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Cost Module for GE Radiant Quench IGCC Aspen Plus Model

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COLLABORATORY FOR PROCESS AND DYNAMIC SYSTEMS MODELING RESEARCH

COST MODULE FOR GE RADIANT QUENCH IGCC ASPEN PLUS MODEL

Report of

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to

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Disclaimer

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Introduction

This report describes the input parameters in the cost model developed for an integrated gasification combined cycle plant (IGCC) operating with a GE radiant quench gasifier. The performance model for this system was developed by the Department of Energy's National Energy Technology Laboratory (NETL) as an Aspen Plus steady-state process simulation. The performance model was delivered to Carnegie Mellon for the purpose of adding a cost model, as described in this report. Parameters from the performance model that are required for the cost model are identified in this report.

The cost model is divided into four separate areas: (1) financing parameters, (2) capital cost parameters, (3) operating and maintenance parameters, and (4) levelized cost parameters. Each input parameter is described briefly in the following sections. Intermediate and final result parameters are not described here; however, a final cost report is provided for two illustrative cases.

Aspen Plus Parameters

Power Generation or Use

The following power generation or electricity use parameters from the Aspen Plus flowsheet are used by the cost model. These parameters must be present in the Aspen Plus performance model.

Parameter	Description	Units
GTSUM	Gas turbine net power output	hp
STSUM	Power output from steam turbines	hp
WST	Power output from steam turbines (same as STSUM)	hp
WO2COM	Power for gasifier O_2 compressor	hp
WASU	Power for air separation unit	hp
WN2COM	Power for N_2 compressor	hp
WTGRPM	Power for tail gas pump	hp
WTGRCY	Power for tail gas recycle	hp
WCNDPM	Power for condensed water pump in steam cycle	hp
WGASEX	Power output from syngas expender	hp
WGT	Net power output of gas turbine system	hp
WHPPMP	Power of high pressure pump in steam cycle	hp
WIPPMP	Power of IP pump in steam cycle	hp
WLPPMP	Power of low pressure pump in steam cycle	hp
WQBOST	Power of quench water boost pump	hp
WQPMP	Power of quench water pump	hp
WSLRPM	Power of slurry preparation pump	hp
WSLYPM	Power of slurry pump	hp
WSYNBT	Power of booster for syngas from Selexol	hp
WTGREC	Power of tail gas recycle compressor	hp
WGTCOM	Power of gas turbine compressors	hp

Temperatures and Pressures

The following temperature and pressure parameters from the Aspen Plus flowsheet are used by the cost model. These parameters must be present in the Aspen Plus performance model.

Parameter	Description	Units
PGASIF	Gasifier operation pressure	psi
TGASIF	Gasifier operation temperature	F
TFIRE	Operation temperature of gas turbine combustor	F
TCOMB	Temperature of gas mixture fed into gas turbine combustor	F
TGTPOC	Temperature of exhaust from gas turbine	F
TSHSTM	Operation temperature of high pressure superheater in the steam cycle	F
TRESTM	Operating temperature of HRSG reheater	F
TLPSTM	Temperature of steam fed into the low pressure steam turbine	F
PHPS	Pressure of steam fed into the high pressure superheater	psi

Flow Rates and Concentrations

The following flow rate and concentration parameters from the Aspen Plus flowsheet are used by the cost model. These parameters must be present in the Aspen Plus performance model.

Parameter	Description	Units
MCFGI	Mass flow of coal fed into the gasifier	lb/hr
PPEH2O	Moisture percentage in the coal	
O2IN	O_2 mass flow from air separation unit	lb/hr
H2OIN	H_2O mass flow for coal slurry preparation	lb/hr
GTFUL1	Syngas mass flow rate fed into gas turbine combustor	lb/hr
GTFUL2	Syngas mass flow rate fed into gas turbine combustor	lb/hr
GTAIR	Air mass flow rate fed into gas turbine compressor	lb/hr
STSTM	Flow rate of main steam fed into high pressure steam turbine	lb/hr
FIPSTM	Mass flow rate of water fed into IP evaporator	lb/hr
FLPSTM	Mass flow rate of steam fed into the low pressure steam turbine	lb/hr
CO	Mole flow of CO fed into sour gas treatment unit (Selexol)	lbmol/hr
CO2	Mole flow of CO_2 fed into sour gas treatment unit (Selexol)	lbmol/hr
O2	Mole flow rate of oxygen fed into gasifier	lbmol/hr
SGLT	Mass flow rate of syngas from quench unit	lb/hr
SGTOSR	Mole flow of syngas fed into Selexol unit for sulfur removal	lbmol/hr
SFRCL	Mass flow of sulfur from Claus unit	lb/hr
RH2O	Mass flow rate of make-up water in steam cycle	lb/hr
PH2O	Mass flow rate of water from condenser in steam cycle	lb/hr
HPS	Mass flow rate of steam fed into the high pressure superheater	lb/hr
SGTOSC	Mole flow rate of syngas from quench unit	lbmol/hr

Input Parameters

Performance

Many of the cost parameters are linked directly to performance parameters already present in the Aspen Plus simulation delivered by NETL, as described in the previous section. However, several additional performance parameters must be added to satisfy the requirements of the cost model added to the simulation. These are described briefly below.

Parameter	Description	Default Value	Units
CF	Capacity Factor	0.75	Fraction
HHVCOAL	Coal Heating Value (HHV)	11,666	Btu/lb (wet)
NUMBER_LABOR	Total number of laborers	20	Laborers/day
YEAR	Construction Time[1]	4	Years
NASU	Total ASU Operating Trains	1	Integer
T	Atmospheric Temperature	59.0	F
EFFASU	ASU Oxygen Purity	0.95	Fraction
NG	Total Gasifier Trains	2 or 3[2]	Integer
NGO	Operating Gasifier Trains	2	Integer
NLT	Total Low Temp. Cooling Trains	1	Integer
NS	Total Selexol Sulfur Capture Trains	1	Integer
EFFS	Selexol Sulfur H_2S Removal Efficiency	0.98[3]	Fraction
NC	Total Claus System Trains	2	Integer
NBS	Total Beavon-Stretford System Trains	2	Integer
NGT	Total GE 7FB Gas Turbine Trains	2	Integer
NHR	Total Heat Recovery Steam Generator Trains	1	Integer
NST	Total Steam Turbine Trains	1	Integer

[1] This is the idealized construction period in years. It is used to determine the allowance for funds used during construction (AFUDC).
[2] The number of total gasifier trains depends on whether a spare train is available or not.
[3] This is the default value provided by the NETL Aspen Plus flowsheet.

