IECM User Manual

DE-AC26-04NT41917

November 2009

Disclaimer

IECM User Manual

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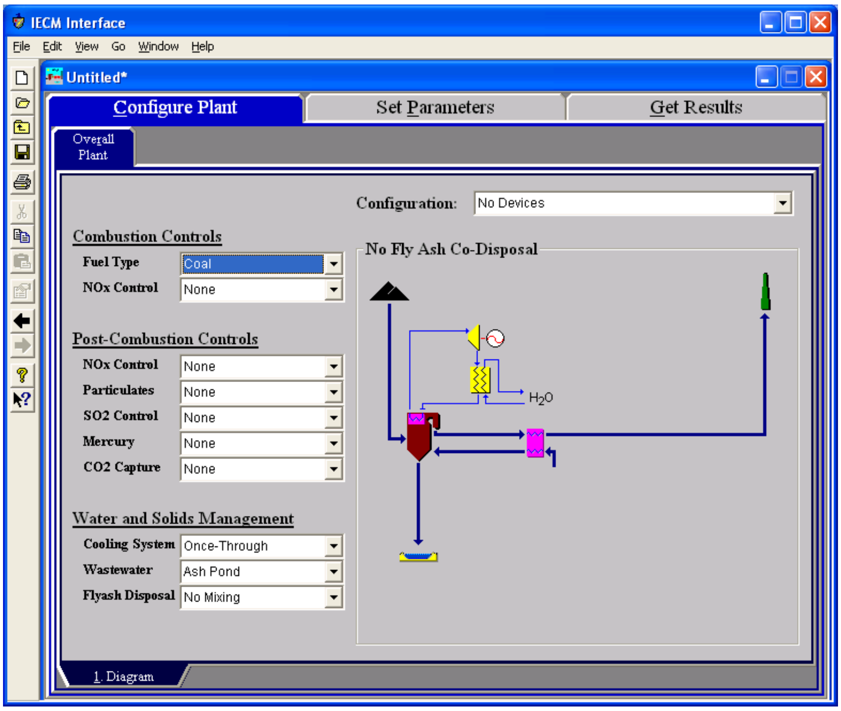
This document contains a new User Manual developed for the new Water Systems modules of the IECM. The previous User Manual for the remainder of the IECM follows the new Water Systems User Manual.

Water Systems

Water Systems 4

Cooling System Configuration

This screen is only available for pulverized coal power plants. However, the option of **Cooling System** is available for all plant types. Inputs for configuration of the Cooling System are briefly introduced below.



Cooling System- Configuration Plant Input Screen

Cooling System: This option determines the cooling technology: “Once-Through”, “Wet Cooling Tower”, and “Air Cooled Condenser”. The **default** technology is the **Once-Through** cooling system.

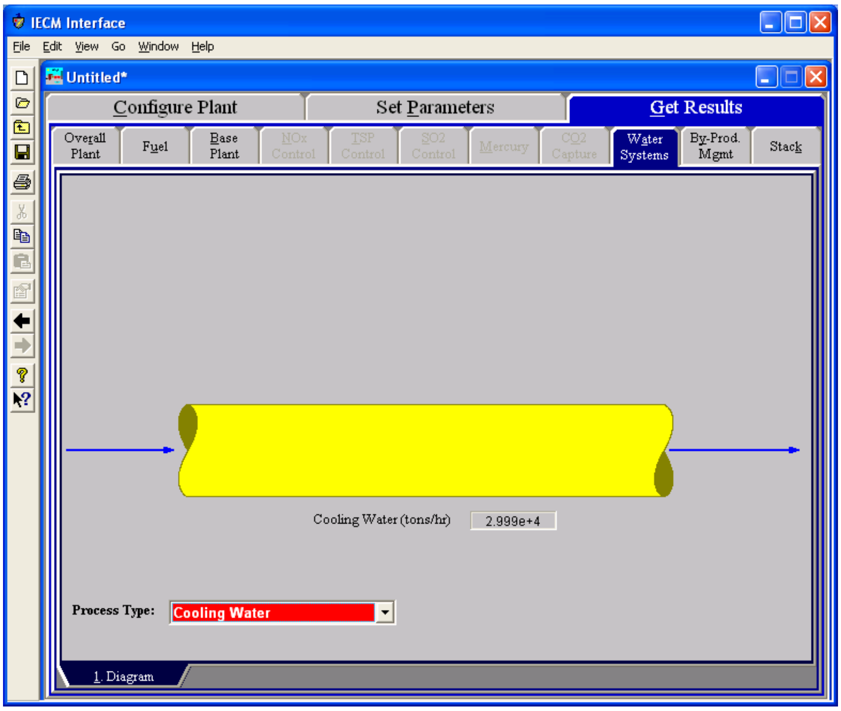
Once-Through: Cooling water is withdrawn from a natural waterbody, passed through the steam condenser and returned to the waterbody.

Wet Cooling Tower: Cooling water is recirculated through the wet tower and back to the condenser. The tower mainly relies on the latent heat of water evaporation to transfer waste heat to the atmosphere.

Air Cooled Condenser: The air cooled condenser utilizes the sensible heating of atmospheric air passed across finned-tube heat exchangers to reject heat.

Once-Through Water Systems Results

This screen is available for all plant types when the once-through cooling system is loaded.

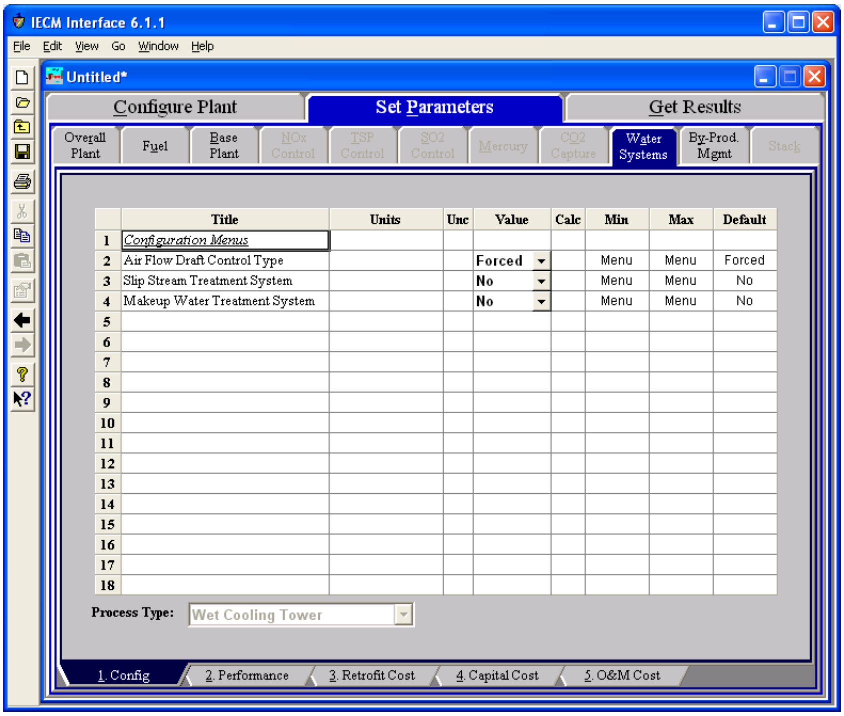


Once-Through- Cooling Water Result Screen

Cooling Water: This variable presents the amount of cooling water through the primary steam cycle plus auxiliary cooling.

Wet Cooling Tower Configuration

This screen is available for all plant types. Inputs for configuration of the Wet Cooling Tower are entered on the **Config** input screen.



Wet Cooling Tower- Config. Input Screen

The parameters are described briefly below.

Air Flow Draft Control Type: This option determines the type of air flow draft: “Natural” or “Forced”. The “Natural” draft utilizes buoyancy to make natural rising of air through the tower, whereas the “Forced” draft uses the fan at the intake to force air through the tower. The choice of draft type has an effect on tower evaporation loss. Currently, only “Forced” draft type is available.

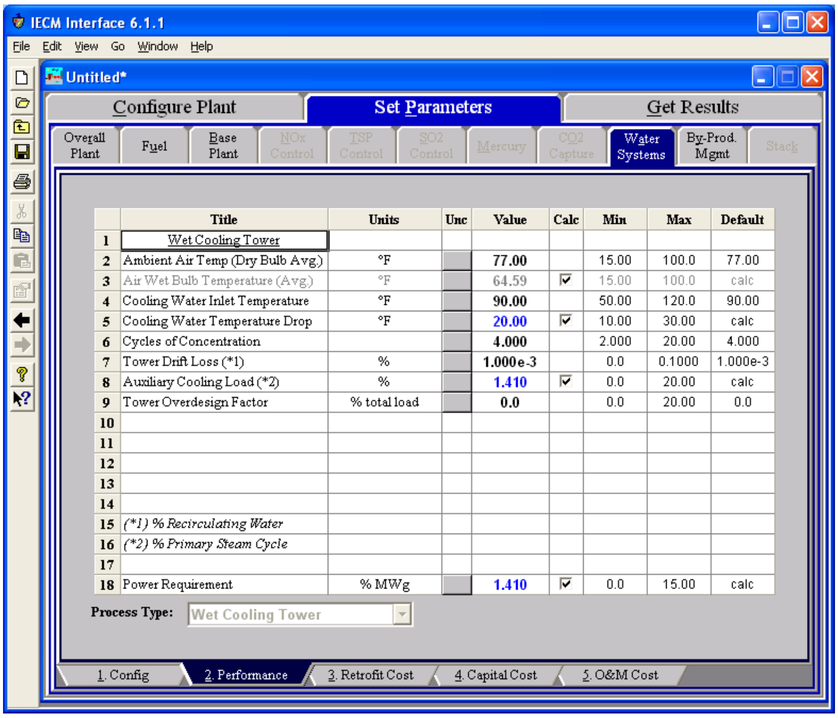
Slip Stream Treatment System: This option determines whether a slip stream treatment system is loaded. The choice (“Yes” or “No”) of a slip stream treatment system depends on site-specific quality of cooling water in the closed-loop recirculating system.

Makeup Water Treatment System: This option determines whether a makeup water treatment system is needed. The choice (“Yes” or “No”) of a makeup water treatment system depends on site-specific quality of makeup water for the cooling system.

Wet Cooling Tower Performance Inputs

This screen is available for all plant types. Inputs for performance of the Wet Cooling Tower technology are entered on the **Performance** input screen.

Each parameter is described briefly below.



Wet Cooling Tower- Performance Input Screen

Ambient Air Temp (Dry Bulb Avg.): This refers basically to the ambient air temperature measured by a thermometer. This input specifies annual average ambient temperature.

Air Wet Bulb Temperature (Avg.): This refers to the temperature of air that is cooled adiabatically to saturation at a constant pressure by evaporation of water into it. That is calculated in terms of ambient dry bulb temperature and humidity. That is the lowest temperature that can be reached by evaporating water into the air.

Cooling Water Inlet Temperature: This is the temperature of the cooling water entering the wet tower.

Cooling Water Temperature Drop: This parameter specifies the temperature drop range of cooling water across the wet tower.

Cycles of Concentration: That is a measure of the degree to which dissolved solids are being concentrated in the circulating water and is estimated in terms of concentration ratio of dissolved solids in the circulating versus makeup water. That is reversely related to the blowdown. Improving the quality of makeup water for the cooling system can increase the cycle of concentration and decrease the amount of tower blowdown.

Tower Drift Loss: This parameter specifies a percent of the quantity of cooling water as drift loss.

Auxiliary Cooling Load: This parameter specifies additional heat load on the auxiliary equipments and expressed as a percentage of the load on the primary steam cycle. The default value comes from the PISCES model.

Overdesign Factor: This parameter overdesigns the wet tower size.

Slip Stream Inlet: This parameter specifies the underflow as a percent of the quantity of cooling water. This option is only available when the Slip Stream Treatment System is loaded.

Slip Stream Underflow: This parameter specifies the underflow as a percent of the quantity of slip stream. This option is only available when the Slip Stream Treatment System is loaded.

Cooling Makeup Underflow: This parameter specifies the underflow as a percent of the quantity of entering water treated. This option is only available when the Makeup Water Treatment System is loaded.

Power Requirement: This is the power needed to run the pumps and other equipments for the water cooling system. It is also referred to as a base plant energy penalty. In the PC power plants, it is expressed as a percentage of the gross plant capacity. In the IGCC plants, it is calculated based on the steam turbine power output and expressed as a scaled percentage of the total gross power outputs including the gas and steam turbines.

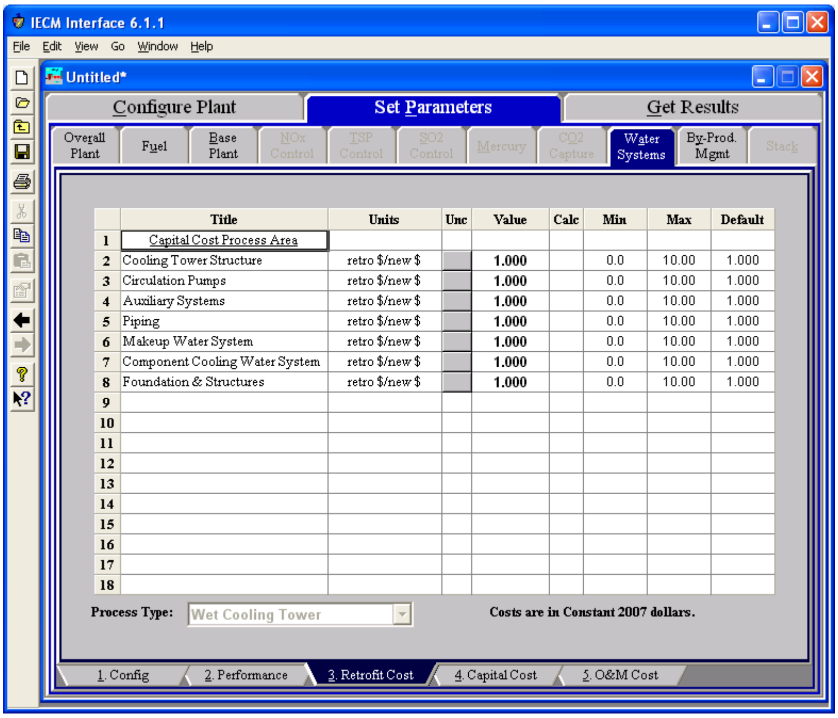
Wet Cooling Tower Retrofit Cost Inputs

This screen is available for all plant types. Inputs for capital costs of modifications to process areas to implement the Wet Cooling Tower are entered on the **Retrofit Cost** input screen for the Wet Cooling Tower system.

The retrofit cost factor of each process is a multiplicative cost adjustment which considers the cost of retrofitted capital equipment relative to similar equipment installed in a new plant. These factors affect the capital costs directly and the operating and maintenance costs indirectly.

Direct capital costs for each process area are calculated in the IECM. These calculations are reduced form equations derived from more sophisticated models and reports. The sum of the direct capital costs associated with each process area is defined as the process facilities capital (PFC). The retrofit cost factor provided for each of the process areas can be used as a tool for adjusting the anticipated costs and uncertainties across the process area separate from the other areas.

Uncertainty can be applied to the retrofit cost factor for each process area in each technology. Thus, uncertainty can be applied as a general factor across an entire process area, rather than as a specific uncertainty for the particular cost on the capital or O&M input screens. Any uncertainty applied to a process area through the retrofit cost factor compounds any uncertainties specified later in the capital and O&M cost input parameter screens.



Wet Cooling Tower- Retrofit Cost Input Screen

Each parameter is described briefly below.

Capital Cost Process Area

Cooling Tower Structure: This area deals with the cooling tower and installation. The erected tower includes structure, fans, motors, gear boxes, fill, drift eliminators, etc.

Circulation Pumps: This area deals with the circulating cooling water pumps.

Auxiliary Systems: This area deals with a closed-loop process that utilizes a higher quality water to remove heat from ancillary equipments and transfers that heat to the main circulating cooling water system.

Piping: This area deals with the circuiting cooling water piping. The piping system is equipped with butterfly isolation valves and all required expansion joints.

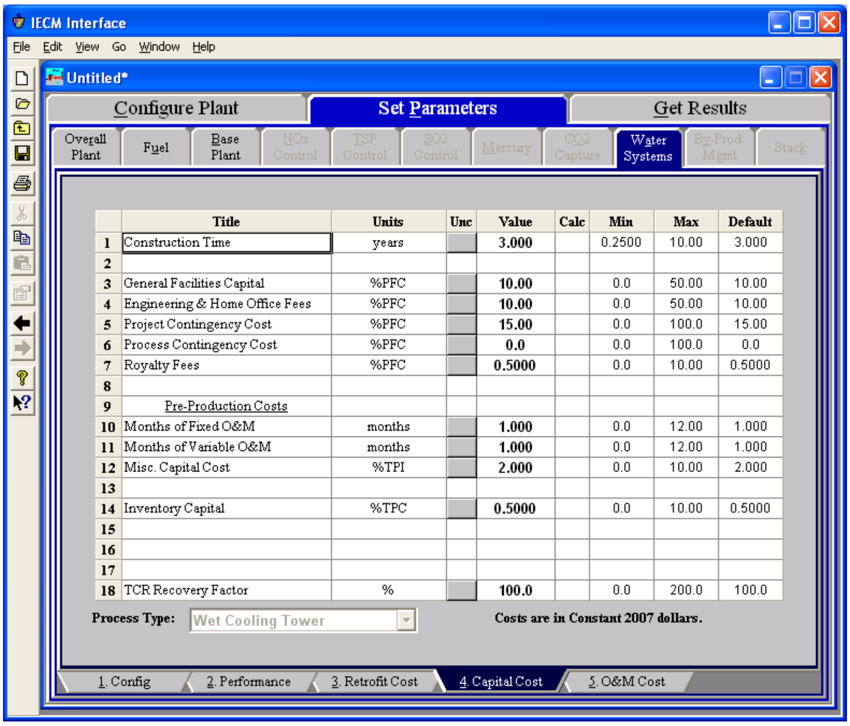
Makeup Water System: This area deals with the capital equipments to provide makeup water for the cooling system.

Component Cooling Water System: This area deals with the component cooling water system.

Foundation & Structures: This area deals with the circulating water system foundation and structures.

Wet Cooling Tower Capital Cost Inputs

This screen is available for all plant types.



Wet Cooling Tower-Capital Cost Input Screen

Each parameter is described briefly below.

Construction Time: This is the idealized construction period in years. It is used to determine the allowance for funds used during construction (AFUDC).

General Facilities Capital (GFC): 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%.

Engineering & Home Office Fees: The engineering & home office fees are a percent of total direct capital cost. This is an overhead fee paid to the architect/engineering company. These fees typically range from 7-15%.

Project Contingency Cost: This is 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.

Process Contingency Cost: 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.

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

Pre-Production Costs: 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 applied to the O&M costs over a specified period of time (months). The two time periods for fixed and variable O&M costs are described below with the addition of a miscellaneous capital cost factor.

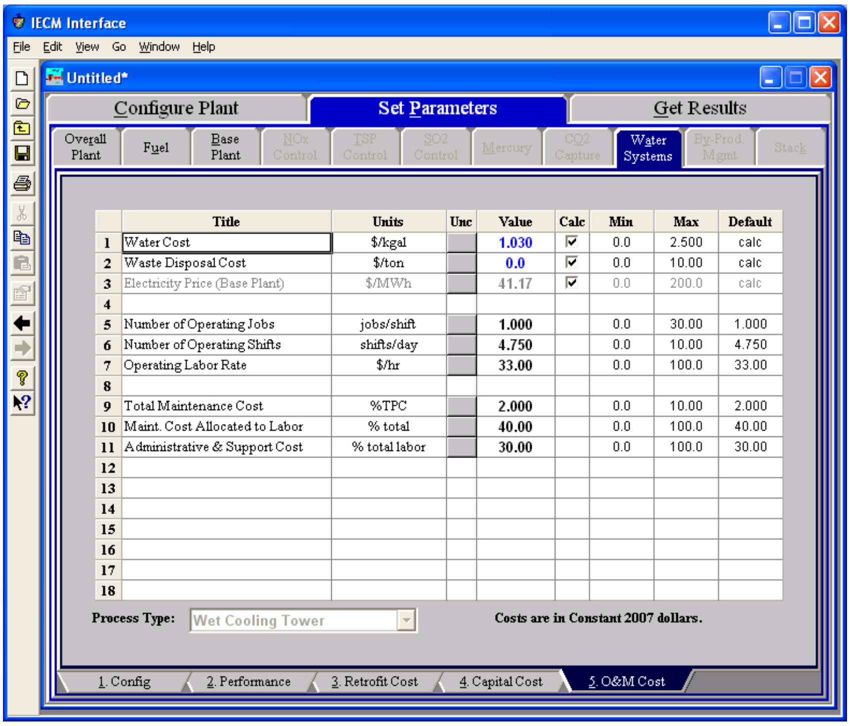
- **Months of Fixed O&M:** Time period of fixed operating costs used for preproduction to cover training, testing, major changes in equipment, and inefficiencies in start-up. This includes operating, maintenance, administrative and support labor. It also considers maintenance materials.
- **Months of Variable O&M:** Time period of variable operating costs used for preproduction to cover chemicals, water, consumables, and solid disposal charges in start-up, assuming 100% load. This excludes any fuels.
- **Misc. Capital Cost:** This is a percent of total plant investment (sum of TPC and AFUDC) to cover expected changes to equipment to bring the system up to full capacity.

Inventory Capital: Percent of the total direct capital for raw material supply based on 100% capacity during a 60 day period. These materials are considered storage. The inventory capital includes fuels, consumables, by-products, and spare parts. This is typically 0.5%.

TCR Recovery Factor: The actual total capital required (TCR) as a percent of the TCR in a new power plant. This value is 100% for a new installation and may be set as low as 0% for a wet cooling tower that has been paid off.

Wet Cooling Tower O&M Cost Inputs

This screen is available for all plant types.



Wet Cooling Tower- O&M Cost Input Screen

O&M costs are typically expressed on an average annual basis and are provided in either constant or current dollars for a specified year, as shown on the bottom of the screen. Each parameter is described briefly below:

Water Cost: This is the cost of water in dollars per thousand gallons.

Waste Disposal Cost: This is the waste disposal cost for the wet tower.

Electricity Price (Base Plant): This is the price of electricity and is calculated as a function of the utility cost of the base plant, where the base plant is a combustion boiler and an air preheater.

Number of Operating Jobs: This is the total number of operating jobs that are required to operate the plant per eight-hour shift.

Number of Operating Shifts: This is the total number of equivalent operating shifts in the plant per day. The number takes into consideration paid time off and weekend work (3 shifts/day * 7 days/5 day week * 52 weeks/(52 weeks - 6 weeks PTO) = 4.75 equiv. Shifts/day).

Operating Labor Rate: The hourly cost of labor is specified in the base plant O&M cost screen. The same value is used throughout the other technologies.

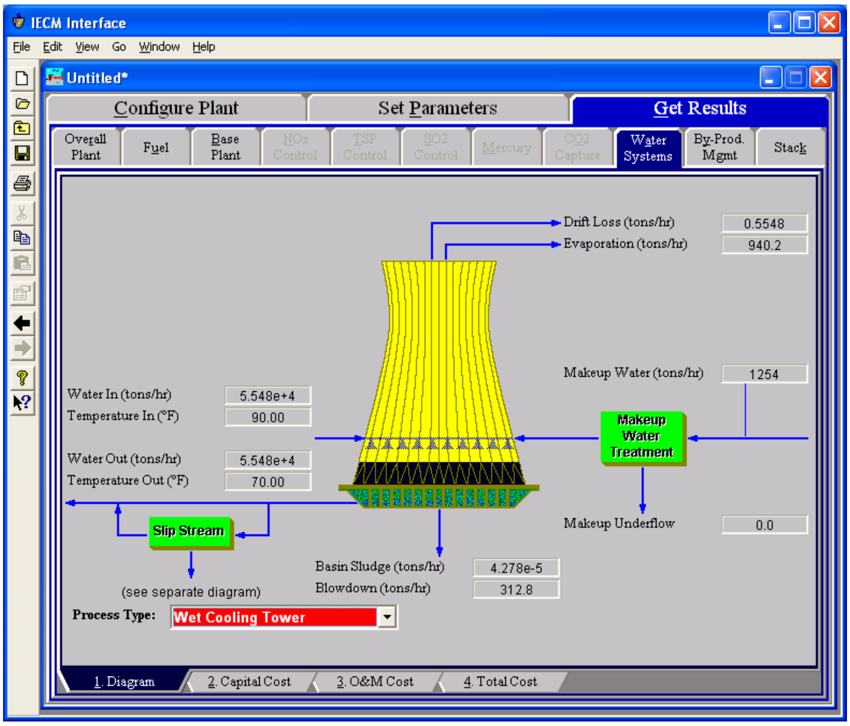
Total Maintenance Cost: This is the annual maintenance cost as a percentage of the total plant cost. Maintenance cost estimates can be developed separately for each process area.

Maint. Cost Allocated to Labor: Maintenance cost allocated to labor as a percentage of the total maintenance cost.

Administrative & Support Cost: This is the percent of the total operating and maintenance labor associated with administrative and support labor.

Wet Cooling Tower Diagram

This screen is available for all plant type. The **Diagram** result screen displays an icon for the Wet Cooling Tower selected and values for major flows in and out of it.



Wet Cooling Tower- Diagram

Each result is described briefly below.

Cooling Water Entering Wet Tower

Water In: The amount of recirculating cooling water entering the wet tower. That depends on the plant size, steam cycle heat rate and cooling water temperature drop range. That is the sum of cooling water through the main steam cycle, and amine-based carbon capture system if applicable.

Temperature In: The temperature of recircualting cooling water entering the wet tower.

Cooling Water Exiting Wet Tower

Water Out: The amount of recirculating cooling water exiting the wet tower. That is equal to the amount of cooling water entering the wet tower based on water mass balance. That is the sum of cooling water through the main steam cycle, and amine-based carbon capture system if applicable.

Temperature Out: The temperature of reciruclating cooling water exiting the wet tower. That is calculated in terms of the inlet cooling water temperature and cooling water temperature drop range.

Wet Tower Performance

Makeup Water: The cooling tower operation is maintained by making up fresh water at the same rate as the water losses (evaporation, blowdown, and drift loss) from the tower.

Makeup Underflow: This output gives the amount of wastes from cooling makeup water treatment system.

Evaporation: In wet cooling towers, water has direct contact with ambient air and cooling is achieved mainly by the evaporation process in which some of the water leaves with the air. The evaporation process is the largest source of cooling tower water losses. That is estimated based on the mass and energy balance mode. Evaporation loss varies with meteorological conditions and displays a seasonal pattern.

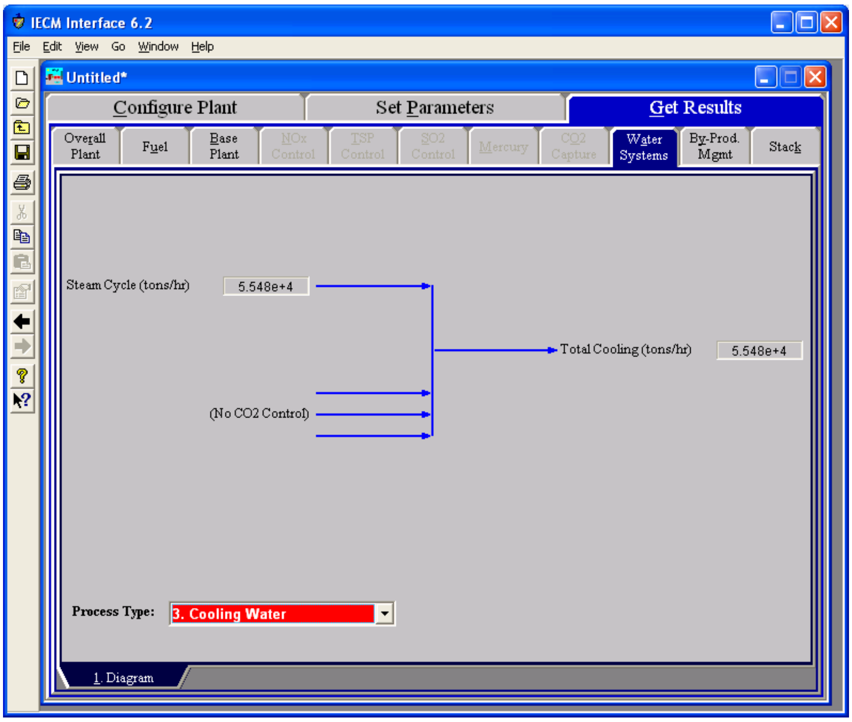
Blowdown: Because water evaporated in the cooling tower consists of pure water, the concentration of salts or other impurities will increase in the recirculating water. To avoid a high concentration and subsequent scaling of the surface within the tower, it is necessary to blow down a portion of the water that depends on the cycle of concentration and evaporation loss.

Drift Loss: A relatively small amount of entrained water lost as fine droplets in the air discharge from a tower, which is frequently referred to as tower drift loss.

Basin Sludge: This output specifies the amount of the basin sludge of the cooling tower system. That is an intermittent waste stream that contains collected soil, dust, and suspended solids in the tower basin.

Wet Cooling Tower –Cooling Water Diagram

This screen is available when the wet cooling tower is loaded.



Wet Cooling Tower- Cooling Water Result Screen

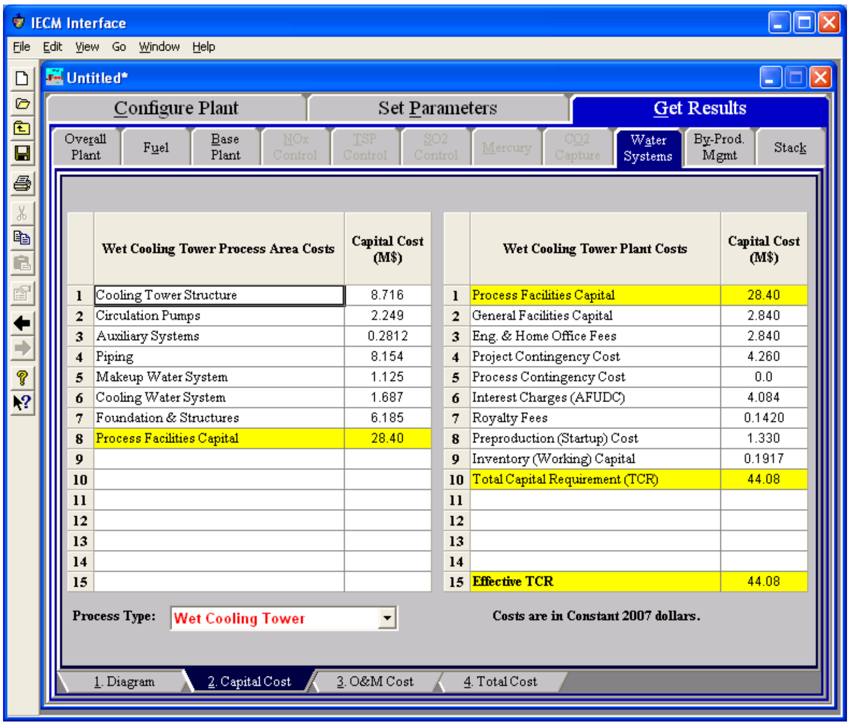
Each result is described briefly below

Total Cooling: This variable presents the amount of cooling water through the main steam cycle plus auxiliary cooling.

Steam Cycle: This variable presents the amount of cooling water through the main steam cycle.

Wet Cooling Tower Capital Cost Results

This screen is available for all plant types. The **Capital Cost** result screen displays tables for the direct and indirect capital costs related to the Wet Cooling Tower technology.



Wet Cooling Tower-Capital Cost Result Screen

Capital costs are typically expressed in either constant or current dollars for a specified year, as shown on the bottom of the screen. Each result is described briefly below

Direct Capital Costs

Cooling Tower Structure: This area deals with the cost for the cooling tower and installation.

Circulation Pumps: This area deals with the cost for the circulating cooling water pumps.

Auxiliary Systems: This area deals with the cost for a closed-loop process that utilizes a higher quality water to remove heat from ancillary equipments and transfers that heat to the main circulating cooling water system.

Piping: This area deals with the cost for the circuiting cooling water piping.

Makeup Water System: This area deals with the cost for the capital equipments to provide makeup water for the cooling system.

Cooling Water System: This area deals with the cost for the component cooling water system.

Foundation & Structures: This area deals with the cost for the circulating water system foundation and structures.

Process Facilities Capital: The process facilities capital is the total constructed cost of all on-site processing and generating units listed above, including all direct and indirect construction costs. All sales taxes and freight costs are included where applicable implicitly. That is regressed as a function of the recirculating cooling water flow rate based on the National Energy Technology Laboratory baseline studies for fossil fuel power plants (2007). The cooling tower used for cost estimation is a multi-cell wood frame counterflow mechanical draft cooling tower. This result is highlighted in yellow.

Total Capital Costs

Process Facilities Capital: (see definition above)

General Facilities Capital: The general facilities include construction costs of roads, office buildings, shops, laboratories, etc. Sales taxes and freight costs are included implicitly.

Eng. & Home Office Fees: The engineering & home office fees are a percent of total direct capital cost. This is an overhead fee paid to the architect/engineering company.

Project Contingency Cost: Capital cost contingency factor covering the cost of additional equipment or other costs that would result from a more detailed design of a definitive project at the actual site.

Process Contingency Cost: Capital cost contingency factor applied to a new technology in an effort to quantify the uncertainty in the technical performance and cost of the commercial-scale equipment.

Interest Charges (AFUDC): Allowance for funds used during construction, also referred to as interest during construction, is the time value of the money used during construction and is based on an interest rate equal to the before-tax weighted cost of capital. This interest is compounded on an annual basis (end of year) during the construction period for all funds spent during the year or previous years.

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

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.

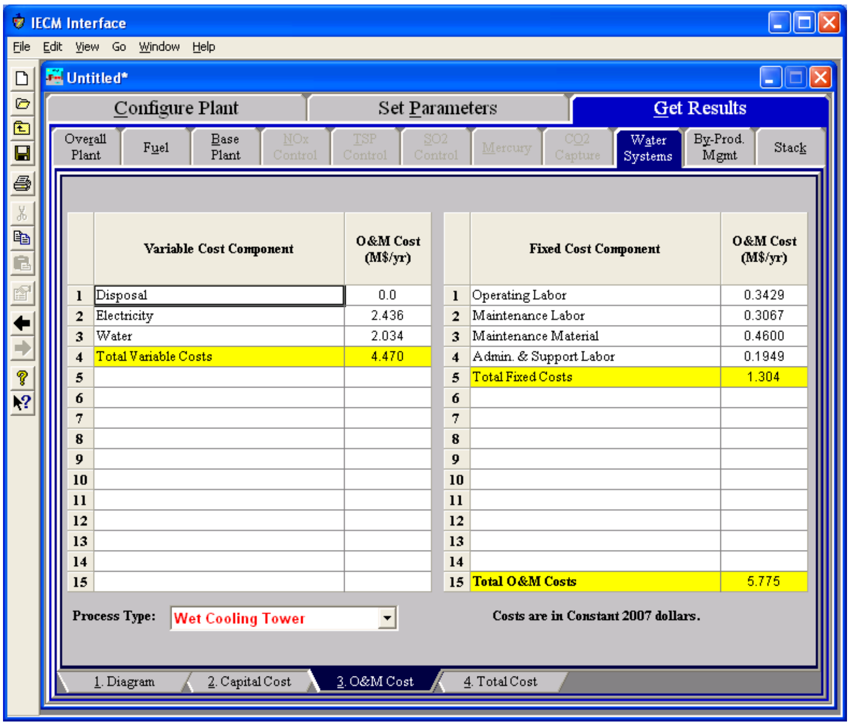
Inventory (Working) Capital: The raw material supply based on 100% capacity during a 60 day period. These materials are considered storage. The inventory capital includes fuels, consumables, by-products, and spare parts.

Total Capital Requirement (TCR): Money that is placed (capitalized) on the books of the utility on the service date. TCR includes all the items above. This result is highlighted in yellow.

Effective TCR: The TCR of the wet cooling tower that is used in determining the total power plant cost. The effective TCR is determined by the “TCR Recovery Factor” for the wet cooling tower.

Wet Cooling Tower O&M Cost Results

This screen is available for all plant types. The **O&M Cost** result screen displays tables for the variable and fixed operation and maintenance costs involved with the Wet Cooling Tower technology.



Wet Cooling Tower- O&M Cost Result Screen

O&M costs are typically expressed on an average annual basis and are provided in either constant or current dollars for a specified year, as shown on the bottom of the screen. Each result is described briefly below

Variable Cost Components

Variable operating costs and consumables are directly proportional to the amount of kilowatts produced and are referred to as incremental costs. All the costs are subject to inflation.

Disposal: Total cost to dispose the collected tower waste solids and wastewater.

Electricity: Cost of power consumption of the scrubber. This is a function of the gross plant capacity and the cooling system energy penalty performance input parameter.

Water: This is the annual cost of the water used by the cooling system.

Total Variable Costs: This is the sum of all the variable O&M costs listed above. This result is highlighted in yellow.

Fixed Cost Components

Fixed operating costs are essentially independent of actual capacity factor, number of hours of operation, or amount of kilowatts produced. All the costs are subject to inflation.

Operating Labor: Operating labor cost is based on the operating labor rate, the number of personnel required to operate the plant per eight-hour shift, and the average number of shifts per day over 40 hours per week and 52 weeks.

Maintenance Labor: The maintenance labor is determined as a fraction of the total maintenance cost.

Maintenance Material: The cost of maintenance material is the remainder of the total maintenance cost, considering the fraction associated with maintenance labor.

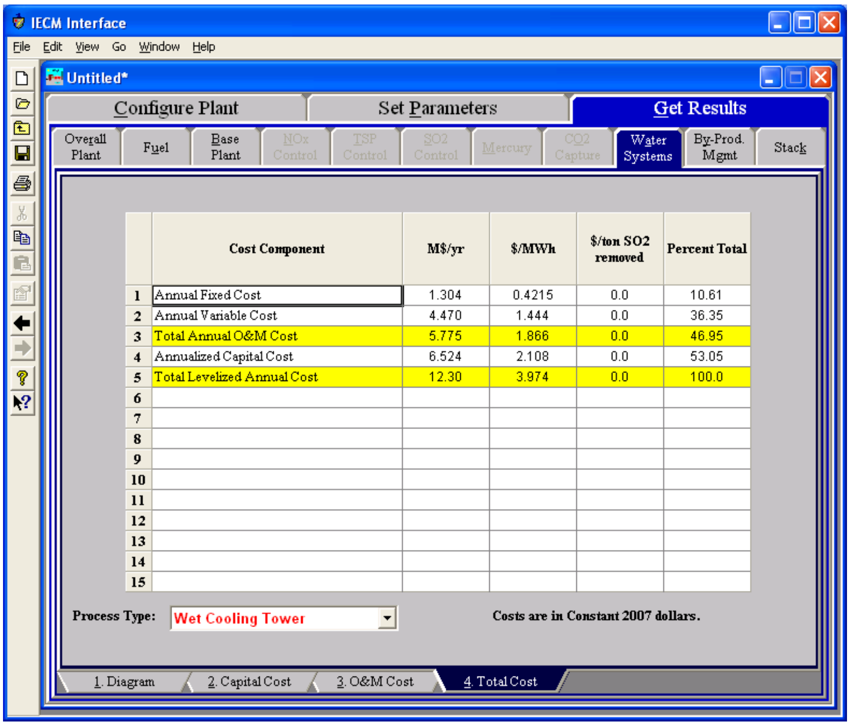
Admin. & Support Labor: The administrative and support labor is the only overhead charge. It is taken as a fraction of the total operating and maintenance labor costs.

Total Fixed Costs: This is the sum of all the fixed O&M costs listed above. This result is highlighted in yellow.

Total O&M Costs: This is the sum of the total variable and total fixed O&M costs. It is used to determine the base plant total revenue requirement. This result is highlighted in yellow.

Wet Cooling Tower Total Cost Results

This screen is available for all plant types. The **Total Cost** result screen displays a table which totals the annual fixed, variable, operations and maintenance, and capital costs associated with the Wet Cooling Tower technology.



Wet Cooling Tower- Total Cost Result Screen

Cost Component

Total costs are typically expressed in either constant or current dollars for a specified year, as shown on the bottom of the screen. Each result is described briefly below.

Annual Fixed Cost: The operating and maintenance fixed costs are given as an annual total. This number includes all maintenance materials and all labor costs.

Annual Variable Cost: The operating and maintenance variables costs are given as an annual total. This includes all reagent, chemical, steam, and power costs.

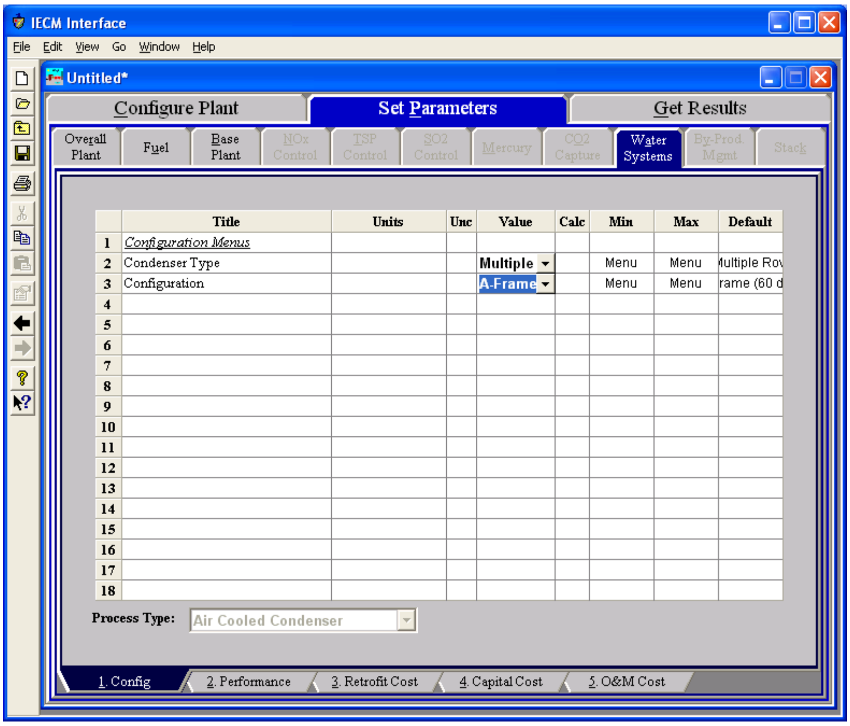
Total Annual O&M Cost: This is the sum of the annual fixed and variable operating and maintenance costs above. This result is highlighted in yellow.

Annualized Capital Cost: This is the total capital cost expressed on an annualized basis, taking into consideration the levelized carrying charge factor, or fixed charge factor, over the entire book life.

Total Levelized Annual Cost: The total annual cost is the sum of the total annual O&M cost and annualized capital cost items above. This result is highlighted in yellow.

Air Cooled Condenser Configuration

This screen is available for all plant types. Inputs for configuration of the Air Cooled Condenser are entered on the **Config** input screen.



Air Cooled Condenser- Config. Input Screen

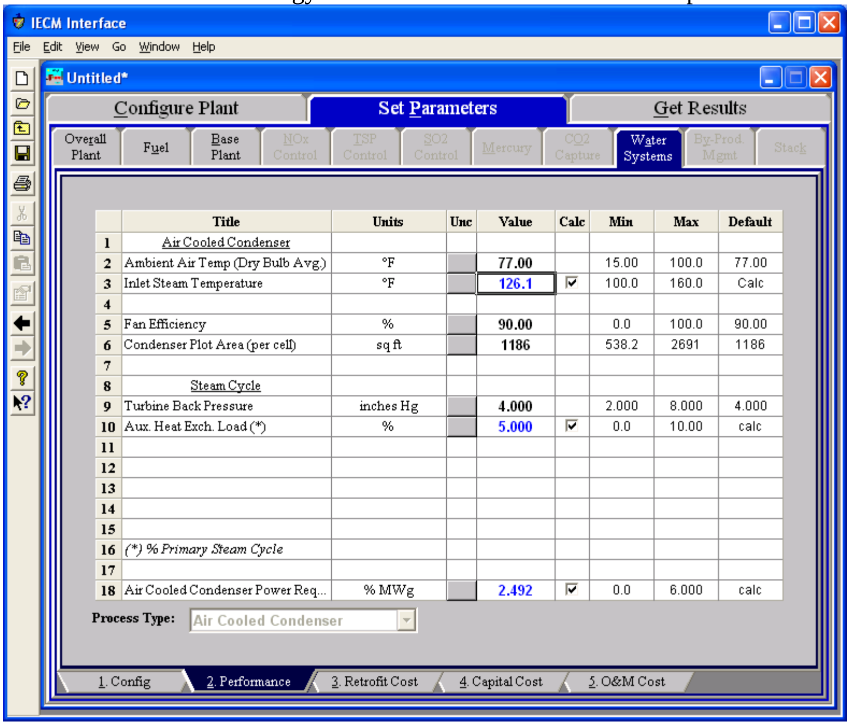
The parameters are described briefly below.

Condenser Type: This menu controls the configuration of the condenser. In practice, there are two condenser types (Single Row or Multiple Row). There is only a Multiple-Row condenser modeled in the current version.

Configuration: This menu shows the geometry of the dry cooling system framework. An air cooled condenser is comprised of fin tube bundles grouped together in parallel and arranged typically in an A-frame configuration. The A-Frame configuration usually has an apex angle of 60^o.

Air Cooled Condenser Performance Inputs

This screen is only available for all plant types. Inputs for performance of the Air Cooled Condenser technology are entered on the **Performance** input screen.



Air Cooled Condenser- Performance Input Screen

The parameters are described briefly below.

Ambient Air Temp (Dry Bulb Avg.): This refers basically to the ambient air temperature measured by a thermometer. This input specifies annual average ambient temperature.

Inlet Steam Temperature: That is the temperature of exhaust steam entering the air cooled condenser system. That is calculated as a function of the steam turbine backpressure. The difference between inlet steam and ambient air temperatures significantly affects the performance and cost of the dry cooling system.

Fan Efficiency: This parameter specifies the electricity efficiency of fan drive system. That is a percent of electrical power inputs to the fans.

Condenser Plot Area (per cell): This parameter specifies the footprint or plot area of one cell. One cell typically consists of multiple condenser bundles and is served by a large axial flow fan located at the floor of each cell.

Turbine Back Pressure: This parameter specifies the quantity of steam turbine backpressure. For the plant installed with a wet cooling system, the steam backpressure ranges from 1.5 to 2.0 inches of Mercury (inches Hg) whereas the steam backpressure for the plant installed with a dry cooling system ranges from 2.0 to 8.0 inches Hg. Turbine back pressure affects the steam cycle heat rate, and indirectly has an effect on the cooling system size when air cooled condensers are loaded.

Aux. Heat Exch. Load: This parameter specifies additional heat load on the auxiliary condenser and is expressed as a percentage of the load on the primary condenser.

Air Cooled Condenser Power Requirement: This parameter specifies the power needed to operate the big fans in the dry cooling system. It is also referred to as an energy penalty to the base plant. The electricity required for these big fans is estimated using the air cooled condenser performance model and is expressed as a percentage of the gross plant capacity. That is a function of the initial temperature difference between inlet steam and air and ambient pressure.

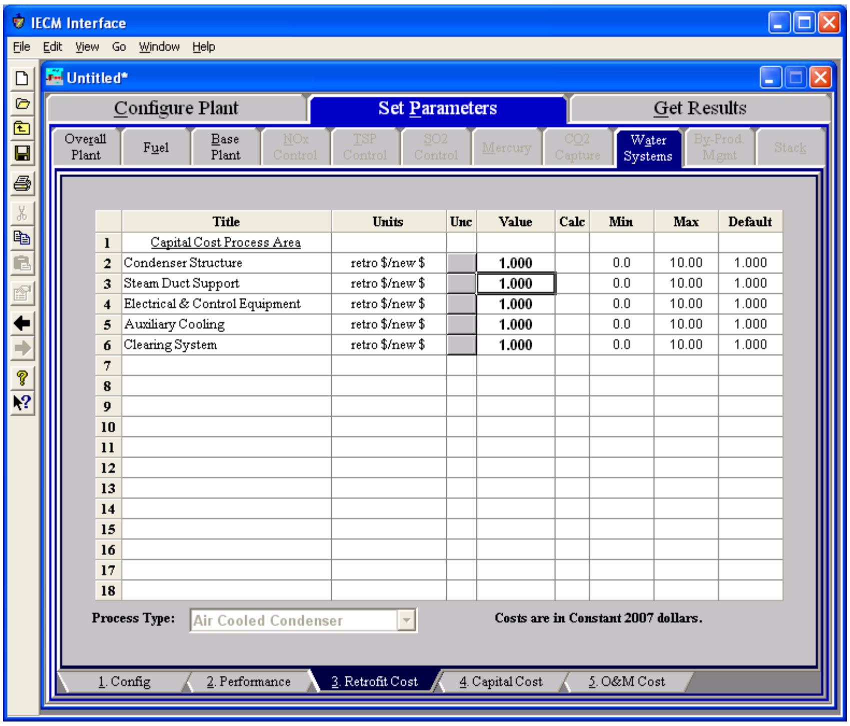
Air Cooled Condenser Retrofit Cost Inputs

This screen is only available for all plant types. Inputs for capital costs of modifications to process areas to implement the Air Cooled Condenser are entered on the **Retrofit Cost** input screen for the Air Cooled Condenser system.

The retrofit cost factor of each process is a multiplicative cost adjustment which considers the cost of retrofitted capital equipment relative to similar equipment installed in a new plant. These factors affect the capital costs directly and the operating and maintenance costs indirectly.

Direct capital costs for each process area are calculated in the IECM. These calculations are reduced form equations derived from more sophisticated models and reports. The sum of the direct capital costs associated with each process area is defined as the process facilities capital (PFC). The retrofit cost factor provided for each of the process areas can be used as a tool for adjusting the anticipated costs and uncertainties across the process area separate from the other areas.

Uncertainty can be applied to the retrofit cost factor for each process area in each technology. Thus, uncertainty can be applied as a general factor across an entire process area, rather than as a specific uncertainty for the particular cost on the capital or O&M input screens. Any uncertainty applied to a process area through the retrofit cost factor compounds any uncertainties specified later in the capital and O&M cost input parameter screens.



Air Cooled Condenser- Retrofit Cost Input Screen

The parameters are described briefly below.

Capital Cost Process Area

Condenser Structure: This area deals with the air cooled condenser equipments including finned tube heat exchanger elements, fans and motors, ACC support structure, steam exhaust duct, piping and valves, air removal equipment and support for start-up, training, and testing. The erection and installation of the ACC at the site is also included in this area.

Steam Duct Support: This area deals with steam duct support and column foundations.

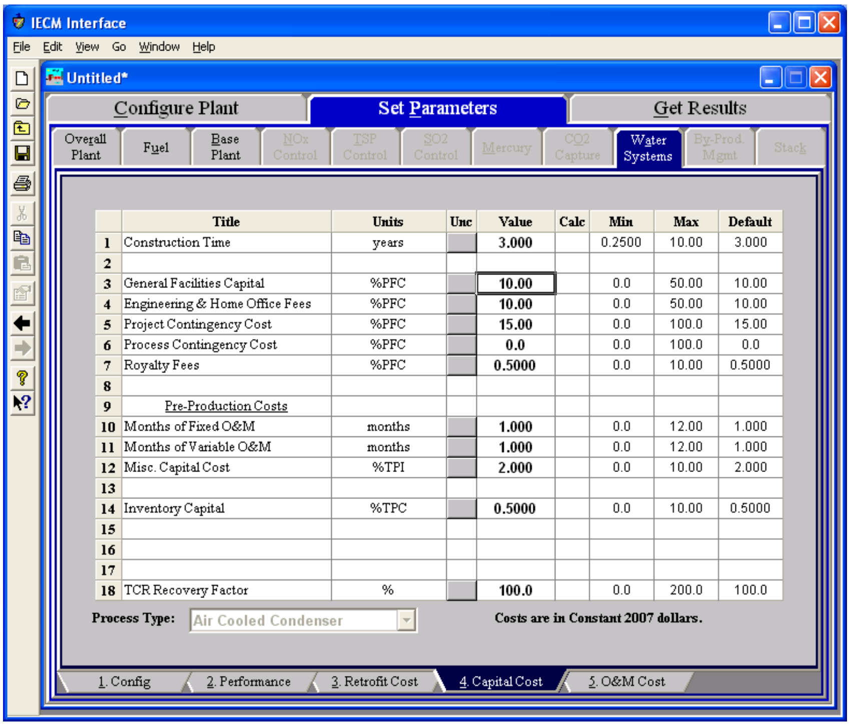
Electrical & Control Equipment: This area deals with fan, pump motor wiring and controls, etc.

Auxiliary Cooling: That deals with separate fin-fan unit or others. Typically, that is 5% additional heat load.

Clearing System: That area handles with cleaning finned tube surfaces. That is small but required at most sites.

Air Cooled Condenser Capital Cost Inputs

This screen is available for all plant types.



Air Cooled Condenser- Capital Cost Input Screen

Each parameter is described briefly below.

Construction Time: This is the idealized construction period in years. It is used to determine the allowance for funds used during construction (AFUDC).

General Facilities Capital (GFC): 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%.

Engineering & Home Office Fees: The engineering & home office fees are a percent of total direct capital cost. This is an overhead fee paid to the architect/engineering company. These fees typically range from 7-15%.

Project Contingency Cost: This is 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.

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

Pre-Production Costs: 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 applied to the O&M costs over a specified period of time (months). The two time periods for fixed and variable O&M costs are described below with the addition of a miscellaneous capital cost factor.

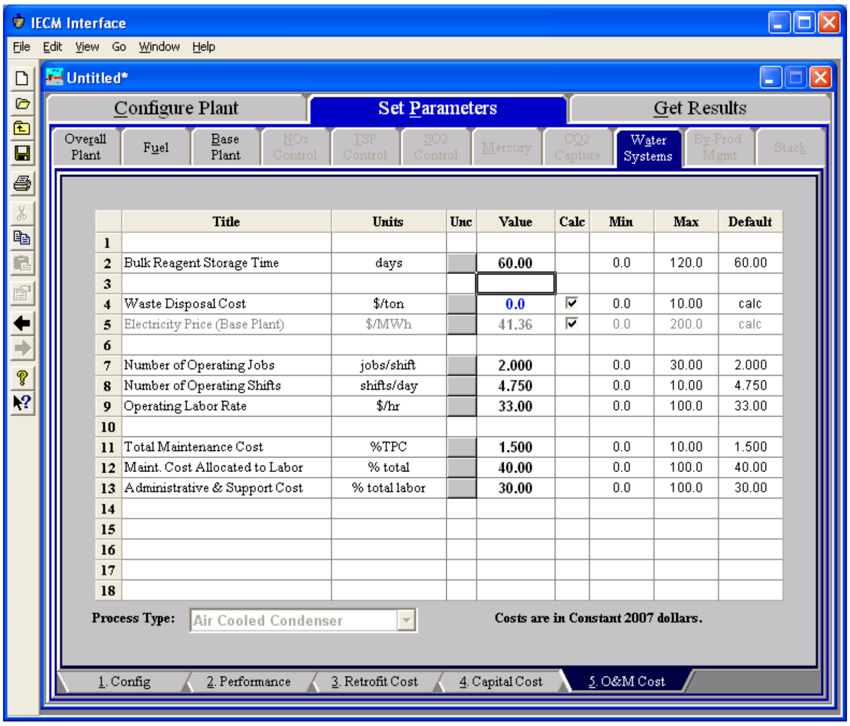
- **Months of Fixed O&M:** Time period of fixed operating costs used for preproduction to cover training, testing, major changes in equipment, and inefficiencies in start-up. This includes operating, maintenance, administrative and support labor. It also considers maintenance materials.
- **Months of Variable O&M:** Time period of variable operating costs used for preproduction to cover chemicals, water, consumables, and solid disposal charges in start-up, assuming 100% load. This excludes any fuels.
- **Misc. Capital Cost:** This is a percent of total plant investment (sum of TPC and AFUDC) to cover expected changes to equipment to bring the system up to full capacity.

Inventory Capital: Percent of the total direct capital for raw material supply based on 100% capacity during a 60 day period. These materials are considered storage. The inventory capital includes fuels, consumables, by-products, and spare parts. This is typically 0.5%.

TCR Recovery Factor: The actual total capital required (TCR) as a percent of the TCR in a new power plant. This value is 100% for a new installation and may be set as low as 0% for a dry cooling system that has been paid off.

Air Cooled Condenser O&M Cost Inputs

This screen is available for all plant types.



Air Cooled Condenser- O&M Cost Input Screen

O&M costs are typically expressed on an average annual basis and are provided in either constant or current dollars for a specified year, as shown on the bottom of the screen. Each parameter is described briefly below:

Waste Disposal Cost: This is the waste disposal cost for the wet tower.

Electricity Price (Base Plant): This is the price of electricity and is calculated as a function of the utility cost of the base plant, where the base plant is a combustion boiler and an air preheater.

Number of Operating Jobs: This is the total number of operating jobs that are required to operate the plant per eight-hour shift.

Number of Operating Shifts: This is the total number of equivalent operating shifts in the plant per day. The number takes into consideration paid time off and weekend work (3 shifts/day * 7 days/5 day week * 52 weeks/(52 weeks - 6 weeks PTO) = 4.75 equiv. Shifts/day).

Operating Labor Rate: The hourly cost of labor is specified in the base plant O&M cost screen. The same value is used throughout the other technologies.

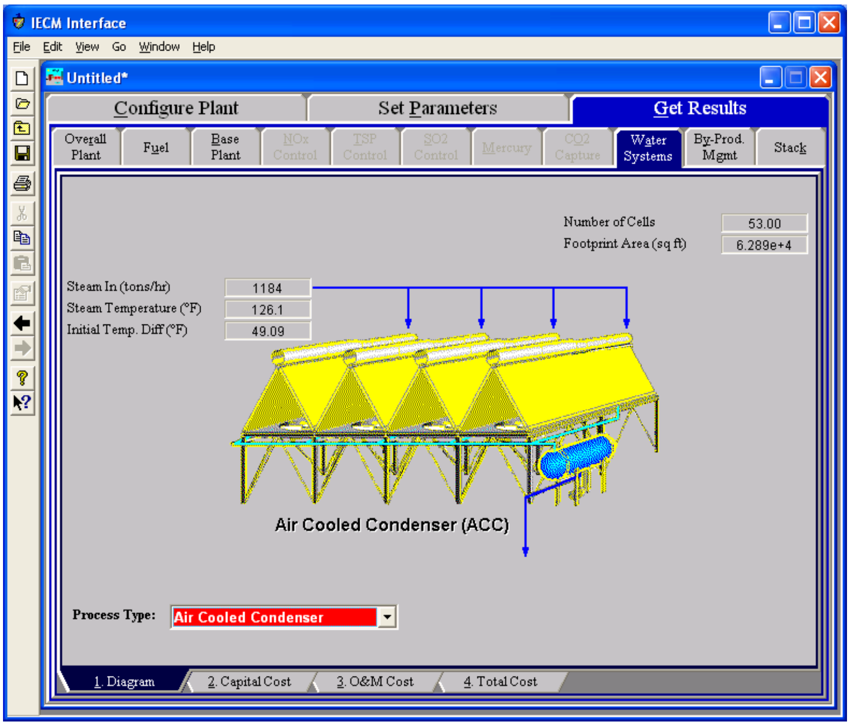
Total Maintenance Cost: This is the annual maintenance cost as a percentage of the total plant cost. Maintenance cost estimates can be developed separately for each process area.

Maint. Cost Allocated to Labor: Maintenance cost allocated to labor as a percentage of the total maintenance cost.

Administrative & Support Cost: This is the percent of the total operating and maintenance labor associated with administrative and support labor.

Air Cooled Condenser Diagram

This screen is available for all plant type. The Diagram result screen displays an icon for the Air Cooled Condenser selected and values for major flows in and out of it and its size.



Air Cooled Condenser- Diagram

Each result is described briefly below

Number of Cells: Number of cells in the dry cooling system. Each cell has eight heat exchanger bundles in the default. The heat exchanger bundle consists of two-row staggered plat-finned flat tubes.

Footprint Area: The plot area of the dry cooling system. That is a function of initial temperature difference between inlet steam and air and ambient pressure.

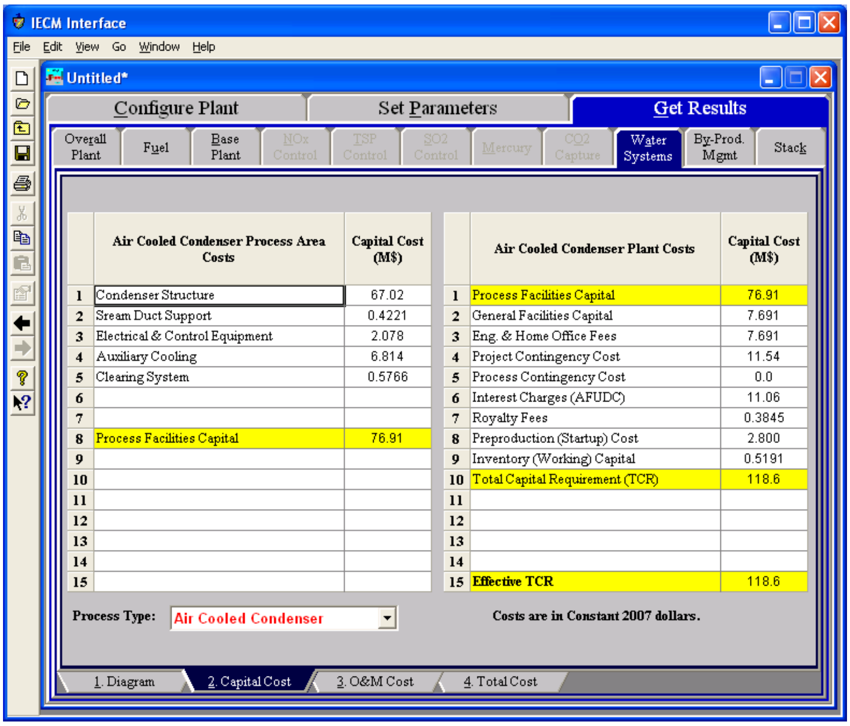
Steam In: The total mass flow rate of the exhaust steam. That depends on the plant size and steam cycle heat rate.

Steam Temperature: The temperature of exhaust steam entering the air cooled condensers. That is empirically estimated in terms of the steam turbine back pressure.

Initial Temp. Diff.: That is the temperature difference between inlet steam and steam of the dry cooling system. This variable significantly affects the performance and cost of the dry cooling system.

Air Cooled Condenser Capital Cost Results

This screen is available for all plant types. The **Capital Cost** result screen displays tables for the direct and indirect capital costs related to the Air Cooled Condenser technology.



Air-Cooled Condenser- Capital Cost Result Screen

Capital costs are typically expressed in either constant or current dollars for a specified year, as shown on the bottom of the screen. Each result is described briefly below

Direct Capital Costs

Condenser Structure: This area deals with the cost of air cooled condenser equipments, erection and installation of the air cooled condensers at the site. The cost of the ACC equipments is estimated as a function of initial temperature difference between inlet steam and air based on the cost data estimated by Electric Power Research Institute. The erection accounted for approximately 30% of the sum of the equipment and erection cost, which is equivalent to about 43% of the ACC equipment cost.

Scream Duct Support: This area deals with the cost of steam duct support and column foundations.

Electrical & Control Equipment: This area deals with the cost of fan, pump motor wiring and controls, etc.

Auxiliary Cooling: That deals with the cost of auxiliary cooling including separate fin-fan unit or others.

Clearing System: That deals with the cost of clearing finned tube surfaces.

Process Facilities Capital: The process facilities capital is the total constructed cost of all on-site processing and generating units listed above, including all direct and indirect construction costs. All sales taxes and freight costs are included where applicable implicitly. That highly depends on the initial temperature difference between inlet steam and air. This result is highlighted in yellow.

Total Capital Costs

Process Facilities Capital: (see definition above)

General Facilities Capital: The general facilities include construction costs of roads, office buildings, shops, laboratories, etc. Sales taxes and freight costs are included implicitly.

Eng. & Home Office Fees: The engineering & home office fees are a percent of total direct capital cost. This is an overhead fee paid to the architect/engineering company.

Project Contingency Cost: Capital cost contingency factor covering the cost of additional equipment or other costs that would result from a more detailed design of a definitive project at the actual site.

Process Contingency Cost: Capital cost contingency factor applied to a new technology in an effort to quantify the uncertainty in the technical performance and cost of the commercial-scale equipment.

Interest Charges (AFUDC): Allowance for funds used during construction, also referred to as interest during construction, is the time value of the money used during construction and is based on an interest rate equal to the before-tax weighted cost of capital. This interest is compounded on an annual basis (end of year) during the construction period for all funds spent during the year or previous years.

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

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.

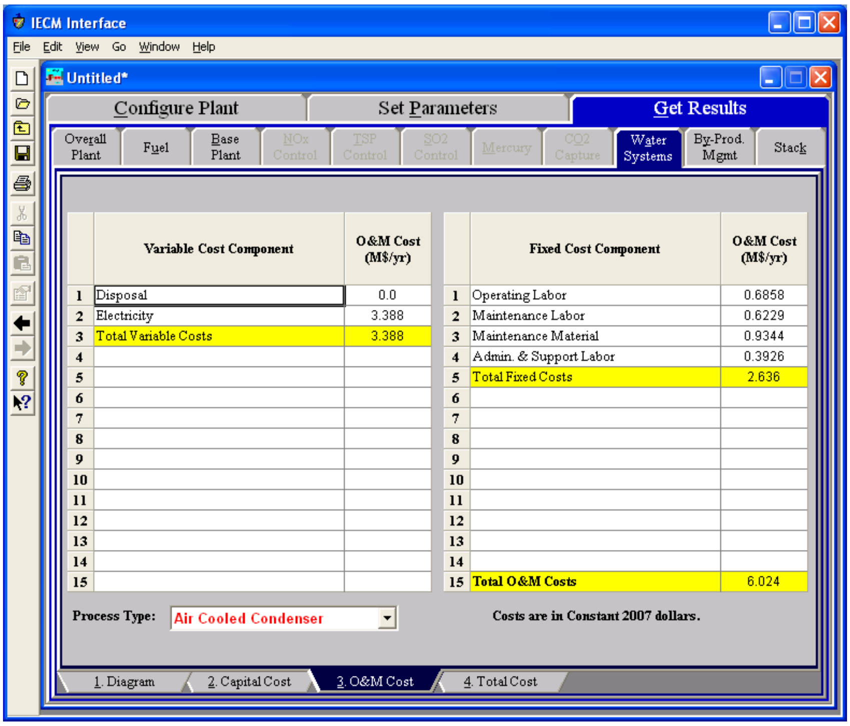
Inventory (Working) Capital: The raw material supply based on 100% capacity during a 60 day period. These materials are considered storage. The inventory capital includes fuels, consumables, by-products, and spare parts.

Total Capital Requirement (TCR): Money that is placed (capitalized) on the books of the utility on the service date. TCR includes all the items above. This result is highlighted in yellow.

Effective TCR: The TCR of the dry cooling system that is used in determining the total power plant cost. The effective TCR is determined by the “TCR Recovery Factor” for the dry cooling system.

Air Cooled Condenser O&M Cost Results

This screen is available for all plant types. The **O&M Cost** result screen displays tables for the variable and fixed operation and maintenance costs involved with the Air Cooled Condenser technology.



Air Cooled Condenser- O&M Cost Result Screen

O&M costs are typically expressed on an average annual basis and are provided in either constant or current dollars for a specified year, as shown on the bottom of the screen. Each result is described briefly below

Variable Cost Components

Variable operating costs and consumables are directly proportional to the amount of kilowatts produced and are referred to as incremental costs. All the costs are subject to inflation.

Disposal: Total cost to dispose the collected cleaning wastes.

Electricity: Cost of power consumption of the scrubber. This is a function of the gross plant capacity and the cooling system energy penalty performance input parameter.

Total Variable Costs: This is the sum of all the variable O&M costs listed above. This result is highlighted in yellow.

Fixed Cost Components

Fixed operating costs are essentially independent of actual capacity factor, number of hours of operation, or amount of kilowatts produced. All the costs are subject to inflation.

Operating Labor: Operating labor cost is based on the operating labor rate, the number of personnel required to operate the plant per eight-hour shift, and the average number of shifts per day over 40 hours per week and 52 weeks.

Maintenance Labor: The maintenance labor is determined as a fraction of the total maintenance cost.

Maintenance Material: The cost of maintenance material is the remainder of the total maintenance cost, considering the fraction associated with maintenance labor.

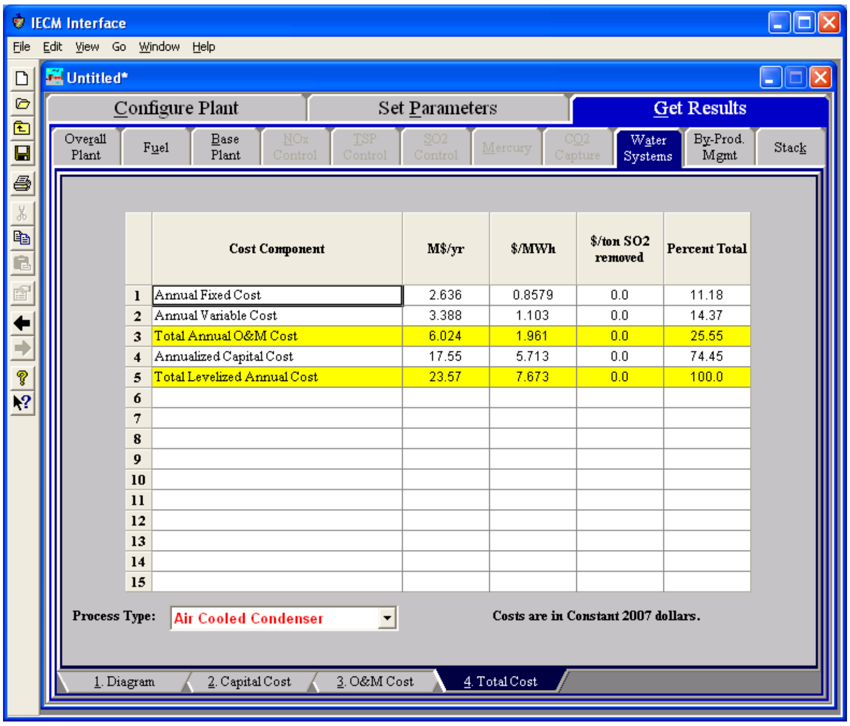
Admin. & Support Labor: The administrative and support labor is the only overhead charge. It is taken as a fraction of the total operating and maintenance labor costs.

Total Fixed Costs: This is the sum of all the fixed O&M costs listed above. This result is highlighted in yellow.

Total O&M Costs: This is the sum of the total variable and total fixed O&M costs. It is used to determine the base plant total revenue requirement. This result is highlighted in yellow.

Air Cooled Condenser Total Cost Results

This screen is available for all plant types. The **Total Cost** result screen displays a table which totals the annual fixed, variable, operations and maintenance, and capital costs associated with the Air Cooled Condenser technology.



Air Cooled Condenser- Total Cost Result Screen

Cost Component

Total costs are typically expressed in either constant or current dollars for a specified year, as shown on the bottom of the screen. Each result is described briefly below.

Annual Fixed Cost: The operating and maintenance fixed costs are given as an annual total. This number includes all maintenance materials and all labor costs.

Annual Variable Cost: The operating and maintenance variables costs are given as an annual total. This includes all reagent, chemical, steam, and power costs.

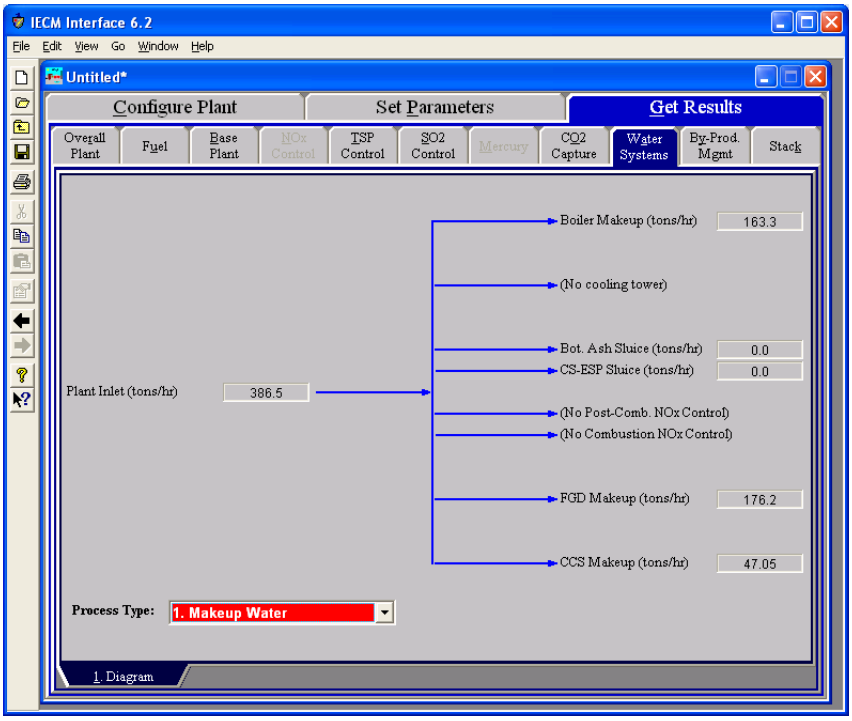
Total Annual O&M Cost: This is the sum of the annual fixed and variable operating and maintenance costs above. This result is highlighted in yellow.

Annualized Capital Cost: This is the total capital cost expressed on an annualized basis, taking into consideration the levelized carrying charge factor, or fixed charge factor, over the entire book life.

Total Levelized Annual Cost: The total annual cost is the sum of the total annual O&M cost and annualized capital cost items above. This result is highlighted in yellow.

Makeup Water System Results

This screen is only available for pulverized coal power plants. Major outputs are briefly described below.



Makeup Water Result Screen

Plant Inlet: this variable presents the total amount of makeup water required by the plant for boiler, cooling system, bottom ash sluice, fly ash sluice, FGD, and carbon capture system if applicable.

Boiler Makeup: This variable presents the amount of makeup water for the main steam cycle to supplement boiler blowdown and miscellaneous steam losses, which mainly depends on the boiler blowdown rate.

Cooling Makeup: This variable presents the amount of makeup water for the cooling system. There is no makeup water required for once-through and air cooled condenser systems. For the wet cooling tower, the makeup water is required to supplement the evaporation, blowdown and drift losses.

Bot. Ash Sluice: This variable presents the amount of makeup water used for sluicing bottom ash that is collected at the bottom of the boiler. In a wet sluicing system, bottom ash is sluiced with water and transported to a bottom ash pond where the ash settles in the pond. There may no need of makeup water to sluice bottom ash as the blowdown from the wet tower and bottom ash pond overflow can be reused as sluice water.

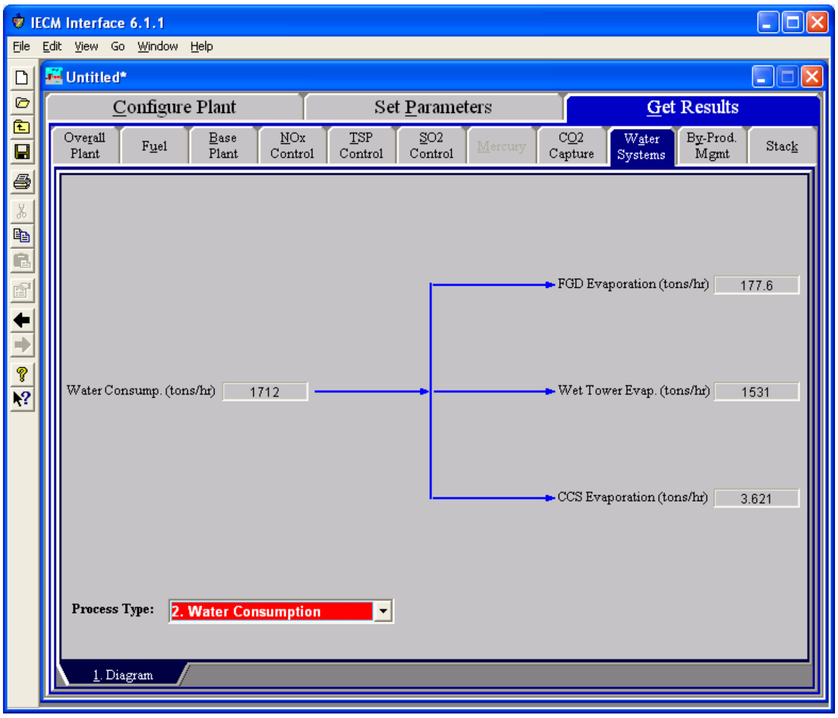
CE-ESP Sluice: This variable presents the amount of makeup water used for sluicing fly ash that is entrained in the flue gas and removed by air pollution control system equipment such as ESP. There may no need of makeup water to sluice fly ash as the blowdown from the wet tower and bottom ash pond overflow can be reused as sluice water.

FGD Makeup: The variable presents the amount of makeup water needed to replace the evaporated water in the reagent sluice circulation stream.

CCS Makeup: The variable presents the amount of makeup water needed to replace the loss from contact cooler evaporation, dilute the makeup MEA, and supplement the reclaimer loss when amine-based capture system is used.

Water Consumption Results

This screen is only available for pulverized coal power plants. This screen summarizes water consumption across the entire plant. Major outputs are briefly described below.



Water Consumption Result Screen

Water Consumption: This variable presents the total amount of water consumed across the entire plant including associated environmental control technologies.

FGD Evaporation: This variable presents the amount of evaporation water in FGD when it is loaded.

Wet Tower Evap.: This variable presents the amount of evaporation and drift losses in the wet tower when the wet cooling tower system is loaded.

CCS Evaporation: This variable presents the amount of evaporation loss in direct contact cooler when the amine-based capture system is loaded.

Integrated Environmental Control Model

User Manual

Carnegie Mellon University

Note:

This User Documentation applies to Version 5.2.2, and was last updated in 2007.

Version 6.2 incorporates some additional modifications that should be easily understood but are not fully documented in this volume.

This manual was produced using *ComponentOne Doc-To-Help.*™

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Power Block 373

Disclaimer

Acknowledgements

This report is an account of research sponsored by the U.S. Department of Energy's National Energy Technology Center (DOE/NETL) under Contract No. DE-AC21-92MC29094.

Introduction

The Integrated Environmental Control Model

This Integrated Environmental Control Model with Carbon Sequestration (IECM-cs) and Interface were developed for the U. S. Department of Energy's National Energy Technology Laboratory (NETL), formerly known as the Federal Energy Technology Center (FETC), under contracts No. DE-AC22-92PC91346 and DE-AC21-92MC29094.

Purpose

The product of this work is a desktop computer model that allows different technology options to be evaluated systematically at the level of an individual plant or facility. The model takes into account not only avoided carbon emissions, but also the impacts on multi-pollutant emissions, plant-level resource requirements, costs (capital, operating, and maintenance), and net plant efficiency.

In addition, uncertainties and technological risks also can be explicitly characterized. The modeling framework is designed to support a variety of technology assessment and strategic planning activities by DOE and other organizations.

The model currently includes four types of fossil fuel power plants: a pulverized coal (PC) plant, a natural gas-fired combined cycle (NGCC) plant, a coal-based integrated gasification combined cycle (IGCC) plant, and an oxyfuel combustion plant. Each plant can be modeled with or without CO2 capture and storage. The IECM-cs can thus be employed to quantify the costs and emission reduction benefits of CCS for a particular system or to identify the most cost-effective option for a given application.

This model also can be used to quantify the benefits of technology R&D and to identify advanced technology options having the highest potential payoffs.

A Graphical User Interface (GUI) facilitates the configuration of the technologies, entry of data, and retrieval of results.

System Requirements

The current model requires the following configuration:

- Intel-based computer running Windows 98 (or better) or Windows NT 4.0 (or better) operating system
- Pentium Processor

- any SVGA (or better) display—at a resolution of 800x600 (or more) pixels[1]
- at least 40 Megabytes of free hard disk space
- at least 128 Megabytes of total memory

Uncertainty Features

The ability to characterize uncertainties explicitly is a feature unique to this model. As many as one hundred input parameters can be assigned probability distributions. When input parameters are uncertain, an uncertainty distribution of results is returned. Such result distributions give the *likelihood* of a particular value, in contrast to conventional single-value estimates.

The model can run using single deterministic values or uncertainty distributions. The conventional deterministic form using single values for all input parameters and results may be used, or probabilistic analyses may be run—for instance, to analyze advanced technology costs (see Appendix A for more details).

Software Used in Development

The underlying engineering models are written in Intel® Visual Fortran. Fortran runtime libraries are included with the IECM Interface software. This language provides the flexibility to configure many various power plant designs while also providing the power to conduct probabilistic analyses.

All databases are in Microsoft® Access format and may be viewed in Access, as long as they are not changed. This format is a software industry standard and facilitates sharing and updating of information.

To simplify the use of the model, a Graphical User Interface (GUI) has been added. The interface eliminates the need to master the underlying commands normally required for model operation. The interface is written in Microsoft® Visual C++, a standard software development tool for the Windows environment. Visual C++ runtime libraries are included with the IECM Model software and do not need to be licensed separately.

Wise for Windows Installer was used to generate full installer programs. This product was chosen based on its flexibility and its support of Visual Basic runtime libraries and Microsoft Data Access Components (MDAC)[2]. The Visual Basic runtime libraries provide the support needed to run the database file compactor program provided with the IECM. MDAC provides the software support needed to link Microsoft® Access data files to the IECM interface program. Wise for Windows Installer provides the VB and MDAC installation as an option, rather than forcing the user to download it from Microsoft and install it prior to installing the IECM.

[1] Smaller screen resolution results in the interface screens being scaled smaller. The taskbar, part of the Windows operating system, reduces the useable resolution of the screen if it is always visible. This may force the IECM interface to be scaled down slightly. To avoid this situation, select the "Auto Hide" option of the Taskbar properties in Windows.

[2] The current version of MDAC is 2.8. This is installed with the full installer for the IECM. Any update installers provided for upgrading the IECM from a previous version to the current version do not upgrade MDAC unless the user updates MDAC separately.

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User Documentation and Help

User Manual

The *User Manual* gives further information on both the interface and the underlying model. It provides detailed descriptions of plant configurations, parameter settings, and result screens. It also describes technical details behind the model's operation and includes an introduction to uncertainty analysis.

Technical Manuals

The *Technical manuals* are detailed engineering descriptions of the technologies and costing assumptions used in the IECM. These manuals are not provided by default with the IECM software; however, they can be downloaded with any web browser from http://www.iecm-online.com.

Online Help

Online help is provided via a Windows Help File containing the full text of the *User Manual*.

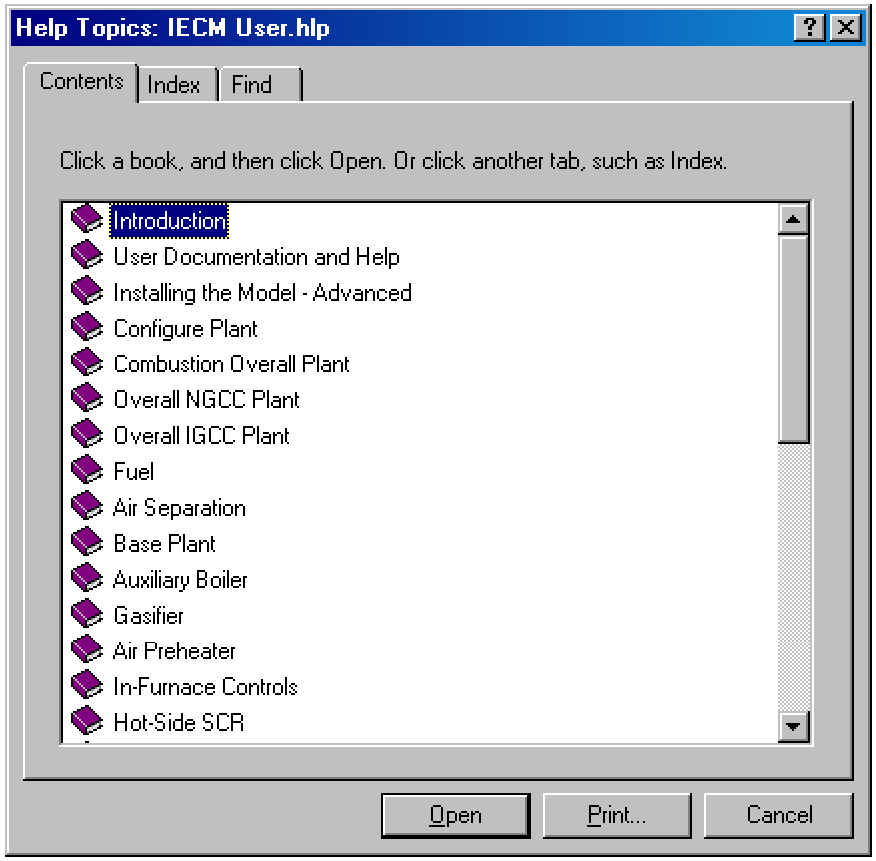
Accessing the IECM Help file:

If you are not running the IECM interface, click the **Help** icon inside the IECM folder on the **Start** menu. This opens the help file to the table of contents.

If you are running the IECM interface, do any one of the following:

- Press the **F1** key. The IECM supports context-sensitive help and will open the help file to the topic associated with the item or screen you are viewing.
- Pull down the **Help** menu at the top of the IECM window. Select **Help Topics**. This opens the help file to the table of contents.
- Click the **Context-Sensitive Help** icon on the toolbar on the left side of the IECM window. The IECM supports context-sensitive help and will open the help file to the topic associated with the item or screen you are viewing.
- Click the **Help Topics** icon on the toolbar on the left side of the IECM window. This opens the help file to the table of contents. If this method does not work, try one of the other options above.

The IECM Help File Contents window will display.



The IECM Help File Topics Window

Installing the Model

Installation Options

Normal installation is described in *Getting Started.* This section addresses installation from a network drive or the worldwide web. This section also describes advanced features of the installation program and the files installed.

Local and Network Installation

The Setup program can be run from a local hard drive or a network server. Installing from a hard drive eases the burden of sharing one IECM compact disk (CD) between multiple users. Installing from a network server simplifies the process of installing the entire package on a series of personal computers connected to the network. However, both methods require some familiarity with creating and finding folders and sub-directories on a network hard drive.

NOTE:
You may also install the interface to a network server. All files will be loaded to the server except the shortcut in the start menu of the local personal computer. The interface will run from the server and all sessions will be saved to the network drive, meaning that others with access to the network drive may change or delete them. Installation to a network server is not currently supported.

Installing the IECM from a Local Hard Drive

To install from a local hard drive, copy the SETUP.EXE installer program from the IECM compact disk (CD) disk into one sub-directory or folder on your personal hard drive.

1. On the personal computer, click the Start button.
2. Choose **Run…** from the Start menu.
3. Type "`X:\XXX\Media\SETUP.EXE`" where "X:\XXX\" is the drive and directory on your local hard drive to which you copied the files.

The Installation Program will begin. Follow the instructions on the screen.

If you receive an error message while running Setup, restart your computer and run the installation program again. If Setup still returns an error message, call Technical Support.

Installing the IECM from a Network

To install from a network hard drive:

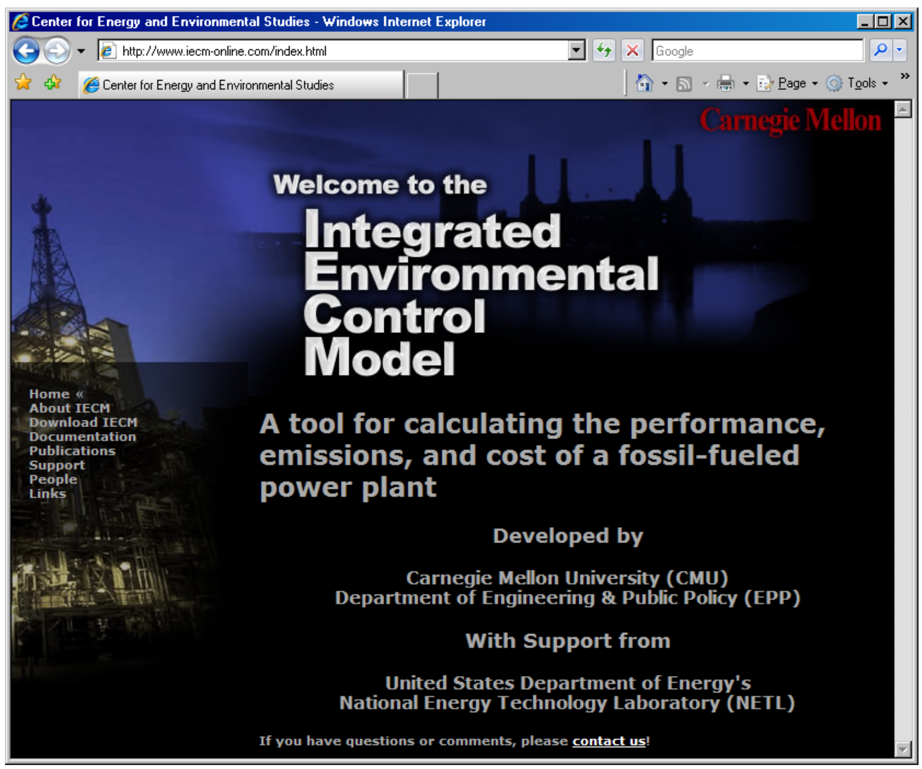
1. Copy the contents of the IECM compact disk (CD) disk into one sub-directory or folder on a network hard drive.
2. On the personal computer, click the Start button.
3. Choose **Run**… from the Start menu.
4. Type “`X:\XXX\Media\SETUP.EXE`” where “X:\XXX\” is the drive and directory on the network hard drive to which you copied the files.

The Installation Program will begin. Follow the instructions on the screen.

If you receive an error message while running Setup, restart your computer and run the installation program again. If Setup still returns an error message, call Technical Support

Internet Installation

The contents of the IECM CD-ROM are also available on the worldwide web (www.iecm-online.com). The media, documentation and various text files can be downloaded to your local computer or network hard drive.

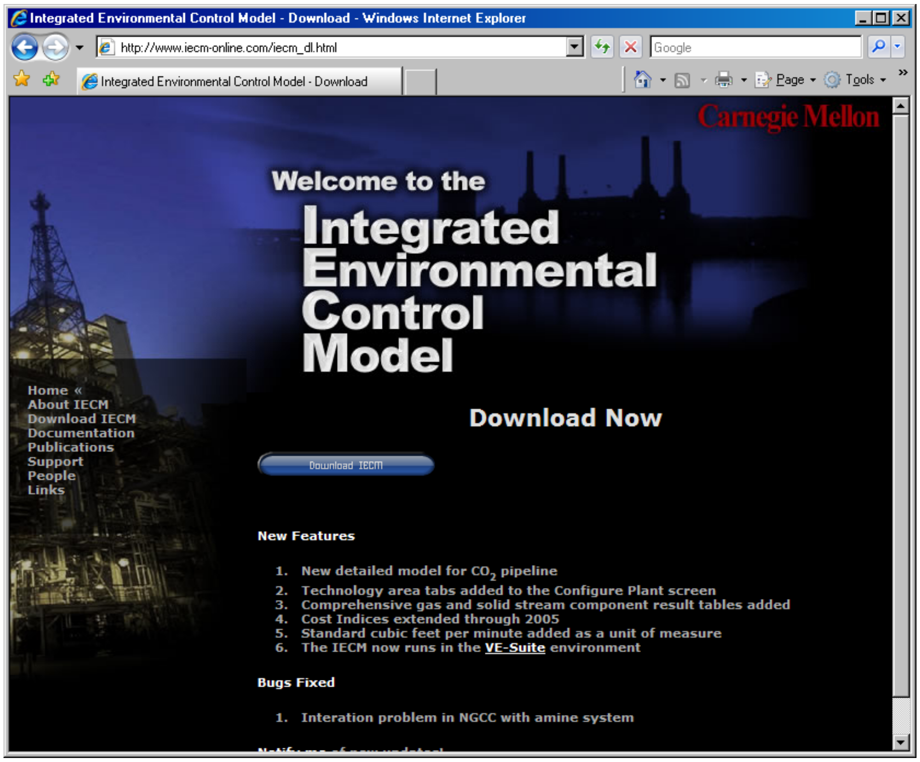


www.iecm–online.com Home Page

Downloading the IECM from the internet.

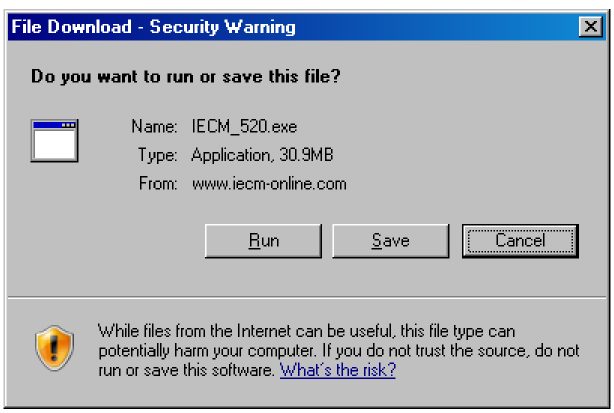
To download the install software to your computer:

1. Open a web browser program (e.g., Internet Explorer or Netscape).
2. In the "Address" line of the browser, type the following http://www.iecm-online.com/iecm_dl.com. You will see the iecm–download page.



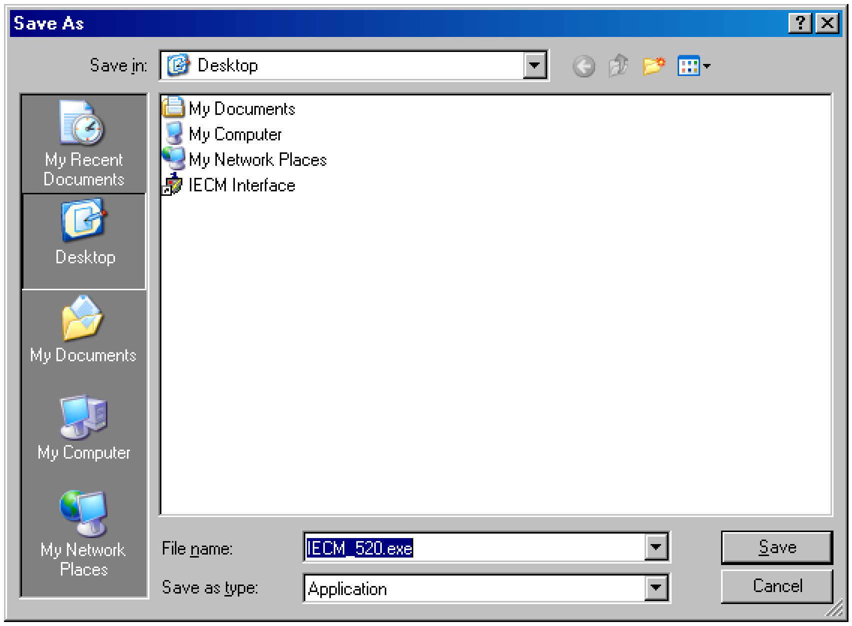
www.iecm–online.com Download Page

3. Click the text on the left labeled **Download IECM**.
4. Click on the blue button labeled **Download IECM**. A dialog box will appear.



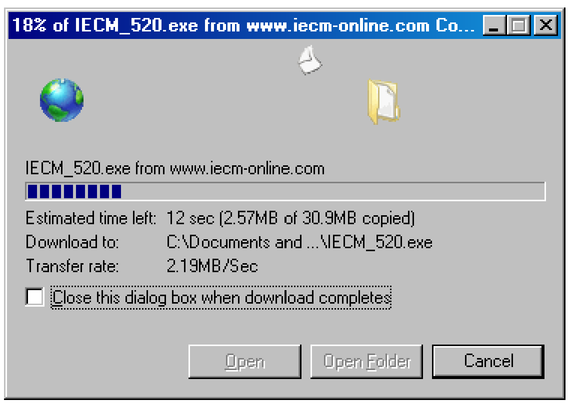
File download dialog box; save the program to disk

5. Click on the **Save** button.



Save file dialog box; use this to select the location to save the program

6. Choose a location to save the setup file and click the "Save" button.



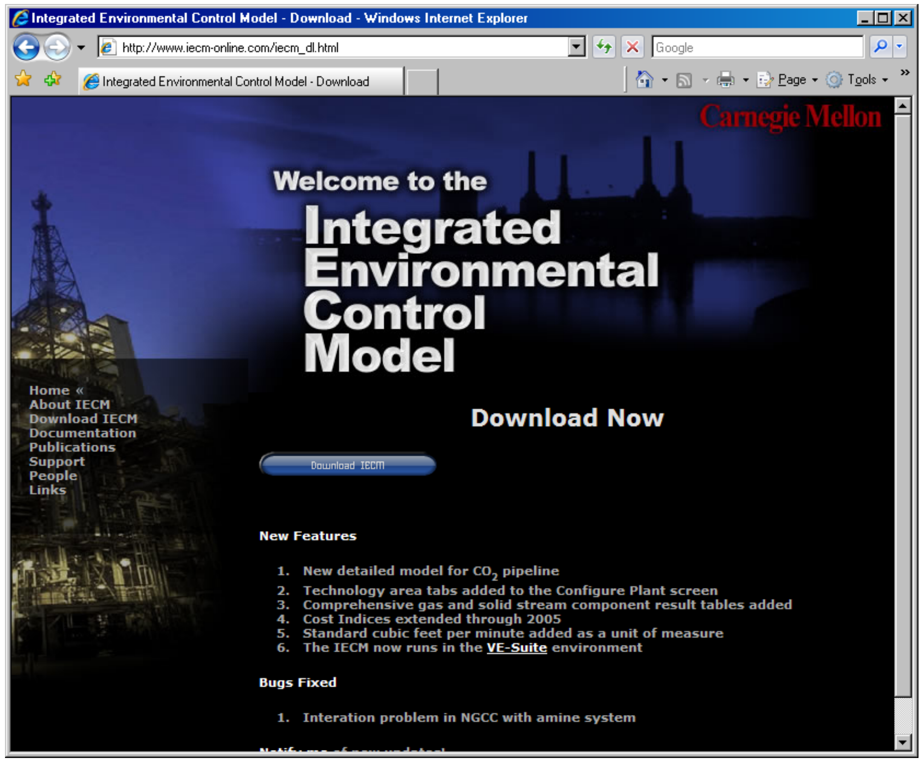
File download progress indicator

The download will begin. Once it is finished, you can proceed to install the IECM software. If you receive an error message while running the install program, restart your computer and run the installation program again. If it still returns an error message, contact Technical Support

Installing the IECM from the internet

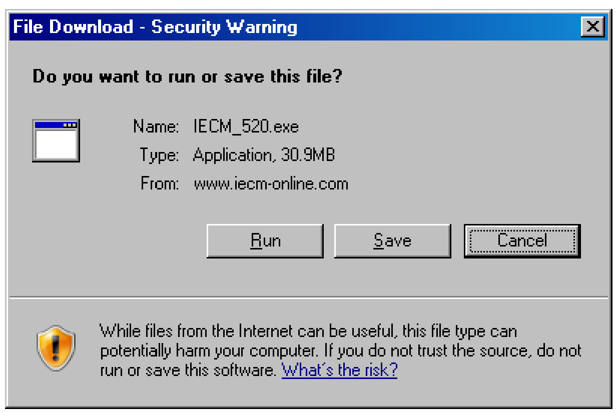
To install the software to from the internet directly onto your computer:

1. Open a web browser program (e.g., Internet Explorer or Netscape).
2. In the "Address" line of the browser, type the following http://www.iecm-online.com/iecm_dl.html. You will see the iecm–download page.



www.iecm–online.com Download Page

3. Click on the blue button labeled **Download IECM**. A dialog box will appear.



File download dialog box; run the program directly

4. Click on the **Run** button.

The installer program will download to a temporary location on your hard drive. Once it is finished, the installer program will automatically proceed to install the IECM software. If you receive an error message while running the install program, restart your computer and run the installation program again. If it still returns an error message, contact Technical Support. Once the installer program is completed, it will be deleted from the temporary location on your hard drive.

Files Added by Install

This section provides a full list and short description of the files installed by the IECM installer software. The software is divided into three categories.

Help Files

The following help files are installed by default in the `C:\PROGRAM FILES\IECM_CS` directory by the installation program:

`Iecmint.cnt`: IECM "Getting Started" online help contents file.

`Iecmint.hlp`: IECM "Getting Started" online help file.

Program Files

All applications and their support files specific to the IECM software itself are considered program files. These can be installed into any directory during installation. The folder can be changed from the default location suggested during installation.

`GSPROP32.DLL`: Graphics Server for Windows 6.15 support file.

`GSW32.EXE`: Graphics Server for Windows 6.15 program file.

`GSWAG32.DLL`: Graphics Server for Windows 6.15 support file.

`GSWDLL32.DLL`: Graphics Server for Windows 6.15 support file.

`LTDIS13N.DLL`: Graphics Server for Windows 6.15 support file.

`LTEFX13N.DLL`: Graphics Server for Windows 6.15 support file.

`LTFIL13N.DLL`: Graphics Server for Windows 6.15 support file.

`LTKRN13N.DLL`: Graphics Server for Windows 6.15 support file.

`MFC71.DLL`: Microsoft Foundation Class .support file for Visual Studio .NET.

`MFC71U.DLL`: Microsoft Foundation Class .support file for Visual Studio .NET.

`MSVCR71.DLL`: Microsoft Visual C runtime library.

`HISTORY.TXT:` History of the IECM software, including features installed and planned.

`IECMILIB.DLL`: IECM interface support file. It handles all database, uncertainty and model access.

`IECMINT.EXE`: IECM program file for the interface.

`IECMINT.MDB`: Microsoft Access 97 template database file.

`LHS.DLL`: IECM interface support file. It handles all uncertainty sampling.

`LHS_C.DLL`: IECM interface support file. It handles all uncertainty sampling.

`LICENSE.TXT`: IECM license agreement.

`MODEL.DLL`: IECM interface model support file. It contains all the technology performance and cost modules.

`SPR32d60.dll`: Spread 6.0 support file.

`Tab32d30.dll`: Tab Pro 3.1 support file.

`UNWISE32.EXE:` Uninstaller program. This requires an installer log created during installation.

Interface Files

The "C:\Program Files\IECM_CS/intdb" directory contains the database files used by the IECM interface. These contain default data used in the interface program. The following files are installed by the installation program:

`Intdesc.mdb`: Microsoft Access database file. It contains all the descriptions for the IECM interface screens.

`Model_Default_fules.mdb`: Microsoft Access database file. It contains the model default coal information.

Session Database Files

The "C:\Program Files\IECM_CS\sessdb" directory contains the database files created by the IECM interface. All user data associated with sessions are stored here. These files are not created by the installation program; rather, they are created by the IECM Interface at runtime if they are not available. This means that user data cannot be overwritten by the installation program.

System Files

Several files are installed into the windows system directory. These system files are common to many Windows applications. All of these files are created and distributed freely through Microsoft ® Corporation using their installer packages. These system files are unique to the other IECM components listed above because they are hard-wired into the system registry file. In order to maintain consistency with the operating system and stability with the IECM interface, these special system files must be stored in the windows system directory and installed with software installers directly from Microsoft.

A full list of the Microsoft ® Corporation files installed is provided in the INSTALLR.TXT file located on the IECM compact disk (CD).

Microsoft Data Access Components

The use of Microsoft Access database files requires the installation of ODBC drivers and support files from Microsoft. ODBC is a programming interface that enables applications to access data in database management systems that use Structured Query Language (SQL) as a data access standard. The Microsoft MDAC package is included with the IECM installer program as delivered directly from Microsoft and delivers this important functionality. Files are installed into the "C:\Windows\System32" directory.

Microsoft Visual Basic 4.0 Runtime

The components of this package are installed from within the IECM installer as delivered by Microsoft. They provide Microsoft Visual Basic support files and are installed into the “C:\Windows\System32” directory and the “C:\Program Files\Common\Microsoft” directory.

Microsoft MFC 4.2

The components of this package are installed from within the IECM installer as delivered by Microsoft. They are Microsoft Visual C++ support files delivered under the Microsoft Foundation Class libraries. They are installed into the “C:\Windows\System32” directory.

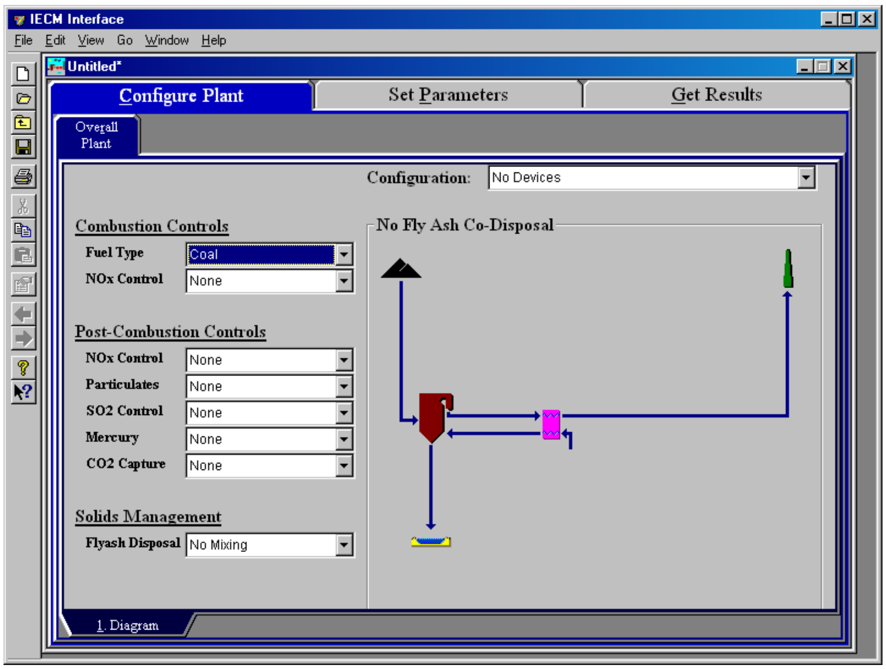
Files Modified by Install

Currently no user files are modified when the IECM software is installed. All user files are stored in the “C:\Program Files\IECM_CS\Sessdb” directory.

Configure Plant

Configuring the Combustion Boiler Plant

The following configuration options are available when the **Combustion (Boiler)** is selected as the plant type from the **New Session** pull down menu.



Configure Plant – Combustion (Boiler) input screen

The figure above shows the base configuration of the PC plant. Combustion, post-combustion, and solids management controls must be configured by the user. The following sections describe each popup menu on the configuration screen.

Pre-configuration settings can be selected using the Configuration menu at the top of the screen. **No Devices** is the default.

Combustion Controls

These configuration options determine the type of furnace and any technologies for reducing NO_x emissions.

Fuel Type: Coal is the primary fuel used by the PC plant. The choices also include the following which are grayed out and may be available in the future:

- **Coal**
- **Oil**
- **Natural Gas**
- **Other**

NO_x Control: From this configuration screen, you may choose.

- **None**
- **In-Furnace Controls:** Controls include an assortment of options which combine low NO_x burners (LNB) with overfire air (OFA), selective non-catalytic reduction (SNCR), and natural gas reburn. These options are selected from a pull-down menu in the **Set Parameters** menu

Post-Combustion Controls

These configuration options determine the presence and type of post-combustion emissions controls.

NO_x Control: The default option is **None**. The choices available are

- **None**, for no post-combustion NO_x control
- **Hot Side SCR** for a Hot-Side Selective Catalytic Reduction technology. Although an SCR technology can be positioned at various points along the flue gas train, the IECM considers only the hot-side, high dust configuration. **Hot Side SCR** may be together with **In-Furnace Controls**.

Particulates: The default option is **None**. The **None** setting is not available when the Mercury technology option is either **Carbon Injection** or **Carbon + Water Injection**. This assures the removal of the carbon being injected immediately downstream of the air preheater.

Multiple fabric filter types are provided. Fabric filter types are based on the bag cleaning techniques used. Various bag-cleaning techniques influence other process parameters. The choice of the bag cleaning method is usually based on the type of coal used—and therefore the filterability of the ash—and your experience with filtering the particular kind of ash. The particular option you select determines the air to cloth ratio, bag life, bag length, power requirements, pressure drop, capital costs and O&M costs.

The choices available are:

- **None:** for no post-combustion particulate control
- **Cold Side ESP:** for a Cold-Side Electrostatic Precipitator
- **Reverse Gas Fabric Filter:** Uses an off-line bag cleaning technique in which an auxiliary fan forces a relatively gentle flow of filtered flue gas backwards through the bags causing them to partially collapse and dislodge the dust cake. Over 90% of baghouses in U. S. utilities use reverse-gas cleaning.

- **Reverse Gas Sonic Fabric Filter:** Uses a variation of Reverse Gas cleaning in which low frequency pneumatic horns sound simultaneously with the flow of reverse gas to add energy to the dust cake removal process.
- **Shake & Deflate Fabric Filter:** Uses a method for off-line cleaning in which the bags are mechanically shaken immediately after or while a small quantity of filtered gas is forced back to relax the bags. The amount of filtered gas used is smaller than that used in Reverse Gas cleaning.
- **Pulse-Jet Fabric Filter:** Uses a method for on-line cleaning in which pulses of compressed air are blown down inside and through the bags to remove dust cake while the bags are filtering flue gas. Wire support cages are used to prevent bag collapse during filtration and ash is collected outside of the bags.

SO_2 Control: The default option is **None**. The following choices available are:

- **None:** for no post-combustion SO_2 control
- **Wet FGD:** for a Wet Flue Gas Desulfurization technology. Multiple reagent options are available under the **SO_2 Control** tab in the **Set Parameters** section of the interface.
- **Lime Spray Dryer:** for a dry scrubber using lime as a reagent. The interface places this technology before the particulate control technology in the plant design and diagrams.

Mercury: The default option is **None**. Other options are only available if a particulate control is configured. The options provided are:

None: for no mercury control

- **Carbon Injection:** Although some mercury removal is accomplished naturally in a power plant. It is believed that some mercury is captured or trapped in ash and is removed with bottom ash and fly ash. Carbon injection is provided as a technology to achieve higher removals by injecting fine particles of activated carbon into the flue gas after the air preheater.
- **Carbon + Water Injection:** Because the removal increases with lower flue gas temperatures, water injection is added to the carbon injection as a second technology option.

CO_2 Capture: The default option is **None**. The following choices available are:

None: for no CO_2 capture.

- **Amine System:** this option puts an amine scrubber at the end of the flue gas train. Other locations may be available in the future.
- **CO_2 Adsorption:** this option is grayed out and may be available in the future.
- **O_2 Transport Membrane:** this option is grayed out and may be available in the future.
- **Cryogenics:** this option is grayed out and may be available in the future.

Solids Management

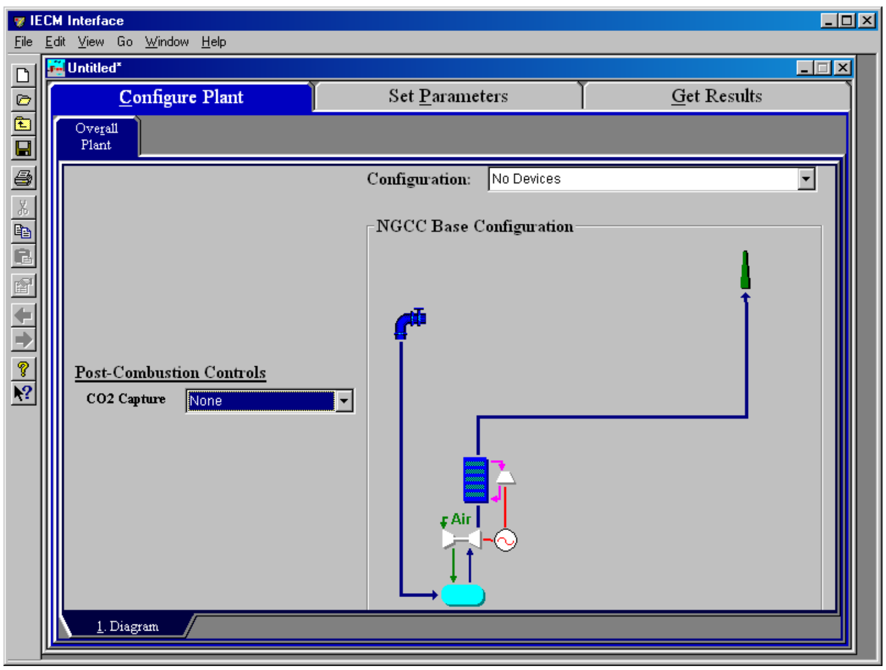
Flyash Disposal: This configuration setting determines how flyash is disposed. Fly ash collected from a particulate removal system is typically combined with other solid waste streams if other waste streams exist. The waste disposal option has little effect on the rest of the IECM. The choices are

No Mixing: for no flyash mixing. This option disposes the flyash separately.

- **Mixed w/FGD Wastes:** to dispose flyash with FGD wastes. This option can only be selected if a wet FGD is configured under the **SO_2 Control** option.
- **Mixed w/ Bottom Ash:** to dispose flyash with bottom ash (e.g. in the pond).

Configuring the Combustion Turbine Plant

The following configuration options are available when the **Combustion (Turbine)** is selected as the plant type from the **New Session** pull down menu.



Configure Plant – Combustion (Turbine) input screen.

The figure above shows the base configuration of the Combustion (Turbine) or NGCC plant. Only post-combustion controls can be configured by the user. The following sections describe each popup menu on the configuration screen.

Pre-configuration settings can be selected using the Configuration menu at the top of the screen. **No Devices** is the default.

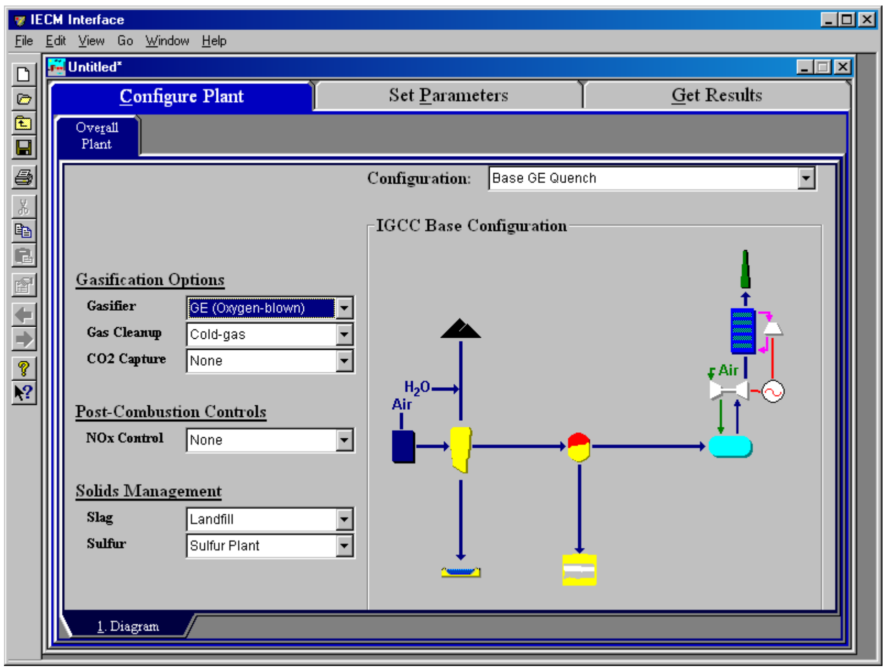
Post-Combustion Controls

CO_2 Capture: The default is **None**. The following options are available:

- **None:** No CO_2 capture is used.
- **Amine System:** An MEA scrubber is the only method currently available in the IECM for capturing CO_2.
- **CO_2 Adsorption:** This method of CO_2 capture is grayed out in the menu and is planned for a future release of the model.
- **O_2 Transport Membrane:** This method of CO_2 capture is grayed out in the menu and is planned for a future release of the model.
- **Cryogenics:** This method of CO_2 capture is grayed out in the menu and is planned for a future release of the model.

Configuring the IGCC

The following configuration options are available when the **IGCC** is selected as the plant type from the **New Session** pull down menu.



Configure Plant – IGCC input screen.

The figure above shows the base configuration of the IGCC plant. Gasification, post-combustion, and solids management controls can be configured by the user. The following sections describe each popup menu on the configuration screen.

Pre-configuration settings can be selected using the Configuration menu at the top of the screen. **Base GE Quench** is the default.

Gasification Options

Gasifier: There is a pull down menu so that the user may select the gasifier type. The choices are:

- **GE (Oxygen blown):** This is the only gasifier currently available in the model.

- **E-Gas (Oxygen blown):** This option is grayed out in the pull down menu and will be available in a future release of the model.
- **KRW (Air blown):** This option is grayed out in the pull down menu and will be available in a future release of the model.
- **Shell (Oxygen blown):** This option is grayed out in the pull down menu and will be available in a future release of the model.

Gas Cleanup: This menu will be used in the future to allow a user to select a suite of gas cleanup technologies. Particular devices for removing solids and sulfur while altering the syngas temperature are loaded with this menu. Presently, Cold-gas Cleanup is used with the GE (Oxygen-blown) gasifier in the model. The future choices will be:

- **None:** This option is grayed out in the pull down menu and will be available in a future release of the model.
- **Warm-gas:** This option is grayed out in the pull down menu and will be available in a future release of the model.
- **Cold-gas:** This is implemented in the model.

CO_2 Capture: The default is **None**. The user may select from the CO_2 Capture pull down menu whether or not to capture CO_2 and the method of capture.

- **None:** no CO_2 capture is used.
- **Sour Shift + Selexol:** This option is the only one currently available in the model.
- **Sweet Shift + Selexol:** This option is grayed out in the pull down menu and will be available in a future release of the model.
- **Shift + Comb. CO_2/H_2S:** This option is grayed out in the pull down menu and will be available in a future release of the model.

Post-Combustion Controls

NO_x Control: At present the only option available for selection is **None**. The following are provided in the menu:

- **None:** No NO_x control is used.
- **SCR:** This option is grayed out and will be available in a future release of the model.

Solids Management

Slag: Landfill is the default. The following choices are available:

- **None:** Slag collected is not sent to a landfill.
- **Landfill:** The slag collected is disposed in a landfill.

