BRITISH COLUMBIA UTILITIES COMMISSION

IN THE MATTER OF THE UTILITIES COMMISSION ACT
RSBC 1996, CHAPTER 473

and

FortisBC Energy Inc.
Application for a Certificate of Public Convenience and Necessity
for the Tilbury Liquefied Natural Gas Storage Expansion Project

Vancouver, B.C.
March 11th, 2021

WEB-BASED WORKSHOP

BEFORE:

A.K. Fung, Q.C.,	**Panel Chair**
T.A. Loski,	**Commissioner**
R.I. Mason,	**Commissioner**
D.M. Morton,	**Commissioner**

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Christopher WEAFER Patrick WEAFER David Craig Janet Rhodes	Commercial Energy Consumers Association of British Columbia (CEC)
James LANGLEY	Sentinel Energy Management Inc. (SENTINEL ENERGY)

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Ian Finke
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Lisa Dang
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INDEX

PAGE

1 **VANCOUVER, B.C.**
2 **March 11th, 2021**
3 **(PROCEEDINGS COMMENCED AT (9:00 A.M.)**
4 MR. CHERNIKHOWSKY: Good morning everyone, if we could
5 get started. Welcome to FortisBC's workshop to review
6 the Tilbury LNG storage expansion project. My name is
7 Paul Chernikhowsky, and I'm the director of regulatory
8 projects and resource planning at FortisBC. In
9 previous roles with the company I was our director of
10 engineering and integrity management, so I've met many
11 of you in previous proceedings.
12 Before we start the FortisBC portion of the
13 session, I'd like to invite Commissioner Fung to
14 provide some opening remarks.
15 THE CHAIRPERSON: Thank you very much, Mr.
16 Chernikhowsky, and good morning everyone, and on
17 behalf of the B.C. Utilities Commission, I welcome you
18 to this workshop. And as you're aware, this workshop
19 is part of the public hearing process that the B.C.
20 Utilities Commission has established to review the
21 application by Fortis.
22 My name is Anna Fung and I am the Deputy
23 Chair of the B.C. Utilities Commission, and the Chair
24 of the panel assigned to hear this matter. With me
25 today are my three fellow panel members, Commissioner
26 David Morton, Tom Loski and Richard Mason. As well as

1 a number of BCUC staff who I will introduce later,
2 along with our BCUC Legal Counsel, Mr. Lino Bussoli
3 from Bridgehouse Law LLP.
4 Now, the purpose of this workshop today is
5 for FEI to present its application to the panel and
6 interveners, and for us to ask clarifying questions
7 about FEI's presentation. I remind all of us that
8 there will be ample opportunity for us to ask detailed
9 or technical questions in the course of the IR process
10 that will follow the workshop.
11 In addition, transcripts of this workshop
12 will be posted to the BCUC Website for detailed review
13 as soon as possible after the workshop.
14 Now, FEI has sent us a copy of the agenda
15 for this workshop, which is scheduled to last until
16 4:00 P.M. today. Now, I understand that FEI has
17 scheduled morning and afternoon breaks, along with a
18 lunch break at noon.
19 **Proceeding Time 9:02 a.m. T2**
20 I just want to let everyone know now that
21 Commission Morton has a hard stop at four o'clock
22 today as he has a call scheduled for that time. So if
23 it looks like that the workshop will need to extend
24 beyond 4:00 P.M., I would ask that we take a 20-minute
25 break at four o'clock before reconvening at 4:20. So
26 please keep that in mind.

Now, I would like to remind all of you to please mute your microphones and keep them muted until you're called upon to speak and appear via Teams video. If you have a question or comment that you wish to make during the workshop, please use your virtual hand to speak so that we can maintain some semblance of order. And since we're dealing with technology here I cannot promise you that everything will go according to plan, but in a worst-case scenario if we lose any parties we will temporarily adjourn the workshop and try to regroup and figure out where to go from here.

I'd like to remind everyone that this workshop is being transcribed and also being broadcast to the public via streaming. And please know that no recordings or rebroadcasts of this workshop will be permitted beyond that required by our Hearing Officers, Mr. Hal Bemister and Mr. Keith Bemister of Allwest Reporting for transcription services.

Now, just a couple of words about confidentiality. As you're aware, while this workshop is limited to registered interveners who are appearing via Teams video, we cannot guarantee confidentiality since we do not know who may be sitting in the same room with you or may walk by while we're each online within our homes or offices.

1 Now, I do not anticipate the need to file
2 any exhibits today, including confidential exhibits,
3 in the course of today's workshop, but in necessary we
4 will deal with that by asking that they be filed with
5 the Commission Secretary after today's workshop in
6 accordance with Part 4 of the BCUC Rules of Practice
7 and Procedure. And to assist with the transcription
8 of the workshop, please remember to state your name
9 before you speak.
10 **Proceeding Time 9:04 a.m. T3**
11 And I'd like to now introduce you to the
12 BCUC staff on this proceeding who will be present for
13 all or part of the workshop today. They are: Nicola
14 Simon as project manager. Phil Stallard as lead
15 staff, along with Ivan Lapczak, Avery Jones, Lisa
16 Dang, Tanya Lai, Gillian Sykes, and Cory Vincent.
17 I will now call on either Mr. Chernikhowsky
18 or Ms. Bevacqua from FEI who will be facilitating this
19 workshop, to introduce to you the FEI team who are
20 present. And Mr. Chernikhowsky or Ms. Bevacqua, over
21 to you please.
22 MR. CHERNIKHOWSKY: Thank you, I'll take it from there,
23 and thank you for that introduction, Madam Chair.
24 I do want to express our appreciation to
25 the BCUC for accommodating this virtual meeting. I
26 think we'd all agree that in an ideal world this

1 session would have been held in person, but we've all
2 had to learn to adapt over the past months. In fact,
3 it was exactly one year ago today that the World
4 Health Organization declared COVID-19 to be a global
5 pandemic.
6 We have a number of presenters and
7 participants spread throughout the province today, and
8 as such I would like to acknowledge that we are
9 collectively gathered on the traditional, ancestral
10 and unceded territories of B.C.'s Indigenous peoples.
11 I'm presenting today from Kelowna, which is
12 located within the traditional territory of the Syilx
13 people, who have called this area for their home for
14 millennia. And as alluded to, as our first order of
15 business I'd like to introduce Ilva Bevacqua as our
16 facilitator today. She'll give us a brief review of
17 the Microsoft Teams platform, and go over some general
18 meeting logistics.
19 MS. BEVACQUA: Thank you, Paul. Good morning everyone.
20 This workshop is to review FortisBC Energy Inc. or
21 FEI's TLSE Project. Today we have our presentation
22 from FEI as well as one from Guidehouse. We expect
23 the workshop will last the full day, so as mentioned
24 by Madam Chair, we do have several breaks planned, and
25 hopefully the day will run according to plan.
26 I did send out some basic instructions on

how to use Microsoft Teams for those that may not be familiar with it, and hopefully the technology works well for us today. We do encourage participants to use their video cameras when speaking, so that we have the benefit of seeing each other.

Given the large amount of material to go over, the number of participants, and in an effort to make the most efficient use of everyone's time today, Mr. Doug Slater, FEI's Vice President of External and Indigenous Relations will be our moderator for questions.

In Doug's previous role as the director of regulatory affairs, he led the preparation and filing of the TLSE application, making him ideally suited to manage the flow of questions during the session to the most appropriate person.

While we have a designated open question period at the conclusion of presentations, if you have clarifying questions to ask about the material being presented, we will pause after each speaker to address questions before moving on.

In order to maintain the flow of the presentation material, if you have a burning question while a speaker is presenting, we do encourage you to type your question in the meeting chat, so that you don’t lose your thought.

1 Doug will then read and moderate the
2 questions in the chat, or you will be invited to ask
3 your question if more detail or clarification is
4 needed.
5 **Proceeding Time 9:08 a.m. T4**
6 And of course at any time you may raise your virtual
7 hand and at an appropriate pause point Doug will
8 invite you to speak. When called upon please unmute
9 your mike and turn on your video camera if it's not
10 already on and state your name for the record, it will
11 benefit our court reporters any anyone listening to
12 the audio broadcast. When your question and any
13 follow-up has been responded to, you can put yourself
14 back on mute.
15 We have the following key participates with
16 us today, most of whom will be presenting. So from
17 FEI we have Mr. Doyle Sam, executive vice president,
18 operations and engineering; Ms. Diane Roy, vice
19 president regulatory affairs; Mr. Mike Leclair, vice
20 president major projects and LNG; Mr. Doug Slater,
21 vice present eternal and indigenous relations. Of
22 course you've already met Paul Chernikhowsky, director
23 of regulatory projects and resource planning. We have
24 Mr. Shawn Hill, director of energy supply and Mr. Ian
25 Finke, director of LNG operation. We also have a few
26 FEI support people participating in the meeting and if

they need to speak during the session they will introduce themselves and the role for the record.

We also have with us from Guidehouse Mr. Paul Moran, who is the associate director of energy, sustainability and infrastructure at Guidehouse. And finally, we have counsel for FortisBC from Faskens, we have Matt Ghikas and his co-counsel Madison Grist.

I will now go through each intervener group present today and ask that one representative speak up and introduce their participants. So we start with the Residential Consumer Intervenor group or the RCIG.

MR. MASON: Hi, my name is Sam Mason, I'm one of the two participants here representing the RCI -- actually we're now going by RCIA, "association." So apologies for the name change there. The RCIA was formed this past January through an agreement between Midgard Consulting, who I work for, and the BCUC with a goal of establishing a separate non-profit legal entity that aims to become self-sufficient and self-sustaining. Our mandate is to represent residential ratepayers in BCUC matters, in particular in relation to public proceedings and hearings and in a manner which strives to avoid discrimination against any residential ratepayer groups.

In the case of the Tilbury proceeding, we are presenting the interests of FortisBC Energy Inc.'s

1 residential ratepayers whose rate and services would
2 be effected by the project. And representing us here
3 today is myself and Brady Ryall of Ryall Engineering.
4 Thank you.
5 MS. BEVACQUA: Thank you. And from the BC Sustainable
6 Energy Association or BCSEA.
7 MR. ANDREWS: Good morning, I'm Bill Andrews, counsel
8 for the BC Sustainable Energy Association. Also
9 participating in the workshop today are Tom Hackney
10 and Matt Jackson.
11 MS. BEVACQUA: Thank you. And from the Citizens for My
12 Sea to Sky Society.
13 MR. FINN: Hi, my name is Eoin Finn, I'm the research
14 director for Citizens for My Sea to Sky Society, which
15 is otherwise known as My Sea to Sky. And I also am a
16 member of a group called the Friends of Tilbury who
17 are concerned with the expansion of the Tilbury LNG
18 facility. I have many years in consulting. Retired
19 as a partner in KPMG. And the history includes some
20 time with a predecessor of Guidehouse as
21 Pricewaterhouse.
22 The concern of our members are many, but
23 principally to do with the safety, the environmental
24 impacts and the effect on our members' bills from
25 Fortis of this expansion. So I look forward to
26 hearing the arguments in favour presented by

1 Guidehouse and FEI. Thank you.
2 MS. BEVACQUA: Thank you. From the British Columbia Old
3 Age Pensioners' Organization *et al*, or BCOAPO.
4 MS. MIS: Good morning. My name is Irina Mis, last
5 name M-I-S, representing BCOAPO. And my co-counsel.
6 Leigha Worth, W-O-R-T-H, is joining us shortly. Thank
7 you.
8 MS. BEVACQUA: Thank you. Commercial Energy Consumers
9 Association of B.C. or CEC.
10 MR. C. WEAFER: Good morning, it's Chris Weafer
11 representing the Commercial Energy Consumers from the
12 law firm of Owen Bird. Co-counsel on the call is
13 Patrick Weafer. And we also have David Craig and
14 Janet Rhodes from the CEC participating in the
15 workshop and we look forward to the day's proceedings.
16 Thank you.
17 MS. BEVACQUA: Thanks you. And our final intervener in
18 Sentinel Energy Management.
19 MR. LANGLEY: Hi, my name is Jim Langley with Sentinel.
20 I represent the interests of large industrial users on
21 the FortisBC system and our interests are along the
22 lines of whether it's the appropriate resource and
23 whether the costs are assigned appropriately. Thank
24 you very much.
25 MS. BEVACQUA: Thank you. And during the open question
26 period at the end of the session we will canvass

1 participants for questions in the same order as we did
2 the introductions, followed by BCUC staff and wrapping
3 the question up from the panel.
4 **Proceeding Time 9:02 a.m. T5**
5 Now, with those logistics out of the way
6 I'll turn it back to Paul.
7 MR. CHERNIKHOWSKY: I believe Commission Mason has a
8 question.
9 MS. BEVACQUA: Okay.
10 COMMISSIONER MASON: Thanks very much, I'd just like to
11 state for the record that Mr. Sam Mason of the
12 Residential Consumer Interveners Group is no relation
13 of Commission Mason. Thank you.
14 MS. BEVACQUA: Thank you.
15 **PRESENTATION BY MR. CHERNIKHOWSKY:**
16 MR. CHERNIKHOWSKY: Okay, thanks very much, Ilva, for
17 that introduction. If we could move on to slide
18 number 2, please? Okay, we have our agenda here for
19 today. In broad terms, we're going to provide a brief
20 summary and highlight what we consider to be the most
21 salient points of the application. Next, we'll have a
22 review and orientation of the Tilbury facility itself.
23 Then we'll explore some of the foundational concepts
24 that underpin the application. We'll explain what
25 "resiliency" means to FortisBC, as well as how it
26 applies to us given that we operate in a rather unique

1 geography. Next, we'll talk about the development of
2 a critical concept that we refer to as our minimum
3 resiliency planning objective. That will be followed
4 by the presentation by Guidehouse and then we'll break
5 for lunch.
6 When we come back we'll look at how we
7 evaluate numerous potential solutions to meet the
8 planning objective and specifically how our solution
9 has many other benefits to the FortisBC system and
10 customers that go beyond the pure planning objective.
11 We'll address the panel's request to discuss the
12 extent to which there are potential synergies and
13 overlaps between the project and other large capital
14 projects planned by FEI in the same period. And,
15 finally, we'll review the proposed TLSE project and
16 how it will operate in more detail. And then we'll
17 conclude with the open question and answer session to
18 address any issues that weren't previously addressed.
19 And, as mentioned, we have listed some
20 times here for guidance but thing may shift depending
21 on how interactive the discussion gets. So we may
22 have to adjust our times that we break but we'll still
23 work to get them in so that everyone has a chance to
24 get up and move around occasionally.
25 Before we do get into our slides I just a
26 few additional opening remarks. As Ilva mentioned, we

1 have a number of different presenters listed,
2 including Paul Moran from Guidehouse with us today.
3 You may also know Guidehouse from their former name of
4 Navigant. His participation is to address the request
5 from the panel to have a presentation from FEI's
6 retained consultant, Guidehouse. We're all remote but
7 he's particularly remote as he's joining us from
8 Houston, Texas, a state which, coincidently, is in the
9 midst of reassessing its own system resilience after
10 the recent cold weather there. So thank you for
11 joining us, Paul.
12 I also want to thank the panel again for
13 their workshop guidance letter of February 17th. Those
14 four requests have helped allow us to focus the
15 presentation and ensure that we cover the specific
16 items of interest to the panel. We'll speak to each
17 at various points during our presentation and we'll
18 highlight at the appropriate time.
19 Hopefully everyone has had a chance to
20 review the application prior today, at least at a high
21 level, and that everyone has some familiarity with the
22 need for and the scope of the project. But as a
23 reminder and as alluded by Commission Fung, today's
24 review sessions is just the first step in the BCUC
25 regulatory process. Going forward there will still be
26 opportunities to ask questions to FEI about the

1 project in the form of written information requests.
2 Our goal today is clarity. We want everyone to leave
3 the session feeling better informed about why FEI has
4 proposed the project and what it is about and we're
5 hopeful that will lead to a more effective and
6 efficient information request process.
7 And, lastly, I'd like to speak briefly to
8 confidentiality. As the panel is aware, we filed two
9 versions of the application, one redacted and one
10 confidential. And we felt this was necessary to
11 ensure the proper protection of sensitive information
12 related to FEI's gas system. Our preference is always
13 to be as transparent as possible, but unfortunately we
14 live in a world where information about utility
15 systems and their limitations can be used by malicious
16 actors. For our presentation we've been careful to
17 ensure that everything we're discussing today can be
18 found in the public document.
19 **Proceeding Time 9:18 a.m. T6**
20 But if there are questions raised that stray into the
21 confidential aspects, we may have to flag those and
22 suggest that they be dealt with during the information
23 request process as confidential IRs.
24 Okay, and if we could move to slide number
25 3 please? We'll be conveying a large amount of
26 information today, and some of it may be quite

1 involved and technical, but there are some key
2 concepts that we captured on this slide which
3 summarize the application.
4 First and foremost, the TLSE project is a
5 resiliency project. And resiliency, as we'll discuss
6 in a moment, is essentially about being able to
7 withstand and recover from unforeseen, significant
8 events. And it is necessary to enhance the resiliency
9 of gas supply to FortisBC's customers. And
10 specifically, the hundreds of thousands of
11 residential, commercial and industrial customers in
12 various areas of our system who rely on gas for
13 heating, cooking and commercial and industrial
14 processes.
15 The second important concept is that during
16 the development of the TSLE Project, FEI developed
17 what we refer to as our Minimum Resiliency Planning
18 Objective. And for simplicity, I'll refer to it here
19 as the planning objective. And this planning
20 objective is specific to FEI and its unique
21 circumstances, location and system configuration. Mr.
22 Sam will expand upon this later, but basically what
23 this objective says is that the FEI system should be
24 able to withstand a three-day disruption of gas supply
25 into the Lower Mainland area. What we also refer to
26 in the application as a "No flow" event.

The planning objective is based on our operating experience, including the events of October 9th, 2018 when gas ceased to flow in the pipeline system that delivers most of the gas into the Lower Mainland and Vancouver Island.

The next takeaway is that if we are unable to meet that objective, it could result in significant consequences. The widespread loss of gas supply could have serious impacts on customers who rely on gas for heating and hot water during extreme cold weather conditions. And those consequences could expand even beyond FEI and its customers, and impact the electricity grid, society and the province as a whole.

And last, while the primary objective of the TLSE project is to enhance our resiliency, it is very important to recognize that it provides many other benefits. In other words, it has significant value, and will directly support our system operations, and even gas supply to other FEI projects, and it will allows us to avoid some potential capital costs elsewhere, all to the benefit of our customers.

Now, of course we will expand upon each of these concepts in more detail, but I'd ask you that you keep them in mind as we go through our presentation today.

So, I'd now like to turn this over to Mike

1 Leclair, and he'll provide us a bit more context of
2 the TLSE project, and how it does or doesn't relate to
3 aspects of the Tilbury Site.
4 **PRESENTATION BY MR. LECLAIR:**
5 Yeah, thanks Paul. So, my name is Mike
6 Leclair and I'm the Vice President of Major Projects
7 and LNG for FortisBC. And this part of the
8 presentation I am going to speak to the Tilbury
9 Facilities that are in operation today, and then
10 briefly introduce the TLSE project. Next slide
11 please.
12 So, first I just wanted to provide a bit of
13 background for the panel in terms of what exactly is
14 LNG, and what are the units of measurement that we are
15 going to be discussing today.
16 So, to start, Liquefied Natural Gas, or
17 LNG, is simply the same natural gas, or renewable
18 natural gas that we use in our homes and businesses
19 everyday. It's simply cooled down to minus 162
20 degrees Celsius, when the gas turns into a liquid.
21 And in this liquid form, it actually only takes up 1
22 six-hundredth of the volume as it does in its gaseous
23 form.
24 LNG is not flammable in this liquid form.
25 We store it in double-walled tanks with an internal
26 steel wall and an outer concrete wall, and effectively

1 this acts like a thermos to keep the LNG isolated from
2 anything external to the tank.
3 Now, in terms of units, storage volume is
4 measured in billion cubic feet, and storage determines
5 how long you continue to meet your load at your
6 desired -- or at your rate of regasification.
7 And so, to give you a sense of the
8 magnitude of what our proposed storage volume and the
9 TLSE project, we could provide approximately three
10 days of support for our customers and for utilizing
11 the full proposed regasification rate.
12 **Proceeding Time 9:23 a.m. T7**
13 And to provide some context, at the same
14 regasification rate our existing Tilbury facilities,
15 our Tilbury base tank at 0.6 Bcf could only provide
16 approximately 18 hours of supply for our customers.
17 Now, regasification capacity is measured in
18 million cubic feet per day. And regasification
19 capacity effectively determines what portion of your
20 daily load or what portion of load you can meet. And
21 to give you a sense, our proposed regasification of
22 800 million cubic feet per day is sufficient to
23 support nearly 100 percent of the coldest winters days
24 in the past 10 years. And our existing plant
25 regasification capacity, on the other hand, would only
26 meet about 17 percent of the Lower Mainland design

load.

Next slide please, Paul?

Now, first, I'm going to speak to the existing Tilbury assets and how they came to be into operation. So situated in the top-left corner of the slide, in orange -- sorry, noted in yellow, are the Tilbury base plant facilities. So throughout this presentation we'll refer to these facilities as the "Tilbury base plant".

So for the past 50 years FortisBC has been safely operating the Tilbury base plant. Back in 1971, the Tilbury base plant was built in size to support peak demand. So the intended purpose of the base plant was really to ensure that adequate natural gas supply was available for FEI's customers on the coldest days. Managing short duration periods where energy demand from our customers exceeded available supply.

Then in 2010 FEI also started providing LNG for the transportation industry. Served from the base plant, LNG offers customers an alternative fuel to reduce operating costs and lower emissions on the rate schedule 46.

Now, situated on the top-right corner of the slide, depicted in white, are the Tilbury 1A assets. So for the remainder of the presentation we

1 will refer to these assets as "Tilbury 1A" or "T1A".
2 The purpose of the T1A facilities is to
3 serve LNG sales under rate schedule 46 to meet a
4 growing demand from our customers. The Tilbury 1A
5 facilities consist of 33 million cubic feet a day
6 liquefaction capacity and a 1 billion cubic foot
7 storage tank and associated truck loading facilities.
8 With the T1 facilities coming into service it
9 effectively separated LNG sales from the base plant,
10 allowing each facility to serve a distinct purpose.
11 Next slide please, Paul.
12 So now I'm just going to briefly, sort of,
13 orientate where the TLSE project assets will reside on
14 the site. So this slide provides some insight and
15 there they are depicted in orange. And throughout the
16 presentation we will refer to these proposed assets as
17 the "TLSE project". As noted in the application, the
18 TLSE project supports the delivery of energy that is
19 currently being used or consumed. It does not create
20 a new demand or the need for additional liquefaction.
21 We can see the proposed 3 BCF storage tank
22 in the middle of the screen. Effectively this tank
23 provides many of the same benefits as the original
24 base plant tank did, but is sized appropriately to
25 meet the current-day energy demands of British
26 Columbians to ensure energy is there when they need it

1 the most. Next to the tanks are the proposed
2 vaporization units or regasification units.
3 Next slide please, Paul.
4 Now, finally, on this last slide I'm just
5 going to briefly introduce the TLSE project. Mr.
6 Finke will provide some more detail later in the
7 presentation, a more fulsome description, and also
8 provide some insight as to the operating
9 configuration.
10 The TLSE project is really comprised of two
11 main new construction elements. And then, of course,
12 all the associated infrastructure and systems to
13 connect those together into our existing operation.
14 **Proceeding Time 9:27 a.m. T8**
15 The first component is the 3 Bcf storage
16 tank. And the second component for the TLSE project
17 is the regasification equipment or the vaporization
18 units that can produce up to 800 million cubic feet a
19 day of gas, and eject it back into the system to meet
20 the energy demands of our customers.
21 Later in the presentation, as Paul noted, I
22 will speak to other planned development on the Tilbury
23 site, but at this point I will pass it back to Paul.
24 MR. SLATER: Thank you, Mike. Maybe I'll pause for a
25 moment before we switch speakers, and see if there are
26 any questions? I do see a question from Mr. Bill

1 Andrews. So maybe I'll start with that one.
2 The question is, where is Tilbury Phase 2
3 on the site. So Mike, if I could direct that question
4 to you.
5 MR. LECLAIR: So I don't know if you want to go --
6 actually I'll just speak to that here. So we will --
7 that might be, Mr. Andrews, that might be better
8 addressed later in the presentation. We do speak to
9 future development, so maybe if we could hold that,
10 that might be addressed, better addressed there.
11 MR. ANDREWS: Okay. Another question, why is there no
12 liquefaction associated with the TLSE project?
13 MR. LECLAIR: Thank you for the question, Mr. Andrews.
14 The TLSE project is going to leverage available
15 liquefaction capacity on the site to fill the tank.
16 MR. ANDREWS: Existing liquefaction, and not phase 2
17 liquefaction?
18 MR. LECLAIR: Correct.
19 MR. ANDREWS: I have an exceedingly technical simple
20 question about the units of measurement. In the
21 environmental assessment office materials, cubic
22 metres of gas is used, rather than cubic feet. Can
23 one reliably use simple conversion between cubic feet
24 and cubic metres to get equivalent measures?
25 MR. SLATER: So thanks for that question. I'm not
26 sure, Mike, if you wanted Mr. Finke to answer that, or

1 not? But I'll leave it to you.
2 MR. LECLAIR: Yeah, I was thinking maybe Mr.
3 Chernikhowsky.
4 MR. CHERNIKHOWSKY: Yes, sorry, I had it on mute there.
5 Yes, you can convert between the cubic metres and
6 cubic feet using a standard conversion factors. One
7 thing I would just briefly note is that whenever we
8 refer to the storage volumes, for example in Bcf,
9 that's the equivalent gas volume. The actual tank, of
10 course, is smaller because it's storing that volume in
11 the form of LNG. So we have to keep that 600 to 1
12 conversion in mind as you're doing that.
13 MR. ANDREWS: Okay, thank you.
14 MR. SLATER: Thank you, Paul.
15 I notice that Mr. Finn has his hand up.
16 Mr. Finn if you want to go ahead and please ask your
17 question?
18 MR. FINN: Thank you. My question is much along the
19 lines of Mr. Andrews. There, in the application
20 material, there are two projects described. One is
21 the environmental assessment application, and the
22 other being this one, this phased expansion.
23 So one describes a huge increase in
24 liquefaction, and also the associated project of a
25 marine jetty in the Fraser. This one makes no mention
26 of liquefaction. And so I'm a bit confused as to

which -- are these the same projects? Or are we talking about two entirely different projects?

MR. SLATER: Thank you, Mr. Finn. I will ask Mr. Leclair to maybe address the scope of this project versus the EA?

MR. LECLAIR: Yeah. Thank you, Mr. Finn. So, first off I will say, I will, as I mentioned in Mr. Andrews, cover this component a little bit later in the presentation. So we will dive into some more detail there. It is -- the TLSE project is the resiliency project that we are speaking about here today, and I mentioned does leverage existing liquefaction.

Proceeding Time 9:32 a.m. T9

And then as a part of that we are required to apply for an environmental assessment application. And so I will dive into that a little bit later, but there are no other assets associated with the TLSE project other than what I described here.

MS. WORTH: This is Leigha Worth here for BCOAPO. I have a follow-up question on Mr. Andrews' question, if that's okay? I'm just wondering why FEI doesn't provide consistent unit measurements in all of its materials, whether, you know, before the B.C. Utilities Commission and, you know, the environmental filings that it's making?

MR. SLATER: Thank you, Ms. Worth. I'll as Mr.

1 Chernikhowsky to address that question, please.
2 MR. CHERNIKHOWSKY: Yeah, we acknowledge that there are
3 different units of measurement used. Mainly we choose
4 the units given the context that we work in, and so
5 many of the documents that we use, for example, in the
6 long-term gas resources plans and so on will refer to
7 in many cases cubic feet of measurement. In
8 government applications often they refer to cubic
9 metres and litres and things like that. And so
10 unfortunately, and this is common in the gas industry,
11 you'll see that where units of energy are sometimes
12 measured in joules, in the U.S. they're measured in
13 therms. That's just an unfortunate necessity. We do
14 try to be as consistent as possible, though, is what I
15 would say.
16 MR. SLATER: Thank you, Paul. At this time there are
17 no other hands raised or question in the comments, so
18 I'll pass it back over to Paul.
19 **PRESENTATION BY MR. CHERNIKHOWSKY:**
20 MR. CHERNIKHOWSKY: Okay, thank you very much. So now
21 that we have a basic understanding of what the TLSE
22 project is, I'd like to explain some of the concepts
23 that form the foundation of this project's
24 justification and specifically what I'm referring to
25 here is the word "resiliency" itself. The other
26 concept we want to explore is the gas supply region

that FEI operates in. And as mentioned before there are some very unique characteristics to our area that also introduce operational challenges and realities that aren't necessarily faced by other gas utilities in Canada or even North America.

So if we move onto slide 10, which we're on, I'd like to start out by discussing three important concepts that support our ability to deliver gas for our customers, and these directly align with the Guidehouse framework that Mr. Moran will speak about shortly and he'll expand upon that framework in much more detail at that time. But first I'd like to touch on three key definitions and explain our perspective on each of them

To help, on this slide I have a diagram excerpted from page 25 of the application. The first concept is integrity. And what I'm referring to here is the integrity of physical assets themselves. We've historically proposed many projects, both in CPCNs and through revenue requirements applications that ensure the integrity of our system. Integrity is about activities designed to prevent equipment failures and ensuring our individuals assets are fit for service.

A good example of an integrity project is our inland gas upgrades, which was approved by the BCUC in early 2020. Another is our recently filed

1 costal transmission system TIMC application and I'll
2 briefly speak to that a bit later. Both of those
3 projects are about ensuring the ongoing integrity of
4 our underground transmission pipeline assets.
5 Reliability is a higher level concept.
6 It's the ability to consistently deliver energy when
7 customers demand it. When you turn on your gas
8 cooktop or your thermostat calls for heat, you expect
9 the appliance to come on and stay on. And a very
10 common way to achieve reliability is through
11 redundancy. For example, we install duplicate
12 equipment at our gate stations. This allows us to
13 take equipment out of service for maintenance without
14 interrupting supply to customers. So a reliable
15 system depends on assets being available for service
16 when necessary and having enough redundancy in the
17 system to be able to respond to planned and unplanned
18 equipment outages. And these two concepts, integrity
19 and reliability, basically cover off our day-to-day
20 activities of operating the gas system.
21 **Proceeding Time 9:37 a.m. T10**
22 Resiliency is the top level concept and it
23 builds on integrity and goes beyond reliability. It's
24 about ensuring that we have the ability to respond to
25 large and new or unexpected disruptions to the gas
26 system. These disruptions can be less frequent, large

1 seismic events, wild fires or landslides are good
2 examples, but that can happen and we should plan for
3 them. Because it's higher level it often requires
4 multiple tools working together to achieve it, and
5 we'll explain that shortly.
6 If we could move to slide 11, please.
7 As a company FEI was been safely and
8 reliably delivering gas to our customers in one form
9 or another for almost 160 years. The vast majority of
10 our assets are underground and that has pros and cons
11 when it comes to reliability and resiliency. The main
12 benefit of burying our assets is that it protects them
13 from many of the hazards that could otherwise damage
14 them.
15 And in contrast, consider the electric
16 utility division of FortisBC. As we note on this
17 slide, our overhead power lines experience relatively
18 frequent but short duration outages: lightning, wind,
19 trees, motor vehicle accidents, animals. None of
20 those, though, are real risks to our buried gas
21 infrastructure. And if you think about your own
22 personal experience with the reliability of electric
23 service, I expect that everyone on this call has
24 probably experienced an electric outage in the last
25 year or so, but hopefully it didn't last more than a
26 few hours.

On the downside, buried pipeline are exposed to a different set of potentially more impactful negative elements. Landslides, washouts, seismic events all have the potential to damage and disrupt underground gas lines. Even managing our pipeline integrity is more challenging. Our assets are buried so we can't see them. Instead, we have to run in-line inspection tools that collect data on the pipes from the inside out.

So linking back to our electric outage analogy, the vast majority of our gas customers have never had a gas service outage. Other than for planned meter exchange or a third-party accidently digging into a buried line in the vicinity, gas outages are relatively rare. But the key point is that they can occur and when they do gas outages can often be more widespread and long duration. And they can be widespread because of our location in the region and they can be lengthy because of the complex purging and appliance relay process that has to occur to safely restore customers. And we'll speak more about that in a bit as well.

So, if we could move on to slide 12, please.

Once we've determined that enhanced resiliency is necessary, the next obvious question is,

how do we accomplish that? And there's a number of possible solutions. Again, each has pros and cons, but the takeaway here is there's generally no single route to resiliency. Instead, we view it like the overlapping Venn diagram on this slide, which is excerpted from page 28 of the application.

