British Columbia Transmission
CORPORATION™

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December 23, 2004

Mr. Robert J. Pellatt
Commission Secretary
British Columbia Utilities Commission
P.O. Box 250
600 - 900 Howe Street
Vancouver, BC V6Z 2N3

Dear Mr. Pellatt:

Re: British Columbia Transmission Corporation
2004 Transmission System Capital Plan

Further to our letter of December 20 2004, BCTC files its evaluation of the NorskeCanada Demand Management proposal in response to the British Columbia Utilities Commission's direction at page 34 of the Commission's November 19, 2004 Decision on BCTC's Capital Plan Application.

This filing is being submitted through the BCUC website, with hardcopies to be provided to the Commission on December 24, 2004. Electronic copies will be made available to Intervenors.

Yours truly,

Cameron Lusztig
Director, Regulatory Affairs

Cc: Richard Stout
Chief Regulatory Officer
British Columbia Hydro and Power Authority
Registered Intervenors

EVALUATION OF NORSKECANADA'S DEMAND MANAGEMENT PROPOSAL DATED SEPTEMBER 2, 2004

Report Number: #SP2004-51

December 2004

System Planning (Lower Mainland & Vancouver Island)
British Columbia Transmission Corporation

Executive Summary

This report evaluates NorskeCanada's September 2004 Demand Management Proposal in response to the BCUC's Direction to BCTC in the BCUC's Reasons for Decision (page 34) on BCTC's Capital Plan Application.

NorskeCanada's proposal offers 30 to 210 MW of demand management by a combination of shifting and curtailment of NorskeCanada's loads on Vancouver Island. NorskeCanada proposes that it could be called on for 26 days during the winter period and 4 days during non-winter period, with a maximum of 7 calls per winter and 2 calls per non-winter.

NorskeCanada's proposal could provide some mitigation of the potential risks in supply to Vancouver Island loads. However, NorskeCanada's Demand Management proposal by itself is unable to solve capacity deficits on Vancouver Island in 2007 and beyond, according to the October 2004 load forecast issued by BC Hydro (i.e., with no new generation added on Vancouver Island).

Notwithstanding the above, BCTC believes that NorskeCanada's proposal, in combination with other stopgap measures, could help resolve the forecast short-term capacity shortfalls prior to the installation of the proposed Vancouver Island Transmission Reinforcement Project.

BCTC will continue to work with NorskeCanada and BC Hydro to pursue the proposal and associated details of implementation requirements, costs and benefits for its proposal in more detail. BCTC is also prepared to work with NorskeCanada and BC Hydro to develop a trial program for its Demand Management Proposal. BCTC believes that it could be in a position to begin a trial of NorskeCanada's proposal during the maintenance outage period during 2005, and at other times during 2005. This will provide a better understanding of the benefits of the proposal, of its costs and implementation requirements and improve the proposal.

Table of Contents

1. Introduction

This report evaluates NorskeCanada's September 2004 Demand Management Proposal in response to the BCUC's Direction to BCTC in the BCUC's Reasons for Decision (page 34) on BCTC's Capital Plan Application.

2. NorskeCanada's Proposal

NorskeCanada submitted their Demand Management Proposal to the BCUC in September 2004. This proposal offers 30 to 140 MW reduction of its load on Vancouver Island based on demand management at Elk Falls Mill with an option at Crofton Mill for an additional 20 to 70 MW. The service could be executed in 10 MW blocks with limited usage. NorskeCanada proposes that it could be called on for 26 days during the winter period and 4 days during non-winter period, with a maximum of 7 calls per winter and 2 calls per non-winter.

NorskeCanada confirmed to BCTC that the Demand Management Proposal is a combination of load shifting and load curtailment. It was also confirmed that automatic load shedding schemes could be used to curtail the load if desired by BCTC. NorskeCanada also confirmed that assuming a three-month lead time for the service to be available is a reasonable assumption. NorskeCanada indicated that they would be able to combine demand management at Elk Falls Mill and Crofton Mill to provide up to 210 MW of demand management available under more restricted conditions than above.

NorskeCanada was unable to provide to a breakdown of the amounts available for load shifting and for load curtailment that are in its proposal. However, this detail is not required for the purpose of this analysis and did not affect BCTC's review of NorskeCanada's proposal.

3. Demand Side Management

Demand Side Management is typically achieved through load reduction, load shifting, and/or load curtailment.

Load reduction reduces power consumption by using more efficient power devices, which effectively reduces power consumption whenever that equipment is operating (relative to what it would have been otherwise). Load reduction has been accepted by system planners as being a reliable option and is simply accommodated in the planning analysis by using a lower load forecast with PowerSmart options included.

Load shifting is a pre-arranged shifting of load from high load hours to low load hours to reduce system coincident peak load, while energy consumption remains about the same. In many jurisdictions, the customer receives a financial benefit from shifting their peak usage to off-peak hours (e.g., reduction in monthly peak demand charges or time of use rates). Load shifting is part of the NorskeCanada proposal.

Load curtailment is the interruption or removal of load from the system. This can be used to pre-arrange for the reduction of load under pre-determined, specific conditions, for example after an outage. The energy is usually not taken at another time. Load curtailment is also part of the NorskeCanada proposal.

Both load shifting and load curtailment increase the load factor of the system (or average loading). Load reduction (PowerSmart) would produce little or no change to the system load factor (or average loading).

NorskeCanada's proposal offers 30 to 210 MW of demand management using a combination of shifting and curtailing some of their loads on Vancouver Island.

4. Transmission Planning Criteria

The purpose of deterministic system planning studies and the application of planning criteria is to test the robustness of the system to withstand the variety of conditions it operates under, any time of the year. Thus, studying a peak winter condition under a single contingency does not mean that system reinforcement is needed only for a short period during the winter. The system is continually challenged with expected and unexpected combinations of load pattern, generation pattern, equipment outages, and equipment de-rating throughout the year. The testing and evaluation of all possible conditions would be extremely onerous. Instead, the application of the deterministic approach through deterministic benchmark testing has been successfully applied for many years in the development of transmission systems, and continues to be in common use today.

It is important to recognize that the deterministic approach is only valid when the system is enhanced with facilities that are available almost all the time, such as with transmission lines or generation that is on-line most of the time. Planners would normally look for a portfolio of measures to ensure a reliable system when considering the implementation of an enhancement that is only available for part of the year. Alternatively, when there is insufficient time to implement a permanent long-term solution, it may be necessary to implement one or more stopgap or temporary measures to mitigate the potential reliability risks such as loss of customer load or equipment damage from overloading.

The drivers of system planning are the system generation and load forecast for a planned area. System planning criteria are applied to determine whether transmission reinforcements are required to meet the defined system performance criteria.

For supply to Vancouver Island, one of the key deterministic criteria is what is commonly referred to as the N-1 criterion.[1] This standard requires that the transmission system should be able to withstand an outage of any single element (such as a transmission line, a generator or a transformer) under any system condition. There should be no loss of customer load or overloading of any equipment. In addition, any resultant variation in voltage or frequency must be within acceptable limits. Planners generally focus on winter peak load (when demand tends

[1] The N-1 criterion means Category B of Table I, WECC Reliability Criteria April 2004, Page 24 (Reference 1).

to be the highest) and summer peak load (when line ratings tend to be the lowest) as two of the key benchmarks for testing.

