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MANITOBA PUBLIC UTILITIES BOARD

RE:

CENTRA GAS  
2010 COST OF GAS APPLICATION  
and 2011/2012 GENERAL RATE APPLICATION

Before Board Panel:

- Graham Lane - Board Chairman
- Monica Girouard - Board Member
- Len Evans - Board Member

HELD AT:

Public Utilities Board  
400, 330 Portage Avenue  
Winnipeg, Manitoba  
April 13th, 2010

APPEARANCES

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Bob Peters

) Board Counsel

Marla Murphy

) Centra Gas Manitoba

Kris Saxberg

) CAC/MSOS

Kola Ruzycki

) Just Energy (Manitoba)

L.P.

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EXHIBITS

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2			
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4		information in the scoring of the	
5		matrix	198
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1 --- Upon commencing at 9:04 a.m.

2

3 THE CHAIRPERSON: Okay, good morning,  
4 everyone. Welcome to the Board's Hearing in respect of  
5 Centra Gas Manitoba Inc.'s Cost of Gas Application for  
6 the 2009/'10 gas year, and, also, Centra's 2010/'11  
7 fiscal year.

8 I am Graham Lane, the Chairman of the  
9 Public Utilities Board, and I'm pleased to be joined on  
10 this panel by Dr. Len Evans and Monica Girouard. Also  
11 assisting the Board is Mr. Hollis Singh, associate Board  
12 secretary.

13 Centra filed its application last year on  
14 December the 18th. We can see that Centra is seeking  
15 approval of new supplementary gas transportation to  
16 Centra and distribution to customers rates effective May  
17 1, 2010.

18 Collectively, these new rates seek to  
19 collect an additional 5 1/2 million from Centra's  
20 customers. From the filing, Centra's non-primary cost of  
21 gas is forecast to increase by 12.1 million for the  
22 '09/'10 gas year compared to the cost imbedded in rates.

23 Simultaneously, Centra proposes to reduce  
24 the magnitude of rate riders that are currently in place  
25 by an aggregate amount of 6.6 million. If granted, the

1 net effect of these two (2) changes on non-primary gas  
2 costs would be an increase of the 5.5 million that I  
3 previously mentioned.

4                   Centra's also seeking approval of actual  
5 gas costs incurred during the November 1, 2008 to October  
6 31, 2009 gas year, that in the amount of 437 million.  
7 Centra's also seeking final approval of interim orders of  
8 the Board related to both primary gas and non-primary gas  
9 rates. These orders relate to non-primary gas rates  
10 approved as of August the 1st, 2009 and primary gas rates  
11 approved as of August the 1st, 2009, November the 1st,  
12 2010, and most recently, February 1st, 2010.

13                   The Board notes that there is also an  
14 interim Order 179 issued on December 2009 related to  
15 Centra's derivative hedging program that should be  
16 considered in this proceeding.

17                   While the Board is aware that there  
18 already exists a process for adjusting primary gas rates  
19 every three (3) months, on the quarter of the gas year,  
20 the next gas quarter falls on May the 1st, 2010, which is  
21 the same date Centra requested adjustments in non-primary  
22 gas rates.

23                   To further compound rate issues, May 1st,  
24 2010 is also the date scheduled for adjustment of non-gas  
25 rates that flow from the Board's GRA Orders 116/09 and

1 1/28/09. The Board would appreciate at some point an  
2 overall review of all the rate impacts targeted for May  
3 1, 2010.

4 Finally, Centra has responded to a number  
5 of directives issued by the Board in previous issue --  
6 previous Orders. The Board is interested in Centra's  
7 responses and updates to these various matters and  
8 expects that information will -- that that information  
9 will also be discussed during this Hearing.

10 So with that, I will now turn to Mr.  
11 Peters for his introductions and opening remarks. Mr.  
12 Peters, good morning.

13 MR. BOB PETERS: Yes. Thank you. Good  
14 morning, Mr. Chairman and good morning to Board members,  
15 Dr. Evans, Ms. Girouard.

16 For the record, my name is Bob Peters and  
17 I am counsel to the Board in this proceeding. The Board  
18 is also assisted this morning by its engineering and  
19 accounting advisors, Brady Ryall, a professional  
20 engineer, of Energy Consultants International to my  
21 right, and Roger Cathcart, chartered accountant, of  
22 Cathcart Advisors to my left.

23 As mentioned by the Chairman, Centra is  
24 seeking approval of new rates for supplemental gas,  
25 transportation to Centra and distribution to customers

1 beginning May the 1st of 2010.

2                   Centra is also seeking approval of actual  
3 gas costs incurred up to October 31, 2009, as well as the  
4 disposition of balances accrued to various purchase gas  
5 variance accounts.

6                   I expect, Mr. Chairman, to cover the  
7 additional items you mentioned in your opening comments,  
8 including Centra's plans for derivative hedging and  
9 various prior Board directives including the Affordable  
10 Energy Program and Lower Income Efficiency Programs.

11                   I will have questions and documents to  
12 review with Centra's witnesses related to the various  
13 rate adjustments sought for May the 1st of this year.  
14 Those rate adjustments are threefold for non-primary gas  
15 rates, for primary gas rates and also for non-gas cost  
16 rates as you've mentioned, Mr. Chairman.

17                   Mr. Chairman and Board members, three (3)  
18 days have been scheduled for the oral evidence from the  
19 witnesses this week. We're not certain that we're going  
20 to need all those days but with that in mind, I'll turn  
21 to the procedures recommended for the oral hearing today  
22 and tomorrow and, if necessary, Thursday.

23                   In terms of procedures we'll have --  
24 excuse me, I forgot to provide a copy to counsel  
25 opposite, but I am suggesting that following my opening

1 comments you turn to Mr. Saxberg representing the  
2 Consumer's Association of Canada (Manitoba) Inc., the  
3 Manitoba Society of Seniors, who we'll be referring to by  
4 the acronym of "CAC/MSOS" throughout. And after Mr.  
5 Saxberg then to Ms. Ruzycki to hear from Just Energy  
6 (Manitoba) Limited Partnership. And following her  
7 opening comments turn to Centra's counsel, Ms. Murphy,  
8 for any opening comments, introductions and proceeding  
9 with the direct evidence.

10 I will indicate that the procedures are  
11 located at the front of the black binders that I've  
12 handed out to parties in the room today, they're on blue  
13 paper.

14 And one (1) item that I didn't mention is  
15 that the Board is anticipating and I believe we'll hear  
16 from Mr. William Carroll presenting at approximately 1:15  
17 today, and he has some information he would like to  
18 provide to the Board at that time and we'll welcome him  
19 then.

20 In terms of panels, the -- my  
21 understanding is Centra will put in its case through two  
22 (2) witness panels. The first witness panel seated  
23 before will be examined directly by Centra's counsel and  
24 then cross-examined by myself and the Intervenors.

25 And then there's a second panel that we've

1 called the "Cost of Service/Customer Service" witness  
2 panel, it contains two (2) of the same individuals on the  
3 first panel; that is, Mr. Warden and Mr. Barnlund,  
4 they'll be joined by Mr. Kuczek and Ms. Derksen, and we  
5 will hear from them as well.

6 In terms of exhibits that are related to  
7 these proceedings, the Board's secretary has handed out  
8 an exhibit list and I would just indicate that -- I'll  
9 take the liberty of putting them on the record for all  
10 the parties.

11 The PUB Exhibit 1 would be the Notice of  
12 Hearing dated December 21.

13

14 --- EXHIBIT PUB-1: Notice of Hearing

15

16 MR. BOB PETERS: PUB Exhibit 2 would be  
17 the transcript from the Pre-Hearing Conference which this  
18 Board held on January the 15th.

19

20 --- EXHIBIT PUB-2: Pre-Hearing Conference.

21

22 MR. BOB PETERS: Exhibit PUB-3 would be  
23 the Procedural Order of 13/10, dated January 28th.

24

25 --- EXHIBIT PUB-3: Procedural Order of 13/10,



1 documents, which is more accurately a binder of  
2 documents, as PUB Exhibit 6 this morning. This book of  
3 documents contains Information Responses. It contains  
4 some information from Centra related to its application,  
5 as well as its February 19th filing.

6                   There are two (2) documents that, I  
7 believe, and believe only two (2) documents, that were  
8 not either filed or prepared by Centra included in that  
9 book of documents and we'll come to those, and I'm  
10 trusting we can work through them, but if there's any  
11 objection, certainly my friend, Ms. Murphy, will have an  
12 opportunity to -- to indicate.

13

14 --- EXHIBIT PUB-6:   Exhibit binder of documents  
15                   containing Information Responses and  
16                   information from Centra related to its  
17                   application, as well as its February  
18                   19th filing.

19

20                   MR. BOB PETERS:   In addition, on the  
21 exhibits, Centra Exhibit 1 would be their application  
22 dated December 18th, that was filed at the pre-hearing  
23 conference, as was Centra Exhibit 2, which was a draft  
24 timetable.

25

                  Centra Exhibit 3 was the affidavit of

1 publication and service.

2                   Centra Exhibit 4 would be an advance  
3 metering infrastructure report filed February 2nd.

4                   Centra Exhibit 5 would be an affordable  
5 energy program marketing program.

6                   And Centra Exhibit 6 would be the furnace  
7 replacement program, filing of December 23rd and updates  
8 on February 19th.

9

10 --- EXHIBIT CENTRA-4:           Advance metering  
11                                    infrastructure report filed  
12                                    February 2nd

13

14 --- EXHIBIT CENTRA-5:           Affordable energy program  
15                                    marketing program.

16

17 --- EXHIBIT CENTRA-6:           The furnace replacement  
18                                    program, filing of December  
19                                    23rd and updates on February  
20                                    19th.

21

22                   MR. BOB PETERS:       Turning to Centra  
23 Exhibit CAC/MSOS number 7, that's Centra/CAC/MSOS number  
24 7, is the Information Request posed of CAC/MSOS, and it  
25 dealt with the curriculum vitae of Mark Stauff.

1 --- EXHIBIT CENTRA/CAC/MSOS-7: Information Request  
2 posed of CAC/MSOS, and it dealt with  
3 the curriculum vitae of Mark Stauff  
4

5 MR. BOB PETERS: Then Centra Exhibit 8  
6 would be the rebuttal evidence that was filed by the  
7 Utility.  
8

9 --- EXHIBIT CENTRA-8: Rebuttal evidence filed by  
10 the Utility.  
11

12 MR. BOB PETERS: And then Centra Exhibits  
13 9-1 through 9-7 would be the witness qualifications of  
14 those appearing on the first and second witness panels.  
15

16 --- EXHIBIT CENTRA-9-1 TO 9-7: Witness qualifications  
17

18 MR. BOB PETERS: Turning to the exhibits  
19 on behalf of CAC/MSOS, I propose that we mark as Exhibits  
20 1-1 through to 1-21, the first round Information Requests  
21 and Centra's responses, and Exhibits 2-22 following  
22 through to 2-35 would be the second round Information  
23 Requests.  
24

25 --- EXHIBIT CAC/MSOS-1-1 through to 1-21:

1 First Round Information Requests.

2

3 --- EXHIBIT CAC/MSOS-2-22 TO 2-35:

4 Second Round Information Requests.

5

6 MR. BOB PETERS: And CAC Exhibit number 3  
7 would be the evidence of Mr. Mark Stauff dated, March  
8 18th of 2010.

9

10 --- EXHIBIT CAC/MSOS-3: Evidence of Mark Stauff dated  
11 March 18th, 2010.

12

13 MR. BOB PETERS: Turning to, excuse me,  
14 Just Energy (Manitoba) L.P.'s exhibits, I propose that  
15 Exhibit JEMLP/Centra 1-1 through 1-4 would be the  
16 exhibits related to Just Energy's first round Information  
17 Requests and Centra's responses to those Information  
18 Requests.

19

20 --- EXHIBIT JEMLP/CENTRA-1-1 TO 1-4: Just Energy's  
21 first round Information Requests and  
22 Centra's responses to those Information  
23 Requests.

24

25 MR. BOB PETERS: There will be additional

1 exhibits that we will provide this morning and perhaps  
2 even through opening comments by other parties, so we'll  
3 keep that list at hand, Mr. Chairman.

4 Subject to any questions that you may have  
5 for me at this time, those conclude my opening comments.  
6 I will again suggest that the Board turn to Mr. Saxberg,  
7 counsel to CAC/MSOS, for his opening comments before  
8 turning to Ms. Ruzycki for her opening comments. Thank  
9 you, Mr. Chairman.

10 THE CHAIRPERSON: Thank you, Mr. Peters.  
11 Mr. Saxberg...?

12

13 OPENING COMMENTS BY CAC/MSOS:

14 MR. KRIS SAXBERG: Thank you. Good  
15 morning, Mr. Chairman and members of the Board, ladies  
16 and gentlemen. It's nice to see everybody again. My  
17 name's Kris Saxberg and I'm the lawyer for the Consumers'  
18 Association of Canada (Manitoba) branch and the Manitoba  
19 Society of Seniors.

20 These organizations represent, notionally,  
21 at least, the residential consumers of natural gas in  
22 Manitoba. As in previous applications, CAC/MSOS will be  
23 here throughout the Hearing and will participate in all  
24 aspects of the process, including cross-examination,  
25 presentation of evidence, and closing submissions.



1 evidence though, and the fact that Centra chose not to  
2 challenge that evidence through cross-examination, and  
3 will be relying on -- on that in support of  
4 recommendations that we expect to be making in closing  
5 submissions.

6                   For its part, for the record, Centra has  
7 stated that its decision not to cross-examine is not to  
8 be taken as a sign of the company's concurrence with Mr.  
9 Stauff's position, and that's acknowledged.

10                   From my vantage point, I would submit that  
11 the facts in issue will be made apparent during cross-  
12 examination of the Centra panel, and at the end of the  
13 day it may be that the debate turns on policy and opinion  
14 rather than findings of fact.

15                   The primary focus of my clients'  
16 intervention, thus, is to ensure that the new gas supply  
17 arrangements are prudent and appropriate, and that the  
18 methodology for securing reliable gas at Alberta market  
19 prices is the most optimal methodology at this point in  
20 time, and going forward.

21                   The problem with assessing the  
22 appropriateness of the new gas supply arrangements,  
23 however, is that Centra has refused to make the contract,  
24 or the details of the contract available to these  
25 Intervenors. Centra has, we understand, filed a copy of

1 the contract with the Board in confidence.

2                   And so that means, I suppose, that  
3 everyone in this room, save and except for those on this  
4 side of the hearing room that I'm sitting -- seated at,  
5 have seen the contract and its pricing mechanisms. And I  
6 just want to note that -- for the record, that that puts  
7 CAC/MSOS at a serious disadvantage in terms of the  
8 effectiveness of -- of its intervention, and -- and may  
9 result in some awkward moments through the course of the  
10 proceeding.

11                   CAC/MSOS has not made a motion to compel  
12 production of the contract, at least not yet. And we  
13 intend to test the Centra panel -- panel as to the  
14 reasons for the non-disclosure, and then afterwards,  
15 consider our position.

16                   We presume that the Board hasn't decided  
17 the issue, and that the matter is, therefore, very much  
18 alive in this proceeding. Procedurally we're of the view  
19 that Centra should have made a motion with evidence in  
20 support to seal this file, or to make this process --  
21 this proceeding go in-camera with respect to the review  
22 of the contract, rather than -- than doing what it's done  
23 here, which is just simply make a unilateral decision on  
24 its own without first consulting with stakeholders about  
25 the impact of -- of this -- of this very important

1 decision to withhold the production of the details of the  
2 contract.

3                   This Board is imbued with all of the  
4 powers of the Court of Queen's Bench with respect to  
5 matters, including the production of documents that are  
6 necessary for the Board to have in order to fulfill its  
7 purpose and mandate under the Public Utilities Board Act.

8                   A confidentiality agreement, if there is  
9 such an agreement in place here, and -- and I haven't  
10 seen any information on the record that says that there  
11 is, does not supercede the jurisdiction of the Board.

12                   So the Board is free at any point in the  
13 Hearing that it feels appropriate, or after perhaps one  
14 of the Intervenors makes a motion, to consider the matter  
15 and to rule on it. And so we'll have to see how that  
16 issue plays itself out during the course of the Hearing.

17                   Those are my introductory remarks, subject  
18 to any questions that you may have, Mr. Chairman.

19                   THE CHAIRPERSON: Thank you, Mr. Saxberg.  
20                   Ms. Ruzycki for Just Energy.

21

22 OPENING COMMENTS BY JUST ENERGY:

23                   MS. NOLA RUZYCKI: Good morning, Mr.  
24 Chair, Board members, others. I am here representing  
25 Just Energy (Manitoba) L.P., and I will be in attendance

1 today -- most of today and most of tomorrow. I don't  
2 anticipate to have a large number of questions. They'll  
3 mainly be focused on the new ConocoPhillips' contract and  
4 the fixed-price offering. And that's all I have.

5 THE CHAIRPERSON: Thank you.

6 Now, Ms. Murphy, your turn for opening  
7 comments and introductions before we ask the Centra  
8 witness panel be sworn. After the witness panel is  
9 sworn, we can proceed with Centra's direct evidence.

10

11 OPENING COMMENTS BY CENTRA GAS MANITOBA:

12 MS. MARLA MURPHY: Thank you, Mr.  
13 Chairman. Good morning, Mr. Chairman and members of the  
14 Board, Board advisors, ladies and gentlemen.

15 For the record, my name is Marla Murphy,  
16 and I appear on behalf of Centra Gas Manitoba this  
17 morning. With me is Mr. Vince Warden, who's the senior  
18 vice president, finance and administration, and chief  
19 financial officer for Centra; Mr. Howard Stephens, who's  
20 the division manager of gas supply; Mr. Neil Kostick,  
21 manager, gas supply, transportation and storage; Mr.  
22 Brent Sanderson, manager, gas market analysis and  
23 administration; and Mr. Greg Barnlund, who's the manager  
24 of regulatory services.

25 We're also assisted by the able people

1 behind us: Lori Stewart, Terrill Sigurdson, Terri  
2 Bercier, and Cory Radic (phonetic). Thank you -- sorry,  
3 Cory Rach, I'm sorry.

4 Just by way of a housekeeping matter, I  
5 should note that I believe there's one more exhibit to be  
6 marked on the Centra exhibit list this morning.

7 We circulated electronically a letter of  
8 April 13th which included six (6) different items to be  
9 updated: PUB/Centra 34(b); PUB/Centra 45(b) with a  
10 revised attachment; PUB/Centra 63, revised; PUB/Centra 67  
11 and 68; and the rate schedules and bill impacts for May  
12 1st. We have copies that have been circulated this  
13 morning, and additional copies available for anyone who  
14 doesn't have it in the room.

15 I'd suggest that that be marked as Centra  
16 Exhibit Number 10, if that's acceptable.

17 THE CHAIRPERSON: That's fine, and we  
18 have it.

19

20 --- EXHIBIT NO. CENTRA-10: Updated items: PUB/Centra  
21 34(b); PUB/Centra 45(b) with a revised  
22 attachment; PUB/Centra 63, revised;  
23 PUB/Centra 67 and 68; and the rate  
24 schedules and bill impacts for May 1st.

25

1 MS. MARLA MURPHY: I don't intend to make  
2 any formal comments this morning, so if the panel could  
3 be sworn, we could begin with direct.

4 THE CHAIRPERSON: Thank you.

5 Mr. Singh, please.

6

7 CENTRA COST OF GAS PANEL:

8

9 VINCE WARDEN, Sworn

10 HOWARD STEPHENS, Sworn

11 NEIL KOSTICK, Sworn

12 BRENT SANDERSON, Sworn

13 GREG BARNLUND, Sworn

14

15 THE CHAIRPERSON: Thank you, Mr. Singh.

16 MS. MARLA MURPHY: I should just indicate  
17 also, Mr. Chairman, that the witness CVs were filed this  
18 morning and they're Exhibits 1 -- Centra 9-1 through 9-5  
19 for this particular panel.

20 I'll begin with Mr. Warden.

21

22 EXAMINATION-IN-CHIEF BY MS. MARLA MURPHY:

23 MS. MARLA MURPHY: Mr. Warden, are you  
24 familiar with the application and the evidence filed on  
25 behalf of Centra Gas and marked as Centra Exhibit 1 in

1 this proceeding?

2 MR. VINCE WARDEN: Yes, I am.

3 MS. MARLA MURPHY: And was that evidence  
4 prepared under your direction and control?

5 MR. VINCE WARDEN: Yes, it was.

6 MS. MARLA MURPHY: Is the evidence filed  
7 as Centra Exhibit 1 true, to the best of your information  
8 and belief?

9 MR. VINCE WARDEN: Yes.

10 MS. MARLA MURPHY: And do you adopt that  
11 evidence on behalf of Centra Gas?

12 MR. VINCE WARDEN: Yes.

13 MS. MARLA MURPHY: Mr. Warden, could you  
14 please outline your areas of responsibility with respect  
15 to this panel?

16 MR. VINCE WARDEN: Yes. I will be  
17 discussing policy issues with respect to gas supply  
18 matters.

19 MS. MARLA MURPHY: And could you please  
20 outline for the Board what Centra's seeking with this  
21 application?

22 MR. VINCE WARDEN: Yes, Centra's  
23 application is described more fully at tab 2 of its  
24 application. However, in summary, Centra is seeking the  
25 following:

1                   Number 1. Approval of supplemental gas  
2 transportation to Centra and distribution to customers,  
3 sales and transportation rates effective May the 1st,  
4 2010.

5                   Number 2. Approval of November the 1st,  
6 2009 to October 31st, 2010, forecast gas costs estimated  
7 as of November the 2nd, 2009, to be approximately \$300.6  
8 million, including non-primary gas costs of 69.1 million.

9                   Number 3. Final approval of the balances  
10 and dispositions of non-primary gas PGVA and gas cost  
11 deferral account balances accumulated to October 31st,  
12 2009, with carrying costs to April the 30th, 2010, of  
13 approximately 2.8 million.

14                   And the final approval -- Number 4. Final  
15 approval of gas costs from November the 1st, 2008, to  
16 October 31st, 2009, of 437.0 million.

17                   Centra is also seeking final approval of  
18 various interim Orders issued by the PUB, including Order  
19 170/09 relating to Centra's hedging of primary gas  
20 purchases.

21                   And, Mr. Chairman, as you requested in our  
22 opening remarks, we will put together a summary of the  
23 customer rate impacts of all the rates -- all the changes  
24 to be implemented effective April -- I'm sorry, May the  
25 1st, 2010.

1 MS. MARLA MURPHY: Mr. Warden, do you  
2 have any comments on PUB Order 170/09, which directed  
3 Centra to phase out hedging by August of 2011?

4 MR. VINCE WARDEN: Yes, I do. This has  
5 been a very difficult issue, obviously, we are all very  
6 concerned about the significant increase to gas costs  
7 that have occurred during a downward trend in gas prices.  
8 However, Centra does need some method of addressing  
9 extreme volatility in natural gas prices.

10 I can assure you that if we were faced  
11 with a 20 percent rate increase in February of a cold  
12 winter in the absence of hedging, we would need some  
13 other method to smooth the rate impact. Hedging has been  
14 very effective in constraining volatility in gas prices.

15 While Centra has chosen not to apply to  
16 review and vary Order 170/09, we do question whether the  
17 total elimination of hedging is the best course of  
18 action.

19 We will be reviewing this matter over the  
20 next several months and we expect to apply to the Board  
21 for some alternative rate-smoothing methodology at the  
22 appropriate time.

23 As a matter of interest to the Board, I  
24 did conduct a quick survey of my counterparts in other  
25 Utilities in Canada, and I have found that - and I'll

1 just go across Canada very quickly - the Utilities that  
2 I've talked to.

3 In BC, hedging is in place for 60 to 75  
4 percent of the volumes.

5 In Alberta there is no hedging; 0 percent  
6 in Alberta.

7 In Saskatchewan, 75 percent of volumes.

8 In Quebec up to 75 percent of volumes.

9 In Ontario, the hedging program was  
10 discontinued by the OEB in the summer of 2007, due to  
11 similar circumstances that we've seen here, and that was  
12 due to losses that were occurring in a declining price  
13 environment.

14 MS. MARLA MURPHY: Mr. Warden, could you  
15 please provide the Board with a brief update on recent  
16 TCPL matters and the impact of those proceedings on  
17 Centra.

18 MR. VINCE WARDEN: Yes, in response to a  
19 substantial drop in throughput on the TransCanada main  
20 line, TransCanada implemented a significant increase to  
21 its transportation tolls.

22 While TransCanada justified the need to  
23 recover its fixed costs over declining volumes, the toll  
24 increase resulted in a very negative reaction from local  
25 -- local distribution companies, including Centra Gas

1 Manitoba.

2 TransCanada responded to its customers'  
3 demands by discussing various concepts at the Tolls Task  
4 Force of which Centra is an active member. While these  
5 matters are still under discussion, Centra is encouraged  
6 by the willingness of TransCanada to recognize and  
7 address this serious issue. Essentially, TransCanada is  
8 attempting to improve the competitiveness of the main  
9 line by lowering tolls and increasing throughput.

10 TransCanada is proposing to discuss a new  
11 business model with its stakeholders throughout the  
12 summer and present a comprehensive package by the end of  
13 September 2010.

14 MS. MARLA MURPHY: Mr. Warden, are there  
15 any other matters that you'd like to update the Board on?

16 MR. VINCE WARDEN: Yes, I thought it might  
17 be helpful to provide the Board with a brief update on  
18 the financial position of Centra at this time. You may  
19 recall that Centra ended the fiscal year March 2009 with  
20 a net income of \$9 million, which was \$6 million higher  
21 than the \$3 million forecast for that year.

22 The higher than forecast net income was  
23 largely due to the colder than normal weather experienced  
24 from December of 2008 to March of 2009. This fiscal  
25 year, 2009/'10, we seen a complete reversal of the

1 financial -- the positive financial results of 2008/'09.

2 In fact, warmer-than-normal weather,  
3 combined with the impacts of the economic downturn will  
4 likely result in a net loss for Centra for the 2009/'10  
5 fiscal year. While results are still very preliminary,  
6 we won't be publishing our results for another couple of  
7 months, the forecasted net income will not be achieved  
8 and a net loss will likely be incurred.

9 On a much more positive note, I am pleased  
10 to inform you that Centra was recently recognized by the  
11 Canadian Gas Association for having the best annual  
12 safety record among natural gas utilities in Canada.  
13 This is the second time in three (3) years that Centra  
14 has been -- has received this award, and it recognizes  
15 the high priority that Centra and its employees place on  
16 safe-work practices.

17 Thank you. That concludes my opening  
18 comments.

19 MS. MARLA MURPHY: Thank you, Mr. Warden.

20 Mr. Barnlund, we'll go to the far end and  
21 ask you to outline your responsibilities with respect to  
22 this Hearing.

23 MR. GREG BARNLUND: Good morning, Mr.  
24 Chairman, members of the Public Utilities Board, ladies  
25 and gentlemen. I will be appearing on both witness

1 panels for this application and will testify to the  
2 approvals being sought by the Corporation in this  
3 application, matters arising from Centra's 2009/'10 and  
4 2010/'11 General Rate Application, the confirmation of  
5 interim orders, and the regulatory treatment of the new  
6 gas supply contract.

7 MS. MARLA MURPHY: Mr. Barnlund, can you  
8 just review for the record the approvals that were  
9 received by Centra since it last appeared before this  
10 Board in the spring of 2009?

11 MR. GREG BARNLUND: Certainly. Centra  
12 appeared before this Board ten (10) months ago, in June  
13 2009, in a public hearing for its 2009/'10 and 2010/'11  
14 General Rate Application.

15 Flowing from that application, the Board  
16 issued order 116 of 09 on July 27th, 2009 which approved  
17 both primary gas and non-primary gas rates on an interim  
18 basis effective August 1, 2009. Centra is now seeking  
19 final approval and confirmation of those matters in this  
20 application.

21 On September 16th, 2009 this Board issued  
22 a second order in respect to that General Rate  
23 Application. In order 128/09, the Board directed certain  
24 adjustments to Centra's revenue requirement, including  
25 adjustments to finance expense, inclusion of \$3.8 million

1 in each test year for continuation of funding for the  
2 furnace replacement program and adjustments to the  
3 amortization of DSM investments.

4 The Board further directed certain changes  
5 to the level of basic monthly charge and the  
6 implementation of non-gas rates on May 1, 2010, which Ms.  
7 Derkson will testify to when the second panel is called  
8 later in this Hearing.

9 Centra filed revised revenue requirement,  
10 rate base, and cost of service schedules reflective of  
11 the directed changes on February 19th, 2010, and those  
12 schedules underpin Centra's current application insofar  
13 as non-gas cost recoveries are concerned.

14 MS. MARLA MURPHY: Mr. Barnlund, are  
15 there other interim Orders that Centra would like  
16 confirmed at this time?

17 MR. GREG BARNLUND: Yes. On October  
18 29th, 2009 the PUB issued Order 147 of 09, and on January  
19 13th, 2010 the PUB issued Order 4 of 10, both of which  
20 approved on an interim basis primary gas rates for  
21 November 1, 2009 and February 1, 2010 respectively.

22 Centra is seeking those Orders and the  
23 rates from those Orders to be confirmed as final in this  
24 proceeding.

25 MS. MARLA MURPHY: Mr. Warden made

1 mention this morning of order 170/09. Can you provide  
2 some additional information regarding the application  
3 that gave rise to that Order?

4 MR. GREG BARNLUND: Yes. On October 9th,  
5 2009 Centra sought approval of a revised derivatives  
6 hedging policy and derivatives hedging operation  
7 principles and procedures from this Board.

8 Through a written process, the Board  
9 sought comments from interested parties, and also sought  
10 Centra's reply to those comments. Those documents were  
11 filed in this proceeding in response to information  
12 request PUB Centra 22-A.

13 The PUB weighed the evidence provided in  
14 those submissions and issued interim Order 170 of 09 on  
15 December 21st, 2009. That Order was issued on an interim  
16 basis to be confirmed, varied, or otherwise dealt with  
17 through this public Hearing process.

18 Centra has filed no new evidence in this  
19 proceeding seeking any variance to that Order.

20 MS. MARLA MURPHY: Mr. Barnlund, can you  
21 please speak briefly to the regulatory approvals that  
22 Centra seeks in regards to the new gas commodity supply  
23 contract?

24 MR. GREG BARNLUND: Certainly. As  
25 discussed at the 2009 Hearing for the General Rate

1 application, Centra had entered into an RFP process to  
2 obtain competitive proposals for the provision of its  
3 primary gas supply requirements.

4 This process concluded in 2009 with Centra  
5 entering into an agreement with ConocoPhillips Canada  
6 Marketing and Trading ULC. In this proceeding, Mr.  
7 Kostick will provide testimony on those matters.

