(9:07 a.m.)

CHAIRMAN:

Q. Thank you. Good morning. Good morning, Ms. Newman, do you have any preliminary items?

MS. NEWMAN:

Q. No, Chair.

CHAIRMAN:

Q. Good morning, Mr. Haynes. How are you?

MR. JAMES HAYNES (SWORN)

Q. Thank you, sir. Good morning, Ms. Greene. When you're ready to start your direct examination, please.

GREENE, Q.C.:

Q. Good morning, Mr. Chair and Commissioners. Mr. Haynes, what is your position with Newfoundland and Labrador Hydro?

A. I'm the Vice-President of Production.

Q. Evidence was filed on behalf of Hydro called Production, and in the pre-filed application, it was stated that this evidence would be adopted by you at this hearing. Do you adopt the production evidence filed with Hydro's Application as your evidence in this proceeding?

A. I do.

Q. Mr. Haynes, I'd like first to look at Schedule 2 to your evidence. And looking at Schedule 2 there, could you please summarize the capacity and energy capabilities of Hydro's production facilities and the changes from the 2002 cost of service?

A. On the Island Interconnected System, Hydro owns and operates nine hydro plants capable of producing a peak of 927 megawatts and annual average energy of 4582 gigawatt hours. There has been an addition of one plant in 2003, Granite Canal, which was included in the previous numbers. It has a peak capacity of 40 megawatts and an average annual energy capability of 224 gigawatt hours. These hydroelectric plants represent approximately 61 percent of the Hydro-owned total capacity and average energy production capability. As well, on the island, Hydro own and operate one of the largest--a large oil-fired steam electric plant at Holyrood, three gas turbines and three diesel plants, with a total peak capability of 598 megawatts and a annual firm energy capability of 2996 gigawatt hours. The Holyrood thermal plant is the largest and

provides 40 percent of Hydro's average annual energy capability and 31 percent of Hydro's capacity. In addition, Hydro has entered power purchase contracts with four non-utility generators or NUGS for a total of 66 megawatts and an average energy capability of 394 gigawatt hours.

Through these facilities, both owned and contracted by Newfoundland Hydro in 2004, Hydro will provide approximately 82 percent of the Island's energy capability and supply approximately 83 percent of the Island's generation capacity. On the Labrador system, Hydro owns and operates a gas turbine and a diesel plant in the Goose Bay area with a total capacity of 38 megawatts. However, almost all of the power and energy requirements of the Interconnected Labrador System are supplied through a purchase contract with CF(L)Co.

Q. Mr. Haynes, what are some of the major challenges facing the production division, looking forward?

A. There are a number. These include: maintaining reliable production of power and

energy with aging generation facilities; operating an isolated electrical system in a harsh physical environment; improving the efficiency of existing energy production facilities; and also improving the production and operating maintenance activities; and as well, improving the environmental performance, particularly with respect to our Holyrood facility.

Q. What initiatives has Hydro undertaken to improve the efficiency of existing energy production facilities?

A. Over 1,060 megawatts or approximately68 percent of Hydro's capacity on the Island Interconnected System has been in service for over 25 years. This is made up of 12 generating plants, both hydroelectric and thermal, with the majority having a capacity in excess of 50 megawatts. Hydro has commenced a process of replacing key components of these facilities where the amount of maintenance or the number of breakdowns is increasing or where the original vendor support is questionable or, in fact, non-existent. As the dependence upon Holyrood

Page 5

MR. HAYNES:

increases with time, Hydro has made a concerted effort, with the assistance of the original equipment manufacturers or the OEM's through partnering agreements to significantly improve the plant's availability, particularly during the 1990s.

A number of initiatives were introduced within the production environment to enhance energy production facility, including a controllable loss program at Holyrood and a unit commitment program at the Energy Control Centre. All designed to allow optimum scheduling and loading of the hydraulic units and also to increase the efficiency of the Holyrood plant. This has led to an efficiency improvement at the Holyrood plant and Hydro is recommending with this application that we move to 624 kilowatt hours per barrel to be used for the annual energy conversion factor at Holyrood. This is a 3.1 percent increase over the efficiency used for the cost of service prior to the 2001 GRA, and a one and a half percent improvement over the current figure of 615. This alone results in a fuel

Page 6

savings of approximately 1.2 million dollars in the 2004 test year, since the last hearing.

Q. You said earlier that one of the challenges for the production division is improving the productivity of operating and maintenance activities. What has the division achieved in this area?

A. Over the period of 1999 to 2002, through process change, technology improvements, the permanent complement in the production division has been reduced by approximately six percent from 320 to 300 positions. This improvement comes despite the additional maintenance costs associated with the Granite Canal facility and increase in demands for IT and communication facilities and capability.

Q. The last challenge you mentioned a moment ago was improving environmental performance, particularly at the Holyrood plant. How has Hydro addressed this challenge?

A. In an effort to define and minimize our environmental footprint, Hydro has adopted the ISO 14001 Environmental Management System Standard. Following external audits, the Holyrood facility was registered initially in

Page 7

1999 and was re-registered in 2002. Hydro's hydraulic facilities were registered during 2000. To maintain certification to this ISO 14001 standard, Hydro has to demonstrate it is committed to continue improvement in environmental performance. With respect to Holyrood, we are currently in the process of evaluating emission abatement technologies. The implementation of continuous emission monitoring during this year and the additional ground level monitoring capability in 2004 will greatly improve our ability to monitor and quantify our discharge and the resulting ground level concentrations. This will enable a more informed decision on the various means to mitigate the plant's impact on the environment and address public expectations, as well as a changing regulatory environment.

Q. What measures of key performance indicators do you use within the production division to measure performance of production facilities and what have been the results to date?

(9:16 a.m.)

A. We use reliability, unit efficiency, productivity measures to track our

Page 8

performance. In particular, we use the CEA standard measures of incapability factor, derated adjusted forced outage rate or DAFOR and failure rate to measure generator reliability. Another measure used for reliability in our particular situation is a number of under frequency load shedding events per year, which are usually initiated by a sudden change or a sudden outage, I should say, of significant generation.

In the CEA standard measures used, Hydro's performance is better than CEA in many areas, other than hydraulic unit failure, and if you could go, to Table 5 of my evidence, please? In particular, the incapability factor for Holyrood has been improving in recent years due to a consistent effort by both Hydro's staff and through critical partnering arrangements with OEMs. This is illustrated in Table 2, which basically gives the ICDF from 1990 to 2002 and demonstrates the significant change since we started partnering with the OEMs. And if you go to Table 4, please? Table 4 indicates the other factors with respect to the hydraulic--sorry,

Page 9

MR. HAYNES:

with respect to the thermal plant, the ICDF, the DAFOR and the failure rate. It is important that the 25 percent target continue for this critical plant that has been supplying an increasing portion of the system's energy requirement.

The under frequency events measure was below expectations in 2002 and a number of initiatives, as outlined in my evidence, are underway in 2003 and will continue in 2004 in an attempt to keep this number to eight or less per year.

Q. How are you doing with respect to unit efficiency measures?

A. The most critical unit efficiency measure is the Holyrood fuel conversion factor. This factor can be quite variable due to the effects of hydraulic production levels, unit loading and general system conditions. For that reason, Hydro targets improvements based on unit average monthly output rather than a particular conversion factor. The curve in Schedule 5, Mr. O'Reilly, in my evidence shows this relationship, and as you can see, there's

Page 10

quite a variation in the actual kilowatt hours per barrel. All these blue dots are basically monthly figures and the reddish line is basically the best fit between the lot.

We strive to move the curve upward so that any given output we use less fuel, but there are numerous influencing factors which change basically on a daily--which can change on a daily basis.

Recent years performance and changes implemented at the Holyrood plant has led to a recommended average conversion factor of 624 kilowatt hours per barrel for fuel costing purposes, as I noted previously.

Q. Mr. Haynes, at the previous hearing in 2001, there was considerable discussion on fuel management. How has Hydro addressed this?

A. The responsibility for control and management of all aspects of fuel rests with my position, vice-president of production. Individual tasks within the process of purchasing, storage, utilization of fuel, are carried out within various departments but the overall responsibility is mine. In accordance with the direction from Order No. P.U. 7, a report

Page 11

was filed on December 23rd, 2002 outlining the policies with respect to fuel and procedures and other aspects of fuel management, including a review of the adequacy of our fuel storage, particularly at Holyrood, and fuel price hedging possibilities. It is included as Exhibit 1 to my evidence. The report does not recommend any specific actions, as there are no demonstrable cost benefits in either increasing the fuel storage facilities or entering into a financial hedging program.

Q. What is the forecast cost of No. 6 fuel in the 2004 revenue requirement, as revised in August of this year?

A. One of Hydro's largest category of costs is No. 6 fuel for the Holyrood plant. Hydro bases its forecast fuel expense on fuel price projections provided by an internationally recognized source, the PIRA Group. This forecast price is applied to the number of barrels of oil required to meet the anticipated load after taking into account the forecast hydraulic production. In 2004, the No. 6 fuel cost is forecasted to be 84.4 million, using a forecast average price of

Page 12

29.20 per barrel and hydraulic production based on a 30-year record of historical inflow average, as directed by the Board.

Q. During the 2001 hearing, there was also significant discussion and assessment of Hydro's hydraulic production forecast. How has Hydro addressed the concerns raised by the Board during that hearing?

A. As directed by the Board in Order P.U. 7, Hydro did retain a consultant to complete an independent assessment of Hydro's hydraulic production forecasting methodology, with the terms of reference pre-approved by the Board. SGE Acres were retained to carry out this independent assessment, which resulted in several recommendations, all of which Hydro fully endorse. The SGE Acres report has been filed with my evidence as Exhibit 2, and in order to have this issue fully discussed and assist the Board in its decision, Ms. Susan Richter, Senior Hydro Technical Engineer for SGE Acres, will testify to discuss the report findings and its recommendations.

Q. Mr. Haynes, is Hydro recommending to the Board that the full historic inflow record be

GREENE, Q.C.:
utilized to develop the 2004 cost of service hydraulic production?
A. Hydro is recommending the use of the full historic record in developing average hydraulic production estimates, as explained in the SGE Acres report. However, given the other significant drivers in this particular application, Hydro is not asking that it be implemented for the 2004 test year revenue requirement. Hydro is seeking resolution of this issue during the proceeding so that for its next filing, the full historic record will be utilized and utilized for other forecasting activities prior to the next filing.
Q. Mr. Haynes, you're also responsible for load forecasting at Hydro. Could you please explain the various load forecasts which Hydro prepares and their use?
A. Hydro prepares a separate five-year operating load forecast by month for the Island and Labrador Interconnected Systems and for each of the Isolated Rural Systems. These are used in generation scheduling, system planning, budgeting, rate setting and cost of service

analysis. As well, we prepare a longer, a 20-year longer term planning forecast of the annual peak and energy requirements of the Province's electrical systems. This is used for long-term supply analysis with particular emphasis on the Island Interconnected System and is used to set the timing of the requirement for the next source of power and energy.
Q. Your pre-filed evidence refers to a number of new supply sources coming into service during 2003. Could you please provide an update on the status of these?
A. Yes. These new sources consist of Granite Canal hydroelectric project, which was constructed by Hydro, and two other sources, one a hydroelectric project constructed by the Exploits River Hydro Partnership and the other, a co-generation facility constructed by Corner Brook Pulp and Paper Limited, both with the resulting energy purchased by Hydro through long-term purchase agreements. The Granite Canal project went into commercial operation in July of this year. The Bishop Falls portion of the Exploits River project

was completed in March of this year, and the Grand Falls portion is expected to be completed within the next couple of weeks. The Corner Brook Pulp and Paper facility was brought into service in January of this year.
Q. Mr. Haynes, in August, the Government announced that it had given approval in principle for the establishment of a wind demonstration project in the province. Could you please provide the Board with an update on progress to date with respect to the wind project?
A. Hydro is currently negotiating a power purchase agreement with the proponent for a 25-megawatt wind project to be located near the Town of St. Lawrence on the Burin Peninsula. The project is capable of producing approximately 96 gigawatt hours per year under average wind conditions and should the agreement be finalized this fall, could be producing energy with some or possibly all of the projected 38 wind turbines during the fall of 2004.
Q. And that would be with the wind turbines being installed during 2004? Is that correct?

A. That's correct, yes.
Q. Okay. If the wind demonstration project proceeds, will it affect the timing of the requirements for additional generation supply on the Island Interconnected System, as outlined in your evidence?
A. Yes, based on the current load forecast, the project could delay the requirement of a new generation supply by approximately one year, to approximately 2011.
Q. In the Order of the Board with respect to Hydro's last hearing, Order No. P.U. 7, the Board ordered that Hydro should file, as part of this application, a detailed study on the cost of service assignment of the Great Northern Peninsula assets, the Doyles-Port aux Basques assets and the Burin Peninsula assets. Would you please summarize the conclusions of the study, which was filed in response to this direction and is filed as Exhibit JRH-3?
A. Yes. The study resulted in the following recommendations. It is recommended that the generation assets on the GNP should be assigned common plant. This is a change from the 2003 GRA which was filed as directed in

Page 17

MR. HAYNES:

P.U. 7, where these assets were specifically assigned to Hydro Rural. Secondly, the Hydro-owned generation on the Burin Peninsula should remain assigned to common plant, as was previously done in the 2003 GRA. The GNP transmission assets should remain specifically assigned to Hydro Rural, as was previously done in the 2003 GRA. The Doyles-Port aux Basques transmission assets should remain specifically assigned to Newfoundland Power, as was previously done in the 2003 GRA, and the Burin Peninsula transmission assets should remain assigned to common plant as was previously done in the 2003 GRA.

Q. Thank you, Mr. Chair. That completes my direct examination of Mr. Haynes.

CHAIRMAN:

Q. Thank you, Ms. Greene. Good morning, Mr. Browne.

BROWNE, Q.C.:

Q. Mr. Chairman.

CHAIRMAN:

Q. When you're ready, please.

BROWNE, Q.C.:

Page 18

Q. Mr. Haynes, you're an engineer by profession. What type of engineer are you?

A. Electrical engineer.

Q. Your resume with the introduction to your evidence indicates you are a transmission planning engineer. What type work does that entail?

A. That was prior to 1989. I worked in the transmission planning department of Newfoundland and Labrador Hydro, doing interconnection evaluations, determining when transmission additions would be required to meet system load or transformer upgrades and also did fault studies, stability studies and things of that nature.

Q. And the resume also indicates you are currently vice-president of production. What are your responsibilities in that position, generally?

A. As the vice-president of production, there are six departments that report to me: system planning; information systems, information technology and telecommunications, IS&T; generation engineering; system operations; hydro production; and thermal production.

Page 19

Q. And how long are you in that position? Since 1999, is it?

A. Yes, a little over two years.

Q. At 2001, you were at point?

A. Yes.

Q. What are your goals in that position? What do you see your goals as being?

A. My I guess primary objection is to ensure that we deliver power and energy at a cost effective price and keep our reliability as high as we possibly can, given the age and our challenges. That would be the first and foremost. It's basically cost and reliability.

Q. So it's down to these two factors?

A. Well, there's lots of other things within the various divisions, but those would be the key things. We plan the system. We operate the system, and we endeavour to do it cost effectively and provide the greatest reliability that we can.

Q. I notice that you were, for a period, general manager of CF(L)Co. What were your responsibilities there?

A. Basically, that position is responsible for

Page 20

all on-site activities which cover production, transmission, water management, pretty well anything and everything with respect to CF(L)Co, except the financial support that's provided by Newfoundland and Labrador Hydro.

Q. Were you a liaison with Hydro Quebec in that position?

A. Yes, we were on a--we have what's called an operating committee with Hydro Quebec, which discusses operational matters between CF(L)Co and Hydro Quebec.

Q. There was some discussion last week concerning work that was undertaken by Hydro and billed to CF(L)Co. Do you have any knowledge as to the way that is done?

A. Some of this is a bit historic, but CF(L)Co's approach to some change with respect to the plant are that basically that Hydro Quebec will pay a fair portion of that cost. In fact, most of the costs for improvements, beyond the contracts. At certain times, if CF(L)Co does not have the resources, the engineers available, that they have in the past used Newfoundland and Labrador Hydro engineering, who would basically undertake

Page 21

MR. HAYNES:
that work and do it for CF(L)Co, who would in fact charge Hydro Quebec and also pay Newfoundland Hydro for their services.
(9:30 a.m.)
Q. Is there anyone else that you seek to do that work, CF(L)Co seeks to do that work besides Newfoundland and Labrador Hydro?
A. CF(L)Co does retain its own consultants for various things that it do. It also uses some expertise within Newfoundland Hydro in transmission areas or generation areas, but they are not precluded to going and hiring a contractor or consultant directly.
Q. And what about reference to Hydro Quebec? Have you used any of the expertise that would be available there?
A. CF(L)Co has, on occasion, had people from CF(L)Co involved in certain aspects and they have some rights under the power contract to influence the way some things are done, but Newfoundland Hydro has not directly sought engineering services or technical support from Hydro Quebec directly.
Q. What do you mean when you say under the

Page 22

contract, they have an ability to influence the way things are done? Can you expand upon that?
A. They set certain parameters around the power system frequency regulation, that sort of thing, but that's about it.
Q. But in terms of Newfoundland and Labrador Hydro providing services to CF(L)Co. and billing for those services, has there been any discussion with Hydro Quebec as to what a fair way to billing would be in reference to these services?
A. Not to my knowledge.
Q. To your knowledge has there ever been an objection from Hydro Quebec in reference to the way this billing was done?
A. When I was at CF(L)Co., there was obviously lots of discussion on the prices, but we agreed at the end of the day that they would pay the rates that were proposed.
Q. And the rates that were proposed were based on what factors?
A. Based on cost plus appropriate markup and covering off CF(L)Co's risk. There was a fair bit--you know, there hasn't been that much of

Page 23

late, as I understand, but there was a fair bit of improvement to the overall system made when Hydro Quebec were trying to meet the goals, if you will, of their whole grid, and it would require CF(L)Co. cooperation, and they paid for that, and they paid a fair cost.
Q. And when you say a fair cost, do you mean market rates and how do you determine if these are market rates?
A. I wouldn't necessarily say market rates. It was based on cost plus appropriate markups.
Q. So you'd believe that Newfoundland and Labrador Hydro was getting a fair return for the work being provided?
A. A considerable amount of that was not done by Newfoundland -
Q. Pardon? Can you slow down a little bit?
A. I'm sorry. A considerable portion of that work is not done by Newfoundland Hydro, it's done by CF(L)Co's resources. But in the work that Newfoundland Hydro carried out for CF(L)Co., who in turn did some for Hydro Quebec, they were fairly compensated. Hydro was fairly compensated, in my view.
Q. Your resume also indicates that you are a

Page 24

member of the Institute of Electrical and Electronic Engineers, and that you've served as a member of the Generation Council of the Canadian Electricity Association. What does that involve?
A. A member of IEEE, it's just a professional society where you can subscribe to different interest groups, generally in your work area. I subscribe to Power Systems Engineering Group and Electric Installation Group, the two specific sub-societies. The Generation Council of CEA basically is a group of utilities, Canadian utilities at the moment, on the Generation Council, who get together to discuss items of common interest and some of which are related to government regulation, particularly Department of Fisheries regulations with respect to hydro plants and thermal plants, Kyoto and many other items.
Q. How often do you meet in that capacity?
A. There are meetings, approximately four per year. I would not suggest that I get to every one, but sometimes just sit in by telephone and it's most cost effective obviously sometimes.