Another key issue in the deterministic planning methodology is to verify that the system can be maintained. In most cases, this means ensuring there is sufficient capacity that equipment can be taken out of service to perform routine maintenance. This condition is typically referred to as N-1-1 (a single element forced out of service, while 1 element is already out-of-service).

In more recent years, BCTC (and previously BC Hydro) has applied probabilistic analysis to supplement the deterministic criteria. This method was used, for example, in producing a report for the Vancouver Island Generation Project in 2003 on Expected Energy Not Served for various scenarios. This methodology is useful to gain better insights into the impacts of the multitude of load conditions, single contingencies and multiple contingencies. This type of analysis is still typically used to supplement the conclusions of the deterministic studies when comparing long term alternatives if additional insights are required.

5. Transmission Planning for Vancouver Island

This section summarizes some of the key issues that need to be resolved in planning adequate capacity to meet the needs on Vancouver Island. There are other planning issues that arise, but these are the primary considerations when reviewing the adequacy of supply to Vancouver Island in the context of deterministic analysis.

The first issue to resolve is supply to Vancouver Island from the mainland during the peak winter load. A single contingency of a 500 kV line (Lower Mainland to Vancouver Island) may result in exceeding a limit (equipment overload).

It is also important to ensure that a single 500 kV line can be taken out of service without putting loads on Vancouver Island at risk of blackout should there be a forced outage during the planned maintenance period. BCTC typically undertakes this work during the non-winter period, resulting in operating with a single 500 kV connection to Vancouver Island for about 4 to 6 weeks per year. There is also a risk that BCTC could be forced to operate with a single 500 kV connection to Vancouver Island due to a lengthy forced outage of one of the 500 kV overhead or submarine cables comprising the connection to Vancouver Island.

Another potential capacity shortfall is on Vancouver Island, heading south from Dunsmuir in the mid-Island (“Cutplane D”). Prior to the addition of capacity in the south part of the Island (either new generation or new transmission capacity), there will be a shortage of capacity heading south from Dunsmuir. As with supply to Vancouver Island, this issue needs to be considered during both winter peak loads, summer peak loads during equipment maintenance, and other possible contingencies.

6. Evaluation of NorskeCanada Proposal

NorskeCanada’s Demand Management Proposal offers “on-call” demand management that could be used during system contingencies and, therefore, could provide some mitigation of the potential risks in supply to Vancouver Island loads. However, BCTC concludes that the NorskeCanada Demand Management Proposal by itself is unable to solve capacity deficits on Vancouver Island in 2007 and beyond, according to the October 2004 load forecast issued by BC Hydro (e.g., with no new generation added on Vancouver Island).

As noted above, BCTC operates on a single 500 kV connection to Vancouver Island for 4 to 6 weeks per year (routine planned maintenance) during the non-winter period. Given this extended period of time, and the potential of other lengthy forced outages, BCTC is concerned about the proposed limitation on the number of days of calls for curtailment in NorskeCanada's proposal during the non-winter period.

NorskeCanada's proposal is only available for a specified number of days and for a specific number of calls (26 days and 7 calls per winter, 4 days and 2 calls per non-winter). BCTC notes that the impacts of nature and equipment malfunctions may occur at any time. Accordingly, BCTC must take this situation into account for planning purposes.

The availability of NorskeCanada's proposal is illustrated by the load duration curve and build-up of resources on page 6 of the NorskeCanada proposal. This is clearly focused on the narrow period of peak load, and does not recognize that there are often capacity restrictions at other than peak hour periods and that restrictions often arise due to multiple contingencies. For example, during maintenance of the 500 kV connections, there are generator outages, generator restrictions and risk of a contingency on the remaining 500 kV line. None of these are addressed by the analysis provided on the load duration curve. Accordingly, as indicated above, while NorskeCanada's proposal could provide some mitigation of the potential risks in supply to Vancouver Island, the proposal by itself is unable to solve all potential capacity deficits on Vancouver Island in 2007 and beyond.

This conclusion also applies to the longer term application of NorskeCanada's proposal. While the NorskeCanada proposal may satisfy the N-1 criteria under some system conditions, as indicated, the deterministic approach used to evaluate the robustness of the system is ultimately only valid when the system is enhanced with facilities that are available almost all of the time, such as with transmission lines or generation that is on-line most of the time. NorskeCanada's Demand Management Proposal does not satisfy this criteria. In comparison, a transmission line is available virtually all the time, irrespective of how often or how long the system is exposed to the unexpected.

Notwithstanding the above, BCTC believes that NorskeCanada's proposal, in combination with other stopgap measures, could help resolve the forecast short term capacity shortfalls prior to the installation of the proposed Vancouver Island Transmission Reinforcement Project. BCTC identified a number of measures that may be used to resolve short-term capacity shortfalls, in BCTC's response to BCUC IR No. 1 1.1 for the VI CFT EPA Review. These include:

- The Transmission Emergency Constraint Management Process (TECMP);
- Dynamic monitoring (and upgrade/uprating) of the 500 kV cables;
- HVDC operational reliability improvement (life support); and
- Remedial Action Schemes.

Depending on the anticipated reliability and economics of these various measures, and the forecast shortfall in supply, NorskeCanada's proposal may be of assistance during the period of time between fall 2007 and the earliest in-service date of the currently proposed 230 kV cables.

It should be noted that BCTC has only considered NorskeCanada's proposal from a technical and not an economic perspective. BCTC did not understand the Commission's Direction to require it to compare NorskeCanada's proposal from an economic perspective to other potential alternatives at this point in time. The NorskeCanada proposal also offers the possibility of providing Voltage Support and Inertial Stabilization. While BCTC appreciates this offer, there is currently no need for these services.

Finally, Vancouver Island historical power flow data indicates that the NorskeCanada's daily peak load is not coincident with the VI daily peak hour for most of the year. This suggests the need for BCTC to work closely with NorskeCanada and BC Hydro to determine what has been incorporated in the BC Hydro load forecast. BCTC will also ensure coordination with any load shifting or load curtailment programs that might exist between BC Hydro and NorskeCanada.

7. Conclusion

BCTC appreciates NorskeCanada's effort to assist in bridging the potential capacity shortfall on Vancouver Island and its proposal to assist in providing flexibility for system planning and operation. NorskeCanada's proposal offers 30 to 210 MW of load reduction, based on demand management at Elk Falls Mill and at Crofton, during specified periods.

a) BCTC concludes that the NorskeCanada Demand Management Proposal by itself is unable to solve capacity deficits on Vancouver Island in 2007 and beyond, according to the October 2004 load forecast issued by BC Hydro (e.g., with no new generation added on Vancouver Island).

b) BCTC believes that NorskeCanada's proposal, in combination with other stopgap measures, could help resolve the short term capacity shortfalls prior to the proposed Vancouver Island Transmission Reinforcement Project.

c) BCTC will work with NorskeCanada and BC Hydro to pursue the proposal and associated implementation requirements, costs and benefits for its proposal in more detail including restrictions on its availability.

d) As recommended by NorskeCanada in their proposal, BCTC is prepared to work with NorskeCanada and BC Hydro to develop a trial program for its Demand Management Proposal. BCTC believes that it could be in a position to begin a trial of NorskeCanada's proposal during the maintenance outage period during 2005, and at other times during 2005. This will provide a better understanding of the benefits of the proposal, of its costs and implementation requirements and potentially improve the proposal.

e) BCTC continues to support the efforts on demand side management from all parties including NorskeCanada. However, BCTC wishes to emphasize for prudent long-term system planning purposes that it does not support the use of customer curtailment to meet the minimum reliability standard (N-1). Moreover, BCTC continues to believe that the long-term solution for Vancouver Island supply should have a combination of on-Island generation and transmission.