Sulfur: Sulfur captured can be processed by the following equipment options:

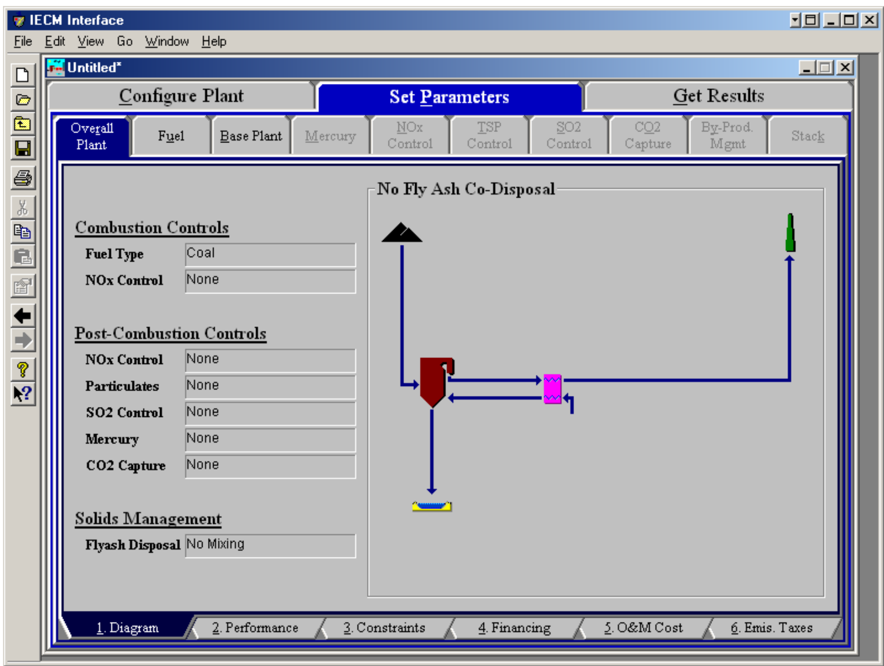
- **Sulfur Plant:** Sulfur is processed into a solid form. This option is the only one currently available in the model.

- **Sulfuric Acid Plant:** Sulfur is processed into an acid form. This option is grayed out in the pull down menu and may be available in a future release of the model.

Combustion Overall Plant

The input parameter screens described in the following sections are available when the **Combustion (Boiler)** is selected as the plant type from the **New Session** pull down menu. These screens apply to the power plant as a whole, not to specific technologies.

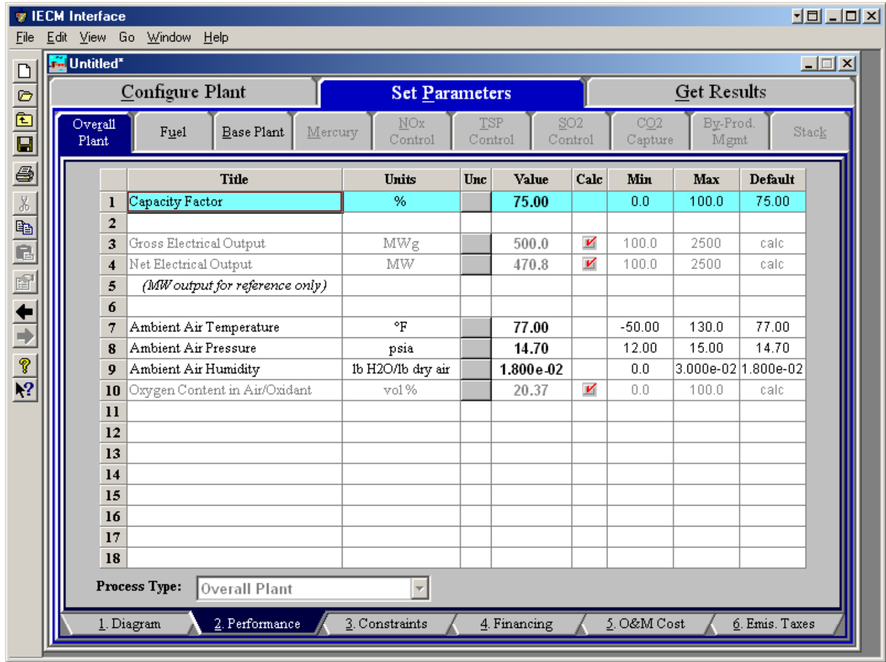
Combustion Overall Plant Diagram



Combustion Overall Plant – Diagram result screen.

This **Diagram** appears in the **Configure Plant**, **Set Parameters** and **Get Results** program areas. The screen displays the plant configuration settings on the left side of the page and a diagram of the configured plant on the right of the page. No input parameters or results are displayed on this screen.

Combustion Overall Plant Performance Inputs



Combustion Overall Plant—Performance input screen.

The parameters available on this screen establish the plant availability, electrical requirements, and ambient conditions for the power plant. These parameters have a major impact on the performance and costs of each of the individual technologies.

Capacity Factor: This is an annual average value, representing the percent of equivalent full load operation during a year. The capacity factor is used to calculate annual average emissions and materials flows.

Gross Electrical Output: This is the gross output of the generator(s) in megawatts (MWg). The value does not include auxiliary power requirements. The model uses this information to calculate key mass flow rates. The value here is shown for reference only. The value can be changed for a combustion plant by navigating to the Base Plant Performance Inputs (page 95) screen.

Net Electrical Output: This is the net plant capacity, which is the gross plant capacity minus the losses due to plant equipment and pollution equipment (energy penalties). The value cannot be changed and is shown for reference only.

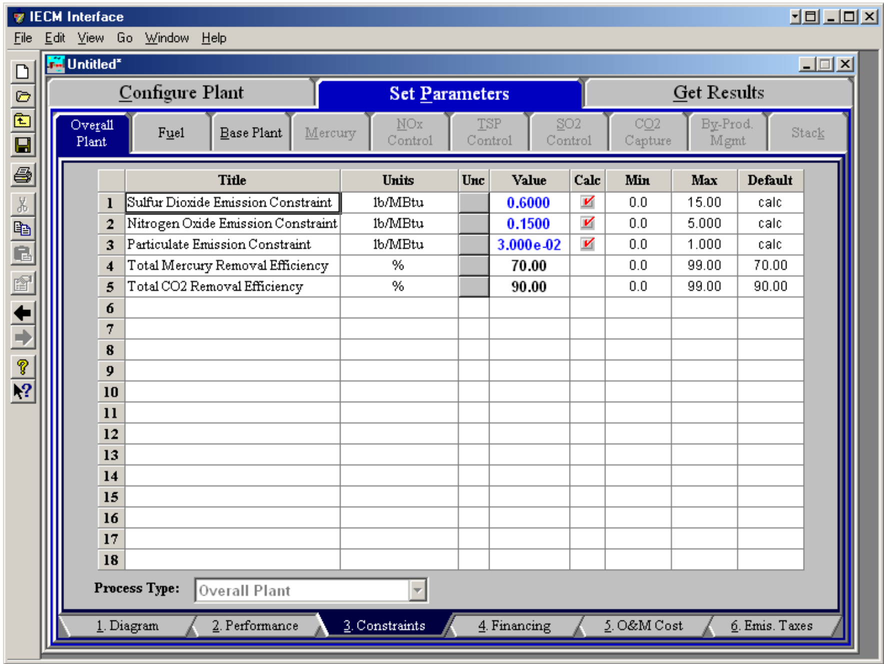
Ambient Air Temperature: This is the inlet temperature of the ambient combustion air prior to entering the preheater. The model presumes an *annual average* temperature. Inlet air temperature affects the boiler energy balance and efficiency. It provides a reference point for the calculation of pressure throughout the system. Currently, the model cannot have temperatures below 77°F.

Ambient Air Pressure: This is the absolute pressure of the air inlet stream to the boiler. The air pressure is used to convert flue gas molar flow rates to volume flow rates.

Ambient Air Humidity: This is the water content of the inlet combustion air. This value is used in calculating the total water vapor content of the flue gas stream. The value is referred to as the specific humidity ratio, expressed as a ratio of the water mass to the dry air mass.

Combustion Overall Plant Constraints Inputs

The **Constraints** input parameters define the emission constraints as they apply to the gases emitted from the power plant.



Overall Plant – Emission Constraints input screen.

This screen accepts input for the allowable emission limits for sulfur dioxide, nitrogen oxides and particulate matter. Mercury and carbon dioxide are constrained by their removal efficiencies across the entire plant.

The default values for the calculated inputs reflect current United States New Source Performance Standards (NSPS), which are applicable to all units constructed since 1978. SO_2 emission limits are based on the NSPS limits that are a function of the sulfur content of the coal.

The emission constraints determine the removal efficiencies of control systems for SO_2, NO_x, and particulate matter required to comply with the specified emission constraints. As discussed later, however, user-specified values for control technology performance may cause the plant to over-comply or under-comply with the emission constraints specified in this screen. Each parameter is described briefly below.

Sulfur Dioxide Emission Constraint: The emission constraint is defined by the 1979 revised NSPS. The calculated value is determined by the potential emission of the raw coal, minus the amount of sulfur retained in the ash streams. The emission limit is dependent on the fuel type and is used to determine the removal efficiency of SO_x control systems.

Nitrogen Oxide Emission Constraint: The combined emissions of NO_2 and NO_3 of present power plants are constrained by NSPS standards. The limit is a function of the coal rank and fuel type and is used to determine the removal efficiency of NO_x control systems.

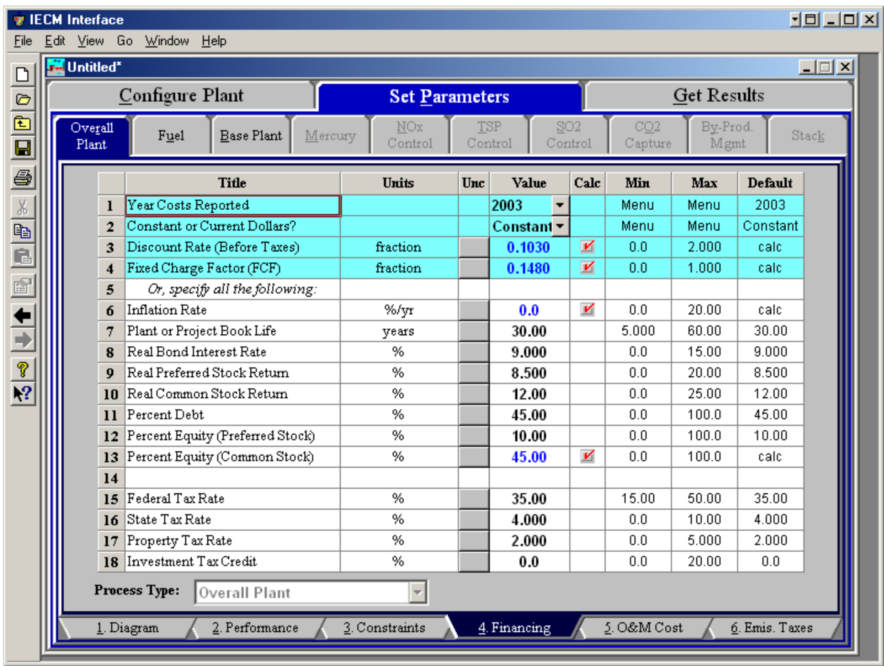
Particulate Emission Constraint: The emission constraint of the total suspended particulates is defined by the NSPS standards of 1978. The limit is a function of the fuel type and is used to determine the removal efficiency of particulate control systems.

Total Mercury Removal Constraint: The emission constraint of total after the economizer. Mercury removed in the furnace due to bottom ash removal is not considered in this constraint. The limit determines the removal efficiency of the particulate control systems.

Total CO_2 Removal Constraint: The emission constraint applies to all the air emission sources in the power plant, primary or secondary. The default value is based on recent discussions and is not based on any currently enforced law.

Combustion Overall Plant Financing Inputs

Inputs for the financing costs of the base plant itself are entered on the **Financing** input screen.



Overall Plant—Financing input screen.

This screen 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.

Each parameter is described briefly below.

Year Costs Reported: This is the year in which all costs are given or displayed, both in the input screens and the results. A cost index is used by the IECM to scale all costs to the cost year specified by this parameter. The cost year is reported on every input and result screen associated with costs throughout the interface.

Constant or Current Dollars: Constant dollar analysis does not include the affect of inflation, although real escalation is included. Current dollar analysis includes inflation and real escalation. This choice allows you to choose the mode of analysis for the entire IECM economics. The cost basis is reported on every input and result screen associated with costs throughout the interface.

Discount Rate (Before Taxes): 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).

Fixed Charge Factor (FCF): The fixed charge factor is one of the most important parameters in the IECM. 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.

One may specify a fixed charge factor, or fill in the following inputs and the model will calculate the FCF based on them:

Inflation Rate: 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.

Plant or Project Book Life: This is the years of service expected from a capital investment. It is also the period over which an investment is recovered through book depreciation.

Real Bond Interest Rate: This is a debt security associated with a loan or mortgage. It is the most secure form of security but the lowest in its return.

Real Preferred Stock Return: This equity security is the second most speculative type and pays the second highest rate of return. The holder of the stock is a part owner of the company.

Real Common Stock Return: This is the most speculative type of equity security sold by a utility and pays the highest relative return. The holder of the stock is a part owner of the company.

Percent Debt: This is the percent of the total capitalization that is associated with debt money. This includes loans and mortgage bonds.

Percent Equity (Preferred Stock): This is the percent of the total capitalization that is associated with the sale of preferred stock.

Percent Equity (Common Stock): This value is the remainder of the capitalization, calculated as 100% minus the percent debt, minus the percent equity in preferred stock.

Federal Tax Rate: This is the federal tax rate. It is used to calculate the amount of taxes paid and deferred.

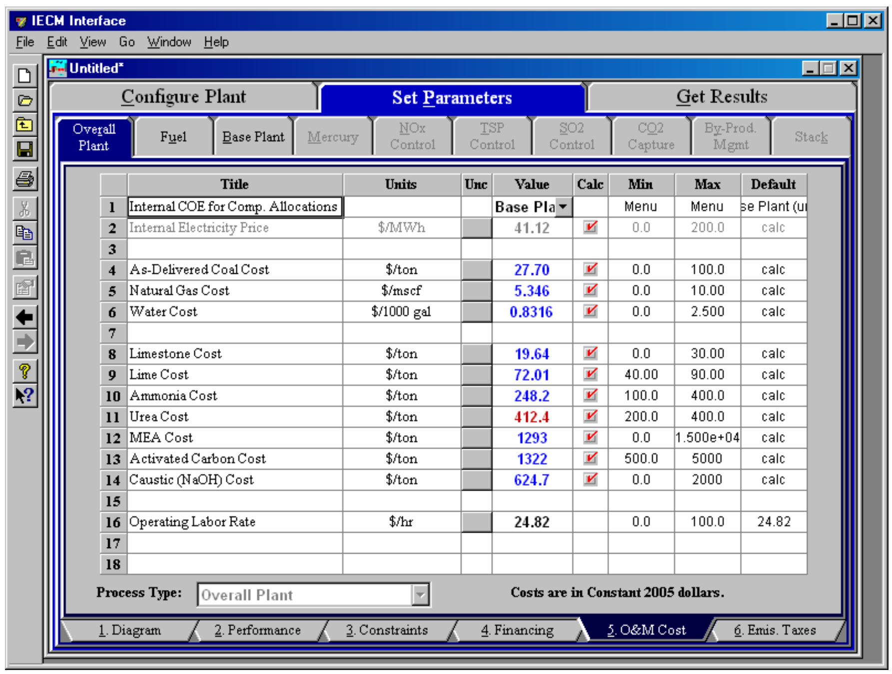
State Tax Rate: This is the state tax rate. It is used to calculate the amount of taxes paid and deferred.

Property Tax Rate: The property tax rate, or ad valorem, is used to calculate the carrying charge.

Investment Tax Credit: This is an immediate reduction in income taxes equal to a percentage of the installed cost of a new capital investment. It is zero by default. It is used to set the initial balance and the book depreciation.

Combustion Overall Plant O&M Inputs

This screen combines the variable O&M unit costs from all the model components and places them in one spot. These values will also appear in the technology input screens where they are actually used. Values changed on this screen will reflect exactly the same change everywhere else they appear. O&M costs are typically expressed on an average annual basis and are provided in either constant or current dollars for a specified year, as shown on the bottom of the screen.



Overall Plant – O&M Cost input screen.

Internal COE for Comp. Allocations: This is a pop-up selection menu that determines the method for determining electricity costs within the power plant. The selection of this pop-up menu determines the actual internal electricity price on the next line. The options are:

- **Base Plant (uncontrolled)**
- **User Specified**
- **Total Plant COE**

Internal Electricity Price: This is the price of electricity and is calculated as a function of the utility cost of the base plant. The base plant for the **Combustion (Boiler)** model is assumed to be a coal pile, combustion boiler, air preheater, and disposal sites. This value is calculated and provided for reference purposes only unless **User Specified** is selected in the pop-up in the previous line.

As-Delivered Coal Cost: This is the cost of the coal as-delivered.

Natural Gas Cost: This is the cost of natural gas in dollars per thousand standard cubic feet.

Water Cost: This is the cost of water in dollars per thousand gallons.

Limestone Cost: This is the cost of limestone in dollars per ton.

Lime Cost: This is the cost of lime in dollars per ton.

Ammonia Cost: This is the cost of ammonia in dollars per ton.

Urea Cost: This is the cost of natural gas in dollars per ton.

MEA Cost: This is the cost of MEA in dollars per ton.

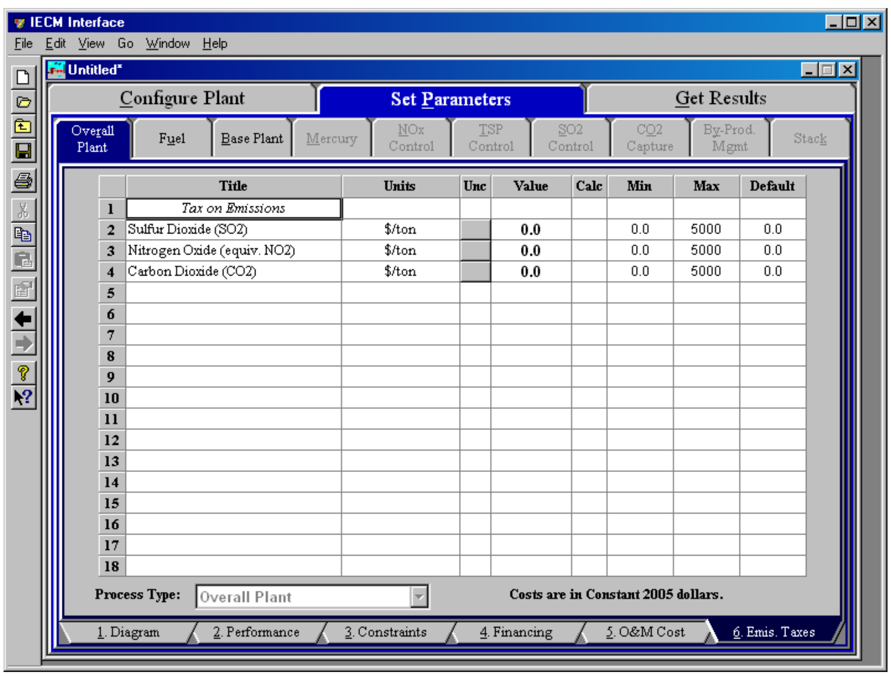
Activated Carbon Cost: This is the cost of activated carbon in dollars per ton.

Caustic (NaOH) Cost: This is the cost of caustic (NaOH) gas in dollars per ton.

Operating Labor Rate: The hourly cost of labor is specified in the base plant O&M cost screen. The same value is used throughout the other technologies.

Combustion Overall Plant Emis. Taxes Inputs

This screen allows users to specify emission taxes or credits as part of the overall plant cost economics. Taxes or credits are typically provided in either constant or current dollars for a specified year, as shown on the bottom of the screen.



Emission Constraint Emission Taxes input screen.

The **Emis. Taxes** input screen allows the user to enter the taxes on emissions in dollars per ton. The final costs determined from these inputs are available under the stack tab in the results section of the IECM. The costs are added to the overall plant cost, not a particular technology.

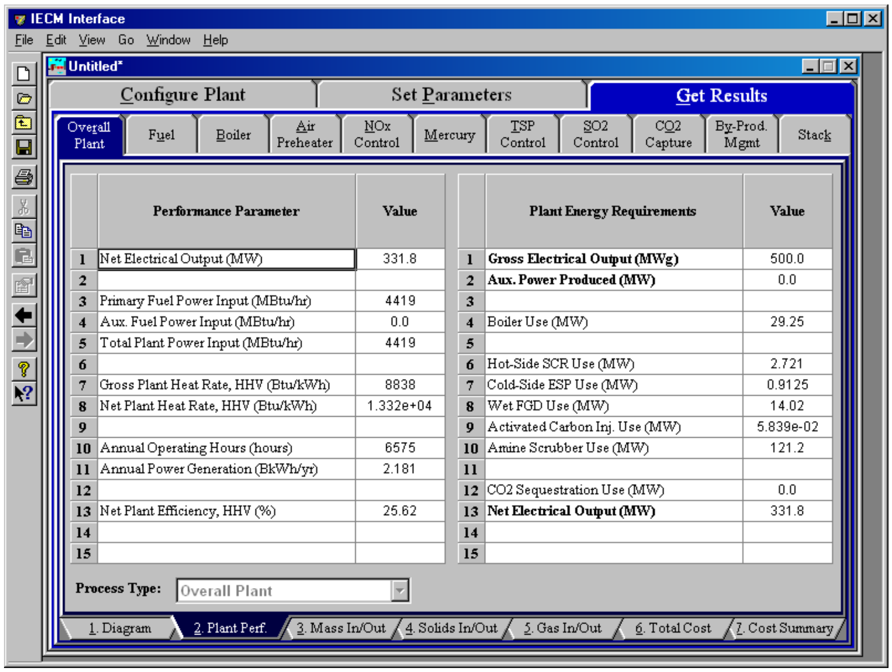
Tax on Emissions

Sulfur Dioxide (SO_2): The user may enter a cost to the plant of emitting sulfur dioxide in dollars per ton.

Nitrogen Oxide (equiv. NO_x) : The user may enter a cost to the plant of emitting nitrogen oxide in dollars per ton.

Carbon Dioxide (CO_2): The user may enter a cost to the plant of emitting carbon dioxide in dollars per ton.

Combustion Overall Plant Performance Results



Combustion Overall Plant – Plant Perf. result screen.

The **Plant Perf.** result screen displays performance results for the plant as a whole. Heat rates and power in and out of the power plant are given. Each result is described briefly below.

Performance Parameter

Net Electrical Output: This is the net plant capacity, which is the gross plant capacity minus the losses due to plant equipment and pollution equipment (energy penalties).

Primary Fuel Power Input: This is the fuel energy input for the plant, given on an hourly basis (maximum capacity). This rate is also referred to as the fuel power input.

Aux. Fuel Power Input: This is the fuel energy input for the auxiliary natural gas boiler if used with the Amine System. This is additional fuel energy used by the plant, given on an hourly basis. This rate is also referred to as the auxiliary fuel power input.

Total Plant Power Input: This is the total of all the fuel energy used by the plant, given on an hourly basis (maximum capacity). This rate is also referred to as the total plant power input.

Gross Plant Heat Rate: This is the heat rate of the gross cycle including the effects of the boiler efficiency. This is considered the gross heat rate.

Net Plant Heat Rate: This is the net heat rate, which includes the effect of plant equipment and pollution control equipment.

Annual Operating Hours: This is the number of hours per year that the plant is in operation. If a plant runs 24 hours per day, seven days per week, with no outages, the calculation is 24 hours * 365 days. or 8,760 hours/year.

Annual Power Generation: This is the net annual power production of the plant. The capacity factor and all energy credits or penalties are used in determining its value.

Net Plant Efficiency: The net plant efficiency is displayed here on a HHV basis.

Plant Power Requirements

A second group of results provide a breakdown of the internal power consumption for the individual technology areas. These are all given in units of megawatts. Individual plant sub-components will only be displayed when they are configured in the **Configure Plant** section of the model.

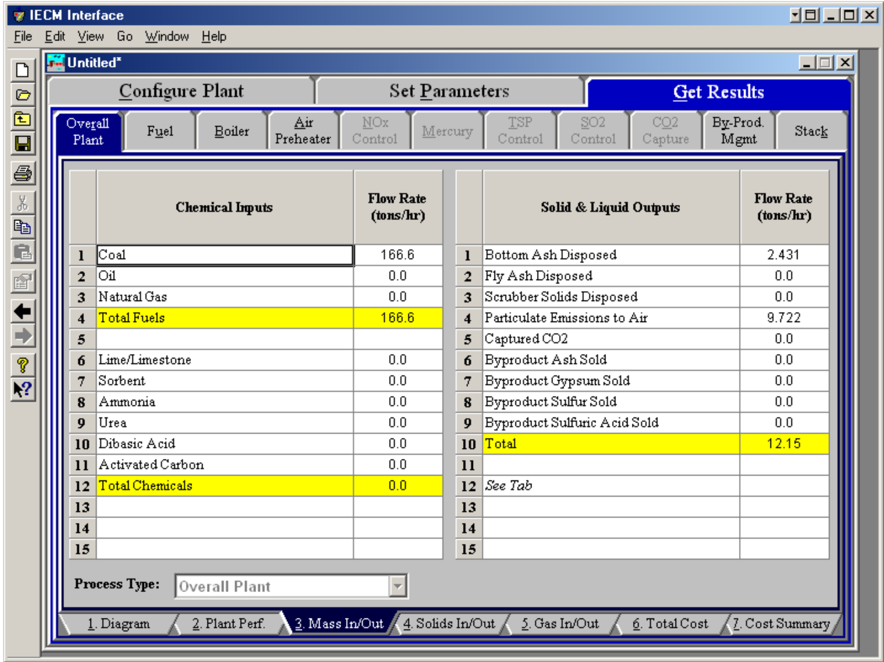
Gross Electrical Output: This is the gross output of the generator in megawatts (MWg). The value does not include auxiliary power requirements. The model uses this information to calculate key mass flow rates. The value is an input parameter.

Aux. Power Produced: If an auxiliary natural gas boiler is used to provide steam and power for the Amine System, this is the additional electricity that it produces.

Component Electrical Uses: Power used by various plant and pollution control equipment is reported in the middle portion of the second column. The number displayed varies as a function of the components configured in the power plant.

Net Electrical Output: This is the net plant capacity, which is the gross plant capacity plus any auxiliary electrical output minus the losses due to plant equipment and pollution equipment (energy penalties). This is the same value used in the first column.

Combustion Overall Plant Mass In/Out



Combustion Overall Plant – Mass In/Out result screen.

The **Mass In/Out** result screen displays the flow rates of fuels and chemicals into the plant and solid and liquid flow rates out of the plant. Each result is described briefly below.

Input Flow Rates

Coal: Total mass of coal entering the boiler on a wet basis.

Oil: Total mass of oil used in the power plant

Natural Gas: Total mass of natural gas used in the power plant

Total Fuels: This is the total fuel mass entering the power plant. This result is highlighted in yellow.

Lime/Limestone: Total mass of this reagent used in the power plant on a wet basis.

Sorbent: This is the total mass of sorbent used in the power plant. The sorbent currently used is an amino acid used in the CO_2 capture device.

Ammonia: Total mass of ammonia used in the power plant.

Urea: Total mass of urea used in the power plant. Urea is the reagent used to reduce NO_x in the SNCR technology.

Dibasic Acid: Total mass of dibasic acid used in the power plant.

Activated Carbon: Total mass of activated carbon injected in the power plant.

Total Chemicals: This is the total reagent mass entering the power plant. This result is highlighted in yellow.

Output Flow Rates

Bottom Ash Disposed: Total mass of bottom ash collected in the power plant on a dry basis.

Fly Ash Disposed: Total mass of fly ash collected in the power plant on a dry basis.

Scrubber Solids Disposed: Total mass of scrubber solid wastes collected in the power plant on a dry basis.

Particulate Emissions to Air: Solids that remain in the flue gas and exit the plant are reported on a mass basis.

Captured CO_2: If a CO_2 capture technology has been selected, the mass flow of CO_2 captured is reported. It is transported off site. See the [CO_2 Transport System] (page 355) for more information.

Byproduct Ash Sold: Total mass of ash (bottom and fly ash) sold in commerce as a by-product on a dry basis.

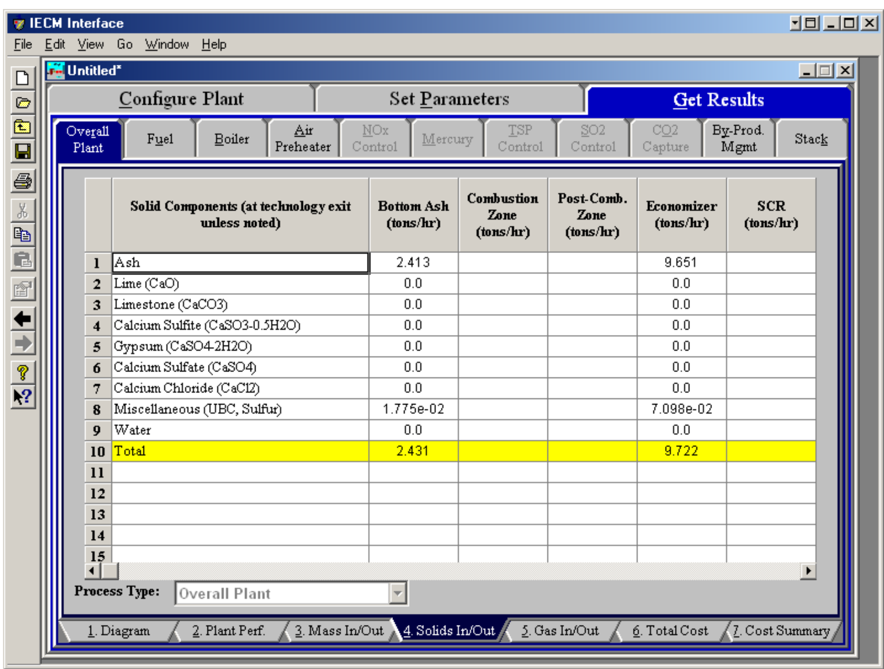
Byproduct Gypsum Sold: Total mass of flue gas treatment solids sold in commerce as a by-product on a dry basis.

Byproduct Sulfur Sold: Total mass of elemental sulfur recovered from flue gas and sold in commerce as a by-product on a dry basis.

Byproduct Sulfuric Acid Sold: Total mass of sulfuric acid recovered from the flue gas and sold in commerce as a by-product.

Total: This is the total wet solid mass exiting the power plant. This result is highlighted in yellow.

Combustion Overall Plant Solids Emissions



Combustion Overall Plant – Solids Emissions result screen.

The **Solids In/Out** result screen displays the values for the flow of the solid components in the gas and condensed streams throughout the various stages of the power plant. Each result is described briefly below. Note that each column represents the flow rate at the exit of the technology specified at the top of the column. Note that the solids are not reported in this detail inside the technology result screens.

Solid Components

Ash: Total mass of ash (primarily solid oxides).

Lime (CaO): Total mass flow of lime. This is typically added as a reagent and will react with the flue gas to form another compound.

Limestone ($CaCO_3$): Total mass flow of limestone. This is typically added as a reagent and will react with the flue gas to form another compound.

Calcium Sulfite ($CaSO_3$-$^1/_2H_2O$): Total mass flow of calcium sulfite, a byproduct of lime or limestone reacting with sulfur in the flue gas.

Gypsum ($CaSO_4$-$2H_2O$): Total mass flow of gypsum, a byproduct of lime or limestone reacting with sulfur in the flue gas.

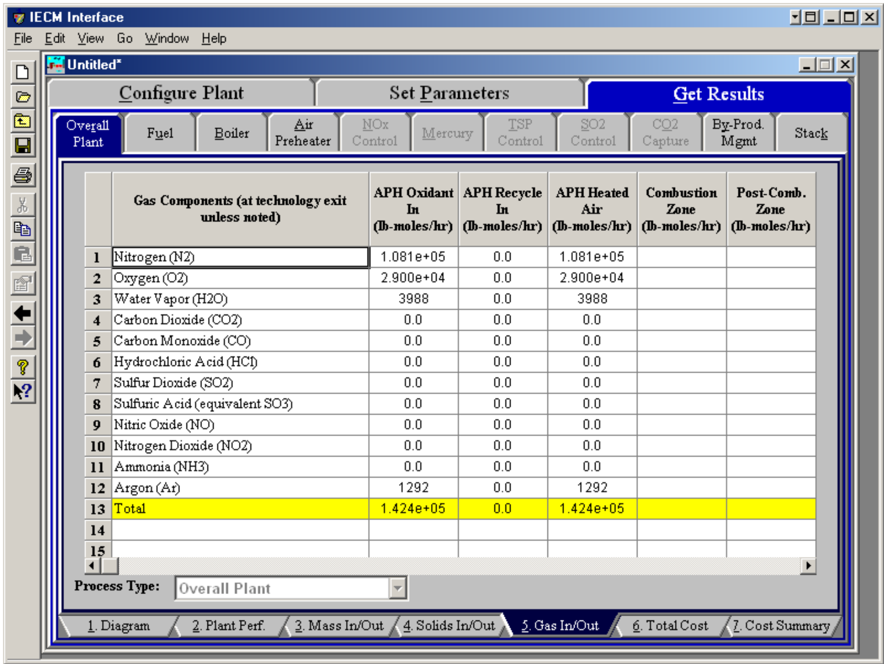
Calcium Sulfate ($CaSO_4$): Total mass flow of calcium sulfate, a byproduct of lime or limestone reacting with sulfur in the flue gas.

Calcium Chloride ($CaCl_2$): Total mass flow of calcium sulfate, a byproduct of lime or limestone reacting with chlorine or chlorine compounds in the flue gas.

Miscellaneous (UCB, Sulfur): Total mass flow of other solids in the flue gas. This includes unburned carbon or unburned sulfur from the boiler.

Water: Total mass flow of condensed water associated with the solids stream. This is more clearly represented in what is considered liquid streams. See the **Gas In/Out** screen for a summary of the evaporated water flow rate through the power plant.

Combustion Overall Plant Gas Emissions



Combustion Overall Plant – Gas Emissions result screen.

The **Gas In/Out** result screen displays the values for the flow of the gas components in the flue gas throughout the various stages of the power plant. Each result is described briefly below. Note that each column represents the flow rate at the exit of the technology specified at the top of the column. These are also reported elsewhere in the particular technology result screens but duplicated here to provide a broad look at gas emissions.

Stack Gas Components

Nitrogen (N_2): Total mass of emitted nitrogen.

Oxygen (O_2): Total mass of emitted oxygen.

Water Vapor (H_2O): Total mass of water vapor.

Carbon Dioxide (CO_2): Total mass of carbon dioxide.

Carbon Monoxide (CO): Total mass of carbon monoxide.

Hydrochloric Acid (HCl): Total mass of hydrochloric acid.

Sulfur Dioxide (SO_2): Total mass of sulfur dioxide.

Sulfuric Acid (equivalent SO_3): Total mass of sulfuric acid.

Nitric Oxide (NO): Total mass of nitric oxide.

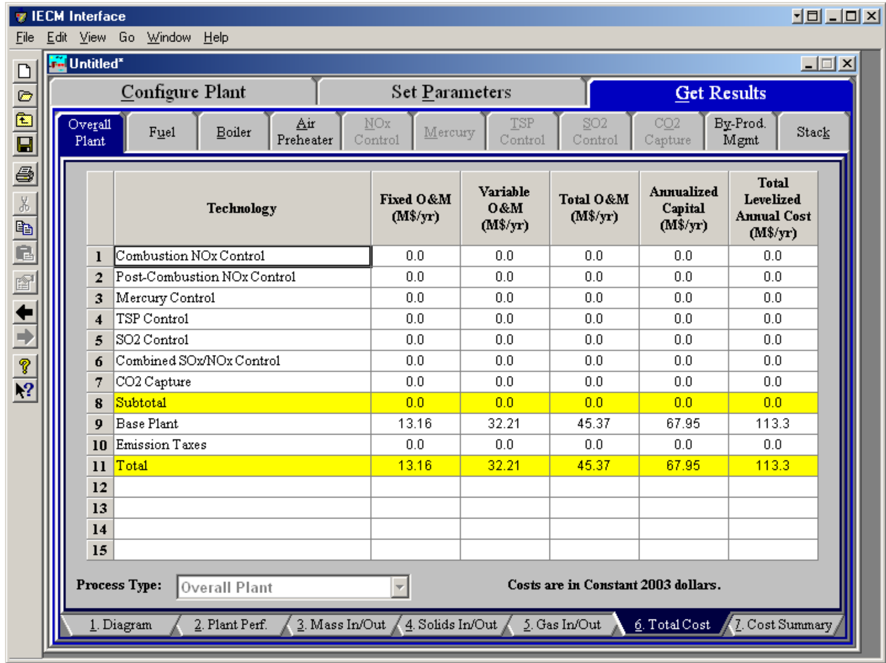
Nitrogen Dioxide (NO_x): Total mass of nitrogen dioxide.

Ammonia (NH_3): Total mass of ammonia.

Argon (Ar): Argon is present in small quantities in atmospheric air. The argon emitted from the power plant is shown on a mass basis.

Total Gases: Total flow rate of all gases. This result is highlighted in yellow.

Combustion Overall Total Cost



	Technology	Fixed O&M (M$/yr)	Variable O&M (M$/yr)	Total O&M (M$/yr)	Annualized Capital (M$/yr)	Total Levelized Annual Cost (M$/yr)
1	Combustion NOx Control	0.0	0.0	0.0	0.0	0.0
2	Post-Combustion NOx Control	0.0	0.0	0.0	0.0	0.0
3	Mercury Control	0.0	0.0	0.0	0.0	0.0
4	TSP Control	0.0	0.0	0.0	0.0	0.0
5	SO2 Control	0.0	0.0	0.0	0.0	0.0
6	Combined SOx/NOx Control	0.0	0.0	0.0	0.0	0.0
7	CO2 Capture	0.0	0.0	0.0	0.0	0.0
8	Subtotal	0.0	0.0	0.0	0.0	0.0
9	Base Plant	13.16	32.21	45.37	67.95	113.3
10	Emission Taxes	0.0	0.0	0.0	0.0	0.0
11	Total	13.16	32.21	45.37	67.95	113.3
12						
13						
14						
15						

Combustion Overall Plant Total Cost result screen.

The **Total Cost** result screen displays a table which totals the annual fixed, variable, operations, maintenance, and capital costs associated with the power plant as a whole. The costs summarized on this screen are expressed on an average annual basis and are provided in either constant or current dollars for a specified year, as shown on the bottom of the screen. Each technology (row) is described briefly below.

Combustion NO_x Control: The total cost of the In-Furnace NO_x controls used.

Post-Combustion NO_x Control: The total cost of all the Post-Combustion NO_x removal modules used.

Mercury Control: The total cost of all the mercury control modules used.

TSP Control: The total cost of all the conventional particulate removal modules used.

SO_2 Control: The total cost of all the SO_2 conventional removal modules used.

Combined SO_x/NO_x: The total cost of all the combined SO_x/NO_x advanced removal modules used.

Subtotal: This is the cost of the conventional and advanced abatement technology modules alone. This is the total abatement cost. The subtotal is highlighted in yellow.

Base Plant: The total cost of the base plant without consideration of any abatement technologies. This can be used to compare with other power plant types.

Emission Taxes: The total cost of taxes assessed to stack emissions is provided here.

Total: This is the total cost of the entire power plant. This result is highlighted in yellow.

Each cost category (column) is described briefly below.

Fixed O&M: The operating and maintenance fixed costs are given as an annual total. This number includes all maintenance materials and all labor costs for each technology.

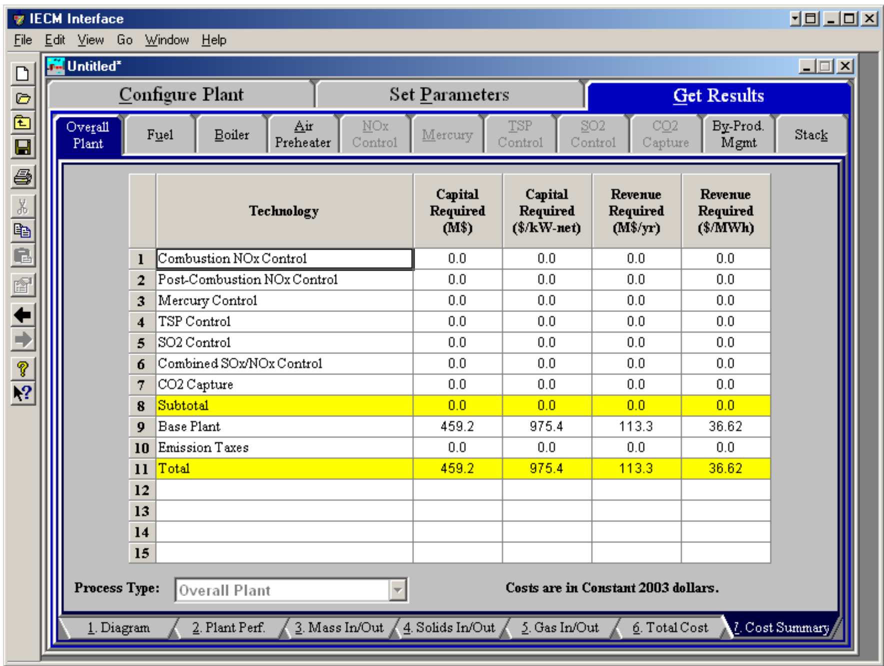
Variable O&M: The operating and maintenance variables costs are given as an annual total. This includes all reagent, chemical, steam, and power costs associated with a technology.

Total O&M: This is the sum of the annual fixed and variable operating and maintenance costs for each technology.

Annualized Capital: This is the total capital cost expressed on an annualized basis, taking into consideration the levelized carrying charge factor, or fixed charge factor, over the entire book life.

Total Levelized Annual Cost: The total annual cost is the sum of the total annual O&M cost and annualized capital cost items above. This result is highlighted in yellow

Combustion Overall Plant Cost Summary



Combustion Overall Plant Cost Summary result screen.

The **Cost Summary** result screen displays costs associated with the power plant as a whole. The costs summarized on this screen are expressed in either constant or current dollars for a specified year, as shown on the bottom of the screen. Each technology (row) is described briefly below.

Combustion NO_x Control: The total cost of the In-Furnace NO_x controls used.

Post-Combustion NO_x Control: The total cost of all the Post-Combustion NO_x removal modules used.

Mercury Control: The total cost of all the mercury control modules used.

TSP Control: The total cost of all the conventional particulate removal modules used.

SO_2 Control: The total cost of all the SO_2 conventional removal modules used.

Combined SO_x/NO_x: The total cost of all the combined SO_x/NO_x advanced removal modules used.

Subtotal: This is the cost of the conventional and advanced abatement technology modules alone. This is the total abatement cost. The subtotal is highlighted in yellow.

Base Plant: The total cost of the base plant without consideration of any abatement technologies. This can be used to compare with other power plant types.

Total: This is the total cost of the entire power plant. This result is highlighted in yellow.

Each cost category (column) is described briefly below.

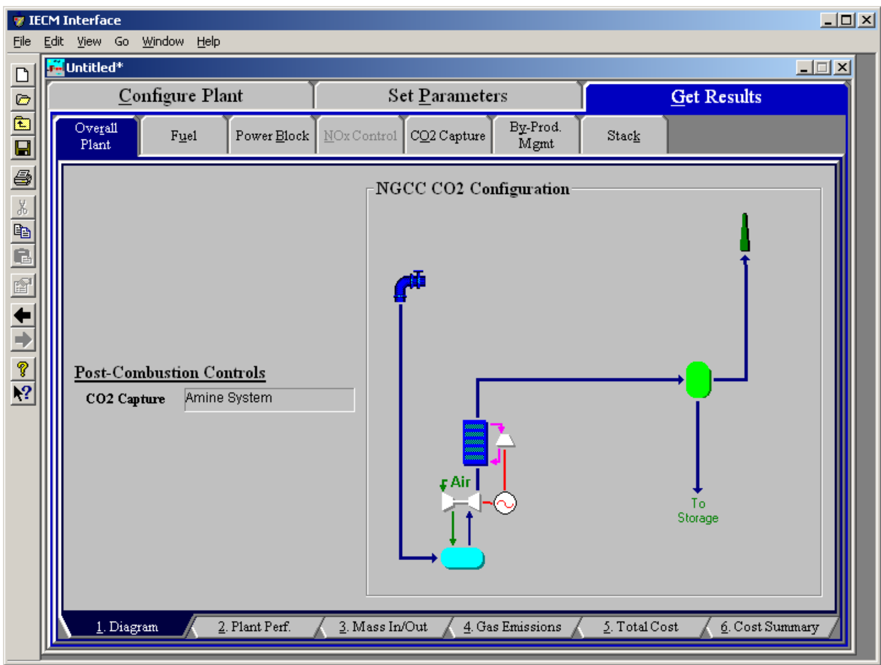
Capital Required: The total capital requirement (TCR). This is the money that is placed (capitalized) on the books of the utility on the service date. The total cost includes the total plant investment plus capitalized plant startup. Escalation and allowance for funds used during construction (AFUDC) are also included. The capital cost is given on both a total and an annualized basis.

Revenue Required: Amount of money that must be collected from customers to compensate a utility for all expenditures in capital, goods, and services. The revenue requirement is equal to the carrying charges plus expenses. The revenue required is given on both an annualized and a net power output basis.

Overall NGCC Plant

The input parameter screens described in the following sections are available when the **Combustion (Turbine)** is selected as the plant type from the **New Session** pull down menu. These screens apply to the power plant as a whole, not to specific technologies.

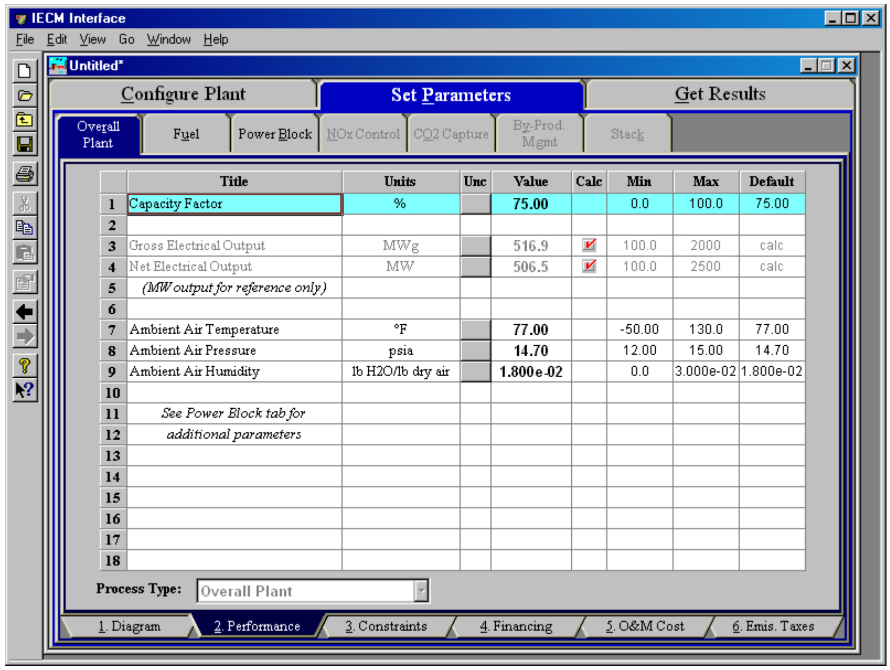
Overall NGCC Plant Diagram



Overall NGCC Plant – Diagram input screen

The **Overall NGCC Plant Diagram** appears in the **Configure Plant**, **Set Parameters** and in the **Get Results** program area. The screen displays the plant configuration settings on the left side of the page and a diagram of the configured plant on the right of the page. No input parameters or results are displayed on this screen.

Overall NGCC Plant Performance Inputs



Overall NGCC Plant – Performance input screen.

The parameters available on this screen establish the plant availability, electrical requirements, and ambient conditions for the power plant. These parameters have a major impact on the performance and costs of each of the individual technologies.

Capacity Factor: This is an annual average value, representing the percent of equivalent full load operation during a year. The capacity factor is used to calculate annual average emissions and materials flows.

Gross Electrical Output: This is the gross output of the generator in megawatts (MWg). The value does not include auxiliary power requirements. The model uses this information to calculate key mass flow rates. The value here is shown for reference only. The value is controlled primarily by the number of gas turbines selected from the **Power Block** tab.

Net Electrical Output: This is the net plant capacity, which is the gross plant capacity minus the losses due to plant equipment and pollution equipment (energy penalties). The value cannot be changed and is shown for reference only.

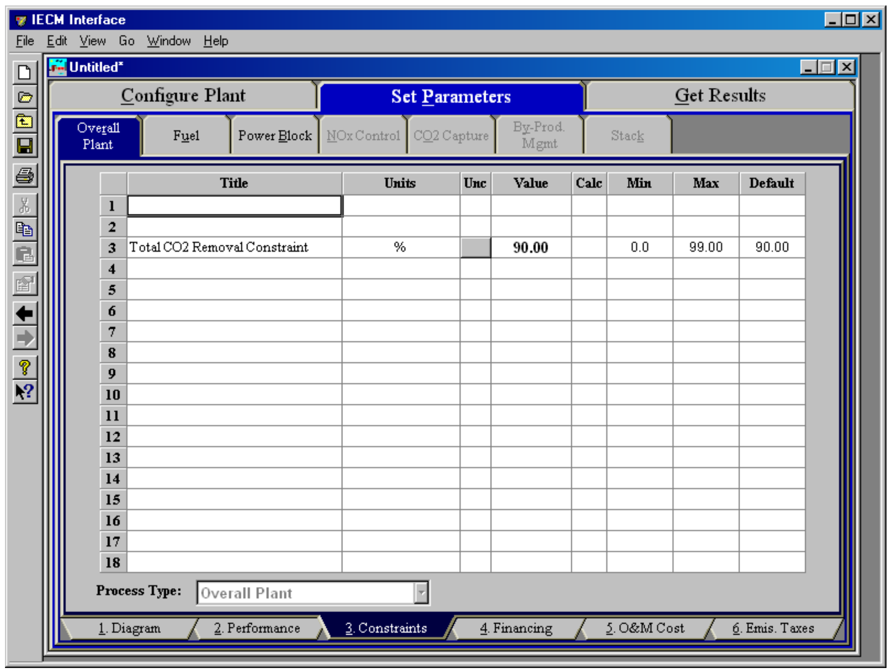
Ambient Air Temperature: This is the inlet temperature of the ambient combustion air prior to entering the preheater. The model presumes an *annual average* temperature. Inlet air temperature affects the boiler energy balance and efficiency. It provides a reference point for the calculation of pressure throughout the system. Currently, the model cannot have temperatures below 77F.

Ambient Air Pressure: This is the absolute pressure of the air inlet stream to the boiler. The air pressure is used to convert flue gas molar flow rates to volume flow rates. The default value is 14.7 psia.

Ambient Air Humidity: This is the water content of the inlet combustion air. This value is used in calculating the total water vapor content of the flue gas stream. The value is referred to as the specific humidity ratio, expressed as a ratio of the water mass to the dry air mass. The default value is 0.018.

Overall NGCC Plant Constraints Inputs

The **Constraints** input parameters define the emission constraints as they apply to the gases emitted from the power plant. Constraints for sulfur dioxide, nitrogen dioxides, particulates, and mercury are not needed due to the cleaner emissions from NGCC plants.



Overall NGCC Plant – Emission Constraints input screen.

The emission constraints determine the removal efficiencies of control systems that capture CO_2. The level of capture is set to comply with the specified emission constraints. As discussed later, however, user-specified values for control technology performance may cause the plant to over-comply or under-comply with the emission constraints specified in this screen. Each parameter is described briefly below.

Total CO_2 Removal Constraint: The emission constraint applies to all the air emission sources in the power plant, primary or secondary. The default value is based on recent discussions and is not based on any currently enforced law.

Overall NGCC Plant Financing Inputs

Inputs for the financing costs of the base plant itself are entered on the **Financing** input screen.

Overall NGCC Plant – Financing input screen.

This screen 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.

Each parameter is described briefly below.

Year Costs Reported: This is the year in which all costs are given or displayed, both in the input screens and the results. A cost index is used by the IECM to scale all costs to the cost year specified by this parameter. The cost year is reported on every input and result screen associated with costs throughout the interface.

Constant or Current Dollars: Constant dollar analysis does not include the affect of inflation, although real escalation is included. Current dollar analysis includes inflation and real escalation. This choice allows you to choose the mode of analysis for the entire IECM economics. The cost basis is reported on every input and result screen associated with costs throughout the interface.

Discount Rate (Before Taxes): This is also known as the “cost of money”. It is the return required by investors in order to attract investment capital. It is equal to the weighted sum of the return on debt and equity. It is the time value of money or the discount rate used in present worth arithmetic.

Fixed Charge Factor (FCF): The fixed charge factor is one of the most important parameters in the IECM. 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.

One may specify a fixed charge factor, or fill in the following inputs and the model will calculate the FCF based on them:

Inflation Rate: 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.

Plant or Project Book Life: This is the years of service expected from a capital investment. It is also the period over which an investment is recovered through book depreciation.

Real Bond Interest Rate: This is a debt security associated with a loan or mortgage. It is the most secure form of security but the lowest in its return.

Real Preferred Stock Return: This equity security is the second most speculative type and pays the second highest rate of return. The holder of the stock is a part owner of the company.

Real Common Stock Return: This is the most speculative type of equity security sold by a utility and pays the highest relative return. The holder of the stock is a part owner of the company.

Percent Debt: This is the percent of the total capitalization that is associated with debt money. This includes loans and mortgage bonds.

Percent Equity (Preferred Stock): This is the percent of the total capitalization that is associated with the sale of preferred stock.

Percent Equity (Common Stock): This value is the remainder of the capitalization, calculated as 100% minus the percent debt, minus the percent equity in preferred stock.

Federal Tax Rate: This is the federal tax rate. It is used to calculate the amount of taxes paid and deferred.

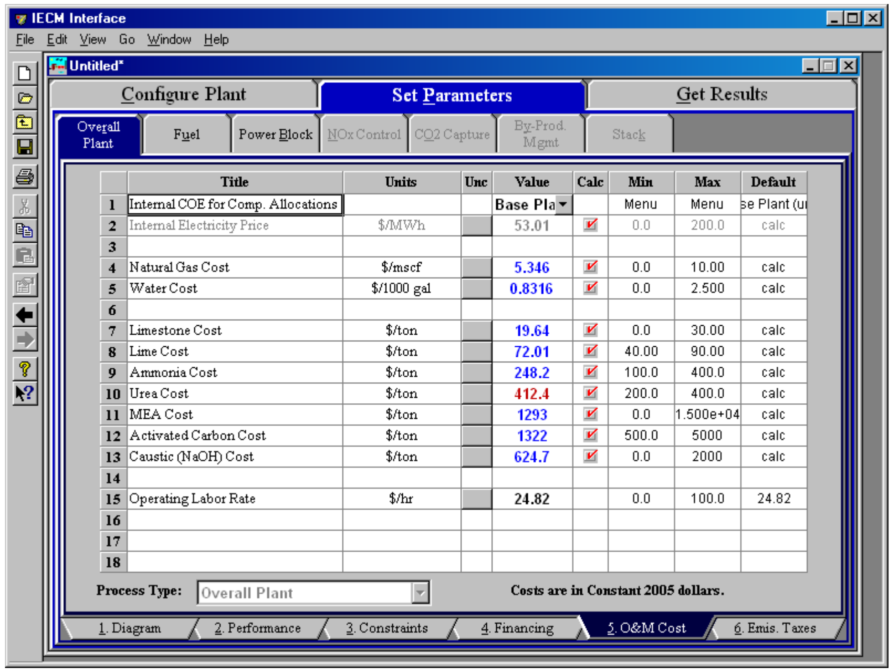
State Tax Rate: This is the state tax rate. It is used to calculate the amount of taxes paid and deferred.

Property Tax Rate: The property tax rate, or ad valorem, is used to calculate the carrying charge.

Investment Tax Credit: This is an immediate reduction in income taxes equal to a percentage of the installed cost of a new capital investment. It is zero by default. It is used to set the initial balance and the book depreciation.

Overall NGCC Plant O&M Cost Inputs

This screen combines the variable O&M unit costs from all the model components and places them in one spot. These values will also appear in the technology input screens where they are actually used. Values changed on this screen will reflect exactly the same change everywhere else they appear. O&M costs are typically expressed on an average annual basis and are provided in either constant or current dollars for a specified year, as shown on the bottom of the screen.



Overall NGCC Plant – O&M Cost input screen.

Internal COE for Comp. Allocations: This is a pop-up selection menu that determines the method for determining electricity costs within the power plant. The selection of this pop-up menu determines the actual internal electricity price on the next line. The options are

- **Base Plant (uncontrolled)**
- **User Specified**
- **Total Plant COE**

Internal Electricity Price: This is the price of electricity and is calculated as a function of the utility cost of the base plant. The base plant for the **Combustion (Turbine)** model is assumed to be the natural gas supply, power block, and stack. This value is calculated and provided for reference purposes only unless **User Specified** is selected in the pop-up in the previous line.

As-Delivered Coal Cost: This is the cost of the coal as-delivered.

Natural Gas Cost: This is the cost of natural gas in dollars per thousand standard cubic feet.

Water Cost: This is the cost of water in dollars per thousand gallons.

Limestone Cost: This is the cost of limestone in dollars per ton.

Lime Cost: This is the cost of lime in dollars per ton.

Ammonia Cost: This is the cost of ammonia in dollars per ton.

Urea Cost: This is the cost of natural gas in dollars per ton.

MEA Cost: This is the cost of MEA in dollars per ton.

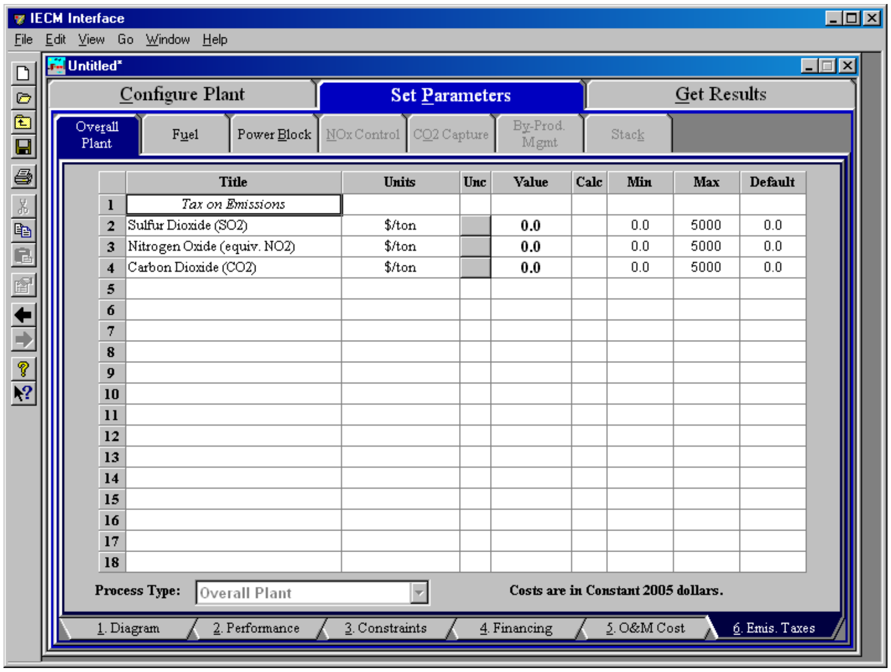
Activated Carbon Cost: This is the cost of activated carbon in dollars per ton.

Caustic (NaOH) Cost: This is the cost of caustic (NaOH) gas in dollars per ton.

Operating Labor Rate: The hourly cost of labor is specified in the base plant O&M cost screen. The same value is used throughout the other technologies.

Overall NGCC Plant Emis. Taxes Inputs

This screen allows users to specify emission taxes or credits as part of the overall plant cost economics. Taxes or credits are typically provided in either constant or current dollars for a specified year, as shown on the bottom of the screen.



Emission Constraint Emission Taxes input screen.

The **Emis. Taxes** input screen allows the user to enter the taxes on emissions in dollars per ton. The final costs determined from these inputs are available under the stack tab in the results section of the IECM. The costs are added to the overall plant cost, not a particular technology.

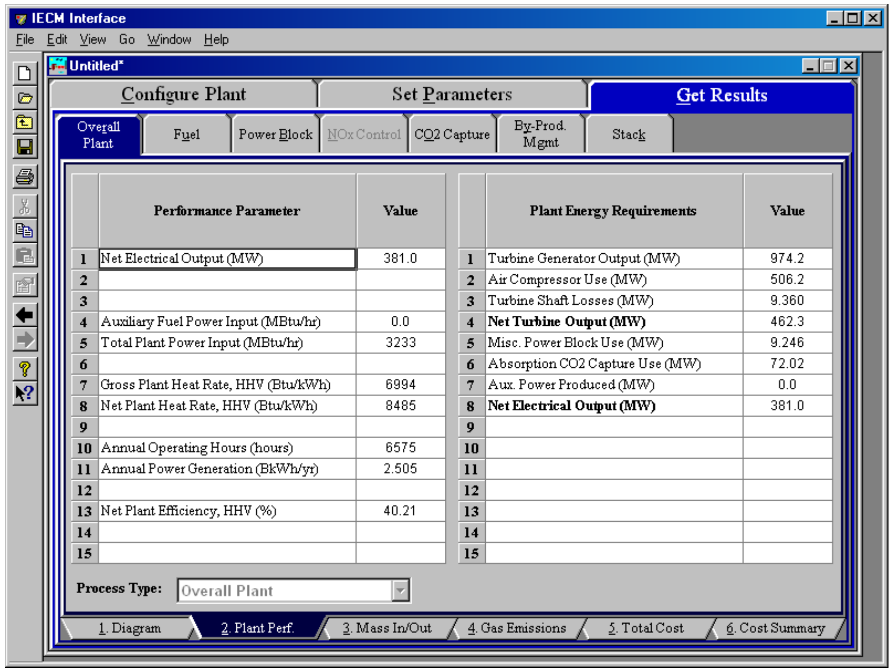
Tax on Emissions

Sulfur Dioxide (SO_2): The user may enter a cost to the plant of emitting sulfur dioxide in dollars per ton.

Nitrogen Oxide (equiv. NO_2): The user may enter a cost to the plant of emitting nitrogen oxide in dollars per ton.

Carbon Dioxide (CO_2): The user may enter a cost to the plant of emitting carbon dioxide in dollars per ton.

Overall NGCC Plant Performance Results



Overall NGCC Plant – Performance results screen.

The **Plant Perf.** result screen displays performance results for the plant as a whole. Heat rates and power in and out of the power plant are given. Each result is described briefly below.

Performance Parameter

Net Electrical Output: This is the net plant capacity, which is the gross plant capacity minus the losses due to plant equipment and pollution equipment (energy penalties).

Aux. Fuel Power Input: This is the fuel energy input for the auxiliary natural gas boiler if used with the Amine System. This is additional fuel energy used by the plant, given on an hourly basis. This rate is also referred to as the auxiliary fuel power input.

Total Plant Power Input: This is the total of all the fuel energy used by the plant, given on an hourly basis (maximum capacity). This rate is also referred to as the total plant power input.

Gross Plant Heat Rate, HHV: This is the gross heat rate of the entire plant.

Net Plant Heat Rate, HHV: This is the net heat rate of the entire plant (including aux power produced) which includes the effect of plant equipment and pollution control equipment.

Annual Operating Hours: This is the number of hours per year that the plant is in operation. If a plant runs 24 hours per day, seven days per week, with no outages, the calculation is 24 hours * 365 days. or 8,760 hours/year.

Annual Power Generation: This is the net annual power production of the plant. The capacity factor and all energy credits or penalties are used in determining its value.

Net Plant Efficiency, HHV: This is the net efficiency of the entire plant.

Plant Power Requirements

A second group of results provide a breakdown of the internal power consumption for the individual technology areas. These are all given in units of megawatts. Individual plant sub-components will only be displayed when they are configured in the **Configure Plant** section of the model.

Turbine Generator Output: This is the power generated by the turbine.

Air Compressor Use: The power required to operate the air compressor.

Turbine Shaft Losses: This value accounts for any turbine electricity losses other than power used for the air compressor.

Net Turbine Output: This if the net power generated by the turbine. This is the gross output of the turbine minus the power required by the air compressor and any miscellaneous losses.

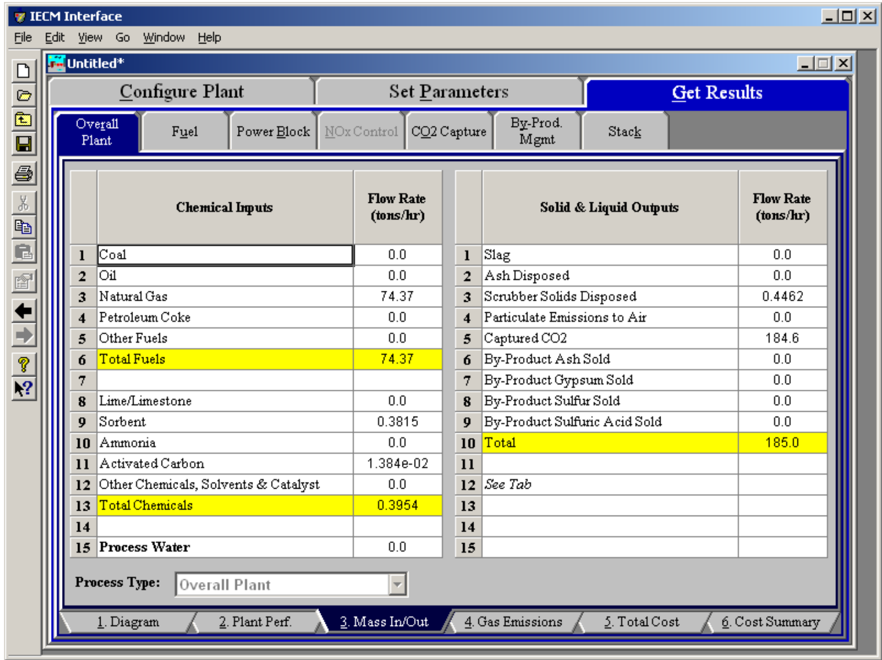
Misc. Power Block Use: This is the power required to operate pumps and motors associated with the power block area.

Absorption CO_2 Capture Use: If a CO_2 Capture system is in use, this is the power required to operate the system.

Aux. Power Produced: If an auxiliary natural gas boiler is used to provide steam and power, this is the additional power that it produces.

Net Electrical Output: This is the net plant capacity, which is the gross plant capacity minus the losses due to plant equipment and pollution equipment (energy penalties).

Overall NGCC Plant Mass In/Out Results



Overall NGCC Plant – Mass In/Out results screen.

Chemical Inputs

Coal: Flow rate of coal used in the power plant.

Oil: Flow rate of oil used in the power plant

Natural Gas: : Flow rate of natural gas used in the power plant

Petroleum Coke: Total mass of petroleum coke used in the power plant

Other Fuels: Flow rate of other fuels used in the power plant

Total Fuels: This is the flow rate of fuel entering the power plant. This result is highlighted in yellow.

Lime/Limestone: Total mass of this reagent used in the power plant on a wet basis.

Sorbent: Total mass of sorbent used in the power plant

Ammonia: Total mass of ammonia used in the power plant.

Activated Carbon: Flow rate of activated carbon injected in the power plant.

Other Chemicals, Solvents & Catalyst: Flow rate of other chemicals, solvents and catalysts used in the power plant.

Total Chemicals: Flow rate of reagent entering the power plant. This result is highlighted in yellow.

Process Water: Flow rate of water used in the power plant.

Solid & Liquid Outputs

Slag: Flow rate of slag from the power plant on a dry basis.

Ash Disposed: Flow rate of ash from the power plant on a dry basis.

Scrubber Solids Disposed: Flow rate of scrubber treatment solid wastes from the power plant on a dry basis.

Particulate Emissions to Air: Solids that remain in the flue gas and exit the plant are reported on a mass basis.

Captured CO_2: Flow rate of the captured CO_2.

Byproduct Ash Sold: Flow rate of ash (bottom and fly ash) sold in commerce as a by-product on a dry basis.

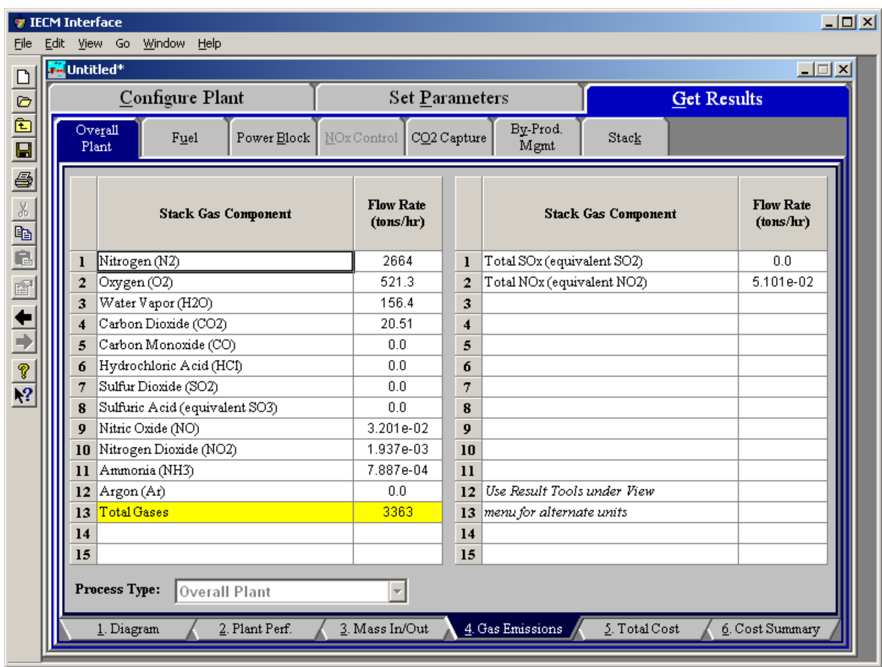
Byproduct Gypsum Sold: Flow rate of flue gas treatment solids sold in commerce as a by-product on a dry basis.

Byproduct Sulfur Sold: Flow rate of elemental sulfur recovered from flue gas and sold in commerce as a by-product on a dry basis.

Byproduct Sulfuric Acid Sold: Total mass of sulfuric acid recovered from the flue gas and sold in commerce as a by-product.

Total: This is the total wet solid mass exiting the power plant. This result is highlighted in yellow.

Overall NGCC Plant Gas Emissions Results



Overall NGCC Plant – Gas Emissions result screen.

Stack Gas Component

Each result is described briefly below:

Nitrogen (N_2): Total mass of nitrogen.

Oxygen (O_2): Total mass of oxygen.

Water Vapor (H_2O): Total mass of water vapor.

Carbon Dioxide (CO_2): Total mass of carbon dioxide.

Carbon Monoxide (CO): Total mass of carbon monoxide.

Hydrochloric Acid (HCl): Total mass of hydrochloric acid.

Sulfur Dioxide (SO_2): Total mass of sulfur dioxide.

Sulfuric Acid (equivalent SO_3): Total mass of sulfuric acid.

Nitric Oxide (NO): Total mass of nitric oxide.

Nitrogen Dioxide (NO_2): Total mass of nitrogen dioxide.

Ammonia (NH_3): Total mass of ammonia.

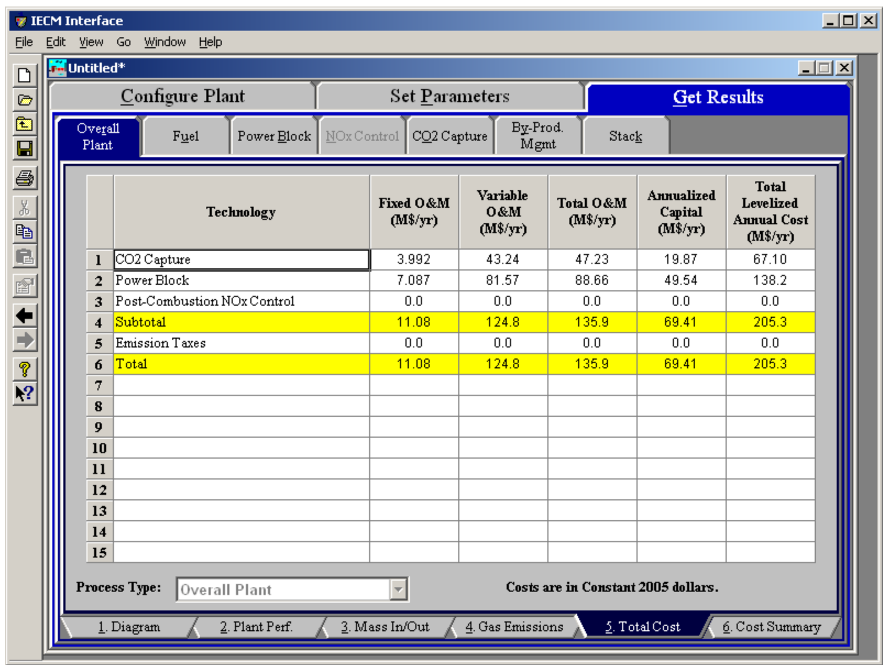
Argon (Ar): Argon is present in small quantities in atmospheric air. The argon emitted from the power plant is shown on a mass basis.

Total Gases: Total of the individual components listed above. This item is highlighted in yellow.

Total SO_x (equivalent SO_2): Total mass of SO_x as equivalent SO_2.

Total NO_x (equivalent NO_2): Total mass of NO_x as equivalent NO_2.

Overall NGCC Plant Total Cost Results



	Technology	Fixed O&M (M$/yr)	Variable O&M (M$/yr)	Total O&M (M$/yr)	Annualized Capital (M$/yr)	Total Levelized Annual Cost (M$/yr)
1	CO2 Capture	3.992	43.24	47.23	19.87	67.10
2	Power Block	7.087	81.57	88.66	49.54	138.2
3	Post-Combustion NOx Control	0.0	0.0	0.0	0.0	0.0
4	Subtotal	11.08	124.8	135.9	69.41	205.3
5	Emission Taxes	0.0	0.0	0.0	0.0	0.0
6	Total	11.08	124.8	135.9	69.41	205.3
7						
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Overall NGCC Plant – Total Cost results screen.

The **Total Cost** result screen displays a table which totals the annual fixed, variable, operations, maintenance, and capital costs associated with the power plant as a whole. Each technology (row) is described briefly below.

Technology

CO_2 Capture: The total cost of all the CO_2 Capture modules used.

Power Block: The total cost of the power block without consideration of any abatement technologies. The Power Block contains the air compressor, gas turbine, steam turbine and heat recovery steam generator areas.

Post-Combustion NO_x Control: The total cost of all the Post-Combustion NO_x removal modules used.

Subtotal: This is the cost of the conventional and advanced abatement technology modules alone. This is the total abatement cost. The subtotal is highlighted in yellow.

Emission Taxes: This is the sum of the user assessed taxes on the plant emissions of SO_2, NO_x and CO_2.

Total: This is the total cost of the entire power plant. This result is highlighted in yellow.

Each cost category (column) is described briefly below.

Fixed O&M: The operating and maintenance fixed costs are given as an annual total. This number includes all maintenance materials and all labor costs for each technology.

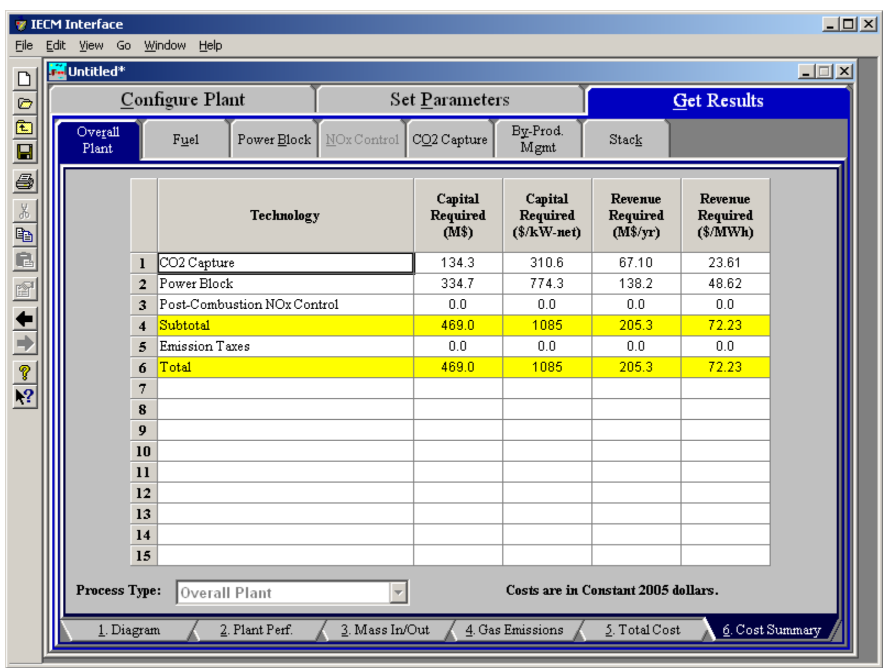
Variable O&M: The operating and maintenance variables costs are given as an annual total. This includes all reagent, chemical, steam, and power costs associated with a technology.

Total O&M: This is the sum of the annual fixed and variable operating and maintenance costs for each technology.

Annualized Capital: This is the total capital cost expressed on an annualized basis, taking into consideration the levelized carrying charge factor, or fixed charge factor, over the entire book life.

Total Levelized Annual Cost: The total annual cost is the sum of the total annual O&M cost and annualized capital cost items above. This result is highlighted in yellow

Overall NGCC Plant Cost Summary Results



	Technology	Capital Required (M$)	Capital Required ($/kW-net)	Revenue Required (M$/yr)	Revenue Required ($/MWh)
1	CO2 Capture	134.3	310.6	67.10	23.61
2	Power Block	334.7	774.3	138.2	48.62
3	Post-Combustion NOx Control	0.0	0.0	0.0	0.0
4	Subtotal	469.0	1085	205.3	72.23
5	Emission Taxes	0.0	0.0	0.0	0.0
6	Total	469.0	1085	205.3	72.23
7					
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Overall NGCC Plant – Cost Summary results screen.

The **Cost Summary** result screen displays costs associated with the power plant as a whole. Each technology (row) is described briefly below.

Technology

CO_2 Capture: This is the capital cost for the equipment that captures CO_2 in the plant.

Power Block: This is the capital cost for the power block process area of the plant.

Post-Combustion NO_x Control: This is the capital cost for the equipment that captures post-combustion NO_x in the plant.

Subtotal: This is the cost of the conventional and advanced abatement technology modules alone. This is the total abatement cost. The subtotal is highlighted in yellow.

Emission Taxes: This is the sum of the user assessed taxes on the plant emissions of SO_2, NO_x and CO_2.

Total: This is the sum of all of the above capital costs for all of the process areas in the plant.

Each cost category (column) is described briefly below.

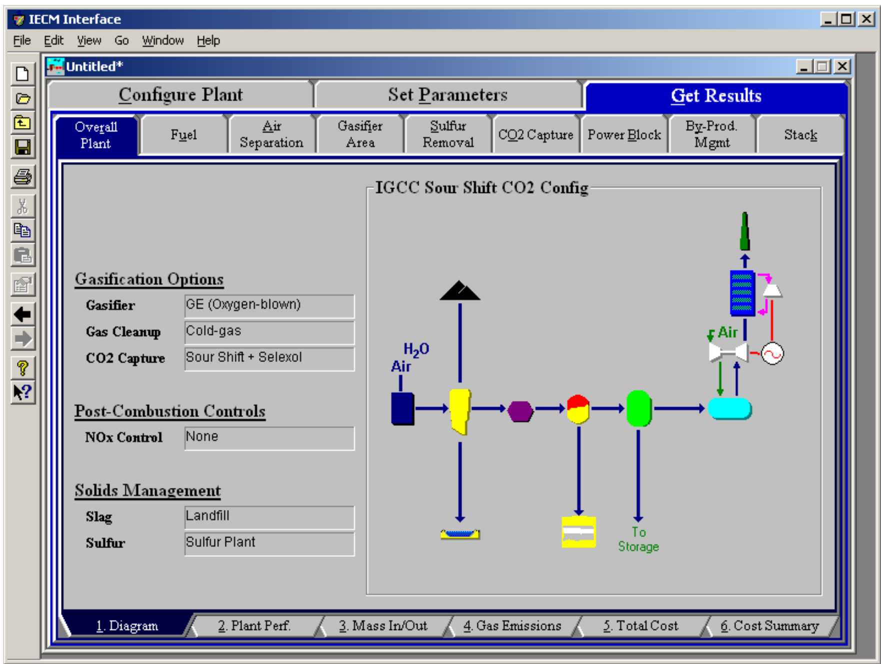
Capital Cost: The total capital requirement (TCR). This is the money that is placed (capitalized) on the books of the utility on the service date. The total cost includes the total plant investment plus capitalized plant startup. Escalation and allowance for funds used during construction (AFUDC) are also included. The capital cost is given on both a total and an annualized basis.

Revenue Required: Amount of money that must be collected from customers to compensate a utility for all expenditures in capital, goods, and services. The revenue requirement is equal to the carrying charges plus expenses. The revenue required is given on both an annualized and a net power output basis.

Overall IGCC Plant

The input parameter screens described in the following sections are available when the **IGCC** is selected as the plant type from the **New Session** pull down menu. These screens apply to the power plant as a whole, not to specific technologies.

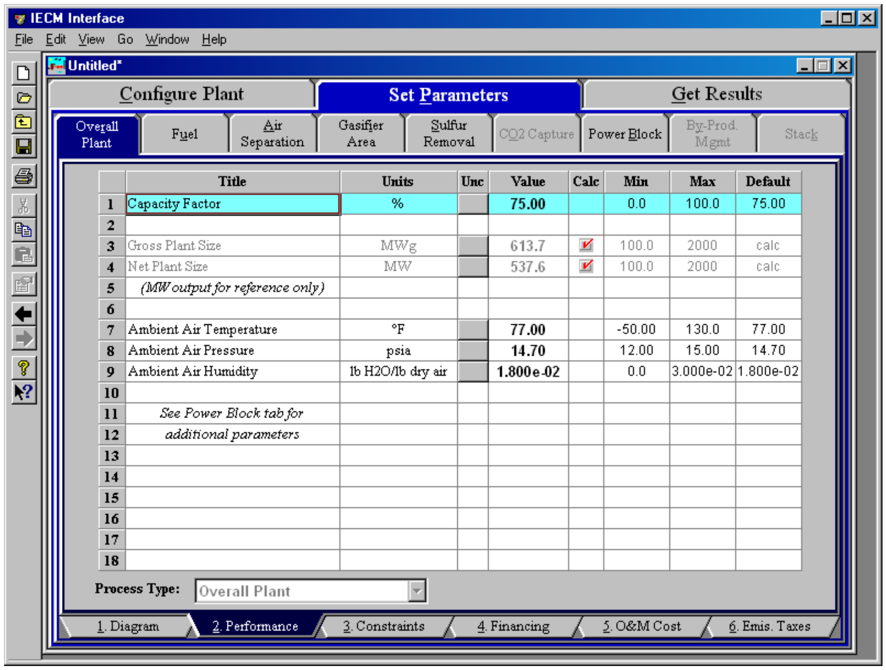
Overall IGCC Plant Diagram



Overall IGCC Plant – Diagram screen.

The **Overall IGCC Plant Diagram** appears in the **Configure Plant**, **Set Parameters** and in the **Get Results** program area. The screen displays the plant configuration settings on the left side of the page and a diagram of the configured plant on the right of the page. No input parameters or results are displayed on this screen.

Overall IGCC Plant Performance Inputs



Overall IGCC Plant – Performance input screen.

The parameters available on this screen establish the plant availability, electrical requirements, and ambient conditions for the power plant. These parameters have a major impact on the performance and costs of each of the individual technologies.

Capacity Factor: This is an annual average value, representing the percent of equivalent full load operation during a year. The capacity factor is used to calculate annual average emissions and materials flows.

Gross Plant Size: This is the gross output of the generator in megawatts (MW_g). The value does not include auxiliary power requirements. The model uses this information to calculate key mass flow rates. It is shown here for information only.

Net Plant Size: This is the net plant capacity, which is the gross plant capacity minus the losses due to plant equipment and pollution equipment (energy penalties). It is shown here for information only.

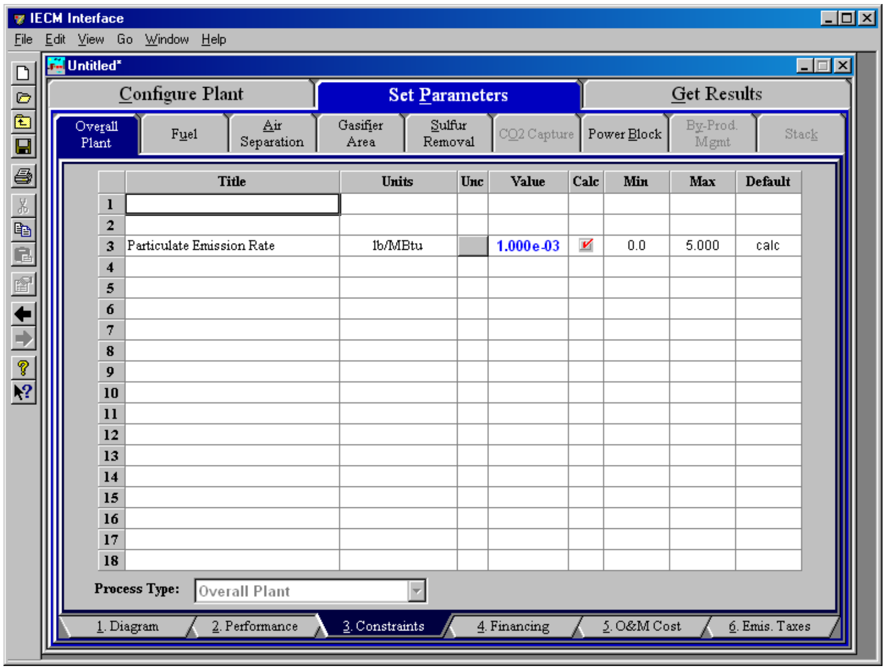
Ambient Air Temperature: This is the inlet temperature of the ambient combustion air prior to entering the preheater. The model presumes an *annual average* temperature. Inlet air temperature affects the boiler energy balance and efficiency. It provides a reference point for the calculation of pressure throughout the system. Currently, the model cannot have temperatures below 77^{o}F.

Ambient Air Pressure: This is the absolute pressure of the air inlet stream to the boiler. The air pressure is used to convert flue gas molar flow rates to volume flow rates.

Ambient Air Humidity: This is the water content of the inlet combustion air. This value is used in calculating the total water vapor content of the flue gas stream. The value is referred to as the specific humidity ratio, expressed as a ratio of the water mass to the dry air mass.

Overall IGCC Plant Constraints Inputs

The **Constraints** input parameters define the emission constraints as they apply to the gases emitted from the power plant. Constraints for sulfur dioxide, nitrogen dioxides, carbon dioxide, and mercury are not needed due to the cleaner emissions from IGCC plants.



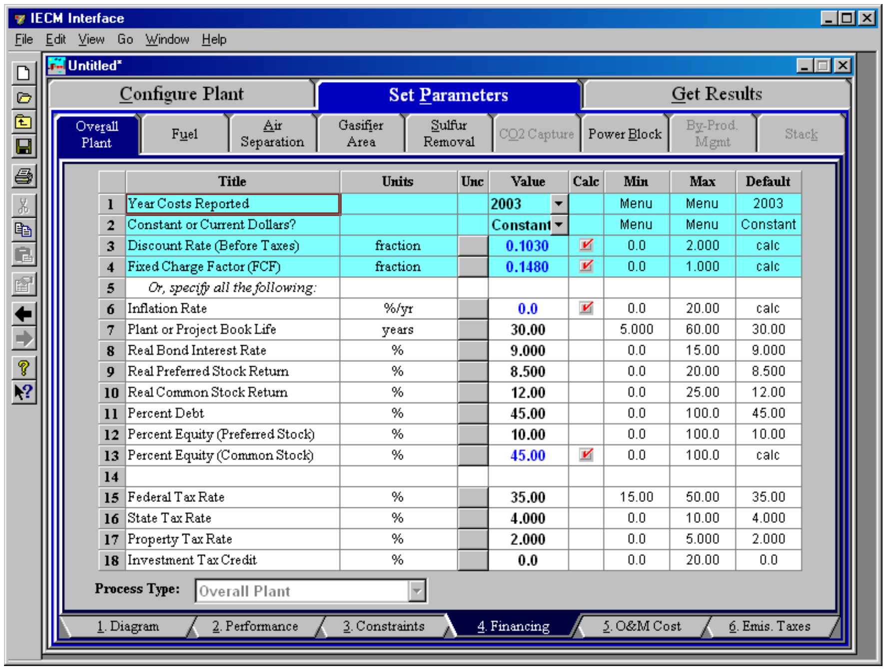
Overall IGCC Plant – Emission Constraints input screen.

The emission constraints determine the removal efficiencies of control systems that capture particulates. The level of capture is set to comply with the specified emission constraints. As discussed later, however, user-specified values for control technology performance may cause the plant to over-comply or under-comply with the emission constraints specified in this screen. Each parameter is described briefly below.

Particulate Emission Constraint: The emission constraint of the total suspended particulates is a function of the fuel type and is used to determine the removal efficiency of particulate control systems (if used).

Overall IGCC Plant Financing Inputs

Inputs for the financing costs of the base plant itself are entered on the **Financing** input screen.



	Title	Units	Unc	Value	Calc	Min	Max	Default
1	Year Costs Reported			2003		Menu	Menu	2003
2	Constant or Current Dollars?			Constant		Menu	Menu	Constant
3	Discount Rate (Before Taxes)	fraction		0.1030		0.0	2.000	calc
4	Fixed Charge Factor (FCF)	fraction		0.1480		0.0	1.000	calc
5	*Or, specify all the following:*							
6	Inflation Rate	%/yr		0.0		0.0	20.00	calc
7	Plant or Project Book Life	years		30.00		5.000	60.00	30.00
8	Real Bond Interest Rate	%		9.000		0.0	15.00	9.000
9	Real Preferred Stock Return	%		8.500		0.0	20.00	8.500
10	Real Common Stock Return	%		12.00		0.0	25.00	12.00
11	Percent Debt	%		45.00		0.0	100.0	45.00
12	Percent Equity (Preferred Stock)	%		10.00		0.0	100.0	10.00
13	Percent Equity (Common Stock)	%		45.00		0.0	100.0	calc
14								
15	Federal Tax Rate	%		35.00		15.00	50.00	35.00
16	State Tax Rate	%		4.000		0.0	10.00	4.000
17	Property Tax Rate	%		2.000		0.0	5.000	2.000
18	Investment Tax Credit	%		0.0		0.0	20.00	0.0

Overall IGCC Plant – Financing input screen.

This screen 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.

Each parameter is described briefly below.

Year Costs Reported: This is the year in which all costs are given or displayed, both in the input screens and the results. A cost index is used by the IECM to scale all costs to the cost year specified by this parameter. The cost year is reported on every input and result screen associated with costs throughout the interface.

Constant or Current Dollars: Constant dollar analysis does not include the affect of inflation, although real escalation is included. Current dollar analysis includes inflation and real escalation. This choice allows you to choose the mode of analysis for the entire IECM economics. The cost basis is reported on every input and result screen associated with costs throughout the interface.

Discount Rate (Before Taxes): This is also known as the “cost of money”. It is the return required by investors in order to attract investment capital. It is equal to the weighted sum of the return on debt and equity. It is the time values of money on the discount rate used in present worth arithmetic. One may specify a Fixed Charge Factor and Discount Rate, or fill in the following inputs and the model will calculate them.

Fixed Charge Factor (FCF): The fixed charge factor is one of the most important parameters in the IECM. 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.

One may specify a fixed charge factor, or fill in the following inputs and the model will calculate the FCF based on them:

Inflation Rate: 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.

Plant or Project Book Life: This is the years of service expected from a capital investment. It is also the period over which an investment is recovered through book depreciation.

Real Bond Interest Rate: This is a debt security associated with a loan or mortgage. It is the most secure form of security but the lowest in its return.

Real Preferred Stock Return: This equity security is the second most speculative type and pays the second highest rate of return. The holder of the stock is a part owner of the company.

Real Common Stock Return: This is the most speculative type of equity security sold by a utility and pays the highest relative return. The holder of the stock is a part owner of the company.

Percent Debt: This is the percent of the total capitalization that is associated with debt money. This includes loans and mortgage bonds.

Percent Equity (Preferred Stock): This is the percent of the total capitalization that is associated with the sale of preferred stock.

Percent Equity (Common Stock): This value is the remainder of the capitalization, calculated as 100% minus the percent debt, minus the percent equity in preferred stock.

Federal Tax Rate: This is the federal tax rate. It is used to calculate the amount of taxes paid and deferred.

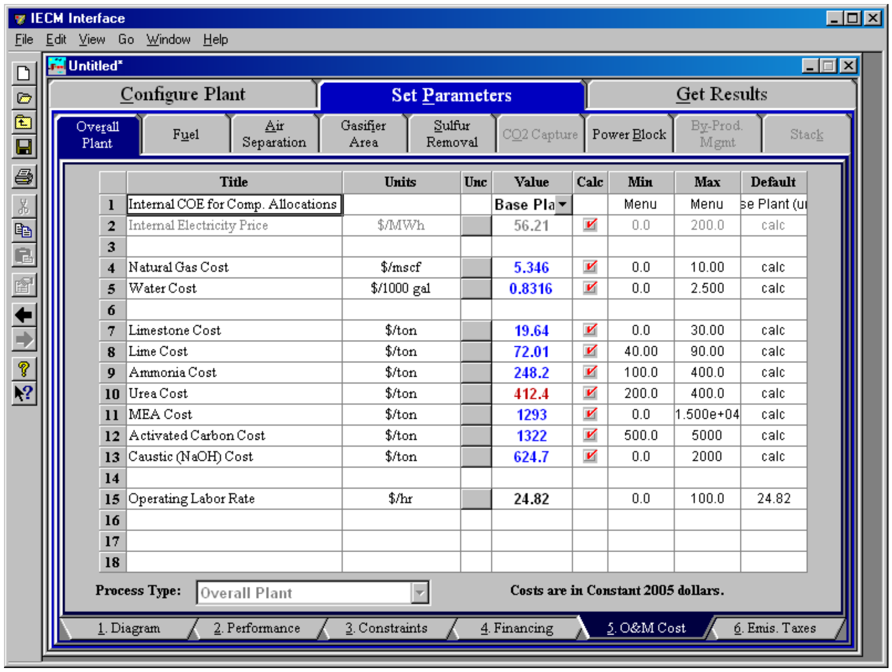
State Tax Rate: This is the state tax rate. It is used to calculate the amount of taxes paid and deferred.

Property Tax Rate: The property tax rate, or ad valorem, is used to calculate the carrying charge.

Investment Tax Credit: This is an immediate reduction in income taxes equal to a percentage of the installed cost of a new capital investment. It is zero by default. It is used to set the initial balance and the book depreciation.

Overall IGCC Plant O&M Cost Inputs

This screen combines the variable O&M unit costs from all the model components and places them in one spot. These values will also appear in the technology input screens where they are actually used. Values changed on this screen will reflect exactly the same change everywhere else they appear. O&M costs are typically expressed on an average annual basis and are provided in either constant or current dollars for a specified year, as shown on the bottom of the screen.



Overall IGCC Plant – O& M Cost input screen.

Internal COE for Comp. Allocations: This is a pop-up selection menu that determines the method for determining electricity costs within the power plant. The selection of this pop-up menu determines the actual internal electricity price on the next line.The options are

- **Base Plant (uncontrolled)**
- **User Specified**
- **Total Plant COE**

Internal Electricity Price: This is the price of electricity and is calculated as a function of the utility cost of the base plant. The base plant for the **IGCC** model is assumed to be a coal pile, air separation unit, gasifier, power block, and disposal sites. This value is calculated and provided for reference purposes only unless **User Specified** is selected in the pop-up in the previous line.

As-Delivered Coal Cost: This is the cost of the coal as-delivered.

Natural Gas Cost: This is the cost of natural gas in dollars per thousand standard cubic feet.

Water Cost: This is the cost of water in dollars per thousand gallons.

Limestone Cost: This is the cost of limestone in dollars per ton.

Lime Cost: This is the cost of lime in dollars per ton.

Ammonia Cost: This is the cost of ammonia in dollars per ton.

Urea Cost: This is the cost of natural gas in dollars per ton.

MEA Cost: This is the cost of MEA in dollars per ton.

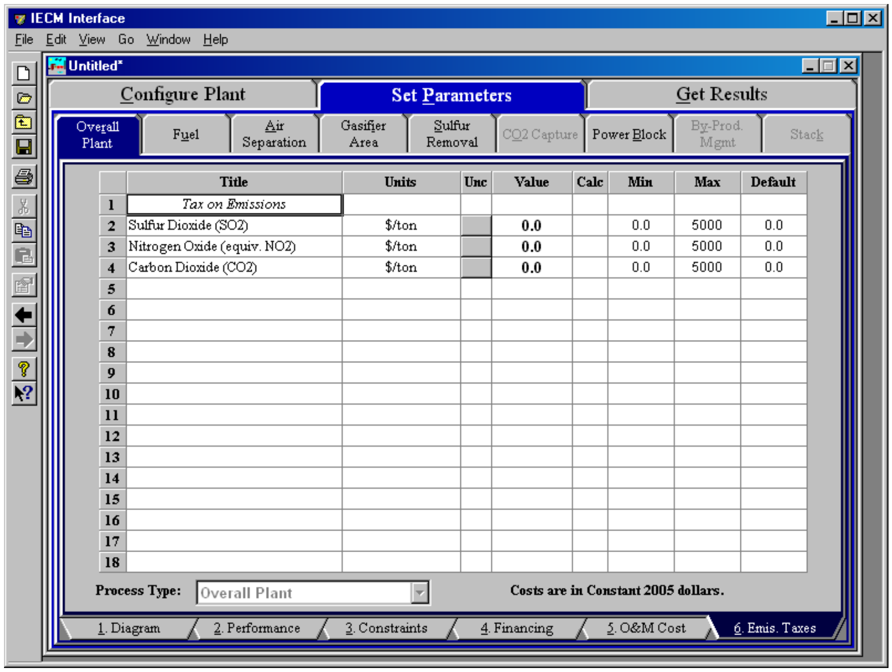
Activated Carbon Cost: This is the cost of activated carbon in dollars per ton.

Caustic (NaOH) Cost: This is the cost of caustic (NaOH) gas in dollars per ton.

Operating Labor Rate: The hourly cost of labor is specified in the base plant O&M cost screen. The same value is used throughout the other technologies.

Overall IGCC Plant Stack Emis. Taxes Inputs

This screen allows users to specify emission taxes or credits as part of the overall plant cost economics. Taxes or credits are typically provided in either constant or current dollars for a specified year, as shown on the bottom of the screen.



Overall IGCC Plant – Emis. Taxes input screen.

The **Emis. Taxes** input screen allows the user to enter the taxes on emissions in dollars per ton. The final costs determined from these inputs are available under the stack tab in the results section of the IECM. The costs are added to the overall plant cost, not a particular technology.

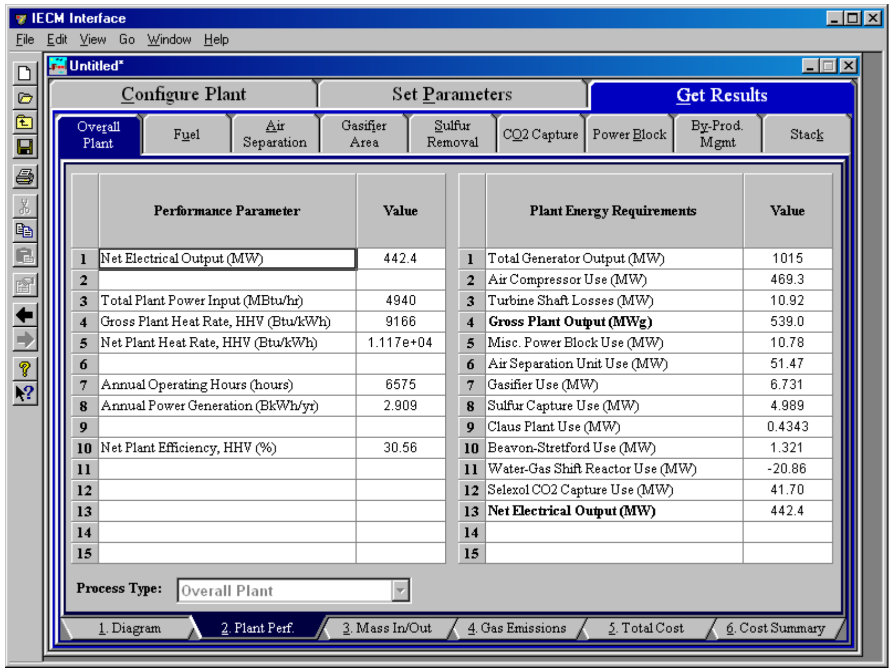
Tax on Emissions

Sulfur Dioxide (SO_2): The user may enter a cost to the plant of emitting sulfur dioxide in dollars per ton.

Nitrogen Oxide (equiv. NO_2): The user may enter a cost to the plant of emitting nitrogen oxide in dollars per ton.

Carbon Dioxide (CO_2): The user may enter a cost to the plant of emitting carbon dioxide in dollars per ton.

Overall IGCC Plant Performance Results



Overall IGCC Plant – Performance result screen.

The **Plant Perf.** result screen displays performance results for the plant as a whole. Heat rates and power in and out of the power plant are given. Each result is described briefly below.

Performance Parameter

Net Electrical Output: This is the net plant capacity, which is the gross plant capacity minus the losses due to plant equipment and pollution equipment (energy penalties).

Total Plant Power Input: This is the total of all the fuel energy used by the plant, given on an hourly basis (maximum capacity). This rate is also referred to as the total plant power input.

Gross Plant Heat Rate, HHV: This is the gross heat rate of the entire plant.

Net Plant Heat Rate, HHV: This is the net heat rate of the entire plant (including aux power produced) which includes the effect of plant equipment and pollution control equipment.

Annual Operating Hours: This is the number of hours per year that the plant is in operation. If a plant runs 24 hours per day, seven days per week, with no outages, the calculation is 24 hours * 365 days. or 8,760 hours/year.

Annual Power Generation: This is the net annual power production of the plant. The capacity factor and all power credits or penalties are used in determining its value.

Net Plant Efficiency, HHV: This is the net efficiency of the entire plant.

Plant Power Requirements

A second group of results provide a breakdown of the internal power consumption for the individual technology areas. These are all given in units of megawatts. Individual plant sub-components will only be displayed when they are configured in the **Configure Plant** section of the model.

Total Generator Output: This is the gross power generated by the turbine.

Air Compressor Use: The power required to operate the air compressor.

Turbine Shaft Losses: This variable accounts for any turbine electricity losses that are not incorporated into the lossed due to air compressor use.

Gross Plant Output: This is the net power generated by the turbine. This is the gross output of the turbine minus the power required by the air compressor and any miscellaneous losses.

Misc. Power Block Use: This is the electrical power required to operate pumps and motors associated with the power block area.

Air Separation Unit Use: This is the power utilization of the compressors in the air separation system.

Gasifier Use: This is the power utilization of the gasification system.

Sulfur Capture Use: This is the power utilization of the sulfur capture system (this does not include the claus or beavon stretford systems).

Claus Plant Use: This is the power utilization of the claus plant equipment.

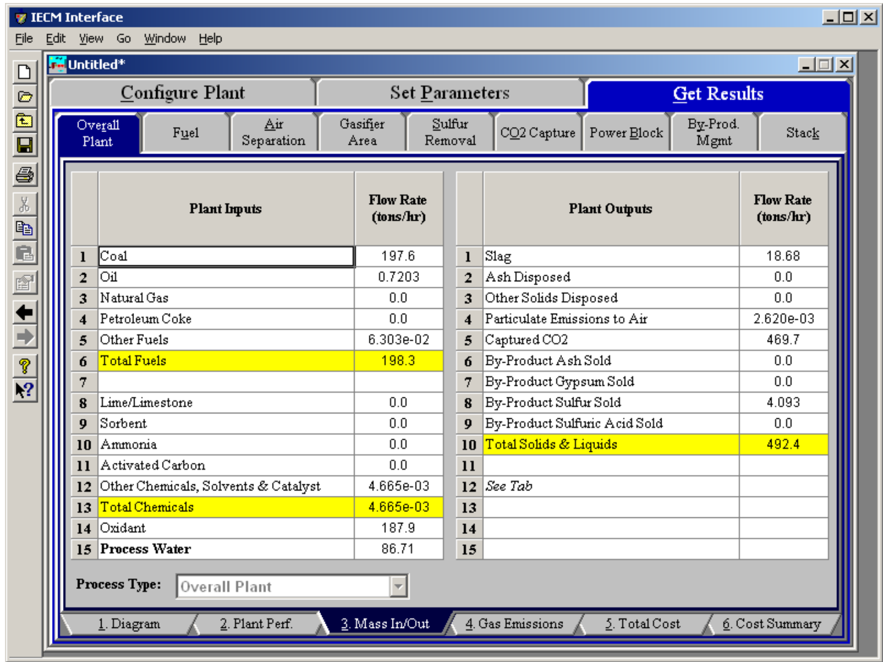
Beavon Stretford Use: This is the power utilization of the beavon stretford system**.**

Water-Gas Shift Reactor Use: This is the power-equivalent of the steam recovered from the water-gas shift reactor.

Selexol CO_2 Capture Use (MW): This is the power utilization of the CO_2 capture system.

Net Electrical Output: This is the net plant capacity, which is the gross plant capacity minus the losses due to plant equipment and pollution equipment (energy penalties).Also included are credits from steam generated and reused to produce electricity.

Overall IGCC Plant Mass In/Out Results



Overall IGCC Plant – Mass In/Out result screen.

Plant Inputs

Coal: Flow rate of coal used in the power plant.

Oil: Flow rate of oil used in the power plant.

Natural Gas: : Flow rate of natural gas used in the power plant

Petroleum Coke: Total mass of petroleum coke used in the power plant

Other Fuels: Flow rate of other fuels used in the power plant

Total Fuels: This is the flow rate of fuel entering the power plant. This result is highlighted in yellow.

Lime/Limestone: Total mass of this reagent used in the power plant on a wet basis.

Sorbent: Total mass of sorbent used in the power plant

Ammonia: Total mass of ammonia used in the power plant.

Activated Carbon: Flow rate of activated carbon injected in the power plant.

Other Chemicals, Solvents & Catalyst: Flow rate of other chemicals, solvents and catalysts used in the power plant.

Total Chemicals: Flow rate of reagent entering the power plant. This result is highlighted in yellow.

Oxidant: Flow rate of oxidant entering the power plant. This includes oxygen, nitrogen and argon.

Process Water: Flow rate of water used in the power plant.

Plant Outputs

Slag: Flow rate of slag from the power plant on a dry basis.

Ash Disposed: Flow rate of ash from the power plant on a dry basis.

Other Solids Disposed: Flow rate of scrubber and other treatment solid wastes from the power plant on a dry basis.

Particulate Emissions to Air: Flow rate of particulates emitted to the air from the plant.

Captured CO_2: Flow rate of the captured CO_2.

Byproduct Ash Sold: : Flow rate of ash (bottom and fly ash) sold in commerce as a by-product on a dry basis.

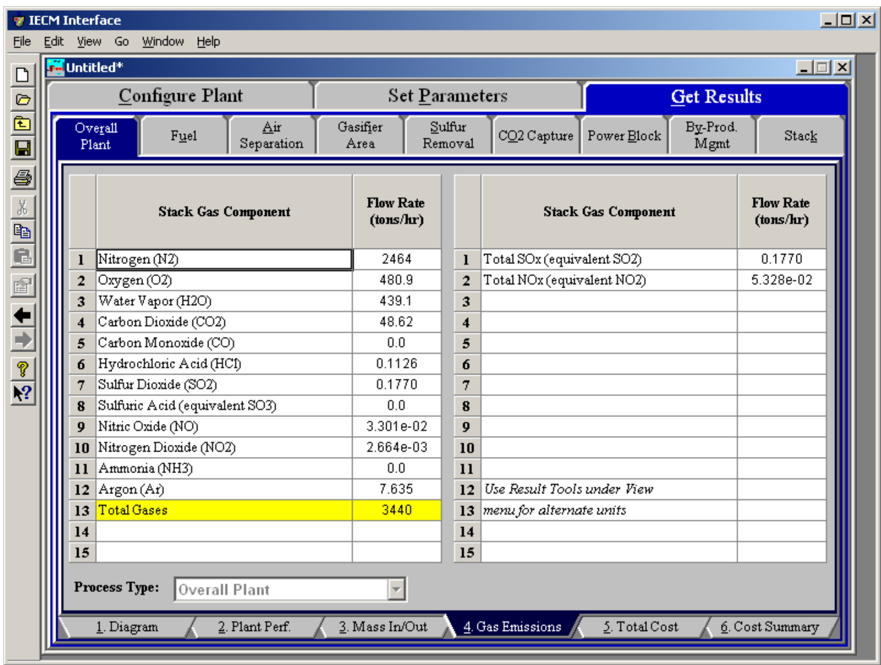
Byproduct Gypsum Sold: : Flow rate of flue gas treatment solids sold in commerce as a by-product on a dry basis.

Byproduct Sulfur Sold: Flow rate of elemental sulfur recovered from flue gas and sold in commerce as a by-product on a dry basis.

Byproduct Sulfuric Acid Sold: Total mass of sulfuric acid recovered from the flue gas and sold in commerce as a by-product.

Total Solids & Liquids: This is the total wet solid mass exiting the power plant. This result is highlighted in yellow.

Overall IGCC Plant Gas Emissions Results



Overall IGCC Plant – Gas Emissions result screen.

Stack Gas Component

Each result is described briefly below:

Nitrogen (N_2): Total mass of nitrogen.

Oxygen (O_2): Total mass of oxygen.

Water Vapor (H_2O): Total mass of water vapor.

Carbon Dioxide (CO_2): Total mass of carbon dioxide.

Carbon Monoxide (CO): Total mass of carbon monoxide.

Hydrochloric Acid (HCl): Total mass of hydrochloric acid.

Sulfur Dioxide (SO_2): Total mass of sulfur dioxide.

Sulfuric Acid (equivalent SO_3): Total mass of sulfuric acid.

Nitric Oxide (NO): Total mass of nitric oxide.

Nitrogen Dioxide (NO_2): Total mass of nitrogen dioxide.

Ammonia (NH_3): Total mass of ammonia.

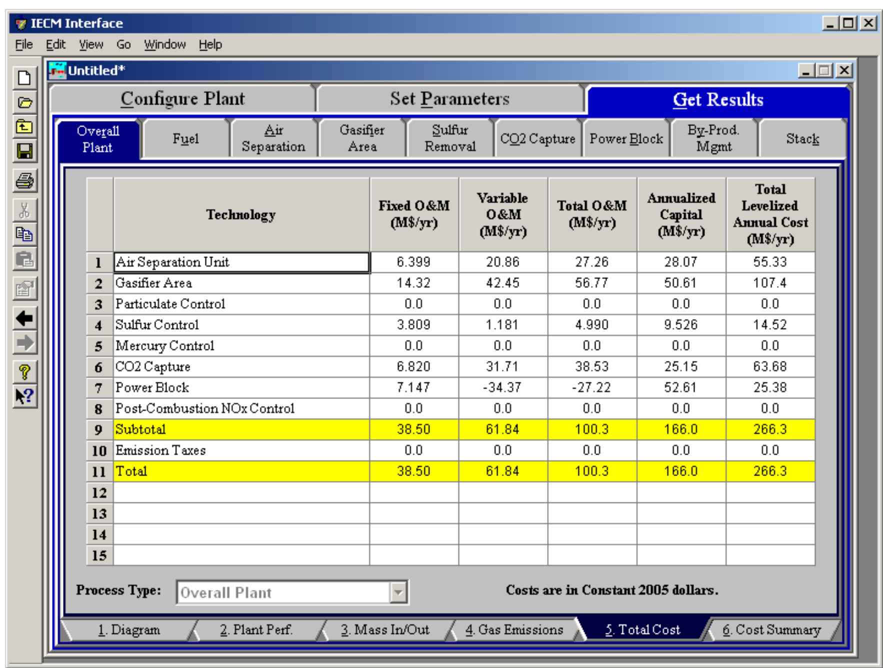
Argon (Ar): Total mass of argon.

Total Gases: Total of the individual components listed above. This item is highlighted in yellow.

Total SOx (equivalent SO_2): Total mass of SO_x as equivalent SO_2.

Total NOx (equivalent NO_2): Total mass of NO_x as equivalent NO_2.

Overall IGCC Plant Total Cost Results



	Technology	Fixed O&M (M$/yr)	Variable O&M (M$/yr)	Total O&M (M$/yr)	Annualized Capital (M$/yr)	Total Levelized Annual Cost (M$/yr)
1	Air Separation Unit	6.399	20.86	27.26	28.07	55.33
2	Gasifier Area	14.32	42.45	56.77	50.61	107.4
3	Particulate Control	0.0	0.0	0.0	0.0	0.0
4	Sulfur Control	3.809	1.181	4.990	9.526	14.52
5	Mercury Control	0.0	0.0	0.0	0.0	0.0
6	CO2 Capture	6.820	31.71	38.53	25.15	63.68
7	Power Block	7.147	-34.37	-27.22	52.61	25.38
8	Post-Combustion NOx Control	0.0	0.0	0.0	0.0	0.0
9	Subtotal	38.50	61.84	100.3	166.0	266.3
10	Emission Taxes	0.0	0.0	0.0	0.0	0.0
11	Total	38.50	61.84	100.3	166.0	266.3
12						
13						
14						
15						

Overall IGCC Plant – Total Cost result screen.

The **Total Cost** result screen displays a table which totals the annual fixed, variable, operations, maintenance, and capital costs associated with the power plant as a whole. Each technology (row) is described briefly below.

Technology

Air Separation Unit: This is the capital cost for the Air Separation process area of the plant.

Gasifier Area: This is the capital cost for the equipment in the gasifier process area of the plant.

Particulate Control: This is the capital cost for the equipment that performs particulate capture in the plant.

Sulfur Control: This is the capital cost for the equipment that performs sulfur capture in the plant.

Mercury Control: This is the capital cost for the mercury process area of the plant.

CO_2 Capture: This is the capital cost for the equipment that performs CO_2 capture in the plant.

Power Block: This is the capital cost for the power block process area of the plant.

Post-Combustion NO_x Control: This is the capital cost for the equipment that captures post-combustion NO_x in the plant.

Subtotal: This is the cost of the conventional and advanced abatement technology modules alone. This is the total abatement cost. The subtotal is highlighted in yellow.

Emission Taxes: This is the sum of the user assessed taxes on the plant emissions of SO_2, NO_x and CO_2.

Total: This is the total cost of the entire power plant. This result is highlighted in yellow.

Each cost category (column) is described briefly below.

Fixed O&M: The operating and maintenance fixed costs are given as an annual total. This number includes all maintenance materials and all labor costs for each technology.

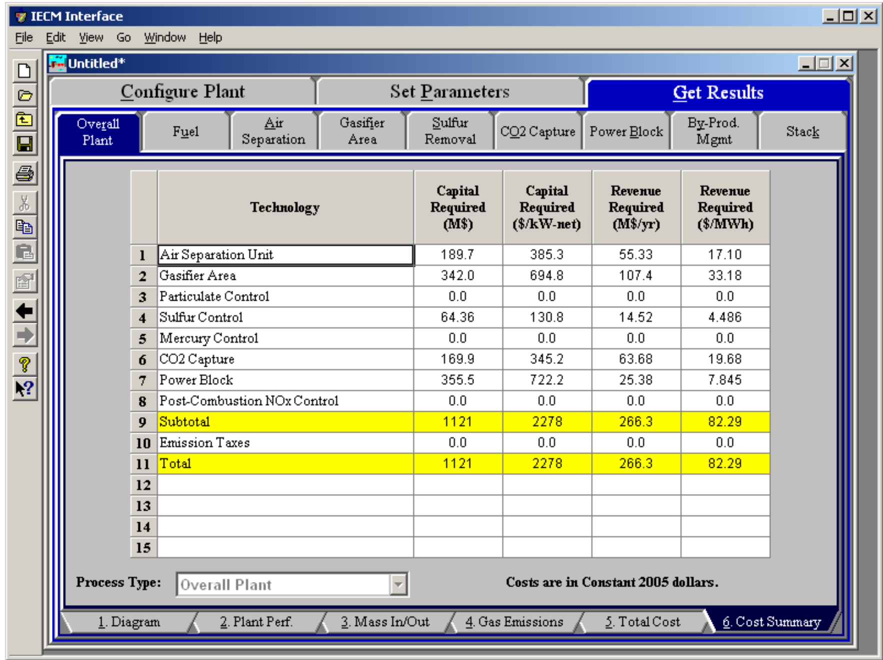
Variable O&M: The operating and maintenance variables costs are given as an annual total. This includes all reagent, chemical, steam, and power costs associated with a technology.

Total O&M: This is the sum of the annual fixed and variable operating and maintenance costs for each technology.

Annualized Capital: This is the total capital cost expressed on an annualized basis, taking into consideration the levelized carrying charge factor, or fixed charge factor, over the entire book life.

Total Levelized Annual Cost: The total annual cost is the sum of the total annual O&M cost and annualized capital cost items above. This result is highlighted in yellow

Overall IGCC Plant Cost Summary Results



	Technology	Capital Required (M$)	Capital Required ($/kW-net)	Revenue Required (M$/yr)	Revenue Required ($/MWh)
1	Air Separation Unit	189.7	385.3	55.33	17.10
2	Gasifier Area	342.0	694.8	107.4	33.18
3	Particulate Control	0.0	0.0	0.0	0.0
4	Sulfur Control	64.36	130.8	14.52	4.486
5	Mercury Control	0.0	0.0	0.0	0.0
6	CO2 Capture	169.9	345.2	63.68	19.68
7	Power Block	355.5	722.2	25.38	7.845
8	Post-Combustion NOx Control	0.0	0.0	0.0	0.0
9	Subtotal	1121	2278	266.3	82.29
10	Emission Taxes	0.0	0.0	0.0	0.0
11	Total	1121	2278	266.3	82.29
12					
13					
14					
15					

Overall IGCC Plant – Cost Summary result screen.

Technology

Air Separation Unit: This is the capital cost for the Air Separation process area of the plant.

Gasifier Area: This is the capital cost for the gasifier process area of the plant.

Particulate Control: This is the capital cost for the equipment that captures particulates in the plant.

Sulfur Control: This is the capital cost for the equipment that captures sulfur in the plant.

Mercury Control: This is the capital cost for the mercury process area of the plant.

CO_2 Capture: This is the capital cost for the equipment that captures CO_2 in the plant.

Power Block: This is the capital cost for the power block process area of the plant.

Post-Combustion NO_x Control: This is the capital cost for the post-combustion equipment that captures NO_x in the plant.

Total: This is the sum of the capital costs for all the process areas in the plant.

Each cost category (column) is described briefly below.