Page 25

BROWNE, Q.C.:

Q. Now pertaining to your evidence, can we go to page one of your evidence and in line 23, you indicate that the system planning department is responsible for planning all new generation. Can you explain what that involves?

A. Basically, the system planning department, which comprised generation, transmission and distribution planning, along with economic analysis department, look at and review the load forecast to see if transmission line loading is capable of carrying the load that we anticipate. So they will actually do technical studies, what's called Load Flow studies to look at transmission line loadings, transformer loadings and to identify capital budget improvements that are required. They also review particularly in the generation area, the Island load forecast and they, for instance as I mentioned in my opening, they look at the timing of the next generation source that is required to serve the energy and power needs of the Province.

Q. Now you mentioned in your opening that the

Page 26

next new generation appears to be wind generation. Is that correct?

A. That is under discussion at the present time, with the proponent, yes.

Q. And who is the proponent?

A. It's a company or a group of companies called Newind.

Q. And they're in private enterprise?

A. I think they are a group of companies, local companies and mainland companies, that have got together to a consortium, if you will, to promote this particular project.

Q. I'll ask you some more about that later. But aside from them, what new generation is currently being planned?

A. There are no specific plans on the Interconnected System for generation beyond what's currently in place, the Granite Canal and the two NUGS, along with the possible wind project.

Q. So that's it?

A. That's it from the Interconnected System, yes. Our next source is, you know, 2010/2011 and there's adequate time. Every year, we review the timing of that. Any, you know,

Page 27

significant changes in the load or the situation on the Island Interconnected System and we will adjust our timing and ensure that the appropriate studies are done in time that we can build a source or buy a source or whatever to meet those future requirements.

Q. So 2010 and 2011 are not that far off. What are you planning for 2010 and 2011, in terms of new generation?

A. We have no specific conclusive project that we would do at that particular time. The process would normally be that--we have some, we have Island Pond, which was mentioned in the evidence, as a 36-megawatt potential hydro plant in the Bay D'Espoir water shed area. We would likely go and review costing for--depending on the amount of load required in 2010/2011, we may prepare cost estimates for gas turbines. We may go to an RFP process where we would seek proposals from private companies and then we would evaluate the whole and at the end of the day, we would propose what's most economic and in the long-term best interest to the consumers, to the Public Utilities Board for approval.

Page 28

Q. So after Island Pond and the wind generation, that's about it. Otherwise you're looking--are you straining at that point to find new generation?

A. Hydro doesn't have any--other than Island Pond is the only, you know, significant resource that we have in our portfolio, if you will, other than, you know, building a gas turbine plant or a combined cycle plant at Holyrood or elsewhere. There are other small hydro projects on the island that other people have rights to, which we would likely solicit bids for and evaluate what is the most appropriate next source. In the very long term, once all these small hydros are used, basically we do see a thermal future, unless we get a Labrador in feed, of course.

Q. Now you say there, in your first sentence, that the system planning department is responsible for planning all new generation. How many people are working there in the system planning department?

A. I think there are approximately--I shouldn't guess, I guess.

Q. You can ballpark it, if you like.

Page 29

MR. HAYNES:

A. I think it's ten actually that are there, and that's distribution planning. That's distribution planning, generation planning and transmission planning. They also do--there's a lot of ongoing, you know, yearly or annual activities. There are 12 actually. There's a lot of annual activities with respect to operational support, doing load flows, stability analysis, reviewing diesel plant. All the isolated diesel areas have to have a review of the load forecast and whether there's new diesel generation required or change outs required.

Q. Yes, but you just informed that the next plan, save for the wind generation, is Island Pond and that won't be until 2010 or 2011. Is that what you're telling us?

A. I didn't say the next one would be Island Pond. Island Pond is one of a--Island Pond is one that we have. We would have to evaluate Island Pond against the economics of any other proposal and evaluate--it may not be Island Pond. It may well be, but we don't know that at this point in time.

Page 30

Q. Now when you were completing Granite Canal, you must have had a fair complement of people involved in working on that, did you?

A. From within Hydro?

Q. Yes.

A. There were five or six people engaged in that pretty well full time.

Q. Well, what are they doing now, those five or six people, now that Granite Canal is completed?

A. Granite Canal is online and producing. It's not exactly finished. There's still work ongoing, which we expect to take us to the end of the year, cleaning up deficiencies and a few things like that. But for most of the people, if not all the people who were assigned to that particular project, we had backfilled with temporary and term employees, and basically they would be--most of those would be finished their work with Hydro towards the end of the year, unless there's other work that comes in to take its place.

Q. So those people will be--their work is complete?

A. Yes, and it has slowed down in the last number

Page 31

of months, but I mean, there were a fair--the Granite Canal team, if you will, were four or five people who were dedicated full time and we basically backfilled those positions with temporary or term engineers or spread it around amongst other areas or, in some cases, some work could be delayed until a later date.

Q. Now in planning new generation, the ten people you got there in the planning department, it seems to me, would they be overly busy right now, if nothing is coming on in the foreseeable future?

A. As I mentioned, in the generation and planning side, there are only a couple who are dedicated--who are allocated primarily to generation expansion for, you know, the major generation, and yes, they are very busy with lots of other things. They're involved in other committee work, reviewing--they are involved in the abatement technologies for Holyrood plant on the economic side and also several areas along those lines.

Q. Now you've been very general in describing--you were specific in describing Island Pond and the wind generation, but you're been very

Page 32

general in describing what you're looking for after that. Can you be a little more specific as to telling the Public Utilities Board as to what the plan is? If you don't choose Island Pond, where is electricity headed in this province, in terms of where is the plan?

A. I have been less than specific because we do not know what the next source will be. It's a matter of what the options are available at the time, the cost of fuel, if natural gas is available, and so on. It will be--that will be the subject of an evaluation which will start in three or four years. What we will do is we will--Hydro will ensure that there are appropriate cost estimates in place or we go to an RFP and then we will evaluate the next source. It will be premature to say what that particular source will be until we actually do a full economic evaluation, which we would not undertake at this particular time. But the competition would be Island Pond, gas turbines, a combined cycle plant, or you know, or a fourth machine at Holyrood for instance, or you know, several, two or three or four or whatever is required of all the other small

Page 33

MR. HAYNES:
hydro that may be developed by others. It will be the subject to an economic and technical evaluation.
Q. And is there a time line for this as to where you're headed?
A. In 2005, we need to be--2005, 2006 at the latest, we would need to be kind of landing on a solution to propose to the Public Utilities Board, but we don't have that done at this point in time. The load forecast does not require that we have a definitive solution for 2010 or 2011.
Q. You indicate, on line 27 of your evidence, that the department prepares load forecasts. Can you give us a description of how that is done?
A. Well, there are multiple load forecasts. There are isolated system load forecasts, but I guess, I'm assuming the one that you're most interested in is the one that dictates the next source. Basically, we do an econo-metric forecast and we do have the provincial government do some economic forecast and that basically drives a model which determines the

Page 34

loading capacity requirements. There's a iterative process. A load forecast is done which considers the gross domestic--the GDP of the province, the housing starts and a whole raft of other things, and there was an RFI, I believe, submitted which kind of lists those things. So that is looked at. It churns out a bunch of numbers, if you will, on the energy and power requirements of the Interconnected System. We go through and we do a rate exercise and there's an iterative process, you know, that you go around until you come down to a--until you arrive at a load forecast whereby things are more or less balanced if you will. You do look at, you know, elasticity to a point of view. If you had--submitting a rate increase, there may be some dulling of the load forecast, so you have to do two or three iterations to arrive at a point that says this is the load forecast, and it's revised every year.
Q. And that's the long-term load forecast?
A. That's the long-term load forecast.
Q. Okay. What about the short-term load forecast year over year? How is that completed?

Page 35

A. The short-term load forecast takes information from the Industrial Customers, Newfoundland Power and our own forecast for Rural, and we generate these. These are used basically for budgetary purposes, for revenue requirements in the test year, for instance. But we basically take the information from the customers and we review it. We question it if we feel it's a little bit odd or it doesn't kind of fit our expectations, and we build the forecast for the system from there. That then, in turn, will go and do the hydrothermal split, which we'll consider the water resources we have available and generates everything from that, from a cost point of view.
Q. Now in terms of when your customers provide you with their forecast, at what time of year is that normally done?
A. That's usually done around this time of the year, in the fall.
Q. And it's for what period?
A. It's usually one to five year horizon.
Q. And during the course of a year, is there any update given in the forecast that has been

Page 36

provided?
A. The forecast from the customers may or may not be updated. We usually go back for a reality check, if you will, and if there is any significant change in the forecast, we will basically do a revision and we will revise our estimates, our production estimates, our fuel estimates, based on the energy that we anticipate needing by the end of the year.
Q. And since you've been in charge of this particular department, have you been required to do any updating pursuant to the forecasts that were given to you?
A. Yes, that's quite common to revise the forecast. I mean, the weather obviously drives a lot of it. If it's a mild winter, we usually decrease our fuel use. If it's a harsh winter, and depending on the water situation, we will increase the usage, and this has been revised, is being revised now, for the filing that we will undertake towards the end of October, early November. That will all be revised for -
Q. In which direction would it be revised?
A. The forecast, the overall forecast, there's a

Page 37

MR. HAYNES:
little bit more fuel required because our inflows have basically continued in a downward trend. We're still below average on our inflow situation this year. So there is a requirement for more volume of fuel, somewhat balanced by the exchange rate, so there is a change, but -

Q. So if there's more rain in the forecast coming up, will that be of assistance?

A. Yes, certainly, it would be, yes. We have to maintain the--we have guidelines around the reservoir operation to maintain a guide curve and we occasionally dip below that, but it's not a comfortable place to be and we are, right now, just a little bit above it or on the line. If we get more rain, it'll help us. If we get less rain, it'll obviously require more fuel consumption at Holyrood.

Q. Now when you were mentioning previously the new capacity that you're looking to and the various expansion, you didn't mention conservation. How is conservation factored into the timing for additional capacity? Have you looked at that as a possibility and a way

Page 38

of avoiding new capacity coming on?

A. If we look at conservation or DSM in the Isolated Diesel areas, specifically when new capacity is required and when the load forecast indicate that a requirement is, for a new diesel plant is required, we do do an exercise to the economic analysis to determine whether there are any costs--any economic merit into actually initiating some demand side management, you know, through compact florescent lighting and whatever. On the provincial grid, we had not undertaken anything other than our HYDROWISE Program to attempt to educate the general public that conservation is important, but we have not undertaken any "initiatives" in that particular area. I mean, submitting a thing that can be done, from my point of view, is through rates, to encourage people to conserve or to be--make wise choices regarding the use of electricity.

Q. What do you mean through rates?

A. Well if the rates--if people do not appreciate the cost effectiveness, overall cost effectiveness of electricity versus, for

Page 39

instance, oil fired heat, or whatever, then they will naturally make a decision which they think is most cost effective. The capital cost, obviously, of oil-fired system is a bit higher than electric heat, as Mr. Wells mentioned the other day, and people tend to go with their, I guess, their initial short-term cost, as opposed to the long term, but, you know, we do not have a "Demand Side Management Program" per se. We do have the HYDROWISE Program which is basically an education tool.

Q. How do you measure the HYDROWISE Program to determine if it is being effective?

A. Well it was only implemented this year and that was implemented by our customer services department. I'm reluctant to comment on how it would measure. I suspect that Sam Banfield may be more appropriate to answer that particular question.

Q. But there's no one in the new generation department that is responsible for finding, avoiding expanding the system through finding better ways to conserve and to urge people to conserve?

A. Not specifically--not specific to any

Page 40

particular individual's job requirements to be solely responsible for that particular aspect, no.

Q. And in your meetings nationally with the Canadian Energy Council and the particular sub-group you're involved with, is there much discussion of conservation?

A. Some, yes, there is some. It's not a major focus of the CEA, I mean, they do advocate, as we do, the wise use of energy, but it's really--the most gains will be made from education of general public and consumers of what their options are. But typically, people do not--if they're willing to pay, they don't think twice before they turn the thermostat up or buy more appliances. I mean, we had less growth recently than we had before when there was a lot of electrification going on, never slowed a bit, but still, is the primary choice of new home builders is electric heat.

Q. How does that help you in your planning of the system, the fact that people out there still choose electric heat?

A. It doesn't help or hinder us from the point of view of system planning. Basically the

Page 41

MR. HAYNES:
manifestation is through the load forecast. We look at the housing starts and a function done of how many new housing starts are all electric and that's all factored into the equation to come up with the load forecast. And then we basically strive for the least cost way to meet that particular demand. We have not made major efforts into trying to influence what the total energy requirements of the Province are.

Q. In terms of the conservation theme, what efforts have been made and what plan have you in place to reduce the amount of fuel that's required at the Holyrood Generating Station?

A. What we have been striving to do at Holyrood is to make sure that for every barrel that we do burn, that we squeeze as many kilowatt hours as we can out of it through, you know, through our efforts in the plant and through system dispatch. We have--most new sources, I would suggest that all new sources basically have some difficulty competing with the marginal cost of Holyrood. Granite Canal was close, but most sources are more expensive

Page 42

than Holyrood. Holyrood is still a cost-effective source of energy for the Province.

Q. And you mention that people are still putting electric heat and baseboard electrical radiation into their homes. If in account of--have you done any analysis to find out how much that is really costing, in terms of the fuel requirements for Holyrood?

A. You mean on a household basis?

Q. Yes, just generally, you know, is this really costing you--costing Hydro a lot financially to provide this service?

A. Well, it cost the home owner, I guess, electricity or it cost them capital cost and fuel cost if he buys from whichever oil company. I don't think we have gone down through and, from a corporate point of view, and specifically looked at what that is. I mean, I know that our economist has looked at the overall, the overall efficiency or effectiveness of, say, oil-fired home heat versus Holyrood, and I mean, that's the high level or the bird's eye view is that we are burning oil at a 35 to 40 percent efficient process and a homeowner could put in a furnace

Page 43

and burn it at 80 percent efficient process.

Q. But why aren't homeowners told that?

A. I'm sure they would be by the oil companies.

Q. But why isn't Hydro taking the lead in telling people that there will be a more efficient process by putting in your own furnace, rather than having Hydro burning bunker C fuel at the Holyrood generating station?

A. We have not targeted the customers of Newfoundland Power from the point of view that they're in a diesel system, it looks after itself because the rate structure is, you know, the more you use, the more you pay. We have not targeted Newfoundland Power customers from that particular aspect?

Q. Why haven't you?

A. We did not feel it was our role to actually persuade or to discourage use by another company's customers.

Q. Well, whose role would it be? Whose responsibility would it be to inform people concerning the efficiencies that could be gained by if they put a furnace in their home as opposed to the lack of efficiency you have in Holyrood by burning oil there?

Page 44

A. I guess it's really a consumer education process and it's a consumer education thing. I think the HYDROWISE Program does assist in that there. I think the--I would think that the various entities can have some responsibility, whether it's the PUB or the Government through NRCAN (phonetic), Federal Government Programs, but Hydro has not taken that upon itself to speak directly to the customers of Newfoundland Power.

Q. But Hydro generally has no program attempting to persuade consumers to use less energy as a technically acceptable alternative to new generation?

A. No, although Hydro does encourage the wise use of energy, but we have no, we have not instituted programs on a customer-by-customer basis, whereby we could actually show them or encourage them not to put in electric heat.

Q. Have you undertaken any studies, has Hydro undertaken any studies to show that conservation, a massive conservation would be a technically acceptable alternative to new generation?

A. Not specifically. Not recently, not that I'm

Page 45

MR. HAYNES:
aware.
Q. And why wouldn't you look to that as a possibility?
A. Look to actually going on a massive campaign for conservation?
Q. Yes, to examine conservation as opposed to putting in alternative new energy?
A. I think from a--I think on a go-forward basis that there may be gains to be made by influencing or encouraging people to put in oil-fired electric heat. I think maybe some of the environmental programs with the Federal Government may be of some assistance because it is more environmentally appropriate as well, you know, to get 80 percent efficiency out of a home furnace than it is 37 percent efficiency out of Holyrood. But for people to go back and retrofit their homes to be, you know, a hot-air furnace or a hot-water furnace or whatever would be prohibitive and I think the only in-roads you may make is on new construction and that will be education over time. We have not undertaken any specific target program to curtail power or energy use.

Page 46

Q. And in terms of new construction, even if you undertook that as a project to point out the fact that you just pointed out to us, that people would be more efficient in putting a furnace into their home, than having you burn the oil at Holyrood. Have you considered that as a possibility of lessening the strain on the system?
A. Not as a major impact into the next source, we have not considered that at this point in time.
Q. Have you done an analysis to determine where that would get you?
A. Not to my knowledge.
Q. In terms of system planning and system operation, on page 2, lines 8 and 9, you make reference to the Energy Control System and the co-ordination with Newfoundland Power and the non-utility generators and the Industrial Customers. The non-utility generators, they provide back-up service of sorts. How do they get into this equation?
(10:00 a.m.)
A. No, all the non-utility generators provide power energy to Hydro on a kind of a take or

Page 47

pay basis and basically when they generate, we take it and basically we displace primarily Holyrood fuel. Maybe not in the immediate--you know, in the middle of the summer, obviously, we wouldn't be displacing Holyrood fuel directly, but we would generate less of our hydraulic and the fuel would be displaced at a later point in time. There would be some time lag on that particular activity.
Q. And Newfoundland Power has its own generation sources too.
A. Yes, but they are behind Newfoundland Power delivery points and most of the NUGS actually deliver into the system and then it's accounted for Newfoundland Power, that's taken off their load forecast and then accounted for in their load forecast.
Q. How do you determine how much energy you require from the NUGS at any given day?
A. It's based--primarily we take as they generate. We don't--most of the NUGS do not have a lot of storage capability. They're not necessarily run of the river, all run of a river, but basically when they generate, we take the power or take the energy, I should

Page 48

say. So there's no appreciable effort from the point of view of dispatching those NUGS and with respect to the amount of NUG power that we have right now, which is approximately 66 megawatts, I believe, that's not a major issue for Hydro. We can easily absorb that into our system and we will work our facilities around those. We have more storage capability.
Q. So in terms of the NUGS, they can produce as much, according to capacity as they can, and you will take it into the system, is that the way it works basically?
A. That's correct.
Q. Now, the NUGS, is that an expensive form of power for you to purchase?
A. Well most of them are new plants and all the new plants typically are obviously more expensive than the, you know, Bay D'Espoirs and the Upper Salmons and so on, it's a bit more expensive than--it's more expensive than Holyrood, it's a bit more expensive than Granite Canal, but it's probably on par with Island Pond or not too far from that.
Q. So the power you're buying from the NUGS is

Page 49

BROWNE, Q.C.:
more expensive than the power you could produce with fuel at Holyrood?
A. On a marginal basis, yes. Holyrood fuel basically if you consider the O & M and so on at Holyrood, you wouldn't be much more than $60.00 per megawatt hour and the Granite Canal is about 53, 54 and the NUGS are higher again.
Q. Well from a business perspective, is that the wisest course, to be purchasing from the NUGS?
A. That depends, when you go down through and look at your load forecast, we have to do something. We have to meet the load. We plan a system for loss of load expectation or loss of load hours of 2 point hours and we plan the system to meet the hydraulic firm, so when we get to that particular point, we have to do something. As I mentioned, when we go through, for instance our next source, we will evaluate all those options and we will propose to the Public Utilities Board what is the most cost-effective way to meet that load at that time. Now that may be NUGS, it may be Island Pond, it may be Holyrood 4, it may be whatever. It will be the lowest evaluated