In broad terms, to increase resiliency you can add more supply into the system or you can add storage within the system, in the event that you don't have enough supply. Or, last, you can use load management to reduce consumption when you don't have enough supply or storage. And in our situation employing multiple complimentary solutions allows one to move to the centre of that Venn diagram where you can achieve resiliency in the most optimal and cost-effective manner.

And, incidentally, this is exactly like FEI's annual contracting plan process. Every year we consider a number of different ways to source our necessary gas supply. And to select that optimal gas supply we use what we call a portfolio approach. Between our commercial off-system gas purchases, storage and various financial instruments we ensure that we source the necessary gas supply for the lowest reasonable cost of service.

But there's one very significant

1 distinction between gas supply planning and resiliency
2 planning. Gas supplying is highly dependent on
3 contractual arrangements that assume that the
4 underlying gas transmission lines are available to
5 deliver the gas that you purchased and that doesn't
6 necessarily work in the context of resiliency. FEI is
7 highly dependent on other transmission companies for
8 our gas supply.
9 **Proceeding Time 9:42 a.m. T11**
10 If those underlying upstream systems, the
11 actual pipelines that deliver gas to us are not
12 available, then no amount of contractual resources
13 outside the system will help. And so as we
14 highlighted the call out at the bottom of the slide,
15 resiliency comes from the access to physical and
16 controllable assets that are always accessible, and
17 are not subject to curtailments or suspensions during
18 emergencies.
19 And with the last slide in my section, if
20 we can move to slide number 13 please?
21 So there is no one-size-fits-all approach
22 to building resiliency, especially when it comes to
23 determining solutions that are appropriate for a
24 specific operator. And that's because one needs to
25 take into account the region that the utility operates
26 in.

1 As the utility on the west coast of British
2 Columbia, with most of our load in the Lower Mainland
3 and on Vancouver Island, we have some unique
4 considerations that don't necessarily apply to
5 utilities in Alberta or Ontario, for example.
6 And so with that, I will turn it over to
7 Mr. Shawn Hill, who will provide more information on
8 resiliency it the context of the region that FEI
9 operates in.
10 MR. SLATER: So Paul, thank you for that. Maybe I'll
11 just take a quick pause, and see if there are any
12 questions before we move on to the next speaker?
13 MR. ANDREWS: Bill Andrews here, I have a question. In
14 Fortis' most recent long-term gas resource plan,
15 concept of resilience in this context didn't appear to
16 be mentioned or to be prominent. Can you explain the
17 genesis of how the emphasis on resilience here
18 compares to Fortis' existing long-term plans?
19 MR. SLATER: Thank you, Mr. Andrews, for the question.
20 I'll start by just may be highlighting we did outline
21 in section 9 of the application how the concept of
22 resiliency in this project is consistent with our
23 long-term resource plan. And then maybe with that, I
24 can pass it to -- well actually, I think we're going
25 to address, as we move on in the presentation, how you
26 know, the impact of the Enbridge incident and how that

1 highlighted some of the needs to accelerate our
2 investment in resiliency. So maybe I'll hold that
3 second part of that answer if I could?
4 MR. ANDREWS: Okay.
5 MR. HILL: Thanks, Doug, can everybody hear me?
6 MR. SLATER: Sorry, Shawn, we also have Mr. Finn has a
7 question, has his hand up. Mr. Finn, go ahead and
8 please ask your question?
9 MR. FINN: Thank you. A key issue in this application
10 is the reliability of the reliability record of the T-
11 South pipeline. But I searched through the almost 800
12 pages of information presented here, for any record of
13 the outages, the outage history of T-South, and
14 couldn’t find any.
15 But I did find in one of the references,
16 the GTI's assessment of Natural Gas and Electric
17 Distribution Service Reliability, a diagram on page 14
18 which -- or sorry, on figure 14, which talks about the
19 relative reliabilities of electric and gas services,
20 which the previous speakers spoke about. And it says
21 that the reliability is such, of gas systems being
22 underground, is roughly one outage every 428 years.
23 When combined with the idea here that the resiliency
24 is required for the coldest days in and around the
25 Lower Mainland, you would expect the coincident
26 probability to be somewhere of the order of one every

1 4,000 years.
2 And there are other, in the Guidehouse
3 material, I failed to see any assessment of the
4 relative probabilities of things which this previous
5 speaker alluded to of seismic events, which I looked
6 up and it turns out that there is a 30 percent
7 possibility of a significant seismic event in the
8 Lower Mainland once very 50 years.
9 So, I'm a bit puzzled. I would also
10 mention that, of course, we've have had fires in the
11 nearby Burns Bog, which there have been, I believe,
12 nine of them in the last 40 years.
13 **Proceeding Time 9:47 a.m. T12**
14 I'm a bit puzzled as to why there was no
15 data on the reliability of T-South, nor was there any
16 significant discussion of the relative importance or
17 incidences of other events which would affect the
18 reliability of Fortis' service in the material.
19 So, in the absence of any data to the
20 contrary, can we assume that the figures that are
21 refenced here are reliable and that we're talking
22 about an extremely unlikely event?
23 MR. SLATER: Thank you, Mr. Finn, for the question. We
24 did file some information in section 3, which was
25 redacted for confidentiality in a confidential
26 appendix on the frequency of some of the pipeline

1 incidents over time. So, I'm not sure that's a
2 question we can answer here today, but perhaps a good
3 question for the IR process as we -- that's coming up
4 in a couple of weeks.
5 MR. FINN: I can't imagine that the history of the
6 outages in T-South are a matter of secrecy. Surely,
7 they're recorded by all the million customers who
8 presumably were affected by it one way or the other?
9 MR. SLATER: Yes, the -- you know, indeed some of that
10 -- certain parts of that information are not
11 confidential, but we did file that section
12 confidentially so I'm unable to speak to it today but
13 would be happy to answer questions in the IR process
14 about that.
15 MR. FINN: Thank you.
16 MR. SLATER: Thank you. I also note Mr. Tom Hackney
17 has a question. Go ahead, Mr. Hackney, and answer
18 your question -- or ask your question, sorry.
19 MR. HACKNEY: Thank you. Yes, so this is about the
20 definition of "resiliency". And is it fair to say
21 that resiliency, as conceived by Fortis, is something
22 that has to do with reducing the risk of an outage and
23 also reducing the consequences of an outage should it
24 occur? Or is resiliency simply aimed at the first
25 part of that, reducing the risk of an outage
26 occurring?

1 MR. SLATER: Thank you for the question, I'll ask Mr.
2 Chernikhowsky to address that one, if you could, Paul?
3 MR. CHERNIKHOWSKY: Sure, thank you, Mr. Hackney.
4 Well, first of all, the concept of risk includes the
5 two ideas of probability and consequences. So, yes,
6 strengthening your system and increasing resiliency
7 actually addresses both of those. It helps reduce the
8 probability of an event affecting your system, but if
9 it does affect you it also helps you mitigate the
10 consequences as well. So having on-storage system
11 ensures that in the event that a no-flow event occurs
12 to FortisBC we would be able to withstand it. Having
13 resiliency also means that if you don't have enough
14 resources in your system, you have some other way of
15 having a controlled shutdown, potentially. And we'll
16 speak more about both those concepts coming up.
17 MR. HACKNEY: Thank you. And are these quantified in
18 the materials?
19 MR. CHERNIKHOWSKY: Can you explain what you mean by
20 "quantified"?
21 MR. HACKNEY: I guess, does Fortis develop a numeric
22 definition of what constitutes resiliency or is this a
23 qualitative concept?
24 MR. CHERNIKHOWSKY: So you're referring to in terms of
25 probabilities of events happening, I think is what
26 you're getting at there?

1 MR. HACKNEY: Yeah, some kind of numeric benchmark to
2 determine whether the current application is going to
3 increase the resiliency to an acceptable degree or
4 something of that nature.
5 MR. CHERNIKHOWSKY: So, actually, Ilva, if I could ask
6 you to flip back to the slide that shows the pyramid
7 diagram, please?
8 So on this one you'll note we actually have
9 some definitions or some explanations, perhaps, for
10 each of these definitions. In reliability we talk
11 about that can be typically measured using performance
12 metrics. So you can generally determine how frequent
13 a pipeline is or isn't available for service.
14 **Proceeding Time 9:52 a.m. T13**
15 Resiliency within the industry is typically
16 not measured using performance metrics. It is
17 generally a qualitative concept because it is
18 difficult to assign specific probabilities and
19 consequent numbers to an event. So in general, yes,
20 the industry does tend to treat resiliency as somewhat
21 of a qualitative concept.
22 MR. HACKNEY: Thank you.
23 MR. SLATER: Thank you. At this time it doesn't look
24 like we have any other hands raised or questions in
25 the comment box, so I'll hand it back over to Mr.
26 Hill.

PRESENTATION BY MR. HILL:

MR. HILL: Thank you, Mr. Slater. Can everybody hear me?

Good morning everyone. My name is Shawn Hill, I'm the director of energy supply at Fortis. In my role today I'm responsible for the development of a commercial gas supply portfolio that serves bundled sales customers rate schedules 1 through 7. A further responsibility that I have in working with our gas control team each day is to ensure that we match supply and demand on a physical basis to provide reliable service to customers. With those two areas of responsibility in mind, I'll take the next two slides to review the physical characteristics of FEI's three main service territories and how those regions tie into the upstream infrastructure.

Further, we will review the concept of when putting a commercial gas supply portfolio together, we will need a diverse set of resources to best fit the load profile that we are serving. This concept helps to produce an efficient gas supply portfolio for customers. In FEI's view this concept can also be applied to resiliency.

One thing that I want to mention before we turn to the next slide relates to the idea of physical versus commercial. As we know, the natural gas

business is very reliable, so we often think of these two concepts as being the same thing. But we need to distinguish these concepts when we view resources through the lens of resiliency. Under emergency events, commercial arrangements like our annual contracting plan or our gas supply portfolio would get suspended. This leads us to the issue we're trying to answer today. What physical resources do you have under your control to manage the situation?

If we can move to the next slide.

This slide is just a regional outline of the province. It outlines the three main service territories that FEI serves. There's the Interior System, the Lower Mainland System and the Vancouver Island System. In 2020 it was 195 Bcf of consumption across these service territories.

Let's get into some of the details a little bit, each of the physical attributes of each of the systems. Let's first start with the Interior. Just for context, the dotted line in the middle of the screen running north to south in the middle of the province is the Westcoast T-South line.

The Interior System is able to access gas off the T-South System in two different locations, mainly at Savona and Kingsvale, and we will see those two points in the next slide. Further, the system

ties into the TC energy system that runs north to south on the eastern side of the province. You'll also see that on the next slide as well. This area, the Interior System, has the most pipeline diversity of our three service territories. It's a wide -- it's a big area, as you can see from its physical footprint. And there's many compression stations across the system to help us move the gas around on a daily basis. This service territory consumes about 30 percent of our annual load.

The biggest service territory that we have is the Lower Mainland. It consumes about 60 percent of our total load and receives the majority of its gas from the Westcoast T-South System at the border between Northwest pipe and Westcoast. This system also receives (inaudible) displacement gas from Jackson Prairie and Mist, downstream or off system storage assets. And we'll talk about that on the next slide as well.

Proceeding Time 9:56 a.m. T14

As Mr. Leclair has already talked about, Tilbury is also situated in the Lower Mainland, physically in that service territory.

Our final system is the Vancouver Island system, which starts in Coquitlam at the V1 compressor

station and runs down the island to Victoria with the biggest load centre. This facility is home to our Mt. Hayes facility, which provides system capacity and gas supply benefits to both the Interior -- or to both the Vancouver Island system and the Lower Mainland.

Can move to the next slide.

This slide is a regional outline of the Pacific Northwest, including British Columbia and Alberta and is meant to reflect the infrastructure that's available for FEI to contract for. We're going to spend some time here on this slide to help orient people to different locations and what assets are available to us. And this is what we do in the gas supply area that I'm responsible for, is looking at contracting for resources to meet our load profile over time.

First of all, this overall region has a very poor load factor, which means that it has high winter demand, low seasonal or low summer demand and that's a factor in the resources that are available to us in the region.

In the north there's the production facilities that the West Coast T-North system tie into. And that runs from north to south in the middle of the province and that's in the blue line. Those production facilities produce gas that flow down the

1 T-South line all the way into our service territory
2 and actually physically move across into the Pacific
3 Northwest to Seattle and Portland as well.
4 Those three major load centres, Vancouver,
5 Portland and Seattle, are the main reason why this
6 infrastructure has been developed over time. So we
7 have the west coast T-South line, the pipeline running
8 north to south in the province, and another pipeline
9 that we have to service the region as well is the
10 Northwest Pipe Gorge capacity that runs from Stanfield
11 into Portland and it runs -- it's a bi-directional
12 pipeline. So those are the two main pipelines that we
13 have into the region.
14 The Gorge capacity is most utilized in the
15 winter to meet that winter demand and flows east to
16 west in the wintertime.
17 Once those two straws in the wintertime,
18 the pipelines become full, we use incremental assets
19 at the Jackson Prairie storage off system and the Mist
20 facility in Oregon. Both those facilities provide
21 incremental supply to the region once the physical
22 capacity of those two pipelines are used in
23 wintertime.
24 I just want to mention a couple more points
25 on this slide, relates to the points that I made on
26 the previous slide. You can see the Savona and

1 Kingsvale physical connection for the interior off the
2 T-South line and we can also see the East Kootenay
3 Exchange that attaches to the TransCanada or TC Energy
4 System on the eastern side of the province.
5 One thing that I would like to distinguish
6 is that the Jackson Prairie and Mist storage
7 facilities are what we could call in-market or -- in-
8 market. And they differ from what the Aitken Creek
9 storage facility can provide in the north of the
10 system. And the Aitken Creek facility is listed at
11 the top of the page and is, basically, that facility
12 is more like a winter commodities -- it provides
13 seasonal supply into the T-South system and basically
14 to move gas from that facility we are ultimately
15 limited by the T-South capacity that can flow. So it
16 can't provide -- the Aitken Creek facilities cannot
17 provide the same type of things that the Jackson
18 Prairie or Mist facilities can provide. And the
19 reason for that is because the Jackson Prairie and
20 Mist facilities, under normal operations, can provide
21 displacement to FEI.
22 **Proceeding Time 10:01 a.m. T15/16**
23 What that means is that we can actually
24 physically and commercially take gas that is flowing
25 north to south, take that gas physically in as load
26 increases, and withdraw gas downstream and give

1 somebody physically gas out of those two contracted
2 storage facilities. It's a common concept in the gas
3 supply world, and it is a very efficient manner to
4 provide a gas supply portfolio that is cost effective
5 for customers.
6 The main point that I wanted to mention,
7 and I think it kind of ties into if I understood Bill
8 Andrews' question earlier, relates to how is the
9 infrastructure developed over the course of time in
10 this region? And really what the industry as a
11 practice always has taken the development of new
12 resources to meet incremental load growth over time.
13 So, basically, as the demand of the region
14 grows, parties look to provide and expand the existing
15 facilities. And primarily, because of the poor load
16 factor in the region, those developments have been
17 short in duration, i.e. assets that provide 20 to 30,
18 or 40 days of resources rather than a pipeline
19 expansion. So, as an outcome, the region as it grows
20 and has added new resources, by default, from a
21 commercial energy perspective, we've gotten resiliency
22 as a byproduct.
23 The final point that I wanted to make, and
24 it's going to come up across -- a little later on, is
25 I just wanted to highlight the Prince George facility,
26 Prince George Town, and there is a red dot on the

slide there. And that's basically the October 9th, 2018 point, just north of that area was where the rupture occurred on the T-South line. And we just wanted to reference it here to make -- to give some of the people a context of where that rupture occurred.

The final point that I'll make related to this slide is along the -- is related to resiliency. And that is if you purely look at this regional infrastructure from a lens of resiliency, you can see that we have 338 Bcf of supply into the region in the winter time over the 151 days, versus only 46 Bcf of resources of storage. Therefore, if we lose pipeline capacity for any length of time in the region, we have some challenges from a resiliency perspective.

I've got one more slide, but I'm happy to take questions there before we kind of get into a different concept?

MR. SLATER: Thank you, Shawn. We have a few hands up. So maybe I'll start with Commissioner Fung.

Madam Chair, please go ahead and ask your questions.

THE CHAIRPERSON: Thank you very much, Mr. Slater, but I will wait my turn, because there were two other people at least, including Mr. Andrews, so I am happy to defer to them first, in order that they can ask their questions.

1 MR. SLATER: Okay. Maybe then I think probably Mr.
2 Langley had his hand up first. So, Mr. Langley, if
3 you'd like to go ahead and ask your question?
4 THE CHAIRPERSON: Is Mr. Langley on mute?
5 MR. SLATER: It appears he may be having some technical
6 difficulties. So maybe we'll move to the next
7 question. I note there was one question posted in the
8 chat from Mr. Andrews. Mr. Andrews asks Shawn, how
9 does the Gorge Pipeline provide supply to FEI?
10 MR. HILL: Great question, Mr. Andrews. Actually,
11 contractually or commercially, FEI does not contract
12 for any Gorge capacity, if you will, moving gas from
13 Stanfield into the I-5 corridor. We do not contract
14 for resources on there.
15 **Proceeding Time 10:06 a.m. T17**
16 But what he is trying to point out here is,
17 collectively, as the region as a whole how gas gets
18 into the I-5 corridor from those two pieces of
19 infrastructure, pipelines, Westcoast and the Gorge,
20 and ultimately they become physically limited by the
21 capacity of those two pipelines. So we don't actually
22 contract for supply from that area, but it does
23 provide incremental supply into the region for the I-5
24 corridor. That capacity is mainly held by the
25 utilities to the south of us, Northwest Natural,
26 Puget, Vista, for example.

1 MR. SLATER: Thank you, Shawn. I guess next I'll move
2 back to Commissioner Fung. Madam Chair, please go
3 ahead and ask your question.
4 THE CHAIRPERSON: Thank you very much, Mr. Slater.
5 Mr. Hill, I just want to understand the
6 language that's being used here. When you're talking
7 about the region in question, are you talking about
8 the province of British Columbia and the areas
9 including the three services areas that are served by
10 Fortis collectively?
11 MR. HILL: Yeah, I think that's a fair
12 characterization. I think basically what I'm
13 characterizing here is the region, the gas physical
14 infrastructure that's available to the region as a
15 whole, which includes Fortis's service territories.
16 THE CHAIRPERSON: Okay, thank you very much. So I
17 assume that this particular project that's being
18 proposed, and it's being proposed on the basis of
19 addressing resiliency, is a project then that would
20 result in resiliency benefits for the entire region
21 and that you're not proposing in the foreseeable
22 future separate projects on account of resiliency for
23 the Interior service area as well as the Vancouver
24 Island areas. Is that correct or am I mistaken?
25 MR. HILL: Yeah. So I think Paul and I will get into
26 that a little bit this afternoon, Madam Fung. Related

to basically, you know, the Island has Mt. Hayes for resiliency already. The Lower Mainland, our biggest load centre, receives all of its gas on the T-South system, so we've sized the project to meet the Lower Mainland demand. But by stationing that project in the Lower Mainland, it incrementally provides benefits to our Interior System as well from a resiliency perspective and we'll get into that this afternoon a little bit.

THE CHAIRPERSON: Okay, thank you very Much, Mr. Hill. Those are my questions.

MR. SLATER: Okay, maybe I'll just quickly check to see if Mr. Langley is back on the call. Mr. Langley, are you able to unmute yourself?

MR. LANGLEY: Can you hear me now?

MR. SLATER: Yes, we can hear you now. Please go ahead and ask your question.

MR. LANGLEY: Sorry about the technical difficulties there. But I just got back online in time to hear Madam Fung's question and effectively I think I had the same query about how these guys were handling resiliency in the Interior, so I'll wait until this afternoon. Thank you.

MR. SLATER: Thank you, Mr. Langley.

Next in line is Mr. Finn. Mr. Finn, if you want to ask your question, please go ahead.

1 MR. FINN: Yes. I have several questions, but I'm
2 going to hold all of our -- this one until this
3 afternoon. I note that the cause of the T-South
4 rupture was eventually traced back to pretty lax
5 testing procedures on the part of Enbridge and that
6 they have in the meantime vowed to significantly
7 improve those. And they have initiated a program,
8 which is hardly mentioned in this thing, called the T-
9 South Reliability Program, which involves a great deal
10 of effort on Enbridge's part to improve the
11 reliability of its T-South System, including replacing
12 many of the compressor stations and improving their
13 testing ability and improving the pipelines in some
14 cases.
15 I'm surprised that -- well, let me ask the
16 question. Is this factored into your analysis? And
17 that the improvements to the T-South reliability that
18 Enbridge is making would seem to be their business and
19 you might stick to your knitting on providing peak
20 shaving to the Lower Mainland, which you have done
21 successfully since 1971. But this is a significant
22 change of your role and to start talking about vast
23 storage capabilities in the event that Enbridge
24 doesn't do its job.
25 **Proceeding Time 10:11 a.m. T18**
26 MR. SLATER: Thank you, Mr. Finn. Sorry, could you --

1 I just sort of missed the question in there. Was the
2 question about have we, have we taken into account,
3 you know, Enbridge's integrity management program into
4 our program? Is that a fair characterization?
5 MR. FINN: Yes.
6 MR. SLATER: Okay, I'm going to maybe call upon Doyle
7 Sam to answer that question if I could.
8 MR. SAM: Thank you, Mr. Finn and Mr. Slater. Yes, the
9 question of T-South and its integrity program is a
10 question that we have had. Suffice to say we have had
11 a number of discussions with the management of the
12 company of the T-South, and asked them about their
13 integrity management program. We had a meeting last
14 fall. We understand that they have taken some more
15 preventative measures when it comes to their integrity
16 management. They are running the latest tools when it
17 comes to crack-like detection. They've also adjusted
18 their frequency of when they run their tools. And so
19 as we know, they have taken some steps to improve
20 their integrity management as far as the pipeline
21 integrity concern or a crack-like feature.
22 However, there is no guarantee that even
23 with that they may not have another failure. The
24 integrity tools that we run, our experiences, there is
25 no guarantee that they catch everything. But
26 obviously what they are doing has satisfied the

1 National Energy Board as well.
2 So hopefully that helps and adds some
3 context to what we know of what the T-South system is
4 doing when it comes to integrity and reliability.
5 MR. FINN: Thank you.
6 MR. SLATER: Thank you, Doyle. I note that Mr. Andrews
7 has his hand up? Mr. Andrews, if you want to go ahead
8 and ask your question?
9 MR. ANDREWS: Yes, a follow up to my question about the
10 Gorge Pipeline. This question relates to the Mist and
11 Jackson Prairie storages. On the slide it says 20 --
12 19 and 25 billion cubic feet for each of those two
13 facilities. My first question is, are those figures
14 amounts that Fortis has contractual rights to? And
15 secondly, how does having -- you said displacement, if
16 physical gas is short because of a disruption on the
17 T-South pipeline, how would displacing gas at Jackson
18 Prairie or Mist provide physical gas to the Lower
19 Mainland?
20 MR. SLATER: Thank you, Mr. Andrews. I'm going to ask
21 Shawn Hill to answer that question, please?
22 MR. HILL: I'll answer, I think there were two
23 questions there, Mr. Andrews. The first question is
24 out of the 25 and the 19 Bcf of storage at those two
25 off-system storage facilities, Fortis contracts for
26 about 5 Bcf of storage from those two facilities in

1 general. So that's the first question.
2 And you're absolutely right, Mr. Andrews,
3 on a normal -- so what commercially, I think that's
4 the distinction I wanted to make. Under normal
5 operations, Jackson Prairie and Mist are a cost-
6 effective way for us to meet our load profile over
7 time, by displacement. But you're absolutely right.
8 In a physical outage of gas flow, those storage
9 assets, particularly in the winter, are not going to
10 be a value to FEI in getting gas to the Lower
11 Mainland. Like in other words, there is a hydraulic
12 -- in a sense of displacement, there is always gas
13 flowing north to south off the West Coast system, into
14 the Pacific Northwest. And on a incident event where
15 there is a no-flow, gas would be not flowing into
16 FEI's Lower Mainland System, and also to the
17 Seattle/Portland area. Therefore, the withdraws of
18 gas out of Jackson Prairie and Mist would ultimately,
19 hydraulically, find a null point where it couldn't
20 physically get back to our system.
21 MR. ANDREWS: So looking at the numbers on slide 15,
22 that in the top portion of T-South to Huntingdon at
23 257, is that the total capacity of T-South? Or is
24 that what Fortis draws? Or has contractual
25 entitlement to?
26 MR. HILL: Yeah, that's basically 1.7 Bcf of physical

capacity that the market can contract for, times 151 days. That is the amount of gas that can physically move down that piece of system in a winter period. So that's 1.7 Bcf of gas, times 151 days.

Proceeding Time 10:16 a.m. T19

MR. ANDREWS: So then the numbers below for Jackson Prairie say at 25, is that the total storage capacity of the facility?

MR. HILL: That's the total energy at the facilities in total. And then they have a deliverability, I think the max deliverability out of Jackson Prairie is about 1 Bcf on any given day, and Mist is probably about a half of Bcf of deliverability.

MR. ANDREWS: So the proposed TLSE project, in terms of a storage asset, would show up here as 3 million cubic feet?

MR. HILL: Yeah, that's correct. Small in comparison to what the region has in total, right?

MR. ANDREWS: All right, thank you.

MR. SLATER: Thank you, Shawn. And just by way of clarity, when we are referring to regional resources, we do include the I-5 corridor, so Portland, Seattle, down south there, just as a point of clarification.

I'll next move on to Mr. Hackney. Mr. Hackney, I notice you have a question typed into the chat box, I could read that for you? Or perhaps you

1 want to just ask that verbally? So I will leave the
2 choice to you.
3 MR. HACKNEY: Thank you, yes. My question is whether
4 Fortis' -- is Fortis' case in favour of the Tilbury
5 Expansion partly predicated on a perception or
6 characterization that the regional supply of
7 infrastructure is aging and becoming less reliable?
8 MR. SLATER: Thank you for the question. Just as far
9 as the maybe condition of the infrastructure, I might
10 just ask Mr. Chernikhowsky to address that question.
11 MR. CHERNIKHOWSKY: Yes, thanks, Mr. Hackney. I think
12 I would take this in two directions. One is that yes,
13 I think it's a reality that many of the threats and
14 hazards that affect pipeline infrastructure are what
15 we refer to as time dependent. So, a defect in a
16 pipeline, the longer it's present, and the longer it
17 is present, and the longer that the pipeline operates,
18 the more likely it is to manifest itself.
19 Yes, all operators do run inspection tools,
20 but as Mr. Sam referred to, no tool is perfect, and
21 sometimes features are missed. So that is one
22 reality.
23 The other one, which I think we are seeing
24 some evidence of as well is the impacts of climate
25 change. And the impacts that that has on
26 infrastructure as well. Whether it's due to water

1 flows, land movement and what have you. There maybe
2 some increased risk from that as well.
3 MR. SLATER: Thank you, Mr. Chernikhowsky. I'm not
4 sure if Mr. Langley's hand is up fresh, or if it's old
5 from previously, but maybe while we confirm that,
6 we'll just move forward to Mr. Finn? Mr. Finn, please
7 go ahead and ask your question.
8 MR. FINN: Okay, it's again in relation to that slide
9 which shows the T-South to Huntingdon, number as 257.
10 I'd like it explained as to how much of that supply
11 goes south of the border into the Williams Northwest
12 Pipeline System, and how much actually goes west to
13 the Fortis System? Because it looks to me looking at
14 Jackson Prairie and Mist, that their send out
15 capability is at least twice what B.C.'s worst case
16 demand would look like, and that supply could be drawn
17 up on for many days of outage, in the event that T-
18 South did go down. Maybe you could explain -- how
19 much of the 257 actually winds up win Fortis' system?
20 MR. SLATER: Thank you, Mr. Finn, for the question.
21 The amount of gas off T-South that comes in to Fortis'
22 system and down south is something that we did file
23 confidentially in the application.
24 **Proceeding Time 10:21 a.m. T20**
25 So we're unable to comment on that today but it is
26 included in the application. So, apologize for that

1 but we'll leave that detail confidential.
2 MR. FINN: All right, thank you.
3 MR. SLATER: And then I'll just -- one last check with
4 Mr. Langley here. Mr. Langley, do you have a new
5 question or is hand left up from previously?
6 MR. LANGLEY: New question. Just checking you can hear
7 me?
8 MR. SLATER: You betcha, go ahead and ask your
9 question.
10 MR. LANGLEY: Okay. I'm wondering, this whole
11 application I think, and certainly a lot of the
12 questions that we're hearing from some of the
13 interveners, is hinged a lot on what precipitated to
14 the Fortis system in the October 2018 outage. And I'm
15 wondering if it might be illustrative for people if
16 you guys did a, I don't know how big a presentation,
17 but just sort of some description of what happened on
18 that day to your resources, what you were able to rely
19 on and what you weren't able to rely on in order to
20 keep your system above water, if you will, and how big
21 a role weather played in making -- in allowing the
22 system to make it through until the assets could come
23 back online. Is that part of this presentation today?
24 MR. SLATER: Yes, great question, Mr. Langley. That
25 will be addressed today and it's also addressed in
26 detail, you'll find it in section 3 of the

1 application, some of which has been filed
2 confidentially, but we'll be going through the pieces
3 that we can share as we progress through the
4 presentation. So maybe we'll wait for that and see
5 what questions fall out of there, if that's okay?
6 MR. LANGLEY: Thank you.
7 MR. SLATER: And back to Madam Chair, please go ahead
8 and ask your question.
9 THE CHAIRPERSON: Thank you very much, Mr. Slater.
10 Just a matter of process, I note that in your schedule
11 you had contemplated taking a break at 10:05 and then
12 another short break at 11:00 with a lunch break at
13 12:10. So I'm just realizing that it's now 10:23, so
14 perhaps you can just think about when might be a
15 convenient time for you to take a break and whether
16 you want to wait till 11:00. So I'll leave it in your
17 hands to consider.
18 MR. SLATER: Yes, thank you, Madam Chair. Shawn has
19 two slides left before the break, so maybe we'll just
20 keep moving along in the spirit of the time that we
21 have today and I'll pass it back over to Shawn and
22 then we can take the break and reassess.
23 So back to you, Shawn.
24 MR. HILL: Thanks, Doug, can we actually go to the next
25 slide? Yeah, perfect.
26 So just want to spend a little bit of time,

we've talked about the commercial, some of the commercial resources that we have in place in the region to contract for and I just want to orient people to this slide. You're going to see it a couple of times today. It's what we call a load duration curve or a load -- that profiles the load of our customers over the, in this particular case, over a gas year from November to October. And as I mentioned, you can see that our load profile in the winter months is, you know, considerably higher than it is in the dead of summer. And so that's what we would call a poor load factor.

For the bundled rate schedules 1 through 7, we put a plan in place to meet design load, a winter loads in the wintertime, which is -- so a design load is a really cold winter and we design our portfolio, gas supply portfolio, in a commercial sense to meet that load profile. And that design load also includes the coldest day in that year, which is our design peak day.

The resources, as Paul mentioned earlier in the day, and a principle of putting this commercial gas supply resources together is to match the appropriate resource and its associated cost and its attributes against the load profile that you're trying to serve. And obviously, basically, let's take a look

at what those two or three options are.

Pipeline is place to serve duration of load, basically because you contract for capacity on the pipeline under a commercial determined tariff for -- paying us for a certain amount of capacity for 365 days a yeah. So you're basically paying for that amount of capacity whether you use it or not. And because of that poor load factor in the region, that has a high cost for customers because that capacity is not necessarily utilized in the summertime. So we want to match our pipeline appropriately best to our load profile in the wintertime.

Then the next resources that we used to match load over and above the pipeline is storage resources like Jackson Prairie and Mist. And that is for, basically, resources that exceed the pipelines into the region.

Proceeding Time 10:26 a.m. T21

They also -- because that's cost effective because we only need them for shorter durations of time. So that's a cost-effective way to meet that load profile.

The other thing that I'd just like to point out about those off-system storage recourses is the region is highly dependent on weather and variations in the weather, even on the inter-days or within the

1 day. So those storage assets help us manage those
2 fluctuations and we call on those resources and review
3 that supply demand picture to two or three times a
4 day.
5 And, finally, at the top of the stack is
6 our curtailments of industrial customers that we have
7 under our rate schedules and also the two LNG
8 facilities that we have, Mt. Hayes and Tilbury. And
9 those are cost-effective resources to meet that needle
10 peak from a planning perspective.
11 As we mentioned earlier in my presentation,
12 and in Paul's presentation earlier, it's FEI's view
13 that when we look at resiliency we need to take this
14 portfolio approach to resiliency and best matching
15 resources to the problem or issue you're trying to
16 solve, duration or short-term issues. And that's a
17 cost-effective approach to increase the resiliency for
18 customers.
19 The final point, if we can move to the next
20 slide, I've only got one slide left and then I guess
21 I'm standing, it sounds like, in front of everybody
22 for a break. So the final one that I'll talk about is
23 what I talked about at the very start of my
24 presentation is to distinguish the concepts of
25 commercial versus physical. And basically I think
26 this kind of is leading what Mr. Langley was talking

about, which is covered in section 3 of the application about, yes, we contract for commercial arrangements on upstream infrastructure and that's highly reliable. But when things go awry or we have an issue of an emergency event, what physical resources do we have left to manage the situation?