8 On October 16th, 2009, Centra filed  
9 information on the public record as to the selection  
10 matrix and the redacted results of the evaluation of the  
11 competing primary gas supply proposals.

12 Under separate confidential filing, Centra  
13 provided the PUB with details of the contract that was  
14 negotiated entered in -- and entered into between the two  
15 (2) parties. Centra has requested this contract --  
16 contractual detail be treated on a confidential basis.

17 The justification for Centra's request for  
18 confidentiality has been given in response to Information  
19 Requests PUB/Centra 64-B, and in the responses to CAC-  
20 MSOS/Centra 1-A and 2-A.

21 Centra is not seeking PUB approval of the  
22 contract itself, rather, it seeks approval of the gas  
23 cost consequences that arise from these arrangements.  
24 This approach is consistent with past regulatory practice  
25 in this jurisdiction.

1 MS. MARLA MURPHY: Thank you, Mr.  
2 Barnlund.

3 Mr. Kostick, could you please outline your  
4 areas of responsibility with respect to this application?

5 MR. NEIL KOSTICK: Yes. Good morning,  
6 Mr. Chairman, members of the Board, ladies and gentlemen.  
7 In my testimony, I will be providing evidence with  
8 respect to Centra's gas supply contract, the RFP process,  
9 storage and transportation operations, and the Capacity  
10 Management Program and its results.

11 MS. MARLA MURPHY: Mr. Kostick, can you  
12 please describe the recent developments with respect to  
13 Centra's gas supply st -- transportation and storage  
14 arrangements?

15 MR. NEIL KOSTICK: Yes. Through a  
16 comprehensive RFP process that concluded in 2009, Centra  
17 entered into a new three (3) year supply contract for  
18 primary gas, which took effect November 1st, 2009.

19 The new contract provides for reliable  
20 firm supply, with embedded optionality to adjust required  
21 volumes on a day-to-day and intra-day basis in order to  
22 respond to weather-driven load variability.

23 Centra's new supplier is ConocoPhillips  
24 Canada Marketing and Trading. This contract replaced the  
25 two (2) year contract with another supplier, that expired

1 on October 31st, 2009. Centra is currently engaged in a  
2 review of transportation and storage alternatives,  
3 including their impact on go -- gas commodity  
4 acquisition, in advance of the expiry of its US  
5 transportation and storage contracts in 2013. This  
6 process, which will include stakeholder consultation is  
7 expected to extend into 2011.

8 MS. MARLA MURPHY: Mr. Kostick, can you  
9 please summarize the Request For Proposal process that  
10 Centra undertook in connection with the new gas supply  
11 contract?

12 MR. NEIL KOSTICK: Certainly. Centra  
13 issued an RFP to fifty (50) counter-parties, and this RFP  
14 was developed with the assistance of ICF International.  
15 Six (6) proposals were received and evaluating -- and  
16 evaluated according to the matrix included as the  
17 attachment to PUB- 16-A.

18 The matrix was designed to evaluate the  
19 potential suppliers and their proposals over a range of  
20 criteria in order to identify the best combination of  
21 supplier and proposal attributes available on the market  
22 for the specific service that Centra requires.

23 MS. MARLA MURPHY: Mr. Kostick, could you  
24 please detail the amounts included in this application  
25 arising from Centra's Capacity Management Program?

1                   MR. NEIL KOSTICK:    For the 2008/'09 gas  
2 year, actual capacity management revenues, excluding  
3 carrying costs, totalled \$5.2 million as shown on  
4 schedule 4.3.1. The particulars of the types of  
5 transactions, and the revenues generated from each are  
6 also detailed on this schedule.

7                   For the 2009/'10 gas year, incorporated in  
8 this application, Centra has forecast capacity management  
9 revenues at \$6.96 million, excluding carrying costs,  
10 based on the five (5) year rolling average of Centra's  
11 actual capacity management results. These forecast  
12 amounts have been included on schedule 5.1.3(a), line 50.

13                   MS. MARLA MURPHY:    Thank you, Mr.  
14 Kostick.

15                   Mr. Sanderson, would you please outline  
16 your areas of responsibility with respect to this panel?

17                   MR. BRENT SANDERSON:    Good morning, Mr.  
18 Chairman, members of the Public Utilities Board, ladies  
19 and gentlemen. In my testimony I will be providing  
20 evidence related to Centra Gas costs for -- Centra's gas  
21 costs for the period of November 1st, 2008, through  
22 October 31st, 2009, as well as the related PGVA and other  
23 gas cost deferral balances, and derivatives hedging  
24 results for the period from November 1st, 2008 to October  
25 31st, 2009.

1 I will also be providing evidence with  
2 respect to Centra's gas cost forecast for the 2009/'10  
3 gas year.

4 MS. MARLA MURPHY: With respect to the  
5 request for final approval of gas costs for the period  
6 November 1st, 2008 to October 31st, 2009, could you  
7 please provide the Board with the actual gas costs for  
8 which Centra is seeking approval?

9 MR. BRENT SANDERSON: Yes. Centra's  
10 request for final approval of gas costs for the period  
11 November 1st, 2008 through October 31st, 2009 is detailed  
12 in schedule 4.0.0, which identifies that final gas cost  
13 for that period were in the amount of \$437 million.

14 MS. MARLA MURPHY: Mr. Sanderson, would  
15 you please outline the PGVA and other gas cost deferral  
16 balances for which Centra's seeking approval?

17 MR. BRENT SANDERSON: Centra's requesting  
18 final approval of all non-primary gas PGVA and gas cost  
19 deferral balances for the period of November 1st, 2008 to  
20 October 31st, 2009 in the amount of \$10.4 million.

21 With amortization of prior period gas cost  
22 deferrals and carrying costs to April 31st, 2009, the  
23 total amount owing to Centra is approximately \$2.8  
24 million.

25 MS. MARLA MURPHY: Finally, Mr.

1 Sanderson, would you please outline the 2008/'09 gas year  
2 costs for which Centra's seeking approval?

3 MR. BRENT SANDERSON: Centra's forecast  
4 gas costs for the 2009/'10 gas year included a forward  
5 price strip as of November 2nd, 2009. The resulting gas  
6 cost forecast for the 2009/'10 gas year is \$300.6  
7 million, detailed in schedule 5.1.3(a).

8 This includes a forecast addition to gas  
9 costs of \$19.8 million as a result of Centra's derivative  
10 hedging activities for the 2009/'10 gas year on a  
11 forecast basis. Of the 300 and point -- \$300.6 million  
12 gas cost forecast for '09/'10, approximately \$69.1  
13 million is non-primary gas costs.

14 This amount represents an increase of  
15 approximately \$12.1 million compared to the non-primary  
16 gas costs imbedded in existing base rates, as shown on  
17 schedule 5.1.4.

18 MS. MARLA MURPHY: Thank you, Mr.  
19 Sanderson.

20 Mr. Chairman, that concludes our direct  
21 evidence this morning, and the panel is available for  
22 cross-examination.

23 THE CHAIRPERSON: Thank you, Ms. Murphy.  
24 Mr. Peters...?

25 MR. BOB PETERS: Yes, thank you.

1

2 CROSS-EXAMINATION BY MR. BOB PETERS:

3 MR. BOB PETERS: Good morning, panel.  
4 Mr. Warden, as the vice-president on this panel and just  
5 so we don't have a fight amongst vice-presidents on the  
6 next panel, I'll turn to you to direct any questions if -  
7 - they're open to all, but if you have someone you want  
8 to answer, you of course will let the Board know.

9 The Board is interested in the best  
10 corporate evidence of Centra Gas Manitoba Inc. Is that  
11 acceptable, sir?

12 MR. VINCE WARDEN: Just to be clear, we -  
13 - we never have a fight amongst vice-presidents.

14 MR. BOB PETERS: We'll wait to see and  
15 we'll congratulate Mr. Kuczek later.

16 Let's start with the last time you were  
17 before the Board, and it was mentioned in the direct  
18 evidence that there was a GRA filing ten (10) months ago,  
19 correct?

20 MR. VINCE WARDEN: Yes.

21 MR. BOB PETERS: And at that Hearing  
22 there was approval of non-primary gas rates, as well as  
23 primary gas rates, and non-gas cost rates as well.

24 MR. VINCE WARDEN: Correct.

25 MR. BOB PETERS: And in the -- at the

1 time you were last before the Board the annual gas costs  
2 for the '07/'08 year, and that would have been the fiscal  
3 year of the company, were approved at approximately \$400  
4 million.

5 MR. VINCE WARDEN: I'll accept that, Mr.  
6 Peters, subject to check, but I think that's right.

7 MR. BOB PETERS: All right. And then  
8 there was also the 2008 stub period cost of gas that was  
9 approved for the period of April 1 to October 31 of 2008.

10

11 Do you recall that as well?

12 MR. VINCE WARDEN: Yes, I recall that.

13 MR. BOB PETERS: And you'll take it,  
14 subject to check, that that was approximately \$123.7  
15 million.

16 MR. VINCE WARDEN: I'll accept that, yes.

17 MR. BOB PETERS: And at that same time,  
18 when you were before the Board ten (10) months ago, you  
19 gave a forecast as to what the 2008/2009 gas year gas  
20 cost would be, and that would have been at \$395 million,  
21 correct?

22 MR. VINCE WARDEN: Yes.

23 MR. BOB PETERS: And one (1) of the  
24 differences is that you migrated from your fiscal year to  
25 a gas year, correct?

1 MR. VINCE WARDEN: Correct.

2 MR. BOB PETERS: And the gas year  
3 commences on November 1st and ends on October 31, which  
4 doesn't line up with your fiscal year anymore.

5 MR. VINCE WARDEN: That's right.

6 MR. BOB PETERS: Can you tell the Board  
7 in general terms, having done that, has there been any  
8 benefit to consumers from migrating to the gas year as  
9 opposed to the fiscal year?

10 MR. BRENT SANDERSON: As we gave in  
11 evidence at the last General Rate Application hearing,  
12 the expectation was based on an historical analysis that  
13 moving to the management of the gas cost deferral  
14 accounts to the gas year period versus the corporate  
15 fiscal year period, would have historically reduced the  
16 magnitude of year-over-year residuals of the non-primary  
17 gas PGVA accounts by approximately 80 percent  
18 historically, relative to what the corporation brought  
19 forward for disposition each year since the unbundling of  
20 rates and PGVA accounts.

21 And the effect since we've moved to the  
22 gas year is that that anticipated benefit has been  
23 realized and the balance that we're bringing forward for  
24 disposition in this proceeding is much smaller than what  
25 would have historically been the norm.

1                   MR. BOB PETERS:    Is it as a result of the  
2 aggressive rate rider that -- that's still in place  
3 today, Mr. Sanderson, that's bringing down that PGVA  
4 balance for non-primary gas or is it the change in the  
5 gas year?

6                   MR. BRENT SANDERSON:    It's directly as a  
7 result of moving to managing the Purchase Gas Variance  
8 Accounts over the industry year period over which we  
9 balance our company's purchases and sales on behalf of  
10 customers.  Previously, a lot of the year-over-year  
11 variation in these cum -- cumulative PGVA account  
12 balances were as a result of the mismatch between the  
13 annual period over which we balance purchases and sales  
14 and over which we were managing those accounts.  So it's  
15 a direct result of the move to the gas year period.

16                   MR. BOB PETERS:    All right.  And also, as  
17 was noted by the panel, the Board issued a second GRA  
18 Order 128 of '09; that contained various recommendations,  
19 as well as directives on the revenue requirement issues  
20 that you spoke about; correct?

21                   MR. GREG BARNLUND:    Yes.

22                   MR. BOB PETERS:    And the application that  
23 you put before the Board, that Mr. Warden reviewed, when  
24 you're asking this Board for new rates on May 1st, for  
25 supplemental gas, transportation to Centra and

1 distribution to customers, those we'll collectively the  
2 "non-primary gas costs."

3 Would that be fair?

4 MR. GREG BARNLUND: I'm sorry, Mr.  
5 Peters, could you repeat that?

6 MR. BOB PETERS: That was my easiest  
7 question. The -- what you're asking for in terms of May  
8 1 approvals related to the new rates for supplemental  
9 gas, transportation to Centra and distribution to  
10 customers, those baskets we're all going to lump in as  
11 the non-primary gas costs, correct?

12 MR. GREG BARNLUND: Yes.

13 MR. BOB PETERS: And just so we're clear,  
14 the supplemental gas represents the gas not procured  
15 necessarily from the Western Canadian Sedimentary Basin  
16 but it provides gas to meet the load throughout the  
17 colder portion of our season?

18 MR. GREG BARNLUND: I believe you could  
19 characterize it as that, yes.

20 MR. BOB PETERS: And then the  
21 transportation to Centra represents the transportation  
22 tolls and charges that the Utility has to pay, and those  
23 transportation tolls are either by way of contract or by  
24 a federal regulator?

25 MR. GREG BARNLUND: That's correct.

1                   MR. BOB PETERS: And then the distribution  
2 to customers' portion of the non-primary gas costs,  
3 that's just a small portion related to unaccounted-for  
4 gas and I believe also the Minell pipeline charges?

5                   MR. GREG BARNLUND: Yes, that's correct.

6                   MR. BOB PETERS: Mr. Warden mentioned  
7 that the November 1, 2009 to October 31 of 2010 forecast  
8 gas costs are forecast at \$300.6 million, correct?

9                   MR. GREG BARNLUND: Yes.

10                  MR. BOB PETERS: And of that \$300 million  
11 there was approximately \$69 million that was related to  
12 non-primary gas costs?

13                  MR. GREG BARNLUND: That's correct.

14                  MR. BOB PETERS: All right. We'll come  
15 to a review of that in a few minutes.

16                  What that's telling the Board is that  
17 based on Centra's forecast, there would be \$231 million  
18 of primary gas cost needed in the current gas year?

19                  MR. GREG BARNLUND: Based on the forecast  
20 of November 2nd, yes.

21                  MR. BOB PETERS: Just while I have that  
22 thought, is there an advantage to Centra, to consumers,  
23 if Centra comes before the Board with a more current  
24 forecast than the November 2nd, 2009 forecast that is  
25 before them now?

1                   MR. GREG BARNLUND:    With respect to the  
2 primary gas portion of our annual forecast gas costs that  
3 you referred to, the quarterly rate adjustment mechanism,  
4 that's implicit in that mechanism.  And I think, as you  
5 well know, there's a more up-to-date forecast before the  
6 Board right now, and for consideration with respect to  
7 May 1st rates for our primary gas costs.

8                   With respect to the -- what you  
9 characterized as the non-primary gas costs, we've looked  
10 at the numbers at this point, and with the more -- the  
11 most up-to-date figures that we have, the forecast  
12 residual as at October 31st, at this point in time, is  
13 still expected to be less than 1 percent of our annual  
14 purchase gas cost forecast.

15                   So given the -- the extent of work that  
16 would be required to fully update the application for a  
17 more current strip for the non-primary gas costs, I -- in  
18 my opinion, I don't believe that the effort will be  
19 warranted at this point.

20                   MR. BOB PETERS:    Just so the Board's  
21 aware of, when you say "effort," can you put that into  
22 person hours, or person days, or weeks?

23                   MR. BRENT SANDERSON:    You're really  
24 putting me on the spot here, Mr. Peters.  It -- it feeds  
25 through every element of the application.  Rates would

1 have to be re-designed and re-struck. The analytical  
2 group would have to re-cast all of the forecasts and so  
3 forth. And it would be significant. I really wouldn't  
4 be in a position to be able to give you an hour figure,  
5 but it would be significant.

6 Also, keeping in mind that we still have a  
7 significant portion of the gas year ahead of us, and any  
8 variance that we might pick up, however small in -- that  
9 might affect the rates at this point could be offset by  
10 future changes over the remainder of the gas year if  
11 conditions aren't normal.

12 MR. BOB PETERS: And I suppose the other  
13 point is that what you -- what you get wrong with the  
14 forecast from November 2nd, 2009 on non-primary gas  
15 costs, is going to end up in a deferral account?

16 MR. BRENT SANDERSON: That's correct, and  
17 we will apply carrying costs to whatever that balance is  
18 either owing to the customer, or to Centra, and it will  
19 be brought forward at a future dispos -- a future hearing  
20 for full disposition.

21 MR. BOB PETERS: The comment -- the  
22 second last comment you made, Mr. Sanderson, about  
23 there's a lot of the gas year left, but not a lot of  
24 volumes left?

25 MR. BRENT SANDERSON: We have actual

1 figures up to the end of February at this point. So  
2 there is -- the weather can turn. I think if we all  
3 think back to last year, we could -- we could get some  
4 unexpected cold for a significant period of time over the  
5 remaining few months. But on the whole, in the summer  
6 months, there is much less volume in the winter, but  
7 there is still the opportunity for a significant turn in  
8 the weather, which may result in increased loads.

9 MR. BOB PETERS: All right. Included in  
10 the application that Mr. Warden spoke about, and that we  
11 just talked about was final approval and disposition of  
12 non-primary gas, purchased gas variance accounts, as well  
13 as the gas cost deferral accounts that have accumulated  
14 to October 31 of '09?

15 MR. GREG BARNLUND: That's correct.

16 MR. BOB PETERS: And from October 31 of  
17 '09, those accounts are collecting or accruing carrying  
18 costs at Centra's short-term borrowing rate?

19 MR. GREG BARNLUND: That's correct.

20 MR. BOB PETERS: And the forecast to  
21 April 30th of this year is that the net amount of those  
22 deferral accounts, those PGVAs, is \$2.8 million?

23 MR. GREG BARNLUND: On a forecast basis,  
24 yes.

25 MR. BOB PETERS: And it can only be that,

1 because you just told us you only have accurate until the  
2 end of March?

3 MR. GREG BARNLUND: Yes, that's correct.

4 MR. BOB PETERS: Also being sought from  
5 the Board, in item D of the application, and that would  
6 be found at tab 1 of the book of documents, is the  
7 approval of the actual gas costs from November 1, '08 to  
8 October 31, '08 of \$437 million, correct?

9 MR. GREG BARNLUND: Yes, that's correct.

10 MR. BOB PETERS: And that \$437 million  
11 represents primary gas, as well as non-primary gas costs,  
12 correct?

13 MR. GREG BARNLUND: Yes.

14 MR. BOB PETERS: And just so the Board  
15 has a comparator, that \$437 million of last gas year's  
16 costs would be comparable to item B in your application  
17 at tab 1 of the book of documents and, that is, about  
18 \$300 million being forecast for the current gas year?

19 MR. GREG BARNLUND: Yes.

20 MR. BOB PETERS: When you were last  
21 before the Board, your forecast to the Board was that the  
22 gas costs from November 1, '08, to October 31, '09 were  
23 going to be \$395.9 million?

24 MR. GREG BARNLUND: Yes, I believe that's  
25 correct.

1 MR. BOB PETERS: And they've come in at  
2 \$437 million?

3 MR. GREG BARNLUND: Yes.

4 MR. BOB PETERS: Included in the  
5 application, an item number -- item -- or lettered "E" on  
6 the application at tab 1 of the book of documents -  
7 that's 1(e) - is the final approval of the supplemental  
8 transportation and distribution sales rates effective  
9 August 1st, '09 which were approved on an interim basis  
10 in Order 116/09.

11 MR. GREG BARNLUND: Yes, that's correct.

12 MR. BOB PETERS: And the differences  
13 between what was forecast and what has been actual will  
14 be in the PGVAs that we're going to talk about?

15 MR. GREG BARNLUND: Yes, sir.

16 MR. BOB PETERS: All right. Finally, the  
17 final approval of primary gas rates since August 1st,  
18 that includes the August 1st primary gas rate in Order  
19 116 of '09, the November primary gas rate in Order 147 of  
20 '09, and the February 1st primary gas rates in Order 4 of  
21 '10.

22 Have I got them all?

23 MR. GREG BARNLUND: Yes, sir.

24 MR. BOB PETERS: All right. And we'll  
25 come to -- to it as well. The Chairman, in his opening

1 comments, mentioned Order 170 of '09. Mr. Warden also  
2 commented on that in his direct evidence. I took from  
3 those answers to -- that Mr. Warden provided, Centra has  
4 Order 170 of '09, but they're not asking to review or  
5 vary it in any way in this proceeding.

6 MR. GREG BARNLUND: That's correct, sir.

7 MR. BOB PETERS: And we'll talk about  
8 what may come down the road a little bit later.

9 If we turn to the last time you were  
10 before the Board, all three (3) of your -- all three (3)  
11 rate structures, that is, for primary gas, for non-  
12 primary gas costs and for non-gas costs all changed, or  
13 were sought to change, as a result of a GRA last year.

14 MR. GREG BARNLUND: It's correct that we  
15 had applied for changes on all three (3), yes.

16 MR. BOB PETERS: And, in fact, on May the  
17 1st of this year, if Centra's applications are approved  
18 as filed, all three (3) of those will again change in --  
19 in a few weeks from today.

20 MR. GREG BARNLUND: Yes, sir.

21 MR. BOB PETERS: Let's talk about the  
22 non-primary gas costs and rates, just from a high level.  
23 Those non-primary gas costs and rates also related to the  
24 supplemental gas, transportation and distribution to  
25 customers at the GRA, and those were last changed in

1 Order 116 of '09.

2 MR. GREG BARNLUND: That's correct.

3 MR. BOB PETERS: In terms of non-gas  
4 costs, this is often thought about, at least in my mind,  
5 as the distribution cost, but not counting the UFG and  
6 the Minell portion.

7 MR. GREG BARNLUND: That's fair, yes.

8 MR. BOB PETERS: And last time you were  
9 before the Board, you were not seeking a change to the  
10 non-gas costs on August the 1st of 2009, but rather  
11 Centra wanted to increase the distribution rates by 1  
12 percent on February 1st of 2010 to cover the first year's  
13 -- or the first test year's revenue requirement.

14 MR. GREG BARNLUND: Yes, sir.

15 MR. BOB PETERS: The second test year -  
16 that would have been 2010/2011 - Centra sought a May 1 of  
17 2010 increase for those non-gas costs, and you're still  
18 seeking that with the filing that was made on February  
19 19th.

20 MR. GREG BARNLUND: Yes, we are.

21 MR. BOB PETERS: Just while we're at it,  
22 Mr. Chairman, the February 19th filing by Centra has not  
23 been included in its entirety in the book of documents  
24 that I've put before the Board but, I think for the  
25 completeness of the record, I would ask the Board to mark

1 as Exhibit Number 11 Centra's February 19th filing, and  
2 that filing was in response in Board Order 128 of '09.

3 Is that correct?

4 MR. GREG BARNLUND: That's correct.

5 MR. BOB PETERS: All right. Mr.  
6 Chairman, if we could make note of that, we'll have the  
7 entire -- the entire February 19th filing as an exhibit,  
8 although, as I mentioned, I will have only extracts of it  
9 in the book of documents before you.

10 THE CHAIRPERSON: That's fine.

11

12 --- EXHIBIT NO. CENTRA-11: Centra's February 19th filing  
13 in response in Board Order 128/09

14

15 CONTINUED BY MR. BOB PETERS:

16 MR. BOB PETERS: Now in terms of the non-  
17 gas costs, I guess we've -- we've agreed that we can  
18 consider that the deprec -- or the distribution rates,  
19 but it would compi -- it would comprise such elements as  
20 the operating, maintenance, and administration costs,  
21 depreciation, amortization, as well as finance costs.

22 That's the type of costs we were talking  
23 about at the GRA?

24 MR. GREG BARNLUND: Yes, Sir, those are  
25 those costs.

1                   MR. BOB PETERS:    And there was no rate  
2 increase awarded for August 1st, the first test year for  
3 those na -- non-gas costs, is that correct?

4                   MR. GREG BARNLUND:    That's correct.

5                   MR. BOB PETERS:    And there was no rate  
6 increase at any time for those first test year non-gas  
7 costs, is that correct?

8                   MR. GREG BARNLUND:    That's correct.  We  
9 had not sought a rate.  That form of rate change for  
10 August 1, we had applied for that rate change to be  
11 effective February 1, but that was not ultimately  
12 approved.

13                   MR. BOB PETERS:    All right.  And then if  
14 we turn to the book of documents to tab 2, Mr. Chairman  
15 and Board members, I think if we turn to schedule 310,  
16 it's located in the middle although closer to the back of  
17 the filing at tab 2, you can confirm, Mr. Barnland that  
18 tab 2 is now extracts of Exhibit 11 that we just  
19 referenced.

20                   MR. GREG BARNLUND:    Yes, sir, it is.

21                   MR. BOB PETERS:    And you've located  
22 schedule 1 -- sorry, schedule 3.1.0?

23                   MR. GREG BARNLUND:    Yes, I have that.

24                   MR. BOB PETERS:    And if we look at the  
25 first test year in column 3 we can see there were some

1 changes, and these are the impacts of the changes as a  
2 result of the Board order, sir, is that right?

3 MR. GREG BARNLUND: That's correct.  
4 Those changes are reflective of the changes to revenue  
5 requirement that were directed in 128/'09.

6 MR. BOB PETERS: And what the Board will  
7 see as it goes down the net change column, number 3, is  
8 that depreciation and amortization changed by about \$3.5  
9 million, and that reduction in amortization expense was  
10 from moving from a five (5) year amortization period on  
11 DSM costs to ten (10) years, is that correct?

12 MR. GREG BARNLUND: Yes.

13 MR. BOB PETERS: And the parent company,  
14 or the affiliate company, Manitoba Hydro, on the electric  
15 side uses a ten (10) year amortization window as well?

16 MR. GREG BARNLUND: That's correct.

17 MR. BOB PETERS: There's also finance  
18 expense adjustment. There was a new forecast for finance  
19 expense, and it was \$1.1 million lower than what came in  
20 at the GRA, is that correct?

21 MR. GREG BARNLUND: I think there is also  
22 some further direction in terms of the short-term  
23 interest rate to be used in the calculation of the  
24 finance expense, and the net of -- net effect of those --  
25 of those impacts is reflected in column 3 there at line

1 17.

2 MR. BOB PETERS: All right, I was trying  
3 to be polite. There were interest rate adjustments in  
4 terms of what was asked of the company to use in its  
5 forecasts.

6 MR. GREG BARNLUND: That's correct.

7 MR. BOB PETERS: All right. And then we  
8 see there's a \$3.8 million addition to the revenue  
9 requirements, and that relates to the furnace replacement  
10 program being re-instated or continued on in recovery of  
11 rates, correct?

12 MR. GREG BARNLUND: That's correct. The  
13 Board directed that we sustain the funding for the  
14 furnace replacement program at \$3.8 million for each of  
15 the test years and to continue on doing so.

16 MR. BOB PETERS: And that \$3.8 million,  
17 Mr. Barnlund, is from the SGS class only.

18 MR. GREG BARNLUND: That's correct.

19

20 (BRIEF PAUSE)

21

22 MR. BOB PETERS: Before I leave the first  
23 test year, and looking at that depreciation and  
24 amortization reduction of \$3.5 million, you agreed with  
25 me that that came about as a result of the reduction in -

1 - sorry, by -- by moving from a five (5) year  
2 amortization period to a ten (10) period for demand side  
3 management, correct?

4 MR. GREG BARNLUND: Yes.

5 MR. BOB PETERS: And for the years  
6 2007/'08 and 2008/'09 Centra used a five (5) year  
7 amortization period?

8 MR. GREG BARNLUND: That's correct.

9 MR. BOB PETERS: Now, the balance for  
10 those two (2) years should now be amortized over eight  
11 (8) and nine (9) years respectively to fully amortize the  
12 balances over a total of ten (10) years; wouldn't that be  
13 correct?

14 MR. GREG BARNLUND: Well, I believe that  
15 there's a response in PUB/Centra-68 that is addressing  
16 the amortization of the DSM expense, the adjustments that  
17 were made. The question was asked, and we've filed that  
18 response this morning in the -- in the materials that  
19 we've submitted here this morning, I should say.

20 MR. BOB PETERS: All right. And, Mr.  
21 Chairman, duly noted, as -- as part of Centra Exhibit 10  
22 there was a response to PUB/Centra-68-A and -B filed, and  
23 Mr. Barnlund is drawing our attention to the -- the B  
24 portion of it.

25 Can you confirm, Mr. Barnlund, that the

1 rates were not adjusted to reflect the change in  
2 amortization?

3 MR. GREG BARNLUND: Could you be a little  
4 more specific? We changed amortization twice here, so.

5 MR. BOB PETERS: You -- you didn't change  
6 from the five (5) year amortization period.

7 MR. GREG BARNLUND: Let's try that again.

8 MR. VINCE WARDEN: Mr. Peters, perhaps I  
9 can respond to that. We -- we did change from the five  
10 (5) to the ten (10) year amortization period, as  
11 directed. We did that on a perspective basis and did not  
12 adjust the years 2007/'08 and '08/'09.

13

14 (BRIEF PAUSE)

15

16 MR. BOB PETERS: Mr. Warden, when you --  
17 when you give us that answer, what you're telling the  
18 Board is that even though you weren't applying for rate  
19 changes, you kept the five (5) year amortization in place  
20 for the 2007/'08 DSM expenditures for two (2) years, and  
21 then for the 2008/'09 DSM expenditures you used the five  
22 (5) year amortization for one (1) year?

23 MR. VINCE WARDEN: The five (5) year  
24 amortization was applied for the 2007/'08 and '08/'09  
25 fiscal year. So, there are two (2) fiscal years to which

1 the five (5) year amortization applied, so the ten (10)  
2 year amortiza -- ten (10) year amortization commenced in  
3 the fiscal year 2009/'10.

4 MR. BOB PETERS: So the accelerated  
5 amortization resulted in a cumulative revenue shortfall  
6 of approximately \$4.4 million?

7

8 (BRIEF PAUSE)

9

10 MR. VINCE WARDEN: The \$4.4 million is  
11 the amount referenced in response to part B of -- of  
12 PUB/Centra- 68.

13 MR. BOB PETERS: Well, can you -- can you  
14 confirm now, Mr. Warden, that the unamortized balances  
15 for 2008/'09 reflect the use of the higher amortization  
16 rate for the -- for the one (1) year?

17 MR. VINCE WARDEN: Yes, the -- the  
18 balance as -- as at March 31st of 2009 was amortized  
19 perspective over a ten (10) year period.

20 MR. BOB PETERS: Do you agree that if the  
21 amortization took into account that Centra accelerated  
22 the amortization in 2008/'09, the result would be  
23 approximately four hundred and ninety thousand dollars  
24 (\$490,000) less of amortization expense in each of those  
25 years?

1 MR. VINCE WARDEN: No. No. Had we  
2 amortized at the longer period of ten (10) years for  
3 '07/'08 and '08/'09, the amortization would have been  
4 less in the amount of -- a total of \$3.3 million for  
5 those two (2) years.