Financing

This section describes the factors required to determine the carrying charge for all capital investments. The carrying charge is defined as the revenue required for the capital investment. The total charge can also be expressed as a levelized cost factor or fixed charge factor. The fixed charge factor is a function of many items. The fixed charge factor can be specified directly or calculated from the other input quantities below it on the financial input screen.

Parameter	Description	Default Value	Units
FCF	Fixed Charge Factor[4]	0.14	Fraction
DISCOUNT	Discount Rate (before taxes)[5]	0.103	Fraction
INFLATION	Inflation Rate[6]	0.0	Fraction
CPI	Chem. Eng. Cost Index Ratio[7]	1.186	Ratio of $2005/$2000

Capital Cost

The necessary capital cost input parameters associated with each process area in the IGCC flowsheet are listed below. The capital cost parameters and terminology used in the cost model are based on the methodologies developed by the Electric Power Research Institute (EPRI). EPRI has prepared a Technical Assessment Guide (TAG) in order to provide a consistent basis for reporting cost and revenues associated with the electric power industry (EPRI, 1986).

Total capital cost is divided into several specific cost areas, each of which is described in following sections:

- Process Facilities Cost
- General Facilities Cost
- Engineering & Home Office Fees
- Project Contingencies
- Process Contingencies
- Allowance for Funds Used During Construction (AFUDC)
- Royalty Fees
- Startup Costs
- Inventory Costs

These are summed and determine the total capital required. These can be annualized over the booklife of the power plant to give a levelized yearly cost. This levelized cost is used to determine the cost of electricity described in later sections.

[4] The fixed charge factor is one of the most important parameters in financing. It determines the revenue required to finance the power plant based on the capital expenditures. Put another way, it is a levelized factor which accounts for the revenue per dollar of total plant cost that must be collected from customers in order to pay the carrying charges on that capital investment.
[5] This is also known as the cost of money. Discount rate (before taxes) is equal to the sum of return on debt plus return on equity, and is the time value of money used in before-tax present worth arithmetic (i.e., levelization).
[6] This is the rise in price levels caused by an increase in the available currency and credit without a proportionate increase in available goods or services. It does not include real escalation.
[7] The cost information used was gathered in the year 2000. In order to report costs for the year 2006, a cost index is used (Vatavuk,1995).

Process Facility Cost (PFC)

The process facility cost (PFC) is composed of two parts: the direct construction costs and the indirect construction costs. The direct construction costs are provided in the cost model in equation form. The indirect construction costs are provided as a cost factor (shown below). The cost model provides an equation for each process area as a function of one or more performance parameters provided in the Aspen performance model.

Parameter	Description	Default Value	Units
PFC_ASU	Air Separation Unit (ASU) Factor	0.2	Fraction of PFC
PFC_CH	Coal Handing System (CH) Factor	0.2	Fraction of PFC
PFC_G	Gasifier System (G) Factor	0.2	Fraction of PFC
PFC_LT	Low Temp. Gas Cooling System (LT) Factor	0.2	Fraction of PFC
PFC_PC	Process Condensate Treatment System (PC) Factor	0.2	Fraction of PFC
PFC_S	Selexol for Sulfur Removal System (S)[8] Factor	0.2	Fraction of PFC
PFC_C	Claus Plant (C) Factor	0.2	Fraction of PFC
PFC_BS	Beavon-Stretford Plant (BS) Factor	0.2	Fraction of PFC
PFC_BFW	Boiler Feedwater System (BFW) System	0.2	Fraction of PFC
PFC_GT	Gas Turbine System (GT) Factor	0.2	Fraction of PFC
PFC_HR	Heat Recovery Steam Generator System (HR) Factor	0.2	Fraction of PFC
PFC_ST	Steam Turbine System (ST) Factor	0.2	Fraction of PFC
PFC_N2COMP	Nitrogen Compressor (N2COMP) Factor	0.2	Fraction of PFC

General Facility Cost

The general facilities include construction costs of roads, office buildings, shops, laboratories, etc. Sales taxes and freight costs are included implicitly. The cost typically ranges from 5-20% of the plant facility cost.

Parameter	Description	Default Value	Units
GFC_ASU	ASU Factor	0.15	Fraction of PFC
GFC_CH	Coal Handling Factor	0.15	Fraction of PFC
GFC_G	Gasifier Factor	0.15	Fraction of PFC
GFC_LT	Low Temp. Gas Cooling Factor	0.15	Fraction of PFC
GFC_PC	Process Condensate Treatment Factor	0.15	Fraction of PFC
GFC_S	Selexol for Sulfur Factor	0.15	Fraction of PFC
GFC_C	Claus Plant Factor	0.15	Fraction of PFC
GFC_BS	Beavon-Stretford Factor	0.15	Fraction of PFC
GFC_BFW	Boiler Feedwater Factor	0.15	Fraction of PFC
GFC_GT	Gas Turbine Factor	0.15	Fraction of PFC
GFC_HR	Heat Recover Steam Generator Factor	0.15	Fraction of PFC
GFC_ST	Steam Turbine Factor	0.15	Fraction of PFC
GFC_N2COMP	Nitrogen Compressor Factor	0.15	Fraction of PFC

[8] A hydrolysis unit is assumed to be installed ahead of the selexol sulfur capture train. The capital cost of this hydrolysis unit is assumed to be 5% of the selexol sulfur capital cost.

Engineering & Home Office Fees

The engineering & home office fees are a percent of process facilities cost. This is an overhead fee paid to the architect/engineering company. These fees typically range from 7-15%.

Parameter	Description	Default Value	Units
EHO_ASU	ASU Factor	0.10	Fraction of PFC
EHO_CH	Coal Handling Factor	0.10	Fraction of PFC
EHO_G	Gasifier Factor	0.10	Fraction of PFC
EHO_LT	Low Temp. Gas Cooling Factor	0.10	Fraction of PFC
EHO_PC	Process Condensate Treatment Factor	0.10	Fraction of PFC
EHO_S	Selexol for Sulfur Factor	0.10	Fraction of PFC
EHO_C	Claus Plant Factor	0.10	Fraction of PFC
EHO_BS	Beavon-Stretford Factor	0.10	Fraction of PFC
EHO_BFW	Boiler Feedwater Factor	0.10	Fraction of PFC
EHO_GT	Gas Turbine Factor	0.10	Fraction of PFC
EHO_HR	Heat Recover Steam Generator Factor	0.10	Fraction of PFC
EHO_ST	Steam Turbine Factor	0.10	Fraction of PFC
EHO_N2COMP	Nitrogen Compressor Factor	0.10	Fraction of PFC

Project Contingency

This is a factor covering the cost of additional equipment or other costs resulting from a more detailed design. Higher contingency factors will be applied to simplified or preliminary designs and lower factors to detailed or finalized designs.

