JTC

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April 20, 1997

Mr. David Keelty
Fletcher Allen Health Care
Facilities Services - MCHV Campus
111 Colchester Avenue
Burlington, Vermont 05401

Subject: Greater Burlington District Energy Study

Dear David:

We are pleased to clarify your questions on the calculation of district heating cost with our assumptions:

1. We used your annual fuel cost of $738,484, the figure you had provided on our September 30, 1997 meeting.
2. Using a natural gas rate of $4.45 per MMBtu, fuel oil rate of $5.22 per MMBtu, and fuel composition of 98% natural gas / 2% fuel oil, the figures you provided on the same meeting, we calculated annual fuel consumption as follows: 738,484 * 98% / 4.45 + 738,484 * 2% / 5.22 = 165,461.9 MMBtu.
3. With 70% boiler efficiency, useful annual heat consumption becomes 165,461.9 * 70% = 115,823.3 MMBtu.
4. The proposed district heating rate for the first year is $8.7210 per MMBtu.
5. The first year district heating cost is: 115,823.3 * 8.7210 = $1,010,093
6. The proposed district heating rate for the second year is $7.9830 per MMBtu.
7. The second year district heating cost is: 115,823.3 * 7.9830 = $924,618

We would be pleased to answer any further questions you may have.

Sincerely yours

Dr. Ishai Oliker, PE
Joseph Technology Corporation

cc: Ron Belval
Tim Maker

Joseph Technology Corporation

GREATER BURLINGTON DISTRICT ENERGY STUDY

FINAL REPORT

Prepared for:

Burlington Electric Department,
University of Vermont and
Fletcher Alen Health Care
Burlington, Vermont

Prepared by:

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March, 1998

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With HTHW option, the district heating water will be also used to drive absorption chillers at the customer facilities.

Potential heat sales in the first stage are estimated at 394,000 MMBtu/yr for HTHW option. Capital cost in the first stage is estimated at $11.7 million, including the McNeil station retrofit to cogeneration, installation of the transmission piping from McNeil to UVM and FAHC and hook-ups.

With MTHW option, it is assumed that the retrofit of the UVM and FAHC to hot water will result in the reduction of annual heat consumption by 20% (reduction in underground piping losses, steam trap losses and improvement of building controls). Therefore, the potential heat sales in the first stage with MTHW option are estimated at 315,000 MMBtu/yr. Capital cost for the first stage with MTHW option is estimated at $8.5 million not including the cost of building retrofits.

In the second stage, connect the following customers to a MTHW system, supplied with HTHW from McNeil through the UVM boiler plant:

- UVM buildings currently not supplied from their central plant
- Champlain College
- Trinity College
- Mater Christi School
- Red Cross Building
- Taft School

Additional potential heat sales in this stage are estimated at 110,000 MMBtu/yr. Capital cost of this construction stage is estimated at $2.6 million, including the modification of the UVM plant, distribution piping and back-up boiler plant.

In the third stage, gradually expand the MTHW system to Downtown and Waterfront customers. The additional potential heat sales are estimated at 108,000

Currently McNeil is dispatched as part of NEPOOL on the basis of its operating expenses. Typically, it runs weekdays from 7 AM to 10 PM. Once McNeil supplies thermal energy, it must operate continuously. An analysis has been made to determine how the station will fare under impending deregulation of Vermont's electric utility industry. The analysis showed that the biomass-fired McNeil station will qualify for the "renewable energy credits" proposed in Vermont Senate Bill S-62 and, therefore, will remain a viable energy source. The cost of heat extraction from McNeil was also analyzed. It will be comprised of the additional cost of fuel, reimbursement costs for-must run operation (to assure district energy supply) and some additional operating and maintenance expenses. All these costs are included in the economic analysis.

Thermal Source Redundancy and Reliability

The redundancy and reliability of the heat supply will be provided by the UVM and FAHC boiler plants or a newly built in the second and third project stage boiler plant. Table S-1 presents the comparison of available heat supply capacity with peak heat demand with HTHW and MTHW options. The total McNeil boiler capacity is 521 MMBtu/hr, the maximum heat capacity which can be provided from McNeil turbine is 210 MMBtu/hr.

Table S-1
Heat Supply Redundancy

Implementation Stage	Peak Heat Demand MMBtu/hr		Available Capacity, MMBtu/hr.				
	HTHW	MTHW	McNeil	UVM	FAHC	Total	With McNeil Boiler Out of Service
First	193	155	521	148	74	743	222
Second	247	198	521	148	74	743	222
Third	300	241	521	148	74	743	222

UVM and FAHC Hook Ups

Two heat exchangers will be installed at the UVM central boiler plant in order to convert HTHW to steam. Two heat exchangers to convert the HTHW to steam will be also installed at the FAHC central boiler plant. The capital cost is estimated at $523,000 for UVM and $280,000 for FAHC. These costs will be borne by the district energy system.

MTHW Piping System

The MTHW system will be carbon steel pipe insulated with polyurethane and covered with polyethylene. The cost of MTHW piping from McNeil station is estimated at $4.9 million. The total stage two and three capital cost for the MTHW underground piping is estimated at $4.2 million.

Implementation Schedule

For the HTHW option, the first stage of the project is expected to be completed one year after financing becomes available. With the MTHW option, implementation of the project could not begin before the compleation of the retrofit of the UVM and FAHC buildings to hot water The second stage should be completed within five years thereafter. The third stage will be implemented gradually and should be completed within five more years.

Economic Analysis

The economic analysis is based on the following information:

- Financing is tax-exempt.
- Debt is 100%.

will be sufficient to pay the principal and interest on the bonds and cover all expenses, including the 3.5% city operating fee, and have the necessary debt coverage. The break-even cost after the implementation of the second stage is $7.61 per MMBtu, and at the end of the third stage is $7.93 per MMBtu.

MTHW option

For the first year, this cost is estimated at $8.76 per MMBtu and for the second year it is $7.79 per MMBtu. In other words, the heat price to all potential customers will be sufficient to pay the principal and interest on the bonds and cover all expenses, including the 3.5% city operating fee, and have the necessary debt coverage. The break-even cost after the implementation of the second stage is $7.21 per MMBtu, and at the end of the third stage is $7.65 per MMBtu.

Cooling Load Supply

HTHW district heating system also permits the supply of cooling by means of absorption chillers. This alternative can reduce electric cost for customers who have electric chilling. Operating cost comparisons between absorption chillers (with discount district heating rate) and electric chillers have demonstrated the advantage of absorption chillers.

District Heating and Cooling Rates

It is proposed to offer UVM and FAHC a heat rate equal to the break-even cost determined by the economic analysis. It is also proposed to offer them a discount heat rate for absorption cooling in the amount of $5/MMBtu. With the increase of the "renewable energy credits" to McNeil, in the coming years it may be possible to keep the district heating rate constant or even lower over a period as long as 10 years.

- Reduced pollution and elimination of smoke stacks. The McNeil station has an efficient pollution control system with a high stack height. The district energy system will permit elimination of CO_2 emissions (32,000 tons/year) and reduce other pollutants otherwise emitted by oil and natural gas fired heating plants. The McNeil station also provides added benefit of the ability to accurately measure emissions through it's state-of-the-art continuous emission monitoring system. The externality cost savings from pollutant reduction is estimated for HTHW system at $7.3 million and for MTHW system at $9.6 milliion over 20 years.

- Lower capital costs for customers, who need not purchase boilers, stacks, oil tanks, etc., and who can save valuable capital which they can invest elsewhere.

- Increased building space. Without boilers, customers (with the exception of UVM and FAHC) will have more space for lease or storage.

- Improved fire safety. No fuel is delivered, stored or fired at the customer buildings

- Increased reliability of energy supply. Twenty-four hour operation of the system by energy professionals provide high quality heat and cooling supply.

- Increased flexibility of fuel supply. McNeil fires Biomass in addition to natural gas and fuel oil presently used by the customers. The most economically available fuel can be easily used in the future after the distribution piping network is developed.

- Customer insurance costs are expected to go down

- Option 1 used the annual component of $280,172 for the total cost of replacement of the existing 4,800 hp UVM plant at $1,500/hp, and 2,800 hp back-up boilers at $1000/hp for the total cost of $9.97 million (1997 money). The annual component is an amount that has to be deposited in a 6.5% bearing account to accumulate the total cost with 3% escalation in 30 years. Option 2 assumes $189,610 for both: boiler retubing and equipment replacement.

Operation and Maintenance

- Five people were allocated for operation of the UVM central plant in accordance with UVM estimates.

The total first year savings are estimated at $2,450,941 based on option 1 assumptions and $1,159,137 with option 2 assumptions. The total second year savings are estimated at $15,692 based on option 1 assumptions and –400,120 with option 2 assumptions. JTC considers the option 1 assumptions to be conservative and expects the UVM savings with district heating to be higher. Net present value of savings for 20 years is estimated at $7.6 million for option 1 assumptions and $1.6 million for option 2 assumptions.

The net present value of pollutant externality cost savings for UVM is estimated at $3.7 million with HTHW. And at 4.9 million with MTHW.

Advantages for FAHC

The FAHC first and second year energy cost with and without the district heating is presented in Table 3a based on option 1 assumptions and in Table 3b for option 2 assumptions. The major assumptions are as follows:

- Overall boiler seasonal efficiency is 70% for both options

- Obtain official permission to waive the excavation fee issue by the City of Burlington.

Table S-2b
UVM HTHW, low savings assumption

Annual Expenditures for the UVM Central Plant	*Without District Heating (1st year)*		*Without District Heating (2nd year)*		*With District Heating (1st year)*		*With District Heating (2nd year)*		*Savings*	
	Total	*Unit Cost, $/MMBtu*	*Total*	*Unit Cost, $/MMBtu*	*Total*	*Unit Cost, $/MMBtu*	*Total*	*Unit Cost, $/MMBtu*	*1st year*	*2nd year*
FUEL										
Annual Fuel Cost, Including:	1,457,362	5.41	1,493,796	5.55	56,643	0.21	58,059	0.22	1,400,719	1,435,737
Gas	1,244,033		1,275,134		-		-		1,244,033	1,275,134
Oil	156,686		160,603		-		-		156,686	160,603
Back-up Boiler Fuel	56,643		58,059		56,643		58,059		-	-
CAPITAL COMPONENT										
New Backup Boiler 1,195 HP to be installed	1,800,000		-		-				1,800,000	
Boiler Retubing and Control: in 15 years	-		-		-				-	-
Capital Allocation for Equipment Replacement	189,610		189,610		70,000		70,000		119,610	119,610
Annual Debt Service for Existing Plant	190,000		190,000		190,000		190,000		-	
Total Capital Component	2,179,610	8.09	379,610	1.41	260,000	0.97	260,000	0.97	1,919,610	119,610
MAINTENANCE/OPERATIONS (NON-FUEL)										
Labor Cost	450,000		461,250		250,000		256,250		200,000	205,000
Annual Service Contracts	29,696		30,439		29,696		30,438		0	0
Annual Chemicals	22,588		23,153		22,588		23,153		0	0
Annual Parts Cost	99,797		102,292		99,797		102,292		-	-
Annual Insurance	17,184		17,614		17,184		17,614		-	-
Annual Water & Sewer	117,956		120,905		117,956		120,905		0	0
Annual Electric Cost	174,163		178,517		140,250		143,756		33,913	34,761
Annual Staff Training Cost	1,534		1,572		1,534		1,572		-	-
Annual Infrastructure Cost	129,823		133,068		129,823		133,068		-	-
Back-up Boiler O&M	10,000		10,250		10,000		10,250		-	-
Total Maintenance/Operations (non-fuel)	1,052,742	3.91	1,079,060	4.01	818,828	3.04	839,298	3.12	233,914	239,762
DISTRICT HEATING COST										
District Heating Cost[1]	-	0.00	-	0.00	2,395,106	8.89	2,195,229	8.15	(2,395,106)	(2,195,229)
TOTAL ANNUAL COST	4,689,714	17.41	2,952,466	10.96	3,530,577	13.11	3,352,586	12.44	1,159,137	(400,120)

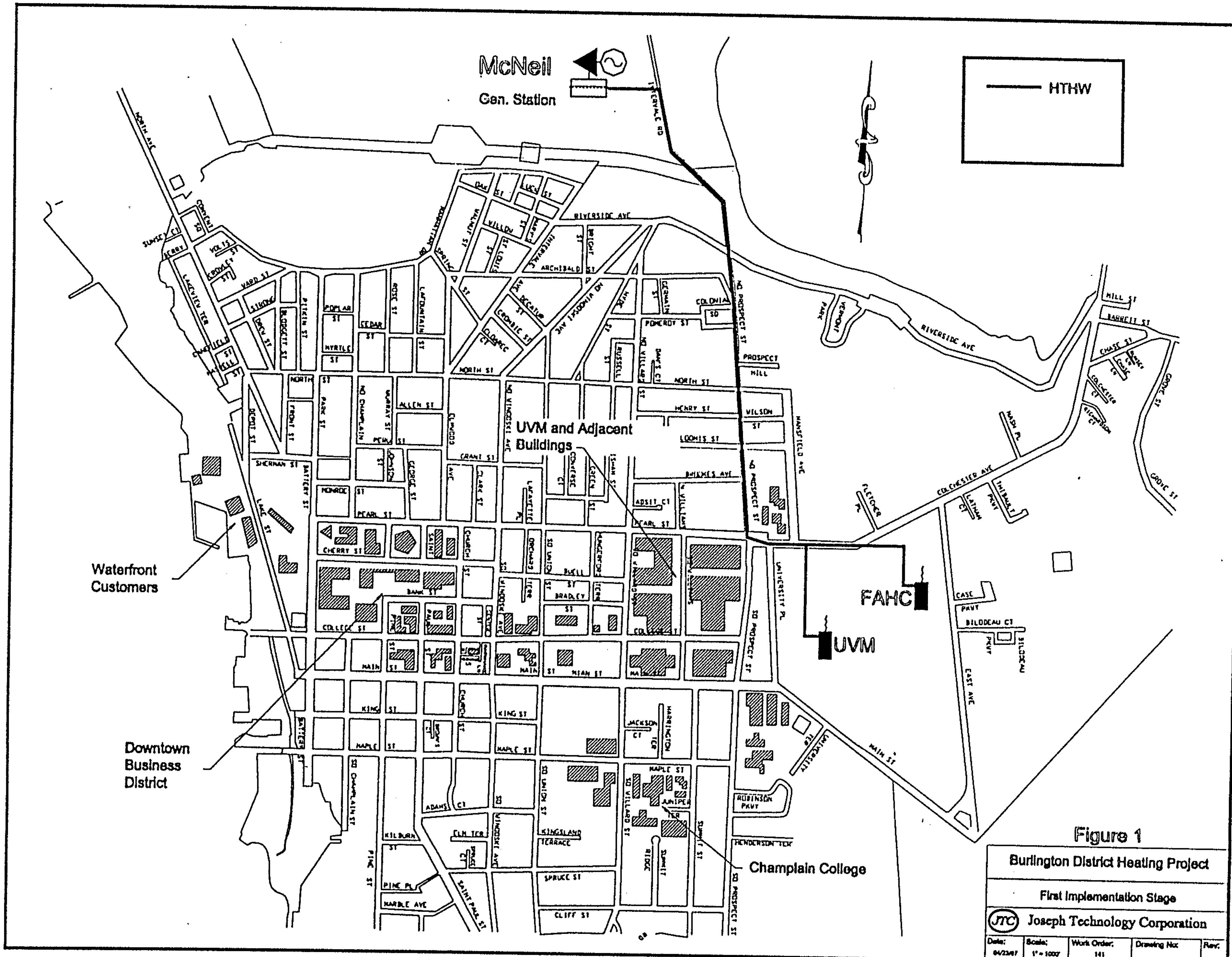
low savings assumption represent judgement of UVM

[1] The district heating rate of $8.89/MMBtu for the first year and $8.15 for the second year is based on UVM estimates for $72,000 to keep UVM boilers in stand-by and $53,000 natural gas cost for boiler room operation during McNeil shut-down

Table S-3b
FAHC HTHW, low savings assumptions

1994 - 96 Annual Expenditures for the FAHC Central Plant	Without District Heating (1st year) Total	Without District Heating (1st year) Unit Cost, $/MMBtu	Without District Heating (2nd year) Total	Without District Heating (2nd year) Unit Cost, $/MMBtu	With District Heating (1st year) Total	With District Heating (1st year) Unit Cost, $/MMBtu	With District Heating (2nd year) Total	With District Heating (2nd year) Unit Cost, $/MMBtu	Savings 1st year	Savings 2nd year
FUEL										
Annual Fuel Cost, Including:	703,272	5.95	720,854	6.10	3,863	0.03	3,960	0.03	699,409	716,894
Gas	689,947		707,196		3,863		3,960		686,084	703,236
Oil	13,325		13,658		-		-		13,325	13,658
CAPITAL COMPONENT										
Replace 2 - 600 BHP boilers (MCHV)	500,000				-		-		500,000	500,000
New 500 BHP boilers (for ACF)	200,000				-		-		200,000	200,000
Replace 100 BHP with 350 BHP (UHC)	150,000				-		-		150,000	150,000
Replace 500 BHP with 350 BHP (UHC)	175,000				-		-		175,000	175,000
Feedwater/Deaeration	300,000		300,000		-		-		300,000	300,000
Miscellaneous Improvements	260,000		210,000		-		-		260,000	260,000
Total First Year Capital Cost	1,585,000		510,000		-		-		1,585,000	1,585,000
Ammortized Annual Capital Cost, 6.5%, 20 years	143,849		143,849		-		-		143,849	143,849
Capital Allocation for Existing Equipment Replacement in 20 years	13,025		13,025		-		-		13,025	13,025
Annual Capital Component: 6.5%, 20 years	156,874	1.33	156,874.18	1.33	-	0.00	-	0.00	156,874	156,874
MAINTENANCE/OPERATIONS (NON-FUEL)										
Labor Cost	109,272		112,004		-		-		109,272	112,004
Annual Service Contracts	4,333		4,442		2,000		2,050		2,333	2,392
Annual Chemicals	25,196		25,826		25,196		25,826		0	0
Annual Parts Cost	2,439		2,500		488		500		1,951	2,000
Annual Insurance	10,674		10,941		5,337		5,470		5,337	5,471
Annual Water & Sewer	61,600		63,140		61,600		63,140		-	-
Annual Electric Cost	12,000		12,300		1,200		1,230		10,800	11,070
Total Maintenance/Operations (non-fuel)	225,515	1.91	231,153	1.96	95,821	0.81	98,216	0.83	129,694	132,936
DISTRICT HEATING COST	-	0.00	-	0.00	1,037,036	8.77	939,547	7.95	(1,037,036)	(939,547)
TOTAL ANNUAL COST	1,085,661	9.19	1,108,880	9.38	1,136,720	9.62	1,041,720	8.81	-51,059	67,157

The low savings assumptions represent the judgement of FAHC


McNeil
Gen. Station
HTHW
UVM and Adjacent Buildings
FAHC
UVM
Waterfront Customers
Downtown Business District
Champlain College
Figure 1
Burlington District Heating Project
First Implementation Stage
Joseph Technology Corporation
Date:
Scale:
Work Order:
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- UVM buildings currently not supplied from their central plant
- Champlain College
- Trinity College
- Mater Christi School
- Red Cross Building
- Taft School

<u>Third Stage</u>

Expand the MTHW system to the downtown and waterfront customers (Figure 3). This stage will include a gradual retrofit and hook-up these customers to the DH system. College Street was chosen for the downtown route because it has a minimum of underground interference's.

Section 2

DISTRICT HEATING LOADS

The DH loads and annual heat consumption of the potential customers is summarized in Table 1 for HTHW option and Table 1a for MTHW option. It is assumed that the retrofit of the UVM and FAHC to MTHW will result in the reduction of annual heat consumption by 20% (reduction in underground piping losses, steam trap losses and improvement of building controls). The heat load duration curves for the three implementation stages for HTHW option are presented in Figures 4, 5, and 6.