6

7 (BRIEF PAUSE)

8

9 MR. BOB PETERS: In any event, I'll come  
10 back to that I think, Mr. Warden, but the -- the net  
11 result on non-gas cost items was that there were no rate  
12 increases were approved, correct?

13 MR. VINCE WARDEN: Correct.

14 MR. BOB PETERS: And the net result was  
15 that the forecast net income would be reduced by about  
16 \$900,000, which was then going to bring it down from 2.9  
17 million to closer to \$2 million on a weather-normal  
18 basis?

19 MR. VINCE WARDEN: Yes.

20 MR. BOB PETERS: Mr. Warden, if I recall,  
21 Mr. Derksen from last year telling the Board that for the  
22 months of April and May it was colder than normal and the  
23 result was that there was \$2 million more of net income  
24 than on a weather-normal basis, he was accurate as of  
25 April and May of last year?

1 MR. VINCE WARDEN: Yes.

2 MR. BOB PETERS: And you told the Board  
3 then in your opening comments that that trend of colder  
4 than normal didn't hold for the balance of the year?

5 MR. VINCE WARDEN: That's correct. This  
6 past winter has been very -- much warmer than normal.

7 MR. BOB PETERS: And so that while after  
8 the Board Order there would have been an expectation of  
9 net income of approximately \$1.979 million, your evidence  
10 today, without giving numbers, is that there will be a  
11 negative number in front of net income, whatever that  
12 amount is?

13 MR. VINCE WARDEN: That's right.

14 MR. BOB PETERS: In terms of the order of  
15 magnitude, are you at liberty to provide an indication of  
16 the order of magnitude of the net loss for the -- for the  
17 last fiscal year?

18 MR. VINCE WARDEN: No. I might just  
19 mention that since this schedule was prepared, we had an  
20 updated financial forecast in the fall of 2009, so we  
21 were forecasting a net income of \$4 million for Centra  
22 for the fiscal year '09/'10. So the net loss is -- to  
23 incur a net loss is quite a significant variance from the  
24 forecast.

25 However, no, I -- I can't -- at this point

1 it's too preliminary to say just the order of magnitude  
2 of that -- of that loss.

3 MR. BOB PETERS: So just to be clear, the  
4 -- the net income will be a loss for the fiscal year?  
5 It's not just a loss relative to the \$4 million that was  
6 forecast in your latest IFF, but it will be a negative  
7 number in absolute terms?

8 MR. VINCE WARDEN: Yes, it will.

9 MR. BOB PETERS: And on a weather-  
10 normalized basis, are you able to indicate what that  
11 result would be?

12 MR. VINCE WARDEN: Well, that -- that  
13 would have been -- the weather normalized would have been  
14 the \$4 million that we had in the financial forecast in  
15 November of 2009. So that would have been the weather-  
16 normalized number.

17 MR. BOB PETERS: And on a weather-  
18 normalized number for -- for the year-end, though, is  
19 that a positive number?

20 MR. VINCE WARDEN: Well, that's -- that  
21 would have been the \$4 million that was in our financial  
22 forecast. That would have been weather normalized.  
23 However, as it turns out with the warmer-than-normal  
24 weather, that will be -- now turn into a -- a negative  
25 number.

1                   MR. BOB PETERS:    It's a negative number  
2 on an actual basis but not on a weather-normal basis?

3                   MR. VINCE WARDEN:    That's true.  Yes.

4                   MR. BOB PETERS:    All right.  So, on a  
5 weather-normal basis, while you say 4 million was your  
6 last forecast, you're not prepared to indicate whether on  
7 a weather-normal bas -- sorry, on a weather-normal basis  
8 whether that 4 million survives at March 31 of 2010?

9                   MR. VINCE WARDEN:    No, because there are  
10 a number of other factors that come into that \$4 million.  
11 So, no, I wouldn't be prepared to -- to say that is the  
12 precise weather-normalized number for -- for '09/'10.

13                   MR. BOB PETERS:    All right.  And I  
14 appreciate we're dancing around it a little bit, Mr.  
15 Warden, but is that \$4 million that was forecast on a  
16 weather-normal basis, that contains some actuals as well  
17 as some forecast; wouldn't that be correct?

18                   MR. VINCE WARDEN:    Yes, that -- that's  
19 true.  If it -- it would have obtain -- contained actuals  
20 up until approximately August the 1st of -- of last year.

21                   MR. BOB PETERS:    Okay.  In turning to  
22 non-gas costs for the second test year, that's the  
23 2010/'11 fiscal year of the Corporation.  Rates are  
24 sought effective May 1st of 2010, the panel has told me,  
25 correct?

1 MR. GREG BARNLUND: That's correct.

2 MR. BOB PETERS: And if we look at tab 2  
3 of the book of documents, and back to your February 19th  
4 filing at -- which was extracts from Exhibit 11,  
5 contained in the book of documents, Centra was seeking a  
6 1 percent increase in those distribution rates effective  
7 May 1st of 2010, correct?

8 MR. GREG BARNLUND: Originally, yes.

9

10 (BRIEF PAUSE)

11

12 MR. BOB PETERS: Just help me out.  
13 Originally, and as you sit here today, you're still  
14 seeking that -- that 1 percent increase?

15 MR. GREG BARNLUND: Well, we're seeking  
16 to implement the increases that were approved with the  
17 adjustments to net -- or to revenue requirement that are  
18 identified in Board Order 128 of '09.

19 MR. BOB PETERS: All right. The -- the  
20 increase was to provide \$5.9 million of additional  
21 revenue to the Corporation?

22 MR. GREG BARNLUND: Subject to check,  
23 yes.

24 MR. BOB PETERS: And we're looking here  
25 at column number 4 on schedule 310, Mr. Barnlund?

1 MR. GREG BARNLUND: Yes.

2 MR. BOB PETERS: And included in that 5.9  
3 or \$6 million of additional revenue was a net income of  
4 approximately \$3 million?

5 MR. GREG BARNLUND: That's correct.

6 MR. BOB PETERS: And in term of the  
7 Board's Order, we see in column number 6, the net change,  
8 that the finance expense was reduced by \$1.8 million to  
9 reflect different interest rates, and that was really the  
10 lower short-term debt and long-term debt -- debt rates?

11 MR. GREG BARNLUND: That's correct.

12 MR. BOB PETERS: And the revenue  
13 requirement was, again, increased by 3.8 million to  
14 restore the furnace replacement program as receiving  
15 dedicated funding from the SGS class?

16 MR. GREG BARNLUND: Yes, that's true.

17 MR. BOB PETERS: There was a \$4.9 million  
18 reduction, again, in amortization expense, and that  
19 related also to the DSM programs, going from five (5)  
20 years to ten (10) years?

21 MR. GREG BARNLUND: Yes, that's correct.

22 MR. BOB PETERS: And it's the same issue  
23 I was clumsy with in terms of talking to Mr. Warden, in  
24 terms of how the -- how the Utility calculated the  
25 unamortized balance of the DSM expenditures?

1 MR. GREG BARNLUND: Yes, it is the same.  
2 Yep.

3 MR. BOB PETERS: All right. And also we  
4 see in column number 6 in schedule 310, there was a \$5  
5 million reduction of an accounting provision for what I  
6 believe was IFRS and other risks facing Centra, correct?

7 MR. GREG BARNLUND: Yes, that's true.

8 MR. BOB PETERS: All right. So the net  
9 effect, as we see from that, is probably best seen -- if  
10 we turn to the last document in tab 2 of the book of  
11 documents, we have schedule 4.0.0. The result of what we  
12 went through in terms of the adjustments to revenue  
13 requirement is that Centra is now seeking non-gas rates  
14 for May 1st of 2010 to recover an additional \$3.4 million  
15 of revenues.

16 Would that be accurate?

17 MR. GREG BARNLUND: Yes, subject to  
18 check.

19 MR. BOB PETERS: Well -- and the Board's  
20 going to have trouble checking that because at line 31 --  
21 I'm sorry, at line 29, the non-gas cost of service in the  
22 far right-hand column is \$147 million?

23 MR. GREG BARNLUND: That's right.

24 MR. BOB PETERS: And that number is 3.4  
25 million higher than the non-gas cost of service that

1 would result at existing rates. Can you confirm that?

2 MR. GREG BARNLUND: I'll take that  
3 subject to check, yeah.

4 MR. BOB PETERS: All right. So that's  
5 where the \$3.4 million is going to come from?

6 MR. GREG BARNLUND: That's -- that's the  
7 genesis of it. That's fair.

8 MR. BOB PETERS: All right. Now to  
9 recover that \$3.4 million of non-gas cost revenues for  
10 the second test year, the basic monthly charge is to  
11 increase for both the SGS class and the LGS class,  
12 correct?

13 MR. GREG BARNLUND: That's correct, but I  
14 guess I might recommend that we might want to discuss  
15 that with Ms. Derksen in the second panel as well too.

16 MR. BOB PETERS: All right. I'll make a  
17 note that we can speak to her about that, but in terms of  
18 -- I'll just keep pushing, and you'll push back when it's  
19 appropriate and --

20 MR. GREG BARNLUND: That's fair.

21 MR. BOB PETERS: My -- my point in  
22 raising that is that the SGS basic monthly charge  
23 increase and the LGS basic monthly charge increases,  
24 those were -- those were determined to the nearest dollar  
25 level, correct?

1 MR. GREG BARNLUND: They appear to be.  
2 They were not part of Centra's application. Centra had  
3 not applied for changes to the level of basic monthly  
4 charge, but those were directed by the PUB in 128/09.

5 MR. BOB PETERS: I wanted to talk about -  
6 - about how much revenue was raised as a result of the  
7 increase in the basic monthly charges to the SGS and LGS  
8 class; is that something I should wait to speak with Ms.  
9 Derksen about?

10 MR. GREG BARNLUND: I'd prefer so, yes.

11 MR. BOB PETERS: All right. I'll make a  
12 note and I'll come back to that. Would Ms. Derksen also  
13 be the person I should forewarn that I want to speak to  
14 her about the -- the method of allocation of the net  
15 income?

16 MR. GREG BARNLUND: Yes. I think all  
17 matters of cost allocation and rate design would be best  
18 discussed with Ms. Derksen.

19 MR. BOB PETERS: Not a problem. We'll  
20 maybe just cover off one (1) more area before the morning  
21 recess, if I could, Mr. Chairman, and that's just so the  
22 Board is aware, at Tab 3 of the book of documents, it  
23 contains Centra's request for final approval of actual  
24 gas costs for the last full gas year. That was November  
25 1, 2008 to October 31, 2009.

1 Is that correct?

2 MR. BRENT SANDERSON: That's correct, Mr.  
3 Peters.

4 MR. BOB PETERS: And that's \$437 million,  
5 Mr. Sanderson?

6 MR. BRENT SANDERSON: Yes, as shown at  
7 line 69 of Schedule 4.0.0.

8 MR. BOB PETERS: And when the Board last  
9 heard from you, Mr. Sanderson, you were telling them that  
10 it was going to be \$396 million, and that's what -- what  
11 was approved in Order 116 of '09, correct?

12 MR. BRENT SANDERSON: That's correct.

13 MR. BOB PETERS: I'm not asking you to  
14 take it personally, but that was based on a forecast that  
15 you last had before the Board.

16 MR. BRENT SANDERSON: Yes, sir.

17 MR. BOB PETERS: When we look at this  
18 schedule, Mr. Sanderson, and we see where the deviations  
19 from the last forecast, or what was approved by the  
20 Board, in the -- in what amounts -- the second column,  
21 the 2008/09 gas year approved, that's what the Board  
22 approved in -- in its -- in its Order 116, correct?

23 MR. BRENT SANDERSON: I guess, to be  
24 technical, Order 116, if I recollect correctly -- just --  
25 just give me one sec.

1 Yes, sir.

2 MR. BOB PETERS: And now we see, in the  
3 second from the right-hand column, the actual costs that  
4 the company incurred, and we see that for the -- for the  
5 fixed costs, which are from lines 1 down to 17, there was  
6 a \$1.9 million I will say adjustment to what was forecast  
7 last time to what the actuals ended up being.

8 MR. BRENT SANDERSON: I would  
9 characterize it as the actuals came in at \$1.9 million  
10 higher than was in -- originally forecast.

11 MR. BOB PETERS: Well, Mr. Sanderson,  
12 would running the strip as we talked about -- and you  
13 wouldn't tell me how many -- how many weekends you'd have  
14 to work to do that -- as late as possible and just before  
15 you testified before the Board, would that remove some of  
16 that inaccuracy?

17 MR. BRENT SANDERSON: Not with respect to  
18 fixed costs. Those are not driven by market price  
19 movements in natural gas, generally speaking; they're  
20 more driven by unforecastable events such as adjustments  
21 in TransCanada Pipeline tolls and so forth.

22 MR. BOB PETERS: And that's what I wanted  
23 to turn to is -- is, if these are fixed costs, not  
24 dependent on volume, not dependent on market prices, how  
25 is it that they fluctuate that widely over a period of

1 the ten (10) months you've been away?

2 MR. BRENT SANDERSON: Well, looking at  
3 the variances in -- in the schedule in question, the --  
4 the variances that you see there, having a second look  
5 at, those are mostly the US components of our portfolio,  
6 our US pipeline and storage assets, and so that would be  
7 driven by fluctuations in US exchange rates.

8 MR. BOB PETERS: What exchange rate is  
9 embedded in your forecast?

10 MR. BRENT SANDERSON: You'll just have to  
11 give me one (1) moment.

12

13 (BRIEF PAUSE)

14

15 MR. BRENT SANDERSON: You just have to  
16 bear with me. We're dealing with a number of different  
17 forecasts and actual exchange rates, so I'm just going to  
18 have my resource on the back table pull that number up  
19 for me.

20

21 (BRIEF PAUSE)

22

23 MR. BRENT SANDERSON: Just to refresh my  
24 -- make sure I heard the question clearly, what was your  
25 question regarding the period that you're interested in,

1 in terms of exchange rates, and whether it was actual or  
2 forecast?

3 MR. BOB PETERS: All right, let's --  
4 let's approach it this way then, Mr. Sanderson. In  
5 Schedule 4.0.0 found at Tab 3 of the Board's counsels'  
6 book of documents you have the gas year fixed costs  
7 approved by the Board from order 116 of '09, and then you  
8 have the actuals, and your explanation, as I understood  
9 it, to the Board, was that some of that can be explained  
10 as a result of exchange rate fluctuations.

11 MR. BRENT SANDERSON: I would say  
12 virtually all of it. And I think -- and there -- it's  
13 safe to say the direction of that variance would imply,  
14 on the face of it, that our actual incurred Canada/US  
15 exchange rates were higher than was originally forecast  
16 and imbedded in rates.

17 THE CHAIRPERSON: Is that because of the  
18 plunge in the Canadian dollar that followed the, if you  
19 want to call it, economic crisis?

20 MR. BRENT SANDERSON: I'm sorry, I -- I  
21 couldn't hear the question; could you repeat it, please?

22 THE CHAIRPERSON: Following the failure,  
23 Lehman Brothers, et cetera, et cetera, et cetera, the  
24 Canadian dollar fell from practically par all the way  
25 down to seventy-six (76) cents; so this is what you're

1 talking about, correct?

2 MR. BRENT SANDERSON: As to the -- the  
3 cause, that's, I guess, a subjective determination, but,  
4 yes, the Canadian dollar did fall significantly in value  
5 late in 2009 and in the earlier part of this year, and  
6 has since come back significantly.

7

8 CONTINUED BY MR. BOB PETERS:

9 MR. BOB PETERS: Mr. Sanderson, I located  
10 the -- the number I was looking at at -- I found it at  
11 Tab 4, page 5 of 17 of your application. It's in your  
12 application, Tab 4, page 5 of 17.

13 You were forecasting a US exchange rate of  
14 one point zero two (1.02), and the actual appeared to  
15 come in through the winter period at closer to a dollar  
16 twenty-five (\$1.25).

17

18 (BRIEF PAUSE)

19

20 MR. BRENT SANDERSON: Yes, that's  
21 correct, Mr. Peters.

22 THE CHAIRPERSON: Mr. Sanderson, just to  
23 help you, I think you just misspoke accidentally,  
24 inadvertently, when you were talking about the plunge in  
25 the Canadian dollar, that happened late 2008, not 2009.

1

2

(BRIEF PAUSE)

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MR. BRENT SANDERSON: I'll have to go back and -- and refresh my memory as to the specific timing. I probably -- if -- if we want to talk in detail about when these moves happened, I think it'd be better if I just took it as an undertaking to go back and just clarify all of this.

10

11

12

13

THE CHAIRPERSON: Do you want to take the break now, Mr. Peters, give them a chance to --

14

15

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18

19

MR. BOB PETERS: Yes, that would be fine, Sir.

THE CHAIRPERSON: Okay, we'll have our midmorning break now.

--- Upon recessing at 10:30 a.m.

--- Upon resuming at 10:57 a.m.

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THE CHAIRPERSON: Okay, welcome back, everyone.

MS. MARLA MURPHY: Mr. Chairman, just before Mr. Peters resumes, I might note that we circulated over the break Schedule 1.2.0, which should have been included as part of the April 13th letter in

1 Centra's Exhibit 10. So it's -- the very last page can  
2 be attached to the package. Thank you.

3 THE CHAIRPERSON: Thank you. Have we  
4 solved the issue of when the Canadian dollar plummeted?

5 MR. BRENT SANDERSON: Yes, Sir. I guess  
6 time flies a lot faster than we think it does, and, yes,  
7 you are correct, sir, in that it was approximately  
8 October 2009 as the financial crisis was wrapping up that  
9 we saw a significant move up in the value of the US  
10 dollar, and that was sustained until around April 2009,  
11 when it started coming off fairly significantly.

12 And yes, a -- a lot of market commentators  
13 at the time characterized that as being a result of a  
14 flight to safety. As world financial markets were  
15 melting down, there was significant buying pressure as  
16 governments and investors around the world moved their  
17 money into US dollar denominating currencies. So, yes.  
18 So you're correct as to the timing.

19 THE CHAIRPERSON: So you meant again,  
20 October 2008?

21 MR. BRENT SANDERSON: This is becoming an  
22 ongoing problem. Yes, October 2008 through to April  
23 2009. I'm sorry.

24 THE CHAIRPERSON: A minor obsession with  
25 the year, I guess. Okay, Mr. Peters.

1

2 CONTINUED BY MR. BOB PETERS:

3 MR. BOB PETERS: Yes, thank you. I was  
4 just making a note to make sure Mr. Sanderson didn't  
5 procure my foreign exchange for me.

6 Mr. Sanderson, we were talking foreign  
7 exchange before the morning recess, and I noted that at  
8 Tab 4, page 5 of 17 of Centra's application, as well as  
9 PUB/CENTRA-13, I have some specifics, and the Board has  
10 the specifics of the exchange levels that were imbedded  
11 in the forecast, together what was actually incurred by  
12 Centra.

13 Let me come at it this way, Mr. Sanderson,  
14 would it be correct to say that because Centra  
15 underestimated the fixed costs, it means that the foreign  
16 exchange rate was again, underestimated; you had the  
17 Canadian dollar too high?

18 MR. BRENT SANDERSON: I guess I would  
19 reverse the cause and effect. Because we had  
20 underestimated the -- our US exchange costs, therefore,  
21 our fixed costs were underestimated rather than the other  
22 way around.

23 MR. BOB PETERS: All right. We've got  
24 your point. Can you tell the Board going forward for the  
25 -- for the forecast year, what is Centra doing on foreign

1 exchange rate? I know we'll come to that a little bit  
2 later, but can you remind us.

3 MR. BRENT SANDERSON: What are we doing?  
4 Can you be more specific?

5 MR. BOB PETERS: What assumptions are you  
6 making for foreign exchange in the forecast.

7 MR. BRENT SANDERSON: I just -- can you  
8 just give me a moment?

9

10 (BRIEF PAUSE)

11

12 MR. BRENT SANDERSON: For the portion of  
13 the '09/'10 gas year forecast from November 2009 through  
14 March 31st, 2010, we're assuming a dollar eleven (\$1.11)  
15 Canada/US exchange rate. And for the period of April  
16 2010 through October 31st, 2010, we're assuming a dollar  
17 seven (\$1.07) Canada/US exchange rate. So a dollar seven  
18 (\$1.07) Canadian to -- to the US dollar.

19

20 (BRIEF PAUSE)

21

22 MR. BOB PETERS: That was found on Tab 5,  
23 pages -- page 7 of 10, was it, Mr. Sanderson?

24 MR. BRENT SANDERSON: Yes, that's  
25 correct, Mr. Peters.

1                   MR. BOB PETERS: All right. Let's --  
2 let's get back to Schedule 4.0.0 found at Tab 3 of Board  
3 counsel's book of documents. We turn on this schedule to  
4 the variable transportation costs, and perhaps the one we  
5 could focus on would be the storage gas, line 31,  
6 transportation and delivery cost, forecasting 4 million,  
7 only incurring approximately \$1.7 million of actual  
8 costs.

9                   Can you explain what happened to result in  
10 that variance.

11                   MR. BRENT SANDERSON: You'll see a  
12 counterbalancing variance of approximately \$3.8 million  
13 on line 38, under exchanges with counterparties. We do a  
14 number of capacity management deals that in terms of  
15 their effect on our supply, show up in our costs very  
16 much like a withdrawal from storage.

17                   So we had higher than forecast storage  
18 withdrawals last year, due to the colder than normal  
19 weather. So while our direct withdrawals from storage,  
20 and the transportation costs associated with those were  
21 \$2.5 million less, if you go to line 38, there's a more  
22 than offsetting increase in storage withdrawals, charges  
23 associated with exchanges with counterparties, which in  
24 terms of their nature are the same as a withdrawal from  
25 our storage inventory, it's just by the nature by which

1 they come into our books, and that's \$3.8 million.

2 MR. BOB PETERS: And is it possible that  
3 had there been storage gas you wouldn't have had to incur  
4 a significant amount with the counterparties, because the  
5 two (2) -- the two (2) don't directly offset each other?

6 MR. BRENT SANDERSON: No, the net of the  
7 two (2) is a positive variance or a higher than forecast  
8 storage transportation cost, and that's by virtue of the  
9 fact that our storage requirements were higher than  
10 forecast last winter due to the colder than normal  
11 weather.

12 MR. BOB PETERS: Do I take from that  
13 answer, Mr. Sanderson, that if the weather was normal  
14 those two (2) would have netted out to the same number?

15 MR. BRENT SANDERSON: Or something close  
16 to it, yes.

17 MR. BOB PETERS: All right. In turning  
18 to the lines 47, 48 and 49, this deals with your primary  
19 gas acquisitions, correct?

20 MR. BRENT SANDERSON: That deals with the  
21 commodity supply cost, irrespective of whether it's  
22 primary gas or supplemental gas.

23 MR. BOB PETERS: Well, on these three (3)  
24 lines it's the primary gas molecules that we're talking  
25 about: 47, 48 and 49.

1                   MR. BRENT SANDERSON: I'm sorry, yes, just  
2 the three (3) lines of that group of supply costs. Yes,  
3 you're correct.

4                   MR. BOB PETERS:    And it appears that in  
5 terms of exchanges this is where you had nothing forecast  
6 but you ended up incurring \$59 million of costs on  
7 primary gas exchanges?

8                   MR. BRENT SANDERSON:    Yes, it's very  
9 similar in nature to what we're describing when we're  
10 talking about the variable transportation costs. It's  
11 just when we move below into lines 47, 48 and 49, now  
12 we're talking about the cost of the commodity itself  
13 rather than the variable transportation cost to move it  
14 from storage to the market.

15                  MR. BOB PETERS:    Do I take from that  
16 answer that the molecules associated with the prior  
17 transportation costs are shown on forty-eight (48), that  
18 is, the counterparties that you had exchanges with, the  
19 molecules themselves that are shown on line forty-nine  
20 (49)?

21                  MR. BRENT SANDERSON:    Yes, that's  
22 correct.

23                  MR. BOB PETERS:    Okay. And in terms of  
24 those exchanges it appears that there's \$16 million more  
25 than forecast that had to come from storage?

1 MR. BRENT SANDERSON: Yes, roughly.

2 MR. BOB PETERS: In turning to line 53,  
3 the supplemental supply, zero was forecast to come from  
4 storage and there was actually \$6.7 million of actual  
5 expenses related to supplemental supply.

6 Can you explain how that variance came  
7 about?

8 MR. BRENT SANDERSON: Colder than normal  
9 weather and higher load requirements.

10 MR. BOB PETERS: It was that you weren't  
11 planning on having any supplemental gas?

12 MR. BRENT SANDERSON: Going into the  
13 winter, given the configuration of our portfolio of  
14 storage and transportation assets for the gas year in  
15 question, had weather conditions been normal we did not  
16 expect to require any supplemental supplies from storage.

17 MR. BOB PETERS: So would it be correct  
18 that if zero was being budgeted for normal weather the  
19 \$6.7 million that's found on line 53 represents the  
20 actual weather?

21 MR. BRENT SANDERSON: Yes, that's  
22 correct.

23 MR. BOB PETERS: And in terms of  
24 exchanges with counter-parties for supplemental service  
25 on line 54, again, forecasting zero, the actual was 19

1 million; why that variance?

2 MR. BRENT SANDERSON: Colder than normal  
3 weather.

4 MR. BOB PETERS: Weather only or was  
5 there any increased load -- any increased demand?

6 MR. BRENT SANDERSON: Well, if we want to  
7 really dig down to the mini -- minutia, there's different  
8 things going on in the market at -- at every one of our  
9 customer's premises, but for all intents and purposes you  
10 could say that we have a space-heating market by and  
11 large. And so any variances, actual versus forecast, is  
12 going to be predominantly the result of weather.

13 MR. BOB PETERS: Going down to line 58,  
14 to the hedging impact, the -- it appears that there was  
15 10 million -- sorry, \$10 million more added to gas costs  
16 as a result of hedging than what was forecast when you  
17 were at the GRA.

18 MR. BRENT SANDERSON: Yes, that's  
19 correct.

20 MR. BOB PETERS: In turning to line 67  
21 and the capacity management, you put under forecast \$6.8  
22 million, and that's a credit that is automatically -- or  
23 at least built into rates at the beginning of the rate-  
24 setting process, correct?

25 MR. BRENT SANDERSON: Yes. It's embedded

1 in our forecast transportation costs prospectively.

2 MR. BOB PETERS: Even though you haven't  
3 received a penny, you embed \$6.8 million in expectation  
4 that you will recover \$6.8 million of capacity release  
5 revenues.

6 MR. BRENT SANDERSON: That is correct.

7 MR. BOB PETERS: And, in fact, you only  
8 recovered \$5.2 million in capacity revenues, leaving the  
9 company short \$1.6 million, approximately.

10 MR. BRENT SANDERSON: That's correct.

11 MR. BOB PETERS: And because that 1.6  
12 million has already been included in the rates as a -- as  
13 a credit to consumers, you've now got to claim it back.

14 MR. BRENT SANDERSON: Yes, bundled up  
15 with all the rest of the residuals from the other PGVAs  
16 and deferrals that we bring forward for disposition, yes.

17 MR. BOB PETERS: When you were giving  
18 your direct evidence through Ms. Murphy, you referenced -  
19 - or at least the panel referenced -- there was a five  
20 (5) year rolling average that was used to calculate the  
21 capacity management credit to consumers, correct?

22 MR. BRENT SANDERSON: Yes, that's the  
23 methodology that -- that's been employed since the  
24 inception of the perspective refunding of this element of  
25 our costs.

1                   MR. BOB PETERS:    And it comes about  
2 because there had always been some monies to be refunded  
3 to consumers, and rather than wait for the end of the  
4 year, you refund it during the year in which it would be  
5 recognized or earned.

6                   MR. BRENT SANDERSON:   That's been the  
7 policy that's been followed for the past number of years.

8                   MR. BOB PETERS:    Is it time to re-think  
9 that formula, from Centra's perspective?

10

11                                   (BRIEF PAUSE)

12

13                   MR. HOWARD STEPHENS:   It was going to be  
14 my objective today not to answer a question, but I guess  
15 I'm on the hook.

16                   Quite frankly, this has been a subject of  
17 much discussion over the course of the years as to our  
18 capacity management revenues and how you go about  
19 forecasting them. And my position has always been,  
20 because I cannot -- we cannot pre-determine what the  
21 winter will bring and what the market circumstances will  
22 be during the course of the forthcoming period, it's  
23 very, very difficult for us to provide a reasonable  
24 estimate with respect to this. So this is, I'd say, an  
25 agreed-to formula that we use between just -- I mean, as

1 a result of the discussions that we've had over the  
2 number -- over a number of years to provide a forecasted  
3 number.

4 But, I mean, I -- there is very little in  
5 terms of credibility, from my perspective, in terms of  
6 providing that number. It just gives us an opportunity  
7 to put a number in there. Personally, I mean -- and I  
8 think some consideration should be given to the fact  
9 that, especially given the current circumstances and the  
10 huge changes in the marketplace, and, you know, certainly  
11 once we get further down the road with our portfolio  
12 review and potentially start changing the asset mix that  
13 we have, we may want to revisit this, and we may not want  
14 to incorporate any dollars into that.

15 And then, to the extent that we can  
16 generate revenues, associate that which will offset costs  
17 for consumers, then, to that extent, they will get a  
18 bonus at the end of the year, as opposed to having a  
19 circumstance here where we have to collect dollars back  
20 from them that we've given them credit for in advance.

21 MR. BOB PETERS: Well, isn't one of the  
22 problems we have, Mr. Stephens -- and it is good to hear  
23 from you this morning -- that -- that, if you took away  
24 this capacity management credit, which was \$6.8 million  
25 as forecast, that would be tantamount to a rate increase

1 of \$6.8 million to consumers?

2 MR. BRENT SANDERSON: This perspective  
3 inclusion of capacity management revenues and rates is a  
4 double-edged sword. The first year that this method of  
5 dealing with this was introduced, the customers received  
6 a benefit by virtue of the fact whatever was included in  
7 rates prospectively was a bonus in that year and that the  
8 rates were lower by that amount relative to what they  
9 otherwise would have been had it not been included  
10 prospectively.

11 But the difficulty you get into is if you  
12 want to remove that now, you're exactly correct, if we  
13 were to pull this out of our forecast at this point now,  
14 customers would be facing the prospect of rates being a  
15 number of million dollars higher by virtue of removal of  
16 the prospective refunding of this than it otherwise would  
17 have been.

18 MR. BOB PETERS: Mr. Stephens, you  
19 mentioned to the Board in your answer that there have  
20 been huge changes in the marketplace that give Centra  
21 cause to reconsider, or at least to start discussing  
22 what, if any, capacity management credit should be  
23 imbedded in prospective rates.

