NSURB NSPI P871
EXHIBIT# P-2

Nova Scotia Utility and Review Board

IN THE MATTER OF The *Public Utilities Act*, R.S.N.S., 1989, c. 380, as amended

- and -

IN THE MATTER OF an Application by Nova Scotia Power Incorporated for approval of a Load Retention Rate

Responses to Information Requests:

NSUARB - Questions 1 to 33
Irving Oil - Questions 1 to 7
Cape Breton Regional Municipality - Questions 1 to 17

DATED: December 23, 1999

Responses to UARB

Questions 1 - 33

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IN THE MATTER OF: The *Public Utilities Act*, R.S.N.S., 1989, c.380 as amended

IN THE MATTER OF: An Application by Nova Scotia Power Incorporated for approval of a Load Retention Rate

RESPONSE TO INFORMATION REQUEST

TO: **NSUARB**

FROM: **NSPI**

Question IR-1: **The existing GRLF Rate appears to be promoting self-generation while the proposed Load Retention Rate is designed to discourage self-generation and as such the two rates could be considered in conflict with each other. Please comment upon the future role of the present GRLF Rate.**

Response IR-1: NSPI does not see a conflict between these two rates and does not perceive either rate as encouraging or discouraging self generation that is in the interest of all of its customers. The GRLF rate provides a service to the customers who currently have their own generation, and in the provision of that service, it benefits other electric customers. The load retention rate will not preclude self generation unless it is in the best interest of all customers to do so. Where this is not the case, the self generation will proceed and will have the option of being supported by the GRLF rate, again to the benefit of all customers.

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TO: **NSUARB**

FROM: **NSPI**

Question IR-2: **The proposed load retention rate appears to be discouraging customers from using environmentally friendly natural gas in favour of energy derived predominantly from coal fired generation. Please comment.**

Response IR-2: NSPI is committed to meeting all environmental targets and regulations as established for it by government legislation, guidelines or permits. Natural gas is more environmentally friendly than coal and NSPI expects natural gas to play a significant role in the meeting of Nova Scotia's future electricity needs. However, the premature replacement of existing resources with natural gas would unnecessarily increase the cost of electricity to all Nova Scotians.

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FROM: **NSPI**

Question IR-3: **Given the possibility of increased amounts of imported coal being used for generation by NSPI vs. local coal, please discuss how the proposed load retention rate would enable NSPI to follow the expressed intent of the Public Utilities Act R.S.N.S., c.380, 48 (1), regarding the maximization of indigenous Nova Scotia Resources.**

Response IR-3: Currently NSPI generates the majority of its energy from coal and is in the process of converting its oil fired capacity to also use natural gas. It is expected that the cost of energy from coal will continue to be less that the cost of energy from natural gas or oil.

The section of the Public Utilities Act referred to allows NSPI to take steps to maximize the use of indigenous Nova Scotia resources but does not obligate it to do so. NSPI expects natural gas to play a significant role in the supply of electricity within Nova Scotia in the future, but believes that the early replacement of existing resources with natural gas would unnecessarily increase the cost of electricity to all Nova Scotians.

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FROM: **NSPI**

Question IR-4: **The justification of the Tuft's Cove conversion to dual-fuel capability was partly based on the displacement of new generation dictated by environmental considerations. i.e. emissions caps. In determining the annual benefits to NSPI's customers arising from load retention, please confirm that the planning model will take into account the latest available information regarding emissions caps and that the program will schedule the addition of new plant based on both the reliability criteria or emissions criteria, whichever constraint is encountered first.**

Response IR-4: NSPI confirms that this is the case.

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FROM: **NSPI**

Question IR-5: **In Availability Clause 1 of NSPI's submission to this Hearing, it is stated that the load retention rate must not be less than necessary to make the customer in question indifferent with respect to alternate supply versus continuing to purchase the electric power and energy from NSPI. An alternative energy services provider might address this practice if he or she were to perceive the proposed price level as being in contradiction of the Canadian Competition Act Section 50. (1) as follows:**

"Illegal Trade Practices

50. (1) Everyone engaged in a business who

(a) is a party or privy to, or assists in, any sale that discriminates to his knowledge, directly or indirectly, against competitors of a purchaser of articles from him in that any discount, rebate, allowance, price concession or other advantage is granted to the purchaser over and above any discount, rebate, allowance, price concession or other advantage that, at the time the articles are sold to the purchaser, is available to the competitors in respect of a sale of articles of like quality and quantity,

(b) engages in a policy of selling products in any area of Canada at prices lower than those exacted by him elsewhere in Canada, having the effect or tendency of substantially lessening competition or eliminating a competitor in that part of Canada, or designed to have that effect, or

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FROM: **NSPI**

Question IR-5: **(c) engages in a policy of selling products at prices unreasonably low, having the effect or tendency of substantially lessening competition or eliminating a competitor, or designed to have that effect,**

is guilty of an indictable offence and liable to imprisonment for a term not exceeding two years."

Please provide assurance that the price developed by the load retention rate would not be anti-competitive vis a vis the energy services industry.

Response IR-5: In NSPI's submission, the load retention rate is consistent with the purpose of the *Competition Act* which states:

> "The purpose of this Act is to maintain and encourage competition in Canada in order to promote the efficiency and adaptability of the Canadian economy, in order to expand opportunities for Canadian participation in world markets while at the same time recognizing the role of foreign competition in Canada, in order to ensure that small and medium sized enterprises have an equitable opportunity to participate in the Canadian economy and in order to provide consumers with competitive prices and product choices."

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TO: **NSUARB**

FROM: **NSPI**

Response IR-5: Far from being an offense under the Competition Act, NSPI's proposed rate represents exactly the sort of competitive conduct that the Act is intended to promote. The proposed load retention rate is intended to make available to existing customers a rate which makes the customer in question indifferent with respect to alternate energy supply. This is an inherently competitive mechanism. Such an approach to pricing is not the type of economic activity considered to be an illegal trade practice under Section 50 of the *Competition Act*.

The proposed load retention rate does not discriminate, directly or indirectly, against competitors of a customer.

Discriminatory pricing under Section 50(1)(a) addresses harm to competition which occurs as a result of a disfavoured purchaser being placed at a competitive disadvantage in relation to other purchasers of the product or service. It does not deal with a supplier offering different prices to different customers based on their specific circumstances. The Availability criteria makes no distinction about what particular market an energy consumer may be in or the nature or competitiveness of that customer. The only differentiating factor under Availability is whether the customer has an alternate supply of energy.

The price discrimination provision deals with the practice of a seller granting price concessions to one purchaser, which are not available to competing purchasers in respect of a sale of articles of like quality and quantity. It is not concerned with competition between suppliers, but rather with the competitiveness of the purchaser. Sellers are free to charge different prices and offer different concessions in their dealings with customers.

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TO: **NSUARB**

FROM: **NSPI**

Response IR-5: The differentiating factor is whether a customer has the facilities to receive alternate energy supply, which is not discriminatory from a pricing perspective. The customer decision to invest in alternate supply is not within NSPI's control; it is a result of the customer's own entrepreneurship, abilities or proximity to alternate supply. Those circumstances are characteristics of the purchaser's own competitive environment. The proposed rate does not alter or affect the decision to receive alternate supply, it merely responds to it, which is not a type of trade practice which the *Competition Act* is concerned with.

The pricing and other terms and conditions offered under the proposed load retention rate are intended to be determined on a customer by customer basis and submitted to the UARB for approval. As such, the implementation of the availability clause represents conduct that is regulated to protect the public interest and therefore exempt commercial behavior under the "regulated conduct" jurisprudence, which has developed in the context of federal competition law.

Section 50(1)(b) deals with geographic price discrimination, which is a form of regional predatory pricing based on where the price is available in any area of Canada. We submit that there should be no concern here in that regard because the proposed rate is not based on geography. Furthermore, the proposed rate would not, in our submission, have the effect or tendency of substantially lessening competition or eliminating a competitor in any part of Canada or be designed to have that effect. As indicated above, prices, terms and conditions offered under the rate will be submitted to the UARB for approval.

Section 50(1)(c) contains a general prohibition against predatory pricing and specifically refers to unreasonably low prices.

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TO: **NSUARB**

FROM: **NSPI**

Response IR-5: One important factor in assessing predatory pricing is a comparison between the price and the cost of the product sold. The proposed rate is not below costs; it will cover marginal costs and contribute to fixed costs. NSPI does not have a policy or intend to offer prices that are below cost so as to eliminate competitors or deter market entrants. Rather, the express intention is to price in such a way so that it is better for other electric customers to retain the particular purchaser's load than losing the load in question. Accordingly, the pricing mechanism is reasonable.

The intent is described in Availability clause 1 that the customer should be indifferent with respect to what supply it selects, based on price. The other two conditions must also exist, namely that the alternate supply is both technically and economically feasible and retaining the customer's load, at the load retention rate, has a beneficial effect on other NSPI customers. Accordingly, this is a form of incremental pricing which is economically rational. It is not unreasonably low and does not create anti-competitive effects. Finally, prices, terms and conditions offered under the rate will be submitted to the UARB for approval.

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TO: **NSUARB**

FROM: **NSPI**

Question IR-6: **Section 48 (3) of the Public Utilities Act R.S.N.S., c.380, states that "Where Nova Scotia Power Incorporated applies to the Board to increase its capacity to produce power, the Board shall consider, amongst other things, the ability of private producers to supply the company a portion of the increased capacity." Please discuss whether there is a contradiction between the intent of this clause and that of the proposed Load Retention Rate.**

Response IR-6: NSPI does not believe there is any contradiction between the intent of this clause and that of the proposed Load Retention rate. When new generating capacity is required, NSPI will explore all options, including having parties other than NSPI supply that capacity. The load retention rate is designed to discourage the premature addition of new generation, but subject to Availability Clause (1), does not preclude it.

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RESPONSE TO INFORMATION REQUEST

TO: **NSUARB**

FROM: **NSPI**

Question IR-7: **Please provide a table showing latest capacity available to the NSPI system after station service, the forecast of NSPI system load requirements, reserve capacity and percent reserve, for the period 1999 - 2019.**

Response IR-7: For the period 1999 - 2019, Table UARB-IR-7 shows the latest capacity available to the NSPI system after station service, the forecast of NSPI load requirements, reserve capacity and percent reserve.

(NOTE: See also UARB-IR-21)

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RESPONSE TO INFORMATION REQUEST

TO: **NSUARB**

FROM: **NSPI**

Table UARB-IR-7

Year	NSPI Installed Capacity	NSPI System Load	NSPI Interruptible	NSPI Net Firm Load	Reserve Capacity	Reserve %
1999	2212	2017	387	1630	582	35.71%
2000	2212	2008	393	1615	597	36.97%
2001	2212	2032	398	1634	578	35.37%
2002	2212	2050	402	1648	564	34.22%
2003	2212	2061	407	1654	558	33.74%
2004	2212	2058	411	1647	565	34.30%
2005	2212	2056	415	1641	571	34.80%
2006	2212	2054	420	1634	578	35.37%
2007	2212	2056	424	1632	580	35.54%
2008	2212	2062	432	1630	582	35.71%
2009	2212	2071	439	1632	580	35.54%
2010	2212	2083	447	1636	576	35.21%
2011	2212	2101	454	1647	565	34.30%
2012	2212	2123	462	1661	551	33.17%
2013	2212	2149	470	1679	533	31.75%
2014	2212	2178	477	1701	511	30.04%
2015	2212	2209	485	1724	488	28.31%
2016	2212	2244	492	1752	460	26.26%
2017	2212	2281	500	1781	431	24.20%
2018	2212	2322	508	1814	398	21.94%
2019	2212	2365	515	1850	362	19.57%

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RESPONSE TO INFORMATION REQUEST

TO: **NSUARB**

FROM: **NSPI**

Question IR-8: **In Attachment A, Paragraph (2) it is stated that NSPI will conduct an initial screening to determine whether the implementation of the procedures is warranted. Please elaborate on the factors to be considered in the initial screening.**

Response IR-8: This will be a high level screen designed to ensure that the customer has evaluated the alternate supply option at a level of detail which warrants more comprehensive analysis by both NSPI and the customer. The principal factors to be considered include:

- The level of engineering done to support capital cost estimates.
- Plans for the acquisition of fuel.
- The size of unit proposed vis a vis customer electricity and (where appropriate) steam needs.
- The customer's preliminary economic analysis of the alternate supply option versus continued purchases from NSPI.

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TO: **NSUARB**

FROM: **NSPI**

Question IR-9: **In Attachment A, Paragraph (6) it is stated that none of the data or analysis used in the implementation of these procedures or the associated results shall be publicly disclosed. In Table A of Mr. Whalen's evidence it is noted that a number of utilities are shown as having load retention rates whose contracts were not disclosed. Did NSPI investigate whether the regulatory hearing process leading to approval of these contracts was based on confidentiality of the data?**

Response IR-9: Yes. As shown in Table A, the process is generally a closed process and the contract terms are not publicly disclosed.

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TO: **NSUARB**

FROM: **NSPI**

Question IR-10: **The Board's "Rules of Practice and Procedure Respecting Regulatory Proceedings" address the issue of confidentiality in Section 7, Paragraphs (1) through (11). Please discuss any conflicts that NSPI might observe between this document and the proposed load retention rate, insofar as the hearing process is concerned.**

Response IR-10: As noted in Section 7.1, Rule 7 relates to documents filed in respect of a "proceeding". The Rule is designed to provide for a confidential filing within the setting of a public hearing.

Those rules do not restrict the Board, as master of its own procedure from approving the confidential process for the implementation phase of the load retention rate. For the reasons cited in the evidence this information must be confidential.

Notwithstanding the foregoing the provisions of Section 4(3) of the Rules provide the Board with the ability to amend, vary or supplement with or without hearing the Rules if the circumstances of the proceeding require or if it's in the public interest. Clearly if the Board sees merit in the requested process it has the legal authority to implement it.

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TO: **NSUARB**

FROM: **NSPI**

Question IR-11: **What term would be envisaged for a Load Retention Rate contract and what renewal process would be followed at the end of the contract term?**

Response IR-11: NSPI believes this will be determined from the implementation process with the customer. For example, there may be cases where a customer's option to build generation now is not in the best interest of all customers. However, this may change when new generating capacity is required in the province. A term reflecting these circumstances may be appropriate.

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TO: **NSUARB**

FROM: **NSPI**

Question IR-12: **On page 2, lines 13-15, Mr. Huskilson states that NSPI has prepared some preliminary studies:**

a) Please provide copies of all such studies along with all of the data, calculations and supporting work papers.

b) Please provide all of the comments made by or/on behalf of NSPI on the preliminary studies and analyses provided above.

c) Please provide all of the comments received by others on the preliminary studies and analyses provided above.

Response IR-12: The reference in Mr. Huskilson's testimony is to studies that we understand customers to have completed. Based on these conversations with customers and our general knowledge of the options being considered, we believe that there is potential for some customers to supply their own needs.

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TO: **NSUARB**

FROM: **NSPI**

Question IR-13: **Page 2, lines 16-17**

a) Please provide copies of all of the reports, studies and analyses related to the various strategies considered by NSPI to face the potential competition to be posed by the availability of gas in the NSPI's service territory.

b) Please provide copies of all of the written comments made by or/on behalf of NSPI related to the potential competition from natural gas. These comments should include, at least, the following:

i) Internal comments
ii) Comments to NSPI's shareholders
iii) Comments to the financial analysts

c) Did the NSPI consider providing discounts in exchange for long term contracts?

i) If the response is yes, please provide the details
ii) If the response is no, please explain the reasons for not doing so.

Response IR-13: a) The strategy referred to in Lines 16-17 is NSPI's strategy with respect to customers potentially opting to choose an alternate supply of electric energy. NSPI believes that a load retention rate offered on the fundamental principle we are proposing is the best strategy to address that issue.

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TO: **NSUARB**

FROM: **NSPI**

Response IR-13:

NSPI's broader strategy to address competition from natural gas is to manage costs, maintain rate stability, improve our customer service, and develop new products and services that add value for the customer and increase their loyalty to NSPI.

With respect to managing costs and maintaining rate stability, since NSPI was privatized in 1992, rates have increased only 4%, compared to the CPI which has increased 10%. NSPI's last rate increase was in March 1996, and no increase is expected in 2000.

With respect to new products and services, NSPI now offers products such as time of use rates combined with electric thermal storage units, heat pumps and energy use profiles and analysis.

With respect to improving customer service, NSPI has in the last two years segmented the market and established account executives to deal with businesses and industries within those segments. More recently, NSPI has established a Customer Needs Team to work with customers to identify their needs and expectations and develop appropriate metrics around these to allow NSPI's performance to be measured on an ongoing basis. NSPI's analysis of this is not yet complete, but some initiatives such as the outage management improvements are proceeding, based on what customers have already told us.

NSPI believes that future growth will be based on strengthening relationships with customers. This strategy requires fewer studies and analysis and more interaction and feedback from customers.

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TO: **NSUARB**

FROM: **NSPI**

Response IR-13:

b) We have communicated to shareholders and financial analysts in a general way that we expect competition from natural gas. However, because NSPI's strategy for the future is not focused particularly on competition from natural gas, any communication of it has not been couched in terms of direct competition from natural gas.

c) NSPI believes that the load retention rate is the best approach to addressing this issue. In its design, it will address both price and term, plus any other appropriate conditions.

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TO: **NSUARB**

FROM: **NSPI**

Question IR-14: **Page 2, lines 17-18**

a) Please provide the amounts of the exit fee(s) considered, if any.

b) Please provide the approach, data, calculations and work papers used in the development of the exit fee(s) provided above.

c) Please list all of the ancillary services which NSPI believes may be needed by the customers with self-generation.

d) In case a customer proceeds to install its own generation, would NSPI provide the free ancillary services listed above? If yes, please explain the reasons for doing so.

e) Provide the costs and/or rates developed for the ancillary services listed above. If no such data is developed, please explain the reasons for not doing so.

Response IR-14:

a) No specific exit fee was calculated.

b) N/A.

c) The primary ancillary service that would likely be required would be backup service to cover periods when the customer's generation might not be available. However, the interconnection with the NSPI system could also provide voltage and frequency control.

d) None of the ancillary services would be free.

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FROM: **NSPI**

Response IR-14: e) NSPI proposes to provide the ancillary services required under its Generation Replacement and Load Following rate.

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TO: **NSUARB**

FROM: **NSPI**

Question IR-15: **Page 5, lines 5 - 6.**

Please explain the reasons for NSPI seeking load retention rates in view of its Flexible Pricing provision.

Response IR-15 Lines 5 - 6 are part of a quote from John Chamberlain during the 1996 rate case in which he suggested Flexible Pricing as an option. NSPI does not, however, have any such provision.

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TO: **NSUARB**

FROM: **NSPI**

Question IR-16: **Page 2, lines 15-16**

Please provide copies of all of the analyses conducted related to the cost/benefit of load retention rates to NSPI's other customers.

Response IR-16 As stated in Availability Clause (1), the load retention rate will be granted only in circumstances where it can be shown that:

- Retaining the customer's load, at the price offered by this rate, is better for other electric customers than losing the customer load in question.

This analysis can only occur during the implementation phase.

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RESPONSE TO INFORMATION REQUEST

TO: **NSUARB**

FROM: **NSPI**

Question IR-17: Page 8, lines 2-3

a) **Please provide the average number of customers and annual sales and revenues from large industrial customers with and without interruptible and industrial expansion customers for the years 1995-1999.**

b) **Please provide the average number of customers, and annual sales and revenues from large commercial customers, for the years 1995-1999.**

c) **Please provide the average number of customers, and annual sales and revenues from the customers with a minimum load of 2,000 KVA, or 1,800 KW for the years 1995-1999.**

Response IR-17 The attached Table UARB-IR-17 provides the information requested.

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RESPONSE TO INFORMATION REQUEST

TO: **NSUARB**

FROM: **NSPI**

Table UARB-IR-17

	Sales in GW.h				
	1995	**1996**	**1997**	**1998**	**1999**
Large Industrial - Firm Classes	806.1	838.7	836.1	850.5	754.1
Large Industrial - Interruptible Classes including Industrial Expansion	1,486.8	1,384.7	1,440.7	1,965.9	2,439.0
Total Large Industrial	2,292.9	2,223.4	2,276.8	2,816.4	3,193.1
Large Commercial	342.2	353.1	358.9	336.8	341.0
Total > 2 MVA / 1.8 MW	2,635.1	2,576.5	2,635.7	3,153.2	3,534.1

	Revenue in $000s				
	1995	**1996**	**1997**	**1998**	**1999**
Large Industrial - Firm Classes	$37,965	$38,550	$37,797	$39,477	$35,393
Large Industrial - Interruptible Classes including Industrial Expansion	$70,862	$68,187	$69,942	$89,977	$112,317
Total Large Industrial	$108,827	$106,737	$107,739	$129,454	$147,710
Large Commercial	$22,403	$23,434	$23,521	$21,809	$22,023
Total > 2 MVA / 1.8 MW	$131,230	$130,171	$131,260	$151,263	$169,733

	Customer Count				
	1995	**1996**	**1997**	**1998**	**1999**
Large Industrial - Firm Classes	4	4	4	6	5
Large Industrial - Interruptible Classes including Industrial Expansion	34	37	41	41	41
Total Large Industrial	38	41	45	47	46
Large Commercial	15	15	15	15	15
Total > 2 MVA / 1.8 MW	53	56	60	62	61

Includes forecast figures for December 1999; Does not include < 6 customers from other rate classes who are close to 2 MVA / 1.8 MW cut-off

DATE FILED: December 23, 1999

NOVA SCOTIA UTILITY AND REVIEW BOARD

IN THE MATTER OF: The *Public Utilities Act*, R.S.N.S., 1989, c.380 as amended

IN THE MATTER OF: An Application by Nova Scotia Power Incorporated for approval of a Load Retention Rate

RESPONSE TO INFORMATION REQUEST

TO: **NSUARB**

FROM: **NSPI**

Question IR-18 Page 8, line 6

Please provide the development of the fuel and variable expenses of 2.9 cents/KWh.

Response IR-18: The 2.9 cents per kWh referred to on line 6, page 8 of M. E. Whalen's evidence is an assumption used for illustrative purposes. It is approximately the average incremental cost of generation based on Proscreen analysis, used to calculate the load following component of the GRLF rate.

The expected average cost of thermal energy in 2000 (fuel + variable O & M) is estimated to be 2.7 cents per kWh. The fuel cost associated with any specific portion of the total thermal load would be between 2.7 and 2.9 cents.

DATE FILED: December 23, 1999

NOVA SCOTIA UTILITY AND REVIEW BOARD

IN THE MATTER OF: The *Public Utilities Act*, R.S.N.S., 1989, c.380 as amended

IN THE MATTER OF: An Application by Nova Scotia Power Incorporated for approval of a Load Retention Rate

RESPONSE TO INFORMATION REQUEST

TO: **NSUARB**

FROM: **NSPI**

Question IR-19: **Page 9, lines 4-5**

a) Please provide all of the documents related to the survey referenced herein.

b) Please provide all of the analysis of the data received as a result of NSPI's survey.

Response IR-19: a) Supporting documentation is attached for each utility shown in Table A of Mr. Whalen's evidence.

b) The information collected was simply summarized and reported as Table A of NSPI's submission.

DATE FILED: December 23, 1999

Allegheny Power

THE POTOMAC EDISON COMPANY

Electric P. S. C. Md. No. 53
First Revision of
Original Page No. 23
Canceling
Original Page No. 23

ALTERNATIVE GENERATION SCHEDULE
SCHEDULE "AGS"

AVAILABILITY

Available for the sale of electricity to customers, including small power producers and cogenerators which are qualifying facilities as defined in the Public Utility Regulatory Policies Act of 1978. To qualify for this schedule, customer, at the site of customer's service under this schedule, (such site located in the Company's Maryland service territory) must operate or utilize electric service from active electrical generation facilities not owned by the Company ("Alternative Generation Facilities"). Electricity sold under this schedule may not be resold; nor may it be used to operate the auxiliary loads of the alternative generation facilities while those facilities are generating electricity for sale to a subsidiary of the Allegheny Power System, Inc., except during periods of emergency on the alternative generation station service facilities and with the approval of the Company. A recording demand meter must be installed on all connections receiving service under this schedule. An Electric Service agreement shall be executed.

DETERMINATION OF DEMAND

Demand or kW demand noted in this schedule shall be the kW demand integrated over the demand interval. Demand interval shall be of the same duration specified in the rate schedule under which standard service is provided the customer. If standard service is not provided by the Company, the demand interval shall be 30 minutes.

TYPES OF SUPPLY

Types of power supply available are Supplementary, Maintenance (Firm or Interruptible), and Standby (Firm or Interruptible). For the purposes of this schedule, "normal alternative generation" for the current billing period shall be determined as follows:

(1) The most recent three billing periods each of which contains at least one demand interval period during which alternative generation occurred and no Standby or Maintenance Power was used will be selected and the total number of such demand intervals which occur in those periods shall be identified;

(2) The net kWh of alternative generation for all the intervals identified in (1) shall be totaled;

(3) The net kWh totaled in (2) shall be divided by the quantity (total number of intervals ÷ intervals per hour) to obtain the average kW of normal alternative generation.

ISSUED BY MICHAEL P. MORRELL, VICE PRESIDENT

Issued November 25, 1998

To become effective on
all service rendered on
or after November 18, 1998.

Accepted for Filing at the Public Service Commission's Administrative Meeting of November 18, 1998.

ALTERNATIVE GENERATION SCHEDULE
SCHEDULE "AGS" (Continued)

TYPES OF SUPPLY (continued)

SUPPLEMENTARY POWER is power that is used by the customer in addition to that normally produced by the alternative generation facilities. Supplementary Power is available to the customer under applicable existing standard rate schedules with the billing units determined as described herein. All power provided to the customer by the Company shall be deemed Supplementary Power unless the Company determines that it is Maintenance Power or Standby Power as described below.

FIRM OR INTERRUPTIBLE MAINTENANCE POWER is power, which is used by the customer and replaces the alternative generation during periods of scheduled maintenance of the alternative generation facilities. Maintenance Power is subject to the following constraints:

(1) In each calendar year, Firm Maintenance Power may be made available not more than 56 days during the periods from March 1 to May 31, inclusive or from October 1 to November 30, inclusive.

(2) Availability of Firm Maintenance Power shall be determined by the Company upon the customer's written request at least 30 days but not more than 120 days in advance of the date the customer wishes to begin receiving such power. The Company shall notify the customer whether Firm Maintenance Power will be available during the period requested, and if not, when Firm Maintenance Power will be available.

(3) If the customer is informed by the Company that Firm Maintenance Power will not be available as requested, the customer may elect to take Interruptible Maintenance Power for the period for which Firm Maintenance Power will not be available, provided that the customer gives the Company seven days advance written notice thereof. In no event, however, may the number of days upon which Firm or Interruptible Maintenance Power is taken exceed a total of 56 in a calendar year.

(4) If the customer ceases use of Maintenance Power before the end of the scheduled period, the customer must notify the Company by telephone and send or deliver a notice in writing to the Company no later than one business day after the customer ceases such use.

(5) All requests for Firm Maintenance Power and notices of Interruptible Maintenance Power must specify the kilowatt capacity required, as well as the beginning and the end of the Maintenance Power period.

ALTERNATIVE GENERATION SCHEDULE
SCHEDULE "AGS" (Continued)

TYPES OF SUPPLY (continued)

(6) The Company shall not supply Maintenance Power in excess of the normal alternative generation for the billing period.

(7) During any period that Firm Maintenance Power is made available, the Maintenance Power Agreement Capacity shall be the capacity of Firm Maintenance Power expressed in kilowatts that the Company agreed to deliver to the customer during that period.

(8) During any period that Interruptible Maintenance Power is used by the customer, the Maintenance Power Agreement Capacity shall be the capacity expressed in kilowatts of Interruptible Maintenance Power specified in the customer's written notice of Interruptible Maintenance Power use.

FIRM OR INTERRUPTIBLE STANDBY POWER is power made available by the Company for the customer's use and which replaces the alternative generation capacity utilized by the customer during an unscheduled outage of the alternative generation facilities. It will be available under the following conditions:

(1) The customer must contract in advance for either Firm or Interruptible Standby Power, but not both, and an initial Standby Power Agreement Capacity must be specified by the customer and approved by the Company before delivery of Standby Power.

(2) Interruptible Standby Power will be available only to customers who contract for at least 5,000 kW thereof.

(3) Standby Power will not be provided for more than 20% of the hours in any twelve-month period. After those hours of Standby Power have been exhausted, any power supplied, unless determined by the Company to be Maintenance Power, will be billed to the customer as Supplementary Power. If the customer has not previously contracted for Supplementary Power, such Supplementary Power shall be billed as a temporary service under General Service Rate Schedule "G".

(4) The customer shall be deemed to have used Standby Power for any demand interval during which: a) Maintenance Power was scheduled; and b) the demand created exceeds the sum of the then effective Maintenance Power Agreement Capacity and kilowatt portion of the customer's Supplementary Power Demand.

ALTERNATIVE GENERATION SCHEDULE
SCHEDULE "AGS" (Continued)

TYPES OF SUPPLY (continued)

(5) The three-month period beginning on the date the alternative generation facility first begins commercial operation or operates in parallel with the Company's facilities shall not be used in the determination of the number of Standby Power hours used by the customer.

(6) The customer must notify the Company by telephone and send or deliver a follow-up notice in writing within one business day of the beginning of an unscheduled outage of the customer's facilities requiring the use of Standby Power. Such notice shall specify the time the outage began, the cause of the outage, and its estimated duration. At the end of such an unscheduled outage, the customer must notify the Company by telephone and send or deliver a notice in writing to the Company within one business day of the end of the outage. Such notice shall include the final determination of the outage cause and duration. The Company may require verification of the cause of the unscheduled outage.

(7) If a Standby Power Billing Demand is established which is greater than the Standby Power Agreement Capacity, the Standby Power Agreement Capacity shall automatically be increased to that greater value.

(8) The Company shall not provide Standby Power in excess of the normal alternative generation for the billing period.

INTERRUPTIBLE POWER PROVISIONS

Obligations

Interruptible Maintenance or Interruptible Standby Power shall be interrupted when, in the sole judgment of the Company, any production, transmission, or distribution limitations exist. During an interruption period, the customer's total load must be reduced to no more than the sum of the firm capacity, if any, specified in the Electric Service Agreement under which Supplementary Power is provided plus the Firm Standby Power Agreement Capacity, if the customer is using Firm Standby Power at the time, plus the Firm Maintenance Power Agreement Capacity, if any, which may be in effect at the time. The interruption period shall begin with the second full demand interval after commencement of an interruption by the Company and continue through the demand interval immediately preceding termination of that interruption.

ALTERNATIVE GENERATION SCHEDULE
SCHEDULE "AGS" (Continued)

Penalty

The maximum by which the customer's kilowatt demands exceed the sum of the customer's firm capacities (i.e., the sum of the customer's Supplementary, Maintenance, and Standby Firm capacities as applicable) during each interruption period shall be subject to a penalty charge. Only one such penalty shall be assessed per interruption period. The first time that the customer is notified by the Company to interrupt service and the customer fails to reduce load to not more than the sum of its firm capacities, a penalty of $10 per kilowatt shall be applied to those kilowatts in excess of firm capacities. Upon the second occurrence of such a failure to interrupt, a penalty of $10 per kilowatt calculated as set forth above shall be applied and interruptible service shall not be available to the customer for the next two years. Upon the third occurrence of such a failure to interrupt, a $10 per kilowatt penalty shall be applied and interruptible service shall no longer be available to the customer.

MONTHLY RATE

Demand Charge

Firm Standby Power

First 100 Kilowatts of Standby Power Billing Demand or Less	$6.103 net per kilowatt
Additional Kilowatts of Standby Power Billing Demand	$5.638 net per kilowatt
All Kilovars of Standby Reactive Kilovoltampere Demand in Excess of 25% of the Current Kilowatt Standby Power Billing Demand	$ .40 net per kilovar

Interruptible Standby Power

First 100 Kilowatts of Interruptible Standby Power Billing Demand	$5.797 net per kilowatt
Additional Kilowatts of Interruptible Standby Power Billing Demand	$5.332 net per kilowatt
All Kilovars of Standby Reactive Kilovoltampere Demand in Excess of 25% of the Current Kilowatt Interruptible Standby Power Billing Demand	$ .40 net per kilovar

ALTERNATIVE GENERATION SCHEDULE
SCHEDULE "AGS" (Continued)

MONTHLY RATE (Continued)

Demand Charge (Continued)

Firm or Interruptible Maintenance Power

All Kilowatts of Maintenance Power
Billing Demand .....$5.332 net per kilowatt
All Kilovars of Maintenance Reactive
Kilovoltampere Demand in Excess of
25% of the Current Kilowatt Maintenance
Power Billing Demand.....$ .40 net per kilovar

Energy Charge

All Standby and Maintenance Kilowatt-hours .....$0.00531 net per kilowatt-hour

FUEL RATE

Applies to all kilowatt-hours served under this schedule.

LATE PAYMENT CHARGE

Applies to this schedule as set forth in Company Rule No. 12 of this tariff.

DETERMINATION OF DEMANDS

("Normal alternative generation" as used below is defined above in Types of Supply.)

Power Demands

As a preliminary step to the determination of Billing Demands, the customer's Power Demands shall be determined as specified below:

(1) Supplementary Power Demand shall be determined as specified below for the billing period unless the applicable standard rate schedule requires that the determinations specified below be made using other periods. Any instantaneous operating peak provision of the applicable standard rate schedule shall be included.

ALTERNATIVE GENERATION SCHEDULE
SCHEDULE "AGS" (Continued)

Power Demands (Continued)

The demand for each period shall be the highest of:

(a) The maximum kilowatt demand created during the intervals in the period when no Maintenance Power or Standby Power is used, of if no such intervals exist in the period, the lesser of:

(i) the Supplementary Power Demand of the previous period; or

(ii) the maximum kilowatt demand created during the period;

(b) The maximum kilowatt demand created during the period less the normal alternative generation for the billing period; or

(c) The maximum by which a kilowatt demand created during the period exceeds the sum of the then effective Maintenance Power Agreement Capacity and the Standby Power Agreement Capacity being utilized.

(2) Maintenance Power Demand shall be the maximum Maintenance Power Agreement Capacity for the billing period, regardless of whether it is for Firm or Interruptible Maintenance Power.

(3) Standby Power Demand shall be either:

(a) The Lesser of:

(i) The Standby Power Agreement Capacity, or

(ii) The maximum by which a kilowatt demand created during such intervals of the billing period when Standby Power is used exceeds the sum of the then effective kilowatt portion of the Supplementary Power Demand and Maintenance Power Agreement Capacity.

or

(b) For customers who normally have no supplementary power requirements, the maximum kilowatt demand created during such intervals of the billing period when Standby Power is used.

ALTERNATIVE GENERATION SCHEDULE
SCHEDULE "AGS" (Continued)

Power Billing Demands

(1) Supplementary Power Billing Demand shall be the higher of:

(a) The Supplementary Power Demand (if multiple Supplementary Power Demands are required due to the applicable standard rate schedule, they shall be combined as specified by that rate schedule), or

(b) Any minimum demand provisions of the applicable standard rate schedule.

(2) Maintenance Power Billing Demand shall be the Maintenance Power Demand.

(3) Standby Power Billing Demand shall be the higher of:

(a) The Standby Power Demand, or

(b) 60% of the Standby Power Agreement Capacity.

Customer's Reactive Kilovolt-Ampere Demands

The customer's maximum thirty-minute leading or lagging kilovolt-ampere demand shall be apportioned among the various types of service utilized under this schedule in proportion to the customer's kilowatt portion of Supplementary Power Demand, Maintenance Power Demand, and Standby Power Demand.

DETERMINATION OF ENERGY USE

(1) Supplementary Energy Use shall be the lesser of:

(a) The average kilowatt demand during those portions of the billing period when no Maintenance Power or Standby Power is used, or the kilowatt portion of the Supplementary Power Demand if no demand intervals without the use of Maintenance or Standby Power exist in the billing period, multiplied by the quantity (total number of demand intervals in the billing period ÷ demand intervals per hour).

ALTERNATIVE GENERATION SCHEDULE
SCHEDULE "AGS" (Concluded)

DETERMINATION OF ENERGY USE (Continued)

(b) The total kilowatt-hour use.

(2) Maintenance Energy Use and Standby Energy Use shall be determined by apportioning the total kilowatt-hour use less the Supplementary Energy Use in proportion to the products of the power demands and the number of hours that the Maintenance or Standby Power is used.

FACILITIES

Any facilities that are installed by the Company solely to provide Standby Power or Maintenance Power service and which have not been included in the customer's interconnection costs are installed at the customer's expense. The customer is responsible for the total cost of construction plus a monthly maintenance charge for those facilities. Any facilities, including relays and their settings, installed by customer for the purpose of connecting to the Company must be specifically approved by the Company prior to the connection being made and must be subject to the Company's continuing approval.

DATA

The customer shall furnish such detailed load data and data on outages as the Company shall, from time to time, require, together with such supporting documentation as the Company shall request, in order for the Company to collect data and prepare reports as may be required.

TERM

Not less than one year.

GENERAL

Service supplied is subject to the Rules and Regulations Covering the Supply of Electric Service and Rules and Regulations for Meter and Service Installations of the Company as filed with the Commission.

RATE DESIGNATION: 450
CLASS OF SERVICE: COMPETITIVE RATE - LARGE POWER AND LIGHTING
SERVICE AREA: ALL MINNESOTA SERVICE AREA

Availability: To individual customers or to groups of customers within the Company's Large Power and Lighting class who are determined to be subject to "effective competition".

"Effective competition" exists if the customer or customer group is located within the Company's assigned service area and the customer or customer group has the ability to obtain its energy requirements from an energy supplier that is not regulated by the Minnesota Public Utilities Commission (MPUC) under Section 216B.16.

Availability is restricted to those customers with connected loads of not less than 2,000 kW.

Rate: To be specified in contract for service.

Terms and Conditions: The Company will offer competitive rates under the following terms:

(1) A contract for service must be completed and filed as a rate schedule with the MPUC.

(2) All provisions of the Company's Large Power and Lighting rate (including appropriate riders) shall apply except as may be modified in parts (3) through (8) below.

(3) Rates under this tariff are subject to the approval, modification or disapproval of the MPUC. If the competitive rate is modified by the MPUC, the MPUC will issue an order modifying the competitive rate. This modification is subject to the approval of the Company and the customer, who have ten days in which to reject the proposed modification. If no party rejects the proposed modification, the MPUC order becomes final. If either party rejects the MPUC proposed modification, the Company on its behalf or on the behalf of the customer, may submit to the MPUC a modified version of the MPUC proposal.

The rate pursuant to this tariff may take effect on an interim basis after the filing of the contract with the MPUC and upon the date specified. While an interim competitive rate is in effect, the difference between rates under the competitive rate and rates under the standard tariff for that class are not subject to recovery or refund. If the MPUC does not approve the rate, the Company may seek to recover the difference in revenues between the interim competitive rate and the standard tariff from the customer who was offered the competitive rate.

(4) The minimum rate offered under this schedule shall recover at least the incremental cost of providing the service including the cost of additional capacity that is to be added while the rate is in effect and any applicable on-peak or off-peak differential.

RATE DESIGNATION: 45C
CLASS OF SERVICE: COMPETITIVE RATE - LARGE POWER AND LIGHTING
SERVICE AREA: ALL MINNESOTA SERVICE AREA

(5) The maximum rate reduction offered under this schedule shall not exceed the difference between the Company's Large Power and Lighting (including applicable riders) rate and the cost to the Customer of the lowest cost competitive energy supply.

(6) Contract terms for service under this schedule must be no less than one year and no longer than five years.

(7) No rate shall be offered under this schedule which competes with district heating or cooling provided by a district heating utility as defined by Minnesota Statutes Section 216B.166, subdivision 2, paragraph (c).

(8) No rate shall be offered under this schedule to a customer in which the Company has a financial interest greater than fifty (50) percent.

Rules and Regulations: Service hereunder is subject to the provisions of the Company's Electric Service Standards.

PARALLEL GENERATION - (In Excess of 20 kW) ELECTRIC

1. Effective In

All territory served by the company.

2. Availability

Available for all single-phase and 3-phase customers who operate generation facilities which are rated in excess of 20 kW, but not in excess of 12,000 kW. Such facilities shall be connected in parallel with company facilities and shall be approved by Wisconsin Power and Light Company.

3. Rate

a. For customers with generation facilities rated at more than 20 kW.

1) Customer Charge

Facilities rated between 20 kW and 200 kW: $9.75 per month.
Facilities rated at 200 kW or greater: $19.50 per month.

2) Energy Charge R

The company shall pay for all quantities of electricity received from the customer's facilities during each billing period at the following rates:

Voltage Level	Per kWh On-Peak	Per kWh Off-Peak
Transmission	$0.0362	$0.0158
Distribution	$0.0371	$0.0161
Secondary	$0.0387	$0.0167

b. If the customer is not satisfied with these standard rates because they do not reflect the customer's needs or operating characteristics, the company and the customer may negotiate a facility specific rate. Such agreements shall be subject to review by the Public Service Commission of Wisconsin.

c. The company will supply standby, maintenance, or supplemental energy to the customer under the retail rates and rules for which the customer qualifies. In the case of maintenance energy, the demand charges will be prorated for the actual period of usage provided the customer coordinates its maintenance with the company's expected outages.

PARALLEL GENERATION - (In Excess of 20 kW) ELECTRIC

4. Pricing Period

Unless specified to the contrary in writing by the Company to any customer using this schedule, the on-peak and off-peak period available to all customers is as follows:

On-Peak Time Period Length	On-Peak Hours	Off-Peak Hours
14 hours	8 a.m. to 10 p.m., Mon.-Fri.	All other times

The off-peak hours include all other hours Monday through Friday, plus Saturday, Sunday, and holidays designated as such by the Company. The holidays are New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, and Christmas Day, or the day nationally designated to be celebrated as such.

5. Metering and Service Facilities

The Company will furnish and install appropriate metering to measure energy flow. The customer shall make a nonrefundable contribution for the cost of any instrument transformers required by the Company to properly measure use.

The customer shall furnish, install, and wire the necessary service entrance equipment, meter sockets, and meter enclosure or connection cabinets, that may be required by the Company, to properly meter on and off-peak usage.

The customer shall pay for the cost of rebuilding any Company facilities to provide adequate capacity for the parallel generation system. The Company must be reimbursed by the customer for costs, including financing cost over a period not to exceed 2 years.

6. Safety, System Protection, and Power Quality Rules of Interconnection

Parallel generation facilities shall be installed and operated in accordance with the rules specified in Schedule PgS-4, Sheet No. 7.90.

7. Interconnection Facilities

The customer shall furnish, install, operate, and maintain facilities such as relays, switches, synchronizing equipment, control, and protective devices designated by the Company as suitable for parallel operation with the Company system. Facilities shall be accessible at all times to authorized Company personnel. The customer retains the right to appeal to the Public Service Commission of Wisconsin if conditions being imposed by the Company are perceived to be excessively stringent.

PARALLEL GENERATION - (In Excess of 20 kW) ELECTRIC

8. Operation

The company retains the right to require the customer to limit production of energy to an amount no greater than the customer's load at certain times as electrical operating conditions warrant.

9. Contract

The company and the customer shall enter into a contract specifying technical and operating aspects of parallel generation.

10. Liability of the Parties

Each of the parties shall indemnify and save harmless the other party against any and all damages to persons or property occasioned, without the negligence of such other party, by the maintenance and operation by such parties of their respective lines and other electrical equipment. The customer shall be required to maintain $100,000 of liability insurance or demonstrate financial responsibility satisfactory to the company.

11. Service Option

Customers with generation facilities connected in parallel with Company facilities have the option to not be served under Paragraph 3c. of this schedule. In such case, meters used to measure energy and/or demand usage from the Company's system to the customer shall be ratcheted to prevent measurement of reverse flow.

AMERENCIPS

CENTRAL ILLINOIS PUBLIC SERVICE COMPANY
ELECTRIC SERVICE SCHEDULE 9B
SECTION ONE
STANDARD RATES

ILL. C. C. No. 9B
Section One
Original Sheet No. 37.9.1

RIDER 16
ELECTRIC CONTRACT SERVICE
Applicable To Rates 6T, 9T and 9B

AVAILABILITY

Available for any Customer being served by the Company under Rate 6T, Rate 9T or Rate 9B when in the judgement of the Company: (a) it is economically feasible and practical for the customer to utilize an energy source other than the Company's electric service (Bypass) and/or (b) total or partial loss of customer load is imminent.

As a condition of service, Customer will provide to Company affidavits stating Customer's intent to Bypass Company's facilities absent service provided hereunder, and such other evidence as deemed necessary by Company to verify Customer's intent.

This rider will be available to approved applicants through January 1, 2001, or until its continued availability would result in the Company's capacity reserve margin falling below acceptable levels, whichever is first applicable.

CONTRACTS

The customer shall enter into a contract in writing with the Company specifying the nature of the service to be supplied, the prices to be paid, the term of the contract and such other terms and conditions of service as are mutally agreeable. The term of the contract shall not exceed ten years. Revenues from service to the Customer under such contract shall be greater than the applicable incremental customer, facility, energy and capacity costs to serve such Customer, ensuring a positive contribution to fixed costs. No more than twenty-five contracts shall be in effect under this rider at any one time.

All contracts entered into hereunder shall be submitted to the Illinois Commerce Commission for informational purposes. Not less than ten working days before submitting any contract to the Commission, the Company shall submit the contract, together with other supporting documentation as required by the Commission Staff in its analysis of Rider 16 contracts. All submissions to the Staff and the Commission of such contracts and other supporting documentation under this rider shall be treated as proprietary and confidential in nature.

ELIGIBLE LOAD

For a customer entering into Rider 16 Electric Contract Service, service hereunder shall be available only to existing load. A customer taking service under Rider 16 can make application for other applicable rates and riders of this Electric Service Schedule, which in combination with Rider 16 are not at variance with the incremental cost provisions contained herein.

NEGOTIATED SERVICE - ELECTRIC
SCHEDULE NS
(EXPERIMENTAL)

AVAILABILITY:

Schedule NS is designed to allow the Company to offer, on an experimental basis through December 31, 1999, prices and/or terms and conditions that meet unique customer needs.

It is available only to individual customers who would otherwise be eligible for service from the Company under Schedules G, GS, GL, or P and have combined demand of at least 5 MW. The minimum demand may be satisfied based on load at an individual site, or based on the sum of the customer's demand at multiple sites. (A customer may include subsidiaries.) The availability of Schedule NS will be limited to those customers which a) have a demonstrated service alternative, including self generation, fuel switching facility relocation or expansion, production shifting between plants or the potential for bypass or b) would otherwise be paying standard tariff prices that would produce above system average returns as determined by the Company. A confidential informational filing to the Commission Staff will be made to demonstrate that the system return requirement has been met.

The experimental schedule is limited to 300 MW of total participation. Total load enrollment will be measured as the sum of participating customers' maximum loads in the calendar year prior to participation.

SERVICE OPTIONS:

If, after reviewing the Customer's application for service, the Company concludes that the Customer meets eligibility requirements, the Company shall enter into negotiations with the Customer for the purpose of offering such services as are believed to meet the Customer's requirements. Offers may be made in a manner which provides the Customer with increased choices for service. Service options differentiated by contract term, contract quantity, pricing options, and equipment upgrades may be made available to the qualifying Customer. The contract term while negotiable, may contain an exit option for retail access, should it become available in Maryland. The agreed upon services shall be specifically described within the Customer Contract.