Table 1

Potential District Heating Load, HTHW

Implementation Stage	Customers	Peak Demand, MMBtu/hr.	Annual Heat Consumption, MMBtu/yr
First	UVM FAHC	137 56	270,000 124,000
Second	UVM buildings currently not supplied from their central plant, Trinity College, Master Christi School, Champlain College, Red Cross Building, Taft School	54	110,000
Third	Downtown and Waterfront Customers	53	108,000
TOTAL		300	611,000

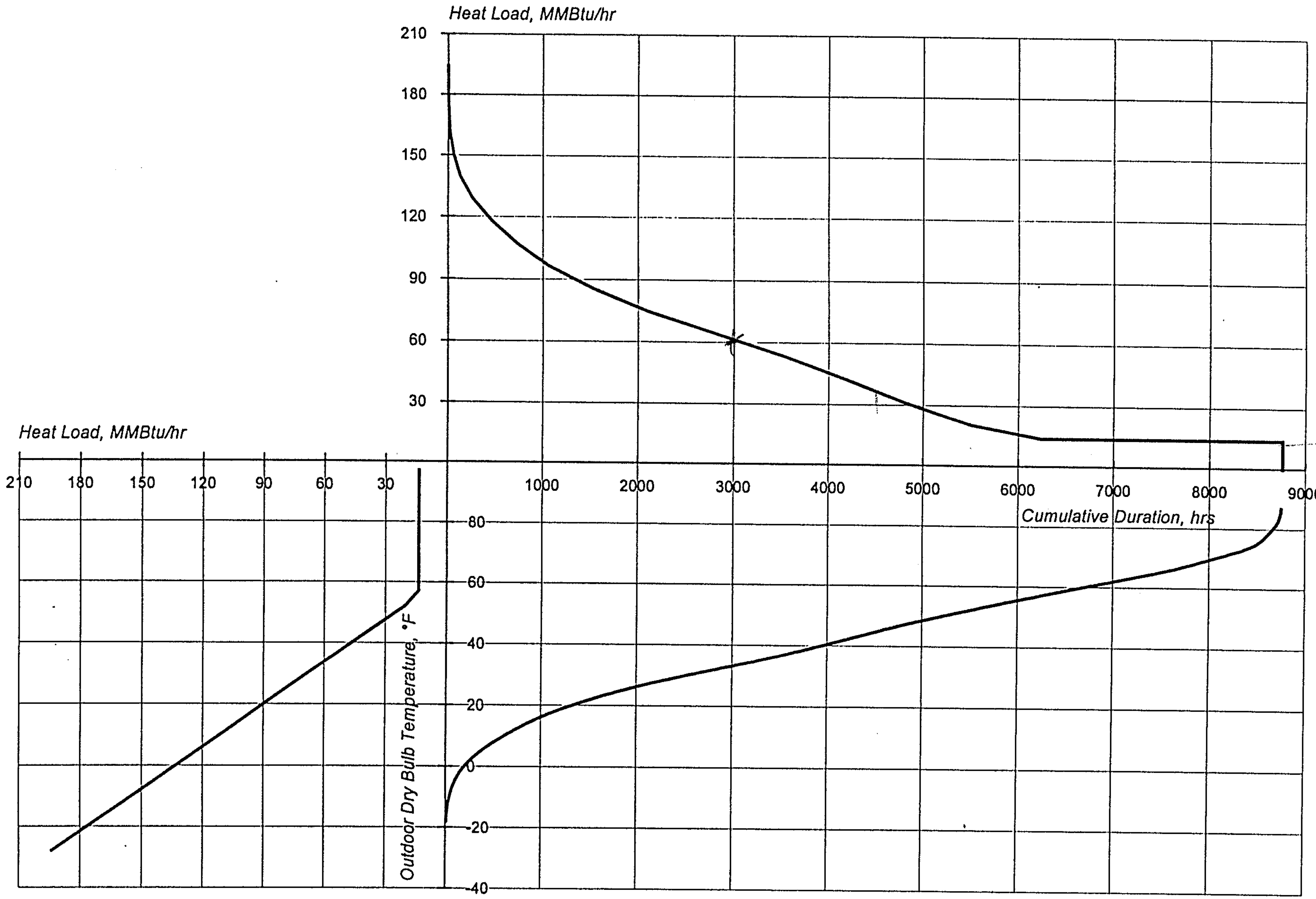


Figure 4. Heat Load Duration Curve for the First Implementation Stage

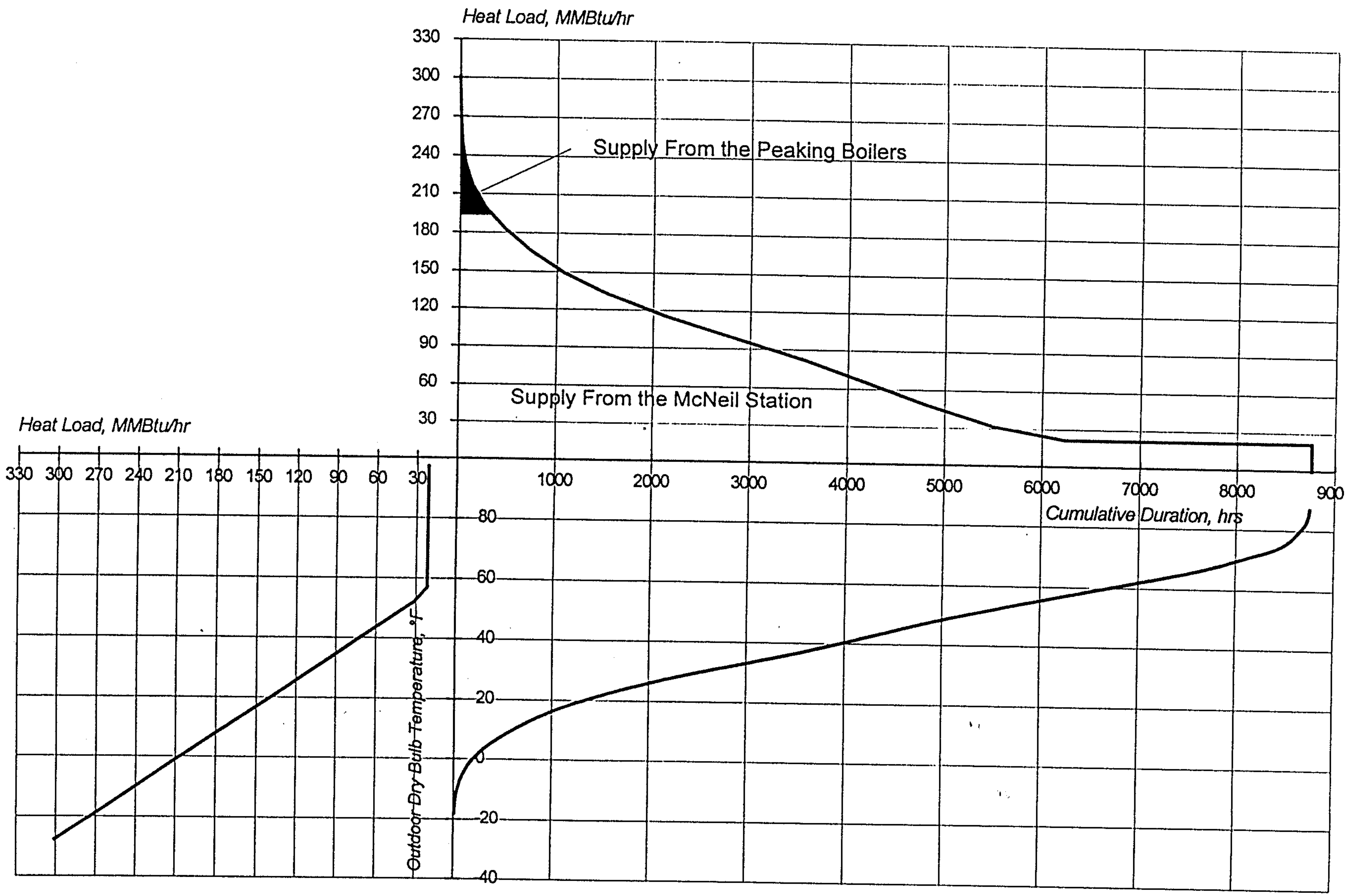
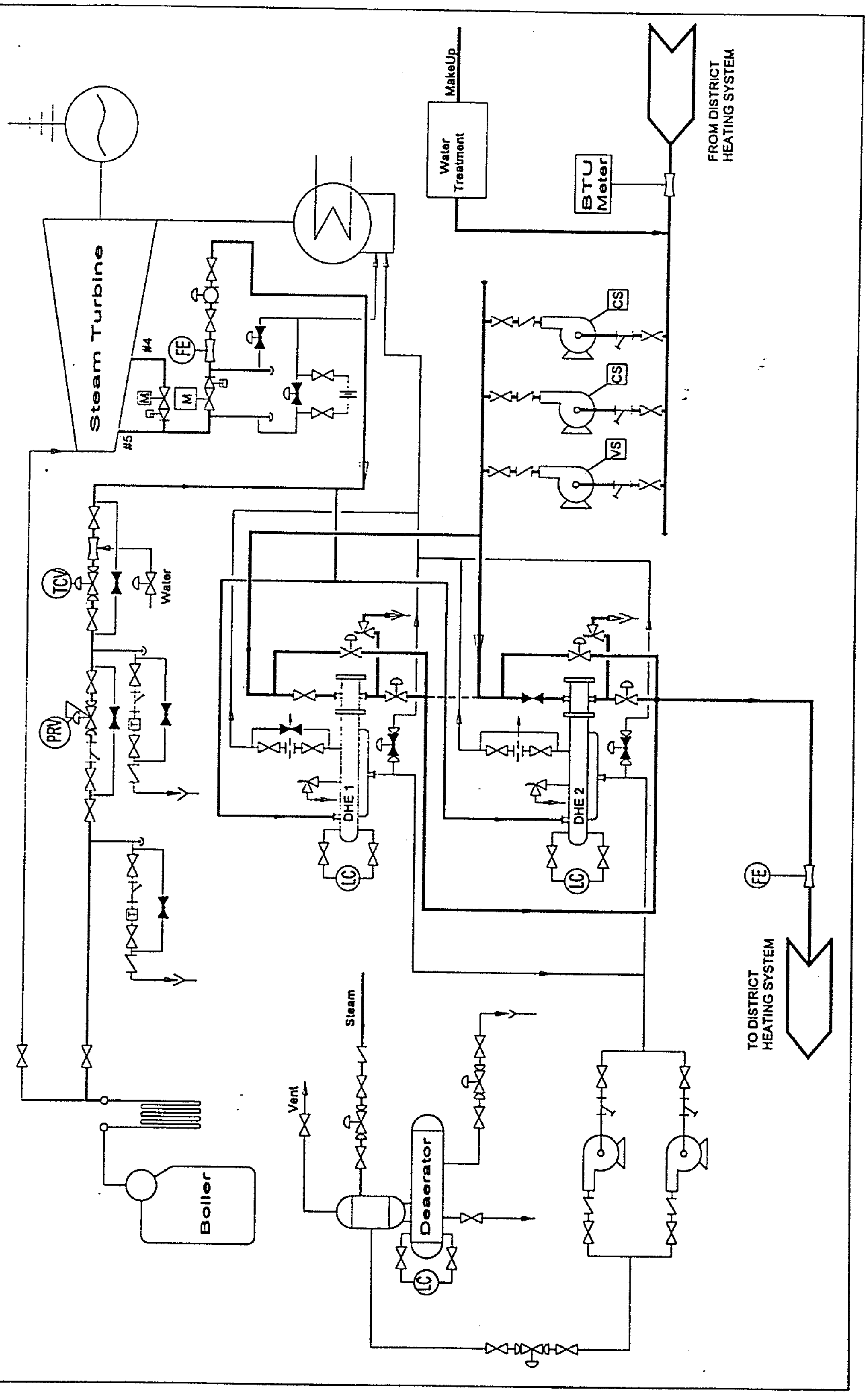


Figure 6. Heat Load Duration Curve for the Third Implementation Stage

Figure 7. DISTRICT HEATING HOT WATER SUPPLY DIAGRAM



Thermal Source Redundancy and Reliability.

The redundancy and reliability of the heat supply will be provided by the UVM and FAHC boiler plants or a newly built in the second and third project stage boiler plant. Table 3 presents the comparison of available heat supply capacity with peak heat demand with HTHW and MTHW options. The total McNeil boiler capacity is 521 MMBtu/hr, the maximum heat capacity which can be provided from McNeil turbine is 210 MMBtu/hr.

Table 3
Heat Supply Redundancy

Implementation Stage	Peak Heat Demand MMBtu/hr		Available Capacity, MMBtu/hr.				
	HTHW	MTHW	McNeil	UVM	FAHC	Total	With McNeil Boiler Out of Service
First	193	155	521	148	74	743	222
Second	247	198	521	148	74	743	222
Third	300	241	521	148	74	743	222

Table 3 shows that if the McNeil station boiler is down heat supply reliability for the first implementation stage is still assured. For the second and third implementation stages additional heat capacity will be required for HTHW option only. For the third stage the additional back-up capacity will be required for both options. This capacity can be supplied by existing larger boilers of downtown customers or installation of additional boilers at the UVM central plant (an addition to the central plant building will be required in this case).

The historic reliability record of modern district heating technologies proposed in this project is very high. Such district heating systems developed by JTC in Jamestown; JFK airport, NY; Springfield, MA; Manitowoc, WI; and cities in the former USSR never had any failures (the longest operating record for 14 years in Jamestown, NY).

Table 4
Capital Cost Estimate for HTHW Piping from McNeil Station

Items	*Size (ea)*	*No.*	*Total Cost*
Mechanical Work			
Straight Pipe with Casing*	16"	11100'	$1,438,560
Straight Pipe with Casing*	8"	4200'	$302,400
Expansion Loops	16"	60	$1,377,540
Expansion Loops	8"	22	$334,620
Elbows with Casing	16"	48	$172,800
Elbows with Casing	8"	18	$30,780
Anchors	16"	66	$142,560
Anchors	8"	26	$11,232
Total Trench Feet		9930'	
Manhole	16X16X8	1	$23,400
Valves for Manhole		2	$14,400
End Seals		4	$4,320
Subtotal			$3,852,612
Civil Work			
Trench Excavation*	16"	7500'	$1,606,500
Trench Excavation*	8"	2430'	$208,202
Site Restoration	16"	7500'	$688,500
Site Restoration	8"	2430'	$89,230
Subtotal			$2,592,432
SUBTOTAL			$6,445,044
Engineering, Construction Management (15% of Total)			$967,000
Contingency (10% of Total)			$645,000
TOTAL			$8,057,044

Note: The $14/sqft City of Burlington Surcharge for Street Opening is Not Included in the Cost Estimates
*The difference between the trench length (for example for 16" - 7500') and straight pipe length (for 16" - 11,100'/2 = 5,550') is attributed to the expansion loops.

UVM and FAHC Hook Ups

Two heat exchangers will be installed at the UVM central boiler plant in order to convert HTHW to steam (Figure 8). Two heat exchangers to convert the HTHW to steam will be also installed at the FAHC central boiler plant (Figure 9). The cost estimates for the UVM and FAHC hook-ups are presented in Tables 5 and 6.

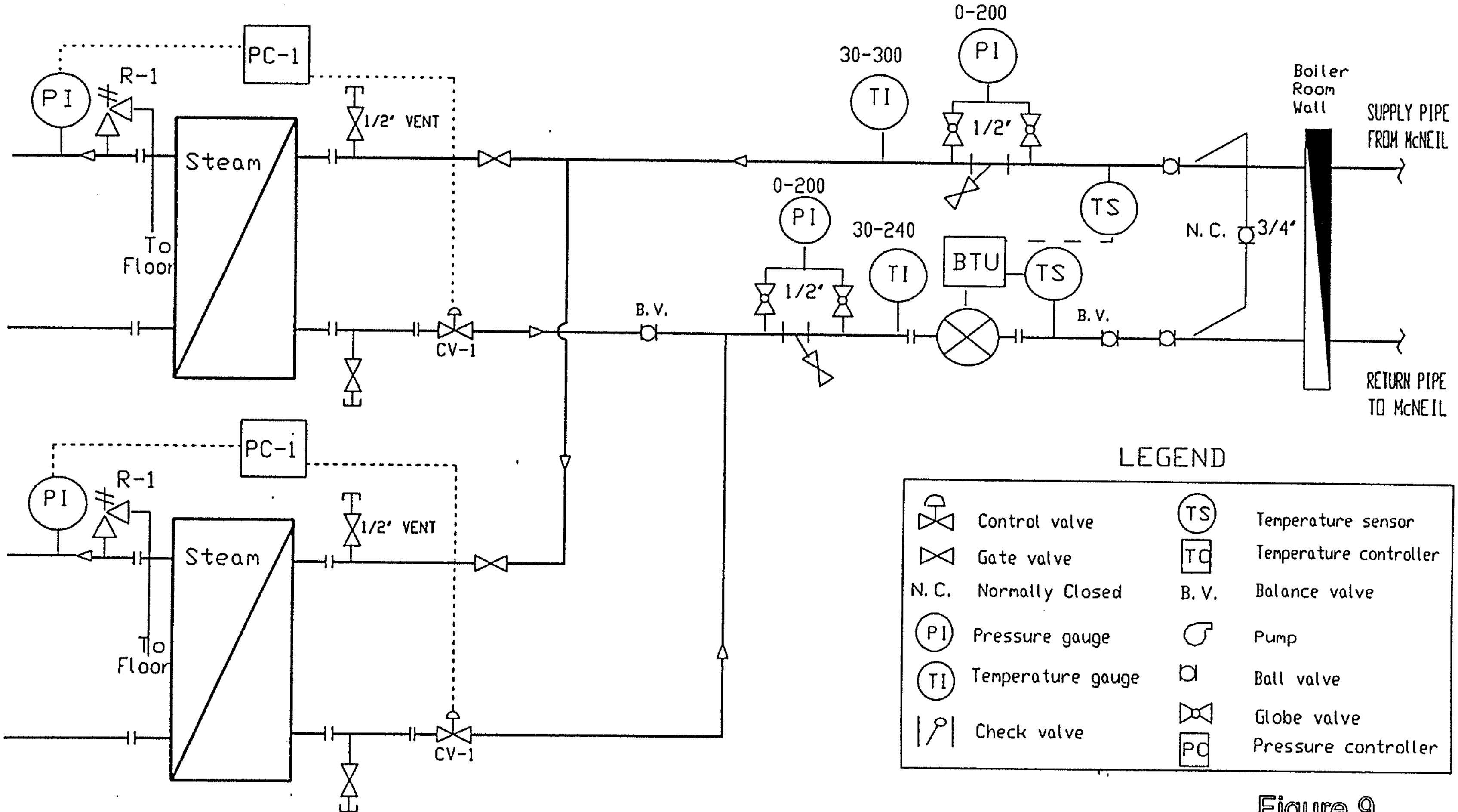


Figure 9

Burlington District Heating Project				
FAHC Hook-Up to District Heating				
JTC Joseph Technology Corporation				
Date: 04/25/97	Scale: N/A	Work Order: 141	Drawing No:	Rev:

Table 7
Capital Cost Estimate for MTHW Piping
(second and third implementation stages)

Items	*Size (ea)*	*No.*	*Total Cost*
Underground Piping			
Straight Pipe with Casing	10"	9800'	$932,927
Straight Pipe with Casing	8"	4200'	$290,531
Straight Pipe with Casing	5"	4000'	$184,464
Straight Pipe with Casing	3"	5000'	$148,230
District Heating Pumps (w/ 1 variable speed)	60 hp	3-50%	$57,000
Pump Concrete Pads		3	$10,000
Motor Control Panel		1	$22,000
Total Trench Feet		11500'	
Valves for Isolation		10	$135,000
Anchors		12	$129,600
End Seals & Valves (2/ customer)		120	$54,000
Subtotal			$1,963,751
Civil Work			
Trench Excavation	10"	9800'	$396,621
Trench Excavation	8"	4200'	$123,515
Trench Excavation	5"	4000'	$78,422
Trench Excavation	3"	5000'	$63,018
Site Restoration	10"	9800'	$297,211
Site Restoration	8"	4200'	$92,557
Site Restoration	5"	4000'	$58,766
Site Restoration	3"	5000'	$47,223
Subtotal			$1,157,335
SUBTOTAL			$3,121,086
Engineering, Construction Management (15% of Total)			$468,000
Contingency (20% of Total)			$624,000
TOTAL			$4,213,086

Note: The $14/sqft City of Burlington Surcharge for Street Opening is Not Included in the Cost Estimates presented in Figure 12. The analysis indicates that the minimum electric output of the station must be about 17 MW during the summer and 32 MW in the winter.

