GAS TURBINE APPLICATIONS©

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ABSTRACT

This paper describes how gas turbines can be applied into service for either:

a) electrical power generation, or

b) mechanical drive application,

considering both technical and simplified economic considerations.

For a starting point in the Electrical Power Generation section, a BASE CASE for a typical industrial facility is described, illustrating the plant's existing electrical power usage, steam production and fuel usage profiles, without cogeneration.

Sequential examples, with illustrations and simplified calculations are then given, showing how a gas turbine generator (GTG) could be integrated into the Base Case* facility, to ultimately save money. The examples progressively increase in complexity, flexibility, cost and efficiency, and include:

i) GTG in Open Cycle Configuration

ii) GTG with Unfired HRSG

iii) GTG with Fired HRSG

iv) Small Combined-Cycle Cogeneration Plant

v) Large Combined-Cycle Cogeneration Plant

In the Mechanical Power Applications section, the BASE CASE scenario is a typical Utility Pipeline Gas Compressor application using a mechanical drive gas turbine. Sequential examples are then given showing how combined-cycle using steam turbine generators could be applied to the typical plant.

The paper includes a very general discussion on Turbine Selection Criteria, including turbine sizing considerations and aero-derivative vs. heavy-duty industrial comparisons.

* *For an illustration of how a steam turbine generator could be integrated into the same Base Case facility, please refer to the Steam Turbine Applications© paper.*

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1.0 ELECTRIC POWER GENERATION APPLICATIONS

1.1 The Base Case

Referring to the enclosed **BASE CASE** graphic, the energy parameters of a typical industrial facility are shown.

The industrial facility purchases **25 MW** of **electricity** from the local electrical utility during **on-peak** periods (4,000 hours per year, 2,000 hours in summer and 2,000 hours in winter) and **off-peak** periods (4,000 hours per year, 2,000 hours in summer and 2,000 hours in winter), for a total of 8,000 hours per year.

The facility's annual **electrical purchase costs** are **$10.76 million per year**, based upon the 1997 Ontario Hydro "Less than 115kV" rates, as follows:

Ontario Hydro 1997 Rates for "Less than 115kV"		Demand	Energy
		$/kw	¢/kw.hr
Winter	On-Peak	13.81	4.63
	Off-Peak	-	3.42
Summer	On-Peak	9.88	4.02
	Off-Peak	-	2.35

The overall annual-average **electrical purchase rates** for the facility are summarized as follows:

On-Peak	7.9 ¢/kw.hr
Off-Peak	2.9 ¢/kw.hr
Annual Average	5.4 ¢/kw.hr

The facility's Steam & Boiler Plant provides 100,000 lb/hr of Process Steam for 8,000 hours per year, via pressure reducing valves and desuperheaters. The Steam Plant is fired with natural gas, and at a unit fuel cost of $3.25 per $\text{mmbtu}_{\text{HHV}}$, the **annual fuel costs** are approximately:

Fuel Costs = 126.0 $\text{mmbtuh}_{\text{HHV}}$ x 8,000 hr/yr x 3.25 $/$\text{mmbtu}_{\text{HHV}}$
= **$3.28 million per year**

Thus, the total **BASE CASE Utility Purchase Costs** for the facility are:

Electricity + = $10.76 million + $3.28 million
Fuel Costs = **$14.04 million per year**

For reference, the BASE CASE Heat to Power Ratio, during on-peak periods is:

$$\textbf{H to P Ratio} = \frac{[100{,}000\ \text{lb}_{\text{stm}}/\text{hr} \times 1{,}008\ \text{btu}/\text{lb}_{\text{stm}}]}{[25{,}000\ \text{kW} \times 3{,}413\ \text{btu}/\text{kw.hr}]}$$

	=	[100.8 mmbtuh] / [85.3 mmbtuh]
H to P Ratio	=	**1.18**

The overall efficiency (HHV) of the Steam Plant is approximately:

Overall HHV	**=**	**Heat Output / Fuel Input**
Efficiency	**=**	100.8 mmbtuh / 126.0 $\text{mmbtuh}_{\text{HHV}}$
	=	**80%**

The company president reviews the factory's annual operating costs, and notes:

> "We're spending $14 million a year on energy!
> Is there anything we can do about it?"

Thus, the steam plant staff will commence a study of the potential means to reduce energy costs, by looking at several alternatives as illustrated* in the following examples.

* *The following examples are very simplified, merely using the ISO-type gas turbine generator performance cataloged data from the Gas Turbine World Handbook listings, with no further adjustment for site elevation, for winter and summer ambient temperatures, or for additional auxiliary losses.*

In the following examples, all financial costs are based upon an 80:20 debt/equity ratio for the indicated powerplant, with debt repayment conditions corresponding to a 15 year term loan obtained at 7.5% interest.

1.2 Alternative 1
Gas Turbine Generator in Open Cycle Configuration

Referring to the enclosed **Alternative 1** graphic, a small gas turbine generator could be installed at the industrial facility, in open (simple) cycle configuration without any exhaust heat recovery. This, of course, would not be cogeneration, but we will examine the opportunities it might provide.

The gas turbine generator uses about 157.5 mmbtuh_{HHV} of fuel to produce approximately 12.61 MW.

The Process Steam requirements would still be met by the existing Steam Plant facilities, and its fuel load would remain the same, at 126.0 mmbtuh_{HHV} (\$3.28 million per year).

For the situation illustrated on the Alternative 1 graphic, the approximate cost of the electrical power (not including financial factors) produced by this open-cycle gas turbine generator is:

Cost of Power = Cost of Fuel / Power Production
= [157.5 mmbtuh_{HHV} x \$3.25/mmbtu_{HHV}] / 12,610 kW
= **4.1 ¢/kw.hr**

This simplified Cost of Self-Generated Power rate is less-expensive than the average on-peak purchase rate (7.9 ¢/kw.hr), but more expensive than the off-peak purchase rate (2.9 ¢/kw.hr). Therefore, this simple-cycle unit should be operated in an on-peak period shaving mode only.

Thus, assuming that there are 4,000 on-peak hours per year, the annual fuel costs attributable to the gas turbine generator itself would be approximately:

GTG Fuel = 157.5 mmbtuh_{HHV} x 4,000 hrs/yr x 3.25 \$/mmbtu_{hHHV}
Cost = **\$2.05 million per year**

Combined with the Boiler fuel, the new annual Total Fuel Cost will increase to:

Total Fuel = \$3.28 million + \$2.05 million
Costs = **\$5.32 million per year**

Since the GTG Power Output is about 12.61 MW, the amount of power now purchased during on-peak periods is reduced from 25 MW to about 12.4 MW.

The electrical savings are approximately:

Electrical = 12,610 kW x 7.9 ¢/kw.hr x 4,000 hr/yr
Savings = **\$3.99 million per year**

For a reduced Annual Electrical Cost of:

New Electrical	=	\$10.76 - \$3.99
Costs	=	**\$6.79 million per year**

The total facility energy costs are now:

Electricity +	=	\$5.32 million + \$6.79 million
Fuel Costs	=	**\$12.1 million per year**

Compared to the Base Case, this represents an annual energy savings of:

Energy	=	\$14.0 million - \$12.1 million
Savings	=	**\$1.9 million per year**

Initially this appears to be a good amount of savings, however, the Powerplant's debt payments and O&M costs will reduce these savings dramatically.

For a nominal plant cost of about \$9.0 million, the annual Debt Payment will be about \$0.8 million/yr. The annual O&M Costs will be about \$0.2 million/yr.

The resultant Net Annual Savings are:

Net Annual	=	Energy Savings - Finance Charge - O&M Cost
Savings	=	\$1.9 - \$0.8 - \$0.2
	=	**\$0.9 million per year**

The simplified Payback Period for this plant is about:

Payback	=	Capital Cost / Net Annual Savings
Period	=	\$9.0 million / \$0.9 million
	=	**10 years**

For reference, the Heat to Power ratio of the new Alternative 1 equipment (which delivers no heat) is:

Equipment	=	[0.0 mmbtuh] / [12,610 kW x 3,413 btu/kw.hr]
H to P Ratio	=	**0.0**

The efficiency (HHV) of the new Alternative 1 equipment is only:

Equipment HHV	=	Power Output /Fuel Input
Efficiency	=	[12,610 kW x 3,413 btu/kw.hr] / 157.5 mmbtuh_{HHV}
	=	43.0 mmbtuh / 157.5 mmbtuh_{HHV}
	=	**27%**

By adding waste heat recovery to the gas turbine exhaust in the next example, we will decrease the plant's net fuel usage, thus increasing the facility efficiency.