PRICING OPTIONS:

Pricing will be determined on a customer by customer basis. The final arrangements between the Company and Customer will be determined through negotiations and shall be included in the Contract.

CONTRACT:

Eligible Customers requesting this Service Classification will be presented with a Contract, which specifies the terms and conditions of the contractual agreement between the Company and Customer. The Contract shall replace the otherwise applicable Service Classification for the Customer. The Customer must sign the Contract prior to commencement of this service and any investment by the Company.

CONFIDENTIALITY:

The Contract shall be considered a confidential document between the Company and Customer. By signing the Contract, the Customer and the Company agree not to share the Contract or information contained within the Contract with anyone except the parties to the contract, the Maryland Public Service Commission and the Office of People's Counsel, unless given written consent from the other party. Violations by the Customer of the confidentiality agreement shall permit the Company to terminate the contract with the Customer and reclassify the Customer by assigning the Customer to the appropriate Schedule. The Customer shall also be responsible for the additional damages or prejudices to any other existing or potential contracts resulting from the breach of confidentiality.

CHANGE IN RATES AND CHARGES:

Unless specifically stated within the Contract, energy sales under this Service Classification shall be subject to the same riders as the Customer's controlling rate schedule. These riders include, Rider 1 (Fuel Rate), Rider 2 (Purchased Capacity Surcharge), Rider 3 (Conservation Surcharge), Rider 14 (Emergency Generation), and Rider 16 (Curtailable Service). Any PSC approved non-base rate surcharge that is created in the future will also apply to the contract.

CONTRACT TERMS FILED WITH THE COMMISSION:

The Company shall notify the Maryland Public Service Commission at least 30 days prior to the effective date of the Contract. The notification will include a confidential informational document.

ELECTRIC RATE SCHEDULE CENTRAL MAINE POWER COMPANY	Page 134.00 First Revision
RATE D-AGDR **OPTIONAL TARGETED SERVICE:RATE D-AGDR** **GENERAL SERVICE: ALTERNATE GENERATION DEFERRAL ENERGY SERVICE**	
Effective Date: For meters read on and after September 6, 1997 Docket No. 97-528	Curtis A. Mildner Vice President

Next Previous Index

AVAILABILITY

This rate is available to any General Service customer who meets the following qualifications:

- the customer's primary business is leather tanning and finishing
- the customer must demonstrate to the Company's satisfaction that installation of an alternative generation process to meet the energy requirements of the customer's business is a viable option. The issues that CMP will review include but are not limited to:
  - environmental permitting/licensing
  - customer's ability to finance, operate, and maintain an alternate generation system
  - distribution of electricity by end uses
- the customer must enter into a Customer Service Agreement which will specify among other things:
  - contract term
  - initial energy prices charged under this service
  - the customer's maximum load level

CHARACTER OF SERVICE

Service will be provided at any available voltage as described in the Company's Contractor's Handbook.

RATES

Customers receiving electrical service under this tariff will be charged the following components:

	ELECTRIC RATE SCHEDULE CENTRAL MAINE POWER COMPANY	Page 134.10 Original

RATE D-AGDR
OPTIONAL TARGETED SERVICE:RATE D-AGDR
GENERAL SERVICE: ALTERNATE GENERATION DEFERRAL
ENERGY SERVICE

Effective Date: For meters read on and after July 15, 1996 Docket No. 96-615	Curtis A. Mildner Vice President

Next Previous Index

RATES (continued)

Access Charge

Energy Charges - Winter and Non-Winter

Reactive Demand Charges

The Winter period includes the billing periods ending in the months of December, January, February, and March. Billing periods ending in the months of April through November comprise the Non-Winter period.

The access charge will be a fixed monthly charge and will be determined as follows:

Customers with an expected maximum load of 20 kW or less will pay a fixed rate of $65.00 per month.

Customers who have an expected maximum load that is greater than 20 kW and who receive power at the secondary voltage level will pay a fixed monthly access charge equal to $6.67 times the customer's expected maximum load.

Customers who have an expected maximum load that is greater than 20 kW and who receive power at the primary voltage level will pay a fixed monthly access charge equal to $6.24 times the customer's expected maximum load.

At least once annually, CMP will review the customer's expected maximum load to determine if the access charge should be adjusted.

The initial energy rates will be negotiated between the customer and the Company as part of the Customer Service Agreement. Energy rates will meet the applicable

ELECTRIC RATE SCHEDULE CENTRAL MAINE POWER COMPANY	Page 134.20 Second Revision
RATE D-AGDR **OPTIONAL TARGETED SERVICE:RATE D-AGDR** **GENERAL SERVICE: ALTERNATE GENERATION DEFERRAL ENERGY SERVICE**	
Effective Date: For meters read on and after December 3, 1998 Docket No. 98-854	Michael R. Cutter Vice President

Next Previous Index

RATES (continued)

pricing flexibility criteria as described in Attachment F of the Alternative Rate Plan (ARP). The energy rates will be adjusted annually, with new rates effective October 1, based on an index of the appropriate alternative fuel price as published in The Wall Street Journal. The index will be computed using the average weekly alternative fuel prices for the current one year period ending August 31 as compared to the average weekly alternative fuel prices for the prior one year period ending August 31.

Any annual adjustment to the energy rates for October 1997 and October 1998 shall be limited by a bandwidth around the previous year's price, such that upward or downward adjustments (1) do not increase energy prices above a maximum ceiling set at the percentage price change approved pursuant to the ARP for Core Rates and (2) do not decrease energy prices below a minimum floor set at ten percent (10%).

Any annual adjustment to the energy rates after October 1998 shall be limited by a bandwidth such that the upward or downward adjustment to energy prices do not exceed ten percent (10%) of the previous year's price.

The reactive demand charge for customers whose core class is Large General Service is $.67 per kilovar (kVar) of reactive demand that exceeds the sum of 50% of the first 1,000 kW of monthly on-peak kW and 25% of all additional monthly on-peak kW demand. For all other customers, the reactive demand charge is $.67 per kilovar (kVar) for all kVar in excess of 50% of the highest monthly kW demand.

The minimum monthly charge for all customers taking service under this rate schedule shall be the access charge.

	ELECTRIC RATE SCHEDULE CENTRAL MAINE POWER COMPANY	Page 135.00 Fourth Revision
RATE DIESEL DEFERRAL RATE DIESEL GENERATION DEFERRAL ENERGY SERVICE		
Effective Date: For meters read on and after March 20, 1997 Docket No. 97-605		Curtis A. Mildner Vice President

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AVAILABILITY

Service under this rate is available for the purpose of operating sawmill and associated manufacturing equipment, using all-electric saws. For the purposes of this rate, sawmills are considered to be businesses in which logs are sawed into boards, planks, or bolts by machinery.

Service under this rate is available for the purpose of operating asphalt producing, rock crushing and concrete producing and fabricating equipment and any associated manufacturing equipment.

Service under this rate is available for the purpose of operating gray and ductile iron foundries with electric induction furnaces and associated manufacturing equipment.

At the discretion of the Company, service provided under this rate will be separately metered. The customer will be required to enter into a Customer Service Agreement.

RATES

Access Charge:
Customers receiving electric energy under this rate schedule will pay a fixed monthly charge, which is determined by multiplying the amounts below by the customer's expected maximum load which will be specified in the Customer Service Agreement. A customer may have two expected maximum load amounts, provided that the customer's operation is seasonal in nature and that the lesser expected maximum load amount (low season amount) is at least 50% less than the higher expected maximum load amount (high season amount). The fixed monthly access charge will be determined as follows:

Customers with an expected maximum load of 20 kW or less will pay a fixed rate of $ 65.00 per month.

Customers who have an expected maximum load that is greater than 20 kW and who receive power at the **secondary** voltage level will pay a fixed monthly access charge equal to $ 6.67 times the customer's expected maximum load.

Customers who have an expected maximum load that is greater than 20 kW and who receive power at the **primary** voltage level will pay a fixed monthly access

charge equal to $ 6.24 times the customer's expected maximum load.

Seasonal customers will have a fixed monthly charge equal to the weighted average of the high and low season amounts, where the low season amounts shall not be less than $ 65.00 per month.

At least once annually, CMP will review the customer's expected maximum load(s) and duration of seasons (with respect to seasonal customers) to determine if the access charge should be changed.

ELECTRIC RATE SCHEDULE CENTRAL MAINE POWER COMPANY	Page 135.10 Seventh Revision
RATE DIESEL DEFERRAL RATE DIESEL GENERATION DEFERRAL ENERGY SERVICE	
Effective Date: For meters read on and after October 1, 1999 Docket No. 99-608	Raymond W. Hepper General Counsel

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RATES (Continued)

Energy Charge:

The energy charge per kilowatt-hour for all kilowatt-hours applicable under this rate schedule are $0.062 during the billing periods ending in the months of December, January, February, and March and $0.052 during the billing periods ending in the months of April through November.

The energy rates will be adjusted annually, with new rates effective October 1, based on an index of diesel fuel prices as published in The Wall Street Journal. The index will be computed using the average weekly diesel prices for the current one year period ending August 31 as compared to the average weekly diesel fuel prices for the prior one year period ending August 31.

Any annual adjustment to the energy rates for October 1997 and October 1998 shall be limited by a bandwidth around the previous year's price, such that upward or downward adjustment (1) do not increase energy prices above a maximum ceiling set at the percentage price change approved pursuant to the Alternative Rate Plan (ARP) for Core Rates and (2) do not decrease below a minimum floor set at ten percent (10%).

Any annual adjustment to the energy rates after October 1998 shall be limited by a bandwidth such that the upward or downward adjustment shall not exceed ten percent (10%) of the previous year's price.

Reactive Demand Charge:

In situations where appropriate metering is installed and customers execute Customer Service Agreements on or after April 3, 1995, the Company will charge customers for reactive demand. The reactive demand charge for customers whose core class is Large General Service is $.67 per kilovar (kVar) of reactive demand that exceeds the sum of 50% of the first 1,000 kW of monthly on-peak kW and 25% of all additional monthly on-peak kW demand. For all other customers, the reactive demand charge is $.67 per kilovar (kVar) for all kVar in excess of 50% of the highest monthly kW demand.

Minimum Charge:

The minimum monthly charge for all customers taking service

under this rate schedule, including seasonal customers, shall be the access charge.

	ELECTRIC RATE SCHEDULE CENTRAL MAINE POWER COMPANY	Page 135.20 Third Revision
RATE DIESEL DEFERRAL RATE DIESEL GENERATION DEFERRAL ENERGY SERVICE		
Effective Date: For meters read on and after October 1, 1998 Docket No. 98-683		Michael R. Cutter Vice President

Next Previous Index

CONTRACT

A Customer Service Agreement shall be required for all customers. The Agreement shall offer service consistent with this tariff and shall specify the expected maximum load level(s) to be used to establish the initial access charge. The Agreement and any amendments shall not extend past 2/29/2000. Any extensions shall require mutual agreement of the parties.

SPECIAL CONDITIONS

Metering:

If service under this rate schedule requires metering facilities in addition to, or in substitution of, the standard facilities that the Company would normally install to provide service, the Company will provide the additional or substitute metering, and the customer will be subject to an additional monthly charge in accordance with Section 13 of the Terms and Conditions.

Other Facilities:

Any other facilities required for service under this rate schedule in excess of those needed for service under the applicable general service rate schedule shall either be furnished, owned and maintained by the customer or shall be furnished, owned and maintained by CMP, and the customer will pay an additional monthly charge in accordance with Section 13 of the Terms and Conditions.

ELECTRONIC REPLICATION OF SHEET ON FILE WITH ICC
– Font and Format May Vary
- Content is Identical –

RATE CS
CONTRACT SERVICE

AVAILABILITY.
Subject to the limitation set forth below on the total number of contracts in effect hereunder at any one time, this rate is available to any non-residential customer taking service from the Company under Rate 6L, Large General Service, as of the effective date below, and for whom bypass of the Company's electric service, in whole or in part, is, in the judgment of the Company, economically feasible and practical.

Service hereunder shall not be available to that portion of any customer's energy requirement which was served at any time under the Company's Rider 27, unless the customer can demonstrate that at the time of application for service hereunder, the generation facilities formerly displaced by Rider 27 are not capable, nor can they reasonably and economically be made capable, of providing the kilowatthours previously served under Rider 27.

PURPOSE.
The purpose of this rate is to maintain existing electricity sales by the Company in a manner which allows economic operation by the customer and which provides a contribution to the Company's fixed cost recovery.

ELIGIBILITY.
A customer seeking a contract hereunder shall make written application to the Company which shall include an affidavit stating the customer's intent to bypass the Company's electric service system absent service hereunder. The customer shall also provide evidence required by the Company to verify (1) the receipt of competitive bids from other suppliers of electricity; (2) the investment required on the part of the customer in order to accomplish the intended bypass; and (3) the ability of the customer to actually engage in the intended bypass.

The Company shall, at its sole discretion, determine whether the customer would have engaged in bypass absent service under this rate and the extent to which service under this rate provides a contribution to the Company's fixed cost recovery. The customer shall be responsible for providing such data as may be required by the Company to make the determination described herein. The Company, in its sole discretion, retains the right to withhold service hereunder.

ELIGIBLE LOAD.
For a customer entering into an initial Rate CS contract, service hereunder shall be available only to existing load, which, for purposes of this rate, is defined as the customer's highest Maximum Demand for the calendar year ended December 31 prior to the effective date of the contract.

For a customer recontracting for Rate CS within twelve months of termination of the effectiveness of the same customer's prior Rate CS contract, service hereunder shall be limited to the volume of Eligible Load under the prior contract.

Service hereunder is not available to any part of the customer's new or expanded load.

CONTRACT TERMS.
The customer shall enter into a contract in writing with the Company specifying the nature of the service to be supplied, the prices to be paid, and such other Terms and Conditions of Service as are mutually agreeable. The term of the contract shall be provided in the contract, but shall in no event exceed 5 years.

All contracts for service under this rate shall terminate no later than May 15 of the year in which the Company must commit to add intermediate or base load capacity to serve ultimate consumers and full requirements wholesale service. Not more than 25 contracts shall be in effect under this rate at any one time.

All contracts entered into hereunder shall be submitted to the Illinois Commerce Commission for informational purposes. Not less than 10 days before submitting such contract to the Commission, the Company shall submit the contract, together with the documentation specified in Finding 8 of the Commission's June 15, 1994, Order in Docket No. 93-0425, to the Commission Staff for review. All submissions to the Staff and the Commission of such contracts under this rate shall be treated on a proprietary basis. Revenues from service to the customer under such contract, which shall reference all applicable rates and riders, shall be greater than the incremental costs to serve such customer, ensuring a positive contribution to fixed costs.

CHARGES.
The charges for service hereunder shall be the charges contained in the contract between the Company and the customer.

GENERAL.
The identity of applicants for this rate and information and documents obtained by the Company from such applicants shall not be disclosed to any nonregulated "affiliated interest" of the Company, as defined in Section 7-101 of the Public Utilities Act; no representative of any such affiliated interest shall be involved in determining the eligibility of the applicant for this rate; and the Company's determination of eligibility for this rate will not be affected, in any way, by the fact that an affiliated interest of the Company is or is not the other supplier of electricity that has issued a competitive bid for the supply of electricity.

Consumers Energy

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

* * * * *

In the matter of the application of CONSUMERS POWER COMPANY for approval of a special contract with The Upjohn Company.	)))))	Case No. U-11001

At the December 15, 1995 meeting of the Michigan Public Service Commission in Lansing, Michigan.

PRESENT: Hon. John G. Strand, Chairman
Hon. John C. Shea, Commissioner
Hon. David A. Svanda, Commissioner

ORDER APPROVING SPECIAL CONTRACT

On December 4, 1995, Consumers Power Company (Consumers) filed an application for approval of a special contract for the supply of retail electric service to The Upjohn Company (Upjohn). Consumers says that Upjohn is one of its largest customers, having a maximum demand in 1994 of 80 megawatts (MW) and energy purchases of 482,000 megawatt-hours.

Consumers represents that Upjohn has experienced fierce competition and has taken actions designed to reduce its costs, including negotiating contracts with major suppliers, implementing energy reduction programs, investigating the potential of locating production outside of Michigan, and soliciting offers for the installation of cogeneration equipment.

Consumers says that it and the Commission have begun to respond to its manufacturing customers' needs to become or stay competitive, including a reduction in the subsidization

DEC 19 1995

provided by manufacturing customers. The result, it says, has been to reduce the gap between what it costs to serve manufacturing customers and the rates they pay. It also notes that the Commission approved special manufacturing contracts between The Detroit Edison Company (Detroit Edison) and Ford Motor Company, General Motors Corporation, and Chrysler Corporation in Case No. U-10646 and between Consumers and General Motors in Case No. U-10961. Those contracts cover more than 1,400 MW of load.

Consumers says that it is also severely threatened by increasing competition and is increasingly being required to use innovative and customer-specific pricing initiatives to meet competitive threats. It says that Upjohn has a combination of thermal and electrical requirements that makes it well-suited to the installation of a cogeneration facility. In addition, Consumers says that Upjohn has the capability to move production to other states.

Therefore, Consumers asserts, it undertook to redefine its traditional business relationship with Upjohn. As a result, Consumers signed a 10-year special contract with Upjohn. It says that the contract is the product of good faith negotiations and compromise, and was negotiated in light of competitive options available to Upjohn. Firm service provided under the contract will be exempt from the power supply cost recovery (PSCR) clause. The contract provides for annual escalations in the rate based upon the producer price index, with a floor and a cap on the permissible escalations. Consumers asserts that the rates and terms and conditions are reasonable and in the public interest.

Consumers says that Upjohn will benefit because it will pay a competitive and predictable price for electricity. Consumers says that it and its customers benefit in the following ways: (1) the retention of this at-risk customer helps to stabilize the company's industrial load, (2) the agreement may help to attract new load and promote economic development, (3) the

aggressive response to retain major industrial customers demonstrates to the financial community Consumers' commitment to meet competitive challenges, and (4) the retention of the load ensures the contribution of this customer to system fixed costs.

Consumers says that it will serve Upjohn at rates above its variable cost to produce electricity and is not requesting, at this time, a change in the rates paid by other customers. Consumers reserves the right, in the future, to seek appropriate ratemaking treatment, which may include a request to recover the revenue effect of the rate discount provided by the contract. It agrees that in making that request it will bear the burden of demonstrating either that the contract terms and prices are justified on the basis of the cost of service or it is more beneficial to other customers for Consumers to retain Upjohn as a customer under the terms of the contract than to lose those sales.

Discussion

The Commission concludes that it should approve the contract as reasonable and in the public interest. In reaching this conclusion, the Commission finds, in the absence of a reason to believe otherwise, that the parties to the contract protected their own interests and reached a mutually beneficial bargain. The Commission also finds that Consumers should have leeway to negotiate prices and other terms as it sees fit, except when the contract provisions would violate statutes, rules, or Commission orders, would run afoul of clearly established Commission policies, would harm other ratepayers, or would otherwise detract from the public interest. On the other hand, the ratemaking treatment to be accorded to the contract is within the Commission's exclusive domain.

There are clear benefits in the contract for Consumers, including the substantial certainty that it will retain Upjohn as a customer. There are clear benefits to Upjohn, including a

reduction in rates. There are benefits for other customers, including retaining Upjohn's contribution to system fixed costs. There are benefits to the general public, including the economic effects of retaining and potentially expanding employment in the state.

The Commission also finds that other customers and the public interest are adequately protected. The primary concern in this regard is the future ratemaking treatment of the rate discount offered by the contract. In the application, Consumers agrees that if it seeks to recover the discount from other customers, it will bear the burden of demonstrating either that the contract terms and prices are justified on the basis of the cost of service or it is more beneficial to other customers for Consumers to retain Upjohn as a customer under the terms of the contract than to lose those sales.

These commitments are apparently patterned after the Commission's discussion in the March 23, 1995 order in Case No. U-10646 that approved contracts between Detroit Edison and General Motors, Ford Motor Company, and Chrysler Corporation and the Commission's October 25, 1995 order in Case No. U-10961 that approved a contract between Consumers and General Motors. The Commission said that it would not make a definitive ruling on the future ratemaking effects of the contracts, but discussed the general principles that should guide future Commission action:

> "[T]he contracts are the product of Detroit Edison's negotiations. It follows that Detroit Edison should assume full responsibility for negotiating the discounted prices and that its shareholders should expect to absorb much, if not all, of any revenue shortfall caused by the pricing and other contract provisions that the utility negotiates. Therefore, unless Detroit Edison can make a compelling showing why a different ratemaking treatment is justified, the Commission will not permit Detroit Edison to reallocate the costs of serving contract customers to other ratepayer classes. To make a compelling showing for a different treatment, Detroit Edison would bear a substantial burden. This burden would require, at a minimum, a clear, convincing, and unequivocal demonstration either (1) that the contract prices and terms are justified on the basis of the cost of service, or (2) that the benefits for other (non-participating)

> ratepayers are substantial and have a value that outweighs the costs that are not recovered from the contract customers. Either showing would require support from a cost-of-service study that identifies and quantifies all costs incurred under the contracts. In addition, both showings would require Detroit Edison to demonstrate that its service provided in conjunction with the contracts has not, and will not in the future, impede the development of competition in its service territory." March 23, 1995 order, Case No. U-10646, p. 21.

The Commission also indicated that other ratepayers should be protected from any underrecoveries of power supply costs and other surcharges and that if average PSCR costs increased as a result of incremental load attributable to the contracts, the added costs would be treated the same as any other category of unrecovered cost created by the contracts. March 23, 1995 order in Case No. U-10646, p. 20. To facilitate implementation of these protections, the Commission required Detroit Edison to treat service under the contracts as a separate rate class for purposes of cost allocation studies in future rate cases and to file annual reports showing actual contract revenues and hypothetical tariff rate revenues using the same billing determinants.

The Commission concluded that, taken as a whole, these protections increased the incentive for the utility to negotiate for the benefit of all customers and decreased the likelihood that contract customers would be subsidized by other customers. The Commission did not find it in the public interest for a utility to negotiate contracts under the belief that the Commission would necessarily shift to other customers the full discount offered by the contracts.

If Consumers seeks to increase other customers' rates as a result of the contract, it is on notice that the principles discussed in the March 23, 1995 order in Case No. U-10646 and the October 25, 1995 order in Case No. U-10961 should apply. Furthermore, as the Commission required of Detroit Edison, Consumers will be required to account for the contract as a

separate rate class in future cost of service studies and to file annual reports of actual contract revenues and hypothetical tariff rate revenues using the same billing determinants.

Approval of the contract does not increase any customer's rates. Therefore, the Commission may approve the contract without providing notice or an opportunity for a hearing, pursuant to MCL 460.6a(1); MSA 22.13(6a)(1).

The Commission FINDS that:

a. Jurisdiction is pursuant to 1909 PA 106, as amended, MCL 460.551 et seq.; MSA 22.151 et seq.; 1919 PA 419, as amended, MCL 460.51 et seq.; MSA 22.1 et seq.; 1939 PA 3, as amended, MCL 460.1 et seq.; MSA 22.13(1) et seq.; 1969 PA 306, as amended, MCL 24.201 et seq.; MSA 3.560(101); and the Commission's Rules of Practice and Procedure, 1992 AACS, R 460.17101 et seq.

b. The contract should be approved as reasonable and in the public interest.

c. Ex parte approval is appropriate.

THEREFORE, IT IS ORDERED that the special contract between Consumers Power Company and The Upjohn Company, attached to the application, is approved.

The Commission reserves jurisdiction and may issue further orders as necessary.

Any party desiring to appeal this order must do so in the appropriate court within 30 days after issuance and notice of this order, pursuant to MCL 462.26; MSA 22.45.

MICHIGAN PUBLIC SERVICE COMMISSION

/s/ John G. Strand
Chairman

(SEAL)

/s/ John C. Shea
Commissioner

/s/ David A. Svanda
Commissioner

By its action of December 15, 1995.

/s/ Dorothy Wideman
Its Executive Secretary

EL PASO ELECTRIC COMPANY

ORIGINAL RATE NO. 30
LOAD RETENTION RATE
X
ALL NEW

APPLICABILITY:

This rate is applicable to all commercial and industrial customers of El Paso Electric Company ("Company") that have taken service from the Company for a period of at least twelve (12) consecutive months, and have a minimum monthly demand of at least 1,500 KW.

TERRITORY:

Areas served by the Company in Dona Ana, Sierra, Otero and Luna Counties.

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NM PUBLIC UTILITY COMMISSION

AVAILABILITY:

The Load Retention Rate is available to customers which meet the following criteria:

1. The Customer must provide notice to the Company that they will request termination of electrical service for either a portion or all of their electrical power and energy requirements due to an alternative generation source, or

2. The Customer must demonstrate that they will leave the El Paso system, or discontinue or curtail service for financial reasons, and

3. The Customer must submit a notarized affidavit that attests to the fact that but for the Load Retention Rate contained herein, the Customer will leave the El Paso Electric system.

MONTHLY RATE:

The Company may enter into negotiations to establish a lower rate not less than the Company's incremental cost of power and energy as estimated over the term of the contract. Sufficient documentation of the cost estimates used in determining the economic feasibility of an alternative generation source shall be provided to the Company for their review. The negotiated rate shall be subject to the review and final approval of the New Mexico Public Utility Commission (NMPUC) and shall be set forth in a contract whose initial term shall not exceed a period of three (3) years.

The Company, at its option, will annually review its incremental cost of providing service to a contracted Load Retention Customer to determine if such costs exceed the Customer's contracted charges. Should the incremental costs exceed the Customer's

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NEW MEXICO PUBLIC UTILITY COMMISSION

Advice Notice No. 175

Signature/Title Thomas L. Newsom / JFP
Assistant Vice President

EL PASO ELECTRIC COMPANY
Continuation of Original Rate No. 30
Load Retention Rate

contracted rate, the Company will adjust the charge to be above or equal to the incremental cost.

REQUIRED INFORMATION:

The Company shall obtain the following information from the Customer, and file that information with the New Mexico Public Utility Commission (NMPUC):

1. The customer shall provide detailed engineering and economic studies and/or related information that clearly demonstrate the customer's ability to displace load;

2. The customer shall provide a sworn affidavit which states that the customer is ready, willing, and able to leave EPE's system should this Load Retention Rate not be offered;

3. The customer shall provide a signed statement from a qualified professional engineer that the customer's potential alternative energy source meets all environmental standards set by applicable governmental entities including the Federal Clean Air Act, and all amendments;

4. An agreement as to the limit placed on the maximum number of KWH that can be taken by the customer under this rate, per year.

TAX ADJUSTMENT:

Billings under this rate may be increased by an amount equal to the sum of taxes payable under the Gross Receipts and Compensating Tax Act and of all other taxes, fees or charges (exclusive of ad valorem, state and federal income taxes) payable by the utility and levied or assessed by any governmental authority on the public utility service rendered, or on the right or privilege of rendering the service, or on any object or event incidental to the rendition of the service.

TERMS OF PAYMENT:

All bills under this rate are due and payable when rendered and become delinquent twenty (20) calendar days thereafter.

TERMS AND CONDITIONS:

The Company's Rules and Regulations apply to service under this rate.

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FOR Service ON
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BY
APPROVED
NEW MEXICO PUBLIC UTILITY COMMISSION

Advice Notice No. 175

Signature/Title Thomas L. Newsom
Assistant Vice President

b) a second amount is calculated as follows:

- the billing demand of the consumption period minus the billing demand noted outside of the test period(s);

  multiplied by:

  10.00¢ per kilowatt of demand in the summer period;

  30.00¢ per kilowatt of demand in the winter period;

  multiplied by the number of hours of the test period(s).

c) the customer's bill corresponds to the sum of the results obtained in Subparagraphs a) and b).

Load Retention Rate

Subdivision 1 - Hydro-Québec's Large-Power Industrial Customers

Application **163**

The Load Retention Rate applies to a contract belonging to an industrial customer which, in accordance with the Rates Bylaw in effect, is subject to Rate L as of the date when said customer obtains the Load Retention Rate or was subject to Rate L during the three years preceding the effective date of the present Bylaw.

Definitions **164**

In this Division, the following terms are defined as follows:

"collaborator": Any physical or moral person other than a supplier, including financial institutions, supplying items defined as being among the variable costs of an industrial customer having a Rate L contract.

"reference period": A period of 12 months for which data are available, preceding the month when Hydro-Québec receives the customer's written application.

"supplier": Any physical or moral person supplying goods or services defined as being among the variable costs of an industrial customer having a Rate L contract, excluding a company or corporation which is controlled by the customer, or which exercises full or shared control over said customer.

"variable costs": Production costs which vary proportionally with quantities produced. These costs include but are not limited to the cost of raw materials, labor and energy. They exclude all other costs which do not vary proportionally with quantities produced, such as fixed assets, amortization, financing costs and administrative overhead.

In applying the Load Retention Rate, electricity costs are not included in variable costs.

Conditions of admission 165

A customer wishing to be subject to the Load Retention Rate must so advise Hydro-Québec in writing. The customer's application must contain the following information:

a) financial statements covering the three years preceding the customer's written application, prepared and audited according to generally recognized accounting principles and auditing standards. These financial statements must include results, balance sheet and changes in financial position, with all related notes;

b) interim financial statements for the period falling between the end of the audited fiscal year and the customer's written application;

c) a detailed listing of variable costs regarding the product or products concerned by the load for which application is being made, the evolution of these costs over the reference period and a projection of costs over the next 12 months;

d) the price at which the product or products concerned has or have been sold over the reference period and a projection of said price for the next 12 months.

Eligibility 166

A customer, to be eligible for the Load Retention Rate, must meet the conditions stipulated in Section 165 as well as the following:

a) the customer must demonstrate that it is experiencing financial difficulties entailing cessation of all or part of its operations;

b) the customer must demonstrate, by invoices or other documents, that it has obtained non-reimbursable reductions from its other suppliers or collaborators over the duration of the commitment;

c) the customer must demonstrate that steps will be taken to improve the firm's profitability.

Hydro-Québec reserves the right to audit all information provided by the customer.

Pending Hydro-Québec's written approval, the contract shall become subject to this Rate, at the option of the customer and according to its written application, either at the beginning of the consumption period in progress when said application is received by Hydro-Québec or upon one of the three succeeding consumption periods.

Property of information 167

Subject to all applicable legislation, Hydro-Québec undertakes to keep confidential all information provided by the customer related to the present Rate and identified as confidential by said customer.

Duration of commitment 168

The Load Retention Rate shall be applied to a contract for a maximum of 24 consumption periods, according to the following conditions:

a) **First application**

- The Load Retention Rate applies to a contract during 12 consumption periods.

b) **Second and last application**

- The Load Retention Rate may once again be applied to the same contract for another 12 consumption periods, consecutive or not to the first 12, but beginning no later than 12 months after the end of the first application.

  The customer must submit a new written application to Hydro-Québec as provided in Section 165 and show that it is still eligible for the Load Retention Rate, in accordance with Section 166. The Rate shall apply again in accordance with Sections 170 and 171.

Determination of the billing coefficient for first application 169

The billing coefficient is determined as follows for the first application:

a) the relative importance of each category of variable costs for the reference period according to the information obtained under Subparagraph c) of Section 165, shall be determined and expressed as a percentage;

b) each percentage calculated according to Subparagraph a) shall be multiplied by the percentage of reduction granted by each supplier or collaborator, in accordance with Section 166, and weighted in accordance with Subparagraphs c) and d) below;

c) each percentage obtained as per Subparagraph b) shall be multiplied by the number of days not exceeding 360 days during which each reduction applies and the result shall be divided by 360 days;

d) each percentage obtained as per Subparagraph c) shall be multiplied by the number of units to which each reduction applies in relation to the total number of units stipulated for the duration of the commitment;

e) percentages obtained for each cost category are added;

f) the result obtained as per Subparagraph e) shall be subtracted from the number (1), and the result corresponds to the billing coefficient.

Determination of the billing coefficient for second and last application 170

The billing coefficient is determined as follows for the second and last application:

a) the relative importance of each category of variable costs for the reference period according to the information obtained under Subparagraph c) of Section 165, shall be determined and expressed as a percentage;

b) each percentage calculated according to Subparagraph a) shall be multiplied by the percentage of reduction granted by each supplier or collaborator, in accordance with Section 166, and weighted in accordance with Subparagraphs c) and d) below;

c) each percentage obtained as per Subparagraph b) shall be multiplied by the number of days not exceeding 360 days during which each reduction applies and the result shall be divided by 360 days;

d) each percentage obtained as per Subparagraph c) shall be multiplied by the number of units to which each reduction applies in relation to the total number of units stipulated for the duration of the commitment;

e) percentages obtained for each cost category are added. The total of the percentages must not exceed the total for the first application;

f) for each consumption period, the result obtained as per Subparagraph e) is multiplied by the number of consumption periods since the beginning of the second application, minus one consumption period. This result is divided by 12;

g) the result obtained as per Subparagraph f) shall be subtracted from the result obtained as per Subparagraph e);

h) the result obtained as per Subparagraph g) is subtracted from the number (1), and the result corresponds to the billing coefficient.

Billing at the Load Retention Rate **171**

For each consumption period, the Load Retention Rate, which is applied to the whole or to any eligible portion of a customer's bill, is applied according to the following calculations:

a) a bill is determined according to the customer's actual consumption data and Rate L in effect, taking into account, if applicable, the discounts for supply at medium or high voltage and adjustment for transformation losses described in Sections 303 and 304. The bill is then multiplied by the billing coefficient determined as per Subparagraph f) of Section 169 in the case of a first application and as per Subparagraph h) of Section 170 in the case of a second and last application;

b) on the other hand, another bill based only on the price of energy at Rate L in effect, increased by 10%, is established;

c) the customer's bill is the highest of a) or b) above.

The Load Retention Rate may apply to the whole or to a portion of the customer's load. Such Rate is applied only to the portion of the load which qualifies. If the Load Retention Rate is applied only to a portion of the load, such portion shall be established by written agreement between the customer and Hydro-Québec.

Subdivision 2 - Municipalities' Large-Power Industrial Customers

Application **172**

This Subdivision applies to municipalities which apply the Load Retention Rate set forth in Subdivision 1 to their large-power industrial customers. In the present Subdivision, "municipality" designates a municipality which is a customer of Hydro-Québec and which operates its own distribution system.

Object **173**

Hydro-Québec shall reimburse the municipality the difference between the customer's normal Rate L bill and the bill resulting from the application of the Load Retention Rate set forth in Subdivision 1, for eligible contracts.

Terms and conditions of application **174**

The reimbursement mentioned in Section 173 shall be subject to the following conditions:

a) the customer of the municipality shall advise the latter in writing as stipulated in Section 165 and provide all relevant supporting documents, as well as all required information in accordance with Section 166;

b) the municipality shall submit to Hydro-Québec the customer's application and all relevant supporting documents as well as all information required in accordance with Section 166. Hydro-Québec shall determine the eligibility of the contract to the Load Retention Rate and advise the municipality in writing of its acceptance or rejection;

c) Hydro-Québec shall reimburse the municipality the difference between the normal Rate L bill and the Load Retention Rate bill throughout the period during which the contract remains eligible for the Load Retention Rate; Hydro-Québec shall begin to apply the adjustment on the first electricity bill which it issues to the municipality after the 30 days following the end of the consumption period during which it has transmitted to the municipality the acceptance mentioned in Subparagraph b) above.

NORTHERN INDIANA PUBLIC SERVICE COMPANY
IURC Electric Service Tariff
Original Volume No. 10

First Revised Sheet No. 14.1
Superseding
Substitute
Original Sheet No. 14.1

RIDER GA
GENERATION ALTERNATIVE RIDER

TO WHOM AVAILABLE

This is an experimental Rider available to Customers who intend on installing on- site generation technology as an energy source, and who agree to postpone the installation and receive service under any of the following rate schedules:

Rate 824 - General Service – Large Use

Rate 825 - Metal Melting Service

Rate 826 - Off-Peak Service

Rate 832 - Industrial Power Service

Rate 833 - Industrial Power Service

The availability of this Rider shall be limited to Customers who propose a minimum of 500 KW of potential on-site generation capacity at each Customer location. Additionally, the project must be a viable project subject to review and approval by the Company. This Rider is further limited to Customer locations that can utilize the total electric output of the potential on-site generation facility for at least 4,500 hours per year. Application for service under this Rider must be made before December 31, 1995.

CONTRACT

Service under this Rider requires a contract between the Customer and the Company. The Company will negotiate with the Customer the specific terms of the Contract which shall provide for service by the Company of all the alternative electric power requirements of the Customer for a period of up to five (5) years.

TERMS OF WRITTEN CONTRACT

Upon approval by the Commission of the written contract between the Customer and the Company governing the application of this Rider GA to the electrical load of the Customer, the specific terms of such written contract shall, solely as between the Customer and the Company, be deemed to be a part of this Rider GA.

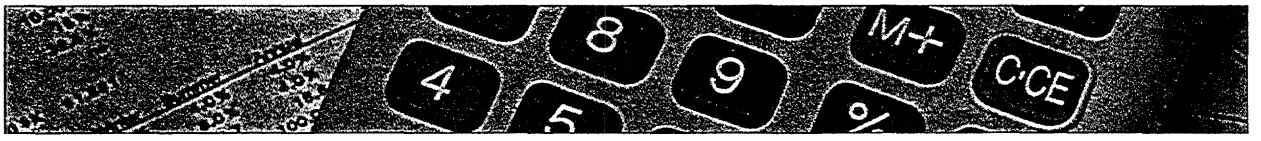
SUB-RIDER DESIGNATION

Any written contract submitted by the Company for approval under this Rider GA and approved by the Commission shall be filed with the Commission as a separate sub-rider designated Rider GA – (insert sequential number).

ONTARIO HYDRO

LOAD RETENTION AND EXPANSION

1999 Price Option



DESCRIPTION

The Load Retention and Expansion Price (LREP) provides a mechanism that allows Hydro to respond with a negotiated price in situations where Hydro faces competition from lower-cost energy suppliers and where such negotiations could be expected to influence existing or potential customers' decisions regarding:

- Shifting production or relocating plants to another jurisdiction;
- Fuel switching;
- Customer owned and operated self-generation projects; or
- Plant expansion or location in Ontario.

Snapshot

LOAD RETENTION AND EXPANSION

- Allows for electricity price negotiations where load would be at risk with new or existing direct industrial customers of Ontario Hydro or large customers of Hydro-supplied MEUs.
- Process:
  - Customer prepares business case
  - Third-party review
  - Price negotiation on load at risk

BENEFITS

For existing and potential Ontario Hydro Direct customers and Large Use customers of municipal utilities faced with major decisions that involve energy cost considerations, a LREP could ensure that their electricity prices are highly competitive. This is naturally good for the provincial economy as a whole, as well as for the utilities that will retain or acquire these customers.

ELIGIBILITY

The following customers can apply for this option, provided their demand exceeds 5 MW:

- New or existing direct industrial customers of Ontario Hydro, or
- Large customers of a municipal electric utility or a distributing company supplied by Hydro.

The LREP is applied solely at the discretion of Hydro and is not available for load transfers between customers supplied directly or indirectly by Hydro.

In cases of load retention related to shifting production, relocating plants, or transferring demand to another jurisdiction or to a franchised supply authority not supplied directly or indirectly by Hydro, the customer applying for the discount must satisfy an independent third-party reviewer that it has a genuine opportunity to implement the project. The applicant must also provide:

- evidence of its ability both to immediately sever physical ties from its supply authority and to establish supply from a franchised supply authority not supplied directly or indirectly by Hydro;
- estimates of the capital and other costs involved in both severing connection ties with Hydro, a municipal electric utility or a distributing company supplied by Hydro and establishing them with the alternative supply authority;
- a documented business case for the LREP that includes a written offer, detailing the price quoted and the terms and conditions of service from another supply authority that is entitled to serve the applicant.

In cases of load retention related to customer owned and operated self-generation or fuel-switching projects, the applicant shall provide a documented business case that includes a detailed engineering design and estimates of the project's capital and other costs. An independent third-party reviewer also must be satisfied that the customer has a genuine opportunity to establish the project or, in the case of fuel switching, use an alternative energy source.

For load new to Ontario Hydro or a Municipal Electric Utility, the applicant shall provide a documented business case which includes, among other things, a written offer from another utility or alternative fuel utility. The offer shall detail the cost or price and relevant terms and conditions. Independent third-party review also applies in these cases.

All applicants, in any of the above cases, shall supply detailed information about their goods, services, technologies and markets.

PRICING

Any negotiated LREP will apply only to that portion of the load demonstrated to be at risk. After all information provided by the customer has been considered, prices will be negotiated on an individual basis and be subject to the following guidelines:

- Discounts will be set at the minimum level needed to respond to the bona fide offer from another Supply Authority or alternative energy source, but in any event the price will not be less than the minimum price limit of:
  i) Real Time Pricing II prices for firm power sales, and
  ii) Surplus power prices for interruptible power sales;
  plus an allowance to cover administration;

- Discounts will not result in a bill reduction below the minimum billing provisions; and

- Capital contribution towards new facilities will be calculated on the net revenue streams from customers taking power under this option.

TERMS AND CONDITIONS

- Ontario Hydro's evaluation will include, among other things: a review and assessment of the third-party reviewer's report; the supporting documentation provided by the applicant; and the effect, if any, that granting the LREP to the applicant has on directly competing customers who purchase similar quantities of power. After completing this evaluation, Hydro will, at its sole discretion, decide, first of all, whether or not to enter into LREP negotiations and, secondly, the level of the negotiated price.

- LREP contract terms are limited to no more than 5 years.

- Customers with LREP contracts are required to demonstrate a commitment to energy efficiency. A comprehensive audit must be conducted within six months of starting on this option and all energy efficiency measures identified in the audit which meet internal payback and approval criteria must be implemented.

- Any LREP agreements reached through negotiations are subject to Ontario Hydro Board approval and Order in Council approval by the provincial government. The applicant shall inform Hydro which portions of the agreement reached and information provided are confidential.

ECONOMIC DEVELOPMENT INITIATIVES RIDER

PURPOSE

This rider provides for an incentive rate billing option to existing commercial and industrial customers and new industrial customers to encourage economic development in the Company's service area.

APPLICATION PROVISIONS

This rider is applicable to existing commercial and industrial customers and new industrial customers served under Rate Schedules GS-3, LP-4, LP-5, and PR-1(R) with at least a one month Billing KW of 500 KW or greater under contract with the Company. Existing customers must sign a contract agreeing to (1) increase production or (2) expand physical plant at the service location. (C)

This rider is applied to customer baseline load, but is not applied to incremental or decremental kilowatt or kilowatt-hour usage under Rate Schedule PR-1(R).

DEFINITIONS

1. Base Period -- The base period is normally the twelve months ended December 31, 1986. If twelve months of billing history are unavailable for the period ended December 31, 1986, the base period is the first full twelve months of billing. If less than twelve months of billing history are available, the Company determines a base period use pattern prior to rider application. If, in the opinion of the Company, any billing month(s) during the base period is not representative of the customer's normal usage pattern, the Company may change the base period to reflect normal use conditions.

The base period established when this rider is applied initially at a service location to a customer's bill shall remain the base period for all subsequent applications of this rider at the same service location for the same customer. If, during the phase-in period, a customer purchases energy from the Company and from an electric generation supplier, base period usage shall include, on a pro rata basis, KW and KWH purchased from the Company and from the electric generation supplier. (C)

2. Sales Tax Exemption Certificate -- A Pennsylvania Sales Tax Exemption Certificate submitted by the customer to the Company which indicates the service address and certifies that, on an annual basis, more than fifty percent of the electricity purchased is exempt from sales tax because it is used in manufacturing operations.

3. Service Location -- A location having one or more points of delivery for electric service billed by the Company under a single rate application.

4. New Service Location -- A service shown on the Sales Tax Exemption Certificate which (a) previously has not been supplied electric service by the Company, (b) previously has been supplied electric service, provided the new service is for a different manufacturing operation than the previous operation, or (c) was disconnected at least twelve months prior to application for service under this rider.

5. Qualifying Service Location -- A new service location identified on the Sales Tax Exemption Certificate or an existing service location which qualifies under the application provisions of this rider.