Parameter	Description	Default Value	Units
PROJ_ASU	ASU Factor	0.15	Fraction of PFC
PROJ_CH	Coal Handling Factor	0.15	Fraction of PFC
PROJ_G	Gasifier Factor	0.15	Fraction of PFC
PROJ_LT	Low Temp. Gas Cooling Factor	0.15	Fraction of PFC
PROJ_PC	Process Condensate Treatment Factor	0.15	Fraction of PFC
PROJ_S	Selexol for Sulfur Factor	0.15	Fraction of PFC
PROJ_C	Claus Plant Factor	0.15	Fraction of PFC
PROJ_BS	Beavon-Stretford Factor	0.15	Fraction of PFC
PROJ_BFW	Boiler Feedwater Factor	0.15	Fraction of PFC
PROJ_GT	Gas Turbine Factor	0.15	Fraction of PFC
PROJ_HR	Heat Recover Steam Generator Factor	0.15	Fraction of PFC
PROJ_ST	Steam Turbine Factor	0.15	Fraction of PFC
PROJ_N2COMP	Nitrogen Compressor Factor	0.15	Fraction of PFC

Process Contingency

This quantifies the design uncertainty and cost of a commercial-scale system. This is generally applied on an area-by-area basis. Higher contingency factors are applied to new regeneration systems tested at a pilot plant and lower factors to full-size or commercial systems.

Parameter	Description	Default Value	Units
PROC_ASU	ASU Factor	0.05	Fraction of PFC
PROC_CH	Coal Handling Factor	0.05	Fraction of PFC
PROC_G	Gasifier Factor	0.15	Fraction of PFC
PROC_LT	Low Temp. Gas Cooling Factor	0.00	Fraction of PFC
PROC_PC	Process Condensate Treatment Factor	0.10	Fraction of PFC
PROC_S	Selexol for Sulfur Factor	0.10	Fraction of PFC
PROC_C	Claus Plant Factor	0.10	Fraction of PFC
PROC_BS	Beavon-Stretford Factor	0.10	Fraction of PFC
PROC_BFW	Boiler Feedwater Factor	0.00	Fraction of PFC
PROC_GT	Gas Turbine Factor	0.125	Fraction of PFC
PROC_HR	Heat Recover Steam Generator Factor	0.025	Fraction of PFC
PROC_ST	Steam Turbine Factor	0.025	Fraction of PFC
PROC_N2COMP	Nitrogen Compressor Factor	0.05	Fraction of PFC

Royalty Fees

Royalty charges may apply to some portions of generating units incorporating new proprietary technologies.

Parameter	Description	Default Value	Units
ROYAL_ASU	ASU Factor	0.005	Fraction of PFC
ROYAL_CH	Coal Handling Factor	0.005	Fraction of PFC
ROYAL_G	Gasifier Factor	0.005	Fraction of PFC
ROYAL_LT	Low Temp. Gas Cooling Factor	0.005	Fraction of PFC
ROYAL_PC	Process Condensate Treatment Factor	0.005	Fraction of PFC
ROYAL_S	Selexol for Sulfur Factor	0.005	Fraction of PFC
ROYAL_C	Claus Plant Factor	0.005	Fraction of PFC
ROYAL_BS	Beavon-Stretford Factor	0.005	Fraction of PFC
ROYAL_BFW	Boiler Feedwater Factor	0.005	Fraction of PFC
ROYAL_GT	Gas Turbine Factor	0.005	Fraction of PFC
ROYAL_HR	Heat Recover Steam Generator Factor	0.005	Fraction of PFC
ROYAL_ST	Steam Turbine Factor	0.005	Fraction of PFC
ROYAL_N2COMP	Nitrogen Compressor Factor	0.005	Fraction of PFC

Preproduction Startup Cost

These costs consider the operator training, equipment checkout, major changes in unit equipment, extra maintenance, and inefficient use of fuel or other materials during start-up. These are typically based on a portion of the total plant investment (TPI). The total plant investment is defined as:

Total Plant Investment (TPI) = Plant Facility Cost + General Facility Cost + Engineering & Home Office Fees + Project Contingency + Process Contingency + AFUDC

Parameter	Description	Default Value	Units
STARTUP_ASU	ASU Factor	0.02	Fraction of TPI
STARTUP_CH	Coal Handling Factor	0.02	Fraction of TPI
STARTUP_G	Gasifier Factor	0.02	Fraction of TPI
STARTUP_LT	Low Temp. Gas Cooling Factor	0.02	Fraction of TPI
STARTUP_PC	Process Condensate Treatment Factor	0.02	Fraction of TPI
STARTUP_S	Selexol for Sulfur Factor	0.02	Fraction of TPI
STARTUP_C	Claus Plant Factor	0.02	Fraction of TPI
STARTUP_BS	Beavon-Stretford Factor	0.02	Fraction of TPI
STARTUP_BFW	Boiler Feedwater Factor	0.02	Fraction of TPI
STARTUP_GT	Gas Turbine Factor	0.02	Fraction of TPI
STARTUP_HR	Heat Recover Steam Generator Factor	0.02	Fraction of TPI
STARTUP_ST	Steam Turbine Factor	0.02	Fraction of TPI
STARTUP_N2COMP	Nitrogen Compressor Factor	0.02	Fraction of TPI

Operating & Maintenance Costs

Miscellaneous Unit Costs

Several unit costs are needed to determine key operating and maintenance costs. These are described briefly below.

Parameter	Description	Default Value	Units
COAL_PRICE	Coal Price (As-delivered)	1.34	$/MBtu
SUL_PRICE	Sulfur Credit Price	58.0	$/ton
RATE_LABOR	Labor Rate	24.82	$/hour
ASH_DIS	Ash Disposal Charge	10.0	$/ton

Maintenance Cost

The annual maintenance costs as given as a fraction of the process facilities capital cost. Maintenance cost estimates can be developed separately for different sections of the plant. Here are the default values for each section of the IGCC plant:

Parameter	Description	Default Value	Units
MNT_ASU	ASU Factor	0.02	Fraction of PFC
MNT_CH	Coal Handling Factor	0.02	Fraction of PFC
MNT_G	Gasifier Factor	0.035	Fraction of PFC
MNT_LT	Low Temp. Gas Cooling Factor	0.03	Fraction of PFC
MNT_PC	Process Condensate Treatment Factor	0.02	Fraction of PFC
MNT_S	Selexol for Sulfur Factor	0.02	Fraction of PFC
MNT_C	Claus Plant Factor	0.02	Fraction of PFC
MNT_BS	Beavon-Stretford Factor	0.02	Fraction of PFC
MNT_BFW	Boiler Feedwater Factor	0.015	Fraction of PFC
MNT_GT	Gas Turbine Factor	0.015	Fraction of PFC
MNT_HR	Heat Recover Steam Generator Factor	0.015	Fraction of PFC
MNT_ST	Steam Turbine Factor	0.015	Fraction of PFC
MNT_N2COMP	Nitrogen Compressor Factor	0.02	Fraction of PFC

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Illustrative Results

IGCC: GE Radiant/Quench Gasifier (no CO_2 Capture)

The following results are generated for the cost model added to the IGCC Aspen model. The IGCC plant included a GE entrained-flow gasifier with a radiant quench syngas cooling system, followed by a Selexol system to remove sulfur and a power block to generate electricity. The source code can be found in the appendix.