1.3 Alternative 2
Gas Turbine Generator with Unfired Heat Recovery Steam Generator

Referring to the enclosed **Alternative 2** graphic, an unfired heat recovery steam generator (HRSG) could be added to the exhaust of the same gas turbine generator.

The total amount of Process Steam produced is identical to the BASE CASE, with about two-thirds of it coming from the unfired HRSG and the remainder coming from the existing Steam Plant facilities. The "free" steam from the HRSG saves approximately 126.0 – 40.5 = 85.5 mmbtuh$_{HHV}$ of fuel use in the Steam Plant.

For the situation illustrated on this graphic, the cost of the electrical power produced by the gas turbine generator can include a credit for the fuel saved in the Steam Plant, thus:

$$\text{Cost of Power} = \frac{\text{Cost of GTG Fuel - Steam Plant Fuel Credit}}{\text{Power Output}}$$

$$= \frac{[157.5\ \text{mmbtuh}_{HHV} - 85.5\ \text{mmbtuh}_{HHV}] \times \$3.25/\text{mmbtu}_{HHV}}{12.610\ \text{kW}}$$

$$= \frac{[72.0 \times \$3.25]}{12{,}610}$$

$$= \mathbf{1.8\ ¢/kw.hr}$$

This is significantly less than the off-peak period purchase rates (2.9 ¢/kw.hr), thus the cycle can probably be operated economically all year round.

The GTG offsets an average of 12.61 MW of purchased power all year round, thus the annual electrical costs decrease to approximately:

Electrical	=	[25,000 kW - 12,610 kW] x 8,000 hrs/yr x 5.4 ¢/kw.hr
Costs	=	12,390 x 8,000 x $0.054
	=	**$5.33 million per year**

The total fuel requirements, including both the gas turbine generator and the Steam Plant is now roughly 157.5 + 40.5 = 198.0 mmbtuh$_{HHV}$, for an annual cost of:

Fuel	=	198.0 x 8,000 x $3.25
Costs	=	**$5.15 million per year**

Thus, the Alternative 2 total Utility Purchase Costs for the facility are:

Electricity +	=	$5.33 million + $5.15 million
Fuel Costs	=	**$10.5 million per year**

Compared to the BASE CASE, this is a net decrease, or potential savings of:

Energy = \$14.0 million - \$10.5 million
Savings = **\$3.6 million per year**

For a plant capital cost of \$12.5 million, the debt payments are about \$1.1 million per year. Combined with an annual O&M cost of about \$0.5 million per year, the **Net Annual Savings** of this Alternative 2 is about **\$2.0 million per year**, and the simplified **Payback Period** is reduced to about **6.5 years**.

The overall efficiency of the complete industrial facility, including the Steam Plant and the new Alternative 2 equipment has increased to:

Overall = [Power + Heat, total] / Fuel, total
Efficiency$_{HHV}$ = [43.0 mmbtuh + 100.8 mmbtuh] /198.0 mmbtuh$_{HHV}$
= **73%**

The Heat to Power ratio of the Alternative 2 "cogeneration" equipment is:

Equipment H to P Ratio = $\frac{[67{,}900\ lb_{stm}/hr \times 1{,}008\ btu/lb_{stm}]}{[12{,}610\ kW \times 3413\ btu/kw.hr]}$
= 68.4 mmbtuh / 43.0 mmbtuh
= **1.59**

which is a fairly good match to the BASE CASE Heat to Power Ratio of 1.18.

This Alternate 2 demonstrates a more expensive, but more efficient cycle which is capable of providing process steam, at no extra fuel cost compared to Alternative 1, resulting in a significant reduction in facility operating costs, and an improvement in the simplified Payback Period.

However, we have only partially satisfied the total heat and total power demands of the industrial facility.

In the next example, we will address the remainder of the heat load.

1.4 Alternative 3
<u>Gas Turbine Generator with Fired Heat Recovery Steam Generator</u>

Referring to the enclosed **Alternative 3** graphic, a larger capacity HRSG with a duct burner is added to the exhaust of the same gas turbine generator, instead of the previous Alternative 2 smaller, unfired HRSG unit.

The amount of duct burner firing is varied as required, to provide all the Process Steam. The existing Steam Plant is no longer shown, since in this scenario, it is no longer providing steam (in practice, the water treatment, condensate and feedwater, etc. facilities in the Steam Plant would still be required).

As in Alternative 2, the GTG still offsets 12.61 MW of purchased power, thus the facility's annual **Electrical Costs** remain at **$5.33 million per year**.

Approximately 35.2 $mmbtuh_{HHV}$ of fuel is required in the HRSG duct burner to raise the remaining 32 kpph of Process Steam. Thus, the total fuel consumption is roughly 157.5 + 35.2 = 192.7 $mmbtuh_{HHV}$. The facility's annual **Fuel Costs** thus increase further to approximately **$5.01 million per year**.

The facility's total **Energy Costs** reduce to **$10.3 million per year**, for a net **Energy Savings** of **$3.7 million per year**.

Based upon a Capital Cost of $13.2 million, the Debt Repayment is approximately $1.2 million per year. Combined with an annual O&M Cost of approximately $0.5 million, the **Net Annual Savings** are approximately **$2.0 million per year**, for a simplified **Payback Period** of about **6.6 years**.

The **Efficiency** of this cycle has increased to approximately **75%**, while the equipment **Heat to Power Ratio** now is **2.34**.

Compared to the Base Case, we have provided all the process heat, but it is still feasible to make more electrical power, in order to bring the H to P ratio closer to the existing 1.18.

Compared to Alternative 2, we can see that this Alternative 3 scheme with the addition of a duct burner, allows the cogeneration equipment to actually follow the steam loads, as they vary.

The amount of electrical power produced by the GTG is relatively constant, and the cycle lacks the ability to follow variations in Plant electrical load, which will be addressed in the next alternative.

1.5 Alternative 4
Small Combined-Cycle Cogeneration Plant

Referring to the enclosed **Alternative 4** graphic, a fairly expensive combined-cycle cogeneration plant is shown, using the same gas turbine generator, an even larger, high-pressure fired HRSG, and an auto-extraction condensing steam turbine generator (STG).

Because of the high steam pressure system shown, new feedwater, water treatment, etc. facilities will be required. A condenser and large quantities of condenser cooling water will be required. The Steam Plant could potentially be retired.

The actual power output of the cycle and the total fuel required is dependent upon the amount of HRSG duct firing, the amount of extraction steam taken from the STG, and the amount of STG exhaust steam produced and condensed.

The total power output of the cycle at the operating condition shown is exactly 25 MW, thus decreasing the facility's **Electrical Costs** to **zero**.

The total amount of fuel for the GTG and the HRSG's duct burner, at the typical operating point shown, is 157.5 + 117.5 = 275.0 $\text{mmbtuh}_{\text{HHV}}$, for an approximate annual **Fuel Cost** of **$7.15 million per year**.

Compared to the Base Case, the facility energy costs have been almost halved, and the Energy Savings are now approximately $6.9 million per year.

For a plant Capital Cost of $23.5 million (and an annual Debt Repayment of about $2.1 million) and a $1.2 million annual O&M Cost, the **Net Annual Savings** are approximately **$3.6 million per year**, for a **Payback Period** of about **6.6 years**.

For the operating point shown, the **Efficiency** of the Alternative 4 "cogeneration" equipment is about **68%**, while the cycle perfectly matches the original **Heat to Power Ratio** of **1.18**.

As depicted, this Alternative 4 can supply all the required Process Steam and all the required Electricity, with inherent flexibility to follow normal variations in each.