(Continued)

ECONOMIC DEVELOPMENT INITIATIVES RIDER (CONTINUED)

DEFINITIONS (Continued)

6. Billing Adjustments - Existing Customers. For that portion of the customer's load purchased from the Company, a reduction of $2 per kilowatt and 1 cent per kilowatt-hour shall apply, respectively, to each kilowatt of Billing KW and each kilowatt-hour of energy billed in excess of the Billing KW and kilowatt-hours for the corresponding billing month of the base period for service supplied to a customer's Qualifying Service Location. For that portion of the customer's load purchased from an electric generation supplier, the following reductions shall apply for Rate Schedules GS-3, LP-4, and LP-5. (C)(D)

	GS-3	LP-4	LP-5
Distribution Charge (Effective 1-1-99)	$0.270/KW 0.140¢/KWH	$0.140/KW 0.070¢/KWH	$0.020/KW 0.010¢/KWH
Competitive Transition Charge (Effective 1-1-99 through 8-9-99)	$0.490/KW 0.243¢/KWH	$0.530/KW 0.264¢/KWH	$0.570/KW 0.283¢/KWH
Competitive Transition Charge (Effective 8-10-99 through 12-31-99)	$0.133/KW 0.066¢/KWH	$0.144/KW 0.072¢/KWH	$0.155/KW 0.077¢/KWH
Competitive Transition Charge (Effective 1-1-00 through 12-31-00)	$0.077/KW 0.038¢/KWH	$0.085/KW 0.042¢/KWH	$0.092/KW 0.046¢/KWH
Competitive Transition Charge (Effective 1-1-01 through 12-31-01)	$0.075/KW 0.037¢/KWH	$0.083/KW 0.041¢/KWH	$0.088/KW 0.045¢/KWH
Competitive Transition Charge (Effective 1-1-02 through 12-31-02)	$0.071/KW 0.035¢/KWH	$0.080/KW 0.039¢/KWH	$0.085/KW 0.042¢/KWH
Competitive Transition Charge (Effective 1-1-03 through 12-31-03)	$0.068/KW 0.034¢/KWH	$0.076/KW 0.038¢/KWH	$0.083/KW 0.041¢/KWH
Competitive Transition Charge (Effective 1-1-04 through 12-31-04)	$0.064/KW 0.032¢/KWH	$0.073/KW 0.037¢/KWH	$0.080/KW 0.040¢/KWH
Competitive Transition Charge (Effective 1-1-05 through 12-31-05)	$0.061/KW 0.030¢/KWH	$0.069/KW 0.034¢/KWH	$0.074/KW 0.037¢/KWH
Competitive Transition Charge (Effective 1-1-06 through 12-31-06)	$0.058/KW 0.029¢/KWH	$0.065/KW 0.033¢/KWH	$0.070/KW 0.035¢/KWH
Competitive Transition Charge (Effective 1-1-07 through 12-31-07)	$0.054/KW 0.027¢/KWH	$0.063/KW 0.031¢/KWH	$0.068/KW 0.034¢/KWH
Competitive Transition Charge (Effective 1-1-08 through 12-31-08)	$0.047/KW 0.023¢/KWH	$0.053/KW 0.027¢/KWH	$0.058/KW 0.029¢/KWH
Competitive Transition Charge (Effective 1-1-09 through 12-31-09)	$0.270/KW 0.133¢/KWH	$0.310/KW 0.155¢/KWH	$0.330/KW 0.166¢/KWH

(Continued)

(C) Indicates Change
(D) Indicates Decrease

ECONOMIC DEVELOPMENT INITIATIVES RIDER (CONTINUED)

	GS-3	LP-4	LP-5
Intangible Transition Charge (Effective 8-10-99 through 12-31-99)	$0.357/KW 0.177¢/KWH	$0.386/KW 0.192¢/KWH	$0.415/KW 0.206¢/KWH
Intangible Transition Charge (Effective 1-1-00 through 12-31-00)	$0.373/KW 0.187¢/KWH	$0.415/KW 0.207¢/KWH	$0.448/KW 0.222¢/KWH
Intangible Transition Charge (Effective 1-1-01 through 12-31-01)	$0.365/KW 0.182¢/KWH	$0.407/KW 0.203¢/KWH	$0.432/KW 0.217¢/KWH
Intangible Transition Charge (Effective 1-1-02 through 12-31-02)	$0.349/KW 0.173¢/KWH	$0.390/KW 0.194¢/KWH	$0.415/KW 0.208¢/KWH
Intangible Transition Charge (Effective 1-1-03 through 12-31-03)	$0.332/KW 0.166¢/KWH	$0.374/KW 0.188¢/KWH	$0.407/KW 0.202¢/KWH
Intangible Transition Charge (Effective 1-1-04 through 12-31-04)	$0.316/KW 0.159¢/KWH	$0.357/KW 0.180¢/KWH	$0.390/KW 0.193¢/KWH
Intangible Transition Charge (Effective 1-1-05 through 12-31-05)	$0.299/KW 0.148¢/KWH	$0.341/KW 0.171¢/KWH	$0.366/KW 0.183¢/KWH
Intangible Transition Charge (Effective 1-1-06 through 12-31-06)	$0.282/KW 0.139¢/KWH	$0.315/KW 0.159¢/KWH	$0.340/KW 0.172¢/KWH
Intangible Transition Charge (Effective 1-1-07 through 12-31-07)	$0.266/KW 0.132¢/KWH	$0.307/KW 0.153¢/KWH	$0.332/KW 0.166¢/KWH
Intangible Transition Charge (Effective 1-1-08 through 12-31-08)	$0.253/KW 0.125¢/KWH	$0.287/KW 0.145¢/KWH	$0.312/KW 0.155¢/KWH
Intangible Transition Charge (Effective 1-1-09 through 12-31-09)	$0.000/KW 0.000¢/KWH	$0.000/KW 0.000¢/KWH	$0.000/KW 0.000¢/KWH

7. Billing Adjustments - New Customers. For that portion of the customer's load purchased from the Company, a reduction of 1 cent per kilowatt-hour shall apply to all kilowatt-hours billed in excess of 400 hours use of the monthly Billing KW for service supplied to a customer's Qualifying Service location. For that portion of the customer's load purchased from an electric generation supplier, the following reductions shall apply for Rate Schedules GS-3, LP-4, and LP-5. (C)(D)

(Continued)

(C) Indicates Change
(D) Indicates Decrease

ECONOMIC DEVELOPMENT INITIATIVES RIDER (CONTINUED)

	GS-3	LP-4	LP-5
Distribution Charge (Effective 1-1-99)	0.140¢/KWH	0.070¢/KWH	0.010¢/KWH
Competitive Transition Charge (Effective 1-1-99 through 8-9-99)	0.243¢/KWH	0.264¢/KWH	0.283¢/KWH
Competitive Transition Charge (Effective 8-10-99 through 12-31-99)	0.066¢/KWH	0.072¢/KWH	0.077¢/KWH
Competitive Transition Charge (Effective 1-1-00 through 12-31-00)	0.038¢/KWH	0.042¢/KWH	0.046¢/KWH
Competitive Transition Charge (Effective 1-1-01 through 12-31-01)	0.037¢/KWH	0.041¢/KWH	0.045¢/KWH
Competitive Transition Charge (Effective 1-1-02 through 12-31-02)	0.035¢/KWH	0.039¢/KWH	0.042¢/KWH
Competitive Transition Charge (Effective 1-1-03 through 12-31-03)	0.034¢/KWH	0.038¢/KWH	0.041¢/KWH
Competitive Transition Charge (Effective 1-1-04 through 12-31-04)	0.032¢/KWH	0.037¢/KWH	0.040¢/KWH
Competitive Transition Charge (Effective 1-1-05 through 12-31-05)	0.030¢/KWH	0.034¢/KWH	0.037¢/KWH
Competitive Transition Charge (Effective 1-1-06 through 12-31-06)	0.029¢/KWH	0.033¢/KWH	0.035¢/KWH
Competitive Transition Charge (Effective 1-1-07 through 12-31-07)	0.027¢/KWH	0.031¢/KWH	0.034¢/KWH
Competitive Transition Charge (Effective 1-1-08 through 12-31-08)	0.023¢/KWH	0.027¢/KWH	0.029¢/KWH
Competitive Transition Charge (Effective 1-1-09 through 12-31-09)	0.133¢/KWH	0.155¢/KWH	0.166¢/KWH

(Continued)

ECONOMIC DEVELOPMENT INITIATIVES RIDER (CONTINUED)

	GS-3	LP-4	LP-5
Intangible Transition Charge (Effective 8-10-99 through 12-31-99)	0.177¢/KWH	0.192¢/KWH	0.206¢/KWH
Intangible Transition Charge (Effective 1-1-00 through 12-31-00)	0.187¢/KWH	0.207¢/KWH	0.222¢/KWH
Intangible Transition Charge (Effective 1-1-01 through 12-31-01)	0.182¢/KWH	0.203¢/KWH	0.217¢/KWH
Intangible Transition Charge (Effective 1-1-02 through 12-31-02)	0.173¢/KWH	0.194¢/KWH	0.208¢/KWH
Intangible Transition Charge (Effective 1-1-03 through 12-31-03)	0.166¢/KWH	0.188¢/KWH	0.202¢/KWH
Intangible Transition Charge (Effective 1-1-04 through 12-31-04)	0.159¢/KWH	0.180¢/KWH	0.193¢/KWH
Intangible Transition Charge (Effective 1-1-05 through 12-31-05)	0.148¢/KWH	0.171¢/KWH	0.183¢/KWH
Intangible Transition Charge (Effective 1-1-06 through 12-31-06)	0.139¢/KWH	0.159¢/KWH	0.172¢/KWH
Intangible Transition Charge (Effective 1-1-07 through 12-31-07)	0.132¢/KWH	0.153¢/KWH	0.166¢/KWH
Intangible Transition Charge (Effective 1-1-08 through 12-31-08)	0.125¢/KWH	0.145¢/KWH	0.155¢/KWH
Intangible Transition Charge (Effective 1-1-09 through 12-31-09)	0.000¢/KWH	0.000¢/KWH	0.000¢/KWH

GENERAL CONDITIONS

The provisions of this rider are available to customers who became eligible on or before December 31, 1989.

The billing adjustment under this rider will continue through December 31, 2009. All provisions of this rider will terminate on January 1, 2010.

The rate reductions under this rider are applicable to base rate charges before application of the State Tax Adjustment Surcharge included in this tariff.

(Continued)

ECONOMIC DEVELOPMENT INITIATIVES RIDER (CONTINUED)

GENERAL CONDITIONS (Continued)

Minimum bills under the applicable rate schedule are not reduced by the application of this rider.

This rider applies only once per customer. Eligible customers who elect to receive billing adjustments under this rider as new customers subsequently may not elect to receive billing adjustments under this rider as existing customers.

This rider does not apply to customers who have on-site generation which can be substituted for the Company's service, unless the on-site generation is maintained solely for use in case of interruption of Company's service.

An electric service contract is required for billing under this rider.

The Company will monitor the effects of this rider and make appropriate modifications or close the rider to additional applications as approved by the Pennsylvania Public Utility Commission.

COMPETITIVE RATE RIDER (R) (C)

New applications for service under this Rider are limited to customers of the Company who have not had the opportunity to purchase capacity and energy from their choice of electric generation supplier pursuant to the enrollment procedures contained in the Commission's order at Docket Nos. M-00960890F.0014 and M-00960890F.0015. No new applications will be accepted after August 27, 1998. (C)

PURPOSE

This rider provides competitive rates to existing and new commercial and industrial customers served under Rate Schedules LP-5, LP-6, and IS-T who can demonstrate that they have a viable competitive alternative to purchasing electric service from the Company and intend to select that alternative to the detriment of the Company and its ratepayers. (C)

APPLICATION PROVISIONS

This rider is applicable to existing and new commercial and industrial customers with a monthly maximum demand of 5,000 KW or greater year-round who are served, or who qualify to be served, under Rate Schedules LP-5, LP-6, and IS-T.

The Company will not enter into new contracts for interruptible service if the amount of interruptible power from all customers served under Rate Schedules IS-1, IS-P, IS-T, PR-2(R), the Competitive Rate Rider, and Interruptible Service by Agreement exceeds a total of 500 MW.

GENERAL CONDITIONS

1. The customer must demonstrate that it has a viable competitive alternative to service under Rate Schedule LP-5, LP-6, or IS-T to be eligible for this rider. The customer must provide written information, satisfactory to Company, documenting the customer's competitive alternative. Because of the proprietary nature of the customer's information, this information shall remain confidential.

2. The customer also must demonstrate, to the satisfaction of the Company, that the customer intends to implement the competitive alternative and is financially able to do so.

3. The Company will provide, upon request, a written description of the information that the customer must provide to the Company.

4. The Company shall be the sole judge of whether or not a competitive rate under this rider is appropriate based on the information provided by the customer.

5. The Company will develop competitive rates and terms, on a case-by-case basis, if the Company, in its sole judgement, determines that they are appropriate. The Company is not obligated to match the customer's costs for an alternative source of energy. The rate shall be sufficient to recover all of the Company's appropriate short-run marginal costs of the service and make a contribution to the Company's fixed costs, but shall not exceed the rate for comparable service under Rate Schedule LP-5, LP-6, or IS-T.

(Continued)

COMPETITIVE RATE RIDER (R) (CONTINUED) (C)

GENERAL CONDITIONS (Continued)

6. To promote energy conservation and efficiency, the Company may require that the customer implement energy efficiency measures prescribed by the Company.

7. The State Tax Adjustment Surcharge is applicable to service under this Rider. (C)

8. The Economic Development Initiatives Rider and Industrial Development Initiatives Rider provisions of Rate Schedule LP-5 and the Demand Free Day provision of Rate Schedules LP-5 and LP-6 included in this tariff are not applicable to service under this Rider.

9. This Rider does not apply to customers who have on-site generation which can be substituted for the Company's service, unless the on-site generation is maintained solely for use in case of interruption of Company's service. (C)

10. An electric service contract is required for billing under this Rider. The competitive rate shall be specified in the contract. Because of the proprietary nature of the terms of the contract, the terms shall remain confidential. (C)

(C)

ECONOMIC EFFICIENCY RIDER (EER)

AVAILABILITY. To any High Tension Power (Rate HT) or General Service (Rate GS) customer that satisfies all of the following eligibility requirements:

1. The customer must agree to purchase at least 5,000 kW of On-Peak demand during each billing month.

2. The customer must provide documentation of a viable, currently available competitive alternative to service under Rate HT or Rate GS including any applicable riders. The customer must provide a written description of the competitive alternative and any further information that the Company requires in order to document the cost and demonstrate the viability of the customer's competitive alternative. The Company shall be the sole judge of whether the customer is eligible for a rate negotiated pursuant to this rider based upon the information provided by the customer. The Company may require that the information that the customer must provide include: (1) an engineering study that contains information regarding site suitability, space requirements, equipment lists, vendor quotes, and a detailed construction schedule with clearly identified milestones, and (2) a study containing a minimum five-year life cycle evaluation of the competitive alternative that includes capital, installation, fuel, operating and maintenance, and any other anticipated costs. The Company need not require all, or any, of the preceding information if the customer already has in place a competitive alternative, in which case the Company will require such written proof of the existence and nature of the alternative as the Company deems appropriate and necessary.

3. The customer must demonstrate, to the satisfaction of the Company, that the customer is financially capable and willing to implement its viable, currently available competitive alternative.

CONDITIONS OF SERVICE. Electric service under this rider shall be firm.

RATE, BILLING AND UNBUNDLING. The rates negotiated and established shall be based upon the customer's documented, viable, currently available competitive alternative. The rates will be, in the sole judgment of the Company, competitive, but the Company shall not be obligated to agree to rates that match the customer's costs under the customer's viable, currently available competitive alternative. The rates shall not result in charges that yield an average cost per kWh that is less than the end-block (lowest energy rate) price of the customer's applicable Base Rate (Rate HT or Rate GS).

Effective as of January 1, 1999, the Company will unbundle EER contracts as follows:

For contracts that do not address the right to Direct Access and/or unbundling, and that contain discount factors applicable to the capacity charge and first two energy blocks of the bundled Rate HT or to some subset of those three charges (in effect as of the effective date of the contract), the unbundled charges will be, starting January 1, 1999: (i) the Rate HT unbundled Distribution Service Charges, and Energy and Capacity Charges; and (ii) the Rate HT CTC/ITC charges discounted to yield total charges that are less than what the total Rate HT charges would be by an amount determined using the Customer's negotiated overall percentage discount. If this process would yield a negative CTC/ITC charge due to the magnitude of the customer's negotiated overall percentage discount, the CTC/ITC charge will be set to zero. Any remaining discounts required to achieve the customer's negotiated overall percentage discount will be applied to the Energy and Capacity Charges.

For contracts that contain provisions governing the customer's rights upon the advent of Direct Access and/or unbundling, the Company will unbundle the customer's contract in accordance with the terms and conditions of the customer's Contract.

For contracts first effective after December 31, 1996, the Company will unbundle the customer's contract in accordance with the terms and conditions of the customer's Contract.

OTHER RIDERS. No other riders are available in conjunction with the EER after January 1, 1996, except that: 1) a Rate HT customer that qualifies for service under Interruptible Rider 1 (IR-1) may obtain IR-1 service, and 2) a customer that wishes to operate customer-owned generation equipment in parallel with the Company's system may obtain service under the Auxiliary Service Rider (ASR). Backup, maintenance, or supplemental power (as defined in the ASR) will be billed under Rate GS or HT and not under EER.

TERM OF CONTRACT/RIGHTS AND CONSEQUENCES ASSOCIATED WITH DIRECT ACCESS. The customer must enter into a written contract with the Company, and the term of the contract shall be for a minimum of five years unless the law applicable to a particular customer prevents the customer from entering into a contract with a minimum term of five years. The customer or the Company may terminate the contract at the end of the term of contract by giving written notice of termination at least one hundred-eighty (180) days before the end of the term of contract. If neither party gives such notice, then the contract shall continue upon the same terms and conditions from year to year until terminated by either the customer or the Company giving the other at least one hundred-eighty (180) days prior written notice.

For contracts in effect at any time before December 31, 1996 that do not contain provisions governing the customer's rights upon the advent of Direct Access and/or unbundling, and that contain discount factors applicable to the capacity charge and first two energy blocks of the bundled Rate HT or to some subset of those three charges (in effect as of the effective date of the contract), the term of contract will be extended to the later of any applicable statutory rate cap period or any rate cap period contained in the Joint Petition for Full Settlement then in effect. Customers with such contracts may continue service under their contract while also obtaining

Competitive Energy Supply. If such a customer obtains Competitive Energy Supply, the customer will continue to pay the unbundled Distribution Service Charges and Competitive Transition Charges as designed in accordance with the "Rate And Billing And Unbundling" section, above.

For contracts in effect at any time on or before December 31, 1996, that contain provisions governing the customer's rights upon the advent of Direct Access and/or unbundling, the term of contract will remain as stated in the contract, and the customer will be entitled to obtain Competitive Energy Supply only in accordance with the terms and conditions of the customer's contract. Contract expiration shall not affect the applicability of any statutory rate cap or any rate cap contained in the Joint Petition for Full Settlemenithen in effect.

For contracts first effective after December 31, 1996, the term of contract will be as stated in the contract, and the customer will be entitled to obtain Competitive Energy Supply only in accordance with the Customer's contract. Contract expiration shall not affect the applicability of any statutory rate cap or any rate cap contained in the Joint Petition for Full Settlemenithen in effect, which rate caps will be those applicable to the Customer's base rate.

CONFIDENTIALITY. Because of their proprietary nature, the terms and conditions of the customer's contract shall remain confidential. The customer's contract will require the customer to maintain the confidentiality of the terms and conditions of the contract. The contract will also provide that if the customer breaches its contract by violating its confidentiality provisions, then the customer's bill, before application of the State Tax Adjustment Clause, will be increased by 10% for a period of 12 months (or for the balance of the term of contract term if that is less than 12 months). If the law applicable to a particular customer prevents the customer from keeping the terms and conditions of the contract confidential, then these Confidentiality provisions shall not apply.

Schedule REDR
RETENTION ECONOMIC DEVELOPMENT RATE

APPLICABILITY

Applicable to existing customers with demands of at least 200 kW and not more than 4,000 kW with a Standard Industrial Classification Code of 200 through 3999 (Manufacturing), or 781 (Motion Picture Production and Allied Services). The customer must demonstrate to the satisfaction of the Utility that relocation of their entire operations to a site outside the Utility's service territory is a viable alternative. Customers will be eligible for service under this Schedule only if their decision to remain in California is made in connection with California Trade and Commerce Department Red Team efforts made prior to offering and acceptance of the discount below. (California Trade and Commerce Department Red Team is a public-private task force that assists individual companies throughout the state in overcoming barriers to conducting business in California.) Also, the customer must sign an affidavit stating that the discounts offered under this Schedule were a material factor in the customer's decision to retain its load within the Utility's service territory.

Customers with demands of 500 kW or less must be served under General Service Schedules GS-2 or TOU-GS-2. Customers with demands in excess of 500 kW must be served under General Service Schedules TOU-8 or I-6.

This Schedule is not applicable to customers taking service under Schedules AEDR, SSGDR or TOU-8-CR-1. This Schedule is also not applicable to customers taking service under the Spot Pricing Option of Schedule I-6, or to customers taking service under the Economic Development Rate provision of Schedule TOU-8. No customer subject to the Environmental Pricing Credit agreement may take service under this Schedule.

The combined eligible load served under Schedules AEDR, EEDR, and REDR is limited to 100 MW for all participants. If SCE does not request extension of this Schedule for the remainder of the transition period by March 31, 2000, then this Schedule shall be closed to new customers as of March 31, 2000, or when the 100 MW limit is reached, whichever occurs first.

TERRITORY

Within the entire territory served.

RATES

Unless provided herein, or in the Retention Economic Development Rate Agreement, all charges and provisions of the customer's Otherwise Applicable Tariff shall apply, except that the customer's energy and demand charges shall be subject to discount as follows:

(Continued)

Schedule REDR
RETENTION ECONOMIC DEVELOPMENT RATE
(Continued)

RATES (Continued)

Year 1	25%
Year 2	20%
Year 3	15%
Year 4	10%
Year 5	5%
Year 6	0%
Year 7	0%

The discount does not apply to the California Alternate Rates for Energy Surcharge, as set forth in Preliminary Statement, Part O, Section 5, or the Public Utilities Commission Reimbursement Fee.

All discounted charges shall be subject to a Minimum Charge computed as set forth in the Retention Economic Development Rate Agreement.

SPECIAL CONDITIONS

1. Otherwise Applicable Tariff: The customer's regularly filed rate schedule under which service is rendered.

2. Agreement: The customer must sign the Retention Economic Development Rate Agreement in order to take service under this Schedule.

3. Affidavit: All customers taking service under this Schedule are required to sign an affidavit stating, under penalty of perjury, that the terms and conditions of this Schedule were a material factor in its decision to retain load within the Utility's service territory.

4. All customers must agree to maintain a minimum level of load for seven years from the date service is first rendered under this provision as set forth in the Retention Economic Development Rate Agreement.

(Continued)

Schedule REDR
RETENTION ECONOMIC DEVELOPMENT RATE
(Continued)

SPECIAL CONDITIONS (Continued)

5. Contribution to Margin (CTM) Credit: This credit is limited to a combined total of 55 MW of load from all customers to which the CTM Credit is extended. It is applicable only to customers with a SIC Code classification that has an "Industry and Consumer Spending Job Multiplier" that equals or exceeds the median job multiplier for all industries statewide. Job multipliers are determined by the California Trade and Commerce Agency. The terms and conditions of this credit are set forth in the CTM Agreement which customer must sign in order to receive the CTM Credit.

6. Recorded Demands greater than 4,000 kW: The customer may remain on this Schedule if its recorded demand is greater than 4,000 kW. However, no discount shall apply to any recorded demand greater than 4,000 kW or any associated kilowatthours.

7. Revenue Accounting: For purposes of revenue accounting, the total charges under this Schedule shall be converted into the following rate components: Distribution, Transmission, Transmission Revenue Balancing Account Adjustment (TRBAA), Averaged Power Exchange (PX) Energy Charge, Competition Transition Charge (CTC), Public Purpose Programs Charge (PPPC), and Nuclear Decommissioning Charge (NDC). The discount is based on the total bill as determined for Bundled Service Customers under the customer's Otherwise Applicable Tariff, by way of a reduction to the Generation Charge. The values for the Distribution, Transmission, TRBAA, PPPC, and NDC rate components shall be as described in the Rate Components Section of the customer's Otherwise Applicable Tariff. The values for the Averaged PX Energy Charge and the CTC which is determined residually shall be determined in accordance with Schedule PX and account for the balance of the charges.

8. Seasons and Time Periods: Consistent with the seasons and time periods defined in Schedule TOU-8 applicable to Qualifying Facilities, the summer season shall commence at 12:00 a.m. on June 1 and continue until 12:00 a.m. on October 1. The winter season shall commence at 12:00 a.m. on October 1 and end at 12:00 a.m. on June 1. During the winter season, a super off-peak time period of midnight to 6:00 a.m. shall apply.

9. Other Discounts: Load served under the terms and conditions of this Schedule and associated agreement is not eligible for any other discount or reduced rate.

(Continued)

Schedule REDR
RETENTION ECONOMIC DEVELOPMENT RATE
(Continued)

SPECIAL CONDITIONS (Continued)

10. Billing: A Customer's bill is first calculated according to the total rates and conditions above. The following adjustments are made depending on the option applicable to the customer.

    a. Bundled Service Customers receive supply and delivery services solely from Edison. The Customer's bill is based on the total rates set forth above. The Power Exchange (supply) component is equal to the Averaged Power Exchange (PX) Energy Charge as set forth in Schedule PX.

    b. Direct Access Customers purchase energy from an Energy Service Provider and continue receiving delivery services from Edison. The Averaged PX Energy Charge is determined as specified for a Bundled Service Customer. The customer's bill will be calculated as for a Bundled Service Customer, but the Customer will receive a credit for the Averaged PX Energy Charge.

    c. Hourly PX Pricing Option Customers receive supply and delivery services solely from Edison. A Customer taking Hourly PX Pricing Option service must have an interval meter installed at its premise to record hourly usage, since PX Energy Costs change hourly. If such metering is not currently installed, it shall be installed at the customer's expense before Hourly PX Pricing can be provided. Edison's charges for such metering are determined as set forth in Rule 2. The bill for a Hourly PX Pricing Option Customer is determined by calculating the bill as if it were for a Bundled Service Customer, then crediting the bill by the amount of the Averaged PX Energy Charge, as determined for Bundled Service and Direct Access Customers, then adding the hourly PX Energy Cost amount which is determined by multiplying the hourly energy used in the billing period by the hourly PX Energy Cost determined as set forth in Section 1 of Schedule PX, and the appropriate hourly Line Loss Adjustment Factors as set forth in Section 3 of Schedule PX, and the Uncollectibles expense factor of 1.00313.

11. Generation Charge: The generation charge is calculated based on the total rate less the sum of: Distribution, Transmission, Public Purpose Programs, Nuclear Decommissioning, and Fixed Transition Amount (where applicable) charges, the Transmission Revenue Balancing Account Adjustment (TRBAA), and the Public Utilities Commission Reimbursement Fee. The Competition Transition Charge (CTC) is calculated residually by subtracting the Averaged PX Energy Charge calculated as set forth in Schedule PX from the generation charge (See Rate Components Table).

12. Negotiating of CTC Payment Method: Nothing in this rate schedule prohibits a marketer or broker from negotiating with Customers the method by which their Customer will pay the CTC.

NOVA SCOTIA UTILITY AND REVIEW BOARD

IN THE MATTER OF: The *Public Utilities Act*, R.S.N.S., 1989, c.380 as amended

IN THE MATTER OF: An Application by Nova Scotia Power Incorporated for approval of a Load Retention Rate

RESPONSE TO INFORMATION REQUEST

TO: **NSUARB**

FROM: **NSPI**

Question IR-20: **Page 9, lines 13-14**

a) Please provide a copy of EPRI's survey of Innovative Rates

b) Please provide all of the other documents related to the EPRI's survey.

Response IR-20:

a) This EPRI document (EPRI TR-100469s Volumes 1 - 3) is protected by copyright. As a result, NSPI is unable to provide copies for public release. However, the report can be reviewed at NSPI's offices by contacting Mel Whalen at (902) 428-6875.

b) There are no other related documents related to the ERPI survey. However, the attached survey by the Illinois Commerce Commission includes additional information on load retention rates as of 1994.

DATE FILED: December 23, 1999

SURVEY OF STATE

ECONOMIC DEVELOPMENT UTILITY

RATES AND POLICIES

-- STAFF REPORT --



ILLINOIS COMMERCE COMMISSION

Dennis L. Sweatman, Director
Edward J. Wisniewski, Economic Analyst
Economic Development Program

July 1994

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INTRODUCTION

This report describes the results of a survey which identified states that permit particular innovative utility rate mechanisms for the gas and electric industries. The report also provides insight into the rationale for such rate offerings, discusses Illinois' relative competitive position from an economic development standpoint, and identifies significant trends since the completion of a similar survey effort by the Illinois Commerce Commission in 1989.

Beginning with an overview of general findings, the report moves to defining and discussing the survey results for three sets of economic development related rate mechanisms. The report continues with the identification of state positions on two issues of increasing importance (competitive bidding and electric retail wheeling) that have extensive economic development implications. Finally, the report compares selected offerings in Illinois with the states of Indiana, Michigan, Ohio, and Wisconsin (From a geographic standpoint, these states can be viewed as Illinois' primary competitors for attracting new businesses and retaining existing businesses).

For purposes of the survey used in developing this report, the types of innovative rates and policies are limited to incentive based, market responsive, and efficiency mechanisms. These mechanisms are used to encourage business development, alter customer's load shape favorably to the benefit of all parties involved, retain existing load, and address inadequacies in existing rate design to respond to market pressures. The three basic rate mechanisms are as follows:

- *Incentive rates* - rates that increase the total margin to the utility through the greater utilization of otherwise unused capacity (see table 2 for a state-by-state summary).

- *Retention/Market Driven rates* - rates discounted to a level comparable with the customer's next best alternative and allowing for adequate coverage of marginal utility costs (see table 4 for a state-by-state summary).

- *Efficiency rates* - rates designed to alter the existing pattern of customer consumption to enhance the efficient utilization of the utilities' resources (see table 5 for a state-by-state summary).

The information contained in this report does not constitute a policy statement or rulemaking of the Illinois Commerce Commission. Statements regarding the results of the survey represent the opinions and conclusions of the authors and do not necessarily depict the views of the Commission.

GENERAL FINDINGS

The general findings of the survey illustrate the extent to which economic development utility rates or other similar vehicles are utilized among the states to compete for business customers. As competition continues in the gas industry and makes its way into the electric industry, states compete with greater intensity for business customers. As a result, state public utility commissions have been increasingly compelled to offer utilities more flexibility in serving their customers. The presence of innovative rates provides significant indication of the existence of state competition for new customers.

To illustrate this, utilities in 39 of the 45 states responding to the survey (including Washington, DC) offer economic development/incentive rates, as defined by this study, through the use of tariffs and/or special contracts approved by state public utility commissions. A similar study undertaken by the Illinois Commission in 1989 identified 36 states that offered such rates. Generally, the utilities in such states offer reduced rates in order to stimulate sales and enhance their revenues, and ease the fixed cost contributions of other ratepayers. By engaging in such activities, the frequency of rate cases may be reduced and business activity stimulated. Benefits from such actions generally include increased capital investment, increased employment levels, and increased tax contributions.

Another example illustrates the states' desire to retain existing business activity and enhance the efficient use of existing utility production resources. Forty-one states offer load

retention rates, that is, rates altered to retain the customer by mirroring the economics of the customer's energy alternative.

Among midwestern states (Illinois, Indiana, Michigan, Iowa, and Wisconsin) only Illinois and Michigan offer economic development rates to gas customers, while Wisconsin is the only state in this group that does not offer such rates to electric customers.

Finally, 37 states offer at least one type of innovative rate (such as an interruptible rate) for the purpose of enhancing the efficiency of existing utility production facilities, while at the same time reducing the energy bills of business customers.

SECTION A. Economic Development/Incentive Rates

Economic development/incentive utility rates are intended to stimulate economic activity (job creation and capital investment). By reducing a participating customer's overall utility costs, the rates help to improve the prospects for business growth. In addition, the rates can a) help improve the efficiency of the utilities' systems by utilizing available capacity, b) provide a contribution to the fixed costs of the utilities, and c) attract new load to the utilities' systems which, if retained after the discounts are phased-out, will spread fixed costs over a broader customer base, thereby making ratepayers' rates lower than otherwise would be the case.

Seventy-six percent of states surveyed allow utilities to offer some form of economic development rates to gas and/or electric customers. Illinois is 1 of 14 states (24 percent) that offer economic development rates within both the gas and electric industries through special contracts and/or tariffs, the terms of which may have a fair amount of flexibility. Illinois, like 29 other states (57 percent) responding to the survey, makes such rates available to new load regardless of whether the customer is new to the system or is an existing customer. However, discounts for existing customers only pertain to load additions. Nine other states (18 percent) allow economic development rates to pertain to existing load as well as additional customer load.

The following summarizes survey responses made regarding economic development/incentive rates and specifically identifies Illinois' positions. Table 1 condenses survey responses, while Table 2 reflects individual state-by-state responses.

1. Are utilities allowed to offer economic development/incentive rates as defined above? (Illinois - Yes)

   Yes 39 No 11 No Response 1

2. For what utilities are such rates offered? (Illinois - Gas and Electric)

   Electric Only 15 Gas Only 5 Both 14 No Response 17

3. What rate mechanisms are available to do so? (Illinois - Special Contracts and Tariffs)

   Tariffs Only 6 Special Contracts Only 3 Both 29 No Response 13

4. Are such rates fixed (i.e., predetermined discounts) or flexible (case-by-case negotiation)? (Illinois - fixed or flexible)

   Fixed Only 12 Flexible Only 7 Both 19 No Response 13

5. What load is applicable? (Illinois - Existing Business, Load Addition; New Customer, Entire Load)

Existing Business, Load Addition	30	Existing Business, Entire Load	9
New Customer, Entire Load	39	No Response	12

6. Is there a requirement that revenues received for the portion of load subject to discount must equal or exceed the marginal cost to serve such load? (Illinois - Yes)

   No 6 Yes 28 No Response 17

7. At the time of a rate case for utilities offering such rates, what treatment do such rates receive? (Illinois - The Illinois Commission reserves the right to assign responsibility (for any revenue requirements shortfall) at the time of a ratecase. However, ratepayers have historically been assigned such responsibility).

Stockholders bear responsibility 3	Ratepayers bear responsibility 10
Shared responsibility 3	No treatment considered 14
Other 3	No response 18

8. Are Impacts of such rates tracked? (Illinois - Yes)

Yes 21 No 13 No Response 17

9. Identify Commission considerations utilized to justify such rates. (Illinois - Promote Jobs, Increase utilization of existing resources, Encourage expansion of existing industry, and Encourage location within the state)

Promote job creation 22
Increase utility plant utilization 19 Other 21
Expansion of Existing Industry 21 No Response 12

Table 1 States Offering Economic Development Rates

State	Economic Development Rate offered (1)	Applicable Industries (2)	Rate Mechanism (3)	Rate Type If Tariffs Allowed (4)	Applicable Load (5)	Rates Exceed MC (6)	Rate Treatment (7)	Impacts Assessed (8)	Rate Justification (9)
Illinois	YES	Electric, Gas	SC,Tar	Fix,Flex	EIn,NEnt	YES	RP	YES	Exp,Inc,Pro,Oth

SUMMARY:

(1)
YES – 39
NO – 11
NO RESPONSE – 1

(2)
BOTH GAS AND ELECTRIC – 14
ELECTRIC ONLY – 15
GAS ONLY – 5
NO RESPONSE – 17

(3)
BOTH TARIFFS AND
SPECIAL CONTRACTS – 29
TARIFFS ONLY – 6
SPECIAL CONTRACTS ONLY – 3
NO RESPONSE – 13

(4)
BOTH FIXED AND FLEXIBLE – 19
FIXED ONLY – 12
FLEXIBLE ONLY – 7
NO RESPONSE – 13

(5)
EXISTING BUSINESS, LOAD ADDITION – 30
EXISTING BUSINESS, ENTIRE LOAD – 9
NEW CUSTOMER, ENTIRE LOAD – 39
NO RESPONSE – 12

(6)
YES – 28
NO – 6
NO RESPONSE – 17

(7)
STOCKHOLDERS – 3
RATEPAYERS – 10
SHARED – 3
NOT CONSIDERED – 14
NO RESPONSE – 18

(8)
YES – 21
NO – 13
NO RESPONSE – 17

(9)
PROMOTE JOB CREATION – 22
INCREASE UTILITY PLANT UTILIZATION – 19
EXPANSION OF EXISTING INDUSTRY – 21
OTHER – 21
NO RESPONSE – 12

Table 2 States Offering Economic Development Rates

State	Economic Development Rate offered	Applicable Industries	Rate Mechanism (1)	Rate Type If Tariffs Allowed (2)	Applicable Load (3)	Rates Exceed MC	Rate Treatment (4)	Impacts Assessed	Rate Justification (5)
Alabama	YES	Gas	SC,Tar	Fix,Flex	Ein,NEnt	NO	RP	YES	Pro
Alaska	NO								
Arizona	YES	Electric,Gas	SC,Tar	Fix,Flex	Ein,NEnt	YES	RP	NO	Oth
Arkansas	YES	Electric	SC,Tar	Fix,Flex	Ein,NEnt	YES	RP	YES	Exp,Oth
California	YES	Electric	Tar	Fix	Ein,NEnt	YES	RP	YES	Oth
Colorado	NO								
*Connecticut	YES		SC,Tar	Fix	Ein,NEnt				Exp,Oth
Delaware	NO								
Florida	NO								
Georgia	YES	Electric	Tar	Fix	Ein,NEnt	YES		YES	Pro
*Hawaii									
Idaho	NO								
Illinois	YES	Electric, Gas	SC,Tar	Fix,Flex	Ein,NEnt	YES	RP	YES	Exp,Inc,Pro,Oth
Indiana	YES	Electric	SC,Tar	Fix,Flex	Ein,NEnt	YES	SH	NO	Pro,Inc,Exp
Iowa	YES	Electric, Gas	SC,Tar	Flex	EEnt,NEnt	YES	SH	YES	Oth
Kansas	YES	Electric,Gas	SC,Tar	Fix	Ein,NEnt	YES	NC	NO	Pro,Exp,Oth
Kentucky	YES	Electric,Gas	SC	Flex	Ein,NEnt	YES	Oth	YES	Pro,Oth
*Louisiana	YES		SC,Tar	Fix	Ein,NEnt				Exp,Inc,Pro,Oth
Maine	YES	Electric	SC,Tar	Fix,Flex	EEnt,NEnt	YES	Oth	NO	Inc,Oth
Maryland	YES	Electric	Tar	Fix	EEnt,NEnt	YES	NC	YES	Pro
Massachusetts	YES	Electric, Gas	SC,Tar	Fix,Flex	EEnt,NEnt	YES	NC	YES	Inc
Michigan	YES	Electric, Gas	SC,Tar	Fix,Flex	Ein,NEnt	YES	RP	YES	Exp,Pro
Minnesota	YES	Electric	Tar	Fix	Ein,NEnt	YES	RP	YES	Exp,Pro
Mississippi	NO								
Missouri	YES	Electric, Gas	SC,Tar	Fix	Ein,NEnt	NO	Oth	YES	Inc,Oth
Montana	NO								
Nebraska	NO								
Nevada	NO								
New Hampshire	YES	Electric,Gas	SC	Flex	Ein,NEnt	YES	NC	YES	Pro,Exp
*New Jersey	YES		SC,Tar	Fix	Ein,NEnt				Exp,Inc,Pro,Oth
*New Mexico	YES		SC,Tar	Flex	Ein,NEnt				Exp,Inc,Oth
New York	YES	Electric	SC,Tar	Fix,Flex	EEnt,NEnt	YES	Shared	YES	Pro,Inc,Exp,
North Carolina	YES	Gas	Tar	Fix	EEnt,NEnt	YES	NC	NO	Inc
North Dakota	YES	Electric	SC,Tar	Fix,Flex	Ein,NEnt	YES	NC	NO	Pro,Exp,Oth
Ohio	YES	Electric	SC,Tar	Fix,Flex	Ein,NEnt	YES	Shared	YES	Pro,Exp,Oth
Oklahoma	YES	Electric, Gas	SC	Flex	Ein,NEnt	NO	NC	NO	Inc
Oregon	YES	Electric, Gas	SC,Tar	Flex	Ein,NEnt	YES	RP	NO	Oth
Pennsylvania	YES	Electric,Gas	SC,Tar	Flex	Ein,NEnt	NO	NC	YES	Pro,Inc,Exp
Rhode Island	YES	Electric	SC,Tar	Fix	Ein,NEnt	YES	NC	YES	Pro,Inc,Exp
South Carolina	YES	Electric	SC, Tar	Fix,Flex	Ein,NEnt	NO	NC	YES	Pro,Inc,Exp
South Dakota	YES	Electric	SC,Tar	Fix,Flex	Ein,NEnt	YES	NC	NO	Inc
Tennessee	YES	Gas	SC,Tar	Fix,Flex	Ein,NEnt	NO	RP	YES	Exp,Oth
Texas	YES	Electric	Tar	Fix	Ein,NEnt	YES	NC	NO	Pro,Inc,Exp
Utah	NO								
Vermont	YES	Electric	SC,Tar	Fix,Flex	Ein,NEnt	YES	NC	NO	Pro,Inc,Exp
Virginia	YES	Gas	SC,Tar	Fix,Flex	Ein,NEnt	YES	SH	YES	Pro,Inc
*Washington	YES				EEnt,NEnt				Oth
West Virginia	YES	Electric, Gas	SC,Tar	Fix,Flex	Ein,NEnt	YES	RP	NO	Pro,Exp,Oth
Wisconsin	NO								
Wyoming	YES	Electric,Gas	SC,Tar	Fix,Flex	EEnt,NEnt	YES	NC	NO	Inc,Oth
Washington DC	YES	Gas	SC,Tar	Fix,Flex	EEnt,NEnt	YES	Shared	YES	Oth

* Denotes a state that did not respond. Any information listed for these is as per the Commission's 1989 survey.

KEY:

(1)
SC – Special Contract
Tar – Tariff

(2)
Fix – Fixed Rate
Flex – Flexible Rate

(3)
Ein – Existing Business Incremental Load
EEnt – Existing Business Entire Load
NEnt – New Business Entire Load

(4)
RP – Rate Payer
SH – Stock Holder
Shared – RP and SH
Oth – Other
NC – None Considered

(5)
Exp – Encourage Expansion of Existing Industry
Inc – Increase Utilization of Utility Plant
Pro – Promote Job Creation
Oth – Other

SECTION B. Load Retention Rates

Load retention rates are generally discounted utility rates offered on a customer's existing load in response to a bonafide threat of bypass, and in exchange for the customer's agreement to continue receiving service from the serving utility. Such rates are intended to sustain current system load and retain a significant portion of customer revenues as well as contributions to fixed costs of the utility.

Load retention rates affect economic development by reducing energy costs to the customer. The use of these rates is appropriate when such rates make it uneconomical for a customer to bypass the utility's system by installing or expanding cogeneration or self-generation facilities. In other words, load retention rates serve to discourage bypass of the electric utility via cogeneration and/or self-generation when it would be uneconomic to do so. On-the-other-hand, since load retention rates are generally set above the utility's marginal cost of providing service, customers that can cogenerate or self-generate electricity at a cost that is less than the utility's offered discounted rate (and are willing to assume associated risks) are not discouraged from doing so.

Ratepayers benefit from retaining the potential bypasser's load since revenues received under the discounted rates help minimize potential deficiencies in revenue requirements. If the load is lost (e.g., the customer bypasses the utility by installing cogeneration facilities), other ratepayers would have to make-up the lost revenue through higher rates.

Eighty percent of the states surveyed offer load retention rates to gas and/or electric customers. Illinois is one of 18 states (35 percent) that offers load retention rates to both electric and gas customers. Illinois is 1 of 29 states (57 percent) in which load retention rates are offered in the gas industry and 1 of 25 states (49 percent) in which such rates are offered in the electric industry.

The following summarizes responses made from Section B of the innovative rates survey dealing with load retention rates and specifically identifies Illinois' positions. Table 3 summarizes responses from all states, while Table 4 reflects individual state-by-state responses.

1. Are utilities allowed to offer load retention rates as defined above? (Illinois - Yes)

   Yes 41 No 8 No Response 2

2. For what utilities? (Illinois - Gas and Electric)

   Electric Only 7 Gas Only 11 Both 18 No Response 15

3. What rate mechanisms are available to do so? (Illinois - Special Contracts and Tariffs)

   Tariffs Only 6 Special Contracts Only 8 Both 26 No Response 11

4. Are such rates fixed (i.e., specified level of discounts regardless of the customer or situation), flexible (case-by-case negotiation), or both? (Illinois - fixed or flexible)

   Fixed Only 6 Flexible Only 25 Both 9 No Response 11

5. Is there a requirement that revenues received for the portion of load subject to discount must equal or exceed the marginal cost to serve such load? (Illinois - Yes)

No 1 Yes 35 No Response 15

6. At what point does the Commission determine treatment of lost revenues?

Due to the similarity in nature, responses to questions 6 and 7 have been consolidated as one response.

7. What party or parties has the Commission determined to be responsible for revenue requirements shortfall due to such rates? (Illinois - Determined at ratecase)

Stockholders bear responsibility 3
Ratepayers in general bear responsibility 3
Responsibility shared between stockholders and ratepayers 3
No decision made until a rate case 26
No Response 15
Other 1

8. Are Impacts of such rates tracked? (Illinois - *No)

Yes 21 No 15 No Response 15

9. Please identify Commission considerations utilized to justify such rates. (Illinois - Retain existing jobs, Maintain utilization of utility plant, and Retain existing industry)

Retain existing jobs 12
Maintain utilization of utility plant 24
Retain existing industry 19
No Response 15
Other 11

* Although not tracked as extensively as economic development/incentive rates, selected information on load retention rates is monitored for use in evaluating such proposals.

Table 3	States Offering Load Retention Rates							
State	Load Retention Rate offered (1)	Applicable Industries (2)	Rate Mechanism (3)	Rate Type If Tariffs Allowed (4)	Rates Exceed MC (5)	Rate Treatment (6)	Impacts Assessed (7)	Rate Justification (8)
Illinois	YES	Electric,Gas	SC,Tar	Fix,Flex	YES	ND	NO	ReJ,MuP,REI

SUMMARY:		
(1) YES – 41 NO – 8 NO RESPONSE – 2	(4) BOTH FIXED AND FLEXIBLE – 9 FIXED ONLY – 6 FLEXIBLE ONLY – 25 NO RESPONSE – 11	(7) YES – 21 NO – 15 NO RESPONSE – 15
(2) BOTH ELECTRIC AND GAS – 18 ELECTRIC ONLY – 7 GAS ONLY – 11 NO RESPONSE – 15	(5) YES – 35 NO – 1 NO RESPONSE – 15	(8) RETAIN EXISTING JOBS – 12 MAINTAIN USE OF UTILITY PLANT – 24 RETAIN EXISTING INDUSTRY – 19 NO RESPONSE – 15 OTHER – 11
(3) BOTH TARIFFS AND SPECIAL CONTRACTS – 26 TARIFFS ONLY – 6 SPECIAL CONTRACTS ONLY – 8 NO RESPONSE – 11	(6) STOCKHOLDERS – 3 RATEPAYERS – 3 SHARED – 3 DETERMINED AT RATE CASE – 26 NO RESPONSE – 15 OTHER – 1	

Table 4 States Offering Load Retention Rates

State	Load Retention Rate offered	Applicable Industries	Rate Mechanism (1)	Rate Type If Tariffs Allowed (2)	Rates Exceed MC	Rate Treatment (3)	Impacts Assessed	Rate Justification (4)
Alabama	YES	Gas	SC,Tar	Flex	YES	RP	YES	MuP,REI
*Alaska								
Arizona	YES	Electric,Gas	SC,Tar	Flex	YES	Shared	NO	REI,Oth
Arkansas	YES	Electric	SC	Flex	YES	ND	NO	MuP,REI
California	YES	Electric,Gas	SC	Flex	YES	ND	YES	Oth
Colorado	YES	Electric,Gas	SC	Flex	YES	SH	NO	REI
*Connecticut	YES		SC,Tar	Fix				
Delaware	NO							
Florida	YES	Electric,Gas	SC,Tar	Flex	YES	Shared	YES	MuP,REI
Georgia	YES	Gas	Tar	Flex	YES	ND	YES	MuP
*Hawaii								
Idaho	NO							
Illinois	YES	Electric,Gas	SC,Tar	Fix,Flex	YES	ND	NO	ReJ,MuP,REI
Indiana	YES	Electric	SC,Tar	Fix,Flex	YES	ND	NO	ReJ,MuP,REI
Iowa	YES	Electric,Gas	SC,Tar	Flex	YES	SH	YES	Oth
Kansas	YES	Gas	SC,Tar	Flex	YES	ND	YES	ReJ,MuP,REI
Kentucky	YES	Electric,Gas	SC	Flex	YES	ND	YES	ReJ,REI
*Louisiana	YES		SC,Tar	Fix				
Maine	YES	Electric,Gas	SC,Tar	Fix,Flex	YES	Oth	YES	MuP,Oth
Maryland	NO							
Massachusetts	YES	Electric,Gas	SC	Flex	YES	ND	NO	MuP
Michigan	YES	Electric,Gas	SC,Tar	Fix,Flex	YES	ND	NO	ReJ,REI
Minnesota	YES	Electric,Gas	Tar	Flex	YES	ND	YES	MuP
Mississippi	NO							
Missouri	YES	Gas	SC	Flex	YES	ND	YES	REI,MuP
Montana	YES	Electric,Gas	SC,Tar	Flex	YES	ND	NO	ReJ,REI,MuP
Nebraska	NO							
Nevada	YES	Gas	Tar	Flex	YES	ND	NO	MuP
New Hampshire	YES	Electric	Tar	Fix	YES	ND	YES	ReJ,MuP,REI
*New Jersey	YES		SC,Tar	Fix				
*New Mexico	YES		SC,Tar	Flex				
New York	YES	Electric,Gas	SC,Tar	Fix,Flex	YES	ND	YES	ReJ,MuP,REI
North Carolina	YES	Gas	Tar	Flex	YES	RP	YES	MuP
North Dakota	YES	Electric	SC	Flex	YES	ND	NO	ReJ,MuP,REI
Ohio	YES	Electric	SC,Tar	Fix,Flex	YES	SH	YES	MuP
Oklahoma	NO							
Oregon	YES	Electric,Gas	SC,Tar	Flex	YES	ND	NO	Oth
Pennsylvania	YES	Electric,Gas	SC,Tar	Flex	YES	ND	YES	ReJ,MuP,REI
Rhode Island	NO							
South Carolina	YES	Gas	SC,Tar	Flex	NO	RP	YES	ReJ,MuP,REI
South Dakota	YES	Electric,Gas	SC,Tar	Flex	YES	ND	NO	MuP,REI
Tennessee	YES	Gas	SC	Flex	YES	ND	YES	Oth
Texas	YES	Electric	SC,Tar	Fix,Flex	YES	ND	NO	ReJ,MuP,REI
Utah	YES	Electric,Gas	SC,Tar	Fix	YES	ND	YES	Oth
Vermont	NO							
Virginia	YES	Gas	Tar	Flex	YES	ND	YES	Oth
*Washington	YES							
West Virginia	YES	Electric,Gas	SC,Tar	Flex	YES	ND	NO	MuP
Wisconsin	YES	Gas	SC,Tar	Fix	YES	Shared	YES	Oth
Wyoming	YES	Electric	SC,Tar	Fix,Flex	YES	ND	NO	Oth
Washington DC	YES	Gas	SC,Tar	Fix,Flex	YES	ND	YES	MuP,Oth

* Denotes a state that did not respond. Any information listed for these is as per the Commission's 1989 survey.