And that's what this application is all about, is to make Tilbury, from a resiliency perspective, bigger so that we can withstand a three-day event while providing our traditional gas supply benefits and operational benefits to our customers. So, in a sense, the Tilbury application or this application is about giving us some certainty around that no-flow event for three days.

I'm happy to take any more questions on those last couple of slides.

MR. SLATER: So, just perhaps in the interest of time here I just wanted to sort of, you know, touch back on a couple of the questions before we go to break. But there were a number of questions that got to the role of off system storage at Jackson Prairie and Mist and the Gorge and how they support FEI during an emergency event. And essentially what Shawn is saying is that those recourse, those off system resources to the south, can only help FEI when gas is physically flowing to the south.

And so the process of displacement, which Shawn is going to talk to a little later today in the presentation, essentially relies on us taking -- trading gas, if you will, taking gas at Huntingdon and giving it back out of the storage areas to the south. That's how displacement works and it's kind of critical and it really only works when gas is physically flowing. So if T-South is interrupted and there is no gas flowing, we can't rely on our storage assets that are off system, so they aren't really a substitute to the project but I thought I'd better sort of circle back on that to assist with some of those questions.

So, with that, I note we are at 10:30 here. We're a little bit behind, so as Madam Chair pointed out, perhaps we will take our ten-minute break and come back and get restarted. So that leaves us to 10:40.

THE CHAIRPERSON: All right, thank you very much, Mr. Slater, and thank you, Mr. Hill.

MR. HILL: Thank you.

THE CHAIRPERSON: We'll reconvene at 10:40.

(PROCEEDINGS ADJOURNED AT 10:30 A.M.)

(PROCEEDINGS RESUMED AT 10:48 A.M.) T22-24

THE CHAIRPERSON: All right. Thank you everyone and I hope you had the opportunity to enjoy a little bit of

a break.

I just want to raise an issue that has now come up twice in this morning's workshop and that pertains to the fact that apparently some information that has been filed as part of Section 3 of the application, which was filed confidentially, it appears that some of that information may not or in fact is not confidential. As you will be aware, the Commission has accepted FEI's filing of the application including confidential information on a confidential basis to date. However, we have not made any ruling on the confidentiality, the request, with respect to any of the information that has been filed confidentially.

Now, the panel intends to seek submissions as soon as practicable on the confidentially request from all parties, after which it will rule on the confidentially request. However, to the extent that any of the information that has been filed confidentially to date is not confidential, we would ask that FEI refile that information on a non-confidential basis with whatever redactions is considered appropriate and put that on the record in place of the original filing, just so parties are absolutely clear as to which sections are redacted and confidential and which ones are not in FEI's

1 estimation. That will allow us the opportunity to
2 review the request, as well as the submissions that
3 have been made with respect to confidentiality, and to
4 make an appropriate ruling.
5 With that said, I would encourage on behalf
6 of the panel FEI to consider responding as fully as
7 possible with respect to questions that pertain to
8 non-confidential information at this workshop.
9 Because the purpose of this workshop is for us -- all
10 participants to get a full picture of the application
11 based on the information that's been filed, which
12 presumably includes non-confidential information. So
13 I would like FIE to keep that in mind as we go forward
14 for the remainder of this workshop.
15 MR. GHIKAS: Thank you, Commissioner Fung. It's Matt
16 Ghikas here. And I will say I appreciate the
17 Commission's comments in this regard. Fortis is
18 trying to balance, you know, obviously wanting to be
19 as informative as possible at this stage and with the
20 application, but there is a very serious security
21 issue that's involved in compiling information and
22 putting it in one place and making it easily
23 accessible to potential malicious actors. That's
24 where the concern and the hesitancy is coming from.
25 So I just want to make sure that the
26 Commission understands the spirit in which Fortis is

1 taking that care at this time. We welcome the
2 opportunity to make submissions on issues and
3 certainly we'll, you know, look to the Commission to
4 make a final determination as to what should be
5 confidential and what shouldn't be.
6 **Proceeding Time 10:53 a.m. T25**
7 But there is, I think, a justified, in my
8 submission, a justified reticence to make comments in
9 a public forum, at least until he Commission has made
10 that determination, about the extent to which Fortis
11 is reliant on particular pipeline infrastructure and
12 the extent of the harm that could result from a
13 disruption of that infrastructure. Even though people
14 understand that there was an issue with the T-South
15 disruption in 2018, the full ramifications of that are
16 not and may not be readily apparent and compiled in
17 one place as to the implications of it.
18 So, you know, I'm happy to field further
19 questions but I just wanted to acknowledge that your
20 -- the panel's concern. We're pleased to address it,
21 but I did think it was important to just make
22 absolutely clear that this is coming from a place that
23 is in the interests of both the company and all
24 ratepayers and frankly all British Columbians in
25 general, not making it too easy for a malicious actor.
26 So I'll stop there.

1 THE CHAIRPERSON: Thank you, Mr. Ghikas. I appreciate
2 your concern and the panel will take your comments
3 into account, and you have the opportunity to make the
4 same submission or similar submissions when we go out
5 for comments with respect to the confidentiality
6 requests. However, I would reiterate the panel's
7 request for FEI to refile, if it feels appropriate,
8 any filings of information that is already done to
9 date in light of what has been said this morning
10 during the workshop, to the extent that any of the
11 information that's currently contained in the
12 application has been filed on a confidential basis is
13 not after all confidential.
14 MR. GHIKAS: Thank you. We will take that away,
15 Chairman Fung, and, you know, it was certainly our
16 intent when we filed the application to begin with to
17 make sure that we were doing that and following the
18 standard rules, but we will take it away and look at
19 it again.
20 THE CHAIRPERSON: Thank you very much, Mr. Ghikas.
21 And, also, to all the FEI witnesses that
22 are currently before us at this workshop and to the
23 extent I realize people are not giving testimony here,
24 however, it will be part of the record, so if upon
25 reflection you've come to the realization that certain
26 information is not confidential and you're able to

1 provide that information in the context of this
2 workshop, we would encourage you to do so. So thank
3 you very much.
4 So over and back to you, Mr. Slater.
5 MR. C. WEAFER: Chairman Fung, Chris Weafer. Could I
6 just ask a question?
7 THE CHAIRPERSON: Absolutely.
8 MR. C. WEAFER: I just wanted to clarify the order from
9 the Chair with respect to timing. As I understand it,
10 and this is just a process question, that Fortis is
11 being given the opportunity to refile and revisit its
12 confidentiality position and after that there will be
13 opportunity for submission on confidentiality. Is
14 that correct or will you be looking for submissions on
15 confidentiality before they've taken that opportunity?
16 THE CHAIRPERSON: Obviously it would be simpler if
17 Fortis were able to determine now or within short
18 order whether or not it needs to refile, in which case
19 there would be room for submissions on the new version
20 of the application with further information that's
21 unredacted. However, if that's not feasible or that's
22 something that Fortis is not prepared to do, then I
23 guess we will have no choice but to go out for
24 submissions on the current version of the application
25 with the confidentiality requests as it has been
26 filed.

1 MR. C. WEAFER: Thank you, that's helpful. I
2 appreciate that.
3 THE CHAIRPERSON: So I will leave it to Mr. Ghikas and
4 leave it in his capable hands to advise everyone as to
5 what FEI's preference is in that regard.
6 **Proceeding Time 10:57 a.m. T26**
7 MR. GHIKAS: Yeah, we will go and advise -- one way or
8 the other we will advise everybody as soon as
9 possible, but for today's purposes the redactions --
10 Fortis' position on the redactions that have been done
11 to date is that they are appropriate and justified.
12 And so the -- you know, while we can go away and look
13 at them again and consider them in light of what the
14 Commission has said, the comments that the panel has
15 made are the lens through which Fortis was proceeding
16 when they made the redactions in the first place. And
17 the rules recognize security related concerns and that
18 is what Fortis has been trying to do. And I recognize
19 that the default is that materials should be made
20 public, should be made public wherever possible
21 subject to those constrains, but the -- I mean, the
22 intent was to strike a balance that the Commission
23 would find acceptable and that respected the public
24 interest balancing that goes on in that analysis.
25 So, you know, from our perspective and from
26 Fortis' perceptive, we don't anticipate providing a

1 revised document based on the comments that you
2 provided. We will go away and we will look at it and
3 I'll get instructions on it, you know, afterwards, but
4 the challenge is that everything that you're saying is
5 something that Fortis has considered in trying to be
6 as careful as possible in what was redacted and what
7 wasn't.
8 Obviously the Commission may disagree at
9 the end of the day as to whether the line -- you know,
10 the balance that Fortis tried to strike was correct,
11 but the considerations that you're enumerating,
12 Commissioner Fung, are exactly the types of
13 considerations that Fortis was trying to apply.
14 So I mean we take your concern and, you
15 know, your expression -- you know, take your
16 expression as some skepticism as to whether or not
17 they did strike the right balance, all of that is, you
18 know, fair comment. But, you know, we will look to
19 take the opportunity to provide any further
20 information to help you inform your decision on
21 whether or not more needs to be realized.
22 THE CHAIRPERSON: Mr. Ghikas, I don't want to engage in
23 a debate on this issue, but I would point out that
24 this has only arisen as a result of FEI acknowledging
25 in the course of this morning's workshop on two
26 occasions that certain information that's already

filed on a confidential basis as part of Section 3 of the application were not in fact on its face confidential. I will leave it at that. And I will look forward to receiving your confirmation as to how FEI proceeds to move forward on the filing or non-filing of a new version of the -- of Section 3, for instance. With that I'm happy to move on. Thank you.

MR. SLATER: Thank you, Madam Chair. I'm just going to quickly pass it over to Doyle Sam who is going to present the next section of the presentation today.

PRESENTATION BY MR. SAM:

MR. SAM: Thank you, Mr. Slater. By way of introduction, my name is Doyle Sam and I am the executive accountable for the operations and engineering of our transmission, distribution and compression facilities. I would like to note that I was in this role during a T-South event, providing support during our emergency operations centre. And our operational contingency planning subsequent to the event knowing we were going to be in a constrained gas supply for some time.

Our operations team has a particular interest in this project, as I will show, given that a gas supply disruption could manifest itself into a significant operational restoration response to make the system safe and restore gas to our customers.

1 Slide 19, please, Ilva.
2 Our project scope is founded from the
3 development and definition of a minimum resiliency
4 planning objective, as Mr. Chernikhowsky mentioned, to
5 address the specific and unique characteristics of
6 FortisBC's system and the region as a whole.
7 **Proceeding Time 11:02 a.m. T27**
8 Our objective is to have the ability to
9 withstand and recover from a three-day no-flow event
10 on the T-South system, without having to shut down
11 portions of our gas distribution system that would
12 result in our firm customers being without natural
13 gas.
14 We use the T-South incident and the
15 potential consequence of that event, or a similar
16 future event, as the primary input to develop our
17 planning objective, and we focused on a T-South
18 disruption, because we obtain much of our natural gas
19 from the system.
20 We have characterized our planning
21 objective as the minimum, knowing that a no-flow event
22 could last longer than three days, or the two days we
23 saw with the T-South incident. And that gas supply
24 can be constrained for a much longer time period, and
25 for a number of different reasons.
26 Given our reference to the T-South incident

in our application, I thought it might be helpful to take us back to that incident. So I'll move to slide 20.

The incident occurred on the evening of October 9th, 2018, just north of Prince George. And I'll cover off a question from Mr. Andrews. He questioned about the timing of the 2017 long-term resource plan? And clearly our resource plan predated the event, given that it was in 2017, and as Mr. Hill explained, the resource plan is really about where is the next molecule of physical gas coming from, and really less focused on resilience and reliability, unless there are two pipeline options that are the same, we can consider resiliency and reliability.

The failure on October 9th, occurred on the 36-inch pipeline, that shares a common right of way with a 30-inch pipeline. And both lines operate as an integrated system. The no-flow event and the immediate loss of supply occurred when the adjoining 30 inch line was shut in over precautionary safety measures.

The picture on the slide was taken after the resulting fire was extinguished, and was safe to visit the site. I note the ruptured section of pipeline in the lower right hand corner of the picture, and you will see two sections of the pipe in

the top half of the picture. The picture also shows the charred earth, and you can see some trees that were charred and burned from the fire that resulted from the incident as well.

There were a number of phases to the incident from our perspective. The first phase, which we are referring to as the no-flow event, and the 48 hours immediately following the rupture, when there was no new gas entering the T-South system. The rupture was about 750 kilometres away from our load, so we were able to survive in part during this no-flow event from a number of different options and tools.

Gas was still in the pipelines, which is referred to as line pack, and Mr. Hill will talk a little bit more about line pack, but there was physical gas still in the 750 kilometres of line. We requested customer curtailment, including public appeals, and will talk a little bit more about that.

We actioned mutual aid, through the Northwest Mutual Aid agreement. We were able to reduce Vancouver Island demand on the system by using our Mt. Hayes liquefied natural gas facility on the island to supply that demand. And I will point out, October, on October 10th, it was 11 degrees Celsius in the Lower Mainland. So clearly we saw mild weather, which also helped suppress the load and the demand on

1 the system. As well the relatively favourable weather
2 obviously helped with the repairs and the mitigation
3 for Enbridge.
4 I will note though that had a few things
5 happen differently, thousands of customers in the
6 Lower Mainland would have been without gas for weeks,
7 and even months. And it is this no-flow event that
8 underscores our application.
9 Phase 2 refers to the period after the 30
10 inch pipeline was reinstated, but at a reduced
11 capacity. And the ruptured 36-inch pipeline remained
12 out of service to undergo repairs. And I will come
13 back to Phase 2 and Phase 3 a little bit later.
14 Moving to slide 21, I wanted to cover off a
15 few of the more notable milestones of the no-flow
16 event. Effectively what happened in the first 48
17 hours.
18 **Proceeding Time 11:07 a.m. T28**
19 Within just two ours of event happening our
20 emergency operations centre was activated and we began
21 notifying our larger customers of the incident.
22 Shortly thereafter we initiated curtailment of our
23 interruptible and firm customers. And we effectively
24 shut the valve between the Lower Mainland system and
25 Vancouver Island to reduce the Vancouver Island load
26 on the system.

1 Within just five hours of the event the
2 Northwest Mutual Aid agreement was activated, with the
3 first call and all of the members initiating plans to
4 reduce demand. For example, Washington and Oregon
5 looked and shut-in large gas electrical generators to
6 reduce the demand. There was maintenance work on the
7 Gorge pipeline that was expedited to increase the
8 capacity. There was an expedited return to service of
9 the Jackson Prairie storage facility which was
10 currently in a maintenance turnaround.
11 Although we sent out some initial
12 communication and conservation messaging on the night
13 of the incident, we focused most of our voluntary
14 curtailment messaging starting at seven o'clock in the
15 morning. Although we could have started earlier with
16 a more focused approach, we felt there was no benefit
17 prior to the morning news and as such the system still
18 incurred 12 hours of the normal demand overnight.
19 Just over 12 hours from the event we were
20 regasifying liquefied natural gas from our Mt. Hayes
21 facility to not only fully support the Vancouver
22 Island load, but we were also able to reopen the valve
23 between the systems and back feed a bit of that gas
24 into the Lower Mainland system.
25 Our friends south of the border were able
26 to expedite the Jackson Prairie shutdown and because

1 the demands were low we were actually able to start
2 flowing a little bit of gas north. And although the
3 30-inch line was returned to service about 36 hours
4 after the initial pipeline failure, gas was not
5 available until about 12:30 in the afternoon as the
6 whole system needed to be restarted and effectively
7 repressurized. We restored service to our firm
8 customers at about one o'clock p.m., almost 48 hours
9 after the incident. And that action effectively ended
10 the no-flow event, as we've termed it.
11 And I will note that this is the first time
12 anyone associated with this project can recall that we
13 were required to curtail firm customers.
14 I would also like to note that the timeline
15 was impacted by a resulting fire that needed to be
16 brought under control before the site was safe to
17 access. I raise this as a reminder that this event
18 happened in October and had the same event happened
19 during a hot, dry summer season and resulted in a
20 fire, it is conceivable that access would have been
21 restricted for multiple days or weeks for safety
22 concerns. This timeline conveys the decisions that
23 needed to be made and were made in real time and
24 despite best efforts actions take hours, not minutes,
25 to implement and all companies affected by the T-South
26 incident were going through more steps. And had the

1 T-South incident occurred with only a few different
2 variables or circumstances, these tools and timelines
3 would have been insufficient to prevent more customers
4 from losing their natural gas supply for an extended
5 period of time.
6 Moving to slide 22. This incident was a
7 learning opportunity that pointed out a broader system
8 vulnerability for our customers and such, I wanted to
9 cover the key learnings. As the previous timeline
10 slide conveyed, we have limited time to make critical
11 decisions to preserve the system and match the demand
12 in a supply emergency. The location of the incident
13 can affect us in two ways. First, as we saw with the
14 T-South incident being about 750 kilometres from the
15 load centre, that distance provided us with some line
16 pack gas supply. If the event would have occurred
17 closer to the Lower Mainland system, the available
18 line pack reduces and we could find ourselves with
19 being required to react in as little as two hours.
20 Also, pipelines go across country and as
21 such if the incident occurs in a relatively remote
22 area, geography can affect the time to access and
23 mitigate the issue. Weather, as we saw with the
24 October 9th incident, can also have a significant
25 impact on how much time we have to respond.
26 **Proceeding Time 11:11 a.m. T29**

1 Colder weather creates a higher system demand,
2 reducing the time to respond, and a winter snowstorm
3 could create delays to access the incident site and
4 thereby create a longer no-flow event.
5 As well, an incident in the summer can also
6 create an issue with demand and supply. And as
7 pointed out, the added fire risk can create an equal
8 or even longer no-flow event than we saw. Effectively
9 an incident at any time of the year would still
10 require a solution like we are proposing to mitigate
11 or eliminate the negative customer impacts.
12 Unlike the electric industry, we have very
13 limited real-time consumption data on which to base
14 our response. And in the absence of real-time
15 reliable data, we are forced to be more conservative
16 to avoid an uncontrolled shutdown. Which with
17 hindsight may result in unnecessary, planned customer
18 outages. From the previous slide, I've shown that
19 even expedited efforts will take many hours to
20 coordinate the response to balance the demand with the
21 supply. And many decisions need to be made, most
22 relying on multiple parties to manage through an
23 emergency like this. As such, this project is all
24 about having a back-up gas supply that could be used
25 to primarily avoid customer outages all together and
26 ride through a no-flow event, or to either buy enough

time to avoid an uncontrolled shutdown of the system, or as a last resort, execute a controlled shut-in. Neither of which are desirable, as both will result in lengthy outages for a large number of customers. As I will show, these actions are not easily reversed, and gas outages can create health and safety impacts.

On slide 23, this timeline was extracted from our application, and is used to convey the no-flow event and the subsequent restricted flow events. Our proposed project's primary purpose is to mitigate the risks and consequences associated with zero gas supply entering our pipeline system.

The first phase shown here in red was almost two full days in duration, in which there was no new gas available for use from the T-South system. And I've already covered that in some detail as the no-flow event.

The orange section of this timeline is the restricted flow portion of the event, and this timeline can be broken into two phases of note. The first phase is the time period in which the 30-inch pipeline was restored, but the 36-inch line still remained out of service. And for this two to three week period, the T-South system was restricted from as low as about 38 percent capacity, to as high as only 50 percent capacity through to the first week of

1 November.
2 Once the 36-inch line was returned to
3 service during the first full week of November, the
4 capacity on T-South was still restricted. During the
5 remaining winter of 2018/2019, while integrity work
6 was completed on the system and available capacity
7 during this 13-month period ranged from 60 to 90
8 percent. This flow restricted period, along with
9 associated capacity restrictions is significant.
10 Knowing the T-South system is 100 percent contracted
11 for its capacity during the winter.
12 On Slide 24, as Mr. Chernikhowsky
13 mentioned, unlike the electric industry that has
14 developed reliability planning standards in response
15 to large outages, the gas industry does not have any
16 industry adopted reliability or resiliency standards.
17 And as we saw from Mr. Hill's slide, we do
18 not have the pipeline diversity that we see in
19 Alberta, or the underground storage geographically
20 located in a load center like Ontario enjoys. As
21 such, our system creates some unique challenges and
22 risks for our customers that other jurisdictions do
23 not need to consider.
24 We are focusing our efforts to mitigate any
25 gas supply disruption that occurred -- could occur,
26 upstream of our Lower Mainland system. The event

1 could be from another disruption to the T-South
2 system, or the event could be from a disruption on
3 FEI's own Southern Crossing pipeline system. Or we
4 could also have a supply disruption caused from an
5 incident on our transmission system located in the
6 Lower Mainland.
7 **Proceeding Time 11:16 a.m. T30**
8 We have chosen a minimum three-day no-flow
9 event based on the T-South event. Although the
10 actually no-flow event was two days in that case,
11 we've effectively added an additional day to our
12 planning objective. To recognize that that event
13 happened during relative mild weather with the
14 associated lower system demand and the actual location
15 of the event in favourable weather conditions at the
16 time resulted in relatively easy access to the site to
17 access and take the appropriate measures.
18 We used a time based analysis to assess how
19 much time would we need in a no-flow event to enable
20 the company to preferably manage through the no-flow
21 event and preserve gas service to our customers or, in
22 a less desirable situation, afford us the time to
23 action other tools to prevent an uncontrolled system
24 collapse, to preserve service to as many customers as
25 possible and to minimize the overall outage impacts to
26 our customer. And while the planning objective was

1 determined by FortisBC, Guidehouse, as we will hear
2 later from Mr. Moran, validated our approach and
3 decision framework.
4 If I move to slide 25, and I was going to
5 spend some time talking about what our response tools
6 currently are. And we have a number of tools that
7 have been very effective to manage through small gas
8 supply events and they all provide value. However,
9 they have significant drawbacks when measured against
10 an event of this magnitude. We need dependable, firm
11 tools that can be actioned through decisions in real-
12 time that will either supply and flow a gas molecule
13 or reduce the demand for that same natural gas
14 molecule.
15 The curtailment of customer load, large
16 customer load, interruptible load, is the first
17 measure following an emergency event. In order to
18 curtail customers we first contact each customer and
19 request they curtain gas use. The customers must then
20 begin the process of transferring to an alternate
21 energy source or shut down. Depending on the nature
22 of the customer's business, the time of day that the
23 request is made and the expediency of their
24 compliance, it may take customers several hours to
25 fully curtail from the time of initial request.
26 I also note that the company has limited

1 tools to confirm compliance with the request. And as
2 such, effectively the time required to enact and the
3 number of customers required to get any material
4 curtailment volume, interruptible volume which tops
5 out at about 10 to 15 percent of our winter peak,
6 limits the value of this option depending on the
7 emergency.
8 In addition to curtailing larger customers,
9 we also issue public communication to community
10 customers to reduce their use of natural gas to help
11 stabilize and prolong system life during an emergency
12 event. The response time could vary. During the
13 night people are less likely to be on social media or
14 watching television and recognizing that customers
15 rely on natural gas for hot water and home heating,
16 they are going to be less willing to volunteer
17 curtailment in the middle of winter. And as such we
18 are faced with the challenges of a customer's
19 willingness to voluntary curtail and even if so, the
20 limited non-firm volume benefit this action would
21 provide is a significant shortcoming.
22 Our current on-system storage systems at
23 Mt. Hayes and Tilbury, LNG storage systems, are very
24 valuable. They're just not big enough for this type
25 of event and our current plant's design, they need
26 many hours from the time of notice to begin supplying

1 gas before they can actually supply gas to our
2 pipeline system. Time which may be insufficient
3 depending on the nature of the incident.
4 Off-system storage resources are of limited
5 value given the lack of pipeline diversity. For
6 example, we have access to a great underground storage
7 resource with Aitken Creek. However, as we saw in the
8 T-South event, we could not access the volume given
9 the location of the incident. We also have
10 contractual access to the gas that's south of the
11 border. With the nature of the contracts and system
12 design prevents any material gas from flowing north
13 into our system during high demands.
14 **Proceeding Time 11:21 a.m. T31**
15 As we saw with the T-South no-flow
16 emergency, all commercial activity was curtailed and
17 there was no available physical resources to purchase
18 any incremental supply.
19 Mutual Aid was another tool that we used.
20 Mutual Aid requires the cooperation and collaboration
21 on industry participants. This requires scheduling of
22 emergency meetings, discussion of potential
23 strategies, internal approval within each
24 organization, and a coordinated implementation. And
25 notwithstanding the goodwill of our Mutual Aid
26 partners, Mutual Aid is voluntary and does require

1 access to physical gas and infrastructure to be
2 successful.
3 Coming back to the October 9th incident, we
4 employed all of these tools. And it was only for the
5 time of year, location of the incident, customer
6 curtailment, our limited onsite LNG storage, and great
7 Mutual Aid cooperation that prevented tens of
8 thousands of our customers from being without gas for
9 a long time. Had even one of these events variables
10 been more negative, these tools would have been
11 insufficient to prevent large sections of our system
12 being shut down to preserve the broader (inaudible) of
13 the system.
14 I'm going to turn to slide 26 and spend
15 some time talking about supply continuity and why it's
16 so important. And I want to take a few minutes to do
17 a comparison, because when supply is disrupted it has
18 a much different impact than what we might find with
19 electrical outages of which we may be more familiar
20 with. First off, and like an electricity outage, a
21 gas supply outage would negatively impact all
22 customers, be they residential, commercial, or more
23 health care sensitive customers. That is however
24 where the similarities end. The impact to customers
25 from a gas supply outage is much greater due to the
26 different properties in part of the commodity and the

end use appliance, both of which drive a very different outage restoration response and time to restore service safely.

When compared to an electrical outage the biggest difference is the time and stapes required to restore service once gas supply has been fully restored. And by way of illustration I'm going to use an electrical supply outage example that we all experience on a fairly frequent basis. A windstorm causes a tree to fall on our electrical transmission line or a main distribution line. All of our power goes out. The company then goes to remove the tree, fix the line, and then hits a switch and electricity supply is restored, all of our power comes on, and the customer outage ends.

The outage duration could be hours or in some cases in the Lower Mainland we have had hundreds of thousands of customers that lost initial supply and were out to, say, three to five days. The duration of a gas supply outage to customers could be orders of magnitude greater.

If we lose pressure in our gas system for even a hour, there are a number of steps that need to be taken to restore service safely to our customers. First, we need the dispatch technicians to go to all of the customers' premises to manually close the valve

at your house. In the absence of gas pressure within the system, we need to assume and expect that we may have air in our gas lines that can enter through fittings, leaks, or third-party damages. And when that happens and if we were to just reintroduce house -- reintroduce gas to your house, appliances may not light, they may light and then go out, and that could cause and create a gas concentration in my building that could cause a safety risk.

Once we close every premise valve, we will then need to pressurize the system with natural gas. We will do a manual leak patrol. Effectively, we will walk every kilometre of the line that we suspect may have been damaged to confirm that we do not have any damages or leaks. If we find leaks, we will need to repair them, and then purge the effected system with nitrogen to remove any air. We will then cycle this process until we confirm no leaks and no air are in our lines. And it is this leak detection repair and purging cycle which creates the greatest unknown in predicting how long our customers will be out of gas. And in a worst-case scenario we have 20,000 kilometres of pipeline in the Lower Mainland that could require the step.

Proceeding Time 11:26 a.m. T32

Once that purging is complete, we will

travel to the customer's premise to open the valve and re-light their appliances. So how much time is that all going to take? Thankfully our industry does not, and our company does not have a lot of experience with outages of this magnitude. However, there are a few proxies that we can use.

To manually close the valves, we know that we can do that relatively quickly. Days, or a couple of weeks, depending on whether we have to say, close 10,000 valves or substantially more, and how many technicians are available for the task.

The re-pressurization and purging cycle is a big unknown. We do have an example from another company in Canada that had an event that reportedly took them two weeks to repair and purge the system of just 20,000 customers during summer weather.

Appliance relights. People may have read about the Black Hills Company Service disruption in Aspen Colorado that occurred last December. The reports indicate that it took 170 technicians, 36 hours to complete 3,500 relights. Effectively on average, it took a technician in excess of 1.5 hours per relight.

It's very easy to translate these numbers, to see that an outage of say 100,000 customers would extend very quickly into weeks, if not months for some

1 customers. And as we know, we have hundreds of
2 thousands of customers in the Lower Mainland.
3 And not so obvious, but an outage of this
4 duration would also have a significant impact on the
5 local electrical system, and would likely overload
6 that system, causing electrical outage as well.
7 The electrical distribution system is
8 designed for the current expected peak electrical
9 load, and does not provide any spare capacity to
10 absorb the energy served by natural gas. Effectively,
11 if I were to lose gas in my home in the middle of
12 winter for more than a couple of hours, I'm likely
13 going to be plugging in any electric heaters I can
14 find. And if I knew it is going to be longer than a
15 day or two, maybe an electric hot water tank, maybe
16 some wired baseboard heaters, really to ensure the
17 safety of my family. And if my neighbours do the
18 same, the power company's distribution system is not
19 designed to handle our combined increase load, which
20 will overload the local electrical system, causing
21 electrical outages in my neighbourhood as well.
22 And to put that into perspective, on
23 January 14th in 2020, the peak volume of gas delivered
24 between 7 and 8 o'clock in the morning was the
25 equivalent to over 18,000 megawatts of electrical
26 generating capacity. When compared to BC Hydro's

1 entire generating capacity of around 12,000 megawatts.
2 Effectively, if we were to lose natural gas
3 as an energy supply, and this was converted to
4 electricity, the demand on electric system would be
5 about 2.5 times what it is today for that peak hour.
6 And electrical distribution systems are not designed
7 to handle that demand.
8 And it is because of this unintended and
9 real impact on the electric grid, that we believe this
10 project has a bit of a provincial resiliency benefit
11 as well, that extends beyond just our gas customers.
12 And the T-South event had significant consequences for
13 a number of customers. But it could have been orders
14 of magnitudes worse. And as such, we engaged Price
15 Water Coopers to conduct a study that confirmed that
16 the socio-economic impacts would be significant.
17 I'm going to turn to my last slide, slide
18 27, and I thought I would close off with what are some
19 of the sources of supply disruption that we could see?
20 And although we've used the T-South incident to inform
21 our planning objective, a no-flow event come from a
22 number of different sources. The T-South no-flow
23 event and restricted flow was the result of a pipeline
24 integrity failure.
25 **Proceeding Time 11:31 a.m. T33**
26 We have also seen upstream equipment

1 failures in the form of compressor failures that have
2 restricted flows as well. The same event can happen
3 on our systems. Seismic events, landslides, flooding
4 can also create no-flow events, as well as third-party
5 activities. And with respect to third-party
6 activities, a number of years ago one of our
7 transmission pipelines in the Interior was compromised
8 by a third party doing unapproved excavation work that
9 hit and ruptured our transmission pipeline with a
10 bulldozer.
11 And then lastly, like that was suspected
12 with the Black Hills event, vandalism or other similar
13 acts can cause a no-flow or restricted flow event.
14 Regardless of the cause or type of event, we have
15 limited to no control of upstream assets or external
16 forces and an event like these could happen as earlier
17 as next week.
18 So with that I will close there and open it
19 up, Mr. Slater, to any questions before we pass it
20 over to Mr. Paul Moran of Guidehouse.
21 MR. SLATER: Thank you, Doyle. I note that Brady Ryall
22 has a question and her hand up and also put a question
23 in the comments. If you want to go ahead and ask your
24 question?
25 MR. RYALL: Sure thing. Yeah, the question I typed in
26 the comments, I think it refers back to slide 20 or

21. That was how did the Tilbury base plant and the -- I think 21 would be better. How was the Tilbury base plant and the T1A plant utilized by FEI during the T-South no-flow event?

MR. SAM: Thank you for that question. The T1 plant was not in operation yet. It was still in construction and commissioning, so we were unable to use it for the event. And the base plant was not used. We were preserving that storage as long as we could have in case the event went beyond the 48 hours. We did use the Mt. Hayes, as I alluded to, for Vancouver Island support and to back feed a bit into the Lower Mainland.

MR. RYALL: Thank you. One other question, but I'll come back. I'll let the other participants go ahead.