This Alternative 4 is relatively expensive, but still maintains good efficiency and a reasonable Payback Period.

1.6 Alternative 5
Large Combined-Cycle Cogeneration Plant

Referring to the enclosed **Alternative** 5 graphic, an even larger and more expensive combined-cycle cogeneration plant is shown, with a 50 MW GTG, a large fired HRSG and an auto-extraction condensing STG. This facility makes all the required electricity (and more) and all the required process steam.

This is a small version of the typical combined-cycle cogeneration plant which has been constructed in North America over the past decade, typically by third-party developers, especially in the USA under the PURPA Act.

In this example, we have assumed that our industrial facility is the investor, and that the electrical power made in excess of 25 MW could and would be sold to the electrical utility at about the same rate as the previous purchase rate.

The total power output of the cycle at the operating condition shown, is 51.2 + 23.8 = 75.0 MW. Having satisfied the internal 25 MW demand, i.e. **Electrical Purchase Costs** are **zero**, there is still about 50.0 MW available for **sale** to the utility.

The resultant revenue from **Electricity Sales** would be approximately **$21.53 million per year**, although the **Fuel Cost** would be approximately **$16.32 million per year**, for a **Net Revenue** of approximately **$5.32 million per year**.

Since the Facility owner is the investor, the Net Annual Savings/Revenue will include the original $14.0 million savings, plus the above Net Revenue, for a **Net Benefit** of about **$19.3 million per year**.

For a plant Capital Cost of about $50 million (annual Debt Repayment of about $4.5 million) and a $3.0 million annual O&M Cost, the **Net Annual Savings** are approximately **$11.8 million per year**, for a **Payback Period** of about **4.3 years**.

The plant **Efficiency** is approximately **57%**, and the equipment **Heat to Power Ratio** is about **0.34**, both demonstrating the domination of electrical power production in this Alternative 5 cycle.

On paper, this Alternative 5 looks much more attractive (i.e. best Payback Period) than any of the previous alternatives. However, because of the amount of capital required, the industrial facility would rarely execute this project without a partner. Because of the risk associated with using only 1 x 50 MW GTG as the basis of the plant, the proponent may want 2 x 25 MW GTGs instead, or some alternate configuration. These factors could increase the plant cost and/or diminish the project economic returns.

1.7 Summary Comparison of Electric Power Generation Cases

The following table summarizes the Electric Power Generation cases:

Alt.	Configuration	Eff'y %	Heat to Power Ratio	Cost ($mm)	Annual Opr'tng Cost ** ($mm)	Annual Savings ($mm)	Simplified Payback Period
Base Case	Boiler Plant + Utility Electricity	80% thermal	1.18	-	$14.0	-	-
1	Base Case + Open Cycle GTG	27%* on-peak	0.0*	$9.0	12.1+1.0 ~ $13.1	$0.9	10 years
2	Base Case + GTG w/ Unfired HRSG	73%*	1.59 *	$12.5	10.5+1.5 ~ $12.0	$2.0	6.5 years
3	Base Case + GTG w/ Fired HRSG	75%	2.34 *	$13.2	10.3+1.7 ~ $12.0	$2.0	6.6 years
4	Small Combined Cycle Plant	68%	1.18	$23.5	7.1+3.3 ~ $10.4	$3.6	6.6 years
5	Large Combined Cycle Plant	57%	0.34	$50.0	-5.2+7.5 ~ $2.2	$11.8	4.3 years

* For the new equipment only.
** Including fuel, electricity purchases/revenues, O&M and finance charges, as applicable.

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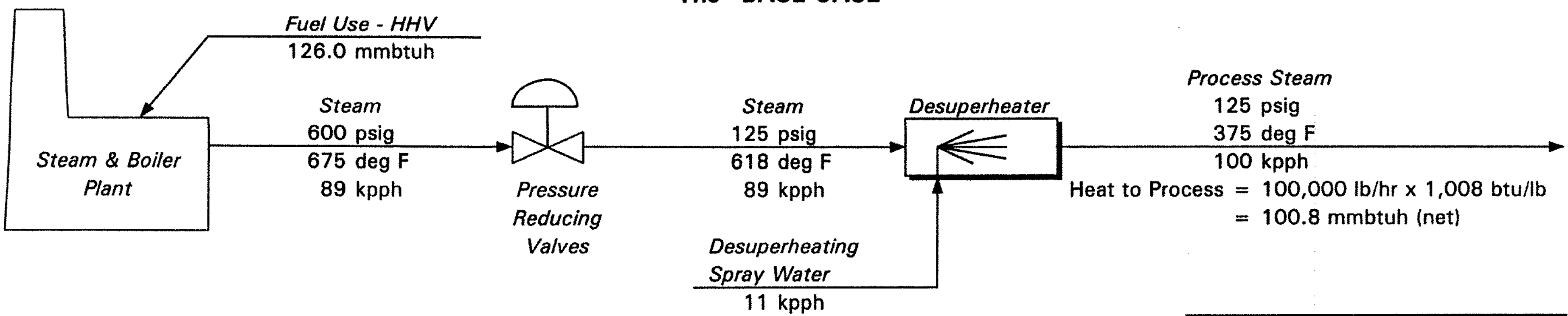
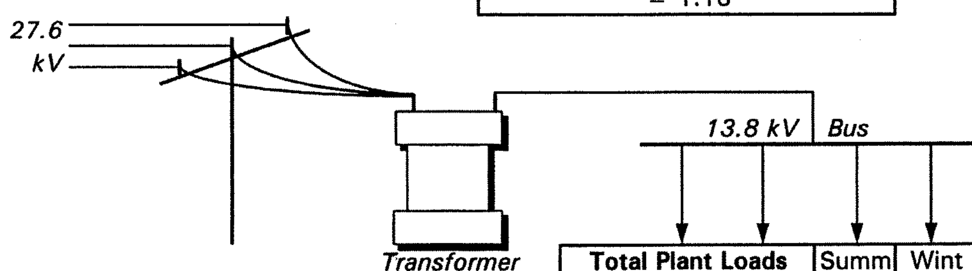
Electric Power Generation Applications

The "BASE CASE"



Facility BASE Heat to Power Ratio
100,000 lb/hr x 1,008 btu/lb
25,000 kw x 3,413 btu/kw.hr
= 1.18



Total Plant Loads	Summ	Wint	Hrs*
On-Peak MW	25.0	25.0	4000
Off-Peak MW	25.0	25.0	4000

* 50% summer, 50% winter

On-Site Energy Production		
Heat Made:	100.8	mmbtuh
Power Made:	n/a	mmbtuh
Fuel Used:	126.0	mmbtuh-HHV
Thermal Efficiency (steam):		80%

Facility Utility Purchase Costs		
Fuel Cost:	$410	per hour
Fuel Cost:	$3.28	million/yr
Steam Cost:	$4.10	$/'000lb
Elect Purch:	$10.76	million/yr
On-Pk Elect:	7.9	¢/kw.hr
Off-Pk Elect:	2.9	¢/kw.hr
Annual Elect:	5.4	¢/kw.hr

Total Utility Cost per year
$3.28 + $10.76 = $14.0 million
BASE CASE

Economics Basis for Above
Fuel: $3.25 per mmbtu - HHV
Elect: 1997 Ontario Hydro rates
* 8,000 hrs of operation per year

