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FINAL REPORT

EVALUATION OF SUPPLY-SIDE OPTIONS FOR THE PLZEN DISTRICT HEATING SYSTEM

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by

GILBERT/COMMONWEALTH, INC

and

Subcontractors:

EGU Praha
RAEN, Ltd
Energoprojekt Praha
CityPlan

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EVALUATION OF SUPPLY-SIDE OPTIONS FOR THE PLZEN DISTRICT HEATING SYSTEM

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Abbreviations and Acronyms

AID	Agency for International Development
Btu	British thermal unit
CEM	Continuous Emission Monitor
CFB	Circulating Fluidized Bed
Ck	Czech crowns (Koruna)
CO	Carbon monoxide
CP	Cogeneration Plant
CSD	Czechoslovak Railways
DH	District Heating
DHS	District Heating System
DOE	Department of Energy
DSI	Duct Sorbent Injection
EGP	EnergoProjekt Praha
EGU	EGU
ESP	Electrostatic Precipitator
FBC	Fluidized Bed Combustion
FGD	Flue Gas Desulphurization
G/C	Gilbert/Commonwealth
GJ	Gigajoules, (10^9 joules)
GT	Gas Turbine
GTCC	Gas Turbine Combined Cycle
HP	Heating Plant
HRSG	Heat Recovery Steam Generator
HS	Heating Station
HW	Hot Water
ISO	International Standards Organization
Kc	Czech Crown (Koruna)
kPa	kilopascal
kW	kilowatt
LHV	Lower Heating Value
mg/m^3	milligram per cubic meter
MPa	Megapascal
MWe	Megawatt, electric
MWh	Megawatt-hour

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MWt	Megawatt, thermal
NA	Not Applicable
NOx	Nitric Oxides
NPV	Net Present Value
O_2	Oxygen
O&M	Operations and Maintenance
PC	Pulverized Coal
PFBC	Pressurized Fluidized Bed Combustion
Q	Heat
SO_2	Sulfur dioxide
ST	Steam Turbine
t	tonne
t/h	tonne/hour
TEZA	TEZA district heating company
TJ	Terajoules, (10^{12} joules)
U S	United States
VAT	Value Added Tax
ZCE	Zapadoceske Energeticke Zavody district heating company

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EXECUTIVE SUMMARY

This work was sponsored by the U S Agency for International Development (AID), and under contract to the U S Department of Energy (DOE), and performed by Gilbert/Commonwealth (G/C) G/C was assisted by four Czech subcontractors EGU Praha, Energoprojekt, RAEN, and CityPlan Pacific Northwest Laboratories (PNL) is responsible for integrating this supply-side work with their demand-side effort

The primary objective of this study is to determine the most cost effective heat supply option(s) for the Plzen District Heating companies that meet the anticipated heat and steam demands, and the new emission regulations The G/C scope includes an analysis of the current supply-side situation of the district heating systems in Plzen, excluding Skoda, who independently supplies heat to the Skvrnany area Recommendations for future emissions compliance and potential expansion/upgrading of the existing systems are offered

The primary basis for the supply-side work is a comprehensive study performed previously by Energoprojekt (EGP) A review by G/C found that the choice of variants by EGP was appropriate, the technical approach excellent, and the economic analysis accounted for the important variables when combined with sensitivity analyses However, since the EGP report was completed, many conditions have changed in the Czech Republic, requiring this re-assessment

While the initial focus of this study was the review of the 1991 Energoprojekt supply-side report, additional tasks performed are intended to provide the City of Plzen with a stronger basis for decision making

Several key considerations influenced this study

- the need to reassess energy use patterns,
- the future of many of the 595 small boilers in light of pending environmental regulations, i e , their potential for retrofit, or retirement as their consumers connect to the District Heating (DH) system,
- competitiveness of current and projected DH operating costs,
- economic inputs to the study in the context of a changing Czech economy, including the future price of fuels, especially imported natural gas,
- the relative capital cost of foreign vs domestic expenditures,
- the long-term cost of emissions compliance, and
- the potential to expand the present centralized DH system to include the area served by Svetovar (i e decision to complete Heat Line East II)

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The heat supply sources in the Plzen area can be categorized into three groups, which were addressed in this study as follows

- **Central heating plants**
  The central heating plants are the focus of this study with special emphasis placed on CP Plzen, the cooperating sources, and the future of Heat Station Svetovar,
- **Decentralized 595 small boilers**
  The decentralized 595 small boilers were considered for efficiency improvement, emissions reduction, and retirement (with consumer connection to DH system), and
- **Small home furnaces**
  Small home furnaces emissions estimates were made without a detailed consideration for potential improvement of efficiency or emissions

The following sections summarize the findings of this study

Current Centralized District Heating Supply System

Centralized DH is presently supplied to the City of Plzen by the following sources

- Cogeneration Plant (CP) Plzen, with collaborating sources Bory and peak source Kosutka,
- cooperating (with CP Plzen) steam source, West Bohemian Brewery Boiler House (Zapadoceske Pivovary),
- cooperating steam source (with CP Plzen), Railway Maintenance Company Boiler House (Zos),
- independent hot water DH system Doubravka (Letna and Doubravka stations),
- independent hot water DH system Svetovar, and
- on the west side, Skoda Works, supplying large quantities of heat and steam to its own production facilities, and heat to the habitation Skvrnany

The Central DH system is the focus of this study The relative location of these sources is shown schematically in Exhibit E-1, and described in Section 2 0

Several of the existing boiler units are near the end of their useful life, especially in the older independent DH systems (Doubravka and Svetovar) These boilers may soon need replacement, or significant upgrading With the onset of environmental regulations, a decision to invest capital in the upgrade, or to invest in a higher efficiency replacement plant will soon be made This study offers a basis for this decision

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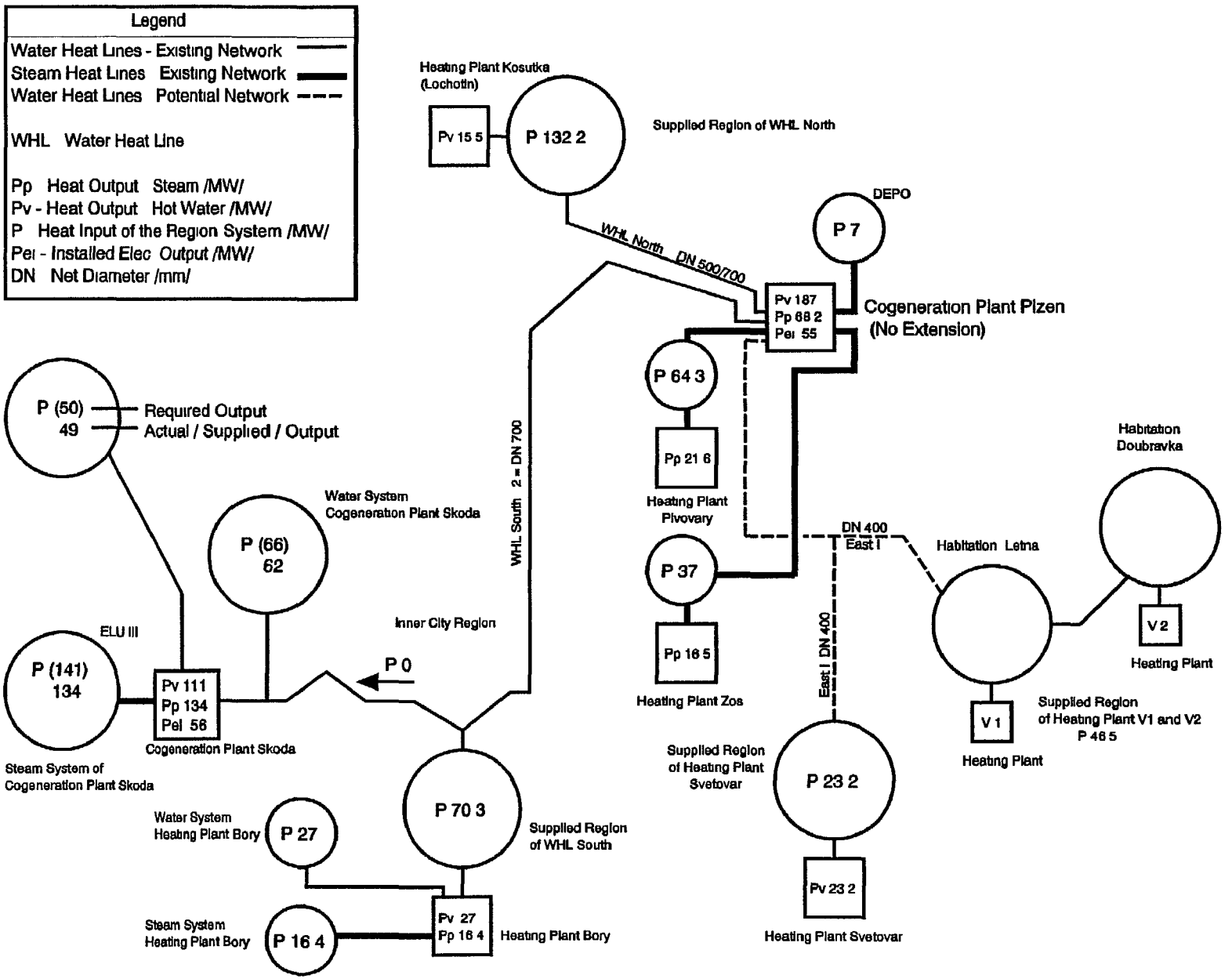
Exhibit E- 1
EXISTING DISTRICT HEATING SYSTEM IN PLZEN



Evaluation of Small Decentralized Sources

In addition to the centralized supply, there are 595 small boilers which provide a significant contribution to local pollution The total capacity of these boilers is approximately the same as the central DH system, excluding Skoda The status of these boilers, their potential to improve efficiency and emissions, and potential to connect to the DH system are characterized in Section 3 0 of this study

A related study concluded that small cogeneration system retrofits are not economically viable for these boilers, unless some special circumstance exists Further, it is concluded that small boiler consumers which have the possibility to be connected to the DH system, should do so, and that the City of Plzen should strongly encourage compliance with environmental regulations among small boiler owners and provide incentives to do so

Finally, there are numerous small home furnaces which contribute significantly to pollution in Plzen Some characterization of these furnaces was done in accounting for their emissions, but development of specific recommendations for improvement of these small units was outside the project scope The U S AID and DOE sponsored projects in Krakow should provide a wealth of information on methods of improving small furnace technology

The Revised Demand Assessment

The demand projection was reassessed to include additional parameters, including conservation by existing consumers, population growth (minimal), commercial/industrial growth, and new DH consumers from the pool of 595 small boilers Resulting costs of operation, and therefore competitiveness of DH with other energy sources, will depend heavily on the realization of these forecasts In turn, a reduction in the cost of energy supply will encourage new consumers to connect to the DH system The resulting supply costs will also have an impact on the incentive to conserve energy

The range of projected total demand through the year 2010, as used in this study, is presented in Exhibit E-2 Variants were evaluated for both the high (expected) and low of this range Note that in the high demand projection, about 25% increase in current overall demand is expected over the study period Most of this increased demand is located on Heat Lines South and East, and is attributed to anticipated connections of small boiler consumers Demand from existing consumers is expected to decrease through conservation efforts The low demand projection rises for the first few years, and then falls to its original level by 2010

Technology Review and Development of New Variants

Based on the changes to the demand projections, and on other requirements, new/revised variants (options) were developed Variants consider the operating method and economics included in a range of demand projections Improvement in system efficiency, summer operation, and reliability are considered The result is the expected "least cost" approach to meet the range of projected demands and the environmental regulations

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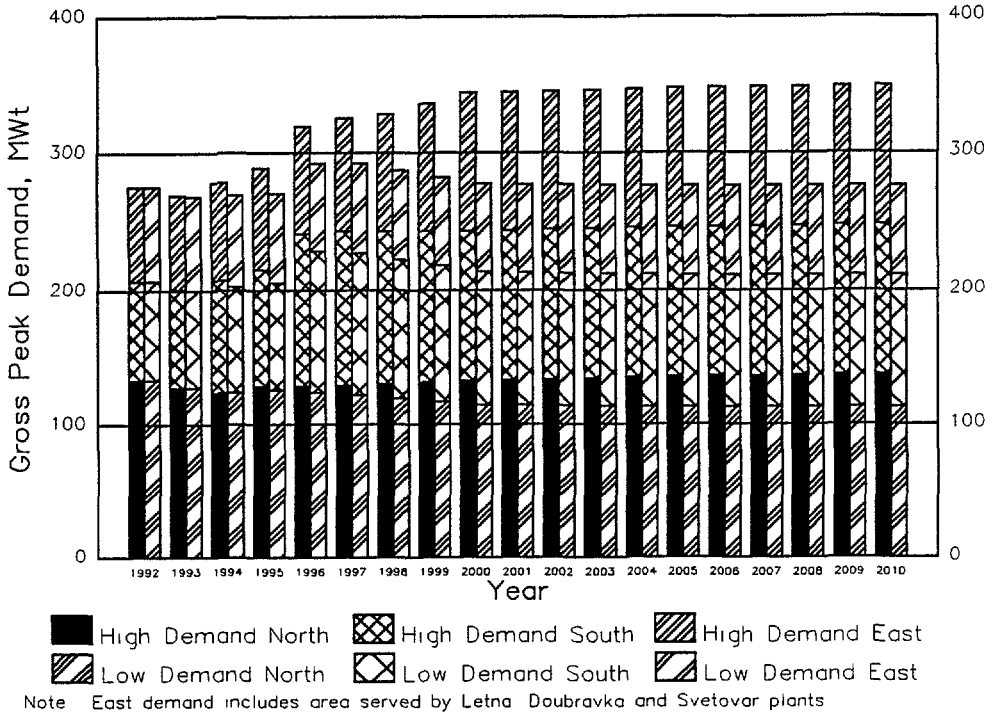
Exhibit E-2
TOTAL PLZEN DISTRICT HEATING DEMAND PROJECTION (excluding Skvrnany area)



Note East demand includes area served by Letna Doubravka and Svetovar plants

The variants (options) considered in the Plzen analysis are mainly distinguished by the selection of the plant technology for CP Plzen IV The basic plant technologies selected for analysis as Plzen IV are a (1) Gas-Fired Gas Turbine Combined Cycle, and (2) a Circulating Fluidized Bed (CFB) boiler The variant naming convention was selected to avoid confusion with the previous Energoprojekt designations Not all of the variants were investigated by each company The table below characterizes each variant by the Plzen IV technology selection and the investigating company

Variant	Investigator	Description of Distinguishing Feature (Choice of CP Plzen IV)
A1	EGU	Combined cycle plant with two 60 9 MWe (ISO) Gas Turbines
A2	EGU & G/C	Combined cycle plant with one 60 9 MWe (ISO) Gas Turbine
A3	G/C	Combined cycle plant with one 47 MWe (ISO) Gas Turbine
A4	EGP	Combined cycle plant with one 90 MWe (ISO) Gas Turbine
B1	EGU & G/C	Cogeneration plant with one CFB boiler and a 32 MWe steam turbine
C1	G/C	Life extension of existing units and subsequent introduction of a CFB boiler with a 32 MWe steam turbine in 2003

Not all variants were investigated by each company The EGU and EGP analyses are presented in Section 7 0 and the G/C analysis is found in Section 8 0

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A review of suitable technologies for the Plzen district heating systems resulted in a selection of technologies similar to those originally investigated in the 1991 Energoprojekt study In the G/C study, emissions reduction/system upgrade technologies were qualitatively considered and screened, while the selected options were analyzed quantitatively Emissions reduction technologies considered for district heating boilers include the following

- Integrated Gasification Combined Cycle (IGCC),
- Fuel cells,
- Conventional Pulverized Coal Fired (PC-fired) with Flue Gas Desulfurization (FGD),
- Fluidized Bed Combustion (FBC),
- Gas Turbine Combined Cycle (GTCC),
- Flue Gas Desulfurization (FGD) Retrofit,
- Duct Sorbent Injection (DSI),
- Gas Engine or Gas Turbine Repowering,
- Fuel Switching (including gas conversion), and
- Baghouse for particulate cleanup

The primary technologies selected for the study variants included FBC, GTCC, Fuel Switching and Baghouse

Two significant findings resulting from the technology evaluation are

1 Pressurized Fluidized Bed Combustion (PFBC) is a promising technology to burn low grade, low cost indigenous fuels in district heating systems, and at a much higher electric to heat ratio than conventional cogeneration systems Since PFBC is now reaching technical maturity, it could be available in a few years for widespread commercial use Choosing Variant C1, which postpones a decision for increased capacity, could result in this additional option

2 Duct Sorbent Injection (DSI) technology uses a lime slurry to capture SO_2 within a flue gas duct, and is feasible for moderate levels of SO_2 removal It provides a viable option to the fuel switch for CP Plzen II, in the case of potential problems caused by switching to black coal While the fuel switch is included in all of the investigated variants, DSI should not be eliminated as a possible alternative

Economic Analysis of New/Revised Variants

As described in Section 8 0, capital and operating costs developed for each variant are based on vendor quotes, in-house experience, and engineering judgement Capital cost of all new equipment, and cost associated with retirement of units is included Maintenance costs were estimated according to available ZCE information, and projections were prorated by the age of each unit Fuel cost projections were based on current Czech prices, evaluation of remaining subsidies, and comparisons with world prices and trends

In the G/C analysis, a simplified approach is used to "model" the system The performance of each studied plant is determined, and then an annual stream of costs is developed for each variant through the year 2010

Each variant is then structured to meet a demand and energy forecast of hot water and steam The production of electricity is also considered Calculations performed by EGU and EGP were evaluated and compared for the common variants investigated

Comparisons of G/C results made with the results of EGU for Variant A2 and B1 showed that the G/C simplified approach yields results which are accurate in terms of fuel use On a relative basis, the comparisons appear to be valid

Plant Operating Characteristics In the G/C model (Section 8 2), fuel usage to meet hot water and steam demands is determined by characterizing the ability of each unit to meet a given thermal demand for both steam and hot water on a delivery of heat (MWt) basis Generating units are dispatched in the model in a prioritized order until demand and minimum load criteria are met The boiler duty is estimated as the sum of the steam duty, hot water duty, turbine power and heat rejected to the cooling tower This boiler duty is augmented by an operating factor to capture operational influences like startup, shutdown, and equipment degradation

Some simpifying assumptions were made to model each steam turbine to account for varying extractions and steam flows A turbine curve was received from CP Plzen personnel for Plzen II Electric production of each turbine component is based upon the exhaust flow of the turbine The performance data for the other turbines were based upon typical turbine efficiencies for the sizes of interest, a simple heat balance, and miscellaneous support calculations

Gas turbines are significantly affected by ambient temperature, elevation and operating load As a result, developed performance data for the gas turbines of interest accounts for these major variables

Economic Analysis Several assumptions, found in Section 8 6, were made to support the economic analysis The primary tool for investigating the economic merit of each proposed variant is a spreadsheet model designed to simulate plant operations Available facilities are dispatched to meet steam and hot water demands in accordance with an established dispatching order

Cost streams associated with fuel requirements to meet steam and hot water demands are developed along with revenue from electrical production in a step-by-step procedure As the result of model simulations performed for each variant (detail presented in Appendix F), the cumulative present worth of projected operating and capital expenditures is presented in Exhibit E-3 and summarized below

Variant	Total Operating & Capital Costs US $(000)	Present Worth of Total Cost US $(000)	Present Worth of Cost Savings vs Base Case	Internal Rate of Return on Cost Savings
C1 (Base Case)	266,422	137,991	Base	Base
A2	325,436	179,443	(41,452)	Negative
A3	327 521	177 438	(39 477)	Negative
B1	251,302	141,052	(3,061)	5 97%

It is concluded that, given the level of gas prices, power sales revenues and capital costs anticipated, gas turbine variants (A2 and A3) are not cost competitive either with the FBC variant (B1) or the Base Case (C1) representing FBC and life extension In terms of the cumulative present worth of projected costs, the Base Case (C1) is superior to Variant B1 although results are within 2%

The economic analysis of variants investigated by EGU and Energoprojekt (A1, A2,A4 and B1), using quantities developed by EGU and EGP and economic assumptions consistent with G/C, is presented in Section 7 0 Generally, the variant which would be selected based on these calculations is B1, which is consistent G/C's results (EGU and EGP did not evaluate Variant C1, Life Extension)

Sensitivity Analyses Several sensitivity analyses were conducted, including the impact of lower demand, escalation, and then an "Indifference Analysis," which explores several parameters independently

As presented in Section 8 6, the results of applying the lower demand did not change the conclusions Another sensitivity of removing all escalation left the conclusions unchanged

In the "Indifference Analysis," we have represented, for each major component of cost, the unit cost adjustment that would be required for the overall present worth of each respective variant to be equivalent to that of the Base Case (C1) Exhibit E-4 indicates the magnitude of adjustments required under the assumption that all other cost components remain unchanged An indication of "NA" means that it is not possible to attain equilibrium through any logical adjustment of this factor in isolation

An example of the use of this method is the adjustment of natural gas prices The exhibit shows that a 43% adjustment to gas prices would be needed to make Variant A3 and C1 (Base) equivalent A similar exercise can be conducted for other numbers on this table

While negative adjustments of greater than 100% in total operating expenses would appear to be illogical, such expense totals include "expense credits" for excess power sales, which, if of sufficient magnitude could more than offset expenses otherwise incurred

Exhibit E-3
SUMMARY OF ECONOMIC ANALYSIS RESULTS

CUMULATIVE COST 1993 – 2010 $(000)

VARIANT Case)	Capital & Removal Costs	FUEL COST					Net Power Interchange	Fixed & Variable Expenses	Sorbent Ash Removal & Penalties	Maintenance	Total Operating Expenses	Total Capital & Operating Expenses
		Natural Gas	Oil	Lignite	Black Coal	Total						
C1 (Base)	57 020	898	1 887	68 465	165 575	236 825	(193 610)	79 158	24 398	62 631	209 401	266 422
A2	79 033	222 345	8 741	27 429	146 989	405 504	(298 270)	71 102	10 031	58 037	246 404	325 436
A3	70 020	206 226	9 921	27 429	148 785	392 361	(273 027)	70 790	10 117	57 261	257 502	327 521
B1	64 490	4 170	1 982	98 647	134 078	238 878	(222 611)	81 212	31 573	57 759	186 811	251 302

CUMULATIVE PRESENT WORTH $(000)

VARIANT Case)	Capital & Removal Costs	FUEL COST					Net Power Interchange	Fixed & Variable Expenses	Sorbent Ash Removal & Penalties	Maintenance	Total Operating Expenses	Total Capital & Operating Expenses
		Natural Gas	Oil	Lignite	Black Coal	Total						
C1 (Base)	32 223	531	922	37 884	79 771	119 108	(95 511)	41 360	10 098	30 713	105 768	137 991
A2	58 825	97 495	4 732	23 695	68 641	194 563	(146 346)	38 398	4 923	29 080	120 618	179 443
A3	51 667	90 072	5 376	23 695	69 622	188 765	(135 081)	38 283	4 968	28 835	125 771	177 438
B1	47 283	1 379	982	55 599	61 966	119 926	(112 526)	42 995	14 300	29 075	93 769	141 052

PRESENT WORTH COST SAVINGS $(000) (Versus Base Case)

VARIANT (Case)	Capital & Removal Costs	FUEL COST					Net Power Interchange	Fixed & Variable Expenses	Sorbent Ash Removal & Penalties	Maintenance	Total Operating Expenses	Total Capital & Operating Expenses	Internal Rate of Return (1)
		Natural Gas	Oil	Lignite	Black Coal	Total							
C1 (Base)	BASE	BASE	BASE	BASE	BASE	BASE	BASE	BASE	BASE	BASE	BASE	BASE	BASE
A2	(26 602)	(96 964)	(3 810)	14 189	11 130	(75 455)	50 835	2 962	5 175	1 633	(14 850)	(41 452)	Negative
A3	(19 444)	(89 541)	(4 454)	14 189	10 150	(69 657)	39 570	3 076	5 130	1 878	(20 003)	(39 447)	Negative
B1	(15 060)	(848)	(60)	(17 715)	17 806	(817)	17 015	(1 636)	(4 202)	1 638	11 999	(3 061)	5 97%

NOTE (1) Based on Cost Savings vs Base Case

Exhibit E-4

INDIFFERENCE ANALYSIS SUMMARY

CUMULATIVE PRESENT WORTH $(000)

VARIANT (Case)	Capital & Removal Costs	FUEL COST					Net Power Interchange	Fixed & Variable Expenses	Sorbent Ash Removal & Penalties	Maintenance	Total Operating Expenses	Total Capital & Operating Expenses
		Natural Gas	Oil	Lignite	Black Coal	Total						
C1 (Base)	32 223	531	922	37 884	79 771	119 108	(95 511)	41 360	10 098	30 713	105 768	137 991
A2	58 825	97 495	4 732	23 695	68 641	194 563	(146 346)	38 398	4 923	29 080	120 618	179 443
A3	51 667	90 072	5 376	23 695	69 622	188 765	(135 081)	38 283	4 968	28 835	125 771	177 438
B1	47 283	1 379	982	55 599	61 966	119 926	(112 526)	42 995	14 300	29 075	93 769	141 052

ADJUSTMENT REQUIRED IN SPECIFIC COST ELEMENTS IN ORDER TO EQUATE CUMULATIVE PRESENT WORTH OF THIS CASE WITH THAT OF THE BASE CASE

VARIANT (Case)	Capital & Removal Costs (1)	FUEL COST					Net Power Interchange	Fixed & Variable Expenses	Sorbent Ash Removal & Penalties	Maintenance	Total Operating Expenses	Total Capital & Operating Expenses
		Natural Gas	Oil	Lignite	Black Coal	Total						
C1 (Base)	BASE	BASE	BASE	BASE	BASE	BASE	BASE	BASE	BASE	BASE	BASE	BASE
A2	−70 5%	−42 8%	NA	NA	372 4%	−54 9%	181 5%	NA	NA	NA	−279 1%	−23 1%
A3	−76 3%	−44 1%	NA	NA	388 7%	−56 6%	199 7%	NA	NA	NA	−197 2%	−22 2%
B1	−6 5%	NA	NA	−17 3%	17 2%	−374 5%	118 0%	−187 1%	−72 8%	186 9%	25 5%	−2 2%

NOTE (1) Adustment in Capital Cost for alternative case only i e no corresponding adjustment in Base Case
All other adjustments apply for both Base Case and Alternative Case

Financial Analysis While sufficient information is not available to make a complete review of the financial consequences of alternative decisions regarding future operations of CP Plzen, some additional perspective may be gained from even a somewhat limited analysis

The financial analysis results for Variant B1 are presented in Exhibit E-5 Also shown is an attempt to establish some indication of the resulting cost of hot water, at least to the extent that it is impacted by prospective capital costs and operating expenses As noted, no reliable data were available for the inclusion of debt service, if any, and remaining depreciation charges related to plants presently in service In other respects, however, estimated hot water costs are derived by subtracting from total costs the costs directly attributable to, or allocated to steam deliveries Qualifying assumptions and conditions are presented in Sections 8 6 and 8 8

The levelized cost of hot water as developed over the complete analysis period follows

	Levelized Cost of Hot Water	
Variant	$ U S /MWh	kC/GJ
C1	$16 02	124 60
A2	$21 67	168 58
A3	$21 53	167 40
B1	$17 69	137 60

While these costs are incomplete, they represent a second useful measure of the relative merit of the variants The relative level of costs is generally consistent with economic analysis results Detailed data for variants other than B1 are contained in Appendix F

As a comparison to the "costs" above, it is of interest to note the historical and projected price of heat for dwellings in Plzen as summarized below

	Cost of Hot Water for Dwellings	
Year	$ U S /MWh	kC/GJ
1992-93	$15 43	120
1993-94	$17 61	137
1994-95	$21 86	170
1995-96	$32 14	230-270

These values show a transition from pricing during the 1992-1993 heating season which was still subsidized/controlled, to actual market prices, expected to occur in 1995-96 For subsequent years the price of heat will reflect the escalation of the associated fuel costs (Reference Appendix D, p 36)

Care must be taken when making comparisons of these annual projected costs with the levelized costs resulting from the G/C financial analysis, and in recognizing that the developed costs are incomplete for the reasons previously stated However, a comparison brings credibility to the costs which were independently developed by the G/C model

VARIANT B1

Exhibit E-5

PROJECTED FINANCIAL COSTS OF VARIANT B1

High Demand

FINANCIAL COST (000) (Including Inflation)

	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
ACCRUAL BASIS	(Exclusive of Interest Expense if any and Depreciation Charges related to existing plant (Production Transmission Distribution et al)																	
Operating Expenses																		
Operation & Maintenance	5 544	6 234	6 922	12 534	16 666	14 022	15 474	17 753	18 378	19 485	20 703	22 623	22 290	28 447	24 795	26 337	28 898	30 477
Depreciation Expense	8	44	1 186	2 357	2 383	2 397	2 412	2 428	2 430	2 432	2 666	2 912	2 915	2 917	2 919	2 921	2 924	2 926
Total Operating Expenses	5 552	6 277	8 108	14 891	19 049	16 419	17 885	20 181	20 808	21 916	23 369	25 535	25 205	31 364	27 713	29 258	31 822	33 403
Interest Expense	9	57	1 369	3 895	4 973	4 575	4 107	3 576	2 959	2 247	1 714	1 478	1 330	1 203	1 068	924	769	600
Equity Return	9	9	55	1 379	2 735	2 767	2 784	2 803	2 823	2 825	2 828	3 121	3 428	3 432	3 434	3 437	3 440	3 443
Total Expense & Return	5 570	6 344	9 532	20 166	26 756	23 760	24 776	26 560	26 589	26 989	27 912	30 133	29 964	35 998	32 216	33 619	36 030	37 446
Income Tax Effect @ 45%	8	8	45	1 129	2 238	2 264	2 278	2 293	2 309	2 312	2 314	2 553	2 805	2 808	2 810	2 812	2 814	2 817
Total Cost	5,577	6,352	9,576	21,295	28,994	26,023	27,054	28,853	28,899	29 301	30,226	32 687	32,769	38,806	35,026	36,431	38,845	40,263
Estimated Hot Water Revenue Requirement	(Exclusive of Interest Expense if any and Depreciation Charges related to existing plant (Production Transmission Distribution et al)																	
Total Cost (Above) less																		
Cost of Steam																		
Operation & Maintenance	4 251	4 632	4 933	6 298	6 570	7 615	7 644	8 970	8 807	9 418	9 613	10 360	8 990	9 439	9 911	10 406	10 925	11 471
Allocated Depreciation	3	16	432	747	749	751	754	757	756	756	827	902	901	901	900	900	900	900
Allocated Return	4	4	20	437	860	867	870	874	879	878	877	966	1 060	1 060	1 059	1 059	1 059	1 059
Income Tax Effect	3	3	16	358	704	710	712	715	719	718	718	791	867	867	867	867	867	867
Total Steam	4 260	4 654	5 401	7 840	8 883	9 943	9 980	11 315	11 161	11 770	12 035	13 019	11 817	12 266	12 737	13 232	13 751	14 297
Equals Cost of Hot Water	1 317	1 697	4 175	13 455	20 111	16 080	17 074	17 538	17 737	17 531	18 190	19 668	20 951	26 540	22 288	23 199	25 093	25 966
HOT WATER – $/MWH	$2 46	$3 07	$7 28	$17 31	$25 54	$20 33	$21 50	$21 99	$22 20	$21 91	$22 69	$24 50	$26 05	$32 96	$27 64	$28 73	$31 04	$32 07
Present Worth	$2 46	$2 62	$5 31	$10 81	$13 63	$9 27	$8 38	$7 33	$6 32	$5 33	$4 72	$4 36	$3 96	$4 28	$3 07	$2 73	$2 52	$2 22
Levelized Cost to Date		$3 07	$5 01	$8 49	$11 80	$13 02	$13 94	$14 62	$15 14	$15 51	$15 83	$16 15	$16 45	$16 87	$17 10	$17 30	$17 51	$17 69
CASH BASIS	(Exclusive of Debt Service related to existing plant (Production Transmission Distribution et al)																	
O & M Expenses	5 544	6 234	6 922	12 534	16 666	14 022	15 474	17 753	18 378	19 485	20 703	22 623	22 290	28 447	24 795	26 337	28 898	30 477
Equity Return	9	9	55	1 379	2 735	2 767	2 784	2 803	2 823	2 825	2 828	3 121	3 428	3 432	3 434	3 437	3 440	3 443
Debt Service																		
Foreign Interest	–	–	82	251	333	326	317	308	299	288	277	264	251	236	221	204	186	166
Principal	–	–	–	44	95	102	111	120	129	140	151	164	177	191	207	224	242	262
Total	–	–	82	295	428	428	428	428	428	428	428	428	428	428	428	428	428	428
Domestic Interest	9	57	1 287	3 645	4 639	4 249	3 789	3 268	2 661	1 959	1 438	1 213	1 080	966	848	720	583	434
Principal	–	11	67	1 670	3 508	3 980	4 493	5 070	5 721	6 402	7 059	4 233	982	1 010	1 084	1 165	1 252	1 402
Total	9	69	1 354	5 315	8 147	8 229	8 282	8 338	8 382	8 362	8 497	5 446	2 062	1 977	1 932	1 885	1 835	1 836
Total Cost before Income Tax	5 562	6 312	8 413	19 523	27 976	25 445	26 968	29 322	30 010	31 099	32 456	31 618	28 208	34 283	30 589	32 086	34 600	36 183
Income Tax Effect @ 45%	8	8	45	1 129	2 238	2 264	2 278	2 293	2 309	2 312	2 314	2 553	2 805	2 808	2 810	2 812	2 814	2 817
Total Financial Cost	5,570	6,319	8,458	20,652	30,214	27,708	29 246	31,615	32,320	33 411	34,770	34,171	31,013	37 091	33 398	34 898	37,415	39,000

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Environmental Analysis

A primary assumption is that environmental requirements are satisfied for all variants However, each variant results in a different quantity of pollutants produced by the system The environmental analysis study area is larger than the one selected for the investigation of primary variants (described in Section 2 0) This was done to capture a larger fraction of the emissions sources in Plzen and obtain a better representation of the relative changes in total emissions as changes are made to the central DH systems

The plants/plant groups selected for this emissions analysis include the following

- Central Heating Plant Plzen (ZCE) and cooperating sources (CP Plzen, Brewery and Railway Station Zos),
- Heating Plant Doubravka, including Letna (V1) and Doubravka (V2),
- Heating Plants Svetovar and Bory,
- Cogeneration Plant Skoda,
- Small Decentralized Boilers, and
- Home Heating Furnaces (very rough estimate)

The present distribution of particulate, SO_2, NOx, and CO emissions for the city of Plzen is shown in Exhibit E-6 All emissions source types share significant fractions of these emissions Note the following

- CP Plzen has a lower share of particulate since high efficiency ESPs are used for particulate removal on their large plants,
- CP Plzen has a higher share of NOx emissions because uncontrolled large boilers are generally higher in NOx,
- The CP Plzen share of SO_2 emissions is high because lower grade, higher sulfur fuels are generally burned in central stations and heating plants, and
- home furnaces have a disproportionate share of CO emissions, which is typical of these kinds of units

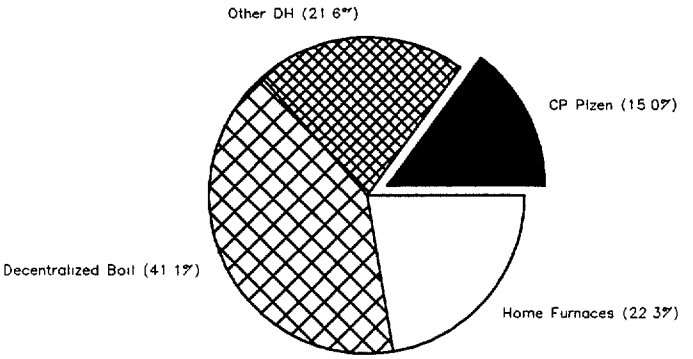
Using Variant B1 as a basis, emissions improvement in the entire Plzen area is represented in Exhibit E-7 for the years 1993 and 2010 Assumptions include

- Skoda and Svetovar assume SO_2 emissions reduced by 70%
- Decentralized small boilers assume 22% of capacity switches to district heating, 10% conservation through the study period, and other improvements are made as recommended in Section 4 0
- Home furnaces assume 10% conservation (no other improvements)

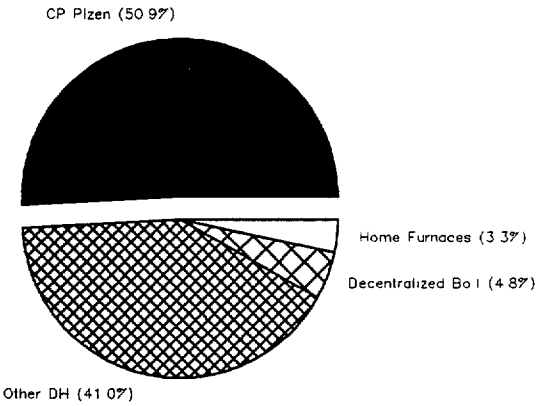
Reductions in emissions, especially SO_2 and particulate, are significant

Exhibit E-6
1993 DISTRIBUTION OF EMISSIONS FOR THE CITY OF PLZEN

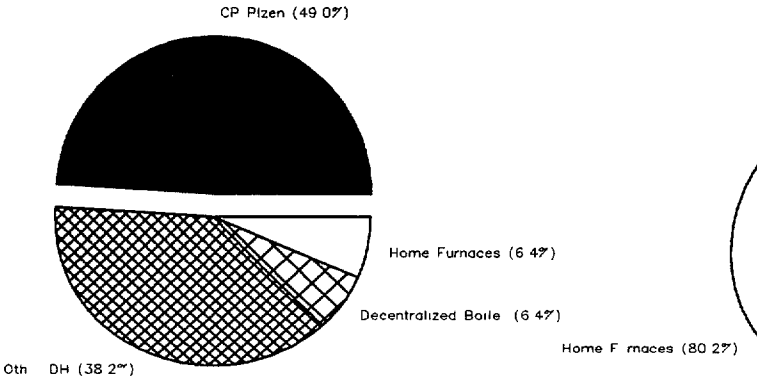
PARTICULATE EMISSIONS



SO_2 EMISSIONS



NOx EMISSIONS



CO EMISSIONS

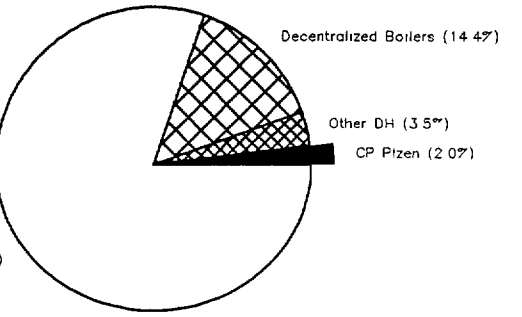


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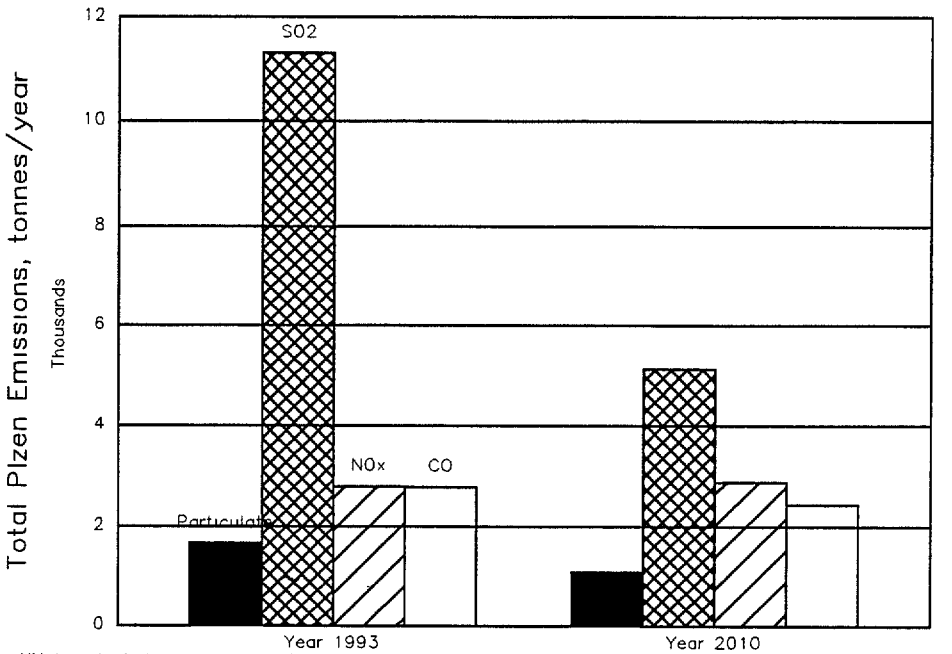
Exhibit E-7
1993 vs 2010 EMISSIONS IN CITY OF PLZEN
WITH SMALL BOILER CHANGES IMPLEMENTED (Variant B1)



NNote Includes improvements to small boilers but no changes to home furnaces except conservation

Focusing now on variants for CP Plzen, as shown in Exhibit E-8, particulate emissions are reduced dramatically from current (1993) levels when environmental controls are in place in the year 1997 There are significant expected differences between the gas turbine variant (A3) and both of the FBC variants (B1 and C1)

A comparison of SO_2 emissions is shown in Exhibit E-9 A benefit to increased operation with natural gas (Variants A2 and A3) is the reduced level of SO_2 emissions A simple "cost of removal" was calculated using the Czech emission penalties as a weighting criteria between particulate and SO_2 Calculated values of removal for particulate and SO_2 are 8,169 and 2,723 $/tonne respectively Comparing to a value of 500 to 1500 $/tonne in the U S , this result implies that additional environmental correction by selecting Variant A2 or A3 is unwarranted

Similar comparisons are presented in Section 9 0 for NOx and CO emissions, for which large changes are not projected

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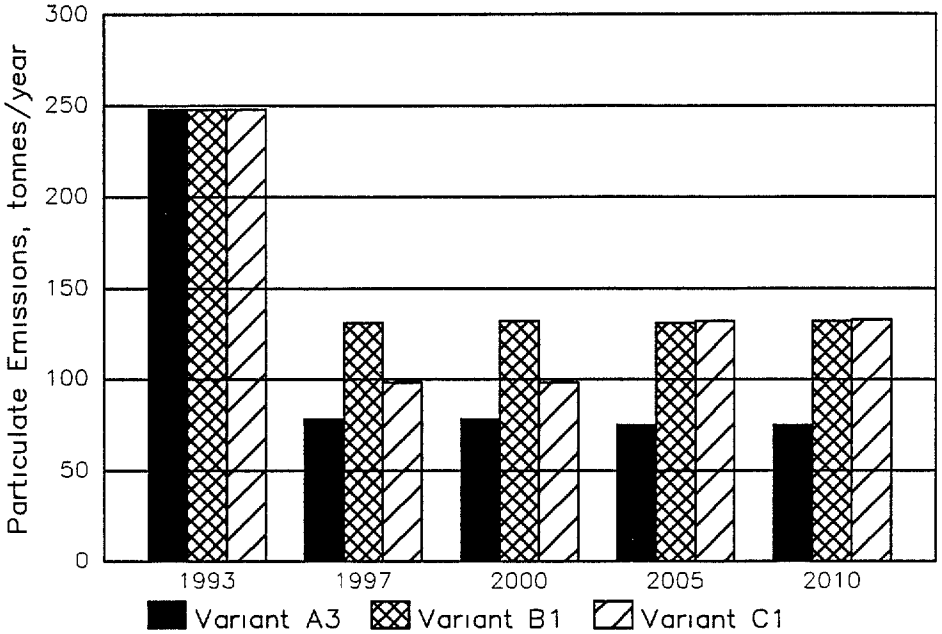
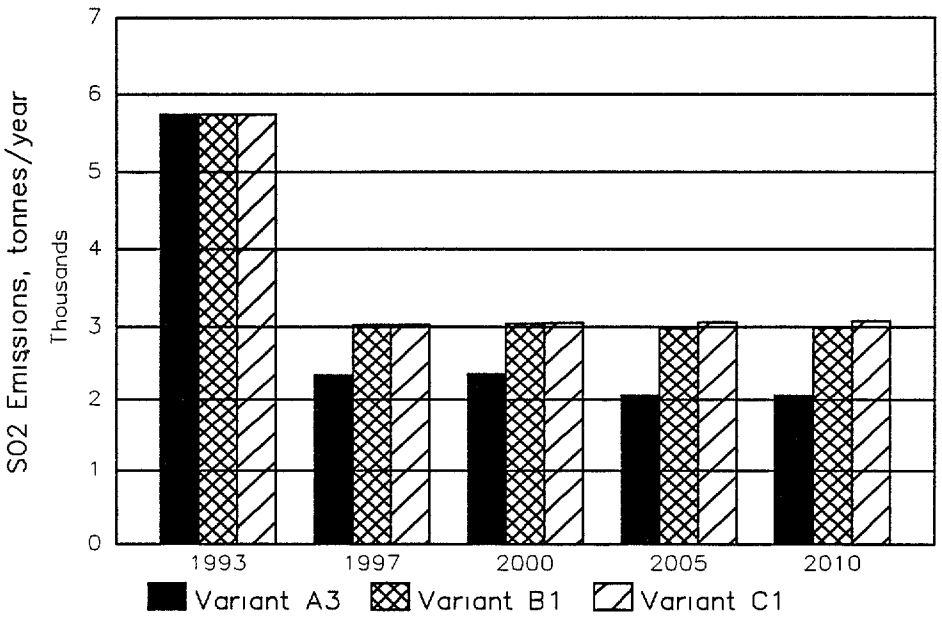
Exhibit E-8
CP PLZEN PARTICULATE EMISSIONS BY VARIANT



Note Assumed connection of Heat Line East I by 1997
Heat Line East II (Svetovar) not included

Exhibit E-9
CP PLZEN SO_2 EMISSIONS BY VARIANT



Note Assumed connection of Heat Line East I by 1997
Heat Line East II (Svetovar) not included

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The changes planned for CP Plzen and cooperating district heat sources, combined with implementation of reasonable changes to many of the 595 small boilers, will produce dramatic changes to particulate and SO_2 emissions in the City of Plzen Potential changes to small home furnaces should also be investigated due to the large fraction of emissions contributed by these sources Wherever possible and economically justified, these sources should be connected to the district heating system The programs being conducted in Krakow, Poland by U S AID and U S DOE will be useful to the City of Plzen in establishing policies to deal with these significant sources

CONCLUSIONS AND RECOMMENDATIONS

Conclusions and Recommendations have been developed in two general areas "Selection of Promising Variants" and "Recommendations for Plant Improvements / Further Study "

Selection of Promising Variants

The following conclusions/recommendations are offered

1 The CFB boiler variants (B1 and C1) are recommended over the GTCC variants (A2, and A3) on the basis of the Cumulative Present Worth of Projected Costs resulting from the G/C economic analysis (Section 8 6) The GTCC variants are clearly higher in cost (between 26 and 30% higher) than the CFB boiler variants The selection of the CFB boiler variants over the GTCC variants are further supported by the following

- Sensitivity analyses (Section 8 7 3) show that in order for Variant A2 (60 9 MWe GTCC) to be competitive with the C1 base case (Life Extension with future CFB), significant changes in fuel or capital costs would be required Any one of the following significant changes would be required to make Variant A2 competitive with C1 on a Cumulative Present Worth of Projected Costs basis
  - a decrease in the cost of natural gas of approximately 43%,
  - a decrease in capital and demolition costs of approximately 71%, or
  - an increase in the cost of black coal by approximately 370%
- The G/C Financial analysis (Section 8 8) results further support this conclusion
- The sensitivity analysis (8 7 1) based on the low demand requirements did not alter the conclusions based on the high demand requirements The GTCC variants are clearly higher in cost than the CFB boiler variants B1 and C1

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- Economic analyses (Section 7 0) based on technical input from EGU, and Energoprojekt are consistent in this conclusion
- The GTCC depends on imported natural gas which gives rise to security concerns The CFB boiler burns low quality, low price, indigenous lignite

2 The Cumulative Present Worth of Projected Costs for Variant B1 (160 tonne/h CFB boiler) and Variant C1 (Life Extension with future CFB) are virtually the same (C1 at $141 million, B1 at $137 million) Therefore, a decision should be based on other factors such as

- Concern that future emission compliance requirements may be more stringent (favors C1 by deferring the technology commitment and allowing time for the Czech emissions regulations to catch up with the rest of the European community),
- desire to minimize capital expenditures in the early years of privatized operation, and ease the cost burden to either the consumer or the DH company as state subsidies are removed, (favors C1 by deferring the addition of capacity),
- desire to delay capital expenditures because future financing interest and terms may become more attractive as they approach Western conditions (favors C1),
- concern over the uncertain demand projections (favors C1 because the addition of CP Plzen IV is not required until 2003),
- desire to implement a more advanced technology such as pressurized fluidized bed combustion (PFBC), which offers a higher electric/heat ratio (favors C1 by deferring the technology decision for more than five years),
- desire to take advantage of current potential long term fuels contracts (favors B1), and
- concern over potential effective equipment price increases (favors B1 because capital investments are made in the near term)

Based upon the preceding considerations, Variant C1 (the Base Case) is recommended by Gilbert/Commonwealth

3 Further investigation of Variants B1 and C1 with regard to an accelerated construction schedule for plant modifications reveals that an approximate 12% improvement in Present Worth of Projected Cost for Variants B1 and C1 is possible during the years 1995 and 1996, when the reconstruction occurs (Section 8 3) This analysis assumes that both Plzen II cogen boilers would be available during these years

4 Based on Conclusion 3, it may not be necessary to build the Plzen III gas/oil steam boiler as previously planned, especially if additional cooperation with the Brewery is possible In fact, in the G/C analysis (Section 8 6), plants were successfully dispatched to meet load without utilizing Plzen III by relying on cooperation of the Brewery

5 Emissions compliance for all stoker (grate) boilers can be met most cost effectively by switching to low sulfur black (bituminous) coal and installing a baghouse For the Letna plant, however, switching to gas and standby duty should be considered because of the close proximity to residential housing

6 The district heating operation in Svetovar is not presently interconnected with the CP Plzen DH system In order for the Svetovar DH system to meet the new emission requirements by 1997, they could either modify the present supply system for compliance, or connect to the Plzen district heating system Three categories of plant modifications were considered (1) a cogeneration retrofit, (2) a switch to coal, and (3) a switch to gas (Section 8 9)The following comments and recommendations are offered

- It is unlikely that the cogeneration retrofit option will be able to compete with the District Heating Company as presently structured Unless dramatic changes occur in the pricing schemes for the two basic commodities provided (i e , the price of heat and electricity), emphasis should still be placed on improving the efficiency of the existing system through modifications in the distribution system and replacement of antiquated equipment when its useful life is over
- With respect to the fuel switching options, the switch to black coal and the addition of a baghouse is more cost effective than the switch to natural gas
- Based on a break-even analysis and constant demand, connecting the Svetovar district heating system to the Plzen district heating system is more economical than the black coal or natural gas fuel switch option The payback period for estimated costs incurred in connecting Svetovar should be on the order of two to three years If demand could be increased with new consumers, the payback period would be even shorter
- It is recommended that Svetovar be connected to the central district heating system through the proposed Heat Line East II
- With the interconnection of Svetovar, the demand seen by the centralized system would be higher, offering the potential to provide additional cogeneration during the summer months The reliability of heat supply to the Svetovar consumers would be improved and the cost of heat in Plzen could be more competitive with other forms of energy

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7 Without considering a switch to district heating, potential exists to make significant improvements to many of the 595 small boilers, including switching to natural gas, installing new burners, boiler tuning, installing boiler controls, and boiler replacement with more efficient units This potentially can result in

- reduced fuel use by more than 22%,
- reduced particulate and SO_2 emissions by 80%,
- reduced NOx emissions by 72%,
- reduced CO emissions by more than 80%, and
- reduced VOC emissions by more than 80%

8 At least 64 MWt (representing 80 boilers) of small boiler capacity should be retired and their consumers connected to the district heating system More boilers may be suitable along Heat Line East II, if this project continues

9 Small cogeneration alternatives should be considered only under special circumstances, and in isolated or remote areas of the City where the Central DH System cannot be extended It is highly unlikely that small cogeneration systems will be able to compete with district heating as presently structured Exceptions may include situations where (1) large numbers of cogeneration units apply with the utility as a group to negotiate an electric rate, or (2) some combination of government incentives are available to offset the initial capital cost Unless dramatic changes occur in the pricing schemes for the two basic commodities (electricity and heat), emphasis should still be placed on improving the efficiency of the existing system through modifications in the distribution system and replacement of antiquated equipment when its useful life is over (Section 4 4 and 8 9 1)

10 Emissions analysis conclusions

- The changes planned for CP Plzen and cooperating district heat sources, combined with implementation of changes to many of the 595 small boilers, will produce dramatic reductions to particulate and SO_2 emissions in the City of Plzen of 35% and 55% respectively (Section 9 0)
- Potential changes to home furnaces should be investigated due to the large fraction of emissions contributed by these sources Wherever economically justified, these sources should be connected to the district heating system Programs being conducted in Krakow, Poland by U S AID will yield good characterizations of performance and potential improvements to operation of these furnaces and should be useful to the City of Plzen in establishing policies to deal with these significant sources (Section 9 0)

Recommendations for Plant Improvement / Further Study

Several issues emerged during the study which were not directly compared between variants, but may be important for the future of centralized district heating (DH) in Plzen

1 A well maintained and managed CP Plzen central district heating system should prove to be economically superior to other competing heat or cogeneration sources for the following reasons

- larger scale plants result in better cost economy of scale, better performance, and can more efficiently generate electricity,
- with the plants and systems "in place" only the costs of improvements and maintenance need to be considered,
- district heating technology is constantly improving, and
- a central plant can burn inexpensive low grade fuels and control emissions

2 The future of the 595 small boilers spread through the city offer a significant expansion potential for centralized DH, however, not all of the true interconnection potential is expected to be realized The future disposition of these small heat sources can be strongly influenced by incentives offered by the government, attractive connection arrangements by ZCE, the completion of heat line East II, and by education of the people in the economic/financial evaluation of centralized DH verses individual boilers

3 Significant improvement in the operation of all plants is possible with addition of more sophisticated controls Currently, a boiler "factor" of 1 07 is used to account for boiler age, changing loads, etc This factor should be reduced to half simply by better and safer control of O_2 during load change, and may offer the potential to reduce the current safe minimum load setting This change, which is relatively inexpensive, could result in a savings of 3 to 4% of current coal requirements Controls improvements could also be extended to improve the operation and dispatch of units

4 Reduction of system leakages can be improved through the gradual replacement of primary piping with corrosion resistant pipe with integrated leak detection and by the replacement of secondary systems with more modern two pipe systems, where possible It appears that losses equivalent to 4 to 5% of the overall heat generation may be saved through these changes The future metering of heat and required measurements will also help to better assess the true magnitude of these losses

5 The management of Plzen district heating activities will best be consolidated into a single privatized company, and governed by a regulatory body Based on interviews with modern district heating companies, significantly greater efficiency in utilization of operations and maintenance personnel is possible

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1.0 INTRODUCTION

This work was sponsored by the U S Agency for International Development (AID), Bureau for Europe, and under contract to the U S Department of Energy (DOE), Fossil Energy This report is written to the City of Plzen, and takes into account their knowledge of their own system and present situation

Gilbert/Commonwealth, Inc (G/C) was contracted to evaluate a study conducted in 1989-90 by Energoprojekt Praha for the City of Plzen, analyze the current supply-side situation of the district heating system in Plzen, and offer recommendations for future emissions compliance and potential expansion/upgrading of the existing system

Pacific Northwest Laboratories (PNL), also under contract to U S DOE, through U S AID, is responsible for a demand-side evaluation, and also integration of the supply- and demand-side efforts

1 1 BACKGROUND

When this study was initiated, the split of Czechoslovakia was only a plan The Czech Republic is now an independent state, and considerable effort by government has been directed toward the affairs and issues related to the split and related changes The first wave of privatization is completed, and the second wave is underway However, there is still considerable emphasis on compliance with Law 309, and industry is moving in the direction of meeting these environmental regulations Plans are being finalized to make appropriate modifications to facilities which are affected by the legislation

Under the old system, operation of the Plzen district heating companies and cooperating industries has been conducted on the basis of economic policies and central planning, with little freedom to assess alternatives based on economic least cost and financial attractiveness The incentive was not provided to deliver energy at competitive rates, explore the benefits of new technology, improve plant operating efficiency, or manage an efficient organization

In spite of the work/business environment, a desire to improve was provided within many of the individuals themselves It is apparent that excellent engineering capability exists within the design and operating organizations, and that under the new system, there is a desire to "privatize" and begin to operate in a market driven economy While the timing of privatization is always a question, the steps required to make privatization successful are quite clear The prioritization of these steps and assistance in decision making are areas, in addition to new technology, where the U S can be of assistance

This effort, and others like it, are the first steps toward upgrading the existing system in Plzen using "least-cost" planning techniques The following sections describe the basis/objectives for the work, introduce the project team, and list the overall approach and assumptions

1.3 SUPPLY SIDE TEAM AND SCOPE

This supply side work was conducted by Gilbert/Commonwealth, Inc, with significant assistance from four Czech subcontractors

- EGU Prague,
- Energoprojekt Prague a s ,
- RAEN s r o , and
- CityPlan s r o

Each subcontractor contributed significant portions of input to the work Their assistance was necessary to insure the accuracy of the study by G/C, and was also required to gather the necessary data Four subcontractors were chosen to provide several opinions of the situation, different inputs according to their expertise Subcontractors selectively performed each of the 18 designated tasks shown in Exhibit 1-1, with some overlap where more than one opinion or additional input was considered necessary A more detailed scope of work is included in Appendix A to this Volume

EGU Prague performed significant assessment work on the Plzen District Heating system prior to the Energoprojekt (EGP) study[1], and therefore were well qualified to contribute to the current study EGU was awarded the largest portion of the subcontracted work

Energoprojekt a s (EGP), the original author of the 1991 report, was responsible for providing key data inputs, as well as contribution of new ideas relative to the initial work EGP has conducted two additional studies pertinent to the subject work, and therefore, EGP has provided current knowledge of the system based on these most recent efforts

RAEN, s r o was selected for tasks involving the 595 small decentralized boilers, fuels information/pricing, and a general review of the report They are experienced in the thermal analysis, industrial boilers, and have access to useful information about these small boilers

CityPlan s r o is a new engineering consulting firm located in Prague CityPlan was selected because of their expertise in energy matters Because they were not previously directly involved in the Plzen work, an objective assessment is assured

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1 4 OVERALL APPROACH AND ASSUMPTIONS

The initial focus of this study was the review of the 1991 Energoprojekt supply-side report[1] Additionally, several tasks are intended to further characterize the EGP study work and provide the City of Plzen with a basis for decision making

There are three categories of sources to be considered They were addressed in this study as follows

- Central heating plants focus of this study with special emphasis on CP Plzen and cooperating sources, and consideration of future of HS Svetovar,
- decentralized 595 small boilers considered for efficiency improvement, emissions reduction, and retirement (consumer connection to DH system), and
- small home furnaces emissions estimate only with no consideration for potential improvement of efficiency or emissions

Our general assumptions used in the analysis are summarized as follows

- Emphasis for this study is on the Central Cogeneration Plant (CP) Plzen Selection of variants, technical assessments, economic analyses, and recommendations are emphasized for the CP Plzen facility Conclusions and recommendations, however, should also generally apply to Skoda works, independent steam producers, and Heating Plant Svetovar
- The assumed demand profile relies on the following
  - previous information developed by Energoprojekt,
  - current projections solicited from ZCE regarding conservation, committed and potential new DH consumers, and likely retirement scenarios for existing units,
  - an assessment of the potential to add new DH consumers from the pool of 595 small boilers,
  - current projections solicited from Skoda regarding the trends in their business, and their plans or intent to change the quantity of DH energy supplied,
  - current assessment of energy demand and plans for boiler expansion from the Plzen Brewery and Paper Mill Jatecni, and
  - potential energy savings in the residential, commercial, and government sector coupled with an assessment of likely savings in those sectors based on energy price

- Write a Final Report to the City of Plzen including specific recommendations for action
- Assist PNL in their effort to integrate the supply- and demand-side reports

Generally, each situation was explored using a range of input parameters supported by reasonable assumptions This is necessary because of the uncertainty in the Czech Republic of many economic issues The favored solution(s) are recommended to address a range of potential outcomes Variants which enhance system flexibility are recommended to satisfy a range of potential demand situations Future work or detailed studies concerning the favored variant(s) are recommended

Section 2 0 introduces a summary of existing centralized systems in Plzen Section 3 0 presents a brief review of the Energoprojekt report [1] Section 4 0 includes the results of a study to investigate the potential for efficiency improvement and emissions reduction for decentralized heat supply systems (595 small boilers) In Section 5 0, an estimate of future demands is presented Sections 6 0, 7 0, and 8 0 present the technical and economic analysis conducted by G/C and its subcontractors, Section 9 0 presents an analysis of present and future emissions in the City of Plzen, and Section 10 0 provides specific conclusions and recommendations to the City of Plzen Several appendices, which contain analysis detail and background, follow the main report

1 5 REFERENCES

1 Energoprojekt Praha, The Study to Finalize the Concept of the Pilsen Heat Supply System, Part 1 - Technical Report and Part 2 - Economic Report, EGP 22210, December 1991

2.0 BASELINE DESCRIPTION OF EXISTING CENTRALIZED HEAT SUPPLY SYSTEM

Centralized district heat is presently supplied to the City of Plzen by Cogeneration Plant (CP) Plzen, with collaborating sources Bory and peak source Kosutka Sources which cooperate with CP Plzen include West Bohemian Brewery Boiler House (Zapadoceske Pivovary) and the Railway Maintenance Company Boiler House (Zos) On the west, Skoda supplies large quantities of heat and steam to its own production (about 80%), and also supplies heat to the habitation Skvrnany Independent district heating sources include Letna (V1), Doubravka (V2), and Svetovar

The existing connections in the centralized systems are presented in Exhibit 2-1 A Plzen map, obtained from the Energoprojekt study, is provided in Appendix H Heat Line East I, which will connect the Plzen system to Letna/Doubravka, is nearing completion Plans for Heat Line East II, connecting the area served by Svetovar, have been suspended, but may be considered at a later date

The existing DH system boiler units are presented in summary form in Exhibit 2-2 Exhibit 2-3, from the previous Energoprojekt study, shows the general layout of existing equipment at CP Plzen with environmental controls It has been demonstrated that there is sufficient space at the site to accommodate the technologies of each of the primary variants investigated in this study

The primary variants analyzed in this study focus on the CP Plzen district heating plant, as well as current and planned cooperating units A sensitivity study addressing whether Svetovar should be connected to the central heating system was performed and is discussed in Section 8 9

2 1 COGENERATION PLANT PLZEN

The hot water system of CP Plzen supplies heat to buildings in the North and part of the South The peak design parameters of the water are 160/70°C CP Plzen also supplies steam to Zapadoceske Pivovary (West Bohemia Breweries), and CSD Czechoslovak Railways During the summer period, the Brewery assumes the supply of steam to the system, while the larger CP Plzen steam boilers are out of service One view of CP Plzen is shown in Exhibit 2-4, and the coal yard, including space for the new facility, is shown in Exhibit 2-5 The plant appears to be well maintained, and the operators are proud of the facility

Minimum continuous steam output of the pulverized coal boilers of 170 t/h capacity (each) is 104 t/h, i e 61% of nominal output The high pressure cogeneration equipment in (CP), part II only operates during the heating period In summer months the heat delivery in hot water is covered by operation of the hot water grate boilers, while the steam supply is met by the Brewery and the railway

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Exhibit 2-2
SUMMARY OF DISTRICT HEATING BOILERS IN PLZEN

Plant / Operator	Boiler Unit	No of Boilers	Year in Service	Boiler Steam Conditions: Flow tonne/h	Temp deg C	Pressure MPa	Fuel Type	Delivery Capacity[a]: HW MWt	Steam MWt	Electric MWe
Plzen I / ZCE	HW Grate Boilers	3	1977	NA	160		brown coal	105		
Plzen II / ZCE	Cogen PC Boilers	2	1983	170	540	13 6	brown coal	65[c]	100	55
Kosutka / ZCE (standby)	Hot Water Boiler	2	1981	NA			heavy oil	34 8		
Bory / TEZA	HW Grate	2	1965	NA	150		brown coal	23 2		
	Steam Grate	2	1965	8	220		brown coal		10 8	
	Steam Grate	1	1965	16	220		brown coal		10 7	
	Steam Boiler (Loos)	1	1973		220		light oil		9 8	
Letna V1 / TEZA	Grate Boiler	4	1963	0	130		brown coal	23 2		
	Hot Water (standby)	1	1974	0	130		light oil	9 8		
Doubravka V2 / TEZA	Grate Boiler	4	1963/6	0	130		brown coal	23 2		
Svetovar / TEZA	Grate Boiler	4	1957/8	0	130		brown coal	23 2		
Subtotal ZCE/TEZA		26						242 4	131 3	55
Brewery	Steam Boiler K4	1	1974	24			gas		15 7	
	Steam Boiler K5	1	1973	12			gas		7 8	
	Steam Boiler K6	1	1985	25			gas		16 3	
	Steam Boiler K7	1	1989	25			gas		16 3	
Railway ZOS	Steam Grate	2		12	280	1 5	brown coal		17	
Subtotal Brewery/ZOS		6						0	73 1	0
Skoda ELUIII[b]	Cogen PC Boiler K1	1	1982	160	540	9 4	brown coal		75	28
	Cogen PC Boiler, K4	1	1960	150	530	9 5	brown coal		72	28
	Steam Boiler K5	1	1975	75	350	1 8	heavy oil		49	
	Steam Boiler K6	1	1978	75	350	1 8	heavy oil		49	
	Cogen PC Boiler K3 (under construction)	1	1994	160			brown coal		78	28
Subtotal–Skoda		5							323	84
TOTAL PLZEN AREA		37						242 4	527 4	139

Note a Capacities do not necessarily represent the maximum for each commodity
b Skoda not a subject of detailed study, but shown here for completeness
c The indicated CPII HW capacity of 65 MW_t is coincident with the indicated steam and electric capacity The total HW and steam capacity can not exceed 165 MW_t

blr–sum wk3

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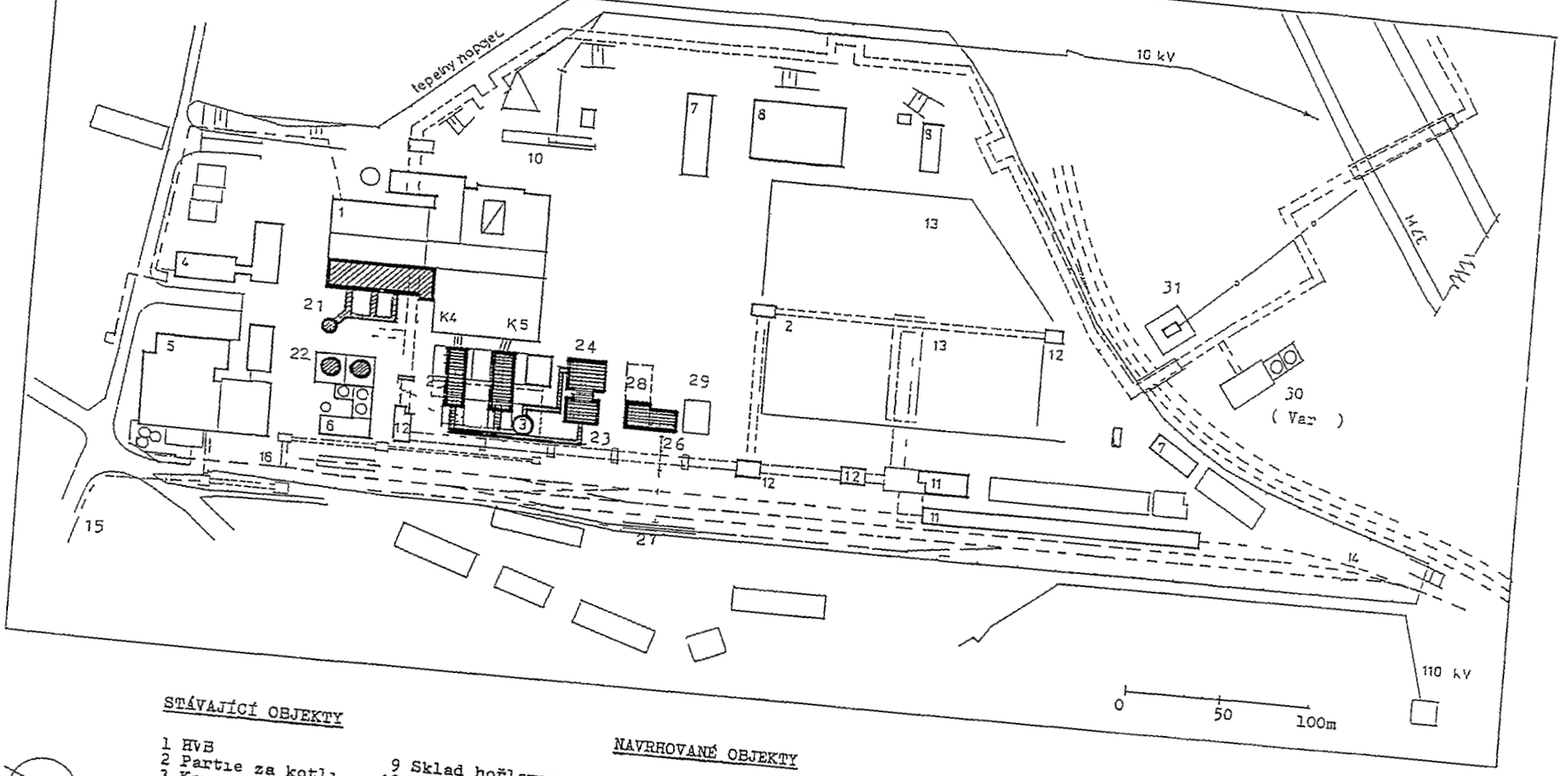
TEPLÁRNA PLZEŇ

SITUACE



STÁVAJÍCÍ OBJEKTY

1 HVB
2 Partie za kotli
3 Komin
4 Vstupni objekty
5 CHUV
6 Mazut hospod
7 Garaže
8 Dilny
9 Sklad hořlavin
10 Trafo
11 Hlub zásobník
12 Přesypna věž
13 Skládka paliva
14 Kolejiště
15 Hydrant odpovel
16 Potrubni most

NAVRHOVANÉ OBJEKTY

21 Komin
22 Olej nádrže
23 Oh chl spalin
24 Reaktor
25 Elektroodlučovače
26 Váp hospodářství
27 Vjkl vápence
28 Kompresorovna
29 ČOV
30 Chladici okruh
31 Reg. st. plynu

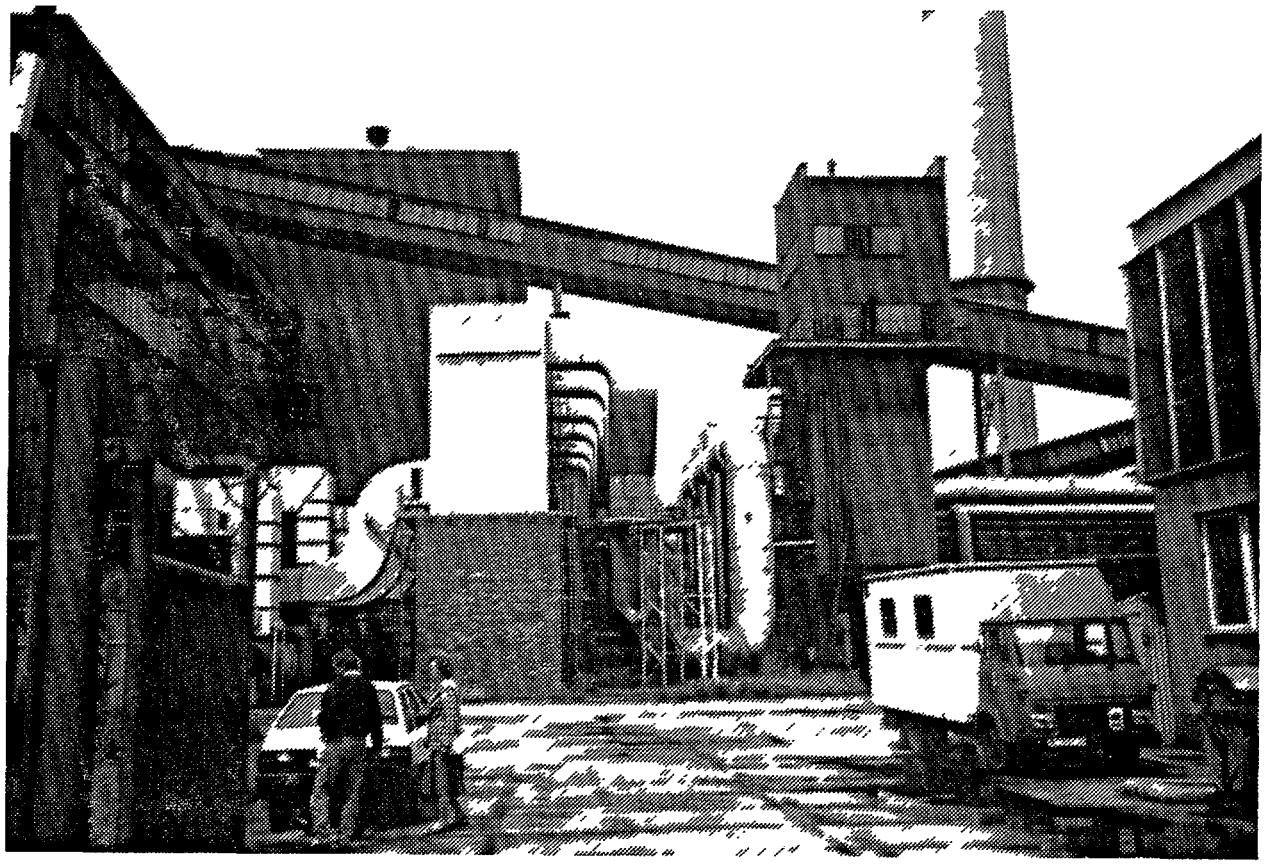
-Rekonstrukce K1-3 / Plyn - Ole /
-Odsíření K4-5

VARIANTA

Exhibit 2 3
SITE PLAN FOR CP PLZEN
(for Variant 1 Energoprojekt study)

BEST AVAILABLE COPY

Exhibit 2-4
COGENERATION PLANT PLZEN MAIN PLANT



In case of an outage of the 170 t/h boiler, the maximum possible heat delivery from the cogeneration plant in hot water is 144 MWt, and steam 34 MWt

Presently, brown coal is burned with the following characteristics

sulfur	0 5 to 0 95%
ash	13 4 to 18 5%
moisture	34 to 37 1%
heating value (LHV)	12 73 MJ/kg

Grate hot water boilers are equipped with cyclone flyash separators with efficiency of about 80% Pulverized coal-fired steam boilers are equipped with electrostatic filters with overall efficiency of 99 5 %

Several changes to the CP Plzen plant equipment will be necessary to comply with environmental regulations

Exhibit 2-5
COGENERATION PLANT PLZEN COAL YARD

2 2 PEAK LOAD PLANT KOSUTKA

Kosutka contains hot water boilers of 2 x 17 4 MWt capacity firing heavy heating oil, and were commissioned in 1981 The heating plant cooperates with the cogeneration plant in winter peak load period when outside temperatures fall below -10°C Kosutka also serves as a stand-by heat source in cases of the CP boiler failure

During the moderate winters in years 1991 and 1992 the heating plant was not in operation, whereas this year, in the end of January and early February, Kosutka had to be used

This year the heating plant is being reconstructed for the use of natural gas as fuel The peak-load supply of natural gas for the heating plant Kosutka has been contracted with the West-Bohemian Gas Works (Zapado eske plynarny) in a special tariff price Burning of oil is not being considered, because the existing oil handling equipment is outdated and does not meet the present regulations

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2 3 ENTERPRISE TEZA

Town enterprise TEZA consists of three separate systems (four stations) Bory, Letna V1/Doubravka V2, and Svetovar They are described in the following sections

2 3 1 Heating Plant Bory

Heating plant Bory consists of hot water and steam boilers burning Sokolov brown coal (lignite similar to CP Plzen) and light heating oil, with a total installed capacity of 54 5 MWt The attainable plant thermal output is 49 8 MWt, of which 16 4 MWt can be supplied as steam A view of the Bory facility is shown in Exhibit 2-6

Exhibit 2-6
HEATING PLANT BORY (TEZA)

The heating plant Bory supplies the living quarter Bory with hot water of parameters 150/70°C (maximum delivery is 24 3 MWt), and neighboring consumers with steam of parameters 0 95 MPa, 220°C (maximum delivery of 13 1 MWt) A heat exchanger makes it possible to deliver hot water from the steam boilers This is convenient because a large consumer is the neighboring hospital which has a higher steam load during the day, while the residence loads peak during the night

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The heating plant is near the end of its life span, and some modification of the hot water network is required to connect to the system of CP Plzen The connection with the main pipe line South has already been realized, but the pressure conditions at the end of the feeder need some improvement

2 3 2 Letna V1 and Doubravka V2

These interconnected heating plants supply heat in hot water of 130/70°C to living quarters Letna and Doubravka The total output thermal capacity of both heating plants is 46 5 MWt The heating plants are connected with a pipeline conduit 2xDN 250

The heating plants contribute significantly to pollution in the eastern part of the city Letna V1 is located in close proximity to residences, and there is limited space for reconstruction for environmental compliance Doubravka V2 is not far away

The connection of the respective hot water distribution networks is now under construction Construction preparation for the hot water pipe line East I has been completed The East I line will consist of 795 meters of 2xDN 500 pipe and 950 meters of 2xDN 350 pipe The connection will be completed in the year 1994

2 3 3 Heating Plant Svetovar

These hot water grate boilers were erected in years 1957-58, and supply a part of the living quarter Slovany with heat Their total capacity is 23 2 MWt, and the hot water has parameters 130/80°C The units are enclosed within a building, as the building was formerly a brewery An outside view of the Svetovar facility is shown in Exhibit 2-7

This plant is not in good condition, and modification of the plants with pollution control equipment is difficult because of limited space at the site Several proposals have been made to provide a connection to the centralized system, and to retire these units

2 4 SOURCES COOPERATING WITH CP PLZEN

Sources which cooperate with CP Plzen include West Bohemian Brewery Boiler House (Zapadoceske Pivovary) and the Railway Maintenance Company Boiler House (Zos)

2 4 1 West Bohemian Brewery Boiler House

The Brewery operates four gas boilers, installed during the years 1974-1989, with a total capacity 86 t/h = 56 1 MWt The boiler house cooperates with CP Plzen during winter peak load periods by steam delivery to the system using the capacity of two boilers In summer periods, CP Plzen does not deliver steam and the brewery boiler house takes over the supply of steam to the system

Current plans are to install a fifth gas-fired boiler of 25 t/h capacity Further cooperation is in the best interest of both parties

Exhibit 2-7
HEATING PLANT SVETOVAR (TEZA)

2 4 2 Railway Maintenance Company Boiler House

The Railway company operates two steam grate boilers with steam parameters of 1 5 MPa, 280°C The output capacity is 16 5 MWt The factory is connected to the steam distribution system of the CP Plzen The boiler house cooperates with the CP Plzen in the winter peak load period and supplies the system in summer, when CP Plzen does not deliver steam The boilers are at the end of their life span and their retirement is imminent

2 5 SKODA WORKS

The Skoda plant supplies the main factory with hot water and steam, and through the feeder 2xDN 400, delivers heat to the Skvrnany habitation areas There are several large and efficient high pressure boilers and cogen units with a total thermal output capacity of 245 MWt The construction of an additional unit, K3, has been resumed

After commissioning of the new unit in the year 1994, the output capacity of the plant will increase up to 323 MWt This will make it possible to successively retire individual boilers for reconstruction with environmental controls The pulverized coal-fired boilers will be equipped with a desulphurisation plant and new flyash separators Boilers K5 and K6 will be fired with tar oil with a sulphur content as low as 0 6 %

Following the installation of environmental controls, unit K4/TG10 will be retired and mothballed (preserved) The heat supply to the factory and to the living quarters will satisfy the units K1/TG8 and K3/TG1, and oil fired boilers K5 and K6 The total output capacity of the plant will then be 251 MWt

The future of Skoda works with a new corporate restructuring is a question The level of production achieved will influence the amount of steam and hot water needed Although the Skoda works is described here for completeness, it is not considered in the dispatch analysis of CP Plzen and the cooperating units for the analyzed variants

2.6 SYSTEM INTERCONNECTIONS

As shown schematically in Exhibit 2-1, the existing centralized system is served by a network of supply and return piping of various sizes The piping is maintained in relatively good condition It is estimated that about half of the existing piping system has already been replaced The leakage in the primary circuit is estimated to be 0 125% of system volume, well within the 5% Czech requirement Greater leakages are estimated for the secondary circuits, where many of the older four-pipe systems are not well maintained The new heat line East I is being constructed using a new plastic pipe, a product of Denmark While limited in maximum temperature to about 130°C, it is corrosion free, resulting in minimum to zero leakage

3.0 TECHNICAL REVIEW OF ENERGOPROJEKT REPORT (EGP 222)

The following sections present our review of the original Energoprojekt work[1] The Energoprojekt report served as a basis and provided significant input to the G/C and subcontractor effort Only this section, Section 3 0, will address the Energoprojekt report, the remaining sections and the Appendix will consist of the Gilbert/Commonwealth (and subcontractors) analysis of the Plzen district heating situation

3.1 GENERAL REVIEW

The EGP report was a good professional effort, and was organized in a manner where information could be found However, information, such as descriptions of the variants, could have been presented in additional tables for quick reference, such as shown in Exhibit 3-1

The choice of variants by EGP was logical (except the nuclear option IIc, which is not discussed here), and represented a reasonable range of choices, based on the assumptions Fluidized bed combustion (FBC) is a good choice, considering the quality of available indigenous coals, and allows continued use of low-cost fuels, support of the mining industry, and represents less reliance on imported natural gas fuel

The investigation of a high efficiency gas turbine combined cycle to determine the integration of this type of unit into the system, and consider costs and its operation in a sensitivity analysis with natural gas prices is also a logical choice

The EGP approach was straightforward and was based on some simplifying assumptions For example

- a general change in residential demand due to conservation was assumed, as directed by the city,
- the demand requirement estimates did not allow for a range of outcomes,
- the decentralized supply of heat to several areas would be served by natural gas,
- changes in efficiency and operations due to emissions reduction equipment was not included in the performance calculations, and
- changes in the cost of plant operations with privatization were not considered

The demand assumptions may be the most critical, as outlined in the next section The demand forecast must include an analysis of the potential and likely change in the number of consumers due to growth and retirement of small decentralized boilers, as well as conservation efforts prompted by legislative actions (for metering, billing) and rising costs of energy While these aspects were all addressed in the EGP report, simplifying assumptions made could under- or over-estimate the overall demand forecast

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The cost of plant operations, especially labor, will change with privatization Labor costs by productive manhour will rise, but efficiency of this labor will also rise

Exhibit 3-1
SUMMARY OF VARIANTS INVESTIGATED BY ENERGOPROJEKT

	Variants		
Parameter for Year 2000	**I**	**IIIa**	**IIIb**
Demand Projection New Consumers Hot Water Heat Requirement Steam Requirement	 Natural gas 423 MWt 237 MWt	Tied to DHS 482 MWt 240 MWt	
Meet 1996 Emission Requirements	Considered for all operating units		
Extension of Heat Distribution Lines	No change	Heat Line East I by 1994 Heat Line East II by 1996	
Reconstruction Measures / Year 2000 Status			
Plzen I Boilers	Gas/Oil retrofit		
Plzen II Cogen	FGD Retrofit		
Plzen III Cogen	None	Fluidized Bed Cogen 160 t/h 13 6 MPa, 540C	Gas Turbine CC GT 47 MWe, ST 14 MWe
Plzen IV Boilers	None	None	2 boilers, 35 and 11 6 MWt
Kosutka Boilers	Convert to gas		
Bory Boilers	Peak hot water source, steam to own consumers		
Letna Boilers	Gas/Oil retrofit	Retired 1996	
Doubravka Boilers	Gas/Oil retrofit	Gas/Oil retrofit	Retired 1996
Svetovar Boilers	Gas/Oil retrofit	Retired 1996	
Brewery Boilers	Assumed addition of 25 MWt gas-fired boiler		
Railway (Zos) Boilers	No change		
Skoda Boilers	New Cogen K3, FGD retrofit to K1, K4 Retired		

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Since the EGP work was completed, some conditions have changed

- natural gas conversion of the local boiler rooms is proceeding in the central part of the town and the Slovany area,
- the forecasts of future energy costs have changed,
- the construction of Skoda boiler K3 has resumed,
- the heat demands in steam of Pilsner Brewery are going up due to increasing beer production, and
- significant progress has been made toward privatization of ZCE

These changed conditions can significantly impact the approach taken for selection of variants, and also their evaluation

3.2 REVIEW OF SPECIFIC ENERGOPROJEKT VARIANTS

The following sections provide specific comments with regard to each variant analyzed

3.2.1 Variant I

Variant I provides a good baseline, examining the effect of minimal capital changes to the system, while still trying to meet the projected demand Variant I assumes that the emissions problems presented by 595 small boilers will be solved by conversion to natural gas, and that existing units with short remaining life will be upgraded and retrofit to burn natural gas/oil to solve environmental problems

Variant I simply tries to meet demand, and does not attempt to make the entire DH system more efficient and cost competitive in the long term With privatization, the DH System will be in competition with decentralized natural gas and electricity, and therefore must be efficient in operations, and without subsidy While this variant may be attractive from a capital investment standpoint, its inefficient operation would probably result in the future loss of additional DH consumers

3.2.2 Variant IIIa (and IIa)

Variant IIIa presents a more conservative approach than its counterpart Variant IIa toward meeting assumed additional demand Variant IIa entailed the installation of more supply capacity than Variant IIIa In light of the reduction in the anticipated demand, only Variant IIIa was reviewed in detail

Variant IIIa shows an improvement in operating efficiency of the whole DH system by suggesting installation of an efficient high-pressure FBC boiler with cogen, retirement of inefficient boilers, and also improving system reliability by connections of now independent systems In the EGP report, additional consumers are added to the system, preferring the DH system to natural gas conversion

3.2.3 Variant IIIb (and IIb)

Variant IIIb also presents a more conservative approach than its counterpart Variant IIb, but with the same intent Variant IIb entailed the installation of more supply capacity than Variant IIIb In light of the reduction in the anticipated demand, only Variant IIIb was reviewed in detail

Variant IIIb shows a large improvement in the efficiency of the DH system, but also results in a larger dependency on natural gas fuel Combined cycle systems are now very efficient in fuel utilization, and allow more electricity to be generated and sold Assuming that the Combined Cycle will integrate well with dispatch of current units, the benefits of this variant will be determined on economics and risk

3.3 OTHER VARIANT CONSIDERATIONS

There were other analyses conducted in the EGP study such as distribution lines, fuels analysis, and waste disposal These important areas will be examined in the G/C work as part of the overall cost/benefit analysis

3 3.1 Additional Variants to be Considered

Primarily due to the new demand projections, additional or modified variants are required to address the new situation These are necessary to provide the lowest cost of reliable energy supply

3 3.2 Implications of 595 small boilers

The 595 small boilers present a potentially significant influence on planning for the DH system Many of these boiler owners will be forced to choose between only a few alternatives, such as a fuel switch or a tie-in to the DH system The decision will likely be based solely on economics of the situation as perceived by the owner or cooperative Certainly, there will be an impact of regulations of the DH industry, the availability of DH supply, the accessibility to natural gas connections and/or better quality solid fuel

The potential to add even a small percentage of the 586 boilers to the DH system can significantly impact the demand projections Because supply and demand are now close, supply requirements will be affected The influence of emission regulations plays a very significant part in this analysis

3.4 REVIEW OF ECONOMIC REPORT

This review follows the order presented in the EGP report

3.4.1 General Review

Overall, the economic analysis conducted by Energoprojekt was conducted in a professional manner There are certain aspects of the analysis which may lead to different conclusions and recommendations under today's conditions

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In the following sections of this Report, a basic methodology will be presented which incorporates those approaches found acceptable in the Energoprojekt Report, combined with enhancements planned for this effort

In particular, there is concern that the demands may change with each of the variants under consideration due to efficiency differentials, pricing impacts at the end-use, and impacts due to higher conservation impacts on the baseline demand projection

Insufficient detail was provided in the report on the individual breakdown of capital costs between local and foreign expenditures In economic terms, the expected cost to the Czech economy for significant foreign costs for material and labor could influence the decision process Also, the level of local expenditures for capital does not include breakdowns of labor, material, or alternatives when selecting specific locally produced equipment

Finally, much of the analysis focused on the expected quantities and price of the electricity produced by the District Heating variants This is certainly an important consideration as a benefit to the projects under consideration However, by including that benefit in the Present Worth Analysis to the degree presented in the EGP report, biases the selection of larger projects when compared to the smaller projects with less electrical output This may be the correct approach, but some consideration may be given to the pricing levels of the district heating outputs to ensure that the primary objective of meeting demands in district heating at the lowest possible cost is likewise met

3.4.2 Description of Evaluation Method

The methodology chosen by Energoprojekt was appropriate in that standard economic analysis utilizing Net Present Values (NPVs) as the basis of selection relies on the differentials in costs and benefits as conducted

In any cogeneration project, the allocation of costs between three products is often open to criticism depending on the method chosen in assigning costs While Energoprojekt may very well have captured all of the appropriate costs and benefits in its analysis, it would be better to show the various components to be sure

The sensitivity analysis was performed in an extremely appropriate fashion and focused on those costs and benefits important to the analysis

3 4.3 Characterization of Evaluated Variants (Section 3)

While the written descriptions of each variant was necessary in this section, it would have been helpful to introduce another diagram or table which highlighted the differences for ease of the reader

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3.4.4 Values Required for Economic Evaluation (Section 4)

Investment Costs The inclusion of an appendix, delineating the level of detail for each variant, split between local and foreign expenditures would have been helpful to the reader As such, no comment can be made as to the appropriateness of the expenditures

It would also be appropriate to provide summary tables rather than graphs, or in addition to the graphs provided for each variant

Operating and Other Cost Factors The basic analysis, which included the primary operating costs, was appropriate An attempt could have been made to identify the real growth differentials between competing fuels, show the quantities used, and provide details on the quantities of emissions used in the cost analysis The discount rate utilized in the analysis was considered to be appropriate for the Czech Republic

3.4.5 The Economic Calculation Result (Section 5)

The comment regarding the pricing of heat is considered to be accurate within the context of the analysis undertaken However, the prime benefit analyzed was the electric energy sold rather than the least cost plan to sell heat energy (GJ) As previously discussed, a project that meets the objective of supplying heat only, regardless of the amount of electricity, would in fact be the least cost option to pursue As long as the NPV is positive, then it has met its objective Again, the economic analysis could have included an economic rate of return as an additional measure of results

Likewise, the sensitivity analysis could have included the Economic Rate of Return for each case investigated to further support the recommended decision The dynamic calculation was a good first step in attempting to capture this aspect of change in costs and prices

3.4.6 Risks and Uncertainties (Section 6)

The discussion itself mentions the problems associated with electric production pricing and its impacts However, no mention is made of country risks where fuel is provided, or the uncertainties of sufficient foreign exchange Attempts should be made to at least discuss those items and provide quantities where possible

3.4.7 Conclusions and Recommendations (Section 7)

Given the review conducted and the discussion on each of the chapters in the economic analysis, there is reason to believe that some uncertainty still exists, especially when one considers the changes that have occurred to date However, given the level of effort and the complexity of the project, it should be mentioned that the analysis was performed in a professional manner

3.5 REFERENCES

1 Energoprojekt Praha, The Study to Finalize the Concept of the Pilsen Heat Supply System, Part 1 - Technical Report and Part 2 - Economic Report, EGP 22210, December 1991

4.0 SMALL DECENTRALIZED SOURCES

The city of Plzen has approximately 595 boilers that are currently supplying hot water to both residential and commercial buildings These boilers range in size from 0 035 MWt to 3 MWt and burn a wide variety of coals, city gas, natural gas and fuel oils Generally the stacks for small boilers are low which causes the pollutants to affect the immediate area According to the new emissions regulations, all boilers above 0 2 MWt must, by 1997, conform to emission limits for pollutants Those coal-burning units greater than 0 2 MWt must therefore clean the flue gas, switch to natural gas, or, shut down since paying penalties may not be acceptable or cost effective A promising alternative is to extend distribution lines from the central heating system to the distribution point of the decentralized source A study was performed to investigate options for the small boilers (1) determine how many of the small boilers could potentially be retired, with their consumers connected to the central system, (2) how many could or should convert to natural gas, and (3) also investigate other possiblities

The scope of the G/C analysis includes only the approximately 595 small boilers, and does not include individual residential furnaces However, the recommendations offered for the 595 boilers could be extended to many of these individual furnaces The following sections include characterization of the boilers and consideration of options for emissions reduction

4 1 CHARACTERIZATION OF SMALL BOILERS

A comprehensive data base exists, based on records kept by the state, which characterizes the 595 boilers It provides location, fuel type, emissions, boiler efficiency, rated output in MWt and fuel consumption Exhibit 4-1 summarizes the types of small boilers in Plzen by fuel use and capacity, and presents information on fuel consumption, total output, efficiency and the number of boilers It also provides an indication of the potential for use of emission control equipment Note that 591 boilers are accounted for in this data base compared to 595 in other references For the purposes of this study, it was not considered necessary to reconcile or adjust these numbers

Hand-fired boilers especially are not conducive to modification or to the addition of back-end equipment Note that there are 61 hand-fired coke boilers and 68 hand-fired lignite boilers identified In addition to the hand fired boilers, the other solid fuel boilers are typified by steel boilers with counter-rotating chain grates for the production of low or middle pressure steam, and steel boilers with reciprocating grates for the production of hot water or low pressure steam

Of the 595 boilers, 65 are burning coal (including coke) and 165 burn lignite (including brown coal) These are the boilers that have a potential to be retired, and their consumers connected into the central heating system if they cannot comply with the emission regulation economically Exhibit 4-1 (located in Appendix H) is a map of Plzen which shows where these and other boilers are located

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Exhibit 4-1
CHARACTERIZATION OF SMALL DECENTRALIZED BOILERS

Category	Number of Boilers	Total MW Out	Annual Fuel Use	Fuel Use Units	Average Efficiency
Stoker Coke Fired Boilers > = 0 2 MW	1	0 680	60,000	kg	42 0
Hand Fired Coke Boilers < = 0 2 MW	21	3 088	427,205	kg	59 2
Hand Fired Coke Boilers > = 0 2 MW	40	12 379	2,061,199	kg	65 1
Other Coke Boilers < 0 2 MW	3	0 394	22,969	kg	70 3
Subtotal Coal/Coke Boilers	65	16 541	2,571,373	kg	63 6
Stoker Fired Lignite Boilers < 0 2 MW	2	0 230	45,444	kg	70 0
Stoker Fired Lignite Boilers > = 0 2 MW	92	90 718	27 182,570	kg	55 4
Hand Fired Lignite Boilers < 0 2 MW	23	3 556	537 421	kg	39 9
Hand Fired Lignite Boilers > = 0 2 MW	45	19 057	3,099 750	kg	53 8
Other Lignite Boilers < 0 2 MW	1	0 033	1,712	kg	51 0
Other Lignite Boilers > = 0 2 MW	2	0 860	179,818	kg	70 3
Subtotal Lignite Boilers	165	114 454	31,046,715	kg	55 1
City Gas Fired Boilers < 0 2 MW	94	10 424	3,511,035	m^3	76 8
City Gas Fired Boilers > 0 2 MW	154	103 484	28,055,954	m^3	77 3
Subtotal City Gas Fired Boilers	248	113 908	31 566,989	m^3	77 2
Natural Gas Fired Boilers < 0 2 MW	39	3 933	678,617	m^3	77 7
Natural Gas Fired Boilers > 0 2 MW	55	32 012	4 704,562	m^3	79 6
Subtotal Natural Gas Fired Boilers	94	35 945	5 383,179	m^3	79 4
Light Oil Fired Boilers < 0 2 MW	4	0 580	66 706	kg	71 0
Light Oil Fired Boilers > 0 2 MW	15	18 221	1,386,926	kg	75 2
Subtotal Light Oil Fired Boilers	19	18 801	1,453,632	kg	75 0
Total	591	299 65			

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The 248 boilers currently burning city gas are expected to convert to natural gas by 1996 They are now supplied from two North Bohemian gasifiers which are over 20 years old and will be decommissioned in the year 2000 The city of Prague has already completely switched from city gas to natural gas Other Czech cities are following this example

The small boiler data base was used by RAEN to arrange the data into a useable form for this study, and to propose a scenario for the City of Plzen for likely fuel switching, connection to the central system, or electrification EGU and Energoprojekt independently developed additional data, based on several discussions with ZCE, and then corroborated with RAEN to develop a reasonable scenario for the demand requirements which could be assumed for the centralized heat supply system

The following sections explore emissions reduction options for the small boilers

4 2 BOILER MODIFICATIONS AND CONVERSIONS TO NATURAL GAS

Many of the coal/lignite burning boilers can be converted to natural gas To assess the potential of natural gas conversion, a survey was completed which categorized the boilers according to capacity and age as follows

over	0 5 MWt
under	0 5 MWt
over	20 years old
under	20 years old
between	14 and 20 years old

This first analysis was conducted independent of potential connection of the small boilers to district heating Exhibit 4-2 shows these categories and provides recommendations for conversion to natural gas, where available The "Modification/Option Number" is a convenient designation to divide the emission control approach by boiler capacity, fuel, boiler age, and the near-term availability of a natural gas connection

The next series of nine exhibits is divided into two distinct categories (1) boilers that do not need a connection of natural gas, and (2) boilers that will need such a connection A further subdivision is by age and boiler capacity Those boilers suitable and recommended for natural gas and other modifications are indicated in the series of exhibits Also shown is the resulting fuel usage benefit if the fuel changes and efficiency measures are implemented Exhibit 4-3 provides a summary of this work, and presents the existing and future emissions for each category of boilers after the conversions have been made to satisfy pollution regulations While the timing, cost, and potential for implementation is not known, these changes represent goals for the boiler owners and the city

Exhibit 4-2
SPECIFICATION OF POTENTIAL BOILER IMPROVEMENTS

Modification/ Option Number	Boiler Capacity [MWt]	Current Fuel[a]	Boiler Age [Year]	Natural Gas Connection Available?	Suggested Arrangements and Boiler Modifications
1	All	L C	>= 20	Yes	Replace the present boilers with NG boilers with low-NO_x burners, efficiency 90%, NO_x 60%
2	All	L, C	>= 20	No	Replace the present boilers with new coal boilers, efficiency 75%
3	< 0 5	L, C	>= 20	No	Replace the present boilers with elektroboilers
4	< 0 5	L, C	< 20	No	No exchange
5	< 0 5	L, C	< 20	Yes	Installation of new NG burners with low-NO_x to the present boilers, efficiency 90% NO_x 60%
6	>= 0 5	L C	> 14	No	Installation of control of quantity of combustion air by oxygen probe to the present boilers, efficiency 75%
7	>= 0 5	L, C	14 > 20	Yes	Replace the present boilers with NG boilers with low-NO_x efficiency 90%, NO_x 60%
8	All	CG, NG L+CG, C+CG	>= 20	Yes	The same as No 7
9	All	CG, NG	< 20	Yes	Installation to the present boilers of new NG burners with low-NO_x, efficiency 90%, NO_x 60%
10	All	LO, HO	< 20	No	No exchange
11	All	LO, HO	>= 20	No	Replace the present boilers with new oil boilers with low-NO_x burners, efficiency 87%, NO_x 80%

Note a Fuel designation

L =	Lignite	CG =	City Gas	LO =	Light Oil
C =	Coal	NG =	Natural Gas	HO =	Heavy Oil

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Exhibit 4-3
SMALL BOILER EMISSIONS AND ENERGY USE SUMMARY TABLE

Exhibit Number[a]	Number of Boilers	Total Output [MW]	Status	Fuel Consumption [GJ/y]	Emissions [t/y]				
					Parti-culate	SO_2	NO_x	CO	CxHy
4-4	42	44 49	Exist	213,268	306 01	223 74	47 15	82 21	31 7
			Sugg	117,403	1 046	0 03	3 98	1 107	0 443
4-5	18	24 17	Exist	84,846	49 09	45 45	13 39	10 31	3 33
			Sugg	65,931	34 63	32 82	6 42	6 99	2 28
4-6	21	26 83	Exist	79,440	123 91	103 7	17 63	29 51	9 07
			Sugg	65 802	29 73	24 55	5 75	6 14	2 31
4-7	70	95 6	Exist	388,166	62 5	46	49 29	22 95	6 42
			Sugg	346,284	47 74	40 41	19 95	15 75	5 05
4-8	90	23 08	Exist	82 781	69 09	68 64	12 47	157 87	33 48
			Sugg	52,551	0 48	0 006	1 77	0 49	0 2
4-9	100	25 15	Exist	104,529	48 06	28 77	11 02	61 04	13 18
			Sugg	73,176	17 79	12 56	4 05	31 02	6 66
4-10	23	5 93	Exist	24 790	19 16	21 21	4 29	29 37	6 51
			Sugg	15,385	0 14	0 005	0 53	0 15	0 06
3-11	226	46 083	Exist	223 507	4 467	2 59	22 66	6 21	1 86
			Sugg	195,429	2 74	1 81	7 63	4 27	1 27
TOTAL	590	291 3	Exist	1 201 327	682 29	540 1	177 9	399 47	105 55
			Sugg	931,961	134 30	112 19	50 08	65 917	18 273

Note a Exhibit 3-4 Age >20 years, Capacity >0 5 MWt, Gas Connection required
Exhibit 3-5 Age >20 years Capacity >0 5 MWt, Gas Connection not required
Exhibit 3-6 Age <20 years, Capacity >0 5 MWt, Gas Connection required
Exhibit 3-7 Age <20 years, Capacity >0 5 MWt, Gas Connection not required
Exhibit 3-8 Age >20 years Capacity <0 5 MWt Gas Connection required
Exhibit 3-9 Age >20 years Capacity <0 5 MWt Gas Connection not required
Exhibit 3-10 Age <20 years Capacity <0 5 MWt Gas Connection required
Exhibit 3-11 Age <20 years Capacity <0 5 MWt Gas Connection not required

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Details to support the values in Exhibit 4-3 are presented in the next eight exhibits Exhibits 4-4, 4-6, 4-8, and 4-10 show the number of boilers, total output, option cl sification annual fuel use and emissions for the first category, i e where a gas connection is required, and by four combinations of age/capacity

Exhibits 4-5, 4-7, 4-9, and 4-11 give similar information for boilers of the second category, i e, where a gas connection is not required Calculation results are provided for the "existing" situation and also the resulting situation if suggestions are implemented Each exhibit also includes reduced fuel use, where applicable, as a result of implementing the changes

The solid fuel-fired small boiler decisions will ultimately be based on the cost or perceived cost to convert to natural gas versus the cost of hot water supplied from the central system Each case will be different depending on the type of boiler, age, size and other factors Because natural gas costs are currently low, it is possible that conversion to gas will appear more economical than a connection to the central system In the long term, the real comparison will depend more on the relative increases in energy cost to the small consumer between the present fuel and the options

Regulations issued by the city could influence the choice of gas or district heating by requiring that all boilers adjacent to existing hot water pipelines utilize the district heating option, or they could influence the location of natural gas line extensions A more acceptable form of influence which can motivate boiler owners/operators could be provided by incentives in the form of tax relief or credits

While capital costs were not generated for these modifications, the tables represent the benefits which can potentially be achieved As fuel prices rise, energy efficiency policies are introduced, and competing efficient energy sources are available, these benefits will be realized

Exhibit 4-4
EMISSIONS FOR BOILERS WITH GAS INTRODUCTION (Age >20 years, Capacity >0 5 MWt)

					Boiler Capacity >= 0 5 MWt Age >= 20 years			Introduction to Gas Required? Yes				
								Emissions [t/y]				
Number of Boilers	Total Output [MW]	Modification Category Number[a]	Status	Fuel	Fuel Consumption [GJ/y]	Heating Value [MJ/kg] [MJ/Nm^3]	Efficiency [%]	Particulate	SO_2	NO_x	CO	CxHy
1	0 68	1	Exist	C	1 560	26	42	1 14	1 03	0 19	2 65	0 6
			Sugg	NG	728	34	90	0 006	0	0 03	0 007	0 003
41	43 81	1	Exist	L	211,708	13 5	50	304 9	222 7	47 0	79 6	31 1
			Sugg	NG	116,675	34	90	1 04	0 03	3 95	1 1	0 44
42	44 49		Exist		213,268			306 0	223 7	47 2	82 2	31 7
			Sugg		117,403			1 05	0 03	3 98	1 11	0 443

Note a Modification Category Number refers to categories in Exhibit 4-2

Exhibit 4-5
EMISSIONS FOR BOILERS WITHOUT GAS INTRODUCTION (Age >20 years, Capacity >0 5 MWt)

					Boiler Capacity >= 0 5 MW Age >= 20 years			Introduction to Gas Required? No				
								Emissions [t/y]				
Number of Boilers	Total Output [MW]	Modification Category Number[a]	Status	Fuel	Fuel Consumption [GJ/y]	Heating Value [MJ/kg] [MJ/Nm^3]	Efficiency [%]	Particulate	SO_2	NO_x	CO	CxHy
5	10 33	8	Exist	CG	49,369	15	73	0 97	0 29	6 04	1 04	0 35
			Sugg	NG	40,044	34	90	0 36	0 01	1 35	0 38	0 15
9	10 8	2	Exist	L	26,028	13 5	53	47 62	38 29	4 99	9 13	2 89
			Sugg	L	18,393	13 5	75	33 87	27 33	3 56	6 5	2 05
4	3 04	11	Exist	LO	9 449	40	69	0 5	6 87	2 36	0 14	0 09
			Sugg	LO	7 494	40	87	0 4	5 48	1 51	0 11	0 08
18	24 17		Exist		84 846			49 09	45 45	13 39	10 31	3 33
			Sugg		65 931			34 63	32 82	6 42	6 99	2 28

Note a Modification Category Number refers to categories in Exhibit 4 2

Exhibit 4-6
EMISSIONS FOR BOILERS WITH GAS INTRODUCTION (Age <20 years, Capacity >0 5 MWt)

					Boiler Capacity >= 0 5 MW Age < 20 years			Introduction to Gas Required? Yes				
								Emissions [t/y]				
Number of Boilers	Total Output [MW]	Modification Category Number[a]	Status	Fuel	Fuel Consumption [GJ/y]	Heating Value [MJ/kg] [MJ/Nm^3]	Efficiency [%]	Particulate	SO_2	NO_x	CO	CxHy
21	26 83	7	Exist	L	79,440	13 5	71	123 91	103 7	17 63	29 51	9 07
		6	Sugg	NG, L	65,802	34, 13 5	90, 75	29 73	24 55	5 75	6 14	2 31
21	26 83		Exist		79,440			123 91	103 7	17 63	29 51	9 07
			Sugg		65,802			29 73	24 55	5 75	6 14	2 31

Note a Modification Category Number refers to categories in Exhibit 4-2

Exhibit 4-7
EMISSIONS FOR BOILERS WITHOUT GAS INTRODUCTION (Age <20 years, Capacity >0 5 MWt)

					Boiler Capacity > = 0 5 MW Age < 20 years			Introduction to Gas No				
								Emissions [t/y]				
Number of Boilers	Total Output [MW]	Modification Category Number[a]	Status	Fuel	Fuel Consumption [GJ/y]	Heating Value [MJ/kg] [MJ/Nm^3]	Efficiency [%]	Particulate	SO_2	NO_x	CO	CxHy
39	47 47	9	Exist	CG	210,316	15	77	4 1	1 19	26 39	4 34	1 54
			Sugg	NG	179,937	34	90	1 87	0 06	7 11	1 98	0 79
12	19 78	9	Exist	NG	75,740	34	83	0 67	0 02	4 21	0 72	0 25
			Sugg	NG	69,849	34	90	0 62	0 02	2 38	0 66	0 23
3	1 95	9	Exist	CG, NG	3,692 4	15	83	0 07	0 02	0 47	0 08	0 03
			Sugg	NG	3405	34	90	0 03	0 001	0 13	0 04	0 01
4	10 59	9	Exist	CG, LO	32,576	20	80	0 48	0 29	3 09	0 53	0 18
			Sugg	NG	28,956	34	90	0 29	0 009	1 1	0 31	0 12
1	0 6	9	Exist	L, CG	2,678 7	14	84	10 35	2 66	0 32	3 74	0 17
			Sugg	NG	2500	34	90	0 02	0 001	0 09	0 03	0 01
9	10 44	6	Exist	L	35,762	13 5	72	44 9	35 23	8	13 2	4
			Sugg	L	34,236	13 5	75	42 98	33 73	7 66	12 64	3 83
1	2 91	10	Exist	LO	5,901	40	78	0 31	4 75	1 48	0 09	0 06
			Sugg	LO	5,901	40	78	0 31	4 75	1 48	0 09	0 06
1	1 86	10	Exist	LO, HO	21 500	40	83	1 62	1 84	5 33	0 25	0 19
			Sugg	LO, HO	21 500	40	83	1 62	1 84	5 33	0 25	0 19
70	95 6		Exist		388,166			62 5	46	49 29	22 95	6 42
			Sugg		346,284			47 74	40 41	19 95	15 75	5 0

Note a Modification Category Number refers to categories in Exhibit 4-2

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Exhibit 4-8
EMISSIONS FOR BOILERS WITH GAS INTRODUCTION (Age >20 years, Capacity <0 5 MWt)

					Boiler Capacity < 0 5 MW Age > = 20 years			Introduction to Gas Yes				
								Emissions [t/y]				
Number of Boilers	Total Output [MW]	Modification Category Number[a]	Status	Fuel	Fuel Consumption [GJ/y]	Heating Value [MJ/kg] [MJ/Nm^3]	Efficiency [%]	Particulate	SO_2	NO_x	CO	CxHy
31	7 6	1	Exist	L	17 676	13 5	48	28 04	20 53	3 94	31 47	6 48
			Sugg	NG	9,622	34	90	0 085	0 003	0 32	0 09	0 04
42	11 04	1	Exist	C	49,230	26	62	22 53	30 95	5 87	86 42	18 87
			Sugg	NG	33 914	34	90	0 31	0 001	1 15	0 32	0 13
17	4 44	1	Exist	L, C	15,875	18	51	18 52	17 16	2 66	39 98	8 13
			Sugg	NG	9 015	34	90	0 08	0 002	0 3	0 08	0 03
90	23 08		Exist		82,781			69 09	68 64	12 47	157 87	33 48
			Sugg		52,551			0 475	0 006	1 77	0 49	0 2

Note a Modification Category Number refers to categories in Exhibit 4 2

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Exhibit 4-9
EMISSIONS FOR BOILERS WITHOUT GAS INTRODUCTION GAS (Age >20 years, Capacity <0 5 MWt)

					Boiler Capacity < 0 5 MW Age >= 20			Introduction to Gas No				
								Emissions [t/y]				
Number of Boilers	Total Output [MW]	Modification Category Number[a]	Status	Fuel	Fuel Consumption [MJ/y]	Heating Value [MJ/kg] [MJ/Nm^3]	Efficiency [%]	Particulate	SO_2	NO_x	CO	CxHy
7	1 4	7 (70%) 3 (30%)	Exist	C	6,102	26	63	2 45	3 73	0 8	10 42	2 43
			Sugg	C, E	3,588	26	75, 100	1 44	2 2	0 47	6 13	1 43
2	22	8	Exist	C NG	259 2	30	69	0 17	0 12	0 03	0 38	0 09
			Sugg	NG	198 7	34	90	0 002	0	0 006	0 002	0
3	93	2	Exist	C W	640	20	62	0 33	0 53	0 1	1 37	0 32
			Sugg	C	687 8	26	75	0 21	0 35	0 06	0 82	0 2
37	9 35	8	Exist	CG	40,807	15	66	0 82	0 24	5 21	0 87	0 31
			Sugg	NG	29,925	34	90	0 27	0 11	1 01	0 28	0 11
8	2 69	8	Exist	CG,	7,810	15	68	0 14	0 02	0 98	0 16	0 05
			Sugg	NG	5,901	34	90	0 05	0 00	0 2	0 06	0 02
11	3 28	2 (70%) 3 (30%)	Exist	L	5,525	13 5	47	9 25	6 47	1 24	13 82	2 75
			Sugg	L, E	2 424	13 5	75 100	4 06	2 84	0 54	6 06	1 21
6	1 66	2	Exist	L, C	11,785	18	46	19 09	8 89	1 95	29 12	6 93
			Sugg	L, C	7,088	18	75	11 46	5 34	1 17	17 51	3 63
5	1 26	8	Exist	L, CG	5,460	14	62	15 47	6 62	0 71	4 9	0 3
			Sugg	NG	3,761	34	90	0 05	0 00	0 12	0 05	0 01
6	1 05	11	Exist	LO	2,908	40	69	0 13	2 14	0 69	0 04	0 03
			Sugg	LO	2,307	40	87	0 1	1 71	0 44	0 04	0 02
15	3 31	8	Exist	NG	23 233	34	67	0 21	0 00	1 31	0 22	0 08
			Sugg	NG	17,295	34	90	0 15	0 00	0 59	0 16	0 06
100	25 15		Exist		104,529			48 06	28 7	11 02	61 04	13 18
			Sugg		73,176			17 792	12 5	4 046	31 02	6 66

Note a Modification Category Number refers to categories in Exhibit 4-2

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Exhibit 4-10
EMISSIONS FOR BOILERS WITH GAS INTRODUCTION (Age <20 years, Capacity <0 5 MWt)

					Boiler Capacity < 0 5 MW Age < 20							Introduction to Gas Yes
Number of Boilers	Total Output [MW]	Modification Category Number[a]	Status	Fuel	Fuel Consumption [GJ/y]	Heating Value [MJ/kg] [MJ/Nm^3]	Efficiency [%]	Emissions [t/y]				
								Particulate	SO_2	NO_x	CO	CxHy
9	2 31	5	Exist	C	10,225	26	57	4 83	6 15	1 22	17 74	3 88
			Sugg	NG	6,476	34	90	0 06	0 002	0 22	0 06	0 02
7	2 46	5	Exist	L	11,596	13 5	54	11 87	12 42	2 58	4 25	1 01
			Sugg	NG	6 996	34	90	0 06	0 002	0 24	0 07	0 03
7	1 16	5	Exist	L, C	2,969	18	58	2 46	2 64	0 49	7 38	1 62
			Sugg	NG	1,913	34	90	0 02	0 001	0 07	0 02	0 01
23	5 93		Exist		24,790			19 16	21 21	4 29	29 37	6 51
			Sugg		15,385			0 14	0 005	0 53	0 15	0 06

Note a Modification Category Number refers to categories in Exhibit 4 2

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Exhibit 4-11
EMISSIONS FOR BOILERS WITHOUT GAS INTRODUCTION (Age <20 years, Capacity <0 5 MWt)

					Boiler Capacity < 0 5 MW Age < 20 Introduction to Gas Required? No							
Number of Boilers	Total Output [MW]	Modification Category Number[a]	Status	Fuel	Fuel Consumption [GJ/y]	Heating Value [MJ/kg] [MJ/Nm^3]	Efficiency [%]	Emissions [t/y]				
								Particulate	SO_2	NO_x	CO	CxHy
1	0 13	9	Exist	C	151 8	30	71	0 1	0 07	0 02	0 22	0 05
			Sugg	NG	119 8	34	90	0 001	0 01	0 005	0 001	0 001
122	27 3	9	Exist	L	117,403	15	77	2 39	0 67	14 95	2 51	0 88
			Sugg	NG	100,445	34	90	1 05	0 04	3 96	1 1	0 45
30	4 23	9	Exist	L C	19,677	15	82	0 38	0 1	2 46	0 42	0 15
			Sugg	NG	17,928	34	90	0 17	0 008	0 66	0 19	0 06
67	12 86	9	Exist		84,055	34	80	0 75	0 02	4 75	0 8	0 27
			Sugg		74,716	34	90	0 67	0 02	2 53	0 72	0 25
1	0 033	4	Exist		25 9	13 5	51	0 04	0 03	0 006	0 08	0 02
			Sugg		25 9	13 5	51	0 04	0 03	0 006	0 08	0 02
1	0 32	4	Exist		864	18	53	0 8	0 73	0 14	2 16	0 48
			Sugg		864	18	53	0 8	0 73	0 14	2 16	0 48
4	1 21	10	Exist		1 330	40	74	0 007	0 97	0 33	0 02	0 01
			Sugg		1,330	40	74	0 007	0 97	0 33	0 02	0 01
226	46 08		Exist		223,507			4 467	2 59	22 656	6 21	1 86
			Sugg		195,429			2 738	1 808	7 631	4 271	1 271

Note a Modification Category Number refers to categories in Exhibit 4 2

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4.3 CONNECTION TO THE DH SYSTEM

A subsequent analysis was conducted to determine the potential to connect selected small boilers to the central district heating (DH) system The central heating system offers the following advantages

- ability to use inexpensive fuels with cost-effective environmental controls
- ability to cogenerate on a large, cost effective scale
- utilization of large efficient power plants
- ability to minimize overcapacity
- ability to provide greater reliability of service

The primary disadvantage of the central DH system is that heat must be transferred over a distance The heat loss, maintenance cost, and control of this "distribution" system is important to efficient operation of the DH system, and its competitiveness with other energy forms The technology asociated with heat distribution is continually being improved, resulting in a reduction of losses as this new technology is implemented

It has been shown in many situations that DH is cost effective In the City of Plzen, much of the cost of the DH system has already been expended, and so it can be concluded that if the system is operated in an efficient manner, it will be cost-effective for reasonably dense population centers

ZCE has been active in determining the potential for new markets in the central DH system area Agreements between 20 small boiler plants and ZCE have already been made to connect them to the DH system by 1994 A listing of these plants is shown in Exhibit 4-12 The total demand for these plants is about 27 MWt after adjusting for capacity margin, conservation and coincident demand Note that this adjustment is significant and represents an advantage of a central system A small boiler must be purchased in certain available sizes, and could represent 20-30% overcapacity Also, the fact that all heat loads do not occur exactly at the same time results in a savings for "non-coincident" demand

The low balance figures in Exhibit 4-12 assume by judgement that 25% will not connect to the DH system This is because the agreements are not firm, and it is still possible that some users may change their mind and select another option Note that some of the plants are now burning city gas and natural gas

Exhibit 4-13 lists additional boiler plants that have a potential for connecting to the central system This list was prepared by RAEN, independently from that provided in Exhibit 4-12 and then corroborated with EGU's findings Engineering judgement was used to determine which boilers were suitable for connection This judgement, based on the "economic

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Exhibit 4-12
HEAT SUPPLY PROMISED FROM DHS ZČE UP TO 1996

	Applicant (customer)	Address of the Customer	Start Up	Demand GJ/y	Requested[a] Therm Power kWt	Reduced[b] Therm Power kWt
PIPELINE SOUTH						
1	Magistrat města	Lukavicka 9	09/1993	4015	544	435 2
2	Magistrat města	Čechova 28	09/1993	1231	191	152 8
3	Magistrat města	Pod Zahorskem 26	09/1993	11247	3050	2440 0
4	Min školstvi	Gymnazium Petakova 2	1993	9000	2566	2052 8
5	Vojenska nemocnice	Sklad Kozinova 6	09/1993	800	130	104 0
6	Min zdravotnictvi	I pol Denisovo nabř	1993	8580	2000	1600 0
7	Plzeňske komunikace	• Preslova 13	1993	828	210	168 0
8	Min školstvi	Chodske nam 1 (navyš)	1993	13005	1880	1504 0
9	RECOOP TOUR a s Praha	Sady 5 května	1993	29299	3045	2436 0
10	SČM výrob družstev	Radobyčicka 24	1993	4500	700	560 0
11	Kmart ČR a s Praha	OD Prior Americka 47	1993	12000	1800	1440 0
15	Škoda a s Plzeň	Zimni stadion	1994	12500	2273	1818 4
16		OD + garaže Gerska	1995	13772	2500	2000 0
19	Min° hospodařstvi	Dum obuvi Americka	?	1876	1240	992 0
20	ISRAM s r o Plzeň	Štruncovy sady	?	1100	150	120 0
SUBTOTAL - reduced power - high balance				123753	22279	17823 2
		- low balance				13367 4
PIPELINE NORTH						
12	Min stavebnictvi	Stř GERA + garaže	1993/94	2880	570	456 0
13	CURAMED	EDEKA Plzeň - Bolevec	1994	1470	260	208 0
18	Spr pošt a telekom	SOU spoju Lochotin	1996	15000	2260	1808 0
SUBTOTAL - reduced power - high balance				19350	3090	2472 0
		low balance				1854 0
PIPELINE EAST						
14	Min prumyslu ČR	Stavebni stroje	1994	28588	7000	5600 0
17	Min prumyslu ČR	EPRO s p Cvokařska 10	1995	9800	1900	1520 0
SUBTOTAL reduced power - high balance				38388	8900	7120 0
		- low balance				5340 0
TOTAL - reduced power - high balance					34269	27415 2
		low balance				20561 4

Notes a Current demand
b Projected demand based on efficiency improvement and coincident demand

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Exhibit 4-13
LOCAL BOILERS SUITABLE TO BE CONNECTED TO DHS - ZČE - HIGH BALANCE

Boiler No	Inst Therm Output kWt	Fuel	Heat Value MJ/kg	Consultation t/y	Consultation GJ/y	Efficiency %	Demand GJ/y	Time Factor h/y	Power kWt
PIPELINE SOUTH									
10	4640	HU	14 5	815	11817 5	0 73	8626 8	2200	1089
12	4610	HU	14 5	1566	22707 0	0 73	16576 1	2000	2302
40	2320	HU	14 5	47	681 5	0 73	497 5	2200	62 8
46	2158	HU	14 5	500	7250 0	0 73	5292 5	2200	668 2
75	1000	HU	14 5	147	2131 5	0 73	1556 0	2200	196 5
76	990	KOKS	26 4	243	6415 2	0 73	4683 1	2200	591 3
78	954	KOKS	26 4	233	6151 2	0 73	4490 4	2200	567 0
84	874	KOKS	26 4	174	4593 6	0 73	3353 3	2200	423 4
96	750	KOKS	26 4	154	4065 6	0 73	2967 9	2200	374 7
112	636	KOKS	26 4	232	6124 8	0 73	4471 1	2200	564 5
117	636	HU	14 5	560	8120 0	0 73	5927 6	2100	784 1
131	543	HU	15 0	112	1680 0	0 73	1226 4	2200	154 8
134	524	KOKS	26 4	61	1610 4	0 73	1175 6	2000	163 3
160	708	HU	15 0	132	1980 0	0 73	1445 4	2200	182 5
174	353	KOKS	26 4	69	1821 6	0 73	1329 8	2200	167 9
181	318	HU	15 0	80	1200 0	0 73	876 0	2200	110 6
183	318	KOKS	26 4	85	2244 0	0 73	1638 1	2200	206 8
184	318	HU	15 0	93	1395 0	0 73	1018 4	2200	128 6
200	295	KOKS	26 4	56	1478 4	0 73	1079 2	2200	136 3
202	280	KOKS	26 4	60	1584 0	0 73	1156 3	2100	153 0
205	273	KOKS	26 4	14	369 6	0 73	269 8	2200	34 1
207	272	HU	15 0	81	1215 0	0 73	887 0	2200	112 0
220	234	LTO	41 5	3	124 5	0 8	99 6	1000	27 7
222	234	HU	16	66	1056 0	0 73	770 9	2200	97 3
223	234	LTO	41 5	3	124 5	0 8	99 6	1000	27 7
225	232	KOKS	26 4	30	792 0	0 73	578 2	2400	66 9
226	232	KOKS	26 4	50	1320 0	0 73	963 6	2400	111 5
TOTAL	24936						73056 1	2135	9504
PIPELINE NORTH									
3	8730	LTO	41 5	1041	43201 5	0 8	34561 2	2200	4363
TOTAL	8730						34561 2	2200	4363
PIPELINE EAST									
1	10590	SP x	14 6	1629	23780 1	0 81	19261 9	1200	4458
6	5820	HU	14 5	304	4408 0	0 73	3217 8	2000	446 9
13	4210	HU	14 5	350	5075 0	0 73	3704 8	2000	514 5
20	3480	HU	14 5	857	12426 5	0 73	9071 3	2000	1259
27	3060	HU	14 5	1011	14659 5	0 73	10701 4	2000	1351
72	1050	HU	14 5	65	942 5	0 73	688 0	2000	95 6
106	680	KOKS	26 4	60	1584 0	0 73	1156 3	2000	160 6
129	544	KOKS	26 4	88	2323 2	0 73	1695 9	2200	214 1
169	375	KOKS	26 4	127	3352 8	0 73	2447 5	2200	309 0
TOTAL	29809						51945 1	1638	8810
BOILERS	63475						159562 3	1954	22679

x fuel consumption in 10^3 m^3/y HU lignite KOKS coke LTO fuel oil light SP city gas

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distance" of the boiler from an existing primary distribution line, accounts for the price differential in fuels, the capital cost associated with the DH installation, the number of such boilers in close proximity, and available capacity on existing substations

In this listing it is known that there are plants that may not connect to the DH system Therefore the potential effect on the heat demand has been separated into a "high" balance and a "low" balance The high balance is shown in Exhibit 4-13 The low balance excludes the following power plants 1, 12, 40, 72, 84, 134, 160, 183, 202, 220, 223, and 225 These numbers correspond to the plant numbers in the data base The high and low balance provide a reasonable range, knowing that even during the publication of this work, decisions are being made by the small boiler owners

The total number of boilers (33) represented by the 12 plants shown in Exhibit 4-12 are summarized by fuel in Exhibit 4-14 The combination of both "promised" boilers and "connected" (potential), for both high and low demand situations summarized in Exhibit 4-15, was used in the calculation of central DH system demand requirements to support the study

The cost associated with the proposed DH connections for the high and low balance scenarios is provided in Exhibits 4-16 and 4-17 Estimates were made for heat exchanger stations, branch pipelines, and connections to each new consumer These costs are included in each variant for both the high and low balance, and also included connections for expected new commercial enterprises

In summary, of the approximately 300 MWt demand now being provided by independent power plants, 27 MWt has been promised a connection to the DH system by 1994 and there is a potential to connect an additional 23 MWt for a total of about 50 MWt From another viewpoint, of the 595 boilers, there is a potential of retiring 113, practically all which burn coal or lignite This has the potential to provide a significant environmental benefit, as discussed in Section 9 0

Exhibit 4-14
PLZEN "PROMISED" BOILER SUMMARY

Primary Fuel	No of Boilers	Original Total MWt	% MW
Coal	4	1 160	3 65
City Gas	2	0 986	3 10
Unknown	9	11 050	34 76
Lignite	16	18 044	56 77
Natural Gas	2	0 546	1 72
TOTAL	33	31 786	100 00

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Exhibit 4-15
PLZEN "HIGH BALANCE" BOILER SUMMARY
(including both "promised" and "connected" boilers)

Primary Fuel	No of Boilers	Total MWt	% MW
Coal	29	8 310	13 09
City Gas	4	10 590	16 68
Lignite	42	35 375	55 73
Light Oil	5	9 198	14 29
Total	80	63 473	100 00

Exhibit 4-16
CP PLZEN "HIGH BALANCE" COST OF DISTRICT HEAT CONNECTION

	Units	1993	1994	1995	1996	1997	2000	2005	2010
PIPELINE NORTH									
New Consumers									
Promised from ZCE	MWt		0 5	0 7	0 7	2 5	2 5	2 5	2 5
Connected Boilers	MWt			4 4	4 4	4 4	4 4	4 4	4 4
New Commercial	MWt			1 9	2 9	4 0	12 5	15 1	17 1
Total	MWt		0 5	7 0	8 0	10 9	19 4	22 0	24 0
Increase of Delivery	MWt		0 5	6 5	1 0	2 9	8 5	2 6	2 0
Cost-New Branch Pipelines	10^6Kc		0 3	3 9	0 6	1 7	5 1	1 6	1 2
Cost-New Heat Exch Stations	10^6Kc		0 4	5 2	0 8	2 3	6 8	2 1	1 6
PIPELINE SOUTH									
New Consumers									
Promised from ZCE	MWt	3 0	12 8	14 8	16 7	17 8	17 8	17 8	17 8
Connected Boilers	MWt		2 9	5 4	7 8	9 5	9 5	9 5	9 5
Total	MWt	3 0	15 7	20 2	24 5	27 3	27 3	27 3	27 3
Increase of Delivery	MWt	3 0	12 7	4 5	4 3	2 8	0 0	0 0	0 0
Cost-New Branch Pipelines	10^6Kc	1 8	7 6	2 7	2 6	1 7	0 0	0 0	0 0
Cost-New Heat Exch Stations	10^6Kc	2 4	10 2	3 6	3 4	2 2	0 0	0 0	0 0
PIPELINE EAST									
New Consumers									
Promised from ZCE	MWt				5 6	7 1	7 1	7 1	7 1
Connected Boilers	MWt				4 5	5 1	8 8	8 8	8 8
Total	MWt				10 1	12 2	15 9	15 9	15 9
Increase of Delivery	MWt				10 1	2 1	3 7	0 0	0 0
Cost-New Hot Water Mains	10^6Kc			32 3					
Cost-New Branch Pipelines	10^6Kc				6 1	1 3	2 2	0 0	0 0
Cost-New Heat Exch Stations	10^6Kc				8 1	1 7	3 0	0 0	0 0
Total Investment Cost	10^6Kc	4 2	18 5	47 7	21 6	10 9	17 1	3 6	2 8

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Exhibit 4-17
CP PLZEN "LOW BALANCE" COST OF DISTRICT HEAT CONNECTION
(including both "promised" and "connected" boilers)

Low Balance Parameters	Units	1993	1994	1995	1996	1997	2000	2005	2010
PIPELINE NORTH									
New Consumers									
Promised from ZCE	MWt		0 4	0 5	0 5	1 9	1 9	1 9	1 9
Connected Boilers	MWt			3 5	3 5	3 5	3 5	3 5	3 5
New Commercial	MWt			1 0	1 0	1 0	1 0	1 0	1 0
Total	MWt		0 4	5 0	5 0	6 4	6 4	6 4	6 4
Increase of Delivery	MWt		0 4	4 6	0 0	1 4	0 0	0 0	0 0
Cost-New Branch Pipelines	10^6Kc		0 2	2 8	0 0	0 8	0 0	0 0	0 0
Cost-New Heat Exch Stations	10^6Kc		0 3	3 7	0 0	1 1	0 0	0 0	0 0
PIPELINE SOUTH									
New Consumers									
Promised from ZCE	MWt	2 3	9 6	11 1	12 5	13 4	13 4	13 4	13 4
Connected Boilers	MWt		1 7	3 2	4 7	5 7	5 7	5 7	5 7
Total	MWt	2 3	11 3	14 3	17 2	19 1	19 1	19 1	19 1
Increase of Delivery	MWt	2 3	9 0	3 0	2 9	1 9	0 0	0 0	0 0
Cost-New Branch Pipelines	10^6Kc	1 4	5 4	1 8	1 7	1 1	0 0	0 0	0 0
Cost-New Heat Exch Stations	10^6Kc	1 8	7 2	2 4	2 3	1 5	0 0	0 0	0 0
PIPELINE EAST									
New Consumers									
Promised from ZCE	MWt				4 2	5 3	5 3	5 3	5 4
Connected Boilers	MWt					0 6	2 2	3 4	3 4
Total	MWt				4 2	5 9	7 5	8 7	8 7
Increase of Delivery	MWt				4 2	1 7	1 6	1 2	0 0
Cost-New Hot Water Mains	10^6Kc			32 3					
Cost-New Branch Pipelines	10^6Kc				2 5	1 0	1 0	0 7	0 0
Cost-New Heat Exch Stations	10^6Kc				3 4	1 4	1 3	1 0	0 0
Total Investment Cost	10^6Kc	3 2	13 2	42 9	9 9	7 0	2 2	1 7	0 0

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4 4 THE COGENERATION OPTION FOR SMALL BOILERS

An independent study was performed by CityPlan, as subcontractor on this project, to determine the potential for cogeneration retrofits in small boiler houses The complete study is provided in Appendix C Cogeneration is an option which is technically feasible, and the CityPlan evaluation focuses on the "economic" feasibility of the opportunity The configuration set forth by CityPlan includes a small gas engine, manufactured in the Czech Republic, which exhausts into an existing boiler, modified for such a connection The gas-fired engine would produce electricity to be used by the building or building group which consumes the heat

A separate analysis was performed by Gilbert/Commonwealth to augment the CityPlan work, and to provide perspective on these kinds of arrangements in the United States Also, assumptions in the CityPlan study were modified to be consistent with U S practices as a prediction of the direction of cogeneration arrangements in the Czech Republic Important assumptions which strongly influence this option are (1) the sale price of cogenerated electricity to the grid, (2) the sale price of hot water energy to consumers, and (3) the amount of equity assumed to be available from the government or private investors

A discussion of these assumptions is provided in more detail in Section 8 9, where cogeneration options are explored for Svetovar on a slightly larger scale

The net effect of a change in the price of two important commodities produced by the "mini-cogeneration" option is a reduced level of revenues from the CityPlan estimate by about 14% A final adjustment to the CityPlan work is a change to the assumed capitalization structure When these adjustments are made, the "project" produces a negative cumulative cash flow through the study period of twenty years No consideration was given to a potential government subsidy or special financial arrangements, i e, the project was considered to stand on its own

Unless dramatic changes to pricing schemes occur for the two basic commodities considered, emphasis should be placed on improving the present systems and strive to produce heat in the most economical manner

4 5 CONCLUSIONS AND RECOMMENDATIONS

The results of this study were derived from work done by RAEN, EGU, and Energoprojekt Data, calculations and demand projections were correlated so that the results were consistent

It has not been determined why those 113 power plants close to existing DH pipelines did not in the past choose to connect to the central system Now that the central system must be upgraded to meet pollution regulations and perhaps be increased in capacity, it is recommended that, for environmental reasons, and where feasible, those boilers should be shut down and their current consumers should be tied to the central system Not only will

this reduce the pollutants in densely populated areas but the added consumers will help to reduce overall DH costs Depending on future gas price increases, it should also be more economical to the consumers

It is also recommended that the power plants that cannot now connect to the DH system be notified of the importance of complying with the new environmental regulations The suggested changes as shown in Exhibit 4-2 should be presented to the operators of the power plants and the implementation should be monitored by Plzen city officials Policies and regulations implemented by the city could expedite this effort

For the long term, however, the objective should be to discontinue operation of the small solid fuel boilers located in the city residential areas This may require an analysis of the DH pipelines which could result in a detailed hydraulic model of the system With a model, line extensions and utilization can be added to the existing system and predictions made of the effects on the entire system The model could also estimate costs of these changes

With regard to mini-cogeneration options for small boiler houses, the G/C analysis showed that this arrangement will not be cost effective under normal conditions which are projected by the Czech Republic, and that an investment in the central DH system will be more cost effective

5.0 THE REVISED DEMAND ASSESSMENT

As introduced in Section 1 3, the demand projection has been reassessed to include more parameters than previously considered in the Energoprojekt (EGP) report [1] Forecasting demand is the most important aspect of planning for the supply-side Resulting costs of operation, and therefore competitiveness of district heating with other energy sources, will depend heavily on the realization of these forecasts In turn, reducing the cost of energy supply will encourage new consumers to connect to the DH system Further, the resulting supply costs will have an impact on the incentive to conserve energy The process of determining a compatible supply and demand is therefore iterative by nature

Demands were evaluated for each of the district heating systems, including Cogeneration Plant (CP) Plzen, Doubravka, and Svetovar, but exclusive of Skoda Works It was assumed in each variant that the areas served by Letna and Doubravka plants (V1 and V2) would be combined with the area now served by CP Plzen starting in 1997 In the studied variants, the area served by Svetovar was not considered to be connected based on current plans of the city, however, a separate analysis was performed (reported in Section 8 9) which evaluated the economic possibilities of such a connection Therefore, the "study area" was evaluated from the viewpoint of CP Plzen, i e from today's current situation to an "enlarged" system in 1997 when the area served by Letna and Doubravka is added, and continuing with this "enlarged" system through the year 2010

A projection of the total district heat demand through the year 2010 for CP Plzen, Letna, Doubravka and Svetovar district heating plants is presented in Exhibit 5-1 These projections have not been influenced by price or competition of competing energy sources The higher demand has been assumed as the expected projection, while the low demand case was used to assess conditions and results if the expected demand was not realized The high demand is used in most comparisons and discussions

Note in Exhibit 5-1 that demand does not increase dramatically even in the high demand case Increases shown are due primarily to the addition of a few new consumers and a switch of small decentralized boiler consumers to district heating In the low demand case, the total demand is reduced through the study period due to conservation efforts, and a lower estimate of new consumers

A summary of the range of projected total demand for CP Plzen through the year 2010 is presented in Exhibits 5-2 through 5-5 The demand for CP Plzen represents the primary "study area" of this work Exhibit 5-5 shows the connection of the Doubravka system (Letna and Doubravka plants) to CP Plzen occuring in 1996 Prior to 1996, the Doubravka system operates independently

These exhibits show a rather steady demand for all areas except the south line, which benefits from new consumer additions (primarily a switch to district heating) The differences between high and low demand shown in all exhibits reflect high and low estimates of new consumers and conservation efforts

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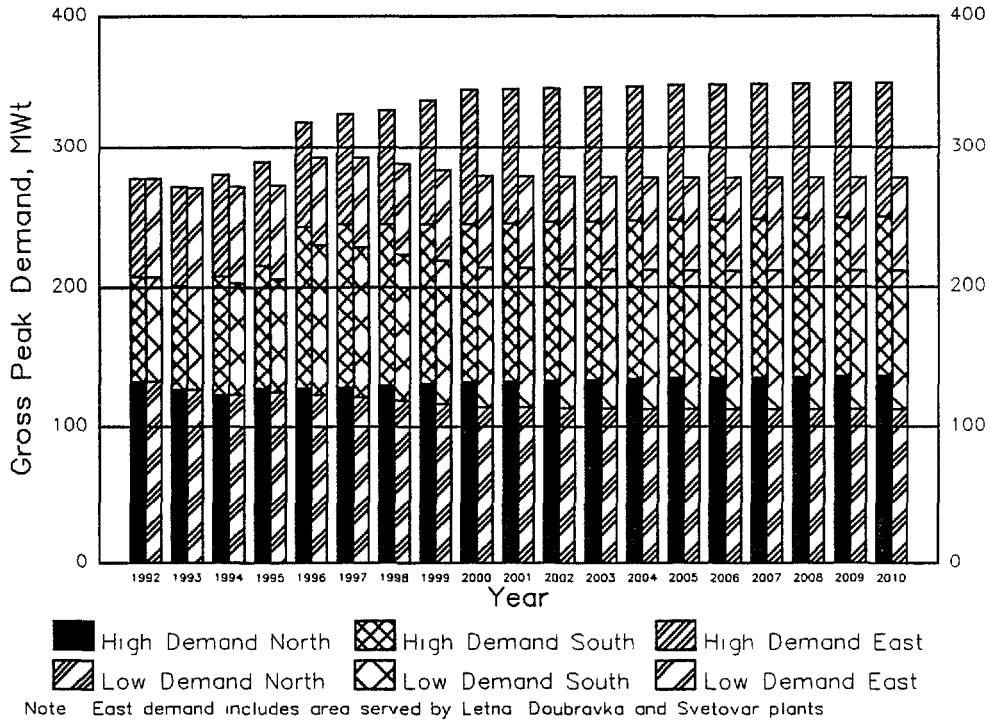
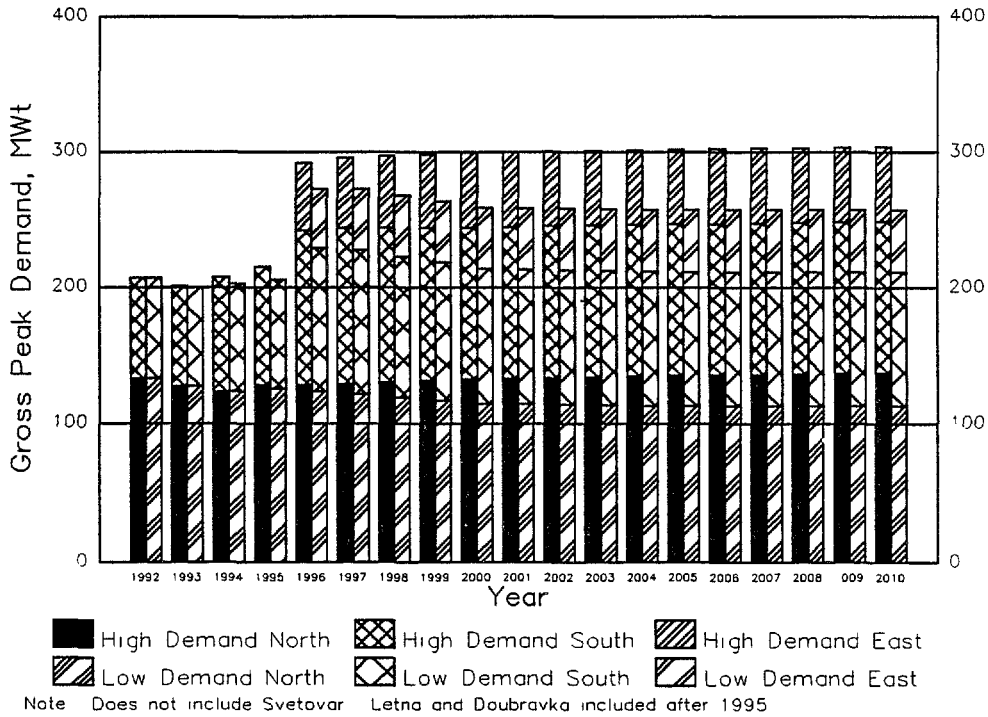
Exhibit 5-1
TOTAL PLZEN DISTRICT HEATING DEMAND PROJECTION (excluding Skvrnany area)



Note East demand includes area served by Letna Doubravka and Svetovar plants

Exhibit 5-2
CP PLZEN DISTRICT HEATING DEMAND PROJECTION



Note Does not include Svetovar Letna and Doubravka included after 1995

Exhibit 5-3
CP PLZEN DISTRICT HEATING DEMAND PROJECTION NORTH

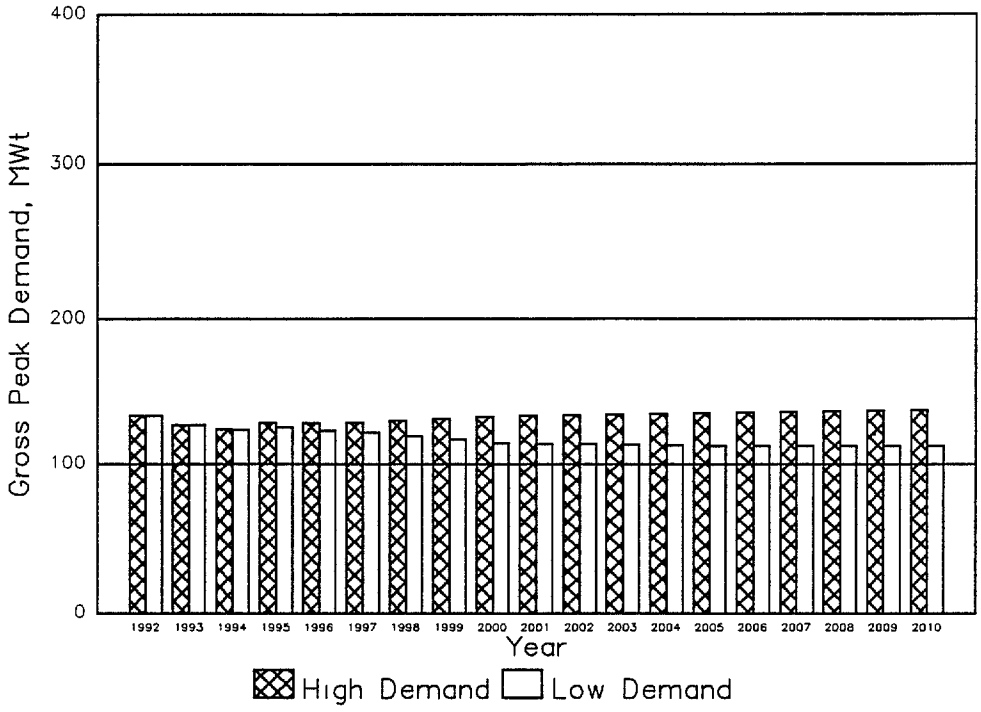


Exhibit 5-4
CP PLZEN DISTRICT HEATING DEMAND PROJECTION SOUTH

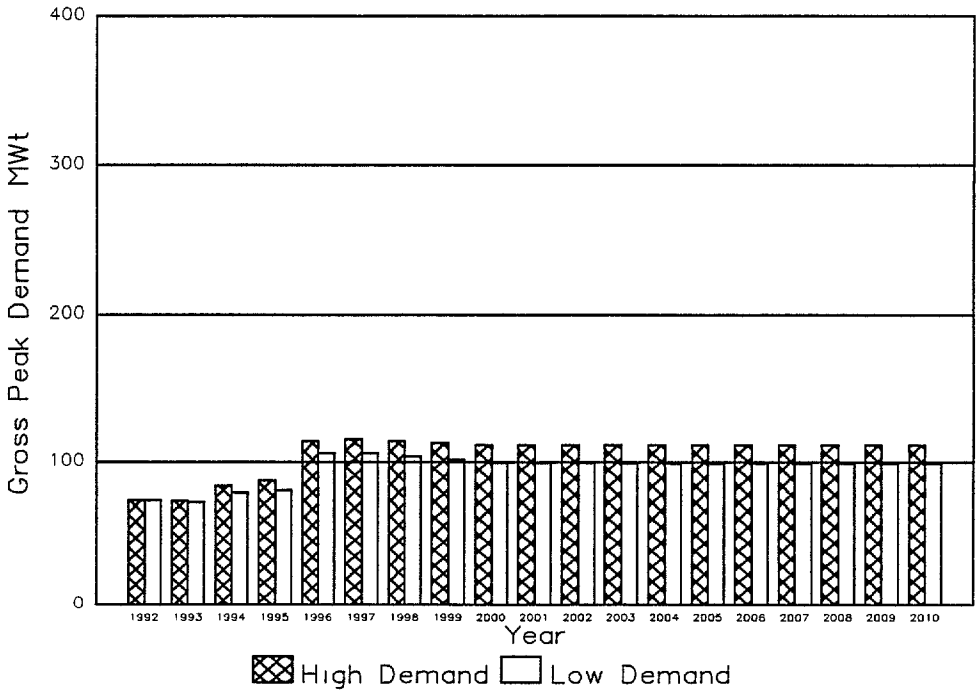


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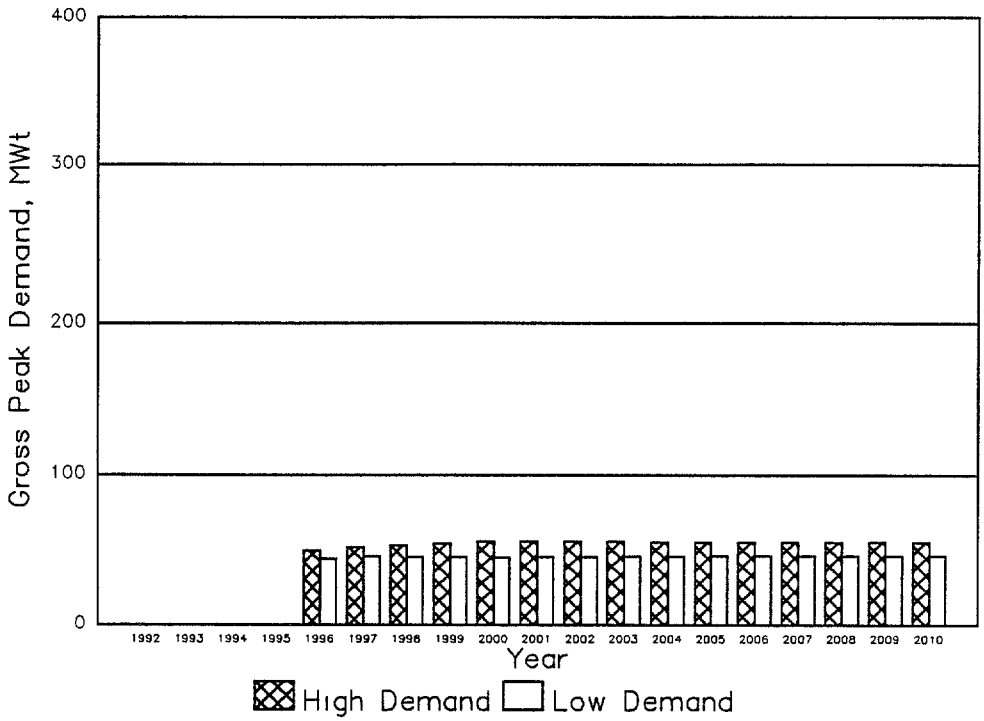
Exhibit 5-5
CP PLZEN DISTRICT HEATING DEMAND PROJECTION EAST



5 1 INFLUENCE OF CONSERVATION BY EXISTING DISTRICT HEAT CONSUMERS

Residential and commercial consumers are expected to conserve from their present level of consumption, as discussed in the companion demand-side study performed by Pacific Northwest Laboratories (PNL) [2] The PNL study identified a 40% conservation potential for many district heating buildings

There are a variety of changes that can be made to better control heat and to reduce losses on the demand side Implementation of these changes will depend on availability of controls, legislation, and enforcement, along with other incentives and choices to consumers

It is assumed that the reduction in heat demand by the existing DH consumers in groups of residential flats will range from 13% to 20%, being gradually developed over the entire study period Recent legislation requires that heat be metered at the lowest denominator of end use Background supporting the potential to conserve, and the cost associated with this conservation, is presented in the demand-side study by PNL [2]

Even though the legislation imposes many requirements by the year 1994, it was assumed that actual implementation will require more time due to specific end use problems,

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familiarity with new pricing structures, and time required to actually install all required equipment, including instrumentation

The impact of conservation in the residential sector was extrapolated to the commercial and public sectors, where it is assumed that the same physical conservation measures will be applied The potential to reduce consumption in these sectors may actually be greater, especially in the public sector, since implementation can be controlled by the government

The resulting savings in peak capacity requirement is commensurate with these conservation assumptions The savings estimate is phased in gradually, and is reflected in Exhibits 5-2 through 5-5, as well as in the economic analysis presented in Section 8 0

5 2 INFLUENCE OF NEW DISTRICT HEAT CONSUMERS (exclusive of decentralized small boilers)

Based on input from the City of Plzen regarding the population growth of the city, this component of demand results from the addition of new residences, and associated commercial services, and is extremely small

Development of existing communities by commercial enterprises adds to this component This is possible in the Pipeline North, where residential systems are newer

The result is included as new demand in Exhibits 5-2 through 5-5

5 3 INFLUENCE OF EXISTING HEAT/STEAM BOILER RETIREMENT

Several boilers in the Plzen area are nearing the end of their useful life, namely the Svetovar, Doubravka, Letna grate boilers The enforcement of environmental regulations may encourage retirement, since costly renovations are needed for each plant, or a conversion to low sulfur coal or gas/oil will be required For the lower efficiency plants, the more expensive gas or light oil fuel will not be an attractive option for other than emergency status

In Variants A1 through A4 and B1, retirement of older units in 1997 has been assumed, while in Variant C1, the older plants' life is extended to a total of approximately 40 years in order to save capital

The primary influence of considered boiler retirements is generally to shift demand to CP Plzen However, the secondary influence is to lower the overall cost of supplying heat by increasing electrical revenues Thus, as overall costs are reduced, boiler retirements may result in more new consumers than in the case of no boiler retirements

5 4 INFLUENCE OF NEW DH CONSUMERS FROM THE POOL OF DECENTRALIZED SMALL BOILERS

The current status of the decentralized small boilers is presented in Section 4 0 These boilers represent a considerable source of energy use and emissions The decisions made by individual owners, and the options which are made available to them could have a profound effect on the energy future of Plzen

Emission reductions are required for all boilers above 0 2 MWt in size (further discussed in Section 6 3 1) This will require a decision on the part of these solid fuel-fired boiler owners to make a change Units firing liquid fuel may also require controls In most cases, the choices will be as follows

- Provide the appropriate environmental controls to the units,
- Switch to a smokeless low sulfur coal, gas, or oil fuel,
- Collaborate with other owners and install a larger environmentally acceptable unit to serve the community or cooperative, or
- Tie in to the district heat system, if possible

For small units, the first option will probably not be economically feasible The second option will be an economic choice dependent on fuel price and availability The third option will be a choice based on geographical location, size of heat requirement, and economics Such an analysis is done in terms of a calculation of "economic distance" which accounts for price differential of fuels, capital cost associated with the installation, the number of boilers in close proximity, capacity requirements, and demand use patterns

The last option, a tie-in to the DH system, should be considered for all owners for whom this option is technically feasible An analysis is done similar to the "economic distance" calculation mentioned above An additional circumstance may be flow capacity on the existing primary network line, and also nearby substation capacity Their choice will also be dependent on the cost of other comparable options The uncertainty of the future price of natural gas is certainly a key variable in this decision Also, the uncertainty of the future cost of heat from the newly privatized DH system will be a factor

If costs are perceived to be equal with natural gas options, the inherent convenience of gas would be the preferred choice Therefore, the cost of supply for the DH system must be lower by some margin

A detailed analysis was performed by RAEN, in which the current small boilers were categorized, and recommendations made for gas conversion or connection to the DH system according to size, boiler type, current fuel type, and location (proximity to the DH distribution lines A subsequent analysis resulting from discussions between EGU, ZCE, and RAEN identified the current commitments and potential addition of new consumers G/C, EGU, and RAEN met in Prague to finalize this assessment, and the result is presented in Section 4 0, and also included in the demand estimate

The result is included in Exhibits 5-2 through 5-5

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5 5 INFLUENCE OF INDUSTRIAL CONSUMERS/SUPPLIERS

Industrial consumers comprise a significant percentage of energy use in the existing DH system, and are also large users of energy for processes and production For the purposes of this study, however, industrial demand was not addressed as a major influence on the DH demand for the following reasons

- While industrial DH consumers are major users of energy, they also utilize a large portion of produced energy in their own operations Potential changes in these operations cannot be quantified at this time
- In the case of a downturn of industrial production, industry may pursue DH consumers to offset some operating losses, however, in this unstable condition, the cost of that produced energy may be high, and also the surplus energy may also be unstable as they seek to reduce overall operation costs or to restore original production levels
- In the case of an upturn in industrial production, industry may desire to decrease delivery of heat to the DH system, and thus create a weak supply situation
- In the case of the arrival of new industry to the Plzen area, it would certainly be possible to negotiate with the industry to either provide excess energy to the DH system or become a consumer The price/cost of this energy would also be negotiated Therefore, some flexibility exists with this situation

Current plans of the three major industrial users were briefly considered in the analysis, however, projected changes were not included for the reasons stated above Generally, cooperation of industrial users with the centralized system may serve to improve system reliability, and reduce overall cost of heat supplied The reader may refer to the PNL demand side study[1], which provides a short discussion on industry groups in Plzen, with some basic estimate of potential energy savings Industries reviewed by PNL include

- Steel and Machine Tool Industry,
- Food Industry (including the Pilsner Urquell Brewery as the most stable member),
- Pulp and Paper Industry, and
- Other smaller industries

G/C's review of Skoda, through subcontractor CityPlan, revealed that the future is quite uncertain Skoda uses 80% of the energy it generates, and sells 20% to heat consumers Skoda is now initiating new business lines and making alliances with foreign manufacturers in an effort to prepare for the future Therefore it is very difficult to look beyond the next few years in terms of energy supply to district heating

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A primary heat line connecting Skoda to the CP Plzen system is in place, but is not currently used While not a part of this study, it would be worthwhile to investigate the future use of this connection to improve overall system reliability and flexibility

5 6 REFERENCES

1 Energoprojekt Praha, The Study to Finalize the Concept of the Pilsen Heat Supply System, Part 1 - Technical Report and Part 2 - Economic Report, EGP 22210, December 1991

2 Pacific Northwest Laboratories, et al, Pilsen Integrated Resource Assessment Demand Side Assessment, U S AID study, March 1993

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6.0 TECHNICAL DESCRIPTION OF NEW/REVISED VARIANTS

New and revised variants are considered, selected and described in this section The variants (options) considered in the Plzen analysis are mainly distinguished by the selection of the plant technology for Plzen IV The basic plant technologies selected for analysis as Plzen IV are a (1) Gas-Fired Gas Turbine Combined Cycle, and (2) a Circulating Fluidized Bed (CFB) boiler The variant naming convention was selected to avoid confusion with the previous Energoprojekt designations Not all of the variants were investigated by each company The table below characterizes each variant by the CP IV technology selection and the investigating company

Variant	Investigator	Description of Distinguishing Feature (Choice of CP IV)
A1	EGU	Combined cycle plant with two 60 9 MWe (ISO) Gas Turbines
A2	EGU & G/C	Combined cycle plant with one 60 9 MWe (ISO) Gas Turbine
A3	G/C	Combined cycle plant with one 47 MWe (ISO) Gas Turbine
A4	EGP	Combined cycle plant with one 90 MWe (ISO) Gas Turbine
B1	EGU & G/C	Cogeneration plant with one CFB boiler and a 32 MWe steam turbine
C1	G/C	Life extension of existing units and subsequent introduction of a CFB boiler with a 32 MWe steam turbine in 2003

Not all variants were investigated by each company The EGU and EGP analyses are presented in Section 7 0 and the G/C analysis is found in Section 8 0

Section 6 1 describes the approach used in developing or revising the variants Section 6 2 describes the spectrum of technologies which were considered for analysis and identifies the selected technologies to be applied to the Plzen situation The selected variants are described more fully in Section 6 3

6.1 APPROACH TO THE DEVELOPMENT OF NEW/REVISED VARIANTS

Based on the demand projections presented in Section 5 0, and on the requirements for other considerations described in Section 1 3, variants have been developed Improvement in system efficiency, summer operation, and reliability are considered The result is the "least cost" approach to meet the range of projected demands

One of the considerations in evaluating the variants is performance at low load periods Currently, CP Plzen is limited in the production of electricity because the large pc-fired units can operate only at 60% load This means that when the system requirement drops below this load, the load must be supplied by Plzen I units, which produce hot water and no electricity The ability to produce electricity is lost for more than four months of the year, representing a considerable loss of potential revenue from electricity sales The connection

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of nearby district heating systems served by Letna and Doubravka plants and the consideration of variants which can cogenerate at lower loads serve to significantly increase the flexibility of the system and provide for additional electricity sales/revenue Further, the connection of Svetovar can also help this situation

Note that for each of the variants, the analysis addresses both a high and low demand projection The timing of capacity decisions is important If a decision must be made at the present, i e without knowledge of future demand, then the installed capacity must be able to meet the high demand If such a decision appears later, or can be postponed, then a different equipment requirement may be possible, since there is "knowledge" of what is now the future demand

6.2 TECHNOLOGY DISCUSSION

A review of suitable technologies for the Plzen district heating systems resulted in a selection of basic technologies similar to those originally investigated in the 1991 Energoprojekt study Technologies originally considered can be divided into three groups emissions reduction, emissions reduction/system upgrade, and operations improvement This study quantitatively addresses emissions reduction/system upgrade technologies, and qualitatively addresses other options Emissions reduction technologies which were considered for district heating boilers include the following

- Integrated Gasification Combined Cycle,
- Fuel cells,
- Conventional Pulverized Coal Fired (PC-fired) with Flue Gas Desulfurization (FGD),
- Fluidized Bed Combustion (FBC),
- Gas Turbine Combined Cycle,
- Flue Gas Desulfurization (FGD) Retrofit,
- Duct Sorbent Injection (DSI),
- Gas Engine or Gas Turbine Repowering,
- Fuel Switching (including gas conversion), and
- Baghouse for particulate cleanup

While Integrated Gasification Combined Cycle and Fuel Cells are feasible technologies for district heating, they are relatively capital intensive, and were not included in the selected variants Also, PC-Fired boilers are the technology currently employed for Plzen II and, while feasible, are felt to be higher cost for locally available fuels when FGD must be included for SO_2 removal The remaining technologies are described in the following sections

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6.2.1 Atmospheric Fluidized Bed Combustion

Atmospheric Fluidized Bed (AFB) Combustion (AFBC) technology is characterized by the use of a solid material contained in a vessel in which air and fuel are introduced and combustion takes place The solid material may be limestone, allowing a high level of SO_2 removal to take place during the combustion process Therefore, no post-combustion technology is needed to remove SO_2 Combustion temperatures are generally designed between 780 and 870°C and provide inherently low NOx emissions Initial designs were "bubbling" types, characterized by air velocities of 1 2 to 3 m/s Current designs called "circulating" fluidized beds (CFBs) have much higher velocities, and continuously recirculate entrained solids using cyclones

The progress of AFBC development has been monitored in several conferences, highlighted by the International Conference on FBC which has been held bi-annually for approximately 25 years FBC technology is available with "commercial" guarantees by many international vendors and is cost-competitive with pc-fired designs

CFB boilers can be designed for a wide variety of fuels, and for lower quality solid fuels, CFB has become the "technology of choice " They are very suitable for the types of coals found in eastern Europe, and can also co-fire biomass and waste materials

CFB installations can be accomplished as a retrofit, utilizing existing steam turbine equipment, and sometimes even existing boiler foundations and other equipment In this case, the existing boiler would be removed

A few installations have utilized a boiler retrofit concept which involves removal of the bottom portion of an existing top-supported boiler and substituting a bottom-supported bubbling-type FBC unit beneath the existing boiler Consideration of this type of retrofit requires a more detailed design study to determine feasibility Vendors of FBC boilers are generally less willing to bid on this type of retrofit due to problems which have occurred with previous installations Since FBC boilers are shown to be one of the favored variants in this study, a follow-on study to be performed by the City or ZCE could include the investigation of an FBC boiler retrofit Since some cost savings may result, this option may be favorable from a financial viewpoint

The FBC technology chosen for Variants B1 and C1 is a circulating-type FBC (CFB) boiler which is offered by several international vendors The vendor on the U S side who supplied design information and costs for CP Plzen CFB boiler is the Foster Wheeler Energy Corporation (FWEC) FWEC has initiated discussions with a Slovak boiler manufacturer, where most of the fabrication of a boiler would take place Foster Wheeler would provide most of the boiler design and the manufacture of a few of the components Competitive bidding for the FBC boiler would result in the least-cost design which conforms to the specification

6.2.2 Pressurized Fluidized Bed Combustion

Pressurized Fluidized Bed Combustion (PFBC) is a promising technology to burn low grade, low cost indigenous fuels in district heating systems PFBC results in a much higher electric/heat ratio compared to its AFBC counterpart, and is actually more comparable to