KEY:

(1)
SC – Special Contract
Tar – Tariff

(2)
Fix – Fixed Rate
Flex – Flexible Rate

(3)
RP – Rate Payer
SH – Stock Holder
ND – Not Determined Until Ratecase
Shared – RP and SH
Oth – Other

(4)
ReJ – Retain Existing Jobs
MuP – Maintain Utilization of Utility Plant
REI – Retain Existing Industry
Oth – Other

SECTION C. Economic Development Related Rates

For purposes of this report, economic development related rates are those that provide an economic motivation to a customer in exchange for the alteration of the customer's load pattern (not necessarily requiring a net change in total energy consumed). Three such rate types were surveyed.

1) *Interruptible* rates are reduced rates available to customers willing to accept interruption of some or all of their service in exchange for rates lower than those charged to firm customers. Interruptible rates also benefit the utility because curtailment of load, primarily at times of utility-specific capacity constraints, can reduce both long-run and short-run marginal costs. Long-run costs are reduced since the utility doesn't have to install additional capital resources such as generation facilities or additional gas main otherwise needed. Short-run costs can be lowered by interruption during more expensive periods of facility operation. Thus, the use of interruptible rates affects economic development by freeing up resources for the utility and reducing customer utility bills. Illinois is 1 of 37 states (73 percent) that enables utilities to offer such rates.

2) Reduced rates for *off-peak* load are normally offered as part of the overall rate structure of a utility. These rates are lower than those applicable to year-round firm service or service during peak periods. Off-peak rates help reduce customers' energy costs in proportion to the amount of load consumed during off-peak times. In Illinois, off-peak

periods for electric utilities are defined as the non-summer months and/or certain hours of the day that are not considered a part of the utility's peak load time. For gas utilities, the off-peak period occurs during the non-winter months. Off-peak rates also reduce the utility's cost of providing service since no additional peaking capacity is needed to supply off-peak load. Virtually all the electric and gas utilities regulated by the Illinois Commission offer some type of off-peak rate. Illinois is 1 of 33 states (65 percent) that permits utilities to offer such rates.

3) *Real time* rates, as the name suggests, provide customers with timely cost of service information. Such rates are reflective of actual utility production costs at various periods of operation. Such rates promote the efficient use of resources to the extent that a customer can alter operations based upon the availability of rate information. Illinois does not currently offer real time rates on a significant scale. In part, this is due to the lack of sufficient information and possibly the means to communicate such information.

Illinois is 1 of only 18 states (35 percent) that offers economic development related rates to both gas and electric customers. The following summarizes responses made to Section C of the survey dealing with economic development related rates. Table 5 reflects individual state-by-state responses.

1. Are utilities allowed to offer other economic development related rates? (Illinois - Yes)

Yes 42 No 6 No Response 3

Rate Type Offered:

Interruptible rates 37 (Illinois - Yes)
Time-of-day rates 33 (Illinois - Yes)
Real time rates 15 (Illinois - No)

2. For what utilities? (Illinois - Gas and Electric)

Electric Only 13 Gas Only 1 Both 23 No Response 14

3. What rate mechanisms are available to offer such rates? (Illinois - Special Contracts and Tariffs)

Tariffs Only 16 Special Contracts Only 1 Both 20 No Response 14

4. Are such rates fixed (i.e., specified level of discounts regardless of the customer or situation), flexible (case-by-case negotiation), or both? (Illinois - fixed and flexible)

Fixed Only 13 Flexible Only 5 Both 19 No Response 14

5. Is there a requirement that revenues received for the portion of load subject to discount must equal or exceed the cost to serve such load less the system benefit resulting from alteration of customer usage?

Upon further consideration of this question, it was deemed that question number 8 better represented justification for such rate offerings. Thus, figures have not been compiled.

6. Does the Commission monitor the impacts of such rates?
(Illinois - No)

Yes 25 No 12 No Response 14

7. Are the net benefits of such rates allocated to a specific rate class?

The responses to such question were inconclusive.

8. Please identify Commission considerations utilized to justify such rates. (Illinois - Increase utilization of utility plant and other)

Enhance the competitiveness of a specific industry 11
Increase the efficiency of utility plant utilization 32
Other 13 No Response 14

Table 5 — Economic Development Related Rates

State	Related Rates Offered	Industry	Rate Type Offered			Rate Mechanism	Rate Type	Impacts Assessed	Rate Justification
			Interruptible	Time-of-day	Real Time	(1)	(2)		(3)
Alabama	YES	Electric	X	X	X	Tar	Fix	YES	ECI,IUP
*Alaska									
Arizona	YES	Electric	X	X		SC,Tar	Fix,Flex	NO	ECI,Oth
Arkansas	YES	Electric	X	X		SC	Flex	NO	Oth
California	YES	Electric	X	X	X	Tar	Fix	YES	Inc
Colorado	YES	Electric,Gas	X			Tar	Fix	YES	Inc
*Connecticut	YES								
Delaware	YES	Electric,Gas	X			Tar	Fix	YES	Inc
Florida	YES	Electric	X	X		Tar	Fix	YES	Oth
Georgia	YES	Electric,Gas	X	X	X	Tar	Fix,Flex	YES	Inc,Oth
*Hawaii									
Idaho	NO								
Illinois	YES	Electric,Gas	X	X		SC,Tar	Fix,Flex	NO	Inc,Oth
Indiana	YES	Electric	X	X	X	SC,Tar	Fix,Flex	NO	Inc
Iowa	YES	Electric,Gas	X	X	X	SC,Tar	Fix,Flex	YES	Inc,Oth
Kansas	YES	Electric,Gas	X	X	X	SC,Tar	Flex	YES	ECI,Inc
Kentucky	YES	Electric,Gas	X	X		SC,Tar	Fix,Flex	YES	Oth
*Louisiana	YES								
Maine	YES	Electric	X	X		Tar	Fix	YES	Oth
Maryland	NO								
Massachusetts	YES	Electric,Gas	X	X		SC,Tar	Fix,Flex	YES	Inc
Michigan	YES	Electric	X	X	X	SC,Tar	Fix	YES	ECI,Inc
Minnesota	NO								
Mississippi	NO								
Missouri	YES	Electric,Gas	X	X		SC,Tar	Fix,Flex	YES	Inc
Montana	YES	Electric,Gas	X			Tar	Fix	NO	Inc
Nebraska	NO								
Nevada	YES	Electric,Gas	X	X		Tar	Fix,Flex	NO	Inc,Oth
New Hampshire	YES	Electric,Gas	X	X		Tar	Fix	NO	Inc
*New Jersey	YES								
*New Mexico	YES								
New York	YES	Electric,Gas	X	X	X	Tar	Fix	YES	Inc
North Carolina	YES	Gas	X			Tar	Flex	YES	Inc
North Dakota	YES	Electric,Gas	X	X		Tar	Fix	NO	Inc
Ohio	YES	Electric	X	X	X	SC,Tar	Fix,Flex	YES	Inc,Oth
Oklahoma	YES	Electric,Gas	X	X	X	SC,Tar	Fix,Flex	YES	Inc
Oregon	YES	Electric,Gas	X	X	X	SC,Tar	Fix,Flex	YES	Inc
Pennsylvania	YES	Electric,Gas	X	X		Tar	Flex	YES	ECI,Inc
Rhode Island	YES	Electric,Gas	X	X		SC,Tar	Fix,Flex	YES	ECI,Inc
South Carolina	YES	Electric	X	X	X	SC,Tar	Fix,Flex	NO	ECI,Inc
*South Dakota									
Tennessee	YES	Electric,Gas	X	X	X	Tar	Fix	YES	ECI,Inc
Texas	YES	Electric	X	X		SC,Tar	Fix,Flex	NO	Inc
Utah	YES	Electric,Gas	X	X		SC,Tar	Fix,Flex	YES	Inc
Vermont	YES	Electric,Gas	X	X		SC,Tar	Fix,Flex	YES	ECI,Inc
Virginia	NO								
*Washington	YES								
West Virginia	YES	Electric	X	X	X	SC,Tar	Flex	NO	ECI,Inc
Wisconsin	YES	Electric	X	X		Tar	Fix	YES	ECI,Inc,Oth
Wyoming	YES	Electric,Gas	X	X	X	SC,Tar	Fix,Flex	NO	Inc,Oth
Washington DC	YES	Electric,Gas	X	X		SC,Tar	Fix,Flex	YES	Inc,Oth

* Denotes a state that did not respond. Any information for these is as per the Commission's 1989 survey.

KEY:

(1)
SC – Special Contract
Tar – Tariff

(2)
Fix – Fixed
Flex – Flexible

(3)
ECI – Enhance the Competitiveness of a Specific Industry
Inc – Increase the Utilization of Utility Plant
Oth – Other

SECTION D. Other Economic Development Related Policies

There are several utility commission policies that have economic development implications. Two of the more popular economic development related topics in the electric industry are competitive bidding for new generation and retail wheeling.

Under a basic *competitive bidding* arrangement, utilities solicit bids from potential power suppliers for a specified level of service over a specified time period. Several issues surround the topic of competitive bidding, and Illinois is currently involved in a rulemaking to address such matters (docket #92-0145). Illinois is 1 of 21 states (41 percent) that is formally addressing or has established policy addressing the topic.

Retail wheeling occurs when power is transmitted to an end user over facilities owned by an entity other than the power generator. While retail wheeling has not been formally investigated in Illinois, a Commission Task Force is conducting informal sessions on the status of competition and the implications of retail wheeling upon it. Only 8 states (16 percent) are developing or have implemented a retail wheeling policy.

Both competitive bidding and retail wheeling could bring significant changes to the electric industry. As a result, those users having access to competitively priced power stand to gain significant price concessions from currently tariffed power rates. To the extent that such users obtain significant price concessions, their long term financial integrity will be enhanced.

Captive customers (those not having electricity alternatives), on-the-other-hand, will likely seek protection from resulting pressures on utilities to shift investment cost recovery burdens to them. However, proponents of carefully implemented competitive bidding and retail wheeling policies point to efficiencies that might result for society as a whole.

The following summarizes the responses made to Section D of the survey dealing with related policies. Table 6 reflects individual state-by-state responses.

1. Does the State and the Commission allow for such economic development related policies?

   The survey generated minimal response to this question, indicating that the question was too broadly defined. For this reason responses have not been provided.

2. What is the State's policy status regarding competitive bidding for new electric generation? (Illinois - policy in development)

   Policy implemented 11
   Policy in development 10
   No such policy implemented or in development 6
   Policy considered, but not implemented 16
   No Response 8

3. What is the State's policy status regarding retail wheeling of power? (Illinois - no policy implemented or formally in development, although interest in the topic is increased)

   Policy implemented 2
   Policy in development 6
   No such policy implemented or in development 33
   Policy considered, but not implemented 3
   No Response 8

Table 6	Status of Economic Development Related Policies							
State	Competitive Bidding for New Generation				Retail Wheeling			
	Policy Implemented	Policy in Development	Policy Cons. But Not Impl.	No Policy Impl. or in Dev.	Policy Implemented	Policy in Development	Policy Cons. But Not Impl.	No Policy Impl. or in Dev.
Alabama				X				X
*Alaska								
Arizona			X					X
Arkansas		X						X
California		X				X		
Colorado				X			X	
Connecticut								
Delaware			X					X
Florida	X							X
Georgia		X						X
*Hawaii								
Idaho				X				X
Illinois		X						$X
Indiana		X						X
Iowa				X				X
Kansas				X				X
Kentucky			X					X
*Louisiana								
Maine	X							X
Maryland				X				X
Massachusetts	X							X
Michigan	X					X		
Minnesota		X						X
Mississippi				X				X
Missouri				X				X
Montana	X							X
Nebraska				X				X
Nevada	X				@X			
New Hampshire			X					X
*New Jersey								
*New Mexico							X	
New York	X							X
North Carolina				X				X
North Dakota				X				X
Ohio		X				X		
Oklahoma				X				X
Oregon	X							X
Pennsylvania		X					X	
Rhode Island	X				#X			
South Carolina				X		X		
*South Dakota								
Tennessee				X				X
Texas		X				X		
Utah			X					X
Vermont			X			X		
Virginia	X							X
*Washington								
West Virginia		X						X
Wisconsin	X							X
Wyoming				X				X
Washington DC				X				X

* Denotes a state that did not respond.

A policy exists to consider each proposal on its own merits. However, no such efforts have been allowed.
@ State law permits retail wheeling under very limited circumstances.
$ The Illinois Commission is informally considering the issue.

SECTION E. Comparison With Midwestern States

In the contest among states to retain existing business and attract new businesses, accessibility to low cost energy can be a significant factor in determining the relative competitiveness of one state against another. Utility rate related items that would affect a state's competitive position include:

- The extent to which utilities have pricing flexibility
- The rate at which utilities are able to accelerate depreciation of existing facilities
- The extent to which utilities are freed from the obligation to serve.
- The cost competitiveness of the utility itself.

In addition to the above noted items, other factors related to state actions affecting competition include the following:

- Other states' positions enabling their generators to compete in Illinois
- Other states' positions regarding retail wheeling or other means of market entry
- Other states' utility costs of service
- Other states' level of existing and potential generation facilities.

A full discussion of the items listed above is beyond the scope of this report. However, on a regional basis, the items should be considered when comparing states. For example, in terms of midwestern states, the following tables illustrate how selected states compare in regard to the availability of economic development utility rates and load retention rates:

Table 7 Availability of Economic Development Rates For Competing States			
State	Rate Offered	Industry	Rate Treatment
Illinois	YES	ELECTRIC, GAS	RATE PAYERS
Indiana	YES	ELECTRIC	SHAREHOLDERS
Michigan	YES	ELECTRIC,GAS	RATE PAYERS
Ohio	YES	ELECTRIC	SHARED
Wisconsin	NO		

Table 8 Availability of Load Retention Rates For Competing States		
State	Rate Offered	Industry
Illinois	YES	ELECTRIC,GAS
Indiana	YES	ELECTRIC
Michigan	YES	ELECTRIC,GAS
Ohio	YES	ELECTRIC
Wisconsin	YES	GAS

CLOSING

The results of the Illinois Commerce Commission's survey illustrate how utility-related economic development rates and activities play an integral role in carrying out the states' overall strategy to promote economic growth. The use of utility rate structures and regulatory policies to facilitate economic development continues to evolve to meet the changing conditions of the utility industry and business environment. Based on the results of the survey, it appears that such tools are considered important to maintaining a competitive position in retaining, expanding, and recruiting business enterprises.

APPENDIX

SURVEY METHODOLOGY

- The survey instrument utilized by the Commission in its 1989 survey of economic development/incentive rates was used as the starting point for question development.
- From the 1989 effort, the survey was broadened to capture the policy status for two important matters, competitive bidding and retail wheeling.
- A mailing list was compiled from NARUC directories.
- Surveys were mailed on March 3 for return by March 25.
- Thirty-one of the 50 surveys mailed (including Washington DC) were received by the March 25 due date.
- For those commissions not responding, a second survey mailing was made on April 1.
- By April 15, 41 responses were received, and a final attempt to secure the 9 outstanding responses was made by phone during the week of April 22. Three (3) additional responses were secured.

SURVEY LIMITATIONS

- The survey instrument did not readily allow respondents to identify policies that differed by industry (gas or electric) due to the survey format.
- As with any survey instrument, the responses are to some extent a function of the respondent's understanding of the topics and interpretation of questions asked.
- Due to the nature of the survey's subject matter, the variable levels of state tracking, and the somewhat subjective nature of the survey utilized, the extent to which such rates are applied (saturation level) within each state cannot be determined.
- Six Commissions did not formally reply to the survey, and the Alaska Commission provided an incomplete response. This is not to be perceived as significant as none of the states are considered major competitors of Illinois.

ECONOMIC DEVELOPMENT QUESTIONNAIRE

State Commission_____ Respondent_____ Phone #(____)_____

The following questionnaire consists of four sections which seek to identify the extent to which each State Commission permits the utilization of utility innovative rates and/or policies. Any necessary comments should be included on page 4 and referenced to the relevant section and question number. It should be noted that each state may differ in its classification of such rates and policies; therefore, for purposes of comparison, please consider the four main categories as defined below.

Section A: **Economic Development/Incentive Rates - discounted utility rates offered for, a) significant load additions by existing customers, and/or b) load additions created by customers new to the utility system.**

Please mark the appropriate response (Note: more than one item per question can be marked if necessary).

1. Are utilities allowed to offer economic development/incentive rates as defined above?
   Yes_____ No_____ If No, move to Section B.

2. For what utilities? (Please Specify)
   Electric_____ Gas_____ Other_____

3. What rate mechanisms are available to do so? (Please Specify)
   Tariffs_____ Special Contracts_____ Other_____

4. Are such rates fixed (i.e. 50 percent demand discounts), flexible (case-by-case negotiation), or both?
   Fixed_____ Flexible_____

5. What load is applicable?
   Existing Customer, Load Addition_____ New Customer, Entire Load_____
   Existing Customer, Entire Load_____ New Customer, Portion of Load_____

6. Is there a requirement that revenues received for the portion of load subject to discount must equal or exceed the marginal cost to serve such load?
   No_____ Yes_____ If yes, how are such costs defined? _____

7. At the time of a rate case for utilities offering such rates, what treatment do such rates receive?
   The disparity between standard tariffed and discounted rates is recognized and stockholders bear responsibility_____
   The disparity between standard tariffed and discounted rates is recognized and ratepayers bear responsibility_____
   The disparity between standard tariffed and discounted rates is recognized and a specific class of ratepayers bears responsibility_____ if ratepayers' responsibility, identify class(es)_____
   No treatment considered_____
   Other_____ (please explain)_____

8. Are Impacts of such rates tracked?
   Yes_____ No_____ If yes, please identify tracking measures_____

9. Please identify Commission considerations utilized to justify such rates.
   Promote job creation_____ Increase utility plant utilization_____

ECONOMIC DEVELOPMENT QUESTIONNAIRE

Section B: **Load Retention Rates - discounted utility rates offered on a customer's existing load in response to a viable threat of bypass and in exchange for the customer's agreement to continue service from the serving utility.**

Please mark the appropriate response (Note: more than one item per question can be marked if necessary).

1. Are utilities allowed to offer load retention rates as defined above?
   Yes_____ No_____ If No, move to Section C.

2. For what utilities? (Please Specify)
   Electric_____ Gas_____ Other_____

3. What rate mechanisms are available to do so? (Please Specify)
   Tariffs_____ Special Contracts_____ Other_____

4. Are such rates fixed (i.e. specified level of demand discounts regardless of the customer or situation), flexible (case-by-case negotiation), or both?
   Fixed_____ Flexible_____

5. Is there a requirement that revenues received for the portion of load subject to discount must equal or exceed the marginal cost to serve such load?
   No_____ Yes_____ If yes, how are such costs defined? _____
   _____

6. At what point does the Commission determine treatment of lost revenues?
   Immediately_____ Other_____
   At next rate case_____

7. To what party or parties has the Commission determined responsible for lost revenues due to such rates?
   Stockholders bear responsibility_____
   Ratepayers in general bear responsibility, apportioned to each class_____
   Only a specific class(es) of ratepayers bears responsibility_____ (Please Specify Class)
   No decision made until a rate case_____
   Other_____ (please explain)_____

8. Are Impacts of such rates tracked?
   Yes_____ No_____ If yes, please identify measures_____

9. Please identify Commission considerations utilized to justify such rates.
   Retain existing jobs_____ Maintain utilization of utility plant_____
   Retain existing industry_____ Other_____

ECONOMIC DEVELOPMENT QUESTIONNAIRE

Section C: **Other Economic Development Related Rates - rates that provide an economic motivation in exchange for the alteration of the customer's load pattern (not necessarily requiring a net change in total energy consumed).**

Please mark the appropriate response (Note: more than one item per question can be marked if necessary).

1. Are utilities allowed to offer other economic development related rates?
   Yes_____ If yes, what types? Interruptible rates_____ Time-of-day rates_____
   Real time rates_____ Other_____
   No_____ If No, move to Section D.

2. For what utilities? (Please Specify)
   Electric_____ Gas_____ Other_____

3. What rate mechanisms are available to do so? (Please Specify)
   Tariffs_____ Special Contracts_____ Other_____

4. Are such rates fixed (i.e. specified level of demand discounts regardless of the customer or situation), flexible (case-by-case negotiation), or both?
   Fixed_____ Flexible_____

5. Is there a requirement that revenues received for the portion of load subject to discount must equal or exceed the cost to serve such load less the system benefit resulting from alteration of customer usage?
   No_____ Yes_____ If yes, how are such costs defined? _____
   _____

6. Does the Commission monitor the impacts of such rates?
   Yes_____ No_____ If yes, please identify measures_____

7. Are the net benefits of such rates allocated to a specific rate class?
   Yes_____ No_____, benefits are shared by all ratepayers by means of a decline in the utility's overall cost of service (under rate of return regulation) or received by stockholders (under incentive regulation).

8. Please identify Commission considerations utilized to justify such rates.
   Enhance the competitiveness of a specific industry_____
   Increase the efficiency of utility plant utilization_____
   Other_____

ECONOMIC DEVELOPMENT QUESTIONNAIRE

Section D: **Other Economic Development Related Policies - policies that promote economic development that may not be directly related to rate structures. For example, utility funds may be used to establish a revolving loan fund to provide below market-rate loans for economic development projects.**

Please mark the appropriate response (Note: more than one item per question can be marked if necessary).

1. Does the State and the Commission allow for such economic development related policies?
   Yes_____ No_____
   If yes, please specify policy and associated industry _____
   (i.e. utility funded business loans)

2. What is the State's policy status regarding competitive bidding for new electric generation?
   Policy implemented_____ Policy in development_____
   No such policy implemented or in development_____
   Policy considered, but not implemented_____

3. What is the State's policy status regarding retail wheeling of power?
   Policy implemented_____ Policy in development_____
   No such policy implemented or in development_____
   Policy considered, but not implemented_____

COMMENTS:(Please reference associated section and question number):_____

1999 NSPI-P-871

NOVA SCOTIA UTILITY AND REVIEW BOARD

IN THE MATTER OF: The *Public Utilities Act*, R.S.N.S., 1989, c.380 as amended

IN THE MATTER OF: An Application by Nova Scotia Power Incorporated for approval of a Load Retention Rate

RESPONSE TO INFORMATION REQUEST

TO: **NSUARB**

FROM: **NSPI**

Question IR-21: **Please provide a copy of NSPI's latest generating capacity planning report.**

Response IR-21: The latest generating capacity planning report completed by NSPI was filed with the UARB in response to **Order NSUARB-P-865 of the Utility and Review Board relating to Integrated Resource Planning**. This report consisted of 17 reports and responses to interrogatories filed between 1994 and 1998, and was filed confidentially with the UARB.

More recent generation planning studies have been done, however, but no formal reports have been prepared. Based on current assumptions, new generation capacity may be justified on an economic basis in the 2008 - 2010 time frame. This, however, is highly uncertain. In the event that it should be justified, it would not necessarily be supplied by NSPI.

(NOTE: See also UARB-IR-7)

DATE FILED: December 23, 1999

NOVA SCOTIA UTILITY AND REVIEW BOARD

IN THE MATTER OF: The *Public Utilities Act*, R.S.N.S., 1989, c.380 as amended

IN THE MATTER OF: An Application by Nova Scotia Power Incorporated for approval of a Load Retention Rate

RESPONSE TO INFORMATION REQUEST

TO: **NSUARB**

FROM: **NSPI**

Question IR-22: **Please provide the reasons and cost support for establishing the minimum level of 2,000 KVA or 1,800 KW.**

Response IR-22: The following factors were considered in NSPI's decision to propose that this rate would be available to customers who are considering an alternate supply of at least 2000 kVa or 1800 kW:

a) Larger units are more likely to be economically attractive to customers at this time. This may change in the future, however, as the technology and economies of smaller generating units continue to improve.

b) Beginning with a limited set will allow the process to be tested and refined, if necessary. It can be extended to smaller generating units as appropriate.

c) The 2 MVA level is consistent with the entry level for other rates such as Large Industrial, Large Commercial, GRLF, and Surplus Power Rate.

DATE FILED: December 23, 1999

1999 NSPI-P-871

NOVA SCOTIA UTILITY AND REVIEW BOARD

IN THE MATTER OF: The *Public Utilities Act*, R.S.N.S., 1989, c.380 as amended

IN THE MATTER OF: An Application by Nova Scotia Power Incorporated for approval of a Load Retention Rate

RESPONSE TO INFORMATION REQUEST

TO: **NSUARB**

FROM: **NSPI**

Question IR-23: **Please explain the reasons for excluding the following provisions from the Proposed Load Retention Rate filed on December 6, 1999 which were included in the proposed Load Retention Rate attached with the NSPI's letter of September 30, 1999 to the Board:**

a) **Availability Section**

i) **The customer option to leave NSPI's system is both technically and economically feasible.**

ii) **The language "... and for whom preliminary economic analysis suggest that benefits to both NSPI and the customer are sufficient to warrant the process outlined in Attachment A from Item No. 2 of the Availability Provision.**

b) **Item No. 3 of Special Conditions which stated, "Special conditions associated with the rate(s) . . . the UARB is provided in the procedures of Attachment A."**

c) **Item No. 6 of Attachment A, which provides the determination of the costs on an annual basis.**

d) **Item No. 11 of Attachment A which required a determination of the benefit to customers.**

e) **Item No. 12 requiring UARB's approval of the rate.**

DATE FILED: December 23, 1999

1999 NSPI-P-871

NOVA SCOTIA UTILITY AND REVIEW BOARD

IN THE MATTER OF: The *Public Utilities Act*, R.S.N.S., 1989, c.380 as amended

IN THE MATTER OF: An Application by Nova Scotia Power Incorporated for approval of a Load Retention Rate

RESPONSE TO INFORMATION REQUEST

TO: **NSUARB**

FROM: **NSPI**

Response IR-23:

a) i) The wording of the availability clause was revised to clarify the intent of the rate offer, which is to address the potential loss of electric load directly attributable to the potential use of an alternate energy supply.

ii) This clause was removed from the Availability section of the rate and was included as item (2) of Attachment A in the December 6 submission in order to better separate the process of investigating and determining the load retention price from the availability for the rate.

b) Special Condition (3) of the September 30th submission became Special Condition (1) of the December 6th submission. The intent of this condition is unchanged, but the wording was revised to clarify exactly what items were being referred to; i.e. "the price, terms and conditions," as well as any special conditions already in place.

c) Item (6) of the September 30th submission was removed because it was implicit in Item (5) and was felt to be redundant. It is therefore included in the December 6th submission as Item (7). In order to compare the cost to the customer of continuing to purchase their energy requirements from NSPI or providing it from an alternate supply, the annual costs must naturally be determined for both.

d) Item (11) of the September 30th submission was removed as an explicit item because it is a natural component of Item (11) of the December 6th submission. The benefits to the customer of not having to build, own and operate their own generation unit are difficult to quantify but will be part of the discussions and determination of the price that is required to retain the customer.

DATE FILED: December 23, 1999

NOVA SCOTIA UTILITY AND REVIEW BOARD

IN THE MATTER OF: The *Public Utilities Act*, R.S.N.S., 1989, c.380 as amended

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RESPONSE TO INFORMATION REQUEST

TO: **NSUARB**

FROM: **NSPI**

Response IR-23 e) Item (12) was removed from Attachment A, which is the procedure to be followed to determine the proposed load retention rate, and has been reflected in Item (3) of the Special Conditions of the December 6th submission. The UARB has final approval of all proposed rates and NSPI felt that this would be a more appropriate place for this statement.

DATE FILED: December 23, 1999

NOVA SCOTIA UTILITY AND REVIEW BOARD

IN THE MATTER OF: The *Public Utilities Act*, R.S.N.S., 1989, c.380 as amended

IN THE MATTER OF: An Application by Nova Scotia Power Incorporated for approval of a Load Retention Rate

RESPONSE TO INFORMATION REQUEST

TO: **NSUARB**

FROM: **NSPI**

Question IR-24: **Please explain the reasons for not including the generating unit's Availability Factor in Item 8 of Attachment A in the economic analysis of self generation.**

Response IR-24: As stated in the opening sentence of Item (8), Attachment A, the list of appropriate factors to be considered in reviewing the cost of the customer of the alternate supply includes, but is not limited to the items listed. The list was not meant to be exhaustive, and including the assumptions regarding the generation unit's availability factor would be entirely appropriate.

DATE FILED: December 23, 1999

NOVA SCOTIA UTILITY AND REVIEW BOARD

IN THE MATTER OF: The *Public Utilities Act*, R.S.N.S., 1989, c.380 as amended

IN THE MATTER OF: An Application by Nova Scotia Power Incorporated for approval of a Load Retention Rate

RESPONSE TO INFORMATION REQUEST

TO: **NSUARB**

FROM: **NSPI**

Question IR-25:

(a) Please provide a detailed description of NSPI's forecasting and planning models referenced to in Item No. 10 of Attachment A.

(b) Also, provide the type of data and assumptions to be used in NSPI's models referenced above.

(c) Please provide a copy of a study or analysis conducted by using the above referenced forecasting and planning models.

Response IR-25:

a) The models that are referred to in Item 10 are PROSCREEN, a utility planning tool supplied by New Energy Associates and used by utilities across North America, and NSPI's internal financial models.

A detailed description of PROSCREEN is attached. In general, this model is used to assess various options available to a utility to minimize its costs, subject to various constraints. NSPI expects to use it to assess the viability of the load retention rate on a case by case basis.

(NOTE: The attached description is the 1994/95 vintage. Some upgrades have occurred since then, but updated documentation is now provided by an online system and printouts are not readily available.)

NSPI's financial model referred to is a standard Statement of Earnings model that summarizes revenues and costs and calculates income tax and earnings. This model is expected to be used in conjunction with PROSCREEN to estimate bottom line impacts of losing customer load to self generation, as well as the impacts of offering a load retention rate.

DATE FILED: December 23, 1999

NOVA SCOTIA UTILITY AND REVIEW BOARD

IN THE MATTER OF: The *Public Utilities Act*, R.S.N.S., 1989, c.380 as amended

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RESPONSE TO INFORMATION REQUEST

TO: **NSUARB**

FROM: **NSPI**

Response IR-25:

b) The detailed description of PROSCREEN provided in (a) includes discussion of input data.

c) This is being filed separately as a confidential document.

DATE FILED: December 23, 1999

PROSCREEN II®

PROSCREEN II OVERVIEW

By Energy Management Associates
The Utilities Division of EDS

This manual was produced using *Doc-To-Help*®, by WexTech Systems, Inc.



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INTRODUCTION

Introduction

PROSCREEN II, a computer software system developed by Energy Management Associates (EMA), The Utilities Division of EDS, supports electric and gas utility decision analysis and corporate planning. The system combines quality planning software, a proven track record, EMA's commitment to ongoing maintenance and support, comprehensive user documentation, and fast response to client needs. PROSCREEN II is available as a demand–side management screener, as a demand and supply optimization system, as a comprehensive planning tool for quick evaluation of hundreds of alternatives, as a finance and rates planning system and as selected application modules that complement planning capabilities already in place. PROSCREEN II consists of twelve application modules:

- LOAD FORECAST ADJUSTMENT (LFA)
- DSVIEW COST EFFECTIVENESS (DCE)
- DSVIEW PROGRAM DESIGN (DPD)
- GENERATION AND FUEL (GAF)
- CAPITAL EXPENDITURE AND RECOVERY (CER)
- CLASS REVENUE (CRM)
- HOLDING COMPANY (HCM)
- FINANCIAL REPORTING AND ANALYSIS (FIR)
- PROVIEW (PRV)
- SCENARIO ANALYSIS (SCE)
- STRATAGEM EXTENSION
- PROSCREEN II DECISION ANALYSIS (PSDA)

A flexible control system ties the application modules together and automates data transfer from one module to another. To interface with the PROSCREEN II database containing all inputs and outputs, a user may choose between the control system and a PC–based Graphical User Interface (GUI).

PROSCREEN II's GUI adds full–screen spreadsheet data entry/edit capability, on–line documentation, graphic display of data, menu–driven scenario definition, program execution, and reporting. With either the control system or the GUI, it is easy to change selected inputs, run the application modules, and display results.

Figure OVERVIEW–1 below outlines the structure of PROSCREEN II.

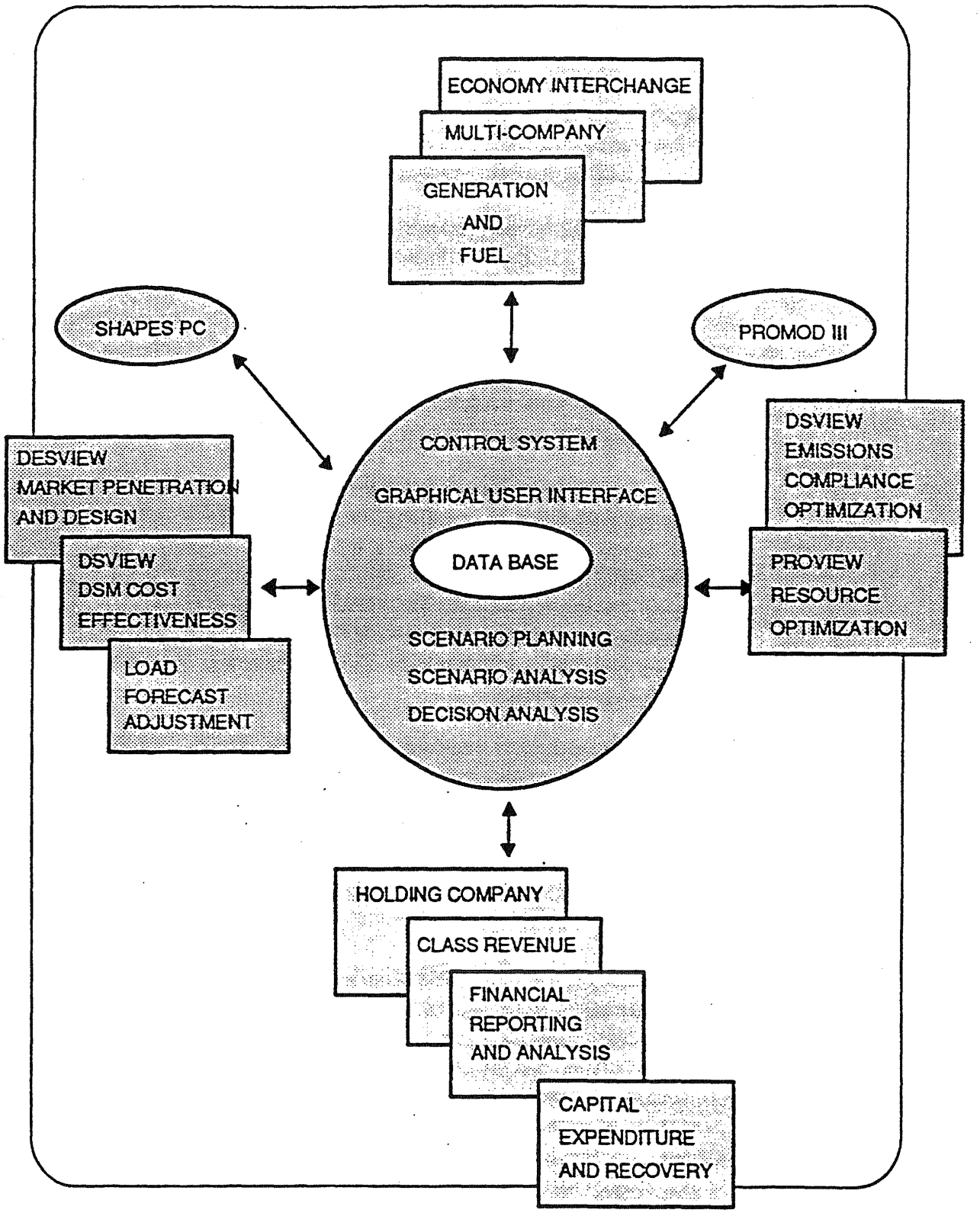


Figure OVERVIEW-1
PROSCREEN II Integrated Planning System

PROSCREEN II: Evolution of the Industry Leader

PROSCREEN II is fully supported by the technical and consulting services of Energy Management Associates. PROSCREEN II is an evolving product, enhanced and upgraded continuously. The PROSCREEN II system of today is not the PROSCREEN II system of two years ago.

PROSCREEN II's development since 1982 has proceeded in lockstep with that of the industry. In its earliest versions, PROSCREEN II was well suited for engineering, economic, and rudimentary financial analysis of central generating station alternatives. It was a major advance from then prevailing practices because financial consequences and constraints of resource decisions were an integral part of analysis. This advance allowed utilities to make the difficult decisions to cancel nuclear units or postpone base load additions on the basis of severe financial risk and strain.

In the early 1980's utilities faced record–high interest rates. The high cost of raising external funds in a capital intensive industry and the need to finance major new base load additions gave rise to creative financing methods. PROSCREEN II captured these developments by providing a comprehensive financial model within the integrated planning system. To support the evaluation of critical financial issues, PROSCREEN II added logic to handle zero coupon bonds, variable rate debt instruments, deferral accounting and leases, and asset sales.

Concurrently, as higher fuel costs were recovered from customers, the effect of price on future demand became a concern. At this time, EMA incorporated price elasticity feedback into PROSCREEN II. Energy requirements and peak demand could be automatically modified in response to prices that reflected changing operating costs and new plant additions. Lag periods and degrees of price elasticity could be tested. The impact of phase-in plans on rate shock could be explored.

Many utilities in the early 1980's had more generating capacity than needed to serve their customers. Increased competition forced a focus on avoidance of losing major industrial users to other utilities, other fuels, or production facilities outside the U.S. Similarly, wholesale customers were vulnerable. Retaining load and attracting new customers meant new rate programs and attention to cost allocation and rate class profit margin. To assist in these efforts, PROSCREEN II incorporated cost allocation and class–by–class revenue analysis capabilities.

In the late 1980's it became clear that more automated balancing of demand and supply alternatives was needed. To meet this need, EMA's optimization experts developed the ability to simultaneously optimize supply and

demand–side alternatives. PROVIEW represents a major step forward in integrated resource planning. More opportunities than ever before can be examined with less front–end work by the user. Demand and supply can be evaluated on a level playing field.

As policy makers and utilities launched least cost planning initiatives, demand–side management (DSM) programs gained greater importance in total integrated resource planning. EMA added capabilities to analyze changes in demand and link those changes to promotional costs, investments in hardware (like dispatch control devices), and rate incentives. EMA added DSVIEW Cost Effectiveness Module (DCE), a detailed DSM screening tool, as a stand–alone or fully integrated module of PROSCREEN II. DSVIEW–DCE is instrumental in helping analysts determine cross subsidies which may result from demand–side management programs, understand the overall impact on customer costs, screen many DSM options based on cost effectiveness criteria, and develop demand–side management programs that complement supply–side alternatives in a "least–cost" plan.

In 1990, PROSCREEN II was enhanced to deal with new complications facing utility planners. Emissions reporting and dispatch allows full evaluation of compliance planning strategies, including prospects for emissions trading. The supply/demand optimization now takes into account environmental costs and environmental externalities.

Increased need for risk assessment in utility planning led PROSCREEN II to develop and introduce PROSCREEN II Decision Analysis (PSDA). Working in conjunction with Strategic Decisions Group's Supertree Decision Analysis software, PSDA brings a quantitative consideration of uncertainty to the planning process. This package has additionally been linked with Decision Programming Language (DPL). Scenario Planning Study Coach was recently introduced to ease the mechanics of study set–up and evaluation. The result is a more structured, proceduralized approach to study design, enhanced presentation of results, and more defensible decisions.

Changes in the industry have emphasized the need to evaluate and present the results of many options under numerous conditions in a quick and organized manner. The PROSCREEN II Graphical User Interface (GUI) was introduced to PC users in early 1992, removing much of the mechanical user interaction required to input data, execute a study, and analyze results. It is now possible to run all the financial and production costing modules as well as Scenario Planning and Decision Analysis under GUI. Furthermore, data can be managed on the PC with the GUI and ported to a second platform to more fully utilize the enhanced computing power available. PROSCREEN II provides a true client/server environment.

Early 1993 innovations include release of a GUI for the UNIX platform and introduction of a new DSVIEW Module, DSVIEW Program Design Module (DPD). Currently, there are more than 30 full–time analysts dedicated to serving a growing PROSCREEN II client base of over 80 utilities. The PROSCREEN II system will continue to evolve and improve to meet the changing needs of a changing industry. The result will be continued unparalleled capability for utility planning.

General Description

PROSCREEN II's advantage as an integrated planning system is its strength in all functional areas of utility planning. PROSCREEN II allows analysts to address all aspects of an integrated planning study at the depth and accuracy level required for informed decisions. Hourly chronological load patterns are recognized. Production cost simulations are comprehensive, yet fast. Financial analyses are accurate and thorough. Rate–level determinations reflect each utility's customer class definition and cost–of–service allocation factors. The system employs dynamic programming to optimize demand– and supply–side resource portfolios. Sophisticated screening methodologies are available to perform DSM program design, refinement, cost/benefit analysis and DSM portfolio development. And PROSCREEN II analyses can now be integrated into Decision Analysis studies to address the effects of uncertainty on business decisions.

In PROSCREEN II, integrated demand/supply screening and optimization is accomplished within a single system that handles demand–side programs, production costing, environmental reporting, capital budgeting, and financial, tax, and revenue requirements forecasts on a rate class basis. Using a single, integrated software system for demand– and supply–side analysis makes these studies much more manageable, ensures consistency in data assumptions, and provides credible, auditable results.

PROSCREEN II is also connected with EMA's PROMOD III® production costing system. A detailed PROMOD III database can be automatically translated into the format used by the Generation and Fuel Module so that only a single database for the generating system need be permanently maintained. PROMOD III production cost results can also be directly used by PROSCREEN II's financial modules for an examination of the financial implications of PROMOD III study results. PROSCREEN II's demand–side modules serve as the source load data for PROMOD III.

With PROSCREEN II, utility management can examine many more options in a shorter period of time. The system has been designed to streamline the many steps in a comprehensive integrated planning effort and to handle the mechanics. This minimizes human error, inconsistencies, and repetitive data

entry. For instance, if a combustion turbine's in–service date is delayed in the optimization program, the new in–service date is automatically specified to the production costing module as well as the capital budgeting and financial modules. The module also performs year–by–year "round robin" processing in order to appropriately address price elasticity.

PROSCREEN II provides a wide variety of standard reports ranging from unit by unit generating statistics to construction project accounting reports to comprehensive pro forma financial results. The system includes full input summaries and detailed diagnostics.

The Scenario Analysis System supplements these standard reports with a full range of scenario comparison capabilities. The Scenario Analysis System captures, stores, and reports essential results of multiple–case studies. The analyst defines the key study assumptions and results needed to evaluate each case. PROSCREEN II then stores these results and reports them in a choice of four executive summary formats. Hundreds of least–cost planning cases can be evaluated without looking at each individual computer run.

The Scenario Planning feature of PROSCREEN II is a study coach which helps ease efficiency of study set–up. Scenario Planning streamlines the work necessary to create a study by facilitating set–up of new or existing data combinations. It also eases definition of decisions and uncertainty conditions and output of key results. Users benefit from Scenario Planning's ability to perform structured organization, reduce user interaction and error potential, and consolidate and present key results.

The PROSCREEN II Decision Analysis module extends the abilities of the utility analyst by providing a link between the modeling power of PROSCREEN II and the Decision Analysis capabilities of Supertree software. Utility planners are now able to formulate and analyze complex business decisions in the face of great uncertainty.

Diversity of Client Base and of Applications

Over 85 utilities now rely on PROSCREEN II for corporate and integrated planning. These utilities have diverse systems, demands, and organizational structures. Users include investor–owned, municipal, government and cooperative utilities and range in size from very large (24,000 MW) to very small (565 MW) electric utilities. The financial modules of PROSCREEN II have been specifically designed to address the need of public power organizations, municipals, and cooperatives.

These utilities rely on PROSCREEN II for a broad range of applications within the framework of integrated planning. Selected applications include:

- Marketing Program Evaluation
- Promotional Rates Assessment
- Demand–Side Management Evaluation
- Price Elasticity Impact
- Integrated Demand/Supply Least Cost Plans
- Analysis of Environmental Regulations
- Environmental Compliance Planning
- Financial Feasibility Of Construction Programs
- Capital Asset Repositioning
- Corporate Restructuring
- Diversification
- Merger and Acquisitions
- Competitive Analysis
- Financial Forecasts
- Impact Of New Legislation
- Scenario Risk Analysis
- Decision Analysis Risk Assessment

Full Range of Evaluation Criteria

PROSCREEN II provides a full range of evaluation criteria so that every aspect of a plan can be assessed:

RATES	Average Class Prices - Base and Fuel
	Class Rate Increases - Base and Fuel
ECONOMICS	Present Worth of Revenue Requirements
	Marginal Energy Costs
	Marginal Capacity Costs
RELIABILITY/ OPERATIONS	Reserves
	Emergency Energy
	Loss of Load Hours
	Fuel and Capacity Mix
	Load Diversity
FINANCIAL INTEGRITY	External Financing
	Interest Coverage Ratios

	Quality of Earnings
	Internal Generation of Funds
	Capital Structure
CUSTOMER	"No Losers"
IMPACT	Cross Subsidies
	Program Participants
SOCIETAL	"Total Resource Cost"
IMPACT	Customer Costs
	Consumer Value
	Environmental Externalities
SHAREHOLDER	Return on Common Equity
IMPACT	Earnings Per Share
	Common Dividends
	Dividend Yield
	Shareholder Value

Modular Structure

Analysts use the individual modules of PROSCREEN II to develop an understanding of specific areas of interest (e.g., power system operation or rate level determination) as well as for complete integrated planning.