BASE CASE SCENARIO

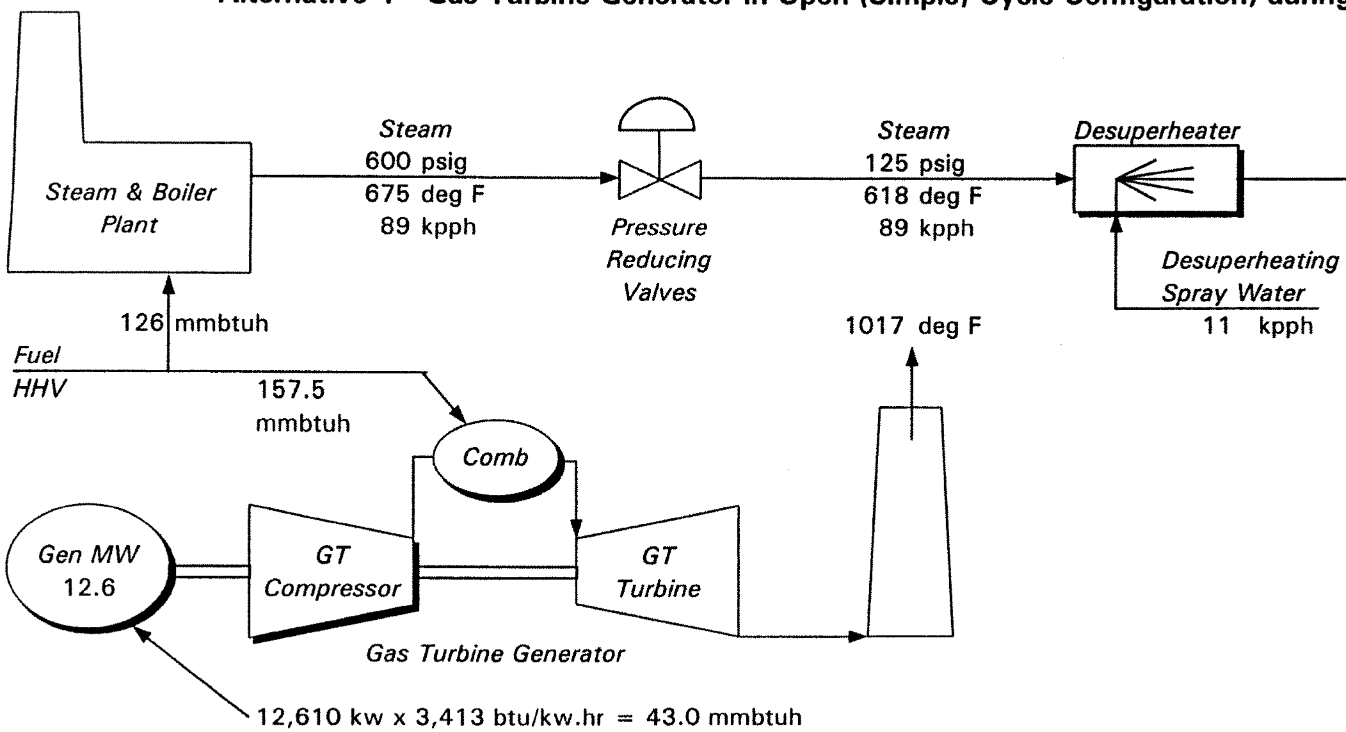
An industrial facility utilizing ~25 MW of electrical power and 100,000 lb/hr of process steam, 8,000 hrs/yr.

The facility's Steam & Boiler Plant produces superheated steam, which is reduced to the process steam pressure by pressure reducing valves (PRV'S) and cooled to the process steam temperature by desuperheaters (DSH).

Power is purchased from the local electrical Utility. The Steam & Boiler Plant uses natural gas only.

Electric Power Generation Applications

Alternative 1 - Gas Turbine Generator in Open (Simple) Cycle Configuration, during On-Peak Hours Only



On-Site Energy Production During On-Peak Periods		
Heat Made:	100.8	mmbtuh
Power Made:	43.0	mmbtuh*
Fuel Used*:	283.5	mmbtuh-HHV
Thermal Efficiency*:		51%
Heat/Power Ratio*:		2.34

Facility Utility Purchase Costs		
Boiler Fuel:	$410	per hour
GTG Fuel*:	$512	per hour*
Fuel Cost:	$5.32	million/yr
Elect Purch:	12.4	MW-on peak
Elect Purch:	25.0	MW-off peak
Elect Purch:	$6.79	million/yr
Total Utility Cost / yr reduced to: $5.32 + $6.79 = $12.1 million		

* During On-Peak hours only

Simplified Investment Potential**
Base Case minus Alt. 1:
$14.0 - $12.1 = $1.9 million/yr
Potential savings for gas turbine investment purposes

** Finance and O&M costs to be paid from $1.9 mm savings

ALTERNATIVE 1 SCENARIO

A SIMPLE CYCLE gas turbine generator is installed to operate during ON-PEAK PERIODS only (4,000 hrs/yr), reducing on-peak demand and energy charges. The Steam & Boiler Plant still provides the required process steam. Capital Cost about $9 million CAD.

Advantages

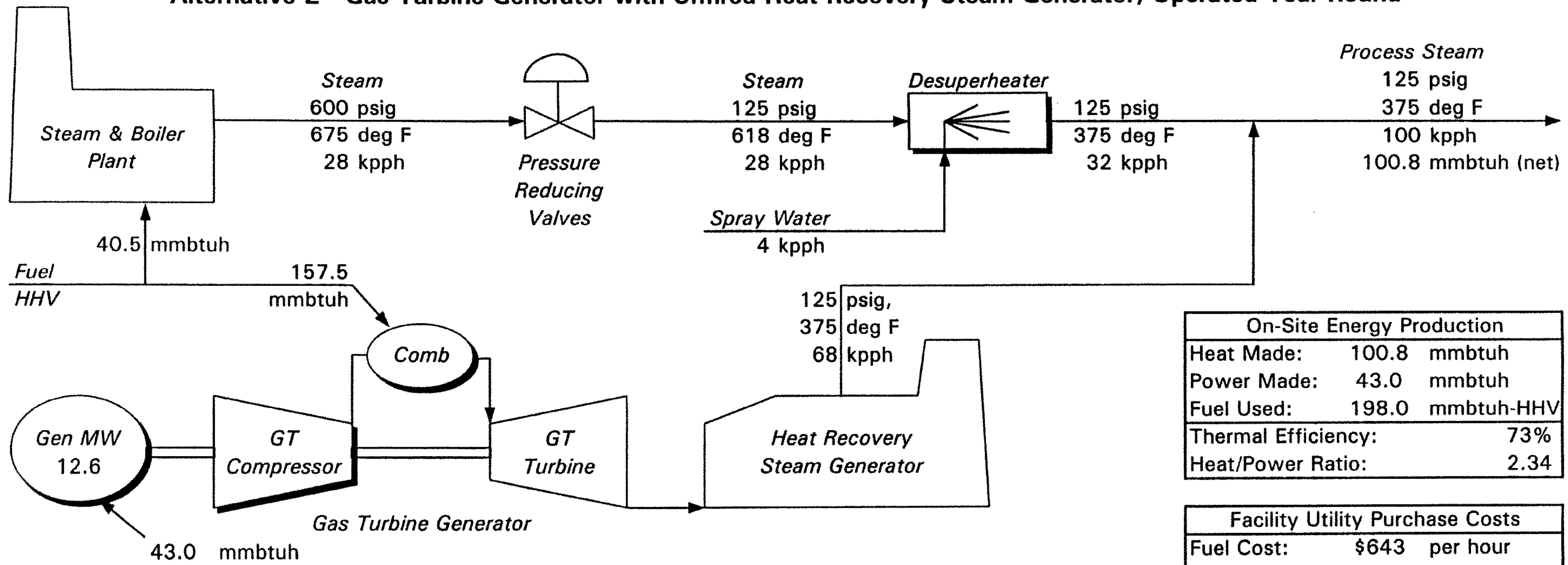
Net Utility purchase costs reduced from $14.0 mm to $12.1 mm, a "savings" of $1.9 mm /yr.

Disadvantages

**The annual finance charge ($0.8 mm) and O&M costs ($0.2 mm) reduce these savings to about $0.9 mm/yr.
Simple payback about $9.0 / $0.9 = 10 years.
GT exhaust heat wasted. Overall on-site efficiency could be better.
Backup Power Agreement required with electrical Utility.