Table 8
McNeil Station Operating Parameters In Cogeneration Mode (HTHW)

DH Load Characteristics				DH Extractions					Steam Properties At DH Extractions					Fuel Consumption, MMBtu/hr		
Heat Load, MMBtu/hr	Supply Temp., °F	Return Temp., °F	DH Water Flow Rate, lb/hr	Extraction 4, MMBtu/hr	Extraction 5, MMBtu/hr	Extraction 4, lb/hr	Extraction 5, lb/hr	Min. Steam Flow Into Turbine, lb/hr	Pressure at Extract. 4 at Min. Steam Flow, psi	Pressure at Extract. 5 at Min. Steam Flow, psi	Saturation Temp. at Extract. 4, °F	Saturation Temp. at Extract. 5, °F	Min. Electric Generation, MW	Plant Total DH Mode	Condensing Cycle For The Same Electric Generation	Attributed To Heat
10	325	225	99,305	7	3	6,636	3,454	131,893	58	116	291	339	16	267	266	1
30	325	225	297,915	21	9	20,959	9,516	161,736	61	138	294	352	18	300	291	9
40	380	280	397,219	18	22	18,624	23,429	246,029	95	200	324	382	27	408	383	25
50	380	280	496,524	21	29	22,128	30,381	252,554	93	200	322	382	27	417	382	35
60	380	280	595,829	24	36	25,528	37,454	260,566	91	200	321	382	27	428	382	45
70	380	280	695,134	27	43	28,551	44,888	268,555	89	200	319	382	27	438	382	56
80	380	280	794,439	30	50	31,208	52,672	276,521	87	200	318	382	27	448	383	66
90	380	280	893,744	33	57	34,075	60,296	286,023	85	201	316	382	27	460	384	76
100	380	280	993,049	35	65	36,011	68,770	293,944	83	200	315	382	27	470	384	86
110	380	280	1,092,354	37	73	38,291	76,964	303,421	82	200	314	382	27	482	386	96
120	380	280	1,191,658	39	81	40,332	85,388	312,887	81	200	312	382	28	494	387	106
130	380	280	1,290,963	41	89	42,090	94,086	322,339	79	201	311	382	28	507	389	118
140	380	280	1,390,268	42	98	43,574	103,048	331,774	78	200	310	382	28	520	390	130
150	380	280	1,489,573	47	103	48,915	108,633	347,771	79	209	312	385	29	542	399	142
160	380	280	1,588,878	53	107	54,506	114,034	363,864	81	219	313	389	30	564	411	152
170	380	280	1,688,183	58	112	60,369	119,232	380,055	83	228	314	393	31	585	423	162
180	380	280	1,787,488	64	116	66,544	124,187	396,350	84	238	316	397	32	607	434	172

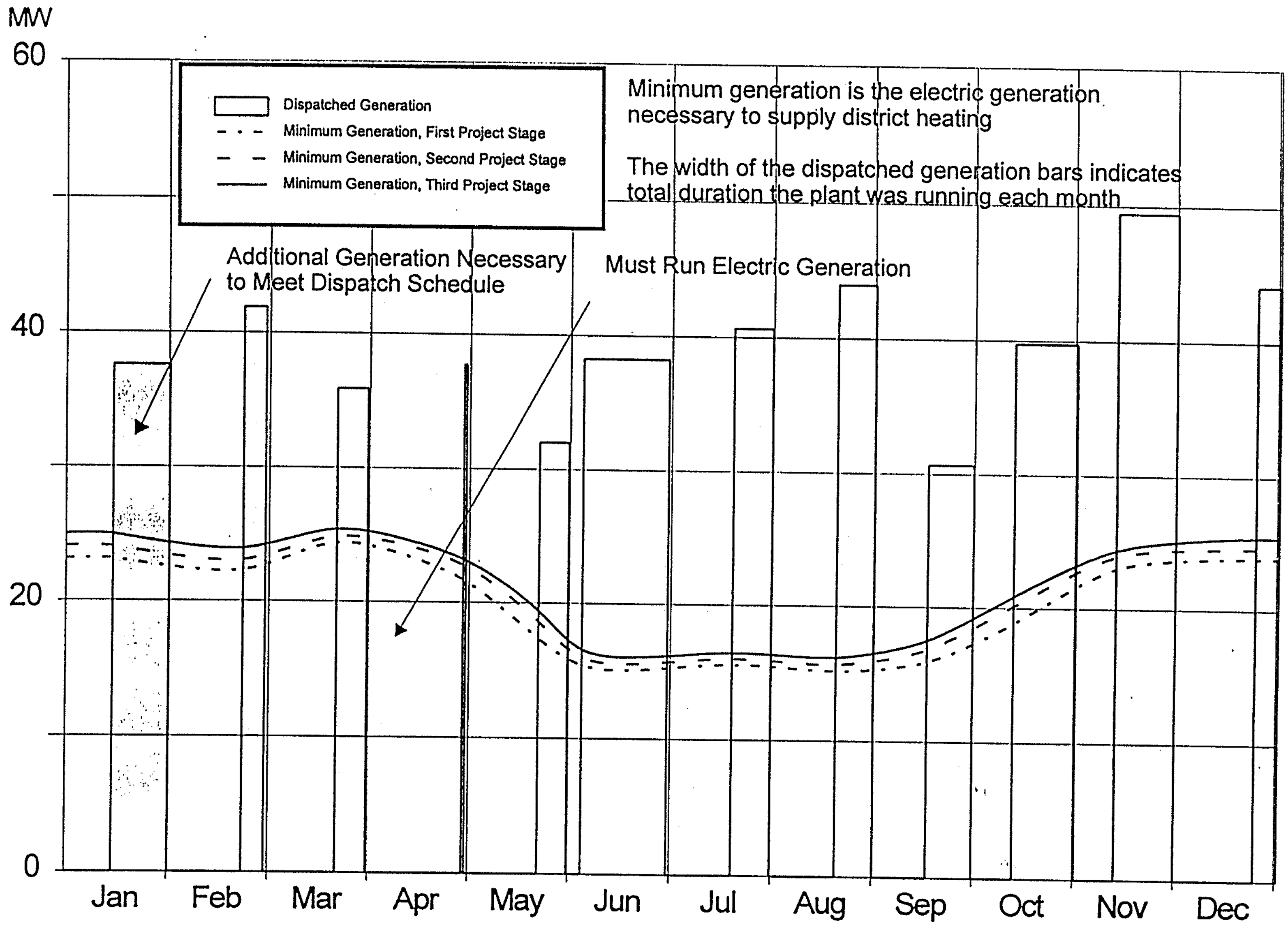
Table 9
McNeil Station Operation in DH Mode for First Implementation Stage (HTHW)

	Gross Heat Generation	Net Heat Supplied to Customers	Min. Power Generation	Dispatched Generation	Must Run Generation	Add-L Gen-N To Meet Dispatch	Total Gen-N In DH Mode (min. gen-n. plus add-l. gen-n.)	Total Fuel Input At Min Power Gen-N Mode	Total Fuel Input For The Same Electric Gen-N In Condensing Mode	Total Fuel Allocated For DH	Plant Fuel Utilization In Condensing Mode	Plant Fuel Utilization In DH Mode
	MMBtu	MMBtu	MWh	MWh	MWh	MWh	MWh	MMBtu	MMBtu	MMBtu		
January	68,907	65,462	17,216	15,326	7,777	4,796	22,012	326,762	266,930	59,832	22.0%	39.1%
February	60,252	57,239	15,533	6,786	11,917	2,478	18,011	292,985	241,079	51,906	22.0%	38.7%
March	55,200	52,440	18,139	7,998	12,702	2,604	20,743	328,509	284,027	44,482	21.8%	35.6%
April	32,744	31,107	15,617	792	15,161	346	15,963	275,916	254,129	21,787	21.0%	31.2%
May	19,148	18,190	12,897	6,919	9,152	3,268	16,165	234,707	226,273	8,434	19.5%	26.9%
June	12,089	11,485	11,052	15,336	4,897	9,585	20,637	206,440	203,494	2,946	18.5%	24.1%
July	11,742	11,155	11,536	11,234	7,252	7,600	19,136	216,342	213,934	2,409	18.4%	23.6%
August	11,793	11,203	11,242	15,698	5,848	10,684	21,926	210,595	208,028	2,568	18.4%	23.8%
September	14,517	13,791	11,439	10,152	6,180	4,907	16,346	211,099	206,112	4,987	18.9%	25.4%
October	24,467	23,244	13,998	17,968	5,494	9,560	23,558	251,502	238,082	13,420	20.1%	28.7%
November	40,440	38,418	16,564	21,420	6,603	11,786	28,350	294,369	264,889	29,480	21.3%	32.9%
December	62,844	59,702	17,759	7,328	13,797	3,179	20,938	329,790	276,985	52,805	21.9%	37.4%
Total	414,143	393,436	172,991	136,958	106,780	70,793	243,785	3,179,016	2,883,961	295,055	20.5%	31.6%

Table 10
McNeil Station Operation in DH Mode for Second Implementation Stage (HTHW)

	Gross Heat Generation	Net Heat Supplied to Customers	Min. Power Generation	Dispatched Generation	Must Run Generation	Add-L Gen-N To Meet Dispatch	Total Gen-N In DH Mode (min. gen-n. plus add-l. gen-n.)	Total Fuel Input At Min Power Gen-N Mode	Total Fuel Input For The Same Electric Gen-N In Condensing Mode	Total Fuel Allocated For DH	Plant Fuel Utilization In Condensing Mode	Plant Fuel Utilization In DH Mode
	MMBtu	MMBtu	MWh	MWh	MWh	MWh	MWh	MMBtu	MMBtu	MMBtu		
January	86,909	82,564	17,898	15,326	8,085	4,422	22,320	353,285	274,197	79,089	22.3%	41.9%
February	76,312	72,496	16,056	6,786	12,319	2,357	18,412	315,557	246,539	69,018	22.2%	41.5%
March	70,535	67,008	18,484	7,998	12,944	2,501	20,985	347,869	287,429	60,440	21.9%	38.4%
April	41,859	39,766	16,399	792	15,920	324	16,722	293,806	262,751	31,055	21.3%	33.3%
May	24,478	23,254	13,832	6,919	9,816	2,996	16,829	249,996	237,054	12,942	19.9%	28.7%
June	15,454	14,682	11,478	15,336	5,085	9,348	20,826	213,613	208,938	4,676	18.7%	25.6%
July	15,011	14,260	11,857	11,234	7,454	7,480	19,337	222,116	218,305	3,811	18.5%	25.0%
August	15,075	14,321	11,609	15,698	6,039	10,508	22,117	216,947	212,871	4,077	18.6%	25.2%
September	18,558	17,630	12,091	10,152	6,533	4,607	16,699	221,706	213,904	7,802	19.3%	27.0%
October	31,277	29,714	14,971	17,968	5,876	8,969	23,940	268,910	249,084	19,826	20.5%	30.6%
November	51,696	49,111	17,213	21,420	6,861	11,396	28,609	312,957	271,875	41,082	21.6%	35.3%
December	80,009	76,008	18,285	7,328	14,205	3,062	21,346	353,384	282,364	71,020	22.1%	40.3%
Total	527,172	500,814	180,173	136,958	111,137	67,969	248,142	3,370,146	2,965,310	404,837	20.7%	33.9%

Figure 12
McNeil Station Electric Generation in District Heating Mode



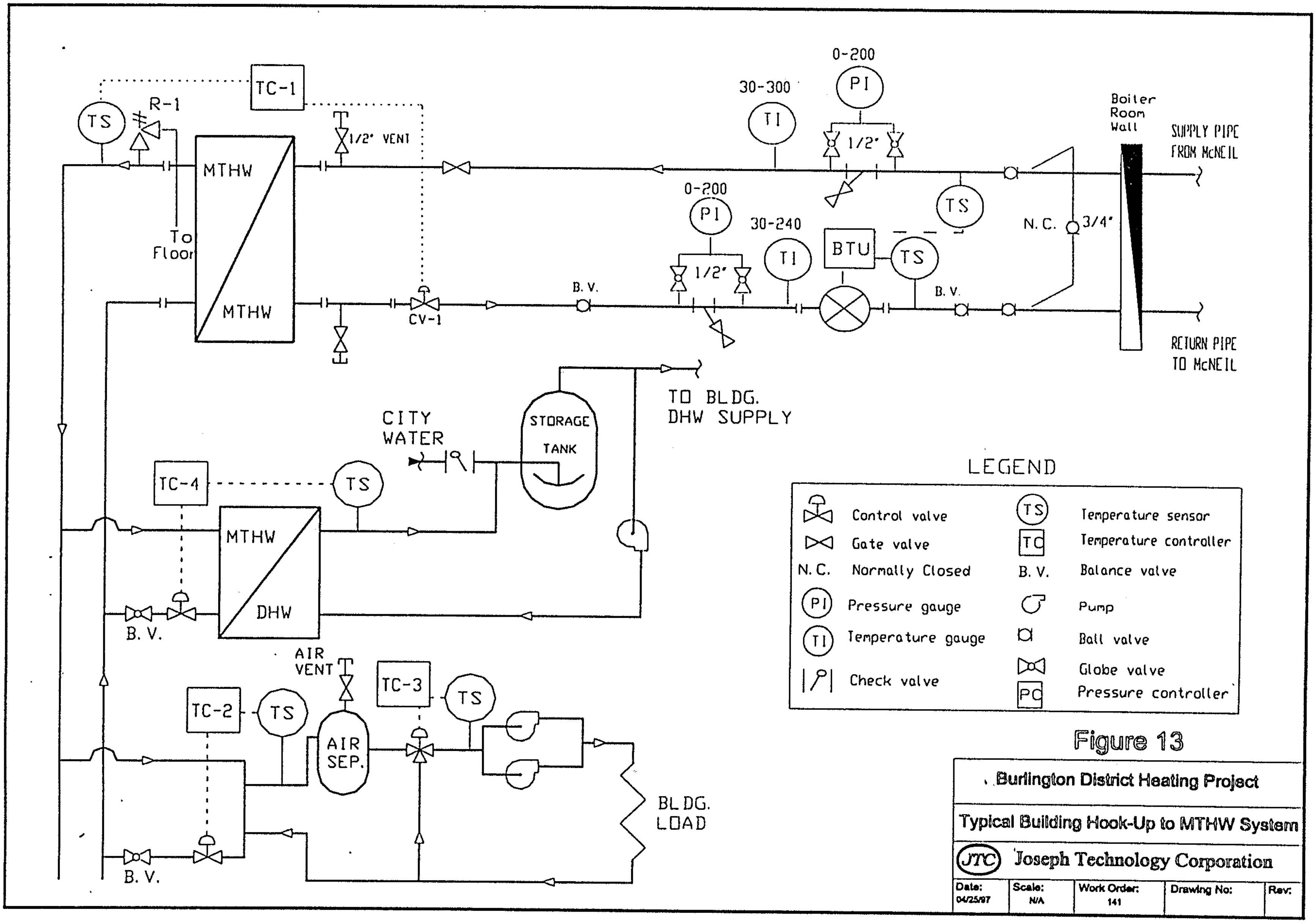

TC-1
TS
R-1
1/2" VENT
MTHW
MTHW
To Floor
CV-1
30-300
TI
0-200
PI
1/2"
0-200
PI
1/2"
30-240
TI
BTU
TS
TS
B. V.
B. V.
N. C.
3/4"
Boiler Room Wall
SUPPLY PIPE FROM McNEIL
RETURN PIPE TO McNEIL
TO BLDG. DHW SUPPLY
CITY WATER
STORAGE TANK
TC-4
TS
MTHW
DHW
B. V.
AIR VENT
TC-2
TS
AIR SEP.
TC-3
TS
BLDG. LOAD
B. V.
LEGEND
Control valve
Gate valve
N. C. Normally Closed
PI Pressure gauge
TI Temperature gauge
Check valve
TS Temperature sensor
TC Temperature controller
B. V. Balance valve
Pump
Ball valve
Globe valve
PC Pressure controller
Burlington District Heating Project
Typical Building Hook-Up to MTHW System
JTC Joseph Technology Corporation
Date: 04/25/97
Scale: N/A
Work Order: 141
Drawing No:
Rev:

Figure 13

Any existing steam load (such as sterilization and kitchen requirements) which will not function on hot water must be supplied with an alternate source of steam (small steam electric boilers).

The developed building retrofit costs are summarized in Table 12 for UVM and Table 13 for FAHC. The total building retrofit cost is estimated at $2.8 million for UVM and $0.8 million for FAHC.

The total UVM and FAHC retrofit cost was estimated at $5.1 million (Table 14). A capital cost of installation of MTHW transmission piping from McNeil station to UVM and FAHC was estimated at $4.9 million (Table 15). This is $3.1 million less than the cost of stallation of HTHW piping.

The MTHW supplied from the McNeil station will be separated from UVM and FAHC systems by heat exchangers similar to the HTHW option.

McNeil Station

Cycle analysis was performed for McNeil station MTHW option. Lower heating medium temperature allows higher utilization of extraction #4. This increases cogeneration and fuel utilization rates.

A station heat balance analysis was performed for the range of DH loads assuming MTHW supply temperature requirements. The minimum generation and heating fuel consumption were evaluated for each heating load. The results of this analysis are presented in Table 16.

The bin method was used to calculate monthly fuel consumption, minimum and must-run generation and other important quantities for each proposed project implementation stage (Tables 17 - 19).

Table 13
FAHC Building Retrofit Cost

Building	Space heating-distribution inside the building LTW/LPS	Domestic HW HW/HPS/LPS	Type of Humidification System	Asbestos Abatement	Building Retrofit Cost	Asbesto Removal Cost	Humidification Retrofit Cost	Total Retrofit Cost
Mc Clure	LTW	LPS	Steam	Y	4,000	1,500	52,974	58,474
Medical Records	LTW	LPS		Y	4,000	1,500	-	5,500
Fletcher	LPS	LPS		Y	52,390	1,500	-	53,890
Engineering	LPS	LPS		Y	62,376	1,500	-	63,876
Adams	LTW	LPS		Y	4,000	1,500	-	5,500
Shepardson S.	LPS	LPS	Steam	Y	76,648	1,500	7,265	85,413
Baird	LTW/LPS	LPS	Steam	Y	143,394	1,500	27,879	172,773
Smith	LTW/LPS	LPS	Steam	Y	65,256	1,500	12,251	79,007
Patrick	LPS	LPS	Steam	Y	111,840	1,500	10,784	124,124
Brown	LTW/LPS	LPS	Steam	Y	36,738	1,500	6,548	44,786
Shepardson N.	LTW/LPS	LPS	Steam	Y	65,050	1,500	12,210	78,760
Burgess	LTW	Electric		Y	4,000	1,500	-	5,500
TOTAL					**629,692**	**18,000**	**129,910**	**777,602**

Table 16
McNeil Station Operating Parameters In Cogeneration Mode (MTHW)

DH Load Characteristics				DH Extractions					Steam Properties At DH Extractions					Fuel Consumption, MMBtu/hr		
Heat Load, MMBtu/hr	Supply Temp., °F	Return Temp., °F	DH Water Flow Rate, lb/hr	Extraction 4, MMBtu/hr	Extraction 5, MMBtu/hr	Extraction 4, lb/hr	Extraction 5, lb/hr	Min. Steam Flow Into Turbine, lb/hr	Pressure at Extract. 4 at Min. Steam Flow, psi	Pressure at Extract. 5 at Min. Steam Flow, psi	Saturation Temp. at Extract. 4, °F	Saturation Temp. at Extract. 5, °F	Min. Electric Generation, MW	Plant Total DH Mode	Condensing Cycle For The Same Electric Generation	Attributed To Heat
10	250	160	110,339	10	0	10,108	-	131,918	58	120	291	341	16	267	266	1
30	250	160	331,016	30	0	30,426	-	161,664	61	147	294	357	18	300	292	7
40	250	160	441,355	40	0	40,635	-	176,609	63	160	295	364	19	320	305	15
50	250	160	551,694	50	0	50,877	-	191,605	64	174	297	370	20	338	317	22
60	250	160	662,032	60	0	61,151	-	206,646	66	188	299	377	21	356	328	28
70	250	160	772,371	70	0	71,454	-	221,729	67	201	300	382	22	375	339	36
80	250	160	882,710	80	0	81,788	-	236,858	68	215	301	388	23	396	349	47
90	250	160	993,049	89	1	91,181	1,016	252,097	70	228	303	393	24	416	359	58
100	250	160	1,103,387	89	11	91,181	11,850	267,957	72	232	304	394	25	437	367	70
110	250	160	1,213,726	89	21	91,181	22,720	283,872	73	236	306	395	26	458	375	83
120	250	160	1,324,065	89	31	91,181	33,628	299,840	75	239	307	397	27	478	382	96
130	250	160	1,434,404	89	41	91,181	44,568	315,856	76	243	309	398	28	498	389	109
140	250	160	1,544,742	88	52	91,181	55,544	331,926	78	247	310	400	29	520	397	124
150	250	160	1,655,081	88	62	91,181	66,556	348,047	79	251	312	401	30	542	407	135
160	250	160	1,765,420	88	72	91,181	77,587	364,197	81	255	313	403	31	564	418	146
170	250	160	1,875,759	88	82	91,181	88,649	380,392	83	259	314	404	32	586	428	157
180	250	160	1,986,097	88	92	91,181	99,746	396,637	84	262	316	405	33	607	439	168

Table 19

McNeil Station Operation in DH Mode for Final Implementation Stage (MTHW)

	Gross Heat Generation	Net Heat Supplied to Customers	Min. Power Generation	Dispatched Generation	Must Run Generation	Add-L Gen-N To Meet Dispatch	Total Gen-N In DH Mode (min. gen-n. plus add-l. gen-n.)	Total Fuel Input At Min Power Gen-N Mode	Total Fuel Input For The Same Electric Gen-N In Condensing Mode	Total Fuel Allocated For DH	Plant Fuel Utilization In Condensing Mode	Plant Fuel Utilization In DH Mode
	MMBtu	MMBtu	MWh	MWh	MWh	MWh	MWh	MMBtu	MMBtu	MMBtu		
January	91,037	86,485	17,559	15,326	7,932	4,608	22,167	348,316	271,852	76,464	22.0%	43.3%
February	80,134	76,128	15,693	6,786	12,040	2,441	18,134	310,304	243,831	66,472	22.0%	43.1%
March	74,535	70,808	16,910	7,998	11,841	2,973	19,882	326,779	272,754	54,025	21.2%	40.5%
April	44,263	42,049	13,886	792	13,481	397	14,283	261,904	238,111	23,793	19.9%	35.0%
May	25,888	24,593	12,482	6,919	8,858	3,388	15,870	233,338	223,765	9,572	19.0%	29.4%
June	16,348	15,531	11,378	15,336	5,041	9,404	20,782	212,292	208,396	3,896	18.6%	26.0%
July	15,880	15,086	11,972	11,234	7,526	7,438	19,410	223,391	220,013	3,378	18.6%	25.4%
August	15,947	15,150	11,646	15,698	6,058	10,490	22,136	217,282	213,753	3,529	18.6%	25.6%
September	19,629	18,648	11,450	10,152	6,186	4,902	16,352	213,779	207,806	5,973	18.8%	27.5%
October	33,076	31,423	13,082	17,968	5,134	10,117	23,198	245,348	230,448	14,899	19.4%	31.7%
November	54,663	51,930	14,874	21,420	5,929	12,802	27,676	282,857	249,186	33,671	20.4%	37.3%
December	84,294	80,080	17,440	7,328	13,549	3,250	20,690	341,942	274,945	66,996	21.6%	42.1%
Total	555,695	527,910	168,372	136,958	103,577	72,209	240,581	3,217,530	2,854,860	362,670	20.1%	35.1%

of the revenue from the DH system to contribute to McNeil's economic viability. Part of this contribution will be paid by district heating system as penalties for must run generation. By paying the must run penalties the DH system will effectively increase McNeil's capacity factor.

Current Station Operations

Currently, McNeil is dispatched as part of NEPOOL on the basis of its operating expenses, consisting of fuel and other production (but not capital) costs. Because of the presence of Vermont Yankee ($4.48/MWh reported) and 100 MW of comparably cheap hydro in Vermont, McNeil, with total production expenses of around $40/MWh (see below) is dispatched on the long shoulder of the system load duration curve. This results in erratic calls on the station's capacity, both in terms of how many hours a day it is called on and what power level it is called on to operate at, which is apparently rarely its full rating. Historical data are shown in Table 20. The heat rate, which varies with power, is taken from the 1996 tests of the station.