Reference

1. Western Electricity Coordinating Council, Reliability Criteria, April 2004.

Appendix

1. NorskeCanada Demand Management Proposal, Sept. 2004.

Norske Skog Canada Limited
16th Floor, 250 Howe Street
Vancouver, British Columbia
Canada V6C 3R8

Tel: 604 654 4000
Fax: 604 654 4048

NorskeCanada

September 2, 2004

By E-mail and Courier

British Columbia Utilities Commission
Box 250
600-900 Howe Street
Vancouver, B.C.
V6Z 2N3

Attention: Robert J. Pellatt, Commission Secretary

Dear Sirs/Mesdames:

Re: Project No. 3698376
British Columbia Transmission Corporation
2004 Transmission System Capital Plan

NorskeCanada herewith submits its proposal for Demand Management in response to BCTC's Capital Plan submission. We believe that this proposal will allow the most cost effective, reliable and flexible solution to be implemented for the capacity issues to and on Vancouver Island.

Our proposal is based on Demand Management at our Elk Falls Mill (Campbell River) with an option for DM at our Crofton Mill. We understand that the Crofton location will help resolve a North-South backbone constraint until the new 230 kV transmission system is in service.

The Demand Management Service that we are proposing is more reliable than generation and can be contracted for "bridging" or for longer terms to meet the needs of on-going single-contingency conditions. Once installed, generation will not offer "real" choices for variable capacity and contract duration, as the pricing structure will be mainly based on the capital cost. As explained further in the proposal, this package is not bound by capital cost recovery and therefore offers true flexibility in variable capacity and contract duration; a great advantage to suit the users' needs.

With this submission, we specifically request that the Commission direct BCTC and BC Hydro to engage in discussions to review the NorskeCanada proposal and report back, either endorsing the proposal or not, by November 1, 2004.

We are supportive of the 230 kV transmission option outlined in BCTC's application, as reliability of service is an important issue for all Vancouver Island residents. We encourage as fast a review and approval as possible as we also believe this project is the most cost effective solution.

We wish to thank BCTC for their assistance to date in developing this proposal and for the time and effort they made in helping us formulate a useful Demand Management package. We believe this proposal addresses their criteria. We would welcome the opportunity to talk to other parties such as BC Hydro about alternative conditions or configurations for our Demand Management that may provide benefit to their systems or plants.

Thank you for the opportunity to submit this proposal and for the opportunity to be involved with BCTC's Transmission System Capital Plan review.

Yours truly,

NORSKE SKOG CANADA LIMITED

Jess M. Beaman
Sr. Vice-President, Operations

Copy: BCTC
Interested Parties

BCTC CAPITAL PLAN REVIEW

PROJECT No. 3698376

NORSKECANADA

DEMAND MANAGEMENT PROPOSAL

(“NCDMP”)

September 2, 2004

NorskeCanada Demand Management Proposal (NCDMP)
August 27, 2004

1. Executive Summary

NorskeCanada is pleased to submit NorskeCanada's Demand Management Proposal (NCDMP) that will allow BC Hydro and British Columbia Transmission Corporation (BCTC) the maximum flexibility in selecting resource and transmission options for Vancouver Island (VI) Capacity and Energy, based on concepts contained in the 2004 Integrated Electricity Plan. NCDMP is presented as a "tool" for BCTC to consider in conjunction with their capital plans for Vancouver Island.

As the largest electricity consumer on VI, NorskeCanada has a financial interest in keeping Hydro rates as low as possible for all ratepayers. NorskeCanada further believes, that as a conscientious corporate citizen of BC, it is obligated to offer NCDMP as a flexible and environmentally sound solution to a localized issue that it has influence to resolve. It is intuitive to suggest that to have effective Demand Management an entity must have significant demand under its control to manage. NorskeCanada represents approximately 25% of VI's capacity and energy.

Our proposal allows for the broadest range of capacity and flexibility, and/or for bridging the F2007 to F2009 capacity shortfall until the new 230 kV transmission link can be in service. NCDMP is the best alternative for reliable supply to VI by providing a very cost effective and reliable solution. We believe that the transmission solution should be pursued to provide the security that VI customers need, and within a low cost portfolio to all ratepayers.

The intended design of this proposal is to make NCDMP appear, from a power system operator's perspective, very similar to a medium capacity (30 – 140MW) Simple Cycle (SC) peaking power station, with high reliability and relatively low utilization for energy, due to the relatively high cost of natural gas, or even higher distillate costs. This proposal, coupled with the anticipated 230 kV link from the mainland, will provide enhanced system reliability and flexibility to meet the foreseeable contingencies.

It is our contention that exposure to a capacity shortfall, during an N-1 contingency, will occur very infrequently (typically only with one 500 kV line down) during winter days and will only be for short periods. A low utilization factor SC peaking plant seems very capable of providing for this requirement. We also recognize that a peaker may be called on during the coldest winter days to help support VI as well as the Mainland load even without an N-1 condition. The time span, from previous evidence given during VIGP's CPCN hearings, indicates that 10 days is a reasonably expected maximum duration for cold weather operation and NCDMP allows for this. Comparison of NCDMP to a SC peaking plant, and to VIGP, as a reference used in the Integrated Electricity Plan (IEP) 2004, are tabulated as follows:

Item	NCDMP	SC Peaker	VIGP
Implementation Schedule (earliest)	Nov. 2004	Nov. 2005[1]	May 2007
Capital Cost (millions $CAD)	See Explanatory Notes[2]	35	280
Capacity (MW)	30-140MW	45MW	250MW
Normal Utilization	5-30 days/yr	5-30 days/yr	354 days/yr[3]
Maximum Utilization	30 days/yr	336 days/yr[4]	354 days/yr
Capacity Charge ($/MW/yr) (see section 3d for details)	50,000	75,000 - 89,000 -	82,000 - 88,000 –
Energy Charge ($/MWhr) (see section 3d for details)	112.5[5]	116-148[6]	73-93[7]
Contracted term (see section 3d for details)	Rolling 3 yr	10-15 years	25-35 years
Fuel Used	None	Natural Gas / Distillate	Natural Gas Only
Incremental Greenhouse Gas Emissions	None	11,138 tons/year[8]	779,000 tons/year
Incremental NOx Emissions	None	8.44 tons/year[8]	100 tons/year[9]
Incremental CO Emissions	None	5.14 tons/year[8]	56 tons/year[9]
Rapid Response Time to Load	3 sec.	5 min.	Not Applicable
Normal Response Time to Load	3 min.	15 min.	Not Applicable

[1] Earliest possible date, recognizing that shortfall is not forecast to occur until winter 2007/08.
[2] Although actual capital cost is relatively low, NorskeCanada will incur annual core business related cost due to suboptimal operation of mills and specific machinery, reallocation of products produced at each mill, shipping and logistics, etc., which are intended to be covered by the contract capacity charge, and which are necessary to enable NorskeCanada to offer demand management services.
[3] 97% Reliability
[4] 92% Reliability, corresponding to industry practice and prudent capital cost.
[5] Based on 10 days utilizing HLH only.
[6] Based on natural gas, however it is generally accepted that distillate firing is substantially more expensive.
[7] Based on natural gas volatility – Part 6 IEP Para. 3.2
[8] Based on 16 hours/day and 30 days.
[9] Reference Table 10.3-1 page 10-28 of VIGP – Application for Approval Certificate filed with the BC-EAO – June 2002 (No duct burner).