The configuration of a PROSCREEN II installation varies, depending on each user's applications, data availability, and staff resources. Many utilities rely on the entire system for strategic, corporate, and integrated planning. A common "subset" configuration is one designed for integrated resource planning without refined financial and rate capabilities. PROVIEW, DSVIEW, the Load Forecast Adjustment Module, the Generation and Fuel Module, and PROSCREEN II Decision Analysis comprise this configuration. Other utilities utilize the financial components and rely on PROMOD III for production costing. This configuration commonly includes the Capital Expenditure and Recovery Module, the Financial Reporting and Analysis Module, the Class Revenue Module, and PROSCREEN II Decision Analysis. Many utility companies which started with one or the other of these configurations have migrated to the full integrated system.

The modules comprising the entire PROSCREEN II system are discussed in detail in the following sections.

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OPERATING ENVIRONMENT

Introduction

PROSCREEN II is available for installation on a wide range of computer systems or for use on EMA's time–sharing computer service. PROSCREEN II will operate on all PRIME, VAX, Data General, IBM CMS, MVS, and MVS/XA systems. PROSCREEN II will also run on 80386 and 80486–based PCs under the DOS operating system. In addition, PROSCREEN II is available on UNIX–based RISC workstations provided by SUN, IBM, and MIPS. PROSCREEN II Decision Analysis is a PC–based system.

As a strategic planning tool designed to address top management issues, PROSCREEN II offers maximum ease of use. The system is meant to be used by an analyst whose expertise is in utility planning and not in software development or programming.

Control System

Users have two options for interfacing with the modules and the strategic database. One option, the PROSCREEN II Control System, is a flexible interface which uses a set of English–language line commands to access the system. The user can request output results on a year–by–year basis and change input data assumptions during any year within the study interval for which a PROSCREEN II module run is made.

The Control System is comprised of features which include the ability to add to or multiply by existing inputs. An Executive Command Facility enables users to batch PROSCREEN II commands together and execute them with a single command in an interactive session. The Operating System Bridge allows the user to issue operating system commands from within PROSCREEN II's interactive environment. The system allows the user to edit files on-line and to open and close files dynamically during the PROSCREEN II session without having to exit into the host operating system.

Graphical User Interface (GUI)

Another interface option is the PROSCREEN II Graphical User Interface (GUI). The GUI provides a menu–driven alternative to the Control System. This interface guides the user through a logical sequence of steps necessary to generate new or access old datasets, edit data, run the modules of PROSCREEN II, review and analyze the results, and file the output for reference or future usage. In addition, the GUI facilitates execution of scenario planning studies by leading the user through the steps necessary to create various decision and uncertainty files. Another feature, capture mode, allows users to create a Control System–based trail of any GUI actions taken in a particular interactive session.

Additional GUI features include:

- Pull Down Menu Access to Data, Modules, Reports
- Mouse, Cursor, or Key Letter control
- Powerful Built-in Spreadsheet/Data Entry and Data Access
- On-Line Data documentation
- Convenient Function Keys for Data Editing
- Three Dimensional Viewing of Data
- Graphics
- Audit Trail
- Bridge to Spreadsheet, Graphics, Editor, View Facility, DOS

Client/Server Environment

EMA recently introduced Client/Server computing as an innovative option enabling users to expand the capability of their hardware platforms. In a Client/Server environment, users can set up a PROSCREEN II database on a PC running in Windows™, send the run to another platform for processing, then open another window and work in another application during the run.

Client/Server eliminates the need to wait for completion of a run before opening another application, thereby providing a boost to productivity. It allows users to take advantage of the processing capabilities of another operating platform while maintaining the easier–to–use PC GUI interface.

Interface Capabilities

PROSCREEN II is linked to spreadsheets and other software programs by an interface specifically developed to allow porting of data to and from PROSCREEN II without the need for re–keying. Additionally, the GUI can output any spreadsheet page in LOTUS .PRV–comparable format. All reports and diagnostics are in ASCII format and can be imported into LOTUS and other software systems.

Users may traverse the GUI spreadsheet by using the arrow keys, the Page Up and Page Down keys, the Home and End keys, and the right and left arrow keys in conjunction with the CTRL key.

Within the GUI spreadsheet, the following functions are active:

- Help Screen
- Directory command – displays an entry from the C and D sections of the documentation
- Graphics
- Choose another page or viewing orientation if the current set of variables has a third dimension
- Transpose the current two–dimensional view of data
- Rotate the data if the current set of variables has a third dimension
- Go to a specified index number
- Search the occurrence labels of a chosen dimension for a user–specified character string
- Change the width of the row label or column
- Change the display format of the current row
- Toggle formulas or index numbers
- Save without exiting the spreadsheet – saves the values in memory only, not on disk
- Write the current view of the data to a .PRN file
- Copy range
- Escalate the current cell
- Replicate the current cell or a portion of a row or column
- Fill the current page with the values in the current cell, row, or column
- Copy the values in the current page of the data to another page in the subset of data

- Multiply the values in a range of the data
- Add a specified number to the values in a range of the data
- Cumulatively escalate values in all or a portion of a row or column

Reporting

The PROSCREEN II report writer provides numerous standard output reports, an Input Summary, user–defined scenario reports, and diagnostic reports.

PROSCREEN II Data Transfer

PROSCREEN II modules automatically communicate with each other. This means that a user can run the entire system without manually transferring key outputs from one module (e.g., production costs from GAF) to another module (e.g., FIR). There are also built–in features that allow changes in prices for customer classes to be automatically fed back to the LFA Module for price elasticity calculations. Initial loading of data into PROSCREEN II is through a fixed format input file similar to that used by EMA's PROMOD III or the GUI.

PROSCREEN II operates with a single database for all modules. Once the database is set up, the user can load the data into PROSCREEN II with a single command. The data exists separately from the system so that a single session can include use of numerous databases or alternative versions of a single database.

Data is referred to by name through an easy–to–use hierarchy which substantially reduces the user's problem of accessing data. The first order of the hierarchy is by module (FIR, CER, etc.), followed by data type (INPUT, TRANSFER, OUTPUT), followed by an additional qualifier appropriate to the particular characteristics of each module. Each data item has a unique name which can be accessed by typing any unique abbreviation for the data name. Full descriptions of all data items are available in an on–line data directory.

Both the PROSCREEN II Control System and the GUI include the Scenario Analysis System for complete flexibility in comparing one scenario to another. Through this system, users can easily prepare presentation–quality comparison reports of study results in a matter of minutes. PROSCREEN II results for any number of scenarios are saved in the Scenario Library through a single command.

The STRATAGEM extension of PROSCREEN II provides an automated facility for more extensive analysis of PROSCREEN II data within a fourth

generation relational modeling system. STRATAGEM's powerful commands and its easy–to–develop custom screens greatly expand the power of the PROSCREEN II system to perform ad hoc analysis, custom reports, graphics, decision analysis, and satellite models.

Finally, PROSCREEN II provides complete documentation and support for user customization through a "User Subroutine" feature. All PROSCREEN II database variables are available for company specific logic within the code. Logic incorporated at these strategic locations will not interfere with future deliveries of improved versions of the system.

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LOAD FORECAST ADJUSTMENT MODULE (LFA)

Introduction

The Load Forecast Adjustment (LFA) Module is a multi–purpose tool for creating and modifying load forecasts and evaluating demand–side management programs. Using the LFA, a strategic planner may address key issues related to future electricity or gas demand and impacts attributed to each customer group. Results from this analysis can be automatically transferred to other PROSCREEN II modules to determine production costs, system reliability, DSM cost–effectiveness, financing and revenue requirements, and a variety of other indicators affected by loads.

Because availability of load data is often limited, the LFA is designed to process data at the level of detail readily available. Load data is processed in the LFA by user–defined load groups. It is possible to define these load groups as very detailed or very summary in scope. The LFA categorizes group data based on availability of hourly load shapes. Customer groups for which shapes are not available are processed differently than those with shapes.

A key feature of the LFA is its ability to accommodate different levels of detail for different categories of load. If load shapes are unavailable or not needed for some customer groups, the user can easily organize the data to allow the LFA to approximate the missing information. For example, a study which analyzes the loss of a large industrial customer may need detailed modeling of only those rate classes affected by the reallocation of costs. Hourly load shapes could be entered for these classes, and the user need only enter peak, energy, and coincidence factors for any remaining load classes.

The analysis of programs which lack historic data, such as new demand–side technologies, will also benefit from the LFA's unique features. For example, a relamping program may be quickly modeled with estimates of energy savings per customer and reductions in peak demand. The hourly impact of these programs is based upon optional rules specified by the user. Conversely, the evaluation of programs such as direct control of end–use loads (DLC

hardware) can be based on more detailed data such as estimated net changes in seasonal demand, energy, and hourly customer shapes.

The LFA Module calculates the impact of changing prices on the initial forecast. When processing in round robin mode, the modified load forecast is passed to the Generation and Fuel (GAF) Module for production costing and to the Financial Reporting and Analysis (FIR) Module for financial analysis. The new electric prices resulting from the FIR are then used for further price impacts in subsequent years of the PROSCREEN II simulation.

The LFA Module may be used in conjunction with DSVIEW, PROVIEW and other PROSCREEN II modules to evaluate DSM programs. The recommended process for evaluating DSM programs includes three separate stages: screening, integrated demand/supply optimization, and detailed analysis. The process can be likened to a funnel, as depicted in *Figure OVERVIEW LFA–1*. The LFA Module plays an important role in each of these stages.

Screening of DSM programs is accomplished through use of the LFA Module in conjunction with DSVIEW and input marginal costs or the GAF Module. DSM programs in the LFA Module database are evaluated one at a time and are ranked based on cost effectiveness measures from the following perspectives: utility, participant, community (total resource), society, or the typical consumer (RIM). Capacity deferral benefits are calculated using the capacity credit logic in the LFA and/or the reliability equalization logic in the GAF. Energy benefits are calculated with a separate GAF production cost run for each DSM program or through exogenously calculated marginal energy costs.

The cost effectiveness measures calculated in the initial screening of DSM alternatives will result in a multi–objective decision space. DSVIEW pivots off this accumulated information and develops packages of demand–side alternatives which may be used as discrete levels of investment in DSM that may compete against supply–side options in a fully integrated resource optimization.

Integrated *optimization* of DSM programs may be accomplished by the LFA Module in conjunction with the GAF Module and PROVIEW. LFA load groups representing DSM programs are identified as explicit options in PROVIEW along with supply options. The optimal mix of DSM and supply options is developed using PROVIEW's dynamic programming capability. Several load groups may be easily combined into a single DSM alternative if desired in PROVIEW. In addition to the optimal plan, PROVIEW develops multiple suboptimal DSM portfolios for further analysis.

The user also has available the same inputs to examine alternate DSM program penetrations. These "penetration factor" inputs make it easy to examine in detail the production, financial, and rate impacts of specific programs.

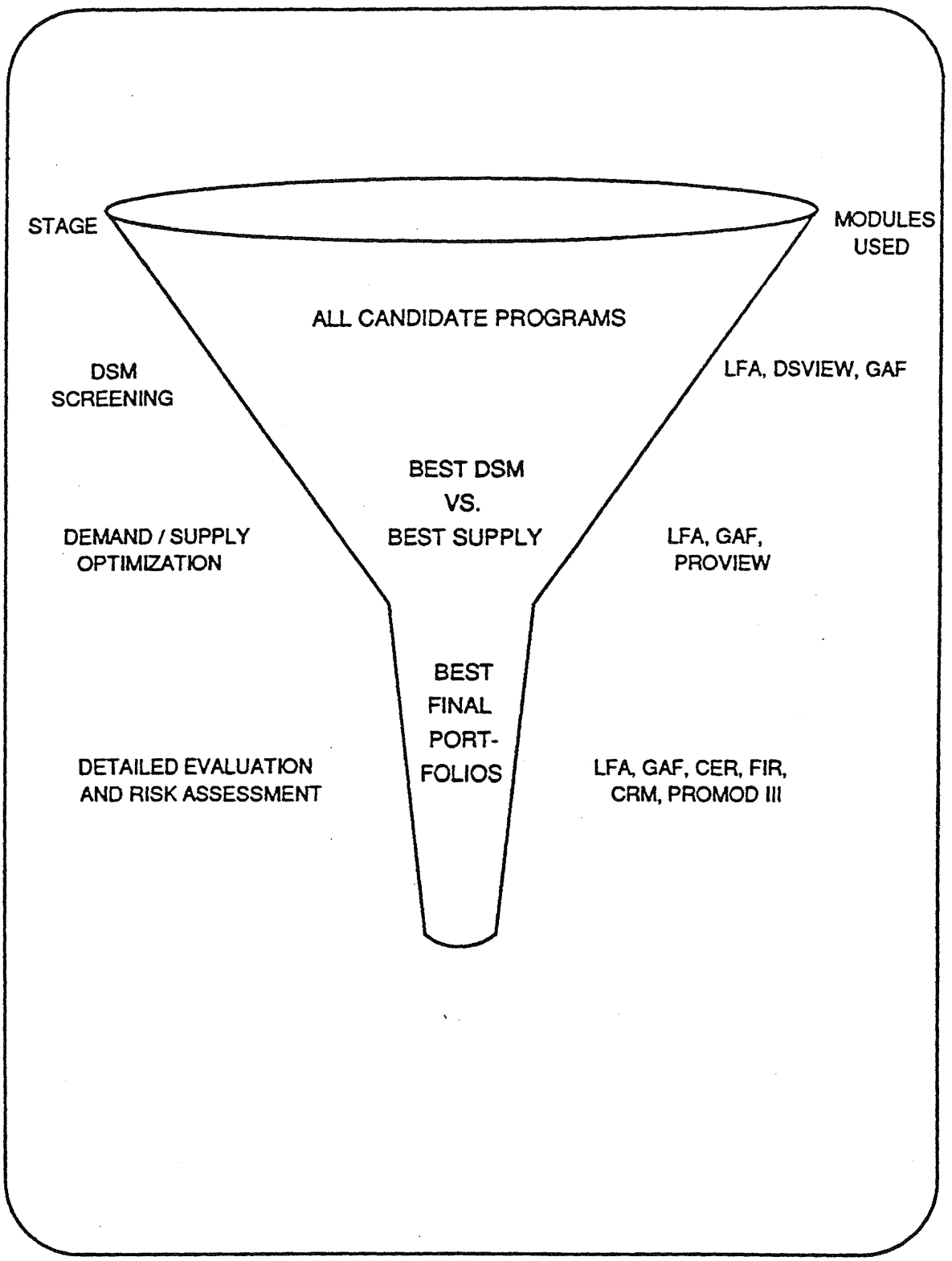


Figure OVERVIEW.LFA-1
Recommended DSM Evaluation Methodology

General Capabilities

- The module provides a comprehensive demand–side program evaluation capability, with inputs for program cost, load impact, timing, and capital costs.

- Load impacts may be input chronologically for each program, or may be determined by the module based on inputs for peak, energy, and program type.

- The module, in conjunction with the GAF Module, provides for the dispatch of Direct Load Control (DLC). The module develops the data for DLC, including the characteristics of the underlying load to be controlled, the contribution of the DLC capacity to the minimum savings required before DLC is dispatched economically, and the constraints to DLC operation. DLC is dispatched in the GAF according to an economic decision rule both to reduce peak and to maintain reliability.

- Load shape data may be supplied in detail if data is available or at an aggregate level for those groups which do not have adequate load shape data. The LFA Module thus allows the user to quickly develop a load shape projection for the company and system total, but gradually expand the detail of modeling as data availability increases.

- Load data can be defined in varying levels of detail. The degree of data aggregation is determined by the user. Any number of data "groups" may be specified. Data groups are summed to "class" totals. Class totals are summed to company totals. Data groups may correspond to end-uses, rate categories, customer categories, class totals, or even company totals.

- MWH data may be input seasonally or annually. If the user desires, the MWH for each season may be specified as a percent of the annual value. Peak load in MW or as a load factor may be input. If peak loads are not input for a group, peak is determined from input load profiles.

- End-use or DSM load shapes are determined from a variety of input formats. The user may enter a typical week profile directly for each season; enter typical daily load shapes and the frequency that each load shape occurs; or enter typical weekday, weekend day, and peak day load profiles. An EEI format preprocessor is part of the system. DSM programs can be specified as load impact "after" the program or as a combined "before and after" input.

- Class load profiles are computed to determine class peak and company load profile and peak demand.

- Load can also be calculated by region or area. This is used directly by PROMOD III.

- Most calculations are performed seasonally, where seasons are defined by the number of seasons and number of days in each season.

- The module provides a mechanism to reconcile the electric price assumption underlying the load forecast and the electric price resulting from the PROSCREEN II simulation. This mechanism is intended to reflect a company's existing load forecasting process.

- Price response can be specified in a flexible manner. The LFA Module allows a variable lag structure input with lag coefficients specified for as many as ten prior years.

- Results are reported by end–use group, by class, and by company.

- Numerous diagnostics supplement the standard reports.

- The LFA Module interfaces with PROMOD III and therefore guarantees that load and DSM programs are treated in a manner consistent with PROSCREEN II.

Figure OVERVIEW.LFA–2 provides a general overview of the LFA Module.

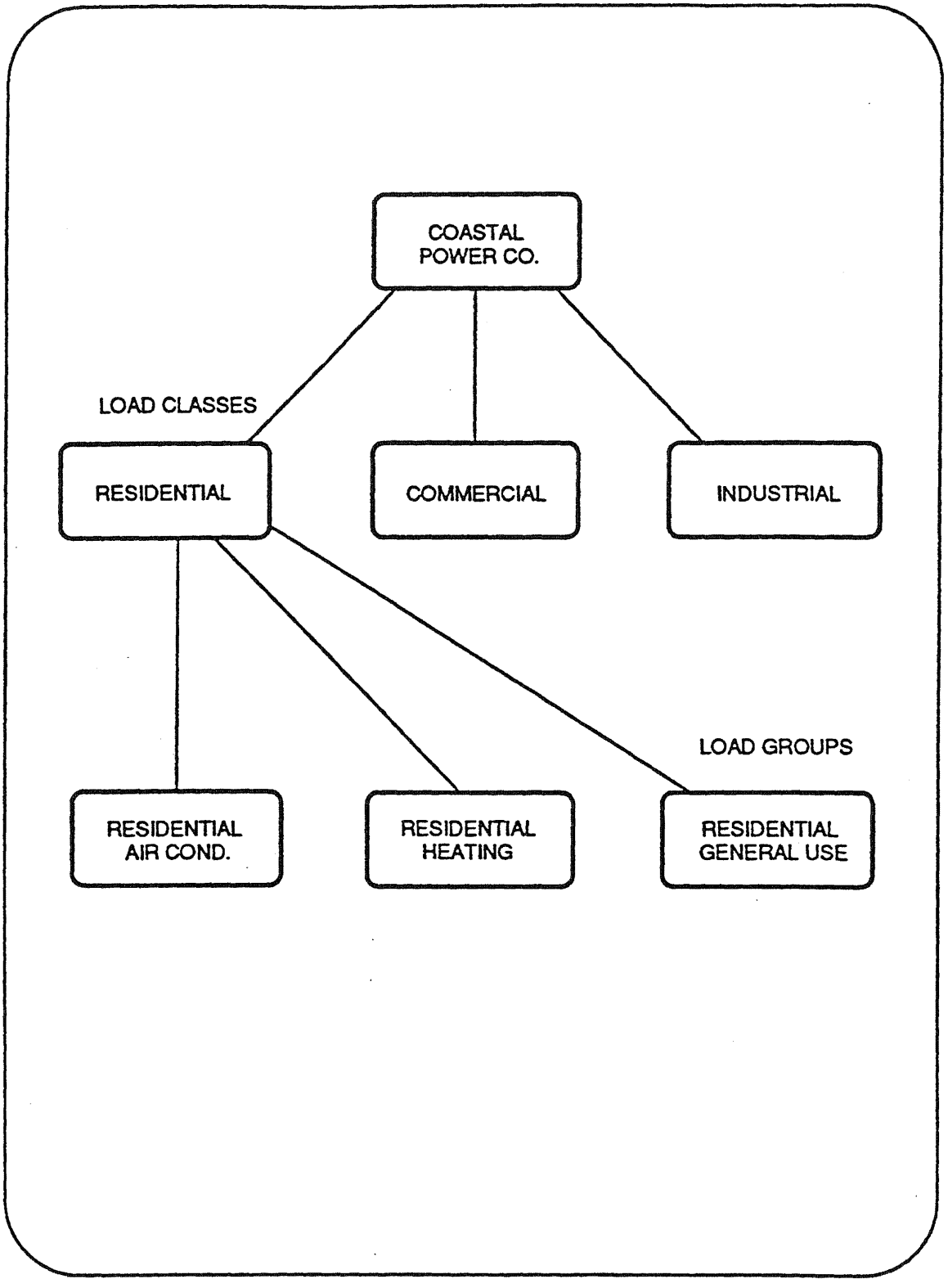


Figure OVERVIEW.LFA-2
Sample Load Forecast Adjustment Module Database

Module Methodology

The LFA Module allows the user to create electric company load forecasts to be transferred to the GAF Module for production costing purposes. The LFA processes the components of company load at a class and group level, where load groups sum to load classes and load classes sum to total company load. The contribution of class loads to company load also provides important transfer information for use in the Class Revenue Module (CRM) of PROSCREEN II. In addition to the company load and class transfers, the LFA provides estimates of total demand–side program costs and customer costs for use in the CER, FIR, and PROVIEW Modules.

Company peak, energy, and load shape are developed for each season defined in the PROSCREEN II database. Seasons are identified by the number of days in each season. A user–defined number of seasons may be modeled, the maximum being defined at the time of the PROSCREEN II delivery. Each season's load shape is represented by a chronological 168–hour load profile called a typical weekly profile.

Data is entered at the group level and consists of a seasonal forecast of noncoincident peak, sales, and a typical weekly shape. This shape may be input as a typical week or the profile can be built from a library of typical daily load shapes; or the profile can be built from a library of typical weekdays, weekend days, and peak days; or this profile may be processed from EEI data.

Cost (benefits) associated with DSM initiatives may be provided explicitly for each program, including fixed, variable and one–time implementation costs (benefits) for both the utility as well as the customer. The following DSM related expenses, customer costs and benefits may be modeled:

- Customer Fixed Costs
- New Participants One–Time Costs
- Customer Variable Costs
- Utility Fixed DSM Expense
- Utility New Participants Expense
- Utility Variable DSM Expense
- New Participants Incentive Payment
- Variable Incentive Payment
- Fuel Switch Savings (Costs)
- New Participants External Costs (Benefits)
- Variable External Costs (Benefits)

The shape impacts of DSM programs may be specified or a variety of automated system load inputs may be specified. Automated inputs include:

- Peak Shave
- Unscheduled Reduction
- Peak Build
- Unscheduled Build
- Valley Build
- Valley Shave
- Conservation

Dispatchable direct load control (DLC) programs may be evaluated in conjunction with the GAF Module. PROSCREEN II's DLC algorithm links the LFA and GAF Modules allowing dispatch decisions for DLC to benefit from the commitment, outage, and cost information available in the generating unit logic while retaining the chronology of load information. Loads available for control are developed in the LFA as well as a number of inputs associated with the description of payback and contractual use limitations (daily, monthly, and yearly for both hours and events). Each load group with load available for control is passed to the production costing module and evaluated against the expected marginal operating costs that would be experienced had no load control been available.

The LFA Module first develops energy sales and peak demand for each load group by multiplying the inputs by a user–defined penetration factor (less persistence) and by adjusting for price elasticity impacts. For groups which have shape data input, the LFA compares the load factor of the group shape to the implied load factor in the group peak and sales forecast. Any discrepancy is eliminated by modifying the load profile. Finally, the module develops the group requirements shape by scaling the sales shape by the user input group loss factor for the season.

Once each group has been processed, the hourly profiles are summed to create class load profiles and the class profiles are in turn summed to produce total company loads which are transferred to the GAF Module.

In many instances, peak, energy, and profile data requirements cannot be obtained for every load group represented in the database. In such cases the module will allow the following combinations of minimum data inputs:

1. Load shape and sales forecast. Noncoincident peak will be calculated by fitting the given energy under the given shape.

2. Load shape and noncoincident peak. Sales will be developed for each hour by multiplying the normalized shape against the input peak.

In the event that an hourly profile is unavailable for an input load group, the user has the ability to input peak, sales, and a coincidence factor for the load group. The user must also input an aggregate company shape representing the load profile of all groups for which hourly profile data is not entered, plus any other groups with hourly profile data which the user may wish to include in the aggregate shape. The module will first process all groups and classes which are included in the aggregate shape and which have a defined load shape. It will subtract the sum of these given load profiles from the input aggregate load profile. The resulting "residual" shape is assumed to be associated with all of the load groups for which shape information was not provided.

The LFA user also has the option of having the model calculate the impact of changing prices on the initial load forecast. This is accomplished by having the user input the base prices assumed in the initial load forecast, as well as the peak and energy elasticity coefficients for each load group modeled. Elasticity can be performed at either the average system price level or at the load class level with the alternate prices either being input directly by the user or being transferred from the FIR/CRM Module. The latter option requires the use of the round robin processing methodology.

When calculating the impacts of price elasticity, the LFA evaluates the impact of changing price on each individual load group before summing the modified profiles to the class and company level. Only the adjusted load is passed on to the GAF Module.

For combination electric and gas utilities that use Class Revenue, the gas sales forecast may be housed in the LFA Module for later use in the classification, allocation and revenue requirement calculations.

Module Results

The LFA Module produces the following reports.

- Input Summary By Data Qualifier
- Hourly Load Shape Report
- System Report
- Class Sales
- Class Requirements
- Class Detail

- Group Detail

In addition to standard output reports, diagnostics are provided to allow for detailed evaluation of LFA Module processing results. These diagnostics include:

- Group, Class & Company Seasonal Peak and Energy Results
- Group Requirements Seasonal Shapes
- Class Requirements Seasonal Shapes
- Company Requirements Seasonal Shapes
- Group Seasonal Load Shape
- Aggregation Table
- Adjustment Shape
- Aggregate Shape
- Residual Shape
- Change Commands for Coincidence Factors
- Write PROMOD III LLIB and LDAT records to Interface File
- Weighted Average Price Calculations
- DSM Program Calculations
- Write Adjusted Load Group LLIB Cards
- EEI Conversion Load Duration Plot
- EEI Conversion Chronological Plot
- EEI Conversion Statistical Summary
- Write PS II LLIB, GRSL, GRYR Records

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GENERATION AND FUEL MODULE (GAF)

Introduction

The Generation and Fuel (GAF) Module simulates power system operation using proven probabilistic methods. It provides production costs and generation reliability measures that are essential to supply and demand planning. The GAF Module fulfills a strategic planning role in that it requires less computer resources than more detailed production costing modules, without sacrificing overall accuracy.

General Capabilities

- The GAF Module uses probabilistic production costing techniques to simulate the effects of forced outages.

- Most module calculations are performed seasonally, where seasons are defined by number of seasons and by number of days per season.

- Sales, purchases, and hydro generation are accounted for on a seasonal basis.

- The user can explicitly define an hour–by–hour schedule for a transaction or simply specify when the transaction tends to occur (during peak load hours, low load hours, or randomly) and the GAF will schedule the transaction appropriately.

- Thermal generating units are represented by two capacity segments; each segment may have a distinct heat rate and availability. The units which are classified as must–run are committed first, followed by enough other units to satisfy a user–input commitment criterion. The remaining units are committed on an economic start–up and dispatch basis, subject to fuel limits and spinning reserve requirements.

- The dispatch of thermal units and economy energy may be performed on a seasonal or annual basis.

- Pumped hydro projects and direct load control programs are economically dispatched on a seasonal basis, based on marginal cost. (Direct load control programs may be modeled only if the LFA Module is licensed.)

- Pumped hydro projects are economically dispatched on a seasonal basis.

- Units are dispatched to conform to upper and lower limitations on fuel usage.

- Unit dispatch is performed on an 'as burned' or replacement cost of fuel basis.

- Unit, company and system emissions are calculated based on actual runtimes and fuel usage. Emissions allowances are purchased or sold on the basis of system performance and the inputs for allowance cost and allowance base for each effluent. The cost of allowances is reflected in the dispatch lambda used in dispatch order decisions.

- Environmental externalities are calculated for emissions, emergency energy, and direct load control.

- Multicompany dispatch with interchange accounting for holding companies or power pool simulation is provided.

- Numerous diagnostic reports which document detailed calculations are provided.

Production Costing Methodology for the GAF Module

Figure OVERVIEW.GAF–1 presents the general design of the GAF Module. As shown, the production costing procedure consists of two stages. In the first stage, the operation of hydro generation, sale and purchase transactions and the economic operation of pumped storage facilities are simulated. The result of this first stage is the remaining annual or seasonal thermal load duration curve. In the second stage, the expected operation of the thermal generating units within the year is simulated by a probabilistic technique. The results are the production costs and system reliability indices.

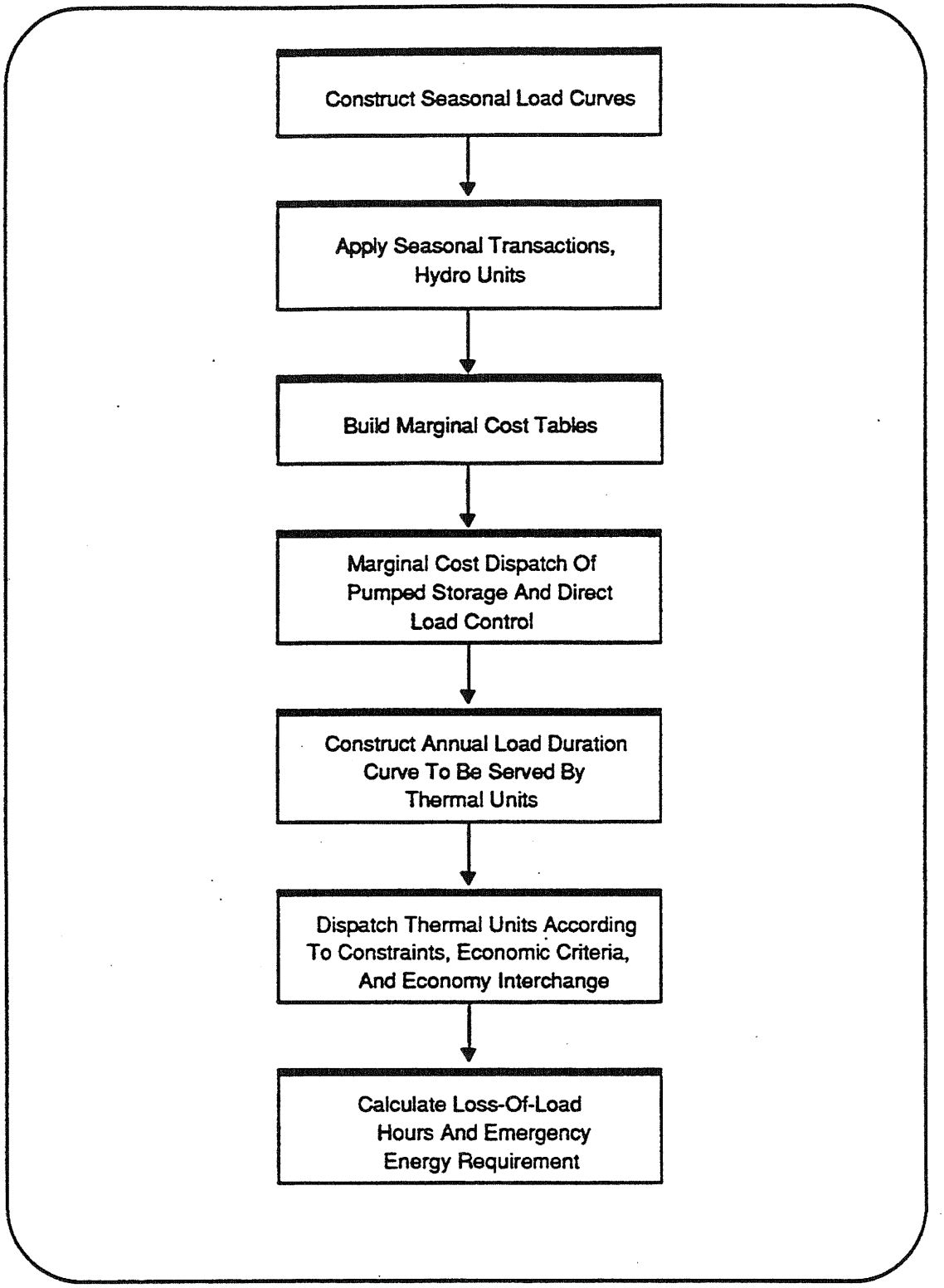


Figure OVERVIEW.GAF-1
Overview of Generation And Fuel Module

Dispatch of Non–Thermal Resources

System load data is passed in the form of a typical 168–hour weekly load shape to the GAF from the LFA Module. Then, the dispatch of non–thermal resources is performed in the following order:

1. The transactions (sales or purchases) that are input in the form of hourly values for each season are added to (in the case of sales) or subtracted from (in the case of purchases) the chronological load curves.

2. The hydro generating units are dispatched one at a time. Each hydro unit has a minimum (must–run) MW capacity, a maximum MW capacity, and a total energy MWH for the season. The remaining load after step 1 is first modified by subtracting from it the minimum hydro generation for every hour. The remaining hydro energy is used for peak shaving. This peak–shaving energy is calculated by subtracting the minimum hydro generation from the total hydro energy. The peak–shaving capacity is the difference between the maximum MW capacity and the minimum MW capacity of the unit.

3. The transactions that are characterized by seasonal capacity and energy are scheduled. For each sale transaction, the user chooses whether the sale is a valley fill or peak build sale, or is to be applied uniformly to the load curves. For each purchase transaction, the user chooses whether the purchase is a peak shave or valley reduction purchase, or is to be applied uniformly to the load curves.

4. Pumped storage hydro is scheduled. Storage dispatch is based on the expected generation cost at each hour before storage, pond storage limitations, cycle efficiency, and minimum savings. The storage algorithm works from highest cost hour down for generation and from lowest cost hour up for pumping, reducing the remaining load at high cost hours and increasing the load at low cost hours. This process is performed subject to the minimum savings and pond limit constraints. An option is available for the capacity of storage not used for economic reasons to be used for reliability purposes.

5. Direct load control devices are scheduled. The LFA Module provides information on underlying loads that are available for control and DLC dispatch parameters. All DLC devices are dispatched simultaneously so as to achieve the greatest possible savings and in such a way that a new peak is avoided. Payback is explicitly considered in addition to

contractual constraints such as maximum number of interruptions and maximum hours of interruptions for each program.

After the dispatch of non–thermal resources is completed, the remaining load is served by thermal generating units. The thermal dispatch is performed on a seasonal or an annual basis as determined by the user for each water year. If annual dispatch is chosen, the modified seasonal load curves are combined into an annual load curve.

Dispatch of Thermal Resources

Each generating unit may be represented by one or two capacity segments. Each capacity segment may have a distinct heat rate. A unit may be designated as a must–run unit, in which case its minimum segment is dispatched before any upper segment in the system. Other thermal unit inputs include commission date, retirement date, immature forced outage rate, mature forced outage rate, and partial forced outage rate at the minimum capacity level.

Planned maintenance may be explicitly modeled for each generating unit by specifying the start and end dates for each maintenance, or by entering a start date and number of weeks of maintenance in each year. Optionally, only the annual number of weeks of maintenance may be specified, in which case maintenance is scheduled for the unit to levelize reserves or LOLP across seasons. Maintenance may be handled as either a deration of the unit's capacity, or as an adjustment to its forced outage rate.

The widely accepted probabilistic production costing procedure is used to project the operation of each generating unit. The minimum segments of the must–run units are dispatched first, followed by enough other minimum segments to satisfy a user–defined dispatch commitment criterion. The remaining segments are dispatched in an economic order approximating the economic dispatch procedure of a system operator. Sufficient reserves are maintained to satisfy user–defined spinning reserve requirements first by limiting unit output and automatically adjusting fuel mix during dispatch. If fuel limits are still exceeded, the system modifies the energy outputs of the generating units, resulting in a departure from economic dispatch. The impact of economy energy purchases and sales are determined on an economic basis.

After all available resources have been utilized, several reliability indices are determined. Among these are:

- Expected hours with negative margin (Loss of Load Hours, or LOLH)
- Expected emergency energy
- Reserve Margin

Alternatively, reliability measures, such as LOLH and expected emergency energy, may be fixed so that equivalent capacity benefits for DSM programs may be calculated. The GAF has the ability to calculate the equivalent capacity benefit of an incremental change in load based on a broad reliability measure. This relieves the user of the uncertain task of estimating a capacity benefit which for many DSM programs (e.g. direct load control) may be difficult to measure. This is a significant improvement over the traditional calculation of the impact on the reserve margin (peak hour impact).

Emissions are calculated each year on a unit by unit basis. Removal efficiency characteristics of each unit are input. The individual unit results are then aggregated into company and system emissions totals and rates. The cost of emissions, whether such cost is in the form of allowance purchase price, emissions tax, or emissions externalities result from the thermal dispatch. Separate inputs allow these emissions costs to be included in a unit's dispatch lambda if desired.

Network Economy Interchange (NEI) Modeling

Introduction

The Network Economy Interchange (NEI) feature of the GAF helps reduce operating costs for a group of interconnected utililties by developing the most beneficial unit dispatch schedule for the group.

In a situation where there is unlimited transmission capacity between interconnected systems, the interchange process reaches economic equilibrium. At equilibrium, the marginal costs of all systems are virtually identical. To reach the point of equilibrium, the NEI feature performs interchange among interconnected systems in order to levelize the marginal costs. Interchange is economical as long as the difference in marginal cost is greater than the minimum savings criterion among systems.

In power systems, particularly large systems covering major geographical areas, unlimited transmission capacities seldom exist, due to physical or contractual transmission limits. To neglect transmission capacity limits is to overestimate the benefit of economy interchange. This problem may not be severe if transmission constraints are not binding. However, in transmission–poor systems, overestimation of economy interchange benefits may distort overall system production costs.

The NEI feature provides a marginal cost–based algorithm for economy interchange among connected systems, while enforcing transmissions limits for all hours. NEI accomplishes this by systematically matching potential buyers and sellers and incrementally equalizing their marginal costs.

Figure OVERVIEW.GAF–2 is a schematic flow diagram showing how NEI is incorporated into the overall GAF modeling structure. After all other load modifications are complete (transactions, hydro, pumped hydro, and direct load control), the GAF implements economy interchange. Interchange results are used to modify hourly loads of the internal companies. The GAF then executes the thermal dispatch for every internal company. If there is more than one internal company, the NEI feature sums company outputs to obtain the pool results.

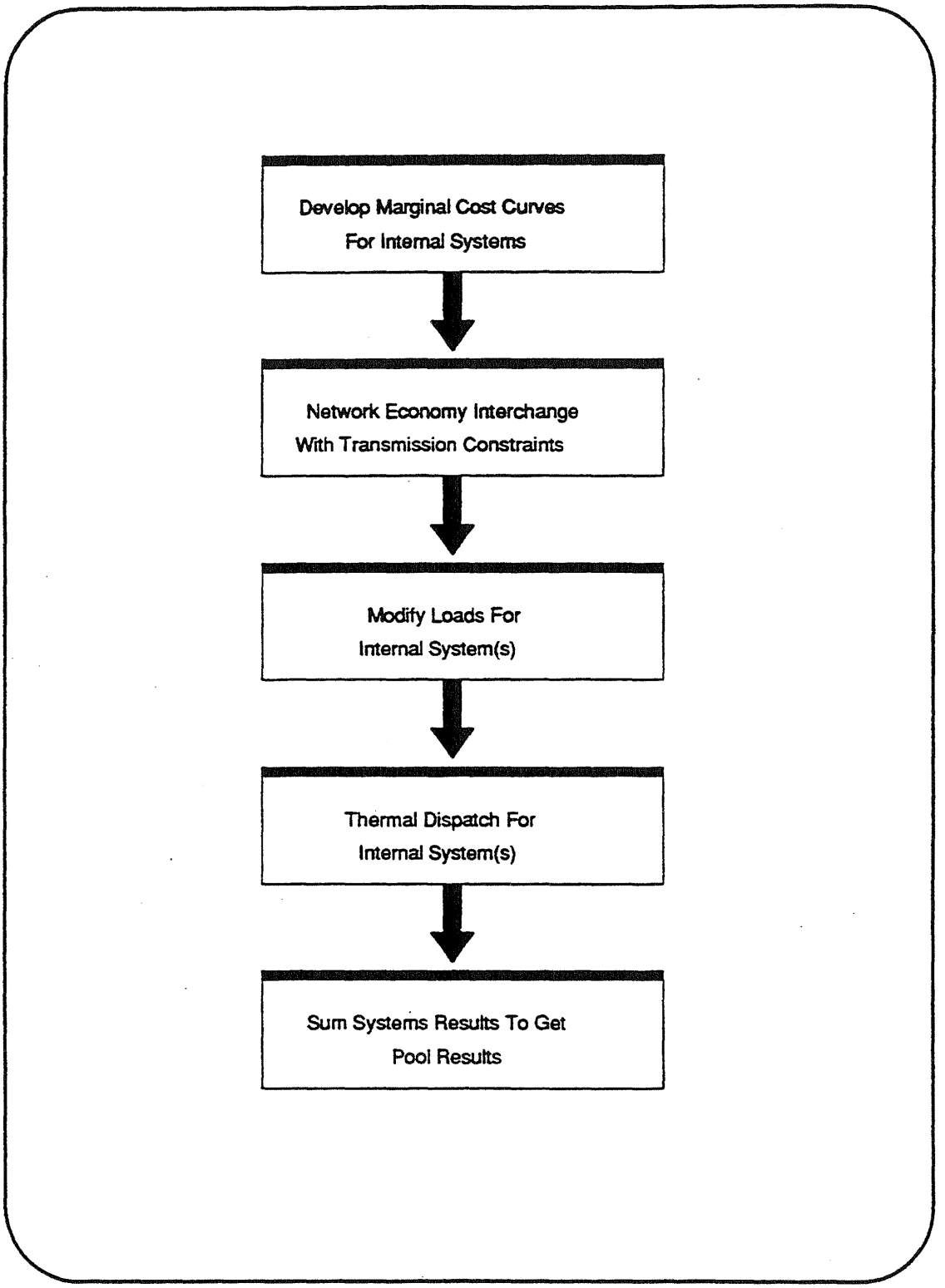


Figure OVERVIEW.GAF-2
Generation And Fuel
Schematic Diagram of the Network Economy Interchange

Output Reports

These reports are provided by the GAF Module:

- System Report (includes company reports and multi–company interchange reports)
- Seasonal Summary Report
- Capacity Report
- Unit Report
- Plant Report
- Hydro Unit Report
- Storage Unit Report
- Direct Load Control Report
- Fuel Data Report
- Fuel Class Report (includes company reports)
- Input Summaries
- System Emissions Report
- Emission Report by Effluent
- Transaction Report

In addition to standard output reports, numerous diagnostics are provided to allow for detailed evaluation of GAF Module processing and results. These diagnostics include:

- Load As Transferred From The LFA (MWH)
- Load As Transferred From The LFA (% Of Peak)
- Load Before Pumped Hydro Adjustment (MWH)
- Load Before Pumped Hydro Adjustment (% Of Peak)
- Load After Pumped Hydro Adjustment (MWH)
- Load After Pumped Hydro Adjustment (% Of Peak)
- Thermal Unit Dispatch
- Limited Fuel
- Company Fuel Type
- Capacity Sellback
- Dispatch Lambda

- Spinning Reserve Look Ahead
- Inflation / Escalation
- In–Dispatch Limited Fuel
- Externality Calculations
- Dispatch Lambda Emissions Adder
- Marginal Cost Curve (PS & DLC)
- Marginal Dispatch Cost Curve
- Direct Load Control
- Load After DLC Adjustment (MWH)
- Load After DLC Adjustment (% Of Peak)
- Chronological Marginal Costs
- Marginal Cost RLIBS
- Reliability
- Water Year System Report
- Water Year Seasonal Report
- Water Year Hydro, Pumped Storage & Unit
- Water Year Fuel Class & Fuel Type
- Economy Interchange
- Multi–Company Interchange
- Expansion Scheduler
- Energy Reserve Margin
- Maintenance Subperiod Array
- Daily Seasonal Definition
- Capacity And Reserve
- Seasonal Maintenance Week

All operating data necessary for specific project or overall system economic and financial calculations are automatically stored in PROSCREEN II's integrated data base during the execution of the GAF Module. In addition to standard output reports, numerous diagnostics detailing the operation of the GAF Module are available on an annual and seasonal basis.

DSVIEW SYSTEM (DSV)

Introduction

The DSVIEW System consists of the DSVIEW Program Design (DSVIEW–DPD) Module and the DSVIEW Cost Effectiveness (DSVIEW –DCE) Module . This section presents an overview of both modules.

DSVIEW's advantage as a DSM planning system is its depth in representation of both demand–side and supply–side costs and operations. This capability enables utilities to comprehensively screen the impacts of demand–side measures with a degree of accuracy appropriate for informed decisions. The DSVIEW System Modules recognize hourly chronological load patterns. Production cost simulations performed are comprehensive, yet fast. Detailed benefit/cost ratios quickly provide users with a powerful understanding of the impacts of each individual demand–side program on the utility, the participant, the typical utility customer, the community, and society in general. Heuristics developed for the DSVIEW System Modules suggest combinations of demand–side alternatives to study the interactive nature of alternatives and develop a comprehensive DSM supply curve.

EMA recognizes that obtaining an *optimal* integrated resource plan is not merely the running of a computer program. Rather it is the execution of a well–organized process, the objectives of which are applications of management, analysis, and judgement. The DSVIEW System Modules provide the first step of an integrated resource planning process by efficiently reducing a large number of demand–side alternatives to a feasible number of demand–side packages which may be considered discrete blocks to be offset by supply–side alternatives.

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DSVIEW COST EFFECTIVENESS MODULE (DSVIEW–DCE)

Introduction

The Cost Effectiveness portion of the DSVIEW System (DSVIEW–DCE) has three primary components which run stand–alone or integrated:

- **Load Forecast Adjustment** (LFA) **Module** models chronological seasonal loads (by end–use and/or class) and hourly impacts of DSM programs (including peak, energy, fixed and variable costs, customer costs, penetration curves, etc.).

- **Generation and Fuel** (GAF) **Module** provides very fast production costing simulation and capacity delay benefits. The GAF has considerable benchmark accuracy compared to PROMOD III®, the industry standard.

- **DSVIEW Cost Effectiveness** (DSVIEW–DCE) **Module** develops detailed estimates of standard benefit/cost ratios of DSM options modeled in the LFA Module. The user has an option of exogenously estimating the base case supply plan's marginal operating and avoided capital costs or modeling them in the GAF Module.

DSVIEW–DCE provides a variety of standard reports ranging from group–by–group load forecasts to portfolio analysis. In addition, detailed Input Summaries in report–quality format are generated as requested for documenting assumptions of any study.

DSVIEW DSM Cost Effectiveness Module

The DSVIEW–DCE Module is a detailed demand–side management screening model that analyzes the impact of individual DSM programs from a variety of perspectives. DSVIEW–DCE permits screening of DSM programs based on standard or user–defined cost effectiveness measures. These may be calculated

as benefit/cost ratios or net present values from a number of perspectives, including:

- Program Participant
- Utility Total Resource (TRC)
- Society
- All Utility Customers (RIM)

Analysts may modify these measures of cost effectiveness or create new measures of their own. In addition to the traditional components of standard cost effectiveness tests, DSVIEW has the capability to include changes in value (from the consumer's vantage point) due to DSM. For example, a load–building program would never pass the TRC test unless the value of the additional service it provided was included in the measurement.