Capital Cost: The total capital requirement (TCR). This is the money that is placed (capitalized) on the books of the utility on the service date. The total cost includes the total plant investment plus capitalized plant startup. Escalation and allowance for funds used during construction (AFUDC) are also included. The capital cost is given on both a total and an annualized basis.

Revenue Required: Amount of money that must be collected from customers to compensate a utility for all expenditures in capital, goods, and services. The revenue requirement is equal to the carrying charges plus expenses. The revenue required is given on both an annualized and a net power output basis.

Fuel

The screens associated with the **Fuel Technology** Navigation Tab display and define the composition and cost of the fuels used in the plant. The IECM supports the use of various fuels, ranging from coals of various rank, fuel oil of various weight, and natural gas of various places of origin. Default properties of fuels are provided, but user-specified properties can also be easily substituted.

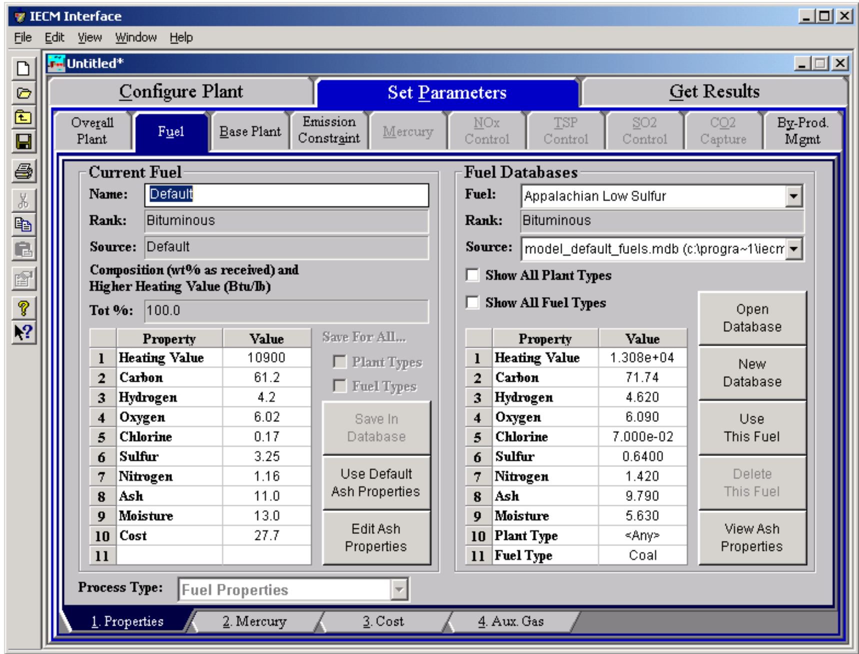
The combustion model currently supports the use of pulverized coal in the furnace, with natural gas available as a reburn option to the in-furnace NOx controls and an optional natural gas auxiliary boiler. The coal properties can be modified. The natural gas properties will be made available in the future. At present, a common Pennsylvania natural gas is assumed (NGCC).

The natural gas combined cycle (NGCC) plant configurations all assume natural gas for fuel. The properties can be specified by the user.

The integrated gasification combined cycle (IGCC) plant configurations assume coal gasification to produce a synthetic fuel gas. The coal properties must be chosen from a predetermined set of coals.

Fuel Properties Coal Input

The selection of the particular coal model default, cleaned, saved externally, or user-specified and its ultimate and ash properties are selected and editable on the **Properties** input screen.



Fuel – Properties input screen.

There are two panes on the Fuel Properties input screen: one for the composition, higher heating value, and cost of the **Current Fuel**, the other for properties of the fuels in the **Fuel Databases**. The **Current Fuel** is the fuel for which the model will conduct its calculations. The IECM interface currently supports only one fuel selection per session. The **Fuel Databases** pane displays the properties for other selectable fuels. From this screen, you may choose a fuel from the model defaults, enter a user-defined fuel, or choose a previously saved user-defined fuel. Properties of existing fuels may be modified and new fuels may be created and saved to user specified databases. The user-specified databases can be transferred from one user to another. A full suite of buttons have been provided to make the selection and management of the fuel properties easier.

Both the **Current Fuel** pane and the **Fuel Databases** pane display the following information: for a fuel.

Name: This is the name of the fuel, it may be the trade name or a unique identifier supplied by the user.

Rank: The rank of a coal refers to the degree of coalification endured by the organic matter. It is estimated by measuring the moisture content, specific energy, reflectance of vitrinite or volatile matter (these are known as rank parameters

Source: The model provides the values for default fuel properties, these can be used "as is" or modified and used. Modified fuels maybe stored in a new database or an existing database. Source displays the database file from which the data was retrieved, or indicates that the data has been enetered by the user.

Fuel Properties: The property value spreadsheet is used to display the heating value and content of carbon, hydrogen, oxygen, chlorine, sulfur, nitrogen, ash, and moisture are specified on a weight percent basis for coal fuels. The data can be edited only in the **Current Coal** pane. The fuel composition is used in a combustion equation to calculate the flue gas composition in the furnace. The heating value is used to calculate the mass flow rate of fuel. Property data also determines the fuel rank (bituminous, subbituminous, or lignite). This, in turn, determines the default values of several boiler parameters. The editable fuel properties are:

- **Heating Value:** This is the higher heating value of the fuel in Btu/lb.
- **Carbon:** The weight percent of carbon in the fuel on a wet basis.
- **Hydrogen:** This is the weight percent of hydrogen in the fuel on a wet basis.
- **Oxygen:** This is the weight percent of oxygen in the fuel on a wet basis.
- **Chlorine:** This is the weight percent of chlorine in the fuel on a wet basis.
- **Sulfur:** This is the weight percent of sulfur in the fuel on a wet basis.
- **Nitrogen:** This is the weight percent of nitrogen in the fuel on a wet basis.
- **Ash:** This is the weight percent of ash in the fuel on a wet basis.
- **Moisture:** This is the weight percent of moisture in the fuel on a wet basis.
- **Cost:** This is the total as-delivered cost of the coal on a wet basis. A default value is provided for the default coals provided in the model. This value can be updated on this input screen or the fuel cost screen.

Ash Properties: The property value spreadsheet is also used to display the oxide content of the ash in coal on a percent of total ash basis. The data can be edited only in the **Current Fuel** pane. The ash content is used to determine the resistivity of the ash. This, in turn, determines the specific collection area (SCA) of the cold-side ESP. The editable ash properties are:

- **SiO_2:** The percent by weight of silicon dioxide in the ash.
- **Al_2O_3:** The percent by weight of Aluminum Oxide in the ash.
- **Fe_2O_3:** The percent by weight of ferric oxide in the ash.
- **CaO:** The percent by weight of calcium oxide in the ash.
- **MgO:** The percent by weight of magnesium oxide in the ash.
- **Na_2O:** The percent by weight of sodium oxide in the ash.
- **K_2O:** The percent by weight of potassium oxide in the ash.
- **TiO_2:** The percent by weight of titanium dioxide in the ash.
- **MnO_2:** The percent by weight of manganese dioxide in the ash.
- **P_2O_5:** The percent by weight of phosphorus pentoxide in the ash.
- **SO_3:** The percent by weight of sulfur trioxide in the ash.

The **Current Fuel** pane displays two check boxes that are grayed out when the “model_default_fuels.mdb” database file is currently open. If a personal fuel database is opened, these two check boxes become active. The check boxes serve to allow the fuel to be available to multiple plant types or fuel types. The current fuel must be saved to make the restrictions permanent. Once saved, all new sessions will use these filters to determine which fuels will be listed in the **Fuel** menu. These check boxes are:

Plant Types: This is a filtering agent that specifies whether or not this fuel is restricted to the current plant type. If the box is not checked, the fuel will only be available to new sessions with the same plant type as the current session. If the box is checked, the fuel will be available to all new sessions, regardless of their plant type.

Fuel Types: This is a filtering agent that specifies whether or not this fuel is restricted to a particular fuel type. If the box is not checked, the fuel will only be available to new sessions that use the same primary fuel type as the current session. If the box is checked, the fuel will be available to all new sessions, regardless of the primary fuel type they use. This filter will be more important when oil fuels are made available in the IECM.

The **Fuel Databases** pane displays two additional items that verify whether or not a particular fuel is restricted to particular plant types or for primary fuel types. Either a particular plant type and fuel type will be specified or the word "<All>" will be displayed.

Selecting a Fuel

The **Current Fuel** pane displays the fuel that is in use by the model. The **Fuel Databases** pane initially displays the first default fuel in the model's default database. To make the fuel that is displayed in the **Fuel Database** pane the fuel to be used by the model, press the **Use this Fuel** button. The fuel will then be displayed in the **Current Fuel** pane. To view the ash properties, press the **View Ash Properties** button in the **Fuels Database**, the ash properties are displayed and the button that was pressed, labeled **View Ash Properties** has changed to **View Fuel Properties.** This button toggles between **View Ash Properties** and **View Fuel Properties.** To find other fuels:

Select a Different Fuel in the Open Database: Select the pull down menu on the text box labeled **Fuel:**. The list of fuels in the database is displayed another fuel can be chosen.

Select a Different Open Database: Select the pull down menu on the text box labeled **Source:**. The list of other open databases is displayed.

Open Another Fuel Database: When pressed the button labeled **Open Database** will display the Windows **Open** screen. All files with **.fdb** extension will be displayed. **.fdb** is the default extension for the **Fuel Databases** files. Select a file and press the **Open** button.

Modifying a Fuel

The fuel values that are displayed in the **Current Fuel** pane may be modified. Put the cursor into the cell containing the value of the property to be edited and enter the new value. To edit the ash properties of the current fuel; press the **Edit Ash Properties** button in the **Current Fuel** pane, the ash properties are displayed and the button that was pressed, labeled **Edit Ash Properties** has changed to **Edit Fuel Properties.** This button toggles between **Edit Ash Properties** and **Edit Fuel Properties.** . The ash properties may be edited in the same way as the fuel properties. Place the cursor in the value of the property to be modified and enter the new value. The model will run using the fuel that is displayed in the **Current Fuel** pane.

Saving a Modified Fuel

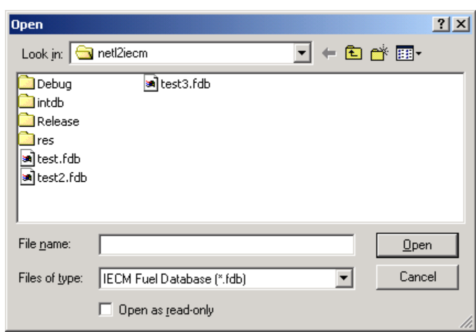
A fuel that has been modified may be saved to any user specified fuel database except the default database, **model_default_fuels.mdb**. Use the **Save in Database** button to save the modified fuel, displayed in the **Current Fuel** pane to the database that is displayed in the **Source** text box. If the default database, **model_default_fuels.mdb** is displayed in the text box titled **Source**, the **Save in Database** button will be grayed out, not active. Activate the **Save in Database,** by opening another database or creating a new database**.**

Deleting a Fuel

A fuel that is displayed in the **Fuel Databases** pane, may be deleted using the **Delete this Fuel** button, if it is not a model default fuel. Fuels in the model default database, **model_default_fuels.mdb,** cannot be deleted.

Open Database

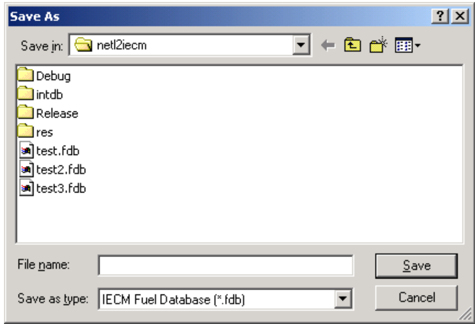
Press the **Open Database** button on the **Fuels Database** pane and the **Windows Open Screen** will appear. A valid fuel database file as an **.fdb** extension. Click on the database file to open and press the **Open** button. The **Fuels Database** displays the first fuel in the selected database and the **Source**: text box displays the full path and file name of the database that has just been opened.



Fuels – Windows Open screen.

New Database

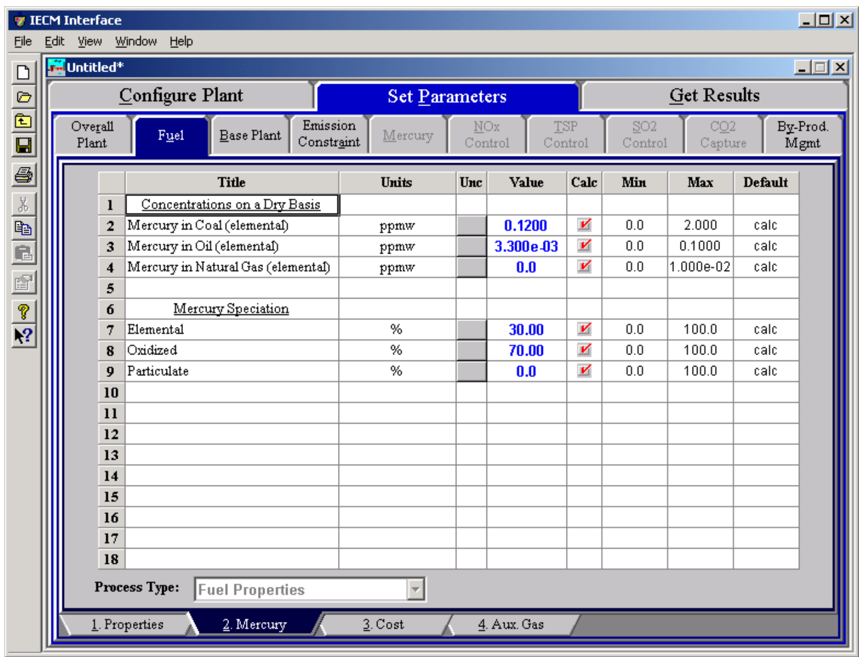
Press the **New Database** button on the **Fuels Database** pane and the **Windows Save As Screen** will appear. Type in the name of the new database file into the **File name:** text box. All fuel database files have an **.fdb** extension. Press the **Save** button. The **Source**: text box displays the full path and file name of the new database and all other fuel values in the **Fuels Database** pane will be blank



Fuels – Windows Save As screen.

Fuel Mercury Input

The concentration of mercury in the as-fired coal and speciation of mercury after combustion are entered on the **Mercury** input screen



Fuel – Mercury input screen.

Each parameter is described briefly below:

Concentration on a Dry Basis

Trace elements found in fuels are typically measured and reported as a mass concentration given on a dry basis. The IECM uses this concentration in conjunction with the fuel flow rate and fuel moisture to determine the mass flow rate. Currently Mercury is the only trace species tracked in the IECM.

Mercury in Coal (elemental): This input parameter specifies the mass concentration of total mercury in the coal given on a dry basis. The mercury concentration should be given on an elemental basis, not on a mercury compound basis. The default value is a function of the coal rank.

Mercury in Oil (elemental): This input parameter specifies the mass concentration of total mercury in the oil. The mercury concentration should be given on an elemental basis, not on a mercury compound basis.

Mercury in Natural Gas (elemental): This input parameter specifies the mass concentration of total mercury in the natural gas. The mercury concentration should be given on an elemental basis, not on a mercury compound basis.

Mercury Speciation

Once the fuel is combusted, the mercury can be identified in primarily two chemical states: elemental (Hg^0) and oxidized (Hg^{+2}). Although mercury can alternatively be reported as particulate or gas phase, the IECM assumes Mercury is reported on an elemental and oxidized basis.

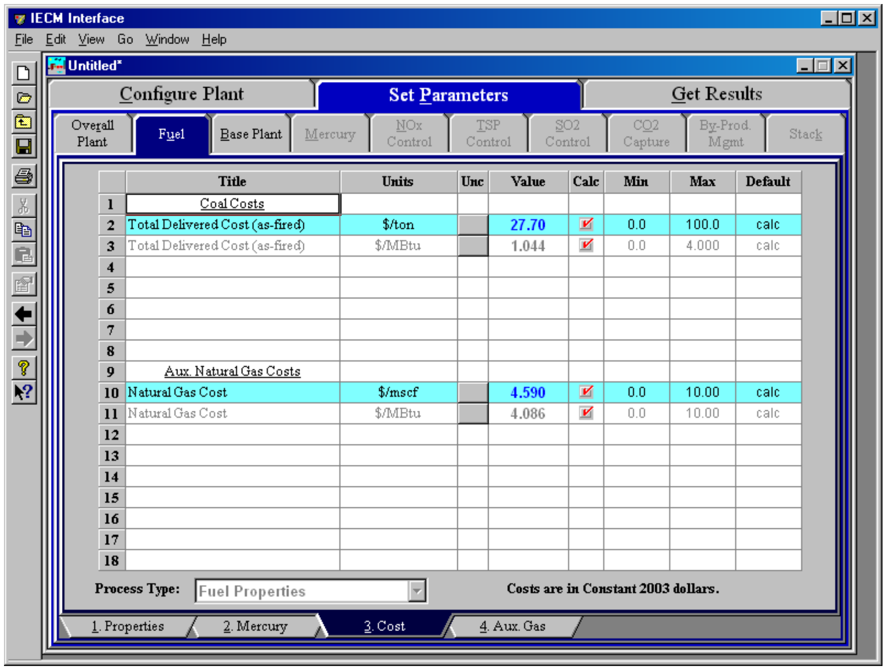
Elemental: This is the percent of total mercury that is in an elemental state (Hg^0) after combustion. Elemental mercury is typically unreactive and passes through a power plant. The default value is a function of the coal rank.

Oxidized: This is the percent of total mercury that is in an oxidized state (Hg^{+2}) after combustion. Oxidized mercury is very reactive and typically forms mercury compounds. The default value is a function of the coal rank.

Particulate: This parameter is not currently used in the IECM. It's value is set to force the sum of the speciation types to be 100%.

Fuel Cost Input

The cost of the cleaned coal, transportation costs, and other miscellaneous for coal and the auxiliary natural gas costs are accessed on the **Cost** input screen. Note that coal parameters are not displayed for the **Combustion (Turbine)** plant type.



Fuel –Cost input screen.

Each parameter is described briefly below.

Coal Costs

Coal is the primary fuel for the combustion plant type. The costs associated with the coal have been simplified and contain only the total as-fired cost.

Total Delivered Cost (as-fired): This is the total cost of delivered coal on a wet ton basis in dollars per ton. It is assumed to contain any costs of cleaning and transportation. The total cost in units of $/ton is the same value as shown on the fuel properties screen.

Total Delivered Cost (as-fired): This is also provided in units of $/MBtu. This value cannot be edited. It is based on the value given above in units of $/ton.

Aux. Natural Gas Costs

Natural gas is an auxiliary fuel used as an option for the combustion NOx control and the amine CO_2 capture configurations.

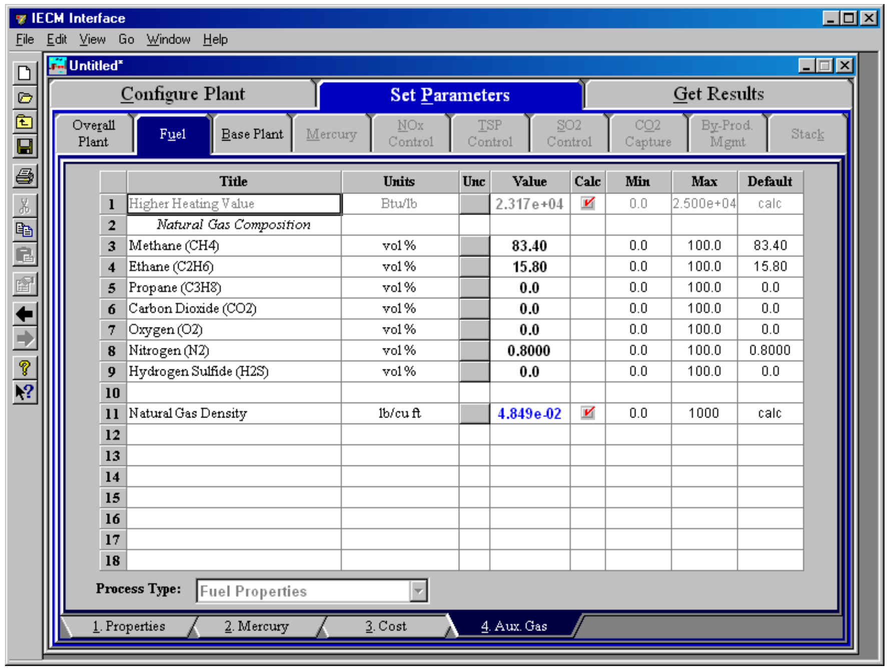
Natural Gas Cost: This is also provided in units of $/MBtu. This value cannot be edited. It is based on the value given in units of $/mscf.

Natural Gas Cost: This is also provided in units of $/MBtu. This value cannot be edited.

Fuel Aux. Gas Properties Input

The natural gas composition and density can be entered on the natural gas properties screen. The screen below is shown when accessed from the **Combustion (Turbine)** plant type. It is also available for combustion plant configurations that include **CO_2 Capture** with an Auxiliary Natural Gas Boiler or In-Furnace **NO_x**

Control with Gas Reburn and is accessed by selecting 4. Aux. Gas from the Fuel Screen of the Set Parameters Tab



Fuel – Auxiliary Natural Gas input screen.

The **Natural Gas** input screen displays and allows the user to update the fuel properties of Natural Gas.

Higher Heating Value: Higher heating value (HHV) is the thermal energy produced in Btu/lb of fuel from completely burning the fuel to produce carbon dioxide and liquid water. The latent heat of condensation is included in the value. This value is calculated from the natural gas composition below and cannot be changed by the user.

Natural Gas Composition

Methane (CH4): The volume, by percent, of methane in the natural gas.

Ethane (C2H6): The volume, by percent, of ethane in the natural gas.

Propane (C3H8): The volume, by percent, of propane in the natural gas.

Carbon Dioxide (CO2): The volume, by percent, of carbon dioxide in the natural gas.

Oxygen (O2): The volume, by percent, of oxygen in the natural gas.

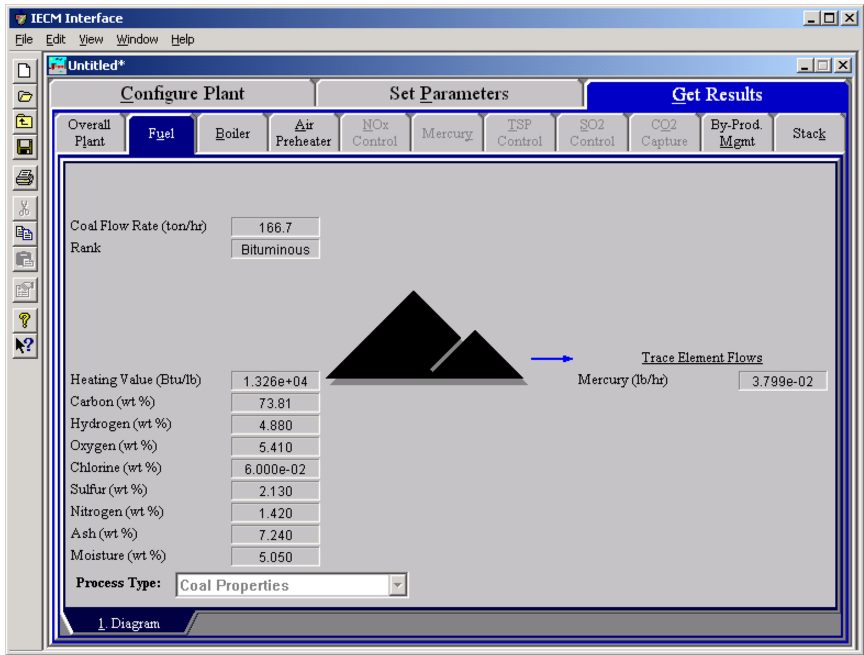
Nitrogen (N2): The volume, by percent, of nitrogen in the natural gas.

Hydrogen Sulfide (H2S): The volume, by percent, of hydrogen sulfide in the natural gas.

Natural Gas Density: The natural gas density is a weighted average of the individual densities of the natural gas constituents. This value is used in many unit conversion operations.

Fuel Coal Diagram

The **Fuel** Technology Navigation Tab in the **Get Results** program area contains the **Diagram** result screen. It displays the properties set up in the Fuel Properties input screens of the of the **Set Parameters** program area.



Fuel — Diagram result screen for coal.

The **Coal Diagram** result screen displays fuel composition and flow rate information, which is described briefly below.

Coal Flow Rate: Coal flow rate into the boiler on a wet basis. Waste products removed prior to the burners are not considered here.

Rank: The rank of the coal based on the higher heating value. This is primarily determined by the higher heating value and to a lesser degree by the sulfur and ash content.

Heating Value: Higher heating value (HHV) is the thermal energy produced in Btu/lb of fuel (wet) from completely burning the fuel to produce carbon dioxide and liquid water. The latent heat of condensation is included in the value.

Carbon: The carbon content of the coal by weight on an elemental and wet basis.

Hydrogen: The hydrogen content of the coal by weight on an elemental (H) and wet basis.

Oxygen: The oxygen content of the coal by weight on an elemental (O) and wet basis.

Chlorine: The chlorine content of the coal by weight on an elemental (Cl) and wet basis.

Sulfur: The sulfur content of the coal by weight on an elemental (S) and wet basis.

Nitrogen: The nitrogen content of the coal by weight on an elemental (N) and wet basis.

Ash: The ash content of the coal by weight on a wet basis.

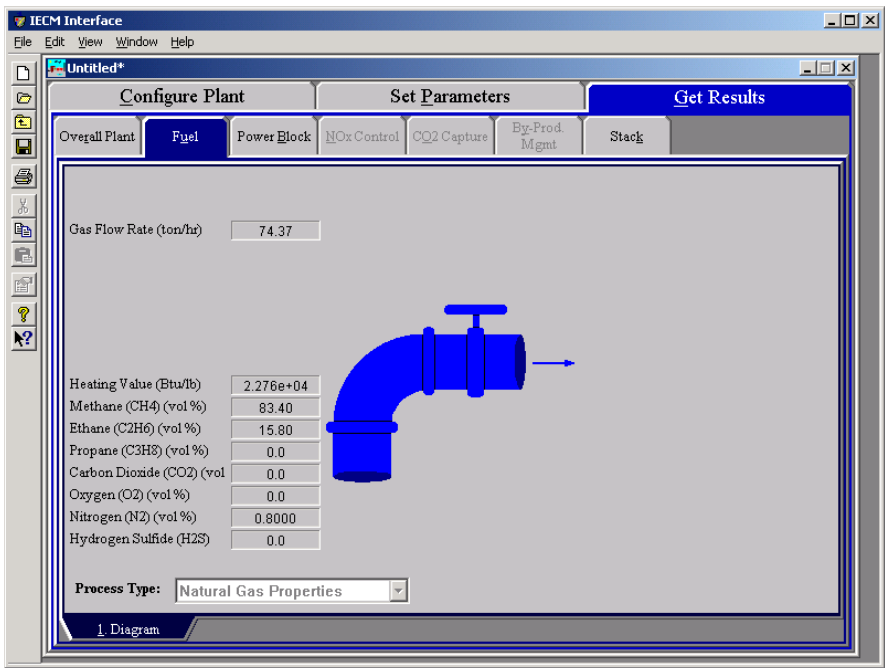
Moisture: The inherent moisture content of the coal by weight.

Trace Element Flows

Trace elements are now supported in the IECM. The mass flow rate is reported in units of pounds per unit of time. All values reflect the elemental mass flow rate.

Mercury: This is the elemental mercury flow rate in coal. At present, mercury is not tracked in the IGCC plant type and is displayed as a zero value.

Fuel Natural Gas Diagram



Fuel – Diagram result screen for natural gas.

The **Natural Gas Diagram** result screen displays fuel composition and flow rate information, which is described briefly below.

Gas Flow Rate: The natural gas flow rate to the turbine.

Heating Value: Higher heating value (HHV) is the thermal energy produced in Btu/lb of fuel.

Methane (CH_4): The volume, by percent, of methane in the natural gas.

Ethane (C_2H_6): The volume, by percent, of ethane in the natural gas.

Propane (C_3H_8): The volume, by percent, of propane in the natural gas.

Carbon Dioxide (CO_2): The volume, by percent, of carbon dioxide in the natural gas.

Oxygen (O_2): The volume, by percent, of oxygen in the natural gas.

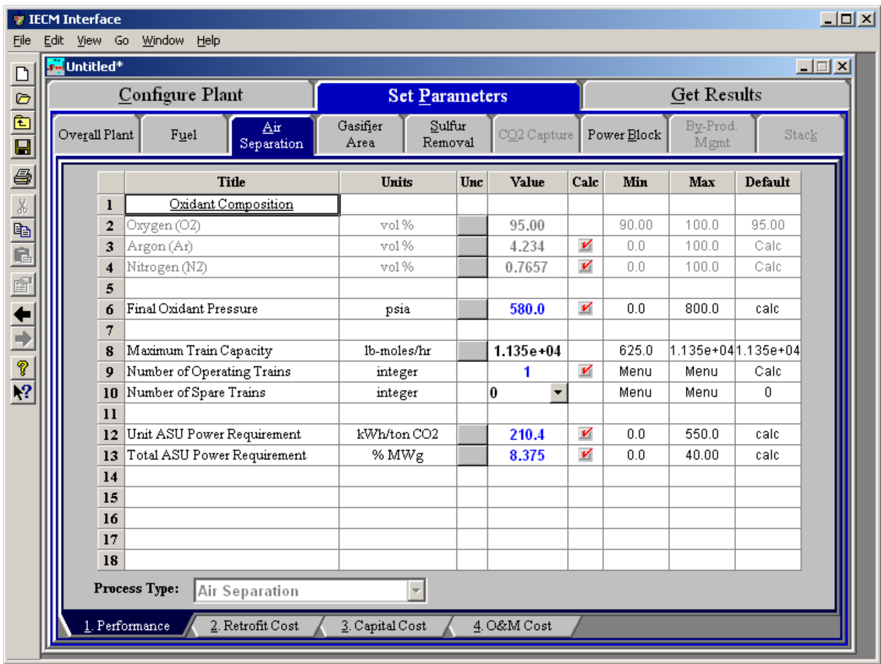
Nitrogen (N_2): The volume, by percent, of nitrogen in the natural gas.

Hydrogen Sulfide (H_2S): The volume, by percent, of hydrogen sulfide in the natural gas.

Air Separation

This chapter illustrates the configuration, inputs and results of the air separation technology. It is presently used only for the IGCC plant configurations.

Air Separation Performance Inputs



Air Separation – Performance input screen.

Oxidant Composition

Oxygen (O_2): This is the percent of oxygen that is in the oxidant that is produced by the air separation unit. The value is fixed for the IGCC plant type.

Argon (Ar): This is the percent of argon that is in the oxidant that is produced by the air separation unit.

Nitrogen (N_2): This is the percent of nitrogen that is in the oxidant that is produced by the air separation unit.

Final Oxidant Pressure: The final oxidant stream from the ASU can be provided at a high pressure. The default value is determined by the plant type being used.

Maximum Train Capacity: The maximum production rate of oxidant is specified here. It is used to determine the number of operating trains required.

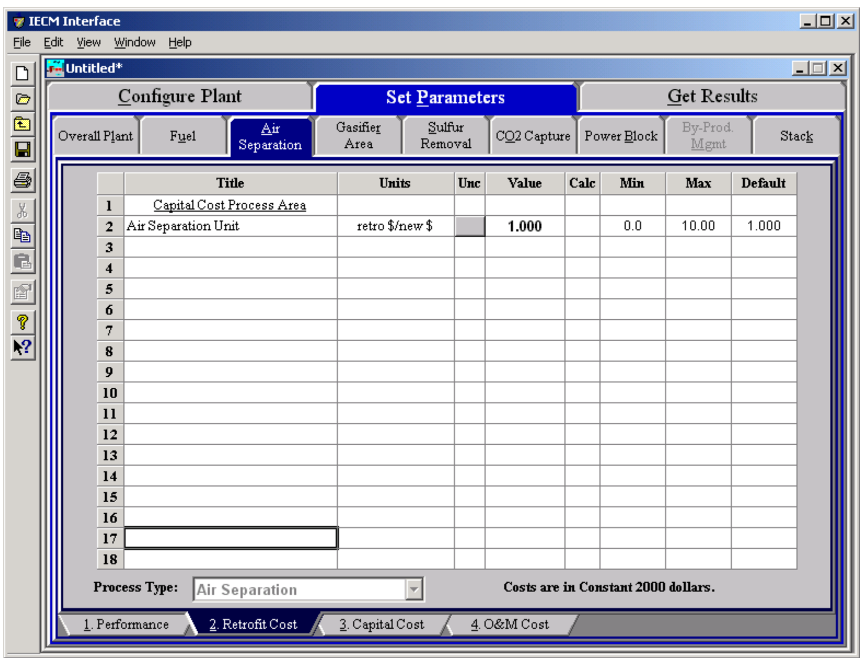
Number of Operating Trains: This is the total number of operating trains. It is used primarily to calculate capital costs. The value must be an integer

Number of Spare Trains: This is the total number of spare trains. It is used primarily to calculate capital costs. The value must be an integer.

Unit ASU Power Requirement: The main air compressor (MAC) pressurizes atmospheric air to approximately 550 kPA (65 psig), but is expressed as a function of the oxygen product required.

Total ASU Power Requirement: This is the electricity used by the air separation unit for internal use. A majority of the power is used for the main air compressor and a secondary amount used for the product stream compressor (if required). It is expressed as a percent of the gross plant capacity.

Air Separation Retrofit Cost Inputs

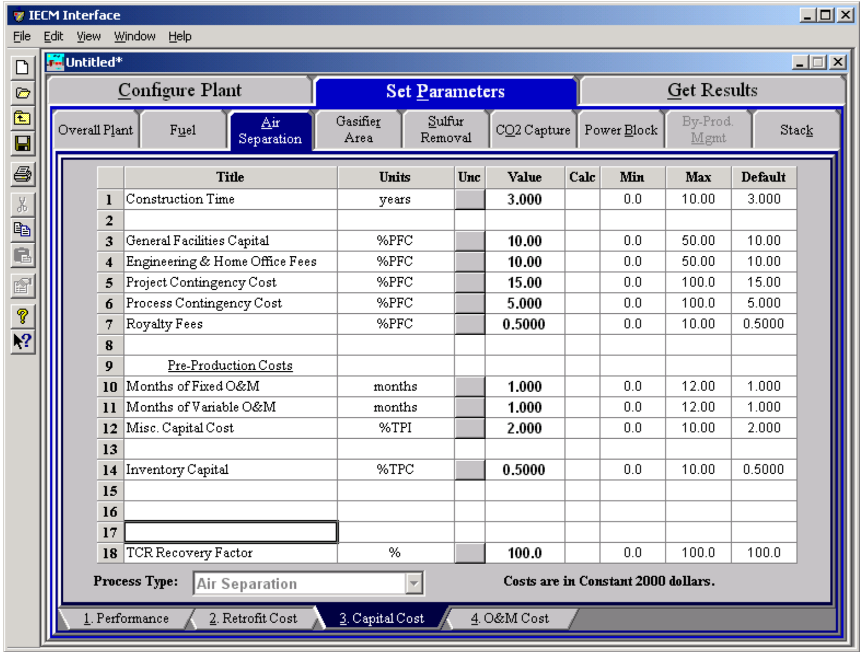


Air Separation – Retrofit Cost input screen.

Capital Cost Process Area

Air Separation Unit: The retrofit factor is a ratio of the costs of retrofitting an existing facility with an air separation unit versus a new facility, using the same equipment.

Air Separation Capital Cost Inputs



Air Separation – Capital Cost input screen.

Inputs for capital costs are entered on the **Capital Cost** input screen.

Construction Time: This is the idealized construction period in years. It is used to determine the allowance for funds used during construction (AFUDC).

General Facilities Capital (GFC): 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%.

Engineering & Home Office Fees: The engineering & home office fees are a percent of total direct capital cost. This is an overhead fee paid to the architect/engineering company. These fees typically range from 7-15%.

Project Contingency Cost: This is 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.

Process Contingency Cost: 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.

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

Pre-Production Costs: 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 applied to the O&M costs over a specified period of time (months). The two time periods for fixed and variable

O&M costs are described below with the addition of a miscellaneous capital cost factor.

- **Months of Fixed O&M:** Time period of fixed operating costs used for preproduction to cover training, testing, major changes in equipment, and inefficiencies in start-up. This includes operating, maintenance, administrative and support labor. It also considers maintenance materials.

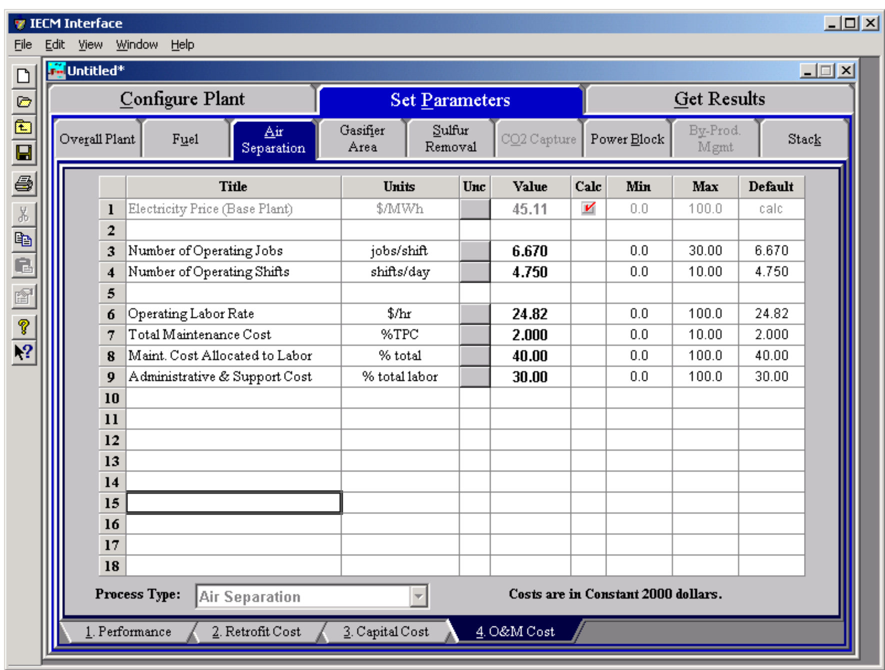
- **Months of Variable O&M:** Time period of variable operating costs used for preproduction to cover chemicals, water, consumables, and solid disposal charges in start-up, assuming 100% load. This excludes any fuels.

- **Misc. Capital Cost:** This is a percent of total plant investment (sum of TPC and AFUDC) to cover expected changes to equipment to bring the system up to full capacity.

Inventory Capital: Percent of the total direct capital for raw material supply based on 100% capacity during a 60 day period. These materials are considered storage. The inventory capital includes fuels, consumables, by-products, and spare parts. This is typically 0.5%.

TCR Recovery Factor: The actual total capital required (TCR) as a percent of the TCR in a new power plant. This value is 100% for a new installation and may be set as low as 0% for a fabric filter that has been paid off.

Air Separation O&M Cost Inputs



Air Separation – O&M Cost input screen.

Inputs for O&M costs are entered on the **Air Separation O&M Cost** input screen. O&M costs are typically expressed on an average annual basis and are provided in either constant or current dollars for a specified year, as shown on the bottom of the screen.

Electricity Price (Base Plant): This is the price of electricity and is calculated as a function of the utility cost of the base plant, where the base plant for the IGCC Model is an air separation unit, gasifier and the power block

Number of Operating Jobs: This is the total number of operating jobs that are required to operate the plant per eight-hour shift.

Number of Operating Shifts: This is the total number of equivalent operating shifts in the plant per day. The number takes into consideration paid time off and weekend work (3 shifts/day * 7 days/5 day week * 52 weeks/(52 weeks - 6 weeks PTO) = 4.75 equiv. Shifts/day)

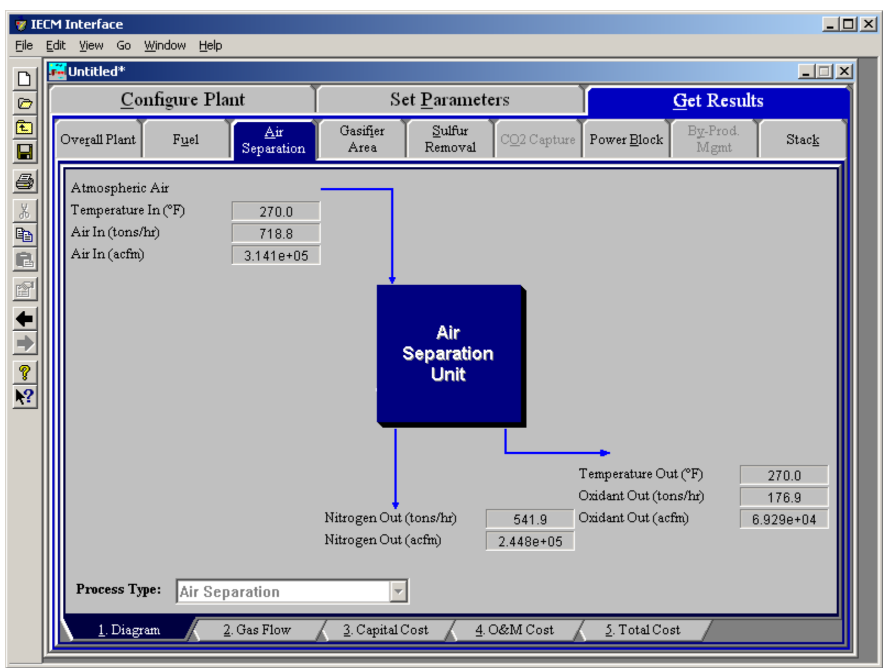
Operating Labor Rate: The hourly cost of labor is specified in the base plant O&M cost screen. The same value is used throughout the other technologies.

Total Maintenance Cost: This is the annual maintenance cost as a percentage of the total plant cost. Maintenance cost estimates can be developed separately for each process area.

Maint. Cost Allocated to Labor: Maintenance cost allocated to labor as a percentage of the total maintenance cost.

Administrative & Support Cost: This is the percent of the total operating and maintenance labor associated with administrative and support labor.

Air Separation Diagram



Air Separation – Diagram result screen.

The **Air Separation Diagram** result screen displays an icon for the Air Separation Unit and values for major flows in and out of it. Each result is described briefly below in flow:

Atmospheric Air Temperature In: Temperature of the atmospheric air entering the air separation unit.

Atmospheric Air In: Mass flow rate of air entering the air separation unit, based on the atmospheric air temperature and atmospheric pressure.

Atmospheric Air In: Volumetric flow rate of air entering the air separation unit, based on the atmospheric air temperature and atmospheric pressure.

Nitrogen Out: Mass flow rate of the nitrogen exiting the Air Separation Unit.

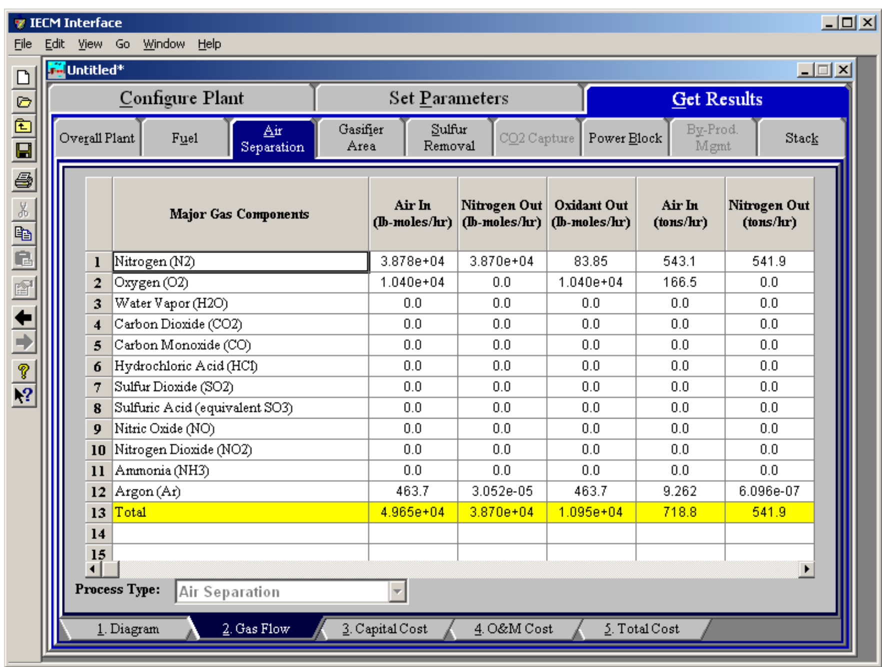
Nitrogen Out: Volumetric flow rate of the nitrogen exiting the Air Separation Unit.

Temperature Out: Temperature of the oxidant exiting the Air Separation Unit.

Oxidant Out: Mass flow rate of the oxidant exiting the Air Separation Unit.

Oxidant Out: Volumetric flow rate of the oxidant exiting the Air Separation Unit.

Air Separation Gas Flow Results



	Major Gas Components	Air In (lb-moles/hr)	Nitrogen Out (lb-moles/hr)	Oxidant Out (lb-moles/hr)	Air In (tons/hr)	Nitrogen Out (tons/hr)
1	Nitrogen (N2)	3.878e+04	3.870e+04	83.85	543.1	541.9
2	Oxygen (O2)	1.040e+04	0.0	1.040e+04	166.5	0.0
3	Water Vapor (H2O)	0.0	0.0	0.0	0.0	0.0
4	Carbon Dioxide (CO2)	0.0	0.0	0.0	0.0	0.0
5	Carbon Monoxide (CO)	0.0	0.0	0.0	0.0	0.0
6	Hydrochloric Acid (HCl)	0.0	0.0	0.0	0.0	0.0
7	Sulfur Dioxide (SO2)	0.0	0.0	0.0	0.0	0.0
8	Sulfuric Acid (equivalent SO3)	0.0	0.0	0.0	0.0	0.0
9	Nitric Oxide (NO)	0.0	0.0	0.0	0.0	0.0
10	Nitrogen Dioxide (NO2)	0.0	0.0	0.0	0.0	0.0
11	Ammonia (NH3)	0.0	0.0	0.0	0.0	0.0
12	Argon (Ar)	463.7	3.052e-05	463.7	9.262	6.096e-07
13	Total	4.965e+04	3.870e+04	1.095e+04	718.8	541.9
14						
15						

Air Separation – Gas Flow result screen.

Each result is described briefly below.

Nitrogen (N_2): Total mass of nitrogen.

Oxygen (O_2): Total mass of oxygen.

Water Vapor (H_2O): Total mass of water vapor.

Carbon Dioxide (CO_2): Total mass of carbon dioxide.

Carbon Monoxide (CO): Total mass of carbon monoxide.

Hydrochloric Acid (HCl): Total mass of hydrochloric acid.

Sulfur Dioxide (SO_2): Total mass of sulfur dioxide.

Sulfuric Acid (equivalent SO_3): Total mass of sulfuric acid.

Nitric Oxide (NO): Total mass of nitric oxide.

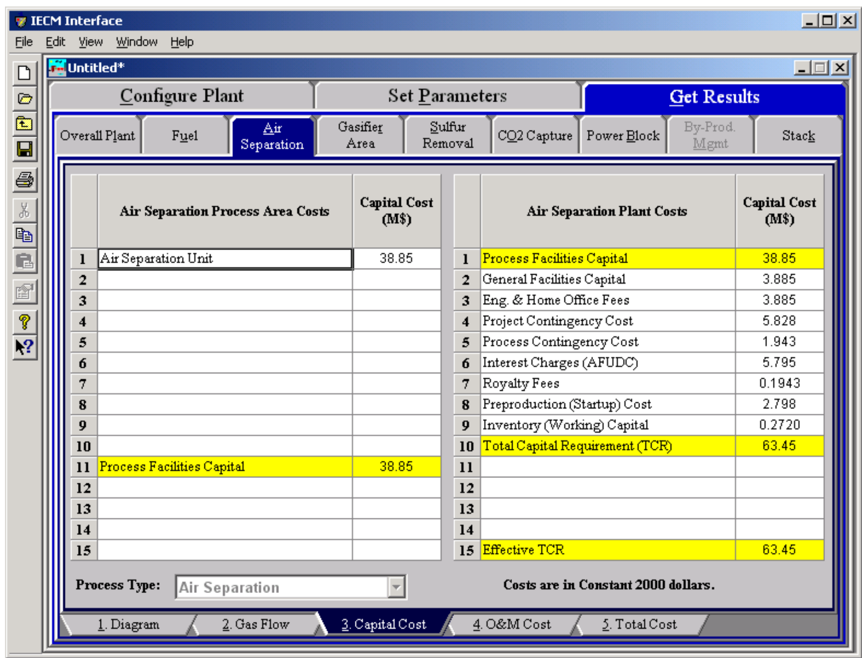
Nitrogen Dioxide (NO_2): Total mass of nitrogen dioxide.

Ammonia (NH_3): Total mass of ammonia.

Argon (Ar): Total mass of argon.

Total: Total of the individual components listed above. This item is highlighted in yellow.

Air Separation Capital Cost Results



Air Separation Capital Cost results screen.

The **Air Separation Capital Cost** result screen displays tables for the capital costs. Capital costs are typically expressed in either constant or current dollars for a specified year, as shown on the bottom of the screen. Each result is described briefly below:

Air Separation Process Area Costs

Air Separation Unit: The cost of oxygen plants depends mostly on the oxygen feed rate to the gasifier, because size and cost of compressors and air separation systems are proportional to this flow rate. The number of trains is determined based on the total mass flow rate of oxygen. The minimum number of operating trains is two

Process Facilities Capital: The process facilities capital is the total constructed cost of all on-site processing and generating units listed above, including all direct and indirect construction costs. All sales taxes and freight costs are included where applicable implicitly. This result is highlighted in yellow.

Air Separation Plant Costs

Process Facilities Capital: (see definition above)

General Facilities Capital: The general facilities include construction costs of roads, office buildings, shops, laboratories, etc. Sales taxes and freight costs are included implicitly.

Eng. & Home Office Fees: The engineering & home office fees are a percent of total direct capital cost. This is an overhead fee paid to the architect/engineering company.

Project Contingency Cost: Capital cost contingency factor covering the cost of additional equipment or other costs that would result from a more detailed design of a definitive project at the actual site.

Process Contingency Cost: Capital cost contingency factor applied to a new technology in an effort to quantify the uncertainty in the technical performance and cost of the commercial-scale equipment.

Interest Charges (AFUDC): Allowance for funds used during construction, also referred to as interest during construction, is the time value of the money used during construction and is based on an interest rate equal to the before-tax weighted cost of capital. This interest is compounded on an annual basis (end of year) during the construction period for all funds spent during the year or previous years.

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

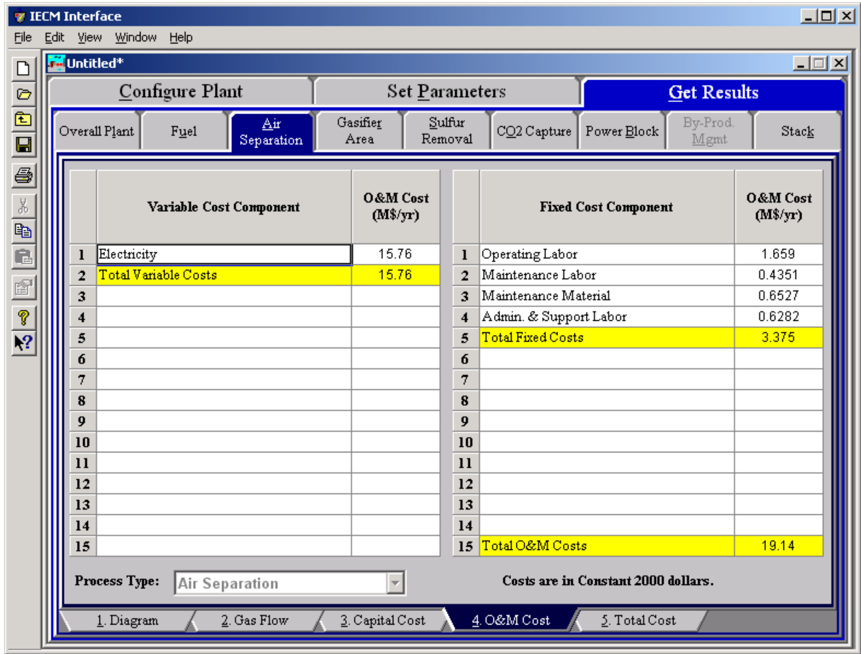
Preproduction (Startup) Cost: These costs consider the operator training, equipment checkout, major changes in unit equipment, extra maintenance, and inefficient use of fuel or other materials during start-up.

Inventory (Working) Capital: The raw material supply based on 100% capacity during a 60 day period. These materials are considered storage. The inventory capital includes fuels, consumables, by-products, and spare parts.

Total Capital Requirement (TCR): Money that is placed (capitalized) on the books of the utility on the service date. TCR includes all the items above. This result is highlighted in yellow.

Effective TCR: The TCR of the spray dryer that is used in determining the total power plant cost. The effective TCR is determined by the “TCR Recovery Factor”.

Air Separation O&M Cost Results



Air Separation – O&M Cost results screen.

O&M costs are typically expressed on an average annual basis and are provided in either constant or current dollars for a specified year, as shown on the bottom of the screen.

Variable Cost Component

Electricity: The cost of electricity consumed by the Air Separation System.

Total Variable Costs: This is the sum of all the variable O&M costs listed above. This result is highlighted in yellow.

Fixed Cost Components

Fixed operating costs are essentially independent of actual capacity factor, number of hours of operation, or amount of kilowatts produced. All the costs are subject to inflation.

Operating Labor: Operating labor cost is based on the operating labor rate, the number of personnel required to operate the plant per eight-hour shift, and the average number of shifts per day over 40 hours per week and 52 weeks.

Maintenance Labor: The maintenance labor is determined as a fraction of the total maintenance cost.

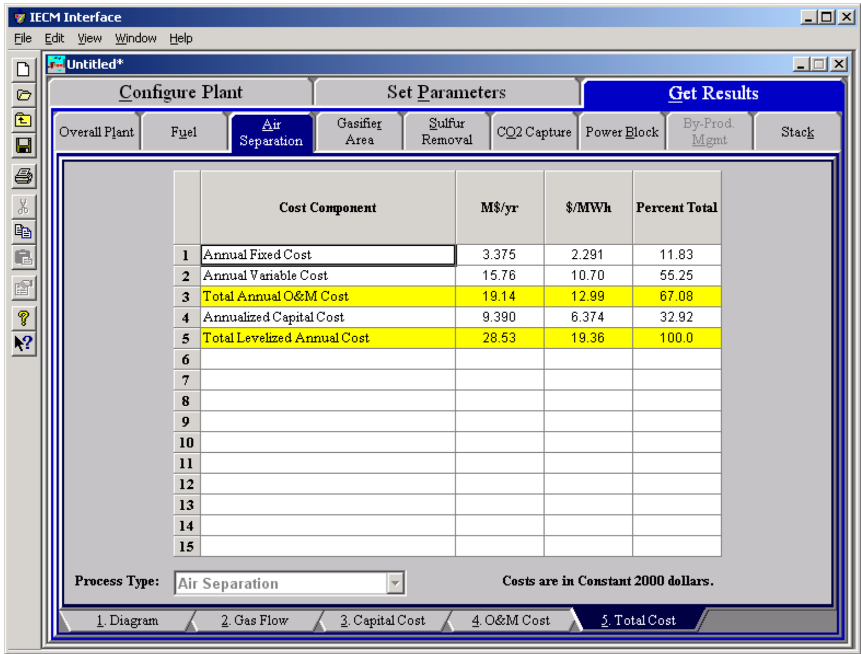
Maintenance Material: The cost of maintenance material is the remainder of the total maintenance cost, considering the fraction associated with maintenance labor.

Admin. & Support Labor: The administrative and support labor is the only overhead charge. It is taken as a fraction of the total operating and maintenance labor costs.

Total Fixed Costs: This is the sum of all the fixed O&M costs listed above. This result is highlighted in yellow.

Total O&M Costs: This is the sum of the total variable and total fixed O&M costs. It is used to determine the base plant total revenue requirement. This result is highlighted in yellow.

Air Separation Total Cost Results



Air Separation – Total Cost results screen.

The **Total Cost** result screen displays a table which totals the annual fixed, variable, operations and maintenance, and capital costs associated with the **Air Separation Unit**. Each result is described briefly below.

Cost Component

Annual Fixed Cost: The operating and maintenance fixed costs are given as an annual total. This number includes all maintenance materials and all labor costs.

Annual Variable Cost: The operating and maintenance variables costs are given as an annual total. This includes all reagent, chemical, steam, and power costs.

Total Annual O&M Cost: This is the sum of the annual fixed and variable operating and maintenance costs above. This result is highlighted in yellow.

Annualized Capital Cost: This is the total capital cost expressed on an annualized basis, taking into consideration the levelized carrying charge factor, or fixed charge factor, over the entire book life.

Total Levelized Annual Cost: The total annual cost is the sum of the total annual O&M cost and annualized capital cost items above. This result is highlighted in yellow.

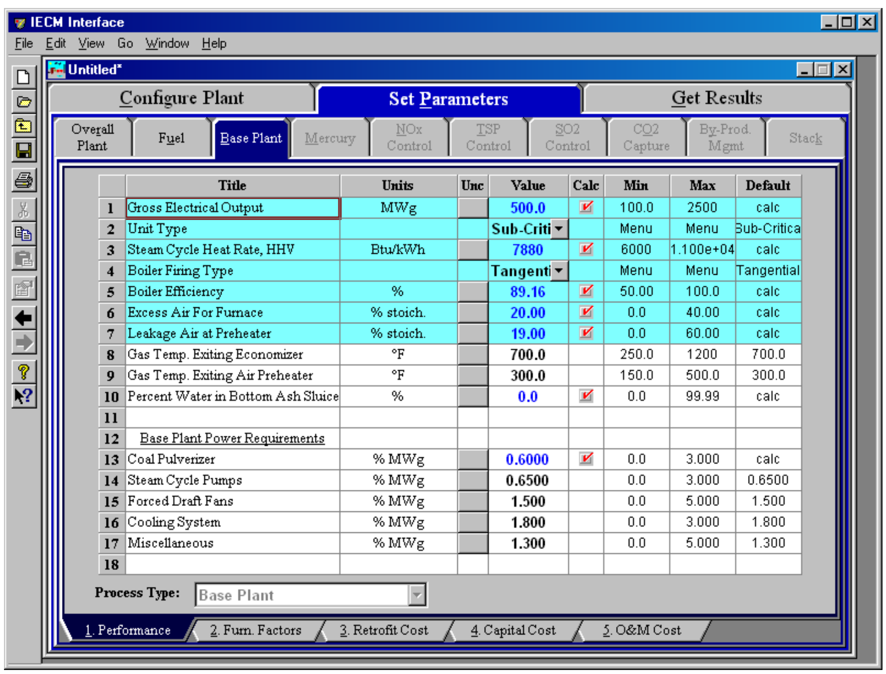
Base Plant

The **Base Plant** Technology Navigation Tab screens display and define the performance and costs directly associated with the combustion power plant, particularly the boiler. Pre-combustion and post-combustion control technologies are not considered part of the Base Plant.

The screens described in this chapter all apply to the **Combustion (Boiler)** plant type.

Base Plant Performance Inputs

Inputs for the major flow rates and concentrations of the gas and solids streams are entered on the **Performance** input screen



	Title	Units	Unc	Value	Calc	Min	Max	Default
1	Gross Electrical Output	MWg		500.0	✓	100.0	2500	calc
2	Unit Type			Sub-Criti		Menu	Menu	Sub-Critica
3	Steam Cycle Heat Rate, HHV	Btu/kWh		7880	✓	6000	1.100e+04	calc
4	Boiler Firing Type			Tangenti		Menu	Menu	Tangential
5	Boiler Efficiency	%		89.16	✓	50.00	100.0	calc
6	Excess Air For Furnace	% stoich.		20.00	✓	0.0	40.00	calc
7	Leakage Air at Preheater	% stoich.		19.00	✓	0.0	60.00	calc
8	Gas Temp. Exiting Economizer	°F		700.0		250.0	1200	700.0
9	Gas Temp. Exiting Air Preheater	°F		300.0		150.0	500.0	300.0
10	Percent Water in Bottom Ash Sluice	%		0.0	✓	0.0	99.99	calc
11								
12	Base Plant Power Requirements							
13	Coal Pulverizer	% MWg		0.6000	✓	0.0	3.000	calc
14	Steam Cycle Pumps	% MWg		0.6500		0.0	3.000	0.6500
15	Forced Draft Fans	% MWg		1.500		0.0	5.000	1.500
16	Cooling System	% MWg		1.800		0.0	3.000	1.800
17	Miscellaneous	% MWg		1.300		0.0	5.000	1.300
18								

Base Plant—Performance input screen.

The first six inputs are highlighted in blue. Each parameter is described briefly below.

Gross Electrical Output: This is the gross output of the generator in megawatts (MW_g). The value does not include auxiliary power requirements. The model uses this information to calculate key mass flow rates.

Unit Type: This is the type of steam turbine system being used. The possible selections are: Sub-Critical, Super-Critical, and Ultra-Supercritical. This selection determines the steam cycle heat rate default value.

Steam Cycle Heat Rate: This is the gross amount of energy in steam needed to produce a kilowatt-hour (kWh) of electricity at the generator. This variable does not consider auxiliary power requirements. This heat rate, plus the boiler efficiency, is used to figure out the overall plant performance (i.e., the gross cycle heat rate).

Boiler Firing Type: Combination boilers are most often represented by three types: wall, tangential, and cyclone. The 'wall' category is the most general and represents variations such as opposed, top, cell, and others. The solution of boiler type affects the boiler efficiency and furnace emission factors.

Boiler Efficiency: This is the percentage of fuel input energy transferred to steam in the boiler. The model default is to calculate the boiler efficiency using standard algorithms described in the literature. The efficiency is a function of energy losses due to inefficient heat transfer across the preheater, latent heat of evaporation, incomplete combustion, radiation losses, and unaccounted losses.

Excess Air for Furnace: This is the excess theoretical air used for combustion. It is added to the stoichiometric air requirement calculated by the model. The value is calculated and based on the fuel type and boiler type.

Leakage Air at Preheater: This is the additional excess air introduced because of leakage into the system at or beyond the air preheater. It is based on the stoichiometric air required for combustion. The leakage air increases the total gas volume downstream of the air preheater.

Gas Temperature Exiting Economizer: This is the temperature of the flue gas exiting the economizer. The temperature is used in the calculation of the flue gas volume and air preheater performance.

Gas Temperature Exiting Air Preheater: This is the temperature of the flue gas exiting the air preheater. The temperature is used in the calculation of the flue gas volume and air preheater performance.

Percent Water in Bottom Ash Sluice: Bottom ash collected can be removed from the combustion bolier and disposed by sluicing the bottom ash with water. This is the percent water in the sluice.

Base Plant Power Requirements

These parameters specify the electrical power requirements of pulverizers, steam pumps, forced draft fans, cooling system equipment (fans and pumps), and other miscellaneous equipment excluding gas cleanup systems. These power requirements or penalties are expressed as a percent of a gross plant capacity and are used to calculate the net plant performance.

Coal Pulverizer: This is the power needed to run the coal pulverizers prior to the coal being blown into the boiler. It is also referred to as an energy penalty to the base plant. The value is calculated and based on the fuel type. It is expressed as a percentage of the gross plant capacity.

Steam Cycle Pumps: This is the power needed to operate the pumps in the steam cycle. It is also referred to as an energy penalty to the base plant. It is expressed as a percentage of the gross plant capacity.

Forced Draft Fans: This is the power required for the forced draft fans and primary air fan expressed as a percentage of the gross plant capacity. It is also referred to as an energy penalty for the base plant.

Cooling System: This is the power needed to run the pumps and other equipment for the water cooling system. It is expressed as a percentage of the gross plant capacity. It is also referred to as a base plant energy penalty.

Miscellaneous: This is the power used by any other miscellaneous equipment in the base plant, not including equipment used for pollution control equipment. It is expressed as a percentage of the gross plant capacity. It is also referred to as a base plant energy penalty.

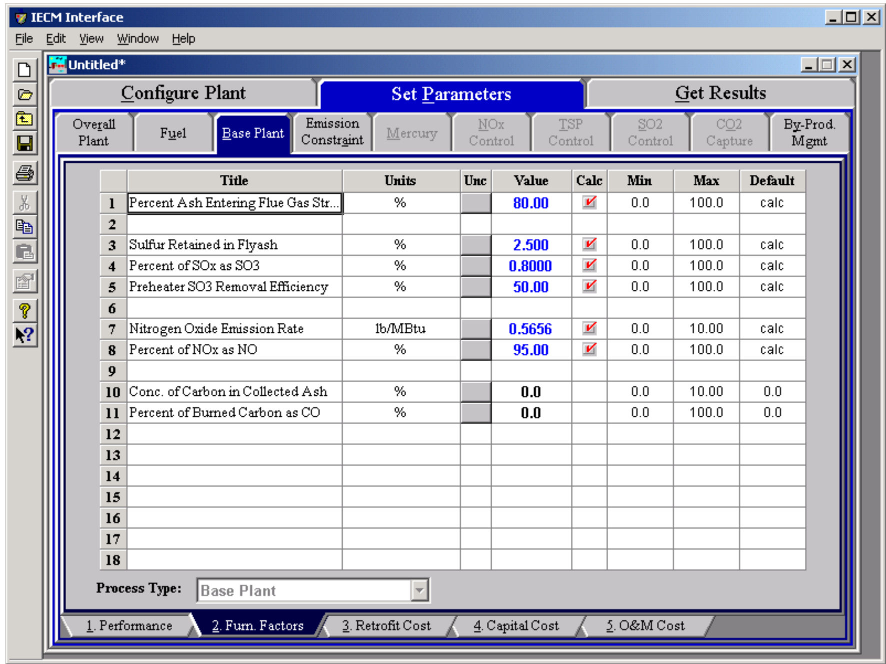
Base Plant Furnace Factors Inputs

Inputs for the furnace factors that effect the major flow rates and concentrations of the gas and solids streams are entered on the **Furnace Factors** input screen.

This screen accepts inputs for the flue gas and ash products emitted from the boiler into the flue gas and ash streams. Factors in emissions include: incomplete combustion and thermodynamic equilibrium between gas species associated with the combustion products.

This screen's inputs are needed to calculate boiler efficiency and air pollutant emissions. The emission of carbon, ash, sulfur and nitrogen are specified by the United States Government's Environmental Protection Agency's (EPA) compilation of emission factors. Also included from the compilation are the incomplete transfer percentages of solid and gaseous forms of these substances.

This screen is available for all plant configurations.



Base Plant – Furn. Factors input screen.

Each parameter is described briefly below:

Percent Ash Entering Flue Gas Stream: The default values for this parameter are a function of the fuel and boiler types and are based on the AP-42 EPA emission factors. Ash not entering the flue gas stream is assumed to be removed as bottom ash. This is also referred to as the overhead ash fraction.

Sulfur Retained in Flyash: This parameter gives the percent of total sulfur input to the boiler that is retained in the flyash stream of a coal-fired power plant. The default values are a function of the selected boiler type and the coal rank as specified by the AP-42 EPA compilation of emission factors.

Percent of SO_x as SO_3: This parameter quantifies the sulfur species in the flue gas stream. Sulfur not converted to SO_2 is assumed to be converted to SO_3. The default value is based on emission factors derived by Southern Company[3] and are a function of the selected coal.

Preheater SO_3 Removal Efficiency: Sulfuric acid (H_2SO_4) is created downstream of the boiler by the reaction of SO_3 with H_2O. A percent of the sulfuric acid is condensed on particulates in the preheater and removed from the flue gas. This parameter specifies the amount of SO_3 removed from the flue gas in the preheater as a function of the coal rank. The default value is taken from the removal efficiency reported in the literature (references are below). This efficiency then determines the mass of SO_3 removed from the flue gas in the collector. For more information see also:

- www.netl.doe.gov/publications/proceedings/98/98fg/hardman.pdf
- www.netl.doe.gov/publications/proceedings/98/98fg/rubin.pdf

[3] Hardman, R., R. Stacy, et al. (1998). Estimating Total Sulfuric Acid Emissions from Coal-FIred Power Plants, Southern Company Services.

Nitrogen Oxide Emission Rate: This parameter establishes the level of NO_x emissions from the boiler. The default values reflect the AP-42 EPA emission factors. It is a function of boiler firing method and the coal rank. The model calculates this value and expresses it in pounds of equivalent NO_2 per ton of coal.

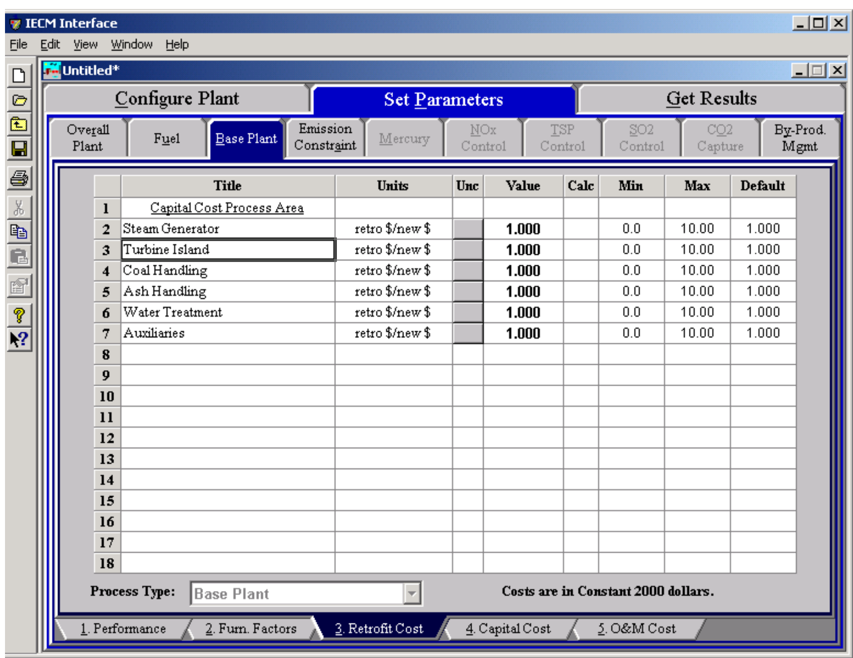
Percent of NO_x as NO: This parameter establishes the level of nitric oxide (NO) in the flue gas stream. The remainder of the total NO_x emissions is assumed to be nitrogen dioxide (NO_2). The default parameters reflect the AP-42 EPA emission factors and are dependent on the fuel type.

Conc. of Carbon in Collected Ash: This parameter accounts for retention of carbon in the fly ash and bottom ash. The amount of carbon in the collected ash streams is typically known. It is used to calculate the total unburned carbon in coal, boiler efficiency and flue gas composition.

Percent of Burned Carbon as CO: This parameter accounts for any incomplete combustion in the furnace, and is used to calculate boiler efficiency and flue gas composition. The remainder is assumed to be CO_2 or unburned carbon.

Base Plant Retrofit Cost Inputs

Inputs for the capital costs of modifications to process areas of the base plant itself are entered on the **Retrofit Cost** input screen



Base Plant—Retrofit Cost input screen.

The retrofit cost factor of each process is a multiplicative cost adjustment, which considers the cost of retrofitted capital equipment relative to similar equipment installed in a new plant. These factors affect the capital costs directly and the operating and maintenance costs indirectly.

Direct capital costs for each process area are calculated in the IECM. These calculations are reduced form equations derived from more sophisticated models and reports. The sum of the direct capital costs associated with each process area is defined as the process facilities capital (PFC). The retrofit cost factor provided for each of the process areas can be used as a tool for adjusting the anticipated costs and uncertainties across the process area separate from the other areas.

Uncertainty can be applied to the retrofit cost factor for each process area in each technology. Thus, uncertainty can be applied as a general factor across an entire process area, rather than as a specific uncertainty for the particular cost on the capital or O&M input screens. Any uncertainty applied to a process area through the retrofit cost factor compounds any uncertainties specified later in the capital and O&M cost input parameter screens.

Each **Capital Cost Process Area** is described briefly below.

Steam Generator: This area accounts for the steam cycle equipment and pumps.

Turbine Island: This area accounts for the turbine island and associated pumps.

Coal Handling: This area accounts for the mechanical collection and transport equipment of coal in the plant.

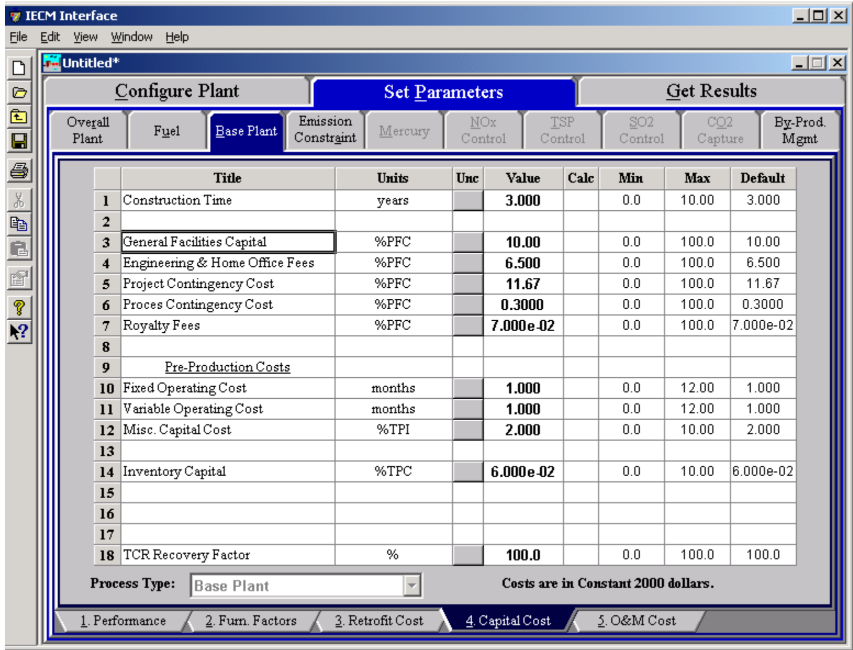
Ash Handling: This area accounts for the mechanical collection and transport of ash in the plant.

Water Treatment: This area accounts for the pumps, tanks, and transport equipment used for water treatment.

Auxiliaries: Any miscellaneous auxiliary equipment is treated in this process area.

Base Plant Capital Cost Inputs

Inputs for the capital costs of the Combustion (Boiler) base plant itself are entered on the **Capital Cost** input screen.



Base Plant—Capital Cost input screen

The necessary capital cost input parameters associated with the base plant are on this input screen. The capital cost parameters and terminology used in the IECM are based on the methodologies developed by the Electric Power Research Institute (EPRI). They have prepared a Technical Assessment Guide (TAG) in order to provide a consistent basis for reporting cost and revenues associated with the electric power industry. This system of reporting is used by a wide audience, including energy engineers, researchers, planners, and managers. The IECM has been developed around this TAG system so that costs associated with various technologies can be compared directly on a consistent basis and communicated in the language used by the audience listed above.

Construction Time: This is the idealized construction period in years. It is used to determine the allowance for funds used during construction (AFUDC).

General Facilities Capital (GFC): 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%.

Engineering & Home Office Fees: The engineering & home office fees are a percent of total direct capital cost. This is an overhead fee paid to the architect/engineering company. These fees typically range from 7-15%.

Project Contingency Cost: This is 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.

Process Contingency Cost: 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.

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

Pre-Production Costs

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 applied to O&M costs over a specified period of time (months).

Fixed Operating Cost: Time period of fixed operating costs (operating and maintenance labor, administrative and support labor, and maintenance materials) used for plant startup.

Variable Operating Cost: Time period of variable operating costs at full capacity (chemicals, water, and other consumables, and waste disposal changes) used for plant startup. Full capacity estimates of the variable operating costs will assume operations at 100% load.

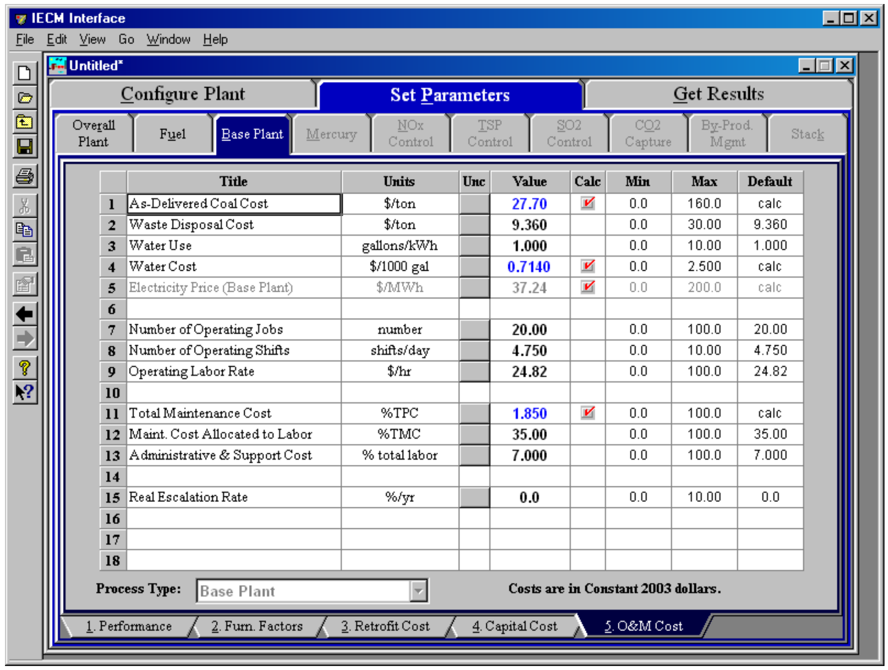
Misc. Capital Cost: This is a percent of total plant investment (sum of TPC and AFUDC) to cover expected changes to equipment to bring the system up to full capacity.

Inventory Capital: Percent of the total direct capital for raw material supply based on 100% capacity during a 60 day period. These materials are considered storage. The inventory capital includes fuels, consumables, by-products, and spare parts. This is typically 0.5%.

TCR Recovery Factor: The actual total capital required (TCR) to finance the base plant as a percent of the TCR of a new power plant. This value is 100% for a new plant and may be set as low as 0% for a base plant that has been paid off.

Base Plant O&M Cost Inputs

Inputs for the operation and maintenance costs of the Combustion (Boiler) base plant itself are entered on the **O&M Cost** input screen.



Base Plant—O&M Cost input screen

The EPRI TAG method of categorization has been used for operating and maintenance costs screens. It provides a consistent basis of reporting for a wider audience of users.

O&M costs are expressed on an average annual basis and are provided in either constant or current dollars for a specified year, as shown on the bottom of the screen. The costs are broken down into two categories: variable and fixed. Variable costs include the costs of reagents, chemicals, water, and other materials consumed during plant operation. Fixed costs are associated with labor and overhead charges. All operating costs are subject to inflation.

The base plant considers a more detailed breakdown for the costs associated with the fuel. Together they characterize the fuel costs. Each parameter is described briefly below.

As-Delivered Coal Cost: This is the cost of the delivered coal in dollars per wet ton. The value is calculated by the IECM from the particular regional coal selected. It does not include any cleaning costs.

Waste Disposal Cost: This is the bottom ash disposal cost for the base plant.

Water Use: This is the water used by the base plant.

Water Cost: This is the water cost as used for the base plant.

Electricity Price (Base Plant): This is the price of electricity and is calculated as a function of the utility cost of the base plant, where the base plant is defined as combustion boiler and an air preheater.

Number of Operating Jobs: This is the total number of operating jobs that are required to operate the plant per eight-hour shift.

Number of Operating Shifts: This is the total number of equivalent operating shifts in the plant per day. The number takes into consideration paid time off and weekend work (3 shifts/day * 7 days/5 day week * 52 weeks/(52 weeks - 6 weeks PTO) = 4.75 equiv. Shifts/day)

Operating Labor Rate: The hourly cost of labor is specified in the base plant O&M cost screen. The same value is used throughout the other technologies.

Total Maintenance Cost: This is the annual maintenance cost as a percentage of the total plant cost. Maintenance cost estimates can be developed separately for each process area.

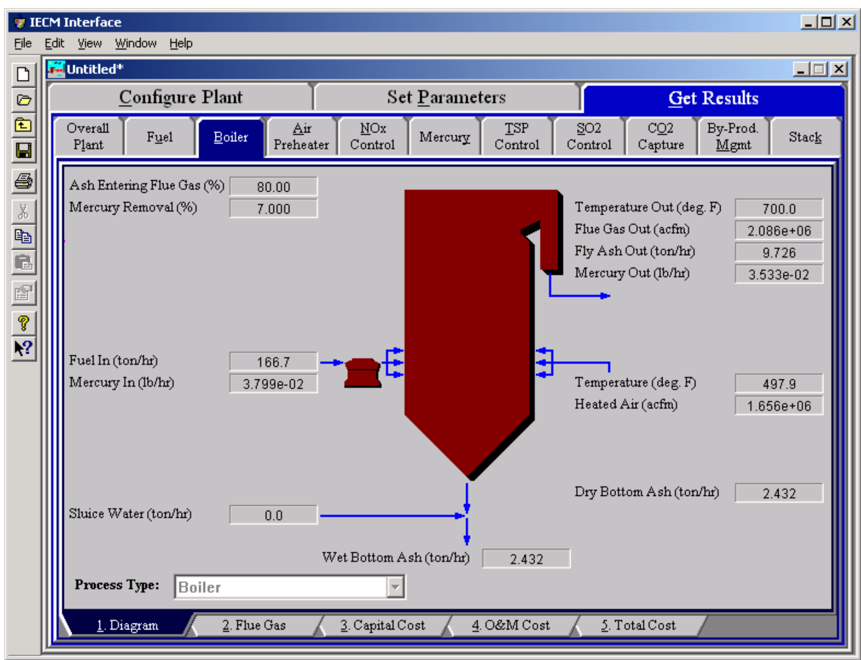
Maint. Cost Allocated to Labor: Maintenance cost allocated to labor as a percentage of the total maintenance cost.

Administrative & Support Cost: This is the percent of the total operating and maintenance labor associated with administrative and support labor.

Real Escalation Rate: This is the annual rate of increase of an expenditure due to factors such as resource depletion, increased demand, and improvements in design, manufacturing or construction techniques (negative rate). The real escalation rate does not include inflation.

Boiler Diagram

The **Diagram** result screen displays an icon for the Combustion Boiler and values for major flows in and out of it.



Boiler—Diagram result screen.

Each result is described briefly below in flow order (not from top to bottom and left to right as they display on the screen).

Fuel Entering Boiler

Wet Fuel In: Fuel flow rate into the boiler on a wet basis. Waste products removed prior to the burners are not considered here.

Mercury In: This is the mass flow rate of total mercury entering the boiler. The mass reflects the molecular weight of elemental mercury.

Boiler Performance

Ash Entering Flue Gas: Percent of the ash in coal exiting the boiler in the flue gas.

Mercury Removal: Percent of the total mercury in coal removed from the boiler in the bottom ash.

Air Entering Boiler

Temperature: Heated air temperature measured at the burners. This is generally determined by the combustion air temperature exiting the air preheater.

Heated Air: Volumetric flow rate of the air at the burners, based on the air temperature at the burners and atmospheric pressure.

Flue Gas Exiting the Economizer

Temperature Out: Temperature of the flue gas at the exit of the economizer.

Flue Gas Out: Volumetric flow rate of the flue gas at the exit of the economizer, based on the temperature at the exit of the economizer and atmospheric pressure.

Fly Ash Out: Total solids mass flow rate in the flue gas at the exit of the economizer. This includes ash, unburned carbon and unburned sulfur.

Mercury Out: Total mass of mercury exiting the economizer. The value is a sum of all the forms of mercury (elemental, oxidized, and particulate).

Bottom Ash

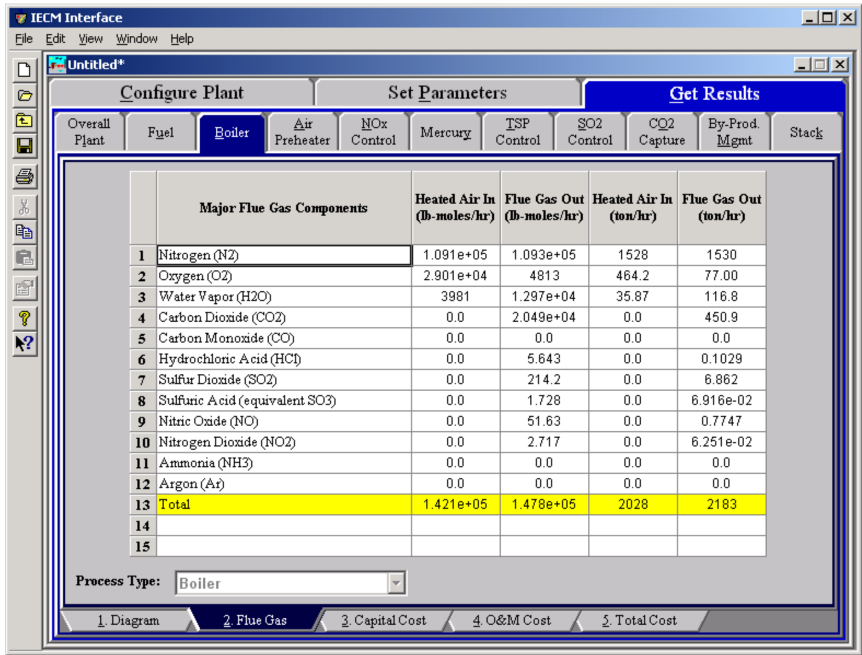
Sluice Water: Water added to the dry bottom ash. This water is added for transportation purposes.

Dry Bottom Ash: Total solids mass flow rate of the bottom ash. This includes ash, unburned carbon and unburned sulfur. The value is given on a dry basis.

Wet Bottom Ash: Total solids mass flow rate of the bottom ash for waste management. This includes dry bottom ash and sluice water. The value is given on a wet basis.

Boiler Flue Gas Results

The **Flue Gas** result screen displays a table of quantities of flue gas components entering the combustion boiler in heated air and exiting the boiler in the flue gas. For each component, quantities are given in both moles and mass per hour.



Boiler— Flue Gas result screen.

Each result is described briefly below.

Nitrogen (N_2): Total mass of nitrogen.

Oxygen (O_2): Total mass of oxygen.

Water Vapor (H_2O): Total mass of water vapor.

Carbon Dioxide (CO_2): Total mass of carbon dioxide.

Carbon Monoxide (CO): Total mass of carbon monoxide.

Hydrochloric Acid (HCl): Total mass of hydrochloric acid.

Sulfur Dioxide (SO_2): Total mass of sulfur dioxide.

Sulfuric Acid (equivalent SO_3): Total mass of sulfuric acid.

Nitric Oxide (NO): Total mass of nitric oxide.

Nitrogen Dioxide (NO_2): Total mass of nitrogen dioxide.

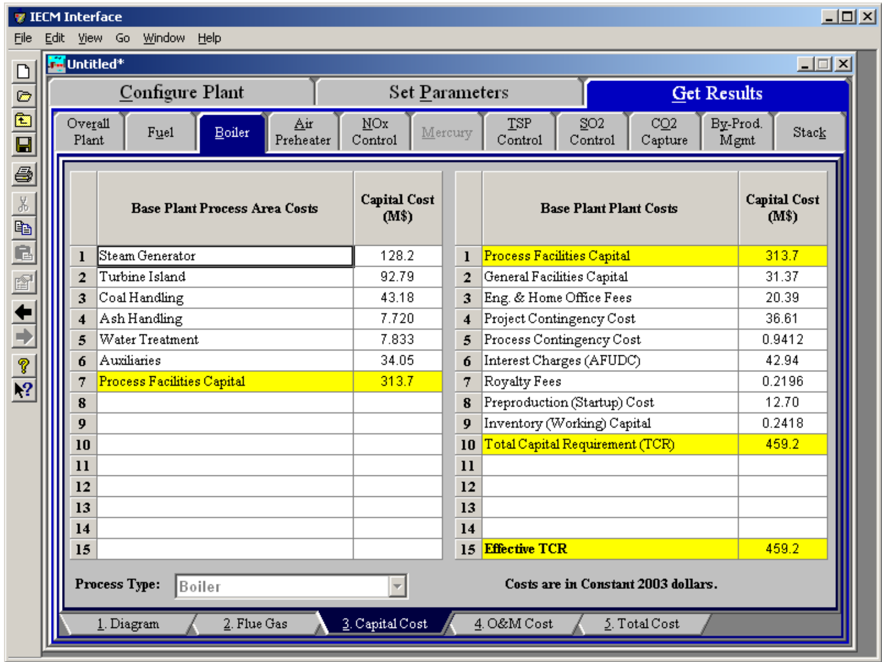
Ammonia (NH_3): Total mass of ammonia.

Argon (Ar): Total mass of argon.

Total: Total of the individual components listed above. This item is highlighted in yellow.

Boiler Capital Cost Results

The **Capital Cost** result screen displays tables for the direct and indirect capital costs related to the Combustion Boiler.



Boiler—Capital Cost result screen.

Capital costs are typically expressed in either constant or current dollars for a specified year, as shown on the bottom of the screen. Each result is described briefly below.

Direct Capital Costs

The direct capital costs described here apply to the "base power plant" without any of the environmental control options that are separately modeled in the IECM. While the purpose of the IECM is to model the cost and performance of emission control systems, costs for the base plant are also needed to properly account for pre-combustion control options that increase the cost of fuel, and affect the characteristics or performance of the base plant. Base plant costs are also needed to calculate the internal cost of electricity which determines pollution control energy costs.

Each process area direct capital cost is a reduced-form model based on regression analysis of data collected from several reports and analyses. They are described in general below. The primary factors in the model that effect the capital cost of the base plant are the plant size, the coal rank, and the geographic location of the plant.

Steam Generator: This area accounts for the steam cycle equipment and pumps.

Turbine Island: This area accounts for the turbine island and associated pumps.

Coal Handling: This area accounts for the mechanical collection and transport equipment of coal in the plant.

Ash Handling: This area accounts for the mechanical collection and transport of ash in the plant.

Water Treatment: This area accounts for the pumps, tanks, and transport equipment used for water treatment.

Auxiliaries: Any miscellaneous auxiliary equipment is treated in this process area.

Process Facilities Capital: The process facilities capital is the total constructed cost of all on-site processing and generating units listed above, including all direct and indirect construction costs. All sales taxes and freight costs are included where applicable implicitly. This result is highlighted in yellow.

Total Capital Costs

Process Facilities Capital: See definition above. This result is highlighted in yellow.

General Facilities Capital: The general facilities include construction costs of roads, office buildings, shops, laboratories, etc. Sales taxes and freight costs are included implicitly.

Eng. & Home Office Fees: The engineering & home office fees are a percent of total direct capital cost. This is an overhead fee paid to the architect/engineering company.

Project Contingency Cost: Capital cost contingency factor covering the cost of additional equipment or other costs that would result from a more detailed design of a definitive project at the actual site.

Process Contingency Cost: Capital cost contingency factor applied to a new technology in an effort to quantify the uncertainty in the technical performance and cost of the commercial-scale equipment.

Interest Charges (AFUDC): Allowance for funds used during construction, also referred to as interest during construction, is the time value of the money used during construction and is based on an interest rate equal to the before-tax weighted cost of capital. This interest is compounded on an annual basis (end of year) during the construction period for all funds spent during the year or previous years.

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

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.

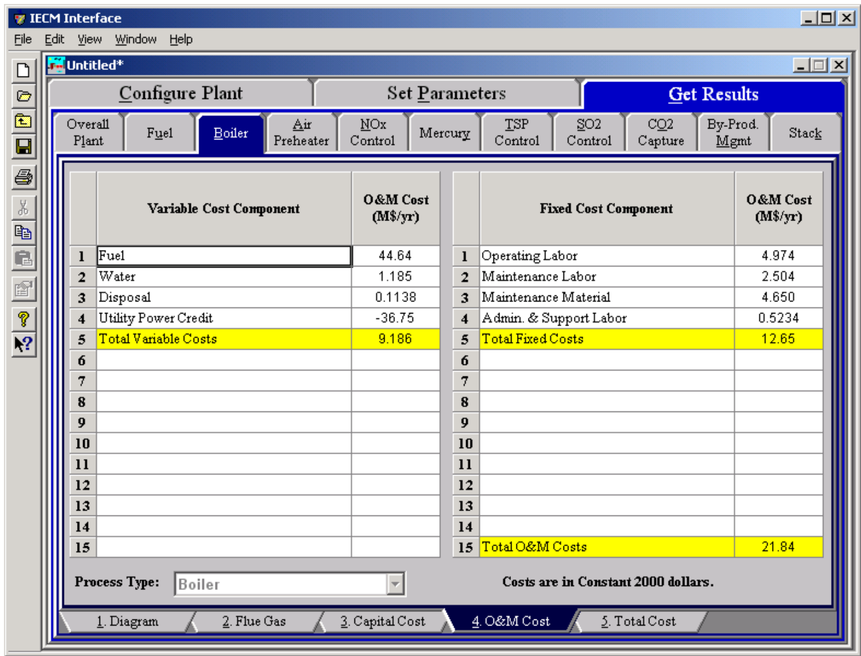
Inventory (Working) Capital: The raw material supply based on 100% capacity during a 60 day period. These materials are considered storage. The inventory capital includes fuels, consumables, by-products, and spare parts.

Total Capital Requirement (TCR): Money that is placed (capitalized) on the books of the utility on the service date. TCR includes all the items above. This result is highlighted in yellow.

Effective TCR: The TCR of the base plant that is used in determining the total power plant cost. The effective TCR is determined by the "TCR Recovery Factor" for the base plant.

Boiler O&M Cost Results

The **O&M Cost** result screen displays tables for the variable and fixed operation and maintenance costs involved with the combustion base plant. The variable O&M costs are calculated from the variable costs for fuel, water consumption and bottom ash disposal (from the furnace). The fixed O&M costs are based on maintenance and labor costs.



The Boiler—O&M Cost result screen.

O&M costs are typically expressed on an average annual basis and are provided in either constant or current dollars for a specified year, as shown on the bottom of the screen. Each result is described briefly below.

Variable Cost Components

Variable operating costs and consumables are directly proportional to the amount of kilowatts produced and are referred to as incremental costs. All the costs are subject to inflation.

Fuel: The total cost of as-fired fuel. Minemouth cost, coal cleaning costs and transportation costs are all included.

Water: The total cost of water consumed by the base plant for direct or reheat use.

Disposal: The total cost of bottom ash disposal. The value is given on a wet ash basis. This does not consider by-product ash sold in commerce.

Utility Power Credit: Power consumed by abatement technologies result in lower net power produced and lost revenue. The IECM charges each technology for the internal use of electricity and treats the charge as a credit for the base plant. When comparing individual components of the plant, these utility charges are taken into consideration. For total plant costs they balance out and have no net effect on the plant O&M costs.

Total Variable Costs: This is the sum of all the variable O&M costs listed above. This result is highlighted in yellow.

Fixed Cost Components

Fixed operating costs are essentially independent of actual capacity factor, number of hours of operation, or amount of kilowatts produced. All the costs are subject to inflation.

Operating Labor: Operating labor cost is based on the operating labor rate, the number of personnel required to operate the plant per eight-hour shift, and the average number of shifts per day over 40 hours per week and 52 weeks.

Maintenance Labor: The maintenance labor is determined as a fraction of the total maintenance cost.

Maintenance Material: The cost of maintenance material is the remainder of the total maintenance cost, considering the fraction associated with maintenance labor.

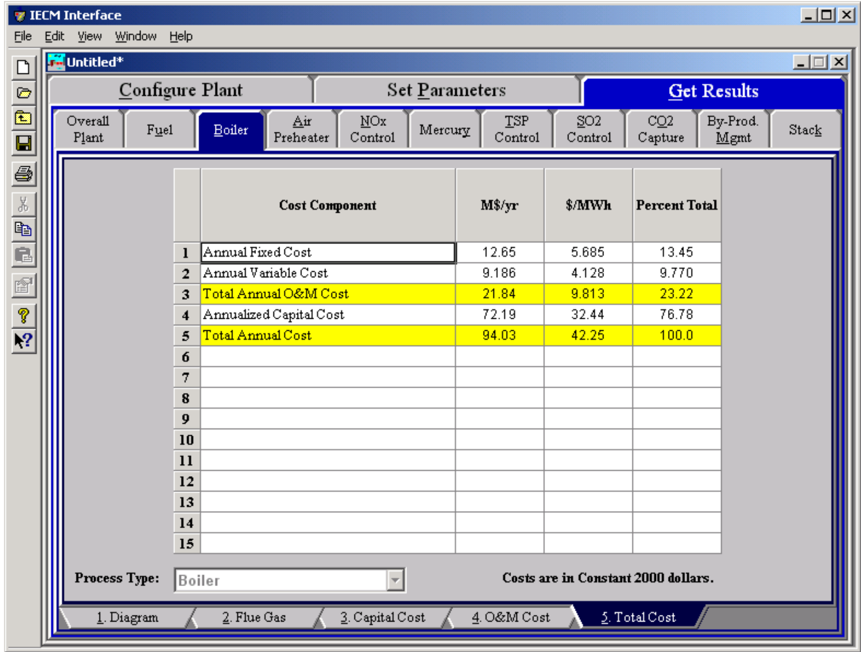
Admin. & Support Labor: The administrative and support labor is the only overhead charge. It is taken as a fraction of the total operating and maintenance labor costs.

Total Fixed Costs: This is the sum of all the fixed O&M costs listed above. This result is highlighted in yellow.

Total O&M Costs: This is the sum of the total variable and total fixed O&M costs. It is used to determine the base plant total revenue requirement. This result is highlighted in yellow.

Boiler Total Cost Results

The **Total Cost** result screen displays a table which totals the annual fixed, variable, operations and maintenance, and capital costs associated with the boiler.



Boiler—Total Cost result screen.

Cost Component

Total costs are typically expressed in either constant or current dollars for a specified year, as shown on the bottom of the screen. Each result is described briefly below.

Annual Fixed Cost: The operating and maintenance fixed costs are given as an annual total. This number includes all maintenance materials and all labor costs.

Annual Variable Cost: The operating and maintenance variables costs are given as an annual total. This includes all reagent, chemical, steam, and power costs.

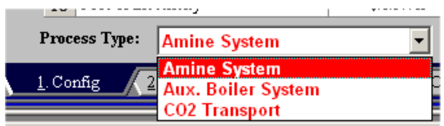
Total Annual O&M Cost: This is the sum of the annual fixed and variable operating and maintenance costs above. This result is highlighted in yellow.

Annualized Capital Cost: This is the total capital cost expressed on an annualized basis, taking into consideration the levelized carrying charge factor, or fixed charge factor, over the entire book life.

Total Annual Cost: The total annual cost is the sum of the total annual O&M cost and annualized capital cost items above. This result is highlighted in yellow.

Auxiliary Boiler

An **Auxiliary Boiler System** is available as an option from within the amine scrubber system. It is specified from the **Set Parameters** program area of the **CO2 Capture** configuration input screen using the **Process Type** pull-down menu at the bottom of the screen.

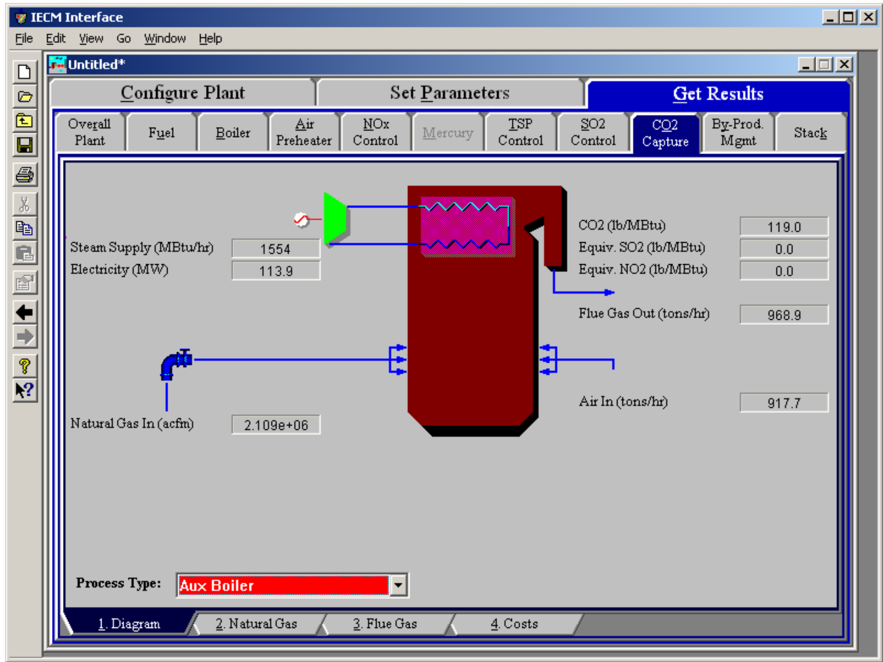


Auxiliary Boiler – Process Type

Input parameters are included as part of the amine system and not specified separately. Several performance result screens are provide separately for the auxiliary boiler system, but cost results are incorporated into the amine system. The following sections describe the results that are displayed explicitly for the auxiliary boiler system.

Auxiliary Boiler Diagram

The **Diagram** result screen displays an icon for the Auxiliary Boiler and values for major flows in and out of it. The auxiliary boiler is available in the **Combustion (Boiler)** and **Combustion (Turbine)** plant types when an amine scrubber is configured. It is a sub-system inside the amine scrubber when the auxiliary boiler option is added.



Auxiliary Boiler – Diagram.

Each result is described briefly below.

Air and Fuel

Air In: The mass flow rate of fresh air is provided. This is the stoichiometric amount of air and excess air as specified on the CO_2 Capture input screen.

Natural Gas In: This is the flow rate of natural gas necessary to provide the heat necessary to provide regeneration heat to the MEA regenerator.

Steam and Power Generation

Steam Supply: This is the total steam energy required by the CO_2 regenerator. The steam is supplied to the MEA regenerator.

Electricity: Low pressure steam generated by the auxiliary boiler may be used to generate electricity in a steam turbine. This electricity supplements that produced by the base plant.

Flue Gas Exiting Aux. Boiler System

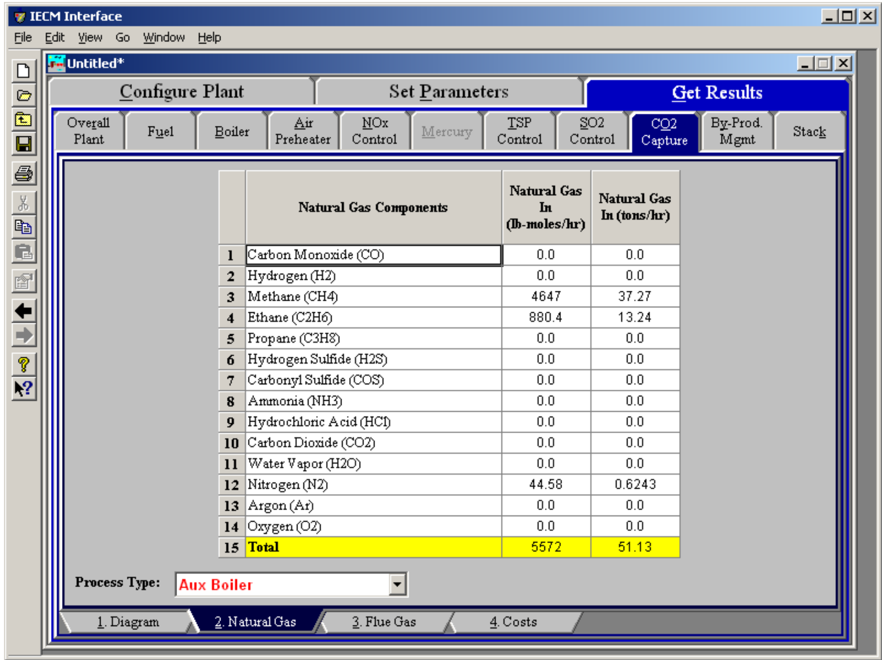
CO_2: This is the flow rate of emission dioxide from the auxiliary boiler. It is emitted from a secondary stack.

Equivalent SO_2: This is the emission rate of sulfur dioxide from the auxiliary boiler. It is emitted from a secondary stack.

Equivalent NO_2: This is the emission rate of nitrogen dioxide from the auxiliary boiler. It is emitted from a secondary stack.

Auxiliary Boiler Natural Gas Results

This screen is only available for the **Combustion (Boiler)** and **Combustion (Turbine)** plant types. It is a sub-system inside the amine scrubber when the auxiliary boiler option is added.



Auxiliary Boiler System – Natural Gas.

Natural Gas Components

The breakdown of components in the natural gas entering the auxiliary boiler are described briefly below:

Carbon Monoxide (CO): Total mass of carbon monoxide.

Hydrogen (H_2): Total mass of hydrogen.

Methane (CH_4): Total mass of methane.

Ethane (C_2H_6): Total mass of ethane.

Propane (C_3H_8): Total mass of propane.

Hydrogen Sulfide (H_2S): Total mass of hydrogen sulfide.

Carbonyl Sulfide (COS): Total mass of carbonyl sulfide.

Ammonia (NH_3): Total mass of ammonia.

Hydrochloric Acid (HCl): Total mass of hydrochloric acid.

Water Vapor (H_2O): Total mass of water vapor.

Carbon Dioxide (CO_2): Total mass of carbon dioxide.

Nitrogen (N_2): Total mass of nitrogen.

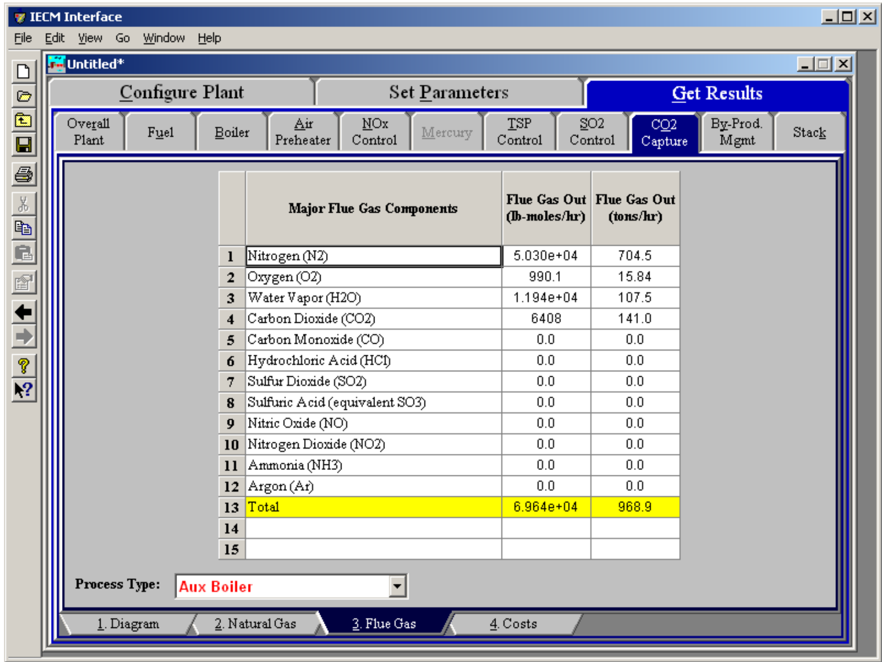
Argon (Ar): Total mass of argon.

Oxygen (O_2): Total mass of oxygen.

Total: Total of the individual components listed above. This item is highlighted in yellow.

Auxiliary Boiler Flue Gas Results

This screen is only available for the **Combustion (Boiler)** and **Combustion (Turbine)** plant types.



	Major Flue Gas Components	Flue Gas Out (lb-moles/hr)	Flue Gas Out (tons/hr)
1	Nitrogen (N2)	5.030e+04	704.5
2	Oxygen (O2)	990.1	15.84
3	Water Vapor (H2O)	1.194e+04	107.5
4	Carbon Dioxide (CO2)	6408	141.0
5	Carbon Monoxide (CO)	0.0	0.0
6	Hydrochloric Acid (HCl)	0.0	0.0
7	Sulfur Dioxide (SO2)	0.0	0.0
8	Sulfuric Acid (equivalent SO3)	0.0	0.0
9	Nitric Oxide (NO)	0.0	0.0
10	Nitrogen Dioxide (NO2)	0.0	0.0
11	Ammonia (NH3)	0.0	0.0
12	Argon (Ar)	0.0	0.0
13	Total	6.964e+04	968.9
14			
15			

Auxiliary Boiler System – Flue Gas result screen

Major Flue Gas Components

Natural gas fired in the auxiliary boiler produces a flue gas. This flue gas is emitted to the atmosphere via a secondary stack. Each component is described briefly below:

Nitrogen (N_2): Total mass of nitrogen.

Oxygen (O_2): Total mass of oxygen.

Water Vapor (H_2O): Total mass of water vapor.

Carbon Dioxide (CO_2): Total mass of carbon dioxide.

Carbon Monoxide (CO): Total mass of carbon monoxide.

Hydrochloric Acid (HCl): Total mass of hydrochloric acid.

Sulfur Dioxide (SO_2): Total mass of sulfur dioxide.

Sulfuric Acid (equivalent SO_3): Total mass of sulfuric acid.

Nitric Oxide (NO): Total mass of nitric oxide.

Nitrogen Dioxide (NO_2): Total mass of nitrogen dioxide.

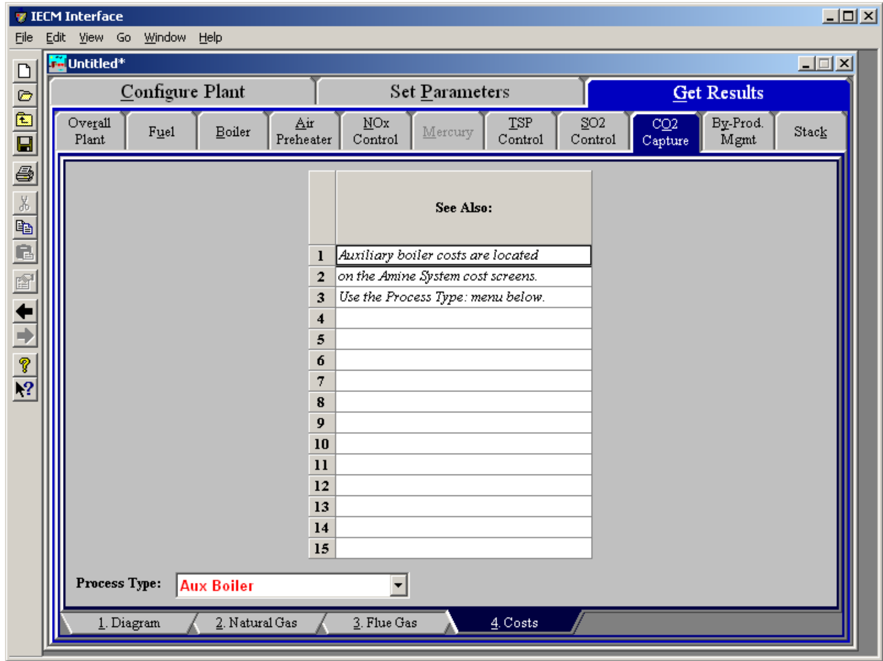
Ammonia (NH_3): Total mass of ammonia.

Argon (Ar): Total mass of argon.

Total: Total of the individual components listed above. This item is highlighted in yellow.

Auxiliary Boiler Costs Results

This screen is only available for the Combustion (Boiler) and Combustion (Turbine) plant types.



Amine System – Total Cost result screen.

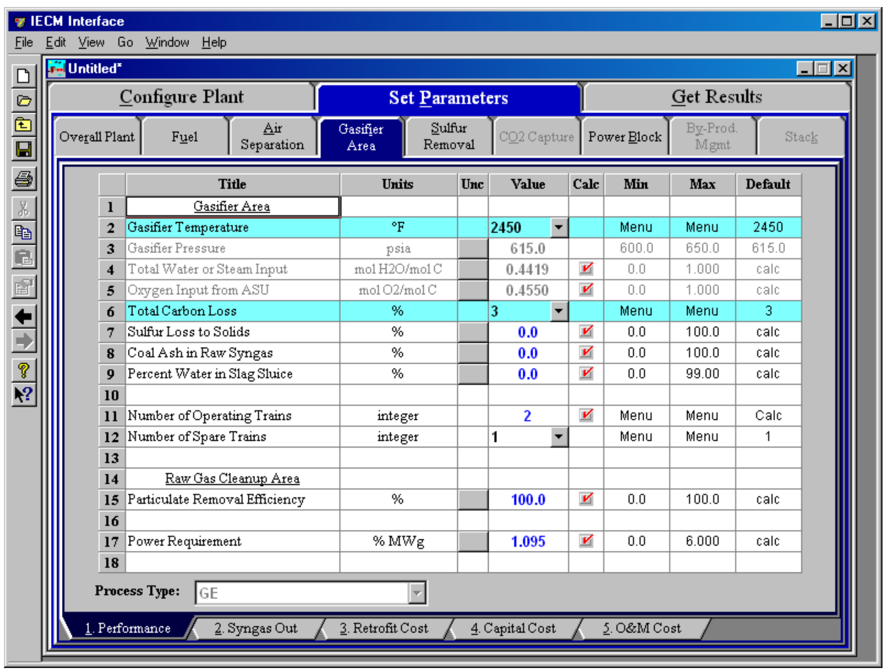
The **Costs** result screen displays a note, pointing the user to the amine system cost screens. Because the auxiliary boiler is a sub-system of the amine system, the costs associated with the **Auxiliary Boiler** are displayed by the **Amine System** cost screens. View these by selecting the **Amine System** from the **Process Type** menu on the bottom of the screen.

Gasifier

This gasifier chapter describes the coal gasification equipment used in the IGCC plant types.

Gasifier Performance Inputs

This screen is only available for the IGCC plant type.



Gasifier – Performance input screen.

Gasifier Area

Gasifier Temperature: This is the temperature of the syngas exiting GE Entrained-Flow Reactor.

Gasifier Pressure: This is the pressure of the syngas exiting GE Entrained-Flow Reactor.

Total Water-or-Steam Input: This is the ratio of water to carbon in the coal slurry.

Oxygen Input from ASU: The GE gasifier requires a constant value for the oxygen (O_2) in the oxidant to carbon (C) in coal ratio.

Total Carbon Loss: This the percent of carbon in the fuel that is lost.

Sulfur Loss to Solids: This is the percent of the sulfur in coal that is lost in the slag.

Coal Ash in Raw Syngas: This is the percent of ash in the coal that is in the syngas.

Percent Water in Slag Sluice: This is the percent of the slag sluice that is water.

Number of Operating Trains: This is the total number of operating trains. It is used primarily to calculate capital costs. The value must be an integer

Number of Spare Trains: This is the total number of spare trains. It is used primarily to calculate capital costs. The value must be an integer.

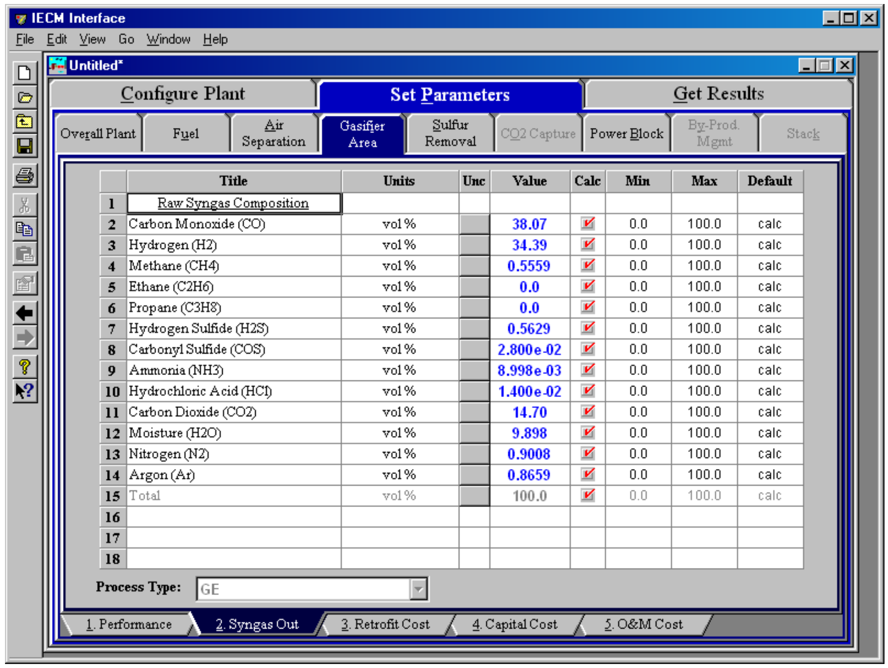
Raw Gas Cleanup Area

Fly Ash Removal Efficiency: This is the percentage of the ash which is removed by the raw gas cleanup process.

Power Requirement: This is the equivalent electrical output of thermal (steam) energy used for reheat, plus the actual electrical output power required.

Gasifier Syngas Inputs

The syngas generated by the gasifier is calculated as a function of the coal, water, and oxidant input flow rates, the carbon loss, and the gasifier temperature. The composition may be changed by the user. The location of this syngas composition is after the gasification but prior to the low temperature cooling and water quench. Hence, the steam content of the syngas is typically in the 10 – 15% by volume range. This screen is only available for the IGCC plant type.



	Title	Units	Unc	Value	Calc	Min	Max	Default
1	Raw Syngas Composition							
2	Carbon Monoxide (CO)	vol %		38.07		0.0	100.0	calc
3	Hydrogen (H2)	vol %		34.39		0.0	100.0	calc
4	Methane (CH4)	vol %		0.5559		0.0	100.0	calc
5	Ethane (C2H6)	vol %		0.0		0.0	100.0	calc
6	Propane (C3H8)	vol %		0.0		0.0	100.0	calc
7	Hydrogen Sulfide (H2S)	vol %		0.5629		0.0	100.0	calc
8	Carbonyl Sulfide (COS)	vol %		2.800e-02		0.0	100.0	calc
9	Ammonia (NH3)	vol %		8.998e-03		0.0	100.0	calc
10	Hydrochloric Acid (HCl)	vol %		1.400e-02		0.0	100.0	calc
11	Carbon Dioxide (CO2)	vol %		14.70		0.0	100.0	calc
12	Moisture (H2O)	vol %		9.898		0.0	100.0	calc
13	Nitrogen (N2)	vol %		0.9008		0.0	100.0	calc
14	Argon (Ar)	vol %		0.8659		0.0	100.0	calc
15	Total	vol %		100.0		0.0	100.0	calc
16								
17								
18								

Gasifier – Gas Flow result screen..

Raw Syngas Composition

Carbon Monoxide (CO): Total mass of carbon monoxide.

Hydrogen (H_2): Total mass of hydrogen.

Methane (CH_4): Total mass of methane.

Ethane (C_2H_6): Total mass of methane.

Propane (C_3H_8): Total mass of methane.

Hydrogen Sulfide (H_2S): Total mass of hydrogen sulfide.

Carbonyl Sulfide (COS): Total mass of carbonyl sulfide.