In summary NorskeCanada believes that it can provide a Demand Management service which in most respects is equal or superior to an SC peaking plant, with the advantage of short-term flexible capacity contracts, and is the least cost solution to capacity issues facing VI. It is imperative that NCDMP be evaluated as a flexible optional resource at the same time as commitments are made in regards to VI-CFT and the 230 kV link schedule, so that a least cost and holistic solution for a localized VI issue is derived.

NCDMP is an effective reliability tool that BCTC may use in solving the issues identified in their capital plan submission for Vancouver Island.

2. Vancouver Island – Capacity and Energy Supply Resources

a. Resources and Discussion of N-1 Contingencies

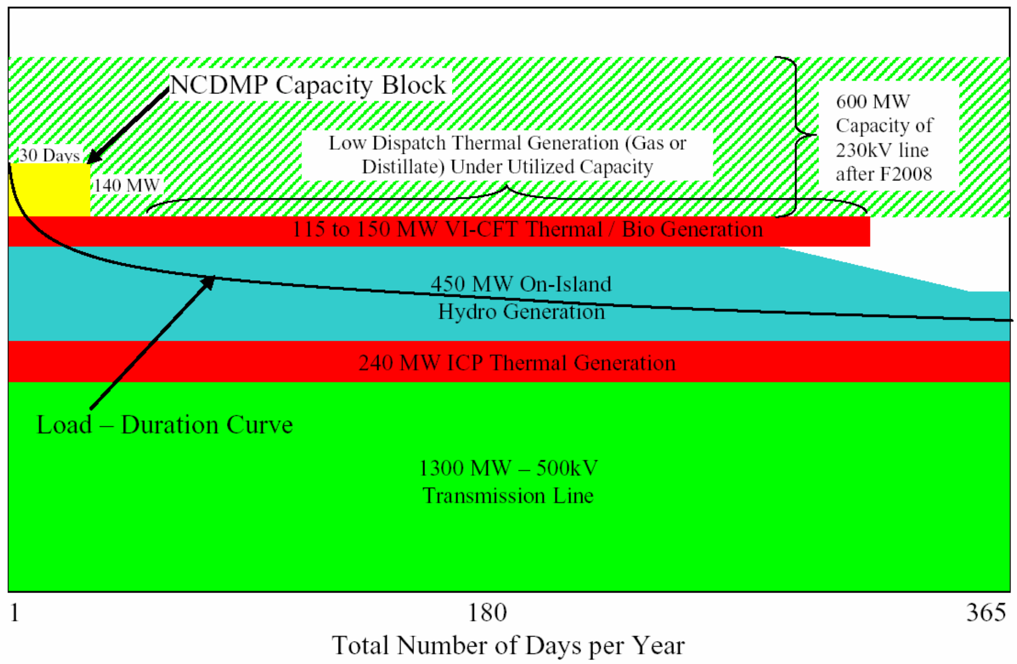
Vancouver Island (VI) is currently served by the following supply resources:

- Two 500kV circuits of 1200MW nominal capacity each (1300 MW emergency rating each line);
- An HVDC system with a "new" capacity of 792 MW (Pole 2 alone has a 476 MW demonstrated capacity); however, only 240 MW is being considered firm from both poles for planning purposes, and eventually is de-rated to 0 MW by F2007. It is important to note that BCTC has requested sustaining capital so that Pole 2 may be operated up to its 476 MW nameplate rating, utilizing sea return, during system emergencies;
- A 138 kV system that can connect to the VI system but typically just feeds the Gulf Islands, and is proposed to be replaced by a new 230kV system discussed elsewhere;
- An aggregate supply of 450 MW of on-island hydro based generation; and
- 240 MW at ICP (ICG), a Combined Cycle Gas Turbine plant (CCGT) capable of both natural gas and distillate operation.

The current peak load serviced on VI is approximately 2200 MW and forecast to grow to about 2400 to 2500 MW by F2015, depending upon the success of the PowerSmart program. It is important to note that the load on VI is highly seasonal, and with a high degree of correlation to the ambient temperature, largely due to space heating loads. This duration represents very few total days even in "cold" winters.

Figure 1 illustrates a typical demand duration by days over the year with the actual yearly curve being influenced by the weather conditions. It illustrates that a short term, medium capacity resource fits well in meeting the left side days and peak load.

Figure 1 – Illustrative Load – Demand Curve and Available Resources on Vancouver Island



Tabulated below are the supply-demand balance situations at various key time frames during an N-1 event, being the loss of one of the 500 kV circuits.

Table 1 – Supply-Demand Balance N-1 MW Capacity by Year[8]				
Supply Resource	F2005	F2008	F2009	F2015
500kV Single Circuit[9]	1300	1300	1300	1300
HVDC[10]	240	0	0	0
On-Island Hydro-Generation	450	450	450	450
On-Island Thermal Generation[11]	240	240 to 390	240 to 390	240 to 390
New 230kV link	0	0	600	600
NorskeCanada Demand Mgt.	30 to 85	30 to 140	0[12]	0[12]
Supply Total	**2260 to 2315**	**2130 to 2280**	**2590 to 2740**	**2590 to 2740**
Demand Total w/ PowerSmart 2	**2150**	**2210**	**2225**	**2400**
Demand Total w/o PowerSmart 2	**2175**	**2275**	**2300**	**2510**
Balance with Power Smart 2	**110 to 165**	**-80 to 70**	**365 to 515**	**190 to 340**
Balance without Power Smart 2	**85 to 140**	**-145 to 5**	**290 to 440**	**80 to 230**

Several key factors shown in Table 1 deserve to be highlighted:

During F2005 the total supply available, excluding NCDMP, is 2230 MW. However, by including NCDMP for the winter of 2004/05 for the full 140 MW of capacity available, the capacity now becomes 2370 MW. This scenario now becomes very close to being able to carry not only an N-1 contingency of one 500kV circuit being unavailable, but would virtually cover a simultaneous contingency of the unreliable HVDC link having a total capacity of 2130 MW to cover 2150 MW of demand.