Page 50

cost over the term to meet the needs of the system.
Q. Okay, so you're buying as much from the NUGS as they can produce. What about Newfoundland Power's generation, how does that work in your control system?
A. Basically we don't control any of Newfoundland Power's generation, nor do we actually control the NUGS. Newfoundland Power's generation, Newfoundland Power can generate approximately, in Schedule 2, on an average capability of about 424 gigawatt hours and basically they do that and it's absorbed in their system. Obviously they don't buy it from us, it's not purchased and blended in, if you will, it's totally behind their delivery points, our delivery points from Newfoundland Power.
Q. So it directly affects their own customers and not you?
A. Yes, if they weren't there, if they never had those Hydroplants, I would presume that they would be looking to buy another, you know, point four, 424 gigawatt hours on average from Newfoundland and Labrador Hydro.
Q. Has there ever been a study undertaken at

Page 51

Hydro involving Newfoundland Power and their generation capacity to see if Hydro should be taking over the generation from them or it could purchase the generation from them?
A. Not to my knowledge. Most of their plants are, except for Rose Blanche, I guess, have been there for quite a number of years and I would suggest that their capital cost is long since written off and they're probably very, very cost effective for Newfoundland Power just to absorb that into their system and sell it as they do. And there are a lot of small plants, most of Hydro plants--not all, most of them are larger plants.
Q. When you call upon Newfoundland Power to generate, yourselves, have you had occasion to call upon them to supplement your system?
A. We don't normally call upon them to generate on their hydro plants. They usually try to ensure that those plants are available in the winter during peak. We do call upon them on some of their thermal generation if we have a situation whereby we need power, and I think that's set out in one of the exhibits, what the pecking order is, if you will, of when we

Page 52

would call for that particular load. And I think in some of our RFI's it was actually indicated the times when we actually called upon them to generate thermal. On any particular day, if we find ourselves in a situation where because of outages or unscheduled outages that we found ourselves a little bit tight on generation, we wouldn't hesitate to call Newfoundland Power to make sure that all their Hydro is on or even call Industrial Customers to see if they can, you know, could be of assistance.
Q. Now about a month ago or it might have been a little longer, it might have been six weeks or so, the electricity went off on at least most of the Island, at least the Avalon, due to a failure where, in Bay D'Espoir, was it?
A. Bay D'Espoir station service.
Q. Okay. How were the services that Newfoundland Power, and others, had to offer incorporated to assist you there?
A. I think at that particular time we, I'm not sure if we actually asked for--I think we may have actually initiated a request for Newfoundland Power to start their gas

Page 53

MR. HAYNES:
turbines, but I think by the time that that was ready to go, I think we may have had the situation looked after with other generations. I think we actually had some generation, our GNP turned on the diesels and so on, until we got that problem resolved at Bay D'Espoir, which has been since resolved, by the way.
Q. So you initiated the request to them to help out with the deficit, but by the time you ready, you didn't require it? How long does it take them to get going?
A. That's in our RFI as well, I think it's probably about a half an hour, you know, assuming that the gas turbine is operational. Sometimes the gas turbines are--our gas turbines and Newfoundland Power's gas turbines don't necessarily have a stellar record of starting when you want them to start. They're pretty good, but occasionally they don't do as they're requested, as they're supposed to do, but I think it's about a half an hour or an hour.
Q. Now where would the sources of Newfoundland Power's gas turbines be that would assist you

Page 54

in feeding to the system when you have a deficit situation, such as that?
A. Our largest gas turbine is on the Burin Peninsula.
Q. Okay, so it's on the Burin Peninsula, whereabouts on the Burin is it?
A. I think Green Hill is--my geography, I don't remember exactly from my planning days exactly where it is, but it's near the foot of the Burin Peninsula where the gas turbine is located.
Q. Okay, so if you require additional power because of outages and you're requiring their thermal power, they will begin generating down at the foot of the Burin Peninsula?
A. If we get down to that hierarchy of requests for generation, we obviously will start our own Hardwood in Stephenville, whatever is required, but if they get down there, they would be one of the ones that they could put on fairly quickly and I would assume that they would have all their hydro plants, as much as they can as well.
Q. And from the foot of the Burin Peninsula, from the boot, they would be generating electricity

Page 55

for the entire grid, is that correct?
A. Oh yes, it all goes into the grid, it will displace, you know, it will reduce transmission from the--from Sunnyside down and allow power to be used somewhere else. I mean, the electrons go wherever electrons go, but it's an assistance--all the generation, as we are suggesting in our review, is used and useful to the overall system.
Q. And where else would Newfoundland Power be able to generate thermally from, what other points on the Island?
A. I think they have--a diesel generator is located in--they have diesel generators, two and a half megawatts in St. John's; they have a half of megawatt in Port Union; two and a half megawatts in Port aux Basques; and they also have one point seven megawatts of portable diesel generators; and they have the gas turbines at the Green Hill; and there's also the 15 megawatt gas turbines that they're moving to the Bonavista Peninsula. All of those generation are used and useful when we need it.
Q. And all these could assist in feeding the

Page 56

entire system?
A. Yes, as would the generators and the GNP or, you know, anywhere else.
Q. What would be the source of the generation on the Great Northern Peninsula?
A. Basically there are three diesel plants on the Great Northern Peninsula owned by Hydro, one at St. Anthony, Hawke's Bay and Roddickton and there are a total of--I think at Hawke's Bay there are two two and a half megawatt units; at St. Anthony there are four one megawatt units and two two and a half megawatt units; and at Roddickton there are two units at 850 kilowatts, but they're all used and useful when we're in a pinch.
Q. Now were you in a pinch six weeks ago when the system went down?
A. Yes, we had initiated a request to Newfoundland Power, we had also started generation that we had available because basically Bay D'Espoir plant was basically completely flat.
Q. And the generation you had available from the Northern Peninsula, was that used to feed the entire system?

Page 57

MR. HAYNES:

A. It fed into the system, so it would have allowed generation at Holyrood or wherever to be used, you know, when a generator generates, it doesn't go in any particular place, it just goes into the grid, and it contributes to the overall grid. There's no accounting of where the electrons go, if you will, so it feeds, it displaces, the load flow will just rearrange itself automatically to meet the load.

Q. Now you mention in your evidence concerning information systems and telecommunication systems that you have. I just want you to take us through those on page 3, at line 30, you mention the local area networks, LANS. What kind of system is that and how does it operate?

A. I'm not sure of the actual manufacturer, if that's what you mean, but basically -

Q. No, I'm not asking you that.

A. Okay, basically it's all these things that you see around here in this room so that we can tie all these computers together, so we have email, have access to Internet if required, that we exchange data, it's all done

Page 58

electronically. It's a connection--and all our main systems are connected, St. John's, Head Office is connected to Bishop Falls and a lot of the systems that they run in Bishop Falls actually run on computers in here, particularly the JD Edwards System and so on. It's all done through the LAN/WAN.

Q. So it's an electronic connection?

A. Oh yes, it uses the Microwave System and so on.

Q. And you mention the wide area network, WANS, what's that?

A. The LAN is, for instance, in Hydro Place there's a LAN, it's a local area network, so all the desks and all the computers are all wired and connected up to servers within the building and so on. The wide area, that basically extends its reach so that we have connections to Bishop Falls' office and Port Saunders' office and Goose Bay, et cetera, and to Bay D'Espoir and Holyrood, that is the thing that connects all those communication facilities to our integrated system is the WAN.

Q. And the wide area network in the LAN and the -

Page 59

A. Same sort of data goes over it, but it would typically involve other communication systems such as Microwave System, for instance. In the building of Hydro, there may be, you know, it's basically hard wired and then as you get into the WAN area, you would actually, you know, use fibre optic links, possibly to Newfoundland Tel or through our own or the Microwave System. It just extends the reach to--but it usually involves another intermediate area communication system, such as microwave or fibre or whatever.

(10:15 a.m.)

Q. And the Microwave System, how does that work? Life if there was an outage, I gather your local area network would be down as well at Hydro Place, would it not?

A. Some, not necessarily all, there are some things that are powered on, you know, on a--the Energy Management System will not go down normally during an outage and there are, I think probably the AS400 probably stays ongoing, some of the peripherals may drop, but I think the main computer would actually continue to function.

Page 60

Q. And would it continue to function and pick up information in other areas of the Province?

A. The Microwave System is basically separate from the rest and it has its own emergency power sources that will run with everything else flat, for awhile. All the Microwave sites are--have some redundant power supply, obviously we'd prefer to hook it up to the grid, but there is usually a diesel or some other power supply on site, batteries and so on, to keep it going so that we can recover; otherwise, if we lose communications, we are obviously handicapped in returning the system to service.

Q. And you mention here, internal phone systems, that's just LAN lines, is it?

A. In the office phones we had a number of years ago, I guess, like most people, at one point in time, we would always require that from a Newfoundland Tel or T&T or whoever at the time, I guess over the years we have basically purchased these switches and put them in our buildings and saw significant savings in cost and operating cost as well by owning the switch. So, most of the, not necessarily all,

Page 61

MR. HAYNES:
but most of the significant switches that we have now are owned by Hydro as opposed to being leased from Newfoundland Telephone and being administered by them, we do it ourselves.
Q. Have you have a situation where the LANS network went down and the WANS went down and the Microwave went down and the internal phone system went down at the same time?
A. I don't think that we had an event where we lost all of those things the same time, no. We have, obviously, you know, depending on what happened here and there, we may have had certain failures in the system. We've lost the Energy Management System on two occasions which would handicap our return to service, but that's under--that's presently being a spec for replacement to enhance that. But we haven't lost everything at one time. We have contingency plans in place if we lose the Energy Management System, whereby we go back on VHF radio and whatever is available, but, you know, we have contingency plans for losing these things, but we have not experienced a

Page 62

total absolute failure of everything.
Q. In terms of the VHF radio system, you have made application to this Board in the last number of applications for your capital works to put in a new VHF radio system. Why do you need that where you have so many alternatives that you can use?
A. A lot of that was discussed, I guess, in the last two Capital hearings, and in our view, the VHF system is the most reliable, it's the backbone, it's the back stop to the failure of anything else that we have, and it reaches people in the field who have no access to cell phone sites or other communication systems to facilitate the return to--for instance, if you were restoring a transmission line and it's out in the middle of the wilderness area, VHF radio is the only means of communication with the crew, from a safety point of view, from a material's point of view and just to expedite the return to service of those pieces of equipment.
Q. Have you ongoing discussions with Newfoundland Power re their VHF radio system and any discussions in reference to having one

Page 63

provider and two users for that, yourself and -
A. We have had various discussions over the years with Newfoundland Power on that aspect and I guess, you know, we do coexist right now with Works Services & Transportation which basically is effectively paying for half the cost. With respect to the last order from our 2003 Capital hearing, we have initiated meetings with Newfoundland Power to address if there are ways and means that we can integrate or that we can use the same system in the future. Those meetings have just started, but we are preparing--we are still endeavouring to somewhere along the way come back with another Capital Budget proposal to the Board for consideration to move on. We strongly feel that we have to replace the VHF radio system and recognize--we recognize the Board Order and we are trying to accommodate all of those requests.
Q. So that's ongoing now?
A. That's ongoing, yes.
Q. I asked you previously about Granite Canal and now that Granite Canal is completed, will

Page 64

there be reductions in staffing as a result of the completion of Granite Canal?
A. As I mentioned, I think there are some term engineers, particularly, and so on that will be reduced and some have been reduced in respect to cluing up the conclusion of Granite Canal, but there are no permanent staff reductions planned because of Granite Canal; in fact, from the point of view of, you know, taking on Granite Canal, we have no increased the operating maintenance staff because of that. We are basically going to incorporate Granite Canal operating and maintenance into the Bay D'Espoir system as it is today, with no increase in staff.
Q. So the answer is no?
A. Well there are some temporary--term engineers that will be reduced as towards the end of the year, but there are no--there is no anticipation that it would actually reduce our original complement, solely due to Granite Canal.
Q. And how many term engineers will be gone at the end of the year as a result?
A. There were, in production division, there were

Page 65

MR. HAYNES:
four hired initially, two are gone and there are two to go.
Q. And that's already accounted for in the evidence, the fact that these four positions are eliminated?
A. That's all--all of that is all in the 2004 Cost of Service forecast.
Q. How come a project, such as Granite Canal, you would only see fit at the end of the project to let four people go? It seems to me the magnitude of the project would have had a lot more people working there, would it not?
A. Well there were in excess of 300 people working on the project, but basically what we did was through our generation and engineer department and there were other departments involved as well, you know, transmission, obviously, had to be built and Microwave Systems and Communications Systems were done. But basically most of the work was all done through contractors to the joint venture and we only had really five, five to six people who were allocated pretty well fulltime to the Granite Canal project. So there was not--

Page 66

there was no major, you know, these were basically senior engineers and technical people who brought their background and skills and experience and Churchill Falls, Newfoundland Hydro, to that particular project.
Q. So it's all contracted out and you only had five people working there?
A. I think five people were allocated fulltime to the project, yes.
Q. From the entire Hydro complement there was only five people?
A. There was a lot of other people involved at different time for different stages, but they would not have been a fulltime commitment, you know, obviously we would have had time involved from the Bay D'Espoir operations people, the maintenance people, to review a drawing or to review an operating philosophy to say whether they agreed or whether they could add anything to it, but those were, you know, I won't say spurious, but they were, on the design stage, there were a lot of things done, decided and we moved on. But there was not a, you know, five people for a turn-key

Page 67

project would be adequate. And they were seasoned experienced people who were allocated to the project.
Q. On page 7 of your evidence, lines 16 and 17, you make reference to the Labrador Interconnected System and the 38.3 megawatt gas turbine and diesel plant capacity there, used for backup and limited peaking capacity, how often have these units been utilized?
A. From a generation point of view, primarily used when there is a problem with a single--there's a single 138 kV line from Churchill Falls to Goose Bay and Churchill Falls actually maintained that particular line and while they do do a lot of live line maintenance, there are occasions when the line has to be out of service. And when the line is out of service, the gas turbines and possibly a diesel plant would be utilized.
Q. From your own experience there, has that been once a year or twice a year or every ten years or -
A. I would say a couple of times a year it's probably used, but I'm really guessing. Certainly it is used on occasion and I'm aware

Page 68

of several that it has been used. It's also, for instance, a couple of years ago, we were into this insulator problem and we replaced a lot of the insulators, so it was used considerably during the Insulator Replacement Program for the 138 kV line because it was more cost effective to take the line out of service. That would be a horrendous job to do hot, so basically it was de-energized and just get in and get out and it would be used at that particular time. I would add too, that the gas turbine in Goose Bay also functions as a synchronous condenser, which provides voltage support at the end of the line and also allows a transfer of more megawatts to the Goose Bay area.
Q. So they're absolutely essential for that system there in your opinion?
A. Yes, in my opinion.
Q. On page 13 of your evidence, can we go there please? And lines 18 to 29, you indicate that the ECC utilizes the Energy Management System to optimize the use of hydro and thermal resources, optimizing the mix and minimize water spillage. How is that done? How is the

Page 69

BROWNE, Q.C.:
water spillage minimized?
A. There's a fairly complex--there are a lot of factors that come into that because of the number of reservoirs that we have, the number of potential spillage sites that we have. So in the day-to-day running of the hydraulic system, the system operation and operation's people look at, on a weekly basis, the reservoirs, how much water is there, how much room to, you know, we have to go to full supply. They have to look at the load forecast for the next week to determine how much generation is required from each of the hydraulic facilities and they have to plan the discharge of water so the water is there in time for the hydro plants to generate. If they miss the boat, if they release too much water from the upcountry structures, the water is en route and basically they have to make sure that the generation, the load is there to take the load, otherwise, depending upon the difference between where a reservoir is and full supply level, if they exceed full supply, they would have to spill. So there's a fair--

Page 70

it's more of a hydraulic management. They have to look at the load forecast, you have to look at the actual--they would take into consideration the actual weather forecast, if they anticipate a lot of rain, they may back off a little bit because they anticipate a fair bit of rain, because some of the reservoirs respond fairly quickly to a significant rain store. So basically it's a hydraulic planning. They have to plan the water to be at the intake of the hydraulic structure for when the hydraulic structure needs to generate. It's a fairly complicated process.
Q. Is there any planning with Newfoundland Power and the Industrial Customers as part of this optimization process?
A. Not significant planning. If the optimization process for most of our plants is because we have significant storage. As you have hydro plants that have a lot less storage capability, your ability to optimize is significantly reduced. The Bay D'Espoir, the big hydro plants would be the most appropriate for that particular approach, particularly the

Page 71

run of the river plants because we have Bay D'Espoir, we have Upper Salmon, we have Granite Canal all on the same reservoir system, so there's a -
Q. What about the NUGS, are they part of this optimization at all?
A. No, they basically, as they generate, we buy. And most of those have very limited storage capability.
Q. Newfoundland Power has indicated that if the wholesale power rate is changed to a demand energy rate from the current energy only rate, there's a danger that its hydro generating facilities would be operated at less than optimum with the possibility of spillages. What's your thoughts on that?
A. But they did say that they would operate under the Act, which basically was the most efficient resources, I mean, I think what they said was there may be an incentive to-an incentive to stray from that mantra. But I don't think there's any doubt that Newfoundland Light & Power, Newfoundland Hydro will operate all the facilities in the best interest of the rate payers. I think on a

Page 72

demand energy rate, I think that that is a long-term--I don't think the pay back of a demand energy rate are not short term, they're longer term when it comes down to the things you discussed before with respect to the next generation source and maybe having some control or influence over the long-term load growth, that that may assist in that. But it's not a short-term thing, it's something that, you know, the demand energy rate should, over time, it may over time, depending on the way the rates are implemented by Newfoundland Power, have some influence on the future choices of consumers.
Q. And you indicate your Energy Management System optimizes the use of hydro and thermal resources to optimize the mix and minimize water spillage. Did they have a lesser vehicle than you have to minimize their water spillage?
A. I think in the case of Newfoundland Power was similar to the NUGS. I don't think, you know, I'm not suggesting they don't have spill, when you undertake to construct a hydro plant, you look at a whole raft of things. You look at

Page 73

MR. HAYNES:
particularly the hydraulic regime and you look at as much information as you can. You would never build a hydro plant and design a hydro plant that never spills because the economics would not be there. So there's always a built-in acceptance of some spills from each and every plant you build. Depending on the economics at the time of some of the older plants, Newfoundland Power may spill in some areas more often because of the plant. The other thing I would suggest with Newfoundland Power was that because Newfoundland and Labrador Hydro basically back stops the generation of basically everybody on the Island, that they can generate--they can, I would suggest in 99.9 percent of the cases, as long as they have the equipment available, that they can generate whatever they want.

Q. Who is "they"?

A. Newfoundland Power. They can generate whatever--I don't think they would be forced to spill because of, you know, load conditions. They can generate and basically Newfoundland and Labrador Hydro would look

Page 74

after it in their reservoir system. And we have much, you know, we have more reservoir storage ability than Newfoundland Power or any of the NUGS to do that.