Ammonia (NH_3): Total mass of ammonia.

Hydrochloric Acid (HCl): Total mass of hydrochloric acid.

Carbon Dioxide (CO_2): Total mass of carbon dioxide.

Moisture (H_2O): Total mass of water vapor.

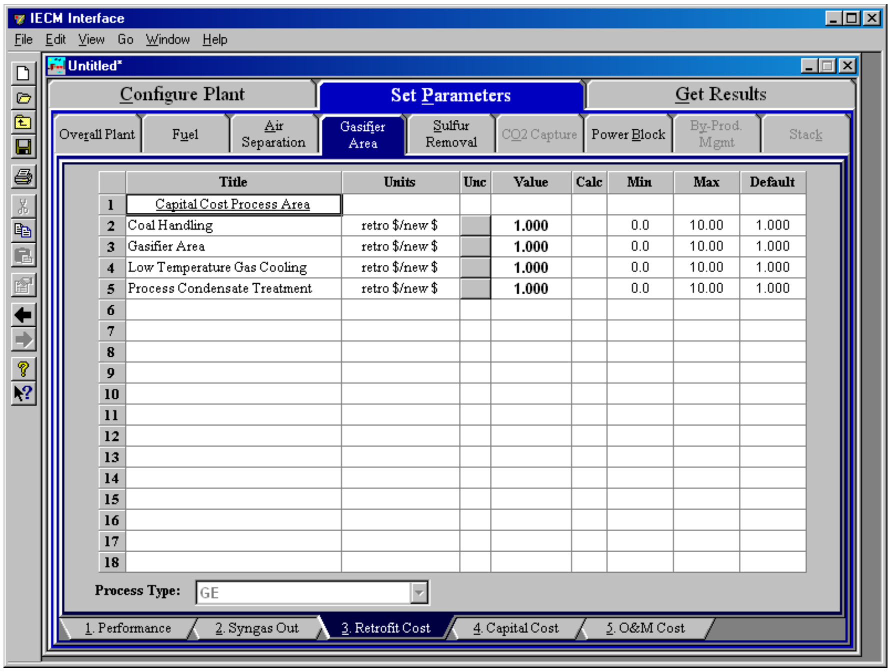
Nitrogen (N_2): Total mass of nitrogen.

Argon (Ar): Total mass of argon.

Total: Total of the individual components listed above. This item is highlighted in yellow.

Gasifier Retrofit Cost Inputs

This screen is only available for the IGCC plant type.



Gasifier – Retrofit Cost input screen.

Capital Cost Process Area

Coal Handling: Coal handling involves unloading coal from a train, storing the coal, moving the coal to the grinding mills, and feeding the gasifier with positive displacement pumps. A typical coal handling section contains one operating train and no spare train. A train consists of a bottom dump railroad car unloading hopper, vibrating feeders, conveyors, belt scale, magnetic separator, sampling system, deal coal storage, stacker, reclaimer, as well as some type of dust suppression system. Slurry preparation trains typically have one to five operating trains with one spare train. The typical train consists of vibrating feeders, conveyors, belt scale, rod mills, storage tanks, and positive displacement pimps to feed the gasifiers. All of the equipment for both the coal handling and the slurry feed are commercially available. A regression model was developed for the direct cost of coal handling and slurry preparation using the data collected for possible independent variables affecting direct capital cost. Coal feed rate to the gasifier on as-received basis is the most common and easily available independent variable. The direct cost model for the coal handling is based upon the overall flow to the plant rather than on a per train basis.

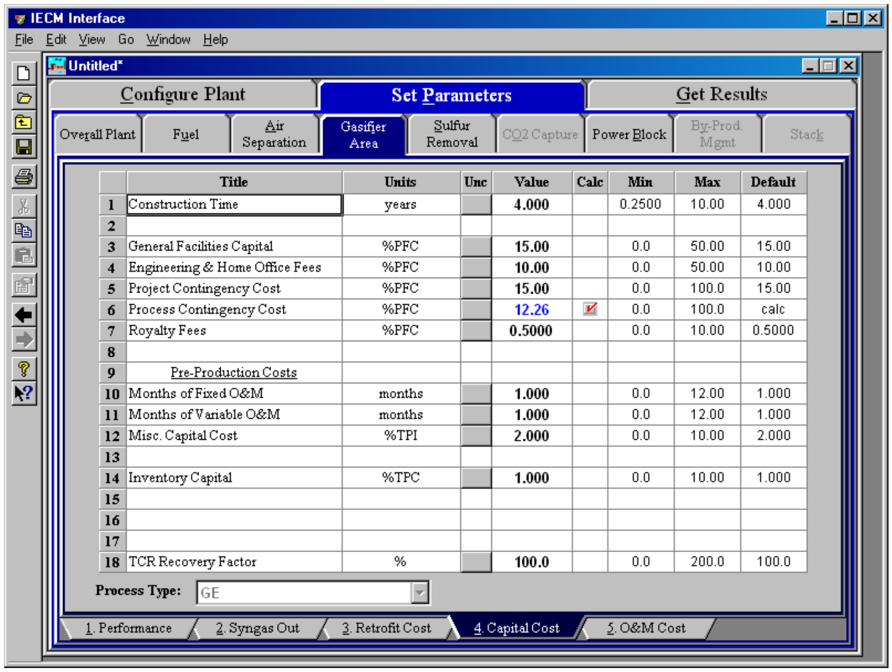
Gasifier Area: The GE gasification section of an IGCC plant contains gasifier, gas cooling, slag handling, and ash handling sections. For IGCC plants of 400 MW to 1100 MW, typically 2 to 4 operating gasification trains are used along with one spare train. The mass flow of coal to the gasifier is assumed to be between 3000 and 3500 tons/day per train (as_received).

Low Temperature Gas Cooling: The low temperature gas cooling section includes a series of three shell and tube exchangers. The number of operating trains are estimated based on the total syngas mass flow rate and the range of syngas flow rates per train used.

Process Condensate Treatment: This model is based upon one data point from AP-5950. Because the treated process condensate is used as make-up to the gas scrubbing unit, and because blowdown from the gas scrubbing unit is the larger of the flow streams entering the process condensate treatment section, it is expected that process condensate treatment cost will depend primarily on the scrubber blowdown flow rate.

Gasifier Capital Cost Inputs

This screen is only available for the IGCC plant type.



Gasifier – Capital Cost input screen.

Inputs for capital costs are entered on the **Capital Cost** input screen.

Construction Time: This is the idealized construction period in years. It is used to determine the allowance for funds used during construction (AFUDC).

General Facilities Capital (GFC): 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%.

Engineering & Home Office Fees: The engineering & home office fees are a percent of total direct capital cost. This is an overhead fee paid to the architect/engineering company. These fees typically range from 7-15%.

Project Contingency Cost: This is 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.

Process Contingency Cost: 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.

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

Pre-Production Costs: 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 applied to the O&M costs over a specified period of time (months). The two time periods for fixed and variable O&M costs are described below with the addition of a miscellaneous capital cost factor.

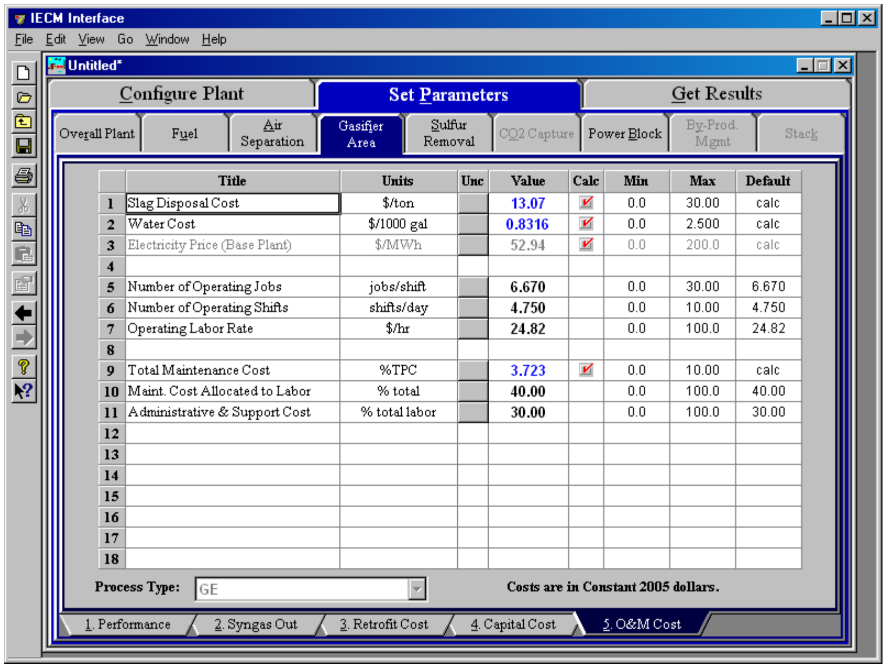
- **Months of Fixed O&M:** Time period of fixed operating costs used for preproduction to cover training, testing, major changes in equipment, and inefficiencies in start-up. This includes operating, maintenance, administrative and support labor. It also considers maintenance materials.
- **Months of Variable O&M:** Time period of variable operating costs used for preproduction to cover chemicals, water, consumables, and solid disposal charges in start-up, assuming 100% load. This excludes any fuels.
- **Misc. Capital Cost:** This is a percent of total plant investment (sum of TPC and AFUDC) to cover expected changes to equipment to bring the system up to full capacity.

Inventory Capital: Percent of the total direct capital for raw material supply based on 100% capacity during a 60 day period. These materials are considered storage. The inventory capital includes fuels, consumables, by-products, and spare parts. This is typically 0.5%.

TCR Recovery Factor: The actual total capital required (TCR) as a percent of the TCR in a new power plant. This value is 100% for a new installation and may be set as low as 0% for a fabric filter that has been paid off.

Gasifier O&M Cost Inputs

This screen is only available for the IGCC plant type.



Gasifier – O&M Cost input screen.

Inputs for O&M costs are entered on the **Gasifier O&M Cost** input screen. O&M costs are typically expressed on an average annual basis and are provided in either constant or current dollars for a specified year, as shown on the bottom of the screen.

Slag Disposal Cost: This is the solid disposal cost per ton.

Water Cost: This is the cost of the water per 1000 gallons.

Electricity Price (Base Plant): This is the price of electricity and is calculated as a function of the utility cost of the base plant, where the base plant is defined as an air separation unit, gasifier and the power block.

Number of Operating Jobs: This is the total number of operating jobs that are required to operate the plant per eight-hour shift.

Number of Operating Shifts: This is the total number of equivalent operating shifts in the plant per day. The number takes into consideration paid time off and weekend work (3 shifts/day * 7 days/5 day week * 52 weeks/(52 weeks - 6 weeks PTO) = 4.75 equiv. Shifts/day)

Operating Labor Rate: The hourly cost of labor is specified in the base plant O&M cost screen. The same value is used throughout the other technologies.

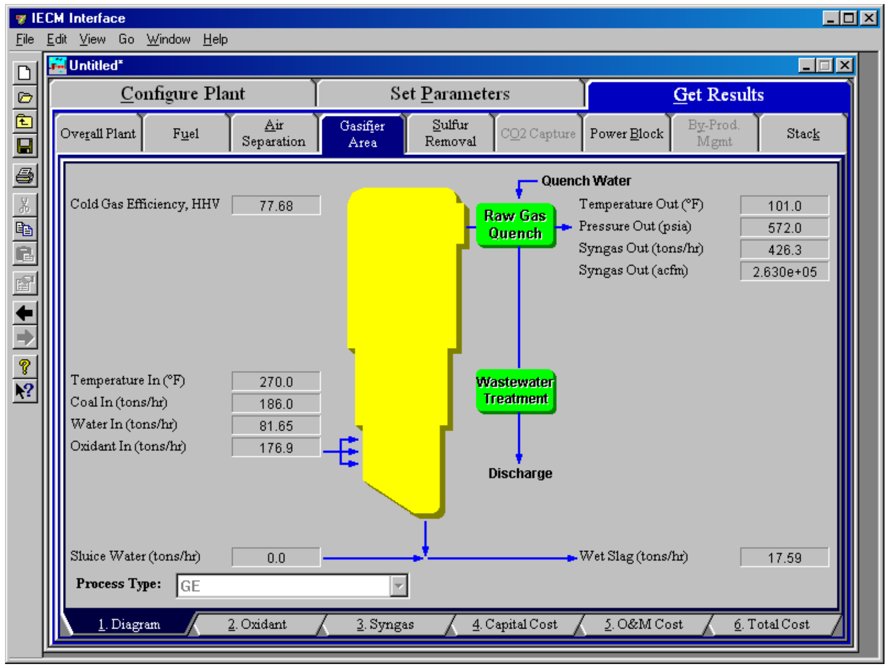
Total Maintenance Cost: This is the annual maintenance cost as a percentage of the total plant cost. Maintenance cost estimates can be developed separately for each process area.

Maint. Cost Allocated to Labor: Maintenance cost allocated to labor as a percentage of the total maintenance cost.

Administrative & Support Cost: This is the percent of the total operating and maintenance labor associated with administrative and support labor.

Gasifier Diagram

This screen is only available for the IGCC plant type.



Gasifier – Diagram result screen.

The **Gasifier Diagram** result screen displays an icon for the Gasifier Unit and values for major flows in and out of it. Each result is described briefly below in flow:

Cold Gas Efficiency: This is the ratio of the heat contents calculated at room temperature of the syngas fuel output and the coal fuel input. The higher heating value is used here.

Temperature In: This is the temperature of the oxidant stream into the gasifier.

Coal In: This is the mass flow of coal into the gasifier on a wet-basis.

Water In: This is additional mass flow of water added to the coal. (Wet coal already contains some water).

Oxidant In: This is the mass flow of oxidant into the gasifier.

Sluice Water: Slag collected can be removed from the gasifier and disposed by sluicing the slag with water.

Temperature Out: This is the syngas temperature exiting the raw gas quench.

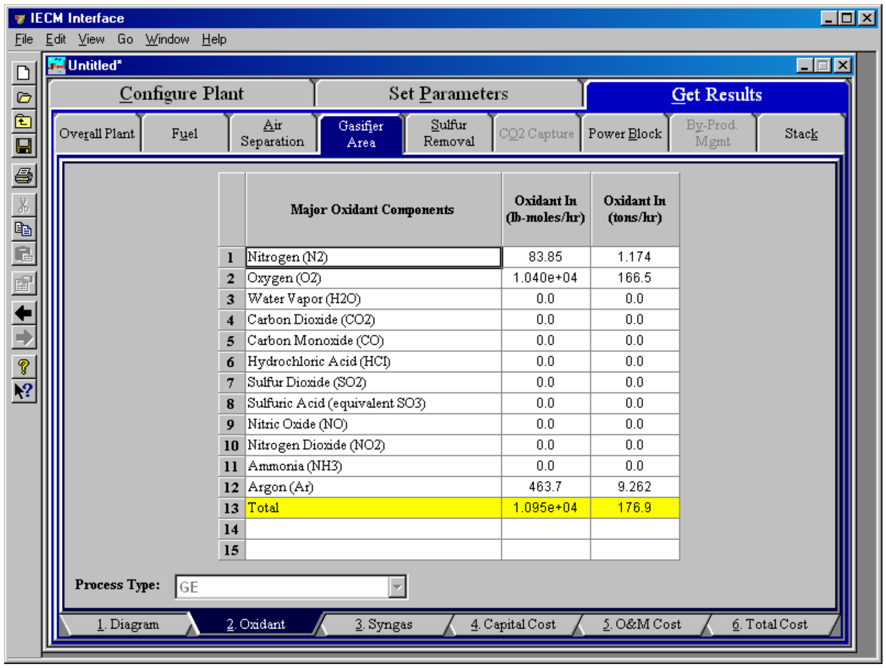
Pressure Out: .This is the approximate pressure of the syngas exiting the raw gas quench.

Syngas Out:.This is the mass flow rate of syngas exiting the gasification but prior to the raw gas quench process.

Syngas Out:.This is the volumetric flow rate of syngas exiting the gasification but prior to the raw gas quench process.

Wet Slag:.Slag collected is removed from the gasifier. Sluice water may or may not be used to facilitate its transportation. This is the total slag flow rate leaving the gasifier on a wet basis.

Gasifier Oxidant Results



Gasifier – Gas Flow result screen..

Each result is described briefly below.

Nitrogen (N_2): Total mass of nitrogen.

Oxygen (O_2): Total mass of oxygen.

Water Vapor (H_2O): Total mass of water vapor.

Carbon Dioxide (CO_2): Total mass of carbon dioxide.

Carbon Monoxide (CO): Total mass of carbon monoxide.

Hydrochloric Acid (HCl): Total mass of hydrochloric acid.

Sulfur Dioxide (SO_2): Total mass of sulfur dioxide.

Sulfuric Acid (equivalent SO_3): Total mass of sulfuric acid.

Nitric Oxide (NO): Total mass of nitric oxide.

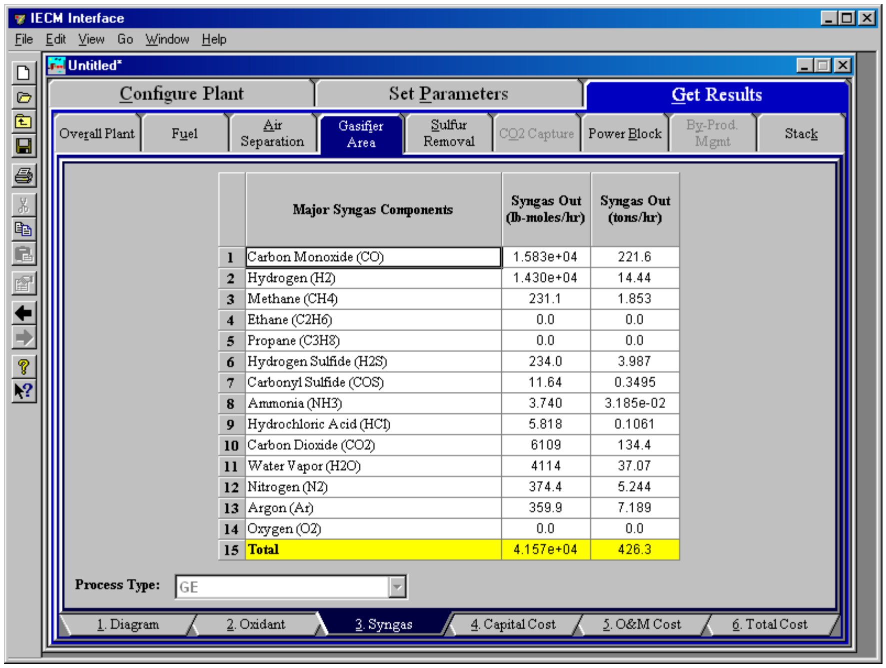
Nitrogen Dioxide (NO_2): Total mass of nitrogen dioxide.

Ammonia (NH_3): Total mass of ammonia.

Argon (Ar): Total mass of argon.

Total: Total of the individual components listed above. This item is highlighted in yellow.

Gasifier Syngas Results



Gasifier – Gas Flow result screen..

Major Syngas Components

Carbon Monoxide (CO): Total mass of carbon monoxide.

Hydrogen (H_2): Total mass of hydrogen.

Methane (CH_4): Total mass of methane.

Ethane (C_2H_6): Total mass of ethane.

Propane (C_3H_8): Total mass of propane.

Hydrogen Sulfide (H_2S): Total mass of hydrogen sulfide.

Carbonyl Sulfide (COS): Total mass of carbonyl sulfide.

Ammonia (NH_3): Total mass of ammonia.

Hydrochloric Acid (HCl): Total mass of hydrochloric acid.

Carbon Dioxide (CO_2): Total mass of carbon dioxide.

Water Vapor (H_2O): Total mass of water vapor.

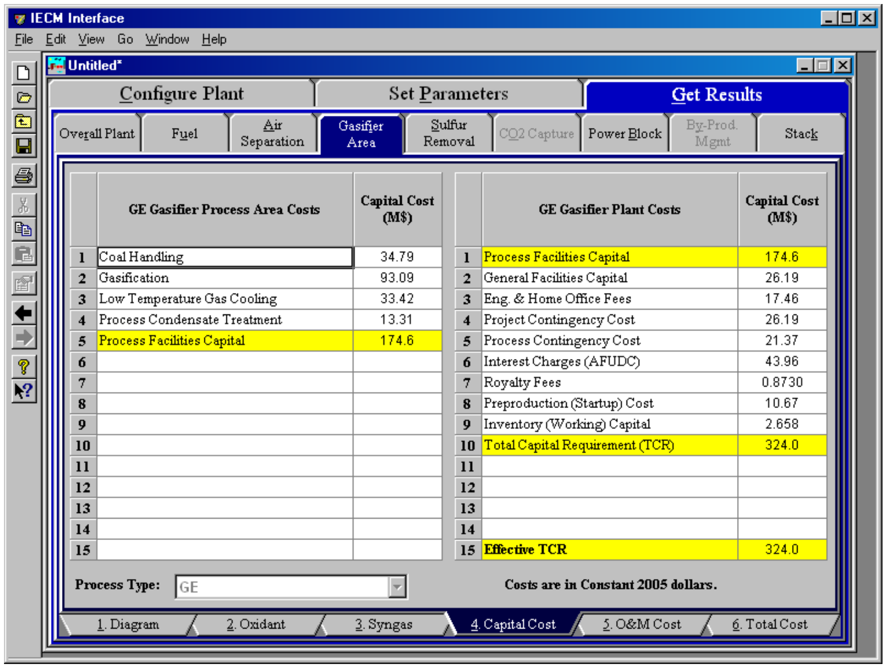
Nitrogen (N_2): Total mass of nitrogen.

Argon (Ar): Total mass of argon.

Oxygen (O_2): Total mass of oxygen.

Total: Total of the individual components listed above. This item is highlighted in yellow.

Gasifier Capital Cost Results



Gasifier Capital Cost results screen.

The **GE Gasifier Capital Cost** result screen displays tables for the capital costs. Capital costs are typically expressed in either constant or current dollars for a specified year, as shown on the bottom of the screen. Each result is described briefly below:

GE Gasifier Process Area Costs

Coal Handling: This is the cost associated with the coal handling process area. Coal handling involves unloading coal from a train, storing the coal, moving the coal to the grinding mills, and feeding the gasifier with positive displacement pumps. A typical coal handling section contains one operating train and no spare train. A train consists of a bottom dump railroad car unloading hopper, vibrating feeders, conveyors, belt scale, magnetic separator, sampling system, deal coal storage, stacker, reclaimer, as well as some type of dust suppression system. Slurry preparation trains typically have one to five operating trains with one spare train. The typical train consists of vibrating feeders, conveyors, belt scale, rod mills, storage tanks, and positive displacement pimps to feed the gasifiers. All of the equipment for both the coal handling and the slurry feed are commercially available. The direct cost model for the coal handling is based upon the overall flow to the plant rather than on a per train basis.

Gasifier Area: The GE gasification section of an IGCC plant contains gasifier, gas cooling, slag handling, and ash handling sections. For IGCC plants of 400 MW to 1100 MW, typically 4 to 8 operating gasification trains are used along with one spare train.

Low Temperature Gas Cooling: This is the cost associated with the Low Temperature Gas Cooling process area. The low temperature gas cooling section includes a series of three shell and tube exchangers.

The number of operating trains are estimated based on the total syngas mass flow rate and the range of syngas flow rates per train used.

Process Condensate Treatment: The treated process condensate is used as make-up to the gas scrubbing unit, and because blowdown from the gas scrubbing unit is the larger of the flow streams entering the process condensate treatment section, it is expected that process condensate treatment cost will depend primarily on the scrubber blowdown flow rate.

Process Facilities Capital: The process facilities capital is the total constructed cost of all on-site processing and generating units listed above, including all direct and indirect construction costs. All sales taxes and freight costs are included where applicable implicitly. This result is highlighted in yellow.

GE Gasifier Plant Costs

Process Facilities Capital: (see definition above)

General Facilities Capital: The general facilities include construction costs of roads, office buildings, shops, laboratories, etc. Sales taxes and freight costs are included implicitly.

Eng. & Home Office Fees: The engineering & home office fees are a percent of total direct capital cost. This is an overhead fee paid to the architect/engineering company.

Project Contingency Cost: Capital cost contingency factor covering the cost of additional equipment or other costs that would result from a more detailed design of a definitive project at the actual site.

Process Contingency Cost: Capital cost contingency factor applied to a new technology in an effort to quantify the uncertainty in the technical performance and cost of the commercial-scale equipment.

Interest Charges (AFUDC): Allowance for funds used during construction, also referred to as interest during construction, is the time value of the money used during construction and is based on an interest rate equal to the before-tax weighted cost of capital. This interest is compounded on an annual basis (end of year) during the construction period for all funds spent during the year or previous years.

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

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.

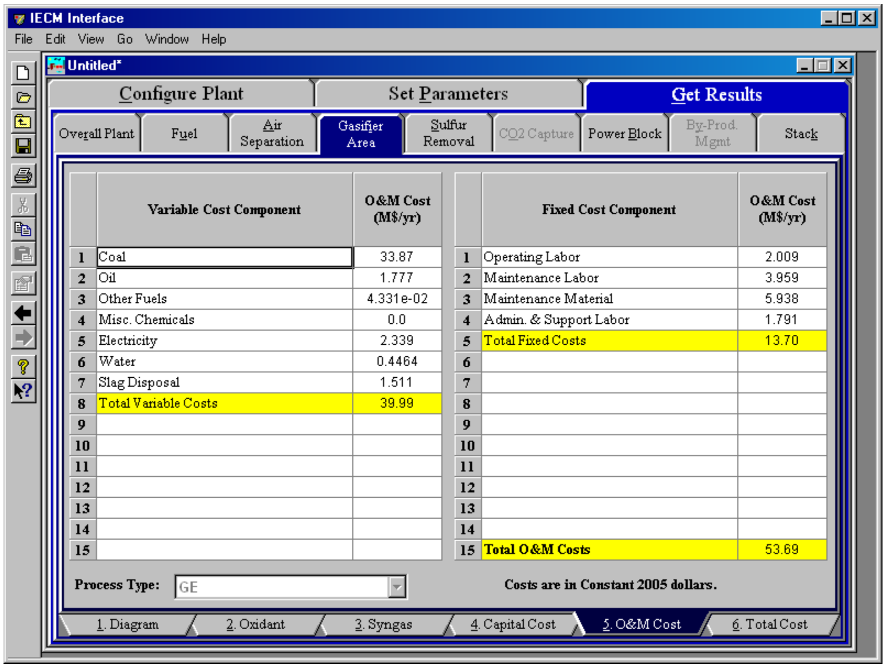
Inventory (Working) Capital: The raw material supply based on 100% capacity during a 60 day period. These materials are considered storage. The inventory capital includes fuels, consumables, by-products, and spare parts.

Total Capital Requirement (TCR): Money that is placed (capitalized) on the books of the utility on the service date. TCR includes all the items above. This result is highlighted in yellow.

Effective TCR: The TCR of the spray dryer that is used in determining the total power plant cost. The effective TCR is determined by the "TCR Recovery Factor".

Gasifier O&M Cost Results

This screen is only available for the IGCC plant type.



Gasifier – O&M Cost results screen.

O&M costs are typically expressed on an average annual basis and are provided in either constant or current dollars for a specified year, as shown on the bottom of the screen.

Variable Cost Component

Coal: This is the annual cost of the coal used by the gasifier.

Oil: This is the annual cost of the oil consumed by the gasifier.

Other Fuels: This is the annual cost of any other fuels used by the gasifier.

Misc. Chemicals: This is the annual cost of the miscellaneous chemicals used by the gasifier.

Electricity: The cost of electricity consumed by the processes in the gasifier area..

Water: This is the annual cost of the water used by the gasifier.

Slag Disposal: This is the solid disposal cost per year for the GE entrained-flow reactor.

Total Variable Costs: This is the sum of all the variable O&M costs listed above. This result is highlighted in yellow.

Fixed Cost Components

Fixed operating costs are essentially independent of actual capacity factor, number of hours of operation, or amount of kilowatts produced. All the costs are subject to inflation.

Operating Labor: Operating labor cost is based on the operating labor rate, the number of personnel required to operate the plant per eight-hour shift, and the average number of shifts per day over 40 hours per week and 52 weeks.

Maintenance Labor: The maintenance labor is determined as a fraction of the total maintenance cost.

Maintenance Material: The cost of maintenance material is the remainder of the total maintenance cost, considering the fraction associated with maintenance labor.

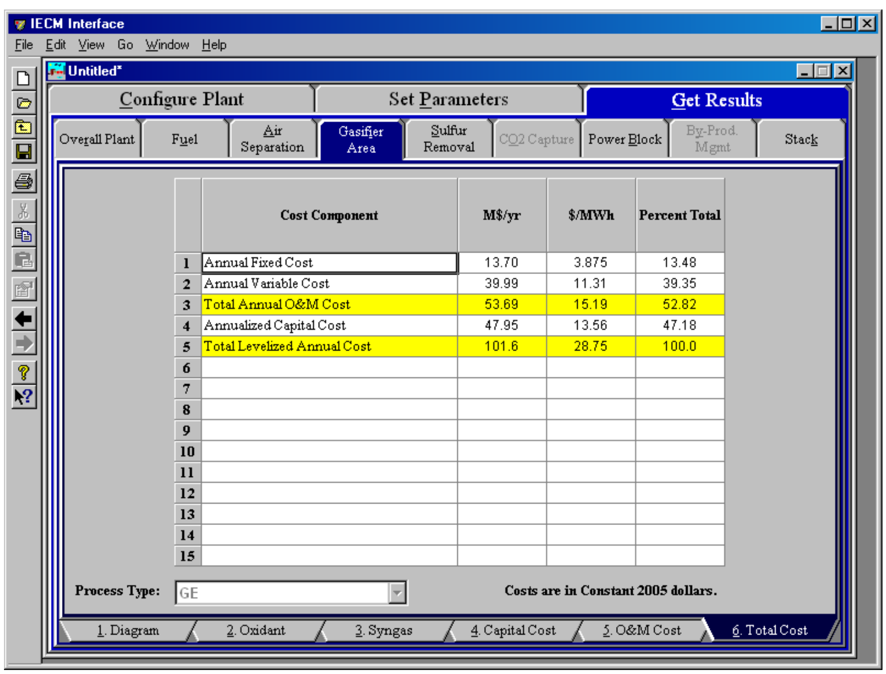
Admin. & Support Labor: The administrative and support labor is the only overhead charge. It is taken as a fraction of the total operating and maintenance labor costs.

Total Fixed Costs: This is the sum of all the fixed O&M costs listed above. This result is highlighted in yellow.

Total O&M Costs: This is the sum of the total variable and total fixed O&M costs. It is used to determine the base plant total revenue requirement. This result is highlighted in yellow.

Gasifier Total Cost Results

This screen is only available for the IGCC plant type.



Gasifier – Total Cost results screen.

The **Total Cost** result screen displays a table which totals the annual fixed, variable, operations and maintenance, and capital costs associated with the **Gasifier Unit**.

Total costs are typically expressed in either constant or current dollars for a specified year, as shown on the bottom of the screen. Each result is described briefly below.

Cost Component

Annual Fixed Cost: The operating and maintenance fixed costs are given as an annual total. This number includes all maintenance materials and all labor costs.

Annual Variable Cost: The operating and maintenance variables costs are given as an annual total. This includes all reagent, chemical, steam, and power costs.

Total Annual O&M Cost: This is the sum of the annual fixed and variable operating and maintenance costs above. This result is highlighted in yellow.

Annualized Capital Cost: This is the total capital cost expressed on an annualized basis, taking into consideration the levelized carrying charge factor, or fixed charge factor, over the entire book life.

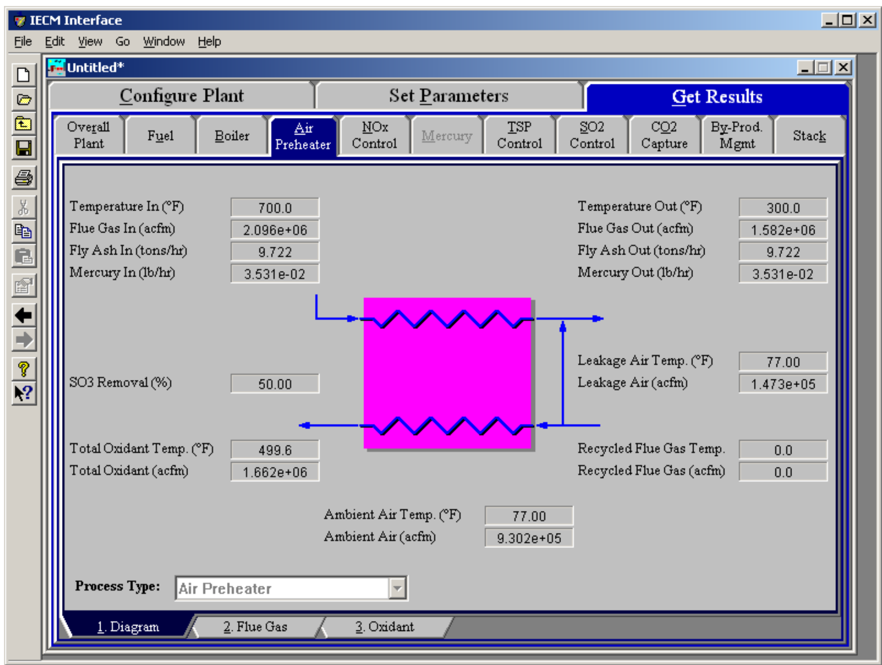
Total Levelized Annual Cost: The total annual cost is the sum of the total annual O&M cost and annualized capital cost items above. This result is highlighted in yellow.

Air Preheater

The **Air Preheater** Technology Navigation Tab in the **Get Results** program area contains result screens that display the flow rates and temperatures of substances through the air preheater. This is only available in the Combustion (Boiler) plant type.

Air Preheater Diagram

This screen is only available for the Combustion (Boiler) plant type.



Air Preheater – Diagram.

The **Diagram** result screen displays an icon for the Air Preheater and values for major flows in and out of it. Each result is described briefly below in flow order (not from top to bottom and left to right as they display on the screen).

Recycled Flue Gas Entering Preheater

Flue gas can be recycled back into the boiler when an **O_2-CO_2 Recycle** configuration is specified in **Configure Plant**. This is more commonly known as an "oxyfuel" configuration. Flue gas is not recycled in any other configuration.

Recycled Flue Gas Temp: Temperature of the recycled flue gas entering the induced-draft fan.

Recycled Flue Gas: Volumetric flow rate of the recycled flue gas entering the induced-draft fan.

Atmospheric Air Entering Preheater

Ambient Air Temp: Temperature of the atmospheric air entering the induced-draft fan.

Ambient Air: Volumetric flow rate of air entering the induced-draft fan, based on the atmospheric air temperature and atmospheric pressure.

Heated Air Exiting Preheater

Heated Oxidant Temp: Heated combustion air or recycled flue gas temperature exiting the air preheater. This is a complicated function of the heat content and temperatures of the flue gas.

Heated Oxidant: Volumetric flow rate of the combustion air or recycled flue gas exiting the air preheater, based on the combustion air temperature and atmospheric pressure.

Leakage Air

Leakage Air Temp: Temperature of the atmospheric air leaking across the air preheater into the flue gas. This is determined by the leakage parameter on the base plant performance input screen.

Leakage Air: Volumetric flow rate of the atmospheric air leaking across the air preheater into the flue gas. This is based on the leakage temperature and atmospheric pressure.

Flue Gas Entering Preheater

Temperature In: Temperature of the flue gas entering the air preheater. This is determined by the flue gas outlet temperature of the module upstream of the air preheater (e.g., the boiler economizer).

Flue Gas In: Volumetric flow rate of the flue gas entering the air preheater, based on the flue gas inlet temperature and atmospheric pressure.

Fly Ash In: Total solids mass flow rate in the flue gas entering the air preheater. This is determined by the solids exiting the module upstream of the air preheater (e.g., the boiler economizer).

Mercury In: Total mass of mercury entering the air preheater in the flue gas. The value is a sum of all the forms of mercury (elemental, oxidized, and particulate).

Air Preheater Performance

SO3 Removal: Percent of the SO_3 removed from the flue gas.

Cooled Flue Gas Exiting Preheater

Temperature Out: Temperature of the flue gas exiting the air preheater. This is determined by the parameter on the base plant performance input screen.

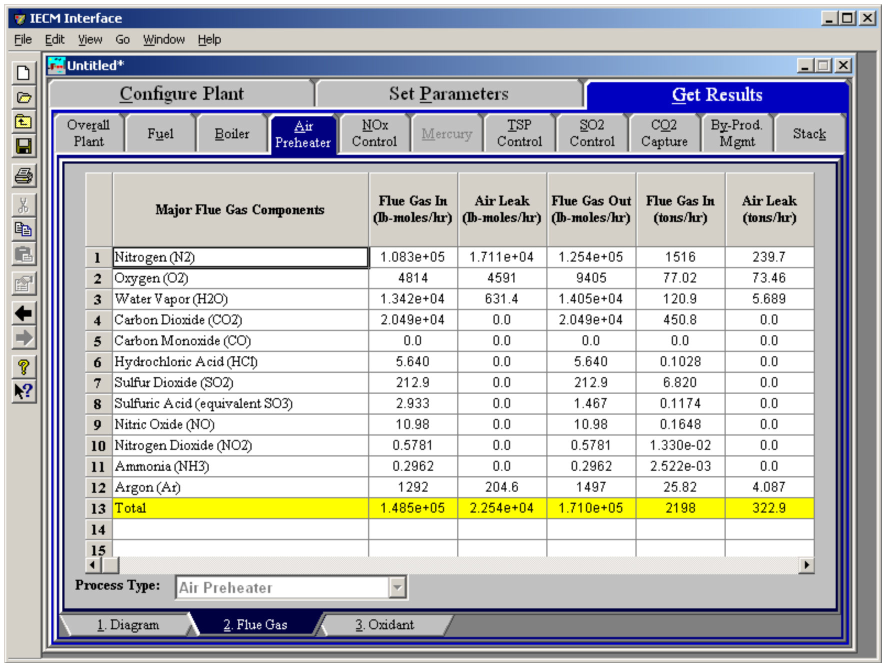
Flue Gas Out: Volumetric flow rate of the flue gas exiting the air preheater, based on the flue gas exit temperature and atmospheric pressure.

Fly Ash Out: Total solids mass flow rate in the flue gas exiting the air preheater. This is a function of the percent ash entering the flue gas (furnace emissions input parameter) and the ash content of the fuel.

Mercury Out: Total mass of mercury exiting the air preheater in the flue gas. The value is a sum of all the forms of mercury (elemental, oxidized, and particulate).

Air Preheater Flue Gas Results

This screen is only available for the **Combustion (Boiler)** plant type.



	Major Flue Gas Components	Flue Gas In (lb-moles/hr)	Air Leak (lb-moles/hr)	Flue Gas Out (lb-moles/hr)	Flue Gas In (tons/hr)	Air Leak (tons/hr)
1	Nitrogen (N2)	1.083e+05	1.711e+04	1.254e+05	1516	239.7
2	Oxygen (O2)	4814	4591	9405	77.02	73.46
3	Water Vapor (H2O)	1.342e+04	631.4	1.405e+04	120.9	5.689
4	Carbon Dioxide (CO2)	2.049e+04	0.0	2.049e+04	450.8	0.0
5	Carbon Monoxide (CO)	0.0	0.0	0.0	0.0	0.0
6	Hydrochloric Acid (HCl)	5.640	0.0	5.640	0.1028	0.0
7	Sulfur Dioxide (SO2)	212.9	0.0	212.9	6.820	0.0
8	Sulfuric Acid (equivalent SO3)	2.933	0.0	1.467	0.1174	0.0
9	Nitric Oxide (NO)	10.98	0.0	10.98	0.1648	0.0
10	Nitrogen Dioxide (NO2)	0.5781	0.0	0.5781	1.330e-02	0.0
11	Ammonia (NH3)	0.2962	0.0	0.2962	2.522e-03	0.0
12	Argon (Ar)	1292	204.6	1497	25.82	4.087
13	Total	1.485e+05	2.254e+04	1.710e+05	2198	322.9
14						
15						

Air Preheater – Flue Gas result screen.

Major Flue Gas Components

The **Flue Gas** result screen displays a table of quantities of flue gas components entering and exiting the air preheater. For each component entering and exiting in flue gas, values are given in both moles and mass per hour. For each component entering in atmospheric air, values are given in moles per hour. Each result is described briefly below.

Nitrogen (N2): Total mass of nitrogen.

Oxygen (O2): Total mass of oxygen.

Water Vapor (H2O): Total mass of water vapor.

Carbon Dioxide (CO2): Total mass of carbon dioxide.

Carbon Monoxide (CO): Total mass of carbon monoxide.

Hydrochloric Acid (HCl): Total mass of hydrochloric acid.

Sulfur Dioxide (SO2): Total mass of sulfur dioxide.

Sulfuric Acid (equivalent SO3): Total mass of sulfuric acid.

Nitric Oxide (NO): Total mass of nitric oxide.

Nitrogen Dioxide (NO2): Total mass of nitrogen dioxide.

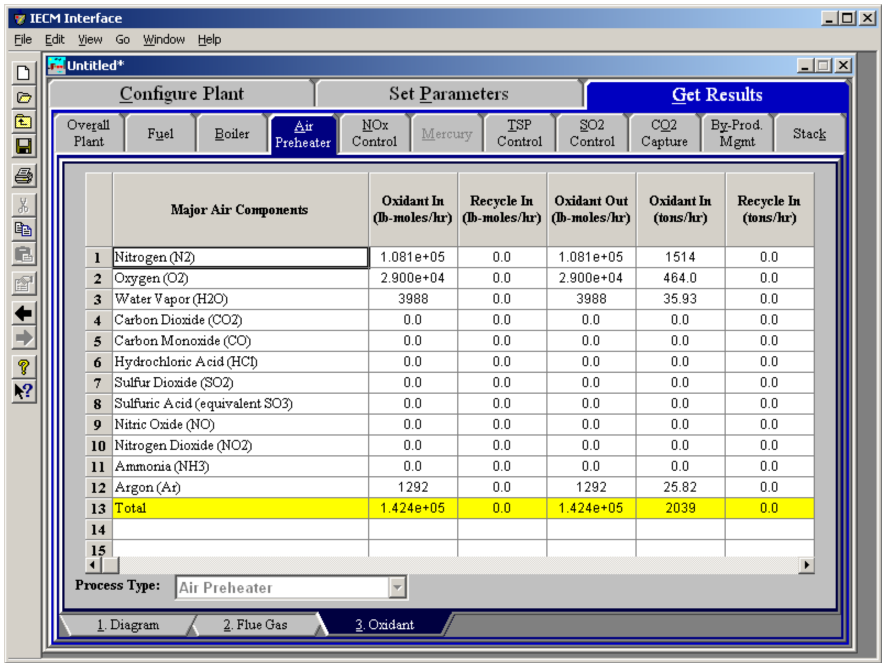
Ammonia (NH3): Total mass of ammonia.

Argon (Ar): Total mass of argon.

Total: Total of the individual components listed above. This item is highlighted in yellow.

Air Preheater Oxidant Results

This screen is only available for the Combustion (Boiler) plant type.



	Major Air Components	Oxidant In (lb-moles/hr)	Recycle In (lb-moles/hr)	Oxidant Out (lb-moles/hr)	Oxidant In (tons/hr)	Recycle In (tons/hr)
1	Nitrogen (N2)	1.081e+05	0.0	1.081e+05	1514	0.0
2	Oxygen (O2)	2.900e+04	0.0	2.900e+04	464.0	0.0
3	Water Vapor (H2O)	3988	0.0	3988	35.93	0.0
4	Carbon Dioxide (CO2)	0.0	0.0	0.0	0.0	0.0
5	Carbon Monoxide (CO)	0.0	0.0	0.0	0.0	0.0
6	Hydrochloric Acid (HCl)	0.0	0.0	0.0	0.0	0.0
7	Sulfur Dioxide (SO2)	0.0	0.0	0.0	0.0	0.0
8	Sulfuric Acid (equivalent SO3)	0.0	0.0	0.0	0.0	0.0
9	Nitric Oxide (NO)	0.0	0.0	0.0	0.0	0.0
10	Nitrogen Dioxide (NO2)	0.0	0.0	0.0	0.0	0.0
11	Ammonia (NH3)	0.0	0.0	0.0	0.0	0.0
12	Argon (Ar)	1292	0.0	1292	25.82	0.0
13	Total	1.424e+05	0.0	1.424e+05	2039	0.0
14						
15						

Air Preheater – Flue Gas result screen.

Oxidant Gas Components

The **Oxidant** result screen displays a table of quantities of air or recycled flue gas components entering and exiting the air preheater. For each component entering and exiting in flue gas, values are given in both moles and mass per hour. For each component entering in atmospheric air, values are given in moles per hour. Each result is described briefly below.

Nitrogen (N_2): Total mass of nitrogen.

Oxygen (O_2): Total mass of oxygen.

Water Vapor (H_2O): Total mass of water vapor.

Carbon Dioxide (CO_2): Total mass of carbon dioxide.

Carbon Monoxide (CO): Total mass of carbon monoxide.

Hydrochloric Acid (HCl): Total mass of hydrochloric acid.

Sulfur Dioxide (SO_2): Total mass of sulfur dioxide.

Sulfuric Acid (equivalent SO_3): Total mass of sulfuric acid.

Nitric Oxide (NO): Total mass of nitric oxide.

Nitrogen Dioxide (NO_2): Total mass of nitrogen dioxide.

Ammonia (NH_3): Total mass of ammonia.

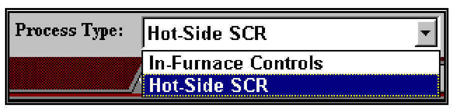
Argon (Ar): Total mass of argon.

Total: Total of the individual components listed above. This item is highlighted in yellow.

In-Furnace Controls

The **NOx Control** Technology Navigation Tab contains screens that address combustion or post-combustion air pollution technologies for Nitrogen Oxides.

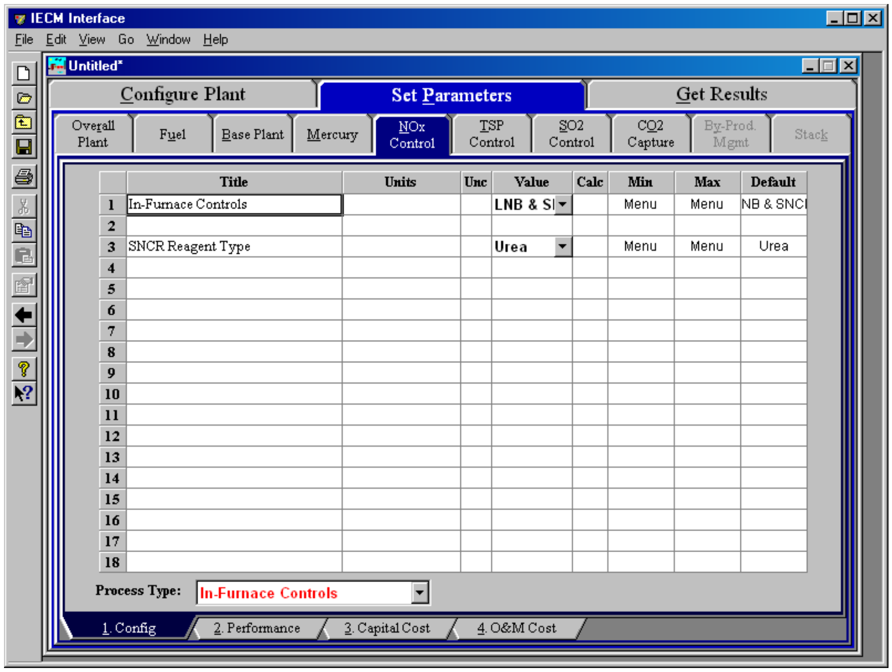
These screens are available if the In-Furnace Controls for the **Combustion (Boiler)** plant type configurations have been selected for NO_x control under Combustion Controls. If you have selected both In-Furnace Controls and a Hot-Side SCR for NO_x control, you may switch between the two sets of screens that configure these technologies by using the Process Type pull-down menu at the bottom of the screen



The Process Type pull-down menu

In-Furnace Controls Configuration

This screen is only available for the **Combustion (Boiler)** plant type. Inputs for configuring the NO_x Control technology are entered on the **Config** input screen. Each parameter is described briefly below.



In – Furnace Controls – Config input screen.

In – Furnace Controls

This pull-down menu chooses what type of in-furnace NO_x controls are used. These technologies reduce NO_x between the primary fuel injection into the furnace and the economizer. These can be used in the combinations given in addition to the SCR. The low NO_x burner options are not displayed when a cyclone boiler is configured. The full list of choices is:

LNB – Low NO_x burners are a combustion NO_x control. These burners replace the upper coal nozzle of the standard two-nozzle cell burner with a secondary air port. The lower burner coal nozzle is enlarged to the same fuel input capacity as the two standard coal nozzles. The LNB operates on the principle of staged combustion to reduce NO_x emissions. Approximately 70% of the total air (primary, secondary, and excess air) is supplied through or around the coal-feed nozzle. The remainder of the air is directed to the upper port of each cell to complete the combustion process. The fuel-bound nitrogen compounds are converted to nitrogen gas, and the reduced flame temperature minimizes the formation of thermal NO_x. The net effect of this technology is greater than 50% reduction in NO_x formation with no boiler pressure part changes and no impact on boiler operation or performance. Low NO_x burners are not available for cyclone boilers.

LNB & OFA – Low NO_x burners (see above) with overfire air is another combustion NO_x reduction method. Overfire air is an enhancement to LNB to reduce NO_x formation by further separating the air injection locations. An addition of approximately 10% NO_x is reduced by the addition of OFA. A portion of the secondary air used by LNB is diverted to injection ports located above the primary combustion zone, reducing available oxygen in the primary combustion zone. Overfire air in the IECM refers to separated OFA for both wall and tangential-fired boilers. This option is not supported for cyclone boilers.

Gas Reburn – Gas reburn is a post-combustion NO_x reduction method. Gas reburn substitutes up to one-fourth of the heat input of coal with natural gas, reducing the NO_x up to 60% as a function of the amount of reburn. The natural gas is injected above the primary combustion zone to create a reducing zone. Reburn has been shown to be effective for wall and tangential-fired boilers and more recently for cyclone boilers.

SNCR – Selective non-catalytic reduction is a post-combustion NO_x reduction method. This process removes NO_x from flue gas by injecting one of two nitrogen-based reagents, ammonia or urea, in the presence of oxygen to form nitrogen and water vapor. Optimum removal is achieved in a temperature window of 1600-2000 F. Although the technology is very simple, the narrow temperature window provides the primary challenge. Ammonia slip and ash contamination are additional concerns that must be considered with SNCR.

LNB & SNCR – Low NO_x burners can be used in conjunction with SNCR to achieve very high NO_x removals. Both technologies are described in detail above.

If a Tangential or Wall Furnace Type have been selected in **Configure Plant**, then all five options will display. If you have selected a Cyclone Furnace type, then only **Gas Reburn** and **SNCR** will display.

The default for Tangential and Wall furnaces is **LNB & SNCR**. The default for a Cyclone furnace is **Gas Reburn**.

SNCR Reagent Type

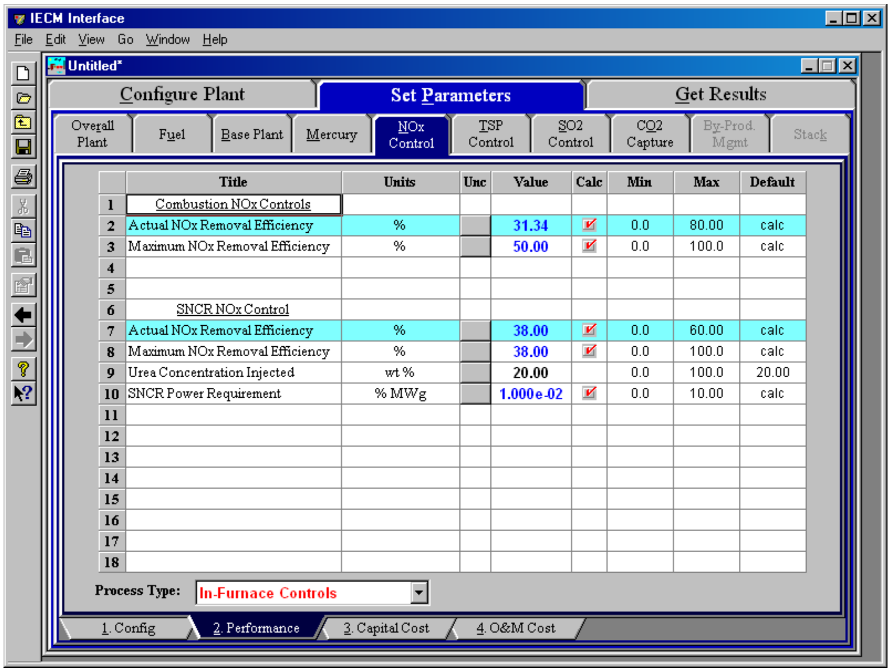
Only displayed when **SNCR** or **LNB & SNCR** have been selected in the In-Furnace Controls pull-down menu. Nitrogen-based reagent injection is used in an SNCR to reduce NO_x in the presence of oxygen to form nitrogen and water vapor. The reagent choices are:

Urea – Urea ($CO(NH_2)_2$) is typically diluted to a 15-20% concentration with water. Urea has the advantage of safety and ease of storage and handling. Urea is the default reagent used in the IECM.

Ammonia – Ammonia can be supplied in two forms: anhydrous (NH_3) and aqueous(NH_4OH). The IECM considers only anhydrous ammonia. Ammonia may be an advantage when using an SNCR in conjunction with an SCR system.

In-Furnace Controls Performance Input

This screen is only available for the Combustion (Boiler) plant type.



In – Furnace Controls – Performance input screen.

Inputs for the performance of the **In-Furnace Controls** NO_x control technology are entered on the on the **Performance** input screen. Combustion NOx Controls These inputs will display if any combustion technology is used in the option selected in the **In-Furnace Controls** pull-down menu. This includes the **LNB, LNB + OFA, Gas Reburn**, and the **LNB + SNCR** options.

Combustion NO_x Controls

Actual NOx Removal Efficiency: This is the NO_x removal efficiency of the **LNB**, **LNB + OFA**, and **Gas Reburn** options, and the **LNB** removal portion of the **LNB + SNCR** option. The percent reduction of NO_x is calculated by comparing the actual NO_x emission to the uncontrolled NO_x emission. The removal is a function of the **In-Furnace Control** type selected in the pull-down menu, the boiler type, and the maximum removal efficiency (below). **Note:** that the removal is not a function of the NO_x emission constraint. This input is highlighted in blue.

Maximum NOx Removal Efficiency: The maximum removal efficiency of NO_x sets the upper bound for the actual NO_x removal efficiency (above). The maximum removal is a function of the In-Furnace control type and the boiler type.

Natural Gas Heat Input: This input will only display if **Gas Reburn** is selected in the **In-Furnace Controls** pull-down menu. The flow rate of natural gas injected is determined by this input on a Btu heat input basis.

SNCR NO_x Control

These inputs will only display if **SNCR** or **LNB & SNCR** is selected in the In-Furnace Controls pull-down menu.

Actual NOx Removal Efficiency: The actual NO_x removal efficiency is a function of the maximum NO_x removal efficiency (below) and the NO_x emission constraint. This input is highlighted in blue.

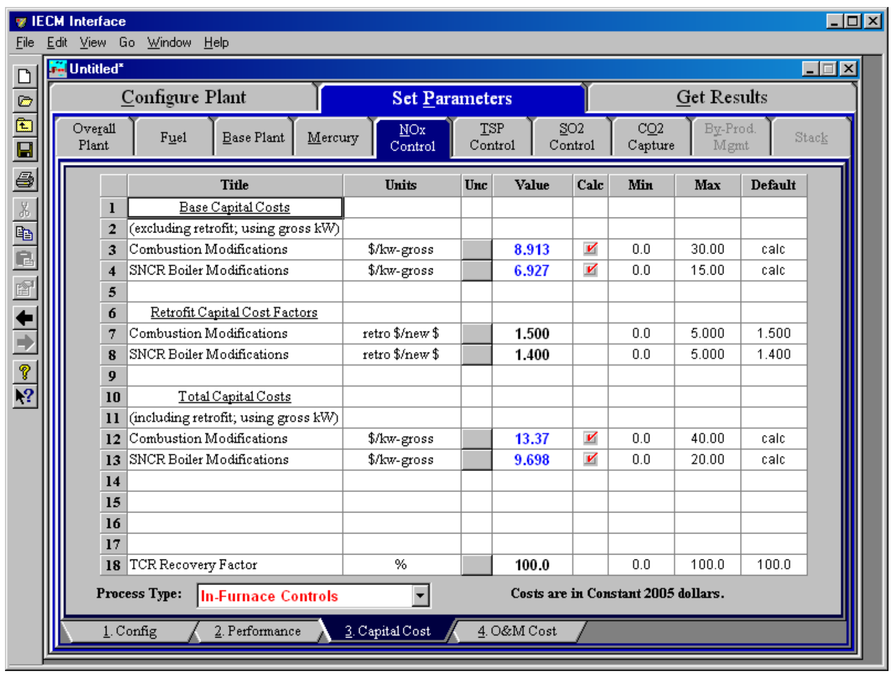
Maximum NOx Removal Efficiency: The maximum removal efficiency is calculated as a function of the gross electrical output. Because of difficulty mixing the reagent in the flue gas for larger boilers, the maximum efficiency decreases with increasing plant size.

Urea Concentration Injected: Urea is typically injected as a liquid diluted by water. This parameter defines the amount of water used to dilute the urea prior to injection.

SNCR Power Requirement: As mentioned above, the power requirement for the SNCR is a function of gross electrical output of the power plant. The value is determined by the need for tank heaters when urea reagent is used.

In-Furnace Controls Capital Cost

This screen is only available for the Combustion (Boiler) plant type. Unlike most capital cost input screens, these technologies costs are provided as total capital costs on an energy input basis.



In–Furnace Controls – Capital Cost input screen.

The **Combustion Modifications** inputs will not display if **SNCR** is selected in the In-Furnace Controls pull-down menu. The **SNCR Boiler Modifications** inputs will only display if **SNCR** or **LNB & SNCR** is selected

Base Capital Costs

The base capital costs (excluding retrofit, using gross KW) specify the total base capital costs, not considering any retrofit factors. No detailed information about direct or indirect costs is given. The costs are given as a total in units of dollars per gross kilowatt.

Combustion Modifications: This is the base capital cost of the **LNB**, **LNB + OFA**, and **Gas Reburn** options, and the LNB removal portion of the **LNB + SNCR** option. This parameter is not shown when one of these options is not selected.

SNCR Boiler Modifications: This specifies the total base capital cost for the **SNCR** boiler NO_x removal equipment alone. This parameter is not shown when one of the SNCR options is not selected.

Retrofit Capital Cost Factors

Retrofit cost factors allow you to differentiate between the base cost of purchasing the capital equipment and the actual cost incurred. These factors vary from unit to unit.

Combustion Modifications: This is the retrofit cost factor for the **LNB**, **LNB + OFA**, and **Gas Reburn** options, and the LNB removal portion of the **LNB + SNCR** option. This parameter is not shown when one of these options is not selected

SNCR Boiler Modifications: This is the retrofit cost factor for the **SNCR** option alone. This parameter is not shown when one of the SNCR options is not selected

Total Capital Costs:

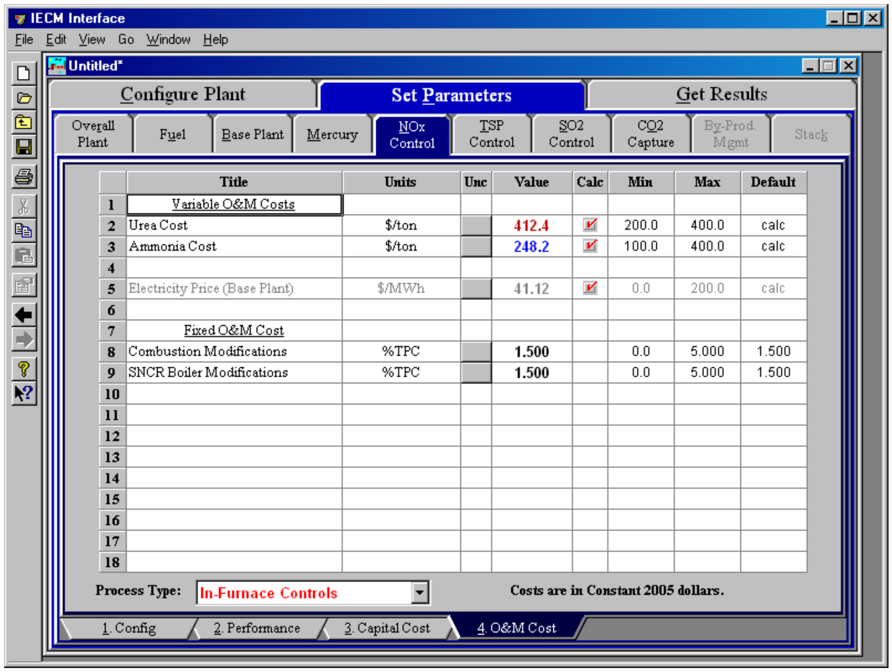
Combustion Modifications: This is the total capital cost of the **LNB, LNB + OFA,** and **Gas Reburn** options, and the LNB removal portion of the **LNB + SNCR** option. This combines the base capital cost with the retrofit cost factor. This parameter is not shown when one of these options is not selected.

SNCR Boiler Modifications: This specifies the total capital cost for the **SNCR** boiler NO_x removal equipment alone. This parameter is not shown when one of the SNCR options is not selected

TCR Recovery Factor: The actual total capital required (TCR) as a percent of the TCR in a new power plant. This value is 100% for a new installation and may be set as low as 0% for in-furnace controls that has been paid off.

In-Furnace Controls O&M Cost

This screen is only available for the Combustion (Boiler) plant type.



In-Furnace Controls – O&M Cost input screen.

O&M costs are typically expressed on an average annual basis and are provided in either constant or current dollars for a specified year, as shown on the bottom of the screen. Each parameter is described briefly below.

Variable O&M Costs

Urea Cost: This is the cost of urea used for any of the SNCR options. This input will only display if **SNCR** or **LNB & SNCR** is selected in the In-Furnace Controls pull-down menu

Ammonia Cost: This is the cost of ammonia used for any of the SNCR options. This input will only display if **SNCR** or **LNB & SNCR** is selected in the In-Furnace Controls pull-down menu

Natural Gas Cost: This is the cost of natural gas used for the Gas Reburn option. This input will only display if **Gas Reburn** is selected

Electricity Price (Base Plant): This is the price of electricity and is calculated as a function of the utility cost of the base plant, where the base plant is defined as combustion boiler and an air preheater.

Fixed O&M Cost

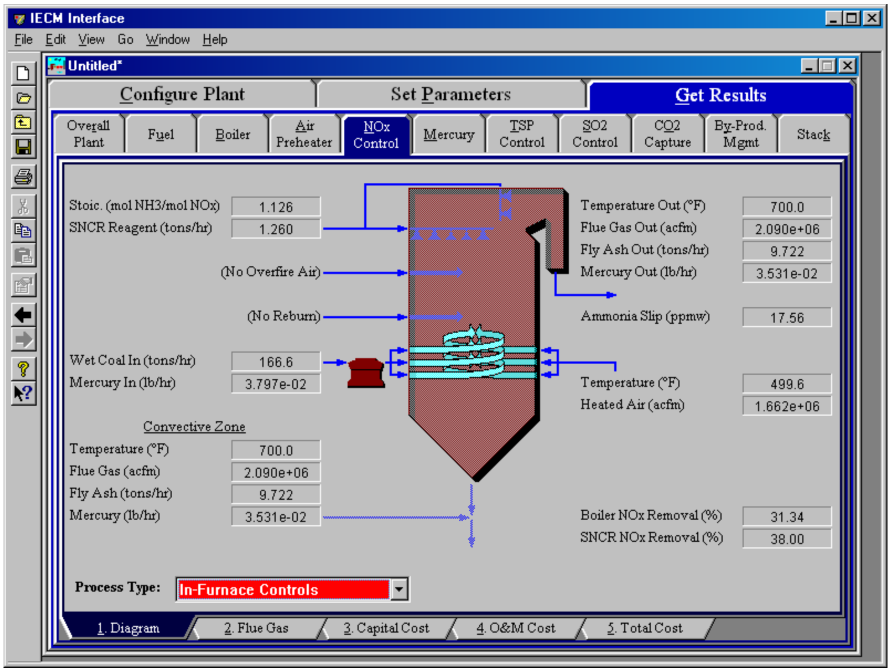
Fixed O&M costs are given as a total cost, rather than itemized costs broken down by individual maintenance and labor costs. The results are given as a percent of the total capital cost.

Combustion Modifications: This is the total fixed operating and maintenance cost for boiler NO_x modifications made in the combustion zone (LNB, OFA, natural gas reburn). This parameter is not shown if one of these options is not selected.

SNCR Boiler ModificationsVariable O&M Costs: This is the total fixed O&M cost for the **SNCR** equipment alone. This input is not shown if one of the SNCR options is not selected.

In-Furnace Controls Diagram

This screen is only available for the Combustion (Boiler) plant type.



In-Furnace Controls – Diagram

The **Diagram** result screen displays an icon for the **In-Furnace Controls** NO_x technology selected and values for major flows in and out of it.

Fuel Entering Boiler

Wet Coal In: Fuel flow rate into the boiler on a wet basis. Waste products removed prior to the burners are not considered here.

Mercury In: This is the mass flow rate of total mercury entering the boiler. The mass reflects the molecular weight of elemental mercury.

Air Entering Boiler

Temperature: Heated air temperature measured at the burners. This is generally determined by the combustion air temperature exiting the air preheater.

Heated Air: Volumetric flow rate of the air at the burners, based on the air temperature at the burners and atmospheric pressure.

Flue Gas Exiting Convective Zone

This the area of the furnace between the combustion zone and the SNCR (if present). Changes in the flue gas after combustion due to in-furnace combustion NO_x controls are reflected here.

Temperature: Temperature of the flue gas exiting the convective zone.

Flue Gas: Volumetric flow rate of the flue gas exiting the convective zone, based on the temperature exiting the convective zone and atmospheric pressure.

Fly Ash: Total solids mass flow rate in the flue gas exiting the convective zone. This includes ash, unburned carbon and unburned sulfur.

Mercury: Total mass of mercury in the flue gas exiting the convective zone. The value is a sum of all the forms of mercury (elemental, oxidized, and particulate).

Flue Gas Exiting the Economizer

Temperature Out: Temperature of the flue gas at the exit of the economizer.

Flue Gas Out: Volumetric flow rate of the flue gas at the exit of the economizer, based on the temperature at the exit of the economizer and atmospheric pressure.

Fly Ash Out: Total solids mass flow rate in the flue gas at the exit of the economizer. This includes ash, unburned carbon and unburned sulfur.

Mercury Out: Total mass of mercury in the flue gas exiting the economizer. The value is a sum of all the forms of mercury (elemental, oxidized, and particulate).

Gas Reburn

Reburn Gas: This is the flow rate of natural gas into the boiler. This result will only display if **Gas Reburn** is selected in the In-Furnace Controls pull-down menu

SNCR

The SNCR is located in the upper portion of the boiler. Several parameters are reported as a summary. These results will only display if **SNCR** or **LNB & SNCR** is selected in the In-Furnace Controls pull-down menu in the **Set Inputs** part of the interface.

Stoic.: This is the actual reagent stoichiometry used in the SNCR. Note that urea has double the moles of nitrogen relative to that of ammonia.

SNCR Reagent: This is the mass flow rate of reagent (urea or ammonia) injected by the SNCR into the boiler. Note that water used to dilute the urea is included in this flow rate.

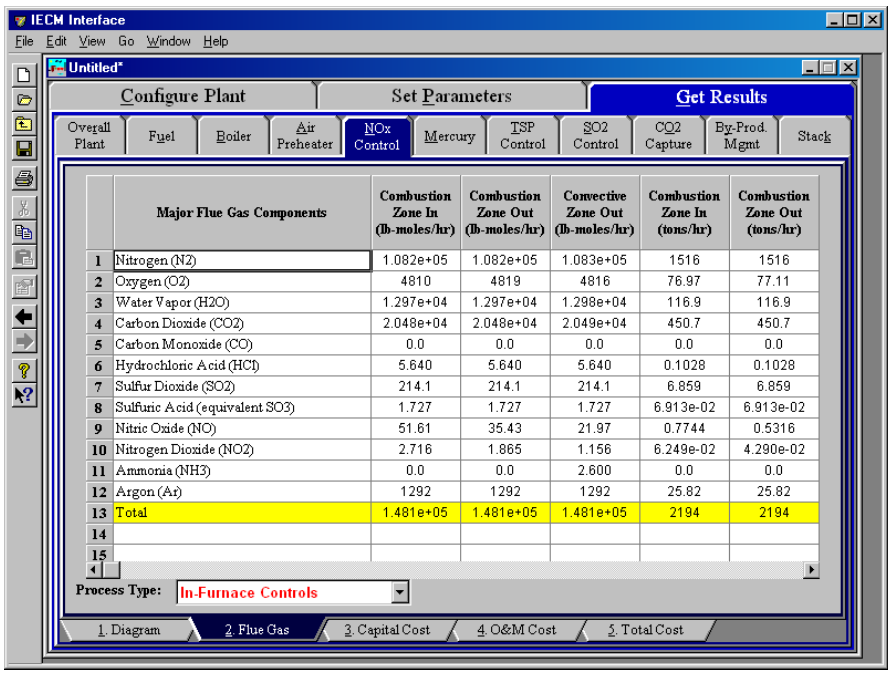
NO_x Removal Performance

Boiler NOx Removal: This is the composite removal efficiency of the boiler NO_x technologies associated with low NO_x burners, overfire air, and reburn. It does not include the removal efficiency of an SNCR system.

SNCR NOx Removal: This is the removal efficiency of the SNCR system alone. It does not take into consideration any other NO_x reduction prior to the SNCR.

In-Furnace Controls Flue Gas Results

This screen is only available for the Combustion (Boiler) plant type.



	Major Flue Gas Components	Combustion Zone In (lb-moles/hr)	Combustion Zone Out (lb-moles/hr)	Convective Zone Out (lb-moles/hr)	Combustion Zone In (tons/hr)	Combustion Zone Out (tons/hr)
1	Nitrogen (N2)	1.082e+05	1.082e+05	1.083e+05	1516	1516
2	Oxygen (O2)	4810	4819	4816	76.97	77.11
3	Water Vapor (H2O)	1.297e+04	1.297e+04	1.298e+04	116.9	116.9
4	Carbon Dioxide (CO2)	2.048e+04	2.048e+04	2.049e+04	450.7	450.7
5	Carbon Monoxide (CO)	0.0	0.0	0.0	0.0	0.0
6	Hydrochloric Acid (HCl)	5.640	5.640	5.640	0.1028	0.1028
7	Sulfur Dioxide (SO2)	214.1	214.1	214.1	6.859	6.859
8	Sulfuric Acid (equivalent SO3)	1.727	1.727	1.727	6.913e-02	6.913e-02
9	Nitric Oxide (NO)	51.61	35.43	21.97	0.7744	0.5316
10	Nitrogen Dioxide (NO2)	2.716	1.865	1.156	6.249e-02	4.290e-02
11	Ammonia (NH3)	0.0	0.0	2.600	0.0	0.0
12	Argon (Ar)	1292	1292	1292	25.82	25.82
13	Total	1.481e+05	1.481e+05	1.481e+05	2194	2194
14						
15						

In-Furnace Controls – Flue Gas result screen.

The **Flue Gas** result screen for **In-Furnace Controls** displays a table of quantities of gas components entering and exiting the combustion zone. For each component, quantities are given in both moles and mass per hour. It also displays quantities of gas components exiting the convective zone in moles per hour. Each result is described briefly below.

Major Flue Gas Components

Nitrogen (N_2): Total mass of nitrogen.

Oxygen (O_2): Total mass of oxygen.

Water Vapor (H_2O): Total mass of water vapor.

Carbon Dioxide (CO_2): Total mass of carbon dioxide.

Carbon Monoxide (CO): Total mass of carbon monoxide.

Hydrochloric Acid (HCl): Total mass of hydrochloric acid.

Sulfur Dioxide (SO_2): Total mass of sulfur dioxide.

Sulfuric Acid (equivalent SO_3): Total mass of sulfuric acid.

Nitric Oxide (NO): Total mass of nitric oxide.

Nitrogen Dioxide (NO_2): Total mass of nitrogen dioxide.

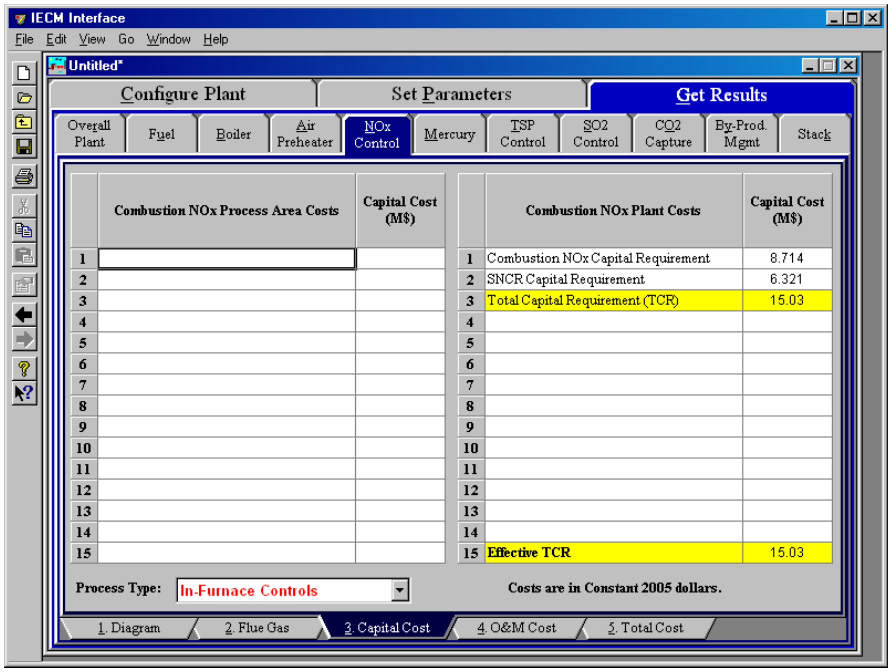
Ammonia (NH_3): Total mass of ammonia.

Argon (Ar): Total mass of argon

Total: Total of the individual components listed above. This item is highlighted in yellow.

In-Furnace Controls Capital Cost Results

This screen is only available for the Combustion (Boiler) plant type.



In-Furnace Controls – Capital Cost result screen.

The **Capital Cost** result screen displays tables for the direct and indirect capital costs related to the **In-Furnace Controls** NO_x control technology. Capital costs are typically expressed in either constant or current dollars for a specified year, as shown on the bottom of the screen.

Total Capital Costs

Combustion NOx Capital Requirement: The total capital costs, including retrofit costs, for the LNB, OFA, and gas reburn technologies are included here. A zero is displayed when none of these technologies are installed.

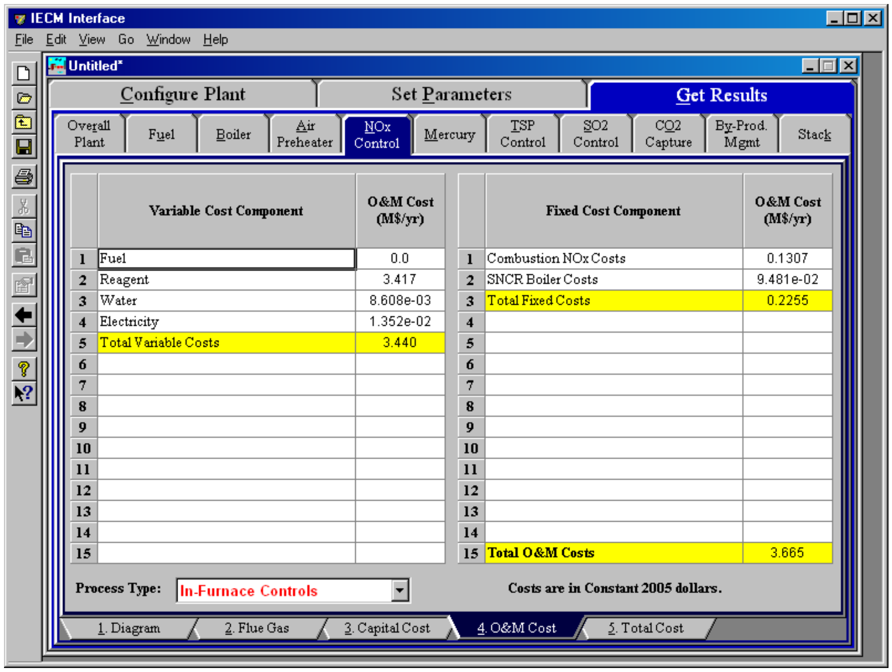
SNCR Capital Requirement: The total capital costs, including retrofit costs, for the SNCR technology is included here. A zero is displayed when an SNCR is not installed.

Total Capital Requirement: Sum of the above**.**

Effective TCR: The TCR of the retrofit NO_x controls that is used in determining the total power plant cost. The effective TCR is determined by the "TCR Recovery Factor" for the hot-side SCR.

In-Furnace Controls O&M Cost Results

This screen is only available for the Combustion (Boiler) plant type.



In-Furnace Controls– O&M Cost result screen.

The **O&M Cost** result screen displays tables for the variable and fixed operation and maintenance costs involved with the **In-Furnace Controls** NO_x control technology. O&M costs are typically expressed on an average annual basis and are provided in either constant or current dollars for a specified year, as shown on the bottom of the screen. Each result is described briefly below

Variable Cost Components

Variable operating costs and consumables are directly proportional to the amount of kilowatts produced and are referred to as incremental costs. All the costs are subject to inflation.

Fuel: The total fuel costs associated with gas reburn are included here.

Reagent: The total reagent costs (urea and ammonia) used for the SNCR system are included here.

Water: This is the cost of the water used to dilute the urea for the SNCR.

Power: This is the power used for the pumps to move reagents and water in the SNCR.

Total Variable Costs: This is the sum of the entire variable O&M costs listed above. This result is highlighted in yellow.

Fixed Cost Components

Fixed operating costs are essentially independent of actual capacity factor, number of hours of operation, or amount of kilowatts produced. All the costs are subject to inflation.

Combustion NOx Costs: This is the fixed O&M costs associated with the LNB, OFA, and gas reburn systems.

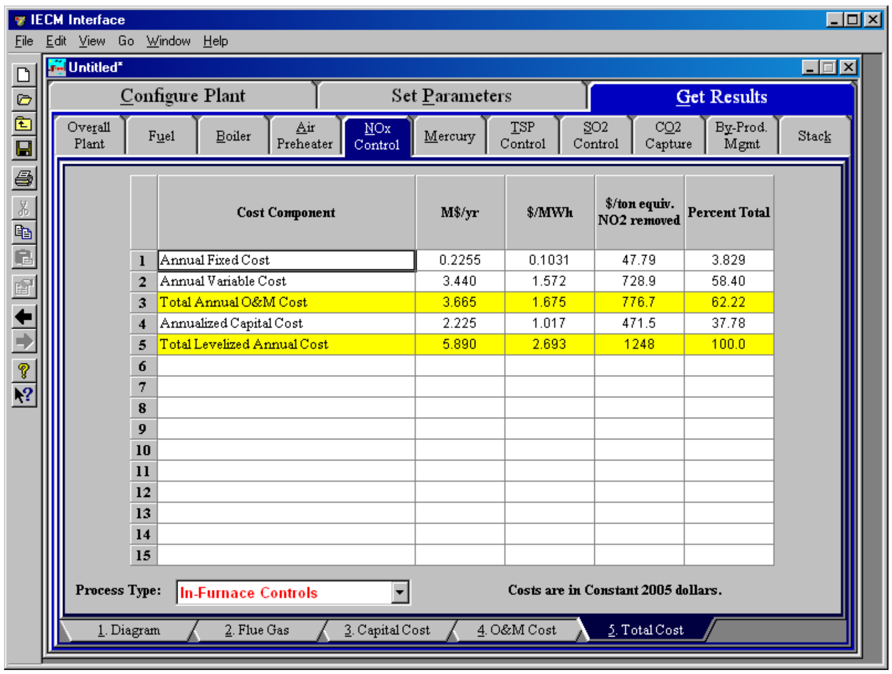
SNCR Boiler Costs: This is the fixed O&M costs associated with the SNCR system.

Total Fixed Costs: This is the sum of all the fixed O&M costs listed above. This result is highlighted in yellow.

Total O&M Costs: This is the sum of the total variable and total fixed O&M costs. It is used to determine the base plant total revenue requirement. This result is highlighted in yellow.

In-Furnace Controls Total Cost Results

This screen is only available for the Combustion (Boiler) plant type.



In-Furnace Controls – Total Cost result screen

Cost Component

The **Total Cost** result screen displays a table which totals the annual fixed, variable, operations and maintenance, and capital costs associated with the **In-Furnace Controls** NO_x Control technology. These costs are typically expressed in either constant or current dollars for a specified year, as shown on the bottom of the screen. Each result is described briefly below. Note that all costs expressed in $/ton of NO_2 removed assume tons of equivalent NO_2.

Annual Fixed Cost: The operating and maintenance fixed costs are given as an annual total. This number includes all maintenance materials and all labor costs.

Annual Variable Cost: The operating and maintenance variables costs are given as an annual total. This includes all reagent, chemical, steam, and power costs.

Total Annual O&M Cost: This is the sum of the annual fixed and variable operating and maintenance costs above. This result is highlighted in yellow.

Annualized Capital Cost: This is the total capital cost expressed on an annualized basis, taking into consideration the levelized carrying charge factor, or fixed charge factor, over the entire book life.

Total Levelized Annual Cost: The total annual cost is the sum of the total annual O&M cost and annualized capital cost items above. This result is highlighted in yellow.

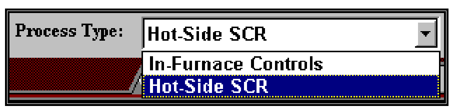
Hot-Side SCR

The **NOx Control** Technology Navigation Tab contains screens that address combustion or post-combustion air pollution technologies for Nitrogen Oxides in the **Combustion (Boiler)** plant type configurations.

If you have selected a Hot-Side SCR, there will be six input screens and therefore six Input Navigation Tabs. If you have selected In-Furnace Controls, there will be four input screens and therefore four Input Navigation Tabs.

These input screens are only available if a Hot-Side SCR has been selected under Post-Combustion Controls in the **Configure Plant** program area.

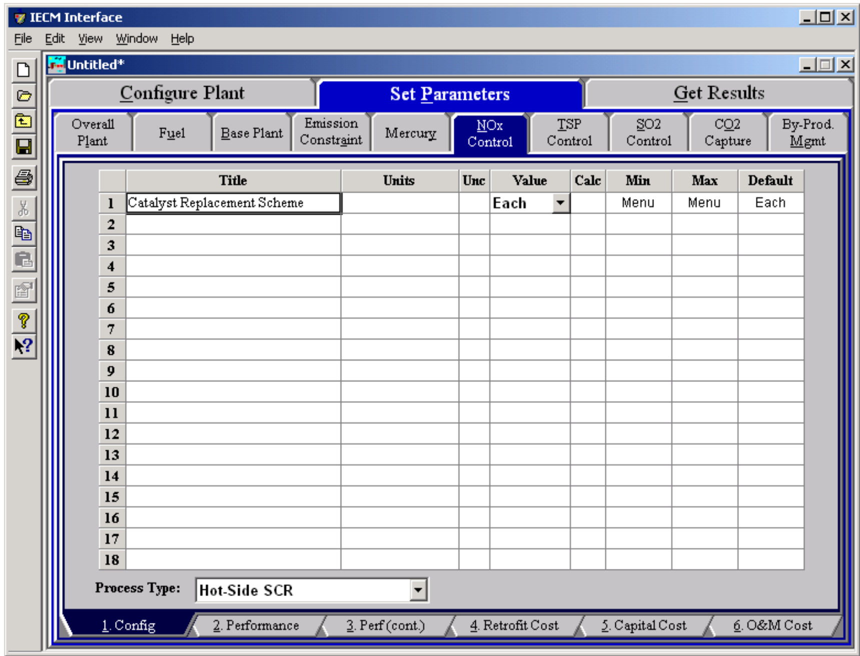
If you have selected both In-Furnace Controls and a Hot-Side SCR for NO_x control, you may switch between the two sets of screens that configure these technologies by using the Process Type pull-down menu at the bottom of the screen.



The Process Type pull-down menu

Hot-Side SCR Configuration

This screen is only available for the Combustion (Boiler) plant type.



Hot–Side SCR – Config. input screen.

Inputs for configuring the **Hot–Side SCR** NO_x Control technology are entered on the **Config** input screen. Each parameter is described briefly below.

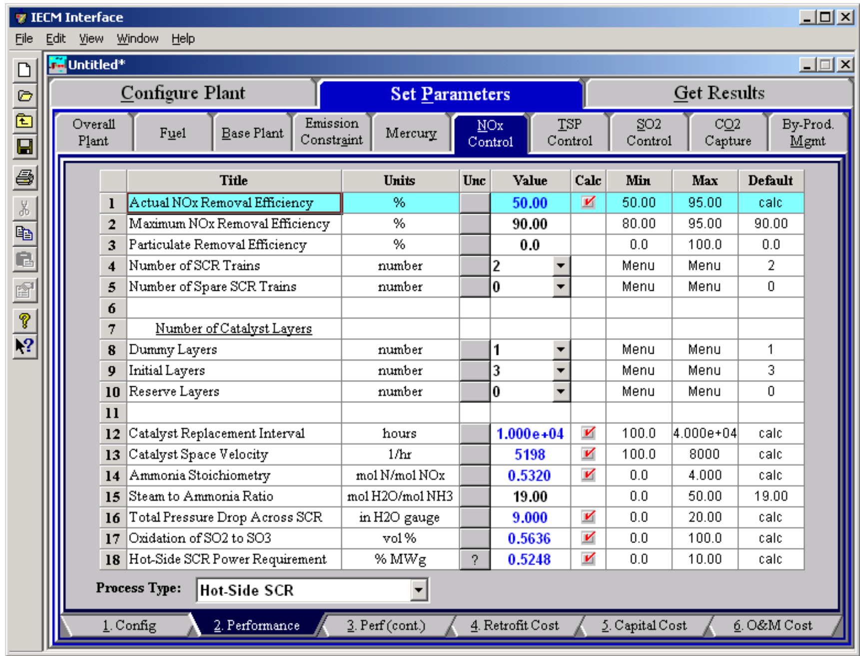
Catalyst Replacement Scheme: Catalyst is installed in the SCR as a series of layers. These activity or effectiveness of these layers decreases with time due to fouling and poisoning. The layers are replaced with clean layers on a regular basis in one of two ways: all at once or one layer at time (staggered). The selection of the replacement scheme involves trade-offs between capital and annual costs via the initial catalyst requirement and the replacement interval. More specifically:

- **Each** – Individual Layers. Replacing individual layers sequentially, rather than simultaneously, increases the effective catalyst life for a given volume of catalyst, decreasing the replacement interval. This reduces the O&M cost relative to simultaneous replacement.The default setting is **Each**.

- **All** – All Layers: Simultaneous replacement may lead to a smaller initial catalyst volume to achieve the same design activity as a sequential replacement scheme. This reduces the capital cost but increases the O&M cost.

Hot-Side SCR Performance Inputs

This screen is only available for the Combustion (Boiler) plant type.



Hot–Side SCR – Performance input screen.

Inputs for the performance of the **Hot–Side SCR** NO_x control technology are entered on the on the **Performance** input screen. Each parameter is described briefly below.

Actual NOx Removal Efficiency: The actual removal efficiency is dependent on the minimum and maximum removal efficiencies of the SCR and the emission constraint for NO_x. The model assumes a minimum removal of 50%. The actual removal is set to match the constraint, if feasible. It is possible that the SCR may under or over comply with the emission constraint. This input is highlighted in blue.

Maximum NOx Removal Efficiency: This parameter specifies the maximum efficiency possible for the absorber on an annual average basis. The value is used as a limit in calculating the actual NO_x removal efficiency for compliance.

Particulate Removal Efficiency: The ash in the high dust gas entering the SCR collects on the catalyst layers and causes fouling. Ash removal is not a design goal; rather, it is a reality which is taken into consideration by this parameter.

Number of SCR Trains: This is the total number of SCR equipment trains. It is used primarily to calculate the capital costs. The value must be an integer.

Number of Spare SCR Trains: This is the total number of spare SCR equipment trains. It is used primarily to calculate capital costs. The value must be an integer.

Number of Catalyst Layers: The total number of catalyst layers is a sum of the dummy, initial and spares used. All catalyst layer types are of equal dimensions, geometry, and catalyst formulation. You specify each value; the value must be an integer. The catalyst layer types and quantities are combined with pressure drop information to determine the auxiliary power requirements and the capital cost of the SCR technology. A layer may be interpreted as either a full layer (e.g., typically 1 meter deep), or a half layer (e.g., typically 0.5 meters deep) to represent alternative SCR catalyst replacement schemes. There is a limit of 8 total initial and reserve layers.

- **Dummy Layers:** This is the number of dummy catalyst layers. The value must be an integer. A dummy layer corrects the flow distribution. It is used to calculate the total pressure drop across the SCR and the auxiliary power requirements.
- **Initial Layers:** This is the number of initial active catalyst layers. The value must be an integer. Three layers are installed initially. It is used to calculate the total pressure drop across the SCR and the auxiliary power requirements.
- **Reserve Layers:** This is the number of reserve or extra catalyst layers. These are available for later catalyst additions. The value must be an integer. It is used to calculate the total pressure drop across the SCR and the auxiliary power requirements.

Catalyst Replacement Interval: This parameter calculates the operating hour interval between catalyst replacements. The interval is determined by the decision to replace all at once or each of them separately after each interval. Currently, the model is not set up to replace two half layers simultaneously.

Catalyst Space Velocity: The calculated space velocity is determined by several factors, including many of the reference parameters in the next Section. The space velocity is used to determine the catalyst volume required.

Ammonia Stoichiometry: This is the molar stoichiometry ratio of ammonia to NO_x entering the SCR device. The calculated quantity is based on an assumed NO_x removal reaction stoichiometry of 1:1 for both NO and NO_2, and a specified ammonia slip. It affects the amount of ammonia used and the amount of NO_x converted to moisture.

Steam to Ammonia Ratio: The molar ratio of steam to ammonia is used to determine the amount of steam injected to vaporize the ammonia. The value assumes the steam is saturated at 450 degrees Fahrenheit and the ammonia is diluted to 5 volume percent of the injected gas.

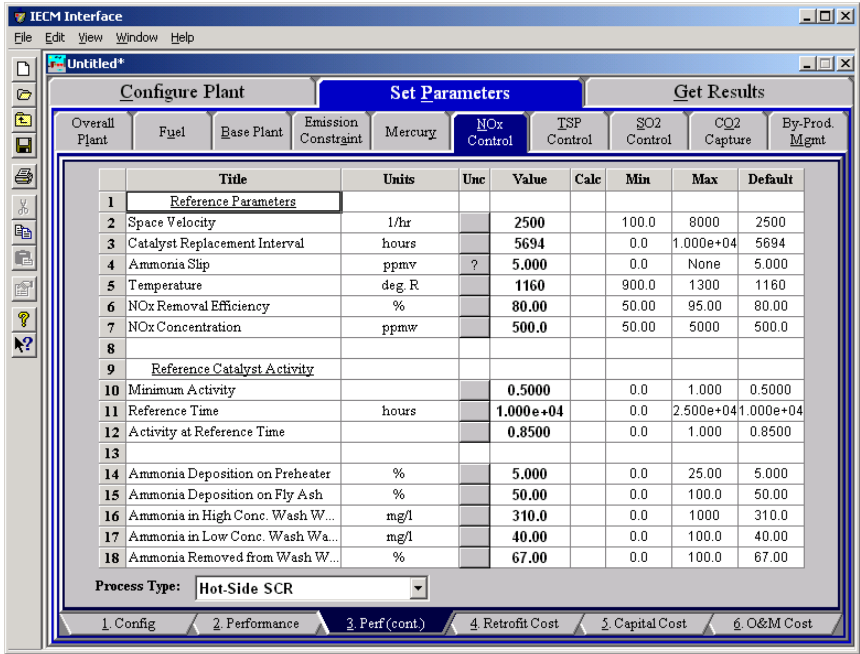
Total Pressure Drop Across SCR: The total is determined from the individual pressure drops due to air preheater deposits, the active catalyst layers, the dummy catalyst layers, the ammonia injection system and the duct work. It is used to calculate the total pressure drop across the SCR and the auxiliary power requirements.

Oxidation of SO_2 to SO_3: The oxidation rate is calculated for a high sulfur catalyst and affects the flue gas composition. It uses the space velocity and the inlet temperature. The SO_3 produced acts as an ash-conditioning agent if an ESP is used downstream.

Hot-Side SCR Power Requirement: The default calculation of auxiliary power is based on the additional pressure drop, electricity to operate pumps and compressors, and equivalent energy for steam consumed. It is expressed as a percent of the gross plant capacity.

Hot-Side SCR Performance (Continued)

This screen is only available for the Combustion (Boiler) plant type.



Hot–Side SCR – Perf.(cont.) input screen

The Hot-Side SCR system has additional inputs for performance entered on the **Perf (Cont.)** input screen. Many of the calculated quantities on the **Performance** screen are determined by the reference parameters described below.

Reference Parameters

The first set of reference parameters is primarily used to determine the actual space velocity. The values are used with actual operating conditions through a series of correction factors in the IECM. If you set the actual space velocity displayed on the **Performance** screen, this set of input parameters is not used by the IECM and does not have to be set.

Space Velocity: This is the reference space velocity for a high dust system. It is used to calculate the actual space velocity.

Catalyst Replacement Interval: This is the reference operating life in hours associated with the reference space velocity for the high dust catalyst. It is used to calculate the actual space velocity.

Ammonia Slip: Ammonia slip accounts for the ammonia passing through the reactor unchanged and further downstream. The value is based on an 80 percent or lower NO_x removal efficiency. It is used in calculating the ammonia stoichiometry and actual space velocity.

Temperature: This is the operating temperature associated with the reference space velocity. It is used to determine the actual space velocity.

NO_x Removal Efficiency: This is the NO_x removal efficiency associated with the reference design specifications for the SCR system. It is used to determine the actual space velocity.

NO_x Concentration: This is the inlet NO_x concentration associated with the reference design specifications for the SCR system. It is used to determine the actual space velocity

Reference Catalyst Activity

Catalyst activity decreases with operating time due to plugging and catalyst poisoning. The loss is a complex function of the catalyst formulation and geometry, the operating conditions associated with the flue gas, including temperature and composition, and the loading and composition of the fly ash. This complex function is represented by an exponential decay formula in the IECM. The following parameters are used to determine the reference catalyst activity, assuming the initial activity has a value of unity:

Minimum Activity: The minimum activity is a lower limit for catalyst activity decay. The actual activity approaches this value over a long period of time.

Reference Time: This is the time that corresponds to a particular activity known for the catalyst. It is used to determine a decay rate constant.

Activity at Reference Time: A second activity reference point is needed to determine the activity decay rate. The activity should correspond to the reference time specified. It is used to determine a decay rate constant.

Ammonia Deposition on Preheater: This is the percent of the ammonia slip that is deposited as ammonium salts in the air preheater. It is treated like a partition coefficient.

Ammonia Parameters

Ammonia Deposition on Fly Ash: This is the percent of the ammonia slip that is absorbed onto the fly ash. It is treated like a partition coefficient. This is important for high dust systems.

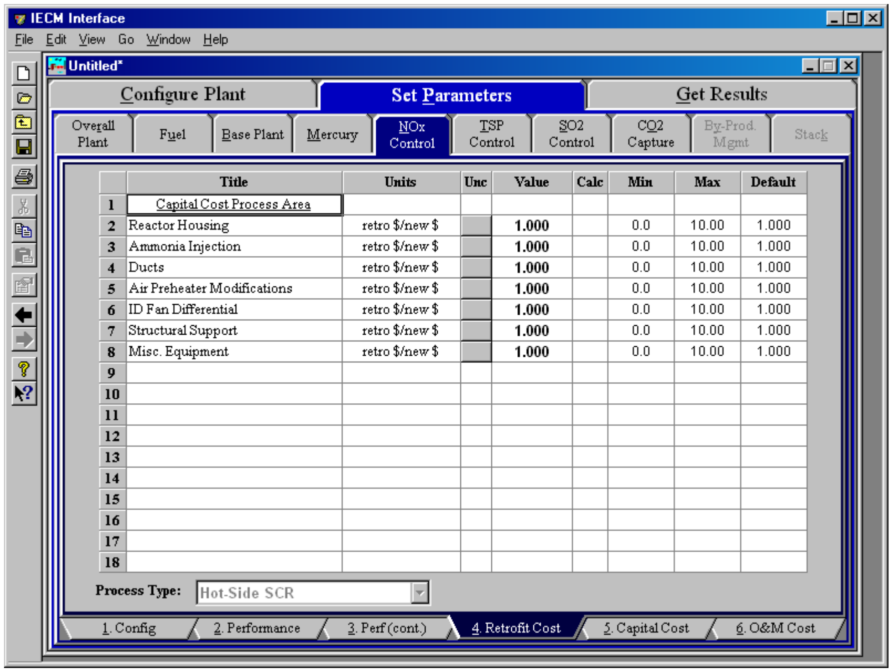
Ammonia in High Conc. Wash Water: The ammonia that deposits in the air preheater is periodically removed by washing. It is initially highly concentrated and requires denitrification pretreatment prior to regular treatment. This is the average concentration in that stream.

Ammonia in Low Conc. Wash Water: The ammonia that deposits in the air preheater is periodically removed by washing. The concentration is initially high, but gradually decreases. This is the average concentration of the low concentration stream.

Ammonia Removed from Wash Water: The ammonia that deposits in the air preheater is periodically removed by washing. This is the average amount of ammonia removed from the high and low concentrated streams.

Hot-Side SCR Retrofit Cost

This screen is only available for the Combustion (Boiler) plant type.



Hot–Side SCR – Retrofit Cost input screen.

The **Hot-Side SCR** system has inputs for the capital costs of modifications to process areas necessary to implement the technology entered on the **Retrofit Cost** input screen.

The retrofit cost factor of each process is a multiplicative cost adjustment, which considers the cost of retrofitted capital equipment relative to similar equipment installed in a new plant. These factors affect the capital costs directly and the operating and maintenance costs indirectly.

Direct capital costs for each process area are calculated in the IECM. These calculations are reduced form equations derived from more sophisticated models and reports. The sum of the direct capital costs associated with each process area is defined as the process facilities capital (PFC). The retrofit cost factor provided for each of the process areas can be used as a tool for adjusting the anticipated costs and uncertainties across the process area separate from the other areas.

Uncertainty can be applied to the retrofit cost factor for each process area in each technology. Thus, uncertainty can be applied as a general factor across an entire process area, rather than as a specific uncertainty for the particular cost on the capital or O&M input screens. Any uncertainty applied to a process area through the retrofit cost factor compounds any uncertainties specified later in the capital and O&M cost input parameter screens. Each parameter is described briefly below.

Capital Cost Process Area

Reactor Housing: The reactor housing costs include carbon steel reactor vessel with six inches of mineral wool insulation, vessel internals and supports, steam sootblowers, reactor crane and hoist, installation, labor, foundations, structures, piping, and electrical equipment.

Ammonia Injection: The ammonia unloading, storage, and supply system includes a storage vessel with a seven day capacity, an ammonia vaporizer, mixer, injection grid, ductwork, dampers, and a truck unloading station.

Ducts: The ductwork includes economizer bypass and outlet ducts, SCR inlet and outlet ducts, SCR and economizer control dampers, air preheater inlet plenum, various expansion joints in the ductwork, and air preheater cross-over ducting.

Air Preheater Modifications: Thicker and smoother material is used for the heat transfer surfaces in the preheater. A larger motor is provided for the heat exchanger. High pressure steam soot blowers and water wash spray nozzles are also added.

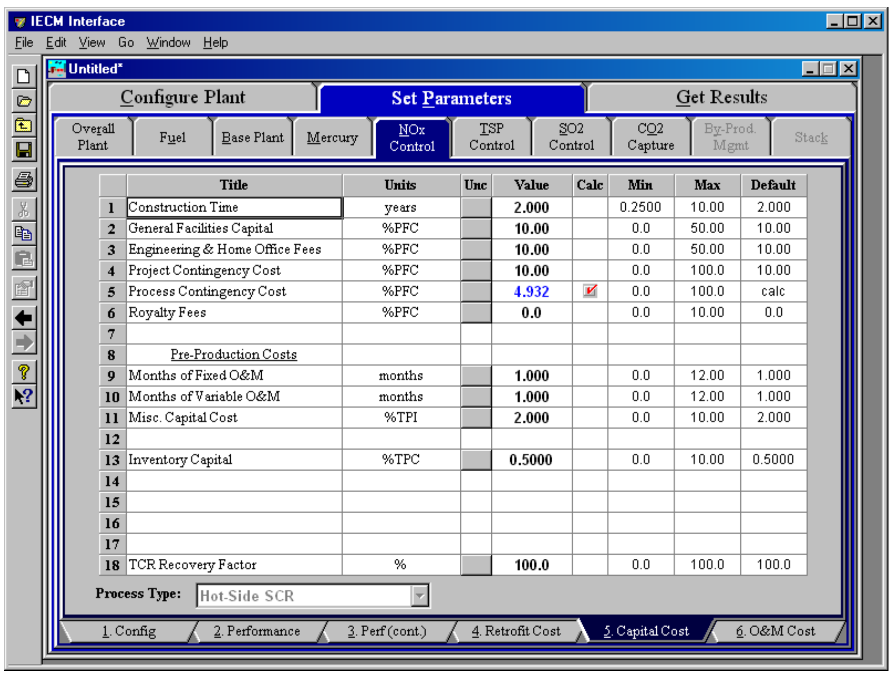
ID Fan Differential: The ID fans must be sized to deal with the increased flue gas pressure drop resulting from the additional ductwork and the SCR reactor.

Structural Support: The costs of this area are related primarily to the structural support required for the SCR reactor housing, ductwork, and air preheater.

Misc. Equipment: This area includes the capital costs incurred for ash handling addition, water treatment addition, and flow modeling for a hot-side SCR system.

Hot-Side SCR Capital Cost Inputs

This screen is only available for the Combustion (Boiler) plant type.



Hot–Side SCR – Capital Cost input screen.

Inputs for the capital costs of the **Hot–Side SCR** NO_x control technology are entered on the **Capital Cost** screen for the Hot-Side SCR, and the **Capital Cost** input screen for In-Furnace Controls. Each parameter is described briefly below.

Construction Time: This is the idealized construction period in years. It is used to determine the allowance for funds used during construction (AFUDC).

General Facilities Capital (GFC): 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%.

Engineering & Home Office Fees: The engineering & home office fees are a percent of total direct capital cost. This is an overhead fee paid to the architect/engineering company. These fees typically range from 7-15%.

Project Contingency Cost: This is 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.

Process Contingency Cost: 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.

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

Pre-Production Costs: 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 applied to the O&M costs over a specified period of time (months). The two time periods for fixed and variable O&M costs are described below with the addition of a miscellaneous capital cost factor.

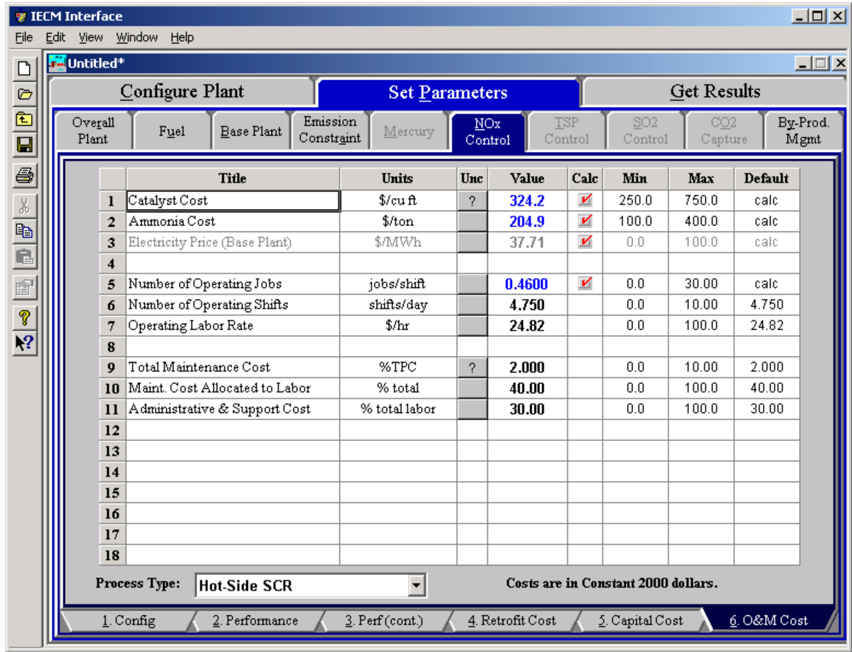
- **Months of Fixed O&M:** Time period of fixed operating costs used for preproduction to cover training, testing, major changes in equipment, and inefficiencies in start-up. This includes operating, maintenance, administrative and support labor. It also considers maintenance materials.
- **Months of Variable O&M:** Time period of variable operating costs used for preproduction to cover chemicals, water, consumables, and solid disposal charges in start-up, assuming 100% load. This excludes any fuels.
- **Misc. Capital Costs:** This is a percent of total plant investment (sum of TPC and AFUDC) to cover expected changes to equipment to bring the system up to full capacity.

Inventory Capital: Percent of the total direct capital for raw material supply based on 100% capacity during a 60 day period. These materials are considered storage. The inventory capital includes fuels, consumables, by-products, and spare parts. This is typically 0.5%.

TCR Recovery Factor: The actual total capital required (TCR) as a percent of the TCR in a new power plant. This value is 100% for a new installation and may be set as low as 0% for a hot-side SCR that has been paid off.

Hot-Side SCR O&M Cost Inputs

This screen is only available for the Combustion (Boiler) plant type.



Hot–Side SCR – O&M Cost input screen.

Inputs for the operation and maintenance costs of the **Hot–Side SCR** NO_x control technology are entered on the **O&M Cost** input screen. O&M costs are typically expressed on an average annual basis and are provided in either constant or current dollars for a specified year, as shown on the bottom of the screen. Each parameter is described briefly below.

Catalyst Cost: This is the cost of the catalyst used for the SCR technology.

Ammonia Cost: This is the cost of the ammonia used for the SCR technology.

Electricity Price (Base Plant): This is the price of electricity and is calculated as a function of the utility cost of the base plant, where the base plant is a combustion boiler and an air preheater.

Number of Operating Jobs: This is the total number of operating jobs that are required to operate the plant per eight-hour shift.

Number of Operating Shifts: This is the total number of equivalent operating shifts in the plant per day. The number takes into consideration paid time off and weekend work (3 shifts/day * 7 days/5 day week * 52 weeks/(52 weeks - 6 weeks PTO) = 4.75 equiv. Shifts/day).

Operating Labor Rate: The hourly cost of labor is specified in the base plant O&M cost screen. The same value is used throughout the other technologies.

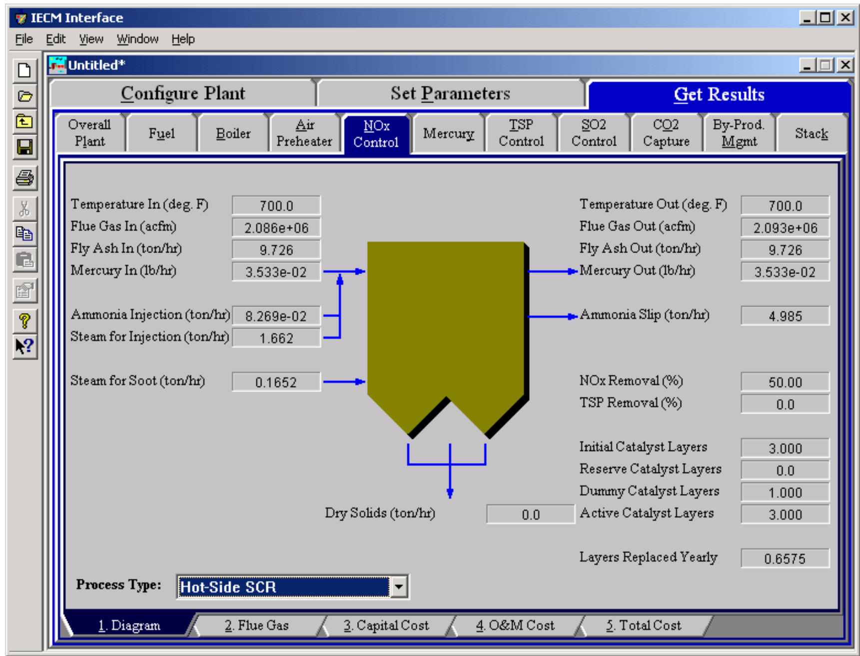
Total Maintenance Cost: This is the annual maintenance cost as a percentage of the total plant cost. Maintenance cost estimates can be developed separately for each process area.

Maint. Cost Allocated to Labor: Maintenance cost allocated to labor as a percentage of the total maintenance cost.

Administrative & Support Cost: This is the percent of the total operating and maintenance labor associated with administrative and support labor.

Hot-Side SCR Diagram

This screen is only available for the Combustion (Boiler) plant type.



Hot–Side SCR – Diagram result screen.

The **Diagram** result screen displays an icon for the **Hot–Side SCR** NO_x technology selected and values for major flows in and out of it.

Reagent

Ammonia Injection: The total mass flow rate of ammonia injected into the SCR. This is a function of the NO_x concentration in the flue gas and the ammonia stoichiometric performance input value.

Steam for Injection: The total mass flow rate of steam into the SCR. This is the amount of steam added to the SCR to vaporize and transport ammonia into the inlet gas stream. This is determined by the steam to ammonia ratio input value and the ammonia injection.

Catalyst

Steam for Soot: This is the amount of steam blown into the hot-side SCR to remove soot buildup on the catalyst layers. The soot blowing steam is assumed to be directly proportional to catalyst volume.

Initial Catalyst Layers: This is the number of initial active catalyst layers. Three layers are installed initially. It is used to calculate the total pressure drop across the SCR and the auxiliary power requirements. This is set by the input parameter.

Reserve Catalyst Layers: This is the number of reserve or extra catalyst layers. These are available for later catalyst additions. It is used to calculate the total pressure drop across the SCR and the auxiliary power requirements. This is set by the input parameter.

Dummy Catalyst Layers: This is the number of dummy catalyst layers. A dummy layer corrects the flow distribution. It is used to calculate the total pressure drop across the SCR and the auxiliary power requirements. This is set by the input parameter.

Active Catalyst Layers: This is the number of initial active catalyst layers. Three layers are installed initially. It is used to calculate the total pressure drop across the SCR and the auxiliary power requirements. It is equal to the number of initial and reserve catalyst layers.

Layers Replaced Yearly: Average catalyst layer replacement rate per year. This assumes that all catalyst layers are of equal depth.

Flue Gas Entering SCR

Temperature In: Temperature of the flue gas entering the SCR. This is determined by the flue gas outlet temperature of the module upstream of the SCR (e.g., the boiler economizer)

Flue Gas In: Volumetric flow rate of flue gas entering the SCR, based on the flue gas temperature entering the SCR and atmospheric pressure.

Fly Ash In: Total solids mass flow rate in the flue gas entering the SCR. This is determined by the solids exiting from the module upstream of the SCR (e.g., the boiler economizer).

Mercury In: Total mass of mercury entering the hot-side SCR in the flue gas. The value is a sum of all the forms of mercury (elemental, oxidized, and particulate).

Flue Gas Exiting SCR

Temperature Out: Temperature of the flue gas exiting the SCR. The model currently does not alter this temperature through the SCR.

Flue Gas Out: Volumetric flow rate of the flue gas exiting the SCR, based on the flue gas temperature exiting the SCR and atmospheric pressure.

Fly Ash Out: Total solids mass flow rate in the flue gas exiting the SCR. This is a function of the ash removal parameter on the SCR performance input screen.

Ammonia Slip: Total mass flow rate of ammonia that is unreacted and exits the SCR in the flue gas stream. This is a function if the ammonia injection flow rate, NO_x concentration in the flue gas, and NO_x removal efficiency.

Mercury Out: Total mass of mercury exiting the hot-side SCR in the flue gas. The value is a sum of all the forms of mercury (elemental, oxidized, and particulate).

SCR Performance

NOx Removal: Actual removal efficiency of NO_x in the SCR. This is a function of the minimum (50%) and maximum removal efficiencies

(SCR performance input parameter) and the emission constraint for NO_x (emission constraints input parameter). It is possible that the SCR may over or under-comply with the emission constraint.

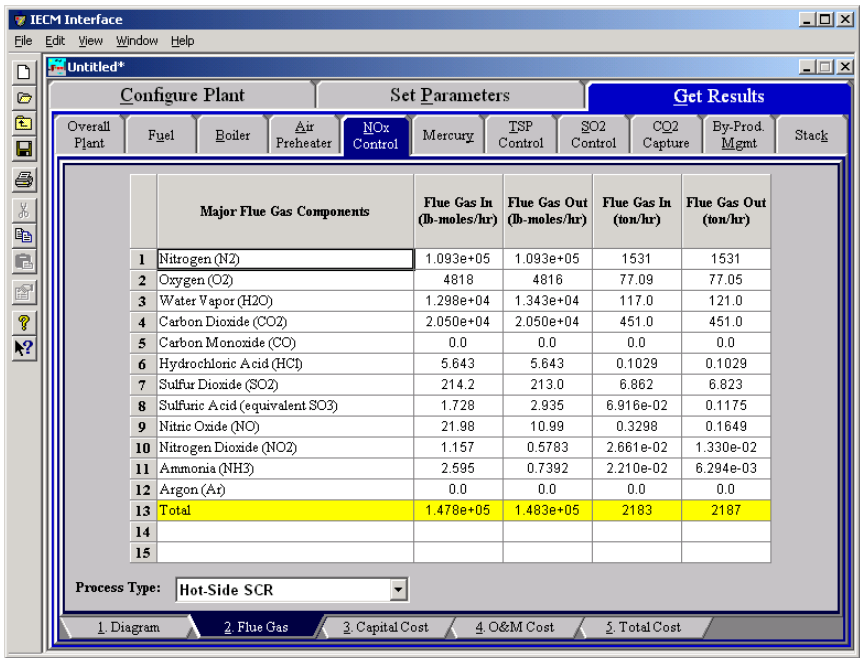
TSP Removal: Actual particulate removal efficiency in the SCR. This is set by the SCR input parameter.

Collected Solids

Dry Solids: Total solids mass flow rate of solids removed from the SCR. This is a function of the solids content in the flue gas and the particulate removal efficiency of the SCR.

Hot-Side SCR Flue Gas Results

This screen is only available for the Combustion (Boiler) plant type.



	Major Flue Gas Components	Flue Gas In (lb-moles/hr)	Flue Gas Out (lb-moles/hr)	Flue Gas In (ton/hr)	Flue Gas Out (ton/hr)
1	Nitrogen (N2)	1.093e+05	1.093e+05	1531	1531
2	Oxygen (O2)	4818	4816	77.09	77.05
3	Water Vapor (H2O)	1.298e+04	1.343e+04	117.0	121.0
4	Carbon Dioxide (CO2)	2.050e+04	2.050e+04	451.0	451.0
5	Carbon Monoxide (CO)	0.0	0.0	0.0	0.0
6	Hydrochloric Acid (HCl)	5.643	5.643	0.1029	0.1029
7	Sulfur Dioxide (SO2)	214.2	213.0	6.862	6.823
8	Sulfuric Acid (equivalent SO3)	1.728	2.935	6.916e-02	0.1175
9	Nitric Oxide (NO)	21.98	10.99	0.3298	0.1649
10	Nitrogen Dioxide (NO2)	1.157	0.5783	2.661e-02	1.330e-02
11	Ammonia (NH3)	2.595	0.7392	2.210e-02	6.294e-03
12	Argon (Ar)	0.0	0.0	0.0	0.0
13	Total	1.478e+05	1.483e+05	2183	2187
14					
15					

Hot–Side SCR – Flue Gas result screen.

Major Flue Gas Components

The **Flue Gas** result screen for the **Hot-Side SCR** displays a table of quantities of flue gas components entering and exiting the SCR. For each component, quantities are given in both moles and mass per hour. Each result is described briefly below.

Nitrogen (N_2): Total mass of nitrogen.

Oxygen (O_2): Total mass of oxygen.

Water Vapor (H_2O): Total mass of water vapor.

Carbon Dioxide (CO_2): Total mass of carbon dioxide.

Carbon Monoxide (CO): Total mass of carbon monoxide.

Hydrochloric Acid (HCl): Total mass of hydrochloric acid.

Sulfur Dioxide (SO_2): Total mass of sulfur dioxide.

Sulfuric Acid (equivalent SO_3): Total mass of sulfuric acid.

Nitric Oxide (NO): Total mass of nitric oxide.

Nitrogen Dioxide (NO_2): Total mass of nitrogen dioxide.

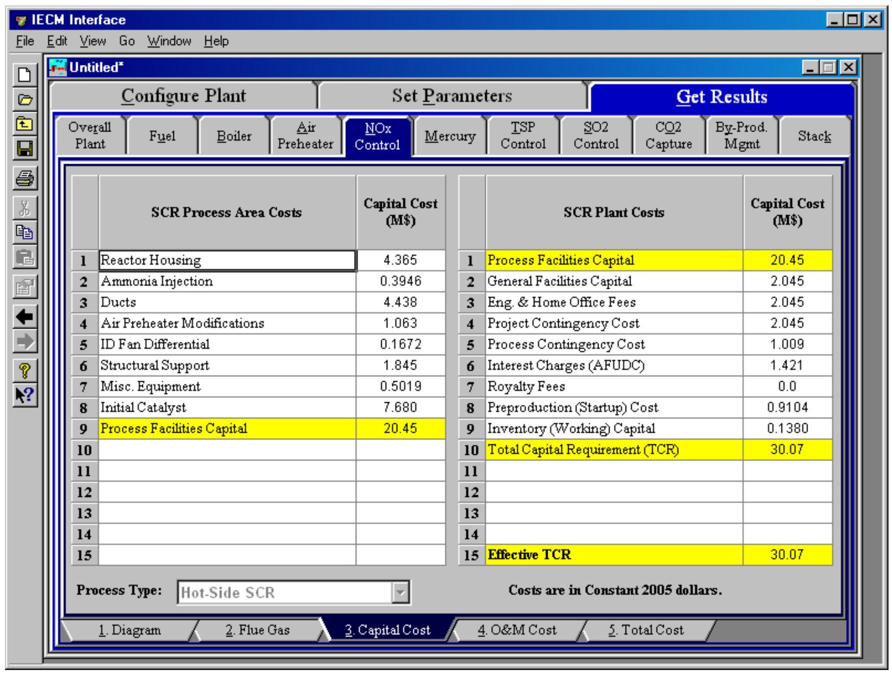
Ammonia (NH_3): Total mass of ammonia.