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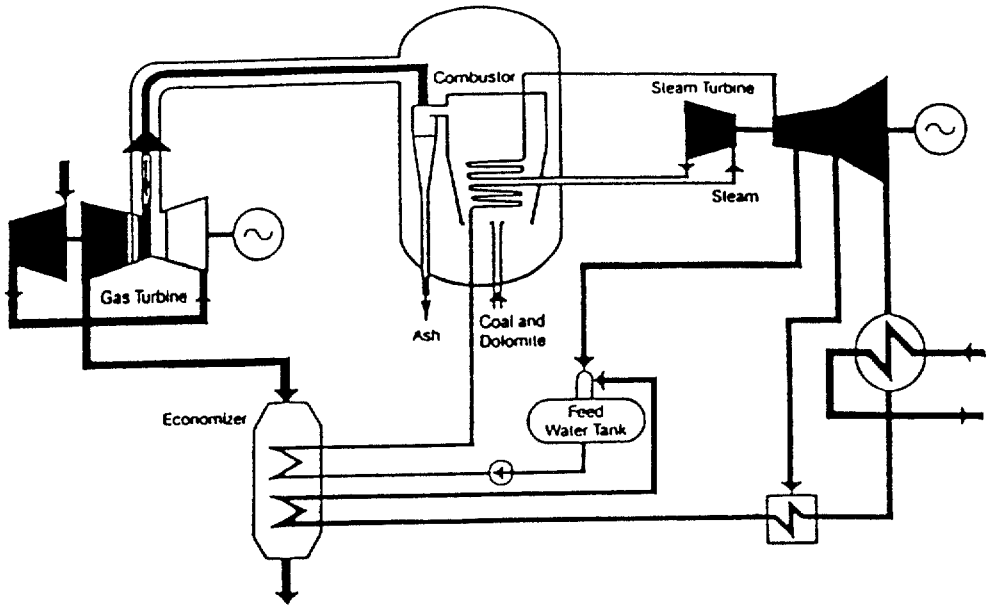
a gas-fired gas turbine combined cycle PFBC is also lower in NOx emissions A schematic is presented in Exhibit 6-1

Exhibit 6-1
PRESSURIZED FLUIDIZED BED COMBUSTION COMBINED CYCLE CONCEPT



There is currently a project in the Ostrava area to construct a PFBC plant for district heating This plant will be similar to four others which have recently been built and operated

While this technology is promising, it is not ready for commercial application in the time required for this project However, the selection of Variant C1 would allow re-consideration of PFBC technology when additional demonstration time has been accrued

6.2.3 Gas Turbine Combined Cycle

Gas turbines are available in discrete sizes from less than one MWe to over 150 MWe in electrical output Waste heat boilers are available for almost any gas turbine Gas turbines and waste heat boilers are used in combination with steam turbines in the gas turbine combined cycle (GTCC) The efficiency of the gas turbine has risen through the years, and the popularity of GTCC technology has risen significantly throughout the world Two primary advantages of this technology are the relatively low capital cost and the short construction time In the United States, gas turbines are generally used to meet peak loads, but the GTCC has also recently been used to meet some intermediate electrical loads The short lead times have been useful because there has been a long delay in construction of larger coal-fired baseload plants, and the recent low natural gas prices have encouraged its use

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A disadvantage of the use of large gas turbines in the Czech Republic is the requirement to import the most expensive portion of the equipment, making this technology less cost competitive than in the West Maintenance for this equipment is also considered to be higher due to the import of spare parts In the near future, it may be possible to lower the cost since there have been discussions about the manufacture of large gas turbines in the Czech Republic by Brno Since most of the manufacturing work would be done within the Czech Republic, the cost would be considerably reduced, however, the situation would not be as competitive as in the western world, so that the cost advantage may be somewhat diminished Also, special financing and other arrangements proposed by the manufacturer in a competitive bid may soon enhance the competitiveness of this technology A variation in capital cost is explored in the "Indifference Analysis" in Section 8 7

Natural gas prices will also control the application of GTCC in the Czech Republic While the world capital cost of the gas turbine is relatively low, compared to coal burning technologies, fuel prices remain higher In the United States, natural gas prices are very low and many competitive situations have been created for GTCC However, in the Czech Republic, we expect that the competitiveness of imported natural gas prices is expected to be less, and certainly, the security considerations associated with heavy dependence on this fuel are also greater

For the purposes of this study, the gas turbine portion of the GTCC is assumed to be imported and to carry a world market price Several different sizes and configurations of gas turbines were considered in Variants A1 (EGU only), A2, A3, and A4 (Energoprojekt only)

6.2 4 Gas Turbine or Engine Repowering

A gas turbine or reciprocating engine can also be used to "repower" an existing boiler to allow production of electricity from an existing low pressure steam or hot water boiler, or to obtain a higher electric to heat ratio for an existing cogeneration system

In this configuration, the exhaust from a gas turbine or engine firing natural gas or oil is used as a heat source input for an existing boiler Supplementary fuel is used in the boiler to obtain full steam or hot water output Thermodynamically, there are many advantages to such a system The cost effectiveness of any installation is dependent on the price of premium gas/oil fuels and the sales price of electricity that can be negotiated with the electric utility

There have recently been many opportunities for small boiler repowering and cogeneration systems in the United States While overall efficiency cannot compete with larger units, a potential advantage is often tied to "peak shaving," where the equipment and operating cost are justified by the savings of peak demand charges assessed by a utility These situations are very site specific and require a site specific assessment to determine economic attractiveness Where electricity is generated only for internal use by a customer, there may also be an savings Where a single unit is proposed, a utility would be required to provide standby power to the user, in the case of a unit outage It is possible that if a large number of units were proposed, less standby power would be required, because the combined reliability of many units would be higher than a single unit

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While not selected as a primary variant, this situation applied to the Svetovar area and a potential smaller substation-sized unit is di ussed further in Section 8 9

6.2.5 Flue Gas Desulfurization Retrofit

Flue Gas Desulfurization (FGD) retrofit was considered for the Plzen II units to reduce SO_2 emissions to or below compliance levels A study was recently completed by ZCE which compared this technology, and it was considered as Alternate 2 to Variant B by EGU Prague Their complete study is found in Appendix C While FGD has become much more cost competitive in recent years, with the development of dry systems, and wet systems with fewer major vessels, the FGD system still requires an extensive reconstruction of the facility, and the cost is expected to be prohibitive

6.2.6 Duct Sorbent Injection

Duct Sorbent Injection (DSI) technology was developed as a low capital cost alternative to conventional FGD scrubber systems In addition to low initial investment, other significant advantages of a duct injection system are its simplicity and that it may be applied at plants with limited available space and/or difficult construction access because the exiting duct(s) is used as the reaction vessel Modifications to the duct(s) are required to install the injection equipment (humidification and/or sorbent injection nozzles), but no large reactor vessels are required A duct injection process results in few changes to the existing flue gas system, and minimal plant real estate is required The retrofit of a duct injection system is relatively simple, and it can be accomplished quickly

Additional advantages to using a duct injection system include

- minimal operation and maintenance personnel requirements,
- generation of a dry solid waste product,
- no requirement for a gas reheat system, and
- will not affect unit operation and heat transfer surface requirements

Few O&M personnel are required for a duct injection system due to its simplicity and limited new equipment requirements The dry solid waste produced is an advantage because it can typically be handled by the existing fly ash handling system No dewatering equipment such as thickeners or vacuum filters are needed A flue gas reheat system is not required in the system design because the temperature of the gas after sorbent injection/humidification is sufficiently above the saturation temperature as to minimize corrosion potential in the duct leading to the ID fans and chimney and in the ID fans and chimney themselves

Disadvantages of duct injection technology are

- SO_2 removal is limited to 50-70%
- low reagent utilization efficiency
- use of relatively expensive reagents
- an increase in particulate loading to the ESP
- the potential for solids deposition in the ductwork and ESP
- little full-scale operating experience in the U S

Duct injection technology has been successfully demonstrated at the pilot plant scale However, full scale applications of this technology are limited

Although lower in capital cost than conventional scrubber systems, the inherently moderate SO_2 removal and low sorbent utilization tend to drive the levelized cost of duct injection (in terms of dollars per ton of SO_2 removed) relatively high Factors which favor a low capital cost, high levelized cost technology are

- low sulfur coal
- requirement for a moderate SO_2 removal
- small to medium-sized plants
- low plant capacity factors
- short remaining plant life

These are the general plant criteria which should be considered when evaluating the application of duct injection technology to a specific plant

Exhibit 6-2 is a flow sheet for a lime slurry injection system Exhibits 6-3 and 4 show $/ton of SO_2 removal as a function of % sulfur in the coal and % sulfur removal based on U S economics

DSI technology provides a viable option to the fuel switch for Plzen II, in the case of potential problems caused by switching to black coal While the fuel switch is included in all of the investigated variants, DSI should not be eliminated as a possible alternative

Exhibit 6-2
DUCT SORBENT INJECTION PROCESS FLOWSHEET

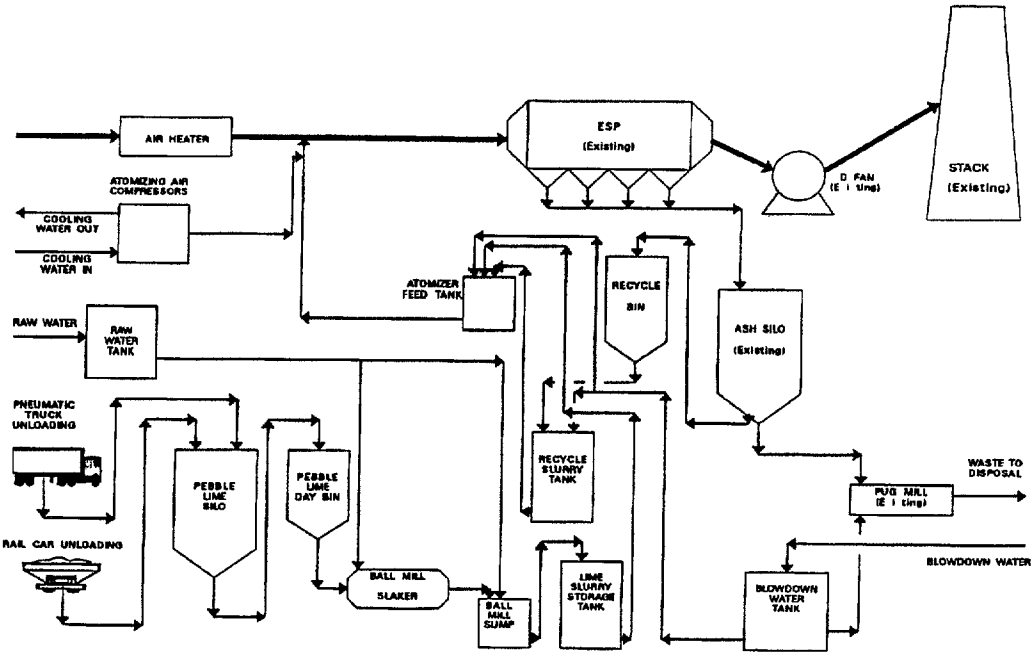

Exhibit 6-3
U S LEVELIZED CONTROL COST vs SO_2 REMOVED WITH DUCT SORBENT INJECTION

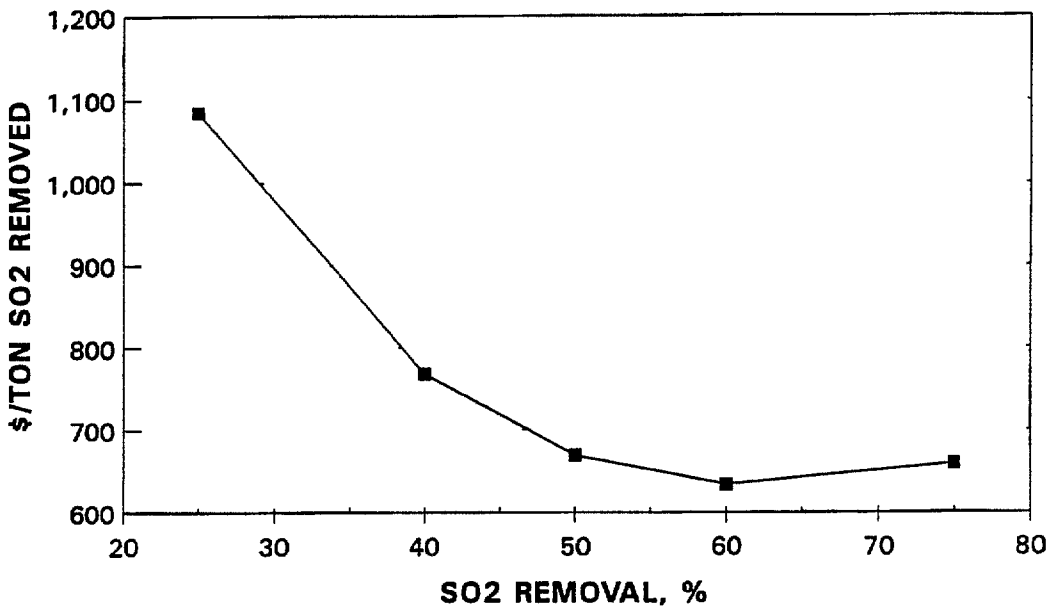

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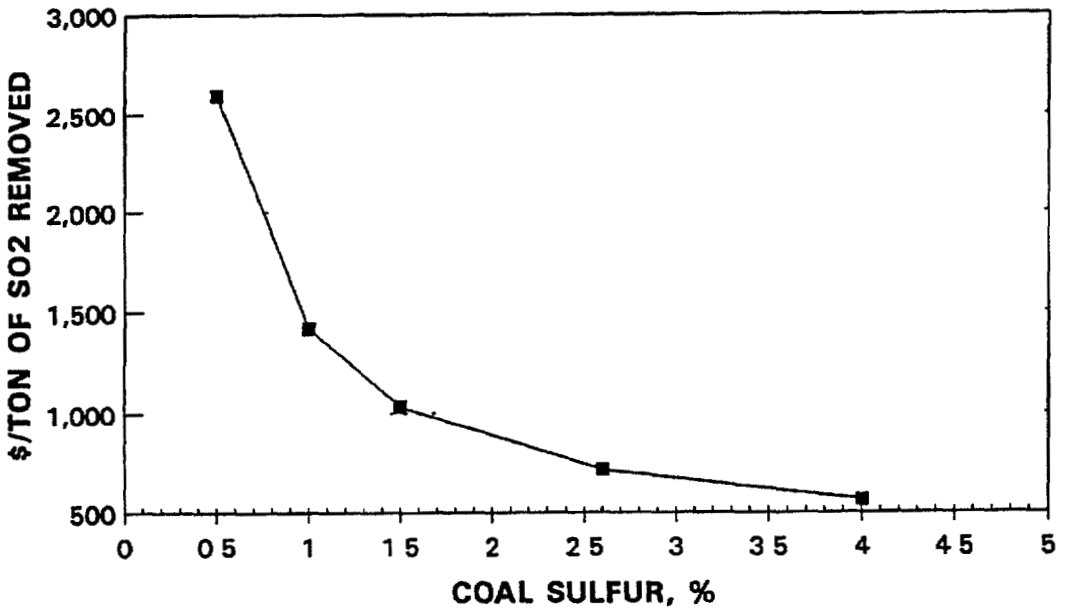
Exhibit 6-4
U S LEVELIZED CONTROL COST vs COAL SULFUR % WITH DUCT SORBENT INJECTION



6.2.7 Fuel Switching

Fuel switching is a common option which can be used to meet environmental regulations Units designed to burn high- or medium-sulfur coal can be successfully switched to low-sulfur coal or natural gas in order to meet SO_2 environmental regulations The effects of fuel switching on the existing unit are dependent on the unit's design and the characteristic of the proposed fuel For proposed fuels that are similar in nature to the design fuel, the impact on the plant performance and facilities is low Conversely, when the proposed fuel is considerably different from the design fuel, the changes may require extensive modifications and result in a loss in generating capacity

In evaluating a potential fuel switch, consideration must be given to the effect of the proposed fuel on the following areas

- steam generator, (burners, superheaters, economizers, sootblowers, etc)
- balance of plant equipment, (pulverizers, ESP, air heaters, fans, etc),
- plant facilities, (coal and ash handling, fire protection, etc),
- effects on performance/operation, (auxiliary load changes, boiler efficiency, minimum load, etc), and
- effects on capacity (slagging, erosion, fouling, corrosion, throughput limitations, etc)

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Any coal switching program which proceeds beyond the initial study phase should utilize long and short term test burns to verify design and operational impacts

The advantages of fuel switching to a low -impact low-sulfur coal include

- potentially limited capital costs,
- no additional reagent handling required, and
- no additional real estate is required

The advantages of switching to natural gas are similar to those for the low-impact low-sulfur coal, except that the capital cost will sometimes be higher The disadvantages of fuel switching include

- likely higher fuel costs, and
- potential unit derating, performance loss, or impact to minimum load capability

Factors which may favor fuel switching include

- availability of low sulfur fuel at a reasonable cost,
- small to medium-plant size,
- low plant capacity factor, and
- short remaining plant life

For the Plzen II units, the boiler was originally designed for a low grade lignite fuel Switching to low sulfur coal will present design problems that must be overcome First, pulverization of the harder black coal will require rework or replacement of the four coal mills on each unit Second, the unit must be retrofitted with additional particulate control, since the existing electrostatic precipitator (ESP) performance will be reduced with the lower sulfur coal due to an anticipated change in ash resistivity While this can sometimes be accommodated through ESP modification or flue gas conditioning with SO_3 or NH_3, projected performance improvements are not quantifiable without a detailed analysis Therefore, a baghouse was specified in this study for particulate control If capital requirements are too high, the ESP modification alternate approach should be investigated further

With regard to boiler performance, tests were conducted on Plzen II with the proposed black coal in April 1993 in cooperation with the firm Prvni Brnenska Strojirna Satisfactory results were obtained for emissions, but there were some problems with steam temperatures and boiler control Also, some testing of NOx reduction techniques by different mill arrangements was carried out Some comments on these tests are contained in Appendix B in a report by CityPlan

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Recommendations by the manufacturer of the boilers, CKD Dukla, and Prvni Brnenska Strojirna are

- retrofit of coal mills,
- retrofit of coal burners,
- ash handling system retrofit,
- modification of superheat surface, and
- retrofit ESP or install baghouse particulate controls

The extent of all of these modifications is now unknown The details should be resolved by the competitive bidding process by more than one boiler manufacturer Guarantees on emissions, including CO and NOx are required as part of the bid

Some preliminary cost numbers are reported in Section 8 0 for the fuel switching option If extensive boiler work is required, DSI technology should be considered as an alternate approach, and the capital cost compared

6.2.8 Baghouse for Particulate Removal

Baghouses are gaining in popularity because of their capability to routinely reduce particulate emissions to extremely low levels In the past, their cost has been higher than comparable ESP installations, but recent trends toward extremely low particulate emission standards have made the cost more competitive Also, the recent trend toward fuel switching has increased the popularity of baghouses because of their reduced sensitivity to coal type

A switch to low sulfur coal will generally cause problems in an ESP because the original design plate area and electrical equipment is sized to correspond to a particular ash resistivity and other ash characteristics Lower sulfur coals generally have higher ash resistivities and require additional surface area, which is not a simple retrofit While performance can be enhanced by flue gas conditioning, the baghouse offers a reasonable solution, especially for a small to medium sized plant

6 3 DESCRIPTION OF NEW/REVISED VARIANTS

Variants were selected using the 1991 Energoprojekt report as a starting point The variants (options) considered are mainly distinguished by the selection of the plant technology for Plzen IV The basic plant technologies selected for analysis as Plzen IV are a (1) Gas-Fired Gas Turbine Combined Cycle, and (2) a Circulating Fluidized Bed (CFB) boiler The variant naming convention was selected to avoid confusion with the previous Energoprojekt designations Not all of the variants were investigated by each company The table below characterizes each variant by the CP IV technology selection and the investigating company

Variant	Investigator	Description of Distinguishing Feature (Choice of CP IV)
A1	EGU	Combined cycle plant with two 60 9 MWe (ISO) Gas Turbines
A2	EGU & G/C	Combined cycle plant with one 60 9 MWe (ISO) Gas Turbine
A3	G/C	Combined cycle plant with one 47 MWe (ISO) Gas Turbine
A4	EGP	Combined cycle plant with one 90 MWe (ISO) Gas Turbine
B1	EGU & G/C	Cogeneration plant with one CFB boiler and a 32 MWe steam turbine
C1	G/C	Life extension of existing units and subsequent introduction of a CFB boiler with a 32 MWe steam turbine in 2003

Not all variants were investigated by each company The EGU and EGP analyses are presented in Section 7 0 and the G/C analysis is found in Section 8 0

Characteristics of Variants A2, A3, A4, B1 and C1 are summarized in Exhibit 6-5 and described in the paragraphs which follow A1 is not included in the exhibit, since it is essentially a larger version of the described variants Information on this variant is found in Section 6 3 1 and in Appendix C

A table illustrating the introduction and retirement of each unit for variants A2, A3, B1 and C1 through the year 2010 is presented as Exhibit 6-6 These values in a similar expanded exhibit were used to establish a reasonable operating margin for the system It was assumed that 85% of the peak load must be satisfied when the largest single unit was out of service Czech regulations use an even lower value of 78% While the loss of the largest boiler unit for a substantial period of time is unlikely, it is possible and should be accounted for This exercise also served to balance the approach of each variant investigated in terms of supplying this margin

Common to all variants are a switch to low sulfur coal for Plzen I and Plzen II, and the addition of baghouse filters to those units These technologies were described previously, as well as alternatives to these technologies which can also be considered by the City of Plzen

A more detailed description of each variant is provided in subsequent sections

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Exhibit 6-5
SUMMARY OF SELECTED VARIANTS

	Principal Variants for High Demand			
Parameter	**A2 & A3**	**A4**	**B1**	**C1**
Responsible Company	EGU G/C	Energoprojekt	EGU, G/C	G/C
Emission Requirements	1997 Emissions Compliance Required for all units			
Extension of Heat Distribution Lines	Heat Line East I by 1994 Heat Line East II considered in separate analysis in Section 8 0			
Existing Plzen I Boilers	Retrofit to Low Sulfur Bituminous & Baghouse Particulate Control			
Existing Plzen II Cogen	Retrofit to Low Sulfur Bituminous & Baghouse Particulate Control (G/C alternate is retrofit to Duct Sorbent Injection)			
Plzen III Steam Boiler (considered only in EGU study)	Gas-Fired 43 5 MWt 1994 introduction	not required	Gas-Fired 43 5 MWt 1994 introduction	not required
Plzen IV Cogen (performance @ -12°C)	Gas Turbine CC gas fired 65 MWt 89 MWe (A2) 60 MWt 73 MWe (A3) 1997 introduction	Gas Turbine CC gas fired 133 MWt 141 MWe 1997 introduction	Fluidized Bed lignite fired 160 t/h 75 MWt 32 MWe 1997 introduction	Fluidized Bed lignite fired 160 t/h 75 MWt 32 MWe 2005 introduction
Plzen V Boiler	2x58 MWt 2004 Introduction	23 5 MWt 2004 Introduction	2x58 MWt 2004 Introduction	None (extend Plzen I)
Kosutka HW Boiler	Convert to gas use as emergency unit			
Bory HW Boilers	Retire 1997			Low sulfur coal Baghouse Retire 2003
Bory Steam Boilers	Continue serving existing steam customers			
Letna HW Boilers	Retire 1997			Convert to gas Retire 2003
Doubravka HW Boilers	Retire 1997			Low sulfur coal Baghouse Retire 2003
Svetovar HW Boilers	Considered separately for connection to CP Plzen or independent operation			
Brewery Boilers	Assumed addition of 25 MWt gas-fired boiler, continued DH cooperation			
Railway (Zos) Boilers	Modification needed but required changes not considered in study			

Exhibit 6-6
PLZEN DISTRICT HEATING SYSTEM UNITS IN SERVICE BY YEAR

Parameter	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
High HW Demand	207 0	209 8	212 7	215 5	291 8	295 7	297 0	298 2	299 5	300 0	300 5	301 0	301 5	302 0	302 4	302 8	303 2	303 6	304 0
Low HW Demand	207 0	206 6	206 2	205 8	272 8	272 7	268 1	263 4	258 8	258 5	258 2	257 9	257 6	257 3	257 3	257 3	257 3	257 3	257 3
High Stm Demand	93 0	92 4	91 7	91 1	99 8	100 0	100 0	100 0	100 0	99 9	99 8	99 8	99 7	99 6	99 6	99 6	99 6	99 6	99 6
Low Stm Demand	93 0	92 4	91 7	91 1	90 5	88 9	88 9	88 9	88 9	88 9	88 9	88 9	88 9	88 9	88 9	88 9	88 9	88 9	88 9
Adj High Stm Dem	79 1	78 5	78 0	77 4	84 8	85 0	85 0	85 0	85 0	84 9	84 9	84 8	84 7	84 7	84 7	84 7	84 7	84 7	84 7
Adj Low Stm Dem	79 1	78 5	78 0	77 4	76 9	75 6	75 6	75 6	75 6	75 6	75 6	75 6	75 6	75 6	75 6	75 6	75 6	75 6	75 6
Brewery Offset[a]	56 1	56 1	56 1	56 1	56 1	56 1	56 1	56 1	56 1	56 1	56 1	56 1	56 1	56 1	56 1	56 1	56 1	56 1	56 1
Plzen High Stm Demand	23 0	22 4	21 9	21 3	28 7	28 9	28 9	28 9	28 9	28 8	28 8	28 7	28 6	28 6	28 6	28 6	28 6	28 6	28 6
Plzen Low Stm Demand	23 0	22 4	21 9	21 3	20 8	19 5	19 5	19 5	19 5	19 5	19 5	19 5	19 5	19 5	19 5	19 5	19 5	19 5	19 5
Total Adj High MWt Peak[b]	230 0	232 2	234 5	236 8	320 5	324 6	325 9	327 1	328 4	328 8	329 3	329 7	330 1	330 6	331 0	331 4	331 8	332 2	332 6
Total Adj Low MWt Peak[b]	230 0	229 0	228 1	227 1	293 6	292 2	287 5	282 9	278 3	278 0	277 7	277 4	277 1	276 8	276 8	276 8	276 8	276 8	276 8

Summary High Demand Margin MWt (w/o largest unit)[c]																			
Case A2	4	2	−1	−42	−42	22	21	19	18	18	17	17	16	27	27	26	26	26	25
Case A3	4	2	−1	−42	−42	6	4	3	2	2	1	1	0	11	11	10	10	9	9
Case B1	4	2	−1	−42	−42	32	31	30	29	28	28	28	27	38	37	37	37	36	36
Case B2	4	2	−1	−42	−42	−5	−6	30	29	28	28	28	27	38	37	37	37	36	36
Case C1	4	2	−1	−42	−42	37	36	34	33	33	32	37	37	37	36	36	35	35	35

Summary Low Demand Margin MWt (w/o largest unit)[c]																			
Case A2	4	5	6	−32	−16	53	57	61	66	66	66	67	67	20	20	20	20	20	20
Case A3	4	5	6	−32	−16	36	41	45	50	50	50	51	51	4	4	4	4	4	4
Case B1	4	5	6	−32	−16	63	68	72	76	77	77	77	78	31	31	31	31	31	31
Case B2	4	5	6	−32	−16	26	30	35	39	39	40	40	40	31	31	31	31	31	31
Case C1	4	5	6	−32	−16	68	72	76	81	81	81	50	50	50	50	50	50	50	50

Notes a Brewery total here does not consider potential addition of capacity
b Total adjusted MWt peak is set for analysis of margin requirements only
c This analysis is not detailed sufficiently to consider all possible demand and coincident demand combinations

30-Aug-93

6 3 1 Variant A1 Combined Cycle Plant employing Two 60 9 MWe (ISO) Gas Turbines

Variant A1 originally resulted from a proposal by Siemens to install two V64 3 gas turbines in a combined cycle (GTCC) configuration By competitive bidding, the turbine could be supplied by another comparable manufacturer Variant A1 is characterized in Exhibit 6-7 and 6-8

Exhibit 6-7
CHARACTERISTICS OF VARIANT A1

Major System Equipment Changes			
Plant	Installed Year	Major Equipment Description	Output/ Characteristic
Plzen I	1997	Two baghouse units for particulate control	
Plzen II	1997	New pulverizers for hard coal firing Two baghouse units for particulate control	
Plzen III	1994	New gas/oil-fired steam boiler	65 tonne/h
Plzen IV	1997	Two gas turbines, Siemens V64 3 Dual-pressure waste heat boiler high pressure steam low pressure steam Condensing steam turbine w/ two regulated extractions 1st extraction pressure 2nd extraction pressure Maximum total thermal output Maximum total electrical output	2x60 9 MWe (ISO) 2x66 9 MWe (-12°C) 2x88 5 MWt 8 1 MPa 505°C 0 5 MPa, 200°C 45 MWe 1 0-1 4 MPa 0 06-0 12 MPa 125 MWt 168 4 MWe
Kosutka	1997	Convert to gas operation	
Letna Doubravka Bory (HW) ZOS	1997 1997 1997 1997	Retire Retire Retire Retire	
Plzen V	2005	New gas/oil-fired hot water boiler(s) (high demand only)	58 MWt

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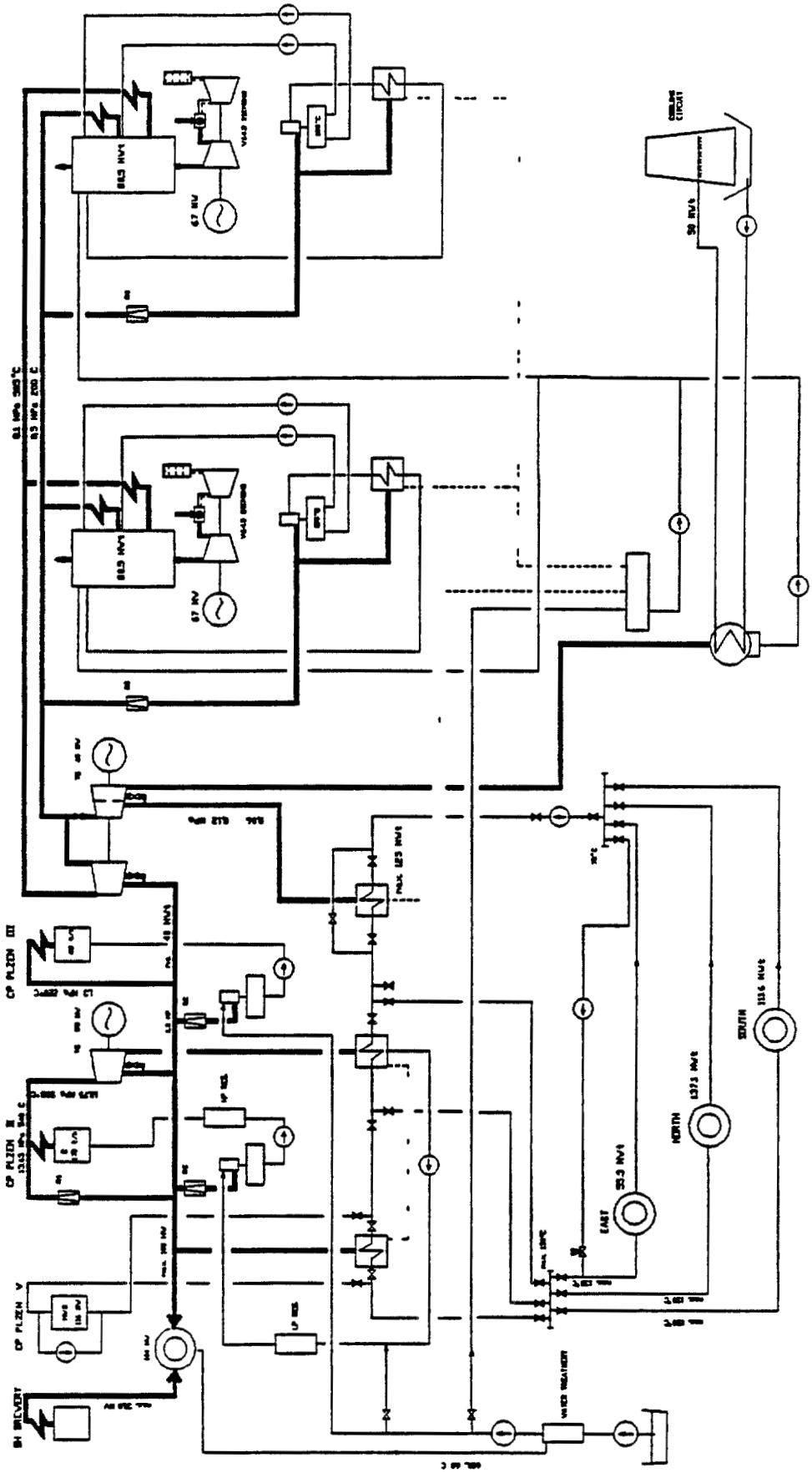
Exhibit 6-8
VARIANT A1 SCHEMATIC ARRANGEMENT



G9

It is assumed that the GTCC will cover the basic heat supply during the week days of the heating period For week days in the summer, the GTCC will supply heat in both steam and hot water Because of the low price of electricity, the GTCC will be shut down on the weekends This operating sequence provides the best opportunity to prove economic attractiveness of the GTCC

The large size of this combined cycle allows the older plants Letna, Doubravka, Bory (hot water only), and Railway Maintenance Company, as well as one of the Plzen I 35 MWt plants to be shut down Heating Plant Kosutka would be maintained as a standby source

In the high demand case, a new oil/gas-fired unit is included in the year 2005 to replace the remaining 2x35 MWt hot water boilers of Plzen I For the low demand case, this boiler is not needed, and the steam and hot water demand can be realized by the remaining units

Calculations performed by EGU and technical results are presented in Appendix C The operation of the Cogeneration Plant (CP) can be seen in Diagrams D1 and D2 (Appendix C) for the High Balance condition, and in Diagrams D4 and D5 for the Low Balance It can be seen that the GTCC cooperates with the Brewery boiler house and with the existing units to supply both steam and hot water to the system

The gross electric power generation, including both the GTCC and the existing back pressure turbine, as well as the natural gas consumption are presented in Diagrams D3 and D6 for the high and low balance respectively

The results of the production balance of heat and electricity in CP Plzen and the corresponding fuel consumption in selected years are shown in Table 11 and 12 (Appendix C) for the high and low balance Tables 11a and 12a provide operational results for only the combined cycle

It is assumed that Plzen II units will be out of service in successive years 1995 and 1996 to be reconstructed for hard coal firing To make up for the shortfall during this period, a planned gas-fired boiler is installed early to cover the steam/hot water shortfall In Section 8 0, a case is made for keeping the Plzen II units in service during the entire winter period, and performing the plant modifications during the summer shutdown period

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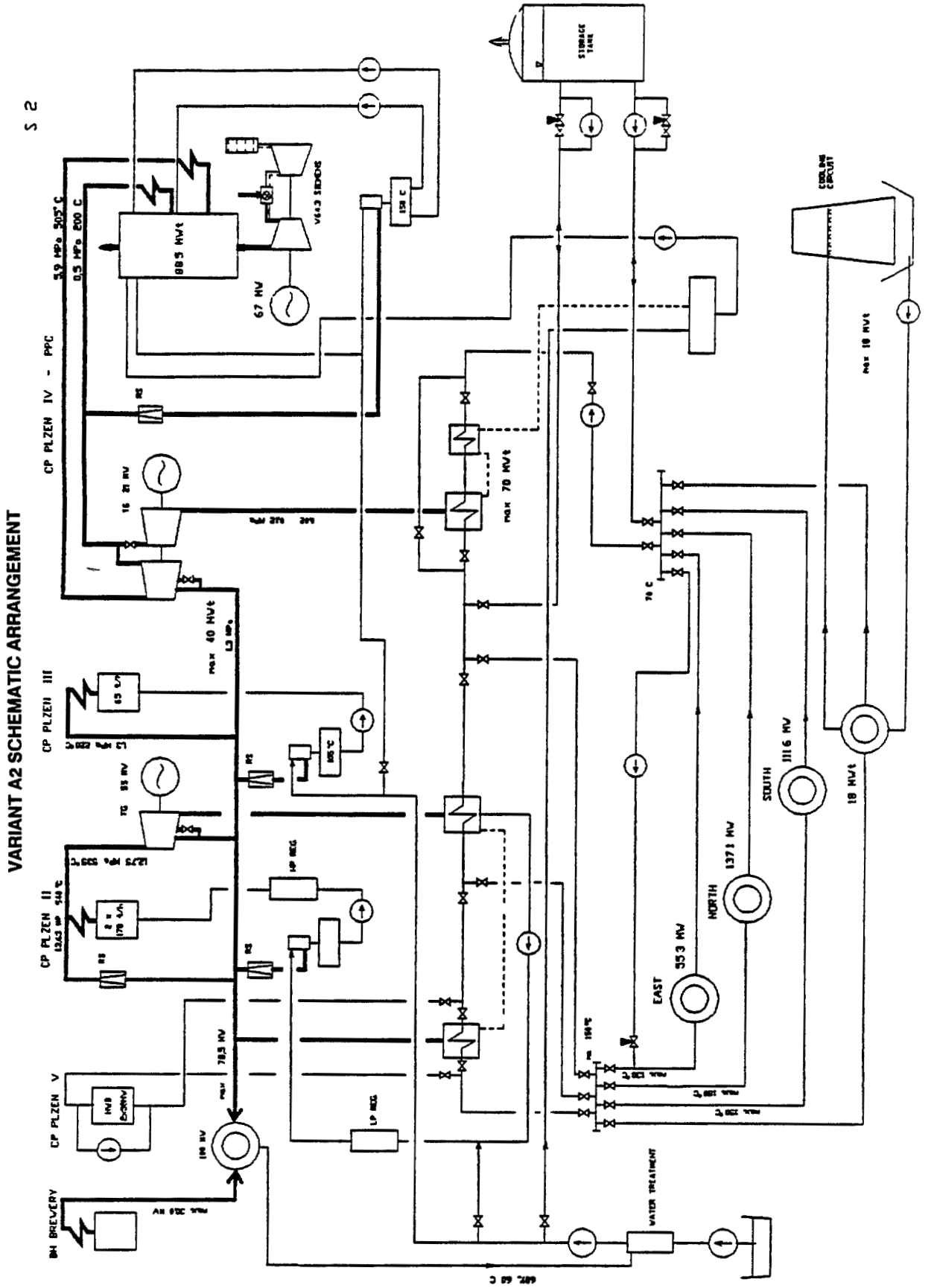
6 3 2 Variant A2 Combined Cycle Plant Employing a Single 60 9 MWe (ISO) Gas Turbine

Variant A2, investigated by both Gilbert/Commonwealth and EGU, uses much of the same equipment as Variant A1, except that a single Siemens V64 3 Gas Turbine and associated equipment are specified Again, by competitive bidding, the turbine could be supplied by another comparable manufacturer Variant A2 is characterized in Exhibit 6-9 and 6-10

Exhibit 6-9
CHARACTERISTICS OF VARIANT A2

Major System Equipment Changes			
Plant	Installed Year	Major Equipment Description	Output/ Characteristic
Plzen I	1997	Three baghouse units for particulate control	
Plzen II	1997	New pulverizers for hard coal firing Two baghouse units for particulate control	
Plzen III (EGU only)	1994	New gas/oil-fired steam boiler	65 tonne/h
Plzen IV	1997	One gas turbine, Siemens V64 3 Dual-pressure waste heat boiler high pressure steam low pressure steam Back Pressure steam turbine w/ one regulated extraction extraction pressure exhaust pressure Maximum total thermal output Maximum total electrical output	1x60 9 MWe (ISO) 1x66 9 MWe (-12°C) 1x88 5 MWt 5 9 MPa 505°C 0 5 MPa 200°C 21 MWe 1 0-1 4 MPa 0 06-0 12 MPa 65 MWt 89 MWe
Kosutka	1997	Convert to gas operation	
Letna Doubravka Bory (HW) ZOS	1997 1997 1997 1997	Retire Retire Retire Retire	
Plzen V Plzen I	2004 2004	New gas/oil-fired hot water boiler(s) Retire	2x58 MWt (high demand) 1x58 MWt (low demand)

Exhibit 6-10
VARIANT A2 SCHEMATIC ARRANGEMENT



102

In this variant Plzen IV will operate in a similar way as Variant A1, except that the smaller size GTCC will necessitate the operation of additional units to satisfy demand Retirement of older plants, however, with the exception of Plzen I, will be the same as in Variant A1

Calculations performed by EGU and technical results are presented in Appendix D The operation of the Cogeneration Plant (CP) can be seen in Diagrams D7 and D8 for the High Balance condition, and in Diagrams D10 and D11 for the Low Balance It can be seen that the GTCC cooperates with the Brewery boiler house and with the existing units to supply both steam and hot water to the system

The gross electric power generation, including both the GTCC and the existing back pressure turbine, as well as the natural gas consumption are presented in Diagrams D9 and D12 for the high and low balance respectively

The results of the production balance of heat and electricity in CP Plzen and the corresponding fuel consumption in selected years are shown in Table 13 and 14 for the high and low balance Tables 13a and 14a provide operational results for only the combined cycle

6 3 3 Variant A3 Combined Cycle Plant Employing a Single 47 MWe (ISO) Gas Turbine

Gilbert/Commonwealth introduced a third Gas Turbine Combined Cycle option as Variant A3 This option utilizes a Westinghouse 251 of output approximately 47 MWe, and a waste heat boiler and steam turbine sized accordingly For consistency, other aspects such as plant retirements, and supplementary plant introductions, were prepared similar to the previous variants As with the previous cases, by competitive bidding, the turbine could be supplied by another comparable manufacturer Variant A3 is characterized in Exhibit 6-11 The configuration is similar to Variant A2, except for the smaller heat and electrical output

In this variant, Plzen IV will operate in a similar way as Variant A1, except that the smaller size will necessitate the operation of different units to satisfy demand Retirement of older plants, with the exception of Plzen I, will be the same as in Variant A1

Calculations for Variant A3 are reported in Section 8 0, where the G/C technical and economic modelling effort is presented

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Exhibit 6-11
CHARACTERISTICS OF VARIANT A3

Major System Equipment Changes			
Plant	Installed Year	Major Equipment Description	Output/ Characteristic
Plzen I	1997	Three baghouse units for particulate control	
Plzen II	1997	New pulverizers for hard coal firing Two baghouse units for particulate control	
Plzen III	1994	New gas/oil-fired steam boiler	65 tonne/h
Plzen IV	1997	One gas turbine, Westinghouse W251 B11/12 Dual-pressure waste heat boiler high pressure steam low pressure steam Back Pressure steam turbine w/ one regulated extraction extraction pressure exhaust pressure Maximum total thermal output Maximum total electrical output	1x 47 MWe (ISO) 1x54 MWe (-12°C) 1x81 MWt 5 9 MPa, 505°C 0 5 MPa 200°C 19 MWe 1 0-1 4 MPa 0 06-0 12 MPa 60 MWt 73 MWe
Kosutka	1997	Convert to gas operation	
Letna Doubravka Bory (HW) ZOS	1997 1997 1997 1997	Retire Retire Retire Retire	
Plzen V Plzen I	2004 2004	New gas/oil-fired hot water boiler(s) Retire	2x58 MWt (high demand) 1x58 MWt (low demand)

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6.3 4 Variant A4 Combined Cycle Plant Employing a Single 90 MWe (ISO) Gas Turbine

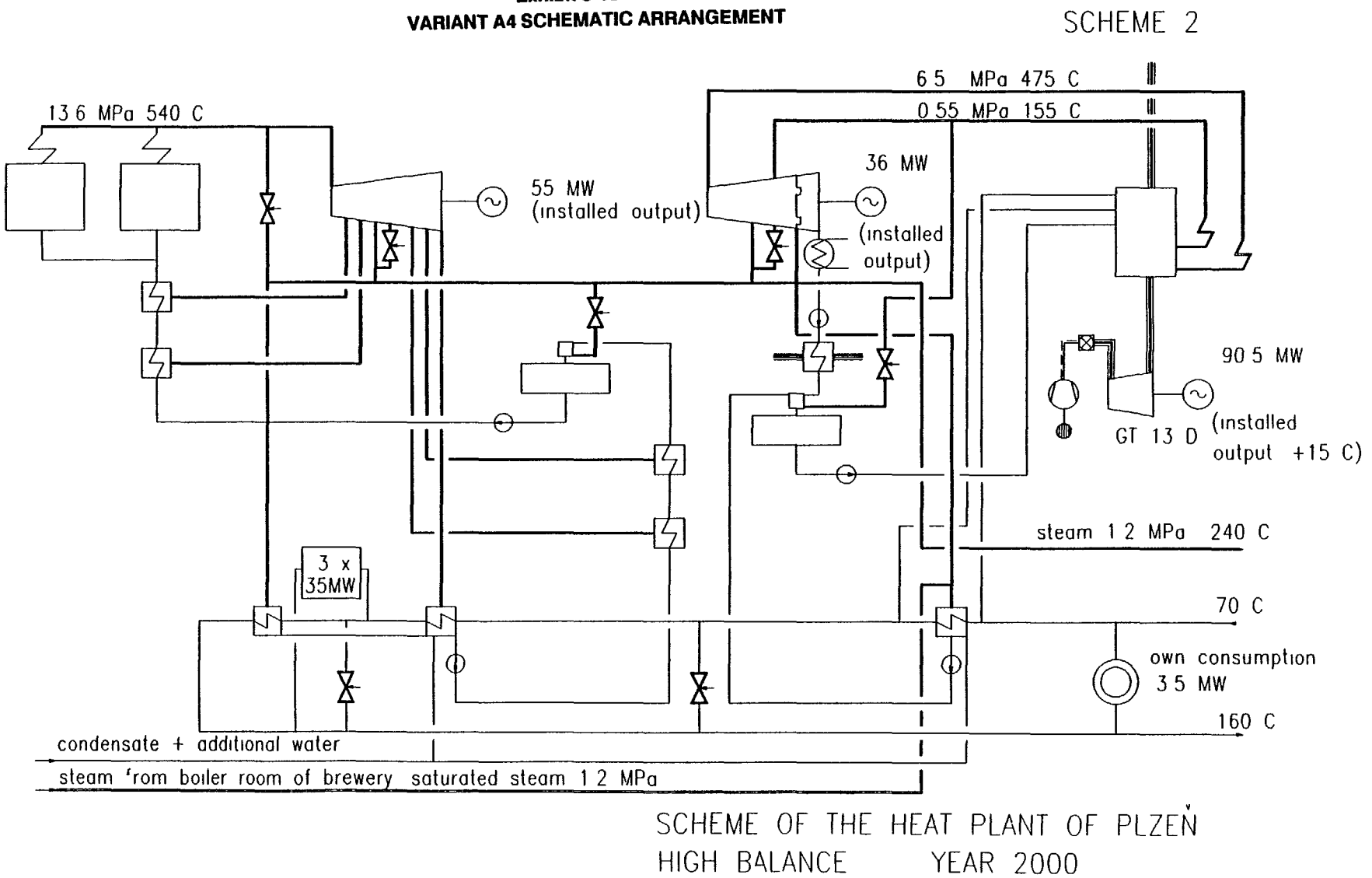
Variant A4 was proposed independently by subcontractor Energoprojekt Variant A4 uses much of the same equipment as Variant A1, except that a single 90 MWe ABB Type 13 Gas Turbine and associated equipment are specified Again, by competitive bidding, the turbine could be supplied by another comparable manufacturer This variant does not call for the construction of a new Plzen III steam boiler, but Energoprojekt proposes that steam demands can be covered by cooperation with the Brewery boiler house They agree that the Plzen II retrofit can be accommodated outside of the peak segment of the heating season Variant A4 is characterized in Exhibit 6-12 and 6-13

Exhibit 6-12
CHARACTERISTICS OF VARIANT A4

Major System Equipment Changes			
Plant	Installed Year	Major Equipment Description	Output/ Characteristic
Plzen I	1997	Three baghouse units for particulate control	
Plzen II	1997	New pulverizers for hard coal firing Two baghouse units for particulate control	
Plzen IV	1997	One gas turbine, ABB Type 13 Dual-pressure waste heat boiler high pressure steam low pressure steam Condensing steam turbine w/ two regulated extractions 1st extraction pressure 2nd extraction pressure Maximum total thermal output Maximum total electrical output	1x94 MWe (ISO) 1x105 MWe (-12°C) 1x93 MWt 6 5 MPa, 475°C 0 55 MPa, 155°C 36 MWe 1 0-1 4 MPa 0 06-0 12 MPa 133 MWt 141 MWe
Kosutka Letna Doubravka Bory (HW) ZOS	1997 1997 1997 1997 1997	Retire Retire Retire Retire Retire	
Plzen V Plzen I	2004 2004	New gas/oil-fired hot water boiler(s) Retire	35 MWt (high demand) 28 MWt (low demand)

105

Exhibit 6-13
VARIANT A4 SCHEMATIC ARRANGEMENT



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In Variant A4, Plzen IV will operate in a similar way as Variant A1, except that the smaller size will necessitate the operation of different units to satisfy demand Retirement of older plants, with the exception of Plzen I, will be the same as in Variant A1 Cooperation with the Brewery will result in the replacement of capacity of two of the Brewery's older boilers in CP Plzen

Calculations performed by Energoprojekt and technical results are presented in Appendix D The operation of the CP Plzen and the results can be seen in Tables I/1-I/3 (Appendix D) for the Low Balance condition, and II/1-II/3 for the High Balance condition The GTCC cooperates with the Brewery boiler house and with the existing units to supply both steam and hot water to the system

6.3.5 Variant B1: Combined Cycle Plant Employing a Single Large Circulating Fluidized Bed Boiler

Variant B1 introduces the Circulating Fluidized Bed (CFB) boiler Unlike the Gas Turbine, which must be imported to the Czech Republic, the CFB boiler could be designed by a U S or other manufacturer, and then fabricated and constructed in the Czech Republic Foster Wheeler of the U S has preliminary agreements with a Slovak manufacturer to produce boilers in this mode By competitive bidding, the best arrangement could be obtained Variant B1 is characterized in Exhibit 6-14 and 6-15

The analysis of this variant currently assumes the new extraction/condensing turbine provides the first stage of district heating, the existing back pressure turbine provides the second stage, and the hot water boilers provide the third stage An improved arrangement may result by switching the existing back pressure turbine and the new condensing turbine This would maximize the electric generation for the existing turbine, by minimizing the exhaust pressure, while having little impact on the power output of the new condensing turbine

Two options are given for environmental compliance for the existing CP Plzen II units The first option considers a fuel switch to low sulfur black coal, as shown above A second option is the installation of FGD systems, designated as B2 Variant B2 was not investigated in detail, since previous studies by ZCE have independently shown this variant to be less cost effective than B1

Another variant was considered as an alternate to Variant B1 Since future demand is uncertain, it may be prudent to add less capacity at first, assumed to be half the size of the CFB boiler in Variant B1, and then if demand does not materialize, the second "half-size" unit need not be added While this approach is logical, it does not add much to the study of Variant B1 since the Plzen I units are also nearing retirement, and any excess capacity installed early could offset this capacity This alternate was also not considered in detail in the model approach

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Exhibit 6-14
CHARACTERISTICS OF VARIANT B1

Major System Equipment Changes			
Plant	Installed Year	Major Equipment Description	Output/ Characteristic
Plzen I	1997	Three baghouse units for particulate control	
Plzen II	1997	New pulverizers for hard coal firing Two baghouse units for particulate control	
Plzen III	1994	New gas/oil-fired steam boiler	43 5 MWt
Plzen IV	1997	One Foster Wheeler CFB boiler	1x160 tonne/h
		Condensing steam turbine w/ two regulated extractions 1st extraction pressure 2nd extraction pressure Maximum total thermal output	13 63 MPa 540°C 32 MWe 1 0-1 4 MPa 0 06-0 12 MPa 75 MWt
Kosutka	1997	Convert to gas operation	
Letna Doubravka Bory (HW) ZOS	1997 1997 1997 1997	Retire Retire Retire Retire	
Plzen V Plzen I	2004 2004	New gas/oil-fired hot water boiler(s) Retire	2x58 MWt (high demand) 1x58 MWt (low demand)

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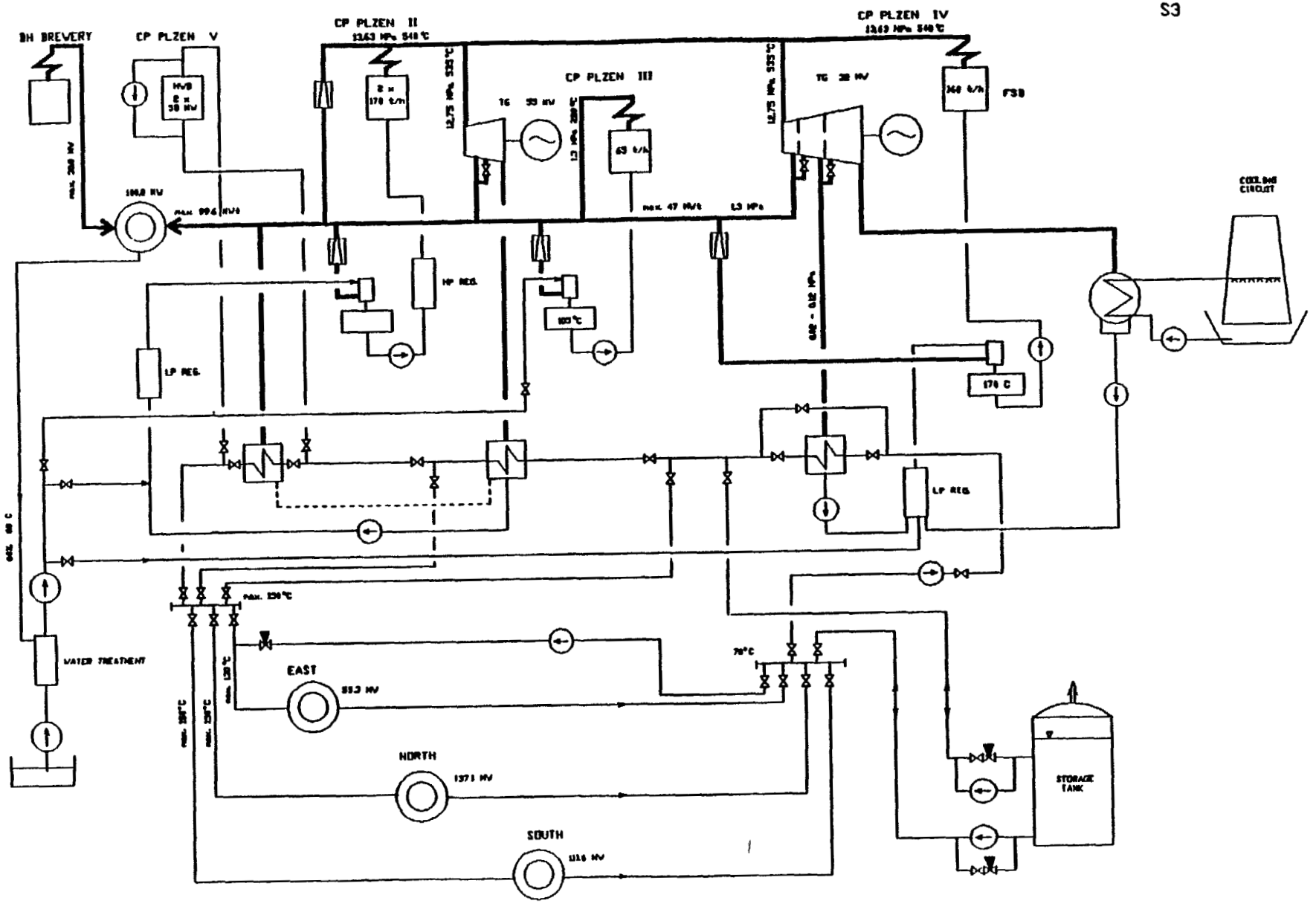
Exhibit 6-15
VARIANT B1 SCHEMATIC ARRANGEMENT

S3



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6.3.6 Variant C1· Extend the Life of Existing Units

In this variant, existing plants are run beyond their presently planned life It is not unusual to operate a boiler in the U S for 40 or even 50 years Generally, the integrity of thick-walled high pressure parts are a controlling life factor In light of the uncertainties associated with emissions regulations, financing terms/interest rates, and the uncertainty of profitable operation in a privatized environment, it may be prudent to maintain the units in operation for 6 to 8 more years, and then proceed with replacement with more efficient and environmentally capable technology

The major equipment associated with Variant C1 is characterized in Exhibit 6-16

Exhibit 6-16
CHARACTERISTICS OF VARIANT C1

Major System Equipment Changes			
Plant	Installed Year	Major Equipment Description	Output/ Characteristic
Plzen I	1997	Three baghouse units for particulate control	
Plzen II	1997	New pulverizers for hard coal firing Two baghouse units for particulate control	
Plzen III	1994	New gas/oil-fired steam boiler	43 5 MWt
Plzen IV	2003	One Foster Wheeler CFB boiler	1x160 tonne/h
		Condensing steam turbine w/ two regulated extractions 1st extraction pressure 2nd extraction pressure Maximum total thermal output	13 63 MPa 540°C 32 MWe 1 0-1 4 MPa 0 06-0 12 MPa 75 MWt
Kosutka	1997	Convert to gas operation	
Letna Doubravka Bory (HW) ZOS	2003 2003 2003 2003	Retire Retire Retire Retire	

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Maintenance (discussed in Section 8 5) is considered to increase at a substantial rate for the older equipment, and thus a difference for maintenance between old and new equipment has been established The purchase of a new CFB boiler unit is still envisioned, but at a later date This provides an opportunity to utilize a more advanced technology such as a Pressurized Fluidized Bed boiler Another feature of Variant C1 is that Plzen I units are maintained operational through the end of the study period, thus eliminating the need for purchase of another gas/oil unit during the period

6 4 EMISSIONS COMPLIANCE CONSIDERATIONS

Compliance with new emissions regulations is a critical consideration for the least cost plan Regulations require that new particulate removal equipment be purchased for every solid fuel unit, that fuel quality be upgraded, and/or new technology be employed A brief description of these regulations are provided in Section 9 0 It is assumed for this study that emissions regulations will be met, and that the payment of fines is unacceptable, except for brief periods of reconstruction

6.5 COMMENTS ON IMPLEMENTATION SCHEDULES

The schedule of introduction of new units was presented in Exhibit 6-6 During the years 1995-1997, the plant modifications should occur in a timely fashion in order to achieve the least cost Plans by ZCE include taking each of the Plzen II plants out of service in successive years 1995 and 1996, so that modifications to hard coal firing may take place

In the U S, outages caused by modifications to power plants are generally held to a minimum To achieve a pulverizer replacement, for example, one pulverizer at a time would be replaced while the plant was in operation Critical changes would be made while the plant was out of service, for example, on weekends, or other low-demand times In the case of CP Plzen, there is a significant period where the plant is currently out of service With careful planning/scheduling, engineering, and possibly through the use of an outside contractor, the job could be done during the normal outage period, or perhaps such a period extended by one or two months

Consideration should also be given to seeking an extension to the compliance date Plzen IV (the CFB boiler or GTCC) could be constructed first, followed by modification to the existing Plzen II units during the year 1997 There are so many changes planned, that it would be prudent to spread the capital expenditures and construction work over a longer period than one or two years

7.0 ANALYSIS OF VARIANTS BY EGU AND ENERGOPROJEKT

A significant effort was put forth by EGU to determine the performance and operating costs for Variants A1, A2, and B1, and by Energoprojekt for Variant A4 This section presents an economic analysis (Section 7 1) which applies G/C assumptions to the EGU and Energoprojekt effort, and a summary of their effort/results (Sections 7 2 and 7 3 respectively) Their detailed reports are likewise found in Appendices C and D Results from EGU and Energoprojekt were also used to validate independent calculations performed by Gilbert/Commonwealth, which are reported in Section 8 0

A separate analysis of small cogeneration units was performed by CityPlan This analysis was used in the development of options for Svetovar (Section 8 9), and also in the evaluation of the 595 small boilers (Section 4 0) It is not addressed in this section The complete CityPlan analysis is found in Appendix B

This summary is presented in exhibits which compare key operating parameters for the year 2000, and the High Demand Several parameters are summarized in Exhibit 7-1 from the results found in Appendix C

The analyses results found in Appendix C and D show a substantial reduction in emissions from the base year 1992 As expected, emissions are much lower for the gas turbine variants, however, all variants are designed to meet emissions regulations in the year 1997 There is some decrease in emissions from the year 2000 to 2010 for all variants The EGU and Energoprojekt emissions results differ substantially from the Gilbert/Commonwealth analysis, primarily in the estimate for gas turbine emissions G/C assumed a low-NOx combustor for the gas turbines, typical of today's installations This combustor would provide NOx emissions at about 25% of the Czech regulation The G/C analysis of emissions is found in Section 9 0

7 1 ECONOMIC ANALYSIS OF VARIANTS A1, A2, A4, AND B1

Using many of the same assumptions and methods discussed in detail in Section 8 0, an analysis was performed by using inputs prepared by EGU and Energoprojekt into a spreadsheet which calculated Cumulative Present Worth of projected costs as a figure-of-merit Detailed calculations of performance were provided by EGU (Variants A1, A2 and B1) and Energoprojekt (Variant A4) Both parties worked to the same set of basic assumptions, with only some slight differences Quantity information for fuel usage, limestone use, water use, ash disposal quantities, electric generation, and capital requirements was calculated independently by EGU and Energoprojekt G/C made certain adjustments to the capital costs to be consistent between cases and to allow for uncertainties and contingencies in the capital expenditures

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Exhibit 7-1
SUMMARY OF KEY OPERATING PARAMETERS AND RESULTS

	Units	Variant			
		A1	A2	A4	B1
Engineering Organization		EGU	EGU	EGP	EGU
Installed output of steam boilers	MWt	276 2	276 2	232 9	396 5
Installed output of hot water boilers	MWt	70 0	105 0	105 0	105 0
Installed output of waste heat boilers	MWt	177 0	88 5	180 0	
Heat supply per year - steam	TJ/y	1277	1235	1300	1286
Heat Supply per year - hot water	TJ/y	2905	2905	2871	2905
Heat production - total	TJ/y	4182	4140	4171	4191
Net Electric power production	MWh/y	959 8	569 1	952 2	373 4
Specific heat consumption - heat		1 19	1 22		1 25
Specific heat consumption - electric		5 54	5 02		5 33
Total fuel consumption	TJ/y	10,644	8 157	9 601	7,554
Lignite, 10 05 MJ/kg	TJ/y	0	0	0	2857
Coal, 18 47 MJ/kg	TJ/y	371	657	55	209
Coal, 17 38 MJ/kg	TJ/y	3379	3745	2769	4315
Natural gas 33 4 MJ/m3	TJ/y	6853	3714	6777	91
Oil, 41 6 MJ/kg	TJ/y	41	41		82

The basis for calculations is the assumption of real escalation provided in Exhibit 8-3, and repeated here as Exhibit 7-2 Quantity information provided by the subcontractors are summarized in Exhibit 7-3 (two pages) With real escalation applied, and costs on the same basis, present worth and cumulative present worth of projected variant cost streams are calculated as shown in Exhibit 7-4 (two pages) A summary of the results of the analysis is shown below

Variant	Variant Description	Engineer	Cumulative Net Present Worth, million Kc	Change from Variant B1
A1	120 MWe GTCC	EGU	5 569	+48%
A2	60 MWe GTCC	EGU	4 739	+26%
A4	90 MWe GTCC	Energoprojekt	4 458	+19%
B1	75 MWt CFB	EGU	3 758	-

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Cumulative Present Worth provides the best single measure of the real cost of alternatives It does not directly consider financing requirements, but rather provides a least-cost representation of each variant considering all applicable cost streams In this approach, capital costs are treated in the year they occur It is apparent that the cost of each of the gas turbine variants is significantly higher than the CFB variant, and that small adjustments in fuel pricing, capital charges, etc, will not alter this outcome Three reasons are apparent for this difference

- First, the gas turbines for all three variants must all be imported, which increases the cost of gas turbines relative to the equipment used in Variant B1, which is subtantially supplied within the Czech Republic,

- Second, natural gas prices are expected to rise significantly above the price for low quality lignite, which can be effectively used in the CFB, and

- Third, and perhaps less significant, is the fact that peak periods of electricity revenue are not necessarily coincident with peak periods of heat requirement

These three reasons do not take into account any risk associated with natural gas supply, which may introduce another cost, depending on the security of supply If the analysis results were otherwise equivalent, or within 10%, other factors should be considered in the decision, e g the security of fuel supply, and the effect on local and state economies of using imported fuel

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Exhibit 7-2
ESCALATION FACTORS ASSUMED FOR ECONOMIC ANALYSIS
(see Exhibit 8-3)

Cost Item	Escalation Factors by Year 1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
General Inflation																		
Foreign		3.0%	3.5%	3.5%	3.5%	3.5%	3.5%	3.5%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%
Domestic		7.5%	6.5%	6.0%	6.0%	6.0%	6.0%	6.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%
Real Escalation																		
Lignite 10.05 MJ/kg		4.9%	4.9%	4.9%	1.9%	1.9%	1.9%	1.9%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Lignite 12.7 MJ/kg		4.9%	4.9%	4.9%	1.9%	1.9%	1.9%	1.9%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Black Coal 18.47 MJ/kg		0.0%	0.0%	0.0%	1.9%	1.9%	1.9%	1.9%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Black Coal 17.38 MJ/kg		0.0%	0.0%	0.0%	1.9%	1.9%	1.9%	1.9%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Natural Gas		3.7%	3.7%	3.7%	2.8%	2.8%	2.8%	2.8%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Oil		7.2%	7.2%	7.2%	2.9%	2.9%	2.9%	2.9%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Purchased Steam		0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Purchased Power		4.9%	4.9%	4.9%	1.9%	1.9%	1.9%	1.9%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Power Sales Revenues		4.9%	4.9%	4.9%	1.9%	1.9%	1.9%	1.9%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Ash disposal		14.0%	14.0%	14.0%	0.0%	0.0%	0.0%	70.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Limestone		0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Water cost		6.0%	6.0%	5.0%	1.0%	1.0%	1.0%	1.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Labor		0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Other O&M		0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Emissions Penalties	-70.0%	100.0%	0.0%	33.3%	0.0%	25.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Capital Cost – Foreign		4.5%	3.0%	2.5%	2.5%	2.5%	2.5%	2.5%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%
Capital Cost – Domestic		0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
COMPOUNDED																		
General Inflation																		
Foreign	1.0000	1.0300	1.0661	1.1034	1.1420	1.1819	1.2233	1.2661	1.3168	1.3694	1.4242	1.4812	1.5404	1.6021	1.6661	1.7328	1.8021	1.8742
Domestic	1.0000	1.0750	1.1449	1.2136	1.2864	1.3636	1.4454	1.5321	1.6087	1.6891	1.7736	1.8623	1.9554	2.0532	2.1558	2.2636	2.3768	2.4956
Real Escalation																		
Lignite 10.05 MJ/kg	1.0000	1.0486	1.0996	1.1530	1.1747	1.1969	1.2196	1.2429	1.2429	1.2429	1.2429	1.2429	1.2429	1.2429	1.2429	1.2429	1.2429	1.2429
Lignite 12.7 MJ/kg	1.0000	1.0486	1.0996	1.1530	1.1747	1.1969	1.2196	1.2429	1.2429	1.2429	1.2429	1.2429	1.2429	1.2429	1.2429	1.2429	1.2429	1.2429
Black Coal 18.47 MJ/kg	1.0000	1.0000	1.0000	1.0000	1.0188	1.0381	1.0578	1.0780	1.0780	1.0780	1.0780	1.0780	1.0780	1.0780	1.0780	1.0780	1.0780	1.0780
Black Coal 17.38 MJ/kg	1.0000	1.0000	1.0000	1.0000	1.0188	1.0381	1.0578	1.0780	1.0780	1.0780	1.0780	1.0780	1.0780	1.0780	1.0780	1.0780	1.0780	1.0780
Natural Gas	1.0000	1.0367	1.0747	1.1142	1.1449	1.1768	1.2096	1.2435	1.2435	1.2435	1.2435	1.2435	1.2435	1.2435	1.2435	1.2435	1.2435	1.2435
Oil	1.0000	1.0717	1.1485	1.2309	1.2662	1.3027	1.3402	1.3789	1.3789	1.3789	1.3789	1.3789	1.3789	1.3789	1.3789	1.3789	1.3789	1.3789
Purchased Steam	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
Purchased Power	1.0000	1.0486	1.0996	1.1530	1.1747	1.1969	1.2196	1.2429	1.2429	1.2429	1.2429	1.2429	1.2429	1.2429	1.2429	1.2429	1.2429	1.2429
Power Sales Revenues	1.0000	1.0486	1.0996	1.1530	1.1747	1.1969	1.2196	1.2429	1.2429	1.2429	1.2429	1.2429	1.2429	1.2429	1.2429	1.2429	1.2429	1.2429
Ash disposal	1.0000	1.1400	1.2996	1.4815	1.4815	1.4815	1.4815	2.5186	2.5186	2.5186	2.5186	2.5186	2.5186	2.5186	2.5186	2.5186	2.5186	2.5186
Limestone	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
Water cost	1.0000	1.0600	1.1236	1.1798	1.1916	1.2035	1.2155	1.2277	1.2277	1.2277	1.2277	1.2277	1.2277	1.2277	1.2277	1.2277	1.2277	1.2277
Labor	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
Other O&M	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
Emissions Penalties	0.3000	0.6000	0.6000	0.8000	0.8000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
Capital Cost – Foreign	1.0000	1.0450	1.0764	1.1033	1.1308	1.1591	1.1881	1.2178	1.2300	1.2423	1.2547	1.2672	1.2799	1.2927	1.3056	1.3187	1.3319	1.3452
Capital Cost – Domestic	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000

Exhibit 7-3
QUANTITY INFORMATION FOR ECONOMIC ANALYSIS

Variant A1 High Demand		Annual Quantity by year																		
Quantity		1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Fuel Quantity																				
Lignite 10 05 MJ/kg	TJ/y		0	0				0	0		0	0	0	0		0	0	0	0	
Lignite 12 7 MJ/kg	TJ/y	4229	4229	4229	3963	4862		0	0		0	0	0	0		0	0	0	0	
Coal 18 47 MJ/kg	TJ/y		0	0			365	365	365	371	371	371	371	371		0	0	0	0	
Coal 17 38 MJ/kg	TJ/y		0	0			3340	3340	3340	3379	3379	3379	3379	3379	3127	3127	3127	3127	3127	3134
Natural Gas 33 4 MJ/m	TJ/y		0	0	418	455	6835	6835	6835	6853	6853	6853	6853	6853	7518	7518	7518	7518	7518	7539
Oil 41 6 MJ/kg	TJ/y	18	18	18	117	117	37	37	37	41	41	41	41	41	273	273	273	273	273	280
Limestone quantity	10 tonne/y		0	0				0	0		0	0	0	0		0	0	0	0	
Ash quantity	10 tonne/y	49 5	49 5	49 5	46 4	56 9	69 4	69 4	69 4	70 2	70 2	70 2	70 2	70 2	58 6	58 6	58 6	58 6	58 6	58 7
Water quantities																				
raw water	10 m /y	1100	1100	1100	1165	1407	2739	2739	2739	2757	2757	2757	2757	2757	2828	2828	2828	2828	2828	2837
softened water	10 m /y	68	68	68	71	96	97	97	97	99	99	99	99	99	99	99	99	99	99	100
demineralized water	10 m /y	359	359	359	352	385	386	386	386	386	386	386	386	386	384	384	384	384	384	384
Labor	staff	293	293	293	293	293	300	300	300	300	300	300	300	300	270	270	270	270	270	270
Electric power prod – gross	GWh/y	158 0	158 0	158 0	136 7	156 7	1 016 7	1016 7	1 016 7	1 021 3	1 021 3	1 021 3	1 021 3	1 021 3	1 070 2	1 070 2	1 070 2	1 070 2	1 070 2	1 073 4
Electric power sales – net	GWh/y	119 3	119 3	119 3	106 0	118 2	959 8	959 8	959 8	963 8	963 8	963 8	963 8	963 8	1 012 6	1 012 6	1 012 6	1 012 6	1 012 6	1 015 5
during peak period (gr)	GWh/y	26 1	26 1	26 1	22 6	25 9	251 8	251 8	251 8	252 9	252 9	252 9	252 9	252 9	265	265	265	265	265	265 8
during high tarriff (gr)	GWh/y	30 5	30 5	30 5	26 4	30 3	278 2	278 2	278 2	279 5	279 5	279 5	279 5	279 5	292 9	292 9	292 9	292 9	292 9	293 8
during low tarriff (gr)	GWh/y	101 4	101 4	101 4	87 7	100 5	486 7	486 7	486 7	488 9	488 9	488 9	488 9	488 9	512 3	512 3	512 3	512 3	512 3	513 8
Total Fuel	TJ/y	4,247	4 247	4 247	4,498	5 434	10 577	10,577	10 577	10,644	10,644	10 644	10 644	10,644	10,918	10 918	10 918	10 918	10 918	10 953
Capital Cost – Foreign	10 Kc/y		0 00	0 00	802 87	802 87	0 00	0 00	0 00	0 00										
Capital Cost – Domestic	10 Kc/y		5 30	103 08	898 28	876 28	13 83	7 24	7 24	7 24	0 93	0 93	48 68	48 68	0 93	0 71	0 71	0 71	0 71	0,71

Variant A2 High Demand		Annual Quantity by year																		
Quantity		1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Fuel Quantity																				
Lignite 10 05 MJ/kg	TJ/y		0	0				0	0		0	0	0	0		0	0	0	0	
Lignite 12 7 MJ/kg	TJ/y	4229	4229	4229	3963	4862		0	0		0	0	0	0		0	0	0	0	
Coal 18 47 MJ/kg	TJ/y		0	0			651	651	651	657	657	657	657	657		0	0	0	0	
Coal 17 38 MJ/kg	TJ/y		0	0			3715	3715	3715	3745	3745	3745	3745	3745	3802	3802	3802	3802	3802	3814
Natural Gas 33 4 MJ/m	TJ/y		0	0	418	455	3677	3677	3677	3714	3714	3714	3714	3714	3897	3897	3897	3897	3897	3912
Oil 41 6 MJ/kg	TJ/y	18	18	18	117	117	40	40	40	41	41	41	41	41	468	468	468	468	468	474
Limestone quantity	10 tonne/y		0	0				0	0		0	0	0	0		0	0	0	0	
Ash quantity	10 tonne/y	49 5	49 5	49 5	46 4	56 9	81 7	81 7	81 7	82 3	82 3	82 3	82 3	82 3	71 3	71 3	71 3	71 3	71 3	71 5
Water quantities			0	0				0	0		0	0	0	0		0	0	0	0	
raw water	10 m /y	1100	1100	1100	1165	1407	2093	2093	2093	2113	2113	2113	2113	2113	2124	2124	2124	2124	2124	2638
softened water	10 m /y	68	68	68	71	96	97	97	97	99	99	99	99	99	100	100	100	100	100	85
demineralized water	10 m /y	359	359	359	352	385	386	386	386	386	386	386	386	386	384	384	384	384	384	343
Labor	staff	293	293	293	293	293	310	310	310	310	310	310	310	310	275	275	275	275	275	275
Electric power prod – gross	GWh/y	158 0	158	158	136 7	156 7	614 2	614 2	614 2	620 4	620 4	620 4	620 4	620 4	627 7	627 7	627 7	627 7	627 7	630 1
Electric power sales – net	GWh/y	119 3	119 3	119 3	106 0	118 2	563 4	563 4	563 4	569 1	569 1	569 1	569 1	569 1	576 3	576 3	576 3	576 3	576 3	578 5
during peak period (gr)	GWh/y	26 1	26 1	26 1	22 6	25 9	147 0	147	147	148 5	148 5	148 5	148 5	148 5	150 2	150 2	150 2	150 2	150 2	150 8
during high tarriff (gr)	GWh/y	30 5	30 5	30 5	26 4	30 3	154 0	154	154	155 6	155 6	155 6	155 6	155 6	157 4	157 4	157 4	157 4	157 4	158 0
during low tarriff (gr)	GWh/y	101 4	101 4	101 4	87 7	100 5	313 1	313 1	313 1	316 3	316 3	316 3	316 3	316 3	320 0	320	320	320	320	321 1
Total Fuel	TJ/y	4 247	4 247	4 247	4,498	5 434	8,083	8 083	8 083	8 157	8 157	8 157	8 157	8 157	8 167	8 167	8 167	8 167	8 167	8,200
Capital Cost – Foreign			0 00	0 00	401 41	401 41	0 00	0 00	0 00	0 00	0 00	0 00	0 00	0 00	0 00	0 00	0 00	0 00	0 00	0 00
Capital Cost – Domestic			5 31	103 08	468 81	446 17	13 83	7 24	7 24	7 24	0 93	0 93	92 44	92 44	0 93	0 71	0 71	0 71	0 71	0 71

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Exhibit 7-3 (continued)
QUANTITY INFORMATION FOR ECONOMIC ANALYSIS

Variant A4 High Demand		Annual Quantity by year																		
Quantity		1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Fuel Quantity																				
Lignite 10 05 MJ/kg	TJ/y		0	0				0	0		0	0	0	0		0	0	0	0	
Lignite 12 7 MJ/kg	TJ/y	4652	4652	4652	4370	1058		0	0		0	0	0	0		0	0	0	0	
Coal 18 47 MJ/kg	TJ/y		0	0	84	135	51	51	51	55	55	55	55	55		0	0	0	0	
Coal 17 38 MJ/kg	TJ/y		0	0		3817	2556	2556	2556	2769	2769	2769	2769	2769	2779	2779	2779	2779	2779	2798
Natural Gas 33 4 MJ/m	TJ/y	263	263	263	269	887	6747	6747	6747	6777	6777	6777	6777	6777	6840	6840	6840	6840	6840	6854
Oil 41 6 MJ/kg	TJ/y	20	20	20	20	20		0	0		0	0	0	0		0	0	0	0	
Limestone quantity	10 tonne/y		0	0				0	0		0	0	0	0		0	0	0	0	
Ash quantity	10 tonne/y	62 4	62 4	62 4	56 1	71 7	45 8	45 6	45 6	49 3	49 3	49 3	49 3	49 3	48 6	48 6	48 6	48 6	48 6	48 9
Water quantities			0	0				0	0		0	0	0	0		0	0	0	0	
raw water	10 m /y	1100	1100	1100	1165	1407	2416	2416	2416	2435	2435	2435	2435	2435	2476	2476	2476	2476	2476	2737 5
softened water	10 m /y	68	68	68	71	96	97	97	97	99	99	99	99	99	100	100	100	100	100	85
demineralized water	10 m /y	359	359	359	352	385	386	386	386	388	386	386	386	386	384	384	384	384	384	343
Labor	staff	293	293	293	293	293	310	310	310	310	310	310	310	310	275	275	275	275	275	275
Electric power prod – gross	GWh/y	209 9	209 9	209 9	144 7	151 2	984 6	984 6	984 6	996 8	996 8	996 8	996 8	996 8	1004 8	1004 8	1004 8	1004 8	1004 8	1007 2
Electric power sales – net	GWh/y	165 7	165 7	165 7	99 4	100 4	941 1	941 1	941 1	952 2	952 2	952 2	952 2	952 2	959 8	959 8	959 8	959 8	959 8	962 1
during peak period (gr)	GWh/y	34 7	34 7	34 7	23 9	24 9	208 6	208 6	208 6	211 1	211 1	211 1	211 1	211 1	212 8	212 8	212 8	212 8	212 8	213 3
during high tarriff (gr)	GWh/y	40 6	40 5	40 5	27 9	29 2	233 1	233 1	233 1	236 9	236 9	236 9	236 9	236 9	238 8	238 8	238 8	238 8	238 8	239 4
during low tarriff (gr)	GWh/y	134 7	134 7	134 7	92 8	97 1	542 9	542 9	542 9	548 8	548 8	548 8	548 8	548 8	553 2	553 2	553 2	553 2	553 2	554 5
			0	0				0	0		0	0	0	0		0	0	0	0	
			0	0				0	0		0	0	0	0		0	0	0	0	
Total Fuel	TJ/y	4 935	4 935	4 935	4 743	5 917	9,354	9 354	9 354	9,601	9 601	9 601	9 601	9 601	9,619	9 619	9 619	9 619	9 619	9 652
Capital Cost – Foreign					529 43	529 43														
Capital Cost – Domestic			5 31	23 48	569 93	547 30	13 83	7 24	7 24	7 24	0 93	0 93	0 93	0 93	0 93	0 71	0 71	0 71	0 71	0 71

Variant B1 High Demand		Annual Quantity by year																		
Quantity		1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Fuel Quantity																				
Lignite 10 05 MJ/kg	TJ/y		0	0			2857	2857	2857	2857	2857	2857	2857	2857	2857	2857	2857	2857	2857	2857
Lignite 12 7 MJ/kg	TJ/y	4229	4229	4229	3983	4882		0	0		0	0	0	0		0	0	0	0	
Coal 18 47 MJ/kg	TJ/y		0	0			209	209	209	209	209	209	209	209		0	0	0	0	
Coal 17 38 MJ/kg	TJ/y		0	0			4252	4252	4252	4315	4315	4315	4315	4315	4206	4206	4206	4206	4206	4237
Natural Gas 33 4 MJ/m	TJ/y		0	0	418	455	91	91	91	91	91	91	91	91	171	171	171	171	171	171
Oil 41 6 MJ/kg	TJ/y	18	18	18	117	117	82	82	82	82	82	82	82	82	283	283	283	283	283	283
Limestone quantity	10 tonne/y		0	0			27	27	27	27	27	27	27	27	27	27	27	27	27	27
Ash quantity	10 tonne/y	49 5	49 5	49 5	46 4	56 9	137 1	137 1	137 1	138 3	138 3	138 3	138 3	138 3	132 4	132 4	132 4	132 4	132 4	132 9
Water quantities																				
raw water	10 m /y	1100	1100	1100	1165	1407	1940	1940	1940	1956	1956	1956	1956	1956	1947	1947	1947	1947	1947	1955
softened water	10 m /y	68	68	68	71	96	97	97	97	99	99	99	99	99	99	99	99	99	99	100
demineralized water	10 m /y	359	359	359	352	385	386	386	386	388	386	386	386	386	384	384	384	384	384	384
Labor	staff	293	293	293	293	293	323	323	323	323	323	323	323	323	295	295	295	295	295	295
Electric power prod – gross	GWh/y	158	158	158	136 7	158 7	431 8	431 8	431 8	435 3	435 3	435 3	435 3	435 3	428 9	428 9	428 9	428 9	428 9	430 7
Electric power sales – net	GWh/y	119 3	119 3	119 3	106	118 2	370 3	370 3	370 3	373 4	373 4	373 4	373 4	373 4	367 6	367 6	367 6	367 6	367 6	369 1
during peak period (gr)	GWh/y	26 1	26 1	26 1	22 6	25 9	71 4	71 4	71 4	72	72	72	72	72	70 9	70 9	70 9	70 9	70 9	71 2
during high tarriff (gr)	GWh/y	30 5	30 5	30 5	26 4	30 3	83 3	83 3	83 3	84 1	84 1	84 1	84 1	84 1	82 8	82 8	82 8	82 8	82 8	83 2
during low tarriff (gr)	GWh/y	101 4	101 4	101 4	87 7	100 5	276 9	276 9	276 9	279 3	279 3	279 3	279 3	279 3	275 2	275 2	275 2	275 2	275 2	276 3
Total Fuel	TJ/y	4 247	4 247	4 247	4,498	5 434	7,491	7 491	7,491	7 554	7,554	7 554	7 554	7 554	7 517	7,517	7 517	7,517	7 517	7,548
Capital Cost – Foreign					50 14	50 14														
Capital Cost – Domestic			5 31	23 48	648 06	625 42	13 83	7 24	7 24	7 24	0 93	0 93	92 44	92 44	0 93	0 71	0 71	0 71	0 71	0 71

Exhibit 7-4
ECONOMIC ANALYSIS RESULTS OF EGU AND ENERGOPROJEKT VARIANTS

Variant A1 High Demand		Annual Costs million Kc/y																		
Cost Item	unit/ref	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Feedstock Cost																				
Lignite 10 05 MJ/kg	4		0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0
Lignite 12 7 MJ/kg	1		147 5	154 7	152 0	195 5	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0
Coal 18 47 MJ/kg	2		0 0	0 0	0 0	0 0	22 9	23 3	23 7	24 6	24 6	24 6	24 6	24 6	0 0	0 0	0 0	0 0	0 0	0 0
Coal 17 38 MJ/kg	3		0 0	0 0	0 0	0 0	177 6	180 9	184 4	190 1	190 1	190 1	190 1	190 1	175 9	175 9	175 9	175 9	175 9	176 3
Natural Gas 33 4 MJ/m	8		0 0	0 0	44 9	50 7	782 7	804 4	826 9	852 3	852 3	852 3	852 3	852 3	935 0	935 0	935 0	935 0	935 0	937 6
Oil 41 6 MJ/kg	7		1 4	1 5	10 7	11 4	3 7	3 8	3 9	4 5	4 5	4 5	4 5	4 5	29 9	29 9	29 9	29 9	29 9	30 6
Limestone	340		0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0
Ash disposal cost	100		5 0	5 6	6 0	8 4	10 3	10 3	10 3	17 7	17 7	17 7	17 7	17 7	14 8	14 8	14 8	14 8	14 8	14 8
Water cost																				
raw water	0 56		0 616	0 653	0 733	0 930	1 828	1 846	1 864	1 895	1 895	1 895	1 895	1 895	1 944	1 944	1 944	1 944	1 944	1 950
softened water	12 75		0 867	0 919	1 017	1 444	1 474	1 488	1 503	1 550	1 550	1 550	1 550	1 550	1 550	1 550	1 550	1 550	1 550	1 565
demineralized water	34 43		12 360	13 102	13 617	15 639	15 836	15 994	18 154	16 316	16 316	16 316	16 316	16 316	16 231	16 231	16 231	16 231	16 231	16 231
Labor	121		35 5	35 5	35 5	35 5	36 3	36 3	36 3	36 3	36 3	36 3	36 3	36 3	32 7	32 7	32 7	32 7	32 7	32 7
Electric power prod – gross																				
Electric power sales – net																				
during peak period (gr)	980		−19 31	−20 25	−18 88	−22 08	−273 65	−278 82	−284 11	−290 70	−290 70	−290 70	−290 70	−290 70	−305 41	−305 41	−305 41	−305 41	−305 41	−306 30
during high tarriff (gr)	780		−17 96	−18 84	−17 56	−20 55	−240 63	−245 18	−249 84	−255 71	−255 71	−255 71	−255 71	−255 71	−268 68	−268 68	−268 68	−268 68	−268 68	−269 47
during low tarriff (gr)	690		−52 83	−55 40	−51 59	−60 31	−372 41	−379 44	−386 65	−395 68	−395 68	−395 68	−395 68	−395 68	−415 71	−415 71	−415 71	−415 71	−415 71	−416 87
Maintenance		48 9	48 9	48 9	48 9	48 9	73 3	73 3	73 3	73 3	73 3	73 3	73 3	73 3	71 2	71 2	71 2	71 2	71 2	71 2
Overhead		24 6	24 6	24 6	24 6	24 6	34	34	34	34	34	34	34	34	33	33	33	33	33	33
Other material		1 5	1 5	1 5	1 5	1 5	1 3	1 3	1 3	1 3	1 3	1 3	1 3	1 3	1 2	1 2	1 2	1 2	1 2	1 2
Capital cost – Foreign			0 0	0 0	864 2	885 8	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0
Capital cost – Domestic			5 3	103 1	698 3	676 3	13 8	7 2	7 2	7 2	0 9	0 9	48 7	48 7	0 9	0 7	0 7	0 7	0 7	0 7
TOTAL COST – Variant A1			193	298	1 814	1 854	288	291	300	319	313	313	360	360	324	324	324	324	324	325
PRESENT WORTH (PW)			193	274	1 555	1 472	212	198	189	186	169	158	167	155	129	119	110	102	95	88
CUMULATIVE PW			193	467	2 022	3 494	3 706	3 903	4 093	4 279	4 448	4 604	4 771	4 925	5 054	5 173	5 284	5 386	5 481	5 569

Variant A2 High Demand		Annual Costs million Kc/y																		
Cost Item	unit/ref	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Feedstock Cost																				
Lignite 10 05 MJ/kg	4		0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0
Lignite 12 7 MJ/kg	1		147 5	154 7	152 0	195 5	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0
Coal 18 47 MJ/kg	2		0 0	0 0	0 0	0 0	40 8	41 5	42 3	43 5	43 5	43 5	43 5	43 5	0 0	0 0	0 0	0 0	0 0	0 0
Coal 17 38 MJ/kg	3		0 0	0 0	0 0	0 0	197 5	201 3	205 1	210 7	210 7	210 7	210 7	210 7	213 9	213 9	213 9	213 9	213 9	214 6
Natural Gas 33 4 MJ/m	8		0 0	0 0	44 9	50 7	421 0	432 8	444 8	461 9	461 9	461 9	461 9	461 9	484 6	484 6	484 6	484 6	484 6	486 5
Oil 41 6 MJ/kg	7		1 4	1 5	10 7	11 4	4 0	4 1	4 3	4 5	4 5	4 5	4 5	4 5	51 2	51 2	51 2	51 2	51 2	51 8
Limestone	340		0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0
Ash disposal cost	100		5 0	5 6	6 0	8 4	12 1	12 1	12 1	20 7	20 7	20 7	20 7	20 7	18 0	18 0	18 0	18 0	18 0	18 0
Water cost																				
raw water	0 56		0 616	0 653	0 733	0 930	1 397	1 411	1 425	1 453	1 453	1 453	1 453	1 453	1 460	1 460	1 460	1 460	1 460	1 814
softened water	12 75		0 867	0 919	1 017	1 444	1 474	1 488	1 503	1 550	1 550	1 550	1 550	1 550	1 565	1 565	1 565	1 565	1 565	1 331
demineralized water	34 43		12 360	13 102	13 617	15 639	15 836	15 994	16 154	16 316	16 316	16 316	16 316	16 316	16 231	16 231	16 231	16 231	16 231	14 498
Labor	121		35 5	35 5	35 5	35 5	37 5	37 5	37 5	37 5	37 5	37 5	37 5	37 5	33 3	33 3	33 3	33 3	33 3	33 3
Electric power prod – gross																				
Electric power sales – net																				
during peak period (gr)	980		−19 31	−20 25	−18 88	−22 08	−155 23	−158 16	−161 17	−165 92	−165 92	−165 92	−165 92	−165 92	−167 97	−167 97	−167 97	−167 97	−167 97	−168 64
during high tarriff (gr)	780		−17 96	−18 84	−17 56	−20 55	−129 43	−131 88	−134 38	−138 38	−138 38	−138 38	−138 38	−138 38	−140 10	−140 10	−140 10	−140 10	−140 10	−140 63
during low tarriff (gr)	690		−52 83	−55 40	−51 59	−60 31	−232 79	−237 19	−241 69	−248 83	−248 83	−248 83	−248 83	−248 83	−251 96	−251 96	−251 96	−251 96	−251 96	−252 83
Maintenance		48 9	48 9	48 9	48 9	48 9	66	66	66	66	66	66	66	66	65 1	65 1	65 1	65 1	65 1	65 1
Overhead		24 6	24 6	24 6	24 6	24 6	33 1	33 1	33 1	33 1	33 1	33 1	33 1	33 1	32 4	32 4	32 4	32 4	32 4	32 4
Other material		1 5	1 5	1 5	1 5	1 5	1 5	1 5	1 5	1 5	1 5	1 5	1 5	1 5	1 3	1 3	1 3	1 3	1 3	1 3
Capital cost – Foreign			0 0	0 0	432 1	442 9	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0
Capital cost – Domestic			5 3	103 1	468 8	446 2	13 8	7 2	7 2	7 2	0 9	0 9	92 4	92 4	0 9	0 7	0 7	0 7	0 7	0 7
TOTAL COST – Variant A2			193	298	1 152	1 181	329	329	336	353	347	347	438	438	360	360	360	360	360	359
PRESENT WORTH (PW)			193	274	988	937	242	224	212	206	187	173	203	188	143	132	122	113	105	97
CUMULATIVE PW			193	467	1 455	2 392	2 634	2 858	3 069	3 275	3 462	3 636	3 838	4 026	4 169	4 301	4 424	4 537	4 642	4 739

Exhibit 7-4 (continued)
ECONOMIC ANALYSIS RESULTS OF EGU AND ENERGOPROJEKT VARIANTS

Variant A4 High Demand		Annual Costs million Kc/y																		
Cost Item	unit/ref	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Feedstock Cost																				
Lignite 10 05 MJ/kg	4		0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0
Lignite 12 7 MJ/kg	1		162 3	170 2	167 6	42 6	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0
Coal 18 47 MJ/kg	2		0 0	0 0	5 2	8 3	3 2	3 3	3 3	3 6	3 6	3 6	3 6	3 6	0 0	0 0	0 0	0 0	0 0	0 0
Coal 17 38 MJ/kg	3		0 0	0 0	0 0	199 2	135 9	138 5	141 1	155 8	155 8	155 8	155 8	155 8	156 3	156 3	156 3	156 3	156 3	157 4
Natural Gas 33 4 MJ/m	8		26 3	27 3	28 9	98 8	772 6	794 1	816 2	842 8	842 8	842 8	842 8	842 8	850 6	850 6	850 6	850 6	850 6	852 4
Oil 41 6 MJ/kg	7		1 6	1 7	1 8	2 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0
Limestone	340		0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0
Ash disposal cost	100		6 2	7 1	7 3	10 6	6 8	6 8	6 8	12 4	12 4	12 4	12 4	12 4	12 2	12 2	12 2	12 2	12 2	12 3
Water cost																				
raw water	0 56		0 616	0 653	0 733	0 930	1 612	1 628	1 645	1 674	1 674	1 674	1 674	1 674	1 702	1 702	1 702	1 702	1 702	1 882
softened water	12 75		0 867	0 919	1 017	1 444	1 474	1 488	1 503	1 550	1 550	1 550	1 550	1 550	1 565	1 565	1 565	1 565	1 565	1 331
demineralized water	34 43		12 360	13 102	13 617	15 639	15 836	15 994	16 154	16 316	16 316	16 316	16 316	16 316	16 231	16 231	16 231	16 231	16 231	14 498
Labor	121		35 5	35 5	35 5	35 5	37 5	37 5	37 5	37 5	37 5	37 5	37 5	37 5	33 3	33 3	33 3	33 3	33 3	33 3
Electric power prod – gross																				
Electric power sales – net																				
during peak period (gr)	980		−26 85	−28 15	−17 69	−18 68	−229 53	−233 87	−238 31	−245 63	−245 63	−245 63	−245 63	−245 63	−247 59	−247 59	−247 59	−247 59	−247 59	−248 18
during high tarriff (gr)	780		−24 94	−28 15	−16 44	−17 44	−204 14	−208 00	−211 95	−219 39	−219 39	−219 39	−219 39	−219 39	−221 14	−221 14	−221 14	−221 14	−221 14	−221 70
during low tarriff (gr)	690		−73 37	−76 94	−48 42	−51 30	−420 59	−428 54	−436 69	−449 60	−449 60	−449 60	−449 60	−449 60	−453 18	−453 18	−453 18	−453 18	−453 18	−454 25
Maintenance		48 9	48 9	48 9	48 9	48 9	66	66	66	66	66	66	66	66	65 1	65 1	65 1	65 1	65 1	65 1
Overhead		24 6	24 6	24 6	24 6	24 6	33 1	33 1	33 1	33 1	33 1	33 1	33 1	33 1	32 4	32 4	32 4	32 4	32 4	32 4
Other material		1 5	1 5	1 5	1 5	1 5	1 5	1 5	1 5	1 5	1 5	1 5	1 5	1 5	1 3	1 3	1 3	1 3	1 3	1 3
Capital cost – Foreign			0 0	0 0	569 9	584 1	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0
Capital cost – Domestic			5 3	23 5	569 9	547 3	13 8	7 2	7 2	7 2	0 9	0 9	0 9	0 9	0 9	0 7	0 7	0 7	0 7	0 7
TOTAL COST – Variant A1			**201**	**224**	**1 394**	**1 534**	**235**	**237**	**245**	**265**	**259**	**259**	**259**	**259**	**250**	**250**	**250**	**250**	**250**	**248**
PRESENT WORTH (PW)			**201**	**207**	**1 195**	**1 218**	**173**	**161**	**154**	**155**	**140**	**129**	**120**	**111**	**99**	**92**	**85**	**79**	**73**	**67**
CUMULATIVE PW			**201**	**408**	**1 603**	**2 821**	**2 993**	**3 154**	**3 309**	**3 463**	**3 603**	**3 732**	**3 852**	**3 963**	**4 062**	**4 154**	**4 239**	**4 318**	**4 391**	**4 458**

Variant B1 High Demand		Annual Costs million Kc/y																		
Cost Item	unit/ref	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Feedstock Cost																				
Lignite 10 05 MJ/kg	4		0 0	0 0	0 0	0 0	110 2	112 3	114 4	116 6	116 6	116 6	116 6	116 6	116 6	116 6	116 6	116 6	116 6	116 6
Lignite 12 7 MJ/kg	1		147 5	154 7	152 0	195 5	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0
Coal 18 47 MJ/kg	2		0 0	0 0	0 0	0 0	13 1	13 3	13 6	13 8	13 8	13 8	13 8	13 8	0 0	0 0	0 0	0 0	0 0	0 0
Coal 17 38 MJ/kg	3		0 0	0 0	0 0	0 0	228 1	230 3	234 7	242 7	242 7	242 7	242 7	242 7	236 6	236 6	236 6	236 6	236 6	238 4
Natural Gas 33 4 MJ/m	8		0 0	0 0	44 9	50 7	10 4	10 7	11 0	11 3	11 3	11 3	11 3	11 3	21 3	21 3	21 3	21 3	21 3	21 3
Oil 41 6 MJ/kg	7		1 4	1 5	10 7	11 4	8 2	8 5	8 7	9 0	9 0	9 0	9 0	9 0	31 0	31 0	31 0	31 0	31 0	31 0
Limestone	340		0 0	0 0	0 0	0 0	9 2	9 2	9 2	9 2	9 2	9 2	9 2	9 2	9 2	9 2	9 2	9 2	9 2	9 2
Ash disposal cost	100		5 0	5 6	6 0	8 4	20 3	20 3	20 3	34 8	34 8	34 8	34 8	34 8	33 3	33 3	33 3	33 3	33 3	33 5
Water cost																				
raw water	0 56		0 616	0 653	0 733	0 930	1 295	1 307	1 321	1 345	1 345	1 345	1 345	1 345	1 339	1 339	1 339	1 339	1 339	1 344
softened water	12 75		0 867	0 919	1 017	1 444	1 474	1 488	1 503	1 550	1 550	1 550	1 550	1 550	1 550	1 550	1 550	1 550	1 550	1 565
demineralized water	34 43		12 360	13 102	13 617	15 639	15 836	15 994	16 154	16 316	16 316	16 316	16 316	16 316	16 231	16 231	16 231	16 231	16 231	16 231
Labor	121		35 5	35 5	35 5	35 5	39 1	39 1	39 1	39 1	39 1	39 1	39 1	39 1	35 7	35 7	35 7	35 7	35 7	35 7
Electric power prod – gross																				
Electric power sales – net																				
during peak period (gr)	980		−19 31	−20 25	−18 88	−22 08	−70 52	−71 85	−73 22	−75 23	−75 23	−75 23	−75 23	−75 23	−74 02	−74 02	−74 02	−74 02	−74 02	−74 32
during high tarriff (gr)	780		−17 96	−18 84	−17 56	−20 55	−65 48	−66 72	−67 99	−69 94	−69 94	−69 94	−69 94	−69 94	−68 80	−68 80	−68 80	−68 80	−68 80	−69 12
during low tarriff (gr)	690		−52 83	−55 40	−51 59	−60 31	−192 56	−196 20	−199 93	−205 47	−205 47	−205 47	−205 47	−205 47	−202 28	−202 28	−202 28	−202 28	−202 28	−203 07
Maintenance		48 9	48 9	48 9	48 9	48 9	73 9	73 9	73 9	73 9	73 9	73 9	73 9	73 9	69 7	69 7	69 7	69 7	69 7	69 7
Overhead		24 6	24 6	24 6	24 6	24 6	37 2	37 2	37 2	37 2	37 2	37 2	37 2	37 2	35 4	35 4	35 4	35 4	35 4	35 4
Other material		1 5	1 5	1 5	1 5	1 5	2	2	2	2	2	2	2	2	1 7	1 7	1 7	1 7	1 7	1 7
Capital cost – Foreign			0 0	0 0	54 0	55 3	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0
Capital cost – Domestic			5 3	23 5	648 1	625 4	13 8	7 2	7 2	7 2	0 9	0 9	92 4	92 4	0 9	0 7	0 7	0 7	0 7	0 7
TOTAL COST – Variant A1			**193**	**216**	**953**	**972**	**254**	**248**	**249**	**265**	**259**	**259**	**351**	**351**	**265**	**265**	**265**	**265**	**265**	**266**
PRESENT WORTH (PW)			**193**	**200**	**817**	**772**	**186**	**169**	**157**	**155**	**140**	**130**	**162**	**150**	**105**	**98**	**90**	**84**	**77**	**72**
CUMULATIVE PW			**193**	**393**	**1 211**	**1 983**	**2 169**	**2 338**	**2 495**	**2 650**	**2 790**	**2 920**	**3 082**	**3 232**	**3 338**	**3 435**	**3 528**	**3 609**	**3 687**	**3 758**

The following sections include a summary of the work conducted by EGU and Energoprojekt

7 2 SUMMARY OF EGU ANALYSIS OF VARIANTS A1, A2, AND B1

EGU started with the 1991 study by Energoprojekt and developed variants quite similar in concept to those previously investigated EGU played a significant role in the analysis of the small boiler population in Plzen to determine the potential for additional capacity requirements They established the following conditions to begin the analysis

- Conservation measures will be effective in reducing the heat requirements for the central system
- Construction of concentrated blocks of new multistory housing is not likely in the near future
- No increase of heat requirements from industrial concerns is expected due to the likely implementation of heat saving technologies
- A large scale reconstruction of gas supply in the City of Plzen is taking place, focusing on the change from Town Gas to Natural Gas Also a switch from solid fuels (coke and coal) to gas is occurring now This switch to gas is also available for major heat sources as soon as the capacity of the high pressure gas system is completed in Plzen
- All heat sources are required to comply with the new Clean Air Act

EGU considered that the development of the District Heating system (DHS) will now be in competition with natural gas, i e people will have choices between the DHS and forms of decentralized supply

It was EGU's opinion that the sources operated by TEZA are obsolete, past their useful life, and are not suitable for reconstruction to meet environmental standards, and that the best alternative is to connect these small systems to the central CP Plzen system, and liquidate the boilers If the systems are not connected, EGU recommends converting these boilers to natural gas

EGU has investgated the needs of other boilers operated by ZCE to convert to bituminous coal firing, and have calculated the associated capital costs

In general, EGU supports cogeneration for the system, and its capability to reduce the overall cost of heat by the increased production of electricity for internal use and sale To further improve the effectiveness of the system, cogeneration units should be run for more hours in the year, instead of the current situation where the large turbine-generator is not able to run during low demand periods due to minimum load restrictions

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While the capacity of existing network mains was not the focus of this study, EGU suggests that overcapacity, especially in the oversized South main, should be exploited by adding new consumers wherever possible

EGU proceeded to develop variants (presented in Section 6 0), and performed calculations necessary to develop fuel requirements and commodity uses as input to the economic analysis Their development of plant sizes is logical, and covers the projected high and low demands

An example of the procedure used by EGU is presented below for Variant A2, High Demand Their general approach was also used by Gilbert/Commonwealth as a template in the development of a computer model to evaluate the variants

Baseline input for the economic analysis included projected cost of fuels and other commodities, as well as capital costs of equipment modifications and additions were prepared They are contained in Appendix C

First, the demands were characterized as outlined in Section 5 0 The hot water and steam demands were represented as being covered by heat sources as shown in Exhibit 7-5 Calculations were made for each tariff period for the points shown in Exhibits 7-6 and 7-7 for hot water and steam delivery respectively Gas consumption and power output, as intermediate calculations, are shown in Exhibit 7-8 A summary of the calculation results are shown in Exhibit 7-9 Contained in this table are many of the necessary inputs to the economic analysis Further results containing calculations of emissions, ash production, operating personnel and water consumption are shown in Exhibit 7-10

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Exhibit 7-5
SUMMARY OF REQUIRED HEAT SOURCES BY YEAR - VARIANT A2 (EGU)

Alternat A var 2 Heat supply hot water high balance								Tab 7 a)
Year		1992	1995	1996	1^97	2000	2005	2010
Hot water demands brutto	MWt	207 0	215 5	291 8	295 7	299 5	302 0	304 0
	TJ/y	1990	2074	2801	2836	2871	2889	2906
Heat supply								
CP Plzeň I HWB	MWt	105 0	105 0	105 0	105 0	105 0		
	TJ/y	670	750	1100	482	486		
II HPP	MWt	95 0	70 0	70 0	82 7	86 5	78 0	80 0
	TJ/y	1311	1245	1460	1230	1247	1243	1250
III SB 65 t/h	MWt				43 0	43 0	43 0	43 0
	TJ/y				34	35	36	36
IV CC 1 x V 64 3	MWt				65 0	65 0	65 0	65 0
	TJ/y				1090	1103	1115	1120
V HWB	MWt						116 0	116 0
	TJ/y						495	500
CP Plzeň total	MWt	200 0	175 0	175 0	295 7	299 5	302 0	304 0
	TJ/y	1981	1995	2560	2836	2871	2889	2906
Interconennected units								
Peak HP Košutka	MWt	7 0	32 0	32 0				
HP Bory	MWt			30 0				
HP V1 + V2	MWt			45 0				
Interconennected units total	MWt	7 0	32 0	107 0				
	TJ/y	9	79	241				
Units total	MWt	207 0	207 0	282 0	295 7	299 5	302 0	304 0
	TJ/y	1990	2074	2801	2836	2871	2889	2906
Not covered	MWt	0 0	8 5	9 8	0 0	0 0	0 0	0 0

Alternative A var 2 Heat supply steam high balance								Tab 7 b)
Year		1992	1995	1996	1997	2000	2005	2010
Heat balance Plzeň steam	MWt	93 0	91 1	99 8	100 0	100 0	99 6	99 6
	TJ/y	1125	1102	1207	1300	1300	1290	1290
Heat supply								
CP Plzeň II HPP	MWt	70 0	11 0	11 0	78 5	78 5	85 0	85 0
	TJ/y	730	500	540	850	850	886	886
III SB 65 t/h	MWt		43 5	43 5	(41 5)	(41 5)	(41 5)	(41 5)
	TJ/y		467	500	285	285	285	285
IV CC 1 x V 64 3	MWt				(25 0)	(25 0)	(25 0)	(25 0)
	TJ/y				100	100	100	100
CP Plzeň total	MWt	70 0	54 5	54 5	78 5	78 5	85 0	85 0
	TJ/y	730	967	1040	1235	1235	1271	1271
Interconennected units								
BH Brevery	MWt	23 0	36 6	45 3	21 5	21 5	14 6	14 6
	TJ/y	395	135	167	65	65	19	19
Units total	MWt	93 0	91 1	99 8	100 0	100 0	99 6	99 6
	TJ/y	1125	1102	1207	1300	1300	1290	1290
Not covered	MWt	0 0	0 0	0 0	0 0	0 0	0 0	0 0

Abreviations
SB Steam Boiler
BH Boiler House
HWB Hot Water Boiler
CC Combined Cycle
HPP High Pressure Part of CP

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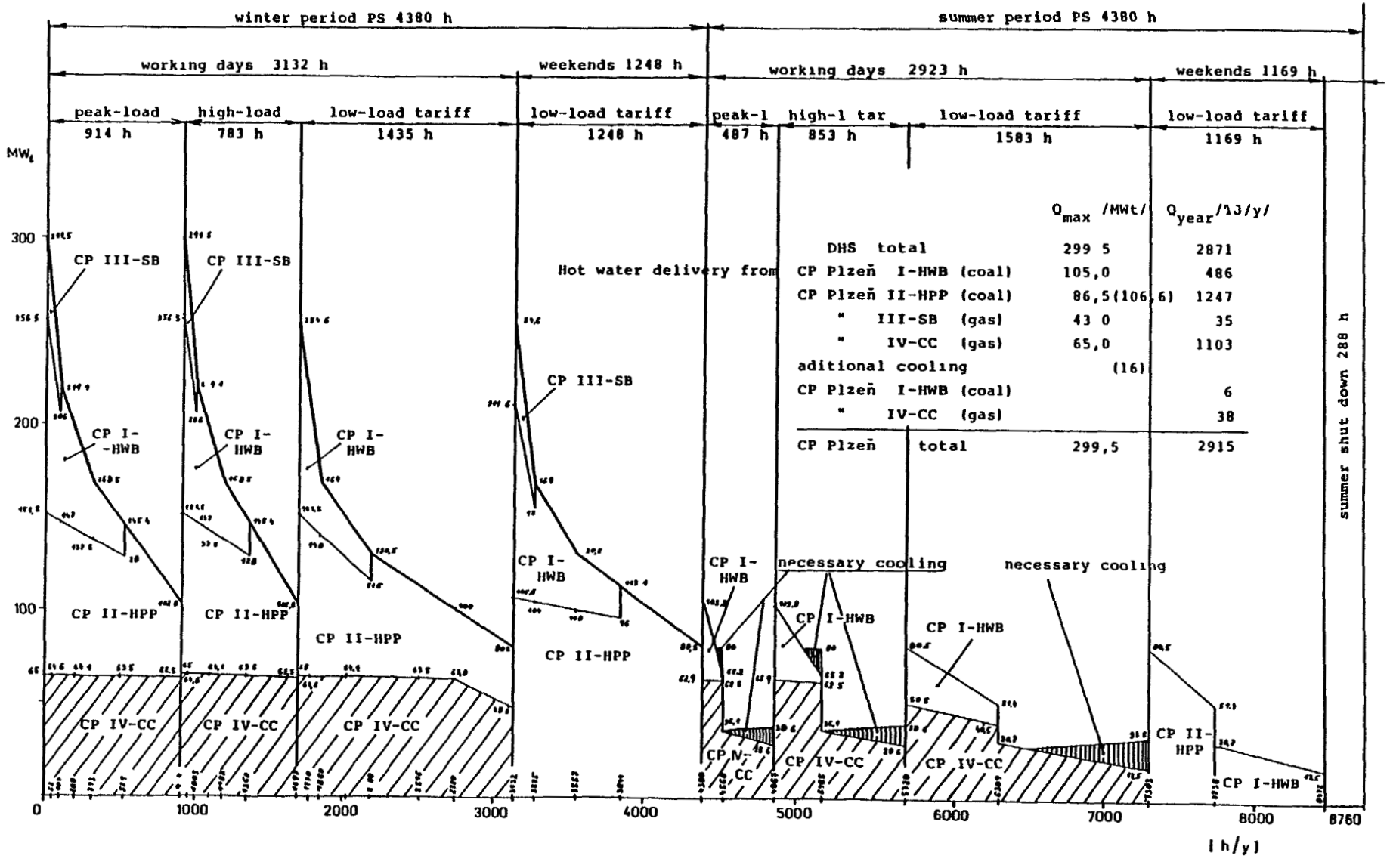
Exhibit 7-6
HOT WATER DELIVERY LOGIC - YEAR 2000 - VARIANT A2 (EGU)

CP Plzen Alt A Var 2 year 2000 - high balance - CC with 1x GT V64 3 Siemens + 1x back-pressure steam turbine with extraction

Diagram of hot water delivery (lasting curve according to the ambient temperature) divided into particular tariff ranges in Power system (PS)

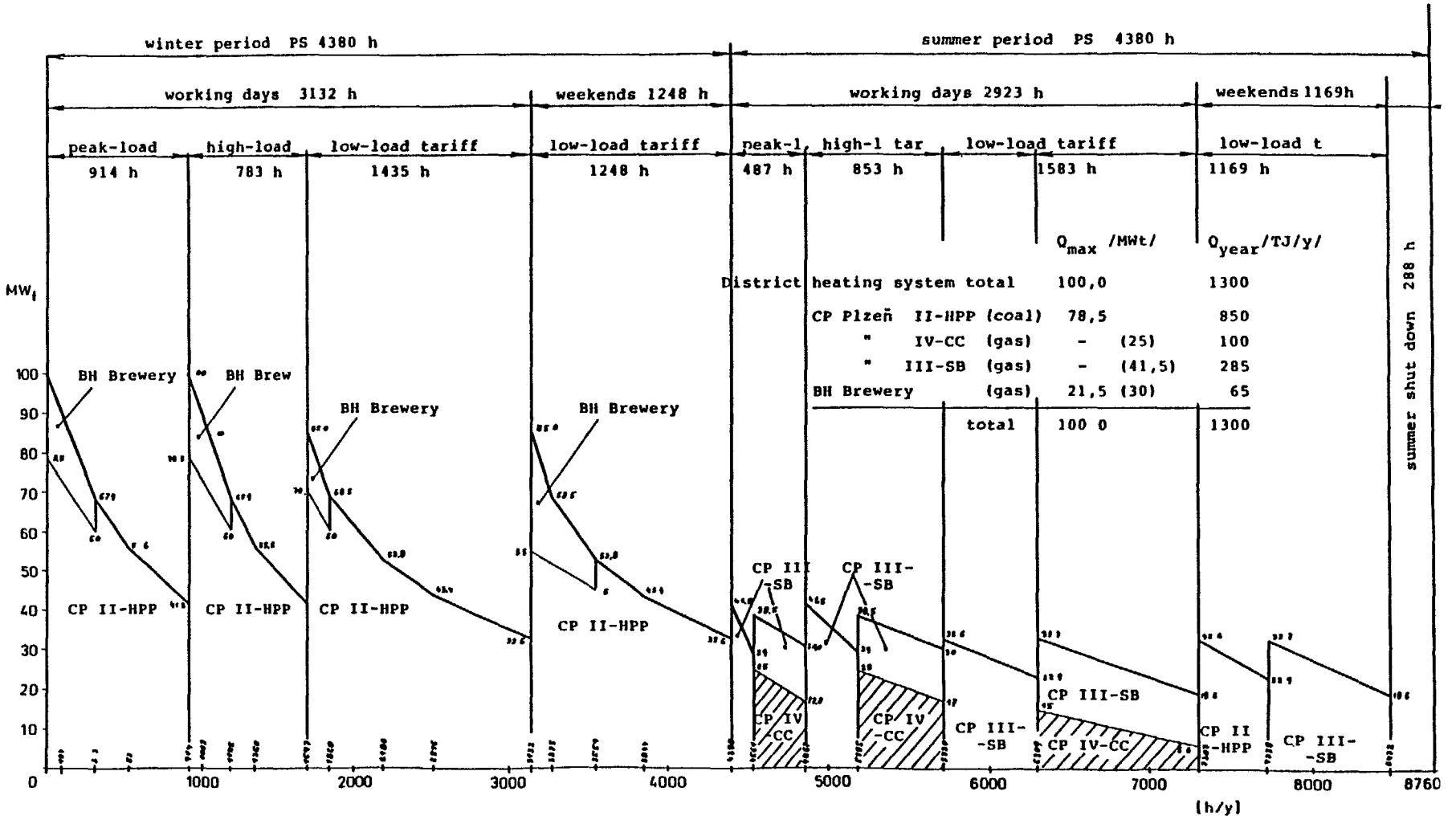


	Q_{max} /MWt/	Q_{year} /TJ/y/
DHS total	299 5	2871
CP Plzeň I-HWB (coal)	105,0	486
CP Plzeň II-HPP (coal)	86,5 (106,6)	1247
" III-SB (gas)	43 0	35
" IV-CC (gas)	65,0	1103
aditional cooling	(16)	
CP Plzeň I-HWB (coal)		6
" IV-CC (gas)		38
CP Plzeň total	299,5	2915

Exhibit 7-7
STEAM DELIVERY LOGIC - YEAR 2000 - VARIANT A2 (EGU)

CP Plzeň Alt A Var 2 year 2000 - high balance - CC with GT V64 3 Siemens + 1x back-pressure steam turbine with extraction

Diagram of steam delivery (lasting curve according to the ambient temperature) divided into particular tariff ranges in Power system (PS)



	Q_{max} /MWt/	Q_{year}/TJ/y/
District heating system total	100,0	1300
CP Plzeň II-HPP (coal)	78,5	850
" IV-CC (gas)	- (25)	100
" III-SB (gas)	- (41,5)	285
BH Brewery (gas)	21,5 (30)	65
total	100 0	1300

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Exhibit 7-8
ELECTRIC POWER AND GAS CONSUMPTION - YEAR 2000 - VARIANT A2 (EGU)

D9

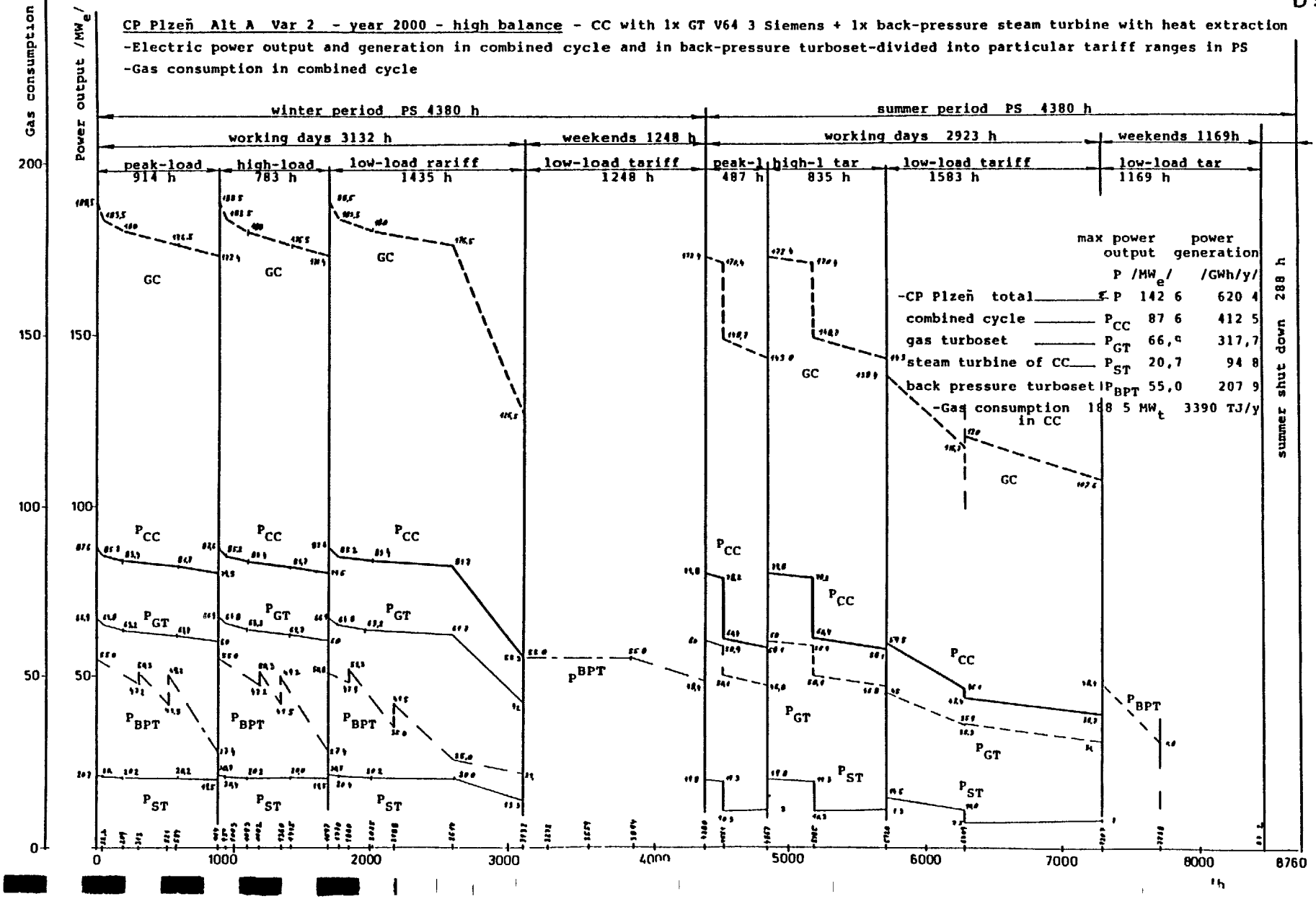

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Exhibit 7-9
OPERATIONS DATA / RESULTS - YEAR 2000 - VARIANT A2 (EGU)

Alternative A Var 2 - High balance
CP PLZEN with CC 1 x GT V 64 3 Siemens + 1 x back - pressure steam turbine with extractions
Heat and power production - operational data - fuel consumption Tab 13

	Units	y 1992	y 1995	y 1996	y 1997	y 2000	y 2005	y 2010
Total installed heat output of steam boilers	MWt	232 9	160 0	160 0	276 2	276 2	276 2	276 2
Total steam mass flow	t/h	340	235	235	405	405	405	405
Total installed heat output of hot water boilers	MWt	105 0	105 0	105 0	105 0	105 0	116 0	116 0
Total installed output of waste - heat boilers	MWt				88 5	88 5	88 5	88 5
Total heat output of cogeneration plant (-12°C)	MWt	273 5	233 0	233 0	377 7	381 5	390 5	392 5
in this for domain consumption	MWt	3 5	3 5	3 5	3 5	3 5	3 5	3 5
Outlet heat output for external consumption	MWt	270 0	229 5	229 5	374 2	378 0	387 0	389 0
from which steam	MWt	70 0	54 5	54 5	78 5	78 5	85 0	85 0
hot water	MWt	200 0	175 0	175 0	295 7	299 5	302 0	304 0
Heat supply per year steam	TJ/y	730	967	1040	1235	1235	1271	1271
Heat supply per year - hot water	TJ/y	2015	2029	2594	2870	2905	2923	2940
from which domain consumption	TJ/y	34	34	34	34	34	34	34
external consumption	TJ/y	1981	1995	2560	2836	2871	2889	2906
Heat production total	TJ/y	2745	2996	3634	4105	4140	4194	4211
Power output - CP II	MWe	55 0	55 0	55 0	55 0	55 0	55 0	55 0
Power output - CC (-12°C)	MWe				87 6	87 6	87 6	87 6
Total power output of CP (-12°C)	MWe	55 0	55 0	55 0	142 6	142 6	142 6	142 6
Average power output CP during peak load tariff	MWe	18 6	16 1	18 5	104 9	106 0	107 2	107 7
Total electric power generation - brutto	GWh/y	158 0	136 7	156 7	614 2	620 4	627 7	630 1
from which in peak load tariff zone	GWh/y	26 1	22 6	25 9	147 0	148 5	150 2	150 8
in high load tariff zone	GWh/y	30 5	26 4	30 3	154 0	155 6	157 4	158 0
in low load tariff zone	GWh/y	101 4	87 7	100 5	313 1	316 3	320 0	321 2
Total electric power generation - netto	GWh/y	152 0	132 2	151 6	599 4	605 4	612 6	614 9
Electricity consumption for elect production	GWh/y	6 0	4 5	5 1	14 8	15 0	15 1	15 2
Electricity consumption for heat production	GWh/y	26 7	19 1	22 9	22 6	22 7	22 3	22 3
Pumping energy	GWh/y	6 0	7 1	10 5	13 4	13 6	14 0	14 1
Total electricity consumption	GWh/y	32 7	26 2	33 4	36 0	36 3	36 3	36 4
Heat consumption in fuel for heat production	TJ/y	3475	3793	4632	4997	5040	5015	5035
Specific heat consumpt in fuel per heat product	GJ/GJ	1 27	1 27	1 27	1 22	1 22	1 20	1 20
Heat consumption in fuel for elect generation	TJ/y	772	705	802	3086	3117	3152	3165
Specific heat consumpt in fuel per elect generat	GJ/MWh	4 89	5 16	5 12	5 02	5 02	5 02	5 02
Total fuel consumption	TJ/y	4247	4498	5434	8083	8157	8167	8200
from which lignite 12 7 MJ/kg	TJ/y	4229	3963	4862				
	th t/y	333 0	312 0	382 8				
coal 18,47 MJ/kg	TJ/y				651	657		
	th t/y				35 2	35 6		
coal 17,38 MJ/kg	TJ/y				3715	3745	3802	3814
	th t/y				213 8	215 5	218 8	219 4
natural gas 33,4 MJ/m3	TJ/y		418	455	3677	3714	3897	3912
	mil m3/y		12 5	13 6	110 1	111 2	116 7	117 1
oil 41 6 MJ/kg	TJ/y	18	117	117	40	41	468	474
	th t/y	4	2 8	2 8	1 0	1 0	11 3	11 4

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Exhibit 7-10
OTHER OPERATIONS RESULTS YEAR 2000 - VARIANT A2 (EGU)

Alternative A - Emission, slagg production personnel, water cosumption — Tab 19

	Units	y 1992	y 1995	y 1996	y 1997	y 2000	y 2005	y 2010
Alternative A Var 1 - High balance								
Emission ash	t/y	425 5	407 5	498 1	117 9	118 9	129 1	129 7
Emission SO2	t/y	4437 4	4206 5	5148 0	2031 2	2057 5	1640 5	1847 7
Emission NOx	t/y	1003 3	1010 6	1227 0	2643 9	2669 4	2517 7	2525 4
Emission CO	t/y	166 8	161 1	196 8	171 6	173 3	154 6	155 1
Emission CxHx	t/y	50 1	48 6	59 3	49 3	49 9	40 9	41 1
Slagg production	th t/y	49 5	46 4	56 9	69 4	70 2	58 6	58 7
Number of personnel	pers	293	293	293	300	300	270	270
Water consumption - raw	th m3/y	1100	1165	1407	2739	2757	2828	2837
- softened	th m3/y	68	71	96	97	99	99	100
- demineral	th m3/y	359	352	385	386	386	384	384
Alternative A Var 1 - Low balance								
Emission ash	t/y	425 5	390 0	466 1	111 1	107 6	111 6	111 3
Emission SO2	t/y	4437 4	4024 3	4819 1	1831 3	1782 2	1664 4	1655 7
Emission NOx	t/y	1003 3	969 1	1147 9	2452 0	2379 8	2363 7	2355 5
Emission CO	t/y	166 8	154 2	184 0	161 1	156 0	145 1	144 7
Emission CxHx	t/y	50 1	46 5	55 5	46 2	44 7	37 0	36 9
Slagg production	th t/y	49 5	44 4	53 3	62 7	61 1	56 7	56 4
Number of personnel	pers	293	293	293	300	300	266	266
Water consumption - raw	th m3/y	1100	1119	1314	2633	2545	2642	2638
- softened	th m3/y	68	68	90	90	85	85	85
- demineral	th m3/y	359	352	349	343	343	343	343
Alternative A Var 2 - High balance								
Emission ash	t/y	425 5	407 5	498 1	99 2	100 1	118 4	119 0
Emission SO2	t/y	4437 4	4206 5	5146 0	2384 7	2404 7	2303 2	2312 6
Emission NOx	t/y	1003 3	1010 6	1227 0	2605 1	2627 4	2513 0	2522 3
Emission CO	t/y	166 8	161 1	196 8	172 4	173 9	147 5	148 1
Emission CxHx	t/y	50 1	48 6	59 3	55 6	56 1	43 3	43 4
Slagg production	th t/y	49 5	46 4	56 9	81 7	82 3	71 3	71 5
Number of personnel	pers	293	293	293	310	310	275	275
Water consumption - raw	th m3/y	1100	1165	1407	2093	2113	2115	2124
- softened	th.m3/y	68	71	96	97	99	99	100
- demineral	th m3/y	359	352	385	386	386	384	384
Alternative A Var 2 - Low balance								
Emission ash	t/y	425 5	390 0	466 1	101 4	97 5	96 3	96 3
Emission SO2	t/y	4437 4	4024 3	4819 1	2189 2	2123 2	1938 9	1938 9
Emission NOx	t/y	1003 3	969 1	1147 9	2387 8	2317 1	2191 0	2191 0
Emission CO	t/y	166 8	154 2	184 0	151 2	146 4	128 9	128 9
Emission CxHx	t/y	50 1	46 5	55 5	47 3	45 6	36 6	36 6
Slagg production	th t/y	49 5	44 4	53 3	71 5	69 6	62 8	62 8
Number of personnel	pers	293	293	293	310	310	271	271
Water consumption - raw	th m3/y	1100	1119	1314	1971	1904	1866	1866
- softened	th m3/y	68	68	90	90	85	85	85
- demineral	th m3/y	359	352	349	343	343	343	343

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7 4 ENERGOPROJEKT ANALYSIS OF VARIANT A4

Energoprojekt analyzed the potential of Variant A4, which adds capacity to the system with a Gas Turbine Combined Cycle based on an ABB 90 MWe gas turbine Energoprojekt also recommended greater cooperation with the Brewery source of steam, and suggested that the Plzen III steam generator suggested by EGU would not be required This section provides a summary of their activities A full report supplied by Energoprojekt is provided as Appendix D

Energoprojekt utilized the high and low demand scenarios agreed upon by G/C, RAEN, and EGU, which assumes the connection of Heat Line East I, and also the same connections of new users and connection of other users from the area of feeders South, North and East I (after construction) Energoprojekt also used data on the current state (heat sources) and some other data (such as bituminous coal data from Zbuch) provided through the work of EGU and RAEN

Energoprojekt agreed with EGU in the opinion that many of the older units should be retired because of age and the difficulty to retrofit environmental controls

Energoprojekt assumed that Plzen II would not be out of service for the peak of the heating season, and that reconstruction of these boilers to meet environmental regulations could take place during the interim period If this was not possible, they recommended using a mobile hot water boiler to meet the shortfall

Results prepared by Energoprojekt are similar in form to the EGU work The full deliverable provided by Energoprojekt is presented in Appendix D In summary, their work shows consistency with the results of EGU and G/C in their gas turbine based variants Their ideas about enlarged cooperation of the Brewery and maintaining capability of Plzen II during the peak season deserve further consideration

Energoprojekt provided independent cost estimates to match the strategy they prepared for Variant A4 They took into account the cost of providing an ash disposal site for CP Plzen to accommodate future ash disposal requirements Also, they provided costs for changes/upgrades to the Brewery boilers which cooperate with the steam distribution system

Energoprojekt also provided some good insight into coming changes in commodity prices, financing possibilities, and other issues They provided a sound basis for changing prices in fuels This information was used extensively to guide the study effort

The Energoprojekt calculations proceeded in a similar fashion to EGU, using the same demands as characterized in Section 5 0 The hot water and steam demands were represented as being covered by heat sources as shown in Exhibit 7-11 Calculations were made for each tariff period for the points shown in Exhibits 7-12 and 7-13 for hot water and steam delivery respectively Power output was then calculated as shown in Exhibit 7-14 A summary of the calculation results are shown in Exhibits 7-15 and 7-16 Contained in these tables are many of the necessary inputs to the economic analysis

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Exhibit 7-11
SUMMARY OF REQUIRED HEAT SOURCES BY YEAR - VARIANT A4 (ENERGOPROJEKT)

HIGH BALANCE
CP Plzen with CC 1 x GT 13 ABB + 1 x condense steam turbine with two heat extractions

	Units	y 1992	y 1995	y 1996	y 1997	y 2000	y 2005	y 2010
Total installed heat output of steam boilers	[MW]	232 9	232 9	232 9	232 9	232 9	232 9	232 9
Total steam mass flow	[t/h]	340	340	340	340	340	340	340
Total installed heat output of brewery	[MW]	56 1	56 1	56 1	56 1	56 1	56 1	56 1
Total steam mass flow	[t/h]	86	86	86	86	86	86	86
Total installed heat output of hot water boilers	[MWt]	105	105	105	105	105	35	35
Total installed output of waste heat boiler	[MWt]				180	180	180	180
Total heat demand (12 C)	[MWt]	303 5	310 1	395 1	399 2	403	405 1	407 1
from which own consumption HP Plzen	[MWt]	3 5	3 5	3 5	3 5	3 5	3 5	3 5
external consumption	[MWt]	300	306 6	391 6	395 7	399 5	401 6	403 6
from which steam	[MWt]	93	91 1	99 8	100	100	99 6	99 6
hot water	[MWt]	207	215 5	291 8	295 7	299 5	302	304
Covered by sources (external consumption)								
HP Kosutka	[MWt]			18 1				
HP Bory	[MWt]			22 9				
HP Letna, Doubravka (V 1 V 2)	[MWt]			39 5				
HP ZOS (Railway Maint Co)	[MWt]							
HP Pivovar (Brewery)	[MWt]	20 5	27 1	31 6			54 5	54 5
HP Plzen	[MWt]	279 5	279 5	279 5	395 7	399 5	342 5	342 5
uncovered	[MWt]						4 6	6 6
Heat supply per year steam	[TJ/y]	1125	1102	1207	1300	1300	1290	1290
Heat supply per year hot water	[TJ/y]	1990	2074	2801	2386	2871	2889	2906
from which own consumption	[TJ/y]	34	34	34	34	34	34	34
external consumption	[TJ/y]	1956	2039	2766	2802	2837	2854	2872
Heat production total	[TJ/y]	3115	3176	4008	4136	4171	4179	4196
Power output CP II	[MWe]	55	55	55	55	55	55	55
Power output CC (12 C)	[MWe]				141	141	141	141
Total power output of CP (12 C)	[MWe]	55	55	55	196	196	196	196
Total electric power generation brutto	[GWh/y]	209 9	144 7	151 2	984 6	996 8	1004 8	1007 2
from which in peak load tariff zone	[GWh/y]	34 7	23 9	24 9	208 6	211 1	212 8	2213 3
in high load tariff zone	[GWh/y]	40 5	27 9	29 2	233 1	236 9	238 8	239 4
in low load tariff zone	[GWh/y]	134 7	92 9	97 1	542 9	548 8	553 2	554 5
Own electricity consumption	[GWh/y]	38 2	37 3	38 9	31 3	32 1	32 4	32 4
Pumping energy	[GWh/y]	6	6 1	11 9	12 2	12 5	12 6	12 7
Total electricity consumption	[GWh/y]	44 2	45 3	50 8	43 5	44 6	45	45 1
Total electric power generation netto	[GWh/y]	165 7	99 4	100 4	941 1	952 2	959 8	962 1

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Exhibit 7-12
HOT WATER DELIVERY LOGIC - YEAR 2000 - VARIANT A4 (ENERGOPROJEKT)

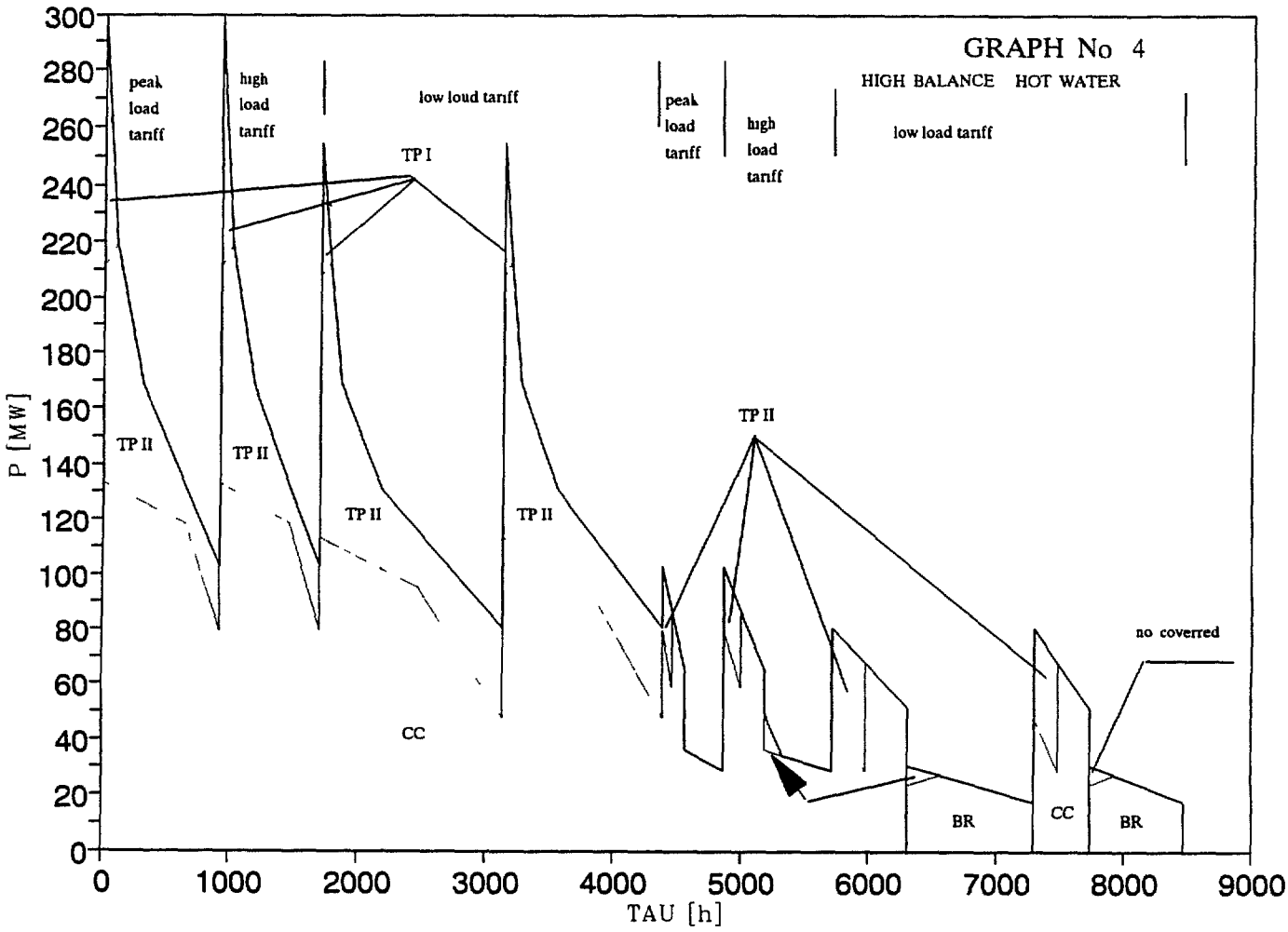

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Exhibit 7-13
STEAM DELIVERY LOGIC - YEAR 2000 - VARIANT A4 (ENERGOPROJEKT)

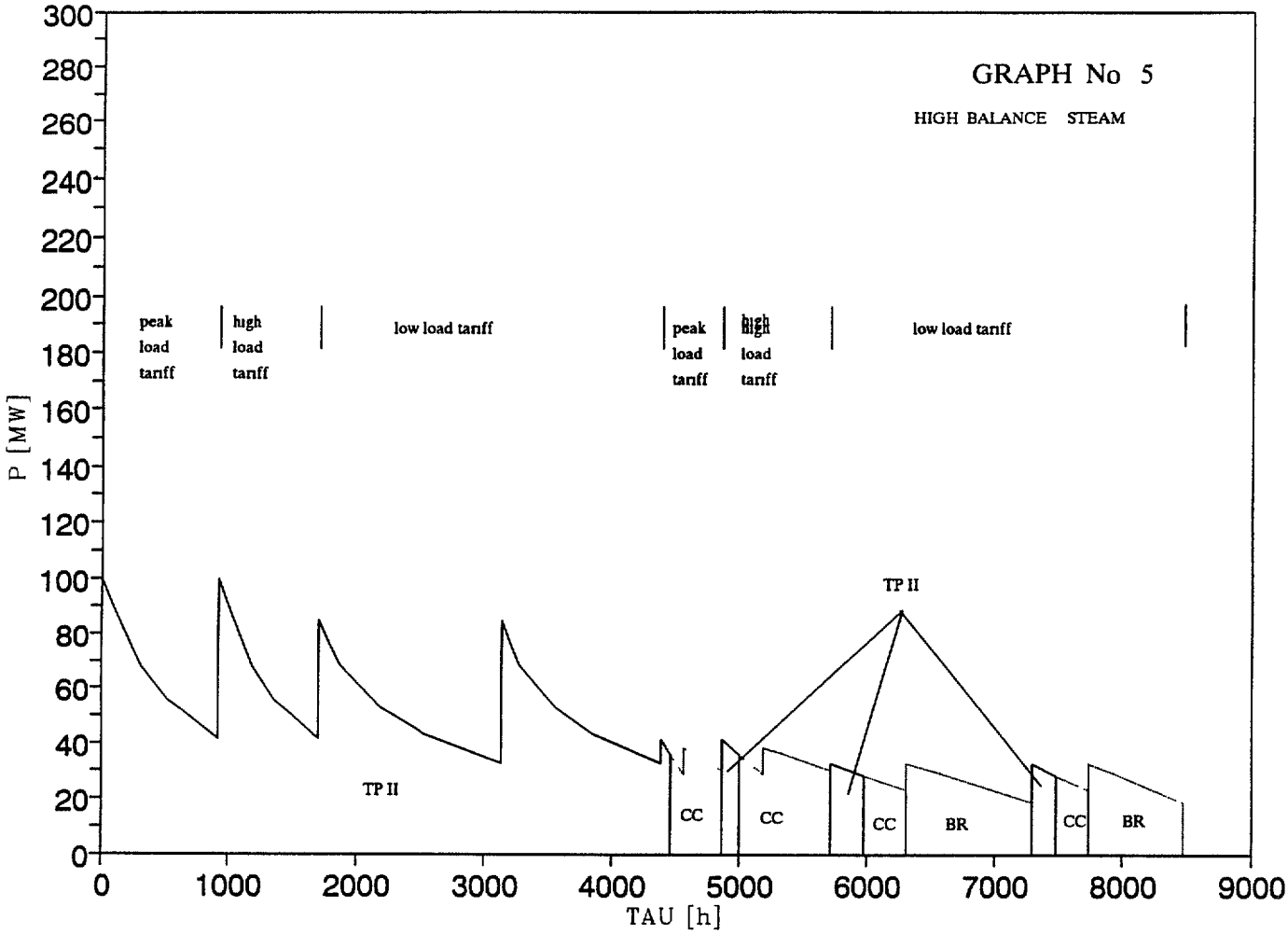

Exhibit 7-14
ELECTRIC POWER PRODUCTION - YEAR 2000 - VARIANT A4 (ENERGOPROJEKT)

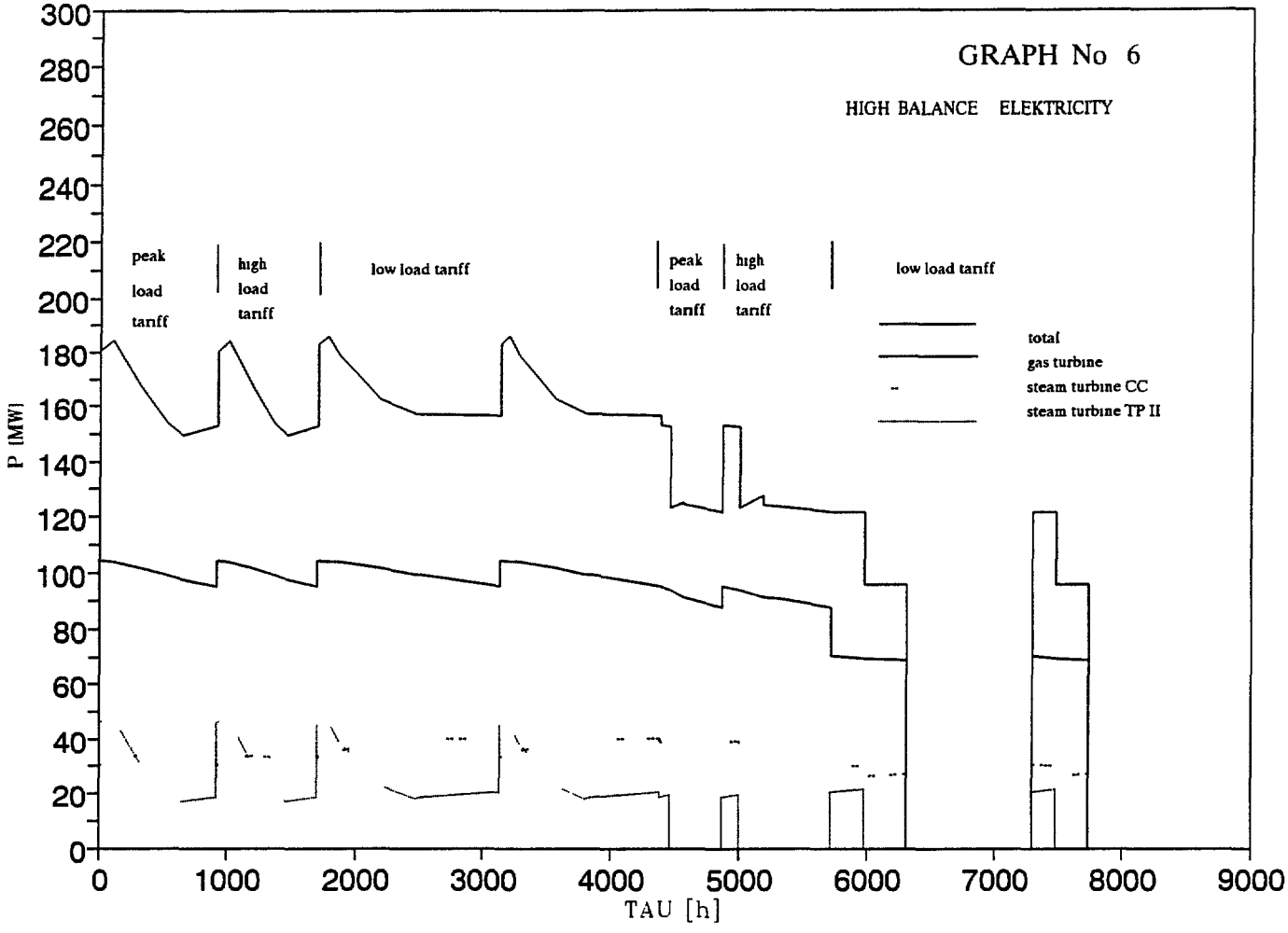

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Exhibit 7-15
TOTAL FUEL CONSUMPTION RESULTS - YEAR 2000 - VARIANT A4 (ENERGOPROJEKT)

HIGH BALANCE total fuel consumption
CP Plzen with CC 1 x GT 13 ABB + 1 x condense steam turbine with two heat extractions

	Units	y 1992	y 1995	y 1996	y 1997	y 2000	y 2005	y 2010
Total fuel consumption	[TJ/y]	4935	4743	5917	9354	9601	9619	9652
from which brown coal 12 7 MJ/kg	[TJ/y]	4652	4370	1058				
	[th t/y]	366 3	344 1	83 3				
bituminous coal 18 47 MJ/kg	[TJ/y]		84	135	51	55		
	[th t/y]		4 5	7 3	2 8	3		
bituminous coal 17 38 MJ/kg	[TJ/y]			3817	2556	2769	2779	2798
	[th t/y]			219 6	147	159 3	159 9	161
natural gas 33 55 MJ/m3	[TJ/y]	263	269	887	6747	6777	6840	6854
	[mil m3/y	7 8	8	26 4	200 5	202 2	203 9	204 3
oil 41 6 MJ/kg	[TJ/y]	20	20	20				
	[th t/y]	0 5	0 5	0 5				

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Exhibit 7-16
OPERATIONS RESULTS - YEAR 2000 - VARIANT A4 (ENERGOPROJEKT)

HIGH BALANCE

Basic operation characteristics of CC with 1 x GT 13 ABB

	Units	y 1997	y2000	y 2005	y 2010
Nominal power output of CC	[MWe]	141	141	141	141
from which nominal power output of GT	[MWe]	105	105	105	105
nominal power output of ST	[MWe]	36	36	36	36
Max thermal output in hot water (12 C)	[MWt]	133	133	133	133
Heat production of CC steam	[TJ/y]	172	191	190	188
hot water	[TJ/y]	2002	1999	2004	2014
total	[TJ/y]	2174	2190	2194	2202
Max power output of CC with delivery of heat in hot water	[MWe]	134 5	134 5	134 5	134 5
Electric power generation of CC brutto					
from gas turbine	[GWh/y]	625 5	630 9	632 1	634 7
from steam turbine	[GWh/y]	234 4	236 3	236 8	237 7
combined cycle total	[GWh/y]	859 9	867 2	868 9	872 4
from which in peak load tariff zone	[GWh/y]	182	183 5	183 9	184 6
in high load tariff zone	[GWh/y]	210 1	211 9	212 3	213 2
in low load tariff zone	[GWh/y]	467 8	471 8	472 7	474 6
Total heat consumption fuel	[TJ/y]	6737	6757	6763	6778
natural gas 33 55 MJ/m3	[mil m3/y]	200 8	201 4	201 6	201 9
Average year efficiency for heat and power generation	%	78 2	78 6	78 7	78 8

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8.0 ANALYSIS OF NEW/REVISED VARIANTS BY GILBERT/COMMONWEALTH

This section summarizes our approach to the analysis of the primary variants introduced in Section 6 0 The variants (options) considered in the Plzen analysis are mainly distinguished by the selection of the plant technology for Plzen IV The basic plant technologies selected for analysis as Plzen IV are a (1) Gas-Fired Gas Turbine Combined Cycle, and (2) a Circulating Fluidized Bed (CFB) boiler The variant naming convention was selected to avoid confusion with the previous Energoprojekt designations Not all of the variants were investigated by each company The table below characterizes each variant by the CP IV technology selection and the investigating company

Variant	Investigator	Description of Distinguishing Feature (Choice of CP IV)
A1	EGU	Combined cycle plant with two 60 9 MWe (ISO) Gas Turbines
A2	EGU & G/C	Combined cycle plant with one 60 9 MWe (ISO) Gas Turbine
A3	G/C	Combined cycle plant with one 47 MWe (ISO) Gas Turbine
A4	EGP	Combined cycle plant with one 90 MWe (ISO) Gas Turbine
B1	EGU & G/C	Cogeneration plant with one CFB boiler and a 32 MWe steam turbine
C1	G/C	Life extension of existing units and subsequent introduction of a CFB boiler with a 32 MWe steam turbine in 2003

Not all variants were investigated by each company The EGU and EGP analyses are presented in Section 7 0 and the G/C analysis is found in Section 8 0

The technical basis and approach, economic basis and approach, the results of the analysis, and sensitivity studies are presented

8 1 BASIS AND APPROACH FOR ANALYSIS

Applicable capital and operating costs associated with each station and for each variant were identified The performance of each plant studied was determined, and then a stream of costs were developed for each variant on a year to year basis through 2010 Each variant is structured to meet a demand and energy forecast of hot water and steam, and the production of electricity is also considered

In the previous section, the results of calculations of EGU and Energoprojekt were summarized These calculations determined the production of steam, hot water, and electricity, fuel requirements, ash quantities, emissions, and other cost inputs, by analyzing selected operating points on the load duration curve for the postulated variants The bulk of these analyses were performed with a detailed, but time consuming, manual analysis method

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In the G/C analysis, a similar, but more simplified, approach is used to "model" the system In this way, sensitivity analyses can be conducted by changing model inputs Comparisons were made with the results of EGU for Variant A2 and B1 to validate the work done by G/C, and it was found that the simplified approach yields results which are slightly higher in terms of fuel use Some different assumptions of losses, efficiencies account for most of the differences However, on a relative basis, the comparisons appear to be valid, and the conclusions drawn from the result should also be valid

The emphasis of the G/C analysis is placed on a least-cost planning model, which is based on an economic comparison of the variants Some insight into the financial requirements for each variant is used as a secondary evaluation, and is discussed in a later section

A demand forecast range, as well as a range of important economic variables is considered through the analysis in an effort to identify the least cost variant which also has the flexibility to adapt to the uncertain future

The following sections present the input to G/C's technical and economic model, the basis for the cost assumptions, and then an illustrative description of a model example (Variant B1) The detail for each of the model variants is contained in Appendix F

8 2 PLANT OPERATING CHARACTERISTICS

This section documents the overall plant modeling methodology, key assumptions and sources of various input for the plant operation

The objective of modeling the plant operating characteristics is ultimately to develop the fuel usage associated with meeting the hot water and steam demands through the use of the available generation units in a given variant scenario This is accomplished by characterizing the ability of each unit to meet a given thermal demand for both steam and hot water on a MW_t basis Most of these capacities were taken from EGU supplied data The boiler capacities and steam turbines are assumed to be independent of the ambient conditions, and operational mode The capacity of the gas turbine and HRSG, however, are modeled with a temperature functionality described in Section 8 2 3

The generating units are dispatched in a prioritized order until the demand is met The units are checked to ensure all minimum load criteria are met and operational loads are adjusted if required The associated electricity production from the cogeneration steam turbines are estimated by flow to power relationships

The boiler duty (i e , the heat imparted to the working fluid) is estimated as the sum of the steam duty (Q_{stm}), hot water duty(Q_{hw}), turbine power (MW_e) and heat rejected ($Q_{rejection}$) to the cooling tower by the following equation

$$Q_{duty} = Q_{hw} + Q_{stm} + MWe/(gen\ eff) + Q_{rejection}$$

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This boiler duty is augmented by an operating factor, (K_{op}), to capture operational influences like startup, shutdown, and equipment degradation, and then divided by the boiler efficiency to determine the estimated fuel use

$$Q_{fuel} = (Q_{duty} * K_{op}) / (\text{boiler eff})$$

The fuel consumed and electricity generated in the gas turbine is determined by first determining the operating load point required to met the thermal demand as dispatched With the gas turbine load point, fuel consumption and electricity is determined through the use of part load tables developed for the model (found on the last page of the GT appendices in Appendix F)

8 2 1 Load Duration and Demand Data

The district heating plants are dispatched to meet the required hot water and steam demand The utilized demand curves for the steam and hot water were based on the demand curves from the EGU analysis for the year 2000 Demands for other years were simply adjusted by the ratio of peak demand for the year of interest to the peak demand for the year 2000 The demand data defined by the load duration has been broken down into 12 periods to facilitate the analysis These divisions are consistent with the EGU divisions for the gas turbine analyses The principal division is simply a division between summer and winter Both of these seasonal divisions are further divided into four subperiods defined by four different price levels (tariffs) for the external sale of electricity The four summer periods where further subdivided into heating and non-heating periods The resulting twelve load duration periods are characterized by the period duration, peak load, minimum load and total energy consumed The characteristic data was based on data supplied by EGU and is presented in Exhibit 8-1

From this data, a load duration curve was simulated for each of the periods by an equation which precisely satisfies the peak energy demand and the total energy consumed This equation was based upon an equation utilized in the HEATMAP™,(1) District Heating program The equation predicts the heat required for a given point in time (Q_t) by the equation below

$$Q_t = (Q_{peak})(1-(\text{hr}/\text{period hrs})^{1/\text{slope}})$$

where Q_t = Hourly heat demand above the minimum demand for that period, MW_t

Q_{peak} = Peak heat demand above the minimum demand for that period, MW_t

slope = (period hrs)(Q_{peak}, MW_t)/(Period MWh) -1

Period MWh = Period MWh for loads above the minimum demand, MWh

Heat demands for intermediate points in time predicted by this equation match the EGU intermediate points reasonably well

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Exhibit 8-1
SUMMARY OF SYSTEM OPERATING CHARACTERISTIC DATA FOR THE YEAR 2000

		Hot Water Demand			Steam Demand		
Period	Period Duration (hours)	Peak Load (MW)	Min Load (MW)	Total Energy (MWh)	Peak Load (MW)	Min Load (MW)	Total Energy (MWh)
Winter							
Peak	914	299 5	102 8	148,997	100 0	41 5	58,240
High	783	299 5	102 8	127,628	100 0	41 5	49 851
Low	1435	254 6	80 5	183 233	85 0	32 6	71,588
Weekend	1248	254 6	80 5	159 414	85 0	32 6	62,276
Summer- Heating							
Peak	181	102 8	65 2	15,204	41 5	29 0	6,380
High	318	102 8	65 2	26,712	41 5	29 0	11,210
Low	589	80 5	51 4	38 845	32 6	22 9	16 345
Weekend	435	80 5	51 4	26,688	32 6	22 9	12,071
Summer- Non-heating							
Peak	306	36 1	28 6	9,899	38 5	30 5	10 557
High	535	36 1	28 6	17,307	38 5	30 0	18,324
Low	994	30 7	17 5	23 995	32 7	18 6	25 496
Weekend	734	30 7	17 5	17 689	32 7	18 6	18 827

The plant send out heat demand (i e , customer requirements plus the network losses), was augmented by an additional station service requirement of 1 5% of the demand for both hot water and steam The hot water demand was further increased by an additional 1% to reflect the heat loss in the steam to hot water heat exchanger Thus hot water demand was effectively increased by 2 52%, while the steam demand was increased by 1 5% This approach may not be in exact alignment with the approach taken by EGU EGU utilized a station service of 3 5 MW_t, which corresponds to approximately 1% of the total thermal demand The larger station service assumption by G/C will predict slightly larger fuel usage values, as well as potential short falls where EGU would have none

8.2 2 Steam Turbine Performance Data

The steam turbines associated with the cogeneration units produce electricity that depends upon the amount of steam entering the turbine, and the amount of steam being extracted In the model the steam turbines were simulated by artificially defining turbine components, so that it is possible to estimate the amount of electricity produced from a turbine component associated with the process steam extraction, designated as turbine (a), and a turbine component associated with the hot water requirement, designated as turbine (b)

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In this model, electric production of each of these turbine components is based upon the exhaust flow of the turbine, since both the steam and hot water demands correlate to the turbine exhaust flows of the defined turbine components The exhaust flow for both the "process steam" turbine, turbine (a), and the "district heat" turbine, turbine (b), is determined by dividing the heat requirement of the process steam or district heat by the enthalpy drop associated with the end use From this exhaust flow, the generated power is predicted The utilized enthalpy drop value for the supplied process steam reflects the 40% makeup requirement

The performance data for CP II turbine was based upon a turbine performance curve received from the plant This information was manipulated so that it could be put in the form required by the model As part of this effort, a simple heat balance model was exercised in order to correlate the throttle flow with the exhaust flow This was required because the steam extraction used for regenerative feedwater heating reduces the exhaust flow as compared to the throttle flow

The performance data for the other turbines were based upon typical turbine efficiencies for the sizes of interest, a simple heat balance, and miscellaneous support calculations

The steam turbine associated with the CFB boiler (CP IV) is a condensing turbine with a cooling tower This required a third artificial turbine component, turbine (c), in addition the "process steam" and "hot water" turbines, turbines (a) and (b) The third component represents the steam that goes from the throttle all the way through to the condensing exhaust Logic was built into the model to make sure the cooling tower capacity is not exceeded A cooling tower capacity of 25 MW_t was assumed in the CFB case This is in line with the Energoprojekt methodology which sized the cooling tower to 75% of the turbine rating size, (75% of 32 MW_t = 24 MW_t) The cooling tower capacity of 25 MW_t was chosen as being reasonable, and should be evaluated further if the CFB option is chosen

The steam turbine associated with the GTCC (CP IV) is a back pressure turbine with a low pressure steam induction In developing the performance data for this turbine, the low pressure induction flows were modeled and accounted for, although the effect of a varying process steam extraction on the ratio between the low pressure induction flow and the intermediate steam turbine flow was not accounted for This approximation should not introduce a significant error in light of the low pressure and low flow of the induction steam

Associated with the turbine components are maximum capacity values for both the high pressure extraction steam and the total thermal delivery (both steam and hot water) Since the extraction flow of a turbine is limited to by a maximum flow it is therefore limited in the maximum steam heat demand it can meet The turbine's total heat delivery (for both steam and hot water) is also limited since the throttle inlet flow and generator are both limited

This model predicts the steam turbine electric power generation by assuming the high pressure extraction steam, from turbine (a), is only utilized for meeting the steam demand, and the low pressure extraction or exhaust, from turbine (b), is only utilized to meet the hot

water demand Under some conditions, operational requirements may mandate that some of the delivered hot water demand be supplied from high pressure extraction steam via a steam to hot water heat exchanger in order not to exceed the turbine generator limit Since our model does not account for this alternate hot water supply, the model limits the predicted electric generation to that of the known turbine generator limit to avoid predicting too large an electric production

It should be mentioned that because the simulation program models each of the twelve periods individually, the electricity production is based on the average steam flows for the turbine within that period Specifically, the model calculates the MWhs of both hot water and steam supplied by a given turbine, and determines the hours of operation required by the load duration curve An average thermal delivery (MW_t) for steam and hot water are then determined These average supplied levels are converted to turbine exhaust flows and ultimately to electric power generation

The performance of the steam turbines is modeled by one set of performance values for all of the twelve periods That is, the varying ambient and hot water return temperatures do not impact the performance of the steam turbines in the model This is a simplification that potentially could be improved in future models

A generator efficiency is associated with each of the turbine components so that the electric generation can be converted to a thermal equivalent The thermal equivalent and the steam and hot water demands are added in order to determine the required thermal duty of the associated boiler or HRSG

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8.2 3 Gas Turbine Data

Gas turbines are significantly affected by ambient temperature, elevation and operating load As a result, developed performance data for the gas turbines of interest accounts for these major variables The developed performance data is based on an elevation of 330 meters (1083 ft), and accounts for a spectrum of ambient temperatures (0 to 100°F) and load points (25, 50, 75 and 100%) The developed gas turbine performance data assumes low NOx burners, with no steam or water injection, and a 13" H_2O exhaust pressure drop (consistent with HRSG operation) The developed performance data includes the gas turbine electric power generation, the required fuel flow, and the exhaust gas temperature and flowrate

The Westinghouse 251B11/12 performance data was developed from current ISO values(2) and Westinghouse(3) corrections for temperature, load, elevation, and the exhaust pressure drop

The Siemens V64 3 performance data was also developed from current ISO data(2) and the Westinghouse correction factors for temperature, load, elevation, and the exhaust pressure drop Correction factors for the Siemens gas turbine were not available at the time of the analysis, so the Westinghouse corrections were used The Westinghouse corrections should be reasonable for any similarly sized industrial gas turbine

The twelve load duration bins consistent of three different ambient temperature bins Winter, Summer heating, and Summer non-heating The average temperatures for these three periods are 3 0, 11 6 and 18 3°C (37 4, 52 9, and 64 9°F) respectively Use of the average temperature in a period allows a single temperature to reasonably predict the total MWh by predicting an average MWe output for the period This average may be notably different than the output at the coldest or warmest point in the period, but the predicted MWh should be very reasonable

The usable heat available from the Heat Recovery Steam Generator (HRSG) has been estimated by assuming a HRSG gas exhaust temperature of 215°F, a gas heat capacity of 0 25 Btu/lb,°F and the gas turbine exhaust flow and temperature predicted for the required load point and specific ambient temperature The HRSG exhaust temperature of 215°F is based on a hot water return temperature of 160°F, a drain cooler approach of 15°F, and an economizer approach of 40°F The HRSG heat available is determined by the following equation

$$\text{HRSG Heat Available} = (\text{Gas flowrate})(T_{exhaust,gt} - 215°F)(Cp)$$

A cooling tower has been added on the district heating loop for the gas turbine case in order to allow operation of the gas turbine at higher load levels than would otherwise be allowed by the thermal demands alone This allows for an increased electric production during the high tariff electric rate periods The selection of the cooling tower size is a subject for future study, should the gas turbine combined cycle option be chosen

8 2 4 Boilers

All of the boilers have unique boiler efficiency and minimum load data in the model Steam and hot water capacities are also associated with the hot water and steam boilers (The capacity values of the cogeneration units are not associated with the boiler but the turbine components as previously mentioned)

The required fuel determined for each of the boilers is augmented by an operating factor which reflects numerous operating phenomena such as startup and shutdown, operation at less than full load, equipment degradation from design, and less than optimal control These operating factors have been developed by EGU and are based on operating history of these unit types (e g , 7% for the Brewery, and 2% for Plzen V) The operating factor inputs in the model include both the station service factors discussed previously and the operating factors, and are summarized in Exhibit 8-7, (e g , 7% + 1 5% for the Brewery, and 2% + 2 5% for Plzen V) Improvement in these operating factors are possible through the use of more advanced control systems, which allow better control of boiler O_2, and possibly a more optimized balance of heat within the system

8 3 CAPITAL COSTS

For each of the variants, capital costs were developed for additional equipment required to meet the expected loads and comply with environmental regulations New plant configurations and modifications to older plants were estimated Where possible, the capital costs were divided between labor, materials, equipment, construction costs, and other costs, as necessary A further breakdown between Czech costs and foreign costs are also provided by category This is helpful in estimating the future price of foreign costs as a result of currency exchange considerations