MR. SLATER: Sounds great. Then I'll move on to Phil Stallard. Go ahead and please ask your question.

MR. STALLARD: Hi, yeah, it's Phil Stallard with BCUC staff. So my question was referring to the sort of basis for the three-day objective and also referring back to the previous part of the presentation where we had the load duration curve presented on the screen.

So just a bit of an intro before I get to my question is, obviously the load duration curve illustrates it quite clearly that throughout a year no day is the same and there is a considerable variance

in peak demand, but also no three-day consecutive period is necessarily the same in terms of the levels of demand that would be observed.

So with that in mind I was just hoping that you'd be able to give a bit of an explanation of kind of what kind of assumptions you have made, what that three-day period represents in terms of the extent of peak demands that's observed and, as I say, there's a continuity of the extent of the -- sorry, the consecutive days or peaks that might be assumed within that?

MR. SLATER: Thank you for the question. I actually -- this question may be best for Shawn Hill to answer as it relates to the demand curve and actual consumption. So maybe if I could ask Shawn to address the question.

MR. HILL: Yeah, thanks, Doug. I do have a couple of slide to directly get to this, Phil, later on this afternoon. But generally we took an approach of looking at our design and normal curves for certain rate classes and determined a cumulative view to determine the size of the inventory that we needed to get to the minimum three-day event. I like to meet that minimum requirement and that's how we came up with the 2 Bcf.

So basically we took design curves, looked at those, also validated them against actual curves.

1 It just so happens that the 2016/2017 winter is pretty
2 close to our design curve, so we validated that to
3 come up with the minimum inventory level.
4 So as Mike Leclair talked about earlier
5 this morning, there's two concepts, the inventory that
6 we need and then the capacity, the gasification. So
7 those two things are inter -- like they're linked
8 obviously, so we got to the 2 Bcf for the size and 800
9 of gasification to look at the actually daily send out
10 needed.
11 Hopefully that answers your question.
12 MR. STALLARD: Yeah, thank you. If there's anything
13 else I'll perhaps come back to it when we get into the
14 detailed numbers around the project itself. Thank
15 you.
16 MR. SLATER: Thank you for that. So I believe Mr.
17 Langley is next. Mr. Langley, if you want to go ahead
18 and ask your question.
19 MR. LANGLEY: Yeah, just microphone check. You guys
20 hear me?
21 MR. SLATER: You betcha.
22 MR. LANGLEY: You do. Okay, good. Sorry, this
23 question is for Mr. Sam. I understood most of what he
24 talked about, but I wanted to ask a little bit about
25 this relighting process.
26 **Proceeding Time 11:37 a.m. T34**

1 I guess I'm having difficulty in understanding, given
2 the description, let's use the T-South incident as an
3 example where, you know, the pipe broke, you guys lost
4 supply, you were living off line pack for a while and
5 let's argue that instead of making it through that you
6 lost a community, and I'll just pick Ioco as an
7 example. You know, the pressure if it's down so low
8 people lose their furnaces and everything else and,
9 you know, maybe you isolate the system, whatever it
10 is, the pressure's come back up.
11 And what I guess I don't understand is are
12 you telling us that you're going to walk all of the
13 distribution lines in Ioco prior to turning on those
14 customers again? Or why would we assume that there
15 would be a leak or other physical concern in Ioco that
16 is related to an outage that might happen hundred of
17 kilometres away? Wouldn't you just turn the stopcocks
18 back on and go about your relights?
19 MR. SAM: Yeah, so, thank you for the question, Mr.
20 Langley. In the event that -- the example you're
21 relying on is that we don't take any proactive
22 measures and we just let the gas pressure system just
23 naturally reduce pressure with the demand that you or
24 I would have it on it. And at some point in time
25 what's going to happen is the pressure will become so
26 low and we do run the risk of air getting into our

lines. These lines are no long pressurized. And air could come in from natural fittings that could seep a little bit. We also have third-party damages in our system and we have a number of third-party damages, folks, contractors, digging, excavators, pounding posts, that damage our lines. So we have a number of damages every day that we manage when our lines get compromised from third-party damages.

And so effectively what we would do is we would then, to make sure it's safe, we'd go and close the valve at your house and then we will open up the master valve. And so that effectively prevents any air that could be from that broken line that was hit from entering your house. And so we will do a leak patrol to try and determine and make sure that our lines are still safe and we're not having any leaks that are escaping natural gas. And if there is leaks there is the potential that we will have air and we need to purge it.

And so then from a safety perspective, once we are satisfied with that, we will then come to your home and we will enter your home, if you allow us to enter your home, and we will relight all of your appliances. And we do that to ensure that there's no air that's in your gas lines within your home. And that's a requirement from regulation that if utilities

1 or companies, if we shut off your gas, we are required
2 to relight your appliances to ensure that your
3 appliances are relit and operating safely. And so
4 that's what we refer to that could take an hour, could
5 take an hour and a half.
6 It's the same process we go through when
7 we're doing meter exchange today. We'll change out
8 our meter and then we'll go and relight your
9 appliances in your home.
10 Is that of some help?
11 MR. LANGLEY: Yeah, but I guess what I'm surmising from
12 what you've told me though, is that wouldn't you only
13 do those types of secondary checks in areas where you
14 knew or suspected there were third-party damage? I
15 mean, I don't know how many third-party -- you
16 mentioned you get it daily. I can't imagine it's all
17 over the system daily. I mean, there must be some, I
18 don't know what you'd call it, kind of work priority
19 that says, you know what? There is no third-party
20 damage in that community, we're not going to do that
21 process there, we're going to go to those areas that
22 we do suspect we have third-party damage.
23 Do you do that process or do you just
24 blanket, "We're checking everything"?
25 MR. LANGLEY: So we would optimize all of that, yes.
26 And, as you know, we do odourize our gas, so if there

are leaks, we may find out from the public notifying us of the odour. We receive over -- across our system-wise, we have over three third-party damages per day in our system. And they go from the Island to the Interior and not very predictable. But, yes, we would optimize to -- whatever time we could to minimize that without enduring additional risk.

MR. LANGLEY: Okay, thank you.

MR. CHERNIKHOWSKY: Yeah, Mr. Langley, it's Paul Chernikhowsky, I'll just add a little bit more to what Doyle was saying there. And, yeah, so on average we experience about 1,000 system damages per year throughout our system. So, as he says, that translates to about three per day. So now imagine if the gas supply in an area was off, for example, for 30 days. Well, potentially there's some number of damages that are going to occur in that area.

Proceeding Time 11:42 a.m. T35

The problem is we won't know, because by definition the gas isn’t flowing, so people are going to continue doing their underground excavating activities. They're going to damage our system, but we will have no idea until we re-pressurize the system. And that's when we find these leaks. That's why we have to do that manual patrol of all of the lines before we re-pressurize them. Because we don’t

1 know whether it's been damaged or not.
2 So hopefully that's a little bit of help as
3 well.
4 MR. LANGLEY: Thank you.
5 MR. SLATER: Thank you, Paul. Thank you for that.
6 Next up we have Mr. Finn? Mr. Finn, if you want to
7 unmute and go ahead and ask your question?
8 MR. FINN: I actually have a couple, and I want to
9 pursue this line pack idea.
10 You have 1,000 kilometres of lets say 30-
11 inch and 36-inch looped pipes in the whole T-South
12 system to at least as far as Sumas. You have the
13 distribution system of Fortis, which is fairly
14 extensive, including that to Vancouver Island at an
15 elevated pressure of 2160 psi.
16 I did some math on that, and figured that
17 you have as much as 28 hours of line pack before you
18 drop below the one atmosphere 14.7 psi, and let air
19 into the system, what you call hydraulic collapse.
20 The entire outage of the 30-inch pipe,
21 which was done for safety reasons, was only 32 hours.
22 So you have most of it, which potential could be
23 covered by line pack. I would like to get some
24 comments on that, and before maybe you could just take
25 note while I ask my other question.
26 Fortis has a program coming up whereby it

is going to replace gas meters with the automated metering system, which would allow a shut down, either complete or partial, customer demand in the event of an outage, which should help greatly in reducing the .8 Bcf per day requirement that occasioned this whole application.

Maybe you might comment on how that's going to help reduce the need for people to walk around and do re-lights, which having been a customer for 40 years, I turn off my gas furnace every spring, and turn it back on in the fall. And most people do on their own, so far, thankfully without incident.

So, maybe on both of those points, talk about the efficacy of line pack, and second of all the impact of automated metering project that you've got upcoming. Thanks.

MR. SLATER: Thank you, Mr. Finn. Maybe I'll -- Doyle is going to jump in on the line pack question. And maybe for two different people, so we'll come back to that AMI one after Doyle is finished.

MR. SAM: Yes, so thank you, Mr. Slater, thank you Mr. Finn. So, I'll start with AMI first. And AMI, we'll see later in my presentation that you are correct. Automated metering infrastructure will help us with our response. And effectively AMI with ability to remotely closing valves, we could maintain pressure in

the system and as such that would reduce the duration of our outage response. It would not reduce the outage, but it would reduce the outage duration. And I'll cover that a little bit more closely, as I'm going to talk a little bit about AMI.

As far as line pack, I'm not going to go into the math. We might need to take that as an IR if we need to. I will only raise that we are not the only customer drawing on the T-South system at the time. As Mr. Hill pointed out, it is I still also being drawn on from the Pacific Northwest, through Washington and Oregon.

And as we can all appreciate, the location of the disruption would also indicate how much volume you have remaining in your line pack. And so, for example, the closer and closer, as I alluded to, the closer and closer it gets to your load center, the less volume you have available. And there is a reference, I wish I had it offhand, but there is a reference in our application. I think Guidehouse did a calculation on line pack, and how much that would help us out.

So, I'll stop there, and see if that answers any of your questions, or we may need to move it to someone else, Doug.

MR. SLATER: Thank you. Mr. Finn, has that answered

your question? I think you're on mute, Mr. Finn.

MR. FINN: Sorry, I would think we'd need to get into the detail of that answer to satisfy me. And the estimation of a requirement for a three-day outage, that line pack is not being factored sufficiently into that estimation as to why we need such a big and expensive tank. Thanks.

MR. SLATER: Thank you, we have two more questions. I'm not sure who is first here, but since Brady, you've asked one question, I'll just maybe move to Commissioner Fung quickly and then back to you before we move on.

THE CHAIRPERSON: Thank you, Mr. Slater. I will defer to Mr. Ryall first, because mine is just about process. So thank you.

MR. SLATER: Okay, thank you. So, Mr. Ryall, the floor is yours. Please ask your question.

MR. RYALL: I certainly don’t mind being deferred in the order for Commissioners, but I will go ahead now, thank you, Madam Chair.

Could you provide -- I'm on slide 26, sorry. This is referring to the term "Hydraulic collapse," which is a term I've not heard before.

Proceeding Time 11:48 a.m. T36

And I've talked to my colleagues in the gas industry and it's not really a term that they're familiar with.

Could your provide a little more description, what exactly do you mean by "hydraulic collapse"?

MR. SLATE: Thank you for the question. Doyle, pass this one to you.

MR. SAM: What we refer to as "hydraulic collapse", it's more on the distribution system and it refers to the examples that was given earlier that if we don't take action the load and the customers can continue withdraw natural gas out of the system and over time the pressure in the system will collapse. And the whole system will collapse, we will not know which sections have which pressure and which systems do not. So it's an unattended event.

The alternative to that is that if we close the valving our main valve, we can avoid hydraulic collapse because it'll be in a controlled manner. So hydraulic collapse is when it's basically unintentional because of the draw from the system and your pressure just naturally decreases in your pipeline system.

MR. RYALL: When you say you are unaware of what the pressures are in your system, does Fortis not maintain some telemetry in its gate stations and regulating stations and even on its medium pressure system that provides some of that information?

MR. SAM: Yes, we have pressure monitors. We have some

1 telemetry as well for stations. What I'm referring to
2 is that we clearly do not have visibility of the
3 length and volume of our distribution and how it's
4 networked throughout the Lower Mainland. So we have
5 20,000 kilometres of distribution line, we do not have
6 pressure monitors on all the line. We do have
7 pressure at all of our gate stations, but we don't
8 have any end use pressure or anything like that.
9 MR. HILL: Doyle, I can add, it's Shawn here. We have
10 a SCADA system that the gas controllers look at and
11 telemetry and eyes into the system are on the
12 transmission system, not down into the distribution
13 system, as Doyle has said.
14 MR. RYALL: And that would also mean some large
15 industrial customers, which presumably you have more
16 advanced metering on those. You don't monitor the
17 pressure on some of those customers?
18 MR. HILL: Yes, we do. Yeah, we have telemetry on some
19 of the large customers for sure but not down into the
20 -- as Doyle says, the distinction is between
21 transmission or distribution.
22 MR. RYALL: Okay, sorry, I was meaning larger
23 distribution customers.
24 MR. HILL: We don't have a lot of -- we have more
25 customers, large customers, off of the transmission
26 system, if you will, not a lot of customers in the

1 distribution network, if that helps.
2 MR. RYALL: Okay, thank you.
3 MR. SLAYER: Thank you, I'll now pass it over to
4 Commissioner Fung, or Madam Chair rather, around
5 process.
6 THE CHAIRPERSON: Thank you, Mr. Slater. It's just and
7 observation but I just want to flag the fact that
8 we're about half way through FEI's presentation, based
9 on the slides that were forwarded to us. It's taken
10 us almost three hours to go through this now and I
11 notice that Guidehouse presentation is scheduled for
12 one hour and we've got the remaining half of FEI's
13 slides to go through in the afternoon.
14 So you might want to think about how you
15 wish to proceed going forward for the rest of the
16 afternoon. So, just leaving that for you to think
17 about, Mr. Slater, and to propose something. Because
18 we may not have enough time.
19 MR. SLATER: Yes. I think we've reached the point
20 where a break would make senses, Madam Chair. And
21 what maybe might be helpful is if we did break now, if
22 we came back at 12:30, we could pick up a little bit
23 of time in our lunch break and then we'll try to, you
24 know, get through the rest of the material while
25 leaving time for questions at the end, if that works.
26 We'd certainly be open to a shorter lunch break but

1 make that proposal.
2 THE CHAIRPERSON: Why don't I ask if there's anybody
3 who has any objections to what Mr. Slater has just
4 proposed? In other words, taking our lunch break now
5 and coming back at 12:30? If that does not work for
6 anybody for whatever reason, please let us know and
7 speak up now.
8 Hearing none, I think you've just bought
9 yourself a half-hour lunch break, Mr. Slater. So
10 thank you.
11 MR. SLATER: Thank you, Madam Chair.
12 THE CHAIRPERSON: Enjoy and we'll see you back here at
13 12:30. Thank you, everybody.
14 **(PROCEEDINGS ADJOURNED AT 11:52 A.M.)**
15 **(PROCEEDINGS RESUMED AT 12:31 A.M.) T37/38**
16 MR. SLATER: Perfect. Madam chair, are we okay to
17 proceed? I think we've checked the attendance and it
18 looks like everybody is back.
19 THE CHAIRPERSON: Yes, thank you very much, Mr. Slater.
20 And I hope everybody enjoyed their somewhat
21 abbreviated lunch break.
22 We're in your hands, Mr. Slater. Please go
23 ahead.
24 MR. SLATER: Thank you very much. Just before turning
25 it over to Mr. Moran, I'm just going to mention that
26 we will try to get through the material in an

1 expedited fashion this afternoon to leave time for
2 questions, so we'll do our best and thanks for
3 everybody's flexibility on the lunch timing.
4 Over to you, Mr. Moran.
5 **PRESENTATION BY MR. MORAN:**
6 MR. MORAN: Good afternoon. I just want to thank the
7 Commission for allowing me the opportunity to be
8 before you today. The agenda I have for today is
9 outlined on the next slide, please. Just real quickly
10 I wanted to just introduce myself and my
11 qualifications, speak to the duty of independence,
12 just outline here today the scope of the Guidehouse
13 engagement, provide a very quick high level summary of
14 our findings or opinion, then move into a discussion
15 across the major findings. We'll land on the
16 conclusions of the Guidehouse report, and then lastly
17 we'll have some time for some questions. Happy to
18 take questions along the way as well as folks raise
19 their hands, just I'd ask somebody to please alert me
20 to that.
21 Slide 2, please.
22 I just wanted again to confirm our duty of
23 independence. The findings in this report are based
24 on our objective basis and our experience, which is
25 really a function of my direct experience in the
26 natural gas industry and providing strategic advisory

consulting services to clients across the utility sector, both natural gas and electric.

Just a little bit about me. I'm the Associate Director in our Energy, Sustainability and Infrastructure practice at Guidehouse, formerly known as Navigant. I have about a little bit more than 17 years of energy industry experience, including consulting as well as previously serving as the director of strategic planning for natural gas utility and electric utility in Houston, Texas called CenterPoint Energy. And then lastly I was key author of a recent work commissioned by the American Gas Foundation entitled *Building a Resilient Energy Future: How the Natural Gas System Contributes to US Energy System Resilience*.

Slide 3, please.

On slide 3 I just wanted to outline for you the scope of our engagement. We were retained to develop a framework to inform FEI's resiliency decision-making. Guidehouse was not hired to necessarily recommend a particular project, but really to develop a framework for decision makers to think through how to think about resilience.

And to address that framework we asked four major questions. What does resiliency mean in the context of the natural gas market across supply and

delivery, and why is that important? How is the resiliency of the FEI distribution system affected by the characteristics of the natural gas value chain, including midstream pipeline capacity, availability of storage, both on-system and off-system, and the composition of the load/customer base?

That leads to our next question, which is in the case of FEI, to what extent is on-system storage either an alternative or a complement to other resiliency measures such as pipeline infrastructure, off-system storage, interruptible service and other demand control measures that have been introduced today? And then finally, we leave with a framework, specific framework about what are the key considerations that should go into determining the optimal amount of on-system storage for FEI?

And on slide 4, please.

On slide 4 I just want to summarize at a very high level summary of our opinion. A key finding is that the Tilbury Tank Expansion Project provides an effective means to strengthen the resilience of the FEI system.

Proceeding Time 12:36 a.m. T39

To derive at that key finding, some supporting findings, to begin with, is number one, resiliency is mission critical and resiliency is not

1 reliability. And reliability can be a source of
2 resiliency but it does not always provide resiliency.
3 Across the North American natural gas
4 energy delivery system there's several characteristics
5 that provide a high level of inherent resiliency to
6 the natural gas system. But B.C. and the province
7 does not have the same level of high inherent
8 resiliency based on available infrastructure in the
9 region.
10 Resiliency solutions need to be customized
11 to the specific resiliency need. There is no one-
12 size-fits-all approach for a natural gas utility in
13 thinking through resiliency.
14 And then, lastly, on system storage offers
15 a wide range and unique set of resiliency benefits to
16 FEI that other alternatives do not provide. And we
17 talk about that through -- can folks hear me okay?
18 MR. SLATER: Yes, we can hear you okay.
19 MS. BEVACQUA: I just want to interrupt one second.
20 Keith at Allwest, we've had a few people ask whether
21 the audio broadcast is operating, maybe you could
22 check that?
23 THE COURT REPORTER: Broadcaster's fixed, just get it
24 switched over. My apologies.
25 MS. BEVACQUA: Thank you. And, Madam Chair?
26 THE CHAIRPERSON: Yes, thank you very much, Ilva.

Just a quick question, Mr. Moran. I don't want to interrupt you during your presentation but I did -- I was a little curious about your comment that reliability can provide resiliency but not always. I'm not quite sure what you mean by that and reliability in what form?

MR. MORAN: Yes, that's a great question and let's jump to that. Let's jump to the next slide and begin to address your question, Madam Chair.

THE CHAIRPERSON: Okay, thank you.

MR. MORAN: So in section one we'll talk about what does resiliency mean in the context of the natural gas market across supply and deliver and why is resiliency important. And I want to directly address your question on the next slide.

Looking again on slide 6, I want to differentiate between reliability and resilience. Reliability is the ability to consistently deliver energy, in this case natural gas, to the FEI customer base. Resiliency is the ability to stand up to, respond, recover from and adapt to a high impact low likelihood disruption event, such as extreme weather, a cyber-attack, an accident or a malfunction of the system.

And so, Madam Chair, why is or how can reliability support resiliency but not always? I'll

1 talk about that in a moment, but just to get a direct
2 answer to your question, by virtue of having a level
3 of redundancy and diversity of access to upstream
4 supply, for example, or to additional -- having less
5 than -- have more diverse access to storage, that
6 facilitate resiliency. Because if their system were
7 to fail you have a -- to an extent to which you can
8 eliminate a single point of failure, then assets that
9 promote reliability are there to serve a resiliency
10 event. But that's not necessarily always the case
11 because if there was -- and we'll talk about this in a
12 moment. If there's an instance of a natural gas
13 utility that by definition, where it's located or that
14 either those physical assets are not available to
15 contract to or just not geographically in the
16 neighbourhood, you know, proximate to the natural gas
17 utility service territory, then the features of the
18 system that promote reliability are not there to serve
19 resiliency.
20 Let me pause there, Madam Chair, and ask,
21 did I address your question?
22 THE CHAIRPERSON: Yes, you did. Thank you very much.
23 MR. MORAN: Perfect, thank you.
24 THE CHAIRPERSON: Please continue.
25 MR. MORAN: Okay. Let's move to slide 7, please?
26 So this speaks on slide 7 a bit more to

1 your question in a little bit more detail, Madam
2 Chair. How can a gas distribution company achieve
3 resiliency? So, to answer that question we really
4 need to understand the sources of resiliency and the
5 benefits that it can provide from those sources and
6 then think through the implications for FEI in this
7 case.
8 **Proceeding Time 12:40 p.m. T40**
9 So, across the energy value chain, there is
10 many characteristics of the natural gas delivery
11 system that lend themselves to either reducing
12 reliance on a single set of assets, so that's kind of
13 redundancy or duplicity. The fact that a significant
14 portion of the asset base is underground reduces the
15 exposure to above ground threats, such as inclement
16 weather or severe weather.
17 In many instances the transmission system
18 is looped, or there is parallel transmission
19 distribution networks. So that just increases the
20 deliverability in the event of an isolated gas network
21 disruption.
22 Overall, across North America, it's a
23 highly networked pipeline transmission system. And so
24 that is a form -- that lends itself to being there to
25 serve our resilience event, because it reduces the
26 risk of a supply disruption, and it provides

1 alternatives to access upstream supply.
2 Off-system storage, just like upstream
3 transportation capacity, pipeline capacity, it
4 provides a source of resiliency because storage can
5 augment production volumes that either aren't there in
6 the event of inclement weather, or there is a
7 significant period of increased demand that outpaces
8 daily production volumes, so storage can be the
9 provider of additional volumes. It also enables
10 alternative access to upstream supply.
11 And then lastly, on-system storage
12 capacity. On-storage system capacity offers a unique
13 set of resiliency benefits. First off, it's on-site,
14 so it's an amount of storage that is impervious to
15 upstream supply disruptions. So the ability to store,
16 amount of volume, and inject it, we'll call it the
17 deliverability or the vaporization. That enables the
18 natural gas utility to prepare for potential
19 resiliency event.
20 On-system storage also can balance supply
21 and demand fluctuations, you know, across the day
22 enough to meet peak demand or during periods of
23 extreme seasonal demand. And then very importantly,
24 it provides operational control to manage an upstream
25 disruption.
26 Earlier Mr. Doyle Sam talked about the

1 implications of a hydraulic collapse on the system.
2 On-system storage can -- it's a significant benefit in
3 enabling the natural gas utility to order a controlled
4 shutdown because that storage and that vaporization,
5 that deliverability is actually on the system.
6 So, what we wanted to do here is just kinda
7 provide an overview of the sources of resiliency, and
8 then we'll walk through kind of what does this mean
9 for FEI.
10 Moving to the next slide please.
11 We're going to characterize on slide 8, the
12 FEI system as an "End of Pipe" LDC -- oh, there's a
13 question, Madam Chair?
14 THE CHAIRPERSON: Yes, thank you, Mr. Moran. If you
15 could just move back quickly to slide number 7? I'm
16 curious as to whether you've done any analysis of the
17 relative benefits or costs of these various options?
18 And how would you rank them in terms of priority or
19 relative to costs of implementing these various
20 solutions?
21 MR. MORAN: Mm-hmm. So I was not tasked with doing a
22 cost-benefit analysis of the various options available
23 that are outlined here on slide 7, for FEI. But I
24 will in a few moments outline a framework for thinking
25 about how to build a portfolio of assets that
26 strengthen resiliency in a moment.

1 THE CHAIRPERSON: Okay, that's fine. Thank you very
2 much.
3 MR. MORAN: Sure. So slide 8, this begins to address
4 the framework that I was talking about, Madam Chair.
5 In a moment we'll describe better for the audience
6 here today what we mean by an "End of Pipe" LDC. But
7 essentially what we're saying is the FEI system, given
8 its location in the province of British Columbia, in
9 the upper left-hand corner of North America, it
10 doesn't have the same level of geographic adjacency to
11 pipeline storage infrastructure that other parts of
12 North Canada and United States have.
13 **Proceeding Time 12:45 p.m. T41**
14 And so the sources across the value chain
15 of resiliency that I talked about in a moment across
16 production distribution, those options just aren't
17 necessarily there in a significant amount of size that
18 other natural gas utilities could potentially benefit
19 from. And so what this means is -- and then the other
20 factor that I wanted to mention, so in addition to a
21 pipeline asset being adjacent from a geographic
22 perspective that would enable if there's more than one
23 pipeline – let's say there's two – a natural gas
24 utility can share some level of diversity of supply
25 and deliverability by contracting on those two
26 pipelines rather than having all of it, dependability,

1 be factored into one pipeline.
2 So it's a question of what is adjacent.
3 And then the next piece of it is what's available in
4 the market. So for example, that second pipeline if
5 it were to actually be there, does it have space to
6 contract on or is all the capacity contracted to other
7 customers? So it's a combination of geographic
8 adjacency, is there infrastructure, and the reason
9 we're talking about that additional infrastructures
10 available and then what is that market availability.
11 Those are two key considerations, Madam Chair.
12 Informed decision making about the relative benefits
13 and capabilities of the sources of resiliency for a
14 particular natural gas utility.
15 Okay, is there a hand up? Oh, Madam Chair.
16 THE CHAIRPERSON: I believe not.
17 MR. MORAN: Okay. I'm sorry. I know there was a
18 particular question from the Commission relative to
19 the examples that we put forth in our reports, so I
20 want to spend a little bit of time around this.
21 The key point of providing these examples
22 on slide 9 was that utilities across North America
23 have sought and gained regulatory approval for
24 investments, specifically to improve system
25 resiliency. It's a relatively new consideration and
26 part of that is because it isn't -- sometimes it isn't

until an event occurs that we recognize the level of resiliency that we have on a particular energy delivery system.

So an example is New Jersey Natural Gas, they experienced a series of extreme storms in the 2011-2012 period, including superstorm Sandy, that resulted in some significant energy supply instructions across both electricity and natural gas in New Jersey. And these events reveal the inherent lack of resilience across the natural gas system for New Jersey Natural Gas.

Specifically the event recognized that parts of the distribution system, the compressor stations that were flooded, were impacted by that severe weather. There was a pipeline outage a little bit further upstream and part of their system was dependent on that single pipeline for deliverability, so they lacked the kind of redundancy that we're talking about as a source of resiliency. And then -- so to mitigate this in the future they sought for approval for a series of investments to (a) increase the access to upstream principal infrastructure so they would increase supply diversity. They wanted to make some investments to strengthen and reinforce the distribution system that wasn't specifically protecting those compression stations from flooding,

1 and then lastly they wanted to increase and optimize
2 an on-system storage asset to improve its ability to
3 withstand a resiliency event.
4 And then Dominion Energy in Utah had a
5 similar but different resiliency event, where it was
6 increasingly experiencing upstream supply disruption
7 that resulted when periods of cold extreme winter
8 weather impacted upstream production. So essentially
9 the storage assets that we talked about a minute ago
10 that could provide resiliency benefit to mitigate
11 against fluctuations in production or in supply, those
12 assets were in place in that particular part of Utah
13 to contract to.
14 So again, we didn't pass the geographic
15 adjacency or the market availability test. And so
16 they sought and they evaluated a range of options to
17 mitigate that event in the future. And they too were
18 able to receive approval for an on-system storage
19 solution.
20 So this is not to say that on-system
21 storage solutions which were used by both these
22 utilities obstructed their resiliency, is necessarily
23 the right answer. The point of the examples is that
24 increasingly what we're seeing as major system
25 failures are causing supply disruption and they
26 increasingly reveal the need for improved system

1 resiliency.
2 **Proceeding Time 12:50 p.m. T42**
3 Similarly down in here in Texas, as you
4 guys are aware, there was recently a significant
5 weather event, at least for this part of the world,
6 that resulted in production freezes, resulted in
7 freezes on the generation equipment and it led to a
8 widespread power outage because the winter reliability
9 standards weren't strong enough to withstand the kind
10 of weather that we experienced. So, you know,
11 increasingly it's a weather event that can reveal
12 weaknesses in the system and reveal the need for
13 increased resiliency. So that's finding number one.
14 The second finding is that there is
15 regulatory precedent from these two jurisdictions for
16 natural gas utilities to seek and gain approval for
17 system investment that specifically are aimed to
18 strengthen the overall resiliency on the system.
19 And then the third major finding is I think
20 a very important one too, is that the approved
21 resiliency actions are very much dependent on the
22 resiliency need. There is no one-size-fits-all answer
23 to improving resiliency. It really has to be thought
24 through in terms of the ability to withstand an
25 upstream disruption, as well as an onstream -- excuse
26 me, on-system disruption. Okay?

1 Moving to slide 10.
2 In our next body of the next chapter of our
3 work we begin to think through how is the resiliency
4 of FEI's distribution system affected by the
5 characteristics of the natural gas system value chain
6 across pipeline capacity, storage availability, both
7 on-system and off-system, and the composition of the
8 local customer base of the load.
9 So on slide 11 I've just outlined some of
10 the key findings and we'll go through these hopefully
11 relatively quickly to stay on schedule today.
12 So we talked about a minute ago sources of
13 resiliency across a natural gas value chain. We
14 talked about how geographic adjacency and market
15 availability are critical to thinking through how to
16 construct a portfolio of assets that can enhance
17 resiliency. Let's talk about what this means in terms
18 of the FEI distribution system relative to the overall
19 natural gas value chain.
20 So finding number one is that B.C., British
21 Columbia, has significant natural gas resources. And
22 so the availability of supply is a source of
23 resiliency in and of itself. However, the pipeline
24 infrastructure serving the region covers long
25 distances and it connects supply resources in the
26 North and Alberta to load centres throughout the

1 province for their southernmost portions of the
2 province. And so it's for that reasons that FEI is
3 critically dependent on the existing transportation,
4 storage infrastructure in the province, especially the
5 Enbridge B.C. pipeline or the T-South Pipeline, and
6 that the province itself has a relatively low amount
7 of interconnectedness that is a source of resiliency
8 when compared to other regions of North America.
9 And we'll talk about this in a moment, but
10 pipeline utilization in the region, including the
11 United States Pacific Northwest and in British
12 Columbia, it has been reaching 100 percent in recent
13 years, especially during periods of peak seasonal
14 demand. And so the implication of that is that,
15 again, thinking through the two questions in terms of
16 geographic adjacency and market availability, if those
17 assets are being highly utilized during periods of
18 peak utilization, peak demand, then they're not
19 available from a market availability perspective for
20 FEI to contract on to strengthen its resiliency. And
21 then similarly, there's limited on-system storage,
22 that has been talked about this morning, in the FEI
23 service territory. The utility does have contractual
24 relationships with storage assets in the Pacific
25 Northwest, but it doesn't have operational control
26 over these assets. And as has been mentioned by

1 others this morning as well, if there were to be a
2 disruption on the T-South Pipeline, for example, that
3 significantly limits the ability to displace the
4 volumes that would come up from the South, from the
5 Mist and the other storage asset to serve FEI. So,
6 again it's the dependency on a single pipeline for a
7 significant portion of deliverability that is a
8 critical source of the lack of resiliency today on the
9 FEI system.
10 There's a question. Can I address that
11 now? Or --
12 MR. SLATER: Yes, there is a question, Mr. Moran. So
13 it's maybe up to you if you want to address it now or
14 hold it until the end of your presentation.
15 MR. MORAN: "Please discuss the availability or lack
16 thereof of objective measures of resiliency applicable
17 to a gas distribution." Yeah, let me touch upon that
18 now and we can property expand on it in the question
19 and answer session.
20 **Proceeding Time 12:55 p.m. T43**
21 As has been discussed by others, defining
22 from Guidehouse as well, that there is no agreed upon
23 regulated measure of what level of resiliency is
24 required for a natural gas system. Electrical system
25 we have -- in the United States for example, we have
26 requirements as to what that is. So there is no

1 industry standard for resiliency. Moreover, what
2 we're finding is that it isn't until an event occurs
3 that we haven't -- that we recognize where the sources
4 of resiliency are on our system, and what is the
5 strength of those resiliency sources.
6 And so in the case of FEI, we know what
7 that is, given what happened in October of 2018. We
8 know what that is in Dominion in Utah given what
9 happened with those production freezes. We know what
10 it is in New Jersey Natural Gas, given the sequence of
11 storms that hit that service territory. And now, we
12 know what it is in California, last summer, across the
13 energy delivery system when there was a historical
14 warm or hot weather, compounded by enormous forest
15 fires that clouded over the solar panels, and also
16 resulted in a lack of wind. And so two key sources of
17 power crossed with solar and wind renewable resources
18 were not available and natural gas had to provide
19 significant volumes to provide the power and avert
20 rolling blackouts.
21 And then lastly is the example from Texas,
22 where we know now that the winter reliability
23 standards for generation were not strong enough to
24 withstand the weather event that occurred.
25 And so how do we know where low-risk, high-
26 consequence problem is? Spend a lot of money on

1 redrawing -- yeah, I'll talk about this in a moment,
2 but the answer to that question is, not to be
3 flippant, but really it's a risk management question.
4 And risk is -- and we'll talk about this in a moment,
5 it's the ability -- risk is the impact of uncertainty
6 on the ability of a company to fulfill its objectives.
7 Or, it has also been described as the possibility of
8 an event occurring that will significantly disrupt the
9 ability of the company to fulfill its mission.
10 So it's really less about the probability
11 of an event, and it's more about the magnitude of the
12 impact of that event. And so I frequently use this
13 metaphor with my clients in thinking through risk
14 mitigation measures. Why do we carry an umbrella?
15 It's really not because we think it's going to rain.
16 It's because we fear getting wet. And so what I mean
17 by that is, for example, if I'm going to run out
18 across the street, pick up a gallon of milk, and get
19 out of the car, and it's a pretty heavy duty rain, but
20 for the next thing I'm going to do is go home and take
21 care, put dinner on the table for my children, I'm
22 okay with getting wet.
23 If I am heading to a job interview, I do
24 not want to be wet. And so I will carry the umbrella.
25 So again it's the impact of the event. It's not
26 necessarily the probability of that event. And so

we'll talk about this in a moment, but we have put forth a risk management type of framework to guide decision-making relative to how to strengthen resiliency. So it's really less about looking backwards, and it's more about looking forwards and understanding the impact of an event and what are the things that we can do to mitigate it.