DSVIEW–DCE analyzes demand–side options in conjunction with the LFA Module. The LFA Module allows detailed treatment of system, class, or end–use loads, enabling planners to specify demand–side programs on an hourly chronological basis. Demand–side alternatives may be examined with various levels of market penetration. The programs in turn modify peak demand, energy sales, and chronological typical week load profiles. DSM programs in DSVIEW–DCE may decrease or increase system sales and requirements.

Benefits are based on marginal energy costs which are either input from other production costing systems or calculated dynamically through an explicit production cost simulation incorporating each program's hourly load impact. DSVIEW–DCE is delivered as either a stand–alone system or fully integrated with PROSCREEN II. When integrated with the GAF Module, DSVIEW–DCE provides a methodology to calculate marginal capacity benefits dynamically by determining each program's reliability benefit as compared with an equivalent amount of supply. External costs and benefits (e.g. environmental) are explicitly considered by both configurations.

Detailed diagnostics provide complete descriptions of the benefit/cost ratio and net benefits. DSM programs are ranked by the standard measures of effectiveness. A final composite ranking may be developed based upon a user–specified weighting scheme which reduces the five measures down to a single measure of effectiveness in the following manner:

$$CR_i = \Sigma_j W_j * RANK_{ij}$$

where: CR_i = Composite ranking, plan i

W_j = Weighting factor, objective j

$RANK_{ij}$ = Ranking of plan i, based on objective j

Packages of DSM programs called portfolios are developed based on the initially calculated benefit/cost ratios and user–supplied data on levels of investment and attitudes toward risk. A package–building heuristic develops a rank order for the supply of DSM. Next, DSVIEW–DCE evaluates individual programs in combination with other programs until the module reaches the specified portfolio–building criteria. For example, the module builds DSM portfolios representing discrete levels of investment in DSM. These portfolios may be used in integrated resource planning models (e.g. PROVIEW) to represent alternatives to traditional supply options.

Results reported by the module include benefit/cost ratios and net benefits for each DSM program, DSM programs ranked by effectiveness measure, a final composite ranking, and portfolio results. Full LFA and GAF (optional) reports and diagnostics are available. Standard DSVIEW–DCE reports are:

- Benefit/Cost Ratio Report
- Program Ranks Report (for each measure of cost effectiveness)
- Composite Ranks Report
- Portfolio Report
- DSM Supply Curve Report

DSVIEW–DCE Module Methodology

Existing utility system demand conditions are modeled in the LFA Module and existing system supply conditions are modeled either in the GAF Module or directly input as a set of marginal cost tables. These tables may be produced exogenously by other production cost models (e.g. PROMOD III). The data required for the DSM alternatives is composed of two sections: load shape impacts and program costs.

Module inputs are flexible, allowing for a variety of representations of utility and customer costs, for example, a fixed amount per year, an incremental amount per number of new participants, or an amount per total number of participants to date. Incentive payments and external costs (benefits) are entered as a function of the number of new participants or the total number of participants to date. Fuel switch savings or costs (for inclusion in the participants, total resource, and societal measures) are a function of the total number of participants to date. A set of capital expenditures may also be specified. This variety of inputs associated with DSM costs and benefits, in conjunction with the detailed calculation of energy costs or benefits, allows the user the flexibility to model a wide variety of DSM options.

DSVIEW–DCE's structure is depicted in *Figure OVERVIEW.DSV–1* and may be summarized as follows:

1 DSVIEW–DCE constructs a capital cost table. This table contains the present value of all capital expenditures associated with the DSM option.

2 A production cost simulation estimates the value of the business–as–usual case.

3 For a given DSM alternative, DSVIEW–DCE evaluates hourly load impact and develops differentials from the base case for class sales, revenues, customer costs, and utility costs for each year of the study period. An end effects analysis is performed to account for costs and benefits of DSM alternatives which may occur after the end of the study period. It is also possible to examine the impact of end effects computed over a less-than-infinite period.

4 The module calculates present value of benefits and costs and develops benefit/cost ratios.

5 The module calculates rankings based on the different cost effectiveness measures. It calculates a composite measure of effectiveness based on the standard measures and a user–specified weighting scheme.

6 DSVIEW–DCE packages individual DSM programs into portfolios representing discrete levels of investment in DSM. These portfolios are built based upon the initially calculated benefit/cost ratios and user supplied data on levels of investment and attitudes towards risk.

7 Final results are provided in standard output formats.

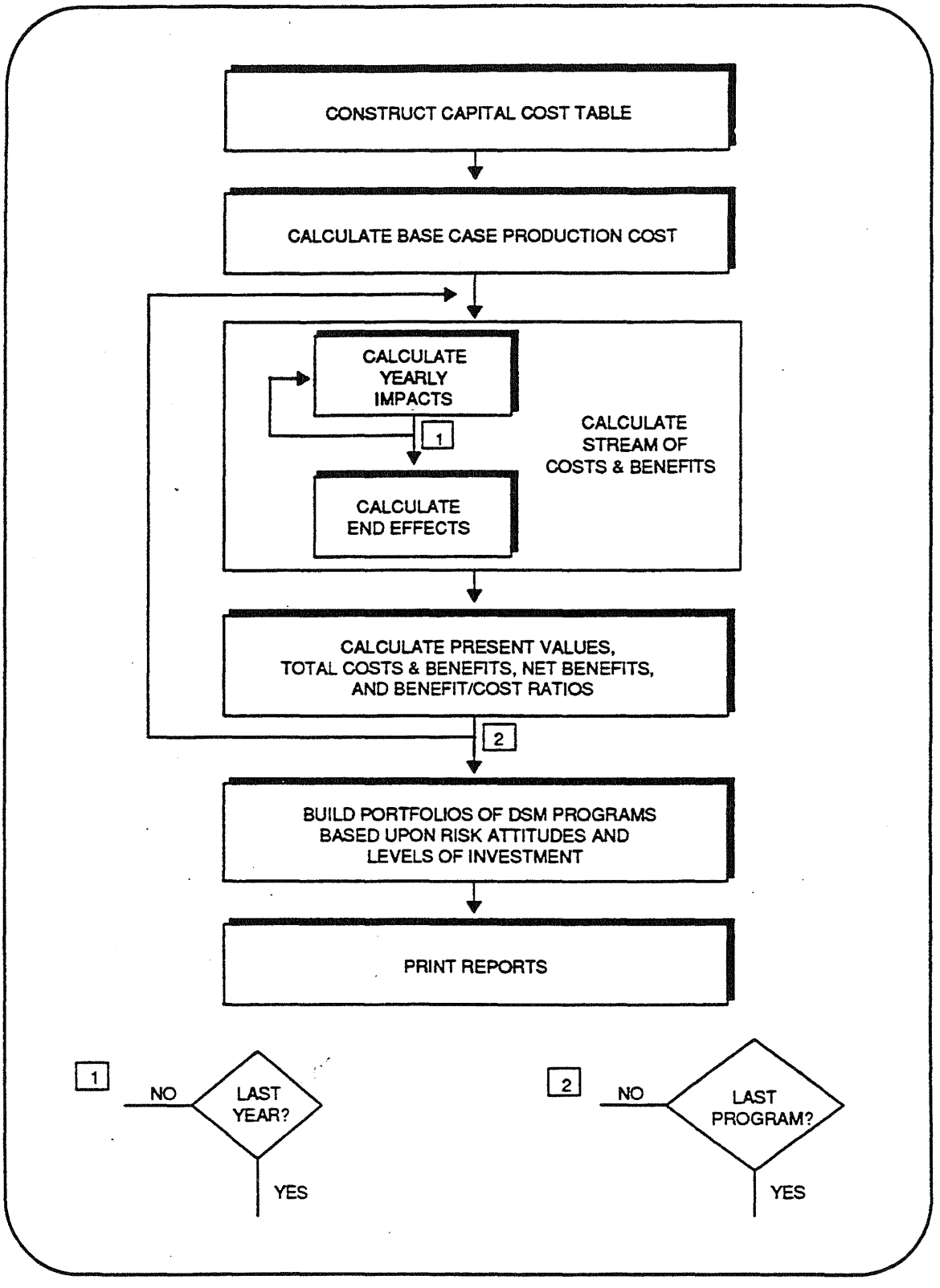


Figure OVERVIEW.DSV-1
DSVIEW–DCE Cost Effectiveness Methodology

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DSVIEW PROGRAM DESIGN MODULE (DSVIEW - DPD)

NSP does not currently license the **DPD** module. The function of the **DPD** module is to design **DSM** programs. **COMPASS** is used for this purpose. A description of the **DPD** module is not included.

PROVIEW MODULE (PRV)

Introduction

The PROVIEW (PRV) Module is a resource planning model which determines the least–cost balanced demand and supply plan for a utility system under prescribed sets of constraints and assumptions. PROVIEW incorporates a wide variety of expansion planning parameters including alternative technologies, unit conversions, cogenerators, unit capacity sizes, load management, marketing and conservation programs, fuel costs, reliability limits, emissions trading and environmental compliance options in order to develop a coordinated integrated plan which would be best suited for the utility. PROVIEW works in concert with the GAF Module to simulate the operation of a utility system. PROVIEW's optimization logic then determines the cost and reliability effects of adding resources to the system or modifying the load through demand-side management (DSM) programs.

The module allows modeling of emissions–related constraints, emissions allowance trading, and emissions reduction alternatives (e.g. scrubbers, fuel switching). These capabilities are used both to develop optimal environmental compliance strategies and to incorporate resource planning.

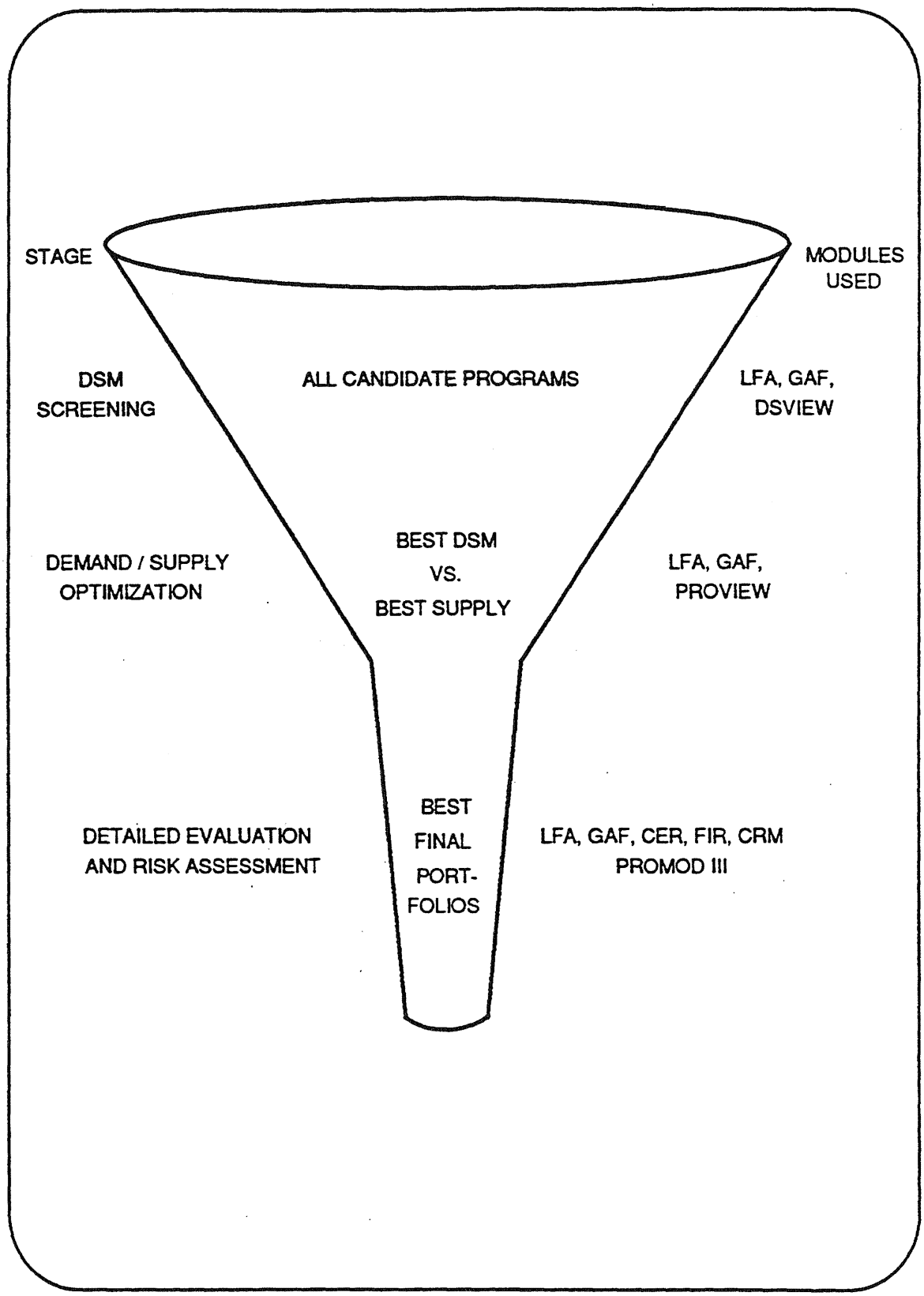
Figure OVERVIEW.PRV–1 graphically depicts the process by which PROVIEW works with other modules to evaluate DSM programs in three separate stages: screening, integrated supply/demand optimization, and detailed analysis.

DSM programs are screened by using the LFA Module in conjunction with DSVIEW–DCE and the GAF Module. DSM programs in the LFA Module database are evaluated one at a time and are ranked based on industry standard cost effectiveness measures such as participant cost, utility cost, total resource cost, societal cost, and ratepayer impact measure (average rate). Groups of programs are then developed into portfolios based on the results of the ranking process. The LFA allows detailed treatment of system, class or end–use loads, enabling you to specify demand side programs on an hourly chronological basis. Capacity deferral benefits are calculated using the capacity credit logic in the LFA and/or the reliability equalization logic in the GAF. Energy cost

benefits are calculated with a separate GAF production cost run for each DSM program.

Once portfolios of DSM programs have been developed, the LFA Module is used in conjunction with PROVIEW to perform integrated demand and supply optimization. LFA load groups representing DSM programs or portfolios of DSM programs are specified as explicit PROVIEW alternatives. In this way, DSM programs compete on a "level playing field" with supply options. The optimal DSM/supply plan is then developed using PROVIEW's dynamic programming capability. In addition to the optimal plan, PROVIEW retains multiple suboptimal DSM/supply plans for further analysis.

The final step in evaluation of DSM programs involves use of the LFA Module in conjunction with all modules of PROSCREEN II and in conjunction with PROMOD III, EMA's detailed production costing system. The CER Module provides the annual capital expenditure impacts of DSM programs and allows assessment of DSM program costs which are capitalized. The FIR Module allows the evaluation of the impact of DSM programs on average rates, rate increase requirements and timing, and financial performance. The impact of DSM on class rates and cross subsidy issues may be thoroughly evaluated in the CRM. Finally, detailed estimates of DSM program impacts on production costs can be evaluated by passing the results of the LFA to PROMOD III.



OVERVIEW.PRV-1
Recommended DSM Evaluation Methodology

General Capabilities

- Data input is structured in a similar manner to PROSCREEN II GAF data. The PROVIEW data base is compatible with PROMOD III data base translator results.

- PROVIEW provides quick turn–around time by eliminating options that are not feasible and by eliminating unnecessary detail.

- PROVIEW allows for a full enumeration of all combinations of expansion options and/or demand-side management (DSM) programs through its Dynamic Programming option. The system can thus be highly rigorous in its determination of a least–cost expansion plan for the entire planning period.

- PROVIEW provides an option to use the California Iteractive Cost–Effectiveness Methodology (ICEM) as an alternative to dynamic programming.

- Production cost calculations are performed for each alternative through the execution of the GAF Module. Demand side programs and associated sales impacts are computed through the execution of the LFA Module.

- PROVIEW provides several capital cost representations. These include an economic carrying charge approach or an in–service date charge which represent the present value of all future capital costs associated with an alternative.

- PROVIEW explicitly handles end effects in determination of the least cost plan. The end effects analysis approximates the capital and production cost of replacing the resulting utility system in kind over the user–input end effects period.

- PROVIEW provides for one of six objective functions to be used in the least-cost optimization: minimization of utility costs, minimization of average study period rates, minimization of total societal cost (total resource cost), minimization of customer class rates, total resource costs, or $/ton removed.

- PROVIEW provides numerous constraints for the user to reduce the number of options to consider. Minimum and maximum number to add, minimum and maximum reserve or loss of load hours, and first

year available to add are but a few. PROVIEW can define alternatives as mutually exclusive or inclusive in a year. It can also restrict alternatives to be dependent upon certain other alternatives being in service (the second unit in a station is dependent upon the first unit having been constructed). PROVIEW also allows options such as phased construction of combined cycle units to be evaluated quickly. Maximum emissions levels can also be specified to reduce the alternatives considered.

- PROVIEW allows complete evaluation of suboptimal plans. All plans are saved in PROVIEW's database for subsequent reporting and analysis. The user may specify the ranking of significantly different plans. Significantly different plans are developed as of a certain year of the analysis.

- Numerous diagnostics which explain in detail how PROVIEW reaches its optimal plan decision are available.

- PROVIEW results include a database that contains the results of all plans. The analyst can select any of these plans to be automatically set up in the LFA, GAF, CER, and FIR Modules for more extensive evaluation. In conjunction with the PROSCREEN II Decision Analysis (PSDA) Module, the effects of uncertainty in the choice of an optimal plan can be completely evaluated.

Module Inputs

PROVIEW requires the data supplied by the user to be separated into two sections: the first section characterizes the existing utility system and the other section characterizes the potential expansion or DSM options. The existing utility system data set is composed of the PROSCREEN II GAF and LFA Module data sets, which are fully described in the GAF Module documentation and LFA Module documentation. Briefly, data requirements for the existing system are grouped according to load, hydro unit, transaction, thermal unit, storage unit, fuel type, fuel class, and general parameter data. Data requirements for the existing load forecast are grouped according to load group, load shape, load class, and parameter data.

The data required for the planning alternative section contains information relating to alternative resources that may be added or DSM programs that may be implemented. Data in this section defines alternative unit characteristics, construction costs, resource addition limits, and resulting system reliability constraints. Alternative option information is specified in a general manner so

that any proposed available option can be commissioned at any time during the study period.

Module Methodology

PROVIEW's Dynamic Programming calculations are summarized as follows:

1. A capital cost table is constructed. This table contains either the economic carrying charge or in–service date charge for every alternative for every possible in–service year.

2. Feasible current–year states (combinations of alternatives) are determined by examining every combination of user–defined resource additions or demand-side management program. Feasible states are those which meet reliability dependency and tunnel constraints. One–year capital and production costs are calculated and used to determine the accumulated cost–to–date. Each feasible state description is saved along with the associated accumulated cost–to–date.

3. The module repeatedly analyzes and saves feasible states for each year during the planning period. At the end of this planning period, a matrix of possible states for each year has been constructed. Note that each feasible state in the final year represents the end product of a different expansion plan.

4. Each potential expansion plan is subjected to end effects analysis. The end effects analysis adds to the accumulated cost–to–date of the capital and production cost of replacing the resulting utility system in kind, over a user–specified end effects period.

5. The expansion plan with the lowest accumulated cost after end–effects is selected as the least–cost plan. PROVIEW's present worth of average rates objective function is available when demand-side management programs are available.

6. The module traces back through the matrix of feasible states to identify the components of the optimal plan and the components of each sub–optimal plan.

7. The optimal plan is set up in the LFA, GAF, and CER for subsequent analysis and reporting. All plans are saved in the database.

Figure OVERVIEW.PRV–2 shows the general logic flow of PROVIEW's Dynamic Programming option.

Output Reports

The following reports are produced by PROVIEW:

- Least Cost Plan Summary
- Demand Side Report
- Tunnel Report
- Significantly Different Plans
- System Cost Report
- Integrated Plan Report
- Study Period Plan Comparison
- Planning Period Plan Comparison
- Planning Period Emissions Analysis

PROVIEW produces the following diagnostics.

- Reserve Analysis
- Levelized and Replacement Cost Tables
- Capital Cost Table
- Origin State Diagnostics
- State Analysis Summary
- State Analysis List
- Accepted State Diagnostics
- Levelization Calculations
- Dispatch of 1st End Effects State
- End Effects Period
- ICEM Summary
- ICEM Detailed
- First Year Test

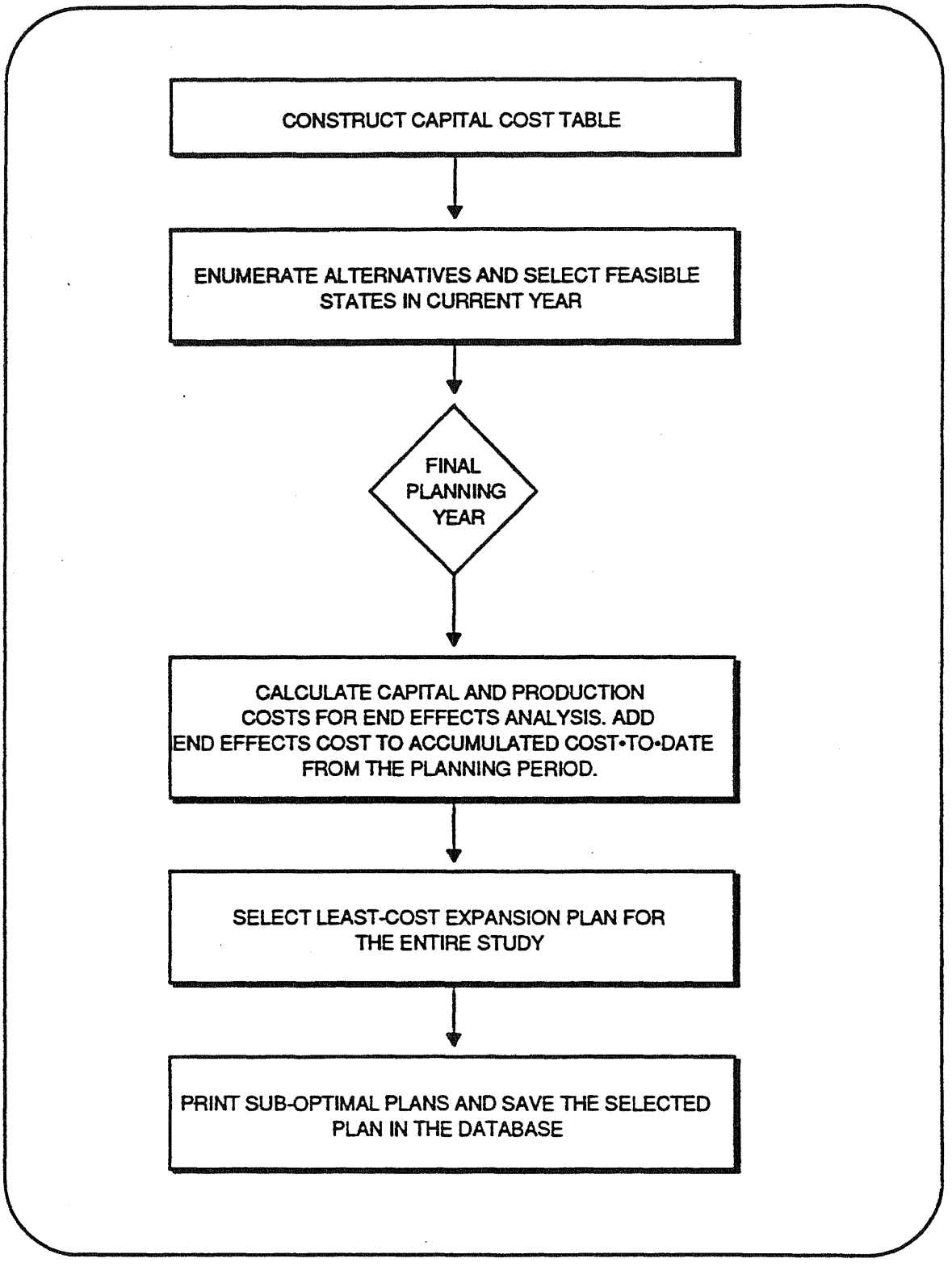


Figure OVERVIEW.PRV-2
Dynamic Programming Option

CAPITAL EXPENDITURE AND RECOVERY MODULE (CER)

Introduction

The Capital Expenditure and Recovery (CER) Module provides a method of readily comparing and evaluating the economics of generation alternatives. In addition, the CER Module, through its interaction with the Financial Reporting and Analysis (FIR) Module, allows the strategic planner to analyze the financial implications of an individual project or an entire construction program.

General Capabilities

- The CER Module allows the strategic planner to examine the financial effects on the company's consolidated operations of construction alternatives intended to meet the forecasted system demand. Complete economic evaluation reports using both minimum revenue requirements (MRR) and discounted cash flow techniques are available.

- The CER Module simulates the financial effects resulting from changes in the treatment of the tax effects of depreciation allowances for funds used during construction (AFUDC), and investment tax credits (ITC). The depreciation tables of the 1981 and 1982 Tax Act are handled automatically. All provisions of the 1986 Tax Act are incorporated, including the tax depreciation methods and the Average Rate Assumption Method for handling "excess" deferred taxes.

- Any number of major projects (those which close to plant at the end of the expenditure stream) and blanket projects (those which close to plant as expenditures are made) can be evaluated. Highly flexible logic allows users to specify close to plant amounts for book and tax purposes on a project–by–project basis. DSM projects can be modeled to capitalize expenses associated with conservation programs.

- The CER provides for a convenient method of examining alternate plans. A project's in–service date is changed with a single command.

All annual expenditures for that project are automatically shifted, taking inflation and escalation rates into account.

- A variety of reports display results for individual projects, for user–defined aggregations of projects, and for the entire system.

- Project phase–ins and disallowances are easily analyzed. Through interaction with the FIR Module, the user may examine the rate and financial impacts of alternative regulatory treatment of cancelled or partially cancelled projects.

- The CER Module allows for a project–to–GAF–unit tie. Fuel cost and O&M expense can then be passed to the CER by project for use in its revenue requirements calculations. The CER, if desired, will also use the GAF unit's commission date as the project in–service date. Thus, unit slippage can be assessed in both the GAF and CER with only one data change.

- Using the project–to–GAF–unit tie, the PROVIEW Module will output a CER database for the selected plan containing the appropriate in–service dates for expansion units.

Figure OVERVIEW.CER–1 provides a general overview of the CER Module.

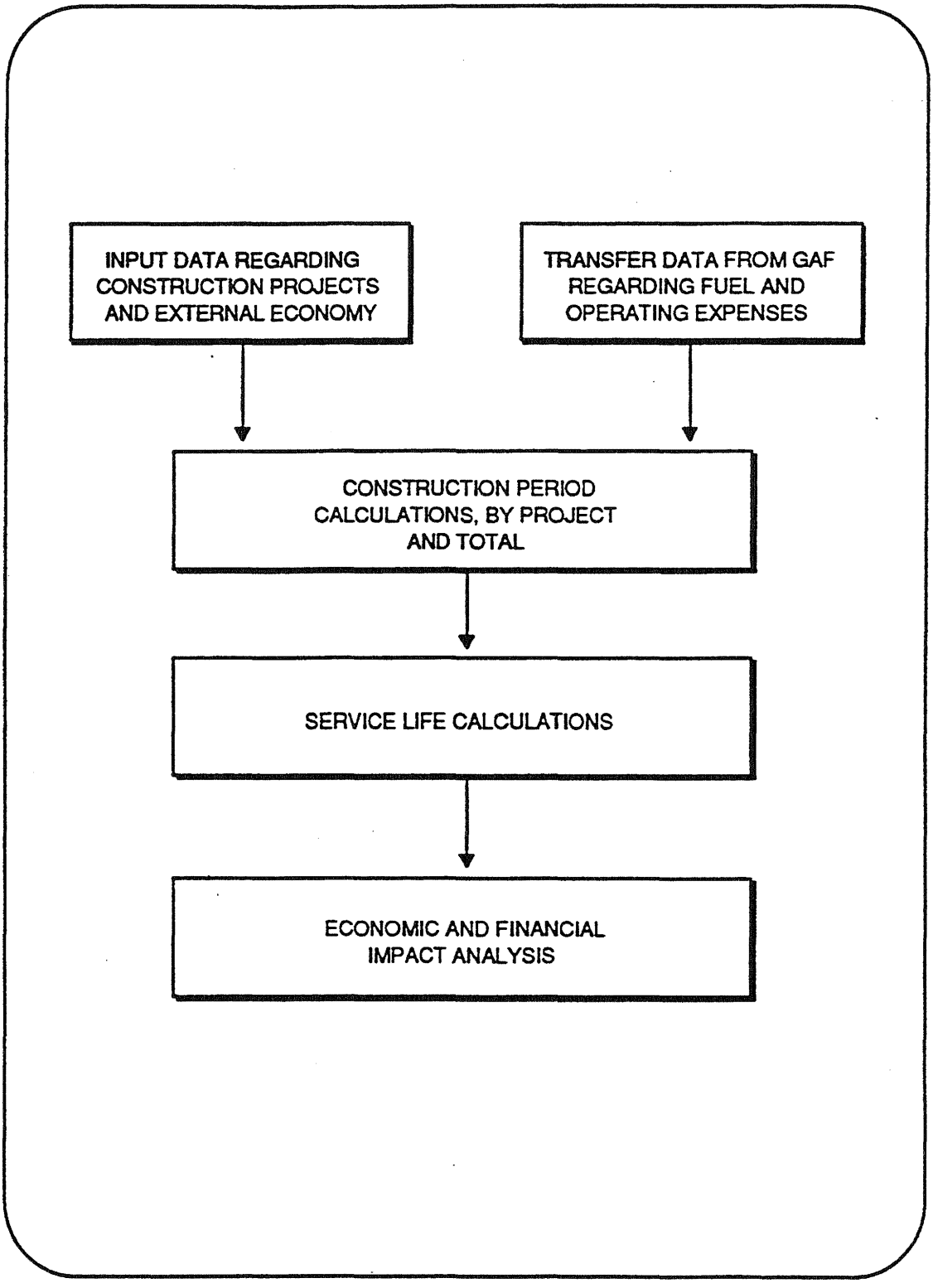


Figure OVERVIEW.CER-1
Overview Of Capital Expenditure And Recovery Module

Accounting, Tax, and Economic Calculations for the CER Module

The accounting and tax calculations are separated into three stages: construction period calculations, in–service date (close to plant) calculations, and service life calculations. The module is run for the number of years specified by the user. However, construction and commercial operation may start at any time during a year, and all calculations will be adjusted accordingly.

Construction Period Calculations

The construction period begins with the construction start date and ends immediately before the in–service date. Items calculated for this period include:

- Capital Expenditures - These are entered either as annual amounts in constant base year dollars or as nominal dollars. If desired, a total dollar amount to be spent can be input, along with an S–curve to distribute the expenditures over an appropriate range of years. Individual project escalation rates may be specified, as well as a general inflation rate applicable to all capital costs. For a blanket project, the user can input annual percentages or dollar amounts of expenditures to be closed to plant. These amounts can vary for book and tax purposes.

- Construction Work In Progress (CWIP) - Capital expenditures and AFUDC are added to this account each year during construction.

- CWIP in Rate Base - This value is calculated by multiplying a user–specified percentage of CWIP in the rate base for each project in each year by the amount of construction work in progress.

- AFUDC - The balance of CWIP less cumulative AFUDC is multiplied by the eligible percentage and the AFUDC rate to compute the AFUDC for the current year. If the user elects to compound AFUDC, the entire CWIP balance can be used in this calculation.

- ITC - This may be calculated during the construction period if the user elects to take ITC on progress payments. The capital expenditures of the year are multiplied by the user–specified percentage eligible and the user–supplied ITC rate for this computation. These functions have been retained in the CER despite the elimination of ITC for most projects in the 1986 Tax Act.

- Overheads - If desired, capitalized overheads are deducted for tax purposes during the construction period but are capitalized for financial reporting purposes.

In–Service Date Calculations

In the year that the project goes into service, the following calculations are made:

- Closed to Plant - For major projects, the CWIP balance is closed to plant at the end of the in–service date. This includes any expenditures and AFUDC for the current year. Closing is assumed to take place on the last day of the in–service month. For major projects with expenditures after the in–service date, expenditures are closed to plant in the year they are made. For blanket projects, amounts are closed in the years following their expenditure according to a user–input schedule. This schedule can be specified as either percentage or dollar amounts, and can vary for book and tax purposes for the same project.

- ITC - This is calculated in the same manner as above. However, the basis is the amount closed to plant less AFUDC closed to plant less expenditures which have already earned ITC as a progress payment.

Service Life Calculations

In each year after a project has been closed to plant, the following calculations are made for that project:

- Book Depreciation - Book basis is the total amount closed to plant, including AFUDC. Depreciation can be calculated using any of the methods available for calculating tax depreciation, although the straight–line method is the default.

- Tax Depreciation - Tax basis is the amount closed to plant less any AFUDC included in the closed to plant amount and less any capitalized overheads which have already been deducted for tax purposes. One of twelve depreciation methods may be used. They are:

  - 1982 Tax Act (rates automatically determined by tax life)
  - Double Declining Balance (DDB)
  - Straight Line (SL)
  - Sum of the Years Digit (SYD)

- DDB switching to SL
- SYD switching to SL
- DDB switching to SYD and SL
- User Specified Percentage
- 150% Declining Balance switching to SL
- 150% Declining Balance
- Units of Production
- Do Not Calculate Depreciation

Tax depreciation for the first in–service year is calculated using one of four methods: fraction of the year, half–year convention, modified half–year convention, or mid–quarter convention.

- Tax and Insurance Cost - User-specified rates for property taxes, other taxes, and insurance costs are applied to the amount closed to plant excluding AFUDC.

- Nuclear Fuel - The GAF Module provides annual fuel burn and fuel cost for each nuclear unit. The CER Module calculates the capital expenditures using the annual nuclear fuel burn from the GAF Module for either a single nuclear fuel project or multiple nuclear fuel projects. Book depreciation is equal to nuclear fuel cost in each year and tax depreciation is calculated using the project capital expenditures and the plant closing schedule. DOE nuclear waste disposal costs may be modeled.

- Decommissioning Costs - The CER Module accounts for the practice of recovering an estimate of decommissioning costs over the life of the plant.

Economic Calculations

The CER Module also calculates the annual present worth and the accumulated present worth of the revenue requirements associated with each project. Reports show the determination of present worth of revenue requirements using both a minimum revenue requirements and a discounted cash flow approach. This enables the CER Module to be used for engineering economic evaluations of specific projects, including life–cycle economic comparisons of alternative projects. System analysis reports are also available for investigation of the revenue requirements for an entire plan, including fuel and O&M as transferred from the GAF Module or from PROMOD III.

Public Power Capabilities in the Capital Expenditure and Recovery Module

PROSCREEN II also has logic designed very specifically for simulating the unique financial decision environment of cooperatives, municipals and other public power entities. One of the important aspects of such environments is the ability to automatically determine the debt financing required for a specific construction project, including the financing required to pay interest during construction.

The CER Module uses its bond sizing calculations to determine the issue amount (construction advance), interest during construction, issuance costs, and amortization schedule. Available amortization methods include the three methods approved by the Federal Financing Bank. The resulting issuance amount, interest, principal, debt service, and balance remaining are summarized by project before being transferred to the FIR Module for inclusion in the automatic financing process. Other cooperative–specific logic is discussed in the next section describing the FIR module.

Output Reports

The following reports are provided by the CER Module:

- System Report
- Class Report
- Project Report
- Project Financial Cost Flows
- Project Revenue Requirements
- System Revenue Requirements
- Busbar Costs Report
- Bond Sizing Report

In addition to standard output reports, diagnostics are provided to allow for detailed evaluation of CER Module processing and results. These diagnostics include:

- Bond Sizing
- Deferred Taxes
- AFUDC
- Plant Closings
- Other Costs: Property Taxes, Other Taxes, And Insurance Costs
- Income Taxes

FINANCIAL REPORTING AND ANALYSIS MODULE (FIR)

Introduction

The Financial Reporting and Analysis (FIR) Module is designed to combine results from the Load Forecast Adjustment (LFA) Module, the Generation and Fuel (GAF) Module, and the Capital Expenditure and Recovery (CER) Module, with additional input from the strategic planner, to produce a series of financial statements and other selected financial information. The FIR Module produces:

- Consolidated Income Statement
- Balance Sheet
- Statement of Cash Flows
- Rate Base Report
- Plant Report
- Financial Ratios Report
- Tax Report
- Rates and Regulatory Lag Report
- Rate Class Report
- Reserve Funds Report
- Corporate Value Analysis Report

Through interaction with the other application modules, the FIR Module allows the strategic planner to examine the effects of the following factors on company financial operations:

- Construction Programs
- Alternative Resource Plans
- Cost And Inflation Scenarios
- Capital Market Conditions
- Impact Of Acquisition Alternatives On Consolidated Financial Operations
- Timing And Magnitude Of Rate Changes
- Impact Of Regulatory Lag
- Alternative Measures Of Financial Performance

- Financing Requirements And Composition
- Refinancing
- Changes In Tax Law
- Merger And Acquisition
- Equity Development Plans
- Earnings Projections
- Corporate Impact Analysis

General Capabilities

- The FIR Module considers construction expenditures, revenue requirements, generation and non–generation costs, taxes (if applicable), and financing alternatives to analyze the impact of a strategic scenario.

- Special planning issues such as leveraged leases and incremental rate phase–in plans are modeled. Leases are modeled individually and include provisions for capitalized lease payments, lease amortization, lease obligation amortization, and factors controlling how lease obligations affect financial results.

- The timing and amount of long and short term financing are determined automatically according to specified criteria, or according to user–supplied schedules for each type of financial instrument. Short term debt and short term investments are used in an attempt to maintain a given cash balance prior to the issuance of long term financing.

- Existing debt can be modeled as individual issuances with fixed or variable coupon rates. A discount, premium, or issuance cost can be associated with these user–specified debt issues. PROSCREEN II calculates the interest expense for each issue. Users may input the principal payments for each debt issue or PROSCREEN II will calculate levelized debt service payments. Information such as beginning–of–year principal balance, interest expense, principal payment and end–of–year principal balance is available for each issuance through a diagnostic report.

- All inputs to the FIR may be entered based on user–specified escalation rates or annual amounts.

- Users have the ability to enter any deferred debit or credit balances as well as any changes to these balances through deferred expense or revenue respectively.

- Federal tax liability is calculated and payments are simulated on taxable entities (including taxable REA cooperatives). Net operating losses are applied against taxable income before federal income taxes are computed. Investment tax credits are also applied on a combined basis and may be carried forward from previous years. The Alternative Minimum Tax (AMT) provisions of the 1986 Tax Act are fully handled as a parallel tax system, including provisions for the conversion in 1990 to adjusted current earnings. The FASB 109 Deferred Tax logic is available to account for all temporary differences that arise when adopting SFAS 109 tax methodology.

- Automatic annual rate increases necessary to achieve the required rate of return on total capital, average or end-of-year rate base, common equity, or a coverage ratio as specified by the planner are computed. This rate increase is then modified to account for the effects of regulatory lag. Alternatively, a schedule of rates may be provided by the user.

- A full cost of service methodology is available for determining rates at the jurisdictional level. Cost may be allocated and/or assigned from the company to the jurisdictional level. A more comprehensive cost allocation to the rate class level is also available if desired.

- Financial and earning impacts of expenses which are not recovered through rates or of assets on which a return may not be earned are analyzed. The FIR Module can calculate DSM non–cash regulatory expenses for lost revenues and shareholder savings resulting from DSM programs. You can choose one of two methods for integration of these expenses: the default or the CER method.

- The combining of companies in contemplation of merger or acquisition (acquiring or being acquired) may be evaluated. PROSCREEN II is well–suited to modeling multi–entity operation and organization. Jointly owned generating assets and transactions are reflected in the GAF and CER Modules, while separate and integrated financial results of the proposed combination companies can be accomplished using the FIR Module's jurisdictional modeling capability.

- Working capital needs are computed through the automatic calculation of current liability and asset accounts. Accrual factors allow automatic

specification of balance sheet accounts as a function of expense levels. Accounts receivable may be specified as a dollar input or as a percent of revenues for each rate class.

- Designation of jurisdictions as gas, electric, "other regulated" or non–regulated is available. Other regulated jurisdictions may represent steam, water, or any other regulated segment of the business. Non–regulated jurisdictions may be reported on the Income Statement as "above–the–line" or "below–the–line" (part of Other Income).

- Rate of return levels for both gas, electric, or "generic" bases may be specified. The user can examine the impact of construction work in progress in the rate base through interaction with the CER Module. In addition, a bonus return can be earned on specified net plant such as DSM–related construction.

- For REA Cooperative users, capital credit retirements are available in the FIR as an input or PROSCREEN II can calculate capital credits dynamically as an input percent times a user–specified prior year's net margin. In addition, stabilization reserve account modeling gives the user the ability to execute the FIR with user input rates for several years. This may be used to simulate earlier years when excess margins existed, thus permitting the build–up of a stabilization reserve account. In later years, this account may be drawn down to meet targeted margin levels without a rate increase. At the point when the account is fully depleted, the FIR begins calculating required rate increases based on the chosen revenue requirement method.

- The FIR Module allows the user to model short-term debt as one financing instrument. Additional flexibility is provided through an Other Interest Expense input.

Figure OVERVIEW.FIR–1 shows an overview of the logic flow for the FIR Module typically applicable for investor owned utilities

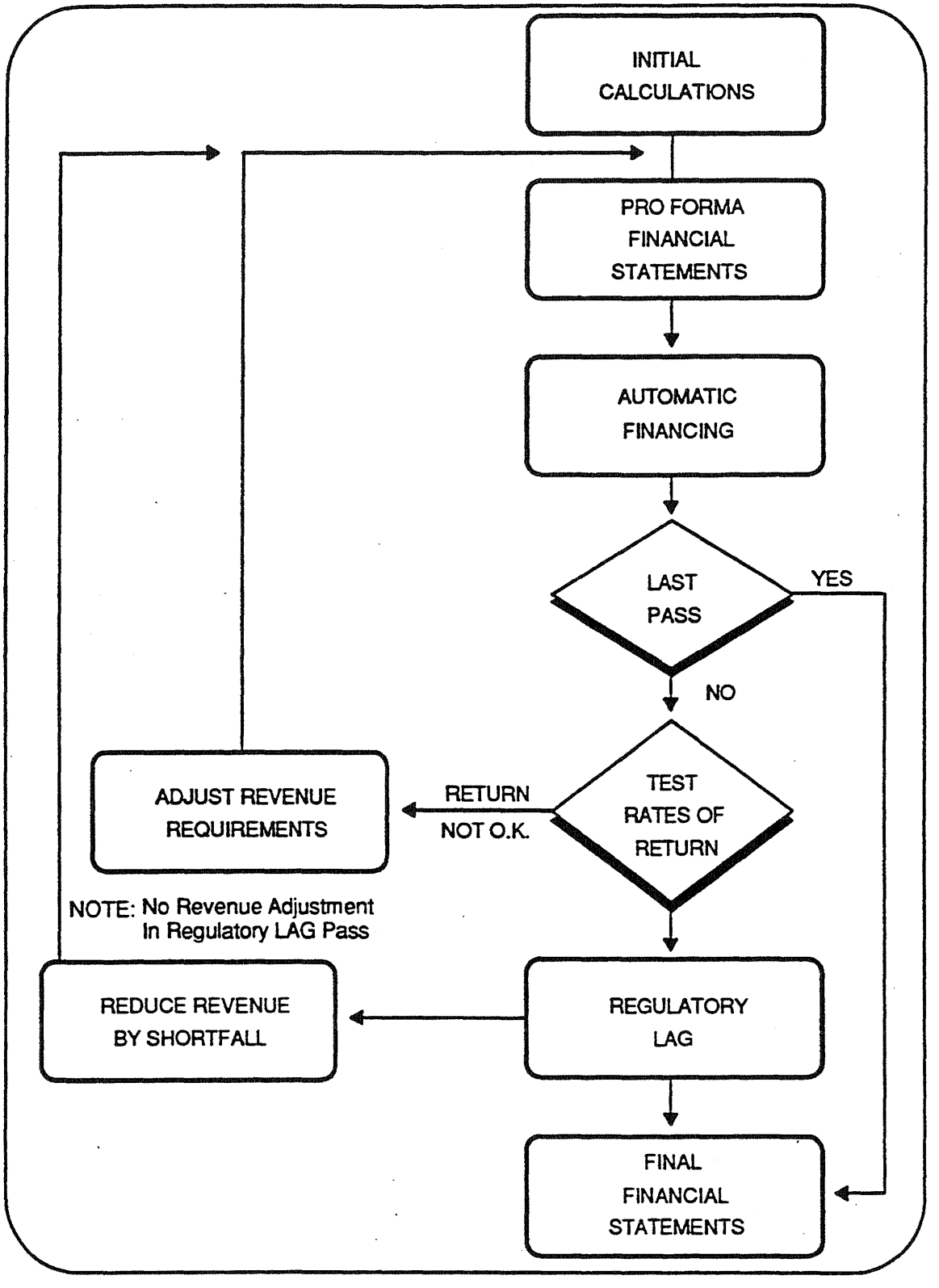


Figure OVERVIEW.FIR-1
Overview Of Financial Reporting And Analysis Module

Initial Calculations

In producing financial results for any year, the FIR Module performs a set of initial calculations. Beginning balances are updated by additions to plant, depreciation, and changes in CWIP as transferred from the CER Module. Liability accounts are updated by known financings and retirements as specified by the user. Revenues before rate increases, fuel clause revenues, and other revenues are totaled. Finally, expense items such as fuel, operations and maintenance, depreciation, etc., are direct inputs or are processed as transfers from the GAF.

The results of these preliminary calculations are an Income Statement, Balance Sheet, and Statement Of Cash Flows which do not necessarily meet the desired cash level or the desired rate of return. These targets are satisfied by the automatic financing and rate setting process.

Automatic Financing

The FIR Module simulates the activity of the corporate treasurer in satisfying the utility's need for liquidity. It automatically provides a realistic pattern of financings under a wide variety of alternative levels of internal and external sources of funds. By specifying alternative financing constraints, the strategic planner can assess specific financial goals such as desired capitalization, desired coverage ratios, or earnings per share.

The starting point of automatic financing is the Statement of Cash Flows. An initial calculation of this statement generates a negative or positive liquidity position (a cash deficit or surplus) which must be brought to desired levels. To correct a negative liquidity position, the FIR Module first sells short-term investments and issues short–term debt up to a limit specified by the strategic planner. If these measures do not eliminate the cash deficit, long-term financing commences as follows:

1. Long–Term Debt is issued in an amount equal to a minimum dollar issue amount, plus additional incremental issue amounts until the minimum interest coverage ratio is met, the maximum debt–to–capital ratio is met, or the maximum long-term debt financing limit is reached.

2. If the utility is investor–owned preferred stock is issued in an amount equal to a minimum issue amount, plus additional increment issue amounts until either the minimum preferred coverage ratio is met or the maximum preferred to capital ratio is met.