The complete capital cost estimate summary is provided in Appendix E. Summaries which include the costs for each of the variants studied by G/C, are represented in the first 8 pages of Appendix E Many of the costs were supplied by EGU, based on recent input from equipment vendors, and are representative of costs to obtain equipment/systems within the Czech Republic The only large expenditure for imported equipment are the gas turbines, since gas turbines in these large sizes are not currently manufactured within the Czech Republic

Three additional costs were included Engineering, Owner's Cost, and Contingency Engineering was assumed to be 5%, Owner's Cost was assumed to be 4% of the capital cost Engineering covers the requirement of any outside services procured as part of the project Even though these projects will probably be fixed price supplied by the vendor, there will be miscellaneous charges incurred through the course of the project

Owner's Cost provides recognition of the effort required by the owner to implement capital projects Bid request preparation, bid evaluation, design reviews, construction monitoring, environmental permit preparation, public relations, engineering/vendor relations, and other costs require recognition to properly compare variants

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A 15% Project Contingency was added to all capital costs to account for the cost of additional equipment or other costs that would result if a more detailed design effort were carried out With a contingency, the cost becomes more representative of he end result of the project, and is a better indication of the required budget

A brief summary of the total capital costs (without inflation or escalation) associated with selected variants for the High and Low Demand is presented in Exhibit 8-2 All costs are presented in Kc x 1000, and include a combination of in-country costs and foreign exchange costs

8 3.1 Capital Costs of Environmental Controls

The environmental control options available for each of the variants included switching to low sulfur coal for SO_2 control, adding bag filters for particulate control, and using CFB technology or natural gas-fired combined cycle technology for added system capacity This section will address only those plant modifications required for environmental controls The addition of a new CFB or gas turbine plant is discussed in Section 8 3 2

The switch to low sulfur coal requires several changes to the pc-fired boilers, including a changeout/modification of the mills, which are currently designed for the softer lignite/brown coal Tests have already been conducted with the boiler, and it has been found that combustion performance is satisfactory and the ash handling capacity should be sufficient to handle the higher ash black coal Plant controls were assumed to be changed only to accommodate the new systems

There is a concern that the boilers may need additional modification to accommodate the change to black coal Modifications to heat transfer surfaces within the boiler or changes to the present ash handling system may be required A choice between boiler modifications and a boiler capacity derate may also be possible All variants share this expense, and so this additional work does not affect the selection of the most promising variant

An alternative to a switch to low sulfur coal is Duct Sorbent Injection (DSI) technology, as introduced in Section 6 0 DSI capital cost is relatively low For both Plzen II boilers, the capital cost for such an installation would be approximately $US 6 million, or almost 170 million Kc In addition, a baghouse filter would be required, as currently planned for the switch to black coal Operating costs, including the cost of lime for SO_2 removal, would be offset by the reduced cost of continued use of the current lignite fuel Further investigation should be undertaken to determine the complete project cost associated with a switch to low sulfur coal If this cost is prohibitive, a more detailed evaluation of DSI technology should be undertaken to determine the benefits

Capital costs for replacing the coal mills were provided by EGU These costs were compared to vendor costs obtained by G/C on similar projects, and they are within a reasonable range

Exhibit 8-2
SUMMARY OF CAPITAL COSTS FOR SELECTED VARIANTS
(1993 Kc x 1000, without inflation or escalation)

Year	Variant A2	Variant A3	Variant B1	Variant C1
High Demand				
1993	5 307	5,307	5,307	5 307
1994	23,480	23,480	23 480	23,480
1995	870,239	751,269	698 196	178,264
1996	847,578	728,633	675 560	155,628
1997	13,831	13,831	13,831	13 831
1998	7,237	7 237	7,237	7,237
1999	7,237	7 237	7,237	7 237
2000	7,237	7 237	7 237	7 237
2001	933	933	933	534,923
2002	933	933	933	534 923
2003	92 438	92,438	92 438	933
2004	92,438	92,438	92 438	933
2005	933	933	933	933
2006-10	3,538	3,538	3,538	3 538
Total	1,973,362	1,735,447	1,629,299	1,474 405
Low Demand				
1993	1,712	1,712	1,712	1 712
1994	7,063	7,063	7,063	7,063
1995	832,348	713 378	660,305	140,373
1996	825 410	706,440	653 367	133 435
1997	3,724	3 724	3 724	3 724
1998	428	428	428	428
1999	385	385	385	385
2000	385	385	385	385
2001	214	214	214	307,260
2002	171	171	171	307,217
2003	56,539	56,539	56,539	171
2004	56,539	56,539	56 539	171
2005	171	171	171	171
Total	1,785,089	1,547,151	1,441,002	902,493

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A plant shutdown for one heating season was considered by EGU to implement the modifications to the Plzen II units In a June 1993 meeting between G/C, Energoprojekt, and EGU, a consensus was reached that a shutdown for the whole season is not necessary Plant modifications of this type are frequently made in the U S while the plant experiences only a minimal shutdown for critical connections/tests In the case of CP Plzen, each spare mill could be replaced or modified in sequence, with an outage required only for a short period Since the plant is normally out for an extended period of 3 to 4 months, this approach should be feasible The overall cost benefit of keeping the pc-fired plants operational during the peak periods vs providing capacity from coal-fired stoker (grate) boilers and gas-fired boilers was analyzed in a separate study by G/C and found to reduce the annual operating cost of the affected years by approximately 12%

It has been assumed that the stoker boilers can burn the black coal with little or no modification Again, tests have been conducted to verify this performance

All boilers will be required to modify their existing system for particulate control The higher resistivity of the lower sulfur coal is expected to reduce the performance of the existing ESP units on the pc-fired plants As a result, either an upgraded ESP system or a bag filter replacement will be required The study assumed a bag filter, although an investigation of potential ESP improvements or flue gas conditioning should be conducted

The existing stoker boilers have only cyclones as particulate control with an efficiency of between 70 and 85%, although Letna has no particulate control All of these units will require either ESPs or bag filters Bag filters are assumed for the study

Baghouse costs were provided by EGU for the two large pc-fired boilers and the 3x35 MW_t stoker boilers at CP Plzen These costs were reasonable and equivalent to approximately 60-65% of U S prices A recent installation in the Trmice DH plant in Usti-nad-Labem reported costs slightly higher than we are using in this study, however, they are within a reasonable range

For the smaller boilers, the baghouse costs were scaled by an appropriate factor, and then a substantial difficulty factor (overall, about 25%) was added to account for the lack of space at the smaller sites A more detailed design assessment should be conducted to verify feasibility for these modifications The result of modifications to the stoker boilers should be to reduce particulate emissions by a factor of 100 or more

8 3 2 Capital Costs of New Facilities

New facilities are added in all of the variants as described in Section 6 0 They include

- gas/oil fired steam boiler (Plzen III, EGU only)
- gas/oil fired hot water boiler (Plzen V)
- 160 tonne/h Circulating Fluidized Bed boiler (Plzen IV)
- 50, 60, 90 and 120 MWe (approximate) gas turbine combined cycle systems (Plzen IV)

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New facility costs were prepared by EGU and Energoprojekt and verified by Gilbert/Commonwealth Some factors were added as mentioned above All plants are considered to be purchased through normal competitive bidding Certainly, through the bidding process, special financing arrangements may be possible which could reduce capital requirements, reduce or defer interest payments, or extend the term of financing No special financial arrangements were assumed by G/C in this analysis

When a variant is selected, further study should be conducted by ZCE/TEZA to optimize the size, design, and operating philosophy of the new plant The results of this study provide only a preference for a specific technology, and not the details associated with project implementation

8.3.3 Other Capital Costs

Capital costs were included for retirement of existing units (in appropriate variants) and for connection of decentralized boilers

Very rough estimates of costs for boiler retirement were assumed to be 5 6 million Kc for site costs plus 5 6 million per boiler for the smaller 5 8 MW_t stoker units Costs for larger boilers were scaled accordingly, but the site charge remained the same While these costs may vary significantly according to how the job of equipment removal and site restoration is accomplished, recognition of the expense has been provided, and relative differences between different boiler sizes has been recognized

Costs for connections of decentralized boilers to the CP Plzen system were prepared by EGU and ZCE and include costs for piping, heat exchangers, and associated equipment For the purposes of this study, it is assumed that this cost is borne solely by ZCE

8 4 FUEL AVAILABILITY / COST

Fuel costs were obtained from a variety of sources, and were compared to world prices(4) and to the relative value of other fuels available in the Plzen area The fuels considered in this analysis include lignite/brown coal of varying quality, black or hard coal (bituminous) with low sulfur content, natural gas, and no 2 oil (light oil)

A generic discussion of the world fuel pricing trends for Eastern Europe is included in Section 8 4 1 Fuel prices, availability and analysis assumptions specific to the Plzen area are discussed in Section 8 4 2 to 8 4 4 for coal, natural gas, and oil respectively The characteristics and initial prices assumed for this study are included as Exhibit 8-3

The real escalation assumed in connection with these fuel prices is presented in Section 8 6, along with other escalation factors

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Exhibit 8-3
SUMMARY OF FUEL CHARACTERISTICS ASSUMED FOR STUDY

FUELS TABLE											
Fuel no		1	2	3	4	5	6	7	8	9	10
Type		brown	black	black	brown		#6 oil	#2 oil	gas		
Mine		Sokolov	Zbuch	Zbuch	Sokolov						
Fuel company			Zud	Zud			WBGW		WBGW		
Lower Heating Value	MJ/kg	12 70	18 47	17 38	10 05		40 60	41 60	42 40		
	Btu/lb	5,463	7,946	7,477	4,323	0	17,466	17,896	18,240		
	MJ/Nm³								33 5		
Percent sulfur	%	0 70%	0 40%	0 40%	1 50%		1 50%	0 18%	0 00%		
Percent ash	%	16 00%	30 40%	33 20%	23 80%		0 30%	0 10%	0 00%		
Cost	Kc/t	443	1135	907	330			3300			
	Kc/Nm³								3 35		
	$/10⁶Btu	$1 31	$2 31	$1 96	$1 24			$2 99	$3 77		
	Kc/GJ	34 88	61 45	52 19	32 84		0 00	79 33	100 01		
Proximate Analysis											
Moisture	%	35 50%	11 20%	11 20%	36 60%						
Fixed Carbon	%	20 60%	36 50%	34 70%	16 80%						
Volatiles	%	27 90%	21 90%	20 90%	22 80%						
Ash	%	16 00%	30 40%	33 20%	23 80%						
TOTAL	%	100 00%	100 00%	100 00%	100 00%	0 00%	0 00%	0 00%	0 00%	0 00%	0 00%
Ultimate Analysis											
Carbon	%	34 98%	48 10%	45 80%	28 08%		85 83%	86 00%	72 61%		
Sulfur	%	0 70%	0 40%	0 40%	1 50%	0 00%	1 50%	0 18%	0 00%	0 00%	0 00%
Hydrogen	%	2 81%	3 25%	3 08%	2 24%		11.50%	12 70%	23.67%		
Moisture	%	35 50%	11 20%	11 20%	36 60%		0 40%	0 20%	0 00%		
Nitrogen	%	0 53%	0 85%	0 82%	0 40%		0 35%	0 70%	1 81%		
Oxygen	%	9 48%	5 80%	5 50%	7 38%		0 12%	0 12%	1 91%		
Ash	%	16 00%	30 40%	33 20%	23 80%	0 00%	0 30%	0 10%	0 00%	0 00%	0 00%
TOTAL	%	100 00%	100 00%	100 00%	100 00%	0 00%	100 00%	100 00%	100 00%	0 00%	0 00%
Intermediate calcs											
F Factor (0% O_2)	m³/t (daf)	7,254	8,373	8,373	7,213	0	10,133	10,384	11,532	0	0
O_2 Correction	%	6%	6%	6%	6%	6%	3%	3%	3%	6%	6%
F_1 Factor	m³/t (daf)	10,156	11,723	11,722	10,098	0	11,822	12,114	13,454	0	0
F_2 Factor	m³(daf)/GJ	388	371	375	398		289	290	317		
F_3 Factor	scf/10⁶Btu	14,440	13,800	13,961	14,814		10,765	10,809	11,814		

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8 4 1 World Fuel Pricing Trends of Eastern Europe

The influence of oil pricing on the price of competitive fuels, primarily natural gas and coal, is well known in the energy field Oil has always been the price driver for all energy forms over the last several decades At the same time, the cost of production for oil has had little impact on the ultimate price of oil in today's energy pricing scenario's

For the eastern block countries of Europe, those previously associated with the Soviet Union, the price of energy was dictated by the Soviet Union through the sale of its oil and natural gas into the region With the rapid decline of the Soviet economy, there is currently a distorted view of energy pricing throughout the region The continuation of subsidized energy pricing is on its way out as market forces drive each country to seek its own deals with international suppliers of energy Even the old Soviet empire must now compete in order to sell its vast energy resources

Oil Pricing Trends

Since 1990-91 when the Gulf War influenced the price of oil from a low of approximately $15 per barrel to a high of about $40 per barrel, oil has maintained a relatively stable price level The price of oil has ranged from about $17-$19 per barrel, with current mid-year 1993 pricing about $18 74 per barrel Despite continued efforts by OPEC to drive the price up, market forces have kept it at the levels indicated

With the industrial world in a prolonged business slump, the price of oil is expected to maintain its current level throughout 1994 The supply situation is such that even without Iraq production, there remains sufficient supplies to meet all of the expected demand in both the industrialized nations and the third world

With the industrial nations focusing on conservation and clean fuel technologies, the underdeveloped countries will have adequate access to the producing nations In many of the producing countries, the sale of oil is crucial to their development schemes as a means of securing foreign exchange No shortage of oil production is currently predicted through the 2010 time frame

Natural Gas Pricing Trends

Unlike oil, natural gas is highly dependent on pipeline capacity as the means for delivery to the markets of eastern Europe Except for a minor amount flowing west to east from the North Sea fields, almost all of the natural gas flows east to west from the Soviet Union through the Ukraine into Eastern Europe This dependence on a single source of supply is an area of concern for many of the countries in the region However, it would appear that the need for foreign currency outweighs political events in the existing countries of the previous Soviet Block The price of natural gas from the region is based on existing contracts between the satellite countries of eastern Europe and the Soviet Union

In terms of world fuel pricing, the price of natural gas has for many years been tied to the price of oil Prior to the 1970's, natural gas was considered as a throwaway fuel

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with little or no value Once the pipelines throughout the Middle East and Europe were constructed, the price of gas rose dramatically as a replacement fuel for oil, which was rapidly increasing in price As more demand was created for natural gas in the residential and industrial sectors, its price actually exceeded that of oil It has now taken on the mantle of a premium fuel due to its clean burning characteristics

As the price of natural gas increased relative to the price of oil, more drilling activity was directed toward gas rather than oil supplies This resulted in an overabundance of gas through the 1980's and a drop in the price of gas The traditional relationship between gas and oil was in the range of 1 5 times the price of oil, accenting its premium fuel characteristics As supplies increased, the price dropped until today its relationship is more along the lines of 1 15 times the price of oil While minor disruptions are likely to occur in Eastern Europe due to political events, there are other alternatives currently being investigated from the Middle East

Coal Pricing Trends

As with natural gas, coal pricing is likewise driven by the price of oil In Eastern Europe, there are indigenous supplies of "brown coal" which is utilized to a great extent throughout the region Without environmental controls, this has been a significant source of pollution, which is just now being addressed by eastern European countries This will lead to a reduced demand for this coal unless coal cleaning is initiated at the production mines Current pricing is approximately $45 per ton for the better coals in the Czech Republic While it is true that coal pricing is highly dependent on oil prices, this is only one aspect of coal pricing Of the primary fuels, coal is unique since coal pricing is somewhat tied to the actual cost of production Nevertheless, the price of good quality coals have historically yielded an oil to coal pricing ratio of approximately 1 7 to 2 0

8 4.2 Local Coal Availability / Cost

There is a considerable supply of low quality fuel available in the Czech Republic Organizational changes have altered or will soon alter the structure of mining and supply Currently, most mining operations are losing money, but as subsidies are removed, mines with marketable and competitive products will be profitable, while those with uncompetitive products discontinued

In this study, we have assumed that contract quantities of both lignite and higher quality black coal will be available The prices of low quality lignite/brown coal have not yet escalated, and they are expected to rise, but will still be lower than higher quality fuels Fluidized bed combustion technology can capitalize on the availability and relative low cost of low quality fuel

The current price of brown coal at 12 7 MJ/kg is purchased for 443 Kc/t, including VAT and transport It is expected that this price will rise by 25-50% by 1996, with a ceiling of 660 Kc/t From this time it is expected that the price will rise only with inflation

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High quality black coal (bituminous) coal is not viewed as a long term solution, since the quantity of reserves is more limited The prices of this higher quality coal have already escalated such that further increases are not anticipated in the near term Contract prices have been offered in the range of 900 to 1135 Kc/t for pc-fired and stoker-fired boilers respectively The respective heating values assumed are 17 4 and 18 5 MJ/kg When compared to offerings for import of similar quality fuel, it is not expected that these prices will rise significantly They are expected to rise perhaps 8 to 15% by 1996 and then by inflation, or slightly less, in the future Signing of long-term contracts for this fuel will help to stabilize the price

The United States pricing structure was not used directly in this study as an example, or for comparison Here in the U S, a mixed situation including long term contracts, spot markets, competition from natural gas markets, rampant gas turbine construction, and reaction to clean air legislation have served to upset pricing structures U S pricing is now in a state of transition

8 4 3 Local Natural Gas Availability / Cost

Since almost all of the gas fired options incorporate imported gas from either Russia at the current time, or possibly from European sources in the future, each variant with significant amounts of gas utilization must be viewed with a risk factor for foreign supply Gas contracts are now being negotiated with Russia Also, the split of Czech and Slovak Republics has caused concern (for some) over the control of gas distribution, since the pipeline from Russia travels the length of the Slovak Republic Thus, political issues enter into a consideration for the future of gas supply which may not be of concern with coal supply

The current price of natural gas for large scale consumers is 3 3 Kc/m^3, including 5% VAT A complete change in pricing of this fuel is significantly affecting the price of gas for small consumers, who formerly paid a lower price than large consumers However, the price for large consumers is still expected to rise by 25% in 1994, and then from 1995, it is expected to follow the movement of world prices

8 4 4 Local Oil Availability / Cost

Oil is currently used in standby units and for startup of the larger plants It is expected that new gas fired boilers will be equipped with dual-fuel capability, but will predominantly use gas Oil is excellent as a standby fuel, and can be used as a backup emergency supply in the case of gas interruption Oil can also used strategically as a tool for negotiating the price of natural gas with the distribution/supply company

The price of oil is volatile in the Czech Republic, but the growth is expected to be slow, increasing by 10-20% in 1996 from a current price of 3000 Kc/t Since not much oil use is anticipated compared to the use of other fuels, this price will not substantially affect the comparison of variants

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8 5 OPERATING AND MAINTENANCE COSTS

As with the capital costs, operating and maintenance (O&M) costs, exclusive of fuel, for each of the variants were developed based on operating history of the existing facilities, while for new plants, vendor estimates were reviewed and utilized within the context of Czech operating conditions

Some operating costs were supplied by EGU for CP Plzen TEZA operating costs were not available Based on CP Plzen and in-house G/C estimates, operating and maintenance costs for each facility were estimated Several assumptions are used in these estimations

- Operating and maintenance crews were assumed to continue to be large as in the current situation,
- Maintenance costs are based on very rough industry averages and do not necessarily represent the approach of a specific maintenance program,
- There is a charge for retirement of a plant which will include demolition and reclamation
- There are no unusual increases in the price of water
- The price of ash disposal is as defined in Section 8 5 1

The cost of raw and treated water was included by operating unit Also, the cost of limestone for the CFB boiler and the cost of ash disposal was included

Labor cost was supplied by EGU in terms of existing staffing for CP Plzen It is expected that labor requirements will be reduced considerably through the years of the study, however, since these projections could not be made with a sound basis, they were left constant By example, the current number of employees for ZCE (CP Plzen) were reported as nearly 300, which does not include those plants operated by TEZA A recent visit to a U S district heating facility in St Paul, Minnesota revealed that the entire company including management, secretarial, accounting, plant operations, maintenance, and field personnel are a total of 39 people While this facility is smaller (199 MW_t, 146 MW_t billed, with 0 89 MWe electric generation and a 4500 ton chilled water system), the large ZCE staff still represents a substantial difference in efficiency of operations It is true that, in the U S, personnel are contracted for non-routine maintenance and plant modifications, but even if this were accounted for, it would still be a significant difference Over a period of time, Plzen operations are expected to approach the same level of operating efficiency Labor cost trends will see less of a change as wages rise concurrently with changes in operating efficiency Some general information about the St Paul facility is included as Appendix G

Maintenance costs were distributed among the units according to the schedule and method presented in Exhibit 8-4 Maintenance estimates are keyed from the relative initial capital cost of each unit, by varying percentages based on industry averages Input received from the Plzen companies was not detailed, and it was difficult to obtain current operating costs for these facilities The approach taken in the study is very general, but should be consistent on a relative basis

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Exhibit 8-4
ASSUMED MAINTENANCE SCHEDULES AND COST SUMMARY

UNSCHEDULED MAINTENANCE

RANDOM NUMBER MAINTENANCE ACTIVITY
Scale = 1 10

Unit	Code	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
											Y	E	A	R					
		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18
Existing Brewery	BR	5	5	8	8	5	6	5	9	8	6	6	8	6	7	10	10	8	6
Existing Plzen I	P1	4	7	4	5	8	7	8	7	6	7	7	8	6	8	9	8	7	8
Existing Plzen II	P2	8	7	4	8	7	9	8	7	6	9	8	9	9	7	7	7	7	10
Existing Kosutka	K	8	7	8	5	8	5	7	8	6	5	6	7	8	8	9	10	6	10
Existing Letna I	L1	4	8	8	6	6	6	9	9	9	9	5	8	9	8	6	8	10	7
Existing Letna II	L2	4	4	4	5	6	7	9	9	7	9	7	6	6	10	9	6	7	7
Existing Doubrav	D	8	5	6	6	7	5	7	5	6	9	6	8	7	8	10	10	8	6
Existing Bory	BO	5	7	7	4	7	5	8	9	7	8	9	9	8	8	8	7	8	7
Existing T/G #1	T1	6	6	8	6	5	6	5	7	6	7	9	10	8	10	7	6	6	8
Plzen III Plzen III	P3	1	2	1	2	1	–	1	2	–	1	2	3	3	1	3	3	2	3
Plzen IV–1xCFB	P4FB1	–	2	–	2	2	2	1	1	1	1	2	3	–	1	1	–	–	2
Plzen IV–2xCFB	P4FB2	1	–	1	–	2	–	2	1	–	1	–	3	3	3	2	3	2	1
Plzen IV–1xGTCC	P4GT1	1	1	–	1	–	1	–	2	–	2	3	–	1	2	1	3	2	1
Plzen IV–2xGTCC	P4GT2	2	1	2	2	2	–	2	–	1	1	3	1	3	1	1	2	2	1
Plzen V Plzen V	P5	1	1	–	–	–	–	2	2	–	2	–	1	1	–	–	1	3	3
T/G #2 T/G #2	T2	2	1	1	2	–	–	–	–	–	2	3	–	–	2	2	2	–	2
		36	38	33	45	34	41	37 5	45 5	36 5	45 5	45	53 5	40	42 5	45 5	44	42	53

SCHEDULED MAINTENANCE

Unit	Code	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18
		1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
		$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)
Existing Brewery	BR	75	200	75	75	75	100	250	100	100	100	125	300	125	125	125	150	350	150
Existing Plzen I	P1	442	455	469	484	498	514	529	545	562	579	597	615	633	653	673	693	714	736
Existing Plzen II	P2	1278	1316	1357	1398	1440	1484	1530	1576	1624	1674	1725	1777	1831	1887	1944	2004	2085	2128
Existing Kosutka	K	105	108	111	114	118	121	125	129	133	137	141	145	150	154	159	164	169	174
Existing Letna I	L1	255	263	271	279	287	296	305	314	324	334	344	354	365	376	388	400	412	424
Existing Letna II	L2	53	55	56	58	60	62	64	66	68	70	72	74	76	78	81	83	86	88
Existing Doubrav	D	233	240	247	255	263	271	279	287	296	305	314	324	334	344	354	365	376	388
Existing Bory	BO	195	201	207	213	220	227	233	241	248	255	263	271	279	288	297	306	315	325
Existing T/G #1	T1			200					250					300					350
Plzen III Plzen III	P3				88	91	93	96	99	102	105	108	112	115	119	122	126	130	134
Plzen IV–1xCFB	P4FB1						722	744	767	790	815	839	865	891	918	946	975	1005	1035
Plzen IV–2xCFB	P4FB2						831	856	882	909	937	965	995	1025	1056	1088	1121	1156	1191
Plzen IV–1xGTCC	P4GT1						673	693	714	736	758	781	805	830	855	881	908	936	964
Plzen IV–2xGTCC	P4GT2						542	558	575	593	611	630	649	668	689	710	731	754	777
Plzen V Plzen V	P5														202	208	215	221	228
T/G #2 T/G #2	T2							150					175					200	

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In Exhibit 8-4, there is a general unit age factor which assigns increased maintenance costs for older units While these costs are high, they are expected to include some value for increased forced outages of older units, i e reduced reliability In Variant C1, the continuation of units Letna, Doubravka, Bory, and Plzen I were considered These units are substantially penalized for age by increased maintenance costs, and also by efficiency, since newer units are more efficient The tradeoff between increased operating cost and capital investment is a useful result of the study

8 5.1 Ash Disposal Requirements

Ash disposal is an increasingly serious problem in the United States Ash properties are unique for each coal and are influenced by not only original chemical composition of the ash, but also the coal preparation and combustion process, which tend to produce unique ash physical and chemical characteristics

In the U S, according to the Environmental Protection Agency (EPA), fly ash waste, bottom ash waste, slag waste, and flue gas emission control waste generated primarily from the combustion of coal or other fossil fuels are solid wastes which are exempt from being characterized as hazardous wastes (EPA 40CFR261 4) Instead, these are designated as "high volume" wastes Therefore, coal combustion waste is regulated only by the state authorities

State laws are changing which govern disposal of solid waste, and increasing measures are being taken to protect groundwater from coal waste leachate A recent survey was taken of ten states to determine what requirements will be imposed for the landfill of solid waste While the requirements in each state vary, common requirements for landfill appear in most of the legislation, including

- Liners, which generally specify clay in thicknesses varying from 2 to 5 feet, synthetic liners are usually accepted as alternates,
- leachate collection and treatment,
- groundwater monitoring, and
- site closure

Haulback to the mine is allowed in most states, and come under the jurisdiction of a waste management bureau or a bureau governing such activities at an active mine site, such as "Bureau of Mining and Reclamation This is an attractive option and should be used to reduce costs whenever possible

It is difficult to anticipate the direction of Czech legislation regarding ash disposal In this study, recognition is given to the differences between ash marketability of black coal, lignite, and FBC lignite ash Also, the impact of likely stricter landfill requirements in the near future is recognized by including an increased cost for landfill preparation or mine haulback

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The ash disposal costs for the Plzen study was addressed in the following manner

- Current and near future ash disposal costs (1993-1996) were provided by EGU through ZCE for the currently used lignite fuel
- The incremental cost of the new U S regulation as estimated by the U S EPA was applied at 60% of the projected U S cost, arbitrarily starting in the year 2000
- Because the black coal reportedly has the potential to receive byproduct credits, we have arbitrarily credited the black coal ash disposal at 50% of the established disposal cost for all years of the analysis Certainly this will be dependent on the development of markets for this ash, and so we have been conservative to apply a 50% factor
- Fluidized Bed Combustion similarly may develop markets for its ash Since it is a new technology, we have more conservatively applied a 25% byproduct credit in the year 2000, and then a 50% credit in the year 2005, as this market develops Uses for FBC ash are being investigated around the world, with promising results
- From the year 2000, ash disposal costs are assumed to follow the cost of inflation

The costs used for ash disposal are embodied into a single Kc/tonne value which incorporates the cost of landfill development, haulage, and regulatory requirements for monitoring Actual costs will depend on a more detailed in-country investigation into available options

The costs represented in the study are as follows (not including inflation)

	Total Disposal Cost in Kc/tonne		
year	black coal	lignite	lignite with FBC
1993	NA	100	NA
1996	74	148	148
2000	126	252	189
2005	126	252	126
2010	126	252	126

Ash disposal is a very complex issue and one that is difficult to predict in terms of what is expected to happen in the next 10 to 15 years in the Czech Republic For this reason, we have adopted a general approach, and one that does reflect tightening regulation, increased costs, and recognition of potential markets for ash

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8 6 ECONOMIC ANALYSIS

In order to provide a basis for the evaluation of each primary variant previously defined, the economic analysis described in this section compares projected operating results under each circumstance with that projected under a continuation of the status quo, modified only to the extent required to meet system growth and to satisfy environmental constraints

To accomplish this purpose, a computer spreadsheet model was specifically created as a vehicle for the simulation of annual system operations over the projected period through the year 2010 Typical model output data is illustrated in the discussion of the analysis application as contained in Section 8 6 2 Analysis results developed for each variant are summarized in Section 8 6 3, and various sensitivity analyses are accomplished in Section 8 7

As a prerequisite, however, the major assumptions underlying the analysis are set forth in the following paragraphs

8 6.1 Economic Analysis Assumptions

By its nature, any projection of future circumstances necessitates the adoption of certain assumptions with respect to study elements that cannot be predetermined with any degree of certainty In order to ensure credible analyses, it is important that assumptions remain consistent for all variants studied unless specific conditions, properly noted, require otherwise Further, it is essential that such assumptions be explicitly stated so that analysis results may be properly interpreted Details of the technical assumptions are defined in earlier sections Other major assumptions employed in this analysis are presented in the following paragraphs

1 Because District Heating demands vary significantly throughout the year, simulations are developed for a range of representative operating conditions Winter and summer periods are obviously distinct Within each season, this analysis further addresses both steam and hot water demands in subperiods defined primarily on the basis of variations in price levels associated with opportunities for external sales of electricity The twelve simulation periods and representative characteristics assumed in each were presented in Exhibit 8-1

2 Demand data indicated in Exhibit 8-1 are for the year 2000 Although all demands and total duty MWh's are varied each year in accordance with the overall demand projections developed in Section 5 0, it is assumed that the same relative period characteristics are maintained for all years

3 Load characteristics in each period are further defined in terms of load duration curves as indicated in Exhibit 8-5

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Exhibit 8-5
ASSUMED LOAD DURATION CURVES FOR STUDY PERIODS (high demand)

TEST YEAR PERIODS	Percentile	W-Pk	W-Hi	W-Lo	W-Wknd	S-Pk1	S-Pk2	S-Hi1	S-Hi2	S-Lo1	S-Lo2	S-Wknd1	S-Wknd2
Hot Water Hours at % Level	–	914	783	1435	1248	181	306	318	535	589	994	435	734
	10	914	783	1435	1248	181	306	318	535	589	994	435	734
	20	914	783	1435	1248	181	306	318	535	589	994	435	734
	30	914	783	1435	1248	181	306	318	535	589	994	435	734
	40	745	638	1010	878	181	306	318	535	589	994	435	734
	50	493	422	618	538	181	306	318	535	589	994	435	734
	60	297	254	339	296	181	306	318	535	589	925	435	583
	70	155	132	157	137	148	306	261	535	489	694	361	512
	80	62	53	53	46	99	295	174	515	326	462	241	341
	90	13	11	8	7	49	147	87	258	163	231	120	171
	100	–	–	–	–	–	–	–	–	–	–	–	–
Max Full Duty Load as % of Peak Load		34 3	34 3	31 6	31 6	63 4	79 2	63 4	79 2	63 9	57 0	63 9	57 0
Steam	–	914	783	1435	1248	181	306	318	535	589	994	435	734
	10	914	783	1435	1248	181	306	318	535	589	994	435	734
	20	914	783	1435	1248	181	306	318	535	589	994	435	734
	30	914	783	1435	1248	181	306	318	535	589	994	435	734
	40	914	783	1358	1181	181	306	318	535	589	994	435	734
	50	707	603	938	816	181	306	318	535	589	994	435	734
	60	491	420	596	519	181	306	318	535	589	922	435	681
	70	307	262	332	290	180	306	317	535	589	692	435	511
	80	158	135	146	127	120	295	211	485	396	461	292	340
	90	51	43	36	31	80	147	106	242	198	231	148	170
	100	–	–	–	–	–	–	–	–	–	–	–	–
Max Full Duty Load as % of Peak Load		41 5	41 5	38 4	38 4	69 9	79 2	69 9	79 2	70 2	56 9	70 2	56 9

Max Full Duty – Hot Water	MW	102 8	102 8	80 5	80 5	65 2	28 6	65 2	28 6	51 4	17 5	51 4	17 5
Max Full Duty – Steam	MW	41 5	41 5	32 6	32 6	29	30 5	29	30 5	22 9	18 6	22 9	18 6
Peak Load – Hot Water	MW	299 50	299 50	254 60	254 60	102 80	36 10	102 80	36 10	80 50	30 70	80 50	30 70
Peak Load – Steam	MW	100 00	100 00	85 00	85 00	41 50	38 50	41 50	38 50	32 60	32 70	32 60	32 70
MWH – Hot Water	MWH	148997	127628	183233	159414	15204	9899	26712	17307	38845	23955	28688	17689
MWH – Steam	MWH	58240	49851	71588	62276	6380	10557	11210	18324	16345	25496	12071	18827

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4 In addition to indicated demands, which account only for customer requirements (adjusted for system losses, etc), additional loads are assumed for the station service and related requirements on the basis of the following percentage increments

Steam	1 50 %	
Hot Water	2 52%	(See Section 8 2 1 for basis)

Since boiler and other operating unit capabilities applied are net of considerations for these requirements, the above factors are recognized only in the determination of fuel costs

5 Electrical loads including pumping and operational requirements are assumed generally on the basis of information supplied by EGU

6 Purchase power costs are established at the following 1993 price levels as assumed under Rate B2 in the price list for electric energy published by the Ministry of Industry and Trade

Capacity Charge	222 Kc	(US $7 93)	per kW/Mo
Energy Charge			
Peak Period	0 980 Kc	(US $0 0350)	per kWh
High Period	0 780 Kc	(US $0 0279)	per kWh
Low Period	0 690 Kc	(US $0 0246)	per kWh
Weekend Period	0 690 Kc	(US $0 0246)	per kWh

Since the periods utilized in the simulation analysis were established in accordance with the peak, high and low periods defined for electric tariff purposes, the respective energy rates could be applied as appropriate for individual analysis periods In addition, a capacity charge was assessed on the basis of that rate indicated above and assuming a 75% capacity factor

The peak period energy rate is in effect up to seven hours per weekday in the winter months and up to four hours per weekday in the months of April through September Recognizing this and similar criteria for the high and low tariff periods to establish the number of annual hours in each period, and by applying the respective period energy charges indicated above, the composite annual rate for energy purchases under the assumed Tariff Schedule (B2) is approximately $0 0273 (0 764 Kc) per kWh However, considering the effect of the capacity charge at the assumed capacity factor (75%), the average effective cost per kWh is approximately $0 0418 (1 171 Kc) per kWh

7 It is assumed that a market exists for all electrical generation in excess of internal requirements Revenues from the sale of electricity are assumed to be priced at the same level as the above energy charges However, no payment equivalent to the capacity charge has been applied In order to

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qualify for a capacity payment, it is generally required that firm energy (energy that is available for dispatch by the electric utility) be continuously available to the grid, and that the utility system be sufficiently in deficit to warrant payment of capacity related charges Given the current situation regarding electricity supples in the Czech Republic, it is assumed that the DH company would not presently qualify for capacity payments

Under the above treatment, the composite cost of electricity purchased for the serving utility (1 171 Kc per kWh) is approximately 53% greater than the assumed composite payment for electricity sold to the grid (0 764 Kc per kWh) In fact, considering a potential additional capacity charge of 95 Kc per kW per month for contract demand (as stipulated for Rate Tariff B2 but impractical to apply in this analysis without specific knowledge of potential contract arrangements), the cost for purchased power could exceed the level of payments for electricity sales by a ratio of up to 1 75 to 1 This relative distinction between purchase and sales price levels is not inconsistent with experience in the United States where ratios of 2 to 1 or more are not uncommon

8 All unit price and unit costs are assumed at Year 1993 levels Where currency conversions were required, an Exchange Rate of 28 Kc/$US has been applied

9 The following (1993) unit costs have been adopted in the development of Operation and Maintenance Expenses

Fuel Cost			Other O&M Cost		
Fuel Type	US$/$10^6$Btu	Kc/GJ	O & M Category	US $/MWh	Kc/MWh
Natural Gas	$ 3 77	100 00	Raw Water & Treating	$ 0 10	2 8
#2 Oil	$ 2 99	79 30	Demineralized Water	$ 1 41	39 5
Lignite (CFB)	$ 1 24	32 84	Other O&M	$ 0 41	11 5
Black Coal					
PC-Fired	$ 1 96	52 20		US $/ton	Kc/tonne
Stokers	$ 2 31	61 50			
			Sorbent (Limestone)	$ 11 01	340
			Ash & Waste Disposal	$ 3 24	100

Refer to previous Sections 8 4, 8 5, and 8 5 1 for discussions on fuel, O&M, and ash disposal costs respectively

10 Assumed scheduled maintenance is based on estimates for individual plants as indicated in Exhibit 8-4 This table also contains random number generated assumptions of unscheduled maintenance episodes

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11 In order to give consideration particularly for the temperature sensitive characteristics of gas turbines (Variants A2 and A3), the following ambient temperatures are adopted for the relevant periods

Winter	3 0°C
$Summer_1$	11 6°C
$Summer_2$	18 3°C

12 Unit dispatching is prioritized generally giving consideration to fuel types, operating efficiencies and power cogeneration capabilities Load dispatch results predicted by EGU provided input to the prioritization selected for the G/C model While we believe dispatching sequences to be a reasonable representation of probable operations, no attempt has been made to fully optimize unit dispatch

13 In isolated cases where relatively minor commodity shortfalls occur, recognition is given in operating statistics and the case is penalized at an assumed level of U S $10 00 per MWh (HW) This assumed value turns out to be immaterial, since no material shortfalls developed

14 For purposes of Economic Analysis, projected costs are developed in thousands of U S Dollars, in all cases exclusive of general inflation Where appropriate, however, estimated levels of real escalation have been assumed as shown in Exhibit 8-6 (Real escalation is the annual rate of increase of an expenditure that is due to factors such as resource depletion, increased demand, and improvements in design or manufacturing [negative rate] The real escalation rate does not include inflation)

In the case of fuel costs, it is assume that local costs for natural gas, oil and lignite will increase to world price levels by year 1996 and follow World Bank fuel cost projections beyond that point The price for black coal, however, appears to have already achieved or exceeded world price levels, and no real escalation is assumed through 1996 Thereafter, black coal is also trended at world price projection levels

Because fuel prices are generally among the most significant cost factors in electric utility operations, trends similar to those adopted for fuel costs have been applied for both purchased power and electric sales price levels Real escalation associated with emission penalties reflect the distinct steps stipulated in the staged introduction of such regulations

15 Capital cost estimates have been segregated between domestic and off-shore requirements In the latter case, future costs are escalated on a basis representative of assumed relative domestic and foreign inflation rates as a surrogate for possible Exchange Rate variances

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Exhibit 8-6
ASSUMED ESCALATION FACTORS AND SCHEDULES

	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
General Inflation Rate																		
Foreign	–	0 0300	0 0350	0 0350	0 0350	0 0350	0 0350	0 0350	0 0400	0 0400	0 0400	0 0400	0 0400	0 0400	0 0400	0 0400	0 0400	0 0400
Domestic	–	0 0750	0 0650	0 0600	0 0600	0 0600	0 0600	0 0600	0 0500	0 0500	0 0500	0 0500	0 0500	0 0500	0 0500	0 0500	0 0500	0 0500
Real Escalation																		
Natural Gas	–	0 0367	0 0367	0 0367	0 0276	0 0278	0 0279	0 0280	–	–	–	–	–	–	–	–	–	–
Oil	–	0 0717	0 0717	0 0717	0 0287	0 0288	0 0288	0 0289	–	–	–	–	–	–	–	–	–	–
Lignite	–	0 0486	0 0486	0 0486	0 0188	0 0189	0 0190	0 0191	–	–	–	–	–	–	–	–	–	–
Black Coal	–	–	–	–	0 0188	0 0189	0 0190	0 0191	–	–	–	–	–	–	–	–	–	–
Purchased Steam Cost	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
Purchased Power Cost	–	0 0486	0 0486	0 0486	0 0188	0 0189	0 0190	0 0191	–	–	–	–	–	–	–	–	–	–
Power Sales Revenues	–	0 0486	0 0486	0 0486	0 0188	0 0189	0 0190	0 0191	–	–	–	–	–	–	–	–	–	–
Ash Disposal Costs	–	0 1400	0 1400	0 1400	–	–	–	0 7000	–	–	–	–	–	–	–	–	–	–
Other O&M	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
Emissions Penalties	–0 7000	1 0000	–	0 3333	–	0 2500	–	–	–	–	–	–	–	–	–	–	–	–
Capital Cost – Foreign	–	0 0450	0 0300	0 0250	0 0250	0 0250	0 0250	0 0250	0 0100	0 0100	0 0100	0 0100	0 0100	0 0100	0 0100	0 0100	0 0100	0 0100
Capital Cost – Domestic	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
COMPOUNDED																		
General Inflation – Foreign	1 0000	1 0300	1 0661	1 1034	1 1420	1 1819	1 2233	1 2661	1 3168	1 3694	1 4242	1 4812	1 5404	1 6021	1 6661	1 7328	1 8021	1 8742
General Inflation – Domestic	1 0000	1 0750	1 1449	1 2136	1 2864	1 3636	1 4454	1 5321	1 6087	1 6891	1 7736	1 8623	1 9554	2 0532	2 1558	2 2636	2 3768	2 4956
Real Escalation																		
Natural Gas	1 0000	1 0367	1 0747	1 1142	1 1449	1 1768	1 2096	1 2435	1 2435	1 2435	1 2435	1 2435	1 2435	1 2435	1 2435	1 2435	1 2435	1 2435
Oil	1 0000	1 0717	1 1485	1 2309	1 2662	1 3027	1 3402	1 3789	1 3789	1 3789	1 3789	1 3789	1 3789	1 3789	1 3789	1 3789	1 3789	1 3789
Lignite	1 0000	1 0486	1 0996	1 1530	1 1747	1 1969	1 2196	1 2429	1 2429	1 2429	1 2429	1 2429	1 2429	1 2429	1 2429	1 2429	1 2429	1 2429
Black Coal	1 0000	1 0000	1 0000	1 0000	1 0188	1 0381	1 0578	1 0780	1 0780	1 0780	1 0780	1 0780	1 0780	1 0780	1 0780	1 0780	1 0780	1 0780
Purchased Steam Cost	1 0000	1 0000	1 0000	1 0000	1 0000	1 0000	1 0000	1 0000	1 0000	1 0000	1 0000	1 0000	1 0000	1 0000	1 0000	1 0000	1 0000	1 0000
Purchased Power Cost	1 0000	1 0486	1 0996	1 1530	1 1747	1 1969	1 2196	1 2429	1 2429	1 2429	1 2429	1 2429	1 2429	1 2429	1 2429	1 2429	1 2429	1 2429
Power Sales Revenues	1 0000	1 0486	1 0996	1 1530	1 1747	1 1969	1 2196	1 2429	1 2429	1 2429	1 2429	1 2429	1 2429	1 2429	1 2429	1 2429	1 2429	1 2429
Ash Disposal Costs	1 0000	1 1400	1 2996	1 4815	1 4815	1 4815	1 4815	2 5186	2 5186	2 5186	2 5186	2 5186	2 5186	2 5186	2 5186	2 5186	2 5186	2 5186
Other O&M	1 0000	1 0000	1 0000	1 0000	1 0000	1 0000	1 0000	1 0000	1 0000	1 0000	1 0000	1 0000	1 0000	1 0000	1 0000	1 0000	1 0000	1 0000
Emissions Penalties	0 3000	0 6000	0 6000	0 8000	0 8000	1 0000	1 0000	1 0000	1 0000	1 0000	1 0000	1 0000	1 0000	1 0000	1 0000	1 0000	1 0000	1 0000
Capital Cost – Foreign	1 0000	1 0450	1 0764	1 1033	1 1308	1 1591	1 1881	1 2178	1 2300	1 2423	1 2547	1 2672	1 2799	1 2927	1 3056	1 3187	1 3319	1 3452
Capital Cost – Domestic	1 0000	1 0000	1 0000	1 0000	1 0000	1 0000	1 0000	1 0000	1 0000	1 0000	1 0000	1 0000	1 0000	1 0000	1 0000	1 0000	1 0000	1 0000

16 Since the analysis of all variants develops projected results of operations over a series of years (through Year 2010), consideration of the time value of money necessitates the application of an appropriate discount rate in order to establish the present value of the each alternative cost stream This procedure has the additional advantage of providing a uniform basis and a single quantity (the cumulative present worth) for the comparison of each option proposed

The discount rate applied, in order to properly represent anticipated carrying charges, is most commonly established as the assumed composite cost of money, expressed in the same terms as those reflected in the steam of costs to be discounted Since, for purposes of this analysis, all costs as developed in current (1993) dollars are adjusted only for "real" escalation, the appropriate discount rate is established as the composite cost of money expressed in real terms under the following assumed capital structure

Source	% of Total	Real Cost(1)	Weighted Cost
Equity	25 %	11 %	2 75 %
Debt	75 %	7 %	5 25 %
Composite			8 00 %

Note (1) Rates as assumed are equivalent to apparent rates (including inflation) of 20% and 15% respectively for equity and debt the basis applied for financial analysis in Section 8 8

According to this basis, a Real Discount Rate of 8% is applied for economic analysis purposes

8 6 2 Analysis Application

As previously indicated, the primary tool for investigating the economic merit of each of the several system configurations proposed is a spreadsheet model designed to simulate plant operations under each alternative circumstance Since, except for specific component operating characteristics and relevant inputs, the same methodology have been imposed in each case, a description of model outputs for the Circulating Fluidized Bed (CFB) boiler variant (B1) will be generally descriptive for all

The unique characteristics of each variant are represented in a "Facilities Data Sheet" descriptive of all plant facilities in place As illustrated in Exhibit 8-7, which characterizes the situation in Year 2005, data include specifics as to the operating efficiencies, minimum operating levels, and maximum outputs of each applicable commodity (steam, hot water, electricity) In addition, primary and secondary fuels and other operation and maintenance expenses criteria are identified, as well as each unit's availability during each analysis operating period Individual Data Sheets of this type are, in fact, the essence of each case

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Exhibit 8-7
FACILITIES DATA INPUT SHEET

CASE B1 — Test Year = 2005

Station Use Unaccounted for etc — Electric kW: –

% of Demand — Water: – ; Steam: –

Facilities Data

DESCRIPTION	UNIT	EXISTING FACILITIES						NEW FACILITIES						Steam Purchase	Power Purchase	Power Sales
	BASIS	2	3		5	6	7	8	9	0			2	3		5
				Brewery	Plzen IIa	Plzen IIb		Plzen III	Plzen IVa Extract	Plzen IVb Exhaust	Plzen IVc Rejection	Cooling	Plzen V			
THERMAL DATA																
Efficiency – 80% to Full Load	%1			86 0%	84 0%	84 0%		91 1%	87 0%	87 0%	87 0%		91 1%			
Half Load	%2			86 0%	84 0%	84 0%		91 1%	87 0%	87 0%	87 0%		91 1%			
Minimum Load	%3			86 0%	84 0%	84 0%		91 1%	87 0%	87 0%	87 0%		91 1%			
Minimum Operation	%			7 3%	–	25 0%		25 0%	–	40 0%			12 5%			
Feedwater Temp																
Operation Adjustment Factor	Factor			0 085	0 085	0 095		0 040	0 050	0 060	0 060		0 045			
BOILER OUTPUT	Boiler MW									120 000						
Quantity	Mlb/Hr				749 700											
Pressure	PSIA				1976											
Temperature	Temp F				1004											
Enthalpy	MBTU/lb				1 477											
PRODUCT – LP STEAM	Priority	*		6	2				1							
Quantity	Mlb/Hr				116.204			143 300	110 000							
	MWts			56 100	100 000	165 000		43 500	47 000	115 000						
Pressure	PSIA				152			189								
Temperature	Temp F				428			428								
Enthalpy	MBTU/lb				1.230			1.230								
PRODUCT – HOT WATER	Priority			6		4				3		Cooling	5			
Quantity	MWtw			56 100		165 000		43 500		75 000		25 000	116 000			
Temperature – Supply	Temp F					320°				320°						
Return	Temp F					158				158						
TURBINE DATA	UNITe				Turb IA	Turb IB			Turb IIA	Turb IIB	Turb IIC					
	Priority				3	4			1	2					Purchase	Yes
Rated Capacity–Electric	KW				19720	55000			8800	25900					as Req d	
Capability – Max Steam	KW1				19720	55000			8800	25900						
75 % Steam	KW75				14060	40200			6280	18930						
50 % Steam	KW50				8430	25420			3780	11970						
25% Steam	KW25				2780	10620			1240	5000						
Steam Required – Maximum	M#/Hr Max				308 644	365 900			137 700	172.300						
Minimum	M#/Hr Min					91 500				43 000						
Outlet Steam Pressure	PSI				189	17 4			189	17 4						
Enthalpy Drop – Turbine	MBTU/lbt				0 2588	0 4157			0 2588	0 4157						
Sink	MBTU/lbs				1 1646	0 9146			1 1646	0 9700						
Generator Efficiency	%g				96 5%	96 5%			96 0%	96 0%	96 0%					
Power Ratio	Factor										0 3357					
FUELS DATA																
Primary Fuel	Type			Gas	Coal	Coal		Gas	Lignite	Lignite			Gas			
Cost	$/MMBTU			$3 77	$1 96	$1 96		$3 77	$1.24	$1.24			$3 77			
Percent Use	% Use			100 0%	99 6%	99 6%		55 0%	99 6%	99 6%			100 0%			
Secondary/Supplemental Fue	Type				Oil	Oil		Oil	Oil	Oil						
Cost	$/MMBTU				$2 99	$2.99		$2 99	$2 99	$2 99						
Percent Use	% Use				0 4%	0 4%		45 0%	0 4%	0 4%						
COST DATA (1993 Basis)	CK/$ =	28														
Number of Personnel	Number	92		30	160	–		8	56							
Average Wage & Benefits	$(000)	4 2		4.2	4.2	–		4.2	4.2							
Other Fixed Costs	$(000)	$879														
Raw Water & Treating Costs	$/MWHw	$0 10														
Demineralized Water Costs	$/MWHs	$1 41														
Other Variable O&M Costs	$/MWH	$0 41														
Limestone	$/Ton	$11 01														
Waste Disposal Costs	$/Ton	$3 24														
Emissions Code	CODEe			ST–2A8	PC–2B3	PC–2B3		ST–3A8	FB–2B4	FB–2B4	FB–2B4		ST–2A8			
Unscheduled Maintenance	CODE m			BR	P2	T1		P3	P4FB1	T2			P5			
Cost per Episode	Unit $(000)			2 0	2 0	1 0		2 0	2 5	1 0			2 0			
Purchased Power	$/kW														$7 93	
Energy Charge – Peak	Cents/KWHw															
Off–Peak	Cents/KWHs															
MONTHLY DATA	Avg Temp °C				AVAILABILITY										Ck	$US
W–Pk	3 0			100%	100%	100%		100%	100%	100%	100%	100%	100%		980	$35 0
W–Hi	3 0			100%	100%	100%		100%	100%	100%	100%	100%	100%		780	$27 8
W–Lo	3 0			100%	100%	100%		100%	100%	100%	100%	100%	100%		690	$24 6
W–Wknd	3 0			100%	100%	100%		100%	100%	100%	100%	100%	100%		690	$24 6
S–Pk1	11 6			100%	100%	100%		100%	–	–	–	100%	100%		980	$35 0
S–Pk2	18 3			100%	100%	100%		100%	100%	100%	100%	100%	100%		980	$35 0
S–Hi1	11 6			100%	100%	100%		100%	–	–	–	100%	100%		780	$27 8
S–Hi2	18 3			100%	100%	100%		100%	100%	100%	100%	100%	100%		780	$27 8
S–Lo1	11 6			100%	100%	100%		100%	–	–	–	100%	100%		690	$24 6
S–Lo2	18 3			100%	100%	100%		100%	100%	100%	100%	100%	100%		690	$24 6
S–Wknd1	11 6			100%	100%	100%		100%	–	–	–	100%	100%		690	$24
S–Wknd2	18.3			100%	100%	100%		100%	100%	100%	100%	100%	100%		690	$2

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Since, however, system components and characteristics obviously vary over time even within a given c 'se, multiple Data Sheets are required to represent the evolving situation at each pertinent .nterval For example, in connection with the year by year simulation of operating results under the subject variant, replacement Facilities Data Sheets, similar in form but different in content, are read into the model in the respective years on account of the following circumstances

1993	Present Situation
1996	Other plants (Letna, Bory, etc) are made available for single year New Fluidized Bed boiler (Plzen IV) comes into service
1997	Plzen II modified to reflect installation of baghouse and switch to low grade black coal firing Other Plants modified to reflect changes in efficiencies, environmental impacts, etc
2005	Plzen I retired Plzen V introduced

In the simulation for intervening years, facilities as represented in the most recently introduced data sheet are utilized in meeting current loads For example, the Data Sheet in Exhibit 8-7, although indicated for the year 2005, remains in effect for all years through 2010

In the simulation for each year, available facilities are dispatched to meet steam and hot water demands in accordance with a dispatching order stipulated in the currently effective data sheet Loading is assumed in accordance with load duration curve characteristics defined for each simulation period as illustrated previously in Exhibit 8-5

Load durations, measured in hours for each tenth percentile increment of peak demand, as shown in this Exhibit, are developed from data representative of historical loading conditions in the respective seasonal and subseasonal periods Absolute requirements in terms of peak MW demands and total kWh of energy in each of the twelve representative duty cycles are illustrated at year 2000 levels All data are modified for each analysis year in accordance with overall projections of maximum demand requirements for both steam and hot water Further exhibits, illustrative of model outputs are based on the simulation of system operations under Variant B1 conditions as applied in the year 2010

The projected energy requirements of each commodity in the year 2010 and the assigned duty cycles for each of the then available plants in meeting the respective loads are shown in page 1 of Exhibit 8-8 Initially indicated without regard to minimum load restrictions, loadings are subsequently adjusted in recognition of individual plant criteria

In page 2 of Exhibit 8-8, service to meet steam and hot water loads are consolidated as cumulative outputs for individual facilities although it may be noted that Plzen II and Plzen IV each retain two component designations, "a" and "b" This convention has been adopted to maintain the identity of steam and hot water deliveries through the extraction stage (a) and the exhaust stage (or secondary extraction stage) (b) of steam turbine generators I and II and the associated electric generation

VARIANT B1

Exhibit 8-8
LOAD DISPATCH AND ENERGY USE CALCULATIONS (page 1 of 3)

High Dema

			WINTER				SUMMER								
			Peak	High	Low	Weekend	Peak 1	Peak 2	High 1	High 2	Low 1	Low 2	Wkend 1	Wkend 2	
PRODUCT – LP STEAM															
Customer Requirement	MWH		58007	49652	71302	62027	6354	10515	11165	18251	16280	25394	12023	18752	359720
Station Use	MWH	–	–	–	–	–	–	–	–	–	–	–	–	–	–
			58007	49652	71302	62027	6354	10515	11165	18251	16280	25394	12023	18752	359720
	2	3		5	6		8	9	0		2	3		5	
	MWts		Average Loading – MW												
	–		–	–	–	–	–	–	–	–	–	–	–	–	
	–		–	–	–	–	–	–	–	–	–	–	–	–	
Brewery	56 100		–	–	–	–	–	–	–	–	–	–	–	–	
	–		–	–	–	–	–	–	–	–	–	–	–	–	
	–		–	–	–	–	–	–	–	–	–	–	–	–	
	–		–	–	–	–	–	–	–	–	–	–	–	–	
Plzen IIa	100 000		24 8	24 8	12 7	12 7	35 1	–	35 1	–	27 6	–	27 6	–	
Plzen IVa	47 000		46 3	46 3	43 0	43 0	–	34 4	–	34 1	–	25 5	–	25 5	
			Unit Energy Output – MWH (Before Adjustment for Minimum Loading Limitation)												
			–	–	–	–	–	–	–	–	–	–	–	–	
			–	–	–	–	–	–	–	–	–	–	–	–	
Brewery			–	–	–	–	–	–	–	–	–	–	–	–	
			–	–	–	–	–	–	–	–	–	–	–	–	
			–	–	–	–	–	–	–	–	–	–	–	–	
			–	–	–	–	–	–	–	–	–	–	–	–	
Plzen IIa			15688	13401	9546	8314	6354	–	11165	–	16280	–	12023	–	
Plzen IVa			42319	36251	61756	53713	–	10515	–	18251	–	25394	–	18752	
Total			58007	49652	71302	62027	6354	10515	11165	18251	16280	25394	12023	18752	359720
Steam Not Served	MWH		–	–	–	–	–	–	–	–	–	–	–	–	–
Total excluding HRSG supply			58007	49651 6	71301 6	62026 9	6354 48	10514 8	11165 2	18250.7	16279 6	25394	12022.7	18751 7	
PRODUCT – HOT WATER															
Customer Requirement	MWH		151236	129546	185986	161809	15432	10048	27113	17567	39429	24315	29119	17955	809555
Station Use	MWH	–	–	–	–	–	–	–	–	–	–	–	–	–	–
			151236	129546	185986	161809	15432	10048	27113	17567	39429	24315	29119	17955	809555
	2	3		5	6	7	8	9	0		2	3		5	
BASIS UNIT	MWtw		Average Loading – MW												
	–		–	–	–	–	–	–	–	–	–	–	–	–	
	–		–	–	–	–	–	–	–	–	–	–	–	–	
Brewery	56 100		9 3	9 3	–	–	–	–	–	–	–	–	–	–	
Plzen V	116 000		42 3	42 3	20 7	20 7	–	–	–	–	–	–	–	–	
Plzen IIb	165 000		118 9	118 9	95 6	95 6	85 3	–	85 3	–	66 9	–	66 9	–	
Plzen IVb	75 000		28 7	28 7	32 0	32 0	–	32 8	–	32 8	–	24 5	–	24 5	
	–		–	–	–	–	–	–	–	–	–	–	–	–	
	–		–	–	–	–	–	–	–	–	–	–	–	–	
Total			199.2	199.2	148.2	148 3	85 3	32 8	85 3	32 8	66 9	24.5	66 9	24.5	
			Unit Energy Output – MWH (Before Adjustment for Minimum Loading Limitation)												
			–	–	–	–	–	–	–	–	–	–	–	–	
			–	–	–	–	–	–	–	–	–	–	–	–	
Brewery			75	64	–	–	–	–	–	–	–	–	–	–	
Plzen V			16281	13898	2960	2586	–	–	–	–	–	–	–	–	
Plzen IIb			108668	93110	137157	119336	15432	–	27113	–	39429	–	29119	–	
Plzen IVb			26231	22474	45869	39887	–	10048	–	17567	–	24315	–	17955	
			–	–	–	–	–	–	–	–	–	–	–	–	
			–	–	–	–	–	–	–	–	–	–	–	–	
Total			151236	129546	185986	161809	15432	10048	27113	17567	39429	24315	29119	17955	809555
Hot Water Not Served	MWH		–	–	–	–	–	–	–	–	–	–	–	–	–
Total excluding HRSG supply			151236	129546	185986	161809	15432.4	10047 7	27113.3	17567	39428.6	24314 9	29119	17954 8	
ADJUSTED FOR MINIMUM LOADING – MWH															
Steam			Unit Utilization after Adjustment for Minimum Loading – MWH (Steam)												
			–	–	–	–	–	–	–	–	–	–	–	–	
			–	–	–	–	–	–	–	–	–	–	–	–	
Brewery			–	–	–	–	–	–	–	–	–	–	–	–	
			–	–	–	–	–	–	–	–	–	–	–	–	
			–	–	–	–	–	–	–	–	–	–	–	–	
			–	–	–	–	–	–	–	–	–	–	–	–	
Plzen IIa			15688	13401	9546	8314	6354	–	11165	–	16280	–	12023	–	
Plzen IVa			42319	36251	61756	53713	–	10515	–	18251	–	25394	–	18752	
Total			58007	49652	71302	62027	6354	10515	11165	18251	16280	25394	12023	18752	
Hot Water			Unit Utilization after Adjustment for Minimum Loading – MWH (Hot Water)												
			–	–	–	–	–	–	–	–	–	–	–	–	
			–	–	–	–	–	–	–	–	–	–	–	–	
Brewery			84	71	–	–	–	–	–	–	–	–	–	–	
Plzen V			16328	13959	3603	3147	–	–	–	–	–	–	–	–	
Plzen IIb			108593	93041	136513	118774	15432	–	27113	–	39429	–	29119	–	
Plzen IVb			26231	22474	45869	39887	–	10048	–	17567	–	24315	–	17955	
			–	–	–	–	–	–	–	–	–	–	–	–	
			–	–	–	–	–	–	–	–	–	–	–	–	
Total			151236	129546	185986	161809	15432	10048	27113	17567	39429	24315	29119	17955	

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VARIANT B1

High Demand

Exhibit 8-8
LOAD DISPATCH AND ENERGY USE CALCULATIONS (page 2 of 3)

TOTAL UNIT UTILIZATION BEFORE REQUIREMENT FOR ELECTRIC GENERATION – MWH

	WINTER				SUMMER								
	Peak	High	Low	Weekend	Peak 1	Peak 2	High 1	High 2	Low 1	Low 2	Wkend 1	Wkend 2	
	Output to meet Steam and Hot Water Requirements – MWH												
	–	–	–	–	–	–	–	–	–	–	–	–	
	–	–	–	–	–	–	–	–	–	–	–	–	
Brewery	84	71	–	–	–	–	–	–	–	–	–	–	
Plzen V	16328	13959	3603	3147	–	–	–	–	–	–	–	–	
Plzen IIb	108593	93041	136513	118774	15432	–	27113	–	39429	–	29119	–	
Plzen IVb	26231	22474	45869	39887	–	10048	–	17567	–	24315	–	17955	
Plzen IIa	15688	13401	9546	8314	6354	–	11165	–	16280	–	12023	–	
Plzen IVa	42319	36251	61756	53713	–	10515	–	18251	–	25394	–	18752	
Total	209243	179197	257288	223836	21787	20563	38279	35818	55708	49709	41142	36706	1169275

ADDITIONAL REQUIREMENT FOR BACK PRESSURE STEAM TURBINES – MWH

	Basis %g	Thermal output represented in electric generation – MWHt											
	–	–	–	–	–	–	–	–	–	–	–	–	–
	–	–	–	–	–	–	–	–	–	–	–	–	–
	–	–	–	–	–	–	–	–	–	–	–	–	–
	–	–	–	–	–	–	–	–	–	–	–	–	–
Turb IB	0 965	49611	42507	79140	68859	8865	–	15575	–	22101	–	16322	–
Turb IIB	0 96	13673	11715	24241	21080	–	5327	–	9314	–	12376	–	9139
Turb IA	0 965	1716	1466	1044	909	874	–	1536	–	1867	–	1379	–
Turb IIA	0 96	8235	7055	11883	10335	–	1941	–	3364	–	4348	–	3211
Total		73236	62742	116309	101184	9739	7268	17111	12678	23969	16724	17701	12349

STEAM TO CONDENSING TURBINES AND REJECTION – MWH

	Incremental thermal output represented in electric generation and rejection – MWHt											
	–	–	–	–	–	–	–	–	–	–	–	–
	–	–	–	–	–	–	–	–	–	–	–	–
	–	–	–	–	–	–	–	–	–	–	–	–
	–	–	–	–	–	–	–	–	–	–	–	–
	–	–	–	–	–	–	–	–	–	–	–	–
Turb IIC	19221	16465	28451	24745	–	8889	–	15705	–	37408	–	27623
	–	–	–	–	–	–	–	–	–	–	–	–
	–	–	–	–	–	–	–	–	–	–	–	–

UNIT UTILIZATION – TOTAL MWH

	Unit Utilization MWH											
	–	–	–	–	–	–	–	–	–	–	–	–
	–	–	–	–	–	–	–	–	–	–	–	–
Brewery	84	71	–	–	–	–	–	–	–	–	–	–
Plzen V	16328	13959	3603	3147	–	–	–	–	–	–	–	–
Plzen IIb	158204	135548	215654	187633	24297	–	42688	–	61530	–	45441	–
Plzen IVb and Plzen IVc	59126	50654	96561	85712	–	24264	–	42585	–	74099	–	54717
Plzen IIa	17404	14866	10590	9224	7229	–	12702	–	18147	–	13402	–
Plzen IVa	50554	43306	73639	64048	–	12456	–	21615	–	29742	–	21962
Total	301700	258405	402047	349764	31526	36720	55390	64200	79677	103841	58843	76679

INPUT ENERGY REQUIRED BEFORE EFFICIENCY ADJUSTMENT

	BTU/kW	Energy Input before Efficiency Adjustment – MMBTU											
	3 412	–	–	–	–	–	–	–	–	–	–	–	–
	3 412	–	–	–	–	–	–	–	–	–	–	–	–
Brewery	3 412	285	243	–	–	–	–	–	–	–	–	–	–
Plzen V	3 412	55710	47629	12295	10739	–	–	–	–	–	–	–	–
Plzen IIb	3 412	539793	462489	735810	640204	82902	–	145652	–	209941	–	155046	–
Plzen IVb and Plzen IVc	3 412	201738	172833	336291	292449	–	82789	–	145301	–	252826	–	186694
Plzen IIa	3 412	59384	50724	36134	31472	24665	–	43338	–	61917	–	45727	–
Plzen IVa	3 412	172490	147759	251255	218532	–	42499	–	73749	–	101479	–	74935
Total		1029401	881677	1371785	1193396	107567	125289	188989	219050	271858	354305	200773	261629

EFFICIENCY

	BASIS %1	BASIS %2	Efficiency											
		–	–	–	–	–	–	–	–	–	–	–	–	–
		–	–	–	–	–	–	–	–	–	–	–	–	–
Brewery	–	–	86 0%	86 0%	86 0%	86 0%	86 0%	86 0%	86 0%	86 0%	86 0%	86 0%	86 0%	86 0%
Plzen V	–	–	91 1%	91 1%	91 1%	91 1%	91 1%	91 1%	91 1%	91 1%	91 1%	91 1%	91 1%	91 1%
Plzen IIb	–	–	84 0%	84 0%	84 0%	84 0%	84 0%	84 0%	84 0%	84 0%	84 0%	84 0%	84 0%	84 0%
Plzen IVb and Plzen IVc	–	–	87 0%	87 0%	87 0%	87 0%	87 0%	87 0%	87 0%	87 0%	87 0%	87 0%	87 0%	87 0%
Plzen IIa	–	–	84 0%	84 0%	84 0%	84 0%	84 0%	84 0%	84 0%	84 0%	84 0%	84 0%	84 0%	84 0%
Plzen IVa	–	–	87 0%	87 0%	87 0%	87 0%	87 0%	87 0%	87 0%	87 0%	87 0%	87 0%	87 0%	87 0%

INPUT ENERGY REQUIRED

		Unit Energy Input MMBTU												
	–	–	–	–	–	–	–	–	–	–	–	–	–	–
	–	–	–	–	–	–	–	–	–	–	–	–	–	–
Brewery	8 5%	360	306	–	–	–	–	–	–	–	–	–	–	666
Plzen V	4 5%	63914	54643	14106	12320	–	–	–	–	–	–	–	–	144983
Plzen IIb	9 5%	703756	602970	959312	834666	108084	–	189893	–	273710	–	202141	–	3874533
Plzen IVb and Plzer IVc	6 0%	245830	210608	409792	356368	–	100884	–	177059	–	308084	–	227498	2036123
Plzen IIa	8 5%	76705	65518	46672	40651	31859	–	55978	–	79977	–	59064	–	456423
Plzen IVa	5 0%	208178	178330	303239	263745	–	51292	–	89008	–	122475	–	90439	1306705
Total		1298742	1112375	1733121	1507751	139942	152176	245871	266066	353687	430559	261205	317937	7819433

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VARIANT B1

High D mun

Exhibit 8-8
LOAD DISPATCH AND ENERGY USE CALCULATIONS (page 3 of 3)

			WINTER				SUMMER								
			Peak	High	Low	Weekend	Peak 1	Peak 2	High 1	High 2	Low 1	Low 2	Wkend 1	Wkend 2	
FUEL COST – BOILERS (Lignite)															
	Lignite %	Weighted $/MMBTU	Fuel Cost – Lignite $(000)												
	–	–	–	–	–	–	–	–	–	–	–	–	–	–	
	–	–	–	–	–	–	–	–	–	–	–	–	–	–	
Brewery	–	–	–	–	–	–	–	–	–	–	–	–	–	–	
Plzen V	–	–	–	–	–	–	–	–	–	–	–	–	–	–	
Plzen IIb	–	–	–	–	–	–	–	–	–	–	–	–	–	–	
Plzen IVb and Plzen IVc	99 6%	$1 24	304	260	506	440	–	125	–	219	–	380	–	281	2515
Plzen IIa	–	–	–	–	–	–	–	–	–	–	–	–	–	–	
Plzen IVa	99 6%	$1 24	257	220	375	326	–	63	–	110	–	151	–	112	
Total			561	480	881	766	–	188	–	329	–	532	–	393	4129
FUEL COST – BOILERS (Coal)															
	Coal %	Weighted $/MMBTU	Fuel Cost – Black Coal $(000)												
	–	–	–	–	–	–	–	–	–	–	–	–	–	–	
	–	–	–	–	–	–	–	–	–	–	–	–	–	–	
Brewery	–	–	–	–	–	–	–	–	–	–	–	–	–	–	
Plzen V	–	–	–	–	–	–	–	–	–	–	–	–	–	–	
Plzen IIb	99 6%	$1 95	1374	1177	1673	1629	211	–	371	–	534	–	395	–	
Plzen IVb and Plzen IVc	–	–	–	–	–	–	–	–	–	–	–	–	–	–	
Plzen IIa	99 6%	$1 95	150	128	91	79	62	–	109	–	156	–	115	–	
Plzen IVa	–	–	–	–	–	–	–	–	–	–	–	–	–	–	
Total			1524	1305	1964	1709	273	–	480	–	690	–	510	–	8455
FUEL COST – BOILERS (Gas)															
	Gas %	Weighted $/MMBTU	Fuel Cost – Natural Gas $(000)												
	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
Brewery	100 0%	$3 77	1	1	–	–	–	–	–	–	–	–	–	–	3
Plzen V	100 0%	$3 77	241	206	53	46	–	–	–	–	–	–	–	–	547
Plzen IIb	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
Plzen IVb and Plzen IVc	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
Plzen IIa	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
Plzen IVa	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
Total			242	207	53	46	–	–	–	–	–	–	–	–	549
FUEL COST – BOILERS (Oil)															
	Oil %	Weighted $/MMBTU	Fuel Cost – Oil $(000)												
	–	–	–	–	–	–	–	–	–	–	–	–	–	–	
	–	–	–	–	–	–	–	–	–	–	–	–	–	–	
Brewery	–	–	–	–	–	–	–	–	–	–	–	–	–	–	
Plzen V	–	–	–	–	–	–	–	–	–	–	–	–	–	–	
Plzen IIb	0 4%	$0 01	8	7	11	10	1	–	2	–	3	–	2	–	
Plzen IVb and Plzen IVc	0 4%	$0 01	3	3	5	4	–	1	–	2	–	4	–	3	
Plzen IIa	0 4%	$0 01	1	1	1	0	0	–	1	–	1	–	1	–	
Plzen IVa	0 4%	$0 01	2	2	4	3	–	1	–	1	–	1	–	1	
Total			15	13	21	18	2	2	3	3	4	5	3	4	92
HOT WATER SHORTFALL		MWH	–	–	–	–	–	–	–	–	–	–	–	–	
Assumed Equivalent Cost	$/MWH	$10 00													
SUPPLEMENTAL HOT WATER COST – $(000)			–	–	–	–	–	–	–	–	–	–	–	–	–
Water and Other Variable O&M Expenses – Boilers $(000)															
	Basis $/MWHr	Basis $/MWH	Variable O&M Expense $(000)												
	–	–	–	–	–	–	–	–	–	–	–	–	–	–	
	–	–	–	–	–	–	–	–	–	–	–	–	–	–	
Brewery	$0 10	$0 41	0	0	–	–	–	–	–	–	–	–	–	–	
Plzen V	$0 10	$0 41	8	7	2	2	–	–	–	–	–	–	–	–	
Plzen IIb	$0 10	$0 41	146	125	214	186	24	–	42	–	60	–	45	–	
Plzen IVb and Plzen IVc	$0 10	$0 41	73	63	119	104	–	31	–	54	–	103	–	76	
Plzen IIa	$0 10	$0 41	32	27	19	17	13	–	23	–	33	–	24	–	
Plzen IVa	$0 10	$0 41	92	79	134	117	–	23	–	39	–	54	–	40	
Total			351	300	488	424	37	54	65	94	93	157	69	116	2,249
Limestone and Ash Removal Expenses – Boilers $(000)															
	Limestone $/MMBTU	Removal $/MMBTU	Limestone Injection & Ash Removal Expenses $(000)												
	–	–	–	–	–	–	–	–	–	–	–	–	–	–	
	–	–	–	–	–	–	–	–	–	–	–	–	–	–	
Brewery	–	–	–	–	–	–	–	–	–	–	–	–	–	–	
Plzen V	–	–	–	–	–	–	–	–	–	–	–	–	–	–	
Plzen IIb	–	0 072	50	43	69	60	8	–	14	–	20	–	14	–	
Plzen IVb and Plzen IVc	0.212	0 133	85	73	142	123	–	35	–	61	–	106	–	79	
Plzen IIa	–	0 072	5	5	3	3	2	–	4	–	6	–	4	–	
Plzen IVa	0.212	0 133	72	62	105	91	–	18	–	31	–	42	–	31	
Total			213	182	318	277	10	53	18	92	25	149	19	110	1 465
Removal Costs Only			116	100	167	145	10	20	18	36	25	57	19	42	756
By–Product Sales $(000)			48	41	67	58	5	7	9	12	13	19	9	14	300
Emissions Penalties – Boilers $(000)															
		Emissions $/MMBTU	Emissions Penalties $(000)												
		–	–	–	–	–	–	–	–	–	–	–	–	–	
		–	–	–	–	–	–	–		–	–	–	–	–	
Brewery		–	–	–	–	–	–	–		–	–	–	–	–	
Plzen V		–	–	–	–	–	–	–	–	–	–	–	–	–	
Plzen IIb		–	–	–	–	–	–	–	–	–	–	–	–	–	
Plzen IVb and Plzen IVc		–	–	–	–	–	–	–	–	–	–	–	–	–	
Plzen IIa		–	–	–	–	–	–	–	–	–	–	–	–	–	
Plzen IVa		–	–	–	–	–	–	–	–	–	–	–	–	–	
Total			–	–	–	–	–	–	–	–	–	–	–	–	–
Emissions by Type – Tons															
		Units per Ton	Emissions – Tons												
Particulate		2000	23 3	20 0	32 5	28 3	2 6	3 0	4 5	5 2	6 5	6 4	4 8	6 2	145 3
SO_2		2000	546 1	467 7	746 0	649 0	71 1	50 1	124 9	87 7	179 7	141 9	132 7	104 8	3 301 6
NOx		2000	209 2	179 2	276 6	240 6	21 8	28 6	38 2	50 2	55 0	67 3	40 6	64 5	1 291 9
CO		2000	8 9	7 6	12 2	10 6	0 9	1 0	1 6	1 7	2 3	2 9	1 7	2 2	53 7

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Although electric outputs are summarized in subsequent exhibits, related thermal requirements for both back pressure and condensing turbines are combined at this point to establish total unit utilization as represented in MWh's (MWh) In this connection, a third turbine designation, turbine (c), has been utilized to denote a turbine which exhausts steam through the condensing exhaust and rejects heat through the cooling tower Finally, energy requirements are stated in MMBtu's before the adjustment for individual plant efficiencies and operating factors in establishing necessary gross energy inputs

Based upon this data, fuel costs are developed in page 3 of Exhibit 8-8 recognizing the specific fuel or fuels applicable for each operating unit Unit prices indicated in this schedule are a weighted composite expressing the relative utilization of primary and secondary fuels This exhibit serves further to demonstrate the manner and basis under which other variable expenses are incorporated in total projected costs

Average electrical output (in kW) of back pressure turbine/generators I and II is shown in Page 1 of Exhibit 8-9 giving recognition to the level of flow through each turbine component of the respective turbines measured relative to the level of flow necessary to attain maximum electrical output Output at reduced flow levels is interpolated linearly from data at 25% flow intervals for the respective turbine components included in the currently effective Facilities Data Sheet The electrical output indicated for the condensing turbine component (modeled as component C of Turbine/Generator II) is established as a fixed percentage of the steam output available to the turbine while accounting (in page 2 of Exhibit 8-9) for the maximum heat absorption capacity of the cooling tower associated with this scenario

To the extent that electrical generation is in excess of system requirements, it is a basic assumption of this analysis that a ready market for sales of this commodity exists at varying price levels, which, in fact, establish the criteria for the segregation of annual loads into the time periods adopted for this analysis As further shown in page 1 of Exhibit 8-9, in the sample case, substantial excess generation (represented as negative requirements) exists in all 12 time periods Revenues from external sales are credited to Variant B1 in aggregate amounts developed by applying the appropriately assumed price to the level of excess generation represented in the respective periods

Model output data similar to that discussed above is contained in Appendix F for each variant investigated In those cases involving gas turbines, the electrical outputs and the utilization of their exhaust heat is treated in detail considering the performance characteristics of the respective gas turbines at various ambient temperatures (as represented by the respective analysis periods) and at various load levels as dictated by steam and hot water load requirements Such data are developed in the schedule represented here as page 2 of Exhibit 8-9 For the subject case, however, this reference provides only for a summary of the level of heat rejection to the cooling tower necessary in each time period

A graphical representation of unit utilization and electrical output in each time period is shown in Exhibit 8-10

Exhibit 8-9
ELECTRIC GENERATION AND INTERCHANGE (page 1 of 2)

VARIANT B1 — High Dema

	WINTER				SUMMER								
	Peak	High	Low	Weekend	Peak 1	Peak 2	High 1	High 2	Low 1	Low 2	Wkend 1	Wkend 2	
Avg KW Required – Pumping	3020	3020	2567	2567	1036	364	1036	364	812	310	812	310	1676
Sta Use	8899	8897	7625	7627	4936	2867	4936	2862	3825	2286	3825	2286	5701
Total	11919	11917	10192	10194	5973	3231	5973	3226	4637	2595	4637	2595	7377

BACK PRESSURE TURBINE/GENERATOR OUTPUT – AVERAGE KW

BASIS UNITe	Back Pressure Turbine/Generator Output & Contract Purchase												
	–	–	–	–	–	–	–	–	–	–	–	–	
	–	–	–	–	–	–	–	–	–	–	–	–	
	–	–	–	–	–	–	–	–	–	–	–	–	
	–	–	–	–	–	–	–	–	–	–	–	–	
Turb IB	52380	52367	53220	53244	47263	–	47263	–	36210	–	36209	–	
Turb IA	2620	2613	1345	1346	4662	–	4662	–	3059	–	3059	–	
Turb IIB	14362	14363	16217	16215	–	16712	–	16712	–	11953	–	11953	
Turb IIA	8650	8649	7950	7950	–	6089	–	6036	–	4199	–	4199	
Total T/G Output	78011	78013	78731	78756	51924	22802	51925	22749	39270	16152	39269	16152	53923
Balance Required	–66093	–66096	–68540	–68561	–45952	–19571	–45952	–19523	–34633	–13557	–34632	–13557	

CONDENSING TURBINE OUTPUT – AVERAGE KW

	Generator Efficiency	Condensing Turbine Output – KW												
		–	–	–	–	–	–	–	–	–	–	–	–	–
		–	–	–	–	–	–	–	–	–	–	–	–	–
		–	–	–	–	–	–	–	–	–	–	–	–	–
		–	–	–	–	–	–	–	–	–	–	–	–	–
		–	–	–	–	–	–	–	–	–	–	–	–	–
Turb IIC	96 0%	6777	6777	6389	6390	–	9362	–	9460	–	12128	–	12128	1 04
		–	–	–	–	–	–	–	–	–	–	–	–	
		–	–	–	–	–	–	–	–	–	–	–	–	
Total Condens Turb Output		6777	6777	6389	6390	–	9362	–	9460	–	12128	–	12128	6790
Balance Required		–72870	–72872	–74929	–74951	–45952	–28933	–45952	–28983	–34633	–25685	–34632	–25685	
GT Capability @ Full Load		49627	49627	49627	49627	47720	46233	47720	46233	47720	46233	47720	46233	

GAS TURBINE OUTPUT – AVERAGE KW

	Gas Turbine Output – KW												
	–	–	–	–	–	–	–	–	–	–	–	–	
	–	–	–	–	–	–	–	–	–	–	–	–	
	–	–	–	–	–	–	–	–	–	–	–	–	
	–	–	–	–	–	–	–	–	–	–	–	–	
	–	–	–	–	–	–	–	–	–	–	–	–	
	–	–	–	–	–	–	–	–	–	–	–	–	
Total GT Output (KW)	–	–	–	–	–	–	–	–	–	–	–	–	–
Balance Required (KW)	–72870	–72872	–74929	–74951	–45952	–28933	–45952	–28983	–34633	–25685	–34632	–25685	
Hours in Period	914	783	1435	1248	181	306	318	535	589	994	435	734	
Balance Required (MWH)	–63953	–54790	–102220	–88930	–8317	–5989	–14613	–10445	–20399	–13476	–15065	–9951	
PURCHASED POWER	75%	75%	75%	75%	75%	75%	75%	75%	75%	75%	75%	75%	
Peak Demand KW	–	–	–	–	–	–	–	–	–	–	–	–	
Demand Charge – $/KW	7 93	7 93	7 93	7 93	7 93	7 93	7 93	7 93	7 93	7 93	7 93	7 93	
Energy Charge – $/KWH	0 0350	0 0279	0 0246	0 0246	0 0350	0 0350	0 0279	0 0279	0 0246	0 0246	0 0246	0 0246	
Demand Charge – $(000)	–	–	–	–	–	–	–	–	–	–	–	–	
Energy Charge – $(000)	–	–	–	–	–	–	–	–	–	–	–	–	
Total – $(000)	–	–	–	–	–	–	–	–	–	–	–	–	–
POWER SALES													
Energy Credit – Cents/KWH	0 0350	0 0279	0 0246	0 0246	0 0350	0 0350	0 0279	0 0279	0 0246	0 0246	0 0246	0 0246	
Energy Credit $(000)	2238 3	1526 3	2519 0	2191 5	291 1	209 6	407 1	291 0	502 7	332 1	371 2	245 2	11

VARIANT B1

Exhibit 8-9
ELECTRIC GENERATION AND INTERCHANGE (page 2 of 2)

High Dema

	WINTER				SUMMER							
	Peak	High	Low	Weekend	Peak 1	Peak 2	High 1	High 2	Low 1	Low 2	Wkend 1	Wkend 2

Interpolated Exhaust Temperature °F

	Exhaust Temperature °F											
	–	–	–	–	–	–	–	–	–	–	–	–
	–	–	–	–	–	–	–	–	–	–	–	–
	–	–	–	–	–	–	–	–	–	–	–	–
	–	–	–	–	–	–	–	–	–	–	–	–
	–	–	–	–	–	–	–	–	–	–	–	–
	–	–	–	–	–	–	–	–	–	–	–	–

Interpolated Exhaust Flow M#/Hr

	Exhaust Flow M#/Hr											
	–	–	–	–	–	–	–	–	–	–	–	–
	–	–	–	–	–	–	–	–	–	–	–	–
	–	–	–	–	–	–	–	–	–	–	–	–
	–	–	–	–	–	–	–	–	–	–	–	–
	–	–	–	–	–	–	–	–	–	–	–	–
	–	–	–	–	–	–	–	–	–	–	–	–

Available Exhaust Heat MMBTU/Hr

	Exhaust Heat MMBTU/Hr											
	–	–	–	–	–	–	–	–	–	–	–	–
	–	–	–	–	–	–	–	–	–	–	–	–
	–	–	–	–	–	–	–	–	–	–	–	–
	–	–	–	–	–	–	–	–	–	–	–	–
	–	–	–	–	–	–	–	–	–	–	–	–
	–	–	–	–	–	–	–	–	–	–	–	–

Steam Available – MW per Hour (Without Supplementary Firing)

	Enthalpy Rise	Total Steam Available without Supplementary Firing M#/Hr											
	–	–	–	–	–	–	–	–	–	–	–	–	–
	–	–	–	–	–	–	–	–	–	–	–	–	–
	–	–	–	–	–	–	–	–	–	–	–	–	–
	–	–	–	–	–	–	–	–	–	–	–	–	–
	–	–	–	–	–	–	–	–	–	–	–	–	–
	3 412	–	–	–	–	–	–	–	–	–	–	–	–
		–	–	–	–	–	–	–	–	–	–	–	–

Supplementary Firing – Maximum Exhaust Heat MMBTU/Hr

	–	–	–	–	–	–	–	–	–	–	–	–
	–	–	–	–	–	–	–	–	–	–	–	–
	–	–	–	–	–	–	–	–	–	–	–	–
	–	–	–	–	–	–	–	–	–	–	–	–
	–	–	–	–	–	–	–	–	–	–	–	–
	–	–	–	–	–	–	–	–	–	–	–	–

Steam Rejection – Avg MW (To Cooling Tower)

	Maximum Capacity	Steam Rejection – Average MW											
From Condensing	25 000	14 0	14 0	13 2	13 2	–	19 3	–	19 5	–	25 0	–	25 0
From Gas Turbines	25 000	–	–	–	–	–	–	–	–	–	–	–	–
Total		14 0	14 0	13 2	13 2	–	19 3	–	19 5	–	25 0	–	25 0

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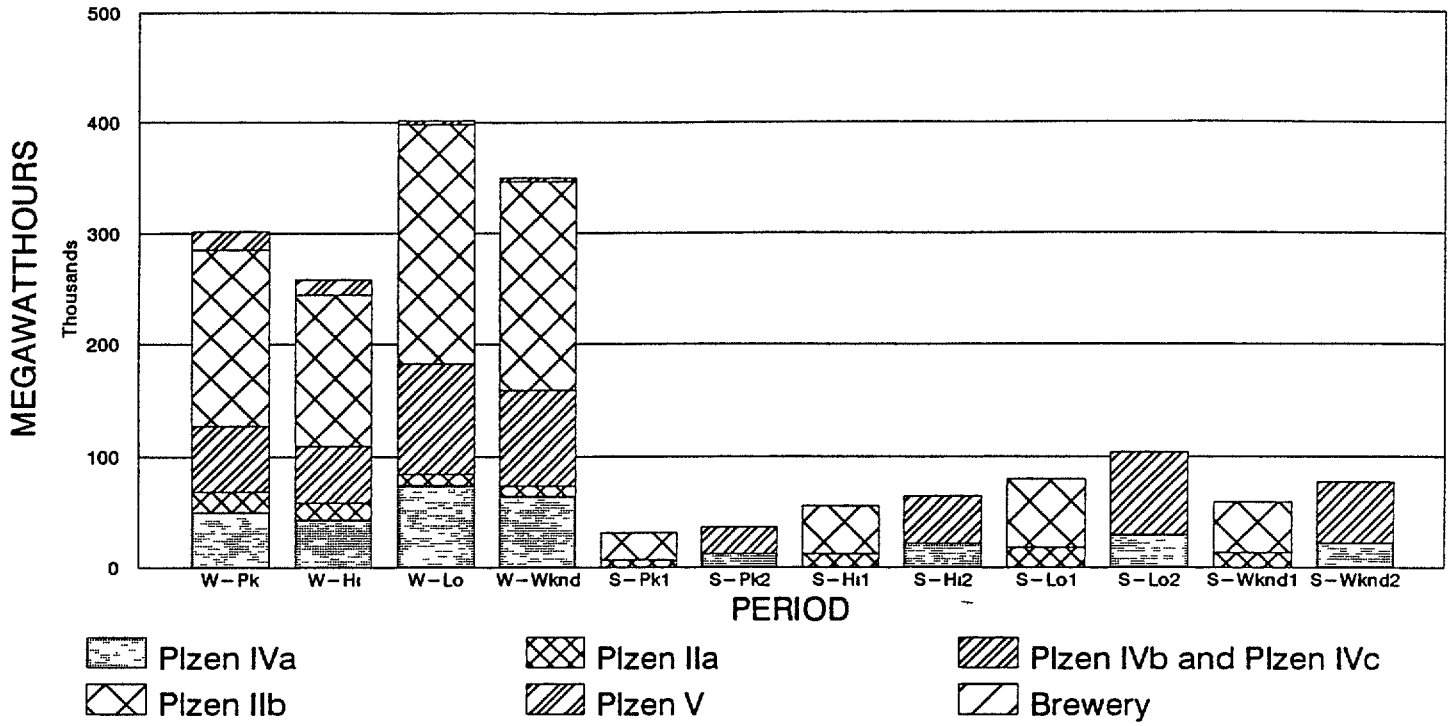
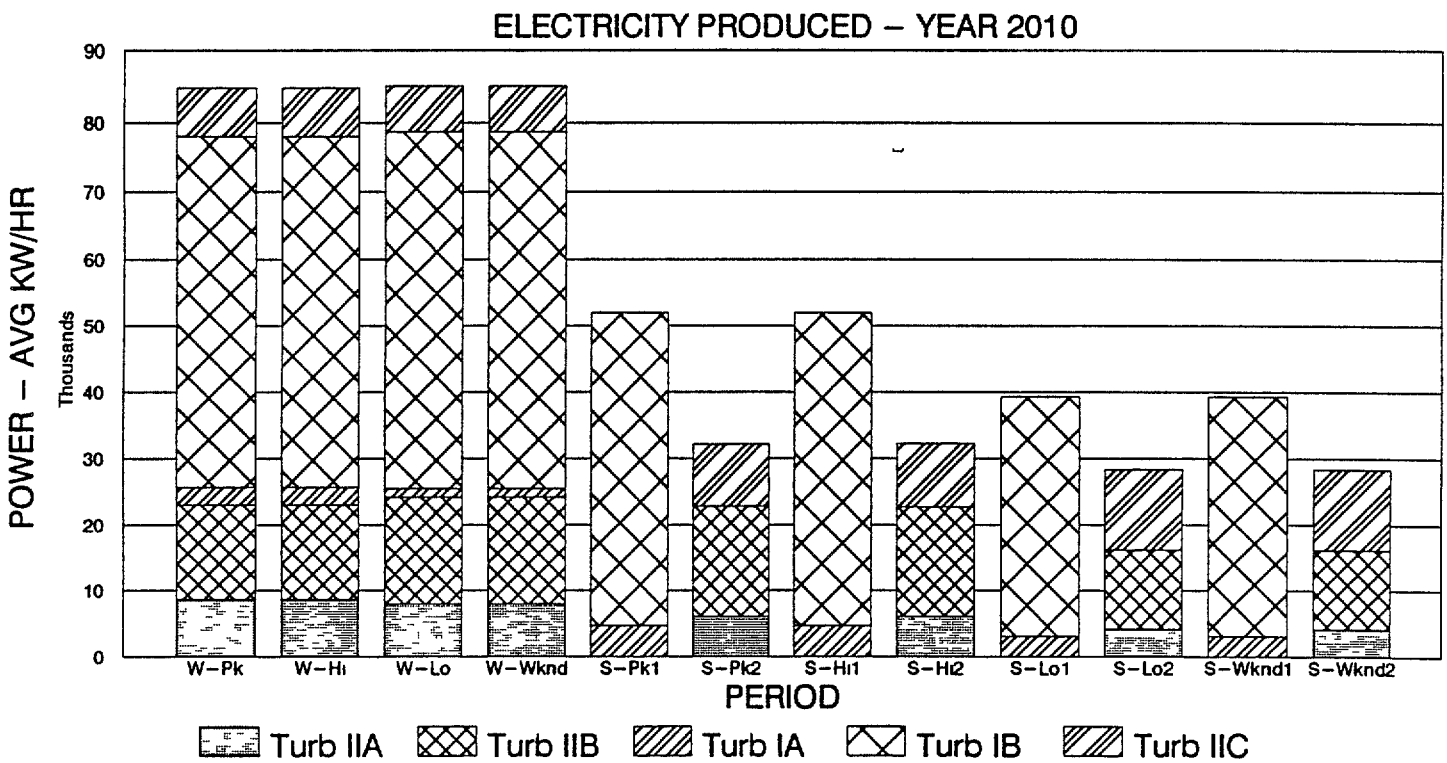
VARIANT B1

High Dema

Exhibit 8-10
GRAPHICAL REPRESENTATION OF LOAD DISPATCH AND ENERGY USE CALCULATIONS





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In the manner described above, available facilities were hypothetically dispatched to meet projected load requirements in each analysis year 1993 through 2010 For each year, fuel costs, other variable operating expenses and revenues (expense credits) for sales of electricity and ash disposal by-products were developed, but at this stage, always in terms of base year (1993) dollars Exhibit 8-11, which also characterizes the facilities in place in year 2010, provides a summary of net operating expenses on this basis, by time periods for that year Maintenance expenses are not include at this point

For economic analysis purposes, annual expenses determined in the manner described above are adjusted only for estimated real escalation in the summary of projected operating and capital expenditures shown for Variant B1 in Exhibit 8-12 and graphically in Exhibit 8-13 In addition to those expenses detailed through the discussion of the preceding model outputs, maintenance expenses are included in this summary on the basis of the maintenance schedule previously referenced in connection with the list of assumptions set forth above, but only to the extent that specific facilities are among those available for this specific case in any projection year

Estimated capital expenditures assumed in connection with modifications of existing plants or the installation of new facilities are shown in the year incurred, and are subject only to the escalation of off shore costs, to the extent represented, under rationale considering assumed relative domestic and foreign inflation levels Finally, in Exhibit 8-12, the present worth of annual expenditures is established by applying a real discount rate of 8% under the convention of average expenditures occurring at mid-year The cumulative present worth of such annual costs is then considered the primary figure of merit in the evaluation of the proposed alternative system configurations

Exhibit 8-12, however, also develops data further indicative of operating consequences under the example cases Total production of each commodity, while generally dictated by demands in the case of steam and hot water, is useful in demonstrating the predicted level of electrical production, and, in isolated cases, of shortfalls occurring primarily in the production of hot water Unit costs represented in connection with the production of each commodity are developed from a detailed recapitulation of each facilities utilization and may be useful in further comparison of variant or for other purposes It should be noted, however, that while these costs include fuel and other variable expenses, they do not include maintenance costs, personnel and general plant costs or capital expenditures

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VARIANT B1

High Dema

Exhibit 8-11
FACILITIES DATA INPUT SHEET

CASE B1 — Test Year = 2010 — Facilities Data

Station Use Unaccounted for etc — Electric kW – — % of Dem nd: Water –, Steam –

DESCRIPTION	UNIT	EXISTING FACILITIES						NEW FACILITIES						Steam Purchase	Power Purchase	Power Sales
				Brewery	Plzen IIa	Plzen IIb		Plzen III	Plzen IVa Extract	Plzen IVb Exhaust	Plzen IVc Rejection	Cooling	Plzen V			
THERMAL DATA																
Efficiency – 80% to Full Load	%1			86 0%	84 0%	84 0%		91 1%	87 0%	87 0%	87 0%		91 1%			
Half Load	%2			86 0%	84 0%	84 0%		91 1%	87 0%	87 0%	87 0%		91 1%			
Minimum Load	%3			86 0%	84 0%	84 0%		91 1%	87 0%	87 0%	87 0%		91 1%			
Minimum Operation	%			7 3%	–	25 0%		25 0%	–	40 0%			12 5%			
Feedwater Temp																
Operation Adjustment Factor	Factor			0 085	0 085	0 095		0 040	0 050	0 060	0 060		0 045			
BOILER OUTPUT	Boiler MW									120 000						
Quantity	Mlb/Hr				749 700											
Pressure	PSIA				1976											
Temperature	Temp °F				1004°											
Enthalpy	MBTU/lb				1 477											
PRODUCT – LP STEAM	Priority			6	2				1							
Quantity	Mlb/Hr				116 204			143 300	110 000							
	MWts			56 100	100 000	165 000		43 500	47 000	115 000						
Pressure	PSIA				152			189								
Temperature	Temp °F				426°			426°								
Enthalpy	MBTU/lb				1 230			1 230								
PRODUCT – HOT WATER	Priority			6		4				3		Cooling	5			
Quantity	MWtw			56 100		165 000		43 500		75 000		25 000	116 000			
Temperature – Supply	Temp °F					320°				320°						
Return	Temp °F					156°				156						
TURBINE DATA	UNITs				Turb IA	Turb IB			Turb IIA	Turb IIB	Turb IIC					
	Priority				3	4			1	2					Purchase	Yes
Rated Capacity–Electric	KW				19720	55000			8800	25900					as Req d	
Capability – Max Steam	KW1				19720	55000			8800	25900						
75 % Steam	KW75				14080	40200			6260	18930						
50 % Steam	KW50				8430	25420			3760	11970						
25% Steam	KW25				2780	10620			1240	5000						
Steam Required – Maximum	M#/Hr Max				308 644	365 900			137 700	172 300						
Minimum	M#/Hr Min					91 500				43 000						
Outlet Steam Pressure	PSI				169	17 4			169	17 4						
Enthalpy Drop – Turbine	MBTU/lbt				0 2588	0 4157			0 2588	0 4157						
Sink	MBTU/lbs				1 1646	0 9146			1 1646	0 9700						
Generator Efficiency	%g				96 5%	96 5%			96 0%	96 0%	96 0%					
Power Ratio	Factor										0 3357					
FUELS DATA																
Primary Fuel	Type			Gas	Coal	Coal		Gas	Lignite	Lignite			Gas			
Cost	$/MMBTU			$3 77	$1 96	$1 96		$3 77	$1 24	$1 24			$3 77			
Percent Use	% Use			100 0%	99 6%	99 6%		55 0%	99 6%	99 6%			100 0%			
Secondary/Supplemental Fue	Type				Oil	Oil		Oil	Oil	Oil						
Cost	$/MMBTU				$2 99	$2 99		$2 99	$2 99	$2 99						
Percent Use	% Use				0 4%	0 4%		45 0%	0 4%	0 4%						
COST DATA (1993 Basis)	CK$ =	28														
Number of Personnel	Number	92		30	180	–		8	56							
Average Wage & Benefits	$(000)	4 2		4 2	4 2	–		4 2	4 2							
Other Fixed Costs	$(000)	$679														
Raw Water & Treating Costs	$/MWHw	$0 10														
Demineralized Water Costs	$/MWHs	$1 41														
Other Variable O&M Costs	$/MWH	$0 41														
Limestone	$/Ton	$11 01														
Waste Disposal Costs	$/Ton	$3 24														
Emissions Code	CODEe			ST–2A8	PC–2B3	PC–2B3		ST–3A8	FB–2B4	FB–2B4	FB–2B4		ST–2A8			
Unscheduled Maintenance	CODE m			BR	P2	T1		P3	P4FB1	T2			P5			
Cost per Episode	Unit $(000)			2 0	2 0	1 0		2 0	2 5	1 0			2 0			
Purchased Power	$/kW															
Energy Charge – Peak	Cents/KWHw															
Off–Peak	Cents/KWHs															
MONTHLY DATA	Avg Temp C				AVAILABILITY											
W–Pk	3 0			100%	100%	100%		100%	100%	100%	100%	100%	100%			
W–Hi	3 0			100%	100%	100%		100%	100%	100%	100%	100%	100%			
W–Lo	3 0			100%	100%	100%		100%	100%	100%	100%	100%	100%			
W–Wknd	3 0			100%	100%	100%		100%	100%	100%	100%	100%	100%			
S–Pk1	11 6			100%	100%	100%		100%	–	–	–	100%	100%			
S–Pk2	18 3			100%	100%	100%		100%	100%	100%	100%	100%	100%			
S–Hi1	11 6			100%	100%	100%		100%	–	–	–	100%	100%			
S–Hi2	18 3			100%	100%	100%		100%	100%	100%	100%	100%	100%			
S–Lo1	11 6			100%	100%	100%		100%	–	–	–	100%	100%			
S–Lo2	18 3			100%	100%	100%		100%	100%	100%	100%	100%	100%			
S–Wknd1	11 6			100%	100%	100%		100%	–	–	–	100%	100%			
S–Wknd2	18 3			100%	100%	100%		100%	100%	100%	100%	100%	100%			

TEST YEAR SIMULATION RESULTS	WINTER				SUMMER								
	Peak	High	Low	Weekend	Peak 1	Peak 2	High 1	High 2	Low 1	Low 2	Wkend 1	Wkend 2	TOTAL
OPERATING EXPENSES													
Natural Gas	242	207	53	46	–	–	–	–	–	–	–	–	549
Oil	15	13	21	18	2	2	3	3	4	5	3	4	92
Lignite	561	480	861	766	–	188	–	329	–	532	–	393	4 129
Black Coal	1 524	1 305	1 964	1 709	273	–	480	–	690	–	510	–	8 455
Total Fuel Cost	2 341	2 005	2 918	2 539	275	190	483	332	695	537	513	396	13 224
Supplemental Cost–Shortfall Penalty)	–	–	–	–	–	–	–	–	–	–	–	–	–
Purchased Power Cost	–	–	–	–	–	–	–	–	–	–	–	–	–
Credit for Power Sales	(2 238)	(1 526)	(2 519)	(2 191)	(291)	(210)	(407)	(291)	(503)	(332)	(371)	(245)	(11 125)
Net Power Interchange Cost	(2 238)	(1 526)	(2 519)	(2 191)	(291)	(210)	(407)	(291)	(503)	(332)	(371)	(245)	(11 125)
Other O&M – Fixed OH & Other	252	216	396	345	50	84	88	148	163	274	120	203	2 339
Variable	351	300	488	424	7	54	65	94	93	157	69	116	2 49
Limestone Injection & Ash Removal	213	182	318	277	10	53	18	92	25	149	19	110	1 465
Credit for By–Product Sales	(46)	(41)	(57)	(58)	(5)	(7)	(9)	(12)	(13)	(19)	(9)	(14)	(300)
Emissions Penalties	–	–	–	–	–	–	–	–	–	–	–	–	–
Total Excluding Maintenance	871	1 137	1 535	1 335	76	164	236	363	461	–	340	566	7 851

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VARIANT B1

High Demand

Exhibit 8-12
PROJECTED OPERATING AND CAPITAL EXPENDITURES SUMMARY

COST EXCL INFLATION (000)

	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
OPERATING EXPENSES																		
Fuel Cost – Natural Gas	–	–	–	105	4	4	4	5	5	5	5	5	660	665	669	674	678	683
Oil	62	68	74	15	117	121	124	128	129	129	129	129	126	126	126	126	126	127
Lignite	6 790	7 255	7 752	5 631	4 840	4 933	5 029	5 126	5 127	5 127	5 128	5 128	5 129	5 129	5 130	5 130	5 131	5 131
Black Coal	–	–	–	5 370	8 782	8 988	9 196	9 413	9 429	9 442	9 455	9 468	9 064	9 074	9 084	9 094	9 104	9 114
Total Fuel Cost	6 852	7 323	7 827	11 121	13 742	14 045	14 353	14 673	14 690	14 703	14 716	14 730	14 980	14 995	15 010	15 025	15 040	15 055
Supplemental Cost (Shortfall)	–	–	0	–	–	–	–	–	–	–	0	–	–	(0)	–	(0)	–	–
Purchased Power Cost	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
Credit for Power Sales	(7,290)	(7 768)	(8,216)	(8,225)	(12 893)	(13 167)	(13 448)	(13 735)	(13 748)	(13 758)	(13 768)	(13 775)	(13 779)	(13 789)	(13 800)	(13 807)	(13 817)	(13 828)
Net Power Interchange	(7,290)	(7 768)	(8,216)	(8,225)	(12 893)	(13 167)	(13 448)	(13 735)	(13 748)	(13 758)	(13 768)	(13 775)	(13 779)	(13 789)	(13 800)	(13 807)	(13 817)	(13 828)
Fixed O&M and Overheads	2 300	2 300	2 300	2 510	2 542	2 542	2 542	2 542	2 542	2 542	2 542	2 542	2 339	2 339	2 339	2 339	2 339	2 339
Other Variable O & M	1 457	1 473	1 486	1 642	2 228	2 232	2 235	2 239	2 241	2 241	2 242	2 243	2 243	2 244	2 245	2 246	2 248	2 249
Sorbent and Ash Removal	245	285	331	651	1 832	1 835	1 837	2 632	2 633	2 635	2 636	2 637	2 608	2 609	2 610	2 611	2 612	2 613
Credit By-Product Sales	–	–	–	(197)	(302)	(303)	(303)	(304)	(304)	(305)	(305)	(305)	(299)	(299)	(299)	(300)	(300)	(300)
Emission Penalties	24	48	49	25	–	–	–	–	–	–	–	–	–	–	–	–	–	–
Maintenance Expenses	1 956	2 137	2 268	2 801	2 290	3 099	3 490	3 542	3 372	3 478	3 610	4 077	3 308	3 296	3 397	3 520	4 037	4 084
Plant Removal Costs	–	–	–	–	3 517	–	–	–	–	–	–	–	–	2 462	–	–	–	–
Total O&M Expense	5 544	5 799	6 046	10 328	12 956	10 283	10 706	11 587	11 424	11 535	11 673	12 148	11 399	13 855	11 501	11 635	12 158	12 212
CAPITAL COSTS																		
Foreign	–	–	1927	1976	–	–	–	–	–	–	–	–	–	–	–	–	–	–
Domestic	190	839	23145	22336	494	259	259	259	33	33	3301	3301	33	25	25	25	25	25
Total	190	839	25072	24312	494	259	259	259	33	33	3301	3301	33	25	25	25	25	25
TOTAL COST	5,734	6,637	31,118	34,640	13,450	10,542	10,964	11,846	11,457	11,568	14,974	15,449	11,433	13,881	11,527	11,660	12,184	12 237
Present Worth	5 517	5 914	25 672	26 460	9 513	6 904	6 648	6 651	5 956	5 569	6 674	6 376	4 369	4 911	3 776	3 537	3 422	3 183
Cumulative Present Worth	5 517	11 431	37 102	63 563	73 076	79 979	86 628	93 279	99 235	104 804	111 478	117 854	122 223	127 134	130 910	134 447	137 869	141 052
OPERATING STATISTICS																		
TOTAL PRODUCTION – MWH																		
LP Steam	333 355	331 188	329 021	360 443	361 165	361 165	361 165	361 165	361 165	360 804	360 443	360 082	359 720	359 720	359 720	359 720	359 720	359 720
Hot Water	534 466	552 841	573 853	777 066	787 452	790 913	794 109	797 571	798 903	800 234	801 566	802 897	804 229	805 294	806 359	807 424	808 489	809 555
Electricity	306 534	312 254	315 750	312 792	463 516	464 729	465 848	467 062	467 528	467 891	468 253	468 616	468 799	469 169	469 538	469 907	470 276	470 645
COST OF PRODUCTION – $/MWH (Variable Costs only)																		
LP Steam	$10 46	$10 77	$11 08	$12 38	$11 93	$12 05	$12 18	$12 96	$12 96	$12 96	$12 96	$12 96	$12 78	$12 78	$12 78	$12 78	$12 78	$12 78
Hot Water	$8 56	$8 85	$9 15	$10 08	$11 00	$11 16	$11 32	$11 82	$11 82	$11 82	$11 82	$11 82	$12 01	$12 01	$12 01	$12 01	$12 02	$12 02
Electricity	$9 20	$9 51	$9 81	$11 06	$15 26	$15 44	$15 62	$16 43	$16 42	$16 42	$16 41	$16 41	$16 24	$16 23	$16 23	$16 22	$16 22	$16 21
NOT SERVED – MWH																		
LP Steam	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
Hot Water	–	–	26	–	–	–	–	–	–	–	0	–	–	(0)	–	(0)	–	–
Electricity	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
EMISSIONS – TONNES																		
Particulates	248	259	272	416	131	131	131	132	132	132	132	132	131	131	132	132	132	132
SO_2	5 745	5 854	5 965	3 620	3 020	3 029	3 037	3 046	3 050	3 053	3 055	3 058	2 983	2 986	2 988	2 990	2 992	2 995
NOx	1 373	1 398	1 423	1 605	1 590	1 594	1 599	1 604	1 605	1 607	1 608	1 610	1 588	1 589	1 591	1 592	1 593	1 594
CO	56	59	62	144	76	76	77	77	78	78	78	78	63	63	63	63	63	63

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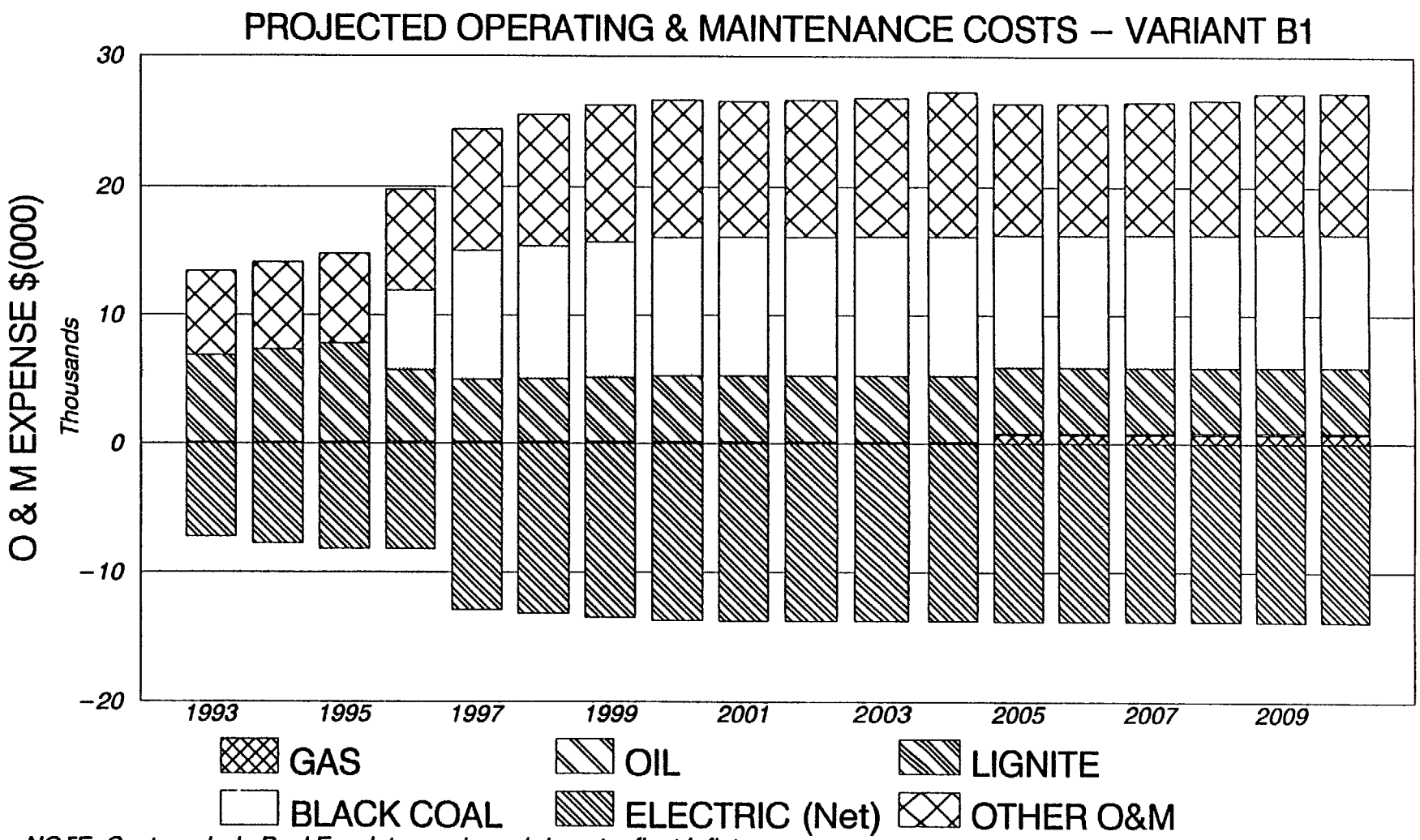
VARIANT B1

Exhibit 8-13
PROJECTED OPERATING AND MAINTENANCE COSTS SUMMARY

High Demand



NOTE Costs include Real Escalation only and do not reflect Inflation

8 6 3 Analysis Results

As the result of model simulations performed under each alternative configuration of plant components, and as represented in Appendix F for each variant, the cumulative present worth of projected operating and capital expenditures was developed for each variant as detailed in Exhibit 8-14, as shown graphically in Exhibit 8-15, and as summarized below

Variant	Total Operating & Capital Costs US $(000)	Present Worth of Total Cost US $(000)	Present Worth of Cost Savings vs Base Case	Internal Rate of Return on Cost Savings
C1 (Base Case)	266,422	137,991	Base	Base
A2	325,436	179 443	(41 452)	Negative
A3	327,521	177,438	(39 477)	Negative
B1	251,302	141,052	(3,061)	5 97%

From the results summarized above, it may be concluded that, given the level of gas prices, power sales revenues and capital costs anticipated, those variants developed around gas turbines (A2 and A3) are not cost competitive either with the Fluidized Bed variant (B1) or the Base Case (C1) representing essentially life extension In terms of the cumulative present worth of projected costs, Base Case (C1) is superior to Variant B1 although results are within 2% of each other and total non discounted costs for the variant are actually somewhat lower This apparent contradiction results because the discount rate applied (8%) is higher than the indicated internal rate of return of 5 97% (the discount rate which would equate the present worth of the two cases) That is to say, a discount rate of less than 5 97% would have to be applied in order for the present worth of projected costs for Variant B1 to be less than that for the Base Case

The above results and related conclusions are, of course, predicated on those capital costs and other assumptions underlying the analyses as thus far described In order to investigate the potential impact of alternative factors on initial conclusions, additional sensitivity analyses were performed as set forth in Section 8 7

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Exhibit 8-14
SUMMARY OF ECONOMIC ANALYSIS RESULTS

CUMULATIVE COST 1993 – 2010 $(000)

VARIANT Case)	Capital & Removal Costs	FUEL COST					Net Power Interchange	Fixed & Variable Expenses	Sorbent Ash Removal & Penalties	Maintenance	Total Operating Expenses	Total Capital & Operating Expenses
		Natural Gas	Oil	Lignite	Black Coal	Total						
C1 (Base)	57 020	898	1 887	68 465	165 575	236 825	(193 610)	79 158	24 398	62 631	209 401	266 422
A2	79 033	222 345	8 741	27 429	146 989	405 504	(298 270)	71 102	10 031	58 037	246 404	325 436
A3	70 020	206 226	9 921	27 429	148 785	392 361	(273 027)	70 790	10 117	57 261	257 502	327 521
B1	64 490	4 170	1 982	98 647	134 078	238 878	(222 611)	81 212	31 573	57 759	186 811	251 302

CUMULATIVE PRESENT WORTH $(000)

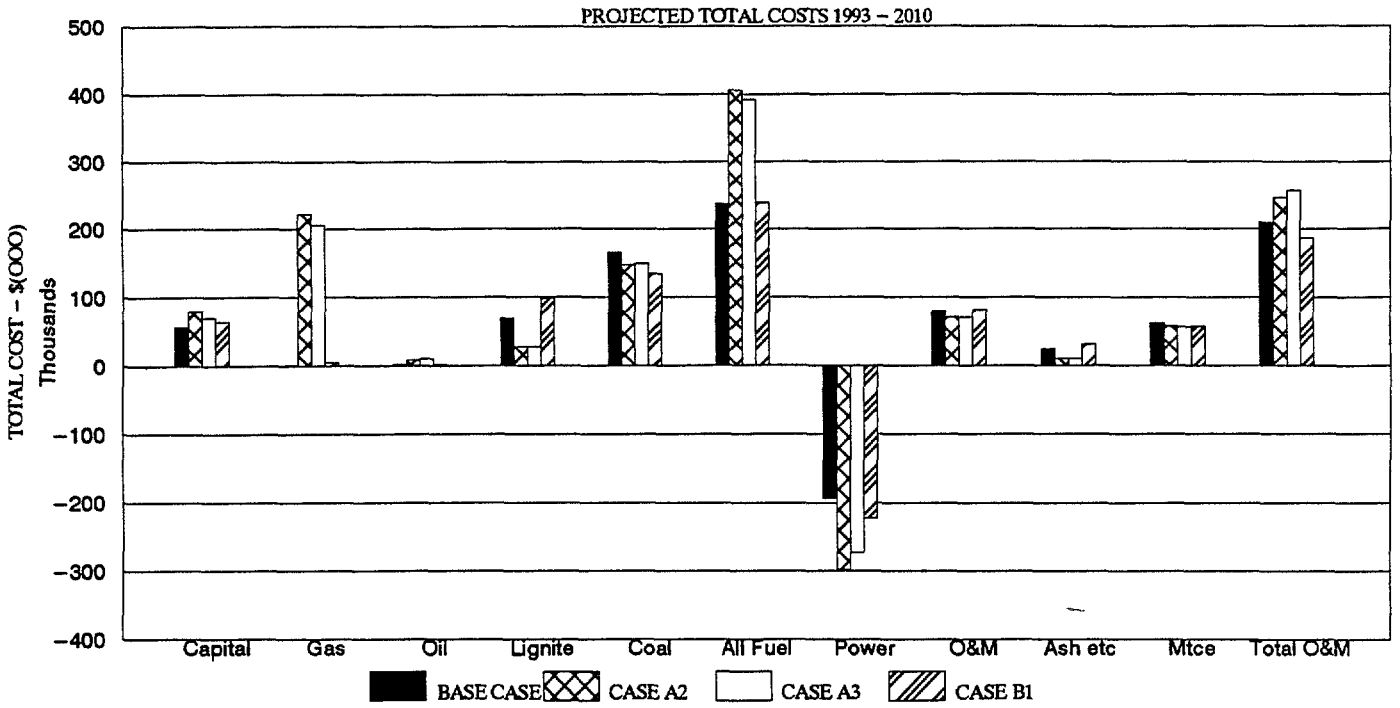
VARIANT Case)	Capital & Removal Costs	FUEL COST					Net Power Interchange	Fixed & Variable Expenses	Sorbent Ash Removal & Penalties	Maintenance	Total Operating Expenses	Total Capital & Operating Expenses
		Natural Gas	Oil	Lignite	Black Coal	Total						
C1 (Base)	32 223	531	922	37 884	79 771	119 108	(95 511)	41 360	10 098	30 713	105 768	137 991
A2	58 825	97 495	4 732	23 695	68 641	194 563	(146 346)	38 398	4 923	29 080	120 618	179 443
A3	51 667	90 072	5 376	23 695	69 622	188 765	(135 081)	38 283	4 968	28 835	125 771	177 438
B1	47 283	1 379	982	55 599	61 966	119 926	(112 526)	42 995	14 300	29 075	93 769	141 052

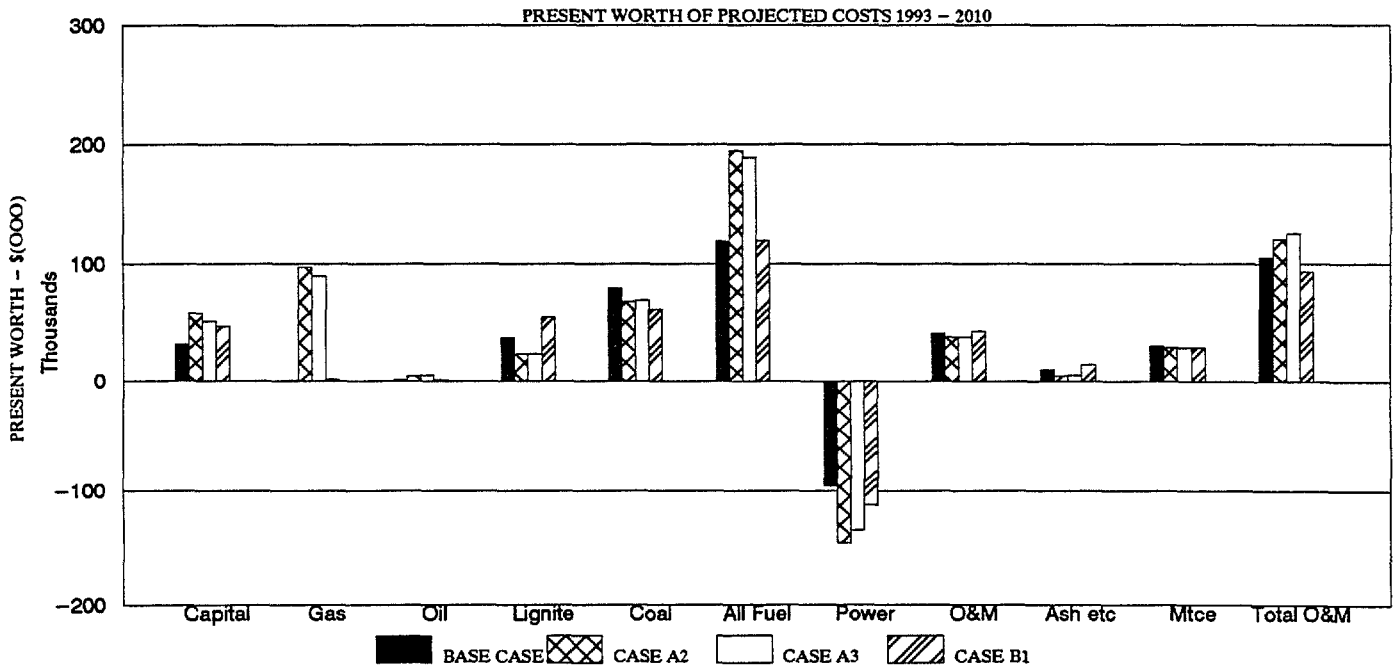
PRESENT WORTH COST SAVINGS $(000) (Versus Base Case)

VARIANT (Case)	Capital & Removal Costs	FUEL COST					Net Power Interchange	Fixed & Variable Expenses	Sorbent Ash Removal & Penalties	Maintenance	Total Operating Expenses	Total Capital & Operating Expenses	Internal Rate of Return (1)
		Natural Gas	Oil	Lignite	Black Coal	Total							
C1 (Base)	BASE	BASE	BASE	BASE	BASE	BASE	BASE	BASE	BASE	BASE	BASE	BASE	BASE
A2	(26 602)	(96 964)	(3 810)	14 189	11 130	(75 455)	50 835	2 962	5 175	1 633	(14 850)	(41 452)	Negative
A3	(19 444)	(89 541)	(4 454)	14 189	10 150	(69 657)	39 570	3 076	5 130	1 878	(20 003)	(39 447)	Negative
B1	(15 060)	(848)	(60)	(17 715)	17 806	(817)	17 015	(1 636)	(4 202)	1 638	11 999	(3 061)	5 97%

NOTE (1) Based on Cost Savings vs Base Case

Exhibit 8-15
GRAPHICAL SUMMARY OF ECONOMIC ANALYSIS RESULTS





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8 7 SENSITIVITY ANALYSES

Several sensitivity analyses were conducted to explore the effect of changes to selected initial assumptions and potential outcomes The impact of lower demand and escalation are specifically addressed, and an "Indifference Analysis" is employed to quantify the magnitude of adjustments necessary to make costs associated with each variant comparable to those projected under the Base Case

8 7 1 The Effect of Lower Demand Levels

While it is considered that those levels of steam and hot water demands reflected in the above analyses are more probable, the realization of reduced demand levels, if anticipated in a timely fashion, could cancel, modify or at least postpone the construction of facilities considered essential under the higher demand scenario Since the gas turbine variants focus on the cogeneration advantage (in a favorable environment) of maximizing electric energy for external sale, reduced demand levels would have little impact on results already developed Consequently, considering this factor only variants C1 and B1 were reanalyzed with a low demand In anticipation of lower demand levels, the following modifications were made to the respective cases

Case C1 Circulating Fluidized Bed boiler Plant Plzen IV, in service in year 2003, was reduced to 1/2 of the capacity previously proposed

Case B1 Gas/Oil fired Hot Water Grate Plant Plzen V, in service year 2005, was reduced from two 58 MW_t units to one 58 MW_t unit

Under the revised circumstances described above, model simulations were completed for both cases in order to develop projected costs in the reduced demand environment Results as summarized in Exhibits 8-16 and 8-17 indicate cumulative present worth costs of $119 7 million (3,673 2 million Kc) and $132 8 million (3 940 million Kc) for C1 and B1 respectively, suggesting that the Base Case is even more superior to Variant B1 under reduced demand conditions

8 7 2 The Effect of Real Escalation

As is generally the case, only real escalation has been recognized in the performance of this economic analysis To the extent that this factor has significant impact on some cost elements and little or none on others, it is quite possible that results may be influenced either favorably or unfavorably by escalation factors which while presently perceived as appropriate may not actually be realized Real escalation factors as applied in this analysis are summarized in Exhibit 8-6 Of particular impact, especially for the gas turbine variants, are those factors illustrated in Exhibit 8-18 that are related to the projected cost of natural gas and the revenue levels associated with projected sales of excess electric power It is significant to note that foreign costs also reflect a significant escalation introduced in recognition of a potential for upward pressures in currency exchange rates While it is by no means suggested that this situation will occur, it was considered prudent to at least recognize the eventuality

Sensitivity Analysis – VARIANT C1

Low Demand

Exhibit 8-16
PROJECTED OPERATING AND CAPITAL EXPENDITURES
VARIANT C1 - LOW DEMAND

COST EXCL INFLATION (000)

	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
OPERATING EXPENSES																		
Fuel Cost – Natural Gas	–	–	–	494	57	43	37	32	32	31	–	–	–	–	–	–	–	–
Oil	62	67	72	111	92	94	96	97	97	97	243	242	242	242	242	242	242	242
Lignite	6 774	7 149	7 552	2 909	–	–	–	–	–	–	2 649	2 649	2 649	2 649	2 649	2 649	2 649	2 649
Black Coal	–	–	–	7 021	12 379	12 486	12 585	12 687	12 678	12 669	9 868	9 858	9 849	9 849	9 849	9 849	9 849	9 849
Total Fuel Cost	6 836	7 216	7 624	10 536	12 528	12 623	12 718	12 817	12 807	12 798	12 761	12 750	12 740	12 740	12 740	12 740	12 740	12 740
Supplemental Cost (Shortfall)	–	–	–	–	0	–	–	–	–	–	–	–	–	–	–	–	–	–
Purchased Power Cost	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
Credit for Power Sales	(7 275)	(7 674)	(8 101)	(4 639)	(8 190)	(8 330)	(8 475)	(8 621)	(8 621)	(8 621)	(11 667)	(11 659)	(11 653)	(11 654)	(11 655)	(11 652)	(11 653)	(11 653)
Net Power Interchange	(7 275)	(7 674)	(8 101)	(4 639)	(8 190)	(8 330)	(8 475)	(8 621)	(8 621)	(8 621)	(11 667)	(11 659)	(11 653)	(11 654)	(11 655)	(11 652)	(11 653)	(11 653)
Fixed O&M and Overheads	2 300	2 300	2 300	2 510	2 510	2 510	2 510	2 510	2 510	2 510	2 592	2 592	2 592	2 592	2 592	2 592	2 592	2 592
Other Variable O & M	1 454	1 458	1 463	1 330	1 532	1 524	1 516	1 508	1 507	1 506	1 777	1 776	1 776	1 776	1 776	1 776	1 776	1 776
Sorbent and Ash Removal	244	280	322	514	645	639	633	1 065	1 064	1 064	1 785	1 785	1 784	1 784	1 784	1 784	1 784	1 784
Credit By-Product Sales	–	–	–	(129)	(218)	(216)	(214)	(211)	(211)	(211)	(242)	(241)	(241)	(241)	(241)	(241)	(241)	(241)
Emission Penalties	23	47	48	46	–	–	–	–	–	–	–	–	–	–	–	–	–	–
Maintenance Expenses	1 956	2 137	2 268	2 801	2 890	2 993	3 247	3 447	3 265	3 369	3 696	4 163	4 205	4 031	4 156	4 291	4 819	4 898
Plant Removal Costs	–	–	–	–	–	–	–	–	–	–	–	–	3 517	–	–	–	–	–
Total O&M Expense	5 539	5 766	5 925	12 969	11 698	11 744	11 935	12 514	12 322	12 415	10 703	11 166	14 719	11 026	11 151	11 289	11 816	11 895
CAPITAL COSTS																		
Foreign	–	–	–	–	–	–	–	–	1266	1279	–	–	–	–	–	–	–	–
Domestic	61	252	5013	4766	133	15	14	14	9944	9942	6	6	6	–	–	–	–	–
Total	61	252	5013	4766	133	15	14	14	11210	11221	6	6	6	–	–	–	–	–
TOTAL COST	5,600	6,018	10,938	17,734	11,831	11,760	11,949	12,528	23,532	23,637	10,709	11,172	14,725	11,026	11,151	11,289	11,816	11,895
Present Worth	5 389	5 362	9 024	13 546	8 368	7 701	7 246	7 034	12 234	11 378	4 773	4 610	5 627	3 901	3 653	3 424	3 319	3 093
Cumulative Present Worth	5 389	10 751	19 775	33 321	41 689	49 390	56 636	63 670	75 904	87 282	92 055	96 665	102 292	106 193	109 847	113 271	116 590	119 683

OPERATING STATISTICS

	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
TOTAL PRODUCTION – MWH																		
LP Steam	333 355	331 188	329 021	326 854	321 076	321 076	321 076	321 076	321 076	321 076	321 076	321 076	321 076	321 076	321 076	321 076	321 076	321 076
Hot Water	532 335	539 792	548 047	726 469	726 193	713 953	701 436	689 187	688 388	687 589	686 790	685 991	685 192	685 192	685 192	685 192	685 192	685 192
Electricity	305 849	308 042	310 497	193 400	306 508	305 494	304 458	303 445	303 378	303 312	396 893	396 651	396 410	396 410	396 410	396 410	396 410	396 410
COST OF PRODUCTION – $/MWH (Variable Costs only)																		
LP Steam	$10 46	$10 80	$11 13	$14 61	$13 88	$14 06	$14 25	$14 95	$14 95	$14 95	$13 91	$13 91	$13 91	$13 91	$13 91	$13 91	$13 91	$13 91
Hot Water	$8 56	$8 87	$9 19	$10 45	$12 00	$12 18	$12 36	$12 81	$12 81	$12 81	$12 31	$12 31	$12 31	$12 31	$12 31	$12 31	$12 31	$12 31
Electricity	$9 20	$9 53	$9 86	$12 62	$12 48	$12 67	$12 86	$13 39	$13 39	$13 39	$14 49	$14 49	$14 49	$14 49	$14 49	$14 49	$14 49	$14 49
NOT SERVED – MWH																		
LP Steam	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
Hot Water	–	–	–	–	10	–	–	–	–	–	–	–	–	–	–	–	–	–
Electricity	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
EMISSIONS – TONS																		
Particulates	272	276	281	729	102	101	101	100	100	100	117	117	117	117	117	117	117	117
SO_2	6 318	6 359	6 406	4 181	3 096	3 066	3 035	3 004	3 002	3 000	2 937	2 935	2 932	2 932	2 932	2 932	2 932	2 932
NOx	1 033	1 046	1 060	1 134	1 268	1 251	1 233	1 216	1 215	1 214	1 022	1 021	1 020	1 020	1 020	1 020	1 020	1 020
CO	1	1	1	41	7	7	6	6	6	6	42	42	42	42	42	42	42	42

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Sensitivity Analysis – VARIANT B1

Low Demand

Exhibit 8-17
PROJECTED OPERATING AND CAPITAL EXPENDITURES
VARIANT B1 - LOW DEMAND

COST EXCL INFLATION (000)

	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
OPERATING EXPENSES																		
Fuel Cost – Natural Gas	–	–	–	494	–	–	–	–	–	–	–	–	153	153	153	153	153	153
Oil	62	67	72	111	109	111	112	114	114	114	114	114	113	113	113	113	113	113
Lignite	6 774	7 149	7 552	2 909	4 766	4 846	4 927	5 011	5 010	5 009	5 009	5 008	5 011	5 011	5 011	5 011	5 011	5 011
Black Coal	–	–	–	7 021	7 751	7 755	7 755	7 756	7 747	7 737	7 727	7 718	7 611	7 611	7 611	7 611	7 611	7 611
Total Fuel Cost	6 836	7 216	7 624	10 536	12 626	12 712	12 795	12 882	12 871	12 861	12 850	12 840	12 889	12 889	12 889	12 889	12 889	12 889
Supplemental Cost (Shortfall)	–	–	–	–	–	–	–	–	–	(0)	(0)	–	0	0	0	0	0	0
Purchased Power Cost	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
Credit for Power Sales	(7 275)	(7 674)	(8 101)	(4 639)	(12 184)	(12 295)	(12 408)	(12 520)	(12 512)	(12 505)	(12 497)	(12 487)	(12 481)	(12 481)	(12 482)	(12 480)	(12 480)	(12 481)
Net Power Interchange	(7 275)	(7 674)	(8 101)	(4 639)	(12 184)	(12 295)	(12 408)	(12 520)	(12 512)	(12 505)	(12 497)	(12 487)	(12 481)	(12 481)	(12 482)	(12 480)	(12 480)	(12 481)
Fixed O&M and Overheads	2 300	2 300	2 300	2 510	2 542	2 542	2 542	2 542	2 542	2 542	2 542	2 542	2 339	2 339	2 339	2 339	2 339	2 339
Other Variable O & M	1 454	1 458	1 463	1 330	2 081	2 066	2 051	2 036	2 035	2 034	2 033	2 032	2 031	2 031	2 031	2 031	2 031	2 031
Sorbent and Ash Removal	244	280	322	514	1 758	1 748	1 738	2 452	2 451	2 450	2 449	2 448	2 441	2 441	2 441	2 441	2 441	2 441
Credit By-Product Sales	–	–	–	(129)	(282)	(279)	(276)	(273)	(273)	(273)	(273)	(273)	(271)	(271)	(271)	(271)	(271)	(271)
Emission Penalties	23	47	48	46	–	–	–	–	–	–	–	–	–	–	–	–	–	–
Maintenance Expenses	1 956	2 137	2 268	2 801	2 290	3 099	3 490	3 542	3 372	3 478	3 610	4 077	3 308	3 296	3 397	3 520	4 037	4 084
Plant Removal Costs	–	–	–	–	3 517	–	–	–	–	–	–	–	–	2 462	–	–	–	–
Total O&M Expense	5 539	5 766	5 925	12 969	12 348	9 592	9 930	10 660	10 485	10 586	10 714	11 178	10 256	12 705	10 343	10 469	10 986	11 032
CAPITAL COSTS																		
Foreign	–	–	1927	1976	–	–	–	–	–	–	–	–	–	–	–	–	–	–
Domestic	61	252	21792	21544	133	15	14	14	8	6	2019	2019	6	–	–	–	–	–
Total	61	252	23719	23519	133	15	14	14	8	6	2019	2019	6	–	–	–	–	–
TOTAL COST	5,600	6,018	29,644	36,488	12,481	9,607	9,944	10,673	10,492	10,592	12,733	13,198	10,262	12,705	10,343	10,469	10,986	11,032
Present Worth	5 389	5 362	24 456	27 872	8 828	6 292	6 030	5 993	5 455	5 099	5 675	5 447	3 921	4 495	3 389	3 176	3 086	2 869
Cumulative Present Worth	5 389	10 751	35 206	63 078	71 906	78 198	84 228	90 220	95 675	100 774	106 449	111 895	115 817	120 312	123 700	126 876	129 962	132 831

OPERATING STATISTICS

	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
TOTAL PRODUCTION – MWH																		
LP Steam	333 355	331 188	329 021	326 854	321 076	321 076	321 076	321 076	321 076	321 076	321 076	321 076	321 076	321 076	321 076	321 076	321 076	321 076
Hot Water	532 335	539 792	548 047	726 469	726 202	713 953	701 436	689 187	688 388	687 589	686 790	685 991	685 192	685 192	685 192	685 192	685 192	685 192
Electricity	305 849	308 042	310 497	193 400	434 681	430 069	425 359	420 695	420 389	420 082	419 776	419 469	419 211	419 211	419 211	419 211	419 211	419 211
COST OF PRODUCTION – $/MWH (Variable Costs only)																		
LP Steam	$10 46	$10 80	$11 13	$14 61	$12 01	$12 15	$12 29	$13 09	$13 09	$13 09	$13 09	$13 09	$12 91	$12 91	$12 91	$12 91	$12 91	$12 91
Hot Water	$8 56	$8 87	$9 19	$10 45	$11 03	$11 19	$11 35	$11 87	$11 87	$11 87	$11 88	$11 88	$11 85	$11 85	$11 85	$11 85	$11 85	$11 85
Electricity	$9 20	$9 53	$9 86	$12 62	$15 78	$16 04	$16 31	$17 24	$17 24	$17 25	$17 25	$17 26	$17 08	$17 08	$17 08	$17 08	$17 08	$17 08
NOT SERVED – MWH																		
LP Steam	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
Hot Water	–	–	–	–	–	–	–	–	–	(0)	(0)	–	0	0	0	0	0	0
Electricity	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
EMISSIONS – TONS																		
Particulates	272	276	281	729	135	134	132	131	131	131	131	131	131	131	131	131	131	131
SO_2	6 318	6 359	6 406	4 181	3 056	3 019	2 981	2 944	2 942	2 939	2 937	2 934	2 913	2 913	2 913	2 913	2 913	2 913
NOx	1 033	1 046	1 060	1 134	1 196	1 182	1 168	1 155	1 154	1 153	1 152	1 151	1 149	1 149	1 149	1 149	1 149	1 149
CO	1	1	1	41	50	49	48	48	48	48	48	48	47	47	47	47	47	47

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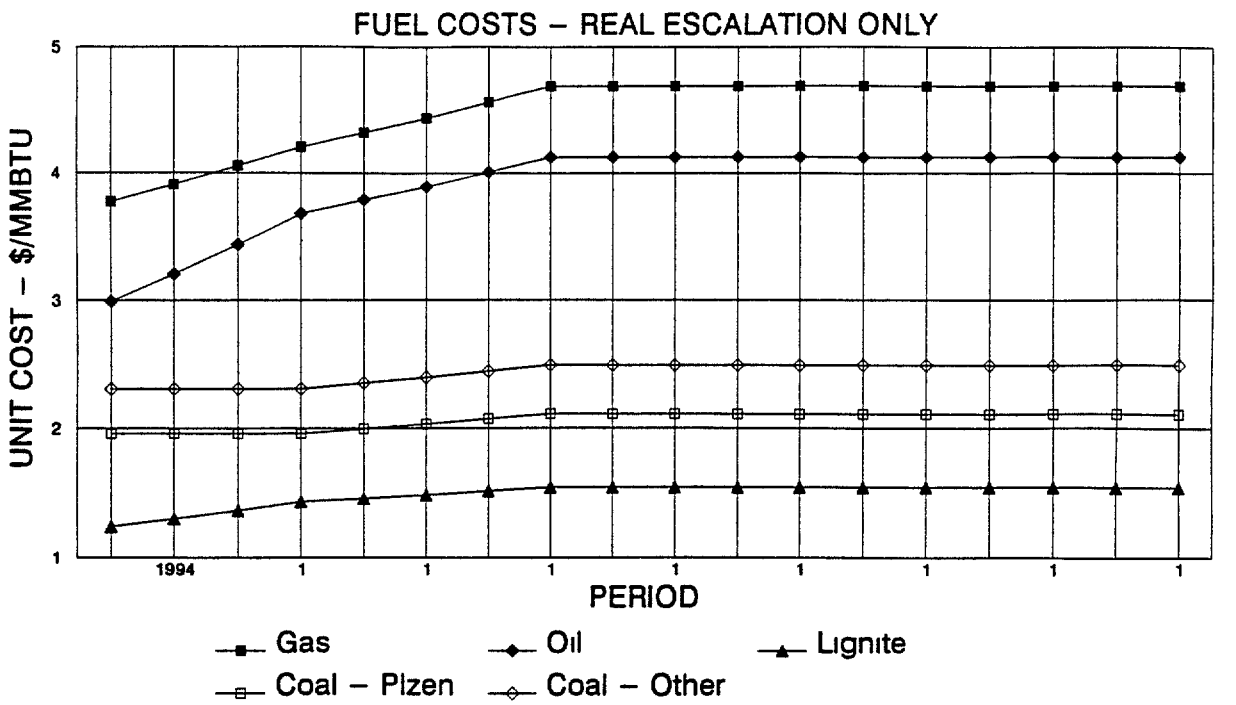
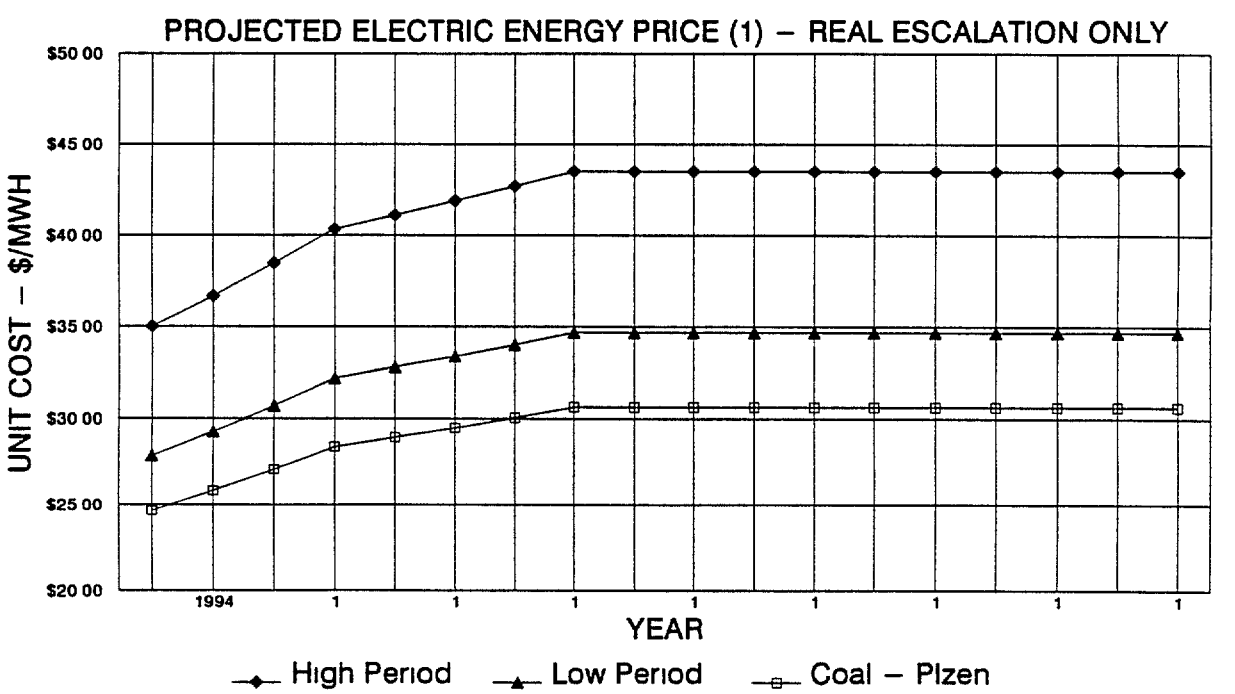
Exhibit 8-18
PROJECTED FUELS AND POWER SALES COST ESCALATION





NOTE (1) Energy price levels shown are assumed for both power purchases and power sales In addition a capacity charge established at a 1993 level of $7 93 per KW per month and escalated in the same fashion is assumed for power purchases only

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Although it would have been possible to modify escalation factors on a selective basis, the risk remains that unintended bias might continue to influence results Further, since it was perceived that the gas turbine cases were potentially the most severely impacted by escalation considerations, the elimination of all escalation, while not realistic, would probably represent somewhat of a "best case" scenario for Variants A2 and A3 Indeed, reanalysis on this basis, as summarized in the two pages of Exhibit 8-19, do result in a reduced cost level for each variant However, it is apparent that even on this basis, C1 and B1 remain superior to the gas turbine variants, and, although the margin is reduced, the present worth of projected costs for the Base Case is still less than that for Variant B1

8 7 3 Indifference Analysis

Rather than performing reanalysis under conditions reflecting somewhat arbitrarily established increases or decreases in sensitive assumptions, i e, Capital Costs +20%, Fuel Costs -15%, etc, we have chosen instead to represent, for each major component of cost, the unit cost adjustment that would be required in order for the overall present worth of each respective variant to be equivalent to that of the Base Case (C1)

The table at the bottom of Exhibit 8-20 indicates the magnitude of adjustments required under the assumption that all other cost components for that case and the Base Case remain unchanged For example, in order for the present worth of costs for Variant A2 to equal that of the Base Case (C1), the price of natural gas would have to be reduced by approximately 43%, or conversely, the price of black coal would have to be increased by 372% An indication of "NA" means that it is not possible to attain equilibrium through any logical adjustment of this factor in isolation While negative adjustments of greater than 100% in total operating expenses would appear to be illogical, it must be remembered that, as developed, such expense totals include "expense credits" for excess power sales, which, if of sufficient magnitude could more than offset expenses otherwise incurred Whether this circumstance is likely to occur to the degree indicated as being required is another matter

Finally, in order to add further perspective to this analysis, Exhibit 8-21 provides the same type of data except that in this case, it addresses present worth values developed in the absence of real escalation in the manner described above

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Sensitivity Analysis

Exhibit 8-19
PROJECTED OPERATING AND CAPITAL EXPENDITURES SUMMARY
EXCLUDING REAL ESCALATION (page 1 of 2)

BASE CASE (C1)	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2,008	2009	2010
OPERATING EXPENSES																		
Fuel Cost – Natural Gas	–	–	–	95	93	98	102	106	108	110	4	4	4	4	5	5	5	5
Oil	62	63	65	12	79	79	79	79	79	79	93	93	93	94	94	94	94	94
Lignite	6 790	6 919	7 050	4 884	–	–	–	–	–	–	4 126	4 126	4 126	4 127	4 127	4 128	4 128	4 129
Black Coal	–	–	–	5 370	13 188	13 224	13 258	13 291	13 305	13 315	8 771	8 783	8 794	8 806	8 818	8 830	8 842	8 854
Total Fuel Cost	6 852	6 983	7 115	10 360	13 360	13 400	13 437	13 477	13 493	13 504	12 994	13 006	13 019	13 031	13 044	13 056	13 069	13 081
Supplemental Cost (Shortfall)	–	–	0	–	–	–	–	–	–	–	0	–	–	0	–	0	–	–
Purchased Power Cost	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
Less Sales of Electricity	(7,290)	(7,408)	(7,472)	(7,133)	(7,058)	(7,060)	(7,065)	(7,067)	(7,069)	(7,071)	(11,077)	(11,082)	(11,090)	(11,099)	(11,107)	(11,113)	(11,121)	(11,130)
Net Power Interchange	(7 290)	(7 408)	(7 472)	(7 133)	(7 058)	(7 060)	(7 065)	(7 067)	(7 069)	(7 071)	(11 077)	(11 082)	(11 090)	(11 099)	(11 107)	(11 113)	(11 121)	(11 130)
Fixed O&M and Overheads	2 300	2 300	2 300	2 510	2 510	2 510	2 510	2 510	2 510	2 510	2 592	2 592	2 592	2 592	2 592	2 592	2 592	2 592
Variable O&M	1 457	1 473	1 488	1 642	1 650	1 652	1 654	1 657	1 657	1 658	2 242	2 243	2 243	2 244	2 246	2 247	2 248	2 249
Sorbent and Ash Removal	245	250	254	440	470	472	473	474	474	475	1 047	1 047	1 047	1 048	1 048	1 049	1 049	1 050
Credit By-Product Sales	–	–	–	(133)	(159)	(159)	(160)	(94)	(94)	(94)	(121)	(121)	(121)	(121)	(121)	(121)	(122)	(122)
Emission Penalties	78	80	82	31	–	–	–	–	–	–	–	–	–	–	–	–	–	–
Maintenance Expenses	1 956	2 137	2 268	2 801	2 890	2 993	3 247	3 447	3 265	3 369	3 698	4 163	4 205	4 031	4 156	4 291	4 819	4 898
Plant Removal Costs	–	–	–	–	–	–	–	–	–	–	–	–	3,517	–	–	–	–	–
Total O&M Expense	5 599	5 815	6 035	10 517	13 864	13 808	14 097	14 404	14 237	14 351	11 372	11 847	15 412	11 728	11 858	12 000	12 534	12 818
CAPITAL COSTS																		
Foreign	–	–	–	–	–	–	–	–	1 791	1 791	–	–	–	–	–	–	–	–
Domestic	190	839	6 367	5 556	494	259	259	259	17 314	17 314	33	33	33	25	25	25	25	25
Total	190	839	6 367	5 556	494	259	259	259	19 104	19 104	33	33	33	25	25	25	25	25
TOTAL COST	5,788	6,654	12,402	16,075	14,158	14,068	14,356	14,662	33,341	33,455	11,405	11,880	15,445	11,751	11,882	12,026	12,559	12,844
Present Worth	5 570	5 926	10 231	12 279	10 014	9 212	8 705	8 232	17 333	16 104	5 063	4 903	5 902	4 158	3 893	3 648	3 528	3 268
Cum Present Worth	5 570	11 496	21 729	34 008	44 022	53 234	61 939	70 172	87 505	103 609	108 693	113 595	119 497	123 655	127 548	131 196	134 723	138 011

CASE A2	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2,008	2009	2010
OPERATING EXPENSES																		
Fuel Cost – Natural Gas	–	–	–	95	11 943	11 984	12 021	12 063	12 079	12 090	12 101	12 112	13 894	14 013	14 032	14 051	14 070	14 089
Oil	62	63	65	12	723	732	741	750	754	757	760	763	53	53	53	53	53	53
Lignite	6 790	6 919	7 050	4 884	–	–	–	–	–	–	–	–	–	–	–	–	–	–
Black Coal	–	–	–	5,370	9,968	9,992	10,014	10,038	10,047	10,054	10,062	10,069	8,701	8,703	8,705	8,707	8,709	8 711
Total Fuel Cost	6 852	6 983	7 115	10 360	22 634	22 708	22 776	22 850	22 880	22 902	22 923	22 945	22 748	22 769	22 790	22 811	22 832	22 853
Supplemental Cost (Shortfall)	–	–	0	–	(0)	(0)	–	–	0	0	0	0	–	–	–	–	0	(0)
Purchased Power Cost	–	–	–	–	45	45	46	46	46	46	46	46	46	46	46	46	46	46
Less Sales of Electricity	(7 290)	(7 408)	(7 472)	(7 133)	(15 319)	(15 369)	(15 417)	(15 467)	(15 488)	(15 502)	(15 516)	(15 527)	(15 527)	(15 541)	(15 555)	(15 566)	(15 580)	(15 594)
Net Power Interchange	(7 290)	(7 408)	(7 472)	(7 133)	(15 274)	(15 323)	(15 371)	(15 421)	(15 442)	(15 456)	(15 470)	(15 482)	(15 481)	(15 495)	(15 509)	(15 520)	(15 534)	(15 546)
Fixed O&M and Overheads	2 300	2 300	2 300	2 510	2 372	2 372	2 372	2 372	2 372	2 372	2 372	2 372	2 237	2 237	2 237	2 237	2 237	2 237
Variable O&M	1 457	1 473	1 488	1 642	1 651	1 654	1 656	1 659	1 660	1 660	1 660	1 660	1 660	1 661	1 662	1 663	1 663	1 664
Sorbent and Ash Removal	245	250	254	440	358	359	360	361	361	361	361	362	319	319	319	319	319	319
Credit By-Product Sales	–	–	–	(133)	(121)	(121)	(121)	(72)	(72)	(72)	(72)	(72)	(63)	(63)	(63)	(63)	(63)	(63)
Emission Penalties	78	80	82	31	–	–	–	–	–	–	–	–	–	–	–	–	–	–
Maintenance Expenses	1 956	2 137	2 268	2 801	2 285	3 047	3 438	3 489	3 315	3 421	3 552	4 009	3 415	3 403	3 508	3 642	4 152	4 204
Plant Removal Costs	–	–	–	–	3,517	–	–	–	–	–	–	–	–	2 462	–	–	–	–
Total O&M Expense	5 599	5 815	6 035	10 517	17 423	14 695	15 107	15 237	15 074	15 188	15 328	15 794	14 835	17 293	14 944	15 088	15 606	15 666
CAPITAL COSTS																		
Foreign	–	–	14 337	14 337	–	–	–	–	–	–	–	–	–	–	–	–	–	–
Domestic	190	839	16,743	15,935	494	259	259	259	33	33	3,301	3,301	33	25	25	25	25	25
Total	190	839	31 080	30 272	494	259	259	259	33	33	3 301	3 301	33	25	25	25	25	25
TOTAL COST	5,788	6,654	37,115	40,789	17,917	14,953	15,365	15,496	15,107	15,221	18,628	19,098	14,868	17,318	14,969	15,113	15,832	15,691
Present Worth	5 570	5 926	30 619	31 157	12 673	9 793	9 317	8 700	7 854	7 327	8 302	7 881	5 681	6 128	4 904	4 585	4 391	4 081
Cum Present Worth	5 570	11 496	42 117	73 274	85 947	95 740	105 057	113 757	121 611	128 938	137 241	145 121	150 803	156 930	161 834	166 419	170 809	174 890

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Sensitivity Analysis

Exhibit 8-19
PROJECTED OPERATING AND CAPITAL EXPENDITURES SUMMARY
EXCLUDING REAL ESCALATION (page 2 of 2)

CASE A3	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2,008	2009	2010
OPERATING EXPENSES																		
Fuel Cost – Natural Gas	–	–	–	95	10 934	10 962	10 989	11 019	11 032	11 041	11 050	11 059	13 195	13 212	13 230	13 247	13 265	13 282
Oil	62	63	65	12	831	841	850	860	863	867	870	873	53	53	53	53	53	53
Lignite	6 790	6 919	7 050	4 884	–	–	–	–	–	–	–	–	–	–	–	–	–	–
Black Coal	–	–	–	5 370	10 177	10 201	10 224	10 249	10 258	10 266	10 273	10 281	8 702	8 704	8 706	8 708	8 709	8 711
Total Fuel Cost	6 852	6 983	7 115	10 360	21 941	22 005	22 063	22 128	22 153	22 173	22 193	22 213	21 950	21 969	21 989	22 008	22 027	22 047
Supplemental Cost (Shortfall)	–	–	0	–	–	–	–	–	(0)	–	–	0	–	0	–	–	–	–
Purchased Power Cost	–	–	–	–	45	45	46	46	46	46	46	46	46	46	46	46	46	46
Less Sales of Electricity	(7,290)	(7,408)	(7,472)	(7,133)	(13,905)	(13,940)	(13,975)	(14,011)	(14,027)	(14,039)	(14,051)	(14,060)	(14,055)	(14 067)	(14 078)	(14,087)	(14,098)	(14,110)
Net Power Interchange	(7 290)	(7 408)	(7 472)	(7 133)	(13 859)	(13 894)	(13 930)	(13 966)	(13 981)	(13 993)	(14 005)	(14 014)	(14 009)	(14 021)	(14 032)	(14 041)	(14 052)	(14 064)
Fixed O&M and Overheads	2 300	2 300	2 300	2 510	2 372	2 372	2 372	2 372	2 372	2 372	2 372	2 372	2 204	2 204	2 204	2 204	2 204	2 204
Variable O&M	1 457	1 473	1 488	1 642	1 643	1 646	1 648	1 650	1 651	1 652	1 652	1 652	1 653	1 654	1 655	1 655	1 656	1 657
Sorbent and Ash Removal	245	250	254	440	365	368	366	367	368	368	368	368	319	319	319	319	319	319
Credit By-Product Sales	–	–	–	(133)	(123)	(123)	(124)	(73)	(73)	(73)	(73)	(73)	(63)	(63)	(63)	(63)	(63)	(63)
Emission Penalties	78	80	82	31	–	–	–	–	–	–	–	–	–	–	–	–	–	–
Maintenance Expenses	1 956	2 137	2 268	2 601	2 285	3 047	3 436	3 489	3 315	3 421	3 552	4 009	3 294	3 282	3 380	3 510	4 018	4 064
Plant Removal Costs	–	–	–	–	3,517	–	–	–	–	–	–	–	–	2 462	–	–	–	–
Total O&M Expense	5 599	5 815	6 035	10 517	18 141	15 417	15 832	15 968	15 805	15 920	16 058	16 527	15 346	17 808	15 450	15 591	16 109	16 163
CAPITAL COSTS																		
Foreign	–	–	11 470	11 470	–	–	–	–	–	–	–	–	–	–	–	–	–	–
Domestic	190	839	15 362	14 553	494	259	259	259	33	33	3 301	3 301	33	25	25	25	25	25
Total	190	839	26 831	26 023	494	259	259	259	33	33	3 301	3 301	33	25	25	25	25	25
TOTAL COST	5,788	6,654	32,868	36,540	18,635	15,675	16,091	16,228	15,838	15,953	19,360	19,828	15,380	17,831	15,475	15,617	16,134	16,188
Present Worth	5 570	5 928	27 114	27 912	13 180	10 265	9 757	9 110	8 234	7 679	6 829	6 183	5 877	6 309	5 070	4 737	4 532	4 210
Cum Present Worth	5 570	11 498	38 612	66 523	79 704	89 969	99 726	108 837	117 071	124 750	133 379	141 562	147 439	153 747	158 817	163 554	168 086	172 296

CASE B1	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2,008	2009	2010
OPERATING EXPENSES																		
Fuel Cost – Natural Gas	–	–	–	95	3	3	3	4	4	4	4	4	531	535	538	542	546	549
Oil	62	63	65	12	92	93	93	93	93	93	93	93	91	92	92	92	92	92
Lignite	6 790	6 919	7 050	4 884	4 120	4 122	4 123	4 124	4 125	4 125	4 126	4 126	4 126	4 127	4 127	4 128	4 128	4 129
Black Coal	–	–	–	5,370	8,620	8,658	8,694	8,732	8,747	8,759	8,771	8,783	8,409	8,418	8,427	8 436	8,446	8,455
Total Fuel Cost	6 852	6 983	7 115	10 360	12 835	12 878	12 913	12 954	12 969	12 982	12 994	13 006	13 158	13 171	13 184	13 198	13 211	13 224
Supplemental Cost (Shortfall)	–	–	0	–	–	–	–	–	–	–	0	–	–	(0)	–	(0)	–	–
Purchased Power Cost	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
Less Sales of Electricity	(7 290)	(7 408)	(7 472)	(7 133)	(10 976)	(11 001)	(11 026)	(11 051)	(11 061)	(11 069)	(11 077)	(11 082)	(11 086)	(11 094)	(11 103)	(11 108)	(11 117)	(11 125)
Net Power Interchange	(7 290)	(7 408)	(7 472)	(7 133)	(10 976)	(11 001)	(11 026)	(11 051)	(11 061)	(11 069)	(11 077)	(11 082)	(11 086)	(11 094)	(11 103)	(11 108)	(11 117)	(11 125)
Fixed O&M and Overheads	2 300	2 300	2 300	2 510	2 542	2 542	2 542	2 542	2 542	2 542	2 542	2 542	2 339	2 339	2 339	2 339	2 339	2 339
Variable O&M	1 457	1 473	1 488	1 642	2 228	2 232	2 235	2 239	2 241	2 241	2 242	2 243	2 243	2 244	2 245	2 246	2 248	2 249
Sorbent and Ash Removal	245	250	254	440	1 237	1 238	1 240	1 045	1 046	1 046	1 047	1 047	1 035	1 036	1 036	1 037	1 037	1 038
Credit By-Product Sales	–	–	–	(133)	(204)	(204)	(205)	(121)	(121)	(121)	(121)	(121)	(119)	(119)	(119)	(119)	(119)	(119)
Emission Penalties	78	80	82	31	–	–	–	–	–	–	–	–	–	–	–	–	–	–
Maintenance Expenses	1 956	2 137	2 268	2 601	2 290	3 099	3 490	3 542	3 372	3 478	3 610	4 077	3 308	3 296	3 397	3 520	4 037	4 084
Plant Removal Costs	–	–	–	–	3,517	–	–	–	–	–	–	–	–	2 462	–	–	–	–
Total O&M Expense	5 599	5 815	6 035	10 517	13 469	10 782	11 189	11 149	10 886	11 098	11 236	11 710	10 878	13 334	10 980	11 112	11 638	11 689
CAPITAL COSTS																		
Foreign	–	–	1 791	1 791	–	–	–	–	–	–	–	–	–	–	–	–	–	–
Domestic	190	839	23,145	22,336	494	259	259	259	33	33	3,301	3,301	33	25	25	25	25	25
Total	190	839	24 936	24 127	494	259	259	259	33	33	3 301	3 301	33	25	25	25	25	25
TOTAL COST	5,788	6,654	30,971	34,644	13,963	11,040	11,447	11,408	11,019	11,131	14,537	15,012	10,912	13,359	11,005	11,138	11,661	11,715
Present Worth	5 570	5 928	25 550	26 464	9 878	7 230	6 941	6 405	5 729	5 358	6 479	6 195	4 170	4 727	3 805	3 379	3 275	3 047
Cum Present Worth	5 570	11 498	37 048	63 512	73 388	80 618	87 559	93 964	99 693	105 051	111 530	117 725	121 895	126 622	130 227	133 605	136 881	139 927

Exhibit 8-20
INDIFFERENCE ANALYSIS SUMMARY

CUMULATIVE PRESENT WORTH $(000)

VARIANT (Case)	Capital & Removal Costs	FUEL COST					Net Power Interchange	Fixed & Variable Expenses	Sorbent, Ash Removal & Penalties	Maintenance	Total Operating Expenses	Total Capital & Operating Expenses
		Natural Gas	Oil	Lignite	Black Coal	Total						
C1 (Base)	32 223	531	922	37 884	79 771	119 108	(95 511)	41 360	10 098	30 713	105,768	137 991
A2	58 825	97 495	4 732	23 695	68 641	194 563	(146 346)	38 398	4 923	29 080	120 618	179 443
A3	51 667	90 072	5,376	23 695	69 622	188 765	(135 081)	38 283	4 968	28 835	125 771	177 438
B1	47 283	1 379	982	55 599	61 966	119,926	(112 526)	42 995	14 300	29 075	93 769	141 052

ADJUSTMENT REQUIRED IN SPECIFIC COST ELEMENTS IN ORDER TO EQUATE CUMULATIVE PRESENT WORTH OF THIS CASE WITH THAT OF THE BASE CASE

VARIANT (Case)	Capital & Removal Costs (1)	FUEL COST					Net Power Interchange	Fixed & Variable Expenses	Sorbent Ash Removal & Penalties	Maintenance	Total Operating Expenses	Total Capital & Operating Expenses
		Natural Gas	Oil	Lignite	Black Coal	Total						
C1 (Base)	BASE	BASE	BASE	BASE	BASE	BASE	BASE	BASE	BASE	BASE	BASE	BASE
A2	−70 5%	−42 8%	NA	NA	372 4%	−54 9%	181 5%	NA	NA	NA	−279 1%	−23 1%
A3	−76 3%	−44 1%	NA	NA	388 7%	−56 6%	199 7%	NA	NA	NA	−197 2%	−22 2%
B1	−6 5%	NA	NA	−17 3%	17 2%	−374 5%	118 0%	−187 1%	−72 8%	186 9%	25 5%	−2 2%