Table 20

Historical Utilization of McNeil Station

	Operating Hours per Month	Average Power (MW)	Capacity Factor (%)	Heat Rate Btu/kWh
1996	287	39	31.1	14,760
1995	299	38	31.1	14,850
1994	204	34	20.6	15,340
1993	403	39	19.0	14,760
1992	321	40	35.5	14,650
1991	180	40	19.6	14,650

A linear regression on historical fuel costs (Figure 14) indicates that the price of wood fuel has actually been falling steadily at $0.15/ton per year and gives a price of $17.50 per ton in 1996, close to actual cost in 1996 of $17.32/gr.ton.

Table 21
FERC "Form 1"

Line No.	Item (a)	Plant Name: * Joseph McNeil (f)			Line No.
1	Kind of Plant (Steam, Internal Combustion, Gas Tutbine or Nuclear)	Steam			1
2	Type of Plant Construction (Conventional, Outdoor Boiler, Full Outdoor, Etc.)	Conventional			2
3	Year Originally Constructed	1984			3
4	Year Last Unit was Installed	1984			4
5	Total Installed Capacity (Maximum Generator Name Plate Ratings in MW)	6.50			5
6	Net Peak Demand on Plant -- MW (60 minutes)	7			6
7	Plant Hours Connected to Load	3882			7
8	Net Continuous Plant Capability (Megawatts)	7			8
9	When Not Limited by Condenser Water	0			9
10	When Limited by Condenser Water	0			10
11	Average Number of Employees	39			11
12	Net Generation, Exclusive of Plant Use -- KWh	$17,545,000			12
13	Cost of Plant: Land and Land Rights	$759			13
14	Structures and Inprovements	$2,179,942			14
15	Equipment Costs	$6,374,292			15
16	Total Cost	$8,554,993			16
17	Cost per kW of Installed Capacity (line 5)	$1,316			17
18	Production Expenses: Oper. Supv. & Engr.	$14,144			18
19	Fuel	$579,324			19
20	Coolants and Water (Nuclear Plants Only)	$73,346			20
21	Steam Expenses	$0			21
22	Steam From Other Sources	$0			22
23	Steam Transferred (Cr.)	$0			23
24	Electric Expenses	$29,731			24
25	Misc. Steam (or Nuclear) Power Expenses	$35,558			25
26	Rents	$0			26
27	Allowances	$0			27
28	Maintenance Superviesion and Engineering	$13,099			28
29	Maintenance of Structures	$6,629			29
30	Maintenance of Boiler (Or Reactor) Plant	$30,405			30
31	Maintenace of Electric Plant	$19,805			31
32	Maintenance Misc. Steam (or Nuclear) Plant	$5,097			32
33	Total Production Expenses	$807,138			33
34	Expenses per Net kWh	$0.05			34
35	Fuel: Kind (Coal, Gas, Oil, or Nuclear)	oodchip	Oil	Gas	35
36	Unit: (Coal - tons of 2,000 lb.) (Oil - barrels of 42 gals.) (Gas - Mcf) (Nuclear - indicate)	Tons	Barrels	Mcf	36
37	Quantity (Units) of Fuel Burned	2,137	17	1,582	37
38	Avg, Heat Cont. of Fuel Burned (Btu per lb. of coal, per gal of oil, or per Mcf of gas) (Give unit if nuclear)	4,750	136,491	1,002,476	38
39	Average Cost of Fuel per Unit, as Deliverd f.o.b. Plant During Year	$23.720	$23.840	$1.960	39
40	Average Cost of fuel per Unit Burned	$24.820	$25.000	$1.960	40
41	Avg. Cost of Fuel Burned per Million Btu	$2.610	$4.360	$1.960	41
42	Avg. Cost of Fuel Burned per kWh Net Gen	$0.036	$0.000	$0.039	42
43	Average Btu per kWh Net Generation	$13,955	$0	$16,943	43

well below production costs as calculated above because a substantial part of the total production costs are being reported elsewhere as fixed expenses, such as capacity charges or fixed operations expenses, which are added to the rate base and charged to customers independent of the amount of energy generated. We will see in a following section that this is a common practice - that almost all generation stations report only a portion of their total costs of production as the energy costs that govern dispatch. As a result, NEPOOL "marginal generation costs" are substantially below the rates that will actually govern dispatch after restructuring.

Although in this study, for simplicity and clarity, we will continue to roll all charges together into an energy cost, we do not mean that all electric energy sales contracts after restructuring will have only an energy-related charge. Contracts may have fixed components and capacity-related components as well as energy-related components. But all of these cost components will be directly associated with the sale of a specified block of power and/or energy, in contrast to the situation today when significant charges are associated with the existence of the station, but not with whether it is dispatched or not. Nuclear power plants, with very large O&M charges, are the most prominent example of this.

As a result, the only way to estimate McNeil's performance with or without DH or renewable energy credits is to compare its <u>full</u> costs to the <u>full</u> costs of providing energy from the other generators in or contributing to NEPOOL. We begin this process in subsequent sections.

<u>Characterization of Other Electric Generation Stations in Vermont</u>

To establish McNeil's prospects in a restructured era, it is necessary to have an accurate characterization of the other power plants with which it will be competing to provide electric energy. We found in the previous section that historically reported "pool marginal costs" do not reflect the actual costs of running generation stations, so in this section we present data on the other generating stations in Vermont. Because it will be useful when discussing the plans for restructuring the industry, the stations are broken out by type, with those that will the cumulative energy provided in 1995 at or below the value in the "Production Cost" column. Similar statistics should apply to the hydro units in the lower half of the table, and the same average production cost of \$8/MWh is assumed for these dams, also. Generation and production at the non-renewable 140 MW S. C. Moore station is not available and is estimated from the first set of hydro stations in the same way.

Green Mountain Power has installed several wind turbines shown in Table 24. Two of them date from 1989. No current data was readily available on them, but is not worth pursuing because they are so small. Eleven 550 kW turbines were erected last fall. They experienced operational difficulties during the winter and are being re-furbished. The 14.4 GWh generation figure is a prediction. The capital costs are quite high, but should be covered by stranded costs settlements, leaving only fairly low estimated operating expenses if the units work reliably.

Biomass and landfill methane plants are shown in Table 25. We have not been able to obtain the operation costs for the plants in this category other than McNeil, but except for the Rygate plant owned by Catamount Energy and CRSS, they are quite small. Table 26 shows the non-renewable generation in Vermont, including a set of little-used peaking units and the 53% share of the Vermont Yankee nuclear station owned by Vermont utilities.

BED has supplied current energy prices for McNeil (incremental price of \$23.98/MWh) and Vermont Yankee (\$4.48/MWh) which are considerably lower than the production costs listed in Tables 23, 24 and 25. In the case of Vermont Yankee, the BED-supplied energy price is close to the cost of fuel alone found on the FERC Form 1. The rest of operations and maintenance, which brings the total production cost up to the \$23.80/MWh cited in Table 26, are not counted in the energy prices used as the basis of current dispatch but are currently passed back to customers as fixed costs entered into the "rate base". The similar treatment of McNeil was discussed above, and other generation stations are presumably treated the same. As discussed in the previous section, only the total non-capital costs of generation can serve as a reliable basis for estimating post-restructuring economic performance.

Table 24
Vermont Wind Generators

Name	Owner	Ln#	Year Built	Capacity MW (NP)	Generation MWh	Capacity Factor	Cost k$	Cap@10% $/MWh	Operation k$	Maint. k$	ProdCst $/MWh	Cumulative MWh
Carthusians	GMPC	1	1989	0.1								
Carthusians	GMPC	2	1989	0.1	predicted:						estimate:	
Searsburg	GMPC	1	1996	6.1	14,400	27.2%	10,400	72.2	29	115	10.0	14,400
Total:				6.3	14400							

Table 25
Vermont Biomass

Name	Owner	Ln#	Year Built	Capacity MW (NP)	Generation MWh('95)	Capacity Factor	Cost k$	Cap@10% $/MWh	Operation & Fuel k$	Maint. k$	ProdCst $/MWh	Cumulative MWh
Rygate	Catamount Energy and CRSS			20.3	174,271	98%	<estimate	?				355,233
McNeil	**BED, others**		**1984**	**50.0**	**159,500**	**36.4%**	**77,773**	**48.8**	**6,655**	**682**	**46.0**	**180,962**
Landfill Methane	ZAPCO			1.0	6,132	70%	<estimate	?			?	21,462
Simpson	Simpson Paper			3.0	13,140	50%	<estimate	?			?	15,330
Sawmills (~6)	Various		?	0.5	2,190	50%	<estimate	?			?	2,190
Total:				74.8	355,233							

Table 26
Vermont Non-Renewable Generation

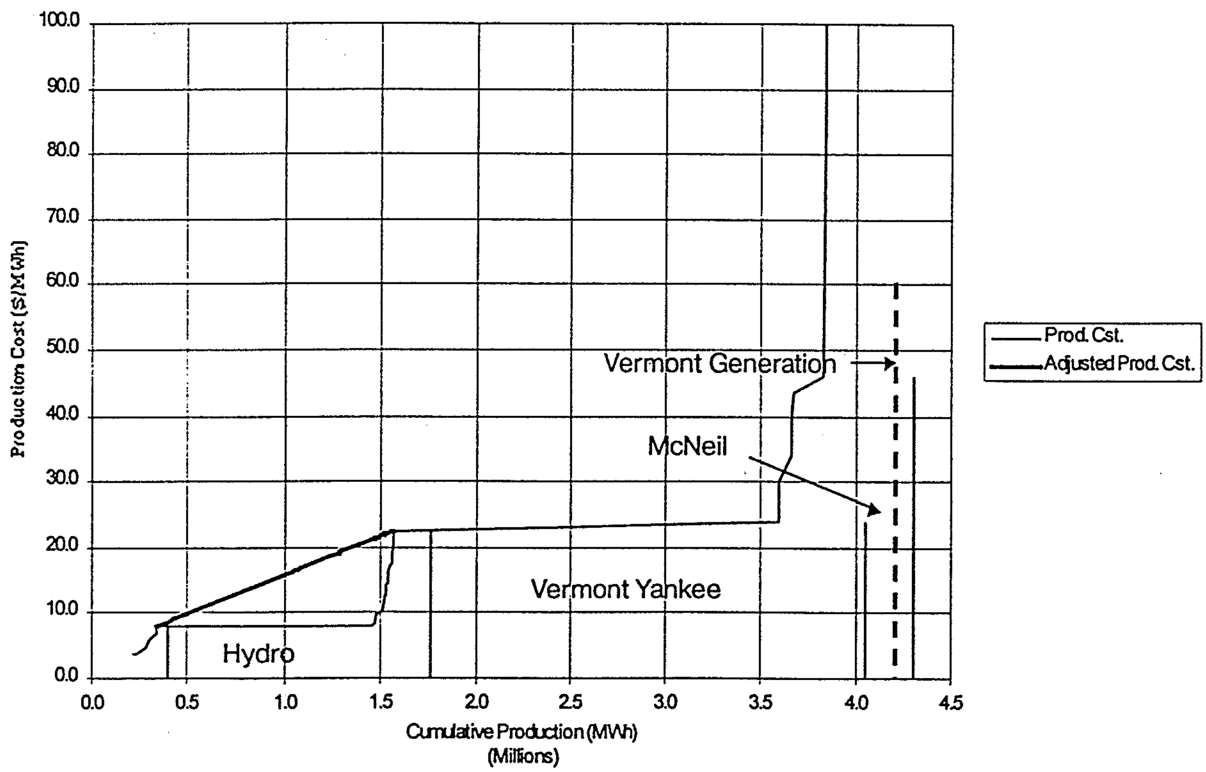
Name	Owner	Ln#	Year Built	Capacity MW (NP)	Generation MWh('95)	Capacity Factor	Cost k$	Cap@10% $/MWh	Operation & Fuel k$	Maint. k$	ProdCst $/MWh	Cumulative MWh
Colchester GT	GMPC		1965	18.0	305	0.2%	1,664	545.6	52	61	369.8	2,118,712
Ascutney GT	CVPS		1961	13.2	803	0.7%	2,013	250.8	166	35	250.1	2,118,407
Rutland GT	CVPS		1962	13.2	994	0.9%	1,437	144.5	168	61	230.1	2,117,604
Various Diesels				20.4	1,787	1.0%		0.0			146.0	2,116,610
Berlin 5 GT	GMPC		1972	41.9	5,550	1.5%	4,796	86.4	418	48	83.9	2,114,823
Burlington GT	BED		1971	28.0	3,709	1.5%		0.0			83.9	2,109,273
Wyman	GMPC		1978	7.0	6,436	10.5%	281	4.4	281	0	43.7	2,105,564
Stony Brook	GMPC		1981	30.2	63,683	24.1%	10,039	15.8	2,031	142	34.1	2,099,128
Vermont Yankee	CVPS,GMP,BED=55%		1972	297.0	2,035,445	78.2%	195,207	9.6	32,712	15,802	23.8	2,035,445
Total:				468.9	2,118,712							

monopolistic or collusive distortion of the market by GenCo's, the bid system should result in a market which works like the pool did, only more accurately. That is, every producer is brought on line in order of increasing marginal cost of production, and every producer receives revenue equal to the integrated product of his production times the hourly pool marginal cost of production over the period when pool marginal cost exceeds his cost of production. The difference is that because there is no longer a "rate base" to cover many of the expenses, dispatch and pool marginal costs will be dictated by at least the total production and new capital costs associated with each generation station.

There is a special set of conditions for municipal utilities such as BED (S-062, §8015). Munis will be allowed to remain vertically integrated, retaining control of their generation plant. They are assured rates which will allow recovery of prudent operating costs for transmission and distribution as well as all existing stranded costs. However, "a municipal electric utility, an electric cooperative, or a small electric company engaged in the provision of competitive retail and generation services after January 1, 1997, shall not be assured recovery of costs associated with those activities " (S-062, §8015 (k)). In other words, BED can sell power to itself, but it must do so on a competitive basis; the board will not permit the pass-through of above market operating expenses. It is therefore important to determine how McNeil is likely to be dispatched in the competitive market.

Although dispatch will continue to be coordinated by NEPOOL or a successor organization at a regional level, a study of Vermont as if it were a power pool lends insight into how McNeil will be dispatched. All of the units in Tables 23-26 are combined and ordered by total production costs in Table 28. The cumulative energy produced at each price level is shown in the right-hand column and graphed in the Figure 16. A few units for which no cost information was available appear as the first, zero-cost entries. The only significant unit in this category is the Rygate plant, and since it is a qualifying facility with must-run contracts (according to DPS sources), this is not a serious distortion. The figure has been corrected to indicate that all the publicly-held hydro does not have a production cost of exactly \$8/MWh, but rather follows the same cost distribution as the privately-held dams for which cost statistics were available. The big flat area is of course Vermont Yankee, followed by four miscellaneous units and then McNeil. With Vermont generation (consumption minus imports) at about 3,800 MWh, it is clear that McNeil is Vermont's marginal unit - the one that would be turned up or down, on or off to meet load variations. The fact that it runs at about a 30% capacity factor, rather than the 60-70% indicated by this analysis, results from NEPOOL's ability to supply less expensive energy from outside Vermont.

Figure 16
NEPOOL Marginal Cost Distribution



This analysis shows qualitatively that under the full-cost accounting that will follow restructuring, and looking at the competition within Vermont, McNeil can expect to continue to operate as a cycling plant. The full marginal cost of production will be substantially higher than the currently reported values displayed in Figure 16, although there are no signs here that they will be high enough to increase McNeil's capacity factor significantly. Essentially, because no units were reporting the full costs of production, the switch to full cost accounting will lead to higher reported prices, but may not produce any drastic changes in dispatch. A more precise prediction of performance over the next few years, especially with respect to competition within NEPOOL but outside Vermont, can only be obtained by as McNeil, Rygate, wind turbines and perhaps small hydro, which are called "Tier 1" technologies, and new technologies and projects, implemented after Jan 1, 1998, which are referred to as "Tier 2. The only distinction between Tier 1 and Tier 2 seems to be whether or not the generating facility already exists or will be built in 1998 or thereafter. To qualify, projects must be less than 80 MW capacity and, for hydro, meet certain FERC licensing and water quality standards (S-062, §8002: 14,21,22,23).

The use of renewable sources will then be guaranteed by a "portfolio" system, wherein each retailer of electricity must show by possession of "credits" that a specified fraction of his electricity was obtained from renewable sources (S-062, §8026). Since the electricity itself is hard to track, the system is managed simply by having the operators of renewable generating stations (such as McNeil) issue and sell credits representing their generation, under the control of the Public Service Board. Since these credits are of value to the retailers (to prove they have used the specified fraction of renewable energy), they will pay the renewable generators for them. At this point, no one is prepared to guess the values. The credits will be tradable, so we can expect middlemen and futures markets to develop.

The law further specifies that "the required level for part one shall be at least equal to that proportion of the retail electric consumption and associated transmission and distribution losses in 1995 in Vermont that met the standard for part one" (S-062: §8026(b)). Table 27 shows that if small hydro is counted as renewable, the total renewable contribution to Vermont's consumption is 24%, while if small hydro is not counted (see further discussion below), renewables contribute 6.8%. The statute specifically bases the renewable credits on "electric energy production" (S-062: §8026(d)) rather than capacity.

This should lead to increased demands on McNeil's output because of the way it is phrased. The fixed quantity is the <u>fraction</u> of Vermont's consumption; as consumption increases absolutely (it has been going up about one per cent per year lately), we can expect the demand for renewable energy to increase at about 1% per year, also, amounting to an extra 3-9 GWh each year. (Assume an average 5 GWh per year.) But the only place this energy can come from is McNeil, since all other Tier 1 (existing) renewable sources are either quite deregulated market, we must ask what the DH system must pay McNeil to make high capacity factor operation viable.

The Costs of Operating McNeil as a "Must-Run" Station

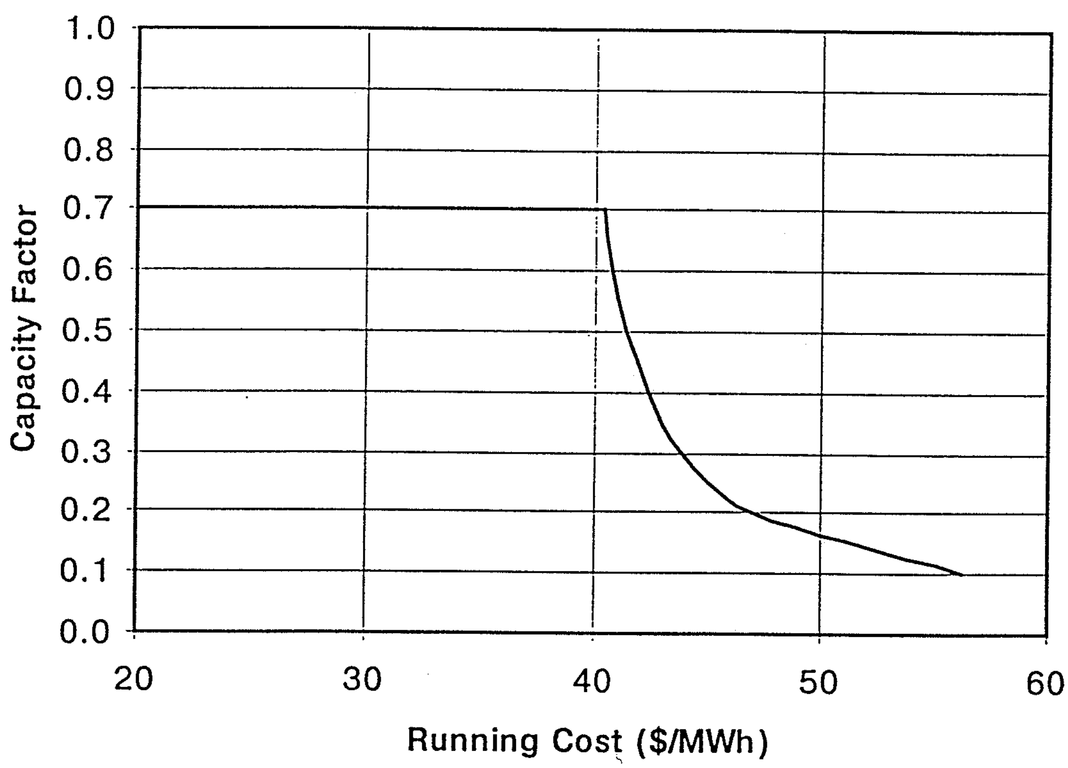
Once McNeil is supplying thermal energy to a substantial customer base, it must run essentially all the time. Generation downtime can be accommodated since boiler steam can be valved around the turbine to keep the DH system supplied, but for analytic purposes we will simply assume continuous generation. This is a dramatic increase from current operation, where Table 12 showed a typical capacity factor of 31%. The station need not run at full load, however, but only at the 17 to 32 MW indicated in Table 8 and 16 as necessary to provide various levels of thermal energy.

The minimum generation in DH mode was compared to 1996 station dispatch on the monthly bases for HTHW option (Figure 12) in order to estimate the amount of electric energy that McNeil would have to produce over the dispatch. The LTHW option dispatch profile is similar to one shown in Figure 12.

The minimum generation curves were developed using the minimum generation for each corresponding heat load (Table 8 and 15) and monthly climatological data for Burlington. Monthly dispatched generation is summarized in Tables 9-11 for HTHW and Tables 17-19 for MTHW. The dispatched generation curve was constructed based on hours the station was operated each month of 1996 and monthly capacity factor provided by BED. If the station would be dispatched the same way it was in 1996 - the annual must run generation will be 120 GWh for the first implementation stage, 125 GWh for the second implementation stage and 134 GWh for the third implementation stage.

However, applying 5 GWh annual increase in demand for renewable energy from 1996, the annual must run generation becomes 110 GWh for the first implementation stage, 90 GWh for the second implementation stage and 74 GWh for the third implementation stage for HTHW option, and 93 GWh, 99 GWh and 105 GWh respectively for MTHW option.