Electric Power Generation Applications

Alternative 2 - Gas Turbine Generator with Unfired Heat Recovery Steam Generator, Operated Year-Round



On-Site Energy Production		
Heat Made:	100.8	mmbtuh
Power Made:	43.0	mmbtuh
Fuel Used:	198.0	mmbtuh-HHV
Thermal Efficiency:		73%
Heat/Power Ratio:		2.34

Facility Utility Purchase Costs		
Fuel Cost:	$643	per hour
Fuel Cost:	$5.15	million/yr
Elect Purch:	12.4	MW-on peak
Elect Purch:	12.4	MW-off peak
Elect Purch:	$5.33	million/yr
Total Utility Cost / yr reduced to:		
$5.15 + $5.33 = $10.5 million		

Simplified Investment Potential**
Base Case minus Alt. 2:
$14.0 - $10.5 = $3.6 million/yr
Potential savings for gas turbine
& HRSG investment purposes

** Finance and O&M costs to be paid from $3.6 mm savings

ALTERNATIVE 2 SCENARIO

A low-pressure, unfired HRSG is installed on the GTG exhaust to recover waste heat and generate process steam.

Less steam is required from the Steam Plant itself. The existing Steam Plant feedwater, condensate and water treatmen systems are kept.

Capital Cost about $12.5 million CAD.

Advantages

A nominal "savings" of $3.6 mm/yr, compared to Base Case.

On-site operating efficiency increased.

Disadvantages

**Annual finance charge of $1.1 mm and O&M cost of $0.5 mm reduce savings to about $2.0 mm/yr. Simple payback about $12.5 / $2.0 = 6.5 years.

With an unfired HRSG, the HRSG steam production can not be controlled.

Increased plot plan requirements, near to the Steam Plant. Backup Power Agreement required with Utility.

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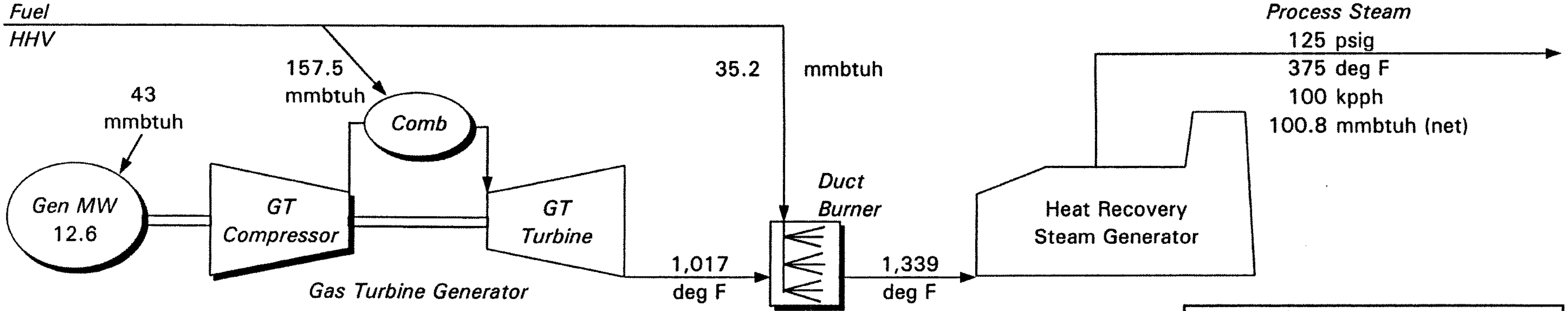
Electric Power Generation Applications

Alternative 3 - Gas Turbine Generator with Fired Heat Recovery Steam Generator, Operated Year-Round



The Steam & Boiler Plant is no longer shown, since it's only required for backup now.

The existing feedwater, condensate and water treatment systems are kept.

On-Site Energy Production		
Heat:	100.8	mmbtuh
Power:	43.0	mmbtuh
Fuel:	192.7	mmbtuh-HHV
Thermal Efficiency:		75%
Heat/Power Ratio:		2.34

Facility Utility Purchase Costs		
Fuel Cost:	$626	per hour
Fuel Cost:	$5.01	million/yr
Elect Purch:	12.4	MW-on peak
Elect Purch:	12.4	MW-off peak
Elect Purch:	$5.33	million/yr
Total Utility Cost per year		
$5.01 + $5.33 = $10.3 million		

ALTERNATIVE 3 SCENARIO

A larger, low-pressure HRSG, with duct firing capability, is installed on the GT exhaust, in lieu of an unfired HRSG. The amount of HRSG duct burner firing is varied to follow process steam load. Less, or no steam is required from the Steam Plant itself, and the existing boilers could potentially be retired or maintained as backup.
Capital Cost about $13.2 million CAD.

Advantages

A nominal "savings" of $3.7 mm/yr, compared to the Base Case.
On-site operating efficiency further increased. Process steam load can be followed, via duct burner.

Disadvantages

**The annual finance charge of $1.2 mm, and the annual O&M cost of $0.5 mm reduce savings to about $2.0 mm Cdn /yr. Simple payback about $13.2 / $2.0 = 6.6 years.
Increased plot plan requirements, near to the Steam Plant.
Backup Power Agreement required with electrical Utility.

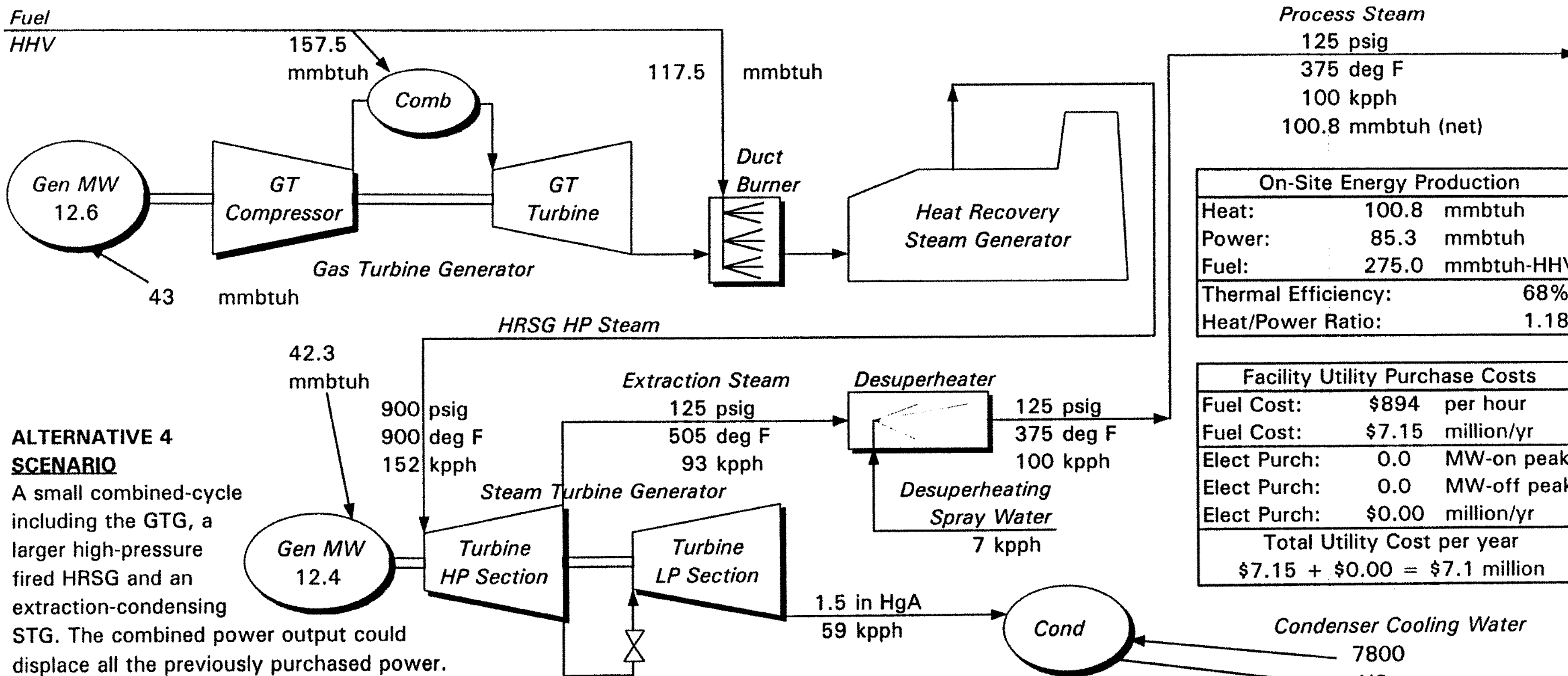
Simplified Investment Potential**
Base Case minus Alt. 3:
$14.0 - $10.3 = $3.7 million/yr
Potential savings for gas turbine & HRSG investment purposes