NOTE (1) Adustment in Capital Cost for alternative case only i e no corresponding adjustment in Base Case
All other adjustments apply for both Base Case and Alternative Case

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Exhibit 8-21
INDIFFERENCE ANALYSIS SUMMARY EXCLUDING ESCALATION

CUMULATIVE PRESENT WORTH – EXCLUDING REAL ESCALATION $(000)

VARIANT Case)	Capital & Removal Costs	FUEL COST					Net Power Interchange	Fixed & Variable Expenses	Sorbent Ash Removal & Penalties	Maintenance	Total Operating Expenses	Total Capital & Operating Expenses
		Natural Gas	Oil	Lignite	Black Coal	Total						
BASE	31 800	445	716	33 661	75 281	110 103	(80 878)	41 360	4 913	30 713	106 211	138 011
A2	56 791	79 702	3 552	22 245	64 715	170 215	(122 392)	38 398	2 798	29 080	118 099	174 890
A3	50 040	73 623	4 031	22 245	65 641	165 540	(113 222)	38 283	2 820	28 835	122,256	172 296
B1	47,029	1 117	762	48 221	58 423	108 522	(94 860)	42 995	7 167	29 075	92 899	139 927

ADJUSTMENT REQUIRED IN SPECIFIC COST ELEMENTS IN ORDER TO EQUATE CUMULATIVE PRESENT WORTH OF THIS CASE WITH THAT OF THE BASE CASE

VARIANT (Case)	Capital & Removal Costs (1)	FUEL COST					Net Power Interchange	Fixed & Variable Expenses	Sorbent Ash Removal & Penalties	Maintenance	Total Operating Expenses	Total Capital & Operating Expenses
		Natural Gas	Oil	Lignite	Black Coal	Total						
BASE	BASE	BASE	BASE	BASE	BASE	BASE	BASE	BASE	BASE	BASE	BASE	BASE
A2	−64 9%	−46 5%	NA	NA	349 1%	−61 4%	188 8%	1245 2%	NA	NA	−310 2%	−21 1%
A3	−68 5%	−46 9%	NA	NA	355 6%	−61 8%	206 0%	1114 5%	NA	NA	−213 7%	−19 9%
B1	−4 1%	NA	NA	−13 2%	11 4%	121 2%	113 7%	−117 1%	−85 0%	117 0%	14 4%	−1 4%

NOTE (1) Adustment in Capital Cost for alternative case only i e no corresponding adjustment in Base Case
All other adjustments apply for both Base Case and Alternative Case

8 8 FINANCIAL ANALYSIS

While sufficient information is not available to make a complete review of the financial consequences of alternative decisions regarding future operations of the District Heating System, some additional perspective may be gained from even a somewhat limited analysis

Building upon data previously established in the economic analysis a financial perspective on projected results under sample case, Variant B1, is presented in Exhibit 8-22 Where capital costs in the economic analysis were treated as full requirements in the year of occurrence, and only the impact of estimated real escalation was recognized, the financial analysis includes the impact of general inflation and treats capital requirements alternately on an accrual basis (with depreciation based on an assumed 25 year service life) and a cash basis incorporating debt service under terms of the assumed capital structure set forth below General inflation assumptions applied are those indicated in previously referenced Exhibit 8-6 It was assumed that foreign costs would be funded by loans at 8% to be repaid in 20 years (These terms are typical of current loans both in Western Europe and the United States, and are notably different from the domestic loan terms in the Czech Republic) The capital structure assumed in funding foreign and domestic capital costs respectively are as follows

Funding Source	% of Total	Assumed Cost	Weighted Cost	Assumed Term
Foreign				
Debt	100 %	8 %	8 %	20 Years
Domestic				
Equity	25 %	20 %	5 %	
Debt	75 %	16 %	12 %	8 Years
Composite[a]			17 %	

Note a Applied as Discount Rate on Financial Basis

Reflecting these terms, interest expense and, where applicable, principal repayments shown in Exhibit 8-22 reflect semi-annual equal payment debt service installments Annual equity return is established at 5% of cumulative domestic capital costs including inflation through the previous year The effect of Income Taxes is incorporated at a rate of 45% and in an amount derived by dividing the Equity Return by one minus the assumed tax rate

Further in Exhibit 8-22, we have attempted to establish some indication of the resulting cost of hot water, at least to the extent that it is impacted by prospective capital costs and operating expenses As noted, no reliable data were available for the inclusion of debt service, if any, and remaining depreciation charges related to plant presently in service Such costs would obviously represent an additional factor to consider in defining total commodity costs, In other respects, however, estimated hot water costs are derived by subtracting from total costs the costs directly attributable to, or allocated to steam deliveries

VARIANT B1

High Demand

Exhibit 8-22
PROJECTED FINANCIAL COSTS OF VARIANT B1

FINANCIAL COST (000) (Including Inflation)

	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
ACCRUAL BASIS	(Exclusive of Interest Expense if any and Depreciation Charges related to existing plant (Production Transmission Distribution et al)																	
Operating Expenses																		
Operation & Maintenance	5 544	6 234	6 922	12 534	16 666	14 022	15 474	17 753	18 378	19 485	20 703	22 623	22 290	28 447	24 795	26 337	28 898	30 477
Depreciation Expense	8	44	1 186	2 357	2 383	2 397	2 412	2 428	2 430	2 432	2 666	2 912	2 915	2 917	2 919	2 921	2 924	2 926
Total Operating Expenses	5 552	6 277	8 108	14 891	19 049	16 419	17 885	20 181	20 808	21 916	23 369	25 535	25 205	31 364	27 713	29 258	31 822	33 403
Interest Expense	9	57	1 369	3 895	4 973	4 575	4 107	3 576	2 959	2 247	1 714	1 478	1 330	1 203	1 068	924	769	600
Equity Return	9	9	55	1 379	2 735	2 767	2 784	2 803	2 823	2 825	2 828	3 121	3 428	3 432	3 434	3 437	3 440	3 443
Total Expense & Return	5 570	6 344	9 532	20 166	26 756	23 760	24 776	26 560	26 589	26 989	27 912	30 133	29 964	35 998	32 216	33 619	36 030	37 446
Income Tax Effect @ 45%	8	8	45	1 129	2 238	2 264	2 278	2 293	2 309	2 312	2 314	2 553	2 805	2 808	2 810	2 812	2 814	2 817
Total Cost	5,577	6,352	9,576	21,295	28,994	26,023	27,054	28,853	28,899	29,301	30,226	32,687	32,769	38,806	35,026	36,431	38,845	40,263
Estimated Hot Water Revenue Requirement	(Exclusive of Interest Expense if any and Depreciation Charges related to existing plant (Production Transmission Distribution et al)																	
Total Cost (Above) less																		
Cost of Steam																		
Operation & Maintenance	4 251	4 632	4 933	6 298	6 570	7 615	7 644	8 970	8 807	9 418	9 613	10 360	8 990	9 439	9 911	10 406	10 925	11 471
Allocated Depreciation	3	16	432	747	749	751	754	757	756	756	827	902	901	901	900	900	900	900
Allocated Return	4	4	20	437	860	867	870	874	879	878	877	966	1 060	1 060	1 059	1 059	1 059	1 059
Income Tax Effect	3	3	16	358	704	710	712	715	719	718	718	791	867	867	867	867	867	867
Total Steam	4 260	4 654	5 401	7 840	8 883	9 943	9 980	11 315	11 161	11 770	12 035	13 019	11 817	12 266	12 737	13 232	13 751	14 297
Equals Cost of Hot Water	1 317	1 697	4 175	13 455	20 111	16 080	17 074	17 538	17 737	17 531	18 190	19 668	20 951	26 540	22 288	23 199	25 093	25 966
HOT WATER – $/MWH	$2 46	$3 07	$7 28	$17 31	$25 54	$20 33	$21 50	$21 99	$22 20	$21 91	$22 69	$24 50	$26 05	$32 96	$27 64	$28 73	$31 04	$32 07
Present Worth	$2 46	$2 62	$5 31	$10 81	$13 63	$9 27	$8 38	$7 33	$6 32	$5 33	$4 72	$4 36	$3 96	$4 28	$3 07	$2 73	$2 52	$2 22
Levelized Cost to Date		$3 07	$5 01	$8 49	$11 80	$13 02	$13 94	$14 62	$15 14	$15 51	$15 83	$16 15	$16 45	$16 87	$17 10	$17 30	$17 51	$17 69
CASH BASIS	(Exclusive of Debt Service related to existing plant (Production Transmission Distribution et al)																	
O & M Expenses	5 544	6 234	6 922	12 534	16 666	14 022	15 474	17 753	18 378	19 485	20 703	22 623	22 290	28 447	24 795	26 337	28 898	30 477
Equity Return	9	9	55	1 379	2 735	2 767	2 784	2 803	2 823	2 825	2 828	3 121	3 428	3 432	3 434	3 437	3 440	3 443
Debt Service																		
Foreign Interest	–	–	82	251	333	328	317	308	299	288	277	264	251	236	221	204	186	166
Principal	–	–	–	44	95	102	111	120	129	140	151	164	177	191	207	224	242	262
Total	–	–	82	295	428	428	428	428	428	428	428	428	428	428	428	428	428	428
Domestic Interest	9	57	1 287	3 645	4 639	4 249	3 789	3 268	2 661	1 959	1 438	1 213	1 080	966	848	720	583	434
Principal	–	11	67	1 670	3 508	3 980	4 493	5 070	5 721	6 402	7 059	4 233	982	1 010	1 084	1 165	1 252	1 402
Total	9	69	1 354	5 315	8 147	8 229	8 282	8 338	8 382	8 362	8 497	5 446	2 062	1 977	1 932	1 885	1 835	1 836
Total Cost before Income Tax	5 562	6 312	8 413	19 523	27 976	25 445	26 968	29 322	30 010	31 099	32 456	31 618	28 208	34 283	30 589	32 086	34 600	36 183
Income Tax Effect @ 45%	8	8	45	1 129	2 238	2 264	2 278	2 293	2 309	2 312	2 314	2 553	2 805	2 808	2 810	2 812	2 814	2 817
Total Financial Cost	5,570	6,319	8,458	20,652	30,214	27,708	29,246	31,615	32,320	33,411	34,770	34,171	31,013	37,091	33,398	34 898	37,415	39,000

It was assumed that the value of electricity was already compensated for in terms of revenues from external sale, credits for which have already been recognized in the development of (net) operating expenses Consequently, remaining costs, whether subsidizing or subsidized by, electrical sales were assumed to be associated with the production of heat manifested in the form of steam and ultimately hot water

Having previously established (in connection with the economic analysis) an indication of the variable expenses attributable to meeting steam requirements, these costs could be directly recognized by adjusting for inflation Fixed O&M expense and maintenance costs are included on an allocated basis considering relative steam and hot water production in that year Depreciation and return on equity are similarly allocated in order to recognize a capital component of steam costs In the composite, these costs were then deducted from total costs to derive the annual cost of hot water to the limited extent defined above Annual unit costs, measured in $ per MWh produced, were then a function of annual production with the results indicated Finally, through discounting at the discount rate derived above, a levelized cost for hot water was extrapolated as an indication of revenue requirements through each time segment For example, if a single price were to be adopted to apply through the entire analysis period, in the illustrated case, that price would be $17 69, if an initially adopted price were to remain constant through the first five years, that price would be $13 02, and so forth

It must be emphasized that these costs, as presented, are incomplete for the reasons stated above and are in any case somewhat crude, and therefore not fully credible bases for establishing finite pricing policies They may, however, represent a further useful measure of the relative merit of the variants analyzed, for each of which the levelized cost of hot water as developed over the complete analysis period follows It may be noted that the relative level of costs is generally consistent with economic analysis results

	Levelized Cost of Hot Water	
Variant	$ U S /MWh	kC/GJ
C1	$16 02	124 6
A2	$21 67	168 58
A3	$21 53	167 4
B1	$17 69	137 6

Detailed data supporting results reflected above for variants other than B1 are contained in Appendix F

It is of interest to note the present and projected price of heat for dwellings During the 1992-1993 heating season, the price of heat was state subsidized and controlled to a ceiling of 120 Kc/GJ This level was risen to 137 Kc/GJ for the 1993-94 heating season, and is anticipated to rise to approximately 170 for 1994-95 The difference between these values and the true cost of heat is covered by state subsidies (Reference Appendix D, p 36)

The removal of subsidies and the transition to actual prices is expected to occur in 1995-96 The unsubsidized price is expected to rise to approximately 250 Kc/GJ (with a projected range of 220-270 Kc/GJ) For subsequent years the price of heat will reflect the escalation

of the associate fuel costs These historical and projected prices of heat are summarized below

Year	Cost of Hot Water for Dwellings $ U S /MWh	kC/GJ
1992-93	$15 43	120
1993-94	$17 61	137
1994-95	$21 86	170
1995-96	$32 14	250

Care must be taken in making comparisons of these annual projected costs with the levelized costs resulting from the financial analysis, and in recognizing that the developed costs are incomplete for the reasons previously stated

8.9 EVALUATION OF THE SVETOVAR OPTIONS

The district heating operation in Svetovar is not presently interconnected with the Plzen District Heating system In order for the Svetovar district heating system to meet the new emission requirements by 1997, the Svetovar DH system could either modify its present supply system for compliance, or connect with the Plzen district heating system Plans to extend the central CP Plzen system (Heat Line East II) were suspended because the economics of continuing the work were uncertain It was suggested that this study include an analysis of the potential of proceeding with Heat Line East II

The modification options available to Svetovar for continued independent operation include

- switching to low sulfur coal and adding a baghouse,
- converting the hot water boilers to natural gas firing, and
- retrofitting the boilers with a small gas turbine or engine cogeneration unit

Section 8 9 1 discusses the independent operation options, while Section 8 9 2 presents the option of connecting Svetovar to the Plzen district heating system

8 9 1 Independent Operation of the Svetovar DH System

The following subsections present the fuel switching and the cogeneration retrofit options for the continued independent operation of the Svetovar DH system

Fuel Switching

The first two modification options, switching to low sulfur coal and switching to natural gas would require modifications similar to those estimated for the Letna and Doubravaka units in the main Plzen heating analysis of Section 8 0 Letna was retrofitted for a fuel switch to natural gas, while Doubravka was switched to black coal including the addition of a baghouse The capital cost of the Letna and Doubravka conversion should be applicable to

Svetovar because of the similarity in the unit size and design (Each of the plants has four 5 8 IW_t hot water grate boilers)

Operating and maintenance expenses were estimated in a manner consistent with the previous analysis described in Section 8 6, and using the same assumptions for fuel price and ash disposal The projected operating and capital cost for the gas conversion case and the black coal / baghouse conversion case are presented in Exhibits 8-23 and 8-24 respectively Since, it was assumed that interconnection with the Plzen system was physically impracticable prior to 1993, analyses were initiated from that date The cumulative present worth of projected costs for these modification options as applied to Svetovar are summarized for the second, third, fifth, and tenth year in the table below

Cumulative Present Worth of Projected Cost of Svetovar Operations ($ Millions)

Years after Fuel Switch	2	3	5	10
Switch to Gas	3 39	6 11	11 14	21 25
Switch to Black coal	3 39	5 26	8 70	15 53

Since the fuel switch to black coal is less costly, that option is compared to the cost of operating Svetovar as part of the centralized district heating system in Section 8 9 2 The rest of this section addresses the independent operation option of retrofitting the units for cogeneration

Cogeneration

A separate analysis on small cogeneration options was carried out by Gilbert/Commonwealth's subcontractor (CityPlan, Ltd) This was considered to be an alternative option in certain instances where the District Heating System was either unavailable or for areas of the City of Plzen where consumers may have the option of extensions to the system or installing a private cogeneration plant in competition to the system

In the review of the analysis conducted by CityPlan Ltd , several portions of the analysis are considered key to the results presented within their Report These specific elements include (1) the sale price of cogenerated electricity to the grid, (2) the sale price of hot water energy to consumers, and, (3) the amount of equity assumed to be available from the Government or private investors

In order to measure the impact of differing assumptions on the overall results presented within CityPlan's analysis, a separate but similar analysis was conducted using different prices and capitalization structure from that utilized by CityPlan It is first necessary to describe the proposed modifications to CityPlan's analysis

SVETOVAR

Independent System (Convert to Gas)

EXHIBIT 8-23
PROJECTED FINANCIAL COSTS OF THE INDEPENDENT SVETOVAR SYSTEM CONVERTED TO GAS IN 1997

COST EXCL INFLATION (000)

	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
OPERATING EXPENSES																		
Fuel Cost – Natural Gas	–	–	–	–	3 287	3 378	3 472	3 570	3 570	3 570	3 570	3 570	3 570	3 570	3 570	3 570	3 570	3 570
Oil	–	–	12	13	–	–	–	–	–	–	–	–	–	–	–	–	–	–
Lignite	–	–	1 258	1 320	–	–	–	–	–	–	–	–	–	–	–	–	–	–
Black Coal	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
Total Fuel Cost	–	–	1 270	1 332	3 287	3 378	3 472	3 570	3 570	3 570	3 570	3 570	3 570	3 570	3 570	3 570	3 570	3 570
Supplemental Cost (Shortfall)	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
Purchased Power Cost	–	–	50	52	53	54	55	56	56	56	56	56	56	56	56	56	56	56
Credit for Power Sales	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
Net Power Interchange	–	–	50	52	53	54	55	56	56	56	56	56	56	56	56	56	56	56
Fixed O&M and Overheads	–	–	119	119	102	102	102	102	102	102	102	102	102	102	102	102	102	102
Other Variable O & M	–	–	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94
Sorbent and Ash Removal	–	–	53	60	–	–	–	–	–	–	–	–	–	–	–	–	–	–
Credit By-Product Sales	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
Emission Penalties	–	–	17	22	–	–	–	–	–	–	–	–	–	–	–	–	–	–
Maintenance Expenses	–	–	287	291	299	308	323	332	342	352	354	370	383	392	400	416	432	438
Plant Removal Costs	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
Total O&M Expense	–	–	1 889	1 971	3 835	3 937	4 047	4 154	4 164	4 174	4 176	4 192	4 205	4 214	4 222	4 238	4 254	4 260
CAPITAL COSTS																		
Foreign	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
Domestic	–	–	206	206	3	3	3	3	3	3	3	3	3	3	3	3	3	3
Total	–	–	206	206	3	3	3	3	3	3	3	3	3	3	3	3	3	3
TOTAL COST	–	–	2,095	2,177	3,838	3,940	4,050	4,157	4,167	4,177	4,179	4,195	4,208	4,217	4,225	4,241	4,257	4,263
Present Worth	–	–	1 729	1 663	2 715	2 580	2 456	2 334	2 166	2 011	1 863	1 731	1 608	1 492	1 384	1 287	1 196	1 109
Cumulative Present Worth	–	–	1 729	3 391	6 106	8 686	11 142	13 476	15 643	17 654	19 516	21 248	22 856	24 348	25 732	27 019	28 214	29 323

OPERATING STATISTICS

	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
TOTAL PRODUCTION – MWH																		
LP Steam	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
Hot Water	–	–	61 249	61 249	61 249	61 249	61 249	61 249	61 249	61 249	61 249	61 249	61 249	61 249	61 249	61 249	61 249	61 249
Electricity	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
COST OF PRODUCTION – $/MWH (Variable Costs only)																		
LP Steam	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
Hot Water	–	–	$25 35	$26 57	$56 87	$58 36	$59 90	$61 48	$61 48	$61 48	$61 48	$61 48	$61 48	$61 48	$61 48	$61 48	$61 48	$61 48
Electricity	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
NOT SERVED – MWH																		
LP Steam	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
Hot Water	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
Electricity	–	–	1 647	1 647	1 647	1 647	1 647	1 647	1 647	1 647	1 647	1 647	1 647	1 647	1 647	1 647	1 647	1 647
EMISSIONS – TONNES																		
Particulates	–	–	287	287	–	–	–	–	–	–	–	–	–	–	–	–	–	–
SO_2	–	–	968	968	–	–	–	–	–	–	–	–	–	–	–	–	–	–
NOx	–	–	172	172	41	41	41	41	41	41	41	41	41	41	41	41	41	41
CO	–	–	90	90	5	5	5	5	5	5	5	5	5	5	5	5	5	5

SVETOVAR

Independent System (Black Coal & Baghouse)

EXHIBIT 8-24
PROJECTED FINANCIAL COSTS OF THE INDEPENDENT SVETOVAR SYSTEM WITH BLACK COAL AND A BAGHOUSE

COST EXCL INFLATION (000)

	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
OPERATING EXPENSES																		
Fuel Cost – Natural Gas	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
Oil	–	–	12	13	13	14	14	15	15	15	15	15	15	15	15	15	15	15
Lignite	–	–	1 258	1 320	–	–	–	–	–	–	–	–	–	–	–	–	–	–
Black Coal	–	–	–	–	2 067	2 106	2 146	2 187	2 187	2 187	2 187	2 187	2 187	2 187	2 187	2 187	2 187	2 187
Total Fuel Cost	–	–	1 270	1 332	2 080	2 119	2 160	2 201	2 201	2 201	2 201	2 201	2 201	2 201	2 201	2 201	2 201	2 201
Supplemental Cost (Shortfall)	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
Purchased Power Cost	–	–	50	52	53	54	55	56	56	56	56	56	56	56	56	56	56	56
Credit for Power Sales	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
Net Power Interchange	–	–	50	52	53	54	55	56	56	56	56	56	56	56	56	56	56	56
Fixed O&M and Overheads	–	–	119	119	119	119	119	119	119	119	119	119	119	119	119	119	119	119
Other Variable O & M	–	–	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94
Sorbent and Ash Removal	–	–	53	60	–	–	–	–	–	–	–	–	–	–	–	–	–	–
Credit By-Product Sales	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
Emission Penalties	–	–	17	22	–	–	–	–	–	–	–	–	–	–	–	–	–	–
Maintenance Expenses	–	–	287	291	299	308	323	332	342	352	354	370	383	392	400	416	432	438
Plant Removal Costs	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
Total O&M Expense	–	–	1 889	1 971	2 645	2 695	2 751	2 802	2 812	2 822	2 824	2 840	2 853	2 862	2 870	2 886	2 902	2 908
CAPITAL COSTS																		
Foreign	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
Domestic	–	–	206	206	3	3	3	3	3	3	3	3	3	3	3	3	3	3
Total	–	–	206	206	3	3	3	3	3	3	3	3	3	3	3	3	3	3
TOTAL COST	–	–	2,095	2,177	2,648	2,698	2,754	2,805	2,815	2,825	2,827	2,843	2,856	2,865	2,873	2,889	2,905	2,911
Present Worth	–	–	1 729	1 663	1 873	1 767	1 670	1 575	1 464	1 360	1 260	1 173	1 092	1 014	941	876	816	757
Cumulative Present Worth	–	–	1 729	3 391	5 264	7 031	8 701	10 276	11 740	13 100	14 360	15 534	16 625	17 639	18 580	19 457	20 273	21 030

OPERATING STATISTICS

	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
TOTAL PRODUCTION – MWH																		
LP Steam	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
Hot Water	–	–	61 249	61 249	61 249	61 249	61 249	61 249	61 249	61 249	61 249	61 249	61 249	61 249	61 249	61 249	61 249	61 249
Electricity	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
COST OF PRODUCTION – $/MWH (Variable Costs only)																		
LP Steam	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
Hot Water	–	–	$25 35	$26 57	$37 43	$38 08	$38 74	$39 41	$39 41	$39 41	$39 41	$39 41	$39 41	$39 41	$39 41	$39 41	$39 41	$39 41
Electricity	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
NOT SERVED – MWH																		
LP Steam	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
Hot Water	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
Electricity	–	–	1 647	1 647	1 647	1 647	1 647	1 647	1 647	1 647	1 647	1 647	1 647	1 647	1 647	1 647	1 647	1 647
EMISSIONS – TONNES																		
Particulates	–	–	287	287	–	–	–	–	–	–	–	–	–	–	–	–	–	–
SO_2	–	–	968	968	–	–	–	–	–	–	–	–	–	–	–	–	–	–
NOx	–	–	172	172	48	48	48	48	48	48	48	48	48	48	48	48	48	48
CO	–	–	90	90	6	6	6	6	6	6	6	6	6	6	6	6	6	6

In regards to the proposed sale of electricity to the grid, CityPlan assumed a sale price of 1500 Kc per MWh from the proposed variants At this sale price level, a capacity payment must be included since the energy component is approximately 770 Kc per MWh based on the most recent prices for energy from the distribution company In order to achieve a capacity payment, it is generally required that firm energy is available to the grid, and that the system is sufficiently in deficit to warrant payment of capacity related charges Given the current situation regarding electricity supplies in the Czech Republic, and the fact that the estimated load factor is about 71%, it would appear that the mini-cogen options would not qualify for capacity payments at the current time Therefore, it is assumed in this alternate analysis that the energy payments of 770 Kc per MWh would be the sale price of any electricity generated for the grid

Likewise, the sale of thermal energy utilized in the CityPlan analysis was at a level of 112 5 Kc per GJ Current pricing in Plzen has been estimated at a much higher rate based on the analyses prepared for the feasibility study by Gilbert/Commonwealth Therefore, for this analysis, a rate of 180 Kc per GJ has been assumed for the sale of thermal energy

The net effect of the changes in price for the two commodities produced by the mini-cogeneration option (Variant #1) is a reduced level of revenues from that estimated by CityPlan Overall revenues are reduced by approximately 14% Electricity sales have been reduced by about 50%, while thermal sales have increased by almost 60% This reduction in revenue has obviously had a significant impact on the overall results of the mini-cogeneration options

The final adjustment to the CityPlan analysis is the capitalization structure proposed for either a private concern or with Government subsidies Due to the current financial situation of the Government, it is unlikely that any project is going to be subsidized to a 50% level by Government Also, a private entity would not provide a 50% equity position in competition with subsidized alternatives More likely is a capitalization structure for project financing along more traditional lines of a 20-80 or 25-75 split between equity and debt respectively

Using a 25-75 split for equity and debt results in higher payments for debt service over the life of the project No attempt was made to change the repayment period for the debt (10 years) or the interest rate of 10% Although such terms are somewhat different than those applied in our base analyses, they were considered to be not unreasonable for project financing options in the Czech Republic The net result of the change in capital structure was an increase in debt service payments from 2 5 million Kc per year to a levelized payment of 3 7 million Kc per year

After the above adjustments were made to the analysis, the mini-cogeneration options became much less viable as alternatives to the centralized district heating alternative Exhibit 8-25 provides the details in the same manner as those provided in the CityPlan report (see Appendix B) As shown, the net cumulative cash flows remain negative throughout the study period of twenty years

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VARIANT B1

High Demand Plus Svetovar

Exhibit 8-25
SMALL COGENERATION OPTION FINANCIAL ANALYSIS SUMMARY

COST EXCL INFLATION (000)

	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
OPERATING EXPENSES																		
Fuel Cost – Natural Gas	–	–	6	185	18	20	22	24	25	26	26	27	993	999	1 005	1 011	1 017	1 023
Oil	62	68	78	17	122	126	129	133	134	134	134	134	130	130	130	130	130	130
Lignite	6 790	7 255	8 195	5 988	4 871	4 964	5 060	5 159	5 160	5 160	5 160	5 161	5 161	5 162	5 162	5 163	5 163	5 164
Black Coal	–	–	–	5 461	9 402	9 612	9 825	10 046	10 059	10 068	10 078	10 088	9 488	9 495	9 501	9 508	9 514	9 521
Total Fuel Cost	6 852	7 323	8 279	11 651	14 413	14 722	15 037	15 363	15 377	15 388	15 398	15 409	15 772	15 785	15 799	15 812	15 825	15 838
Supplemental Cost (Shortfall)	–	–	–	–	–	(0)	–	(0)	–	–	0	–	0	–	–	–	–	–
Purchased Power Cost	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
Credit for Power Sales	(7,290)	(7 768)	(8 381)	(8 324)	(13,245)	(13 504)	(13 771)	(14 041)	(14 044)	(14 044)	(14 045)	(14 042)	(14 043)	(14 046)	(14 048)	(14 047)	(14 049)	(14 052)
Net Power Interchange	(7,290)	(7 768)	(8 381)	(8 324)	(13,245)	(13 504)	(13 771)	(14 041)	(14 044)	(14 044)	(14 045)	(14 042)	(14 043)	(14 046)	(14 048)	(14 047)	(14 049)	(14 052)
Fixed O&M and Overheads	2 300	2 300	2 419	2 629	2 661	2 661	2 661	2 661	2 661	2 661	2 661	2 661	2 458	2 458	2 458	2 458	2 458	2 458
Other Variable O & M	1 457	1 473	1 532	1 682	2 279	2 282	2 284	2 286	2 287	2 287	2 287	2 287	2 287	2 288	2 289	2 289	2 290	2 290
Sorbent and Ash Removal	245	285	349	674	1 873	1 875	1 877	2 695	2 697	2 697	2 698	2 699	2 656	2 657	2 657	2 658	2 659	2 660
Credit By-Product Sales	–	–	–	(200)	(313)	(314)	(315)	(315)	(315)	(316)	(316)	(316)	(307)	(307)	(308)	(308)	(308)	(308)
Emission Penalties	24	48	53	30	–	–	–	–	–	–	–	–	–	–	–	–	–	–
Maintenance Expenses	1 956	2 137	2 539	2 801	2 577	3 395	3 795	3 856	3 696	3 812	3 954	4 431	3 673	3 672	3 785	3 920	4 449	4 508
Plant Removal Costs	–	–	–	–	3 517	–	–	–	–	–	–	–	–	2 462	–	–	–	–
Total O&M Expense	5 544	5 798	6 790	10 943	13 760	11 116	11 567	12 504	12 357	12 484	12 638	13 128	12 496	14 969	12 632	12 783	13 324	13 395
CAPITAL COSTS																		
Foreign	–	–	1927	1976	–	–	–	–	–	–	–	–	–	–	–	–	–	–
Domestic	190	839	23351	22543	494	259	259	259	33	33	3301	3301	33	25	25	25	25	25
Total	190	839	25278	24518	494	259	259	259	33	33	3301	3301	33	25	25	25	25	25
TOTAL COST	5,733	6,637	32,069	35,461	14,254	11,375	11,826	12,763	12,390	12,517	15,939	16,430	12,529	14,994	12,657	12,808	13,349	13,420
Present Worth	5 517	5 913	26 456	27 088	10 082	7 449	7 171	7 166	6 441	6 025	7 104	6 780	4 788	5 305	4 147	3 885	3 749	3 490
Cumulative Present Worth	5 517	11 430	37 886	64 973	75 055	82 505	89 675	96 841	103 283	109 308	116 412	123 193	127 980	133 285	137 432	141 317	145 067	148 557

OPERATING STATISTICS

	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
TOTAL PRODUCTION – MWH																		
LP Steam	333 355	331 188	329 021	360 443	361 165	361 165	361 165	361 165	361 165	360 804	360 443	360 082	359 720	359 720	359 720	359 720	359 720	359 720
Hot Water	534 466	552 841	635 127	838 315	848 701	852 163	855 358	858 820	860 152	861 483	862 815	864 146	865 478	866 543	867 608	868 673	869 739	870 804
Electricity	306 534	312 254	323 285	317 861	477 240	477 696	478 117	478 531	478 664	478 727	478 790	478 852	478 915	479 021	479 128	479 235	479 341	479 448
COST OF PRODUCTION – $/MWH (Variable Costs only)																		
LP Steam	$10 60	$10 91	$11 12	$12 42	$11 98	$12 11	$12 24	$13 03	$13 03	$13 03	$13 03	$13 03	$12 85	$12 85	$12 85	$12 85	$12 85	$12 85
Hot Water	$8 64	$8 93	$9 14	$10 10	$11 04	$11 20	$11 37	$11 87	$11 87	$11 87	$11 87	$11 87	$12 16	$12 17	$12 17	$12 17	$12 17	$12 17
Electricity	$9 29	$9 60	$9 80	$11 08	$15 11	$15 29	$15 48	$16 28	$16 28	$16 28	$16 28	$16 27	$16 11	$16 11	$16 10	$16 10	$16 10	$16 09
NOT SERVED – MWH																		
LP Steam	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
Hot Water	–	–	–	–	–	(0)	–	(0)	–	–	0	–	0	–	–	–	–	–
Electricity	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
EMISSIONS – TONS																		
Particulates	274	286	347	527	149	149	150	150	150	150	150	150	149	149	149	149	149	149
SO_2	6 333	6 454	6 952	4 271	3 488	3 496	3 503	3 511	3 514	3 517	3 519	3 521	3 398	3 400	3 402	3 403	3 405	3 407
NOx	1 514	1 541	1 650	1 838	1 835	1 839	1 843	1 847	1 849	1 850	1 851	1 852	1 816	1 817	1 818	1 819	1 820	1 821
CO	61	65	83	181	94	94	95	96	96	96	96	96	72	72	72	72	72	72

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In summary, it is highly unlikely that small cogeneration alternatives will be able to compete with the District Heating Company as presently structured Exceptions may include situations where (1) large numbers of these cogeneration units apply with the utility as a group to negotiate a better electric rate, or (2) some combination of government incentives are available to offset the initial capital cost Unless dramatic changes occur in the pricing schemes for the two basic commodities provided, emphasis should still be placed on improving the efficiency of the existing system through modifications in the distribution system and replacement of antiquated equipment when its useful life is over

8 9 2 Connection of Svetovar to the Plzen District Heating System

While it is technically feasible to link the two systems, the connection would make economic sense only if the anticipated operational cost savings at least offset the cost of the connecting pipeline within a desired payback period In light of the above conclusions in the analysis of the independent operation options, a break-even analysis of connecting Svetovar to the central district heating system was performed considering only the lowest cost independent operation option - a switch to black coal firing

Since the combined capacity of the existing Svetovar boilers, at 23 2 MW_t (4 x 5 8 MW_t), is barely adequate to meet the indicated peak hot water demand of approximately 23 MW_t, a requirement for additional capacity is apparent, should further growth be anticipated by connection of additional consumers, or increased usage by existing residential or commercial customers However, the necessity for substantial additional investment would only serve to add further support to a decision to merge with the Plzen system should that appear beneficial under present conditions As a result, no attempt was made to consider future growth in Svetovar, and the analysis was conducted by adding a constant 23 megawatts to Plzen's hot water demands and alternatively by maintaining that demand level for a projection of independent system operations

The break-even analysis was performed by using the G/C simulation model to project the production costs of providing Svetovar's hot water requirements alternatively from the Plzen system and as an independent operation To the extent that the present worth of costs associated with continued independent operation exceed those under consolidated operations, an outer bound of feasible connection costs may be established Since this margin will obviously vary over different time frames, it is appropriate to establish a reasonable point of reference

In the U S, non-regulated industrial and commercial enterprises would generally try to achieve payback on their investment in no more than 2 to 3 years However for completeness, the break-even results for time frames from two through ten years are summarized in the table below

Cumulative Present Worth of Projected Cost of Svetovar Operations ($, Millions)

Years after Fuel Switch	2	3	5	10
Independent Operation				
Svetovar (Black coal)	3 39	5 26	8 70	15 53
B1 without Svetovar	63 56	73 08	86 63	117 85
Total Costs	66 95	78 34	95 33	133 38
Connected Operation				
B1 with Svetovar	64 97	75 06	89 68	123 19
Break-even Amount of Connection for Payback within indicated period	1 98	3 29	5 65	10 19

For the sake of illustration, the development of the 3 year payback break-even investment figure is discussed in the following paragraphs

The coal switch option was previously shown to be the most cost effective independent operation option Therefore, it was adopted for the independent operation cost element The cumulative present worth of projected costs for Svetovar under this continued independent operational mode is $5 26 million (after year 3)

As a basis for measuring costs in a consolidated system, the initial results developed under Variant B1 were adopted From the summary of projected costs shown in Exhibit 8-12, it may be seen that the present worth of projected costs through year 1997 (the third year of operation assuming a 1995 Svetovar interconnection), for the Plzen system excluding Svetovar is approximately $75 06 million Reanalysis of Variant B1 adjusted to include incremental hot water demands of 23 megawatts and other pertinent facets of Svetovar operations produced a modified Variant B1 cost of $73 08 million as shown in Exhibit 8-26) at corresponding year 1997 This represents an increase of approximately $2 0 million over the present worth of projected costs as previously determined

Since this difference of approximately $2 0 million is $3 3 million less than the cost of continued independent operation ($5 26 million), it would appear that merging Svetovar into the CP Plzen system would be justified on a 3 year payback criteria if the Heat Line East II pipeline project could be completed for less than that same $3 3 million Under this same methodology, the break-even amount for other lengths of time are developed in the preceding table

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EXHIBIT 8-26

PROJECTED FINANCIAL COSTS OF THE CONNECTED SVETOVAR SYSTEM AND VARIANT B1 (HIGH DEMAND)

FINANCIAL ANALYSIS – VARIANT No 1

STATEMENTS OF INCOME AND EXPENSES

OPERATING DATA	Year/10^3 Kc	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
REVENUES																					
Electricity Sales	10^3 Kc	9 587	9 587	9 587	9 587	9 587	9 587	9 587	9 587	9 587	9 587	9 587	9 587	9 587	9 587	9 587	9 587	9 587	9 587	9 587	9 587
Thermal ENergy Sales	10^3 Kc	15,143	15,143	15,143	15,143	15,143	15,143	15,143	15,143	15,143	15,143	15,143	15,143	15,143	15,143	15,143	15,143	15,143	15,143	15,143	15,143
Gross Revenues	10^3 Kc	24 731	24 731	24 731	24 731	24 731	24 731	24 731	24 731	24 731	24 731	24 731	24 731	24 731	24 731	24 731	24 731	24 731	24 731	24 731	24 731
EXPENSES																					
Fuel Costs	10^3 Kc	20 215	20 215	20 215	20 215	20 215	20 215	20 215	20 215	20 215	20 215	20 215	20 215	20 215	20 215	20 215	20 215	20 215	20 215	20 215	20 215
O & M Costs	10^3 Kc	1 433	1 433	1 433	1 433	1 433	1 433	7 393	1 433	1 433	1 433	1 433	1 433	1 433	7 393	1 433	1 433	1 433	1 433	1 433	1 433
Emission Fees	10^3 Kc	20	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25
Depreciation	10^3 Kc	1,037	2,104	2,104	2,104	2,104	2,104	2,104	2,104	2,104	2,104	2,104	2,104	2,104	2,104	2,104	0	0	0	0	0
Total Operating Expenses	10^3 Kc	22 705	23 777	23 777	23 777	23 777	23 777	29 737	23 777	23 777	23 777	23 777	23 777	23 777	29 737	23 777	21 673	21 673	21 673	21 673	21 673
Interest Expense	10^3 Kc	2 253	2 107	1 947	1 770	1 576	1 361	1 124	863	575	258	0									
Taxes	10^3 Kc	(102)	(519)	(447)	(387)	(280)	(183)	(2 759)	41	170	313	429	429	429	(2 253)	429	1 376	1 376	1 376	1 376	1 376
Net Income	10^3 Kc	(329)	(1 872)	(1 440)	(1 184)	(901)	(590)	(8 889)	50	208	383	525	525	525	(7 259)	525	1 682	1 682	1 682	1 682	1 682
AFTER–TAX CASH FLOW ANALYSIS																					
SOURCE																					
Net Income	10^3 Kc	(329)	(1 872)	(1 440)	(1 184)	(901)	(590)	(8 889)	50	208	383	525	525	525	(7 259)	525	1 682	1 682	1 682	1 682	1 682
Depreciation	10^3 Kc	1,037	2,104	2,104	2,104	2,104	2,104	2,104	2,104	2,104	2,104	2,104	2,104	2,104	2,104	2,104	0	0	0	0	0
Total Sources	10^3 Kc	708	432	664	920	1 203	1 514	(6 785)	2 154	2 312	2 487	2 629	2 629	2 629	(5 155)	2 629	1 682	1 682	1 682	1 682	1 682
USE																					
Loan Principal	10^3 Kc	1 418	1 563	1 724	1 900	2 095	2 310	2 546	2 807	3 095	3 412										
Net Cash Flow	10^3 Kc	(710)	(1 132)	(1 060)	(980)	(892)	(796)	(9 331)	(654)	(783)	(926)	2 629	2 629	2 629	(5 155)	2 629	1 682	1 682	1 682	1 682	1 682
Cummulative Cash Flow	10^3 Kc	(710)	(1 841)	(2 901)	(3 881)	(4 774)	(5 569)	(14 901)	(15 554)	(16 337)	(17 263)	(14 634)	(12 006)	(9 377)	(14 532)	(11 904)	(10 222)	(8 540)	(6 858)	(5 177)	(3 495)

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A rough estimate of the cost to connect Svetovar to the CP Plzen plant was determined by G/C to be $1 93 million (54 Kc million) This is based on an approximate pipeline length of 3 5 km for a 400 DN two pipe system These numbers have been developed by information supplied by EGU and in a manner consistent with other capital projects The cost of connecting substations along the pipeline is not included in this evaluation The actual price can differ from the estimated figure due to real technical conditions and quotes of suppliers

Since the estimated pipeline cost of $1 9 million is approximately equal to the two year break-even value and less than the three year break-even value of $3 3 million, it is recommended that Heat Line East II be constructed to connect Svetovar to CP Plzen

8.10 References

1 "HeatMap, A Computerized Tool For Analyzing District Heating and Cooling System Feasibility," Washington State Energy Office, Version 1 0, June 1992

2 "Gas Turbine World, The 1992-1993 Handbook," Peqout Publishing, Fairfield CT, Volume 14

3 "251B11/12 Econopac Application Handbook," Westinghouse Power Generation Business Unit, September 1991

4 "Price Prospects for Major Primary Commodities, 1990-2005," Volumes 1, 2, and the Quarterly Review of Commodity Markets, First Quarter 1993, World Bank, Washington D C , 1993

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9.0 ENVIRONMENTAL ANALYSIS

The objective of this study is to investigate the least cost approach for satisfying heat and steam requirements of the Plzen District Heating system One of the primary analysis assumptions is that environmental requirements are satisfied for each variant However, each variant results in a different quantity of pollutants produced by the system While no monetary credit was associated with over-compliance, such a value could be applied by the City in their decision process

This section provides an analysis of the emissions for each variant described in Section 6 0 The following sections present the environmental study area, calculation basis, applicable emissions regulations, and then the emissions evaluation

9 1 ENVIRONMENTAL STUDY AREA

The study area included in the environmental analysis is larger than that selected for the investigation of primary variants (described in Section 2 0) This was done to capture a larger fraction of the emissions sources in Plzen and obtain a better representation of the relative changes in total emissions as changes are made to the central system

The plants/plant groups selected for this emissions analysis include the following

- Central Heating Plant Plzen (ZCE) and cooperating sources (Plzen, Brewery and Railway Station Zos),
- Heating Plant Letna (V1) and Doubravka (V2) serving the Doubravka area,
- Heating Plant Svetovar,
- Heating Plant Bory,
- Cogeneration Plant Skoda,
- Small Decentralized Boilers, and
- Home Heating Furnaces (very rough estimate)

9 2 BASIS FOR EMISSIONS CALCULATIONS

Emission factors for ZCE (CP Plzen and Kosutka), TEZA (Letna, Doubravka, and Bory), and Skoda units were developed from a small amount of data available from measurements for some of the ZCE boilers, past experience in emissions measurements for similar boilers, and judgement in applying the available data to boilers of different sizes or configurations The emissions factors and calculations used for various boiler types are presented in Appendix A

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The home heating furnace emissions estimates are based solely on fuel use information provided in a demand-side report prepared by PNL and subcontractors and are provided only for rough comparison purposes

9 3 EMISSIONS COMPLIANCE REGULATIONS

Compliance with new emissions regulations is a critical consideration for the least cost plan Regulations require that new particulate removal equipment be purchased for every solid fuel unit, that fuel quality be upgraded, and/or new technology be employed

The applicable environmental acts are

- Environmental Act No 17/91, and
- Act No 388/91 (Government Environmental Fund)

Specific acts for air pollution control are

- Act No 309/91 regarding atmosphere pollution protection
- Act No 389/91 regarding governmental control of atmosphere protection and air pollution fees
- Provision to the act No 309/91 from 10/1991

Sources are categorized according to thermal output as follows

- Small up to 0 2 MWt
- Medium from 0 2 MWt to 5 MWt
- Large greater than 5 MWt

Fines for pollution above stated limits for middle and large sources

- Particulate emissions 3000 Kc/t
- SO_2 emissions 1000 Kc/t
- NOx emissions 800 Kc/t
- CO emissions 600 Kc/t

These fines will be assessed at partial levels according to the following schedule

- Years 1992 - 1993 30%
- Years 1994 - 1995 60%
- Years 1996 - 1997 80%
- After 1998 100%

Fines may also be assessed to small boiler owners, at the discretion of local agencies

Measurement of emissions for regulatory purposes will be by an "independent office" of the state Larger plants will probably require Continuous Emission Monitors (CEMs) Regulations are now being developed for "enforcement" purposes

A summary of Air Emission Regulations is presented in Exhibit 9-1

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Exhibit 9-1
MAXIMUM STANDARDS FOR AIR POLLUTION FROM MIDDLE AND LARGE SOURCES

	Middle Sources	Large Sources		
Regulated Parameter[a]	**0 2 to 5 MWt** (mg/m^3)	**5 to 50 MWt** (mg/m^3)	**50 to 300 MWt** (mg/m^3)	**> 300 MWt** (mg/m^3)
Solid Fuel Emissions				
Particulate	250	150	100	100
SO_2	2500	2500	1700	500
NOx	650	650	650	650
CO	250	250	250	250
Liquid Fuel Emissions				
Particulate	100	100	50	50
SO_2	Note b	1700	1700	500
NOx	500	450	450	450
CO	175	175	175	175
Gas Fuel Emissions				
Particulate	10	10	10	10
SO_2	35	35	35	35
NOx	200	200	200	200
CO	100	100	100	100
FBC Emissions[c]				
Particulate		50	50	50
SO_2		500	500	500
NOx		400	400	400
Gas Turbine Emissions[d]				
SO_2		1700	1700	
NOx		350	300	
CO		100	100	

Notes

a All standards in mg/m^3 and related to dry flue gas at 101 32 kPa 0C and 3% O_2 for liquid and gaseous fuels and 6% O_2 for solid fuels

b Maximum standard is not yet defined except that only 1% sulfur content is allowed

c Special regulations for Fluidized Bed Combustion boilers

d Special regulations for gas turbines Smaller size is less than 60 000 m^3/h actual volumetric flow of flue gas larger size is greater than 60 000 m^3/h

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9 4 COMPARISON OF EMISSIONS FOR SELECTED YEARS

Emissions comparisons were made for years 1993 (present situation), 2000 (following implementation of emission controls and boiler upgrades, initial conservation efforts, and demand growth) and 2010 (following retirement of several existing boilers and demand growth from the year 2000, and full realization of conservation efforts) The comparison is presented in Exhibit 9-2

The distribution of particulate, SO_2, NOx and CO emissions for the city of Plzen is shown in Exhibit 9-3 for the years 1993 and 2010 (projected) All emissions source segments share a significant fraction of these emissions Note that home furnaces have a disproportionate share of CO emissions, which is typical of these kinds of units

Emission values in the future years for small boilers are reduced by 22% to represent the fraction of boiler load which is transferred to district heating in 1997, and then further reduced 10% for conservation, 5% in the year 2000 and 5% in the year 2005 Specific changes to improve operations recommended in Section 4 0 are not considered, in this set of graphs, to be implemented since a cost-benefit analysis for these changes was not performed Home furnaces are also reduced by 10% for conservation, 5% in the year 2000 and 5% in 2005, but no other changes/improvements are recognized

The entire Plzen area is now explored In Exhibit 9-4, the change in emissions for the city between years 1993 and 2010 is depicted Many assumptions are made, including

- Skoda and Svetovar reduce SO_2 emissions by 70%,
- decentralized small boilers benefit from conservation and 22% of capacity of boilers switch to district heating,
- decentralized small boilers and home furnaces benefit from 10% conservation, and
- Variant B1 is implemented

The two sets of values represent the result of implementing changes to boilers as recommended in Section 4 0 as well as other benefits from implementing emissions control options

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Exhibit 9-2
SUMMARY OF PARTICULATE, SO_2 AND NOx EMISSIONS FOR PLZEN

	Emissions by Variant tonnes per year																	
	Variant A2						Variant A3				Variant B1				Variant C1 (baseline)			
	CP Plzen[a]	Other DH[b]	Decentral Small Blrs[c]	Home Furnaces[d]	Total	Change from 1993	CP Plzen[a]	Other Sources[e]	Total	Change from 1993	CP Plzen[a]	Other Sources[e]	Total	Change from 1993	CP Plzen[a]	Other Sources[e]	Total	Change from 1993
Year 1993																		
Particulate	248	358	682	370	1 658	0 0%	248	1 410	1 658	0 0%	248	1 410	1 658	0 0%	248	1 410	1 658	0 0%
SO_2	5 745	4 637	540	375	11 297	0 0%	5 745	5 552	11 297	0 0%	5 745	5 552	11 297	0 0%	5 745	5 552	11 297	0 0%
NOx	1 373	1 070	178	178	2 799	0 0%	1 373	1 426	2 799	0 0%	1 373	1 426	2 799	0 0%	1 373	1 426	2 799	0 0%
CO	56	97	400	2 230	2 782	0 0%	56	2 726	2 782	0 0%	56	2 726	2 782	0 0%	56	2 726	2 782	0 0%
Year 1997																		
Particulate	77	136	532	370	1 115	−32 7%	78	1 038	1 116	−32 7%	131	1 038	1 169	−29 5%	98	1 038	1 136	−31 5%
SO_2	2 307	1 318	421	375	4 420	−60 9%	2 349	2 113	4 462	−60 5%	3 020	2 113	5 133	−54 6%	3 027	2 113	5 140	−54 5%
NOx	1 303	978	139	178	2 598	−7 2%	1 316	1 295	2 611	−6 7%	1 590	1 295	2 885	3 1%	1 621	1 295	2 916	4 2%
CO	96	71	312	2 230	2 709	−2 6%	105	2 613	2 718	−2 3%	76	2 613	2 689	−3 4%	146	2 613	2 759	−0 8%
Year 2000																		
Particulate	77	132	506	351	1 066	−35 7%	78	989	1 067	−35 6%	132	989	1 121	−32 4%	98	989	1 087	−34 4%
SO_2	2 321	1 295	400	356	4 373	−61 3%	2 364	2 051	4 415	−60 9%	3 046	2 051	5 097	−54 9%	3 049	2 051	5 100	−54 9%
NOx	1 310	956	132	170	2 567	−8 3%	1 324	1 257	2 581	−7 8%	1 604	1 257	2 861	2 2%	1 631	1 257	2 888	3 2%
CO	99	73	296	2 119	2 586	−7 0%	107	2 487	2 594	−6 8%	77	2 487	2 564	−7 8%	149	2 487	2 636	−5 2%
Year 2005																		
Particulate	75	136	479	333	1 023	−38 3%	75	948	1 023	−38 3%	131	948	1 079	−34 9%	132	948	1 080	−34 9%
SO_2	2 054	1 329	379	337	4 099	−63 7%	2 054	2 045	4 099	−63 7%	2 983	2 045	5 028	−55 5%	3 061	2 045	5 106	−54 8%
NOx	1 232	982	125	161	2 500	−10 7%	1 233	1 268	2 501	−10 7%	1 588	1 268	2 856	2 0%	1 611	1 268	2 879	2 8%
CO	45	73	280	2 007	2 406	−13 5%	45	2 361	2 406	−13 5%	63	2 361	2 424	−12 9%	78	2 361	2 439	−12 3%
Year 2010																		
Particulate	75	136	479	333	1 023	−38 3%	75	948	1 023	−38 3%	132	948	1 080	−34 9%	133	948	1 081	−34 8%
SO	2 056	1 329	379	337	4 101	−63 7%	2 056	2 045	4 101	−63 7%	2 995	2 045	5 040	−55 4%	3 075	2 045	5 120	−54 7%
NOx	1 234	982	125	161	2 502	−10 6%	1 236	1 268	2 504	−10 6%	1 594	1 268	2 862	2 2%	1 618	1 268	2 886	3 1%
CO	45	73	280	2 007	2 406	−13 5%	45	2 361	2 406	−13 5%	63	2 361	2 424	−12 9%	79	2 361	2 440	−12 3%

Notes a Including cooperating sources include Plzen Brewery Railway Zos Starting in 1997 includes Letna Doubravka and Bory (HW only)

b Other District Heating includes Letna and Doubravka prior to 1997 Also includes a rough estimate of Skoda Works and Svetovar through entire period

c This estimate based on values developed in Section 3 0 assuming that recommendations are not implemented Also reduced emissions for boilers connected to District Heating for the High Demand case and assumed a total of 10% conservation impemented in the years 2000 and 2005

d Rough estimate based on demand−side analysis presented in Reference 1 (PNL 1993) Conservation measures to reduce energy requirements by a total of 10% assumed to be implemented in the years 2000 and 2005 Otherwise no improvements assumed to furnaces Total solid and gas fuel consumed = 857212 and 1157834 GJ/y respectively based on 1989 data

e Content of this value assumed to be the same as Variant A2

11/11/93 k \plzen\workarea\lnr\GC EMIS wk3

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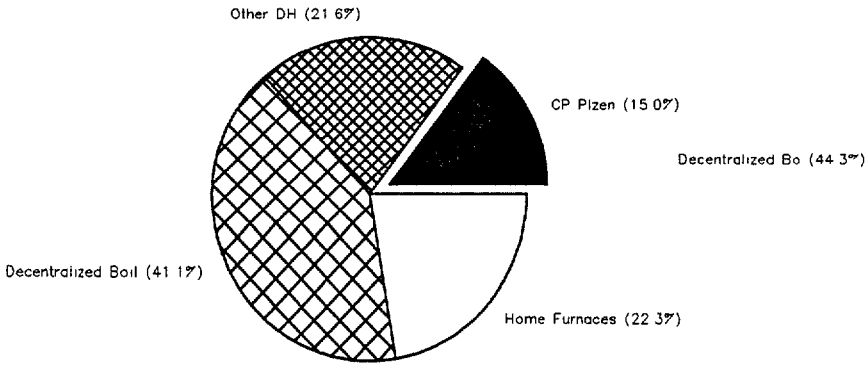
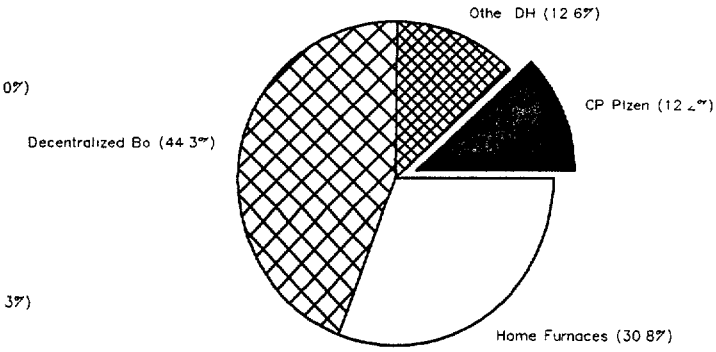
Exhibit 9-3
EMISSIONS FOR CITY OF PLZEN 1993 vs 2010 (Variant B1)

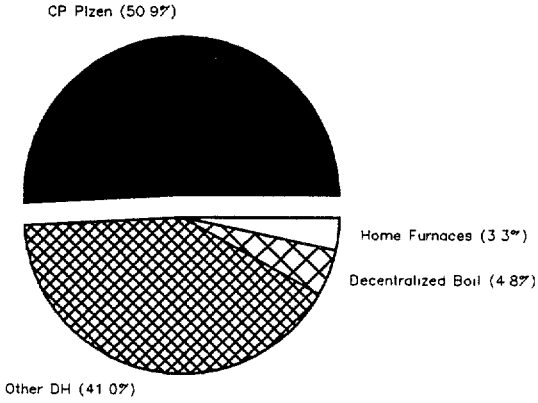
CURRENT PARTICULATE EMISSIONS



YEAR 2000 PARTICULATE EMISSIONS



CURRENT SO_2 EMISSIONS



YEAR 2000 SO_2 EMISSIONS

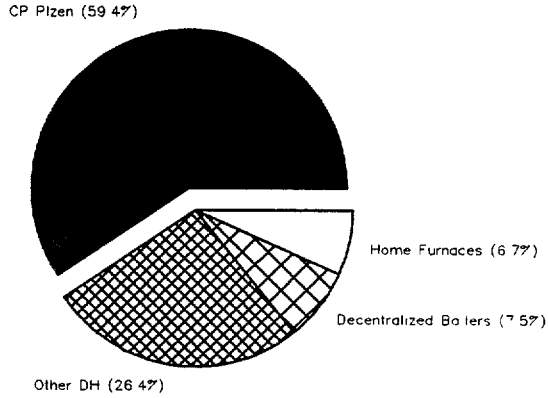


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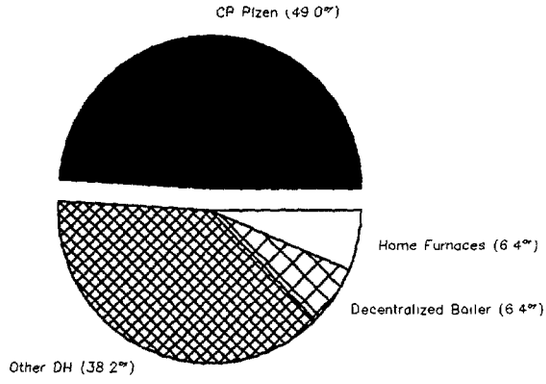
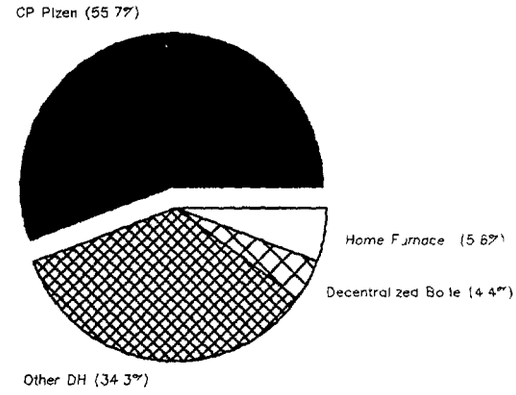
Exhibit 9-3 (continued)
EMISSIONS FOR CITY OF PLZEN 1993 vs 2010 (Variant B1)

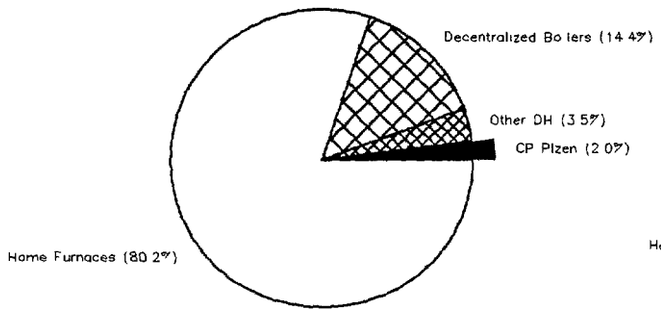
CURRENT NOx EMISSIONS



YEAR 2000 NOx EMISSIONS



CURRENT CO EMISSIONS



YEAR 2000 CO EMISSIONS

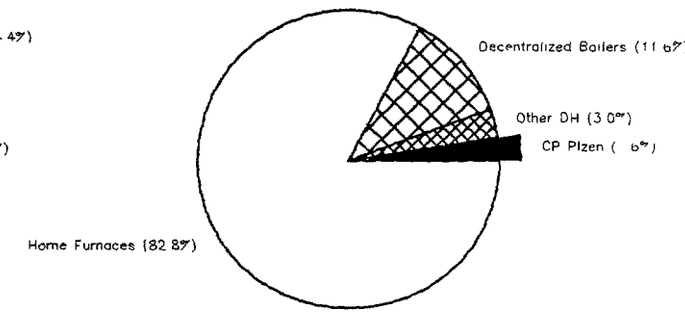
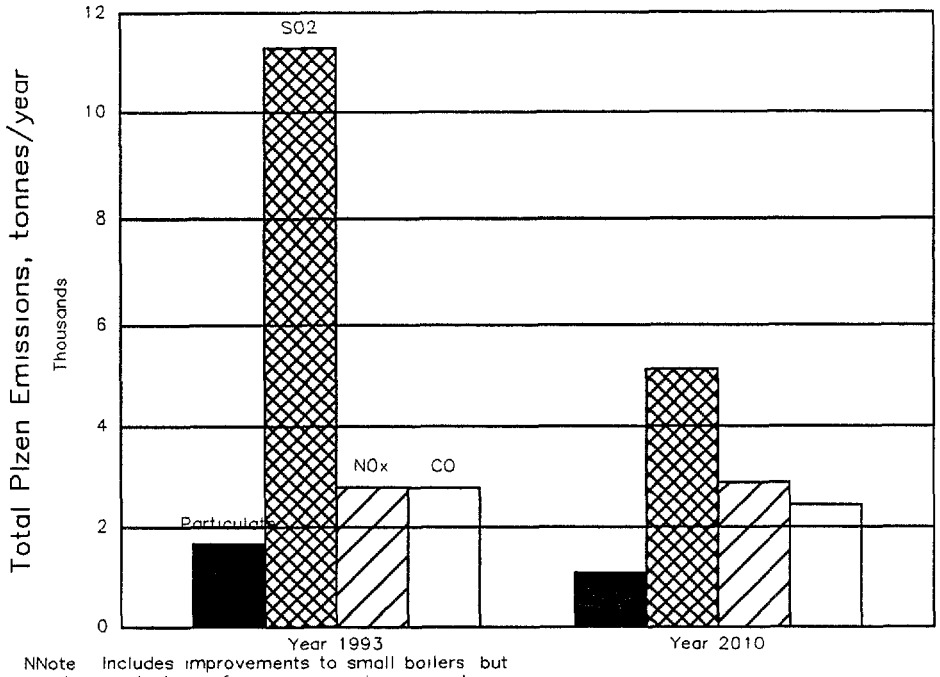


Exhibit 9-4
1993 vs 2010 EMISSIONS IN CITY OF PLZEN
WITH SMALL BOILER CHANGES IMPLEMENTED (Variant B1)



NNote Includes improvements to small boilers but no changes to home furnaces except conservation

A comparison is now made between variants and is confined to emissions of CP Plzen only In this context, the Brewery is included as a cooperating source, and Letna and Doubravka are included beginning in 1997 These results are somewhat skewed because the study area changes between 1993 and 1997 Later, a set of graphs for the total emission values is presented

As shown in Exhibit 9-5, particulate emissions are reduced dramatically when environmental controls are in place in the year 1997 There are also significant expected differences between the gas turbine variant (A3) and both of the FBC variants (B1 and C1)

A similar comparison of SO_2 emissions is shown in Exhibit 9-6 A benefit to increased operation with natural gas is the reduced level of SO_2 emissions This is also expected To determine the "value" of removing the additional SO_2, a simple cost of removal was calculated Using Variants A3 and B1 as examples, the following numbers are used

Variant	Cumulative Present Worth of Projected Costs	Cumulative Costs	Cumulative Particulate Emissions, tonnes	Cumulative SO_2 Emissions, tonnes
A3	$ 177,438,000	$ 327,521,000	2,269	52 412
B1	$ 141,052,000	$ 251,302,000	3,038	63,466
Difference	$ 36 386,000	$ 76 219,000	769	11 054

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There is not sufficient variation in NOx emissions to allow for this difference, since either technology is capable of further NOx reduction Using these values, and providing a weighted priority to each pollutant according to the Czech established penalties for each pollutant, it was determined that the costs of obtaining this additional emissions control by choosing Variant A3 would be as follows

SO_2 = 2,723 $/tonne

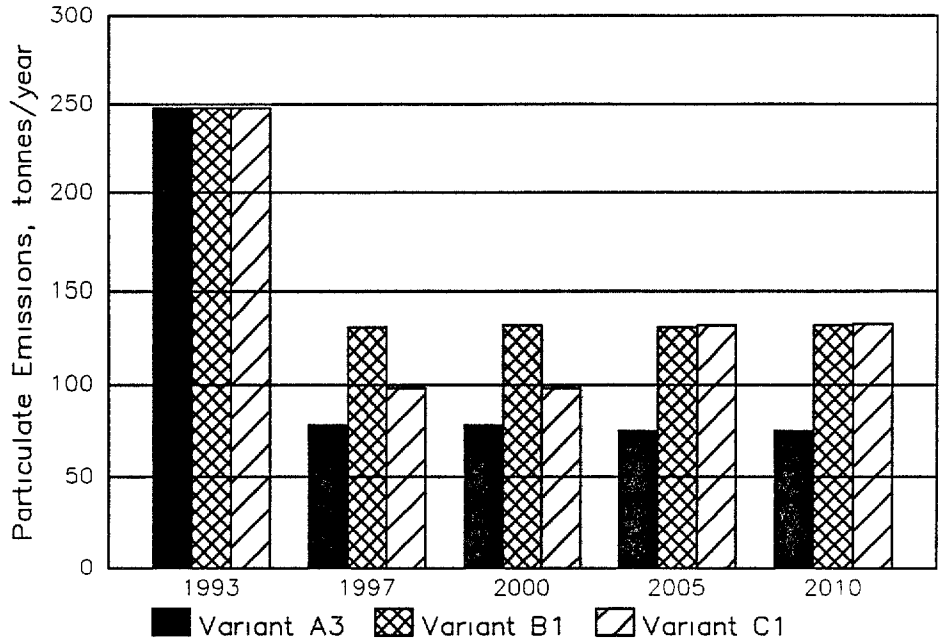
Particulate = 8,169 $/tonne

These results can be used to compare to other alternatives of SO_2 removal In the U S , for example, SO_2 removal is worth less than 1200 $/ton, and more appropriately 400-500 $/ton, in their system of trading and emissions Even with the correction for tons to tonnes, there is insufficient motivation for selecting Variant A3 on the basis of improved emissions reduction

The NOx emissions comparison is shown in Exhibit 9-7 Comparing A3 to B1 or C1 shows that NOx is also reduced We have made certain assumptions regarding NOx levels which appear to favor the gas turbine, but further reductions of both the gas turbine and FBC are possible, if this is required The starting assumption is that emissions regulations would be met, this is accomplished by all variants

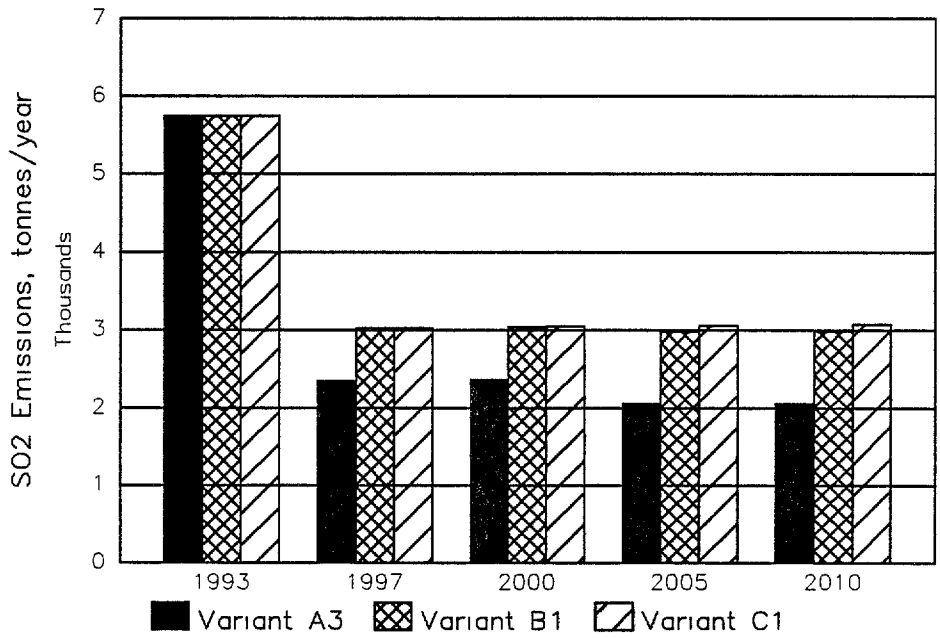
A similar comparison is made for CO emissions in Exhibit 9-8 CO emissions can be extremely variable and can depend as much or more on the method of operation and "tuning" of the equipment, as to the type of equipment Very often, a reduction in CO can be achieved by improving boiler control Small domestic furnaces burning coal can be extremely high CO emitters, and their operation also can result in extremely variable CO emissions For these reasons, projections of CO can be very misleading In the exhibit, an increase is shown for the first period This is due to the expansion of CP Plzen to include coal-burning grate boilers Doubravka and Bory in the system Grate boilers are much higher CO emitters than pc-fired boilers, and therefore, have a strong influence on system CO emissions

Exhibit 9-5
CP PLZEN PARTICULATE EMISSIONS BY VARIANT



Note Assumed connection of Heat Line East I by 1997
Heat Line East II (Svetovar) not included

Exhibit 9-6
CP PLZEN SO_2 EMISSIONS BY VARIANT



Note Assumed connection of Heat Line East I by 1997
Heat Line East II (Svetovar) not included

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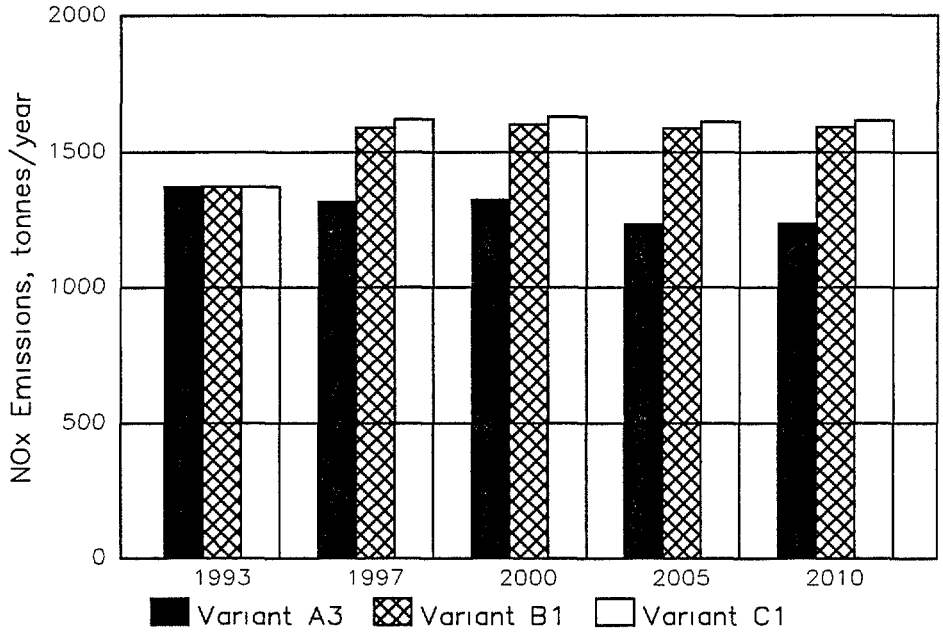
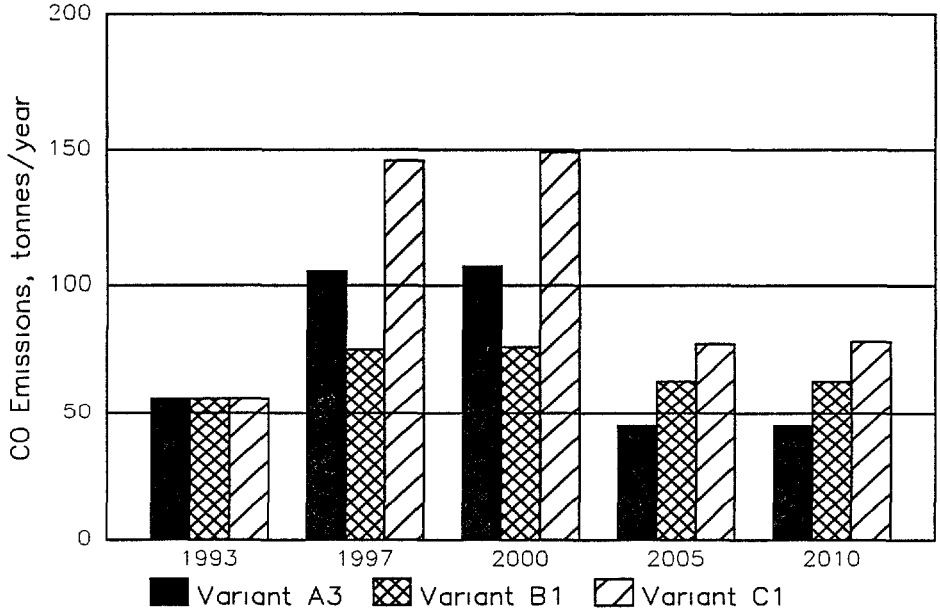
Exhibit 9-7
CP PLZEN NOx EMISSIONS BY VARIANT



Note Assumed connection of Heat Line East I by 1997
Heat Line East II (Svetovar) not inlcuded

Exhibit 9-8
CP PLZEN CO EMISSIONS BY VARIANT



Note Assumed connection of Heat Line East I by 1997
Heat Line East II (Svetovar) not included

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Should future regulations become more strict, as they are expected to approach west European standards, a question arises as to which variant would be flexible to accommodate further reductions? The following comments are offered

- Variant C1 postpones decisions until a future date This provides an advantage because a different technology can be selected at a future date Also, even if the same technology is selected at a future date, it is possible that a tighter specification can be written at that time For example, further SO_2 and NOx reduction can be achieved by modifying the design of the FBC for Variant C1

- All of the gas turbine variants have capability to further reduce NOx in the initial design Also, they are each capable of further NOx reduction by retrofitting with a technology such as water injection In all cases, if further reduction is required and known in advance of the equipment order, the cost will be reduced by specifying this in the initial design

The changes planned for CP Plzen and cooperating district heat sources, combined with implementation of reasonable changes to many of the 595 small boilers, will produce dramatic changes to particulate and SO_2 emissions in the City of Plzen Potential changes to small home furnaces should also be investigated due to the large fraction of emissions contributed by these sources Wherever possible and economically justified, these sources should be connected to the district heating system The programs being conducted in Krakow, Poland by U S AID and U S DOE will yield good characterizations of performance and potential improvements to operation of these furnaces The output from these programs should be useful to the City of Plzen in establishing policies to deal with these significant sources

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10.0 CONCLUSIONS AND RECOMMENDATIONS

Conclusions and Recommendations have been developed in two general areas "Selection of Promising Variants" and "Recommendations for Plant Improvements / Further Study"

10.1 SELECTION OF PROMISING VARIANTS

The variants (options) considered in the Plzen analysis are mainly distinguished by the selection of the plant technology for Plzen IV The basic plant technologies selected for analysis as Plzen IV are a (1) Gas-Fired Gas Turbine Combined Cycle, and (2) a Circulating Fluidized Bed (CFB) boiler The variant naming convention was selected to avoid confusion with the previous Energoprojekt designations Not all of the variants were investigated by each company The table below characterizes each variant by the CP IV technology selection and the investigating company

Variant	Investigator	Description of Distinguishing Feature (Choice of CP IV)
A1	EGU	Combined cycle plant with two 60 9 MWe (ISO) Gas Turbines
A2	EGU & G/C	Combined cycle plant with one 60 9 MWe (ISO) Gas Turbine
A3	G/C	Combined cycle plant with one 47 MWe (ISO) Gas Turbine
A4	EGP	Combined cycle plant with one 90 MWe (ISO) Gas Turbine
B1	EGU & G/C	Cogeneration plant with one CFB boiler and a 32 MWe steam turbine
C1	G/C	Life extension of existing units and subsequent introduction of a CFB boiler with a 32 MWe steam turbine in 2003

Not all variants were investigated by each company The EGU and EGP analyses are presented in Section 7 0 and the G/C analysis is found in Section 8 0

The demand projections utilized in the G/C analysis are based on the study area covering the Plzen, Doubravka (Letna and Doubravka plants) district heating systems, but is exclusive of Skoda Works The projections where adjusted to include the effects of conservation, the addition of new consumers, and the retirement of small boilers whose consumers will connect to the DH system

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The G/C analysis of the selected primary variants and demand projections resulted in the following Cumulative Present Worth of Projected Costs

Variant	Cumulative Present Worth of Projected Costs $US (000)	equivalent Kc (000)
C1	$137 991	3 863 748
A2	$179,443	5,024,404
A3	$177 438	4 968 264
B1	$141,052	3,949,456

The Cumulative Present Worth of Projected Costs is the figure of merit used for selection between competing alternatives on an economic basis Lower Cumulative Present Worth of Projected Costs figures are desirable

The following conclusions/recommendations are offered

1 The CFB boiler variants (B1 and C1) are recommended over the GTCC variants (A2, and A3) on the basis of the Cumulative Present Worth of Projected Costs resulting from the G/C economic analysis (Section 8 6) The GTCC variants are clearly higher in cost (between 26 and 30% higher) than the CFB boiler variants The selection of the CFB boiler variants over the GTCC variants are further supported by the following

- Sensitivity analyses (Section 8 7 3) show that in order for Variant A2 (60 9 MWe GTCC) to be competitive with the C1 base case (Life Extension with future CFB), significant changes in fuel or capital costs would be required Any one of the following significant changes would be required to make Variant A2 competitive with C1 on a Cumulative Present Worth of Projected Costs basis
  - a decrease in the cost of natural gas of approximately 43%,
  - a decrease in capital and demolition costs of approximately 71%, or
  - an increase in the cost of black coal by approximately 370%
- The G/C Financial analysis (Section 8 8) results further support this conclusion
- The sensitivity analysis (8 7 1) based on the low demand requirements did not alter the conclusions based on the high demand requirements The GTCC variants are clearly higher in cost than the CFB boiler variants B1 and C1

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- Economic analyses (Section 7 0) based on technical input from EGU, and Energoprojekt are consistent in this conclusion
- The GTCC depends on imported natural gas which gives rise to security concerns The CFB boiler burns low quality, low price, indigenous lignite

2 The Cumulative Present Worth of Projected Costs for Variant B1 (160 tonne/h CFB boiler) and Variant C1 (Life Extension with future CFB) are virtually the same (C1 at $141 million, B1 at $137 million) Therefore, a decision should be based on other factors such as

- Concern that future emission compliance requirements may be more stringent (favors C1 by deferring the technology commitment and allowing time for the Czech emissions regulations to catch up with the rest of the European community),
- desire to minimize capital expenditures in the early years of privatized operation, and ease the cost burden to either the consumer or the DH company as state subsidies are removed, (favors C1 by deferring the addition of capacity),
- desire to delay capital expenditures because future financing interest and terms may become more attractive as they approach Western conditions (favors C1),
- concern over the uncertain demand projections (favors C1 because the addition of CP Plzen IV is not required until 2003),
- desire to implement a more advanced technology such as pressurized fluidized bed combustion (PFBC), which offers a higher electric/heat ratio (favors C1 by deferring the technology decision for more than five years),
- desire to take advantage of current potential long term fuels contracts (favors B1), and
- concern over potential effective equipment price increases (favors B1 because capital investments are made in the near term)

Based upon the preceding considerations, Variant C1 (the Base Case) is recommended by Gilbert/Commonwealth

3 Further investigation of Variants B1 and C1 with regard to an accelerated construction schedule for plant modifications reveals that an approximate 12% improvement in Present Worth of Projected Cost for Variants B1 and C1 is possible during the years 1995 and 1996, when the reconstruction occurs (Section 8 3) This analysis assumes that both Plzen II cogen boilers would be available during these years

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4 Based on Conclusion 3, it may not be necessary to build the Plzen III gas/oil steam boiler as previously planned, especially if additional cooperation with the Brewery is possible In fact, in the G/C analysis (Section 8 6), plants were successfully dispatched to meet load without utilizing Plzen III by relying on cooperation of the Brewery

5 Emissions compliance for all stoker (grate) boilers can be met most cost effectively by switching to low sulfur black (bituminous) coal and installing a baghouse For the Letna plant, however, switching to gas and standby duty should be considered because of the close proximity to residential housing

6 The district heating operation in Svetovar is not presently interconnected with the CP Plzen DH system In order for the Svetovar DH system to meet the new emission requirements by 1997, they could either modify the present supply system for compliance, or connect to the Plzen district heating system Three categories of plant modifications were considered (1) a cogeneration retrofit, (2) a switch to coal, and (3) a switch to gas (Section 8 9)The following comments and recommendations are offered

- It is unlikely that the cogeneration retrofit option will be able to compete with the District Heating Company as presently structured Unless dramatic changes occur in the pricing schemes for the two basic commodities provided (i e , the price of heat and electricity), emphasis should still be placed on improving the efficiency of the existing system through modifications in the distribution system and replacement of antiquated equipment when its useful life is over
- With respect to the fuel switching options, the switch to black coal and the addition of a baghouse is more cost effective than the switch to natural gas
- Based on a break-even analysis and constant demand, connecting the Svetovar district heating system to the Plzen district heating system is more economical than the black coal or natural gas fuel switch option The payback period for estimated costs incurred in connecting Svetovar should be on the order of two to three years If demand could be increased with new consumers, the payback period would be even shorter
- It is recommended that Svetovar be connected to the central district heating system through the proposed Heat Line East II
- With the interconnection of Svetovar, the demand seen by the centralized system would be higher, offering the potential to provide additional cogeneration during the summer months The reliability of heat supply to the Svetovar consumers would be improved and the cost of heat in Plzen could be more competitive with other forms of energy

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7 Without considering a switch to district heating, potential exists to make significant improvements to many of the 595 small boilers, including switching to natural gas, installing new burners, boiler tuning, installing boiler controls, and boiler replacement with more efficient units This potentially can result in

- reduced fuel use by more than 22%,
- reduced particulate and SO_2 emissions by 80%,
- reduced NOx emissions by 72%,
- reduced CO emissions by more than 80%, and
- reduced VOC emissions by more than 80%

8 At least 64 MWt (representing 80 boilers) of small boiler capacity should be retired and their consumers connected to the district heating system More boilers may be suitable along Heat Line East II, if this project continues

9 Small cogeneration alternatives should be considered only under special circumstances, and in isolated or remote areas of the City where the Central DH System cannot be extended It is highly unlikely that small cogeneration systems will be able to compete with district heating as presently structured Exceptions may include situations where (1) large numbers of cogeneration units apply with the utility as a group to negotiate an electric rate, or (2) some combination of government incentives are available to offset the initial capital cost Unless dramatic changes occur in the pricing schemes for the two basic commodities (electricity and heat), emphasis should still be placed on improving the efficiency of the existing system through modifications in the distribution system and replacement of antiquated equipment when its useful life is over (Section 4 4 and 8 9 1)

10 Emissions analysis conclusions

- The changes planned for CP Plzen and cooperating district heat sources, combined with implementation of changes to many of the 595 small boilers, will produce dramatic reductions to particulate and SO_2 emissions in the City of Plzen of 35% and 55% respectively (Section 9 0)
- Potential changes to home furnaces should be investigated due to the large fraction of emissions contributed by these sources Wherever economically justified, these sources should be connected to the district heating system Programs being conducted in Krakow, Poland by U S AID will yield good characterizations of performance and potential improvements to operation of these furnaces and should be useful to the City of Plzen in establishing policies to deal with these significant sources (Section 9 0)

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10 2 RECOMMENDATIONS FOR PLANT IMPROVEMENT / FURTHER STUDY

Several issues emerged during the study which were not directly compared between variants, but may be important for the future of centralized district heating (DH) in Plzen

1 A well maintained and managed CP Plzen central district heating system should prove to be economically superior to other competing heat or cogeneration sources for the following reasons

- larger scale plants result in better cost economy of scale, better performance, and can more efficiently generate electricity,
- with the plants and systems "in place" only the costs of improvements and maintenance need to be considered,
- district heating technology is constantly improving, and
- a central plant can burn inexpensive low grade fuels <u>and</u> control emissions

2 The future of the 595 small boilers spread through the city offer a significant expansion potential for centralized DH, however, not all of the true interconnection potential is expected to be realized The future disposition of these small heat sources can be strongly influenced by incentives offered by the government, attractive connection arrangements by ZCE, the completion of heat line East II, and by education of the people in the economic/financial evaluation of centralized DH verses individual boilers

3 Significant improvement in the operation of all plants is possible with addition of more sophisticated controls Currently, a boiler "factor" of 1 07 is used to account for boiler age, changing loads, etc This factor should be reduced to half simply by better and safer control of O_2 during load change, and may offer the potential to reduce the current safe minimum load setting This change, which is relatively inexpensive, could result in a savings of 3 to 4% of current coal requirements Controls improvements could also be extended to improve the operation and dispatch of units

4 Reduction of system leakages can be improved through the gradual replacement of primary piping with corrosion resistant pipe with integrated leak detection and by the replacement of secondary systems with more modern two pipe systems, where possible It appears that losses equivalent to 4 to 5% of the overall heat generation may be saved through these changes The future metering of heat and required measurements will also help to better assess the true magnitude of these losses

5 The management of Plzen district heating activities will best be consolidated into a single privatized company, and governed by a regulatory body Based on interviews with modern district heating companies, significantly greater efficiency in utilization of operations and maintenance personnel is possible

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APPENDIX A: EMISSION FACTORS

CP PLZEN EMISSION FACTORS
Fuels Table

11/10/93

FUELS TABLE											
Fuel no		1	2	3	4	5	6	7	8	9	10
Type		brown	black	black	brown		#6 oil	#2 oil	gas		
Mine		Sokolov	Zbuch	Zbuch	Sokolov						
Fuel company			Zud	Zud			WBGW				
Lower Heating Value	MJ/kg	12 70	18 47	17 38	10 05		40 60	41 60	42 40		
	Btu/lb	5 463	7 946	7 477	4 323	0	17 466	17 896	18 240		
	MJ/Nm³								33 5		
Percent sulfur	%	0 70%	0 40%	0 40%	1 50%		1 50%	0 18%	0 00%		
Percent ash	%	16 00%	30 40%	33 20%	23 80%		0 30%	0 10%	0 00%		
Cost First Year	Kc/t	443	1135	907	330			3300			
	Kc/Nm³								3 35		
	$/10⁶Btu	$1 31	$2 31	$1 96	$1 24			$2 99	$3 77		
	Kc/GJ	34 88	61 45	52 19	32 84		0 00	79 33	100 01		
Proximate Analysis											
Moisture	%	35 50%	11 20%	11 20%	36 60%						
Fixed Carbon	%	20 60%	36 50%	34 70%	16 80%						
Volatiles	%	27 90%	21 90%	20 90%	22 80%						
Ash	%	16 00%	30 40%	33 20%	23 80%						
TOTAL	%	100 00%	100 00%	100 00%	100 00%	0 00%	0 00%	0 00%	0 00%	0 00%	0 00%
Ultimate Analysis											
Carbon	%	34 98%	48 10%	45 80%	28 08%		85 83%	86 00%	72 61%		
Sulfur	%	0 70%	0 40%	0 40%	1 50%	0 00%	1 50%	0 18%	0 00%	0 00%	0 00%
Hydrogen	%	2 81%	3 25%	3 08%	2 24%		11 50%	12 70%	23 67%		
Moisture	%	35 50%	11 20%	11 20%	36 60%		0 40%	0 20%	0 00%		
Nitrogen	%	0 53%	0 85%	0 82%	0 40%		0 35%	0 70%	1 81%		
Oxygen	%	9 48%	5 80%	5 50%	7 38%		0 12%	0 12%	1 91%		
Ash	%	16 00%	30 40%	33 20%	23 80%	0 00%	0 30%	0 10%	0 00%	0 00%	0 00%
TOTAL	%	100 00%	100 00%	100 00%	100 00%	0 00%	100 00%	100 00%	100 00%	0 00%	0 00%
Intermediate calcs											
F Factor (0% O_2)	m³/t (daf)	7 254	8 373	8 373	7 213	0	10 133	10 384	11 532	0	0
O_2 Correction	%	6%	6%	6%	6%	6%	3%	3%	3%	6%	6%
F_1 Factor	m³/t (daf)	10 156	11 723	11 722	10 098	0	11 822	12 114	13 454	0	0
F_2 Factor	m³(daf)/GJ	388	371	375	398		289	290	317		
F_3 Factor	scf/10⁶Btu	14,440	13,800	13,961	14,814		10,765	10,809	11,814		

Emission Fines for middle (> 0 2 MWt) and large sources					
	Emission Fines				
	kC/tonne	$/ton			
Emission	1998+	1992–3	1994–5	1996–7	1998+
% Fee		30%	60%	80%	100%
Particulate	3000	$29 16	$58 32	$77 76	$97 20
SO_2	1000	$9 72	$19 44	$25 92	$32 40
NOx	800	$7 78	$15 55	$20 74	$25 92
CO	600	$5 83	$11 66	$15 55	$19 44

CP PLZEN EMISSION FACTORS

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	1	2	3	4	5	6	7	8	9
	Boiler Size / Type / Fuel	Mine/ Supply	Fuel No	%S	% Ash	LHV MJ/kg	LHV Btu/lb	Gas Factor* (LHV) scf/10 Btu	Ash Production lb/10 Btu
Individual Boilers 50 to 300 MWt									
PC-2E1	PC-brown coal w/ ESP	0 00	1	0 70%	16 0%	12 70	5 463	14 440	29 29
PC-2B1	PC-brown coal w/ baghouse	0 00	1	0 70%	16 0%	12 70	5 463	14 440	29 29
PC-2E3	PC-black coal w/ ESP	Zud	3	0 40%	33 2%	17 38	7 477	13 961	44 40
PC-2B3	PC-black coal w/ baghouse	Zud	3	0 40%	33 2%	17 38	7 477	13 961	44 40
FB-2B4	CFB-poor brown coal w/baghouse	0 00	4	1 50%	23 8%	10 05	4 323	14 814	55 05
ST-2C1	Grate-brown coal w/ cyclones	0 00	1	0 70%	16 0%	12 70	5 463	14 440	29 29
ST-2E1	Grate-brown coal w/ ESP	0 00	1	0 70%	16 0%	12 70	5 463	14 440	29 29
ST-2B1	Grate-brown coal w/ baghouse	0 00	1	0 70%	16.0%	12 70	5 463	14 440	29 29
ST-2C2	Grate-black coal w/ cyclones	Zud	2	0 40%	30 4%	18 47	7 946	13 800	38 26
ST-2E2	Grate-black coal w/ESP	Zud	2	0 40%	30 4%	18 47	7 946	13 800	38 26
ST-2B2	Grate-black coal w/ baghouse	Zud	2	0 40%	30 4%	18 47	7 946	13 800	38 26
ST-2A6	Heavy oil w/o particulate control	WBGW	6	1 50%	0.3%	40 60	17 466	10 765	0 17
ST-2E6	Heavy oil w/ ESP	WBGW	6	1 50%	0.3%	40 60	17 466	10 765	0 17
ST-2B6	Heavy oil w/ baghouse	WBGW	6	1 50%	0.3%	40 60	17 466	10 765	0 17
ST-2A7	Light Oil	0 00	7	0 18%	0 1%	41 60	17 896	10 809	0 06
ST-2A8	Natural Gas	0 00	8	0 00%	0 0%	42 40	18,240	11 814	0 00
Individual Boilers 5 to 50 MWt		0 00		0 00%	0 0%	0 00	0	0	
ST-3C1	Grate-brown coal w/o particulate control	0 00	1	0 70%	16.0%	12 70	5 463	14 440	29 29
ST-3E1	Grate-brown coal w/ cyclones	0 00	1	0 70%	16.0%	12 70	5 463	14 440	29 29
ST-3B1	Grate-brown coal w/ baghouse	0 00	1	0 70%	16 0%	12 70	5 463	14 440	29 29
ST-3C2	Grate-black coal w/o particulate control	Zud	3	0 40%	33 2%	17 38	7 477	13 961	44 40
ST-3E2	Grate-black coal w/ cyclones	Zud	3	0 40%	33 2%	17 38	7 477	13 961	44 40
ST-3B2	Grate-black coal w/ baghouse	Zud	3	0 40%	33 2%	17 38	7 477	13 961	44 40
ST-3A6	Heavy oil w/o particulate control	WBGW	6	1 50%	0 3%	40 60	17 466	10 765	0 17
ST-3E6	Heavy oil w/ ESP	WBGW	6	1 50%	0 3%	40 60	17 466	10 765	0 17
ST-3B6	Heavy oil w/ baghouse	WBGW	6	1 50%	0 3%	40 60	17 466	10 765	0 17
ST-3A7	Light oil	0 00	7	0 18%	0 1%	41 60	17 896	10 809	0 06
ST-3A8	Natural Gas	0 00	8	0 00%	0 0%	42 40	18,240	11,814	0 00
Individual Boilers 0 2 to 5 MWt		0 00		0 00%	0.0%	0 00	0	0	
HF-4A1	Hand fired-brown coal	0 00	1	0 70%	16 0%	12 70	5 463	14 440	29 29
HF-4B1	Hand fired-brown coal w/ baghouse	0 00	1	0 70%	16 0%	12 70	5 463	14 440	29 29
HF-4A3	Hand fired-black coal	Zud	3	0 40%	33 2%	17 38	7 477	13 961	44 40
HF-4B3	Hand fired-black coal w/ baghouse	Zud	3	0 40%	33 2%	17 38	7 477	13 961	44 40
ST-4C1	Grate-brown coal w/o particulate control	0 00	1	0 70%	16 0%	12 70	5 463	14 440	29 29
ST-4E1	Grate-brown coal w/ cyclones	0 00	1	0 70%	16 0%	12 70	5 463	14 440	29 29
ST-4B1	Grate-brown coal w/ baghouse	0 00	1	0 70%	16 0%	12 70	5 463	14 440	29 29
ST-4C2	Grate-black coal w/o particulate control	Zud	3	0 40%	33 2%	17 38	7 477	13 961	44 40
ST-4E2	Grate-black coal w/ cyclones	Zud	3	0 40%	33.2%	17 38	7 477	13 961	44 40
ST-4B2	Grate-black coal w/ baghouse	Zud	3	0.40%	33 2%	17 38	7 477	13 961	44 40
ST-4A6	Heavy oil w/o particulate control	WBGW	6	1 50%	0 3%	40 60	17 466	10 765	0 17
ST-4E6	Heavy oil w/ ESP	WBGW	6	1 50%	0 3%	40 60	17 466	10 765	0 17
ST-4B6	Heavy oil w/ baghouse	WBGW	6	1 50%	0 3%	40 60	17 466	10 765	0 17
ST-4A7	Light Oil	0 00	7	0 18%	0 1%	41 60	17 896	10 809	0 06
ST-4A8	Natural Gas	0 00	8	0 00%	0 0%	42 40	18 240	11,814	0 00
Individual Boilers < 0 2 MWt		0 00		0 00%	0 0%	0 00	0	0	
HF-5A1	Hand fired-brown coal	0 00	1	0 70%	16 0%	12 70	5 463	14 440	29 29
HF-5B1	Hand fired-brown coal w/ baghouse	0 00	1	0 70%	16 0%	12 70	5 463	14 440	29 29
HF-5A3	Hand fired-black coal	Zud	3	0 40%	33 2%	17 38	7 477	13 961	44 40
HF-5B3	Hand fired-black coal w/ baghouse	Zud	3	0 40%	33 2%	17 38	7 477	13 961	44 40
ST-5C1	Grate-brown coal w/o particulate control	0 00	1	0 70%	16 0%	12 70	5 463	14 440	29 29
ST-5E1	Grate-brown coal w/ cyclones	0 00	1	0 70%	16 0%	12 70	5 463	14 440	29 29
ST-5B1	Grate-brown coal w/ baghouse	0 00	1	0 70%	16 0%	12 70	5 463	14 440	29 29
ST-5C2	Grate-black coal w/o particulate control	Zud	3	0 40%	33 2%	17 38	7 477	13 961	44 40
ST-5E2	Grate-black coal w/ cyclones	Zud	3	0 40%	33 2%	17 38	7 477	13 961	44 40
ST-5B2	Grate-black coal w/ baghouse	Zud	3	0 40%	33 2%	17 38	7 477	13 961	44 40
ST-5A6	Heavy oil w/o particulate control	WBGW	6	1 50%	0 3%	40 60	17 466	10 765	0 17
ST-5E6	Heavy oil w/ baghouse	WBGW	6	1 50%	0 3%	40 60	17 466	10 765	0 17
ST-5A7	Light Oil	0 00	7	0 18%	0 1%	41 60	17 896	10 809	0 06
ST-5A8	Natural Gas	0 00	8	0 00%	0 0%	42 40	18 240	11 814	0 00
Gas Turbines by Mfr/Model > 50 MWt									
GT-251	W251 on Natural Gas	0 00	8	0 00%	0 0%	42 40	18 240		0 00
GT-643	Siemens 64 3 on Natural Gas		8	0 00%	0 0%	42 40	18 240		0 00
GT-B13	BBC Type 13 on Natural Gas		8	0 00%	0 0%	42 40	18 240		0 00

Notes a At 0 C and
b Standard is maximum of 1% oil to be used
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CP PLZEN EMISSION FACTORS

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		1	10	11	12	13	14	15	16	17	18
		Particulate Emission Calculations									
		Uncontrolled		Part	Controlled			Limit		> Limit
Boiler Size / Type / Fuel		lb/10 Btu	mg/m	Rem l, %	lb/10 Btu	mg/m	Source	lb/10 Btu	mg/m	lb/10 Btu
Individual Boilers 50 to 300 MWt										
PC-2E1	PC-brown coal w/ ESP	12 62	14 000	99 3%	0 088	98	EGU	0 090	100	0 000
PC-2B1	PC-brown coal w/ baghouse	12 62	14 000	99 7%	0 038	42		0 090	100	0 000
PC-2E3	PC-black coal w/ ESP	12 20	14 000	98 0%	0 244	280	EGU	0 087	100	0 157
PC-2B3	PC-black coal w/ baghouse	12 20	14 000	99 7%	0 037	42		0 087	100	0 000
FB-2B4	CFB-poor brown coal w/baghouse	12 95	14 000	99 7%	0 039	42		0 046	50	0 000
ST-2C1	Grate-brown coal w/ cyclones	3 61	4 000	80 0%	0 721	800	EGU	0 090	100	0 631
ST-2E1	Grate-brown coal w/ ESP	3 61	4 000	99 0%	0 036	40		0 090	100	0 000
ST-2B1	Grate-brown coal w/ baghouse	3 61	4 000	99 7%	0 011	12		0 090	100	0 000
ST-2C2	Grate-black coal w/ cyclones	3 45	4 000	80 0%	0 689	800	EGU	0 086	100	0 603
ST-2E2	Grate-black coal w/ESP	3 45	4 000	99 0%	0 034	40		0 086	100	0 000
ST-2B2	Grate-black coal w/ baghouse	3 45	4 000	99 7%	0 010	12		0 086	100	0 000
ST-2A6	Heavy oil w/o particulate control	0 1288	192	0 0%	0 129	192	AP42	0 034	50	0 095
ST-2E6	Heavy oil w/ ESP	0 1288	192	99 0%	0 001	2	AP42	0 034	50	0 000
ST-2B6	Heavy oil w/ baghouse	0 1288	192	99 7%	0 000	1	AP42	0 034	50	0 000
ST-2A7	Light Oil	0 0157	23	0 0%	0 016	23	AP42	0 034	50	0 000
ST-2A8	Natural Gas		0	0 0%	0 000	0		0 007	10	0 000
Individual Boilers 5 to 50 MWt										0 000
ST-3C1	Grate-brown coal w/o particulate control	3 61	4 000	60 0%	1 443	1 600	EGU	0 135	150	1 307
ST-3E1	Grate-brown coal w/ cyclones	3 61	4 000	80 0%	0 721	800		0 135	150	0 586
ST-3B1	Grate-brown coal w/ baghouse	3 61	4 000	99 7%	0 011	12		0 135	150	0 000
ST-3C2	Grate-black coal w/o particulate control	3 49	4 000	60 0%	1 395	1 600	EGU	0 131	150	1 264
ST-3E2	Grate-black coal w/ cyclones	3 49	4 000	80 0%	0 697	800		0 131	150	0 567
ST-3B2	Grate-black coal w/ baghouse	3 49	4 000	99 7%	0 010	12		0 131	150	0 000
ST-3A6	Heavy oil w/o particulate control	0 1288	192	0 0%	0 129	192	AP42	0 067	100	0 062
ST-3E6	Heavy oil w/ ESP	0 1288	192	99 0%	0 001	2	AP42	0 067	100	0 000
ST-3B6	Heavy oil w/ baghouse	0 1288	192	99 7%	0 000	1	AP42	0 067	100	0 000
ST-3A7	Light oil	0 0157	23	0 0%	0 016	23	AP42	0 067	100	0 000
ST-3A8	Natural Gas		0	0 0%	0 000	0		0 007	10	0 000
Individual Boilers 0 2 to 5 MWt								0 000		0 000
HF-4A1	Hand fired-brown coal	1 37	1523	0 0%	1 373	1 523	AP42	0 225	250	1 147
HF-4B1	Hand fired-brown coal w/ baghouse	1 37	1523	99 7%	0 004	5	AP42	0 225	250	0 000
HF-4A3	Hand fired-black coal	1 00	1151	0 0%	1 003	1 151	AP42	0 218	250	0 785
HF-4B3	Hand fired-black coal w/ baghouse	1 00	1151	99 7%	0 003	3	AP42	0 218	250	0 000
ST-4C1	Grate-brown coal w/o particulate control	3 61	4 000	60 0%	1 443	1 600		0 225	250	1 217
ST-4E1	Grate-brown coal w/ cyclones	3 61	4 000	80 0%	0 721	800		0 225	250	0 496
ST-4B1	Grate-brown coal w/ baghouse	3 61	4 000	99 7%	0 011	12		0 225	250	0 000
ST-4C2	Grate-black coal w/o particulate control	3 49	4 000	60 0%	1 395	1 600		0 218	250	1 177
ST-4E2	Grate-black coal w/ cyclones	3 49	4 000	80 0%	0 697	800		0 218	250	0 479
ST-4B2	Grate-black coal w/ baghouse	3 49	4 000	99 7%	0 010	12		0 218	250	0 000
ST-4A6	Heavy oil w/o particulate control	0 1288	192	0 0%	0 129	192	AP42	0 067	100	0 062
ST-4E6	Heavy oil w/ ESP	0 1288	192	99 0%	0 001	2	AP42	0 067	100	0 000
ST-4B6	Heavy oil w/ baghouse	0 1288	192	99 7%	0 000	1	AP42	0 067	100	0 000
ST-4A7	Light Oil	0 0157	23	0 0%	0 016	23	AP42	0 067	100	0 000
ST-4A8	Natural Gas		0	0 0%	0 000	0		0 007	10	0 000
Individual Boilers < 0 2 MWt								0 000		0 000
HF-5A1	Hand fired-brown coal	1 37	1523	0 0%	1 373	1 523		0 000		0 000
HF-5B1	Hand fired-brown coal w/ baghouse	1 37	1523	99 7%	0 004	5		0 000		0 000
HF-5A3	Hand fired-black coal	1 00	1151	0 0%	1 003	1 151		0 000		0 000
HF-5B3	Hand fired-black coal w/ baghouse	1 00	1151	99 7%	0 003	3		0 000		0 000
ST-5C1	Grate-brown coal w/o particulate control	3 61	4 000	60 0%	1 443	1 600		0 000		0 000
ST-5E1	Grate-brown coal w/ cyclones	3 61	4 000	80 0%	0 721	800		0 000		0 000
ST-5B1	Grate-brown coal w/ baghouse	3 61	4 000	99 7%	0 011	12		0 000		0 000
ST-5C2	Grate-black coal w/o particulate control	3 49	4 000	0 0%	3 487	4 000		0 000		0 000
ST-5E2	Grate-black coal w/ cyclones	3 49	4 000	80 0%	0 697	800		0 000		0 000
ST-5B2	Grate-black coal w/ baghouse	3 49	4 000	99 7%	0 010	12		0 000		0 000
ST-5A6	Heavy oil w/o particulate control	0 1288	192	0 0%	0 129	192	AP42	0 000		0 000
ST-5E6	Heavy oil w/ baghouse	0 1288	192	99 7%	0 000	1	AP42	0 000		0 000
ST-5A7	Light Oil	0 0196	29	0 0%	0 020	29	AP42	0 000		0 000
ST-5A8	Natural Gas		0	0 0%	0 000	0		0 000		0 000
Gas Turbines by Mfr/Model > 50 MWt										
GT-251	W251 on Natural Gas		0	0 0%	0 000	0		0 000		0 000
GT-643	Siemens 64 3 on Natural Gas		0	0 0%	0 000	0		0 000		0 000
GT-B13	BBC Type 13 on Natural Gas		0	0 0%	0 000	0		0 000		0 000

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CP PLZEN EMISSION FACTORS

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	1	19	20	21	22	23	24	25
		SO_2 Emission Calculations						
		Uncont	SO	Controlled		Limit		> Limit
Boiler Size / Type / Fuel		lb/10 Btu	Rem I, %	lb/10 Btu	mg/m	lb/10⁶Btu	mg/m	lb/10 Btu
Individual Boilers 50 to 300 MWt								
PC-2E1	PC-brown coal w/ ESP	2 434	0 0%	2 434	2700	1 533	1700	0 90
PC-2B1	PC-brown coal w/ baghouse	2 434	0 0%	2 434	2700	1 533	1700	0 90
PC-2E3	PC-black coal w/ ESP	1 016	0 0%	1 016	1166	1 482	1700	0 00
PC-2B3	PC-black coal w/ baghouse	1 016	0 0%	1 016	1166	1 482	1700	0 00
FB-2B4	CFB-poor brown coal w/baghouse	6 592	93 0%	0 461	499	0 463	500	0 00
ST-2C1	Grate-brown coal w/ cyclones	2 434	0 0%	2 434	2700	1 533	1700	0 90
ST-2E1	Grate-brown coal w/ ESP	2 434	0 0%	2 434	2700	1 533	1700	0 90
ST-2B1	Grate-brown coal w/ baghouse	2 434	0 0%	2 434	2700	1 533	1700	0 90
ST-2C2	Grate-black coal w/ cyclones	0 957	0 0%	0 957	1110	1 465	1700	0 00
ST-2E2	Grate-black coal w/ESP	0 957	0 0%	0 957	1110	1 465	1700	0 00
ST-2B2	Grate-black coal w/ baghouse	0 957	0 0%	0 957	1110	1 465	1700	0 00
ST-2A6	Heavy oil w/o particulate control	1 632	0 0%	1 632	2428	1 143	1700	0 49
ST-2E6	Heavy oil w/ ESP	1 632	0 0%	1 632	2428	1 143	1700	0 49
ST-2B6	Heavy oil w/ baghouse	1 632	0 0%	1 632	2428	1 143	1700	0 49
ST-2A7	Light Oil	0 191	0 0%	0 191	283	1 147	1700	0 00
ST-2A8	Natural Gas	0 000	0 0%	0 000	0	0 026	35	0 00
Individual Boilers 5 to 50 MWt						0 000		0 00
ST-3C1	Grate-brown coal w/o particulate control	2 434	0 0%	2 434	2700	2 254	2500	0 18
ST-3E1	Grate-brown coal w/ cyclones	2 434	0 0%	2 434	2700	2 254	2500	0 18
ST-3B1	Grate-brown coal w/ baghouse	2 434	0 0%	2 434	2700	2 254	2500	0 18
ST-3C2	Grate-black coal w/o particulate control	1 016	0 0%	1 016	1166	2 179	2500	0 00
ST-3E2	Grate-black coal w/ cyclones	1 016	0 0%	1 016	1166	2 179	2500	0 00
ST-3B2	Grate-black coal w/ baghouse	1 016	0 0%	1 016	1166	2 179	2500	0 00
ST-3A6	Heavy oil w/o particulate control	1 632	0 0%	1 632	2428	1 143	1700	0 49
ST-3E6	Heavy oil w/ ESP	1 632	0 0%	1 632	2428	1 143	1700	0 49
ST-3B6	Heavy oil w/ baghouse	1 632	0 0%	1 632	2428	1 143	1700	0 49
ST-3A7	Light oil	0 191	0 0%	0 191	283	1 147	1700	0 00
ST-3A8	Natural Gas	0 000	0 0%	0 000	0	0 026	35	0 00
Individual Boilers 0 2 to 5 MWt						0 000		0 00
HF-4A1	Hand fired-brown coal	2 434	0 0%	2 434	2700	2 254	2500	0 18
HF-4B1	Hand fired-brown coal w/ baghouse	2 434	0 0%	2 434	2700	2 254	2500	0 18
HF-4A3	Hand fired-black coal	1 016	0 0%	1 016	1166	2 179	2500	0 00
HF-4B3	Hand fired-black coal w/ baghouse	1 016	0 0%	1 016	1166	2 179	2500	0 00
ST-4C1	Grate-brown coal w/o particulate control	2 434	0 0%	2 434	2700	2 254	2500	0 18
ST-4E1	Grate-brown coal w/ cyclones	2 434	0 0%	2 434	2700	2 254	2500	0 18
ST-4B1	Grate-brown coal w/ baghouse	2 434	0 0%	2 434	2700	2 254	2500	0 18
ST-4C2	Grate-black coal w/o particulate control	1 016	0 0%	1 016	1166	2 179	2500	0 00
ST-4E2	Grate-black coal w/ cyclones	1 016	0 0%	1 016	1166	2 179	2500	0 00
ST-4B2	Grate-black coal w/ baghouse	1 016	0 0%	1 016	1166	2 179	2500	0 00
ST-4A6	Heavy oil w/o particulate control	1 632	0 0%	1 632	2428	1 09	1618	0 54
ST-4E6	Heavy oil w/ ESP	1 632	0 0%	1 632	2428	1 09	1618	0 54
ST-4B6	Heavy oil w/ baghouse	1 632	0 0%	1 632	2428	1 09	1618	0 54
ST-4A7	Light Oil	0 191	0 0%	0 191	283	1 06	1573	0 00
ST-4A8	Natural Gas	0 000	0 0%	0 000	0	0 026	35	0 00
Individual Boilers < 0 2 MWt						0 000		0 00
HF-5A1	Hand fired-brown coal	2 434	0 0%	2 434	2700	0 000		0 00
HF-5B1	Hand fired-brown coal w/ baghouse	2 434	0 0%	2 434	2700	0 000		0 00
HF-5A3	Hand fired-black coal	1 016	0 0%	1 016	1166	0 000		0 00
HF-5B3	Hand fired-black coal w/ baghouse	1 016	0 0%	1 016	1166	0 000		0 00
ST-5C1	Grate-brown coal w/o particulate control	2 434	0 0%	2 434	2700	0 000		0 00
ST-5E1	Grate-brown coal w/ cyclones	2 434	0 0%	2 434	2700	0 000		0 00
ST-5B1	Grate-brown coal w/ baghouse	2 434	0 0%	2 434	2700	0 000		0 00
ST-5C2	Grate-black coal w/o particulate control	1 016	0 0%	1 016	1166	0 000		0 00
ST-5E2	Grate-black coal w/ cyclones	1 016	0 0%	1 016	1166	0 000		0 00
ST-5B2	Grate-black coal w/ baghouse	1 016	0 0%	1 016	1166	0 000		0 00
ST-5A6	Heavy oil w/o particulate control	1 632	0 0%	1 632	2428	0 000		0 00
ST-5E6	Heavy oil w/ baghouse	1 632	0 0%	1 632	2428	0 000		0 00
ST-5A7	Light Oil	0 191	0 0%	0 191	283	0 000		0 00
ST-5A8	Natural Gas	0 000	0 0%	0 000	0	0 000		0 00
Gas Turbines by Mfr/Model > 50 MWt								
GT-251	W251 on Natural Gas	0 000	0 0%	0 000	ERR	0 000	1700	0 00
GT-643	Siemens 64 3 on Natural Gas	0 000	0 0%	0 000	ERR	0 000	1700	0 00
GT-B13	BBC Type 13 on Natural Gas	0 000	0 0%	0 000	ERR	0 000	1700	0 00

Notes a
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	1	26	27	28	29	30	31
		NOx Emission Calculations					
		Emissions			Limit		> Limit
Boiler Size / Type / Fuel		lb/10 Btu	mg/m	Source	lb/10 Btu	mg/m	lb/10 Btu
Individual Boilers 50 to 300 MWt							
PC-2E1	PC-brown coal w/ ESP	0 586	650	EGU	0 586	650	0 000
PC-2B1	PC-brown coal w/ baghouse	0 586	650	EGU	0 586	650	0 000
PC-2E3	PC-black coal w/ ESP	0 567	650	EGU	0 567	650	0 000
PC-2B3	PC-black coal w/ baghouse	0 567	650	EGU	0 567	650	0 000
FB-2B4	CFB-poor brown coal w/baghouse	0 311	336	EGU	0 370	400	0 000
ST-2C1	Grate-brown coal w/ cyclones	0 432	479	EGU	0 586	650	0 000
ST-2E1	Grate-brown coal w/ ESP	0 432	479	EGU	0 586	650	0 000
ST-2B1	Grate-brown coal w/ baghouse	0 432	479	EGU	0 586	650	0 000
ST-2C2	Grate-black coal w/ cyclones	0 413	479	EGU	0 560	650	0 000
ST-2E2	Grate-black coal w/ESP	0 413	479	EGU	0 560	650	0 000
ST-2B2	Grate-black coal w/ baghouse	0 413	479	EGU	0 560	650	0 000
ST-2A6	Heavy oil w/o particulate control	0 504	750	EGU	0 302	450	0 202
ST-2E6	Heavy oil w/ ESP	0 504	750	EGU	0 302	450	0 202
ST-2B6	Heavy oil w/ baghouse	0 504	750	EGU	0 302	450	0 202
ST-2A7	Light Oil	0 157	232	AP42	0 304	450	0 000
ST-2A8	Natural Gas	0 140	190	AP42	0 148	200	0 000
Individual Boilers 5 to 50 MWt							0 000
ST-3C1	Grate-brown coal w/o particulate control	0 432	479	EGU	0 586	650	0 000
ST-3E1	Grate-brown coal w/ cyclones	0 432	479	EGU	0 586	650	0 000
ST-3B1	Grate-brown coal w/ baghouse	0 432	479	EGU	0 586	650	0 000
ST-3C2	Grate-black coal w/o particulate control	0 418	479	EGU	0 567	650	0 000
ST-3E2	Grate-black coal w/ cyclones	0 418	479	EGU	0 567	650	0 000
ST-3B2	Grate-black coal w/ baghouse	0 418	479	EGU	0 567	650	0 000
ST-3A6	Heavy oil w/o particulate control	0 504	750	EGU	0 302	450	0 202
ST-3E6	Heavy oil w/ ESP	0 504	750	EGU	0 302	450	0 202
ST-3B6	Heavy oil w/ baghouse	0 504	750	EGU	0 302	450	0 202
ST-3A7	Light oil	0 157	232	AP42	0 304	450	0 000
ST-3A8	Natural Gas	0 120	163	AP42	0 148	200	0 000
Individual Boilers 0 2 to 5 MWt		0 000			0 000		0 000
HF-4A1	Hand fired-brown coal	0 361	400	B&W	0 586	650	0 000
HF-4B1	Hand fired-brown coal w/ baghouse	0 361	400	B&W	0 586	650	0 000
HF-4A3	Hand fired-black coal	0 349	400	B&W	0 567	650	0 000
HF-4B3	Hand fired-black coal w/ baghouse	0 349	400	B&W	0 567	650	0 000
ST-4C1	Grate-brown coal w/o particulate control	0 361	400	B&W	0 586	650	0 000
ST-4E1	Grate-brown coal w/ cyclones	0 361	400	B&W	0 586	650	0 000
ST-4B1	Grate-brown coal w/ baghouse	0 361	400	B&W	0 586	650	0 000
ST-4C2	Grate-black coal w/o particulate control	0 349	400	B&W	0 567	650	0 000
ST-4E2	Grate-black coal w/ cyclones	0 349	400	B&W	0 567	650	0 000
ST-4B2	Grate-black coal w/ baghouse	0 349	400	B&W	0 567	650	0 000
ST-4A6	Heavy oil w/o particulate control	0 504	750		0 336	500	0 168
ST-4E6	Heavy oil w/ ESP	0 504	750		0 336	500	0 168
ST-4B6	Heavy oil w/ baghouse	0 504	750		0 336	500	0 168
ST-4A7	Light Oil	0 157	232	AP42	0 337	500	0 000
ST-4A8	Natural Gas	0 100	136	AP42	0 148	200	0 000
Individual Boilers < 0 2 MWt		0 000			0 000		0 000
HF-5A1	Hand fired-brown coal	0 361	400	B&W	0 000		0 000
HF-5B1	Hand fired-brown coal w/ baghouse	0 361	400	B&W	0 000		0 000
HF-5A3	Hand fired-black coal	0 349	400	B&W	0 000		0 000
HF-5B3	Hand fired-black coal w/ baghouse	0 349	400	B&W	0 000		0 000
ST-5C1	Grate-brown coal w/o particulate control	0 361	400	B&W	0 000		0 000
ST-5E1	Grate-brown coal w/ cyclones	0 361	400	B&W	0 000		0 000
ST-5B1	Grate-brown coal w/ baghouse	0 361	400	B&W	0 000		0 000
ST-5C2	Grate-black coal w/o particulate control	0 349	400	B&W	0 000		0 000
ST-5E2	Grate-black coal w/ cyclones	0 349	400	B&W	0 000		0 000
ST-5B2	Grate-black coal w/ baghouse	0 349	400	B&W	0 000		0 000
ST-5A6	Heavy oil w/o particulate control	0 504	750		0 000		0 000
ST-5E6	Heavy oil w/ baghouse	0 504	750		0 000		0 000
ST-5A7	Light Oil	0 141	209	AP42	0 000		0 000
ST-5A8	Natural Gas	0 100	136	AP42	0 000		0 000
Gas Turbines by Mfr/Model > 50 MWt							
GT-251	W251 on Natural Gas	0 092	145	W	0 190	300	0 000
GT-643	Siemens 64 3 on Natural Gas	0 092	145	W	0 190	300	0 000
GT-B13	BBC Type 13 on Natural Gas	0 092	145	W	0 190	300	0 000

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CP PLZEN EMISSION FACTORS

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	1	32	33	34	35	36	37
		CO Emission Calculations					
		Emissions			Limit		> Limit
Boiler Size / Type / Fuel		lb/10 Btu	mg/m	Source	lb/10 Btu	mg/m	lb/10 Btu
Individual Boilers 50 to 300 MWt							
PC-2E1	PC-brown coal w/ ESP	0 018	20	EGU	0 225	250	0 000
PC-2B1	PC-brown coal w/ baghouse	0 018	20	EGU	0 225	250	0 000
PC-2E3	PC-black coal w/ ESP	0 017	20	EGU	0 218	250	0 000
PC-2B3	PC-black coal w/ baghouse	0 017	20	EGU	0 218	250	0 000
FB-2B4	CFB-poor brown coal w/baghouse	0 019	20	EGU	0 231	250	0 000
ST-2C1	Grate-brown coal w/ cyclones	0 225	250	EGU	0 225	250	0 000
ST-2E1	Grate-brown coal w/ ESP	0 225	250	EGU	0 225	250	0 000
ST-2B1	Grate-brown coal w/ baghouse	0 225	250	EGU	0 225	250	0 000
ST-2C2	Grate-black coal w/ cyclones	0 215	250	EGU	0 215	250	0 000
ST-2E2	Grate-black coal w/ESP	0 215	250	EGU	0 215	250	0 000
ST-2B2	Grate-black coal w/ baghouse	0 215	250	EGU	0 215	250	0 000
ST-2A6	Heavy oil w/o particulate control	0 074	110	EGU	0 118	175	0 000
ST-2E6	Heavy oil w/ ESP	0 074	110	EGU	0 118	175	0 000
ST-2B6	Heavy oil w/ baghouse	0 074	110	EGU	0 118	175	0 000
ST-2A7	Light Oil	0 013	20		0 118	175	0 000
ST-2A8	Natural Gas	0 015	20		0 074	100	0 000
Individual Boilers 5 to 50 MWt							0 000
ST-3C1	Grate-brown coal w/o particulate control	0 225	250	EGU	0 225	250	0 000
ST-3E1	Grate-brown coal w/ cyclones	0 225	250	EGU	0 225	250	0 000
ST-3B1	Grate-brown coal w/ baghouse	0 225	250	EGU	0 225	250	0 000
ST-3C2	Grate-black coal w/o particulate control	0 218	250	EGU	0 218	250	0 000
ST-3E2	Grate-black coal w/ cyclones	0 218	250	EGU	0 218	250	0 000
ST-3B2	Grate-black coal w/ baghouse	0 218	250	EGU	0 218	250	0 000
ST-3A6	Heavy oil w/o particulate control	0 074	110	EGU	0 118	175	0 000
ST-3E6	Heavy oil w/ ESP	0 074	110	EGU	0 118	175	0 000
ST-3B6	Heavy oil w/ baghouse	0 074	110	EGU	0 118	175	0 000
ST-3A7	Light oil	0 013	20		0 118	175	0 000
ST-3A8	Natural Gas	0 015	20		0 074	100	0 000
Individual Boilers 0 2 to 5 MWt		0 000			0 000		0 000
HF-4A1	Hand fired-brown coal	8 237	9135	AP42	0 225	250	8 011
HF-4B1	Hand fired-brown coal w/ baghouse	8 237	9135	AP42	0 225	250	8 011
HF-4A3	Hand fired-black coal	6 019	6904	AP42	0 218	250	5 801
HF-4B3	Hand fired-black coal w/ baghouse	6 019	6904	AP42	0 218	250	5 801
ST-4C1	Grate-brown coal w/o particulate control	0 225	250	EGU	0 225	250	0 000
ST-4E1	Grate-brown coal w/ cyclones	0 225	250	EGU	0 225	250	0 000
ST-4B1	Grate-brown coal w/ baghouse	0 225	250	EGU	0 225	250	0 000
ST-4C2	Grate-black coal w/o particulate control	0 218	250	EGU	0 218	250	0 000
ST-4E2	Grate-black coal w/ cyclones	0 218	250	EGU	0 218	250	0 000
ST-4B2	Grate-black coal w/ baghouse	0 218	250	EGU	0 218	250	0 000
ST-4A6	Heavy oil w/o particulate control	0 074	110	EGU	0 118	175	0 000
ST-4E6	Heavy oil w/ ESP	0 074	110	EGU	0 118	175	0 000
ST-4B6	Heavy oil w/ baghouse	0 074	110	EGU	0 118	175	0 000
ST-4A7	Light Oil	0 013	20		0 118	175	0 000
ST-4A8	Natural Gas	0 015	20		0 074	100	0 000
Individual Boilers < 0 2 MWt		0 000			0 000		0 000
HF-5A1	Hand fired-brown coal	8 237	9135	AP42	0 000		0 000
HF-5B1	Hand fired-brown coal w/ baghouse	8 237	9135	AP42	0 000		0 000
HF-5A3	Hand fired-black coal	6 019	6904	AP42	0 000		0 000
HF-5B3	Hand fired-black coal w/ baghouse	6 019	6904	AP42	0 000		0 000
ST-5C1	Grate-brown coal w/o particulate control	0 225	250		0 000		0 000
ST-5E1	Grate-brown coal w/ cyclones	0 225	250		0 000		0 000
ST-5B1	Grate-brown coal w/ baghouse	0 225	250		0 000		0 000
ST-5C2	Grate-black coal w/o particulate control	0 218	250		0 000		0 000
ST-5E2	Grate-black coal w/ cyclones	0 218	250		0 000		0 000
ST-5B2	Grate-black coal w/ baghouse	0 218	250		0 000		0 000
ST-5A6	Heavy oil w/o particulate control	0 074	110		0 000		0 000
ST-5E6	Heavy oil w/ baghouse	0 074	110		0 000		0 000
ST-5A7	Light Oil	0 013	20		0 000		0 000
ST-5A8	Natural Gas	0 015	20		0 000		0 000
Gas Turbines by Mfr/Model > 50 MWt							
GT-251	W251 on Natural Gas	0 012	11 6	W	0 104	100	0 000
GT-643	Siemens 64 3 on Natural Gas	0 012	11 6	W	0 104	100	0 000
GT-B13	BBC Type 13 on Natural Gas	0 012	11 6	W	0 104	100	0 000

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CP PLZEN EMISSION FACTORS

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	1	38	39	40	41	42	43	44	45	46	47	48
		Limestone	Ash	Emission Factor Summary				Emission Penalties				
		Req't	Disposal	Particulate	SO	NOx	CO	Particulate	SO	NOx	CO	Composite
Boiler Size / Type / Fuel		lb/10 Btu	lb/10 Btu	lb/10 Btu	lb/10 Btu	lb/10 Btu	lb/10 Btu	$/10 Btu	$/10 Btu	$/10 Btu	$/10 Btu	$/10 Btu
Individual Boilers 50 to 300 MWt												
PC-2E1	PC-brown coal w/ ESP		29 20	0 088	2 434	0 586	0 018	$0 00	$14 61	$0 00	$0 00	$14 61
PC-2B1	PC-brown coal w/ baghouse		29 25	0 038	2 434	0 586	0 018	$0 00	$14 61	$0 00	$0 00	$14 61
PC-2E3	PC-black coal w/ ESP		44 16	0 244	1 016	0 567	0 017	$7 63	$0 00	$0 00	$0 00	$7 63
PC-2B3	PC-black coal w/ baghouse		44 37	0 037	1 016	0 567	0 017	$0 00	$0 00	$0 00	$0 00	$0 00
FB-2B4	CFB-poor brown coal w/baghouse	38 49	62 73	0 039	0 461	0 311	0 019	$0 00	$0 00	$0 00	$0 00	$0 00
ST-2C1	Grate-brown coal w/ cyclones		28 56	0 721	2 434	0 432	0 225	$30 67	$14 61	$0 00	$0 00	$45 28
ST-2E1	Grate-brown coal w/ ESP		29 25	0 036	2 434	0 432	0 225	$0 00	$14 61	$0 00	$0 00	$14 61
ST-2B1	Grate-brown coal w/ baghouse		29 27	0 011	2 434	0 432	0 225	$0 00	$14 61	$0 00	$0 00	$14 61
ST-2C2	Grate-black coal w/ cyclones		37 57	0 689	0 957	0 413	0 215	$29 31	$0 00	$0 00	$0 00	$29 31
ST-2E2	Grate-black coal w/ESP		38 23	0 034	0 957	0 413	0 215	$0 00	$0 00	$0 00	$0 00	$0 00
ST-2B2	Grate-black coal w/ baghouse		38 25	0 010	0 957	0 413	0 215	$0 00	$0 00	$0 00	$0 00	$0 00
ST-2A6	Heavy oil w/o particulate control		0 04	0 129	1 632	0 504	0 074	$4 63	$7 92	$2 61	$0 00	$15 16
ST-2E6	Heavy oil w/ ESP		0 17	0 001	1 632	0 504	0 074	$0 00	$7 92	$2 61	$0 00	$10 54
ST-2B6	Heavy oil w/ baghouse		0 17	0 000	1 632	0 504	0 074	$0 00	$7 92	$2 61	$0 00	$10 54
ST-2A7	Light Oil		0 04	0 016	0 191	0 157	0 013	$0 00	$0 00	$0 00	$0 00	$0 00
ST-2A8	Natural Gas		0 00	0 000	0 000	0 140	0 015	$0 00	$0 00	$0 00	$0 00	$0 00
Individual Boilers 5 to 50 MWt			0 00						$0 00	$0 00	$0 00	$0 00
ST-3C1	Grate-brown coal w/o particulate control		27 84	1 443	2 434	0 432	0 225	$63 54	$2 92	$0 00	$0 00	$66 46
ST-3E1	Grate-brown coal w/ cyclones		28 56	0 721	2 434	0 432	0 225	$28 48	$2 92	$0 00	$0 00	$31 40
ST-3B1	Grate-brown coal w/ baghouse		29 27	0 011	2 434	0 432	0 225	$0 00	$2 92	$0 00	$0 00	$2 92
ST-3C2	Grate-black coal w/o particulate control		43 01	1 395	1 016	0 418	0 218	$61 43	$0 00	$0 00	$0 00	$61 43
ST-3E2	Grate-black coal w/ cyclones		43 71	0 697	1 016	0 418	0 218	$27 54	$0 00	$0 00	$0 00	$27 54
ST-3B2	Grate-black coal w/ baghouse		44 39	0 010	1 016	0 418	0 218	$0 00	$0 00	$0 00	$0 00	$0 00
ST-3A6	Heavy oil w/o particulate control		0 04	0 129	1 632	0 504	0 074	$2 99	$7 92	$2 61	$0 00	$13 53
ST-3E6	Heavy oil w/ ESP		0 17	0 001	1 632	0 504	0 074	$0 00	$7 92	$2 61	$0 00	$10 54
ST-3B6	Heavy oil w/ baghouse		0 17	0 000	1 632	0 504	0 074	$0 00	$7 92	$2 61	$0 00	$10 54
ST-3A7	Light oil		0 04	0 016	0 191	0 157	0 013	$0 00	$0 00	$0 00	$0 00	$0 00
ST-3A8	Natural Gas		0 00	0 000	0 000	0 120	0 015	$0 00	$0 00	$0 00	$0 00	$0 00
Individual Boilers 0 2 to 5 MWt			0 00	0 000	0 000	0 000	0 000	$0 00	$0 00	$0 00	$0 00	$0 00
HF-4A1	Hand fired-brown coal		27 91	1 373	2 434	0 361	8 237	$55 76	$2 92	$0 00	$77 87	$136 55
HF-4B1	Hand fired-brown coal w/ baghouse		29 28	0 004	2 434	0 361	8 237	$0 00	$2 92	$0 00	$77 87	$80 79
HF-4A3	Hand fired-black coal		43 40	1 003	1 016	0 349	6 019	$38 16	$0 00	$0 00	$56 38	$94 54
HF-4B3	Hand fired-black coal w/ baghouse		44 40	0 003	1 016	0 349	6 019	$0 00	$0 00	$0 00	$56 38	$56 38
ST-4C1	Grate-brown coal w/o particulate control		27 84	1 443	2 434	0 361	0 225	$59 15	$2 92	$0 00	$0 00	$62 08
ST-4E1	Grate-brown coal w/ cyclones		28 56	0 721	2 434	0 361	0 225	$24 10	$2 92	$0 00	$0 00	$27 02
ST-4B1	Grate-brown coal w/ baghouse		29 27	0 011	2 434	0 361	0 225	$0 00	$2 92	$0 00	$0 00	$2 92
ST-4C2	Grate-black coal w/o particulate control		43 01	1 395	1 016	0 349	0 218	$57 19	$0 00	$0 00	$0 00	$57 19
ST-4E2	Grate-black coal w/ cyclones		43 71	0 697	1 016	0 349	0 218	$23 30	$0 00	$0 00	$0 00	$23 30
ST-4B2	Grate-black coal w/ baghouse		44 39	0 010	1 016	0 349	0 218	$0 00	$0 00	$0 00	$0 00	$0 00
ST-4A6	Heavy oil w/o particulate control		0 04	0 129	1 632	0 504	0 074	$2 99	$8 81	$2 18	$0 00	$13 98
ST-4E6	Heavy oil w/ ESP		0 17	0 001	1 632	0 504	0 074	$0 00	$8 81	$2 18	$0 00	$10 99
ST-4B6	Heavy oil w/ baghouse		0 17	0 000	1 632	0 504	0 074	$0 00	$8 81	$2 18	$0 00	$10 99
ST-4A7	Light Oil		0 04	0 016	0 191	0 157	0 013	$0 00	$0 00	$0 00	$0 00	$0 00
ST-4A8	Natural Gas		0 00	0 000	0 000	0 100	0 015	$0 00	$0 00	$0 00	$0 00	$0 00
Individual Boilers < 0 2 MWt			0 00	0 000	0 000	0 000	0 000	$0 00	$0 00	$0 00	$0 00	$0 00
HF-5A1	Hand fired-brown coal		27 91	1 373	2 434	0 361	8 237	$0 00	$0 00	$0 00	$0 00	$0 00
HF-5B1	Hand fired-brown coal w/ baghouse		29 28	0 004	2 434	0 361	8 237	$0 00	$0 00	$0 00	$0 00	$0 00
HF-5A3	Hand fired-black coal		43 40	1 003	1 016	0 349	6 019	$0 00	$0 00	$0 00	$0 00	$0 00
HF-5B3	Hand fired-black coal w/ baghouse		44 40	0 003	1 016	0 349	6 019	$0 00	$0 00	$0 00	$0 00	$0 00
ST-5C1	Grate-brown coal w/o particulate control		27 84	1 443	2 434	0 361	0 225	$0 00	$0 00	$0 00	$0 00	$0 00
ST-5E1	Grate-brown coal w/ cyclones		28 56	0 721	2 434	0 361	0 225	$0 00	$0 00	$0 00	$0 00	$0 00
ST-5B1	Grate-brown coal w/ baghouse		29 27	0 011	2 434	0 361	0 225	$0 00	$0 00	$0 00	$0 00	$0 00
ST-5C2	Grate-black coal w/o particulate control		40 92	3 487	1 016	0 349	0 218	$0 00	$0 00	$0 00	$0 00	$0 00
ST-5E2	Grate-black coal w/ cyclones		43 71	0 697	1 016	0 349	0 218	$0 00	$0 00	$0 00	$0 00	$0 00
ST-5B2	Grate-black coal w/ baghouse		44 39	0 010	1 016	0 349	0 218	$0 00	$0 00	$0 00	$0 00	$0 00
ST-5A6	Heavy oil w/o particulate control		0 04	0 129	1 632	0 504	0 074	$0 00	$0 00	$0 00	$0 00	$0 00
ST-5E6	Heavy oil w/ baghouse		0 17	0 000	1 632	0 504	0 074	$0 00	$0 00	$0 00	$0 00	$0 00
ST-5A7	Light Oil		0 04	0 020	0 191	0 141	0 013	$0 00	$0 00	$0 00	$0 00	$0 00
ST-5A8	Natural Gas		0 00	0 000	0 000	0 100	0 015	$0 00	$0 00	$0 00	$0 00	$0 00
Gas Turbines by Mfr/Model > 50 MWt												
GT-251	W251 on Natural Gas		0 00	0 000	0 000	0 092	0 012	$0 00	$0 00	$0 00	$0 00	$0 00
GT-643	Siemens 64 3 on Natural Gas		0 00	0 000	0 000	0 092	0 012	$0 00	$0 00	$0 00	$0 00	$0 00
GT-B13	BBC Type 13 on Natural Gas		0 00	0 000	0 000	0 092	0 012	$0 00	$0 00	$0 00	$0 00	$0 00

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APPENDIX B:
RESULTS OF CITYPLAN ANALYSIS - PLZEN DISTRICT HEATING SYSTEM

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CityPlan Ltd.

Document No _____

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Plzeň District Heating System

A Proposed variants to follow

B. Technical comments for extend of the heating plant Plzeň

C Switching to low sulphure coal

D Mini-cogeneration model

E Remarks to the economic report of 1991's study

Prague August 1993

Draft for
Gilbert / Commonwealth, Inc

For information concerning this study please contact

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- Ing Vladimir Vlk

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A. PROPOSED VARIANTS TO FOLLOW

CityPlan has visited several times plants within City of Plzeň and had discussions with management of the Škoda heating plant, with Mrs Brebisova from Townhall and with Mr Hruby, general manager of cogeneration plant Plzeň
Results of these discussions are included into following recommendations

ŠKODA HEATING PLANT ELÚ III

Boiler K3 is currently retrofitted as a pulverised brown coal burned boiler Today is probably no more possibility to change this decision and modify this project to another option as is fluidized bed technology or switch to low sulphur bituminous coal from Zbůch mine near to Plzeň It means, that there is need extend this project with flue gas desulphurization equipment to 1998 year - deadline for fulfil clean air law No 309/91Sb
But there is possible another additional project - to use new technologies for fly ash management and decrease amount of ash disposeing As possible technology is recommend evaluate pelletising technology Pellets can be moved with conventional bulk material handling equipment without producing a dusty environment The pellets can be disposed of in any type site and do not need to be placed in a lined landfill Slight modifications to the palletising process can produce usable products such as lightweight aggregate or aggregate to be utilised in asphalt
In the present time is not clear conception and consumption of heat for Škoda technology purposes

COGENERATION HEATING PLANT PLZEŇ

This plant became to be municipal company through privatisation process The City of Plzeň will own probably more than 51% of shares
Three 35 MW_t boilers (Plzeň I) seems to be unsuitable to retrofit In the opposite two 108 MW_t (Plzeň I) steam boilers are suitable to be retrofitted or with flue gas desulphurizaton or with switching to low sulphur bituminous coal The final decision is not yet made and there are needs some additional operation tests and some engineering works for estimate, if switching to another kind of coal is simply feasible
The major emphases is putting into decision on new technology for additional heat power instead three old 35 MW_t boilers and other needs The right size of new power unit will be known from different options and recommendations which will be described by another part of this study (end use sector)

Now it seems to be more clear that the city, and the utility as well, are more than willing to choose natural gas combined cycle technology This technology has a lot of advantages It is cheaper, cleaner and more suitable for municipal site than coal technology There is not also ash disposal problem This project is also supported by local energy industry - Škoda Plzeň company - interested to manufacture components for combined cycle technology (perhaps with KWU - Siemens)

We recommend that this new unit could (under economy conditions of course) serve as a base load unit and coal boilers after retrofitting could serve only in winter cold season The bigger amount of electricity will have positive influence on economy of plant when we expect increase of electricity price Plant will be thus able to generate electricity whole year To be sure, that this project is quite feasible, there is necessary provide some additional financial study and engineering works
Before final decision and tender process is necessary to accommodate size of combined cycle power unit to realistic heat demand with utilisation of all suitable information

Another possibility, especially on the current electricity and fuel price level, is CCT technology especially fluidized bed technology Summary of advantages different new technologies is in part B Problems joined with switching to low sulphur coal are discussed in part C

ANOTHER HEATING PLANTS

Heating plants Košutka, Letna, Doubravka, Světovar and Bory are old and therefore we recommend check possibility of reconstruction to co-generation plants as well as install some mini-cogeneration units instead of decentralized coal boilers within the city Example of mini-cogeneration model and its economy is discussed in part D

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B. TECHNICAL COMMENTS FOR EXTEND OF THE HEATING PLANT PLZEŇ

AFBC TECHNOLOGY

Technology ABFC is considered as most economicaly acceptable from currently used clean coal technologies

There are many plants of different sizes operating throughout the world on the base of a wide variety of low-quality fuels The maximum boiler size for Plzeň plant could be 160 t/h - 250 t/h and this is within the current capabilities of AFBC suppliers including Czech republic

AFBC boiler technology is very good to burn the high ash coal as well as pre-sorted municipal waste and biomass It could be interesting for the city and surrounding agricultural farms

Current AFBC plants operate with good efficiency and high availability

AFBC allow operate with reduced SO_2, NO_x and give good possibilities to comply with anticipated future emission requirements The control of these emissions does not require extraordinary scrubbing equipment

AFBC ash can be relative easy pelletised and used as fill material

PFBC TECHNOLOGY

Although some PFBC plants have been put into operation, they must be considered as demonstration projects Information about the operation results of these plants are not still sufficient to estimate their long-term performance This technology (ABB Carbon) will be demonstrated in Czech Republic in city of Ostrava

The appropriate gas clean technology is also required in this time to reduce erosion and corrosion effects on gas on turbine components In this time is necessary to use specialy designed gas turbines

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But PFBC requires the least amount of plot space

IGCC TECHNOLOGY

IGCC is not yet mature technology There are today some demonstration and commercial plants in industrial operation The technology of this systems has not yet reached a sufficient plant performance and efficiency

Experience with brown coal gasification is still limited

IGCC requires more plot space than AFBC and PFBC

GTCC TECHNOLOGY

GTCC is today a commercially proven and used technology
But use of natural gas as fuel can make the project in Czech Republic dependent on foreign suppliers and would leave the project vulnerable to price fluctuations

The GTCC cycle is suitable to generate of electric power at higher rate

GTCC fulfil the emission requirements relatively easy because the used fuel for the gas turbine is clean Major problem could be with NO_x in the future only

GTCC practically did not generate solid waste

CONCLUSION

For non competitive current price of natural gas versus North Bohemia lignite technology AFBC provides the most attractive economics of the considered cases

But to have a better understanding of factors which most influence the economics, a sensitivity analysis is necessary provide for each of the major input variables (capital cost, electrical price, fuel price, efficiency, operating and maintenance cost, and capacity factor) for all options

From our real experience electrical and/or heat price and investment have the biggest influence on NPV, followed by capacity factor and fuel cost The other variables such as O & M and efficiency are not as significant

Although AFBC is not as efficient as the competing technology, fuel costs and therefore plant efficiencies do not impact economics as dramatically, since the value of the fuel is much lower than electricity by comparison

Although GTCC requires lower capital cost than AFBC, its economy is very sensitive to the cost of natural gas Natural gas is currently more expensive than coal on the base heating value of the fuel Since natural gas is in short available in the plant, it also follows that it would be still more expensive and more subject to higher prices and escalation rates

AFBC has advantage to join its technology which regional waste management and to add pre - sorted waste as a fuel to lignite But there is not clear when coal price will be increased by so call "social expenses" for environment degradation and potential CO_2 tax Another problem which can involve decision to natural gas is waste disposal cost (new ash deponie)

It is necessary follow study to collect and calculate more accuracy cases with all additional costs

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C. SWITCHING TO LOW SULPHURE COAL

To change of fuel it is necessary to respect following

- price of fuel
- conditions of technologies

PRICE OF FUEL

LIGNITE WITH LOW HEATING VALUE (APPROX 10 MJ/KG)
As a result of CityPlant's discussions with the supplier and a review of escalation trends, the prices are assumend to increase to 400 - 500 Kc per ton in 1996

LIGNITE WITH HIGHER HEATING VALUE (APPROX 16 MJ/KG)

The price increase is assumed at the same rate of escalation, as in the case of the lower quality lignite i e approx 600-700 Kc per ton in 1996

BITUMINOUS COAL

Future price of the coal will be based on world prices, i e minimum 1500 - 1800 Kc per ton for coal 25 MG/kg
We estimate the for coal from Zbůch at 1000 - 1200 Kc per ton in 1996

NATURAL GAS

- The price is expected to increase to approx 4500 Kc per thousand Nm3 in 1996
- The representatives of the gas industry presume that the price will be at the lower limit 4500 Kc per thousand Nm3 We recommend to utilize the upper limit for the following reasons
  - The previosly assumed increase of natural gas import from former USSR of 7 billion Nm3 was based on a stable situation and great amount of investment into pipeline projects

- These investments are delayed as a result of the unstable situation in the former USSR
- Transit costs for gas are about twice as high as the transport of equivalent energy in petroleum
- Sources of natural gas are located 4,000 - 5,000 km away and command world-level prices
- The price of natural gas will increase parallel to petroleum price (which determines the trend of all energy prices) and as result of supply source diversification costs

IMPORTED COAL AND NATURAL GAS

The source of these fuels are outside CR The payment for these fuels goes outside CR and reflects world prices The use of these fuels decreases employment in the North-west Bohemia, Central Bohemia and North Moravia regions, and has adverse social and political consequences

ELECTRICITY

Price of electricity has essential influence on cogeneration economy We estimate, that market price from ČEZ utility on 110kV level will be 1300 - 1500 Kc/MWh Under new energy law price from independent suppliers will be derived from price of bigger supplier, it means ČEZ utility

CONDITIONS OF TECHNOLOGIES

All boilers in the cogeneration heating plants Plzeň and ELU III are designed for lignite with the low heating value approx 10 MJ/kg

In the present time are proceed discussions about use of low sulphur bituminous coal from the mine Zbůch which is located near City of Plzeň

Analysis of bituminous coal from Zbuch

• Type	powder
Sizing	0 mm to 6 mm
Water	11 %
Ash	42 %
Sulphur	0,5 %
Heating Value	15,95 MJ kg ^{1}

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In the cogeneration plant Plzeň were provided tests of bituminous coal combustion by participation of the manufactures ČKD Dukla, a s and Prvni brněnska strojirna Combustion test at the hot water boilers (producer ČKD Dukla, a s) was provided with following measurement

- quantity of air
  quantity of residue
  analysis of emissions

The results of test are following

boiler efficiency	78 %
maximum of boiler efficiency	81 %
boiler efficiency with secondary air	80,7 %
boiler efficiency without sec air	78 %
CO emissions	218 mg/m^3
SO_2 emissions	1 926 mg/m^3
NO_x emissions	578 mg/m^3

In April 1993 were realized the combustion test on the boiler No K4 in cooperation with technicians of the firm Prvni brnenska strojirna
During combustion test was registered overrun of the output steam temperature on the left side over piping because steam temperature into output common line was under design value The steam temperature into over piping was registered 570 °C and it can reduce life of piping and superheater The cause of over temperature was wrong order of injections II (on the left and right side) Present results of test are influenced on piping and boiler leak

Also it was taking the measurements of air quantity into boiler at range from 19 Nm^3/s to 29 Nm^3/s This cause of high air quantity adverse influences combustion process

The cause of boiler's leakages is flue gas over temperature (197 °C) and flow disproportion between flue gas and air through air heater Ljungstrom

For very good burning it must be controled feed of coal and air quantity to boiler This control is very important for combustion With retrofit it will change probably all boiler control system

During the test powered coal equipment was loaded at range from 9,54 t/hour to 16,6 t/hour

Nominal steam load 175 t/hour of boiler No K4 is possible to achieve by operating with two coal mills only Operation with three mills is not sensitive to failure of one of them, but the operation due to low load of the mills is not so steady like with two mills Flue gas flap on inlet of coal mills was be half-close for reduce ventilation of mills

The test results are following

- boiler efficiency by steam load 175 t/hr and two coal mills 85,5 %
- boiler efficiency by min steam load and two coal mills 85,4%
- boiler efficiency by steam load 168,8 t/hr and three coal mills 85,1%
- SO_2 emissions < 1 700 mg/Nm^3
- NO_x emissions by operating of three coal mills > 700 mg/Nm^3
- NO_x emissions by operating of two coal mills < 500 mg/Nm^3

The results of combustion tests of steam boilers was provided are not to release from manufacture of boilers
As results from disscusion with producers of boilers, ČKD Dukla and Prvni brněnská strojirna, we are claiming for modification

1 must be retrofited powdered coal equipment
2 must be retrofited powdered coal burners
3 must be retrofited ash handling system
4 must be change superheater system to achieve the same efficiency of boilers
5 must be retrofited ESP or installed new baghouses

Advantages of bituminous coal burning

using low sulphure coal near to City of Plzeň

the switching to low sulphure coal save the cost of FGD equipment

- lower investment then FGD

Risk of bituminous coal burning

The bituminous coal prices are still supported and it does not include so called social (external) costs It will increase in the future due to economic transition from central planned to market economy

Inexperienced Czech boiler s manufacturers retrofit lignite boilers with bituminous coal

Unwilling manufactures to guarantee emission limits NO_x after retrofit

Closing remark

The final decision of retrofit can to be made after additional combustion tests of bituminous coal on the base of these preliminary test results

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D MINI-COGENERATION MODEL

1. Mini-cogeneration variants

The proposal is based on the current condition of dozens decentralized heating plants in City of Plzeň and on the need to reconstruct it To improve economy of the heat production we investigated to replace existing boiler room with small co-generation heating plants Heating expenses are reduced by revenues from the sale of el power El power is there by-product of the heat production

New variants respect requirements to maintain existing primary distribution system and to replace only technology equipment of the source

New technology could be placed in the existing facilities

Model size consider aproximately 10 MW thermal plant (not located), but results could be representative for size since 0,5MW We consider that existing boilers will be partly replaced with gas engine, partly equiped with gas burner as pickload boiler

All equipment is consider on Czech industry base

1 1 PROPOSED VARIANTS OF CO-GENERATION PLANT

- ***Variant No 1*** 1 gas motor + 2 boilers
- ***Variant No 2*** 2 gas motors + 1 boiler
- ***Variant No 3*** 2 gas motors + 2 boiler

Natural gas is considered as the fuel for all three above variants

Variant No 1

To cover needed heat output there will be installed 1 gas engine (heat output 2,676 MW_t (el output 2 MW_e) and 1 existing boiler, which will have heat output of 2,91 MW_t (after conversion from heavy oil or coal to natural gas) Second boiler will serve as a back-up in case of breakdown To ensure the rated power generation and thus maximum efficiency, there will be used hot water accumulator

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Variant No 2

To cover needed heat output there will be installed 2 gas engines (total output 3,702 MW_t , 2,8 MW_e) and 1 boiler with output 2,91 MW_t (after fuel conversion) This boiler will operate only during extreme weather with low temperature Hot water, accumulator is being considered in this variant as in variant 1

Variant No 3

To cover needed heat output there will be installed 2 gas engines (total output 3,702 MW_t , 2,8 MW_e) and 2 boilers total output 5,82 MW_t (after fuel conversion) One boiler will be in operation and second will serve a reserve (for extreme weather with very low temperature) Hot water, accumulator is being considered

All the variants will require construction connection to the grid

2. Economy and financing

2 1 INVESTMENT AND OPERATION COST ESTIMATE

Investment cost (thous CK)

	var. 1	var. 2	var. 3
Fuel conversion of Boilers	220	110	220
Engines	19775	31182	31182
Conn to the exist distributors	2000	2000	2000
Hot water accumulator	2300	2300	2300
Building Adaptations	900	1100	1100
Connection to the grid	1600	1700	1700
I & C	500	600	600
Engineering	3200	3400	3400
Total	**30495**	**42392**	**42502**

Operation cost (thous CK)

	var. 1	var. 2, 3
Auxiliary consumption	1624	2000
Cost of Water (15 CK/m^3)	8	8
Wages of Workers	270	270
Cost of NG per year (3,2 CK/m^3)	20215	21323
Maintenance Cost	297	468
Overhead cost	300	300
Emissions Fees	25	26
Other Expences	461	567
Total	**23200**	**24962**

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2 2 FINANCIAL ANALYSIS

Main goals of financial analysis is to estimate the business future of variants
The financial analysis is valid for the following assumptions

- zero inflation
- depreciation 15 years life time expectancy of technology
- price of electricity 1 50 CK to 2 00 CK per kWh
- account done for 20 years period with 2 general repair of gas engines

- option 1 1 gas engine and 2 gas boilers
- option 2 2 gas engines and 1 gas boiler
- option 3 2 gas engines and 2 gas boilers

The goals of financing

discount interest rate	9 5%
internal rate of return	15%
debt service ratio	135%
net equity investment or subsidy	50%
foreign debt financing	50%, for 10 years, 10% interest

The risks

- No risk of the decreased electricity and heat prices, the prices will grow up during 2 or 3 years
- To eliminate the risk of increased capital costs it is necessary to sign a contract with a fixed price
- The risk of decreased gas price is the most probable Higher price of gas will be ofcourse followed by the higher prices of electricity and heat

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3. The conclusion

At the end of this report you can see the graph the price of electricity versus the price of heat

The data are given in the economic analysis tables and the graphs The cash-flow graph includes the general repair of engines

It is possible to consider all the options Option 1 is more profitable having the average price of electricity to 1 30 CK/kWh The options 2 and 3 are more profitable having the average price of electricity up 1 40 Kc/kWh According to the estimated capital costs it is hard to decide which option is the best But when we consider prices of heat around the heat utilities in Czech republic we can say, that this model solution will be in the short time fully competitive

Table of overall datas

	1st var.	2nd var.	3rd var
Investment Cost (thous CK)	30 495	42 392	42 502
NG Consumption(thous Nm^3)	6 317,1	6 663,4	6 663,4
Price of NG (CK/m^3)	3,2	3,2	3,2
Operation Cost (thous CK)	461	567	567
Maintenance Cost*) (thous CK)	297	468	468
Other Expence (thous CK)	300	300	300
Emissions Fees (thous CK)	20	21	21
Sales of Electricity (MWh/year)	12 450,7	15 337,2	15 337,2
Sales of Thermal (GJ/year)	84 130,5	84 130,5	84 130,5
Number of Workers	5	5	5

*Note *) Besides the above costs, there is considered a general repair work of diesel engines (two general repairs over the engines lifetime)*

Advantages of variant 1

- lower investment cost
- smaller construction space
- lower price of heat in case of the salesprice of electricity lower than 1,30 CK/kWh
- more simple connection to the grid

Advantages of variant 2 and 3

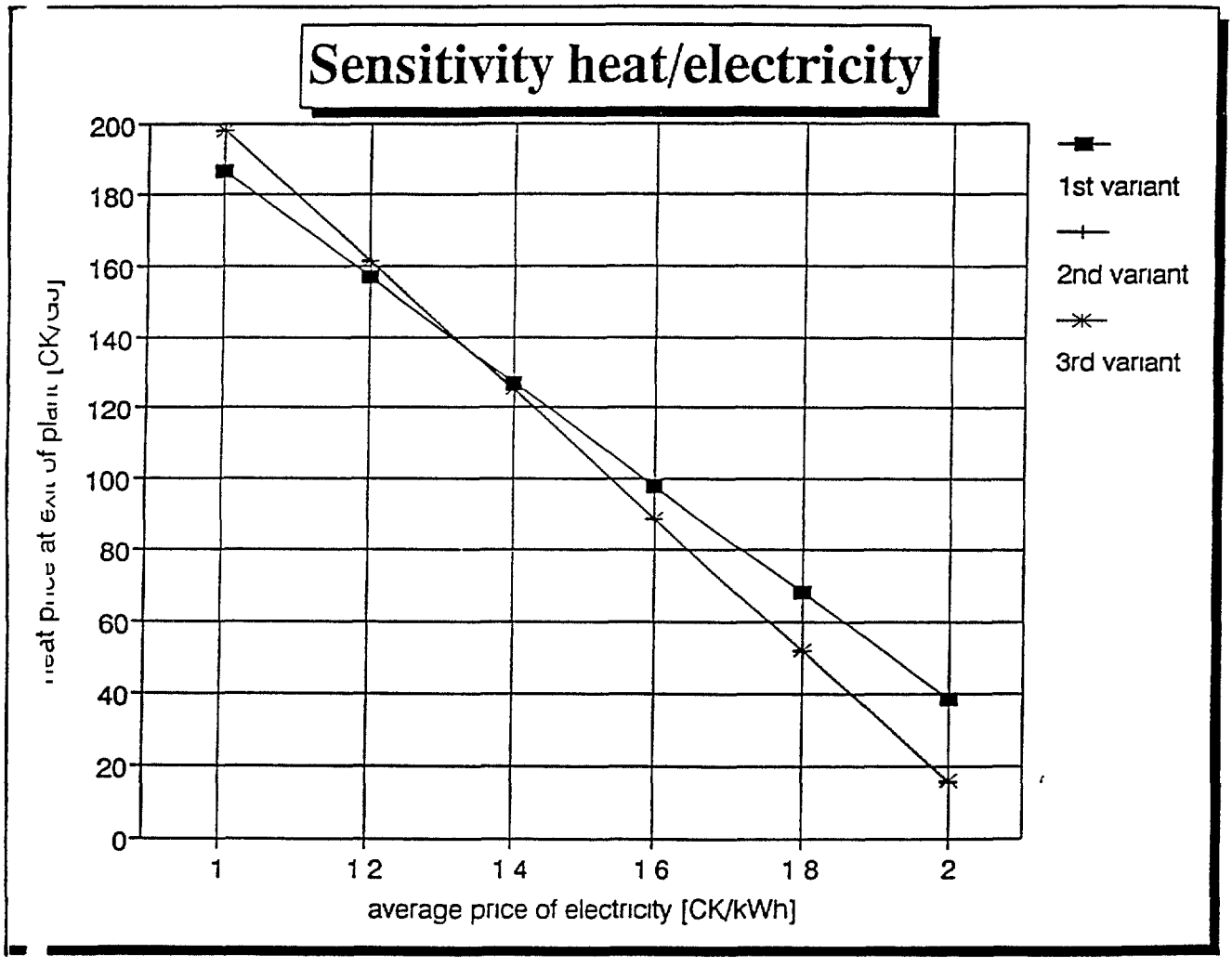
- improved reliability in case of failure of 1 motor
- lower price of heat in case of the salesprice of electricity higher is than 1,40 CK/kWh

In all cases investment return time is approx 7 years

All variants are good demonstration of advantages and competitiveness of co-generation

NEXT RECOMMENTED STEPS

- to work out application for participation of state in the demonstration project
- to discuss a possibility to include the project in PHARE program
- to discuss a project in bilateral co-operation (USA, Denmark, Germany, Austria)
- to begin commercial negotiation with ZČE regarding price for electricity


Sensitivity heat/electricity
200
180
160
140
120
100
80
60
40
20
0
1
1 2
1 4
1 6
1 8
2
average price of electricity [CK/kWh]
1st variant
2nd variant
3rd variant

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FINANCIAL ANALYSIS - VARIANT No 1

			PROJECT MANAGEMENT				OPERATION SERVICE				
			I Q	II Q	III Q	IV Q	1 year	2 year	3 year	4 year	5 year
	Investment Costs	thous CK	800	800	8387 5	20507 5	0	0	0	0	0
1 0	Discount Interest Rate	%	9 50%								
2 0	Total Capital Costs	thous CK	0								
3 0	Grant of Czech Government	thous CK	15247 5								
4 0	CR Debt Financing	thous CK	0								
4 1	Term	years	0								
4 2	Interest Rate	%	0 00%								
5 0	External Debt Financing	thous CK	15247 5								
5 1	Term	years	10								
5 2	Interest Rate	%	10 00%								

TOTAL INVESTMENT COSTS	30 495	mil CK	
NET PRESENT VALUE	7 064862	mil CK	
INTERNAL RATE OF RETURN	15 00%		
YEARS RETURN ON INVESTMENT	7	year	
DEBT SERVICE RATIO (MAX,MIN,AVG)	207 42%	20 45%	179 39%

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FINANCIAL ANALYSIS VARIANT No 1

STATEMENTS OF INCOME AND EXPENSE

Ope ati g Dat	y		start oon	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
El ct icity Sale	tho	CK		18676	18676	18676	18676	18676	18676	18676	18676	18676	18676	18676	18676	18676	18676	18676	18676	18676	18676	18676	18676
Tha m l E e gy Sal s	thou	CK	x	9465	9465	9465	9465	9465	9465	9465	9465	9465	9465	9465	9465	9465	9465	9465	9465	9465	9465	9465	9465
G o R u	thous	CK		28141	28141	28141	28141	28141	28141	28141	28141	28141	28141	28141	28141	28141	28141	28141	28141	28141	28141	28141	28141
Fuel Costs	thous	CK	x	20215	20215	20215	20215	20215	20215	20215	20215	20215	20215	20215	20215	20215	20215	20215	20215	20215	20215	20215	20215
Ope atio s & M intenance C sts	th us	CK		1433	1433	1433	1433	1433	1433	7393	1433	1433	1433	1433	1433	1433	7393	1433	1433	1433	1433	1433	1433
Emi ion Fee	th us	CK		20	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25
D pre i tion	thous	CK	x	1037	2104	2104	2104	2104	2104	2104	2104	2104	2104	2104	2104	2104	2104	2104	0	0	0	0	0
Total Operating Expense	thous	CK	x	22705	23778	23778	23778	23778	23778	29737	23778	23778	23778	23778	23778	23778	29737	23778	21673	21673	21673	21673	21673
Inte est E pense	thous	CK	x	1525	1429	1324	1208	1081	941	787	617	431	228	0	0	0	0	0	0	0	0	0	0
Taxes	thous	CK		1760	1320	1368	1420	1477	1540	0	1666	1770	1862	1963	1963	1963	0	1963	2910	2910	2910	2910	2910
Net Income	thous	CK	x	2151	1814	1672	1735	1805	1882	2383	2060	2163	2276	2400	2400	2400	1597	2400	3557	3557	3557	3557	3557

AFTER TAX CASH FLOW ANALYSIS

SOURCE																							
N t Income	thous	CK	x	2151	1814	1672	1735	1805	1882	2383	2060	2163	2276	2400	2400	2400	1597	2400	3557	3557	3557	3557	3557
Depreciation	thous	CK	x	1037	2104	2104	2104	2104	2104	2104	2104	2104	2104	2104	2104	2104	2104	2104	0	0	0	0	0
Total Sources	thous	CK	x	3188	3718	3776	3839	3909	3986	279	4164	4267	4380	4504	4504	4504	507	4504	3557	3557	3557	3557	3557
USE																							
Loan Principal	thous	CK	x	957	1052	1158	1273	1401	1541	1695	1864	2051	2256	0	0	0	0	0	0	0	0	0	0
NET CASH FLOW	thous	CK	0	2231	2665	2618	2566	2509	2446	1974	2300	2216	2124	4504	4504	4504	507	4504	3557	3557	3557	3557	3557
CUMULATIVE CASH FLOW	thous	CK	0	2231	4896	7515	10081	12589	15035	13061	15361	17577	19701	24205	28709	33213	33720	38224	41781	45338	48895	52452	56009

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FINANCIAL ANALYSIS VARIANT No 1

	Ope ating Data	year	start con	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
1 0	Fuel Heavy Oil low sulphu	t/yea	x	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
1 1	P ce	CK/t	x	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2 0	Fu l Heavy Oil middle sulphur	t/y ar		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2 1	P	CK/t		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3 0	Fu l Natu al Gas	Nm3/yea	x	6317116	6317116	6317116	6317116	6317116	6317116	6317116	6317116	6317116	6317116	6317116	6317116	6317116	6317116	6317116	6317116	6317116	6317116	6317116	6317116
3 1	P i e	CK/Nm3	x	3 2	3 2	3 2	3 2	3 2	3 2	3 2	3 2	3 2	3 2	3 2	3 2	3 2	3 2	3 2	3 2	3 2	3 2	3 2	3 2
4 0	Fu l P open Butan	t/year	x	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
4 1	P ice	CK/t	x	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
5 0	Make up W t r	m3/yea		548	548	548	548	548	548	548	548	548	548	548	548	548	548	548	548	548	548	548	548
5 1	Price With Ch mical T e tment	CK/m3	x	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15
6 0	Operations Costs	tous CK/year	x	461	461	461	461	461	461	461	461	461	461	461	461	461	461	461	461	461	461	461	461
7 0	Maintenance Costs	tous CK/year	x	297	297	297	297	297	297	6256 85	297	297	297	297	297	297	6256 85	297	297	297	297	297	297
8 0	Total Othe Expense	tous CK/year	x	300 0	300 0	300 0	300 0	300 0	300 0	300 0	300 0	300 0	300 0	300 0	300 0	300 0	300 0	300 0	300 0	300 0	300 0	300 0	300 0
9 0	Numbe of Workers		x	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
9 1	Av age Wage	CK/yea		54000	54000	54000	54000	54000	54000	54000	54000	54000	54000	54000	54000	54000	54000	54000	54000	54000	54000	54000	54000
9 2	T s on Weges	% on wages		36 00%	36 00%	36 00%	36 00%	36 00%	36 00%	36 00%	36 00%	36 00%	36 00%	36 00%	36 00%	36 00%	36 00%	36 00%	36 00%	36 00%	36 00%	36 00%	36 00%
10 0	D prec ation	%/yea		3 40%	6 90%	6 90%	6 90%	6 90%	6 90%	6 90%	6 90%	6 90%	6 90%	6 90%	6 90%	6 90%	6 90%	6 90%	0 00%	0 00%	0 00%	0 00%	0 00%
11 0	Ta es on P ofit	% o prof t		45 00%	45 00%	45 00%	45 00%	45 00%	45 00%	45 00%	45 00%	45 00%	45 00%	45 00%	45 00%	45 00%	45 00%	45 00%	45 00%	45 00%	45 00%	45 00%	45 00%
12 0	Em ssion SO2	t/y		0 057	0 057	0 057	0 057	0 057	0 057	0 057	0 057	0 057	0 057	0 057	0 057	0 057	0 057	0 057	0 057	0 057	0 057	0 057	0 057
12 1	F e	CK/t	x	800	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000
13 0	Emi ons NOx	t/year	x	23 373	23 373	23 373	23 373	23 373	23 373	23 373	23 373	23 373	23 373	23 373	23 373	23 373	23 373	23 373	23 373	23 373	23 373	23 373	23 373
13 1	Fee	CK/t	x	640	800	800	800	800	800	800	800	800	800	800	800	800	800	800	800	800	800	800	800
14 0	Emis ions CO2	t/year		1 708	1 708	1 708	1 708	1 708	1 708	1 708	1 708	1 708	1 708	1 708	1 708	1 708	1 708	1 708	1 708	1 708	1 708	1 708	1 708
14 1	F e	CK/t	x	480	600	600	600	600	600	600	600	600	600	600	600	600	600	600	600	600	600	600	600
15 0	Emis ion Particulates	t/year	x	1 832	1 832	1 832	1 832	1 832	1 832	1 832	1 832	1 832	1 832	1 832	1 832	1 832	1 832	1 832	1 832	1 832	1 832	1 832	1 832
15 1	Fee	CK/t	x	2400	3000	3000	3000	3000	3000	3000	3000	3000	3000	3000	3000	3000	3000	3000	3000	3000	3000	3000	3000
16 0	Electricity Production	GWh/year	x	13 53335	13 53335	13 53335	13 53335	13 53335	13 53335	13 53335	13 53335	13 53335	13 53335	13 53335	13 53335	13 53335	13 53335	13 53335	13 53335	13 53335	13 53335	13 53335	13 53335
17 0	Thermal Production	TJ/year	x	84 13052	84 13052	84 13052	84 13052	84 13052	84 13052	84 13052	84 13052	84 13052	84 13052	84 13052	84 13052	84 13052	84 13052	84 13052	84 13052	84 13052	84 13052	84 13052	84 13052
18 0	Sales Electricity	GWh/year	x	12 45068	12 45068	12 45068	12 45068	12 45068	12 45068	12 45068	12 45068	12 45068	12 45068	12 45068	12 45068	12 45068	12 45068	12 45068	12 45068	12 45068	12 45068	12 45068	12 45068
18 1	P ice	CK/kWh	x	1 5	1 5	1 5	1 5	1 5	1 5	1 5	1 5	1 5	1 5	1 5	1 5	1 5	1 5	1 5	1 5	1 5	1 5	1 5	1 5
19 0	Sales Th mal to Inhabitants	TJ/year	x	84 13052	84 13052	84 13052	84 13052	84 13052	84 13052	84 13052	84 13052	84 13052	84 13052	84 13052	84 13052	84 13052	84 13052	84 13052	84 13052	84 13052	84 13052	84 13052	84 13052
19 1	P ice	CK/GJ		112 5	112 5	112 5	112 5	112 5	112 5	112 5	112 5	112 5	112 5	112 5	112 5	112 5	112 5	112 5	112 5	112 5	112 5	112 5	112 5