Figure 17
McNeil Running Cost



Based on these assumptions and taking into account the McNeil must-run penalties (developed in Section 4) the break-even price of heat for the three implementation stages has been developed.

The central boiler plants at UVM and FAHC will have to be maintained in operable condition by the existing personnel. Two boilers will be kept warm five months per year with heat supplied from the McNeil station. The district heating company will pay for this service. This cost ($23,000) is estimated using the load of 4% of the total boiler capacity for two boilers for 3600 hours per year at McNeil fuel cost. The district heating company will also pay for the gas necessary to fire the UVM boilers during the McNeil shutdown time. This is estimated at $40,000.

Two people have been allocated to the district heating company.

Wood fuel characteristics used in the study are as follows:

- Average wood wet basis moisture content: 45%
- Average wood heating value content as fired: 4620 Btu/lb

__HTHW Option__

In the first project stage no peaking boilers will be required because the McNeil station will be able to satisfy the entire load. In the second stage, 1,000 MMBtu/year need to be supplied from the UVM boiler plant. In the third stage 9,000 MMBtu/year (1.4% of total annual heat demand) must be supplied from supplemental peaking sources. In the second and third stage, the UVM and FAHC peaking boiler plants will not be sufficient to provide 100% back-up in case of McNeil station shut down on the coldest day of the year. Therefore, construction of additional peaking boilers will be required. The capital cost of this new boiler plant is estimated at $900,000 for the second and $1.8 million for the third stage, and included in the feasibility analysis.

Table 30
ECONOMIC ANALYSIS (HTHW)

McNeil Station - District Heating Mode
Stage One Only

ANNUAL CARRYING CHARGES

Investments ($1000)	stage 1	Economic Factors			
Year	1999	Debt Ratio	1.00	Property Tax	2%
Bonds Issued	$11,670	Interest Accrued on Bonds - %	6.50	Insurance Rate - %	0.15
Escalation	$591			Insurance Escalation	1.3%
AFDC	$552	Term to Pay the Bonds - Yrs	30	Grace Period, Yrs	0
Discount	$130	Cash on Hand - % of Investment	0		
Bond insurance	$130				
Issuance expen	$300				
Reserve Fund	$1,281				
Total Amount	$14,653				

Year	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
Bond Principal Remaind	14,653	14,484	14,303	14,111	13,906	13,688	13,455	13,208	12,944	12,663
Principal Repaid	170	181	192	205	218	232	248	264	281	299
Interest Accrued on Bonds	952	941	930	917	904	890	875	858	841	823
Insurance	23	23	23	23	24	24	24	25	25	25
Annual Carrying Charges ($1000)	1,145	1,145	1,145	1,146	1,146	1,146	1,146	1,147	1,147	1,147

Year	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Bond Principal Remaind	12,364	12,046	11,707	11,345	10,961	10,551	10,115	9,650	9,155	8,628
Principal Repaid	318	339	361	385	410	436	465	495	527	561
Interest Accrued on Bonds	804	783	761	737	712	686	657	627	595	561
Insurance	26	26	26	27	27	27	28	28	28	29
Annual Carrying Charges ($1000)	1,148	1,148	1,148	1,149	1,149	1,150	1,150	1,150	1,151	1,151

Table 30
ECONOMIC ANALYSIS (HTHW)

McNeil Station - District Heating Mode
Stage One Only

REQUIRED COST OF HEAT

Year	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
C. Carrying Charges ($1000)	1,145	1,145	1,145	1,146	1,146	1,146	1,146	1,147	1,147	1,147
D. Operating Expenses ($1000)										
1. Must Run Penalty	864	837	808	778	745	710	673	634	592	548
2. Fuel for DH Cost	719	737	756	774	794	814	834	855	876	898
3. Additional Fuel to Keep 2 UVM Boilers in Stand-	21	21	22	22	23	23	24	25	25	26
4. Natural Gas Cost For UVM Boiler Room Operati	40	41	42	43	44	45	46	47	48	50
5. Pumping Power Cost	13	13	14	14	14	15	15	15	16	16
6. Makeup Water Cost	10	10	11	11	11	11	12	12	12	13
7. Labor	95	98	101	104	107	111	114	117	121	125
8. McNeil DH O&M	62	64	66	68	70	72	74	76	78	81
Total Operating Expenses	1,824	1,822	1,819	1,814	1,808	1,801	1,792	1,781	1,769	1,755
Total Expenses	2,969	2,967	2,964	2,960	2,954	2,947	2,938	2,928	2,916	2,903
E. Operating Fee ($1000)										
City Fee	104	104	104	104	103	103	103	102	102	102
Property Tax	72	70	67	65	63	60	58	55	53	51
Operating Revenue after Fee	3,145	3,141	3,135	3,128	3,120	3,110	3,099	3,086	3,072	3,055
Breakeven Unit Cost - $/MMBtu	7.99	7.98	7.97	7.95	7.93	7.91	7.88	7.84	7.81	7.77
Breakeven Unit Cost With Debt Coverage	8.72	8.71	8.70	8.68	8.66	8.63	8.61	8.57	8.54	8.49
Annual Adjustment - $/MMBtu		0.73	0.73	0.73	0.73	0.73	0.73	0.73	0.73	0.73
District Heating Cost - $/MMBtu	8.72	7.98	7.97	7.95	7.93	7.91	7.88	7.84	7.81	7.77

Year	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
C. Carrying Charges ($1000)	1,148	1,148	1,148	1,149	1,149	1,150	1,150	1,150	1,151	1,151
D. Operating Expenses ($1000)										
1. Must Run Penalty	501	451	399	344	286	224	160	92	20	0
2. Fuel for DH Cost	921	944	967	991	1,016	1,042	1,068	1,094	1,122	1,150
3. Additional Fuel to Keep 2 UVM Boilers in Stand-	27	27	28	29	29	30	31	32	32	33
4. Natural Gas Cost For UVM Boiler Room Operati	51	52	53	55	56	58	59	60	62	64
5. Pumping Power Cost	16	16	17	17	17	18	18	19	19	20
6. Makeup Water Cost	13	13	14	14	14	15	15	15	16	16
7. Labor	128	132	136	140	144	149	153	158	163	167
8. McNeil DH O&M	83	86	88	91	94	96	99	102	105	109
Total Operating Expenses	1739	1722	1702	1681	1657	1631	1603	1572	1539	1558
Total Expenses	2,887	2,870	2,851	2,829	2,806	2,781	2,753	2,723	2,690	2,709
E. Operating Fee ($1000)										
City Fee	101	100	100	99	98	97	96	95	94	95
Property Tax	48	46	43	41	39	36	34	31	29	26
Operating Revenue after Fee	3,036	3,016	2,994	2,969	2,943	2,914	2,883	2,849	2,813	2,830
Breakeven Unit Cost - $/MMBtu	7.72	7.67	7.61	7.56	7.48	7.41	7.33	7.24	7.16	7.19
Breakeven Unit Cost With Debt Coverage	8.45	8.40	8.34	8.28	8.21	8.14	8.06	7.97	7.88	7.93
Annual Adjustment - $/MMBtu	0.73	0.73	0.73	0.73	0.73	0.73	0.73	0.73	0.73	0.73
District Heating Cost - $/MMBtu	7.72	7.67	7.61	7.56	7.48	7.41	7.33	7.24	7.16	7.19

Table 31
ECONOMIC ANALYSIS (HTHW)

McNeil Station - District Heating Mode
Stage One and Two Only

ANNUAL CARRYING CHARGES

Investments ($1000)			Economic Factors			
	stage 1	stage 2				
Year	1999	2004	Debt Ratio	1.00	Property Tax	2%
Bonds Issued	$11,670	$2,585	Interest Accrued on Bonds - %	6.50	Insurance Rate - %	0.15
Escalation	$591	$488			Insurance Escalation	1.3%
AFDC	$552	$138	Term to Pay the Bonds - Yrs	30	Grace Period, Yrs	0
Discount	$130	$40	Cash on Hand - % of Investment	0		
Bond insuranc	$130	$40				
Issuance expe	$300	$300				
Reserve Fund	$1,281	$321				
Total Amount	$14,653	$3,912				

Year	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
Bond Principal Remaind	14,653	14,484	14,303	14,111	13,906	17,600	17,322	17,026	16,711	16,376
Principal Repaid	170	181	192	205	218	278	296	315	335	357
Interest Accrued on Bonds	952	941	930	917	904	1,144	1,126	1,107	1,086	1,064
Insurance	23	23	23	23	24	30	31	31	32	32
Annual Carrying Charges ($1000)	**1,145**	**1,145**	**1,145**	**1,146**	**1,146**	**1,452**	**1,453**	**1,453**	**1,453**	**1,454**

Year	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Bond Principal Remaind	16,019	15,638	15,233	14,801	14,342	13,852	13,331	12,776	12,184	11,555
Principal Repaid	381	405	432	460	490	521	555	591	630	671
Interest Accrued on Bonds	1,041	1,016	990	962	932	900	867	830	792	751
Insurance	33	33	33	34	34	35	35	36	36	37
Annual Carrying Charges ($1000)	**1,454**	**1,455**	**1,455**	**1,456**	**1,456**	**1,456**	**1,457**	**1,457**	**1,458**	**1,458**

Table 31
ECONOMIC ANALYSIS (HTHW)

McNeil Station - District Heating Mode
Stage One and Two Only

REQUIRED COST OF HEAT

Year	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
C. Carrying Charges ($1000)	1,145	1,206	1,268	1,329	1,391	1,452	1,453	1,453	1,453	1,454
D. Operating Expenses ($1000)										
1. Must Run Penalty	864	845	825	804	781	756	720	681	641	598
2. Fuel for DH Cost	719	792	868	947	1,030	1,116	1,144	1,173	1,202	1,232
3. Additional Fuel to Keep 2 UVM Boilers in Stand-	21	22	23	23	24	25	26	27	27	28
4. Natural Gas Cost For UVM Boiler Room Operati	40	41	42	43	44	45	46	47	48	50
5. Pumping Power Cost	13	14	15	16	17	19	19	20	20	21
6. Makeup Water Cost	10	10	11	11	11	11	12	12	12	13
7. Labor	95	98	101	104	107	111	114	117	121	125
8. McNeil DH O&M	62	64	66	68	70	72	74	76	78	81
Total Operating Expenses	1,824	1,886	1,950	2,016	2,085	2,155	2,155	2,153	2,151	2,146
Total Expenses	2,969	3,092	3,218	3,346	3,475	3,607	3,607	3,606	3,604	3,600
E. Operating Fee ($1000)										
City Fee	104	108	113	117	122	126	126	126	126	126
Property Tax	72	70	67	65	63	60	58	55	53	51
Operating Revenue after Fee	3,145	3,271	3,398	3,528	3,660	3,793	3,791	3,788	3,783	3,777
Breakeven Unit Cost - $/MMBtu	**7.99**	**7.88**	**7.79**	**7.70**	**7.63**	**7.57**	**7.57**	**7.56**	**7.55**	**7.54**
Breakeven Unit Cost With Debt Coverage	**8.72**	**8.61**	**8.51**	**8.43**	**8.36**	**8.30**	**8.30**	**8.29**	**8.28**	**8.27**
Annual Adjustment - $/MMBtu		**0.69**	**0.69**	**0.69**	**0.69**	**0.69**	**0.72**	**0.73**	**0.73**	**0.73**
District Heating Cost - $/MMBtu	**8.72**	**7.92**	**7.82**	**7.74**	**7.67**	**7.61**	**7.57**	**7.56**	**7.55**	**7.54**

Year	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
C. Carrying Charges ($1000)	1,454	1,455	1,455	1,456	1,456	1,456	1,457	1,457	1,458	1,458
D. Operating Expenses ($1000)										
1. Must Run Penalty	552	504	453	399	342	283	219	153	83	10
2. Fuel for DH Cost	1,263	1,295	1,327	1,360	1,394	1,429	1,465	1,501	1,539	1,577
3. Additional Fuel to Keep 2 UVM Boilers in Stand-	29	29	30	31	32	32	33	34	35	36
4. Natural Gas Cost For UVM Boiler Room Operati	51	52	53	55	56	58	59	60	62	64
5. Pumping Power Cost	20	21	21	22	22	23	23	24	24	25
6. Makeup Water Cost	13	13	14	14	14	15	15	15	16	16
7. Labor	128	132	136	140	144	149	153	158	163	167
8. McNeil DH O&M	83	86	88	91	94	96	99	102	105	109
Total Operating Expenses	2139	2132	2123	2112	2099	2084	2067	2048	2027	2003
Total Expenses	3,594	3,587	3,578	3,567	3,555	3,541	3,524	3,506	3,485	3,462
E. Operating Fee ($1000)										
City Fee	126	126	125	125	124	124	123	123	122	121
Property Tax	48	46	43	41	39	36	34	31	29	26
Operating Revenue after Fee	3,768	3,758	3,746	3,733	3,718	3,701	3,681	3,660	3,636	3,609
Breakeven Unit Cost - $/MMBtu	**7.52**	**7.50**	**7.48**	**7.45**	**7.42**	**7.39**	**7.35**	**7.31**	**7.26**	**7.21**
Breakeven Unit Cost With Debt Coverage	**8.25**	**8.23**	**8.21**	**8.18**	**8.15**	**8.12**	**8.08**	**8.03**	**7.99**	**7.93**
Annual Adjustment - $/MMBtu	**0.73**	**0.73**	**0.73**	**0.73**	**0.73**	**0.73**	**0.73**	**0.73**	**0.73**	**0.73**
District Heating Cost - $/MMBtu	**7.52**	**7.50**	**7.48**	**7.45**	**7.42**	**7.39**	**7.35**	**7.31**	**7.26**	**7.21**

Table 32
ECONOMIC ANALYSIS (HTHW)

McNeil Station - District Heating Mode
All Three Stages

ANNUAL CARRYING CHARGES

Investments ($1000)	stage 1	stage 2	stage 3
Year	1999	2004	2009
Bonds Issued	$11,670	$2,585	$4,328
Escalation	$591	$488	$1,493
AFDC	$552	$138	$262
Discount	$130	$40	$70
Bond insurance	$130	$40	$70
Issuance expense	$300	$300	$300
Reserve Fund	$1,281	$321	$608
Total Amount	$14,653	$3,912	$7,131

Economic Factors			
Debt Ratio	1.00	Property Tax	2%
Interest Accrued on Bonds - %	6.50	Insurance Rate - %	0.15
		Insurance Escalation	1.3%
Term to Pay the Bonds - Yrs	30	Grace Period, Yrs	0
Cash on Hand - % of Investment	0		

Year	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
Bond Principal Remaind	14,653	14,484	14,303	14,111	13,906	17,600	17,322	17,026	16,711	16,376
Principal Repaid	170	181	192	205	216	278	296	315	335	357
Interest Accrued on Bonds	952	941	930	917	904	1,144	1,126	1,107	1,086	1,064
Insurance	23	23	23	23	24	30	31	31	32	32
Annual Carrying Charges ($1000)	1,145	1,145	1,145	1,146	1,146	1,452	1,453	1,453	1,453	1,454

Year	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Bond Principal Remaind	23,149	22,686	22,193	21,668	21,109	20,513	19,878	19,203	18,483	17,717
Principal Repaid	463	493	525	559	596	634	676	720	766	816
Interest Accrued on Bonds	1,505	1,475	1,443	1,408	1,372	1,333	1,292	1,248	1,201	1,152
Insurance	45	46	46	47	47	48	49	49	50	51
Annual Carrying Charges ($1000)	2,013	2,013	2,014	2,015	2,015	2,016	2,016	2,017	2,018	2,018

Table 32
ECONOMIC ANALYSIS (HTHW)

McNeil Station - District Heating Mode
All Three Stages

REQUIRED COST OF HEAT

Year	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
C. Carrying Charges ($1000)	1,145	1,206	1,268	1,329	1,391	1,452	1,564	1,676	1,789	1,901
D. Operating Expenses ($1000)										
1. Must Run Penalty	864	845	825	804	781	756	727	697	665	630
2. Fuel for DH Cost	719	792	868	947	1,030	1,116	1,200	1,287	1,377	1,471
3. Additional Fuel to Keep 2 UVM Boilers in Stand-by	21	22	23	23	24	25	26	27	28	29
4. Natural Gas Cost For UVM Boiler Room Operation	40	41	42	43	44	45	46	47	48	50
5. Pumping Power Cost	13	14	15	16	17	19	20	21	22	24
6. Makeup Water Cost	10	10	11	11	11	11	12	12	12	13
7. Labor	95	98	101	104	107	111	114	117	121	125
8. Back-up Boiler Plants O&M							4	8	12	16
9. McNeil DH O&M	62	64	66	68	70	72	74	76	78	81
Total Operating Expenses	1,824	1,886	1,950	2,016	2,085	2,155	2,223	2,293	2,364	2,438
Total Expenses	2,969	3,092	3,218	3,346	3,475	3,607	3,787	3,969	4,153	4,339
E. Operating Fee ($1000)										
City Fee	104	108	113	117	122	126	133	139	145	152
Property Tax	72	70	67	65	63	60	58	55	53	51
Operating Revenue after Fee	3,145	3,271	3,398	3,528	3,660	3,793	3,977	4,163	4,351	4,541
Breakeven Unit Cost - $/MMBtu	7.99	7.88	7.79	7.70	7.63	7.57	7.65	7.72	7.79	7.86
Breakeven Unit Cost With Debt Coverage	8.72	8.61	8.51	8.43	8.36	8.30	8.40	8.50	8.59	8.68
Annual Adjustment - $/MMBtu		0.69	0.69	0.69	0.69	0.69	0.70	0.73	0.75	0.77
District Heating Cost - $/MMBtu	8.72	7.92	7.82	7.74	7.67	7.61	7.70	7.77	7.84	7.91

Year	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
C. Carrying Charges ($1000)	2,013	2,013	2,014	2,015	2,015	2,016	2,016	2,017	2,018	2,018
D. Operating Expenses ($1000)										
1. Must Run Penalty	594	546	497	444	388	329	267	202	133	61
2. Fuel for DH Cost	1,570	1,609	1,649	1,690	1,733	1,776	1,820	1,866	1,912	1,960
3. Additional Fuel to Keep 2 UVM Boilers in Stand-by	30	31	31	32	33	34	35	35	6	14
4. Natural Gas Cost For UVM Boiler Room Operation	24	25	26	26	27	28	28	29	30	30
5. Pumping Power Cost	24	25	25	26	26	27	28	28	29	30
6. Makeup Water Cost	13	13	14	14	14	15	15	15	16	16
7. Labor	128	132	136	140	144	149	153	158	163	167
8. Back-up Boiler Plants O&M	20	21	21	22	22	23	23	24	24	25
9. O&M Increase	83	86	88	91	94	96	99	102	105	109
Total Operating Expenses	2486	2487	2487	2485	2481	2476	2469	2460	2419	2413
Total Expenses	4,499	4,500	4,501	4,499	4,496	4,492	4,485	4,477	4,437	4,431
E. Operating Fee ($1000)										
City Fee	157	158	158	157	157	157	157	157	155	155
Property Tax	48	46	43	41	39	36	34	31	29	26
Operating Revenue after Fee	4,704	4,704	4,701	4,698	4,692	4,685	4,676	4,665	4,621	4,612
Breakeven Unit Cost - $/MMBtu	7.88	7.88	7.88	7.87	7.86	7.85	7.83	7.81	7.74	7.73
Breakeven Unit Cost With Debt Coverage	8.72	8.72	8.72	8.71	8.70	8.69	8.68	8.66	8.59	8.57
Annual Adjustment - $/MMBtu	0.80	0.84	0.84	0.84	0.84	0.84	0.84	0.84	0.84	0.84
District Heating Cost - $/MMBtu	7.93	7.88	7.88	7.87	7.86	7.85	7.83	7.81	7.74	7.73

MTHW Option

The MTHW system saves about 40% in construction cost of transmission piping from McNeil to UVM and FAHC because of lower piping and installation costs. The MTHW conserves energy at McNeil by using a lower pressure turbine extraction which increases the cogeneration rate and overall fuel utilization.

A 20% reduction in customer heat consumption can be achieved due to reduced heat losses in undergound piping, steam traps, and improved controls.

The MTHW option provides total annual fuel savings due to increased fuel utilization at the McNeil station and reduced customer consumption of 128,000 MMBtu of fuel fired which translates into annual savings of $320,000.

The McNeil parameters with and without DH are summarized below:

McNeil Station Generation and Fuel Consumption (MTHW)

Annual Quantity	1995	1996	District Heating Stage 1	Stage 2	Stage 3
Without DH					
Total Fuel Consumption, MMBtu, Including	2,137,017	2,298,281			
Wood, Tons	196,627	221,529			
Gas, Mcf	130,703	23,000			
Oil, gal	55,696	169,000			
Net Electric Generation, kWhr	135,956,200	136,998,600			
With DH					
Fuel Consumption, MMBtu			4,117,000	4,274,000	4,429,000
Net Electric Generation, kWh			227,586,000	234,307,000	240,581,000
DH Sales, MMBtu			314,842	424,387	531,904
Fuel Allocated for DH, MMBtu			153,560	255,953	362,670
Fuel Allocated for DH, % of Total			3.7	6.0	8.2

The economic analyses for the MTHW option for all three project stages are presented in Tables 33 - 35. It is assumed that the UVM and FAHC will be responsible for retrofit to MTHW.