** Finance and O&M costs to be paid from $3.7 mm savings

GAS TURBINE APPLICATIONS ©

Electric Power Generation Applications

Alternative 4 - Small Combined-Cycle Cogeneration Plant



On-Site Energy Production		
Heat:	100.8	mmbtuh
Power:	85.3	mmbtuh
Fuel:	275.0	mmbtuh-HHV
Thermal Efficiency:		68%
Heat/Power Ratio:		1.18

Facility Utility Purchase Costs		
Fuel Cost:	$894	per hour
Fuel Cost:	$7.15	million/yr
Elect Purch:	0.0	MW-on peak
Elect Purch:	0.0	MW-off peak
Elect Purch:	$0.00	million/yr
Total Utility Cost per year		
$7.15 + $0.00 = $7.1 million		

ALTERNATIVE 4

SCENARIO

A small combined-cycle including the GTG, a larger high-pressure fired HRSG and an extraction-condensing STG. The combined power output could displace all the previously purchased power.
An extraction on the steam turbine provides the required process steam. Capital Cost about $23.5 million CAD.

Advantages

A nominal "savings" of $6.9 mm/yr, compared to the Base Case.
On-site operating efficiency good. Cycle is flexible to follow electrical & steam load, by varying duct firing.

Disadvantages

**The annual finance charge of $2.1 mm and annual O&M cost of $1.2 mm reduce the savings to $3.6 mm/yr. Simple payback about $23.5 / $3.6 = 6.6 years.
Increased plot plan requirements. Cooling water or other condensing means required.
Backup Power Agreement required with electrical Utility.

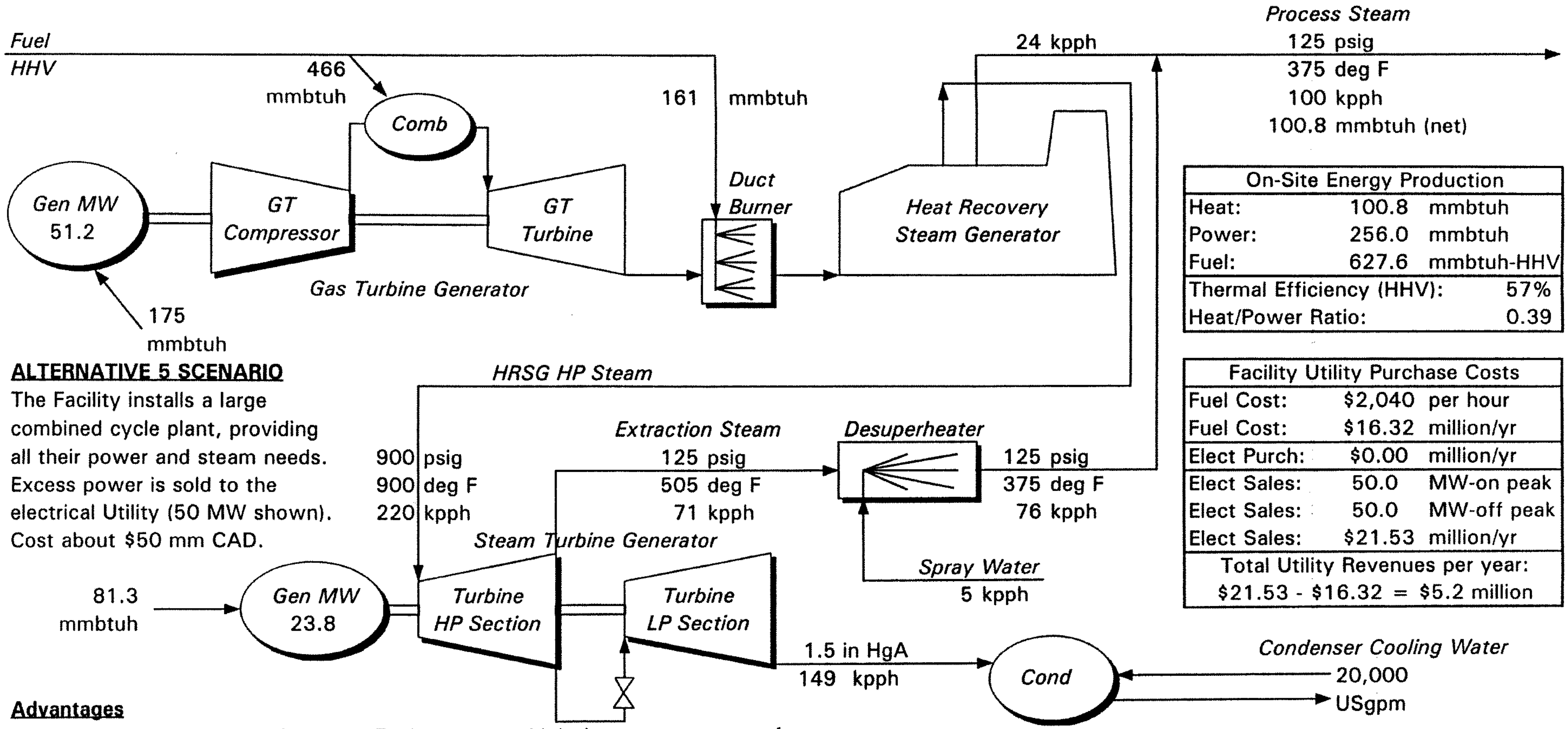
Simplified Investment Potential**
Base Case minus Alt. 4:
$14.0 - $7.1 = $6.9 million/yr
Potential savings for combined cycle investment purposes

** Finance and O&M costs to be paid from $6.9 mm savings

GAS TURBINE APPLICATIONS ©

Electric Power Generation Applications

Alternative 5 - Large Combined-Cycle Cogeneration Plant



ALTERNATIVE 5 SCENARIO

The Facility installs a large combined cycle plant, providing all their power and steam needs. Excess power is sold to the electrical Utility (50 MW shown). Cost about $50 mm CAD.

On-Site Energy Production		
Heat:	100.8	mmbtuh
Power:	256.0	mmbtuh
Fuel:	627.6	mmbtuh-HHV
Thermal Efficiency (HHV):		57%
Heat/Power Ratio:		0.39

Facility Utility Purchase Costs		
Fuel Cost:	$2,040	per hour
Fuel Cost:	$16.32	million/yr
Elect Purch:	$0.00	million/yr
Elect Sales:	50.0	MW-on peak
Elect Sales:	50.0	MW-off peak
Elect Sales:	$21.53	million/yr
Total Utility Revenues per year:		
$21.53 - $16.32 = $5.2 million		

Advantages

Electrical purchases reduced to zero. Fuel costs very high, but a net revenue of $5.2 mm/yr due to electrical sales is realized. Total "savings" about $19.3 mm/yr.
Plant is flexible to follow facility electrical & steam load, and to manage electrical demand.

Disadvantages

**The annual finance charge of $4.5 mm and the annual O&M costs of $3.0 mm reduce savings to $11.8 mm/yr. Simple payback about $50 / $11.8 = 4.3 years.
New steam, feedwater, makeup water plants required. Cooling water or other condensing means required.
Backup Power Agreement and Power Sales Agreement required.

Simplified Investment Potential**
Base Case savings + Alt. 5 revenue:
$14.0 + $5.2 = $19.3 million/yr
Potential revenues for combined cycle investment purposes

** Finance and O&M costs to be paid from $19.3 mm savings

2.0 MECHANICAL POWER APPLICATIONS

Today, aero-derivative gas turbines are typically installed in gas pipeline compression applications, due to their relatively high efficiency, quick startup capability and the ability for quick maintenance changeout.

In the past, low-pressure ratio two-shaft industrial-type gas turbines (frequently with recuperators to raise efficiencies) were installed for pipeline gas compression service. Many of these older units are still operating.