24 Is this along the lines that we read Mr.  
25 Stauff's evidence, where he was talking about changes in

1 the marketplace and making it more challenging for Centra  
2 to recover the capacity management revenues?

3 MR. HOWARD STEPHENS: Certainly. The  
4 fact -- I mean, the assets that we hold, I mean, the  
5 assets that we hold, I mean, and, well, the circumstances  
6 out of the marketplace, and given the fact that there is  
7 a significantly larger amount of gas down east provides  
8 fewer opportunities for us to generate revenues. We as --  
9 -- and they also indicated in the application, in order to  
10 deal with the increasing TransCanada tolls, we have done  
11 further de-contracting, which Mr. -- what's his name --  
12 Kostick will speak to.

13 And from that perspective, when we de-  
14 contract on TransCanada's pipelines we have less access  
15 capacity in that circumstance, so the potential for us to  
16 generate revenues on that if there is a market for it --  
17 there are, you know, several ifs in this equation -- I  
18 mean, it has -- it will have the tendency to reduce that.

19 And I mean, you know, I think the eve --  
20 the evidence that I've led over the course of the years  
21 is, if we have the ideal portfolio for Centra Manitoba,  
22 we would have no capacity management revenues because  
23 they are revenues that we are generating based upon  
24 having assets in place that are actually, at times during  
25 the course of the year, in excess of our requirements.

1                   So when they are in excess of our  
2 requirements and given the wide weather variations that  
3 we can experience, we are, I mean, bound to have those  
4 circumstances. We will generate the revenues, but there  
5 is no guarantee that they're necessarily going to be very  
6 profitable, and, I mean, so it becomes a very difficult  
7 issue in terms of trying to provide a forecast, and  
8 that's why we settled on this formula as a five (5) year  
9 rolling average, which is an accommodation, I guess.

10                   MR. BOB PETERS: Well, do you track -- or  
11 just before I get there, Mr. Stephens, I -- I thought Mr.  
12 Stauff also mentioned that there was competitive  
13 pressures because of other pipelines or other  
14 transmission capabilities, such as the -- was it the  
15 Rocky Mountain Express or --

16                   MR. HOWARD STEPHENS: I mean, and that's  
17 what I alluded to in terms of there are new supply  
18 basins, I mean, and the development of shale gas and the  
19 introduction of shale gas into the marketplace, we have a  
20 number of different supply basins that are effectively, I  
21 mean, making the transportation of gas from Alberta to  
22 eastern markets, which was -- been a significant  
23 component of our capacity management business much less  
24 attractive.

25                   And, so, from that perspective, I mean, we

1 have less opportunity then to generate revenues.

2 MR. BOB PETERS: Do you still track, Mr.  
3 Stephens, your unrecovered fixed costs, whether for use  
4 by Centra customers or through capacity release sales?

5 MR. HOWARD STEPHENS: We provide an  
6 overall utilization factor with respect to our pipeline  
7 capacity -- TransCanada Pipeline capacity. It's in one  
8 of the schedules, but I don't know off the top of my head  
9 which one.

10 MR. BOB PETERS: Okay. I take from all  
11 of those answers that while Centra is looking at it and  
12 considering it, this is not considered to be the time to  
13 actually make the -- the final position on what to do  
14 with this capacity management revenue. That may be a  
15 matter that is better addressed when Mr. Kostick and you  
16 look at what's going to happen to replace your assets  
17 that -- that -- the arrangements which expire in 2013.

18 MR. HOWARD STEPHENS: It has always been  
19 a concern of mine that we would credit customers with a  
20 do -- a number of dollars, and then have the potential of  
21 having to pull them back. We've -- I mean, and for the  
22 most part, we've been able to exceed our targets or the  
23 avera -- I mean, based upon the formula that we use to  
24 calculate that. We've run into that circumstances here.

25 I don't really like that, but, I mean, I

1 think the approp -- well, I don't think we want to make a  
2 change on a willy-nilly basis. I think we'd want to do  
3 this on a more informed basis, you know, once we have a  
4 better sense in terms of what we're going to hold in  
5 terms of assets and the potential for revenues to be  
6 generated.

7 MR. BOB PETERS: All right. Thank you,  
8 Mr. Stephens.

9 I want to turn to the next document in the  
10 book of documents, Tab 4. And just to lead into it,  
11 perhaps, Mr. Sanderson, you've told the Board that when  
12 they approved a forecast of 2008/'09 gas costs in Order  
13 116 of '09, Centra had every expectation that whatever  
14 the Board forecast wouldn't be the exactly correct number  
15 but you'd have to wait and see what the actual numbers  
16 were.

17 MR. BRENT SANDERSON: That's been the  
18 case as long as I've been in this business.

19 MR. BOB PETERS: And I think --

20 MR. HOWARD STEPHENS: I'll add to that,  
21 sir. I -- I would be -- I would likely have a heart  
22 attack or a stroke if the numbers actually matched up.

23 MR. BOB PETERS: well, we wouldn't want  
24 that, Mr. Stephens.

25 So to prevent you from having that concern

1 the Board has approved purchase gas variance accounts or  
2 deferral accounts where you track the difference between  
3 forecast and actual?

4 MR. BRENT SANDERSON: Yes, that's  
5 correct.

6 MR. BOB PETERS: And in the book of  
7 documents, Tab 4, you will see a coloured graph. I can  
8 indicate that replacement pages were provided to Centra  
9 this morning, I'm not sure if they made it through to  
10 everybody, but the photocopying -- the colour  
11 photocopying maybe didn't do them justice. And I'm  
12 actually looking, Ms. Murphy, at Tab 4, the -- just the  
13 coloured chart.

14 MR. BRENT SANDERSON: I have that updated  
15 version now, Mr. Peters.

16 MR. BOB PETERS: All right. And you'll  
17 see at the top of the chart there's numbers 1, 2, 3, 4  
18 and 5 representing five (5) different stages.

19 MR. BRENT SANDERSON: Yes, I do.

20 MR. BOB PETERS: Let's start with Stage 1  
21 and this should appear as a blue line on the graph. This  
22 is the non-primary gas purchase gas variance accounts in  
23 totality; do you accept that?

24 MR. BRENT SANDERSON: It would depend on  
25 the stage depicted. I've checked some of the figures and

1 I do have one (1) concern regarding Period 2.

2 MR. BOB PETERS: All right. Well, what -  
3 - what's attempted to be done is to use some of the data  
4 points that were available in the filing. And it would  
5 be misleading to suggest the data points lined up on a  
6 straight line but from the data points used, can you  
7 accept that in Stage 1 the PGVAs related to non-primary  
8 gas costs for supplemental gas, transportation, the UFG  
9 and Minell portion of distribution, and the heat value  
10 accounts, as well as any prior period accounts are  
11 accumulating in Stage 1?

12 MR. BRENT SANDERSON: Yes, I would agree  
13 with that.

14 MR. BOB PETERS: And they accumulated  
15 until October 31 of 2008 when the PGVA was closed?

16 MR. BRENT SANDERSON: Correct.

17 MR. BOB PETERS: And then turning to  
18 Stage 2 from November 1st of '08 to July 31, of '09, we  
19 recognize that the Board Orders 116 of '09 came in to  
20 effect on August 1st, correct?

21 MR. BRENT SANDERSON: Yes, sir.

22 MR. BOB PETERS: All right. So Stage 2  
23 the time line is just from November 1st of '08 until July  
24 31st of '09, to just before when the Board's order  
25 issued, there was a new PGVA for non-primary gas costs

1 established and that's for the '08/'09 year that's the  
2 red line near the bottom of the page, correct?

3 MR. BRENT SANDERSON: Yes.

4 MR. BOB PETERS: And the prior period,  
5 that is, prior to November 1 of 2008, that is the blue  
6 line that we've talked about, and it doesn't quite  
7 plateau but it stops its growth because it was closed off  
8 as you told the Board, October 31, and then there have  
9 been some carrying costs which have caused a slight  
10 growth in that account.

11 MR. BRENT SANDERSON: Correct.

12 MR. BOB PETERS: And if you added the red  
13 to the blue you'd get the green line; would you accept  
14 that?

15 MR. BRENT SANDERSON: I've gone back and  
16 I'm not sure where the \$2.3 million figure referenced  
17 with respect to those accumulating PGVAs for that -- the  
18 '08/'09 gas year come from. My figures, if I go back and  
19 check them, show that as of July 31st those balances  
20 would have been \$5.3 million, as at July 31st, as opposed  
21 to the 2.3 million. That's the only number that I take  
22 issue with in this schedule.

23 MR. BOB PETERS: Well, we'll check that  
24 but I was looking at that as the compilation of -- of --  
25 and we'll come to Schedule 4.1.0, Mr. Sanderson, and

1 maybe we have a -- an error that's in the drawing, but  
2 we'll come to that.

3 In any event, the Order 116 of '09 started  
4 to collect the -- the deferral account represented by the  
5 blue line, and the blue line only?

6 MR. BRENT SANDERSON: Yes, sir.

7 MR. BOB PETERS: And then in Stage 3, we  
8 go from August 1st, which is the day of the Board's  
9 order, until October 31 of 2009, that's a three (3) month  
10 period, post-order 116 of '09, correct?

11 MR. BRENT SANDERSON: I would agree.

12 MR. BOB PETERS: And it -- it starts with  
13 the Board order, and it ends with the end of the gas year  
14 on October 31 of 2009?

15 MR. BRENT SANDERSON: Correct.

16 MR. BOB PETERS: And in -- in Stage 3,  
17 there is a new rider that the Board approved for prior  
18 period PGVAs, and that is shown, because the blue line is  
19 coming down, that -- that's being refunded, or recovered,  
20 and paid to Centra?

21 MR. BRENT SANDERSON: Yes, sir.

22 MR. BOB PETERS: And because the PGVA is  
23 closed on October 31 of 2009 -- well, we can turn to  
24 Stage 4, where the '08/'09 PGVA closes, and its plateau  
25 just represents maybe some slight accumulation of

1 carrying costs. That Stage 4, Mr. Sanderson, is from  
2 November 1, '09 to April 30th of 2010, and on April -- on  
3 May the 1st of 2010 you're asking this Board to put a  
4 rate rider into effect, correct?

5 MR. BRENT SANDERSON: Yes, we are.

6 MR. BOB PETERS: And in the meantime,  
7 from November 1 to April 30th, in Stage 4, the rate rider  
8 that the Board approved in order 116 of '09 keeps  
9 collecting money that's owed to Centra, and you see the  
10 blue line dropping?

11 MR. BRENT SANDERSON: Yes.

12 MR. BOB PETERS: And you don't see the  
13 red line dropping, because there hasn't been a deferral  
14 account -- sorry, there hasn't been a rate rider to  
15 recover that deferral account yet approved by the Board?

16 MR. BRENT SANDERSON: I agree.

17 MR. BOB PETERS: Now when we get to Stage  
18 5, from May the 1st of 2010 to what I've suggested would  
19 be April 30th of 2011, that's where Centra is seeking new  
20 non-gas rate riders effective May the 1st, to recover the  
21 balance of the '08/'09 PGVA represented by the red line,  
22 as well as the prior period deferral accounts, which is  
23 represented by the blue line?

24 MR. BRENT SANDERSON: I'm not sure that I  
25 agree with what you just said. We're talking about April

1 30th, 2011 now?

2 MR. BOB PETERS: We're -- no, we're --  
3 we're -- let's talk May 1st of 2010. If Centra is  
4 successful in its application to the Board, the Board --  
5 you would have the Board approve a rate rider effective  
6 May the 1st that's going to recover the balance of the  
7 '08/'09 deferral accounts, and those are represented by  
8 the red line.

9 MR. BRENT SANDERSON: Yes, sir.

10 MR. BOB PETERS: And you're proposing to  
11 the Board that it would take one (1) year to recover that  
12 balance; that's how you've designed the rate rider?

13 MR. BRENT SANDERSON: Correct.

14 MR. BOB PETERS: And then when we look at  
15 that blue line that's still starting in pag -- in Stage  
16 4, the blue line isn't very high on the chart, but there  
17 is some residual balance, and you want that money also  
18 recovered over the next twelve (12) months, starting May  
19 the 1st?

20 MR. BRENT SANDERSON: That's correct.

21 MR. BOB PETERS: Now what's not on this  
22 chart, Mr. Sanderson, is that there is a new PGVA balance  
23 accruing for non-primary gas costs that started November  
24 1st of 2009, and it's going to run its course until  
25 October 31 of 2010?

1                   MR. BRENT SANDERSON:    That -- October --  
2    yes, correct.

3                   MR. BOB PETERS:    And that's not shown on  
4    the graph yet, and you haven't filed evidence related to  
5    that yet?

6                   MR. BRENT SANDERSON:    No.  And as I  
7    stated earlier, the -- our latest forecast for -- implied  
8    that if we have normal conditions for the remainder of  
9    the year, the residual of those accounts at October 31st  
10   should be relatively immaterial.

11                  MR. BOB PETERS:    Well let's be careful,  
12   we don't want Mr. Stephens to have a stroke here.

13                  We don't mind them being immaterial, but  
14   they won't be zero?

15                  MR. BRENT SANDERSON:    To paraphrase what  
16   I said earlier, they haven't been as long as I've been in  
17   this business.

18                  MR. BOB PETERS:    All right.  And so what  
19   -- what we've tried to show through a graph -- and you've  
20   -- you've been generous in helping us through it, that  
21   there's stages, and in the right-hand side there's some -  
22   - some speaking points.  I might have to go back and  
23   check on that.  I took that \$2.3 million from your  
24   schedule 4.1.0, Mr. Sanderson, also found at tab 4 of the  
25   book of the documents.  It's the -- it's the other page

1 in tab 4, and I -- I did some rough math.

2                   Centra didn't add them up, but I added up  
3 your supplemental gas on lines 5, transportation on line  
4 6, distribution on 7, and heating value on 8; came up  
5 with my \$2.3 million.

6                   MR. BRENT SANDERSON:    Okay.  I see why  
7 there'd be the difference.  Those balances on schedule  
8 4.1.0 of tab 4 of your book of documents, that rough math  
9 that you added up there, those balances are depicted as  
10 on October 31st of 2000...at October 31st of 2009,  
11 whereas on your chart with the lines, the description of  
12 period two (2) implies that that was the net balance at  
13 August 31st of 2009.

14                   So it's just a difference in the timing at  
15 which you picked.  So I -- I agree with the number you've  
16 shown, with the caveat that that was the balance at  
17 October 31st as opposed to August 31st.

18                   MR. BOB PETERS:    All right.  I thank you  
19 for that clarification.  Where it intersects that -- that  
20 vertical line may not be the exact data point, but it is  
21 the correct data points used starting at stage 4.

22                   MR. BRENT SANDERSON:    Yes.  Correct.

23                   MR. BOB PETERS:    Okay.  Well, we can live  
24 with that, I think.

25                   If we turn to schedule 4.1.0 a bit further

1 -- and it's the second document found in tab 4 of Board  
2 counsel's book of documents -- where starting period here  
3 is November 1 of 2009, for our line 1 deferral accounts,  
4 the October 31, 2009 and earlier balances of \$8.085  
5 million.

6 MR. BRENT SANDERSON: Correct. That --  
7 at October 31st, 2009, that would have been the remainder  
8 in the primary -- prior period PGVAs that we're currently  
9 disposing of by way of that rate rider approved for last  
10 August 1st, 2009.

11 MR. BOB PETERS: And that would have been  
12 mimicked by the blue line on the -- the graph, also found  
13 in tab 4.

14 MR. BRENT SANDERSON: Yes, correct.

15 MR. BOB PETERS: And that's mostly due to  
16 supplemental gas, from what you've told us, in terms of  
17 how the year was colder than normal?

18 MR. BRENT SANDERSON: This goes back to  
19 the year before. We've just been discussing our -- the -  
20 - we're talking about the -- the winter and so forth.  
21 This would have been for the '07/'08 fiscal year, plus  
22 stub period to October 31st, 2008, so, the period just  
23 prior to that winter that we were discussing earlier this  
24 morning.

25 MR. BOB PETERS: All right. And turning

1 to the 2008 and 2009 gas year, which started November 1st  
2 of 2008 and closed on Halloween 2009, that's where I came  
3 up with my \$2.3 million - the red line on the graph. And  
4 that -- you agree with those calculations?

5 MR. BRENT SANDERSON: Yes, we agree with  
6 those now, yes.

7 MR. BOB PETERS: And when we add the red  
8 line to the green line -- or to the blue line, we get the  
9 green line at \$10.415 million as a -- as a -- as a peak  
10 on -- on the green line showing what the actual would be  
11 on line 10 of schedule 4.1.0.

12 MR. BRENT SANDERSON: I would agree.

13 MR. BOB PETERS: And on stage 4 of the  
14 graph, the rider the Board approved in Order 116 of '09,  
15 it collects about \$7.6 million up until April 30th of  
16 this year, correct?

17 MR. BRENT SANDERSON: Correct.

18 MR. BOB PETERS: And you show that on  
19 line 12 of schedule 4.1.0, that those deferral accounts  
20 have been -- are being recovered rather aggressively  
21 through a rate rider that was approved the last time  
22 Centra was before the Board.

23 MR. BRENT SANDERSON: I would agree, Mr.  
24 Peters.

25 MR. BOB PETERS: And, although

1 aggressively recovering it, not totally, there's a  
2 balance of about \$2.8 million, which was in stage 5 -  
3 represented by the green line on the graph in tab 4 of  
4 the book of documents - and that's still owing to Centra.  
5 And that is what Centra wants a rate rider to be put in  
6 place for starting May the 1st of 2010.

7 MR. BRENT SANDERSON: Yes, sir.

8 MR. BOB PETERS: And just so there's no  
9 confusion, it is clear that the rate rider is to remain  
10 in place and it's calculated to be in place for twelve  
11 (12) months, unless there's further application by Centra  
12 or Order of the Board.

13 MR. BRENT SANDERSON: Yes, that's what  
14 we've applied for.

15 MR. BOB PETERS: I'm not sure if we need  
16 Ms. Derksen for this, but in stage 5, to recover that  
17 \$2.8 million, starting on May the 1st, and the new rate  
18 rider you proposed, Centra would have allocated that \$2.8  
19 million among each of the rate classes using their cost  
20 allocation model.

21 MR. BRENT SANDERSON: Yes, that would be  
22 correct.

23 MR. BOB PETERS: And can you go so far as  
24 to say that you would take each class' allocated amount  
25 and you would divide that amount by the volumes forecast

1 for that class to calculate the rate rider?

2 MR. BRENT SANDERSON: As we dig down into  
3 the technicalities of our rate design methodologies, I  
4 think this is where I'll hand it off to the next panel  
5 and Ms. Derksen, just so I don't say anything out of turn  
6 that I'd live to regret.

7 MR. BOB PETERS: All right. I wasn't  
8 going to go much further, but I'll make a note to -- to  
9 come back with Ms. Derksen on that.

10 You did tell the Board that a new purchase  
11 gas variance account was accruing for non-primary gas  
12 costs from November 1st of '09 through to today and will  
13 -- will continue on to October 31 of 2010.

14 You've acknowledged it's not shown in the  
15 application, it's not shown in the graphs, and the best  
16 evidence you've given the Board is that it's going to  
17 have a rather nominal balance. That's my word, maybe not  
18 yours.

19 MR. BRENT SANDERSON: I would agree with  
20 the characterization and that's our expectation at this  
21 point with the best information below -- available to us  
22 today.

23

24

(BRIEF PAUSE)

25

1                   MR. BOB PETERS:    Mr. Sanderson, you  
2 haven't put a number on the record, so let me start. Let  
3 me just see if you agree with this.

4                   If the amount of the non-primary gas PGVA  
5 for the current gas year that we're in turns out to be  
6 less than \$2.8 million, that will mean the rate rider  
7 you're asking for starting May the 1st would have to be  
8 decreased the next time you came in to adjust for non-  
9 primary gas rates.

10                  MR. BRENT SANDERSON:    Yes, Sir.

11                  MR. BOB PETERS:    All right. Now the hard  
12 question. Is it tracking to come in more or less than  
13 \$2.8 million as a residual balance?

14                  MR. BRENT SANDERSON:    At this point,  
15 given the uncertainties ahead of us between now and next  
16 April 30th, keeping in mind that the amount we'll bring  
17 forward for disposition next year will not only include  
18 the residuals from the current gas year, but any residual  
19 that might be remaining from this \$2.8 million that we  
20 are going to be disposing of over the coming twelve (12)  
21 months if the rates we've requested are approved, I'm --  
22 I'm not comfortable of giving you that kind of assurance  
23 at this point. There's just too many things that can  
24 happen.

25                  MR. BOB PETERS:    I'm not sure you

1 misspoke or if I didn't understand your reference. The -  
2 - the PGVA for non-primary gas costs for the current gas  
3 year that we're in right now, that will close on October  
4 31 of 2010, correct?

5 MR. BRENT SANDERSON: Correct.

6 MR. BOB PETERS: And then it'll depend on  
7 when you come in with your next cost of gas filing, and  
8 if it is again for a May 1 adjustment, there would only  
9 be carrying costs to that balance.

10 MR. BRENT SANDERSON: And then, netted in  
11 with that balance, would be any residual from the \$2.8  
12 million of prior period deferrals that we are bringing  
13 forward at this proceeding for disposal of. So, we are  
14 intending to dispose of that amount over the coming  
15 twelve (12) months, which cuts into next winter, and you  
16 can understand the -- the weather uncertainty and the  
17 potential swings in weather.

18 And so there's more to what we would be  
19 bringing forward at a future proceeding than just any  
20 minor residual from the current year's PGVA, so I'm just  
21 -- I just want to go to great lengths to just  
22 characterize that if I give you a number today just on  
23 those '09/'10 PGVAs and isolations, they're -- in  
24 isolation, there's more that feeds into it in terms of  
25 what will be brought forward at a future proceeding. But

1 I'm safe -- I'm comfortable in saying that the balances  
2 would not be expected to be material given the move to  
3 the gas year management of the PGVAs.

4 That has dealt with the lion's share of  
5 what contributes to making these balances potentially  
6 large and -- and -- and more of an issue, if you will.

7 MR. BOB PETERS: It may be, Mr.  
8 Sanderson, that this \$2.8 million that we see on schedule  
9 4.1.0 or the green line on the graph starting on stage 5,  
10 that \$2.8 million may be recovered in total and you may  
11 over-recover that amount, correct?

12 MR. BRENT SANDERSON: Or just as easily  
13 under-recover it to some degree.

14 MR. BOB PETERS: And that's because the  
15 recovery is premised on there being normal weather?

16 MR. BRENT SANDERSON: Yes, that's  
17 correct.

18 MR. BOB PETERS: Mr. Sanderson, if  
19 there's money owing to Centra, this \$2.8 million plus  
20 whatever nominal balances accruing in the current year,  
21 why not leave the existing aggressive rate rider on that  
22 this Board approved in Order 116 of last year and just  
23 continue with that rider?

24 MR. BRENT SANDERSON: Then my  
25 expectations would be that we would be significantly

1 over-recovering the amounts that we expect to need to  
2 recover from customers. The current rate rider is  
3 recovering \$9 million -- in excess of \$9 million over an  
4 annualized period, whereas the best numbers available to  
5 us tell us that we need \$2.8 million. So there would be  
6 no case, I think, that we could make to leave such an  
7 aggressive rate recovery rider in place when we don't  
8 expect that our requirements are that great.

9 MR. BOB PETERS: Can the Board take from  
10 your answers that Centra's plan is to wait until the PGVA  
11 for the current gas year closes on October 31 of 2010 and  
12 then a new Cost of Gas Application will be forthcoming  
13 from Centra to apply for new rates and rate riders?

14 MR. GREG BARNLUND: Mr. Peters, I think  
15 that there are a number of factors that are taken into  
16 consideration in terms of the -- whether or not we'd be  
17 applying for a cost-of-gas adjustment in that time  
18 period. And I think that, as we move forward through  
19 this year, there will be a number of factors we'll be  
20 assessing and we'll come to some determination in the  
21 fall of this year as to what -- what our next steps would  
22 be in that regard.

23 MR. BOB PETERS: I'm trying to read  
24 through your -- through your spoken word on that, Mr.  
25 Barnlund, but are you suggesting then that there may be a

1 GRA in the horizon?

2 MR. GREG BARNLUND: There's been no  
3 definitive decision made on that yet, but reflecting back  
4 on Mr. Warden's comments in terms of financial results,  
5 those things will be taken into consideration as we do  
6 our financial forecasting for this year and at some point  
7 in time in the fall we'll have a -- a position as to  
8 whether we're going to seek further changes to non-gas  
9 costs at that time.

10 MR. BOB PETERS: All right. Leaving  
11 aside the non-gas costs but in terms of gas costs itself  
12 and the primary gas takes care of itself, if I can use  
13 those words, on a quarterly basis, it has been Centra's  
14 practice to come in at least on an annual basis to deal  
15 with the non-primary gas costs?

16 MR. GREG BARNLUND: Generally speaking  
17 and, as I said, we'll have to reflect on the magnitude of  
18 -- of the recoveries that -- that would have to be  
19 implemented as a -- you know, as a result of the results  
20 that we see here at the close of this gas year.

21 MR. BOB PETERS: All right. I think I'm  
22 not going to get anything better than that from you, sir,  
23 and I'll -- I'll leave it at that.

24 I want to turn to the next topic which is,  
25 in your application, you're seeking approval of November

1 1, 2009 to October 31, 2010 forecast gas costs.

2 And at tab 5 of the book of documents we  
3 find your forecast; is that correct?

4 MR. BRENT SANDERSON: Yes, that's  
5 correct.

6 MR. BOB PETERS: And we talked earlier  
7 that this forecast that you've put before the Board in  
8 schedule 5.1.3(b) found at tab 5 of Board counsel's book  
9 of documents, which has been marked as Exhibit PUB-6,  
10 that forecast was premised on a November 2nd, 2009, strip  
11 that the Corporation ran; that is, those were the  
12 forecast gas costs for the various months that applied to  
13 this forecast?

14 MR. BRENT SANDERSON: Yes.

15 MR. BOB PETERS: And would it be -- would  
16 it be factually correct, Mr. Sanderson, to say that's a  
17 rather mechanistic exercise?

18 MR. BRENT SANDERSON: For some time our  
19 primary gas applications and forecasts have been -- I  
20 would fairly characterize those as mechanistic. And I  
21 think since we've moved to the management of our PGVA --  
22 non-primary PGVA deferrals to the gas year period, I  
23 think it's fair to say that we've moved to a much more  
24 mechanistic process with respect to our non-primary gas  
25 costs as well.

1                   MR. BOB PETERS:    And using the word  
2 "mechanistic," indicating that there's not a whole lot of  
3 room for judgment or subjective input into that forecast.

4                   MR. BRENT SANDERSON:   Neither is there  
5 any need.  As long as your information is current, the  
6 process is self-correcting and served us very well, I  
7 think.

8                   MR. BOB PETERS:    The self-correcting part  
9 are the PGVAs the Board has approved.

10                  MR. BRENT SANDERSON:   And the biggest  
11 element of that being the potential for large year-over-  
12 year residuals has been reduced substantially, so that  
13 would have been the only outstanding concern with  
14 following a mechanistic process, and that's been dealt  
15 with to our satisfaction coming out of the last GRA.

16                  MR. BOB PETERS:    On schedule 5.1.3(b),  
17 found at tab 5 of the book of documents, we see a total  
18 of \$300.6 million as the current gas year's forecast,  
19 correct?

20                  MR. BRENT SANDERSON:   Yes, clarifying  
21 again that that was as of the strip taken November 2nd,  
22 2009.

23                  MR. BOB PETERS:    And as one of the  
24 witnesses mentioned in their direct evidence, that  
25 includes non-primary gas costs of \$69.1 million.

1 MR. BRENT SANDERSON: Correct.

2 MR. BOB PETERS: You won't find the \$69.1  
3 million discretely broken out on schedule 5.1.3, but  
4 you'd have to turn to the next page, to schedule 5.1.4,  
5 to get those numbers, correct?

6 MR. BRENT SANDERSON: Correct.

7 MR. BOB PETERS: And you're asking the  
8 Board to approve the rate schedules that are based on  
9 this forecast.

10 MR. BRENT SANDERSON: Yes.

11 MR. BOB PETERS: Looking at the forecast,  
12 at lines 33 and 34, there's reference to primary gas,  
13 either direct to load or to storage.

14 Those primary gas molecules have their  
15 price impacted by the new supply contract with  
16 ConocoPhillips, would that be correct?

17 MR. BRENT SANDERSON: Yes, and the cost  
18 impacts of that contract are reflected in these numbers  
19 in terms of the underlying pricing mechanism.

20 MR. BOB PETERS: Just make sure the Board  
21 understands what your reference was, Mr. Sanderson.  
22 Lines 33 and 34, those numbers that -- that are shown on  
23 those lines are as a result of Centra using the pricing  
24 formula in the ConocoPhillips' agreement.

25 MR. BRENT SANDERSON: That was the point

1 that I was -- just wanted to make sure that was clear.  
2 Yes, I agree. That was just a different way of saying  
3 what I had -- my intended meaning.

4 MR. BOB PETERS: Lines 35, 36, 37 and 38,  
5 those would be the non-primary gas molecules or  
6 commodity, also known as supplemental gas.

7 MR. BRENT SANDERSON: Yes.

8 MR. BOB PETERS: Let's talk about  
9 something we just alluded to briefly earlier and, that  
10 is, a few years ago, Centra was forecasting zero (0)  
11 volumes of supplemental gas to meet a normal weather  
12 winter in Manitoba, and the plan back then was to meet  
13 the load only with primary gas and only go to market for  
14 supplemental gas if needed.

15 Is that correct?

16 MR. BRENT SANDERSON: Given the  
17 configuration of our storage and transportation assets at  
18 that time, correct.

19 MR. BOB PETERS: Well, let's follow that  
20 further. Maybe you can explain to the Board why you are  
21 now re-introducing a supplemental gas forecast.

22 MR. BRENT SANDERSON: Mr. Kostick will be  
23 able to cover this in a bit more depth when you cross-  
24 examine him, I'm sure, later on, but the fact is -- is  
25 that, as loads in Manitoba -- weather normalized loads

1 have declined over the past number of years due to  
2 increased conservation and more efficient use of natural  
3 gas, we review our portfolio of assets going into every  
4 winter and make adjustments, as necessary, in order to  
5 use our portfolio of assets as optimally as possible.

6                   We have 15.5 million gigajoules of storage  
7 capacity in Michigan and as loads -- loads shrink over  
8 time, we -- and TCPL tolls on the main line have gone up,  
9 we've taken action to shed some of that capacity. And as  
10 our deliverability directly out of the Western Canadian  
11 Sedimentary Basin goes down, we're able to make up for  
12 that difference by relying more heavily on our storage  
13 assets, or the gas that we've inventoried in storage over  
14 the course of the summer, some of that being supplemental  
15 gas.