Table 33
ECONOMIC ANALYSIS (MTHW)

McNeil Station - District Heating Mode
Stage One Only

ANNUAL QUANTITIES

Start of Evaluation	2004			Stage 1		
Unit Costs	1997	Escalation	Heat Source -	Cogeneration	Property Tax	2%
Capital Costs		2.5%	Disp. (exist.) Gen-n, MWh/yr	136,958	Insurance Rate - %	1.50
Penalty for Must Run, $/MWh	9.00	2.5%	Must Run Generation, MWh/yr	90,581	Cost of Capital - %	6.50
Fuel Price, $/MMBtu	2.32	2.5%	Pumping Power, MWh/yr	318	Investment ($1000)	1,597
Makeup Water - $/1000 cuft	75.00	2.5%	Fuel Allocated for DH, MMBtu/yr	153,560	City Operation Fee - %	3.5
Labor Rate, $/man.yr	45,000	3.0%	District Heat Output (MMBtu/yr)	314,842	Incremental O&M - %	0.5
Aux. Power Price, $/kWh	0.031	2.5%	Labor Force, man.yr	2		
Annual Must Run Decreace, MWh		5,000				

Year	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
A. Annual Quantities										
1. District Heat - MMBtu/yr	314,842	314,842	314,842	314,842	314,842	314,842	314,842	314,842	314,842	314,842
3. Must Run Generation - MWh/yr	50,581	45,581	40,581	35,581	30,581	25,581	20,581	15,581	10,581	5,581
4. Fuel Allocated for DH - MMBtu/yr	153,560	153,560	153,560	153,560	153,560	153,560	153,560	153,560	153,560	153,560
6. Pumping Power, MWh/yr	318	318	318	318	318	318	318	318	318	318
7. Must Run Gen. Adjusted for Pumping - MWh/yr	50,263	45,263	40,263	35,263	30,263	25,263	20,263	15,263	10,263	5,263
8. Makeup Water - 1000cuft	134	134	134	134	134	134	134	134	134	134
9. Labor - man.yr	2	2	2	2	2	2	2	2	2	2
B. Unit Costs										
2. Penalty for Must Run Generation-$/MWh	10.698	10.966	11.240	11.521	11.809	12.104	12.407	12.717	13.035	13.361
3. Aux. Power Price - $/kWh	0.037	0.038	0.039	0.040	0.041	0.042	0.043	0.044	0.045	0.046
4. Makeup Water - $/1000 cuft	75.00	76.88	78.80	80.77	82.79	84.86	86.98	89.15	91.38	93.66
5. Fuel - $/MMBtu										
Wood	2.76	2.83	2.90	2.97	3.04	3.12	3.20	3.28	3.36	3.44
Oil	5.86	6.01	6.16	6.31	6.47	6.63	6.80	6.97	7.14	7.32
Nat. Gas	2.65	2.72	2.78	2.85	2.93	3.00	3.07	3.15	3.23	3.31
6. Labor - $/man.yr	55,344	57,005	58,715	60,476	62,291	64,159	66,084	68,067	70,109	72,212

Year	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
A. Annual Quantities										
1. District Heat - MMBtu/yr	314,842	314,842	314,842	314,842	314,842	314,842	314,842	314,842	314,842	314,842
3. Must Run Generation - MWh/yr	581	318	318	318	318	318	318	318	318	318
4. Fuel Alloc-d for DH - MMBtu/yr	153,560	153,560	153,560	153,560	153,560	153,560	153,560	153,560	153,560	153,560
6. Pumping Power, MWh/yr	318	318	318	318	318	318	318	318	318	318
7. Must Run Gen. Adjusted for Pumping - MWh/yr	263	0	0	0	0	0	0	0	0	0
8. Makeup Water - 1000cuft	134	134	134	134	134	134	134	134	134	134
9. Labor - man.yr	2	2	2	2	2	2	2	2	2	2
B. Unit Costs										
2. Penalty for Must Run Generation-$/MWh	13.695	14.037	14.388	14.748	15.116	15.494	15.881	16.279	16.685	17.103
3. Aux. Power Price - $/kWh	0.04	0.04	0.04	0.04	0.04	0.04	0.05	0.05	0.05	0.05
4. Makeup Water - $/1000 cuft	96.01	98.41	100.87	103.39	105.97	108.62	111.34	114.12	116.97	119.90
5. Fuel - $/MMBtu										
Wood	3.53	3.62	3.71	3.80	3.90	3.99	4.09	4.20	4.30	4.41
Oil	7.50	7.69	7.88	8.08	8.28	8.49	8.70	8.92	9.14	9.37
Nat. Gas	3.39	3.48	3.56	3.65	3.74	3.84	3.93	4.03	4.13	4.24
6. Labor - $/man.yr	74,378	76,609	78,908	81,275	83,713	86,225	88,811	91,476	94,220	97,047

Table 33
ECONOMIC ANALYSIS (MTHW)

McNeil Station - District Heating Mode
Stage One Only

ANNUAL CASH FLOW

Year	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
Proposed DH Rate (average, without escalation)	8.76	8.68	8.60	8.51	8.42	8.31	8.20	8.09	7.96	7.83
Annual Cost	2,476,655	2,452,128	2,425,621	2,397,050	2,366,327	2,333,361	2,298,059	2,260,324	2,220,055	2,177,147
Annual Revenue	2,757,597	2,733,715	2,707,861	2,679,952	2,649,899	2,617,612	2,582,998	2,545,960	2,506,396	2,464,204
Annual Surplus	280,942	281,587	282,240	282,902	283,572	284,251	284,939	285,636	286,342	287,057

Year	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Proposed DH Rate (average, without escalation)	7.68	7.74	7.82	7.91	7.99	8.08	8.17	8.26	8.35	8.45
Annual Cost	2,129,026	2,149,276	2,173,908	2,199,213	2,225,208	2,251,911	2,279,340	2,307,515	2,336,454	2,366,178
Annual Revenue	2,416,807	2,437,791	2,463,166	2,489,224	2,515,981	2,543,457	2,571,669	2,600,637	2,630,379	2,660,916
Annual Surplus	287,781	288,515	289,258	290,011	290,774	291,546	292,329	293,122	293,925	294,739

Table 34
ECONOMIC ANALYSIS (MTHW)

McNeil Station - District Heating Mode
Stage One and Two Only

ANNUAL QUANTITIES

Start of Evaluation	2004			Stage 1	Stage 2		
Unit Costs	1997	Escalation	Heat Source -	Cogeneration	Cogeneration	Property Tax	2%
Capital Costs		2.5%	Disp. (exist.) Gen-n, MWh/yr	136,958	136,958	Insurance Rate - %	1.50
Penalty for Must Run, $/MWh	9	2.5%	Must Run Generation, MWh/yr	90,581	97,302	Cost of Capital - %	6.50
Fuel Price, $/MMBtu	2.32	2.5%	Pumping Power, MWh/yr	318	429	Investment ($1000)	2,178
Makeup Water - $/1000 cuft	75.00	2.5%	Fuel Allocated for DH, MMBtu/yr	153,560	255,953	City Operation Fee - %	3.5
Labor Rate, $/man.yr	45,000	3.0%	District Heat Output (MMBtu/yr)	314,842	424,173	Incremental O&M - %	0.5
Aux. Power Price, $/kWh	0.031	2.5%	Labor Force, man.yr	2	2		
Annual Must Run Decreace, MWh		5,000					

Year	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
A. Annual Quantities										
1. District Heat - MMBtu/yr	314,842	336,708	358,574	380,440	402,307	424,173	424,173	424,173	424,173	424,173
3. Must Run Generation - MWh/yr	50,581	48,925	43,270	39,614	35,958	32,302	27,302	22,302	17,302	12,302
4. Fuel Allocated for DH - MMBtu/yr	153,560	174,039	194,517	214,996	235,474	255,953	255,953	255,953	255,953	255,953
6. Pumping Power, MWh/yr	318	341	363	385	407	429	429	429	429	429
7. Must Run Gen. Adjusted for Pumping - MWh/yr	50,263	48,585	42,907	39,229	35,551	31,873	26,873	21,873	16,873	11,873
8. Makeup Water - 1000cuft	134	134	134	134	134	134	134	134	134	134
9. Labor - man.yr	2	2	2	2	2	2	2	2	2	2
B. Unit Costs										
2. Penalty for Must Run Generation-$/MWh	10.698	10.966	11.240	11.521	11.809	12.104	12.407	12.717	13.035	13.361
3. Aux. Power Price - $/kWh	0.037	0.038	0.039	0.040	0.041	0.042	0.043	0.044	0.045	0.046
4. Makeup Water - $/1000 cuft	75.00	76.88	78.80	80.77	82.79	84.86	86.98	89.15	91.38	93.66
5. Fuel - $/MMBtu										
Wood	2.76	2.83	2.90	2.97	3.04	3.12	3.20	3.28	3.36	3.44
Oil	5.86	6.01	6.16	6.31	6.47	6.63	6.80	6.97	7.14	7.32
Nat. Gas	2.65	2.72	2.78	2.85	2.93	3.00	3.07	3.15	3.23	3.31
6. Labor - $/man.yr	55,344	57,005	58,715	60,476	62,291	64,159	66,084	68,067	70,109	72,212

Year	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
A. Annual Quantities										
1. District Heat - MMBtu/yr	424,173	424,173	424,173	424,173	424,173	424,173	424,173	424,173	424,173	424,173
3. Must Run Generation - MWh/yr	7,302	2,302	429	429	429	429	429	429	429	429
4. Fuel Alloc-d for DH - MMBtu/yr	255,953	255,953	255,953	255,953	255,953	255,953	255,953	255,953	255,953	255,953
6. Pumping Power, MWh/yr	429	429	429	429	429	429	429	429	429	429
7. Must Run Gen. Adjusted for Pumping - MWh/yr	6,873	1,873	0	0	0	0	0	0	0	0
8. Makeup Water - 1000cuft	134	134	134	134	134	134	134	134	134	134
9. Labor - man.yr	2	2	2	2	2	2	2	2	2	2
B. Unit Costs										
2. Penalty for Must Run Generation-$/MWh	13.695	14.037	14.388	14.748	15.116	15.494	15.881	16.279	16.685	17.103
3. Aux. Power Price - $/kWh	0.04	0.04	0.04	0.04	0.04	0.04	0.05	0.05	0.05	0.05
4. Makeup Water - $/1000 cuft	96.01	98.41	100.87	103.39	105.97	108.62	111.34	114.12	116.97	119.90
5. Fuel - $/MMBtu										
Wood	3.53	3.62	3.71	3.80	3.90	3.99	4.09	4.20	4.30	4.41
Oil	7.50	7.69	7.88	8.08	8.28	8.49	8.70	8.92	9.14	9.37
Nat. Gas	3.39	3.48	3.56	3.65	3.74	3.84	3.93	4.03	4.13	4.24
6. Labor - $/man.yr	74,378	76,609	78,908	81,275	83,713	86,225	88,811	91,476	94,220	97,047

Table 34
ECONOMIC ANALYSIS (MTHW)

McNeil Station - District Heating Mode
Stage One and Two Only

ANNUAL CASH FLOW

Year	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
Proposed DH Rate (average, without escalation)	8.76	8.56	8.39	8.25	8.12	8.01	7.96	7.90	7.83	7.76
Annual Cost	2,476,655	2,586,704	2,698,456	2,811,980	2,927,348	3,044,629	3,020,588	2,994,387	2,965,931	2,935,125
Annual Revenue	2,757,597	2,882,259	3,008,622	3,136,759	3,266,740	3,398,633	3,375,448	3,350,115	3,322,539	3,292,622
Annual Surplus	280,942	295,554	310,167	324,779	339,391	354,004	354,860	355,728	356,607	357,498

Year	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Proposed DH Rate (average, without escalation)	7.68	7.60	7.62	7.70	7.79	7.89	7.98	8.08	8.18	8.28
Annual Cost	2,898,542	2,862,644	2,870,639	2,906,780	2,943,874	2,981,943	3,021,014	3,061,111	3,102,262	3,144,492
Annual Revenue	3,256,942	3,221,958	3,230,878	3,267,957	3,306,001	3,345,032	3,385,078	3,426,163	3,468,313	3,511,557
Annual Surplus	358,400	359,314	360,239	361,177	362,127	363,089	364,064	365,051	366,052	367,065

Table 35
ECONOMIC ANALYSIS (MTHW)

McNeil Station - District Heating Mode
All Three Stages

ANNUAL QUANTITIES

				Stage 1	Stage 2	Stage 3		
Start of Evaluation	2004							
Unit Costs	1997	Escalation	Heat Source -	Cogeneration	Cogeneration	Cogeneration	Property Tax	2%
Capital Costs		2.5%	Disp. (exist.) Gen-n, MWh/yr	136,958	136,958	136,958	Insurance Rate - %	1.50
Penalty for Must Run, $/MWh	9	2.5%	Must Run Generation, MWh/yr	90,581	97,302	103,577	Cost of Capital - %	6.50
Fuel Price, $/MMBtu	2.32	2.5%	Pumping Power, MWh/yr	318	429	534	Investment ($1000)	3,966
Makeup Water - $/1000 cuft	75.00	2.5%	Fuel Allocated for DH, MMBtu/yr	153,560	255,953	362,670	City Operation Fee -	3.5
Labor Rate, $/man.yr	45,000	3.0%	District Heat Output (MMBtu/yr)	314,842	424,173	527,910	Incremental O&M - %	0.5
Aux. Power Price, $/kWh	0.031	2.5%	Labor Force, man.yr	2	2	2		
Annual Must Run Decreace, MWh		5,000	Average DH Tariff (1997 prices)					

Year	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
A. Annual Quantities										
1. District Heat - MMBtu/yr	314,842	336,708	358,574	380,440	402,307	424,173	444,920	465,668	486,415	507,163
3. Must Run Generation - MWh/yr	50,581	46,925	43,270	39,614	35,958	32,302	28,557	24,812	21,067	17,322
4. Fuel Allocated for DH - MMBtu/yr	153,560	174,039	194,517	214,996	235,474	255,953	277,296	298,640	319,983	341,327
6. Pumping Power, MWh/yr	318	341	363	385	407	429	450	471	492	513
7. Must Run Gen. Adjusted for Pumping - MWh/yr	50,263	46,585	42,907	39,229	35,551	31,873	28,107	24,341	20,575	16,809
8. Makeup Water - 1000cuft	134	134	134	134	134	134	134	134	134	134
9. Labor - man.yr	2	2	2	2	2	2	2	2	2	2
B. Unit Costs										
2. Penalty for Must Run Generation-$/MWh	10.698	10.968	11.240	11.521	11.809	12.104	12.407	12.717	13.035	13.361
3. Aux. Power Price - $/kWh	0.037	0.038	0.039	0.040	0.041	0.042	0.043	0.044	0.045	0.046
4. Makeup Water - $/1000 cuft	75.00	76.88	78.80	80.77	82.79	84.86	86.98	89.15	91.38	93.66
5. Fuel - $/MMBtu										
Wood	2.76	2.83	2.90	2.97	3.04	3.12	3.20	3.28	3.36	3.44
Oil	5.86	6.01	6.16	6.31	6.47	6.63	6.80	6.97	7.14	7.32
Nat. Gas	2.65	2.72	2.78	2.85	2.93	3.00	3.07	3.15	3.23	3.31
6. Labor - $/man.yr	55,344	57,005	58,715	60,476	62,291	64,159	66,084	68,067	70,109	72,212

Year	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
A. Annual Quantities										
1. District Heat - MMBtu/yr	527,910	527,910	527,910	527,910	527,910	527,910	527,910	527,910	527,910	527,910
3. Must Run Generation - MWh/yr	13,577	8,577	3,577	534	534	534	534	534	534	534
4. Fuel Alloc-d for DH - MMBtu/yr	362,670	362,670	362,670	362,670	362,670	362,670	362,670	362,670	362,670	362,670
6. Pumping Power, MWh/yr	534	534	534	534	534	534	534	534	534	534
7. Must Run Gen. Adjusted for Pumping - MWh/yr	13,043	8,043	3,043	0	0	0	0	0	0	0
8. Makeup Water - 1000cuft	134	134	134	134	134	134	134	134	134	134
9. Labor - man.yr	2	2	2	2	2	2	2	2	2	2
B. Unit Costs										
2. Penalty for Must Run Generation-$/MWh	13.695	14.037	14.388	14.748	15.116	15.494	15.881	16.279	16.685	17.103
3. Aux. Power Price - $/kWh	0.04	0.04	0.04	0.04	0.04	0.04	0.05	0.05	0.05	0.05
4. Makeup Water - $/1000 cuft	96.01	98.41	100.87	103.39	105.97	108.62	111.34	114.12	116.97	119.90
5. Fuel - $/MMBtu										
Wood	3.53	3.62	3.71	3.80	3.90	3.99	4.09	4.20	4.30	4.41
Oil	7.50	7.69	7.88	8.08	8.28	8.49	8.70	8.92	9.14	9.37
Nat. Gas	3.39	3.48	3.56	3.65	3.74	3.84	3.93	4.03	4.13	4.24
6. Labor - $/man.yr	74,378	76,609	78,908	81,275	83,713	86,225	88,811	91,476	94,220	97,047

Table 35
ECONOMIC ANALYSIS (MTHW)

McNeil Station - District Heating Mode
All Three Stages

ANNUAL CASH FLOW

Year	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
Proposed DH Rate (average, without escalation)	8.76	8.56	8.39	8.25	8.12	8.01	8.15	8.27	8.40	8.51
Annual Cost	2,476,655	2,586,704	2,698,456	2,811,980	2,927,348	3,044,629	3,239,497	3,436,499	3,635,709	3,837,204
Annual Revenue	2,757,597	2,882,259	3,008,622	3,136,759	3,266,740	3,398,633	3,624,938	3,853,377	4,084,024	4,316,956
Annual Surplus	280,942	295,554	310,167	324,779	339,391	354,004	385,441	416,878	448,315	479,753

Year	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Proposed DH Rate (average, without escalation)	8.56	8.52	8.48	8.49	8.58	8.68	8.78	8.89	8.99	9.10
Annual Cost	4,009,331	3,987,002	3,962,327	3,965,079	4,014,370	4,064,922	4,116,767	4,169,937	4,224,466	4,280,389
Annual Revenue	4,520,521	4,499,495	4,476,141	4,480,230	4,530,876	4,582,800	4,636,035	4,690,614	4,746,570	4,803,938
Annual Surplus	511,190	512,493	513,813	515,151	516,506	517,878	519,268	520,677	522,104	523,549

Sensitivity Analysis Report

Figure 18 — **Fuel Price**

Custom distribution with parameters:				Relative Prob.
Continuous range	2.32	to	2.33	0.800000
Continuous range	2.33	to	2.61	0.200000
Total Relative Probability				1.000000

Mean value in simulation was 2.35

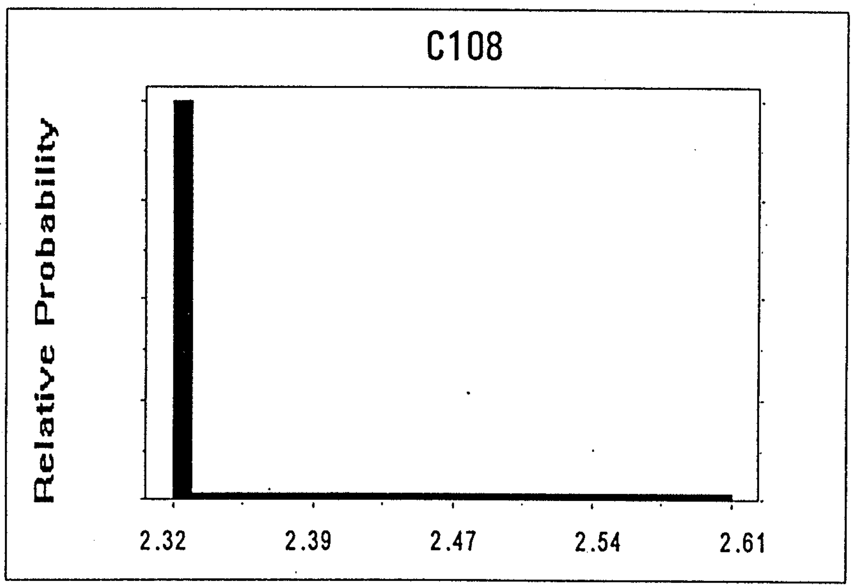
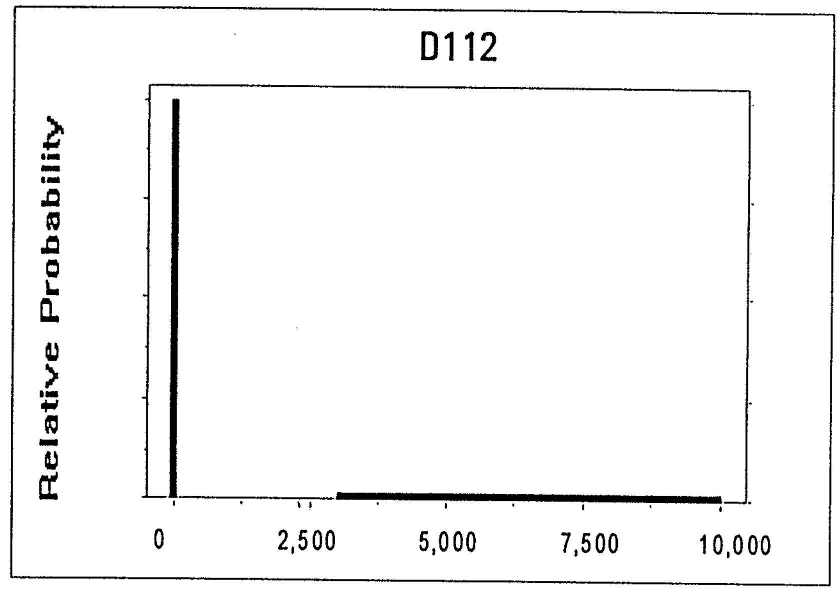


Figure 19 — **Annual Must Run Decreace**

Custom distribution with parameters:				Relative Prob.
Single point	0			0.100000
Continuous range	3,000	to	10,000	0.900000
Total Relative Probability				1.000000