Q. So you don't agree then with what they're stating that if there is a demand energy rate from the current energy only rate, that there is a--that that danger of spillage, as they are professing, is in fact there?

A. I think the context of their statement was that if they were to use their hydro generation or their generation to reduce the peak, that what they would do is they would impound, possibly impound more water going into the winter than they would normally do and there would be a risk of spillage because if you have a full reservoir and you can discharge "X" thousand of cubic feet a full load and the inflows are "X" thousand cubic feet, plus 10 percent, then 10 percent of the water will have to be spilled. So I think it's more of a matter of the way they plan the winter generation.

Q. So if you had to plan that and were moving to a demand energy rate, what would you do?

Page 75

A. We would plan the whole, but it would be a little bit prohibitive to plan the whole for, I don't know how many plants Newfoundland Power has, but there are numerous number of small hydro plants. It would be a lot more difficult to do with a lot of small plants, as opposed to several significant storage areas, you know, the Bay D'Espoirs, for instance, and the Upper Salmons.

Q. But if you were given a job, if Newfoundland Power has come to seek your advice as to ways to minimize water spillage in a demand energy rate system. What would your advice to them be?

A. I'm not sure what my advice would be, I would suggest that if we were to go with a demand energy rate, that Newfoundland Power would probably have to seek to minimize that risk to rate design, as opposed to--and to ensure that even if, you know, that they would not have a major financial incentive to risk spill, that maybe rate design would look after that in a sense that the rates would, to the end consumer, would be somehow--provide them a negative to increase their demand in the

Page 76

wintertime to avoid that.

Q. Can you expand upon that a little, just give us your views on the demand and energy rate and how that would work, ultimately?

A. I'm not--I wouldn't profess to know a lot about the demand and energy rate, but I guess what we were proposing to Newfoundland Power, I guess, or what we're now proposing is to go with the demand energy rate. The benefits, as I said, are long term, that over a period of time that you would encourage the end consumers to be--they would get a better price feed back with respect to, for instance, winter usage. With respect to Newfoundland Power's hydro plants, I mean, there's no doubt that when they look at the whole of the demand charge and they look at the possibility of having their hydro plants one hundred percent capable, that they could shave their peak during the winter. That may be cost effective for them. They may be able to put in a rate structure which would kind of reduce that probability less than what it is today. Today, with an energy only rate, you know, Newfoundland Hydro picks up any shortfall in

Page 77

MR. HAYNES:
energy--in the capacity requirements and it's not something they have to worry about. It's definitely a consideration for Newfoundland Power, you know, it's something that they would have to think about, but it would be a business risk to them which they would have to address and resolve possibly through the rate structure.
Q. But you're here before this Board, Hydro is here advocating the demand energy rate be implemented from the current energy only rate?
A. Yes.
Q. What benefits do you see in that to Hydro?
A. I think as I have said, it's a longer term--it's in the longer term we see--we may see some impact on the load forecast, expansion of electric use, depending on the rate structure that's ultimately employed by Newfoundland Power. But Newfoundland Power right now do not have any--there is no strong factor to curtail demand in Newfoundland Power with an energy only rate. Obviously demand and energy rate would treat them the same as the Industrial Customers who do have some, you

Page 78

know, repercussions if they exceed the power on order, for instance.
Q. And in reference to what we began this discussion, to minimize water spillage, you have your Energy Management System in place for that purpose and they could have something similar, is that correct?
A. I'm not sure what they have, but I presume they look at all their hydro plants to some degree of optimize--at least right now, optimizing the water usage.
Q. In terms of the system that's there to minimize water spillage as you refer to it in your evidence and optimize the mix, how exactly is that done? Is that some kind of computerized projection?
A. The hydro thermal mix?
Q. Yes.
A. As I mentioned, that whole process which was done on system operations, looks at the availability of the machines, what machines are available, it looks at reservoir and storage levels, it looks at load forecast.
Q. So it's all computerized, is it?
A. A lot of computer programs to assist us and

Page 79

there's obviously some judgment invoked by Mr. Henderson and his group, but there's a fair bit of assistance by computerized models to do that and then it comes back and optimizes and reduce our risk of spillage. We also attempt in a control arena to, as came up on the screen when I started, we put in the curve for the relationship between the barrels of oil consumed versus generation. There is--the Energy Control Centre has a fair influence on the actual average load of Holyrood. The higher the average load, usually the higher the conversion rate, so there's a whole raft of factors that come into it. They try to keep that up, they minimize reduce of spill and at the end of the day, they're trying to weigh a whole raft of different options to do the best job, to have the least cost to maintain the service.
Q. And does the computer, put it in vulgar terms, does a computer tell you exactly what the mix is and what you have to do and then you exercise your judgment based upon what the computer is telling you?
A. I'm not exactly sure, I think there's--at the

Page 80

end of the day there's judgment involved, but I think the modelling, the several programs that they do actually run, do come out and give a suggested course. Then they have to consider the weather and they have to consider if there's a machine that's scheduled out next week or a transmission line scheduled out next week, so there's a whole other bunch of factors that come into play.
Q. And are these software programs that your purchase for hydro production?
A. Some are purchased, yes, some are stand-alone systems that look at the load forecasting, you know, the load forecast for next week, which is driven by the weather forecast, so there are several different tools used.
Q. And the software programs are out there, that are subject to purchase, I guess, by anyone who wishes to buy them or are they developed for each particular utility out there?
A. I think--there's a core of programs that you buy, but there's always changes that suit your particular system and situation. But there's no one program that's going to be the "be all and end all" that does it all. There's still

Page 81

MR. HAYNES:
a lot of, you know -
Q. It's human judgment as well.
A. Human judgment, experience of the operators and the fellows in the control centre applied to that.
Q. So, in terms of Newfoundland Power, they're using as the excuse for not wanting to move to a demand energy rate that the possibility of spillage, there are programs out there can be adapted to assist with that. Would you believe that that would be the case?
A. I'm reluctant to agree to Newfoundland Power's specific situation.
Q. You haven't studied their system.
A. I'm really not sure of the -
Q. But you do know that there are computerized programs out there for Hydro production.
A. Yes, but one is a financial issue and one is a--one may be a financial issue versus, you know, squeezing every kilowatt hour out of every gallon of water. They don't always come together, unfortunately.
Q. In terms of the Energy Management System generally, are there plans to increase the

Page 82

amount of remote control of hydro plants in the province?
A. We have looked at--we don't have remote control over two of our small hydro plants, Snook's Arm and Venam's Bight and we have not looked at any particular thing in the short term to provide any remote control. We are looking at increasing remote control of some of our structures, hydraulic control structures. Right now, some of our hydraulic control structures are manned most of the time and we are looking, we are reviewing that. We have no conclusions yet, but--and if the conclusions are that it's an economic thing to do, it'll eventually come forward as capital budget proposal. But all of our primary plants are remote controlled. And the diesel plants, most of them are remote controlled; the gas turbines are all remote controlled.
Q. What plants out there are not remote controlled?
A. Snook's Arm and Venam's Bight, but they's two very small old plants up on the Baie Verte Peninsula.
Q. So, it's only two we're talking?

Page 83

A. Only two and Roddickton Hydro, I think, is also--Roddickton mini hydro which is looked after by TRO is not remote controlled from a control centre.
Q. How many employees would be involved in these areas where they're not remote controlled?
A. In Snook's Arm and Venam's Bight there are no, I don't think there are any employees. I think we have a, kind of, basically starts and stops as the water is available. It's a very small run of the river sort of plant. The maintenance is done -
Q. And what about in Roddickton?
A. Roddickton, I'm not--that's in TRO. I don't think there's anybody specifically assigned solely to looking after that plant. I think it's more of--it's kind of on automatic, if there's water, it runs; if there's not, it doesn't, but I'm not 100 percent certain on the Roddickton mini hydro.
Q. It's your evidence that they haven't done any study of Newfoundland Power's generating stations to see if they're savings which could be found by putting them under your Energy Management System, generally.

Page 84

A. No, we have not looked at that, no.
Q. Would you have a view on that, an opinion?
A. I haven't really thought about it, but you know, it depends on the size of the plant. If you--in our control centre right now, we basically have, on shift, we have one operator and basically one supervisor who's obviously doing a fair bit of, in some respects, some of the operating things along with the operator. And we're looking after nine plants and all the transmission systems and so on. If you were to inundate that control centre with looking after another 20 or 30 small hydro plants, I think you have a staffing issue off the bat. I don't think that could be done in a simple way, we have not looked it. The small plants are of questionable value on any control centre because there's very little storage capability. The value of doing all this generation planning and so on or dispatch planning, is usually when there's a submitting of reservoir storage where you have some flexibility to move load around and dispatch at different times of the day and do an overhaul. On the small run of the river plants,

Page 85

MR. HAYNES:
basically you use turbine water when it's available as the NUGS are doing right now.
Q. Now, in your opinion, does Hydro expertise lie in generation in this province?
A. I think Hydro's expertise lies in generation and in the bulk transmission grid as we also maintain quite a diesel expertise because we operate so many isolated diesel systems and the distribution that goes with it, but primarily generation and the bulk grid transmission are two of the big areas that we serve. And there's also a significant, obviously, involvement in the distribution/isolated diesel areas. But generation is an area that we take a fair bit of pride in as is the transmission and distribution. I think we do it all appropriately.
Q. I mean, there's talk out there in the community generally about Hydro taking over Newfoundland Power's generation. You must have heard those discussions from time to time within Hydro.
A. Awhile ago. The current thing is

Page 86

Newfoundland Hydro taking over all of Newfoundland Power; I don't think there was any discussion -
Q. That's not a bad idea either, but -
A. We'll leave that to others.
Q. We don't get that far. In terms of to manage Newfoundland Power's generation or to take over Newfoundland Power's generation, discussions within Hydro in reference to that, have you been party to any of those discussions?
A. No.
Q. Do you think it would be practical for Hydro to take over Newfoundland Power's generation?
A. I really haven't thought about it, so I really have no opinion. It would be the subject of a fair study looking at the number of plants, the physical location, the fact that we do not have human resources out in many of these areas. That's a big question; it would be-- I'm not -
(10:45 a.m.)
Q. Newfoundland Power has some problems moving to the demand energy rate because they fear spillage in the areas which they generate.

Page 87

Hydro could be there to give them some advice as to how to go about that, I guess, would they?
A. We will help in any way we can.
Q. If we go to page 18, line 7 to 9. 2002 is referenced on that page and some troubles that you had during that year at various events, one initiated by a customer event that caused some difficulties. What was that? Who was the customers and can you expand upon that?
A. I think the specifics in that particular situation was that when we do have a bust up or whatever, we co-ordinate with all our customers from the point of view of picking up load. And that particular event, I think they picked up load a little bit too fast. As you pick up load, obviously the governors have to react and wicket gates have to open or whatever the case is to allow more water to keep, you know, the generation match to the demands. And that particular time, it was Newfoundland Power actually, I think, picked up a larger chunk of load, if you will, than the system could take. So, it actually caused the frequency to go down and initiate another

Page 88

event. It happens on occasions.
Q. Was 2002 an exceptional year for these so called events?
A. It was an exceptionally bad year from our point of view, yes, we had 17 under frequency events and for various reasons. They weren't all in generation, transmission, terminal stations, the energy control centre, there were several various reasons. So far this year, to the end of the September, we had eight events this year so far. We started off very well, but we had a few events happen.
Q. And the 17 events in 2002, when you look back at it, could you have done things that would have avoided -
A. Well, there were some things, you know, picking up a load too fast and occasionally there's a human error that creeps in there one way or another that happens; those things are done. Often times when I looks at the thermal plant, I guess we have 9 events related to Holyrood in 2002. Holyrood in a fairly complex creature and it doesn't, you know, there are numerous things out there that can cause a system to, cause a unit to trip and

Page 89

MR. HAYNES:
with 175 megawatts on units one and two, it will absolutely force under frequency load change (phonetic) to be initiated when it does trip. But we have undertaken several things in Holyrood and elsewhere to look at this. You know, we're undertaking review of our tripping logic to see if everything that initiates a trip right now, maybe it can be an alarm. It was designed based on the, you know, the standard industry design, if you will, but we are looking at those things and we have actually retained a consultant to look at some aspects of the key systems that can cause under frequency tripping in Holyrood.

Q. So, you feel you have this under control?

A. We are striving to improve it. I hope it's under control; I'm sure it is. The action that we've taken, you know, we've gone and we've actually met with the Public Utilities Board on occasion to review this, but we are reviewing all on line testing that we do. In Holyrood because of the steam plant, there's hundreds and hundreds and hundreds of daily or monthly tests that are done on line. So,

Page 90

we're reviewing all those things to see if things could be delayed or if we actually need to alert the control centre to run back on load while we do it because it increased risks. So, a lot of those things had been done and there are some things that are presently in progress to improve our performance.

Q. On page 28 of your evidence, line 11 to 13, you indicate the forecast hydraulic production for 2004 is based on the 30 year average for the existing plants where Granite Canal, the estimate was obtained from a power and energy analysis. What's that, a power and energy analysis?

A. When you propose or go into design process for hydro plant, you basically look at the hydrology of the flows that you anticipate. And Granite Canal is a part of the Bay D'Espoir system, so we know how much water was turbined at Bay D'Espoir and Upper Salmon. So, you can assume how much water actually is available to the Granite Canal. So, that was--to determine how much water was available and therefore, how much energy it could produce.

Page 91

Q. And that's the analysis?

A. Yes, but we obviously don't have a 30 year operating record for Granite Canal because basically it was just a pond back in the Bay D'Espoir reservoir and we had gauging in certain places, but we were not measuring specifically the Granite Canal lake discharge. We determined what that discharge is by looking at the whole hydraulic study, the power energy study analysis and came up with a 224 gigawatt hours average which we anticipate.

Q. Now, you mention in your evidence concerning the Holyrood generating station, that you've moved to a new type fuel that has less sulphur content, I guess, over the past year or so.

A. No, not yet. We used to buy, I think if you go back quite a number of years, we used to buy 2.8 percent sulphur was our specification. In our specification right now, we've actually specified 2.2 percent sulphur which allows us to meet the 25,000 tonne per year cap. And in our contract we have the provisions to move to a lower sulphur content fuel and one of the primary reasons is that there is pending

Page 92

legislation or legislation that may be inactive which may force us to go to a maximum of 2 percent sulphur fuel.

Q. Is that federal legislation?

A. Provincial legislation, Provincial Draft Air Quality Regulations are basically calling for, I think they started off at one point in time at 1.8 percent as the maximum that we could import into the province. And I guess, between the various dialogues, I guess between all the users, obviously the Industrial Customers are some is now changed to 2 percent. But that has not been enacted as of yet, or not been whatever the legal term is to promulgate it or whatever, but we are in a position to obviously to adjust our contract to that, if and when it does happen.

Q. But if you do adjust your contract, that will be more expensive fuel, would it not?

A. About two to three percent more expensive to go from 2.2 percent to 2 percent, yes. And our forecast is based on 2.2 percent, what's in our filing. Any impact in the interim would actually fall to the RSP anyway, you know, if it happens after the hearing.

Page 93

BROWNE, Q.C.:

Q. I'm sure that will be the case. In terms of the emissions that are coming from that plant, and the content of the fuel, are you looking to the climate control plan for Canada, the so-called Kyoto implementation program to assist Hydro in any way in reducing emissions there?

A. With respect to the emissions at Holyrood, Kyoto basically is greenhouse gas. And greenhouse gas, I mean, the two big components of greenhouse gas from Holyrood are the CO2 and nitrous oxide. There are some things that we can do from a capital point of view to reduce the nitrous oxide levels. There's really nothing that we can do with respect to carbon dioxide levels because you burn carbon and it's a part of the process. And with respect to Kyoto, I guess, there's still a lot of uncertainty, how that's going to manifest itself and in Holyrood, barring natural gas which would have a, I think, probably 30 percent or so, 25 to 35 percent reduction in CO2, we are stuck with number 6 oil. We may be, when Kyoto gets finally implemented or

Page 94

when all the dust settles on how it's going to happen, we may be forced to buy emission credits or use our own credits from the Granite Canal et cetera to meet those obligations. It may not be an actual reduction in the CO2, it may be through emission credits.

Q. It's my understanding right now that the federal government has put money on the table for use by the provinces and consumers in this budgetary year for implementation of some of the climate control plan. What is Hydro doing to try to incorporate that into their plan, to make use of available dollars?

A. The only thing that we have applied to from the federal government at this point is time is a subsidy with respect to the wind power generation thing called GPPI.

Q. Is that part of the climate control plan for Canada?

A. That is a part of the whole package deal to go with renewables and so on, but we have not sought any particular funding for other things and I think that planning has that information. I mean, there's nothing, to my

Page 95

mind, to my knowledge, has come to date, as being an opportunity at this point in time.

Q. Who is the point person there at Hydro? We have this new federal program with millions of dollars available in the name of Kyoto, who is the point person at Hydro looking at that to see what can be availed of in the short term and the long term?

A. Primarily it would be our planning department, but the environment department are, I mean, there is a few people that look at -

Q. These are departments, is there a point person--is there one person there looking at Kyoto and the climate control plan for Canada and the announcements that came out of the federal government the Spring of hundreds of millions of dollars available? Is there a person there looking at that to see what Hydro could get for itself, for consumers, for the province generally?

A. I would put that basically on the Director of Assistant Planning, would be the one that I would hold accountable to see if there's anything that's available. But as I said, the only thing that we've applied for, to date, is

Page 96

the wind subsidy from the federal government under Green Power Procurement Program.

Q. So, you know of no on person responsible in the organization -

A. The Director of Assistant Planning would be -

Q. Who would that be?

A. Hubert Budgell would be the primary to look at if there are options to reduce our costs by ultimate sources or fast tracking other potential generation, but as I mentioned before, other than Island Pond and some small hydros out there by third parties, our future, barring the Labrador in-feed is thermal, there's not much else out there in large scale renewable that we do have and obviously wind, wind has a future, but we're not there yet.

Q. In terms of the future and wind, surely wind is used in a number of provinces in Canada, isn't it, as a source of generation?

A. Yes, it is and in most jurisdictions it's because there is legislative minimum wind renewals or there are federal and provincial programs to encourage it. From a point of view of a straight economic basis, it's not necessarily the--I think it will compete with,

Page 97

MR. HAYNES:

you now, I think in 2010 or whenever we go for a new source, it will likely be a contender for future generation sources. In today, the federal government have programs to encourage that technology, to encourage the construction and most of them are being facilitated because there are, you know, Green Power Procurement Initiatives by the federal government. They are willing to pay an extra two or three cents a kilowatt hour for wind energy. Without those things, most of them are of questionable economics, unless you're in a jurisdiction where their next source is extremely expensive, but it would not compete with Granite Canal, for instance, but it may compete with NUGs.

Q. How would they compete with NUGS?

A. I think they're, you know, nip and tuck, they're pretty close to NUGS as we see them right now.

Q. So this project that's now under way, I guess, is it, down the Burin Peninsula, you don't hold up much hope for that in terms of an economic use of--in terms of the economics of

Page 98

it.