Argon (Ar): Total mass of argon

Total: Total of the individual components listed above. This item is highlighted in yellow.

Hot-Side SCR Capital Cost Results

This screen is only available for the Combustion (Boiler) plant type.



Hot-Side SCR – Capital Cost result screen.

The **Capital Cost** result screen displays tables for the direct and indirect capital costs related to the **Hot–Side SCR** NO_x control technology. Capital costs are typically expressed in either constant or current dollars for a specified year, as shown on the bottom of the screen. Each result is described briefly below:

Direct Capital Costs

Each process area direct capital cost is a reduced-form model based on regression analysis of data collected from several reports and analyses of hot-side SCR units. They are described in general with specific model parameters that effect them described in particular.

Reactor Housing: The reactor housing costs include carbon steel reactor vessel with six inches of mineral wool insulation, vessel internals and supports, steam soot blowers, reactor crane and hoist, installation labor, foundations, structures, piping, and electrical equipment. The costs are a function of the number of vessels, including spares, and the volume of catalyst required. Catalyst costs are excluded.

Ammonia Injection: The ammonia unloading, storage, and supply system includes a storage vessel with a seven day capacity, an ammonia vaporizer, mixer, injection grid, ductwork, dampers, and a truck unloading station. The costs are a function of the ammonia injected.

Ducts: The ductwork includes economizer bypass and outlet ducts, SCR inlet and outlet ducts, SCR and economizer control dampers, air preheater inlet plenum, various expansion joints in the ductwork, and air preheater cross-over ducting. The costs are a function of the flue gas flow rate through the SCR.

Air Preheater Modifications: Thicker and smoother material is used for the heat transfer surfaces in the preheater. A larger motor is provided for the heat exchanger. High pressure steam soot blowers and water wash spray nozzles are also added. The costs are a function of the number of operating vessels, and the heat transfer efficiency of the air preheater (UA product).

ID Fan Differential: The ID fans must be sized to deal with the increased flue gas pressure drop resulting from the additional ductwork and the SCR reactor. The costs are a function of the flue gas flow rate and pressure drop across the SCR.

Structural Support: The costs of this area are related primarily to the structural support required for the SCR reactor housing, ductwork, and air preheater. The costs are a function of the reactor housing costs, duct costs and air preheater modification costs above.

Misc. Equipment: This area includes the capital costs incurred for ash handling addition, water treatment addition, and flow modeling for a hot-side SCR system. The costs are a function of the gross plant capacity.

Initial Catalyst: The cost of the initial catalyst charge is included in the total direct cost, because it is such a large and integral part of the SCR system. The costs are a function of the initial catalyst charge.

Process Facilities Capital: The process facilities capital is the total constructed cost of all on-site processing and generating units listed above, including all direct and indirect construction costs. All sales taxes and freight costs are included where applicable implicitly. This result is highlighted in yellow.

Total Capital Costs

Process Facilities Capital: (see definition above)

General Facilities Capital: The general facilities include construction costs of roads, office buildings, shops, laboratories, etc. Sales taxes and freight costs are included implicitly.

Eng. & Home Office Fees: The engineering & home office fees are a percent of total direct capital cost. This is an overhead fee paid to the architect/engineering company.

Project Contingency Cost: Capital cost contingency factor covering the cost of additional equipment or other costs that would result from a more detailed design of a definitive project at the actual site.

Process Contingency Cost: Capital cost contingency factor applied to a new technology in an effort to quantify the uncertainty in the technical performance and cost of the commercial-scale equipment.

Interest Charges (AFUDC): Allowance for funds used during construction, also referred to as interest during construction, is the time value of the money used during construction and is based on an interest rate equal to the before-tax weighted cost of capital. This interest is compounded on an annual basis (end of year) during the construction period for all funds spent during the year or previous years.

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

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.

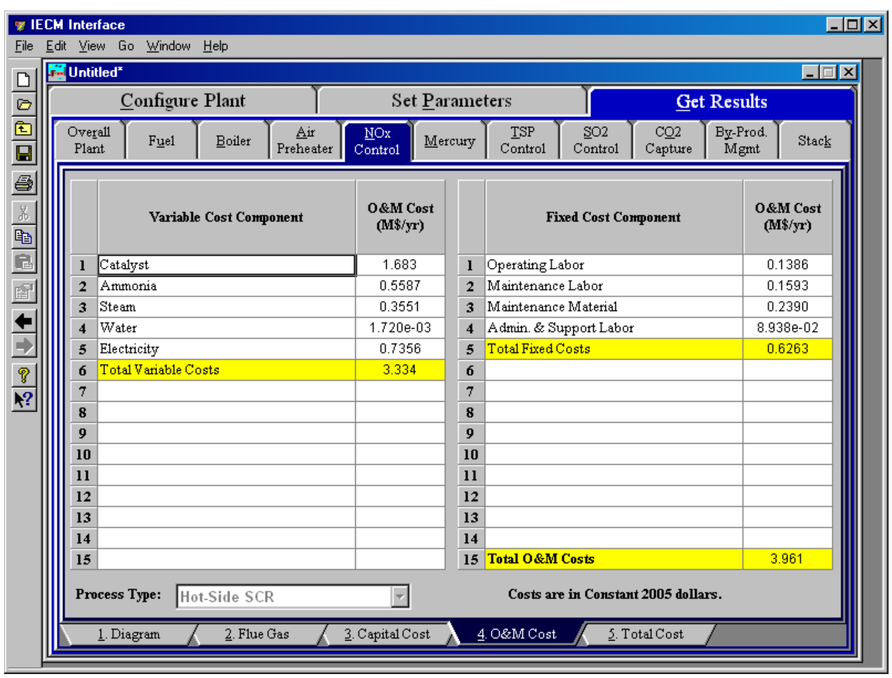
Inventory (Working) Capital: The raw material supply based on 100% capacity during a 60 day period. These materials are considered storage. The inventory capital includes fuels, consumables, by-products, and spare parts.

Total Capital Requirement (TCR): Money that is placed (capitalized) on the books of the utility on the service date. TCR includes all the items above. This result is highlighted in yellow.

Effective TCR: The TCR of the hot-side SCR that is used in determining the total power plant cost. The effective TCR is determined by the "TCR Recovery Factor" for the hot-side SCR.

Hot-Side SCR O&M Cost Results

This screen is only available for the Combustion (Boiler) plant type.



	Variable Cost Component	O&M Cost (M$/yr)		Fixed Cost Component	O&M Cost (M$/yr)
1	Catalyst	1.683	1	Operating Labor	0.1386
2	Ammonia	0.5587	2	Maintenance Labor	0.1593
3	Steam	0.3551	3	Maintenance Material	0.2390
4	Water	1.720e-03	4	Admin. & Support Labor	8.938e-02
5	Electricity	0.7356	5	Total Fixed Costs	0.6263
6	Total Variable Costs	3.334	6		
7			7		
8			8		
9			9		
10			10		
11			11		
12			12		
13			13		
14			14		
15			15	Total O&M Costs	3.961

Hot-Side SCR – O&M Cost result screen.

The **O&M Cost** result screen displays tables for the variable and fixed operation and maintenance costs involved with the **Hot Side SCR** NO_x control technology. O&M costs are typically expressed on an average annual basis and are provided in either constant or current dollars for a specified year, as shown on the bottom of the screen. Each result is described briefly below:

Variable Cost Components

Variable operating costs and consumables are directly proportional to the amount of kilowatts produced and are referred to as incremental costs. All the costs are subject to inflation.

Catalyst: Replacement catalyst cost per year for the hot-side SCR. This is a function of the number of catalyst layers, the number of layers replaced each year, and the catalyst space velocity (all three are performance input parameters).

Ammonia: Ammonia reagent cost per year for the hot-side SCR. This is a function of the concentration of NO_x in the flue gas and the ammonia mass flow rate.

Steam: Annual cost of steam used for ammonia vaporization and ammonia injection. This is a function of the steam to ammonia ratio (performance input parameter) and the ammonia mass flow rate.

Water: Cost of water used to wash ammonia that deposits in the air preheater. This is a function of the efficiency and concentration of ammonia removed by wash water performance input parameters and the amount of ammonia salts deposited on the air preheater.

Electricity: Cost of electricity consumption of the hot-side SCR. This is a function of the gross plant capacity and the SCR energy penalty performance input parameter.

Total Variable Costs: This is the sum of all the variable O&M costs listed above. This result is highlighted in yellow.

Fixed Cost Components

Fixed operating costs are essentially independent of actual capacity factor, number of hours of operation, or amount of kilowatts produced. All the costs are subject to inflation.

Operating Labor: Operating labor cost is based on the operating labor rate, the number of personnel required to operate the plant per eight-hour shift, and the average number of shifts per day over 40 hours per week and 52 weeks.

Maintenance Labor: The maintenance labor is determined as a fraction of the total maintenance cost.

Maintenance Material: The cost of maintenance material is the remainder of the total maintenance cost, considering the fraction associated with maintenance labor.

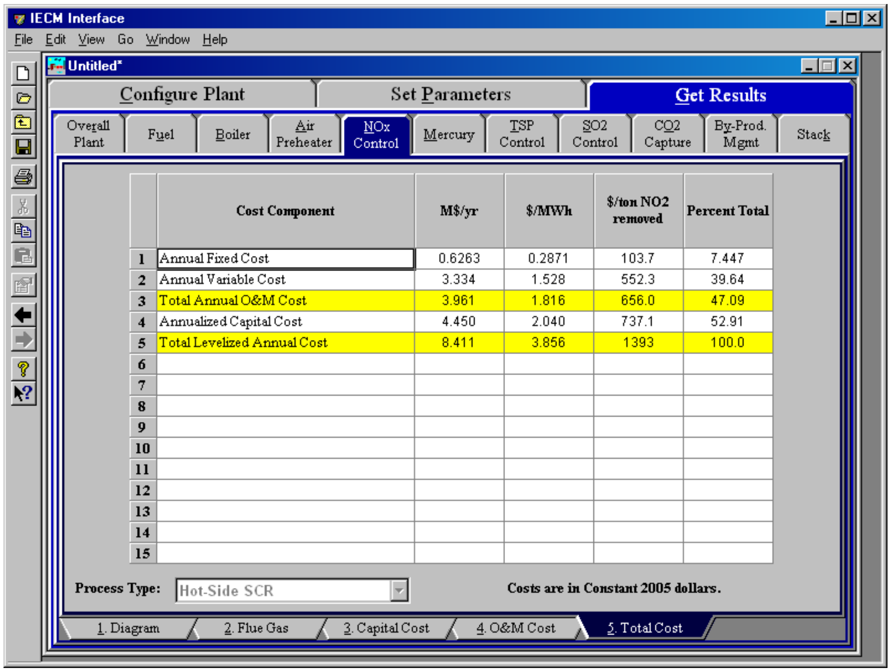
Admin. & Support Labor: The administrative and support labor is the only overhead charge. It is taken as a fraction of the total operating and maintenance labor costs.

Total Fixed Costs: This is the sum of all the fixed O&M costs listed above. This result is highlighted in yellow.

Total O&M Costs: This is the sum of the total variable and total fixed O&M costs. It is used to determine the base plant total revenue requirement. This result is highlighted in yellow.

Hot-Side SCR Total Cost Results

This screen is only available for the Combustion (Boiler) plant type.



Hot-Side SCR – Total Cost result screen.

The **Total Cost** result screen displays a table which totals the annual fixed, variable, operations and maintenance, and capital costs associated with the **Hot–Side SCR** NO_x Control technology. Note that all costs expressed in $/ton of NO_2 removed assume tons of equivalent NO_2. Total costs are typically expressed in either constant or current dollars for a specified year, as shown on the bottom of the screen. Each result is described briefly below.

Cost Component

Annual Fixed Cost: The operating and maintenance fixed costs are given as an annual total. This number includes all maintenance materials and all labor costs.

Annual Variable Cost: The operating and maintenance variables costs are given as an annual total. This includes all reagent, chemical, steam, and power costs.

Total Annual O&M Cost: This is the sum of the annual fixed and variable operating and maintenance costs above. This result is highlighted in yellow.

Annualized Capital Cost: This is the total capital cost expressed on an annualized basis, taking into consideration the levelized carrying charge factor, or fixed charge factor, over the entire book life.

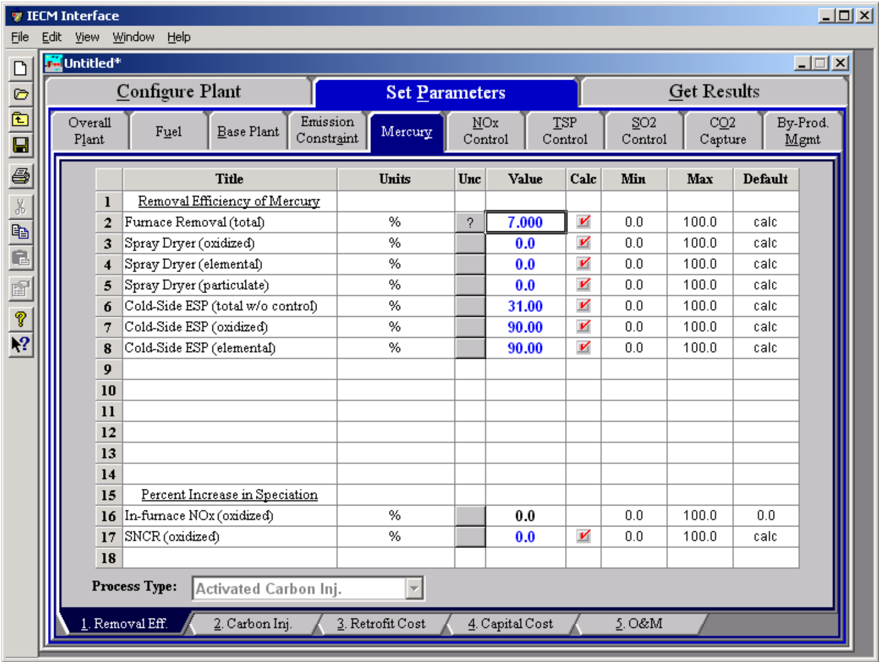
Total Levelized Annual Cost: The total annual cost is the sum of the total annual O&M cost and annualized capital cost items above. This result is highlighted in yellow.

Mercury

Mercury Control is a Technology Navigation Tab in the **Set Parameters** and in the **Get Results** program area. These screens define and display results for the performance and costs directly associated with the removal of mercury from each technology in the power plant Pre-combustion and post-combustion control technologies are all considered. Special consideration is given to flue gas conditioning used to enhance mercury removal. Water and activated carbon injection are currently considered as conditioning agents.

Mercury Removal Efficiency Inputs

This screen is only available for the **Combustion (Boiler)** plant type. Inputs for the removal of the speciated mercury from the flue gas stream are entered on the **Removal Eff.** input screen.



Mercury – Removal Efficiency input screen.

Each parameter is described briefly below.

Removal Efficiency of Mercury

The removal of mercury for each control technology configured is given as a percent of the total entering the control technology. The user is given the opportunity to specify the removal separately for each speciation type. Control technologies not currently configured are hidden.

Furnace Removal (total): Mercury present in ash is removed from the furnace through the removal of bottom ash. The speciation is not known, so the removal is specified as a total removal. The mercury removed in bottom ash is not credited toward the required removal to meet the mercury emission constraint.

Fabric Filter

Fabric Filter (total w/o control): Mercury present in ash is removed from the fabric filter through the removal of captured fly ash. The speciation is not known, so the removal is specified as a total removal. The value shown is determined without regard to particular mercury control methods. It has a substantial effect on the amount of activated carbon needed to meet the required removal of mercury.

Fabric Filter (oxidized): The fabric filter typically removes some mercury without adding a specific mercury control technology. This mercury is present in the ash and is removed with the collected ash. When a mercury control technology is added, the removal is enhanced. The default value is set to meet the overall removal efficiency constraint, with consideration given to the mercury removed by flue gas desulfurization and elemental mercury oxidized in a NO_x control technology. The lower limit is set by the removal efficiency of ash alone as specified by “Fabric Filter (total w/o control)” specified above.

Fabric Filter (elemental): Elemental mercury is assumed to be removed with the same efficiency as the removal of oxidized mercury specified above.

Cold – Side ESP

Cold-Side ESP (total w/o control): Mercury present in ash is removed from the cold-side ESP through the removal of captured fly ash. The speciation is not known, so the removal is specified as a total removal. The value shown is determined without regard to particular mercury control methods. It has a substantial effect on the amount of activated carbon needed to meet the required removal of mercury.

Cold-Side ESP (oxidized): The cold-side ESP typically removes some mercury without adding a specific mercury control technology. This mercury is present in the ash and is removed with the collected ash. When a mercury control technology is added, the removal is enhanced. The default value is set to meet the overall removal efficiency constraint, with consideration given to the mercury removed by flue gas desulfurization and elemental mercury oxidized in a NO_x control technology. The lower limit is set by the removal efficiency of ash alone as specified by “Cold-Side ESP (total w/o control)” specified above.

Cold-Side ESP (elemental): Elemental mercury is assumed to be removed with the same efficiency as the removal of oxidized mercury specified above.

Wet FGD

Wet FGD (oxidized): The wet lime/limestone FGD typically removes all the oxidized mercury due to its' high solubility in water.

Wet FGD (elemental): Elemental mercury is assumed to pass through the wet lime/limestone FGD. It is assumed that elemental mercury is present in the flue gas and is unreactive.

Spray Dryer

Spray Dryer (oxidized): Oxidized mercury is assumed to pass through the lime spray dryer. Although soluble in water, moisture injected into the spray dryer evaporates, resulting in the mercury remaining in the flue gas. The default value is zero.

Spray Dryer (elemental): Elemental mercury is assumed to pass through the lime spray dryer. It is assumed that elemental mercury is present in the flue gas and is unreactive.

Percent Increase in Speciation

Although NO_x control technologies do not remove mercury from the flue gas, they can change the mercury from one form to another. This is particularly true when catalysts are present. In this case, elemental mercury is converted to oxidized mercury. The parameters in this section define the percent increase in oxidized mercury across the control technology.

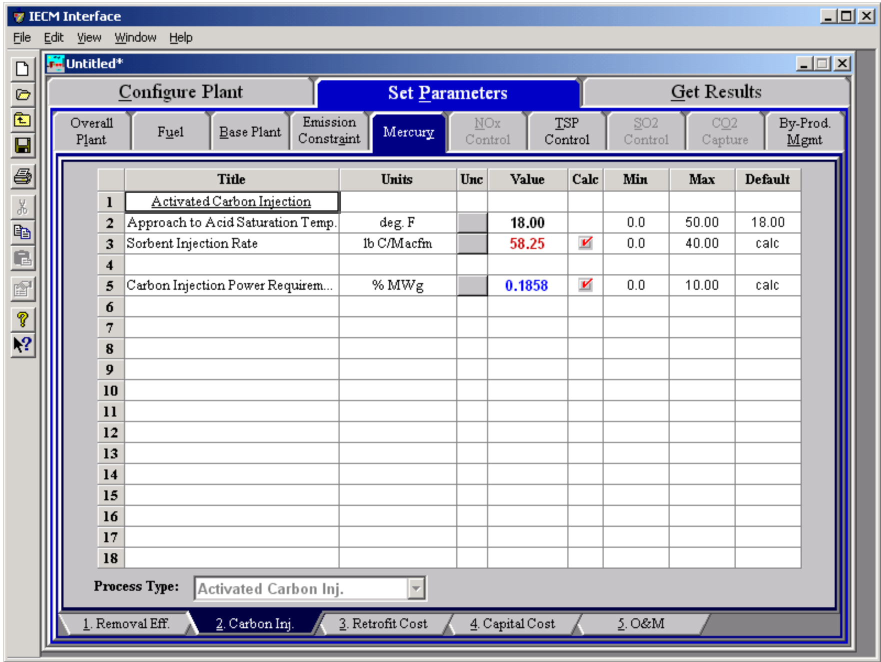
In-furnace NOx (oxidized): Low NO_x burners with or without overfire air and gas reburn can effect the amount of oxidized mercury. At present, there is insufficient information available to specify a default value. The default is set to zero.

SNCR (oxidized): An SNCR does not affect the relative amounts of oxidized and elemental mercury. The default is set to zero.

Hot-Side SCR (oxidized): Hot-side SCR as a control technology chances elemental mercury to oxidized mercury. It is believed that the catalyst is responsible for this shift in speciation. The default value is a function of the coal rank.

Mercury Carbon (and Water) Injection Inputs

This screen is only available for the Combustion (Boiler) plant type. Inputs for activated carbon and water injected into the flue gas are entered on the **Carbon Inj.** input screen. Water can be optionally added to reduce the flue gas temperature and enhance the effect of the carbon on removing mercury. Note that the actual removal of the carbon and mercury are accomplished in particulate and flue gas desulfurization control technologies downstream



Mercury – Removal Efficiency input screen.

Each parameter is described briefly below.

Activated Carbon Injection

Injection of water to reduce the flue gas temperature and activated carbon to enhance mercury removal are the only control technologies presently incorporated into the IECM.

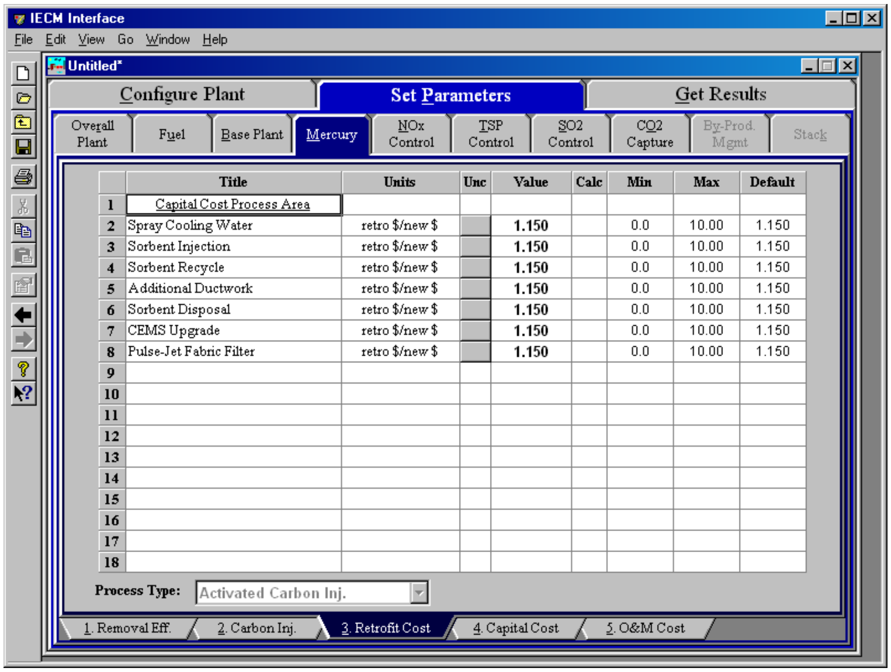
Approach to Acid Saturation Temperature: When water is selected to be injected with the activated carbon this parameter appears on the **Removal Efficiency** input screen. It is important to keep the flue gas temperature above the sulfuric acid dew point temperature. This avoids condensation of acid on equipment. This parameter determines the amount of water injected into the flue gas. If the approach is above the actual temperature, the temperature is dropped to be the approach above the dew point. The dew point is a function of the SO_3 and H_2O content in the flue gas and the pressure of the flue gas.

Sorbent Injection Rate: The flue gas temperature, the mercury removal efficiency in the particulate device, the coal rank, and the mercury removal efficiency without control, determines the injection rate of activated carbon into the flue gas. Mercury removal due to the ash removed in a cold-side ESP or fabric filter in the absence of enhanced mercury control methods is specified in the input screen. The default value is most sensitive to the flue gas temperature and the mercury removal efficiency without control.

Carbon Injection Power Requirement: The power required for the water and carbon injection system is a function of carbon injection rate, the water injection rate, and the flue gas flow rate. This assumes the addition of a fan in the flue gas to balance the pressure drop. The default value is calculated as the ratio of the actual energy consumption by the gross electrical output of the power plant.

Mercury Retrofit Cost Inputs

This screen is only available for the Combustion (Boiler) plant type. Inputs for the capital costs of modifications to process areas of the activated carbon and water injection system are entered on the **Retrofit Cost** input screen.



Mercury – Retrofit Cost input screen.

The retrofit cost factor of each process is a multiplicative cost adjustment, which considers the cost of retrofitted capital equipment relative to similar equipment installed in a new plant. These factors affect the capital costs directly and the operating and maintenance costs indirectly.

Direct capital costs for each process area are calculated in the IECM. These calculations are reduced form equations derived from more sophisticated models and reports. The sum of the direct capital costs associated with each process area is defined as the process facilities capital (PFC). The retrofit cost factor provided for each of the process areas can be used as a tool for adjusting the anticipated costs and uncertainties across the process area separate from the other areas.

Uncertainty can be applied to the retrofit cost factor for each process area in each technology. Thus, uncertainty can be applied as a general factor across an entire process area, rather than as a specific uncertainty for the particular cost on the capital or O&M input screens. Any uncertainty applied to a process area through the retrofit cost factor compounds any uncertainties specified later in the capital and O&M cost input parameter screens.

Each parameter is described briefly below. Although the user cannot set the capital cost directly, the descriptions below include the key parameters used to determine the capital cost itself. The input parameters on this screen adjust this capital cost as calculated in the IECM.

Capital Cost Process Area

Spray Cooling Water: This capital cost area represents the materials and equipment necessary to inject water into the flue gas duct for the purpose of cooling the flue gas to a prerequisite temperature. Equipment includes water storage tanks, pumps, transport piping, injection grid with nozzles, and a control system. The direct capital cost is a function of the water flow rate.

Sorbent Injection: This capital cost area represents the materials and equipment necessary to deliver the activated carbon into the flue gas. Equipment includes silo pneumatic loading system, storage silos, hoppers, blowers, transport piping, and a control system. The direct capital cost is a function of the sorbent flow rate.

Sorbent Recycle: This capital cost area represents the materials and equipment necessary to recycle ash and activated carbon from the particulate collector back into the duct injection point. The purpose is to create a equilibrium state where the carbon is reintroduced to improve performance. Equipment includes hoppers, blowers, transport piping, and a control system. The direct capital cost is a function of the recycle rate of ash and spent sorbent.

NOTE: Sorbent recycling is a feature to be added in a future version of the IECM.

Additional Ductwork: This capital cost area represents materials and equipment for ductwork necessary beyond the other process areas. Extra ductwork may be required for difficult retrofit installations.

NOTE: Future versions of the IECM will include parameters to determine a capital cost for this area. The current version assumes no additional ductwork.

Sorbent Disposal: This capital cost area represents materials and equipment required to house and dispose the collected sorbent. Equipment includes hoppers, blowers, transport piping, and a control system. This is in excess of existing hoppers, tanks, and piping used for existing particulate collectors. The direct capital cost is determined by the incremental increase in collected solids in the particulate collector.

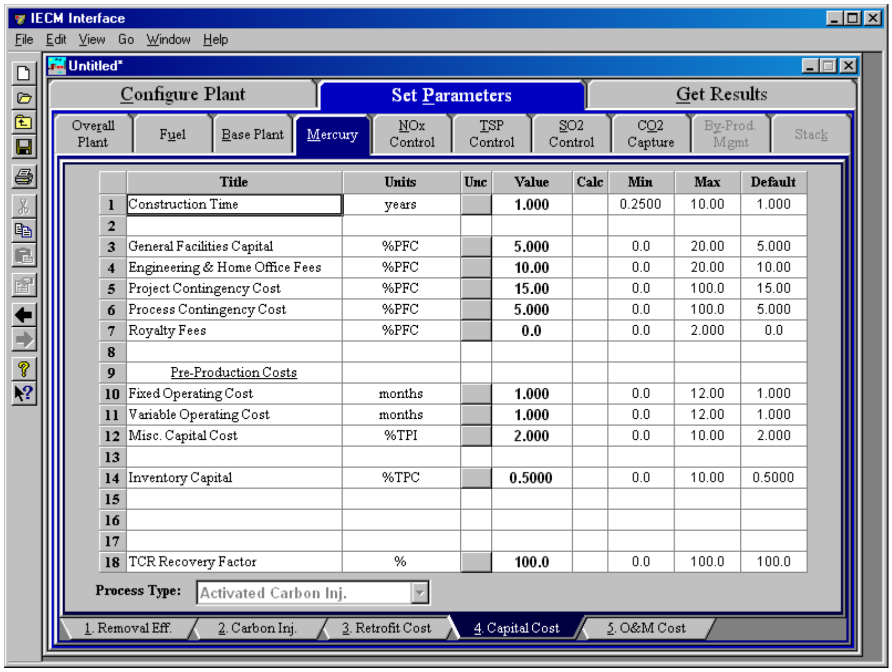
CEMS Upgrade: This capital cost area represents materials and equipment required to install a continuous emissions monitoring system (CEMS) upgrade. The direct capital cost is determined by the net electrical output of the power plant.

Pulse-Jet Fabric Filter: This capital costs area represents an upgrade to an existing cold-side ESP, where one section at the back end of the unit is replaced with a pulse-jet fabric filter. This can be considered a pseudo-COHPAC. Equipment includes pulse-jet FF, filter bags, ductwork, dampers, and MCCs, instrumentation and PLC controls for baghouse operation. Equipment excludes ash removal system, power distribution and power supply, and distributed control system. The direct capital cost is a function of the flue gas flow rate and the air to cloth ratio of the fabric filter.

NOTE: The IECM currently does not support multiple particulate devices in the same configuration nor a modified cold-side ESP.

Mercury Capital Cost Inputs

This screen is only available for the Combustion (Boiler) plant type. Inputs for the capital costs of the activated carbon and water injection system are entered on the **Capital Cost** input screen.



Mercury – Capital Cost input screen.

The necessary capital cost input parameters associated with the base plant are on this input screen. The capital cost parameters and terminology used in the IECM are based on the methodologies developed by the Electric Power Research Institute (EPRI). They have prepared a Technical Assessment Guide (TAG) in order to provide a consistent basis for reporting cost and revenues associated with the electric power industry. This system of reporting is used by a wide audience, including energy engineers, researchers, planners, and managers. The IECM has been developed around this TAG system so that costs associated with various technologies can be compared directly on a consistent basis and communicated in the language used by the audience listed above.

Total Plant Cost (TPC) is the sum of the process facilities capital, general facilities capital, engineering and home office fees, and the contingencies (project and process). This is considered the cost on an instantaneous basis (overnight), and expressed in December dollars of a reference year.

Direct Capital Costs: Direct capital costs for each process area are calculated in the IECM. These calculations are reduced form equations derived from more sophisticated models and reports. The sum of the direct capital costs associated with each process area is defined as the process facilities capital (PFC). This is the basis for all other capital cost parameters.

The process facilities capital for the technology is the total constructed cost of all on-site processing and generating units, including all direct and indirect construction costs. All sales taxes and freight costs are included where applicable implicitly. These direct capital costs are generally calculated by the IECM and not presented directly on input screens. However, when important input variables are required for these calculations, they are listed at the top of the input screen.

Indirect Capital Costs: Costs that are indirectly applied to the technology are based on the process facilities cost. Each of the cost factors below is expressed as a percentage of the process facilities cost, and is entered on this screen. Each parameter is described briefly below.

Construction Time: This is the idealized construction period in years. It is used to determine the allowance for funds used during construction (AFUDC).

General Facilities Capital (GFC): 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%.

Engineering & Home Office Fees: The engineering & home office fees are a percent of total direct capital cost. This is an overhead fee paid to the architect/engineering company. These fees typically range from 7-15%.

Project Contingency Cost: This is 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.

Process Contingency Cost: 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.

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

Pre-Production Costs: 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 applied to O&M costs over a specified period of time (months).

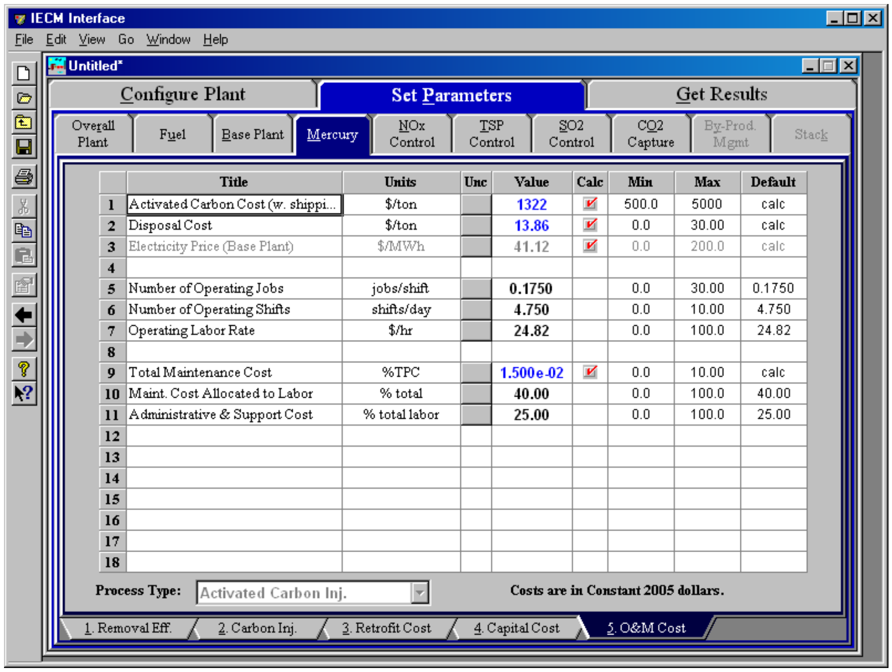
- **Fixed Operating Cost:** Time period of fixed operating costs (operating and maintenance labor, administrative and support labor, and maintenance materials) used for plant startup.
- **Variable Operating Cost:** Time period of variable operating costs at full capacity (chemicals, water, and other consumables, and waste disposal changes) used for plant startup. Full capacity estimates of the variable operating costs will assume operations at 100% load.
- **Misc. Capital Cost:** This is a percent of total plant investment (sum of TPC and AFUDC) to cover expected changes to equipment to bring the system up to full capacity.

Inventory Capital: Percent of the total direct capital for raw material supply based on 100% capacity during a 60 day period. These materials are considered storage. The inventory capital includes fuels, consumables, by-products, and spare parts. This is typically 0.5%.

TCR Recovery Factor: The actual total capital required (TCR) as a percent of the TCR in a new power plant. This value is 100% for a new installation and may be set as low as 0% for an activated carbon and water injection system that has been paid off.

Mercury O&M Cost Inputs

This screen is only available for the Combustion (Boiler) plant type.



Mercury – O&M input screen.

Inputs for the operation and maintenance costs of the mercury control technology are entered on the **O&M** cost input screen. O&M costs are typically expressed on an average annual basis and are provided in either constant or current dollars for a specified year, as shown on the bottom of the screen.

Activated Carbon Cost (w. shipping): This is the cost for the activated carbon, including the cost of shipping.

Disposal Cost: This is the disposal cost for the particulate control system. It is assumed that the ash is not hazardous, therefore can be disposed with the collected fly ash.

Electricity Price (Base Plant): This is the price of electricity and is calculated as a function of the utility cost of the base plant, where the base plant is a combustion boiler and an air preheater.

Number of Operating Jobs: This is the total number of operating jobs that are required to operate the plant per eight-hour shift.

Number of Operating Shifts: This is the total number of equivalent operating shifts in the plant per day. The number takes into consideration paid time off and weekend work (3 shifts/day * 7 days/5 day week * 52 weeks/(52 weeks - 6 weeks PTO) = 4.75 equiv. Shifts/day).

Operating Labor Rate: The hourly cost of labor is specified in the base plant O&M cost screen. The same value is used throughout the other technologies.

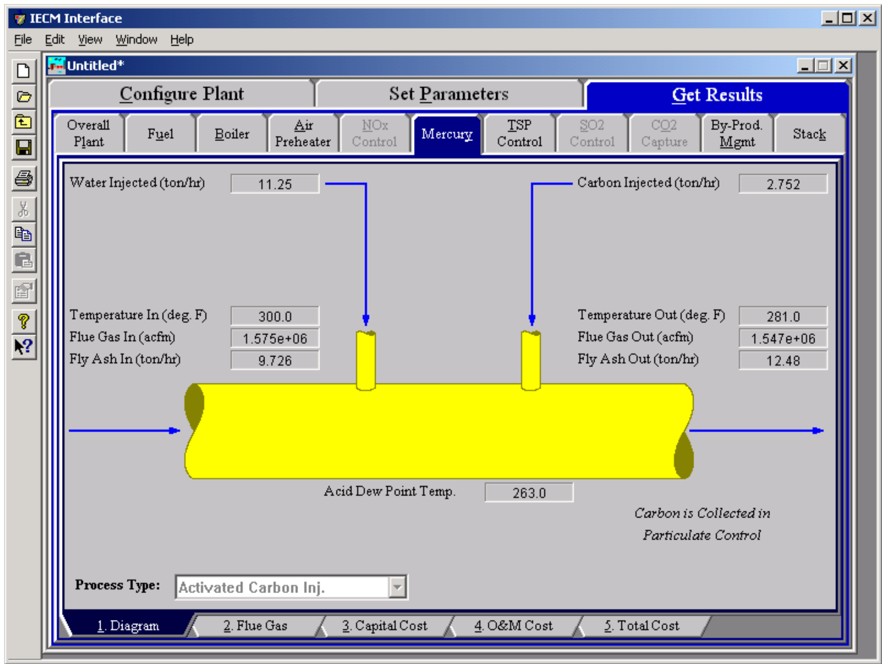
Total Maintenance Cost: This is the annual maintenance cost as a percentage of the total plant cost. Maintenance cost estimates can be developed separately for each process area.

Maint. Cost Allocated to Labor: Maintenance cost allocated to labor as a percentage of the total maintenance cost.

Administrative & Support Cost: This is the percent of the total operating and maintenance labor associated with administrative and support labor.

Mercury Diagram

This screen is only available for the Combustion (Boiler) plant type. The **Diagram** result screen displays an icon for the water and carbon injection systems, both part of the overall mercury control option and values for major flows in and out of it



Mercury— Diagram result screen

Each result is described briefly below in flow order (not from top to bottom and left to right as they display on the screen).

Flue Gas Prior to Injection

Temperature In: Temperature of the flue gas prior to flue gas conditioning.

Flue Gas In: Volumetric flow rate of the flue gas prior to flue gas conditioning, based on the temperature prior to flue gas conditioning and atmospheric pressure.

Fly Ash In: Total solids mass flow rate in the flue gas prior to flue gas conditioning. This includes ash, unburned carbon and unburned sulfur.

Flue Gas After Injection

Temperature Out: Temperature of the flue gas after flue gas conditioning. This should be above the acid dew point temperature at the bottom of the screen.

Flue Gas Out: Volumetric flow rate of the flue gas after flue gas conditioning, based on the temperature after flue gas conditioning and atmospheric pressure.

Fly Ash Out: Total solids mass flow rate in the flue gas after flue gas conditioning. This includes ash, unburned carbon, activated carbon, and unburned sulfur.

Acid Dew Point: This is the temperature that H_2SO_4 vapor condenses into the liquid phase. .

Flue Gas Conditioning

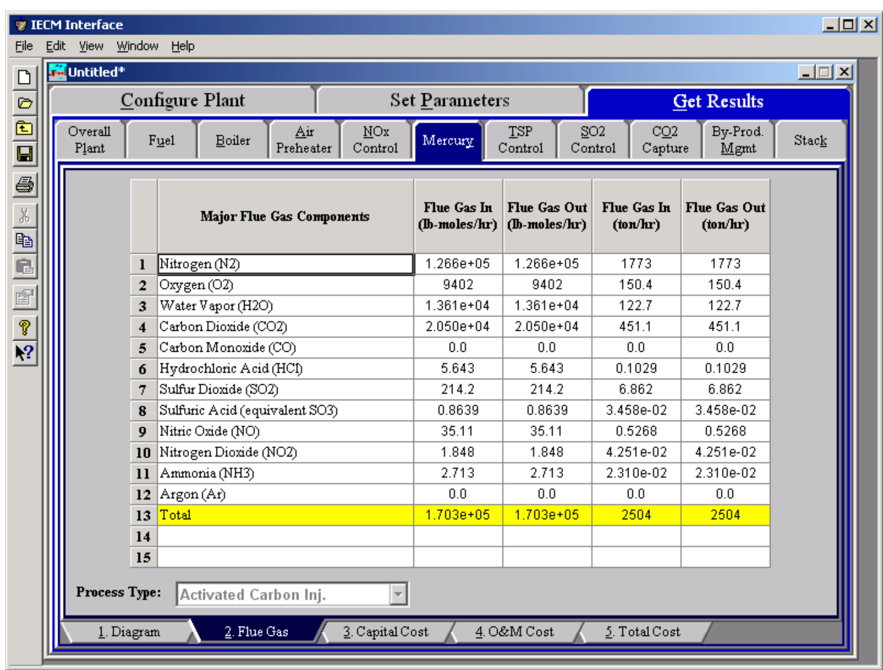
Water Injected: Water added to the flue gas to reduce the temperature No water is injected if water injection is not specified in the configuration or the inlet temperature is within the approach to saturation relative to the acid dew point.

Carbon Injected: Total activated carbon mass flow rate injected into the flue gas.

NOTE: Carbon injected into the flue gas is collected downstream in the particulate control device (e.g., the cold-side ESP).

Mercury Flue Gas Results

This screen is only available for the Combustion (Boiler) plant type. The **Flue Gas** result screen displays a table of quantities of flue gas components entering and exiting the flue gas conditioning area. For each component, quantities are given in both moles and mass per hour.



	Major Flue Gas Components	Flue Gas In (lb-moles/hr)	Flue Gas Out (lb-moles/hr)	Flue Gas In (ton/hr)	Flue Gas Out (ton/hr)
1	Nitrogen (N2)	1.266e+05	1.266e+05	1773	1773
2	Oxygen (O2)	9402	9402	150.4	150.4
3	Water Vapor (H2O)	1.361e+04	1.361e+04	122.7	122.7
4	Carbon Dioxide (CO2)	2.050e+04	2.050e+04	451.1	451.1
5	Carbon Monoxide (CO)	0.0	0.0	0.0	0.0
6	Hydrochloric Acid (HCl)	5.643	5.643	0.1029	0.1029
7	Sulfur Dioxide (SO2)	214.2	214.2	6.862	6.862
8	Sulfuric Acid (equivalent SO3)	0.8639	0.8639	3.458e-02	3.458e-02
9	Nitric Oxide (NO)	35.11	35.11	0.5268	0.5268
10	Nitrogen Dioxide (NO2)	1.848	1.848	4.251e-02	4.251e-02
11	Ammonia (NH3)	2.713	2.713	2.310e-02	2.310e-02
12	Argon (Ar)	0.0	0.0	0.0	0.0
13	Total	1.703e+05	1.703e+05	2504	2504
14					
15					

Mercury – Flue Gas result screen.

Major Flue Gas Components

Each result is described briefly below.

Nitrogen (N_2): Total mass of nitrogen.

Oxygen (O_2): Total mass of oxygen.

Water Vapor (H_2O): Total mass of water vapor.

Carbon Dioxide (CO_2): Total mass of carbon dioxide.

Carbon Monoxide (CO): Total mass of carbon monoxide.

Hydrochloric Acid (HCl): Total mass of hydrochloric acid.

Sulfur Dioxide (SO_2): Total mass of sulfur dioxide.

Sulfuric Acid (equivalent SO_3): Total mass of sulfuric acid.

Nitric Oxide (NO): Total mass of nitric oxide.

Nitrogen Dioxide (NO_2): Total mass of nitrogen dioxide.

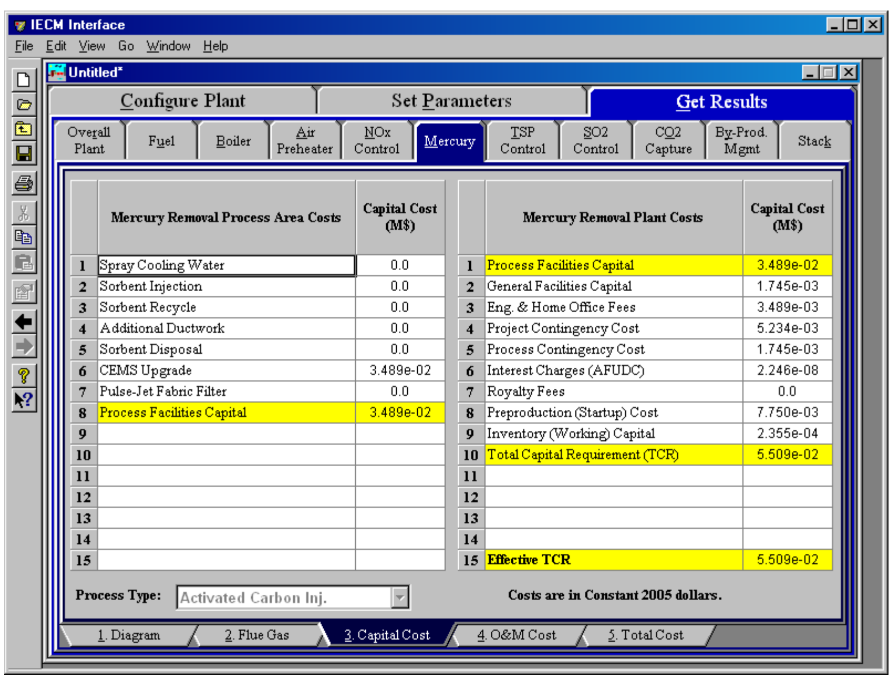
Ammonia (NH_3): Total mass of ammonia.

Argon (Ar): Total mass of argon.

Total: Total of the individual components listed above. This item is highlighted in yellow.

Mercury Capital Cost Results

This screen is only available for the Combustion (Boiler) plant type. The **Capital Cost** result screen displays tables for the direct and indirect capital costs related to the water and carbon injection systems, both part of the overall mercury control option.



Mercury – Capital Cost result screen.

Capital costs are typically expressed in either constant or current dollars for a specified year, as shown on the bottom of the screen. Each result is described briefly below.

Direct Capital Costs

The direct capital costs described here apply to the various mercury control equipment added to the power plant. These controls may physically be part of other control technologies, but have their particular capital costs considered here.

Each process area direct capital cost is a reduced-form model based on regression analysis of data collected from several reports and analyses. They are described in general below. The primary factors in the model that effect the capital cost of the base plant are the plant size, the amount of water injected, the amount of activated carbon injected, and the sulfur and moisture content of the coal.

Spray Cooling Water: This capital cost area represents the materials and equipment necessary to inject water into the flue gas duct for the purpose of cooling the flue gas to a prerequisite temperature. Equipment includes water storage tanks, pumps, transport piping, injection grid with nozzles, and a control system. The direct capital cost is a function of the water flow rate.

Sorbent Injection: This capital cost area represents the materials and equipment necessary to deliver the activated carbon into the flue gas. Equipment includes silo pneumatic loading system, storage silos, hoppers, blowers, transport piping, and a control system. The direct capital cost is a function of the sorbent flow rate.

Sorbent Recycle: This capital cost area represents the materials and equipment necessary to recycle ash and activated carbon from the particulate collector back into the duct injection point. The purpose is to create a equilibrium state where the carbon is reintroduced to improve performance. Equipment includes hoppers, blowers, transport piping, and a control system. The direct capital cost is a function of the recycle rate of ash and spent sorbent.

NOTE: Sorbent recycling is a feature to be added in a future version of the IECM.

Additional Ductwork: This capital cost area represents materials and equipment for ductwork necessary beyond the other process areas. Extra ductwork may be required for difficult retrofit installations.

NOTE: Future versions of the IECM will include parameters to determine a capital cost for this area. The current version assumes no additional ductwork.

Sorbent Disposal: This capital cost area represents materials and equipment required to house and dispose the collected sorbent. Equipment includes hoppers, blowers, transport piping, and a control system. This is in excess of existing hoppers, tanks, and piping used for existing particulate collectors. The direct capital cost is determined by the incremental increase in collected solids in the particulate collector.

CEMS Upgrade: This capital cost area represents materials and equipment required to install a continuous emissions monitoring system (CEMS) upgrade. The direct capital cost is determined by the net electrical output of the power plant.

Pulse-Jet Fabric Filter: This capital costs area represents an upgrade to an existing cold-side ESP, where one section at the back end of the unit is replaced with a pulse-jet fabric filter. This can be considered a pseudo-COHPAC. Equipment includes pulse-jet FF, filter bags, ductwork, dampers, and MCCs, instrumentation and PLC controls for baghouse operation. Equipment excludes ash removal system, power distribution and power supply, and distributed control system. The direct capital cost is a function of the flue gas flow rate and the air to cloth ratio of the fabric filter.

NOTE: The IECM currently does not support multiple particulate devices in the same configuration nor a modified cold-side ESP.

Process Facilities Capital: The process facilities capital is the total constructed cost of all on-site processing and generating units listed above, including all direct and indirect construction costs. All sales taxes and freight costs are included where applicable implicitly. This result is highlighted in yellow.

Total Capital Costs

Process Facilities Capital: See definition above. This result is highlighted in yellow.

General Facilities Capital: The general facilities include construction costs of roads, office buildings, shops, laboratories, etc. Sales taxes and freight costs are included implicitly.

Eng. & Home Office Fees: The engineering & home office fees are a percent of total direct capital cost. This is an overhead fee paid to the architect/engineering company.

Project Contingency Cost: Capital cost contingency factor covering the cost of additional equipment or other costs that would result from a more detailed design of a definitive project at the actual site.

Process Contingency Cost: Capital cost contingency factor applied to a new technology in an effort to quantify the uncertainty in the technical performance and cost of the commercial-scale equipment.

Interest Charges (AFUDC): Allowance for funds used during construction, also referred to as interest during construction, is the time value of the money used during construction and is based on an interest rate equal to the before-tax weighted cost of capital. This interest is compounded on an annual basis (end of year) during the construction period for all funds spent during the year or previous years.

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

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.

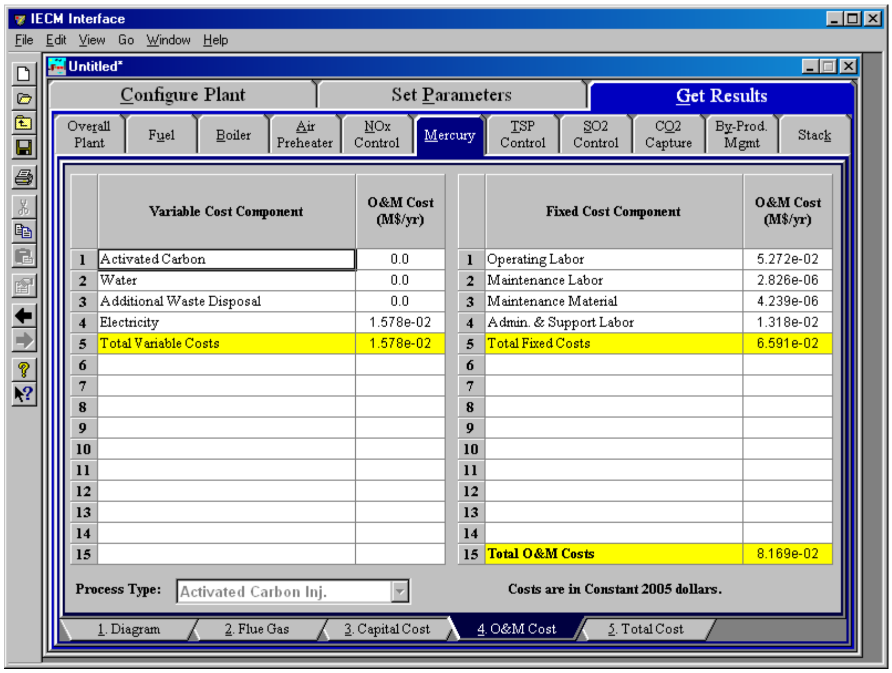
Inventory (Working) Capital: The raw material supply based on 100% capacity during a 60 day period. These materials are considered storage. The inventory capital includes fuels, consumables, by-products, and spare parts.

Total Capital Requirement (TCR): Money that is placed (capitalized) on the books of the utility on the service date. TCR includes all the items above. This result is highlighted in yellow.

Effective TCR: The TCR of the water and carbon injection controls that is used in determining the total power plant cost. The effective TCR is determined by the "TCR Recovery Factor" for the water and carbon injection system.

Mercury O&M Cost Results

This screen is only available for the Combustion (Boiler) plant type. The **O&M Cost** result screen displays tables for the variable and fixed operation and maintenance costs related to the water and carbon injection systems, both part of the overall mercury control option. The variable O&M costs are calculated from the variable costs for carbon, water consumption and fly ash disposal (from the particulate control device). The fixed O&M costs are based on maintenance and labor costs



Mercury – O&M Cost result screen.

O&M costs are typically expressed on an average annual basis and are provided in either constant or current dollars for a specified year, as shown on the bottom of the screen. Each result is described briefly below.

Variable Cost Components

Variable operating costs and consumables are directly proportional to the amount of kilowatts produced and are referred to as incremental costs. All the costs are subject to inflation.

Activated Carbon: This is the activated carbon cost for flue gas conditioning.

Water: This is the water cost for flue gas conditioning.

Additional Waste Disposal: This is the solid disposal cost per year for the flue gas conditioning. Only the removal of carbon from the particulate device is considered here.

Electricity: This is the power utilization cost per year for the flue gas conditioning.

Total Variable Costs: This is the sum of all the variable O&M costs listed above. This result is highlighted in yellow.

Fixed Cost Components

Fixed operating costs are essentially independent of actual capacity factor, number of hours of operation, or amount of kilowatts produced. All the costs are subject to inflation.

Operating Labor: Operating labor cost is based on the operating labor rate, the number of personnel required to operate the plant per eight-hour shift, and the average number of shifts per day over 40 hours per week and 52 weeks.

Maintenance Labor: The maintenance labor is determined as a fraction of the total maintenance cost.

Maintenance Material: The cost of maintenance material is the remainder of the total maintenance cost, considering the fraction associated with maintenance labor.

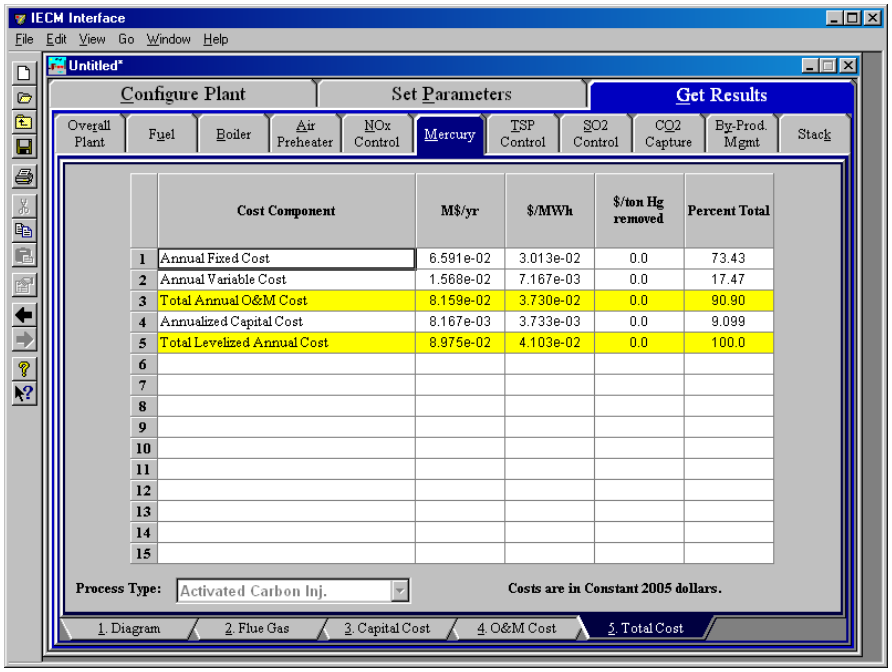
Admin. & Support Labor: The administrative and support labor is the only overhead charge. It is taken as a fraction of the total operating and maintenance labor costs.

Total Fixed Costs: This is the sum of all the fixed O&M costs listed above. This result is highlighted in yellow.

Total O&M Costs: This is the sum of the total variable and total fixed O&M costs. It is used to determine the base plant total revenue requirement. This result is highlighted in yellow.

Mercury Total Cost Results

This screen is only available for the Combustion (Boiler) plant type. The **Total Cost** result screen displays a table which totals the annual fixed, variable, operations and maintenance, and capital costs related to the water and carbon injection systems, both part of the overall mercury control option.



Mercury – Total Cost result screen.

Total costs are typically expressed in either constant or current dollars for a specified year, as shown on the bottom of the screen. Each result is described briefly below.

Cost Component

Annual Fixed Cost: The operating and maintenance fixed costs are given as an annual total. This number includes all maintenance materials and all labor costs.

Annual Variable Cost: The operating and maintenance variables costs are given as an annual total. This includes all reagent, chemical, steam, and power costs.

Total Annual O&M Cost: This is the sum of the annual fixed and variable operating and maintenance costs above. This result is highlighted in yellow.

Annualized Capital Cost: This is the total capital cost expressed on an annualized basis, taking into consideration the levelized carrying charge factor, or fixed charge factor, over the entire book life.

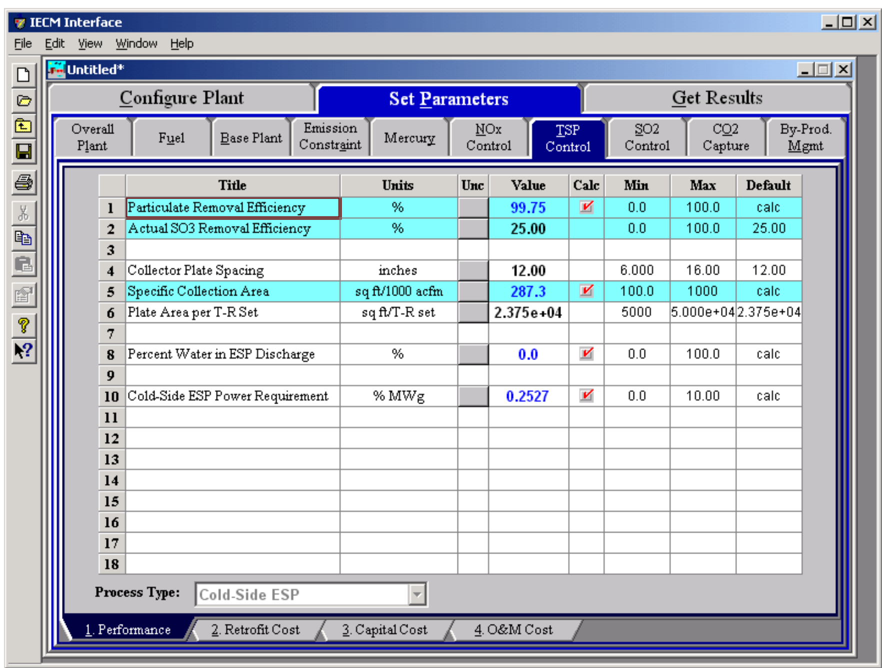
Total Levelized Annual Cost: The total annual cost is the sum of the total annual O&M cost and annualized capital cost items above. This result is highlighted in yellow.

Cold-Side ESP

The **TSP Control**. Technology Navigation screens define and display flows and costs related to the particulate control technology. These screens are available only if the **Cold–Side ESP** TSP control technology is selected in the **Combustion (Boiler)** plant type configurations.

Cold-Side ESP Performance Inputs

This screen is only available for the **Combustion (Boiler)** plant type. Inputs for the performance of the Cold–Side ESP TSP control technology are entered on the **Performance** input screen. Many of the parameters are calculated by the IECM. Each parameter is described briefly below.



Cold–Side ESP – Performance input screen.

ESPs consist of a series of parallel plates with rows of electrodes in between them and carry a high voltage of opposite polarity. As the particle laden flue gas enters the unit, the particles are charged by the electrodes and is attracted to the plates. At controlled intervals the plates are rapped which shakes the dust to a hopper below. However, some of the dust is re-entrained and carried to the next zone or out of the stack. Most ESPs use rigid collecting plates with shielded air pockets (baffles) through which ash falls into the hoppers after rapping.

The major design parameters which can significantly impact the total system capital cost are *gas flow volume* (which depends on the generating unit size), *SCA*, the collecting plate area per transformer-rectifier (T-R) set and the spacing between collector plates.

Particulate Removal Efficiency: The calculated value determines the removal efficiency needed to comply with the specified particulate emission limit set earlier. This efficiency then determines the mass of particulate matter removed in the collector.

Actual SO_3 Removal Efficiency: The default value is taken from the removal efficiency reported in the literature (references are below). This efficiency then determines the mass of SO_3 removed from the flue gas in the collector. For more information see also:

- www.netl.doe.gov/publications/proceedings/98/98fg/hardman.pdf
- www.netl.doe.gov/publications/proceedings/98/98fg/rubin.pdf

Collector Plate Spacing: The collector plate spacing is typically 12 inches. The spacing is used to determine the specific collection area.

Specific Collection Area: The specific collection area (SCA) is the ratio of the total plate area and flue gas volume. It sizes the ESP. The value is calculated from the removal efficiency, plate spacing, and the drift velocity. It is used to determine the capital cost and the total collection area required.

Plate Area per T-R Set: This is the total surface area of one T-R set of plates. It is used to determine the total number of T-R sets needed and the capital costs.

Percent Water in ESP Discharge: This is the water content of the collected fly ash. Fly ash disposed with bottom ash is assumed to be sluiced with water and dry otherwise. The occluded water in wet fly ash is difficult to remove, resulting in a rather high water content when the fly ash is mixed with bottom ash.

Cold-Side ESP Power Requirement: The default calculation is based on the T-R set power consumption with estimates for auxiliary power requirements and electro-mechanical efficiencies of fan motors. The T-R set power consumption is a function of removal efficiency.

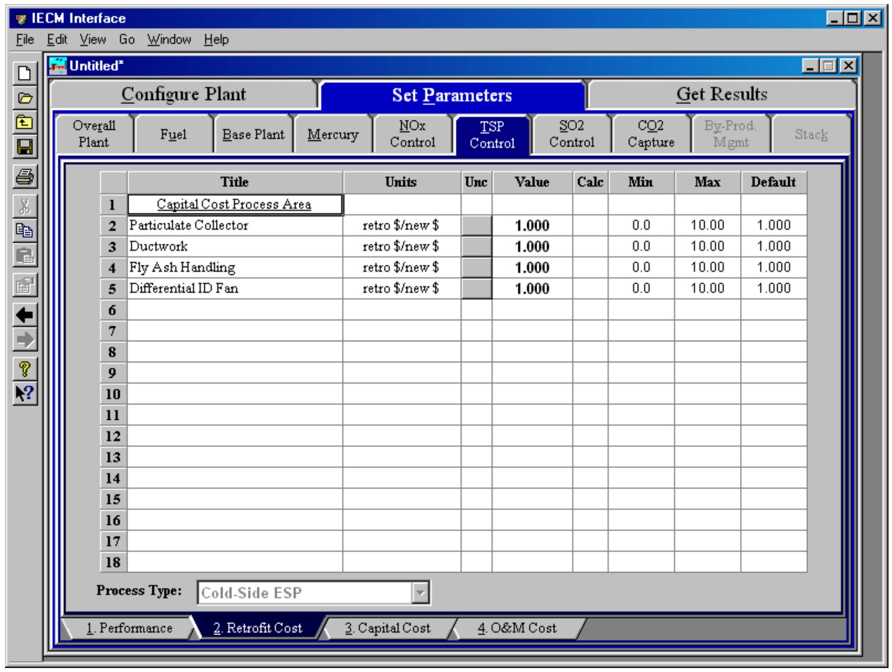
Cold-Side ESP Retrofit Cost Inputs

This screen is only available for the Combustion (Boiler) plant type. Inputs for the capital costs of modifications to process areas to implement the Particulate control technology are entered on the **Retrofit Cost** input screen.

The retrofit cost factor of each process is a multiplicative cost adjustment, which considers the cost of retrofitted capital equipment relative to similar equipment installed in a new plant. These factors affect the capital costs directly and the operating and maintenance costs indirectly.

Direct capital costs for each process area are calculated in the IECM. These calculations are reduced form equations derived from more sophisticated models and reports. The sum of the direct capital costs associated with each process area is defined as the process facilities capital (PFC). The retrofit cost factor provided for each of the process areas can be used as a tool for adjusting the anticipated costs and uncertainties across the process area separate from the other areas.

Uncertainty can be applied to the retrofit cost factor for each process area in each technology. Thus, uncertainty can be applied as a general factor across an entire process area, rather than as a specific uncertainty for the particular cost on the capital or O&M input screens. Any uncertainty applied to a process area through the retrofit cost factor compounds any uncertainties specified later in the capital and O&M cost input parameter screens.



Cold–Side ESP – Retrofit Cost input screen.

Each parameter is described briefly below.

Capital Cost Process Area

Particulate Collector: This area covers the material and labor, flange to flange, for the equipment and labor cost for installation of the entire collection system.

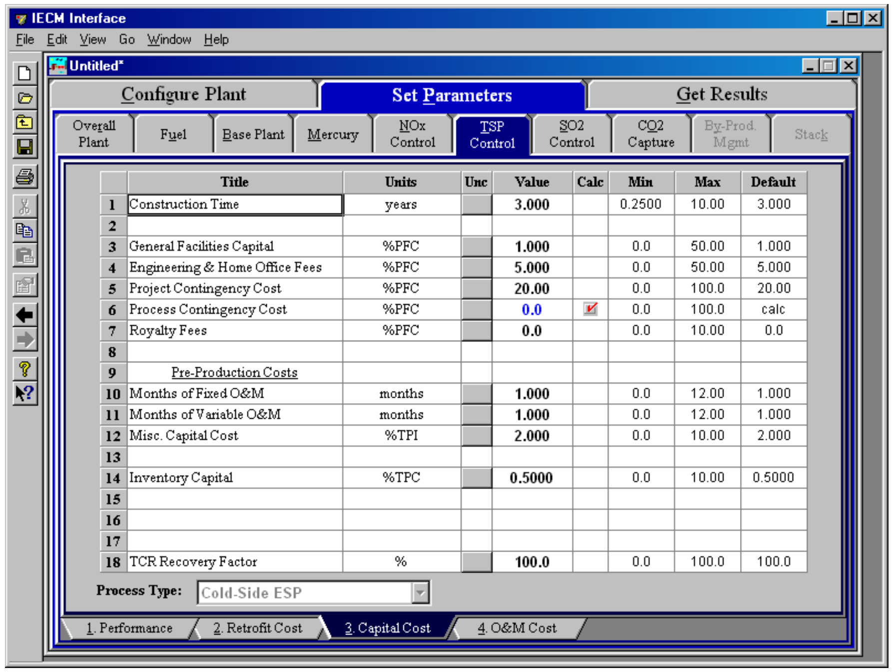
Ductwork: This area includes the material and labor for the ductwork needed to distribute flue gas to the inlet flange, and from the outlet flange to a common duct leading to the suction side of the ID fan.

Fly Ash Handling: The complete fly ash handling cost includes the conveyor system and ash storage silos.

Differential ID Fan: The complete cost of the ID fan and motor due to the pressure loss that results from particulate collectors.

Cold-Side ESP Capital Cost Inputs

This screen is only available for the **Combustion (Boiler)** plant type. Inputs for the capital costs of particulate control technology are entered on the **Capital Cost** input screen.



	Title	Units	Unc	Value	Calc	Min	Max	Default
1	Construction Time	years		3.000		0.2500	10.00	3.000
2								
3	General Facilities Capital	%PFC		1.000		0.0	50.00	1.000
4	Engineering & Home Office Fees	%PFC		5.000		0.0	50.00	5.000
5	Project Contingency Cost	%PFC		20.00		0.0	100.0	20.00
6	Process Contingency Cost	%PFC		0.0		0.0	100.0	calc
7	Royalty Fees	%PFC		0.0		0.0	10.00	0.0
8								
9	Pre-Production Costs							
10	Months of Fixed O&M	months		1.000		0.0	12.00	1.000
11	Months of Variable O&M	months		1.000		0.0	12.00	1.000
12	Misc. Capital Cost	%TPI		2.000		0.0	10.00	2.000
13								
14	Inventory Capital	%TPC		0.5000		0.0	10.00	0.5000
15								
16								
17								
18	TCR Recovery Factor	%		100.0		0.0	100.0	100.0

Cold–Side ESP – Capital Cost input screen.

The necessary capital cost input parameters associated with the electrostatic precipitator control technology are shown on this input screen.

Indirect Capital Costs: Costs that are indirectly applied to the technology are based on the process facilities cost. Each of the cost factors below is expressed as a percentage of the process facilities cost, and is entered on this screen. Each parameter is described briefly below.

Construction Time: This is the idealized construction period in years. It is used to determine the allowance for funds used during construction (AFUDC).

General Facilities Capital (GFC): 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%.

Engineering & Home Office Fees: The engineering & home office fees are a percent of total direct capital cost. This is an overhead fee paid to the architect/engineering company. These fees typically range from 7-15%.

Project Contingency Cost: This is 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.

Process Contingency Cost: 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.

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

Pre-Production Costs : 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 applied to the O&M costs over a specified period of time (months)The two time periods for fixed and variable O&M costs are described below with the addition of a miscellaneous capital cost factor.

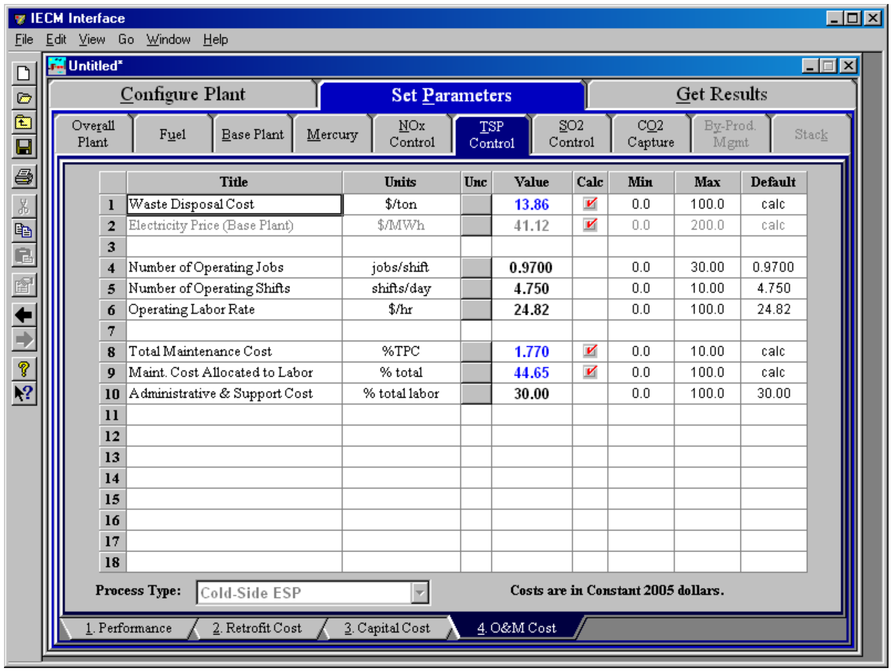
- **Months of Fixed O&M:** Time period of fixed operating costs used for preproduction to cover training, testing, major changes in equipment, and inefficiencies in start-up. This includes operating, maintenance, administrative and support labor. It also considers maintenance materials.
- **Months of Variable O&M:** Time period of variable operating costs used for preproduction to cover chemicals, water, consumables, and solid disposal charges in start-up, assuming 100% load. This excludes any fuels.
- **Misc. Capital Cost:** This is a percent of total plant investment (sum of TPC and AFUDC) to cover expected changes to equipment to bring the system up to full capacity.

Inventory Capital: Percent of the total direct capital for raw material supply based on 100% capacity during a 60 day period. These materials are considered storage. The inventory capital includes fuels, consumables, by-products, and spare parts. This is typically 0.5%.

TCR Recovery Factor: The actual total capital required (TCR) as a percent of the TCR in a new power plant. This value is 100% for a new installation and may be set as low as 0% for a cold-side ESP that has been paid off.

Cold-Side ESP O&M Cost Inputs

This screen is only available for the **Combustion (Boiler)** plant type.



Cold–Side ESP – O&M Cost screen input.

O&M costs are typically expressed on an average annual basis and are provided in either constant or current dollars for a specified year, as shown on the bottom of the screen. Inputs for the operation and maintenance costs of the particulate control technology are entered on this screen.

Waste Disposal Cost: This is the disposal cost for the particulate control system.

Electricity Price (Base Plant): This is the price of electricity and is calculated as a function of the utility cost of the base plant, where the base plant is defined as combustion boiler and an air preheater.

Number of Operating Jobs: This is the total number of operating jobs that are required to operate the plant per eight-hour shift.

Number of Operating Shifts: This is the total number of equivalent operating shifts in the plant per day. The number takes into consideration paid time off and weekend work (3 shifts/day * 7 days/5 day week * 52 weeks/(52 weeks - 6 weeks PTO) = 4.75 equiv. Shifts/day)

Operating Labor Rate: The hourly cost of labor is specified in the base plant O&M cost screen. The same value is used throughout the other technologies.

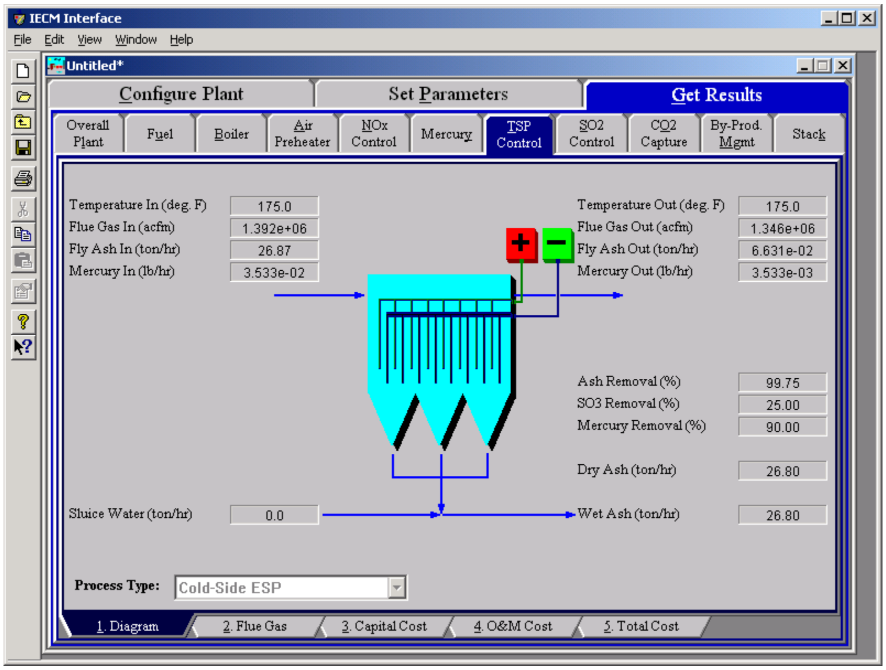
Total Maintenance Cost: This is the annual maintenance cost as a percentage of the total plant cost. Maintenance cost estimates can be developed separately for each process area.

Maint. Cost Allocated to Labor: Maintenance cost allocated to labor as a percentage of the total maintenance cost.

Administrative & Support Cost: This is the percent of the total operating and maintenance labor associated with administrative and support labor.

Cold-Side ESP Diagram

This screen is only available for the Combustion (Boiler) plant type. The **Diagram** result screen displays an icon for the particulate control technology selected and values for major flows in and out of it.



Cold–Side ESP – Diagram

Each result is described briefly below:

Flue Gas Entering ESP

Temperature In: Temperature of the flue gas entering the particulate control technology. This is determined by the flue gas outlet temperature of the module upstream of the air preheater (e.g., the air preheater).

Flue Gas In: Volumetric flow rate of the flue gas entering the particulate control technology, based on the flue gas inlet temperature and atmospheric pressure.

Fly Ash In: Total solids mass flow rate in the flue gas entering the air preheater. This is determined by the solids exiting the module upstream of the particulate control technology (e.g., the air preheater).

Mercury In: Total mass of mercury entering the particulate control technology. The value is a sum of all the forms of mercury (elemental, oxidized, and particulate).

Flue Gas Exiting ESP

Temperature Out: Temperature of the flue gas exiting the particulate control technology. The model currently does not alter this temperature through the particulate control technology.

Flue Gas Out: Volumetric flow rate of the flue gas exiting the particulate control technology, based on the flue gas exit temperature and atmospheric pressure.

Fly Ash Out: Total solids mass flow rate in the flue gas exiting the particulate control technology. This is a function of the ash content of the inlet flue gas and the ash removal efficiency performance input parameter.

Mercury Out: Total mass of mercury exiting the particulate control technology. The value is a sum of all the forms of mercury (elemental, oxidized, and particulate).

ESP Performance

Ash Removal: Ash removal efficiency of the particulate control technology. This is a function of the ash emission constraint and the inlet ash mass flow rate.

SO_3 Removal: Percent of SO_3 in the flue gas removed from the particulate control technology. The SO_3 is assumed to combine with H_2O and leave with the ash solids as a sulfate (in the form of H_2SO_4).

Mercury Removal: Percent of the total mercury removed from the particulate control technology. The value reflects a weighted average based on the particular species of mercury present (elemental, oxidized, and particulate).

Collected Fly Ash

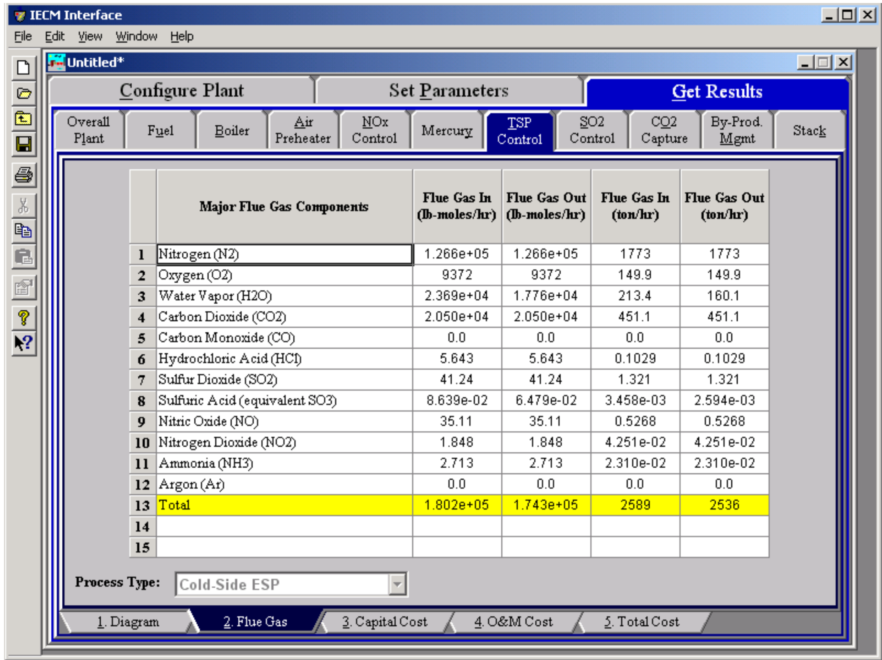
Dry Ash: Total mass flow rate of the solids removed from the ESP. This is a function of the solids content in the flue gas and the particulate removal efficiency of the ESP. The value is given on a dry basis.

Sluice Water: Water added to the dry fly ash. This water is added for transportation purposes.

Wet Ash: Total mass flow rate of the solids removed for waste management. This includes dry fly ash and sluice water. The value is given on a wet basis.

Cold-Side ESP Flue Gas Results

This screen is only available for the **Combustion (Boiler)** plant type. The Flue **Gas** result screen displays a table of quantities of flue gas components entering and exiting the Particulate Control Technology. For each component, quantities are given in both moles and mass per hour.



Cold–Side ESP – Flue Gas results screen.

Each result is described briefly below**:**

Major Flue Gas Components

Nitrogen (N2): Total mass of nitrogen.

Oxygen (O2): Total mass of oxygen.

Water Vapor (H2O): Total mass of water vapor.

Carbon Dioxide (CO2): Total mass of carbon dioxide.

Carbon Monoxide (CO): Total mass of carbon monoxide.

Hydrochloric Acid (HCl): Total mass of hydrochloric acid.

Sulfur Dioxide (SO2): Total mass of sulfur dioxide.

Sulfuric Acid (equivalent SO3): Total mass of sulfuric acid.

Nitric Oxide (NO): Total mass of nitric oxide.

Nitrogen Dioxide (NO2): Total mass of nitrogen dioxide.

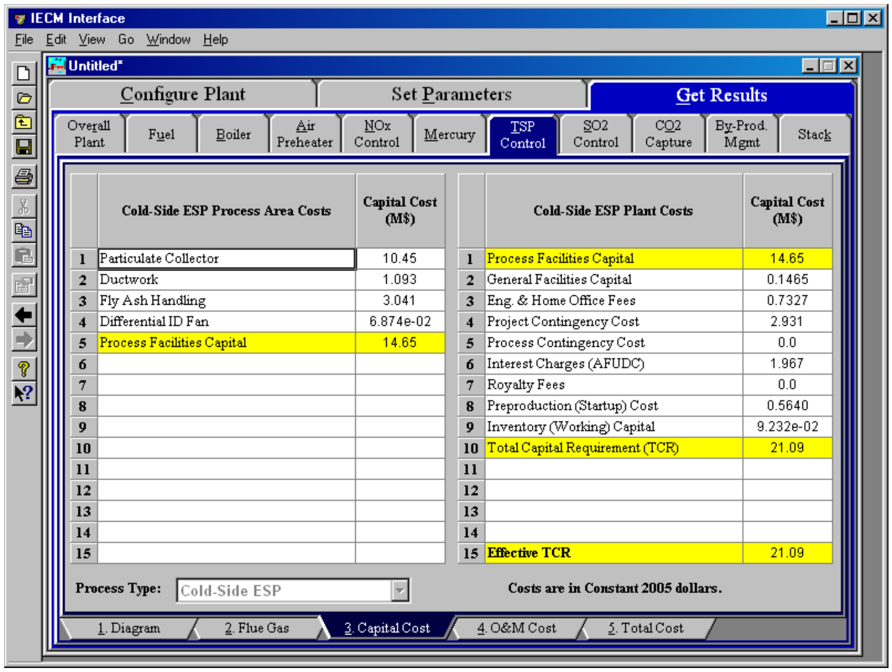
Ammonia (NH3): Total mass of Ammonia.

Argon (Ar): Total mass of Argon.

Total: Total of the individual components listed above. This item is highlighted in yellow.

Cold–Side ESP Capital Cost Results

This screen is only available for the **Combustion (Boiler)** plant type. The **Capital Cost** result screen displays tables for the direct and indirect capital costs related to the particulate control technology.



Cold-Side ESP — Capital Costs results screen.

Direct Capital Costs

Each process area direct capital cost is a reduced-form model based on regression analysis of data collected from several reports and analyses of particulate control technology units. They are described in general below. The primary factors in the model that effect the capital costs of the cold-side ESP are the specific and total collection areas of the T-R plate sets, and the flue gas flow rate through the ESP. The primary model factors that effect the capital costs of the fabric filter are the fabric filter type, the air to cloth ratio, the number of bags and compartments, and the flue gas flow rate through the fabric filter.

Capital costs are typically expressed in either constant or current dollars for a specified year, as shown on the bottom of the screen. The parameters are described below.

Particulate Collector: This area covers the material and labor, flange to flange, for the equipment and labor cost for installation of the entire collection system.

Ductwork: This area includes the material and labor for the ductwork needed to distribute flue gas to the inlet flange, and from the outlet flange to a common duct leading to the suction side of the ID fan.

Fly Ash Handling: The complete fly ash handling cost includes the conveyor system and ash storage silos.

Differential ID Fan: The complete cost of the ID fan and motor due to the pressure loss that results from particulate collectors.

Process Facilities Capital: The process facilities capital is the total constructed cost of all on-site processing and generating units listed above, including all direct and indirect construction costs. All sales taxes and freight costs are included where applicable implicitly. This result is highlighted in yellow.

Total Capital Costs

Process Facilities Capital: (see definition above)

General Facilities Capital: The general facilities include construction costs of roads, office buildings, shops, laboratories, etc. Sales taxes and freight costs are included implicitly.

Eng. & Home Office Fees: The engineering & home office fees are a percent of total direct capital cost. This is an overhead fee paid to the architect/engineering company.

Project Contingency Cost: Capital cost contingency factor covering the cost of additional equipment or other costs that would result from a more detailed design of a definitive project at the actual site.

Process Contingency Cost: Capital cost contingency factor applied to a new technology in an effort to quantify the uncertainty in the technical performance and cost of the commercial-scale equipment.

Interest Charges (AFUDC): Allowance for funds used during construction, also referred to as interest during construction, is the time value of the money used during construction and is based on an interest rate equal to the before-tax weighted cost of capital. This interest is compounded on an annual basis (end of year) during the construction period for all funds spent during the year or previous years.

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

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.

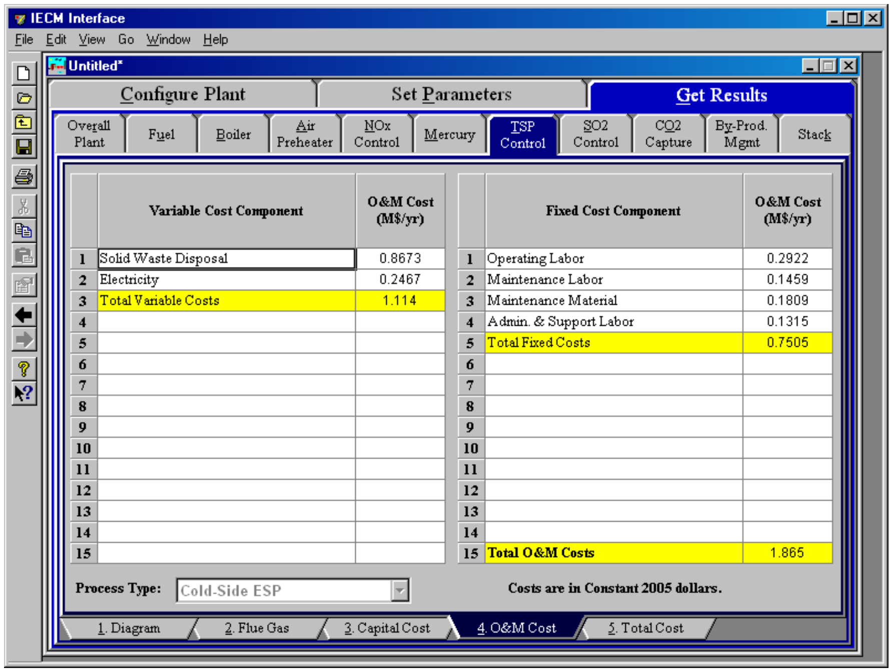
Inventory (Working) Capital: The raw material supply based on 100% capacity during a 60 day period. These materials are considered storage. The inventory capital includes fuels, consumables, by-products, and spare parts.

Total Capital Requirement (TCR): Money that is placed (capitalized) on the books of the utility on the service date. TCR includes all the items above. This result is highlighted in yellow.

Effective TCR: The TCR of the cold-side ESP that is used in determining the total power plant cost. The effective TCR is determined by the **TCR Recovery Factor** for the cold-side ESP.

Cold–Side ESP O&M Cost Results

This screen is only available for the **Combustion (Boiler)** plant type. The **O&M Cost** result screen displays tables for the variable and fixed operation and maintenance costs involved with the Cold–Side ESP TSP particulate control technology.



Cold–Side ESP – O&M Cost result screen.

O&M costs are typically expressed on an average annual basis and are provided in either constant or current dollars for a specified year, as shown on the bottom of the screen. Each result is described briefly below

Variable Cost Component

Variable operating costs and consumables are directly proportional to the amount of kilowatts produced and are referred to as incremental costs. All the costs are subject to inflation.

Solid Waste Disposal: Total cost to dispose the collected fly ash. This does not consider by-product ash sold in commerce.

Power: Cost of power consumption of the particulate control technology. This is a function of the flue gas flow rate, ash removal efficiency and the type of coal (ash properties).

Total Variable Costs: This is the sum of all the variable O&M costs listed above. This result is highlighted in yellow.

Fixed Cost Components

Fixed operating costs are essentially independent of actual capacity factor, number of hours of operation, or amount of kilowatts produced. All the costs are subject to inflation.

Operating Labor: Operating labor cost is based on the operating labor rate, the number of personnel required to operate the plant per eight-hour shift, and the average number of shifts per day over 40 hours per week and 52 weeks.

Maintenance Labor: The maintenance labor is determined as a fraction of the total maintenance cost.

Maintenance Material: The cost of maintenance material is the remainder of the total maintenance cost, considering the fraction associated with maintenance labor.

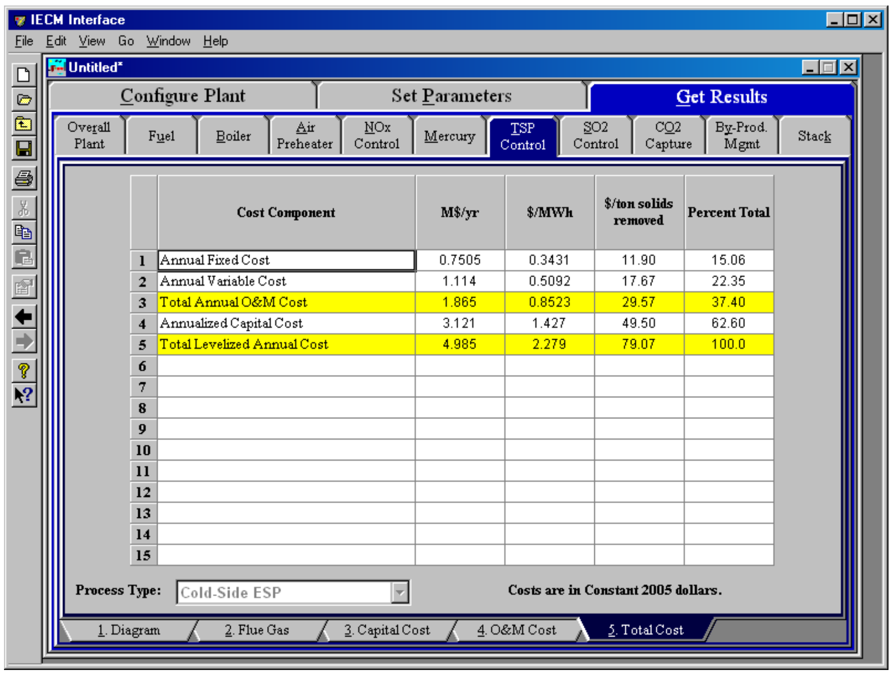
Admin. & Support Labor: The administrative and support labor is the only overhead charge. It is taken as a fraction of the total operating and maintenance labor costs.

Total Fixed Costs: This is the sum of all the fixed O&M costs listed above. This result is highlighted in yellow.

Total O&M Costs: This is the sum of the total variable and total fixed O&M costs. It is used to determine the base plant total revenue requirement. This result is highlighted in yellow.

Cold-Side ESP Total Cost Results

This screen is only available for the **Combustion (Boiler)** plant type. The **Total Cost** result screen displays a table which totals the annual fixed, variable, operations and maintenance, and capital costs associated with the Cold–Side ESP TSP Control technology.



Cold–Side ESP – Total Cost result screen.

Total costs are typically expressed in either constant or current dollars for a specified year, as shown on the bottom of the screen. Each result is described briefly below.

Cost Component

Annual Fixed Cost: The operating and maintenance fixed costs are given as an annual total. This number includes all maintenance materials and all labor costs.

Annual Variable Cost: The operating and maintenance variables costs are given as an annual total. This includes all reagent, chemical, steam, and power costs.

Total Annual O&M Cost: This is the sum of the annual fixed and variable operating and maintenance costs above. This result is highlighted in yellow.

Annualized Capital Cost: This is the total capital cost expressed on an annualized basis, taking into consideration the levelized carrying charge factor, or fixed charge factor, over the entire book life.

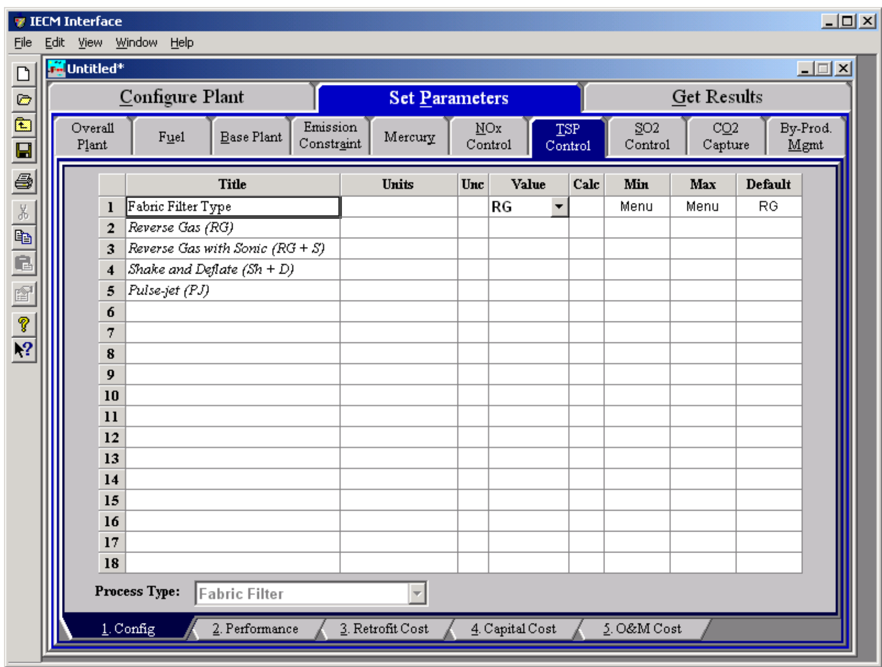
Total Levelized Annual Cost: The total annual cost is the sum of the total annual O&M cost and annualized capital cost items above. This result is highlighted in yellow.

Fabric Filter

The **TSPControl** Technology Navigation Tab contains screens that design and display flows and costs related to the particulate control technology. Shown in the Combustion (Boiler) plant type configurations.

Fabric Filter Configuration

This screen is only available for the Combustion (Boiler) plant type.



Fabric Filter – Configuration input screen.

Fabric Filter Type

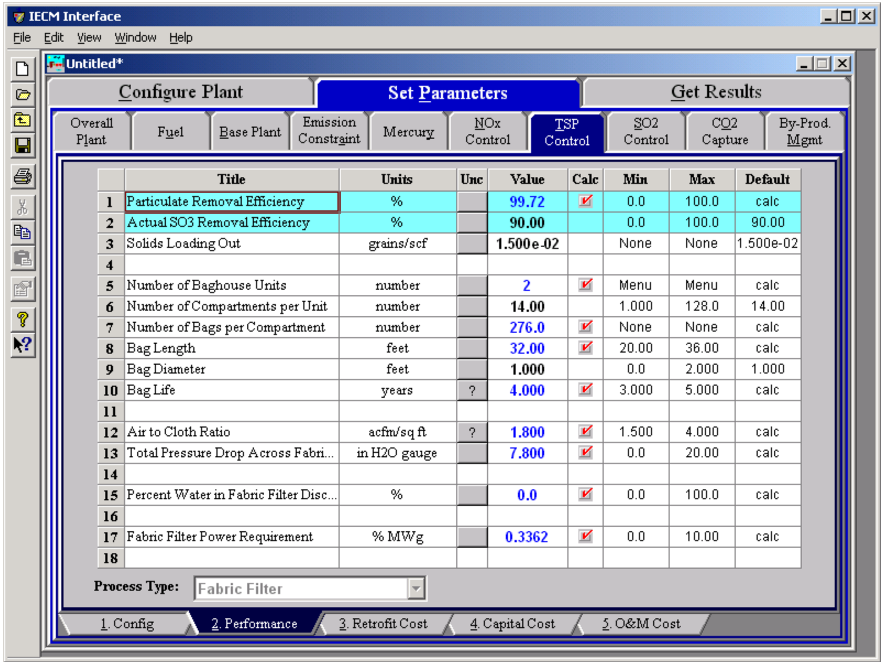
Fabric filters consist of a large number of long tubular filter bags arranged in parallel flow paths. As the ash-laden flue gas passes through these filters, much of the particulate matter is removed. Ash accumulated on the bags is removed periodically by various methods of cleaning. Choose the cleaning method in the **Config.** input screen. The available methods are:

- Reverse Gas (RG)
- Reverse Gas with Sonic (RG + S)

- Shake and Deflate (Sh + D)
- Pulse-jet (PJ)

Fabric Filter Performance Inputs

This screen is only available for the Combustion (Boiler) plant type.



Fabric Filter – Performance input screen.

The baghouse system is very efficient in removing particulate matter from the flue gas. It's model design is simple, requiring few parameters to characterize its effects on the overall performance of the plant. For properly designed fabric filters, the size of the system is independent of the removal efficiency.

Although the performance is determined by very few parameters, there are several design parameters necessary to determine the cost. These factors are also determined in this section. The major design parameters that can significantly impact the total system cost of the fabric filter are *gas flow volume* (which depends on the generating unit size), *A/C ratio*, the *flange-to-flange pressure drop* in the baghouse and the *bag life*.

Particulate Removal Efficiency: The calculated removal is set to comply with the particulate emission limit set earlier. The mass removed is then determined. If you select a spray dryer, the particulate removal efficiency applies to the combined mass of flyash and sulfur-laden wastes. This input is highlighted in blue.

Actual SO_3 Removal Efficiency: The default value is taken from the removal efficiency reported in the literature (references are below). This efficiency then determines the mass of SO_3 removed from the flue gas in the collector. For more information see also:

- www.netl.doe.gov/publications/proceedings/98/98fg/hardman.pdf
- www.netl.doe.gov/publications/proceedings/98/98fg/rubin.pdf

Solids Loading Out: This is the fabric filter output loading. It is an average value based on typical fabric filter units. The value is used to determine the particulate removal efficiency.

Number of Baghouse Units: This is the number of baghouse units. The value is based on the gross plant size. The value must be an integer. Each unit contains several compartments. It is used to calculate the capital cost of the baghouse.

Number of Compartments per Unit: This parameter specifies the average number of compartments used per baghouse unit. It is used to calculate the capital cost of the baghouse.

Number of Bags per Compartment: The number of individual bags per compartment is calculated by comparing the required bag surface area to the bag dimensions and the total number of compartments. It is used to calculate the capital cost of the baghouse.

Bag Length: Bag length generally fall into two size categories: 30-36 ft or 20 -22 ft in length. It is based on the fabric filter type and used to calculate the capital cost of the baghouse.

Bag Diameter: Bags are generally between 2/3 and 1 foot in diameter. The value is based on the fabric filter type and used to calculate the capital cost of the baghouse.

Bag Life: Bag life is typically between 3-5 years. The bag life values are dependent on the fabric filter type and are used to calculate the cost of the baghouse.

Air to Cloth Ratio: The Air to Cloth ratio is the most important baghouse parameter. It is the ratio of volumetric flue gas flow rate and total bag cloth area. The calculated value is a function of fabric filter type. It is used to determine the cost and power use of the baghouse.

Total Pressure Drop across Fabric Filter: Baghouse pressure drop (flange-to-flange) is caused by pressure losses in gas flow as it moves through the bag fabric and dust cake. Typical values range from 6 to 8 in. H_2O and depend on the baghouse type selected. The value affects the power consumption.

Percent Water in Fabric Filter Discharge: This is the water content of the collected fly ash. Fly ash disposed with bottom ash is assumed to be sluiced with water and dry otherwise. The occluded water in wet fly ash is difficult to remove, resulting in a rather high water content when the fly ash is mixed with bottom ash.

Fabric Filter Power Requirement: The default calculation is based on the air-to-cloth ratio and the flue gas flow rate. The power accounts for the auxiliary power requirements and electro-mechanical efficiencies of fan motors.

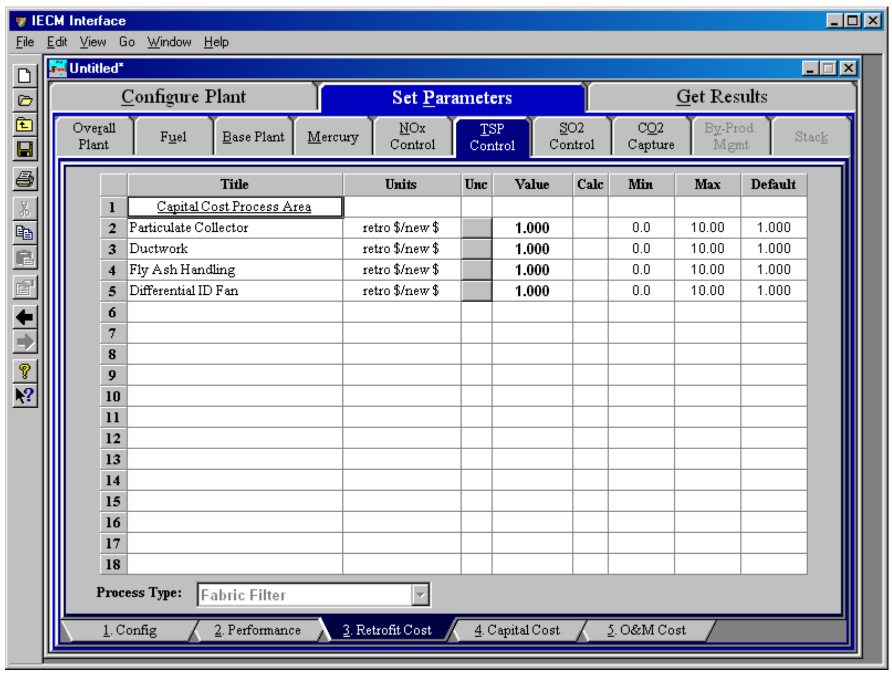
Fabric Filter Retrofit Inputs

This screen is only available for the Combustion (Boiler) plant type. Inputs for the capital costs of modifications to process areas to implement the Particulate control technology are entered on the **Retrofit Cost** input screen.

The retrofit cost factor of each process is a multiplicative cost adjustment, which considers the cost of retrofitted capital equipment relative to similar equipment installed in a new plant. These factors affect the capital costs directly and the operating and maintenance costs indirectly.

Direct capital costs for each process area are calculated in the IECM. These calculations are reduced form equations derived from more sophisticated models and reports. The sum of the direct capital costs associated with each process area is defined as the process facilities capital (PFC). The retrofit cost factor provided for each of the process areas can be used as a tool for adjusting the anticipated costs and uncertainties across the process area separate from the other areas.

Uncertainty can be applied to the retrofit cost factor for each process area in each technology. Thus, uncertainty can be applied as a general factor across an entire process area, rather than as a specific uncertainty for the particular cost on the capital or O&M input screens. Any uncertainty applied to a process area through the retrofit cost factor compounds any uncertainties specified later in the capital and O&M cost input parameter screens.



Fabric Filter – Retrofit Cost input screen.

Capital Cost Process Area

Particulate Collector: This is the cost for the collecting equipment, based on actual vendor prices. Included in the cost are the mechanical equipment and labor, particulate removal system, alternate cleaning system, gas conditioning system, structural supports, electrical, and instrumentation.

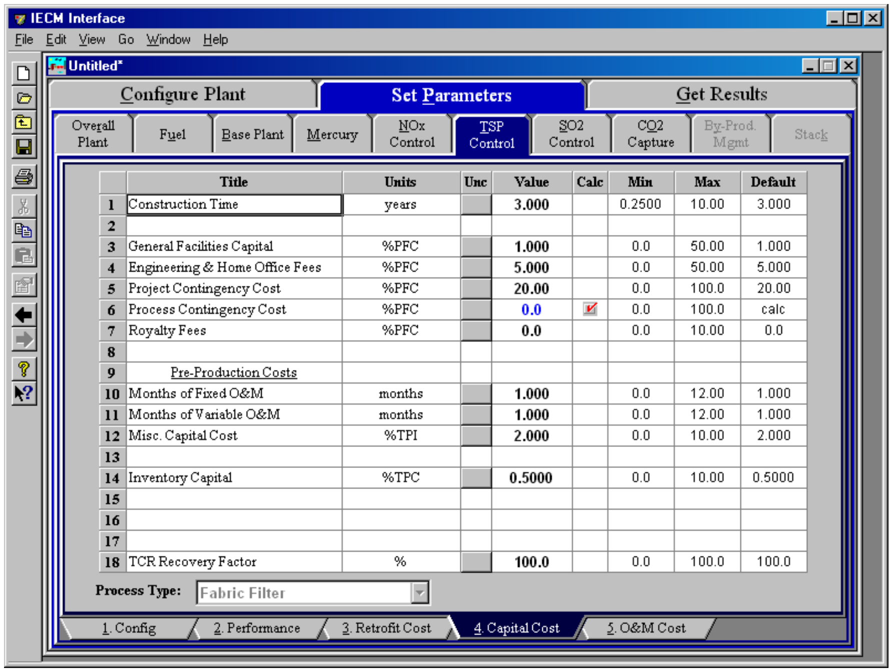
Ductwork: This is the cost of all the mechanical, electrical, and supports of the ductwork to and from the collector.

Fly Ash Handling: This is the cost of all the mechanical, conveyors, storage, and electrical portions of the ash handling system. The costs are based on actual vendor prices.

Differential ID Fan: This area includes the additional cost of the ID fan and the motor due to the pressure loss that results from the particulate collectors. Also included are the erection, piping, electrical, and foundation costs.

Fabric Filter Capital Cost Inputs

This screen is only available for the Combustion (Boiler) plant type.



Fabric Filter – Capital Cost input screen.

The necessary capital cost input parameters associated with the fabric filter control technology are shown on this input screen (no distinction is made between the various types of fabric filtersEach parameter is described briefly below.

Indirect Capital Costs: Costs that are indirectly applied to the technology are based on the process facilities cost. Each of the cost factors below is expressed as a percentage of the process facilities cost, and is entered on this screen. Each parameter is described briefly below.

Construction Time: This is the idealized construction period in years. It is used to determine the allowance for funds used during construction (AFUDC).

General Facilities Capital (GFC): 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%.

Engineering & Home Office Fees: The engineering & home office fees are a percent of total direct capital cost. This is an overhead fee paid to the architect/engineering company. These fees typically range from 7-15%.

Project Contingency Cost: This is 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.

Process Contingency Cost: 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.

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

Pre-Production Costs: 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 applied to the O&M costs over a specified period of time (months)The two time periods for fixed and variable O&M costs are described below with the addition of a miscellaneous capital cost factor.

- **Months of Fixed O&M:** Time period of fixed operating costs used for preproduction to cover training, testing, major changes in equipment, and inefficiencies in start-up. This includes operating, maintenance, administrative and support labor. It also considers maintenance materials.

- **Months of Variable O&M:** Time period of variable operating costs used for preproduction to cover chemicals, water, consumables, and solid disposal charges in start-up, assuming 100% load. This excludes any fuels.

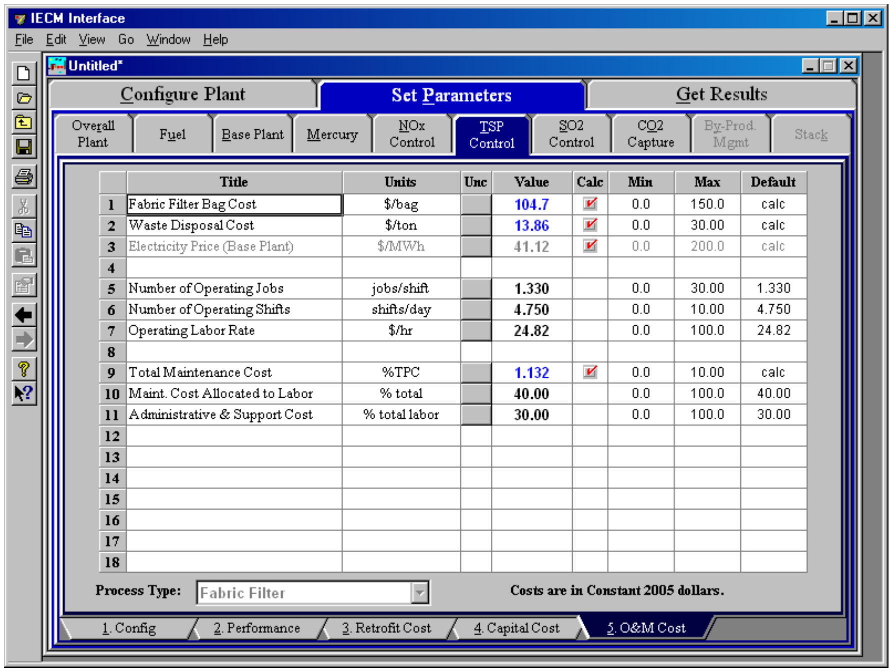
- **Misc. Capital Costs:** This is a percent of total plant investment (sum of TPC and AFUDC) to cover expected changes to equipment to bring the system up to full capacity.

Inventory Capital: Percent of the total direct capital for raw material supply based on 100% capacity during a 60 day period. These materials are considered storage. The inventory capital includes fuels, consumables, by-products, and spare parts. This is typically 0.5%.

TCR Recovery Factor: The actual total capital required (TCR) as a percent of the TCR in a new power plant. This value is 100% for a new installation and may be set as low as 0% for a fabric filter that has been paid off.

Fabric Filter O&M Cost Inputs

This screen is only available for the Combustion (Boiler) plant type.



Fabric Filter – O&M Cost input screen.

O&M costs are typically expressed on an average annual basis and are provided in either constant or current dollars for a specified year, as shown on the bottom of the screen.

Fabric Filter Bag Cost: This is the cost of a fabric filter bag as used for the fabric filter technology.

Waste Disposal Cost: This is the disposal cost for the particulate control system.

Electricity Price (Base Plant): This is the price of electricity and is calculated as a function of the utility cost of the base plant, where the base plant is a combustion boiler and an air preheater.

Number of Operating Jobs: This is the total number of operating jobs that are required to operate the plant per eight-hour shift.

Number of Operating Shifts: This is the total number of equivalent operating shifts in the plant per day. The number takes into consideration paid time off and weekend work (3 shifts/day * 7 days/5 day week * 52 weeks/(52 weeks - 6 weeks PTO) = 4.75 equiv. Shifts/day)

Operating Labor Rate:

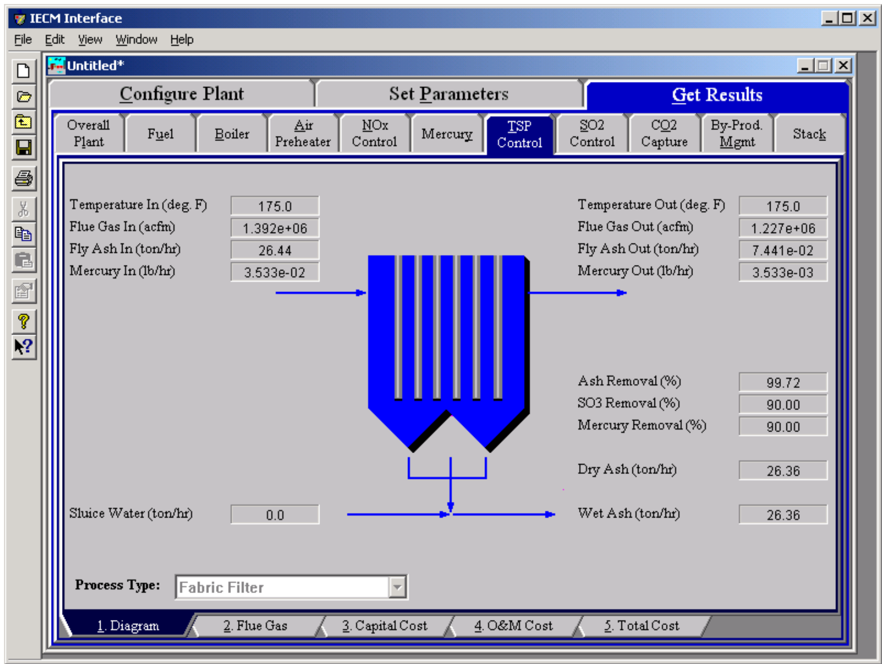
Total Maintenance Cost: This is the annual maintenance cost as a percentage of the total plant cost. Maintenance cost estimates can be developed separately for each process area.

Maint. Cost Allocated to Labor: Maintenance cost allocated to labor as a percentage of the total maintenance cost.

Administrative & Support Cost: This is the percent of the total operating and maintenance labor associated with administrative and support labor.

Fabric Filter Diagram

This screen is only available for the Combustion (Boiler) plant type. The **Diagram** result screen displays an icon for the **Fabric Filter** particulate control technology selected and values for major flows in and out of it.



Fabric Filter – Diagram

Each result is described briefly below

Flue Gas Entering Filter

Temperature In: Temperature of the flue gas entering the particulate control technology. This is determined by the flue gas outlet temperature of the module upstream of the air preheater (e.g., the air preheater).

Flue Gas In: Volumetric flow rate of the flue gas entering the particulate control technology, based on the flue gas inlet temperature and atmospheric pressure.

Fly Ash In: Total solids mass flow rate in the flue gas entering the air preheater. This is determined by the solids exiting the module upstream of the particulate control technology (e.g., the air preheater).

Mercury In: Total mass of mercury entering the particulate control technology. The value is a sum of all the forms of mercury (elemental, oxidized, and particulate).

Flue Gas Exiting Filter

Temperature Out: Temperature of the flue gas exiting the particulate control technology. The model currently does not alter this temperature through the particulate control technology.

Flue Gas Out: Volumetric flow rate of the flue gas exiting the particulate control technology, based on the flue gas exit temperature and atmospheric pressure.

Fly Ash Out: Total solids mass flow rate in the flue gas exiting the particulate control technology. This is a function of the ash content of the inlet flue gas and the ash removal efficiency performance input parameter.

Mercury Out: Total mass of mercury exiting the particulate control technology. The value is a sum of all the forms of mercury (elemental, oxidized, and particulate).

Fabric Filter Performance

Ash Removal: Ash removal efficiency of the fabric filter technology. This is a function of the ash emission constraint and the inlet ash mass flow rate.

SO3 Removal: Percent of SO_3 in the flue gas removed from the particulate control technology. The SO_3 is assumed to combine with H_2O and leave with the ash solids as a sulfate (in the form of H_2SO_4).

Mercury Removal: Percent of the total mercury removed from the particulate control technology. The value reflects a weighted average based on the particular species of mercury present (elemental, oxidized, and particulate).

Collected Fly Ash

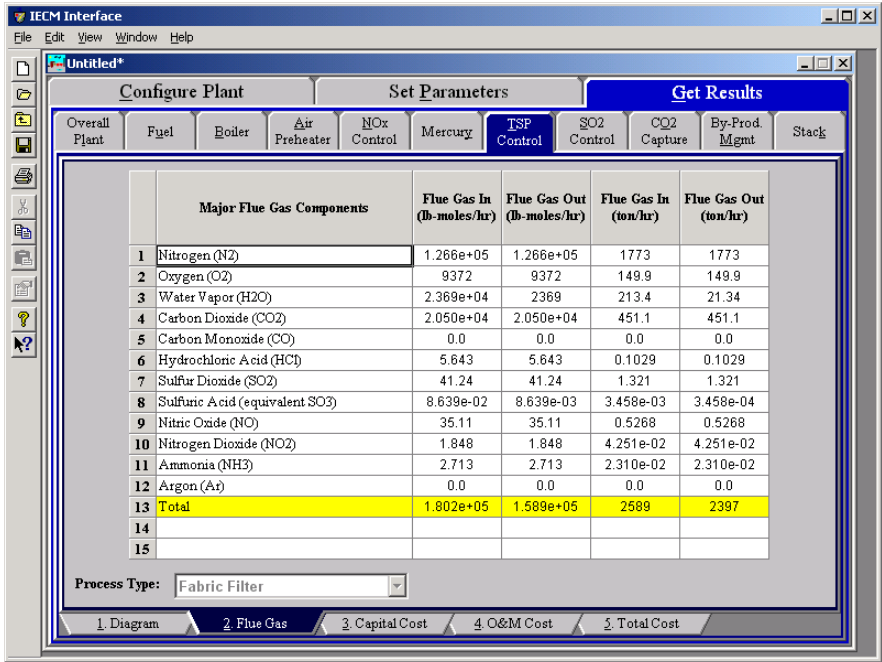
Dry Ash: Total mass flow rate of the solids removed from the fabric filter. This is a function of the solids content in the flue gas and the particulate removal efficiency of the fabric filter. The value is given on a dry basis.

Sluice Water: Water added to the dry fly ash. This water is added for transportation purposes.

Wet Ash: Total mass flow rate of the solids removed for waste management. This includes dry fly ash and sluice water. The value is given on a wet basis.

Fabric Filter Flue Gas Results

This screen is only available for the Combustion (Boiler) plant type. The **Flue Gas** result screen displays a table of quantities of flue gas components entering and exiting the Particulate Control Technology. For each component, quantities are given in both moles and mass per hour.



	Major Flue Gas Components	Flue Gas In (lb-moles/hr)	Flue Gas Out (lb-moles/hr)	Flue Gas In (ton/hr)	Flue Gas Out (ton/hr)
1	Nitrogen (N2)	1.266e+05	1.266e+05	1773	1773
2	Oxygen (O2)	9372	9372	149.9	149.9
3	Water Vapor (H2O)	2.369e+04	2369	213.4	21.34
4	Carbon Dioxide (CO2)	2.050e+04	2.050e+04	451.1	451.1
5	Carbon Monoxide (CO)	0.0	0.0	0.0	0.0
6	Hydrochloric Acid (HCl)	5.643	5.643	0.1029	0.1029
7	Sulfur Dioxide (SO2)	41.24	41.24	1.321	1.321
8	Sulfuric Acid (equivalent SO3)	8.639e-02	8.639e-03	3.458e-03	3.458e-04
9	Nitric Oxide (NO)	35.11	35.11	0.5268	0.5268
10	Nitrogen Dioxide (NO2)	1.848	1.848	4.251e-02	4.251e-02
11	Ammonia (NH3)	2.713	2.713	2.310e-02	2.310e-02
12	Argon (Ar)	0.0	0.0	0.0	0.0
13	Total	1.802e+05	1.589e+05	2589	2397
14					
15					

Fabric Filter – Flue Gas result screen.

Each result is described briefly below

Nitrogen (N_2): Total mass of nitrogen.

Oxygen (O_2): Total mass of oxygen.

Water Vapor (H_2O): Total mass of water vapor.

Carbon Dioxide (CO_2): Total mass of carbon dioxide.

Carbon Monoxide (CO): Total mass of carbon monoxide.

Hydrochloric Acid (HCl): Total mass of hydrochloric acid.

Sulfur Dioxide (SO_2): Total mass of sulfur dioxide.

Sulfuric Acid (equivalent SO_3): Total mass of sulfuric acid.