16                   So it's indicative of -- we're taking  
17 action to more fully utilize the assets that we have in  
18 place, so there -- therein the reason for seeing a normal  
19 year requirement for supplemental gas from storage show  
20 up in our normal year forecast.

21                   MR. BOB PETERS: I take it the big driver  
22 in why you're going to supplemental gas, then, is  
23 Centra's de-contracting of supply with TransCanada  
24 Pipeline?

25                   MR. NEIL KOSTICK: Yes. In order to

1 optimize our portfolio we do look at the relative costs  
2 of securiting -- of securing supply from different areas,  
3 also taking into account our fixed contracts that we have  
4 in place; so our US assets are long-term contracts.

5 TransCanada, we contract on an annual  
6 basis, and if TransCanada tolls are rising and highly  
7 volatile, as they have been in recent years, there are  
8 benefits to reducing the amount of contract capacity on  
9 TransCanada and using other sources of supply in order to  
10 reduce the fixed demand charge component that we are  
11 charged from TransCanada.

12 MR. BOB PETERS: Am I correct, Mr.  
13 Kostick, that that becomes a balancing of the 'which one  
14 is cheaper'? At least forecast to be cheaper?

15 MR. NEIL KOSTICK: We do look at that in  
16 terms of the commodity prices. We also have to look at  
17 the fixed transportation costs as well, in terms of the  
18 TransCanada contract levels from Empress to the MDA or  
19 Empress to the SSDA, which are our delivery areas.

20 We have to take into account the fixed-  
21 demand charges that we would be on the hook for,  
22 essentially, for the entire year, and we assess, is there  
23 another way that we can shape our capacity and our firm  
24 supply arrangements such that we don't have to hold as  
25 much pipeline capacity throughout the year.

1                   And that's what we've done in the last  
2 couple of years. And that has included bringing into our  
3 portfolio -- portfolio the use of seasonal delivered  
4 service, in which we can contract on an as-needed basis  
5 for seasonal delivered service, which is categorized as  
6 supplemental supply, and we can, essentially, contract  
7 that as needed through the winter.

8 And, depending on the weather that transpires through the  
9 winter, we can either chose to extend it or shut it off  
10 as we go forward.

11                   So there's a combination of factors that  
12 are considered in the optimization of the portfolio with  
13 respect to commodity costs and also what fixed  
14 transportation costs we may be able to shed.

15                   MR. BOB PETERS: I appreciate we're  
16 looking here at tab 5 of the book of documents and  
17 schedule 5.1.3(b) forecast, Mr. Kostick, but I just want  
18 to -- to look in the rearview mirror for a few minutes.

19                   Did you analyse Centra's performance in  
20 the last year or two to see whether or not it would have  
21 been more cost-effective to have more or less firm  
22 service on TCPL rather than get your supplemental gas in  
23 the method you did or the -- the method Centra did.

24                   MR. NEIL KOSTICK: We are always  
25 reviewing those sorts of considerations and the reduction

1 in TransCanada capacity, we believe, would outweigh the  
2 alternatives.

3 By reducing TransCanada capacity, we shed  
4 fixed demand charges and we are able to shape our supply  
5 accordingly with other sources.

6 MR. BOB PETERS: Well, does that answer -  
7 - let's -- let's be specific. As a result of how it was  
8 handled, let's say for the -- for the last gas year, not  
9 the current gas year, what could you have done  
10 differently to make it even less expensive in gas costs?

11 MR. NEIL KOSTICK: I'm sorry, I didn't  
12 catch the entire question. Would you be able to repeat  
13 it?

14 MR. BOB PETERS: Again, I appreciate  
15 we're looking backwards to the previous gas year.

16 What could Centra have done differently,  
17 had it -- had it known then what it knows now, to  
18 minimize or reduce the gas costs even more than it did?

19

20 (BRIEF PAUSE)

21

22 MR. NEIL KOSTICK: When we contract and  
23 make decisions surrounding our portfolio for any given  
24 season, we have to take into account the nature of the  
25 physical assets that we have in place, the benefits that

1 those assets give us, for example, when it comes to use  
2 of TransCanada, that gives us our ability to swing or  
3 adjust nominations on a day-to-day basis and still have  
4 the opportunity to recover fixed demand charges through  
5 the use of diversions or other capacity release  
6 techniques. So there are a variety of considerations  
7 that are taken into account.

8 As far as a specific action that could be  
9 taken to reduce costs from I believe you're referencing  
10 the 2008/'09 gas year, I don't have a specific  
11 recommendation. There are many different factors that  
12 are at play and many different moving parts, so to speak,  
13 which make such a definitive hindsight analysis  
14 difficult.

15 MR. BOB PETERS: Did you do a hindsight  
16 analysis comparing '07/'08 gas costs when you had no  
17 supplemental gas in your forecast, and you were going to  
18 meet that through primary gas or delivered service?

19 MR. NEIL KOSTICK: What we had with  
20 respect to 2007/'08 versus the portfolio changes that we  
21 made in 2008/'09, we did report in the last Hearing that  
22 our portfolio changes resulted in, I believe,  
23 approximately \$5.7 million in savings relative to the  
24 former portfolio.

25 Now that included a number of different

1 actions, so that is, essentially, what we knew with  
2 respect to 2008 versus 2008/'09.

3 MR. BOB PETERS: Getting back to schedule  
4 5.1.3(b), found at tab 5 of the book of documents, Mr.  
5 Kostick, does Centra wait for the cold weather to  
6 contract for delivered service, or is that delivered  
7 service in place at the start of the gas year?

8

9 (BRIEF PAUSE)

10

11 MR. NEIL KOSTICK: Are you referring  
12 specifically to seasonal delivered service?

13 MR. BOB PETERS: No, no, I was -- I was  
14 referring to all of your delivered service that you --  
15 that you include in your forecast. And if we go down to  
16 line 38, as an example, you'll see delivered service.

17 MR. NEIL KOSTICK: I believe line 38, and  
18 Mr. Sanderson can correct me if I'm wrong about this,  
19 that is a forecast of supply that we may be short for the  
20 firm market in the month of April. Under the  
21 circumstance of colder than normal weather, that is not.

22 MR. BRENT SANDERSON: In -- in the  
23 application in tab 5 we -- we explain what that two  
24 hundred and twenty-seven thousand (227,000) is, and  
25 that's characterized as uncontracted delivered service, a

1 small amount of which is recovered to balance off the  
2 firm customers in the shoulder months when storage is not  
3 available.

4 And, because it's such a marginal source  
5 of supply, basically, that level of requirement in a  
6 normal year forecast you can characterize as noise and  
7 so, therefore, that's why that is left until -- that's  
8 what would -- you would buy on the day, if you will, just  
9 to cover off your -- your peak, and that -- but that is  
10 under normal weather conditions that on contract  
11 delivered service should be expected to be required.

12

13 (BRIEF PAUSE)

14

15 MR. BOB PETERS: Mr. Kostick, I may have  
16 cut you off on -- when you were asking me about whether a  
17 seasonal delivered service -- let's -- let's turn to  
18 that, and that's on line 37 of schedule 5.1.3(b).

19 There's some \$6 million of supply costs  
20 indicated there. That would have been, would it, sir,  
21 for the December, January, February, maybe a bit of March  
22 time period?

23 MR. NEIL KOSTICK: That seasonal  
24 delivered service was contracted for for the months of  
25 November, December, and January.

1                   MR. BOB PETERS:    And -- and when was the  
2 contract entered into?

3                   MR. NEIL KOSTICK:    That would have been  
4 in October.

5                   MR. BOB PETERS:    Is it correct that your  
6 seasonal delivered service then is -- is entered -- or is  
7 contracted at or prior to the start of the gas year?

8                   MR. NEIL KOSTICK:    That's correct.

9

10                                   (BRIEF PAUSE)

11

12                   MR. BOB PETERS:    Mr. Sanderson, I just  
13 want to tidy up a point that you left on the record.  If  
14 you turn to Tab 6 of the book of documents, and get your  
15 way past the -- the coloured page at the beginning,  
16 there's a response to PUB/CENTRA-4C.

17                                   In terms of uncontracted capacity relative  
18 to firm peak day, I take from your answer that the only  
19 uncontracted capacity was that line 38, delivered  
20 service, where the supply costs were around two hundred  
21 and twenty-seven thousand dollars (\$227,000)?

22                   MR. BRENT SANDERSON:    PUB/CENTRA-4C --  
23 just one (1)...

24

25                                   (BRIEF PAUSE)

1                   MR. BRENT SANDERSON:    Yes, your assertion  
2 is correct.

3                   MR. BOB PETERS:    Turning to Tab 6 still,  
4 this time let's stop at that coloured chart, we have the  
5 peak day requirements for firm customers verses the  
6 capacity and the delivered service.

7                   Now, this is snapshot, would it be correct  
8 to say, of -- of the coldest day of the year, or the --  
9 the day when the highest load is placed on the system?

10                  MR. BRENT SANDERSON:    I think we need to  
11 distinguish here between what's being depicted here in --  
12 in this illustration, which is a design peak, the coldest  
13 day experience thus far with our current market make-up,  
14 whereas the other figures we were just discussing is a  
15 normal year.

16                  So there is no provision in a normal year  
17 for -- there -- the normal year forecast doesn't depict  
18 circumstances under which we would experience a design  
19 peak. So I just wanted to make that distinction between  
20 the two (2), because they are markedly different.

21                  MR. BOB PETERS:    All right. And -- and I  
22 appreciate then -- I'm sure the Board has that  
23 clarification.

24                  What you're looking here at your design  
25 peak could be if this was -- if -- if Centra and Manitoba

1 incurred the coldest day on record, this is how you would  
2 meet that peak?

3 MR. NEIL KOSTICK: That's correct.

4 MR. BOB PETERS: And the delivered  
5 service that is shown in, I guess it's purple, that  
6 delivered service would be part of the seasonal delivered  
7 service, or it even could be part of the previously  
8 uncontracted delivered service that the corporation has?

9 MR. NEIL KOSTICK: No, it is neither a  
10 seasonal delivered service, nor is it uncontracted.

11 MR. BOB PETERS: So it's the contracted?

12 MR. NEIL KOSTICK: Yes, we would have  
13 firm peaking deals in place to cover off that seventy-two  
14 thousand (72,000).

15 MR. HOWARD STEPHENS: Mr. Peters, I just  
16 want to point out -- at one (1) point in time we did liv  
17 -- leave that component, or some component of our firm  
18 requirement on a design day uncontracted, and we'd buy it  
19 on a just-in-time basis, if you will. We deliberately  
20 have changed that several years ago, where we go into the  
21 winter now with all of our firm requirements pre-  
22 contracted so that if we do, I mean, have that situation  
23 occur, that we don't have to scramble around and try and  
24 find gas at the last minute.

25 And especially given the changes in the

1 marketplace, and the reduced through-put on the  
2 TransCanada Pipelines, it's a -- it -- it's a nic -- it's  
3 really a risk management mea -- measure. I mean, I don't  
4 want to be in the situation where we have to chase around  
5 to try and find gas on a design day.

6 MR. BOB PETERS: Mr. Chairman, this might  
7 be an appropriate time for the -- for the lunch break,  
8 recognizing at 1:15, Mr. Barber (phonetic) has been  
9 invited to make his presentation.

10 THE CHAIRPERSON: You mean Mr. Carroll?

11 MR. BOB PETERS: I'm sorry, Mr. Carroll,  
12 yes. Thank you.

13 THE CHAIRPERSON: Very good. We'll be  
14 back at 1:15 for Mr. Carroll's presentation. Thank you.

15

16 --- Upon recessing at 12:02 p.m.

17 --- Upon resuming at 1:19 p.m.

18

19 THE CHAIRPERSON: Okay. Welcome back,  
20 everyone. We've agreed at this point in time to hear a  
21 presentation from -- by Mr. Carroll.

22 And, Mr. Carroll, you've presented before  
23 to the Board, and you understand that your presentation  
24 is not evidence, but the Board will be interested in your  
25 comments.

1 MR. WILLIAM CARROLL: I do understand  
2 that, sir.

3 THE CHAIRPERSON: So you can begin.

4

5 PRESENTATION BY MR. WILLIAM CARROLL:

6 MR. WILLIAM CARROLL: Okay. Thank you.  
7 Mr. Chairman, members of the Board, ladies and gentlemen,  
8 my name is Bill Carroll. I'm president of Carroll &  
9 Associates Ltd. I'm here representing the views of a  
10 number of large gas users. A brief has been prepared,  
11 and Mr. Singh has been provided hard copies of that  
12 document and I think he's passed them out. My plan is to  
13 read it into the record.

14 The cover letter is from Carroll &  
15 Associates Ltd. dated April 13th, 2010, addressed to Mr.  
16 Graham Lane, Chairman of the Public Utilities Board.

17 "Dear Mr. Lane,  
18 Re. Fixed-Price and Fixed-Term Contract  
19 for Primary Gas:  
20 The Public Utilities Board had -- has  
21 ordered the staged phase-out of the  
22 hedging program for the pricing of  
23 primary gas. A number of commercial,  
24 industrial and institutional users  
25 believe that they will be negatively

1 affected by further implementation of  
2 this decision. Accordingly, a group of  
3 large users has agreed upon a short  
4 brief that broadly addresses their  
5 concerns. A copy is attached for your  
6 consideration."

7 Signed by yours truly.

8 And I'll read through the brief, the brief  
9 brief. It's dated April 13th, 2010:

10 "Fixed-Price and Fixed-Term Contract  
11 for Primary Gas:

12 The Public Utilities Board has ordered  
13 the staged phase-out of the hedging  
14 program for the pricing of primary gas.

15 Centra Gas has put in place a fixed-  
16 price and fixed-term option for  
17 residential and small commercial users  
18 on a first-come, first-served basis.

19 The Public Utilities Board Order number  
20 170/09, dated December 12th, 2009, the  
21 Board wrote, quote:

22 'Also, as noted in Order 128/09,  
23 consumer desire for long-term price  
24 certainty supports the continuation of  
25 Centra's hedging program for the

1                   quarterly gas system -- for the  
2                   quarterly system gas offering until  
3                   such time as customers are assured of  
4                   the ability to enter into a fixed-price  
5                   and term contract for primary gas with  
6                   Centra. Other than from Centra,  
7                   residential consumers seeking longer  
8                   term rate protection through fixed-  
9                   price and fixed-term contracts have  
10                  only one private retail marketer  
11                  remaining in the market, a situation  
12                  that does not represent any significant  
13                  degree of competition.' Close quote.  
14                  The Board obviously sees the issues  
15                  identified in this statement as  
16                  important for residential consumers.  
17                  Centra's large commercial, industrial  
18                  and institutional users are also in  
19                  need of price certainty. Further,  
20                  rather than no competition faced by  
21                  residential customers, large users are  
22                  faced with many brokers vying for their  
23                  primary gas supply business. As a  
24                  result of the staged elimination of the  
25                  hedging program set out in Board Order

1 170/09, this group of customers will  
2 soon be exposed to either living with  
3 price fluctuations or entering into a  
4 private sector supply relationship.  
5 Price certainty:  
6 For many large users utility costs  
7 represent a significant input cost into  
8 the goods and services produced. Price  
9 certainty is needed by this group of  
10 users as they establish the pricing for  
11 their products and services at budget  
12 time and must live with those estimates  
13 into the future. It is not feasible to  
14 go back and change their product  
15 service prices when operating in a  
16 competitive environment.  
17 Similarly, institutional users are not  
18 able to find new revenues to make up  
19 for budget shortfalls. The reality is  
20 that large users must live with the  
21 utility costs they build into their  
22 pricing structures and being exposed to  
23 huge fluctuations in gas costs as the  
24 market has experienced over the past  
25 few years, is an unacceptable business

1 practice.

2 At the end of the day the commo -- the

3 cost of the commodity is the cost of

4 the commodity and that can be factored

5 into input cost models. What is needed

6 is some degree of short-term certainty

7 obtained either through hedging or some

8 other price smoothing technique.

9 Centra's current hedging program and

10 quarterly rate adjustments helps ensure

11 that large rate fluctuations are

12 attenuated and kept at manageable

13 levels.

14 Gas brokers:

15 All commercial, industrial and

16 institutional users who operate in

17 Manitoba have been approached over the

18 years by various brokers seeing to

19 become their primary gas supplier.

20 Many brokers have come and gone and

21 many have assumed new identities via

22 mergers and acquisitions. Most of the

23 brokers are located outside the

24 province and only one (1) of today's

25 group of brokers has a meaningful local

1 presence. This changing landscape does  
2 not provide comfort to many large gas  
3 users.  
4 Additionally, the primary focus of this  
5 group of users is not on monitoring gas  
6 future prices and making guesses as to  
7 when to lock in supply contracts but  
8 rather in running their businesses.  
9 Business does not wish to enter into a  
10 long-term contract only to find later  
11 that they have guessed wrong with  
12 respect to natural gas pricing levels.  
13 The hedging program offered by Centra  
14 supplied price certainty that required  
15 no input on the part of the users. The  
16 comfort level in having their primary  
17 gas supplied in this manner is  
18 demonstrated by the fact that the  
19 majority of large users continue to  
20 have Centra supply their primary gas  
21 and do not use brokered supply.  
22 It is recognized that brokers are  
23 regulated by the PUB and should they go  
24 out of business that Centra is  
25 obligated to continue the supply of

1 primary gas. Large users also  
2 recognize that there is a premium to be  
3 paid for the hedging program currently  
4 run by Centra but that the program has  
5 value. There is a trust relationship  
6 that exists between Centra Gas and its  
7 commercial, industrial and  
8 institutional customers. There are  
9 major account advisors in place to  
10 answer questions and sort of out  
11 problems and the Utility can provide  
12 local customer service on short notice.  
13 It seems logical, therefore, that the  
14 creation of a fixed price, fixed term  
15 primary gas supply or some other rate  
16 smoothing technique by Centra Gas would  
17 be a welcome option for many large  
18 users.

19 Action requested:

20 The foregoing are the broad issues  
21 facing this group of consumers. Each  
22 industry or service supplier has its  
23 own particular needs and it is not  
24 possible to articulate these in a  
25 document such as this. The goal here

1 is to point out to the Public Utilities  
2 Board that removing the hedging program  
3 without a Centra option for this user  
4 group in place is not sensible.

5 The Board stated in Board Order 179/09,  
6 quote:

7 "Unless persuaded otherwise through an  
8 application to review and vary this  
9 order, the Board will direct the phase-  
10 out of hedging [I've added that] to  
11 occur in three stages commencing with  
12 this order." Close quote.

13 The intent of this document is to bring to  
14 the attention of the Board that a group of major  
15 consumers does not want to be faced with being exposed to  
16 uncontrolled price swings or private sector sourcing of  
17 their primary gas supply. It is recognized that there is  
18 a cost to the Hedging Program, but the protection it  
19 offers has value to many customers.

20 Centra does not profit from prime --  
21 primary gas and we trust Centra's ability to create  
22 fixed-price, fixed-term, or other rate-smoothing options  
23 without building in a profit, as a private broker must.  
24 Therefore, before the elimination of the Hedging Program  
25 is implemented further, we would ask that the Public

1 Utilities Board direct Centra Gas to put in place a  
2 fixed-price fixed-term offering for commercial,  
3 industrial, and institutional users and/or to come  
4 forward with other viable rate-smoothing options that  
5 address the issues faced by this user group.

6                   Respectfully submitted, MacDon Industries  
7 Limited, Standard Aero Limited, the Winnipeg Regional  
8 Health Authority, that looks after all of the -- the  
9 hospitals, and the Winnipeg Airports Authority. And I  
10 must say that there's a few other large users out there  
11 that were involved with this brief, but for various  
12 political, legal, and other reasons, couldn't put their  
13 name on it. And there's a few others that actually are  
14 supplied with by brokers who also agree largely with  
15 what's being said here but, for various reasons, couldn't  
16 put their name on it.

17                   And that, Mr. Chairman, is my  
18 presentation. I'd be happy to answer any questions if I  
19 could.

20                   THE CHAIRPERSON: I have - I have one (1)  
21 question, actually. I'm just wondering whether any large  
22 users in the current situation -- the Board's order did  
23 not prevent Centra from offering fixed-price/fixed-term  
24 contracts for users other than residential or small  
25 commercial, but leaving that aside, I'm wondering whether

1 any of the users had considered if they were interested  
2 in hedging in a one (1) year outlook am -- natural gas  
3 futures.

4 MR. WILLIAM CARROLL: You mean on their  
5 own?

6 THE CHAIRPERSON: Yes, I'm just  
7 wondering.

8 MR. WILLIAM CARROLL: I would say I can't  
9 answer that question.

10 THE CHAIRPERSON: Do you have any  
11 questions?

12 Okay. Well, thank you, Mr. Carroll. We  
13 appreciate the -- the analysis and the commentary. Thank  
14 you.

15 Mr. Peters...?

16

17 CENTRA COST OF GAS PANEL, Resumed:

18

19 VINCE WARDEN, Resumed

20 HOWARD STEPHENS, Resumed

21 NEIL KOSTICK, Resumed

22 BRENT SANDERSON, Resumed

23 GREG BARNLUND, Resumed

24

25 CONTINUED BY MR. BOB PETERS:

1                   MR. BOB PETERS:    Yes, thank you.  I'll  
2    have some questions to continue with the panel.  I'd like  
3    to -- maybe, Mr. Chairman, I'll switch gears here.

4                   And in light of the comments from Mr.  
5    Carroll, maybe just to assist the Board in further  
6    understanding his information, at Tab 14 of the book of  
7    documents, and Mr. Carroll, I didn't provide him with a  
8    copy of it, but I want to look at Centra's response to  
9    PUB Interrogatory 27-A -- and this is the number of  
10   customers by customer class -- and just find out if the  
11   panel is able to help put some numbers to the  
12   demographics that are talked about in Mr. Carroll's  
13   presentation.

14                  Mr. Sanderson, do you have --

15                  MR. BRENT SANDERSON:    I just want --  
16    you'd have to be more specific --

17                  MR. BOB PETERS:    I -- I --

18                  MR. BRENT SANDERSON:    -- in terms of what  
19    you mean by 'demographics'.

20                  MR. BOB PETERS:    All right, I will be.  
21    In terms of customer number, I'm looking at page 1 of 6  
22    at Tab 14 of the Board counsel book of documents.  Have  
23    you located that?

24                  MR. BRENT SANDERSON:    Yes, I have.

25                  MR. BOB PETERS:    And can you tell the

1 Board how many customers Centra has in the large general  
2 service category, and of those, how many are on direct  
3 purchase?

4 MR. BRENT SANDERSON: Would you just give  
5 me a minute to do the math, please?

6

7 (BRIEF PAUSE)

8

9 MR. BRENT SANDERSON: In total, as of the  
10 -- the most recent actual figures that we have, we have  
11 approximately seventy-eight hundred (7,800) customers in  
12 the LGS rate class, and of that total, approximately  
13 eight hundred and fifty (850) of those are on direct  
14 purchase.

15

16 (BRIEF PAUSE)

17

18 MR. BOB PETERS: Mr. Sanderson, I hate to  
19 do this live, but I'm looking at page 1 of 6 of  
20 PUB/CENTRA-27-A.

21 MR. BRENT SANDERSON: Yes?

22 MR. BOB PETERS: And which year are you  
23 taking me to? Are you taking me to 2008/'09?

24 MR. BRENT SANDERSON: Yes, I am.

25 MR. BOB PETERS: All right. And, in

1 terms of large general service customers, there are  
2 sixty-nine hundred and thirty-three (6,933) listed?

3 MR. BRENT SANDERSON: That would be just  
4 the system supply portion, or the portion of that class  
5 that purchase their primary gas from the Utility. If  
6 you'll just follow down in that column under the 'Western  
7 Transportation Service' heading, there's another line  
8 item at line 20, and that's large general service class  
9 as well, and those eight hundred and fifty-six (856)  
10 customers are those who choose to purchase their primary  
11 gas through a marketer under the Western T-Service.

12 MR. BOB PETERS: All right. And then,  
13 moving on, we can do the same analysis to high volume  
14 firm. There are sixty-five (65) system supplied  
15 customers and twenty-six (26) on direct purchase?

16 MR. BRENT SANDERSON: Yes.

17 MR. BOB PETERS: And then, for the  
18 mainline firm, one (1) system supply customer, two (2)  
19 that are buying direct?

20 MR. BRENT SANDERSON: Yes, sir.

21 MR. BOB PETERS: And, to finish it off,  
22 in terms of interruptible sales, thirty-three (33)  
23 customers served by Centra and eight (8) by, I suppose  
24 either -- they would be marketers or by the customer  
25 themselves, registered as a marketer.

1                   MR. BRENT SANDERSON:    Yes, and I -- I  
2    just want to point out, when we get into those larger  
3    classes like the mainline firm and interruptible, we also  
4    have a group of customers that's not shown here, and that  
5    being full transportation service customers.

6                   Oh, pardon me.  Sorry, I see that they are  
7    at the lower part of the schedule.

8                   So if we get into those classes, you know,  
9    if you go to lines 25 through 31, you'll see that's --  
10   there's a number of customers, approximately twelve (12),  
11   that choose to not only line up their own commodity  
12   supply requirements, but their upstream transportation as  
13   well.

14                  MR. BOB PETERS:    And all they take is  
15   transportation from City Gate from Centra?

16                  MR. BRENT SANDERSON:   To their facility,  
17   yes.

18                  MR. BOB PETERS:    All right.  And if we --  
19   we won't do the same analysis, but if we turn ahead to  
20   page 3 of 6, the Board will see the volumes by customer  
21   class shown.  Again, system supply for the year 2008/'09,  
22   you can -- can compare what's being taken by the large  
23   general service customer class by way of system supply  
24   and you can compare that to what the large general  
25   service customers are doing by way of western

1 transportation service direct purchase.

2 MR. BRENT SANDERSON: Yes, you can.

3 MR. BOB PETERS: All right. And your  
4 point about the volumes for the transportation service  
5 reflects at the bottom five (5) or six (6) lines on the  
6 chart, indicating that some high volume customers are  
7 arranging their own molecules and their own  
8 transportation, and just subscribing for Centra's  
9 transportation from City Gate to their facility.

10 MR. BRENT SANDERSON: Yes.

11 MR. BOB PETERS: All right.

12 All right. Thank you for that, Mr.  
13 Chairman. I just wanted to make sure the Board had a  
14 context with some specific numbers and access to numbers  
15 to -- to better understand some of the issues that Mr.  
16 Carroll was mentioning.

17 THE CHAIRPERSON: Thank you, Mr. Peters.  
18 That's helpful.

19

20 CONTINUED BY MR. BOB PETERS:

21 MR. BOB PETERS: All right. I'd like to  
22 turn back to the book of documents, to Tab 5, and I'd  
23 like to go to Schedule 5.1.3(b), down to line 49. We see  
24 the hedging impact on system supply, and as of last  
25 November, Mr. Sanderson, it was shown as \$19.8 million,

1 correct?

2 MR. BRENT SANDERSON: For the '09/'10 gas  
3 year forecast period, yes.

4 MR. BOB PETERS: And that's the forecast  
5 that you're asking this Board approve for the purposes of  
6 setting rates for the up -- for the current gas year?

7 MR. BRENT SANDERSON: No. Actually, that  
8 relates solely to primary gas, so the Board has seen two  
9 (2) subsequent updates to this figure in the February 1  
10 application for new primary gas rates, and the  
11 application that's currently before the Board for  
12 consideration for May 1st rates. So the -- those hedging  
13 impacts are not part of what we're looking for in terms  
14 of the new rates for non-primary gas for May 1.

15 MR. BOB PETERS: Okay. Fair comment.  
16 Included, though, in your \$300 million total forecast for  
17 the year, there have been some revisions to the hedging  
18 impact, as you've mentioned.

19 MR. BRENT SANDERSON: Yes, and we  
20 recently filed an update to those numbers commensurate  
21 with our May 1 Primary Gas Rate Application, or around  
22 the same time.

23 MR. BOB PETERS: And if you'd turn to Tab  
24 16 of the book of documents, most everybody except the  
25 witnesses will have -- have an update on PUB/CENTRA-49 --

1 attachment, it's on pink coloured paper, if that made its  
2 way to you.

3 This is the most recent update. Is it  
4 dated, April the 9th, Mr. Sanderson?

5 MR. BRENT SANDERSON: Yes, it is.

6 MR. BOB PETERS: And what you're showing  
7 the Board here is that, in the shaded area, for all of  
8 those derivative hedging transactions that have settled  
9 and come to be, there's about \$21.7 million of additions  
10 to gas cost.

11 MR. BRENT SANDERSON: Yeah, that sounds  
12 reasonable, short of doing the math here on the stand,  
13 yeah, I would agree with that, subject to check.

14 MR. BOB PETERS: And --

15 THE CHAIRPERSON: Excuse me, Mr. Peters.

16 MR. BOB PETERS: Yes.

17 THE CHAIRPERSON: Mr. Singh, would you  
18 mind making a copy of that for Mr. Carroll? It might be  
19 helpful.

20

21 CONTINUED BY MR. BOB PETERS:

22 MR. BOB PETERS: While we're looking at  
23 PUB/CENTRA-40 -- 49, as we sit here now, your best  
24 forecast for the impact of the hedging results is going  
25 to be a total of \$36.2 million of additions to gas cost.

1 MR. BRENT SANDERSON: Yes, that's  
2 correct.

3 MR. BOB PETERS: And those -- for this --  
4 that just means, if we do the math, there's \$14.5  
5 million, approximately, that has not yet settled because  
6 those gas months have not been delivered and finalized.

7 MR. BRENT SANDERSON: Yeah, again, sub --  
8 taking your math as correct, subject to check, but, yes,  
9 I would agree.

10 MR. BOB PETERS: But your point was that  
11 those additions to gas costs as a result of the Hedging  
12 Program -- and we'll talk a little bit more about the  
13 Hedging Program hopefully soon -- those impacts will be  
14 incorporated and are incorporated into the May 1st, 2010  
15 primary gas filing that is sitting with the Board  
16 presently.

17 MR. BRENT SANDERSON: Yes, that's  
18 correct.

19 MR. BOB PETERS: I guess before I leave  
20 schedule 5.1.3(b), just down to the five (5) year average  
21 capacity management revenues on line 50, 5-0, we see that  
22 -- and I guess it might have been Mr. Warden who, in his  
23 direct evidence, indicated that the five (5) year average  
24 indicates that \$6.9 million will be credited to customers  
25 at the start of the year, and that's been used to reduce

1 the gas costs.