3. Common Stock is issued in an amount equal to the minimum share issue level plus additional incremental issue amounts until cash requirements are met.

All automatic financing is assumed to occur at midyear with no issuance expense. Preferred stock and long–term debt are issued at par value. Common stock is issued at either a user defined market price, or a price which is determined by the module. Market price can be based on computed earnings per share and an input price–earnings (P/E) ratio, a market price to book value ratio, or a discounted cash flow analysis.

Rate Change Logic

After the desired financial condition is reached, the FIR Module recreates the Income Statement, Balance Sheet, and Statement of Cash Flows to account for changes in interest expense, dividends, etc. Expenses and rate base items are allocated to jurisdictions. Net income is recalculated for the company and each jurisdiction and rate of return statistics are computed. The actual rate of return is then compared to the desired rate of return as input by the user. Revenues are adjusted to meet one of the following targets:

- Rate of return on common equity
- Rate of return on total capital
- Rate of return on jurisdictional rate base (user input)
- Rate of return on jurisdictional rate base (weighted cost of capital)
- Rate of return on revenue
- Cooperative and Municipal financing method
- User input rate level by rate class
- Net cash flow to capital expenditures

If the Cooperative and Municipal method is applied, the allowed rate change revenue is equal to total cash required to maintain debt service coverage (DSC) or times interest earned ratio (TIER) targets that satisfy the utility's need for liquidity after all external financing options have been exhausted. If the user–specified rate level option is selected, desired revenues are calculated using the user inputs at the rate class level for base electric or gas rates for all rate classes in a jurisdiction. The other options calculate a desired level of income equal to the product of a user input rate of return and either an average or end-of-year rate base, common equity value, or total capital amount.

The FIR Module again recreates the Income Statement, Balance Sheet, and Statement Of Cash Flows to evaluate the effect of changed revenues on the

company's cash position. If too much or too little cash is generated, automatic financing begins once more. This process continues until the desired cash and rate of return levels are reached.

As a result of this iterative process an incremental amount of revenue is calculated in order to satisfy the desired rate of return in the current year. This amount would correspond to an initial rate change request subject to the approval of the utility's regulators.

Regulatory Lag

Once the desired financial condition and rate of return is reached, the FIR Module considers the impact of regulatory lag on the utility's revenues. Regulatory lag occurs when the test period used to determine utility rates is not the same period as when the rates will be in effect or when rates are kept below a desired level for some other reason. Regulatory lag may be different for each jurisdiction modeled.

Regulatory lag modifies the rate change revenue discussed above. The rate increase awarded may be reduced due to a minimum rate increase input, a percent rate increase relative to inflation cap, and/or by a percent of required increase to be awarded input. Once the rate is calculated, the months of regulatory lag input further reduces revenue by delaying the timing of the increase. Because allowed rate change revenue is used in calculating total revenues, the module recreates all financial statements and repeats automatic financing.

The rate of return comparisons are not repeated during the regulatory lag procedure. After the regulatory lag procedure is performed, the final output reports are prepared.

Class Revenue

The Class Revenue Module (CRM) provides for a complete breakdown of expenses, rate base, and rate increases into jurisdictions (e.g., retail, FERC, etc.), and rate classes (e.g., residential, commercial, industrial). This module is executed as part of the FIR Module. It facilitates study of the impact of alternative plans on load management, conservation, and marketing for each customer grouping.

Public Power Application in the Financial Reporting and Analysis Module

The FIR Module incorporates the explicit financial and rate change characteristics of REA cooperatives, municipals and joint–action agencies without the approximation approaches usually employed by other software systems. In addition to explicit logic, the financial reporting itself is tailored to reflect the general practices of public power utilities.

The modeling of public power entities is controlled by appropriately specifying a data item called the Incorporation Type. There are four Incorporation Types in PROSCREEN II, all handled in the same logic (that is, any client can model any type of utility with the *same* PROSCREEN II system):

- Investor–owned
- Cooperative
- Municipal
- Joint–action Agency

PROSCREEN II's specific rate–change logic for public power companies determines the annual level of rates necessary to yield a sufficient net margin (operating margins plus non–operating expense, where operating margins is defined as total revenues less total operating expenses) to provide for cash needs, while ensuring that all coverage restrictions are satisfied. In doing so, the FIR Module will determine the rate increase required to meet the user–specified Times Interest Earned Ratio (TIER) or minimum Debt Service Coverage (DSC) ratio while maintaining minimum cash requirements.

PROSCREEN II's automatic financing logic for public power entities is depicted in *Figure OVERVIEW.FIR–2* and follows financing decision practices generally used by treasurers and financial analysts. The FIR Module begins with initial calculations for each year involving the Balance Sheet, Statement of Cash Flows, and Income Statement. After updating beginning balances of asset and liability accounts, an estimate of revenues based on prior year ending rates is generated and expense items are processed.

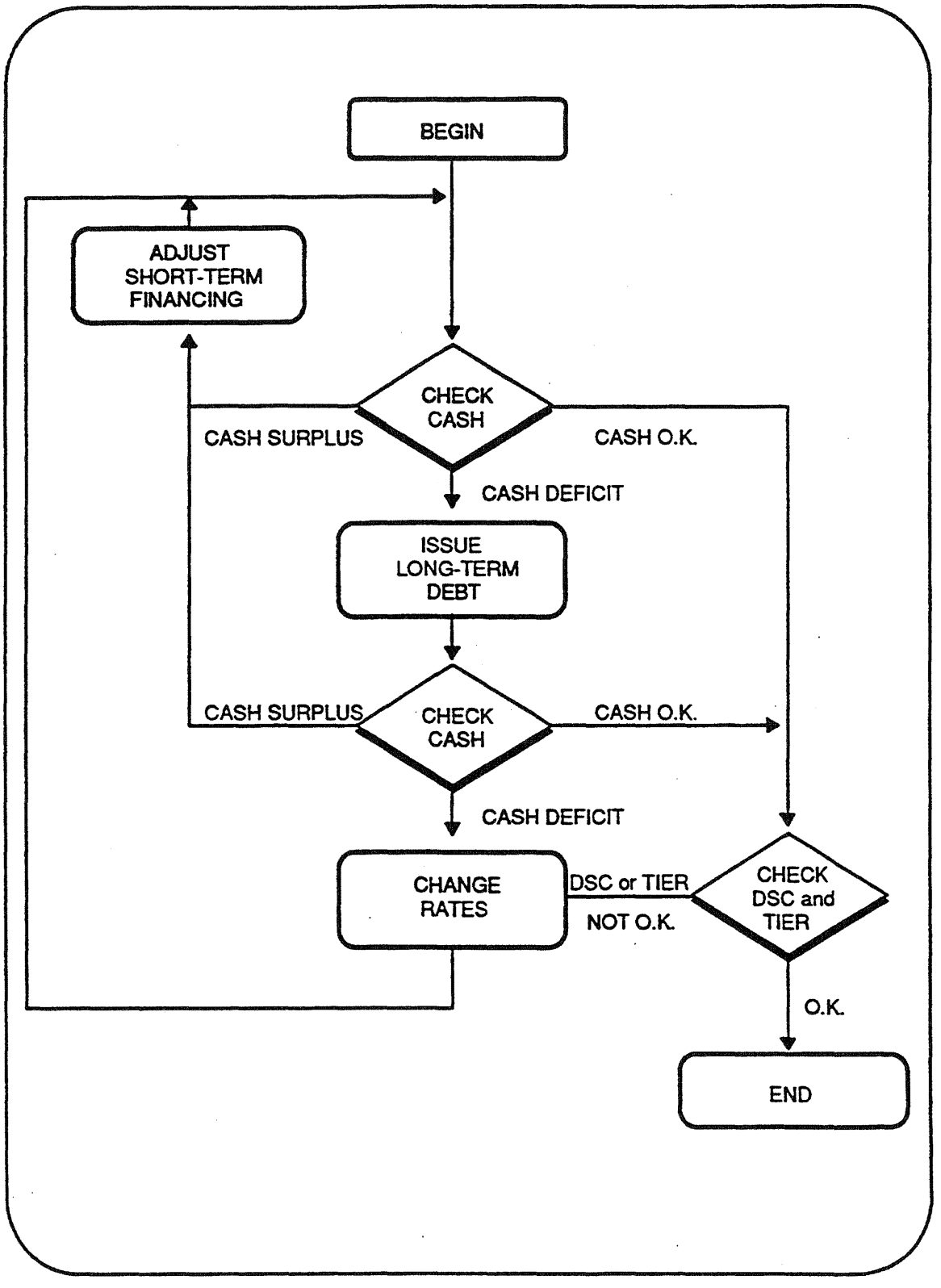


Figure OVERVIEW.FIR-2
Automatic Financing Logic Used For Cooperatives

1. Long-Term Debt is issued in an amount equal to the minimum dollar issue amount plus increments at an incremental issue amount until the minimum DSC is met, the minimum TIER is met, the maximum debt–to–capital ratio is met, or the maximum long–term debt financing limit is reached.

2. If sufficient debt cannot be issued under the analyst's given assumptions, then rates are increased to satisfy the cash deficit. This logic takes into account the fact that raising rates may allow additional debt issuance if TIER or DSC are the restricting factors on debt issuance.

After the desired cash position is reached, the FIR Module re–creates the Income Statement, Balance Sheet, and Statement of Cash Flows to account for the changed values of interest expense, interest income, and taxes (if applicable). The net margin is recalculated and DSC and TIER are computed. The new DSC and TIER computations are compared to the analyst's target values and rate increases or decreases are implemented to meet the minimum DSC and target TIER. If rates were increased, however, to satisfy a cash deficit in a given year, then the TIER target may be exceeded in order to meet cash needs.

Taxable cooperatives may be obligated to pay taxes on earnings from non–member sources, including investment profits from interest earnings, sale of tax credits, and sell back revenues. To properly model any such tax liability, the FIR Module allows taxable operating revenue and expenses to be allocated between member and non–member jurisdictions. The resulting earnings from member jurisdictions are used to offset the total system tax base. The difference between the system tax base and the member earnings is the net tax base attributed to non–member earnings. The FIR Module's detailed tax logic will then use this net tax base to calculate related federal (and state) tax liability.

Fund Accounting Capabilities of the Financial Reporting and Analysis Module

The FIR Module has extensive fund accounting capability, allowing the representation of a municipal utility's reserve fund requirements. The total of all reserve funds is shown on the Balance Sheet as an asset. Investment interest earnings on the reserve fund balances are calculated and flowed through the Income Statement as Other Income. Additions to reserve funds are presented as a part of total capital requirements on the Statement of Cash Flows. The following types of reserve funds can be modeled:

1. Debt Service Reserve Account

2. Reserve and Contingency Reserve Account
3. Debt Service Account
4. Construction Fund
5. Decommissioning Account
6. Ending Balance Account
7. Renewal and Replacement Account
8. Optional Account Defined by Client
9. Additions Fund Account

Output Reports

Standard reports provided by the FIR are formatted differently based on utility type (REA cooperative, investor–owned, municipal) and include:

- Consolidated Income Statement
- Balance Sheet
- Statement of Cash Flows
- Rate Base Report
- Plant Report
- Financial Ratios Report
- Tax Report
- Rates and Regulatory Lag Report
- Reserve Funds Report
- Rate Class Report
- Corporate Value Analysis Report

Detailed diagnostic reports are provided by the FIR Module at the analyst's command for use in following the module's internal logic.

The following diagnostic reporting is provided in the FIR Module:

- Tax Detail Report
- ITC Amortization Diagnostic
- Total Cost by Classification Category
- Unit Cost by Classification Category

- Reserve Fund Account Diagnostic
- Classified Plant Items
- Classified Expense Items
- Allocated and Classified Plant Items By Jurisdiction
- Allocated and Classified Expense Items By Jurisdiction
- Allocated Plant Items by Jurisdiction
- Allocated Expense Items by Jurisdiction
- Allocated Plant Items by Rate Class
- Allocated Expense Items by Rate Class
- Jurisdictional Allocator Data
- Jurisdictional Allocators
- Rate Class Allocator Data
- Rate Class Allocators
- Capital Credits Diagnostic
- Accrued Expense Diagnostic
- Accrued Tax Diagnostic
- Jurisdictional Tax Diagnostic
- Cost of Capital Diagnostic
- Minimum Tax Diagnostic
- Miscellaneous Sources and Uses of Funds
- Other Tax Expense Diagnostic
- Margin Base Revenue Requirements
- Capital Lease Diagnostic
- Prior Year's Alternative Minimum Tax
- Debt and Interest Expense
- Below the Line Tax Adjustment
- Marginal Cost Diagnostic
- GAF to FIR Transfer Diagnostic
- Deferred Tax on AMT and NOL Diagnostic
- Accounts Receivable Diagnostic
- Net Plant Diagnostic
- Other Operating Expenses Diagnostic
- O&M Expense Diagnostic

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CLASS REVENUE MODULE (CRM)

Introduction

The Class Revenue Module (CRM) provides a powerful capability to analyze long range rate strategy and the implications of utility plans on customer classes. The CRM picks up where the jurisdictional logic in the FIR ends. All rate base and expense items that have been classified and allocated to the jurisdictions are subsequently allocated to the rate classes. Revenue requirements are then calculated to meet the target return on rate base. One or more rate classes may have user–input rates, allowing the rates for other rate classes to "float" in order to achieve a target return at the jurisdictional level. Additionally, the user has extensive flexibility in determining the actual structure of rates for each class, with varying proportions of expenses being recovered through the demand, energy, and customer charge portions of the total rate.

General Capabilities

- Specification of multiple electric, gas, or unregulated jurisdictions
- Analysis of revenues and costs at a jurisdictional and class level
- Classification of expense and plant items to demand, energy, customer, or user–defined categories
- Computation of standard allocation factors based upon class load data from the LFA Module and CRM Module inputs
- Default logic to allocate classified plant and expense items to jurisdictions and rate classes
- Ability to develop rates based on marginal as well as embedded cost concepts. Under the marginal cost approach, multiple revenue reconciliation approaches are available

- Direct transfer of electric price results to the LFA Module for elasticity analysis on a rate class basis

- Class revenue requirement based upon class cost of service

- Estimation of class marginal revenue and class rate increases

- Class rate design capabilities

Class revenue forecasts require long–term forecasts of plant and rate base balances, operating and depreciation expenses, taxes and deferred taxes, interest and income as well as class sales and load characteristic data. The FIR Module provides all these items on a total company basis. The LFA Module contains the load data on a class basis.

Cost of service and revenue allocation procedures always involve some judgment. The CRM provides for direct user inputs that will permit the user to exercise judgment, use off–line calculations, or execute custom logic for variables such as specific allocation factors or specific rate of return targets.

Preset groupings of 'ENERGY', 'DEMAND', and 'CUSTOMER' classification categories are automatically defined for rate class and jurisdiction plant and expense items. In addition, the user may define the specific classification categories needed. It is possible to define as many rate classes, jurisdictions, or classification levels as desired at the time of PROSCREEN II delivery. This means the system will be able to handle changes in allocation procedures or even the restructuring of the user's operating environment. Also available is default logic for allocation of plant and expense items to jurisdictions and rate class. This enables automatic allocation of all plant and expense items by using demand, energy, or customer allocators based on industry standards.

A typical database organization is depicted in *Figure OVERVIEW.CRM–1*.

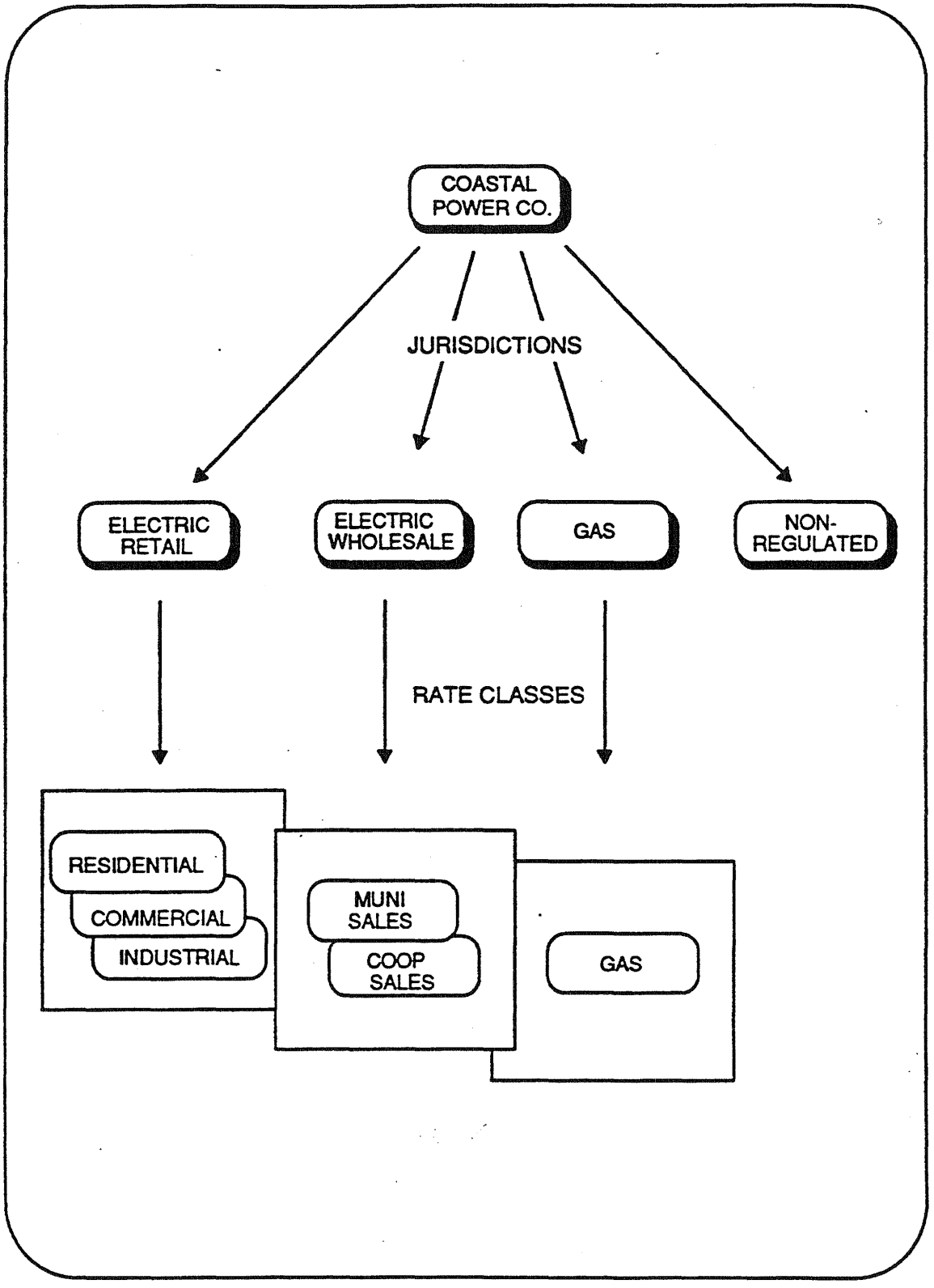


Figure OVERVIEW.CRM-1
Sample Class Revenue Module Database

Module Logic

The CRM employs a two–step process to develop class rate and revenue forecasts. The first step is to calculate a cost of service at the rate class level. The second is to develop rates for each class based on this cost of service. These steps are described below.

Class Cost of Service

The CRM combines the functionalization and classification steps of a cost of service analysis as its initial process, referred to as the classification process. Plant and expense items are assigned to user–defined classification categories such as Demand, Energy, or Customer. Functionalization is accomplished through user–defined asset classes and component schedules in the FIR. For example, the user may wish to segregate production, transmission, distribution, and general plant categories. The user may have as many of these categories, and may organize them in any manner, as desired.

Once the classification/functionalization process is complete, the classified costs are allocated to the various jurisdictions and then to the rate classes within each jurisdiction, based on a default method, a user–defined allocation method, or a combination of methods. A number of allocation methods are automatically available within the CRM, and are based on demand and sales data transferred from the LFA Module. These methods include:

- Coincident Peak Demand (CP)
- Noncoincident Peak Demand (NCP)
- Average and Excess Demand
- KWH Energy Sales (Electric Customers)
- Number of Customers
- Gas MCF Purchases (Gas Customers)

Figure OVERVIEW.CRM–2A and *OVERVIEW.CRM–2B* provide an overview of this process.

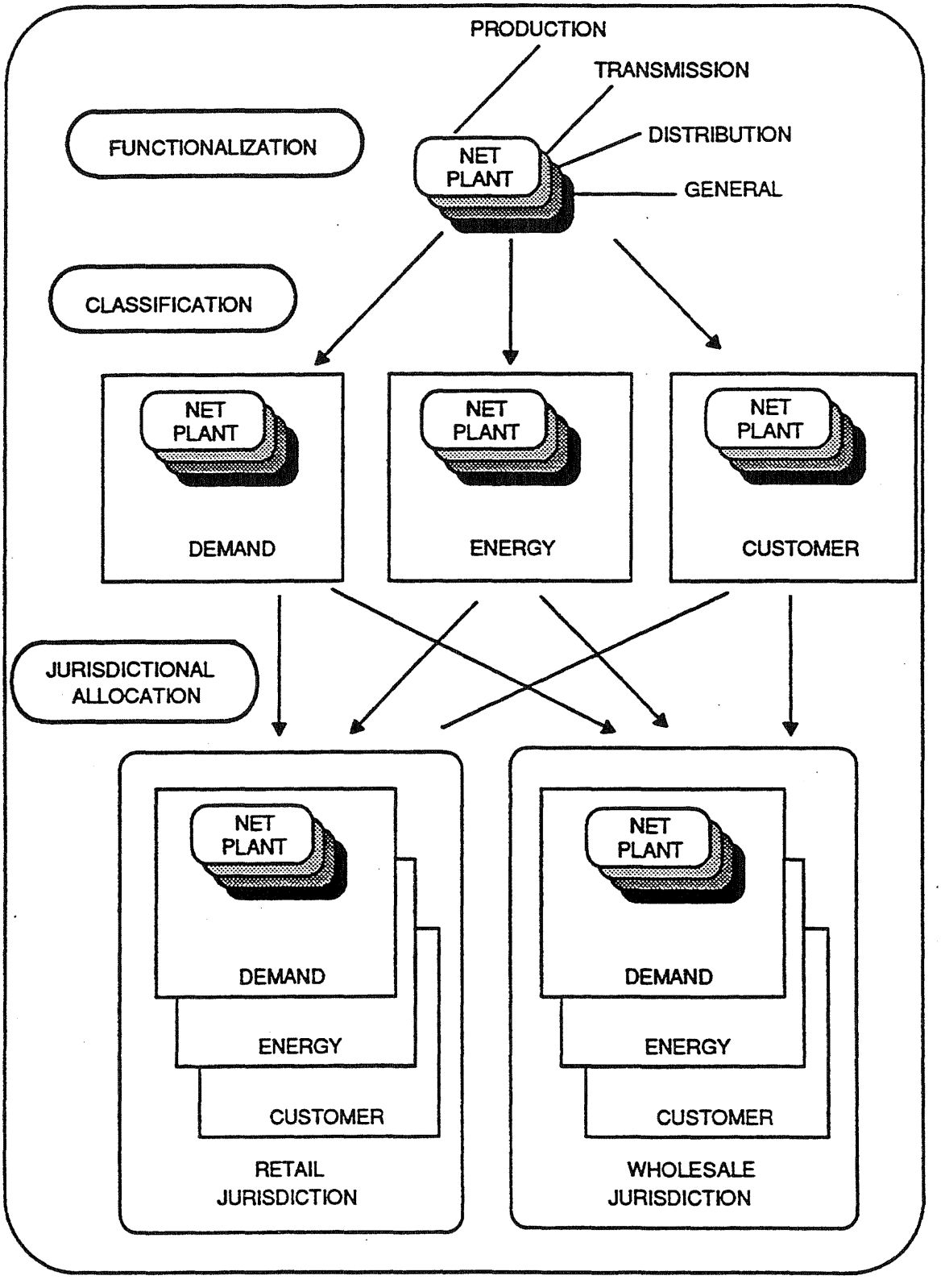


Figure OVERVIEW.CRM-2A
Phase I Of Classification / Allocation Process
Example Of The Allocation Of Net Plant To Jurisdictions

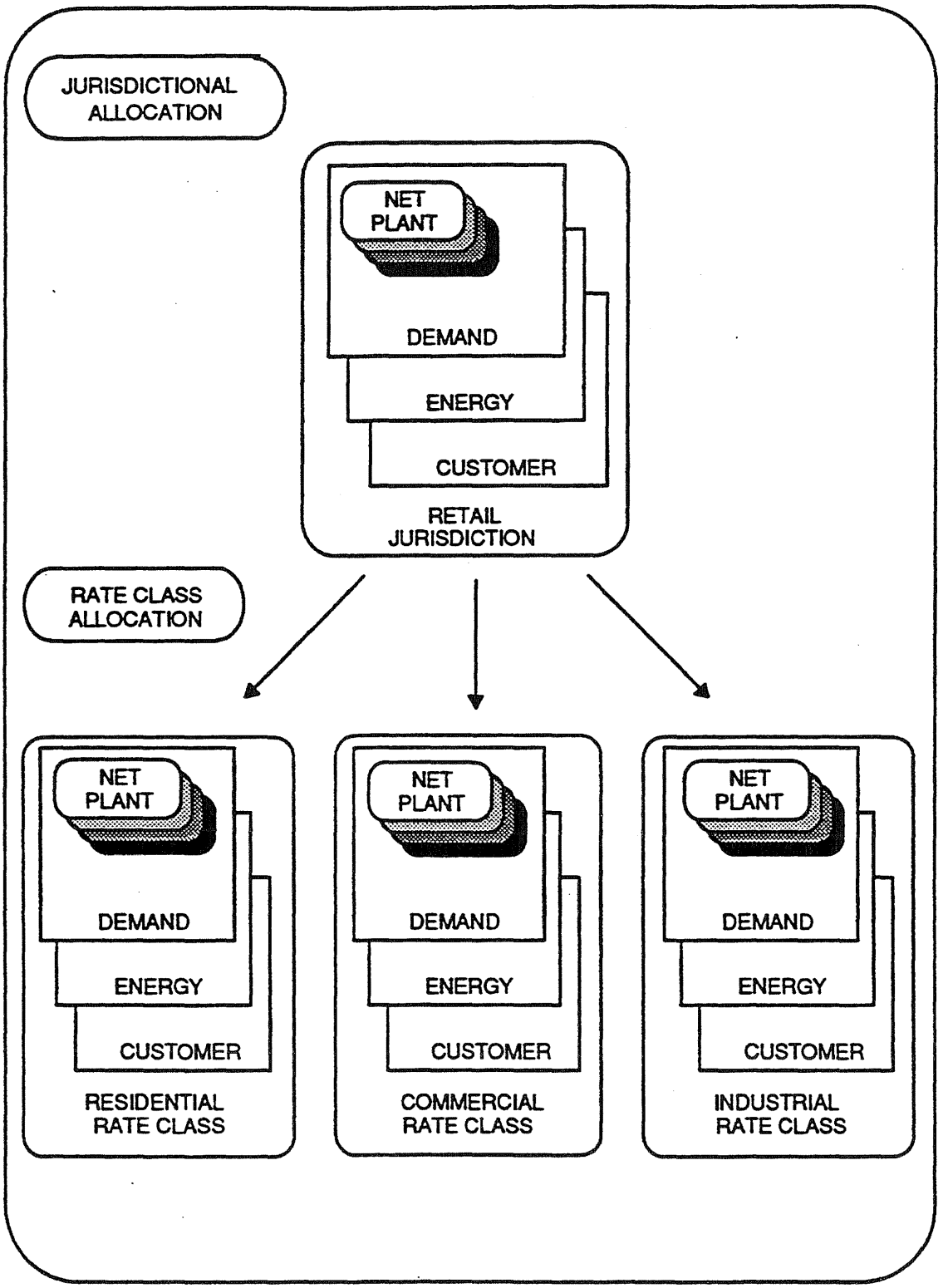


Figure OVERVIEW.CRM-2B
Phase II Of Classification / Allocation Process:
Example Of The Allocation Of Net Plant To Rate Classes

Marginal Cost Rate Determination

Traditional rate determination determines total revenue requirements using accounting information and then functionalizes, classifies and allocates historical embedded costs. The marginal cost methodology also determines total revenue requirements using accounting information. However, a marginal cost allocation approach first determines marginal costs by energy, demand or customer, then computes marginal cost revenues, and scales those revenues to match actual revenue requirements. Thus, when comparing this methodology with the traditional embedded cost methodology, the total revenues are the same, but how the revenues are collected within each rate class differs. The Rate Class Report details the marginal cost related information.

Revenue Determination

The structure of the CRM is designed to provide the user with maximum flexibility in modeling. By altering the number of asset classes or classification categories modeled, it is possible to produce a substantially detailed or a relatively simplistic cost of service analysis, according to the user's requirements. A maximum of flexibility has been built into the module in terms of the actual allocation methodology. Each expense and rate base item may be allocated using different internal allocation methods or ratios, which can be directly input by the user.

Total cost of service for a class is the sum of all allocated expenses and net income. Net income and taxes are based on the actual revenue collected. The actual net income may not equal the "desired" net income for a number of reasons. First, regulatory lag or other shortfall may restrict jurisdictional income (and taxes) to be less than the cost of service income. Further, political realities may favor one rate class versus another in the real world. Finally, promotional rates may be implemented because of the realities of the competitive market.

To reflect these dynamic forces and to allow for special studies, several options are available to control the revenue collected for each class. These options allow the user to control rates for some classes while ensuring that total revenue collected from all classes equals jurisdictional revenues computed earlier. This also ensures that the total net income for all classes and the total taxes for all classes equals jurisdictional net income and jurisdictional taxes. The following options are available:

- Revenue requirements will equal the class cost of service, which includes a specified return on rate base. The target rate of return can vary by class.

- Revenue requirements will equal the cost of service as in (1) above, except that any increase in rates is limited by a class–specific cap. This cap is expressed as a multiple of the average jurisdictional percentage increase. The portion of revenue requirements that exceeds this cap is distributed to the other classes within this jurisdiction.

- The user may input specific percentage rate increases by rate class.

- The user may directly input the rates by rate class.

Once the revenue requirements are determined, the final rate increase is calculated by adjusting the revenue target by the impact of regulatory lag, if desired.

Output Reports

The CRM generates the following:

- Rate Base Report

  The Rate Base Report is produced for each jurisdiction by year.

- Rate Class Report

  The Rate Class Report shows rate base, operating revenue, operating expenses, income and deferred taxes, net income, return on rate base, total customer charge, and ending rate composition for each class within each jurisdiction.

This module also provides a full complement of detailed diagnostic reports:

- Calculation of Allocators

  This diagnostic shows the calculation of CP demand, NCP demand, average and excess demand, energy, and consumer allocators, based on input data in the FIR and transfer data from the LFA. Both the actual data and the calculated allocators are included.

- Expense Classification

  This diagnostic reports the breakdown into classification categories such as Energy, Demand, and Customer for all operating expenses.

- Utility Plant Classification

  This diagnostic shows the breakdown into classification categories such as Energy, Demand, and Customer for the net plant in each asset class modeled in the FIR.

- Classified and Allocated Expenses by Jurisdiction

- This diagnostic shows the breakout of all expenses by classification category and by jurisdiction.

- Classified and Allocated Plant by Jurisdiction

- This diagnostic shows the breakout of all plant items by classification category and by jurisdiction.

- Allocated Expense by Jurisdiction

- This diagnostic shows the breakout of expenses by jurisdiction.

- Allocated Plant by Jurisdiction

- This diagnostic shows the breakout of plant items by jurisdiction.

- Allocated Expenses by Rate Class

- This diagnostic shows the breakout of all expenses by classification category and by rate class.

- Total Cost by Classification Category

- This diagnostic provides the total costs for each classification category modeled, by rate class.

- Unit Cost by Classification Category

- This diagnostic provides the unit cost for each classification category modeled, by rate class. The unit cost is calculated as the total cost for the category and rate class, divided by that class' share of system demand, energy, or customers, as defined by the user.

- Marginal Cost Rate Determination

- This diagnostic illustrates rate determination based on the marginal cost approach, including marginal cost revenue, revenue reconciliation, and final recovered revenue.

NOVA SCOTIA UTILITY AND REVIEW BOARD

IN THE MATTER OF: The *Public Utilities Act*, R.S.N.S., 1989, c.380 as amended

IN THE MATTER OF: An Application by Nova Scotia Power Incorporated for approval of a Load Retention Rate

RESPONSE TO INFORMATION REQUEST

TO: **NSUARB**

FROM: **NSPI**

Question IR-26: **Please provide a copy of the latest short run and long run marginal cost studies conducted by or on behalf of NSPI.**

Response IR-26: The most recent marginal costs were developed in 1994/95 and included in IRP Report IR-R2. Tables 1 and 2 from that report (attached), summarize those costs. Also attached are the explanations of how these costs were developed, taken from the same report.

DATE FILED: December 23, 1999

TABLE 1

MARGINAL ENERGY COSTS

($/MWH)

		WINTER PERIOD		NON-WINTER PERIOD	
YEAR	AVERAGE ALL HOURS	ON-PEAK	OFF-PEAK	ON-PEAK	OFF-PEAK
1996	$26.85	$31.98	$26.20	$27.39	$24.65
1997	27.57	33.17	27.08	28.05	25.18
1998	28.71	34.96	28.23	29.18	26.09
1999	30.57	37.25	29.29	32.03	27.40
2000	32.13	40.11	30.46	33.76	28.57
2001	33.55	43.25	32.92	34.93	29.64
2002	35.75	48.44	35.36	37.05	31.05
2003	38.59	54.89	38.47	39.87	32.57
2004	41.15	61.16	40.67	42.89	24.24
2005	45.42	65.50	44.80	47.86	36.58
2006	48.16	74.84	49.57	53.30	38.85
2007	45.30	64.92	44.38	46.88	37.20
2008	48.07	71.05	46.38	50.22	39.07
2009	52.87	79.90	52.26	54.58	41.51
2010	58.15	82.98	55.93	60.85	43.85
2011	62.88	90.22	60.51	66.26	46.83
2012	65.23	96.12	62.99	72.14	49.89
2013	61.98	89.80	59.53	63.41	47.09
2014	66.55	97.43	63.83	68.73	49.47
2015	68.57	104.30	68.63	74.80	52.71
2016	58.99	83.35	54.90	59.32	47.03
2017	63.42	92.40	60.84	63.38	49.29
2018	75.19	105.72	68.04	76.45	54.62

TABLE 2

MARGINAL CAPACITY COST

($/kW-YR)

YEAR	GENERATION	TRANSMISSION	DISTRIBUTION
1996	$0.00	$26.34	$9.85
1997	0.01	26.86	10.05
1998	0.09	27.40	10.25
1999	0.33	27.95	10.46
2000	1.42	28.51	10.66
2001	4.29	29.08	10.88
2002	13.98	29.66	11.10
2003	24.75	30.25	11.32
2004	14.58	30.86	11.54
2005	27.39	31.47	11.77
2006	5.18	32.10	12.01
2007	10.62	32.75	12.25
2008	28.53	33.40	12.50
2009	16.49	34.07	12.75
2010	39.03	34.75	13.00
2011	57.89	35.45	13.26
2012	17.41	36.15	13.53
2013	36.51	36.88	13.80
2014	54.20	37.61	14.07
2015	5.72	39.13	14.35
2016	11.39	39.92	14.64
2017	56.16	40.72	14.93
2018	0.33	41.53	15.23

The marginal generation capacity costs in Table 2 were determined using a Peaker method. This method uses the capital cost of a combustion turbine as the marginal generation capacity cost, and weights it using the ratio of expected loss of load hours in a given year to the planning target of 1.25 loss of load hours per year. The marginal energy costs were obtained from EMA's production costing module (GAF) of the PROSCREEN II family of computer models.

The marginal transmission cost is based on a statistical approach, in which a linear regression of total transformer kV.A installed, at both 138 kV and 69 kV voltage levels, against annual System Maximum Demand is carried out. The 1984 review of marginal transmission capacity costs (Marginal Cost Based Peak Load Pricing and Load Control Study - Volume 5 - NSPI 1985 Marginal Cost Study) developed such a regression and provided coefficients for both voltage levels. They were used in combination with updated capital costs for transformers to calculate the marginal capacity costs of transmission.

The total marginal transmission capital cost ($/kW) was converted to an annual escalating series over 30 years at a 2% inflation rate and 9% discount rate. The marginal transmission capacity cost contribution, escalating at 2% annually and commencing in 1994 is $22.98/kW. One

percent of the capital cost was added to the estimates to account for operating and maintenance expenses.

The marginal distribution costs were determined by applying load factor to distribution transformer cost. With an installation cost of about $39/kW (1994 $) and an average 50% loading, a capacity charge is about $78.00/kW. This is converted to an annual escalating series over 30 years at 2% annual inflation rate and a 9% discount rate. The 1994 marginal capacity cost is therefore calculated at $6.34/kW. Added to the number is an operating and maintenance cost estimate of 4% of the capital cost component, ($3.12/kW) to give a total of $9.47 kW.

The capital portion of customer costs is developed based on the incremental installed meter cost and the cost for an average service extension as indicated by our standard price index levels. A total annual carrying charge rate of 10.00% (interest at 7% plus depreciation at 3%) was applied to the marginal capital values to obtain the annual carrying charge. The carrying charge was then converted to a per customer charge.

The operating and maintenance costs portion of the customer cost is the Customer Service and Metering costs from the distribution operating function in the Cost of Service Study as well as the Billing & Receipts,

Customer Service and Credit & Collection costs from Administration. Overhead charges are then applied to these amounts to arrive at the total operating cost. The operating charge is then converted to a per customer charge.

The combined capital and operating customer charges represent the total marginal customer cost.

These marginal customer costs are escalated at 2% annually commencing in 1994.

As an example of the process, the Domestic customer cost is based on the following:

Capital

Meter	$ 60.00	
Service Extension	248.00	(46 meters @ 5.40 per meter)
Total Capital	$308.00	
Carrying Charge	$ 31.00	
Operating Cost	59.00	
Total Cost	$ 90.00	(Used as 1996 Start Point)

NOVA SCOTIA UTILITY AND REVIEW BOARD

IN THE MATTER OF: The *Public Utilities Act*, R.S.N.S., 1989, c.380 as amended

IN THE MATTER OF: An Application by Nova Scotia Power Incorporated for approval of a Load Retention Rate

RESPONSE TO INFORMATION REQUEST

TO: **NSUARB**

FROM: **NSPI**

Question IR-27: **Page 3 of the Report refers to NSPI's objective of becoming an energy and services company. Please provide all the documents describing this objective and details of energy and services to be provided by NSPI.**

Response IR-27: The context of the reference is as follows, as quoted from the Report:

> "Our strategic goal is to become an energy and services company. To do that our regulated business must become the customers' choice in energy and services. We are expanding our ability to respond to customer demands for more products, greater service and greater value."

For details of how NSPI is pursuing this strategy, please see response to UARB-IR-13.

DATE FILED: December 23, 1999

NOVA SCOTIA UTILITY AND REVIEW BOARD

IN THE MATTER OF: The *Public Utilities Act*, R.S.N.S., 1989, c.380 as amended

IN THE MATTER OF: An Application by Nova Scotia Power Incorporated for approval of a Load Retention Rate

RESPONSE TO INFORMATION REQUEST

TO: **NSUARB**

FROM: **NSPI**

Question IR-28: **While discussing Sable gas, Page 3 of the Report states: "Our electric business will benefit from the growth in industrial and residential use that had already begun."**

a) **Please describe how NSPI's electric business will benefit from the development of Sable gas.**

b) **Please provide all the studies, analyses, reports and other documents in support of this statement.**

Response IR-28: a) This sentence should be read in the context of the sentence immediately preceding it, which refers to Sable gas and reads: "It is expected to drive economic growth in Nova Scotia that will outpace the rest of Canada for the next several years."

A growing economy normally increases the demand for electricity, and it is in that context that the statement was made.

b) This first statement was based on reports such as the attached Conference Board of Canada report, while the second was based on the realities that NSPI was seeing in the marketplace.

DATE FILED: December 23, 1999

The Conference Board of Canada

PROVINCIAL OUTLOOK

Economic Forecast

AUTUMN 1998

VOL. 13 NO. 4

HIGHLIGHTS

The current international economic and financial turmoil will affect all provinces.

Growth will feel much weaker to Newfoundlanders than the robust forecast suggests.

Spending on large projects will fuel near-term growth in Nova Scotia and New Brunswick.

Hampered by weak consumer activity, the Quebec economy will perform just under the national average.

Despite slower consumer spending growth, near-term domestic demand will remain strong in Ontario.

Strong investment spending will help Alberta weather the collapse in world oil prices.

British Columbia is currently in recession, and growth will be slow in 1999.

Energy Projects Fuel Economy

Outpacing the national average by a wide margin, real Gross Domestic Product (GDP) in Nova Scotia is projected to advance by 3.9 per cent in 1998. The Nova Scotia economy will outperform those of most other provinces this year, propelled in large part by a charged-up non-residential construction sector. Further gains will come from revitalized mineral fuels output, as work continues on the Cohasset/Panuke offshore oil project. The strength in non-residential construction stems largely from the Sable Island Offshore Energy Project (SOEP), which is already well under way. The megaproject has already generated numerous jobs, and more will be added as construction begins on the project's natural gas pipeline later this year. Continued employment growth is indeed encouraging and should provide a boost to consumer confidence. Stronger economic prospects are expected to attract people to the province and deter others from leaving, easing the flow of net interprovincial out-migration over the next few quarters. The solid labour market conditions and stronger demographic outlook will help to bolster consumer spending and revive the province's ailing housing sector next year.

Despite the improved spending and housing conditions in 1999, overall economic activity will not be able maintain the vigorous pace of 1998. Construction and mining, currently powerhouse sectors, will cool somewhat in 1999. Mining output will actually contract in 1999 as the Cohasset/Panuke project comes to an end next June. Meanwhile, non-residential construction activity will still be solid next year; however, it will slow as spending on the SOEP starts to taper off. Total real GDP is forecast to expand by 2.3 per cent in 1999.

The Domestic Economy

Overcast Labour Market

A dark cloud currently hangs over Nova Scotia's labour market. The provincial economy shed close to 4,500 jobs between July and September, in sharp contrast to the 9,800 jobs that were produced during the first half of the year. According to Statistics Canada's Labour Force Survey, the majority of the third-quarter job losses were reported in the primary, construction and service sectors. Gloomy labour market conditions are expected to be short-lived and should give way to a brighter outlook in the coming months, as numerous employment opportunities are expected to unfold in the province's construction and service sectors. The non-residential construction sector is having an extraordinary year, with the SOEP leading the way. The megaproject has been a well-oiled job machine for the province since the start of the year. To date, the SOEP has generated nearly 1,700 jobs for the province. As work continues on the project, more jobs are expected, particularly when construction of the natural gas pipeline begins. Jobs will also be generated in the service sector. In particular, retail trade will benefit from thriving tourism activity. Aided by a weak Canadian dollar, the province's tourism industry is poised for another record-breaking year of growth. Overall, the Nova Scotia economy is expected to create 12,000 new jobs in 1998 and an additional 6,000 in 1999, translating into employment growth of 3.1 per cent and 1.4 per cent, respectively. Meanwhile, the labour force is expected to advance by only 1.3 per cent this year and 0.6 per cent in 1999. Hence, the unemployment rate is projected to drop to 10.7 per cent in 1998 and 9.9 per cent in 1999.

SOEP Will Wash Consumer Blues Away...

Consumer confidence continues to soften in Eastern Canada. The Conference Board's Index of Consumer Attitudes for the Atlantic region slipped to 100.1 in the third quarter, falling 9.6 points from the second quarter (see Chart 1). For Nova Scotia, the drop in confidence likely reflects an about-face in attitudes toward job prospects in the province. This is not surprising, considering the heavy job losses in the third quarter. Moreover, this development coincided with heightened concern about the international financial situation, a sinking Canadian dollar, a sharp increase in interest rates and plunging equity markets. However, pessimism is expected to dissipate in the near term, as numerous employment opportunities, particularly from the SOEP, start to take shape in the province. Stronger near-term opportunities are expected to attract people to Nova

Chart 1

Index of Consumer Attitudes Atlantic Canada
(1991 = 100)

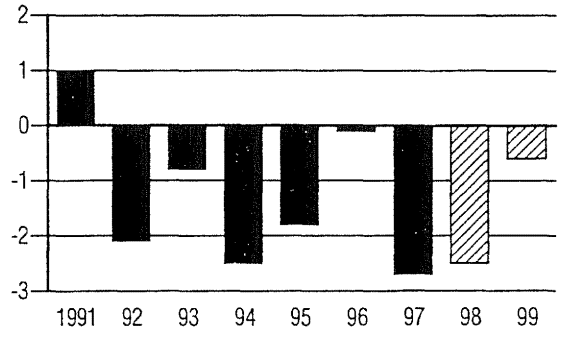


Source: The Conference Board of Canada

Scotia and keep job seekers from leaving. Hence, net interprovincial out-migration is projected to average only 600 people in 1999, compared with 2,500 people in 1998 (see Chart 2). Thus, after a tight-fisted 1998, when spending will rise by 1.7 per cent, consumers are expected to boost outlays in 1999 by 2.9 per cent.

Chart 2

Interprovincial Migration, Nova Scotia
(000s)



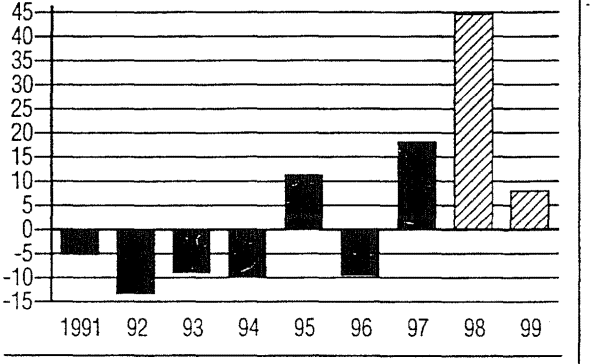
Sources: Statistics Canada; The Conference Board of Canada

...And Power Non-Residential Investment

Nova Scotia is expected to surpass the rest of the country in investment growth this year. Total investment spending is projected to advance by 11.7 per cent this year, before easing to 6.9 per cent in 1999. In line with the investment outlook, real construction output will advance by 22.3 per cent in 1998 and 9.8 per cent in 1999. According to Statistics Canada's latest revised *Private and Public Investment Intentions (PPI)* survey, released in July, stronger construction activity in the mining and transportation sectors will lead to robust non-residential investment spending this year. Led by the $3 billion SOEP (Nova Scotia's portion being worth about $1 billion), non-residential investment spending is forecast to grow by an astounding 44.6 per cent this year, before slowing to 8.0 per cent growth in 1999 (see Chart 3). The SOEP is a two-phase project involving the development of six natural gas fields. Since the project began, three of the fields—Thebaud, Venture and North Triumph—have been developed at a brisk pace and should have no problem meeting the first phase deadline of November 1999. The second phase, which involves the remaining three fields—Alma, Glenelg and South Venture—is expected to begin around 2004 and to be completed by 2006. In conjunction with the first phase of the SOEP, Maritime and Northeast Pipeline will construct a $1 billion natural gas pipeline by November 1999, with approximately $250 million being spent in Nova Scotia.