A. I wouldn't put it that way. It's not under way, we are negotiating with the vendor and we are also negotiating with the federal government for the most attractive terms that we can get for that. And I think, over time, it would likely be a viable source. Today, without the federal government funding and so on, it would be a bit more hard to justify, but I think there's a lot of merit in having a demonstration project, you know, within the system to see how it works. It is, you know, the St. Lawrence area, the first class wind resource, you know, the studies that were done by the proponent indicate that it is a very, very high potential site and we are working with the vendor and our contract negotiations with the federal government to keep the cost, the overall cost as low as possible.

Q. It's 11:00 a.m., do you want to break now.

CHAIRMAN:

Q. Thank you. We'll reconvene at 11:30.

(BREAK - 11:00 a.m.)

(11:30 - RESUME)

CHAIRMAN:

Page 99

A. Ready, Mr. Haynes? When you're ready, Mr. Browne.

BROWNE, Q.C.:

Q. Mr. Haynes, page 31 of your evidence at lines 15 to 16, you indicate that the long term load forecast for the province is a 20-year forecast of annual peak and energy consumption. How can you forecast out that far, 20 years?

A. The forecasting, as I mentioned, is done through an econo-metric model which looks at the expected housing starts which are basically provided to Hydro by the provincial government, the gross domestic product, a whole bunch of other factors which actually go into that exercise. I wouldn't be capable of explaining the intricacies of the econo-metric model, but there's quite a number of inputs which look at load growth, housing starts, gross domestic product, et cetera, population, they all go into this particular model. It's not based on where we are today and expectations of a specific short-term forecast for the customers, it's kind of more of a broader high level approach.

Page 100

Q. Because for the years 11 though 20, I wouldn't think that would be of any great value, would it?

A. The most important thing obviously is the timing for the next source and after that--we do this every year, we do a long-term forecast, but the most critical time period is the next, to identify the timing for the next source.

Q. On page 32, lines 26 to 28, you indicate that high growth is expected on the isolated rural systems, 2.8 percent in 2003 and 3.8 percent in 2004. Is this of concern to Hydro, given the size of the rural deficit?

A. Yes, it is of concern. And from the point of view of the rate structures that are there right now, the rate structures do encourage some--the rate structures themselves that are in the isolated areas do discourage the proliferation of electric heat, but the populations, particularly in Labrador, are growing and most of that load growth is in Labrador on the isolated systems.

Q. So, what action are you taking to help the reduce the size of the rural deficit given

BROWNE, Q.C.:
this anticipated load growth? What's the plan?
A. There were--with respect to the HYDROWISE program, that targets, you know, efforts in those areas and others. With respect to demand side management, when there is an identified need for generation expansion in the rural areas, there is a an exercise carried out by the Economics Department of System Planning to look at whether it's cost effective to initiate some demand side management programs, but other than HYDROWISE and the rate structure that's already in the pediment to further electrification, that's not much else there to be done. The rate structure is punitive when you get above the life line block and that would be the biggest factor. It's not a lot of electric heat growth; it's other growth, population increase, particularly in Labrador and we have not got into--we have not discouraged population, if will, in the isolated areas. There not much we can do.
Q. So, despite everything we hear about out

migration and so on, that is not a factor in the isolated areas of Labrador?
A. I think the out migration, I think on the island system there has been some decrease in the isolate areas, obviously Great Harbour Deep is gone and Petites is going. Most of the other communities are fairly stagnant in their population growth. And even with the population staggering, if you will, in Newfoundland, the demand for electricity is growing. In Labrador, in the Labrador isolate areas, there is an increase and has been demonstrated increase in the energy growth. I think that population is one. I presume that disposable income also drives--is another factor that drives the growth or the load increase. People are buying more things, if you will.
Q. So, basically other than the HYDROWISE program, we can expect a--and that works in favour of conservation--we can expect the rural deficit to grow?
A. Possibly. There were other initiatives, I think the TRO area, which Mr. Martin could speak to about initiatives undertaken in the

isolated areas which he basically looks after to do that. The only thing I could reinforce, I guess, is the fact that when generation is required, we do undertake a DSM, demand side management review to review the economics to see if there is any economic viability into instituting some particular program.
Q. When you institute a program such as HYDROWISE, is that the rural areas and the isolated system, is that a targeted area for the HYDROWISE program?
A. I think the HYDROWISE is probably a bit broader than that. It's basically to everybody, but primarily those are our direct customers, but the HYDROWISE program is applicable to all.
Q. I don't know if you can answer this, but in a previous hearing we heard where Hydro went into the isolated areas of Labrador with a conservation program and taught people how to insulate boilers and to wrap pipes and to do other various conservation methods. Has there been any follow-up done in reference to these programs that have been previously put in place, to your knowledge or are you the best

person to answer that?
A. I'm not the best person to answer. Mr. Banfield of customer services would be the best, most appropriate to answer.
Q. Okay, well we can put Mr. Banfield on notice, we'll want to know all about that. On page 33 of your evidence, line 7 to 10, you indicate that the long-term loan forecast includes the hydro metallurgical industrial facility associated with Voisey's Bay on the Island in 2012. In reference to that, what is expected to be the size of the load there and what plans are being considered to supply that load?
A. Just give me a second here. That was answered actually in a RFI which seems to allude me. I think it's 50 megawatts is the demand and I think the energy was in the order of about 400 megawatt hours, but -
Q. How does that compare -
A. I'm sorry, I have it here now, I apologize.
Q. Okay.
A. Yeah, basically we're looking at approximately 400, as I said, gigawatt hours and 50 megawatts.

Page 105

BROWNE, Q.C.:
Q. Where is coming from? Where are you going to get that?
A. That would be--well, it'll come from the grid obviously, to do it, the actual next source will be, as I mentioned, as we discussed before, it'll be possibly Island Pond or whatever the most economic source is at the particular time when we review in, say, 2005/2006 in time to build.
Q. And what's the potential for Island Pond in terms of output?
A. Island Pond is 36 megawatts and 196 gigawatt hours. It would not, in itself, look after Voisey's Bay Nickel. There would be possibly other things required.
Q. What other things, therefore, are you planning?
A. We don't have any specific plan. As I mentioned, we will, in time to facilitate the construction time for that load growing, that we will enter an RFP to look at other sources, we'll evaluate the cost of gas turbines, Holyrood four and we will review and recommend a generation expansion scenario which would

Page 106

meet the needs of not only Voisey's Bay, but the other intended growth in the system.
Q. Is it conceivable that Hydro wouldn't have the ability to deal with that facility in Argentia, that you might want to inform them to find an alternative source?
A. That's not our mandate; our mandate under the Act is to serve the load forecast need of the Province and we would endeavour to do that. You know, it may be our own sources we purchase as we did with the NUGS recently, it will be whatever the most economic way to meet the load is will be recommended by Hydro to the Public Utilities Board, but it's premature to conclude what those results are at this point in time.
Q. Why do you say that, it's premature?
A. Because we have not done the evaluations of an "X" source, we have not gone for a recent RFP to get the prices of what other proponents may have out there. So, until we do that and do the economic evaluation, it would be a bit--we would not be able to indicate today what that next source would be.
Q. Have you any idea of what the cost would be to

Page 107

develop Island Pond, a ball park?
A. I don't recall offhand, it would be a little bit more than Granite Canal, I suspect.
Q. More than 134 million?
A. I suspect, yet.
Q. So, even though you develop it at 134 million, that entire project wouldn't be sufficient to energize that hydro metallurgical industrial facility?
A. Based on the current load forecast requirements, that in itself would not be, no. You know, there may be--but when you expand a system, you always build a reserve, it will take you a number of years to work yourself down to that particular load as to where you actually generate the next source. Then, I guess, our expectations right now is answer to one of the RFIs, that we anticipate that we would need probably about 80 to 90 megawatts in that time frame to meet Voisey's Bay needs and other load growth in the province.
Q. Have you had any discussions with Voisey's Bay in reference to energizing the project in Argentia?
A. We have a liaison with Voisey's Bay through

Page 108

our System Planning Department to look at the load. There's been not a lot of discussions to date. They're still in a preliminary stage as well. I think they are making progress, but we do not have the definitive. We have a forecast number of 50 megawatts and 394 gigawatt hours. I guess, as their plans solidify over time and they actually refine the process and what they're going to do, that would be firmed up.
Q. So, given the fact that you have little by way of Hydro development left, say, for Island Pond, isn't it of concern to Hydro that if you were to take the entire Island Pond development and dump it into Voisey's Bay, that what's remaining for the development of the rest of the province, is precious little.
(11:45 a.m.)
A. I think there are other non-Hydro owned hydraulic resources that can come into play. We can build thermal plants. I don't think we'll see natural gas necessarily within 10 or 12 years, but that may be something that's on the horizon. But when you go back to Newfoundland and Labrador Hydro's mandate,

Page 109

MR. HAYNES:
basically our mandate is to serve the growing energy and power needs of the province. And I don't think that we would, at least, I could not foresee that Newfoundland Hydro would actually go back and curtail industrial development, for instance, because the resources aren't readily available. We can build something or have it built to meet those needs and we'll evaluate those economics, we'll evaluate the load forecast and we'll recommend to the Board for their approval and consideration of the most economic future source. I would suggest in a 2005/2006 time frame ,that we would be very engaged in that process.

Q. I would imagine an Industrial Customer such as Voisey's Bay would have a tremendous impact on the rate stabilization plan, would it not?

A. That depends on the source of the next supply and depends on our forecast of what fuel is and the structure and design of the rate stabilization plan. It would be a--if it's a thermal source that primarily provides, there will be an increase fuel usage, yes, but it

Page 110

may be Hydro or it may be a combined cycle or conversion of Holyrood to combined cycle, all of which have varying economic history, basis.

Q. You've made reference to a construction of a thermal generation facility. When was the last time Hydro constructed such a facility?

A. I guess the last, other than diesel, the last gas turbine we installed would have been in Happy Valley/Goose Bay and the last steam plant would have been in 1979/1980 at Holyrood, unit number 3.

Q. And did Goose Bay predate Holyrood?

A. No, Goose Bay was after that.

Q. What year was Goose Bay, roughly?

A. I would suggest the mid to late '80s, I don't know the date off hand.

Q. So, your experience in thermal plant construction is limited a bit?

A. Recent construction experience is limited, but I suppose we could also say the same thing for Granite Canal since the last hydro plant we built was in 1989. So, I'm not concerned about that, we operate and maintain, we're doing continuous improvement. We know the creature and when you undertake an exercise

Page 111

like that, you usually get a contract or, you know, you will hire a consultant who's experienced in that particular area.

Q. Schedule 11 of your pre-filed evidence, can we go to that for a moment, please? We'll look at 2002 that shows high megawatt losses and low gigawatt losses in 2002 relative to forecast for 2002/2003/2004. Why is that? You say in footnote 3 that total sales on bulk deliveries and transmission losses are coincident with system peak and actual losses in 2002 include stations -

A. Yes.

Q. - or is that the explanation or-

A. It may well be, I know that the station service, I believe in Holyrood is actually measured that way, it's kind of part of the system losses, but the actual specific transmission losses are highly dependent upon the generation dispatch and how much Holyrood has used and so on. So, the number is an estimate and it varies depending on the ultimate generation dispatch that's prevalent through the year.

Q. It sets losses--what can be done in reference

Page 112

to these, what are you looking at?

A. On the station service losses, I'll just speak on that a little bit because they're kind of beared in 2002. and station service losses for Holyrood, in the plant's efforts to squeeze every kilowatt hour per barrel from a barrel of oil, they are looking at constantly the internal usage of power, be it electrical power or steam, particularly steam. There are lots--steam is bled from the process to heat air to do this, to do that an they are constantly looking at that. With respect to transmission losses, really there is not a tremendous amount you can do. You keep your voltages high in the system through use of synchronise condensers and capacitors. But basically when power is generated at Bay D'Espoir and is transmitted to St. John's, it has to obey the law of physics and losses are unavoidable. You know, you could re-conduct the transmission lines to reduce the losses, but that is--you would very rarely actually do that because it would not be economic, it's usually cheaper to just continue to swallow the losses as opposed to entering a major

Page 113

MR. HAYNES:

project to reconducter. Now, we have reconductered some lines, but more from the point of view of transfer capability as opposed to specifically targeted to reduce losses.

Q. Now, when you're with the Canadian Energy Council and the subcommittee that you're part of there, are transmission losses subject to discussion there and what to do in reference to them or any new technology out there that we have to look forward to?

A. Not in the short term. If they ever futuristically come up with a low temperature superconducting wire, that would be a great plus for losses, but other than that, it's basically I squared R, it's the laws of physics. And if we can't change the resistance of the conductors, then basically the losses are going to be what they are within a certain range, but we do endeavour to keep the system voltages high as reasonable to reduce the losses to allow the transmission of more power, you know, with less current. As you increase the current, the losses go up,

Page 114

there's little we can do about that.

Q. And that's not peculiar to our system; that's peculiar to electricity generally?

A. Yes. You know, there's the synchronise condensers that we have on a system help keep the voltage up and maintain and they contribute some reduction and they use some as well.

Q. Although we live in hope, I think there was a news story this morning of someone saying that they can produce electricity out in Alberta somewhere by other than traditional means.

A. I heard that, yes.

Q. Did you make a phone call?

A. I think they were proposing, as being a power supply for cell phones, so I didn't trigger my interest right off the bat (Laughter). I was looking for a bit more.

Q. Now, there are a few questions that were passed on to you when Mr. Roberts was on the stand, so, if I can make reference to these. One question dealt with CA-150, can we go there, please. That had to do with Goose Bay and where a number of the Armed Forces that are in Goose Bay are leaving there. Have you

Page 115

been notified as to any change in the requirements for Goose Bay and the result?

A. The contract, the Memorandum of Understanding with the NATO allies or the Department of National Defence expires actually in 2006, and our forecasting and we have not made any appreciable change in our forecast for that. I guess as you can see from the CA-150, we have dropped down from 107 to 77 million kilowatt hours over that time frame. And the forecast for 2003/2004 are--they're not significantly different and we don't anticipate--you know, there are some activity in the area with respect to Voisey's Bay Nickel and will be some countering of those, I guess, but we don't anticipate any significant change in the secondary sales to DND, in the foreseeable future.

Q. In terms of Voisey's Bay Nickel, what is Hydro's commitment there in Labrador?

A. We have no commitment at the Voisey's Bay Nickel site. It's basically, I guess, our-- what we are keeping an eye to and what we are forecasting is the appropriate increases in energy and demand that we would see in Goose

Page 116

Bay as being a stationing area for some portions of the Voisey's Bay activity.

Q. Another question I asked previously had to do with computers. And I asked in reference to CA-138, Mr. O'Reilly. And it was indicated in the response that you plan to get more life out of your computers, from three years to four and five years which would be a blessing for consumers. How is that being accomplished?

A. I guess what we had proposed in our last capital budget proposal, that we would start moving to thin clients which basically is a slightly different technology than a PC on someone's desk. Most of the applications will run from a server and their life is anticipated to be five years. I would suggest as well, at least, I hope for, as you mentioned for all consumers that the changing the computer of capabilities and so on has slowed a little bit, I mean, they're still getting bigger and powerful, but they don't necessarily need all that to do our day-to-day work. As long as the operating systems settle a little bit and so on, we won't be forced

Page 117

MR. HAYNES:
there. So, we anticipate five years as being a reasonable time frame, on average, for our PCs in the future.
Q. In terms of customer service and computers, have you ever done any measurement to request the response from consumers if they're willing to pay more for having a call answered in 30 second as opposed to 45 seconds?
A. I'm not aware, but from a customer point of view, that would probably be a better directed question to Mr. Banfield who looks after the customer service area. I know we measure a lot of these things.
Q. The other question I asked of Mr. Roberts which he put forward to you and you probably know the answer to this, it's in reference to travel cost for 2001 and 2002. And I was referring to CA-139, I believe. And I think actually I think it might have been a line in Mr. Roberts evidence where the travel costs were seventeen thousand and fifteen thousand for Generation Engineering 2001 and 202 and we saw them increasing for 2003 and 2004.
A. That particular -

Page 118

Q. Generation Engineering, yes, there it goes.
A. That particular grouping of things, also covers conferences as well and there was an amount of money there for travel and conferences. Travel was actually thirty nine thousand which is indicated NP-259 and travel was seventeen. And the conferences and travel and put in there as our best guess, basically. And if we need it; it's there. And if we--you know, the generation people provide support services to the Hydro Generation which is Cat Arm and Hynes Lake, so there is travel required. We did not experience those levels in 2002.
Q. Yes, but I would imagine you always needed to travel to these particular locations, that hasn't changed. But what has changed in the production division, the generating engineering travel costs have gone up from fifteen thousand in 2002 to sixty four and fifty six thousand which seem to be all time highs since 1996.
A. Well, you would be primarily travelled to the areas for operating projects, but in 1996, I think the anomaly is more 2001/2002 where

Page 119

they're lower and there is some--when they travel out to these areas, they do try to put two of three operating projects, they try to go out and cover off two or three jobs at one time as opposed to going out this week to look at one project and going out two weeks later to looks at another particular project, they'll try to marrying those up and economize on that basis and maybe some capital as well.
Q. In terms of travel cost in 2001 and 2002, you would be doing the Granite Canal during that time and I see that under Generation Operations for 2001 they're thirteen thousand and twenty thousand, yet we see a jump to twenty nine and eighteen thousand for the next two years. Are we missing something here?
A. I'm sorry, could you repeat that question. I'm sorry.
Q. Yes, I'm looking at Generation Engineering and Generation operations line 19 and 20 in the Production division.
A. Yes.
Q. And we see for 2001 and 2002, you would be doing the Granite Canal at that point, wouldn't you?

Page 120

A. We would maintain in Granite Canal, but that would be actually in the last entry there, Hydro generation at line 24. Line 19 is the generation operations is a little bit of a misnomer. It's really the operations, the control centre, system operations. Hydro Generation on line 24 is the actual -
(12:00 p.m.)
Q. Okay. So, the budget line 24 would include work in reference to the Granite Canal?
A. Yes, but we have started a couple of initiatives in Hydro Generation to try to reduce some of that cost by having the operators do more work and so on. So, we are targeting to hold the line on the travel costs associated with Hydro Generation by, you know, we've done a couple of things as evidence in NP, I believe, 87 with respect to operators of Paradise River and remote plant operators to try to minimize or to reduce that particular travel cost, to have them to do more maintenance, therefore, reduce travel costs from some employees of Bay D'Espoir.
Q. All right. Is a lot of this travel discretionary, you mentioned conferences?

Page 121

MR. HAYNES:

A. Well, conferences maybe, but conferences are a valuable way to interact with your peers and to find out what other utilities are doing. We don't do a lot of that and most of the travel within Generation Engineering and hydro operations is basically to go to the plants to review operating problems, to address issues and so on.

Q. And in line 22, we see under "Information Systems and Telecommunications" start at 1997, 125,000, then it goes right up to 347,000 in 2001. It's my understanding that's when you were into using the JD Edwards programs?

A. Actually the big bump, if you will, of 347,000 in 2001 was primarily driven by the fact that, you know, we have over 100 of these sites out there where we support the LAN and WAN and users and we had deployed to the field area some temporary employees who were called client support assistants, client--they are basically people in the field who would actually facilitate user knowledge of PCs and to fix problems that were ongoing, and basically, we have reduced that now and we

Page 122

have one permanent employee out in the field who does that. So that was -

Q. So what are you telling me? There's contractual wages there in line 22 under travel?

A. No, on line 22, we had temporary employees hired who were called client support assistants, who would actually facilitate use and deployment of PCs in the field. We have reduced that now. Those temporary employees are no longer with us. We do have one permanent individual located in the field. That was the bump there primarily.