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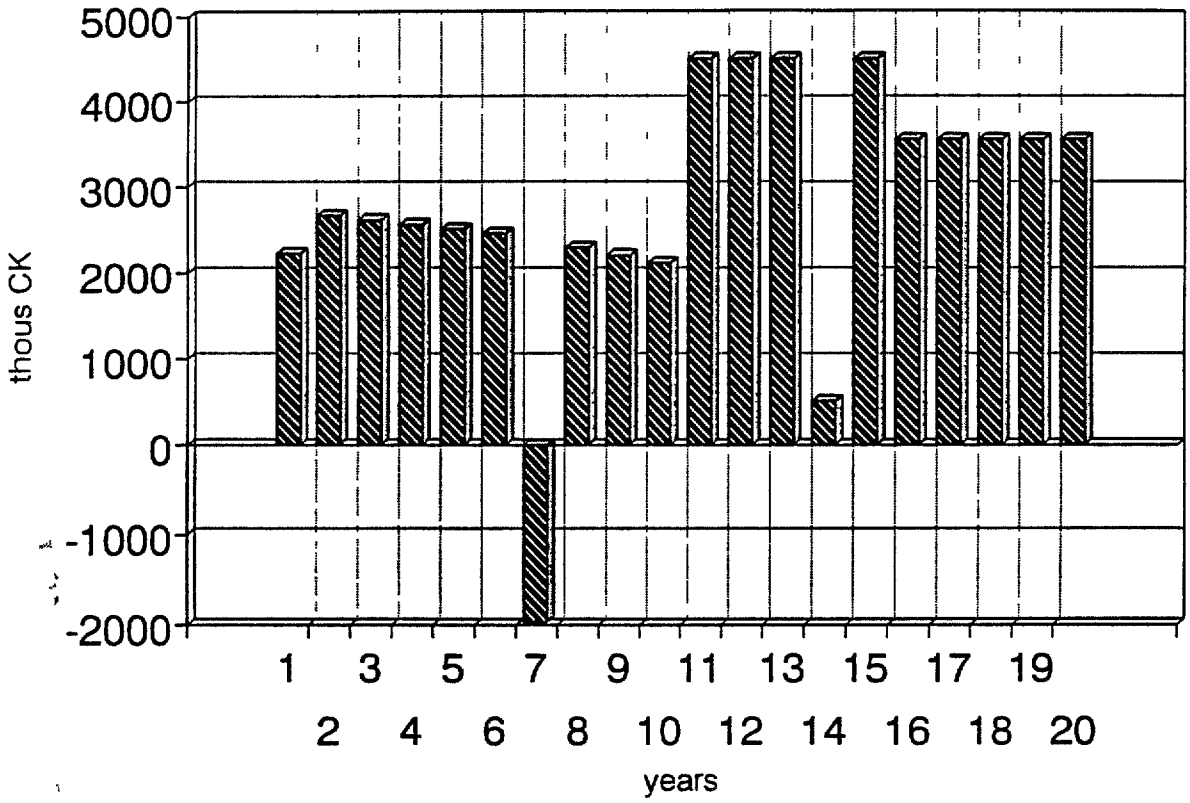
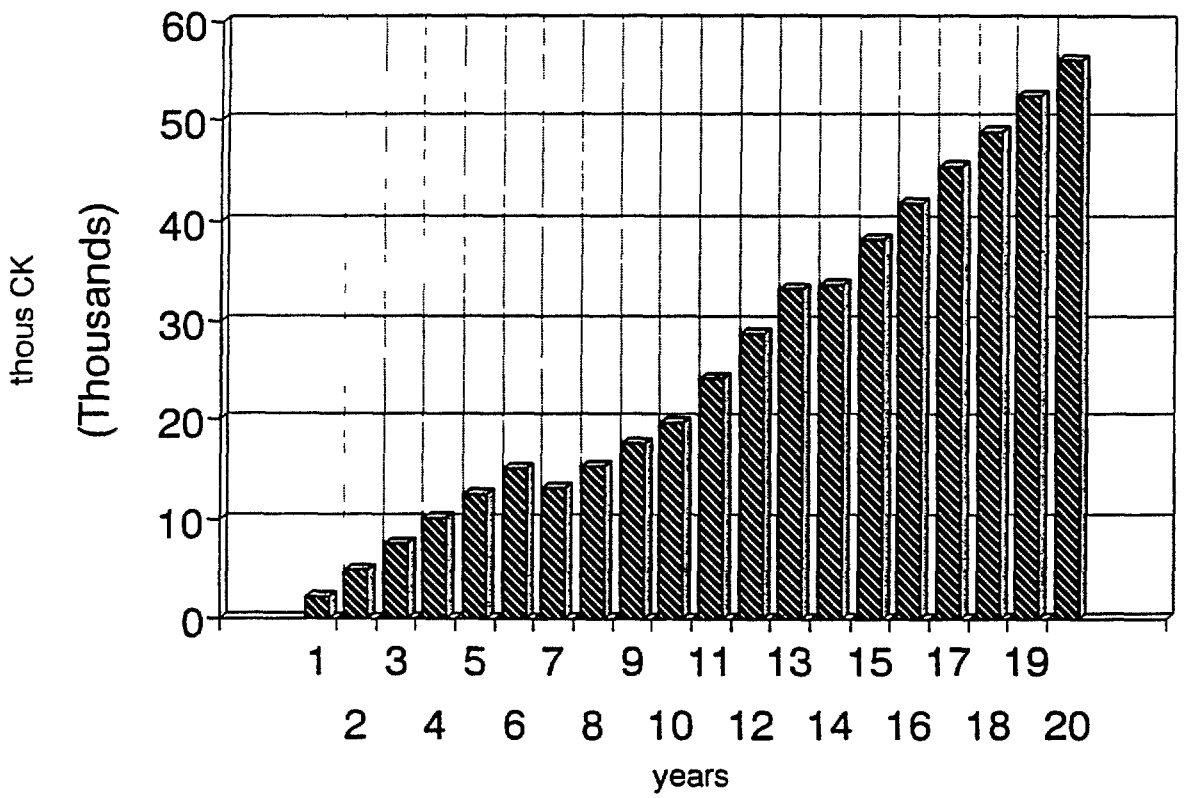
Net Cash Flow

Variant No 1



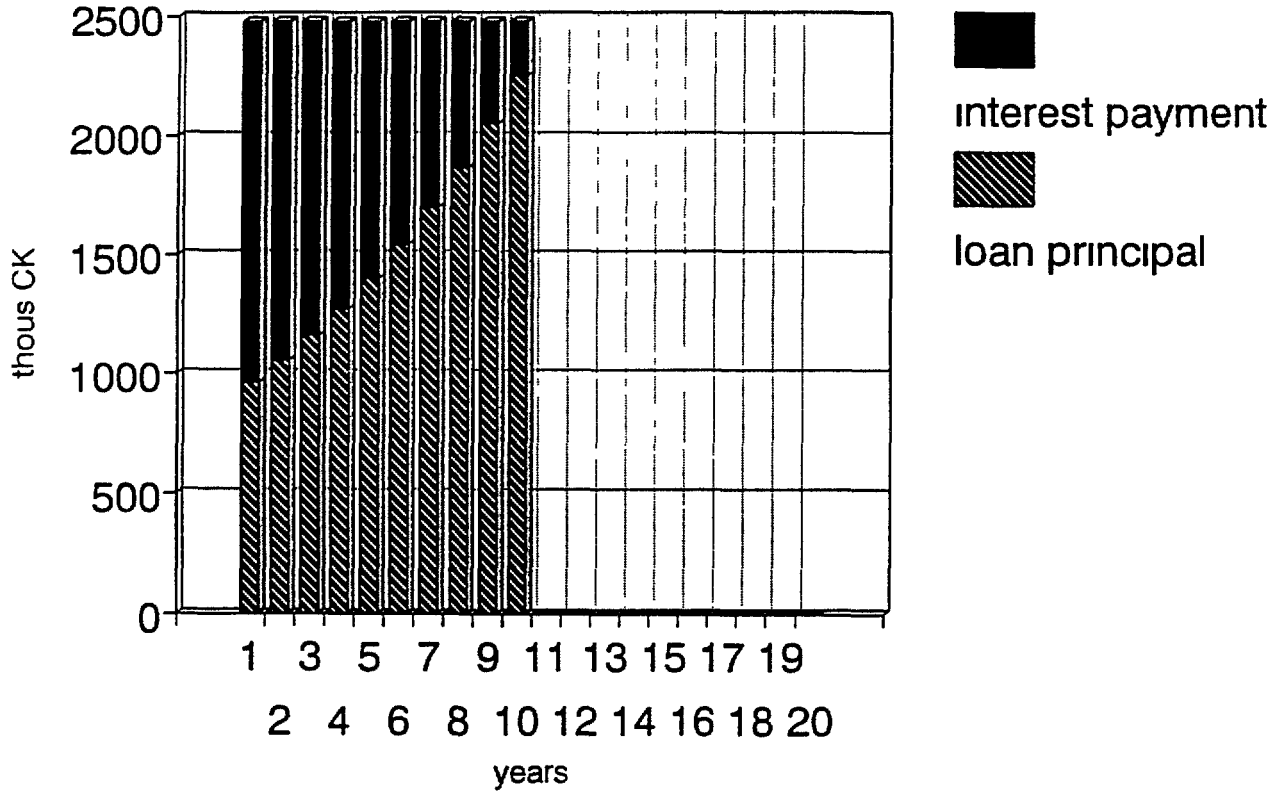
Cumulative Cash Flow

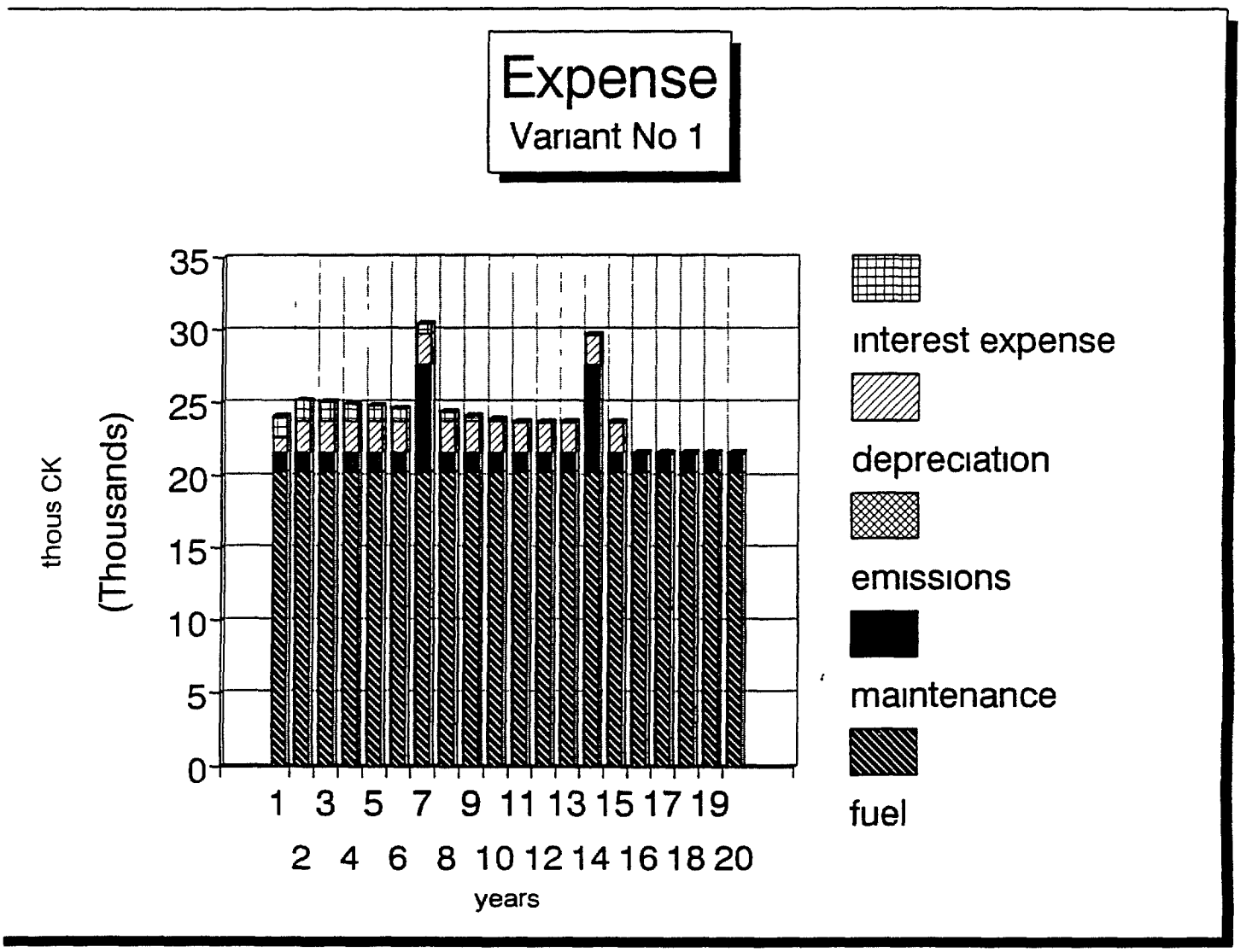
Variant No 1



Loan Principal

Variant No 1




Expense
Variant No 1
thous CK
(Thousands)
35
30
25
20
15
10
5
0
1 3 5 7 9 11 13 15 17 19
2 4 6 8 10 12 14 16 18 20
years
interest expense
depreciation
emissions
maintenance
fuel

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FINANCIAL ANALYSIS - VARIANT No 2

			PROJECT MANAGEMENT				OPERATION SERVICE				
			I Q	II Q	III Q	IV Q	1 year	2 year	3 year	4 year	5 year
	Investment Costs	thous CK	800	800	12341 6	28450 4	0	0	0	0	0
1 0	Discount Interest Rate	%	9 50%								
2 0	Total Capital Costs	thous CK	0								
3 0	Grant of Czech Government	thous CK	21196								
4 0	CR Debt Financing	thous CK	0								
4 1	Term	years	0								
4 2	Interest Rate	%	0 00%								
5 0	External Debt Financing	thous CK	21196								
5 1	Term	years	10								
5 2	Interest Rate	%	10 00%								

TOTAL INVESTMENT COSTS	42 392	mil CK	
NET PRESENT VALUE	9 66559	mil CK	
INTERNAL RATE OF RETURN	15 00%		
YEARS RETURN ON INVESTMENT	7	years	
DEBT SERVICE RATIO (MAX,MIN,AVG)	206 48%	11 4%	175 7%

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FINANCIAL ANALYSIS VARIANT No 2

STATEMENTS OF INCOME AND EXPENSE

Operating Data	yes		Start con	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
Electricity Sales	thous CK	x		23008	23008	23008	23008	23008	23008	23008	23008	23008	23008	23008	23008	23008	23008	23008	23008	23008	23008	23008	23008
Thermal Energy Sales	thous CK	x		8985	8985	8985	8985	8985	8985	8985	8985	8985	8985	8985	8985	8985	8985	8985	8985	8985	8985	8985	8985
G oss Revenue	thous CK			31991	31991	31991	31991	31991	31991	31991	31991	31991	31991	31991	31991	31991	31991	31991	31991	31991	31991	31991	31991
Fuel Costs	tho s CK	x		21323	21323	21323	21323	21323	21323	21323	21323	21323	21323	21323	21323	21323	21323	21323	21323	21323	21323	21323	21323
Operations & Mai te nce C sts	th s CK	x		1710	1710	1710	1710	1710	1710	1710	11036	1710	1710	1710	1710	1710	1710	1710	11036	1710	1710	1710	1710
Emissio s Fe	thous CK			21	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26
Dep ecl tion	thous CK	x		1441	2925	2925	2925	2925	2925	2925	2925	2925	2925	2925	2925	2925	2925	2925	0	0	0	0	0
Total Operating Expense	thous CK	x		24495	25984	25984	25984	25984	25984	25984	35310	25984	25984	25984	25984	25984	25984	25984	32385	23059	23059	23059	23059
Int est E pense	thous CK	x		2120	1987	1840	1679	1502	1308	1093	858	599	314	0	0	0	0	0	0	0	0	0	0
Taxe	thous CK	x		2419	1909	1875	1947	2027	2114	2211	0	2434	2562	2703	2703	2703	2703	2703	0	4019	4019	4019	4019
Net Income	thous CK	x		2957	2211	2291	2380	2477	2584	2702	4177	2974	3131	3304	3304	3304	3304	3304	394	4912	4912	4912	4912

AFTER TAX CASH FLOW ANALYSIS

SOURCE																							
Net Income	th us CK	x		2957	2211	2291	2380	2477	2584	2702	4177	2974	3131	3304	3304	3304	3304	3304	394	4912	4912	4912	4912
Dep ecl tion	thous CK	x		1441	2925	2925	2925	2925	2925	2925	2925	2925	2925	2925	2925	2925	2925	2925	0	0	0	0	0
Total Sou ces	thous CK	x		4398	5136	5216	5305	5402	5509	5627	1252	5899	6056	6229	6229	6229	6229	6229	394	4912	4912	4912	4912
USE																							
Loan Principal	th us CK	x		1330	1463	1609	1770	1947	2142	2356	2592	2851	3136	0	0	0	0	0	0	0	0	0	0
NET CASH FLOW	thous CK		0	3068	3673	3607	3535	3455	3368	3271	3844	3048	2920	6229	6229	6229	6229	6229	394	4912	4912	4912	4912
CUMULATIVE CASH FLOW	thous CK		0	3068	6741	10348	13883	17338	20706	23977	28133	23182	26102	32331	38559	44788	51017	57245	58851	61763	66676	71588	76501

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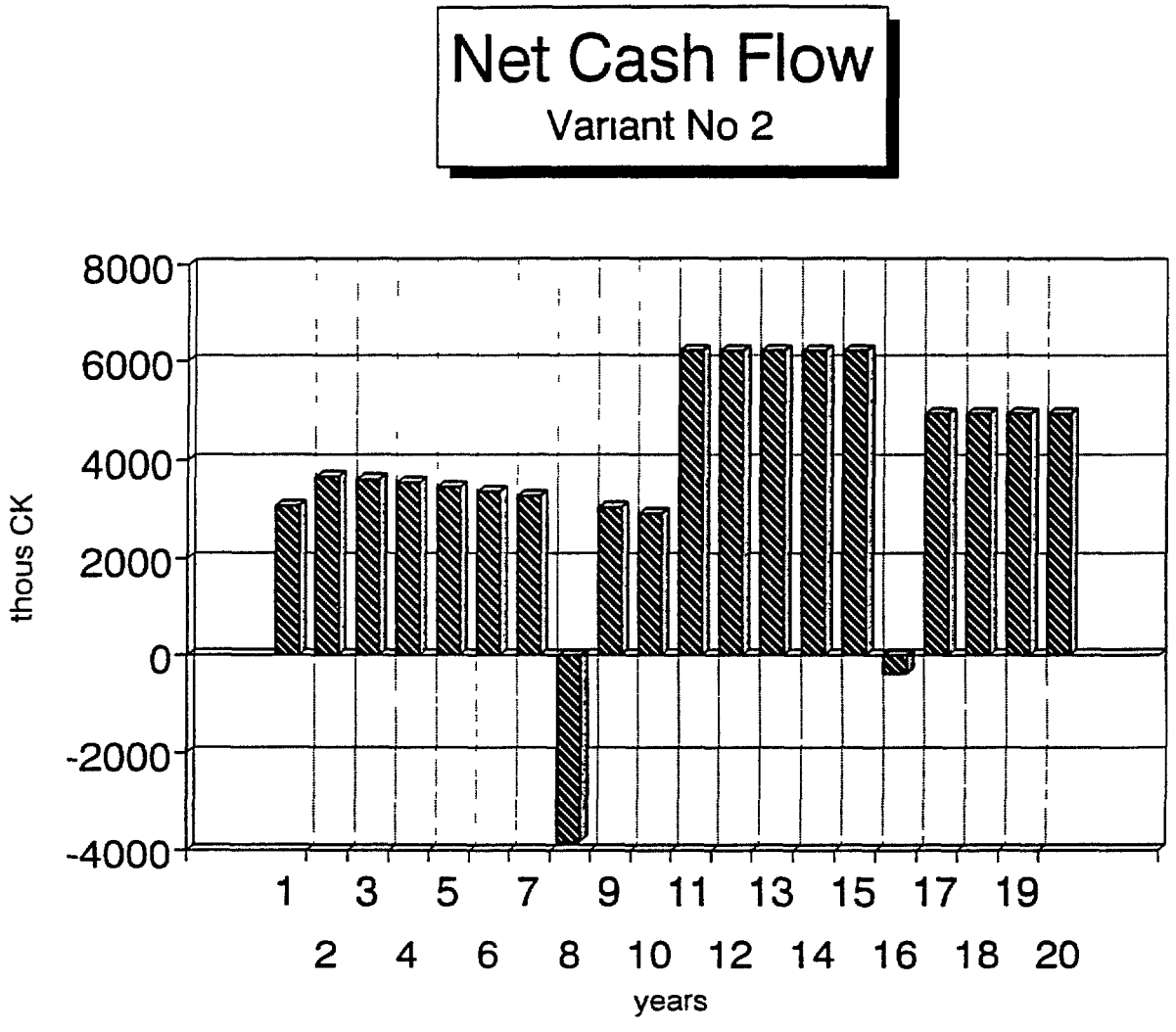
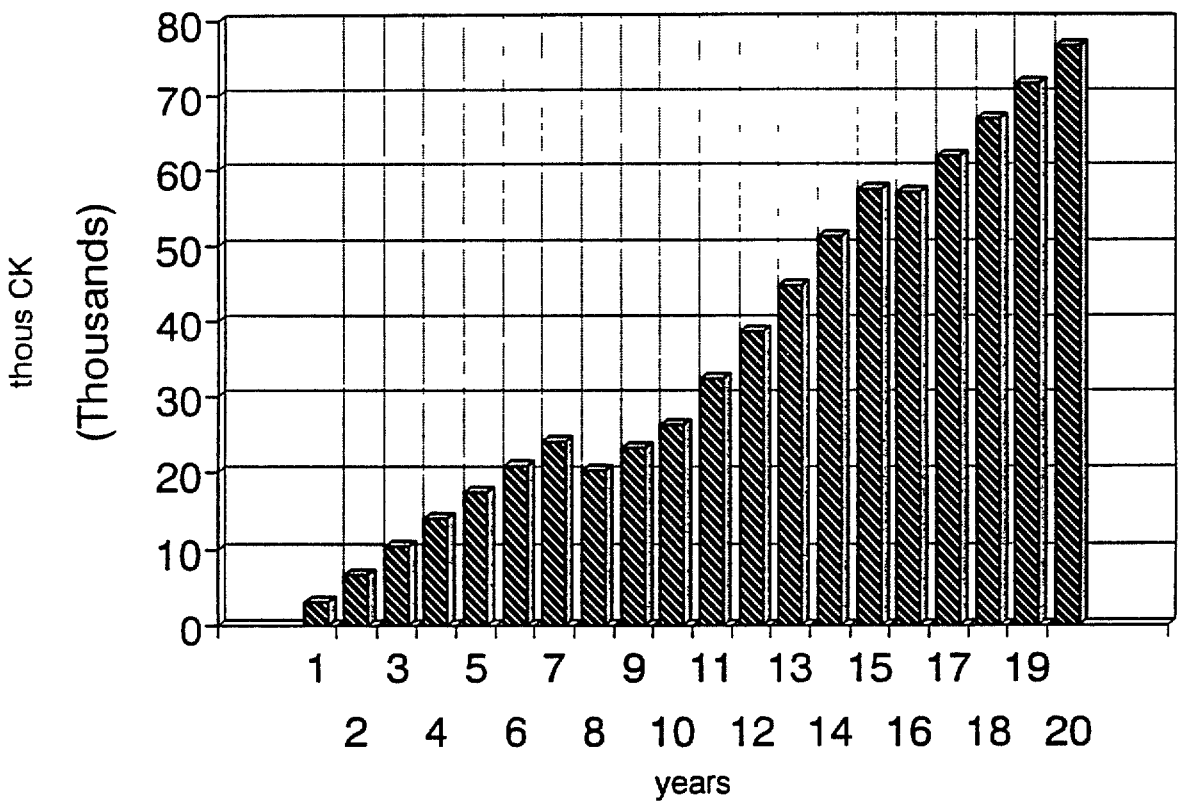
FINANCIAL ANALYSIS VARIANT No 2

	Ope ating Data	year	start con	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
1 0	Fu l Heavy Oil low sulphu	t/year		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
1 1	P ice	CK/t		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2 0	Fuel Heavy Oil middle sulphu	t/year	x	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2 1	Price	CK/t	x	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3 0	Fuel Natural Gas	Nm3/yea	x	6663366	6663366	6663366	6663366	6663366	6663366	6663366	6663366	6663366	6663366	6663366	6663366	6663366	6663366	6663366	6663366	6663366	6663366	6663366	6663366
3 1	Price	CK/Nm3	x	3 2	3 2	3 2	3 2	3 2	3 2	3 2	3 2	3 2	3 2	3 2	3 2	3 2	3 2	3 2	3 2	3 2	3 2	3 2	3 2
4 0	Fuel Propan Butan	t/yea	x	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
4 1	Price	CK/t		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
5 0	M ke up Wate	m3/year		548	548	548	548	548	548	548	548	548	548	548	548	548	548	548	548	548	548	548	548
5 1	Price With Chemical Treatment	CK/m3	x	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15
6 0	Operations Co ts	tous CK/year	x	567	567	567	567	567	567	567	567	567	567	567	567	567	567	567	567	567	567	567	567
7 0	Maintenance Costs	tous CK/year	x	468	468	468	468	468	468	468	9793 6	468	468	468	468	468	468	468	9793 6	468	468	468	468
8 0	Tot l Othe Expense	tous CK/year	x	300 0	300 0	300 0	300 0	300 0	300 0	300 0	300 0	300 0	300 0	300 0	300 0	300 0	300 0	300 0	300 0	300 0	300 0	300 0	300 0
9 0	Number of Wo kers		x	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
9 1	A erage Wage	CK/yea	x	54000	54000	54000	54000	54000	54000	54000	54000	54000	54000	54000	54000	54000	54000	54000	54000	54000	54000	54000	54000
9 2	Taxes on Wages	% on wages	x	36 00%	36 00%	36 00%	36 00%	36 00%	36 00%	36 00%	36 00%	36 00%	36 00%	36 00%	36 00%	36 00%	36 00%	36 00%	36 00%	36 00%	36 00%	36 00%	36 00%
10 0	Depreciation	%/year	x	3 40%	6 90%	6 90%	6 90%	6 90%	6 90%	6 90%	6 90%	6 90%	6 90%	6 90%	6 90%	6 90%	6 90%	6 90%	0 00%	0 00%	0 00%	0 00%	0 00%
11 0	Taxes on Profit	% on profit		45 00%	45 00%	45 00%	45 00%	45 00%	45 00%	45 00%	45 00%	45 00%	45 00%	45 00%	45 00%	45 00%	45 00%	45 00%	45 00%	45 00%	45 00%	45 00%	45 00%
12 0	Emissions SO2	t/yea		0 061	0 061	0 061	0 061	0 061	0 061	0 061	0 061	0 061	0 061	0 061	0 061	0 061	0 061	0 061	0 061	0 061	0 061	0 061	0 061
12 1	F e	CK/t		800	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000
13 0	Emissions NO	t/year	x	24 054	24 054	24 054	24 054	24 054	24 054	24 054	24 054	24 054	24 054	24 054	24 054	24 054	24 054	24 054	24 054	24 054	24 054	24 054	24 054
13 1	Fee	CK/t	x	640	800	800	800	800	800	800	800	800	800	800	800	800	800	800	800	800	800	800	800
14 0	Emis ions CO2	t/year	x	1 801	1 801	1 801	1 801	1 801	1 801	1 801	1 801	1 801	1 801	1 801	1 801	1 801	1 801	1 801	1 801	1 801	1 801	1 801	1 801
14 1	Fee	CK/t	x	480	600	600	600	600	600	600	600	600	600	600	600	600	600	600	600	600	600	600	600
15 0	Emission Particulates	t/yea	x	1 932	1 932	1 932	1 932	1 932	1 932	1 932	1 932	1 932	1 932	1 932	1 932	1 932	1 932	1 932	1 932	1 932	1 932	1 932	1 932
15 1	Fee	CK/t	x	2400	3000	3000	3000	3000	3000	3000	3000	3000	3000	3000	3000	3000	3000	3000	3000	3000	3000	3000	3000
16 0	Elect icity P oduction	GWh/yea	x	16 67086	16 67086	16 67086	16 67086	16 67086	16 67086	16 67086	16 67086	16 67086	16 67086	16 67086	16 67086	16 67086	16 67086	16 67086	16 67086	16 67086	16 67086	16 67086	16 67086
17 0	Th mal P oduction	TJ/year	x	84 13052	84 13052	84 13052	84 13052	84 13052	84 13052	84 13052	84 13052	84 13052	84 13052	84 13052	84 13052	84 13052	84 13052	84 13052	84 13052	84 13052	84 13052	84 13052	84 13052
18 0	Sales Elect icity	GWh/year	x	15 33719	15 33719	15 33719	15 33719	15 33719	15 33719	15 33719	15 33719	15 33719	15 33719	15 33719	15 33719	15 33719	15 33719	15 33719	15 33719	15 33719	15 33719	15 33719	15 33719
18 1	Price	CK/kWh	x	1 5	1 5	1 5	1 5	1 5	1 5	1 5	1 5	1 5	1 5	1 5	1 5	1 5	1 5	1 5	1 5	1 5	1 5	1 5	1 5
19 0	Sales Thermal to Inhabitants	TJ/year	x	84 13052	84 13052	84 13052	84 13052	84 13052	84 13052	84 13052	84 13052	84 13052	84 13052	84 13052	84 13052	84 13052	84 13052	84 13052	84 13052	84 13052	84 13052	84 13052	84 13052
19 1	P ice	CK/GJ	x	106 8	106 8	106 8	106 8	106 8	106 8	106 8	106 8	106 8	106 8	106 8	106 8	106 8	106 8	106 8	106 8	106 8	106 8	106 8	106 8


Net Cash Flow
Variant No 2
8000
6000
4000
2000
0
-2000
-4000
thous CK
1 3 5 7 9 11 13 15 17 19
2 4 6 8 10 12 14 16 18 20
years

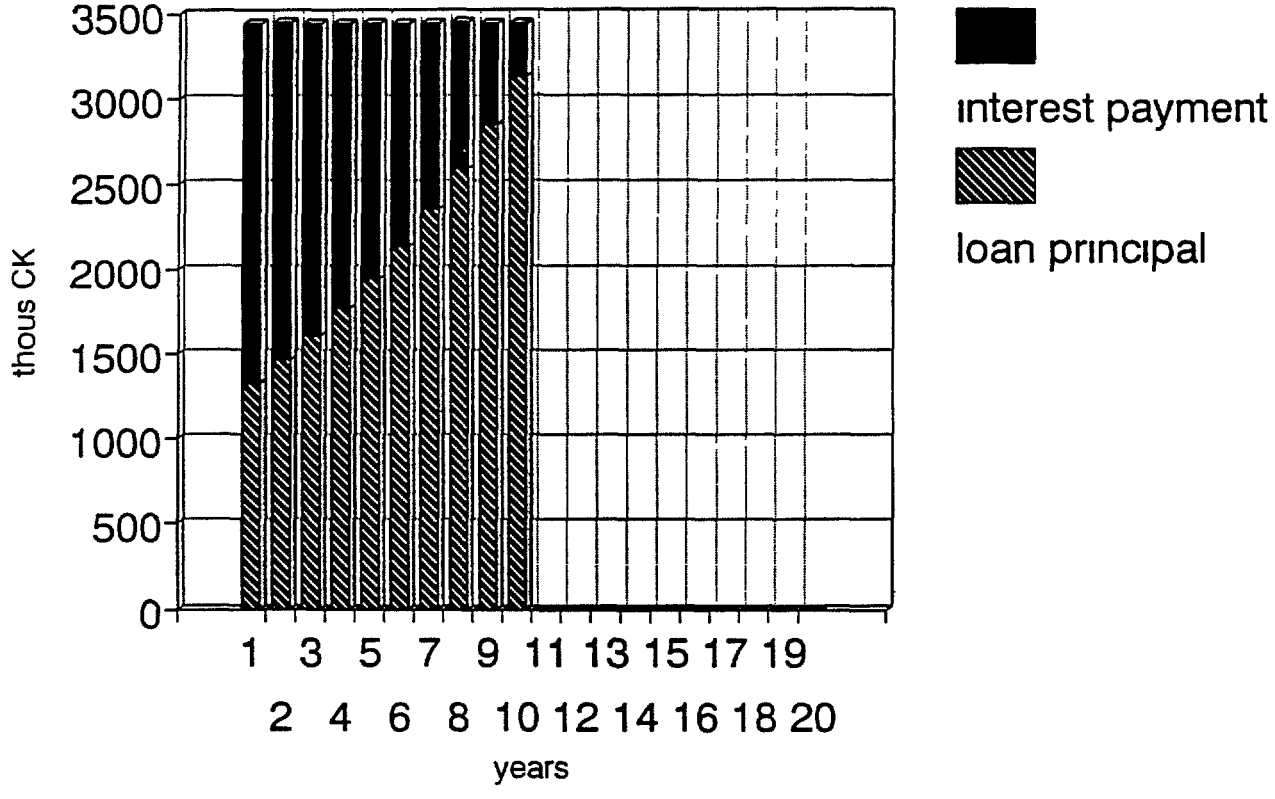
Cumulative Cash Flow

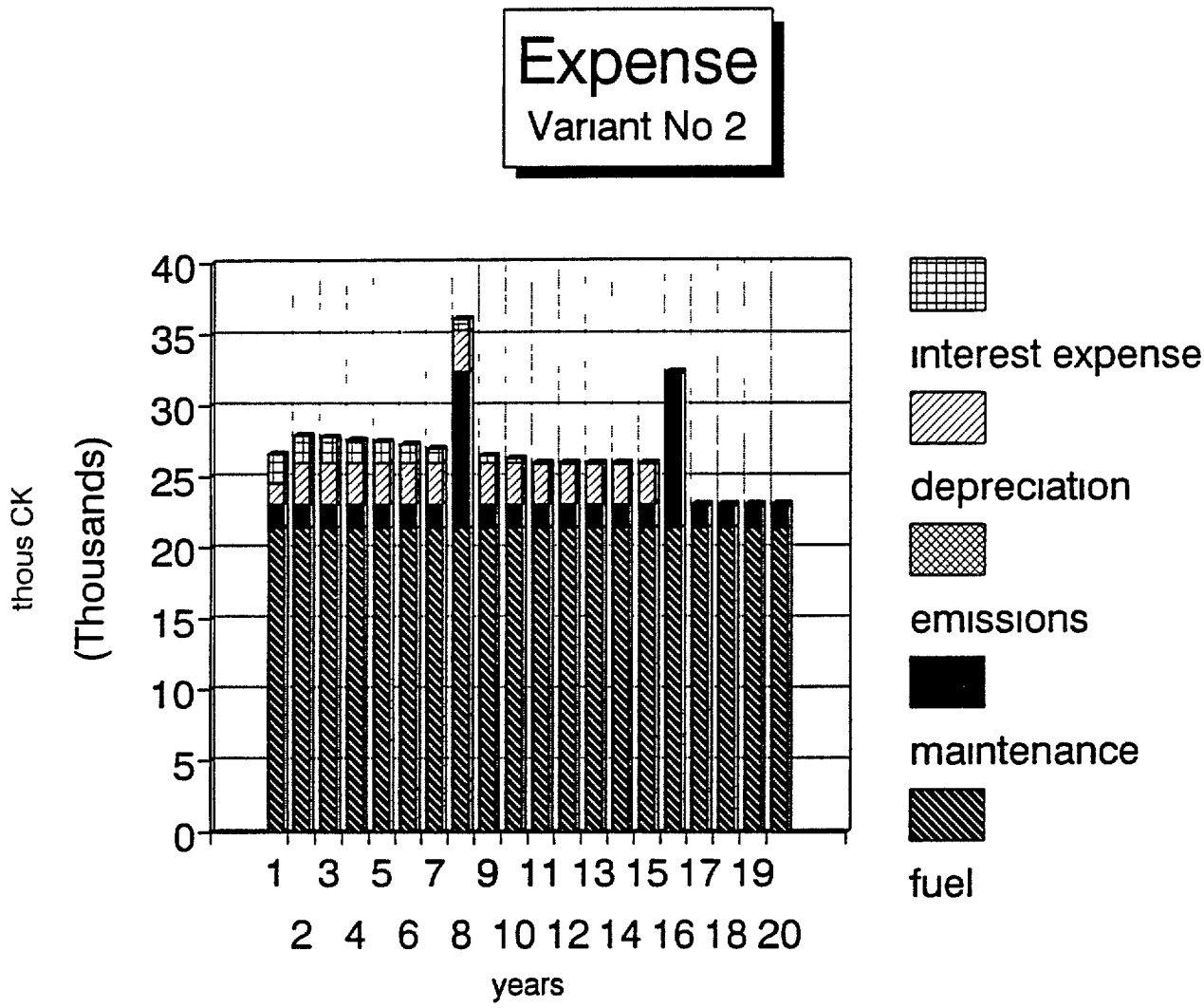
Variant No 2



Loan Principal

Variant No 2




Expense
Variant No 2
thous CK
(Thousands)
40
35
30
25
20
15
10
5
0
1 3 5 7 9 11 13 15 17 19
2 4 6 8 10 12 14 16 18 20
years
interest expense
depreciation
emissions
maintenance
fuel

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FINANCIAL ANALYSIS - VARIANT No 3

			PROJECT MANAGEMENT				OPERATION SERVICE				
			I Q	II Q	III Q	IV Q	1 year	2 year	3 year	4 year	5 year
	Investment Costs	thous CK	800	800	12451 6	28450 4	0	0	0	0	0
1 0	Discount Interest Rate	%	9 50%								
2 0	Total Capital Costs	thous CK	0								
3 0	Grant of Czech Government	thous CK	21251								
4 0	CR Debt Financing	thous CK	0								
4 1	Term	years	0								
4 2	Interest Rate	%	0 00%								
5 0	External Debt Financing	thous CK	21251								
5 1	Term	years	10								
5 2	Interest Rate	%	10 00%								

TOTAL INVESTMENT COSTS	42 502	mil CK	
NET PRESENT VALUE	9 696956	mil CK	
INTERNAL RATE OF RETURN	15 00%	-	
YEARS RETURN ON INVESTMENT	7	years	
DEBT SERVICE RATIO (MAX,MIN,AVG)	206 44%	10 8%	175 7%

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FINANCIAL ANALYSIS VARIANT No 3

STATEMENTS OF INCOME AND EXPENSE

Ope sting Data	y	st rt eon	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
Ele t i ity Sales	thous CK		23006	23006	23006	23006	23006	23006	23006	23006	23006	23006	23006	23006	23006	23006	23006	23006	23006	23006	23006	23006
Th mal E e gy Sales	tho s CK		9006	9006	9006	9006	9006	9006	9006	9006	9006	9006	9006	9006	9006	9006	9006	9006	9006	9006	9006	9006
G oss Revenue	tho s CK	x	32012	32012	32012	32012	32012	32012	32012	32012	32012	32012	32012	32012	32012	32012	32012	32012	32012	32012	32012	32012
F I Costs	thous CK	x	21323	21323	21323	21323	21323	21323	21323	21323	21323	21323	21323	21323	21323	21323	21323	21323	21323	21323	21323	21323
Ope tio s & Maintenance Costs	thous CK		1710	1710	1710	1710	1710	1710	1710	11036	1710	1710	1710	1710	1710	1710	1710	11036	1710	1710	1710	1710
Eml ions Fe s	thous CK		21	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26
D preci tion	thous CK		1445	2933	2933	2933	2933	2933	2933	2933	2933	2933	2933	2933	2933	2933	2933	0	0	0	0	0
Total Operating E pen e	thous CK	x	24499	25992	25992	25992	25992	25992	25992	35318	25992	25992	25992	25992	25992	25992	25992	32365	23059	23059	23059	23059
Inter st E pe se	thous CK	x	2125	1992	1845	1684	1506	1311	1096	860	600	314	0	0	0	0	0	0	0	0	0	0
Ta e	thous CK	x	2424	1813	1679	1951	2031	2119	2216	0	2439	2567	2709	2709	2709	2709	2709	0	4029	4029	4029	4029
Net Income	thous CK	x	2963	2216	2296	2385	2483	2590	2709	4166	2981	3138	3311	3311	3311	3311	3311	373	4924	4924	4924	4924

AFTER TAX CASH FLOW ANALYSIS

SOURCE																						
Net Incom	thous CK		2963	2216	2296	2385	2483	2590	2709	4166	2981	3138	3311	3311	3311	3311	3311	373	4924	4924	4924	4924
Depreci tion	thous CK	x	1445	2933	2933	2933	2933	2933	2933	2933	2933	2933	2933	2933	2933	2933	2933	0	0	0	0	0
Total Sou c s	thous CK		4408	5148	5229	5318	5415	5523	5641	1233	5913	6071	6244	6244	6244	6244	6244	373	4924	4924	4924	4924
USE																						
Lo n Principal	thous CK	x	1333	1467	1613	1775	1952	2147	2362	2598	2858	3144	0	0	0	0	0	0	0	0	0	0
NET CASH FLOW	thous CK	0	3075	3681	3615	3543	3463	3375	3279	3832	3055	2927	6244	6244	6244	6244	6244	373	4924	4924	4924	4924
CUMULATIVE CASH FLOW	thous CK	0	3075	6756	10372	13914	17377	20752	24031	20199	23255	26181	32425	38669	44912	51156	57399	57026	61950	66874	71798	76722

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FINANCIAL ANALYSIS VARIANT No 3

	Operating Data	yea		start con	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
1 0	Fuel H avy Oil low sulphu	t/yea			0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
1 1	Price	CK/t	x		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2 0	Fuel Heavy Oil middle sulphur	t/year	x		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2 1	Price	CK/t	x		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3 0	Fuel Nat al Gas	Nm3/year	x		6663366	6663366	6663366	6663366	6663366	6663366	6663366	6663366	6663366	6663366	6663366	6663366	6663366	6663366	6663366	6663366	6663366	6663366	6663366	6663366
3 1	Price	CK/Nm3	x		3 2	3 2	3 2	3 2	3 2	3 2	3 2	3 2	3 2	3 2	3 2	3 2	3 2	3 2	3 2	3 2	3 2	3 2	3 2	3 2
4 0	Fuel P opan Buta	t/year	x		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
4 1	P ice	CK/t	x		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
5 0	Make up Water	m3/yea	x		548	548	548	548	548	548	548	548	548	548	548	548	548	548	548	548	548	548	548	548
5 1	P ice With Chemical Treatme t	CK/m3			15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15
6 0	Operations Costs	tous CK/yea	x		567	567	567	567	567	567	567	567	567	567	567	567	567	567	567	567	567	567	567	567
7 0	Maint nance Costs	tous CK/y			468	468	468	468	468	468	468	9793 8	468	468	468	468	468	468	468	9793 8	468	468	468	468
8 0	Total Othe Expense	tous CK/yea			300 0	300 0	300 0	300 0	300 0	300 0	300 0	300 0	300 0	300 0	300 0	300 0	300 0	300 0	300 0	300 0	300 0	300 0	300 0	300 0
9 0	Numbe of Workers				5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
9 1	A age Wage	CK/y r			54000	54000	54000	54000	54000	54000	54000	54000	54000	54000	54000	54000	54000	54000	54000	54000	54000	54000	54000	54000
9 2	Ta on Wag s	% on wag s			36 00%	36 00%	36 00%	36 00%	36 00%	36 00%	36 00%	36 00%	36 00%	36 00%	36 00%	36 00%	36 00%	36 00%	36 00%	36 00%	36 00%	36 00%	36 00%	36 00%
10 0	D p sciati	%/y			3 40%	6 90%	6 90%	6 90%	6 90%	6 90%	6 90%	6 90%	6 90%	6 90%	6 90%	6 90%	6 90%	6 90%	6 90%	0 00%	0 00%	0 00%	0 00%	0 00%
11 0	Ta e on P ofit	% on profit			45 00%	45 00%	45 00%	45 00%	45 00%	45 00%	45 00%	45 00%	45 00%	45 00%	45 00%	45 00%	45 00%	45 00%	45 00%	45 00%	45 00%	45 00%	45 00%	45 00%
12 0	Emission SO2	t/year	x		0 061	0 061	0 061	0 061	0 061	0 061	0 061	0 061	0 061	0 061	0 061	0 061	0 061	0 061	0 061	0 061	0 061	0 061	0 061	0 061
12 1	Fee	CK/t	x		800	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000
13 0	Emissions NOx	t/yea	x		24 054	24 054	24 054	24 054	24 054	24 054	24 054	24 054	24 054	24 054	24 054	24 054	24 054	24 054	24 054	24 054	24 054	24 054	24 054	24 054
13 1	Fee	CK/t	x		640	800	800	800	800	800	800	800	800	800	800	800	800	800	800	800	800	800	800	800
14 0	Emissions CO2	t/yea	x		1 801	1 801	1 801	1 801	1 801	1 801	1 801	1 801	1 801	1 801	1 801	1 801	1 801	1 801	1 801	1 801	1 801	1 801	1 801	1 801
14 1	Fee	CK/t	x		480	600	600	600	600	600	600	600	600	600	600	600	600	600	600	600	600	600	600	600
15 0	Emissions Partic lates	t/year	x		1 932	1 932	1 932	1 932	1 932	1 932	1 932	1 932	1 932	1 932	1 932	1 932	1 932	1 932	1 932	1 932	1 932	1 932	1 932	1 932
15 1	Fee	CK/t	x		2400	3000	3000	3000	3000	3000	3000	3000	3000	3000	3000	3000	3000	3000	3000	3000	3000	3000	3000	3000
16 0	El ct icity Productio	GWh/year	x		16 67086	16 67086	16 67086	16 67086	16 67086	16 67086	16 67086	16 67086	16 67086	16 67086	16 67086	16 67086	16 67086	16 67086	16 67086	16 67086	16 67086	16 67086	16 67086	16 67086
17 0	Th mal P oduction	TJ/y ar	x		84 13052	84 13052	84 13052	84 13052	84 13052	84 13052	84 13052	84 13052	84 13052	84 13052	84 13052	84 13052	84 13052	84 13052	84 13052	84 13052	84 13052	84 13052	84 13052	84 13052
18 0	Sales Electricity	GWh/year	x		15 33719	15 33719	15 33719	15 33719	15 33719	15 33719	15 33719	15 33719	15 33719	15 33719	15 33719	15 33719	15 33719	15 33719	15 33719	15 33719	15 33719	15 33719	15 33719	15 33719
18 1	Price	CK/kWh	x		1 5	1 5	1 5	1 5	1 5	1 5	1 5	1 5	1 5	1 5	1 5	1 5	1 5	1 5	1 5	1 5	1 5	1 5	1 5	1 5
19 0	Sales Thermal to Inhabitants	TJ/yea	x		84 13052	84 13052	84 13052	84 13052	84 13052	84 13052	84 13052	84 13052	84 13052	84 13052	84 13052	84 13052	84 13052	84 13052	84 13052	84 13052	84 13052	84 13052	84 13052	84 13052
19 1	Price	CK/GJ	x		107 05	107 05	107 05	107 05	107 05	107 05	107 05	107 05	107 05	107 05	107 05	107 05	107 05	107 05	107 05	107 05	107 05	107 05	107 05	107 05

BEST AVAILABLE COPY

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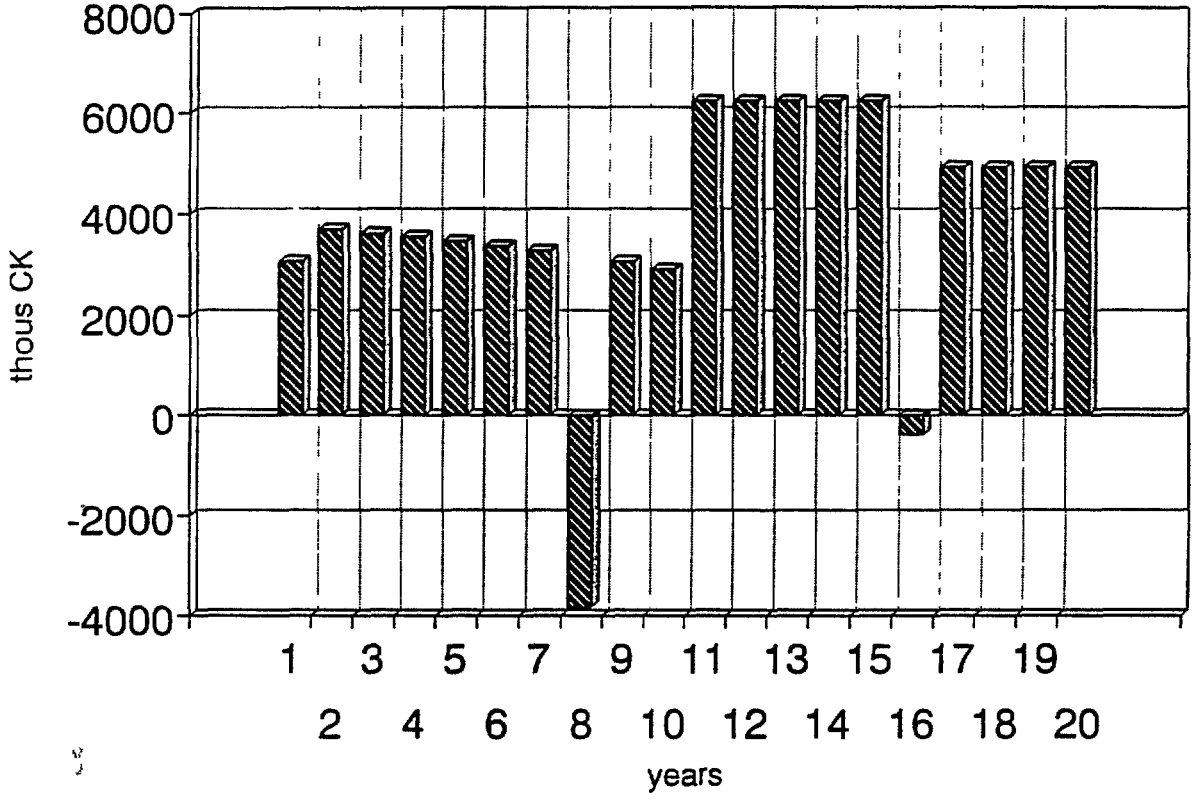
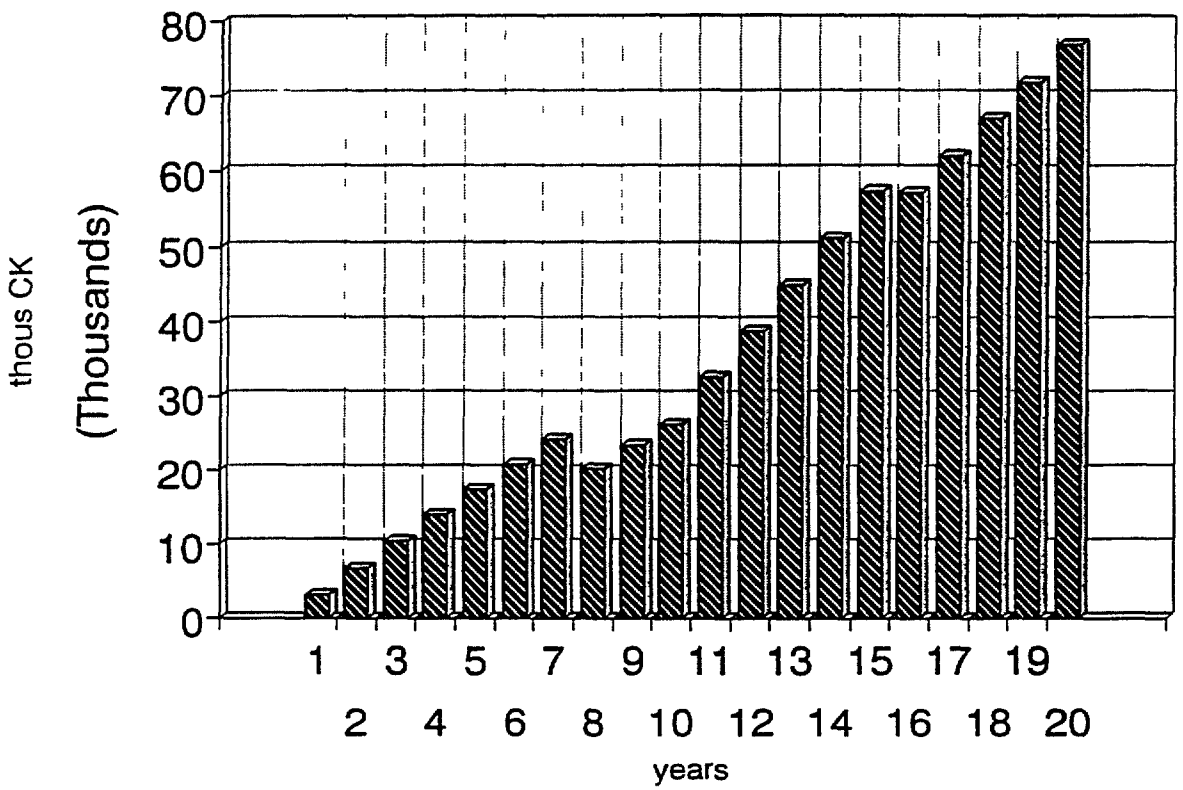
Net Cash Flow

Variant No 3



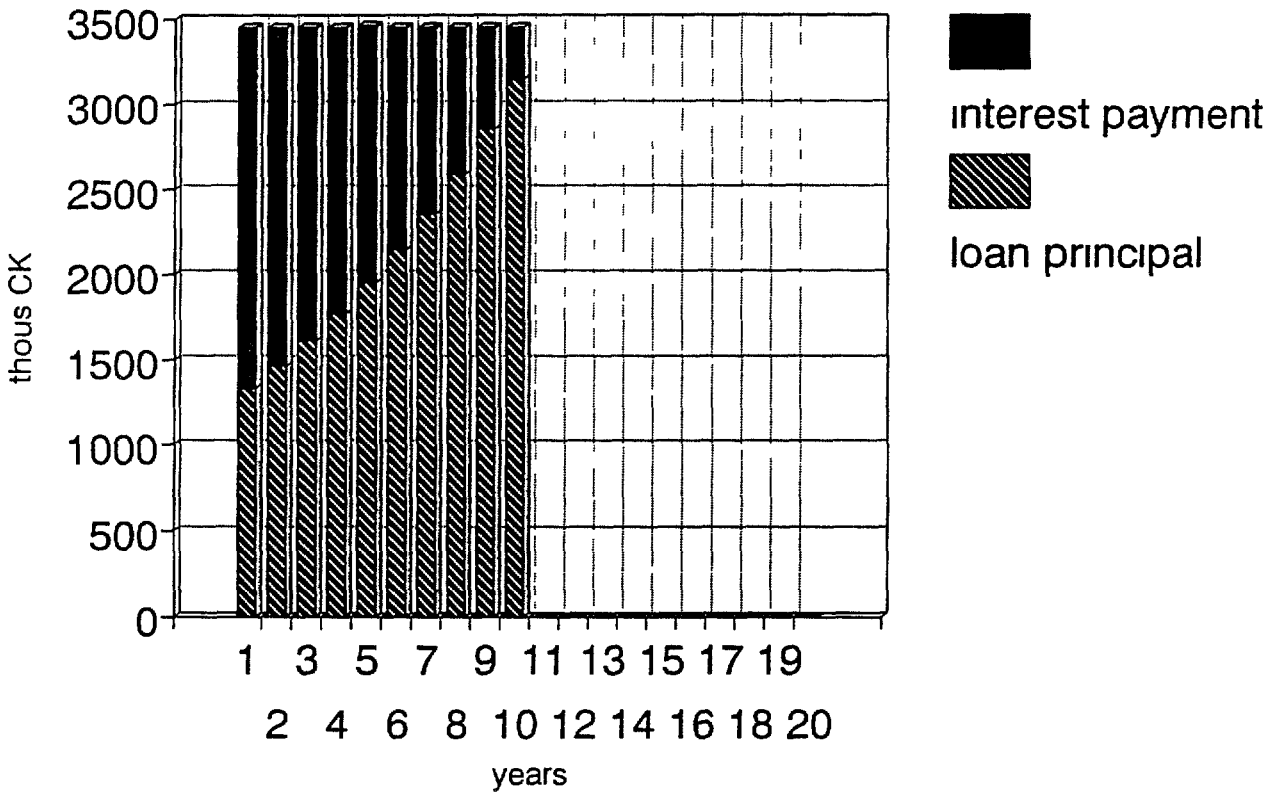
Cumulative Cash Flow

Variant No 3



Loan Principal

Variant No 3



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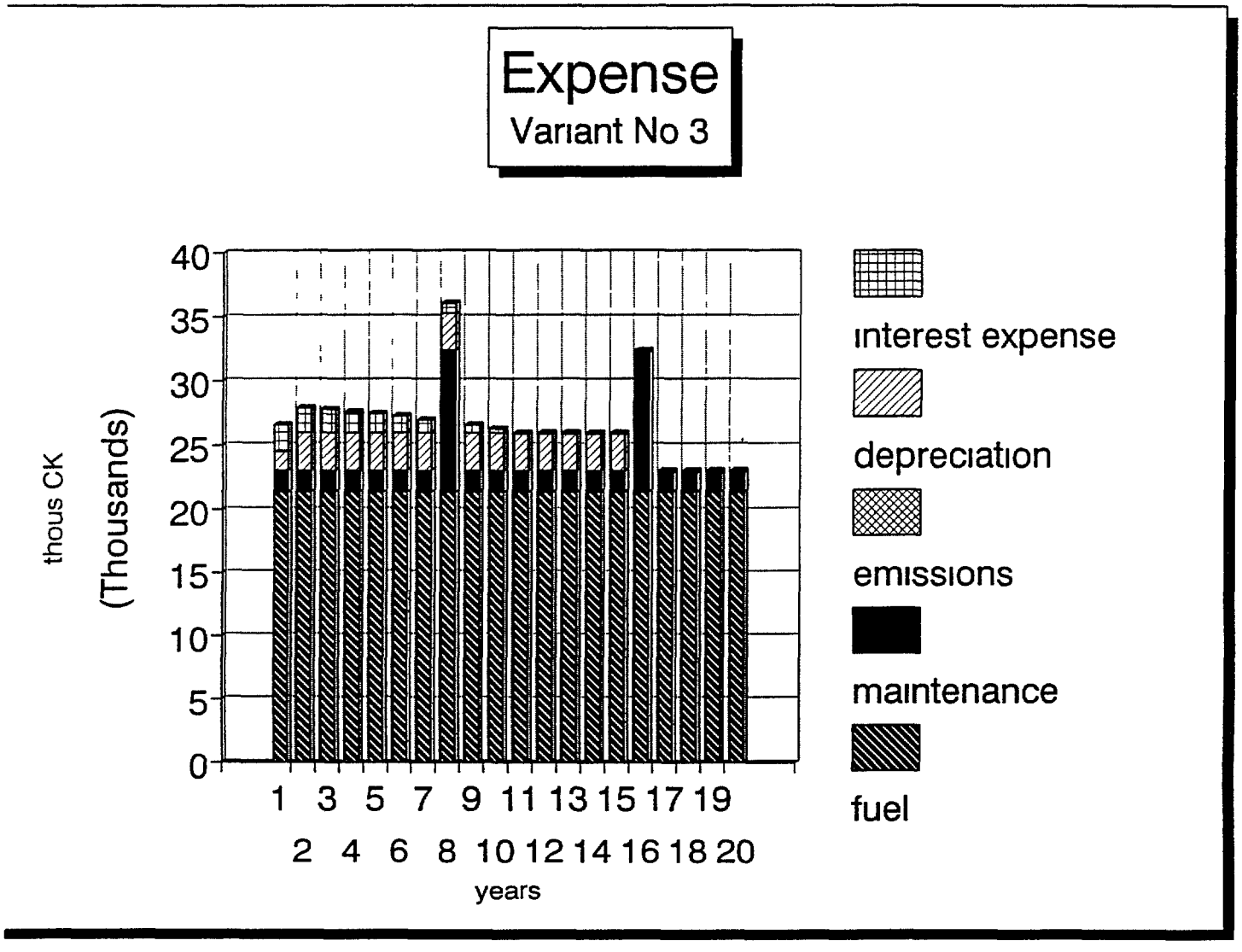
Expense
Variant No 3
thous CK
(Thousands)
40
35
30
25
20
15
10
5
0
1 3 5 7 9 11 13 15 17 19
2 4 6 8 10 12 14 16 18 20
years
interest expense
depreciation
emissions
maintenance
fuel

E. REMARKS TO THE ECONOMIC REPORT OF 1991'S STUDY

At the beginning we remark that the study was written in December 1991, therefore it is more than one year old We shall therefore evaluate it from two viewpoints The first will be the viewpoint of the year of the origin of the study, the second will be the viewpoint of the year 1993

After our opinion will be more appropriate, to consider longer period, possibly up to year 2005, better 2010 As for economic calculation, our standpoint is the following

It is quite correct that variants have equal production effect from the view of heat (at consumer's receiving point)
Difference among variants originate in different production of electricity Therefore it would be suitable to implement the variant of possible market prices of heat and especially electricity, as it is remarked in the study

- it is correct (at this level of transparency of problems) to use criterion of NVP for comparison concerning the chosen period and to limit the study to economic calculation only Any other (especially financial) considerations would be sole fiction
- we could not pass judgement on proclamated use of the cash-flow method, because in the study there is not a single supplement which would demonstrate the method of calculation There is no description (may be only verbal) of the method of calculation
- with regard to the previous position we take into consideration that it is right to take into evaluation all monetary expressible claims and effects, but we cannot really declare that this was really done in the study, especially what concerns the declaration that the costs of nuclear heating plant contain also costs for liquidation of nuclear fuel According to our view the costs contain probably only a part of costs for its temporary storage

The analysis of results, so as documented beginning with the page 26, is logical The distribution of calculations into static and dynamic ones is right As one of study's merits we just consider dynamic calculation A greater space could have been afforded to it, especially to interpretation of results It should be considered as suitable that the authors have not tried to choose optimal variant at all costs, and that they were concerned with trends proved by individual technical solutions in different economic conditions

Although we do not know definite results and mathematical access to calculations, an adequate structure of portions of individual parts of costs on total costs results from graphs on the page 31

At the end of economic report there is a quite correct analysis of economic results Also correct is the proposition to continue the study so that only variants IIIa and IIIb will be evaluated We intercede also to include the variant I (especially with more detailed elaboration of possibilities of reconstruction of gas boiler rooms for combined production) We have no objections to used prices of electricity, heat, fuel e t c with relation to the year 1991

As for the viewpoint of the year 1993 We are convinced that investment costs for nuclear heating plant are much underevaluated, moreover they do not contain all necessery costs for liquidation of burnt nuclear fuel Also the solutions of classical variants will be object of considerable shifting in the area of investments costs Today s prices in total spectrum of economy have changed Possible purchasing price of electricity and prices of heat have changed as well A soon establishment of governmental regulatory body may be expected which will form a new conception - among other things - also for prices of electricity and heat

The chapter about uncertainty risks tries to evaluate problems which authors felt as unsolved and in the year 1991 (p 42 and 43) especially what concerns the declared 20% reduction of heat consumption as a result of economy measures financing of investment e t c This chapter should form the basis for further development of the study in case of conclusion of contract for its second part

As a whole we consider the study to be of quality, corresponding to the level of the year 1991

APPENDIX C: RESULTS OF EGU ANALYSIS - VARIANTS A1, A2 AND B1

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EGÚ Praha akciová společnost
190 11 Praha 9- Běchovice, ☎ 42-2-741474, fax 42-2-741256

Gilberth Commonwealth, INC
Lynn Rubow
P O Box 1498
Reading, PA 19603
U S A.

RECEIVED
JUL 27 1993
LYNN N. RUBOW

22 July 1993

Dear Mr Rubow,

enclosed you will find information related to the Technical Part of the Plzen District Heating Study on Tables, Graphs and Flow Diagrams in the scope we agreed on at June 25, 1993

On Tables 1 to 4 we present heat demand in DHS for two projections, high and low heat demand Those balances have been accepted on our meeting in June 25 and become a basis for further work in EGÚ and EGP

Tables 5 to 10 will give a solution how to cover heat demands from system units
Construction of further Central unit CP Plzen is projected in two alternatives
ALT A based on natural gas and
ALT B on coal
Within Alt A we considered two variants of CC application
-one with 2x GT and 1x condensed ST -Variant 1
-and the other with 1x GT with backpressure GT and additional cooling- Variant 2

Within Alt B we considered two variants of reconstruction dry-bottom pulverised-fired boilers to meet new environmental requirements
Var 1 suggests shifting to quality hard coal with low sulphur content
Var 2 involves Flue Gas Desulphurization enabling to burn inexpensive lignite with higher sulphur content

Enlargement of CP is apparent from Graphs S1,S2 and S3

Assumed CP operation scheme in Alternatives and Variants is outlined in flow diagrams D1 to D15 and has been evaluated in Tables 11-18 In the Tables heat and electrical energy production and fuel consumption is examined for economical evaluation and judgement of feasibility for each option

Cost of construction of new units and reconstruction cost of existing facilities, fuel rates and cost estimates for operation of evaluated variants will be sent next week, by July 30

Description of variants for Technical project needed for a Final Report will be sent by August 12

Package include

24 Tables
18 Flow Diagrams
3 Graphs

Yours sincerely

Stanislav Kalouš
Project Manager

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EGU Praha, a.s.
Praha 9 - Běchovice

Project

Review of Variants to Satisfy Heat Demands in Plzeň

DOE HDQ DE - AC 01 - 88 FE 61657

Technical report to the tasks of EGU Praha a s

August 1993

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1 DEVELOPMENT OF CENTRALIZED HEAT SUPPLY IN PLZEŇ

Further development of centralized heat supply system (DHS) in the town of Plzeň can be estimated by taking into consideration the following conditions

- it can be expected that at the existing heat consumers the consumption of heat taken from district heating systems will decrease due to introduction of economy measures

- erection of further housing quarters in the form of concentrated blocks of multistoreyed houses characterized by high concentration of heat needs is not considered in near future,

- similarly at the industrial consumers of heat it can not be expected that the consumption of heat will increase in the next future It is due to probable implementation of heat saving technologies

- at present in the town of Plzeň a reconstruction of gas supply system from town gas to natural gas is taking place Together with this reconstruction a shift from quality sorted solid fuels (i e coal and coke) to gas is realized From the year 1995 on after increasing the capacity of high pressure gas system in the locality of Plzeň the gaseous fuel will be at disposal even for the use of modernization of heat sources in the DHS

- the heat sources of DHS have to fulfill by the year 1997 the strict demands of the new clean air act

The conditions for the extensive development of DHS in next future i e up to the year 2000 are far from being favorable The centralized heat supply systems will have to cope with the competition of decentralized heat supply from local sources on natural gas

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The obsolete outlived coal burning heating plants that are owned by the municipal enterprise TEZA are one of the greatest source of environment pollution Modernization and reconstruction of their grate boilers to economic burning of quality sorted fuel of low sulphur content, together with installing expensive equipment for flue gases cleaning could not be economic due to the fact that the main technology is already at the end of its lifespan (installed during the sixties) It is thus necessary that by 1997 the heat distribution systems of these sources (local heating plants) will be connected to the heat distribution network of the cogeneration plant ZČE and the existing boilers liquidated If this connection is not realized it will be necessary to replace the old coal burning boilers with new natural gas fired ones

Even the cogeneration plant (CP) ZČE will have to be reconstructed by the year 1997, especially by introducing the environment saving measures In order to increase the operational effectivity of this central source of the system it will be necessary to increase the ratio of combined production of electricity and heat and ensure preferably the all year operation of the coproduction plant The increased ratio of cogeneration has to compensate for the losses in the distribution system by more effective utilization of primary energy supplied in fuel

At the same time it is necessary to guarantee reliable all year delivery of heat to consumers in the steam system so that this favorable type of consumers with balanced heat supply requirments throughout the year will remain It is also recommended to utilize the heat transport capacity of the existing heat network mains that makes possible to connect further consumers to the system It is valid especially for the considerably overdimensionned hot water connecting mains South To the hot water heat network of the system it is necessary to connect the objects situated in the vicinity of the heat mains which are at present heated from local solid and liquid fuel boiler houses

This study proposes and evaluates the further successive development of the cogeneration system of ZČE as follows

a) in the next period i e by the year 1996, the following alterations and reconstructions of the existing cogeneration plant equipment especially due to ecology reasons will have to be realized

- for the hot water boilers 3 x 35 MWt from the first part CP I originated in the seventies a fuel shift to stone coal with low sulphur content and installation of bag flue gas filters is considered
- similarly, for the high pressure steam boilers 2 x 170 t/h a reconstruction of boilers and coal mills to low sulphur content stone coal and installation of new bag filters is being considered As other variant (in alt B var 2) it is considered to continue the operation with burning of lignite but with a new equipment for wet cleaning of flue gases Due to a considerable extent of reconstructions, the part of which are also building works it can be assumed that during the heating period of the years 1995 and 1996 successively one of the boilers of the second part - CP II will have to be out of operation
- in order to quarantee the all year round supply of steam into the steam system and as a source for making up the high pressure boiler capacity during its reconstruction it is proposed to install in advance i e in 1994 a low pressure steam boiler of 65 t/h capacity in the third part of the plant - CP III This boiler would burn both gas and oil
- it is considered that during the year 1995 the living quarters Doubravka and Letna will be connected to the CP system by construction of heat network feeder mains East - 2 x DN 400 The heating plants V1 and V2 will be utilized in winter peak periods only as peak heat sources Together with this connecting the hot water part of the heating plant Bory to the CP system is considered The link with the feeder South already exists The hot water boilers of the heating plant Bory would be in operation in winter peak period only

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The initial intention of connecting also the system of heat plant Světovar to the CP and also the objects heated at present by the local coal boiler houses by means of the feeder East II shall not be realized due to the fact that in this region development of gas distribution system proceeds in large scale The Světovar heating plant owned by the municipal enterprise TEZA shall then be reconstructed for natural gas firing

b) realization of the new capacity installation in the fourth part (fourth period of plant construction) - CP IV is considered in years 1995 - 96 and its commissioning in heating period 1996/97 The new technology shall quarantee the all year basic heat supply to the system and for this heat and power cogeneration is assumed This installation will make possible the liquidation of the outlived heat plants V1 and V2 the hot water part of the heat plant Bory and the coal fired heat plants in the steam system This fourth part CP IV has been projected and analyzed in the following alternatives and variants of this study

Alternative A has been proposed on basis of natural gas burning in application of the efficient combined gas - steam cycle (CC)

In Var 1 large combined cycle (CC) of electric capacity 170 MW and thermal capacity 125 MWt with two combustion turbines and one steam condensation turbine has been proposed

Considering the fact that the building site of the plant is situated in the vicinity of the city center and due to high demand on natural gas consumption the Var 2 analyses a cogeneration plant with smaller combined cycle

In Var 2 combined cycle with electric power 88 MWe and thermal capacity 65 MWt has been proposed The cycle comprises one gas combustion turbine and one steam back pressure turbine with one regulated extraction and additional cooling

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With combined cycles cooperate in heat supply the existing technology of the CP - i e the high pressure cogeneration part CP II and peak hot water boilers CP I burning low sulphur content stone coal, dual fuel steam boiler from the CP III and the brewery steam heating plant which cooperates with the steam distribution network

Alternative B proposes for the new capacity installed in the fourth part of the CP the Westbohemian or Northbohemian lignite New atmospheric circulating fluid bed steam boiler 160 t/h with the desulphurisation effect of the furnace shall operate with cheap low grade coal Together with this boiler a condensation extraction steam turbine will be installed This turbine of electric capacity 32 MW will make possible the supply of heat both in steam and hot water

The existing high pressure cogeneration plant 2 x 170 t/h 1 x 55 MW shall cooperate with the new unit in heat supply As it has not yet been decided about the environment protection measures to be implemented with the existing granulating boilers two variants have been evaluated

In Var i similarly as in Alt A an operation of boilers and coal mills reconstructed to use the local pilsner stone coal with low sulphur content has been considered and evaluated

In Var 2 operation of the granulating boilers burning the Sokolov lignite of the same quality as at present (sulphur content not exceeding 1 %) has been evaluated The boilers are considered to be equipped with new textile flue gas filters and desulpnurisation plant with wet wash of gases

The peak grate boilers 3 x 35 MWt shall use the stone coal with low sulphur content and are to be equipped with new textile filters After realization of this reconstruction it is expected that the grate boilers will remain in operation as late as the year 2004

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c) in the fifth stage of construction - CP V realized by the year 2005 the cogeneration plant construction shall be finished

- as a compensation for the existing grate hot water boilers from the first part new boilers shall be erected in years 2003 and 2004 These boilers in number one or two and capacity 58 MWt each will be adapted to dual fuel either the low sulphur content heating oil or natural gas Their actual number will depend on the output thermal capacity of the technologic equipment installed during the fourth stage of construction (in case of low balance in Alt A Var 1 the existing hot water boilers 3 x 35 MWt could be even liquidated without any compensation after the year 2000

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2 REQUIREMENTS ON HEAT SUPPLY FROM THE CP PLZEŇ SYSTEM

The prognosis of heat demand development both in hot water and steam system of the cogeneration plant has been investigated for the period up to the year 2000 in two levels

a) a prognosis assuming a more intensive development of the system named as high balance is presented in tables 1a and 1b

b) a prognosis assuming a minimum development of the centralized heat supply named as low balance is presented in tables 2a and 2b

The effectiveness of the proposed variants of CP reconstruction and completion has been evaluated on conditions of these extreme levels At the same time it is assumed that the actual future development of the system shall realize within these limits

The balance is founded on results of operation of the existing CP ZČE heat plants owned by TEZA and industrial boiler houses in the steam system which were reached in the years 1991 and 1992 The actual results were adapted to the average climatic conditions

The development of heat demand respect the balance data rendered by ZČE and respect also an analysis of the existing demand of objects supplied by local sources situated in economic distance from the existing feeding mains

The method of determination of heat balances and their results have been discussed with the representatives of Plzeň municipal autnority (the division of conceptual and city development projects) and with the authorized workers of ZČE and TEZA enterprises

The heat demand data as given in tables 1 and 2 have been accepted also as initial data for the work of EGP

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For future it is expected that the existing consumers of heat supplied by the system will decrease their demand as a result of economy measures and after installation of individual measurment of heat consumption The successive suppression of donations and the resulting increase of heat price for the residents shall result in heat demand decrease as well In the period after 1995 extensive application of measures leading to additional improvment of heat insulating qualities of the existing buildings is expected

In case of hign balance prognosis a successive decrease in heat consumption of the existing consumers by the year 2000 amounting 15 % and for the low balance estimation as high as 20 % is considered

The expected increase in heat demand for the new consumers incorporates the following aspects

- the future consumers who were promised the delivery of heat from the heat distribution system by ZČE The list of these clients is given in tables 3 and 3a and their location in the enclosed plan of the town The heat demands of these consumers taken over from the ZČE have been modified and reduced in respect of simultaneity and overestimation of real requirments for heat quantity taken from the system For the low balance prognosis these expected future demands were lowered by 25 % - see table 3a

- heat demands of objects that are at present supplied from their own boiler house burning solid and liquid fuels and that can be effectively connected to the hot water network of the system This can result in liquidation of these ineffective heat sources The basic data were given by an investigation carried through for Plzeň by RAEN enterprise The list of selected boiler houses is given in tables 4 and 4a Their location is shown in the town plan

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In tables 4 and 4a the heat demand has been determined from fuel consumed in the boiler house for each case The input of heat from the system has been derived from the individual characteristics of consumers from the purpose of heat demand and in respect to the existing installed capacity of the boilers The table 4a shows the reduced scope of these consumers (by 40 %) for the low balance prognosis

- in the Northern town new objects of municipal furnishings and services shall be connected to the already existing feeder North These objects shall be successively realized at completion of construction of these housing quarters New massive construction of flats in these localities is not considered

- to the hot water heat network of CP snall be connected the systems of the outlived coal boiler houses V1 and V2 (Doubravka and Letna) owned by the municipal heating enterprise TEZA This connection will be realized in 1995 (heating period 95 / 96) by the new feeder East From 1996 on along with this the heat delivery from the CP Plzeň to the hot water part of the heat plant South - Bory system is considered The connection to the feeder South already exists however it has not yet been put into operation due to commercial reasons No technical problems exist

It seems necessary to guarantee tne reliable all year delivery of steam from the CP to the steam system In operation according to high balance given in table 1a an increase of heat consumption after 1995 at Plzeň breweries is expected Beside tnis connection of a new enterprise Stavebni stroje (Construction Machinery Co) is expected

The heat demand of Železnični opravny (Railways Maintenance Co) and of Železnični depo (Depot) shall decrease in the future In case of low balance prognosis an increase in heat demand of breweries is not considered as well as the connection of Construction Machinery Co

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3 ENVIRONMENT PROTECTION IMPROVMENT AND RETROFITTING OF EXISTING BOILERS AT THE THIRD STAGE OF CONSTRUCTION - CP III

By the end of 1996 it will be necessary to make environment protection improvment and retrofit the existing boilers in CP Plzeň in order to meet the conditions stated by the new Environmental Act 309/91 concerning clean air policy and prevention against pollutants (limits were presented in Encl 2)

The change of fuel to low - sulphur bituminous coal from Plzeň basin - mine Zbůch (see data on tab 28) for hot water grate boilers K1 K2 K3 - 3x 35 MWt - CP I is prepared

Operation tests using this type of fuel have been carried out successfully

For CP II high pressure granulating (dry bottom) boilers K4 and K5 2x 170 t/h which will also in future be used as basic units of CP it will be necessary to implement flue gases desulphurisation equipment or to convert them to hard stone bituminous coal with low sulphur content According to the results of study made by ZCE in May the reconstruction of boilers and mills for bituminous coal in accordance to the offer of Prvni brněnska strojirna (First Brno Machinery Works) is more advantageous than the costly flue gases desulphuration plant Characteristic data of local Plzeň basin-mine Zbůch are shown in the table 28 In connection with the shift to the stone coal the boilers will be equipped with new baghouses with high efficiency of separation

As the reconstruction of high pressure granulating boilers has not yet been finally decided we consider the solution in alt B Var 2 where the fuel basis remains as before (lignite) and the granulating boiler is to be equipped with flue gas desulphurisation plant Assumed is a wet scrubber magnesite system of flue gas cleaning (FGD) - according to the offer of CHEPOS Brno

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Both cases will require a costly retrofitting which imply successive shutdown of boilers in the years 1995/96

Shutdown of a single boiler 170 t/h will result in output drop to 81 MWt when operating with turbine load 25 MW

For the time when environment protection systems are going to be installed at the high pressure boilers (1995 - 96) EGU suggests to install a low pressure dual fuel fired steam boiler (gas and oil) of the capacity 65 t/h = 43,7 MWt and steam parameters 1 3 MPa 220°C in the third stage of construction - CP III

In case of 170 t/h boiler shutdown the new boiler will cover the steam supply during the heating season In summer time the new boiler will supply both steam and hot water (by means of existing peak heat exchangers)

Additional capacity enlargment of the CP Plzeň during construction of the fourth stage makes possible to shutdown and liquidate all aged and environmentally unacceptable heating plants V1 V2 and Bory and also the boiler house of the Railway Maintenance Co

EGU recommends to extend tne installed thermal capacity of the CP Plzeň in the fourth stage through the following alternatives and variants

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4 ALTERNATIVE A VAR 1

4 1 Fourth stage of construction - CP IV

- construction 1995 1996
- operation in heating season 96/97

In respect to the initiatives of Siemens in Plzeň the possibility of using Siemens gas turbines in combined cycle has been taken into consideration

The enlargment of CP Plzeň in the fourth stage of construction - CP IV for heating season 1996/97 is solved by a large gas-steam Combined Cycle (according to Siemens offer) - see Fig S1

- 2 x GT V-64 3 Siemens - basic el output 2x 60 9 MW (ISO conditions)
  at local conditions and at ambient temperature -12 °C
  gross output 2 x 66 9 MW
- 2x steam double pressure exhaust heat recovery boiler
  thermal output 2 x 88 5 MWt
  high-pressure steam 8 1 MPa 505°C
  low-pressure steam 0 5 MPa 200°C
- 1x ST-double-pressure condensing steam turbine with two regulated heat extractions and reduced condensation part
  nominal power output 45 MW
  pressure range of 1 extraction 1 0-1 4 MPa
  pressure range of 2 extraction 0 06-0,12 MPa
  max thermal output of CC (at -12°C) 125 MWt
  max power output of CC (at -12°C) 168 4 MWe

CC will predominantly cover the basic heat supply in hot water into a DHS networks during work days of the heating period For work days in summer the CC will supply heat in both steam and hot water During weekends the CC shall be shut down

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The combined cycle makes possible to shut down the obsolete heating plants v1 and V2 the boiler house of the Railway Maintenance Co and the hot water part of the heating plant Bory- see tables 5 and 6

The heating plant Košutka can be shut down and used as a standby heat source

Similarly one of the hot water boiler in CP I - 35 MWt can be shut down

The operation of CP with CC can be seen in diagrams D1 and D2 - for high balance conditions and in diagrams D4 and D5 for low balance conditions The CC cooperates with the existing units in the CP and with the Brewery boiler house and supply both steam and hot water into the system

The gross electric power generation at CC and the existing back pressure turbine as well as the natural gas consumption are presented in diagram D3 (high balance) and D6 (low balance)

The results of production balance of heat and electricity in the CP and the corresponding fuel consumption in the selected characteristic years are in table 11 for the high balance and in table 12 for the low balance conditions Tables 11a and 12a give operational results of the sole combined cycle

4 2 Fifth stage of construction - CP V

- construction in years 2003 2004
- operation in the heating season 2004/05

The construction of the plant will be completed by installation of one dual fuel hot water boiler (gas and low sulphur content oil) Nominal capacity 58 MWt

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The new boiler shall replace the existing aged 2 x 35 MWt hot water grate boilers of CP I - see tables 5 and 6

In case of lower requirments on delivery of steam and water into the DHS (low balance prognosis) the erection of hot water boiler is not necessary - see table 6 and the fifth stage of CP reconstruction (CP V) need not be realized The demand on heat supply in hot water would be covered by the CC cooperating with the existing high pressure technology CP II and with a low pressure dual fuel boiler 65 t/h - CP III

In the steam system cooperates the Brewery boiler hause - see table 6b and table 29

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5 ALTERNATIVE A VAR 2

5 1 Fourth stage of construction - CP IV

- construction 1995 1996
- operation in heating season 96/97

The enlargment of CP Plzeň in the fourth stage of construction is solved by a small gas steam cycle with one gas turbine and one back-pressure steam turbine - see Fig S2

In this study has again been proposed a gas turbine of the Siemens production On basis of tender selection other unit of similar capacity can be chosen (Westinghouse ABB Alsthom etc)

- 1x GT V-64 3 Siemens-basic output 60 9 MW(ISO cond)
  output gross (in local conditions at ambient temperature -12°C) 66 9 MW
- 1 x steam double-pressure flue gas heat recovery boiler
  thermal output 88 5 MWt
  high-pressure steam 5 9 MPa 505°C
  low-pressure steam 0 5 MPa 200°C
- 1 x ST - double-pressure back-pressure steam turbine with one regulated steam extraction
  nominal power output on generator terminals 21 MW
  pressure range of extraction 1 0 - 1 4 MPa
  backpressure range 0 06 -0 12 MPa

max thermal output of the CC (at -12°C) 65 MWt
max power output of CC (at -12°C) 87 6 MW

CC will predominantly cover the basic heat demand in hot water delivered by DHS network during the work days of the heating period

- For work days in summer the CC will supply heat in both steam and hot water

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During the weekends and holidays the CC will be shut down

In case of low heat consumption in summer the CC operation will be possible by a cooling circuit

The heat accumulator levels up the heat supply in hot water during days and nights in the summer season

An application of back pressure turbine with additional cooling has been given a priority to a condensing turbine due to relatively low amount of heat delivered to condensation in comparison with permanent heat losses in condensation during an all year operation

Output demand for cooling unit is 18 - 20 MWt

The combined gas-steam cycle will permit to shut down and liquidate the obsolete coal heating plants V1 and v2 the boiler house of the Railway Maintenance Co and the hot water part of the heating plant Bory - see tables 7 and 8

The heating plant Košutka can be used as a stand-by heat source

In heat supply to the hot water and steam system cooperate the combined cycle and the existing technology of the CP - the high pressure steam cogeneration part CP II not water boilers CP I and the new dual fuel steam boiler CP III

In the steam supply to the system cooperates also the boiler house of the Breweries during the peak hours

The operation of the CP and CC and cooperating boilers is shown in diagrams D7 and D8 - for high balance conditions and in diagrams D10 and D11 for lower deliveries of heat in to the DHS - according the low balance prognosis

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The production of electric energy on turbogenerators terminals of the CC and the existing back pressure turbine and natural gas consumption in the CC are presented in diagrams D9 - for high balance and D12 - for low balance prognosis

The results of the heat and electricity balance in the CP and the corresponding consumption of fuels in the characteristic years of operation are calculated in table 13 - for high balance and in table 14 - for low balance The tables 13a and 14a bring the operational results of the sole gas-steam cycle

5 2 Fifth stage of construction - CP V

- construction 2003 2004
- operation in the heating season 2004/05

The construction of the plant will be finished by installing the dual fuel hot water boiler (gas and oil with low sulphur content)

In the case of higher heat demands according to high balance two hot water boilers of thermal output 2x58 MWt will be installed

At lower heat demands after the year 2000 according to low balance only one hot water boiler 58 MW installed in the fifth stage of construction will be necessary

New hot water boilers will replace the existing aged 3x 35 MWt hot water grate boilers CP I - see table 7 and 8

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6 ALTERNATIVE B

6 1 Fourth stage of construction CP IV

- construction 1995 1996
- operation in heating season 96/97

The enlargment of CP Plzeň is based on coal and solved by installing of

- 1 x atmospheric fluidized - bed steam boiler of 160 t/h = = 120,44 MWt

circofluid with parameters 13 63 MPa 540°C

The new boiler will burn the Northbohemian or Westbohemian low grade lignite

The characteristic data of the fuel is in table 28

- 1 x condensing steam turbine with two regulated heat extractions

el output on generator terminals	32 MW
admission parameters of steam	12 75MPa 535°C
1 regulated extraction in range	1 0 - 1 4 MPa
2 regulated extraction in range	0 06 - 0 12 MPa

The turbine has a reduced condensation part

Max thermal output of the new steam unit in steam and hot water 75 MWt

The general schematic diagram of the CP Plzeň is shown in Fig S3

The extraction condensation turbine serves as a first stage in heating up the circulating water The existing back pressure

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turbine 55 MW CP II serves as a second stage In this manner the operational results given in tables 15 and 16 have been calculated

Better results in warming the circulating water could be reached with the opposite serial connection of turbines

In the first stage should be ranged the existing back-pressure turbine (this turbine can work with the back pressure as low as 0 03 MPa) In the second stage should work the new condensation extraction turbine In the third stage the hot water boilers and a peak load steam heat exchanger are connected

After installation of the new steam unit it will be possible to shut down the aged heating plants V1 and V2 hot water section of Bory heating plant in hot water system and the boiler house of the Railway Maint Comp in the steam network - see tables 9 - high balance and 10 low balance

The peak heat plant Košutka makes a load reserve

The new cogeneration unit with fluidized bed boiler will cover the basic load in hot water and steam supply

With the new CP unit cooperate in heat delivery (both hot water and steam) the existing CP units - see diagrams D13 and D14 In period of winter peak load and with higher demand on heat delivery (high balance prognosis) even the Brewery boiler house capacity assists partially to cover the needs

As it has not yet been decided about the environment protection measures that are to be implemented at the existing granulating boiler CP II two variants have been evaluated

<u>In variant 1</u> similarly as in Alt A operation of boilers and coal mills reconstructed to use the local Plzeň stone coal with

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low sulphur content has been considered and evaluated - characteristics of the fuel - see tab 28

In Variant 2 operation of the granulating boilers burning the Sokolov lignite of the same quality as at present (see tab 28) has been evaluated The boilers are considered to be equipped with desulphurisation plant with wet wash of gases and with new ash handling equipment

The operational results of the CP Alt B Var 1 are given in tables 15 (high balance) and 16 (low balance)

The operational results of the CP in Var 2 are given in tables 17 (high balance) and 18 (low balance)

6 2 Fifth stage of construction CP V

- construction 2003 2004
- operation heating season 2004/05

Construction of the plant will be completed by installing the dual fuel hot water boilers In the case of higher heat demands according to high balance two hot water boilers of thermal output 2 x 58 MWt will have to be installed

In case of low balance prognosis the heat demand after the year 2000 will require an installation of only one hot water boiler 58 MWt (fifth stage of construction)

New hot water boilers will replace the existing aged 3 x 35 MWt hot water grate boilers CP I - see table 9 and 10

Prague August 1993

EGU Praha a s
Stanislav Kalouš

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Heat balance DHS Plzeň hot water high balance										Tab 1 a)
Year		1992	1993	1994	1995	1996	1997	2000	2005	2010
Pipe line North										
Exist consumers	MWt	133 0	127 0	123 0	121 0	120 0	117 5	113 1	113 1	113 1
New consumers										
promised	MWt			0 5	0 7	0 7	2 5	2 5	2 5	2 5
connected boilers	MWt				4 4	4 4	4 4	4 4	4 4	4 4
new comercial	MWt				1 9	2 9	4 0	12 5	15 1	17 1
Total	MWt	133 0	127 0	123 5	128 0	128 0	128 4	132 5	135 1	137 1
Pipe line South										
Exist consumers	MWt	74 0	70 7	68 4	67 3	66 8	65 4	62 9	62 9	62 9
New consumers										
promised	MWt		3 0	12 8	14 8	16 7	17 8	17 8	17 8	17 8
connected boilers	MWt			2 9	5 4	7 8	9 5	9 5	9 5	9 5
HP Bory hot water part	MWt					22 9	22 9	21 4	21 4	21 4
Total	MWt	74 0	73 7	84 1	87 5	114 2	115 6	111 6	111 6	111 6
Pipe line East										
HP V1+V2	MWt					39 5	39 5	39 5	39 4	39 4
New consumers										
promised	MWt					5 6	7 1	7 1	7 1	7 1
connected boilers	MWt					4 5	5 1	8 8	8 8	8 8
Total	MWt					49 6	51 7	55 4	55 3	55 3
Hot water demands brutto	MWt	207 0	200 7	207 6	215 5	291 8	295 7	299 5	302 0	304 0
	TJ/y	1990	1935	1998	2074	2801	2836	2871	2889	2906
Network losses	MWt	11 7	11 7	11 7	12 2	15 8	16 0	16 2	16 3	16 4
	TJ/y	215	217	217	226	293	297	300	303	305
Netto demands	MWt	195 3	189 0	195 9	203 3	276 0	279 7	283 3	285 7	287 6
	TJ/y	1775	1718	1781	1848	2509	2539	2571	2586	2601

Heat balance Plzeň steam high balance										Tab 1 b)
Year		1992	1993	1994	1995	1996	1997	2000	2005	2010
Brevery	MWt	58 7	58 7	58 7	58 7	62 0	64 3	64 3	64 3	64 3
Railways Maint Co	MWt	29 1	28 5	28 0	27 5	27 0	25 6	25 6	25 6	25 6
Depot	MWt	5 2	5 1	5 0	4 9	4 8	4 6	4 6	4 6	4 6
Construction machinery Co	MWt					6 0	5 5	5 5	5 1	5 1
Steam demands brutto	MWt	93 0	92 3	91 7	91 1	99 8	100 0	100 0	99 6	99 6
	TJ/y	1125	1117	1109	1102	1207	1300	1300	1290	1290
Network losses	MWt	4 9	4 9	4 9	4 9	5 2	5 2	5 2	5 2	5 2
	TJ/y	140	140	140	140	150	150	150	150	150
Netto demands	MWt	88 1	87 4	86 8	86 2	94 6	94 8	94 8	94 4	94 4
	TJ/y	985	977	969	962	1057	1150	1150	1140	1140

Abreviations

BH Boiler House
HWB Hot Water Boiler
SB Steam Boiler
CP Cogeneration Plant
HP Heating Plant
CC Combined Cycle
HPP High Pressure Part of CP

Heat balance DHS Plzeň hot water low balance										Tab 2 a)
Year		1992	1993	1994	1995	1996	1997	2000	2005	2010
Pipe line North										
Exist consumers	MWt	133 0	127 0	123 0	120 0	118 0	115 0	108 0	106 0	106 0
New consumers										
promised	MWt			0 4	0 5	0 5	1 9	1 9	1 9	1 9
connected boilers	MWt				3 5	3 5	3 5	3 5	3 5	3 5
new comercial	MWt				1 0	1 0	1 0	1 0	1 0	1 0
Total	MWt	133 0	127 0	123 4	125 0	123 0	121 4	114 4	112 4	112 4
Pipe line South										
Exist consumers	MWt	74 0	70 7	68 0	66 5	66 0	64 0	59 9	59 2	59 2
New consumers										
promised	MWt		2 3	9 6	11 1	12 5	13 4	13 4	13 4	13 4
connected boilers	MWt			1 7	3 2	4 7	5 7	5 7	5 7	5 7
HP Bory hot water part	MWt					22 9	22 9	20 7	20 7	20 7
Total	MWt	74 0	72 9	79 3	80 8	106 1	106 0	99 7	99 0	99 0
Pipe line East										
HP V1+V2	MWt					39 5	39 4	37 2	37 2	37 2
New consumers										
promised	MWt					4 2	5 3	5 3	5 3	5 3
connected boilers	MWt						0 6	2 2	3 4	3 4
Total	MWt					43 7	45 3	44 7	45 9	45 9
Hot water demands brutto	MWt	207 0	199 9	202 7	205 8	272 8	272 7	258 8	257 3	257 3
	TJ/y	1990	1928	1953	1984	2619	2616	2491	2471	2471
Network losses	MWt	11 7	11 7	11 7	11 9	14 7	14 7	15 0	15 0	15 0
	TJ/y	215	217	217	221	273	273	278	278	278
Netto demands	MWt	195 3	188 2	191 0	193 9	258 1	257 9	243 8	242 3	242 3
	TJ/y	1775	1711	1737	1763	2346	2343	2213	2193	2193

Heat balance Plzeň steam low balance										Tab 2 b)
Year		1992	1993	1994	1995	1996	1997	2000	2005	2010
Brevery	MWt	58 7	58 7	58 7	58 7	58 7	58 7	58 7	58 7	58 7
Railways Maint Co	MWt	29 1	28 5	28 0	27 5	27 0	25 6	25 6	25 6	25 6
Depot	MWt	5 2	5 1	5 0	4 9	4 8	4 6	4 6	4 6	4 6
Steam demands brutto	MWt	93 0	92 3	91 7	91 1	90 5	88 9	88 9	88 9	88 9
	TJ/y	1125	1115	1110	1100	1095	1075	1075	1075	1075
Network losses	MWt	4 9	4 9	4 9	4 9	4 9	4 9	4 9	4 9	4 9
	TJ/y	140	140	140	140	140	140	140	140	140
Netto demands	MWt	88 1	87 4	86 8	86 2	85 6	84 0	84 0	84 0	84 0
	TJ/y	985	975	970	960	955	935	935	935	935

Abreviations

BH Boiler House
HWB Hot Water Boiler
SB Steam Boiler
CP Cogeneration Plant
HP Heating Plant
CC Combined Cycle
HPP High Pressure Part of CP

Heat supply promised from DHS ZČE up to 1996
High balance

Tab 3

Autlet No	Applicant (customer)	Adress of the customer	Start up	Demand GJ/y	Requested therm power kWt	Reduced therm power kWt
PIPELINE SOUTH						
1	Magistrát města	Lukavická 9	09/1993	4015	544	435 2
2	Magistrát města	Čechova 28	09/1993	1231	191	152 8
3	Magistrát města	Pod Záhorskem 26	09/1993	11247	3050	2440 0
4	Min školství	Gymnázium Petákova 2	1993	9000	2566	2052 8
5	Vojenská nemocnice	Sklad Kozinova 6	09/1993	800	130	104 0
6	Min zdravotnictví	I pol Denisovo nábř	1993	8580	2000	1600 0
7	Plzeňské komunikace	Preslova 13	1993	828	210	168 0
8	Min školství	Chodské nám 1 (navyš)	1993	13005	1880	1504 0
9	RECOOP TOUR a s Praha	Sady 5 května	1993	29299	3045	2436 0
10	SČM výrob družstev	Radobyčická 24	1993	4500	700	560 0
11	Kmart ČR a s Praha	OD Prior Americká 47	1993	12000	1800	1440 0
15	Škoda a s Plzeň	Zimní stadion	1994	12500	2273	1818 4
16		OD + garáže Gerská	1995	13772	2500	2000 0
19	Min hospodářství	Dům obuvi Americká	?	1876	1240	992 0
20	ISRAM s r o Plzeň	Štruncovy sady	?	1100	150	120 0
TOTAL				123753	22279	
Reduced power						17823 2
PIPELINE NORTH						
12	Min stavebnictví	Stř GERA + garáže	1993/1994	2880	570	456 0
13	CURAMED	EDEKA Plzeň Bolevec	1994	1470	260	208 0
18	Spr pošt a telekom	SOU spojů Lochotín	1996	15000	2260	1808 0
TOTAL				19350	3090	
Reduced power						2472 0
PIPELINE EAST						
14	Min průmyslu CR	Stavební stroje	1994	28588	7000	5600 0
17	Min průmyslu CR	EPRO s p Cvokařská 10	1995	9800	1900	1520 0
TOTAL				38388	8900	
Reduced power						7120 0
TOTAL				181491	34269	
Reduced power						27415 2

Heat supply promised from DHS ZČE up to 1996

Low balance

Tab 3a

Outlet No	Applicant (customer)	Adress of the customer	Start up	Demand GJ/y	Requested therm power kWt	Reduced therm power kWt
PIPELINE SOUTH						
1	Magistrát města	Lukavická 9	09/1993	2409	544	326 4
2	Magistrát města	Čechova 28	09/1993	739	191	114 6
3	Magistrát města	Pod Záhorskem 26	09/1993	6748	3050	1830 0
4	Min školství	Gymnázium Petákova 2	1993	5400	2566	1539 6
5	Vojenská nemocnice	Sklad Kozinova 6	09/1993	480	130	78 0
6	Min zdravotnictví	I pol Denisovo nábř	1993	5148	2000	1200 0
7	Plzeňské komunikace	Preslova 13	1993	497	210	126 0
8	Min školství	Chodské nám 1 (navýš)	1993	7803	1880	1128 0
9	RECOOP TOUR a s Praha	Sady 5 května	1993	17579	3045	1827 0
10	SČM vyrob družstev	Radobyčická 24	1993	2700	700	420 0
11	Kmart CR a s Praha	OD Prior Americká 47	1993	7200	1800	1080 0
15	Škoda a s Plzeň	Zimní stadion	1994	7500	2273	1363 8
16		OD + garáže Gerská	1995	8263	2500	1500 0
19	Min hospodářství	Dům obuvi Americká	?	1126	1240	744 0
20	ISRAM s r o Plzeň	Štruncovy sady	?	660	150	90 0
TOTAL				74252	22279	
Reduced power						13367 4
PIPELINE NORTH						
12	Min stavebnictví	Stř CERA + garáže	1993/1994	1728	570	342 0
13	CURAMED	EDEKA Plzeň Bolevec	1994	882	260	156 0
18	Spr pošt a telekom	SOU spojů Lochotín	1996	9000	2260	1356 0
TOTAL				11610	3090	
Reduced power						1854 0
PIPELINE EAST						
14	Min průmyslu CR	Stavební stroje	1994	17153	7000	4200 0
17	Min průmyslu CR	EPRO s p Cvokařská 10	1995	5880	1900	1140 0
TOTAL				23033	8900	
Reduced power						5340 0
TOTAL				108895	34269	
Reduced power						20561 4

Local Boilers suitable to be connected to DHS ZCE high balance Tab 4

No	Boilers	Inst therm output kWt	Fuel	Heat value MJ/kg	Consumtion t/y	GJ/y	Efficiency %	Demannd GJ/y	Time factor h/y	Power kWt
PIPELINE SOUTH										
10		4640	HU	14 5	815	11817 5	0 73	8626 8	2200	1089 2
12		4610	HU	14 5	1566	22707 0	0 73	16576 1	2000	2302 2
40		2320	HU	14 5	47	681 5	0 73	497 5	2200	62 8
46		2158	HU	14 5	500	7250 0	0 73	5292 5	2200	668 2
75		1000	HU	14 5	147	2131 5	0 73	1556 0	2200	196 5
76		990	KOKS	26 4	243	6415 2	0 73	4683 1	2200	591 3
78		954	KOKS	26 4	233	6151 2	0 73	4490 4	2200	567 0
84		874	KOKS	26 4	174	4593 6	0 73	3353 3	2200	423 4
96		750	KOKS	26 4	154	4065 6	0 73	2967 9	2200	374 7
112		636	KOKS	26 4	232	6124 8	0 73	4471 1	2200	564 5
117		636	HU	14 5	560	8120 0	0 73	5927 6	2100	784 1
131		543	HU	15 0	112	1680 0	0 73	1226 4	2200	154 8
134		524	KOKS	26 4	61	1610 4	0 73	1175 6	2000	163 3
160		708	HU	15 0	132	1980 0	0 73	1445 4	2200	182 5
174		353	KOKS	26 4	69	1821 6	0 73	1329 8	2200	167 9
181		318	HU	15 0	80	1200 0	0 73	876 0	2200	110 6
183		318	KOKS	26 4	85	2244 0	0 73	1638 1	2200	206 8
184		318	HU	15 0	93	1395 0	0 73	1018 4	2200	128 6
200		295	KOKS	26 4	56	1478 4	0 73	1079 2	2200	136 3
202		280	KOKS	26 4	60	1584 0	0 73	1156 3	2100	153 0
205		273	KOKS	26 4	14	369 6	0 73	269 8	2200	34 1
207		272	HU	15 0	81	1215 0	0 73	887 0	2200	112 0
220		234	LTO	41 5	3	124 5	0 8	99 6	1000	27 7
222		234	HU	16	66	1056 0	0 73	770 9	2200	97 3
223		234	LTO	41 5	3	124 5	0 8	99 6	1000	27 7
225		232	KOKS	26 4	30	792 0	0 73	578 2	2400	66 9
226		232	KOKS	26 4	50	1320 0	0 73	963 6	2400	111 5
TOTAL		24936						73056 1	2135	9504 9
PIPELINE NORTH										
3		8730	LTO	41 5	1041	43201 5	0 8	34561 2	2200	4363 8
TOTAL		8730						34561 2	2200	4363 8
PIPELINE EAST										
1		10590	SP x	14 6	1629	23780 1	0 81	19261 9	1200	4458 8
6		5820	HU	14 5	304	4408 0	0 73	3217 8	2000	446 9
13		4210	HU	14 5	350	5075 0	0 73	3704 8	2000	514 5
20		3480	HU	14 5	857	12426 5	0 73	9071 3	2000	1259 9
27		3060	HU	14 5	1011	14659 5	0 73	10701 4	2200	1351 2
72		1050	HU	14 5	65	942 5	0 73	688 0	2000	95 6
106		680	KOKS	26 4	60	1584 0	0 73	1156 3	2000	160 6
129		544	KOKS	26 4	88	2323 2	0 73	1695 9	2200	214 1
169		375	KOKS	26 4	127	3352 8	0 73	2447 5	2200	309 0
TOTAL		29809						51945 1	1638	8810 7
BOILERS TOTAL		63475						159562 3	1954	22679 4

x fuel consumtion in 10^3 m^3/y HU lignite, KOKS coke LTO fuel oil light SP city gas

Local Boilers suitable to be connected to DHS ZCE low balance

Tab 4a

No	Boilers	Inst therm output kWt	Fuel	Heat value MJ/kg	Consumption t/y	Consumption GJ/y	Efficiency %	Demannd GJ/y	Time factor h/y	Power kWt
PIPELINE SOUTH										
10		4640	HU	14 5	791	11463 0	0 73	8368 0	2200	1056 6
46		2158	HU	14 5	485	7032 5	0 73	5133 7	2200	648 2
75		1000	HU	14 5	143	2067 6	0 73	1509 3	2200	190 6
76		990	KOKS	26 4	236	6222 7	0 73	4542 6	2200	573 6
78		954	KOKS	26 4	226	5966 7	0 73	4355 7	2200	550 0
96		750	KOKS	26 4	149	3943 6	0 73	2878 9	2200	363 5
112		636	KOKS	26 4	225	5941 1	0 73	4337 0	2200	547 6
117		636	HU	14 5	543	7876 4	0 73	5749 8	2100	760 6
131		543	HU	15 0	109	1629 6	0 73	1189 6	2200	150 2
174		353	KOKS	26 4	67	1767 0	0 73	1289 9	2200	162 9
181		318	HU	15 0	78	1164 0	0 73	849 7	2200	107 3
184		318	HU	15 0	90	1353 2	0 73	987 8	2200	124 7
200		295	KOKS	26 4	54	1434 0	0 73	1046 9	2200	132 2
205		273	KOKS	26 4	14	358 5	0 73	261 7	2200	33 0
207		272	HU	15 0	79	1178 6	0 73	860 3	2200	108 6
222		234	HU	16 0	64	1024 3	0 73	747 8	2200	94 4
226		232	KOKS	26 4	49	1280 4	0 73	934 7	2400	108 2
TOTAL		14602						45043 2	2190	5712 0
PIPELINE NORTH										
3		8730	LTO	41 5	833	34561 2	0 80	27649 0	2200	3491 0
TOTAL		8730						27649 0	2200	3491 0
PIPELINE EAST										
6		5820	HU	14 5	243	3526 4	0 73	2574 3	2000	357 5
13		4210	HU	14 5	280	4060 0	0 73	2963 8	2000	411 6
20		3480	HU	14 5	686	9941 2	0 73	7257 1	2000	1007 9
27		3060	HU	14 5	809	11727 6	0 73	8561 1	2200	1081 0
106		680	KOKS	26 4	48	1267 2	0 73	925 1	2000	128 5
129		544	KOKS	26 4	70	1858 6	0 73	1356 7	2200	171 3
169		375	KOKS	26 4	102	2682 2	0 73	1958 0	2200	247 2
TOTAL		18169 0						25596 0	2088	3405 0
BOILERS TOTAL		41501 0						98288 3	2165	12608 1

x fuel consumption in 10^3 m^3/y, HU lignite, KOKS coke LTO fuel oil light SP city gas

Alternative A var 1 Heat supply hot water high balance								Tab 5 a)
Year		1992	1995	1996	1997	2000	2005	2010
Hot water demands brutto	MWt	207 0	215 5	291 8	295 7	299 5	302 0	304 0
	TJ/y	1990	2074	2801	2836	2871	2889	2906
Heat supply								
CP Plzeň I HWB	MWt	105 0	105 0	105 0	70 0	70 0		
	TJ/y	670	750	1100	270	275		
II HPP	MWt	95 0	70 0	70 0	62 0	62 0	76 0	78 0
	TJ/y	1311	1245	1460	974	996	845	850
III SB 65 t/h	MWt				38 7	42 5	43 0	43 0
	TJ/y				32	35	38	40
IV CC 2 x V 64 3	MWt				125 0	125 0	125 0	125 0
	TJ/y				1560	1565	1740	1746
V HWB	MWt						58 0	58 0
	TJ/y						266	270
CP Plzeň total	MWt	200 0	175 0	175 0	295 7	299 5	302 0	304 0
	TJ/y	1981	1995	2560	2836	2871	2889	2906
Interconennected units								
Peak HP Košutka	MWt	7 0	32 0	32 0				
HP Bory	MWt			30 0				
HP V1 + V2	MWt			45 0				
Interconennected units total	MWt	7 0	32 0	107 0				
	TJ/y	9	79	241				
Units total	MWt	207 0	207 0	282 0	295 7	299 5	302 0	304 0
	TJ/y	1990	2074	2801	2836	2871	2889	2906
Not covered	MWt	0 0	8 5	9 8	0 0	0 0	0 0	0 0

Alternative A var 1 Heat supply steam high balance								Tab 5 b)
Year		1992	1995	1996	1997	2000	2005	2010
Heat balance Plzeň steam	MWt	93 0	91 1	99 8	100 0	100 0	99 6	99 6
	TJ/y	1125	1102	1207	1300	1300	1290	1290
Heat supply								
CP Plzeň II HPP	MWt	70 0	11 0	11 0	100 0	100 0	89 0	87 0
	TJ/y	730	500	540	889	889	898	897
III SB 65 t/h	MWt		43 5	43 5	(41 5)	(41 5)	(41 5)	(41 5)
	TJ/y		467	500	193	193	190	190
IV CC 2 x V 64 3	MWt				(38 5)	(38 5)	(38 5)	(38 5)
	TJ/y				195	195	192	192
CP Plzeň total	MWt	70 0	54 5	54 5	100 0	100 0	89 0	87 0
	TJ/y	730	967	1040	1277	1277	1280	1279
Interconennected units								
BH Brevery	MWt	23 0	36 6	45 3	(30)	(30)	10 6	12 6
	TJ/y	395	135	167	23	23	10	11
Units total	MWt	93 0	91 1	99 8	100 0	100 0	99 6	99 6
	TJ/y	1125	1102	1207	1300	1300	1290	1290
Not covered	MWt	0 0	0 0	0 0	0 0	0 0	0 0	0 0

Abreviations

SB Steam Boiler
BH Boiler House
HWB Hot Water Boiler
CC Combined Cycle
HPP High Pressure Part of CP

Alternative A var 1 Heat supply hot water low balance								Tab 6 a)
Year		1992	1995	1996	1997	2000	2005	2010
Hot water demands brutto	MWt	207 0	205 8	272 8	272 7	258 8	257 3	257 3
	TJ/y	1990	1984	2619	2616	2491	2471	2471
Heat supply								
CP Plzeň I HWB	MWt	105 0	105 0	105 0	70 0	70 0		
	TJ/y	670	700	1034	275	262		
II HPP	MWt	95 0	68 8	70 0	75 0	68 0	109 3	109 3
	TJ/y	1311	1180	1365	1046	1005	1070	1070
III SB 65 t/h	MWt				22 7	15 8	43 0	43 0
	TJ/y				20	19	21	21
IV CC 2 x V 64 3	MWt				105 0	105 0	105 0	105 0
	TJ/y				1275	1205	1380	1380
CP Plzeň total	MWt	200 0	173 8	175 0	272 7	258 8	257 3	257 3
	TJ/y	1981	1880	2399	2616	2491	2471	2471
Interconennected units								
Peak HP Košutka	MWt	7 0	32 0	32 0				
HP Bory	MWt			23 8				
HP V1 + V2	MWt			42 0				
Interconennected units total	MWt	7 0	32 0	97 8				
	TJ/y	9	104	220				
Units total	MWt	207 0	205 8	272 8	272 7	258 8	257 3	257 3
	TJ/y	1990	1984	2619	2616	2491	2471	2471
Not covered	MWt	0 0	0 0	0 0	0 0	0 0	0 0	0 0

Alternative A var 1 Heat supply steam low balance								Tab 6 b)
Year		1992	1995	1996	1997	2000	2005	2010
Heat balance Plzeň steam	MWt	93 0	91 1	90 5	88 9	88 9	88 9	88 9
	TJ/y	1125	1100	1095	1075	1075	1075	1075
Heat supply								
CP Plzeň II HPP	MWt	70 0	12 2	11 0	68 9	68 9	55 7	55 7
	TJ/y	730	500	500	612	612	603	603
III SB 65 t/h	MWt		43 5	43 5	(27 1)	(27 1)	(27 1)	(27 1)
	TJ/y		465	460	56	56	50	50
IV CC 2 x V 64 3	MWt				20	20	20	20
	TJ/y				407	407	407	407
CP Plzeň total	MWt	70 0	55 7	54 5	88 9	88 9	75 7	75 7
	TJ/y	730	965	960	1075	1075	1060	1060
Interconennected units								
BH Brevery boiler plant	MWt	23 0	35 4	36 0			13 2	13 2
	TJ/y	395	135	135			15	15
Units total	MWt	93 0	91 1	90 5	88 9	88 9	88 9	88 9
	TJ/y	1125	1100	1095	1075	1075	1075	1075
Not covered	MWt	0 0	0 0	0 0	0 0	0 0	0 0	0 0

Abreviations
SB Steam Boiler
BH Boiler House
HWB Hot Water Boiler
CC Combined Cycle
HPP High Pressure Part of CP

Alternative A var 2 Heat supply hot water high balance								Tab 7 a)
Year		1992	1995	1996	1997	2000	2005	2010
Hot water demands brutto	MWt	207 0	215 5	291 8	295 7	299 5	302 0	304 0
	TJ/y	1990	2074	2801	2836	2871	2889	2906
Heat supply								
CP Plzeň I HVB	MWt	105 0	105 0	105 0	105 0	105 0		
	TJ/y	670	750	1100	482	486		
II HPP	MWt	95 0	70 0	70 0	82 7	86 5	78 0	80 0
	TJ/y	1311	1245	1460	1230	1247	1243	1250
III SB 65 t/h	MWt				43 0	43 0	43 0	43 0
	TJ/y				34	35	36	36
IV CC 1 x V 64 3	MWt				65 0	65 0	65 0	65 0
	TJ/y				1090	1103	1115	1120
V HVB	MWt						116 0	116 0
	TJ/y						495	500
CP Plzeň total	MWt	200 0	175 0	175 0	295 7	299 5	302 0	304 0
	TJ/y	1981	1995	2560	2836	2871	2889	2906
Interconennected units								
Peak HP Košutka	MWt	7 0	32 0	32 0				
HP Bory	MWt			30 0				
HP V1 + V2	MWt			45 0				
Interconennected units total	MWt	7 0	32 0	107 0				
	TJ/y	9	79	241				
Units total	MWt	207 0	207 0	282 0	295 7	299 5	302 0	304 0
	TJ/y	1990	2074	2801	2836	2871	2889	2906
Not covered	MWt	0 0	8 5	9 8	0 0	0 0	0 0	0 0

Alternative A var 2 Heat supply steam high balance								Tab 7 b)
Year		1992	1995	1996	1997	2000	2005	2010
Heat balance Plzeň steam	MWt	93 0	91 1	99 8	100 0	100 0	99 6	99 6
	TJ/y	1125	1102	1207	1300	1300	1290	1290
Heat supply								
CP Plzeň II HPP	MWt	70 0	11 0	11 0	78 5	78 5	85 0	85 0
	TJ/y	730	500	540	850	850	886	886
III SB 65 t/h	MWt		43 5	43 5	(41 5)	(41 5)	(41 5)	(41 5)
	TJ/y		467	500	285	285	285	285
IV CC 1 x V 64 3	MWt				(25 0)	(25 0)	(25 0)	(25 0)
	TJ/y				100	100	100	100
CP Plzeň total	MWt	70 0	54 5	54 5	78 5	78 5	85 0	85 0
	TJ/y	730	967	1040	1235	1235	1271	1271
Interconennected units								
BH Brevery	MWt	23 0	36 6	45 3	21 5	21 5	14 6	14 6
	TJ/y	395	135	167	65	65	19	19
Units total	MWt	93 0	91 1	99 8	100 0	100 0	99 6	99 6
	TJ/y	1125	1102	1207	1300	1300	1290	1290
Not covered	MWt	0 0	0 0	0 0	0 0	0 0	0 0	0 0

Abreviations
SB Steam Boiler
BH Boiler House
HVB Hot Water Boiler
CC Combined Cycle
HPP High Pressure Part of CP

Alternative A var 2 Heat supply hot water low balance								Tab 8 a)
Year		1992	1995	1996	1997	2000	2005	2010
Hot water demands brutto	MWt	207 0	205 8	272 8	272 7	258 8	257 3	257 3
	TJ/y	1990	1984	2619	2616	2491	2471	2471
Heat supply								
CP Plzeň I HWB	MWt	105 0	105 0	105 0	105 0	104 8		
	TJ/y	670	700	1034	270	255		
II HPP	MWt	95 0	68 8	70 0	89 0	89 0	91 3	91 3
	TJ/y	1311	1180	1365	1206	1160	1160	1160
III SB 65 t/h	MWt				13 7	(15 9)	43 0	43 0
	TJ/y				20	8	42	42
IV CC 1 x V 64 3	MWt				65 0	65 0	65 0	65 0
	TJ/y				1120	1068	1060	1060
V HWB	MWt						58 0	58 0
	TJ/y						209	209
CP Plzeň total	MWt	200 0	173 8	175 0	272 7	258 8	257 3	257 3
	TJ/y	1981	1880	2399	2616	2491	2471	2471
Interconennected units								
Peak HP Košutka	MWt	7 0	32 0	32 0				
HP Bory	MWt			23 8				
HP V1 + V2	MWt			42 0				
Interconennected units total	MWt	7 0	32 0	97 8				
	TJ/y	9	104	220				
Units total	MWt	207 0	205 8	272 8	272 7	258 8	257 3	257 3
	TJ/y	1990	1984	2619	2616	2491	2471	2471
Not covered	MWt	0 0	0 0	0 0	0 0	0 0	0 0	0 0

Alternative A var 2 Heat supply steam low balance								Tab 8 b)
Year		1992	1995	1996	1997	2000	2005	2010
Heat balance Plzeň steam	MWt	93 0	91 1	90 5	88 9	88 9	88 9	88 9
	TJ/y	1125	1100	1095	1075	1075	1075	1075
Heat supply								
CP Plzeň II HPP	MWt	70 0	12 2	11 0	70 0	70 0	70 0	70 0
	TJ/y	730	500	500	735	735	722	722
III SB 65 t/h	MWt		43 5	43 5	18 9	18 9	(34 1)	(34 1)
	TJ/y		465	460	180	180	150	150
IV CC 1 x V 64 3	MWt				(31 8)	(31 8)	(31 8)	(31 8)
	TJ/y				160	160	160	160
CP Plzeň total	MWt	70 0	55 7	54 5	88 9	88 9	70 0	70 0
	TJ/y	730	965	960	1075	1075	1032	1032
Interconennected units								
BH Brevery	MWt	23 0	35 4	36 0			18 9	18 9
	TJ/y	395	135	135			43	43
Units total	MWt	93 0	91 1	90 5	88 9	88 9	88 9	88 9
	TJ/y	1125	1100	1095	1075	1075	1075	1075
Not covered	MWt	0 0	0 0	0 0	0 0	0 0	0 0	0 0

Abreviations
SB Steam Boiler
BH Boiler House
HWB Hot Water Boiler
CC Combined Cycle
HPP High Pressure Part of CP

Alternative B Heat supply hot water high balance								Tab 9 a)
Year		1992	1995	1996	1997	2000	2005	2010
Hot water demands brutto	MWt	207 0	215 5	291 8	295 7	299 5	302 0	304 0
	TJ/y	1990	2074	2801	2836	2871	2889	2906
Heat supply								
CP Plzeň I HWB	MWt	105 0	105 0	105 0	105 0	105 0		
	TJ/y	670	750	1100	155	155		
II HPP	MWt	95 0	70 0	70 0	160 5	160 5	155 4	155 4
	TJ/y	1311	1245	1460	2031	2066	1999	2016
IV FSB + TG 32MW	MWt				28 0	28 0	28 0	28 0
	TJ/y				650	650	650	650
V HWB	MWt						116 0	116 0
	TJ/y						240	240
CP Plzeň total	MWt	200 0	175 0	175 0	293 5	293 5	299 4	299 4
	TJ/y	1981	1995	2560	2836	2871	2889	2906
Interconennected units								
Peak HP Košutka	MWt	7 0	32 0	32 0				
HP Bory	MWt			30 0				
HP V1 + V2	MWt			45 0				
Interconennected units total	MWt	7 0	32 0	107 0				
	TJ/y	9	79	241				
Units total	MWt	207 0	207 0	282 0	293 5	293 5	299 4	299 4
	TJ/y	1990	2074	2801	2836	2871	2889	2906
Not covered	MWt	0 0	8 5	9 8	2 2	6 0	2 6	4 6

Alternative B Heat supply steam high balance								Tab 9 b)
Year		1992	1995	1996	1997	2000	2005	2010
Heat balance Plzeň steam	MWt	93 0	91 1	99 8	100 0	100 0	99 6	99 6
	TJ/y	1125	1102	1207	1300	1300	1290	1290
Heat supply								
CP Plzeň II HPP	MWt	70 0	11 0	11 0	(19 5)	(19 5)	9 6	9 6
	TJ/y	730	500	540	308	308	314	314
III SB 65 t/h	MWt		43 5	43 5	43 0	43 0	43 0	43 0
	TJ/y		467	500	150	150	150	150
IV FSB + TG 32MW	MWt				47 0	47 0	47 0	47 0
	TJ/y				828	828	826	826
CP Plzeň total	MWt	70 0	54 5	54 5	90 0	90 0	99 6	99 6
	TJ/y	730	967	1040	1286	1286	1290	1290
Interconennected units								
BH Brevery	MWt	23 0	36 6	45 3	10 0	10 0		
	TJ/y	395	135	167	14	14		
Units total	MWt	93 0	91 1	99 8	100 0	100 0	99 6	99 6
	TJ/y	1125	1102	1207	1300	1300	1290	1290
Not covered	MWt	0 0	0 0	0 0	0 0	0 0	0 0	0 0

Abreviations
SB Steam Boiler
FSB Fluidized Bed Steam Boiler
BH Boiler House
HWB Hot Water Boiler
CC Combined Cycle
HPP High Pressure Part of CP

Alternative B Heat supply hot water low balance								Tab 10 a)
Year		1992	1995	1996	1997	2000	2005	2010
Hot water demands brutto	MWt	207 0	205 8	272 8	272 7	258 8	257 3	257 3
	TJ/y	1990	1984	2619	2616	2491	2471	2471
Heat supply								
CP Plzeň I HWB	MWt	105 0	105 0	105 0	70 0	70 0		
	TJ/y	670	700	1034	150	122		
II HPP	MWt	95 0	68 8	70 0	165 0	160 8	165 0	165 0
	TJ/y	1311	1180	1365	1816	1749	1751	1751
IV FSB +TG 32MW	MWt				28 0	28 0	28 0	28 0
	TJ/y				650	620	620	620
V HWB	MWt						58 0	58 0
	TJ/y						100	100
CP Plzeň total	MWt	200 0	173 8	175 0	263 0	258 8	251 0	251 0
	TJ/y	1981	1880	2399	2616	2491	2471	2471
Interconennected units								
Peak HP Košutka	MWt	7 0	32 0	32 0				
HP Bory	MWt			23 8				
HP V1 + V2	MWt			42 0				
Interconennected units total	MWt	7 0	32 0	97 8				
	TJ/y	9	104	220				
Units total	MWt	207 0	205 8	272 8	263 0	258 8	251 0	251 0
	TJ/y	1990	1984	2619	2616	2491	2471	2471
Not covered	MWt	0 0	0 0	0 0	9 7	0 0	6 3	6 3

Alternative B Heat supply steam low balance								Tab 8 b)
Year		1992	1995	1996	1997	2000	2005	2010
Heat balance Plzeň steam	MWt	93 0	91 1	90 5	88 9	88 9	88 9	88 9
	TJ/y	1125	1100	1095	1075	1075	1075	1075
Heat supply								
CP Plzeň II HPP	MWt	70 0	12 2	11 0	(22 0)	(22 0)	(22 0)	(22 0)
	TJ/y	730	500	500	332	332	332	332
III SB 65 t/h	MWt		43 5	43 5	41 9	41 9	41 9	41 9
	TJ/y		465	460	73	73	73	73
IV FSB +TG 32MW	MWt				47 0	47 0	47 0	47 0
	TJ/y				670	670	670	670
CP Plzeň total	MWt	70 0	55 7	54 5	88 9	88 9	88 9	88 9
	TJ/y	730	965	960	1075	1075	1075	1075
Interconennected units								
BH Brevery	MWt	23 0	35 4	36 0				
	TJ/y	395	135	135				
Units total	MWt	93 0	91 1	90 5	88 9	88 9	88 9	88 9
	TJ/y	1125	1100	1095	1075	1075	1075	1075
Not covered	MWt	0 0	0 0	0 0	0 0	0 0	0 0	0 0

Abreviations
SB Steam Boiler
FSB Fluidized Bed Steam Boiler
BH Boiler House
HWB Hot Water Boiler
CC Combined Cycle
HPP High Pressure Part of CP

Alternative A Var I - High balance
CP PLZEN with CC - 2 x GT V 64 3 Siemens + 1 x condense steam turbine with heat extractions
Heat and power production - operational data - fuel consumption

Tab 11

	Units	y 1992	y 1995	y 1996	y 1997	y 2000	y 2005	y 2010
Total installed heat output of steam boilers	MWt	232 9	160 0	160 0	276 2	276 2	276 2	276 2
Total steam mass flow	t/h	340	235	235	405	405	405	405
Total installed heat output of hot water boilers	MWt	105 0	105 0	105 0	70 0	70 0	58 0	58 0
Total installed output of waste - heat boilers	MWt				177 0	177 0	177 0	177 0
Total heat output of cogeneration plant (-12°C)	MWt	273 5	233 0	233 0	399 2	403 0	394 5	394 5
in this for domain consumption	MWt	3 5	3 5	3 5	3 5	3 5	3 5	3 5
Outlet heat output - for external consumption	MWt	270 0	229 5	229 5	395 7	399.5	391 0	391 0
from which steam	MWt	70 0	54 5	54 5	100 0	100 0	89 0	87 0
hot water	MWt	200 0	175 0	175 0	295 7	299 5	302 0	304 0
Heat supply per year - steam	TJ/y	730	967	1040	1277	1277	1280	1279
Heat supply per year - hot water	TJ/y	2015	2029	2594	2870	2905	2923	2940
from which domain consumption	TJ/y	34	34	34	34	34	34	34
external consumption	TJ/y	1981	1995	2560	2836	2871	2889	2906
Heat production total	TJ/y	2745	2996	3634	4147	4182	4203	4219
Power output - CP II	MWe	55 0	55 0	55 0	55 0	55 0	55 0	55 0
Power output - CC (-12°C)	MWe				167 4	167 4	167 4	167 4
Total power output of CP (-12°C)	MWe	55 0	55 0	55 0	222 4	222 4	222 4	222 4
Average power output CP during peak load tariff	MWe	18 6	16 1	18 5	179 7	180 5	189 2	189 7
Total electric power generation - brutto	GWh/y	158 0	136 7	156 7	1016 7	1021 3	1070 2	1073 4
from which in peak load tariff zone	GWh/y	20 1	22 6	25 9	251 8	252 9	265 0	265 8
in high load tariff zone	GWh/y	30 5	26 4	30 3	278 2	279 5	292 9	293 8
in low load tariff zone	GWh/y	101 4	87 7	100 5	486 7	488 9	512 3	513 8
Total electric power generation - netto	GWh/y	152 0	132 2	151 6	994 1	998 5	1046 3	1049 4
Electricity consumption for elect production	GWh/y	6 0	4 5	5 1	22 6	22 8	23 9	24 0
Electricity consumption for heat production	GWh/y	26 7	19 1	22 9	20 6	20 8	19 6	19 7
Pumping energy	GWh/y	6 0	7 1	10 5	13 7	13 9	14 1	14 2
Total electricity consumption	GWh/y	32 7	26 2	33 4	34 3	34 7	33 7	33 9
Heat consumption in fuel for heat production	TJ/y	3475	3793	4632	4945	4989	4933	4952
Specific heat consumpt in fuel per heat product	GJ/GJ	1 27	1 27	1 27	1 19	1 19	1 17	1.17
Heat consumption in fuel for elect generation	TJ/y	772	705	802	5632	5655	5985	6001
Specific heat consumpt in fuel per elect generat	GJ/MWh	4 89	5 16	5 12	5 54	5 54	5 59	5 59
Total fuel consumption	TJ/y	4247	4498	5434	10577	10644	10918	10953
from whitch lignite 12,7 MJ/kg	TJ/y	4229	3963	4862				
	th t/y	333 0	312 0	382 8				
coal 18,47 MJ/kg	TJ/y				365	371		
	th t/y				19 8	20 1		
coal 17,38 MJ/kg	TJ/y				3340	3379	3127	3134
	th t/y				192 2	194 4	179 9	180 3
natural gas 33,4 MJ/m3	TJ/y		418	455	6835	6853	7518	7539
	mil m3/y		12 5	13 6	204 6	205 2	225 1	225 7
oil 41 6 MJ/kg	TJ/y	18	117	117	37	41	273	280
	th t/y	4	2 8	2 8	9	1 0	6 6	6.7

CP Plzen Alt A - Var 1 - High balance Tab 11a

Basic operation characteristics of CC with 2 x GT V 64 3 Siemens +
+ 1 x condense ST with heat extractions

	Units	y 1997	y 2000	y 2005	y 2010
Nominal power output of CC	MWe	179	179	179	179
from which nominal power output of GT	MWe	2 x 67	2 x 67	2 x 67	2 x 67
nominal power output of ST	MWe	45	45	45	45
Max thermal output - total (-12°C)	MWt	125	125	125	125
- in steam	MWt	40	40	40	40
- in hot water	MWt	125	125	125	125
Heat production - steam	TJ/y	195	195	192	192
Heat production - water	TJ/y	1560	1565	1740	1746
Heat production - total	TJ/y	1755	1760	1932	1938
Max power output of CC (-12°C)	MWe	167 4	167 4	167 4	167 4
Average power output during peak load tariff	MWe	155 5	156 0	160 6	160 6
Electric power generation - brutto					
- gas turbines	GWh/y	631 4	633 2	695 1	697 2
- steam turbine	GWh/y	198 7	199 3	218 8	219 5
- combined cycle total	GWh/y	830 1	832 5	913 9	916 7
from which in peak load tariff zone	GWh/y	217 9	218 5	225 0	225 0
in high load tariff zone	GWh/y	249 3	250 0	257 4	257 4
in low load tariff zone	GWh/y	362 9	364 0	431 5	434 3
Electricity delivery - netto	GWh/y	813 5	815 9	895 6	898 4
Total heat consumption in fuel	TJ/y	6616	6633	7221	7241
- natural gas 33,4 MJ/m3	mil m3/y	198 1	198 6	216 2	216 8
Heat consumption in fuel for heat production	TJ/y	1931	1936	2125	2132
Heat consumption in fuel for elect generation	TJ/y	4685	4697	5096	5110
Specific heat consumpt in fuel per heat product	GJ/GJ	1 10	1 10	1 10	1 10
Specific heat consumpt in fuel per elect generat	GJ/MWh	5 64	5 64	5 58	5 57
Total efficiency for heat and power generation	%	71 7	71 7	72 3	72 3

Alternative A Var 1 - Low balance
CP PLZEN with CC - 2 x GT V 64 3 Siemens + 1 x condense steam turbine with heat extractions
Heat and power production - operational data - fuel consumption Tab 12

	Units	y 1992	y 1995	y 1996	y.1997	y 2000	y 2005	y 2010
Total installed heat output of steam boilers	MWt	232 9	160 0	160 0	276 2	276 2	276 2	276 2
Total steam mass flow	t/h	340	235	235	405	405	405	405
Total installed heat output of hot water boilers	MWt	105 0	105 0	105 0	70 0	70 0		
Total installed output of waste - heat boilers	MWt				177 0	177 0	177 0	177 0
Total heat output of cogeneration plant (-12°C)	MWt	273 5	233 0	233 0	365 1	351 2	336 5	336 5
in this for domain consumption	MWt	3 5	3 5	3 5	3 5	3 5	3 5	3 5
Outlet heat output - for external consumption	MWt	270 0	229 5	229 5	361 6	347 7	333 0	333 0
from which steam	MWt	70 0	55 7	54 5	88 9	88 9	75 7	75 7
hot water	MWt	200 0	173 8	175 0	272 7	258 8	257 3	257 3
Heat supply per year - steam	TJ/y	730	965	960	1075	1075	1060	1060
Heat supply per year - hot water	TJ/y	2015	1914	2433	2650	2525	2505	2505
from which domain consumption	TJ/y	34	34	34	34	34	34	34
external consumption	TJ/y	1981	1880	2399	2616	2491	2471	2471
Heat production total	TJ/y	2745	2879	3393	3725	3600	3565	3565
Power output - CP II	MWe	55 0	55 0	55 0	55 0	55 0	55 0	55 0
Power output - CC (-12°C)	MWe				167 4	167 4	167 4	167 4
Total power output of CP (-12°C)	MWe	55 0	55 0	55 0	222 4	222 4	222 4	222 4
Average power output CP during peak load tariff	MWe	18 6	15 5	17 2	180 7	173 7	190 5	190 3
Total electric power generation - brutto	GWh/y	158 0	131 6	146 1	997 2	958 5	1051 4	1050 5
from which in peak load tariff zone	GWh/y	26 1	21 8	24 2	253 1	243 3	266 9	266 7
in high load tariff zone	GWh/y	30 5	25 4	28 2	279 3	268 5	294 5	294 3
in low load tariff zone	GWh/y	101 4	84 4	93 7	464 7	446 7	490 0	489 6
Total electric power generation - netto	GWh/y	152 0	127 3	141 3	975 2	937 3	1028 2	1027 4
Electricity consumption for elect production	GWh/y	6 0	4 3	4 8	22 0	21 2	23 2	23 1
Electricity consumption for heat production	GWh/y	26.7	18 3	21 4	18 4	17 8	17 6	17 5
Pumping energy	GWh/y	6 0	6 6	9 2	11 0	10 3	10 1	10 1
Total electricity consumption	GWh/y	32 7	24 9	30 6	29 4	28 1	27 7	27 6
Heat consumption in fuel for heat production	TJ/y	3475	3640	4324	4440	4292	4210	4199
Specific heat consumpt in fuel per heat product	GJ/GJ	1 27	1 26	1 27	1 19	1 19	1 18	1 18
Heat consumption in fuel for elect generation	TJ/y	772	681	751	5725	5536	5990	5986
Specific heat consumpt in fuel per elect generat	GJ/MWh	4 89	5 17	5 14	5 74	5 78	5 70	5 70
Total fuel consumption	TJ/y	4247	4321	5075	10165	9828	10200	10185
from whitch lignite 12 7 MJ/kg	TJ/y	4229	3789	4548				
	th t/y	333 0	298 3	358 1				
coal 18,47 MJ/kg	TJ/y				371	354		
	th t/y				20 1	19 2		
coal 17,38 MJ/kg	TJ/y				2981	2908	3023	3007
	th t/y				171 5	167 3	173 9	173 0
natural gas 33,4 MJ/m3	TJ/y		415	410	6790	6544	7152	7153
	mil m3/y		12 4	12 3	203 3	195.9	214 1	214 2
oil 41 6 MJ/kg	TJ/y	18	117	117	23	22	25	25
	th t/y	4	2 8	2.8	6	5	6	6

CP Plzen Alt A - Var 1 - Low balance Tab 12a

Basic operation characteristics of CC with 2 x GT V 64 3 Siemens +
+ 1 x condense ST with heat extractions

	Units	y 1997	y 2000	y 2005	y 2010
Nominal power output of CC	MWe	179	179	179	179
from which nominal power output of GT	MWe	2 x 67	2 x 67	2 x 67	2 x 67
nominal power output of ST	MWe	45	45	45	45
Max thermal output - total (-12°C)	MWt	125	125	125	125
- in steam	MWt	40	40	40	40
- in hot water	MWt	125	125	125	125
Heat production - steam	TJ/y	407	407	407	407
Heat production - water	TJ/y	1275	1205	1380	1380
Heat production - total	TJ/y	1682	1612	1787	1787
Max power output of CC (-12°C)	MWe	167 4	167 4	167 4	167 4
Average power output during peak load tariff	MWe	160 3	153 6	160 6	160 6
Electric power generation - brutto					
- gas turbine	GWh/y	633 4	607 0	672 8	672 8
- steam turbine	GWh/y	197 5	189 3	209 9	209 9
- combined cycle total	GWh/y	830 9	796 3	882 7	882 7
from which in peak load tariff zone	GWh/y	224 5	215 2	225 0	225 0
in high load tariff zone	GWh/y	255 0	244 4	255 5	255 5
in low load tariff zone	GWh/y	351 4	336 7	402 2	402 2
Electricity delivery - netto	GWh/y	814 3	780 4	865 1	865 1
Total heat consumption in fuel	TJ/y	6726	6480	7096	7096
- natural gas 33,4 MJ/m3	mil m3/y	201 4	194 0	212 5	212 5
Heat consumption in fuel for heat production	TJ/y	1850	1773	1966	1966
Heat consumption in fuel for elect generation	TJ/y	4876	4707	5130	5130
Specific heat consumpt in fuel per heat product	GJ/GJ	1 10	1 10	1 10	1 10
Specific heat consumpt in fuel per elect generat	GJ/MWh	5 87	5 91	5 81	5 81
Total efficiency for heat and power generation	%	69 5	69 1	70 0	70 0

Alternative A Var 2 - High balance
CP PLZEN with CC 1 x 6T V 64 3 Siemens + 1 x back - pressure steam turbine with extractions
Heat and power production - operational data - fuel consumption Tab 13

	Units	y 1992	y 1995	y 1996	y 1997	y 2000	y 2005	y 2010
Total installed heat output of steam boilers	MWt	232 9	160 0	160 0	276 2	276 2	276 2	276 2
Total steam mass flow	t/h	340	235	235	405	405	405	405
Total installed heat output of hot water boilers	MWt	105 0	105 0	105 0	105 0	105 0	116 0	116 0
Total installed output of waste - heat boilers	MWt				88 5	88 5	88 5	88 5
Total heat output of cogeneration plant (-12°C)	MWt	273 5	233 0	233 0	377 7	381 5	390 5	392 5
in this for domain consumption	MWt	3 5	3 5	3 5	3 5	3 5	3 5	3 5
Outlet heat output - for external consumption	MWt	270 0	229 5	229 5	374 2	378 0	387 0	389 0
from which steam	MWt	70 0	54 5	54 5	78 5	78 5	85 0	85 0
hot water	MWt	200 0	175 0	175 0	295 7	299 5	302 0	304 0
Heat supply per year - steam	TJ/y	730	967	1040	1235	1235	1271	1271
Heat supply per year - hot water	TJ/y	2015	2029	2594	2870	2905	2923	2940
from which domain consumption	TJ/y	34	34	34	34	34	34	34
external consumption	TJ/y	1981	1995	2560	2836	2871	2889	2906
Heat production total	TJ/y	2745	2996	3634	4105	4140	4194	4211
Power output - CP II	MWe	55 0	55 0	55 0	55 0	55 0	55 0	55 0
Power output - CC (-12°C)	MWe				87 6	87 6	87 6	87 6
Total power output of CP (-12°C)	MWe	55 0	55 0	55 0	142 6	142 6	142 6	142 6
Average power output CP during peak load tariff	MWe	18 6	16.1	18 5	104 9	106 0	107 2	107 7
Total electric power generation - brutto	GWh/y	158 0	136 7	156 7	614 2	620 4	627 7	630 1
from which in peak load tariff zone	GWh/y	26 1	22 6	25 9	147 0	148 5	150 2	150 8
in high load tariff zone	GWh/y	30 5	26 4	30 3	154 0	155 6	157 4	158 0
in low load tariff zone	GWh/y	101 4	87 7	100 5	313 1	316 3	320 0	321 2
Total electric power generation - netto	GWh/y	152 0	132 2	151 6	599 4	605 4	612 6	614 9
Electricity consumption for elect production	GWh/y	6 0	4 5	5 1	14 8	15 0	15 1	15 2
Electricity consumption for heat production	GWh/y	26 7	19 1	22 9	22 6	22 7	22 3	22 3
Pumping energy	GWh/y	6 0	7 1	10 5	13 4	13 6	14 0	14 1
Total electricity consumption	GWh/y	32 7	26 2	33 4	36 0	36 3	36 3	36 4
Heat consumption in fuel for heat production	TJ/y	3475	3793	4632	4997	5040	5015	5035
Specific heat consumpt in fuel per heat product	GJ/GJ	1 27	1 27	1 27	1 22	1 22	1 20	1 20
Heat consumption in fuel for elect generation	TJ/y	772	705	802	3086	3117	3152	3165
Specific heat consumpt in fuel per elect generat	GJ/MWh	4 89	5 16	5 12	5 02	5 02	5 02	5 02
Total fuel consumption	TJ/y	4247	4498	5434	8083	8157	8167	8200
from whitch lignite 12,7 MJ/kg	TJ/y	4229	3963	4862				
	th t/y	333 0	312 0	382 8				
coal 18,47 MJ/kg	TJ/y				651	657		
	th t/y				35 2	35 6		
coal 17,38 MJ/kg	TJ/y				3715	3745	3802	3814
	th t/y				213 8	215 5	218 8	219 4
natural gas 33,4 MJ/m3	TJ/y		418	455	3677	3714	3897	3912
	mil m3/y		12 5	13 6	110 1	111 2	116 7	117 1
oil 41 6 MJ/kg	TJ/y	18	117	117	40	41	468	474
	th t/y	4	2 8	2 8	1 0	1 0	11 3	11 4

CP Plzen Alt A - Var 2 - High balance Tab 13a

Basic operation characteristics of CC with 1 x GT V 64 3 Siemens +
+ 1 x back presure ST with heat extractions

	Units	y 1997	y 2000	y 2005	y 2010
Nominal power output of CC	MWe	88	88	88	88
from which nominal power output of GT	MWe	67	67	67	67
nominal power output of ST	MWe	21	21	21	21
Max thermal output - total (-12°C)	MWt	65	65	65	65
- in steam	MWt	20	20	20	20
- in hot water	MWt	65	65	65	65
Heat production - steam	TJ/y	100	100	100	100
Heat production - water	TJ/y	1090	1103	1115	1120
Necessary cooling	TJ/y	38	38	38	39
Heat production - total	TJ/y	1228	1241	1253	1259
Max power output of CC (-12°C)	MWe	87 6	87 6	87 6	87 6
Average power output during peak load tariff	MWe	76 1	76 9	77 7	78 0
Electric power generation - brutto					
- gas turbine	GWh/y	314 3	317 7	320 9	322 2
- steam turbine	GWh/y	93 8	94 8	95 7	96 1
- combined cycle total	GWh/y	408 1	412 5	416 6	418 3
from which in peak load tariff zone	GWh/y	106 6	107 8	108 9	109 3
in high load tariff zone	GWh/y	119 5	120 8	122 0	122 5
in low load tariff zone	GWh/y	182 0	183 9	185 7	186 5
Electricity delivery - netto	GWh/y	399 9	404 3	408 3	410 0
Total heat consumption in fuel	TJ/y	3353	3390	3424	3438
- natural gas 33,4 MJ/m3	mil m3/y	100 4	101 5	102 5	102 9
Heat consumption in fuel for heat production	TJ/y	1309	1323	1337	1342
Heat consumption in fuel for elect generation	TJ/y	2044	2067	2088	2096
Specific heat consumpt in fuel per heat product	GJ/GJ	1 10	1 10	1 10	1 10
Specific heat consumpt in fuel per elect generat	GJ/MWh	5 01	5 01	5 01	5 01
Total efficiency for heat and power generation	%	79 3	79 3	79 3	79 3

Alternative A Var 2 - Low balance
CP PLZEN with CC - 1 x GT V 64 3 Siemens + 1 x back - pressure steam turbine with extractions
Heat and power production - operational data - fuel consumption

Tab 14

	Units	y 1992	y 1995	y 1996	y 1997	y 2000	y 2005	y 2010
Total installed heat output of steam boilers	MWt	232 9	160 0	160 0	276 2	276 2	276 2	276 2
Total steam mass flow	t/h	340	235	235	405	405	405	405
Total installed heat output of hot water boilers	MWt	105 0	105 0	105 0	105 0	105 0	58 0	58 0
Total installed output of waste - heat boilers	MWt				88 5	88 5	88 5	88 5
Total heat output of cogeneration plant (-12°C)	MWt	273 5	233 0	233 0	365 1	351 2	330 8	330 8
in this for domain consumption	MWt	3 5	3 5	3 5	3 5	3 5	3 5	3 5
Outlet heat output - for external consumption	MWt	270 0	229 5	229 5	361 6	347 7	327 3	327 3
from which steam	MWt	70 0	55 7	54 5	88 9	88 9	70 0	70 0
hot water	MWt	200 0	173 8	175 0	272 7	258 8	257 3	257 3
Heat supply per year - steam	TJ/y	730	965	960	1075	1075	1032	1032
Heat supply per year - hot water	TJ/y	2015	1914	2433	2650	2525	2505	2505
from which domain consumption	TJ/y	34	34	34	34	34	34	34
external consumption	TJ/y	1981	1880	2399	2616	2491	2471	2471
Heat production total	TJ/y	2745	2879	3393	3725	3600	3537	3537
Power output - CP II	MWe	55 0	55 0	55 0	55 0	55 0	55 0	55 0
Power output - CC (-12°C)	MWe				87 6	87.6	87 6	87 6
Total power output of CP (-12°C)	MWe	55 0	55 0	55 0	142 6	142 6	142 6	142 6
Average power output CP during peak load tariff	MWe	18 6	15 5	17 2	105 8	102 1	101 4	101 4
Total electric power generation - brutto	GWh/y	158 0	131 6	146 1	618 0	596 0	592 1	592 1
from which in peak load tariff zone	GWh/y	26 1	21 8	24 2	148 3	143 0	142 1	142 1
in high load tariff zone	GWh/y	30 5	25 4	28 2	157 1	151 5	150 5	150 5
in low load tariff zone	GWh/y	101 4	84 4	93 7	312 6	301 5	299 5	299 5
Total electric power generation - netto	GWh/y	152 0	127 3	141 3	603 3	581 8	578 0	578 0
Electricity consumption for elect production	GWh/y	6 0	4 3	4 8	14 7	14 2	14 1	14 1
Electricity consumption for heat production	GWh/y	26 7	18 3	21 4	20 3	19 7	19 0	19 0
Pumping energy	GWh/y	6 0	6 6	9 2	11 0	10 3	10 0	10 0
Total electricity consumption	GWh/y	32 7	24 9	30 6	31 3	30 0	29 0	29 0
Heat consumption in fuel for heat production	TJ/y	3475	3640	4324	4503	4352	4224	4224
Specific heat consumpt in fuel per heat product	GJ/GJ	1 27	1 26	1 27	1 21	1 21	1 19	1 19
Heat consumption in fuel for elect generation	TJ/y	772	681	751	3108	2999	2980	2980
Specific heat consumpt in fuel per elect generat	GJ/MWh	4 89	5 17	5 14	5 03	5 03	5 03	5 03
Total fuel consumption	TJ/y	4247	4321	5075	7611	7351	7204	7204
from whitch lignite 12,7 MJ/kg	TJ/y	4229	3789	4548				
	th t/y	333 0	298 3	358 1				
coal 18,47 MJ/kg	TJ/y				365	344		
	th t/y				19 8	18 6		
coal 17,38 MJ/kg	TJ/y				3455	3375	3351	3351
	th t/y				198 8	194 2	192 8	192 8
natural gas 33,4 MJ/m3	TJ/y		415	410	3556	3421	3630	3630
	mil m3/y		12 4	12 3	106 5	102 4	108 7	108 7
oil 41 6 MJ/kg	TJ/y	18	117	117	235	211	223	223
	th t/y	.4	2.8	2.8	5 6	5 1	5.4	5 4

CP Plzen Alt A - Var 2 - Low balance Tab 14a

Basic operation characteristics of CC with 1 x GT V 64 3 Siemens +
+ 1 x back - presure ST with heat extractions

	Units	y 1997	y 2000	y 2005	y 2010
Nominal power output of CC	MWe	86	88	88	88
from which nominal power output of GT	MWe	67	67	67	67
nominal power output of ST	MWe	21	21	21	21
Max thermal output - total (-12°C)	MWt	65	65	65	65
- in steam	MWt	20	20	20	20
- in hot water	MWt	65	65	65	65
Heat production - steam	TJ/y	160	160	160	160
Heat production - water	TJ/y	1120	1068	1060	1060
Necessary cooling	TJ/y	24	23	23	23
Heat production - total	TJ/y	1304	1251	1243	1243
Max power output of CC (-12°C)	MWe	87 6	87 6	87 6	87 6
Average power output during peak load tariff	MWe	80 1	76 8	76 3	76 3
Electric power generation - brutto					
- gas turbine	GWh/y	333 6	320 0	318 0	318 0
- steam turbine	GWh/y	95 2	91 3	90 7	90 7
- combined cycle total	GWh/y	428 8	411 3	408 7	408 7
from which in peak load tariff zone	GWh/y	112 2	107 6	106 9	106 9
in high load tariff zone	GWh/y	126 3	121 2	120 4	120 4
in low load tariff zone	GWh/y	190 3	182 5	181 4	181 4
Electricity delivery - netto	GWh/y	420 2	403 1	400 5	400 5
Total heat consumption in fuel	TJ/y	3557	3412	3390	3390
- natural gas 33,4 MJ/m3	mil m3/y	106 5	102 2	101 5	101 5
Heat consumption in fuel for heat production	TJ/y	1408	1351	1342	1342
Heat consumption in fuel for elect generation	TJ/y	2149	2061	2048	2048
Specific heat consumpt in fuel per heat product	GJ/GJ	1 10	1 10	1 10	1 10
Specific heat consumpt in fuel per elect generat	GJ/MWh	5 01	5 01	5 01	5 01
Total efficiency for heat and power generation	%	79 4	79 4	79 4	79 4

Alternative B Var 1 - High balance
CP PLZEN with FSB - 1 x 160 t/y + 1 x condense steam turbine 32 MW
Var 1 = reconstruction of granul boilers 2 x 170t/h CP II from lignite to stone coal
Heat and power production - operational data - fuel consumption Tab 15

	Units	y 1992	y 1995	y 1996	y 1997	y 2000	y 2005	y 2010
Total installed heat output of steam boilers	MWt	232 9	160 0	160 0	396 5	396 5	396 5	396 5
Total steam mass flow	t/h	340	235	235	565	565	565	565
Total installed heat output of hot water boilers	MWt	105 0	105 0	105 0	105 0	105 0	116 0	116 0
Total heat output of cogeneration plant (-12 C)	MWt	273 5	233 0	233 0	387 0	387 0	402 5	402 5
in this for domain consumption	MWt	3 5	3 5	3 5	3 5	3 5	3 5	3 5
Outlet heat output - for external consumption	MWt	270 0	229 5	229 5	383 5	383 5	399 0	399 0
from which steam	MWt	70 0	54 5	54 5	90 0	90 0	99 6	99 6
hot water	MWt	200 0	175 0	175 0	293 5	293 5	299 4	299 4
Heat supply per year - steam	TJ/y	730	967	1040	1286	1286	1290	1290
Heat supply per year - hot water	TJ/y	2015	2029	2594	2870	2905	2923	2940
from which domain consumption	TJ/y	34	34	34	34	34	34	34
external consumption	TJ/y	1981	1995	2560	2836	2871	2889	2906
Heat production total	TJ/y	2745	2996	3634	4156	4191	4213	4230
Power output - back pressure turboset CP II	MWe	55 0	55 0	55 0	55 0	55 0	55 0	55 0
Power output - condese turb with extr CP IV	MWe				32 0	32 0	32 0	32 0
Total power output of CP	MWe	55 0	55 0	55 0	87 0	87 0	87 0	87 0
Average power output CP during peak load tariff	MWe	18 6	16 1	18 5	50 9	51 4	50 6	50 8
Total electric power generation - brutto	GWh/y	158 0	136 7	156 7	431 6	435 3	428 9	430 7
from which in peak load tariff zone	GWh/y	26 1	22 6	25 9	71 4	72 0	70 9	71 2
in high load tariff zone	GWh/y	30 5	26 4	30 3	83 3	84 1	82 8	83 2
in low load tariff zone	GWh/y	101 4	87 7	100 5	276 9	279 3	275 2	276 3
Total electric power generation - netto	GWh/y	152 0	132 2	151 6	416 5	420 1	413 9	415 7
Electricity consumption for elect production	GWh/y	6 0	4 5	5 1	15 1	15 2	15 0	15 0
Electricity consumption for heat production	GWh/y	26 7	19 1	22 9	32 4	32 7	32 2	32 4
Pumping energy	GWh/y	6 0	7 1	10 5	13 8	14 0	14 1	14 2
Total electricity consumption	GWh/y	32 7	26 2	33 4	46 2	46 7	46 3	46 6
Heat consumption in fuel for heat production	TJ/y	3475	3793	4632	5188	5233	5227	5249
Specific heat consumpt in fuel per heat product	GJ/GJ	1 27	1 27	1 27	1 25	1 25	1 24	1 24
Heat consumption in fuel for elect generation	TJ/y	772	705	802	2303	2321	2290	2299
Specific heat consumpt in fuel per elect generat	GJ/MWh	4 89	5 16	5 12	5 34	5 33	5 34	5 34
Total fuel consumption	TJ/y	4247	4498	5434	7491	7554	7517	7548
from whitch								
- lignite 12,7 MJ/kg - CP I HWB + CP II GSB	TJ/y	4229	3963	4862				
	th t/y	333 0	312 0	382 8				
- coal 18,47 MJ/kg - CP I HWB	TJ/y				209	209		
	th t/y				11 3	11 3		
- coal 17,38 MJ/kg - CP II GSB	TJ/y				4252	4315	4206	4237
(after recostruction)	th t/y				244 6	248 3	242 0	243 8
- lignite 10,05 MJ/kg - CP IV FSB	TJ/y				2857	2857	2857	2857
	th t/y				284 3	284 3	284 3	284 3
- natural gas 33,4 MJ/m3 - CP III SB	TJ/y		418	455	91	91	171	171
	mil m3/y		12 5	13 6	2 7	2 7	5 1	5 1
- oil 41 6 MJ/kg - CP III SB + CP V HWB	TJ/y	18	117	117	82	82	283	283
	th t/y	4	2 8	2 8	2 0	2 0	6 8	6 8
Consumpt. of Ca CO3 for desulphur. in FSB	th t/y				27 0	27 0	27 0	27 0

Alternative B Var 1 - Low balance
CP PLZEN with FSB - 1 x 160 t/y + 1 x condense steam turbine 32 MW
Var 1 = reconstruction of granul boilers 2 x 170t/h CP II from lignite to stone coal
Heat and power production - operational data - fuel consumption

Tab 1o

	Units	y 1992	y 1995	y 1990	y 1997	y 2000	y 2005	y 2010
Total installed heat output of steam boilers	MWt	232 9	160 0	160 0	396 5	396 5	396 5	396 5
Total steam mass flow	t/h	340	235	235	565	565	565	565
Total installed heat output of hot water boilers	MWt	105 0	105 0	105 0	70 0	70 0	58 0	58 0
Total heat output of cogeneration plant (-12 C)	MWt	273 5	233 0	233 0	355 4	351 2	343 4	343 4
in this for . domain consumption	MWt	3 5	3 5	3 5	3 5	3 5	3 5	3 5
Outlet heat output - for external consumption	MWt	270 0	229 5	229 5	351 9	347 7	339 9	339 9
from which steam	MWt	70 0	55 7	54 5	88 9	88 9	88 9	88 9
hot water	MWt	200 0	173 8	175 0	263 0	258 8	251 0	251 0
Heat supply per year - steam	TJ/y	730	965	960	1075	1075	1075	1075
Heat supply per year - hot water	TJ/y	2015	1914	2433	2650	2525	2505	2505
from which domain consumption	TJ/y	34	34	34	34	34	34	34
external consumption	TJ/y	1981	1880	2399	2616	2491	2471	2471
Heat production total	TJ/y	2745	2879	3393	3725	3600	3580	3580
Power output - back pressure turboset CP II	MWe	55 0	55 0	55 0	55 0	55 0	55 0	55 0
Power output - condese turb with extr CP IV	MWe				32 0	32 0	32 0	32 0
Total power output of CP	MWe	55 0	55 0	55 0	87 0	87 0	87 0	87 0
Average power output CP during peak load tariff	MWe	18 6	15 5	17 2	50 0	48 8	48 9	48 9
Total electric power generation - brutto	GWh/y	158 0	131 6	146 1	423 9	413 7	413 9	413 9
from which in peak load tariff zone	GWh/y	26 1	21 8	24 2	70 1	68 4	68 4	68 4
in high load tariff zone	GWh/y	30 5	25 4	28 2	81 9	79 9	79 9	79 9
in low load tariff zone	GWh/y	101 4	84 4	93 7	271 9	265 4	265 5	265 5
Total electric power generation - netto	GWh/y	152 0	127 3	141 3	408 9	399 0	399 2	399 2
Electricity consumption for elect production	GWh/y	6 0	4 3	4 8	15 0	14 7	14 7	14 7
Electricity consumption for heat production	GWh/y	26 7	18 3	21 4	29 3	28 3	28 1	28 1
Pumping energy	GWh/y	6 0	6 6	9 2	11 0	10 3	10 2	10 2
Total electricity consumption	GWh/y	32 7	24 9	30 6	40 3	38 6	38 3	38 3
Heat consumption in fuel for heat production	TJ/y	3475	3640	4324	4656	4495	4451	4451
Specific heat consumpt in fuel per heat product	GJ/GJ	1 27	1 26	1 27	1 25	1 25	1 24	1 24
Heat consumption in fuel for elect generation	TJ/y	772	681	751	2297	2249	2250	2250
Specific heat consumpt in fuel per elect generat	GJ/MWh	4 89	5 17	5 14	5 42	5 44	5 44	5 44
Total fuel consumption	TJ/y	4247	4321	5075	6953	6744	6701	6701
from which								
- lignite 12,7 MJ/kg - CP I HWB + CP II GSB	TJ/y	4229	3789	4548				
	th t/y	333 0	298 3	358 1				
- coal 18,47 MJ/kg - CP I HWB	TJ/y				203	165		
	th t/y				11 0	8 9		
- coal 17,38 MJ/kg - CP II GSB	TJ/y				3967	3845	3849	3849
(after recostruction)	th t/y				228 3	221 2	221 5	221 5
- lignite 10,05 MJ/kg - CP IV FSB	TJ/y				2698	2649	2649	2649
	th t/y				268 5	263 6	263 6	263 6
- natural gas 33,4 MJ/m3 - CP III SB	TJ/y		415	410	26	26	26	26
	mil m3/y		12 4	12 3	8	8	8	8
- oil 41 6 MJ/kg - CP III SB + CP V HWB	TJ/y	18	117	117	59	59	177	177
	th t/y	4	2 8	2 8	1 4	1 4	4 3	4 3
Consumpt of Ca CO3 for desulphur in FSB	th t/y				25 5	25 0	25 0	25 0

Alternative 8 Var 2 - High balance
CP PLZEN with FSB - 1 x 160 t/y + 1 x condense steam turbine 32 MW
Var 2 = flue gas desulphuration of granul boilers CP II - lignite
Heat and power production - operational data fuel consumption Tab 17

	Units	y 1992	y 1995	y 1996	y 1997	y 2000	y 2005	y 2010
Total installed heat output of steam boilers	MWt	232 9	160 0	160 0	396 5	396 5	396 5	396 5
Total steam mass flow	t/h	340	235	235	565	565	565	565
Total installed heat output of hot water boilers	MWt	105 0	105 0	105 0	105 0	105 0	116 0	116 0
Total heat output of cogeneration plant (-12 C)	MWt	273 5	233 0	233 0	387 0	387 0	402 5	402 5
in this for domain consumption	MWt	3 5	3 5	3 5	3 5	3 5	3 5	3 5
Outlet heat output - for external consumption	MWt	270 0	229 5	229 5	383 5	383 5	399 0	399 0
from which steam	MWt	70 0	54 5	54 5	90 0	90 0	99 6	99 6
hot water	MWt	200 0	175 0	175 0	293 5	293 5	299 4	299 4
Heat supply per year - steam	TJ/y	730	967	1040	1286	1286	1290	1290
Heat supply per year - hot water	TJ/y	2015	2029	2594	2870	2905	2923	2940
from which domain consumption	TJ/y	34	34	34	34	34	34	34
external consumption	TJ/y	1981	1995	2560	2836	2871	2889	2906
Heat production total	TJ/y	2745	2996	3634	4156	4191	4213	4230
Power output - back pressure turboset CP II	MWe	55 0	55 0	55 0	55 0	55 0	55 0	55 0
Power output - condese turb with extr CP IV	MWe				32 0	32 0	32 0	32 0
Total power output of CP	MWe	55 0	55 0	55 0	87 0	87 0	87 0	87 0
Average power output CP during peak load tariff	MWe	18 6	16 1	18 5	50 9	51 4	50 6	50 8
Total electric power generation - brutto	GWh/y	158 0	136 7	156 7	431 6	435 3	428 9	430 7
from which in peak load tariff zone	GWh/y	26 1	22 6	25 9	71 4	72 0	70 9	71 2
in high load tariff zone	GWh/y	30 5	26 4	30 3	83 3	84 1	82 8	83 2
in low load tariff zone	GWh/y	101 4	87 7	100 5	276 9	279 3	275 2	276 3
Total electric power generation - netto	GWh/y	152 0	132 2	151 6	416 5	420 1	413 9	415 7
Electricity consumption for elect production	GWh/y	6 0	4 5	5 1	15 1	15 2	15 0	15 0
Electricity consumption for heat production	GWh/y	26 7	19 1	22 9	32 4	32 7	32 2	32 4
Pumping energy	GWh/y	6 0	7 1	10 5	13 8	14 0	14 1	14 2
Total electricity consumption	GWh/y	32 7	26 2	33 4	46 2	46 7	46 3	46 6
Heat consumption in fuel for heat production	TJ/y	3475	3793	4632	5188	5233	5227	5249
Specific heat consumpt in fuel per heat product	GJ/GJ	1 27	1 27	1 27	1 25	1 25	1 24	1 24
Heat consumption in fuel for elect generation	TJ/y	772	705	802	2303	2321	2290	2299
Specific heat consumpt in fuel per elect generat	GJ/MWh	4 89	5 16	5 12	5 34	5 33	5 34	5 34
Total fuel consumption	TJ/y	4247	4498	5434	7491	7554	7517	7548
from whitch								
- lignite 12,7 MJ/kg - CP I HWB + CP II GSB	TJ/y	4229	3963	4862	4252	4315	4206	4237
	th t/y	333 0	312 0	382 8	334 8	339 8	331 2	333 6
- coal 18,47 MJ/kg - CP I HWB	TJ/y				209	209		
	th t/y				11 3	11 3		
- lignite 10,05 MJ/kg - CP IV FSB	TJ/y				2857	2857	2857	2857
	th t/y				284 3	284 3	284 3	284 3
- natural gas 33,4 MJ/m3 - CP III SB	TJ/y		418	455	91	91	171	171
	mil m3/y		12 5	13 6	2 7	2 7	5 1	5 1
- oil 41 6 MJ/kg - CP III SB + CP V HWB	TJ/y	18	117	117	82	82	283	283
	th t/y	4	2 8	2 8	2 0	2 0	6 8	6 8
Consumpt of CaCO3 for desulphur in FSB	th t/y				27 0	27.0	27 0	27 0
Consumpt of MgO for FGD of granul. boilers	th t/y				9 5	9 7	9 4	9 5
Fertilizer production MgSO3	th t/y				27 7	28 1	27 4	27 6