No Spare Gasifier Train

```
                    ***  GASIFIER CONDITIONS  ***

               WET COAL FLOW RATE:  0.489685E+06 LB/HR
                 OXYGEN FLOW RATE:  0.387191E+06 LB/HR
                  WATER FLOW RATE:  0.201162E+06 LB/HR
                GASIFIER PRESSURE:   814.7 PSIA
             GASIFIER TEMPERATURE:  2400.0 F
     GASIFICATION EFFICIENCY (HHV):  0.778

                    ***  MS7000 GAS TURBINE CONDITIONS  ***

                       FUEL FLOW RATE:  0.108905E+07 LB/HR
                        AIR FLOW RATE:  0.706498E+07 LB/HR
                   FIRING TEMPERATURE:  2538.0 F
           COMBUSTOR EXIT TEMPERATURE:   663.5 F
          TURBINE EXHAUST TEMPERATURE:  1121.1 F

                    ***  STEAM TURBINE CONDITIONS  ***

            SUPERHEATED STEAM FLOW RATE:  0.157897E+07 LB/HR
          SUPERHEATED STEAM TEMPERATURE:  1055.0 F
                      IP STEAM FLOW RATE:  0.152768E+06 LB/HR
               REHEAT STEAM TEMPERATURE:  1055.0 F
                      LP STEAM FLOW RATE:  0.154450E+07 LB/HR
                    LP STEAM TEMPERATURE:   569.4 F

                    ***  POWER PRODUCTION SUMMARY  ***

                          GAS TURBINE:    0.463818E+09  WATTS
                        STEAM TURBINE:    0.300393E+09  WATTS
                          COMPRESSORS:   -0.379552E+09  WATTS
                         OXYGEN PLANT:   -0.578025E+08  WATTS
                          PLANT TOTAL:    0.646119E+09  WATTS
          PLANT THERMAL EFFICIENCY (HHV):    0.386017E+00
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```
                     COAL HEATING VALUE:    0.116660E+05  BTU/LB
                           CO2 EMISSION:    0.780930E+00  KG/KWH

                   ***   ECONOMIC ASSUMPTION  ***
              CAPACITY FACTOR:   0.750
          FIXED CHARGE FACTOR:   0.140
                DISCOUNT RATE:   0.103
               INFLATION RATE:   0.000
            CONSTRUCTION YEAR:   4.000
         COAL PRICE ($/MMBTU):   1.340

                   ***  IGCC CAPITAL COST SUMMARY ($1000)  ***

                   ***  PROCESS FACILITY COST  ***
               AIR SEPARATION UNIT: 90573.1
                     COAL HANDLING: 75328.8
                          GASIFIER:142280.2
       LOW TEMPERATURE GAS COOLING: 28161.5
                PROCESS CONDENSATE: 17544.0
        SELEXOL FOR SULFUR REMOVAL: 20212.6
                       CLAUS PLANT:  6709.4
             BEAVON-STRETFORD UNIT:     0.0
                 BOILER FEED WATER:  1592.5
                       GAS TURBINE:112586.5
                              HRSG: 36511.3
                     STEAM TURBINE: 61990.3
                     N2 COMPRESSOR: 13571.9
         TOTAL PROCESS FACILITY COST:607062.2

             GENERAL FACILITY COST: 91059.3
         ENGINEERING & OFFICE FEES: 60706.2
               PROJECT CONTINGENCY: 91059.3
               PROCESS CONTINGENCY: 50958.9
                  TOTAL PLANT COST:  900846.0
           TOTAL PLANT COST ($/KW):  1.3939
                             AFUDC:202166.9
            TOTAL PLANT INVESTMENT: 1103012.9
                           ROYALTY:  3035.3
                           STARTUP: 29120.8
                         INVENTORY:   879.1
                              LAND:  2214.7
         TOTAL CAPITAL REQUIREMENT: 1137383.7
    TOTAL CAPITAL REQUIREMENT ($/KW):  1.7599

ANNUAL VARIABLE O&M COST($/YEAR):   55498060.2635469
   ANNUAL FIXED O&M COST($/YEAR):   29228278.8981885
      COST OF ELECTRICITY($/MWH):   57.4699811930687
```