So let's talk about slide 12, if you would. Just to cover some of the basics, this has been outlined today. So I'll spend a little bit of time on this. But on the left-hand side, I wanted to provide kind of a picture of North America natural gas pipeline system, and as we can see, there is a significant amount of infrastructure in North America. But look at the central part of the United States, for example. There is just multiple pipelines, serving production and demand centers. And so if there were to be a pipeline disruption at one or more of those pipelines, there is an ability to reroute gas and use underutilized capacity to fulfill demand obligations.

But as we move over across into in the western part of the United States and into British Columbia, we see that there is just less and less infrastructure available. So the geographic adjacency test that we're talking about, you know, we don’t have that adjacency. And so we see on the right-hand side,

1 just a snapshot of BC's pipeline infrastructure, and
2 we can just underscore this, underscore how currently
3 dependent FEI is on existing transportation and
4 storage to serve its customer base.
5 And let's talk about utilization a little
6 bit as well on slides 13 and 14, beginning on slide 13
7 please.
8 High pipeline utilization means that the
9 system is less able to respond to unplanned outages.
10 And so we see on slide 13 in the green bar, January
11 2017, regional pipeline capacity utilization reached
12 100 percent.
13 **Proceeding Time 12:55 a.m. T44**
14 And what that means is that all of the assets from a
15 transportation perspective are being utilized at that
16 point in time to serve customers across British
17 Columbia, Oregon and Washington State in the United
18 States. If there were to be disruption there's less
19 physical assets available to ensure deliverability of
20 supply.
21 And so pipeline capacity is sufficient to
22 meet demand for an average day in January, but when
23 you take a close peek at how that demand is being met,
24 on the right-hand side you can see that both
25 underground storage and peak LNG assets are required
26 to meet peak day demand. And as the supply forecast

1 continues out the supply side resources are just
2 becoming insufficient to meet peak day demand in the
3 region.
4 And so the takeaway here is regional
5 pipeline utilization is very, very high today, it's
6 expected to grow into the future and the
7 transportation assets and storage assets that are
8 located in Oregon and Washington are going to be
9 increasingly utilized to serve customers in those two
10 states. And FEI is going to be -- its dependency on
11 the T-South pipeline is going to continue to grow.
12 And so when we talked about geographic adjacency and
13 now we're talking about market utilization, the two
14 key factors that inform resiliency decision-making.
15 And on slide 14, this is similar but just
16 speaking to the FEI system in particular is -- a
17 couple takeaways here for consideration. First off,
18 the FEI system features a very high seasonal demand.
19 In the 2021, 2022 year the average winter day demand
20 is going to be, well forecast to be, approximately 2.7
21 times greater than the average summer day.
22 Existing pipeline capacity serves about 70
23 percent of that peak demand, while market area storage
24 and on-system LNG is still about 30 percent. So this
25 begins to illustrate the importance of underground
26 market day storage and LNG on-system storage to serve

peak demand on the FEI system, just to serve peak demand. And so a resiliency event when more and more -- when one of these assets becomes unavailable due to some kind of distribution or an energy delivery disruption on an already highly-utilized system, that has direct implications on how to think through what's available from a geographic adjacency, market availability, the sources of resiliency that we talked about that are provided by transportation infrastructure and storage infrastructure, how that's limited in terms of optionality for FEI.

Slide 15, and kind of what does all this mean for FEI? Well, we've talked about the sources of natural gas supply that serve the province and the FEI system puts a high dependency on B.C. production and FEI's ability to secure adjacent supply is difficult, given where the infrastructure is today. Similarly, moving from supply and production to deliverability, the natural gas pipeline storage infrastructure stored in the region was the FEI again is highly dependent on the infrastructure in the region and so its ability today to reduce its reliance on a single pipeline is very difficult to achieve because of the lack of geographic adjacency and also the high level of market utilization of existing assets.

Then there's the physical layout of the FEI

1 distribution system itself. The Lower Mainland system
2 is very dependent on the T-South pipeline. And so, as
3 a result, the FEI system is just not as inherently
4 resilient as other natural gas utilities in their
5 footprint that have more interconnectivity options.
6 And then the fifth factor is the profile of
7 FEI's customers and its demand. So it's a very high
8 seasonal demand load profile, like I mentioned a
9 minute ago. Winter demand almost three times as high
10 as summer demand. And so that means that the risk of
11 a supply disruption during a period of peak demand is
12 must greater in magnitude than a disruption event that
13 would occur, say, in the summertime.
14 And, again, we'll talk about risk
15 management in a minute, but we're really talking about
16 the impact of uncertainty on the ability of FEI to
17 fulfill its mission, not the probability of that
18 event. It's the possibility of that event and what it
19 means. And prudent risk management teaches us
20 industry accepted standards for risk management show
21 us that it is in fact prudent to think through the
22 implication of event when we're thinking through how
23 to strengthen our resiliency.
24 **Proceeding Time 1:05 p.m. T45**
25 Move to slide 16, please.
26 This chapter of work focused on, in the

cast of FEI to what extent is on-system storage either an alternative to or a complement to other resiliency measures such as pipe infrastructure, off-system storage, interruptible service and other type of demand control measures that we've introduced today.

So let's move to slide 17, please.

So there are alternatives and I will define these in a moment here and then we'll talk through, kind of provide a framework for thinking through kind of how strong are these alternatives as a potential resiliency response mechanisms.

On-system storage is certainly an asset that can help FEI respond to short-term supply disruptions. Alternatives such as line pack and a third-party contractual arrangements or industrial curtailment each have a unique set of their own limitations in terms of responsiveness to a short-term supply disruption in comparison to on-system storage.

Storage assets are efficient for short-duration supply disruptions and peak shaving applications. The pipelines offer a longer duration and they are more efficient for longer deliverability applications. And so on-system storage complements transportation capacity but they provide different types of resiliency.

Guidehouse observed that the FEI

1 distribution system is comprised of multiple formerly
2 independent systems, but they were combined to form
3 FortisBC and so each one of those service territories,
4 as Shawn mentioned earlier today, are different. For
5 the Lower Mainland system it really means that the
6 dependency on the Peace South pipeline is very great
7 and so that that's where a single point of failure
8 risk remains very high.
9 And so as you're talking about, there is no
10 kind of one-size-fits-all resiliency response. We
11 (inaudible) geographic adjacency, market availability,
12 what are the sources of lack of resilience on a
13 particular part of a system as we think through what
14 measures are available to remedy the situation.
15 So let's talk about this on slide 18.
16 Let's go through each alternative and talk about our
17 assessment in terms of its viability.
18 The first one on slide 18 of contracting
19 for additional pipeline underground storage capacity,
20 and as we talked about today, there's just a lack of
21 alternatives both from a geographic adjacency
22 perspective as well as from a market availability
23 perspective. And in fact, if FEI were to contract a
24 greater capacity on the Enbridge B.C. system, the
25 Peace South pipeline, that actually would exacerbate
26 the situation because we would be increasing our

1 dependence on a single pipeline and so that we would
2 not be strengthening resiliency.
3 Third-party commercial agreements for
4 transportation and storage asserts. We're again,
5 because of the -- we talked about geographic
6 adjacency, we'd be subscribing to transportation or
7 storage capacity on the same set of assets, and given
8 that there's just a lack of diversity of
9 deliverability assets, cross storage and
10 transportation, that there's just limited
11 opportunities to execute in a way that's meaningful to
12 strengthening resiliency.
13 Line pack is the next alternative that's
14 been discussed a little bit today, but it's our
15 finding that we really can't think about line pack as
16 a source of supply. Line pack is actually a function
17 of how much gas is in the system, so it offers very
18 limited duration and volumes and it's not a dependable
19 resiliency option to mitigate the single point of
20 failure of the Keystone pipeline.
21 Industrial curtailment and demand response
22 measures. These are very important measures in order
23 to -- (inaudible) when thinking through how to respond
24 to a significant supply disruption and bringing down
25 the system by lowering demand, lowering the required
26 pressure support and hopefully preventing hydraulic

1 failure and collapsing the entire system.
2 A curtailment and demand response are not
3 the same thing as supply. They are tools to mitigate
4 the consequences of a supply disruption, but they
5 don't help provide supply as a means of conjuring that
6 upstream supply disruption.
7 And then lastly, on-system above ground
8 storage. We talked about on-system above ground
9 storage offers a wide range of resiliency benefits.
10 The ones that are important to think through today
11 are, it is actually a form of supply.
12 **Proceeding Time 1:09 p.m. T46**
13 It is a form of deliverability. So it's a function of
14 how much it is being stored, and in the vaporization,
15 the send out ability.
16 On-system storage, unlike upstream
17 transportation, unlike line pack, unlike off-system
18 storage, on-system storage gives FEI control, and huge
19 responsiveness. Specifically what that means is, in
20 the event of a significant upstream supply disruption,
21 the on-system storage is a tool that helps mitigate
22 the potential for hydraulic collapse, and a loss of
23 the entire system, as Mr. Doyle, Mr. Sam Doyle talked
24 about a minute ago. Excuse me, Mr. Doyle Sam.
25 And so, in terms of mitigating the
26 consequences of an upstream supply disruption, it's

really only on-system storage from the perspective of efficacy and availability that offers a remedy to the single point of failure risk that we're trying to mitigate, that is really the source of the lack of resiliency on the Lower Mainland system, on FEI.

Move to slide 19.

Lastly, our last question is what considerations should go into determining the optimal amount of on-system storage for FEI? And here again we have provided, presented a framework that we begin to outline on slide 20. And our framework begins on slide 20 with the premise that we really need to think through developing a resiliency option from the perspective of how to mitigate risk. On-system storage, it's our finding, provides a form of insurance by mitigating the risk of a supply disruption. And specifically that risk is the possibility of a complete failure (audio drops) the system.

So, resiliency through an on-system storage asset, given that it's a unique asset that serves the unique resiliency needs of FEI, provides an insurance benefit by providing duration of supply. And in terms of framework, it's thinking of through what we need this asset to do. We need to think about how much time is required to respond to a system disruption,

1 and how much volume is required in that amount of time
2 to mitigate the risk that we're trying to prevent.
3 So as we talked about, supply disruption
4 can have significant impact on the daily lives of
5 FEI's customers, especially in the winter time. You
6 know, as we learned here, I was without power for
7 about a day and a half, without water for two days, I
8 can tell you, if I didn’t have a gas fireplace, it
9 would have been -- not just extraordinarily cold, it
10 would have frozen my house. And so we really need to
11 think through the consequences of a supply disruption
12 in terms of what it means to the customers and the
13 citizens of the FEI service territory. And if this
14 were to happen in the winter time. It's extremely --
15 a set of unfortunate social circumstances that we'll
16 try to mitigate.
17 And then there's the physical implications.
18 So as we talked about, the loss of supply can lead to
19 a pressure failure, that can contribute to the
20 collapse of the entire system. And if the system were
21 to collapse completely, it would take a significant
22 amount of effort to bring the system back up. And
23 again, that would be days of people not having access
24 to heat, hot water, cooking, as well as the
25 consequences to the economy, because restaurants
26 wouldn’t be able to serve hot meals. We just have --

1 hospitals wouldn't be able to serve their patients.
2 This is whole host of consequences. And so this is
3 the level of risk that a resiliency measure is seeking
4 to mitigate.
5 So the next slide is going to outline kind
6 of a framework we're thinking through, what are the
7 critical capabilities needed for resiliency, and
8 establishing criteria for decision makers to think
9 through the reasonableness of the approach taken by
10 FEI.
11 So, go back to kind of the, what we mean by
12 resiliency. Resiliency, to be considered resilient,
13 we want to think through our ability to prepare,
14 withstand and recover from a high impact event. So
15 the attributes of preparation are really the ability
16 to prepare and prevent that initial system disruption.
17 So what goes into decision-making in terms
18 of preparation? It's the amount of time required to
19 conduct a planned shutdown. The amount of time needed
20 to kind of think through, okay, what just happened,
21 and what do we need to do, you know, curtailing
22 customers, using curtailment, using demand response.
23 **Proceeding Time 12:55 p.m. T47**
24 Because if we can bring down demand in an effectively
25 meaningful way, then that helps kind of mitigate the
26 amount of time required to ease the system back up and

it will also minimize the level of supply disruption so that we can impact the least amount of customers as possible, especially during the wintertime. So that's what goes into preparation.

In terms of withstanding, we need to understand the amount of load on the system at the time of the disruption. This is why I've been talking about the load profile, demand profile, the FEI customer base. We need to understand the amount of load that needs to be retained in the event to a supply disruption so that we can prevent wholesale collapse of the system, i.e. the hydraulic failure, and minimize the impact of a supply disruption.

And then recovery, you know, the amount of time it will take to bring the system back up, the time of year that it occurs, the amount of time that's required to refill the tank, all of those things kind of go into decision-making in terms of the amount of storage required and the amount spend that would require. And so the amount of anticipated time, the level of effort and the expense that's required to restore a supply disruption, that goes into decision-making around recovery.

Let's just to our conclusions on slide 23. As we've talked about, resiliency is mission critical. It's increasingly being recognized that it's necessary

1 for the natural gas system to be resilient, to be able
2 to withstand, respond, adapt to unexpected low-
3 probability high-risk events. The system must have
4 characteristics that enable operators to manage these
5 threats and to make decisions with enough time to
6 prevent a wholesale collapse of the system. This will
7 ensure continuity of service and mitigate the amount
8 of time needed to bring the system back up.
9 As we've talked about, resiliency is not
10 reliability and reliability does not always provide
11 resiliency. A natural gas utility that has a diverse
12 set up upstream assets that it can source supply from,
13 as well as access to a diverse set of storage assets,
14 is inherently going to have greater resiliency than a
15 system that's dependent on one major pipeline for a
16 majority portion of its supply.
17 So those sources of reliability, if they're
18 not geographically adjacent or available in the market
19 place, then it significantly weakens the ability of
20 that distribution system to strengthen its resiliency
21 with existing infrastructure.
22 As I have mentioned, the North American
23 natural gas system is highly resilient but it's a
24 location situation. The province of B.C. just does
25 not have that same level of inherent resiliency that's
26 a feature or a characteristic of some of the overall

North American system.

Resiliency solutions need to be customized to the specific resiliency need. And so we need to think through, okay, what is the source or what is the cause of the lack of resilience? And in the case of FEI, it's a single point of failure risk on the T-South pipeline. And so we need to think through a balance portfolio of capabilities. You know, the ability to maintain system pressure, provide customers with supply must factor into the resiliency solution that is that meets the needs of the Lower Mainland system, the overall FEI system.

And then, lastly, it's on-system storage that offers a wide range and unique set of resiliency benefit to FEI that other alternatives cannot provide. And so there's certain aspects of system resiliency to the natural gas utility and its customers and the community that it serves that only on-system storage can provide to the FEI system, specifically the Lower Mainland part of the system, to mitigate the risk of that single point of failure.

And we've talked about, you know, the risk of a system collapse. We've talked about what this could mean in the wintertime and so it's our finding that FEI has used a framework such as this, that we've outlined for you today, in its decision making in

terms of developing a recommendation on how to strengthen its resiliency.

Those conclude my major remarks today. And, again, I want to thank the Commission for having me and I'm happy to entertain any questions with the time allotted.

MR. SLATER: Thank you, Mr. Moran. We had some questions typed into the chat that -- some of which you addressed and some that are outstanding. So I just was going to start with Mr. Finn's question. Mr. Finn's question was, "Please comment regarding FEI's request for an on-system storage tank rather than existing underground storage and neutral help arrangements." I believe you answered some of this On slide 18, but Mr. Moran, if you have anything to add, and Mr. Finn, if you want to follow up, I'll pass it over to you.

Proceeding Time 1:19 p.m. T48

MR. MORAN: Yeah, I will just add to my earlier remarks that in a period of peak demand those assets are highly utilized and not going to be available. The gas service territories in Oregon and Washington have a greater level of inherent resiliency because they have access directly to on-system storage, so they have the operational control and responsiveness and they have a greater level of it on their system (audio

1 drops) FEI.
2 And so again, we have to think about FEI in
3 its own unique context. It has a -- as I believe I've
4 outlined here, a very high dependency on a single
5 pipeline that's unique to it relative to its
6 neighbours, and so by definition that the T-South
7 Pipeline if it were to experience another disruption,
8 the ability to displace the volumes that are coming
9 south with the ones that would essentially be coming
10 north, because they actually don't flow north as has
11 been described today, that just pushes out those
12 assets in Oregon and Washington to effectively be a
13 resiliency option that FEI can count on, especially
14 during periods of peak usage.
15 I'm sorry, (inaudible), Mr. Finn.
16 MR. FINN: No, I'll defer, thanks.
17 MR. SLATER: Thank you. Maybe I'll just switch over
18 quickly to the participants. Commissioner Mason,
19 please go ahead and ask your question.
20 COMMISSIONER MASON: Thank you. Thank you, Mr. Moran,
21 that was very interesting. I wonder if I could ask
22 about your distinction between on- and off-system
23 storage. Are you referring only to the geographical
24 proximity of storage to the distribution network or
25 are there other characteristics as well?
26 MR. MORAN: Thank you for that question, Commissioner

1 Mason. In this context the on-system storage would be
2 a storage asset either above ground or below ground
3 that's on the FEI system and an off-system storage
4 asset would be Aiken up north in the northern part of
5 British Columbia or in -- I can't recall the other one
6 in Washington/Oregon. They are on other gas utility
7 systems or part of a natural gas pipeline. So not
8 owned -- actually ownership isn't important. Not
9 operated directly by FEI. It's a critical distinction
10 between what is on system and what is off system.
11 Did I answer your question, sir?
12 COMMISSIONER MASON: Yeah. I think the follow up
13 though would be, if there were to be an LNG storage
14 facility in, let's say, Tilbury, so it's physically
15 adjacent to FEI's facilities and FEI had contractual
16 arrangements with that storage facility to re-gasify
17 LNG at their command, is that effectively the same as
18 on-system storage or are there still material
19 differences?
20 MR. MORAN: It's getting closer. The key material
21 difference is the ability to kind of use it at its own
22 discretion to the extent to which it has access to the
23 necessary volumes and that those volumes had not been
24 contracted out to others. Because if they had been
25 contracted to others, then they're effectively not
26 available to FEI on a firm basis.

1 COMMISSIONER MASON: Okay, great. Thanks very much.
2 MR. SLATER: Thank you. Next I'll bounce back to the
3 comment box for a moment and Mr. Andrews had a
4 question. His comment is, his question was oriented
5 to whether FEI had identified a number of different
6 potential points of failure to which the FEI system is
7 susceptible and then determined that a rupture of T-
8 South is the one to address. That is, what about an
9 event at the Tilbury base plant, a cyber-attack, a
10 wildfire, a big earthquake? A rupture of T-South
11 already occurred, what about the next unexpected low-
12 probability, high-hazard event?
13 **Proceeding Time 1:24 p.m. T49**
14 So maybe by way of quick introduction to
15 that, in the presentation a little bit later we will
16 be talking about what the TLSE project can do for the
17 other parts of the system outside of the Lower
18 Mainland and as well with other projects, but perhaps
19 by way of sort of discussing the other risks that Mr.
20 Andrews asks, I'll pass it over to Doyle Sam to answer
21 that question.
22 MR. SAM: Okay, thank you, Mr. Slater, and thank you,
23 Mr. Andrews. And, yes, there are a number of risks
24 that we manage on a regular basis. Some are in our
25 control, come are less in our control. If we look at
26 the T-South incident, as I alluded to earlier, we

could have another incident on the T-South, there is 900 kilometres of line there. We also have our own transmission system. You allude to a wildfire. We have had examples in our system where we've had a wildfire come through and years later we've had mud slides which has relocated our lines. So there are some other events, as you characterize it, that would be maybe lower probability, but high hazard events.

Within our integrity management program we monitor what we can and what we know of. Hard to pinpoint if and when or where that next one might happen, but to suggest that it isn't going to happen, I think we except that we have a lot of infrastructure out there and something as a third-party dig and damage could cause us to have an event as well. We have programs in place to minimize that, but that has happened in the past as well.

So there's a number opportunities, I guess, that cause concern.

MR. ANDREWS: Just to clarify, my point is not disputing whether a rupture of T-South would (audio drops) problem for Fortis. The question is whether other potential events have been put out on the table and then analyzed as to which is the most important to address and at what cost they could be addressed, and then the result of that analysis being that spending

whatever, hundreds of millions of dollars on the TLSE is the highest priority resiliency response.

MR. SLATER: Thank you for that clarification. Doyle, just pass that back to you if that's okay.

MR. SAM: Yes. I think we'll see in a few later slides as well, but when you recognize some of those risks that I do mention, the solution that we proposed actually has some very good mitigative measures to address those as well throughout the broader system, not just within the Lower Mainland. So whether it's something on the T-South system or something in our system, the solution that we propose actually had some fairly significant resiliency benefits to mitigate those as well, so in effect it's a little bit of one-stop shopping as it'll do more than just what we're talking about with the T-South incident.

And it's all around getting, managing a zero flow event, which can come from a number of different sources.

MR. ANDREWS: Okay, well, I'll leave it at that.

MR. CHERNIKHOWSKY: Well, maybe I can provide a little bit more, Mr. Andrews, as well. So all of those risks that you've identified would ultimately be -- if they result in a loss of gas supply for the Lower Mainland, then the TLSE project will mitigate them regardless of whether it is a failure of the T-South System or if

1 someone interferes with gas supply through some other
2 measure, the TLSE will benefit that and we will talk
3 about later how it will benefit in other areas of the
4 system as well.
5 And without going into the details of exact
6 flows or locations of the system, we have been clear
7 in the application that we are heavily dependent on
8 the T-South system. It is, at this point, our most
9 significant risk to gas supply on our system.
10 We have already addressed through some
11 other projects, for example, at our Huntingdon station
12 a couple of years ago we had identified a single point
13 of failure risk within our own system and we mitigated
14 at that time. The Huntingdon -- the gas flow into the
15 Huntingdon supply point right now is our most
16 significant risk to our system and it's on that basis
17 that we brought the TLSE project forward.
18 So when you say that are we looking in a
19 rearview mirror, my argument actually would be that
20 what we're seeing in the front view is the same as
21 what is in the rear view mirror. Unless we take a
22 different route we know what can cause another failure
23 of our system and that's why we're proposing the TLSE.
24 MR. SLATER: Thank you, Paul. I'm just going to bounce
25 back to the participants list here and I believe Mr.
26 Langley is next. So Mr. Langley, if you want to go

ahead and ask your question.

MR. LANGLEY: Hey, sound check again. You can hear me?

MR. SLATER: You betcha.

Proceeding Time 1:29 p.m. T50

MR. LANGLEY: Okay. I apologize, I got on to the call after lunch a little bit late so I don't know if this was covered, but has anywhere in this looking for resiliency, have you guy looked seriously at underground storage as an option? I know that there was some studies back, I think probably in the '90s or something, that rejected that solution, but I'm wondering if anything has been done recently to account for changes in technology, like fraking and whatnot, that might allow for another option other than above ground liquefied natural gas storage? Have you looked at underground and rejected it? Do you have any recent data that suggests that's a non-starter?

MR. SLATER: Yes, thank you for that question, Mr. Langley. Maybe just before I pass this over to Mr. Chernikhowsky, I will mention that that is one of the options that we did consider as part of the analysis and determined it was not feasible. It's section 4.3.5.4 of the application.

And anything to add to that, Paul?

MR. CHERNIKHOWSKY: Sorry, just had to find the unmute.

1 No, I would say that that's well covered in
2 that section of the application and does explain that,
3 yes, back in the '90s that was something that was
4 considered but really it is just not feasible given
5 policy today.
6 MR. SLATER: Thank you.
7 MR. LANGLEY: Sorry, just for clarification. Sorry.
8 Just a clarification point, it's a policy problem, not
9 a geology problem? Is that what you're saying?
10 MR. CHERNIKHOWSKY: It is by regulation. In that
11 section we say that the regulations under the
12 *Petroleum and Natural Gas Act* do not allow for the
13 exploration or the granting of a lease for an
14 underground natural gas storage reservoir in the
15 Fraser Valley.
16 MR. LANGLEY: And is the Fraser Valley your only option
17 for that facility?
18 MR. CHERNIKHOWSKY: Ultimately to get it connected into
19 the Lower Mainland system, yes, it would have to be.
20 MR. LANGLEY: Okay, so Vancouver Island, Georgia Strait
21 is not going to work for you.
22 MR. CHERNIKHOWSKY: Well, we already have the Mt. Hayes
23 storage facility over on Vancouver Island and so
24 Vancouver Island has resiliency provided to it by
25 that. It would not be able to provide enough back
26 flow to the Lower Mainland however. We need something

1 connected to the coastal transmission system.
2 MR. LANGLEY: Understood, thank you.
3 MR. SLATER: Thank you. Maybe I'll just move quickly to
4 Mr. Weafer and then back over to the conversation box
5 to Mr. Finn.
6 Mr. Weafer, please go ahead and ask your
7 question.
8 MR. C. WEAFER: Thank you. To Mr. Moran and perhaps
9 Fortis will comment. As I understand this project,
10 which is a fairly expensive project, the triggering
11 event or a large part of it is a result of the
12 Enbridge event of October 9, 2018. The follow-up from
13 that event was the Canadian Energy Regulator found
14 that Enbridge had not followed its integrity
15 management program.
16 So when we're talking about reliance and
17 reliability, this project is largely driven by
18 Enbridge's reliance reliability issue on that event.
19 So Mr. Moran, what do you say to the role of the
20 regulator or the role of Fortis participating in
21 regulatory processes to ensure that Enbridge ensures
22 that these types of events are less likely to occur?
23 And we've heard their reliability has been fairly
24 solid historically. This is a significant event and
25 the regulator found a problem.
26 So can you just generally comment on the

1 responsibility of the utility to be ensuring that its
2 supplier or transmission pipeline is following its
3 regulatory responsibilities? And Fortis might want to
4 comment on it as well. Thank you.
5 MR. MORAN: So is the question -- thank you for the
6 question, sir. Is the question, what is the
7 responsibility of FEI, FortisBC Energy, to ensure that
8 its supplier is in accordance with regulations put
9 forth by the NEB? Did I hear that correctly?
10 MR. C. WEAFER: Is there a role or responsibility to be
11 looking out -- we can build a big LNG plant or we can
12 also try and ensure that the pipeline that the
13 distributing utility is vulnerable to is doing its
14 job. And so I understand Fortis does participate in
15 the Canadian Energy and regulatory body proceedings.
16 **Proceeding Time 1:34 p.m. T51**
17 But again, we've got an event which a regulator has
18 said has been a result of an integrity management
19 program with the pipeline company, and the ratepayers
20 of Fortis are now going to have to make a very
21 significant investment to try to avoid being impacted
22 by that in the future.
23 It seems to me there is an initial step of
24 trying to deal with it at the front end and ensuring
25 that the pipeline is ensuring its integrity. So, it's
26 as much a comment as a question. I'm not trying to be

1 difficult, but as someone who is observing the
2 interconnection of pipelines, is that not a fairly key
3 role for distribution utilities to play? To put
4 pressure on, to ensure that the regulator is making
5 sure that these events are not occurring, or at least
6 overseeing such that they are not likely to happen, or
7 less likely to happen?
8 MS. MORAN: So the exact goal of FEI relative to ensuring
9 that its transportation provider is meeting the
10 requirements of what it has been put forth by the NEB
11 is a bit outside of what I was asked to opine on, and
12 it is actually a bit outside of my own expertise.
13 Philosophically it seems that's an
14 appropriate question. I would put forth though that
15 the framework that I have provided, that was asked to
16 provide in terms of enabling decision-makers to think
17 through what is an appropriate resiliency measure,
18 really starts with the question, what is the risk?
19 And the risk here is the consequences of a supply
20 disruption during a period of peak demand that could
21 potentially lead to a failure, a shutdown of the
22 system, a collapse of the system. And it's those
23 socio-economic consequences that we are really trying
24 to mitigate.
25 Does the approach that you try to put
26 forward, does that help mitigate that risk? I would

1 argue that it does not. I would argue that pipeline
2 integrity is -- and ensuring, taking the steps and the
3 technology to inspect the pipe and to doing that on a
4 regular basis and to avoiding and to being aware of
5 where integrity issues could arise and doing something
6 to mitigate them, is definitely appropriate. But it
7 doesn't do anything necessarily to mitigate the
8 consequences of that event occurring on the FEI
9 system. And that's what we're trying to do. Put
10 forth a decision-making framework for the decision-
11 makers here to think through what is an appropriate
12 risk mitigation step.
13 MR. SLATER: Thank you, Mr. Moran. I'll just quickly
14 touch -- or pass it over to Mr. Chernikhowsky if you
15 want to touch on anything from the FEI perspective?
16 MR. CHERNIKHOWSKY: Yes, thanks, Doug. And I guess
17 what I would add to that is again, as Mr. Moran
18 alluded to, given the consequences of the risk that
19 we're discussing here, which is an outage to a very
20 wide area and very large numbers of customers. We
21 fully trust that Enbridge maintains their pipeline
22 system adequately. That's not what this discussion is
23 about, ultimately. They have integrity management
24 practices in place for their pipelines as we do.
25 But I guess, Mr. Weafer, I guess if you
26 looked at it almost from a legal perspective, that

unless Enbridge can guarantee with 100 percent certainty that the pipeline will never be unavailable, and whether that's due to an integrity failure or a landslide, or an act of vandalism, we need to have some form of alternate plan-B in place, within the FortisBC system. Any of those -- and those are just three examples, that could impact the T-South system. And I don’t think Enbridge would ever be in a position, or be willing to say that "We will guarantee 100 percent service."

MR. SLATER: Thank you, Paul. I'm just going to turn back to the comments here. And we've -- questions for --

MR. C. WEAFER: Sorry, can I -- just a -- thanks, Mr. Slater, I just wanted to follow up if I could. The point I'm making is, there was a finding that Enbridge breached its integrity management program, and all I'm suggesting, and in response to Mr. Moran, and to you Mr. Chernikhowsky, is that there is a cost-effective participation in process to push Enbridge to ensure that they are meeting those responsibilities. To mitigate the risk and to avoid these costs.

Prior to this explosion, we didn’t have a proposal to build this plant.