Alternative 8 Var 2 - Low balance
CP PLZEN with FSB - 1 x 160 t/y + 1 x condense steam turbine 32 MW
Var 2 = flue gas desulphuration of granul boilers CP II - lignite
Heat and power production - operational data - fuel consumption

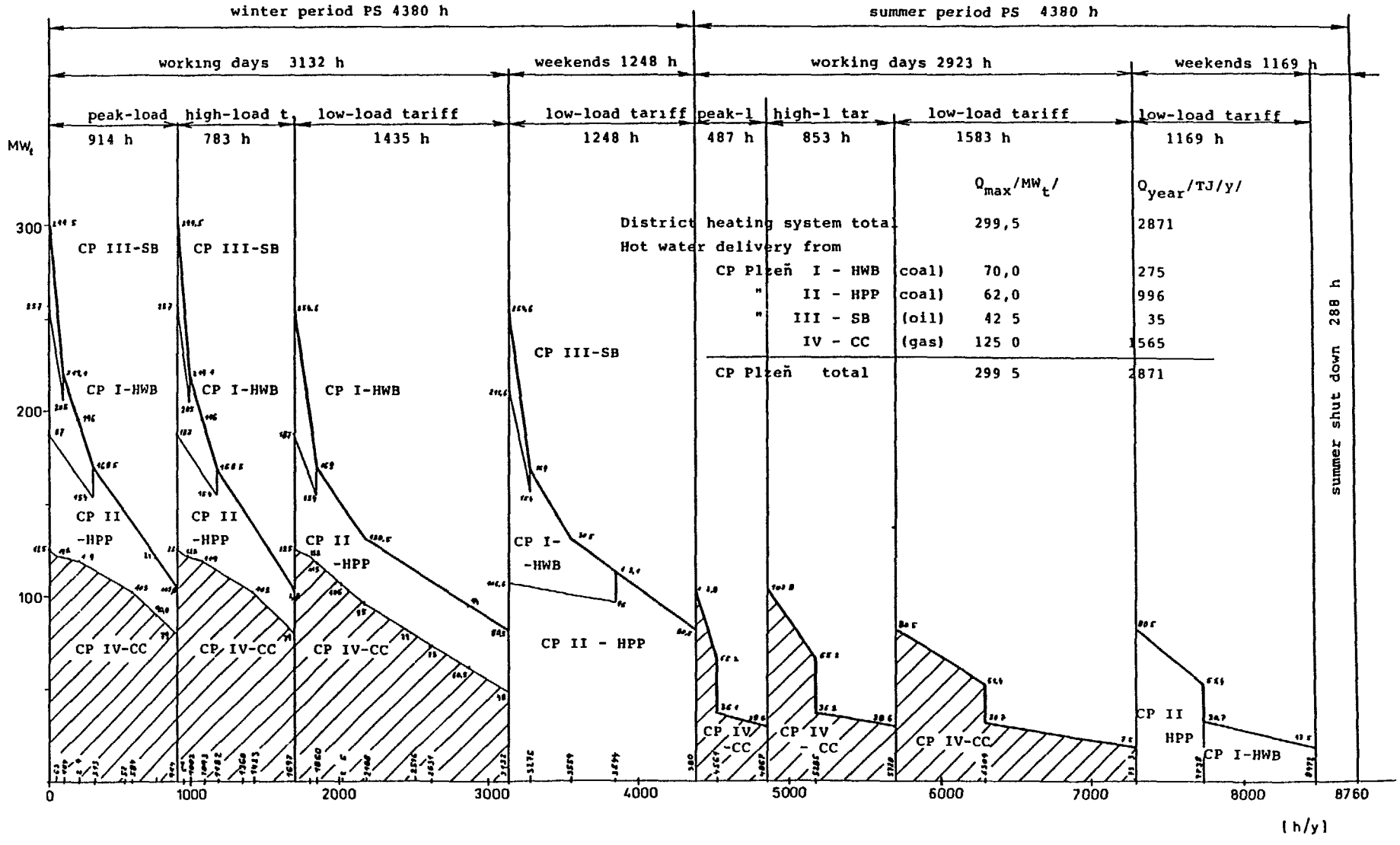
Tab 18

	Units	y 1992	y 1995	y 1996	y 1997	y 2000	y 2005	y 2010
Total installed heat output of steam boilers	MWt	232 9	160 0	160 0	396 5	396 5	396 5	396 5
Total steam mass flow	t/h	340	235	235	565	565	565	565
Total installed heat output of hot water boilers	MWt	105 0	105 0	105 0	70 0	70 0	58 0	58 0
Total heat output of cogeneration plant (-12 C)	MWt	273 5	233 0	233 0	355 4	351 2	343 4	343 4
in this for domain consumption	MWt	3 5	3 5	3 5	3 5	3 5	3 5	3 5
Outlet heat output - for external consumption	MWt	270 0	229 5	229 5	351 9	347 7	339 9	339 9
from which steam	MWt	70 0	55 7	54 5	88 9	66 9	88 9	88 9
hot water	MWt	200 0	173 8	175 0	263 0	258 8	251 0	251 0
Heat supply per year - steam	TJ/y	730	965	960	1075	1075	1075	1075
Heat supply per year - hot water	TJ/y	2015	1914	2433	2650	2525	2505	2505
from which domain consumption	TJ/y	34	34	34	34	34	34	34
external consumption	TJ/y	1981	1880	2399	2616	2491	2471	2471
Heat production total	TJ/y	2745	2879	3393	3725	3600	3580	3580
Power output - back pressure turboset CP II	MWe	55 0	55 0	55 0	55 0	55 0	55 0	55 0
Power output - condese turb with extr CP IV	MWe				32 0	32 0	32 0	32 0
Total power output of CP	MWe	55 0	55 0	55 0	87 0	87 0	87 0	87 0
Average power output CP during peak load tariff	MWe	18 6	15 5	17 2	50 0	48 8	48 9	48 9
Total electric power generation - brutto	GWh/y	158 0	131 6	146 1	423 9	413 7	413 9	413 9
from which in peak load tariff zone	GWh/y	26 1	21 8	24 2	70 1	68 4	68 4	68 4
in high load tariff zone	GWh/y	30 5	25 4	28 2	81 9	79 9	79 9	79 9
in low load tariff zone	GWh/y	101 4	84 4	93 7	271 9	265 4	265 5	265 5
Total electric power generation - netto	GWh/y	152 0	127 3	141 3	408 9	399 0	399 2	399 2
Electricity consumption for elect production	GWh/y	6 0	4 3	4 8	15 0	14 7	14 7	14 7
Electricity consumption for heat production	GWh/y	26 7	18 3	21 4	29 3	28 3	28 1	28 1
Pumping energy	GWh/y	6 0	6 6	9 2	11 0	10 3	10 2	10 2
Total electricity consumption	GWh/y	32 7	24 9	30 6	40 3	38 6	38 3	38 3
Heat consumption in fuel for heat production	TJ/y	3475	3640	4324	4656	4495	4451	4451
Specific heat consumpt in fuel per heat product	GJ/GJ	1 27	1 26	1 27	1 25	1 25	1 24	1 24
Heat consumption in fuel for elect generation	TJ/y	772	681	751	2297	2249	2250	2250
Specific heat consumpt in fuel per elect generat	GJ/MWh	4 89	5 17	5 14	5 42	5 44	5 44	5 44
Total fuel consumption	TJ/y	4247	4321	5075	6953	6744	6701	6701
from whitch								
- lignite 12,7 MJ/kg - CP I HWB + CP II GSB	TJ/y	4229	3789	4548	3967	3845	3849	3849
	th t/y	333 0	298 3	358 1	312 4	302 8	303 1	303 1
- coal 18,47 MJ/kg - CP I HWB	TJ/y				203	165		
	th t/y				11 0	8 9		
- lignite 10,05 MJ/kg - CP IV FSB	TJ/y				2698	2649	2649	2649
	th t/y				268 5	263 6	263 6	263 6
- natural gas 33,4 MJ/m3 - CP III SB	TJ/y		415	410	26	26	26	26
	mil m3/y		12 4	12 3	8	8	8	8
- oil 41 6 MJ/kg - CP III SB + CP V HWB	TJ/y	18	117	117	59	59	177	177
	th t/y	4	2 8	2 8	1 4	1 4	4 3	4 3
Consumpt of CaCO3 for desulphur in FSB	th t/y				25 5	25 0	25 0	25 0
Consumpt. of MgO for FGD of granul boilers	th t/y				8 9	8 6	8 6	8 6
Fertilizer production MgSO3	th t/y				25 8	25 0	25 1	25 1

D1

CP Plzeň Alt A Var 1 year 2000 - high balance - CC with 2x GT V64 3 Siemens + 1x Condense steam turbine with heat extractions

Diagram of hot water delivery (lasting curve according to the ambient temperature) divided into particular tariff ranges in Power system (PS

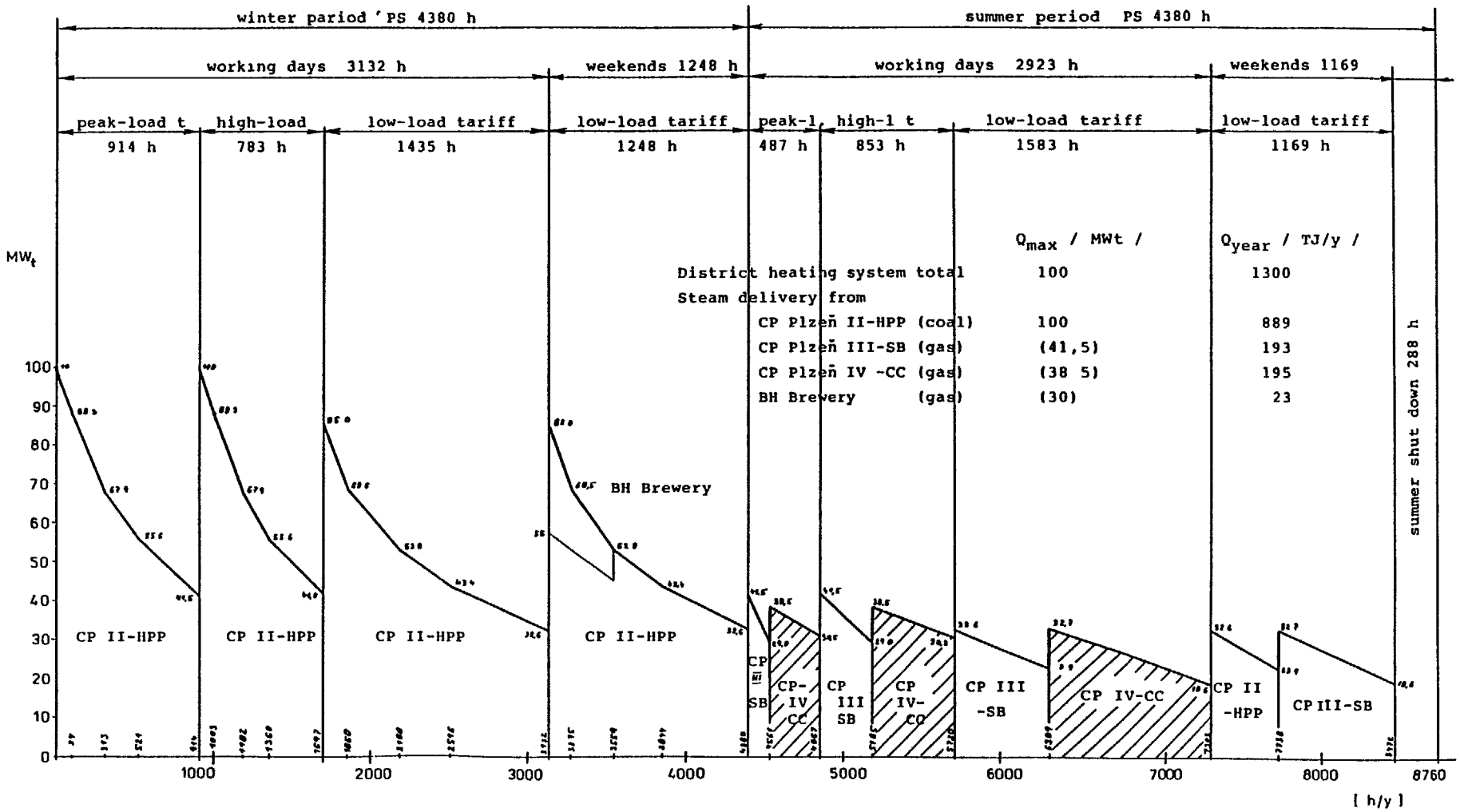


		Q_{max}/MW_t/	Q_{year}/TJ/y/
District heating system total		299,5	2871
Hot water delivery from			
CP Plzeň I - HWB	(coal)	70,0	275
" II - HPP	(coal)	62,0	996
" III - SB	(oil)	42 5	35
IV - CC	(gas)	125 0	1565
CP Plzeň total		299 5	2871

316

CP Plzeň Alt A Var 1 year 2000 - high balance - CC with 2x GT V64 3 Siemens + 1x Condense steam turbine with heat extractions

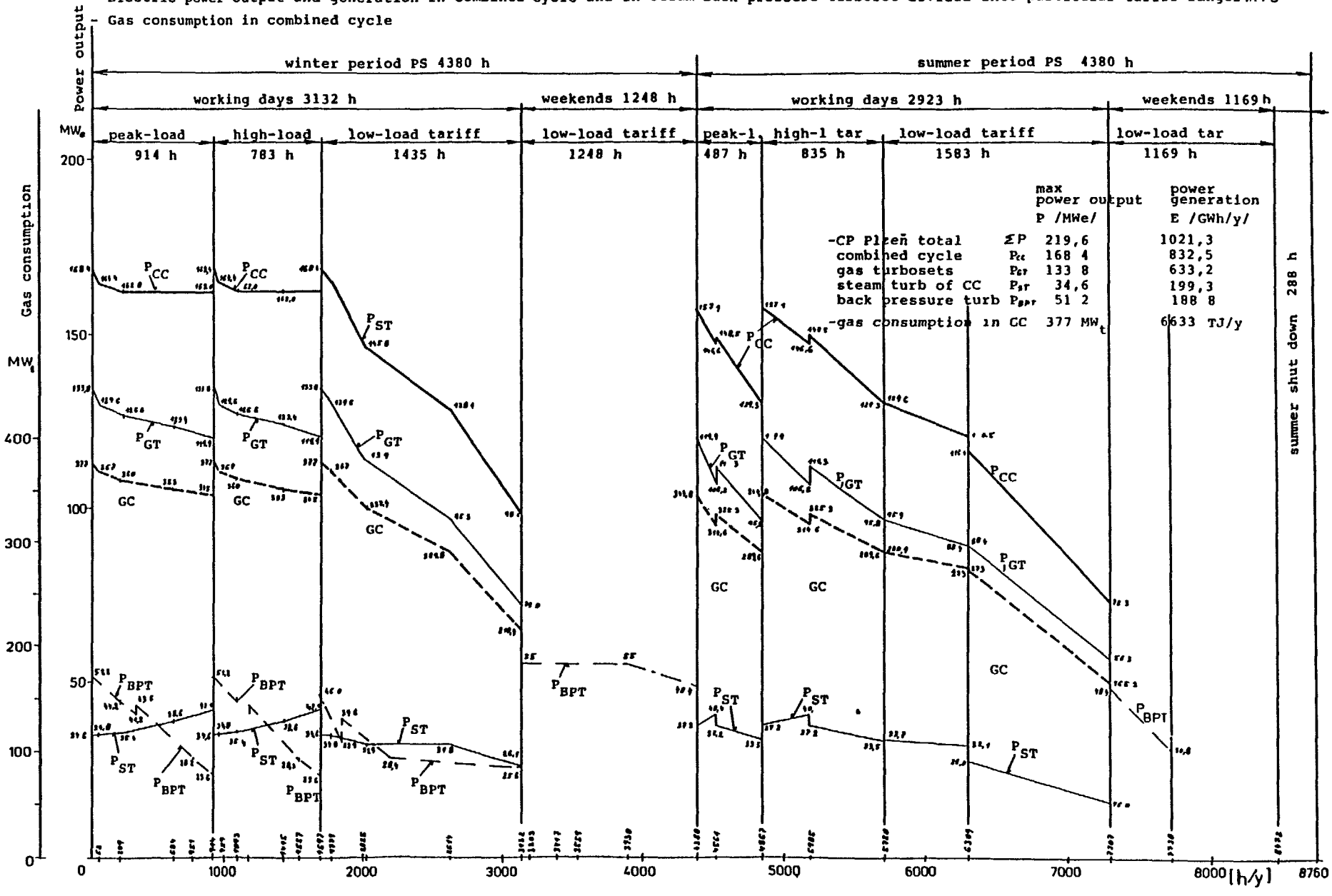
Diagram of steam delivery (lasting curve according to the ambient temperature) divided into particular tariff ranges in Power system (PS)



D 3

CP Plzeň Alt A Var 1 -year 2000 - high balance - CC with 2x GT V64 3 Siemens + 1x condense steam turbine with heat extractions

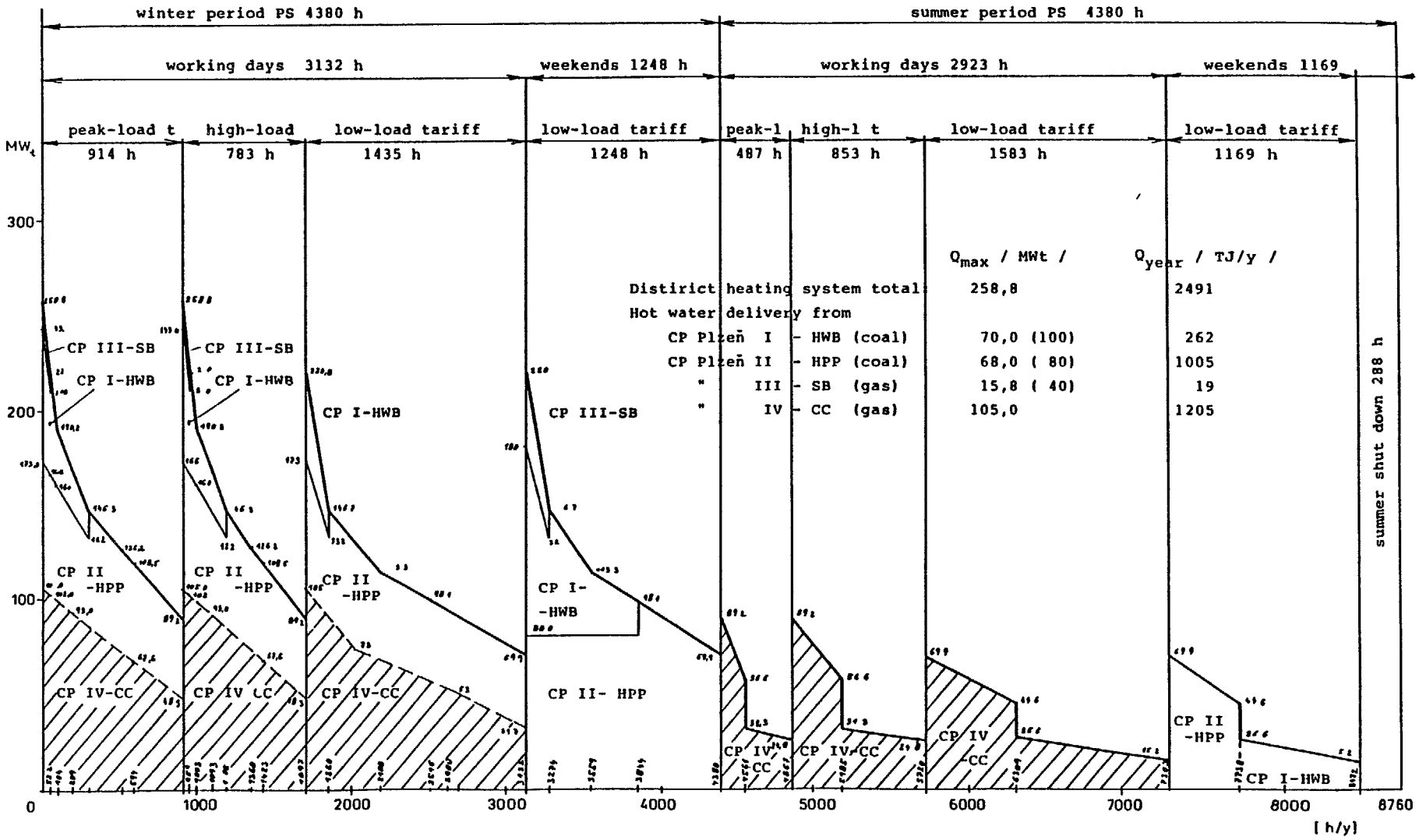
- Electric power output and generation in Combined cycle and in steam back-pressure turboset-divided into particular tariff ranges in PS
- Gas consumption in combined cycle



CP Plzeň Alt A Var 1 year 2000 - low balance - CC with 2x GT V64 3 Siemens + 1x Condense steam turbine with heat extractions

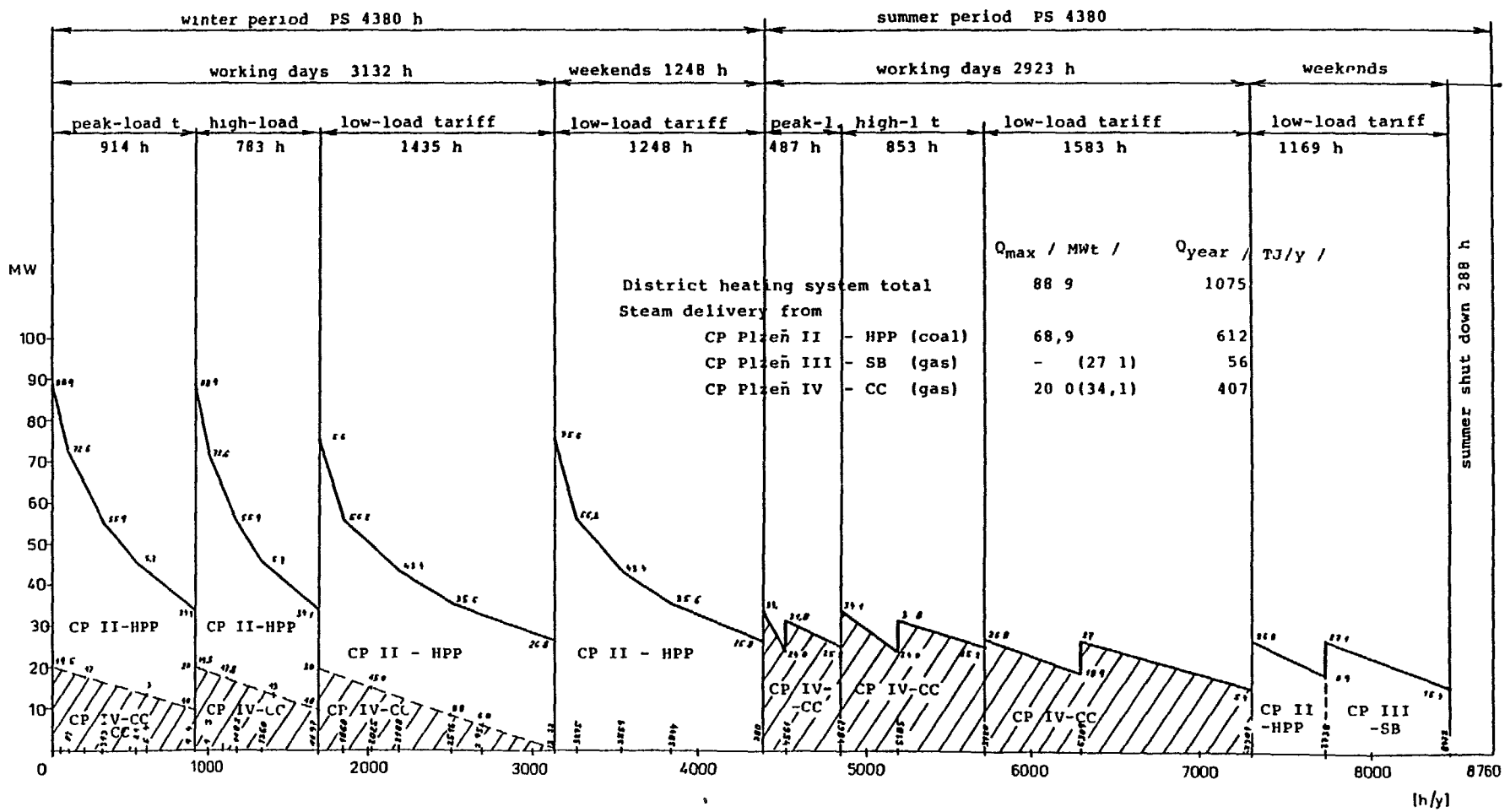
Diagram of hot water delivery (lasting curve according to the ambient temperature) divided into particular tariff ranges in Power system (PS)

D4



CP Plzeň Alt A Var 1 year 2000 - low balance-CC with 2xGT V64 3 Siemens + 1x Condense steam turbine with heat extractions

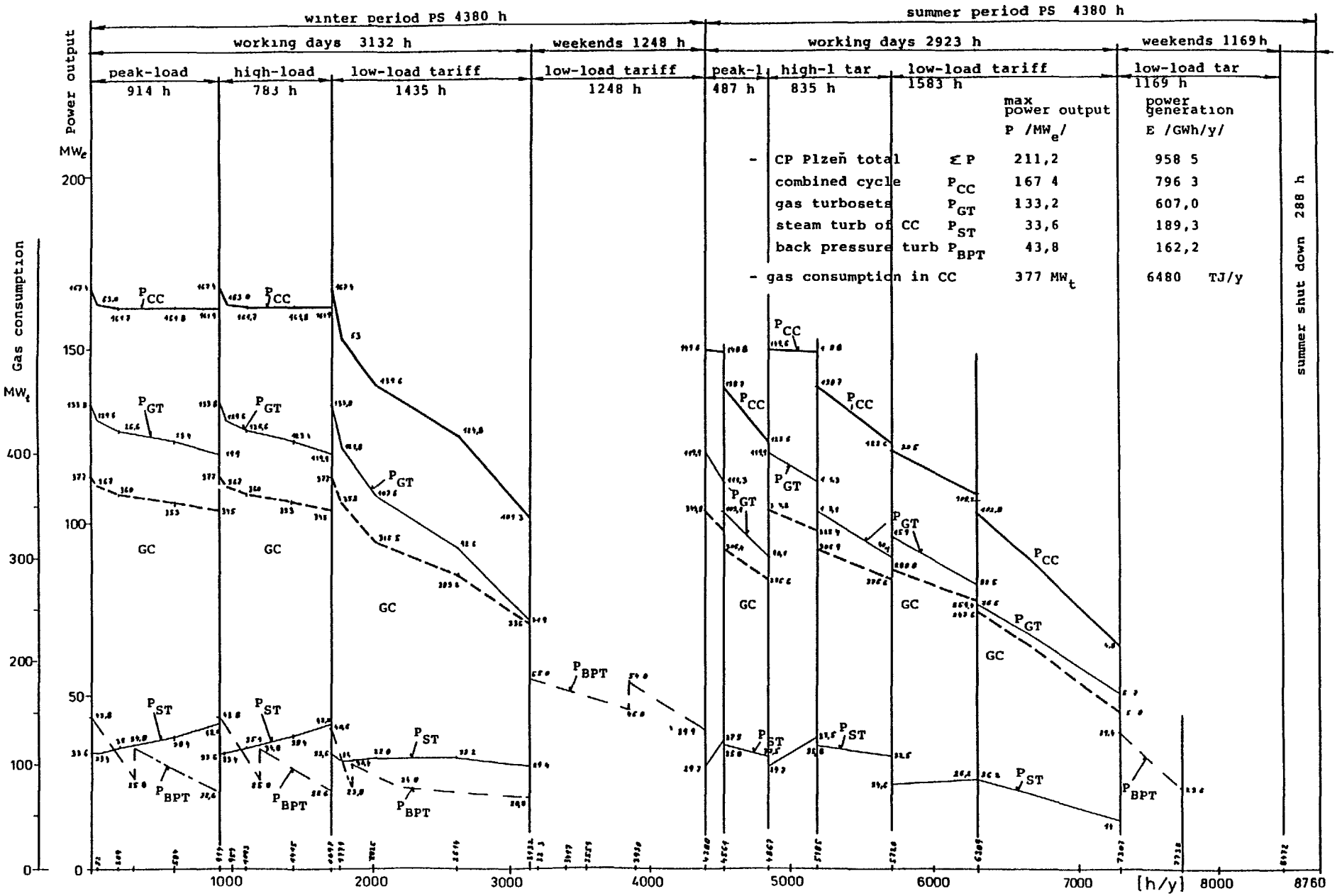
Diagram of steam delivery (lasting curve according to the ambient temperature) divided into particular tariff ranges in Power system (PS)



CP Plzeň Alt A Var 1 -year 2000 - low balance - CC with 2x GT V64 3 Siemens + 1x condense steam turbine with heat extractions

D6

- Electric power output and generation in Combined cycle and in steam back-pressure turboset-divided into particular tariff ranges in PS
- Gas consumption in combined cycle

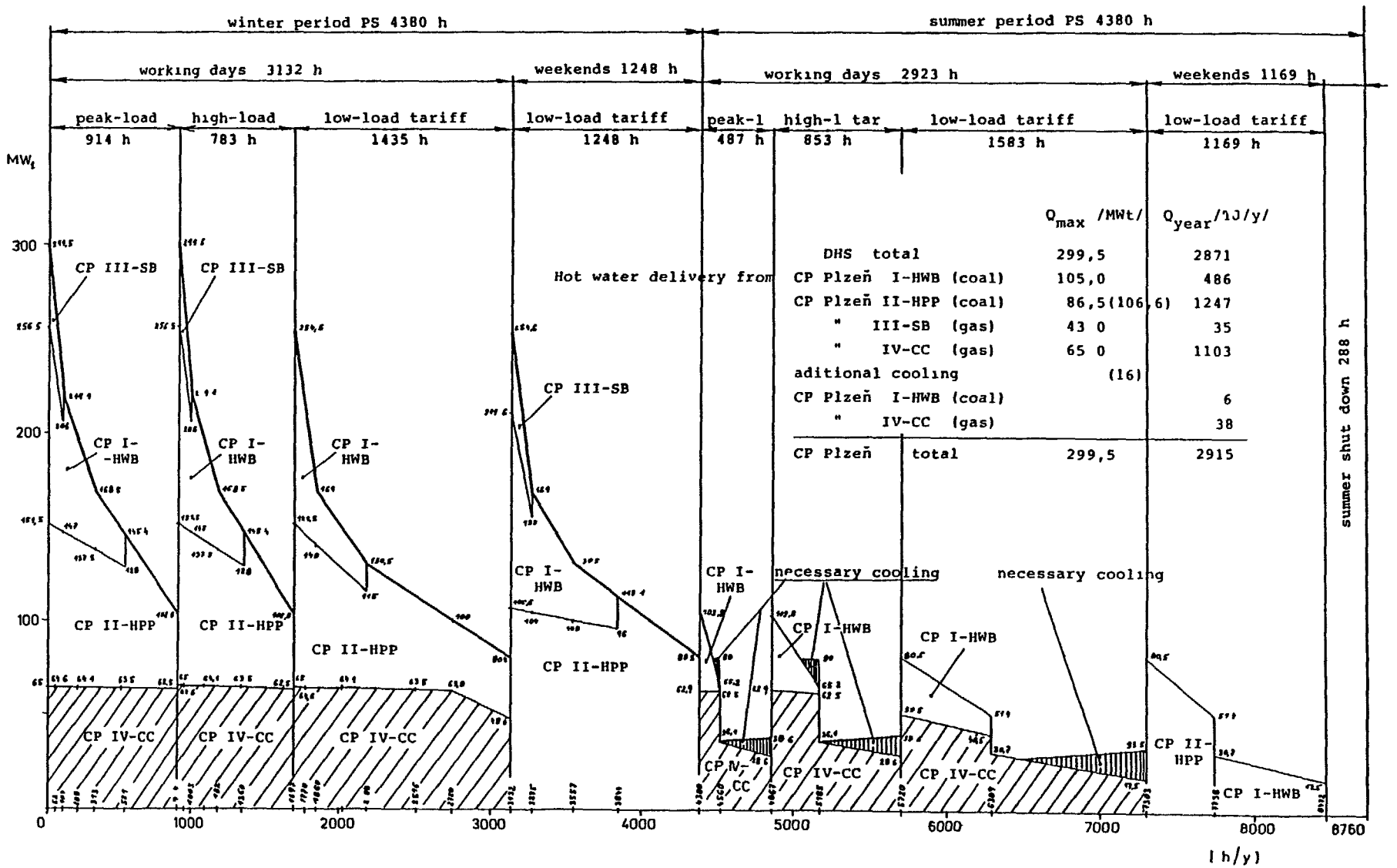


		max power output P /MWe/	power generation E /GWh/y/
- CP Plzeň total	ΣP	211,2	958 5
combined cycle	P_{CC}	167 4	796 3
gas turbosets	P_{GT}	133,2	607,0
steam turb of CC	P_{ST}	33,6	189,3
back pressure turb	P_{BPT}	43,8	162,2
- gas consumption in CC		377 MW_t	6480 TJ/y

32

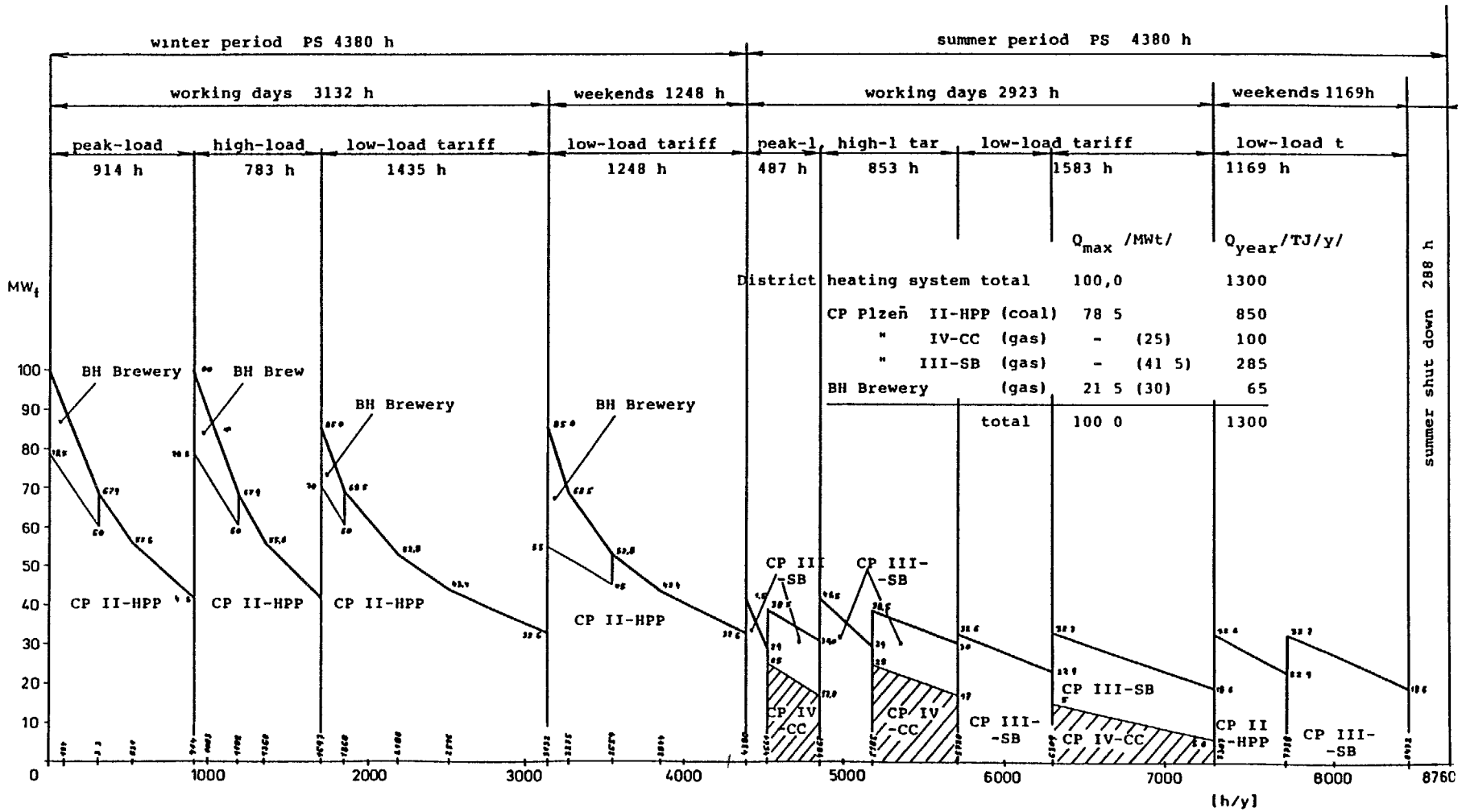
CP Plzen Alt A Var 2 year 2000 - high balance - CC with 1x GT V64 3 Siemens + 1x back-pressure steam turbine with extraction

Diagram of hot water delivery (lasting curve according to the ambient temperature) divided into particular tariff ranges in Power system (PS)



CP Plzeň Alt A Var 2 year 2000 - high balance - CC with GT V64 3 Siemens + 1x back-pressure steam turbine with extraction

Diagram of steam delivery (lasting curve according to the ambient temperature) divided into particular tariff ranges in Power system (PS)



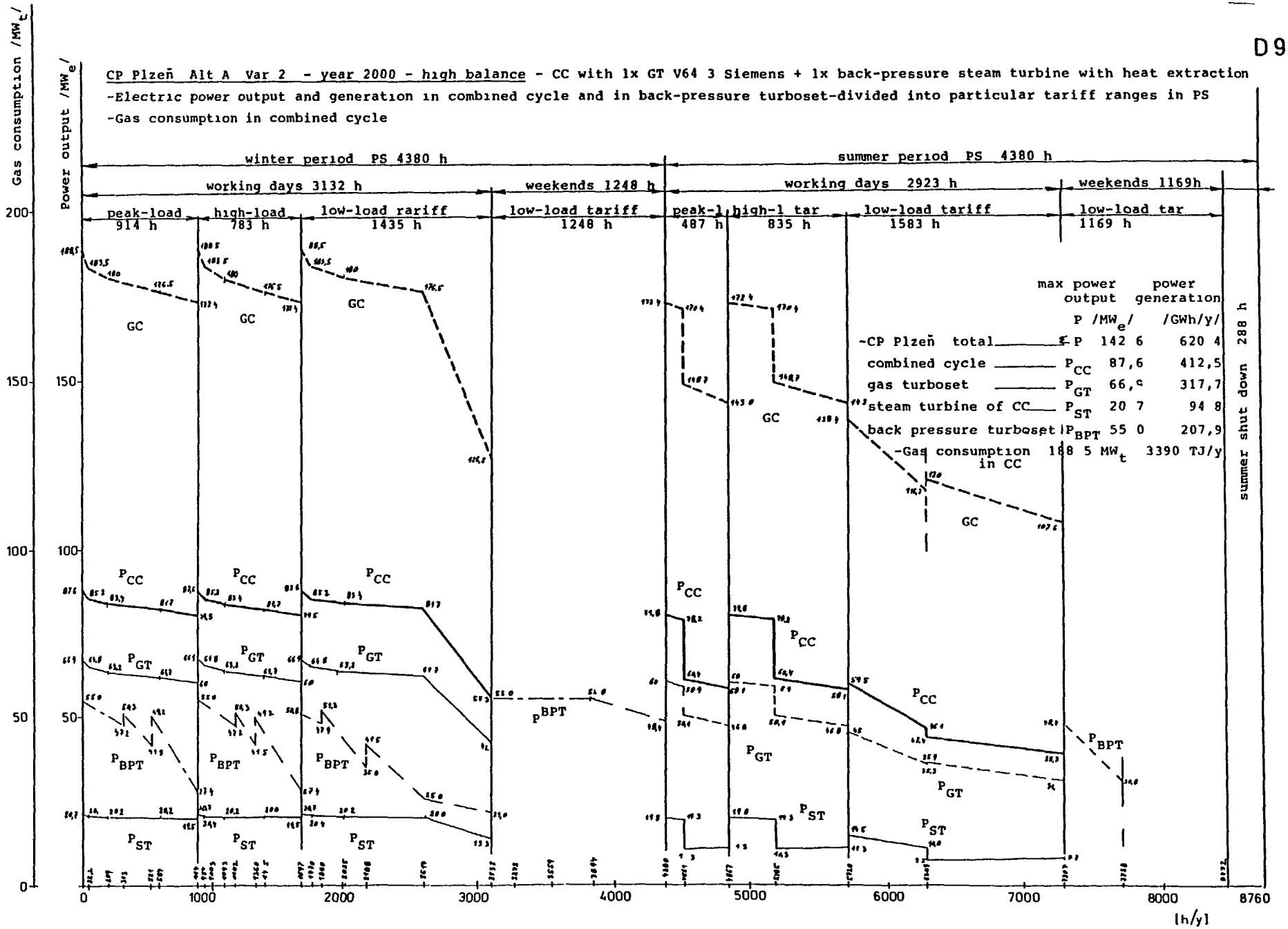
		Q_{max} /MWt/	Q_{year}/TJ/y/
District heating system total		100,0	1300
CP Plzeň II-HPP	(coal)	78 5	850
" IV-CC	(gas)	- (25)	100
" III-SB	(gas)	- (41 5)	285
BH Brewery	(gas)	21 5 (30)	65
	total	100 0	1300

D9

CP Plzeň Alt A Var 2 - year 2000 - high balance - CC with 1x GT V64 3 Siemens + 1x back-pressure steam turbine with heat extraction

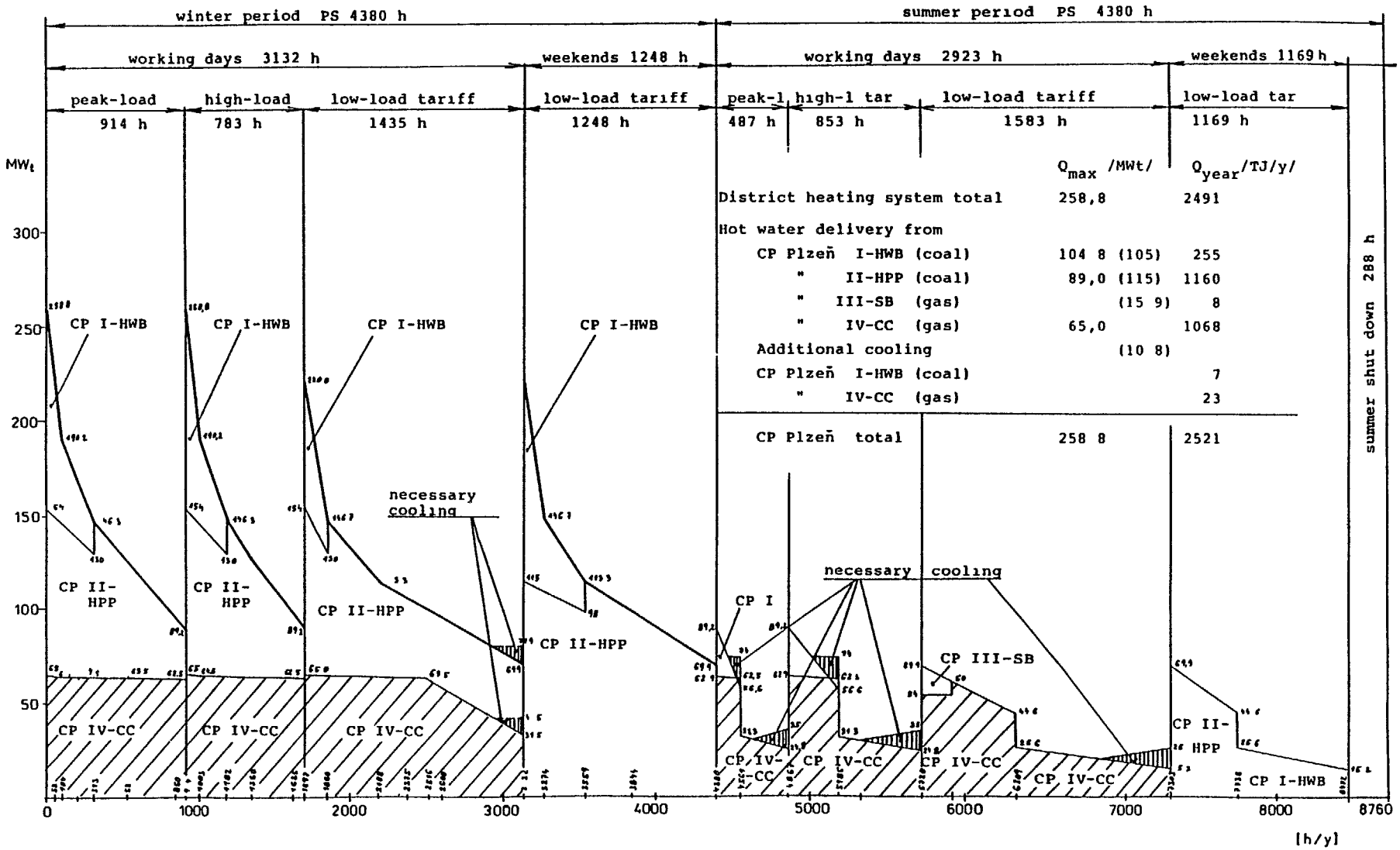
-Electric power output and generation in combined cycle and in back-pressure turboset-divided into particular tariff ranges in PS

-Gas consumption in combined cycle



CP Plzeň Alt A Var 2 year 2000 - low balance - CC with 1x GT V64 3 Siemens + 1x back-pressure steam turbine with extraction

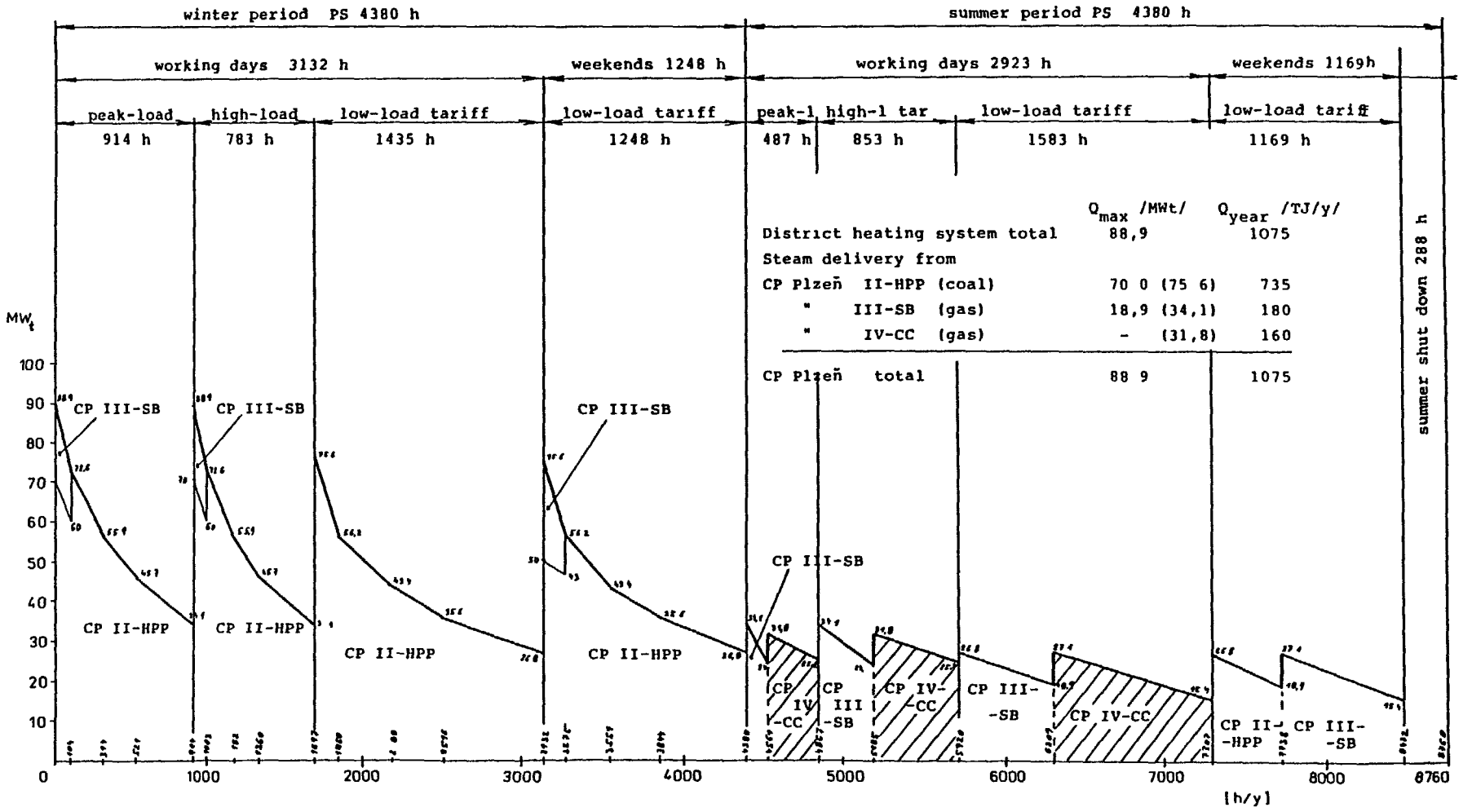
Diagram of hot water delivery (lasting curve according to the ambient temperature) divided into particular tariff ranges in Power system (PS)



	Q_{max} /MWt/		Q_{year}/TJ/y/
District heating system total	258,8		2491
Hot water delivery from			
CP Plzeň I-HWB (coal)	104 8	(105)	255
" II-HPP (coal)	89,0	(115)	1160
" III-SB (gas)		(15 9)	8
" IV-CC (gas)	65,0		1068
Additional cooling		(10 8)	
CP Plzeň I-HWB (coal)			7
" IV-CC (gas)			23
CP Plzeň total	258 8		2521

CP Plzen Alt A Var 2 year 2000 - low balance - CC with GT V64 3 Siemens + 1x back-pressure steam turbine with extraction

Diagram of steam delivery (lasting curve according to the ambient temperature) divided into particular tariff ranges in Power system (PS)

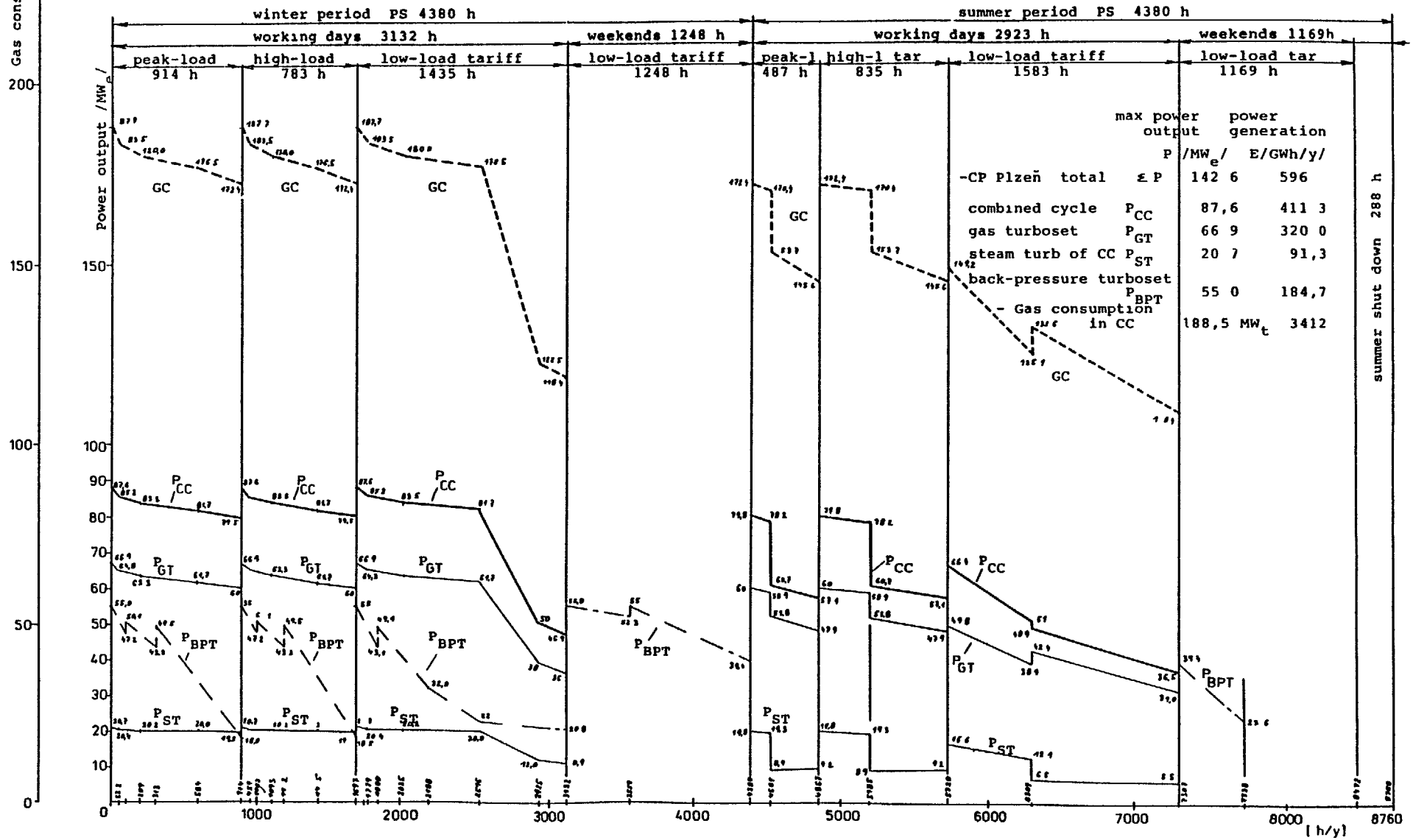


	Q_{max} /MWt/	Q_{year} /TJ/y/
District heating system total	88,9	1075
Steam delivery from		
CP Plzeň II-HPP (coal)	70 0 (75 6)	735
" III-SB (gas)	18,9 (34,1)	180
" IV-CC (gas)	- (31,8)	160
CP Plzeň total	88 9	1075

CP Plzeň Alt A Var 2 - year 2000 - low balance - CC with 1x GT V64 3 Siemens + 1x back-pressure steam turbine with heat extraction

-Electric power output and generation in combined cycle and in steam back-pressure turboset-divided into particular tariff ranges in PS

-Gas consumption in combined cycle

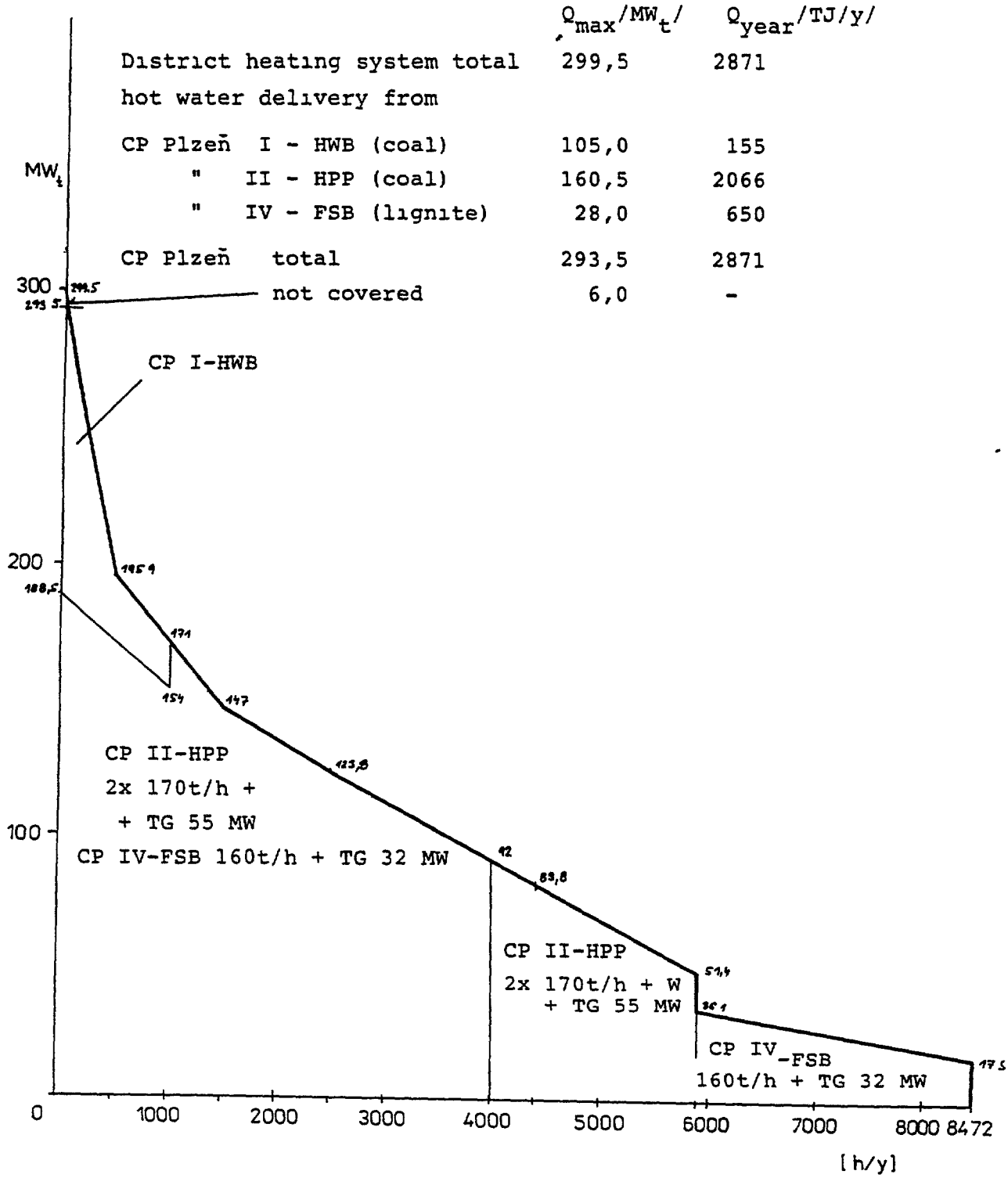


CP Plzeň Alt.B year 2000 - high balance

CP IV = Fluidized bed boiler 160 t/h + condense turbine 32 MW with heat extractions

Diagram of hot water delivery

	Q_{max}/MW_t/	Q_{year}/TJ/y/
District heating system total	299,5	2871
hot water delivery from		
CP Plzeň I - HWB (coal)	105,0	155
" II - HPP (coal)	160,5	2066
" IV - FSB (lignite)	28,0	650
CP Plzeň total	293,5	2871
not covered	6,0	-

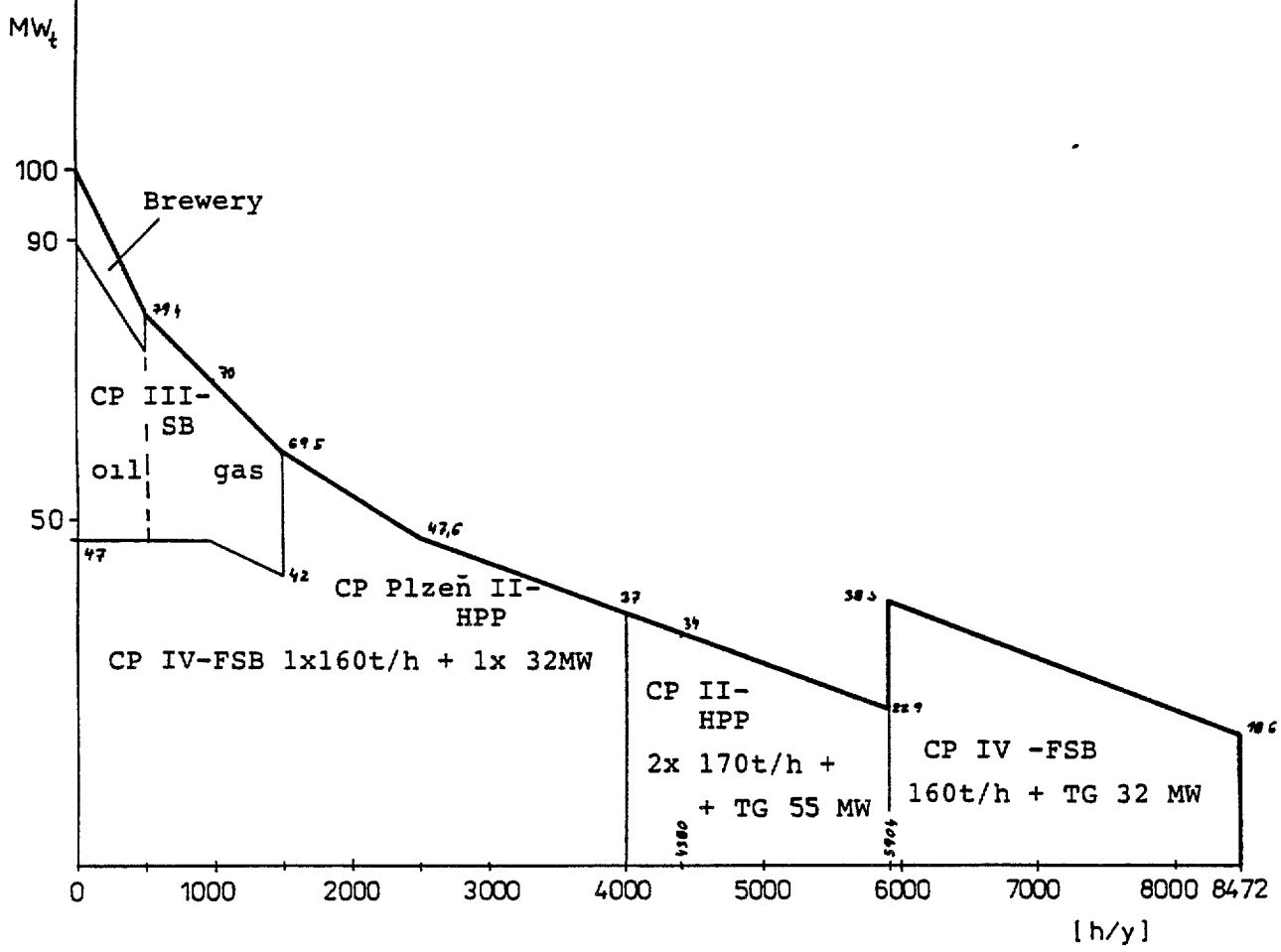


CP Plzeň Alt B year 2000 high balance

CP IV = Fluidized bed boiler 160 t/h+ condense turbine 32 MW with heat extractions

Diagram of steam delivery

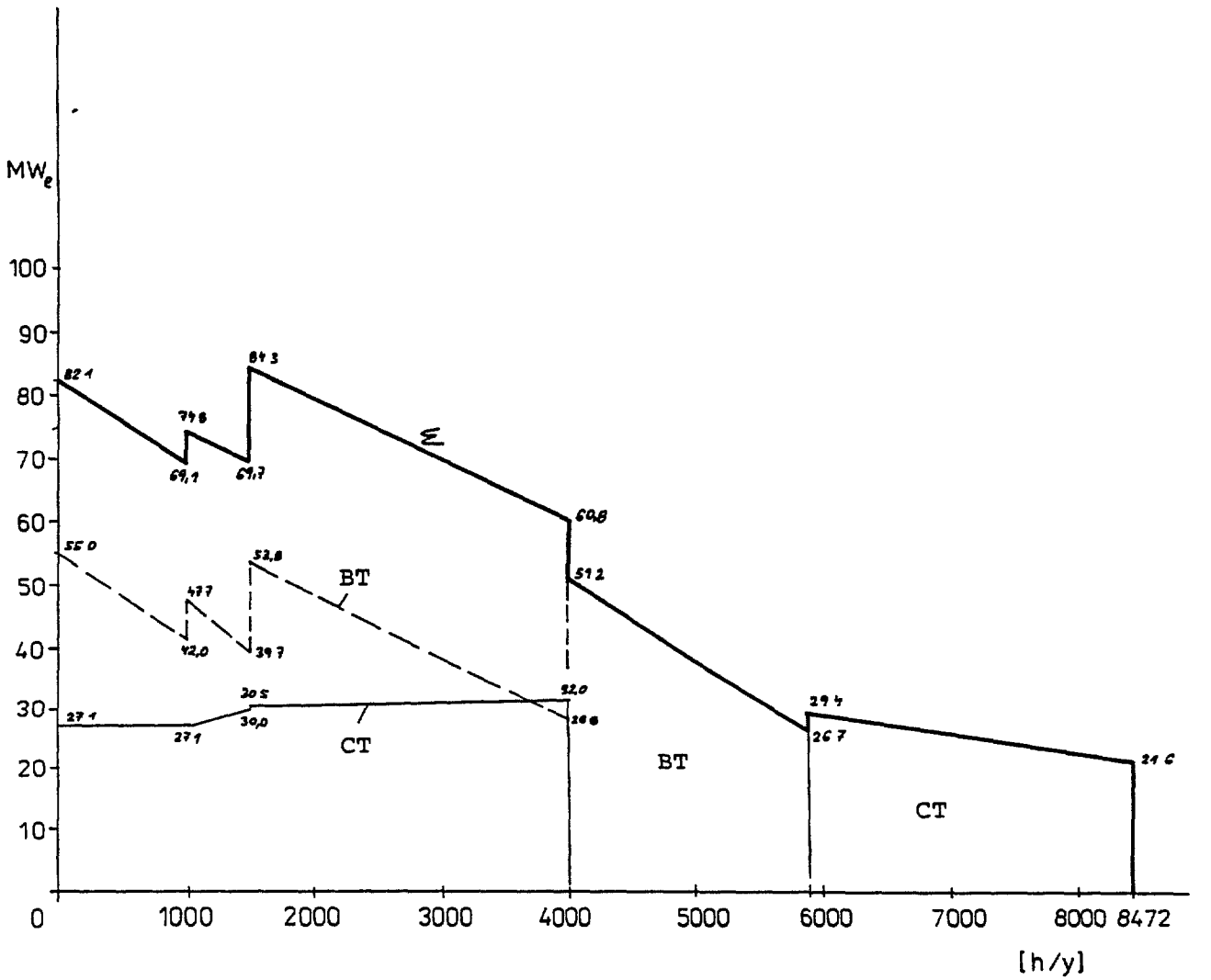
	Q_{max}/MW_t/	Q_{year}/TJ/y/	
District heating system total	100,0	1300	
steam delivery from			
CP Plzeň II - HPP (coal)	(19,5)	308	
" IV - FSB (lignite)	47,0	828	
" III - SB (oil+gas)	43,0	150	70 oil 80 gas
Brewery	10,0	14	



CP Plzeň Alt B year 2000 - high balance

Electric power output and generation

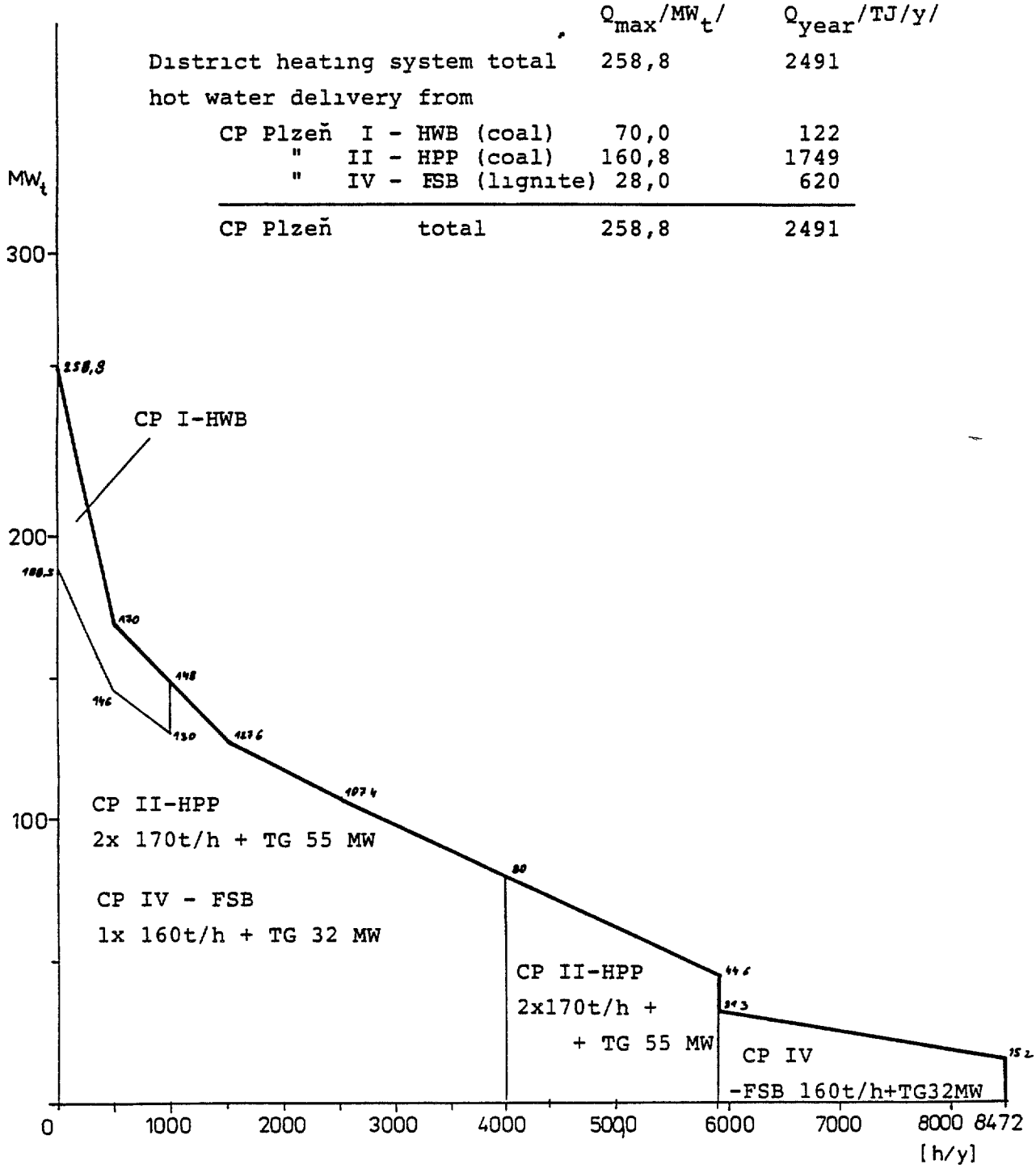
	max power output MW_e	power generation GWh/y
Condense extr.turb (CT)	32,0	185,0
Back-pressure extraction turb (BT)	55,0	250,3
total	87,0	435,3



CP Plzeň Alt B year 2000 - low balance

CP IV=Fluidized bed boiler 160 t/h + condense turbine
32 MW with heat extraction
Diagram of hot water delivery

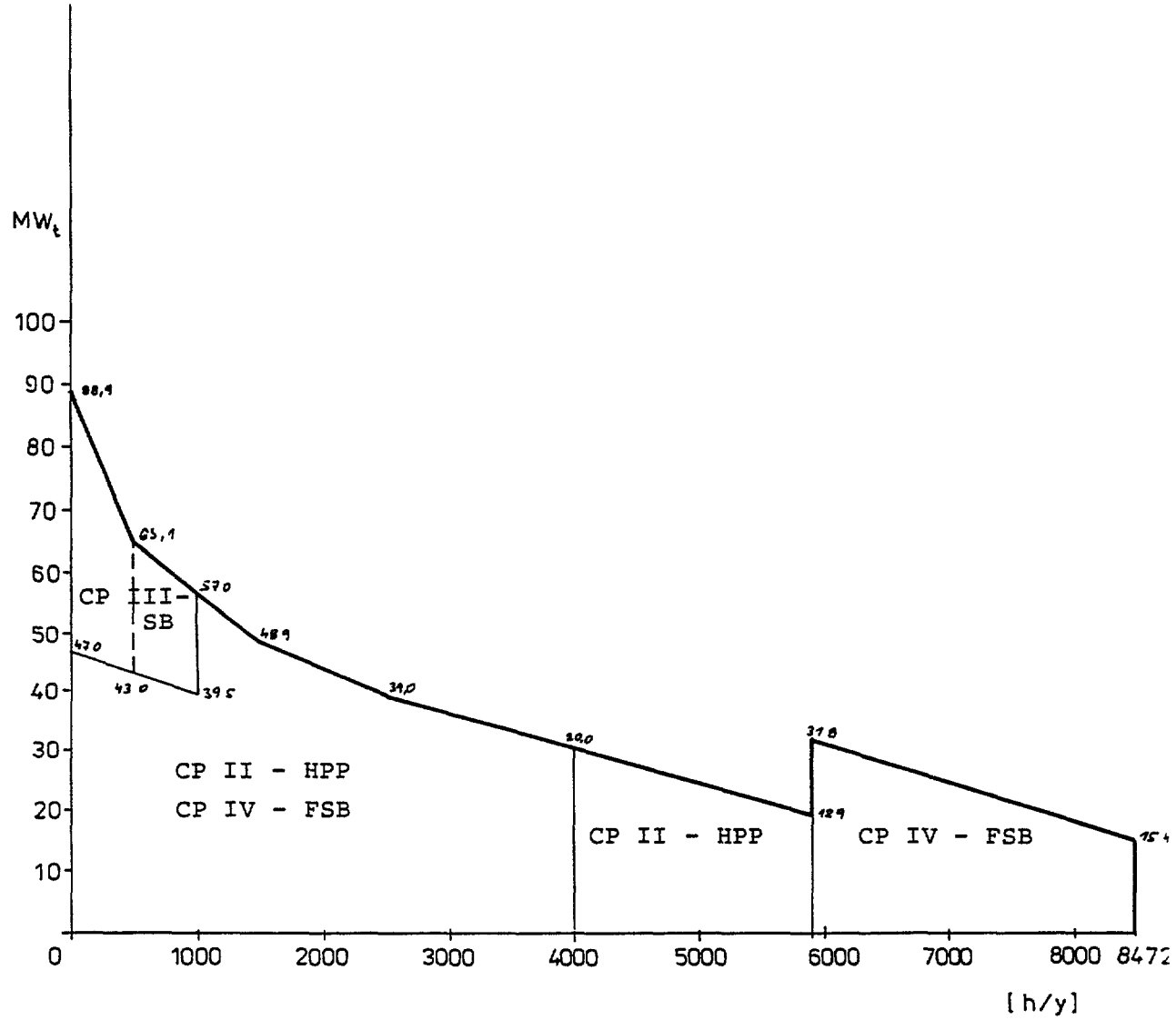
	Q_{max}/MW_t/	Q_{year}/TJ/y/
District heating system total	258,8	2491
hot water delivery from		
CP Plzeň I - HWB (coal)	70,0	122
" II - HPP (coal)	160,8	1749
" IV - FSB (lignite)	28,0	620
CP Plzeň total	258,8	2491



CP Plzeň Alt B year 2000 - low balance

CP IV=Fluidized bed boiler 160 t/h + condense turbine
32 MW with heat extractions
Diagram of steam delivery

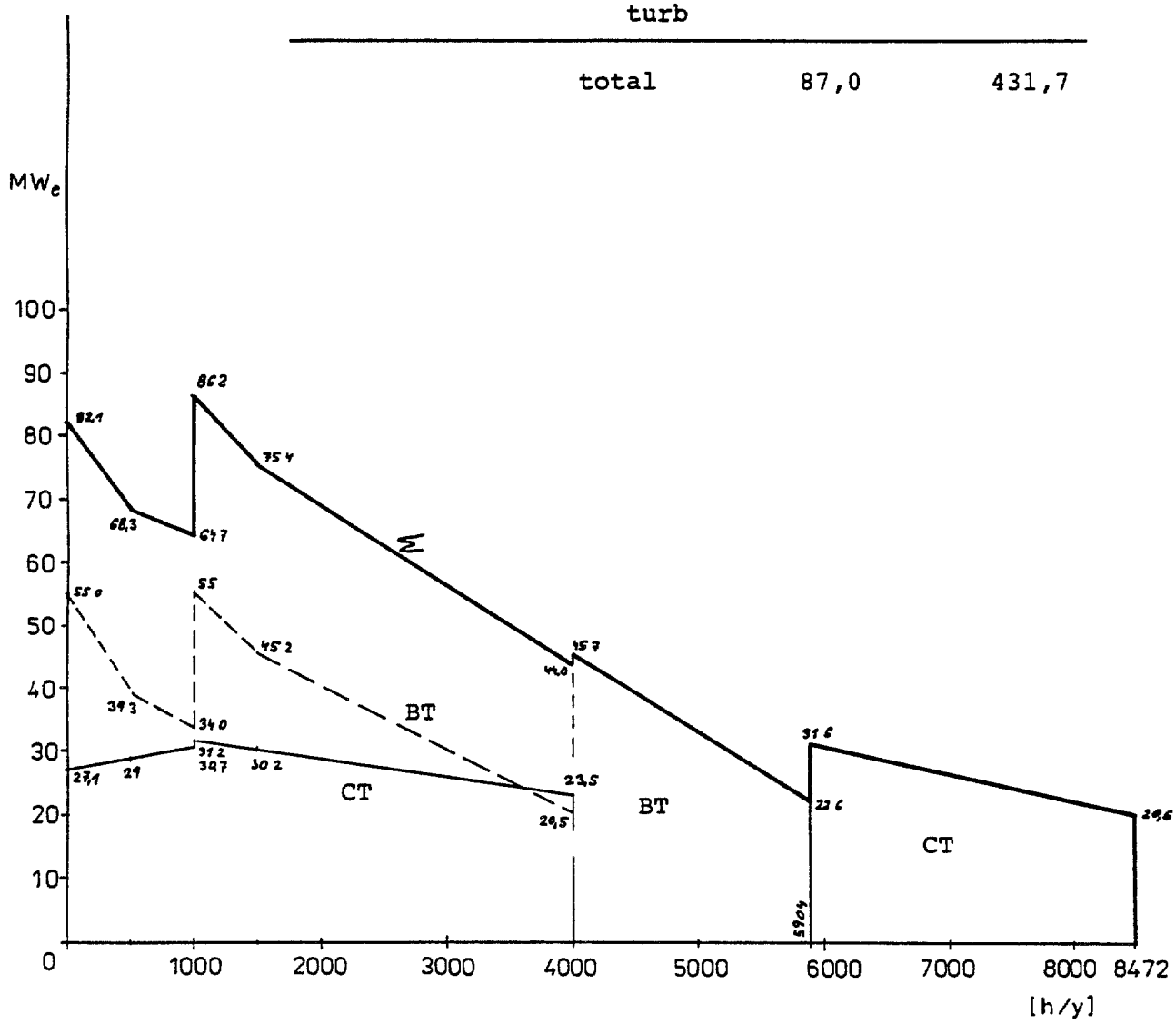
			Q_{max}/MW_t/	Q_{year}/TJ/y/	
District heating system total			88,9	1075	
steam delivery from					
CP Plzeň	II - HPP	(coal)	(22)	332	
"	IV - FSB	(lignite)	47	670	
"	III - SB	(oil - gas)	43,0	73	50 oil 23 gas



CP Plzeň Alt B year 2000 - low balance

Electric power output and generation

		max power output MW_e	power generation GWh/y
Condense extract turb	CT	32,0	182,3
Back-pressure extraction turb	BT	55,0	231,4
total		87,0	431,7



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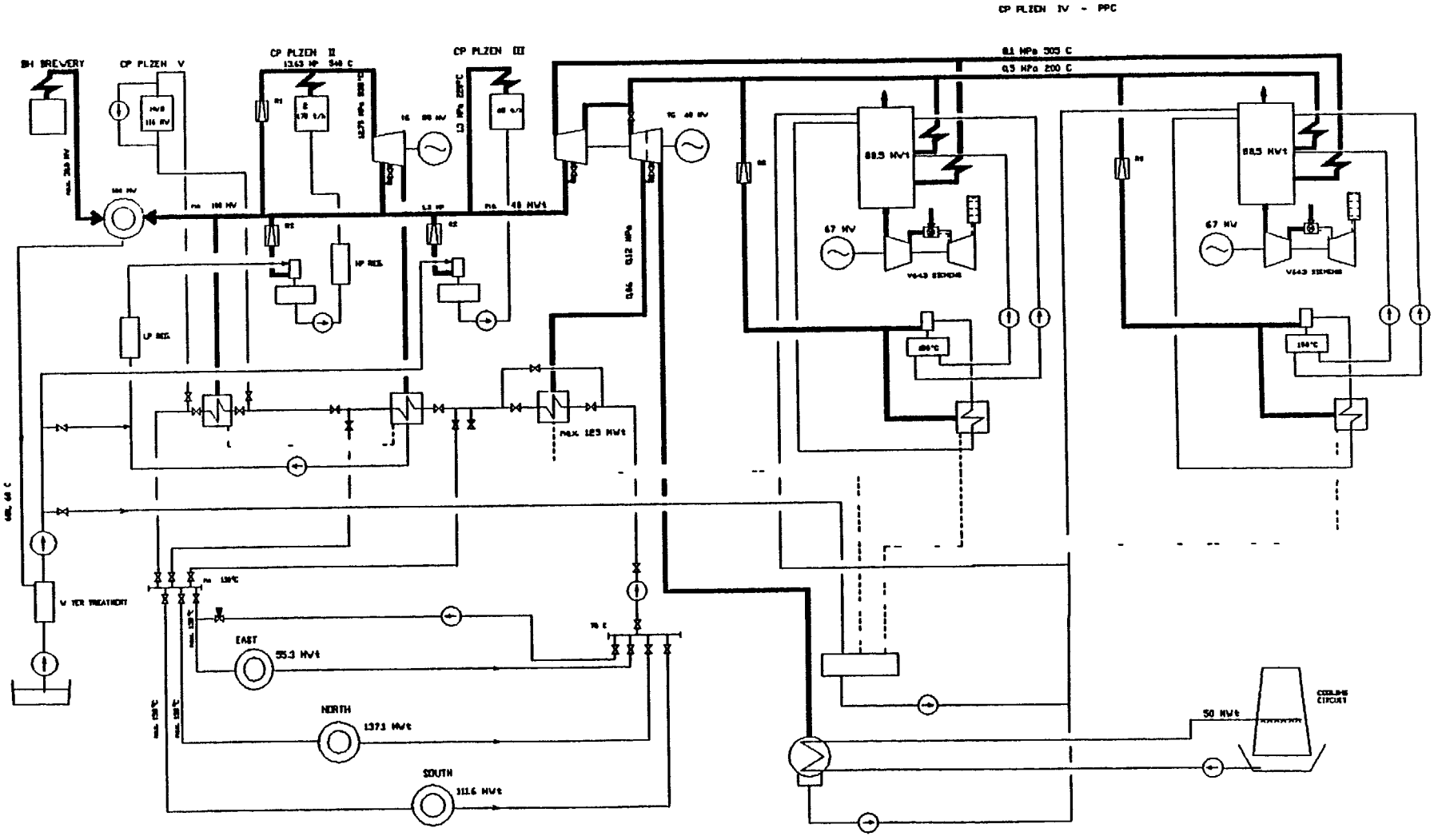
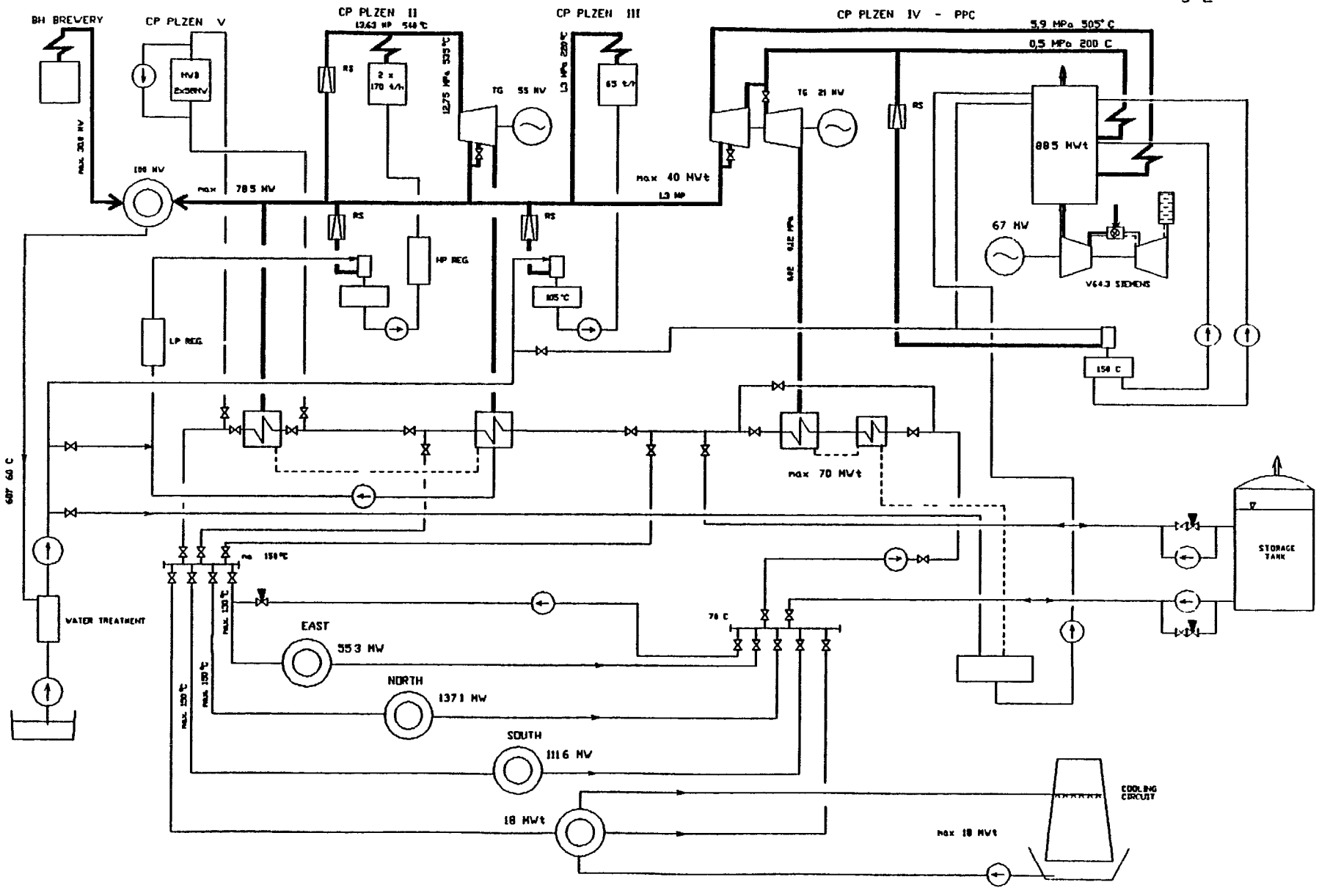
CP PLZEN Alt A var 1



CP PLZEN Alt A, var 2

S 2



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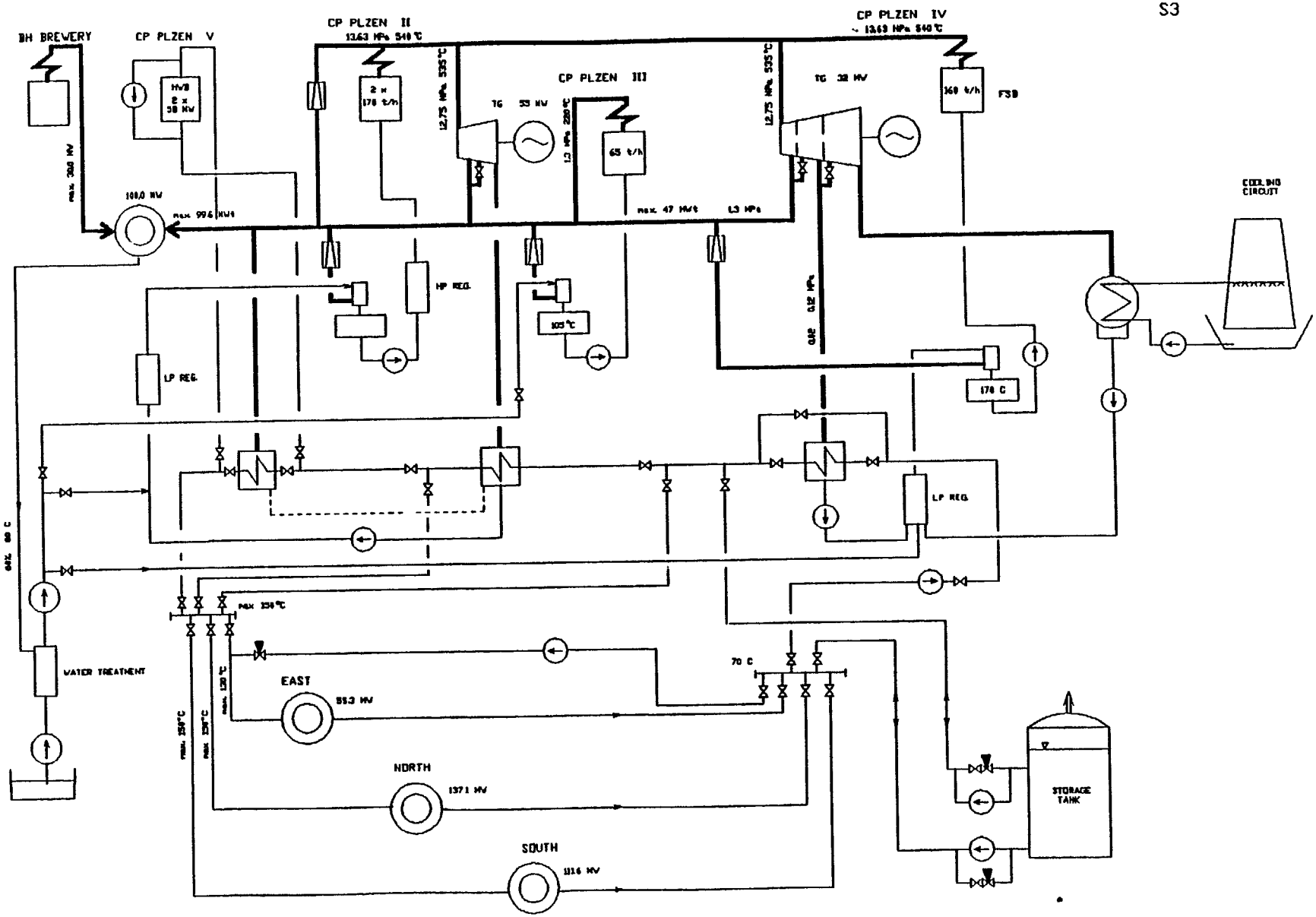
CP PLZEN ALT B

S3



Investment costs (IC) of new DHS networks and heat exchanger stations high balance									Tab 26
Year		1993	1994	1995	1996	1997	2000	2005	2010
Pipeline North									
New consumers									
promised from ZCE	MWt		0 5	0 7	0 7	2 5	2 5	2 5	2 5
connected boilers	MWt			4 4	4 4	4 4	4 4	4 4	4 4
new commercial	MWt			1 9	2 9	4 0	12 5	15 1	17 1
Total	MWt		0 5	7 0	8 0	10 9	19 4	22 0	24 0
Increase of delivery	MWt		0 5	6 5	1 0	2 9	8 5	2 6	2 0
IC new branch pipelines	mio CK		0 3	3 9	0 6	1 7	5 1	1 6	1 2
IC new heat exchanger st	mio CK		0 4	5 2	0 8	2 3	6 8	2 1	1 6
Pipeline South									
New consumers									
promised from ZCE	MWt	3 0	12 8	14 8	16 7	17 8	17 8	17 8	17 8
connected boilers	MWt		2 9	5 4	7 8	9 5	9 5	9 5	9 5
Total	MWt	3 0	15 7	20 2	24 5	27 3	27 3	27 3	27 3
Increase of delivery	MWt	3 0	12 7	4 5	4 3	2 8	0 0	0 0	0 0
IC New branch pipelines	mio CK	1 8	7 6	2 7	2 6	1 7	0 0	0 0	0 0
IC New heat exchanger st	mio CK	2 4	10 2	3 6	3 4	2 2	0 0	0 0	0 0
Pipeline East									
New hot water mains									
East I (2 x DN 400 350)	mio CK			32 3					
New consumers									
promised from ZCE	MWt				5 6	7 1	7 1	7 1	7 1
connected boilers	MWt				4 5	5 1	8 8	8 8	8 8
Total	MWt				10 1	12 2	15 9	15 9	15 9
Increase of delivery	MWt				10 1	2 1	3 7	0 0	0 0
IC New branch pipelines	mio CK				6 1	1 3	2 2	0 0	0 0
IC New heat exchanger st	mio CK				8 1	1 7	3 0	0 0	0 0
IC TOTAL	mio CK	4 2	18 5	47 7	21 6	10 9	17 1	3 6	2 8

Investment costs (IC) of new DHS networks and heat exchanger stations low balance									Tab 27
Year		1993	1994	1995	1996	1997	2000	2005	2010
Pipeline North									
New consumers									
promised from ZCE	MWt		0 4	0 5	0 5	1 9	1 9	1 9	1 9
connected boilers	MWt			3 5	3 5	3 5	3 5	3 5	3 5
new commercial	MWt			1 0	1 0	1 0	1 0	1 0	1 0
Total	MWt		0 4	5 0	5 0	6 4	6 4	6 4	6 4
Increase of delivery	MWt		0 4	4 6	0 0	1 4	0 0	0 0	0 0
IC New branch pipelines	mio CK		0 2	2 8	0 0	0 8	0 0	0 0	0 0
IC New heat exchanger st	mio CK		0 3	3 7	0 0	1 1	0 0	0 0	0 0
Pipeline South									
New consumers									
promised from ZCE	MWt	2 3	9 6	11 1	12 5	13 4	13 4	13 4	13 4
connected boilers	MWt		1 7	3 2	4 7	5 7	5 7	5 7	5 7
Total	MWt	2 3	11 3	14 3	17 2	19 1	19 1	19 1	19 1
Increase of delivery	MWt	2 3	9 0	3 0	2 9	1 9	0 0	0 0	0 0
IC New branch pipelines	mio CK	1 4	5 4	1 8	1 7	1 1	0 0	0 0	0 0
IC New heat exchanger st	mio CK	1 8	7 2	2 4	2 3	1 5	0 0	0 0	0 0
Pipeline East									
New hot water mains									
East I (2 x DN 400 350)	mio CK			32 3					
New consumers									
promised from ZCE	MWt				4 2	5 3	5 3	5 3	5 3
connected boilers	MWt					0 6	2 2	3 4	3 4
Total	MWt				4 2	5 9	7 5	8 7	8 7
Increase of delivery	MWt				4 2	1 7	1 6	1 2	0 0
IC New branch pipelines	mio CK				2 5	1 0	1 0	0 7	0 0
IC New heat exchanger st	mio CK				3 4	1 4	1 3	1 0	0 0
IC TOTAL	mio CK	3 2	13 2	42 9	9 9	7 0	2 2	1 7	0 0

Qualitative charakteristics of solid fuels in CP Plzeň						Tab 28
fuel type			lignite Sokolov	lignite Sokolov	black coal	black coal
comb equip type			existing coal	fluid bed boiler	grate boilers	granulating boilers
LHV	Q_i (r)	MJ/kg	12 7	10 1	18 5	17 4
moisture	W_t (r)	%	34 0 37 1	36 6	11 2	11 2
ash in fuel	A (r)	%	13 4 18 5	23 8	30 4	33 2
ash in dry sample	A (d)	%	20 3 29 4	37 5	34 2	37 4
combustibles cont	V (r) + NV (r)	%	44 4 52 6	39 6	58 4	55 6
in this	V (r)	%	25 5 30 2	22 8	21 9	20 9
volatiles	Vdaf	%	55 0 60 0	55 0 60 0	35 0 40 0	35 0 40 0
non volatile	NV (r)	%	18 9 22 4	16 8	36 5	34 8
combustibles	NVdaf	%	40 0 45 0	40 0 45 0	60 0 65 0	60,0 65 0
sulphur in fuel	S (r)	%	0 5 0 95	1 5	0 4	0 4
sulphur cont in dry sample	S (d)	%	0 8 1 5	2 4	0 5	0 5

Characteristics of operation of cooperating steamboilerhouse of Westbohemian Brewery in steam DHS of CP Plzen

Tab 29

year	Unit	1997	2000	2005	2010
Alt A var 1 high balance					
Max heat output	MWt	(30)	(30)	10 6 (30)	12 6 (30)
Annual heat delivery	TJ/y	23	23	10	11
Consumption of heat in fuel	TJ/y	27 1	27 1	11 9	13 0
Natural gas consumption	$10^3 m^3/y$	811 4	811 4	356 3	389 2
Alt A, var 1 low balance					
Max heat output	MWt			13 2	13 2
Annual heat delivery	TJ/y			15 0	15 0
Consumption of heat in fuel	TJ/y			17 7	17 7
Natural gas consumption	$10^3 m3/y$			529 9	529 9
Alt A var 2 high balance					
Max heat output	MWt	21 5 (30)	21 5 (30)	14 6	14 6
Annual heat delivery	TJ/y	65	65	19	19
Consumption of heat in fuel	TJ/y	76 0	76 0	22 4	22 4
Natural gas consumption	$10^3 m^3/y$	2275	2275	670 7	670 7
Alt A, var 2 low balance					
Max heat output	MWt			18 9	18 9
Annual heat delivery	TJ/y			43	43
Consumption of heat in fuel	TJ/y			50 5	50 5
Natural gas consumption	$10^3 m^3/y$			1512	1512
Alt B high balance					
Max heat delivery	MWt	10	10		
Annual heat delivery	TJ/y	14	14		
Consumption of heat in fuel	TJ/y	16 5	16 5		
Natural gas consumption	$10^3 m^3/y$	494	494		

Repair and maintenance costs, overhead costs other material costs in CP PLZEN — Tab 30

Price level y 1993

	Units	y 1992	y 1997	y 2000	y 2005	y 2010
Alternative A Var 1 High balance						
Repair and maintenance costs	mio CK	48 9	73 3	73 3	71 2	71 2
Overhead cost	mio CK	24 6	34 0	34 0	33 0	33 0
Other material costs	mio CK	1 5	1 3	1 3	1 2	1 2
Total	mio CK	75 0	108 6	108 6	105 4	105 4
Alternative A Var 1 - Low balance						
Repair and maintenance costs	mio CK	48 9	73 3	73 3	68 2	68 2
Overhead costs	mio CK	24 6	34 0	34 0	32 5	32 5
Other material costs	mio CK	1 5	1 2	1 2	1 1	1 1
Total	mio CK	75 0	108 5	108 5	101 8	101 8
Alternative A Var 2 - High balance						
Repair and maintenance costs	mio CK	48 9	66 0	66 0	65 1	65 1
Overhead cost	mio CK	24 6	33 1	33 1	32 4	32 4
Other material costs	mio CK	1 5	1 5	1 5	1 3	1 3
Total	mio CK	75 0	100 6	100 6	98 8	98 8
Alternative A Var 2 - Low balance						
Repair and maintenance costs	mio CK	48 9	66 0	66 0	62 1	62 1
Overhead costs	mio CK	24 6	33 1	33 1	31 9	31 9
Other material costs	mio CK	1 5	1 4	1 4	1 2	1 2
Total	mio CK	75 0	100 5	100 5	95 2	95 2
Alternative B Var 1 - High balance						
Repair and maintenance costs	mio CK	48 9	73 9	73 9	69 7	69 7
Overhead costs	mio CK	24 6	37 2	37 2	35 4	35 4
Other material costs	mio CK	1 5	2 0	2 0	1 7	1 7
Total	mio CK	75 0	113 1	113 1	106 8	106 8
Alternative B Var 1 - Low balance						
Repair and maintenance costs	mio CK	48 9	70 4	70 4	66 3	66 3
Overhead costs	mio CK	24 6	35 3	35 3	33 8	33 8
Other material costs	mio CK	1 5	1 8	1 8	1 5	1 5
Total	mio CK	75 0	107 5	107 5	101 6	101 6
Alternative B Var 2 - High balance						
Repair and maintenance costs	mio CK	48 9	77 4	77 4	73 3	73 3
Overhead costs	mio CK	24 6	38 6	38 6	36 7	36 7
Other material costs	mio CK	1 5	2 2	2 2	1 9	1 9
Total	mio CK	75 0	118 2	118 2	111 9	111 9
Alternative B Var 2 - Low balance						
Repair and maintenance costs	mio CK	48 9	73 8	73 8	69 5	69 5
Overhead costs	mio CK	24 6	36 8	36 8	35 5	35 5
Other material costs	mio CK	1 5	2 0	2 0	1 7	1 7
Total	mio CK	75 0	112 6	112 6	106 7	106 7

Repair and maintenance costs overhead costs other material costs in CP PLZEN — Tab 31

Price level y 1996

	Units	y 1992	y 1997	y 2000	y 2005	y 2010
Alternative A Var 1 High balance						
Repair and maintenance cost	mio CK	46 9	89 4	89 4	86 9	86 9
Overhead costs	mio CK	24 6	40 1	40 1	38 9	38 9
Other material costs	mio CK	1 5	1 6	1 6	1 5	1 5
Total	mio CK	75 0	131 2	131 2	127 [illegible]	127 3
Alternative A Var 1 - Low balance						
Repair and maintenance costs	mio CK	46 9	89 4	89 4	83 2	83 2
Overhead costs	mio CK	24 6	40 1	40 1	38 4	38 4
Other material costs	mio CK	1 5	1 5	1 5	1 4	1 4
Total	mio CK	75 0	131 0	131 0	122 9	122 9
Alternative A Var 2 - High balance						
Repair and maintenance costs	mio CK	48 9	80 5	80 5	79 4	79 4
Overhead cost	mio CK	24 6	39 1	39 1	38 2	38 2
Other material costs	mio CK	1 5	1 9	1 9	1 6	1 6
Total	mio CK	75 0	121 5	121 5	119 3	119 3
Alternative A Var 2 - Low balance						
Repair and maintenance cost	mio CK	48 9	80 5	80 5	75 8	75 8
Overhead cost	mio CK	24 6	39 1	39 1	37 6	37 6
Other material costs	mio CK	1 5	1 8	1 8	1 5	1 5
Total	mio CK	75 0	121 3	121 3	114 9	114 9
Alternative B Var 1 - High balance						
Repair and maintenance costs	mio CK	48 9	90 2	90 2	85 0	85 0
Overhead costs	mio CK	24 6	43 9	43 9	41	41 8
Other material costs	mio CK	1 5	2 5	2 5	2 1	2 1
Total	mio CK	75 0	136 6	136 6	128 9	128 9
Alternative B Var 1 - Low balance						
Repair and maintenance costs	mio CK	48 9	85 9	85 9	80 9	80 9
Overhead costs	mio CK	24 6	41 7	41 7	39 9	39 9
Other material costs	mio CK	1 5	2 3	2 3	1 9	1 9
Total	mio CK	75 0	129 8	129 8	122 6	122 6
Alternative B Var 2 - High balance						
Repair and maintenance costs	mio CK	48 9	94 4	94 4	89 4	89 4
Overhead costs	mio CK	24 6	45 5	45 5	43 3	43 3
Other material costs	mio CK	1 5	2 8	2 8	2 4	2 4
Total	mio CK	75 0	142 7	142 7	135 1	135 1
Alternative B Var 2 - Low balance						
Repair and maintenance costs	mio CK	48 9	90 0	90 0	84 8	84 8
Overhead costs	mio CK	24 6	43 4	43 4	41 9	41 9
Other material costs	mio CK	1 5	2 5	2 5	2 1	2 1
Total	mio CK	75 0	136 0	136 0	128 8	128 8

Repair and maintenance costs, overhead costs number of personnel in DHS networks Tab 3?

	Units	y 1992	y 1997	y 2000	y 2005	y 2010
High balance Price level y 1993						
Repair and maintenance costs	mio CK	11 0	13 5	13 9	1 9	14 1
Overhead costs	mio CK	3 0	4 6	4 9	5 0	5 0
Total	mio CK	14 0	16 1	18 8	16 9	19 1
Number of personnel	pers	1?	1?	18	19	19
Low balance - Price level y 1993						
Repair and maintenance costs	mio CK	11 0	12 8	12 9	12 9	12 9
Overhead costs	mio CK	3 0	4 2	4 2	4 3	4 3
Total	mio CK	14 0	17 0	17 1	17 2	17 2
Number of personnel	pers	12 0	15 0	15 0	15 0	15 0
High balance - Price level y 1996						
Repair and maintenance costs	mio CK	11 0	16 9	17 4	17 4	17 6
Overhead costs	mio CK	3 0	5 5	5 9	6 0	6 0
Total	mio CK	14 0	22 4	23 3	23 4	23 6
Number of personnel	pers	12 0	17 0	18 0	19 0	19 0
Low balance - Price level y 1996						
Repair and maintenance costs	mio CK	11 0	16 0	16 1	16 1	15 1
Overhead costs	mio CK	3 0	5 0	5 0	5 2	5 2
Total	mio CK	14 0	21 0	21 2	21 3	21 3
Number of personnel	pers	12 0	15 0	15 0	15 0	15 0

Alternative A - Emission, slagg production personnel, water consumption

Tab 19

	Units	y 1992	y 1995	y 1996	y 1997	y 2000	y 2005	y 2010
Alternative A Var 1 - High balance								
Emission ash	t/y	425 5	407 5	498 1	117 9	118 9	129 1	129 7
Emission SO2	t/y	4437 4	4206 5	5146 0	2031 2	2057 5	1640 5	1647 7
Emission NOx	t/y	1003 3	1010 6	1227 0	2641 9	2669 4	2517 7	2526 4
Emission CO	t/y	166 8	161 1	196 8	171 6	173 3	154 6	155 1
Emission CxHx	t/y	50 1	48 6	59 3	49 3	49 9	40 9	41 1
Slagg production	th t/y	49 5	46 4	56 9	69 4	70 2	58 6	58 7
Number of personnel	pers	293	293	293	300	300	270	270
Water consumption - raw	th m3/y	1100	1165	1407	2739	2757	2828	2837
- softened	th m3/y	68	71	96	97	99	99	100
- demineral	th m3/y	359	357	385	386	386	384	384
Alternative A Var 1 - Low balance								
Emission ash	t/y	425 5	390 0	466 1	111 1	107 6	111 6	111 3
Emission SO2	t/y	4437 4	4074 3	4819 1	1831 3	1782 2	1664 4	1655 7
Emission NOx	t/y	1003 3	969 1	1147 9	2452 0	2379 8	2362 7	2355 5
Emission CO	t/y	166 8	154 2	184 0	161 1	156 0	145 1	144 7
Emission CxHx	t/y	50 1	46 5	55 5	46 2	44 7	37 0	36 9
Slagg production	th t/y	49 5	44 4	53 3	62 7	61 1	56 7	56 4
Number of personnel	pers	293	293	293	300	300	266	266
Water consumption - raw	th m3/y	1100	1119	1314	2635	2545	2642	2633
softened	th m3/y	68	68	90	90	85	85	85
- demineral	th m3/y	359	352	349	343	343	343	343
Alternative A Var 2 - High balance								
Emission ash	t/y	425 5	407 5	498 1	99 2	100 1	118 4	119 0
Emission SO2	t/y	4437 4	4206 5	5146 0	2384 7	2404 7	2303 2	2312 6
Emission NOx	t/y	1003 3	1010 6	1227 0	2605 1	2627 4	2513 0	2522 3
Emission CO	t/y	166 8	161 1	196 8	172 4	173 9	147 5	148 1
Emission CxHx	t/y	50 1	48 6	59 3	55 6	56 1	43 3	43 4
Slagg production	th t/y	49 5	46 4	56 9	81 7	82 3	71 3	71 5
Number of personnel	pers	293	293	293	310	310	275	275
Water consumption - raw	th m3/y	1100	1165	1407	2093	2113	2115	2124
- softened	th m3/y	68	71	96	97	99	99	100
- demineral	th m3/y	359	352	385	386	386	384	384
Alternative A Var 2 - Low balance								
Emission ash	t/y	425 5	390 0	466 1	101 4	97 5	96 3	96 3
Emission SO2	t/y	4437 4	4024 3	4819 1	2189 2	2123 2	1938 9	1938 9
Emission NOx	t/y	1003 3	969 1	1147 9	2387 8	2317 1	2191 0	2191 0
Emission CO	t/y	166 8	154 2	184 0	151 2	146 4	128 9	128 9
Emission CxHx	t/y	50 1	46 5	55 5	47 3	45 6	36 6	36 6
Slagg productio	th t/y	49 5	44 4	53 3	71 5	69 6	62 8	62 8
Number of personnel	pers	293	293	293	310	310	271	271
Water consumption - raw	th m3/y	1100	1119	1314	1971	1904	1866	1866
- softened	th m3/y	68	68	90	90	85	85	85
- demineral	th m3/y	359	352	349	343	343	343	343

	Units	y 1992	y 1995	y 1996	y 1997	y 2000	y 2005	y 2010
Alternative B Var 1 High balance								
Emission ash	t/y	425 5	407 5	498 1	122 7	123 7	131 1	131 5
Emission SO2	t/y	4437 4	4206 5	5146 0	3686 4	3726 6	3650 4	3667 3
Emission NOx	t/y	1003 3	1010 6	1227 0	2828 2	2860 8	2776 7	2792 7
Emission CO	t/y	166 8	161 1	196 8	271 7	274 5	266 5	269 4
Emission CxHx	t/y	50 1	48 6	57 3	65 9	86 5	82 0	82 3
Slagg production	th t/y	49 5	46 4	56 9	137 1	138 3	132 4	132 9
Number of personnel	pers	293	293	293	323	323	295	295
Water consumption raw	th m3/y	1100	1165	1407	1940	1956	1947	1955
- softened	th m3/y	68	71	96	97	99	99	100
demineral	th m3/y	359	35	385	386	386	384	384
Alternative B Var 1 - Low balance								
Emission ash	t/y	425 5	390 0	466 1	113 7	110 6	115 2	115 2
Emission SO2	t/y	4437 4	4024 3	4819 1	3448 8	3341 7	3315 6	3315 6
Emission NOx	t/y	1003 3	969 1	1147 9	2637 0	2549 6	2513 0	2513 0
Emission CO	t/y	166 8	154 2	184 0	260 4	252 4	245 2	245 2
Emission CxHx	t/y	50 1	46 5	55 5	80 6	77 8	74 5	74 5
Slagg production	th t/y	49 5	44 4	53 3	128 7	124 7	121 8	121 8
Number of personnel	pers	293	293	293	313	313	291	291
Water consumption - raw	th m3/y	1100	1119	1314	1801	1747	1736	1736
- softened	th m3/y	68	68	90	90	85	85	85
- demineral	th m3/y	359	352	349	343	343	343	343
Alternative B Var 2 - High balance								
Emission ash	t/y	425 5	407 5	498 1	481 8	468 2	486 3	469 4
Emission SO2	t/y	4437 4	4206 5	5148 0	1839 3	1846 4	1822 3	1826 8
Emission NOx	t/y	1003 3	1010 6	1227 0	1630 8	1645 7	1592 2	1539 5
Emission CO	t/y	166 8	161 1	196 8	322 8	325 2	313 1	314 3
Emission CxHx	t/y	50 1	48 6	59 3	94 5	100 2	95 4	95 7
Slagg production	th t/y	49 5	46 4	56 9	107 2	107 3	102 8	103 2
Number of personnel	pers	293	293	293	330	330	302	302
Water consumption - raw	th m3/y	1100	1165	1407	1940	1956	1947	1955
softened	th m3/y	68	71	96	97	99	99	100
- demineral	th m3/y	359	352	385	386	386	384	384
Alternative B Var 2 - Low balance								
Emission ash	t/y	425 5	390 0	466 1	448 8	435 3	440 2	440 2
Emission SO2	t/y	4437 4	4024 3	4819 1	1725 6	1671 5	1643 8	1643 8
Emission NOx	t/y	1003 3	969 1	1147 9	1519 8	1406 8	1429 1	1429 1
Emission CO	t/y	166 8	154 2	184 0	302 4	293 1	286 0	286 0
Emission CxHx	t/y	50 1	46 5	55 5	93 2	90 0	86 8	86 8
Slagg production	th t/y	49 5	44 4	53 3	100 8	97 7	94 7	94 7
Number of personnel	pers	293	293	293	320	320	298	298
Water consumption - raw	th m3/y	1100	1119	1314	1801	1747	1736	1736
- softened	th m3/y	68	68	90	90	85	85	85
- demineral	th m3/y	359	352	349	343	343	343	343

The input data for economic assessment — Tab 21

The input data		Units	Price level y 1995	Price level y 1996
Considered inflation rate after y 1995		%		6 0
Discount interest rate			8 0	7 0
Interest rate of investment loan for energy facilities providing by CZ banks			17 0	15 0
Investment loan payback time		years	10	10
Investment credit (ICI) grace period			during construction	
Frequency of part payments		year	1	1
Type of part payments			equal principal amortization	
Lifetime of investment		years	25	25
Depreciation rate new investment		%	4 0	4 0
Rate of income tax		%	45 0	42 0
Average annual wage personnel		th CK/y	85	120
Insurance fee (healt and social insurance)		%	36	36
Fuel price				
lignite (CP I+CP II up to y 1996)	12 70 MJ/kg	CK/t	443	660
		CK/GJ	34 88	51 97
- lignite (CP IV - FSB)	10,05 MJ/kg	CK/t	330	460
		CK/GJ	32 84	45 77
- coal (CP I from y 1997)	18,47 MJ/kg	CK/t	1135	1300
		CK/GJ	61 45	70 38
coal (CP II from y 1997)	17 38 MJ/kg	CK/t	907	1050
		CK/GJ	52 19	60 41
- oil (CP III + CP V)	41,60 MJ/kg	CK/t	3300	3800
		CK/GJ	79 33	91 35
- natural gas (CP III + CC)	35 40 MJ/m3	CK/m3	3 35	3 85
		CK/GJ	100 30	115 27
Price CaCO3 sorbent for FSB (Alt B)		CK/t	340	470
Price MgO sorbent for granul boilers (Alt B-Var 2)		CK/t	2500	3450
Specific price for ash and slagg transport and storing		CK/t	100	180
Selling price of fertilizer MgSO3 (Alt B-Var 2)		CK/t	1500	2000
Selling price of supplied electricity				
- of average 1 kW output during peak load tariff zone		CK/kW,month	229	320
		= CK/kW per year	2743	3840
- of 1 MWh electricity supplied				
- in peak load tariff zone		CK/MWh	666	932
- in high load tariff zone		CK/MWh	567	794
- in low load tariff zone		CK/MWh	522	731
Selling price of heat at the outlet of primary DHS networks (estimated as competitive price of heat from gas fired boilers - new boilers and reconstructed ones from coal to natural gas)		CK/GJ	170	240
Water price				
- raw water		CK/m3	56	85
- softened water		CK/m3	12 75	15.40
- demineral water		CK/m3	34 43	41 00

	Implement years	Technology equipment delivery mio Ck	Technology equipment mounting mio Ck	Building part mio Ck	Total IC mio Ck
Alt A - Var 1 - High balance					
CP III - 1 x SB 65 t/h	1994	45 5	10 0	7 5	63 0
Gas pipeline	1994	3	2	3 0	3 5
Baghouses for CP I HWB (2 x 35 t/h)	1995 1996	15 5	1 0	5	17 0
Switch granulating boilers CP II (2 x 170 t/h) to hard coal	1995-1996	75 0	35 0		110 0
Baghouses for CP II	1995-1996	34 7	2 2	1 1	38 0
Enlargement of circulation pumps station	1995-1996	1 5	3		1 8
CP IV - CC 2 x GT V 64 3 Siemens + ST					
- import 2 x GT (73,2 mio DEM)	1995-1996	1120 0	100 0		1220 0
czech delivery total	1995 1996	525 0	140 0	120 0	785 0
in this waste heat recovery boilers		195 0			
condensing turbine with heat extraction		105 0			
other technological equipment		225 0			
CP IV CC Total	1995-1996	1645 0	240 0	120 0	2005 0
Connection to the electric distribution network	1995-1996	13 0	2 0	5 0	20 0
Connect to the gas distrib network incl reducing station	1995-1996	9	6	8 5	10 0
CP V HWB (1 x 58 MW) gas + oil	2003-2004	57 0	10 0	9 0	76 0
Alt A Var 1 - High balance - TOTAL		1888 4	301 3	154 6	2344 3
Alt A - Var 1 - Low balance					
CP III - 1 x SB 65 t/h	1994	45 5	10 0	7 5	63 0
Gas pipeline	1994	3	2	3 0	3 5
Baghouses for CP I - HWB (2 x 35 t/h)	1995-1996	15 5	1 0	5	17 0
Switch granulating boilers CP II (2 x 170 t/h) to hard coal	1995-1996	75 0	35 0		110 0
Baghouses for CP II	1995-1996	34 7	2 2	1 1	38 0
Enlargement of circulation pumps station	1995-1996	1 5	3		1 8
CP IV - CC 2 x GT V 64 3 Siemens + ST					
- import 2 x GT (73,2 mio DEM)	1995-1996	1120 0	100 0		1220 0
- czech delivery total	1995-1996	525 0	140 0	120 0	785 0
in this waste heat recovery boilers		195 0			
condensing turbine with heat extraction		105 0			
other technological equipment		225 0			
CP IV CC - Total	1995-1996	1645 0	240 0	120 0	2005 0
Connection to the electric distribution network	1995-1996	13 0	2 0	5 0	20 0
Connect to the gas distrib network incl reducing station	1995-1996	9	6	8 5	10 0
Alt A Var 1 - Low balance - TOTAL		1831 4	291 3	145 6	2268 3

Investment costs (IC) Tab 23

	Implement year	Technology delivery mio CK	equipment mounting mio CK	Building part mio CK	Total IC mio CK
Alt A Var 2 - High balance					
CP III - 1 x SB 65 t/h	1994	45 5	10 0	7 5	63 0
Gas pipeline	1994	3	2	3 0	3 5
Baghouses for CP I - HWB (3 x 35 t/h)	1995 1996	23 3	1 5		25 7
Switch granulating boilers CP II (2 x 170 t/h) to hard coal	1995-1996	75 0	35 0		110 0
Baghouses for CP II	1995-1996	34 7	2 2	1 1	38 0
Enlargement of circulation pumps station	1995-1996	1 5	3		1 8
CP IV - CC 1 x GT V 64 3 Siemens + ST					
- import 1 x GT (36,6 mio DEM)	1995-1996	560 0	50 0		610 0
- czech delivery total	1995-1996	282 0	71 0	65 0	418 0
in this waste heat recovery boilers		100 0			
backpressure turb with regulated heat outlet		65 0			
other technological equipment		117 0			
CP IV - CC - Total	1995-1996	842 0	121 0	65 0	1028 0
Connection to the electric distribution network	1995-1996	6 5	1 0	2 5	10 0
Connect to the gas distrib network incl reducing station	1995-1996	8	5	6	8 0
CP V HWB (2 x 58 MW) gas + oil	2003-2004	112 0	19 5	14 5	146 0
Alt A Var 2 - High balance - TOTAL		1141 6	191 2	101 0	1433 6
Alt A - Var 2 - Low balance					
CP III - 1 x SB 65 t/h	1994	45 5	10 0	7 5	63 0
Gas pipeline	1994	3	2	3 0	3 5
Baghouses for CP I HWB (3 x 35 t/h)	1995-1996	23 3	1 5	7	25 5
Switch granulating boilers CP II (2 x 170 t/h) to hard coal	1995-1996	75 0	35 0		110 0
Baghouses for CP II	1995-1996	34 7	2 2	1 1	38 0
Enlargement of circulation pumps station	1995-1996	1 5	3		1 8
CP IV - CC 1 x GT V 64 3 Siemens + ST					
- import 1 x GT (36 6 mio DEM)	1995-1996	560 0	50 0		610 0
czech delivery total	1995-1996	282 0	71 0	65 0	418 0
in this waste heat recovery boilers		100 0			
backpressure turb with regulated heat outlet		65 0			
other technological equipment		117 0			
CP IV - CC - Total	1995-1996	842 0	121 0	65 0	1028 0
Connection to the electric distribution network	1995-1996	6 5	1 0	2 5	10 0
Connect to the gas distrib network incl reducing station	1995-1996	8	5	6 7	8 0
CP V HWB (1 x 58 MW) gas + oil	2003-2004	57 0	10 0	9 0	76 0
Alt A - Var 2 - Low balance - TOTAL		1086 6	181 7	95 5	1363 8

	Implement years	Technology delivery mio CK	equipment mounting mio CK	Building part mio CK	Total IC mio CK
Alt B Var 1 - High balance					
CP III 1 x SB 65 t/h	1994	45 5	10 0	7 5	63 0
Gas pipeline	1994	3	2	3 0	3 5
Baghouses for CP I - HWB (2 x 35 t/h)	1995-1996	23 3	1 5	7	25 5
Switch granulating boilers CP II (2 x 170 t/h) to hard coal	1995-1996	75 0	35 0		110 0
Baghouses for CP II	1995-1996	34 7	2 2	1 1	38 0
enlargement of ciriculation pumps station	1995-1996	1 5	3		1 8
CP IV - FSB 160 t/h + ST 32 MW	1995 1996	641 0	117 0	94 0	852 0
in this boiler house,incl baghouses,fuel handling equipment limestine handling		330 0			
backpressure turb 32 MW with requl heat outlet		82 0			
conneting pipes heating water equipment, compressor station		40 0			
electrical equipment,measurment and control equipment		69 0			
other costs (mounting extr charge,plant desing commissionning)		120 0			
CP V HWB (2 x 58 MW) gas + oil	2003-2004	112 0	19 5	14 5	146 0
Alt B - Var 1 High balance - TOTAL		933 3	185 7	120 8	1239 8
Alt B - Var 1 - Low balance					
CP III - 1 x SB 65 t/h	1994	45 5	10 0	7 5	63 0
Gas pipeline	1994	3	2	3 0	3 5
Baghouses for CP I - HWB (2 x 35 t/h)	1995-1996	15 5	1 0	5	17 0
Switch granulating boilers CP II (2 x 170 t/h) to hard coal	1995-1996	75 0	35 0		110 0
Baghouses for CP II	1995-1996	34 7	2 2	1 1	38 0
Enlargement of ciriculation pumps station	1995-1996	1 5			1 8
CP IV - FSB 160 t/h + ST 32 MW	1995-1996	641 0	117 0	94 0	852 0
in this boiler house,incl baghouses,fuel handling, equipment limestine handling		330 0			
backpressure turb 32 MW with requl heat outlet		82 0			
conneting pipes,heating water equipment compressor station		40 0			
electrical equipment,measurment and control equipment		69 0			
other costs (mounting extr charge,plant desing, commissionning)		120 0			
CP V HWB (1 x 58 MW) gas + oil	2003-2004	57 0	10 0	9 0	76 0
Alt B - Var 1 - Low balance - TOTAL		870 5	175 7	115 1	1161 3

Investment costs (IC)

Tab 24

	Implement year	Technology delivery mio DM	equipment mounting mio DM	building part mio DM	Total IC mio DM
Alt 6 Var 2 High balance					
CP III 1 x 58 65 t/h	1994	45 5	10 0	7 5	63 0
Gas pipeline	1994	3	2	3 0	3 5
Baghouses for CP I HWB (3 x 35 t/h)	1995-1996	7[illegible] 3	1 5	[illegible]	25 5
FGD of granulating boilers CP II (2 x 170 t/h) magnesium technology (HEPOS)	1995-1996	283 0	50 0	22 0	355 0
Enlargement of circulation pumps station	1995-1996	1 5	[illegible]		1 8
CP IV FSB 160 t/h + ST 32 MW	1995-1996	641 0	117 0	94 0	852 0
in this boiler house,incl baghouses fuel handling, equipment limestine handling		330 0			
backpressure turb 32 MW with regul heat outlet		82 0			
conneting pipes,heating water equipment					
compressor station		40 0			
electrical equipment,measurement and control equipment		69 0			
other costs (mounting extr charge,plant desing, commissionning)		120 0			
CP V HWB (2 x 58 MW) gas + oil	2003-2004	112 0	19 5	14 5	146 0
Alt 6 - Var 2 High balance TOTAL		1106 6	196 5	141 7	1446 0
Alt 6 Var 2 - Low balance					
CP III - 1 x 58 65 t/h	1994	45 5	10 0	7 5	63 0
Gas pipeline	1994	3	2	3 0	3 5
Baghouses for CP I - HWB (2 x 35 t/h)	1995-1996	15 5	1 0	5	17 0
FGD of granulating boiler CP II (2 x 170 t/h) - magnesium technology (HEPOS	1995-1996	283 0	50 0	22 0	355 0
Enlargement of circulation pumps station	1995-1996	1 5	3		1 8
CP IV - FSB 160 t/h + ST 32 MW	1995-1996	641 0	117 0	94 0	852 0
in this boiler house,incl baghouses,fuel handling, equipment limestine handling		30 0			
backpressure turb 32 MW with regul heat outlet		82 0			
conneting pipes,heating water equipment, compressor station		40 0			
electrical equipment,measurement and control equipment		69 0			
other costs (mounting extr charge plant desing commissionning)		120 0			
CP V HWB (1 x 58 MW) gas + oil	2003-2004	57 0	10 0	9 0	76 0
Alt 6 - Var 2 - Low balance - TOTAL		1043 8	188 5	136 0	1368 3

APPENDIX D:
RESULTS OF ENERGOPROJEKT ANALYSIS - VARIANT A4

ENERGOPROJEKT a.s.

Review of Variants to Satisfy Heating Demands in Plzen

DRAFT FINAL REPORT

Task - 8, 15

EGP 42 400

AUGUST 1993

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A TASK 8

1 Input Data

The variants designed by ENERGOPROJEKT Praha take account of the heat needed and the circuit of heat consumers as proposed by EGU Praha a s and agreed at Seven on 15 June 1993
Assumed is only the construction of the feeder East I and connection of other users from the area of feeders South, North and East I (after construction) The various scope of connecting new users and the savings of heat suggest two levels of heat needs "low balance" and "high balance" ENERGOPROJEKT Praha also used data on the current state (heat sources) and some other data (such as bituminous coal from Zbuch) newly established within the assignments of the EGU Praha a s The input data are not given here in detail, because they can be found in the study by EGU Praha a s

2 Description of Variants

2.1 Common Features of Solution (Period up to 1966)

Planned for the Plzen Power and Heating Plant in 1995-1996 is the construction of a gas-steam system (CC) also referred to as Tp Plzen III Routine operation of the system should start in 1997 The installation will incorporate a gas turbine ABB GT 13 D (electric capacity 105 MW at -12°C) with waste heat boiler and a steam condensing turbine having two controlled extractions (electric capacity 36 MW)

Plans for the period up to 1996 are that the heating plants ZOS and Pivovar (Brewery) will able to cooperate in the steam system of Tp Plzen and the heating plant Kosutka in the hot-water system of Tp Plzen After construction of the feeder East I (in 1996), cooperation of the heating plants Letna and Doubravka (V1 and V2) is possible

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Assumed in 1996 is also cooperation of the heating plant Bory, which would be feasible even today, but the "balance" incorporates the consumers of hot water from the heating plant Bory into the consumer circuit of ho water as late as 1996 (another operator)

For most present sources it is necessary to take measures to solve the issue of emissions in compliance with the air protection act The heating plants Letna, Doubravka, Bory, Kosutka a ZOS will be shut down (except for the steam section of the heating plant Bory for consumers outside the circuit of heat consumption dealt with) and their capacity will be replaced with the gas-steam system at Tp Plzen The Pivovar heating plant will be operated further and assumed is its lease by operator Tp Plzen so that its capacity can be freely available

The existing equipment of Tp Plzen will be reconstructed by 1996 to burn bituminous coal mined at Zbuch near to Plzen This locality can provide necessary supplies of bituminous coal (coal heating value for TpI boilers 18 47 MJ/kg and for Tp II boilers 17 38 MJ/kg) with sulfur content not exceeding 0 5 % These parameters will make it possible to meet the limit of sulfur dioxide levels in flue gas without the need to erect a desulfurization unit After the year 2000 it will be necessary to open another coal deposit at Zbuch, otherwise coal from Ostrava or from abroad will have to be supplied

Reconstruction of Tp Plzen I is assumed only in the case of the "high balance" The "low balance" terminates the operation of Tp Plzen I in 1997

Tp Plzen II (powdered coal boilers K4 and K5) is supposed to be reconstructed in 1955-1996 to burn bituminous coal The reconstruction includes the modification of the combustion system and coal handling plant and the replacement of electric precipitators Reconstructed will always be one

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boiler at a time We assume that the reconstruction will not extend to the heating period with temperatures calling for maximum operation of the power and heating plant (the reconstruction period should be from March to November) Any failure to meet this assumption results in the capacity disparity of about 30 MW Taken into consideration could be the use of a mobile hot-water boiler during the reconstruction The need to use this boiler will be shown after a detailed time schedule of the reconstruction in Tp Plzen has been compiled in the framework of the design

2 1 1 Gas-Steam Unit at Tp Plzen

As agreed the design of the gas-steam unit incorporates a gas turbine GT 13 D manufactured by the ASEA Brown Boveri The designed gas-steam unit makes up a gas steam cycle with possible heat supplies in the form of both hot water and steam The gas-steam unit is composed of the gas turbine, waste - heat boiler using combustion products from the turbine, and steam condensing turbine with reduced condensation The steam boiler generates steam at two pressure levels The parameters of high-pressure steam are 6 5 MPa and 475°C and its maximum supplies are 151 t/h The parameters of low-pressure steam are 0 55 MPa and 225°C and the steam is supplied at the quantity of not more than 46 t/h To make a maximum use of the heat in flue gas, the boiler also incorporates an exchanger to heat up the feed water of the gas-steam cycle before degasification and still another exchanger to heat up network water (the latter is placed in parallel to the 1st stage of the steam heater of heat water - see the heat diagram) The degasification is designed at 0 12 MPa The boilers are fed by means of low-pressure and high-pressure speed-controlled feed pumps from a feed water tank

The steam turbine is of the mixed-pressure two-casing type with two steam extractions controlled Steam from the first extraction is designed for heating up network water in the

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1st heating stage, whereas extraction II will supply process steam 1 3 MPa and 260°C if this steam is not received by the existing steam back-pressure turbine or other systems (the brewery's boiler plant, etc) The rated electric capacity of the new steam turbine is 36 MW The condenser capacity is designed to 75 % of the rating at fully condensing mode of operation

2 2 Low Balance

The power and heating plant Plzen incorporates a proposal gas-steam system (Tp Plzen III) identical to the solution for "high balance" (see 2 1 1 for description) After installation of the gas-steam system the requirements for heat in the steam and hot-water systems are covered by the power and heating plant Plzen (Tp II and III) and the Pivovar heating plant The power and heating plant Plzen I is shut down in 1997

The gas-steam system is operated in the base part of the heat delivery diagram with the exception of low tariff zones of payment for electricity in summer The Pivovar heating plant is used for peak heat deliveries and during summer shut-downs of the gas-steam system, and Tp Plzen II for steam deliveries and hot water preparation in base heater of Tp Plzen

After the year 2000 it will be necessary to replace two oldest boilers of the Pivovar heating plant The installation is possible at either the Pivovar heating plant or Tp Plzen and will be dependent on the future ownership situation and arrangement of the possible company running the overall power and heating plant system In our basic solution we expect the two boilers to be erected in the area of Tp Plzen

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The mode of operating Tp Plzen and the Pivovar heating plant for individual tariff zones of payments for electricity and the course of electric capacity after 2000 are apparent from graphs 1, 2 and 3 The fundamental data (heat deliveries, fuel consumption, electric power generation, etc) are listed in the tables attached Scheme 1 (year 2000) and 1/A (year 2010) shows the arrangement of Tp Plzen

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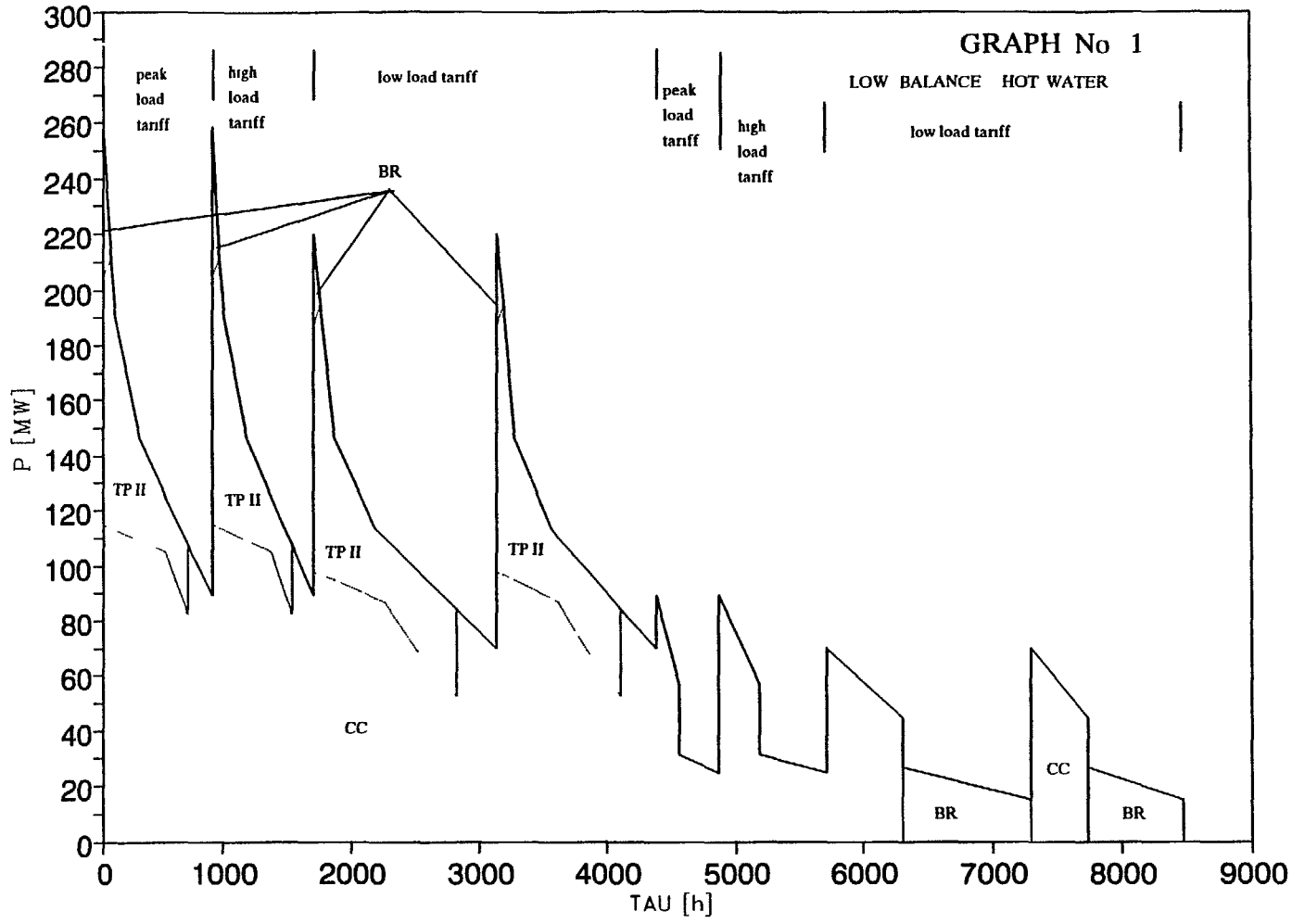
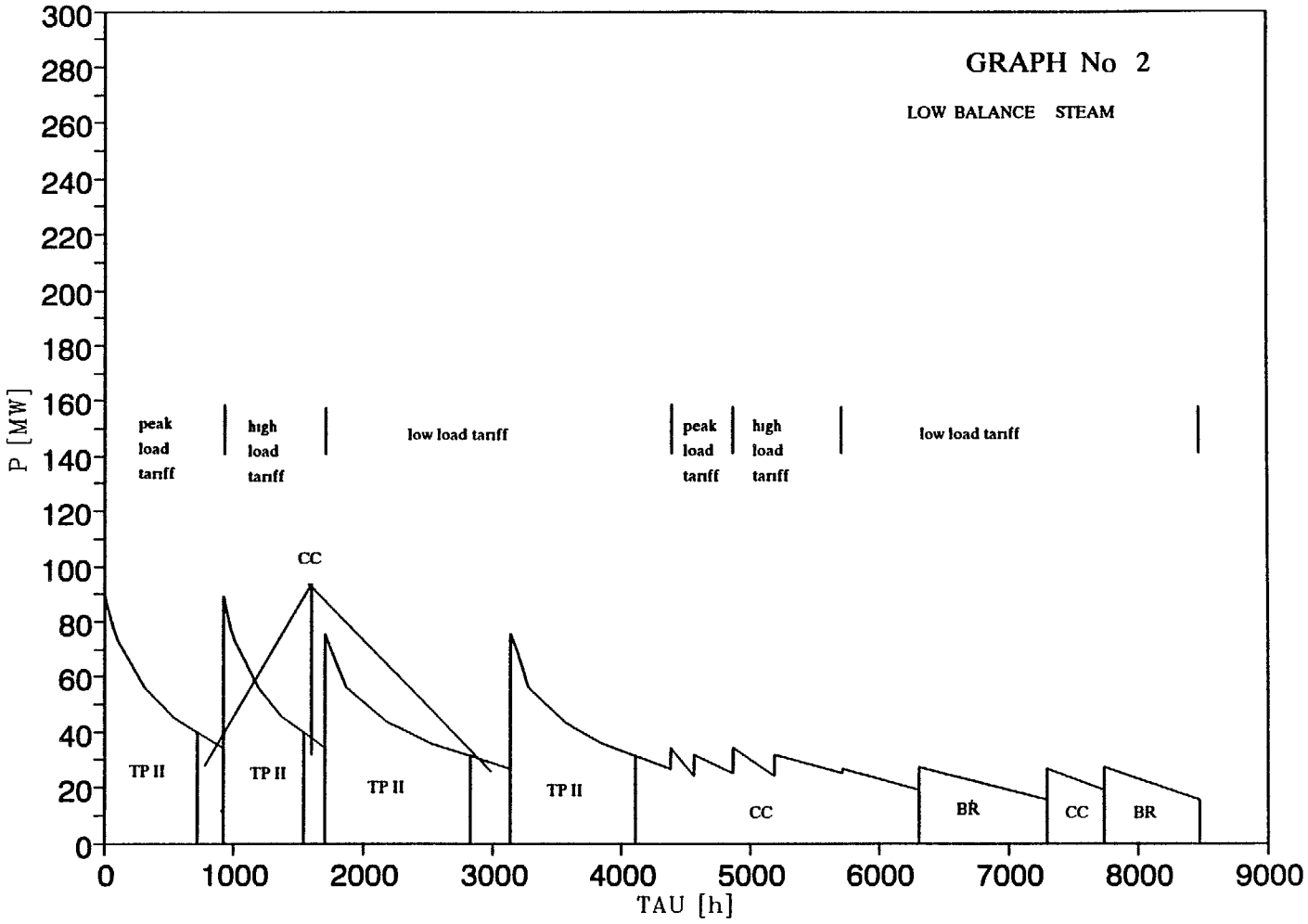
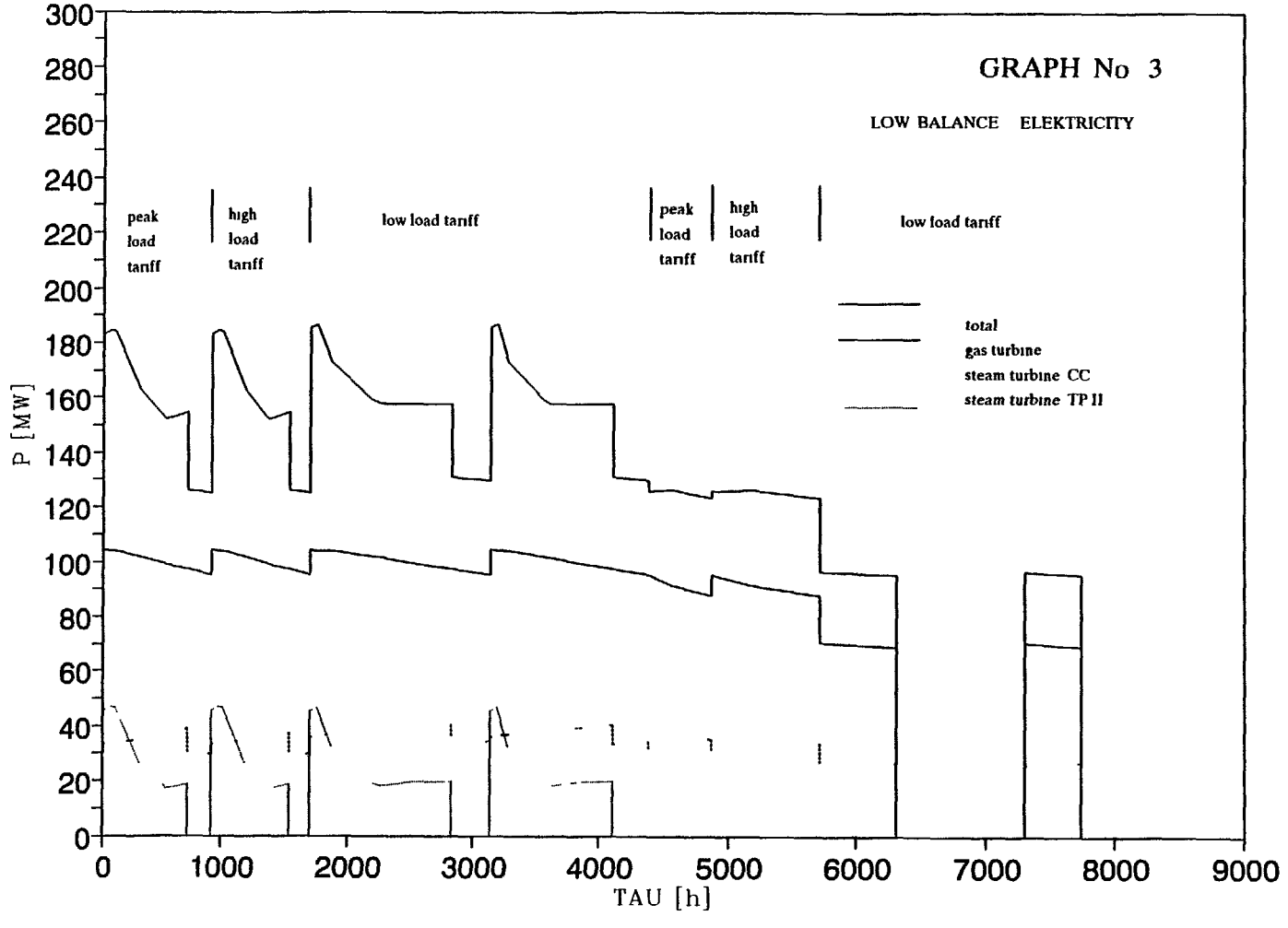

GRAPH No 1
LOW BALANCE HOT WATER
peak load tariff
high load tariff
low load tariff
peak load tariff
high load tariff
low load tariff
BR
TP II
TP II
TP II
TP II
CC
CC
BR
BR
P [MW]
TAU [h]
0
20
40
60
80
100
120
140
160
180
200
220
240
260
280
300
0
1000
2000
3000
4000
5000
6000
7000
8000
9000


GRAPH No 2
LOW BALANCE STEAM
P [MW]
TAU [h]
peak load tariff
high load tariff
low load tariff
peak load tariff
high load tariff
low load tariff
CC
TP II
TP II
TP II
TP II
CC
BR
CC
BR
0
20
40
60
80
100
120
140
160
180
200
220
240
260
280
300
0
1000
2000
3000
4000
5000
6000
7000
8000
9000

261


GRAPH No 3
LOW BALANCE ELEKTRICITY
peak load tariff
high load tariff
low load tariff
peak load tariff
high load tariff
low load tariff
total
gas turbine
steam turbine CC
steam turbine TP II
P [MW]
TAU [h]
0
20
40
60
80
100
120
140
160
180
200
220
240
260
280
300
0
1000
2000
3000
4000
5000
6000
7000
8000
9000

LOW BALANCE

CP Plzen with CC 1 x GT 13 ABB + 1 x condense steam turbine with two heat extractions

	Units	y 1992	y 1995	y 1996	y 1997	y 2000	y 2005	y 2010
Total installed heat output of steam boilers	[MW]	232 9	232 9	232 9	232 9	232 9	232 9	232 9
Total steam mass flow	[t/h]	340	340	340	340	340	340	340
Total installed heat output of brewery	[MW]	56 1	56 1	56 1	56 1	56 1	33	33
Total steam mass flow	[t/h]	86	86	86	86	86	50	50
Total installed heat output of hot water boilers	[MWt]	105	105	105			28	28
Total installed output of waste heat boiler	[MWt]				180	180	180	180
Total heat demand (12 C)	[MWt]	303 5	300 7	366 8	365 1	351 2	349 7	349 7
from which own consumption HP Plzen	[MWt]	3 5	3 5	3 5	3 5	3 5	3 5	3 5
external consumption	[MWt]	300	297 2	363 3	361 6	347 7	346 2	346 2
from which steam	[MWt]	93	91 1	90 5	88 9	88 9	88 9	88 9
hot water	[MWt]	207	205 8	272 8	272 7	258 8	257 3	257 3
Covered by sources (external consumption)								
HP Kosutka	[MWt]							
HP Bory	[MWt]			22 9				
HP Letna Doubravka (V 1 V 2)	[MWt]			38 6				
HP ZOS (Railway Maint Co)	[MWt]							
HP Pivovar (Brewery)	[MWt]	20 5	17 7	22 3	54 5	54 5	28 7	28 7
HP Plzen	[MWt]	279 5	279 5	279 5	289 5	289 5	317 5	317 5
uncovered	[MWt]				17 6	3 7		
Heat supply per year steam	[TJ/y]	1125	1100	1095	1075	1075	1075	1075
Heat supply per year hot water	[TJ/y]	1990	1984	2619	2616	2491	2471	2471
from which own consumption	[TJ/y]	34	34	34	34	34	34	34
external consumption	[TJ/y]	1956	1950	2585	2582	2457	2437	2437
Heat production total	[TJ/y]	3115	3084	3714	3691	3566	3546	3546
Power output CP II	[MWe]	55	55	55	55	55	55	55
Power output CC (12 C)	[MWe]				141	141	141	141
Total power output of CP (12 C)	[MWe]	55	55	55	196	196	196	196
Total electric power generation brutto	[GWh/y]	209 9	143 5	147 7	964 5	950 9	949 3	949 3
from which in peak load tariff zone	[GWh/y]	34 7	23 7	24 4	212 3	209 3	208 9	208 9
in high load tariff zone	[GWh/y]	40 5	27 7	28 5	227 1	223 9	223 6	223 6
in low load tariff zone	[GWh/y]	134 7	92 1	94 8	525 1	517 7	516 8	516 8
Own electricity consumption	[GWh/y]	38 2	37 3	37 5	27 3	26 4	26 3	26 3
Pumping energy	[GWh/y]	6	6	10 4	10 4	9 4	9 3	9 3
Total electricity consumption	[GWh/y]	44 2	43 3	47 9	37 7	35 8	35 6	35 6
Total electric power generation netto	[GWh/y]	165 7	100 2	99 8	926 8	915 1	913 7	913 7

TABLE I/2

LOW BALANCE total fuel consumption

CP Plzen with CC 1 x GT 13 ABB + 1 x condense steam turbine with two heat extractions

	Units	y 1992	y 1995	y 1996	y 1997	y 2000	y 2005	y 2010
Total fuel consumption	[TJ/y]	4935	4611	5523	9189	9013	8992	8992
from which brown coal 12 7 MJ/kg	[TJ/y]	4652	4337	1619				
	[th t/y]	366 3	341 5	127 5				
bituminous coal 18 47 MJ/kg	[TJ/y]							
	[th t/y]							
bituminous coal 17 38 MJ/kg	[TJ/y]			3542	1962	1924	1910	1910
	[th t/y]			203 8	112 9	110 7	109 9	109 9
natural gas 33 55 MJ/m3	[TJ/y]	263	254	342	7227	7109	7082	7082
	[mil m3/y	7 8	7 6	10 2	215 4	211 9	211 1	211 1
oil 41 6 MJ/kg	[TJ/y]	20	20	20				
	[th t/y]	0 5	0 5	0 5				

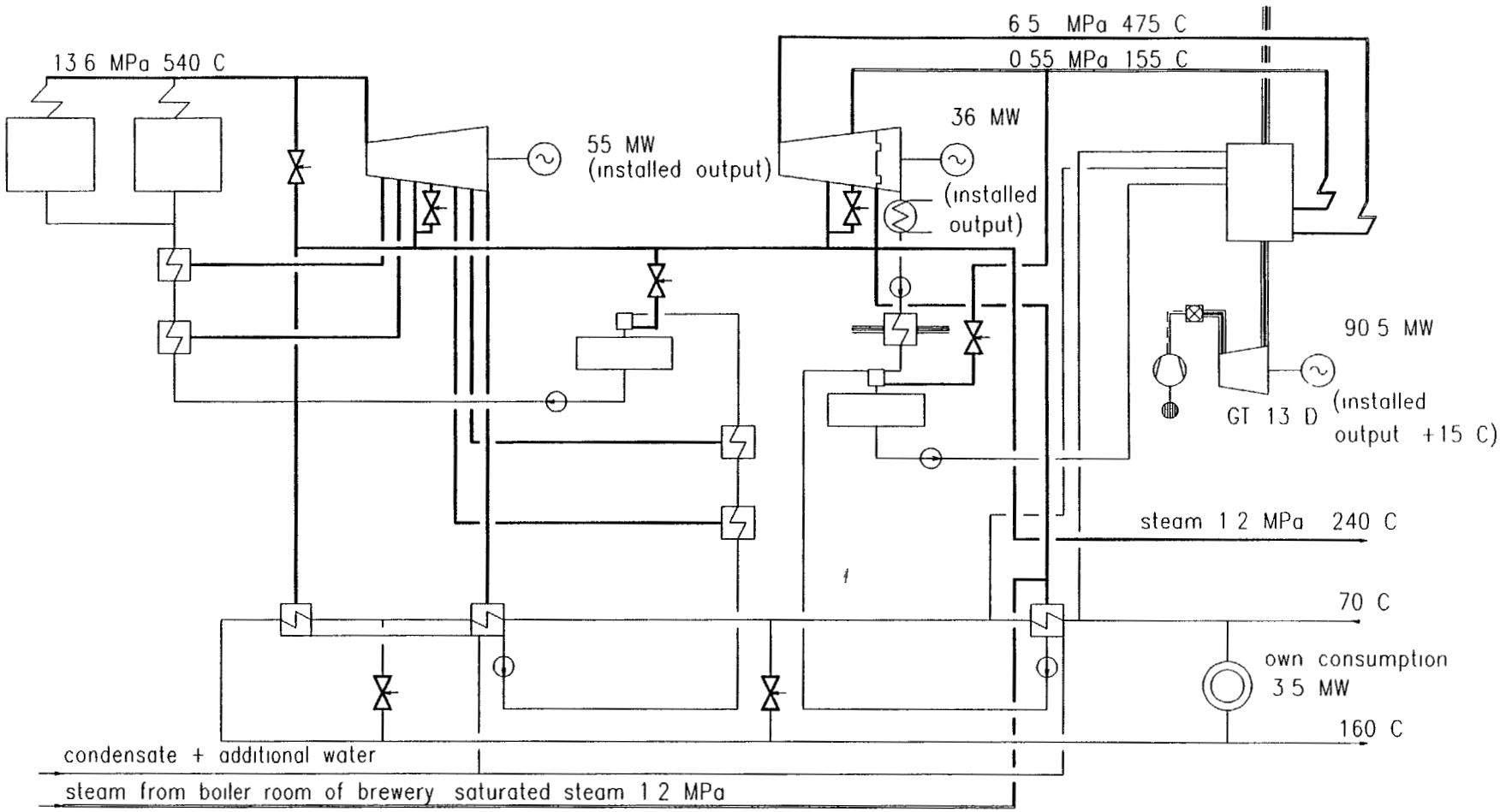
TABLE I/3

LOW BALANCE

Basic operation characteristics of CC with 1 x GT 13 ABB

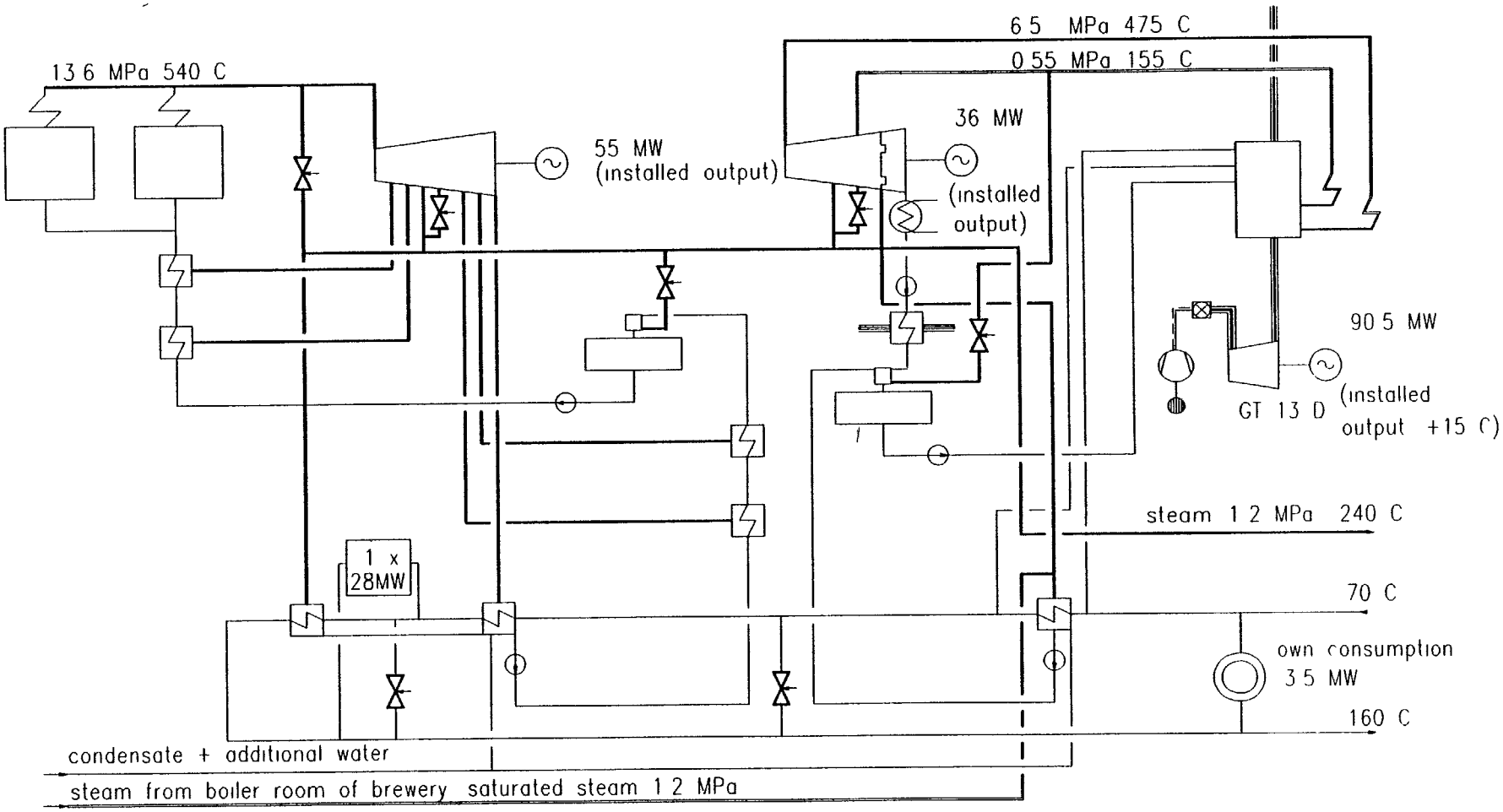
	Units	y 1997	y2000	y 2005	y 2010
Nominal power output of CC	[MWe]	141	141	141	141
from which nominal power output of GT	[MWe]	105	105	105	105
nominal power output of ST	[MWe]	36	36	36	36
Max thermal output in hot water (12 C)	[MWt]	115	115	115	115
Heat production of CC steam	[TJ/y]	334	330	329	329
hot water	[TJ/y]	1853	1832	1828	1828
total	[TJ/y]	2187	2162	2157	2157
Max power output of CC with delivery of heat in hot water	[MWe]	137 5	137 5	137 5	137 5
Electric power generation of CC brutto					
from gas turbine	[GWh/y]	639 4	631	629 2	629 2
from steam turbine	[GWh/y]	233 3	230 2	229 5	229 5
combined cycle total	[GWh/y]	872 7	861 2	858 7	858 7
from which in peak load tariff zone	[GWh/y]	206	203 3	202 7	202 7
in high load tariff zone	[GWh/y]	194 2	191 6	191	191
in low load tariff zone	[GWh/y]	472.5	466 3	465	465
Total heat consumption fuel	[TJ/y]	6854	6775	6761	6761
natural gas 33 55 MJ/m3	[mil m3/y]	203	201 9	201 5	201 5
Average year efficiency for heat and power generation	%	77 7	77 7	77 6	77 6

SCHEME I

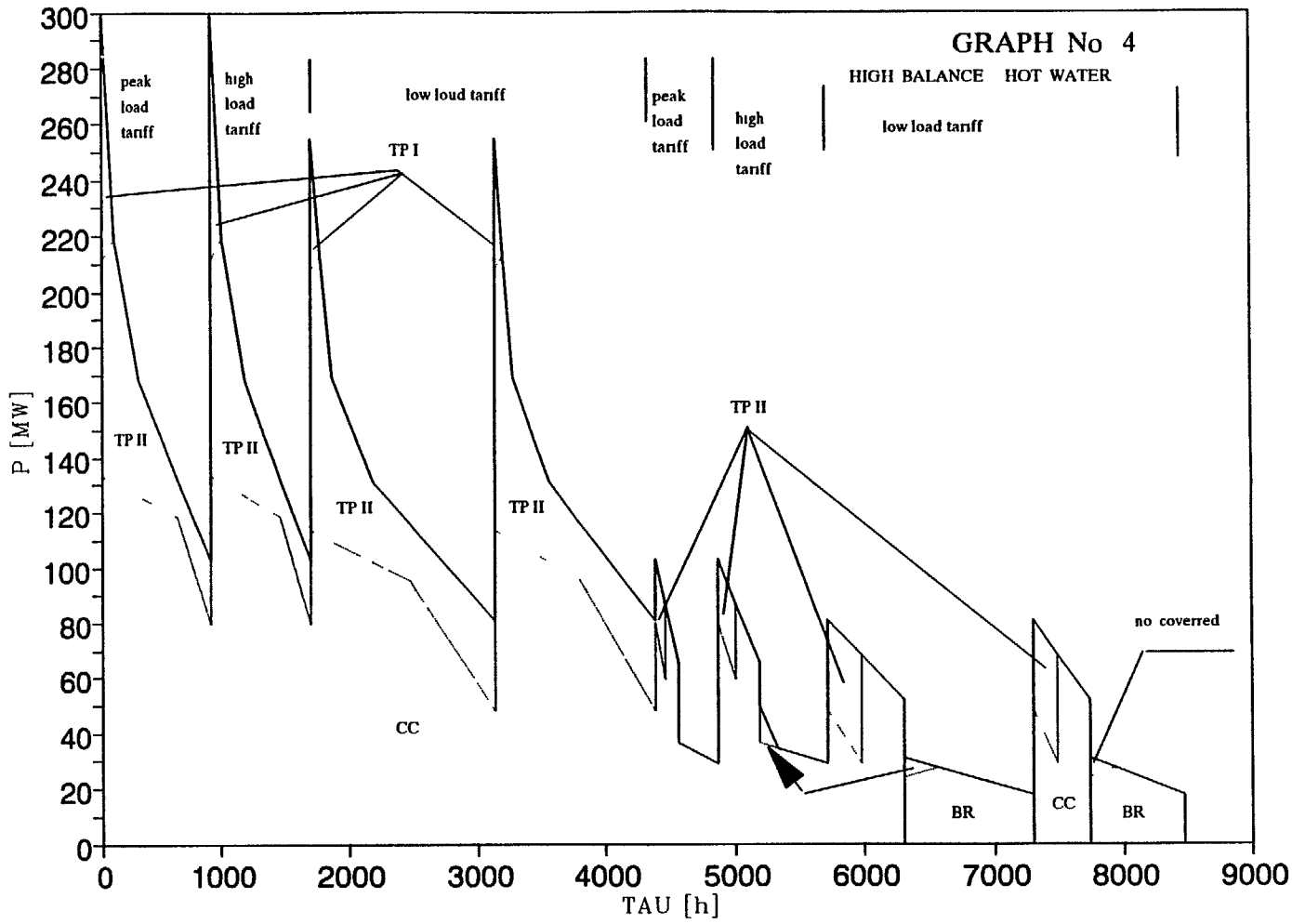


SCHEME OF THE HEAT PLANT OF PLZEŇ
LOW BALANCE YEAR 2000

SCHEME 1/A



SCHEME OF THE HEAT PLANT OF PLZEN
LOW BALANCE YEAR 2010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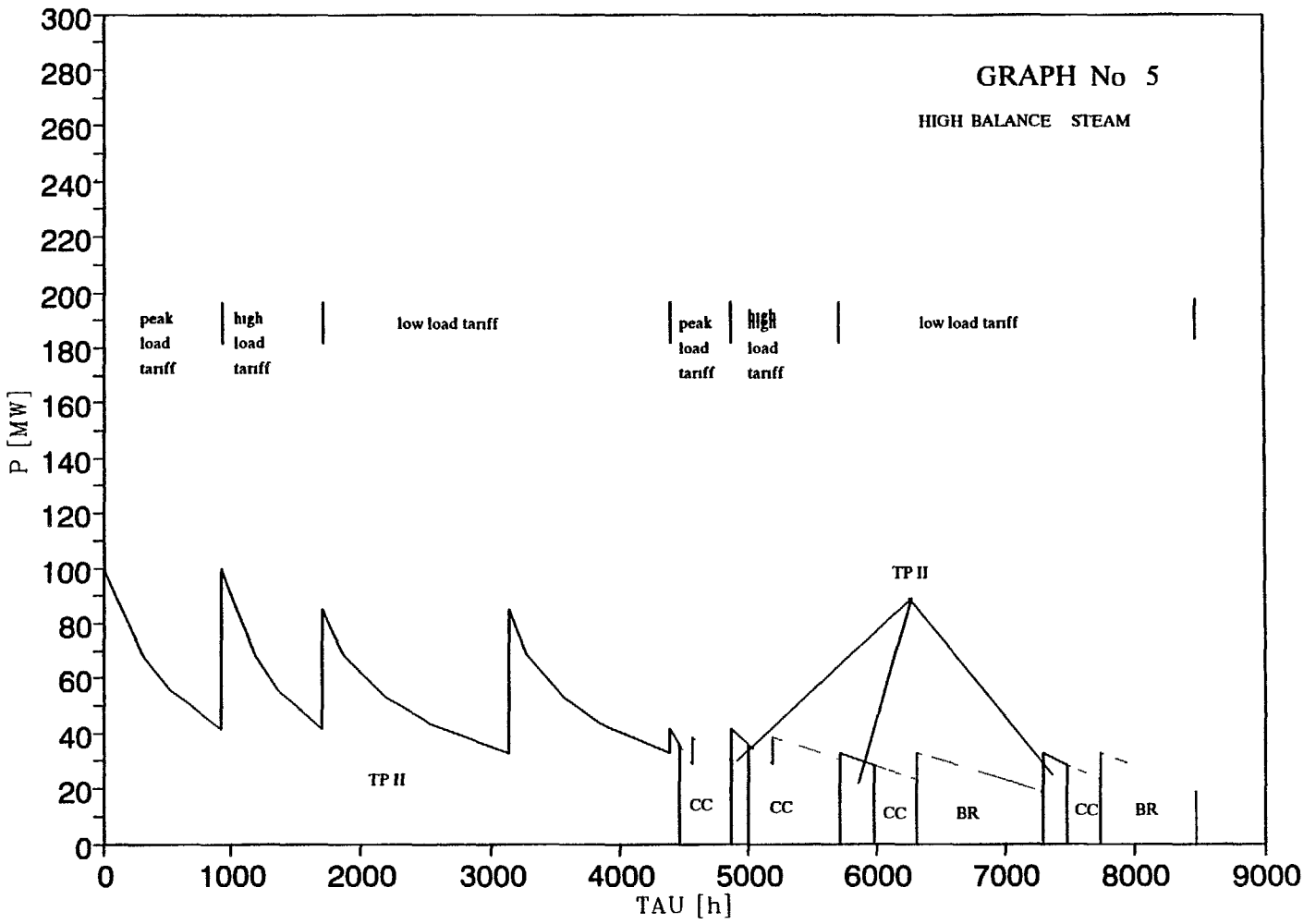
HIGH BALANCE HOT WATER
peak load tariff
high load tariff
low loud tariff
peak load tariff
high load tariff
low load tariff
TP I
TP II
TP II
TP II
TP II
TP II
CC
BR
CC
BR
no coverred
P [MW]
TAU [h]
0
20
40
60
80
100
120
140
160
180
200
220
240
260
280
300
0
1000
2000
3000
4000
5000
6000
7000
8000
9000