Nitric Oxide (NO): Total mass of nitric oxide.

Nitrogen Dioxide (NO_2): Total mass of nitrogen dioxide.

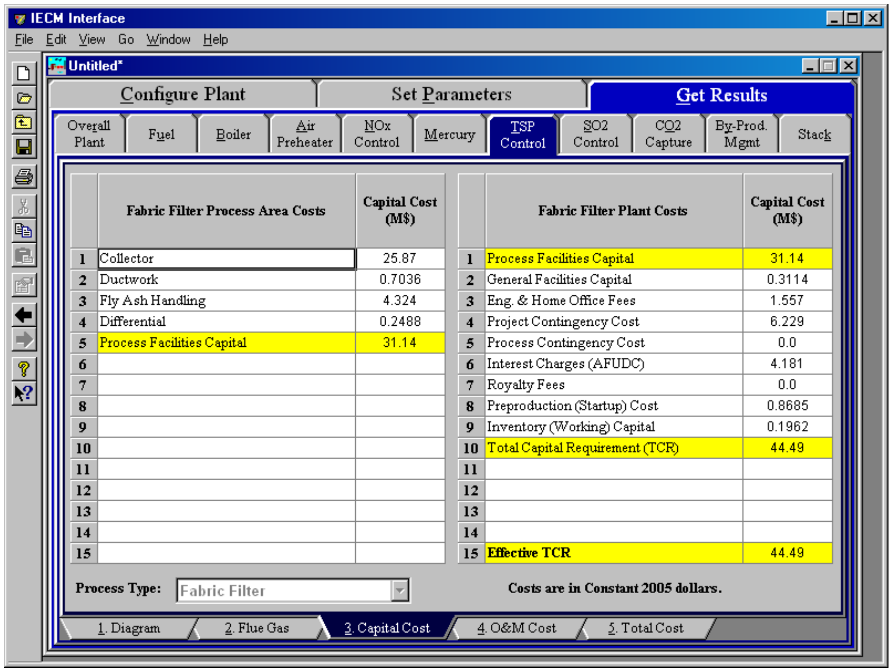
Ammonia (NH_3): Total mass of ammonia.

Argon (Ar): Total mass of argon.

Total: Total of the individual components listed above. This item is highlighted in yellow.

Fabric Filter Capital Cost Results

This screen is only available for the Combustion (Boiler) plant type. The **Capital Cost** result screen displays tables for the direct and indirect capital costs related to the particulate control technology.



Fabric Filter – Capital Cost result screen.

Capital costs are typically expressed in either constant or current dollars for a specified year, as shown on the bottom of the screen. Each result is described briefly below

Direct Capital Costs

Each process area direct capital cost is a reduced-form model based on regression analysis of data collected from several reports and analyses of particulate control technology units. They are described in general below. The primary factors in the model that effect the capital costs of the cold-side ESP are the specific and total collection areas of the T-R plate sets, and the flue gas flow rate through the ESP. The primary model factors that effect the capital costs of the fabric filter are the fabric filter type, the air to cloth ratio, the number of bags and compartments, and the flue gas flow rate through the fabric filter.

Collector: This area covers the material and labor, flange to flange, for the equipment and labor cost for installation of the entire collection system.

Ductwork: This area includes the material and labor for the ductwork needed to distribute flue gas to the inlet flange, and from the outlet flange to a common duct leading to the suction side of the ID fan.

Fly Ash Handling: The complete fly ash handling cost includes the conveyor system and ash storage silos.

Differential: The complete cost of the ID fan and motor due to the pressure loss that results from particulate collectors.

Process Facilities Capital: The process facilities capital is the total constructed cost of all on-site processing and generating units listed above, including all direct and indirect construction costs. All sales taxes and freight costs are included where applicable implicitly. This result is highlighted in yellow.

Total Capital Costs

Process Facilities Capital: (see definition above)

General Facilities Capital: The general facilities include construction costs of roads, office buildings, shops, laboratories, etc. Sales taxes and freight costs are included implicitly.

Eng. & Home Office Fees: The engineering & home office fees are a percent of total direct capital cost. This is an overhead fee paid to the architect/engineering company.

Project Contingency Cost: Capital cost contingency factor covering the cost of additional equipment or other costs that would result from a more detailed design of a definitive project at the actual site.

Process Contingency Cost: Capital cost contingency factor applied to a new technology in an effort to quantify the uncertainty in the technical performance and cost of the commercial-scale equipment.

Interest Charges (AFUDC): Allowance for funds used during construction, also referred to as interest during construction, is the time value of the money used during construction and is based on an interest rate equal to the before-tax weighted cost of capital. This interest is compounded on an annual basis (end of year) during the construction period for all funds spent during the year or previous years.

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

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.

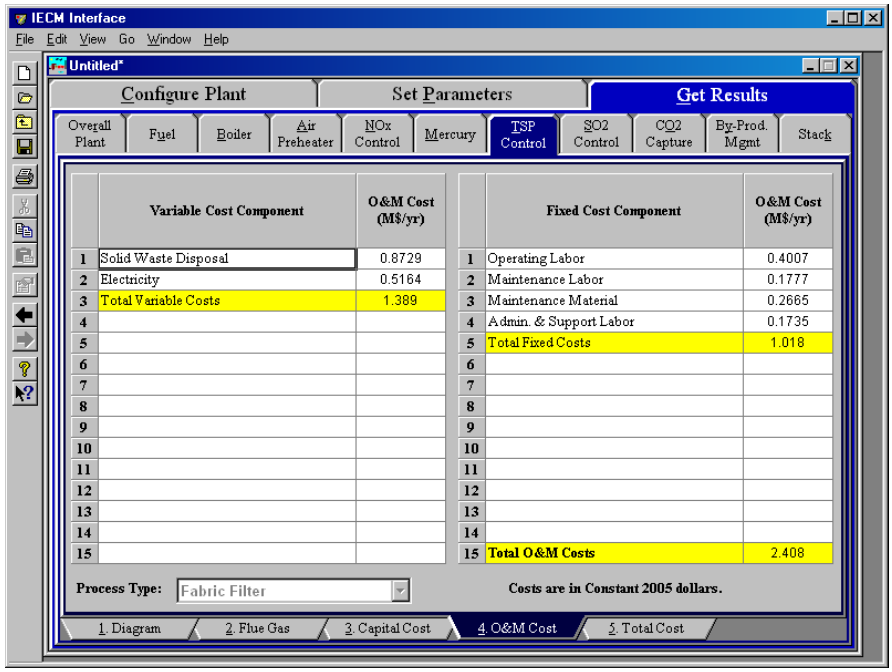
Inventory (Working) Capital: The raw material supply based on 100% capacity during a 60 day period. These materials are considered storage. The inventory capital includes fuels, consumables, by-products, and spare parts.

Total Capital Requirement (TCR): Money that is placed (capitalized) on the books of the utility on the service date. TCR includes all the items above. This result is highlighted in yellow.

Effective TCR: The TCR of the fabric filter that is used in determining the total power plant cost. The effective TCR is determined by the "TCR Recovery Factor" for the fabric filter.

Fabric Filter O&M Cost Results

This screen is only available for the Combustion (Boiler) plant type. The **O&M Cost** result screen displays tables for the variable and fixed operation and maintenance costs involved with the particulate control technology.



Fabric Filter – O&M Cost result screen.

O&M costs are typically expressed on an average annual basis and are provided in either constant or current dollars for a specified year, as shown on the bottom of the screen. Each result is described briefly below:

Variable Cost Component

Variable operating costs and consumables are directly proportional to the amount of kilowatts produced and are referred to as incremental costs. All the costs are subject to inflation.

Solid Waste Disposal: Total cost to dispose the collected fly ash. This does not consider by-product ash sold in commerce.

Electricity: Cost of power consumption of the particulate control technology. This is a function of the flue gas flow rate, ash removal efficiency and the type of coal (ash properties).

Total Variable Costs: This is the sum of all the variable O&M costs listed above. This result is highlighted in yellow.

Fixed Cost Component

Fixed operating costs are essentially independent of actual capacity factor, number of hours of operation, or amount of kilowatts produced. All the costs are subject to inflation.

Operating Labor: Operating labor cost is based on the operating labor rate, the number of personnel required to operate the plant per eight-hour shift, and the average number of shifts per day over 40 hours per week and 52 weeks.

Maintenance Labor: The maintenance labor is determined as a fraction of the total maintenance cost.

Maintenance Material: The cost of maintenance material is the remainder of the total maintenance cost, considering the fraction associated with maintenance labor.

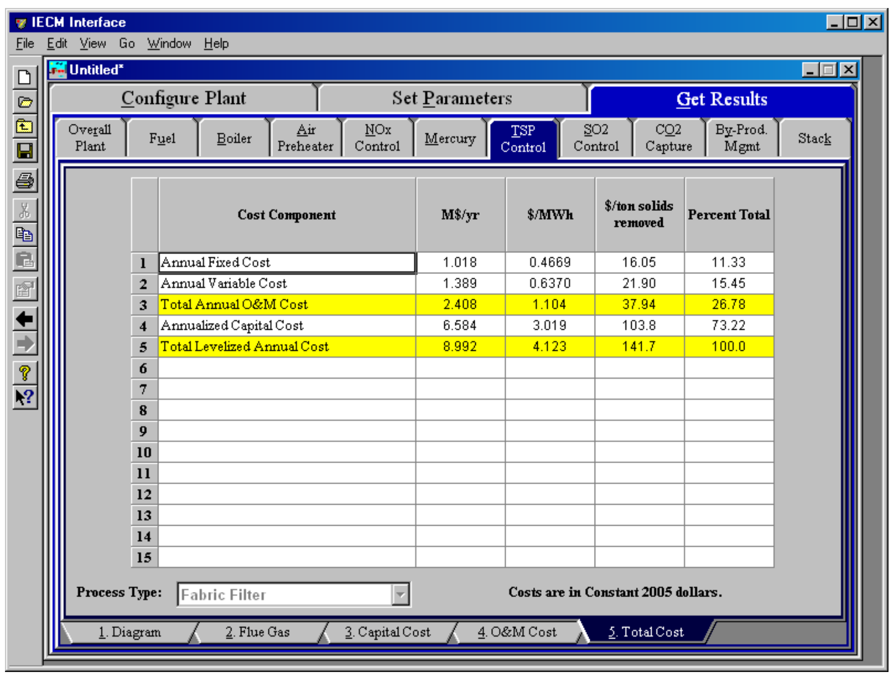
Admin. & Support Labor: The administrative and support labor is the only overhead charge. It is taken as a fraction of the total operating and maintenance labor costs.

Total Fixed Costs: This is the sum of all the fixed O&M costs listed above. This result is highlighted in yellow.

Total O&M Costs: This is the sum of the total variable and total fixed O&M costs. It is used to determine the base plant total revenue requirement. This result is highlighted in yellow.

Fabric Filter Total Cost Results

This screen is only available for the Combustion (Boiler) plant type. The **Total Cost** result screen displays a table which totals the annual fixed, variable, operations and maintenance, and capital costs associated with the Particulate Control technology. The result categories are the same for both the Cold-Side ESP and the Fabric Filter



Fabric Filter – Total Cost result screen.

Total costs are typically expressed in either constant or current dollars for a specified year, as shown on the bottom of the screen. Each result is described briefly below.

Cost Component

Annual Fixed Cost: The operating and maintenance fixed costs are given as an annual total. This number includes all maintenance materials and all labor costs.

Annual Variable Cost: The operating and maintenance variables costs are given as an annual total. This includes all reagent, chemical, steam, and power costs.

Total Annual O&M Cost: This is the sum of the annual fixed and variable operating and maintenance costs above. This result is highlighted in yellow.

Annualized Capital Cost: This is the total capital cost expressed on an annualized basis, taking into consideration the levelized carrying charge factor, or fixed charge factor, over the entire book life.

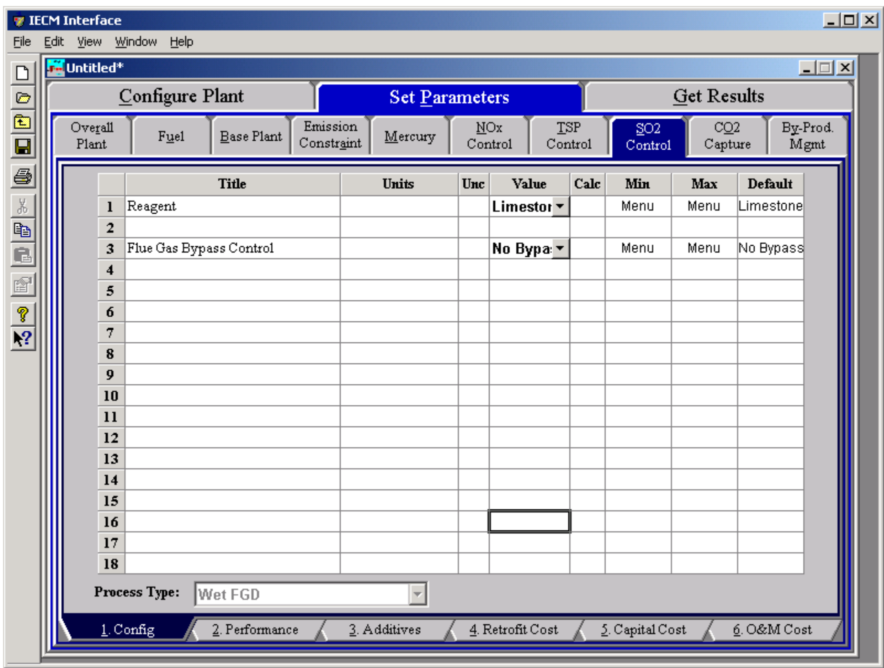
Total Annual Cost: The total annual cost is the sum of the total annual O&M cost and annualized capital cost items above. This result is highlighted in yellow. The hourly cost of labor is specified in the base plant O&M cost screen. The same value is used throughout the other technologies.

Wet FGD

The **SO2 Control** Technology Navigation contains screens that address post-combustion air pollution technologies for Sulfur Dioxide. The model includes options for a Wet FGD. The screens are available if this SO_2 control technology has been selected in **Configure Plant** for the Combustion (Boiler) plant type.

Wet FGD Configuration

This screen is only available for the **Combustion (Boiler)** plant type. Inputs for configuration of the Wet FGD SO_2 control technology are entered on the **Config** input screen.



Wet FGD – Config. Input screen (no bypass). .

Each parameter is described briefly below.

Reagent

For Wet FGD systems, the choice of reagent affects nearly all of the performance and economic parameters of the FGD. Three choices are available:

Limestone: Limestone with Forced Oxidation—A limestone slurry is used in an open spray tower with in-situ oxidation to remove SO_2 and form a gypsum sludge. The main advantages as compared to conventional systems are easier dewatering, more economical disposal of scrubber products, and decreased scaling on tower walls.

Limestone with Additives: Limestone with Dibasic Acid Additive—Dibasic acid (DBA) is added to the Limestone to act as a buffer/catalyst in the open spray tower. The main advantages are increased SO_2 removal and decreased liquid to gas ratio.

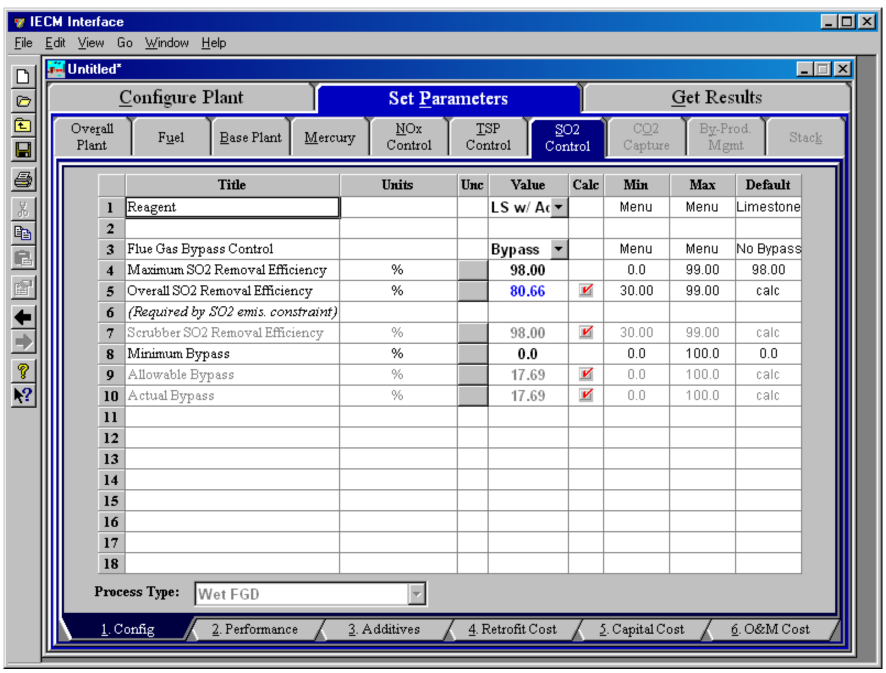
Lime: Magnesium Enhanced Lime System—A magnesium sulfite and lime slurry (maglime) is used to remove SO_2 and form a precipitate high in calcium sulfite. The high alkalinity of the maglime slurry allows very high SO_2 removal. However, the reagent cost is also higher and solid waste is not easily disposed.

Flue Gas Bypass Control

This popup selection menu controls whether or not a portion of the inlet flue gas may bypass the scrubber and recombine with the treated flue gas. Bypass allows the scrubber to operate at full efficiency while allowing some of the flue gas to go untreated. Two choices are available:

No Bypass: This option forces the entire flue gas to pass through the scrubber. This is the default option.

Bypass: This option allows for the possibility of a portion of the flue gas to bypass the scrubber. The amount of bypass is controlled by several additional input parameters described below.



Wet FGD – Config. input screen (with bypass).

The following five choices are available for flue gas bypass:

Maximum SO_2 Removal Efficiency: This parameters specifies the maximum efficiency possible for the absorber on an annual average basis. The value is used as a limit in calculating the actual SO_2 removal efficiency for compliance.

Overall SO_2 Removal Efficiency: This value is the SO_2 removal efficiency required for the entire power plant to meet the SO_2 emission constraint set earlier. It is used to determine the actual flue gas bypass above.

Scrubber SO_2 Removal Efficiency: This is the actual removal efficiency of the scrubber alone. It is a function of the SO_2 emission constraint and the actual flue gas bypass. This value is also shown on the next input screen.

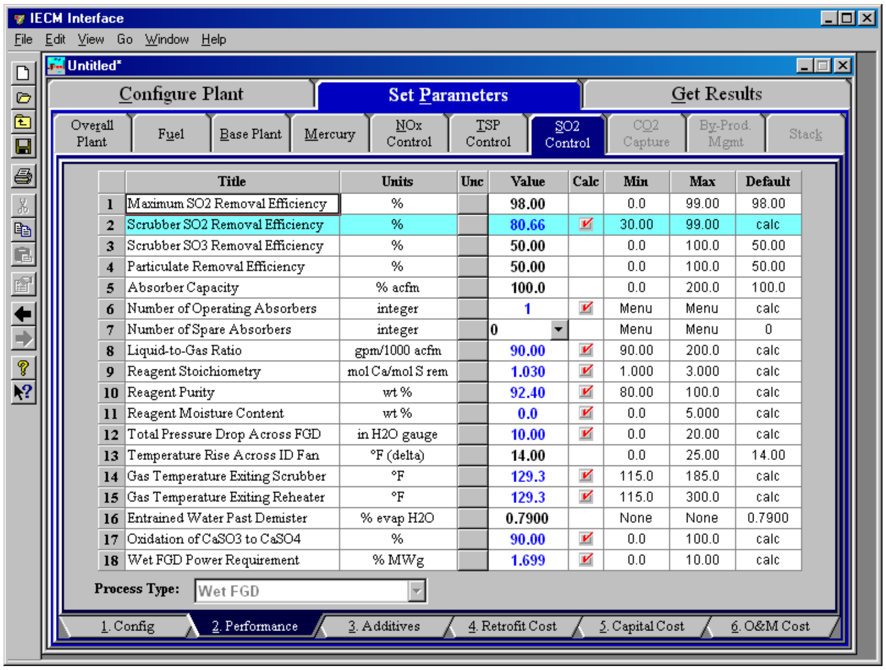
Minimum Bypass: This specifies the trigger point for allowing flue gas to bypass the scrubber. No bypass is allowed until the allowable amount reaches the minimum level set by this parameter.

Allowable Bypass: This is the amount of flue gas that is allowed to bypass the scrubber, based on the actual and maximum performance of the SO_2 removal. It is provided for reference only. The model determines the bypass that produces the maximum SO_2 removal and compares this potential bypass with the minimum bypass value specified above. Bypass is only allowed when the potential bypass value exceeds the minimum bypass value.

Actual Bypass: This displays the actual bypass being used in the model. It is based on all of the above and is provided for reference purposes only.

Wet FGD Performance Inputs

This screen is only available for the **Combustion (Boiler)** plant type. Inputs for performance of the Wet FGD SO_2 control technology are entered on the **Performance** input screen. Each parameter is described briefly below.



Wet FGD – Performance input screen.

Maximum SO_2 Removal Efficiency: This parameters specifies the maximum efficiency possible for the absorber on an annual average basis. The value is used as a limit in calculating the actual SO_2 removal efficiency for compliance.

Scrubber SO_2 Removal Efficiency: This is the annual average SO_2 removal efficiency achieved in the absorber. The calculated value assumes compliance with the SO_2 emission limit specified earlier, if possible. The efficiency is used to determine the liquid to gas ratio and emissions. This input is highlighted in blue.

Scrubber SO_3 Removal Efficiency: The default value is taken from the removal efficiency reported in the literature (references are below). This efficiency then determines the mass of SO_3 removed from the flue gas in the collector. For more information see also:

- www.netl.doe.gov/publications/proceedings/98/98fg/hardman.pdf
- www.netl.doe.gov/publications/proceedings/98/98fg/rubin.pdf

Particulate Removal Efficiency: This is the percent removal of particulate matter entering the FGD system from the upstream particulate collector. Particulate collectors are designed to comply with the specified particulate emission limit. This is additional particulate removal.

Absorber Capacity: This is the percent of the flue gas treated by each operating absorber. This value is used to determine the number of operating absorbers and the capital costs.

Number of Operating Absorbers: This is the number of operating scrubber towers. The number is determined by the absorber capacity and is used to calculate the capital costs. The value must be an integer.

Number of Spare Absorbers: This is the total number of spare absorber vessels. It is used primarily to calculate capital costs. The value must be an integer.

Liquid to Gas Ratio: The design of spray towers for high efficiency is achieved by using high liquid-to-gas (L/G) ratios. The calculated value is a function of the reagent type, the removal efficiency, and stoichiometry. It determines the power requirement and capital cost.

Reagent Stoichiometry: This is the moles of calcium per mole of sulfur removed from the absorber. The stoichiometry is calculated as a function of the reagent type. It is used to determine the liquid to gas ratio, reagent usage, reagent waste, and capital cost.

Reagent Purity: This is the percent of the reagent that is lime (CaO) or limestone ($CaCO_3$). The calculated value is a function of the reagent type. This parameter determines the waste solids produced and the reagent needed to remove the necessary SO_2.

Reagent Moisture Content: This is the moisture content of the reagent. The remaining reagent impurities are assumed to be inert substances such as silicon dioxide (sand). This parameter is used to determine the waste solids produced.

Total Pressure Drop across FGD: This is the total pressure drop across the FGD vessel prior to the reheater. This is used in the calculations of the power requirements (or energy penalty) and thermodynamic properties of the flue gas.

Temperature Rise Across ID Fan: An induced draft (ID) fan is assumed to be located upstream of the FGD system. The fan raises the temperature of the flue gas due to dissipation of electro-mechanical .

Gas Temperature Exiting Scrubber: A thermodynamic equation is used to calculate this equilibrium flue gas temperature exiting the scrubber. The gas is assumed to be saturated with water at the exiting temperature and pressure. The value determines the water evaporated in the scrubber.

Gas Temperature Exiting Reheater: This is the desired temperature of flue gas after the reheater. It is assumed to be equal to the stack gas exit temperature. If scrubber bypass is employed, reheat requirements are reduced or eliminated. It determines the reheat energy required.

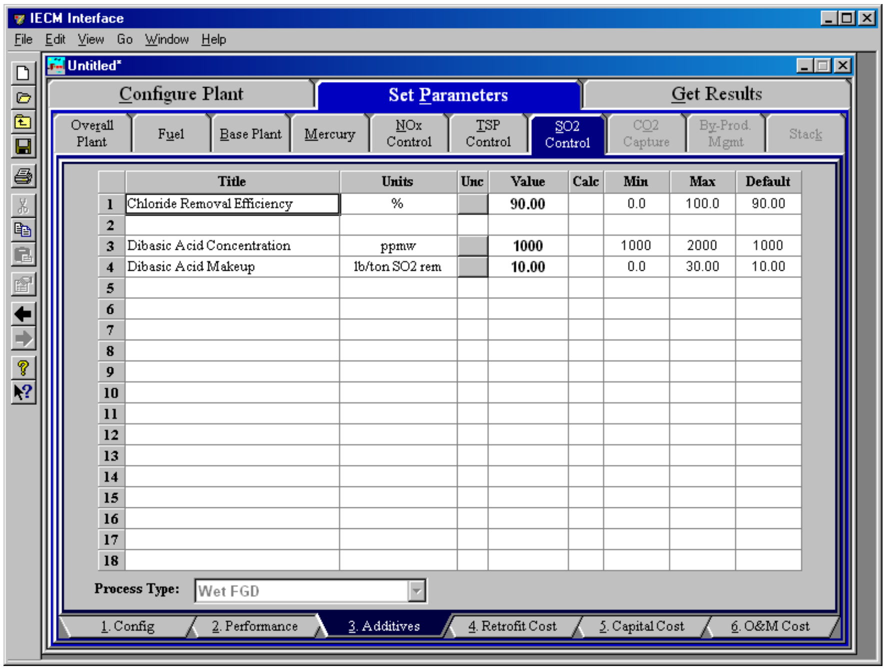
Entrained Water Past Demister: This is a liquid water entrained in the flue gas leaving the demister expressed as a percentage of the total water evaporated in the absorber.

Oxidation of $CaSO_3$ to $CaSO_4$: This parameter determines the mixture of chemical species (calcium sulfite and calcium sulfate) in the solid waste stream. The default values depend on the selection of forced or natural oxidation.

Wet FGD Power Requirement: This is the equivalent electrical output of thermal (steam) energy used for reheat, plus the actual electrical output power required for pumps and booster fans.

Wet FGD Additives Inputs

This screen is only available for the **Combustion (Boiler)** plant type. If a limestone reagent with additives is selected from the **Config** input screen, the screen below will be displayed.



Wet FGD – Additives input screen (for limestone and lime reagents)

The parameters are described briefly below.

Chloride Removal Efficiency: Chlorides in the flue gas inlet stream are removed by the lime/limestone slurry. This parameter determines the amount of chlorides removed.

Dibasic Acid Concentration: Dibasic acid (DBA) is added to limestone to reduce the liquid to gas ratio, enhancing the removal of SO_2. This is the concentration of DBA in the limestone slurry.

Dibasic Acid Makeup: DBA is not completely recovered in the reagent feedback loop. This parameter is used to determine the makeup flow rate of DBA.

Wet FGD Retrofit Cost Inputs

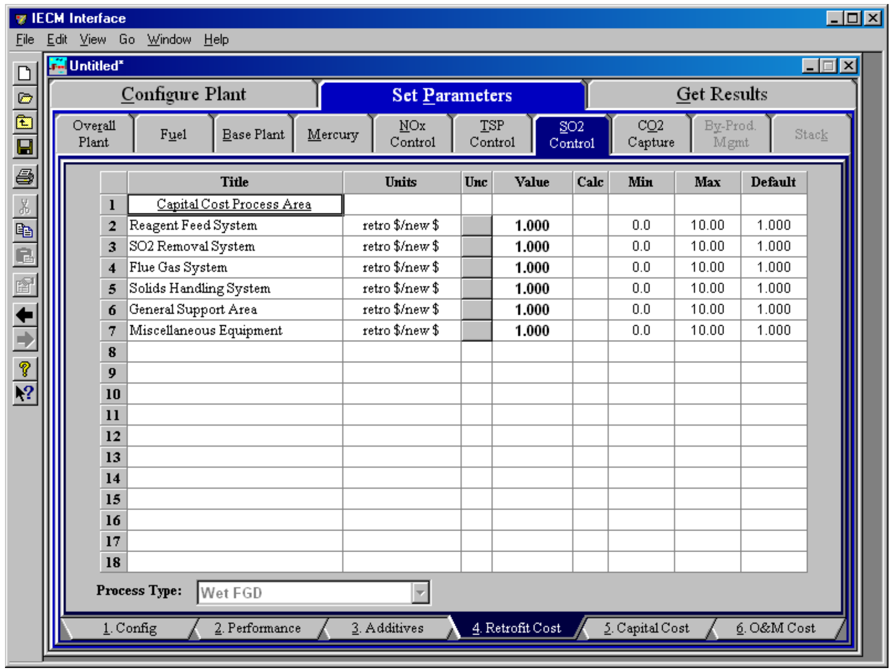
This screen is only available for the **Combustion (Boiler)** plant type. Inputs for capital costs of modifications to process areas to implement the SO_2 control technology are entered on the **Retrofit Cost** input screen for the Wet FGD system.

The retrofit cost factor of each process is a multiplicative cost adjustment which considers the cost of retrofitted capital equipment relative to similar equipment installed in a new plant. These factors affect the capital costs directly and the operating and maintenance costs indirectly.

Direct capital costs for each process area are calculated in the IECM. These calculations are reduced form equations derived from more sophisticated models and reports. The sum of the direct capital costs associated with each process area is defined as the process facilities capital (PFC). The retrofit cost factor provided for each of the process areas can be used as a tool for adjusting the anticipated costs and uncertainties across the process area separate from the other areas.

Uncertainty can be applied to the retrofit cost factor for each process area in each technology. Thus, uncertainty can be applied as a general factor across an entire process area, rather than as a specific uncertainty for the particular cost on the capital or O&M input screens. Any uncertainty applied to a process area through the retrofit cost factor compounds any uncertainties specified later in the capital and O&M cost input parameter screens.

Each parameter is described briefly below.



Wet FGD – Retrofit Cost input screen.

Capital Cost Process Area

Reagent Feed System: This area includes all equipment for storage, handling and preparation of raw materials, reagents, and additives used.

SO2 Removal System: This area deals with the cost of equipment for SO_2 scrubbing, such as absorption tower, recirculation pumps, and other equipment.

Flue Gas System: This area treats the cost of the duct work and fans required for flue gas distribution to SO_2 system, plus gas reheat equipment.

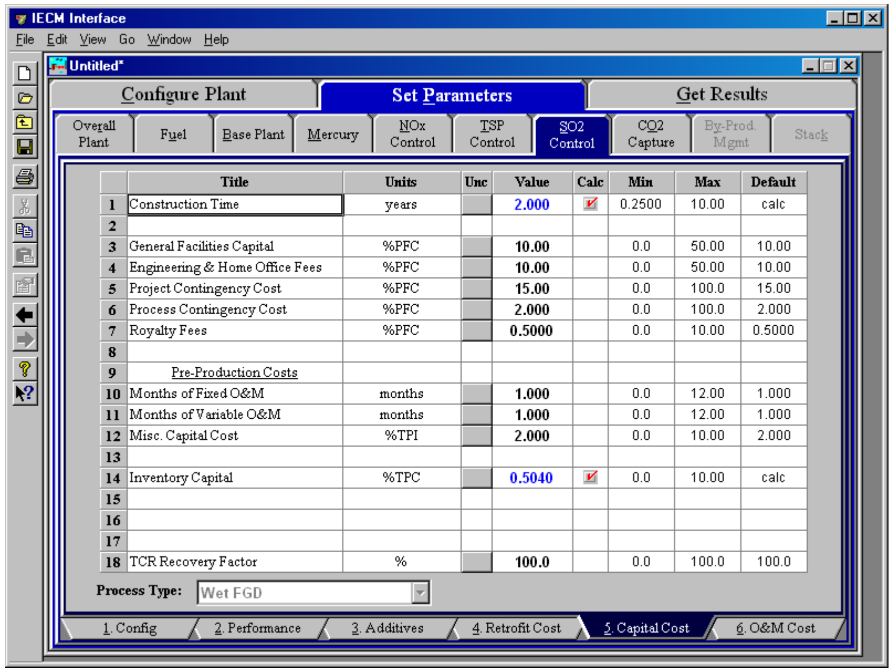
Solids Handling System: This area includes the cost of the equipment for fixation, treatment, and transportation of all sludge/dry solids materials produced by scrubbing.

General Support Area: The cost associated with the equipment required to support FGD system operation such as makeup water and instrument air are treated here.

Miscellaneous Equipment: Any miscellaneous equipment is treated in this process area.

Wet FGD Capital Cost Inputs

This screen is only available for the **Combustion (Boiler)** plant type.



Wet FGD – Capital Cost input screen.

Each parameter is described briefly below

Construction Time: This is the idealized construction period in years. It is used to determine the allowance for funds used during construction (AFUDC).

Bypass Duct Cost Adder: The bypass capital costs are not specified with the other process areas. This parameter allows any direct capital costs incurred by the addition of bypass ducts to be added to the Flue Gas System process area (see retrofit cost screen for a list of the direct cost process areas).

General Facilities Capital (GFC): 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%.

Engineering & Home Office Fees: The engineering & home office fees are a percent of total direct capital cost. This is an overhead fee paid to the architect/engineering company. These fees typically range from 7-15%.

Project Contingency Cost: This is 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.

Process Contingency Cost: 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.

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

Pre-Production Costs: 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 applied to the O&M costs over a specified period of time (months). The two time periods for fixed and variable O&M costs are described below with the addition of a miscellaneous capital cost factor.

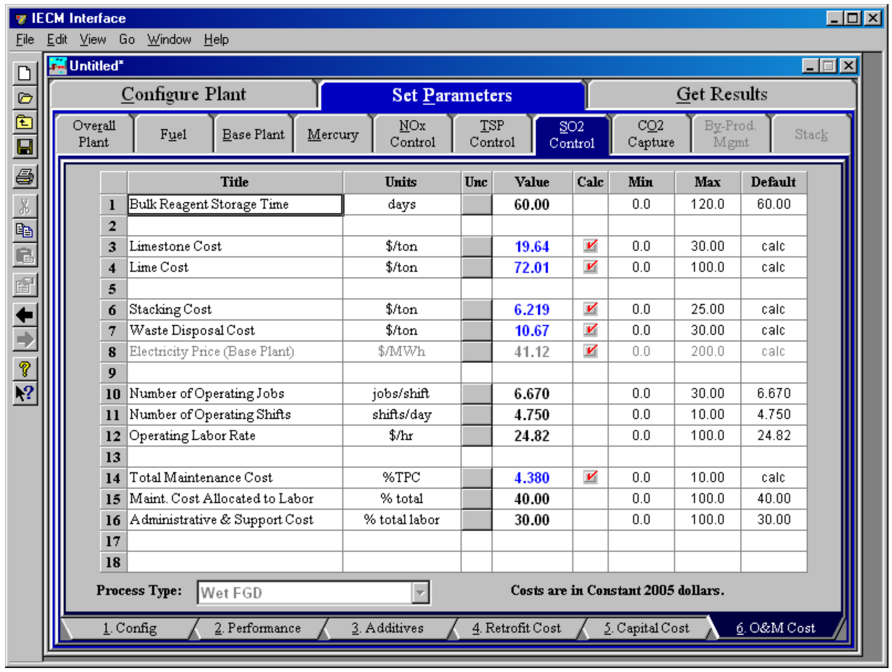
- **Months of Fixed O&M:** Time period of fixed operating costs used for preproduction to cover training, testing, major changes in equipment, and inefficiencies in start-up. This includes operating, maintenance, administrative and support labor. It also considers maintenance materials.
- **Months of Variable O&M:** Time period of variable operating costs used for preproduction to cover chemicals, water, consumables, and solid disposal charges in start-up, assuming 100% load. This excludes any fuels.
- **Misc. Capital Cost:** This is a percent of total plant investment (sum of TPC and AFUDC) to cover expected changes to equipment to bring the system up to full capacity.

Inventory Capital: Percent of the total direct capital for raw material supply based on 100% capacity during a 60 day period. These materials are considered storage. The inventory capital includes fuels, consumables, by-products, and spare parts. This is typically 0.5%.

TCR Recovery Factor: The actual total capital required (TCR) as a percent of the TCR in a new power plant. This value is 100% for a new installation and may be set as low as 0% for a wet FGD that has been paid off.

Wet FGD O&M Cost Inputs

This screen is only available for the **Combustion (Boiler)** plant type.



Wet FGD – O&M Cost input screen

O&M costs are typically expressed on an average annual basis and are provided in either constant or current dollars for a specified year, as shown on the bottom of the screen. Each parameter is described briefly below:

Bulk Reagent Storage Time: This is the number of days of bulk storage of reagent. This factor is used to determine the inventory capital cost.

Limestone Cost: This is the cost of Limestone for the Wet FGD system.

Lime Cost: This is the cost of Lime for the Wet FGD or Lime Spray Dryer system.

Dibasic Acid Cost: This is the cost of the Dibasic Acid for the Wet FGD or Lime Spray Dryer system.

Stacking Cost: This is the stacking cost as used for the Wet FGD system.

Waste Disposal Cost: This is the sludge disposal cost for the FGD system.

Electricity Price (Base Plant): This is the price of electricity and is calculated as a function of the utility cost of the base plant, where the base plant is a combustion boiler and an air preheater.

Number of Operating Jobs: This is the total number of operating jobs that are required to operate the plant per eight-hour shift.

Number of Operating Shifts: This is the total number of equivalent operating shifts in the plant per day. The number takes into consideration paid time off and weekend work (3 shifts/day * 7 days/5 day week * 52 weeks/(52 weeks - 6 weeks PTO) = 4.75 equiv. Shifts/day).

Operating Labor Rate: The hourly cost of labor is specified in the base plant O&M cost screen. The same value is used throughout the other technologies.

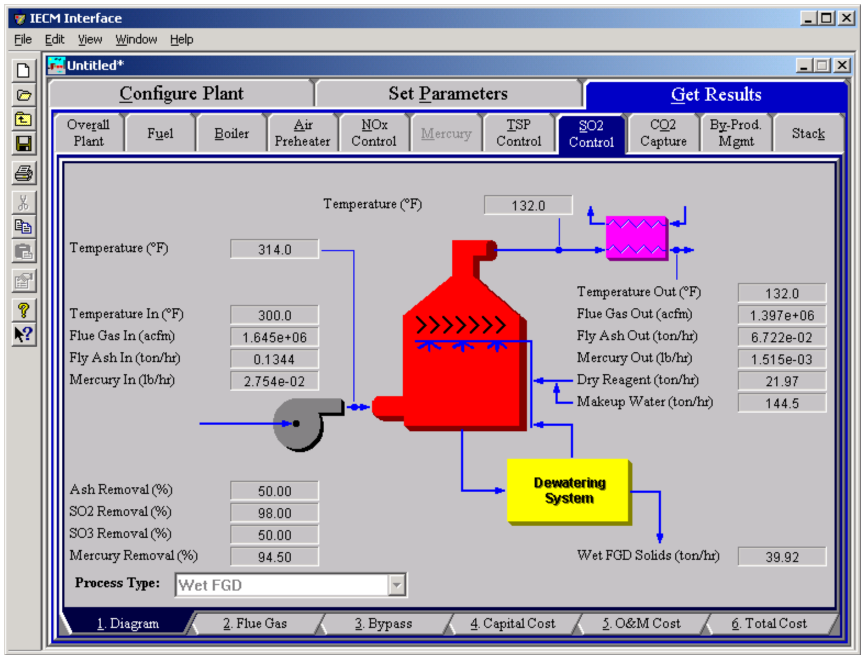
Total Maintenance Cost: This is the annual maintenance cost as a percentage of the total plant cost. Maintenance cost estimates can be developed separately for each process area.

Maint. Cost Allocated to Labor: Maintenance cost allocated to labor as a percentage of the total maintenance cost.

Administrative & Support Cost: This is the percent of the total operating and maintenance labor associated with administrative and support labor.

Wet FGD Diagram

This screen is only available for the Combustion (Boiler) plant type. The **Diagram** result screen displays an icon for theWet FGD SO_2 control technology selected and values for major flows in and out of it.



Wet FGD – Diagram.

Each result is described briefly below.

Reagent

Dry Reagent: The total mass flow rate of lime, limestone or limestone with dibasic acid injected into the scrubber. This is a function of the SO_2 removal efficiency, the reagent purity and the reagent stoichiometric (all performance input parameters).

Makeup Water: Water needed to replace the evaporated water in the reagent sluice circulation stream.

Flue Gas Entering FGD

Temperature In: Temperature of the flue gas entering the scrubber. This is determined by the flue gas outlet temperature of the module upstream of the scrubber (e.g., a particulate removal technology).

Flue Gas In: Volumetric flow rate of flue gas entering the scrubber, based on the flue gas temperature entering the scrubber and atmospheric pressure.

Fly Ash In: Total solids mass flow rate in the flue gas entering the scrubber. This is determined by the solids exiting from the module upstream of the scrubber (e.g., a particulate removal technology).

Mercury In: Total mass of mercury entering the scrubber. The value is a sum of all the forms of mercury (elemental, oxidized, and particulate).

Temperature: Temperature of the flue gas entering the scrubber after the forced draft fan. This is determined by the flue gas inlet temperature of the FGD and the temperature rise across ID fan input parameter.

Flue Gas Exiting FGD

Temperature: Temperature of the flue gas immediately on exiting the scrubber, prior to any flue gas bypass remixing and prior to reheating.

Temperature Out: Temperature of the flue gas exiting the scrubber. This is a function of flue gas bypass, saturation temperature, reheater and .the flue gas component concentrations.

Flue Gas Out: Volumetric flow rate of the flue gas exiting the scrubber after the reheater, based on the flue gas temperature exiting the scrubber and atmospheric pressure.

Fly Ash Out: Total solids mass flow rate in the flue gas exiting the scrubber after the reheater. This is a function of the ash removal and flue gas bypass input parameters.

Mercury Out: Total mass of mercury exiting the scrubber after the reheater. The value is a sum of all the forms of mercury (elemental, oxidized, and particulate).

FGD Performance

Ash Removal: Actual particulate removal efficiency in the scrubber. This is set by the scrubber ash removal input parameter.

SO2 Removal: Actual removal efficiency of SO_2 in the scrubber. This is a function of the maximum removal efficiency (scrubber performance input parameter) and the emission constraint for SO_2 (emission constraints input parameter). It is possible that the scrubber may over or under-comply with the emission constraint.

SO3 Removal: Percent of SO_3 in the flue gas removed from the scrubber. The SO_3 is assumed to combine with H_2O and leave with the ash solids or sluice water as a sulfate (in the form of H_2SO_4).

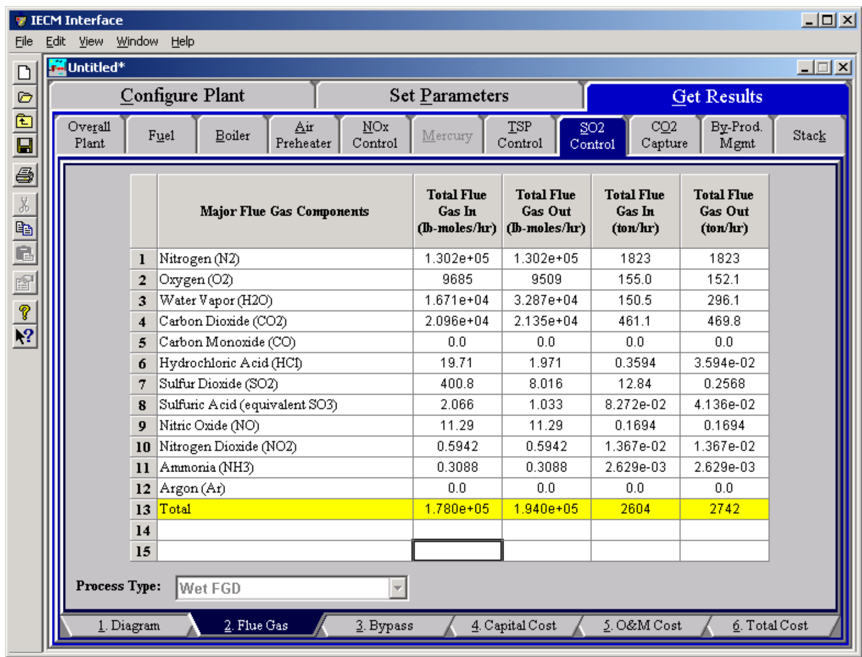
Mercury Removal: Percent of the total mercury removed from the scrubber. The value reflects a weighted average based on the particular species of mercury present (elemental, oxidized, and particulate).

Collected Solids

Wet FGD Solids: Total solids mass flow rate of solids removed from the scrubber. This is a function of the solids content in the flue gas and the particulate removal efficiency of the scrubber. The solids are shown on a wet basis.

Wet FGD Flue Gas Results

This screen is only available for the Combustion (Boiler) plant type. The **Flue Gas** result screen displays a table of quantities of flue gas components entering and exiting the Wet FGD SO_2 Control Technology. For each component, quantities are given in both moles and mass per hour.



	Major Flue Gas Components	Total Flue Gas In (lb-moles/hr)	Total Flue Gas Out (lb-moles/hr)	Total Flue Gas In (ton/hr)	Total Flue Gas Out (ton/hr)
1	Nitrogen (N2)	1.302e+05	1.302e+05	1823	1823
2	Oxygen (O2)	9685	9509	155.0	152.1
3	Water Vapor (H2O)	1.671e+04	3.287e+04	150.5	296.1
4	Carbon Dioxide (CO2)	2.096e+04	2.135e+04	461.1	469.8
5	Carbon Monoxide (CO)	0.0	0.0	0.0	0.0
6	Hydrochloric Acid (HCl)	19.71	1.971	0.3594	3.594e-02
7	Sulfur Dioxide (SO2)	400.8	8.016	12.84	0.2568
8	Sulfuric Acid (equivalent SO3)	2.066	1.033	8.272e-02	4.136e-02
9	Nitric Oxide (NO)	11.29	11.29	0.1694	0.1694
10	Nitrogen Dioxide (NO2)	0.5942	0.5942	1.367e-02	1.367e-02
11	Ammonia (NH3)	0.3088	0.3088	2.629e-03	2.629e-03
12	Argon (Ar)	0.0	0.0	0.0	0.0
13	Total	1.780e+05	1.940e+05	2604	2742
14					
15					

Wet FGD – Flue Gas result screen.

Each result is described briefly below

Major Flue Gas Component

Nitrogen (N_2): Total mass of nitrogen.

Oxygen (O_2): Total mass of oxygen.

Water Vapor (H_2O): Total mass of water vapor.

Carbon Dioxide (CO_2): Total mass of carbon dioxide.

Carbon Monoxide (CO): Total mass of carbon monoxide.

Hydrochloric Acid (HCl): Total mass of hydrochloric acid.

Sulfur Dioxide (SO_2): Total mass of sulfur dioxide.

Sulfuric Acid (equivalent SO_3): Total mass of sulfuric acid.

Nitric Oxide (NO): Total mass of nitric oxide.

Nitrogen Dioxide (NO_2): Total mass of nitrogen dioxide.

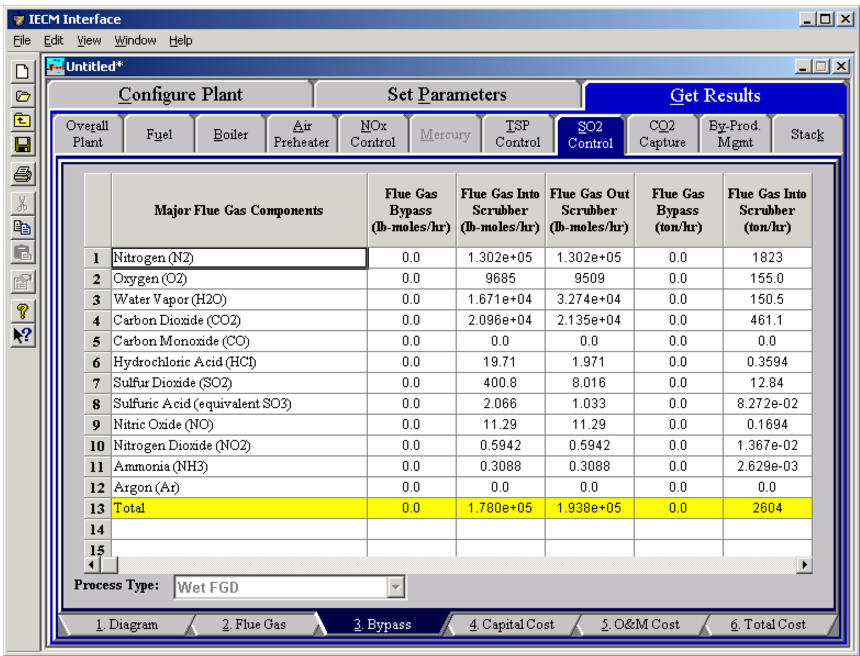
Ammonia (NH_3): Total mass of ammonia.

Argon (Ar): Total mass of argon.

Total: Total of the individual components listed above. This item is highlighted in yellow.

Wet FGD Bypass Results

This screen is only available for the Combustion (Boiler) plant type. The **Flue Gas Bypass** result screen displays a table of quantities of flue gas components entering and bypassing the Wet FGD SO_2 Control Technology. For each component, quantities are given in both moles and mass per hour.



	Major Flue Gas Components	Flue Gas Bypass (lb-moles/hr)	Flue Gas Into Scrubber (lb-moles/hr)	Flue Gas Out Scrubber (lb-moles/hr)	Flue Gas Bypass (ton/hr)	Flue Gas Into Scrubber (ton/hr)
1	Nitrogen (N2)	0.0	1.302e+05	1.302e+05	0.0	1823
2	Oxygen (O2)	0.0	9685	9509	0.0	155.0
3	Water Vapor (H2O)	0.0	1.671e+04	3.274e+04	0.0	150.5
4	Carbon Dioxide (CO2)	0.0	2.096e+04	2.135e+04	0.0	461.1
5	Carbon Monoxide (CO)	0.0	0.0	0.0	0.0	0.0
6	Hydrochloric Acid (HCl)	0.0	19.71	1.971	0.0	0.3594
7	Sulfur Dioxide (SO2)	0.0	400.8	8.016	0.0	12.84
8	Sulfuric Acid (equivalent SO3)	0.0	2.066	1.033	0.0	8.272e-02
9	Nitric Oxide (NO)	0.0	11.29	11.29	0.0	0.1694
10	Nitrogen Dioxide (NO2)	0.0	0.5942	0.5942	0.0	1.367e-02
11	Ammonia (NH3)	0.0	0.3088	0.3088	0.0	2.629e-03
12	Argon (Ar)	0.0	0.0	0.0	0.0	0.0
13	Total	0.0	1.780e+05	1.938e+05	0.0	2604
14						
15						

Wet FGD – Bypass result screen.

Each result is described briefly below

Major Flue Gas Component

Nitrogen (N_2): Total mass of nitrogen.

Oxygen (O_2): Total mass of oxygen.

Water Vapor (H_2O): Total mass of water vapor.

Carbon Dioxide (CO_2): Total mass of carbon dioxide.

Carbon Monoxide (CO): Total mass of carbon monoxide.

Hydrochloric Acid (HCl): Total mass of hydrochloric acid.

Sulfur Dioxide (SO_2): Total mass of sulfur dioxide.

Sulfuric Acid (equivalent SO_3): Total mass of sulfuric acid.

Nitric Oxide (NO): Total mass of nitric oxide.

Nitrogen Dioxide (NO_2): Total mass of nitrogen dioxide.

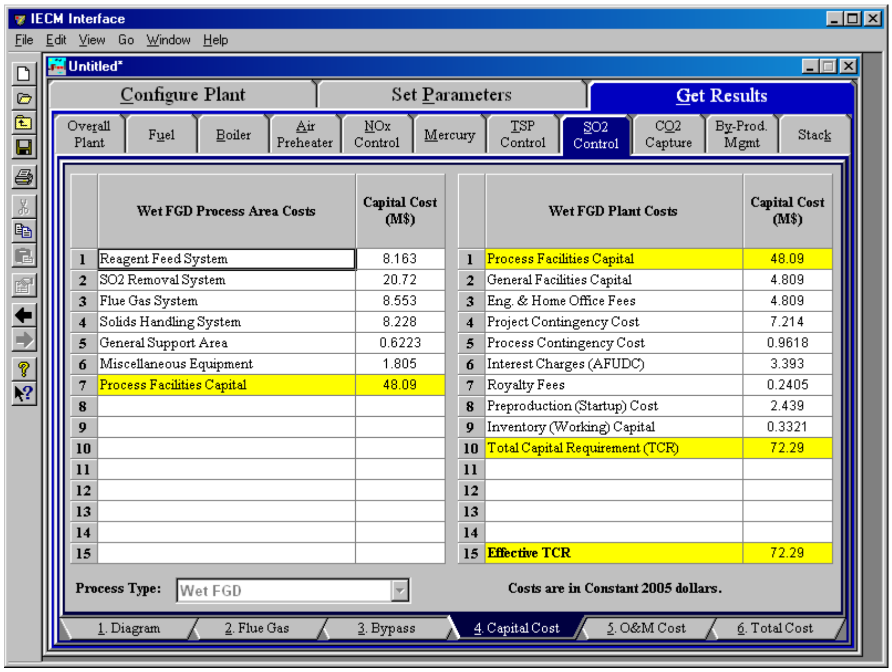
Ammonia (NH_3): Total mass of ammonia.

Argon (Ar): Total mass of argon.

Total: Total of the individual components listed above. This item is highlighted in yellow.

Wet FGD Capital Cost Results

This screen is only available for the **Combustion (Boiler)** plant type. The **Capital Cost** result screen displays tables for the direct and indirect capital costs related to the SO_2 control technology.



	Wet FGD Process Area Costs	Capital Cost (M$)
1	Reagent Feed System	8.163
2	SO2 Removal System	20.72
3	Flue Gas System	8.553
4	Solids Handling System	8.228
5	General Support Area	0.6223
6	Miscellaneous Equipment	1.805
7	Process Facilities Capital	48.09
8		
9		
10		
11		
12		
13		
14		
15		

	Wet FGD Plant Costs	Capital Cost (M$)
1	Process Facilities Capital	48.09
2	General Facilities Capital	4.809
3	Eng. & Home Office Fees	4.809
4	Project Contingency Cost	7.214
5	Process Contingency Cost	0.9618
6	Interest Charges (AFUDC)	3.393
7	Royalty Fees	0.2405
8	Preproduction (Startup) Cost	2.439
9	Inventory (Working) Capital	0.3321
10	Total Capital Requirement (TCR)	72.29
11		
12		
13		
14		
15	Effective TCR	72.29

Wet FGD – Capital Cost result screen.

Capital costs are typically expressed in either constant or current dollars for a specified year, as shown on the bottom of the screen. Each result is described briefly below

Direct Capital Costs

Each process area direct capital cost is a reduced-form model based on regression analysis of data collected from several reports and analyses of particulate control technology units. They are described in general below. The primary factors in the model that effect the capital costs of the scrubbers are the flue gas flow rate through the scrubber, the composition of the flue gas, the reagent stoichiometry, and the reagent flow rate.

Reagent Feed System: This area includes all equipment for storage, handling and preparation of raw materials, reagents, and additives used.

SO_2 Removal System: This area deals with the cost of equipment for SO_2 scrubbing, such as absorption tower, recirculation pumps, and other equipment.

Flue Gas System: This area treats the cost of the duct work and fans required for flue gas distribution to SO_2 system, plus gas reheat equipment.

Solids Handling System: This area includes the cost of the equipment for fixation, treatment, and transportation of all sludge/dry solids materials produced by scrubbing.

General Support Area: The cost associated with the equipment required to support FGD system operation such as makeup water and instrument air are treated here.

Miscellaneous Equipment: Any miscellaneous equipment is treated in this process area.

Process Facilities Capital: The process facilities capital is the total constructed cost of all on-site processing and generating units listed above, including all direct and indirect construction costs. All sales taxes and freight costs are included where applicable implicitly. This result is highlighted in yellow.

Total Capital Costs

Process Facilities Capital: (see definition above)

General Facilities Capital: The general facilities include construction costs of roads, office buildings, shops, laboratories, etc. Sales taxes and freight costs are included implicitly.

Eng. & Home Office Fees: The engineering & home office fees are a percent of total direct capital cost. This is an overhead fee paid to the architect/engineering company.

Project Contingency Cost: Capital cost contingency factor covering the cost of additional equipment or other costs that would result from a more detailed design of a definitive project at the actual site.

Process Contingency Cost: Capital cost contingency factor applied to a new technology in an effort to quantify the uncertainty in the technical performance and cost of the commercial-scale equipment.

Interest Charges (AFUDC): Allowance for funds used during construction, also referred to as interest during construction, is the time value of the money used during construction and is based on an interest rate equal to the before-tax weighted cost of capital. This interest is compounded on an annual basis (end of year) during the construction period for all funds spent during the year or previous years.

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

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.

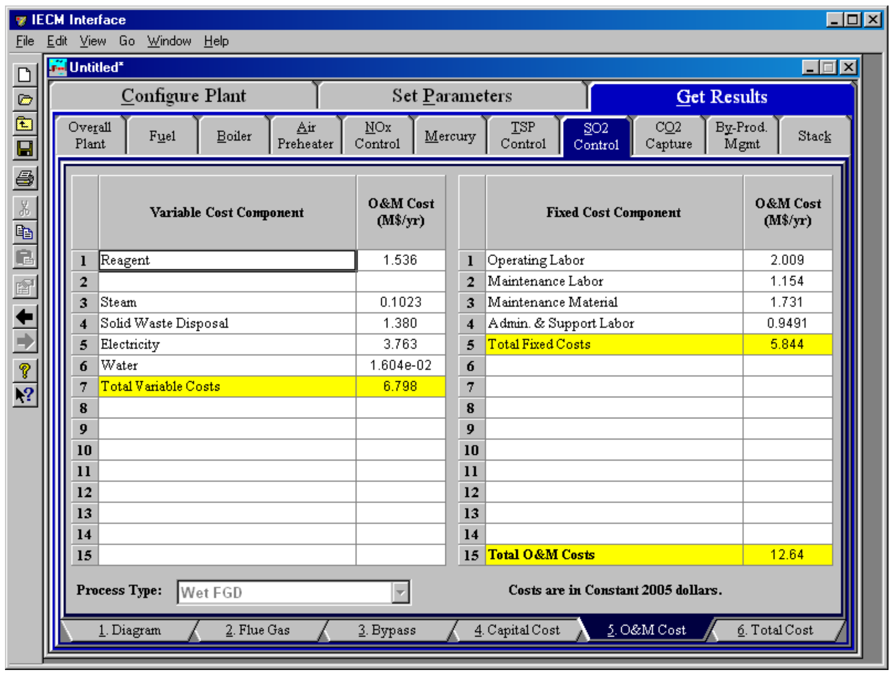
Inventory (Working) Capital: The raw material supply based on 100% capacity during a 60 day period. These materials are considered storage. The inventory capital includes fuels, consumables, by-products, and spare parts.

Total Capital Requirement (TCR): Money that is placed (capitalized) on the books of the utility on the service date. TCR includes all the items above. This result is highlighted in yellow.

Effective TCR: The TCR of the wet FGD that is used in determining the total power plant cost. The effective TCR is determined by the "TCR Recovery Factor" for the wet FGD.

Wet FGD O&M Cost Results

This screen is only available for the Combustion (Boiler) plant type. The **O&M Cost** result screen displays tables for the variable and fixed operation and maintenance costs involved with the SO_2 control technology.



Wet FGD – O&M Cost result screen.

O&M costs are typically expressed on an average annual basis and are provided in either constant or current dollars for a specified year, as shown on the bottom of the screen. Each result is described briefly below

Variable Cost Components

Variable operating costs and consumables are directly proportional to the amount of kilowatts produced and are referred to as incremental costs. All the costs are subject to inflation.

Reagent: The total mass flow rate of lime or limestone injected into the scrubber on a wet basis. This is a function of the SO_2 concentration in the flue gas and the reagent stoichiometric performance input value.

Steam: Annual cost of steam used for direct or reheat use in the scrubber. This is a function of the steam heat rate, reheat energy requirement and gross plant capacity.

Solid Waste Disposal: Total cost to dispose the collected flue gas waste solids. This does not consider by-product gypsum sold in commerce.

Electricity: Cost of power consumption of the scrubber. This is a function of the gross plant capacity and the scrubber energy penalty performance input parameter.

Water: Cost of water for reagent sluice in the scrubber. This is a function of the liquid to gas ratio performance input parameter for the wet FGD. The cost is a function of the flue gas flow rate and the slurry recycle ratio performance input parameter for the spray dryer.

Total Variable Costs: This is the sum of all the variable O&M costs listed above. This result is highlighted in yellow.

Fixed Cost Components

Fixed operating costs are essentially independent of actual capacity factor, number of hours of operation, or amount of kilowatts produced. All the costs are subject to inflation.

Operating Labor: Operating labor cost is based on the operating labor rate, the number of personnel required to operate the plant per eight-hour shift, and the average number of shifts per day over 40 hours per week and 52 weeks.

Maintenance Labor: The maintenance labor is determined as a fraction of the total maintenance cost.

Maintenance Material: The cost of maintenance material is the remainder of the total maintenance cost, considering the fraction associated with maintenance labor.

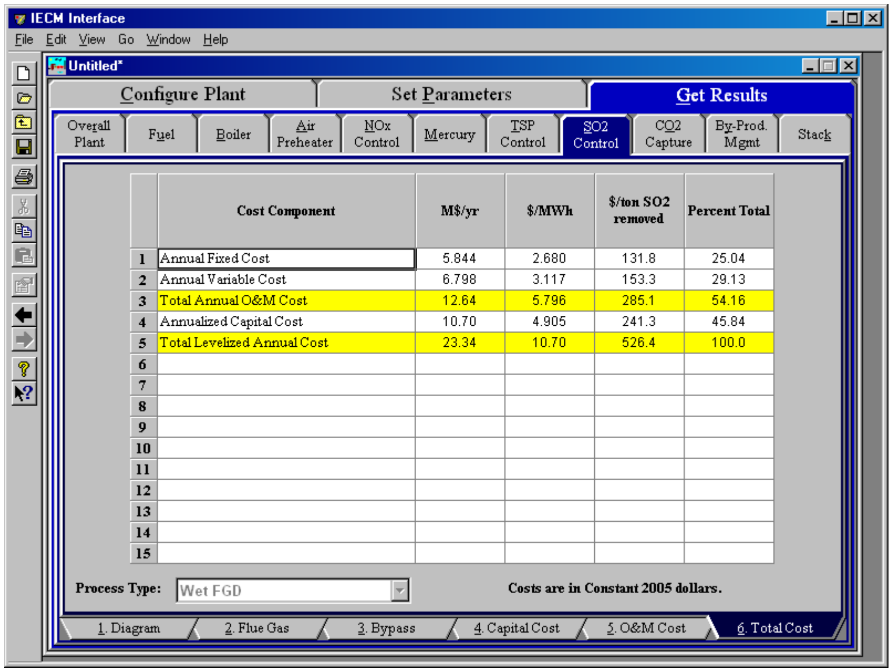
Admin. & Support Labor: The administrative and support labor is the only overhead charge. It is taken as a fraction of the total operating and maintenance labor costs.

Total Fixed Costs: This is the sum of all the fixed O&M costs listed above. This result is highlighted in yellow.

Total O&M Costs: This is the sum of the total variable and total fixed O&M costs. It is used to determine the base plant total revenue requirement. This result is highlighted in yellow.

Wet FGD Total Cost Results

This screen is only available for the Combustion (Boiler) plant type. The **Total Cost** result screen displays a table which totals the annual fixed, variable, operations and maintenance, and capital costs associated with the SO_2 control technology. The result categories are the same for both the Wet FGD and the Lime Spray Dryer.



Wet FGD – Total Cost result screen.

Cost Component

Total costs are typically expressed in either constant or current dollars for a specified year, as shown on the bottom of the screen. Each result is described briefly below.

Annual Fixed Cost: The operating and maintenance fixed costs are given as an annual total. This number includes all maintenance materials and all labor costs.

Annual Variable Cost: The operating and maintenance variables costs are given as an annual total. This includes all reagent, chemical, steam, and power costs.

Total Annual O&M Cost: This is the sum of the annual fixed and variable operating and maintenance costs above. This result is highlighted in yellow.

Annualized Capital Cost: This is the total capital cost expressed on an annualized basis, taking into consideration the levelized carrying charge factor, or fixed charge factor, over the entire book life.

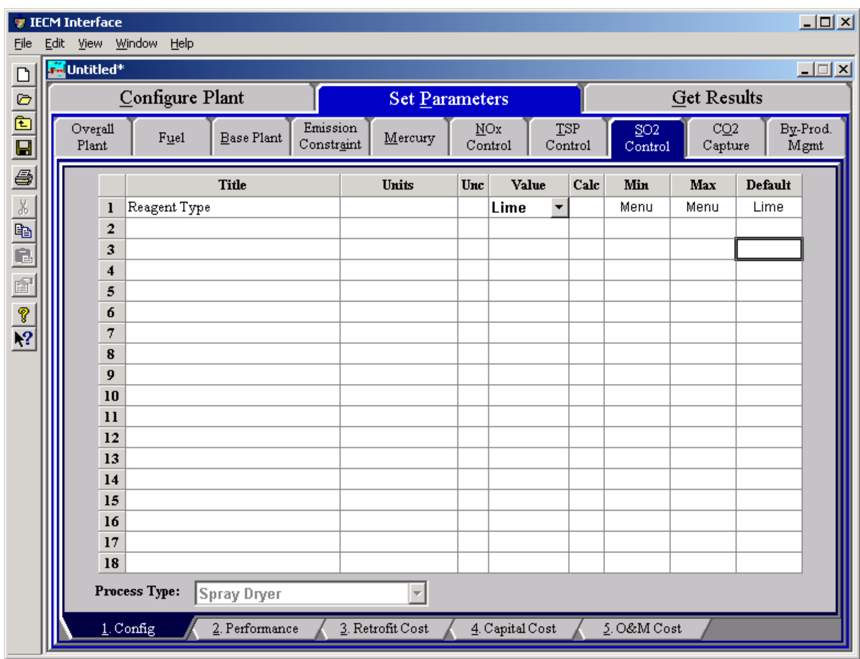
Total Levelized Annual Cost: The total annual cost is the sum of the total annual O&M cost and annualized capital cost items above. This result is highlighted in yellow.

Spray Dryer

The **SO2 Control** Technology Navigation Tab contains screens that address post-combustion air pollution technologies for Sulfur Dioxide. The model includes options for a Lime Spray Dryer. A spray dryer is sometimes used instead of a wet scrubber because it provides simpler waste disposal and can be installed with lower capital costs. These screens are available if the **Lime Spray Dryer** SO_2 control technology has been selected in **Configure Plant** for the **Combustion (Boiler)** plant type.

Spray Dryer Configuration

This screen is only available for the **Combustion (Boiler)** plant type. Inputs for configuration of the **Lime Spray Dryer** SO_2 control technology are entered on the **Config** input screen



Spray Dryer – Config. input screen.

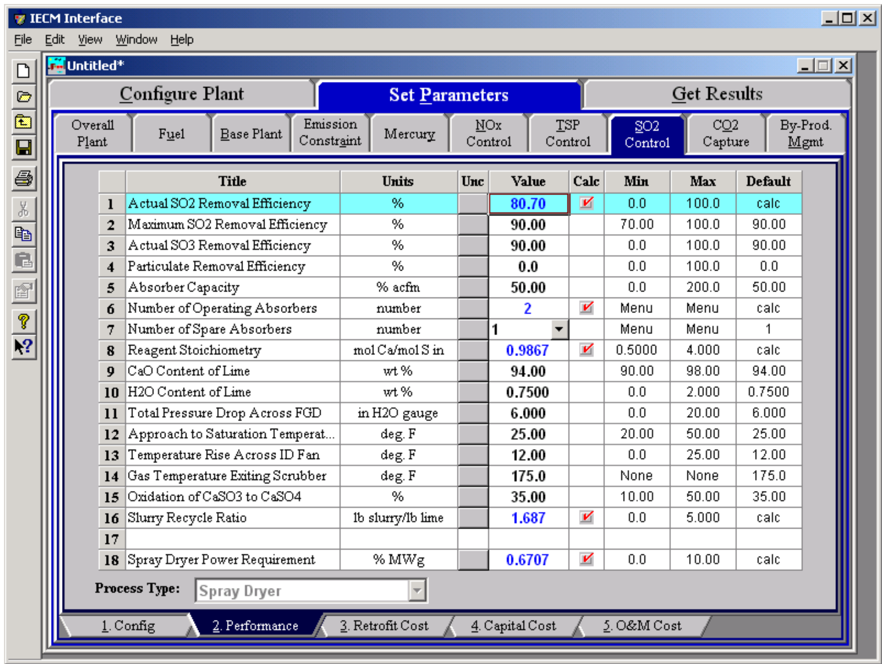
Each parameter is described briefly below.

Reagent: For the Lime Spray Dryer the only option is **Lime**.

- **Lime:** Magnesium Enhanced Lime System—A magnesium sulfite and lime slurry (maglime) is used to remove SO2 and form a precipitate high in calcium sulfite. The high alkalinity of the maglime slurry allows very high SO2 removal. However, the reagent cost is also higher and solid waste is not easily disposed.

Spray Dryer Performance Inputs

This screen is only available for the **Combustion (Boiler)** plant type. Inputs for performance of the **Lime Spray Dryer** SO_2 control technology are entered on the **Performance** input screen.



Spray Dryer – Performance input screen.

In a Lime Spray Dryer, an atomized spray of a mixture of lime slurry and recycled solids is brought into contact with the hot flue gas. The water in the slurry evaporates leaving dry reaction products and flyash, which drops out of the scrubber. A particulate control device such as a baghouse is also used to remove the rest of the dry products from the flue gas before releasing it. The SO_2 removal efficiency is the total of SO_2 removed in the scrubber and the baghouse.

Many lime spray dryer input parameters are similar to those defined above for wet lime/limestone systems. Each parameter is described briefly below.

Actual SO_2 Removal Efficiency: This is the annual average SO_2 removal efficiency achieved in the absorber. The calculated default value assumes compliance with the SO_2 emission limit specified earlier, if possible. The default value reflects other model parameter values, including the sulfur retained in bottom ash. This input is highlighted in blue.

Maximum SO_2 Removal Efficiency: This parameters specifies the maximum efficiency possible for the absorber on an annual average basis. The value is used as a limit in calculating the actual SO_2 removal efficiency for compliance.

Actual SO_3 Removal Efficiency: The default value is taken from the removal efficiency reported in the literature (references are below). This efficiency then determines the mass of SO_3 removed from the flue gas in the collector. For more information see also:

- www.netl.doe.gov/publications/proceedings/98/98fg/hardman.pdf
- www.netl.doe.gov/publications/proceedings/98/98fg/rubin.pdf

Particulate Removal Efficiency: Ash and particulate matter are assumed to be removed by a separate particulate removal device, such as a fabric filter. However, this parameters is provided for conditions where particulates are removed directly from the scrubber.

Absorber Capacity: This is the percent of the flue gas treated by each operating absorber. This value is used to determine the number of operating absorbers and the capital costs.

Number of Operating Absorbers: This is the number of operating scrubber towers. The number is determined by the absorber capacity and is used to calculate the capital costs. The value must be an integer.

Number of Spare Absorbers: This is the total number of spare absorber vessels. It is used primarily to calculate capital costs. The value must be an integer.

Reagent Stoichiometry: This is the moles of calcium per mole of sulfur into the absorber. The stoichiometry is calculated as a function of the required SO_2 removal efficiency, inlet flue gas temperature, inlet sulfur concentration, and approach to saturation temperature.

CaO Content of Lime: This is the percent of reagent that is pure lime (CaO). This parameter determines the waste solids produced and the reagent mass requirements, given the stoichiometry needed for SO_2 removal.

H2O Content of Lime: This is the moisture content of the lime (CaO). The remaining reagent impurities are assumed to be inert substances such as silicon dioxide (sand). This parameter is used to determine the waste solids produced.

Total Pressure Drop Across FGD: This is the total pressure drop across the spray dryer vessel prior to the reheater. This is used in the calculations of the power requirements (or energy penalty) and thermodynamic properties of the flue gas.

Approach to Saturation Temperature: This defines the gas temperature exiting the absorber. The approach is the increment over the water saturation temperature at the exit pressure. As the approach to saturation temperature increases, the evaporation time decreases thereby decreasing removal efficiency.

Temperature Rise Across ID Fan: An induced draft (ID) fan is assumed to be located upstream of the FGD system. The fan raises the temperature of the flue gas due to dissipation of electro-mechanical energy.

Gas Temperature Exiting Scrubber: A thermodynamic equation is used to calculate this equilibrium flue gas temperature exiting the scrubber. The gas is assumed to be saturated with water at the exiting temperature and pressure. The value determines the water evaporated in the scrubber.

Oxidation of CaSO3 to CaSO4: This parameter determines the mixture of the two chemical species in the solid waste stream.

Slurry Recycle Ratio: An atomized spray of a mixture of lime slurry and recycled solids is brought into contact with the hot flue gas. This parameter specifies the amount of solid waste recycled and lime slurry used. It is calculated from the sulfur content of the coal.

Spray Dryer Power Requirement: This is the equivalent electrical output of thermal (steam) energy used for reheat, plus the actual electrical output power required for pumps and booster fans.

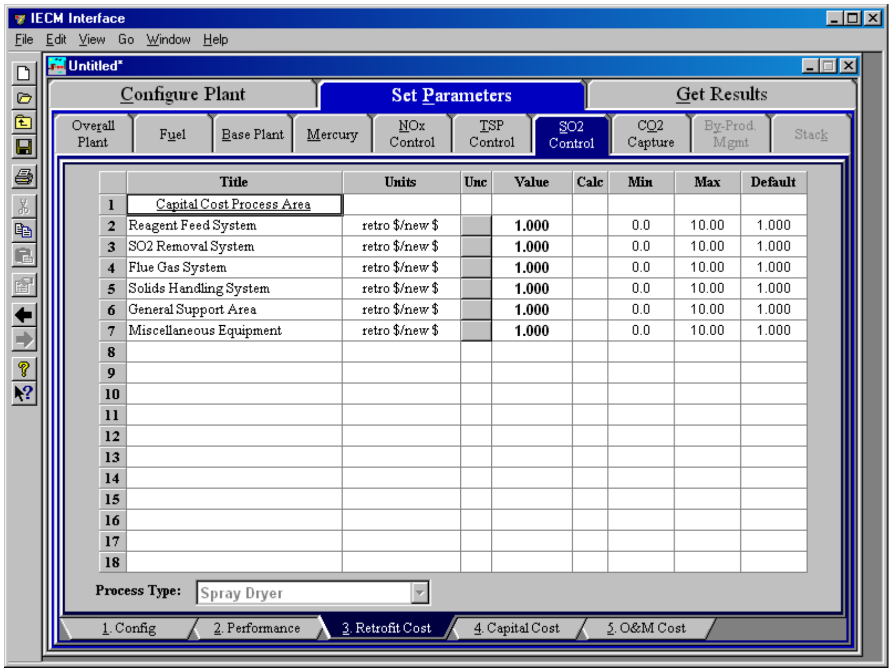
Spray Dryer Retrofit Cost

This screen is only available for the Combustion (Boiler) plant type. Inputs for capital costs of modifications to process areas to implement the SO_2 control technology are entered on the **Retrofit Cost** input screen.

The retrofit cost factor of each process is a multiplicative cost adjustment which considers the cost of retrofitted capital equipment relative to similar equipment installed in a new plant. These factors affect the capital costs directly and the operating and maintenance costs indirectly.

Direct capital costs for each process area are calculated in the IECM. These calculations are reduced form equations derived from more sophisticated models and reports. The sum of the direct capital costs associated with each process area is defined as the process facilities capital (PFC). The retrofit cost factor provided for each of the process areas can be used as a tool for adjusting the anticipated costs and uncertainties across the process area separate from the other areas.

Uncertainty can be applied to the retrofit cost factor for each process area in each technology. Thus, uncertainty can be applied as a general factor across an entire process area, rather than as a specific uncertainty for the particular cost on the capital or O&M input screens. Any uncertainty applied to a process area through the retrofit cost factor compounds any uncertainties specified later in the capital and O&M cost input parameter screens.



Spray Dryer – Retrofit Cost input screen.

Each parameter is described briefly below.

Reagent Feed System: This area includes all equipment for storage, handling and preparation of raw materials, reagents, and additives used.

SO_2 Removal System: This area deals with the cost of equipment for SO_2 scrubbing, such as absorption tower, recirculation pumps, and other equipment.

Flue Gas System: This area treats the cost of the duct work and fans required for flue gas distribution to SO_2 system, plus gas reheat equipment.

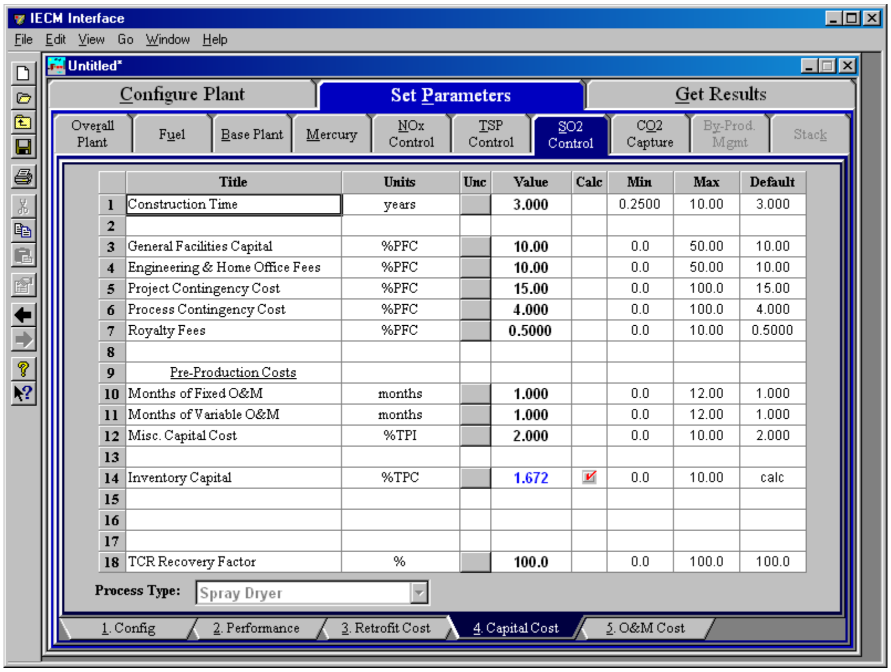
Solids Handling System: This area includes the cost of the equipment for fixation, treatment, and transportation of all sludge/dry solids materials produced by scrubbing.

General Support Area: The cost associated with the equipment required to support FGD system operation such as makeup water and instrument air are treated here.

Miscellaneous Equipment: Any miscellaneous equipment is treated in this process area.

Spray Dryer Capital Cost Inputs

This screen is only available for the **Combustion (Boiler)** plant type.



Spray Dryer – Capital Cost input screen.

Inputs for capital costs are entered on the **Capital Cost** input screen.

Construction Time: This is the idealized construction period in years. It is used to determine the allowance for funds used during construction (AFUDC).

General Facilities Capital (GFC): 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%.

Engineering & Home Office Fees: The engineering & home office fees are a percent of total direct capital cost. This is an overhead fee paid to the architect/engineering company. These fees typically range from 7-15%.

Project Contingency Cost: This is 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.

Process Contingency Cost: 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.

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

Pre-Production Costs: 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 applied to the O&M costs over a specified period of time (months). The two time periods for fixed and variable

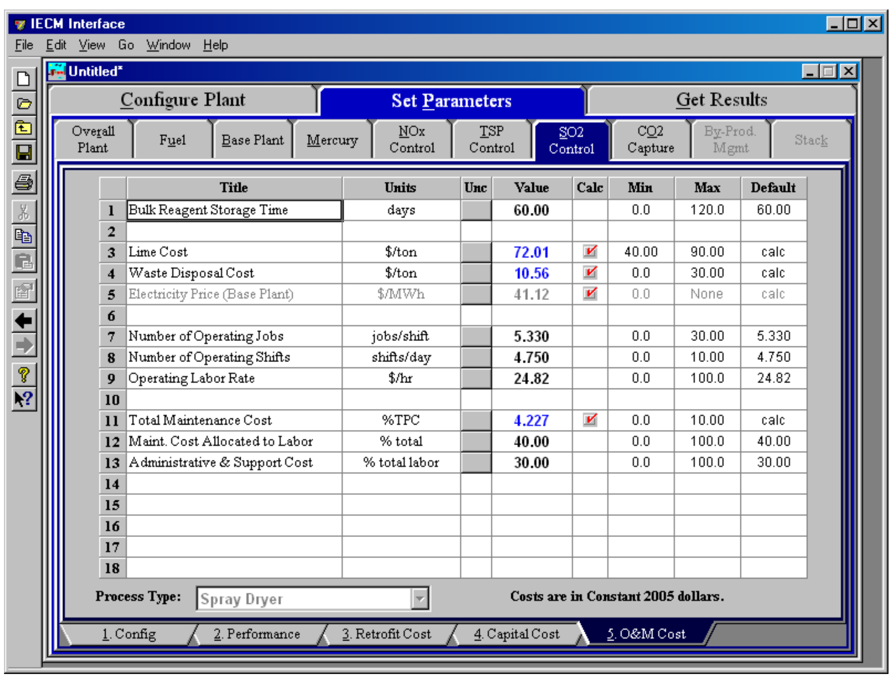
O&M costs are described below with the addition of a miscellaneous capital cost factor.

- **Months of Fixed O&M:** Time period of fixed operating costs used for preproduction to cover training, testing, major changes in equipment, and inefficiencies in start-up. This includes operating, maintenance, administrative and support labor. It also considers maintenance materials.
- **Months of Variable O&M:** Time period of variable operating costs used for preproduction to cover chemicals, water, consumables, and solid disposal charges in start-up, assuming 100% load. This excludes any fuels.
- **Misc. Capital Cost:** This is a percent of total plant investment (sum of TPC and AFUDC) to cover expected changes to equipment to bring the system up to full capacity.
- **Inventory Capital:** Percent of the total direct capital for raw material supply based on 100% capacity during a 60 day period. These materials are considered storage. The inventory capital includes fuels, consumables, by-products, and spare parts. This is typically 0.5%.

TCR Recovery Factor: The actual total capital required (TCR) as a percent of the TCR in a new power plant. This value is 100% for a new installation and may be set as low as 0% for a fabric filter that has been paid off.

Spray O&M Cost Inputs

This screen is only available for the **Combustion (Boiler)** plant type.



Spray Dryer – O&M Cost input screen.

Inputs for operation and maintenance are entered on the **O&M Cost** input tab. O&M costs are typically expressed on an average annual basis and are provided in either constant or current dollars for a specified year, as shown on the bottom of the screen. Each parameter is described briefly below

Bulk Reagent Storage Time: This is the number of days of bulk storage of reagent. This factor is used to determine the inventory capital cost.

Lime Cost: This is the cost of Lime for the Wet FGD or Lime Spray Dryer system.

Waste Disposal Cost: This is the sludge disposal cost for the FGD system.

Electricity Price (Base Plant): This is the price of electricity and is calculated as a function of the utility cost of the base plant, where the base plant is for the **Combustion (Boiler) Model** is a combustion boiler and an air preheater.

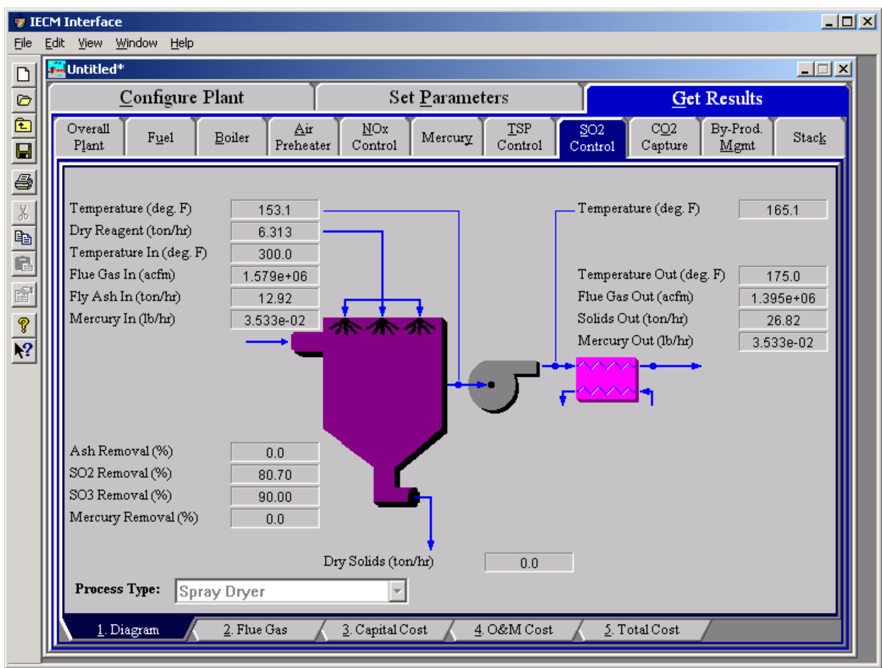
Total Maintenance Cost: This is the annual maintenance cost as a percentage of the total plant cost. Maintenance cost estimates can be developed separately for each process area.

Maint. Cost Allocated to Labor: Maintenance cost allocated to labor as a percentage of the total maintenance cost.

Administrative & Support Cost: This is the percent of the total operating and maintenance labor associated with administrative and support labor.

Spray Dryer Diagram

This screen is only available for the **Combustion (Boiler)** plant type.



Spray Dryer – Diagram

The **Diagram** result screen displays an icon for the Lime Spray Dryer SO_2 control technology selected and values for major flows in and out of it. Each result is described briefly below:

Reagent

Dry Reagent: The total mass flow rate of lime, limestone or limestone with dibasic acid injected into the scrubber. This is a function of the SO_2 removal efficiency, the reagent purity and the reagent stoichiometric (all performance input parameters). The reagent is assumed to be dry.

Flue Gas Entering Dryer

Temperature In: Temperature of the flue gas entering the scrubber. This is determined by the flue gas outlet temperature of the module upstream of the scrubber (e.g., a particulate removal technology).

Flue Gas In: Volumetric flow rate of flue gas entering the scrubber, based on the flue gas temperature entering the scrubber and atmospheric pressure.

Fly Ash In: Total solids mass flow rate in the flue gas entering the scrubber. This is determined by the solids exiting from the module upstream of the scrubber (e.g., a particulate removal technology).

Mercury In: Total mass of mercury entering the scrubber. The value is a sum of all the forms of mercury (elemental, oxidized, and particulate).

Flue Gas Exiting Dryer

Temperature: Temperature of the flue gas immediately after exiting the scrubber. This is a function of saturation temperature, and .the flue gas component concentrations. This temperature is used to determine the flue gas bypass required.

Temperature: Temperature of the flue gas immediately after exiting the induced draft fan. This is a function of flue gas temperature exiting the scrubber, the flue gas bypass and the temperature rise across ID fan input parameter.

Temperature Out: Temperature of the flue gas immediately after exiting the reheater. This is determined by the gas temperature exiting reheater input parameter.

Flue Gas Out: Volumetric flow rate of the flue gas exiting the reheater, based on the flue gas temperature exiting the scrubber and atmospheric pressure.

Solids Out: Total solids mass flow rate in the flue gas exiting the reheater. This is a function of the ash removal parameter on the scrubber performance input screen.

Mercury Out: Total mass of mercury exiting the scrubber after the reheater. The value is a sum of all the forms of mercury (elemental, oxidized, and particulate).

Spray Dryer Performance

Ash Removal: Actual particulate removal efficiency in the scrubber. This is set by the scrubber performance input parameter.

SO_2 Removal: Actual removal efficiency of SO_2 in the scrubber. This is a function of the maximum removal efficiency (scrubber performance input parameter) and the emission constraint for SO_2 (emission constraints input parameter). It is possible that the scrubber may over or under-comply with the emission constraint.

SO_3 Removal: Percent of SO_3 in the flue gas removed from the scrubber. The SO_3 is assumed to combine with H_2O and leave with the ash solids or sluice water as a sulfate (in the form of H_2SO_4).

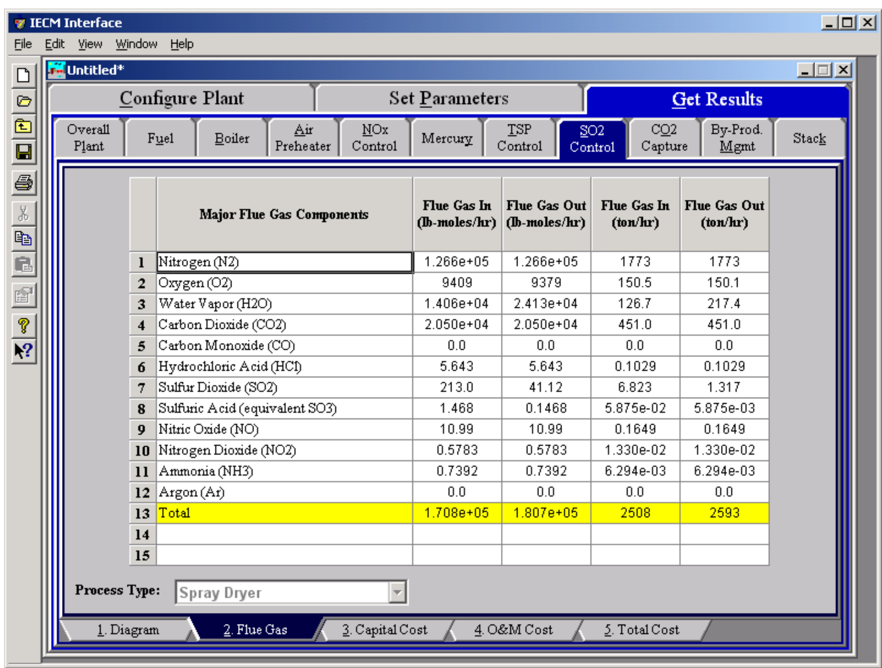
Mercury Removal: Percent of the total mercury removed from the scrubber. The value reflects a weighted average based on the particular species of mercury present (elemental, oxidized, and particulate).

Collected Solids

Dry Solids: Total solids mass flow rate of solids removed from the scrubber. This is a function of the solids content in the flue gas and the particulate removal efficiency of the scrubber. The solids are assumed to be dry.

Spray Dryer Flue Gas Results

This screen is only available for the **Combustion (Boiler)** plant type.



	Major Flue Gas Components	Flue Gas In (lb-moles/hr)	Flue Gas Out (lb-moles/hr)	Flue Gas In (ton/hr)	Flue Gas Out (ton/hr)
1	Nitrogen (N2)	1.266e+05	1.266e+05	1773	1773
2	Oxygen (O2)	9409	9379	150.5	150.1
3	Water Vapor (H2O)	1.406e+04	2.413e+04	126.7	217.4
4	Carbon Dioxide (CO2)	2.050e+04	2.050e+04	451.0	451.0
5	Carbon Monoxide (CO)	0.0	0.0	0.0	0.0
6	Hydrochloric Acid (HCl)	5.643	5.643	0.1029	0.1029
7	Sulfur Dioxide (SO2)	213.0	41.12	6.823	1.317
8	Sulfuric Acid (equivalent SO3)	1.468	0.1468	5.875e-02	5.875e-03
9	Nitric Oxide (NO)	10.99	10.99	0.1649	0.1649
10	Nitrogen Dioxide (NO2)	0.5783	0.5783	1.330e-02	1.330e-02
11	Ammonia (NH3)	0.7392	0.7392	6.294e-03	6.294e-03
12	Argon (Ar)	0.0	0.0	0.0	0.0
13	Total	1.708e+05	1.807e+05	2508	2593
14					
15					

Spray Dryer – Flue Gas result screen.

Major Flue Gas Components

Each result is described briefly below:

Nitrogen (N_2): Total mass of nitrogen.

Oxygen (O_2): Total mass of oxygen.

Water Vapor (H_2O): Total mass of water vapor.

Carbon Dioxide (CO_2): Total mass of carbon dioxide.

Carbon Monoxide (CO): Total mass of carbon monoxide.

Hydrochloric Acid (HCl): Total mass of hydrochloric acid.

Sulfur Dioxide (SO_2): Total mass of sulfur dioxide.

Sulfuric Acid (equivalent SO_3): Total mass of sulfuric acid.

Nitric Oxide (NO): Total mass of nitric oxide.

Nitrogen Dioxide (NO_2): Total mass of nitrogen dioxide.

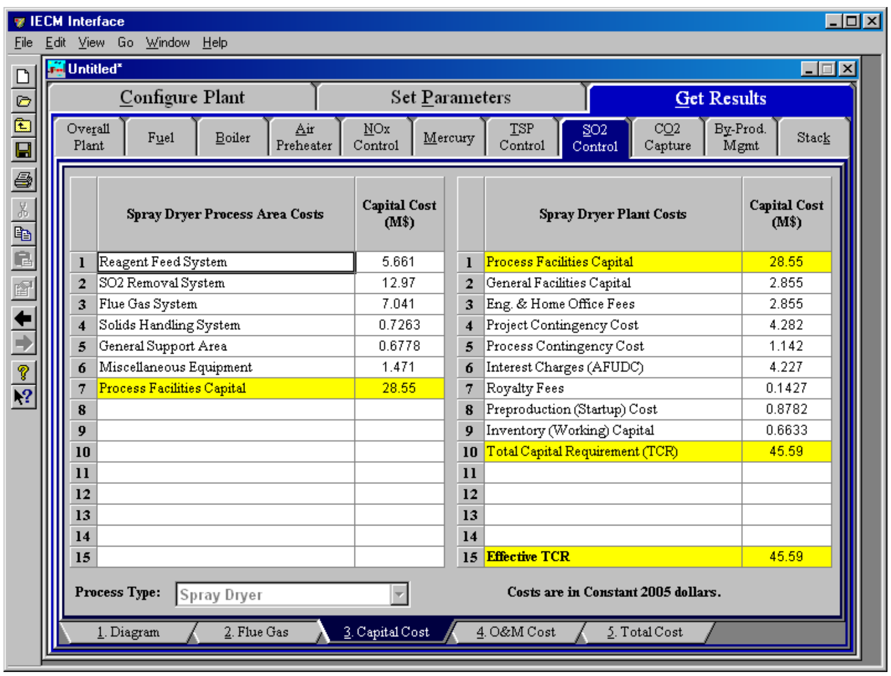
Ammonia (NH3): Total mass of ammonia.

Argon (Ar): Total mass of argon.

Total: Total of the individual components listed above. This item is highlighted in yellow.

Spray Dryer Capital Cost Results

This screen is only available for the **Combustion (Boiler)** plant type.



Spray Dryer – Capital Cost result screen.

The **Capital Cost** result screen displays tables for the direct and indirect capital costs. Capital costs are typically expressed in either constant or current dollars for a specified year, as shown on the bottom of the screen. Each result is described briefly below:

Each process area direct capital cost is a reduced-form model based on regression analysis of data collected from several reports and analyses of particulate control technology units. They are described in general below. The primary factors in the model that effect the capital costs of the scrubbers are the flue gas flow rate through the scrubber, the composition of the flue gas, the reagent stoichiometry, and the reagent flow rate.

Reagent Feed System: This area includes all equipment for storage, handling and preparation of raw materials, reagents, and additives used.

SO_2 Removal System: This area deals with the cost of equipment for SO_2 scrubbing, such as absorption tower, recirculation pumps, and other equipment.

Flue Gas System: This area treats the cost of the duct work and fans required for flue gas distribution to SO_2 system, plus gas reheat equipment.

Solids Handling System: This area includes the cost of the equipment for fixation, treatment, and transportation of all sludge/dry solids materials produced by scrubbing.

General Support Area: The cost associated with the equipment required to support spray dryer system operation such as makeup water and instrument air are treated here.

Miscellaneous Equipment: Any miscellaneous equipment is treated in this process area.

Process Facilities Capital: The process facilities capital is the total constructed cost of all on-site processing and generating units listed above, including all direct and indirect construction costs. All sales taxes and freight costs are included where applicable implicitly. This result is highlighted in yellow.

General Facilities Capital: The general facilities include construction costs of roads, office buildings, shops, laboratories, etc. Sales taxes and freight costs are included implicitly.

Eng. & Home Office Fees: The engineering & home office fees are a percent of total direct capital cost. This is an overhead fee paid to the architect/engineering company.

Project Contingency Cost: Capital cost contingency factor covering the cost of additional equipment or other costs that would result from a more detailed design of a definitive project at the actual site.

Process Contingency Cost: Capital cost contingency factor applied to a new technology in an effort to quantify the uncertainty in the technical performance and cost of the commercial-scale equipment.

Interest Charges (AFUDC): Allowance for funds used during construction, also referred to as interest during construction, is the time value of the money used during construction and is based on an interest rate equal to the before-tax weighted cost of capital. This interest is compounded on an annual basis (end of year) during the construction period for all funds spent during the year or previous years.

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

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.

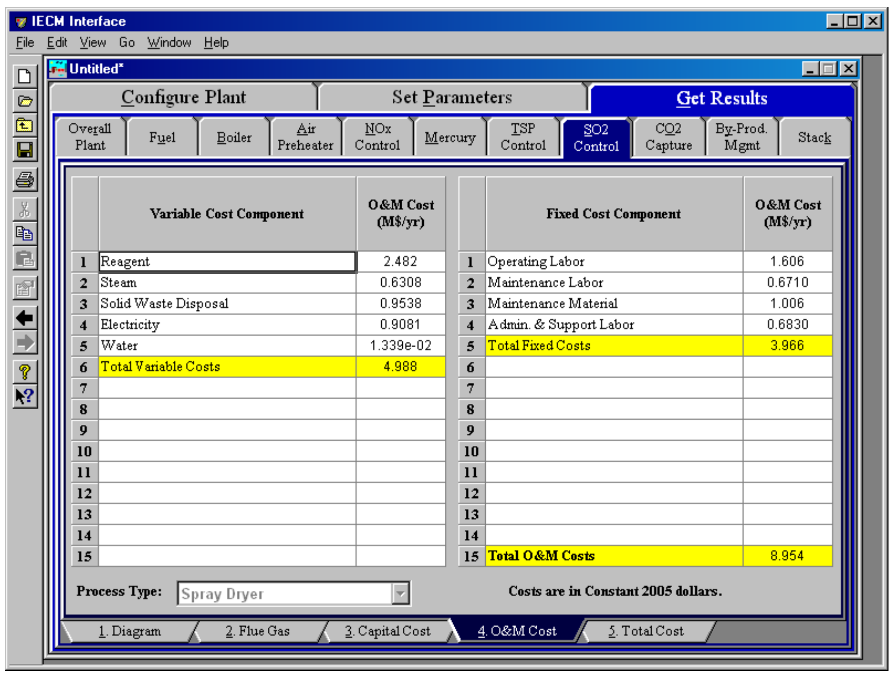
Inventory (Working) Capital: The raw material supply based on 100% capacity during a 60 day period. These materials are considered storage. The inventory capital includes fuels, consumables, by-products, and spare parts.

Total Capital Requirement (TCR): Money that is placed (capitalized) on the books of the utility on the service date. TCR includes all the items above. This result is highlighted in yellow.

Effective TCR: The TCR of the spray dryer that is used in determining the total power plant cost. The effective TCR is determined by the "TCR Recovery Factor".

Spray Dryer O&M Results

This screen is only available for the **Combustion (Boiler)** plant type.



Spray Dryer – O&M Cost result screen.

The **O&M Cost** result screen displays tables for the variable and fixed operation and maintenance costs involved with the SO_2 control technology. O&M costs are typically expressed on an average annual basis and are provided in either constant or current dollars for a specified year, as shown on the bottom of the screen. Each result is described briefly below:

Variable Cost Components

Variable operating costs and consumables are directly proportional to the amount of kilowatts produced and are referred to as incremental costs. All the costs are subject to inflation.

Reagent: Annual cost of lime or limestone injected into the scrubber on a wet basis. This is a function of the SO_2 concentration in the flue gas and the reagent stoichiometric performance input value.

Steam: Annual cost of steam used for direct or reheat use in the scrubber. This is a function of the steam heat rate, reheat energy requirement, and gross plant capacity.

Solid Waste Disposal: Total cost to dispose the collected flue gas waste solids. This does not consider by-product gypsum sold in commerce.

Power: Cost of power consumption of the scrubber. This is a function of the gross plant capacity and the scrubber energy penalty performance input parameter.

Water: Cost of water for reagent sluice in the scrubber. This is a function of the liquid to gas ratio performance input parameter for the wet FGD. The cost is a function of the flue gas flow rate and the slurry recycle ratio performance input parameter for the spray dryer.

Total Variable Costs: This is the sum of all the variable O&M costs listed above. This result is highlighted in yellow.

Fixed Cost Components

Fixed operating costs are essentially independent of actual capacity factor, number of hours of operation, or amount of kilowatts produced. All the costs are subject to inflation.

Operating Labor: Operating labor cost is based on the operating labor rate, the number of personnel required to operate the plant per eight-hour shift, and the average number of shifts per day over 40 hours per week and 52 weeks.

Maintenance Labor: The maintenance labor is determined as a fraction of the total maintenance cost.

Maintenance Material: The cost of maintenance material is the remainder of the total maintenance cost, considering the fraction associated with maintenance labor.

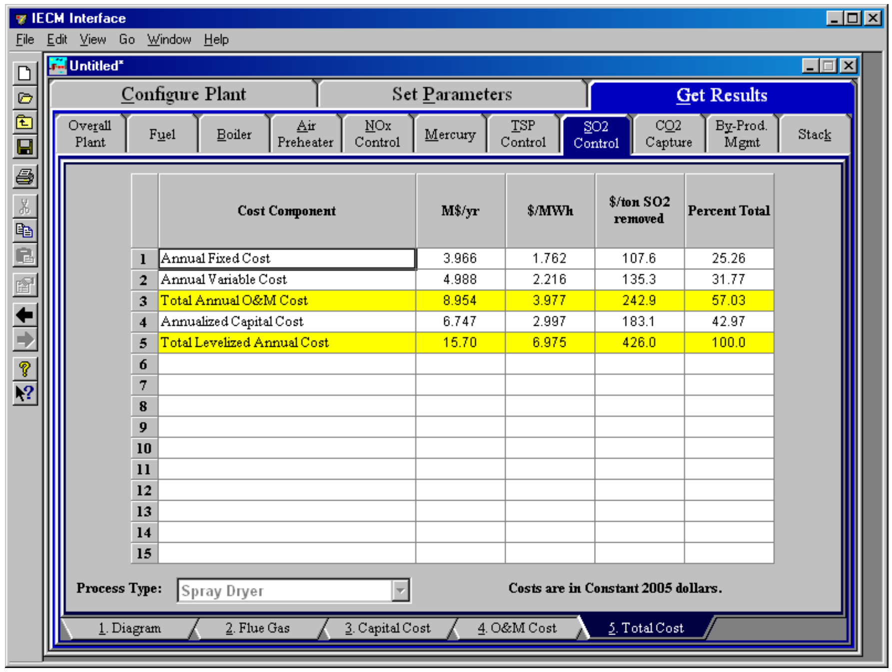
Admin. & Support Labor: The administrative and support labor is the only overhead charge. It is taken as a fraction of the total operating and maintenance labor costs.

Total Fixed Costs: This is the sum of all the fixed O&M costs listed above. This result is highlighted in yellow.

Total O&M Costs: This is the sum of the total variable and total fixed O&M costs. It is used to determine the base plant total revenue requirement. This result is highlighted in yellow.

Spray Dryer Total Cost Results

This screen is only available for the **Combustion (Boiler)** plant type.



Spray Dryer – Total Cost result screen.

Cost Component

The **Total Cost** result screen displays a table which totals the annual fixed, variable, operations, maintenance, and capital costs. Total costs are typically expressed in either constant or current dollars for a specified year, as shown on the bottom of the screen. Each result is described briefly below.

Annual Fixed Cost: The operating and maintenance fixed costs are given as an annual total. This number includes all maintenance materials and all labor costs.

Annual Variable Cost: The operating and maintenance variables costs are given as an annual total. This includes all reagent, chemical, steam, and power costs.

Total Annual O&M Cost: This is the sum of the annual fixed and variable operating and maintenance costs above. This result is highlighted in yellow.

Annualized Capital Cost: This is the total capital cost expressed on an annualized basis, taking into consideration the levelized carrying charge factor, or fixed charge factor, over the entire book life.

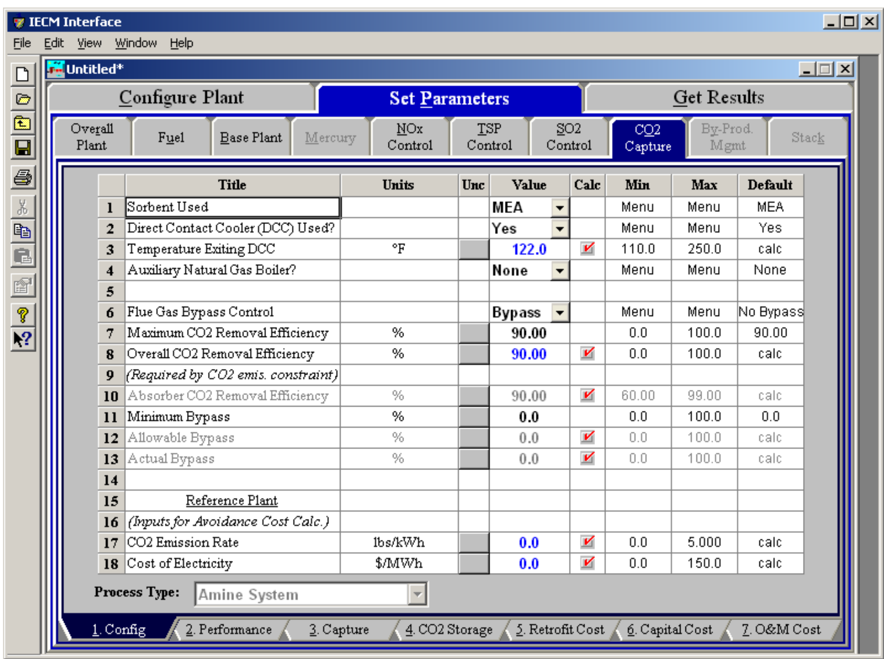
Total Levelized Annual Cost: The total annual cost is the sum of the total annual O&M cost and annualized capital cost items above. This result is highlighted in yellow.

Amine System

The amine CO_2 scrubber is a post-combustion capture technology. It is only used in the **Combustion (Boiler)** and **Combustion (Turbine)** plant type configurations.

Amine System Configuration

This screen is only available for the Combustion (Boiler) and Combustion (Turbine) plant types. The screens under the **CO_2 Capture** Technology Navigation Tab display and design flows and data related to the **Amine System**.



Amine System – Config. input screen (flue gas bypass added).

The parameters below describe the amine system alone. Additional parameters may be added to the screen if an auxiliary boiler or flue gas bypass is specified in the menus provided. The common input parameters are:

Sorbent Used: MEA is the sorbent used in the system and the nominal values of various parameters are based on a process simulation model that uses MEA. At present, no other sorbents are included.

Direct Contact Cooler (DCC) Used: A DCC is configured by default to cool the flue gas before it enters the amine system. The lower flue gas temperature enhances the absorption reaction (absorption of CO_2 in MEA sorbent is an exothermic process) and decreases the flue gas volume. The typically acceptable range of flue gas temperature is about 120-140 ^oF. A DCC is often not needed if a wet FGD is installed upstream.

Temperature Exiting DCC: This is the temperature exiting the DCC. The desirable temperature of the flue gas entering the CO_2 capture system is about 113-122 ^oF. If the inlet temperature to the DCC is at or below this temperature, the DCC is not used. *This variable is only displayed if a DCC is specified.*

Auxiliary Natural Gas Boiler?: An auxiliary natural gas-fired boiler can be added to the amine system. The options available are **None**, **Steam Only**, and **Steam + Power**. It may be added to generate separate power for the amine system (mainly compressors) and low pressure steam for sorbent regeneration. When used, the original steam cycle of the power plant remains undisturbed and the net power generation capacity of the power plant is not adversely affected. The auxiliary boiler comes at an additional cost of capital requirement for the boiler (and turbine) and the cost of supplemental fuel. Also, the auxiliary boiler adds to the CO_2 and NO_x emissions. When an auxiliary boiler is added, an additional process type will be added to the selection menu at the bottom of the screen.

Flue Gas Bypass Control: This popup selection menu controls whether or not a portion of the inlet flue gas may bypass the scrubber and recombine with the treated flue gas. Bypass allows the scrubber to operate at full efficiency while allowing some of the flue gas to go untreated. Two choices are available: **No Bypass** and **Bypass**. The no bypass option is the default and forces the entire flue gas to pass through the scrubber. The bypass option allows for the possibility of a portion of the flue gas to bypass the scrubber. The amount of bypass is controlled by several additional input parameters described below.

Maximum SO_2 Removal Efficiency: This parameters specifies the maximum efficiency possible for the absorber on an annual average basis. The value is used as a limit in calculating the actual SO_2 removal efficiency for compliance. *This is only visible if bypass is specified.*

Overall SO_2 Removal Efficiency: This value is the SO_2 removal efficiency required for the entire power plant to meet the SO_2 emission constraint set earlier. It is used to determine the actual flue gas bypass above. *This is only visible if bypass is specified.*

Scrubber SO_2 Removal Efficiency: This is the actual removal efficiency of the scrubber alone. It is a function of the SO_2 emission constraint and the actual flue gas bypass. This value is also shown on the next input screen. *This is only visible if bypass is specified.*

Minimum Bypass: This specifies the trigger point for allowing flue gas to bypass the scrubber. No bypass is allowed until the allowable amount reaches the minimum level set by this parameter. *This is only visible if bypass is specified.*

Allowable Bypass: This is the amount of flue gas that is allowed to bypass the scrubber, based on the actual and maximum performance of the SO_2 removal. It is provided for reference only. The model determines the bypass that produces the maximum SO_2 removal and compares this potential bypass with the minimum bypass value specified above. Bypass is only allowed when the potential bypass value exceeds the minimum bypass value. *This is only visible if bypass is specified.*

Actual Bypass: This displays the actual bypass being used in the model. It is based on all of the above and is provided for reference purposes only. *This is only visible if bypass is specified.*

Reference Plant

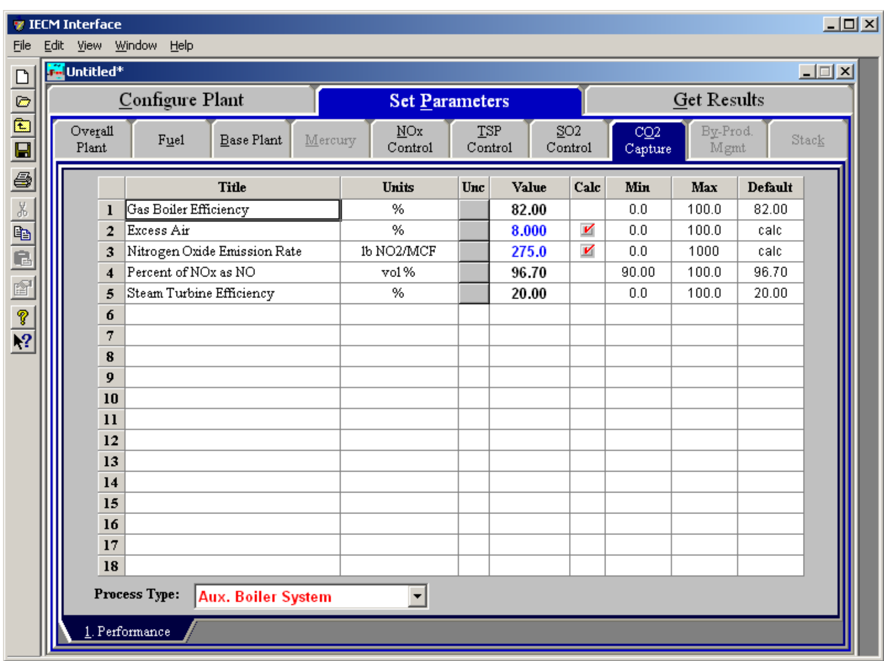
The following reference plant inputs are used to determine the avoided cost of CO_2 avoidance. The default value is zero for both parameters, requiring the user to supply the actual reference plant values. Reference values can be obtained by simulating the same plant configuration minus the CO_2 capture. Analysts commonly express the cost of an environmental control system in terms of either the cost per ton of pollutant removed or the cost per ton "avoided." For an energy-intensive system like amine scrubbers there is a big difference between the cost per ton CO_2 removed and the cost per ton CO_2 avoided based on *net* plant capacity. Since the purpose of adding a capture unit is to reduce the CO_2 emissions per net kWh delivered, the cost of CO_2 avoidance (relative to a reference plant with no CO_2 control) is the economic indicator most widely used. The reference plant parameters required are:

CO_2 Emission Rate: This is the emission rate for the reference power plant (without CO_2 capture)

Cost of Electricity: This is the cost of electricity for the reference power plant (without CO_2 capture)

Auxiliary Boiler Configuration

This screen is only available for the **Combustion (Boiler)** and **Combustion (Turbine)** plant types.



Aux. Boiler System – Performance input screen

An auxiliary boiler may be added to the amine system to produced additional power and steam. It is accessed by using the “Process Type:” menu at the bottom of the input screen. Use this menu to return to the amine system input screens. If an auxiliary boiler is specified, the following parameters are available:

Gas Boiler Efficiency: This is the percentage of fuel input energy transferred to steam in the boiler. The model default is based on standard algorithms described in the literature. It takes into consideration the energy losses due to inefficient heat transfer across the preheater, latent heat of evaporation, incomplete combustion, radiation losses, and unaccounted losses.

Excess Air: This is the excess theoretical air used for combustion in the auxiliary boiler.

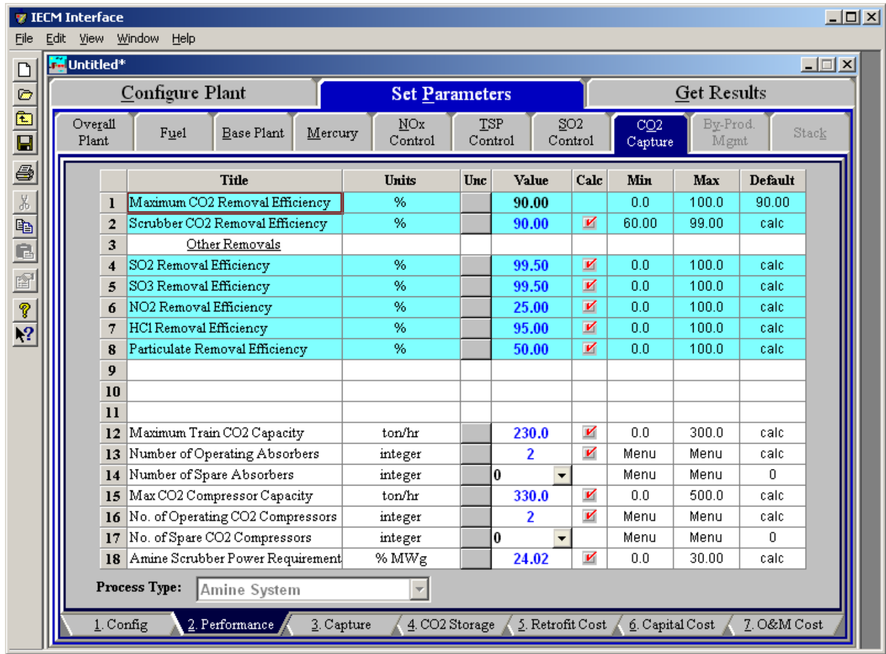
Nitrogen Oxide Emission Rate: This parameter establishes the level of NOx emissions from the boiler. The default value reflects the AP-42 EPA emission factor, which is a function of boiler firing method and the coal rank. The value is given in pounds of equivalent NO2 per ton of coal.

Percent of NO_x as NO: This parameter establishes the level of nitric oxide (NO) in the flue gas stream. The remainder of the total NOx emissions is assumed to be nitrogen dioxide (NO2). The default parameter reflects the AP-42 EPA emission factor, which is dependent on the fuel type.

Steam Turbine Efficiency: The steam turbine efficiency may be considered the power generation efficiency when converting heat of the low pressure (LP) steam into usable electricity. The efficiency is much lower due to the low quality of the steam being converted. This is only visible when steam and power are specified.

Amine System Performance Inputs

This screen is only available for the **Combustion (Boiler)** and **Combustion (Turbine)** plant types.



Amine System – Performance input screen.

The amine-based absorption system for CO_2 removal is a wet scrubbing operation. This process removes other acid gases and particulate matter in addition to CO_2 from the flue gas. These are listed below along with additional performance parameters:

CO_2 Removal Efficiency: Most studies report the CO_2 capture efficiency of the amine-based systems to be 90%, with few others reporting as high as 96% capture efficiency. Here, it has been assumed to be 90%.

SO_2 Removal Efficiency: SO_2 is removed at a very high rate. The default efficiency is 99.5%.

SO_3 Removal Efficiency: SO_3 is removed at a very high rate. The default efficiency is 99.5%.

NO_2 Removal Efficiency: A small amount of NO_2 is removed. The default efficiency is 25%.

HCl Removal Efficiency: HCl is removed at a high rate. The default efficiency is 95%.

Particulate Removal Efficiency: Particulates are removed in any wet scrubbing system at a rate of approximately 50%.

Maximum Train CO_2 Capacity: The default maximum train size is used with the actual CO_2 capture rate to determine the number of trains required.

Number of Operating Absorbers: This is the total number of operating absorber vessels. It is determined by the train capacity specified above and is used primarily to calculate capital costs. The value must be an integer.

Number of Spare Absorbers: This is the total number of spare absorber vessels. It is used primarily to calculate capital costs. The value must be an integer.

Max. CO_2 Compressor Capacity: This is the maximum amount of CO_2 product that can be compressed per hour at the specified pressure (see the storage input screen).