One Spare Gasifier Train

```
                   ***  GASIFIER CONDITIONS  ***

              WET COAL FLOW RATE:  0.489685E+06 LB/HR
              DRY COAL FLOW RATE:  0.686193E-39 LB/HR
                OXYGEN FLOW RATE:  0.387191E+06 LB/HR
                 WATER FLOW RATE:  0.201162E+06 LB/HR
               GASIFIER PRESSURE:   814.7 PSIA
            GASIFIER TEMPERATURE:  2400.0 F
     GASIFICATION EFFICIENCY (HHV):  0.778
```

```
          ***  MS7000 GAS TURBINE CONDITIONS  ***

                FUEL FLOW RATE:  0.108905E+07 LB/HR
                 AIR FLOW RATE:  0.706498E+07 LB/HR
            FIRING TEMPERATURE:  2538.0 F
      COMBUSTOR EXIT TEMPERATURE:   663.5 F
     TURBINE EXHAUST TEMPERATURE:  1121.1 F


          ***  STEAM TURBINE CONDITIONS  ***

       SUPERHEATED STEAM FLOW RATE:  0.157897E+07 LB/HR
     SUPERHEATED STEAM TEMPERATURE:  1055.0 F
                IP STEAM FLOW RATE:  0.152768E+06LB/HR
          REHEAT STEAM TEMPERATURE:  1055.0 F
                LP STEAM FLOW RATE:  0.154450E+07LB/HR
              LP STEAM TEMPERATURE:   569.4 F

          ***  POWER PRODUCTION SUMMARY  ***

                      GAS TURBINE:    0.463818E+09  WATTS
                    STEAM TURBINE:    0.300393E+09  WATTS
                      COMPRESSORS:   -0.379552E+09  WATTS
                     OXYGEN PLANT:   -0.578025E+08  WATTS
                      PLANT TOTAL:    0.646119E+09  WATTS
     PLANT THERMAL EFFICIENCY (HHV):    0.386017E+00
                COAL HEATING VALUE:    0.116660E+05  BTU/LB
                     CO2 EMISSION:    0.780930E+00  KG/KWH

          ***   ECONOMIC ASSUMPTION  ***

          CAPACITY FACTOR:   0.750
       FIXED CHARGE FACTOR:   0.140
            DISCOUNT RATE:   0.103
           INFLATION RATE:   0.000
        CONSTRUCTION YEAR:   4.000
     COAL PRICE ($/MMBTU):   1.340

          ***  IGCC CAPITAL COST SUMMARY ($1000)  ***

          ***  PROCESS FACILITY COST  ***

           AIR SEPARATION UNIT: 90573.1
                 COAL HANDLING: 75328.8
                      GASIFIER:213420.4
   LOW TEMPERATURE GAS COOLING: 28161.5
            PROCESS CONDENSATE: 17544.0
    SELEXOL FOR SULFUR REMOVAL: 20212.6
                  CLAUS PLANT:  6709.4
         BEAVON-STRETFORD UNIT:     0.0
              BOILER FEED WATER:  1592.5
                   GAS TURBINE:112586.5
                          HRSG: 36511.3
                 STEAM TURBINE: 61990.3
                 N2 COMPRESSOR: 13571.9
     TOTAL PROCESS FACILITY COST:678202.4

          GENERAL FACILITY COST:101730.4
     ENGINEERING & OFFICE FEES: 67820.2
           PROJECT CONTINGENCY:101730.4
           PROCESS CONTINGENCY: 61629.9
              TOTAL PLANT COST: 1011113.2
       TOTAL PLANT COST ($/KW):  1.5645
```

```
                    AFUDC:226912.9
       TOTAL PLANT INVESTMENT: 1238026.1
                      ROYALTY:  3391.0
                      STARTUP: 32162.8
                    INVENTORY:   879.1
                         LAND:  2214.7
   TOTAL CAPITAL REQUIREMENT: 1275794.7
TOTAL CAPITAL REQUIREMENT ($/KW):  1.9740

ANNUAL VARIABLE O&M COST($/YEAR):   55498060.2635469
   ANNUAL FIXED O&M COST($/YEAR):   33329746.6692580
      COST OF ELECTRICITY($/MWH):   63.0009601724489
```

List of Abbreviations

Abbreviation	Definition
AFUDC	Allowance for Funds Used During Construction
ASU	Air Separation Unit
BTU	British Thermal Unit
CO_2	Carbon Dioxide
EPRI	Electric Power Research Institute
F	Fahrenheit
GE	General Electric
HHV	Higher Heating Value
HR	Hour
HRSG	Heat Recovery Steam Generation
IGCC	Integrated Gasification Combined Cycle
IP	Intermediate Pressure
kG	Kilogram
kW	Kilowatt
LB	Pound
LP	Low Pressure
MMBtu	10^6 Btu
MWh	Megawatt-Hours
N_2	Nitrogen
O_2	Oxygen
O&M	Operating and Maintenance
NETL	National Energy Technology Laboratory
PFC	Plant Facility Cost
PSIA	Pounds Per Square Inch Absolute
TAG	Technical Assessment Guide
TPI	Total Plant Investment