218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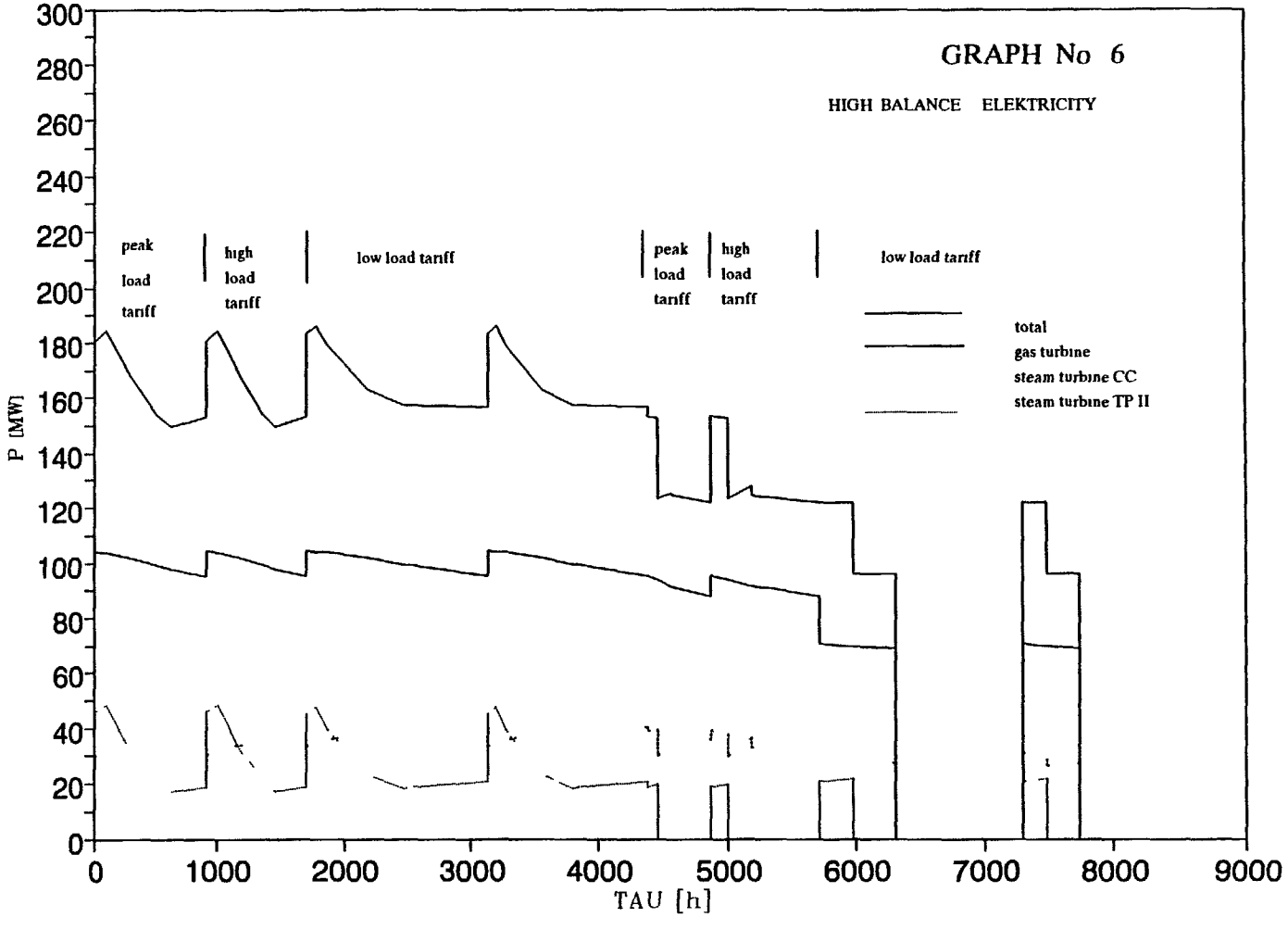
HIGH BALANCE STEAM
peak load tariff
high load tariff
low load tariff
peak load tariff
high load tariff
low load tariff
TP II
TP II
CC
CC
CC
BR
CC
BR
P [MW]
TAU [h]
0
20
40
60
80
100
120
140
160
180
200
220
240
260
280
300
0
1000
2000
3000
4000
5000
6000
7000
8000
9000


GRAPH No 6
HIGH BALANCE ELEKTRICITY
peak load tariff
high load tariff
low load tariff
peak load tariff
high load tariff
low load tariff
total
gas turbine
steam turbine CC
steam turbine TP II
P [MW]
TAU [h]
0
20
40
60
80
100
120
140
160
180
200
220
240
260
280
300
0
1000
2000
3000
4000
5000
6000
7000
8000
9000

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HIGH BALANCE

CP Plzen with CC 1 x GT 13 ABB + 1 x condense steam turbine with two heat extractions

	Units	y 1992	y 1995	y 1996	y 1997	y 2000	y 2005	y 2010
Total installed heat output of steam boilers	[MW]	232 9	232 9	232 9	232 9	232 9	232 9	232 9
Total steam mass flow	[t/h]	340	340	340	340	340	340	340
Total installed heat output of brewery	[MW]	56 1	56 1	56 1	56 1	56 1	56 1	56 1
Total steam mass flow	[t/h]	86	86	86	86	86	86	86
Total installed heat output of hot water boilers	[MWt]	105	105	105	105	105	35	35
Total installed output of waste heat boiler	[MWt]				180	180	180	180
Total heat demand (12 C)	[MWt]	303 5	310 1	395 1	399 2	403	405 1	407 1
from which own consumption HP Plzen	[MWt]	3 5	3 5	3 5	3 5	3 5	3 5	3 5
external consumption	[MWt]	300	306 6	391 6	395 7	399 5	401 6	403 6
from which steam	[MWt]	93	91 1	99 8	100	100	99 6	99 6
hot water	[MWt]	207	215 5	291 8	295 7	299 5	302	304
Covered by sources (external consumption)								
HP Kosutka	[MWt]			18 1				
HP Bory	[MWt]			22 9				
HP Letna Doubravka (V 1 V 2)	[MWt]			39 5				
HP ZOS (Railway Maint Co)	[MWt]							
HP Pivovar (Brewery)	[MWt]	20 5	27 1	31 6			54 5	54 5
HP Plzen	[MWt]	279 5	279 5	279 5	395 7	399 5	342 5	342 5
uncovered	[MWt]						4 6	6 6
Heat supply per year steam	[TJ/y]	1125	1102	1207	1300	1300	1290	1290
Heat supply per year hot water	[TJ/y]	1990	2074	2801	2386	2871	2889	2906
from which own consumption	[TJ/y]	34	34	34	34	34	34	34
external consumption	[TJ/y]	1956	2039	2766	2802	2837	2854	2872
Heat production total	[TJ/y]	3115	3176	4008	4136	4171	4179	4196
Power output CP II	[MWe]	55	55	55	55	55	55	55
Power output CC (12 C)	[MWe]				141	141	141	141
Total power output of CP (12 C)	[MWe]	55	55	55	196	196	196	196
Total electric power generation brutto	[GWh/y]	209 9	144 7	151 2	984 6	996 8	1004 8	1007 2
from which in peak load tariff zone	[GWh/y]	34 7	23 9	24 9	208 6	211 1	212 8	2213 3
in high load tariff zone	[GWh/y]	40 5	27 9	29 2	233 1	236 9	238 8	239 4
in low load tariff zone	[GWh/y]	134 7	92 9	97 1	542 9	548 8	553 2	554 5
Own electricity consumption	[GWh/y]	38 2	37 3	38 9	31 3	32 1	32 4	32 4
Pumping energy	[GWh/y]	6	6 1	11 9	12 2	12 5	12 6	12 7
Total electricity consumption	[GWh/y]	44 2	45 3	50 8	43 5	44 6	45	45 1
Total electric power generation netto	[GWh/y]	165 7	99 4	100 4	941 1	952 2	959 8	962 1

TABLE II/2

HIGH BALANCE total fuel consumption

CP Plzen with CC 1 x GT 13 ABB + 1 x condense steam turbine with two heat extractions

	Units	y 1992	y 1995	y 1996	y 1997	y 2000	y 2005	y 2010
Total fuel consumption	[TJ/y]	4935	4743	5917	9354	9601	9619	9652
from which brown coal 12 7 MJ/kg	[TJ/y]	4652	4370	1058				
	[th t/y]	366 3	344 1	83 3				
bituminous coal 18 47 MJ/kg	[TJ/y]		84	135	51	55		
	[th t/y]		4 5	7 3	2 8	3		
bituminous coal 17 38 MJ/kg	[TJ/y]			3817	2556	2769	2779	2798
	[th t/y]			219 6	147	159 3	159 9	161
natural gas 33 55 MJ/m3	[TJ/y]	263	269	887	6747	6777	6840	6854
	[mil m3/y	7 8	8	26 4	200 5	202 2	203 9	204 3
oil 41 6 MJ/kg	[TJ/y]	20	20	20				
	[th t/y]	0 5	0 5	0 5				

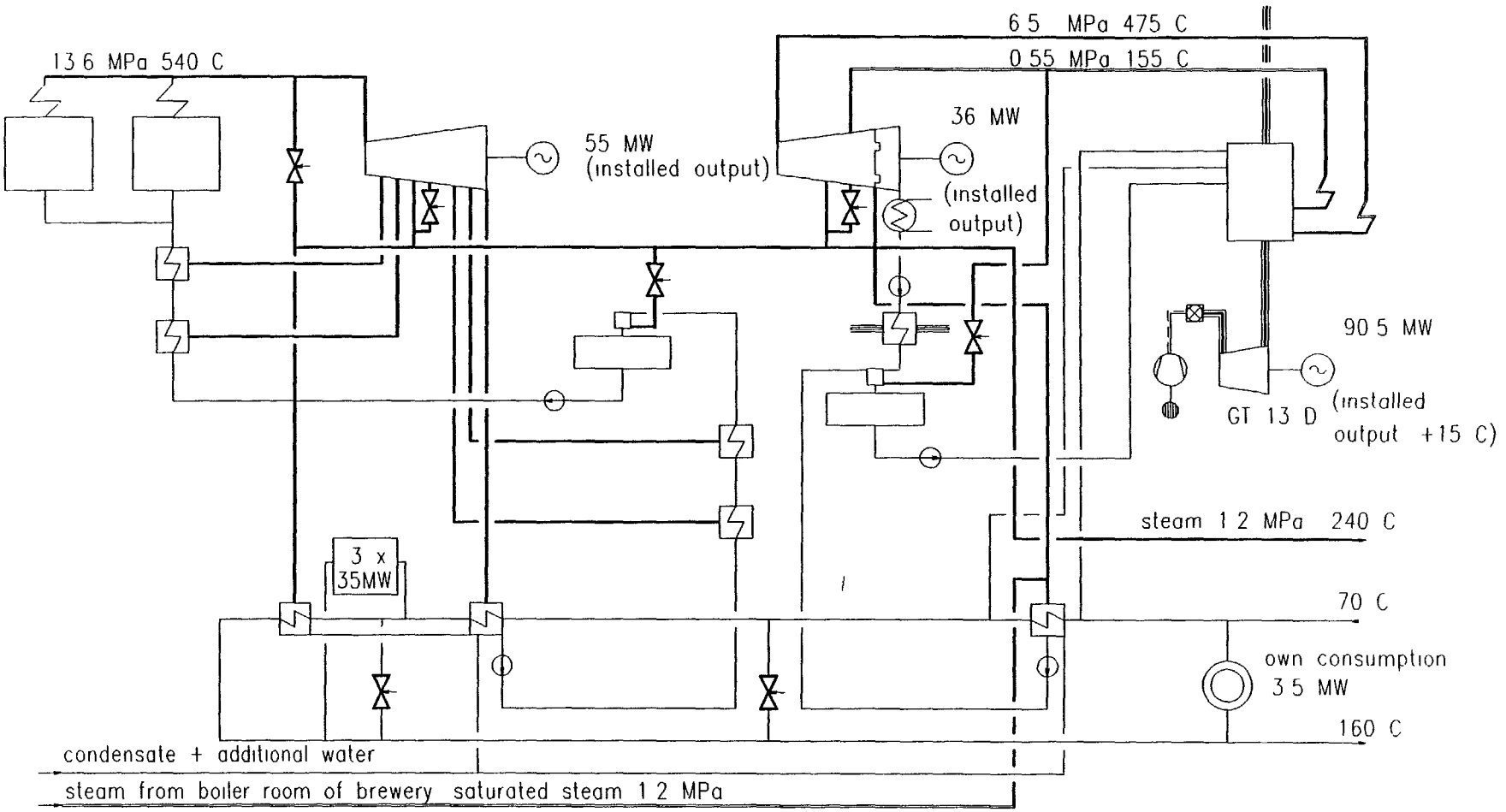
TABLE II/3

HIGH BALANCE

Basic operation characteristics of CC with 1 x GT 13 ABB

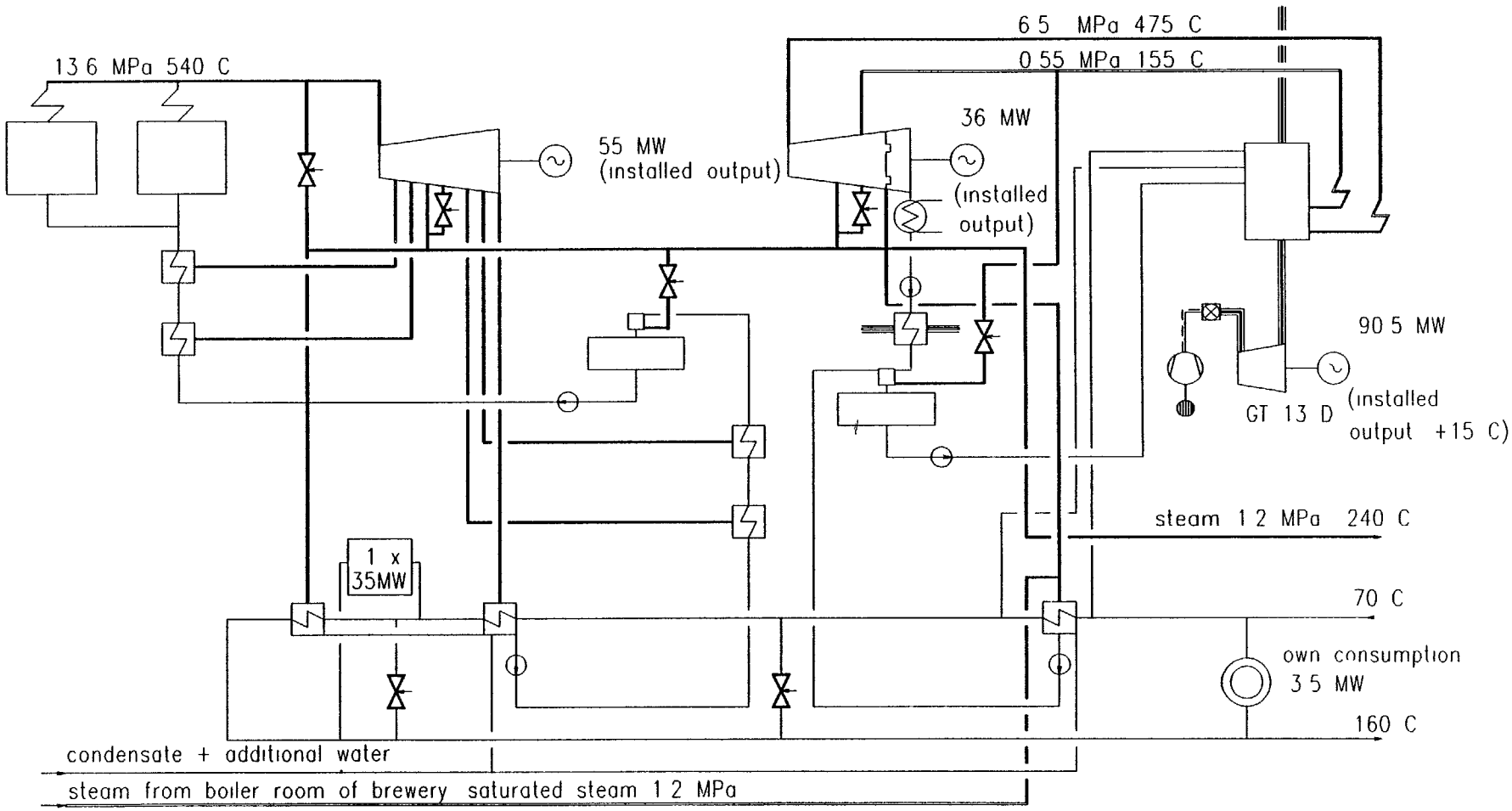
	Units	y 1997	y2000	y 2005	y 2010
Nominal power output of CC	[MWe]	141	141	141	141
from which nominal power output of GT	[MWe]	105	105	105	105
nominal power output of ST	[MWe]	36	36	36	36
Max thermal output in hot water (12 C)	[MWt]	133	133	133	133
Heat production of CC steam	[TJ/y]	172	191	190	188
hot water	[TJ/y]	2002	1999	2004	2014
total	[TJ/y]	2174	2190	2194	2202
Max power output of CC with delivery of heat in hot water	[MWe]	134 5	134 5	134 5	134 5
Electric power generation of CC brutto					
from gas turbine	[GWh/y]	625 5	630 9	632 1	634 7
from steam turbine	[GWh/y]	234 4	236 3	236 8	237 7
combined cycle total	[GWh/y]	859 9	867 2	868 9	872 4
from which in peak load tariff zone	[GWh/y]	182	183 5	183 9	184 6
in high load tariff zone	[GWh/y]	210 1	211 9	212 3	213 2
in low load tariff zone	[GWh/y]	467 8	471 8	472 7	474 6
Total heat consumption fuel	[TJ/y]	6737	6757	6763	6778
natural gas 33 55 MJ/m3	[mil m3/y]	200 8	201 4	201 6	201 9
Average year efficiency for heat and power generation	%	78 2	78 6	78 7	78 8

SCHEME 2



SCHEME OF THE HEAT PLANT OF PLZEŇ
HIGH BALANCE YEAR 2000

SCHEME 2/A



SCHEME OF THE HEAT PLANT OF PLZEN
HIGH BALANCE YEAR 2010

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3 Data for Economic Evaluation

3 1 Investment Costs

Investment costs were determined according to similar projects, information by manufacturers, or estimated The price level corresponds to 1993 Included are all costs linked with preparation, implementation and putting the projects on stream Drawing on the resources by is apparent from Tables 1 and 2 Tables 3 through 5 show variant solutions to the reconstructed boilers at Heating Plant Plzen I and within the scope of the Pivovar heating plant

3 2 Operating Costs

The same cost breakdown is maintained for the operating costs as in our previous studies No detailed surveying into the level of the individual items of the operating costs was requested and therefore only some of the items will be commented on Like before, the operating costs have been split into fuel costs and other operating costs (costs of material, water, wages, repairs and maintenance, overhead costs and others), costs of ash disposal and air pollution fees

3.2 1 Fuel Costs

The current level of prices, and the quality and type of the fuel used correspond to the data ascertained by EGÚ Praha a s and this is why they are not given here For the years to come it is recommended that the data listed in Annex 2 be used, depending of the type of calculation to be done

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3 2 2 Other Operating Costs

What is mentioned above about the current level applies here too An average amount of 30 mill Kč a year is expected for the repairs and maintenance, overhead and other costs No increase in employment is anticipated
Quantity of raw water we assume raised of cooling water for cooling of a new steam turbine against contemporary condition (in high balance to 1,4 mill m^3/year, in low balance to 1,52 mill m^3/year)

3.2 3 Ash Disposal Costs

The amounts of ash matter to be disposed of can be seen in Table 6 Emissions and Ash Matter We expect the same level of the costs (i e , 150 Kč/t) increased by ash disposal fees as set out by the Waste Disposal Fee Act No 62/1992

3 2 4 Air Pollution Fees

The amount of emissions discharged is shown in Table 6 Emissions and Ash Matter The fees are set out by the Act on Air Protection State Administration and Fees for Air Pollution No 389/1991 Coll

3 2 5 Other Input Data

Data on fuel consumption and electric power generation and consumption have been derived from expected heat deliveries and are specified in the annex to the letter of June 29, 1993 The amounts of transfers and allocations to enterprise funds are laid down by tax laws and the Commercial Code, it is also necessary take account of deliveries for social and medical insurance The discount rate is now 8 % and interest rates on long-term credits range between 12 and 15 %

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LOW BALANCE BASIC PROPOSAL

TABLE 1

INVESTMENTS COSTS IN MIL Kč DEVIDED IN YEARS

ITEM	NAME	1995	1996	1997	1998	1999	2000	2004	2005	2009	2010	2011	2012	TOTAL
1	TP I			10				38						48
2	TP II	74	74											148
3	TP III	350	1610											1960
4	TP PLZEN TOTAL													2156
5	ASH STOCK YARD FOR TP PLZEN					38				43				81
6	BREWERY S HEATING PLANT													
7	INVESTMET COSTS TOTAL	424	1684	10		38		38		43				2237

COMENTS

item

1 TP I demolition of equipment (1997),
substitution of worn boilers in heating plant of brewery by a hot water boiler (28 MW 2004)

2 TP II *reconstruction* for bituminous coal

3 TP III construction of gas combined cycle (gas turbine GT 13 D /105 MW on cond 12 C / condensing extraction turbine 36 MW)

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HIGH BALANCE BASIC PROPOSAL

TABLE 2

INVESTMENT COSTS IN MIL Kč DIVIDED IN YEARS

ITEM	NAME	1995	1996	1997	1998	1999	2000	2004	2005	2009	2010	2011	2012	TOTAL
1	TP I	11	11	11				57						90
2	TP II	74	74											148
3	TP III	350	1610											1960
4	TP PLZEN TOTAL													2198
5	ASH STOCK YARD FOR TP PLZEŇ				38				41				43	122
6	BREWERY S HEATING PLANT							38						38
7	INVESTMENT COSTS TOTAL	435	1695	11	38			95	41				43	2358

COMENTS

item

1 TP I reconstruction of three boilers for bituminous coal (1995 1996)
demolition of equipment and construction of a hot water boiler 35 MW (2004)

2 TP II reconstruction for bituminous coal

3 TP III construction of gas combined cycle (gas turbine GT 13 D /105 MW on cond 12 C / condensing extraction turbine 36 MW)

6 Brewery s heating plant substitution of worn boilers

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LOW BALANCE LOCATION OF SUBSTITUTION OF WORN BOILERS BREWERY S HEATING PLANT TABLE 3

IN THE SAME PLACE

INVESTMEN COSTS IN MIL Kč DIVIDED IN YEARS

ITEM	NAME	1995	1996	1997	1998	1999	2000	2004	2005	2009	2010	2011	2012	TOTAL
1	TP I			10										10
2	TP II	74	74											148
3	TP III	350	1610											1960
4	TP PLZEN TOTAL													2118
5	ASH STOCK YARD FOR TP PLZEN					38				43				81
6	BREWERY S HEATING PLANT							38						38
7	INVESTMENT COSTS TOTAL	424	1684	10		38		38		43				2237

COMMENTS

item

1 TP I demolition of equipment (1997)

2 TP II *reconcruction* for bituminous coal

3 TP III construction of gas combined cycle (gas turbine GT 13 D /105 MW on cond 12 C / condensing extraction turbine 36 MW)

6 Brewery s heating plant substitution of worn boilers

HIGH BALANCE RECONSTRUCTION OF TWO BOILERS TP I (1995 1996), DEMOLITION OF ONE BOILER TP I (1997) TABLE 4

INVESTMENT COSTS IN MIL Kč DIVIDED IN YEARS

ITEM	NAME	1995	1996	1997	1998	1999	2000	2004	2005	2009	2010	2011	2012	TOTAL
1	TP I	11	11	4				53						79
2	TP II	74	74											148
3	TP III	350	1610											1960
4	TP PLZEŇ TOTAL													2187
5	ASH STOCK YARD FOR TP PLZEN				38				41				43	122
6	BREWERY S HEATING PLANT							38						38
7	INVESTMENT COSTS TOTAL	435	1695	4	38			91	41				43	2347

COMENTS

item

1 TP I demolition of one boiler (1997) reconstruction of two boilers for bituminous coal (1995 1996)
demolition of two boilers and construction of a hot water boiler 35 MW (2004)

2 TP II reconstruction for bituminous coal

3 TP III construction of gas combined cycle (gas turbine GT 13 D /105 MW on cond 12 C / condensing extraction turbine 36 MW)

6 Brewery s heating plant substitution of worn boilers

HIGH BALANCE RECONSTRUCTION OF ONE BOILER TP I (1996), DEMOLITION OF TWO BOILERS TP I (1997) TABLE 5

INVESTMENT COSTS DEVIDED IN YEARS

ITEM	NAME	1995	1996	1997	1998	1999	2000	2004	2005	2009	2010	2011	2012	TOTAL
1	TP I		11	6				51						68
2	TP II	74	74											148
3	TP III	350	1610											1960
4	TP PLZEN TOTAL													2176
5	ASH STOCK YARD FOR TP PLZEŇ				38				41				43	122
6	BREWERY S HEATING PLANT							38						38
7	INVESTMENT COSTS TOTAL	424	1695	6	38			89	41				43	2336

COMENTS

item

1 TP I reconstruction of one boiler for bituminous coal (1996) demolition of two boilers (1997)
demolition of one boiler and construction of a hot water boiler 35 MW (2004)

2 TP II reconstruction for bituminous coal

3 TP III construction of gas combined cycle (gas turbine GT 13 D /105 MW on cond při 12 C /, condensing extraction turbine 36 MW)

6 Brewery s heating plant substitution of worn boilers

TABLE 6

LOW BALANCE

EMISSIONS AND ASHES PRODUCTION IN YEARS

YEAR	EMISSIONS /IN TONS/ SOLID	SO2	NOX	CO	HYDROCARBONS /CXHX/	ASHES /IN THOUSANDS OF TONS/
1992	530	5340	2340	195	59	62 4
1995	445	4480	1960	163	49	52 3
1996	420	4290	2270	182	54	74 6
1997	145	860	910	122	29	34 3
2000	140	840	895	119	28	33 7
2005	140	835	890	119	28	33 4
2010	140	835	890	119	28	33 4

HIGH BALANCE

EMISSIONS AND ASHES PRODUCTION IN YEARS

YEAR	EMISSIONS /IN TONS/ SOLID	SO2	NOX	CO	HYDROCARBONS /CXHX/	ASHES /IN THOUSANDS OF TONS/
1992	530	5340	2340	195	59	62 4
1995	480	4810	2170	175	53	56 1
1996	420	4320	2150	180	54	71 7
1997	160	1140	1040	136	34	45 6
2000	170	1230	1120	144	37	49 3
2005	170	1215	1115	142	36	48 6
2010	175	1220	1120	143	36	48 9

B TASK 15 Data for Sensitivity Analysis

1 Fuel Prices

1 1 Natural Gas

The current price of natural gas for large-scale consumers is 3 14 Kč + VAT 5 % - i e , a total of 3 297 Kč The price can be expected to rise next year by 25 % (1994) As from 1995 natural gas prices should be fully liberalized in the Czech Republic Then they should follow the movement of world prices

1 2 Coal

1 2 1 Brown Coal

The brown coal presently burnt is 12 7 Mj/kg in heating value and is purchased for 443 Kč/t The price includes 5 % VAT and transport costs With respect to the expected development of prices in the Czech fuel market we anticipate that the price of this coal will rise to be in 1996 by 25-50 % above the current level, depending on cancelling subsidies and development of the national economy The price of 660 Kč/t in 1996 is expected to be a ceiling one Further development of the price of this kind of brown coal should not be rapid and the price should only follow inflation with possible seasonal fluctuations within not more than 5 %

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1 2 2 Bituminous Coal

The offers of bituminous coal deliveries received indicated that the price could be fixed for 900 Kč/t incl transport and VAT (for slag-type boilers, heating value 17 38 MJ/kg) or about 1,135 Kč/t (top stoker-fired hot-water boilers, heating value 18 47 MJ/kg) With respect to the number of offers and possible deliveries of comparable-quality coal from abroad (shipments from overseas are quite real too), we do not expect that the price would rise significantly by the end of 1966 The price increases, if any, should only be connected with inflation trends and could be between 8 and 15 % Further price movements should be slow and slightly under inflation limits if the expected signing of long-term contracts to ensure stability of deliveries is taken into account

1 3 Fuel Oil

Taken into consideration is low-sulfur heavy fuel oil only The alternative designed by the EGP uses this fuel to a limited extent (about 500 t/h) by the end of 1996 In 1966, the heavy fuel oil is supposed to be replaced with natural gas in the Plzen heating plant in connection with the installation of the steam-gas cycle and the oil should be used as stand-by fuel

The heavy fuel oil price is rather volatile fluctuating around the average price of 3,000 Kč/t within 20 % The growth of the average price is anticipated to be slow, moving slightly above 10 % towards 1996 It is recommended that an increase of not more than 20 % be considered Owing to the expected yearly consumption of about 20 TJ we suppose that the development of the heavy fuel oil price will not virtually affect the the economic balance of the Plzen heating plant

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2 Prices of Produced Energy

2 1 Electric Power Price

We estimate that the price of electric power in the period of 1993-1996 should rise from the present 1,000 Kč/MWh or so up to 1,500 Kč/MWh For the purpose of the sensitivity analysis it is recommended that the prices 1,400, 1,500, 1,600 and 1,700 Kč/MWh (1996) be used After 1996 another increase of 5-6 % per year in the price can be expected till 2 000 when it should be equal to world prices

2.2 Heat Price

The price of heat for dwellings is state-controlled at present Its ceiling - 120 Kč/GJ - in force for the 1992-1993 heating season was risen to 137 Kč/GJ for the heating seasons to come and its additional increase to about 170 Kč/GJ is anticipated as from the heating season of 1994-1955 The difference between this price of heat and the actual one is covered with some producers by subsidies from the state budget

The removal of the subsidies and transition to actual prices is expected in 1995-1996 The price of heat should therefore climb to 250 Kč/GJ ranging from 220 to 270 Kč/GJ Its subsequent growth can be derived from the anticipated growth of fuel costs in particular

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3 Investment Costs

The possibility of variation of the investment costs within the individual variants is very limited, at least with the variant designed by the EGP The expected difference of these costs should be below 5 %, which should not affect the economy of the heating plant Spreading the investment work over a prolonged period of time cannot be considered either because most of this work will have to be finished by the end of 1966 and this determines that the EGP variant uses more than 90 % of all resources for spending in 1995 and 1966 The situation with the other variants is likely to be similar

4 Financing

Considered are the following ways of financing

a) own resources
b) credit
c) issue of bonds
d) direct capital participation by another legal entity

4 1 Own Resources

The heating plant Plzen is likely not to have the necessary amount of own resources This case cannot be taken for a limit one It is apparent that a variant which will not be profitable with 100 % of own resources will not be profitable with other ways of financing either

4.2 Credit

In the event of such investment there are three credit sources - domestic banks, foreign banks and the supplier credit Foreign banks are intentionally distinguished

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from domestic ones because they differ in one substantial point - the requested amount of credit While the interest on credits from domestic banks was between 15 and 18 % not long ago and it drops very slowly even though the rate of inflation is low, the interest on long-term credits provided by foreign banks is rather lower At present, the interest rates on long-term credits granted by the biggest banks in the Czech Republic range from 12 % to 15 % and their further decrease can be expected provided that the economic situation will be developing favourably as it has been so far However the interest rate concerning long-term credits will be dropping very slowly, the decrease expected by us being not more than 10 % to 12 % Domestic banks provide credits with the due-date not longer than 5 years, which is not very favourable for financing a project having its service life five times longer

Credits granted by foreign banks are rather cheaper and according to information available to us, obtaining necessary credits with the interest rate as low as 8 % can be taken into account The level of a particular interest rate and and of other fees linked to a credit is a matter of further discussions, a certain advantage of such credits being the possibility to obtain a longer due-date (up to 10 years) and/or postponing instalments by 1 to 2 years

The possibility of obtaining the supplier credit is not feasible with regard to the level of investment costs and the fact that virtually the whole steam-gas equipment would be delivered by the ABB-1 BS consortium of companies The supplier only offers to provide user credits in Germany with the basic interest rate of approximately 8 % without any additional fees (commission, insurance, etc)

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4 3 Issue of Bonds

Owing to paying 10 5 to 12 % interest on bonds in the Czech republic, this way of financing is apparent to be rather more advantageous than credits from domestic banks However, the risk of placing bonds in the market of securities is borne by the one issuing the bonds

4 4 Direct Capital Participation of Another Entity

In its consequences, the direct capital participation of another legal entity is equal to an increase of own capital and, therefore, can be handled in the same manner Such participation can only be considered to a larger extent with the biggest domestic banks and investment funds

The short analysis above suggests that it will be necessary to ascertain how the economic effectiveness of the variants, which will meet the requirement for 100 % of own investment resources, will be affected by various proportions of credits, the proportion of own resources being recommended at the level of 20 % to 40 % with no supplier credit and the balance being provided in the form of credits from foreign or domestic banks

5 Consumer's Savings

The effect of consumer's savings is given by the balance of heat consumption (low and high estimates) A comparison of calculated heat and electric power deliveries with the consumption of fuel preliminarily suggests that the effect of the considered drop in the consumption of heat will limit peak sources in particular so that a decrease in the delivery of heat by 1 % will reduce the delivery of electric power by about 0 5 % only, the consumption of fuel being reduced in proportion

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2 3 High Balance

The power and heating plant Plzen incorporates a gas-steam system (Tp Plzen III) identical to the solution for "low balance" (see 2 1 1 for description) After installation of the gas-steam system the requirements for heat in the steam and hot-water systems are covered by the power and heating plant Plzen (Tp I, II and III) and the Pivovar heating plant

The heating plant Plzen I is to be reconstructed to burn bituminous coal, the reconstruction consisting in modifying the combustion system and replacing the precipitators with those whose parameters comply with the limits for solid emissions The reconstruction is planned for the period of 1994-1996, skirting heating seasons With regard to providing heat deliveries, reconstruction of one boiler is sufficient at low disparity The basic solution suggests that all of the three boilers be reconstructed (with respect to comparatively low costs per unit capacity), the advantage being higher capacity and a reserve which can be used if requirements for heat grow more quickly

The gas-steam equipment is also operated in the base part of the heat delivery diagram, the exceptions being low tariff zones of payments for electric power in summer The Pivovar heating plant is used during shut-downs of the gas-steam system, and Tp Plzen II is used to supply steam and prepare hot water in base heater of Tp Plzen The Pivovar heating plant will be also used for peak deliveries of steam after Tp I is shut down for ever

Assumed after the year 2000 is the end of Tp Plzen I operation, and replaced will only be the capacity sufficient to cover heat requirements (i e , the installation of a gas and oil burned hot-water boiler with capacity 35 MW at Tp

Plzen) It is also necessary to replace the capacity of two oldest boilers at the Pivovar heating plant For the installation of the capacity replacement, the same applies as in the event of "low balance" - i e , the selection of the place of installation depending on the ownership arrangement In this case, we opted for the installation at the Pivovar heating plant

The mode of operating Tp Plzen and the Pivovar heating plant for individual tariff zones of payments for electricity and the course of electric capacity after 2000 are apparent from diagrams 4, 5 and 6 The fundamental data (heat deliveries, fuel consumption, electric power generation, etc) are listed in the tables attached The arrangement of Tp Plzen is apparent from Scheme 2 and 2/A

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APPENDIX F: GILBERT/COMMONWEALTH ECONOMIC ANALYSIS MODEL RESULTS AND DETAILS:

Variant A2: (Seimens V64.3 GTCC for CPIV)

Variant A3: (Westinghouse 251B11/12 for CPIV)

Variant B1: (CFB Boiler and 32 MW steam turbine for CPIV)

Variant C1: (Base case - existing plants with a CFB Boiler in the year 2003)

APPENDIX F: GILBERT/COMMONWEALTH ECONOMIC ANALYSIS MODEL RESULTS AND DETAIL:

Variant A2: (Seimens V64.3 GTCC for CPIV)

	WINTER				SUMMER							
	Peak	High	Low	Weekend	Peak 1	Peak 2	High 1	High 2	Low 1	Low 2	Wkend 1	Wkend 2

Interpolated Exhaust Temperature °F

	Exhaust Temperature °F											
	–	–	–	–	–	–	–	–	–	–	–	–
	–	–	–	–	–	–	–	–	–	–	–	–
	–	–	–	–	–	–	–	–	–	–	–	–
	–	–	–	–	–	–	–	–	–	–	–	–
	–	–	–	–	–	–	–	–	–	–	–	–
GT–V64 3	989	989	989	–	994	997	994	997	994	997	–	–

Interpolated Exhaust Flow M#/Hr

	Exhaust Flow M#/Hr											
	–	–	–	–	–	–	–	–	–	–	–	–
	–	–	–	–	–	–	–	–	–	–	–	–
	–	–	–	–	–	–	–	–	–	–	–	–
	–	–	–	–	–	–	–	–	–	–	–	–
	–	–	–	–	–	–	–	–	–	–	–	–
GT–V64 3	1349 5	1348 9	1093 7	–	1439 6	1415 4	1439 6	1415 4	1439 6	1338 4	–	–

Available Exhaust Heat MMBTU/Hr

	Exhaust Heat MMBTU/Hr											
	–	–	–	–	–	–	–	–	–	–	–	–
	–	–	–	–	–	–	–	–	–	–	–	–
	–	–	–	–	–	–	–	–	–	–	–	–
	–	–	–	–	–	–	–	–	–	–	–	–
	–	–	–	–	–	–	–	–	–	–	–	–
GT–V64 3	261 286	261 161	211 763	–	280 337	276 855	280 337	276 855	280 337	261 778	–	–

Steam Available – MW per Hour (Without Supplementary Firing)

	Enthalpy Rise	Total Steam Available without Supplementary Firing M#/Hr											
	–	–	–	–	–	–	–	–	–	–	–	–	–
	–	–	–	–	–	–	–	–	–	–	–	–	–
	–	–	–	–	–	–	–	–	–	–	–	–	–
	–	–	–	–	–	–	–	–	–	–	–	–	–
	–	–	–	–	–	–	–	–	–	–	–	–	–
HRSG IV	3 412	76 579	76 542	62 064	–	82 162	81 142	82 162	81 142	82 162	76 723	–	–
		76 579	76 542	62 064	–	82 162	81 142	82 162	81 142	82 162	76 723	–	–

Supplementary Firing – Maximum Exhaust Heat MMBTU/Hr

		–	–	–	–	–	–	–	–	–	–	–	–
		–	–	–	–	–	–	–	–	–	–	–	–
		–	–	–	–	–	–	–	–	–	–	–	–
		–	–	–	–	–	–	–	–	–	–	–	–
		–	–	–	–	–	–	–	–	–	–	–	–
		–	–	–	–	–	–	–	–	–	–	–	–

Steam Rejection – Avg MW (To Cooling Tower)

	Maximum Capacity	Steam Rejection – Average MW											
From Condensing	18 000	–	–	–	–	–	–	–	–	–	–	–	–
From Gas Turbines	18 000	18 0	18 0	18 0	–	7 7	7 7	7 7	7 6	6 4	18 0	–	–
Total		18 0	18 0	18 0	–	7 7	7 7	7 7	7 6	6 4	18 0	–	–

Utilized HRSG Energy MW per Hr

	HRSG Energy Utilized – MW/Hr											
	–	–	–	–	–	–	–	–	–	–	–	–
	–	–	–	–	–	–	–	–	–	–	–	–
	–	–	–	–	–	–	–	–	–	–	–	–
	–	–	–	–	–	–	–	–	–	–	–	–
	–	–	–	–	–	–	–	–	–	–	–	–
HRSG IV	58 6	58 5	44 1	–	74 4	73 5	74 4	73 5	75 8	58 7	–	–
	58 6	58 5	44 1	–	74 4	73 5	74 4	73 5	75 8	58 7	–	–

FINANCIAL COST (000) (Including Inflation)

	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
ACCRUAL BASIS	(Exclusive of Interest Expense if any and Depreciation Charges related to existing plant (Production Transmission Distribution et al)																	
Operating Expenses																		
Operation & Maintenance	5 544	6 234	6 922	12 534	21 844	19 789	21 964	24 413	25 373	26 836	28 426	30 723	30 442	37 015	33 803	35 826	38 853	40 947
Depreciation Expense	8	44	1 468	2 940	2 965	2 980	2 994	3 010	3 012	3 015	3 249	3 495	3 497	3 500	3 502	3 504	3 506	3 509
Total Operating Expenses	5 552	6 277	8 390	15 474	24 809	22 769	24 959	27 423	28 386	29 851	31 675	34 218	33 940	40 514	37 305	39 330	42 359	44 456
Interest Expense	9	57	1 615	4 656	6 031	5 698	5 305	4 862	4 345	3 749	3 349	3 233	3 088	2 859	2 615	2 353	2 069	1 762
Equity Return	9	9	55	1 013	1 980	2 012	2 029	2 048	2 068	2 070	2 073	2 366	2 673	2 677	2 679	2 682	2 685	2 688
Total Expense & Return	5 570	6 344	10 060	21 142	32 820	30 478	32 293	34 333	34 798	35 670	37 097	39 816	39 701	46 050	42 600	44 365	47 113	48 906
Income Tax Effect @ 45%	8	8	45	829	1 620	1 646	1 660	1 676	1 692	1 694	1 696	1 936	2 187	2 190	2 192	2 194	2 197	2 199
Total Cost	5,577	6,352	10,105	21,971	34,439	32,124	33,953	36,008	36,490	37,364	38,794	41,752	41,889	48,240	44,792	46,559	49,310	51,105
Estimated Hot Water Revenue Requirement	(Exclusive of Interest Expense if any and Depreciation Charges related to existing plant (Production Transmission Distribution et al)																	
Total Cost (Above) less																		
Cost of Steam																		
Operation & Maintenance	4 111	4 486	4 817	6 541	8 579	9 688	10 041	11 345	11 291	12 180	12 581	15 378	12 310	12 924	13 569	14 247	14 958	15 704
Allocated Depreciation	3	16	535	932	932	934	936	938	938	937	1 008	1 082	1 081	1 081	1 080	1 080	1 080	1 080
Allocated Return	4	4	20	321	623	631	634	638	644	643	643	733	826	826	827	827	827	827
Income Tax Effect	3	3	16	263	509	516	519	522	527	526	526	599	676	676	676	676	676	677
Total Steam	4 121	4 509	5 388	8 056	10 644	11 769	12 131	13 444	13 400	14 287	14 758	17 792	14 893	15 507	16 152	16 830	17 541	18 287
Equals Cost of Hot Water	1 457	1 843	4 717	13 915	23 796	20 355	21 822	22 565	23 091	23 077	24 036	23 960	26 996	32 733	28 640	29 729	31 769	32 818
HOT WATER – $/MWH	$2 73	$3 33	$8 22	$17 91	$30 22	$25 74	$27 48	$28 29	$28 90	$28 84	$29 99	$29 84	$33 57	$40 65	$35 52	$36 82	$39 29	$40 54
Present Worth	$2 73	$2 85	$6 00	$11 18	$16 13	$11 74	$10 71	$9 43	$8 23	$7 02	$6 24	$5 31	$5 10	$5 28	$3 94	$3 49	$3 19	$2 81
Levelized Cost to Date		$3 33	$5 58	$9 07	$13 18	$14 97	$16 33	$17 35	$18 13	$18 71	$19 22	$19 61	$20 03	$20 56	$20 87	$21 16	$21 43	$21 67
CASH BASIS	(Exclusive of Debt Service related to existing plant (Production Transmission Distribution et al)																	
O & M Expenses	5 544	6 234	6 922	12 534	21 844	19 789	21 964	24 413	25 373	26 836	28 426	30 723	30 442	37 015	33 803	35 826	38 853	40 947
Equity Return	9	9	55	1 013	1 980	2 012	2 029	2 048	2 068	2 070	2 073	2 366	2 673	2 677	2 679	2 682	2 685	2 688
Debt Service																		
Foreign Interest	–	–	658	2 007	2 669	2 607	2 541	2 468	2 390	2 306	2 214	2 116	2 009	1 893	1 768	1 633	1 486	1 328
Principal	–	–	–	353	757	818	885	957	1 036	1 120	1 211	1 310	1 417	1 533	1 658	1 793	1 940	2 098
Total	–	–	658	2 360	3 426	3 426	3 426	3 426	3 426	3 426	3 426	3 426	3 426	3 426	3 426	3 426	3 426	3 426
Domestic Interest	9	57	957	2 648	3 361	3 090	2 764	2 393	1 955	1 443	1 135	1 117	1 080	966	848	720	583	434
Principal	–	11	67	1 229	2 545	2 897	3 277	3 704	4 186	4 677	5 121	3 176	982	1 010	1 084	1 165	1 252	1 402
Total	9	69	1 025	3 877	5 906	5 988	6 041	6 097	6 141	6 121	6 256	4 293	2 062	1 977	1 932	1 885	1 835	1 836
Total Cost before Income Tax	5 562	6 312	8 659	19 785	33 155	31 214	33 460	35 984	37 007	38 453	40 181	40 808	38 603	45 094	41 841	43 818	46 798	48 896
Income Tax Effect @ 45%	8	8	45	829	1 620	1 646	1 660	1 676	1 692	1 694	1 696	1 936	2 187	2 190	2 192	2 194	2 197	2 199
Total Financial Cost	5,570	6,319	8,704	20,613	34,775	32,860	35,120	37,660	38,699	40,147	41,877	42,744	40,791	47,284	44,033	46,013	48,995	51,096

			WINTER				SUMMER								
			Peak	High	Low	Weekend	Peak 1	Peak 2	High 1	High 2	Low 1	Low 2	Wkend 1	Wkend 2	
FUEL COST – BOILERS (Lignite)															
	Lignite %	Weighted $/MMBTU	Fuel Cost – Lignite $(000)												
	–	–	–	–	–	–	–	–	–	–	–	–	–	–	
Kosutka	–	–	–	–	–	–	–	–	–	–	–	–	–	–	
Brewery	–	–	–	–	–	–	–	–	–	–	–	–	–	–	
Plzen V	–	–	–	–	–	–	–	–	–	–	–	–	–	–	
Plzen IVb	–	–	–	–	–	–	–	–	–	–	–	–	–	–	
Plzen IIb	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
Plzen IVa	–	–	–	–	–	–	–	–	–	–	–	–	–	–	
Plzen IIa	–	–	–	–	–	–	–	–	–	–	–	–	–	–	
Total			–	–	–	–	–	–	–	–	–	–	–	–	–
FUEL COST – BOILERS (Coal)															
	Coal %	Weighted $/MMBTU	Fuel Cost – Black Coal $(000)												
	–	–	–	–	–	–	–	–	–	–	–	–	–	–	
Kosutka	–	–	–	–	–	–	–	–	–	–	–	–	–	–	
Brewery	–	–	–	–	–	–	–	–	–	–	–	–	–	–	
Plzen V	–	–	–	–	–	–	–	–	–	–	–	–	–	–	
Plzen IVb	–	–	–	–	–	–	–	–	–	–	–	–	–	–	
Plzen IIb	99 6%	$1 95	1162	996	1938	1683	–	–	–	–	–	–	395	–	
Plzen IVa	–	–	–	–	–	–	–	–	–	–	–	–	–	–	
Plzen IIa	99 6%	$1 95	587	502	713	620	–	–	–	–	–	–	115	–	
Total			1749	1498	2651	2303	–	–	–	–	–	–	510	–	8711
FUEL COST – BOILERS (Gas)															
	Gas %	Weighted $/MMBTU	Fuel Cost – Natural Gas $(000)												
	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
Kosutka	100 0%	$3 77	–	–	–	–	–	–	–	–	–	–	–	–	–
Brewery	100 0%	$3 77	2	1	–	1	1	23	1	39	–	–	–	304	372
Plzen V	100 0%	$3 77	260	222	65	428	152	–	267	–	272	–	–	265	1931
Plzen IVb	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
Plzen IIb	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
Plzen IVa	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
Plzen IIa	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
Total			262	224	65	429	152	23	268	39	272	–	–	569	2303
FUEL COST – BOILERS (Oil)															
	Oil %	Weighted $/MMBTU	Fuel Cost – Oil $(000)												
	–	–	–	–	–	–	–	–	–	–	–	–	–	–	
Kosutka	–	–	–	–	–	–	–	–	–	–	–	–	–	–	
Brewery	–	–	–	–	–	–	–	–	–	–	–	–	–	–	
Plzen V	–	–	–	–	–	–	–	–	–	–	–	–	–	–	
Plzen IVb	–	–	–	–	–	–	–	–	–	–	–	–	–	–	
Plzen IIb	0 4%	$0 01	7	6	12	10	–	–	–	–	–	–	2	–	
Plzen IVa	–	–	–	–	–	–	–	–	–	–	–	–	–	–	
Plzen IIa	0 4%	$0 01	4	3	4	4	–	–	–	–	–	–	1	–	
Total			11	9	16	14	–	–	–	–	–	–	3	–	53
HOT WATER SHORTFALL		MWH	–	–	–	–	–	–	–0	–	–	–	–	–	
Assumed Equivalent Cost	$/MWH	$10 00													
SUPPLEMENTAL HOT WATER COST – $(000)			–	–	–	–	–	–	–0 0	–	–	–	–	–	–0.0
Water and Other Variable O&M Expenses – Boilers $(000)															
	Basis $/MWH-hr	Basis $/MWH	Variable O&M Expense $(000)												
	–	–	–	–	–	–	–	–	–	–	–	–	–	–	
Kosutka	$0 10	$0 41	–	–	–	–	–	–	–	–	–	–	–	–	
Brewery	$0 10	$0 41	0	0	–	0	0	1	0	1	–	–	–	34	
Plzen V	$0 10	$0 41	9	8	2	15	5	–	9	–	9	–	–	9	
Plzen IVb	$0 10	$0 41	43	37	29	–	5	9	9	15	21	24	–	–	
Plzen IIb	$0 10	$0 41	123	106	206	179	–	–	–	–	–	–	45	–	
Plzen IVa	$0 10	$0 41	–	–	–	–	13	21	22	37	33	51	–	–	
Plzen IIa	$0 10	$0 41	124	106	151	131	–	–	–	–	–	–	24	–	
Total			299	256	388	325	23	30	41	53	63	74	69	43	1 664
Limestone and Ash Removal Expenses – Boilers $(000)															
	Limestone $/MMBTU	Removal $/MMBTU	Limestone Injection & Ash Removal Expenses $(000)												
	–	–	–	–	–	–	–	–	–	–	–	–	–	–	
Kosutka	–	–	–	–	–	–	–	–	–	–	–	–	–	–	
Brewery	–	–	–	–	–	–	–	–	–	–	–	–	–	–	
Plzen V	–	–	–	–	–	–	–	–	–	–	–	–	–	–	
Plzen IVb	–	–	–	–	–	–	–	–	–	–	–	–	–	–	
Plzen IIb	–	0 072	43	37	71	62	–	–	–	–	–	–	14	–	
Plzen IVa	–	–	–	–	–	–	–	–	–	–	–	–	–	–	
Plzen IIa	–	0 072	22	18	26	23	–	–	–	–	–	–	4	–	
Total			64	55	97	84	–	–	–	–	–	–	19	–	319
Removal Costs Only			64	55	97	84	–	–	–	–	–	–	19	–	319
By–Product Sales $(000)			32	27	49	42	–	–	–	–	–	–	9	–	160
Emissions Penalties – Boilers $(000)															
		Emissions $/MMBTU	Emissions Penalties $(000)												
		–	–	–	–	–	–	–	–	–	–	–	–	–	
Kosutka		–	–	–	–	–	–	–	–	–	–	–	–	–	
Brewery		–	–	–	–	–	–	–	–	–	–	–	–	–	
Plzen V		–	–	–	–	–	–	–	–	–	–	–	–	–	
Plzen IVb		–	–	–	–	–	–	–	–	–	–	–	–	–	
Plzen IIb		–	–	–	–	–	–	–	–	–	–	–	–	–	
Plzen IVa		–	–	–	–	–	–	–	–	–	–	–	–	–	
Plzen IIa		–	–	–	–	–	–	–	–	–	–	–	–	–	
Total			–	–	–	–	–	–	–	–	–	–	–	–	–
Emissions by Type – Tons															
		Units per Ton	Emissions – Tons												
Particulate		2000	16 6	14 2	25 1	21 8	–	–	–	–	–	–	4 8	–	82 5
SO_2		2000	455 1	389 8	689 9	599 3	–	–	–	–	–	–	132 7	–	2 266 8
NOx		2000	82 4	70 5	81 8	44 9	14 9	22 2	26 2	38 8	46 5	56 5	9 3	8 9	502 8
CO		2000	6 7	5 8	9 3	8 3	0 5	0 3	0 8	0 5	1 2	0 6	1 7	1 1	36 8

VARIANT A2

ELECTRIC GENERATION POWER

	WINTER				SUMMER								
	Peak	High	Low	Weekend	Peak 1	Peak 2	High 1	High 2	Low 1	Low 2	Wkend 1	Wkend 2	
Avg KW Required – Pumping	3020	3020	2567	2567	1036	364	1036	364	812	310	812	310	1676
Sta Use	7121	7120	6362	6572	1852	490	1852	485	1233	293	3825	1296	4058
Total	10140	10139	8929	9139	2889	854	2889	849	2044	602	4637	1605	5734

BACK PRESSURE TURBINE/GENERATOR OUTPUT – AVERAGE KW

BASIS UNITe	Back Pressure Turbine/Generator Output & Contract Purchase												
	–	–	–	–	–	–	–	–	–	–	–	–	
	–	–	–	–	–	–	–	–	–	–	–	–	
	–	–	–	–	–	–	–	–	–	–	–	–	
Turb IB	44255	44266	47211	47208	–	–	–	–	–	–	36209	–	
Turb IA	10745	10734	7789	7792	–	–	–	–	–	–	3059	–	
Turb IIB	12525	12517	9123	–	7218	7135	7217	7212	9446	5991	–	–	
Turb IIA	–	–	–	–	3458	3397	3458	3368	2617	2374	–	–	
	–	–	–	–	–	–	–	–	–	–	–	–	
Total T/G Output	67525	67517	64123	55000	10676	10533	10675	10581	12064	8365	39269	–	38002
Balance Required	–57385	–57378	–55194	–45861	–7787	–9679	–7787	–9731	–10019	–7763	–34632	1605	

CONDENSING TURBINE OUTPUT – AVERAGE KW

	Generator Efficiency	Condensing Turbine Output – KW												
		–	–	–	–	–	–	–	–	–	–	–	–	–
		–	–	–	–	–	–	–	–	–	–	–	–	–
		–	–	–	–	–	–	–	–	–	–	–	–	–
		–	–	–	–	–	–	–	–	–	–	–	–	–
		–	–	–	–	–	–	–	–	–	–	–	–	–
		–	–	–	–	–	–	–	–	–	–	–	–	–
		–	–	–	–	–	–	–	–	–	–	–	–	–
		–	–	–	–	–	–	–	–	–	–	–	–	–
Total Condens Turb Output		–	–	–	–	–	–	–	–	–	–	–	–	–
Balance Required		–57385	–57378	–55194	–45861	–7787	–9679	–7787	–9731	–10019	–7763	–34632	1605	
GT Capability @ Full Load		62551	62551	62551	62551	60147	58273	60147	58273	60147	58273	60147	58273	

GAS TURBINE OUTPUT – AVERAGE KW

	Gas Turbine Output – KW												
	–	–	–	–	–	–	–	–	–	–	–	–	
	–	–	–	–	–	–	–	–	–	–	–	–	
	–	–	–	–	–	–	–	–	–	–	–	–	
	–	–	–	–	–	–	–	–	–	–	–	–	
	–	–	–	–	–	–	–	–	–	–	–	–	
GT–V64 3	53932	53886	35737	–	60147	58273	60147	58273	60147	52966	–	–	
Total GT Output (KW)	53932	53886	35737	–	60147	58273	60147	58273	60147	52966	–	–	493507
Balance Required (KW)	–111317	–111264	–90931	–45861	–67934	–67952	–67933	–68005	–70166	–60729	–34632	1605	
Hours in Period	914	783	1435	1248	181	306	318	535	589	994	435	734	
Balance Required (MWH)	–101744	–87119	–103288	–57235	–12296	–20793	–21603	–36382	–41328	–60364	–15065	1178	

PURCHASED POWER	75%	75%	75%	75%	75%	75%	75%	75%	75%	75%	75%	75%	
Peak Demand KW	–	–	–	–	–	–	–	–	–	–	–	2140 3	
Demand Charge – $/KW	7 93	7 93	7 93	7 93	7 93	7 93	7 93	7 93	7 93	7 93	7 93	7 93	
Energy Charge – $/KWH	0 0350	0 0279	0 0246	0 0246	0 0350	0 0350	0 0279	0 0279	0 0246	0 0246	0 0246	0 0246	
Demand Charge – $(000)	–	–	–	–	–	–	–	–	–	–	–	17 0	
Energy Charge – $(000)	–	–	–	–	–	–	–	–	–	–	–	29 0	
Total – $(000)	–	–	–	–	–	–	–	–	–	–	–	46 0	46 0
POWER SALES													
Energy Credit – Cents/KWH	0 0350	0 0279	0 0246	0 0246	0 0350	0 0350	0 0279	0 0279	0 0246	0 0246	0 0246	0 0246	
Energy Credit $(000)	3561 0	2426 9	2545 3	1410 4	430 4	727 8	601 8	1013 5	1018 4	1487 6	371 2	–	15594 3
GAS TURBINE													
Fuel Flow – MMBTU/Hr													
Maximum	594 7	594 7	594 7	594 7	578 2	565 4	578 2	565 4	578 2	565 4	578 2	565 4	
75% Load	487 0	487 0	487 0	487 0	473 5	463 0	473 5	463 0	473 5	463 0	473 5	463 0	
50% Load	379 3	379 3	379 3	379 3	368 8	360 6	368 8	360 6	368 8	360 6	368 8	360 6	
25% Load	271 6	271 6	271 6	271 6	264 1	258 2	264 1	258 2	264 1	258 2	264 1	258 2	

Percent Load

	Percent Load											
	–	–	–	–	–	–	–	–	–	–	–	–
	–	–	–	–	–	–	–	–	–	–	–	–
	–	–	–	–	–	–	–	–	–	–	–	–
	–	–	–	–	–	–	–	–	–	–	–	–
	–	–	–	–	–	–	–	–	–	–	–	–
GT–V64 3	86 2%	86 1%	57 1%	–	100 0%	100 0%	100 0%	100 0%	100 0%	90 9%	–	–

Interpolated Fuel Flow – MMBTU

	Fuel Flow – MMBTU												
	–	–	–	–	–	–	–	–	–	–	–	–	
	–	–	–	–	–	–	–	–	–	–	–	–	
	–	–	–	–	–	–	–	–	–	–	–	–	
	–	–	–	–	–	–	–	–	–	–	–	–	
	–	–	–	–	–	–	–	–	–	–	–	–	
GT–V64 3	489277	418902	588359	–	104662	173025	183881	302510	340584	524965	–	–	3126165
Total	489277	418902	588359	–	104662	173025	183881	302510	340584	524965	–	–	

Fuel Cost – Gas Turbine(s) (Gas) $(000)

	Unit Cost	Fuel Cost – Gas $(000)												
		–	–	–	–	–	–	–	–	–	–	–	–	
		–	–	–	–	–	–	–	–	–	–	–	–	
		–	–	–	–	–	–	–	–	–	–	–	–	
		–	–	–	–	–	–	–	–	–	–	–	–	
		–	–	–	–	–	–	–	–	–	–	–	–	
GT–V64 3	$3 77	1844 6	1579 3	2218 1	–	394 6	652 3	693 2	1140 5	1284 0	1979 1	–	–	
Total		1844 6	1579 3	2218 1	–	394 6	652 3	693 2	1140 5	1284 0	1979 1	–	–	11 766

VARIANT A2

			WINTER				SUMMER								
			Peak	High	Low	Weekend	Peak 1	Peak 2	High 1	High 2	Low 1	Low 2	Wkend 1	Wkend 2	
PRODUCT – LP STEAM															
Customer Requirement	MWH		58007	49652	71302	62027	6354	10515	11165	18251	16280	25394	12023	18752	359720
Station Use	MWH	–	–	–	–	–	–	–	–	–	–	–	–	–	–
			58007	49652	71302	62027	6354	10515	11165	18251	16280	25394	12023	18752	359720
	2	3	4	5	6	7	8	9	10	11	12	13	1	15	
	MWts		Average Loading – MW												
	–		–	–	–	–	–	–	–	–	–	–	–	–	
	–		–	–	–	–	–	–	–	–	–	–	–	–	
Brewery	56 100		–	–	–	–	1 6	–	2 1	–	–	–	–	25 5	
	–		–	–	–	–	–	–	–	–	–	–	–	–	
	–		–	–	–	–	–	–	–	–	–	–	–	–	
	–		–	–	–	–	–	–	–	–	–	–	–	–	
Plzen IVa	40 000		–	–	–	–	34 9	34 4	34 9	34 1	27 6	25 5	–	–	
Plzen IIa	100 000		63 5	63 4	49 7	49 7	–	–	–	–	–	–	27 6	–	
			Unit Energy Output – MWH (Before Adjustment for Minimum Loading Limitation)												
			–	–	–	–	–	–	–	–	–	–	–	–	
			–	–	–	–	–	–	–	–	–	–	–	–	
Brewery			–	–	–	–	40	–	70	–	–	–	–	18752	
			–	–	–	–	–	–	–	–	–	–	–	–	
			–	–	–	–	–	–	–	–	–	–	–	–	
			–	–	–	–	–	–	–	–	–	–	–	–	
Plzen IVa		1 000	–	–	–	–	6314	10515	11095	18251	16280	25394	–	–	
Plzen IIa			58007	49652	71302	62027	–	–	–	–	–	–	12023	–	
Total			58007	49652	71302	62027	6354	10515	11165	18251	16280	25394	12023	18752	359720
Steam Not Served	MWH		–	–	–	–	–	–	–	–	–	–	–	–	–
Total excluding HRSG supply			58007	49651 6	71301 6	62026 9	40 0798	–	70 4223	–	–	–	12022 7	18751 7	
PRODUCT – HOT WATER															
Customer Requirement	MWH		151236	129546	185986	161809	15432	10048	27113	17567	39429	24315	29119	17955	809555
Station Use	MWH	–	–	–	–	–	–	–	–	–	–	–	–	–	–
			151236	129546	185986	161809	15432	10048	27113	17567	39429	24315	29119	17955	809555
	2	3	4	5	6	7	8	9	10	11	12	13	14	15	
BASIS UNIT	MWtw		Average Loading – MW												
	–		–	–	–	–	–	–	–	–	–	–	–	–	
Kosutka	34 800		–	–	–	–	–	–	–	–	–	–	–	–	
Brewery	56 100		9 3	9 3	–	8 8	–	–	–	–	–	–	–	–	
Plzen V	116 000		43 2	43 2	21 7	39 5	56 8	–	56 8	–	31 3	–	–	24 5	
Plzen IVb	64 300		45 3	45 3	35 3	–	28 4	28 2	28 4	28 4	35 7	24 5	–	–	
Plzen IIb	165 000		101 0	101 0	106 7	106 7	–	–	–	–	–	–	66 9	–	
	–		–	–	–	–	–	–	–	–	–	–	–	–	
	–		–	–	–	–	–	–	–	–	–	–	–	–	
Total			198 8	198 8	163 7	155 1	85 3	28 2	85 3	28 4	66 9	24 5	66 9	24 5	
			Unit Energy Output – MWH (Before Adjustment for Minimum Loading Limitation)												
			–	–	–	–	–	–	–	–	–	–	–	–	
Kosutka			–	–	–	–	–	–	–	–	–	–	–	–	
Brewery			87	74	–	80	–	1433	–	2373	–	–	–	–	
Plzen V			17436	14910	3598	28527	10289	–	18077	–	18422	–	–	17955	
Plzen IVb		1 000	41416	35454	29229	–	5144	8615	9036	15194	21007	24315	–	–	
Plzen IIb			92297	79108	153159	133203	–	–	–	–	–	–	29119	–	
			–	–	–	–	–	–	–	–	–	–	–	–	
			–	–	–	–	–	–	–	–	–	–	–	–	
Total			151236	129546	185986	161809	15432	10048	27113	17567	39429	24315	29119	17955	809555
Hot Water Not Served	MWH		–	–	–	–	–	–	–0	–	–	–	–	–	–2E–15
Total excluding HRSG supply			109820	94092	156757	161809	10288 7	1433 13	18077 2	2372 86	18421 6	–	29119	17954 8	
ADJUSTED FOR MINIMUM LOADING – MWH															
Steam			Unit Utilization after Adjustment for Minimum Loading – MWH (Steam)												
			–	–	–	–	–	–	–	–	–	–	–	–	
			–	–	–	–	–	–	–	–	–	–	–	–	
Brewery			–	–	–	–	40	–	70	–	–	–	–	18752	
			–	–	–	–	–	–	–	–	–	–	–	–	
			–	–	–	–	–	–	–	–	–	–	–	–	
			–	–	–	–	–	–	–	–	–	–	–	–	
Plzen IVa			–	–	–	–	6314	10515	11095	18251	16280	25394	–	–	
Plzen IIa			58007	49652	71302	62027	–	–	–	–	–	–	12023	–	
Total			58007	49652	71302	62027	6354	10515	11165	18251	16280	25394	12023	18752	
Hot Water			Unit Utilization after Adjustment for Minimum Loading – MWH (Hot Water)												
			–	–	–	–	–	–	–	–	–	–	–	–	
Kosutka			–	–	–	–	–	–	–	–	–	–	–	–	
Brewery			98	84	–	80	–	1433	–	2373	–	–	–	–	
Plzen V			17619	15062	4385	29012	10289	–	18077	–	18457	–	–	17955	
Plzen IVb			41616	35629	28642	–	5144	8615	9036	15194	20972	24315	–	–	
Plzen IIb			91903	78770	152960	132717	–	–	–	–	–	–	29119	–	
			–	–	–	–	–	–	–	–	–	–	–	–	
			–	–	–	–	–	–	–	–	–	–	–	–	
Total			151236	129546	185986	161809	15432	10048	27113	17567	39429	24315	29119	17955	

TOTAL UNIT UTILIZATION BEFORE REQUIREMENT FOR ELECTRIC GENERATION – MWH

	WINTER				SUMMER								
	Peak	High	Low	Weekend	Peak 1	Peak 2	High 1	High 2	Low 1	Low 2	Wkend 1	Wkend 2	
	Output to meet Steam and Hot Water Requirements – MWH												
	–	–	–	–	–	–	–	–	–	–	–	–	
Kosutka	–	–	–	–	–	–	–	–	–	–	–	–	
Brewery	98	84	–	80	40	1433	70	2373	–	–	–	18752	
Plzen V	17619	15062	4385	29012	10289	–	18077	–	18457	–	–	17955	
Plzen IVb	41616	35629	28642	–	5144	8615	9036	15194	20972	24315	–	–	
Plzen IIb	91903	78770	152960	132717	–	–	–	–	–	–	29119	–	
Plzen IVa	–	–	–	–	6314	10515	11095	18251	16280	25394	–	–	
Plzen IIa	58007	49652	71302	62027	–	–	–	–	–	–	12023	–	
Total	209243	179197	257288	223836	21787	20563	38279	35818	55708	49709	41142	36706	1169275

ADDITIONAL REQUIREMENT FOR BACK PRESSURE STEAM TURBINES – MWH

	Basis %g												
		Thermal output represented in electric generation – MWHt											
	–	–	–	–	–	–	–	–	–	–	–	–	–
	–	–	–	–	–	–	–	–	–	–	–	–	–
	–	–	–	–	–	–	–	–	–	–	–	–	–
	–	–	–	–	–	–	–	–	–	–	–	–	–
Turb IIB	0 96	11925	10209	7875	–	1361	2274	2391	4019	5796	6203	–	–
Turb IB	0 965	41916	35918	70204	61052	–	–	–	–	–	–	16322	–
Turb IIA	0 96	–	–	–	–	652	1083	1146	1877	1606	2459	–	–
Turb IA	0 965	10177	8709	11583	10077	–	–	–	–	–	–	1379	–
Total		64019	54836	89663	71130	2013	3357	3536	5896	7402	8662	17701	–

STEAM TO CONDENSING TURBINES AND REJECTION – MWH

	Incremental thermal output represented in electric generation and rejection – MWHt											
	–	–	–	–	–	–	–	–	–	–	–	–
	–	–	–	–	–	–	–	–	–	–	–	–
	–	–	–	–	–	–	–	–	–	–	–	–
	–	–	–	–	–	–	–	–	–	–	–	–
	–	–	–	–	–	–	–	–	–	–	–	–
	–	–	–	–	–	–	–	–	–	–	–	–
	–	–	–	–	–	–	–	–	–	–	–	–
	–	–	–	–	–	–	–	–	–	–	–	–

UNIT UTILIZATION – TOTAL MWH

	Unit Utilization MWH											
	–	–	–	–	–	–	–	–	–	–	–	–
Kosutka	–	–	–	–	–	–	–	–	–	–	–	–
Brewery	98	84	–	80	40	1433	70	2373	–	–	–	18752
Plzen V	17619	15062	4385	29012	10289	–	18077	–	18457	–	–	17955
Plzen IVb	53541	45838	36517	–	6505	10889	11427	19213	26768	30518	–	–
Plzen IIb	133819	114688	223164	193769	–	–	–	–	–	–	45441	–
Plzen IVa	–	–	–	–	6966	11598	12240	20128	17885	27853	–	–
Plzen IIa	68184	58361	82885	72104	–	–	–	–	–	–	13402	–
Total	273261	234033	346950	294966	23800	23920	41815	41714	63110	58371	58843	36706

INPUT ENERGY REQUIRED BEFORE EFFICIENCY ADJUSTMENT

	BTU/kW	Energy Input before Efficiency Adjustment – MMBTU											
	3 412	–	–	–	–	–	–	–	–	–	–	–	–
Kosutka	3 412	–	–	–	–	–	–	–	–	–	–	–	–
Brewery	3 412	335	286	–	272	137	4890	240	8096	–	–	–	63981
Plzen V	3 412	60115	51393	14961	98990	35105	–	61680	–	62974	–	–	61262
Plzen IVb	3 412	182681	156400	124595	–	22194	37153	38988	65556	91332	104127	–	–
Plzen IIb	3 412	456592	391316	761435	661141	–	–	–	–	–	–	155046	–
Plzen IVa	3 412	–	–	–	–	23769	39571	41764	68676	61025	95033	–	–
Plzen IIa	3 412	232644	199127	282803	246020	–	–	–	–	–	–	45727	–
Total		932368	798521	1183795	1006423	81205	81614	142672	142329	215331	199160	200773	125242

EFFICIENCY

	BASIS %1	BASIS %2	Efficiency											
		–	–	–	–	–	–	–	–	–	–	–	–	–
Kosutka	–	–	90 8%	90 8%	90 8%	90 8%	90 8%	90 8%	90 8%	90 8%	90 8%	90 8%	90 8%	90 8%
Brewery	–	–	86 0%	86 0%	86 0%	86 0%	86 0%	86 0%	86 0%	86 0%	86 0%	86 0%	86 0%	86 0%
Plzen V	–	–	91 1%	91 1%	91 1%	91 1%	91 1%	91 1%	91 1%	91 1%	91 1%	91 1%	91 1%	91 1%
Plzen IVb	–	–	100 0%	100 0%	100 0%	100 0%	100 0%	100 0%	100 0%	100 0%	100 0%	100 0%	100 0%	100 0%
Plzen IIb	–	–	84 0%	84 0%	84 0%	84 0%	84 0%	84 0%	84 0%	84 0%	84 0%	84 0%	84 0%	84 0%
Plzen IVa	–	–	100 0%	100 0%	100 0%	100 0%	100 0%	100 0%	100 0%	100 0%	100 0%	100 0%	100 0%	100 0%
Plzen IIa	–	–	84 0%	84 0%	84 0%	84 0%	84 0%	84 0%	84 0%	84 0%	84 0%	84 0%	84 0%	84 0%

INPUT ENERGY REQUIRED

		Unit Energy Input MMBTU												
	–	–	–	–	–	–	–	–	–	–	–	–	–	–
Kosutka	6 5%	–	–	–	–	–	–	–	–	–	–	–	–	–
Brewery	8 5%	423	360	–	343	173	6169	303	10214	–	–	–	80720	9
Plzen V	4 5%	68967	58961	17164	113567	40275	–	70762	–	72247	–	–	70283	5
Plzen IVb	–	182681	156400	124595	–	22194	37153	38988	65556	91332	104127	–	–	82
Plzen IIb	9 5%	595281	510178	992721	861962	–	–	–	–	–	–	202141	–	316228
Plzen IVa	–	–	–	–	–	23769	39571	41764	68676	61025	95033	–	–	329838
Plzen IIa	8 5%	300499	257206	365287	317776	–	–	–	–	–	–	59064	–	1299831
Total		1147852	983105	1499768	1293648	86410	82893	151817	144447	224604	199160	261205	151003	6225913

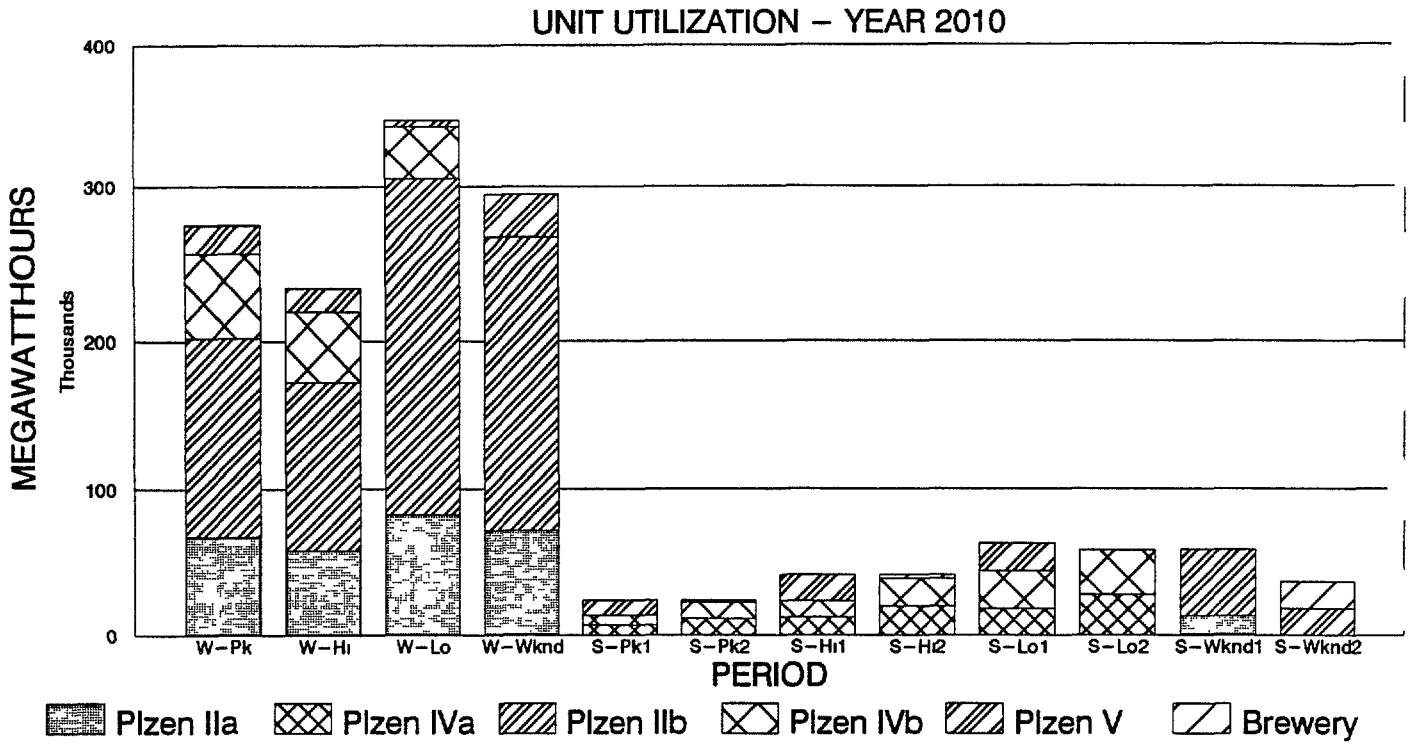
CASE A2 — Test Year = 2010

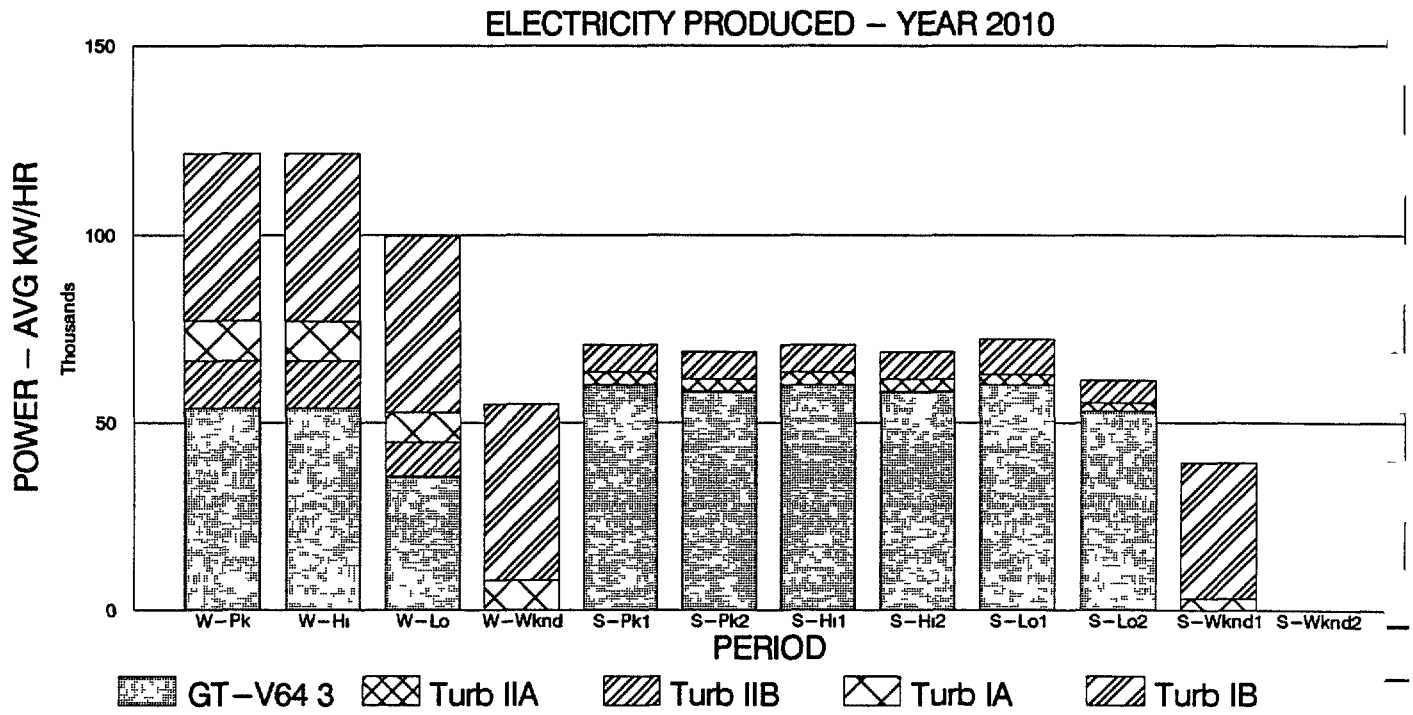
Station Use Unaccounted for etc — Electric kW –; % of Demand: Water –; Steam –

Facilities Data

DESCRIPTION	UNIT	EXISTING FACILITIES		Brewery	Pizen IIa	Pizen IIb	Kosutka	Pizen III	NEW FACILITIES HRSG IV	Pizen IVa	Pizen IVb	Cooling	Pizen V	Steam Purchase	Power Purchase	Power Sales
THERMAL DATA																
Efficiency – 80% to Full Load	%1			86 0%	84 0%	84 0%	90 8%	91 1%	100 0%	100 0%	100 0%		91 1%			
Half Load	%2			86 0%	84 0%	84 0%	90 8%	91 1%	100.0%	100 0%	100 0%		91 1%			
Minimum Load	%3			86 0%	84 0%	84 0%	90 8%	91 1%	100 0%	100 0%	100 0%		91 1%			
Minimum Operation	%			7 3%	–	25 0%	12 5%	20 0%	25 0%	0 0%	25 0%		12 5%			
Feedwater Temp																
Operation Adjustment Factor	Factor			0 085	0 085	0 095	0 065	0 040					0 045			
BOILER OUTPUT	Boiler MW															
Quantity	Mlb/Hr				749 700											
Pressure	PSIA				1976											
Temperature	Temp °F				1004											
Enthalpy	MBTU/lb				1 477											
PRODUCT – LP STEAM	Priority	*		6	1					2						
Quantity	Mlb/Hr				116.204			143.300								
	MWts			56 100	100 000	165 000		43 500		40 000						
Pressure	PSIA				152			189								
Temperature	Temp °F				428			428								
Enthalpy	MBTU/lb				1 230			1 230								
PRODUCT – HOT WATER	Priority			6		3	7				4	Cooling	5			
Quantity	MWtw			56 100		165 000	34 800	43 500			64 300	18 000	116.000			
Temperature – Supply	Temp °F					320°	320°									
Return	Temp °F					158	158									
TURBINE DATA	UNITe				Turb IA	Turb IB			GT–V64 3	Turb IIA	Turb IIB					
	Priority				4	5			1	2	3				Purchase	Yes
Rated Capacity–Electric	KW				19720	55000				4050	21000				as Req d	
Capability – Max Steam	KW1				19720	55000				4050	21000					
75 % Steam	KW75				14080	40200				2890	15350					
50 % Steam	KW50				8430	25420				1730	9700					
25% Steam	KW25				2780	10620				570	4053					
Steam Required – Maximum	M#/Hr Max				308 644	365 900				107 600	271 764					
Minimum	M#/Hr Min					91 500					67 941					
Outlet Steam Pressure	PSI				189	17 4				189	17 4					
Enthalpy Drop – Turbine	MBTU/lbt				0 2568	0 4157										
Sink	MBTU/lbs				1 1646	0 9146				1 2660	0 9146					
Generator Efficiency	%g				96 5%	96 5%				96 0%	96 0%					
Power/Rejection Factor	Factor															
FUELS DATA																
Primary Fuel	Type			Gas	Coal	Coal	Gas	Gas	Gas				Gas			
Cost	$/MMBTU			$3 77	$1 96	$1 96	$3 77	$3 77	$3 77				$3 77			
Percent Use	% Use			100 0%	99 6%	99 6%	100 0%	55 0%	100 0%				100 0%			
Secondary/Supplemental Fuel	Type				Oil	Oil		Oil								
Cost	$/MMBTU				$2 99	$2 99		$2 99								
Percent Use	% Use				0 4%	0 4%		45 0%								
COST DATA (1993 Basis)	CK/$ =	28														
Number of Personnel	Number	82		30	160	–	16	8	8				8			
Average Wage & Benefits	$(000)	4 2		4 2	4 2	–	4 2	4 2	4 2				4 2			
Other Fixed Costs	$(000)	$879														
Raw Water & Treating Costs	$/MWHw	$0 10														
Demineralized Water Costs	$/MWHs	$1 41														
Other Variable O&M Costs	$/MWH	$0 41														
Limestone	$/Ton'	11 01														
Waste Disposal Costs	$/Ton	$3 24														
Emissions Code	CODEe			ST–2A8	PC–2B3	PC–2B3	ST–3A8	ST–3A8	GT–643	GT–643	GT–643		ST–2A8			
Unscheduled Maintenance	CODE m			BR	P2	T1	K	P3	P4GT1	T2			P5			
Cost per Episode	Unit $(000)			2 0	2 0	1 0	2 0	2 0	1 5	1 0			2.0			
Purchased Power	$/kW															
Energy Charge – Peak	Cents/KWHw															
Off–Peak	Cents/KWHs															
MONTHLY DATA	Avg Temp °C				AVAILABILITY											
W–Pk	3 0			100%	100%	100%	100%	100%	100%	100%	100%	100%	100%			
W–Hi	3 0			100%	100%	100%	100%	100%	100%	100%	100%	100%	100%			
W–Lo	3 0			100%	100%	100%	100%	100%	100%	100%	100%	100%	100%			
W–Wknd	3 0			100%	100%	100%	100%	100%	–	–	–	–	100%			
S–Pk1	11 6			100%	–	–	100%	100%	100%	100%	100%	100%	100%			
S–Pk2	18 3			100%	–	–	100%	100%	100%	100%	100%	100%	100%			
S–Hi1	11 6			100%	–	–	100%	100%	100%	100%	100%	100%	100%			
S–Hi2	18 3			100%	–	–	100%	100%	100%	100%	100%	100%	100%			
S–Lo1	11 6			100%	–	–	100%	100%	100%	100%	100%	100%	100%			
S–Lo2	18 3			100%	–	–	100%	100%	100%	100%	100%	100%	100%			
S–Wknd1	11 6			100%	100%	100%	100%	100%	–	–	–	–	100%			
S–Wknd2	18 3			100%	–	–	100%	100%	–	–	–	–	100%			

TEST YEAR SIMULATION RESULTS	WINTER Peak	High	Low	Weekend	SUMMER Peak 1	Peak 2	High 1	High 2	Low 1	Low 2	Wkend 1	Wkend 2	TOTAL
OPERATING EXPENSES													
Natural Gas	2 108	1 803	2 283	429	547	676	961	1 179	1 556	1 979	–	569	14 089
Oil	11	9	16	14	–	–	–	–	–	–	3	–	53
Lignite	–	–	–	–	–	–	–	–	–	–	–	–	–
Black Coal	1,749	1 498	2 851	2,303	–	–	–	–	–	–	510	–	8 711
Total Fuel Cost	3 868	3 310	4 950	2 747	547	676	961	1 179	1 556	1 979	513	569	22 853
Supplemental Cost–Shortfall Penalty	–	–	–	–	–	–	(0)	–	–	–	–	–	(0)
Purchased Power Cost	–	–	–	–	–	–	–	–	–	–	–	46	46
Credit for Power Sales	(3 561)	(2,427)	(2 545)	(1 410)	(430)	(728)	(602)	(1,014)	(1,018)	(1 488)	(371)	–	(15 594)
Net Power Interchange Cost	(3 561)	(2 427)	(2 545)	(1 410)	(430)	(728)	(602)	(1 014)	(1 018)	(1 488)	(371)	46	(15 548)
Other O&M – Fixed OH & Other	241	207	379	330	48	81	84	141	156	263	115	194	2 237
Variable	299	256	388	325	23	30	41	53	83	74	69	43	1 684
Limestone Injection & Ash Removal	64	55	97	84	–	–	–	–	–	–	19	–	319
Credit for By–Product Sales	(32)	(27)	(49)	(42)	–	–	–	–	–	–	(9)	–	(160)
Emissions Penalties	–	–	–	–	–	–	–	–	–	–	–	–	–
Total Excluding Maintenance	877	1 374	3 220	2 033	188	59	484	360	757	–	335	852	11,366


UNIT UTILIZATION – YEAR 2010
MEGAWATTHOURS
Thousands
400
300
200
100
0
W–Pk
W–Hi
W–Lo
W–Wknd
S–Pk1
S–Pk2
S–Hi1
S–Hi2
S–Lo1
S–Lo2
S–Wknd1
S–Wknd2
PERIOD
Plzen IIa
Plzen IVa
Plzen IIb
Plzen IVb
Plzen V
Brewery


ELECTRICITY PRODUCED – YEAR 2010
POWER – AVG KW/HR
Thousands
150
100
50
0
W–Pk
W–Hi
W–Lo
W–Wknd
S–Pk1
S–Pk2
S–Hi1
S–Hi2
S–Lo1
S–Lo2
S–Wknd1
S–Wknd2
PERIOD
GT–V64 3
Turb IIA
Turb IIB
Turb IA
Turb IB

VARIANT A2

PROJECTED OPERATING AND CAPITAL EXPENDITURES

High Demand

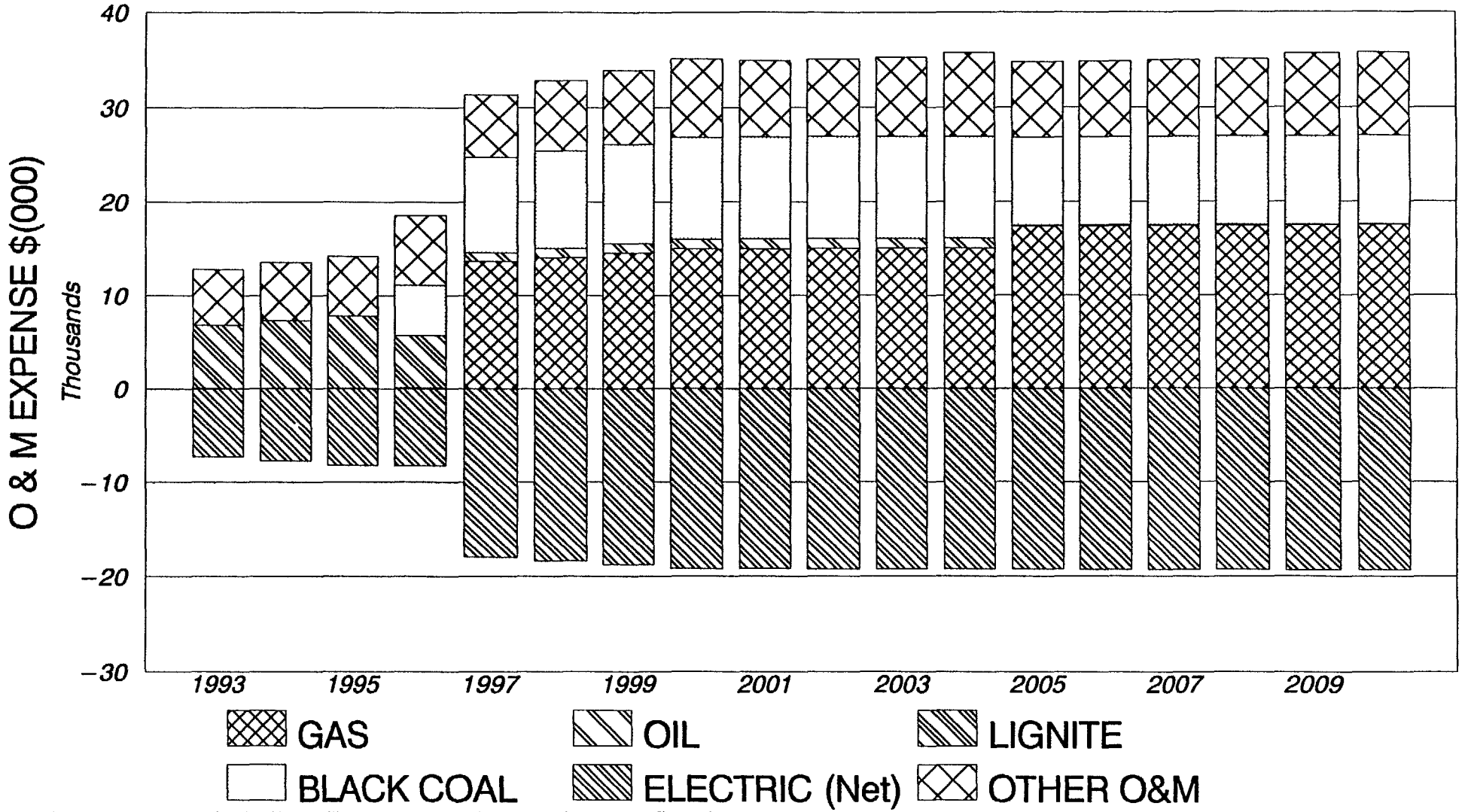
COST EXCL INFLATION (000)

	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
OPERATING EXPENSES																		
Fuel Cost – Natural Gas	–	–	–	105	13 674	14 102	14 541	14 999	15 020	15 034	15 048	15 061	17 401	17 424	17 448	17 472	17 495	17 519
Oil	62	68	74	15	915	954	993	1 034	1 039	1 044	1 048	1 052	74	74	74	74	74	74
Lignite	6 790	7 255	7 752	5 631	–	–	–	–	–	–	–	–	–	–	–	–	–	–
Black Coal	–	–	–	5 370	10 155	10 372	10 593	10 821	10 830	10 839	10 847	10 855	9 380	9 382	9 384	9 386	9 388	9 390
Total Fuel Cost	6 852	7 323	7 827	11 121	24 745	25 428	26 126	26 854	26 890	26 916	26 942	26 968	26 854	26 880	26 905	26 931	26 957	26 983
Supplemental Cost (Shortfall)	–	–	0	–	(0)	(0)	–	–	0	0	0	0	–	–	–	–	0	(0)
Purchased Power Cost	–	–	–	–	53	54	56	57	57	57	57	57	57	57	57	57	57	57
Credit for Power Sales	(7,290)	(7 768)	(8,216)	(8,225)	(17 995)	(18 394)	(18 803)	(19,224)	(19,250)	(19,267)	(19,285)	(19,299)	(19,299)	(19 316)	(19 334)	(19 348)	(19 365)	(19 382)
Net Power Interchange	(7,290)	(7 768)	(8,216)	(8,225)	(17 942)	(18 340)	(18 747)	(19 168)	(19 193)	(19,211)	(19,228)	(19,242)	(19,242)	(19,259)	(19,277)	(19,290)	(19 308)	(19 325)
Fixed O&M and Overheads	2 300	2 300	2 300	2 510	2 372	2 372	2 372	2 372	2 372	2 372	2 372	2 372	2 237	2 237	2 237	2 237	2 237	2 237
Other Variable O & M	1 457	1 473	1 486	1 642	1 651	1 654	1 656	1 659	1 660	1 660	1 660	1 660	1 660	1 661	1 662	1 663	1 663	1 664
Sorbent and Ash Removal	245	285	331	651	531	532	533	908	909	910	910	911	804	804	804	804	804	805
Credit By–Product Sales	–	–	–	(197)	(179)	(180)	(180)	(180)	(180)	(181)	(181)	(181)	(160)	(160)	(160)	(160)	(160)	(160)
Emission Penalties	24	48	49	25	–	–	–	–	–	–	–	–	–	–	–	–	–	–
Maintenance Expenses	1 956	2 137	2 268	2 801	2 285	3 047	3 436	3 489	3 315	3 421	3 552	4 009	3 415	3 403	3 508	3 642	4 152	4 204
Plant Removal Costs	–	–	–	–	3 517	–	–	–	–	–	–	–	–	2 462	–	–	–	–
Total O&M Expense	5 544	5 799	6 046	10 328	16 981	14 513	15 196	15 934	15 772	15 888	16 027	16 497	15 568	18 028	15 680	15 827	16 347	16 407
CAPITAL COSTS																		
Foreign	–	–	15432	15817	–	–	–	–	–	–	–	–	–	–	–	–	–	–
Domestic	190	839	16743	15935	494	259	259	259	33	33	3301	3301	33	25	25	25	25	25
Total	190	839	32175	31752	494	259	259	259	33	33	3301	3301	33	25	25	25	25	25
TOTAL COST	5,734	6,637	38,221	42,080	17,475	14,771	15,455	16,193	15,806	15,921	19,329	19,799	15,602	18,053	15,705	15,852	16,372	16,433
Present Worth	5 517	5 914	31 531	32 143	12 360	9 674	9 371	9 092	8 217	7 664	8 615	8 171	5 962	6 388	5 145	4 809	4 598	4 274
Cumulative Present Worth	5 517	11 431	42 962	75 105	87 465	97 138	106 510	115 601	123 818	131 482	140 097	148 268	154 230	160 617	165 763	170 571	175 170	179 443

OPERATING STATISTICS

	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
TOTAL PRODUCTION – MWH																		
LP Steam	333 355	331 188	329 021	360 443	361 165	361 165	361 165	361 165	361 165	360 804	360 443	360 082	359 720	359 720	359 720	359 720	359 720	359 720
Hot Water	534 466	552 841	573 853	777 066	787 452	790 913	794 109	797 571	798 902	800 233	801 564	802 895	804 229	805 294	806 359	807 424	808 489	809 555
Electricity	306 534	312 254	315 750	312 792	594 053	595 964	597 730	599 672	600 431	600 963	601 496	602 030	601 993	602 518	603 043	603 568	604 094	604 620
COST OF PRODUCTION – $/MWH (Variable Costs only)																		
LP Steam	$10 46	$10 77	$11 08	$12 38	$16 45	$16 72	$17 00	$17 68	$17 68	$17 68	$17 68	$17 68	$17 50	$17 50	$17 50	$17 50	$17 49	$17 49
Hot Water	$8 56	$8 85	$9 15	$10 08	$15 87	$16 19	$16 52	$17 05	$17 05	$17 05	$17 05	$17 05	$16 75	$16 75	$16 75	$16 75	$16 75	$16 75
Electricity	$9 20	$9 51	$9 81	$11 06	$17 98	$18 39	$18 82	$19 39	$19 39	$19 39	$19 39	$19 39	$19 32	$19 32	$19 32	$19 32	$19 31	$19 31
NOT SERVED – MWH																		
LP Steam	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
Hot Water	–	–	26	–	(0)	(0)	–	–	0	1	2	2	–	–	–	–	0	(0)
Electricity	–	–	–	–	1 161	1 165	1 167	1 170	1 171	1 171	1 171	1 173	1 174	1 174	1 175	1 177	1 178	1 178
EMISSIONS – TONNES																		
Particulates	248	259	272	416	77	77	77	77	77	77	77	78	75	75	75	75	75	75
SO_2	5 745	5 854	5 965	3 620	2 307	2 312	2 316	2 321	2 323	2 325	2 326	2 328	2 054	2 054	2 055	2 055	2 056	2 056
NOx	1 373	1 398	1 423	1 605	1 303	1 305	1 307	1 310	1 311	1 311	1 312	1 313	1 232	1 233	1 233	1 233	1 234	1 234
CO	58	59	62	144	96	97	98	99	99	99	100	100	45	45	45	45	45	45

PROJECTED OPERATING & MAINTENANCE COSTS – VARIANT A2



NOTE Costs include Real Escalation only and do not reflect Inflation

APPENDIX F: (Cont'd) GILBERT/COMMONWEALTH ECONOMIC ANALYSIS MODEL RESULTS AND DETAIL:

Variant A3: (Westinghouse 251B11/12 for CPIV)

U04

VARIANT A3 PROJECTED OPERATING AND CAPITAL EXPENDITURES High Demand

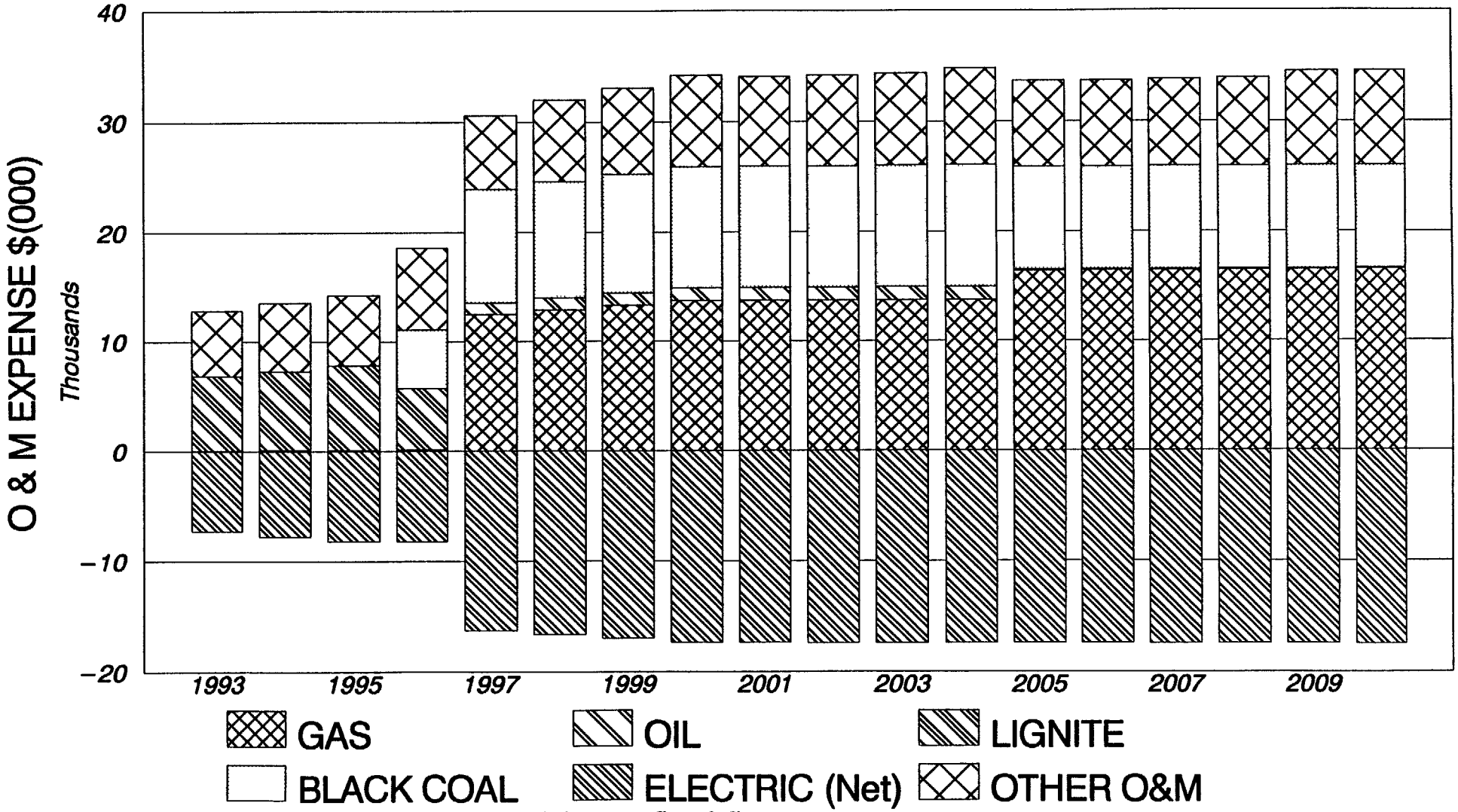
COST EXCL INFLATION (000)

	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
OPERATING EXPENSES																		
Fuel Cost – Natural Gas	–	–	–	105	12 518	12 900	13 292	13 702	13 718	13 729	13 740	13 752	16 407	16 429	16 451	16 472	16 494	16 516
Oil	62	68	74	15	1 052	1 095	1 139	1 185	1 191	1 195	1 199	1 204	74	74	74	74	74	74
Lignite	6 790	7 255	7 752	5 631	–	–	–	–	–	–	–	–	–	–	–	–	–	–
Black Coal	–	–	–	5 370	10 368	10 590	10 815	11 048	11 058	11 066	11 074	11 083	9 380	9 382	9 384	9 387	9 389	9 391
Total Fuel Cost	6 852	7 323	7 827	11 121	23 939	24 585	25 246	25 935	25 967	25 990	26 014	26 038	25 861	25 885	25 909	25 932	25 956	25 980
Supplemental Cost (Shortfall)	–	–	0	–	–	–	–	–	(0)	–	–	0	–	0	–	–	–	–
Purchased Power Cost	–	–	–	–	53	54	56	57	57	57	57	57	57	57	57	57	57	57
Credit for Power Sales	(7,290)	(7 768)	(8,216)	(8,225)	(16 333)	(16 684)	(17 044)	(17 415)	(17 434)	(17 449)	(17 464)	(17 475)	(17 469)	(17 484)	(17 498)	(17 509)	(17 523)	(17 537)
Net Power Interchange	(7,290)	(7 768)	(8,216)	(8,225)	(16,280)	(16 630)	(16 989)	(17 358)	(17 377)	(17 392)	(17 407)	(17 418)	(17 412)	(17 427)	(17 441)	(17 452)	(17 466)	(17 480)
Fixed O&M and Overheads	2 300	2 300	2 300	2 510	2 372	2 372	2 372	2 372	2 372	2 372	2 372	2 372	2 204	2 204	2 204	2 204	2 204	2 204
Other Variable O & M	1 457	1 473	1 486	1 642	1 643	1 646	1 648	1 650	1 651	1 652	1 652	1 652	1 653	1 654	1 655	1 655	1 656	1 657
Sorbent and Ash Removal	245	285	331	651	541	542	543	925	926	926	927	928	804	804	804	804	804	805
Credit By-Product Sales	–	–	–	(197)	(182)	(183)	(183)	(184)	(184)	(184)	(184)	(184)	(160)	(160)	(160)	(160)	(160)	(160)
Emission Penalties	24	48	49	25	–	–	–	–	–	–	–	–	–	–	–	–	–	–
Maintenance Expenses	1 956	2 137	2 268	2 801	2 285	3 047	3 436	3 489	3 315	3 421	3 552	4 009	3 294	3 282	3 380	3 510	4 018	4 064
Plant Removal Costs	–	–	–	–	3 517	–	–	–	–	–	–	–	–	2 462	–	–	–	–
Total O&M Expense	5 544	5 799	6 046	10 328	17 834	15 378	16 073	16 830	16 669	16 785	16 925	17 396	16 243	18 704	16 350	16 494	17 013	17 069
CAPITAL COSTS																		
Foreign	–	–	12345	12654	–	–	–	–	–	–	–	–	–	–	–	–	–	–
Domestic	190	839	15362	14553	494	259	259	259	33	33	3301	3301	33	25	25	25	25	25
Total	190	839	27707	27207	494	259	259	259	33	33	3301	3301	33	25	25	25	25	25
TOTAL COST	5,734	6,637	33,753	37,535	18,328	15,637	16,332	17,088	16,703	16,818	20,227	20,698	16,276	18,729	16,375	16,519	17,038	17,094
Present Worth	5 517	5 914	27 845	28 672	12 963	10 240	9 903	9 595	8 683	8 096	9 015	8 542	6 220	6 627	5 365	5 011	4 786	4 446
Cumulative Present Worth	5 517	11 431	39 276	67 947	80 911	91 151	101 054	110 649	119 332	127 428	136 443	144 985	151 205	157 831	163 196	168 207	172 992	177 438

OPERATING STATISTICS

	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
TOTAL PRODUCTION – MWH																		
LP Steam	333 355	331 188	329 021	360 443	361 165	361 165	361 165	361 165	361 165	360 804	360 443	360 082	359 720	359 720	359 720	359 720	359 720	359 720
Hot Water	534 466	552 841	573 853	777 066	787 452	790 913	794 109	797 571	798 903	800 234	801 566	802 897	804 229	805 294	806 359	807 424	808 489	809 555
Electricity	306 534	312 254	315 750	312 792	545 268	546 680	547 987	549 426	550 011	550 458	550 906	551 354	551 161	551 592	552 024	552 456	552 888	553 321
COST OF PRODUCTION – $/MWH (Variable Costs only)																		
LP Steam	$10 46	$10 77	$11 08	$12 38	$16 57	$16 84	$17 12	$17 81	$17 80	$17 80	$17 80	$17 80	$17 54	$17 54	$17 54	$17 54	$17 54	$17 53
Hot Water	$8 56	$8 85	$9 15	$10 08	$15 92	$16 24	$16 57	$17 10	$17 10	$17 10	$17 10	$17 10	$16 75	$16 75	$16 75	$16 75	$16 75	$16 75
Electricity	$9 20	$9 51	$9 81	$11 06	$17 95	$18 36	$18 77	$19 35	$19 34	$19 34	$19 34	$19 34	$19 20	$19 20	$19 20	$19 20	$19 20	$19 19
NOT SERVED – MWH																		
LP Steam	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
Hot Water	–	–	26	–	–	–	–	–	(0)	–	–	0	–	0	–	–	–	–
Electricity	–	–	–	–	1 161	1 165	1 167	1 170	1 171	1 171	1 171	1 173	1 174	1 174	1 175	1 177	1 178	1 178
EMISSIONS – TONNES																		
Particulates	248	259	272	416	78	78	78	78	78	78	78	78	75	75	75	75	75	75
SO_2	5 745	5 854	5 965	3 620	2 349	2 354	2 359	2 364	2 366	2 367	2 369	2 370	2 054	2 054	2 055	2 055	2 056	2 056
NOx	1 373	1 398	1 423	1 605	1 316	1 319	1 321	1 324	1 325	1 325	1 326	1 327	1 233	1 234	1 234	1 235	1 235	1 236
CO	56	59	62	144	105	106	107	107	108	108	108	109	45	45	45	45	45	45

PROJECTED OPERATING & MAINTENANCE COSTS – VARIANT A3



NOTE Costs include Real Escalation only and do not reflect Inflation

40

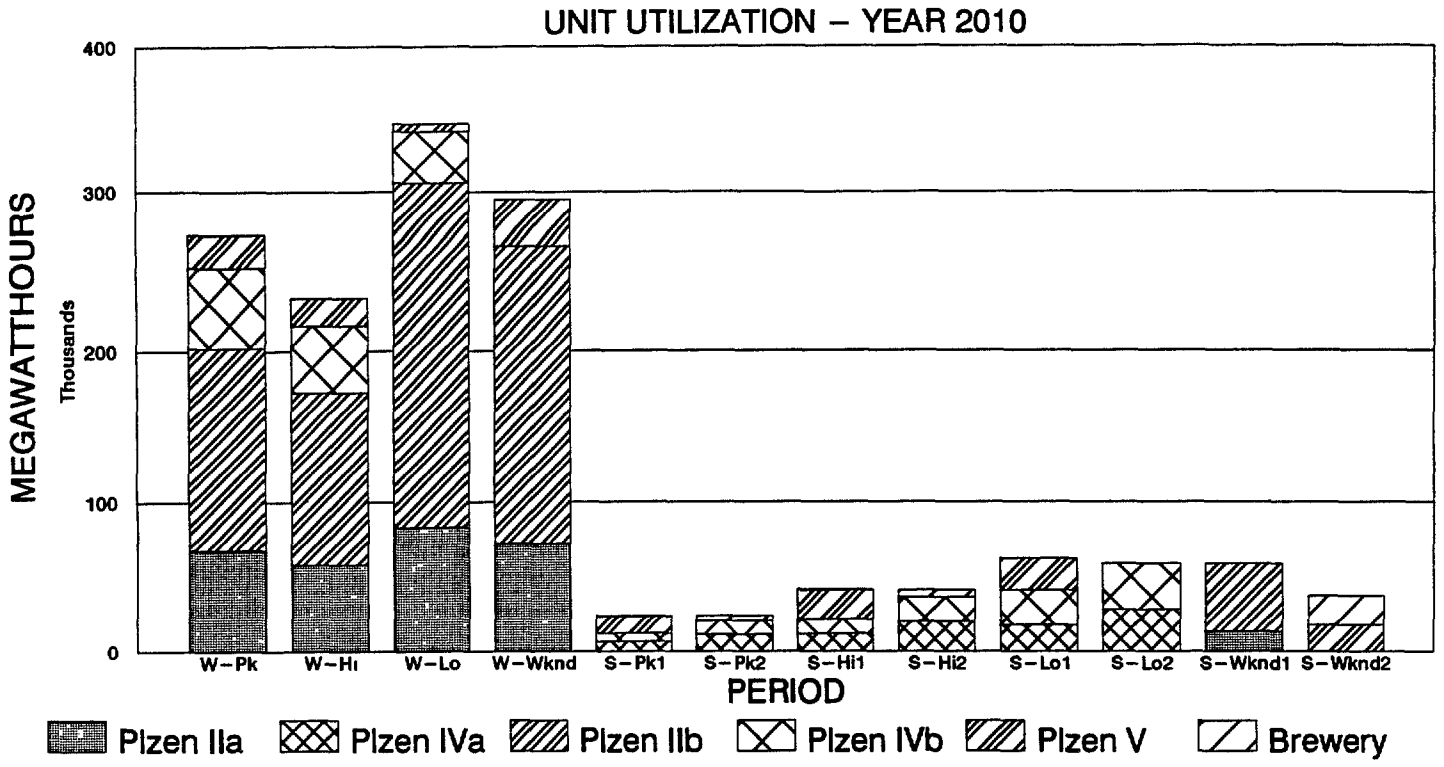
CASE A3 — Test Year = 2010

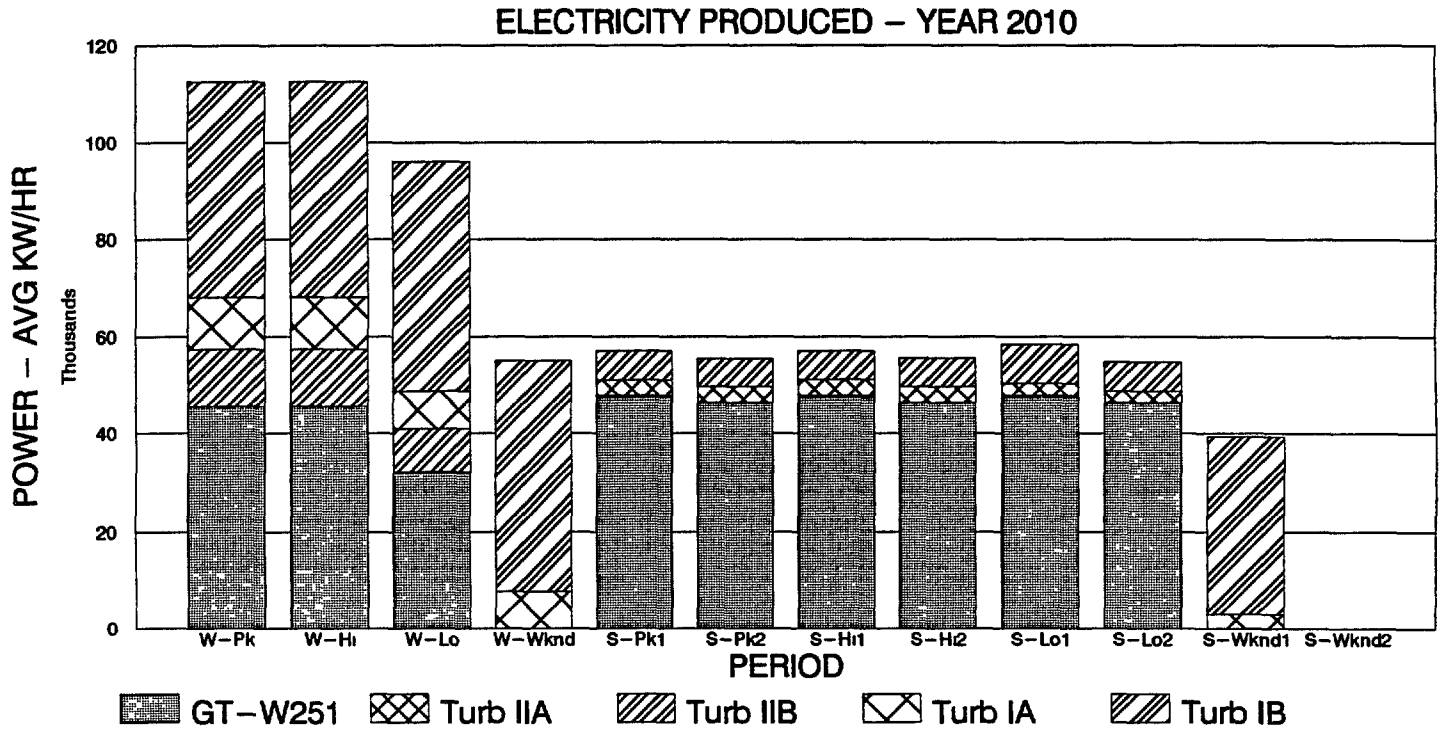
Station Use Unaccounted for etc — Electric kW –; % of Demand: Water –; Steam –

Facilities Data

DESCRIPTION	UNIT	EXISTING FACILITIES		Brewery	Pizen IIa	Pizen IIb	Kosutka		NEW FACILITIES HRSG IV	Pizen IVa	Pizen IVb	Cooling	Pizen V	Steam Purchase	Power Purchase	Power Sales
THERMAL DATA																
Efficiency – 60% to Full Load	%1			86 0%	84 0%	84 0%	90 8%		100 0%	100 0%	100 0%		91 1%			
Half Load	%2			86 0%	84 0%	84 0%	90 8%		100 0%	100 0%	100 0%		91 1%			
Minimum Load	%3			86 0%	84 0%	84 0%	90 8%		100 0%	100 0%	100 0%		91 1%			
Minimum Operation	%			7 3%	–	25 0%	12 5%		25 0%	0 0%	25 0%		12 5%			
Feedwater Temp																
Operation Adjustment Factor	Factor			0 090	0 085	0 065	0 065						0 045			
BOILER OUTPUT	Boiler MW															
Quantity	Mlb/Hr				749 700											
Pressure	PSIA				1976											
Temperature	Temp °F				1004											
Enthalpy	MBTU/lb				1 477											
PRODUCT – LP STEAM	Priority	*		6	1					2						
Quantity	Mlb/Hr				116.204											
	MWts			56 100	100.000	165 000				36 700						
Pressure	PSIA				152											
Temperature	Temp °F				428											
Enthalpy	MBTU/lb				1 230											
PRODUCT – HOT WATER	Priority			6		3	7				4	Cooling	5			
Quantity	MWtw			56 100		165.000	34 800				59 100	18 000	116 000			
Temperature – Supply	Temp °F					320°	320°									
Return	Temp °F					158	158									
TURBINE DATA	UNITe				Turb IA	Turb IB			GT–W251	Turb IIA	Turb IIB					
	Priority				4	5			1	2	3				Purchase	Yes
Rated Capacity–Electric	KW				19720	55000				3710	19260				as Req'd	
Capability – Max Steam	KW1				19720	55000				3710	19260					
75 % Steam	KW75				14080	40200				2650	14080					
50 % Steam	KW50				8430	25420				1590	8890					
25% Steam	KW25				2780	10620				520	3716					
Steam Required – Maximum	M#/Hr Max				308.644	365.900				98 700	249.200					
Minimum	M#/Hr Min					91 500					62 300					
Outlet Steam Pressure	PSI				189	17 4				189	17 4					
Enthalpy Drop – Turbine	MBTU/lbt				0 2588	0 4157										
Sink	MBTU/lbs				1 1646	0 9146				1 2680	0 9146					
Generator Efficiency	%g				96 5%	96 5%				96 0%	96 0%					
Power/Rejection Factor	Factor															
FUELS DATA																
Primary Fuel	Type			Gas	Coal	Coal	Gas		Gas				Gas			
Cost	$/MMBTU			$3 77	$1 86	$1 98	$3 77		$3 77				$3 77			
Percent Use	% Use			100 0%	99 6%	99 6%	100 0%		100 0%				100.0%			
Secondary/Supplemental Fue	Type				Oil	Oil										
Cost	$/MMBTU				$2.99	$2 99										
Percent Use	% Use				0 4%	0 4%										
COST DATA (1993 Basis)	CK/$ =	28														
Number of Personnel	Number	92		30	160	–	16		8				8			
Average Wage & Benefits	$(000)	4 2		4 2	4 2	–	4 2		4 2				4 2			
Other Fixed Costs	$(000)	$879														
Raw Water & Treating Costs	$/MWHw	$0 10														
Demineralized Water Costs	$/MWHs	$1 41														
Other Variable O&M Costs	$/MWH	$0 41														
Limestone	$/Ton'	11 01														
Waste Disposal Costs	$/Ton	$3 24														
Emissions Code	CODEe			ST–2A8	PC–2B3	PC–2B3	ST–3A8		GT–251	GT–251	GT–251		ST–2A8			
Unscheduled Maintenance	CODE m			BR	P2	T1	K		P4GT1	T2			P5			
Cost per Episode	Unit $(000)			2 0	2 0	1 0	2.0		1 5	1 0			2 0			
Purchased Power	$/kW														$7 93	
Energy Charge – Peak	Cents/KWHw															
Off–Peak	Cents/KWHs															
MONTHLY DATA	Avg Temp °C				AVAILABILITY										CK	US$
W–Pk	3 0			100%	100%	100%	100%		100%	100%	100%	100%	100%		980	$35 00
W–Hi	3 0			100%	100%	100%	100%		100%	100%	100%	100%	100%		780	27 86
W–Lo	3 0			100%	100%	100%	100%		100%	100%	100%	100%	100%		690	24 64
W–Wknd	3 0			100%	100%	100%	100%		–	–	–	–	100%		690	24 64
S–Pk1	11 6			100%	–	–	100%		100%	100%	100%	100%	100%		980	35 00
S–Pk2	18 3			100%	–	–	100%		100%	100%	100%	100%	100%		980	35 00
S–Hi1	11 6			100%	–	–	100%		100%	100%	100%	100%	100%		780	27 86
S–Hi2	18 3			100%	–	–	100%		100%	100%	100%	100%	100%		780	27 86
S–Lo1	11 6			100%	–	–	100%		100%	100%	100%	100%	100%		690	24 64
S–Lo2	18 3			100%	–	–	100%		100%	100%	100%	100%	100%		690	24 64
S–Wknd1	11 6			100%	100%	100%	100%		–	–	–	–	100%		690	24 64
S–Wknd2	18 3			100%	–	–	100%		–	–	–	–	100%		690	24 64

TEST YEAR SIMULATION RESULTS	WINTER Peak	High	Low	Weekend	SUMMER Peak 1	Peak 2	High 1	High 2	Low 1	Low 2	Wkend 1	Wkend 2	TOTAL
OPERATING EXPENSES													
Natural Gas	1 989	1 702	2,176	429	515	620	903	1 081	1 441	1 855	–	571	13 282
Oil	11	9	16	14	–	–	–	–	–	–	3	–	53
Lignite	–	–	–	–	–	–	–	–	–	–	–	–	–
Black Coal	1,749	1 498	2,651	2,303	–	–	–	–	–	–	510	–	8 711
Total Fuel Cost	3 749	3 210	4 843	2 747	515	620	903	1 081	1 441	1 855	513	571	22 047
Supplemental Cost–Shortfall Penalty'	–	–	–	–	–	–	–	–	–	–	–	–	–
Purchased Power Cost	–	–	–	–	–	–	–	–	–	–	–	46	46
Credit for Power Sales	(3 272)	(2,230)	(2 465)	(1,410)	(342)	(584)	(479)	(813)	(817)	(1,327)	(371)	–	(14 110)
Net Power Interchange Cost	(3 272)	(2 230)	(2 465)	(1 410)	(342)	(584)	(479)	(813)	(817)	(1 327)	(371)	46	(14 064)
Other O&M – Fixed OH & Other	238	204	373	325	47	80	83	139	153	259	113	191	2 204
Variable	298	255	387	325	23	30	40	52	62	75	69	43	1 657
Limestone Injection & Ash Removal	64	55	97	84	–	–	–	–	–	–	19	–	319
Credit for By–Product Sales	(32)	(27)	(49)	(42)	–	–	–	–	–	–	(9)	–	(160)
Emissions Penalties	–	–	–	–	–	–	–	–	–	–	–	–	–
Total Excluding Maintenance	1,044	1 466	3 188	2 028	242	145	546	459	839	–	333	851	12 003


UNIT UTILIZATION – YEAR 2010
MEGAWATTHOURS
Thousands
400
300
200
100
0
W–Pk
W–Hi
W–Lo
W–Wknd
S–Pk1
S–Pk2
S–Hi1
S–Hi2
S–Lo1
S–Lo2
S–Wknd1
S–Wknd2
PERIOD
Plzen IIa
Plzen IVa
Plzen IIb
Plzen IVb
Plzen V
Brewery


ELECTRICITY PRODUCED – YEAR 2010
POWER – AVG KW/HR
Thousands
120
100
80
60
40
20
0
W–Pk
W–Hi
W–Lo
W–Wknd
S–Pk1
S–Pk2
S–Hi1
S–Hi2
S–Lo1
S–Lo2
S–Wknd1
S–Wknd2
PERIOD
GT–W251
Turb IIA
Turb IIB
Turb IA
Turb IB

			WINTER				SUMMER								
			Peak	High	Low	Weekend	Peak 1	Peak 2	High 1	High 2	Low 1	Low 2	Wkend 1	Wkend 2	
PRODUCT – LP STEAM															
Customer Requirement	MWH		58007	49652	71302	62027	6354	10515	11165	18251	16280	25394	12023	18752	359720
Station Use	MWH	–	–	–	–	–	–	–	–	–	–	–	–	–	–
			58007	49652	71302	62027	6354	10515	11165	18251	16280	25394	12023	18752	359720
	2	3	4	5	6	7	8	9	10	11	12	13	14	15	
	MWts		Average Loading – MW												
	–		–	–	–	–	–	–	–	–	–	–	–	–	
	–		–	–	–	–	–	–	–	–	–	–	–	–	
Brewery	56 100		–	–	–	–	2 0	1 9	2 5	1 9	–	–	–	25 5	
	–		–	–	–	–	–	–	–	–	–	–	–	–	
	–		–	–	–	–	–	–	–	–	–	–	–	–	
	–		–	–	–	–	–	–	–	–	–	–	–	–	
Plzen IVa	36 700		–	–	–	–	34 2	34 0	34 2	33 7	27 6	25 5	–	–	
Plzen IIa	100 000		63 5	63 4	49 7	49 7	–	–	–	–	–	–	27 6	–	
			Unit Energy Output – MWH (Before Adjustment for Minimum Loading Limitation)												
			–	–	–	–	–	–	–	–	–	–	–	–	
			–	–	–	–	–	–	–	–	–	–	–	–	
Brewery			–	–	–	–	169	121	297	199	–	–	–	18752	
			–	–	–	–	–	–	–	–	–	–	–	–	
			–	–	–	–	–	–	–	–	–	–	–	–	
			–	–	–	–	–	–	–	–	–	–	–	–	
Plzen IVa		1 000	–	–	–	–	6185	10394	10668	18051	16280	25394	–	–	
Plzen IIa			58007	49652	71302	62027	–	–	–	–	–	–	12023	–	
Total			58007	49652	71302	62027	6354	10515	11165	18251	16280	25394	12023	18752	359720
Steam Not Served	MWH		–	–	–	–	–	–	–	–	–	–	–	–	–
Total excluding HRSG supply			58007	49651 6	71301 6	62026 9	169 309	121 197	297 484	199 435	–	–	12022 7	18751 7	
PRODUCT – HOT WATER															
Customer Requirement	MWH		151236	129546	185986	161809	15432	10048	27113	17567	39429	24315	29119	17955	809555
Station Use	MWH	–	–	–	–	–	–	–	–	–	–	–	–	–	–
			151236	129546	185986	161809	15432	10048	27113	17567	39429	24315	29119	17955	809555
	2	3	4	5	6	7	8	9	10	11	12	13	14	15	
BASIS UNIT	MWtw		Average Loading – MW												
	–		–	–	–	–	–	–	–	–	–	–	–	–	
Kosutka	34 800		–	–	–	–	–	–	–	–	–	–	–	–	
Brewery	56 100		9 3	9 3	–	8 8	–	–	–	–	–	–	–	–	
Plzen V	116 000		44 5	44 5	24 0	39 5	61 2	–	61 3	–	36 4	–	–	24 5	
Plzen IVb	59 100		43 1	43 1	33 8	–	24 0	23 5	24 0	23 7	30 5	24 5	–	–	
Plzen IIb	165 000		101 0	101 0	106 7	106 7	–	–	–	–	–	–	66 9	–	
	–		–	–	–	–	–	–	–	–	–	–	–	–	
	–		–	–	–	–	–	–	–	–	–	–	–	–	
Total			197 9	197 9	164 5	155 1	85 3	23 5	85 3	23 7	66 9	24 5	66 9	24 5	
			Unit Energy Output – MWH (Before Adjustment for Minimum Loading Limitation)												
			–	–	–	–	–	–	–	–	–	–	–	–	
Kosutka			–	–	–	–	–	–	–	–	–	–	–	–	
Brewery			107	92	–	80	–	2857	–	4874	–	–	–	–	
Plzen V			19445	16630	4849	28527	11086	–	19478	–	21436	–	–	17955	
Plzen IVb		1 000	39387	33716	27978	–	4347	7191	7636	12693	17993	24315	–	–	
Plzen IIb			92297	79108	153159	133203	–	–	–	–	–	–	29119	–	
			–	–	–	–	–	–	–	–	–	–	–	–	
			–	–	–	–	–	–	–	–	–	–	–	–	
Total			151236	129546	185986	161809	15432	10048	27113	17567	39429	24315	29119	17955	809555
Hot Water Not Served	MWH		–	–	–	–	–	–	–	–	–	–	–	–	–
Total excluding HRSG supply			111849	95829 8	158006	161809	11085 8	2856 97	19477 6	4874 5	21436	–	29119	17954 8	
ADJUSTED FOR MINIMUM LOADING – MWH															
Steam			Unit Utilization after Adjustment for Minimum Loading – MWH (Steam)												
			–	–	–	–	–	–	–	–	–	–	–	–	
			–	–	–	–	–	–	–	–	–	–	–	–	
Brewery			–	–	–	–	364	121	513	199	–	–	–	18752	
			–	–	–	–	–	–	–	–	–	–	–	–	
			–	–	–	–	–	–	–	–	–	–	–	–	
			–	–	–	–	–	–	–	–	–	–	–	–	
Plzen IVa			–	–	–	–	5990	10394	10652	18051	16280	25394	–	–	
Plzen IIa			58007	49652	71302	62027	–	–	–	–	–	–	12023	–	
Total			58007	49652	71302	62027	6354	10515	11165	18251	16280	25394	12023	18752	
Hot Water			Unit Utilization after Adjustment for Minimum Loading – MWH (Hot Water)												
			–	–	–	–	–	–	–	–	–	–	–	–	
Kosutka			–	–	–	–	–	–	–	–	–	–	–	–	
Brewery			123	105	–	80	–	2857	–	4874	–	–	–	–	
Plzen V			20108	17194	5432	29012	11086	–	19478	–	21436	–	–	17955	
Plzen IVb			39069	33449	27579	–	4347	7191	7636	12693	17993	24315	–	–	
Plzen IIb			91935	78798	152978	132717	–	–	–	–	–	–	29119	–	
			–	–	–	–	–	–	–	–	–	–	–	–	
			–	–	–	–	–	–	–	–	–	–	–	–	
Total			151236	129546	185986	161809	15432	10048	27113	17567	39429	24315	29119	17955	

VARIANT A3

	WINTER				SUMMER								
	Peak	High	Low	Weekend	Peak 1	Peak 2	High 1	High 2	Low 1	Low 2	Wkend 1	Wkend 2	

TOTAL UNIT UTILIZATION BEFORE REQUIREMENT FOR ELECTRIC GENERATION – MWH

	Output to meet Steam and Hot Water Requirements – MWH												
	–	–	–	–	–	–	–	–	–	–	–	–	
Kosutka	–	–	–	–	–	–	–	–	–	–	–	–	
Brewery	123	105	–	80	364	2978	513	5074	–	–	–	18752	
Pizen V	20108	17194	5432	29012	11086	–	19478	–	21436	–	–	17955	
Pizen IVb	39069	33449	27579	–	4347	7191	7636	12693	17993	24315	–	–	
Pizen IIb	91935	78798	152976	132717	–	–	–	–	–	–	29119	–	
Pizen IVa	–	–	–	–	5990	10394	10652	18051	16280	25394	–	–	
Pizen IIa	58007	49652	71302	62027	–	–	–	–	–	–	12023	–	
Total	209243	179197	257288	223836	21787	20563	38279	35818	55708	49709	41142	36706	1169275

ADDITIONAL REQUIREMENT FOR BACK PRESSURE STEAM TURBINES – MWH

	Basis %g	Thermal output represented in electric generation – MWHt											
	–	–	–	–	–	–	–	–	–	–	–	–	–
	–	–	–	–	–	–	–	–	–	–	–	–	–
	–	–	–	–	–	–	–	–	–	–	–	–	–
	–	–	–	–	–	–	–	–	–	–	–	–	–
Turb IIB	0 96	11229	9613	7642	–	1128	1856	1981	3284	4912	6338	–	–
Turb IB	0 965	41916	35918	70204	61052	–	–	–	–	–	–	16322	–
Turb IIA	0 96	–	–	–	–	621	1083	1107	1878	1635	2509	–	–
Turb IA	0 965	10177	8709	11583	10077	–	–	–	–	–	–	1379	–
Total		63323	54240	89430	71130	1749	2939	3088	5162	6547	8847	17701	–

STEAM TO CONDENSING TURBINES AND REJECTION – MWH

	Incremental thermal output represented in electric generation and rejection – MWHt											
	–	–	–	–	–	–	–	–	–	–	–	–
	–	–	–	–	–	–	–	–	–	–	–	–
	–	–	–	–	–	–	–	–	–	–	–	–
	–	–	–	–	–	–	–	–	–	–	–	–
	–	–	–	–	–	–	–	–	–	–	–	–
	–	–	–	–	–	–	–	–	–	–	–	–
	–	–	–	–	–	–	–	–	–	–	–	–
	–	–	–	–	–	–	–	–	–	–	–	–

UNIT UTILIZATION – TOTAL MWH

	Unit Utilization MWH											
	–	–	–	–	–	–	–	–	–	–	–	–
Kosutka	–	–	–	–	–	–	–	–	–	–	–	–
Brewery	123	105	–	80	364	2978	513	5074	–	–	–	18752
Pizen V	20108	17194	5432	29012	11086	–	19478	–	21436	–	–	17955
Pizen IVb	50299	43062	35221	–	5475	9047	9617	15976	22905	30653	–	–
Pizen IIb	133851	114715	223180	193769	–	–	–	–	–	–	45441	–
Pizen IVa	–	–	–	–	6612	11476	11759	19929	17915	27903	–	–
Pizen IIa	68184	58361	82885	72104	–	–	–	–	–	–	13402	–
Total	272565	233437	346717	294966	23536	23501	41367	40980	62256	58556	58843	36706

INPUT ENERGY REQUIRED BEFORE EFFICIENCY ADJUSTMENT

	BTU/kW	Energy Input before Efficiency Adjustment – MMBTU											
	3 412	–	–	–	–	–	–	–	–	–	–	–	–
Kosutka	3 412	–	–	–	–	–	–	–	–	–	–	–	–
Brewery	3 412	420	358	–	272	1242	10161	1751	17312	–	–	–	63981
Pizen V	3 412	68609	58667	18532	98990	37825	–	66458	–	73140	–	–	61262
Pizen IVb	3 412	171620	146926	120174	–	18679	30867	32813	54511	78152	104586	–	–
Pizen IIb	3 412	456700	391409	761490	661141	–	–	–	–	–	–	155046	–
Pizen IVa	3 412	–	–	–	–	22559	39157	40122	67999	61125	95205	–	–
Pizen IIa	3 412	232644	199127	282803	246020	–	–	–	–	–	–	45727	–
Total		929993	796488	1183000	1006423	80306	80186	141144	139823	212416	199791	200773	125242

EFFICIENCY

	BASIS %1	BASIS %2	Efficiency											
		–	–	–	–	–	–	–	–	–	–	–	–	–
Kosutka	–	–	90 8%	90 8%	90 8%	90 8%	90 8%	90 8%	90 8%	90 8%	90 8%	90 8%	90 8%	90 8%
Brewery	–	–	86 0%	86 0%	86 0%	86 0%	86 0%	86 0%	86 0%	86 0%	86 0%	86 0%	86 0%	86 0%
Pizen V	–	–	91 1%	91 1%	91 1%	91 1%	91 1%	91 1%	91 1%	91 1%	91 1%	91 1%	91 1%	91 1%
Pizen IVb	–	–	100 0%	100 0%	100 0%	100 0%	100 0%	100 0%	100 0%	100 0%	100 0%	100 0%	100 0%	100 0%
Pizen IIb	–	–	84 0%	84 0%	84 0%	84 0%	84 0%	84 0%	84 0%	84 0%	84 0%	84 0%	84 0%	84 0%
Pizen IVa	–	–	100 0%	100 0%	100 0%	100 0%	100 0%	100 0%	100 0%	100 0%	100 0%	100 0%	100 0%	100 0%
Pizen IIa	–	–	84 0%	84 0%	84 0%	84 0%	84 0%	84 0%	84 0%	84 0%	84 0%	84 0%	84 0%	84 0%

INPUT ENERGY REQUIRED

	Unit Energy Input MMBTU												
	–	–	–	–	–	–	–	–	–	–	–	–	–
Kosutka	6 5%	–	–	–	–	–	–	–	–	–	–	–	–
Brewery	9 0%	532	454	–	344	1574	12879	2219	21942	–	–	–	81092	121
Pizen V	4 5%	78712	67307	21261	113567	43395	–	76244	–	83910	–	–	70283	55
Pizen IVb	–	171620	146926	120174	–	18679	30867	32813	54511	78152	104586	–	–	756
Pizen IIb	9 5%	595423	510299	992793	861962	–	–	–	–	–	–	202141	–	3162619
Pizen IVa	–	–	–	–	–	22559	39157	40122	67999	61125	95205	–	–	326167
Pizen IIa	8 5%	300499	257206	365287	317776	–	–	–	–	–	–	59064	–	1299831
Total		1146786	982192	1499515	1293650	86208	82903	151398	144453	223186	199791	261205	151375	6222663

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			WINTER				SUMMER								
			Peak	High	Low	Weekend	Peak 1	Peak 2	High 1	High 2	Low 1	Low 2	Wkend 1	Wkend 2	

FUEL COST – BOILERS (Lignite)

	Lignite %	Weighted $/MMBTU	Fuel Cost – Lignite $(000)												
	–	–	–	–	–	–	–	–	–	–	–	–	–	–	
Kosutka	–	–	–	–	–	–	–	–	–	–	–	–	–	–	
Brewery	–	–	–	–	–	–	–	–	–	–	–	–	–	–	
Pizen V	–	–	–	–	–	–	–	–	–	–	–	–	–	–	
Pizen IVb	–	–	–	–	–	–	–	–	–	–	–	–	–	–	
Pizen IIb	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
Pizen IVa	–	–	–	–	–	–	–	–	–	–	–	–	–	–	
Pizen IIa	–	–	–	–	–	–	–	–	–	–	–	–	–	–	
Total			–	–	–	–	–	–	–	–	–	–	–	–	–

FUEL COST – BOILERS (Coal)

	Coal %	Weighted $/MMBTU	Fuel Cost – Black Coal $(000)												
	–	–	–	–	–	–	–	–	–	–	–	–	–	–	
Kosutka	–	–	–	–	–	–	–	–	–	–	–	–	–	–	
Brewery	–	–	–	–	–	–	–	–	–	–	–	–	–	–	
Pizen V	–	–	–	–	–	–	–	–	–	–	–	–	–	–	
Pizen IVb	–	–	–	–	–	–	–	–	–	–	–	–	–	–	
Pizen IIb	99 6%	$1 95	1162	996	1936	1683	–	–	–	–	–	–	395	–	
Pizen IVa	–	–	–	–	–	–	–	–	–	–	–	–	–	–	
Pizen IIa	99 6%	$1 95	587	502	713	620	–	–	–	–	–	–	115	–	
Total			1749	1498	2651	2303	–	–	–	–	–	–	510	–	8711

FUEL COST – BOILERS (Gas)

	Gas %	Weighted $/MMBTU	Fuel Cost – Natural Gas $(000)												
	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
Kosutka	100 0%	$3 77	–	–	–	–	–	–	–	–	–	–	–	–	–
Brewery	100 0%	$3 77	2	2	–	1	6	49	8	83	–	–	–	306	456
Pizen V	100 0%	$3 77	297	254	80	428	164	–	287	–	316	–	–	265	2091
Pizen IVb	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
Pizen IIb	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
Pizen IVa	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
Pizen IIa	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
Total			299	255	80	429	170	49	296	83	316	–	–	571	2547

FUEL COST – BOILERS (Oil)

	Oil %	Weighted $/MMBTU	Fuel Cost – Oil $(000)												
	–	–	–	–	–	–	–	–	–	–	–	–	–	–	
Kosutka	–	–	–	–	–	–	–	–	–	–	–	–	–	–	
Brewery	–	–	–	–	–	–	–	–	–	–	–	–	–	–	
Pizen V	–	–	–	–	–	–	–	–	–	–	–	–	–	–	
Pizen IVb	–	–	–	–	–	–	–	–	–	–	–	–	–	–	
Pizen IIb	0 4%	$0 01	7	6	12	10	–	–	–	–	–	–	2	–	
Pizen IVa	–	–	–	–	–	–	–	–	–	–	–	–	–	–	
Pizen IIa	0 4%	$0 01	4	3	4	4	–	–	–	–	–	–	1	–	
Total			11	9	16	14	–	–	–	–	–	–	3	–	53

HOT WATER SHORTFALL		MWH	–	–	–	–	–	–	–	–	–	–	–	–	
Assumed Equivalent Cost	$/MWH	$10 00													
SUPPLEMENTAL HOT WATER COST – $(000)			–	–	–	–	–	–	–	–	–	–	–	–	–

Water and Other Variable O&M Expenses – Boilers $(000)

	Basis $/MWHw	Basis $/MWH	Variable O&M Expense $(000)												
	–	–	–	–	–	–	–	–	–	–	–	–	–	–	
Kosutka	$0 10	$0 41	–	–	–	–	–	–	–	–	–	–	–	–	
Brewery	$0 10	$0 41	0	0	–	0	1	2	1	3	–	–	–	34	
Pizen V	$0 10	$0 41	10	9	3	15	6	–	10	–	11	–	–	9	
Pizen IVb	$0 10	$0 41	40	35	28	–	4	7	7	12	18	24	–	–	
Pizen IIb	$0 10	$0 41	123	106	206	179	–	–	–	–	–	–	45	–	
Pizen IVa	$0 10	$0 41	–	–	–	–	12	21	21	36	33	51	–	–	
Pizen IIa	$0 10	$0 41	124	106	151	131	–	–	–	–	–	–	24	–	
Total			298	255	387	325	23	30	40	52	62	75	69	43	1 657

Limestone and Ash Removal Expenses – Boilers $(000)

	Limestone $/MMBTU	Removal $/MMBTU	Limestone Injection & Ash Removal Expenses $(000)												
	–	–	–	–	–	–	–	–	–	–	–	–	–	–	
Kosutka	–	–	–	–	–	–	–	–	–	–	–	–	–	–	
Brewery	–	–	–	–	–	–	–	–	–	–	–	–	–	–	
Pizen V	–	–	–	–	–	–	–	–	–	–	–	–	–	–	
Pizen IVb	–	–	–	–	–	–	–	–	–	–	–	–	–	–	
Pizen IIb	–	0 072	43	37	71	62	–	–	–	–	–	–	14	–	
Pizen IVa	–	–	–	–	–	–	–	–	–	–	–	–	–	–	
Pizen IIa	–	0 072	22	18	26	23	–	–	–	–	–	–	4	–	
Total			64	55	97	84	–	–	–	–	–	–	19	–	319
Removal Costs Only			64	55	97	84	–	–	–	–	–	–	19	–	319
By–Product Sales $(000)			32	27	49	42	–	–	–	–	–	–	9	–	160

Emissions Penalties – Boilers $(000)

	Emissions $/MMBTU	Emissions Penalties $(000)												
	–	–	–	–	–	–	–	–	–	–	–	–	–	
Kosutka	–	–	–	–	–	–	–	–	–	–	–	–	–	
Brewery	–	–	–	–	–	–	–	–	–	–	–	–	–	
Pizen V	–	–	–	–	–	–	–	–	–	–	–	–	–	
Pizen IVb	–	–	–	–	–	–	–	–	–	–	–	–	–	
Pizen IIb	–	–	–	–	–	–	–	–	–	–	–	–	–	
Pizen IVa	–	–	–	–	–	–	–	–	–	–	–	–	–	
Pizen IIa	–	–	–	–	–	–	–	–	–	–	–	–	–	
Total		–	–	–	–	–	–	–	–	–	–	–	–	–

Emissions by Type – Tons

	Units per Ton	Emissions – Tons												
Particulate	2000	16 6	14 2	25 1	21 8	–	–	–	–	–	–	4 8	–	82 6
SO_2	2000	455 1	389 9	689 9	599 3	–	–	–	–	–	–	132 7	–	2 266 9
NOx	2000	79 7	68 3	80 7	44 9	13 6	20 8	24 3	36 3	43 3	56 6	9 3	8 9	486 9
CO	2000	6 8	5 8	9 3	8 3	0 5	0 3	0 9	0 5	1 2	0 6	1 7	1 1	36 9

VARIANT A3

	WINTER				SUMMER								
	Peak	High	Low	Weekend	Peak 1	Peak 2	High 1	High 2	Low 1	Low 2	Wkend 1	Wkend 2	
Avg KW Required – Pumping	3020	3020	2567	2567	1036	364	1036	364	812	310	812	310	1676
Sta Use	7153	7152	6375	6572	1936	575	1938	570	1316	299	3825	1296	4087
Total	10172	10171	8942	9139	2972	939	2974	934	2128	609	4637	1605	5763

BACK PRESSURE TURBINE/GENERATOR OUTPUT – AVERAGE KW

BASIS UNITs	Back Pressure Turbine/Generator Output & Contract Purchase												
	–	–	–	–	–	–	–	–	–	–	–	–	
	–	–	–	–	–	–	–	–	–	–	–	–	
	–	–	–	–	–	–	–	–	–	–	–	–	
Turb IB	44255	44266	47211	47208	–	–	–	–	–	–	36209	–	
Turb IA	10745	10734	7789	7792	–	–	–	–	–	–	3059	–	
Turb IIB	11795	11786	8853	–	5962	5823	5981	5892	8006	6121	–	–	
Turb IIA	–	–	–	–	3296	3396	3342	3370	2665	2423	–	–	
	–	–	–	–	–	–	–	–	–	–	–	–	
Total T/G Output	66795	66786	63853	55000	9278	9219	9323	9263	10671	8544	39269	–	37523
Balance Required	−56622	−56615	−54911	−45861	−6306	−6280	−6350	−6329	−8543	−7935	−34632	1605	

CONDENSING TURBINE OUTPUT – AVERAGE KW

	Generator Efficiency	Condensing Turbine Output – KW												
		–	–	–	–	–	–	–	–	–	–	–	–	–
		–	–	–	–	–	–	–	–	–	–	–	–	–
		–	–	–	–	–	–	–	–	–	–	–	–	–
		–	–	–	–	–	–	–	–	–	–	–	–	–
		–	–	–	–	–	–	–	–	–	–	–	–	–
		–	–	–	–	–	–	–	–	–	–	–	–	–
		–	–	–	–	–	–	–	–	–	–	–	–	–
		–	–	–	–	–	–	–	–	–	–	–	–	–
Total Condens Turb Output		–	–	–	–	–	–	–	–	–	–	–	–	–
Balance Required		−56622	−56615	−54911	−45861	−6306	−6280	−6350	−6329	−8543	−7935	−34632	1605	
GT Capability @ Full Load		49627	49627	49627	49627	47720	46233	47720	46233	47720	46233	47720	46233	

GAS TURBINE OUTPUT – AVERAGE KW

	Gas Turbine Output – KW												
	–	–	–	–	–	–	–	–	–	–	–	–	
	–	–	–	–	–	–	–	–	–	–	–	–	
	–	–	–	–	–	–	–	–	–	–	–	–	
	–	–	–	–	–	–	–	–	–	–	–	–	
	–	–	–	–	–	–	–	–	–	–	–	–	
GT–W251	45653	45614	32093	–	47720	46233	47720	46233	47720	46233	–	–	
Total GT Output (KW)	45653	45614	32093	–	47720	46233	47720	46233	47720	46233	–	–	405218
Balance Required (KW)	−102275	−102229	−87003	−45861	−54025	−54513	−54069	−54562	−56263	−54169	−34632	1605	
Hours in Period	914	783	1435	1248	181	306	318	535	589	994	435	734	
Balance Required (MWH)	−93479	−80045	−100025	−57235	−9779	−16681	−17194	−29191	−33139	−53844	−15065	1178	
PURCHASED POWER	75%	75%	75%	75%	75%	75%	75%	75%	75%	75%	75%	75%	
Peak Demand KW	–	–	–	–	–	–	–	–	–	–	–	2140 3	
Demand Charge – $/KW	7 93	7 93	7 93	7 93	7 93	7 93	7 93	7 93	7 93	7 93	7 93	7 93	
Energy Charge – $/KWH	0 0350	0 0279	0 0246	0 0246	0 0350	0 0350	0 0279	0 0279	0 0246	0 0246	0 0246	0 0246	
Demand Charge – $(000)	–	–	–	–	–	–	–	–	–	–	–	17 0	
Energy Charge – $(000)	–	–	–	–	–	–	–	–	–	–	–	29 0	
Total – $(000)	–	–	–	–	–	–	–	–	–	–	–	46 0	46 0
POWER SALES													
Energy Credit – Cents/KWH	0 0350	0 0279	0 0246	0 0246	0 0350	0 0350	0 0279	0 0279	0 0246	0 0246	0 0246	0 0246	
Energy Credit $(000)	3271 8	2229 8	2464 9	1410 4	342.3	583 8	479 0	813 2	816 6	1326 9	371 2	–	14109 9
GAS TURBINE													
Fuel Flow – MMBTU/Hr													
Maximum	520 7	520 7	520 7	520 7	506 3	495 1	506 3	495 1	506 3	495 1	506 3	495 1	
75% Load	426 4	426 4	426 4	426 4	414 6	405 4	414 6	405 4	414 6	405 4	414 6	405 4	
50% Load	332 1	332 1	332 1	332 1	322.9	315 8	322 9	315 8	322 9	315 8	322 9	315 8	
25% Load	237 8	237 8	237 8	237 8	231 2	226 1	231 2	226 1	231 2	226 1	231 2	226 1	

Percent Load

	Percent Load											
	–	–	–	–	–	–	–	–	–	–	–	–
	–	–	–	–	–	–	–	–	–	–	–	–
	–	–	–	–	–	–	–	–	–	–	–	–
	–	–	–	–	–	–	–	–	–	–	–	–
	–	–	–	–	–	–	–	–	–	–	–	–
GT–W251	92 0%	91 9%	64 7%	–	100 0%	100 0%	100 0%	100 0%	100 0%	100 0%	–	–

Interpolated Fuel Flow – MMBTU

	Fuel Flow – MMBTU												
	–	–	–	–	–	–	–	–	–	–	–	–	
	–	–	–	–	–	–	–	–	–	–	–	–	
	–	–	–	–	–	–	–	–	–	–	–	–	
	–	–	–	–	–	–	–	–	–	–	–	–	
	–	–	–	–	–	–	–	–	–	–	–	–	
GT–W251	448291	383808	555938	–	91639	151496	161002	264871	298207	492116	–	–	2847368
Total	448291	383808	555938	–	91639	151496	161002	264871	298207	492116	–	–	

Fuel Cost – Gas Turbine(s) (Gas) $(000)

	Unit Cost	Fuel Cost – Gas $(000)												
	–	–	–	–	–	–	–	–	–	–	–	–	–	
	–	–	–	–	–	–	–	–	–	–	–	–	–	
	–	–	–	–	–	–	–	–	–	–	–	–	–	
	–	–	–	–	–	–	–	–	–	–	–	–	–	
	–	–	–	–	–	–	–	–	–	–	–	–	–	
GT–W251	$3 77	1690 1	1447 0	2095 9	–	345 5	571 1	607 0	998 6	1124 2	1855 3	–	–	
Total		1690 1	1447 0	2095 9	–	345 5	571 1	607 0	998 6	1124 2	1855 3	–	–	10 735

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Interpolated Exhaust Temperature °F

	WINTER				SUMMER							
	Peak	High	Low	Weekend	Peak 1	Peak 2	High 1	High 2	Low 1	Low 2	Wkend 1	Wkend 2
	Exhaust Temperature °F											
	–	–	–	–	–	–	–	–	–	–	–	–
	–	–	–	–	–	–	–	–	–	–	–	–
	–	–	–	–	–	–	–	–	–	–	–	–
	–	–	–	–	–	–	–	–	–	–	–	–
	–	–	–	–	–	–	–	–	–	–	–	–
GT–W251	970	970	970	–	975	978	975	978	975	978	–	–

Interpolated Exhaust Flow M#/Hr

	Exhaust Flow M#/Hr											
	–	–	–	–	–	–	–	–	–	–	–	–
	–	–	–	–	–	–	–	–	–	–	–	–
	–	–	–	–	–	–	–	–	–	–	–	–
	–	–	–	–	–	–	–	–	–	–	–	–
	–	–	–	–	–	–	–	–	–	–	–	–
GT–W251	1319 4	1318 7	1093 0	–	1356 5	1333 7	1356 5	1333 7	1356 5	1333 7	–	–

Available Exhaust Heat MMBTU/Hr

	Exhaust Heat MMBTU/Hr											
	–	–	–	–	–	–	–	–	–	–	–	–
	–	–	–	–	–	–	–	–	–	–	–	–
	–	–	–	–	–	–	–	–	–	–	–	–
	–	–	–	–	–	–	–	–	–	–	–	–
	–	–	–	–	–	–	–	–	–	–	–	–
GT–W251	249 184	249 061	206 428	–	257 673	254 478	257 673	254 478	257 673	254 478	–	–

Steam Available – MW per Hour (Without Supplementary Firing)

	Enthalpy Rise	Total Steam Available without Supplementary Firing M#/Hr											
	–	–	–	–	–	–	–	–	–	–	–	–	–
	–	–	–	–	–	–	–	–	–	–	–	–	–
	–	–	–	–	–	–	–	–	–	–	–	–	–
	–	–	–	–	–	–	–	–	–	–	–	–	–
	–	–	–	–	–	–	–	–	–	–	–	–	–
HRSG IV	3 412	73 032	72 996	60 501	–	75 520	74.583	75 520	74 583	75 520	74 583	–	–
		73 032	72 996	60.501	–	75.520	74.583	75 520	74 583	75 520	74 583	–	–

Supplementary Firing – Maximum Exhaust Heat MMBTU/Hr

		–	–	–	–	–	–	–	–	–	–	–	–
		–	–	–	–	–	–	–	–	–	–	–	–
		–	–	–	–	–	–	–	–	–	–	–	–
		–	–	–	–	–	–	–	–	–	–	–	–
		–	–	–	–	–	–	–	–	–	–	–	–
		–	–	–	–	–	–	–	–	–	–	–	–

Steam Rejection – Avg MW (To Cooling Tower)

	Maximum Capacity	Steam Rejection – Average MW											
From Condensing	18 000	–	–	–	–	–	–	–	–	–	–	–	–
From Gas Turbines	18 000	18 0	18 0	18 0	–	8 7	7 5	8 3	7 5	6 2	15 7	–	–
Total		18 0	18 0	18 0	–	8 7	7 5	8 3	7.5	6.2	15 7	–	–

Utilized HRSG Energy MW per Hr

	HRSG Energy Utilized – MW/Hr											
	–	–	–	–	–	–	–	–	–	–	–	–
	–	–	–	–	–	–	–	–	–	–	–	–
	–	–	–	–	–	–	–	–	–	–	–	–
	–	–	–	–	–	–	–	–	–	–	–	–
	–	–	–	–	–	–	–	–	–	–	–	–
HRSG IV	55 0	55 0	42 5	–	66 8	67 1	67.2	67 1	69 3	58 9	–	–
	55 0	55 0	42.5	–	66 8	67 1	67.2	67 1	69 3	58 9	–	–

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FINANCIAL COST (000) (Including Inflation)

	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
ACCRUAL BASIS	(Exclusive of Interest Expense if any and Depreciation Charges related to existing plant (Production Transmission Distribution et al)																	
Operating Expenses																		
Operation & Maintenance	5 544	6 234	6 922	12 534	22 941	20 969	23 232	25 785	26 816	28 353	30 019	32 397	31 762	38 402	35 248	37 336	40 436	42 597
Depreciation Expense	8	44	1 274	2 538	2 564	2 578	2 593	2 609	2 611	2 613	2 847	3 093	3 096	3 098	3 100	3 102	3 105	3 107
Total Operating Expenses	5 552	6 277	8 195	15 072	25 505	23 547	25 825	28 394	29 427	30 966	32 866	35 490	34 857	41 500	38 348	40 438	43 541	45 705
Interest Expense	9	57	1 413	4 039	5 221	4 926	4 575	4 179	3 715	3 176	2 841	2 789	2 686	2 481	2 262	2 026	1 772	1 497
Equity Return	9	9	55	934	1 817	1 849	1 866	1 885	1 905	1 908	1 910	2 203	2 511	2 514	2 516	2 519	2 522	2 525
Total Expense & Return	5 570	6 344	9 663	20 045	32 543	30 322	32 266	34 458	35 047	36 050	37 618	40 482	40 054	46 494	43 126	44 984	47 835	49 726
Income Tax Effect @ 45%	8	8	45	764	1 487	1 513	1 527	1 542	1 559	1 561	1 563	1 803	2 054	2 057	2 059	2 061	2 063	2 066
Total Cost	5,577	6,352	9,707	20,809	34,030	31,835	33,793	36,000	36,605	37,610	39,181	42,284	42,108	48,551	45,185	47,045	49,898	51,792
Estimated Hot Water Revenue Requirement	(Exclusive of Interest Expense if any and Depreciation Charges related to existing plant (Production Transmission Distribution et al)																	
Total Cost (Above) less																		
Cost of Steam																		
Operation & Maintenance	4 129	4 505	4 830	6 541	8 716	9 898	10 204	11 578	11 461	12 341	12 661	15 468	12 340	12 956	13 602	14 281	14 993	15 741
Allocated Depreciation	3	16	464	804	806	808	811	813	813	812	883	958	957	957	956	956	956	956
Allocated Return	4	4	20	296	571	580	583	588	593	593	593	682	776	776	776	776	777	777
Income Tax Effect	3	3	16	242	467	474	477	481	485	485	485	558	635	635	635	635	635	636
Total Steam	4 139	4 528	5 330	7 883	10 561	11 760	12 075	13 460	13 352	14 231	14 621	17 666	14 707	15 323	15 970	16 649	17 361	18 110
Equals Cost of Hot Water	1 439	1 824	4 377	12 926	23 469	20 075	21 718	22 541	23 253	23 379	24 560	24 618	27 401	33 228	29 215	30 396	32 537	33 683
HOT WATER – $/MWH	$2 69	$3 30	$7 63	$16 63	$29 80	$25 38	$27 35	$28 26	$29 11	$29 22	$30 64	$30 66	$34 07	$41 26	$36 23	$37 65	$40 24	$41 61
Present Worth	$2 69	$2 82	$5 57	$10 39	$15 90	$11 58	$10 66	$9 42	$8 29	$7 11	$6 37	$5 45	$5 18	$5 36	$4 02	$3 57	$3 26	$2 88
Levelized Cost to Date		$3 30	$5 29	$8 50	$12 64	$14 46	$15 86	$16 91	$17 74	$18 37	$18 91	$19 35	$19 79	$20 34	$20 68	$20 98	$21 27	$21 53
CASH BASIS	(Exclusive of Debt Service related to existing plant (Production Transmission Distribution et al)																	
O & M Expenses	5 544	6 234	6 922	12 534	22 941	20 969	23 232	25 785	26 816	28 353	30 019	32 397	31 762	38 402	35 248	37 336	40 436	42 597
Equity Return	9	9	55	934	1 817	1 849	1 866	1 885	1 905	1 908	1 910	2 203	2 511	2 514	2 516	2 519	2 522	2 525
Debt Service																		
Foreign Interest	–	–	526	1 606	2 135	2 086	2 032	1 975	1 912	1 845	1 772	1 692	1 607	1 514	1 414	1 306	1 189	1 062
Principal	–	–	–	283	605	655	708	766	828	896	969	1 048	1 134	1 226	1 326	1 435	1 552	1 678
Total	–	–	526	1 888	2 741	2 741	2 741	2 741	2 741	2 741	2 741	2 741	2 741	2 741	2 741	2 741	2 741	2 741
Domestic Interest	9	57	886	2 433	3 086	2 840	2 543	2 204	1 802	1 332	1 070	1 096	1 080	966	848	720	583	434
Principal	–	11	67	1 134	2 337	2 664	3 014	3 409	3 855	4 305	4 703	2 948	982	1 010	1 084	1 165	1 252	1 402
Total	9	69	953	3 567	5 422	5 504	5 557	5 614	5 657	5 637	5 772	4 044	2 062	1 977	1 932	1 885	1 835	1 836
Total Cost before Income Tax	5 562	6 312	8 456	18 923	32 921	31 063	33 396	36 025	37 119	38 638	40 442	41 385	39 074	45 633	42 437	44 480	47 533	49 699
Income Tax Effect @ 45%	8	8	45	764	1 487	1 513	1 527	1 542	1 559	1 561	1 563	1 803	2 054	2 057	2 059	2 061	2 063	2 066
Total Financial Cost	5,570	6,319	8,501	19,687	34,408	32,575	34,923	37,567	38,677	40,198	42,005	43,187	41,128	47,690	44,496	46,541	49,597	51,765