Proceeding Time 1:38 p.m. T52

It's a triggering event and when we look at the

1 results of how the triggering event occurred, it was a
2 result of a failure of an integrity management
3 program.
4 So I just want to make sure it's clear,
5 there's a reason it happened and I would think that
6 the mitigation of that risk would include being in the
7 regulator's processes to push Enbridge to make sure
8 this doesn't happen again. That's a more cost-
9 effective solution or part of a cost-effective
10 solution, I'd suggest. So we can deal with it in IRs
11 as well. Thank you for the response.
12 MR. SLATER: Thank you, Mr. Weafer. I'm just going to
13 try to get to these next two questions quickly so we
14 can carry on here. Turning to Mr. Finn's question,
15 I'll just read it in, it is,
16 "Has Guidehouse/FEI sufficiently explored the
17 mutual benefits of cooperation agreements with
18 gas companies with interconnections with T-
19 South? Has any comparative study been done of
20 the costs and benefits of such arrangements
21 relative to the 780 million cost of the proposed
22 expansion?"
23 So maybe I could pass that one to Mr. Moran, first, to
24 comment on?
25 MR. MORAN: So the short answer is no, we were not
26 tasked with looking at the mutual aid agreements. We

1 did take a look at the adjacent infrastructure, from
2 the perspective of geographic adjacency and market
3 utilization, and it's through those two lenses
4 together that we can conclude that the assets in the
5 region, in British Columbia, north Washington State
6 and Oregon are so highly utilized over a period of
7 peak demand that even with the most effective mutual
8 aid there isn't sufficient capacity, infrastructure
9 capacity, across both storage and transportation to
10 mitigate the risk of a supply disruption to the Lower
11 Mainland system of FEI.
12 MR. SLATER: Thank you. And maybe I'll just note that
13 we are going to talk about mutual aid agreements in
14 the presentation so we'll get to the other part of Mr.
15 Finn's question shortly.
16 I notice there are no more hands up at the
17 moment so maybe with that we can move into the next
18 segment of the presentation and it would be perhaps
19 after that that we'll take our break.
20 So over to Mr. Sam and Mr. Hill and I see
21 we're just waiting for the presentation to come up.
22 **PRESENTATION BY MR. SAM:**
23 MR. SAM: Thank you, Mr. Slater. I'm going to walk us
24 through the next section of our presentation, being
25 the process in which we identified and assessed the
26 respective alternatives to meet our planning

1 objective.
2 Moving to slide 30, step one in our process
3 was to identify all the possible alternatives and
4 assess each alternative's feasibility and ability to
5 meet our planning objective. And as was mentioned
6 earlier, resiliency's made up of varying degrees of
7 storage, pipe line diversity and load management
8 tools, of which all must be in balance to manage and
9 produce the optimal use of these tools to provide a
10 cost-effective solution for our customer.
11 From a load management perspective, the
12 only firm tool available would be the installation of
13 an automated metering infrastructure solution for our
14 gas customers, very similar to what electric systems
15 enjoy today. The system would provide for more real
16 time load information as well as the ability to
17 curtail load.
18 We also looked at four pipeline solutions,
19 many of which are not new and with all having varied
20 degrees of complimentary resiliency support. And
21 lastly we assessed the third tool, being additional
22 storage, with consideration of both on and off-system
23 storage of natural gas and liquefied natural gas.
24 Looking at AMI on slide 31, AMI is a
25 complementary tool for our objective but it will not
26 replace supply-side solutions. Automated metering

1 infrastructure can be a load management tool to reduce
2 the demand on the number of gas molecules that we need
3 to provide, but it does not increase the number of gas
4 molecules. AMI would be complementary to our proposed
5 project in a number of ways. First, it would provide
6 valuable near real-time load consumption data. It
7 might allow the company to ride out a disruption and
8 not be forced to take irreversible action by
9 unnecessarily shutting in customers in the absence of
10 good information.
11 **Proceeding Time 1:43 p.m. T53**
12 Looking at our current curtailment request
13 process, we request an interruptible customer to
14 reduce their gas usage and in the absence of
15 dispatching and technician to every interruptible
16 customer, we have no practical means to confirm if the
17 customer complied with our requests and if they did,
18 did they comply for the duration of our request. AMI
19 would also mitigate those concerns.
20 And as a last resort, AMI would enable us
21 to execute a more efficient controlled shutdown as the
22 system could be shut-in in a manner that maintains the
23 gas pressure in the system and that is something that
24 we cannot do today. This would eliminate the need for
25 the manual shut-ins and avoid all of the
26 pressurization and purging activities, all of which

would effectively reduce the customers outage duration to just that of the time required to perform the relights activity, but customers would still see an outage and that outage could still be lengthy.

AMI effectively adds resiliency by reducing the potential of a shutdown or the size of a shutdown. We use the words "potential" as the company would still need sufficient time to get incident information, assess that information, gather the current projected load consumption data, perform the necessary analysis and then develop a plan and program to the implement the plan curtailment. These steps are critical and we cannot bypass them because once a customer has been shut in, that step is not quickly reversed and in effect the company needs a sufficient amount of time following the incident to be able to take advantage of an AMI system.

On slide 32 there has been four pipeline expansions of consideration. The red vertical dashed line is a new pipeline from Station 2 near Chetwynd to Huntingdon. No one has a T-South expansion. This additional pipeline would increase capacity. However, unless this new pipeline was in a completely different right of way, i.e. geographic diversity, it adds limited resiliency benefit as one event could still disrupt all of the pipelines.

The pink dashed line, horizontal line, is an expansion from Oliver to Kingsvale from our Southern Crossing Pipeline. This alternative does not add as much capacity as say the T-South option. However, the capacity added is pretty resilient as it reduces the exposure of the T-South system from say 900 kilometres of exposure length to about 170 kilometres, the length from Kingsvale to Huntingdon.

The yellow dashed line just below the pink dashed line is an expansion of the Southern Crossing Pipeline from Oliver all the way to Huntingdon. This provides some good capacity and would provide the greatest amount of resiliency for that capacity as this would be a second pipeline in a geographically different area.

And lastly, the white dashed line, an expansion across the Gorge, would add some capacity to the system but very limited to no resiliency benefits as it does not tie directly to our system and would require a commercial contract of which we know will be suspended in an emergency event. Effectively to meet our objective, we need access to controllable physical infrastructure.

I would like to note in the table that I've shown here, the relative resiliency benefit, but not the absolute resiliency benefit, as the absolute

1 resiliency benefit is dependent on the actual pipeline
2 size and contract arrangement.
3 And on the next slide I'll show why
4 economics of pipeline built for resiliency alone are
5 challenging. However, a new pipeline sized in a cost
6 effective manner would be complementary to our
7 project.
8 Mr. Hill has presented a similar slide
9 showing our peak demand throughout the year.
10 Pipelines could be, in and of themselves, a complete
11 resiliency solution. However, to build a pipeline for
12 resiliency alone with our system peaking demand
13 profile would create an expense and underlies [*sic*]
14 for our customer.
15 If you look at the graph on the left,
16 effectively the blue area shows the under-utilized
17 capacity of a pipeline if we were to size the pipeline
18 system for a peak demand and not rely on our storage
19 options or interruptible customer curtailment options.
20 **Proceeding Time 1:47 p.m. T54**
21 And if we want a true N minus 1 reliability with
22 pipelines, like we enjoy in the electric industry for
23 their high voltage transmission lines, we would
24 effectively have two pipelines, each sized to handle
25 the peak demand, one of which would effectively be on
26 standby until the event happened. From the gap on the

1 right you can see the blue and green areas represent
2 the amount of un-utilized capacity if we were to
3 solely rely on pipelines to meet our resiliency
4 demand.
5 Put that in perspective. Effectively we
6 would need to more than double the existing pipeline
7 infrastructure that serves our customers today. And
8 while that is technically possible, to put this
9 pipeline option into perspective, we would to need to
10 build, say, a 36 or 42-inch diameter pipeline running
11 900 kilometres from Chetwynd to Huntington, along with
12 ten or so compression stations in a different right-
13 of-way or the same diameter pipeline running 450
14 kilometres as the crow flies from Yahk to Huntingdon,
15 also with associated compression. While technically
16 possible, the economic price tag for resiliency alone
17 is challenging and will be very costly. As was
18 mentioned before, pipeline options are a great tool
19 for long duration restricted flow events, but there
20 are more economic and efficient options to manage no-
21 flow events.
22 And now that I've gone through the load
23 management option and what we looked at for pipeline,
24 I'm going to turn to slide 34, the storage options.
25 So we did consider a number of storage
26 options comprised of both natural gas and liquefied

natural gas, and concluded that some are not feasible and others, while feasible, are more or less desirable to meet our objective. Mr. Chernikhowsky already alluded to the on-system underground storage in Fraser Valley, but that's not feasible from a permitting perspective.

And if we look at off-system underground storage, relying on this supply during a supply emergency is only valuable if the storage is located between your load and the physical location of the incident, or effectively has a geographical diverse pipeline that can be used. And as I had alluded to before, we have access to the Aitken Creek storage in the northern part of B.C. However, it was of no value to us during this incident as we did not have a pipeline that was in service to join to our load.

On-system above ground storage at a new site, this is an LNG liquefied natural gas storage option with regasification, would meet our planning objective, but is a more costly option for our customer than an expansion at our existing brownfield Tilbury site. This option would also require construction of liquefaction facilities and also additional property. And ideally the site would be located in close proximity to pipeline and electrical infrastructure to minimize those incremental

interconnection costs as well.

Using the existing base plant storage, including its regasification, and adding additional storage and regasification capability at our Tilbury site is a consideration. This option, however, would not lead to the economies of scale on a single larger tank and would be most costly over time for our customer, recognizing that the existing base plant facilities are over 50 years old and would still require replacement at some point in the future.

And also with respect to the base plant, as Mr. Hill will point out, our current base plant tank provides real physical gas supply as part of our overall gas supply portfolio. And if the tank was no longer available, FEI would need to go to the market for 150 million cubic feet per day of capacity, a market which is not available today, and even if it was, this market supply would not be cheap given that we'd likely had to pay for capacity for 365 days of the year recognizing we may only need it for a very short period of winter peak.

This brings us to the best storage solution being a replacement of the Base Plant with a new, larger liquefied gas storage tank and regasification at our existing Tilbury site.

If I move to slide 35, we've talked about

1 an optimal portfolio from a gas supply perspective and
2 that is effectively using storage to manage your peaks
3 and interruptible load to manager the demand peaks and
4 using current pipeline capacity for longer duration
5 supply. That methodology holds the same when planning
6 for a more resilient portfolio.
7 **Proceeding Time 1:52 p.m. T55**
8 The most cost-effective solution in our
9 situation is a balance of the three tools of load
10 management, storage and pipeline capacity. For
11 example, to build a storage tank farm to compensate
12 for the long-term pipeline issue is not economical,
13 when one considers the volume of gas that would need
14 to be supplied by this storage. Building a second
15 pipeline system to manage a peak load event is also
16 not cost-effective, as I've shown earlier. And load
17 management tools like AMI can help minimize the impact
18 to customers through the potential avoidance of a
19 shutdown, or limit the shutdown, but only if there is
20 adequate time available to assess, analyze and
21 implement the plan.
22 In conclusion, for a short-term resiliency
23 event, they are most economically managed by storage
24 tools and load management tools, while resiliency for
25 longer duration pipeline concerns need to be achieved
26 by splitting an optimal capacity between existing and

1 new pipelines.
2 And I will note that this project as
3 proposed, will effectively provide N minus 1 gas
4 supply reliability for all of the gas load
5 requirements under this curve for a minimum three-day,
6 no-flow event.
7 So, in conclusion, on slide 36, and after
8 an assessment of the alternatives, our proposal is to
9 effectively make the existing peaking storage assets
10 and regasification equipment we have at Tilbury
11 larger. Our current on-site LNG storage assets and
12 regasification equipment are an ideal solution, they
13 are just not big enough.
14 Our analysis has shown that the proposed
15 solution, and best solution, is a new liquefied
16 natural gas storage tank, sited at our existing
17 Tilbury site, along with the associated regasification
18 equipment. A minimum storage of 2 billion cubic feet
19 is according to our planning objective. However,
20 there are some significant economies of scale to size
21 the tank at 3 billion cubic feet and the incremental
22 volume would not only provide incremental resiliency
23 benefits, but other ancillary benefits for our
24 customers that Mr. Hill and Mr. Chernikhowsky will
25 cover later in our presentation.
26 And so with that, I will stop there, for

any questions prior to passing it over to you, Mr. Hill

MR. SLATER: Sorry, thank you, Doyle. At this time, I don't see any questions in the comment box, just quickly pause if there is any one wants to raise their hand? I see a question from Mr. Brady Ryall? Go ahead please and ask your question.

MR. RYALL: Okay, so 2 Bcf you consider the minimum, 3 Bcf is better, because it provides these incremental benefits. Would more than 3 Bcf provide additional benefits?

MR. SAM: Yes. From an operations perspective, anything that will help resiliency more is better. However, as we've shown in our application, there is an economic point on the size of the tank, and anything over 3 Bcf is a bit more challenging from that perspective. And so in discussions with the cost estimate, and going through that, and Mr. Finke I think a little bit later, it seems like the sweet spot is no more than 3 Bcf from a constructability and cost perspective.

We could site additional tanks, of course, multiples of three, but we also realize that there is a cost of this resiliency project to our customer and we're trying to balance that as well.

MR. RYALL: Okay.

1 MR. SLATER: Okay, so thank you. I don't see any other
2 hands raised, so in the interests of time, we'll keep
3 moving along, and pass the presentation over to Mr.
4 Hill.
5 MS. BEVACQUA: Sorry, Doug? We do have Mr. Finn.
6 MR. SLATER: Oh, sorry, it's not showing up on my side.
7 Please, Mr. Finn, go ahead and ask your question.
8 MR. FINN: Okay, Mr. Doyle has talked about the
9 location of this massive tank at Tilbury, and my
10 question is again around is this the most appropriate
11 location to put a large tank, since there have been
12 other investigations in the past about locating the
13 tanks elsewhere. Howe Sound came to mind as to one
14 previous adventure.
15 You appreciate, Mr. Doyle, that locating a
16 very large 140 feet high tank on the approach path to
17 the airport, opposite a jet fuel facility for that
18 airport, where the citizens who would be at risk in
19 the event of a Burns Bog fire or an earthquake would
20 not be much in favour of it and is this not a far less
21 than ideal location to put a large overground LNG
22 tank?
23 **Proceeding Time 1:57 p.m. T56**
24 And I note that when I'm familiar with the siting of
25 LNG tanks in Japan, which has a considerable
26 experience with earthquakes, where they actually put

them underground so that any spill isn't going to go anywhere.

So the question is: Is Tilbury a suitable location for putting this, given all those risks, and if not, have you considered other locations which would be better? Thanks.

MR. SLATER: Thank you, Mr. Finn, for the question. I'm going to direct the question to Mr. Leclair to address the sort of considerations around tank siting and safety.

MR. LECLAIR: Yeah, thanks, Doug, and thanks for the question, Mr. Finn. So I mean, I guess first off I'd like to maybe remind everybody that FortisBC has been safely operating the Tilbury facility, that includes the production and storage of LNG, for the last half century on the Tilbury site. You know, and that the safe storage and production of LNG is, from a technical perspective, is highly regulated by the B.C. Oil and Gas Commission and numerous other industry standards. And that the TLSE project will be constructed and designed with, you know, current day safety and protection systems.

We staff our plants with highly trained, competent operators 24/7. You know, we have all the appropriate sort of management practices and controls in place, and we also commonly practice emergency

preparedness, not only within our own operations but also with emergency responders and first responders.

In terms of -- so I mean we absolutely, yeah, feel that it is an appropriate place to site the tank given we've been operating that facility for the last half century.

MR. SLATER: Thank you, Mike. I see Panel Member Fung has a hand up, so Madam Chair, I'll pass it over to you.

COMMISSIONER FUNG: Sorry. I just lowered my hand. Thank you.

MR. SLATER: Okay, thank you.

Okay, yeah, my apologies for not seeing those hands up there. With that now I think we're ready to move onto the next section. And again, once we get through sort of the next couple here we'll take our break.

COMMISSIONER FUNG: I believe Mr. Langley has his hand up.

MR. SLATER: Oh, I must be having some kind of glitch here because I'm not able to see that. But Mr. Langley, if you have your hand up, please go ahead and ask your question.

MR. LANGLEY: Yeah, just a follow up to Mr. Finn's question, I guess. It would sound to me like a location for this tank at the — what would you call

1 it? — the interconnect between the Lower Mainland
2 system, Westcoast and Northwest Pipe would, I guess,
3 in theory offer even greater resiliency than the
4 Tilbury site because you wouldn't have all your LNG in
5 one location. And I'm wondering whether you looked at
6 that site seriously, whether it would attract higher
7 or lower costs in your opinion? But given that, you
8 know, you are telling us that LNG is the way to go and
9 given the concerns of some of the people regarding
10 having LNG in an urban area, in a marine area, and
11 whatnot, have you looked at the Fraser Valley area?
12 Particular at the confluence of those three locations
13 where arguably maybe American distribution companies
14 would help you with the costs?
15 MR. SLATER: Thank you for the question, Mr. Langley.
16 I'm going to pass that one over to Mr. Sam to answer.
17 MR. SAM: Thank you, Mr. Slater. I'll just make a
18 couple of comments.
19 We did not look at it specifically for a
20 couple of reasons. First reason is electrical supply.
21 So obviously if we were to site the location
22 somewheres else we would need electrical supply.
23 **Proceeding Time 2:02 p.m. T57**
24 And more in particular we would have to build a
25 liquefaction facility as well. One of the benefits of
26 it located the Tilbury site is we can use the existing

1 liquefaction that is there already. So that would be
2 an added cost and some other impacts as well.
3 The other benefit of locating it where we
4 have it at Tilbury is that this would also provide us
5 with some resiliency benefit of our transmission
6 system in the Lower Mainland. And so if the tank was
7 situated upstream of that, we would not be able to
8 take advantage of the tank for our transmission system
9 that is within the Lower Mainland.
10 MR. SLATER: Thank you, Mr. Sam. I have refreshed, I
11 don't see any hands up, so maybe if somebody else
12 could just confirm I'm correct there then we will move
13 to the next segment of the presentation.
14 THE CHAIRPERSON: You are correct, Mr. Slater.
15 MR. SLATER: Thank you, Madam Chair. Over to Shawn
16 Hill.
17 **PRESENTATION BY MR. HILL:**
18 MR. HILL: Good afternoon, everyone. Can everybody
19 hear me? Hopefully.
20 So I'm actually just going to spend
21 something that I went over this morning about the size
22 of the tank and the gasification equipment that needs
23 to be put in place to meet the three-day planning
24 objective. So what the next two slides are going to
25 show you, the existing base plant today is undersized
26 from both a storage perspective and a gasification

1 perspective to meet the planning objective.
2 So if we can go to the next slide there.
3 So what we've taken here is basically our
4 bundled service load schedules, added firm rate
5 schedule 23 and 25 to that, looked at it on a normal
6 and design curve. What we're looking here is plotting
7 the gasification equipment that we need out to service
8 the daily load and basically we have sized this for
9 800. We did look at in the application the 600 range,
10 but we decided in the end to go to the 800. The main
11 reason for that is consistently we have days in the
12 winter period over the 600. And, as an example, in
13 the 2016/2017 year, which is close to our design year,
14 we had 15 days or 16 days above 600.
15 So from a gasification perspective we've
16 taken a reasonable approach to the 800. We're not
17 building things to cover off our design day, which is
18 the 871, because that's a load probability event of a
19 cold event as well as a supply outage.
20 If we can move to the next slide.
21 And then basically we're looking at the
22 duration or the inventory that we need. The 0.6 is
23 the existing base plant today, which we have -- we've
24 plotted a cumulative three-day demand curves. We've
25 put in here the design year curve, which is in green
26 and we've actually tried to validate that with some

1 different cold year, which I mentioned was the '16/'17
2 year and warm year, the '14/'15 year. And you can see
3 that considerably all three curves are well above the
4 0.6 and we've decided to recommend a 2 Bcf tank to
5 meet the planning objective.
6 That was it for my slides associated with
7 this. Happy to take any couple of questions here.
8 THE CHAIRPERSON: Mr. Hill, it's Commissioner Fung
9 speaking.
10 MR. HILL: Yes?
11 THE CHAIRPERSON: I'm just wondering, and I'm asking
12 you the question as a non-engineer.
13 MR. HILL: That makes two of us.
14 THE CHAIRPERSON: I hope you can help me out.
15 MR. HILL: Sure, I'll give it a shot.
16 THE CHAIRPERSON: In terms slide number 38, which shows
17 the regasification requirements in the Lower Mainland
18 load duration curves, is it feasible for you to use
19 the regasification facilities at Mt. Hayes, for
20 instance, at the LNG facility there to serve the load
21 from the Lower Mainland?
22 MR. HILL: Physically we isolated the Lower Mainland
23 and the Vancouver Island system. Basically, the main
24 restriction to that is in cold events we cannot
25 backflow gas at a V1 compressor station, basically to
26 get gas back into the Lower Mainland, if you will. If

that makes any sense.

THE CHAIRPERSON: Yes, that makes sense to me as a non-engineer, I'll qualify it.

MR. HILL: I always have to ask that question myself.

THE CHAIRPERSON: Thank you.

MR. HILL: It's good.

MR. SAM: Shawn, would it also accurate just to say that a gasification at Mt. Hayes is also only sized to support Vancouver Island, it doesn't have enough capacity also to support the Lower Mainland, correct?

MR. HILL: Yeah, that's correct. Yeah, for sure.

MR. SAM: Thank you.

MR. SLATER: Thank you for that, Shawn. There's a couple of questions, maybe you could just quickly clarify, Bill Andrews and I believe Ms. Worth have a question about why beneath the slides it says "FEW" as in Fortis Energy Whistler. Maybe you could just quickly explain that.

Proceeding Time 2:07 p.m. T58

MR. HILL: Where are you looking here?

MR. SLATER: It says "design load". I'm sort of understanding that we have the Lower Mainland and Whistler loads, RS1 to RS7, RS23 and 25.

MR. HILL: Yeah. So I think we have the Whistler load in here which is about 7 TJs of load too as well, and that might be an error. I'm just realizing that now

here, so. There's about 7 TJs that would be out of this load if Whistler is included in here. So we can take that up in an IR.

MR. SLATER: Thank you, Shawn. And maybe just I'll grab the second question that's in the chat and then go back to hands raised.

Brady Ryall has a question:

"Do the load duration curves exclude interruptible loads?"

So maybe Shawn if you could address that one.

MR. HILL: Yes. In the Lower Mainland section we have Rates 27 and 22. We didn't include those. Basically those are interruptible rates so we didn't size the gasification equipment for serving those loads. You'll notice that Rate 7 is in here. That is an interruptible load, but again it's very small. I think the curve that we have it was about 2 Mcf. So for all intents and purposes, the interruptible load is excluded from these curves.

MR. SLATER: Thank you, Shawn.

Next I'll ask Mr. Finn, please go ahead and ask your question.

MR. FINN: Thank you. I'm curious about the Phase 1A tank. That's the one, I believe it's about 46,000 cubic metres or store 20,000 tonnes of LNG. And the comments that were made in the application about it

1 was that it would not be included even though you
2 would say that it's connected to the base tank. It
3 would not be included in the resiliency calculations
4 required because it was going to be reserved for RS46
5 trucked LNG for private sector customers.
6 Now, I'm aware that Phase 1A was approved
7 without BCUC scrutiny because it was subject to an
8 Order in Council 557 in 2013. And my question is,
9 given that it was indicated in OIC that BCUC had to
10 provide it with a CPCN and to allow it to include the
11 costs which were over $400 million in what ratepayers
12 were expected to pay, my question is, how can you
13 argue that removing it from resiliency requirement
14 when it's been paid for by ratepayers is a reasonable
15 step?
16 MR. SLATER: Thank you for the question, Mr. Finn. So
17 maybe I'll start with one point of clarification and
18 then I'll pass it over to Mr. Leclair to address. But
19 just -- in the application we indicated that there is
20 a difference between a planning and the dealing with
21 an emergency. So most certainly if there were a
22 large-scale emergency we would look towards the volume
23 in the T1A tank to help mitigate that situation. But
24 what we said was from a planning perspective, because
25 that tank is serving the transportation market, that
26 we couldn't rely on the level of inventory, you know,

if and when there was an event.

So maybe with that I'll just quickly pass it over to Mr. Leclair to add any other clarifying comments.

MR. LECLAIR: Yeah, thanks, Doug. I think you characterized that well. It's not simply about who pays, it's really about whether or not there will be any LNG in the tank when its required. We can't count on it being there.

MR. SLATER: Thank you, Mike.

Just going to move onto the next question here. Mr. Langley, please go ahead and ask your question.

MR. LANGLEY: Yeah, my question circles around this idea of -- maybe Commissioner Fung mentioned this question about using Vancouver Island assets to assist in resiliency and you guys pointed out that your V1 compressor station isn't set up to offer that kind of interconnect.

Proceeding Time 2:12 p.m. T59

But we're talking about a $800 million project to get you this resiliency, and I'm wondering how much 800 million would take us in redesigning V1 and the link on Vancouver island, in -- I mean, is it a possibility that you could get 90 percent of your resiliency requirement with 500 million by doing

1 something on that pipeline, and those compression
2 stations? Have you looked at it?
3 MR. SLATER: Thank you, Mr. Langley, for the question.
4 I think I'm going to ask Mr. Hill to address that
5 question around sort of -- and maybe Shawn can sort of
6 elaborate on where those bottlenecks are and what it
7 is that prevents us from utilizing the Vancouver
8 Island storage.
9 MR. HILL: That's fair. Thanks, thanks Doug. Thanks
10 Jim for the question.
11 Basically the Vancouver Island system, we
12 isolated it, looking at it from a resiliency
13 perspective, because basically the Mt. Hayes facility
14 in the inventory and the gasification would help
15 protect that system in a no-flow event.
16 So basically the load and the gasification
17 of that system, and the actual storage is
18 appropriately sized to help us with the resiliency
19 factor on the island there. So, if we take away
20 resources from that facility, you know, it's basically
21 -- you know, basically, Jim, its only got 150 of send-
22 out there as well, and we're talking gasification of
23 800 on the Vancouver Island -- or on the Mainland
24 system.
25 So, it is not, you know, it would have to
26 be considerably revamped, if it was possible. And

then we actually have to add the storage behind it to have any meaningful impact.

MR. LANGLEY: Okay, thank you.

MR. SLATER: Thank you Shawn. I'm not seeing any hands raised, so we're probably at a good place if we wanted to take the afternoon break now, and then come back and finish the remaining sort of three segments of the presentation.

So, Madam chair, I would make that proposal that we take our 10 minute break, and then come back to finish.

THE CHAIRPERSON: That's great. Let's all reconvene then at 2:25. And enjoy your break.

(PROCEEDINGS ADJOURNED AT 2:15 P.M.)

(PROCEEDINGS RESUMED AT 2:25 P.M.) T60/61

MS. BEVACQUA: Okay, we're ready to proceed.

MR. SLATER: Thank you very much, Ilva. So we're going to pass it over to Shawn next. I'm just going to suggest that Shawn and Mr. Chernikhowsky have a couple of segments to get through that we kind of go through those and then pause for questions at the end so we can pick up a little more time here in our pace.

So, with that, over to you, Shawn.

MR. HILL: Thanks, Doug. So, before the break we established that we needed 2 Bcf and 800 MMcf/d to meet the planning objective. And so in the next

slide, couple of slides, Paul and I are going to discuss about why we've asked for an incremental Bcf of storage and why we think that's the superior option for customers.

This section will also cover off two of the items in the guidance letter from the Commission about the workshop relating to the auxiliary benefits that might accrue to ratepayers as a result of this project and also how this project might tie in with other CPCNs or projects that FEI might bring forward to the Commission. So those two items will be covered off in this section.

If we can go to the next -- or, no, just stay here. Stay here, Ilva.

So, basically, in section 4.4.1 of the application we laid out some auxiliary benefits to this project. And this is traditionally more about how we would view an asset like this around gas supply benefits, operational issues, creating capacity for ourselves. This is how generally, you know, projects have been justified to the Commission in the past. So where this one is being justified from a resiliency perspective first and then we're saying, well, given that there's economies of scale we're asking to build 3 Bcf.

So I'm going to touch on the gas supply

1 benefits here on the next slide. So, as we've
2 discussed today already, you know, putting a gas
3 supply portfolio together there's cost-effective
4 resources to meet that load profile that we have. And
5 basically the Tilbury base plant, the gasification
6 part of it, and 0.3 Bcf of storage of the inventory at
7 the base plant is part of our ACP today for our rates
8 1 through 7 customers. So maintaining this benefit to
9 customers in the gas supply has a lot of benefits to
10 customers and absent this renewal of this resource, as
11 the Tilbury facility ages, we'd have to go try to find
12 this incremental resource in the open market.
13 We estimate that this incremental avoided
14 cost for customers is about $30 million a year and
15 that's simply taking -- trying to find this capacity
16 off the West Coast system, taking the existing toll
17 today and multiplying by 365 days, which gives us
18 about $30 million a year. So, again, the benefit of
19 this asset is it maintains our existing gas supply
20 benefits. So absent this resource or maintaining
21 Tilbury over time, we're going to have to find
22 something else to meet our requirements in our annual
23 gas supply portfolio.
24 It also helps to avoid some mitigation of
25 some long-term third-party storage that we hold at
26 Mist. You know, the incremental storage helps us,

gives us flexibility around those renewals with that third party. We do not have renewal rights on those Mist contracts with Northwest Natural.

The final thing that I would say, that I'd like to point out, is that because we're going to have more increase gasification in the sense of greater than the 150 that we have today, this system actually helps us -- will help us backstop other resources in our annual contracting plan, such as if there's a failure or a force majeure event at JPS or Mist on a cold day or even a normal day.

Proceeding Time 2:29 p.m. T62

This asset, because if the gasification is greater than that 150, that will help us provide some backstopping just in normal operations. I think that's all I wanted to say about this slide.

If we can go to the next one.

As well what I'm going to focus on next is how this -- you know, we just talked about maintaining our existing benefits from the plant and now over time, because we have increased gasification, I think I wanted to touch on about how it helps us manage future load growth. So this chart is from our 2017 long-term resource plan that basically outlines that overtime our load is expected to grow, and so that would obviously mean a growth in our peak day over

time. And so basically this asset will help us manage those gas costs for customers and we're going to get into that next.

So just to frame this existing capacity. This is our Interior System, basically -- and as well as our supply resources into the Interior System. So basically we have the TC Energy System on the right-hand side of the equation. We bring gas in from that side of the equation, 245 MMcf/d on a peak day, this is a peak day view of it. Basically we flow 140 north into the Okanagan service territory, going kind of north at Kelowna, and then we continue to push 105 into the Southern Crossing to go to Kingsvale. And then we have Tilbury 150 out to meet the Lower Mainland peak.

So this is our existing systems today. And currently we have a project before the Commission about an upgrade on the Okanagan capacity upgrade project that would expand the capacity on our system to flow gas out of Oliver northbound. And I'm going to show you from a gas supply perspective how this project helps us avoid incremental gas costs to serve that load over time.

Go to the next slide.