Appendix

The Fortran source code used to define cost input parameters and calculate the cost results is listed below. This code has been embedded into the Aspen Plus flow sheet by means of a user block. In Aspen Plus, this code cannot be printed directly. However, a user can read and modify the code in the SUMMARY CALCULATOR found in in the flow sheet. To change any assumption in the cost model, find the parameters and change it.

```
C  --------------- REPORT GASIFIER CONDITIONS ---------------
C

F      MCOALD = MCFGI*(1.0-PERH2O/100.)
       HOC=11666.0
F      WRITE(*,110) MCFGI,MCOALD,O2IN,H2OIN,PGASIF,TGASIF
F 110 FORMAT(25X,'***  GASIFIER CONDITIONS  ***',/
F    1  /11X,'     WET COAL FLOW RATE:', E14.6,'LB/HR',
F    2  /11X,'     DRY COAL FLOW RATE:',E14.6,' LB/HR',
F    3  /11X,'       OXYGEN FLOW RATE:',E14.6,' LB/HR',
F    4  /11X,'        WATER FLOW RATE:',E14.6,' LB/HR',
F    5  /11X,'      GASIFIER PRESSURE:',F8.1,' PSIA',
F    6  /11X,'   GASIFIER TEMPERATURE:',F8.1,' F'/)

C  ---------------- REPORT GAS TURBINE CONDITIONS ----------------
F      WRITE(*,120) GTFULE,GTAIR,TFIRE,TCOMB,TGTPOC
F 120 FORMAT(/21X,'***  MS7000 GAS TURBINE CONDITIONS  ***',/
F    1  /11X,'             FUEL FLOW RATE:',E14.6,' LB/HR',
F    2  /11X,'              AIR FLOW RATE:',E14.6,' LB/HR',
F    3  /11X,'         FIRING TEMPERATURE:',F8.1,' F',
F    4  /11X,' COMBUSTOR EXIT TEMPERATURE:',F8.1,' F',
F    5  /11X,'TURBINE EXHAUST TEMPERATURE:',F8.1,' F'/)

C  --------------- REPORT STEAM TURBINE CONDITIONS ---------------
F      WRITE(*,130) STSTM,TSHSTM,FIPSTM,TRESTM,FLPSTM,TLPSTM
F 130 FORMAT(/24X,'***  STEAM TURBINE CONDITIONS  ***',/
F    1  /11X,'  SUPERHEATED STEAM FLOW RATE:',E14.6,' LB/HR',
F    2  /11X,'SUPERHEATED STEAM TEMPERATURE:',F8.1,' F',
F    3  /11X,'           IP STEAM FLOW RATE:',E14.6,'LB/HR',
F    4  /11X,'     REHEAT STEAM TEMPERATURE:',F8.1,' F',
F    5  /11X,'           LP STEAM FLOW RATE:',E14.6,'LB/HR',
F    6  /11X,'         LP STEAM TEMPERATURE:',F8.1,' F'/)

C  --------------------- REPORT POWER USAGE ---------------------
       PWRNET=WST+WO2COM+WASU+WN2COM+WTGRPM+WTGRCY+WCNDPM+WGASEX+WGT+
     & WHPPMP+WIPPMP+WLPPMP+WQBOST+WQPMP+WSLRPM+WSLYPM+WSYNBT+WTGREC
       PWRNET=PWRNET+38162.30718+9364.3

F      PLANTEFF=-PWRNET*0.7455/(MCFGI*HOC*0.000293)
```

```
F     WRITE(*,140) -WGT*745.5*0.985, -WST*745.5, -WGTCOM*745.5,
     & -WASU*745.5, -PWRNET*745.5,PLANTEFF,HOC,
     & (CO+CO2)*44.04*0.4536/(-PWRNET*745.5/1000.0)
F 140 FORMAT(//23X,'***  POWER PRODUCTION SUMMARY  ***'/
F    1  /11X,'                GAS TURBINE:',E16.6,'  WATTS',
F    2  /11X,'              STEAM TURBINE:',E16.6,'  WATTS',
F    3  /11X,'                COMPRESSORS:',E16.6,'  WATTS',
F    4  /11X,'               OXYGEN PLANT:',E16.6,'  WATTS',
F    5  /11X,'                PLANT TOTAL:',E16.6,'  WATTS',
F    6  /11X,'PLANT THERMAL EFFICIENCY (HHV):',E16.6,
F    7  /11X,'          COAL HEATING VALUE:', E16.6,
F    8  /11X,'               CO2 EMISSION:',E16.6, 'KG/KWH',/)



       COAL=MCFGI
C THERE IS NO B-S UNIT HERE, SO SET SULFUR FORM B-S IS 0
       SFRSB=0
       PGT=WGT
       PST=WST
       POWER=PWRNET


C THI BLOCK IS USED TO CALCULATE THE CAPITAL COST OF IGCC SYSTEM

C DIRECT COST OF THE MAJOR SECTIONS($1000 IN 2000)

C CAPACITY FACTOR
       CF=0.75
C COAL HEATING VALUE (HHV,BTU/LB)
       HHVCOAL=11666.0
C COAL_PRICE:$/MMBTU
       COAL_PRICE=1.34
C SULFUR PRICE ($/TON)
       SUL_PRICE=58.0
C LABOR NUMBER (WORKERS/DAY)
        NUMBER_LABOR=20.0
C FIXED CHARGE FACTOR
       FCF=0.14
C INFLATION RATE
       INFLATION=0.0
C DISCOUNT RATE
        DISCOUNT=0.103
C CONSTRUCTION PERIOD (YEAR)
        YEAR=4.0
C OPERATION LABOR RATE ($/HR)
        RATE_LABOR=24.82

       WRITE(*,145)CF,FCF,DISCOUNT,INFLATION,YEAR,COAL_PRICE
F 145  FORMAT(
F    1  /11X,'     CAPACITY FACTOR:',F8.3,
F    2  /11X,' FIXED CHARGE FACTOR:',F8.3,
F    3  /11X,'       DISCOUNT RATE:',F8.3,
F    4  /11X,'      INFLATION RATE:',F8.3,
F    5  /11X,'   CONSTRUCTION YEAR:',F8.3,
F    6  /11X,'COAL PRICE ($/MMBTU):',F8.3/)

C  Chemical Price Index based on US$ in 2000
C  Chemical Price Index  - original costs are based on US$ in 2000
C  The cost is escalated to the current year prices (2005 US$)
       CPI=1.186
C ASU
```

```
      NASU=1.0
      T=59.0
      EFFASU=0.95
      DCASU=CPI*196.2*NASU*T**0.067/(1-EFFASU)**0.073*(O2/NASU)**0.5618
C COAL HANDLING
      DCCH=CPI*9.92*COAL*0.454*24.0/1000.0
C GASIFIERS WITH ONE SPARING TRAIN (FROM FREY'S COST MODEL)
      NG=2.0
      NGO=2.0
       DCG=CPI*1.1079*216*(COAL*0.4546/1000*24/NGO)**0.677*NG
C LOW TEMPERATURE GAS COOLING:
      NLT=1.0
      DCLT=CPI*0.0156*NLT*(SGLT/NLT)
C PROCESS CONDENSATE TREATMENT
      SBD=380000.0*SGTOSC/56106.0
      DCPC=CPI*9814*(SBD/300000.0)**0.6
C SELEXOL FOR SULFUR REMOVAL
      NS=1.0
      EFFS=0.98
      DCS=CPI*0.304*NS/(1-EFFS)**0.059*(SGTOSR/NS)**0.98
C COS HYDROLYSIS DIRECT COST IS ESTIMATED AS 5% OF THAT OF SELEXOL FOR
C SULFUR REMOVAL,HENCE
      DCS=1.05*DCS
C CLAUS UNIT
      NC=2.0
      DCC=CPI*6.96*NC*(SFRCL/NC)**0.668
C BEAVON-STRETFORD TAIL GAS REMOVAL
      NBS=2
      DCBS=(63.3+72.8*NBS*(SFRSB/NBS)**0.645)*0
C BOILER FEED WATER
      TEMP=RH2O**0.307
      TEMP2=PH2O**0.435
      DCBFW=CPI*0.16*TEMP*TEMP2
C GAS TURBINE
      NGT=2.0
      DCGT=CPI*ABS(168.0*PGT/NGT*0.7455/1000.0)*NGT
C HRSG
      NHR=1.0
      DCHR=CPI*7.98/1000*NHR*PHPS**1.526*(HPS/NHR)**0.242
C STEAM TURBINE
      NST=1.0
      DCST=CPI*ABS(0.145*PST/NST*0.7455)
C N2 COMPRESSOR
      DCN2COMP=CPI*13.0969*WN2COM**0.64

C PROCESS FACILITY COST FACTOR
       PFCF_CH=0.2
       PFCF_ASU=0.2
       PFCF_G=0.2
       PFCF_LT=0.2
       PFCF_S=0.2
       PFCF_C=0.2
       PFCF_BS=0.2
       PFCF_BFW=0.2
       PFCF_PC=0.2
       PFCF_GT=0.2
       PFCF_HR=0.2
       PFCF_ST=0.2
       PFCF_N2COMP=0.2


C PROCESS FACILITY COST
       PFC=(1+PFCF_CH)*DCCH+(1+PFCF_ASU)*DCASU+(1+PFCF_G)*DCG+
```

```
     &  (1+PFCF_LT)*DCLT+(1+PFCF_S)*DCS+(1+PFCF_C)*DCC+(1+PFCF_BS)*DCBS
     &  +(1+PFCF_BFW)*DCBFW
     &  +(1+PFCF_PC)*DCPC+(1+PFCF_GT)*DCGT+(1+PFCF_HR)*DCHR
     &  +(1+PFCF_ST)*DCST+(1+PFCF_N2COMP)*DCN2COMP

         WRITE(*,150)(1+PFCF_ASU)*DCASU,(1+PFCF_CH)*DCCH,
     &  (1+PFCF_G)*DCG,(1+PFCF_LT)*DCLT,(1+PFCF_PC)*DCPC,
     &  (1+PFCF_S)*DCS,(1+PFCF_C)*DCC,(1+PFCF_BS)*DCBS,
     & (1+PFCF_BFW)*DCBFW,(1+PFCF_GT)*DCGT,(1+PFCF_HR)*DCHR,
     & (1+PFCF_ST)*DCST, (1+PFCF_N2COMP)*DCN2COMP,PFC
  150  FORMAT(
F    2  /11X,'         AIR SEPARATION UNIT:',F8.1
F    2  /11X,'              COAL HANDLING :',F8.1,
F    3  /11X,'                    GASIFIER:',F8.1,
F    4  /11X,'LOW TEMPERATURE GAS COOLING:',F8.1,
F    4  /11X,'          PROCESS CONDENSATE:',F8.1,
F    5  /11X,' SELEXOL FOR SULFUR REMOVAL:',F8.1,
F    6  /11X,'                 CLAUS PLANT:',F8.1,
F    7  /11X,'      BEAVON-STRETFORD UNIT:',F8.1,
F    8  /11X,'           BOILER FEED WATER:',F8.1,
F    9  /11X,'                 GAS TURBINE:',F8.1,
F    9  /11X,'                        HRSG:',F8.1,
F    9  /11X,'               STEAM TURBINE:',F8.1,
F    9  /11X,'               N2 COMPRESSOR:',F8.1,
F    9  /11X,'TOTAL PROCESS FACILITY COST:',F8.1/)


C   GENERAL FACILITY COST FACTOR
       PFCF_GENERAL=0.15
C   GENERAL FACILITY COST
       PFC_GENERAL=PFCF_GENERAL*PFC
C   ENGINEERING & HOME OFFICE FEE FACTOR
       EHO_ASU=0.10
       EHO_CH=0.10
       EHO_G=0.10
       EHO_LT=0.10
       EHO_PC=0.10
       EHO_S=0.10
       EHO_C=0.10
       EHO_BS=0.10
       EHO_BFW=0.10
       EHO_GT=0.10
       EHO_HR=0.10
       EHO_ST=0.10
       EHO_N2COMP=0.10
C   ENGINEERING & HOMW OFFICE FEES
       ENGFEE=EHO_ASU*DCASU + EHO_CH*DCCH + EHO_G*DCG +    EHO_LT*DCLT + EHO_PC*DCPC +
EHO_S*DCS + EHO_C*DCC + EHO_BS*DCBS + EHO_BFW*DCBFW + EHO_GT*DCGT + EHO_HR*DCHR +
EHO_ST*DCST + EHO_N2COMP*DCN2COMP

C   PROJECT CONTINGENCY FACTORS
        PROJ_ASU=0.15
        PROJ_CH=0.15
        PROJ_G=0.15
        PROJ_LT=0.15
        PROJ_S=0.15
        PROJ_C=0.15
        PROJ_BS=0.15
        PROJ_BFW=0.15
        PROJ_PC=0.15
        PROJ_GT=0.15
        PROJ_HR=0.15
```

```
        PROJ_ST=0.15
        PROJ_N2COMP=0.15

C PROJECT CONTINGENCY
        PC_ASU=PROJ_ASU*(1+PFCF_ASU)*DCASU
        PC_CH=PROJ_CH*(1+PFCF_CH)*DCCH
        PC_G=PROJ_G*(1+PFCF_G)*DCG
        PC_LT=PROJ_LT*(1+PFCF_LT)*DCLT
        PC_S=PROJ_S*(1+PFCF_S)*DCS
        PC_C=PROJ_C*(1+PFCF_C)*DCC
        PC_BS=PROJ_BS*(1+PFCF_BS)*DCBS
        PC_BFW=PROJ_BFW*(1+PFCF_BFW)*DCBFW
        PC_PC=PROJ_PC*(1+PFCF_PC)*DCPC
        PC_GT=PROJ_GT*(1+PFCF_GT)*DCGT
        PC_HR=PROJ_HR*(1+PFCF_HR)*DCHR
        PC_ST=PROJ_ST*(1+PFCF_ST)*DCST
        PC_N2COMP=PROJ_N2COMP*(1+PFCF_N2COMP)*DCN2COMP

        PROJECT_CONTINGENCY=PC_CH+PC_G+PC_LT+PC_S+PC_C+PC_BS+PC_BFW
     &     +PC_ASU+PC_PC+PC_GT+PC_HR+PC_ST+PC_N2COMP

C PROCESS CONTINGENCY FACTOR

        PROC_CH=0.05
        PROC_ASU=0.05
        PROC_G=0.15
        PROC_LT=0
        PROC_S=0.1
        PROC_C=0.1
        PROC_BS=0.1
        PROC_BFW=0
        PROC_PC=0.1
        PROC_GT=0.125
        PROC_HR=0.025
        PROC_ST=0.025
        PROC_N2COMP=0.025


        P_ASU=PROC_ASU*(1+PFCF_ASU)*DCASU
        P_CH=PROC_CH*(1+PFCF_CH)*DCCH
        P_G=PROC_G*(1+PFCF_G)*DCG
        P_LT=PROC_LT*(1+PFCF_LT)*DCLT