A typical 30,000-hp multi-shaft aero-derivative gas-turbine which is driving a gas-compressor is shown on the enclosed graphic.

2.1 Potential Combined Cycle Application 1

As shown on the subsequent graphic, in certain circumstances it is possible to add waste heat recovery to the exhaust of this turbine-compressor set, and to make high pressure steam for introduction into a condensing steam turbine generator set. When these compressor stations are located in remote areas without significant quantities of cooling water, an air-cooled condenser is required for the steam turbine set.

This is a cogeneration cycle, since two useful forms of energy, electricity (about 7.5 MW) and mechanical power (30,000 hp of gas compression) are produced from the same initial fuel source.

The incremental cost of the combined cycle equipment (about $16.0 million), combined with the low amounts of electrical power which can be sold, result in a fairly long **Payback Period** for this plant, about **10.4 years**.

It must also be noted that the operation of the turbine-compressor unit is normally controlled by the pipeline system flow/pressure requirements, and is possibly being stopped and started rather frequently, or continually operated only at partial load. Such a variance in operating modes would adversely impact the power output of the cycle, and thus the economic return.

The next example alternative will address a means of diminishing these problems.

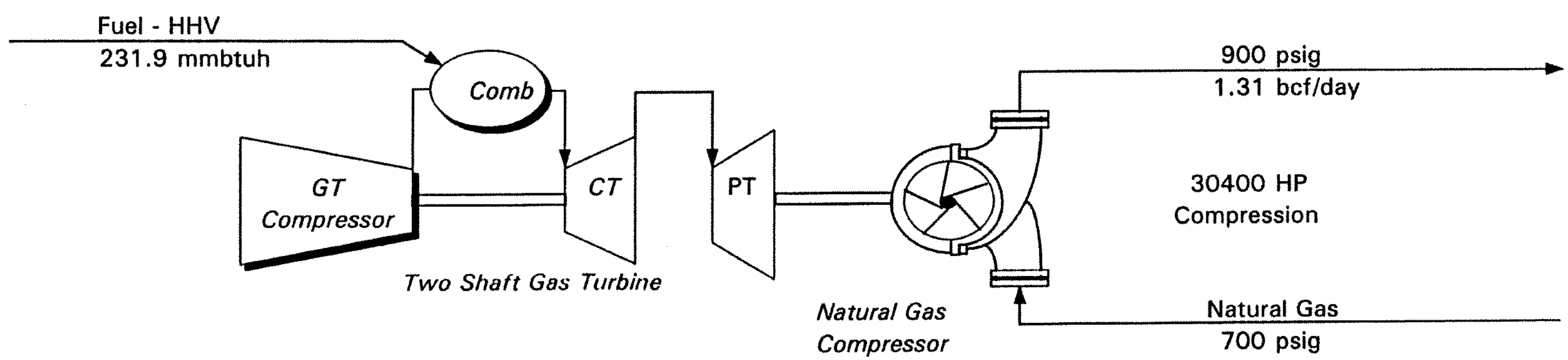
2.2 Potential Combined Cycle Application 2

To increase the revenues of the plant, an additional GTG set, HRSG and a larger condensing STG set could be installed, as shown on the enclosed graphic.

Variations of this type of plant have been constructed on several locations along the Canadian gas pipeline system. The extra GTG could be either an aero-derivative or heavy-duty industrial unit.

For the situation shown on the Alternative 2 graphic, the **Payback Period** is approximately **3.7 years**, about 3 times quicker than the simpler but more riskier (economically) Application 1.

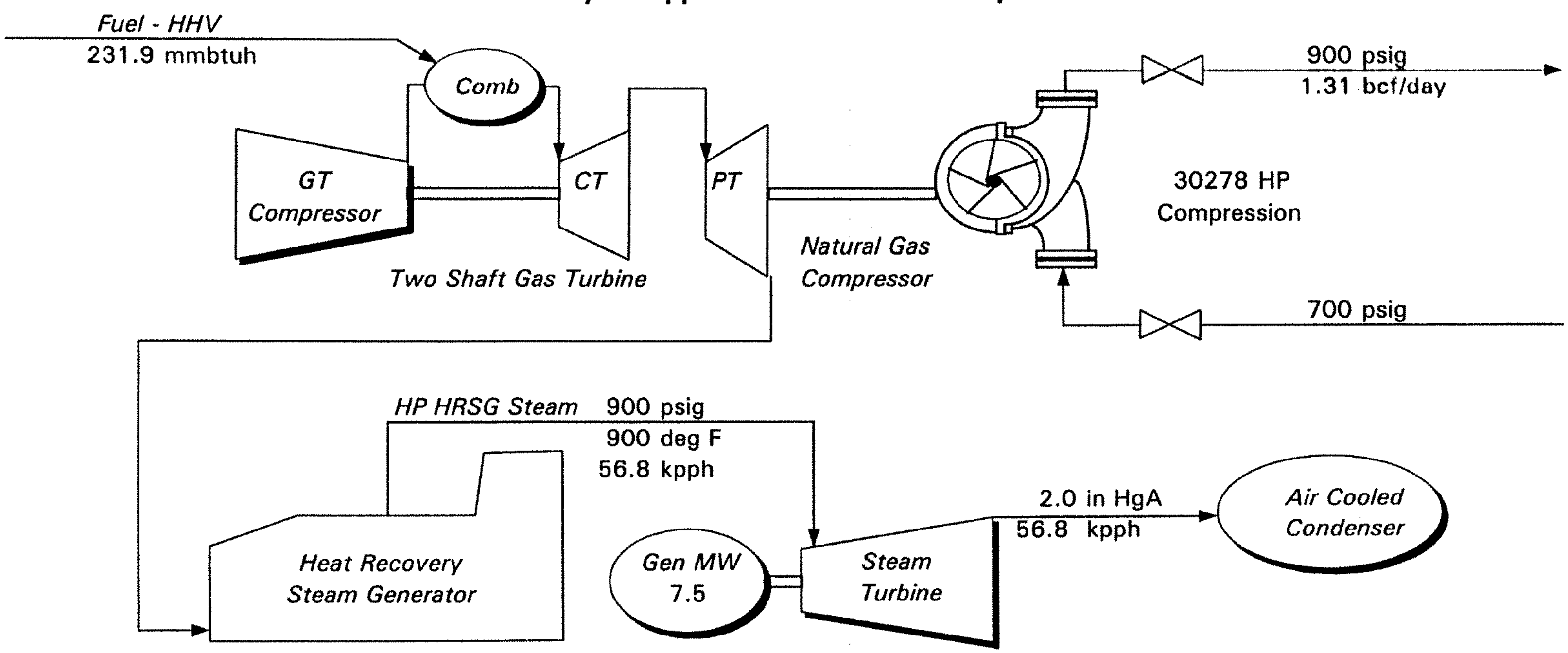
Mechanical Power Applications
Typical Utility Pipeline Gas Compressor Unit



Typical Compressor Station Existing Scenario

Multi-shaft aero-derivative gas turbines are typically used in gas pipeline compression service, due to their relatively high efficiency, quick changeout capability (for maintenance) and quick startup capability.

Mechanical Power Applications
Potential Combined Cycle Application 1 for Gas Compressor Stations



SCENARIO NO. 1

The diagram shows a very simple potential combined-cycle application for gas compression stations. Waste heat is recovered from the gas turbine exhaust to generate steam for a condensing steam turbine generator.

Advantages

· Moderate net income.