2 MR. BRENT SANDERSON: Yes. Actually,  
3 transportation cost, just to be more specific.

4 MR. BOB PETERS: Your correction is that  
5 this \$6.96 million goes to reduce the transportation  
6 component of the rates.

7 MR. BRENT SANDERSON: Yes.

8 MR. BOB PETERS: All right. And this  
9 \$6.9 million number is the simple arithmetic five (5)  
10 year rolling average that's been used for the last few  
11 years.

12 MR. BRENT SANDERSON: Yes, it is.

13 MR. BOB PETERS: It -- it doesn't make  
14 any other adjustments, recognizing that last year you  
15 forecast 6.8 million, but you only recovered 5.2, it  
16 doesn't ask for a downward adjustment recognizing recent  
17 experience.

18 MR. BRENT SANDERSON: Well, it inherently  
19 incorporates recent experience in that -- with part of  
20 that five (5) year average is the actual real -- realized  
21 results from the pri -- prior years, so to the extent, we  
22 may quibble, I guess, with the influence it has on the  
23 five (5) year average, but it's explicitly considered in  
24 the calculation of that number.

25 MR. BOB PETERS: What that really tells

1 us is when the five (5) year average goes up from last  
2 time, the number that dropped off was smaller than the  
3 number that goes on.

4 MR. BRENT SANDERSON: That's correct in  
5 this case, yes.

6

7 (BRIEF PAUSE)

8

9 MR. BOB PETERS: Moving from Schedule  
10 5.1.3(b) to the next page in the book of documents,  
11 there's a copy of Schedule 5.1.4, and this gets the  
12 specific non-primary gas costs breakdown of the \$69.1  
13 million, correct?

14 MR. BRENT SANDERSON: Yes.

15 MR. BOB PETERS: And we look in the  
16 second column and we'll see the supplemental gas, the  
17 transportation, and the distribution components of non-  
18 primary gas spelled out in terms of a specific forecast  
19 for the '09/'10 gas year.

20 MR. BRENT SANDERSON: Yes.

21 MR. BOB PETERS: And in the Chairman's  
22 opening comments he indicated there was a \$12 million  
23 increase from what is in current rates, and I guess that  
24 can be seen on line 10, under column 3. There's a \$12  
25 million increase from what is in -- in -- included in

1 base rates currently.

2 MR. BRENT SANDERSON: No, not what's  
3 included...

4

5 (BRIEF PAUSE)

6

7 MR. BOB PETERS: Let me reword the --

8 MR. BRENT SANDERSON: Just -- I'm just --  
9 I'm just discussing a -- a technical point with Mr.  
10 Barnlund. Yes, you're correct.

11 MR. BOB PETERS: Well, I was going to  
12 rephrase the question so we didn't have to get into that  
13 technicality.

14 But we've talked a little bit about  
15 supplemental gas. It's gone up 6.5 million over the  
16 forecast, and you've explained that generally to be the  
17 colder than normal weather, correct?

18 MR. BRENT SANDERSON: Nope. The numbers  
19 that you're seeing compared here are normal year forecast  
20 verses normal year forecast. So the increase you're  
21 seeing reflected would be any change in the market price  
22 that we expect to pay for supplemental gas verses any  
23 change in our expected requirement for supplemental gas  
24 under normal weather conditions.

25 So the lion's share of the increase is a

1 result of our shedding capacity on TransCanada and  
2 expecting a heavier reliance on our supplemental source  
3 of supply from storage to make up the difference.

4 MR. BOB PETERS: All right. Thank you  
5 for that. In terms of transportation, there's a \$7.6  
6 million difference and a significant portion of that will  
7 be the increase in the TCPL tolls?

8 MR. BRENT SANDERSON: Yes, correct.

9 MR. BOB PETERS: And the distribution  
10 component that goes down about \$2 million, that again is  
11 only for the unaccounted for gas and the Minell pipeline  
12 charges, and that's because the commodity cost is not as  
13 large as it otherwise was forecast to be?

14 MR. BRENT SANDERSON: Exactly.

15 MR. BOB PETERS: Is it accurate to say  
16 that Centra's delivered service supplies appear to have  
17 been more expensive than the alternative of purchasing  
18 primary gas and incurring the transportation costs?

19 MR. BRENT SANDERSON: Not necessarily.  
20 I'd need to go away if you -- I don't have those figures  
21 at hand to be able to make that type of determination  
22 right at the moment.

23 MR. BOB PETERS: Is that -- is that a --  
24 an analysis that has been done, Mr. Kostick?

25 MR. NEIL KOSTICK: I believe you may be

1 referring to a portion of the CAC evidence, which  
2 indicated that the seasonal delivered service for  
3 2008/'9, based on Mr. Stauff's analysis, wound up being  
4 more expensive than primary gas, assuming that we held  
5 additional transportation cap -- capacity on TransCanada  
6 in order to flow more primary gas to the market.

7                   And that may be the case based on that  
8 analysis, bearing in mind that there would be those  
9 charges associated with holding additional TransCanada  
10 capacity in order to move that additional primary gas.  
11 And if we had our firm transportation levels where they  
12 were a number of years ago, we could have done that. But  
13 those firm transportation demand charges would be  
14 incurred over the course of the entire year.

15                   So as an alternative to holding that much  
16 transportation capacity on TransCanada, we contract for  
17 seasonal delivered service, which, in hindsight, may wind  
18 up being more expensive than primary gas, but allow us to  
19 reduce our TransCanada contract levels, resulting in an  
20 overall lower cost approach to serving the market.

21                   MR. BOB PETERS: I followed you up until  
22 your last sentence. How can it be a lower cost to serve  
23 when the seasonal delivered service is more expensive  
24 than if you had maintained your TransCanada service and -  
25 - and brought it in as primary gas?

1                   MR. NEIL KOSTICK:    That would be if --  
2   that's just -- that's under the theoretical assumption  
3   that you would just hold that TransCanada firm  
4   transportation for those three (3) months.  But I was  
5   trying to identify is that you would hold that  
6   TransCanada firm transportation for twelve (12) months.

7                   So that twelve (12) of firm transportation  
8   demand charges on TransCanada is not taken into account  
9   in Mr. Stauff's evidence.

10                  MR. BOB PETERS:    All right.  And you were  
11   prepared to concede that if you only had used three (3)  
12   months of those firm transportation charges, it may have  
13   been more advantageous financially to procure it as  
14   primary gas and incur transportation costs, rather than  
15   go through supplemental service?

16                  MR. HOWARD STEPHENS:   Mr. Peters, I think  
17   I need to explain something, with respect.  We started  
18   down this road this morning in terms of retrospective  
19   review and that we analyse how we did during the prior  
20   winter, and if we make any changes in terms of how we  
21   contract it, et cetera.  You have to recognize that this  
22   is very much -- very much like hedging in trying to  
23   prognosticate prices on a forward-going basis.

24                  When we go into the winter we contract on  
25   the basis that we are going to have a design winter.  The

1 numbers you see here are all based upon normal years.  
2 When we actually go out to contract we contract for a  
3 design year so that we have a sufficient supply to  
4 satisfy the market in that circumstance.

5           Now, if I knew in advance, if I had that  
6 crystal ball -- well, I wouldn't be using it for that  
7 purpose, I'd be using it for other purposes -- but  
8 getting past that, I would know precisely what I'm going  
9 to need. And at the end -- I mean, in the end, as I'm  
10 entering the season, the winter season, if I know it is  
11 going to be warmer than normal I'm not going to fill  
12 storage, or if it's full I'm going to turn around and if  
13 there is a positive benefit associated with my selling  
14 that inventory and then re-buying it again the next  
15 summer at a lower cost, I'm going to go out and hedge  
16 that transaction and make money doing it.

17           But I don't have that benefit because I  
18 don't -- I mean, I have -- my first obligation is to  
19 serve the market. And we do it on the basis of the  
20 information that we have in hand at the time that we have  
21 to make the decisions. We have to make those decisions  
22 in the fall prior to the winter. And so for -- I mean,  
23 every time we go through this analysis and you -- I mean,  
24 we may come across circumstances where, yes, it indeed  
25 has cost us more money to do this this way.

1                   But on the basis of the plan that we put  
2 forward to deal with load during the course of the winter  
3 months and the summer months, we use the best information  
4 available to us at that point in time and then we make --  
5 develop our plans associated with that, and always with  
6 regard to providing reliable service, which is our first  
7 priority.

8                   So, I mean, I guess I take exception and I  
9 get really concerned when we start talking about, you  
10 know, retrospective reviews and could we have done things  
11 better. Absolutely. I mean, if I know after the fact  
12 about how the winter was going to turn out I could change  
13 the whole thing around and I mean -- and we would have an  
14 entirely different outcome but, I mean, I don't have that  
15 luxury. I mean, so -- I mean, going down that road from  
16 my perspective is a -- is an exercise in futility.

17                   MR. BOB PETERS:     But you do have the  
18 luxury, Mr. Stephens, to look in that rearview mirror and  
19 check the decisions you made at the time you made them to  
20 see whether or not next time around you could or should  
21 or would do something different?

22                   MR. HOWARD STEPHENS:    Absolutely. I  
23 mean, and that's through years of experience. I mean, we  
24 learn certainly. I mean, I've been here enough years. I  
25 mean, I've learned a few lessons over the course of the

1 years and I know the things that you should look at,  
2 things that are meaningful, that do give you an  
3 indication as to things that can, I mean, occur and, I  
4 mean, it requires some element of judgment.

5           Even in that circumstance, given the kind  
6 of changes that I've seen in the marketplace, there are  
7 no well established rules in this market.

8           I mean, we've seen huge changes over the  
9 course of the last ten (10) years. I mean, I remember  
10 when I was having a discussion with Mr. Ryall at  
11 lunchtime, I remember making a recommendation in 1999  
12 that based upon the amount that the market can move we  
13 didn't need to hedge.

14           And I no sooner put that paper in front of  
15 the regulator and, I mean, the market changed  
16 significantly simply because the Alliance Pipeline came  
17 on and Foothills Pipe Line came on. Prices went through  
18 the roof because there was all sorts of concern with  
19 respect to the ability of the Western Canadian  
20 sedimentary basin to satisfy the requirements of the  
21 market.

22           And we had an entirely new pricing  
23 structure come to be. I mean, prices doubled over the  
24 course of a couple of months and we lived with the  
25 consequences of that for -- for over a decade now and we

1 see now precisely the opposite occur. And we're seeing  
2 now -- so we're looking at our hedging program and say,  
3 well, is it still relevant? And so we're back -- you  
4 know, it's -- I mean, I'm just watching the clock go  
5 round and around and around.

6 I mean, so when you start talking to me  
7 about retrospective reviews, there are lessons to be  
8 learned but they have to be taken, you know, with a grain  
9 of salt in some circumstances because you cannot forecast  
10 the market. If you could you'd be able to beat the  
11 market, I'd be a rich man and I sure as hell wouldn't be  
12 sitting here.

13 THE CHAIRPERSON: Mr. Stephens, you've  
14 accumulated a lot of knowledge over the years; is that a  
15 fair statement?

16 MR. HOWARD STEPHENS: Well, I may have  
17 accumulated it; I think I've lost half of it, but...

18 THE CHAIRPERSON: How do you propose to  
19 pass it on to the next generation?

20 MR. HOWARD STEPHENS: Well, that -- I  
21 made the comment this morning, sir, that I -- my  
22 objective here today was not to answer any questions. I  
23 have a very competent staff that I'm very pleased to lead  
24 and from that perspective it's been my objective over the  
25 last several years to try and impart as much of my

1 knowledge over to them.

2                   And, quite frankly, I mean, we get them  
3 lots of training. And from that -- and, I mean, the  
4 biggest component of this is you have to have experience  
5 with the business.

6                   So they have, I mean, the benefit of a  
7 mentorship from myself, and I'm not always right,  
8 contrary to what some people think, including me. That -  
9 - that, I mean, is basically the process.

10                   There is no place you can go, I mean, and  
11 that is the one (1) difficulty that we have in the -- the  
12 gas industry, that you can go and get a degree in now  
13 natural gas marketing or acquisition, what have you.  
14 It's something you have to learn through experience, and  
15 I've had the benefit of -- well, I guess I -- this year  
16 is my thirtieth year at Centra Gas, so -- I haven't spent  
17 all my time with respect to gas supply but always been  
18 connected to it.

19                   And, I mean, from -- you get the benefit  
20 of that experience, and you just learn through  
21 experience.

22                   THE CHAIRPERSON: And you share that  
23 knowledge with those within your group so that they have  
24 that opportunity to be mentored, as well?

25                   MR. HOWARD STEPHENS: Absolutely. We

1 have taken -- well, I mean, when Hydro acquired us, I  
2 mean, after we had, and I'll be candid, the somewhat  
3 unfortunate set of circumstances in Centra Gas today with  
4 our -- respect to our hedging program, and Hydro finally  
5 acquired us, I was really the -- I mean, between the --  
6 there were two (2) of us left in gas supply, and I've  
7 taken a number of lessons from that -- I mean, that  
8 particular situation.

9                   And, I mean, in -- and in that regard, I  
10 mean, I had to bring new people into gas supply because I  
11 couldn't do it all by myself. I did it for a little  
12 while, but it was a bit -- bit onerous.

13                   And that's -- I mean, certainly, I mean,  
14 that's why we have grown the department, the division, so  
15 that we are in a position now to deal with the changes in  
16 the marketplace, I mean, and try and foresee changes as  
17 much as we can and be prepared to deal with them.

18                   And we do a lot of work with respect to  
19 modelling certain outcomes in terms of our hedging  
20 program and all of the analysis that we've put before  
21 this Board in terms of demonstrating that, you know,  
22 these are the potential outcomes.

23                   All of that is fine. I mean, all of that  
24 is for the qualitative still though because there are  
25 certain elements of judgment that you have to apply, and

1 that's where the years of experience and the grey hair  
2 sometimes pays off.

3 THE CHAIRPERSON: Well, I'm pleased to  
4 hear that significant responsibility.

5 Mr. Peters...?

6

7 CONTINUED BY MR. BOB PETERS:

8 MR. BOB PETERS: Thank you. Mr.  
9 Stephens, I just wanted to go back, and -- and, Mr.  
10 Kostick, the point that we were talking about was the  
11 2008/'09 -- 2008 and -- and '09, the delivered service  
12 supplies appearing to have been more expensive than  
13 perhaps an alternative.

14 I heard a couple of different reasons for  
15 that in -- if that was factually true. One (1) of them  
16 was you were only comparing three (3) months of firm  
17 transportation to what you might have had to buy in terms  
18 of having twelve (12) months under contract.

19 That was one (1) of the reasons? Have --  
20 have I got that right?

21 MR. NEIL KOSTICK: That's correct.

22 MR. BOB PETERS: And if you had twelve  
23 (12) months of firm transportation and only needed it for  
24 the three (3) months, you would have the opportunity to  
25 release that capacity and try to market it to at least

1 recover your costs?

2 MR. NEIL KOSTICK: If there is a market  
3 for such capacity, that's correct.

4 MR. BOB PETERS: And we don't know if  
5 there was, or -- at this point in time, we don't know if  
6 there was, or you would know if there was based on what  
7 did happen that year?

8 MR. NEIL KOSTICK: If we're talking about  
9 the '08/'09 gas year, there was generally a market for  
10 selling that transportation, although rarely at the full  
11 cost that that transportation is incurred at.

12 MR. BOB PETERS: And Mr. Stephens' point  
13 is, you wouldn't have known that looking through the --  
14 through the windshield. You'd only know that if you  
15 looked in the rearview mirror.

16 MR. NEIL KOSTICK: Yes.

17 MR. HOWARD STEPHENS: Once you run over  
18 the speed bump.

19 MR. BOB PETERS: I want to -- we -- we  
20 talked about on Schedule 5.1.4 the additional \$12 million  
21 related to non-primary gas costs, and I think we agreed  
22 somewhat cagily, Mr. Sanderson, that that was an increase  
23 of 12 million from what is in current rates?

24 MR. BRENT SANDERSON: No longer any need  
25 to be cagey, just that's -- the long and short of it is,

1 that's a correct statement.

2 MR. BOB PETERS: All right. And to  
3 recover the additional \$12 million of non-primary gas  
4 costs, Ms. Derksen will run the supplemental gas, the  
5 transportation, and the distribution component of non-  
6 primary costs through the cost allocation model to  
7 calculate new rates for each class?

8 MR. BRENT SANDERSON: Yeah, and I can  
9 assure you that she's done that already.

10 MR. BOB PETERS: And can you assure the  
11 Board that the base rates -- and I say base rates that  
12 are being proposed for May 1 -- are to yield an  
13 additional \$12 million?

14 MR. BRENT SANDERSON: Well, there's  
15 always a -- a little bit of rounding error in these rates  
16 and what they'll recover relative to forecast costs, yes.  
17 Generally speaking, yes, I would agree with that.

18

19 (BRIEF PAUSE)

20

21 MR. BOB PETERS: Let's now turn to Tab 12  
22 of the book of documents -- we'll leave a few tabs to  
23 discuss with Ms. Derksen when she joins us tomorrow --  
24 and turn to the ConocoPhillips contract.

25 Even though I'm not sworn, I should advise

1 my friend Mr. Saxberg that the person on this side of the  
2 microphone hasn't seen the contract either, but let's  
3 talk about -- about it.

4                   When we talked back in Tab 5 of the book  
5 of documents about the forecast costs, the supply costs  
6 for primary gas of about \$231 million for the current gas  
7 year, that's coming as a result of the pricing under the  
8 ConocoPhillips agreement, correct?

9

10   (BRIEF PAUSE)

11

12                   MR. BRENT SANDERSON:   Mr. Kostick and I  
13 agree in general terms, with the exception of the fact  
14 that approximately 34 million of that would have been gas  
15 inventoried into storage the previous summer under the  
16 predecessor supply agreement before the ConocoPhillips'  
17 agreement.

18                   So with the exception of that \$34 million  
19 of gas expected to be withdrawn from storage under normal  
20 conditions, the remainder would be priced -- would bear  
21 the pricing effects of the ConocoPhillips' agreement.

22                   MR. BOB PETERS:   Does the gas in storage  
23 impact Schedule 5.1.3(b)?

24                   MR. BRENT SANDERSON:   Yes, it does.

25                   MR. BOB PETERS:   And so the primary cost

1 on line 34 of storage gas, that \$34.3 million number is a  
2 blend of not only the forecast injection of the  
3 ConocoPhillips' gas, but also the residual of the Nexen  
4 gas?

5 MR. BRENT SANDERSON: No. The only  
6 storage gas withdrawals reflected in the -- in the '09/10  
7 gas year forecast is gas that was inventoried into  
8 storage between April 2009 and October of 2009, and the  
9 ConocoPhillips' agreement did not come into effect until  
10 November 1st.

11 So it would be gas inventoried into  
12 storage during the 2009 summer, blended with any residual  
13 from the previous year, which it would have been -- bore  
14 the pricing effects of that predecessor agreement, as  
15 well, prior to the ConocoPhillips' agreement. So the  
16 storage gas -- storage supply of primary gas in this --  
17 in this application bear none of the cost consequences of  
18 the ConocoPhillips' agreement.

19 They will in the summer of 2010 as we  
20 begin to refill store -- well, as we've just recently  
21 begun to refill storage, but that would show up in a  
22 subsequent forecast.

23 MR. BOB PETERS: In the current gas year  
24 we're in, the 2009/'10 gas year, which expires October 31  
25 and had started on November 1, there was already some

1 gas, primary gas, in storage?

2 MR. BRENT SANDERSON: Our primary gas to  
3 the extent that -- our primary gas storage inventory, to  
4 the extent that we could fill it, was full as of October  
5 31st.

6 MR. BOB PETERS: And that was full and  
7 supplied only through the Nexen contract, correct?

8 MR. BRENT SANDERSON: Correct.

9 MR. BOB PETERS: And what you're doing in  
10 Schedule 5.1.3(b) is essentially indicating what the cost  
11 of that replacement gas is going to be?

12 MR. BRENT SANDERSON: No, sir. We're --  
13 it's reflecting the cost of the withdrawals during the  
14 winter just completed to serve the load.

15 The cost to refill storage from April 1 of  
16 2010 to October 31st, 2010, following the most recent  
17 winter, will bear the costs of the ConocoPhillips'  
18 agreement, but we will not begin withdrawing any of those  
19 supplies until November 1st of 2010, which is a future  
20 forecast, a future proceeding.

21 MR. BOB PETERS: Okay. Then I have your  
22 point. In the materials, as was pointed out in the  
23 direct evidence, Centra declined to file on the public  
24 record of this proceedings the -- the new contract; is  
25 that correct?

1 MR. GREG BARNLUND: That's correct.

2 MR. BOB PETERS: And can you just  
3 summarize for the Board again, what were the main reasons  
4 that you declined to provide a copy on the public record?

5 MR. GREG BARNLUND: There were several  
6 reasons for that decision. Primarily, when this contract  
7 was entered into there was a provision in the agreement  
8 that provided for confidentiality of the -- of the  
9 contract.

10 Secondly, the counterparty expressed an  
11 interest in maintaining the confidentiality. And in  
12 addition, it's viewed that -- that the further  
13 communication of these pricing terms may represent some  
14 risk in future RFPs or in future supply contract  
15 negotiations.

16 MR. BOB PETERS: Am I correct in those  
17 major reasons, Mr. Barnlund, that it was the  
18 counterparty, ConocoPhillips, who wanted confidentiality  
19 and the confidentiality provision included in the  
20 contract?

21 MR. NEIL KOSTICK: The confidentiality  
22 provision exists in the underlying base contract, which  
23 has been in effect for a number of years. It's, in fact,  
24 fairly standard to transact on the expectation of  
25 confidentiality.

1                   Conoco did also express explicitly their  
2 desire to maintain the -- the specifics of the contract  
3 confidential.

4                   MR. BOB PETERS:     Just on that point, Mr.  
5 Kostick, Centra's request for a proposal included the  
6 North American Energy Standards Board base contract that  
7 you refer to, didn't it?

8                   MR. NEIL KOSTICK:    It included -- no, RFP  
9 was a standard copy of that -- of the NAESB contract,  
10 that's correct.

11                  MR. BOB PETERS:    And -- and that was  
12 filed at CAS/CSMO/CENTRA-1-B? A copy of that was  
13 provided?

14                  MR. NEIL KOSTICK:   I'll take that as  
15 correct.

16                  MR. BOB PETERS:    And in that contract,  
17 sir, there is a provision -- and make sure Ms. Murphy's  
18 hand is close to the buzzer here because I'm not asking  
19 you for any legal interpretation, but under that base  
20 contract is it your understanding that there is, what  
21 I'll call, a forced disclosure provision, where the  
22 provisions of the contract can be disclosed if a  
23 regulatory body orders it be disclosed?

24                  MR. NEIL KOSTICK:   That is my  
25 understanding.

1                   MR. BOB PETERS:    And that's always been  
2 the way that the North American Energy Standards Board  
3 contract has -- they've always had a provision for forced  
4 disclosure under compulsion by either a regulator or a  
5 court of competent jurisdiction?

6                   MS. MARLA MURPHY:    I don't know that Mr.  
7 Kostick is in a position to give that history and,  
8 frankly, neither am I.  But certainly ...

9                   MR. BOB PETERS:    Look to the guy with the  
10 grey hair.

11                  MR. HOWARD STEPHENS:    I can -- I can  
12 confirm that.

13                  MR. BOB PETERS:    All right.  Ms. Murphy's  
14 point is valid.  It's -- however long it's been in the  
15 past it certainly was a provision in the request for  
16 proposal sent out this time, that the standard form with  
17 the forced disclosure provision as clause 14(10) was  
18 included if you're looking for reference.

19                  MR. HOWARD STEPHENS:    That's correct.

20                  MR. BOB PETERS:    And just also I think to  
21 be correct that if a regulator orders disclosure of the  
22 contract before Centra complies Centra is obligated to  
23 notify the counterparty so that the counterparty can have  
24 the opportunity to seek a protective order from the Court  
25 of Queen's Bench should it so decide or to appeal the

1 decision of the regulator. Is that also your  
2 understanding?

3 MR. NEIL KOSTICK: Yes.

4 MR. BOB PETERS: Now, in terms of -- Mr.  
5 Stephens, you've -- in your CV or your witness  
6 qualifications you've indicated you also testified before  
7 the National Energy Board; that's correct?

8 MR. HOWARD STEPHENS: Yes, and a pleasure  
9 it was.

10 MR. BOB PETERS: And in many of those  
11 proceedings you've been involved in a number of  
12 proceedings where you didn't have to testify; isn't that  
13 also correct?

14 MR. HOWARD STEPHENS: No, we keep much  
15 abre -- very much abreast of what goes on at the NEB and  
16 TransCanada Pipelines.

17 MR. BOB PETERS: And by keeping abreast  
18 at what goes on at NEB, you also have yourself come to  
19 the situation where there's confidential information that  
20 Centra wants access to which may not be readily  
21 available, correct?

22 MR. HOWARD STEPHENS: That's correct.

23 MR. BOB PETERS: And in those cases, sir,  
24 does Centra sign a non-disclosure agreement, or an  
25 agreement to keep information confidential?

1 MR. HOWARD STEPHENS: Well, I mean, I  
2 guess the perfect example of that would be being a member  
3 of the Tolls Task Force, TransCanada's alternate dispute  
4 mechanism, if you will.

5 You have to sign a disclosure agreement  
6 saying that -- I mean, anything that is said within the  
7 context of those meetings is without prejudice and is  
8 confidential. I cannot spread the information that -- I  
9 mean, and regarding the dialogue that we have at those --  
10 those meetings, even to this regulatory body.

11 MR. BOB PETERS: And without that non-  
12 disclosure agreement, you wouldn't have been given access  
13 to that confidential information?

14 MR. HOWARD STEPHENS: You wouldn't be  
15 allowed to sit on the committee.

16 MR. BOB PETERS: And if you weren't  
17 allowed to have access to the information or sit on the  
18 committee, you wouldn't be able to effectively represent  
19 Centra's interest at the committee level, or before the  
20 NEB?

21 MR. HOWARD STEPHENS: That's correct.  
22 That's why we -- we made our sales avail -- selves  
23 available to that committee, so that we can have some  
24 influence over the things that go on on the TransCanada  
25 system.

1                   MR. BOB PETERS:    You'd acknowledge that  
2 the Nexen contract was not afforded the same  
3 confidentiality as is being sought for the  
4 ConocoPhillips' agreement.

5                    Would you agree with that, sir?

6                   MR. HOWARD STEPHENS:   Yes, and -- but I'm  
7 not going to give you just a plain old yes.  You knew  
8 that was going to happen.  We're talking about -- and I'm  
9 going to go back to the marketplace again.  We are  
10 talking about a much more competitive environment.

11                   The Nexen agreement, as I recall, and this  
12 is where I'll refer to the Chairman's comment in terms of  
13 teaching people what I remember of -- well, some of what  
14 I remember is -- is gone, but I believe that that was  
15 structured also as -- whether or not it was on the NAESB  
16 contract, or the GISB contract, which is the Gas Industry  
17 Standards Board contract, which was the preda --  
18 predecessor for the NAESB, also had similar language in  
19 it.

20                   So from that perspective, I mean, Nexen  
21 would have been within their right to say to us, No, we  
22 don't want you to put this in the public forum, that it's  
23 confidential, and that from that perspective it -- I  
24 mean, we're not -- we don't want you to put it in there  
25 unless we're absolutely forced to.

1                   MR. BOB PETERS:    So from that answer, do  
2 I take it that the counterparty was the one who dictated  
3 the change in -- in how that contract was publically  
4 disclosed?

5                   MR. HOWARD STEPHENS:    Can you --

6                   MR. BOB PETERS:    Okay.  Let me re --  
7 repeat the question, Mr. Stephens.  Am I correct in  
8 understanding your last answer that Nexen was prepared to  
9 allow its contract to be publically disclosed, whereas  
10 ConocoPhillips has made a request for confidentiality?

11                  MR. HOWARD STEPHENS:    And that's correct,  
12 and I think it has -- and it's a complex answer, but it's  
13 -- it's how we arrived at dealing with Nexen, and the  
14 fact that it was the result of, first of all, an  
15 assignment from the original WGML contracts, and then the  
16 Mirant contracts, and ultimately to Nexen, that through  
17 that process we had to demonstrate to the regulator that,  
18 you know, we had sufficient, you know, coverage to  
19 satisfy our market requirements.

20                  So I don't think anybody was hanging up at  
21 that particular point in time with respect to  
22 confidentiality issues at that time.

23                  MR. BOB PETERS:    Is there a provision  
24 available, to your understanding -- and again, Ms. Murphy  
25 will have the final veto on any legal questions, I

1 appreciate -- but is it Centra's understanding that if  
2 Centra wanted somebody to see the ConocoPhillips'  
3 agreement, Centra could ask that a non-disclosure  
4 agreement be signed?

5 MR. HOWARD STEPHENS: I think we could  
6 prevail upon them in terms of doing that. I don't know  
7 that there's necessarily any benefit associated with that  
8 though, Mr. Peters.

9 MR. BOB PETERS: All right. Let me just  
10 personalize this, and I'll --

11 MR. HOWARD STEPHENS: Should I take my  
12 jacket off, or...

13 MR. BOB PETERS: No, no. I just wanted  
14 to say the personalization is -- I heard in the opening  
15 comments from my friend opposite, Mr. Saxberg, that he,  
16 like me, hasn't necessarily seen the terms and conditions  
17 of the contract.

18 Would there be anything preventing Centra  
19 from requesting of Mr. Saxberg, his client, or his  
20 consultants to enter into a non-disclosure agreement so  
21 that they would have access to it, not -- not from a  
22 legal perspective, but from a mechanical process with  
23 ConocoPhillips?

24

25

(BRIEF PAUSE)

1 MS. MARLA MURPHY: Okay, I've persuaded  
2 Mr. Stephens that it's my turn. The -- the con -- the  
3 NAESB Agreement itself does not contemplate the entrance  
4 into a confidentiality agreement, so we would be left in  
5 the position where we would have to go back to the  
6 supplier to be able to discuss with them whether or not  
7 that was acceptable, and they would ultimately consent,  
8 would certainly be my take on that -- the provisions  
9 there.

10 It -- it does require that we use  
11 reasonable efforts to keep things confidential and  
12 doesn't contemplate disclosing with an agreement to a  
13 third party.

14

15 CONTINUED BY MR. BOB PETERS:

16 MR. BOB PETERS: Appreciate Ms. Murphy's  
17 response. And, Mr. Stephens, the -- the sum of that  
18 response is that there's nothing in the contract itself  
19 that permits Centra the opportunity to use non-disclosure  
20 agreements to share the contract.

21 That would be something that, if I use  
22 your words correctly, you would have to prevail upon the  
23 counterparty to be able to do that?