So as the peak day grows in that corridor, currently 140 today that we have to find, it may over

1 time grow, you know, in the planning horizon after ten
2 years, maybe it's at 170. So we have to find this gas
3 somewhere on the open market. So you'll notice the
4 245 is the exact same number that we had before
5 purchasing as we have today. So what we would do,
6 from a gas, commercial gas supply perspective, is we
7 would reduce our obligation or our flow rate on the
8 105 to 75 and backfill from Tilbury because we have
9 increased gasification over the 150 today. So that 30
10 million in a sense is displacement, just like JPS and
11 Mist is, to our existing facilities today. This is
12 how Tilbury works across over service territories to
13 provide benefits to customers from a gas cost
14 perspective.
15 So basically just to reiterate, we're
16 buying the same amount of gas on the east side, we
17 reduce the flow on a cold day event and backfill.
18 Absent this resource or the gasification at Tilbury,
19 we'd have to find incremental resources in the open
20 market to buy more gas than the 245.
21 The only other comment that I'd like to
22 make here is that also in the -- this IR -- or this,
23 this is discussed in the Okanagan Capacity Upgrade
24 project in BCUC 12.1 and I think Madam Chair said that
25 we might be able to add that to the record here as it
26 was part of today's proceeding. BCUC 12.2 in that

1 proceeding.
2 And also in that IR, what it describes is
3 also avoiding a compression upgrade at the East
4 Kootenay exchange over time and deferring that out
5 over the planning horizon and we estimate that capital
6 deferral to be 20 to 30 million dollars.
7 So before I leave it and turn it over to
8 Paul, I just want to reiterate the concept of
9 displacement here. This asset is -- we're talking
10 about, just like JPS and Mist, we take gas in at the
11 Huntingdon station and backfill from downstream
12 storage to commercially make that work. This is what
13 Tilbury can do for our system as a whole. This
14 example that I've provided is peaking load in the
15 Interior growing, but that also can incur growth in
16 peaking requirements into the Lower Mainland System
17 and we'd be able to service that peak day demand
18 obviously because the asset is located in that system.
19 I'll turn it over to Paul here I think, if
20 that's -- Paul?
21 **Proceeding Time 2:34 p.m. T63**
22 PRESENTATION BY MR. CHERNIKHOWSKY:
23 MR. CHERNIKHOWSKY: Okay, great. Thanks for that
24 Shawn. If we can move to -- Oh, we're on slide 46.
25 So, beyond those gas supply benefits that
26 Mr. Hill just described for the Interior of the

1 FortisBC system, there are other valuable benefits for
2 Interior customers in the form of enhanced resiliency.
3 And Mr. Langley, I think this was an area you wanted
4 us to explore earlier. In fact, this is where I'd
5 like to dispel the perception that the TLSE project
6 solely benefits customers in the Lower Mainland
7 Region. In reality, it will provide improved
8 resiliency for customers all the way from Vancouver,
9 to Kelowna, to Cranbrook. And that's because it would
10 allow us to lose supply from any one gas transmission
11 line in the Interior, and yet still be able to meet
12 customer demand for the vast majority of the year.
13 And that is what we're showing on the slide.
14 Those red x's represent a pipeline path
15 that is out of service. Now, to be clear, it's not
16 intended to say that the system can survive with all
17 of the lines out of service, but rather if any one of
18 those pipelines were out of service, for either
19 planned or unplanned reasons, the capacity provided by
20 the TLSE project would allow us to augment the system
21 gas flows through the displacement process that Shawn
22 just described. So by supplying more gas into the
23 Lower Mainland, more gas would be available in the
24 Interior. Effectively, the gas in the Interior would
25 stay in the Interior, and be rerouted to supply load
26 in that area. While at the same time the Lower

Mainland load is temporarily supplied from the storage at Tilbury.

So, if you could only build one resiliency project, either one in the Interior, or one in the Lower Mainland, then the Lower Mainland makes much more sense because it allows you to address resiliency for both areas at once.

And further, between the resiliency already provided to Vancouver Island through the Mt. Hayes facility, the addition of the TLSE will basically allow us to provide resiliency for all our customers in our major customer service areas.

And now if we could move to slide 47 please.

Continuing on the theme of linkages to other projects, I'd like to walk through our concurrent CPCN capital projects and explore how they do or don’t link to the TLSE. So first, as the BCUC and many interveners are aware, late last year, we filed an application for a CPCN to replace the Pattullo Gas Line, referred to on the slide as the PGR.

The need for this project is quite straightforward, and it's driven by a third-party requirement. Today we have a 20-inch distribution pressure gas line attached to the Pattullo Bridge, it

has been operating since 1957, and it provides gas (audio drops) to customers in Burnaby, New Westminster and parts of Coquitlam. Of course the Province, Ministry of Transportation and Infrastructure, is intended to replace the Pattullo Bridge crossing, and then demolish the old bridge. As such, we also have to replace the supply capacity provided by that current gas line.

The Ministry denied FEI's request to attach a replacement gas line to the new bridge, and so we had to find another solution. We looked at a number of options, and ultimately selected constructing a new six-kilometer gas line through Burnaby. Ultimately the PGR project will address a local constraint in our ability to get gas into Burnaby, New West and Coquitlam. So, put another way, adding supply upstream, whether through storage or pipes, won't do anything to address the constraint of getting gas into this local area of our system.

And in summary, that means the TLSE project does not directly link to the PGR project, either in terms of scope or cost. And really, the only connection is that the TLSE will ensure that there is adequate gas supply to the Lower Mainland overall, and the new PGR project would help deliver that gas to customers.

1 Next, in November of last year we filed an
2 application for a CPCN to construct the Okanagan
3 Capacity Upgrade, shown here as the OCU. This project
4 is about adding gas transmission capacity to meet
5 growing load in the Okanagan area, and especially
6 Kelowna and Vernon.
7 Mr. Hill already walked us through a
8 graphical illustration of how the TLSE can provide gas
9 supply benefits to the OCU project, and ultimately how
10 in the end it could help us defer a future 20 to 30
11 million dollar compression project.
12 **Proceeding Time 2:39 p.m. T64**
13 And again, as noted there is an IR already on the
14 record in the OC process, BCUC IR 1.12.1, that
15 provides more information on that. So I won't say
16 much more at this point.
17 Continuing on. Last month we filed an
18 application for our coastal transmission system,
19 transmission integrity management capabilities project
20 or CTS TIMC or *TimC* we call it for short. I alluded
21 to this one earlier as being an integrity driven
22 project and specifically it will allow us to run a
23 special type of inline inspection tool through our CTS
24 pipeline to detect the potential of cracks in the pipe
25 walls. And although it's an integrity driven project,
26 it actually does have a link to the TLSE. There's two

1 reasons for that. The first is that the additional
2 storage provided by the TLSE allows us more
3 flexibility in system operations.
4 By being located centrally in the CTS
5 pipeline system, we can use those send-out
6 capabilities, the TLSE to adjust flows, gas flows in
7 the CTS pipeline system. And that's very convenient
8 because it gives us wider windows during the year that
9 we can run tools. The tools themselves have to travel
10 at a very specific speed through the pipe to collect
11 high quality date. Normally our gas flow rates are
12 entirely driven by customer or an event. And it's
13 quite different from a typical transmission company,
14 say an Enbridge or a TC Energy. For us, higher loads
15 equals higher flows equals higher tool speeds which
16 may mean lower quality tool data. So having better
17 control over our gas flows opens up wider portions of
18 the year to run inspection tools, and that could lower
19 the future cost to run the tools because we could
20 potentially combine tool runs and reduce mobilization
21 and demobilization costs.
22 The second reason there's a link between
23 the TLSE and CTS TIMC is that it could also allow us
24 to reduce the operating pressure in our transmission
25 pipelines to repair any issues found during pipeline
26 inspections. Normally reducing pressure at peak times

1 would also reduce our ability to deliver gas to our
2 customers. Having the TLSE available could allow us
3 more flexibility, or will allow us more flexibility to
4 reduce the operating pressure in certain pipes to
5 conduct repairs while still ensuring that would meet
6 customer demand.
7 So yes, there is a linkage between the TLSE
8 and the CTS TIMC projects. Although having said that,
9 it is difficult to quantify any direct cost benefits
10 or savings resulting from it.
11 And last, with respect to our automated
12 metering infrastructure, or AMI project, FEI is
13 currently developing an application for a CPCN to
14 install automated metering in all customer locations
15 and we expect to file that application in Q2 of this
16 year. Those new AMI meters will have a number of
17 benefits, the most obvious of which is the ability to
18 read meters remotely, but as explained by Mr. Sam
19 earlier, with respect to system resiliency, there's
20 also two significant benefits provided by AMI.
21 The first is that it will give us near
22 real-time consumption information from all of our
23 customers. And second, if we are forced to curtail
24 customer load because we've used up all other supply
25 or storage solutions, the AMI meters will also be
26 equipped with integrated remote shut-off valves. And

1 those interrelated benefits won't directly impact the
2 cost or scope of either the AMI or the TLSE projects,
3 but as mentioned, they will give us more tools to
4 better operate the gas system.
5 So I hope that's helpful and addresses the
6 panel's interest in the potential linkages and
7 synergies between the proposed capital projects. And
8 I'll just pause there to see if there's any questions.
9 MR. SLATER: Thank you, Paul. Madam Chair, I noticed
10 you had your hand up. I just want to confirm that
11 your question was answered or something's not right on
12 my end.
13 THE CHAIRPERSON: No, I found the answer myself, so I
14 will not trouble you, Mr. Slater. Thank you.
15 MR. SLATER: Thank you. Next in line is Mr. Finn. Mr.
16 Finn, go ahead and ask your question.
17 MR. FINN: Yes, thanks. I noticed in this diagram of
18 the other major projects that the proposed expansion
19 of the Eagle Mountain Gas Pipeline is not mentioned
20 even though I was at a presentation recently where the
21 vice-president of Fortis announced that that would
22 start later this year.
23 MR. SLATER: Thank you, Mr. Finn, for the question.
24 I'm not sure if, Paul, that's one that you
25 can take, but either yourself or Mr. Leclair please go
26 ahead.

1 MR. CHERNIKHOWSKY: Well, perhaps I'll just explain the
2 rationale behind my framing of the slide. But
3 ultimately this is a list of our current CPCN capital
4 projects. So they're the projects that we have to
5 seek approval from the Commission before we proceed
6 with them.
7 MR. FINN: If I may follow up?
8 MR. SLATER: Yes, please go ahead, Mr. Finn.
9 MR. FINN: Yeah, that pipeline was also subject to an
10 Order in Council effectively ordering BCUC to stand
11 aside and give it -- from the normal CPCN process.
12 **Proceeding Time 2:44 p.m. T65**
13 And it excluded storage capacity expansion but still
14 was -- it's an odd one to leave out of your thing
15 because in following Fortis' annual reports and
16 investor briefings it is very prominently in there.
17 Thanks.
18 MR. SLATER: Thank you, Mr. Finn, just wondering --
19 sorry, I didn't catch the question in there. I'm just
20 wondering if you could restated it and then I'll
21 direct it to one of our team members here.
22 MR. FINN: It's still part and parcel of what Fortis is
23 doing and adds to the fact that they're going to be
24 busy boys and a major expansion to Whistler and to
25 Vancouver Island to serve an LNG customer is excluded
26 from this. Why?

1 MR. SLATER: Thank you for restating, Mr. Finn. So I'd
2 like to ask Mr. Leclair if you could address the
3 question posed by Mr. Finn.
4 MR. LECLAIR: Sure, thanks, Doug, and thanks, Mr. Finn.
5 So what I can say is, I mean Fortis is developing the
6 Eagle Mountain project. Is, you know, to serve the
7 Woodfibre LNG facility should it proceed. So we are
8 in the development phase and working through
9 preliminary engineering and permitting on that
10 project. However, whether or not that project
11 proceeds is contingent on a Woodfibre FID or Final
12 Investment Decision to proceed and our development .
13 S so in terms of whether or not it will -- you know,
14 it ultimately proceeds isn't in Fortis' control.
15 MR. FINN: But it is in the impact to ratepayers if it
16 has been allowed to bypass the BCUC CPCN requirement.
17 MR. SLATER: Thank you, Mr. Finn. Yes, it will be a
18 cost for the -- pardon me, for the ratepayer, in this
19 case Woodfibre. I don't -- I'm not sure if there was
20 more question there or if you wanted us to sort of
21 take away the, you know, the question of how does --
22 you know, how does the EGP project, if at all,
23 interact with TLSE?
24 MR. FINN: Thanks, I'll address it in the IR.
25 MR. SLATER: Thank you, Mr. Finn. I'll move next to
26 Madam Chair.

1 THE CHAIRPERSON: Sure, Mr. Slater. It's just a
2 following up on Mr. Finn's question. I realize that
3 the Eagle Mountain project is still under development.
4 However, assuming it proceeds, I guess the question
5 for me is does that particular project, would it
6 replace or diminish the need for the current project?
7 MR. SLATER: Thank you, Madam Chair. I'm actually
8 going to ask Mr. Sam if he could address that question
9 about whether -- you know, whether the EGP would
10 diminish the potential or the need for TLSE.
11 MR. SAM: No, there's -- thank you, Mr. Slater.
12 There's no relation and to be clear the TLSE is not
13 being sized to support any future EGP load that may
14 happen and occur on the system.
15 MR. CHERNIKHOWSKY: And I think I would just add to
16 that as well that the Woodfibre project is, as a
17 transportation customer, and Mr. Hill might be able to
18 clarify this as well, but as a transportation customer
19 Woodfibre will be responsible for sourcing their own
20 supply of gas. They would not be included in the load
21 that the TLSE will be sized for.
22 THE CHAIRPERSON: All right. Thank you very much.
23 MR. HILL: That's correct. I can confirm that, Paul.
24 That load will probably in our transport model
25 customers.
26 MR. CHERNIKHOWSKY: Okay, thank you.

1 THE CHAIRPERSON: Okay, thank you, Mr. Hill.
2 MR. SLATER: Thank you. At this time I'm just double-
3 checking. I have Mr. Andrews with your hand up.
4 Please go ahead, Mr. Andrews, and ask your question?
5 MR. ANDREWS: Would this be a good time for the panel
6 to explain how TLSE relates to the Tilbury Phase 2
7 proposal?
8 MR. SLATER: Somebody's phone ringing.
9 Perhaps, Mr. Andrews, if I could suggest
10 we're going to get into the next sort of part of the
11 presentation maybe touches on that. Perhaps we could
12 maybe hold that question and ask, just following the
13 next segment.
14 **Proceeding Time 2:50 p.m. T66**
15 MR. ANDREWS: Yes.
16 MR. SLATER: I think that's it. I'm just double-
17 checking here. So yes, there are no other questions
18 at the moment so we'll move on, and again Mr. Andrews,
19 we'll touch back on that after the next segment here.
20 Over to Mr. Finke.
21 **PRESENTATION BY MR. FINKE:**
22 MR. FINKE: Okay, hi everyone. Thanks, Mr. Slater. My
23 name is Ian Finke and I am the director of LNG
24 Operations. And my role today is to describe the
25 project in more detail and also provide some context
26 as to how we operate the existing assets at the site

today, as well as how we expect to operate them once the project is complete.

Now, you may recognize this slide from earlier in the presentation. I'm going to use it here again to start off a more detailed explanation of the project. Throughout the presentation we heard from Doyle, Shawn and Paul about how FEI evaluated and arrived at the preferred alternative. Now the infrastructure to achieve this requirement is really comprised of just main additions to the assets at Tilbury. As Mike noted at the beginning of the presentation, the first is the LNG storage tank, which will be sized to hold 3 Bcf, three billion cubic feet, which equates to about 144,000 cubic metres of LNG. By comparison, this is about five times larger than what is currently stored in the existing base (inaudible) plant tank.

The second main component is regasification which can produce up to 800 million cubic feet per day of natural gas to help meet our customers energy needs. The project proposes four units, each capable of delivering 200 million cubic feet per day, but the full capacity being available to support the gas supply system within two hours of being called upon. By comparison the existing infrastructure at Tilbury only provides 150 million cubic feet per day.

As presented in section 6 of the application, a preferred alternative has estimated the cost, approximately 770 million in as-spent dollars included AFUDC. The project is targeted to be in service by late 2026 and is expected to result in an annual average -- sorry, an average annual delivery rate impact of 1.47 percent over the years 2022 to 2027.

If we move to slide 50 we'll dig a little deeper into the details. First, we'll start with the storage tank.

The new tank will be constructed as a double-walled, insulated tank. A cryogenic steel inner vessel will contain the LNG liquid. This vessel will be fully enclosed in an outer concrete tank which will also be lined with steel. The space between the tanks is filled with thermal insulation to keep the LNG at the proper operating temperature. The new tank will be designed and built to meet all current design standards, to ensure safe and reliable operations. It will be a full containment tank, meaning that it is designed to contain the full volume of LNG stored even if there were to be a breach of the inner steel tank holding the LNG.

The filling of the tank will be facilitated by a connection between the new tank and the existing

1 T1A tank. This connection will allow us to use
2 liquefaction from the T1A liquefier to fill the new
3 tank. Now, from the new tank the LNG would travel to
4 the regasification trains which are comprised of both
5 high pressure send-out pumps and submerged bath
6 vaporizers. The high-pressure send-out pumps boost
7 the pressure of the LNG to match the pipeline pressure
8 and the submerged bath vaporizers convert the LNG back
9 to a gaseous state so it can serve our customers
10 energy needs.
11 The final steps before sending the natural
12 gas out to the system includes odourization and
13 metering or measuring. Each of the regasification
14 trains will be capable of operating within a range of
15 50 million cubic feet per day to 200 million cubic
16 feet per day, and as mentioned previously, the full
17 capacity of all four trains would be available to
18 support our customers within a response time of two
19 hours.
20 Another component of the project is what we
21 call auxiliary equipment. For example, there is a
22 significant amount of interconnecting piping required
23 to connect the tank to the regasification trains, the
24 regasification trains to the pipeline system and the
25 existing T1A equipment to the new equipment to
26 facilitate an integrated operations.

1 **Proceeding Time 2:54 p.m. T67**
2 In addition, other project components,
3 which include power and control systems, are captured
4 within this category. These are essentially aspects
5 of the project which ensure long-term safe and
6 reliable operations. And, finally, the project
7 includes decommissioning and the demolition of the
8 above ground portions of the Tilbury base LNG storage
9 tank and liquefaction facilities.
10 Next slide, please.
11 Next, I'm going to spend just a few minutes
12 talking about the current and future operating
13 strategies at the Tilbury facility. First, the
14 existing configuration. Now, as Mike pointed out
15 right at the beginning of the day, the site
16 configuration consists today of the base plant, which
17 is currently utilized for utility peaking and
18 operational support and the T1A facility, which is
19 utilized to provide service to our RS 46 customers.
20 We do have the operational flexibility
21 today to utilize the available liquefaction capacity
22 to support filling both the T1A and the base plant
23 tank. The base plant liquefaction has not been
24 utilized over the past couple years as we have found
25 it more efficient and cost effective to utilize the
26 newly installed liquefaction capacity rather than the

1 older base plan equipment.
2 So from an operations perspective, today we
3 can fill the base tank and the T1A tank, both, from
4 our T1A liquefaction. We provide service to our RS 46
5 customers through the T1A facility and provide
6 resiliency support to our customers through the base
7 plant and the base plant vapourization equipment.
8 Because of the operational flexibility we currently
9 enjoy we can provide regasification of LNG inventory
10 from both the base plant and T1A tank, utilizing the
11 regasification equipment currently located at the base
12 plant facility. We do not, however, currently provide
13 any LNG sales from the base plant tank to equipment.
14 Next slide please.
15 Looking into the future, things change a
16 bit but only in the sense that in place of the old
17 base plant tank and regasification equipment is a much
18 improved resiliency configuration providing longer
19 duration and improved quantity. Both tanks will
20 continue to be filled from existing liquefaction,
21 currently from T1A and potentially in the future from
22 a phase 1B liquefaction. The T1A storage tank
23 continues to provide service to our RS 46 customers,
24 for example BC Ferries, while the TLSE project
25 provides resiliency to the utility.
26 I think it's worth reiterating at this

point that the TLSE project is for resiliency. The project components proposed in this application are for the sole purpose of increasing and improving the resiliency of FEI's natural gas distribution system and will help ensure that we are prepared to respond to either a supply disruption support utility peaking requirements or any of the other numerous benefits which have been previous discussed, both today at the workshop and in the application.

And with that I'd like to take -- at this point I'd like to hand it back over to Mike Leclair who's going to talk about some potential future developments at the site.

PRESENTATION BY MR. LECLAIR:

MR. LECLAIR: Okay, thanks, Mr. Finke. Could we maybe go to the next slide? Perfect, thank you.

So on this slide I am going to discuss the other development plans at Tilbury and most notably the Tilbury 1B expansion. So in 2015, pursuant to an order in council to demand direction 5, FEI received approval to expand the production capability, the Tilbury 1B expansion at the Tilbury facility, with connection to the T1A storage tank. The purpose of the expansion is to serve future demand for LNG customers under rate schedule 46 in the on road transportation marine fueling markets.

As Mr. Finke mentioned, FortisBC is currently providing LNG as a marine fuel to Seaspan Ferries and then to essential service like BC Ferries using a unique truck to ship onboard fueling method. The T1B facility expansion currently remains in the planning stage, with the ultimate execution timelines dependent on how the market develops.

Proceeding Time 2:59 p.m. T68

So if I draw your attention to the slide, in green, I'll sort of sort through the -- or speak to the contemplated Tilbury 1B assets.

At the top right-hand corner of the slide, is the proposed 30-inch costal transmission line expansion, which has an approximate 2 to 3 kilometre expansion required from the Tilbury gate station to the Tilbury facility, in order to support the liquefaction capacity of the Tilbury 1B expansion. However, this 30-inch extension line is also required to support the 800 million cubic feet a day of regasification from the proposed TLSE project.

Now, in the green rectangle to the left of the TLSE assets, is the area contemplated for the Tilbury 1B liquefaction (audio drops). So, depending on the size of the liquefaction ultimately constructed, the expansion may also contemplate a power supply upgrade.

Now, to explain the final scope component of the Tilbury 1B expansion, I just want to identify some practicalities related to the marine fueling market.

So, the current LNG truck to ship fueling market works quite well for smaller vessels, or regional ferries, such as the B.C. Spirit class ferries. However, trans-Pacific vessels require much larger volumes of fuel, and so that really makes the truck-to-ship fueling method impractical. So the standard for the trans-Pacific vessels is really a ship-to-ship fueling method. And to facilitate a ship-to-ship fueling method requires a marine jetty. And effectively, this is the infrastructure necessary to enable a small fueling vessel to dock, fill its cargo with LNG, and then travel out to fuel all the trans-Pacific vessel.

So, if I draw your attention to the left side of the screen and the Tilbury Pacific Jetty, a non-regulated Fortis Company is in the process of developing the Tilbury Pacific Jetty, depicted in the slide in blue. The Tilbury Pacific Jetty is undergoing an environmental assessment process, unrelated to the TLSE project, under provincial 2002 *Environmental Assessment Act*.

So, therefore, to enable LNG marine fuel

1 sales under rate schedule 46, the last major component
2 contemplated under the Tilbury 1B expansion is the
3 interconnection piping to connect the T1A tank to the
4 interconnection point of the Jetty, should the Jetty
5 proceed.
6 To reiterate, the Tilbury Pacific Jetty is
7 not a component of the TLSE project, nor is it a
8 component of the Tilbury 1B expansion.
9 Next, I wanted to touch on the
10 environmental assessment -- or touch on the
11 environmental assessment application, or the EA
12 application, related to the TLSE project. The
13 provincial environmental assessment process is
14 conducted under the *2018 Environmental Assessment Act*,
15 which came into force actually in late 2019. This
16 provincial environmental assessment process is a
17 regulatory process which ensures that any potential
18 environmental, economic, social, cultural, or health
19 effects of a development are thoroughly assessed.
20 This process is overseen by the Environmental
21 Assessment Office, and seeks input from Indigenous
22 nations, the public, scientific professionals, local
23 government, and Federal and Provincial agencies.
24 Now, the TLSE project triggers -- or sorry,
25 the Federal or Environmental Assessment Agency of
26 Canada process is similar to that of the Provincial EA

1 process. And the TLSE project triggers both the
2 Provincial and the Federal assessment processes as a
3 result of the cumulative storage on site will exceed
4 the thresholds.
5 Now, we are at the early engagement stage
6 of the process, and which culminates, this first stage
7 culminates in a readiness decision expected by the EAO
8 later this year.
9 The environmental assessment process
10 includes a cumulative effects assessment. And this is
11 based on all existing and known or foreseeable future
12 developments on the Tilbury site. Effectively, this
13 requires FortisBC to consider all known project
14 development plans, such as the TLSE project, or any
15 potential development plans that could arise at the
16 Tilbury site in the future that should be considered
17 in the cumulative effects assessment.
18 **Proceeding Time 3:04 p.m. T69**
19 As a result in the environmental assessment
20 application the company has identified the potential
21 to increase liquefaction capacity at the Tilbury site
22 in the future. This proposed increase in liquefaction
23 capacity also triggers a requirement for a provincial
24 and federal environmental assessment as it exceeds the
25 threshold of 1 million tonnes per annum of
26 liquefaction on the site. However, it's also

1 important to note that the TLSE project, although it
2 triggers the storage requirement for a federal and
3 provincial EA, does not trigger the liquefaction
4 requirement because it leverages existing
5 infrastructure to fill the tank.
6 In FortisBC's view, the future expansion
7 and liquefaction of Tilbury could be used to serve
8 incremental marine fueling market over the capacity of
9 Tilbury 1A and 1B can provide. In addition, this
10 future liquefaction could also be used to supply
11 FortisBC's low carbon LNG to global markets as they
12 transition from higher intensity carbon energy sources
13 in pursuit of a net-zero energy future. However, it's
14 important to note the company does not have any exact
15 plans on how this future liquefaction may develop and
16 any future development is uncertain and contingent on
17 how the market develops.
18 As I mentioned before, the federal and
19 provincial EA processes are comprehensive in their own
20 and are distinct and the TLSE project requires both
21 approvals to proceeds. And I'd also like to mention
22 that any future development plans at Tilbury still
23 require regulatory approval prior to proceeding to
24 ensure that they're in the best interests of our
25 customers.
26 So with that, Doug, I think we can pause

1 for some questions.
2 MR. SLATER: Thank you, Mike. I'd like to pause for
3 questions. And as sort of promised I'd quickly check
4 back with Mr. Andrews whether his question was
5 answered? I think the question was about the
6 differences in the scope of the TLSE project and the
7 Phase 2 EA. So Mr. Andrews, I just want to check in
8 with you.
9 MR. ANDREWS: Is the Phase 2 EA the same as Phase 1B?
10 MR. LECLAIR: So --
11 MR. SLATER: Go ahead, Mike. Yeah, please.
12 MR. LECLAIR: I jumped the gun, sorry, Doug.
13 MR. SLATER: Yeah, no problem.
14 MR. LECLAIR: Thanks for the question, Mr. Andrews.
15 So, no, the Phase -- the Tilbury Phase 1B expansion
16 does not trigger the federal or provincial
17 environmental assessment. So the Phase 2 EA is
18 effectively the TLSE, the federal and provincial EA
19 assessment associated with the TLSE as well as we've
20 included, as I mentioned, the potential for future
21 liquefaction to be considered in the cumulative
22 effects assessment as a part of that process.
23 MR. ANDREWS: So maybe I'm missing something here. So
24 the Phase 2 environmental assessment application at
25 the provincial EAO includes TLSE. Is that right?
26 MR. LECLAIR: Correct.

1 MR. ANDREWS: That event, did I misread the size of the
2 tank involved with Phase 2? I thought it was
3 extremely small compared to the 3 billion cubic feet
4 proposed for TLSE.
5 MR. SLATER: So maybe I could just help out quickly on
6 that one, Mr. Andrews. And this was pointed out
7 earlier in the presentation, that the units of measure
8 are different in the EA, which sort of is stated in
9 cubic metres, but the equivalent -- and maybe, Mr.
10 Finke you can help us out here, the EA equivalent in
11 Bcf is a little bit larger than three I believe?
12 MR. FINKE: Actually it works out to -- and I won't get
13 the numbers quite right, Mr. Andrews, so I apologize,
14 but it would work out to a threshold of about 138,000
15 cubic metres or somewhere in that range, or
16 petajoules, that's the numbers that they use in the EA
17 for the threshold. And of course we're measuring in
18 Bcf in the application, but having said that, no
19 matter how you cut it, by the time we build the TLSE
20 project we would have triggered that threshold under
21 all the units of measurement. So the EA includes that
22 combined storage there or the proposed TLSE storage
23 unit.
24 MR. SLATER: And, sorry, Ian, the question was just
25 about like how -- what is the size of the tank
26 included in the EA, just to sort of answer Mr.

1 Andrews's question?
2 MR. FINKE: Right. In the EA it's phrased currently as
3 a tank up to 160,000 cubic metres. And of course as
4 we've evolved our thinking with the TLSE tank, that
5 was on the initial project description that was filed
6 last year, early last year actually.
7 MR. SLATER: And could you kindly convert that to Bcf
8 for Mr. Andrews?
9 MR. FINKE: Yeah. I should know that off the top of my
10 head.
11 MR. SLATER: Is it about 4 Bcf?
12 MR. FINKE: Yes, it's -- that's right. But I can do
13 that calculation very quickly here, but not in my
14 head.
15 MR. SLATER: Mr. Andrews, does that help with your
16 question?
17 MR. ANDREWS: Yes. And, well --
18 MR. FINKE: 3.5 Bcf.
19 MR. ANDREWS: Okay. And did you also say that the
20 federal environmental assessment of Phase 2, which
21 includes TLSE, is separate from the provincial?
22 MR. SLATER: Thanks for the question. I'll just pass
23 it off --
24 MR. ANDREWS: It's a different legal requirement, but
25 is the proceedings separate?
26 MR. FINKE: Do you want me to --

1 MR. SLATER: Sorry, Mr. Andrews, you cut out there. I
2 think your question was just about whether the
3 provincial and federal parts of the EA are separate,
4 is that correct?
5 **Proceeding Time 3:10 p.m. T70**
6 MR. ANDREWS: That's correct
7 MR. SLATER: So maybe I could ask Mr. Leclair to answer
8 that.
9 MR. LECLAIR: Yes, so thanks, Mr. Andrews. Yes, they
10 are indeed separate processes with similar
11 requirements, I would say. And there is a
12 substitution process where you can apply to sort of
13 deal with the federal requirements at the provincial
14 level and then that allows sort of both unique -- then
15 they use the same information to make their
16 independent decisions, so that's the link between the
17 two.
18 MR. FINKE: Yeah, and maybe just to confirm, we have
19 applied with the two agencies to have the province --
20 it's called a substituted process, and we have applied
21 for that to occur. We haven't received a ruling on
22 that yet, but if it were to be approved then the
23 province would run both processes on behalf of both
24 agencies with involvement from both.
25 MR. ANDREWS: All right, thank you very much.
26 MR. SLATER: Thank you. Looks like Mr. Brady Ryall is

1 next in line there. So Mr. Ryall, please go ahead and
2 ask your question.
3 MR. RYALL: Certainly. Thank you very much. Going back
4 to slide 52 and the use of the GLCs -- you intended to
5 use the existing liquefaction facilities from T1A. So
6 on this slide it shows a 30-day fill or the one Bcf
7 tank and by my math that means it's a 90-day fill to
8 fill the three Bcf tank. That would be 90 straight
9 days of 100 percent usage of the liquefaction
10 equipment, is that realistically how the system is
11 going to be operated? Or is T1A going to be
12 intermittently using that liquefaction equipment to
13 serve its other customers? And how do you reconcile
14 -- I guess, is the lack of liquefaction being added as
15 part of this project, is that realistic?
16 MR. SLATER: Thank you, Mr. Ryall. I think we'll pass
17 that question over to Mr. Leclair and Mr. Finke. So
18 maybe, Mike, if I could pass it your way.
19 MR. LECLAIR: Yeah, sure. So thanks for the question.
20 So the T1A -- or sorry, rate schedule 46 customers are
21 served from the LNG in the tank. So you're right in
22 that the liquefier takes 30 days to fill the T1A tank,
23 and so the -- but the liquefier in itself doesn't run
24 all the time and so we will be -- and so there is
25 opportunity to use available liquefaction on site to
26 initially fill the tank.

1 And I think it's important to note here is
2 that once the tank is full, you know, I mean there
3 will always be reserving three days of supply for our
4 customers, so that will remain, always remain
5 untouched, of course.
6 MR. FINKE: Maybe just one other thing to add to that is
7 for sort of ongoing, once the tank has been filled and
8 the two billion cubic feet have been reserved, not
9 touched unless its needed for resiliency purpose, we
10 do have a reserve of 5 million cubic feet per day of
11 liquefaction from the T1A facility that is reserved
12 for utility use, not for sale, so we have that to sort
13 of, I guess, cycle that remaining Bcf to help Shawn,
14 Mr. Hill, in his gas planning objectives.
15 MR. HILL: Exactly. Thanks, Ian.
16 MR. SLATER: Thank you. Commissioner Morton, you're
17 next in line. Please go ahead and ask your question.
18 COMMISSIONER MASON: Thanks, Mr. Slater. Mr. Leclair,
19 going back to when we were on slide 55. You said
20 something about increased power requirements. I'm
21 assuming that means electricity that you were talking
22 about. And it wasn't clear to me what phase that was
23 or when that would be required or what it was for.
24 Again, I assume it was for regasification.
25 But in any event, if that's in fact what
26 you said and what you meant, I wonder if you could

please let me know or let us know what does that require, that additional electricity?

Proceeding Time 3:15 p.m. T71

Is that readily available? Does that require any further upgrades and would that be part of this project?

MR. LECLAIR: Thank you, Commission Morton. So the power supply upgrade, as I mentioned, is dependent -- is a component, potentially a component of Tilbury 1B and is not required for the TLSE.

COMMISSIONER MORTON: Okay.

MR. LECLAIR: And it is dependent on the size of liquefaction that's ultimately built on the Tilbury 1B expansion and depending on that size, if it requires additional power we do envision extending or building a 230 kV line, and Ian can probably help me out with the length, and that would be built to the Tilbury Station.

Ian, can you reference the length?

MR. FINKE: Yeah, it's approximately 6 kilometres of line, Commissioner Morton.

COMMISSIONER MORTON: Thank you. And that's something you would -- sorry, that's something that you would build? Fortis would build or BC Hydro would build that?