Chart 3

Non-Residential Construction Investment, Nova Scotia
(percentage change)



Sources: Statistics Canada; The Conference Board of Canada

Also included in the forecast are spending profiles for certain non-energy projects. Michelin North America (Canada) recently announced plans to invest $80 million to increase the Waterville plant's truck tire capacity by 30 per cent. The expansion is expected to create about 130 positions and is slated for completion by early 2000. On the government side, some school construction is in the works. In partnership with private developers, the provincial government recently announced plans to spend $360 million over the next three years building 31 new schools and renovating 60 existing facilities.

Housing starts, in decline since the spring of 1997, have started to come back to life, registering

85.7 per cent growth in the third quarter. The pick-up in housing activity is expected to be sustained, given the current favourable conditions in the economy. The SOEP has brightened the picture for employment, consumer confidence and migration, and all these factors bode well for housing. However, the expected pick-up in activity in the housing market in the last half of 1998 will not be enough to offset the declines registered in the first half of the year. Hence, housing starts are expected to average only 3,257 units in 1998, a decline of 36.1 per cent from 1997. None the less, stronger consumer confidence, coupled with an optimistic demographic outlook next year, will help boost housing starts to 3,830 units in 1999, an increase of 17.6 per cent. Accordingly, residential investment is expected to expand by 4.6 per cent this year and 17.8 per cent in 1999.

Balanced Budget at Risk

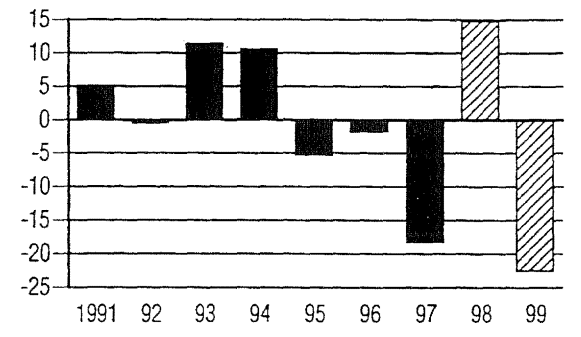
According to the province's annual financial report, the Nova Scotia government ended fiscal 1997–98 with a budget surplus of $38.5 million, $1.1 million more than projected in its budget tabled last June. As announced in the last budget, $10 million of the surplus will be distributed to consumers in the form of an HST rebate on electricity, while the remaining $28.5 million will go toward paying down the province's debt. However, the weak Canadian dollar has put the province's projected $1 million budget surplus for fiscal 1998–99 in jeopardy. In its latest quarterly report, the provincial government reported that the lower Canadian dollar has served to increase the province's debt-servicing costs. That, as well as the unexpected need for more money for health care and community services, is pointing to a possible budget deficit for fiscal 1998–99. In an effort to offset some of the additional costs and fight off a deficit, the provincial government plans to reduce administrative spending by $30 million. This will affect a wide area of government spending, including travel and capital purchases. Overall, the Conference Board projects government spending on goods and services to contract by 0.9 per cent this year, before posting growth of 2.1 per cent in 1999.

Industry Round-Up

The SOEP will not be the only energy project to heat up the economy in 1998. The Cohasset/Panuke offshore oil project will do its part to help increase the province's real mining output by an impressive 14.8 per cent this year. The province's first offshore energy project, which began production in 1992, is set to wrap up by June 1999. When equipment malfunctions and other disruptions shut down production for nearly five months in 1997, only 3.6 million gross barrels of oil were produced through the year. With the project completion date still pegged for mid-1999, remaining oil reserves unrecovered in 1997 will be made up in 1998. Hence, close to 7 million gross barrels of oil will be produced in 1998, nearly doubling last year's production. By June 1999, production at the Cohasset/Panuke fields is expected to wind down, producing about 2 million barrels for the year and bringing total production from the field to 46.5 million barrels. Real mining output should contract by a severe 22.5 per cent in 1999, reflecting completion of the project (see Chart 4). However, by the end of the decade, the mining outlook will improve once again as gas starts flowing from Sable Island.

Chart 4

Real Mining Output, Nova Scotia
(percentage change)

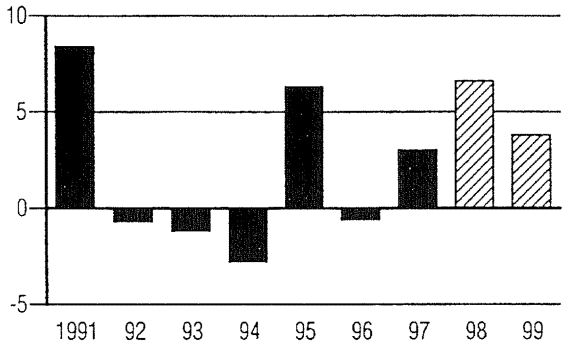


Sources: Statistics Canada; The Conference Board of Canada

Real manufacturing output is expected to expand by a healthy 6.6 per cent in 1998 before easing to 3.3 per cent in 1999 (see Chart 5). The strength in manufacturing shipments this year is largely a reflection of the start-up of Stora Forest Industries' new $750 million super-calendered papermaking plant in Port Hawkesbury, which became operational last May. At full production, the new paper plant has the capacity to manufacture up to 350,000 tonnes of high-quality glossy paper annually for magazines, catalogues and brochures. However, on the downside, Volvo Canada recently announced plans to shut down its car assembly plant in Halifax by mid-December, axing 223 high-paying jobs. Volvo's only car assembly plant in North America is moving production to its larger European plants,

Chart 5

Real Manufacturing Output, Nova Scotia
(percentage change)



Sources: Statistics Canada; The Conference Board of Canada

which have excess capacity and can easily supply the Canadian market. Volvo sells nearly 10,000 cars in Canada every year, the majority of them being assembled at its Halifax plant.

Together with the provincial government, Halifax Port Corporation recently submitted a proposal to Maersk and SeaLand to build a new shipping container terminal in Halifax to accommodate the companies' post-Panamax ships on the East Coast. These giant vessels are capable of holding more than 6,000 containers, compared with the 3,000 to 4,000 containers on regular vessels. The huge new ships would mean 360,000 lifts per year. The capital cost of the project is expected to total close to $500 million. If Halifax is chosen, the province could see approximately 1,700 employed during the construction phase and another 2,000 people during the operational stage. Although not incorporated in the current forecast, this potential undertaking does present an upside risk to the construction outlook, and to the transportation, communication and storage sector, which the Conference Board projects will advance by 4.7 per cent this year and 4.3 per cent in 1999.

Nova Scotia's tourism industry is looking at another record-breaking year in 1998. Recent tourism statistics show occupancy rates, literature requests and traffic are all on the rise and may even outperform 1997, which was a banner year for tourism. Aided by a low Canadian dollar and all the hype surrounding the *Titanic*, the Nova Scotia economy can expect to see tourism revenues surpass the $1 billion level for the second year in row. The retail sector, in particular, is expected to benefit from the province's soaring tourism season. Overall, retail trade is expected to expand by 2.4 per cent this year and 2.0 per cent in 1999.

NOVA SCOTIA UTILITY AND REVIEW BOARD

IN THE MATTER OF: The *Public Utilities Act*, R.S.N.S., 1989, c.380 as amended

IN THE MATTER OF: An Application by Nova Scotia Power Incorporated for approval of a Load Retention Rate

RESPONSE TO INFORMATION REQUEST

TO: **NSUARB**

FROM: **NSPI**

Question IR-29: **Page 4 of the Report mentions about deregulation and separation of generation and retail supply.**

a) Please describe how the proposed Load Retention rate is in conformance with the deregulation and unbundling of services.

b) Provide all the documents in support of the response.

Response IR-29: a) Page 4 is entitled "Market Profile: Changing Global Energy Industry" and was intended to provide shareholders with an overview of how NSPI could be influenced by these changes. The separation of generation, distribution and retail supply has not yet occurred in Nova Scotia. Where it does occur, all existing rates may need revision.

b) N/A

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IN THE MATTER OF: An Application by Nova Scotia Power Incorporated for approval of a Load Retention Rate

RESPONSE TO INFORMATION REQUEST

TO: **NSUARB**

FROM: **NSPI**

"REVISED"

Question IR-30: **Page 14 of the Report mentions about NSPI's direct sales to Quebec, Maine and Maryland.**

a) **Please provide the amounts of power sales in 1998**

b) **Please provide all the cost/benefit analysis of making sales to self generation at Load Retention rates and selling off system power in the wholesale market.**

Response IR-30: a) The amounts of power sales in 1998 are shown in Table UARB-IR-30-A.

Table IR-30-A

	1998 Energy Sales (MWh)
New Brunswick	151,892
Quebec	8,477
Total	160,369

NOTE: Sales shown to Quebec were brokered through Maine and Maryland with delivery at the NB/Quebec border.

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TO: **NSUARB**

FROM: **NSPI**

"REVISED"

Response IR-30: b) NSPI interprets this question to mean "How does the benefit of selling power at load retention rates compare to the benefit of selling power in the export market?"

NSPI does not believe that the current export market can replace the loss of an existing large customer load. An existing customer purchases energy from NSPI during all hours, whereas energy can be sold in the export market only when NSPI's delivered cost to that market is lower than the marginal cost in that market. The opportunities for doing this are generally limited. As shown in response a), sales to the export market in 1998 were 160,369 Mwh. This is less than 2% of the energy produced by NSPI that year.

DATE FILED: January 10, 2000

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IN THE MATTER OF: An Application by Nova Scotia Power Incorporated for approval of a Load Retention Rate

RESPONSE TO INFORMATION REQUEST

TO: **NSUARB**

FROM: **NSPI**

Question IR-31: **Page 16 of the Report mentions NSPI's increased off system sales during off peak hours.**

a) Please indicate whether all of the off system sales would be made during off peak hours.

b) If the response to Part (a) is yes, please explain the reasons for selling only during off peak hours. Also, please provide all the studies and analyses prepared with respect to this response.

c) Please provide the amount of off system sales and associated net revenues from such sales during 1998 and 1999 to date.

d) Please provide the estimated annual off system sales and net revenue for the years 2000-2005.

Response IR-31: a) Not all of the off system sales would be made during off peak hours. Off system sales depend on the availability of NSPI capacity and/or energy, the $/MW or $/MWh price, and the availability of transmission interconnection. Some off system sales could be made during peak hours.

b) N/A

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IN THE MATTER OF: An Application by Nova Scotia Power Incorporated for approval of a Load Retention Rate

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TO: **NSUARB**

FROM: **NSPI**

Response IR-31 c) The amount of off system sales and associated gross revenues from such sales during 1998 and 1999 to date are shown in Table UARB-IR-31-C.

Table UARB-IR-31-C

	Energy Sales MWh	**Revenue $**
Year 1998		
New Brunswick	151,892	3,542,050
Quebec	8,477	236,050
Total for 1998	160,369	3,778,100
Year 1999 (11 months)		
New Brunswick	109,143	2,624,439
Quebec	74,756	1,781,848
Total for 1999	183,899	4,406,287

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NOVA SCOTIA UTILITY AND REVIEW BOARD

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TO: **NSUARB**

FROM: **NSPI**

Response IR-31 d) The estimated annual off system sales for 2000 - 2005 and gross revenue are presented in Table UARB-IR-31-D

Table UARB-IR-31-D

Year	Off System Sales (MWh)	Off System Revenue $
2000	300,000	7,800,000
2001	300,000	7,800,000
2002	300,000	7,800,000
2003	300,000	7,800,000
2004	300,000	7,800,000
2005	300,000	7,800,000

NOTE: For competitive reasons in dealing with marketers, NSPI has not included net revenue.

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RESPONSE TO INFORMATION REQUEST

TO: **NSUARB**

FROM: **NSPI**

Question IR-32: **Pages 18 and 19 of the Report describes the cost increases and other issues related to NSPI's fuel supplies. In view of these costs and concerns, is it not preferable to allow customers to self generate using gas? Please explain the response and provide all documents in support of the response.**

Response IR-32: If new gas fired generation is built in Nova Scotia, prior to the time when it is needed to serve load, it will benefit customers only if the fuel savings it provides are sufficient to offset the capital cost of providing it. This was the basis of NSPI's conversion of Tufts Cove to fire both gas and oil. Any further moves to natural gas would have to compete with coal, and since existing coal fired generation is expected to continue to have lower and less volatile costs than gas fired generation, there would be no fuel savings to support any capital required, hence such a strategy would not benefit all customers.

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RESPONSE TO INFORMATION REQUEST

TO: **NSUARB**

FROM: **NSPI**

Question IR-33: **Page 19 lists NSPI's power purchases since 1993. Please provide the following information:**

a) **Total annual cost of power purchases**

b) **Average and incremental cost of power purchases by each purchased power contract**

c) **Copies of existing and future power purchase contract**

d) **Projected amounts of power to be purchased**

e) **Average and incremental cost of each purchase**

f) **Minimum payment obligations for each existing and future purchased power contracts.**

g) **Does NSPI expect that in the absence of its proposed Load Retention Rate, it would lose loads and revenues in excess of its purchased power amounts and costs? Please provide all the analyses and other documents in support of the response.**

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RESPONSE TO INFORMATION REQUEST

TO: **NSUARB**

FROM: **NSPI**

Response IR-33: a) Table UARB-IR-33-A lists the annual cost of power purchases.

Table UARB-IR-33-A

Year	Total Cost $
1993	$6,469,294
1994	$6,867,993
1995	$15,109,881
1996	$17,179,806
1997	$21,653,635
1998	$16,206,960

b) Table UARB-IR-33-B lists the average and incremental cost of power purchases

Table UARB-IR-33-B

	Supplier A	Supplier B	Supplier C	Supplier D	Supplier E	Off System Purchases
	Average/Incr ($/Mwh)	Average/Incr ($/Mwh)	Average/Incr ($/Mwh)	Average/Incr ($/Mwh)	Average/Incr ($/Mwh)	Average/Incr ($/Mwh)
1993	-	-	-	$59.60	-	$29.88
1994	-	-	-	$61.20	-	$31.11
1995	$29.90	-	$72.80/$27.50	$78.10	$65.40/$26.30	$31.40
1996	$78.20/$25.50	$74.60/$25.60	$67.90/$24.30	$73.10/$24.70	$63.50/$25.00	$40.96
1997	$77.40/$24.10	$73.70/$24.20	$67.10/$23.00	$72.20/$23.50	$62.60/$23.70	$49.33
1998	$76.70/$24.30	$73.00/$24.40	$66.40/$23.10	$71.50/$23.60	$62.00/$23.00	$47.94

c) Copies of the existing power purchase contracts are being filed confidentially. There are no future power purchase contracts presently under negotiation with NSPI.

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TO: **NSUARB**

FROM: **NSPI**

Response IR-33: d) Table UARB-IR-33-D lists the projected amount of power purchases.

Table UARB-IR-33-D

Year	Power Purchase (MWh)
2000	304,100
2001	278,600
2002	346,400
2003	415,600
2004	402,400

e) Table UARB-IR-33-E lists the projected average and incremental cost of each purchase

Table UARB-IR-33-E

	Supplier A	Supplier B	Supplier C	Supplier D	Supplier E	Off System Purchases
	Average/Incr ($/Mwh)	Average/Incr ($/Mwh)	Average/Incr ($/Mwh)	Average/Incr ($/Mwh)	Average/Incr ($/Mwh)	Average/Incr ($/MWh)
2000	$72.87 / $20.26	$69.14 / $20.35	$62.75 / $19.31	$67.81 / $19.69	$58.23 / $19.88	$47.24
2001	$72.15 / $19.46	$68.43 / $19.55	$62.07 / $18.54	$67.12 / $18.91	$57.53 / $19.09	$48.10
2002	$69.03 / $16.52	$65.29 / $16.60	$59.09 / $15.74	$64.09 / $16.05	$54.47 / $16.21	$47.41
2003	$69.45 / $16.74	$65.71 / $16.82	$59.49 / $15.96	$64.49 / $16.27	$54.87 / $16.43	$49.57
2004	$69.70 / $16.81	$65.97 / $16.88	$59.73 / $16.02	$64.74 / $16.33	$55.12 / $16.49	$50.16

f) Under the existing power purchase contracts with non-utility-owned generators, NSPI is obligated to purchase all energy produced from these facilities. As indicated in IR-33-C, there are no future power purchase contracts under negotiation.

NSPI has no minimum payment obligation with off system purchases.

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TO: **NSUARB**

FROM: **NSPI**

Response IR-33: g) As per response IR-33-F, NSPI is obligated to purchase all energy supplied by the existing power purchase contracts. In the absence of the proposed load retention rate, NSPI would both lose the existing customer load and be obligated to continue purchases under the existing power purchase agreements.

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Responses to Irving Oil Limited

Questions 1 - 7

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IN THE MATTER OF: An Application by Nova Scotia Power Incorporated for approval of a Load Retention Rate

RESPONSE TO INFORMATION REQUEST

TO: IRVING OIL LIMITED

FROM: NSPI

Question 1: **Reference: Direct evidence of Christopher Huskilson, Page 2, line 13.**

Please provide copies of the preliminary studies referred to.

Response 1: See UARB Interrogatory 12.

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RESPONSE TO INFORMATION REQUEST

TO: **IRVING OIL LIMITED**

FROM: **NSPI**

Question 2: **Reference: Direct evidence of Christopher Huskilson, page 2, line 18.**

Please provide examples where "the use of exit fees and/or high charges for ancillary charges" has been utilized and approved for this purpose.

Response 2: Because NSPI chose not to follow this course for the reasons indicted in Mr. Huskilson's testimony, we did not pursue this option. However, we believe that such an option has at least been proposed in Alabama and Virginia.

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RESPONSE TO INFORMATION REQUEST

TO: **IRVING OIL LIMITED**

FROM: **NSPI**

Question 3: **Reference: Proposed load retention rate availability condition (2).**

Please explain the rationale for restricting the availability of this rate only to customers who are considering an alternate supply of at least 2,000 KVA or 1,800 KW.

Response 3: See UARB Interrogatory 22.

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RESPONSE TO INFORMATION REQUEST

TO: **IRVING OIL LIMITED**

FROM: **NSPI**

Question 4: **Reference: Proposed load retention rate availability condition (4).**

Please explain the rationale for not making this rate available to new load.

Response 4: The purpose of this rate is to retain existing load. NSPI has other rates to encourage new load. These are the Industrial Expansion Interruptible Rate, the Time-of Day Expansion Rate and the Surplus Power Interruptible Rate.

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NOVA SCOTIA UTILITY AND REVIEW BOARD

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IN THE MATTER OF: An Application by Nova Scotia Power Incorporated for approval of a Load Retention Rate

RESPONSE TO INFORMATION REQUEST

TO: **IRVING OIL LIMITED**

FROM: **NSPI**

Question 5: **Reference: Proposed load retention rate special conditions (1) and (2).**

a) **Please explain why NSPI is not seeking to set a rate which is equivalent for all customers meeting the availability requirements.**

b) **Is it the case that under the proposed load retention rate, two customers of NSPI with identical energy requirements could receive energy under different prices, terms and conditions? If so, upon what basis does NSPI consider the price, terms and conditions under this rate not to be preferential or unjustly discriminatory?**

c) **Is the proposed load retention rate intended to be available only on an interruptible basis? Please explain NSPI's rationale for proposing the availability of this rate on an, as applicable, interruptible or non-interruptible basis, please outline the conditions which it would propose for interruptibility.**

Response 5: a) The rate is equivalent for all customers meeting the Availability conditions. The economics of each individual's alternate supply option (including cogeneration or other on-site generation) will each bring to bear different considerations in the analysis of whether the alternate supply option is a viable one, given NSPI's current rates. The objective is to maintain customer load by being able to offer a price to the specific customer at a level that makes that customer indifferent to the alternate supply option. The price will by necessity vary from customer to customer. In this way, the potential benefit to all customers of maintaining that load will be maximized.

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NOVA SCOTIA UTILITY AND REVIEW BOARD

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TO: **IRVING OIL LIMITED**

FROM: **NSPI**

Response 5:

b) It is theoretically possible that two customers of NSPI with identical energy requirements could receive energy under different prices, terms and conditions. This may be considered discriminatory, however, such price, terms and conditions under this rate would not be unduly preferential or unjustly discriminatory because the proposed rate is remedial in nature and is designed to be responsive to the different circumstances and conditions a specific customer may be able to present in proving its alternate supply option. As noted in the response to 5 (a), it is unlikely that two customers, even with identical energy requirements, would have exactly the same technical and economic feasibility which would make switching to an alternate supply a viable alternative. Price flexibility is required to try to meet the challenge of each customers different circumstances and conditions for the benefit of all customers. This flexible approach is reasonable, and therefore not unjustly discriminatory.

c) The load retention rate will be determined from the cost of the alternate supply, including ancillary services such as stand-by power. The customer may choose firm or interruptible stand-by service, and the load retention rate will be priced accordingly.

DATE FILED: December 23, 1999

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IN THE MATTER OF: An Application by Nova Scotia Power Incorporated for approval of a Load Retention Rate

RESPONSE TO INFORMATION REQUEST

TO: **IRVING OIL LIMITED**

FROM: **NSPI**

Question 6: **Reference: Direct evidence of M. E. Whalen, page 9, lines 4 to 20, page 10, lines 1 to 4.**

Please provide:

a) the names of the utilities contacted;

b) copies of any correspondence between NSPI and these utilities respecting load retention rates;

c) copies of the terms of availability and conditions for load retention rates authorized for these utilities.

Response 6: a) Listing of utilities contacted:

Alabama Power Company
Alliant Utilities
Ameren Services
American Electric Power Service Corp.
B.C. Hydro
Bangor Hydro Electric Company
Boston Edison Co.
Central Vermont Public Svc. Corp.
Central Hudson Gas & Elec. Corp.
Chugoku Electric Power Co., Inc. c/o JEPIC
Commonwealth Edison Company
Connecticut Light & Power Co.
Consumers Energy
Duquesne Light Company
Empire District Electric Co.
EUA Service Corp.
Florida Power Corporation
Georgia Power Company
Green Mountain Power Corporation
Hawaiian Electric Company, Inc.
Allegheny Power
Alliant Gas & Electric Company
AmerenCips
Arizona Public Service Company
Baltimore Gas and Electric
Black Hills Power and Light Co.
Carolina Power and Light Company
Central and South West Services, Inc.
Cinergy Cleco Corporation
Conectiv
Consolidated Edison Co. of NY
Duke Energy Corp.
El Paso Electric Company
Entergy Services, Inc.
FirstEnergy Corp.
Florida Power & Light Company
GPU Energy
Gulf Power Company
Idaho Power Company

DATE FILED: December 23, 1999

1999 NSPI-P-871

NOVA SCOTIA UTILITY AND REVIEW BOARD

IN THE MATTER OF: The *Public Utilities Act*, R.S.N.S., 1989, c.380 as amended

IN THE MATTER OF: An Application by Nova Scotia Power Incorporated for approval of a Load Retention Rate

RESPONSE TO INFORMATION REQUEST

TO: IRVING OIL LIMITED

FROM: NSPI

Illinois Power Company
Kansas City Power & Light Co.
LGE Energy Corp.
Manitoba Hydro
Minnesota Power
Montana Power Company
National Grid Company plc
New Brunswick Power Corp.
Niagara Mohawk Power Corp.
Northern States Power Co. (WI)
Northern Indiana Public Svc. Co.
OG&E Electric Services
Orange and Rockland Utilities, Inc.
PECO Energy Co.
PP&L, Inc.
Public Service Co. of New Mexico
Public Service Electric & Gas Co.
Quebec Hydro
Rochester Gas & Electric Corp.
SaskPower
Sierra Pacific Power Company
Southern Company Services, Inc.
Southern Indiana Gas & Electric Company
Southwestern Public Service Company
St. Joseph Light & Power Company
Texas New Mexico Power Co.
The Dayton Power and Light Co.
TXU Business Services
Upper Peninsula Power Company
Virginia Power
Western Resources Inc.
Wisconsin Public Service Corp.
Indianapolis Power & Light Co.
Key Span Energy Corp.
Madison Gas & Electric Company
MidAmerican Energy Co.
Mississippi Power Company
Montana-Dakota Utilities Co.
Nevada Power Company
New England Electric System
Northeast Utilities Service Co.
Northern States Power Co. (MN)
Northwestern Public Service Co.
Ontario Hydro
Otter Tail Power Co.
Potomac Electric Power Company
Public Service. Co. of New Hampshire
Public Service Co. of Colorado
Puget Sound Energy
Reliant Energy
San Diego Gas & Electric Company
Savannah Electric and Power Co.
Southern Nuclear Operating Co.
Southern California Edison Co.
Southwestern Electric Power Co.
Tampa Electric Company
The Detroit Edison Company
Tucson Electric Power Co.
United Illuminating Company
UtiliCorp United
West Texas Utilities Company
Wisconsin Electric Power Company

DATE FILED: December 23, 1999

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TO: **IRVING OIL LIMITED**

FROM: **NSPI**

b) These utilities were initially contacted by e-mail or fax to determine whether they offered a load retention rate. Further information was collected from those who did by phone and/or from the utility's web site.

c) See UARB Interrogatory 19.

DATE FILED: December 23, 1999

NOVA SCOTIA UTILITY AND REVIEW BOARD

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RESPONSE TO INFORMATION REQUEST

TO: **IRVING OIL LIMITED**

FROM: **NSPI**

"REVISED"

Question IR-7: **Reference 1) Direct evidence of Christopher Huskilson, page 3, lines 5-11:**

> **"To ensure that load retention rates are offered only in circumstances where they are justified, NSPI proposes that such rates be based on the fundamental principle that they be offered only in circumstances where it can be shown that:**
> - ...
> - **Retaining the customers' load through a load retention rate is better for other NSPI customers than losing the customer in question;**
> - ..."

Reference 2) 1998 Nova Scotia Power Annual Report, page 14:

> **"We also began to export power in 1998 following the National Energy Board's approval of our export license, allowing us to sell energy beyond Nova Scotia and New Brunswick and into the United States. Thanks to this license, and the new transmission tariff allowing us to wheel electricity through New Brunswick without selling it to them, we made direct sales in 1998 to Quebec, Main and Maryland."**

DATE FILED: January 10, 2000

NOVA SCOTIA UTILITY AND REVIEW BOARD

IN THE MATTER OF: The *Public Utilities Act*, R.S.N.S., 1989, c.380 as amended

IN THE MATTER OF: An Application by Nova Scotia Power Incorporated for approval of a Load Retention Rate

RESPONSE TO INFORMATION REQUEST

TO: **IRVING OIL LIMITED**

FROM: **NSPI**

"REVISED"

Question 7: **Reference 3) 1998 Nova Scotia Power Annual Report, page 16:**

> **"Nova Scotia is building its electric utility business to become more competitive. In July, the National Energy Board approved the company's export license. This license and the open transmission system in New Brunswick now allow the company to sell energy beyond Nova Scotia and New Brunswick and into the United States. In 1999, Nova Scotia plans to increase exports of energy to regional markets during off peak periods."**

a) **Has NSPI explored the opportunities to replace loss of existing customers' loads through export sales? If so, please provide NSPI's evaluation of this opportunity.**

b) **Please provide a summary of NSPI's export electricity sales during 1999 showing on a monthly basis the destination of the sales, the energy involved and the revenue received.**

c) **Please provide a copy of the most recent interim financial statements for Nova Scotia Power reflecting results in 1999.**

d) **Has NSPI identified circumstances in which it is to the benefit of other NSPI customers to lose the load of a customer or series of customers thereby enabling NSPI to shut down uneconomic generating facilities?**

DATE FILED: January 10, 2000

NOVA SCOTIA UTILITY AND REVIEW BOARD

IN THE MATTER OF: The *Public Utilities Act*, R.S.N.S., 1989, c.380 as amended

IN THE MATTER OF: An Application by Nova Scotia Power Incorporated for approval of a Load Retention Rate

RESPONSE TO INFORMATION REQUEST

TO: IRVING OIL LIMITED

FROM: NSPI

"REVISED"

Question 7:

e) Please provide a ranking of NSPI's generating facilities in order for economic dispatch, providing the marginal costs for energy production for each of these plants.

f) What is the position of NSPI with respect to the wheeling of electricity produced by third parties on a wholesale and retail basis on its transmission lines?

Response 7:

a) NSPI does not believe that the current export market can replace the loss of an existing large customer load. An existing customer purchase energy from NSPI during all hours, whereas energy can be sold in the export market only when NSPI's delivered cost to that market is lower than the marginal cost in that market. The opportunities for doing this are generally limited. As shown in response to UARB Interrogatory 30, sales to the export market in 1998 were 160,369 Mwh. This is less than 2% of the energy produced by NSPI that year.

DATE FILED: January 10, 2000

NOVA SCOTIA UTILITY AND REVIEW BOARD

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RESPONSE TO INFORMATION REQUEST

TO: **IRVING OIL LIMITED**

FROM: **NSPI**

"REVISED"

Response 7: b) Table Irving-7B provides the export sales destination, energy and revenue on a month basis for calendar year 1999.

Table Irving-7B

Month	Destination	Energy (Mwh)	Revenue $
Jan	Canadian Market	3,861	$92,544
Feb	Canadian Market	28,104	628,104
Mar	Canadian Market	43,889	1,037,148
Apr	Canadian Market	34,219	855,225
May	Canadian Market	24,514	593,748
Jun	Canadian Market	17,377	423,558
Jul	Canadian Market	22,275	537,595
Aug	Canadian Market	6,640	157,300
Sep	Canadian Market	1,650	41,725
Oct	Canadian Market	0	0
Nov	Canadian Market	1,370	39,340
Total for 1999		**183,899**	**$4,406,287**

c) NSPI's third quarter financial statements are attached.

DATE FILED: January 10, 2000

Response 7:

d) No. NSPI's existing generating units were built to meet the expected needs of existing customers, and the mix of units was chosen to minimize the cost of meeting those needs. On a day to day operational basis, the most economic units run most and the least economic units run least. However, because of changing daily and seasonal load patterns, forced outages on some units, etc. all units are generally required during any given year. If because of a loss of customer load the least economic unit could be shut down, this would have minimal savings. Fuel costs would be slightly lower but fixed costs would remain unchanged. Hence the impact of the loss of a significant customer load cannot be offset by shutting down generating units.

e) This data is confidential

f) Wheeling of electricity from a generator located in Nova Scotia to markets outside Nova Scotia is permitted under Section 55A of the Public Utilities Act. Otherwise, wheeling in Nova Scotia is not permitted.

NS Power Holdings Inc.

Consolidated Balance Sheet

As at September 30 (unaudited)

millions of dollars

	1999	1998
Assets		
Property, plant and equipment	$2,283.2	$2,266.1
Construction work in progress	49.9	30.5
	2,333.1	2,296.6
Deferred charges	330.6	363.1
Investment in Maritimes & Northeast Pipeline	50.3	-
Current assets	169.6	142.6
	$2,883.6	$2,802.3
Shareholders' Equity and Liabilities		
Common shares	$675.3	$671.5
Retained earnings (note 3)	255.2	212.6
	930.5	884.1
Minority interest	231.3	200.0
Long-term debt	1,286.0	1,083.6
Deferred credits	1.3	2.1
Current liabilities	434.5	632.5
	$2,883.6	$2,802.3

NS Power Holdings Inc.

Consolidated Statement of Changes in Cash Position

For the nine months ended September 30 (unaudited)

millions of dollars

	1999	1998
Operating activities:		
Net earnings adjusted for non-cash items	$183.4	$172.2
Change in operating working capital	(66.8)	(33.1)
Net cash provided by operating activities	116.6	139.1
Net cash provided by financing activities	32.4	15.1
Net cash used in investing activities	(91.3)	(72.2)
Dividends	(54.1)	(82.6)
Increase (decrease) in cash position	3.6	(0.6)
Cash position at beginning of period	0.1	0.7
Cash position at end of period	$3.7	$0.1

NS Power Holdings Inc.

Consolidated Statement of Earnings

For the nine months ended September 30 (unaudited)

millions of dollars (except earnings per common share)

	1999	1998
Revenue		
Electric	$584.0	$550.1
Other	7.4	6.2
	591.4	556.3
Cost of operations		
Fuel for generation and power purchased	196.7	183.7
Operating, maintenance and general	111.4	107.2
Grants in lieu of taxes	6.6	4.1
Provincial capital tax	5.0	5.1
Depreciation	70.7	68.2
	390.4	368.3
Earnings from operations	201.0	188.0
Amortization of Point Aconi costs	(17.3)	(12.5)
Allowance for funds used during construction and equity income	8.0	2.7
Earnings before interest and income taxes	191.7	178.2
Interest	101.3	100.1
Earnings before income taxes	90.4	78.1
Large corporations tax	4.4	4.5
Income tax	5.4	2.5
Net earnings before minority interest	80.6	71.1
Minority interest	8.6	11.5
Net earnings applicable to common shares	$72.0	$59.6
Earnings per common share	$0.83	$0.69

Notes

1. Interim results are not necessarily indicative of results for the full year due primarily to seasonal factors. Sales and related production change significantly over the year as a result of marked differences in temperatures and daylight hours.
2. The comparative financial statements have been presented as if NS Power Holdings Inc. was the parent company as of January 1, 1998.
3. Included as a charge against retained earnings is $1.1 million for costs associated with the reorganization to a holding company structure effective January 1, 1999 (see Note 16 to the 1998 Financial Statements).

Corporate Profile

NS Power Holdings Inc. (NSPH) is a diversified energy and services company. Its wholly-owned subsidiary, Nova Scotia Power Inc. (NSPI), has over 430,000 residential, commercial and industrial customers. NSPI's assets total $2.8 billion and its operations include the generation, transmission and distribution of electric power throughout the province. NSPH also holds a 12.5% stake in the Maritimes & Northeast natural gas pipeline. NSPH common shares trade on the Toronto and Montreal stock exchanges under the symbol NSH.

Responses to Cape Breton Regional Municipality

Questions 1 - 17

NOVA SCOTIA UTILITY AND REVIEW BOARD

IN THE MATTER OF: The *Public Utilities Act*, R.S.N.S., 1989, c.380 as amended

IN THE MATTER OF: An Application by Nova Scotia Power Incorporated for approval of a Load Retention Rate

RESPONSE TO INFORMATION REQUEST

TO: **CAPE BRETON REGIONAL MUNICIPALITY**

FROM: **NSPI**

Question IR-1: **Please provide a description of the existing sources of energy used by NSPI to produce electricity in Nova Scotia. What amount of energy is used (e.g. water, wind, oil, coal)? What is the cost paid by NSPI for each form of energy? For each source of energy, if NSPI utilizes both indigenous resources and imported resources, please distinguish between indigenous and imported amounts used and prices paid.**

Response IR-1: Statistics regarding the existing sources of energy used by NSPI to produce electricity are shown on page 19 of NSPI's 1998 Annual Report. 1998 statistics have been provided in the following table, including energy produced from wind turbines.

Generation type/fuel	GWh produced
Thermal-coal	7015.0
Thermal-oil	2358.3
Hydro	890.9
Purchases	242.0
Wind	0.0
Total	10506.2

Fuel prices must remain confidential. However, our total cost of fuel and purchased power in 1998 was $257.3 million. The use of indigenous coal is maximized to the extent of its availability. Prior to 1998, NSPI used 100% indigenous coal. Since 1998, this percentage has fallen due to supply problems at CBDC. Oil is entirely supplied from offshore sources.

DATE FILED: December 23, 1999

1999 NSPI-P-871

NOVA SCOTIA UTILITY AND REVIEW BOARD

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RESPONSE TO INFORMATION REQUEST

TO: **CAPE BRETON REGIONAL MUNICIPALITY**

FROM: **NSPI**

Question IR-2: **In making this application before the Board, what assumptions are used by NSPI regarding future demand for each form of energy referred to above?**

Response IR-2: This rate application does not require NSPI to make any assumptions about future demand for each form of energy.

DATE FILED: December 23, 1999

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NOVA SCOTIA UTILITY AND REVIEW BOARD

IN THE MATTER OF: The *Public Utilities Act*, R.S.N.S., 1989, c.380 as amended

IN THE MATTER OF: An Application by Nova Scotia Power Incorporated for approval of a Load Retention Rate

RESPONSE TO INFORMATION REQUEST

TO: CAPE BRETON REGIONAL MUNICIPALITY

FROM: NSPI

Question IR-3: **Compared to other jurisdictions in Canada, are Nova Scotia's electricity costs relatively high? If so, what are the reasons for this?**

Response IR-3: Electricity rates in Nova Scotia are somewhat higher than many parts of Canada. One of the largest components of the cost of producing electricity is fuel cost. Electricity costs vary according to the mix and price of the fuel types used to generate electricity. Regions with significant hydroelectric production generally have lower electricity rates because there are no direct fuel costs. Nova Scotia generates, or will generate its electricity using a mix of coal, oil, natural gas and hydro facilities.

NSPI's goals are to manage costs and maintain rate stability. Since 1992, electricity prices have risen by only 4%, while CPI has risen by 10%. Our last rate increase was in 1996, and there are no plans to increase rates in the year 2000.

DATE FILED: December 23, 1999

NOVA SCOTIA UTILITY AND REVIEW BOARD

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RESPONSE TO INFORMATION REQUEST

TO: **CAPE BRETON REGIONAL MUNICIPALITY**

FROM: **NSPI**

Question IR-4: **What is the current capacity of the Tufts Cove generating facility? When will this facility be converted to utilize natural gas? At that time, what will the capacity of the Tufts Cove generating facility be?**

Response IR-4: The current nameplate capacity of the Tuft's Cove generating station is approximately 350 MW.

It is expected that this station will begin utilizing natural gas late in the Fall of 2000. No significant change is expected in the capacity of this facility due to this conversion.

DATE FILED: December 23, 1999

NOVA SCOTIA UTILITY AND REVIEW BOARD

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RESPONSE TO INFORMATION REQUEST

TO: CAPE BRETON REGIONAL MUNICIPALITY

FROM: NSPI

Question IR-5: **Will the conversion of Tufts Cove to natural gas enhance NSPI's overall efficiency?**

Response IR-5: The conversion may slightly decrease the overall efficiency, but is expected to have both economic and environmental benefits.

DATE FILED: December 23, 1999

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NOVA SCOTIA UTILITY AND REVIEW BOARD

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RESPONSE TO INFORMATION REQUEST

TO: **CAPE BRETON REGIONAL MUNICIPALITY**

FROM: **NSPI**

Question IR-6: **What other plans, if any, does NSPI have to utilize natural gas to produce electricity? Do these plans suggest improvements in NSPI's efficiency?**

Response IR-6: NSPI has made no decision to further utilize natural gas at its facilities.

DATE FILED: December 23, 1999

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NOVA SCOTIA UTILITY AND REVIEW BOARD

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RESPONSE TO INFORMATION REQUEST

TO: **CAPE BRETON REGIONAL MUNICIPALITY**

FROM: **NSPI**

Question IR-7: **Does NSPI have any plans to utilize natural gas, directly or indirectly, in the development of district heating systems in any region of Nova Scotia? If so, will such measures enhance NSPI's overall efficiency?**

Response IR-7: NSPI does not have any plans at this time to utilize natural gas in any potential development of district heating systems in Nova Scotia.

DATE FILED: December 23, 1999

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NOVA SCOTIA UTILITY AND REVIEW BOARD

IN THE MATTER OF: The *Public Utilities Act*, R.S.N.S., 1989, c.380 as amended

IN THE MATTER OF: An Application by Nova Scotia Power Incorporated for approval of a Load Retention Rate

RESPONSE TO INFORMATION REQUEST

TO: **CAPE BRETON REGIONAL MUNICIPALITY**

FROM: **NSPI**

Question IR-8: **What, if any, plans does NSPI have to reduce its emissions of Greenhouse gases? Is such reduction a priority for NSPI?**

Response IR-8: NSPI is working within the Canadian Electricity Association to develop an approach which would move the electricity industry to less carbon-intensive electricity generation. The three pillars of this approach are: reduced GHG emission per kilowatt hour of electricity generated, use of electricity generation assets for their full commercial life, and choosing a strategy which incorporates an efficient, integrated approach to reducing other atmospheric emissions associated with the combustion of fossil fuels.

The overall objective of Nova Scotia Power is to contribute to Canada's goal of reducing GHG emissions by moving into the future with more efficient technologies, less carbon-intensive fuels, and renewable sources as they become commercially competitive. This strategy requires that existing generating assets operate until the end of their useful commercial life, thus avoiding the premature turn-over of valuable assets. Premature retirement of facilities would result in a burden to Nova Scotia electricity consumers to pay for the recovery of the costs of stranded assets, forcing higher electricity prices and hurting economic growth in the Province.

DATE FILED: December 23, 1999

NOVA SCOTIA UTILITY AND REVIEW BOARD

IN THE MATTER OF: The *Public Utilities Act*, R.S.N.S., 1989, c.380 as amended

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RESPONSE TO INFORMATION REQUEST

TO: **CAPE BRETON REGIONAL MUNICIPALITY**

FROM: **NSPI**

Question IR-9: **Can coal-fired generating plants be converted to use natural gas? Is such conversion likely to be more or less cost-effective compared with the development of new gas-fired combined-cycle generating capacity?**

Response IR-9: While it is technically possible to do this, it is uneconomic , as explained in NSPI's response to UARB Interrogatory UARB-IR-32.

DATE FILED: December 23, 1999

1999 NSPI-P-871

NOVA SCOTIA UTILITY AND REVIEW BOARD

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RESPONSE TO INFORMATION REQUEST

TO: **CAPE BRETON REGIONAL MUNICIPALITY**

FROM: **NSPI**

Question IR-10: **In a recent report prepared for the Nova Scotia Petroleum Directorate, Michael Gardner states: "Gas and electricity are not easily substituted. Electricity demand in the industrial sector is confined mainly to requirements to drive machinery and equipment, and is not readily displaced by natural gas. The opportunities for gas in the industrial sector are confined essentially to displacing petroleum products for space heating, process heat and feedstock uses." (Gardner Pinfold Consulting Economists Limited, Development and Use of Natural Gas: Socio-Economic Impact on the Cape Breton Regional Municipality, March, 1999, p. A-13.) Does NSPI agree with this assessment?**

Response IR-10: NSPI generally agrees with this assessment, but would point out that natural gas can also be used to fire cogeneration plant that customers can use to generate their own electricity.

DATE FILED: December 23, 1999

NOVA SCOTIA UTILITY AND REVIEW BOARD

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RESPONSE TO INFORMATION REQUEST

TO: **CAPE BRETON REGIONAL MUNICIPALITY**

FROM: **NSPI**

Question IR-11: **Does NSPI currently own a share of the Maritimes and Northeast Pipeline project? If so, what share of the pipeline is owned by NSPI? What was the cost of acquiring this share? What is NSPI's anticipated annual revenue from this asset?**

Response IR-11: NSPI does not own a share of the Maritimes and Northeast Pipeline. NSPI's unregulated parent company, NS Power Holdings Inc. has part ownership in this project.

DATE FILED: December 23, 1999

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NOVA SCOTIA UTILITY AND REVIEW BOARD

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RESPONSE TO INFORMATION REQUEST

TO: CAPE BRETON REGIONAL MUNICIPALITY

FROM: NSPI

Question IR-12: **When is the next opportunity for NSPI to renegotiate the terms of the existing coal contract with the Cape Breton Development Corporation (DEVCO)?**

Response IR-12: The CBDC contract provides for renegotiation of both coal prices and minimum quantities at five-year intervals, with the next interval beginning January 1, 2000.

DATE FILED: December 23, 1999

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NOVA SCOTIA UTILITY AND REVIEW BOARD

IN THE MATTER OF: The *Public Utilities Act*, R.S.N.S., 1989, c.380 as amended

IN THE MATTER OF: An Application by Nova Scotia Power Incorporated for approval of a Load Retention Rate

RESPONSE TO INFORMATION REQUEST

TO: CAPE BRETON REGIONAL MUNICIPALITY

FROM: NSPI

Question IR-13: **If a private corporation assumes all or the majority of the DEVCO assets, does this corporation also assume the rights and responsibilities associated with the existing contract? Under what conditions can this contract be voided?**

Response IR-13: The terms and conditions of this contract are confidential.

DATE FILED: December 23, 1999

NOVA SCOTIA UTILITY AND REVIEW BOARD

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RESPONSE TO INFORMATION REQUEST

TO: **CAPE BRETON REGIONAL MUNICIPALITY**

FROM: **NSPI**

Question IR-14: **Does NSPI have any existing plans to abandon stranded electrical generating assets in any region of Nova Scotia? If so, please explain which assets and the possible cost of so doing.**

Response IR-14: NSPI has no stranded assets, as explained in our response to Irving Oil's Interrogatory Irving-IR-7 (d). However, from time to time, as assets reach the end of their useful lives, they may be retired.

DATE FILED: December 23, 1999

NOVA SCOTIA UTILITY AND REVIEW BOARD

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RESPONSE TO INFORMATION REQUEST

TO: **CAPE BRETON REGIONAL MUNICIPALITY**

FROM: **NSPI**

Question IR-15: **On the NSPI web site, a statement is made to the effect that: "In general, natural gas is 20 - 40 per cent less expensive than alternative fuel choices." Is this correct? If so, why would NSPI seek to prevent existing power consumers from using natural gas? As well, why would NSPI suggest a measure which increases the relative and absolute cost of electricity for consumers who are in the disadvantaged position of not having access to natural gas?**

Response IR-15: The information referenced on NSPI's web site was originally obtained from Ontario and this particular statement pertains to relative energy costs in that jurisdiction. The information on this page of our web site was intended to give customers more general information about natural gas. The clause, which is not applicable to the Nova Scotia market, has now been removed. In Nova Scotia, the gas distribution company has indicated that gas will be priced at 5% less than oil.

By offering the load retention rate to customers who otherwise have a genuine option to leave the system, NSPI's goal is, in fact, to avoid increasing costs faced by other customers.

DATE FILED: December 23, 1999

NOVA SCOTIA UTILITY AND REVIEW BOARD

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RESPONSE TO INFORMATION REQUEST

TO: **CAPE BRETON REGIONAL MUNICIPALITY**

FROM: **NSPI**

Question IR-16: **Will the proposed load retention rate impact upon the competitiveness of industries and regions which do not have access to natural gas? If so, what is the anticipated impact?**

Response IR-16: The load retention rate is designed to maintain the competitiveness of the customers mentioned in the question, by avoiding the need to increase rates due to loss of load to alternate supply sources.

DATE FILED: December 23, 1999

NOVA SCOTIA UTILITY AND REVIEW BOARD

IN THE MATTER OF: The *Public Utilities Act*, R.S.N.S., 1989, c.380 as amended

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RESPONSE TO INFORMATION REQUEST

TO: **CAPE BRETON REGIONAL MUNICIPALITY**

FROM: **NSPI**

Question IR-17: **In what ways does the proposed load retention rate serve the public interest? Is the proposal consistent with the principle of equity? If so, please explain. Is the proposal likely to enhance the efficient use of resources in Nova Scotia? If so, please explain.**

Response IR-17: As stated in the previous two responses, the impact of offering a load retention rate will be to avoid rate increases that would otherwise be necessary due to the loss of load from the system. In this way, all customers are better off than not offering the rate.

The issue of equity has been addressed in NSPI's response to Irving Oil's Interrogatory, Irving-IR-5(b).

This proposal will make efficient use of all Nova Scotia resources by maximizing the use of existing plant until new capacity is required, and minimizing overall electricity costs for Nova Scotians.

DATE FILED: December 23, 1999