24 MR. HOWARD STEPHENS: That's correct, and  
25 I would be loathe to do that because I don't think that

1 would in the interests of our customer, and I don't think  
2 that our holding that contract in confident -- as a  
3 confidential document inhibits the Board in any way from  
4 determining whether or not the gas cost consequences  
5 associated with it are prudent.

6 MR. BOB PETERS: Okay. Well let's just  
7 jump to that answer you've given the Board, Mr. Stephens.

8 What if, in the -- the Board's final  
9 determination, the gas cost consequences are not prudent  
10 in the ConocoPhillips' contract?

11 You've already entered into the contract.  
12 You've already procured gas under the contract. You've  
13 already made payments under the contract.

14 Is there a regulatory provision that if  
15 this regulator doesn't feel that the gas cost  
16 consequences are prudent, that you can get out of the  
17 deal with ConocoPhillips?

18 MR. HOWARD STEPHENS: No, we've signed  
19 the agreement in good faith. I guess, in that  
20 circumstance, I mean, I certainly don't want to be tested  
21 in terms of my thinking with respect to this, that we  
22 would go back to ConocoPhillips and explain the  
23 circumstance to them and see what kind of a result -- I  
24 mean, resolution we could come to.

25 I don't believe that's the circumstance.

1 I think it's -- it's incumbent upon us here today to  
2 demonstrate to you that the process that we used was  
3 sound, best practices, and then from -- I mean, and the  
4 output as a result of that process is going to provide  
5 with cus -- our customers with a gas supply that meets  
6 all of the objectives that are necessary for us to supply  
7 gas in a secure reliable fashion at a very cost  
8 competitive price.

9 MR. BOB PETERS: And I was only raising  
10 the hypothetical, you understand that, that if, for  
11 whatever reason, the Board determined that the gas costs  
12 weren't prudent and they didn't want to flow those  
13 through into gas rates, what I'm hearing you say is,  
14 short of ConocoPhillips providing an accommodation, it  
15 would hit Centra on the retained earnings?

16 MR. HOWARD STEPHENS: Yes, it's -- I  
17 mean, actually, we had some discussion along this line  
18 because prior to -- I'm taking us back in time again.  
19 Sorry for these little time travel trips.

20 Prior to being acquired by Hydro, and when  
21 we were under the old WGML contracts, we always brought  
22 those contracts in and we asked for approval of the cost  
23 consequences, and we always had a hearing prior to  
24 actually taking a delivery underneath those contracts.

25 And, I mean, there were additional

1 provisions within those contracts where WGML was  
2 representing a group of producers that were underpinning  
3 the contract, and they also had to agree to it.

4           So it was a very onerous process on our  
5 part to try and get approval for the contracts because,  
6 as a shareholder of a company, if those -- the costs  
7 allow -- I mean, were disallowed under those gas supply  
8 contracts, it could break the company very quickly. So  
9 we needed that assurance, otherwise, we'd be -- just  
10 weren't prepared to engage.

11           MR. BOB PETERS: Well, those consequences  
12 are still every bit as large, if not larger, Mr.  
13 Stephens, and they could, in your words, break the  
14 company if they were disallowed, couldn't they?

15           MR. HOWARD STEPHENS: Yes. And think it  
16 -- some -- I mean, at some point along the line, and I'm  
17 only speaking from a personal perspective, but we did get  
18 the Board's acknowledgement with respect to the -- in  
19 2004, in the 2004 renegotiative -- renegotiation of the  
20 Nexen contract, and we have that language again in our  
21 application here.

22           I would anticipate that we would get, I  
23 mean, an acknowledgement from the Board that they find  
24 the terms of the contract that we have negotiated are  
25 appropriate and that you will approve, on the basis of

1 the structure that we've put forward and the outcome,  
2 that you will approve those consequences, and we won't  
3 have a surprise at the end of the next -- I mean, or for  
4 next time we're in front of the Board and asking for the,  
5 you know, final close -- close-off with respect to our  
6 quarterly rate applications.

7 MR. BOB PETERS: Mr. Stephens, does it  
8 make the negotiation of the contract harder or impossible  
9 if it's subject to regulatory approval, if the cost  
10 consequences are subject to regulatory approval, like you  
11 had under the Western Gas Marketing Limited arrangements?

12 MR. HOWARD STEPHENS: Well, certainly  
13 that was a very, very onerous process, because we were  
14 looking for the approval of a number of different  
15 parties, all beyond our control. In this circumstance,  
16 to me, it's much more mechanical. I mean, it's a  
17 demonstration of the process that we've used to acquire  
18 the gas, and we've gotten good advice from a consultant  
19 with respect to the appropriate process, we've gotten  
20 comments with respect to the -- well, the -- the  
21 documentation and the RFP, et cetera.

22 So, I mean, I -- I take a great deal of  
23 comfort in the fact that we had -- you know, we cast the  
24 net very wide, I mean, on a very broad basis, to a number  
25 of different counterparts. We specifically identified

1 our requirements. They came back and they addressed each  
2 one of those, I mean, requirements. We had a very  
3 rigorous testing process, and then, from that  
4 perspective, we made our decision in terms of which was  
5 the -- which contract best met the Manitoba consumers'  
6 needs, based upon a number of predetermined attributes.

7 MR. BOB PETERS: I just want to carry it  
8 further, and perhaps off script here, but understand that  
9 -- let's suppose that an Intervener has put in evidence  
10 that suggests that there's a way to determine whether the  
11 cost consequences are prudent.

12 And Centra, on the other hand, has said,  
13 Well, the RFP is evidence of a prudent process and  
14 resulting prudent costs. You could appreciate that there  
15 could be a disagreement amongst parties as to whether the  
16 costs are or are not prudent.

17 MR. HOWARD STEPHENS: Certainly. It  
18 depends on your perspective, and it -- it also determines  
19 -- or is very much dependent upon the attributes that you  
20 look for under the contract. And if there's a different  
21 weighting with respect to any one (1) of those  
22 attributes, if -- whatever counterpart you want to talk  
23 about, and if price is their first consideration, then --  
24 and reliability is a second or a third consideration,  
25 certainly that's going to have a different outcome than

1 if our first consideration is reliability and price is a  
2 secondary consideration.

3 So, I mean, you get into a whole host of,  
4 you know, different variables associated with it.

5 MR. BOB PETERS: All right. Then that  
6 just circles back, and I'll end on this thought: that if  
7 -- if your contract can be subject to a different  
8 perspective from different parties, perhaps disagreement  
9 amongst parties, wouldn't it then be prudent to try to  
10 deal with those different perspectives and concerns  
11 earlier rather than later when trying to get the cost  
12 consequences approved?

13 MR. HOWARD STEPHENS: Give me a minute.  
14 When you say earlier, I mean, far -- I mean, in advance  
15 of the contract coming into place, into -- into force?

16 MR. BOB PETERS: Well, I -- I suppose at  
17 the time you know what is on your term sheet that's about  
18 to be turned into a contract. That would be one  
19 opportunity to do it.

20 What happens now is, this contract was  
21 effective on November 1st, so we had November, December,  
22 January, February, March. We're already into the sixth  
23 month of the contract, and now you're asking the Board to  
24 approve the cost consequences belatedly -- not -- not in  
25 a negative connotation, but after the fact.

1                   MR. HOWARD STEPHENS:   Well, that's --  
2   that's true.  And I think -- I mean, I addressed this  
3   earlier.  I mean, it's the -- regardless of whether or  
4   not -- and I will agree, it would be preferable if we had  
5   the Board's concurrence prior to taking gas under  
6   delivery -- delivery under the -- taking gas delivered  
7   under the contract.  But I think it's -- the more  
8   critical component of it is that the Board sees the  
9   process that we used, and concurs that the process was  
10  sound.  And if they find the process to be sound, the  
11  outcome will be sound.

12                   MR. BOB PETERS:    And you're making Ms.  
13  Murphy's arguments for her, and I appreciate that, Mr.  
14  Stephens.  And -- and just -- can you indicate to the  
15  Board -- I haven't seen the contract, as I've told Mr.  
16  Saxberg -- when was it signed relative to November 1  
17  implementation of gas flowing?  Was it a month before,  
18  two (2) months before?

19                   MR. HOWARD STEPHENS:   Sometime midsummer,  
20  I'll put it that way.

21                   MR. BOB PETERS:    Now the way I wanted to  
22  close was, what if there was an opportunity after  
23  midsummer to approach the Board maybe with a filing and  
24  including Mr. Saxberg and Ms. Ruzycki, and say, if we can  
25  convince ConocoPhillips to allow us to share this by way

1 of a non-disclosure agreement we'd like do that, and is  
2 that something that you thought of doing at the time or  
3 was that not even a contemplation?

4 MR. HOWARD STEPHENS: I guess,  
5 ultimately, I mean, there's two (2) considerations that  
6 come to mind. First of all, I mean, you can have them  
7 sign non-disclosure agreements, you know, until I'm  
8 buried in them. And really there is, I mean, no -- I  
9 have no way to claim damages if they breach those  
10 agreements.

11 Secondly, and I guess, I mean, this may  
12 sound a bit paternalistic, but ultimately, we are the  
13 ones that are responsible for serving the Manitoba market  
14 and from that perspective I may disagree with the parties  
15 that are coming to the table in terms of what's important  
16 in terms of serving this market, but I'm also the one  
17 that's going to answer for it.

18 So, I mean, from that perspective, yes, I  
19 like to get input from any stakeholders, I mean, as much  
20 as we can but there are some circumstances where  
21 stakeholders' interests are not necessarily in alignment  
22 with ours.

23 MR. NEIL KOSTICK: I would just like to  
24 add that Centra, as part of its RFP process, did have a  
25 stakeholder consultation meeting in November of 2008. It

1 advanced to -- of our issuing RFP.

2 MR. BOB PETERS: All right. Good points.

3 Mr. Stephens, while Centra is the one  
4 responsible for serving the load, my question is, well,  
5 why would Centra want to carry all the risk of that when  
6 you're not making any money from the molecules that  
7 you're purchasing?

8 MR. HOWARD STEPHENS: Well, I think  
9 that's always been the case with respect to this, I mean,  
10 in terms of the acquisition of gas. I mean, that's a  
11 pass-through cost and we assume that the regulator agrees  
12 with the pricing formula or the contractual arrangements  
13 that we've put into place to satisfy our customers'  
14 requirements.

15 I mean, we have no motivation but to do  
16 the best that we can with respect to that. I'm a gas  
17 consumer, actually quite a considerable gas consumer; I  
18 don't want to pay anymore than I have to for it.

19 MR. BOB PETERS: Okay.

20 MR. HOWARD STEPHENS: But the other  
21 component of it that, I mean, I think is very important  
22 to recognize is that if we don't leave or have the  
23 confidentiality with respect to this -- and I alluded to  
24 this earlier in terms of the marketplace is different  
25 now. The terms of the contract are confidential simply

1 from the perspective that they set the market, if you  
2 will, for sales into Manitoba. And if you broadcast them  
3 all over the countryside, the next time we go to the  
4 market people are going to know that if, you know, we're  
5 buying gas at index plus two (2) that index plus two (2)  
6 cuts the mustard and that's going to be the nature of the  
7 type of quotes that we will get the next time.

8           And I don't want to have that information  
9 out there as common knowledge because it ta -- puts us in  
10 an awkward position and we may not get, I mean, the same  
11 type of arrangement or offers as we -- I mean, as we have  
12 in this -- during this go around, simply because it's  
13 confidential and the counterparts are prepared to provide  
14 us with more aggressive pricing as long as it's not  
15 advertised all over the countryside.

16           MR. BOB PETERS: Mr. Stephens, you threw  
17 out a legal term about unable to recover damages. My  
18 only thought on that was, couldn't the contract contain a  
19 liquidated damages clause? And I appreciate there's a  
20 legal component to that so I'm not going to ask you to  
21 answer that.

22           But -- but your concern was, if somebody  
23 breaches a non-disclosure agreement what kind of money  
24 can you get from them because it's difficult to show what  
25 damages resulted. That --

1 MR. HOWARD STEPHENS: What --

2 MR. BOB PETERS: -- was your point.

3 MR. HOWARD STEPHENS: What recourse do I  
4 have?

5 MR. BOB PETERS: Well -- and I'm just  
6 suggesting --

7 MR. HOWARD STEPHENS: Yeah.

8 MR. BOB PETERS: -- that if there was a  
9 liquidated damages clause in the contract maybe that's  
10 something the lawyers would -- would look at, but...

11 MR. HOWARD STEPHENS: I think it would be  
12 -- it would be a very thorny issue to try and deal with,  
13 I mean, and demonstrate what damages are being -- you  
14 know, have been actually accrued. And, I mean, I don't  
15 want to get down that road.

16 MR. BOB PETERS: All right. What you do  
17 want to get down to is at the book of documents, Tab 6 --  
18 sorry Tab 12 of the book of documents is PUB/CENTRA-16  
19 and this is a document to which attached is a letter from  
20 Centra, dated October 16th, 2009, and that letter,  
21 amongst other things, contains a decision matrix, albeit  
22 in a redacted form.

23 Is that correct?

24

25 (BRIEF PAUSE)

1 MR. NEIL KOSTICK: I'm sorry, I missed  
2 half the question. I -- could you please repeat it?

3 MR. BOB PETERS: At Tab 16 -- I'm sorry,  
4 at Tab 12 of the book of documents is PUB/CENTRA-16, and  
5 it contains Centra's letter of October 16th, to the  
6 Board, in which there's a decision matrix at the last  
7 page that was used to evaluate the six (6) responses to  
8 the RFP sent out?

9 MR. NEIL KOSTICK: That's correct.

10 MR. BOB PETERS: You sent out fifty (50)  
11 requests for proposals?

12 MR. NEIL KOSTICK: Yes.

13 MR. BOB PETERS: And only six (6) came  
14 back?

15 MR. NEIL KOSTICK: Correct.

16 MR. BOB PETERS: What does that tell  
17 Centra?

18 MR. NEIL KOSTICK: It tells us that our  
19 requirements are very challenging, and there are a  
20 limited number of players in the market that have the  
21 qualifications and willingness to serve those challenging  
22 requirements.

23 MR. BOB PETERS: Did you ask forty-four  
24 (44) people if that was -- if that was correct, or is  
25 that an assumption you're making?

1 MR. NEIL KOSTICK: We know from  
2 discussions with a number of our counterparties, that  
3 they did not feel that they were capable of serving  
4 Centra's requirements, and indicated to us in advance  
5 that they would not be bidding on our RFP requirements.

6

7 (BRIEF PAUSE)

8

9 MR. BOB PETERS: Of the forty-four (44)  
10 who didn't respond, how many did you talk to to get that  
11 understanding that they just felt Centra's requirements  
12 were beyond their capabilities?

13 MR. NEIL KOSTICK: We would have had  
14 discussions with several of those counterparties, mainly  
15 those that we have the closest relationships with to  
16 begin with, and that would inform our understanding of  
17 that situation.

18 MR. BOB PETERS: So probably a sample  
19 group of five (5) counterparties?

20 MR. NEIL KOSTICK: That would be roughly  
21 accurate.

22 MR. BOB PETERS: All right. And you  
23 didn't issue a follow-up exit survey or, you know, why-  
24 did-you-dump-me letter to -- to find out why not more  
25 people specifically had concerns, to see if that's

1 something you could address in -- in your portfolio going  
2 forward?

3 MR. NEIL KOSTICK: We did not do that,  
4 but we also recognize that a number of the parties on  
5 that list are not particularly active in the Alberta  
6 market, and we would have known in advance that they  
7 would not be likely to be bidders.

8 However, we want -- we did want to cast  
9 the widest net possible to include all possibilities as  
10 far as counterparties of any substance in North America.

11 MR. BOB PETERS: And Centra had  
12 assistance in preparing the request for proposal.

13 Is that correct?

14 MR. NEIL KOSTICK: Yes.

15 MR. BOB PETERS: And it was through the  
16 assistance of a company know as ICF Consulting?

17 MR. NEIL KOSTICK: Yes.

18 MR. BOB PETERS: And I think that ICF  
19 report was reviewed at the 2009 GRA when you last  
20 testified, Mr. Kostick?

21 MR. NEIL KOSTICK: Yes.

22

23 (BRIEF PAUSE)

24

25 MR. BOB PETERS: When we turn to the

1 decision matrix, which is the last page of Tab 12 of  
2 Board counsel's book of documents, it's page 3 of 3 of  
3 the attachment, this matrix was prepared with the names  
4 redacted, correct?

5 MR. NEIL KOSTICK: We filed it with the  
6 names redacted.

7 MR. BOB PETERS: As we sit here, we now  
8 know at least who one (1) of the parties are, that's a --

9 MR. NEIL KOSTICK: I believe so, yes.

10 MR. BOB PETERS: -- matter of public  
11 record?

12 MR. NEIL KOSTICK: Yes.

13 MR. BOB PETERS: Are you going to tell me  
14 which one it is, so I don't have to be the one who puts  
15 it on the public record, if I'm not supposed to?

16 MR. HOWARD STEPHENS: Only if we can kill  
17 him after.

18 MS. MARLA MURPHY: Are you ready to sign  
19 that agreement yet?

20 MR. HOWARD STEPHENS: We'll have to shoot  
21 you right after.

22 MR. NEIL KOSTICK: Party A is  
23 ConocoPhillips.

24

25 CONTINUED BY MR. BOB PETERS:

1                   MR. BOB PETERS:    That said, there were  
2 seven (7) criteria selected against which all the parties  
3 were going to be evaluated, correct?

4                   MR. NEIL KOSTICK:    That's correct.

5                   MR. BOB PETERS:    Who fixed the weighting  
6 of these seven (7) criteria?

7                   MR. NEIL KOSTICK:    Centra, with input  
8 from ICF.

9                   MR. BOB PETERS:    And the selection of the  
10 weighting, you would agree with me, is a subjective  
11 exercise?

12                   MR. NEIL KOSTICK:    Agreed.

13                   MR. BOB PETERS:    And Mr. Stephens told us  
14 about that, that somebody may have a different view?

15                   MR. HOWARD STEPHENS:   It is a somewhat  
16 qualitative process as opposed to a quantitative process.  
17 We try to make it as quantitative as possible.

18                   MR. BOB PETERS:    Well, the most important  
19 weighting you gave was to reli -- for reliable service,  
20 correct?

21                   MR. NEIL KOSTICK:    Yes.

22                   MR. BOB PETERS:    And then the second most  
23 important was minimize total gas costs?

24                   MR. NEIL KOSTICK:    That's right.

25                   MR. BOB PETERS:    And does that tell the

1 Board that reliability is more important than cost?

2 MR. NEIL KOSTICK: Yes.

3 MR. BOB PETERS: By not by much; by 25  
4 percent?

5 MR. HOWARD STEPHENS: Well, that depends  
6 on the day we would ask the question on. When it's  
7 thirty (30) below in the middle of January I'll ask you -  
8 - I'll come -- I'll phone you and ask you how important  
9 it is that you get your gas.

10 MR. BOB PETERS: Yeah, and, you know, I  
11 appreciate the lightheartedness of the answer, Mr.  
12 Stephens, but the reality is, if it's the dead of winter  
13 and it's the coldest day on record, my furnace is going  
14 to be working because you've arranged gas either through  
15 some contractual provision or you've drafted the main  
16 line; isn't that correct?

17 MR. HOWARD STEPHENS: Well, I think that  
18 that -- that may have been. And I anticipated that  
19 question. There is not nearly so much gas on the main  
20 line to be drafted. The fact that they're running only  
21 less than half full right now means that there is less  
22 gas going by here and the impact of us drafting their  
23 system could potentially have some pretty significant  
24 outcomes on the other end of the pipe.

25 And, I mean, secondly, it's completely

1 irresponsible on my part to ha -- to build that into my  
2 plan in terms of how I'm going to satisfy that  
3 requirement.

4 MR. BOB PETERS: And you haven't built  
5 that into your plan and -- have you?

6 MR. HOWARD STEPHENS: Absolutely not,  
7 sir.

8 MR. BOB PETERS: But if -- but if we talk  
9 about reliable service, Manitoba has always had reliable  
10 service under Centra's watch?

11 MR. HOWARD STEPHENS: And simply because,  
12 I mean, we recognize that as the first and foremost  
13 attribute that we're looking for.

14 MR. BOB PETERS: And --

15 MR. HOWARD STEPHENS: And where we sit in  
16 the middle of the bald prairie and the kind of  
17 temperature swings we can see.

18 MR. BOB PETERS: And Centra is prepared  
19 to incur fixed transportation costs just to have  
20 available the capability of bringing gas down the main  
21 line rather than having to either have delivered service  
22 or, as a last resort, drafted off the pipeline?

23 MR. HOWARD STEPHENS: Well, drafted off  
24 the pipeline from my perspective is not an alternative  
25 because that is a complete -- completely irresponsible

1 approach to managing any kind of a business. That's  
2 basically stealing the gas from the system.

3           The other components of it in terms of  
4 whether I'm prepared to pay demand charges on the  
5 pipeline, or whatever the nature of the other  
6 arrangements are, as long as they're the most cost  
7 effective and they -- well, they meet the requirements  
8 that we've already discussed that are in the matrix, I  
9 mean, yes, I'm prepared to pay when it's necessary but I  
10 want to do it in the most cost effective way I can but  
11 meet those objectives.

12           MR. BOB PETERS:    And I said drafting was  
13 the last resort, not part of the plan, not that anybody  
14 wanted to, but that option is -- it has to be the last  
15 resort available to Centra?

16           MR. HOWARD STEPHENS:    Yes, but it's a  
17 limit -- a limited time option. And, I mean -- I mean,  
18 TransCanada has looked at this situation and put some  
19 very significant and onerous changes -- or made changes  
20 to their tariff that deal with continued taking of gas  
21 off the system without the authorization to do so.

22           MR. BOB PETERS:    Okay, a couple of  
23 questions then. Mr. Warden might be able to better help  
24 with this. But does Centra have insurance in the event  
25 that Centra had to, as a last resort, draft off the main

1 line which resulted in, let's just say, some manufacturer  
2 shutting down a car plant in -- in Ontario and there was  
3 consequential damages that would be pointed back towards  
4 Centra Gas Manitoba?

5 Is there insurance in place for such an  
6 occurrence?

7 MR. VINCE WARDEN: No, I'm -- Mr. Peters,  
8 I'm not aware of any such insurance that's available to  
9 us.

10 MR. BOB PETERS: All right. And if you  
11 do become aware you can let the Board know through your  
12 counsel; would that be fair?

13

14 (BRIEF PAUSE)

15

16 MR. BOB PETERS: My question is, are you  
17 -- Centra doesn't have that insurance or you're not aware  
18 whether Centra has that insurance?

19 MR. VINCE WARDEN: Centra doesn't have  
20 that insurance.

21 MR. BOB PETERS: All right. Then the  
22 next --

23 MR. HOWARD STEPHENS: I -- I -- I will  
24 add, though, Mr. Peters, that we do have a mutual aid  
25 agreement with other LDCs that, in such a circumstance,

1 LDCs will come to the aid of others to the extent that  
2 it's possible so that we can, you know, acquire gas from  
3 other shippers on the pipeline.

4                   And, ultimately, I mean, in -- in that  
5 dire strait -- and I hope I never -- don't have to face  
6 that in my lifetime -- I mean, we would be in contact  
7 with TransCanada and, I mean, lay out the situation for  
8 them, and the duration that we expect to have a  
9 difficulty, and in that circumstance we would try to come  
10 to some sort of accommodation.

11                   MR. BOB PETERS:    Of course. Can you tell  
12 the Board -- Mr. Stephens, can you tell the Board whether  
13 there has ever been an occurrence where Centra has had to  
14 draft off the pipeline as a last resort?

15                   MR. HOWARD STEPHENS:   No, we've never  
16 deliberately drafted off of the pipeline.

17                   MR. BOB PETERS:    How do you not  
18 deliberately draft?

19                   MR. HOWARD STEPHENS:   Well, sometimes, I  
20 mean, we talked about, I mean, how volatile our load can  
21 be in our circumstances. I mean, there are provisions  
22 within our contract for us to have imbalances between  
23 what we have nominated and what we actually take delivery  
24 of.

25                   And to the extent that there are

1 imbalances, we pay costs associated with that, and those  
2 were all identified within our application. So from that  
3 perspective, I mean, yes, I -- we do draft, but it's  
4 recognized that it's going to occur, and we keep it to a  
5 minimum.

6 MR. BOB PETERS: In the matrix, that's  
7 page 3 of 3 of the attachment at Tab 12 of the book of  
8 documents, there was 40 percent waiting on reliable  
9 service and there was 30 percent waiting on minimizing  
10 the total cost, as I understood the matrix, is that  
11 right?

12 MR. NEIL KOSTICK: That's correct.

13 MR. BOB PETERS: And you went with the  
14 lower cost option, not the higher reliability option.

15 MR. NEIL KOSTICK: We went with the  
16 option that represented the best combination of supplier  
17 and proposal attributes, as identified to the matrix.

18 MR. BOB PETERS: Okay. You're saying --  
19 I appreciate you're giving your answer to that, but I see  
20 that Party B had the perfect score under reliability,  
21 whereas Party A didn't, but you still chose Party A in  
22 terms of providing it, and Party A had a better -- lower  
23 gas cost than did Party B. Wouldn't that be a fair  
24 interpretation?

25 MR. NEIL KOSTICK: That is correct as far

1 as how it was scored, yes.

2 MR. BOB PETERS: And the other items of -  
3 - or criteria that are listed in terms of  
4 creditworthiness and counterparty quality, again, you had  
5 to ascribe some notional weighting to those, but when it  
6 all came down to it, it was the -- it was the reliability  
7 and the total cost that carried the day?

8 MR. NEIL KOSTICK: It's the combination  
9 of attributes, all the categories in total. And as we've  
10 noted in our rebuttal evidence, ConocoPhillips is the  
11 only party that scored in the top two (2) of every  
12 category in the matrix.

13

14 (BRIEF PAUSE)

15

16 MR. BOB PETERS: Just while we're on  
17 that, the ConocoPhillips that scored on this matrix was  
18 ConocoPhillips Canada Marketing and Trading ULC. That  
19 would be the corporate name.

20 MR. NEIL KOSTICK: That would be the  
21 legal entity that we are contracted with, correct.

22 MR. BOB PETERS: And to what extent is  
23 that legal entity -- first of all, it's an affiliation,  
24 an affiliated company to ConocoPhillips Inc., that's your  
25 understanding?

1                   MR. NEIL KOSTICK:    Yes, it is related to  
2 a parent company. Our understanding is that their  
3 operations are quite integrated within Canada.

4                   MR. BOB PETERS:    And -- and why wouldn't  
5 this agreement be with the parent company as opposed to  
6 an affiliate company?

7                   MR. HOWARD STEPHENS:   It's simply not the  
8 nature of their business, Mr. Peters. They have an arm  
9 that deals with the type of transactions that we're  
10 talking about, and that's the one that we're dealing  
11 with.

12                   MR. BOB PETERS:    And in terms of the arm  
13 you were dealing with, while it has the affiliation with  
14 the parent company, what protection did Centra Gas  
15 Manitoba Inc. take as against the corporate parent?

16                   MR. NEIL KOSTICK:    Centra received a  
17 parental guarantee from ConocoPhillips, the parent  
18 company of the marketing arm.

19                   MR. BOB PETERS:    And what is the  
20 guarantee for, guarantee of performance?

21                   MR. NEIL KOSTICK:    Yes.

22

23

(BRIEF PAUSE)

24

25                   MR. BOB PETERS:    If we turn back in Tab

1 12 of the book of documents to the Information Request,  
2 PUB/CENTRA-16, and go to the Question (d). That would be  
3 the (d) portion of this IR. Centra puts a chart on the  
4 top of page 3 of 4 which compares the financial impacts  
5 of the various proposals that it received, is that  
6 correct?

7 MR. NEIL KOSTICK: We provided a forecast  
8 to respond to the information request.

9 MR. BOB PETERS: And, Mr. Kostick, does  
10 that forecast suggest that, if Party B was selected, the  
11 cost consequences of Party B supplying Centra gas for the  
12 '09/'10 gas year would have been eight hundred and forty-  
13 one thousand dollars (\$841,000) more than what Party A  
14 will cost?

15 MR. NEIL KOSTICK: Correct.

16 MR. BOB PETERS: I'm not sure if anything  
17 turns on it, Mr. Kostick, but when I looked at that chart  
18 on the top of page 3 of 4, it didn't seem to correlate --  
19 at least in my mind -- with how you rated the  
20 counterparties on the redacted matrix at the end of this  
21 information request. It appears that Party B was eight  
22 hundred and forty-one thousand dollars (\$841,000) more  
23 expensive than Party B (sic) but it was still in the  
24 neighbourhood of seven hundred thousand dollars  
25 (\$700,000) cheaper than Party C. Am I reading that

1 right?

2 MR. NEIL KOSTICK: Yes.

3 MR. BOB PETERS: And then, when I go to  
4 your matrix and I look under Party C, Party C scored a  
5 seven (7) out of ten (10), as did Party B, in terms of  
6 their minimized commodity costs, and I don't see the two  
7 (2) as being equal. Why would you rank them equal?

8 MR. NEIL KOSTICK: Our matrix  
9 incorporated a variety of information in scoring the  
10 pricing, whereas the response to the PUB IR was a literal  
11 response to the request for a forecast.

12 MR. BOB PETERS: All right. I'm still  
13 disconnected on the two (2). If -- was it Centra who did  
14 the scoring, or was it ICF, or was it both of you?

15 MR. NEIL KOSTICK: We scored the -- we  
16 scored the matrix.

17 MR. BOB PETERS: Okay. Now -- and then  
18 let's go back to my second last question. If Party B is  
19 less expensive than Party C, why do they score the same  
20 on the matrix?

21 MR. NEIL KOSTICK: There were different  
22 pricing elements included in different -- in the  
23 different bids, and one way to compare them would be to  
24 use a form of futures pricing. There are other pieces of  
25 information that could be used in order to come up with

1 the relative scoring between the bids.

2 It is not easy to make an apples-to-apples  
3 comparison, given the different elements contained within  
4 the different bids. As a result, there is a level of  
5 judgment involved, as well, and the results of Centra's  
6 evaluation of the different pricing proposals is  
7 reflected in the matrix.

8 MR. BOB PETERS: Can you give the Board  
9 an idea as to what these other pieces of information  
10 refer to? And I appreciate you may be keeping your cards  
11 close to the vest because you don't want to disclose the  
12 specifics, but -- but how is it that one can be twice as  
13 expensive as another, yet still score the same on the --  
14 the cost value?

