Email chain between Matthew Stobart and others at CB&I discussing options to meet TOTE methane number requirement (3/15/2017)

Message

From:	Schneider, Kurt J [Kurt.Schneider@cbi.com]
Sent:	3/15/2017 3:07:46 PM
To:	Stobart, Matthew E [Matt.Stobart@cbi.com]
Subject:	RE: Tacoma LNG - Status of Alternate Feed Gas Study

Thanks for the update Matt.

Kurt

From: Stobart, Matthew E
Sent: Wednesday, March 15, 2017 10:02 AM
To: Schneider, Kurt J <Kurt.Schneider@cbi.com>; Bertha, Greg J <Greg.Bertha@cbi.com>; Pearson, Thomas C <Thomas.Pearson@cbi.com>; Landfried, Kevin D <Kevin.Landfried@cbi.com>
Cc: Tsurusaki, Ken <Ken.Tsurusaki@cbi.com>; Baker, Jeffery J <Jeffery.Baker@cbi.com>
Subject: Tacoma LNG - Status of Alternate Feed Gas Study

Gents,

Just wanted to send a note to let you know where we are with this issue right now. We passed along the Alternate Feed Gas Composition Report to PSE (Jim Hogan) on Monday evening. I've attached here the report sent to PSE again for reference. Jim was very grateful for the information and seemed to grasp the intricacies quickly. We got some feedback from him yesterday (Tuesday - contained in the below email string). We then had a teleconference with him late in the day yesterday to discuss. Basically Jim says PSE won't pursue a facility design simply to accommodate a turned down case (ie:, for anything less than a full 250,000 GPD LNG production rate). Jim acknowledged it's nice to know what the heavies generation and LNG quality is in the turned down state (because they still might end up operating there temporarily), but they will still have to plan for full production. That then eliminated some of the cases we'd evaluated.

Jim also said that installing another parallel line to their main feed line (to be used as a tailgas line) is highly unlikely…….mostly for permitting reasons and associated risk of reopening the EIS. So far PSE management has been resistant to the tailgas line idea. This of course means that we would need to deal with the heavies on site. This leaves only a couple of options. Either burn it, or get rid of the vapor in another pipeline and/or truck the heavy vapor and liquids away. As we all know, this is a lot of product, and any of these options would also likely trigger permitting issues for the facility and/or reopening the associated EIS. Burning it would require a huge flare.

Jim is brainstorming ideas like trying to inject the vapor state heavies (blended with a lot of incoming gas) into a local distribution pipeline already existing in the Port, or compressing and carting away in tube trailers for injection elsewhere into their system. But it's a lot of gas to inject and/or a lot of tube trailers to fill. He would still have to truck away the accumulated liquid heavies per the original plan for the facility, but at increased frequency.

We also discussed at length the quality of the LNG and the impact that has on the accumulated heavies. We learned from Jim that the 80 Methane Number (MN) requirement comes directly from PSE's contract with TOTE. There are no other requirements in this contract (such as max ethane or propane or any other heavies). They just have to meet the methane number. Which is good news for them (and us) as long as TOTE's engines can use it. Jim is pursuing with TOTE and through other channels information on what the engines can tolerate.

Jim said that PSE is also heavily pursuing the pipeline gas quality issue with Williams (the pipeline supplier). PSE's CEO is the president of the AGA this year and has a lot of stroke. Fortis BC (off the same pipeline) is also experiencing a lot of headaches from the gas quality, and I would guess other users off the line all the way down to California are also experiencing issues (like Clean Energy with their Boron facility).

Bottom line is Jim wanted to know what the change in plant efficiency is in terms of "BTU's in" vs "BTU's in the LNG" compared to our base design. We are calculating that now. Other than that we are to stand down and carry on with business as usual. We are to keep the base design EPC execution of the project in full swing and do nothing more in this regard until further instructed..

Matt

From: Stobart, Matthew E
Sent: Tuesday, March 14, 2017 2:10 PM
To: 'Jim Hogan' <jim.hogan@pse.com>
Cc: Kauhane, Jennifer (jennifer.kauhane@pse.com) <jennifer.kauhane@pse.com>; Tsurusaki, Ken <Ken.Tsurusaki@cbi.com>; Baker, Jeffery J <Jeffery.Baker@cbi.com>; Mullen, Thomas <Thomas.Mullen@cbi.com>; Redman, Randall W <Randall.Redman@cbi.com>
Subject: FW: Discuss gas composition study

Jim,
Here's a little more progression for you to chew on that might help with your thinking about utilizing the local distribution pipeline. You'll need to blend for two reason: 1) to get the Dew Point (DP) above 40DegF so that liquids don't drop out in the line, and 2) to reduce the HHV to pipeline levels. Bottom line is that to get the gas back down to 1200 HHV you need to blend and inject quite a bit of gas (anywhere from 2.5 to 4.5 MMSCFD total injected into the LDP). Don't know what the usage of the LDP is, but that's obviously quite a bit of gas. We can discuss more this afternoon.
Matt

From: Redman, Randall W
Sent: Tuesday, March 14, 2017 1:20 PM
To: Mullen, Thomas <Thomas.Mullen@cbi.com>
Cc: Stobart, Matthew E <Matt.Stobart@cbi.com>
Subject: RE: Discuss gas composition study

Correction to pipeline flows not only including the fuel being used, but I reported the total flow rather than flow from pipeline.