If BC Hydro commits to 150 MW of firm capacity as a result of the VI-CFT, NCDMP would allow for the very short duration of cold winter day peak demand annually, estimated at fewer than 10 days per year. The VI demand under this scenario will have ample coverage out to F2009, assuming no PowerSmart 2 implementation, and out to F2012, if PowerSmart 2 is implemented and achieves the forecast demand

[8] Source data IEP 2004 Part 2 Fig. 6.3. Power Smart 2 is the current Power Smart program as defined in IEP Part 2.
[9] Could be impacted by additional capacity from cable thermal modeling and upgrades as outlined in BCTC Capital Plan currently before BCUC.
[10] Some capacity on Pole 2 likely available, however, reliability remains in question; access future capacity and flexibility in NCDMP could be used to optimize timing of 230kV link.
[11] Assumes from 0 to 150 MW of additional capacity is the result of VI-CFT after F2006.
[12] The entire 140 MW of DM would still be available in these years forward, however, the requirement becomes one of energy supply to the lower mainland versus capacity for VI.

reductions.[13] The above scenario had a multitude of benefits for the system, as a whole, as the system planner, along with its Regulator, will be able to track load growth for a few additional years, to assess the accuracy of the forecasts, as well as track results on the implementation of PowerSmart demand reductions.

A further additional benefit of the NCDMP is the short lead-time to implement, as it could be in place by Quarter 4 2004, and the fact that once implemented the contracted capacity is flexible enough to mitigate schedule risk on the in-service date for the 230 kV link, or any other unforeseen system changes requiring its capacity to change.

b. VI-CFT Evaluation

Surplus on-island capacity (beyond what is required to support the VI load), fuelled by natural gas, will not be a low cost resource for the lower mainland (or for the overall system) simply due to the extra transportation tariff for on-island natural gas.

We believe that all BC ratepayers will benefit from generation sited in the most beneficial location relative to load and system constraints including fuel, and therefore recommend a minimum of natural gas fired on-island generation be added to the system unless this proves to be the true low cost solution over the EPA contact duration.

c. 230kV Transmission Interconnection

The BCTC Capital Plan Application refers to the replacement of the current 138 kV system feeding the Gulf Islands, and southern VI during times of need, to a 230 kV system which can continuously share load with the 500 kV system. It is our understanding that it is not a case of whether this upgrade is required but a matter of when to implement it. Further, it is our understanding that the 230 kV link will solve an on-island north-south contingency problem by providing additional transfer capability to the southern island. The higher reliability of a transmission line compared to a large one-on-one configuration of CCGT power station further strengthens the transmission choice and an early in service date.

NCDMP complements the 230 kV upgrade by allowing flexibility in contract capacity and term, allowing the tracking of load growth, PowerSmart effectiveness and remaining life of the HVDC system to allow for optimal timing of this resource addition. Once the 230 kV upgrade is in place, NorskeCanada would be amicable to renegotiating

[13] Refer to IEP 2004, Part 2, Fig 6.3.

the DM contract or ending this contract and returning to optimal production. This term flexibility and cost benefit is not offered with any other type of resource.

d. Vancouver Island Demand Forecast

The VI Demand Forecast, as contained in the IEP, is subject to uncertainty, as is any commodity forecast. Uncertain elements include PowerSmart, a noble cause worthy of “at risk” investment. However this program is subject to acceptance by users, including NorskeCanada, and it is uncertain as to its actual full impact on longer term demand reduction. Conversely, it may exceed its projected capacity due to better participation than projected or unforeseen commercialization of a “leap” in technology that is immediately accepted.

We believe that NCDMP will allow the flexibility to “backstop” the forecast and for the duration required to validate the assumptions.

e. Demand Management

Virtually all North American electrical jurisdictions recognize some form of Demand Management (DM) as a prudent and rational means of avoiding construction of surplus capacity to fulfill relatively few hours of peak demand, either on a daily or seasonal cycle. In Western Europe it is common to purchase new household appliances with delay timers integrated into the controls systems to facilitate off-peak usage. New Zealand, which historically had an abundance of relatively low cost hydro electricity, has begun a program to upgrade domestic water heating controls so that the demand is effectively curtailed during daily demand peaks.

Areas of North America are starting to consider time-of-use (day) metering which may give electrical consumers the appropriate price signals that truly reflect the “real time” cost of supplying the energy and thus lead to voluntary demand shifting to off-peak hours.

Canada, with its broad seasonal temperature variations, creates a further opportunity to practice DM on an annual, as well as daily, basis.

NorskeCanada directly controls approximately one-quarter of the peak demand on VI, and therefore is extremely well positioned to implement a significant DM initiative that will enhance the reliability and flexibility of the entire VI electrical supply system in such a cost-effective and meaningful way that it simply cannot be ignored.

Obviously, to have the appropriate system impact, a DM proponent must be in a position of controlling significant demand, and have sufficiently capable staff to be able to manage a DM program in coordination with the system operator. NorskeCanada is an entity that can deliver a cost effective and reliable DM program in an efficient and professional manner. The specific details of NCDMP are contained in Section 3.

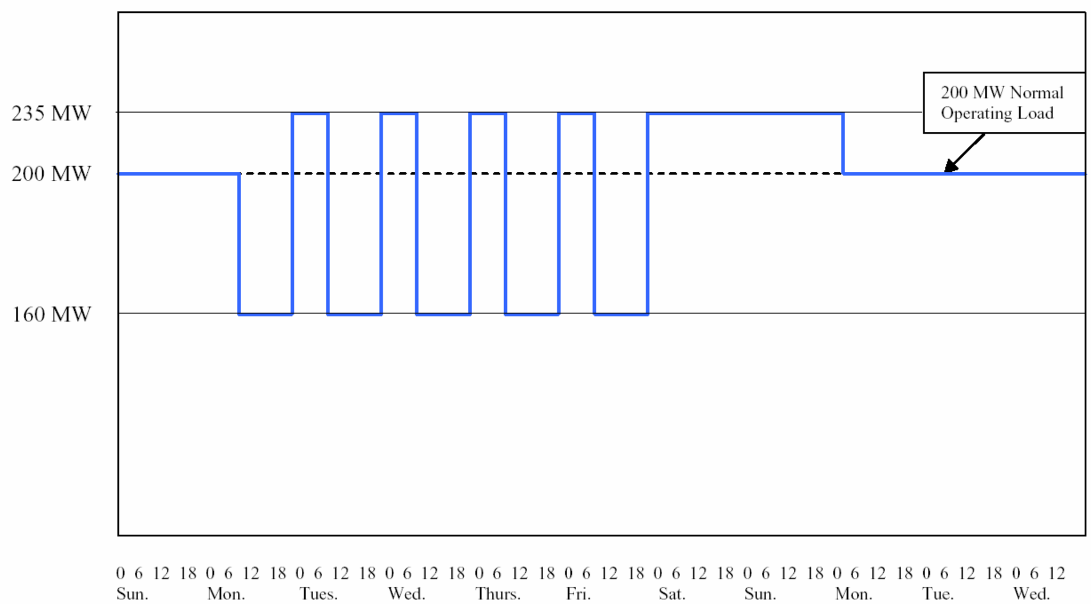
3. NorskeCanada Limited Demand Management Proposal

a. Peak Demand Load Shifting

By internally controlling risks and costs associated with demand management in the integrated pulp and paper operations of NorskeCanada at the three VI mills and two mainland mills, we can offer a simple contract that is based in utility terminology and not in pulp and paper terms. This is achieved by pre-planning for these events, changing our production accordingly and mitigating the affects on our business. These and other “pulp and paper” considerations will not impact the use of DM as it can be used in accordance with the contract terms as and when needed.