Q. Were the wages for these contractual people, are they contained in line 22 there?

A. If they were temporary salaries, it would have been in line 22, yes.

Q. Why would they be in travel? That seems to be -

A. I'm sorry.

Q. - an anomaly.

A. They're not in--not the wages, but their travel expense. Their travel expenses would be in travel.

Q. Oh, I see, okay.

Page 123

A. You know, you have somebody in Port Saunders who's looking after, you know, St. Anthony, Southern Labrador, maybe Goose Bay on occasion, and so on. You have somebody in Bishop Falls who is looking after Bay D'Espoir and Deer Lake and so on. So they were distributed around. So their travel would have been up because they were travelling a fair bit to do that. And we've undertaken several other initiatives there by having some of that done now, done through St. John's, through electronic means as opposed to having somebody actually in the field. But there is still some field support personnel.

Q. What were you doing in 1996 and 1997 in reference to travel and information systems, 101,000, 125,000 as opposed to what you're doing in the forecast year, 244 and 256,000? What has caused these additional costs in the forecast years?

A. In the future, in the 2002, 2003, 2004, we have expanded the WAN and the LAN. We have installed new microwave facilities. You know, we are seeing some additional maintenance on some of the other systems, such as the VHF and

Page 124

those are all projections of what we anticipate to spend for travel. The IS&T department are maintaining sites all over the island and Labrador and we have IS&T people deployed in St. John's, Bishop Falls, a few, and some in Deer Lake. So there's a fair bit of travel to maintain all these particular things at all the stations. The people at Deer Lake will look after the Deer Lake office obviously, Hind's Lake, Granite Canal, all the microwave sites that we have, the VHF systems, that they need to go to. So there is a fair travel by that particular group of communications and IT people.

Q. Why are they travelling so much now as opposed to in the past?

A. In the past, back in the earlier time, we would not have done as much for--we would not have necessarily had as many PCs deployed out there. In 1996, we would not have been as reliant on--so much relying on the computers, such as JD Edwards, et cetera. So there has been an increased need for that support.

Q. You would think that with a computerized system, which they consumers of the Province

Page 125

BROWNE, Q.C.:
have paid for, that we would see a benefit in reduced travel as opposed to more.
A. But there are more facilities to maintain. There are more users to support. I should--in 1999, there was also some extra costs there with respect to the preparation for the Y2K. There was a fair bit of activity along those lines as well.
Q. That would be year 2000, 1999 and 2000?
A. '99 and 2000, yes, there was a bump, yes.
Q. And a spike in 2001 was due to what?
A. Client support assistance, where we had three or four people deployed to the field to look after--we've had a fair number of issues with some of the PCs. Since then, we've gone to a standard platform. We've tried to have one operating system as opposed to multiple, and so we have--you know, we have reduced that from the 2001 now to what we think are sustainable levels.
Q. I think those are the questions that I had arising from Mr. Roberts. I have some questions dealing with the Rate Stabilization Plan, but in view of the fact that there is

Page 126

still ongoing discussions in reference to that, these may not be necessary at this time, so I'm going to pass on those for the time being, mercifully so, I guess, and these will be all our questions for now. Thank you very much, sir.
CHAIRMAN:
Q. Thank you, Mr. Browne, Mr. Haynes. We move now to Newfoundland Power. Good morning, good afternoon, I guess, Mr. Kelly. When you're ready, please.
KELLY, Q.C.:
Q. Thank you, Chair.
CHAIRMAN:
Q. You can begin your cross.
KELLY, Q.C.:
Q. Mr. Haynes, I'd like to start by having a look at some of the system characteristics and how the system works and let's start, if we can, by going to your Schedule 1. Now I understand that you've been the vice-president of production since 2001?
A. Yes.
Q. And you have six departments that report to you, as shown in your Schedule 1 there?

Page 127

A. That's correct.
Q. Okay. And you spoke with Mr. Browne about the system planning department and that is responsible for the generation, transmission and distribution planning as you discussed with him?
A. Yes.
Q. What I'd like to do is I'd like to go through--we won't spend any more time on system planning now, because we'll come back to that a little bit. Can we go through each of the others and just get you to explain what each of these departments are made of and what they do, and let's start with generation engineering.
A. I guess, in our pre-filed evidence, there is a paragraph on page three which describes the role of the department. Basically, they provide engineering support to primarily to the thermal and hydraulic generation departments of Hydro. They look after operating projects, capital projects, with the assistance, obviously, of the people in the field and as required, contractors and consultants.

Page 128

Q. So that's essentially Hydro's principal generation or engineering staff related to generation?
A. The engineering support for generation, that expertise. They look after, for instance, the contract administration and ultimately, the Granite Canal construction.
Q. Okay. Now next one you got there is information systems and telecommunications. I think we have some sense of what IT is, but could you help us understand why IT is in your production department, as opposed to, for example, since it deals with PCs and things like that, one of the other administrative type departments?
A. I guess, in the late 1990s, before I was VP, there was a fair bit of discussion on the role of the communications. We used to have a department called the telecommunications department, and we had a department called MIS, management information services. I guess through reviews and so on, there was thought to be a fair bit of synergy between those particular groups and they were merged and they were retained under the production VP's

Page 129

MR. HAYNES:
position. The MIS prior to that was under the Department of Finance, the finance department.
Q. And MIS is what?
A. MIS was the management information systems department. It used to report to Department of Finance. When the departments were rolled together, because of the synergies we saw between the communications and the MIS department, from the point of view of the LAN, the WAN, the communications, the dependence upon communications as being a key thing, they were married together and they were retained under the production division.
Q. Okay. How many people are in that department now approximately?
A. In that department, in total, there are 67, but they're not all IT people. I think there's probably about more or less 50/50 of IT versus--maybe 60/40 of IT versus, you know, telecommunications, microwave, VHF radio, LAN/WAN people.
Q. Okay. The next block you got up there is system operations, and where does that fit into the production department?

Page 130

A. The system operations department basically look after the day-to-day, 24-hour-a-day, seven-day-a-week operation of the Energy Control Centre. They look after basically the day-to-day administration for the most part of the NUGS purchase contracts. They do the switching for transmission lines. They turn on and off generation and look after the day-to-day ongoings in the control centre.
Q. So that's the overall control of the transmission system?
A. Transmission and generation system, outage coordination and so on.
Q. Now thermal generation then is Holyrood?
A. Yes.
Q. And is it anything other than Holyrood? Because you talked a little bit earlier about number of gas turbines that you've got and diesel units. Where do they fit into the structure of Hydro?
A. Holyrood is--the thermal generation manager, under production division, looks after the three steam machines at Holyrood, plus one gas turbine, which is an 18 or 15-megawatt unit. The gas turbines that are at Hardwoods and

Page 131

Oxen Pond--I'm sorry, at Hardwoods and Stephenville and Goose Bay are looked after through the TRO division, but engineering support is also provided from a generation engineering section. But where these gas turbines are in the field, it was more appropriate and considered to be more cost effective that they be maintained by the individuals in those areas.
Q. And the diesel units, you got a number of those around the province, they also fall, for maintenance purposes, under TRO, correct?
A. Yes, there are--yes, that's correct.
Q. Right. But in terms of system engineering and system's operation, those units really fall under production. Would that be fair?
A. The diesel generation in the TRO engineering department maintain a high level of expertise in the diesel areas. They look after all aspects of the Isolated Diesel generation. There's very little, if any, done by generation engineering or production division for the diesel Isolated systems.
Q. And what about systems operation though? If the control centre wants one of those diesels

Page 132

on, I take it the control centre has the power to call up that diesel unit?
A. That's for the most part done by remote control and they turn those on and off as required.
Q. Through your systems operation in production though, is what I'm trying to understand?
A. Yes. They -
Q. Right.
A. - they don't maintain. They actually turn them on and them off and look after the fuel forecasting and so on, but they don't actually maintain.
Q. And your hydraulic generation is simply all your hydro plants scattered around the province?
A. Yes, they basically look after all the hydro plants.
Q. Okay. Now the production department would be the biggest department, in terms of the items that go into the overall cost of service? Because you've got fuel, you've got all your salaries and things for the production department. Would that be generally correct, Mr. Haynes?

Page 133

MR. HAYNES:
A. From a dollar point of view?
Q. Yes.
A. If you include fuel, yes. I think if you exclude fuel, I'm not quite sure if that's the case.
Q. Even excluding fuel, if we went to Mr. Roberts' Schedule 2 and just looked at the controllable costs, depending on whether you'd look at net or gross, you'd be somewhere between 90 and 100 million, and if we go to your Schedule 6, just on operating alone, you're about 35 million dollars or approximately a little bit better than a third of the total.
A. I don't have Mr.--the TRO, but I would suggest that TRO's is probably pretty darn close, and I don't recall the numbers. They would be fairly close.
Q. But then these other things like fuel and things would come under your department as well?
A. Yes.
(12:16 p.m.)
Q. Okay. So you're responsible for a very large

Page 134

share of the costs that are at issue in this proceeding? Would you agree with that?
A. I guess if you put it that way, yes.
Q. Okay. Now let's look a little bit at Schedule 2, so we look at some of the characteristics of the system here. Now in this summary, and you touched on this with Ms. Greene, you have plants which are owned by Hydro in the first block there, first couple of blocks. Then we have some plants which are owned by the non-utility generators and power sold to Hydro, and then there are plants which are owned by Newfoundland Power and the Industrial Customers, primarily for their own generation purposes, down in the bottom? We got that basically correct?
A. Yes.
Q. Okay. And if we look at column 1, we've got the source, as to whether it's thermal, hydraulic, et cetera, and column 2 provides something called the net capacity, and could you just explain for us how net capacity is determined?
A. I guess the best explanation, I guess, is by way of example. If you were to look at the

Page 135

Holyrood oil-fired steam, it has a net capacity of 466 1/2 megawatts. The nameplate capacity is more like 490 megawatts. That difference is what's used internally in the plant for its own internal usage, and Holyrood would be an extreme example. Holyrood requires more power to keep it going, if you will, than say a hydro plant.
Q. So net capacity is kind of rated capacity less the station service requirement?
A. More or less, yes.
Q. And that would be higher for Holyrood than, for example, the hydro plant because there are many more components that require power in a steam plant? Essentially correct?
A. That's correct. The percentage would be higher of station service.
Q. Okay. Now we get down to the bottom of the--if we scroll up to the bottom of the--there we are--we have the total Island Interconnected System of 1,919 megawatts and out of that, if we work through the capacity, about 65 percent is from hydro generation, that's including hydro, the power from the non-utility generators, except the Corner Brook thermal,

Page 136

and Newfoundland Power's -
A. Actually I had the total capability of Hydro and Hydro's contracts is more. I think it was about 83 percent of the total actually. 1591 over 1919.
Q. Yes, but in that, you probably have the thermal number for Holyrood in too, do you?
A. Yes, I do.
Q. Okay. But if we look at just how much is hydroelectric, I'll suggest to you about 65 percent is hydroelectric? Sound about right?
A. I'll trust your math, yes.
Q. Okay. And then obviously the balance is thermal. Now column 3, if we go back to the top again, we've got something called the average annual energy for each source. So if we look across, for example, at Bay D'Espoir, we've got 2,657 gigawatts and that's based on, in terms of the hydroelectric plants, on a 30-year average hydraulic production?
A. Yes, that's correct.
Q. Okay. And so for the production estimation, you use the 30-year average?
A. That's what we've used in this particular filing, yes.

Page 137

KELLY, Q.C.:
Q. Okay. And let's just look at the forecast, the energy forecast for a second now. Newfoundland Power and the paper mills and the oil refinery provides their own forecast for annual energy requirements or for energy generation rather?
A. Well, it's netted out of their forecast what they would need to buy from us.
Q. Right, but in terms of how much they are going to produce, are capable of producing, that information comes from the power company and from the various industrial customers that have their own generation?
A. By and large, that should be correct.
Q. Okay. And how did you determine the non-utility generation estimates? How is that determined?
A. The non-utility estimates for Star Lake and Rattle Brook were revised in this application to reflect the operating experience that we have to date. Star Lake has basically generated a bit more than they anticipated when they actually built the plant, and I'm not sure, I think Rattle Brook was maybe a

Page 138

much lesser number, but we basically used the same philosophy. On the Corner Brook Pulp and Paper and Exploits River, these numbers were basically arrived at doing engineering studies and were accepted by Hydro. Obviously, as we go on in time, we will find out whether they do better or worse than that, but the contracts basically do call for a specific number, which are as the firms (phonetic).
Q. Sorry. How do get the average annual energy then for Holyrood?
A. The average annual energy for Holyrood is based on 75 percent availability or 25 percent incapability factor. It's basically 466
megawatts times 8760 hours in a year times 75
percent, and we plan the system and then strive to meet that 75 percent availability or 25 percent incapability.
Q. Okay. So that 75 percent factor is what essentially goes into the mix to determine the average annual energy then from Holyrood?
A. Yes.
Q. Okay. Now then column 4, the last far right column gives us something called firm annual energy in gigawatt hours for each of the

Page 139

generation sources. Can you explain what firm annual energy is and how those estimates are determined?
A. The firm number, particularly for hydraulic, is based on us being able to manage the hydraulic resources to survive the worst dry sequence that we had, which is back in the 50s or 60s, and basically, we plan--it does not drive figures on an annual basis for cost of service. It's more of a number that's used primarily for next source identification. What we try to do is protect the firm sequence.
Q. Okay. Can I just stop you there and get you to elaborate on that? But you talked about a sequence of driest years. How many years is that made up of and what's the driest year sequence that's used for this purpose?
A. My recollection is that it's a three-year sequence and I don't remember the particular time, but it's back the 50s or 60s, 50 to 60, in 1950, I think it was the mid to late 50s, the actual sequence occurred. So that's the worst sequence on record that we have, and it's the one that we've designed the system to

Page 140

survive. We plan the system to meet our firm energy supply, based on a repeat of that firm sequence, and that's pretty standard hydro-technical power system sort of stuff.
Q. So to plan how much firm energy you could get out of the system, you postulate a scenario that looks at your three driest years in your operating history? Is that essentially correct?
A. Not necessarily the operating history, of record. Of record.
Q. Of record?
A. Yes.
Q. And this period in the late 50s, early 60s, I take it Hydro was operating plants at that point in time, were they not?
A. The late 50s, I don't think so.
Q. Okay. All right. So that's what you use for the Hydro part of it. What about for the Holyrood part of it, to get the firm annual energy?
A. In Holyrood, we consider the firm and the average to be the same. The average and the firm are 2996. We basically plan our maintenance program, by and large, to meet the

Page 141

MR. HAYNES:
2996 target. On an average basis, it's going to be whatever we can't do hydraulically. We don't use Holyrood to--we do not--our average production from Holyrood, from any point in time to today, would never approach 2996, because basically whatever hydraulic production, we will work around. It picks up the slack, Holyrood does, of whatever energy we can't get from our hydraulic resources. But there's no difference in the peak and the average. We assume the same.
Q. Okay. So for your firm energy criteria, in other words, what you can use to meet the system, you assume that 75 percent capability factor?
A. Yes.
Q. Okay. Now if we just go down that column, under thermal, after you get past Holyrood, you've got Hardwoods, Stephenville, Holyrood gas turbines, and the various diesels, and you show no firm annual energy for each of those units. Can you just explain why that is the case?
A. We don't plan to run the gas turbines or the

Page 142

diesels to meet day-to-day production planning. We use them obviously when we're required, but we do not have any firm numbers peaking plant. The cost of operation is in excess of $100 per megawatt hour, so they're not part of our day-to-day plan. They would just fall off the table on economic priority.
Q. So you don't count them for firm energy requirement in the far column, but they count for the capacity factor in the first column over?
A. Yes, because they are used a lot less than the other plants.
Q. Okay. Now what do you use the estimate of firm annual energy for? What's the primary purpose of that estimate?
A. It's primarily for system planning to identify future generation and condition requirements.
Q. Okay. Now you talked with Mr. Browne about Holyrood and the last unit that was added in Holyrood, Unit 3, you told us was 1979 to '80?
A. Yes.
Q. Okay. And out of the hydroelectric plants or the plants that have come in service since 1980, the bulk of the energy that's come on

Page 143

stream since then have been through various hydroelectric plants. Let's just run down through a couple of those. Cat Arm would have come after the last unit at Holyrood? Would you agree with that?
A. Yes.
Q. And Upper Salmon?
A. That's correct.
Q. Hind's Lake?
A. Yes.
Q. Obviously Granite Canal?
A. Yes.
Q. Paradise River?
A. Yes.
Q. And all of the non-utility generators which are Hydro, with the exception of the Corner Brook Pulp and Paper co-gen project? That would be true too?
A. Yes, there was an upgrade done in Holyrood in the, I guess, mid to late 1990s, I believe, where we actually increased the capability of Holyrood units No. 1 and 2 from 150 to 175 megawatts, but there were no "new" green field plants constructed.
Q. New sources of generation.

Page 144

A. No.
Q. Okay. So the bulk of those, since 1980, have been hydroelectric and in terms of Hydro's stable of potential projects, as you talked about with Mr. Browne, the next potential one would be Island Pond again, a hydroelectric project, correct?
A. That is one that we currently have the rights to and have some preliminary numbers on, yes.
Q. Okay. Now I want to go next to page 36 of your evidence, and look at Section 10, I believe it is. Okay. Now you've got--well, first of all, for system planning purposes, to determine when plant additions are required starts with the development of a load forecast for, let's take the Island Interconnected System, that's the starting point, is it?
A. That's the initial requirement, yes.
Q. Okay. And then you talk about an energy criterion, if you look at beginning at line 11, and then after you get to line 16, you talk about a capacity or demand criterion, and I'd like you to take us through the energy one first and just explain what that means.
A. The energy criteria is basically what we

Page 145

MR. HAYNES:
discussed a few minutes ago, basically it's that we plan the Interconnected System so that we can survive, if you will, if we have a repeat of the firm sequence, which is a fairly common practice in the utility business, to ensure that you can actually survive that particular event. In other words, that we do not have to curtail deliveries of energy because we just do not have the resources available. So that is the energy driver.

Q. So there we're looking at the energy forecast on the firm basis, which is our three driest year sequence, plus Holyrood, and weighing that against the energy forecast for any particular year, is that essentially correct?

A. To give us an estimate of the timing for the next source, yes, that's correct.

Q. Okay, now let's go on to capacity and your LOLH, if you could just explain that loss of load hours?

A. The loss of load hours is, obviously in the electrical business you are delivering related, but I suppose maybe different products in the sense one is energy, i.e.

Page 146

megawatt hours, the other one is capacity of megawatts and in the ideal system, it would be nice if they were all kind of matched up one hundred percent, but it never happens. So on the LOLH, we have to plan the firm capacity and that is one of the reasons why, as we discussed a few minutes ago, we had this peaking plant there and the gas turbines and so on. So what we do is if you go down to a probabilistic approach and we look at the load forecast and the forced outage rates of the equipment and so on, and we analyze that and we come up and basically say that our criteria is that we will plan the system so that we will always have enough capacity available to meet our customers demands, with the exception of, on average, 2.8 hours per year where we cannot do it because of availability or resources.