Mean value in simulation was 5,896



Sensitivity Analysis Report

Figure 22

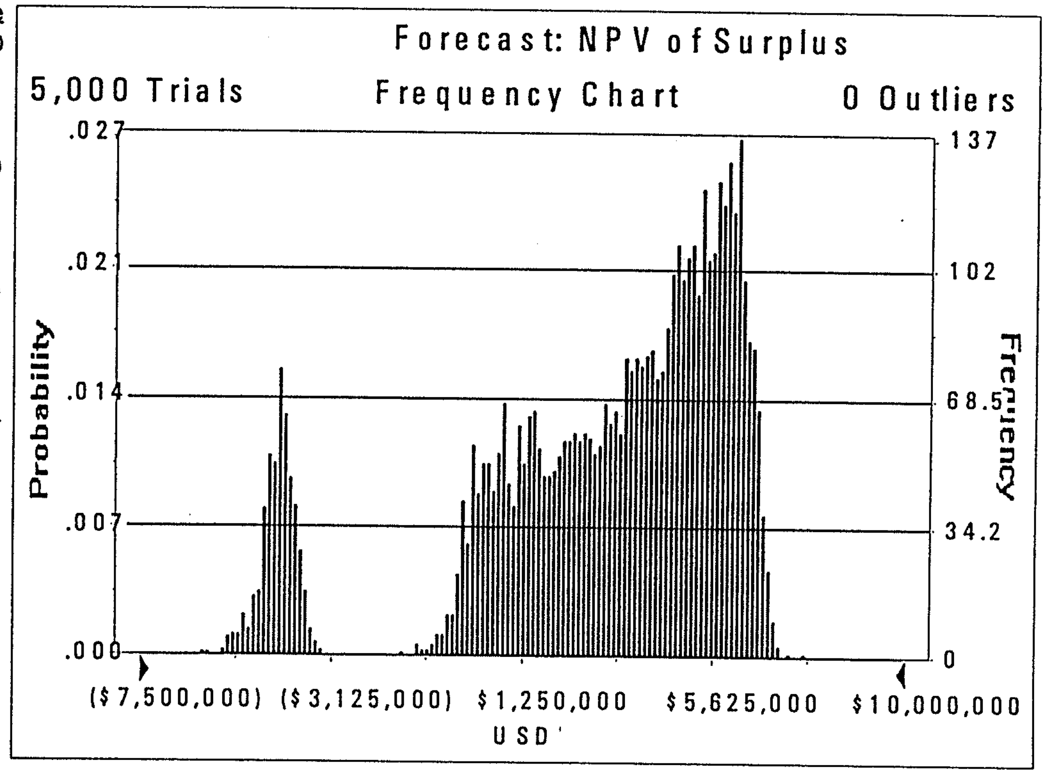
Economic Analysis Sensitivity for Stage One Only
NPV of Surplus

Summary:
Display Range is from ($7,500,000) to $10,000,000 USD
Entire Range is from ($6,048,972) to $7,737,855 USD
After 5,000 Trials, the Std. Error of the Mean is $44,038

Statistics:	Value
Trials	5000
Mean	$3,050,282
Median	$3,898,594
Standard Deviation	$3,113,962
Range Minimum	($6,048,972)
Range Maximum	$7,737,855
Range Width	$13,786,827
Mean Std. Error	$44,038.08
Probability of Break Even or Better	87.68%

Percentiles:

Percentile	USD
0%	($6,048,972)
10%	($3,397,646)
20%	$893,905
30%	$1,988,028
40%	$3,021,386
50%	$3,898,594
60%	$4,628,398
70%	$5,181,608
80%	$5,717,166
90%	$6,192,604
100%	$7,737,855



Sensitivity Analysis Report

Figure 24

Economic Analysis Sensitivity for All Three Stages

Summary:

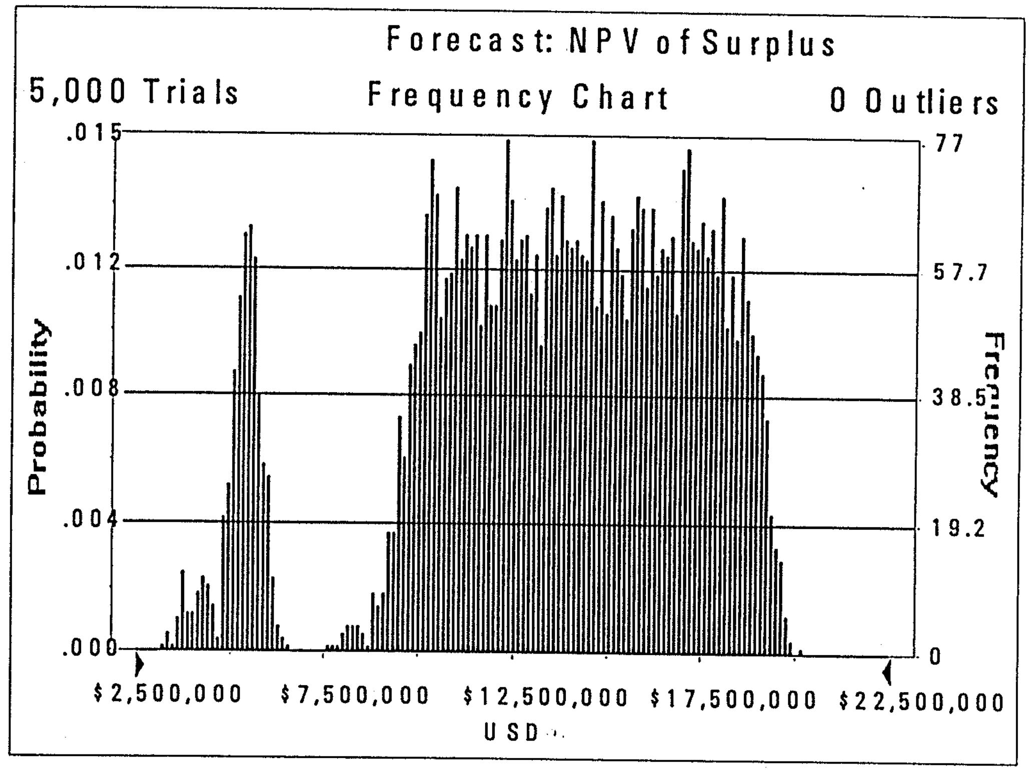
Display Range is from $2,500,000 to $22,500,000 USD
Entire Range is from $3,279,202 to $20,177,876 USD
After 5,000 Trials, the Std. Error of the Mean is $54,554

Statistics:

Statistics	Value
Trials	5000
Mean	$13,421,576
Median	$13,803,566
Standard Deviation	$3,857,584
Range Minimum	$3,279,202
Range Maximum	$20,177,876
Range Width	$16,898,674
Mean Std. Error	$54,554.48
Probability of Break Even or Better	100.00%

Percentiles:

Percentile	USD
0%	$3,279,202
10%	$6,166,344
20%	$10,494,412
30%	$11,620,711
40%	$12,707,058
50%	$13,803,566
60%	$14,874,029
70%	$15,966,539
80%	$17,044,139
90%	$18,098,650
100%	$20,177,876



at \$7.50/MMBtu (double of the present cost). In option 2 - \$53,639 per year is used for this purpose

- Two central plant boilers will be kept warm five months per year with heat supplied from the McNeil station. The district heating company will pay for this service. This cost is estimated using the load of 4% of the total boiler capacity for two boilers for 3600 hours per year at McNeil fuel cost. In option 2 - \$72,000 is allocated annually for this purpose
- District heating company will pay for the gas necessary to fire the UVM boilers during the McNeil shutdown time.

Capital Component

- In option 1 the UVM capital cost estimate of \$2,645,000 for new fifth 1,195 hp back-up boiler was used. In option 2 this cost is \$1,800,000.
- Option 1 used the annual component of \$48,320 for the total cost of boiler retubing and control of \$750,000 (1997 money). The annual component is an amount that has to be deposited in a 6.5% bearing account to accumulate the total cost with 3% escalation in 15 years.
- Option 1 used the annual component of \$280,172 for the total cost of replacement of the existing 4,800 hp UVM plant at \$1,500/hp, and 2,800 hp back-up boilers at \$1000/hp for the total cost of \$9.97 million (1997 money). The annual component is an amount that has to be deposited in a 6.5% bearing account to accumulate the total cost with 3% escalation in 30 years. Option 2 assumes \$189,610 for both: boiler retubing and equipment replacement.

Operation and Maintenance

- Five people were allocated for operation of the UVM central plant in accordance with UVM estimates.

The total first year savings are estimated at \$2,450,941 based on option 1 assumptions and \$1,159,137 with option 2 assumptions. The total second year savings are estimated at \$15,692 based on option 1 assumptions and –400,120 with option 2 assumptions. JTC

Table 36a
UVM HTHW, high savings assumption

Annual Expenditures for the UVM Central Plant	*Without District Heating (1st year)* Total	*Without District Heating (1st year)* Unit Cost, $/MMBtu	*Without District Heating (2nd year)* Total	*Without District Heating (2nd year)* Unit Cost, $/MMBtu	*With District Heating (1st year)* Total	*With District Heating (1st year)* Unit Cost, $/MMBtu	*With District Heating (2nd year)* Total	*With District Heating (2nd year)* Unit Cost, $/MMBtu	*Savings* 1st year	*Savings* 2nd year
FUEL										
Annual Fuel Cost, including:[1]	1,457,362	5.41	1,493,796	5.55	56,643	0.21	58,059	0.22	1,400,719	1,435,737
Gas	1,244,033		1,275,134		-		-		1,244,033	1,275,134
Oil	156,686		160,603		-		-		156,686	160,603
Back-up Boiler Fuel[1]	56,643		58,059		56,643		58,059		-	-
CAPITAL COMPONENT										
New Backup Boiler 1,195 HP to be Installed	2,645,000		-		-				2,645,000	
Boiler Retubing and Control: in 15 years	48,320		48,320		-				48,320	48,320
Capital Allocation for Equipment Replacement[2]	280,172		280,172		-				280,172	280,172
Annual Debt Service for Existing Plant	190,000		190,000		190,000		190,000		-	
Total Capital Component	3,163,492	11.74	518,492	1.92	190,000	0.71	190,000	0.71	2,973,492	328,492
MAINTENANCE/OPERATIONS (NON-FUEL)										
Labor Cost	450,000		461,250		250,000		256,250		200,000	205,000
Annual Service Contracts	29,696		30,439		5,939		6,088		23,757	24,351
Annual Chemicals	22,588		23,153		11,294		11,577		11,294	11,577
Annual Parts Cost	99,797		102,292		19,959		20,458		79,838	81,834
Annual Insurance	17,184		17,614		17,184		17,614		-	-
Annual Water & Sewer	117,956		120,905		58,978		60,453		58,978	60,453
Annual Electric Cost	174,163		178,517		121,914		124,962		52,249	53,555
Annual Staff Training Cost	1,534		1,572		1,534		1,572		-	-
Annual Infrastructure Cost	129,823		133,068		129,823		133,068		-	-
Back-up Boiler O&M	10,000		10,250		10,000		10,250		-	-
Total Maintenance/Operations (non-fuel)	1,052,742	3.91	1,079,060	4.01	626,626	2.33	642,291	2.38	426,116	436,769
DISTRICT HEATING COST										
District Heating Cost[3]	-	0.00	-	0.00	2,349,385	8.72	2,150,580	7.98	(2,349,385)	(2,150,580)
TOTAL ANNUAL COST	5,673,595	21.06	3,091,348	11.48	3,222,654	11.96	3,040,931	11.29	2,450,941	50,417

high savings assumptions represent the best professional judgement of JTC. These assumptions are as follows:

[1] JTC used the UVM actual fuel cost informatioin to estimate the annual heat consumption

[2] Annual capital component is based on the replacement of the existing 4,800 hp UVM plant at $1,500/hp, and 2,800 hp back-up boilers at $1000/hp for the total cost of $9.97 million (1997 money). The annual component is an amount that has to be deposited in a 6.5% bearing account to accumulate the total replacement amount with 3% escalation. With district heating the replacement of the equipment is not necessary for two reasons: the service life of the existing equipment nearly doubles as it operates only as peaking and back-up; the district heating company will eventually assume peaking and back-up responsibility.

[3] District heating cost is based on developed district heating rate and estimated annual heat consumption. The district heating rate includes the cost of fuel to keep the UVM boilers warm and provide a boiler plant operation during McNeil shutdown.

Table 37a
UVM HTHW 20 Year Savings (high savings assumptions)

Annual Heating Consumption	269,395
Fuel Cost Escalation	2.5%
General Inflation	2.5%
Discount Rate	6.0%

year	1	2	3	4	5	6	7	8	9	10
Without District Heating, $										
Fuel	1,457,362	1,493,796	1,531,141	1,569,419	1,608,655	1,648,871	1,690,093	1,732,345	1,775,654	1,820,045
Capital	3,163,492	518,492	518,492	518,492	518,492	518,492	518,492	518,492	518,492	518,492
Maintenance	1,052,742	1,079,060	1,106,037	1,133,688	1,162,030	1,191,081	1,220,858	1,251,379	1,282,663	1,314,730
TOTAL WITHOUT DISTRICT HEATING	5,673,595	3,091,348	3,155,669	3,221,599	3,289,176	3,358,443	3,429,442	3,502,216	3,576,809	3,653,267
With District Heating, $										
Fuel	56,643	58,059	59,511	60,998	62,523	64,086	65,689	67,331	69,014	70,739
Capital	190,000	190,000	190,000	190,000	190,000	190,000	190,000	190,000	190,000	190,000
Maintenance	626,626	642,291	658,349	674,807	691,678	708,970	726,694	744,861	763,483	782,570
District Heating Cost	2,349,385	2,150,580	2,146,797	2,142,095	2,136,429	2,129,755	2,122,023	2,113,185	2,103,188	2,091,980
TOTAL WITH DISTRICT HEATING	3,222,654	3,040,931	3,054,656	3,067,900	3,080,630	3,092,811	3,104,405	3,115,376	3,125,685	3,135,289
Annual Savings, $	2,450,941	50,417	101,013	153,698	208,546	265,633	325,037	386,840	451,124	517,978

year	11	12	13	14	15	16	17	18	19	20
Without District Heating, $										
Fuel	1,865,547	1,912,185	1,959,990	2,008,990	2,059,214	2,110,695	2,163,462	2,217,549	2,272,987	2,329,812
Capital	518,492	518,492	518,492	518,492	518,492	518,492	518,492	518,492	518,492	518,492
Maintenance	1,347,598	1,381,288	1,415,821	1,451,216	1,487,496	1,524,684	1,562,801	1,601,871	1,641,918	1,682,966
TOTAL WITHOUT DISTRICT HEATING	3,731,636	3,811,965	3,894,302	3,978,697	4,065,202	4,153,870	4,244,755	4,337,911	4,433,397	4,531,269
With District Heating, $										
Fuel	72,508	74,321	76,179	78,083	80,035	82,036	84,087	86,189	88,344	90,552
Capital	190,000	190,000	190,000	190,000	190,000	190,000	190,000	190,000	190,000	190,000
Maintenance	802,134	822,187	842,742	863,811	885,406	907,541	930,229	953,485	977,322	1,001,755
District Heating Cost	2,078,939	2,065,126	2,049,930	2,033,289	2,015,139	1,995,415	1,974,048	1,950,968	1,926,101	1,938,131
TOTAL WITH DISTRICT HEATING	3,143,581	3,151,634	3,158,851	3,165,182	3,170,580	3,174,992	3,178,364	3,180,642	3,181,767	3,220,438
Annual Savings, $	588,056	660,331	735,451	813,515	894,622	978,878	1,066,390	1,157,269	1,251,630	1,310,831

NPV of Savings **$7,646,929**

FAHC

The FAHC first and second year energy cost with and without the district heating is presented in Table 38a based on option 1 assumptions and in Table 38b for option 2 assumptions. The major assumptions are as follows:

- Overall boiler seasonal efficiency is 70% for both options
- The total first year capital cost avoidance is $2,330,000 (option 1) and $1,585,000 (option 2).

The second year annual savings are estimated at $232,841 for option 1 and at $67,157 with FAHC assumptions.

Net present value of savings for 20 years is estimated at $4.9 million with JTC assumptions (Table 39) and $2.8 million for option 2 (Table 39 a).

Stage Two / Stage Three Customers

The current second and third stage customer self-generation costs of useful heat have been developed and are summarized in Table 39c. These costs vary from $14.67 to $32 per MMBtu. The self-generation cost includes the following components: fuel, annual cost of capital and operation and maintenance. These customers have low seasonal boiler efficiencies and therefore their self-generation cost is higher than that of UVM and FAHC. With district energy these costs will be reduced by up to 30%. It is proposed that the DH company pay the hook-up costs at the UVM and FAHC. However, the potential customers of the second and third stages will have to retrofit their buildings to MTHW at their own cost. In exchange, the DH rates would allow for an attractive pay-back on their retrofit investment.

The retrofit of second and third stage customers to MTHW will be performed in accordance with the methodology developed for UVM and FAHC.

Table 38b
FAHC HTHW, low savings assumptions

1994 - 96 Annual Expenditures for the FAHC Central Plant	Without District Heating (1st year)		Without District Heating (2nd year)		With District Heating (1st year)		With District Heating (2nd year)		Savings	
	Total	Unit Cost, $/MMBtu	Total	Unit Cost, $/MMBtu	Total	Unit Cost, $/MMBtu	Total	Unit Cost, $/MMBtu	1st year	2nd year
FUEL										
Annual Fuel Cost, Including:	703,272	5.95	720,854	6.10	3,863	0.03	3,960	0.03	699,409	716,894
Gas	689,947		707,196		3,863		3,960		686,084	703,236
Oil	13,325		13,658		-		-		13,325	13,658
CAPITAL COMPONENT										
Replace 2 - 600 BHP boilers (MCHV)	500,000				-		-		500,000	500,000
New 500 BHP boilers (for ACF)	200,000				-		-		200,000	200,000
Replace 100 BHP with 350 BHP (UHC)	150,000				-		-		150,000	150,000
Replace 500 BHP with 350 BHP (UHC)	175,000				-		-		175,000	175,000
Feedwater/Deaeration	300,000		300,000		-		-		300,000	300,000
Miscellaneous Improvements	260,000		210,000		-		-		260,000	260,000
Total First Year Capital Cost	1,585,000		510,000		-		-		1,585,000	1,585,000
Ammortized Annual Capital Cost, 6.5%, 20 years	143,849		143,849		-		-		143,849	143,849
Capital Allocation for Existing Equipment Replacement in 20 years	13,025		13,025		-				13,025	13,025
Annual Capital Component: 6.5%, 20 years	156,874	1.33	156,874.18	1.33	-	0.00	-	0.00	156,874	156,874
MAINTENANCE/OPERATIONS (NON-FUEL)										
Labor Cost	109,272		112,004		-		-		109,272	112,004
Annual Service Contracts	4,333		4,442		2,000		2,050		2,333	2,392
Annual Chemicals	25,196		25,826		25,196		25,826		0	0
Annual Parts Cost	2,439		2,500		488		500		1,951	2,000
Annual Insurance	10,674		10,941		5,337		5,470		5,337	5,471
Annual Water & Sewer	61,600		63,140		61,600		63,140		-	-
Annual Electric Cost	12,000		12,300		1,200		1,230		10,800	11,070
Total Maintenance/Operations (non-fuel)	225,515	1.91	231,153	1.96	95,821	0.81	98,216	0.83	129,694	132,936
DISTRICT HEATING COST	-	0.00	-	0.00	1,037,036	8.77	939,547	7.95	(1,037,036)	(939,547)
TOTAL ANNUAL COST	1,085,661	9.19	1,108,880	9.38	1,136,720	9.62	1,041,720	8.81	-51,059	67,157

The low savings assumptions represent the judgement of FAHC

Table 39b
FAHC HTHW 20 Year Savings (low savings assumptions)

Annual Heating Consumption	118,198
Fuel Cost Escalation	2.5%
General Inflation	2.5%
Discount Rate	6.0%

year	1	2	3	4	5	6	7	8	9	10
Without District Heating, $										
Fuel	703,272	720,854	738,875	757,347	776,281	795,688	815,580	835,969	856,869	878,290
Capital	156,874	156,874	156,874	156,874	156,874	156,874	156,874	156,874	156,874	156,874
Maintenance	225,515	231,153	236,931	242,855	248,926	255,149	261,528	268,066	274,768	281,637
TOTAL WITHOUT DISTRICT HEATING	1,085,661	1,108,880	1,132,681	1,157,076	1,182,081	1,207,711	1,233,982	1,260,910	1,288,511	1,316,801
With District Heating, $										
Fuel	3,863	3,960	4,059	4,160	4,264	4,371	4,480	4,592	4,707	4,824
Capital	-	-	-	-	-	-	-	-	-	-
Maintenance	95,821	98,216	100,672	103,189	105,768	108,413	111,123	113,901	116,748	119,667
District Heating Cost	1,037,036	939,547	945,828	943,863	941,477	938,652	935,365	931,595	927,319	922,515
TOTAL WITH DISTRICT HEATING	1,136,720	1,041,723	1,050,558	1,051,211	1,051,510	1,051,435	1,050,967	1,050,088	1,048,775	1,047,007
Annual Savings, $	(51,059)	67,157	82,122	105,865	130,571	156,276	183,014	210,822	239,736	269,794

year	11	12	13	14	15	16	17	18	19	20
Without District Heating, $										
Fuel	900,248	922,754	945,823	969,468	993,705	1,018,548	1,044,011	1,070,112	1,096,864	1,124,286
Capital	156,874	156,874	156,874	156,874	156,874	156,874	156,874	156,874	156,874	156,874
Maintenance	288,678	295,895	303,292	310,874	318,646	326,612	334,778	343,147	351,726	360,519
TOTAL WITHOUT DISTRICT HEATING	1,345,800	1,375,523	1,405,989	1,437,217	1,469,225	1,502,034	1,535,663	1,570,133	1,605,464	1,641,679
With District Heating, $										
Fuel	4,945	5,069	5,195	5,325	5,458	5,595	5,735	5,878	6,025	6,176
Capital	-	-	-	-	-	-	-	-	-	-
Maintenance	122,659	125,725	128,868	132,090	135,392	138,777	142,247	145,803	149,448	153,184
District Heating Cost	916,910	910,969	904,424	897,248	889,413	880,890	871,650	861,662	850,893	856,317
TOTAL WITH DISTRICT HEATING	1,044,514	1,041,763	1,038,487	1,034,663	1,030,263	1,025,262	1,019,632	1,013,343	1,006,366	1,015,676
Annual Savings, $	301,286	333,760	367,502	402,554	438,962	476,772	516,031	556,790	599,098	626,003

NPV of Savings $2,744,362

Section 10
COOLING LOAD SUPPLY

The construction of the HTHW system offers an opportunity to supply cooling by means of high efficiency absorption chillers. This alternative will permit customers who presently have electric chilling to reduce their electricity cost. It is also proposed to offer district heating based cooling at a substantial discount rate.