In essence, NorskeCanada has attempted to structure this proposal to emulate a high reliability, low utilization and low cost SC peaking power station. By curtailing 30-140 MW of demand in a relatively short period, the net effect on the system would be viewed in much the same way that a peaker would be called on to run. For example, if NCDMP was required to be curtailed during High Load Hours (HLH) on a daily basis for a one week period, it is anticipated that production could be partially made up during Low Load Hours (LLH). Figure 2 illustrates the concept of a 7-day Peak Demand Load Shifting scenario.

Figure 2 - Elk Falls Example 40MW DM



b. Energy Curtailment

NorskeCanada is not proposing to curtail electrical energy usage and incur a corresponding paper production reduction on a calendar basis, however, depending on the total MW's called for, the duration required and a number of "pulp and paper" considerations, some product curtailment might be required. In this case there is insufficient "catch up capacity" to allow for a full recovery during the Low Load Hours and after the event. The proposal is structured such that this "pulp and paper" condition is borne internally by NorskeCanada and would not be a factor in using NCDMP. No jobs would be impacted by this event. It is anticipated that this will be a very modest curtailment requirement over the course of a "normal" winter.

In the event of a longer dispatch of DM more curtailment will be required and there will be greater "pulp and paper" costs, this is reflected in the escalating energy charge in NCDMP.

c. Associated Cost, Benefits and Risks

The associated costs with implementing NCDMP are largely preplanning, production efficiency, shipping, and loss of margin associated with curtailed production. Although not fully estimated, we believe that the incremental capital expenditure to implement NCDMP will be less than $2 million (including contributions to BC Hydro to implement their communication and control system).

As the greatest proportion of cost is “core business” related to paper production and loss of margin on that business, it becomes apparent that NCDMP is an extremely attractive and logical solution to capacity issues on VI. Once the system operator has determined that the need for NCDMP is no longer relevant, the contract capacity will be adjusted or terminated and NorskeCanada will revert to optimal production and shed most of the cost of providing NCDMP. Even the “sunk” capital may have value for insurance to be able to re-contract DM in some future term, or as a resource to accommodate ongoing peak demand days as highlighted in the load curve (Figure 1).

In an effort to create a least-cost alternative with a risk-sharing component, NorskeCanada is prepared to offer a “ratchet” contracted capacity option for the NCDMP. Our proposal is to allow BC Hydro to contract a nominated capacity for a 3-year term, and allow dispatch of up to 130% of nominated capacity (capped at a maximum capacity of 140MW). For the remaining months of the contract, a ratchet would have been set at the actual requested DM capacity for which the incremental capacity will be deemed contracted at a price rate of 115% of base contract capacity. The design of this concept is to allow BC Hydro to contract the minimum capacity, and retain a 30% emergency margin, should it be required. The 115% allows for recovery of costs associated with not being fully prepared for the larger capacity reduction.

NCDMP has many inherent advantages when compared to a fixed SC generator with relatively high sunk capital cost and high energy production costs, especially in the flexibility in timing and capacity. Full comparisons of NCDMP, relative to other forms of generation capacity addition, are discussed in Section 3.e.

Of course, what functionally appears to be a variable capacity, variable term SC peaker plant, NCDMP does have some constraints that a true peaking plant would not. The most significant constraint is the total time that NCDMP can be utilized, versus a greater number of days per year that a GT could operate in a year. Other constraints are related to the number of times per year BC Hydro or BCTC can call to activate and to a minor degree the location of the response. These constraints should have limited impact on the value of NCDMP to meet VI’s requirements.

d. Proposed Basic Terms for NCDMP

As a reference for starting negotiations on NCDMP NorskeCanada proposes the following basic terms for consideration:

Contract Term:	3-year first term, 3-year rolling thereafter[14]
Contract Capacity:	30 to 140 MW in 10MW blocks. Contracted capacity to be set by BC Hydro on renewal.
Emergency Capacity Allotment:	Up to 130% of contracted capacity to a maximum of 140 MW
Normal Ramp to Contract Capacity:	3 minutes
Rapid Ramp to Contract Capacity:	3 seconds
Annual Demand Curtailment (Capacity) Charge:	$50,000 per MW per Year
High Load Hours Energy Charge:	Days are based on an annual cumulative basis. Energy will be charged as follows: 1 to 5 days $100/MWh 6 to 10 days $125/MWh 11 to 15 days $150/MWh 16 to 20 days $175/MWh 21 to 25 days $200/MWh 26 to 30 days $225/MWh
Low Load Hours Energy Charge:	If required by BC Hydro $225/MWh
Rapid Ramp Surcharge:	$500/MW per rapid ramp call
Emergency Capacity Surcharge:	15% of Annual Demand Curtailment (Capacity) Charge
Emergency Capacity Ratchet:	If Emergency Capacity is utilized at any point during a contract term then the contracted capacity is deemed to be raised to the new level and Annual Demand Curtailment (Capacity) Charge will be payable to NorskeCanada for the remaining months of the contract term including surcharge.
Escalation:	At CPI.
Definition of Year:	April 1 to March 31
Definition of Winter Period:	December 1st to March 31st.

[14] NorskeCanada is prepared to offer a one-year “trial term” provided agreement is reached on capital recovery and/or hybrid operation versus fully functional and automated.

Utilization Limit:	30 days per Year with a maximum of 26 days during the Winter Period and 4 days in the non-Winter Period.
Dispatch Limit:	7 calls per Winter Period and 2 calls per non-Winter Period in any Year.
Definition of High Load Hours (HLH):	0600 to 2200 (16 hours) daily. Allows BC Hydro to determine what days NCDMP are needed without restricting BC Hydro's ability to use this service on weekends or holidays if desired.
Definition of Low Load Hours (LLH):	All hours not defined as High Load Hours.
Contract Capacity Reduction:	At NorskeCanada's option, contract capacity may be reduced if the mills' ESA Contract Demand is reduced, with the reduction being available to BC Hydro. The Annual Demand Curtailment (Capacity) Charge will be reduced by the corresponding amount for the remaining months of the contract term.
Capacity Location: **(See section 6 for Crofton)**	Typically all from Elk Falls Mill in Campbell River, however, at NorskeCanada's discretion, a portion could be from Crofton or Port Alberni.

e. Comparison of NCDMP to other BC Hydro Portfolio Options

i. Vancouver Island Generation Project

The configuration of the Vancouver Island Generation Project (VIGP) is a 180 MW single "F" series gas turbine, coupled to a heat recovery steam generator, equipped with supplemental duct firing, producing steam to drive a nominal 100 MW steam turbine generator. This "one on one" configuration of CCGT plant was less popular than a "two on one" 500 MW F-class configuration that made up the most significant blocks of capacity additions during the power supply "bubble" of the late 1990's. Most owners preferred the economy of scale a 500 MW block offered, as well as the greatly enhanced reliability of twin GT trains such that single GT train failures lead to decreased capacity from 500 MW to 300 MW, rather than a total loss of generation. The F-class CCGT plants are generally achieving between 6800 to 7200 BTU/kWh HHV heat rates which in 1995 were considered as "state of the art" achievements. As many of the F-class plants are reaching their third overhaul cycle, the full cost of operation is becoming much better understood by most owners of such facilities.