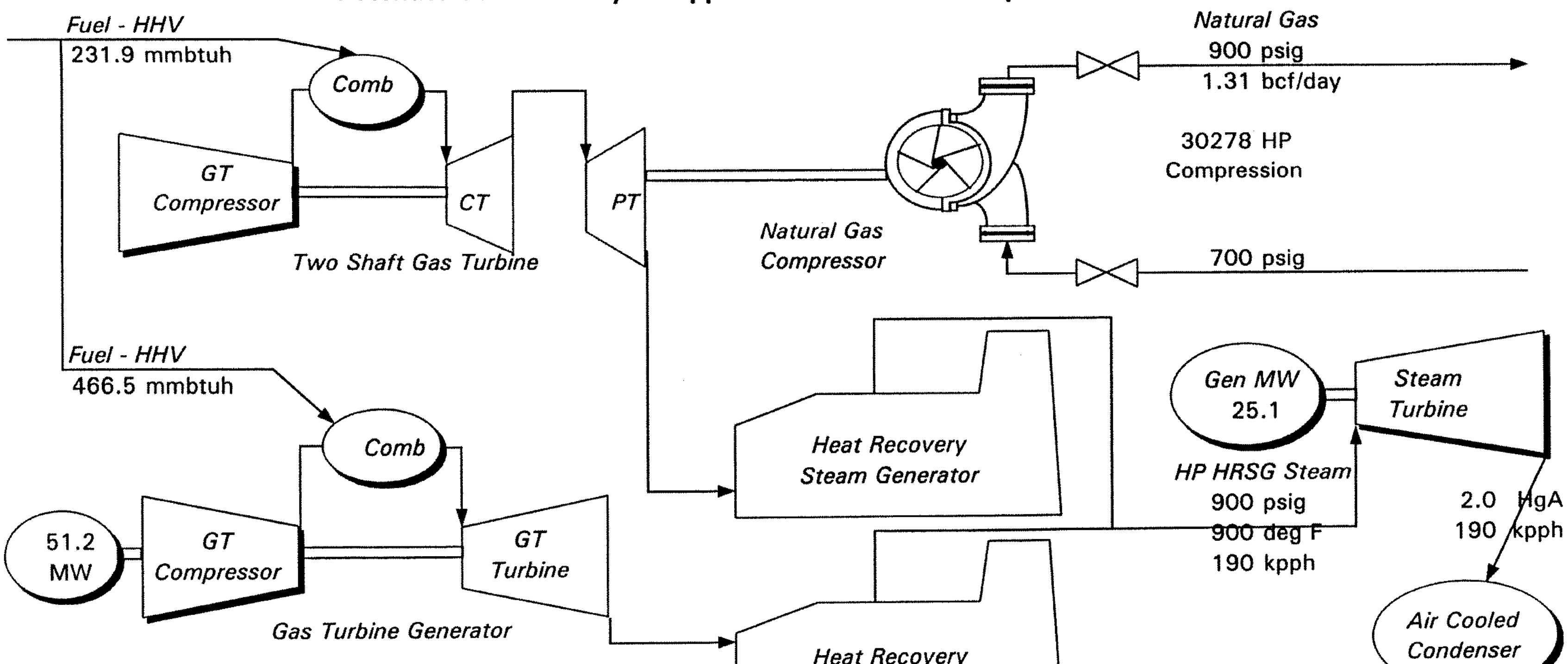
Disadvantages

· Power output is subject to pipeline operating demand, ie. up, down and/or off.
· For the assumptions shown, payback period is too long.
· Need area at compressor station, cycle water, possibly power lines, etc.
· Increased backpressure on compressor drive turbine decreases utility compression capability - hidden cost.

Annual Electrical Sales:	3.7	$mm/yr
Annual Fuel Cost:	0.0	$mm/yr
Annual O&M Cost:	0.3	$mm/yr
Incremental Operators:	0.5	$mm/yr
Annual Finance Cost:	1.4	$mm/yr
Total Expenses	2.2	$mm/yr
Net Income	1.5	$mm/yr
Simple Payback Period	10.4	yrs
Assumptions: Avg. electrical sale price 6.0¢/kw.hr; Fuel cost $3.25/mmbtu; 95% avail'ty (8322 hr/yr) with 100% utilization. Plant cost of $16.0 million.		

Mechanical Power Applications

Potential Combined Cycle Application 2 for Gas Compression Stations



Annual Electrical Sales:	38.1	$mm / yr
Annual Fuel Cost:	12.6	$mm / yr
Annual O&M Cost:	3.3	$mm / yr
Incremental Operators:	1.2	$mm/yr
Annual Finance Cost:	5.3	$mm / yr
Total Expenses	22.4	$mm / yr
Net Income	15.7	$mm / yr
Simple Payback Period	3.7	yrs

Assumptions: Avg. electrical sale price 6.0¢/kw.hr; Fuel cost $3.25/mmbtu; 95% avail'ty (8322 hr/yr) with 100% utilization. Plant cost of $58 million.

SCENARIO 2

Scenario 1 is expanded with a new, large gas turbine generator, an additional HRSG and bigger STG and condenser.

Advantages

- Good net income
- Power output is less sensitive to pipeline operations

Disadvantages

- Need area at compressor station, cycle water, possibly power lines, etc
- Still the hidden cost of Increased backpressure on compressor drive turbine

3.0 TURBINE SELECTION CRITERIA

Cogeneration proponents frequently ask:

- What's the best gas turbine?
- What's the best kind of turbine, aero-derivative or heavy duty industrial?
- How many should we get?
- Should be get a steam turbine too?"

There is no single correct answer to these questions. Each cogeneration opportunity requires a thorough evaluation, considering all of the proponent's applicable factors such as:

a) The existing power load and their seasonal, weekly and daily variations.
b) The existing electrical and fuel purchase costs.
c) The capability to provide additional fuel to the facility.
d) The existing system gas pressures (where applicable).
e) The existing heat load and their seasonal, weekly and daily variations.
f) The condition of existing steam plant equipment (boilers, water treatment, feedwater and condensate systems) and physical facilities.
g) The allowable downtime for maintenance of the cogeneration equipment.
h) The impact of forced outages on the facility's production.
i) The allowable project risk.
j) The corporation's capital investment capability and how many other proposed projects in the facility are competing for the capital required for a cogeneration project.
k) The incremental manpower and resources which would be required to support a cogeneration project.

The following two sections outline only some considerations.

3.1 Turbine Sizing

Gas turbines are available in a wide selection of capacities and efficiencies.

Aero-Derivative units are available from fractional MW sizes (0.3 to 0.6 MW) up to approximately 50 MW. All these units are usually more efficient (up to 40% or 42% - LHV) than their industrial cousins, but where waste heat recovery is required, will usually not produce as much "waste heat".

Heavy-duty Industrial gas turbines are available from fractional MW sizes (0.3 to 0.6 MW) up to approximately 240 MW. Above 50 MW (per unit), the only GTG choice would be heavy-duty industrial. These industrial units are generally not as efficient in simple cycle as their aero-derivative cousins, but will produce more "waste heat".

3.2 Aero-Derivative vs. Heavy Duty Industrial

In this section, we will outline some generalized fundamental differences between aero-derivative gas turbines:

	Aero-Derivative	**Heavy Duty**
Performance	Susceptible to compressor fouling and icing, and foreign object damage	More robust compressor and inlet configuration
	Frequent compressor washing required	Compressor washing still required, but less frequently
	Some units fall off, or actually decrease power output as ambient temperature decreases	For most units, power increases to the generator limit as ambient temperature decreases
	Fairly tolerant of cyclic duty	Optimized for continuous duty at base load
Fuel Considerations	Natural gas to light distillates and jet fuel	Natural gas through to distillates and cheaper heavy or residual fuels
	Generally requires high gas supply pressures	Generally requires a lower gas pressures Expensive treatment of heavy/residual fuels required
Start-up	Quick start-up – 5 to 20 minutes	20 to 60 minutes, depending on size
	Relatively low horsepower starters	High horsepower starters
Loading	Quick loading, sometimes 10% - 25% per minute	Slower loading, 1% to 5% per minute

	Aero-Derivative	Heavy Duty
Shutdown	Many aero-derivatives require a short time of motoring to cool internals after trip, but then can be shut down	Many units require 1-2 days on turning gear after shutdown, but could be motored to assist quicker cooldown.
Maintenance	Borescope inspection ports	Borescope inspection ports
	Generally more frequent inspections required	Inspections less frequent, but requires longer shutdowns
	Maintenance is more expensive (4 kw.hr) and not all can be done at site	Most maintenance can be done at site
	Lease engines available	No lease engines