Q. Okay, so is that a computer run model, which you talked about a probabilistic or statistical type approach to it?

A. It considers the forced outage rates of machines, it considers the load factor and the load shape and so on, but it does come out of

Page 147

a computer model and it may change. The LOLH number that's generated may change over time if the load factor changes or if the load shape changes and so on, but it is basically an output from a program.

Q. Okay, and the theory then is to ensure that you've got enough capacity so that not more than--there's not more than 2.8 hours per year of outages due to a lack of capacity on the system, is that it in a nutshell?

A. That's the plan in a nutshell, yes.

Q. Okay, now, let's go next to Table 8 which I think is on page 37. I want to get you to walk us through this particular table and let's start with--you've got the years, obviously, and then we've got the peak. Just explain what that column means?

A. Well the peak is basically the demand forecast for the Interconnected System, the number of megawatts we would require to fulfil our expected demands, our obligations.

Q. And that's a matter of the peak load on the system as to what you forecast for every year?

A. Yes, there are, you know, there are--yes, that's essentially correct.

Page 148

Q. Okay, let's go over to the energy one.

A. And the energy basically, similarly is the amount of energy that we require to fulfil our customer needs.

Q. Okay, and then net capacity comes back from your Schedule 2?

A. That's what we have available today.

Q. Okay, and you're showing the same numbers all the way down through that column, so I take it that doesn't yet and we have the same thing on firm capability which is the energy side of the ledger in the next column over. That's the same all the way down through, so that wouldn't include yet, for example, anything for the Burin Wind Farm?

A. Well that's correct, if that goes as conceived or as perceived, that will add 25 megawatts to that particular column.

Q. Okay, and we come across, you got your firm capability, again that comes from what we just looked at in Schedule 2, correct?

A. Yes, if we have a repeat of a dry sequence, we would be able to provide 8.7 terawatt hours.

Q. Okay, and then we have our LOLH, now just to help us understand this, just explain then the

Page 149

KELLY, Q.C.:
point six hours per year in 2003? That's obviously something better than your 2.8 you talked about a minute ago?
A. Yeah, well what we don't have shown on the chart would be 2002, which would have anticipated--we would have exceeded that criteria. I don't know what the number is, but it would have been in excess of 2.8 based on a forecast when there was generation committed. Whenever you build new plant or incorporate new megawatt capability into the system, you will stagger that number. So in 2003, we added 40 megawatts for Granite Canal, we added 15 megawatts for Corner Brook Pulp and Paper and 32, I believe, for the Exploits River, so that would actually push that number down. So then you, as your load forecast continues to grow, you will start eroding on that capability by actually increasing that number. And if you get down to 2010, we actually hit that particular criteria of 2.8 and 2011 we've exceeded the criteria, and at that particular time, that would be the message that we really need to address, new

Page 150

peaking--we need more megawatt capability on the system.
Q. Okay, so in 2011 then, your criteria for peak capacity is exceeded and you'd need a capacity requirement for 2011?
A. That would be--on face value, that would be the indication, yes.
Q. Okay, now let's look at the energy balance and have you just explain that column.
A. It's done in a similar way except that you're looking at the firm sequence and basically by adding on the Granite Canals, the Corner Brook Pulp and Paper and the Exploits River, we basically--we have a reserve, if you will, of an energy balance in 2003 of 265 kigawatt hours, and as we--as our load forecast increases, we will erode to that and 2010 we have an energy balance or a deficiency, very small but it's there nonetheless. We, in theory, would not have enough energy, assuming we had a repeat of the firm sequence to meet our commitments.
Q. That negative 10 is in 2009?
A. That's correct.
Q. Okay, so at that stage in 2009, then your

Page 151

energy criteria has been overcome or violated?
A. Yes, you wouldn't necessarily go and rush out and do something based on a deficit of 10. You look at the timing between, you know, the energy balance deficit and the loss of load hours and ideally you would do a project somewhere in that time frame of 2009 to 2011 which would cover off both factors.
Q. Okay, but the first one that is driving the system planning in terms of time frame, would be energy, would you agree with that?
A. Yeah, based on this, yes.
Q. Right. But if you add--if you build a plant which will provide more energy, it will also have the effect of providing more capacity, isn't that--that's also true?
A. Yes, it can be varying numbers, but it is typically true, yes.
Q. Right, let's just go to NP-154 for a second and have a look at that issue and I'll just give you a moment to find that, if you like. Do you have that there?
A. Yes.
Q. And as you come down through your answer, lines 11 and 12, since the next plant addition

Page 152

is required to meet both demand and energy requirements, a reduction in peak only with no associated energy reduction will not defer the next plant addition, although it may have an impact on which options would be considered least cost at that time and beyond. So that the next plant would add both energy and peak capacity is what Hydro's thinking is?
A. Because there's a, you know, there's only about two years, one or two years apart in the LOLH criteria hit (phonetic) and the energy balance, that would be correct.
Q. So as you build to meet the energy violation in 2009, you'll also build for capacity for 2011 and beyond, correct?
A. It would be the consideration of the load forecast and the operating factor of that particular plant, depending on what the resource is, but I'll come together to determine that.
Q. Now, I'd like to take you next to exhibit, Mr. Brockman's exhibit, LBB No. 3, here we go. And Mr. O'Reilly, I don't know if you can put that on the screen so we can get both the two parts of the table together? Okay. In the

Page 153

KELLY, Q.C.:
top part, Mr. Haynes, we have from the 1990 hearing some information taken from Mr. Collett's evidence and then in the bottom, we have reproduced your--Mr. Brockman has reproduced your Table 8 with the same information, some additional information?
A. Yes.
Q. And if we compare the two, we see that the peak demand in 2012 will have only reached 1,728 megawatts; and in 1990, that--Hydro had been forecasting that that would occur by about 1996, approximately?
A. Correct.
Q. Okay, and so overall would you agree that the overall load growth has decreased dramatically since the evidence in the 1990 hearing from what was anticipated?
A. Yes, there's been a fair decrease over that period of time for various factors, that's correct.
Q. And that's also true if we look at the energy, not quite as striking for the energy, but still energy demand--or energy consumption has not grown as fast as anticipated?

Page 154

A. That's correct.
Q. And if we look at the forecast of total Island load indicates that the load factor has improved since 1990, went from 59 percent to roughly about 61 percent?
A. Yes.
Q. Just explain that to the Board, what that means?
A. In an ideal world if you had pure energy resources that had no constraints of forced outage rates and so on and so forth, you'd have a hundred percent load factor. Typically the higher percentage of load factor means that your resources are being used, you know, more--are being utilized more to the maximum ability. Now that's not really, necessarily the case for a Hydro plant where many Hydro plants are designed for, you know, 40 to 60 percent operating factors, so it wouldn't necessarily, the most you would get out of a Hydro plant maybe, you know, operating factor is not the same as load factor, but it influences that. But the closer--let me go back a little bit, the higher your load factor, the flatter your profile; in other

Page 155

words, you turn on megawatts and in an ideal world, maybe we only need 900 or 1000 megawatts of megawatts continuous to meet all the energy requirements of the Island, but the higher the load factor, it's usually a plus for the system.
Q. Okay, now I've given the clerk and provided you last week with Table 1 from Mr. Collett's evidence in 1990. It's a one-page document, page 23.
MS. NEWMAN:
Q. That would be Information Item No. 12 if it's going to be entered as a -
KELLY, Q.C.:
Q. Thank you. Now this table, Mr. Haynes, is the source of some of the information that is in the top block, in terms of LBB-3 that's already on the screen, but I want to take you over to the middle column, which is LOLE index, and as I understand it, that's like our loss of load hours, but is a slightly different index and perhaps we can start by having you explain what that means to the Board?
(12:45 a.m.)

Page 156

A. The loss--the LOLE or loss of load expectation is basically the criteria at that particular time was .2 days per year, I guess depending on which computer models you used for doing your generation planning scenario, I mean, there are different indices, what we use right now is the LOLH which basically you can translate it, there is no significant difference between .2 days per year and 2. 8 hours, it's the same equivalent criteria using different programs, I guess.
Q. And I understand you can't mathematically kind of get from one to the other, but at the end of the whole analysis, the two are pretty much essentially the same, have I got that correct?
A. That's correct.
Q. Okay, and so if we go down through the column under LOLE Index, which equates to your loss of load hours currently being used, we see that that was expected that capacity would be exceeded in 1993?
A. Yes, that's correct.
Q. Okay, now if I go back up above, I also see that it would have been exceeded in 1991 because we have a .0268, but if we go over to-

Page 157

MR. HAYNES:
A. Sorry, it's .2 days per year, not .02, the criteria is .2, so it would not have been exceeded until 1993.
Q. You're correct, thank you for that. So it would have gotten exceeded in 1993 on capacity?
A. That's correct.
Q. Okay, and if we come over to the next couple of columns, they're essentially the same as in your table 8, and we come over to the energy balance column.
A. Yes.
Q. The energy requirement was good until 1996 at that point in time?
A. That's correct.
Q. So back in 1990, we had a capacity constraint affecting the system more quickly than the energy constraint and we have the opposite situation today?
A. Yes, that's correct.
Q. Now, so comparing 1990 with where we are today, today we have new sources of generation being driven more by energy than demand and we have the opposite being the case back in 1990?

Page 158

Would you agree with that?
A. There's not a big difference in the years, but in energy is the first criteria that we violate as in our forecast that we have today.
Q. Today, and back in 1990, it was demand being exceeded in 1993 versus energy in 1996?
A. That's correct.
Q. Okay, now let's move on from there and I'd like to go to your Schedule 4 next and I'd like you to take us through this graph--this series of graphs, and explain to the Board what this means?
A. Schedule 4 is the total system energy storage, basically it is hydraulic only and the red line at the upper most part of the chart is basically how much energy we would anticipate having in our storage based on our reservoir planning criteria, based not necessarily on full supply, but at certain times of the year we would not plan all reservoirs to be full. But that would be the maximum energy that we could have in storage, assuming we had a lot more rain than we're having today.
Q. That line down the bottom is called "maximum operating level" and it's got a bump in the

Page 159

middle kind of running from roughly about April through to September. Why is that there?
A. In the months approaching the spring run off, we would actually plan the reservoirs down a little bit lower so that we would minimize our risk or spill. We would try to capture all possible water that we can from snow melt and so on, so basically we would plan our reservoirs to be a little bit lower in the spring, so that we can ensure that we catch all possible water so that we don't spill anything and so on, and that's why it would be higher. In June and July, we would try to cover off rainfalls, but we would not have to worry about snow melt.
Q. And then why does it drop down again then in September from a planning operation's point of view?
A. Usually in September we have a little bit more rainfall, but it alludes me as to why it's flat after that. I suspect that's just our expected utilization and so on. So it's basically a minimize of potential risk of spill would be the driving factor.

Page 160

Q. Right, because you're going to get rain--more likely to get rain in the fall so you have the potential to capture a little bit of extra if your reservoir is not quite as full?
A. Typically we catch a few of September, pieces of hurricanes as they go by and we get some rain there, but once the cold starts, then that's really, the temperature obviously comes into that picture as well.
Q. Right, so the red line at the top is your perfect world, so to speak?
A. The ideal world, yes.
Q. Okay, let's go down through the other lines.
A. The green line is our minimum storage targets and that is, that line is not necessarily a static line, at different times when we redo the situation as we see it today, there's some changes to that, but not major ones. It is where we would like to be or where we want to be to protect our firm sequence; in other words, when you come into January of this year, we came into that year at a little over 1500 kigawatt hours of energy in storage. Very little risk of spill, but it's not--we would prefer it to be higher and that's the

Page 161

MR. HAYNES:
way we would try to run our Holyrood production would be to pick that up. It did come back up in February when we got an initial melt of the inflow. That's the purplish line, I'm sorry, or whatever colour that is, would be to the date of that particular time. The blue line is basically how we fared last year. We came in a little bit below the minimum and basically stayed, by and large, most of it, except for the latter part of the year, we were a bit under our target, our goals.

Q. And the green line, if we can just focus on that one, is minimum energy storage targets? Just explain how that is intended to work?

A. That is to product our firm capability. The intent is that we should be there, if we were on the green line with our actual--where we are today, that if the firm sequence started right now, we would be in reasonable shape to survive that without having to curtail energy deliveries. And this doesn't include, you know, this doesn't include any generation from gas turbines and so on, basically it's

Page 162

Holyrood and the Hydro plant.

Q. This is pure water we're talking about here?

A. In this particular chart, but it is influenced by, you know, the availability of factors and the 25 percent incapability factor for generating that particular, that green line.

Q. Right, but I notice the green line drops down through January to about April, then rises through the summer and then starts to hopefully rise back December, just walk us through the logic of that?

A. As you're coming into the spring, the load is starting to decrease, you know, and we anticipate a certain inflow which is reflected when the green line starts to take a rise again.

Q. So that would be your snow melt.

A. Snow melt, your inflow and then basically it kind of levels off and then in the fall then, you get snow--you get some rain and you get snow accumulation and so on. So it's, you know, the sole purpose is to assist the hydraulic planning, to minimize the risk of spill would be the primary purpose.

Q. Now I notice you called this schedule "Total

Page 163

System Energy Storage". All the rest of us unsophisticated types would probably look at it as water storage.

A. It is.

Q. But from your point of view, this is energy storage because every gallon of water that's stored is essentially--got an energy value to it? Have I got that essentially correct?

A. Yes, and the access on the left-hand side, it is actually in gigawatt hours, but I mean, if you go down and look at each reservoir, it's "X" thousand of cubic feet at Bay D'Espoir, this conversion factor, plus "X" thousand of cubic feet at Cat Arm and its conversion factor and that's the sum result.

Q. Okay, now I'd like to move next, having looked at that, to discuss a little bit about marginal costs and if we go to NP-171 is probably the starting point and we asked a question there, that was confirmed, that the cost of providing energy at Holyrood on a cents per kilowatt basis is approximately the same for all months of the year. And the answer was the cost of providing energy from Holyrood on a cent per kilowatt basis is

Page 164

approximately the same for all months of the year, except for the effect of fuel cost changes due to fuel purchases in each month. That's just the price of fuel going up or down, as I understand it, and assuming equal unit output levels, and that's essentially the conversion factor for our oil?

A. Yes.

Q. So other than those minor changes, the cost of producing energy is the same at Holyrood for whatever months it's running?

A. Yes, I mean, obviously in the discussions, I guess some of the RFI's with respect to the unit loading and Schedule 5, there's some variation, but basically it is more or less the same.

Q. Okay.

A. It's the incremental fuel cost.

Q. Right. Now, under normal operating conditions then, the cost of producing on a kilowatt-hour basis is approximately the same incrementally over the whole period of the year?

A. After, as I said, after you consider the actual cost of fuel in those months that it generates, but by and large.

Page 165

KELLY, Q.C.:
Q. Now, if we--just have a look at NP-130 next, that cost as we currently have it, as a marginal cost of production is 5.13 cents?
A. Yes, that's based on $29.20 a barrel.
Q. Okay, now the language in the answer at line 8 is the forecast short-run marginal cost of production at Holyrood is. Now, let's just understand the terminology first. Just explain short-run marginal cost?
A. The short-run marginal cost would be if we were to go and look for another, say another kilowatt hour today would be basically the fuel cost, plus the variable O&M. So if the variable O&M is reflection of the additional fuel that is required and so on in the plant to do that, so it comes out to be 51.051.
Q. But it's the cost of getting an extra kilowatt hour out of the system today?
A. In the short term, it doesn't consider, you know, additional maintenance that's required or things like that. It's basically just we need a few extra kilowatts today, here they are.
Q. Right, and that would be contrasted with a

Page 166

long-run marginal cost or long-run incremental cost for some period well into the future?
A. Yes, it wouldn't be--a long-run cost would incorporate a few other unforeseens out there, it would be, you know, the variable O&M or there would be another factor added to make that a little bit higher to reflect other things that would happen on occasions.
Q. Now, if we--I'd like to talk next about the relationship between Holyrood and your hydraulic production. If we have Holyrood shut down, for example we're in the summer, and there's energy at that stage, for example, being supplied by Hydro Power, then that water then is not available then to produce electricity in the winter, would you agree with that? In other words, in one sense it's what, whereas we looked at your graph, there's a certain amount of energy in that hydraulic production?
A. If Holyrood is shut down, then basically most of the energy or all the energy, in effect, would be from hydro resources or our NUGS, but it's typically the most economic way to do it. It's not economical to run Holyrood at very,

Page 167

very low load.
Q. No, but my point is this, that if you were to run, either run Holyrood and burn oil or run the hydraulic plants and use up the water that we have in storage, those are the two options, correct?
A. Pretty well, yes.
Q. Yes. So that the cost of energy on the system, the marginal cost of energy on the system is always the cost of producing out of fuel at Holyrood. Would you agree with that?
A. In the short run. In the long run, you would eventually be pushed to a new generating source, which would have a higher cost. Once you exhaust your capability at Holyrood, you'll be forced into new sources of supply, which would be higher than that.
Q. Right. But within the constraints of the existing system, and we looked at the forecast period for those, the marginal cost of producing energy on the system is always the Holyrood cost because we're either going to use--burn the fuel at Holyrood or use the water out of our storage, correct?
A. In the short term.

Page 168

Q. And in the short term, we're talking about a period of a number of years out over our planning forecast period?
A. You will eventually be driven to a new source of supply, yes.
(1:00 p.m.)
Q. And in fact, at this stage in the planning cycle, Hydro has not yet determined which would be the next source of supply and how that would be done. That's the discussion you had with Mr. Browne this morning?
A. No, we don't know at this point in time, but I can be quite confident it will be more than 51 cents a kilowatt hour or 51 -
Q. 5.1 -
A. - 5.1 cents a kilowatt hour will be the marginal source.
Q. Okay. Now can I take you next to the EES report, to page 22, and if you come down to lines 33 to 35, and you see there's a comment there that begins on line 33. The sentence reads "above 420 gigawatt hours, NP would be charged an energy rate that represents the incremental fuel costs of the Holyrood generating station, which we understand is

Page 169

KELLY, Q.C.:
used as a peaking unit." Is Holyrood used as a peaking unit? Would you agree with that statement or not?
A. No, it's not.
Q. It's not correct?
A. No.
Q. Okay. How would you describe Holyrood?
A. I wouldn't necessarily say it's a "classical" base-loaded plant. That plant operates ten to eleven months of the year, sometimes twelve months a year, there are components of operation. It basically--it picks up the energy requirements basically that we don't do hydraulically. But a peak plant would be your gas turbines, which are put on for a few hours here, a few hours there, just to get you over a short term capacity thing. Holyrood's energy requirement, when you look at that Schedule 2 which we talked about, Holyrood is in there at 2996 gigawatt hours as a firm basis. The peak plants are in there at zero gigawatt hours.
Q. Okay. So Holyrood is more of a base load plant than a peaking plant?