If one assumes a $200 million US capital cost of a VIGP configured power station, given current exchange rates, this would translate to $270 million CAD capital cost. If one further assumes a 50/50 debt equity ratio, consistent with major Canadian mixed utility/IPP owners, and a conservative 12% IRR, one can derive a capacity charge component for this asset in the $85,000 CAD/MW range for a 25 year Power Purchase Agreement (PPA).

The energy charge associated with a plant in this configuration will be in the range of $65/MWh to $75/MWh depending on assumptions for variable O&M, long-term heat rate, degradation and fuel cost. In the Integrated Electricity Plan, BC Hydro has stated that the anticipated energy costs will be $73/MWh to as high as $93/MWh, with fuel cost volatility being the greatest uncertainty[15].

The type of CCGT plant embodied in VIGP proposal is designed to be base load operated and is not conducive to daily starts and stops, without incurring significantly higher O&M costs, as well as suffering reduced reliability. Reliability is diminished due to the common mode failures associated with a single GT train based plant configuration.

Finally, one must concede that F-class plants are on the cusp of economic obsolescence for new installations due to the commercialization of G and H class technologies, and especially in a regime of sustained elevated gas pricing. Financial analysts for many owners of similar assets are in a continual debate regarding the depreciation life of the asset. The debate, centred on the fact that the mechanical and functional life of the asset may be 25 to 35 years, however, if not locked into an EPA of that length of term, the economic life of the asset will be much shorter due to economic obsolescence through technological advancements. One must consider whether BC Hydro committing to a 25 year PPA is the correct solution to relatively short-term problems.

NCDMP, when compared to a VIGP type power station, offers a very short term and flexible solution. At $50,000/MW/Year of contracted capacity, it represents a 30-43% reduction in capacity charge. More importantly, however, there is no long-term commitment to technology that will become economically obsolete well before expiration of the PPA. NCDMP represents

[15] Part 6 IEP Para. 3.2

flexible capacity contracted only for as long as needed, with the ability to be shaped and moulded to nearly real time requirements, rather then becoming a long-term millstone around the necks of ratepayers.

Enhanced reliability is an additional advantage of NCDMP. In fact, one can contemplate that the reliability of NCDMP is approaching 100%, because the contracted capacity is demand shifting rather than supply production. Consider that the system is most likely to be at maximum load when NorskeCanada mills are operating at their peak capacity due to the sheer magnitude of the on-island load they represent. NCDMP is then fully available to dispatch capacity to the system by stopping certain pulping and paper production activities. NCDMP is based on "stopping" load rather than "starting" equipment and as such represents the most reliable capacity possible. Backup systems can be used to eliminate even the very slight chance of loss of the "stop" signal if desired.

ii. Simple Cycle Peak-Demand Station

A SC peaking plant could utilize multiple GE LM6000PC/PD or TM2500 (trailer mounted LM2500), Rolls-Royce RB211 or Pratt & Whitney FT8 gas turbines. For a temporary installation these could be trailer mounted and located near existing substations and a natural gas supply. Distillate fuel can also be accommodated in the GE and Pratt & Whitney units. These aeroderived gas turbines are capable of a rapid ramp to full load and can be cycled on and off on a daily basis. Based on a nominal 50 MW block of capacity, the Capacity Charge for such an installation would be in the range of $75,000 to $89,000 per MW per Year, depending on variables such as the number of units required, lease versus ownership, term of contract, residual value, permitting, and non-recoverable costs, such as civil works, interconnections (electrical and fuel), installation and reclamation labour.

At published heat rates of 9800 to 10,500 BTU/kWh (HHV[16]) one can expect at least a 10-15% increase in the actual heat rate achieved to account for degradation, fuel and electricity to start and synchronize the unit, electricity to "cool-out" and keep the unit rotating to prevent shaft sag after shutdown, which then translates to a market heat rate of approximately 11,000

[16] Higher Heating Value

BTU/kWh. To use the IEP stated energy charge expected from a base loaded VIGP type project with an expected economic heat rate of 6900 BTU/kWh (HHV), $73 to $93 per MWhr[17] becomes $116 to $148 per MWhr.

The above analysis, based on natural gas for peak generation up until F2008, raises serious concerns regarding gas supply. In Terasen Gas (Vancouver Island) Inc.'s application to BCUC for a CPCN for on-island LNG storage, it is categorically stated that the current supply system cannot accommodate the forecast demand for gas in calendar 2007 during the coldest days of the year, without LNG storage in service.[18] An SC plant's value to the electrical system during peak demand periods, implicitly the coldest days of the year, without LNG or capability to switch to distillate fuel would be limited. To incorporate alternative fuel ability as part of the plant design increases energy costs, capital cost, and non-recoverable costs.

The specific design of NCDMP is to solve a relatively short-term problem, having comparable operational characteristics to an SC peaking plant such as described above. The advantages of NCDMP over an SC peaking plant include low capital cost (either sunk or non-recoverable), lower capacity charge, similar energy charge, and a more rapid ramp to full capacity. Additionally, NCDMP does not depend on gas system upgrades to be truly effective in mitigating capacity shortfalls during periods of extreme cold.

The implementation of NCDMP is superior to any physical plant installation, including an SC peaker, and could be functional by November 2004. Unlike the SC peaker, NCDMP will allow BC Hydro to terminate the DM capacity at flexible points in the future.

f. Other Potential Benefits of NCDMP

i. Voltage Support and Inertial Stabilization

Although not part of the basic NCDMP, NorskeCanada would entertain discussion of other ancillary services that the mills could provide to the system, such as voltage support and power factor correction. Only minor changes to exciter systems and overall controls would be required to support such ancillary service provisions.

[17] Based on natural gas volatility – Part 6 IEP Para. 3.2
[18] Section 4 Demand Forecast p.7 and Appendix 9 p.93-101.

With the mechanical dynamics associated with Thermo Mechanical Pulping (TMP) equipment driven by large synchronous motors, running refiners in a spinning, but unloaded state may have a benefit to the system during frequency excursions. Simply by measuring the dynamic response of an unloaded refiner would provide the data for Powertech to analyze and update power system models to determine if benefit to the system is derived.

ii. N-2 Contingencies and Lower Mainland Support

As previously discussed, the sunk costs of approximately $2 million CAD could have a future benefit past the bridging of a capacity shortfall after the 230kV link is established to VI. Referring to Table 1 contained in Section 2.a. one can see that, although capacity is now satisfied during an N-1 event, that NCDMP would be a valuable resource to have available in dealing with a number of N-2 circumstances.

Also of interest to the system operator past F2008 may be the need to curtail on-island demand to support the lower mainland of BC. With the many uncertainties concerning load growth and the degree of success of conservation and efficiency efforts such as PowerSmart, having substantial DM under contract would allow for flexibility in the planning to meet the uncertainty.

4. Conclusion

After considering all of the options for meeting both short-term and long-term electrical capacity requirements of VI, NorskeCanada has come to the conclusion that it can play a significant roll in offering this Demand Management Proposal.

We agree that some on-island generation may be beneficial and economic. However, we are also of the opinion that VI will be best served, from both a reliability and future capacity perspective, by the proposed 230 kV link to the lower mainland and are therefore supportive of expenditures identified for that element of the BCTC Capital Plan. We believe that generation in the VICFT should only be purchased if economic, and that NCDMP be utilized to bridge the capacity and time from when the HVDC link is 0 rated until the 230 kV link can be put into service.