15

16 (BRIEF PAUSE)

17

18 THE CHAIRPERSON: Mr. Peters, I think  
19 we'll take the break right now to give them a chance  
20 to...

21 MR. BOB PETERS: Certainly, sir. Thank  
22 you.

23

24 --- Upon recessing at 2:48 p.m.

25 --- Upon resuming at 3:12 p.m.

1 THE CHAIRPERSON: Okay, welcome back.  
2 Mr. Peters...?

3

4 CONTINUED BY MR. BOB PETERS:

5 MR. BOB PETERS: Yes, thank you. Before  
6 the afternoon recess, Mr. Chairman and Board members, I  
7 was just trying to understand the rankings that were  
8 provided with respect to the minimizing of commodity  
9 costs, and I had tried to review the information provided  
10 at Tab 12 of the book of documents, which indicated, at  
11 least to me, that Counterparty A was the lowest cost,  
12 Counterparty B was the next lowest by -- but still eight  
13 hundred thousand dollars (\$800,000) more than Party A,  
14 and then Party C was a further seven hundred thousand  
15 dollars (\$700,000) more than Party B, all of which led me  
16 to wonder why Party B and Party C would give this -- be  
17 given the same scoring.

18 And Mr. Kostick and I were just exploring  
19 that, so maybe you've got an answer for me, sir.

20 MR. NEIL KOSTICK: Yes, I -- I think it's  
21 worth clarifying that we are looking at essentially two  
22 (2) different pieces of information. The response to  
23 PUB-16-D, responding to the specific request for a  
24 forecast, and as a result, certain information was used  
25 to produce that forecast as requested.

1                   The scoring matrix included information  
2 beyond futures pricing. It included recent historical  
3 pricing as well, in order to make comparisons between the  
4 different parties that had different pricing elements  
5 included in their bids. So there's essentially more  
6 information taken into account in the scoring of the  
7 matrix.

8                   MR. BOB PETERS:    Is that information you  
9 can provide to the Board by way of an undertaking, Mr.  
10 Kostick, or is that something for which confidentiality  
11 is claimed?

12

13   (BRIEF PAUSE)

14

15                   MS. MARLA MURPHY:   Mr. Peters, we'll have  
16 to take that under advisement. I -- I don't think we'll  
17 be able to do that, but we'll certainly take it away and  
18 discuss it and confirm back with you our position.

19

20 --- UNDERTAKING NO. 1:           For Centra to provide more  
21   information in the scoring of  
22   the matrix

23

24 CONTINUED BY MR. BOB PETERS:

25                   MR. BOB PETERS:    All right. Well, thank

1 you for that. I want to turn to just one (1) other item  
2 on the matrix, Mr. Chairman, and witnesses, and that is  
3 under the credit financial substantiation must be  
4 investment grade. There was some desire to give 15  
5 percent of the waiting to how creditworthy the  
6 counterparty was.

7 Would that be correct?

8 MR. NEIL KOSTICK: I apologize once  
9 again. I didn't quite catch all of your question.

10 MR. BOB PETERS: All right. In looking  
11 at the credit or financial worthiness of the  
12 counterparties, that was something worth 15 percent in  
13 the total category weightings.

14 MR. NEIL KOSTICK: The credit aspects of  
15 the counterparties represented 10 percent. It was ten  
16 (10) of the fifteen (15) points in that category.

17 MR. BOB PETERS: And that was the credit  
18 rating or worthiness that Centra was placing on the  
19 counterparty, correct?

20 MR. NEIL KOSTICK: That's right.

21 MR. BOB PETERS: The other was whatever  
22 the conditions were by the counterparty being placed on  
23 Centra --

24 MR. NEIL KOSTICK: Yes.

25 MR. BOB PETERS: -- and how onerous those

1 may have been for Centra; that would have formed part of  
2 that 5 percent ranking.

3 MR. NEIL KOSTICK: Yes.

4 MR. BOB PETERS: But when we looked at  
5 the credit rating and worthiness of the counterparties,  
6 the first thing I'm struck with is how low everybody's  
7 ranking is. Why -- why is that in general the case?

8 MR. NEIL KOSTICK: I'm not an expert in  
9 credit ratings under the different credit rating  
10 agencies, however, they have a wide range of ratings for  
11 investment grade credit ratings. For someone to score a  
12 perfect ten (10), they would have to be at the top of  
13 that continuum, and these reflect essentially where these  
14 parties landed on that continuum.

15 MR. BOB PETERS: But by nobody scoring  
16 above -- well, I shouldn't say that. Party D went above  
17 five (5). But Party D was the most creditworthy of all  
18 of your counterparties.

19 MR. NEIL KOSTICK: That is correct.

20 MR. BOB PETERS: And when you look at  
21 Party A, to receive a ranking of five (5), and then Party  
22 B received a ranking of one (1), is the difference  
23 between the two (2) simply the creditworthiness by the  
24 credit rating agencies?

25 MR. NEIL KOSTICK: It's a reflection of

1 their credit ratings.

2 MR. BOB PETERS: It's the relative  
3 ranking as between the two (2) of them?

4 MR. NEIL KOSTICK: It's where they're  
5 placed on a continuum. So if there were ten (10)  
6 different levels of ratings, a score of one (1) would  
7 indicate being at the bottom of that continuum, a score  
8 of five (5) would indicate being in the middle of that  
9 continuum.

10 MR. BOB PETERS: What was the credit  
11 rating ascribed to -- to party A and party B?

12 MR. NEIL KOSTICK: I believe that was  
13 filed in an IR, and I don't know the number of it  
14 offhand, but we could certainly look it up.

15 MR. BOB PETERS: I'm looking at  
16 PUB/CENTRA-55-D, and I didn't put that in the book of  
17 documents, but what struck me as you're pulling that one  
18 up, Mr. Kostick, is you used Moody's, S&P's, and Dominion  
19 Bond Rating Services, three (3) credit rating agencies?

20 MR. NEIL KOSTICK: Yes.

21 MR. BOB PETERS: And, interestingly  
22 enough, not all of the six (6) counterparties were rated  
23 by each of those three (3) credit rating agencies, were  
24 they?

25 MR. NEIL KOSTICK: That -- that is the

1 case.

2 MR. BOB PETERS: So in some cases, you  
3 had to compare what a Moody's A-1 was relative to a  
4 Standard & Poor's AA?

5 MR. NEIL KOSTICK: Yes. My understanding  
6 is, the different credit ratings used by the different  
7 rating agencies can be viewed equivalently by those  
8 involved in the credit industry. We do have a credit  
9 department that looks at that, and they would have  
10 provided this information at how they would all align on  
11 that continuum.

12 MR. BOB PETERS: So when I look at party  
13 B and their credit rating, it appears that -- which  
14 credit rating did you use for them, by the way? Did you  
15 use the Moody's, the Standard & Poor's, or the DBRS?

16 MR. NEIL KOSTICK: It would have been a  
17 blended result.

18 MR. BOB PETERS: And that blended result  
19 would have been around a triple-B minus or somewhere in  
20 that area?

21 MR. NEIL KOSTICK: The three ratings  
22 shown for party B were all very close, so they would be  
23 all in and around that triple-B minus.

24 MR. BOB PETERS: And then how does that  
25 compare with counterparty A that scored a five (5), which

1 had only one (1) credit agency rating it as an A-1?

2 MR. NEIL KOSTICK: I -- I'm sorry. I'm  
3 not sure I understand your question.

4 MR. BOB PETERS: I'd like -- how do you  
5 relatively weight the A-1 compared to the triple-B?

6 MR. NEIL KOSTICK: Well, if, for example,  
7 as I described earlier, if there are ten (10) different  
8 levels of ratings, and, for example, if a triple-B minus  
9 were at the bottom of that rating, then you would get a -  
10 - a score of one (1). If the A-1 falls within the middle  
11 of that continuum -- in -- in other words, the middle of  
12 a continuum of ten (10) different ratings, then that  
13 would result in the five (5).

14 MR. BOB PETERS: Can you provide that  
15 continuum of ratings that you talk about, that -- that  
16 goes from zero to ten (10), I guess?

17 MR. NEIL KOSTICK: Yes, we can.

18

19 --- UNDERTAKING 2: For Centra to provide  
20 continuum of ratings that  
21 goes from zero to ten (10)

22

23 CONTINUED BY MR. BOB PETERS:

24 MR. BOB PETERS: Okay. I'll -- and then  
25 all I need to do is come down to the counterparty's

1 credit rating and that'll tell me where on the continuum  
2 it is, and that's how I should find out how one (1) party  
3 rated five (5) and one rated (1)?

4 MR. NEIL KOSTICK: That's correct.

5 MR. BOB PETERS: Okay. I'll look forward  
6 to receiving that when you have an opportunity, sir.

7 THE CHAIRPERSON: But you also indicated,  
8 did you not, that you got a parent company guarantee?

9 MR. NEIL KOSTICK: That's correct.

10 THE CHAIRPERSON: That would be  
11 supplementary to the credit rating?

12 MR. NEIL KOSTICK: That is correct, yes.

13

14 CONTINUED BY MR. BOB PETERS:

15 MR. BOB PETERS: But just following up  
16 the -- the Chairman's question, how much more  
17 creditworthy is the parental guarantee than if it wasn't  
18 guaranteed by the parent?

19 MR. NEIL KOSTICK: I guess what should be  
20 clarified is that, in the case of all but one of these  
21 parties, the credit ratings of the parent company was  
22 used, and that was the case with Conoco, as a result, we  
23 required the parental guarantee.

24 The -- as noted, these parties are  
25 generally subsidiary companies, and so whichever party we

1 entered into a contract with, if it was with the  
2 subsidiary company we would have sought to secure a  
3 parental guarantee.

4 MR. BOB PETERS: All right. And are the  
5 credit ratings that are provided here on the scoring  
6 matrix for the counterparty who bid on the contract, or  
7 is it for the parent of the party that bid on the  
8 contract?

9 MR. NEIL KOSTICK: In the one (1) case  
10 where the bidding party had its own credit rating, we  
11 used that credit rating. And in the case of the other  
12 parties, where the bidders did not have their own credit  
13 rating, we used the credit rating of the parent.

14 MR. BOB PETERS: So party A is the credit  
15 rating of the parent company?

16 MR. NEIL KOSTICK: The A one is the  
17 parent credit rating. That's correct.

18 MR. BOB PETERS: And in party B, the  
19 triple B, or the BAA3, that's also of the parent company?

20 MR. NEIL KOSTICK: Yes.

21 MR. BOB PETERS: Okay. I will look for  
22 that matrix, and then I think the rest of my questions  
23 will follow out from that.

24

25 (BRIEF PAUSE)

1                   MR. BOB PETERS:    Can you indicate which  
2 of the -- which of the six (6) counterparties was  
3 standing on its own creditworthiness without a parental  
4 guarantee?

5                   MR. NEIL KOSTICK:    That would be party C,  
6 and it should be worth noting that we gave slightly  
7 greater weight to that credit rating given that it was  
8 directly with that counterparty, and a parental guarantee  
9 would not be required.

10                  MR. BOB PETERS:    Now let's just talk  
11 about this matrix in general, and Mr. Stephens, he  
12 commented on it in some of his comments this afternoon.  
13 But is it Centra's position that because they went  
14 through this matrix, if the Board considers this matrix  
15 to be reasonable, then the cost consequences flowing from  
16 the decisions made on this matrix should also be  
17 considered reasonable?

18                  MR. HOWARD STEPHENS:    Yes, Mr. Peters.  I  
19 guess the short answer -- my short answer is, yes.  
20 Unless they see something in this that, in terms of  
21 criteria that we've used, that are completely out to  
22 lunch, I mean, I would think -- suggest that this is as  
23 scientific a method as you can use in terms of evaluating  
24 the different bids, and we've done due diligence with  
25 respect to that.

1                   MR. BOB PETERS:    All right.  That doesn't  
2 suggest -- that doesn't suggest, Mr. Stephens, that there  
3 isn't a lower cost gas supplier out there for Manitoba,  
4 does it?

5                   MR. HOWARD STEPHENS:   And I think I  
6 addressed that earlier.  I mean, in terms of the supplier  
7 that best fits our identified requirements, and our  
8 needs, as we deem them to be, the counterparty that we  
9 chose is the most appropriate counterparty, and is the  
10 lowest cost for those other essential attributes, as  
11 well.

12                   So I guess the shorter answer would be,  
13 Mr. Peters, yes, there may be somebody else out there  
14 that's prepared to sell me gas at twenty-five (25) cents  
15 a GJ, but it may never materialize.

16                   MR. BOB PETERS:    And it's also possible  
17 that Centra could have arranged its own primary gas  
18 purchases for 2009/'10 on an internal basis in your  
19 department, Mr. Stephens, rather than outsourcing it to  
20 ConocoPhillips?

21                   MR. HOWARD STEPHENS:    No, sir.  I don't  
22 know -- I don't know -- I don't follow your question.

23                   MR. BOB PETERS:    Well, isn't it possible  
24 that -- that Centra itself could have taken on the gas  
25 supply of the primary gas rather than using a -- a

1 contractual vehicle with a counterparty, Centra could  
2 have done it day-to-day, management of its primary gas?

3 MR. HOWARD STEPHENS: We would still be,  
4 I mean, buying our gas through a third-party whether the  
5 term was a three (3) year term, or a three (3) hour term.  
6 We would -- we have no resources. We have absolutely no  
7 natural gas production. So to say that we could take it  
8 on is a fallacy.

9 MR. BOB PETERS: Centra couldn't have  
10 placed orders for natural gas on the national -- natural  
11 gas exchange or some other market?

12 MR. HOWARD STEPHENS: Well, if you're  
13 talking about buying gas on a day-to-day basis, you're  
14 still buying gas from a marketer. You have a contractual  
15 arrangement to buy gas potentially on a screen, a trading  
16 screen, but underpinning that is a marketer with gas  
17 production. We don't have any gas production.

18 MR. BOB PETERS: All right. Well, let --  
19 let's get past that. No matter who you contract with, or  
20 however you get your gas, it's coming from a third party?

21 MR. HOWARD STEPHENS: That's right.

22 MR. BOB PETERS: And it can be that  
23 ConocoPhillips has its own production, or it could be  
24 that the party you chose will secure it from other  
25 providers of gas?

1                   MR. HOWARD STEPHENS:    That is, I mean,  
2   the difference between, I mean, pure -- pure producers.  
3   Some of the producers hire marketers to sell their gas;  
4   some of them do their own marketing.  And, I mean, some  
5   of them you just have marketers that go out and aggregate  
6   the gas.

7                   MR. BOB PETERS:    And my -- my point, and  
8   maybe I took too big of a quantum leap here, Mr.  
9   Stephens, is that it would be possible, and subject to  
10  what you tell us, that Centra could place its own orders  
11  to purchase gas on either a monthly or a daily basis, and  
12  even intra-daily.

13                  MR. HOWARD STEPHENS:    Anything is  
14  possible, sir.

15                  MR. BOB PETERS:    But --

16                  MR. HOWARD STEPHENS:    We can go out and  
17  contract more gas but there would still be another party  
18  that we're buying the gas from.  It's not like we would  
19  hold the assets our self.

20                  MR. BOB PETERS:    Of course.  All right.

21  
22   (BRIEF PAUSE)

23  
24                  MR. HOWARD STEPHENS:    Did you ask me a  
25  question subsequent to that?

1                   MR. BOB PETERS:    No, I was just wishing  
2 you would have stuck to your promise not to get to the  
3 microphone today, Mr. Stephens, but -- but recogni --

4                   MR. HOWARD STEPHENS:    I -- I'm on it now.

5                   MR. BOB PETERS:    Are you ever.  But let's  
6 -- let's keep on that.

7                   There's a suggestion by Mr. Staufft that  
8 some LDCs arrange and purchase their own gas rather than  
9 using a third-party contract to provide their gas, a  
10 third-party arrangement.

11                   MR. HOWARD STEPHENS:    Well, I think it's  
12 -- to me, that's just, I mean, an misunderstanding in  
13 terms of terminology.  Everybody -- I mean, none -- none  
14 of the LDCs is -- I mean, as an LDC, our role is not to  
15 go out and buy production and decimate the investments  
16 associated with that.

17                   Our role is to distribute gas per the  
18 terms of our franchises.  So for us to go and buy -- I  
19 mean, that would be a completely separate arm of the  
20 company, or the Corporation, something we have  
21 contemplated in the past, but it's not our mandate now,  
22 and nor will it be in the near future, that I can see.

23

24

(BRIEF PAUSE)

25

1                   MR. BOB PETERS:    Centra arranges its own  
2 supplemental gas purchases, correct, by way of delivered  
3 service?

4                   MR. HOWARD STEPHENS:   That's correct.

5                   MR. BOB PETERS:    And that's a lot of  
6 work.

7                   MR. HOWARD STEPHENS:   No.  Actually, I  
8 mean we have a list of counterparts that we contact and  
9 indicate how much gas we need to buy for whatever  
10 particular period of time it is, and we get quotes from  
11 them.

12                   MR. BOB PETERS:    All right.  Let's just  
13 carry that into the primary gas side of the business.  
14 You could have a list of counterparties you could phone  
15 up and say, can you provide this, can you deliver this.

16                                Centra may or may not have their firm  
17 transportation, but you could go to counterparties to  
18 that as well.

19                   MR. HOWARD STEPHENS:   And, certainly, at  
20 one point in time we did do that.  We -- I mean, and -- I  
21 mean, and I want to make that very clear.  Mr. Stauff  
22 talks about buying gas on a daily basis for a very long  
23 time.

24                                We left, what we call the swing gas now,  
25 open to purchase each and every day in the open market.

1 And I became increasingly uncomfortable with doing that  
2 simply from the perspective that there was no guarantee  
3 that we could pick the gas up in those days.

4 So the amount of swing that we needed on  
5 those days was dictated. We would do our forecast. We  
6 would do calculation with respect to how much we assumed  
7 having to buy over and above. And we didn't call it base  
8 load gas at that time, but the term associated with it  
9 would apply equally. And we would go and buy gas and, I  
10 mean, and we would buy -- end up buying from two (2) or  
11 three (3) different counterparts.

12 This was all prior to Enron though and the  
13 huge credit issues that, I mean, developed out of that.  
14 And it was shortly after that that I renegotiated our  
15 WGML contract, and, I mean, we went through the -- you  
16 know, I still have the scars on my back associated with  
17 that -- I mean, that discussion, but we negotiated a firm  
18 -- or contractual arrangement for the swing gas where  
19 they had to deliver, I mean, precisely what we asked for  
20 each and every day and allowed for adjustments in it,  
21 which was, I mean -- and we bought the gas on a firm  
22 basis so that I was guaranteed that I could get the gas,  
23 and the price was very attractive.

24 MR. BOB PETERS: And you're telling the  
25 Board those circumstances and that marketing condition

1 doesn't exist any longer.

2 MR. HOWARD STEPHENS: Well, not since the  
3 Enron situation. Nobody is as comfortable. I mean, and  
4 I also allude to the fact that there -- I mean, the  
5 Western Canadian's Sedimentary Basin is not as  
6 forthcoming, and the TransCanada Pipelines, it's much  
7 more difficult to move the gas cost effectively. So, I  
8 mean, all of that led me very quickly to the conclusion  
9 that we -- I mean, we would, you know, migrate our  
10 contracts into something that was a much more bundled  
11 package.

12 MR. BOB PETERS: Is it possible, Mr.  
13 Stephens, that Centra may purchase directly from the  
14 market from numerous sellers under short-term and daily  
15 purchase contracts when it comes time to figure out what  
16 to do with your storage assets and transportation assets  
17 in the United States; isn't that a possibility?

18 MR. HOWARD STEPHENS: If we come to a  
19 conclusion and there is a specific set of assets that is  
20 the ideal fit for Centra, but we can't have them in place  
21 in time for the termination of our existing agreements,  
22 we may go to some interim measure. Other than that, I  
23 don't see that, no.

24 MR. BOB PETERS: Why don't you see it as  
25 possible for a longer term solution rather than just a

1 bridge solution?

2 MR. HOWARD STEPHENS: Simply from the  
3 perspective that if you're buying gas there's no benefit  
4 associated with buying things on a short-term basis. I  
5 mean, it's like anything else, the more I commit to buy,  
6 the more attractive it becomes to the seller; from that  
7 perspective they have the economies of scale and cashflow  
8 associated with that.

9 So, I mean, it is very much, I mean, why  
10 ConocoPhillips was interested in our contract; we are a  
11 good source of cashflow. So they -- they can count on  
12 those dollars rolling in. We're a good, you know, solid  
13 financial outfit. So from that perspective it's a  
14 mutually beneficial situation. Going out and contracting  
15 on a day-to-day basis, I mean, goes back to the heart of  
16 the reliability argument we discussed earlier. And, I  
17 mean, I'm just not comfortable with it and there is no  
18 benefit to be had by it.

19 MR. BOB PETERS: Well, when you say  
20 there's no benefit to be had you don't know that unless  
21 you cost it out, do you, Mr. Stephens?

22 MR. HOWARD STEPHENS: Say again?

23 MR. BOB PETERS: Well, you're saying --  
24 when you say there's no benefit to doing that, to -- to --  
25 - for Centra to purchase directly from the market from

1 numerous sellers, the benefit would have to be determined  
2 financially, wouldn't it?

3 MR. HOWARD STEPHENS: No, I think the --  
4 well, the -- the acid test is going to the market every  
5 day. And then on some days -- I don't want to -- I mean  
6 -- I mean, hit the day that I can't find the supply. And  
7 I've been in that circumstance where we needed to buy  
8 supply, and this is when we were leaving a portion of our  
9 day uncovered, and it was our design day, and I had to  
10 scratch all over the place to find gas and I can tell you  
11 it's not a very comfortable feeling. So from my  
12 perspective that is not a prudent way to operate a gas  
13 utility.

14 MR. NEIL KOSTICK: It is my --

15 MR. VINCE WARDEN: Mr. Peters, maybe --  
16 probably the same thing Neil was going to say -- or Mr.  
17 Kostick was going to say. But we have in -- in Manitoba  
18 we have tremendous swings in demands that can be -- is so  
19 dependent on -- on the weather. So if we were to go to  
20 the market every day to purchase our gas we would have to  
21 have some way to manage those swings.

22 And we don't have local storage that we  
23 can do that. Other -- other utilities, LDCs, that do  
24 that have access to local storage where they can manage  
25 those surpluses and deficits through that withdrawal and

1 injection to storage. We don't have that luxury here in  
2 Manitoba. If we, in the -- in our reconfigured  
3 portfolio, that may evolve in the future if we decide to  
4 go with storage elsewhere, other than in Michigan where  
5 we can inject daily, then something like that would be  
6 manageable but it would just not be manageable under the  
7 current configuration that we have today of assets.

8 MR. BOB PETERS: Well, what you're trying  
9 to do then, Mr. Warden and Mr. Stephens, is you're trying  
10 to offload that responsibility, not in a negative way but  
11 in a contractual way, onto ConocoPhillips?

12 MR. VINCE WARDEN: Well, to somebody that  
13 can manage that, yes, and ConocoPhillips is -- is large  
14 enough that they can manage that within their port --  
15 portfolio of assets.

16 MR. NEIL KOSTICK: Yeah, if I could also  
17 add a further note, the swing optionality that's imbedded  
18 within our contract with ConocoPhillips is very difficult  
19 to obtain in the market. The ability that we have in our  
20 ConocoPhillips contract is to make intraday adjustments,  
21 and it's not only to increase the amount of gas that we  
22 take but we can also reduce the volumes that we have  
23 already indicated to Conoco that we were going to take if  
24 we have changes in weather and changes in mode.

25 So we have the ability to nominate the gas

1 volumes up or down and it's up to ConocoPhillips to  
2 figure out how to either get gas late in the day or get  
3 rid of it; to either get the gas or get rid of it, as  
4 well as the transportation to get it or get rid of it,  
5 and that can be at intraday day 2, which is the late  
6 afternoon nomination window during the day of gas flow.

7           And it should be noted that on weekends  
8 the market is actually closed. Saturday afternoon,  
9 Sunday afternoon, you will not be able to go into the  
10 market and buy gas; you need to rely on a marketer such  
11 as ConocoPhillips to provide that swing service, which we  
12 do not have because we do not have local storage. Most  
13 other LDCs that have access to local storage, they manage  
14 swings in that manner.

15           We replicate the benefits of storage by  
16 contracting in the manner that we do with a very large  
17 player in the Alberta market. The effect of our contract  
18 is that we have the -- essentially the ability to pull  
19 gas from storage as if we had storage located at Empress.  
20 So that is a phenomenal benefit, in my view, that  
21 replicates the value of storage.

22           Another element that needs to be clearly  
23 understood is that ConocoPhillips is, essentially,  
24 providing firm transportation service for us from AECO to  
25 Empress, and they provide that without charging us any

1 fixed demand charges. Virtually anywhere that you go, if  
2 you want firm transportation, there are fixed demand  
3 charges for your maximum requirements on the day.

4 In any given month, we'll identify to  
5 Conoco what our maximum swing might be, and they have the  
6 obligation to supply up to that amount. We might take  
7 zero or we might take 100,000 gigajoules in swing on any  
8 given day. The remarkable part of it is, we pay no fixed  
9 demand charges for that transportation component, that  
10 they'll move gas for us from AECO to Empress.

11 The result of all this is that the Conoco  
12 supply contract mitigates supply risk, because if we are  
13 contracting on our own in the market and it's a Saturday  
14 afternoon or a holiday afternoon and we need additional  
15 gas, the market is actually closed and we may not be able  
16 to get it. We're -- the price risk is mitigated by the  
17 fact that we don't have to contract or attempt to buy gas  
18 in the late afternoon when markets are liquid and you are  
19 essentially at the mercy of the market as far as buying  
20 gas, or, if you're long gas, trying to dispose of it.  
21 And the same applies again for transportation, attempting  
22 to buy it or get rid of it.

23 MR. BOB PETERS: You'd agree with me, Mr.  
24 Kostick, that, for the benefit of -- of what you're  
25 telling us that ConocoPhillips provides, you pay a fee or

1 a premium to them of some amount?

2 MR. NEIL KOSTICK: We pay a price  
3 relative to the AECO -- AECO -- major AECO indices --

4 MR. BOB PETERS: Well --

5 MR. NEIL KOSTICK: -- that is reflective  
6 in our view of the service that's being provided, which  
7 includes moving the gas to Empress.

8 MR. HOWARD STEPHENS: And, I might point  
9 out, it's no different than what we have done in the  
10 past.

11 MR. BOB PETERS: Which means the answer  
12 to my question was, yes, there's a premium or a fee for  
13 that somehow embedded in the contract in some way, shape  
14 or form, because ConocoPhillips isn't doing this for  
15 free?

16 MR. HOWARD STEPHENS: Yes, but they're  
17 doing it in a very cost effective way.

18 MR. BOB PETERS: All right. Well, in  
19 terms of the -- the AECO to Empress transportation, the -  
20 - the firm transportation provided by ConocoPhillips is -  
21 - is done, but ConocoPhillips would also, as I understand  
22 the evidence of Mr. Stauff, then be able to take  
23 advantage of the liquids extraction at -- at Empress, as  
24 well?

25 MR. NEIL KOSTICK: Whoever holds the

1 capacity on the intra-Alberta pipeline system and moves  
2 that gas to Empress does have the -- the right to the  
3 extraction, to the liquids extraction value. So if  
4 Centra held capacity and paid the tolls directly on Nova,  
5 we could collect extraction fees. However, that's only  
6 for any gigajoule of gas that actually flows.

7                   If we hold the capacity ourselves, we may  
8 have a requirement to hold 180,000 gigajoules worth of  
9 capacity to Empress, but may only need half of that or  
10 even a quarter of that on a given day, dependent upon the  
11 weather. So the trade-off of being able to secure those  
12 liquids extraction fees is that you would be paying  
13 unutilized fixed demand charges on the Alberta system,  
14 because our load is -- is quite variable day to day.

15                   MR. BOB PETERS:    So that's a benefit  
16 you've turned over to ConocoPhillips in exchange for them  
17 giving you the firm transportation with no fixed demand  
18 charges?

19                   MR. NEIL KOSTICK:   The -- the puts and  
20 takes of all the -- all the pros and cons of the  
21 different elements where one can derive value, that's all  
22 brought out through the proposal that we received by  
23 ConocoPhillips, and the price that we forecast is  
24 reflective of that contract, and there are benefits to  
25 both parties.

1                   MR. BOB PETERS:    Mr. Stephens, does  
2   Centra continuously monitor itself against the default  
3   option of purchasing directly, in the relative -- in the  
4   -- in the relevant short-term markets, the gas it needs?  
5   Do you -- do you monitor yourself against that option  
6   compared to what you enter into in terms of your  
7   contracts with gas suppliers?

8

9                                   (BRIEF PAUSE)

10

11                   MR. HOWARD STEPHENS:    We, I guess, I  
12   mean, in a larger sense, do that through the portfolio  
13   review that we're looking at doing.  And that -- I mean,  
14   part and parcel of that is not just looking at the  
15   storage and transportation assets, but the impact on our  
16   cost of gas and how we can take the gas.  And if we can  
17   take the gas at a hundred percent base load into storage  
18   and do that more cost effectively than we do it now,  
19   where we don't have the storage and we have to buy a  
20   swing service which may or may not bear some premium,  
21   then we will do that.

22                                So, I mean, from that perspective, yes,  
23   I'm going to guess my answer is "yes" to you.

24                   MR. BOB PETERS:    Under the contract you  
25   signed with ConocoPhillips can you confirm to the Board

1 that the customers served by direct purchasers -- by  
2 direct purchase through retain brokers are not  
3 disadvantaged from what they've compared to the Nexen  
4 Agreement?

5 MR. HOWARD STEPHENS: There's no change,  
6 sir.

7 MR. BOB PETERS: And in terms of the gas  
8 marketer activity, under the terms of the new contract  
9 with ConocoPhillips can Centra accept all direct purchase  
10 customers who may, for whatever reason, want to return to  
11 system supply back to system supply?

12 MR. HOWARD STEPHENS: I see no reason why  
13 not, yeah, and if -- even if it isn't under the context  
14 of the ConocoPhillips contract. I mean, we could always  
15 go to tender and buy more gas, so -- right.

16 MR. BOB PETERS: Mr. Chairman, I perhaps  
17 didn't get quite as far as I had hoped this afternoon,  
18 but this might be an opportune to take -- to break for  
19 the day. And I'd arrange with my friends opposite to  
20 commence at nine o'clock tomorrow morning and we'll -- I  
21 expect to complete -- probably complete the evidence  
22 tomorrow.

23 THE CHAIRPERSON: Very good. Thank you,  
24 Mr. Peters. Thank you, panel, and we'll see you all  
25 tomorrow.

1 --- Upon adjourning at 3:44 p.m.

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5 Certified correct,

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Cheryl Lavigne, Ms.

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