        P_S=PROC_S*(1+PFCF_S)*DCS
        P_C=PROC_C*(1+PFCF_C)*DCC
        P_BS=PROC_BS*(1+PFCF_BS)*DCBS
        P_BFW=PROC_BFW*(1+PFCF_BFW)*DCBFW
        P_PC=PROC_PC*(1+PFCF_PC)*DCPC
        P_GT=PROC_GT*(1+PFCF_GT)*DCGT
        P_HR=PROC_HR*(1+PFCF_HR)*DCHR
        P_ST=PROC_ST*(1+PFCF_ST)*DCST
        P_N2COMP=PROC_N2COMP*(1+PFCF_N2COMP)*DCN2COMP


        PROCESS_CONTINGENCY=P_CH+PC_G+P_LT+P_S+P_C+P_BS+P_BFW+P_PC+P_GT
     &      +P_ASU+P_HR+P_ST+P_N2COMP


C TOTAL PLANT COST
        TPC=PFC+PFC_GENERAL+ENGFEE+PROJECT_CONTINGENCY
     $          +PROCESS_CONTINGENCY

C AFUDC
        AFUDC=TPC*(((1.0+DISCOUNT)**YEAR-(1.0+INFLATION)**YEAR)/
```

```
     &        (YEAR*LOG((1+DISCOUNT)/(1+INFLATION)))-1.0)
C TOTAL PLANT INVESTMENT
        TPI=TPC+AFUDC

C  *********************************
C ANNUAL LABOR COST ($/YEAR)
         COST_LABOR=RATE_LABOR*NUMBER_LABOR*8760.0
C ANNUAL MANAGEMENT COST ($/YEAR)
         COST_MANAGE=0.65*COST_LABOR
C ANNUAL MAINTANCE COST ($/YEAR)

       MNT_ASU=0.02
       MNT_CH=0.02
       MNT_G=0.035
       MNT_LT=0.03
       MNT_PC=0.02
       MNT_S=0.02
       MNT_C=0.02
       MNT_BS=0.02
       MNT_BFW=0.015
       MNT_GT=0.015
       MNT_HR=0.015
       MNT_ST=0.015
       MNT_N2COMP=0.02
       COST_MAINTANCE = TPC/(PFC/1.2)*(MNT_ASU*DCASU + MNT_CH*DCCH + MNT_G*DCG +
MNT_LT*DCLT + MNT_PC*DCPC + MNT_S*DCS + MNT_C*DCC + MNT_BS*DCBS + MNT_BFW*DCBFW +
MNT_GT*DCGT + MNT_HR*DCHR + MNT_ST*DCST + MNT_N2COMP*DCN2COMP)*1000.0


C ANNUAL FIXED OPERATION COST ($/YEAR)
         FOC=COST_LABOR+COST_MANAGE+COST_MAINTANCE

C ANNUAL CONSUMABLES ($/YEAR)
       CONSUM=COAL/355940.0*3991712.0
C FUEL CONSUMABLES ($/YEAR):
       COAL_COST=COAL*HHVCOAL*8760*CF/1000.0/1000.0*COAL_PRICE
C ASH DISPOSAL COST ($/YEAR)
       ASH_DIS=10.0
       ASH_COST=22.65/355940.0*COAL*24.0*365.0*CF*ASH_DIS
C SULFUR BY PRODUCT CREDIT
       SUL_CREDIT=(SFRCL+SFRSB)/2000.0*8760.0*CF*SUL_PRICE

C ANNUAL VARIABLE OPERATION COST ($/YEAR)
       VOC=CONSUM+COAL_COST+ASH_COST-SUL_CREDIT
C ***********************************


C TOTAL CAPITAL REQUIREMENT

       ROYAL_ASU=0.005
       ROYAL_CH=0.005
       ROYAL_G=0.005
       ROYAL_LT=0.005
       ROYAL_PC=0.005
       ROYAL_S=0.005
       ROYAL_C=0.005
       ROYAL_BS=0.005
       ROYAL_BFW=0.005
       ROYAL_GT=0.005
       ROYAL_HR=0.005
       ROYAL_ST=0.005
       ROYAL_N2COMP=0.005
```

```
       ROYALTY=ROYAL_ASU*DCASU + ROYAL_CH*DCCH + ROYAL_G*DCG + ROYAL_LT*DCLT +
ROYAL_PC*DCPC + ROYAL_S*DCS + ROYAL_C*DCC + ROYAL_BS*DCBS + ROYAL_BFW*DCBFW +
ROYAL_GT*DCGT + ROYAL_HR*DCHR + ROYAL_ST*DCST + ROYAL_N2COMP*DCN2COMP

        aINVENTORY=COAL/355940.0*639.0

C PREPRODUCTION STARTUP COSTS (only the capital portion – O&M omitted)
       STARTUP_ASU=0.02
       STARTUP_CH=0.02
       STARTUP_G=0.02
       STARTUP_LT=0.02
       STARTUP_PC=0.02
       STARTUP_S=0.02
       STARTUP_C=0.02
       STARTUP_BS=0.02
       STARTUP_BFW=0.02
       STARTUP_GT=0.02
       STARTUP_HR=0.02
       STARTUP_ST=0.02
       STARTUP_N2COMP=0.02
       STARTUP=TPI * (STARTUP_ASU + STARTUP_CH + STARTUP_G +
        STARTUP_LT + STARTUP_PC + STARTUP_S + STARTUP_C + STARTUP_BS + STARTUP_BFW +
STARTUP_GT + STARTUP_HR + STARTUP_ST + STARTUP_N2COMP)


        STARTUP=STRATUP+(VOC+FOC)/12/1000.
        aLAND=ABS(POWER)*0.7455/1000/505.0*1731.0
        TCR=TPI+ROYALTY+STARTUP+aINVERTORY+aLAND

F     WRITE(*,160) PFC_GENERAL,ENGFEE,PROJECT_CONTINGENCY,
     &             PROCESS_CONTINGENCY,TPC,
     &             TPC/ABS(POWER*0.7457), AFUDC,TPI,ROYALTY,STARTUP,
     &             aINVENTORY,aLAND,TCR,TCR/ABS(POWER*0.7457)
F 160 FORMAT(
F    2  /11X,'    GENERAL FACILITY COST:',F8.1
F    2  /11X,'ENGINEERING & OFFICE FEES:',F8.1
F    2  /11X,'     PROJECT CONTINGENCY :',F8.1,
F    3  /11X,'      PROCESS CONTINGENCY:',F8.1,
F    4  /11X,'         TOTAL PLANT COST:',F10.1,
F    4  /11X,'  TOTAL PLANT COST ($/kW):',F8.4,
F    4  /11X,'                    AFUDC:',F8.1,
F    5  /11X,'   TOTAL PLANT INVESTMENT:',F10.1,
F    6  /11X,'                  ROYALTY:',F8.1,
F    7  /11X,'                  STARTUP:',F8.1,
F    8  /11X,'                INVENTORY:',F8.1,
F    9  /11X,'                     LAND:',F8.1,
F    9  /11X,'TOTAL CAPITAL REQUIREMENT:',F10.1,
F    9  /11X,'                   TCR/kW:',F8.4/)

       VOC=CONSUM+COAL_COST+ASH_COST-SUL_CREDIT

C COE ($/kWh)
       COE=(1000.0*FCF*TCR+(FOC+VOC))/(ABS(POWER*0.7455)/1000.0)/
     &     (CF*8760.0)

       WRITE(*,*)'ANNUAL VARIABLE O&M COST($/YEAR):',VOC
       WRITE(*,*)'   ANNUAL FIXED O&M COST($/YEAR):',FOC
       WRITE(*,*)'      COST OF ELECTRICITY($/MWh):',COE
```