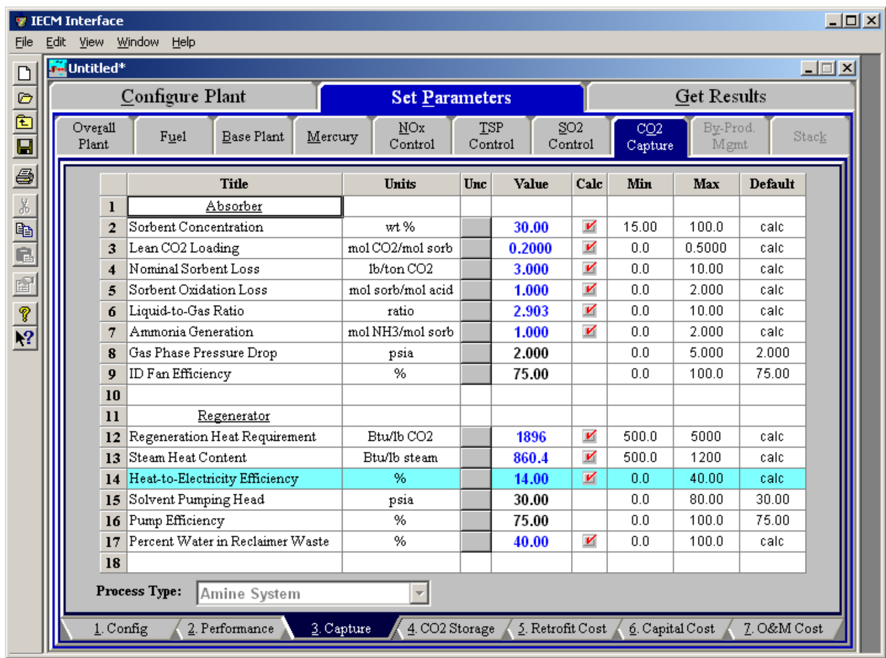
No. of Operating CO_2 Compressors: This is the total number of operating CO_2 compressors. It is used primarily to calculate capital costs. The value must be an integer.

No. of Spare CO_2 Compressors: This is the total number of spare CO_2 compressors. It is used primarily to calculate capital costs. The value must be an integer.

Amine Scrubber Power Requirement: This is the equivalent electrical output of thermal (steam) energy used for reheat, plus the actual electrical power required for pumps and booster fans.

Amine System Capture Inputs

This screen is only available for the **Combustion (Boiler)** and **Combustion (Turbine)** plant types.



Amine System – Capture input screen.

Absorber

The absorber is the vessel where the flue gas makes contact with the MEA-based sorbent, and some of the CO_2 from the flue gas is dissolved in the sorbent. The column may be plate-type or a packed one. Most of the CO_2 absorbers are packed columns using some kind of polymer-based packing to provide large interfacial area.

Sorbent Concentration: The solvent used for CO_2 absorption is a mixture of monoethanolamine (MEA) with water. MEA is a highly corrosive liquid, especially in the presence of oxygen and carbon dioxide, and hence needs to be diluted. Today the commercially available MEA-based technology supplied by Fluor Daniel uses 30%

w/w MEA solvent with the help of some corrosion inhibitors. Other suppliers, who do not use this inhibitor, prefer to use lower MEA concentrations in the range of 15%-20% by weight.

Lean CO_2 Loading: Ideally, the solvent will be completely regenerated on application of heat in the regenerator section. Actually, even on applying heat, not all the MEA molecules are freed from CO_2. So, the regenerated (or lean) solvent contains some "left-over" CO_2. The level of lean solvent CO_2 loading mainly depends upon the initial CO_2 loading in the solvent and the amount of regeneration heat supplied, or alternatively, the regeneration heat requirement depends on the allowable level of lean sorbent loading..

Nominal Sorbent Loss: MEA is a reactive solvent. In spite of dilution with water and use of inhibitors, a small quantity of MEA is lost through various unwanted reactions, mainly the polymerization reaction (to form long-chained compounds) and the oxidation reaction forming organic acids and liberating ammonia. It is assumed that 50 % of this MEA loss is due to polymerization and the remaining 50% of the MEA loss is due to oxidation to acids.

Sorbent Oxidation Loss: The sorbent oxidation loss variable is a ratio of the number moles of sorbent that are lost for every mole of acid formed due to oxidation of the sorbent.

Liquid to Gas Ratio: The liquid to gas ration is the ratio of total molar flow rate of the liquid (MEA sorbent plus water) to the total molar flow rate of flue gas being treated in the absorber.

Ammonia Generation: The oxidation of MEA to organic acids (oxalic, formic, etc.) also leads to formation of NH_3. Each mole of MEA lost in oxidation, liberates a mole of ammonia (NH_3).

Gas Phase Pressure Drop: This is the pressure drop that the flue gas has to overcome as it passes through a very tall absorber column, countercurrent to the sorbent flow.

ID Fan Efficiency: The cooled flue gas is pressurized using a flue gas blower before it enters the absorber. This is the efficiency of the fan/blower to convert electrical power input into mechanical work output.

Regenerator

The regenerator is the column where the weak intermediate compound (carbamate) formed between the MEA-based sorbent and dissolved CO2 is broken down with the application of heat and CO_2 gets separated from the sorbent to leave reusable sorbent behind. In case of unhindered amines like MEA, the carbamate formed is stable and it takes large amount of energy to dissociate. It also consists of a flash separator where CO_2 is separated from most of the moisture and evaporated sorbent, to give a fairly rich CO_2 stream.

Regeneration Heat Requirement: This is the total amount of heat energy required in the reboiler for sorbent regeneration.

Steam Heat Content: The regeneration heat is provided in the form of LP steam extracted from the steam turbine (in case of coal-fired power plants and combined-cycle gas plants), through the reboiler (a heat exchanger). In case of simple cycle natural gas fired power plants, a heat recovery unit maybe required. This is the enthalpy or heat content of the steam used for solvent regeneration.

Heat to Energy Efficiency: This is the efficiency of converting low pressure steam to electricity. The value reflects the loss of electricity to the base plant when the LP steam is used for regenerator heat.

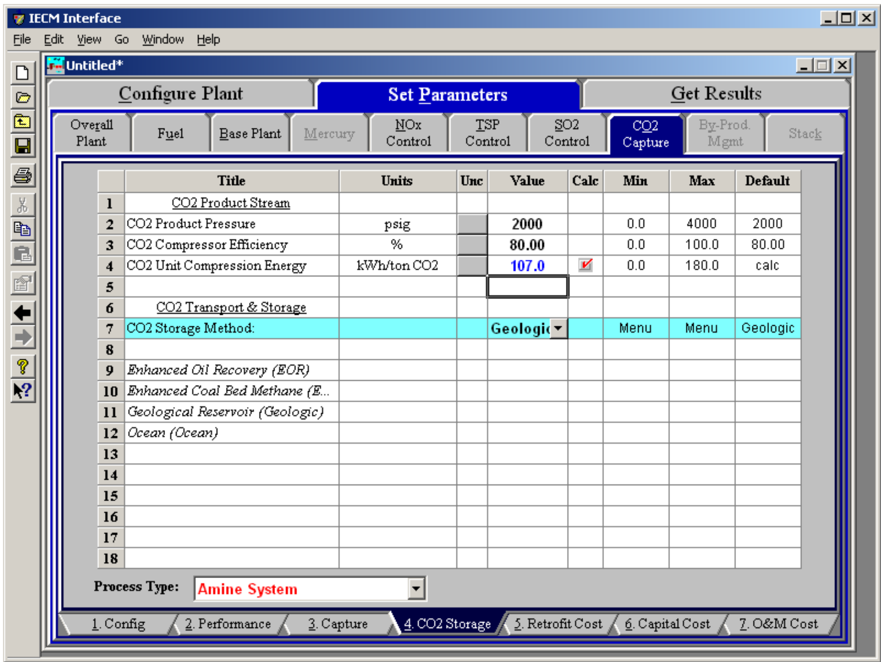
Solvent Pumping Head: The solvent has to flow through the absorber column (generally through packed media) countercurrent to the flue gas flowing upwards. So, some pressure loss is encountered in the absorber column and sufficient solvent head has to be provided to overcome these pressure losses. Solvent circulation pumps are used to provide the pressure head.

Pump Efficiency: This is the efficiency of the solvent circulation pumps to convert electrical power input into mechanical power output.

Percent Water in Reclaimer Waste: This is the amount of water typically present in the reclaimer waste.

Amine System Storage Inputs

This screen is only available for the **Combustion (Boiler)** and **Combustion (Turbine)** plant types.



Amine System – Storage input screen

This screen characterizes the compression and storage location for the product CO_2. A separate pipeline model is provided to specify inputs for that sub-system. The pipeline model is accessed from the **Process Type** menu at the bottom of the screen.

CO_2 Product Stream

The concentrated CO_2 product stream obtained from sorbent regeneration is compressed and dried using a multi-stage compressor with inter-stage cooling.

Product Pressure: The CO_2 product may have to be carried over long distances. Hence it is necessary to compress (and liquefy) it to very high pressures, so that it maybe delivered to the required destination in liquid form and (as far as possible) without recompression facilities en route. The critical pressure for CO_2 is about 1070 psig. The typically reported value of final pressure to which the product CO_2 stream has to be pressurized using compressors, before it is transported is about 2000 psig.

CO_2 Compressor Efficiency: This is the effective efficiency of the compressors used to compress CO_2 to the desirable pressure.

CO_2 Unit Compression Energy: This is the electrical energy required to compress a unit mass of CO_2 product stream to the designated pressure. Compression of CO_2 to high pressures requires substantial energy, and is a principle contributor to the overall energy penalty of a CO_2 capture unit in a power plant.

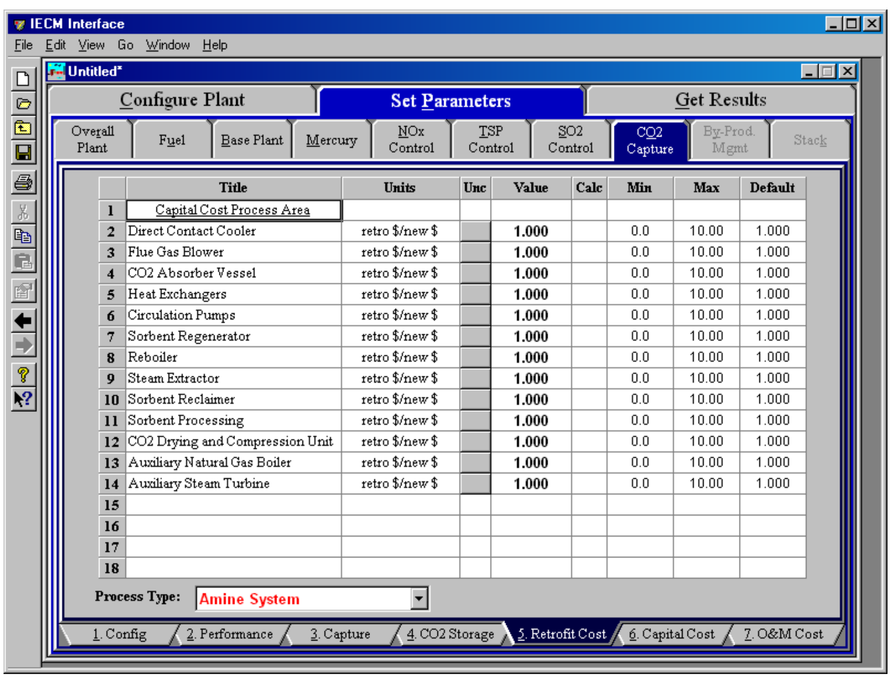
CO_2 Transport & Storage

Storage Method: The default option for CO_2 disposal is underground geological storage.

- **EOR** – Enhanced Oil Recovery
- **ECBM** – Enhanced Coalbed Methane Recovery
- **Geologic** – Geological Reservoir
- **Ocean**

Amine System Retrofit Cost Inputs

This screen is only available for the Combustion (Boiler) and Combustion (Turbine) plant types.



Amine System – Retrofit Cost input screen

Capital Cost Process Area

The retrofit cost factor of each process is a multiplicative cost adjustment, which considers the cost of retrofitted capital equipment relative to similar equipment installed in a new plant. These factors affect the capital costs directly and the operating and maintenance costs indirectly.

Direct capital costs for each process area are calculated in the IECM. These calculations are reduced form equations derived from more sophisticated models and reports. The sum of the direct capital costs associated with each process area is defined as the process facilities capital (PFC). The retrofit cost factor provided for each of the process areas can be used as a tool for adjusting the anticipated costs and uncertainties across the process area separate from the other areas.

Uncertainty can be applied to the retrofit cost factor for each process area in each technology. Thus, uncertainty can be applied as a general factor across an entire process area, rather than as a specific uncertainty for the particular cost on the capital or O&M input screens. Any uncertainty applied to a process area through the retrofit cost factor compounds any uncertainties specified later in the capital and O&M cost input parameter screens.

The following are the **Capital Cost Process Areas** for the Amine System:

Direct Contact Cooler: A direct contact cooler is typically used in plant configurations that do not include a wet FGD. A direct contact cooler is a large vessel where the incoming hot flue gas is placed in contact with cooling water. The cost is a function of the gas flow rate and temperature of the flue gas.

Flue Gas Blower: The flue gas enters the bottom of the absorber column and flows upward, countercurrent to the sorbent flow. Blowers are required to overcome the substantial pressure drop as it passes through a very tall absorber column. The cost is a function of the volumetric flow rate of the flue gas.

CO_2 Absorber Vessel: The capital cost of the absorber will go down with higher MEA concentration and higher CO_2 loading level of the solvent, and lower CO_2 content in the lean solvent. Therefore, a power law relationship based on flue gas flow rate is used. This is based on cost and flow rate data from Fluor Daniel, Inc. The cost assumes one absorber vessel per train. The cost is a function of the volumetric flow rate of the flue gas and the flue gas temperature.

Heat Exchangers: The CO_2-loaded sorbent must be heated in order to strip off CO_2 and regenerate the sorbent. In addition, the regenerated sorbent must be cooled down before it can be recirculated back to the absorber column. Heat exchangers are used to accomplish these two tasks. This area is a function of the sorbent flow rate.

Circulation Pumps: Circulation pumps are required to take the sorbent, introduced at atmospheric pressure, and lift it to the top of the absorber column. This area is a function of the sorbent flow rate.

Sorbent Regenerator: The regenerator (or stripper) is a column where the weak intermediate compound (carbamate) is broken down by the application of heat. The result is the release of CO_2 (in concentrated form) and return of the recovered sorbent back to the absorber. This process is accomplished by the application of heat using a heat exchanger and low-pressure steam. MEA requires substantial heat to dissociate the carbamate. Therefore a flash separator is also required, where the CO_2 is separated from the moisture and evaporated sorbent to produce a concentrated CO_2 stream. This area is a function of the sorbent flow rate.

Reboiler: The regenerator is connected to a reboiler, which is a heat exchanger that utilizes low pressure steam to heat the loaded sorbent. The reboiler is part of the sorbent regeneration cycle. The cost is a function of the sorbent and steam flow rates.

Steam Extractor: Steam extractors are installed to take low pressure steam from the steam turbines in the power plant. The cost is a function of the steam flow rate.

Sorbent Reclaimer: A portion of the sorbent stream is distilled in the reclaimer in order to avoid accumulation of heat stable salts in the sorbent stream. Caustic is added to recover some of the MEA in this vessel. The reclaimer cost is a function of the sorbent makeup flow rate.

Sorbent Processing: The sorbent processing area primarily consists of a sorbent cooler, MEA storage tank, and a mixer. The regenerated sorbent is further cooled with the sorbent cooler and MEA added to makeup for sorbent losses. This area is a function of the sorbent makeup flow rate.

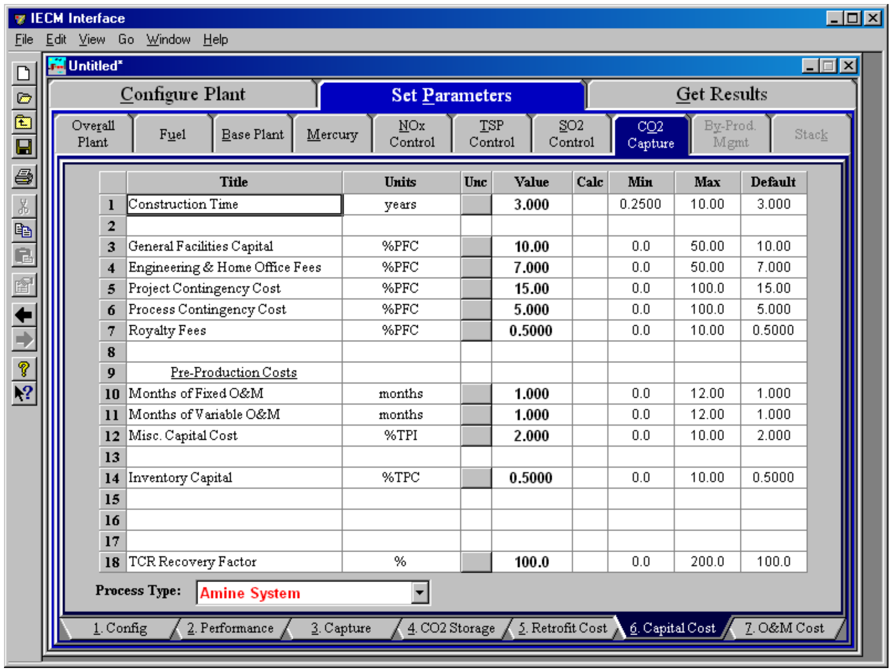
CO_2 Drying and Compression Unit: The product CO_2 must be separated from the water vapor (dried) and compressed to liquid form in order to transport it over long distances. The multi-stage compression unit with inter-stage cooling and drying yields a final CO_2 product at the nominal pressure of 2000 psig. This area is a function of the CO_2 flow rate.

Auxiliary Natural Gas Boiler: An auxiliary natural gas boiler is typically combined with a steam turbine to generate some additional power and/or low pressure steam. The cost is a function of the steam flow rate generated by the boiler. The boiler cost is lower if electricity is not being produced.

Auxiliary Steam Turbine: The steam turbine is used in conjunction with the natural gas boiler to generate some additional power and/or low pressure steam. The cost is a function of the secondary power generated by the turbine.

Amine System Capital Cost Inputs

This screen is only available for the **Combustion (Boiler)** and **Combustion (Turbine)** plant types.



Amine System – Capital Cost input screen.

Inputs for capital costs are entered on the **Capital Cost** input screen.

Construction Time: This is the idealized construction period in years. It is used to determine the allowance for funds used during construction (AFUDC).

General Facilities Capital (GFC): 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%.

Engineering & Home Office Fees: The engineering & home office fees are a percent of total direct capital cost. This is an overhead fee paid to the architect/engineering company. These fees typically range from 7-15%.

Project Contingency Cost: This is 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.

Process Contingency Cost: 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.

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

Pre-Production Costs: 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 applied to the O&M costs over a specified period of time (months). The two time periods for fixed and variable O&M costs are described below with the addition of a miscellaneous capital cost factor.

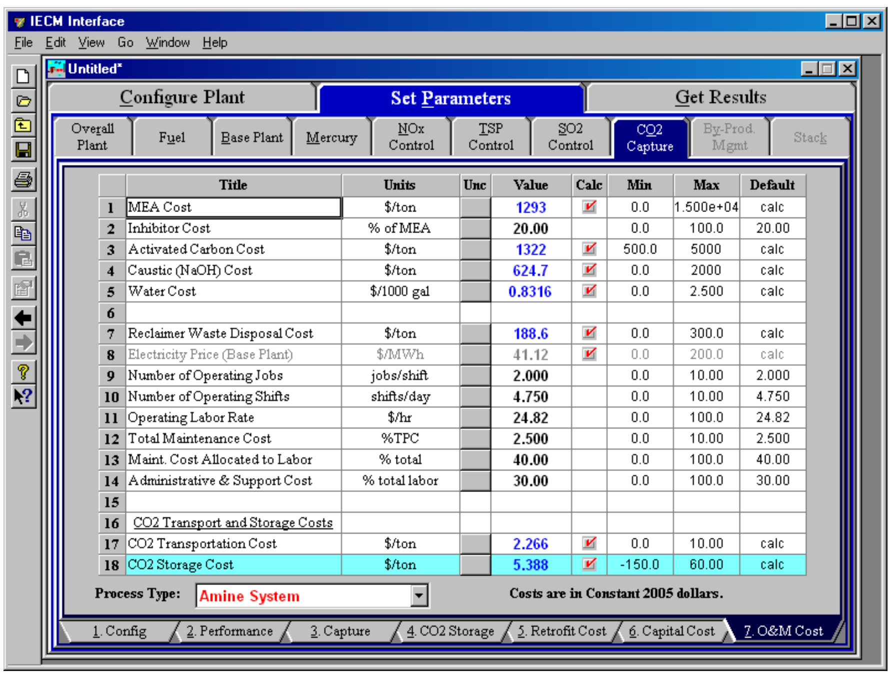
- **Months of Fixed O&M:** Time period of fixed operating costs used for preproduction to cover training, testing, major changes in equipment, and inefficiencies in start-up. This includes operating, maintenance, administrative and support labor. It also considers maintenance materials.
- **Months of Variable O&M:** Time period of variable operating costs used for preproduction to cover chemicals, water, consumables, and solid disposal charges in start-up, assuming 100% load. This excludes any fuels.
- **Misc. Capital Cost:** This is a percent of total plant investment (sum of TPC and AFUDC) to cover expected changes to equipment to bring the system up to full capacity.

Inventory Capital: Percent of the total direct capital for raw material supply based on 100% capacity during a 60 day period. These materials are considered storage. The inventory capital includes fuels, consumables, by-products, and spare parts. This is typically 0.5%.

TCR Recovery Factor: The actual total capital required (TCR) as a percent of the TCR in a new power plant. This value is 100% for a new installation and may be set as low as 0% for a fabric filter that has been paid off.

Amine System O&M Cost Inputs

This screen is only available for the **Combustion (Boiler)** and **Combustion (Turbine)** plant types.



Amine System – O&M Cost input screen.

Inputs for operation and maintenance are entered on the **O&M Cost** input. O&M costs are typically expressed on an average annual basis and are provided in either constant or current dollars for a specified year, as shown on the bottom of the screen. Each parameter is described briefly below

MEA Cost: This is the unit cost of the makeup MEA.

Inhibitor Cost: Addition of inhibitor makes it possible to use higher concentrations of MEA solvent in the system with minimal corrosion problems. Inhibitors are special compounds that come at a cost premium. The cost of inhibitor is estimated as a percent of the cost of MEA. The model default is 20%.

Activated Carbon Cost: This is the cost of the activated carbon in $ per ton.

Caustic (NaOH) Cost: This is the cost of the caustic (NaOH) in $ per ton.

Water Cost: Water is mainly required for cooling and also as process makeup. Cost of water may vary depending upon the location of the power plant.

Natural Gas Cost: This is the cost of the natural gas. *This is only visible if an auxiliary boiler is specified.*

Reclaimer Waste Disposal Cost: The unit cost of waste disposal for the reclaimer waste.

Electricity Price (Base Plant): This is the price of electricity and is calculated as a function of the utility cost of the base plant.

Number of Operating Jobs: This is the total number of operating jobs that are required to operate the plant per eight-hour shift.

Number of Operating Shifts: This is the total number of equivalent operating shifts in the plant per day. The number takes into consideration paid time off and weekend work (3 shifts/day * 7 days/5 day week * 52 weeks/(52 weeks - 6 weeks PTO) = 4.75 equiv. Shifts/day)

Operating Labor Rate: This is the hourly labor rate for operators working with the amine system. This is not used for maintenance, administrative, or support labor.

Total Maintenance Cost: This is the annual maintenance cost as a percentage of the total plant cost. Maintenance cost estimates can be developed separately for each process area.

Maint. Cost Allocated to Labor: Maintenance cost allocated to labor as a percentage of the total maintenance cost.

Administrative & Support Cost: This is the percent of the total operating and maintenance labor associated with administrative and support labor.

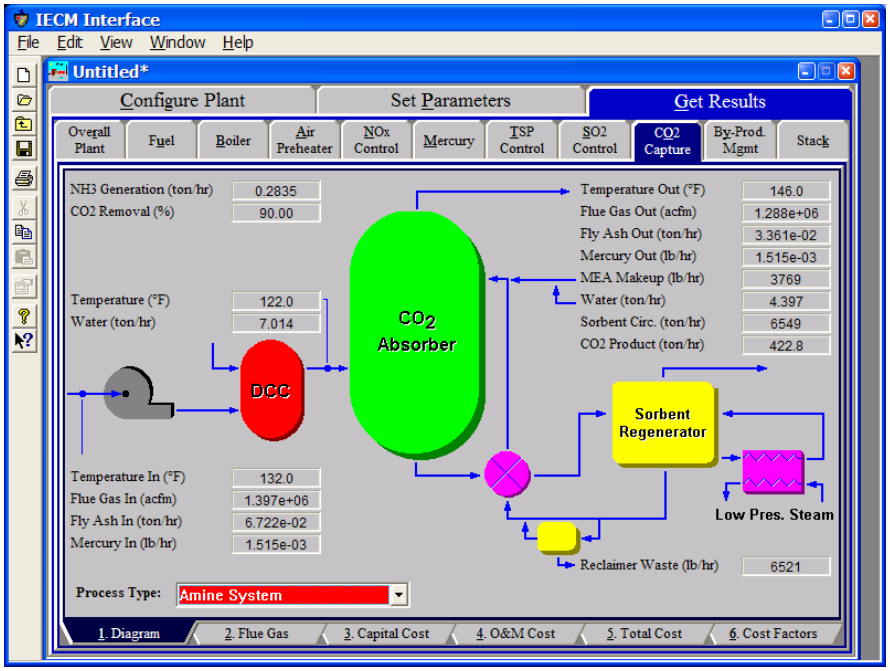
CO2 Transport and Storage Costs

CO_2 Transportation Cost: Transportation of CO_2 product is assumed to take place via pipelines. This is the unit cost of CO_2 transport in $/ton –mile. The cost is calculated from the pipeline sub-process model.

CO_2 Storage Cost: This is the unit cost of CO_2 disposal. Depending upon the method of CO_2 disposal or storage, either there may be some revenue generated (Enhanced Oil Recovery, Coal Bed Methane) which may be treated as a “negative cost”, or additional cost (all other disposal methods).

Amine System Diagram

This screen is only available for the **Combustion (Boiler)** and **Combustion (Turbine)** plant types.



Amine System – Diagram.

Reagent

MEA Makeup: The mass flow rate of fresh MEA needed to replace the amount used in the process.

Water: This is the flow rate of water that is used to mix with the MEA Makeup.

Flue Gas Entering Amine System

Temperature In: Temperature of the flue gas entering the amine system area, prior to any processing. This is determined by the flue gas outlet temperature of the process area upstream.

Flue Gas In: Volumetric flow rate of flue gas entering the amine system.

Fly Ash In: Total solids mass flow rate in the flue gas entering the Amine System. This is determined by the solids exiting from the module upstream.

Mercury In: Total mass of mercury entering the amine system. The value is a sum of all the forms of mercury (elemental, oxidized, and particulate).

Temperature: Temperature of the flue gas entering the amine scrubber system.

Water: This is the flow rate of water into the Direct Contact Cooler.

Flue Gas Exiting Amine System

Temperature Out: Temperature of the flue gas exiting the amine scrubber system.

Flue Gas Out: Volumetric flow rate of the flue gas exiting the amine scrubber.

Fly Ash Out: Total solids mass flow rate in the flue gas exiting the amine scrubber.

Mercury Out: Total mass of mercury exiting the amine scrubber. The value is a sum of all the forms of mercury (elemental, oxidized, and particulate).

Amine System Performance

NH_3 Generation: The flow rate of ammonia by product produced in the amine scrubbing process.

CO_2 Removal: Actual removal efficiency of CO_2 in the amine scrubber.

Sorbent Circ.: The flow rate of the sorbent through the amine scrubber system.

CO_2 Product: Actual amount of CO_2 produced as a result of the amine scrubbing.

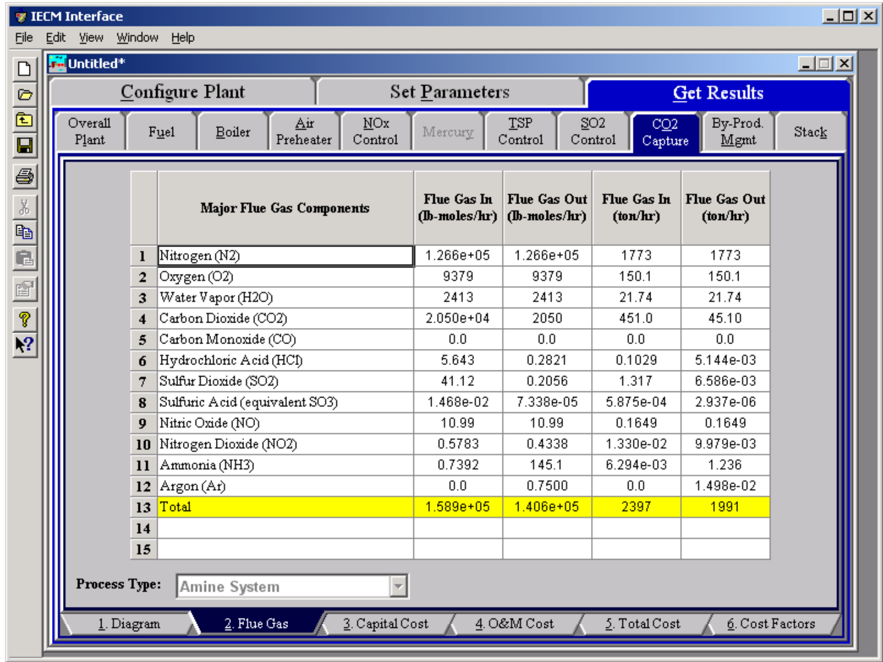
CO_2 Pressure: Compressed CO_2 product pressure. The product stream is compressed and sent through the pipeline system to the configured sequestration system.

Collected Solids

Reclaimer Waste: Total solids mass flow rate of solids removed from the amine scrubber.

Amine System Flue Gas Results

This screen is only available for the **Combustion (Boiler)** and **Combustion (Turbine)** plant types.



Amine System – Flue Gas result screen

Major Flue Gas Components

Each result is described briefly below:

Nitrogen (N2): Total mass of nitrogen.

Oxygen (O2): Total mass of oxygen.

Water Vapor (H2O): Total mass of water vapor.

Carbon Dioxide (CO2): Total mass of carbon dioxide.

Carbon Monoxide (CO): Total mass of carbon monoxide.

Hydrochloric Acid (HCl): Total mass of hydrochloric acid.

Sulfur Dioxide (SO2): Total mass of sulfur dioxide.

Sulfuric Acid (equivalent SO3): Total mass of sulfuric acid.

Nitric Oxide (NO): Total mass of nitric oxide.

Nitrogen Dioxide (NO2): Total mass of nitrogen dioxide.

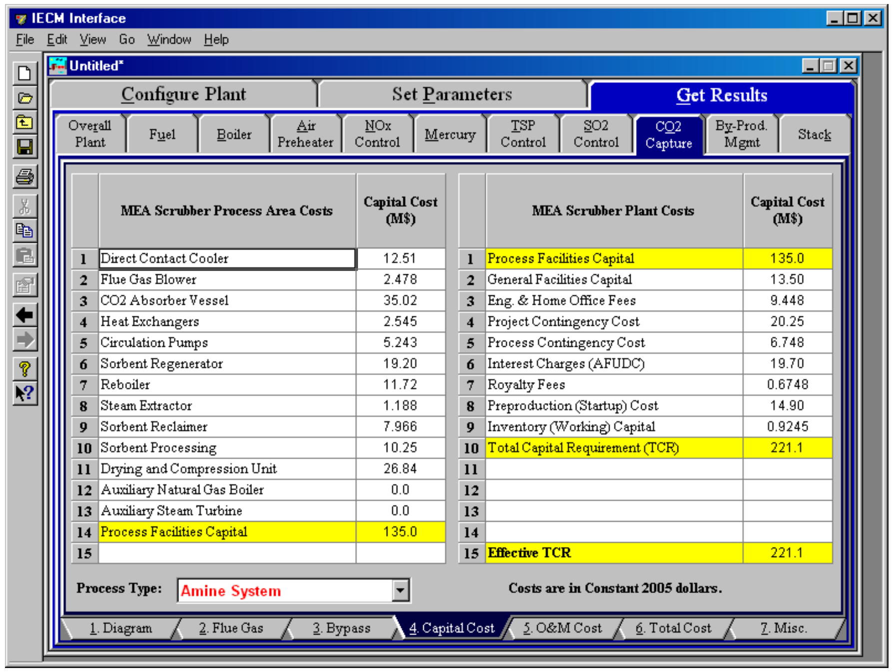
Ammonia (NH3): Total mass of ammonia.

Argon (Ar): Total mass of argon.

Total: Total of the individual components listed above. This item is highlighted in yellow.

Amine System Capital Cost Results

This screen is only available for the **Combustion (Boiler)** and **Combustion (Turbine)** plant types.



	MEA Scrubber Process Area Costs	Capital Cost (M$)
1	Direct Contact Cooler	12.51
2	Flue Gas Blower	2.478
3	CO2 Absorber Vessel	35.02
4	Heat Exchangers	2.545
5	Circulation Pumps	5.243
6	Sorbent Regenerator	19.20
7	Reboiler	11.72
8	Steam Extractor	1.188
9	Sorbent Reclaimer	7.966
10	Sorbent Processing	10.25
11	Drying and Compression Unit	26.84
12	Auxiliary Natural Gas Boiler	0.0
13	Auxiliary Steam Turbine	0.0
14	Process Facilities Capital	135.0
15		

	MEA Scrubber Plant Costs	Capital Cost (M$)
1	Process Facilities Capital	135.0
2	General Facilities Capital	13.50
3	Eng. & Home Office Fees	9.448
4	Project Contingency Cost	20.25
5	Process Contingency Cost	6.748
6	Interest Charges (AFUDC)	19.70
7	Royalty Fees	0.6748
8	Preproduction (Startup) Cost	14.90
9	Inventory (Working) Capital	0.9245
10	Total Capital Requirement (TCR)	221.1
11		
12		
13		
14		
15	Effective TCR	221.1

Amine System – Capital Cost result screen.

The **Capital Cost** result screen displays tables for the capital costs. Capital costs are typically expressed in either constant or current dollars for a specified year, as shown on the bottom of the screen. Each result is described briefly below:

MEA Scrubber Process Area Costs

Direct Contact Cooler: This area includes the equipment required to cool the flue gas in order to improve absorption of CO_2 into the amine sorbent. In case of coal-fired power plant applications that have a wet FGD (flue gas desulfurization) unit upstream of the amine system, the wet scrubber helps in substantial cooling of the flue gases, and additional cooler may not be required.

Flue Gas Blower: The flue gas has to overcome a substantial pressure drop as it passes through a very tall absorber column, countercurrent to the sorbent flow. Hence the cooled flue gas has to be pressurized using a blower before it enters the absorber.

CO2 Absorber Vessel: This is the vessel where the flue gas is made to contact with the MEA-based sorbent, and some of the CO_2 from the flue gas gets dissolved in the sorbent. The column may be plate-type or a packed one. Most of the CO_2 absorbers are packed columns using some kind of polymer-based packing to provide large interfacial area.

Heat Exchangers: The CO_2-loaded sorbent needs to be heated in order to strip off CO_2 and regenerate the sorbent. On the other hand, the regenerated (lean) sorbent coming out of the regenerator has to be cooled down before it could be circulated back to the absorber column. Hence these two sorbent streams are passed through a cross heat exchanger, where the rich (CO_2-loaded) sorbent gets heated and the lean (regenerated) sorbent gets cooled.

Circulation Pumps: The cost associated with the equipment required to support FGD system operation such as makeup water and instrument air are treated here.

Sorbent Regenerator: This is the column where the weak intermediate compound (carbamate) formed between the MEA-based sorbent and dissolved CO_2 is broken down with the application of heat and CO_2 gets separated from the sorbent to leave reusable sorbent behind. In case of unhindered amines like MEA, the carbamate formed is stable and it takes large amount of energy to dissociate. It also consists of a flash separator where CO_2 is separated from most of the moisture and evaporated sorbent, to give a fairly rich CO_2 stream.

Reboiler: The regenerator is connected with a reboiler which is basically a heat exchanger where low-pressure steam extracted from the power plant is used to heat the loaded sorbent

Steam Extractor: In case of coal-fired power plants that generate electricity in a steam turbine, a part of the LP/IP steam has to be diverted to the reboiler for sorbent regeneration. Steam extractors are installed to take out steam from the steam turbines.

Sorbent Reclaimer: Presence of acid gas impurities (SO_2, SO_3, NO_2 and HCl) in the flue gas leads to formation of heat stable salts in the sorbent stream, which can not be dissociated even on application of heat. In order to avoid accumulation of these salts in the sorbent stream and to recover some of this lost MEA sorbent, a part of the sorbent stream is periodically distilled in this vessel. Addition of caustic helps in freeing of some of the MEA. The recovered MEA is taken back to the sorbent stream while the bottom sludge (reclaimer waste) is sent for proper disposal.

Sorbent Processing: The regenerated sorbent has to be further cooled down even after passing through the rich/lean cross heat exchanger using a cooler, so that the sorbent temperature is brought back to acceptable level (about 40 deg C). Also, in order to make up for the sorbent losses, a small quantity of fresh MEA sorbent has to be added to the sorbent stream. So, the sorbent processing area primarily consists of sorbent cooler, MEA storage tank, and a mixer. It also consists of an activated carbon bed filter that adsorbs impurities (degradation products of MEA) from the sorbent stream.

Drying and Compression Unit: The CO_2 product may have to be carried to very long distances via pipelines. Hence it is desirable that it does not contain any moisture in order to avoid corrosion in the pipelines. Also, it has to be compressed to very high pressures so that it gets liquefied and can overcome the pressure losses during the pipeline transport. The multi-stage compression unit with inter-stage cooling and drying yields a final CO_2 product at the specified pressure (about 2000 psig) that contains moisture and other impurities (e.g. N_2) at acceptable levels.

Auxiliary Natural Gas Boiler: The cost of the natural gas boiler is estimated on the basis of the steam flow rate generated from the auxiliary boiler.

Auxiliary Steam Turbine: The regeneration heat is provided in the form of low pressure (LP) steam extracted from the steam turbine (in case of coal-fired power plants and combined-cycle gas plants), through the reboiler (a heat exchanger). In case of simple cycle natural gas fired power plants, a heat recovery unit maybe required.

Process Facilities Capital: The process facilities capital is the total constructed cost of all on-site processing and generating units listed above, including all direct and indirect construction costs. All sales taxes and freight costs are included where applicable implicitly. This result is highlighted in yellow.

MEA Scrubber Plant Costs

Process Facilities Capital: (see definition above)

General Facilities Capital: The general facilities include construction costs of roads, office buildings, shops, laboratories, etc. Sales taxes and freight costs are included implicitly.

Eng. & Home Office Fees: The engineering & home office fees are a percent of total direct capital cost. This is an overhead fee paid to the architect/engineering company.

Project Contingency Cost: Capital cost contingency factor covering the cost of additional equipment or other costs that would result from a more detailed design of a definitive project at the actual site.

Process Contingency Cost: Capital cost contingency factor applied to a new technology in an effort to quantify the uncertainty in the technical performance and cost of the commercial-scale equipment.

Interest Charges (AFUDC): Allowance for funds used during construction, also referred to as interest during construction, is the time value of the money used during construction and is based on an interest rate equal to the before-tax weighted cost of capital. This interest is compounded on an annual basis (end of year) during the construction period for all funds spent during the year or previous years.

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

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.

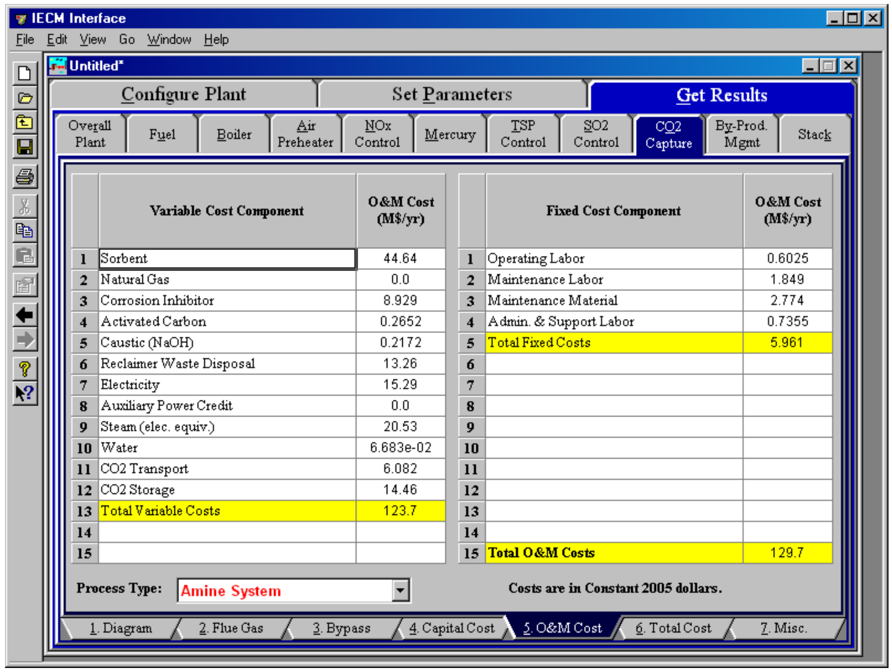
Inventory (Working) Capital: The raw material supply based on 100% capacity during a 60 day period. These materials are considered storage. The inventory capital includes fuels, consumables, by-products, and spare parts.

Total Capital Requirement (TCR): Money that is placed (capitalized) on the books of the utility on the service date. TCR includes all the items above. This result is highlighted in yellow.

Effective TCR: The TCR of the spray dryer that is used in determining the total power plant cost. The effective TCR is determined by the “TCR Recovery Factor”.

Amine System O&M Cost Results

This screen is only available for the **Combustion (Boiler)** and **Combustion (Turbine)** plant types.



Amine System – O&M Cost result screen.

The **O&M Cost** result screen displays tables for the variable and fixed operation and maintenance costs involved with the **CO_2 Capture** technology. O&M costs are typically expressed on an average annual basis and are provided in either constant or current dollars for a specified year, as shown on the bottom of the screen. Each result is described briefly below:

Variable Cost Components

Variable operating costs and consumables are directly proportional to the amount of kilowatts produced and are referred to as incremental costs. All the costs are subject to inflation.

Sorbent: MEA is the default sorbent used in the system and this is the annual cost of the MEA. This is a function of the concentration of CO2 in the flue gas and the flue gas flow rate.

Natural Gas: If the user has added an auxiliary natural gas boiler, the cost of the natural gas used to fuel the boiler is added here.

Corrosion Inhibitor: The inhibitor helps in two ways – reduced sorbent degradation and reduced equipment corrosion. This is the annual cost of the corrosion inhibitor.

Activated Carbon: This is the cost of activated carbon used to adsorb impurities from the sorbent (degradation products of MEA).

Caustic (NaOH): This is the annual cost of caustic. The presence of acid gas impurities (SO_2, SO_3, NO_2 and HCl) in the flue gas leads to formation of heat stable salts in the sorbent stream, which can not be dissociated even on application of heat. In order to avoid accumulation of these salts in the sorbent stream and to recover some of this lost MEA sorbent, a part of the sorbent stream is periodically distilled in this vessel. Addition of caustic helps in freeing of some of the MEA. The recovered MEA is taken back to the sorbent stream while the bottom sludge (reclaimer waste) is sent for proper disposal.

Reclaimer Waste Disposal: This is the reclaimer waste disposal cost per year.

Electricity: The cost of electricity consumed by the Amine System.

Auxiliary Power Credit: An auxiliary natural gas boiler can be added by the user to provide steam and power for the Amine System. If it is added by the user then the additional power it provides is subtracted from the overall operating and maintenance cost.

Steam (elec. equiv.): Cost of steam used in the regeneration of the sorbent. This is a cost that is incurred only when steam is taken from the base plant.

Water: This is the annual cost for water to the amine scrubber system; it is mainly required for cooling and also as process makeup.

CO_2 Transport: The CO_2 captured at the power plant site has to be carried to the appropriate storage/ disposal site. Transport of CO_2 to a storage site is assumed to be via pipeline. This is the annual cost of maintaining those pipelines.

CO_2 Storage: Once the CO_2 is captured, it needs to be securely stored (sequestered). This cost is based upon the storage option chosen on the Amine System – Storage input screen.

Total Variable Costs: This is the sum of the variable O&M costs listed above. This result is highlighted in yellow.

Fixed Cost Components

Fixed operating costs are essentially independent of actual capacity factor, number of hours of operation, or amount of kilowatts produced. All the costs are subject to inflation.

Operating Labor: Operating labor cost is based on the operating labor rate, the number of personnel required to operate the plant per eight-hour shift, and the average number of shifts per day over 40 hours per week and 52 weeks.

Maintenance Labor: The maintenance labor is determined as a fraction of the total maintenance cost.

Maintenance Material: The cost of maintenance material is the remainder of the total maintenance cost, considering the fraction associated with maintenance labor.

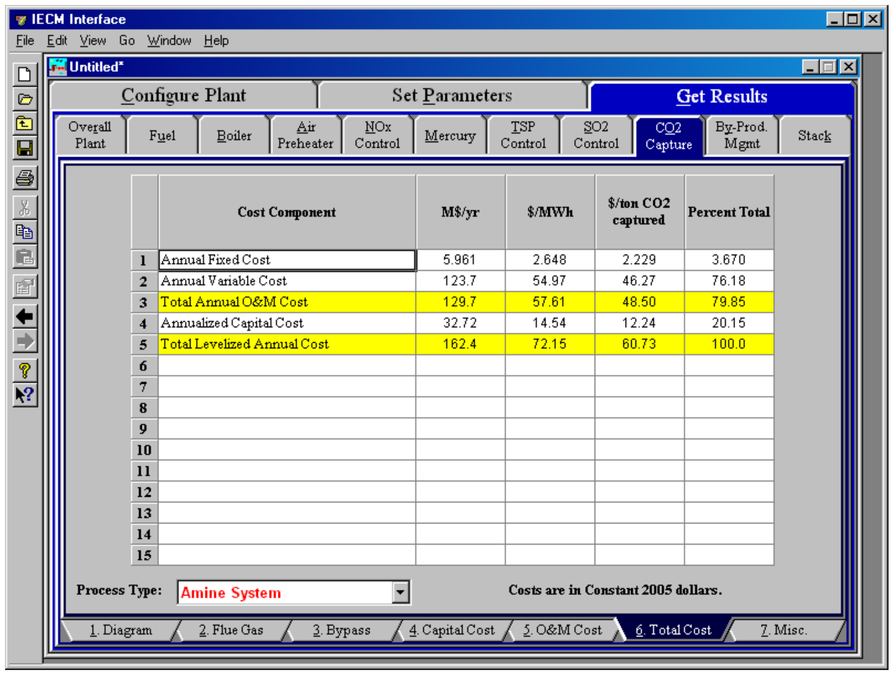
Admin. & Support Labor: The administrative and support labor is the only overhead charge. It is taken as a fraction of the total operating and maintenance labor costs.

Total Fixed Costs: This is the sum of all the fixed O&M costs listed above. This result is highlighted in yellow.

Total O&M Costs: This is the sum of the total variable and total fixed O&M costs. It is used to determine the base plant total revenue requirement. This result is highlighted in yellow.

Amine System Total Cost Results

This screen is only available for the **Combustion (Boiler)** and **Combustion (Turbine)** plant types.



Amine System – Total Cost result screen.

The **Total Cost** result screen displays a table which totals the annual fixed, variable, operations and maintenance, and capital costs associated with the **Amine System CO_2 Control** technology. Total costs are typically expressed in either constant or current dollars for a specified year, as shown on the bottom of the screen. Each result is described briefly below.

Cost Component

Annual Fixed Cost: The operating and maintenance fixed costs are given as an annual total. This number includes all maintenance materials and all labor costs.

Annual Variable Cost: The operating and maintenance variables costs are given as an annual total. This includes all reagent, chemical, steam, and power costs.

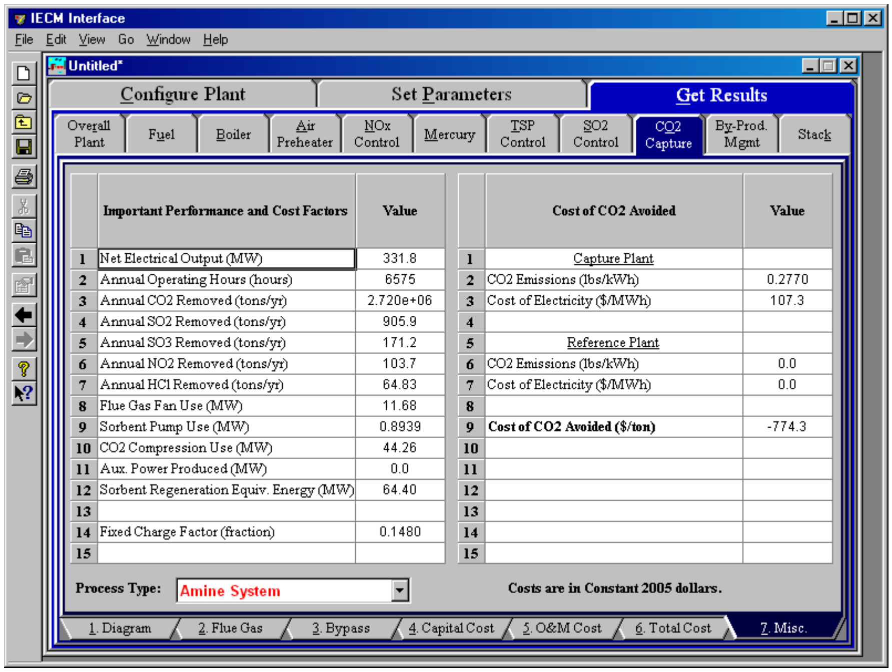
Total Annual O&M Cost: This is the sum of the annual fixed and variable operating and maintenance costs above. This result is highlighted in yellow.

Annualized Capital Cost: This is the total capital cost expressed on an annualized basis, taking into consideration the levelized carrying charge factor, or fixed charge factor, over the entire book life.

Total Levelized Annual Cost: The total annual cost is the sum of the total annual O&M cost and annualized capital cost items above. This result is highlighted in yellow.

Amine System Cost Factors Results

This screen is only available for the Combustion (Boiler) and Combustion (Turbine) plant types.



Amine System – Cost Factors result screen.

Important Performance and Cost Factors

This screen displays information that is key to the model calculations. The data is available else where in the model.

Net Plant Size (MW): This is the net plant capacity, which is the gross plant capacity minus the losses due to plant equipment and pollution equipment (energy penalties).

Annual Operating Hours (hours): This is the number of hours per year that the plant is in operation. If a plant runs 24 hours per day, seven days per week, with no outages, the calculation is 24 hours * 365 days. or 8,760 hours/year.

Annual CO_2 Removed (ton/yr): This is thel amount of CO_2 removed from the flue gas by the CO_2 capture system per year.

Annual SO_2 Removed (ton/yr): This is the amount of SO_2 removed from the flue gas by the CO_2 capture system per year.

Annual SO_3 Removed (ton/yr): This is the amount of SO_3 removed from the flue gas by the CO_2 capture system per year.

Annual NO_2 Removed (ton/yr): This is the amount of NO_2 removed from the flue gas by the CO_2 capture system per year.

Annual HCl Removed (ton/yr): This is the amount of HCl removed from the flue gas by the CO_2 capture system per year.

Flue Gas Fan Use (MW): The flue gas has to be compressed in a flue gas blower so that it can overcome the pressure drop in the absorber tower. This is the electrical power required by the blower.

Sorbent Pump Use (MW): The solvent has to flow through the absorber column (generally through packed media) countercurrent to the flue gas flowing upwards. This is the power required by the solvent circulation pumps to supply pressure to overcome the pressure losses encountered by the solvent in the absorber column.

CO_2 Compression Use (MW): This is the electrical power required to compress the CO_2 product stream to the designated pressure. Compression of CO_2 to high pressures takes lot of power, and is a principle contributor to the overall energy penalty of a CO_2 capture unit in a power plant.

Aux. Power Produced (MW): If an auxiliary natural gas boiler is used to provide steam and power for the Amine System, this is the additional electricity that it produces.

Sorbent Regeneration Equiv. Power (MW): This is the electrical equivalent power for the regeneration steam required (taken from the steam cycle). The equivalent electricity penalty is about 10-15% of the actual regeneration heat requirement.

Fixed Charge Factor (fraction): The fixed charge factor is one of the most important parameters in the IECM. 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.

Cost of CO_2 Avoided

Many analysts like to express the cost of an environmental control system in terms of the cost per ton of pollutant removed or avoided. For energy-intensive CO_2 controls there is a big difference between the cost per ton CO_2 removed and the cost per ton "avoided" based on *net* plant capacity. Since the purpose of adding a CO_2 unit is to reduce the CO_2 emissions per net kWh delivered, the cost of CO_2 avoidance is the economic indicator that is widely used in this field.

Capture Plant

- **CO2 Emissions (lb/kWh):** This is the amount of CO2 vented to the air for every kilowatt hour of electricity produced in the power plant that is using **CO2 Capture Technology**.
- **Cost of Electricity ($/MWh):**The IECM framework calculates the cost of electricity (COE) for the overall **Capture Plant** by dividing the total annualized plant cost ($/yr) by the net electricity generated (kWh/yr)

Reference Plant

- **CO2 Emissions (lb/kWh):** This is the amount of CO2 vented to the air for every kilowatt hour of electricity produced in the power plant with **NO CO2 Capture**.
- **Cost of Electricity ($/MWh):**The IECM framework calculates the cost of electricity (COE) for the overall **Reference Plant** by dividing the total annualized plant cost ($/yr) by the net electricity generated (kWh/yr)
- **Cost of CO_2 Avoided ($/ton):** This is the economic indicator widely used in the field, calculated as the difference between the cost of electricity in the capture plant and the reference plant divided by the difference between the CO2 emissions in the reference plant and the capture plant.
  Cost of CO2 Avoided =
  (Cost of Electricity cap. – Cost of Electricity ref.)
  / (CO2 emissions ref. – CO2 emissions cap.)

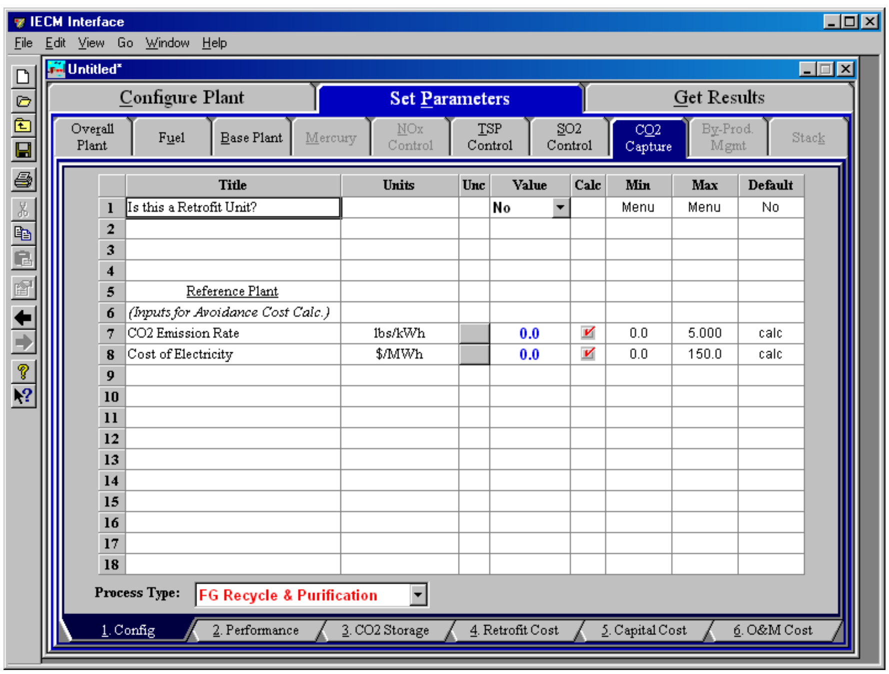
O_2-CO_2 Recycle

The **O_2-CO_2 Recycle** is a post-combustion technology used for CO_2 capture. It is more frequently referred to as “oxyfuel” combustion. Two systems are associated with this technology, **Air Separation** and **Flue Gas Recycle**. The following sections describe the performance and result screens for each of these systems. The **O_2-CO_2 Recycle** option is available in the IECM in the Combustion (Boiler) plant type configuration.

Please refer to the air separation chapter for help with the oxidant feed input parameters and results.

O_2-CO_2 Recycle Configuration

This screen is available for Combustion (Boiler) plant types.



O_2-CO_2 Recycle Flue Gas – Configuration input screen.

Is this a Retrofit Unit? The user may decide whether the unit is added to a new or existing plant.

Reference Plant

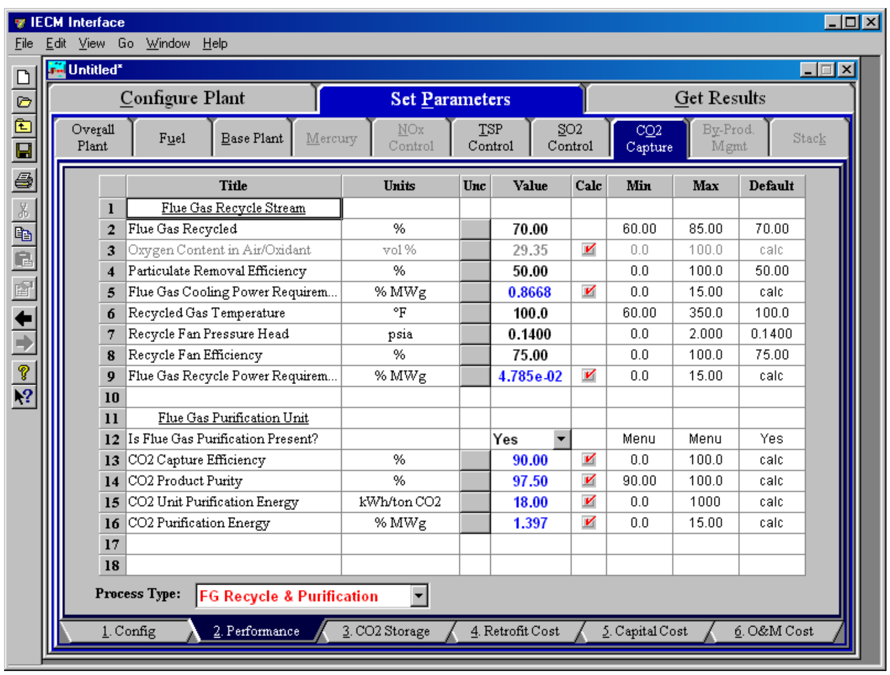
The following reference plant inputs are used to determine the avoided cost of CO_2 avoidance. The default value is zero for both parameters, requiring the user to supply the actual reference plant values. Reference values can be obtained by simulating the same plant configuration minus the CO_2 capture. Analysts commonly express the cost of an environmental control system in terms of either the cost per ton of pollutant removed or the cost per ton “avoided.” For an energy-intensive system like amine scrubbers there is a big difference between the cost per ton CO_2 removed and the cost per ton CO_2 avoided based on *net* plant capacity. Since the purpose of adding a capture unit is to reduce the CO_2 emissions per net kWh delivered, the cost of CO_2 avoidance (relative to a reference plant with no CO_2 control) is the economic indicator most widely used. The reference plant used to compare to the actual plant must be defined as follows:

CO_2 Emission Rate: This is the emission rate for the reference power plant (without CO_2 capture)

Cost of Electricity: This is the cost of electricity for the reference power plant (without CO_2 capture)

O_2-CO_2 Recycle Performance Inputs

This screen is available for Combustion (Boiler) plant types.



O_2-CO_2 Recycle Flue Gas – Performance input screen.

Flue Gas Recycle Stream

Flue Gas Recycled: This is the percentage of the total flue gas that is to be recycled

Oxygen Content in Air/Oxidant: This is the volume percent that is oxygen.

Particulate Removal Efficiency: This is the percentage of particulates that are removed by the **Flue Gas Recycle** system.

Flue Gas Cooling Power Requirement: This is the percentage of the total gross power of the plant required to cool the flue gas being recycled.

Recycled Gas Temperature: This is the temperature of the recycled flue gas.

Recycle Fan Pressure Head: A fan is used to provide a small pressure head for the recycled flue gas stream going back to the boiler. This FGR fan pressure head along with the recycled flue gas flow rate, determine the power used by the fan.

Recycle Fan Efficiency: This is the efficiency of the fan converting electrical power input into mechanical work output.

Flue Gas Recycle Power Requirement: This is the percentage of the total gross power of the plant required to recycle the flue gas.

Flue Gas Purification Unit

Is Flue Gas Purification Present?: The user may add a flue gas purification system.

CO_2 Capture Efficiency: This is the percentage of the CO_2 which the system is able to capture.

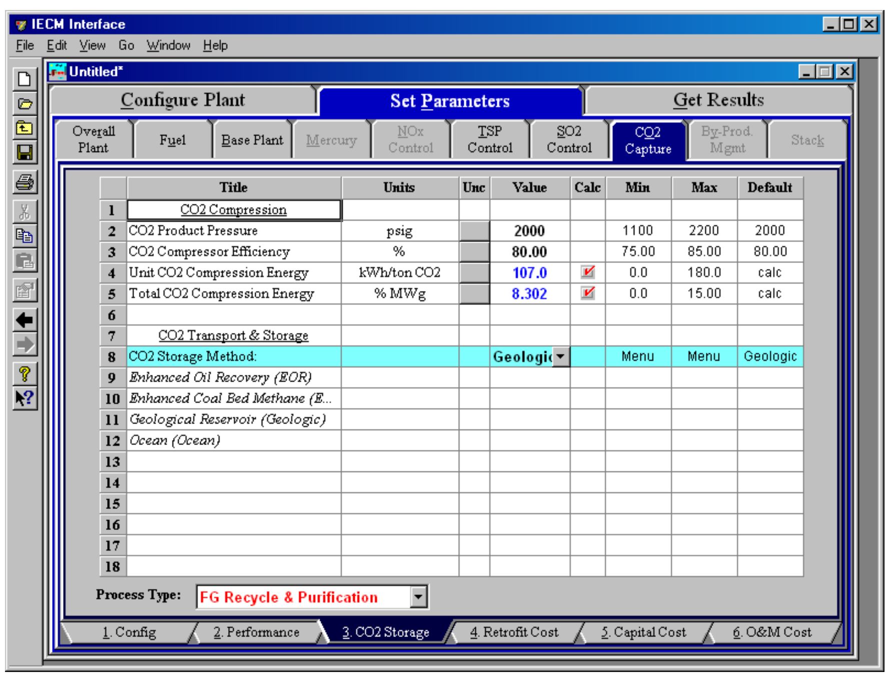
CO_2 Product Purity: This is the percentage of the product that is carbon dioxide.

CO_2 Unit Purification Energy: This is the energy required for one unit to purify the CO_2 product per ton purified.

CO_2 Purification Energy: This is the total energy required to purify the CO_2 product.

O_2-CO_2 Recycle CO_2 Storage Inputs

This screen is available for Combustion (Boiler) plant types.



O_2-CO_2 Recycle Flue Gas – CO_2 storage input screen.

CO2 Compression

The concentrated CO_2 product stream obtained from sorbent regeneration is compressed and dried using a multi-stage compressor with inter-stage cooling.

CO_2 Product Pressure: The CO_2 product may have to be carried over long distances. Hence it is necessary to compress (and liquefy) it to very high pressures, so that it maybe delivered to the required destination in liquid form and (as far as possible) without recompression facilities en route. The critical pressure for CO_2 is about 1070 psig. The typically reported value of final pressure to which the product CO_2 stream has to be pressurized using compressors, before it is transported is about 2000 psig.

CO_2 Compressor Efficiency: This is the effective efficiency of the compressors used to compress CO_2 to the desirable pressure.

Unit CO_2 Compression Energy: This is the electrical energy required to compress a unit mass of CO_2 product stream to the designated pressure. Compression of CO_2 to high pressures requires substantial energy, and is a principle contributor to the overall energy penalty of a CO_2 capture unit in a power plant.

Total CO_2 Compression Energy: This is the electrical energy required to compress the CO_2 product stream to the designated pressure, given as a percent of the total gross power generated by the power plant. Compression of CO_2 to high pressures requires substantial energy, and is a principle contributor to the overall energy penalty of a CO_2 capture unit in a power plant.

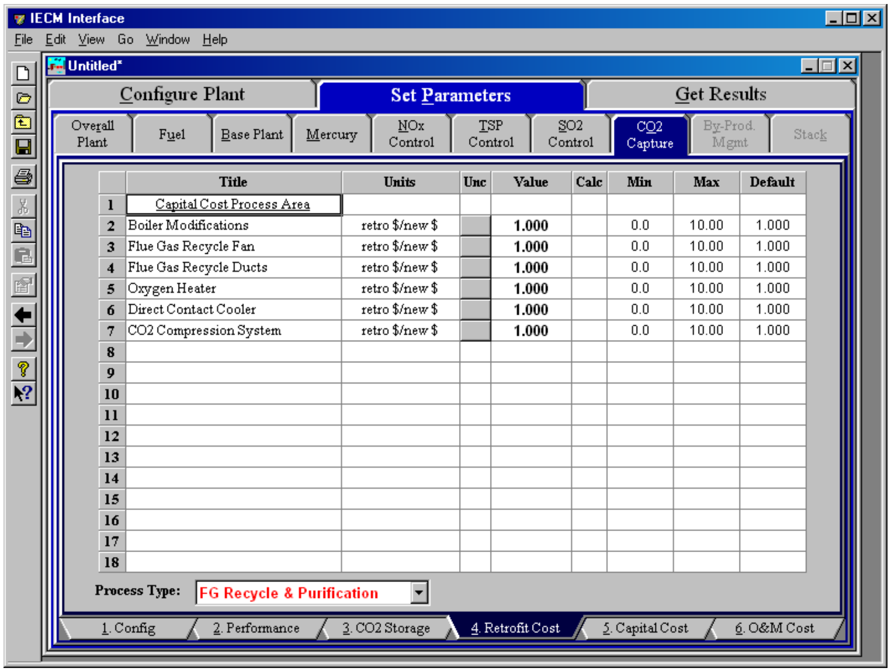
CO2 Transport & Storage

CO_2 Storage Method: The following are the optional methods for CO_2 disposal. The default option for CO_2 disposal is underground geological storage.

- **Enhanced Oil Recovery (EOR)**
- **Enhanced Coal Bed Methane (ECBM)**
- **Geological Reservoir (Geologic)**
- **Ocean (Ocean)**

O_2-CO_2 Recycle Retrofit Cost Inputs

This screen is available for Combustion (Boiler) plant types.



O_2-CO_2 Recycle Flue Gas – Retrofit cost input screen.

Capital Cost Process Area

The retrofit cost factor of each process is a multiplicative cost adjustment, which considers the cost of retrofitted capital equipment relative to similar equipment installed in a new plant. These factors affect the capital costs directly and the operating and maintenance costs indirectly.

Direct capital costs for each process area are calculated in the IECM. These calculations are reduced form equations derived from more sophisticated models and reports. The sum of the direct capital costs associated with each process area is defined as the process facilities capital (PFC). The retrofit cost factor provided for each of the process areas can be used as a tool for adjusting the anticipated costs and uncertainties across the process area separate from the other areas.

Uncertainty can be applied to the retrofit cost factor for each process area in each technology. Thus, uncertainty can be applied as a general factor across an entire process area, rather than as a specific uncertainty for the particular cost on the capital or O&M input screens. Any uncertainty applied to a process area through the retrofit cost factor compounds any uncertainties specified later in the capital and O&M cost input parameter screens.

The following are the **Capital Cost Process Areas** for the **Flue Gas Recycle** portion of the plant:

Boiler Modifications: In case of a *pre-existing* PC plant being retrofitted for CO_2 capture, the boiler must be modified to suit the new oxyfuel combustion system. The cost for these modifications is estimated as a percentage of the cost of the boiler

Flue Gas Recycle Fan: The cost of the fan required for recycling part of the flue gas is scaled on the basis of the flow rate of the flue gas being recycled

Flue Gas Recycle Ducts: Additional ducting is necessary to recycle part of the flue gas in the oxyfuel combustion system. The cost of this ducting is assumed to be a function of the flow rate of recycled flue gas.

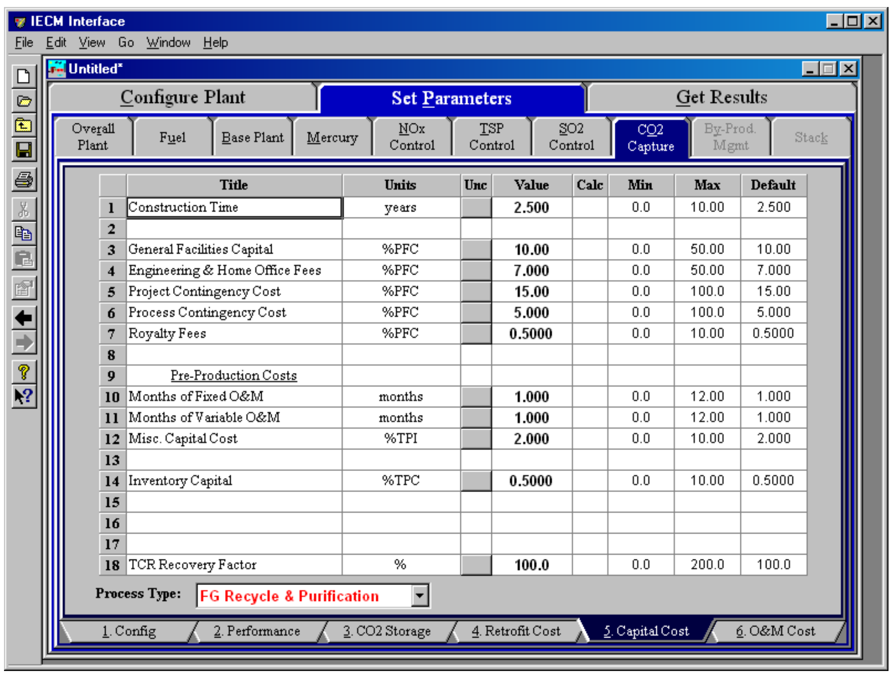
Oxygen Heater: In addition to the air preheater that exists in a conventional PC plant, the oxyfuel combustion system includes an additional heat exchanger called the “oxygen heater” for better heat integration. The cost of this heat exchanger is scaled on the basis of the gross plant size

Direct Contact Cooler: The cost of the flue gas cooler is scaled on the basis of the flow rate of the flue gas.

CO_2 Compression System: The multi-stage compression unit with inter-stage cooling and drying yields the final CO_2 product at the specified pressure (about 2000 psig) that contains only acceptable levels of moisture and other impurities (e.g. N_2) The size (and cost) of this unit will be a function of the CO_2 product compression power.

O_2-CO_2 Recycle Capital Cost Inputs

This screen is available for Combustion (Boiler) plant types.



O_2-CO_2 Recycle Flue Gas – Capital cost input screen.

Inputs for capital costs are entered on the **Capital Cost** input screen.

Construction Time: This is the idealized construction period in years. It is used to determine the allowance for funds used during construction (AFUDC).

General Facilities Capital (GFC): 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%.

Engineering & Home Office Fees: The engineering & home office fees are a percent of total direct capital cost. This is an overhead fee paid to the architect/engineering company. These fees typically range from 7-15%.

Project Contingency Cost: This is 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.

Process Contingency Cost: 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.

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

Pre-Production Costs: 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 applied to the O&M costs over a specified period of time (months). The two time periods for fixed and variable O&M costs are described below with the addition of a miscellaneous capital cost factor.

Months of Fixed O&M: Time period of fixed operating costs used for preproduction to cover training, testing, major changes in equipment, and inefficiencies in start-up. This includes operating, maintenance, administrative and support labor. It also considers maintenance materials.

Months of Variable O&M: Time period of variable operating costs used for preproduction to cover chemicals, water, consumables, and solid disposal charges in start-up, assuming 100% load. This excludes any fuels.

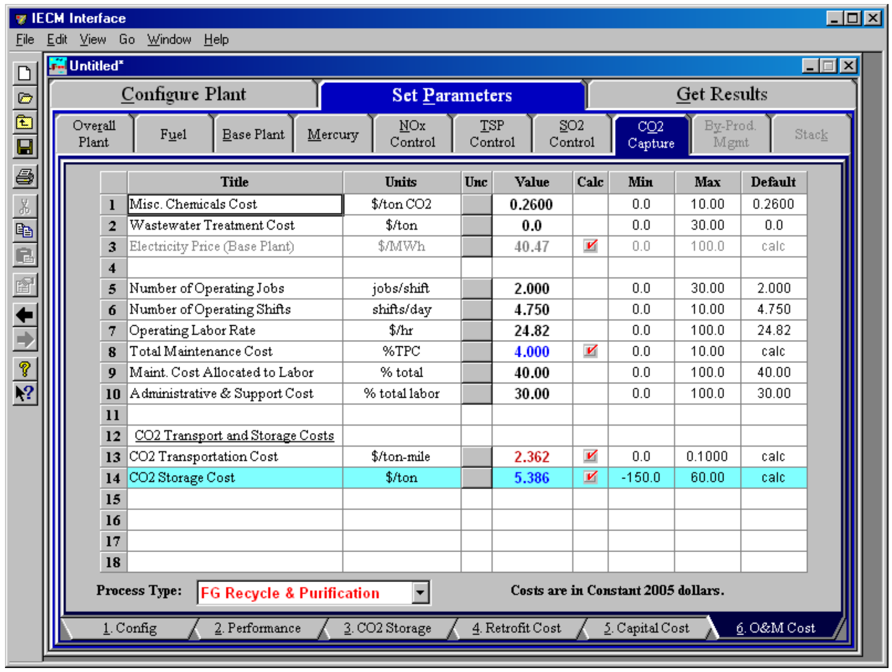
Misc. Capital Cost: This is a percent of total plant investment (sum of TPC and AFUDC) to cover expected changes to equipment to bring the system up to full capacity.

Inventory Capital: Percent of the total direct capital for raw material supply based on 100% capacity during a 60 day period. These materials are considered storage. The inventory capital includes fuels, consumables, by-products, and spare parts. This is typically 0.5%.

TCR Recovery Factor: The actual total capital required (TCR) as a percent of the TCR in a new power plant. This value is 100% for a new installation and may be set as low as 0% for a fabric filter that has been paid off.

O_2-CO_2 Recycle O&M Cost Inputs

This screen is available for Combustion (Boiler) plant types.



O_2-CO_2 Recycle Flue Gas – O&M cost input screen

Inputs for operation and maintenance are entered on the **O&M Cost** input. O&M costs are typically expressed on an average annual basis and are provided in either constant or current dollars for a specified year, as shown on the bottom of the screen. Each parameter is described briefly below

Misc. Chemicals Cost: This is the annual cost of chemicals that are used in the **Flue Gas Recycle** area of the plant. The cost is reported in dollars per ton of CO2 captured.

Wastewater Treatment Cost: This is the annual cost of treating the wastewater that is used in the **Flue Gas Recycle** area of the plant. The cost is reported in dollars per ton.

Electricity Price (Base Plant): This is the price of electricity and is calculated as a function of the utility cost of the base plant, where the base plant is a combustion boiler and an air preheater.

Number of Operating Jobs: This is the total number of operating jobs that are required to operate the plant per eight-hour shift.

Number of Operating Shifts: This is the total number of equivalent operating shifts in the plant per day. The number takes into consideration paid time off and weekend work (3 shifts/day * 7 days/5 day week * 52 weeks/(52 weeks - 6 weeks PTO) = 4.75 equiv. Shifts/day)

Operating Labor Rate: The number of dollars paid per hour to an operator for one hour of work.

Total Maintenance Cost: This is the annual maintenance cost as a percentage of the total plant cost. Maintenance cost estimates can be developed separately for each process area.

Maint. Cost Allocated to Labor: Maintenance cost allocated to labor as a percentage of the total maintenance cost.

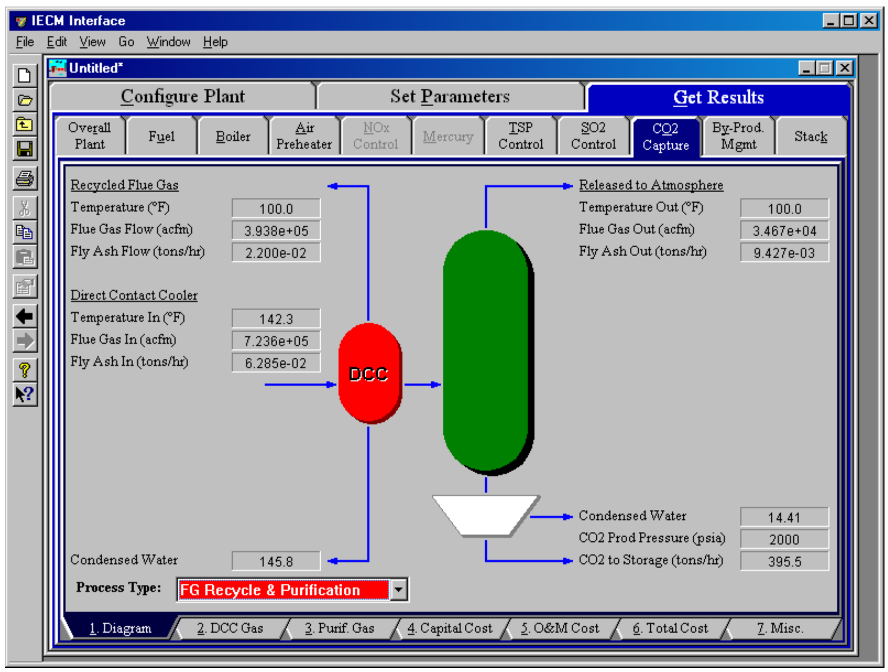
Administrative & Support Cost: This is the percent of the total operating and maintenance labor associated with administrative and support labor.

CO_2 Transport and Storage Costs

- **CO_2 Transportation Cost:** Transportation of CO_2 product is assumed to take place via pipelines. This is the unit cost of CO_2 transport in $/ton –mile.
- **CO_2 Storage Cost:** This is the unit cost of CO_2 disposal. Depending upon the method of CO_2 disposal or storage, either there may be some revenue generated (Enhanced Oil Recovery, Coal Bed Methane) which may be treated as a "negative cost", or additional cost (all other disposal methods).

O_2-CO_2 Recycle Diagram

This screen is available for Combustion (Boiler) plant types.



O_2-CO_2 Recycle Flue Gas – Diagram.

Recycled Flue Gas

Temperature: The temperature of the **Recycled Flue Gas** from the direct contact cooler.

Flue Gas Flow: The mass flow rate of the **Recycled Flue Gas** from the direct contact cooler.

Fly Ash Flow: The mass flow rate of fly ash in the **Recycled Flue Gas** from the direct contact cooler.

Direct Contact Cooler

Temperature In: The temperature of the flue gas, to be recycled, entering the direct contact cooler.

Flue Gas In: The mass flow rate of the flue gas, to be recycled, entering the direct contact cooler.

Fly Ash In: The mass flow rate of fly ash in to the direct contact cooler.

Condensed Water: The mass flow rate of condensed water leaving the direct contact cooler.

Released to Atmosphere

Temperature Out: The temperature of the flue gas being released to the atmosphere.

Flue Gas Out: The mass flow rate of the flue gas being released to the atmosphere.

Fly Ash Out: The mass flow rate of the fly ash being released to the atmosphere.

Other

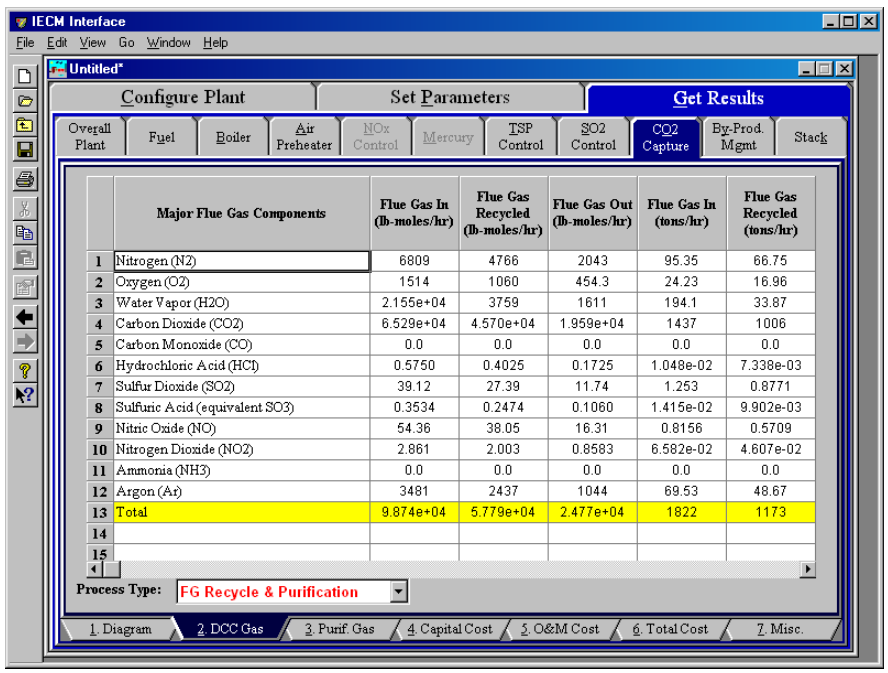
Condensed Water: The mass flow rate of condensed water.

CO_2 Product Pressure: This is the target pressure of product CO_2 being sent to storage.

CO_2 to Storage: The mass flow rate of CO_2 being sent to storage.

O_2-CO_2 Recycle DCC Gas Results

This screen is available for Combustion (Boiler) plant types.



O_2-CO_2 Recycle Flue Gas – DCC Gas result screen.

Major Flue Gas Components

Each result is described briefly below:

Nitrogen (N_2): Total mass of nitrogen.

Oxygen (O_2): Total mass of oxygen.

Water Vapor (H_2O): Total mass of water vapor.

Carbon Dioxide (CO_2): Total mass of carbon dioxide.

Carbon Monoxide (CO): Total mass of carbon monoxide.

Hydrochloric Acid (HCl): Total mass of hydrochloric acid.

Sulfur Dioxide (SO_2): Total mass of sulfur dioxide.

Sulfuric Acid (equivalent SO_3): Total mass of sulfuric acid.

Nitric Oxide (NO): Total mass of nitric oxide.

Nitrogen Dioxide (NO_2): Total mass of nitrogen dioxide.

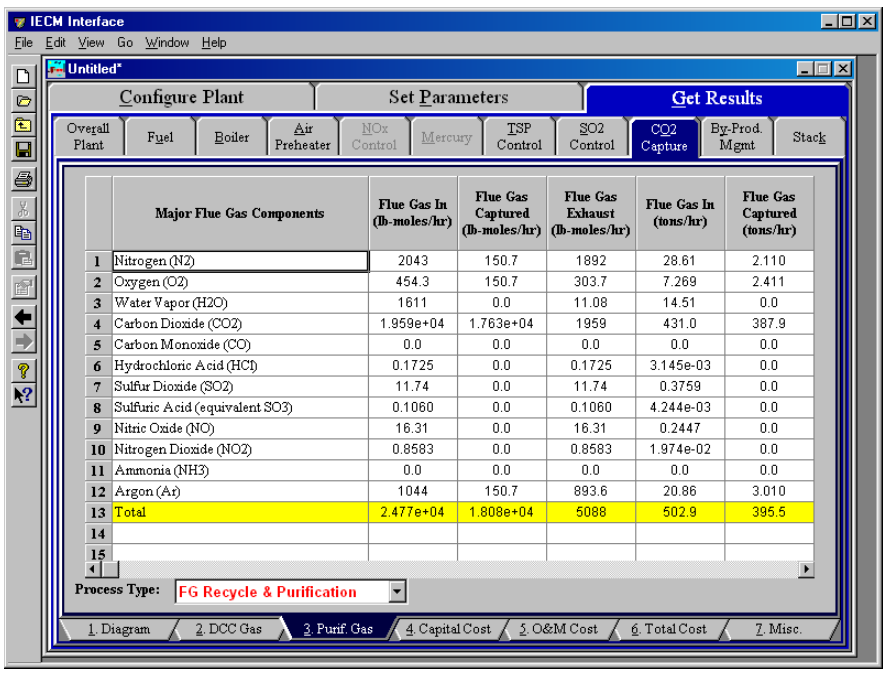
Ammonia (NH_3): Total mass of ammonia.

Argon (Ar): Total mass of argon.

Total: Total of the individual components listed above. This item is highlighted in yellow.

O_2-CO_2 Recycle Purification Gas Results

This screen is available for Combustion (Boiler) plant types.



	Major Flue Gas Components	Flue Gas In (lb-moles/hr)	Flue Gas Captured (lb-moles/hr)	Flue Gas Exhaust (lb-moles/hr)	Flue Gas In (tons/hr)	Flue Gas Captured (tons/hr)
1	Nitrogen (N2)	2043	150.7	1892	28.61	2.110
2	Oxygen (O2)	454.3	150.7	303.7	7.269	2.411
3	Water Vapor (H2O)	1611	0.0	11.08	14.51	0.0
4	Carbon Dioxide (CO2)	1.959e+04	1.763e+04	1959	431.0	387.9
5	Carbon Monoxide (CO)	0.0	0.0	0.0	0.0	0.0
6	Hydrochloric Acid (HCl)	0.1725	0.0	0.1725	3.145e-03	0.0
7	Sulfur Dioxide (SO2)	11.74	0.0	11.74	0.3759	0.0
8	Sulfuric Acid (equivalent SO3)	0.1060	0.0	0.1060	4.244e-03	0.0
9	Nitric Oxide (NO)	16.31	0.0	16.31	0.2447	0.0
10	Nitrogen Dioxide (NO2)	0.8583	0.0	0.8583	1.974e-02	0.0
11	Ammonia (NH3)	0.0	0.0	0.0	0.0	0.0
12	Argon (Ar)	1044	150.7	893.6	20.86	3.010
13	Total	2.477e+04	1.808e+04	5088	502.9	395.5
14						
15						

O_2-CO_2 Recycle Flue Gas – Purif. gas result screen.

Major Flue Gas Components

Each result is described briefly below:

Nitrogen (N_2): Total mass of nitrogen.

Oxygen (O_2): Total mass of oxygen.

Water Vapor (H_2O): Total mass of water vapor.

Carbon Dioxide (CO_2): Total mass of carbon dioxide.

Carbon Monoxide (CO): Total mass of carbon monoxide.

Hydrochloric Acid (HCl): Total mass of hydrochloric acid.

Sulfur Dioxide (SO_2): Total mass of sulfur dioxide.

Sulfuric Acid (equivalent SO_3): Total mass of sulfuric acid.

Nitric Oxide (NO): Total mass of nitric oxide.

Nitrogen Dioxide (NO_2): Total mass of nitrogen dioxide.

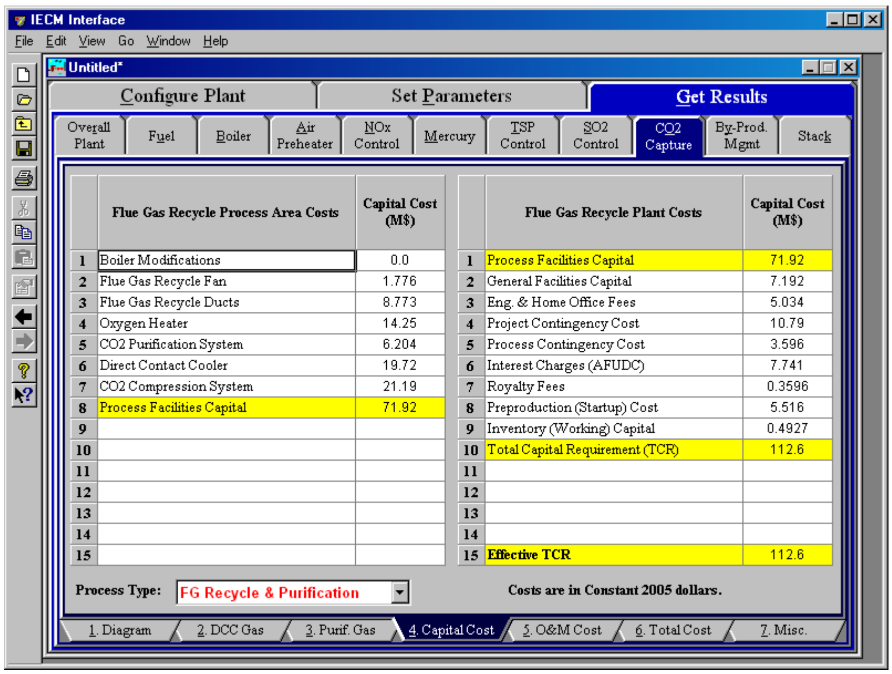
Ammonia (NH_3): Total mass of ammonia.

Argon (Ar): Total mass of argon.

Total: Total of the individual components listed above. This item is highlighted in yellow.

O_2-CO_2 Recycle Capital Cost Results

This screen is available for Combustion (Boiler) plant types.



O_2-CO_2 Recycle Flue Gas – Capital cost result screen.

The **Capital Cost** result screen displays tables for the capital costs. Capital costs are typically expressed in either constant or current dollars for a specified year, as shown on the bottom of the screen. Each result is described briefly below:

Flue Gas Recycle Process Area Costs

Boiler Modifications: In case of a *pre-existing* PC plant being retrofitted for CO_2 capture, the boiler must be modified to suit the new oxyfuel combustion system. The cost for these modifications is estimated as a percentage of the cost of the boiler

Flue Gas Recycle Fan: The cost of the fan required for recycling part of the flue gas is scaled on the basis of the flow rate of the flue gas being recycled

Flue Gas Recycle Ducts: Additional ducting is necessary to recycle part of the flue gas in the oxyfuel combustion system. The cost of this ducting is assumed to be a function of the flow rate of recycled flue gas.

Oxygen Heater: In addition to the air preheater that exists in a conventional PC plant, the oxyfuel combustion system includes an additional heat exchanger called the "oxygen heater" for better heat integration. The cost of this heat exchanger is scaled on the basis of the gross plant size

CO_2 Purification System: The cost of the CO_2 purification system depends on the desired purity level of the CO_2 product, and the total CO_2 product flow rate.

Direct Contact Cooler: The cost of the flue gas cooler is scaled on the basis of the flow rate of the flue gas.

CO_2 Compression System: The multi-stage compression unit with inter-stage cooling and drying yields the final CO_2 product at the specified pressure (about 2000 psig) that contains only acceptable levels of moisture and other impurities (e.g. N_2) The size (and cost) of this unit will be a function of the CO_2 product compression power.

Process Facilities Capital: The process facilities capital is the total constructed cost of all on-site processing and generating units listed above, including all direct and indirect construction costs. All sales taxes and freight costs are included where applicable implicitly. This result is highlighted in yellow.

Flue Gas Recycle Plant Costs

Process Facilities Capital: The process facilities capital is the total constructed cost of all on-site processing and generating units listed above, including all direct and indirect construction costs. All sales taxes and freight costs are included where applicable implicitly. This result is highlighted in yellow.

General Facilities Capital: The general facilities include construction costs of roads, office buildings, shops, laboratories, etc. Sales taxes and freight costs are included implicitly.

Eng. & Home Office Fees: The engineering & home office fees are a percent of total direct capital cost. This is an overhead fee paid to the architect/engineering company.

Project Contingency Cost: Capital cost contingency factor covering the cost of additional equipment or other costs that would result from a more detailed design of a definitive project at the actual site.

Process Contingency Cost: Capital cost contingency factor applied to a new technology in an effort to quantify the uncertainty in the technical performance and cost of the commercial-scale equipment.

Interest Charges (AFUDC): Allowance for funds used during construction, also referred to as interest during construction, is the time value of the money used during construction and is based on an interest rate equal to the before-tax weighted cost of capital. This interest is compounded on an annual basis (end of year) during the construction period for all funds spent during the year or previous years.

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

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.

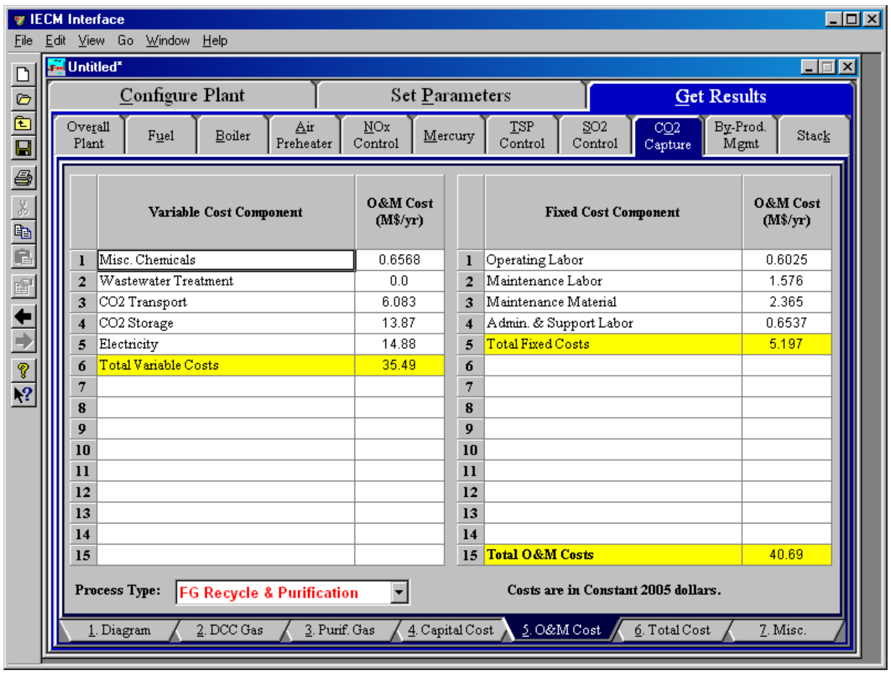
Inventory (Working) Capital: The raw material supply based on 100% capacity during a 60 day period. These materials are considered storage. The inventory capital includes fuels, consumables, by-products, and spare parts.

Total Capital Requirement (TCR): Money that is placed (capitalized) on the books of the utility on the service date. TCR includes all the items above. This result is highlighted in yellow.

Effective TCR: The TCR of the spray dryer that is used in determining the total power plant cost. The effective TCR is determined by the "TCR Recovery Factor".

O_2-CO_2 Recycle O&M Cost Results

This screen is available for Combustion (Boiler) plant types.



O_2-CO_2 Recycle Flue Gas – O&M cost result screen.

The **O&M Cost** result screen displays tables for the variable and fixed operation and maintenance costs involved with the **CO2 Capture** technology. O&M costs are typically expressed on an average annual basis and are provided in either constant or current dollars for a specified year, as shown on the bottom of the screen. Each result is described briefly below:

Variable Cost Components

Variable operating costs and consumables are directly proportional to the amount of kilowatts produced and are referred to as incremental costs. All the costs are subject to inflation.

Misc. Chemicals: A small quantity of chemicals is used in this process, including chemicals, desiccant and lubricants. The aggregate cost of these chemicals is estimated based on the flow rate of CO_2 captured

Wastewater Treatment: The user may enter a cost for treating the moisture condensed from the flue gas.

CO_2 Transport: The CO_2 captured at the power plant site has to be carried to the appropriate storage/ disposal site. Transport of CO_2 to a storage site is assumed to be via pipeline This is the annual cost of maintaining those pipelines.

CO_2 Storage: Once the CO_2 is captured, it needs to be securely stored (sequestered). This cost is based upon the storage option chosen on the O_2-CO_2 Recycle Flue Gas – CO_2 storage input screen.

Electricity: The cost of electricity consumed by the **Flue Gas Recycle** System.

Total Variable Costs: This is the sum of all the variable O&M costs listed above. This result is highlighted in yellow.

Fixed Cost Components

Fixed operating costs are essentially independent of actual capacity factor, number of hours of operation, or amount of kilowatts produced. All the costs are subject to inflation.

Operating Labor: Operating labor cost is based on the operating labor rate, the number of personnel required to operate the plant per eight-hour shift, and the average number of shifts per day over 40 hours per week and 52 weeks.

Maintenance Labor: The maintenance labor is determined as a fraction of the total maintenance cost.

Maintenance Material: The cost of maintenance material is the remainder of the total maintenance cost, considering the fraction associated with maintenance labor.

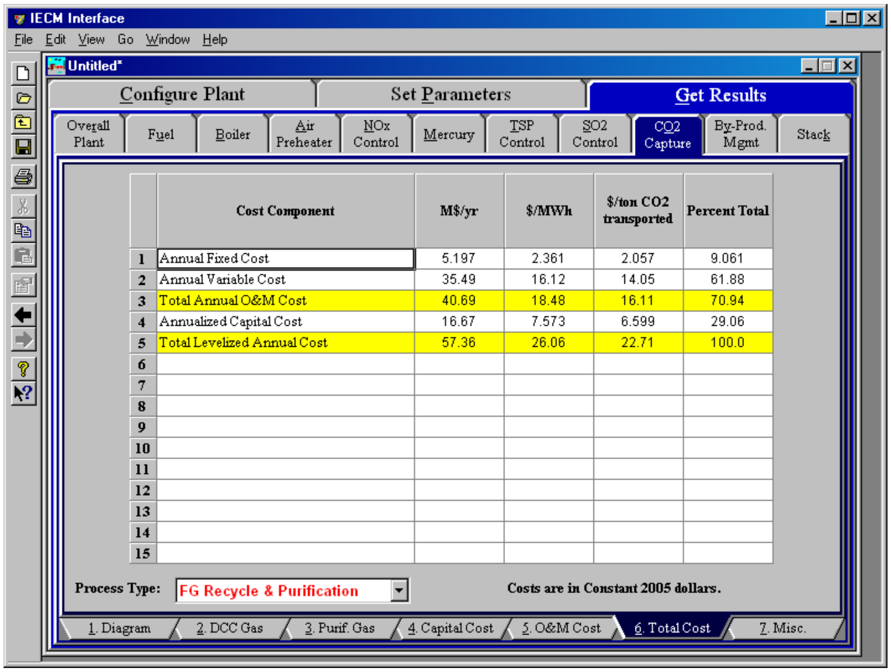
Admin. & Support Labor: The administrative and support labor is the only overhead charge. It is taken as a fraction of the total operating and maintenance labor costs.

Total Fixed Costs: This is the sum of all the fixed O&M costs listed above. This result is highlighted in yellow.

Total O&M Costs: This is the sum of the total variable and total fixed O&M costs. It is used to determine the base plant total revenue requirement. This result is highlighted in yellow.

O_2-CO_2 Recycle Total Cost Results

This screen is available for Combustion (Boiler) plant types.



O_2-CO_2 Recycle Flue Gas – Total cost result screen.

The **Total Cost** result screen displays a table which totals the annual fixed, variable, operations and maintenance, and capital costs associated with the **Flue Gas Recycle** portion of the **CO2 Control** technology. Total costs are typically expressed in either constant or current dollars for a specified year, as shown on the bottom of the screen. Each result is described briefly below.

Cost Component

Annual Fixed Cost: The operating and maintenance fixed costs are given as an annual total. This number includes all maintenance materials and all labor costs.

Annual Variable Cost: The operating and maintenance variables costs are given as an annual total. This includes all reagent, chemical, steam, and power costs.

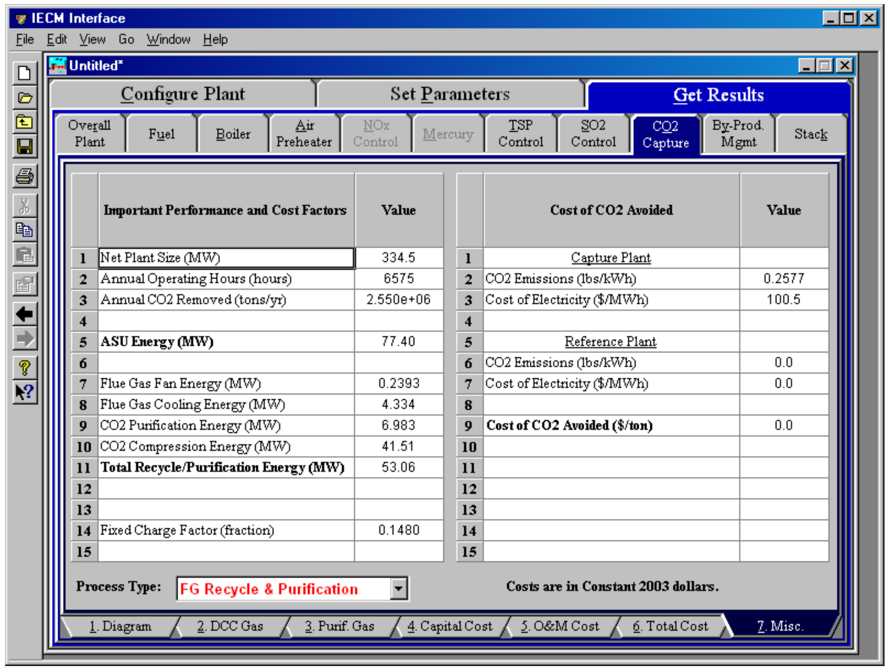
Total Annual O&M Cost: This is the sum of the annual fixed and variable operating and maintenance costs above. This result is highlighted in yellow.

Annualized Capital Cost: This is the total capital cost expressed on an annualized basis, taking into consideration the levelized carrying charge factor, or fixed charge factor, over the entire book life.

Total Levelized Annual Cost: The total annual cost is the sum of the total annual O&M cost and annualized capital cost items above. This result is highlighted in yellow.

O_2-CO_2 Recycle Miscellaneous Results

This screen is available for Combustion (Boiler) plant types.



O_2-CO_2 Recycle Flue Gas – Miscellaneous factor result screen.

The **Misc.** result screen displays a table which totals the annual fixed, variable, operations and maintenance, and capital costs associated with the **Flue Gas Recycle** portion of the **CO_2 Control** technology. Each result is described briefly below.

Important Performance and Cost Factors

This screen displays information that is key to the model calculations. The data is available else where in the model.

Net Plant Size (MW): This is the net plant capacity, which is the gross plant capacity minus the losses due to plant equipment and pollution equipment (energy penalties).

Annual Operating Hours (hours): This is the number of hours per year that the plant is in operation. If a plant runs 24 hours per day, seven days per week, with no outages, the calculation is 24 hours * 365 days. or 8,760 hours/year.

Annual CO_2 Removed (ton/yr): This is the amount of CO_2 removed from the flue gas by the CO_2 capture system per year.

ASU Power (MW)

Flue Gas Fan Power (MW): The flue gas has to be compressed in a flue gas blower so that it can overcome the pressure drop in the absorber tower. This is the electrical power required by the blower.

CO_2 Purification Power (MW)

CO_2 Compression Power (MW): This is the electrical power required to compress the CO_2 product stream to the designated pressure. Compression of CO_2 to high pressures requires considerable power, and is a principle contributor to the overall energy penalty of a CO_2 capture unit in a power plant.

Fixed Charge Factor (fraction): The fixed charge factor is one of the most important parameters in the IECM. 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.

Cost of CO_2 Avoided

Many analysts like to express the cost of an environmental control system in terms of the cost per ton of pollutant removed or avoided. For energy-intensive CO_2 controls there is a big difference between the cost per ton CO_2 removed and the cost per ton "avoided" based on *net* plant capacity. Since the purpose of adding a CO_2 unit is to reduce the CO_2 emissions per net kWh delivered, the cost of CO_2 avoidance is the economic indicator that is widely used in this field.

Capture Plant

CO_2 Emissions (lb/kWh): This is the amount of CO_2 vented to the air for every kilowatt hour of electricity produced in the power plant that is using **CO_2 Capture Technology**.

Cost of Electricity ($/MWh): The IECM framework calculates the cost of electricity (COE) for the overall **Capture Plant** by dividing the total annualized plant cost ($/yr) by the net electricity generated (kWh/yr)

Reference Plant

CO_2 Emissions (lb/kWh): This is the amount of CO_2 vented to the air for every kilowatt hour of electricity produced in the power plant with **No CO_2 Capture**.

Cost of Electricity ($/MWh): The IECM framework calculates the cost of electricity (COE) for the overall **Reference Plant** by dividing the total annualized plant cost ($/yr) by the net electricity generated (kWh/yr)

Cost of CO_2 Avoided ($/ton): This is the economic indicator widely used in the field, calculated as the difference between the cost of electricity in the capture plant and the reference plant divided by the difference between the CO_2 emissions in the reference plant and the capture plant.

Cost of CO_2 Avoided = (Cost of Electricity $_{cap.}$ – Cost of Electricity $_{ref.)}$

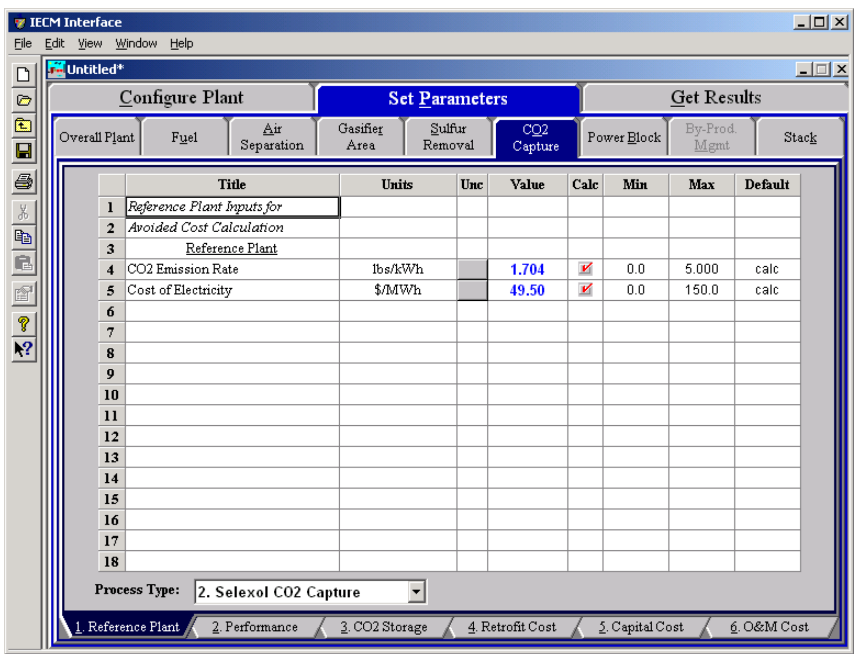
/ (CO_2 emissions $_{ref.}$ – CO_2 emissions $_{cap.)}$

Selexol CO_2 Capture

IGCC systems use less energy-intensive physical absorption processes to capture CO_2 than post-combustion chemical absorption processes required by the **Combustion (Boiler)** or **Combustion (Turbine)** plant types. Physical absorption using Selexol solvent is currently the most effective technique for removing CO_2 from IGCC fuel gases. The CO_2 capture using Selexol is described in the following section.

Selexol CO_2 Capture Reference Plant Inputs

This screen is only available for the **IGCC** plant type.



Selexol CO_2 Capture – Reference Plant input screen.

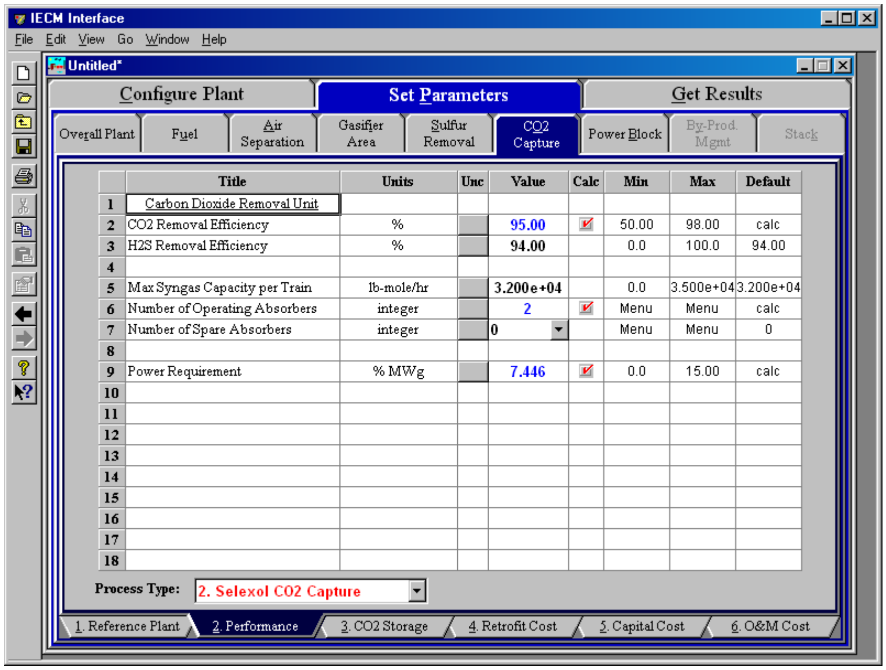
Reference Plant

CO_2 Emission Rate: This is the emission rate for the reference power plant (without CO_2 capture).

Cost of Electricity: This is the cost of electricity for the reference power plant (without CO_2 capture).

Selexol CO_2 Capture Performance Inputs

This screen is only available for the **IGCC** plant type.



Selexol CO_2 Capture – Performance input screen.

Carbon Dioxide Removal Unit

CO_2 Removal Efficiency: CO_2 removal is specified by the user and is used to determine the solvent makeup flow, capital cost, and operating and maintenance costs.

H_2S Removal Efficiency: H_2S is naturally removed with CO_2. This parameter specifies the amount it is captured.

Max Syngas Capacity per Train: Each train contains one absorber vessel that has a maximum flow rate. This parameter determines the maximum flow rate through the vessel.

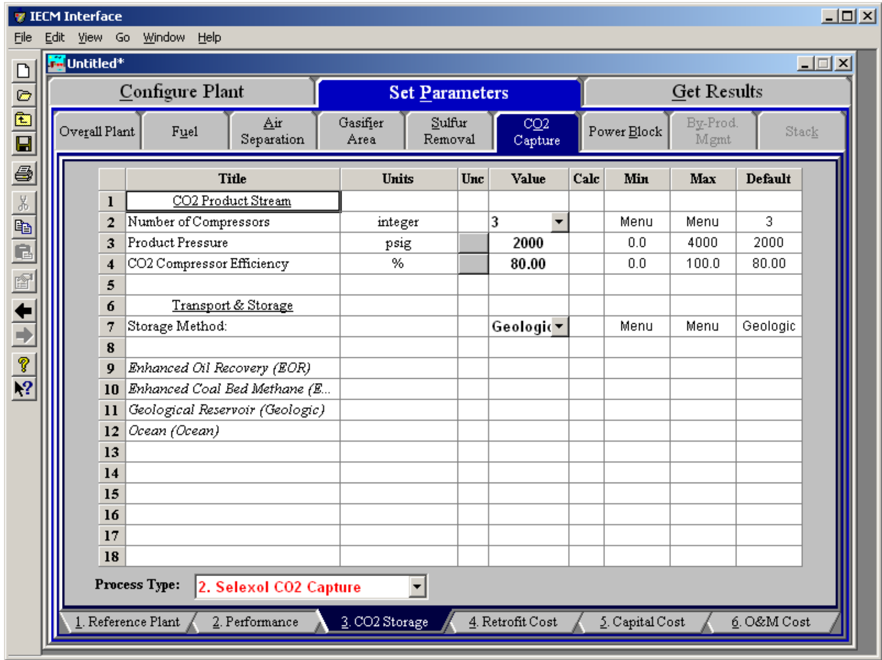
Number of Operating Absorbers: This is the total number of operating absorber vessels. The calculated value is determined by comparing the total flow rate of syngas through the Selexol process and the maximum syngas capacity per train. The value must be an integer.

Number of Spare Absorbers: This is the total number of spare absorber vessels. It is used primarily to calculate capital costs. The value must be an integer.

Power Requirement: This is the electricity used by the **Selexol CO2 Capture System** for internal use. It is expressed as a percent of the gross plant capacity.

Selexol CO_2 Capture CO_2 Storage Inputs

This screen is only available for the **IGCC** plant type.



Selexol CO_2 Capture – CO_2 Storage input screen.

CO_2 Product Stream

The concentrated CO_2 product stream obtained from CO_2 capture technology is compressed and dried using a multi-stage compressor with inter-stage cooling.

Number of Compressors: The number of compressors is a user-specified number. The value is used to determine the capital cost for sequestration.

Product Pressure: The CO_2 product may have to be carried over long distances. Hence, it is necessary to compress (and liquefy) it to very high pressures, so that it may be delivered to the required destination in liquid form and (as far as possible) without recompression facilities en route. The critical pressure for CO_2 is about 1070 psig.

CO_2 Compressor Efficiency: This is the effective efficiency of the compressors used to compress CO_2 to the desired pressure.

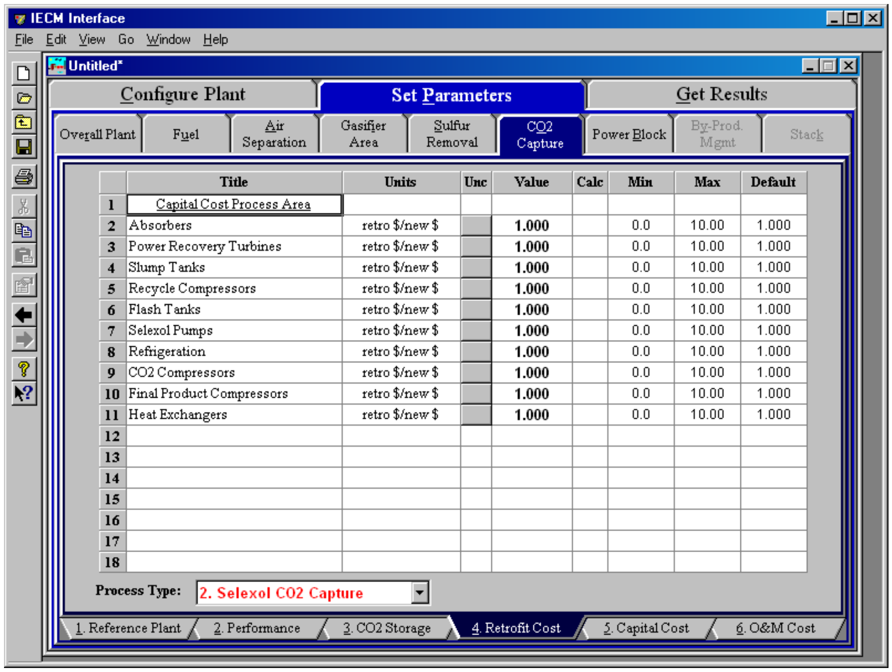
Transport & Storage

Storage Method: The default option for CO_2 disposal is underground geological storage.

- **EOR** – Enhanced Oil Recovery
- **ECBM** – Enhanced Coal Bed Methane
- **Geologic** – Geological Reservoir
- **Ocean**

Selexol CO_2 Capture Retrofit Cost Inputs

This screen is only available for the **IGCC** plant type.



Selexol CO_2 Capture – Retrofit Cost input screen.

Capital Cost Process Area

The retrofit ratios can be specified for the following process areas:

Absorbers: The Selexol absorbers use physical absorption to capture CO_2. Because the solubility of CO_2in the solvent is proportional to its partial pressure in the gas phase, the performance of the absorbers increases with increasing CO_2 partial pressures.

Power Recovery Turbines: The CO_2 rich solvent from the absorber is fed into a set of hydraulic power recovery turbines to recover some of the pressure energy before it is fed into the slump tanks.

Slump Tanks: A slight pressure drop in the slump tanks releases a majority of H_2 and CH_4 and a small amount of CO_2. This process area enriches the CO_2concentration.

Recycle Compressors: Gases from the slump tank are recycled back into the absorber. A compressor is used to compress the gases to the operating pressure of the absorber.

Flash Tanks: CO_2 is released in multiple stages by reducing the pressure in successive flash tanks. Three flash tanks are typically used in a single train. The staging process reduces the power of CO_2 compression later.

Selexol Pumps: The CO_2-lean solvent is pumped back to the absorber operating pressure by a Selexol circulation pump.

Refrigeration: CO_2-lean solvent must be cooled to the absorber operating temperature before being returned to the absorber vessel. A refrigeration unit is used to reduce the temperature of the solvent.

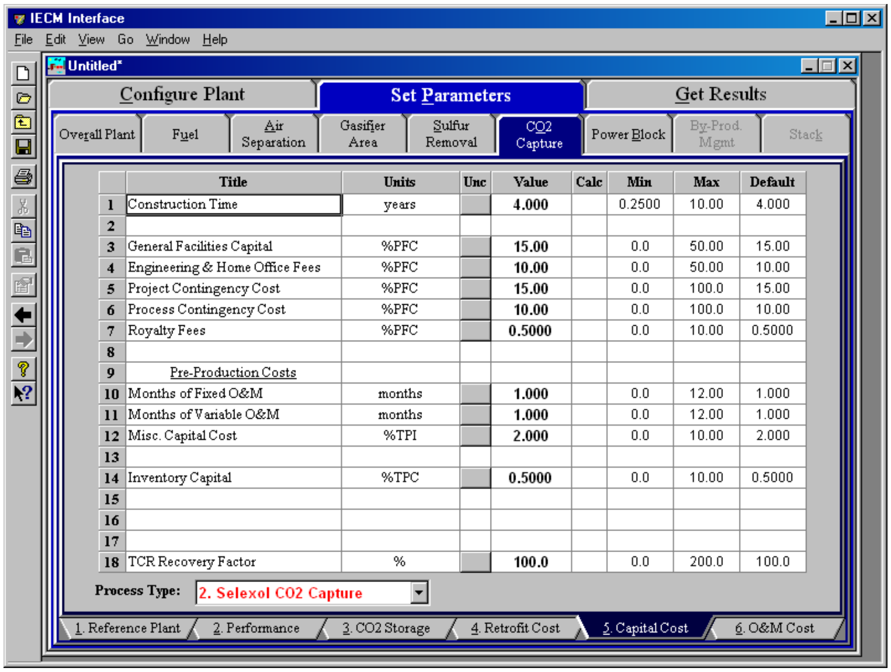
CO_2 Compressors: CO_2 released from the first two flash tanks is compressed to the flashing pressure of the first flash tank. The two CO_2 streams are then combined and sent to the final product compressors.

Final Product Compressors: The product CO_2 must be separated from the water vapor (dried) and compressed to liquid form in order to transport it over long distances. The multi-stage compression unit with inter-stage cooling and drying yields a final CO_2 product at the nominal pressure of 2000 psig. This area is a function of the CO_2 flow rate.

Heat Exchangers: This process area considers miscellaneous heat exchangers used in the overall process.

Selexol CO_2 Capture Capital Cost Inputs

This screen is only available for the IGCC plant type.



Selexol CO_2 Capture – Capital Cost input screen.

Inputs for capital costs are entered on the **Capital Cost** input screen.

Construction Time: This is the idealized construction period in years. It is used to determine the allowance for funds used during construction (AFUDC).

General Facilities Capital (GFC): 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%.

Engineering & Home Office Fees: The engineering & home office fees are a percent of total direct capital cost. This is an overhead fee paid to the architect/engineering company. These fees typically range from 7-15%.

Project Contingency Cost: This is 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.

Process Contingency Cost: 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.

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

Pre-Production Costs: 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 applied to the O&M costs over a specified period of time (months). The two time periods for fixed and variable O&M costs are described below with the addition of a miscellaneous capital cost factor.