APPENDIX F: (Cont'd) GILBERT/COMMONWEALTH ECONOMIC ANALYSIS MODEL RESULTS AND DETAIL:

Variant B1: (CFB Boiler and 32 MW steam turbine for CPIV)

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VARIANT B1 PROJECTED OPERATING AND CAPITAL EXPENDITURES High Demand

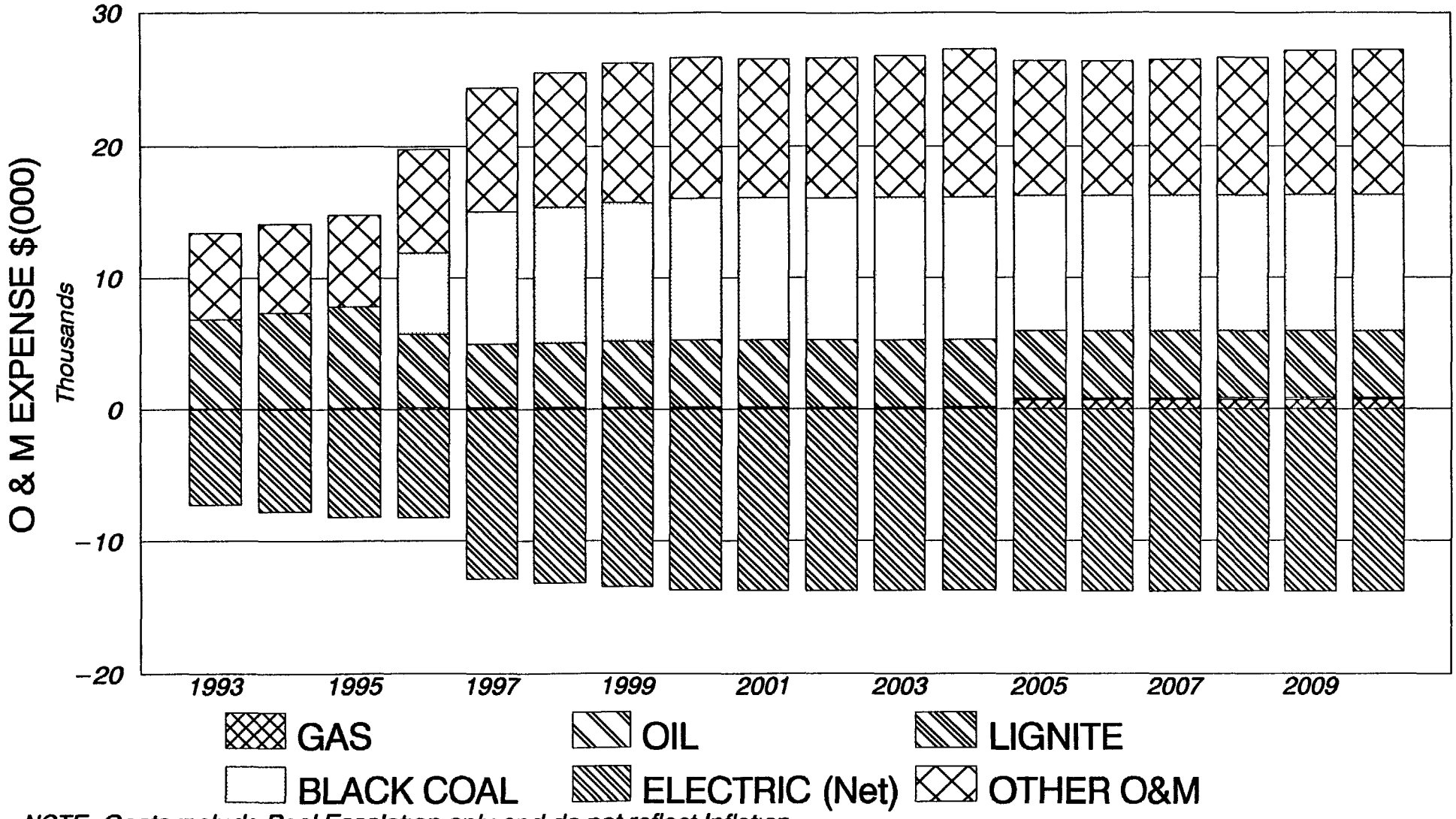
COST EXCL INFLATION (000)

	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
OPERATING EXPENSES																		
Fuel Cost – Natural Gas	–	–	–	105	4	4	4	5	5	5	5	5	660	665	669	674	678	683
Oil	62	68	74	15	117	121	124	128	129	129	129	129	126	126	126	126	126	127
Lignite	6 790	7 255	7 752	5 631	4 840	4 933	5 029	5 126	5 127	5 127	5 128	5 128	5 129	5 129	5 130	5 130	5 131	5 131
Black Coal	–	–	–	5 370	8 782	8 988	9 196	9 413	9 429	9 442	9 455	9 468	9 064	9 074	9 084	9 094	9 104	9 114
Total Fuel Cost	6 852	7 323	7 827	11 121	13 742	14 045	14 353	14 673	14 690	14 703	14 716	14 730	14 980	14 995	15 010	15 025	15 040	15 055
Supplemental Cost (Shortfall)	–	–	0	–	–	–	–	–	–	–	0	–	–	(0)	–	(0)	–	–
Purchased Power Cost	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
Credit for Power Sales	(7,290)	(7 768)	(8,216)	(8,225)	(12 893)	(13 167)	(13 448)	(13 735)	(13 748)	(13 758)	(13 768)	(13 775)	(13 779)	(13 789)	(13 800)	(13 807)	(13 817)	(13 828)
Net Power Interchange	(7,290)	(7 768)	(8,216)	(8,225)	(12 893)	(13 167)	(13 448)	(13 735)	(13 748)	(13 758)	(13 768)	(13 775)	(13 779)	(13 789)	(13 800)	(13 807)	(13 817)	(13 828)
Fixed O&M and Overheads	2 300	2 300	2 300	2 510	2 542	2 542	2 542	2 542	2 542	2 542	2 542	2 542	2 339	2 339	2 339	2 339	2 339	2 339
Other Variable O & M	1 457	1 473	1 486	1 642	2 228	2 232	2 235	2 239	2 241	2 241	2 242	2 243	2 243	2 244	2 245	2 246	2 248	2 249
Sorbent and Ash Removal	245	285	331	651	1 832	1 835	1 837	2 632	2 633	2 635	2 636	2 637	2 608	2 609	2 610	2 611	2 612	2 613
Credit By-Product Sales	–	–	–	(197)	(302)	(303)	(303)	(304)	(304)	(305)	(305)	(305)	(299)	(299)	(299)	(300)	(300)	(300)
Emission Penalties	24	48	49	25	–	–	–	–	–	–	–	–	–	–	–	–	–	–
Maintenance Expenses	1 956	2 137	2 268	2 801	2 290	3 099	3 490	3 542	3 372	3 478	3 610	4 077	3 308	3 296	3 397	3 520	4 037	4 084
Plant Removal Costs	–	–	–	–	3 517	–	–	–	–	–	–	–	–	2 462	–	–	–	–
Total O&M Expense	5 544	5 799	6 046	10 328	12 956	10 283	10 706	11 587	11 424	11 535	11 673	12 148	11 399	13 855	11 501	11 635	12 158	12 212
CAPITAL COSTS																		
Foreign	–	–	1927	1976	–	–	–	–	–	–	–	–	–	–	–	–	–	–
Domestic	190	839	23145	22336	494	259	259	259	33	33	3301	3301	33	25	25	25	25	25
Total	190	839	25072	24312	494	259	259	259	33	33	3301	3301	33	25	25	25	25	25
TOTAL COST	5,734	6,637	31,118	34,640	13,450	10,542	10,964	11,846	11,457	11,568	14,974	15,449	11,433	13,881	11,527	11,660	12,184	12,237
Present Worth	5 517	5 914	25 672	26 460	9 513	6 904	6 648	6 651	5 956	5 569	6 674	6 376	4 369	4 911	3 776	3 537	3 422	3 183
Cumulative Present Worth	5 517	11 431	37 102	63 563	73 076	79 979	86 628	93 279	99 235	104 804	111 478	117 854	122 223	127 134	130 910	134 447	137 869	141 052

OPERATING STATISTICS

	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
TOTAL PRODUCTION – MWH																		
LP Steam	333 355	331 188	329 021	360 443	361 165	361 165	361 165	361 165	361 165	360 804	360 443	360 082	359 720	359 720	359 720	359 720	359 720	359 720
Hot Water	534 466	552 841	573 853	777 066	787 452	790 913	794 109	797 571	798 903	800 234	801 566	802 897	804 229	805 294	806 359	807 424	808 489	809 555
Electricity	306 534	312 254	315 750	312 792	463 516	464 729	465 848	467 062	467 528	467 891	468 253	468 616	468 799	469 169	469 538	469 907	470 276	470 645
COST OF PRODUCTION – $/MWH (Variable Costs only)																		
LP Steam	$10 46	$10 77	$11 08	$12 38	$11 93	$12 05	$12 18	$12 96	$12 96	$12 96	$12 96	$12 96	$12 78	$12 78	$12 78	$12 78	$12 78	$12 78
Hot Water	$8 56	$8 85	$9 15	$10 08	$11 00	$11 16	$11 32	$11 82	$11 82	$11 82	$11 82	$11 82	$12 01	$12 01	$12 01	$12 01	$12 02	$12 02
Electricity	$9 20	$9 51	$9 81	$11 06	$15 26	$15 44	$15 62	$16 43	$16 42	$16 42	$16 41	$16 41	$16 24	$16 23	$16 23	$16 22	$16 22	$16 21
NOT SERVED – MWH																		
LP Steam	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
Hot Water	–	–	26	–	–	–	–	–	–	–	0	–	–	(0)	–	(0)	–	–
Electricity	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
EMISSIONS – TONNES																		
Particulates	248	259	272	416	131	131	131	132	132	132	132	132	131	131	132	132	132	132
SO_2	5 745	5 854	5 965	3 620	3 020	3 029	3 037	3 046	3 050	3 053	3 055	3 058	2 983	2 986	2 988	2 990	2 992	2 995
NO	1 373	1 398	1 423	1 605	1 590	1 594	1 599	[illegible]	1 605	1 607	1 608	1 610	1 588	1 589	1 591	1 592	[illegible]	1 594
C	56	59	62	144	76	76	77	[illegible]	78	78	78	78	63	63	63	63	[illegible]	63

PROJECTED OPERATING & MAINTENANCE COSTS – VARIANT B1



NOTE Costs include Real Escalation only and do not reflect Inflation

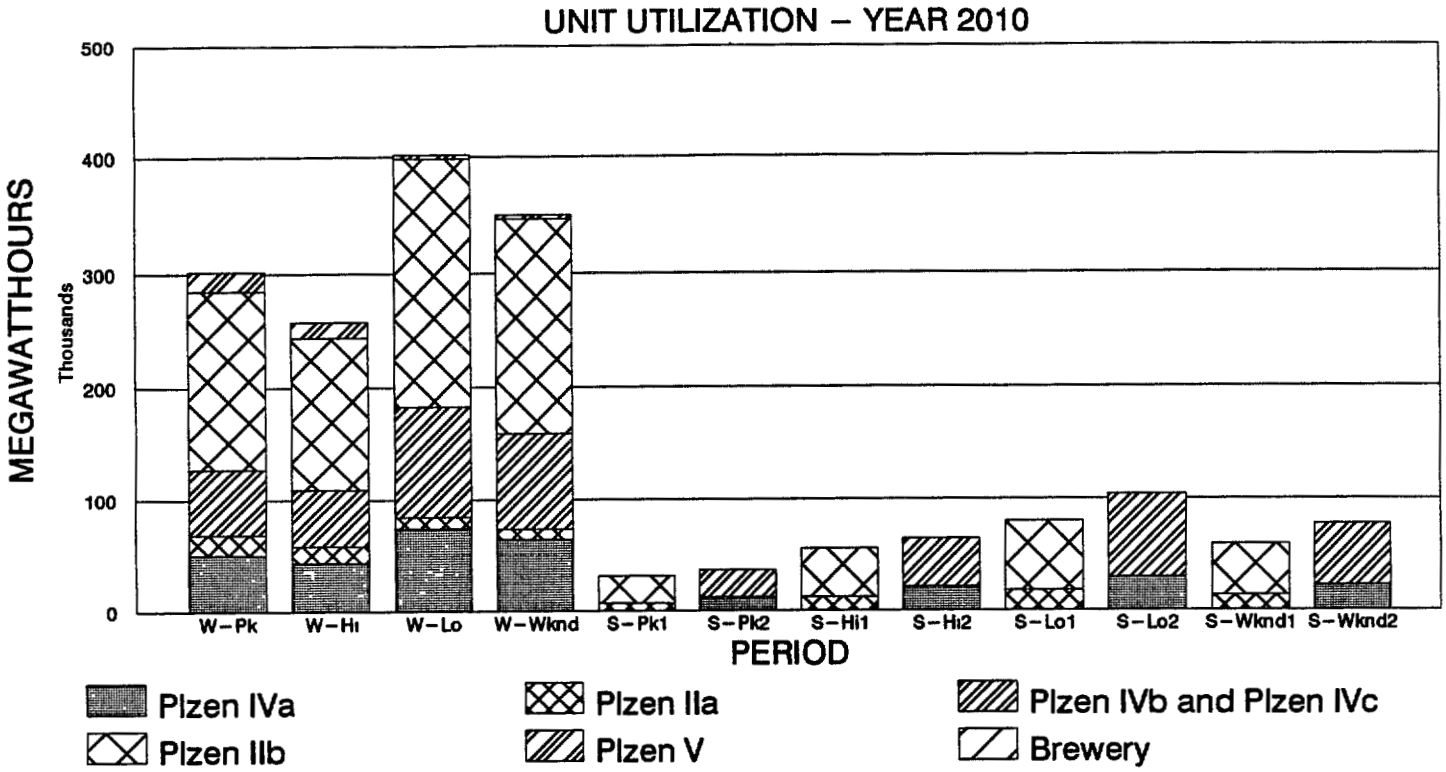
CASE B1 — Test Year = 2010

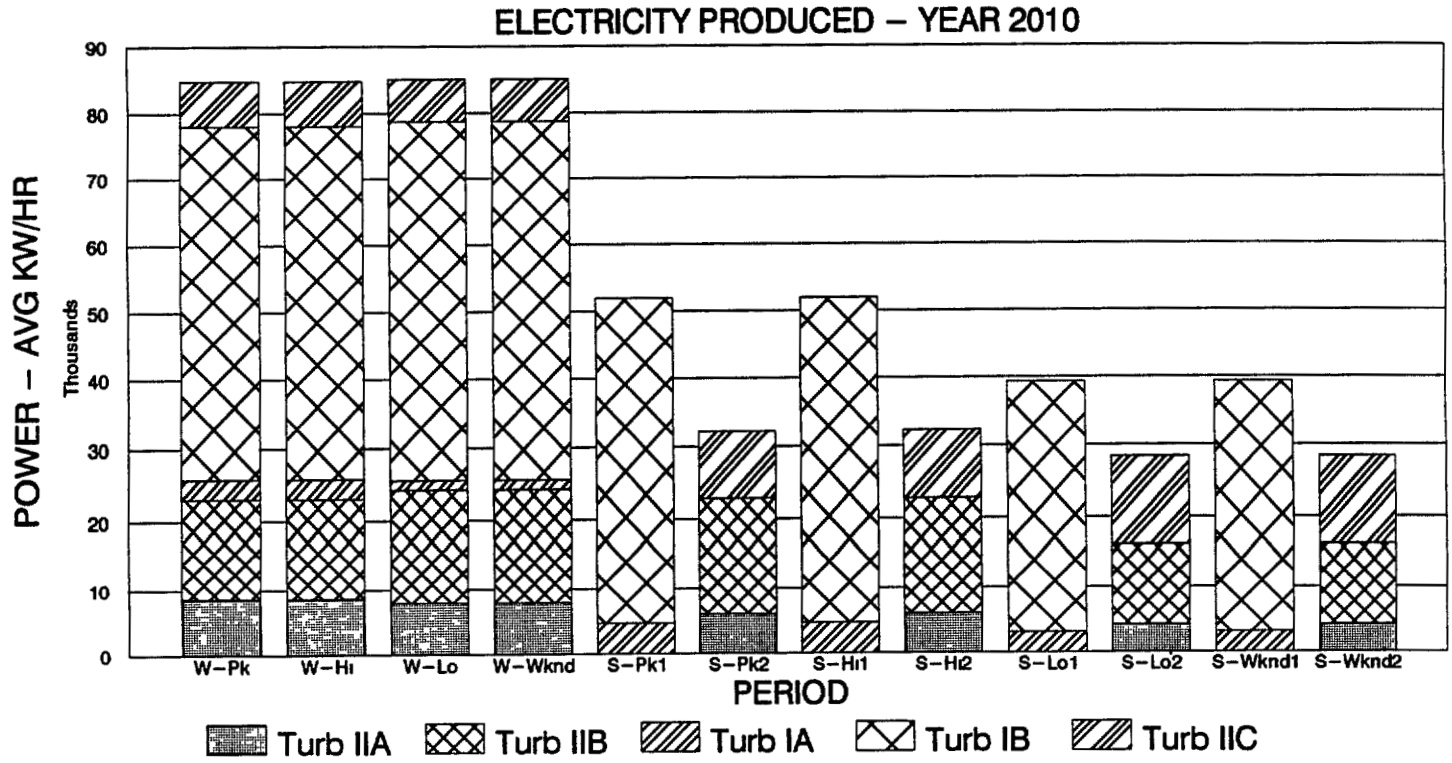
Station Use Unaccounted for etc — % of Demand
ElectricKW – Water – Steam –

Facilities Data

DESCRIPTION	UNIT	EXISTING FACILITIES		Brewery	Pizen IIa	Pizen IIb		NEW FACILITIES Pizen III	Pizen IVa Extract	Pizen IVb Exhaust	Pizen IVc Rejection	Cooling	Pizen V	Steam Purchase	Power Purchase	Power Sales
THERMAL DATA																
Efficiency – 80% to Full Load	%1			86 0%	84 0%	84 0%		91 1%	87 0%	87 0%	87 0%		91 1%			
Half Load	%2			86 0%	84 0%	84 0%		91 1%	87 0%	87 0%	87 0%		91 1%			
Minimum Load	%3			86 0%	84 0%	84 0%		91 1%	87 0%	87 0%	87 0%		91 1%			
Minimum Operation	%			7 3%	–	25 0%		25 0%	–	40 0%			12 5%			
Feedwater Temp																
Operation Adjustment Factor	Factor			0 085	0 085	0 095		0 040	0 050	0 060	0 060		0 045			
BOILER OUTPUT	Boiler MW									120 000						
Quantity	Mlb/Hr				749 700											
Pressure	PSIA				1976											
Temperature	Temp F				1004											
Enthalpy	MBTU/lb				1 477											
PRODUCT – LP STEAM	Priority	*		6	2				1							
Quantity	Mlb/Hr				116 204			143 300	110 000							
	MWts			56 100	100 000	165 000		43 500	47 000	115 000						
Pressure	PSIA				152			189								
Temperature	Temp F				428			428								
Enthalpy	MBTU/lb				1 230			1 230								
PRODUCT – HOT WATER	Priority			6		4				3		Cooling	5			
Quantity	MWtw			56 100		165 000		43 500		75 000		25 000	116 000			
Temperature – Supply	Temp F					320°				320°						
Return	Temp F					158				158						
TURBINE DATA	UNITs				Turb IA	Turb IB			Turb IIA	Turb IIB	Turb IIC					
	Priority				3	4			1	2					Purchase	Yes
Rated Capacity–Electric	KW				19720	55000			8800	25900					as Req d	
Capability – Max Steam	KW1				19720	55000			8800	25900						
75 % Steam	KW75				14060	40200			6280	18930						
50 % Steam	KW50				8430	25420			3760	11970						
25% Steam	KW25				2780	10620			1240	5000						
Steam Required – Maximum	M#/Hr_Max				308 644	365 900			137 700	172 300						
Minimum	M#/Hr_Min					91 500				43 000						
Outlet Steam Pressure	PSI				189	17 4			189	17 4						
Enthalpy Drop – Turbine	MBTU/lbt				0 2588	0 4157			0 2588	0 4157						
Sink	MBTU/lbs				1 1646	0 9146			1 1646	0 9700						
Generator Efficiency	%g				96 5%	96 5%			96 0%	96 0%	96 0%					
Power Ratio	Factor										0 3357					
FUELS DATA																
Primary Fuel	Type			Gas	Coal	Coal		Gas	Lignite	Lignite			Gas			
Cost	$/MMBTU			$3 77	$1 96	$1 96		$3 77	$1 24	$1 24			$3 77			
Percent Use	% Use			100 0%	99 6%	99 6%		55 0%	99 6%	99 6%			100 0%			
Secondary/Supplemental Fue	Type				Oil	Oil		Oil	Oil	Oil						
Cost	$/MMBTU				$2 99	$2 99		$2 99	$2 99	$2 99						
Percent Use	% Use				0 4%	0 4%		45 0%	0 4%	0 4%						
COST DATA (1993 Basis)	CK/$ =	28														
Number of Personnel	Number	92		30	160	–		8	56							
Average Wage & Benefits	$(000)	4 2		4 2	4 2	–		4 2	4 2							
Other Fixed Costs	$(000)	$879														
Raw Water & Treating Costs	$/MWHw	$0 10														
Demineralized Water Costs	$/MWHs	$1 41														
Other Variable O&M Costs	$/MWH	$0 41														
Limestone	$/Ton	$11 01														
Waste Disposal Costs	$/Ton	$3 24														
Emissions Code	CODEe			ST–2A8	PC–2B3	PC–2B3		ST–3A8	FB–2B4	FB–2B4	FB–2B4		ST–2A8			
Unscheduled Maintenance	CODE m			BR	P2	T1		P3	P4FB1	T2			P5			
Cost per Episode	Unit $(000)			2 0	2 0	1 0		2 0	2 5	1 0			2 0			
Purchased Power	$/kW															
Energy Charge – Peak	Cents/KWHw															
Off–Peak	Cents/KWHs															
MONTHLY DATA	Avg Temp C				AVAILABILITY											
W–Pk	3 0			100%	100%	100%		100%	100%	100%	100%	100%	100%			
W–Hi	3 0			100%	100%	100%		100%	100%	100%	100%	100%	100%			
W–Lo	3 0			100%	100%	100%		100%	100%	100%	100%	100%	100%			
W–Wknd	3 0			100%	100%	100%		100%	100%	100%	100%	100%	100%			
S–Pk1	11 6			100%	100%	100%		100%	–	–	–	100%	100%			
S–Pk2	18 3			100%	100%	100%		100%	100%	100%	100%	100%	100%			
S–Hi1	11 6			100%	100%	100%		100%	–	–	–	100%	100%			
S–Hi2	18 3			100%	100%	100%		100%	100%	100%	100%	100%	100%			
S–Lo1	11 6			100%	100%	100%		100%	–	–	–	100%	100%			
S–Lo2	18 3			100%	100%	100%		100%	100%	100%	100%	100%	100%			
S–Wknd1	11 6			100%	100%	100%		100%	–	–	–	100%	100%			
S–Wknd2	18 3			100%	100%	100%		100%	100%	100%	100%	100%	100%			

TEST YEAR SIMULATION RESULTS	WINTER Peak	High	Low	Weekend	SUMMER Peak 1	Peak 2	High 1	High 2	Low 1	Low 2	Wkend 1	Wkend 2	TOTAL
OPERATING EXPENSES*													
Natural Gas	242	207	53	46	–	–	–	–	–	–	–	–	549
Oil	15	13	21	18	2	2	3	3	4	5	3	4	92
Lignite	561	480	881	766	–	188	–	329	–	532	–	393	4 129
Black Coal	1 524	1 305	1 964	1 709	273	–	480	–	690	–	510	–	8 455
Total Fuel Cost	2 341	2 005	2 918	2 539	275	190	483	332	695	537	513	396	13 224
Supplemental Cost–Shortfall Penalty)	–	–	–	–	–	–	–	–	–	–	–	–	–
Purchased Power Cost	–	–	–	–	–	–	–	–	–	–	–	–	–
Credit for Power Sales	(2 238)	(1 526)	(2 519)	(2 191)	(291)	(210)	(407)	(291)	(503)	(332)	(371)	(245)	(11 125)
Net Power Interchange Cost	(2 238)	(1 526)	(2 519)	(2 191)	(291)	(210)	(407)	(291)	(503)	(332)	(371)	(245)	(11 125)
Other O&M – Fixed OH & Other	252	216	396	345	50	84	88	148	163	274	120	203	2 339
Variable	351	300	488	424	37	54	65	94	93	157	69	116	2 249
Limestone Injection & Ash Removal	213	182	318	277	10	53	18	92	25	149	19	110	1 465
Credit for By–Product Sales	(48)	(41)	(67)	(58)	(5)	(7)	(9)	(12)	(13)	(19)	(9)	(14)	(300)
Emissions Penalties	–	–	–	–	–	–	–	–	–	–	–	–	–
Total Excluding Maintenance	871	1 137	1 535	1 335	76	164	238	363	461	–	340	566	7 851


UNIT UTILIZATION – YEAR 2010
MEGAWATTHOURS
Thousands
500
400
300
200
100
0
W–Pk
W–Hi
W–Lo
W–Wknd
S–Pk1
S–Pk2
S–Hi1
S–Hi2
S–Lo1
S–Lo2
S–Wknd1
S–Wknd2
PERIOD
Plzen IVa
Plzen IIa
Plzen IVb and Plzen IVc
Plzen IIb
Plzen V
Brewery


ELECTRICITY PRODUCED – YEAR 2010
POWER – AVG KW/HR
Thousands
90
80
70
60
50
40
30
20
10
0
W–Pk
W–Hi
W–Lo
W–Wknd
S–Pk1
S–Pk2
S–Hi1
S–Hi2
S–Lo1
S–Lo2
S–Wknd1
S–Wknd2
PERIOD
Turb IIA
Turb IIB
Turb IA
Turb IB
Turb IIC

			WINTER				SUMMER								
			Peak	High	Low	Weekend	Peak 1	Peak 2	High 1	High 2	Low 1	Low 2	Wkend 1	Wkend 2	
PRODUCT – LP STEAM															
Customer Requirement	MWH		58007	49652	71302	62027	6354	10515	11165	18251	16280	25394	12023	18752	359720
Station Use	MWH	–	–	–	–	–	–	–	–	–	–	–	–	–	–
			58007	49652	71302	62027	6354	10515	11165	18251	16280	25394	12023	18752	359720
	2	3	4	5	6	7	8	9	10	11	12	13	14	15	
	MWts		Average Loading – MW												
	–		–	–	–	–	–	–	–	–	–	–	–	–	
	–		–	–	–	–	–	–	–	–	–	–	–	–	
Brewery	56 100		–	–	–	–	–	–	–	–	–	–	–	–	
	–		–	–	–	–	–	–	–	–	–	–	–	–	
	–		–	–	–	–	–	–	–	–	–	–	–	–	
	–		–	–	–	–	–	–	–	–	–	–	–	–	
Plzen IIa	100 000		24 8	24 8	12 7	12 7	35 1	–	35 1	–	27 6	–	27 6	–	
Plzen IVa	47 000		46 3	46 3	43 0	43 0	–	34 4	–	34 1	–	25 5	–	25 5	
			Unit Energy Output – MWH (Before Adjustment for Minimum Loading Limitation)												
			–	–	–	–	–	–	–	–	–	–	–	–	
			–	–	–	–	–	–	–	–	–	–	–	–	
Brewery			–	–	–	–	–	–	–	–	–	–	–	–	
			–	–	–	–	–	–	–	–	–	–	–	–	
			–	–	–	–	–	–	–	–	–	–	–	–	
			–	–	–	–	–	–	–	–	–	–	–	–	
Plzen IIa			15688	13401	9546	8314	6354	–	11165	–	16280	–	12023	–	
Plzen IVa			42319	36251	61756	53713	–	10515	–	18251	–	25394	–	18752	
Total			58007	49652	71302	62027	6354	10515	11165	18251	16280	25394	12023	18752	359720
Steam Not Served	MWH		–	–	–	–	–	–	–	–	–	–	–	–	–
Total excluding HRSG supply			58007	49651 6	71301 6	62026.9	6354 48	10514 8	11165.2	18250 7	16279 6	25394	12022.7	18751 7	

PRODUCT – HOT WATER															
Customer Requirement	MWH		151236	129546	185986	161809	15432	10048	27113	17567	39429	24315	29119	17955	809555
Station Use	MWH	–	–	–	–	–	–	–	–	–	–	–	–	–	–
			151236	129546	185986	161809	15432	10048	27113	17567	39429	24315	29119	17955	809555
	2	3	4	5	6	7	8	9	10	11	12	13	14	15	
BASIS UNIT	MWtw		Average Loading – MW												
	–		–	–	–	–	–	–	–	–	–	–	–	–	
	–		–	–	–	–	–	–	–	–	–	–	–	–	
Brewery	56 100		9.3	9 3	–	–	–	–	–	–	–	–	–	–	
Plzen V	116 000		42 3	42 3	20 7	20 7	–	–	–	–	–	–	–	–	
Plzen IIb	165 000		118 9	118 9	95 6	95 6	85 3	–	85 3	–	66 9	–	66 9	–	
Plzen IVb	75.000		28 7	28 7	32 0	32 0	–	32 8	–	32 8	–	24 5	–	24 5	
	–		–	–	–	–	–	–	–	–	–	–	–	–	
	–		–	–	–	–	–	–	–	–	–	–	–	–	
Total			199.2	199.2	148.2	148 3	85 3	32 8	85.3	32 8	66 9	24 5	66 9	24 5	
			Unit Energy Output – MWH (Before Adjustment for Minimum Loading Limitation)												
			–	–	–	–	–	–	–	–	–	–	–	–	
			–	–	–	–	–	–	–	–	–	–	–	–	
Brewery			75	64	–	–	–	–	–	–	–	–	–	–	
Plzen V			16261	13898	2960	2586	–	–	–	–	–	–	–	–	
Plzen IIb			108668	93110	137157	119336	15432	–	27113	–	39429	–	29119	–	
Plzen IVb			26231	22474	45869	39887	–	10048	–	17567	–	24315	–	17955	
			–	–	–	–	–	–	–	–	–	–	–	–	
			–	–	–	–	–	–	–	–	–	–	–	–	
Total			151236	129546	185986	161809	15432	10048	27113	17567	39429	24315	29119	17955	809555
Hot Water Not Served	MWH		–	–	–	–	–	–	–	–	–	–	–	–	–
Total excluding HRSG supply			151236	129546	185986	161809	15432.4	10047 7	27113.3	17567	39428.6	24314 9	29119	17954 8	

ADJUSTED FOR MINIMUM LOADING – MWH

Steam			Unit Utilization after Adjustment for Minimum Loading – MWH (Steam)											
			–	–	–	–	–	–	–	–	–	–	–	–
			–	–	–	–	–	–	–	–	–	–	–	–
Brewery			–	–	–	–	–	–	–	–	–	–	–	–
			–	–	–	–	–	–	–	–	–	–	–	–
			–	–	–	–	–	–	–	–	–	–	–	–
			–	–	–	–	–	–	–	–	–	–	–	–
Plzen IIa			15688	13401	9546	8314	6354	–	11165	–	16280	–	12023	–
Plzen IVa			42319	36251	61756	53713	–	10515	–	18251	–	25394	–	18752
Total			58007	49652	71302	62027	6354	10515	11165	18251	16280	25394	12023	18752
Hot Water			Unit Utilization after Adjustment for Minimum Loading – MWH (Hot Water)											
			–	–	–	–	–	–	–	–	–	–	–	–
			–	–	–	–	–	–	–	–	–	–	–	–
Brewery			84	71	–	–	–	–	–	–	–	–	–	–
Plzen V			16328	13959	3603	3147	–	–	–	–	–	–	–	–
Plzen IIb			106593	93041	136513	116774	15432	–	27113	–	39429	–	29119	–
Plzen IVb			26231	22474	45869	39887	–	10048	–	17567	–	24315	–	17955
			–	–	–	–	–	–	–	–	–	–	–	–
			–	–	–	–	–	–	–	–	–	–	–	–
Total			151236	129546	185986	161809	15432	10048	27113	17567	39429	24315	29119	17955

TOTAL UNIT UTILIZATION BEFORE REQUIREMENT FOR ELECTRIC GENERATION – MWH

	WINTER				SUMMER								
	Peak	High	Low	Weekend	Peak 1	Peak 2	High 1	High 2	Low 1	Low 2	Wkend 1	Wkend 2	
	Output to meet Steam and Hot Water Requirements – MWH												
	–	–	–	–	–	–	–	–	–	–	–	–	
	–	–	–	–	–	–	–	–	–	–	–	–	
Brewery	84	71	–	–	–	–	–	–	–	–	–	–	
Plzen V	16328	13959	3603	3147	–	–	–	–	–	–	–	–	
Plzen IIb	108593	93041	136513	118774	15432	–	27113	–	39429	–	29119	–	
Plzen IVb	26231	22474	45869	39887	–	10048	–	17567	–	24315	–	17955	
Plzen IIa	15688	13401	9546	8314	6354	–	11165	–	16280	–	12023	–	
Plzen IVa	42319	36251	61756	53713	–	10515	–	18251	–	25394	–	18752	
Total	209243	179197	257288	223836	21787	20563	38279	35818	55708	49709	41142	36706	1169275

ADDITIONAL REQUIREMENT FOR BACK PRESSURE STEAM TURBINES – MWH

	Basis %g	Thermal output represented in electric generation – MWHt											
	–	–	–	–	–	–	–	–	–	–	–	–	–
	–	–	–	–	–	–	–	–	–	–	–	–	–
	–	–	–	–	–	–	–	–	–	–	–	–	–
	–	–	–	–	–	–	–	–	–	–	–	–	–
Turb IB	0 965	49611	42507	79140	68859	8865	–	15575	–	22101	–	16322	–
Turb IIB	0 96	13673	11715	24241	21080	–	5327	–	9314	–	12376	–	9139
Turb IA	0 965	1716	1466	1044	909	874	–	1536	–	1867	–	1379	–
Turb IIA	0 96	8235	7055	11883	10335	–	1941	–	3364	–	4348	–	3211
Total		73236	62742	116309	101184	9739	7268	17111	12678	23969	16724	17701	12349

STEAM TO CONDENSING TURBINES AND REJECTION – MWH

	Incremental thermal output represented in electric generation and rejection – MWHt											
	–	–	–	–	–	–	–	–	–	–	–	–
	–	–	–	–	–	–	–	–	–	–	–	–
	–	–	–	–	–	–	–	–	–	–	–	–
	–	–	–	–	–	–	–	–	–	–	–	–
	–	–	–	–	–	–	–	–	–	–	–	–
Turb IIC	19221	16465	28451	24745	–	8889	–	15705	–	37408	–	27623
	–	–	–	–	–	–	–	–	–	–	–	–
	–	–	–	–	–	–	–	–	–	–	–	–

UNIT UTILIZATION – TOTAL MWH

	Unit Utilization MWH											
	–	–	–	–	–	–	–	–	–	–	–	–
	–	–	–	–	–	–	–	–	–	–	–	–
Brewery	84	71	–	–	–	–	–	–	–	–	–	–
Plzen V	16328	13959	3603	3147	–	–	–	–	–	–	–	–
Plzen IIb	158204	135548	215654	187633	24297	–	42688	–	61530	–	45441	–
Plzen IVb and Plzen IVc	59126	50654	98561	85712	–	24264	–	42585	–	74099	–	54717
Plzen IIa	17404	14866	10590	9224	7229	–	12702	–	18147	–	13402	–
Plzen IVa	50554	43306	73639	64048	–	12456	–	21615	–	29742	–	21962
Total	301700	258405	402047	349764	31526	36720	55390	64200	79677	103841	58843	76679

INPUT ENERGY REQUIRED BEFORE EFFICIENCY ADJUSTMENT

	BTU/kW	Energy Input before Efficiency Adjustment – MMBTU											
	3 412	–	–	–	–	–	–	–	–	–	–	–	–
	3 412	–	–	–	–	–	–	–	–	–	–	–	–
Brewery	3 412	285	243	–	–	–	–	–	–	–	–	–	–
Plzen V	3 412	55710	47629	12295	10739	–	–	–	–	–	–	–	–
Plzen IIb	3 412	539793	462489	735810	640204	82902	–	145652	–	209941	–	155046	–
Plzen IVb and Plzen IVc	3 412	201738	172833	336291	292449	–	82789	–	145301	–	252828	–	186694
Plzen IIa	3 412	59384	50724	36134	31472	24665	–	43338	–	61917	–	45727	–
Plzen IVa	3 412	172490	147759	251255	218532	–	42499	–	73749	–	101479	–	74935
Total		1029401	881677	1371785	1193396	107567	125289	188989	219050	271858	354305	200773	261629

EFFICIENCY

	BASIS %1	BASIS %2	Efficiency											
		–	–	–	–	–	–	–	–	–	–	–	–	–
		–	–	–	–	–	–	–	–	–	–	–	–	–
Brewery	–	–	86 0%	86 0%	86 0%	86 0%	86 0%	86 0%	86 0%	86 0%	86 0%	86 0%	86 0%	86 0%
Plzen V	–	–	91 1%	91 1%	91 1%	91 1%	91 1%	91 1%	91 1%	91 1%	91 1%	91 1%	91 1%	91 1%
Plzen IIb	–	–	84 0%	84 0%	84 0%	84 0%	84 0%	84 0%	84 0%	84 0%	84 0%	84 0%	84 0%	84 0%
Plzen IVb and Plzen IVc	–	–	87 0%	87 0%	87 0%	87 0%	87 0%	87 0%	87 0%	87 0%	87 0%	87 0%	87 0%	87 0%
Plzen IIa	–	–	84.0%	84 0%	84 0%	84 0%	84 0%	84 0%	84 0%	84 0%	84 0%	84 0%	84 0%	84 0%
Plzen IVa	–	–	87 0%	87 0%	87 0%	87 0%	87 0%	87 0%	87 0%	87 0%	87 0%	87 0%	87 0%	87 0%

INPUT ENERGY REQUIRED

		Unit Energy Input MMBTU												
	–	–	–	–	–	–	–	–	–	–	–	–	–	–
	–	–	–	–	–	–	–	–	–	–	–	–	–	–
Brewery	8 5%	360	306	–	–	–	–	–	–	–	–	–	–	666
Plzen V	4 5%	63914	54643	14106	12320	–	–	–	–	–	–	–	–	144983
Plzen IIb	9 5%	703756	602970	959312	834666	108084	–	189893	–	273710	–	202141	–	3874533
Plzen IVb and Plzen IVc	6 0%	245830	210608	409792	356388	–	100684	–	177059	–	308084	–	227498	2036123
Plzen IIa	8 5%	76705	65518	46672	40651	31859	–	55978	–	79977	–	59064	–	456423
Plzen IVa	5 0%	208178	178330	303239	263745	–	51292	–	89008	–	122475	–	90439	1306705
Total		1298742	1112375	1733121	1507751	139942	152176	245871	266066	353687	430559	261205	317937	7819433

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VARIANT B1

			WINTER				SUMMER								
			Peak	High	Low	Weekend	Peak 1	Peak 2	High 1	High 2	Low 1	Low 2	Wkend 1	Wkend 2	
FUEL COST – BOILERS (Lignite)															
	Lignite %	Weighted $/MMBTU	Fuel Cost – Lignite $(000)												
	–	–	–	–	–	–	–	–	–	–	–	–	–	–	
	–	–	–	–	–	–	–	–	–	–	–	–	–	–	
Brewery	–	–	–	–	–	–	–	–	–	–	–	–	–	–	
Plzen V	–	–	–	–	–	–	–	–	–	–	–	–	–	–	
Plzen IIb	–	–	–	–	–	–	–	–	–	–	–	–	–	–	
Plzen IVb and Plzen IVc	99 6%	$1 24	304	260	506	440	–	125	–	219	–	380	–	281	2515
Plzen IIa	–	–	–	–	–	–	–	–	–	–	–	–	–	–	
Plzen IVa	99 6%	$1 24	257	220	375	326	–	63	–	110	–	151	–	112	
Total			561	480	881	766	–	188	–	329	–	532	–	393	4129
FUEL COST – BOILERS (Coal)															
	Coal %	Weighted $/MMBTU	Fuel Cost – Black Coal $(000)												
	–	–	–	–	–	–	–	–	–	–	–	–	–	–	
	–	–	–	–	–	–	–	–	–	–	–	–	–	–	
Brewery	–	–	–	–	–	–	–	–	–	–	–	–	–	–	
Plzen V	–	–	–	–	–	–	–	–	–	–	–	–	–	–	
Plzen IIb	99 6%	$1 95	1374	1177	1873	1629	211	–	371	–	534	–	395	–	
Plzen IVb and Plzen IVc	–	–	–	–	–	–	–	–	–	–	–	–	–	–	
Plzen IIa	99 6%	$1 95	150	128	91	79	62	–	109	–	156	–	115	–	
Plzen IVa	–	–	–	–	–	–	–	–	–	–	–	–	–	–	
Total			1524	1305	1964	1709	273	–	480	–	690	–	510	–	8455
FUEL COST – BOILERS (Gas)															
	Gas %	Weighted $/MMBTU	Fuel Cost – Natural Gas $(000)												
	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
Brewery	100 0%	$3 77	1	1	–	–	–	–	–	–	–	–	–	–	3
Plzen V	100 0%	$3 77	241	206	53	46	–	–	–	–	–	–	–	–	547
Plzen IIb	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
Plzen IVb and Plzen IVc	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
Plzen IIa	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
Plzen IVa	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
Total			242	207	53	46	–	–	–	–	–	–	–	–	549
FUEL COST – BOILERS (Oil)															
	Oil %	Weighted $/MMBTU	Fuel Cost – Oil $(000)												
	–	–	–	–	–	–	–	–	–	–	–	–	–	–	
	–	–	–	–	–	–	–	–	–	–	–	–	–	–	
Brewery	–	–	–	–	–	–	–	–	–	–	–	–	–	–	
Plzen V	–	–	–	–	–	–	–	–	–	–	–	–	–	–	
Plzen IIb	0 4%	$0 01	8	7	11	10	1	–	2	–	3	–	2	–	
Plzen IVb and Plzen IVc	0 4%	$0 01	3	3	5	4	–	1	–	2	–	4	–	3	
Plzen IIa	0 4%	$0 01	1	1	1	0	0	–	1	–	1	–	1	–	
Plzen IVa	0 4%	$0 01	2	2	4	3	–	1	–	1	–	1	–	1	
Total			15	13	21	18	2	2	3	3	4	5	3	4	92
HOT WATER SHORTFALL		MWH	–	–	–	–	–	–	–	–	–	–	–	–	
Assumed Equivalent Cost	$/MWH	$10 00													
SUPPLEMENTAL HOT WATER COST – $(000)			–	–	–	–	–	–	–	–	–	–	–	–	–
Water and Other Variable O&M Expenses – Boilers $(000)															
	Basis $/MWHtw	Basis $/MWH	Variable O&M Expense $(000)												
	–	–	–	–	–	–	–	–	–	–	–	–	–	–	
	–	–	–	–	–	–	–	–	–	–	–	–	–	–	
Brewery	$0 10	$0 41	0	0	–	–	–	–	–	–	–	–	–	–	
Plzen V	$0 10	$0 41	8	7	2	2	–	–	–	–	–	–	–	–	
Plzen IIb	$0 10	$0 41	146	125	214	186	24	–	42	–	60	–	45	–	
Plzen IVb and Plzen IVc	$0 10	$0 41	73	63	119	104	–	31	–	54	–	103	–	76	
Plzen IIa	$0 10	$0 41	32	27	19	17	13	–	23	–	33	–	24	–	
Plzen IVa	$0 10	$0 41	92	79	134	117	–	23	–	39	–	54	–	40	
Total			351	300	488	424	37	54	65	94	93	157	69	116	2,249
Limestone and Ash Removal Expenses – Boilers $(000)															
	Limestone $/MMBTU	Removal $/MMBTU	Limestone Injection & Ash Removal Expenses $(000)												
	–	–	–	–	–	–	–	–	–	–	–	–	–	–	
	–	–	–	–	–	–	–	–	–	–	–	–	–	–	
Brewery	–	–	–	–	–	–	–	–	–	–	–	–	–	–	
Plzen V	–	–	–	–	–	–	–	–	–	–	–	–	–	–	
Plzen IIb	–	0 072	50	43	69	60	8	–	14	–	20	–	14	–	
Plzen IVb and Plzen IVc	0 212	0 133	85	73	142	123	–	35	–	61	–	106	–	79	
Plzen IIa	–	0 072	5	5	3	3	2	–	4	–	6	–	4	–	
Plzen IVa	0 212	0 133	72	62	105	91	–	18	–	31	–	42	–	31	
Total			213	182	318	277	10	53	18	92	25	149	19	110	1 465
Removal Costs Only			118	100	167	145	10	20	18	36	25	57	19	42	756
By–Product Sales $(000)			48	41	67	58	5	7	9	12	13	19	9	14	300
Emissions Penalties – Boilers $(000)															
		Emissions $/MMBTU	Emissions Penalties $(000)												
		–	–	–	–	–	–	–	–	–	–	–	–	–	
		–	–	–	–	–	–	–	–	–	–	–	–	–	
Brewery		–	–	–	–	–	–	–	–	–	–	–	–	–	
Plzen V		–	–	–	–	–	–	–	–	–	–	–	–	–	
Plzen IIb		–	–	–	–	–	–	–	–	–	–	–	–	–	
Plzen IVb and Plzen IVc		–	–	–	–	–	–	–	–	–	–	–	–	–	
Plzen IIa		–	–	–	–	–	–	–	–	–	–	–	–	–	
Plzen IVa		–	–	–	–	–	–	–	–	–	–	–	–	–	
Total			–	–	–	–	–	–	–	–	–	–	–	–	–
Emissions by Type – Tons															
		Units per Ton	Emissions – Tons												
Particulate		2000	23 3	20 0	32 5	28 3	2 6	3 0	4 5	5 2	6 5	8 4	4 8	6 2	145 3
SO_2		2000	546 1	467 7	746 0	649 0	71 1	50 1	124 9	87 7	179 7	141 9	132 7	104 8	3 301 6
NOx		2000	209 2	179 2	276 6	240 6	21 8	28 6	38 2	50 2	55 0	87 3	40 6	64 5	1 291 9
CO		2000	8 9	7 6	12 2	10 6	0 9	1 0	1 6	1 7	2 3	2 9	1 7	2 2	53 7

VARIANT B1 — ELECTRIC GENERATION AND NET POWER INTERCHANGE – YEAR 2010 — High Dema

	WINTER				SUMMER								
	Peak	High	Low	Weekend	Peak 1	Peak 2	High 1	High 2	Low 1	Low 2	Wkend 1	Wkend 2	
Avg KW Required – Pumping	3020	3020	2567	2567	1036	364	1036	364	812	310	812	310	1676
Sta Use	8899	8897	7625	7627	4936	2867	4936	2862	3825	2286	3825	2286	5701
Total	11919	11917	10192	10194	5973	3231	5973	3226	4637	2595	4637	2595	7377

BACK PRESSURE TURBINE/GENERATOR OUTPUT – AVERAGE KW

BASIS UNITe	Back Pressure Turbine/Generator Output & Contract Purchase												
	–	–	–	–	–	–	–	–	–	–	–	–	
	–	–	–	–	–	–	–	–	–	–	–	–	
	–	–	–	–	–	–	–	–	–	–	–	–	
	–	–	–	–	–	–	–	–	–	–	–	–	
Turb IB	52380	52387	53220	53244	47263	–	47263	–	36210	–	36209	–	
Turb IA	2620	2613	1345	1346	4662	–	4662	–	3059	–	3059	–	
Turb IIB	14362	14363	16217	16215	–	16712	–	16712	–	11953	–	11953	
Turb IIA	8650	8649	7950	7950	–	6089	–	6036	–	4199	–	4199	
Total T/G Output	78011	78013	78731	78756	51924	22802	51925	22749	39270	16152	39269	16152	53923
Balance Required	–66093	–66096	–68540	–68561	–45952	–19571	–45952	–19523	–34633	–13557	–34632	–13557	

CONDENSING TURBINE OUTPUT – AVERAGE KW

	Generator Efficiency	Condensing Turbine Output – KW												
		–	–	–	–	–	–	–	–	–	–	–	–	–
		–	–	–	–	–	–	–	–	–	–	–	–	–
		–	–	–	–	–	–	–	–	–	–	–	–	–
		–	–	–	–	–	–	–	–	–	–	–	–	–
		–	–	–	–	–	–	–	–	–	–	–	–	–
Turb IIC	96 0%	6777	6777	6389	6390	–	9362	–	9460	–	12128	–	12128	1 042
		–	–	–	–	–	–	–	–	–	–	–	–	–
		–	–	–	–	–	–	–	–	–	–	–	–	–
Total Condens Turb Output		6777	6777	6389	6390	–	9362	–	9460	–	12128	–	12128	6790
Balance Required		–72870	–72872	–74929	–74951	–45952	–28933	–45952	–28963	–34633	–25685	–34632	–25685	
GT Capability @ Full Load		49627	49627	49627	49627	47720	46233	47720	46233	47720	46233	47720	46233	

GAS TURBINE OUTPUT – AVERAGE KW

	Gas Turbine Output – KW												
	–	–	–	–	–	–	–	–	–	–	–	–	
	–	–	–	–	–	–	–	–	–	–	–	–	
	–	–	–	–	–	–	–	–	–	–	–	–	
	–	–	–	–	–	–	–	–	–	–	–	–	
	–	–	–	–	–	–	–	–	–	–	–	–	
	–	–	–	–	–	–	–	–	–	–	–	–	
Total GT Output (KW)	–	–	–	–	–	–	–	–	–	–	–	–	–
Balance Required (KW)	–72870	–72872	–74929	–74951	–45952	–28933	–45952	–28963	–34633	–25685	–34632	–25685	
Hours in Period	914	783	1435	1248	181	306	318	535	589	994	435	734	
Balance Required (MWH)	–63953	–54790	–102220	–88930	–8317	–5989	–14613	–10445	–20399	–13476	–15065	–9951	
PURCHASED POWER	75%	75%	75%	75%	75%	75%	75%	75%	75%	75%	75%	75%	
Peak Demand KW	–	–	–	–	–	–	–	–	–	–	–	–	
Demand Charge – $/KW	7 93	7 93	7 93	7 93	7 93	7 93	7 93	7 93	7 93	7 93	7 93	7 93	
Energy Charge – $/KWH	0 0350	0 0279	0 0246	0 0246	0 0350	0 0350	0 0279	0 0279	0 0246	0 0246	0 0246	0 0246	
Demand Charge – $(000)	–	–	–	–	–	–	–	–	–	–	–	–	
Energy Charge – $(000)	–	–	–	–	–	–	–	–	–	–	–	–	
Total – $(000)	–	–	–	–	–	–	–	–	–	–	–	–	–
POWER SALES													
Energy Credit – Cents/KWH	0 0350	0 0279	0 0246	0 0246	0 0350	0 0350	0 0279	0 0279	0 0246	0 0246	0 0246	0 0246	
Energy Credit $(000)	2238 3	1526 3	2519 0	2191 5	291 1	209 6	407 1	291 0	502 7	332 1	371 2	245 2	11125 1

hch

VARIANT B1 HEAT REJECTION – YEAR 2010 High Dema

	WINTER				SUMMER							
	Peak	High	Low	Weekend	Peak 1	Peak 2	High 1	High 2	Low 1	Low 2	Wkend 1	Wkend 2

Interpolated Exhaust Temperature °F

	Exhaust Temperature °F											
	–	–	–	–	–	–	–	–	–	–	–	–
	–	–	–	–	–	–	–	–	–	–	–	–
	–	–	–	–	–	–	–	–	–	–	–	–
	–	–	–	–	–	–	–	–	–	–	–	–
	–	–	–	–	–	–	–	–	–	–	–	–
	–	–	–	–	–	–	–	–	–	–	–	–

Interpolated Exhaust Flow M#/Hr

	Exhaust Flow M#/Hr											
	–	–	–	–	–	–	–	–	–	–	–	–
	–	–	–	–	–	–	–	–	–	–	–	–
	–	–	–	–	–	–	–	–	–	–	–	–
	–	–	–	–	–	–	–	–	–	–	–	–
	–	–	–	–	–	–	–	–	–	–	–	–
	–	–	–	–	–	–	–	–	–	–	–	–

Available Exhaust Heat MMBTU/Hr

	Exhaust Heat MMBTU/Hr											
	–	–	–	–	–	–	–	–	–	–	–	–
	–	–	–	–	–	–	–	–	–	–	–	–
	–	–	–	–	–	–	–	–	–	–	–	–
	–	–	–	–	–	–	–	–	–	–	–	–
	–	–	–	–	–	–	–	–	–	–	–	–
	–	–	–	–	–	–	–	–	–	–	–	–

Steam Available – MW per Hour (Without Supplementary Firing)

	Enthalpy Rise	Total Steam Available without Supplementary Firing M#/Hr											
	–	–	–	–	–	–	–	–	–	–	–	–	–
	–	–	–	–	–	–	–	–	–	–	–	–	–
	–	–	–	–	–	–	–	–	–	–	–	–	–
	–	–	–	–	–	–	–	–	–	–	–	–	–
	–	–	–	–	–	–	–	–	–	–	–	–	–
	3 412	–	–	–	–	–	–	–	–	–	–	–	–
		–	–	–	–	–	–	–	–	–	–	–	–

Supplementary Firing – Maximum Exhaust Heat MMBTU/Hr

	–	–	–	–	–	–	–	–	–	–	–	–	–
	–	–	–	–	–	–	–	–	–	–	–	–	–
	–	–	–	–	–	–	–	–	–	–	–	–	–
	–	–	–	–	–	–	–	–	–	–	–	–	–
	–	–	–	–	–	–	–	–	–	–	–	–	–
	–	–	–	–	–	–	–	–	–	–	–	–	–

Steam Rejection – Avg MW (To Cooling Tower)

	Maximum Capacity	Steam Rejection – Average MW											
From Condensing	25 000	14 0	14 0	13 2	13 2	–	19 3	–	19 5	–	25 0	–	25 0
From Gas Turbines	25 000	–	–	–	–	–	–	–	–	–	–	–	–
Total		14 0	14 0	13 2	13 2	–	19 3	–	19 5	–	25 0	–	25 0

VARIANT B1

PROJECTED FINANCIAL COSTS AND HOT WATER REVENUE REQUIREMENTS

High Demand

FINANCIAL COST (000) (Including Inflation)

	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
ACCRUAL BASIS	(Exclusive of Interest Expense if any and Depreciation Charges related to existing plant (Production Transmission Distribution et al)																	
Operating Expenses																		
Operation & Maintenance	5 544	6 234	6 922	12 534	16 666	14 022	15 474	17 753	18 378	19 485	20 703	22 623	22 290	28 447	24 795	26 337	28 898	30 477
Depreciation Expense	8	44	1 186	2 357	2 383	2 397	2 412	2 428	2 430	2 432	2 666	2 912	2 915	2 917	2 919	2 921	2 924	2 926
Total Operating Expenses	5 552	6 277	8 108	14 891	19 049	16 419	17 885	20 181	20 808	21 916	23 369	25 535	25 205	31 364	27 713	29 258	31 822	33 403
Interest Expense	9	57	1 369	3 895	4 973	4 575	4 107	3 576	2 959	2 247	1 714	1 478	1 330	1 203	1 068	924	769	600
Equity Return	9	9	55	1 379	2 735	2 767	2 784	2 803	2 823	2 825	2 828	3 121	3 428	3 432	3 434	3 437	3 440	3 443
Total Expense & Return	5 570	6 344	9 532	20 166	26 756	23 760	24 776	26 560	26 589	26 989	27 912	30 133	29 964	35 998	32 216	33 619	36 030	37 446
Income Tax Effect @ 45%	8	8	45	1 129	2 238	2 264	2 278	2 293	2 309	2 312	2 314	2 553	2 805	2 808	2 810	2 812	2 814	2 817
Total Cost	5,577	6,352	9,576	21,295	28,994	26,023	27,054	28,853	28,899	29,301	30,226	32,687	32,769	38,806	35,026	36,431	38,845	40,263
Estimated Hot Water Revenue Requirement	(Exclusive of Interest Expense if any and Depreciation Charges related to existing plant (Production Transmission Distribution et al)																	
Total Cost (Above) less																		
Cost of Steam																		
Operation & Maintenance	4 251	4 632	4 933	6 298	6 570	7 615	7 644	8 970	8 807	9 418	9 613	10 360	8 990	9 439	9 911	10 406	10 925	11 471
Allocated Depreciation	3	16	432	747	749	751	754	757	756	756	827	902	901	901	900	900	900	900
Allocated Return	4	4	20	437	860	867	870	874	879	878	877	966	1 060	1 060	1 059	1 059	1 059	1 059
Income Tax Effect	3	3	16	358	704	710	712	715	719	718	718	791	867	867	867	867	867	867
Total Steam	4 260	4 654	5 401	7 840	8 883	9 943	9 980	11 315	11 161	11 770	12 035	13 019	11 817	12 266	12 737	13 232	13 751	14 297
Equals Cost of Hot Water	1 317	1 697	4 175	13 455	20 111	16 080	17 074	17 538	17 737	17 531	18 190	19 668	20 951	26 540	22 288	23 199	25 093	25 966
HOT WATER – $/MWH	$2 46	$3 07	$7 28	$17 31	$25 54	$20 33	$21 50	$21 99	$22 20	$21 91	$22 69	$24 50	$26 05	$32 96	$27 64	$28 73	$31 04	$32 07
Present Worth	$2 46	$2 62	$5 31	$10 81	$13 63	$9 27	$8 38	$7 33	$6 32	$5 33	$4 72	$4 36	$3 96	$4 28	$3 07	$2 73	$2 52	$2 22
Levelized Cost to Date		$3 07	$5 01	$8 49	$11 80	$13 02	$13 94	$14 62	$15 14	$15 51	$15 83	$16 15	$16 45	$16 87	$17 10	$17 30	$17 51	$17 69
CASH BASIS	(Exclusive of Debt Service related to existing plant (Production Transmission Distribution et al)																	
O & M Expenses	5 544	6 234	6 922	12 534	16 666	14 022	15 474	17 753	18 378	19 485	20 703	22 623	22 290	28 447	24 795	26 337	28 898	30 477
Equity Return	9	9	55	1 379	2 735	2 767	2 784	2 803	2 823	2 825	2 828	3 121	3 428	3 432	3 434	3 437	3 440	3 443
Debt Service																		
Foreign Interest	–	–	82	251	333	326	317	308	299	288	277	264	251	236	221	204	186	166
Principal	–	–	–	44	95	102	111	120	129	140	151	164	177	191	207	224	242	262
Total	–	–	82	295	428	428	428	428	428	428	428	428	428	428	428	428	428	428
Domestic Interest	9	57	1 287	3 645	4 639	4 249	3 789	3 268	2 661	1 959	1 438	1 213	1 080	966	848	720	583	434
Principal	–	11	67	1 670	3 508	3 980	4 493	5 070	5 721	6 402	7 059	4 233	982	1 010	1 084	1 165	1 252	1 402
Total	9	69	1 354	5 315	8 147	8 229	8 282	8 338	8 382	8 362	8 497	5 446	2 062	1 977	1 932	1 885	1 835	1 836
Total Cost before Income Tax	5 562	6 312	8 413	19 523	27 976	25 445	26 968	29 322	30 010	31 099	32 456	31 618	28 208	34 283	30 589	32 086	34 600	36 183
Income Tax Effect @ 45%	8	8	45	1 129	2 238	2 264	2 278	2 293	2 309	2 312	2 314	2 553	2 805	2 808	2 810	2 812	2 814	2 817
Total Financial Cost	5,570	6,319	8,458	20,652	30,214	27,708	29,246	31,615	32,320	33,411	34,770	34,171	31,013	37,091	33,398	34,898	37,415	39,000

APPENDIX F: (Cont'd) GILBERT/COMMONWEALTH ECONOMIC ANALYSIS MODEL RESULTS AND DETAIL:

Variant C1: (Base case - existing plants with a CFB Boiler in the year 2003)

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VARIANT C1 | PROJECTED OPERATING AND CAPITAL EXPENDITURES | High Demand

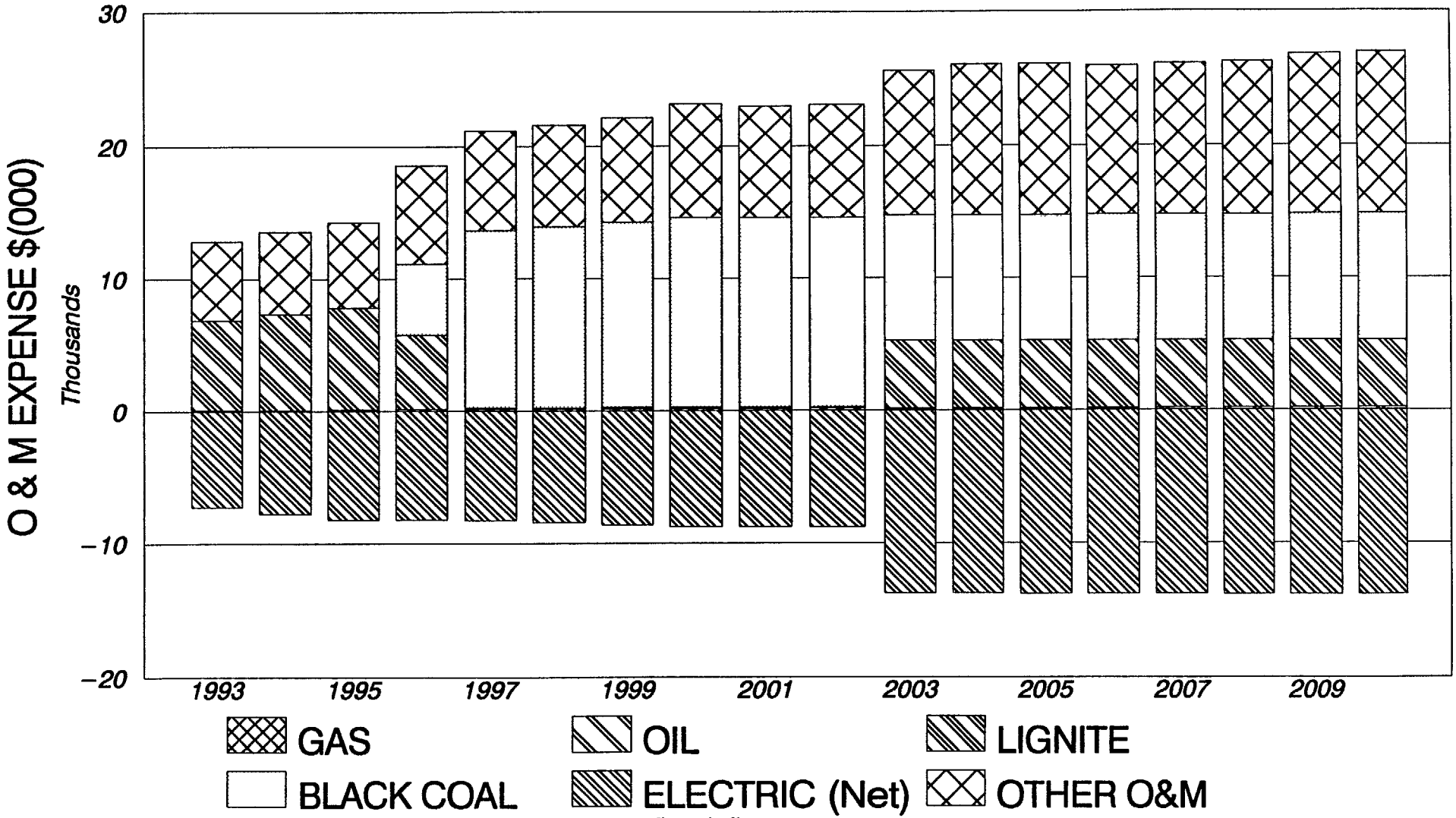
COST EXCL INFLATION (000)

	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
OPERATING EXPENSES																		
Fuel Cost – Natural Gas	–	–	–	105	107	115	123	132	134	136	5	5	5	6	6	6	6	6
Oil	62	68	74	15	99	103	106	109	109	109	129	129	129	129	129	129	129	129
Lignite	6 790	7 255	7 752	5 631	–	–	–	–	–	–	5 128	5 128	5 129	5 129	5 130	5 130	5 131	5 131
Black Coal	–	–	–	5 370	13 436	13 727	14 022	14 328	14 343	14 354	9 455	9 468	9 480	9 493	9 506	9 519	9 531	9 544
Total Fuel Cost	6 852	7 323	7 827	11 121	13 643	13 945	14 251	14 569	14 586	14 599	14 716	14 730	14 743	14 757	14 770	14 784	14 797	14 811
Supplemental Cost (Shortfall)	–	–	0	–	–	–	–	–	–	–	0	–	–	0	–	0	–	–
Purchased Power Cost	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
Credit for Power Sales	(7,290)	(7 768)	(8,216)	(8,225)	(8,291)	(8 450)	(8 616)	(8 784)	(8 786)	(8 788)	(13 768)	(13 775)	(13 784)	(13 795)	(13 805)	(13 812)	(13 823)	(13 833)
Net Power Interchange	(7,290)	(7 768)	(8,216)	(8,225)	(8,291)	(8 450)	(8 616)	(8 784)	(8 786)	(8 788)	(13 768)	(13 775)	(13 784)	(13 795)	(13 805)	(13 812)	(13 823)	(13 833)
Fixed O&M and Overheads	2 300	2 300	2 300	2 510	2 510	2 510	2 510	2 510	2 510	2 510	2 592	2 592	2 592	2 592	2 592	2 592	2 592	2 592
Other Variable O & M	1 457	1 473	1 486	1 642	1 650	1 652	1 654	1 657	1 657	1 658	2 242	2 243	2 243	2 244	2 246	2 247	2 248	2 249
Sorbent and Ash Removal	245	285	331	651	697	699	700	1 193	1 194	1 195	2 636	2 637	2 638	2 639	2 641	2 642	2 643	2 644
Credit By-Product Sales	–	–	–	(197)	(235)	(236)	(236)	(237)	(237)	(237)	(305)	(305)	(305)	(305)	(306)	(306)	(306)	(306)
Emission Penalties	24	48	49	25	–	–	–	–	–	–	–	–	–	–	–	–	–	–
Maintenance Expenses	1 956	2 137	2 268	2 801	2 890	2 993	3 247	3 447	3 265	3 369	3 696	4 163	4 205	4 031	4 156	4 291	4 819	4 898
Plant Removal Costs	–	–	–	–	–	–	–	–	–	–	–	–	3 517	–	–	–	–	–
Total O&M Expense	5 544	5 799	6 046	10 328	12 864	13 113	13 510	14 356	14 191	14 306	11 809	12 285	15 849	12 163	12 293	12 437	12 971	13 055
CAPITAL COSTS																		
Foreign	–	–	–	–	–	–	–	–	2203	2225	–	–	–	–	–	–	–	–
Domestic	190	839	6367	5558	494	259	259	259	17314	17314	33	33	33	25	25	25	25	25
Total	190	839	6367	5558	494	259	259	259	19516	19538	33	33	33	25	25	25	25	25
TOTAL COST	5,734	6,637	12,413	15,886	13,358	13,371	13,769	14,615	33,707	33,844	11,842	12,318	15,883	12,188	12,318	12,463	12,996	13,080
Present Worth	5 517	5 914	10 240	12 135	9 448	8 757	8 349	8 206	17 523	16 292	5 278	5 083	6 069	4 312	4 036	3 780	3 650	3 402
Cumulative Present Worth	5 517	11 431	21 671	33 806	43 253	52 010	60 359	68 565	86 088	102 380	107 658	112 742	118 811	123 123	127 159	130 939	134 589	137 991

OPERATING STATISTICS

	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
TOTAL PRODUCTION – MWH																		
LP Steam	333 355	331 188	329 021	360 443	361 165	361 165	361 165	361 165	361 165	360 804	360 443	360 082	359 720	359 720	359 720	359 720	359 720	359 720
Hot Water	534 466	552 841	573 853	777 066	787 452	790 913	794 109	797 571	798 903	800 234	801 537	802 897	804 229	805 294	806 359	807 424	808 489	809 555
Electricity	306 534	312 254	315 750	312 792	313 693	313 980	314 244	314 530	314 641	314 730	468 253	468 616	468 978	469 351	469 725	470 099	470 472	470 846
COST OF PRODUCTION – $/MWH (Variable Costs only)																		
LP Steam	$10 46	$10 77	$11 08	$12 38	$13 68	$13 84	$14 01	$14 70	$14 69	$14 69	$13 00	$13 00	$13 00	$13 00	$13 00	$12 99	$12 99	$12 99
Hot Water	$8 56	$8 85	$9 15	$10 08	$11 99	$12 17	$12 36	$12 81	$12 81	$12 81	$11 84	$11 84	$11 84	$11 84	$11 84	$11 84	$11 84	$11 84
Electricity	$9 20	$9 51	$9 81	$11 06	$12 39	$12 56	$12 74	$13 25	$13 25	$13 25	$16 45	$16 45	$16 44	$16 44	$16 43	$16 43	$16 42	$16 41
NOT SERVED – MWH																		
LP Steam	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
Hot Water	–	–	26	–	–	–	–	–	–	–	28	–	–	0	–	0	–	–
Electricity	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
EMISSIONS – TONNES																		
Particulates	248	259	272	416	98	98	98	98	98	98	132	132	132	132	132	132	133	133
SO_2	5 745	5 854	5 965	3 620	3 027	3 035	3 042	3 049	3 052	3 054	3 055	3 058	3 061	3 064	3 067	3 069	3 072	3 075
NOx	1 373	1 398	1 423	1 605	1 621	1 624	1 627	1 631	1 632	1 633	1 608	1 610	1 611	1 613	1 614	1 616	1 617	1 618
CO	56	59	62	144	146	147	148	149	149	150	78	78	78	78	79	79	79	79

PROJECTED OPERATING & MAINTENANCE COSTS – VARIANT C1



NOTE Costs include Real Escalation only and do not reflect Inflation

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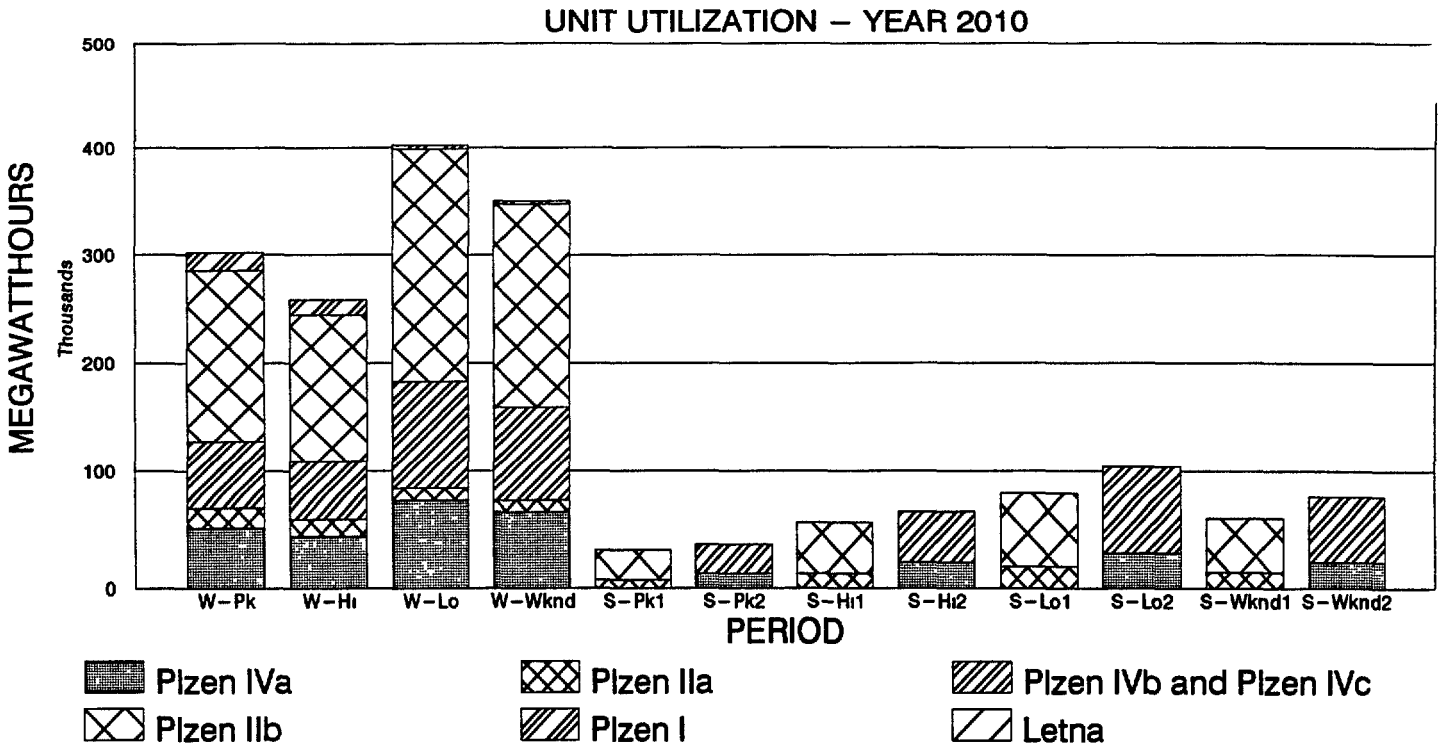
CASE C1 — Test Year = 2010

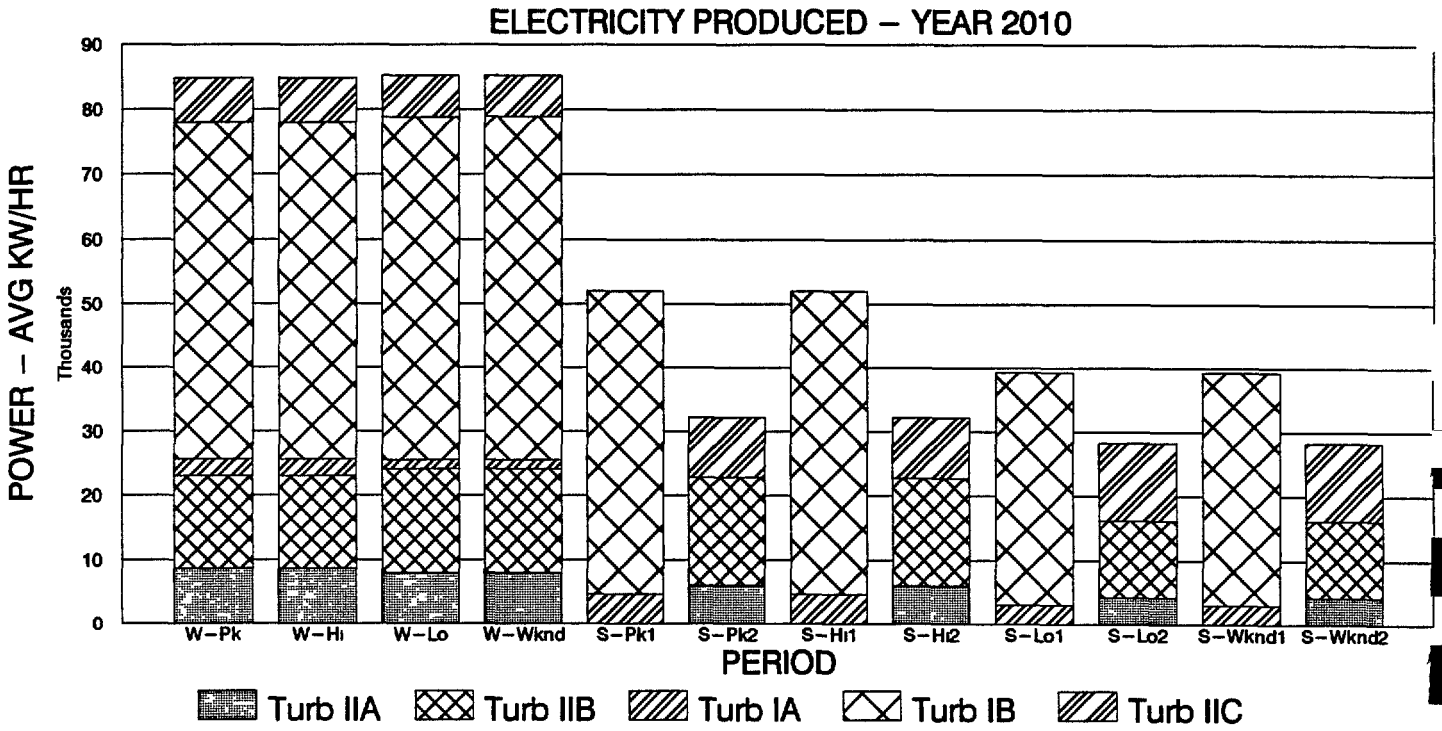
Station Use Unaccounted for etc — Electric kW – — % of Demand: Water –, Steam –

Facilities Data

DESCRIPTION	UNIT	BASIS	EXISTING FACILITIES: Pizen I	Brewery	Pizen IIa	Pizen IIb	Kosutka	Leine	NEW FACILITIES: Pizen III	Pizen IVa Extract	Pizen IVb Exhaust	Pizen IVc Rejection	Cooling	Steam Purchase	Power Purchase	Power Sales
THERMAL DATA																
Efficiency – 80% to Full Load	%1		79 6%	86 0%	84 0%	84 0%	91 0%	91 1%	91 1%	87 0%	87 0%	87 0%				
Half Load	%2		79 6%	86 0%	84 0%	84 0%	91 0%	91 1%	91 1%	87 0%	87 0%	87 0%				
Minimum Load	%3		79 6%	86 0%	84 0%	84 0%	91 0%	91 1%	91 1%	87 0%	87 0%	87 0%				
Minimum Operation	%		10 0%	7 3%	–	25 0%	12.5%	25 0%	25 0%	–	40 0%					
Feedwater Temp																
Operation Adjustment Factor	Factor		0 095	0 065	0 085	0 095	0 065	0 065	0 040	0 050	0 060	0 065				
BOILER OUTPUT	Boiler MW										120 000					
Quantity	Mlb/Hr				749 700											
Pressure	PSIA				1976											
Temperature	Temp °F				1004											
Enthalpy	MBTU/lb				1 477											
PRODUCT – LP STEAM	Priority	*		7	2					1						
Quantity	Mlb/Hr				116,204				143,300	110 000						
	MWts			56 100	100 000	165 000			43 500	47 000	115 000					
Pressure	PSIA				152				189							
Temperature	Temp °F				428				428							
Enthalpy	MBTU/lb				1 230				1 230							
PRODUCT – HOT WATER	Priority		5	7		4	8	6			3		Cooling			
Quantity	MWtw		105 000	56 100		165 000	34 800	23 200	43 500		75 000		25 000			
Temperature – Supply	Temp °F		320°			320°					320°					
Return	Temp °F		158			158					158					
TURBINE DATA	UNITe				Turb IA	Turb IB				Turb IIA	Turb IIB	Turb IIC				
	Priority				3	4				1	2				Purchase	Yes
Rated Capacity–Electric	KW				19720	55000				8800	25900				as Req d	
Capability – Max Steam	KW1				19720	55000				8800	25900					
75 % Steam	KW75				14060	40200				6280	18930					
50 % Steam	KW50				8430	25420				3760	11970					
25% Steam	KW25				2780	10620				1240	5000					
Steam Required – Maximum	M#/Hr Max				308 644	365.900				137 700	172.300					
Minimum	M#/Hr Min					91 500					43 000					
Outlet Steam Pressure	PSI				189	17 4				189	17 4					
Enthalpy Drop – Turbine	MBTU/lbt				0 2588	0 4157				0 2588	0 4157					
Sink	MBTU/lbs				1 1646	0 9146				1 1646	0 9700					
Generator Efficiency	%g				96 5%	96 5%				96 0%	96 0%	96 0%				
Power Ratio	Factor											0 3357				
FUELS DATA																
Primary Fuel	Type		Coal	Gas	Coal	Coal	Gas	Gas	Gas	Lignite	Lignite					
Cost	$/MMBTU		$2.31	$3 77	$1 96	$1 96	$3 77	$3 77	$3 77	$1 24	$1 24					
Percent Use	% Use		99 6%	100 0%	99 6%	99 6%	100.0%	100 0%	55 0%	99 6%	99 6%					
Secondary/Supplemental Fuel	Type		Oil		Oil	Oil			Oil	Oil	Oil					
Cost	$/MMBTU		$2 99		$2.99	$2 99			$2 99	$2 99	$2 99					
Percent Use	% Use		0 4%		0 4%	0 4%			45 0%	0 4%	0 4%					
COST DATA (1993 Basis)	CK/$ =	28														
Number of Personnel	Number	92	40	30	160	–	8	12	8	56						
Average Wage & Benefits	$(000)	4 2	4 2	4 2	4 2	–	4 2	4 2	4 2	4 2						
Other Fixed Costs	$(000)	$879														
Raw Water & Treating Costs	$/MWHw	$0 10														
Demineralized Water Costs	$/MWHs	$1 41														
Other Variable O&M Costs	$/MWH	$0 41														
Limestone	$/Ton'	11 01														
Waste Disposal Costs	$/Ton	$3 24														
Emissions Code	CODEe		ST–3B2	ST–2A8	PC–2B3	PC–2B3	ST–3A8	ST–3A7	ST–3A8	FB–2B4	FB–2B4	FB–2B4				
Unscheduled Maintenance	CODE m		P1	BR	P2	T1	K	L2	P3	P4FB1	T2					
Cost per Episode	Unit $(000)		2 0	2 0	2.0	1 0	2 0	2 0	2 0	2 5	1 0					
Purchased Power	$/kW														$7 93	
Energy Charge – Peak	Cents/KWHw															
Off–Peak	Cents/KWHs															
MONTHLY DATA	Avg Temp °C		AVAILABILITY												CK	US$
W–Pk	3 0		100%	100%	100%	100%	100%	100%	100%	100%	100%	100%			980	$35.00
W–Hi	3 0		100%	100%	100%	100%	100%	100%	100%	100%	100%	100%			780	27 86
W–Lo	3 0		100%	100%	100%	100%	100%	100%	100%	100%	100%	100%			690	24 64
W–Wknd	3 0		100%	100%	100%	100%	100%	100%	100%	100%	100%	100%			690	24 64
S–Pk1	11 6		100%	100%	100%	100%	100%	100%	100%	–	–	–			980	35 00
S–Pk2	18 3		100%	100%	100%	100%	100%	100%	100%	100%	100%	100%			980	35 00
S–Hi1	11 6		100%	100%	100%	100%	100%	100%	100%	–	–	–			780	27 86
S–Hi2	18 3		100%	100%	100%	100%	100%	100%	100%	100%	100%	100%			780	27 86
S–Lo1	11 6		100%	100%	100%	100%	100%	100%	100%	–	–	–			690	24 64
S–Lo2	18 3		100%	100%	100%	100%	100%	100%	100%	100%	100%	100%			690	24 64
S–Wknd1	11 6		100%	100%	100%	100%	100%	100%	100%	–	–	–			690	24 64
S–Wknd2	18 3		100%	100%	100%	100%	100%	100%	100%	100%	100%	100%			690	24 64

TEST YEAR SIMULATION RESULTS	WINTER: Peak	High	Low	Weekend	SUMMER: Peak 1	Peak 2	High 1	High 2	Low 1	Low 2	Wkend 1	Wkend 2	TOTAL
OPERATING EXPENSES													
Natural Gas	3	2	–	–	–	–	–	–	–	–	–	–	5
Oil	16	13	21	18	2	2	3	3	4	5	3	4	94
Lignite	561	480	881	786	–	188	–	329	–	532	–	393	4 129
Black Coal	1,699	1,455	2,003	1,743	273	–	480	–	690	–	510	–	8 854
Total Fuel Cost	2 278	1 951	2 905	2 527	275	190	483	332	695	537	513	396	13 081
Supplemental Cost–Shortfall Penalty'	–	–	–	–	–	–	–	–	–	–	–	–	–
Purchased Power Cost	–	–	–	–	–	–	–	–	–	–	–	–	–
Credit for Power Sales	(2 238)	(1,526)	(2,522)	(2,194)	(291)	(210)	(407)	(291)	(503)	(332)	(371)	(245)	(11 130)
Net Power Interchange Cost	(2 238)	(1 526)	(2 522)	(2 194)	(291)	(210)	(407)	(291)	(503)	(332)	(371)	(245)	(11 130)
Other O&M – Fixed OH & Other	280	240	439	382	55	94	97	164	160	304	133	225	2 592
Variable	351	300	488	425	37	54	65	94	93	157	69	116	2 249
Limestone Injection & Ash Removal	218	187	320	278	10	53	18	92	25	149	19	110	1 477
Credit for By–Product Sales	(50)	(43)	(68)	(59)	(5)	(7)	(9)	(12)	(13)	(19)	(9)	(14)	(306)
Emissions Penalties	–	–	–	–	–	–	–	–	–	–	–	–	–
Total Excluding Maintenance	838	1,108	1,562	1,359	81	173	247	379	478	–	353	588	7 963


UNIT UTILIZATION – YEAR 2010
MEGAWATTHOURS
Thousands
500
400
300
200
100
0
W–Pk
W–Hi
W–Lo
W–Wknd
S–Pk1
S–Pk2
S–Hi1
S–Hi2
S–Lo1
S–Lo2
S–Wknd1
S–Wknd2
PERIOD
Plzen IVa
Plzen IIa
Plzen IVb and Plzen IVc
Plzen IIb
Plzen I
Letna


ELECTRICITY PRODUCED – YEAR 2010
POWER – AVG KW/HR
Thousands
90
80
70
60
50
40
30
20
10
0
W–Pk
W–Hi
W–Lo
W–Wknd
S–Pk1
S–Pk2
S–Hi1
S–Hi2
S–Lo1
S–Lo2
S–Wknd1
S–Wknd2
PERIOD
Turb IIA
Turb IIB
Turb IA
Turb IB
Turb IIC

VARIANT C1

			WINTER				SUMMER								
			Peak	High	Low	Weekend	Peak 1	Peak 2	High 1	High 2	Low 1	Low 2	Wkend 1	Wkend 2	
PRODUCT – LP STEAM															
Customer Requirement	MWH		58007	49652	71302	62027	6354	10515	11165	18251	16260	25394	12023	18752	35972
Station Use	MWH	–	–	–	–	–	–	–	–	–	–	–	–	–	–
			58007	49652	71302	62027	6354	10515	11165	18251	16280	25394	12023	18752	35972
	2	3	4	5	6	7	8	9	10	11	12	13	14	15	
	MWts		Average Loading – MW												
	–		–	–	–	–	–	–	–	–	–	–	–	–	
Brewery	56 100		–	–	–	–	–	–	–	–	–	–	–	–	
	–		–	–	–	–	–	–	–	–	–	–	–	–	
	–		–	–	–	–	–	–	–	–	–	–	–	–	
	–		–	–	–	–	–	–	–	–	–	–	–	–	
	–		–	–	–	–	–	–	–	–	–	–	–	–	
Pizen IIa	100 000		24 8	24 8	12 7	12 7	35 1	–	35 1	–	27 6	–	27 6	–	
Pizen IVa	47 000		48 3	48 3	43 0	43 0	–	34 4	–	34 1	–	25 5	–	25 5	
			Unit Energy Output – MWH (Before Adjustment for Minimum Loading Limitation)												
			–	–	–	–	–	–	–	–	–	–	–	–	
Brewery			–	–	–	–	–	–	–	–	–	–	–	–	
			–	–	–	–	–	–	–	–	–	–	–	–	
			–	–	–	–	–	–	–	–	–	–	–	–	
			–	–	–	–	–	–	–	–	–	–	–	–	
			–	–	–	–	–	–	–	–	–	–	–	–	
Pizen IIa			15688	13401	9546	8314	6354	–	11165	–	16280	–	12023	–	
Pizen IVa			42319	36251	61756	53713	–	10515	–	18251	–	25394	–	18752	
Total			58007	49652	71302	62027	6354	10515	11165	18251	16280	25394	12023	18752	35972
Steam Not Served	MWH		–	–	–	–	–	–	–	–	–	–	–	–	–
Total excluding HRSG supply			58007	49651 6	71301 6	62026 9	6354 48	10514.8	11165.2	18250 7	16279 6	25394	12022 7	18751 7	
PRODUCT – HOT WATER															
Customer Requirement	MWH		151236	129546	185986	161809	15432	10048	27113	17567	39429	24315	29119	17955	80955
Station Use	MWH	–	–	–	–	–	–	–	–	–	–	–	–	–	–
			151236	129546	185986	161809	15432	10048	27113	17567	39429	24315	29119	17955	80955
	2	3	4	5	6	7	8	9	10	11	12	13	14	15	
BASIS UNIT	MWtw		Average Loading – MW												
Kosutka	34 800		–	–	–	–	–	–	–	–	–	–	–	–	
Brewery	56 100		9 3	9 3	–	–	–	–	–	–	–	–	–	–	
Letna	23 200		7.2	7.2	–	–	–	–	–	–	–	–	–	–	
Pizen I	105 000		42.2	42.2	20 7	20 7	–	–	–	–	–	–	–	–	
Pizen IIb	165 000		118 9	118 9	95 6	95 6	85 3	–	85 3	–	66 9	–	66 9	–	
Pizen IVb	75 000		28 7	28 7	32 0	32 0	–	32 8	–	32 8	–	24 5	–	24 5	
	–		–	–	–	–	–	–	–	–	–	–	–	–	
	–		–	–	–	–	–	–	–	–	–	–	–	–	
Total			206 3	206.3	148.2	148.3	85.3	32.8	85 3	32.8	66 9	24 5	66 9	24 5	
			Unit Energy Output – MWH (Before Adjustment for Minimum Loading Limitation)												
Kosutka			–	–	–	–	–	–	–	–	–	–	–	–	
Brewery			27	23	–	–	–	–	–	–	–	–	–	–	
Letna			91	78	–	–	–	–	–	–	–	–	–	–	
Pizen I			16218	13861	2960	2586	–	–	–	–	–	–	–	–	
Pizen IIb			108668	93110	137157	119336	15432	–	27113	–	39429	–	29119	–	
Pizen IVb			26231	22474	45869	39887	–	10048	–	17567	–	24315	–	17955	
			–	–	–	–	–	–	–	–	–	–	–	–	
			–	–	–	–	–	–	–	–	–	–	–	–	
Total			151236	129546	185986	161809	15432	10048	27113	17567	39429	24315	29119	17955	80955
Hot Water Not Served	MWH		–	–	–	–	–	–	–	–	–	–	–	–	–
Total excluding HRSG supply			151236	129546	185986	161809	15432 4	10047 7	27113 3	17567	39428 6	24314.9	29119	17954 8	
ADJUSTED FOR MINIMUM LOADING – MWH															
Steam			Unit Utilization after Adjustment for Minimum Loading – MWH (Steam)												
			–	–	–	–	–	–	–	–	–	–	–	–	
Brewery			–	–	–	–	–	–	–	–	–	–	–	–	
			–	–	–	–	–	–	–	–	–	–	–	–	
			–	–	–	–	–	–	–	–	–	–	–	–	
			–	–	–	–	–	–	–	–	–	–	–	–	
			–	–	–	–	–	–	–	–	–	–	–	–	
Pizen IIa			15688	13401	9546	8314	6354	–	11165	–	16280	–	12023	–	
Pizen IVa			42319	36251	61756	53713	–	10515	–	18251	–	25394	–	18752	
Total			58007	49652	71302	62027	6354	10515	11165	18251	16280	25394	12023	18752	
Hot Water			Unit Utilization after Adjustment for Minimum Loading – MWH (Hot Water)												
Kosutka			–	–	–	–	–	–	–	–	–	–	–	–	
Brewery			27	23	–	–	–	–	–	–	–	–	–	–	
Letna			142	121	–	–	–	–	–	–	–	–	–	–	
Pizen I			16167	13818	3426	2992	–	–	–	–	–	–	–	–	
Pizen IIb			108668	93110	136891	118929	15432	–	27113	–	39429	–	29119	–	
Pizen IVb			26231	22474	45869	39887	–	10048	–	17567	–	24315	–	17955	
			–	–	–	–	–	–	–	–	–	–	–	–	
			–	–	–	–	–	–	–	–	–	–	–	–	
Total			151236	129546	185986	161809	15432	10048	27113	17567	39429	24315	29119	17955	

VARIANT C1

	WINTER				SUMMER								
	Peak	High	Low	Weekend	Peak 1	Peak 2	High 1	High 2	Low 1	Low 2	Wkend 1	Wkend 2	

TOTAL UNIT UTILIZATION BEFORE REQUIREMENT FOR ELECTRIC GENERATION – MWH

	Output to meet Steam and Hot Water Requirements – MWH												
Kosutka	–	–	–	–	–	–	–	–	–	–	–	–	
Brewery	27	23	–	–	–	–	–	–	–	–	–	–	
Letna	142	121	–	–	–	–	–	–	–	–	–	–	
Plzen I	16167	13818	3426	2992	–	–	–	–	–	–	–	–	
Plzen IIb	108668	93110	136691	118929	15432	–	27113	–	39429	–	29119	–	
Plzen IVb	26231	22474	45869	39887	–	10048	–	17567	–	24315	–	17955	
Plzen IIa	15688	13401	9546	8314	6354	–	11165	–	16280	–	12023	–	
Plzen IVa	42319	36251	61756	53713	–	10515	–	18251	–	25394	–	18752	
Total	209243	179197	257288	223836	21787	20563	38279	35818	55708	49709	41142	36706	116927

ADDITIONAL REQUIREMENT FOR BACK PRESSURE STEAM TURBINES – MWH

	Basis %g	Thermal output represented in electric generation – MWHt											
	–	–	–	–	–	–	–	–	–	–	–	–	–
	–	–	–	–	–	–	–	–	–	–	–	–	–
	–	–	–	–	–	–	–	–	–	–	–	–	–
	–	–	–	–	–	–	–	–	–	–	–	–	–
Turb IB	0 965	49611	42507	79251	68956	8865	–	15575	–	22101	–	16322	–
Turb IIB	0.96	13673	11715	24241	21080	–	5327	–	8314	–	12376	–	9139
Turb IA	0 965	1716	1466	1044	909	874	–	1536	–	1867	–	1379	–
Turb IIA	0 96	8235	7055	11883	10335	–	1941	–	3364	–	4348	–	3211
Total		73236	62742	116420	101280	9739	7268	17111	12678	23969	16724	17701	12349

STEAM TO CONDENSING TURBINES AND REJECTION – MWH

	Incremental thermal output represented in electric generation and rejection – MWHt											
	–	–	–	–	–	–	–	–	–	–	–	–
	–	–	–	–	–	–	–	–	–	–	–	–
	–	–	–	–	–	–	–	–	–	–	–	–
	–	–	–	–	–	–	–	–	–	–	–	–
	–	–	–	–	–	–	–	–	–	–	–	–
Turb IIC	19221	16465	28451	24745	–	8889	–	15705	–	37408	–	27623
	–	–	–	–	–	–	–	–	–	–	–	–
	–	–	–	–	–	–	–	–	–	–	–	–

UNIT UTILIZATION – TOTAL MWH

	Unit Utilization MWH											
Kosutka	–	–	–	–	–	–	–	–	–	–	–	–
Brewery	27	23	–	–	–	–	–	–	–	–	–	–
Letna	142	121	–	–	–	–	–	–	–	–	–	–
Plzen I	16167	13818	3426	2992	–	–	–	–	–	–	–	–
Plzen IIb	158279	135616	215942	187885	24297	–	42688	–	61530	–	45441	–
Plzen IVb and Plzen IVc	59126	50654	96561	85712	–	24264	–	42585	–	74099	–	54717
Plzen IIa	17404	14866	10590	9224	7229	–	12702	–	18147	–	13402	–
Plzen IVa	50554	43306	73639	64048	–	12456	–	21615	–	29742	–	21962
Total	301700	258405	402158	349661	31526	36720	55390	64200	79677	103841	58843	76679

INPUT ENERGY REQUIRED BEFORE EFFICIENCY ADJUSTMENT

	BTU/kW	Energy Input before Efficiency Adjustment – MMBTU											
Kosutka	3 412	–	–	–	–	–	–	–	–	–	–	–	–
Brewery	3 412	93	79	–	–	–	–	–	–	–	–	–	–
Letna	3 412	485	414	–	–	–	–	–	–	–	–	–	–
Plzen I	3 412	55163	47146	11689	10210	–	–	–	–	–	–	–	–
Plzen IIb	3 412	540048	462723	736794	641063	82902	–	145652	–	209941	–	155046	–
Plzen IVb and Plzen IVc	3 412	201738	172833	336291	292449	–	82789	–	145301	–	252826	–	186694
Plzen IIa	3 412	59364	50724	36134	31472	24665	–	43338	–	61917	–	45727	–
Plzen IVa	3 412	172490	147759	251255	218532	–	42499	–	73749	–	101479	–	74935
Total		1029401	881677	1372164	1193726	107567	125289	188969	219050	271858	354305	200773	261629

EFFICIENCY

	BASIS %1	BASIS %2	Efficiency											
Kosutka	–	–	91 0%	91 0%	91 0%	91 0%	91 0%	91 0%	91 0%	91 0%	91 0%	91 0%	91 0%	91 0%
Brewery	–	–	86 0%	86 0%	86 0%	86 0%	86 0%	86 0%	86 0%	86 0%	86 0%	86 0%	86 0%	86 0%
Letna	–	–	91 1%	91 1%	91 1%	91 1%	91 1%	91 1%	91 1%	91 1%	91 1%	91 1%	91 1%	91 1%
Plzen I	–	–	79 6%	79 6%	79 6%	79 6%	79 6%	79 6%	79 6%	79 6%	79 6%	79 6%	79 6%	79 6%
Plzen IIb	–	–	84 0%	84 0%	84 0%	84 0%	84 0%	84 0%	84 0%	84 0%	84 0%	84 0%	84 0%	84 0%
Plzen IVb and Plzen IVc	–	–	87 0%	87 0%	87 0%	87 0%	87 0%	87 0%	87 0%	87 0%	87 0%	87 0%	87 0%	87 0%
Plzen IIa	–	–	84 0%	84 0%	84 0%	84 0%	84 0%	84 0%	84 0%	84 0%	84 0%	84 0%	84 0%	84 0%
Plzen IVa	–	–	87 0%	87 0%	87 0%	87 0%	87 0%	87 0%	87 0%	87 0%	87 0%	87 0%	87 0%	87 0%

INPUT ENERGY REQUIRED

		Unit Energy Input MMBTU												
Kosutka	6 5%	–	–	–	–	–	–	–	–	–	–	–	–	
Brewery	8 5%	117	99	–	–	–	–	–	–	–	–	–	–	
Letna	6 5%	587	484	–	–	–	–	–	–	–	–	–	–	
Plzen I	9 5%	75894	64864	16083	14048	–	–	–	–	–	–	–	–	
Plzen IIb	9 5%	704088	603275	960586	835788	108084	–	189893	–	273710	–	202141	–	
Plzen IVb and Plzen IVc	6 0%	245830	210608	409792	356368	–	100884	–	177059	–	308084	–	227498	
Plzen IIa	8 5%	76705	65518	46672	40651	31859	–	55978	–	79977	–	59064	–	45[illegible]
Plzen IVa	5 0%	208178	178330	303239	263745	–	51292	–	89008	–	122475	–	90439	130[illegible]
Total		1311379	1123178	1736382	1510598	139942	152176	245871	266066	353687	430559	261205	317937	784[illegible]

			WINTER				SUMMER								
			Peak	High	Low	Weekend	Peak 1	Peak 2	High 1	High 2	Low 1	Low 2	Wkend 1	Wkend 2	

FUEL COST – BOILERS (Lignite)

	Lignite %	Weighted $/MMBTU	Fuel Cost – Lignite $(000)												
Kosutka	–	–	–	–	–	–	–	–	–	–	–	–	–	–	
Brewery	–	–	–	–	–	–	–	–	–	–	–	–	–	–	
Letna	–	–	–	–	–	–	–	–	–	–	–	–	–	–	
Pizen I	–	–	–	–	–	–	–	–	–	–	–	–	–	–	
Pizen IIb	–	–	–	–	–	–	–	–	–	–	–	–	–	–	
Pizen IVb and Pizen IVc	99 6%	$1 24	304	260	506	440	–	125	–	219	–	380	–	281	2515
Pizen IIa	–	–	–	–	–	–	–	–	–	–	–	–	–	–	
Pizen IVa	99 6%	$1 24	257	220	375	326	–	63	–	110	–	151	–	112	
Total			561	480	881	766	–	188	–	329	–	532	–	393	4129

FUEL COST – BOILERS (Coal)

	Coal %	Weighted $/MMBTU	Fuel Cost – Black Coal $(000)												
Kosutka	–	–	–	–	–	–	–	–	–	–	–	–	–	–	
Brewery	–	–	–	–	–	–	–	–	–	–	–	–	–	–	
Letna	–	–	–	–	–	–	–	–	–	–	–	–	–	–	
Pizen I	99 6%	$2 30	175	149	37	32	–	–	–	–	–	–	–	–	
Pizen IIb	99 6%	$1 95	1374	1178	1875	1632	211	–	371	–	534	–	395	–	
Pizen IVb and Pizen IVc	–	–	–	–	–	–	–	–	–	–	–	–	–	–	
Pizen IIa	99 6%	$1 95	150	128	91	79	62	–	109	–	156	–	115	–	
Pizen IVa	–	–	–	–	–	–	–	–	–	–	–	–	–	–	
Total			1699	1455	2003	1743	273	–	480	–	690	–	510	–	8854

FUEL COST – BOILERS (Gas)

	Gas %	Weighted $/MMBTU	Fuel Cost – Natural Gas $(000)												
Kosutka	100 0%	$3 77	–	–	–	–	–	–	–	–	–	–	–	–	–
Brewery	100 0%	$3 77	0	0	–	–	–	–	–	–	–	–	–	–	1
Letna	100 0%	$3 77	2	2	–	–	–	–	–	–	–	–	–	–	4
Pizen I	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
Pizen IIb	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
Pizen IVb and Pizen IVc	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
Pizen IIa	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
Pizen IVa	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
Total			3	2	–	–	–	–	–	–	–	–	–	–	5

FUEL COST – BOILERS (Oil)

	Oil %	Weighted $/MMBTU	Fuel Cost – Oil $(000)												
Kosutka	–	–	–	–	–	–	–	–	–	–	–	–	–	–	
Brewery	–	–	–	–	–	–	–	–	–	–	–	–	–	–	
Letna	–	–	–	–	–	–	–	–	–	–	–	–	–	–	
Pizen I	0 4%	$0 01	1	1	0	0	–	–	–	–	–	–	–	–	
Pizen IIb	0 4%	$0 01	8	7	11	10	1	–	2	–	3	–	2	–	
Pizen IVb and Pizen IVc	0 4%	$0 01	3	3	5	4	–	1	–	2	–	4	–	3	
Pizen IIa	0 4%	$0 01	1	1	1	0	0	–	1	–	1	–	1	–	
Pizen IVa	0 4%	$0 01	2	2	4	3	–	1	–	1	–	1	–	1	
Total			16	13	21	18	2	2	3	3	4	5	3	4	94

HOT WATER SHORTFALL		MWH	–	–	–	–	–	–	–	–	–	–	–	–	
Assumed Equivalent Cost	$/MWH	$10 00													
SUPPLEMENTAL HOT WATER COST – $(000)			–	–	–	–	–	–	–	–	–	–	–	–	–

Water and Other Variable O&M Expenses – Boilers $(000)

	Basis $/MWHw	Basis $/MWH	Variable O&M Expense $(000)												
Kosutka	$0 10	$0 41	–	–	–	–	–	–	–	–	–	–	–	–	
Brewery	$0 10	$0 41	0	0	–	–	–	–	–	–	–	–	–	–	
Letna	$0 10	$0 41	0	0	–	–	–	–	–	–	–	–	–	–	
Pizen I	$0 10	$0 41	8	7	2	2	–	–	–	–	–	–	–	–	
Pizen IIb	$0 10	$0 41	146	125	214	186	24	–	42	–	60	–	45	–	
Pizen IVb and Pizen IVc	$0 10	$0 41	73	63	119	104	–	31	–	54	–	103	–	76	
Pizen IIa	$0 10	$0 41	32	27	19	17	13	–	23	–	33	–	24	–	
Pizen IVa	$0 10	$0 41	92	79	134	117	–	23	–	39	–	54	–	40	
Total			351	300	488	425	37	54	65	94	93	157	69	116	2 249

Limestone and Ash Removal Expenses – Boilers $(000)

	Limestone $/MMBTU	Removal $/MMBTU	Limestone Injection & Ash Removal Expenses $(000)												
Kosutka	–	–	–	–	–	–	–	–	–	–	–	–	–	–	
Brewery	–	–	–	–	–	–	–	–	–	–	–	–	–	–	
Letna	–	–	–	–	–	–	–	–	–	–	–	–	–	–	
Pizen I	–	0 072	5	5	1	1	–	–	–	–	–	–	–	–	
Pizen IIb	–	0 072	50	43	69	60	8	–	14	–	20	–	14	–	
Pizen IVb and Pizen IVc	0 212	0 133	85	73	142	123	–	35	–	61	–	106	–	79	
Pizen IIa	–	0 072	5	5	3	3	2	–	4	–	6	–	4	–	
Pizen IVa	0 212	0 133	72	62	105	91	–	18	–	31	–	42	–	31	
Total			218	187	320	278	10	53	18	92	25	149	19	110	1 477
Removal Costs Only			122	104	168	147	10	20	16	36	25	57	19	42	769
By-Product Sales $(000)			50	43	68	59	5	7	9	12	13	19	9	14	306

Emissions Penalties – Boilers $(000)

	Emissions $/MMBTU	Emissions Penalties $(000)												
Kosutka	–	–	–	–	–	–	–	–	–	–	–	–	–	
Brewery	–	–	–	–	–	–	–	–	–	–	–	–	–	
Letna	–	–	–	–	–	–	–	–	–	–	–	–	–	
Pizen I	–	–	–	–	–	–	–	–	–	–	–	–	–	
Pizen IIb	–	–	–	–	–	–	–	–	–	–	–	–	–	
Pizen IVb and Pizen IVc	–	–	–	–	–	–	–	–	–	–	–	–	–	
Pizen IIa	–	–	–	–	–	–	–	–	–	–	–	–	–	
Pizen IVa	–	–	–	–	–	–	–	–	–	–	–	–	–	
Total		–	–	–	–	–	–	–	–	–	–	–	–	–

Emissions by Type – Tons

	Units per Ton	Emissions – Tons												
Particulate	2000	23 7	20 3	32 6	28 4	2 6	3 0	4 5	5 2	6 5	8 4	4 8	6 2	146 2
SO_2	2000	584 8	500 9	754 8	656 7	71 1	50 1	124 9	87 7	179 7	141 9	132 7	104 8	3 390 0
NOx	2000	212 7	182 2	277 4	241 3	21 8	28 6	38 2	50 2	55 0	87 3	40 6	64 5	1 299 9
CO	2000	9 1	7 8	12 2	10 6	0 9	1 0	1 6	1 7	2 3	2 9	1 7	2 2	54 0

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	WINTER				SUMMER								
	Peak	High	Low	Weekend	Peak 1	Peak 2	High 1	High 2	Low 1	Low 2	Wkend 1	Wkend 2	
Sta Use % Max Stm 460 0%													kW
Avg KW Required – Pumping	3020	3020	2567	2567	1036	364	1036	364	812	310	812	310	167
Sta Use	8899	8897	7627	7630	4936	2867	4936	2862	3825	2286	3825	2286	570
Total	11919	11917	10194	10197	5973	3231	5973	3226	4637	2595	4637	2595	737

BACK PRESSURE TURBINE/GENERATOR OUTPUT – AVERAGE KW

BASIS UNITe	Back Pressure Turbine/Generator Output & Contract Purchase												
	–	–	–	–	–	–	–	–	–	–	–	–	
	–	–	–	–	–	–	–	–	–	–	–	–	
	–	–	–	–	–	–	–	–	–	–	–	–	
	–	–	–	–	–	–	–	–	–	–	–	–	
Turb IB	52380	52387	53294	53319	47263	–	47263	–	36210	–	36209	–	
Turb IA	2620	2613	1345	1346	4662	–	4662	–	3059	–	3059	–	
Turb IIB	14362	14363	16217	16215	–	16712	–	16712	–	11953	–	11953	
Turb IIA	8650	8649	7950	7950	–	6089	–	6036	–	4199	–	4199	
Total T/G Output	78011	78013	78806	78830	51924	22802	51925	22749	39270	16152	39269	16152	539
Balance Required	–66093	–66096	–68612	–68634	–45952	–19571	–45952	–19523	–34633	–13557	–34632	–13557	

CONDENSING TURBINE OUTPUT – AVERAGE KW

	Generator Efficiency	Condensing Turbine Output – KW												
		–	–	–	–	–	–	–	–	–	–	–	–	–
		–	–	–	–	–	–	–	–	–	–	–	–	–
		–	–	–	–	–	–	–	–	–	–	–	–	–
		–	–	–	–	–	–	–	–	–	–	–	–	–
		–	–	–	–	–	–	–	–	–	–	–	–	–
Turb IIC	96 0%	6777	6777	6389	6390	–	9362	–	9460	–	12128	–	12128	1 04
		–	–	–	–	–	–	–	–	–	–	–	–	–
		–	–	–	–	–	–	–	–	–	–	–	–	–
Total Condens Turb Output		6777	6777	6389	6390	–	9362	–	9460	–	12128	–	12128	67
Balance Required		–72870	–72872	–75001	–75024	–45952	–28933	–45952	–28983	–34633	–25685	–34632	–25685	
GT Capability @ Full Load		49627	49627	49627	49627	47720	46233	47720	46233	47720	46233	47720	46233	

GAS TURBINE OUTPUT – AVERAGE KW

	Gas Turbine Output – KW												
	–	–	–	–	–	–	–	–	–	–	–	–	
	–	–	–	–	–	–	–	–	–	–	–	–	
	–	–	–	–	–	–	–	–	–	–	–	–	
	–	–	–	–	–	–	–	–	–	–	–	–	
	–	–	–	–	–	–	–	–	–	–	–	–	
	–	–	–	–	–	–	–	–	–	–	–	–	
Total GT Output (KW)	–	–	–	–	–	–	–	–	–	–	–	–	–
Balance Required (KW)	–72870	–72872	–75001	–75024	–45952	–28933	–45952	–28983	–34633	–25685	–34632	–25685	
Hours In Period	914	783	1435	1248	181	306	318	535	589	994	435	734	
Balance Required (MWH)	–63953	–54790	–102324	–89020	–8317	–5989	–14613	–10445	–20399	–13476	–15065	–9951	
PURCHASED POWER	75%	75%	75%	75%	75%	75%	75%	75%	75%	75%	75%	75%	
Peak Demand KW	–	–	–	–	–	–	–	–	–	–	–	–	
Demand Charge – $/KW	7 93	7 93	7 93	7 93	7 93	7 93	7 93	7 93	7 93	7 93	7 93	7 93	
Energy Charge – $/KWH	0 0350	0 0279	0 0246	0 0246	0 0350	0 0350	0 0279	0 0279	0 0246	0 0246	0 0246	0 0246	
Demand Charge – $(000)	–	–	–	–	–	–	–	–	–	–	–	–	
Energy Charge – $(000)	–	–	–	–	–	–	–	–	–	–	–	–	
Total – $(000)	–	–	–	–	–	–	–	–	–	–	–	–	–

	WINTER				SUMMER							
	Peak	High	Low	Weekend	Peak 1	Peak 2	High 1	High 2	Low 1	Low 2	Wkend 1	Wkend 2

Interpolated Exhaust Temperature °F

	Exhaust Temperature °F											
	–	–	–	–	–	–	–	–	–	–	–	–
	–	–	–	–	–	–	–	–	–	–	–	–
	–	–	–	–	–	–	–	–	–	–	–	–
	–	–	–	–	–	–	–	–	–	–	–	–
	–	–	–	–	–	–	–	–	–	–	–	–
	–	–	–	–	–	–	–	–	–	–	–	–

Interpolated Exhaust Flow M#/Hr

	Exhaust Flow M#/Hr											
	–	–	–	–	–	–	–	–	–	–	–	–
	–	–	–	–	–	–	–	–	–	–	–	–
	–	–	–	–	–	–	–	–	–	–	–	–
	–	–	–	–	–	–	–	–	–	–	–	–
	–	–	–	–	–	–	–	–	–	–	–	–
	–	–	–	–	–	–	–	–	–	–	–	–

Available Exhaust Heat MMBTU/Hr

	Exhaust Heat MMBTU/Hr											
	–	–	–	–	–	–	–	–	–	–	–	–
	–	–	–	–	–	–	–	–	–	–	–	–
	–	–	–	–	–	–	–	–	–	–	–	–
	–	–	–	–	–	–	–	–	–	–	–	–
	–	–	–	–	–	–	–	–	–	–	–	–
	–	–	–	–	–	–	–	–	–	–	–	–

Steam Available – MW per Hour (Without Supplementary Firing)

	Enthalpy Rise	Total Steam Available without Supplementary Firing M#/Hr											
	–	–	–	–	–	–	–	–	–	–	–	–	–
	–	–	–	–	–	–	–	–	–	–	–	–	–
	–	–	–	–	–	–	–	–	–	–	–	–	–
	–	–	–	–	–	–	–	–	–	–	–	–	–
	–	–	–	–	–	–	–	–	–	–	–	–	–
	3 412	–	–	–	–	–	–	–	–	–	–	–	–
		–	–	–	–	–	–	–	–	–	–	–	–

Supplementary Firing – Maximum Exhaust Heat MMBTU/Hr

	–	–	–	–	–	–	–	–	–	–	–	–
	–	–	–	–	–	–	–	–	–	–	–	–
	–	–	–	–	–	–	–	–	–	–	–	–
	–	–	–	–	–	–	–	–	–	–	–	–
	–	–	–	–	–	–	–	–	–	–	–	–
	–	–	–	–	–	–	–	–	–	–	–	–

Steam Rejection – Avg MW (To Cooling Tower)

	Maximum Capacity	Steam Rejection – Average MW											
From Condensing	25 000	14 0	14 0	13 2	13 2	–	19 3	–	19 5	–	25 0	–	25 0
From Gas Turbines	25 000	–	–	–	–	–	–	–	–	–	–	–	–
Total		14 0	14 0	13 2	13 2	–	19 3	–	19 5	–	25 0	–	25 0

VARIANT C1 PROJECTED FINANCIAL COST AND HOT WATER REVENUE REQUIREMENT High Demand

FINANCIAL COST (000) (Including Inflation)

	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
ACCRUAL BASIS	(Exclusive of Interest Expense if any and Depreciation Charges related to existing plant (Production Transmission Distribution et al)																	
Operating Expenses																		
Operation & Maintenance	5 544	6 234	6 922	12 534	16 548	17 880	19 528	21 995	22 829	24 165	20 945	22 877	30 992	24 972	26 502	28 153	30 828	32 580
Depreciation Expense	8	44	335	605	630	645	659	675	1 905	3 197	3 199	3 202	3 205	3 207	3 209	3 211	3 213	3 216
Total Operating Expenses	5 552	6 277	7 257	13 139	17 178	18 525	20 187	22 670	24 734	27 362	24 144	26 079	34 196	28 179	29 711	31 364	34 042	35 796
Interest Expense	9	57	423	1 033	1 290	1 212	1 103	975	2 178	4 726	5 673	5 006	4 387	3 788	3 123	2 383	1 558	760
Equity Return	9	9	55	419	756	788	806	824	844	2 237	3 699	3 702	3 705	3 708	3 711	3 714	3 717	3 720
Total Expense & Return	5 570	6 344	7 734	14 591	19 225	20 525	22 095	24 470	27 756	34 325	33 516	34 787	42 289	35 675	36 545	37 461	39 316	40 276
Income Tax Effect @ 45%	8	8	45	343	619	645	659	674	691	1 830	3 026	3 029	3 031	3 034	3 036	3 038	3 041	3 043
Total Cost	5,577	6,352	7,779	14,934	19,843	21,169	22,755	25,144	28,446	36,155	36,543	37,816	45,321	38,709	39,581	40,499	42,357	43,319
Estimated Hot Water Revenue Requirement	(Exclusive of Interest Expense if any and Depreciation Charges related to existing plant (Production Transmission Distribution et al)																	
Total Cost (Above) less																		
Cost of Steam																		
Operation & Maintenance	4 268	4 649	4 936	6 301	7 506	8 456	8 541	9 894	9 786	10 441	9 669	10 422	9 142	9 599	10 078	10 581	11 110	11 665
Allocated Depreciation	3	16	122	192	198	202	206	210	593	994	992	991	990	990	990	990	990	989
Allocated Return	4	4	20	133	238	247	252	257	263	695	1 147	1 146	1 145	1 145	1 145	1 145	1 144	1 144
Income Tax Effect	3	3	16	109	195	202	206	210	215	569	939	938	937	937	937	936	936	936
Total Steam	4 277	4 672	5 094	6 735	8 137	9 108	9 205	10 571	10 857	12 698	12 748	13 498	12 214	12 671	13 149	13 652	14 180	14 734
Equals Cost of Hot Water	1 300	1 680	2 685	8 199	11 707	12 062	13 549	14 573	17 589	23 457	23 795	24 319	33 106	26 039	26 432	26 847	28 177	28 584
HOT WATER – $/MWH	$2 43	$3 04	$4 68	$10 55	$14 87	$15 25	$17 06	$18 27	$22 02	$29 31	$29 69	$30 29	$41 17	$32 33	$32 78	$33 25	$34 85	$35 31
Present Worth	$2 43	$2 60	$3 42	$6 59	$7 93	$6 96	$6 65	$6 09	$6 27	$7 13	$6 18	$5 39	$6 26	$4 20	$3 64	$3 16	$2 83	$2 45
Levelized Cost to Date		$3 04	$3 79	$5 70	$7 49	$8 59	$9 51	$10 26	$11 05	$12 05	$12 84	$13 48	$14 32	$14 78	$15 16	$15 49	$15 78	$16 02
CASH BASIS	(Exclusive of Debt Service related to existing plant (Production Transmission Distribution et al)																	
O & M Expenses	5 544	6 234	6 922	12 534	16 548	17 880	19 528	21 995	22 829	24 165	20 945	22 877	30 992	24 972	26 502	28 153	30 828	32 580
Equity Return	9	9	55	419	756	788	806	824	844	2 237	3 699	3 702	3 705	3 708	3 711	3 714	3 717	3 720
Debt Service																		
Foreign Interest	–	–	–	–	–	–	–	–	116	353	468	457	446	433	419	404	388	371
Principal	–	–	–	–	–	–	–	–	–	62	133	144	155	168	182	196	213	230
Total	–	–	–	–	–	–	–	–	116	415	601	601	601	601	601	601	601	601
Domestic Interest	9	57	423	1 033	1 290	1 212	1 103	975	2 062	4 373	5 205	4 549	3 942	3 355	2 704	1 978	1 169	389
Principal	–	11	67	514	983	1 143	1 306	1 490	1 698	3 555	5 616	5 200	4 815	5 317	5 923	6 601	7 360	4 015
Total	9	69	490	1 547	2 274	2 355	2 408	2 465	3 759	7 928	10 822	9 749	8 757	8 671	8 627	8 580	8 530	4 405
Total Cost before Income Tax	5 562	6 312	7 466	14 500	19 578	21 023	22 742	25 284	27 548	34 745	36 066	36 929	44 055	37 953	39 441	41 047	43 675	41 305
Income Tax Effect @ 45%	8	8	45	343	619	645	659	674	691	1 830	3 026	3 029	3 031	3 034	3 036	3 038	3 041	3 043
Total Financial Cost	5,570	6,319	7,511	14,843	20,196	21,668	23,401	25,959	28,239	36,575	39,092	39,957	47,086	40,987	42,477	44,086	46,716	44,348

APPENDIX G:
ST PAUL DISTRICT ENERGY (HEATING AND COOLING) INFORMATION

District Heating Fact Sheet
District Energy St. Paul, Inc.

Service	Hot water district heating piped to customers year-round for space heating, domestic hot water and industrial process use
Provider	District Energy St Paul Inc , an independent, non-profit company
Customers and building area served	136 large buildings and 298 single-family residences in downtown St. Paul and adjacent areas, 23 million square feet of building area served, including 73 percent of downtown building space
Plant/office location	Hans O Nyman Energy Center, 76 West Kellogg Boulevard, St Paul
Production capacity	Three large coal/gas boilers, three gas/oil boilers, backup plant and mobile boiler, total 224 megawatts (765 million Btu per hour) thermal, also 860-kilowatt electric-turbine generator
Fuels used	Primary fuel high-Btu, low-sulfur Eastern coal Secondary fuels natural gas, fuel oil and purchased steam
Distribution system	76,000 feet of twin supply and return piping running from Hans O Nyman Energy Center east to Lafayette Road, north to Empire Builder Industrial Park, and west to United Hospital area
Customer demand	146 megawatts current billed demand, 176 megawatts initial customer demand before adjustments, annual sales, 260,000 megawatt-hours (890,000 million Btu)
Cogeneration	Cogeneration, the simultaneous production of heat and electricity, results in more efficient use of energy Steam from existing boilers is used to power the 860 kilowatt turbine-driven generator Energy from turbine exhaust steam is used to help supply the hot water to district heating customers Generator meets majority of District Energy's electrical requirements
Historical background	1983 Hot water district heating system construction begun, first heating customer served 1985 Initial construction completed, extension to Mount Airy housing complex 1986 Extension to Empire Builder Industrial Park 1987 New name, District Energy St Paul, adopted 1990 Cogeneration of electricity added
For more information	Call Trudy Sherwood at 297-8955

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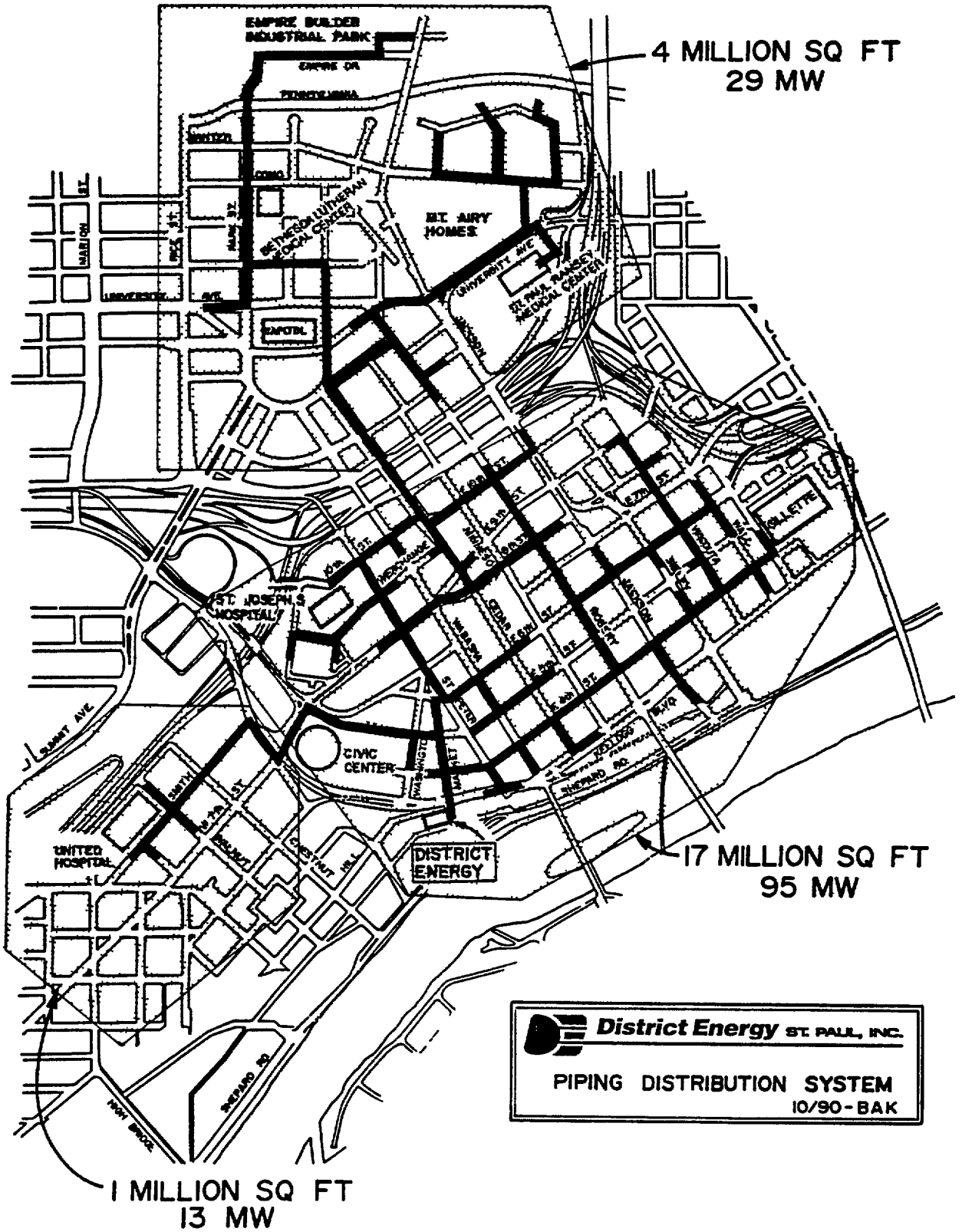
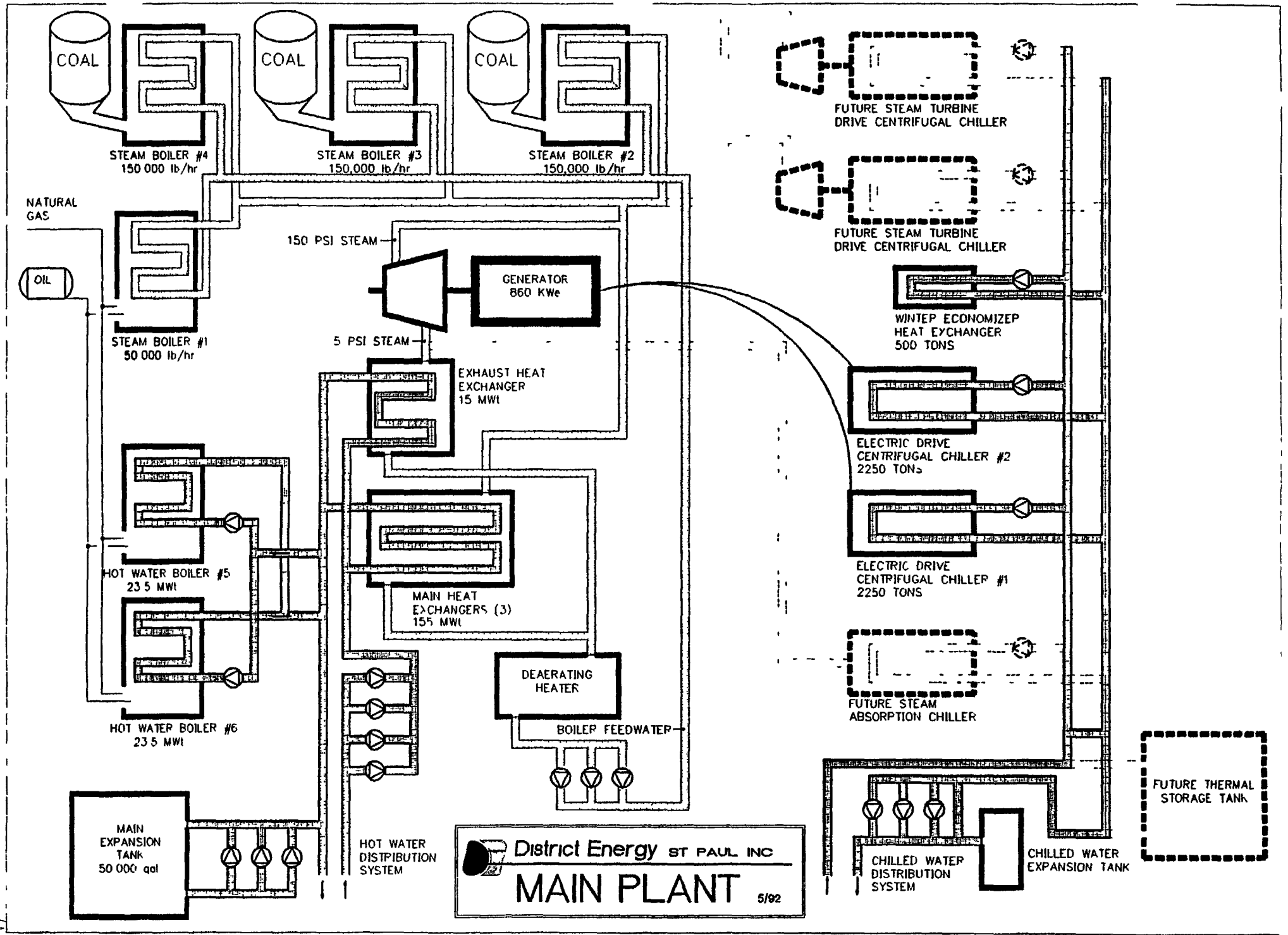

EMPIRE BUILDER INDUSTRIAL PARK
EMPIRE DR
PENNSYLVANIA
SMITH
COMO
MARION ST.
RICE ST.
MAIN ST.
UNIVERSITY AVE.
BETHESDA LUTHERAN MEDICAL CENTER
MT. AIRY HOMES
UNIVERSITY AVE
ST. PAUL RAMSEY MEDICAL CENTER
CAPITOL
JACKSON
ST. JOSEPH'S HOSPITAL
SUMMIT AVE
CIVIC CENTER
UNITED HOSPITAL
DISTRICT ENERGY
SHEPARD RD
HIGH BRIDGE
4 MILLION SQ FT
29 MW
17 MILLION SQ FT
95 MW
1 MILLION SQ FT
13 MW
District Energy ST. PAUL, INC.
PIPING DISTRIBUTION SYSTEM
10/90-BAK


COAL
COAL
COAL
STEAM BOILER #4
150 000 lb/hr
STEAM BOILER #3
150,000 lb/hr
STEAM BOILER #2
150,000 lb/hr
NATURAL GAS
OIL
STEAM BOILER #1
50 000 lb/hr
150 PSI STEAM
GENERATOR
860 KWe
5 PSI STEAM
EXHAUST HEAT EXCHANGER
15 MWt
HOT WATER BOILER #5
23 5 MWt
HOT WATER BOILER #6
23 5 MWt
MAIN HEAT EXCHANGERS (3)
155 MWt
DEAERATING HEATER
BOILER FEEDWATER
MAIN EXPANSION TANK
50 000 gal
HOT WATER DISTRIBUTION SYSTEM
FUTURE STEAM TURBINE DRIVE CENTRIFUGAL CHILLER
FUTURE STEAM TURBINE DRIVE CENTRIFUGAL CHILLER
WINTER ECONOMIZER HEAT EXCHANGER
500 TONS
ELECTRIC DRIVE CENTRIFUGAL CHILLER #2
2250 TONS
ELECTRIC DRIVE CENTRIFUGAL CHILLER #1
2250 TONS
FUTURE STEAM ABSORPTION CHILLER
CHILLED WATER DISTRIBUTION SYSTEM
CHILLED WATER EXPANSION TANK
FUTURE THERMAL STORAGE TANK
District Energy ST PAUL INC
MAIN PLANT
5/92

A Decade of Gains from Hot Water District Heating

Hot water district heating was implemented over 10 years ago to help downtown Saint Paul building owners conserve energy, improve regional air quality and become less dependent on imported fuels. A comparison of the 1989 hot water district heating system to its steam predecessor in 1979 shows that these challenges are being met.

With improved system efficiency, District Energy St. Paul today heats twice the building area with about the same energy input as the previous system. Plant and distribution improvements have boosted thermal efficiencies by over 30 percent, and our customers have reduced their energy consumption by an average of 20 percent by converting and upgrading their heating systems

Significant air quality gains have also been realized. Sulfur dioxide emissions, which contribute to acid rain, have been reduced by 50 percent per unit of energy input Combined with the overall system efficiency increase, this amounts to a 75 percent reduction per unit of end-use energy Carbon dioxide, the main factor in global warming, has been reduced by 50 percent per unit of end-use energy. Also, our closed-loop distribution system reduced system groundwater usage from 100 million gallons per year to zero

Rate stability has also been achieved over the past decade Current rates are more than 30 percent lower than projected in the original hot water district heating feasibility study and are still lower than 1980 steam costs

We are proud of these gains and are working steadily to achieve further improvements For further information on the benefits of district heating and cooling, contact District Energy St Paul at 297-8955

District Energy St Paul, Inc.
76 West Kellogg Boulevard, St. Paul, MN 55102-1611

tls\gains 4/20/92

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District Cooling Fact Sheet
District Cooling St. Paul, Inc.

Service	Year-round chilled water for air conditioning
Provider	District Cooling St Paul Inc , formerly District Energy Services Inc , an affiliate of District Energy St Paul Inc
Committed customers	Ordway Music Theatre, Degree of Honor Building, The Saint Paul Hotel, River Front Educational Center, City Hall Annex, The St Paul Companies - South Building, The Child Care Center at The St Paul, Ramsey County Courthouse/City Hall, AgriBank FCB, Norwest Center Tower and Skyway Buildings, Metro Square Building, Pioneer/Endicott Building, Coleman and Christison, Minnesota Children's Museum, Hans O Nyman Energy Center, Metropolitan Federal Bank Building, Tilsner Warehouse and Saint Paul Public Library
Timing	Start-up of cooling operations April 1993 Start of expansion construction April 1993 Start of chilled water storage tank construction May 1993
Benefits	No use of CFC refrigerants or ground water Capital and operating cost savings More flexible building operation Improved tenant comfort Less space required for cooling equipment
Initial system size	4,500 feet of chilled water pipeline (up to 30 inches in diameter), circulating 175,000 gallons of water Two cooling machines at District Energy's main plant, 4,500 tons of capacity, enough to cool over 2 million square feet of building space
Initial system cost and financing	$8 8 million total, including design, construction, financing and start-up costs funded by $5 8 million HRA revenue bonds, secured by long-term customer contracts, plus $3 0 million subordinated loan from St Paul Housing and Redevelopment Authority
1993 expansion financing	$10 0 million HRA revenue bonds to fund addition of 6,000 feet of chilled water pipeline and 4,900 tons of added cooling capacity
Expansion potential	The system is designed to expand to 30,000 tons of cooling over the next 15 years A 2 5 million-gallon chilled-water storage tank to help reduce peak electric demands will begin construction in May 1993
District cooling systems elsewhere	District cooling systems serve a number of U S cities and many college campuses, airports and military bases Two major utility district cooling systems include Hartford, serving over 14 million square feet of space and Minneapolis, serving over 18 million square feet of space
For information	Call Trudy Sherwood at 297-8955

tls\coolfact 8/13/93

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Chilled Water Storage System Fact Sheet
District Cooling St. Paul, Inc.

Purpose	To store chilled water produced during the night off-peak hours for distribution to district cooling customers in downtown St Paul during the day
Benefits	Increased efficiency of chilled water production Increased reliability of the district cooling system Increased cooling capacity for St Paul Reduced regional peak electric demands Reduced use of CFC refrigerants and groundwater Improved regional air quality
Provider	District Cooling St Paul Inc , an affiliate of District Energy St Paul Inc
Location	Adjacent to the Hans O Nyman Energy Center, 76 West Kellogg Boulevard, St Paul
Capacity	2 5 million gallons of chilled water or nearly 4,000 peak cooling tons, enough to cool approximately 2 million square feet of building space
Construction and size	Cylindrical steel tank, covered with insulation and an aesthetic shell, measuring 72 feet high by 80 feet in diameter
Timing	Construction began in May 1993, completion is anticipated by spring 1994
Storage system cost and financing	$1 7 million total cost net of utility rebate, including design, construction, financing and start-up costs, funding by tax-exempt revenue bonds which are secured by long-term customer contracts
Chilled water storage systems elsewhere	Large chilled water storage systems are in use throughout the U.S , including 4 million gallon tanks at 3M in Maplewood, Minn , and at Cornell University in Ithaca, N Y.
For more information	Call Trudy Sherwood at 297-8955

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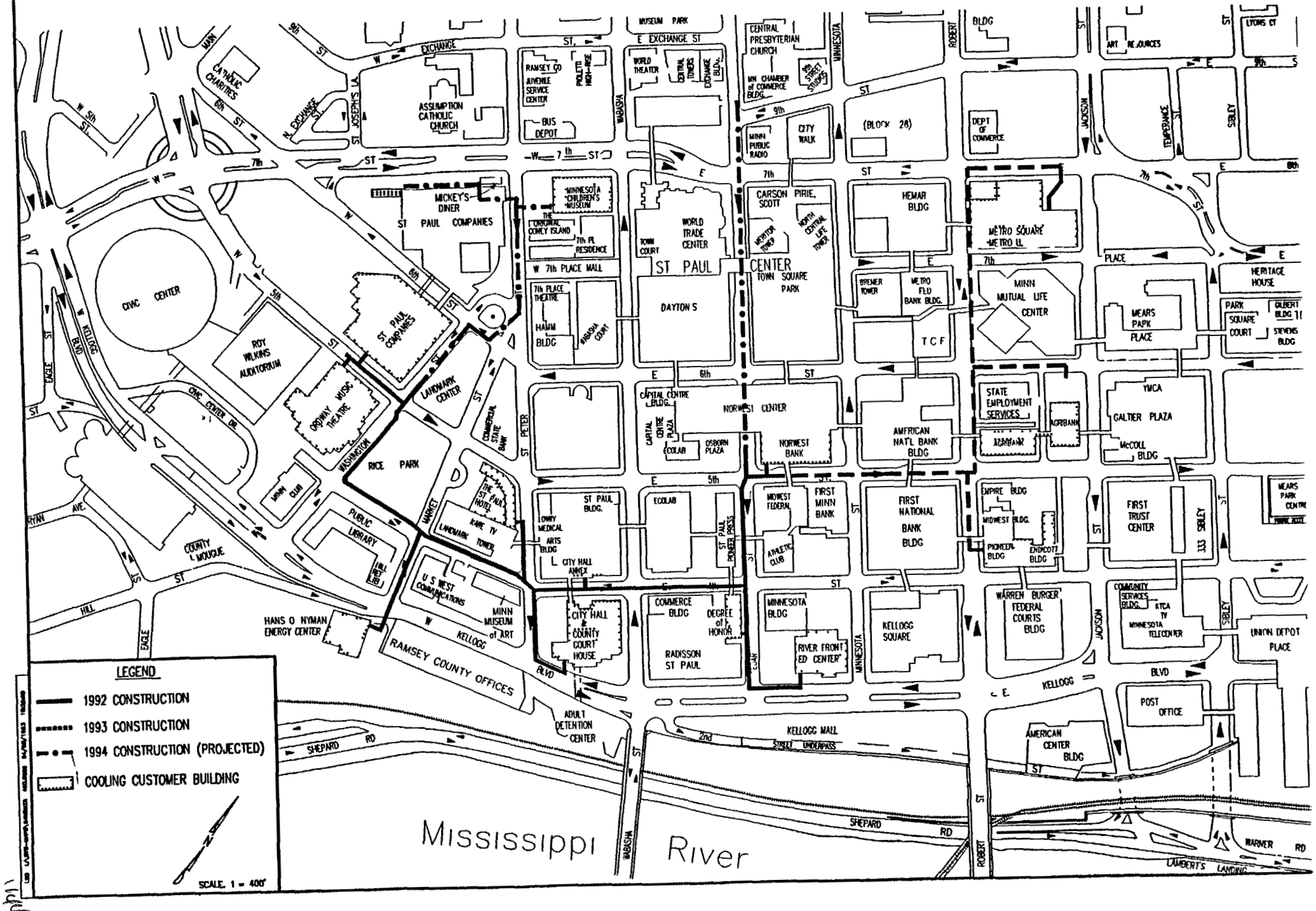
DISTRICT COOLING DISTRIBUTION SYSTEM



District Energy St. Paul

1992

Report of the Chair And President

District heating and cooling systems are starting up and expanding in the United States and around the world—and we're pleased to be part of this exciting growth industry. Our district heating system now serves 23 million square feet of building space, including 73 percent of St. Paul's central business district. Our new district cooling system will serve 1.75 million square feet of building space beginning in April 1993, and expansion plans are already under way!

The past year has been focused on district cooling system construction and plant renovation, making improvements which will benefit both heating and cooling customers in years to come. We've faced numerous challenges, but we've been able to find positive solutions by working together to accomplish key objectives and meet the needs of our customers.

We'd like to recognize two members of our management team—one who retired and one who was promoted. Matthew Schuerger, head of the engineering and planning department, was elected a vice president of District Energy in December. Matt has done an outstanding job as project manager of the district cooling project, and he also previously served as interim director of operations.

Fran Larson retired in October after almost 10 years of service as District Energy's first plant superintendent. His many years of experience in boiler maintenance and operation helped make our plant the modern, efficient facility we operate today.

With Fran's retirement, Peter Lujan was promoted to operations supervisor and David Parenteau to maintenance coordinator. With the addition of Jerry Pittman, our new director of operations, responsibility for safe, reliable heating and cooling service for our customers is in good hands.

We've achieved a great deal since starting from scratch in 1979. District Energy St. Paul is now a recognized leader in hot water district heating in the United States. We've established a nine-year track record of reliable operation, stable rates and strong customer service. We've addressed many of the environmental concerns of the community. We've attracted a distinguished Board of Directors, a knowledgeable and experienced management team, and skilled and dedicated employees.

We feel confident and excited about the opportunities that lie ahead to provide even better service and value for our customers.

The President, Board of Directors and legal counsel, including (from left, sitting) Hans O. Nyman, Barbara L. Lukermann, John D. Taylor (standing) James L. Federson, Robert D. Lowe, Sr., Stephen B. Wellington, Jr., William M. Mahlum (legal counsel), Bernard V. St. Peter and Mark E. Rancone. Not pictured is Robert J. Angleson.

Barbara L. Lukermann
Chair, Board of Directors

Hans O. Nyman
President

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District Energy's 1992 Highlights

- Maintained a 99 999 percent reliability record for our district heating customers
- Substantially completed initial district cooling distribution system, including connection of nine customers with other construction on track for system start-up in April 1993
- Purchased land adjacent to our main plant on Kellogg Boulevard for future expansion of operations
- Added Norwest Center as a major district heating and cooling customer and signed AgriBank FCB as a future district cooling customer
- Completed a major upgrade of our computerized continuous emissions monitoring system to improve environmental monitoring Remained in full compliance with Minnesota Pollution Control Agency stack emission regulations for the year
- Incorporated specific safety objectives into our reliability goal for the benefit of our employees our customers and the community
- Kept the FY 1993 rate increase below the rate of inflation resulting in rates 39 percent below feasibility study projections

About the Company

District Energy St Paul a private nonprofit corporation was established in 1979 and currently provides hot water district heating service to 135 large buildings and 298 single-family homes in downtown St Paul and adjacent areas

Over nine years District Energy customers have reduced their energy consumption by about 20 percent and sulfur dioxide and carbon dioxide emissions have been reduced by 50 to 75 percent The hot water system is so efficient that it now heats twice the building area with about the same amount of energy as the previous steam district heating system

Beginning in April 1993 our affiliate company District Energy Services will begin providing district cooling service to nine St Paul buildings This is just the first phase of an expanding district cooling system planned to serve much of the downtown St Paul area over the coming years

New District Energy Customers

Norwest Center

Ron Mazurek and Dawn Grant studied detailed analyses before deciding to convert Norwest Center to district heating and cooling

Since Norwest Center is home to the St Paul headquarters of one of our region's largest financial institutions its only fitting that it's located in the very heart of downtown St Paul Four major skyways meet at Norwest Center making it a prime location for commercial and retail office space

Built in 1968 Norwest Center celebrates its 25th anniversary in 1993 It consists of a 185 000-square-foot office tower a 96,000-square-foot retail center and a 500-stall parking ramp Besides Norwest Bank the office tower is home to numerous law firms and the retail center hosts such amenities as a travel agency, a temporary agency an office supply store and a food court Norwest Center is owned by a limited partnership and managed by Towle Real Estate Company

"Our job is to provide a safe and comfortable working environment for our tenants says Dawn Grant property manager and assistant vice president at Towle And that kind of focus gets results Some of our tenants have been with us for nearly 20 years

But there's much more to building operations than meets the eye, especially when it comes to heating and cooling Chief Engineer Ron Mazurek has been with the building for over 20 years and recently helped decide to convert the facility to district heating and cooling Both Mazurek and Grant cite better temperature control for tenants and lower maintenance expenses as part of their rationale for change

We did some very detailed analyses, reflects Mazurek The office tower had ground-water-cooled heat pumps so we knew we d have to phase those out no later than 1995 Plus the tower and a portion of the retail center were using chillers that called for ground water as well as soon-to-be-banned CFCs Since District Energy has heated the retail center without a hitch since 1984 it seemed natural for them to provide heating and cooling to the tower The Norwest Tower began district heating service in October 1992 and will begin district cooling service in April 1993

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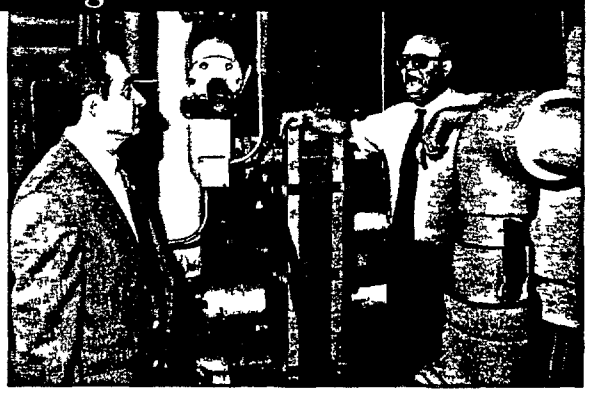
New District Energy Customers

AgriBank



Alex Sleiman, director of customer services, and Wayne Johnson discuss plans for converting AgriBank to district cooling in 1995

Created 75 years ago by an act of Congress, AgriBank FCB (formerly Farm Credit Bank) has stood the test of time as a vital lending institution serving American agriculture With $10 billion in assets AgriBank serves agricultural cooperatives farmers and ranchers in seven states—Minnesota North Dakota, Wisconsin Illinois Michigan Missouri and Arkansas

Nearly 300 AgriBank employees are located in the Farm Credit Services Building at Fifth and Robert in downtown St Paul The original facility was constructed in the late 1960s a second building was added in early 1981 The buildings are connected on floors two through seven but maintain separate heating ventilation and air-conditioning systems

Neither building has ever had a boiler Both used steam from the old central steam system until they were connected to District Energy s new hot water district heating system in 1984 Since then district heating has been used for space heating, domestic hot water in one of the buildings and snow melting on the garage ramps

Our experiences with District Energy have been quite positive says Wayne Johnson, AgriBank's superintendent of buildings and security I can t recall ever having an interruption in service and they ve always been extremely responsive Our good experience played a significant role in our decision to sign up for district cooling too The Farm Credit Services Building is scheduled for connection to the district cooling systems expansion phase in 1995

Right now we re using well water to cool one building and chillers to cool the other We can change over to district cooling at a low capital cost and eliminate our use of well water and chlorofluorocarbon refrigerants Environmental issues are becoming more and more important and I believe District Energy St Paul has taken a lead position on behalf of its customers

District Cooling

Great effort was expended during 1992 toward construction of our $8 8 million initial district cooling system in downtown St Paul Between January and December 1992, our contractor installed 4,500 feet of twin supply and return steel pipes under streets and sidewalks Initially designed to serve eight cooling customers by April 1993 the pipeline system was expanded in September 1992 to serve a major additional cooling customer—Norwest Center

While opening trenches and installing 24- to 30-inch pipes was the most visible sign of district cooling construction in the downtown area major renovation work also took place at our main plant on Kellogg Boulevard The old roof and upper brick walls on the south side of the building were demolished to accommodate two new cooling towers Also demolished and removed was an old coal bunker to make room for a new fourth floor and two 2 250-ton chillers Pumps and other equipment were installed in renovated space on the first and second floors of the building

The operational and environmental benefits of district cooling, including elimination of ozone-depleting chlorofluorocarbon (CFC) refrigerants and ground water for once-through cooling systems, have sparked the interest of many downtown building owners The project also captured the interest of Credit Local de France, Europe's largest financial institution which has agreed to provide credit enhancement for $10 million in expansion financing Expansion plans for 1993 include installation of 3 000 feet of new piping and construction of a chilled water storage tank west of our main plant

Many people have contributed to the successful completion of the initial phase of the district cooling project but three individuals have worked especially hard Matt Schuerger overall project manager, David Urke construction engineer/distribution system and Ron Cackoski construction engineer/plant modifications Their knowledge, skills and determination to bring the project in on schedule and within budget will be rewarded when our first district cooling customers start taking service in April 1993

Ron Cackoski Dave Urke and Matt Schuerger have played key roles in keeping the district cooling project on schedule and within budget

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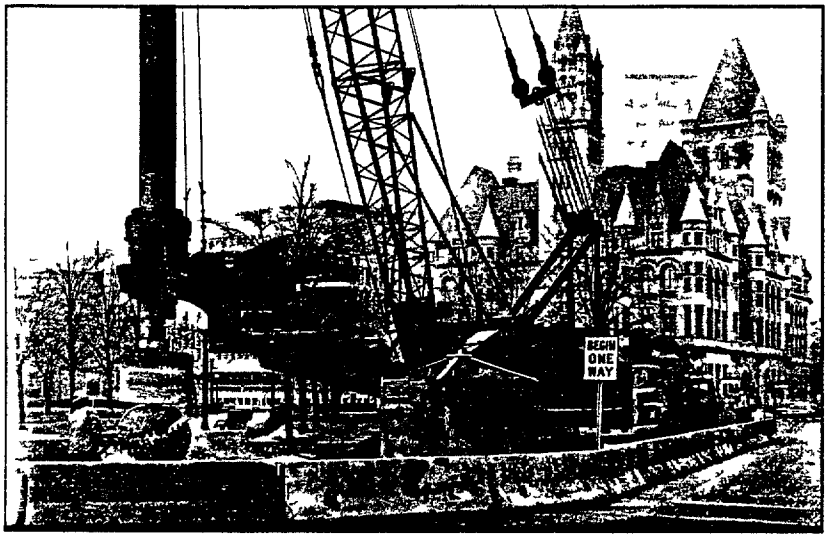
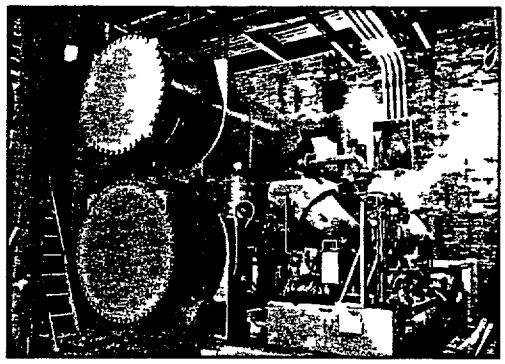
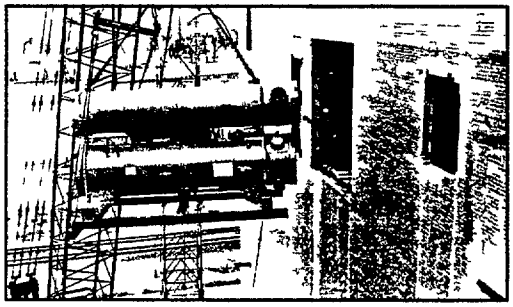
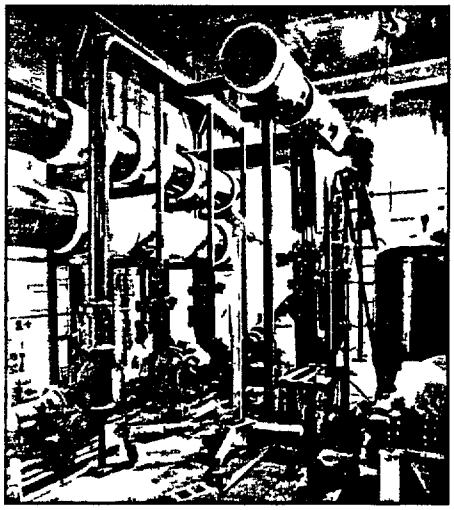
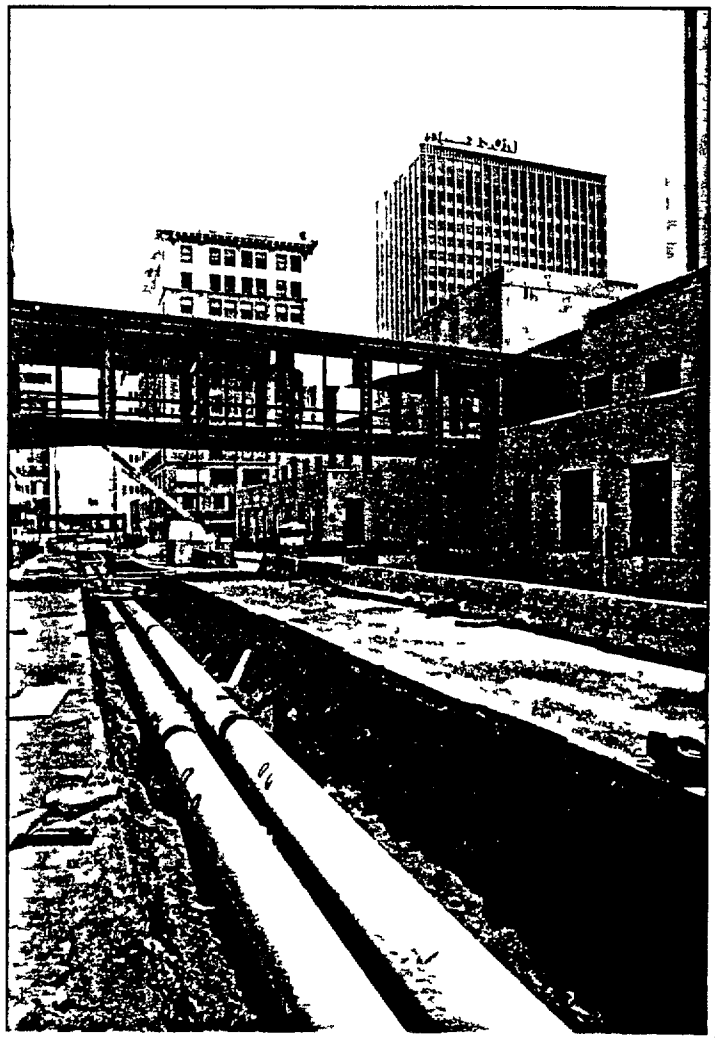
District Cooling











Customer Service

Annual customer surveys indicate that one of the areas in which we rate highest is customer service This response is exactly what we strive for throughout the year

In 1992, we conducted two types of customer surveys—one written and the other in person with our largest customers Through these surveys we learned what was on our customers minds and how we might serve them better

Our Customer Relations Committee made up of a cross-section of District Energy employees meets monthly to review customer service issues and identify ways to promote better customer service both internally and externally

The services we offer our customers include energy use audits, annual seminars for operating engineers and on-site visits to familiarize new operators with district heating advice on building equipment repairs and purchases consultations regarding building conversions, around the clock response to emergencies, customer visits and plant tours and detailed energy projections for budgeting

Operating Highlights

Dave Parenteau Pete Lujan and Jerry Pittman keep the operations department running smoothly ensuring safe reliable service to all District Energy customers

Reliability is a top priority for us and a major reason our customers are satisfied with our service System-wide reliability for 1992 topped 99 99 percent Contributing to our impressive reliability record is our 860-kilowatt cogeneration system With cogeneration we save energy and ensure a reliable source of electricity for our plant

Another contributing factor is our extensive preventive maintenance program in the plant and on the distribution system Major plant projects completed during 1992 included replacing the tiled roofs on two of the large coal-fired boilers upgrading the coal conveyor system redesigning the low-pressure heat exchanger for greater efficiency and rebuilding the boiler grate and ash pit on two coal-fired boilers We also completed the first phase of a combustion make-up air project which will help control air infiltration and improve operations

On the distribution side all of the heating systems 160 underground vaults were inspected and necessary corrosion protection and waterproofing was performed Distribution personnel also supported the district cooling construction project by witnessing and inspecting weld X-rays and observing the cleaning and testing procedures for the newly installed pipes

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Financial Summary

The fiscal year ending September 30, 1992, saw continued growth in customer demand Normalized energy use was also up, creating the basis for additional demand growth in FY 1993

Demand-related costs reflected low floating interest rates on District Energy's primary bond issue and a normal level of system maintenance requirements Higher general and administrative expenses resulted from various factors such as rising health insurance costs and recruiting expenses A significant capital expenditure was made for the purchase of adjacent land for future plant expansion The increase in working capital continued to reflect the build-up of reserves under the company's rate stabilization program

Energy-related costs reflected the fact that coal continued to be District Energy's main fuel However total coal costs were down due to increased purchases of natural gas to take advantage of temporary low prices in the "transportation gas' market Energy refunds totaling $78 000 were made to District Energy customers following year-end

	FY 1992	FY 1991	FY 1990	FY 1989
RATES AND UNIT SALES				
Demand rate ($/kW/mo)	**$4.01**	$3 85	$3 48	$3 29
Energy rate after refund ($/MWh)	**$10 80**	$10 26	$10 09	$10 17
Overall rate ($/MMBtu)	**$11.46**	$10 97	$10 17	$9 79
Demand (kW)	**141,982**	141 207	137 049	140 782
Energy sales (MWh)-actual	**243,688**	233 020	231 785	241 593
Heating season degree days	**7,515**	7 389	7 432	8 074
Energy sales (MWh)-normalized	**257,900**	250 300	247 500	237 500
DEMAND REVENUES AND COSTS				
Net demand revenues	**$6,832,160**	$6 523 769	$5 723 158	$5 558 077
Other non energy revenues	**6,070**	599	17 204	34 200
Deferred franchise fees	**709,288**	668 485	605 706	594 785
Total demand revenues and fees	**$7,547,518**	$7 192 853	$6 346 068	$6 187 062
Demand related costs				
Net cash debt service	**$2,249,626**	$2 212 593	$2 640 656	$2 514 770
Operation and maintenance	**2,200,275**	2 246 141	1 903 576	2 020 845
General and administrative	**1,421,503**	1 220 677	1 145 205	1 252 344
Capital expenditures less new debt	**660,792**	381 168	277 618	412 977
Net demand discounts and other	**313,735**	335 311	190 660	94 727
Change in working capital	**701,587**	796 963	188 353	(108 601)
Total demand related costs	**$7,547,518**	$7 192 853	$6 346 068	$6 187 062
ENERGY REVENUES AND COSTS				
Net energy revenues	**$2,709,809**	$2 465 373	$2 457 261	$2 469 171
Refund to customers	**(77,797)**	(74 053)	(117 817)	(11 999)
Total energy revenues	**$2,632,012**	$2 391 320	$2 339 444	$2 457 172
Energy related costs				
Coal	**$1,491,549**	$1 668 721	$1 491 065	$1 578 946
Other	**1,140,463**	722 599	848 379	878 226
Total energy related costs	**$2,632,012**	$2 391 320	$2 339 444	$2 457 172

A copy of the company s FY 1992 audit report including independent auditor s opinion is available from District Energy s controller on request

Heating System Data

(Year Ending September 30, 1992)

Number of customers		
Downtown and adjacent areas		135
Mount Airy homes		298
Building area served		
Downtown		17,880,000 sq ft
Adjacent areas (including Mount Airy)		4,845,400 sq ft
Total		22 725,400 sq ft
Heat sources		
Main plant 76 West Kellogg Boulevard		
Three coal/gas-fired boilers		132 MW
Three gas/oil-fired boilers		62 MW
St Paul-Ramsey Medical Center Plant		
Four gas/oil-fired boilers		25 MW
Mobile boiler (temporary and/or backup)		5 MW
Total		224 MW
Fuel		
Coal (23 013 tons)	604 177 MMBtu	(52 9%)
Natural gas	536 688 MMBtu	(46 9%)
Oil	1 MMBtu	(0 0%)
Steam	2 139 MMBtu	(0 2%)
Total	1,143 005 MMBtu	(100 0%)
Piping		
Type	prefabricated steel pipe with polyurethane insulation encased in polyethylene jacket	
Diameter		3/4-inch to 28-inch
Length		76 000 feet each supply and return
Volume		650 000 gallons
Operating data		
Temperature	Supply	190-250°F
	Return	140-160°F
Pressure	Supply	180 psi
	Minimum pressure differential	30 psi
Reliability		
Total customer-hours		3 421 400
Outage customer-hours		20
Reliability rate		99 999%
Overall system efficiency		74 6%

Mission Statement

The mission of District Energy St Paul is to promote energy conservation by providing reliable and cost-effective thermal energy and related services wherever economically feasible in St Paul, Minnesota

The company will work to provide a high standard of customer service and will give careful attention to environmental concerns, long-term price stability and good corporate citizenship

The People of District Energy

Directors and Officers

Directors, District Energy St Paul Inc and Affiliates

Barbara L Lukermann *Chair*
Senior Fellow Humphrey Institute of Public Affairs University of Minnesota

Bernard V St Peter *Vice Chair*
Retired Director of Manufacturing Administration, The Gillette Company

Robert J Angleson, *Secretary/Treasurer*
President Zehring & Angleson Inc

Robert D Lowe Sr
International Representative United Association of the Plumbing and Pipe Fitting Industry

James L Pederson
Former Assistant Commissioner Minnesota Department of Administration

John D Taylor
Former President Peninsula Community Foundation

Stephen B Wellington Jr
President Wellington Management Inc

Additional Director, District Energy Services Inc

Mark E Rancone
Commercial Property Manager Roseville Properties

Officers

Hans Nyman *President*

Rudy Brynolfson *Vice President (Finance/Marketing)*

Matthew Schuerger *Vice President (Engineering/Planning)*

Employees

PLANT

Peter Lujan, *Operations Supervisor*

David Parenteau, *Maintenance Coordinator*

Lead Engineers

Jeffrey Amacher *(Relief)*
Ronald Anderson
Scott Ebert
Loren Larson
Joseph Lee *(Relief)*
Chris Nelsen

Shift Engineers

Chad Bednar *(Relief)*
Irvin Kragnes
Michael Marah *(Relief)*
Keith Oklobzija
James Tracy
James Wiemann

General Helpers

Marion Holloway
Greg Miller
Chris McMullen

Senior Maintenance Engineers

Lowell Miller *(Electrician)*
John Skeie *(Mechanic)*

DISTRIBUTION

Ray Schmidt *Distribution Superintendent*

Paul Hazelip *Senior Field Representative*

Erik Henriksen *Distribution Assistant*

OFFICE

Hans Nyman, *President*

Rudy Brynolfson, *Vice President (Finance/Marketing)*

Matthew Schuerger, *Vice President (Engineering/Planning)*

Jerry Pittman *Director of Operations*

Accounting

Joyce Anderson *Controller*

Martha Modrynski, *Accountant*

Barbara Thompson, *Accounts Payable Clerk*

Administration

Ellen Thoma *Personnel and Administration Manager*

Valerie Gerlich *Administrative Assistant/Purchasing*

Char McLean *Receptionist*

Communications

Trudy Sherwood *Marketing Communications Coordinator*

Customer Service

Alex Sleiman *Director of Customer Services and Applications*

Tom Anderson *Meter Specialist/Field Service Technician*

Engineering

Ronald Cackoski *Project Engineer (Mechanical)*

David Urke *Project Engineer (Civil)*

Lela Nikolovski *Engineering Secretary*

Finance

Andrew Kasid *Finance/Marketing Analyst*

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