An economic assessment of these alternatives has been performed. The other opportunity to increase efficiency is the interconnection of the UVM Given Medical Center central chilled water system with the FAHC cooling system. These alternatives are discussed below.

University of Vermont

The Given Medical Complex has a central chilled water system of 1,000 tons capacity. The chillers are old and have to be replaced. The ice rink has two reciprocating chillers producing 8°F brine which is returned at 28°F. These chillers are specific purpose chillers, therefore this portion of the load was not included in the total UVM cooling load. Some of the newer buildings, such as the Stafford, also, have central chilled water systems.

UVM plans to air condition some dormitory complexes so that they can be used to house students attending summer school. The need for summer school is increasing as a means of utilizing the campus year round. Presently UVM also faces the need to replace some older chillers with new non-CFC chillers. The chiller capacities that must be installed in the near future are summarized in Table 40. Total cooling load to be installed is 2,715 tons. This load represents the actual cooling load and does not include the back-up requirements. Recently, UVM has installed a 370 ton single stage absorption chiller at the Marsh building.

consumption (9,000 - 10,000 Btu per ton-hr of cooling) were considered. However their capital cost is higher then the cost of centrifugal electric chillers.

Table 41
Marginal Cost of Thermal Energy for Absorption Cooling

Thermal Load for Absorption Cooling	
Peak Demand For Cooling, MMBtu/hr	57
Annual Consumption, MMBtu	105,165
Annual Cost, $	
Fuel Cost	182,987
Must Run Penalty	112,898
Pumping Power Cost	2,000
Makeup Water Cost	1,300
City Operation Fee	8,976
Total Annual Cost, $	308,160
Marginal Unit Generation Cost, $/MMBtu	2.93

Annual operating costs for two stage absorption and centrifugal electric chillers for UVM have been compared (Table 42). With the capital cost difference of $235,000 between the absorption and electric chillers, the absorption chiller option has an attractive pay-back of only 3.4 years (Table 43). Furthermore, the UVM annual electric bill will be reduced by $296,000.

For FAHC the installation of absorption chillers (Table 44) also yields a 3.7 years pay-back (Table 45). The FAHC annual electric bill will be reduced by $380,000.

The absorption chillers become feasible only at the discount district energy rate and are not feasible at the UVM and FAHC self-generation thermal energy cost.

<u>**Interconnection of the existing cooling systems**</u>

FAHC and UVM Given Medical Center already have central cooling systems. With installation of new absorption chillers, the total combined load of these two facilities is expected to reach 4,000 tons. Interconnection of the chillers is recommended. There is a

Table 44
Comparison of Cooling Alternatives for FAHC

Cooling Load Assessment	
Total Chiller Capacity, ton	3,000
EFLH (Equivalent Full Load Hours)	2,000
Annual Cooling Consumption, ton-hr	6,000,000
Chiller Efficiency	
Absorption Chiller Efficiency, Btu/ton hr	10,000
Centrifugal Chiller Efficiency, kW/ton	0.70
Energy Rates	
District Hot Water Cost, $/MMBtu	5.00
Electric Energy Rate, $/kWh	0.056
Electric Demand Charge, $/kW	14.00
Absorption Chillers	
Annual Energy Consumption, MMBtu	60,000
Total Annual Energy Cost, $	300,000
Electric Centrifugal Chillers	
Annual Energy Consumption, kWh	4,200,000
Annual Energy Cost, $	233,325
Annual Demand Cost, $	147,000
Total Annual Electric Cost, $	380,325
Annual Savings, $	**80,325**

Table 45
Capital Cost Comparison for FAHC

Alternative	Capital Cost, $
Electric Chillers	3,000,000
Absorption Chillers	3,300,000
Capital Cost Difference, $	**300,000**
Simple Pay-back, years	**3.7**

Section 11
FINANCING AND OWNERSHIP

Many ownership and funding strategies are possible for a district energy system. The following instruments may be among alternatives which can be employed through a governmental association to finance a district energy project.

- General obligation bonds are issued by a municipality which pledges its full faith and credit, promising to levy taxes as required for payment of principal and interest.
- Municipal revenue bonds are issued by a municipality pledging the revenues generated from the project to the repayment of principal and interest.
- Industrial development revenue bonds are issued by a state-designated agency on behalf of a private entity who leases the facility from the government and is responsible for payment of principal and interest.
- Urban Development Action Grants, UDAG's, are awarded to local governments on the basis of a national competition which can then lend or grant the funds to private or municipal developers. A major eligibility criterion is a firm financial commitment from the private sector. The private investor must be at risk for the project, not the public participants, although, public financial participation is not discouraged.

General obligation bonds offer the lowest cost of debt because they combine the tax exempt status with a low risk for investors. In this case the bond obligation is backed by the municipal tax base. Thus, this bond issues are rated based on the financial health of the municipality rather then on the viability of the project. However this type of bond financing is hard to obtain because it requires voter approval. There is, generally, a luck of public support for district energy systems because they benefit only the limited portion of electorate. Only publicly owned projects can be financed with general obligation bonds. This would make BED the best suited owner of the district energy system.

Municipal revenue bonds offer another tax exempt debt financing option. The difference between general obligation and revenue bonds is that revenue bonds are only backed by

Special Management Contract Rule. Certain management contracts will not result in the project being treated as a private business use if: (1) the contract term does not exceed five years (including renewals); (2) at least 50% of the management compensation is on a periodic, fixed fee basis; (3) no sharing of net profits is permitted; and (4) the agreement may be terminated by the governmental owner without penalty at the end of any three year period.

Qualified Private Activity Bonds. The interest on a private activity bond is taxable unless the bonds are "qualified private activity bonds." The following qualified private activity bonds are entitled to tax exemptions:

a. Exempt facility bonds (e.g., airports, docks and wharves, mass commuting facilities, facilities for furnishing of water, sewage facilities, solid waste disposal facilities, qualified residential rental projects, facilities for the local furnishing of electric energy or gas, local district heating or cooling facilities, or qualified hazardous waste facilities).
b. Qualified mortgage bonds.
c. Qualified small issue bonds.
d. Qualified student loan bonds.
e. Qualified redevelopment bonds.

Therefore, the Burlington district energy system will be qualified for tax exempt bond financing.

Another investment strategy which gained appeal for a number of reasons is third party financing. The options examined below are directly applicable to private sector incentives for developing district energy systems. A financing arrangement can be structured to place the primary financial risk (in hope of potential rewards) with the third party, permitting system users to concentrate on operation and management of the district energy system. Where system users are unfamiliar or uncomfortable with the substantial investment required for the system, a knowledgeable third party can accept this risk. Third party arrangements often exploit tax incentives intended for major energy investments not otherwise available by back the loan. Long-term contracts offer the assurance of revenue, but sometimes at the expense of profits. If, for example, a strong fluctuation in the price of fuel occurs, the price of energy will change, but may not be accurately passed on to the energy customer. In a short-term contract price adjustments can be made in each successive contract. A long-term contract can still be a good direction to take if escalation of fuel can be taken into account in the price structure of the agreement.

It was determined that municipal revenue bonds be considered for financing the Greater Burlington district energy system.

Hot water district heating systems are currently not regulated in any of U.S. states. Therefore, we do not anticipate that the Burlington district heating hot water system will be regulated by the Vermont Public Service Board or any other regulatory body.

through a fuel chute and is spread across the furnace, where small pieces of the fuel burn while in suspension. Simultaneously, larger pieces of fuel are spread in a thin, even bed on a grate. The burning is accomplished in three stages in a single chamber: moisture evaporation, distillation and burning of volatile mater, and burning of fixed carbon. The boiler is equipped with effective flue gas filtering devices to reduce the particulate. The emissions are constantly monitored at the station. The emissions per MMBtu of wood input were obtained from the plant management and are summarized in Table 46. From this table, it can be seen that while NO_x emission levels of wood and gas firing are very similar in terms of MMBtu fuel input, the particulate mater pollution for McNeil is even lower then that for uncontrolled gas fired boilers.

The primary benefit of cogeneration is capturing heat that would be otherwise rejected to the environment. Therefore, only a portion of the useful district energy comes from firing the fuel and the rest is the recovered waste heat. This allows a substantial decrease in fuel consumption compared with a gas fired boiler with seasonal efficiency of 72%. Burning less fuel means less pollutants released to the environment. The air pollutants released to the atmosphere with the HTHW option versus individual heating is compared in Table 47.

The best way to assign a value to the environmental benefits is by estimation of their externality cost. Economists define "externalities" as follows: when an economic entity bears costs that it does not pay or be compensated for, these costs are said to be external costs. Similarly, when the entity gets benefits that it does not pay for, these benefits are said to be external benefits. In general, these benefits are called externalities.

U.S. environmental standards are the toughest in the world, yet even when power and boiler plants fully meet federal and state environmental regulations, they still cause some pollution. These exhaust emissions comply with applicable environmental regulations, but nonetheless, have an environmental and financial cost to society. Externality theory says that society pays for the external costs of pollution.

Table 47
Environmental Externalities (HTHW)

Annual Quantities

year	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
Annual Heat Consumption, MMBtu	393,436	414,911	436,387	457,863	479,338	500,814	520,044	539,274	558,505	577,735
McNeil										
Fuel Consumption, MMBtu	328,593	352,348	376,104	399,859	423,615	447,370	456,429	465,488	474,547	483,606
NO_x, ton	23.00	24.66	26.33	27.99	29.65	31.32	31.95	32.58	33.22	33.85
SO_2, ton	0.19	0.21	0.22	0.23	0.25	0.26	0.27	0.27	0.28	0.28
Particulates, ton	0.66	0.70	0.75	0.80	0.85	0.89	0.91	0.93	0.95	0.97
CO, ton	16.43	17.62	18.81	19.99	21.18	22.37	22.82	23.27	23.73	24.18
CO_2, ton	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
TOC, ton	4.02	4.31	4.60	4.89	5.18	5.47	5.58	5.69	5.80	5.91
Individual Heating										
Fuel Consumption, MMBtu	517,679	545,936	574,194	602,451	630,708	658,966	684,269	709,572	734,875	760,178
NO_x, ton	36.35	38.33	40.31	42.30	44.28	46.27	48.04	49.82	51.60	53.37
SO_2, ton	26.64	28.09	29.55	31.00	32.46	33.91	35.21	36.51	37.82	39.12
Particulates, ton	3.63	3.83	4.03	4.23	4.43	4.63	4.80	4.98	5.16	5.34
CO, ton	9.09	9.58	10.08	10.57	11.07	11.57	12.01	12.45	12.90	13.34
CO_2, ton	32,116	33,869	35,622	37,375	39,128	40,882	42,451	44,021	45,591	47,161
TOC, ton	1.45	1.53	1.61	1.69	1.77	1.85	1.92	1.99	2.07	2.14

year	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Annual Heat Supply, MMBtu	596,965	596,965	596,965	596,965	596,965	596,965	596,965	596,965	596,965	596,965
McNeil										
Fuel Consumption, MMBtu	492,665	492,665	492,665	492,665	492,665	492,665	492,665	492,665	492,665	492,665
NO_x, ton	34.49	34.49	34.49	34.49	34.49	34.49	34.49	34.49	34.49	34.49
SO_2, ton	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29
Particulates, ton	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99
CO, ton	24.63	24.63	24.63	24.63	24.63	24.63	24.63	24.63	24.63	24.63
CO_2, ton	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
TOC, ton	6.02	6.02	6.02	6.02	6.02	6.02	6.02	6.02	6.02	6.02
Individual Heating										
Fuel Consumption, MMBtu	785,481	785,481	785,481	785,481	785,481	785,481	785,481	785,481	785,481	785,481
NO_x, ton	55.15	55.15	55.15	55.15	55.15	55.15	55.15	55.15	55.15	55.15
SO_2, ton	40.42	40.42	40.42	40.42	40.42	40.42	40.42	40.42	40.42	40.42
Particulates, ton	5.51	5.51	5.51	5.51	5.51	5.51	5.51	5.51	5.51	5.51
CO, ton	13.79	13.79	13.79	13.79	13.79	13.79	13.79	13.79	13.79	13.79
CO_2, ton	48,730	48,730	48,730	48,730	48,730	48,730	48,730	48,730	48,730	48,730
TOC, ton	2.21	2.21	2.21	2.21	2.21	2.21	2.21	2.21	2.21	2.21

Table 47 (Continued)
Environmental Externalities (HTHW)

Annual Externality Cost for All Customers, $

year	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
McNeil										
NO_x	157,659	173,283	189,590	206,604	224,350	242,855	253,966	265,482	277,415	289,778
SO_2	275	303	331	361	392	424	443	464	484	506
Particulates	2,515	2,764	3,024	3,295	3,578	3,874	4,051	4,234	4,425	4,622
CO	17,261	18,972	20,757	22,620	24,563	26,589	27,806	29,067	30,373	31,727
CO_2	0	0	0	0	0	0	0	0	0	0
TOC	18,566	20,405	22,326	24,329	26,419	28,598	29,907	31,263	32,668	34,124
Total	196,276	215,727	236,028	257,210	279,302	302,339	316,173	330,509	345,365	360,757
Individual Heating										
NO_x	249,126	269,293	290,312	312,214	335,030	358,791	381,882	405,903	430,887	456,867
SO_2	38,260	41,357	44,585	47,949	51,453	55,102	58,648	62,337	66,174	70,164
Particulates	13,907	15,033	16,207	17,429	18,703	20,029	21,318	22,659	24,054	25,504
CO	9,547	10,319	11,125	11,964	12,838	13,749	14,634	15,554	16,512	17,507
CO_2	290,182	313,672	338,156	363,667	390,242	417,919	444,816	472,796	501,897	532,158
TOC	6,726	7,270	7,838	8,429	9,045	9,686	10,310	10,958	11,633	12,334
Total	607,748	656,945	708,222	761,652	817,311	875,277	931,608	990,208	1,051,157	1,114,534
Annual Savings	411,473	441,218	472,194	504,442	538,008	572,937	615,435	659,699	705,792	753,777

year	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
McNeil										
NO_x	302,587	310,151	317,905	325,853	333,999	342,349	350,908	359,680	368,672	377,889
SO_2	528	542	555	569	583	598	613	628	644	660
Particulates	4,826	4,947	5,071	5,197	5,327	5,460	5,597	5,737	5,880	6,027
CO	33,129	33,957	34,806	35,676	36,568	37,482	38,419	39,380	40,364	41,374
CO_2	0	0	0	0	0	0	0	0	0	0
TOC	35,632	36,523	37,436	38,372	39,331	40,314	41,322	42,355	43,414	44,500
Total	376,702	386,120	395,773	405,667	415,809	426,204	436,859	447,781	458,975	470,449
Individual Heating										
NO_x	483,876	495,972	508,372	521,081	534,108	547,461	561,147	575,176	589,555	604,294
SO_2	74,312	76,169	78,074	80,026	82,026	84,077	86,179	88,333	90,542	92,805
Particulates	27,012	27,687	28,380	29,089	29,816	30,562	31,326	32,109	32,912	33,735
CO	18,542	19,006	19,481	19,968	20,467	20,979	21,503	22,041	22,592	23,157
CO_2	563,618	577,708	592,151	606,955	622,129	637,682	653,624	669,964	686,714	703,881
TOC	13,063	13,390	13,724	14,068	14,419	14,780	15,149	15,528	15,916	16,314
Total	1,180,422	1,209,933	1,240,181	1,271,186	1,302,966	1,335,540	1,368,928	1,403,151	1,438,230	1,474,186
Annual Savings	803,720	823,813	844,409	865,519	887,157	909,336	932,069	955,371	979,255	1,003,736

NPV of Savings 7,344,951

Table 49
Environmental Externalities (HTHW)

Annual Externality Cost for FAHC, $

year	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
McNeil										
NO_x	46,413	48,372	50,320	52,264	54,210	56,165	56,563	57,019	57,531	58,094
SO_2	81	84	88	91	95	98	99	100	100	101
Particulates	740	772	803	834	865	896	902	909	918	927
CO	5,082	5,296	5,509	5,722	5,935	6,149	6,193	6,243	6,299	6,360
CO_2	0	0	0	0	0	0	0	0	0	0
TOC	5,466	5,696	5,926	6,154	6,384	6,614	6,661	6,714	6,775	6,841
Total	57,781	60,221	62,645	65,065	67,488	69,922	70,417	70,986	71,622	72,324
FAHC										
NO_x	73,340	75,174	77,053	78,979	80,954	82,978	85,052	87,178	89,358	91,592
SO_2	11,263	11,545	11,833	12,129	12,433	12,743	13,062	13,389	13,723	14,066
Particulates	4,094	4,197	4,301	4,409	4,519	4,632	4,748	4,867	4,988	5,113
CO	2,810	2,881	2,953	3,026	3,102	3,180	3,259	3,341	3,424	3,510
CO_2	85,427	87,562	89,751	91,995	94,295	96,652	99,069	101,545	104,084	106,686
TOC	1,980	2,029	2,080	2,132	2,186	2,240	2,296	2,354	2,412	2,473
Total	178,915	183,387	187,972	192,671	197,488	202,425	207,486	212,673	217,990	223,440
Annual Savings	121,133	123,167	125,327	127,606	130,000	132,503	137,069	141,688	146,368	151,116

year	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
McNeil										
NO_x	58,708	60,176	61,680	63,222	64,803	66,423	68,083	69,785	71,530	73,318
SO_2	103	105	108	110	113	116	119	122	125	128
Particulates	936	960	984	1,008	1,034	1,059	1,086	1,113	1,141	1,169
CO	6,428	6,588	6,753	6,922	7,095	7,272	7,454	7,640	7,832	8,027
CO_2	0	0	0	0	0	0	0	0	0	0
TOC	6,913	7,086	7,263	7,445	7,631	7,822	8,017	8,218	8,423	8,634
Total	73,088	74,915	76,788	78,708	80,675	82,692	84,759	86,878	89,050	91,277
FAHC										
NO_x	93,882	96,229	98,634	101,100	103,628	106,218	108,874	111,596	114,386	117,245
SO_2	14,418	14,778	15,148	15,527	15,915	16,313	16,720	17,138	17,567	18,006
Particulates	5,241	5,372	5,506	5,644	5,785	5,930	6,078	6,230	6,386	6,545
CO	3,598	3,687	3,780	3,874	3,971	4,070	4,172	4,276	4,383	4,493
CO_2	109,353	112,087	114,889	117,761	120,705	123,723	126,816	129,987	133,236	136,567
TOC	2,535	2,598	2,663	2,729	2,798	2,868	2,939	3,013	3,088	3,165
Total	229,026	234,751	240,620	246,636	252,802	259,122	265,600	272,240	279,046	286,022
Annual Savings	155,938	159,836	163,832	167,928	172,126	176,429	180,840	185,361	189,995	194,745

NPV of Savings 1,608,890

Table 50 (Continued)
Environmental Externalities (MTHW)

Unit Externality Cost, $/ton

Year	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
NO_x	7,755	7,949	8,148	8,351	8,560	8,774	8,993	9,218	9,449	9,685
SO_2	1,625	1,666	1,707	1,750	1,794	1,838	1,884	1,932	1,980	2,029
Particulates	4,329	4,437	4,548	4,662	4,779	4,898	5,021	5,146	5,275	5,407
CO	1,189	1,218	1,249	1,280	1,312	1,345	1,379	1,413	1,448	1,485
CO_2	10	10	11	11	11	12	12	12	12	13
TOC	5,230	5,361	5,495	5,632	5,773	5,918	6,065	6,217	6,373	6,532

Year	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
NO_x	9,927	10,175	10,430	10,690	10,958	11,232	11,512	11,800	12,095	12,398
SO_2	2,080	2,132	2,185	2,240	2,296	2,353	2,412	2,473	2,534	2,598
Particulates	5,542	5,680	5,822	5,968	6,117	6,270	6,427	6,587	6,752	6,921
CO	1,522	1,560	1,599	1,639	1,680	1,722	1,765	1,809	1,854	1,900
CO_2	13	13	14	14	14	15	15	16	16	16
TOC	6,695	6,862	7,034	7,210	7,390	7,575	7,764	7,958	8,157	8,361

Section 13

CONCLUSION AND RECOMMENDATIONS

The analysis has demonstrated that a district energy system for the Greater Burlington area is technically and economically feasible. The following plan of actions for system implementation is recommended:

- Develop detailed retrofit cost for UVM and FAHC retrofit to MTHW
- Obtain agreement of McNeil owners for the implementation of the district energy system
- Negotiate contracts with UVM and FAHC for purchase of district energy
- Install Btu-meters at the UVM and FAHC central plants as soon as possible to record the actual heat consumption of their facilities.
- Prepare for system financing by the City of Burlington
- Investigate legal issues related to formation of a district energy company by the City of Burlington
- Obtain official permission to waive the excavation fee issue by the City of Burlington.