MR. FINKE: Well, you know, I think at this point the

1 plan, and it's still being discussed with BC Hydro, is
2 that we would build it and potentially transfer
3 ownership down the road. But he have been discussing
4 this potential with BC Hydro for the past little
5 while, so I think that still needs to be worked out.
6 COMMISSIONER MORTON: But in any event, it's not part
7 of this project or it's not required for this project?
8 MR. FINKE: That's right. The power supply we have
9 that feeds the site today is adequate to support both
10 the regasification and the TLSE tank.
11 COMMISSION MORTON: Thank you.
12 MR. SLATER: Thank you. It looks like Mr. Finn is next
13 in line. So Mr. Finn please go ahead and ask your
14 question.
15 MR. FINN: Thanks. Since it was brought up in the
16 discussion of the need for additional rate schedule 46
17 supply, I've read a report commissioned by the Port of
18 Vancouver from Lloyd's Registry in 2017 that basically
19 downplayed the requirement for RS 46 supplies to
20 bunker marine vessels in the Port of Vancouver. It
21 basically predicted that most -- as has happened, that
22 most vessels to comply with low-sulfur fuel
23 requirements would put scrubbers on their boats rather
24 than the more expensive refitting for coping with an
25 LNG propulsion supply. Can you confirm that?
26 And I have a second question or second

1 point on that. One of the statements made by Fortis
2 is that they expect the continued increase in
3 population and use of gas to continue. And I note
4 that four municipalities in the Lower Mainland,
5 Vancouver, North Vancouver City and District and West
6 Vancouver, have all recently introduced zoning
7 regulations that limit or discourage the use of
8 natural gas as a space heating and water heating fuel.
9 So I'm questioning whether future growth in
10 -- and in compliant with what our climate require- --
11 crisis response requirements, whether we can really
12 depend on future growth to use this additional
13 capability. Thanks.
14 MR. SLATER: Thank you, Mr. Finn. I'll give it a stab
15 at answering these questions. So with regard to the
16 sort of effort of marine vessels to meet the IMO's
17 objectives, there's actually sulfur as well as well as
18 carbon emission reductions targets that they've set.
19 Certainly agree that scrubbers are a compliance
20 pathway for the sulfur component. The benefit of LNG
21 is that it's a compliance pathway for both.
22 However, I would point out that that is
23 outside of this proceeding but certainly, you know,
24 certainly a good question.
25 **Proceeding Time 3:19 p.m. T72**
26 On the, you know, sort of use of gas, it's

1 indeed some of the municipalities have put policies in
2 that, you know, discourage the use of -- you know,
3 discourage carbon emissions. Something that, you
4 know, we are very close to. In some of those cases,
5 of course, you know, the compliance pathway is
6 renewable gases and that's something that we've been
7 developing over the last ten years and sort of how we
8 see fitting into, you know, into some of those
9 regulation. I can't say that we are targeting to
10 increase our supply of renewable gas to align with the
11 CleanBC target of 15 percent by 2030. And, you know,
12 over the longer term, out to 2050, we sort of envision
13 a future where, you know, where the majority of the
14 energy we deliver is renewable and in compliance.
15 Certainly that will be a topic that's, you know, sort
16 of dealt with in our next long-term gas resource plan
17 filing that's coming up next year.
18 So, thank you for the question, Mr. Finn.
19 I'm going to --
20 MR. FINN: I have a supplementary, if I could?
21 MR. SLATER: Sure, fire away.
22 MR. FINN: Okay, Fortis on their website has announced
23 to all the public that it has a 30 by 30 plan for
24 dealing with this climate crisis. That is that it
25 will achieve a 30 percent reduction in customer
26 emissions by 2030. My question is, given the

ambitions declared in the phase 2 expansion, what proportion of that 30 percent reduction is attributable to B.C. customers and to this bunkering of vessels in the port and to the objective in the phase 2 expansion of servicing LNG shipments to Asia, Asian customers? What's the breakdown of the 30 percent between those three customer sets?

MR. SLATER: So, I don't know that I have the breakdown but I will just sort of step back and talk a little bit about our climate goal. So, Mr. Finn, we have a climate strategy called our clean growth pathway to 2050 and that pathway leverages, you know, the decarbonization potential of our gas system, as well as our electric system, to achieve our current targets, which are, you know, in B.C. the Paris Accord climate targets, so 80 percent below by 2007. And there's four pillars under that strategy to reduce emissions. And I should say, this is -- the 30 by 30 is our target along the way, the interim target as we move towards 2050. So that's where that sort of -- how that comes in.

So there's four -- the four pillars, the first one is energy efficiency and conservation, so this is really just helping customers use less energy, which contributes to reduced emissions and helping customers save on their energy bills.

The second one, and I touched on this earlier, is renewable gas and hydrogen. So that pillar would involve moving lower carbon energy to our customers over time by replacing natural gas with low-carbon gases like biomethane or hydrogen, all of which we call renewable gases. And, as I mentioned just a moment ago, we are targeting to increase our supply to about 15 percent renewable content by 2030 in alignment with CleanBC. That would contribute to about 75 percent of the emissions reductions that are expected from buildings in that plan as it stands today.

And the third pillar is low and zero carbon transportation. So, you know, that pillar involves deploying EV charging stations across our electric service territory, you know, to support the adoption of electric vehicles, but also helping, in the gas utility, helping heavy duty fleets switch from diesel to natural gas, which also saves emissions and improves local air quality.

Proceeding Time 3:24 p.m. T73

The final pillar, and this is the one you were sort of touching on, is LNG for marine fueling and global markets. So this pillar is based on helping the marine shipping industry switch from bunker oil and diesel to LNG, which very much like the

1 previous pillar helped save emissions in our largest
2 emitting sector. Today we're, as Mike mentioned
3 earlier, Mr. Leclair, that we're providing fuel to BC
4 Ferries and Seaspan, and we're also targeting to
5 support the marine shipping industry as they
6 transition to meet those IMO or International Maritime
7 Organization's objectives that we talked about just
8 briefly a minute ago.
9 And also, we can also lower emissions by
10 providing LNG to global markets for use in industry,
11 transportation and energy generation, which displaces
12 heavier emitting fuels like coal and bunker oil.
13 So those are four pillars of the plan. You
14 know, I don’t have off the top of my head today, Mr.
15 Finn, the amount of megatonnes that are expected out
16 of those. But I would say that the renewable gas and
17 hydrogen and the LNG for marine fueling and global
18 markets are two really -- two of the biggest
19 contributors to the 30 by 30 objective, and to the
20 overall clean growth pathway.
21 And maybe with that I'll just sort of
22 close, you know, the TLSE project is not proposed for
23 the purposes of reducing emissions per se, but it is
24 complimentary to our climate goals. So this project
25 is complimentary in that as we, as we do shift towards
26 greater concentrations of renewable gas in the future,

the tank will help us by providing necessary on-system storage, and ensure that we can deliver that renewable energy to customers when they need it most during those cold winter peaks. So, I hope that helps answer the question.

You know, if you want to dig a bit more into the numbers, we'd be happy to provide those, I just can't recall them off the top of my head today.

MR. FINN: Well, I would just point out that this is the second time I've asked this question. Two months ago I asked the same question at one of your APs, and was promised an answer, so I am still hopeful.

I would also point out that Fortis Inc., your parent, has a 75 percent by 2030 goal, and that B.C. is the outlier. Thanks.

MR. SLATER: That's a good -- I'll just maybe touch on that last point there, thank you, Mr. Finn. So, the distinction between sort of maybe Fortis Inc.'s target and our 30 by 30 objective, is that ours would be --

FEMALE VOICE: Tanks going to be used.

MR. SLATER: I heard someone talking there. Sorry, the distinction is that the -- like our 30 by 30 is reducing our customers' emissions, where the Fortis Inc. target is based on reducing their emissions. So different, different scopes between scope 1, 2 and 3.

But with that, I think I'll just move on to

the next question. So, there is one in the chat, and so just maybe Mr. Sam Mason asked a question,

"Can you please clarify that the TLSE requires the additional pipeline capacity of the Phase 1B project in order to deliver its full 800 MMcf per day capacity to the Lower Mainland? Also, does the TLSE require or envision the use of Phase 1B liquefaction in the long-term?"

So maybe I could ask Mr. Leclair to take that one.

MR. LECLAIR: Sure, thanks Doug. So yes, I can confirm that the TLSE does require the CTS expansion in order to inject energy back into our system. And in addition, the Tilbury 1B expansion also requires the CTS expansion in order to deliver the natural gas to the facility in order to liquefy at that capacity.

And in terms of the TLSE project, we do envision, you know, subsequent to Tilbury 1B expansion occurring, that the TLSE would leverage any existing liquefaction capacity on site that was available at that time, to fill the tank when it was required.

Does that answer your question, Mr. Mason?

MR. MASON: Yeah, in part. Just to follow up on that. Is the -- I guess what I'm trying to say maybe in follow up to Mr. Ryall's questions from earlier is, is the liquefaction capacity of 1B kind of envisioned as

1 necessary in order to fill the TLSE tank in normal
2 operations?
3 MR. LECLAIR: Thank you for the question. I know, so
4 we do envision -- it's not required, and we do
5 envision filling it from the T1A facilities, and just
6 to clarify my point there was, you know, if Tilbury 1B
7 was in service and there was available liquefaction
8 capacity on site, we may leverage it to fill the tank
9 if required.
10 **Proceeding Time 3:29 p.m. T74**
11 MR. MASON: Thank you.
12 MR. SLATER: Thank you. Looks like next I'll move to
13 Mr. -- Mr. Langley, go ahead and please ask your
14 question.
15 I'm not sure if Mr. Langley is still on
16 mute. Are you there? Okay, well maybe we'll hold
17 onto Mr. Langley for a moment and I don't see any
18 other hands raised. At least I'll just quickly double
19 check.
20 THE CHAIRPERSON: I believe Mr. Ryall has a question
21 still.
22 MR. SLATER: Sorry, there we go. Mr. Ryall, please go
23 ahead and ask your question.
24 Thanks for the help.
25 MR. RYALL: Okay, thank you. So if a 30-inch pipeline
26 is required for the TLSC, why is it not part of the

1 CPCN?
2 MR. SLATER: Thanks for that question. Mr. Leclair,
3 I'll just pass that one over to you.
4 MR. LECLAIR: Yeah, thanks for the question, Mr.
5 Ryall. So the CTS, the two to three kilometre CTS
6 expansion was previously approved, I believe through
7 the 2015 OIC amendment.
8 MR. RYALL: Okay. Sorry, I had my hand up for another
9 question, so maybe I could just quickly go on. If I
10 look at the Talking Energy website, which I believe is
11 one of Fortis' websites or external communication
12 portal that appears, it has a rendering of the Tilbury
13 site and it looks a little different than what's shown
14 on slide 55. For one thing, it's got some equipment
15 where the base plant is currently situated, and I
16 don't think I have the ability to share my screen but
17 somebody there who is familiar with what's going to
18 be, I guess, in phase 2, what would appear -- or what
19 equipment is planned or is eventually going to go
20 where the base plant is currently situated?
21 MR. SLATER: Thank you for the question. Mr. Leclair,
22 if I could ask you to answer that one.
23 MR. LECLAIR: Yeah, thanks, Doug, and thanks, Mr. Ryall.
24 So to clarify, as I mentioned earlier, the
25 planned expansions end at the Tilbury 1B expansion in
26 terms of our known plans, and should the TLSC proceed

1 and the base plant be demolished, you know, that is
2 the available space we have on site.
3 So I think really what that picture is just
4 trying to depict is, although we don't have any plans,
5 they are uncertain and contingent, if we were to
6 expand on the site, you know, we would sort of use
7 available space and optimize the facility for, you
8 know, safety, cost, operability, risk mitigation and
9 of course economics and any future development.
10 MR. RYALL: Okay, thank you.
11 COMMISSIONER FUNG: Mr. Slater, I believe Mr. Langley is
12 now back and has his hand up again.
13 MR. SLATER: Thank you, Madam Chair.
14 Mr. Langley, if you want to go ahead and
15 ask your question.
16 MR. LANGLEY: Okay, I apologize. You can hear me now?
17 MR. SLATER: We can hear you now.
18 MR. LANGLEY: Okay. It would appear that, depending on
19 how long you spend on the phone -- I'm calling in and
20 at some point apparently you guys just can't hear me.
21 So I don't know if that's a technical glitch or what.
22 I wanted to take you to slide 52 if I
23 could. And my question really is to understand, you
24 guys have been talking about how existing liquefaction
25 capacity at this site can be leveraged to, you know,
26 help the economics of this project. And I guess what

1 I'm looking at here on the numbers, my recollection
2 back when you just had the original .6 Bcf plant was
3 that you had liquefaction capability on the order of 3
4 million a day and it took you basically to 200 days of
5 summer to refill it, and that was sort of the
6 philosophy, that you used it in the wintertime and
7 then you refilled it in the summer. And yet with this
8 new plant, you can fill it in 30 days, which is kind
9 of a step change in terms of the ratio between
10 liquefaction and storage capacity, and I guess I'm
11 trying to understand, why would you make such a huge
12 step change over those ensuing 25 or 20 years. What's
13 different that you need to refill that tank within 30
14 days?
15 **Proceeding Time 3:34 p.m. T75**
16 MR. SLATER: Thank you, Mr. Langley, that's a really
17 good question. I think I'm going to pass that one to
18 Mr. Finke who can sort of explain some of the
19 bottlenecks in the base plant tank and the boil off
20 gas compressors.
21 MR. FINKE: Yeah, thanks, Mr. Slater. Yeah, so Mr.
22 Langley, you can see we have a 30-day fill and that
23 30-day fill is really from our new facility to our new
24 tank. And so the T1A tank can fill up in 30 days but
25 the connection between the new tank and the old tank
26 actually is quite a bit slower, we show you there is a

120-day fill. And so that's actually, it takes us, you know, almost as much time to fill the base tank from the new tank as it did filling it form the old liquefaction. So, in fact, we really haven't seen much of a step change there other than we're using the newer liquefaction, which we find to be a bit more cost-effective and efficient right now, to produce the LNG. Does that help?

MR. SLATER: I'm not sure if we still have Mr. Langley on the line. Mr. Langley, does that answer your question?

MR. LANGLEY: Oh boy you (audio drops) forget it, sorry guys. Bye. Did you hear that?

MR. SLATER: Yeah, we heard you. We can hear you now, Mr. Langley. Did that answer your question?

MR. LANGLEY: Oh, you can. Well, no. Sorry about this, with the technology.

My question was really along the lines of what was the thinking behind building a 33 MMcf per day liquefaction plant to service a 1 Bcf tank? That's a huge ratio difference compared to what you had before.

MR. SLATER: Thank you for the question, Mr. Langley. I think I'll pass that one on to Mr. Leclair and perhaps Mr. Sam about sort of the ratio between how quickly that can fill and the rationale behind that.

MR. LECLAIR: Yeah, so thanks for the question. Thanks, I'll try to take a stab at that.

I mean, it goes back to what I spoke about previously, is that the base plant, you know, and the T1A facility were really built for distinct purposes. You know, the base plant was built for a peak shaving facility. So, you know, it was only really intended to operate and provide energy to our customers in those short duration periods, you know, on the coldest days where energy supply for our customers exceeded -- sorry, energy demand for our customers exceeded supply. And so it was quite -- you know, during that time you would sit in the winter and get ready for send out and then you had all summer to fill.

Whereas the T1A facility is really built for servicing LNG sales. So, you know, it cycles, you know, much more frequently. And so the tank is there not only to fill the customers but also to provide backup for our liquefier outages and maintenance outages so that we can continue to serve our customers while we're doing preventative maintenance and integrity maintenance or management practices and such on the liquefier.

MR. LANGLEY: Okay, thank you.

MR. SLATER: Thank you. It looks like, Mr. Finn, you're next, please go ahead and ask your question.

1 MR. FINN: Yeah, I think it was Mr. Leclair who earlier
2 said that the Tilbury Marine Jetty was owned by a
3 third party and I think he was referring to WesPac
4 Midstream, who originally noted the idea. But my
5 understanding is that that ownership has changed and
6 Fortis now owns that jetty, am I correct?
7 MR. SLATER: I'll maybe just pass that over to Mr.
8 Leclair to address, if I could?
9 MR. LECLAIR: Yeah, thanks for the question, Mr. Finn.
10 And, so, yes, you are correct and that is what I
11 mentioned in my presentation, is that a non-regulated
12 Fortis company does own the Tilbury Pacific Jetty.
13 **Proceeding Time 3:39 p.m. T76**
14 MR. SLATER: Thank you, Mike. We'll move next to Mr.
15 Ryall who has his hand up. Go ahead and ask your
16 question.
17 MR. RYALL: Okay, thank you. So on this Tilbury site
18 there's a mix of assets that appear to belong to the
19 regulated FEI operation as well as the unregulated
20 Fortis companies. How does -- how are costs allocated
21 -- I guess who owns the property and so is FEI on
22 Fortis Property or is Fortis using FEI property? I'm
23 just wondering how costs are allocated through usage
24 of the site.
25 MR. SLATER: Thank you for the question. We can
26 confirm that the assets on the site are all FEI today,

but perhaps just on your question of cost allocation I can pass that over to Diane Roy.

MS. ROY: Yes, thanks, Doug. I didn't think I'd get a chance to talk today.

Yes, if there any future developments that do occur on that site that are for non-regulated Fortis affiliated companies, or for any other company for that matter, there will be a future proceeding where we'll deal with the cost allocation issues related to that to make sure that any benefits are flowed back to our core customers.

As I said, there is no non-regulated assets there at this time.

MR. RYALL: Okay, thanks. That's very helpful.

MR. ROY: You're welcome.

MR. SLATER: Okay, I'm not seeing any hands raised. So maybe we have one more slide to go. I'll pass it back over to Mr. Chernikhowsky to wrap up here and then go to the question period.

PRESENTATION BY MR. CHERNIKHOWSKY:

MR. CHERNIKHOWSKY: Okay, thanks Doug. So yes, we're coming to our conclusion now so I'd just like to wrap up a little bit.

As I first alluded to we have presented a large amount of information today and we greatly appreciate everyone's interest and participation. I'd

1 just like to restate a few key points that we hope you
2 take away from our session today and as we listed on
3 the slides here.
4 Again, first and foremost the TLSE project
5 is a resiliency project and it will directly benefit
6 hundreds of thousands of residential, commercial and
7 industrial customers throughout our system and will do
8 that by allowing us to provide a dependable gas supply
9 every day of the year, even during those extreme cold
10 winter days when we're most dependent on energy to
11 stay safe and warm.
12 Second, we developed our minimum resiliency
13 planning objective specific to FortisBC and its needs.
14 And it was fundamental in determining the size and
15 scope of the TLSE project.
16 Meeting the planning objective will allow
17 the FEI system to withstand a minimum three-day period
18 of no gas flow into the Lower Mainland area. And we
19 need the TLSE project because if we're unable to meet
20 that objective it could result in significant
21 consequences to customers, society and the province
22 overall.
23 And last, while the primary objective of
24 the TLSE project is to enhance our resiliency it will
25 also provide many other benefits to our customers.
26 And with that, that concludes our

1 presentation portion of our content for today and with
2 that we can move into our open question and answer
3 session and I'll turn it over to Ilva to lead that.
4 MR. SLATER: Thank you, Paul. I think I'll be Ilva
5 today. So again either questions in the comment box
6 or if you want to raise your hands we'd be happy to
7 answer other questions at this time.
8 Mr. Langley, please go ahead and ask your
9 question.
10 MR. LANGLEY: I'm hoping you can hear me.
11 MR. SLATER: We can hear you.
12 Mr. LANGLEY: Great. Good start. I guess this is a
13 follow-up to the question I had about the excess
14 capacity and liquefaction that you guys have at the
15 site. To the extent then that this excess
16 liquefaction comes from facilities that were built for
17 your LNG for transport business, I'm wondering as that
18 business grows is this excess liquefaction going to be
19 available for this project, or are you going to come
20 back in ten years' time and say, "Well, we need to
21 build liquefaction because the transport guys are
22 using it all now because the market's grown." Can you
23 comment on that.
24 **Proceeding Time 3:43 p.m. T77**
25 MR. SLATER: Thank you for the question, Mr. Langley.
26 Maybe I'll ask Mr. Leclair to comment on the state of

liquefaction, what's been reserved and how we sort of see that going.

MR. LECLAIR: Yeah, thanks, Doug, and thanks for the question, Mr. Ryall. So we do have 5 million cubic feet a day of liquefaction reserved on the T1A liquefier. And so that is reserved for the existing Tilbury base tank, which of course will also be used for the TLSE tank when the Tilbury base tank goes away.

And then from there, I mean, we do envision, once the tank is full -- I mean, as Ian mentioned earlier, you know, that we'll always have three days of minimum supply reserved for our customers so then the incremental sort of differential to fill is far less.

MR. SLATER: Thank you, Mike. I guess the next question is from Brady Ryall. Go ahead and ask your question, Mr. Ryall.

MR. RYALL: Okay, thank you. Has FEI surveyed its customers -- I presume you survey your customers regularly on customer satisfaction and those types of metrics, but have you surveyed them on trade-offs between rate increases and either reliability or resiliency benefits? Is that something that you've asked on surveys or focus groups?

MR. SLATER: Thank you for the question, Mr. Ryall.

1 You know, we do do a lot of customer research and
2 surveying. I don't know that we have anybody amongst
3 us today that is aware of the scope of all of that.
4 It would be a good question to ask in the IR process.
5 You know, I'd have to check on that. That's a good
6 question.
7 MR. RYALL: You will see that one then, thank you.
8 COMMISSIONER FUNG: Mr. Slater, I believe Mr. Craig has
9 a question in the chat room that he may wish to pose.
10 MR. SLATER: Thank you very much. Mr. Craig, would you
11 like me to read out your question or would you like to
12 unmute and state it for everybody?
13 MR. CRAIG: You go ahead and read it out and make it
14 fast and efficient.
15 MR. SLATER: Okay, thank you very much. Mr. Craig's
16 question is:
17 "Could resiliency be improved if this project
18 was integrated with a mobile LNG regasification
19 capability to support isolated areas of the
20 system in the event of local system failure
21 issues?"
22 So maybe if I could ask Mr. Sam to take
23 that question.
24 MR. SAM: Thank you, Mr. Slater, and thank you, Mr.
25 Craig, for the question. We do use mobile LNG
26 regasification equipment. Predominantly we use it to

1 help us manage a winter peak. So for example, a
2 number of years ago we set up an LNG system in
3 Whistler to help us get through winter peak. We
4 haven't traditionally considered LNG tanks for, I'll
5 say a system failure, as the reality is the volume
6 that's in a tank is unlikely sufficient to manage
7 anything on our transmission system with the draw
8 that's on our transmission system.
9 MR. SLATER: Thank you, Doyle.
10 Mr. Finn has got his hand up. Mr. Finn, go
11 ahead and ask your question. Mr. Finn, you might be
12 on mute.
13 MR. FINN: Oh, sorry. I note that in the -- isn't
14 that the question of the age? I note that in the
15 application materials, the PwC report on the socio-
16 economic impacts of an outage details, that that is
17 redacted in totality. I can't see any of it.
18 **Proceeding Time 3:48 p.m. T78**
19 Since that's rather germane to the question
20 of the public benefit versus the private benefit to
21 Fortis as a corporation, how much of that can be
22 unredacted so that we can get an idea of what the
23 economic impacts are on large customers, residential
24 customers. Because I recall in the 2018 thing we were
25 all asked to take shorter showers and that was the
26 kind of total effect of the breakage. In other words,

1 can I see the PwC report, can I ask for it to be
2 unredacted and maybe with the exclusion of any
3 customer specific stuff in there. But I think it's an
4 important piece of information. Thank you.
5 MR. SLATER: Thank you, Mr. Finn. So just two quick
6 things to say on that is, first and foremost the --
7 you know, interveners are able to sign an undertaking
8 of confidentiality, and indeed some have, to review
9 confidential information. I would also just
10 acknowledge the points made by Madam Chair earlier in
11 the session for us to sort of take away.
12 Okay, so Mr. -- sorry, Commissioner Mason,
13 if you want to go ahead and ask your question, and
14 then I'll pass it over to Madam Chair.
15 COMMISSIONER MASON: Thank you. I'm wondering if
16 somebody can let me know whether Fortis anticipates
17 ever selling storage type services to third parties
18 using the assets that are currently being applied for
19 under the CPCN or is the purpose of the assets purely
20 and solely to serve existing Fortis customers through
21 the resiliency service?
22 MR. SLATER: Thank you for that question. So we did
23 outline in the application towards the end of Section
24 4.4.1.5 that while this project is primarily proposed
25 to support the resiliency of FEI's system and provide
26 ancillary benefits, one of those ancillary benefits

1 could be, as you described, sort of renting storage
2 space, if you will, to third parties. While we don't
3 have any plans, I think the -- you know, including it
4 in the application was a signal that we would consider
5 that in the future if there was a benefit to
6 ratepayers and if the opportunity presented itself.
7 COMMISSIONER MASON: Thank you.
8 MR. SLATER: So Madam Chair, I'll pass it back over to
9 you.
10 THE CHAIRPERSON: Thank you very much, Mr. Slater. I'm
11 just cognizant of time and as we indicated at the
12 outset of this workshop, Commissioner Morton has a
13 call which he needs to take at 4:00 P.M. It is now
14 3:51 P.M.
15 So I'm just wondering whether it would be
16 possible, at least for the panel and the panel staff,
17 to pose some questions to the speakers that are
18 present, and then we can decide whether or not we wish
19 to adjourn at 4:00 P.M. for 20 minutes and continue
20 with any other questions or whether we can completely
21 adjourn after that at four o'clock. Would that be
22 acceptable to everyone that's present here?
23 All right, hearing no objections I'm going
24 to ask if there are any questions from my fellow panel
25 members that they would care to pose to our speakers
26 from Fortis.

1 COMMISSIONER MASON: No further questions, thank you.
2 THE CHAIRPERSON: Thank you, Commission Mason.
3 COMMISSIONER MORTON: No further questions from me.
4 THE CHAIRPERSON: Thank you, Commissioner Morton.
5 COMMISSIONER LOSKI: And I have no questions.
6 THE CHAIRPERSON: Thank you very much. Now, I will
7 quickly go to our BCUC staff as well as our legal
8 counsel to see whether there are any questions.
9 MS. SIMON: No further questions from BCUC staff.
10 THE CHAIRPERSON: Thank you, Ms. Simon.
11 MR. BUSSOLI: And none from me, Madam Chair.
12 THE CHAIRPERSON: Thank you, Mr. Bussoli. Now, I will
13 turn it back to you, Mr. Slater, and see what you can
14 do in the remaining seven minutes.
15 MR. SLATER: Thank you, Madam Chair.
16 THE CHAIRPERSON: Thank you.
17 MR. SLATER: So again, if you'd like to ask a question,
18 please put up your hand I'll do my best to address
19 those in order.
20 THE CHAIRPERSON: I do remind everyone that you will
21 have an opportunity in the IR process that's to follow
22 this workshop and I suspect not just IR number one,
23 that will -- to ask you detailed technical questions
24 and get information that you may wish to pour over in
25 great detail later on.
26 **Proceeding Time 3:53 p.m. T79**

So, this is not your only opportunity to ask questions.

All right, with that said, I hear somebody that has a comment? Or wish to make a comment? I believe it's Mr. Andrews?

MR. ANDREWS: Yes, I have a question. There were two examples of other jurisdictions in which resiliency was rationale for an improved system capacity project. In some ways, two examples out of all of the gas utilities in North America seems like a small number. Is there a short response that you could give to that? Or that is, are there many, many more examples that you didn’t put forward? Or is this a small number because it's a new thing with the regulators?

THE CHAIRPERSON: I don’t know if Mr. Moran is still with us? Mr. Slater?

MR. SLATER: Yeah, I was just going to check on that myself. Mr. Moran, are you still on the line?

MR. ANDREWS: If he is not, I can put a similar question in to the IRs.

MR. SLATER: Yeah, maybe just to quickly touch on that, Mr. Andrews. We did include some examples of other investments in our system that, you know -- oh. Maybe he was having some technical difficulties. Sorry, I'll just continue here.

MR. MORAN: Can you guys hear me?

1 MR. SLATER: We can, just one moment.
2 MR. MORAN: I'm sorry, I apologize. (Inaudible).
3 MR. SLATER: I was just going to mention that in our
4 application, we include example of other investments
5 in resiliency. You know, the Tilbury -- or sorry, the
6 Mt. Hayes LNG storage facility, some of the pipeline
7 infrastructure in the Lower Mainland. And so there
8 are examples that we've included, but I would say that
9 at times the resiliency has been one of possibly other
10 drivers for the project.
11 And with that, maybe Mr. Moran, I can pass
12 it back over to you.
13 MR. MORAN: Yeah, really quick, thank you for the
14 question. It is a very important question, and I'm
15 glad that it was asked. As I mentioned earlier in my
16 remarks, the single largest source of resiliency
17 across the North American natural gas system, or any
18 particular natural gas utility, are the portions of
19 the value chain that contribute to reliability. So,
20 in other words, having access to more than one
21 upstream supply source. Having diverse transportation
22 options, you know, pipeline options. Even if they all
23 trace back to a single source of supply, just having
24 two pipelines, that redundancy, that's usually
25 inherent in the system, is a key contributor to energy
26 system resiliency, across both electric and gas.

1 But as we take a step away from kind of,
2 you know, what I talked about earlier, geographic
3 adjacency and market availability. You know, why --
4 great question. Why haven't we seen more natural gas
5 utilities in particular reach out and seek approval
6 for assets specifically designed to serve resiliency?
7 And the reason is because of the following.
8 Typically, regulatory paradigm exists to
9 approve asset construction to serve reliability. And
10 a key test in the marketplace that this is going to be
11 an asset that's prudent is that it's being used and
12 useful, and that used and usefulness is typically
13 measured in terms of utilization. And the more highly
14 utilized an asset is, it lends itself to a more
15 prudent review or acceptance on behalf of the
16 ratepayers.
17 But as earlier in the day, as Shawn
18 mentioned, when we see periods of very peak, of very
19 high peak utilization, so in other words, all adjacent
20 assets are highly utilized during a peak period, so
21 they're not available for a market availability
22 perspective. In addition, they are not even really
23 available from -- even if they were, they are not even
24 in the neighbourhood, because we don't have the
25 geographic adjacency.
26 **Proceeding Time 3:58 p.m. T80**

It's only until a resiliency event occurs, and I characterize a resiliency event as something that happens, whether it be weather or climate or a landslide or a manmade event or just a physical failure, that the need for resiliency is revealed. And if it can't be solved through, what I'll characterize, the more normal market paradigm, which is again an asset that's going to used and useful through, as measured by high utilization, high load factor, then typically assets don't need to be requested to be approved that only serve the resiliency need.

And as noted in the application, for the certificate of convenience and necessity for Fortis, this has been designated as a resiliency asset. It's been noted and we've tried to make a point today that the need is to preserve -- to mitigate the risk of a supply disruption that would be so significant that it would result in a system collapse.

Typically, again, right? Those -- typically assets that serve reliability lend themselves to resiliency. When we don't have those assets, we need to come back and seek approval for something to specifically serves the resiliency. And so there's a reason why we haven't seen this happen before because we're now in a situation where we're

seeing more and more frequent climate events, such as what happened in Utah and what was happening in New Jersey, that reveal the need for resiliency. We're seeing that in Texas, we saw it last summer in California and it was revealed in October 2018 in British Columbia.

So I'm hopeful that that has addressed the question, which I think is an important one.

MR. ANDREWS: Thank you.

MR. SLATER: Thank you. And, Madam Chair, at this time I don't see any other hands up here. Just, I'm cognizant of the time with other commitments for the panel, so I'm just wondering if we should close off here for today or sort of in your hands on that.

THE CHAIRPERSON: Sure. Thank you, Mr. Slater.

I just want to give a huge note and thank you personally and on behalf of the B.C. Utilities Commission to all 43 of the participants who have stuck with us to the bitter end at this workshop. And I appreciate you taking time out on what started out as a beautiful spring day here to spend with us so that we can learn more about FEI's application. You've been very patient and I want to thank all the FEI speakers for your presentations, for answering our many questions and for educating us about the application, all of which are greatly appreciated.

And in accordance with today being the first anniversary of the official announcement of COVID-19 as a national pandemic in Canada, I bid you all to stay safe and take good care of yourselves and your loves ones and enjoy what's left of the day.

So, until next time, take care of yourselves. Good night.

(PROCEEDINGS ADJOURNED AT 4:01 P.M.)

I HEREBY CERTIFY THAT THE FORGOING is a true and accurate transcript of the proceedings herein, to the best of my skill and ability.

A.B. Lanigan, Court Reporter

March 11th, 2021