In this proposal, we have demonstrated that NCDMP is economically superior to other solutions, on an annual basis, with the added advantage of only a relatively short-term commitment. On a technical basis, NCDMP is superior in response time and reliability to all alternatives, with only minor considerations for duration of use and number of "starts" when compared to the alternatives.

We believe that NCDMP is a superior proposal for meeting the bridging needs of VI as it represents a variable capacity, variable term peak demand solution that is difficult to achieve without the higher costs of installation of physical equipment. Because most of the costs to provide NCDMP are the result of suboptimal pulp and paper production, they are readily shed sometime in the future by reverting to the optimal mode of production, leading to a win-win for both BC Hydro and all BC rate payers, including NorskeCanada.

5. Recommendations

As the ramifications of choosing to implement NCDMP, or not, are broad and intertwined with several other resource decisions for VI, it is our recommendation that negotiations with BC Hydro and BCTC move forward on an expedited basis so that the BC Utilities Commission has all relevant data when making key decisions.

From our perspective, NCDMP may have direct impact on, at least the following:

- **BCTC Capital Plan** – Currently before BCUC, with a ruling on the plan expected in September/October 2004. NCDMP is a tool to span the capacity and timing issues to permit an orderly in service date for new transmission and can be adjusted in capacity to suit the outcome of the 500 kV cable thermal studies. It also allows for VI "backbone" reinforcement decisions to be made based on the "final" solution.
- **BC Hydro – VI-CFT** – Bids closed Aug. 13, 2004 and the successful proponent(s) will be notified within 120 days (date to be announced by BC Hydro). Consideration of NCDMP is imperative, when making the evaluation of proposals obtained through this call to assemble the least cost and most reliable resource additions.
- **Terasen LNG Storage** – Terasen has made application for a CPCN for on-island LNG storage, anticipating CPCN approval in November 2004. This application makes assumptions regarding increased natural gas demand, due to a significant increase of on-island gas fired generation as a direct result of choices made in the VI-CFT.

NorskeCanada recommends that a trial period of one (or two) year(s) be implemented to allow testing of and to prove out NCDMP principles. This could be done at lower MW's, for less duration and with a narrow window of time, all of which would limit the costs. We believe that any cost for the physical installation for the test could also be substantially reduced. BC Hydro and BCTC may be able to use a temporary communications system for this testing, or use systems that are already in place today serving other functions. Cost associated with work including development for test would be nearly fully recovered with the full NCDMP implementation.

6. Crofton Option

The above was based primarily on load curtailment being at Elk Falls Mill in Campbell River. This location has a number of pulp and paper advantages. It is also possible to offer a similar package for Crofton but some key criteria will be modified.

Crofton does not have the "catch up" capacity that Elk Falls has and makes paper from a different pulp mixture so each tonne of product contains less high energy pulp. The lost tonnage at Crofton would impact our commitment for production of paper with recycled pulp content.

It is anticipated that shifting of production will not be possible for more than 5 or 6 years so this service at Crofton may be restricted in its contract duration.

A mixture of Crofton and Elk Falls curtailments is possible but would need to be developed to suit BC Hydro's and or BCTC's criteria such as whether there would be simultaneous requirement and ratios of curtailment MW's between the mills. NorskeCanada would entertain discussing these criteria at BC Hydro's or BCTC's request.

The following is based on a Crofton only NCDMP.

In section 1. the table for Crofton is:

Item	NCDMP
Implementation Schedule	Nov. 2004
Capital Cost (millions $CAD)	See Explanatory Notes[19]
Capacity (MW)	20-75 MW
Normal Utilization	0-20 days/yr
Maximum Utilization	20 days/yr
Capacity Charge ($/MW/yr)	60,000
Energy Charge ($/MWh)	187[20]
Contracted term	Rolling 3 yr
Fuel Used	None
Incremental Greenhouse Gas Emissions	None
Incremental NOx Emissions	None
Incremental CO Emissions	None
Rapid Response Time to Load	10 sec.
Normal Response Time to Load	10 min.

With a Crofton only option, Table 1 in section 2. would be modified to reflect the limitation of having only 70 MW's of NCDMP available.

Section 3.a. discusses load shifting capability which will be reduced with Crofton NCDMP. Load shifting is still a useful tool to lessen full curtailment impacts but is not as effective as at Elk Falls.

[19] Although actual capital cost is relatively low, NorskeCanada will incur annual core business related cost due to suboptimal operation of mills and specific machinery, reallocation of products produced at each mill, shipping and logistics, etc., which are intended to be covered by the contract capacity charge, and which are necessary to enable NorskeCanada to offer demand management services.

[20] Based on 10 days utilizing HLH only.

Section 3.d. will reflect:

Contract Term:	3-year first term, 3-year rolling thereafter up to 5 or 6 years from acceptance.[21]
Contract Capacity:	20 to 75 MW in 10MW blocks. Contracted capacity to be set by BC Hydro on renewal.
Emergency Capacity Allotment:	Up to 130% of contracted capacity to a maximum of 70 MW
Normal Ramp to Contract Capacity:	10 minutes
Rapid Ramp to Contract Capacity:	10 seconds
Annual Demand Curtailment (Capacity) Charge:	$60,000 per MW per Year
High Load Hours Energy Charge:	Days are based on an annual cumulative basis. Energy will be charged as follows: 1 to 5 days $150/MWh 6 to 10 days $225/MWh 10 to 20 days $300/MWh
Low Load Hours Energy Charge:	If required by BC Hydro $300/MWh
Rapid Ramp Surcharge:	$500/MW per rapid ramp call.
Emergency Capacity Surcharge:	15% of Annual Demand Curtailment (Capacity) Charge
Emergency Capacity Ratchet:	If Emergency Capacity is utilized at any point during a contract term then the contracted capacity is deemed to be raised to the new level and Annual Demand Curtailment (Capacity) Charge will be payable to NorskeCanada for the remaining months of the contract term including surcharge.
Escalation:	At CPI.
Definition of Year:	April 1 to March 31
Definition of Winter Period:	December 1st to March 31st.
Utilization Limit:	20 days per Year with a maximum of 20 days during the Winter Period and 2 days in non-Winter Period.
Dispatch Limit:	7 calls per Winter Period and 2 calls per non-Winter Period in any Year.
Definition of High Load Hours (HLH):	0600 to 2200 (16 hours) daily. Allows BC Hydro to determine what days NCDMP are needed without restricting BC Hydro's ability to use this service on weekends or holidays if desired.
Definition of Low Load Hours (LLH):	All hours not defined as High Load Hours.
Contract Capacity Reduction:	At NorskeCanada's option, contract capacity may be reduced if Crofton's ESA Contract Demand is reduced, with the reduction being available to BC Hydro. The Annual Demand Curtailment (Capacity) Charge will be reduced by the corresponding amount for the remaining months of the contract term.
Capacity Location:	All at Crofton.

[21] NorskeCanada is prepared to offer a one-year "trial term" provided agreement is reached on capital recovery and/or hybrid operation versus fully functional and automated.