homes. Just like you pay a toll to drive on certain roads, producers pay a toll to ship their gas through a pipeline. These tolls, known in the pipeline world as tariffs, let a company like Enstar recover the cost of building a pipeline and also earn a profit. Producers pay these tariffs, but ultimately pass the cost on to you.

So a cheaper pipeline means cheaper gas for consumers. But so does a busier pipeline. As more customers buy gas, the fixed costs of the pipeline get spread over more people. If two pipelines cost the same amount to build, but one carries more gas than the other, that gas would be cheaper to buy. Volume tempers the cost.

Enstar estimates a 700- to 800-mile bullet line carrying 500 million cubic feet of gas per day will cost around $4 billion. It’s called a “smaller” pipeline because it would only be around half the length of the proposed big pipeline, only carry 11 percent of the volume of its larger sibling and only cost 10 percent as much. But it’s still a world-class project. To get a sense of the size of the proposed bullet line, consider this: the five longest Lower 48 gas pipelines completed in 2007 combined run 789 miles, but cost only $1.7 billion and move 3.4 billion cubic feet daily, according to the most recent information from the U.S. Energy Information Administration, the statistical arm of the U.S. Department of Energy. Here's another way to look at it; Those pipelines cover roughly the same distance as the proposed bullet line, but they move nearly seven times as much gas at 40 percent of the cost. By comparison, the lower volume and higher cost of the proposed bullet line would mean higher tariffs, and ultimately, more expensive gas for Alaskans.

Enstar can temper this by anchoring the line to big industrial customers, gas hungry businesses like the mothballed Agrium fertilizer plant in Kenai, the ConocoPhillips and Marathon facility in Nikiski for exporting liquefied natural gas, and various military bases across Alaska. The current demand of natural gas in Alaska is around 500 million cubic feet per day, split fairly evenly between residential and industrial customers. If Enstar could find a way to significantly increase regional demand by adding several new industrial customers, these anchors would go a long way toward easing the cost borne by residential customers. But Enstar can't scale up the bullet line unless it wants to cut all ties with the state. Under the terms of AGIA, the state cannot give "preferential royalty or tax treatment" to a competing pipeline, defined as one that ships more than 500 million cubic feet per day.

The spur line doesn't need as many industrial anchors. It has one of the largest anchors in the world: the Lower 48 electric and heating market. The current proposals for a big pipeline involve shipping up to 4.5 billion cubic feet of gas daily through Canada. The spur line would divert as much as 500 million cubic feet to Alaska, between 5 and 10 percent of the total volume. Essentially, the Lower 48 would ease the burden for Alaska.

The biggest proponent of a spur line is the Alaska Natural Gas Development Authority, a public corporation created by a 2002 ballot measure. ANGDA is semi-autonomous, funded by the legislature but guided by a seven-member board appointed by the governor. For several years, ANGDA has been collecting permits and conducting fieldwork for a spur line. The agency wants to gather enough information this year to hold an open season, where a sponsor looks for shipping commitments to justify the construction of a pipeline. ANGDA believes that by combining all the various utilities in Southcentral that need natural gas, it can create one large customer able to secure a relatively inexpensive supply of stably priced gas for decades.

By definition, though, the spur line needs a main line. And momentum on the main line is uncertain. Some believe the project won't come together fast enough to offset declining Cook Inlet deliverability. Others believe it won't come together at all. Everyone, though, agrees the mainline won't be ready to meet the shortfalls projected over the next few years. Under the best-case scenario, the big pipeline would come online in 2018. More realistically, the pipeline wouldn't likely be online until 2020 or 2021, or longer, leaving customers in Southcentral without proper gas supplies for a gap of seven years or more.

A bullet line trims that gap, but doesn't close it entirely. Anadarko says it needs to drill more wells before it can decide whether to develop Gubik. The company told lawmakers it doesn't see the field coming online before 2016. Enstar could extend the bullet line farther north to Prudhoe Bay, a known source of gas ready to be developed, but that would increase the cost of the project, not only because the line would be 150 miles longer, but also because the quality of North Slope gas means it requires more processing than gas from Gubik.

Upon taking office in late 2006, the Palin administration said the big pipeline would address the needs of Alaska consumers. Earlier this year, though, the administration took a more active role in efforts to build an in-state pipeline, hiring someone to coordinate the various efforts of ANGDA and Enstar. The administration says it still expects AGIA to deliver a pipeline, it just doesn't know if the pipeline will come soon enough to address shortfalls. This raises questions: Why anchor Alaska to a costly bullet line if the administration believes the cheaper option will eventually materialize? Why not look instead for a bridge between now and the time a big pipeline starts shipping gas? Enstar is looking into importing gas for a few years starting in 2011. Why not import for a few more? Wouldn't consumers be willing to pay higher prices for a few years if it meant lower prices for decades to come?

The administration believes it is being prudent. “If we don’t start working on it now, it may be too late to consider that as an option in 2011 or 2012 when we know what our choices really are,” Joe Balash, Palin’s assistant for oil and gas issues, told lawmakers in April.

Speaking to reporters on the last day of the session, Palin framed the issue differently: “Alaskans may at some point be asked to make a choice here: Do we want to import natural gas for use to energize our economy, our homes, our businesses? Or do we want to commercialize our own Alaskan-owned natural gas?” In a recent op-ed in the *Anchorage Daily News*, Palin said she wasn’t “walking away” from anything, not the big pipeline, not the spur line and not efforts to ship liquefied natural gas from Valdez, the “all-Alaska line.” Palin wrote, “We are reviewing all options to ensure Alaskans know all the facts about progress to flow gas to our homes and businesses.” The basic dilemma is the wallet versus the watch. A spur line promises cheaper gas, but is dependent on a large, expensive, complicated project. A bullet line is independent, but its independence will likely make it more expensive. And while imports can be temporary, these pipeline projects are permanent. They’re almost certainly mutually exclusive, as well; Alaska will be stuck with whichever one ultimately gets built.

In the meantime, it’s summer in Anchorage again. Long hours of sunlight mean less electricity, and rising mercury means lower natural gas bills. It’s a temporary reprieve, of course. Come October, winter will creep back over the city, and when it does Southcentral Alaska either will—or won’t—be ready for another big cold snap.

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