Page 170

A. Not base load in the sense that we put it on for 130 megawatts and leave it there, but basically it is required, you know, virtually 90 percent of the year and it's definitely not a peaking plant.
Q. Right. Let's have a look next at how the system operates between thermal and hydraulic production, and a good place to go to look at this question is let's start with NP-172. Do you have that?
A. Yes.
Q. Now let's go down through--the question postulates what happens if you took 25 megawatts off of peak and what I want to focus on is how do you operate the system to account for that load? And at line 6, you begin "the reduction in load could result in a reduction in either Holyrood's stand-by plant or hydraulic plant production. The generating plant that has its output reduced is dependent on current system operating costs. If stand-by plant, such as a gas turbine, is operating it would be reduced first." Now if we'd just stop there. That's relatively rare in the system, isn't it, especially with Granite

Page 171

Canal and the NUGS in place?
A. In today's--as we stand today, yes, it would be rare, but as you approach requirements for next source, it is a possibility, but we don't--it doesn't usually run for energy. It's usually run to shave peak and it's a possibility, but it's -
Q. And those plants -
A. - less likely today, since we just built, you know, Granite Canal.
Q. And those plants, as you talked about with Mr. Browne, do have a value today. We'll come back and look at that in a little bit, a little bit later. But let's leave those aside for the second. If the reservoir storages are high, Holyrood would be reduced before hydraulic units. If the reservoir storages are low, then hydraulic units would be reduced before Holyrood, and during an average daily peak, hydraulic units are generally reduced before Holyrood because Holyrood is base loaded. Now just explain what that means, especially the part about reducing the hydraulic units before Holyrood and why you do that.

Page 172

A. In striving to optimize or to ensure that we are the most cost effective--that we are taking the most cost effective approach, the Energy Control Centre people look at Holyrood and they look at it on a week-ahead basis and they try to dispatch Holyrood at a number, at a high enough load that gives us good economies with respect to energy conversion factor. If you're going to move the machine around, the Holyrood machine around based on 25 megawatts being gone for a few hours a day and then back up, you're going to be moving that machine--you know, it's not a cost effective way to operate the hydro--I'm sorry, the thermal plant. You basically take that particular swing on a hydraulic unit, if there's no gas turbines going. And at the end of the day, what you'll end up with is you'll have met your customer demand, you will have done it a little bit more economically because you retained Holyrood at a higher energy conversion factor capability. The more you load Holyrood, the most efficient it is, to a large extent. And if you're operating at 100 megawatts and you drop down to 75, it's an

Page 173

MR. HAYNES:
inefficient--as indicated in Schedule 5 of my evidence, we have that curve of megawatts versus efficiency. So you don't--you do that on a kind of a look-ahead basis and you may shut down a machine at Holyrood if you had a sustained change, as opposed to running all three machines down at a lower inefficient load. You will try to shut one down and keep two up at a more economic dispatch.

Q. So the peak swings are normally handled by hydraulic, as opposed to changing the operating output of Holyrood, for efficiency reasons?

A. I mean, that's--there's no pat answer, but by and large, that's correct.

Q. That's correct, okay. And if we just go to IC-294, we'll have another look at that same issue. If we scroll up, there we go. The latter part of this answer, it talks about reserve capacity. I'll come back to that a little bit later on. "When load is increasing during peak periods, the power system operator must ensure that the operating generating units have sufficient operating reserve to

Page 174

supply the increasing load without deterioration of the power system frequency and have to account for the rate of increasing load in their decision when to start additional generating units. For that reason, they are able to allow the units to go to full capacity before going to the next step in the loading sequence." Just explain that and where that ties in with Holyrood and our hydraulic discussion. Sorry, I misread that. "Unable to allow the units to go to full capacity." Just explain where that fits into our discussion.

A. Just give me one second, just to read the paragraph in context.

Q. Sure.

A. Okay. So this basically is the day-to-day operation of the control centre, and for instance, you know, maybe the easiest thing is to pick a point in time. Let's say it's today and basically we have X amount of machines on, and you know, there's 1,000 megawatts of load and if you look at the rating of the machines or the ability, we may have 100 megawatts reserved. You do not go up to 100 megawatts

Page 175

or run right up to the pins, if you will, before you start to initiate another generation source. You have to maintain a reserve. You have to look at the expected load increase. If it's coming up around suppertime or in the evening, you know, 4-5:00, the load starts to pick up as people go home and start to turn on their electrical appliances. So the operator has to be kind of one step ahead, knowing where it's going to be. He also has in the back of his mind if there's any work ongoing, if there's any potential for losing a machine because of something in the system or a customer is picking up load. He has to be one step ahead of that. You don't wait until you have no reserve before you start a machine. If you did that, if something happened that there was an unanticipated load increase or if you, you know, lost a machine or there was some run back on load, you may--the machines would not have any room to go. Something like operating a car, I mean, if you operate your car with the gas pedal to the floor, which I don't recommend, by the way, but if you operate the

Page 176

car that way and you had some reason to pick up speed to avoid something, you got nowhere to go. On the system, on a hydro unit and a thermal unit, the system has the same thing. If it's operating, all the valves are wide open, the wicket gates are fully open, there's nowhere to go. Somebody comes on with 15 megawatts of load and your frequency deteriorates. So you have to maintain that reserve on a day-to-day basis.

Q. Okay. And that takes us back then to, at some stage if we have--let's just assume we have one of Holyrood's units running and it's at, as we looked at in NP-172, an efficient stream, depending on how much energy you're going to--how much demand is on the system, you may run a hydraulic plant and at some stage, you might then bring in a second Holyrood unit and shut down a hydraulic plant. Is that essentially correct?

A. You wouldn't bring in a Holyrood unit on a short-term thing, because it takes, you know, a couple of days to get it to go.

Q. Fair enough, yes.

A. But you would--you know, a more apt comparison

Page 177

MR. HAYNES:
would be that you may bring on another hydro unit to have there running at, you know, at some load so it has room to go, to pick up load.
Q. So the short-term peaks over a number of days are covered by hydraulic, but then as we get into the winter period, at some stage that demand is then going to grow and then, do I understand you correctly, you'd bring a second Holyrood unit online and get it up to maximum efficiency then as quickly as possible, adjusting your hydraulic production?
A. You would attempt to put Holyrood on at a very high efficiency. It wouldn't necessarily be at the 175 megawatts, but you would still need a little bit of room to go, but it will be close.
Q. Right.
A. Because it's more efficient that way.
Q. Exactly. Okay. And so what you're then doing is using your hydraulic resources, turning them on and off, to meet the available peaks during the whole system year? That fair?
A. For the most part. I mean, there's a lot of

Page 178

other factors involved in that decision, but that is, on a all things being equal basis, that's more or less the way we apply it.
Q. And as you take water out of that system or as you talk about it in your graph, as you take energy out of that hydraulic system, then that's energy that is not available then at other times. So we come back to ultimately the cost, the marginal cost on the system is the cost of producing out of Holyrood? Is that correct? Same analysis?
A. That's my interpretation, yes.
Q. Okay. All right. Now if I could magically move some of my production from one point in time to another point in time, I still ultimately have that marginal cost at Holyrood in the short term, don't I? In other words, if I move it from 5:00 in the night to midnight, I still have that same marginal cost because I'm either going to burn it at Holyrood in oil or take energy out of my storage, as we've ultimately talked about?
A. All things being equal, yeah, probably.
Q. And if I move it from the winter to the summer, if I could somehow magically move my

Page 179

loads from winter to summer, appreciate that's not easy to do, but if I could do that, I would still have either water or oil out of Holyrood and then I'd still be at 5.13 cents, essentially correct?
A. If you assume that the energy requirements do not change, but sometimes when you do that around, you also change the overall energy needs of the customers because there's a moving around. It's not always--you don't necessarily move a demand and not have some impact on the energy, but it may not be large.
Q. I may move and actually end up with an increase in energy, couldn't I?
A. I'm not sure.
Q. Well, let me just give you a hypothetical. If I moved--if I might try to create a rate structure that might, in fact, give me a lower price in the summer but I still got to heat all of the houses in the winter and I might increase an air-conditioning demand in the summer, mightn't I? So I could actually try to move demand and only increase energy load, possibly.
A. I wouldn't agree with your air-conditioning

Page 180

analogy because, you know--I wouldn't agree with that particular analogy of an air-conditioner. We don't have a big air-conditioning load, and I don't think that people would actually would go there because of the--well, maybe they would if it was a cheaper electricity, but I think by having a higher rate in the winter time or something like that, you actually discourage--you may improve your fact factor further and so on.
Q. But I may increase the demand, load demand and energy demand elsewhere in the system?
A. It's possible, but I'm not--you know, I'm not exactly sure of what the numbers are. You would have to do an econo-metric analysis to look at and perceive what that would be, but I think it would be small.
Q. Has Hydro done any kind of econo-metric analysis like that?
A. With respect to?
Q. Moving from one period to the other and the effects on demand and energy? In your production division, have you done it?
A. I'm not sure that we've actually done a study like that. Our view is that, I guess, by

Page 181

MR. HAYNES:
having, you know, a demand energy rate that you would actually improve the overall efficiency of the system. You may curtail some electrical growth expansion in the winter, which is a positive, because of our marginal costs and delay next sources.
Q. Yes. But have you done--has anybody in the production division that reports to you done any kind of these econo-metric type studies?
A. Not in recent times, to my knowledge, have we undertook any extensive review.
Q. How far back in time?
A. Well, I can only speak to 2001, that I'm aware of. I don't think we've done--I'm not sure of prior.
Q. Not within any knowledge that you have?
A. No, not that I have.
Q. Okay. Now I want to go next and pick up a point that we touched on a little bit as we went through. Let's go back to your Schedule 2, just to kind of set the stage for this one. Schedule--there we go. Now in that schedule, for example, near the bottom, we have a total net capacity of 1,919 megawatts and it

Page 182

includes Newfoundland Power's production of 93 in hydroelectric and 54 in thermal. See that?
A. Yes.
Q. Okay. And all of the generation, including Newfoundland Power's and Hydro's thermal, has an impact on the timing of the next generation addition for capacity purposes, doesn't it?
(1:15 p.m.)
A. It affects the LOLH, yes.
Q. Affects the LOLH, okay. And let's just kind of try to go through this. You have your exhibit JRH No. 3, which is the report on the cost of service assignments.
A. Yes.
Q. And if you go to page 7 of that, you do something called a reliability assessment and I want to get you to walk us through how this works and let's start with what it means. What's a reliability assessment?
A. Just one second please.
Q. Sure.
A. I guess what was actually done in that particular review is that this report was specific to the GNP, Doyles-Port aux Basques and the Burin systems. We went down through

Page 183

and looked at the impact on the LOLH of not having that particular generation available, if it was not there to serve the overall needs of our customers.
Q. Okay.
A. And that information was presented in a table there further on.
Q. Okay. And if we go to that table, which is--we started with your Table 8, and then we go over to your Table 3.3 on page 12.
A. Yes.
Q. In fact, perhaps if we just scroll back to page 11 first and put up that table. That's the same one we looked at at Table 8 in your evidence, isn't it?
A. That's correct.
Q. With the identical data?
A. That's correct.
Q. Okay. Now just take us over to page 12, and just explain what you did in this table here and what the impact is of these various plants on the system planning.
A. Okay. In the first heading, which is called Base Case, that basically is a duplication of what is in Schedule 8. That basically assumes

Page 184

that we have basically 1919 megawatts available, and in 2011, we have a 3.5 LOLH criteria, you know, that's when we would actually see having a close look at new sources. In the next column, which says less the GNP, we have only excluded the GNP generation, which is roughly 15.1 megawatts. So we actually end up with 1904 megawatts available. And it basically moves the LOLE two years to 2009. The next case was at Doyle's-Port aux Basques. We put back the GNP in service and we took out the Doyle's-Port aux Basques generation, which was 15.8 megawatts, leaving 1903 total capability, and that basically, slightly difference in the numbers there in the decimal places further on, but basically, it's still at 2009. When we go to the Burin Peninsula system, which has a lot more generation, we actually--you know, with Doyles, the GNP and Doyle's-Port aux Basques back in, the Burin Peninsula system has 34.7 megawatts of generation in total on that system and when we actually take that out, we actually move the capacity issue from 2011 back to 2007, you know, four-year change

Page 185

MR. HAYNES:
based on that.
Q. And that's just the Burin Peninsula, not Doyles and Great Northern Peninsula?
A. No, these three columns in the middle are by the each, if you will. The GNP only removed, Doyle's only removed, the Burin Peninsula only removed. In the last column, and we also did the energy balance that particular time as well, but in the last column, we actually took out the GNP, Doyle's-Port aux Basques and the Burin systems and the LOLH ended up being three and a half in 2004, which basically is just next year. That's a total of 65.6 megawatts removed from that particular analysis, and the energy was also--it didn't change the year, but there was a slight change in the actual number from 10 to 61.
Q. So if you didn't have all of those thermal units, that generation capacity, then you would have an LOLH problem or a capacity problem for 2004?
A. Yes, that's correct. In fact, it effectively removes 65 or 66 megawatts from the portfolio of generation that's available to meet all

Page 186

customers needs.
Q. And that's that probabilistic scenario that you talked about with the computer model about an hour ago, I guess now, in your evidence?
A. Yes, that's correct.
Q. Okay. Now just so we get a sense as to what plants we're talking about here, just scroll back to page five of your evidence, where you have a table there, in this report. There we go. So the ones up on the Great Northern Peninsula, we have a diesel in Hawke's Bay and Roddickton, a small hydro plant in Roddickton and another diesel in St. Anthony?
A. Most of these are, you know, two or three diesels or four diesels in a plant. They're not one single machine, but the plant itself, the facility is -
Q. The totality of that particular plant.
A. The totality. Hawke's Bay has five megawatts and Roddickton, 1.7.
Q. Okay. And if we look at Doyle's, these are Newfoundland Power generation?
A. That's correct.
Q. We have a diesel in Port-aux-Basques, a gas turbine and Rose Blanche hydro for 15.8, and

Page 187

we come down to the Burin Peninsula, there's the Green Hill turbine, some hydro at West Brook, Lawn, Salt Pond, and your facility at Paradise River?
A. Yes, that's correct.
Q. For approximately about 35. Now does it matter for purposes of system capacity where any of these plants are located?
A. As long as the plants are connected to the grid, and when I say the grid, it does not have to be connected to the bulk, you know, the Newfoundland and Labrador Hydro owned facility. As long as it's connected to the system anywhere, it will assist in serving this purpose of meeting our LOLH criteria. It can be in Port aux Basques. It can be at the three extreme ends of the system, and it will be of benefit to the system.
Q. So, it would be--whether it's in St. Anthony or Grand Falls or St. John's, it doesn't matter in terms of the impact on capacity?
A. It has not significant impact on capacity.
Q. Now, let's just go back to your Schedule 2 for a moment, keeping in mind what we've just looked at on page 5 here. And there are a

Page 188

number of other Newfoundland Hydro systems, gas turbines in Stephenville, Holyrood, for example and there are other thermal stations, Newfoundland Power, small hydro electric stations as well. Do all of them fulfil the same type of function? In other words, you have them in there as part of capacity in this LOLH?
A. Yes.
Q. So, it's the same type of analysis, they're all used and useful for the purpose of meeting that LOLH planning criteria.
A. You wouldn't get into a discussion on the assignment of plant because they're buried in your system, an auxiliary point, but they all factor into the LOLH calculation. They are available and, you know, through control centre, to Newfoundland Power, that can be turned on or whatever. That is the norm.
Q. And they go into your calculation for what you do for overall system planning for the next generation for capacity purposes?
A. Yes, and I think that's in line with, I guess, our approach or what we've done for years, that basically we have looked at the overall

Page 189

MR. HAYNES:
island energy and capacity needs and basically we have, if you will, by and large, backstopped those things for demand and energy.
Q. Okay. Now -
A. It's appropriate that Hydro consider that in the LOLH calculation which would be the overall system planning.
Q. Okay. Now, let's just go to page 15 of your report again, JRH 3, if we could just go back there and this is in the first sentence in paragraph 3, there you go. It talks about the Industrial--this is in the last GRA--the Industrial Customers presented argument to the effect that since the Great Northern Peninsula generation assets have seldom been operated from either generation capacity shortage since their introduction in 1996, therefore, they did not provide substantial benefit to customers outside the Great Northern Peninsula. And then in the following paragraph, you go on, scroll down a bit, you talk about two occasions where the value of the reserve capacity was demonstrated. And

Page 190

I'd like you to take us through those and explain them to the Board.
A. Yes, I think there's--in January 2003 we had a lightening failure at Oxen Pond which caused us a fair bit of system upset and basically in restoring the system to service, you know, the generation was turned on and any generation that's provided in such a situation allows more of generation--there's more generation to meet everybody's needs, to pick the system up again sooner and so on. That would be kind of standard operating procedure, to call upon those units to help out and do what they're designed and intended to do. I wouldn't say, shouldn't say designed, some of these units, I guess, are a fall over from other times, but they are used and useful to do that and I would add that they were used twice in 2003 when we had some issues on the system as recently as a little while ago when we had the Bay D'Espoir problem that we spoke about a while go.
Q. Okay.
A. That the generation on the GNP was called in to play and so on.

Page 191

Q. You talk about two in 2003, is that in addition to the January 30th incident?
A. I guess there one's--there's a new one in September, in September when we lost the Bay D'Espoir, we had difficulties at Bay D'Espoir with the station service and lost the plant, those--the GNP generation was called into play.
Q. Facilities were called--okay, and that would be--that's a good example because that is actually after Granite Canal and after the NUGS come into existence, correct?
A. That's correct.
Q. Okay, can you just touch briefly on the January 31st, 2002 example?
A. Do you mean 2003?
Q. No, you have two, if--you talk on the--as you go down to page 16 there's, I believe, another--end of page 15, a year earlier on January 31st 2002 the load on the interconnected system was at an all-time peak. All three units at Holyrood were operating at near full capacity and hydraulic production on the system was near peak capacity. Could you just explain what happened then, what the

Page 192

point is you're making here?
A. I apologize. Can you just point me to the page again there?
Q. The bottom of 15, last -
A. Okay, I'm sorry, okay.
Q. - and a couple of sentences in the top of 16.
A. Yes, I guess, in 2002, I think that was our record peak and basically all our resources deployed there and if we had lost one of the Holyrood machines which is basically 175 megawatts which is our biggest single source of generation, if anything had happened to that particular machine, we had to run back on load or tripped or whatever, we would have had to call in the gas turbines and any resource that we could. It was 175 megawatts which is a major component of our generation and we would have basically pulled all stops, diesel, gas turbines, whatever is required to get that load back on.
Q. Okay. So, these three examples show the value of these small generation facilities, whether they're yours or Newfoundland Powers and whether, for example, on the Northern Peninsula or out in Wesleyville?

MR. HAYNES:

A. Doesn't matter the location.

Q. Doesn't matter. Chair, this would be a good place to break.

CHAIRMAN:

Q. Thank you, Mr. Kelly, Mr. Haynes. I guess tomorrow is a fairly important day throughout the province, being election day, and I think the only formal requirement that I know of is that everybody must have four clear hours to vote. I think that can be established or that can be accommodated within the schedule we have. Certainly, I think we'll be just sitting at the normal hours tomorrow and if my math serves me correctly, that gives everybody six and a half hours. So, we should have ample time. Anyway, we'll see you at 9:00 in the morning. Thank you.

Upon conclusion.

CERTIFICATE

I, Judy Moss Lauzon, hereby certify that the foregoing is a true and correct transcript in the matter of Newfoundland and Labrador Hydro's 2003 General Rate Application for approval of, among other things, its rates commencing January, 2004, heard on the 20th day of October, A.D., 2003 before the Board of Commissioners of Public Utilities, Prince Charles Building, St. John's, Newfoundland and Labrador and was transcribed by me to the best of my ability by means of a sound apparatus.

Dated at St. John's, Newfoundland and Labrador this 20th day of October, A.D., 2003

Judy Moss Lauzon