Correct answers are:
Case 6A:
For 40 F DP; 0.64 MMSCFD from pipeline for total of 0.95 MMSCFD at 1372 HHV
For 1200 HHV; 2.11 MMSCFD from pipeline for total of 2.42 MMSCFD.

Case 1A:
For 40 F DP; 0.45 MMSCFD from pipeline for total of 1.15 MMSCFD at 1515 HHV
For 1200 HHV; 3.73 MMSCFD from pipeline for total of 4.43 MMSCFD.

From: Redman, Randall W
Sent: Tuesday, March 14, 2017 12:52 PM
To: Mullen, Thomas <Thomas.Mullen@cbi.com>
Cc: Stobart, Matthew E <Matt.Stobart@cbi.com>
Subject: RE: Discuss gas composition study

Clarification:
The mixing I did was for the entire fuel gas vapor. I did not subtract the 6 MMBTU/hr fuel that was being used.
Sorry if this causes any confusion.

I'll recalculate.

From: Redman, Randall W
Sent: Tuesday, March 14, 2017 11:48 AM
To: Mullen, Thomas <Thomas.Mullen@cbi.com>
Cc: Stobart, Matthew E <Matt.Stobart@cbi.com>
Subject: RE: Discuss gas composition study

Does this mean 5A (Full rate, no excess fuel but MN of 78) is out?

The fuel vapor is at a pressure of 100 psig for both 1A and 6A. This is saturated vapor at this pressure and not high enough pressure to get back into the pipeline.
We would need to make some modifications to get into the pipeline (fuel gas compressor, higher separator pressure, or lower feed boost inlet with throttle).

The conditions for the fuel vapor are:
Case 1A:
Methane: 42.7%(mole)
Ethane: 25.0%
Propane: 20.3%
Butanes: 9.8%
C5+: 2.1%
HHV: 1791 BTU/SCF
Flow: 0.78 MMSCFD (2619 lb/hr)

Case 6A:
Methane: 37.5%(mole)
Ethane: 22.5%
Propane: 22.0%
Butanes: 14.2%
C5+: 3.8%
HHV: 1949 BTU/SCF
Flow: 0.39 MMSCFD (1420 lb/hr)

In the 6A case; to dilute the 0.39 MMSCFD flow to a dew point above 40 F, would take 0.79 MMSCFD of pipeline gas. The HHV would still be 1372 BTU/SCF and only 74% Methane.
To get to 1200 BTU/SCF, 2.6 MMSCFD pipeline gas is needed.

Same evaluation could be done for case 1A just not enough time yet.

Randy

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From: Mullen, Thomas
Sent: Tuesday, March 14, 2017 9:39 AM

To: Redman, Randall W <Randall.Redman@cbi.com>
Cc: Stobart, Matthew E <Matt.Stobart@cbi.com>
Subject: FW: Discuss gas composition study

Going to a 2 hour meeting now, but I think you're the best one to cogitate on this anyway.

-Thomas

From: Hogan, Jim [mailto:jim.hogan@pse.com]
Sent: Tuesday, March 14, 2017 9:35 AM
To: Stobart, Matthew E <Matt.Stobart@cbi.com>; Tsurusaki, Ken <Ken.Tsurusaki@cbi.com>; Mullen, Thomas <Thomas.Mullen@cbi.com>
Cc: Kauhane, Jennifer <jennifer.kauhane@pse.com>
Subject: RE: Discuss gas composition study

A couple items to think about before our conversation.

Based on the feedback I have received, a limit of LNG production is not acceptable and we would look at the ramifications of cancelling the project rather than proceed with a plant that can't meet our design volumes. This would eliminate options 1B, 3, 5B, and 6B. The caveat to that would be the potential success that we and other west coast utilities may have pressuring the gas suppliers to increase methane content. I see this as a longer term solution and therefore not something that we can plan for in this exercise.

Based upon that, I feel that 1A and 6A are likely options to discuss further.

A couple questions on fuel vapor generation:

1. What is the content and pressure of the fuel vapor generated (I'm looking at the possibility of converting it to CNG and/or injecting it into the local distribution system).
2. Why can't we take the fuel gas stream and inject it back into the system at the inlet gas compressor, thereby increasing the methane content of our intake stream and diluting the main stream?

Based on the points above, I'd like to better understand the physical implications (plant hardware) of 6A.

Thanks,
Jim

From: Hogan, Jim
Sent: Tuesday, March 14, 2017 7:10 AM
To: Matt Stobart; Ken Tsurusaki (ktsurusaki@cbi.com); Mullen, Thomas
Cc: Kauhane, Jennifer
Subject: Discuss gas composition study

Can you provide some times when all three of you would be available today or tomorrow to walk through the paper?

I think an hour would be adequate at this point. I shared it internally and it needs a few more hours of soak time this morning before I can talk.

Thanks,
Jim