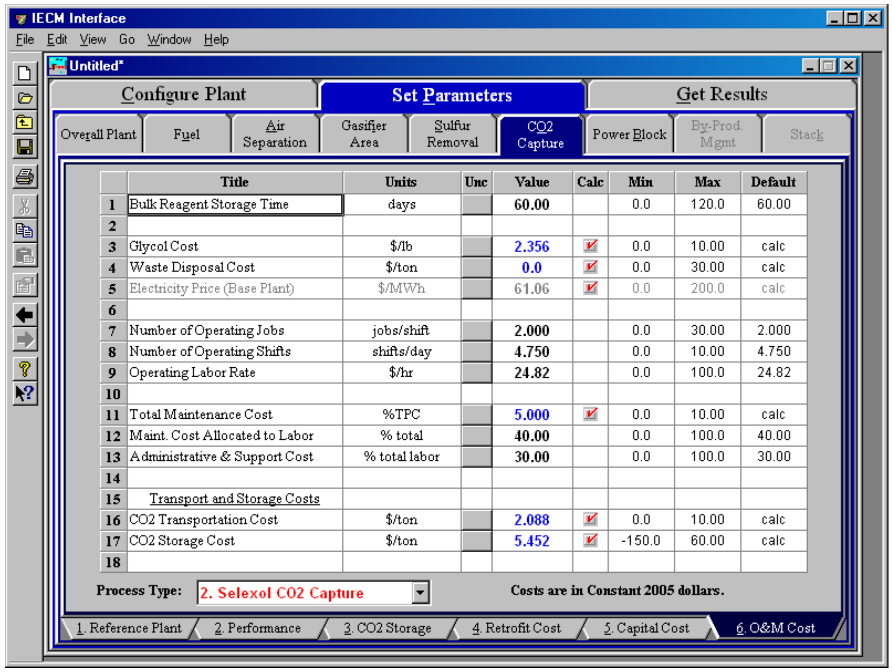
- **Months of Fixed O&M:** Time period of fixed operating costs used for preproduction to cover training, testing, major changes in equipment, and inefficiencies in start-up. This includes operating, maintenance, administrative and support labor. It also considers maintenance materials.
- **Months of Variable O&M:** Time period of variable operating costs used for preproduction to cover chemicals, water, consumables, and solid disposal charges in start-up, assuming 100% load. This excludes any fuels.
- **Misc. Capital Cost:** This is a percent of total plant investment (sum of TPC and AFUDC) to cover expected changes to equipment to bring the system up to full capacity.

Inventory Capital: Percent of the total direct capital for raw material supply based on 100% capacity during a 60 day period. These materials are considered storage. The inventory capital includes fuels, consumables, by-products, and spare parts. This is typically 0.5%.

TCR Recovery Factor: The actual total capital required (TCR) as a percent of the TCR in a new power plant. This value is 100% for a new installation and may be set as low as 0% for a fabric filter that has been paid off.

Selexol CO_2 Capture O&M Cost Inputs

This screen is only available for the **IGCC** plant type.



Selexol CO_2 Capture – O&M Cost input screen.

O&M costs are typically expressed on an average annual basis and are provided in either constant or current dollars for a specified year, as shown on the bottom of the screen. The following inputs for operating and maintenance costs are available:

Bulk Reagent Storage Time: This is the reagent stored at the plant.

Glycol Cost: This is the cost in $/ton for glycol that is used by the Selexol CO_2 capture system.

Waste Disposal Cost: This is the cost of disposing the water that is used in the Selexol CO_2 capture process.

Electricity Price (Base Plant): This is the price of electricity and is calculated as a function of the utility cost of the base plant, where the base plant is an air separation unit, gasifier and the power block

Number of Operating Jobs: This is the total number of operating jobs that are required to operate the plant per eight-hour shift.

Number of Operating Shifts: This is the total number of equivalent operating shifts in the plant per day. The number takes into consideration paid time off and weekend work (3 shifts/day * 7 days/5 day week * 52 weeks/(52 weeks - 6 weeks PTO) = 4.75 equiv. Shifts/day)

Operating Labor Rate: The hourly cost of labor is specified in the base plant O&M cost screen. The same value is used throughout the other technologies.

Total Maintenance Cost: This is the annual maintenance cost as a percentage of the total plant cost. Maintenance cost estimates can be developed separately for each process area.

Maint. Cost Allocated to Labor: Maintenance cost allocated to labor as a percentage of the total maintenance cost.

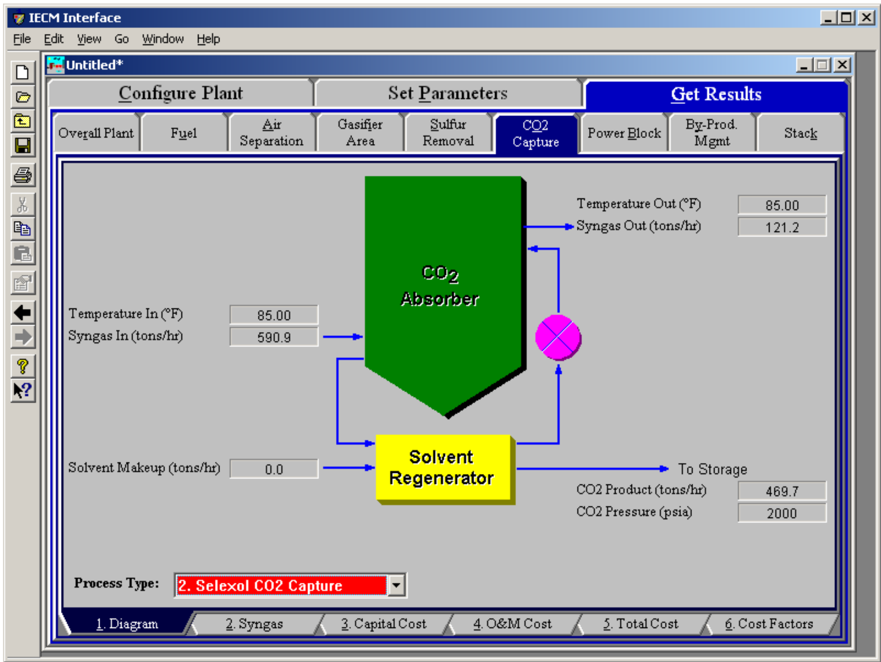
Administrative & Support Cost: This is the percent of the total operating and maintenance labor associated with administrative and support labor.

Transport and Storage Costs

- **CO_2 Transportation Cost:** This is the cost of moving the CO_2 (i.e. pipeline, truck) to the place where it will be sequestered.
- **CO_2 Disposal Cost:** This is the cost of sequestering the CO_2.

Selexol CO_2 Capture Diagram

This screen is only available for the **IGCC** plant type.



Selexol CO_2 Capture – Diagram result screen.

The **Selexol CO_2 Capture Diagram** result screen displays an icon for the Selexol CO_2 capture unit and values for major flows in and out of it. Each result is described briefly below:

Temperature In: Temperature of the syngas entering the CO_2 absorber unit.

Syngas In: Flow rate of the syngas entering the CO_2 absorber unit.

Solvent Makeup: Flow rate of the Selexol solvent added to the regenerator.

Temperature Out: Temperature of the syngas exiting the CO_2 absorber unit.

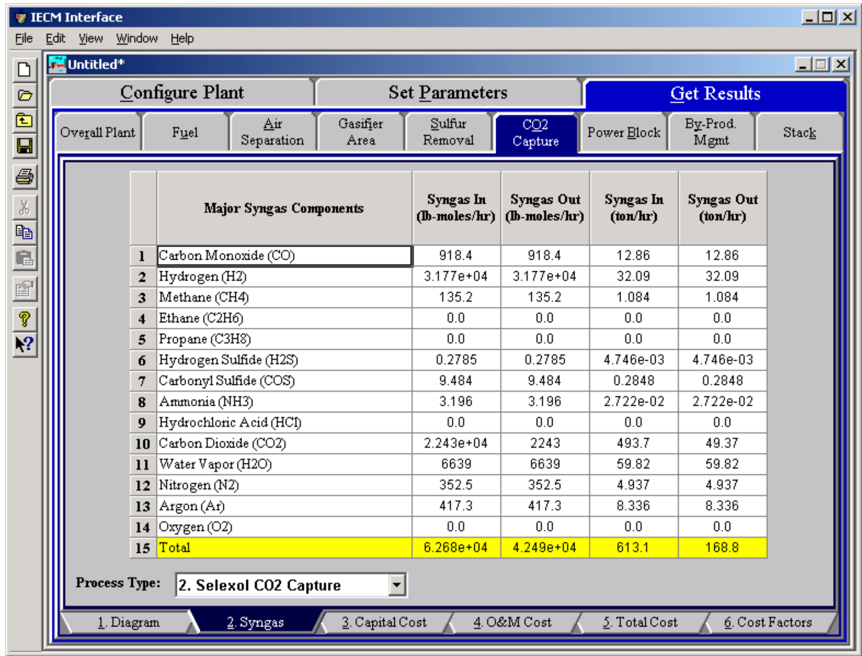
Syngas Out: Flow rate of the syngas exiting the CO_2 absorber unit.

CO_2 Product: Flow rate of the CO_2 product exiting the regenerator.

CO_2 Syngas Pressure: CO_2 product pressure entering the pipeline.

Selexol CO_2 Capture Syngas Results

This screen is only available for the IGCC plant type.



Selexol CO_2 Capture – Gas Flow result screen..

Major Syngas Components

Carbon Monoxide (CO): Total mass of carbon monoxide.

Hydrogen (H_2): Total mass of hydrogen.

Methane (CH_4): Total mass of methane.

Ethane (C_2H_6): Total mass of ethane.

Propane (C_3H_8): Total mass of propane.

Hydrogen Sulfide (H_2S): Total mass of hydrogen sulfide.

Carbonyl Sulfide (COS): Total mass of carbonyl sulfide.

Ammonia (NH_3): Total mass of ammonia.

Hydrochloric Acid (HCl): Total mass of hydrochloric acid.

Carbon Dioxide (CO_2): Total mass of carbon dioxide.

Water Vapor (H_2O): Total mass of water vapor.

Nitrogen (N_2): Total mass of nitrogen.

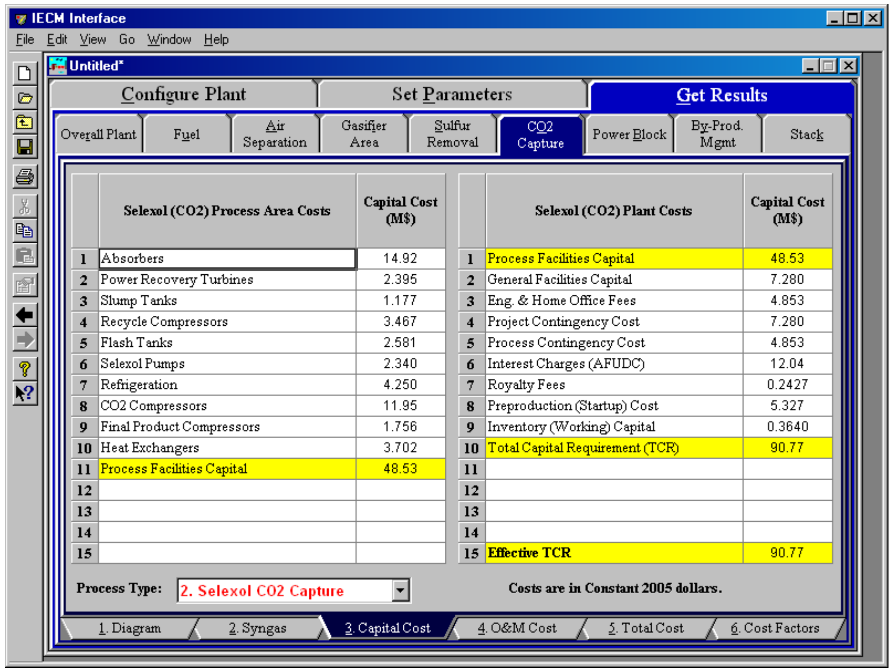
Argon (Ar): Total mass of argon.

Oxygen (O_2): Total mass of oxygen.

Total: Total of the individual components listed above. This item is highlighted in yellow.

Selexol CO_2 Capture Capital Cost Results

This screen is only available for the IGCC plant type.



	Selexol (CO2) Process Area Costs	Capital Cost (M$)
1	Absorbers	14.92
2	Power Recovery Turbines	2.395
3	Slump Tanks	1.177
4	Recycle Compressors	3.467
5	Flash Tanks	2.581
6	Selexol Pumps	2.340
7	Refrigeration	4.250
8	CO2 Compressors	11.95
9	Final Product Compressors	1.756
10	Heat Exchangers	3.702
11	Process Facilities Capital	48.53
12		
13		
14		
15		

	Selexol (CO2) Plant Costs	Capital Cost (M$)
1	Process Facilities Capital	48.53
2	General Facilities Capital	7.280
3	Eng. & Home Office Fees	4.853
4	Project Contingency Cost	7.280
5	Process Contingency Cost	4.853
6	Interest Charges (AFUDC)	12.04
7	Royalty Fees	0.2427
8	Preproduction (Startup) Cost	5.327
9	Inventory (Working) Capital	0.3640
10	Total Capital Requirement (TCR)	90.77
11		
12		
13		
14		
15	Effective TCR	90.77

Selexol CO_2 Capture Capital Cost results screen.

The **Selexol CO_2 Capture Capital Cost** result screen displays tables for the capital costs. Capital costs are typically expressed in either constant or current dollars for a specified year, as shown on the bottom of the screen. Each result is described briefly below:

Selexol (CO_2) Capture Process Area Costs

Absorbers: This is the series of columns where the syngas is made to contact with the Selexol solvent. Some of the CO_2 is absorbed by the CO_2 lean solvent at high pressure in the counter flow absorber. This process area PFC is a function of the solvent flow rate, the capture CO_2 flow rate, and the inlet temperature.

Power Recovery Turbines: The pressure energy in the CO_2 rich solvent is recovered with one or two hydro turbines. This process area PFC is a function of the turbine horsepower and the turbine outlet pressure.

Slump Tanks: H_2 , CO, and CH_4 entrained or absorbed in the solvent is released in the slump tank and recycled back to the absorber. Because extra Selexol is used in the absorber, only a small amount of CO_2 is released in the slump tank. This process area PFC is a function of the solvent flow rate.

Recycle Compressors: The lean solvent is compressed and cooled in preparation for recycling back into the absorbers. This process area PFC is a function of the compressor horse power.

Flash Tanks: Most of the CO_2 absorbed by the solvent is recovered through flashing. The captured CO_2 is then ready for transport and sequestration. To reduce the compression power, three flashing tanks with different pressures are used. There is no heat demand for solvent regeneration because solvent recovery is possible through flashing. This process area PFC is a function of the solvent flow rate.

Selexol Pumps: The lean solvent fed back into the absorber via pumps. This process area PFC is a function of the pump horse power.

Refrigeration: The solvent must be cooled down to the absorber operating temperature (30 °F) by refrigeration. This process PFC is a function of the solvent flow rate and the temperature difference.

CO_2 Compressors: The CO_2 from the flash tanks is compressed to high pressure (>1000psia) for storage using a multi-stage, inter-stage cooling compressor. This process area PFC is a function of the compressor horse power.

Final Product Compressors: Compressed CO_2 from the CO_2 compressors must be further compressed to the final product pressure. This process area PFC is a function of the compressor horse power.

Heat Exchangers: Gas-gas heat exchangers are used to extract heat from the syngas. This process PFC is a function of the heat load of the exchangers and the temperature difference across them.

Process Facilities Capital: The process facilities capital is the total constructed cost of all on-site processing and generating units listed above, including all direct and indirect construction costs. All sales taxes and freight costs are included where applicable implicitly. This result is highlighted in yellow.

Selexol (CO_2) Capture Plant Costs

Process Facilities Capital: (see definition above)

General Facilities Capital: The general facilities include construction costs of roads, office buildings, shops, laboratories, etc. Sales taxes and freight costs are included implicitly.

Eng. & Home Office Fees: The engineering & home office fees are a percent of total direct capital cost. This is an overhead fee paid to the architect/engineering company.

Project Contingency Cost: Capital cost contingency factor covering the cost of additional equipment or other costs that would result from a more detailed design of a definitive project at the actual site.

Process Contingency Cost: Capital cost contingency factor applied to a new technology in an effort to quantify the uncertainty in the technical performance and cost of the commercial-scale equipment.

Interest Charges (AFUDC): Allowance for funds used during construction, also referred to as interest during construction, is the time value of the money used during construction and is based on an interest rate equal to the before-tax weighted cost of capital. This interest is compounded on an annual basis (end of year) during the construction period for all funds spent during the year or previous years.

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

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.

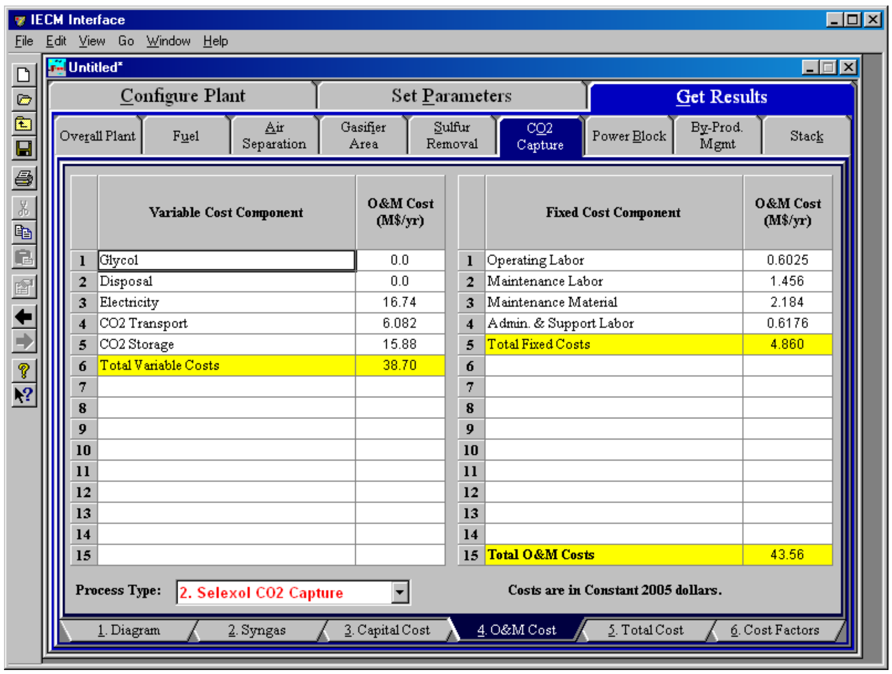
Inventory (Working) Capital: The raw material supply based on 100% capacity during a 60 day period. These materials are considered storage. The inventory capital includes fuels, consumables, by-products, and spare parts.

Total Capital Requirement (TCR): Money that is placed (capitalized) on the books of the utility on the service date. TCR includes all the items above. This result is highlighted in yellow.

Effective TCR: The TCR of the spray dryer that is used in determining the total power plant cost. The effective TCR is determined by the "TCR Recovery Factor".

Selexol CO_2 Capture O&M Cost Results

This screen is only available for the **IGCC** plant type.



	Variable Cost Component	O&M Cost (M$/yr)		Fixed Cost Component	O&M Cost (M$/yr)
1	Glycol	0.0	1	Operating Labor	0.6025
2	Disposal	0.0	2	Maintenance Labor	1.456
3	Electricity	16.74	3	Maintenance Material	2.184
4	CO2 Transport	6.082	4	Admin. & Support Labor	0.6176
5	CO2 Storage	15.88	5	Total Fixed Costs	4.860
6	Total Variable Costs	38.70	6		
7			7		
8			8		
9			9		
10			10		
11			11		
12			12		
13			13		
14			14		
15			15	Total O&M Costs	43.56

Selexol CO_2 Capture – O&M Cost results screen.

O&M costs are typically expressed on an average annual basis and are provided in either constant or current dollars for a specified year, as shown on the bottom of the screen.

Variable Cost Component

Glycol: Selexol is a commercially available physical solvent that is a mixture of dimethyl ether and polyethylene glycol. This is the annual cost of the makeup solvent.

Disposal: This is the annual cost of waste disposal for this process. It does not include the CO_2 product stream disposal cost.

Electricity: The cost of electricity consumed by the CO_2 Selexol system.

CO_2 Transport: The CO_2 captured at the power plant site has to be carried to the appropriate storage/disposal site. Transport of CO_2 to a storage site is assumed to be via pipeline. This is the annual cost of maintaining those pipelines.

CO_2 Storage/Disposal: Once the CO_2 is captured, it needs to be securely stored (sequestered). This annual cost is based upon the storage option chosen.

Total Variable Costs: This is the sum of the variable O&M costs listed above. This result is highlighted in yellow.

Fixed Cost Components

Fixed operating costs are essentially independent of actual capacity factor, number of hours of operation, or amount of kilowatts produced. All the costs are subject to inflation.

Operating Labor: Operating labor cost is based on the operating labor rate, the number of personnel required to operate the plant per eight-hour shift, and the average number of shifts per day over 40 hours per week and 52 weeks.

Maintenance Labor: The maintenance labor is determined as a fraction of the total maintenance cost.

Maintenance Material: The cost of maintenance material is the remainder of the total maintenance cost, considering the fraction associated with maintenance labor.

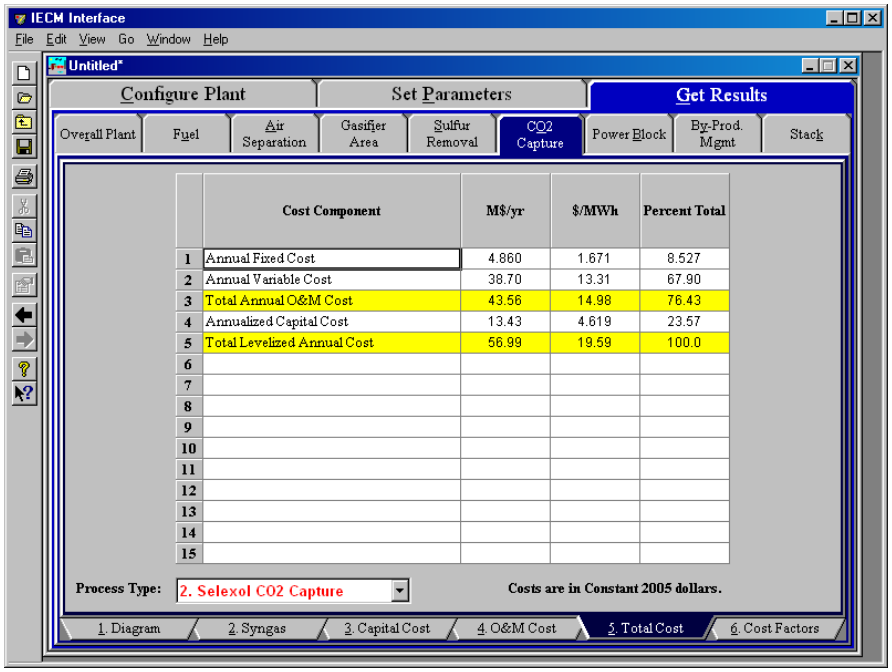
Admin. & Support Labor: The administrative and support labor is the only overhead charge. It is taken as a fraction of the total operating and maintenance labor costs.

Total Fixed Costs: This is the sum of all the fixed O&M costs listed above. This result is highlighted in yellow.

Total O&M Costs: This is the sum of the total variable and total fixed O&M costs. It is used to determine the base plant total revenue requirement. This result is highlighted in yellow.

Selexol CO_2 Capture Total Cost Results

This screen is only available for the **IGCC** plant type.



Selexol CO_2 Capture – Total Cost results screen.

The **Total Cost** result screen displays a table which totals the annual fixed, variable, operations and maintenance, and capital costs associated with the **Selexol CO_2 Capture Unit**. Total costs are typically expressed in either constant or current dollars for a specified year, as shown on the bottom of the screen. Each result is described briefly below.

Cost Component

Annual Fixed Cost: The operating and maintenance fixed costs are given as an annual total. This number includes all maintenance materials and all labor costs.

Annual Variable Cost: The operating and maintenance variables costs are given as an annual total. This includes all reagent, chemical, steam, and power costs.

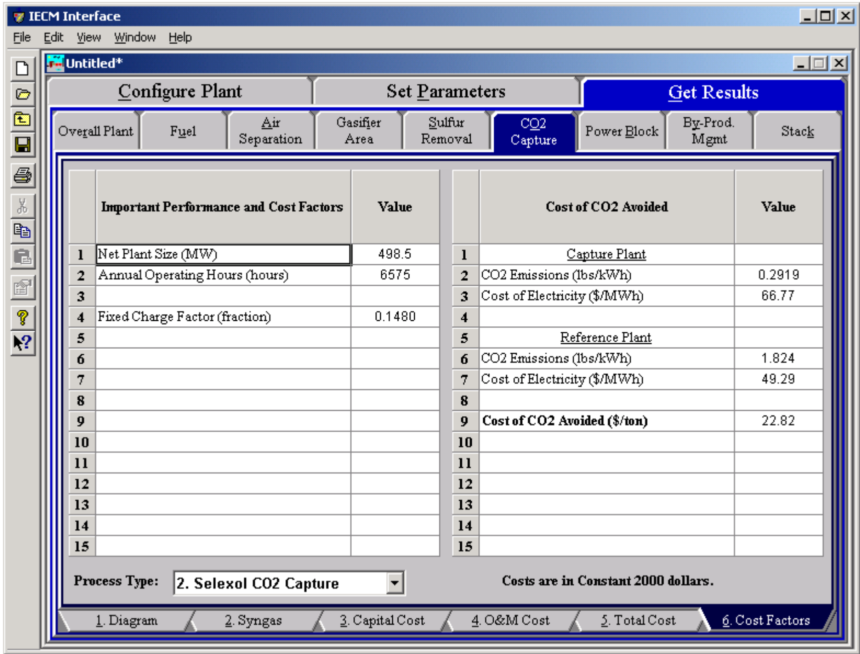
Total Annual O&M Cost: This is the sum of the annual fixed and variable operating and maintenance costs above. This result is highlighted in yellow.

Annualized Capital Cost: This is the total capital cost expressed on an annualized basis, taking into consideration the levelized carrying charge factor, or fixed charge factor, over the entire book life.

Total Levelized Annual Cost: The total annual cost is the sum of the total annual O&M cost and annualized capital cost items above. This result is highlighted in yellow.

Selexol CO_2 Capture Cost Factors Results

This screen is only available for the **IGCC** plant type.



Selexol CO_2 Capture – Cost Factors results screen.

Important Performance and Cost Factors

This screen displays information that is a key to the model calculations. The data is available else where in the model.

Net Plant Size (MW): This is the net plant capacity, which is the gross plant capacity minus the losses due to plant equipment and pollution equipment (energy penalties).

Annual Operating Hours (hours): This is the number of hours per year that the plant is in operation. If a plant runs 24 hours per day, seven days per week, with no outages, the calculation is 24 hours * 365 days or 8,760 hours/year.

Fixed Charge Factor (fraction): The fixed charge factor is one of the most important parameters in the IECM. 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.

Cost of CO_2 Avoided

Capture Plant

- **CO_2 Emissions (lbs/kWh):** This is the amount of CO_2 vented to the air for every kilowatt hour of electricity produced in the power plant that is using a CO_2 Capture technology.
- **Cost of Electricity ($/MWh):** The IECM framework calculates the cost of electricity (COE) for the overall capture plant by dividing the total annualized plant cost ($/yr) by the net electricity generated (kWh/hr).

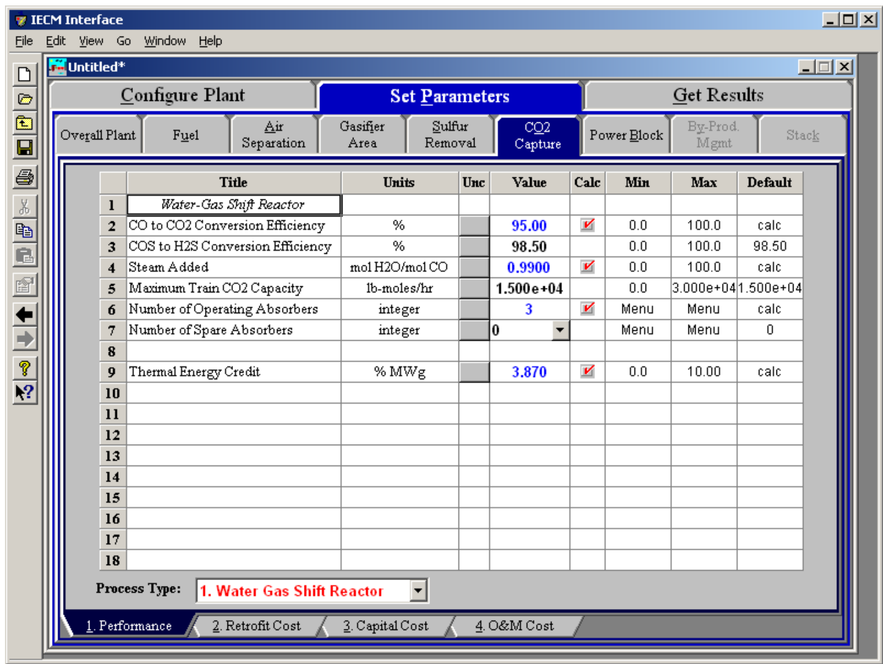
Reference Plant

- **CO2 Emissions (lbs/kWh):** This is the amount of CO_2 vented to the air for every kilowatt hour of electricity produced in the power plant with no CO_2 capture.
- **Cost of Electricity ($/MWh):** The IECM framework calculates the cost of electricity (COE) for the overall reference plant by dividing the total annualized plant cost ($/yr) by the net electricity generated (kWh/hr).

Cost of CO_2 Avoided ($/ton): This is the economic indicator widely used in the field, calculated as the difference between the cost of electricity in the capture plant and the reference plant divided by the difference between the CO_2 emissions in the reference plant and the capture plant.
Cost of CO2 Avoided = (Cost of Electricity cap – Cost of Electricity ref) / (CO2 emissions ref – CO2 emissions cap)

Water Gas Shift Reactor

Water Gas Shift Reactor Performance Inputs



Water Gas Shift Reactor – Performance input screen.

Water Gas Shift Reactor Unit

CO to CO_2 Conversion Efficiency: Most of the CO in the raw syngas is converted into CO_2 through the **Water Gas Shift** reaction. CO_2 is removed from the shifted syngas through a physical absorption unit. This variable is the percentage of CO that is converted to CO_2 in the reaction.

COS to H_2S Conversion Efficiency: COS is difficult to remove in the Selexol unit, so a polishing unit is added to convert COS to H_2S. This is the conversion efficiency of the polishing unit.

Steam Added: This parameter determines the amount of water added to the shift reactor in converting CO to CO_2. The moles of steam added is proportional to the moles of CO converted.

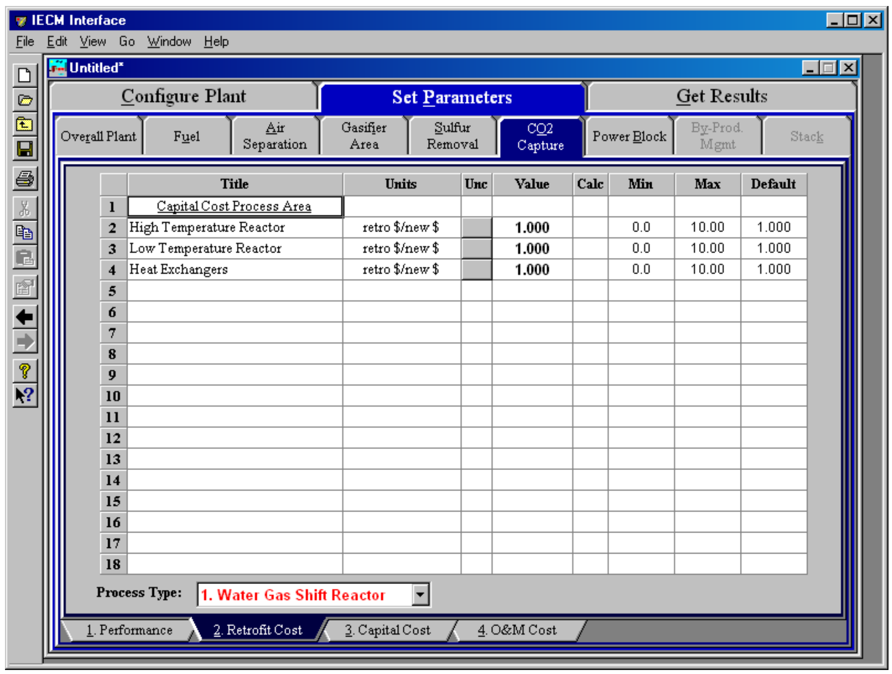
Maximum Train CO_2 Capacity: The maximum production rate of CO_2 is specified here. It is used to determine the number of operating trains required.

Number of Operating Trains: This is the total number of operating trains. It is used primarily to calculate capital costs. The value must be an integer

Number of Spare Trains: This is the total number of spare trains. It is used primarily to calculate capital costs. The value must be an integer.

Thermal Energy Credit: The **Water Gas Shift** reaction is an exothermic process, producing heat that can be extracted and converted to steam for use in generating electricity. This is the thermal energy credit for steam produced and used in the steam cycle.

Water Gas Shift Reactor Retrofit Cost Inputs



Water Gas Shift Reactor – Retrofit Cost input screen.

The retrofit cost factor of each process is is a multiplicative cost adjustment, which considers the cost of retrofitted capital equipment relative to similar equipment installed in a new plant. These factors affect the capital cost directly and the operating and maintenance costs indirectly.

Direct capital costs for each process area are calculated in the IECM. These calculations are reduced form equations derived from more sophisticated models and reports. The sum of the direct capital costs associated with each process area is defined as the process facilities capital (PFC). The retrofit cost factor provided for each of the process areas can be used as a tool for adjusting the anticipated costs and uncertainties across the process area separate from the other areas.

Each **Capital Cost Process Area** is described briefly below.

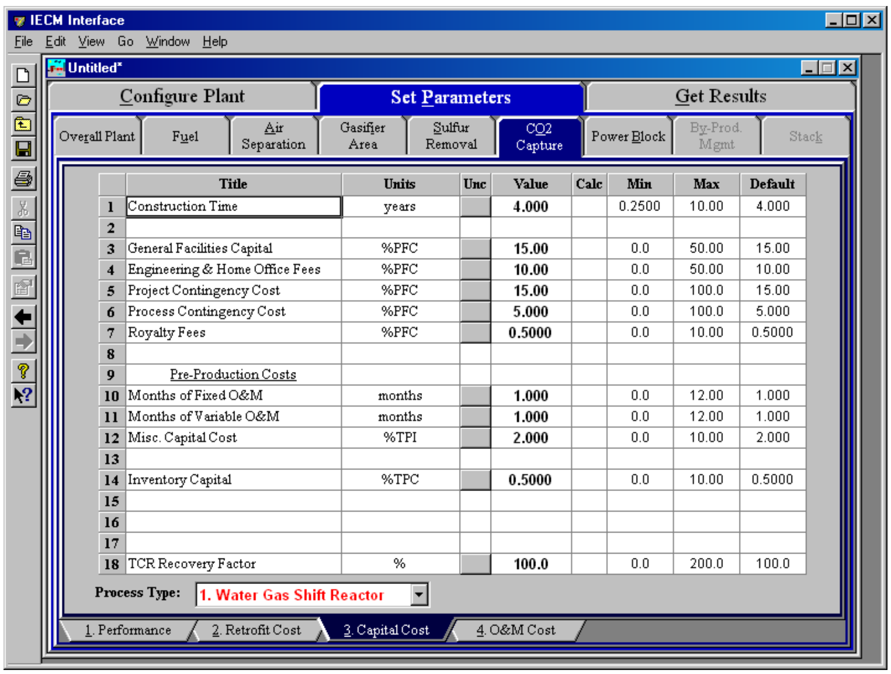
Capital Cost Process Area

High Temperature Reactor: This area accounts for the high temperature reactor vessel used for water gas shift. The iron-based catalyst is designed to be effective at high temperatures (650-1100 °F). The high temperature reactor has a high reaction rate and converts a large amount of CO into CO_2.

Low Temperature Reactor: This area accounts for the low temperature reactor vessel used for water gas shift. The copper-based catalyst is designed to be effective at lower temperatures (450-650 °F). The low temperature reactor has a lower reaction rate, but converts a very high percentage of the remaining CO into CO_2.

Heat Exchangers: The water gas shift process involves substantial cooling because of the exothermic reaction. Heat is recovered and temperature control is maintained through heat exchangers added after each reactor. This process area accounts for the heat exchangers used. Steam generated in the heat exchangers is sent to the steam cycle.

Water Gas Shift Reactor Capital Cost Inputs



	Title	Units	Unc	Value	Calc	Min	Max	Default
1	Construction Time	years		4.000		0.2500	10.00	4.000
2								
3	General Facilities Capital	%PFC		15.00		0.0	50.00	15.00
4	Engineering & Home Office Fees	%PFC		10.00		0.0	50.00	10.00
5	Project Contingency Cost	%PFC		15.00		0.0	100.0	15.00
6	Process Contingency Cost	%PFC		5.000		0.0	100.0	5.000
7	Royalty Fees	%PFC		0.5000		0.0	10.00	0.5000
8								
9	Pre-Production Costs							
10	Months of Fixed O&M	months		1.000		0.0	12.00	1.000
11	Months of Variable O&M	months		1.000		0.0	12.00	1.000
12	Misc. Capital Cost	%TPI		2.000		0.0	10.00	2.000
13								
14	Inventory Capital	%TPC		0.5000		0.0	10.00	0.5000
15								
16								
17								
18	TCR Recovery Factor	%		100.0		0.0	200.0	100.0

Water Gas Shift Reactor – Capital Cost input screen.

Inputs for capital costs are entered on the **Capital Cost** input screen.

Construction Time: This is the idealized construction period in years. It is used to determine the allowance for funds used during construction (AFUDC).

General Facilities Capital (GFC): 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%.

Engineering & Home Office Fees: The engineering & home office fees are a percent of total direct capital cost. This is an overhead fee paid to the architect/engineering company. These fees typically range from 7-15%.

Project Contingency Cost: This is 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.

Process Contingency Cost: 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.

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

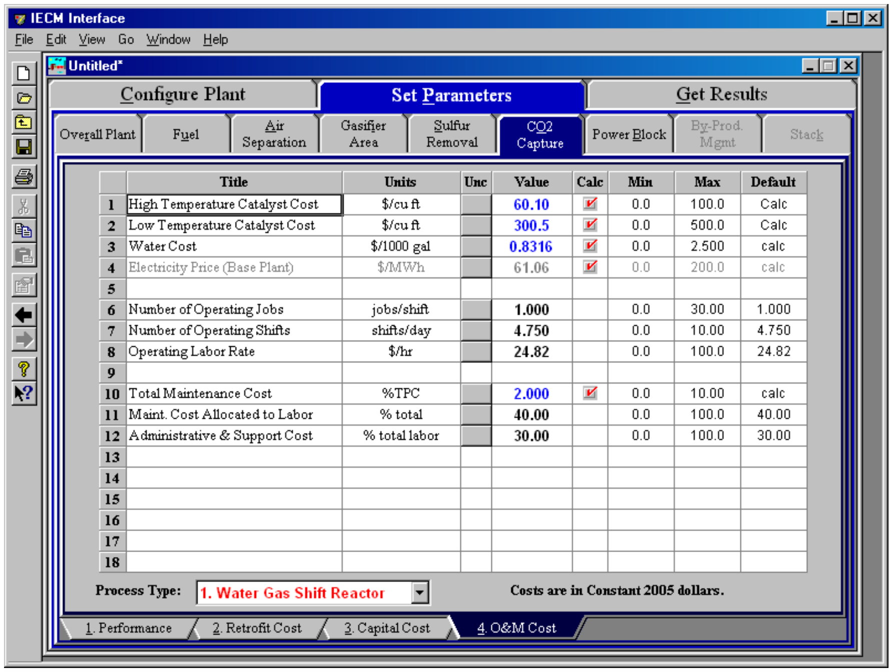
Pre-Production Costs: These costs consider the operator training, equipment checkout, major changes in unit equipment, extra maintenance, and inefficient use of fuel or other materials during start-up. These are typically applied to the O&M costs over a specified period of time (months). The two time periods for fixed and variable O&M costs are described below with the addition of a miscellaneous capital cost factor.

- **Months of Fixed O&M:** Time period of fixed operating costs used for preproduction to cover training, testing, major changes in equipment, and inefficiencies in start-up. This includes operating, maintenance, administrative and support labor. It also considers maintenance materials.
- **Months of Variable O&M:** Time period of variable operating costs used for preproduction to cover chemicals, water, consumables, and solid disposal charges in start-up, assuming 100% load. This excludes any fuels.
- **Misc. Capital Cost:** This is a percent of total plant investment (sum of TPC and AFUDC) to cover expected changes to equipment to bring the system up to full capacity.

Inventory Capital: Percent of the total direct capital for raw material supply based on 100% capacity during a 60 day period. These materials are considered storage. The inventory capital includes fuels, consumables, by-products, and spare parts. This is typically 0.5%.

TCR Recovery Factor: The actual total capital required (TCR) as a percent of the TCR in a new power plant. This value is 100% for a new installation and may be set as low as 0% for a fabric filter that has been paid off.

Water Gas Shift Reactor O&M Cost Inputs



Water Gas Shift Reactor – O & M Cost input screen.

Inputs for O&M costs are entered on the **Water Gas Shift Reactor O&M Cost** input screen. O&M costs are typically expressed on an average annual basis and are provided in either constant or current dollars for a specified year, as shown on the bottom of the screen.

High Temperature Catalyst Cost: This is the unit cost of the iron-based high temperature catalyst.

Low Temperature Catalyst Cost: This is the unit cost of the copper-based low temperature catalyst.

Water Cost: This is unit cost of water used to drive the water gas shift reaction.

Electricity Price (Base Plant): This is the price of electricity and is calculated as a function of the utility cost of the base plant, where the base plant is defined as the air separation unit, gasifier, and the power block.

Number of Operating Jobs: This is the total number of operating jobs that are required to operate the plant per eight-hour shift.

Number of Operating Shifts: This is the total number of equivalent operating shifts in the plant per day. The number takes into consideration paid time off and weekend work (3 shifts/day * 7 days/5 day week * 52 weeks/(52 weeks - 6 weeks PTO) = 4.75 equiv. Shifts/day)

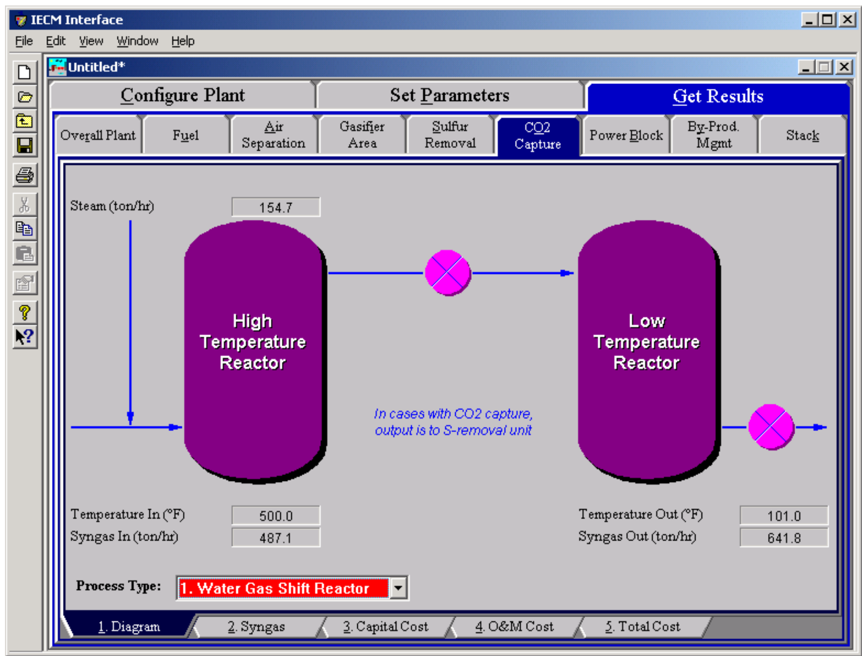
Operating Labor Rate: This is the hourly cost of labor for maintenance, administrative, and support personnel. The same rate is applied to all jobs across all technologies in the power plant.

Total Maintenance Cost: This is the annual maintenance cost as a percentage of the total plant cost. Maintenance cost estimates can be developed separately for each process area.

Maint. Cost Allocated to Labor: Maintenance cost allocated to labor as a percentage of the total maintenance cost.

Administrative & Support Cost: This is the percent of the total operating and maintenance labor associated with administrative and support labor.

Water Gas Shift Reactor Diagram



Water Gas Shift Reactor – Diagram result screen.

The **Water Gas Shift Reactor Diagram** result screen displays an icon for the Water Gas Shift Reactor Unit and values for major flows in and out of it. Each result is described briefly below in flow:

Steam In: This is the flow rate of steam added. The steam reacts with CO to produce H_2 and CO_2 in the presence of the catalyst in the two reactors.

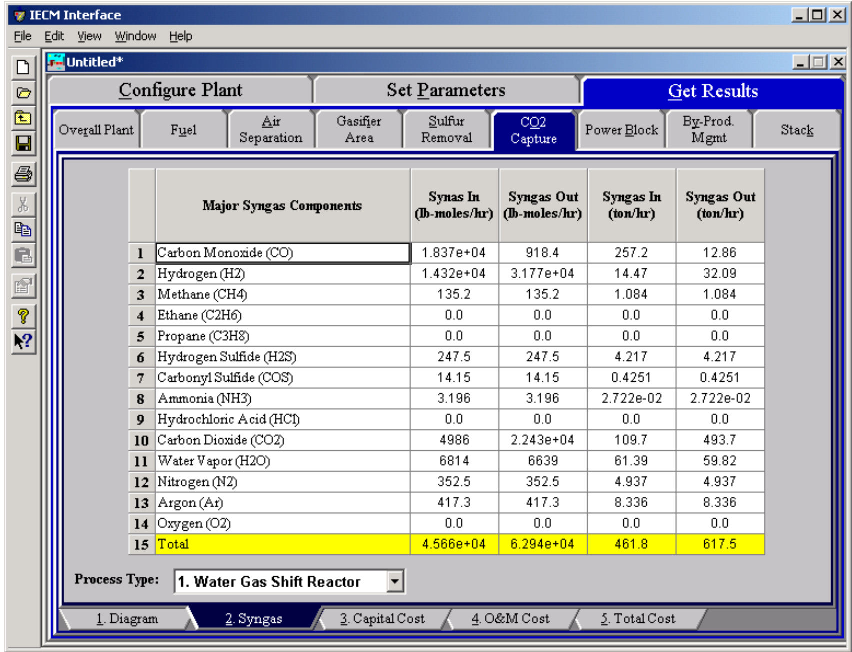
Temperature In: Temperature of the syngas entering the high temperature reactor.

Syngas In: Flow rate of the syngas entering the high temperature reactor.

Temperature Out: Temperature of the syngas exiting the final heat exhanger.

Syngas Out: Flow rate of the syngas exiting the final heat exchanger.

Water Gas Shift Reactor Syngas Results



	Major Syngas Components	Synas In (lb-moles/hr)	Syngas Out (lb-moles/hr)	Syngas In (ton/hr)	Syngas Out (ton/hr)
1	Carbon Monoxide (CO)	1.837e+04	918.4	257.2	12.86
2	Hydrogen (H2)	1.432e+04	3.177e+04	14.47	32.09
3	Methane (CH4)	135.2	135.2	1.084	1.084
4	Ethane (C2H6)	0.0	0.0	0.0	0.0
5	Propane (C3H8)	0.0	0.0	0.0	0.0
6	Hydrogen Sulfide (H2S)	247.5	247.5	4.217	4.217
7	Carbonyl Sulfide (COS)	14.15	14.15	0.4251	0.4251
8	Ammonia (NH3)	3.196	3.196	2.722e-02	2.722e-02
9	Hydrochloric Acid (HCl)	0.0	0.0	0.0	0.0
10	Carbon Dioxide (CO2)	4986	2.243e+04	109.7	493.7
11	Water Vapor (H2O)	6814	6639	61.39	59.82
12	Nitrogen (N2)	352.5	352.5	4.937	4.937
13	Argon (Ar)	417.3	417.3	8.336	8.336
14	Oxygen (O2)	0.0	0.0	0.0	0.0
15	Total	4.566e+04	6.294e+04	461.8	617.5

Water Gas Shift Reactor – Syngas result screen.

Major Syngas Components

Carbon Monoxide (CO): Total mass of carbon monoxide.

Hydrogen (H_2): Total mass of hydrogen.

Methane (CH_4): Total mass of methane.

Ethane (C_2H_6): Total mass of ethane.

Propane (C_3H_8): Total mass of propane.

Hydrogen Sulfide (H_2S): Total mass of hydrogen sulfide.

Carbonyl Sulfide (COS): Total mass of carbonyl sulfide.

Ammonia (NH_3): Total mass of ammonia.

Hydrochloric Acid (HCl): Total mass of hydrochloric acid.

Carbon Dioxide (CO_2): Total mass of carbon dioxide.

Water Vapor (H_2O): Total mass of water vapor.

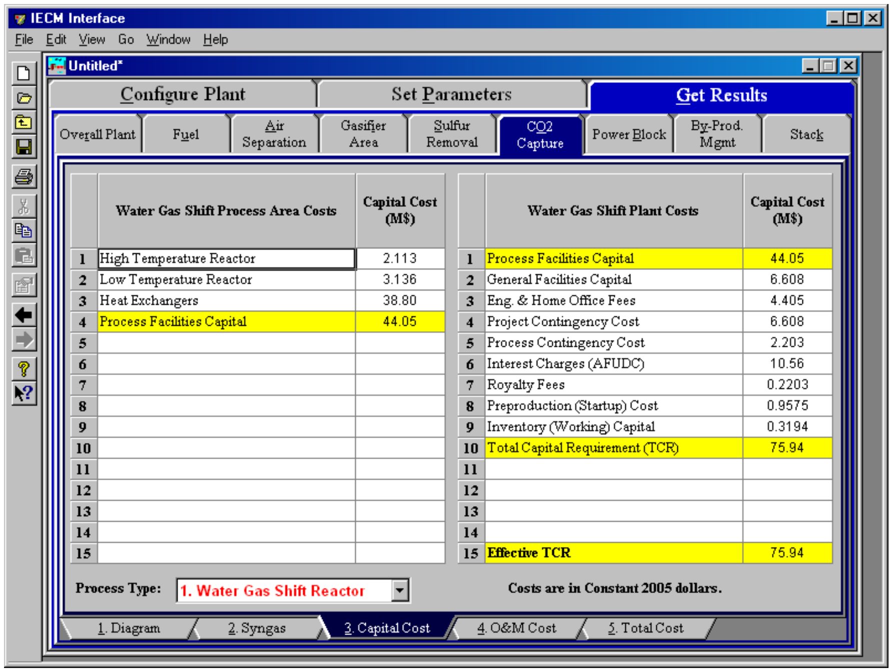
Nitrogen (N_2): Total mass of nitrogen.

Argon (Ar): Total mass of argon.

Oxygen (O_2): Total mass of oxygen.

Total: Total of the individual components listed above. This item is highlighted in yellow.

Water Gas Shift Reactor Capital Cost Results



Water Gas Shift Reactor – Capital Cost result screen.

The **Water Gas Shift Reactor Capital Cost** result screen displays tables for the capital costs. Capital costs are typically expressed in either constant or current dollars for a specified year, as shown on the bottom of the screen. Each result is described briefly below:

Water Gas Shift Reactor Process Area Costs

High Temperature Reactor: This area accounts for the high temperature reactor vessel used for water gas shift. The iron-based catalyst is designed to be effective at high temperatures (650-1100 °F). The high temperature reactor has a high reaction rate and converts a large amount of CO into CO_2.

Low Temperature Reactor: This area accounts for the low temperature reactor vessel used for water gas shift. The copper-based catalyst is designed to be effective at lower temperatures (450-650 °F). The low temperature reactor has a lower reaction rate, but converts a very high percentage of the remaining CO into CO_2.

Heat Exchangers: The water gas shift process involves substantial cooling because of the exothermic reaction. Heat is recovered and temperature control is maintained through heat exchangers added after each reactor. This process area accounts for the heat exchangers used. Steam generated in the heat exchangers is sent to the steam cycle.

Process Facilities Capital: The process facilities capital is the total constructed cost of all on-site processing and generating units listed above, including all direct and indirect construction costs. All sales taxes and freight costs are included where applicable implicitly. This result is highlighted in yellow.

Water Gas Shift Reactor Plant Costs

Process Facilities Capital: (see definition above)

General Facilities Capital: The general facilities include construction costs of roads, office buildings, shops, laboratories, etc. Sales taxes and freight costs are included implicitly.

Eng. & Home Office Fees: The engineering & home office fees are a percent of total direct capital cost. This is an overhead fee paid to the architect/engineering company.

Project Contingency Cost: Capital cost contingency factor covering the cost of additional equipment or other costs that would result from a more detailed design of a definitive project at the actual site.

Process Contingency Cost: Capital cost contingency factor applied to a new technology in an effort to quantify the uncertainty in the technical performance and cost of the commercial-scale equipment.

Interest Charges (AFUDC): Allowance for funds used during construction, also referred to as interest during construction, is the time value of the money used during construction and is based on an interest rate equal to the before-tax weighted cost of capital. This interest is compounded on an annual basis (end of year) during the construction period for all funds spent during the year or previous years.

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

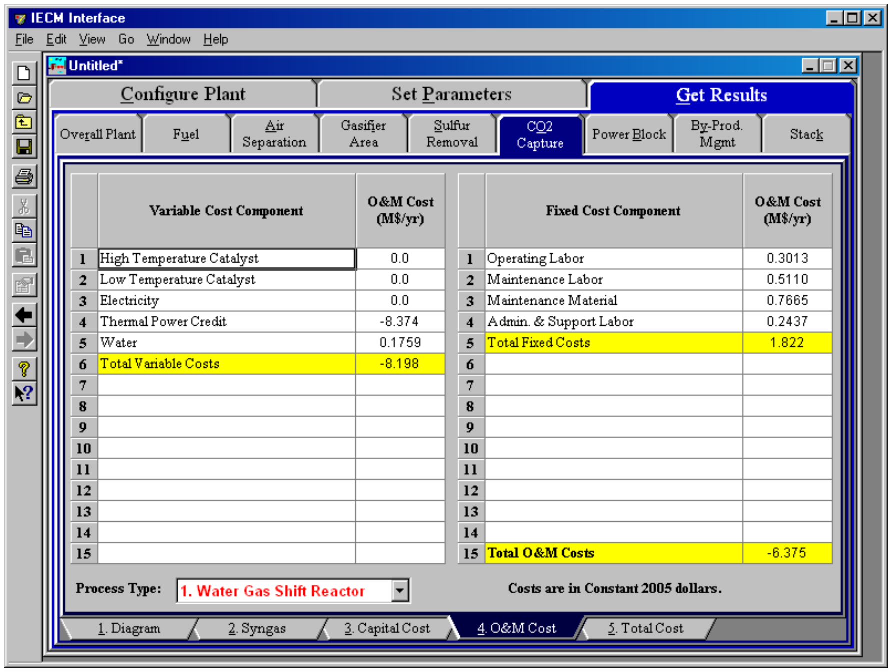
Preproduction (Startup) Cost: These costs consider the operator training, equipment checkout, major changes in unit equipment, extra maintenance, and inefficient use of fuel or other materials during start-up.

Inventory (Working) Capital: The raw material supply based on 100% capacity during a 60 day period. These materials are considered storage. The inventory capital includes fuels, consumables, by-products, and spare parts.

Total Capital Requirement (TCR): Money that is placed (capitalized) on the books of the utility on the service date. TCR includes all the items above. This result is highlighted in yellow.

Effective TCR: The percent of the water gas shift reactor TCR that is used in determining the total power plant cost. The effective TCR is determined by the “TCR Recovery Factor”.

Water Gas Shift Reactor O&M Cost Results



Water Gas Shift Reactor – O & M Cost result screen.

O&M costs are typically expressed on an average annual basis and are provided in either constant or current dollars for a specified year, as shown on the bottom of the screen.

Variable Cost Component

High Temperature Catalyst Cost: This is the replacement cost of the iron-based high temperature catalyst. The initial cost is not included in this parameter.

Low Temperature Catalyst Cost: This is the replacement cost of the copper-based low temperature catalyst.The initial cost is not included in this parameter.

Electricity: The cost of electricity consumed by the water gas shift process areas.

Thermal Power Credit: The credit for thermal power generated from steam provided by the heat exchangers in the water shift reactor vessels.

Water Cost: This is total cost of water used to drive the water gas shift reaction.

Total Variable Costs: This is the sum of all of the variable O&M costs listed above. This result is highlighted in yellow.

Fixed Cost Components

Fixed operating costs are essentially independent of actual capacity factor, number of hours of operation, or amount of kilowatts produced. All the costs are subject to inflation.

Operating Labor: Operating labor cost is based on the operating labor rate, the number of personnel required to operate the plant per eight-hour shift, and the average number of shifts per day over 40 hours per week and 52 weeks.

Maintenance Labor: The maintenance labor is determined as a fraction of the total maintenance cost.

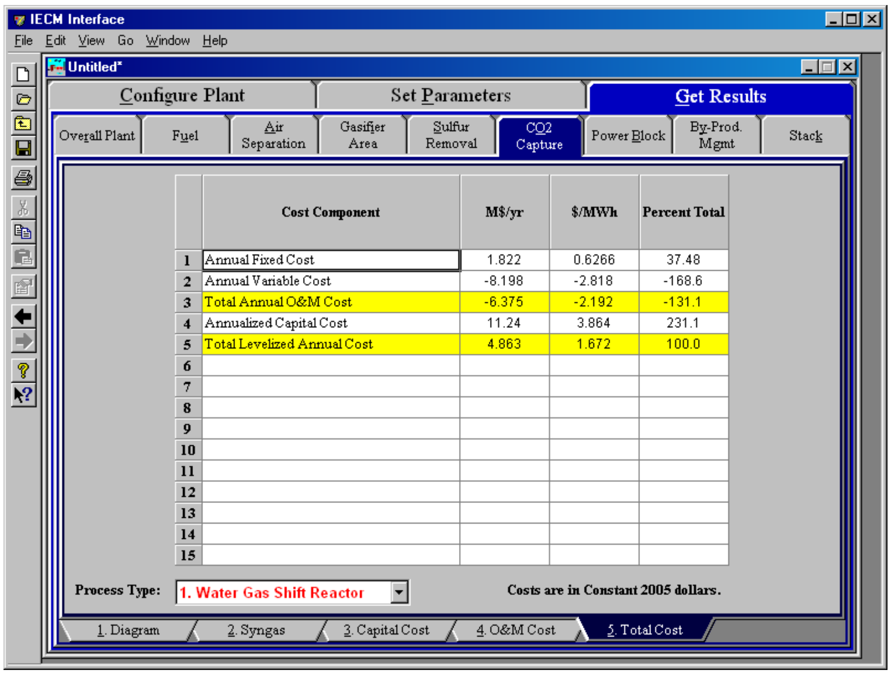
Maintenance Material: The cost of maintenance material is the remainder of the total maintenance cost, considering the fraction associated with maintenance labor.

Admin. & Support Labor: The administrative and support labor is the only overhead charge. It is taken as a fraction of the total operating and maintenance labor costs.

Total Fixed Costs: This is the sum of all the fixed O&M costs listed above. This result is highlighted in yellow.

Total O&M Costs: This is the sum of the total variable and total fixed O&M costs. It is used to determine the base plant total revenue requirement. This result is highlighted in yellow.

Water Gas Shift Reactor Total Cost Results



Water Gas Shift Reactor – Total Cost result screen.

The **Total Cost** result screen displays a table which totals the annual fixed, variable, operations and maintenance, and capital costs associated with the **Water Gas Shift Reactor Unit**. Total costs are typically expressed in either constant or current dollars for a specified year, as shown on the bottom of the screen. Each result is described briefly below.

Cost Component

Annual Fixed Cost: The operating and maintenance fixed costs are given as an annual total. This number includes all maintenance materials and all labor costs.

Annual Variable Cost: The operating and maintenance variables costs are given as an annual total. This includes all reagent, chemical, steam, and power costs.

Total Annual O&M Cost: This is the sum of the annual fixed and variable operating and maintenance costs above. This result is highlighted in yellow.

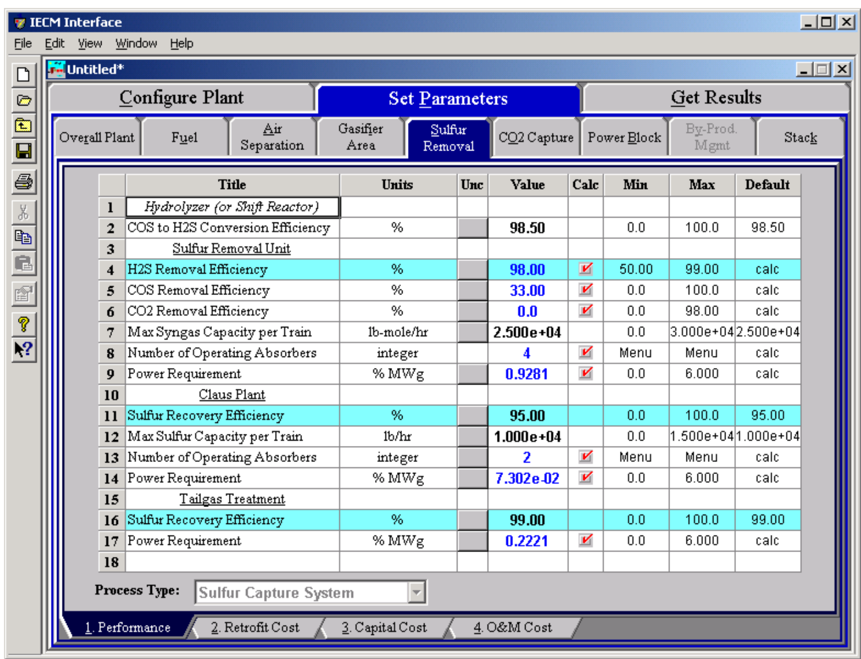
Annualized Capital Cost: This is the total capital cost expressed on an annualized basis, taking into consideration the levelized carrying charge factor, or fixed charge factor, over the entire book life.

Total Levelized Annual Cost: The total annual cost is the sum of the total annual O&M cost and annualized capital cost items above. This result is highlighted in yellow.

Sulfur Removal

SO_2 emissions from IGCC systems are controlled by removing sulfur species from the syngas prior to combustion in the gas turbine. The syngas is assumed to be scrubbed of particulates prior to entering the sulfur removal system and is further cooled to 101 °F prior to entering a Selexol acid gas separation unit. H_2S and COS are removed from the syngas in the Selexol unit and sent to a Claus plant and a Beavon-Stretford tail gas treatment unit for sulfur recovery. The sulfur recovered can be sold as a by-product and credited to the sulfur removal technology area.

Sulfur Removal Performance Inputs



	Title	Units	Unc	Value	Calc	Min	Max	Default
1	Hydrolyzer (or Shift Reactor)							
2	COS to H2S Conversion Efficiency	%		98.50		0.0	100.0	98.50
3	Sulfur Removal Unit							
4	H2S Removal Efficiency	%		98.00	✓	50.00	99.00	calc
5	COS Removal Efficiency	%		33.00	✓	0.0	100.0	calc
6	CO2 Removal Efficiency	%		0.0	✓	0.0	98.00	calc
7	Max Syngas Capacity per Train	lb-mole/hr		2.500e+04		0.0	3.000e+04	2.500e+04
8	Number of Operating Absorbers	integer		4	✓	Menu	Menu	calc
9	Power Requirement	% MWg		0.9281	✓	0.0	6.000	calc
10	Claus Plant							
11	Sulfur Recovery Efficiency	%		95.00		0.0	100.0	95.00
12	Max Sulfur Capacity per Train	lb/hr		1.000e+04		0.0	1.500e+04	1.000e+04
13	Number of Operating Absorbers	integer		2	✓	Menu	Menu	calc
14	Power Requirement	% MWg		7.302e-02	✓	0.0	6.000	calc
15	Tailgas Treatment							
16	Sulfur Recovery Efficiency	%		99.00		0.0	100.0	99.00
17	Power Requirement	% MWg		0.2221	✓	0.0	6.000	calc
18								

Sulfur Removal – Performance input screen.

The acid gas removal system employs the Selexol process for selective removal of hydrogen sulfide (H_2S) and carbonyl sulfide (COS). Usually COS is present in much smaller quantities than H_2S. In this unit, most of the H_2S is removed by absorption in the Selexol solvent, with a typical removal efficiency of 95 to 98 percent. Typically only about one third of COS in the syngas will be absorbed. A hydrolyzer is used to convert the captured COS to H_2S in preparation for the stripping of H_2S from the Selexol solvent, along with sour gas from the process water treatment unit. This concentrated gas stream is then sent to the Claus sulfur plant for recovery of elemental sulfur.

Hydrolyzer (or Shift Reactor)

COS to H_2S Conversion Efficiency: This is the efficiency with which carbonyl sulfide is converted to hydrogen sulfide.

Sulfur Removal Unit

H_2S Removal Efficiency: This is the removal efficiency of H_2S from the inlet syngas stream. The H_2S is removed by an absorption process that is very effective at capture of H_2S.

COS Removal Efficiency: This is the removal efficiency of COS. The absorption process is not very effective at capturing COS, so the removal efficiency default is very low.

CO_2 Removal Efficiency: This is removal efficiency of CO_2 for the sulfur recovery system. This system is optimized to capture sulfur-bearing components of a syngas, but maintains an affinity for CO_2. The CO2 removed is eventually vented to the atmosphere from the Beavon-Stretford technology.

Max Syngas Capacity per Train: This is the maximum flow rate of one Selexol-based sulfur recovery vessel. It is used to determine the number of absorber vessels required to treat the syngas.

Number of Operating Absorbers: This is the number of absorbers required to treat the entire syngas stream. It is used primarily to determine the cost of the sulfur control area.

Power Requirement: This is the equivalent electrical output of thermal (steam) energy used for reheat, plus the actual electrical output power required. It is calculated as a function of the syngas flow rate.

Claus Plant

Sulfur Recovery Efficiency: This is the recovery efficiency of the Claus Plant in converting H_2S to elemental sulfur.

Max Sulfur Capacity per Train: This is the maximum capacity of elemental sulfur from one Claus train.

Number of Operating Absorbers: The number of trains is estimated from the recovered sulfur mass flow rate and the allowable range of recovered sulfur mass flow rate per train

Power Requirement: This is the equivalent electrical output of thermal (steam) energy used for reheat, plus the actual electrical output power required. It is calculated as a function of the sulfur flow from the Claus plant.

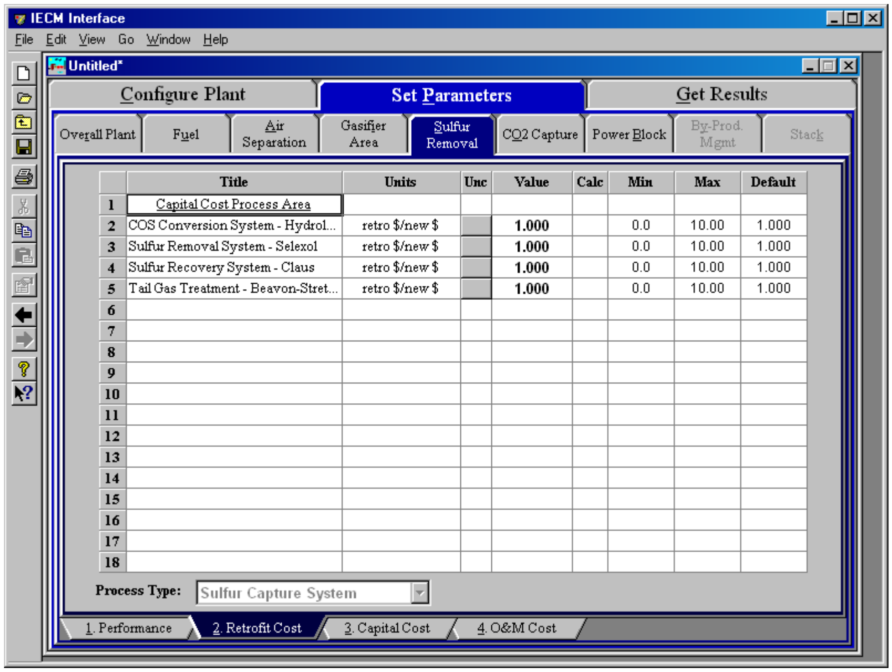
Tailgas Treatment

(Note: The number of trains for this area is the same as the number of trains for the Claus plant process area.)

Sulfur Recovery Efficiency: This is the recovery efficiency of the Beavon-Stretford plant in generating elemental sulfur. The remainder is oxidized to SO_2 and sent to a stack.

Power Requirement: This is the equivalent electrical output of thermal (steam) energy used for reheat, plus the actual electrical output power required for all three technologies above. It is calculated as a function of the sulfur flow rate from the Beavon-Stretford plant.

Sulfur Removal Retrofit Cost Inputs



Sulfur Removal – Retrofit Cost input screen.

Capital Cost Process Area

COS Conversion System - Hydrolyzer: The Hydrolyzer helps to separate the carbon from the sulfur by converting carbonyl sulfide to hydrogen sulfide.

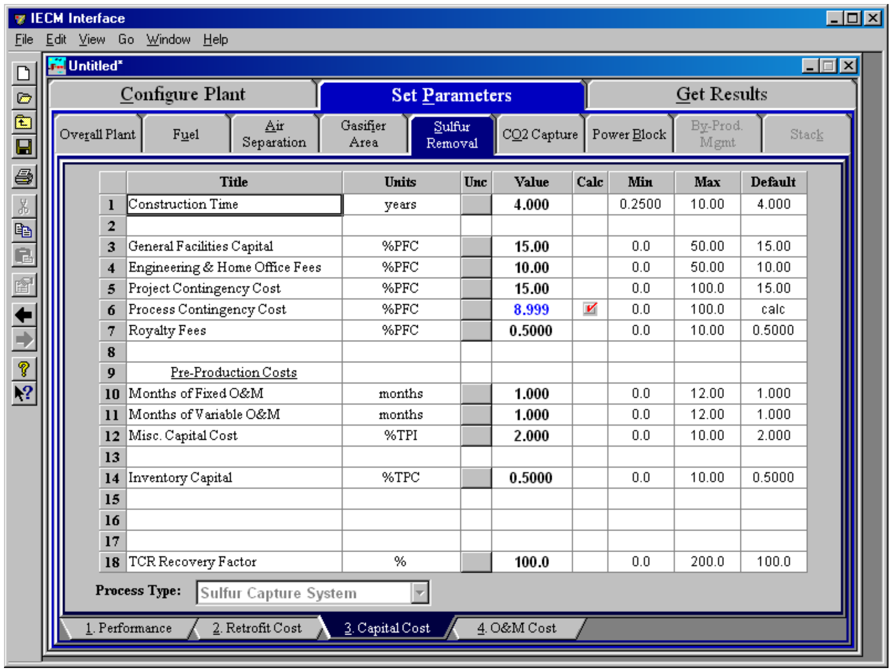
Sulfur Removal System – Selexol: H_2S in the syngas is removed through counter-current contact with Selexol solvent. The cost of the Selexol section includes the acid gas absorber, syngas knock-out drum, syngas heat exchanger, flash drum, lean solvent cooler, mechanical refrigeration unit, lean/rich solvent heat exchanger, solvent regenerator, regenerator air-cooled overhead condenser, acid gas knock-out drum, regenerator reboiler, and pumps and expanders associated with the Selexol process.

Sulfur Recovery System – Claus: The Claus plant contains a two-stage sulfur furnace, sulfur condensers, and catalysts.

Tail Gas Treatment - Beavon-Stretford: The process facilities capital is the total constructed cost of all on-site processing and generating units listed above, including all direct and indirect construction costs.

All sales taxes and freight costs are included where applicable implicitly. This result is highlighted in yellow.

Sulfur Removal Capital Cost Inputs



Sulfur Removal – Capital Cost input screen.

Inputs for capital costs are entered on the **Capital Cost** input screen.

Construction Time: This is the idealized construction period in years. It is used to determine the allowance for funds used during construction (AFUDC).

General Facilities Capital (GFC): 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%.

Engineering & Home Office Fees: The engineering & home office fees are a percent of total direct capital cost. This is an overhead fee paid to the architect/engineering company. These fees typically range from 7-15%.

Project Contingency Cost: This is 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.

Process Contingency Cost: 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.

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

Pre-Production Costs: 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 applied to the O&M costs over a specified period of time (months). The two time periods for fixed and variable O&M costs are described below with the addition of a miscellaneous capital cost factor.

- **Months of Fixed O&M:** Time period of fixed operating costs used for preproduction to cover training, testing, major changes in equipment, and inefficiencies in start-up. This includes operating, maintenance, administrative and support labor. It also considers maintenance materials.

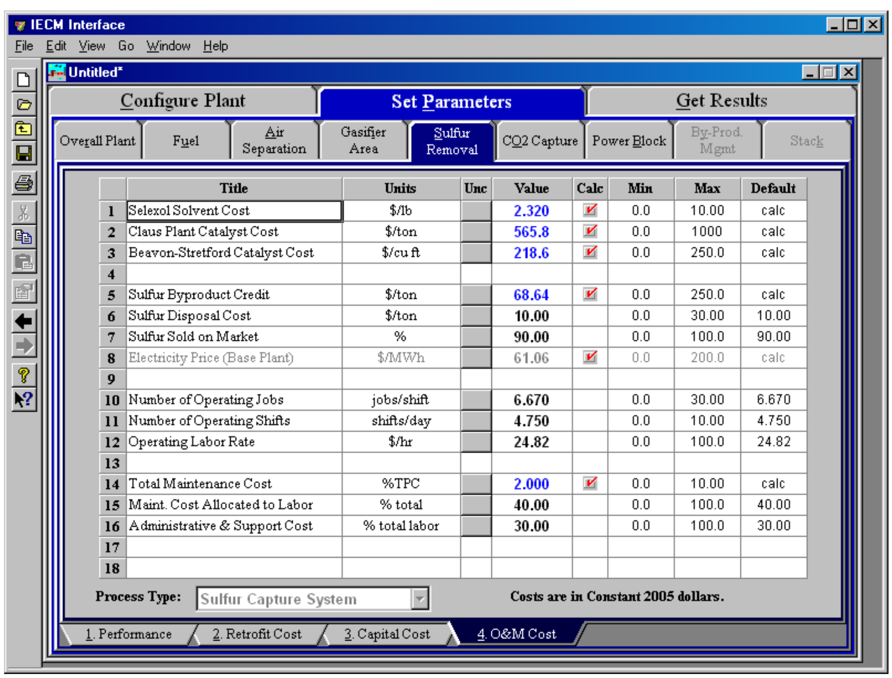
- **Months of Variable O&M:** Time period of variable operating costs used for preproduction to cover chemicals, water, consumables, and solid disposal charges in start-up, assuming 100% load. This excludes any fuels.

- **Misc. Capital Cost:** This is a percent of total plant investment (sum of TPC and AFUDC) to cover expected changes to equipment to bring the system up to full capacity.

Inventory Capital: Percent of the total direct capital for raw material supply based on 100% capacity during a 60 day period. These materials are considered storage. The inventory capital includes fuels, consumables, by-products, and spare parts. This is typically 0.5%.

TCR Recovery Factor: The actual total capital required (TCR) as a percent of the TCR in a new power plant. This value is 100% for a new installation and may be set as low as 0% for a fabric filter that has been paid off.

Sulfur Removal O&M Cost Inputs



Sulfur Removal – O&M Cost input screen.

Inputs for O&M costs are entered on the **Sulfur Removal O&M Cost** input screen. O&M costs are typically expressed on an average annual basis and are provided in either constant or current dollars for a specified year, as shown on the bottom of the screen.

Selexol Solvent Cost: This is the unit cost of Selexol.

Claus Plant Catalyst Cost: This is the unit cost of catalyst used in the Claus plant.

Beavon-Stretford Catalyst Cost: This is the unit cost of catalyst used in the Beavon-Stretford plant.

Sulfur Byproduct Credit: This is the unit price of sulfur sold on the market.

Sulfur Disposal Cost: This is the unit cost of any disposal wastes generated by the sulfur recovery processes.

Sulfur Sold on Market: This is the fraction of the collected sulfur that is sold on the market. Any remaining sulfur is assumed to be utilized at no cost (i.e., neither disposed nor sold).

Electricity Price (Base Plant) : This is the price of electricity and is calculated as a function of the utility cost of the base plant, where the base plant is defined as the air separation unit, the gasifier, and the power block.

Number of Operating Jobs: This is the total number of operating jobs that are required to operate the plant per eight-hour shift.

Number of Operating Shifts: This is the total number of equivalent operating shifts in the plant per day. The number takes into consideration paid time off and weekend work (3 shifts/day * 7 days/5 day week * 52 weeks/(52 weeks - 6 weeks PTO) = 4.75 equiv. Shifts/day)

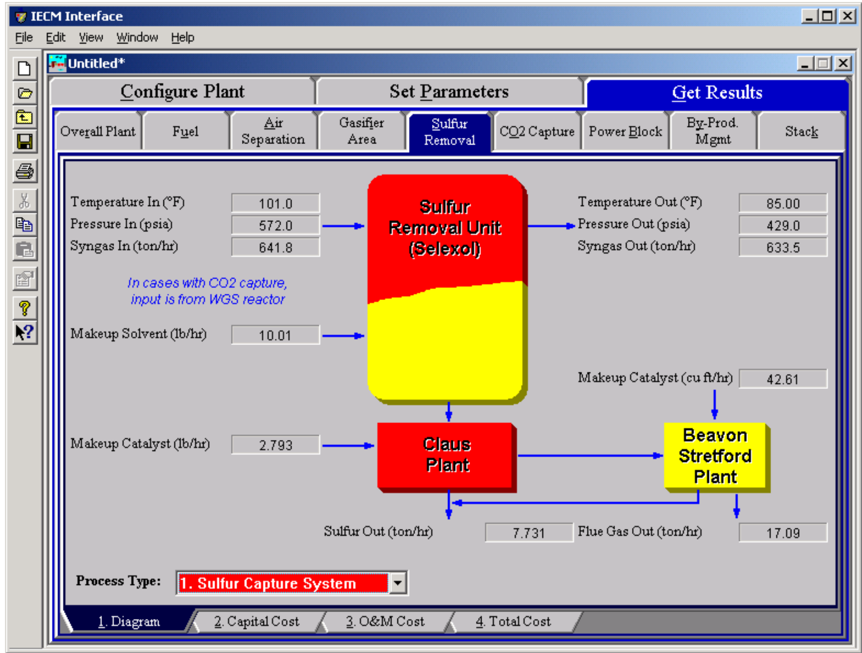
Operating Labor Rate: The hourly cost of labor is specified in the base plant O&M cost screen. The same value is used throughout the other technologies.

Total Maintenance Cost: This is the annual maintenance cost as a percentage of the total plant cost. Maintenance cost estimates can be developed separately for each process area.

Maint. Cost Allocated to Labor: Maintenance cost allocated to labor as a percentage of the total maintenance cost.

Administrative & Support Cost: This is the percent of the total operating and maintenance labor associated with administrative and support labor.

Sulfur Removal Diagram



Sulfur Removal – Diagram result screen.

The **Sulfur Removal Diagram** result screen displays an icon for the **Sulfur Removal Unit (Selexol)**, the **Claus Plant**, the **Beavon Stretford Plant** and values for major flows in and out of it. The user may switch between the three process types' results by choosing from the pull down menu labeled **Process Type**, located above the bottom tabs on the left side of the **Sulfur Removal Diagram**. Each result shown on the **Sulfur Removal Diagram** is described briefly below in flow::

Temperature In: Temperature of the syngas entering the Selexol-based sulfur removal unit.

Pressure In: Pressure of the syngas entering the Selexol-based sulfur removal unit.

Syngas In: Flow rate of the syngas entering the Selexol-based sulfur removal unit.

Makeup Solvent In: This is the Selexol solvent makeup rate into the sulfur removal unit expressed on a continuous basis.

Makeup Catalyst In: This is the catalyst makeup rate for the Claus plant expressed on a continuous basis.

Temperature Out: Temperature of the syngas exiting the Selexol-based sulfur removal unit.

Pressure Out: Pressure of the syngas exiting the Selexol-based sulfur removal unit.

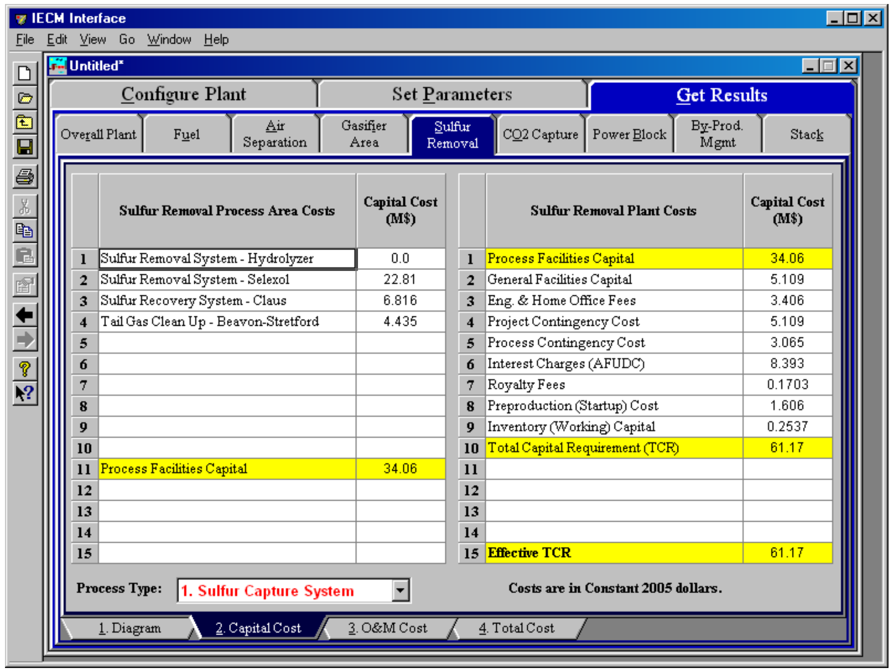
Syngas Out: Flow rate of the syngas exiting the Selexol-based sulfur removal unit.

Makeup Catalyst In: This is the catalyst makeup rate for the Beavon-Stretford plant expressed on a continuous basis.

Sulfur Out: Flow rate of the elemental sulfur collected in both the Claus and Beavon-Stretford plants.

Flue Gas Out: The exhaust gas from the Beavon-Stretford plant is completely burned and sent to a stack. This is the flow rate of combusted exhaust gases.

Sulfur Removal Capital Cost Results



Sulfur Removal Capital Cost results screen.

The **Sulfur Removal Capital Cost** result screen displays tables for the capital costs. Capital costs are typically expressed in either constant or current dollars for a specified year, as shown on the bottom of the screen. Each result is described briefly below:

Sulfur Removal Process Area Costs

Sulfur Removal System - Hydrolyzer This is the capital cost for the hydrolyzer system, which converts carbonyl sulfide to hydrogen sulfide.

Sulfur Removal System - Selexol H_2S in the syngas is removed through counter-current contact with Selexol solvent. The cost of the Selexol section includes the acid gas absorber, syngas knock-out drum, syngas heat exchanger, flash drum, lean solvent cooler, mechanical refrigeration unit, lean/rich solvent heat exchanger, solvent regenerator, regenerator air-cooled overhead condenser, acid gas knock-out drum, regenerator reboiler, and pumps and expanders associated with the Selexol process.

Sulfur Recovery System - Claus The Claus plant contains a two-stage sulfur furnace, sulfur condensers, and catalysts.

Tail Gas Clean Up - Beavon-Stretford The capital cost of a Beavon-Stretford unit varies with the volume flow rate of the input gas streams and with the mass flow rate of the sulfur produced. The regression model is based only on the sulfur produced by the Beavon-Stretford process.

Process Facilities Capital: The process facilities capital is the total constructed cost of all on-site processing and generating units listed above, including all direct and indirect construction costs. All sales taxes and freight costs are included where applicable implicitly. This result is highlighted in yellow.

Sulfur Removal Plant Costs

Process Facilities Capital: (see definition above)

General Facilities Capital: The general facilities include construction costs of roads, office buildings, shops, laboratories, etc. Sales taxes and freight costs are included implicitly.

Eng. & Home Office Fees: The engineering & home office fees are a percent of total direct capital cost. This is an overhead fee paid to the architect/engineering company.

Project Contingency Cost: Capital cost contingency factor covering the cost of additional equipment or other costs that would result from a more detailed design of a definitive project at the actual site.

Process Contingency Cost: Capital cost contingency factor applied to a new technology in an effort to quantify the uncertainty in the technical performance and cost of the commercial-scale equipment.

Interest Charges (AFUDC): Allowance for funds used during construction, also referred to as interest during construction, is the time value of the money used during construction and is based on an interest rate equal to the before-tax weighted cost of capital. This interest is compounded on an annual basis (end of year) during the construction period for all funds spent during the year or previous years.

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

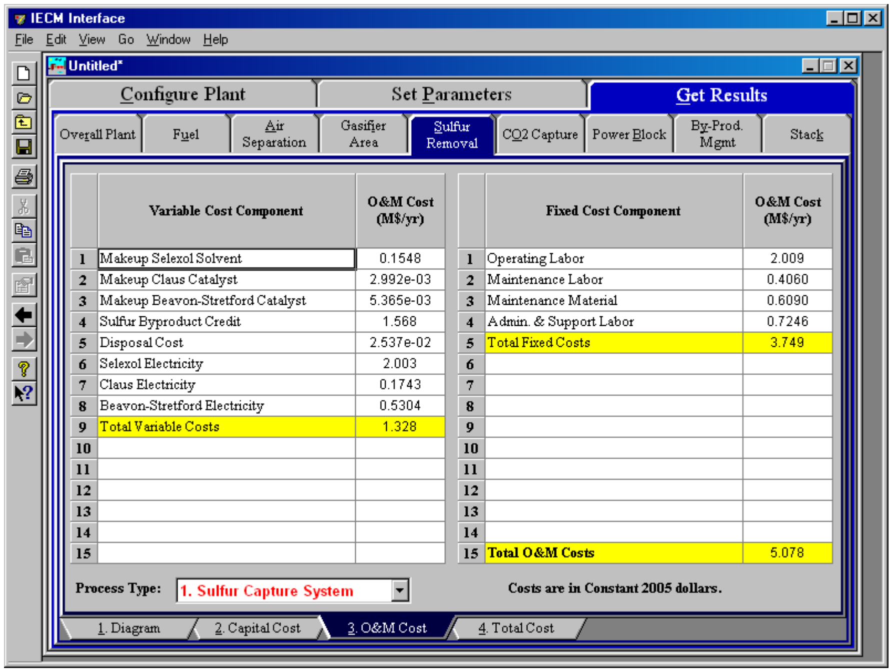
Preproduction (Startup) Cost: These costs consider the operator training, equipment checkout, major changes in unit equipment, extra maintenance, and inefficient use of fuel or other materials during start-up.

Inventory (Working) Capital: The raw material supply based on 100% capacity during a 60 day period. These materials are considered storage. The inventory capital includes fuels, consumables, by-products, and spare parts.

Total Capital Requirement (TCR): Money that is placed (capitalized) on the books of the utility on the service date. TCR includes all the items above. This result is highlighted in yellow.

Effective TCR: The TCR of the spray dryer that is used in determining the total power plant cost. The effective TCR is determined by the “TCR Recovery Factor”.

Sulfur Removal O&M Cost Results



Sulfur Removal – O&M Cost results screen.

O&M costs are typically expressed on an average annual basis and are provided in either constant or current dollars for a specified year, as shown on the bottom of the screen.

Variable Cost Component

Makeup Selexol Solvent This is the annual cost of makeup Selexol.

Makeup Claus Catalyst This is the annual cost of makeup catalyst used in the Claus plant.

Makeup Beavon-Stretford Catalyst This is the annual cost of makeup catalyst used in the Beavon-Stretford plant.

Sulfur Byproduct Credit This is the annual profit for sulfur sold on the market.

Disposal Cost This is the annual cost of all wastes generated by the sulfur recovery processes and disposed.

Selexol Electricity This is the annual cost of electricity used by the Selexol-based sulfur capture process area. It is based on the electricity price of the base plant and the power consumed in the process areas.

Claus Electricity This is the annual cost of electricity used by the Claus plant process area. It is based on the electricity price of the base plant and the power consumed in the process areas.

Beavon-Stretford Electricity: This is the annual cost of electricity used by the Beavon-Stretford process area. It is based on the electricity price of the base plant and the power consumed in the process areas.

Total Variable Costs: This is the sum of all the variable O&M costs listed above. This result is highlighted in yellow.

Fixed Cost Components

Fixed operating costs are essentially independent of actual capacity factor, number of hours of operation, or amount of kilowatts produced. All the costs are subject to inflation.

Operating Labor: Operating labor cost is based on the operating labor rate, the number of personnel required to operate the plant per eight-hour shift, and the average number of shifts per day over 40 hours per week and 52 weeks.

Maintenance Labor: The maintenance labor is determined as a fraction of the total maintenance cost.

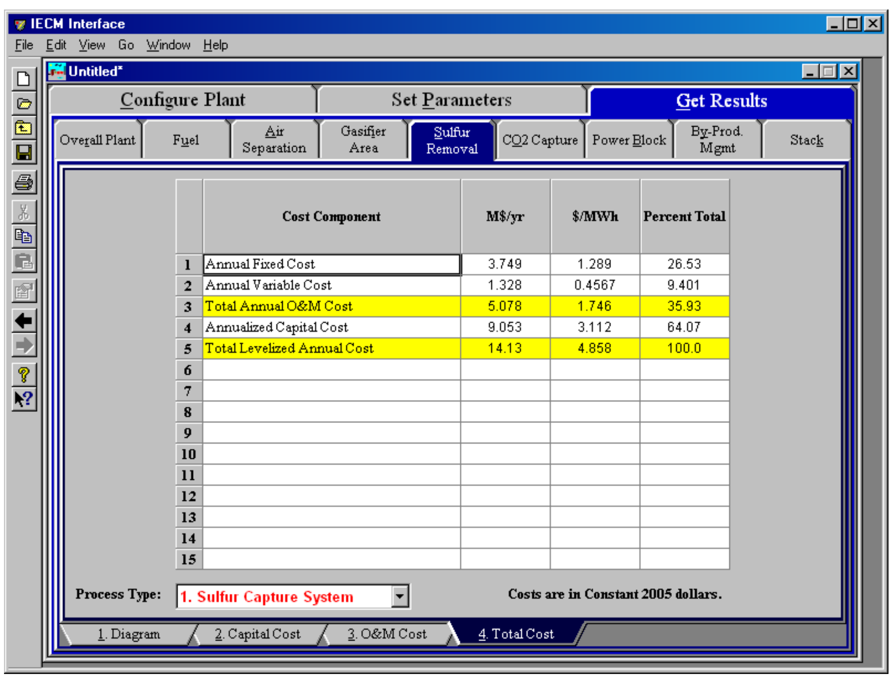
Maintenance Material: The cost of maintenance material is the remainder of the total maintenance cost, considering the fraction associated with maintenance labor.

Admin. & Support Labor: The administrative and support labor is the only overhead charge. It is taken as a fraction of the total operating and maintenance labor costs.

Total Fixed Costs: This is the sum of all the fixed O&M costs listed above. This result is highlighted in yellow.

Total O&M Costs: This is the sum of the total variable and total fixed O&M costs. It is used to determine the base plant total revenue requirement. This result is highlighted in yellow.

Sulfur Removal Total Cost Results



Sulfur Removal – Total Cost results screen.

The **Total Cost** result screen displays a table which totals the annual fixed, variable, operations and maintenance, and capital costs associated with the **Sulfur Removal Unit**. Total costs are typically expressed in either constant or current dollars for a specified year, as shown on the bottom of the screen. Each result is described briefly below.

Cost Component

Annual Fixed Cost: The operating and maintenance fixed costs are given as an annual total. This number includes all maintenance materials and all labor costs.

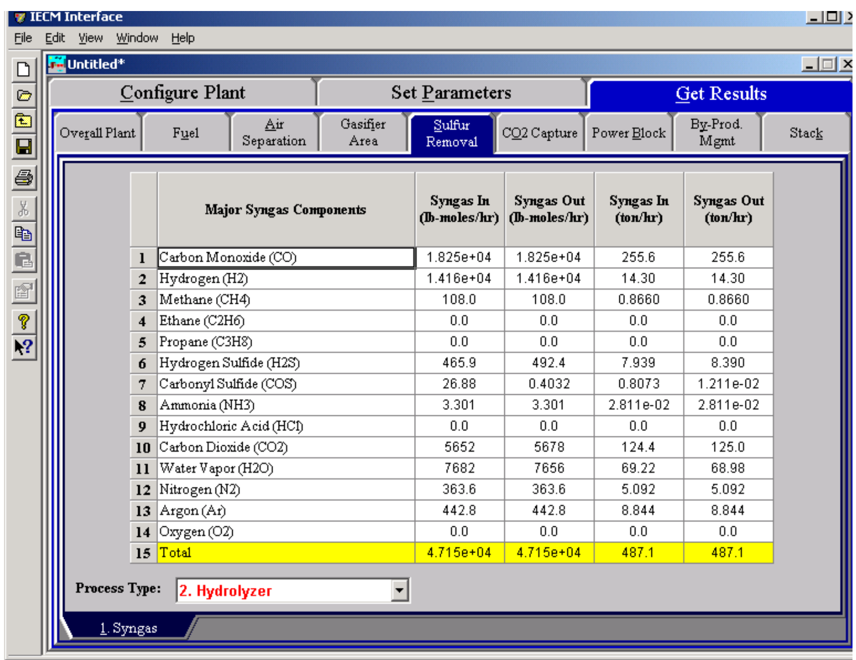
Annual Variable Cost: The operating and maintenance variables costs are given as an annual total. This includes all reagent, chemical, steam, and power costs.

Total Annual O&M Cost: This is the sum of the annual fixed and variable operating and maintenance costs above. This result is highlighted in yellow.

Annualized Capital Cost: This is the total capital cost expressed on an annualized basis, taking into consideration the levelized carrying charge factor, or fixed charge factor, over the entire book life.

Total Levelized Annual Cost: The total annual cost is the sum of the total annual O&M cost and annualized capital cost items above. This result is highlighted in yellow.

Sulfur Removal Hydrolyzer Syngas Results



	Major Syngas Components	Syngas In (lb-moles/hr)	Syngas Out (lb-moles/hr)	Syngas In (ton/hr)	Syngas Out (ton/hr)
1	Carbon Monoxide (CO)	1.825e+04	1.825e+04	255.6	255.6
2	Hydrogen (H2)	1.416e+04	1.416e+04	14.30	14.30
3	Methane (CH4)	108.0	108.0	0.8660	0.8660
4	Ethane (C2H6)	0.0	0.0	0.0	0.0
5	Propane (C3H8)	0.0	0.0	0.0	0.0
6	Hydrogen Sulfide (H2S)	465.9	492.4	7.939	8.390
7	Carbonyl Sulfide (COS)	26.88	0.4032	0.8073	1.211e-02
8	Ammonia (NH3)	3.301	3.301	2.811e-02	2.811e-02
9	Hydrochloric Acid (HCl)	0.0	0.0	0.0	0.0
10	Carbon Dioxide (CO2)	5652	5678	124.4	125.0
11	Water Vapor (H2O)	7682	7656	69.22	68.98
12	Nitrogen (N2)	363.6	363.6	5.092	5.092
13	Argon (Ar)	442.8	442.8	8.844	8.844
14	Oxygen (O2)	0.0	0.0	0.0	0.0
15	Total	4.715e+04	4.715e+04	487.1	487.1

Sulfur Removal Hydrolyzer Syngas results screen.

Major Syngas Components

Carbon Monoxide (CO): Total mass of carbon monoxide.

Hydrogen (H_2): Total mass of hydrogen.

Methane (CH_4): Total mass of methane.

Ethane (C_2H_6): Total mass of ethane.

Propane (C_3H_8): Total mass of propane.

Hydrogen Sulfide (H_2S): Total mass of hydrogen sulfide.

Carbonyl Sulfide (COS): Total mass of carbonyl sulfide.

Ammonia (NH_3): Total mass of ammonia.

Hydrochloric Acid (HCl): Total mass of hydrochloric acid.

Carbon Dioxide (CO_2): Total mass of carbon dioxide.

Water Vapor (H_2O): Total mass of water vapor.

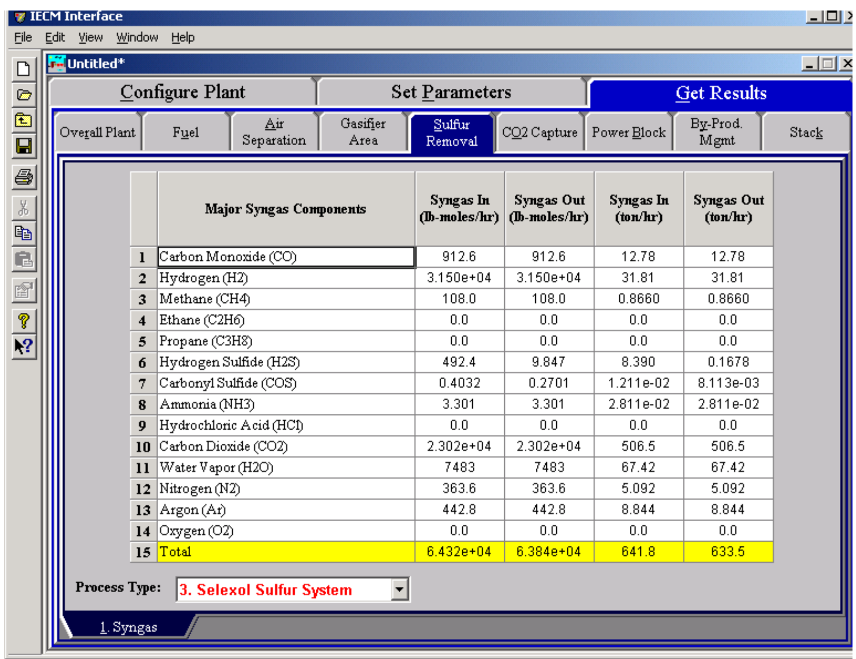
Nitrogen (N_2): Total mass of nitrogen.

Argon (Ar): Total mass of argon.

Oxygen (O_2): Total mass of oxygen.

Total: Total of the individual components listed above. This item is highlighted in yellow.

Sulfur Removal Selexol Sulfur System Syngas Results



	Major Syngas Components	Syngas In (lb-moles/hr)	Syngas Out (lb-moles/hr)	Syngas In (ton/hr)	Syngas Out (ton/hr)
1	Carbon Monoxide (CO)	912.6	912.6	12.78	12.78
2	Hydrogen (H2)	3.150e+04	3.150e+04	31.81	31.81
3	Methane (CH4)	108.0	108.0	0.8660	0.8660
4	Ethane (C2H6)	0.0	0.0	0.0	0.0
5	Propane (C3H8)	0.0	0.0	0.0	0.0
6	Hydrogen Sulfide (H2S)	492.4	9.847	8.390	0.1678
7	Carbonyl Sulfide (COS)	0.4032	0.2701	1.211e-02	8.113e-03
8	Ammonia (NH3)	3.301	3.301	2.811e-02	2.811e-02
9	Hydrochloric Acid (HCl)	0.0	0.0	0.0	0.0
10	Carbon Dioxide (CO2)	2.302e+04	2.302e+04	506.5	506.5
11	Water Vapor (H2O)	7483	7483	67.42	67.42
12	Nitrogen (N2)	363.6	363.6	5.092	5.092
13	Argon (Ar)	442.8	442.8	8.844	8.844
14	Oxygen (O2)	0.0	0.0	0.0	0.0
15	Total	6.432e+04	6.384e+04	641.8	633.5

Selexol Sulfur System Syngas results screen.

Major Syngas Components

Carbon Monoxide (CO): Total mass of carbon monoxide.

Hydrogen (H_2): Total mass of hydrogen.

Methane (CH_4): Total mass of methane.

Ethane (C_2H_6): Total mass of ethane.

Propane (C_3H_8): Total mass of propane.

Hydrogen Sulfide (H_2S): Total mass of hydrogen sulfide.

Carbonyl Sulfide (COS): Total mass of carbonyl sulfide.

Ammonia (NH_3): Total mass of ammonia.

Hydrochloric Acid (HCl): Total mass of hydrochloric acid.

Carbon Dioxide (CO_2): Total mass of carbon dioxide.

Water Vapor (H_2O): Total mass of water vapor.

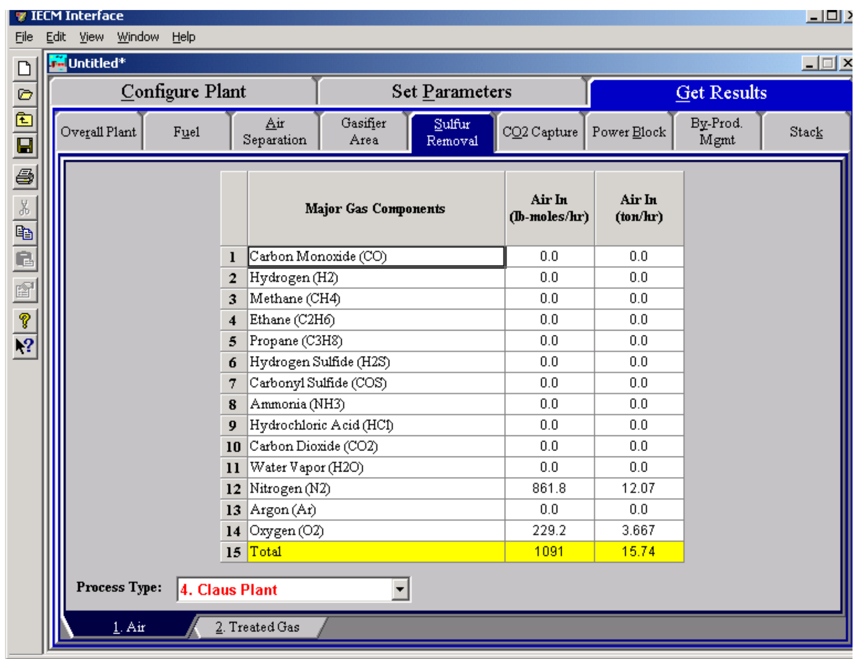
Nitrogen (N_2): Total mass of nitrogen.

Argon (Ar): Total mass of argon.

Oxygen (O_2): Total mass of oxygen.

Total: Total of the individual components listed above. This item is highlighted in yellow.

Sulfur Removal Claus Plant Air Results



	Major Gas Components	Air In (lb-moles/hr)	Air In (ton/hr)
1	Carbon Monoxide (CO)	0.0	0.0
2	Hydrogen (H2)	0.0	0.0
3	Methane (CH4)	0.0	0.0
4	Ethane (C2H6)	0.0	0.0
5	Propane (C3H8)	0.0	0.0
6	Hydrogen Sulfide (H2S)	0.0	0.0
7	Carbonyl Sulfide (COS)	0.0	0.0
8	Ammonia (NH3)	0.0	0.0
9	Hydrochloric Acid (HCl)	0.0	0.0
10	Carbon Dioxide (CO2)	0.0	0.0
11	Water Vapor (H2O)	0.0	0.0
12	Nitrogen (N2)	861.8	12.07
13	Argon (Ar)	0.0	0.0
14	Oxygen (O2)	229.2	3.667
15	Total	1091	15.74

Sulfur Removal Claus Plant Air results screen.

Major Syngas Components

Carbon Monoxide (CO): Total mass of carbon monoxide.

Hydrogen (H_2): Total mass of hydrogen.

Methane (CH_4): Total mass of methane.

Ethane (C_2H_6): Total mass of ethane.

Propane (C_3H_8): Total mass of propane.

Hydrogen Sulfide (H_2S): Total mass of hydrogen sulfide.

Carbonyl Sulfide (COS): Total mass of carbonyl sulfide.

Ammonia (NH_3): Total mass of ammonia.

Hydrochloric Acid (HCl): Total mass of hydrochloric acid.

Carbon Dioxide (CO_2): Total mass of carbon dioxide.

Water Vapor (H_2O): Total mass of water vapor.

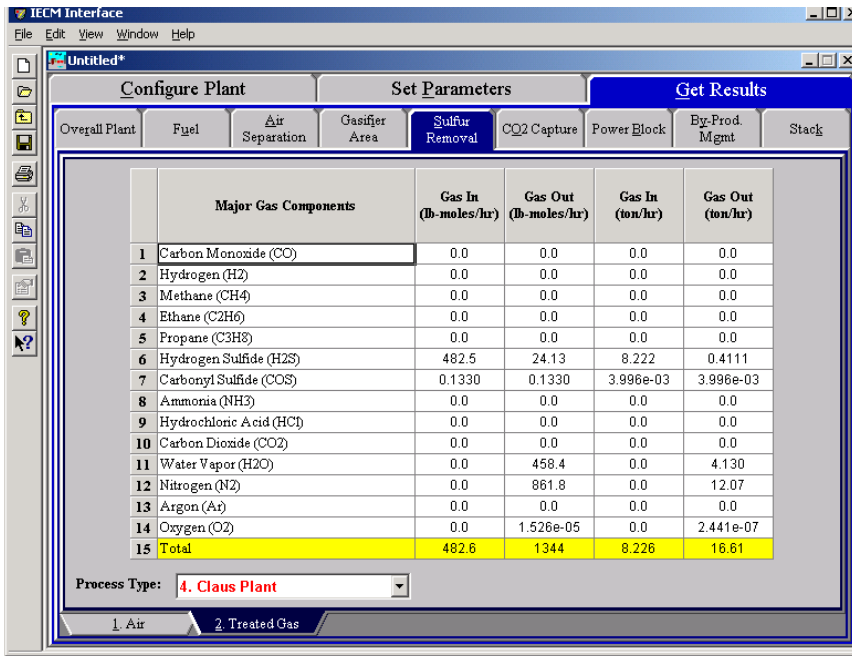
Nitrogen (N_2): Total mass of nitrogen.

Argon (Ar): Total mass of argon.

Oxygen (O_2): Total mass of oxygen.

Total: Total of the individual components listed above. This item is highlighted in yellow.

Sulfur Removal Claus Plant Treated Gas Results



	Major Gas Components	Gas In (lb-moles/hr)	Gas Out (lb-moles/hr)	Gas In (ton/hr)	Gas Out (ton/hr)
1	Carbon Monoxide (CO)	0.0	0.0	0.0	0.0
2	Hydrogen (H2)	0.0	0.0	0.0	0.0
3	Methane (CH4)	0.0	0.0	0.0	0.0
4	Ethane (C2H6)	0.0	0.0	0.0	0.0
5	Propane (C3H8)	0.0	0.0	0.0	0.0
6	Hydrogen Sulfide (H2S)	482.5	24.13	8.222	0.4111
7	Carbonyl Sulfide (COS)	0.1330	0.1330	3.996e-03	3.996e-03
8	Ammonia (NH3)	0.0	0.0	0.0	0.0
9	Hydrochloric Acid (HCl)	0.0	0.0	0.0	0.0
10	Carbon Dioxide (CO2)	0.0	0.0	0.0	0.0
11	Water Vapor (H2O)	0.0	458.4	0.0	4.130
12	Nitrogen (N2)	0.0	861.8	0.0	12.07
13	Argon (Ar)	0.0	0.0	0.0	0.0
14	Oxygen (O2)	0.0	1.526e-05	0.0	2.441e-07
15	Total	482.6	1344	8.226	16.61

Sulfur Removal Claus Plant Treated Gas results screen.

Major Syngas Components

Carbon Monoxide (CO): Total mass of carbon monoxide.

Hydrogen (H_2): Total mass of hydrogen.

Methane (CH_4): Total mass of methane.

Ethane (C_2H_6): Total mass of ethane.

Propane (C_3H_8): Total mass of propane.

Hydrogen Sulfide (H_2S): Total mass of hydrogen sulfide.

Carbonyl Sulfide (COS): Total mass of carbonyl sulfide.

Ammonia (NH_3): Total mass of ammonia.

Hydrochloric Acid (HCl): Total mass of hydrochloric acid.

Carbon Dioxide (CO_2): Total mass of carbon dioxide.

Water Vapor (H_2O): Total mass of water vapor.

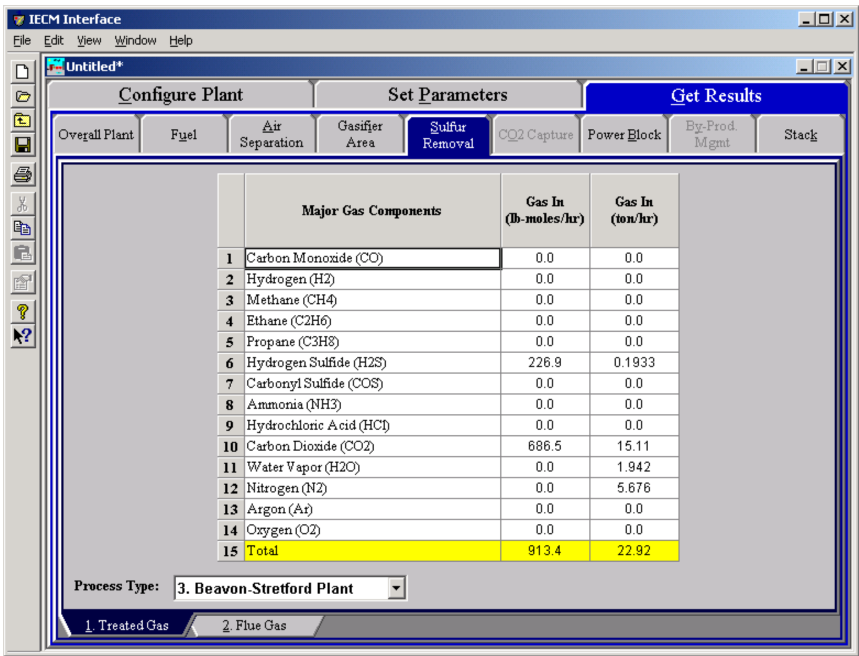
Nitrogen (N_2): Total mass of nitrogen.

Argon (Ar): Total mass of argon.

Oxygen (O_2): Total mass of oxygen.

Total: Total of the individual components listed above. This item is highlighted in yellow.

Sulfur Removal Beavon Stretford Plant Treated Gas Results



Sulfur Removal Beavon Stretford Plant Treated Gas results screen.

Major Syngas Components

Carbon Monoxide (CO): Total mass of carbon monoxide.

Hydrogen (H_2): Total mass of hydrogen.

Methane (CH_4): Total mass of methane.

Ethane (C_2H_6): Total mass of ethane.

Propane (C_3H_8): Total mass of propane.

Hydrogen Sulfide (H_2S): Total mass of hydrogen sulfide.

Carbonyl Sulfide (COS): Total mass of carbonyl sulfide.

Ammonia (NH_3): Total mass of ammonia.

Hydrochloric Acid (HCl): Total mass of hydrochloric acid.

Carbon Dioxide (CO_2): Total mass of carbon dioxide.

Water Vapor (H_2O): Total mass of water vapor.

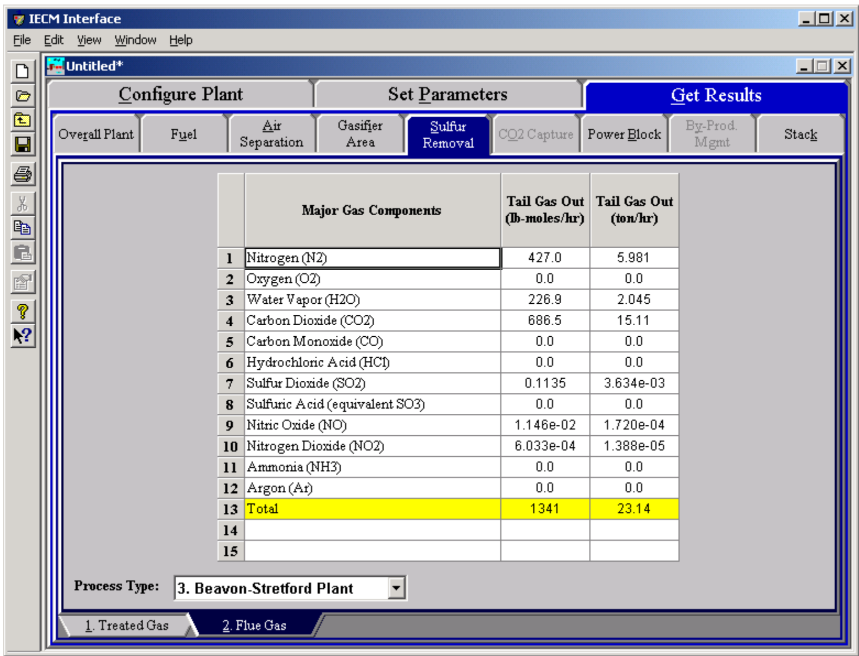
Nitrogen (N_2): Total mass of nitrogen.

Argon (Ar): Total mass of argon.

Oxygen (O_2): Total mass of oxygen.

Total: Total of the individual components listed above. This item is highlighted in yellow.

Sulfur Removal Beavon Stretford Plant Flue Gas Results



Sulfur Removal Beavon Stretford Plant Flue Gas Results

Major Flue Gas Components

Nitrogen (N_2): Total mass of nitrogen.

Oxygen (O_2): Total mass of oxygen.

Water Vapor (H_2O): Total mass of water vapor.

Carbon Dioxide (CO_2): Total mass of carbon dioxide.

Carbon Monoxide (CO): Total mass of carbon monoxide.

Hydrochloric Acid (HCl): Total mass of hydrochloric acid.

Sulfur Dioxide (SO_2): Total mass of sulfur dioxide.

Sulfuric Acid (equivalent SO_3): Total mass of sulfuric acid (on an SO_3equivalency basis).

Nitric Oxide (NO): Total mass of nitric oxide.

Nitrogen Dioxide (NO_2): Total mass of nitrogen dioxide.

Ammonia (NH_3): Total mass of ammonia.

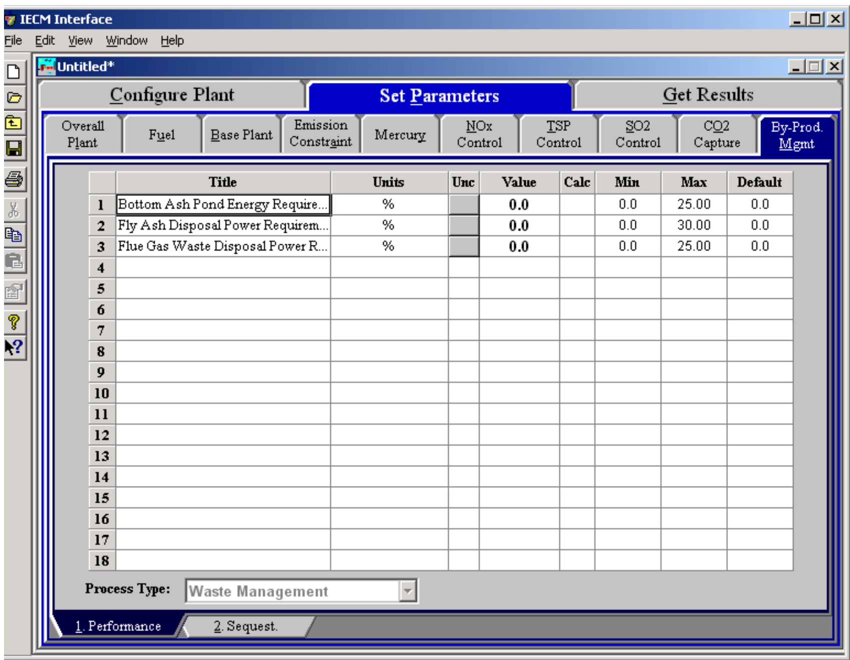
Argon (Ar): Total mass of argon.

Total: Total of the individual components listed above. This item is highlighted in yellow.

By Product Management

The **ByProduct Mgmt** Technology Navigation Tab screens display and design the management of by products and waste disposal.

By Product Management Performance Inputs



By Product Management – Performance input screen.

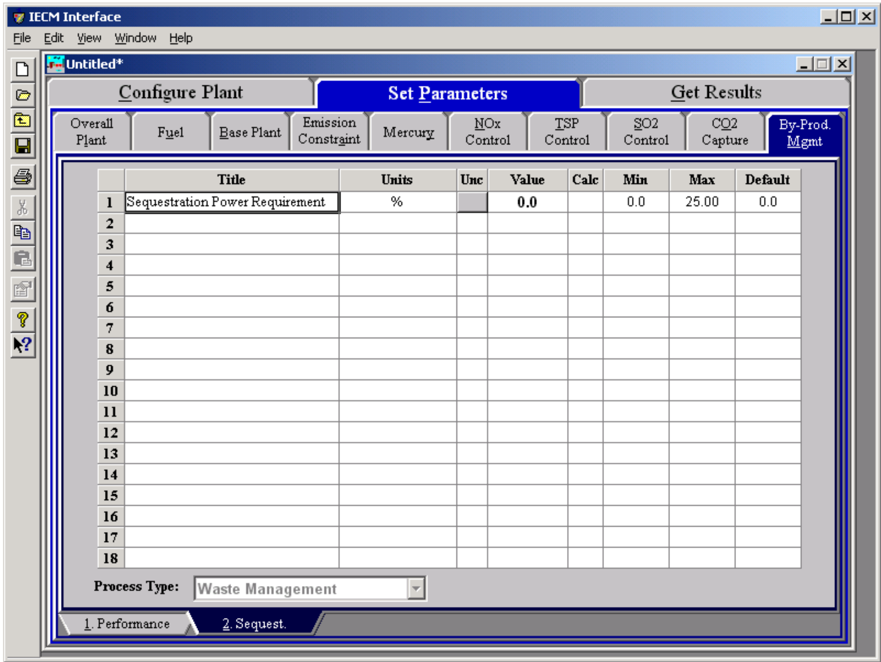
General inputs regarding solid waste management are entered on the **Performance** input screen. This screen is displayed for all plant configurations. One or more of the following By Product Management options will be shown on the input screen depending upon the options selected in the **Configure Plant** program area. Each of the possible parameters are described briefly below.

Bottom Ash Pond Energy Requirements: The energy requirement is zero by default. Any requirements are considered by the abatement technologies that dispose solids into the bottom ash pond.

Fly Ash Disposal Power Requirements: The energy requirement is zero by default. Any requirements are considered by the abatement technologies that dispose of fly ash.

Flue Gas Waste Disposal Power Requirements: The energy requirement is zero by default. Any requirements are considered by the abatement technologies that dispose of flue gas waste.

By Product Management Sequestration Input



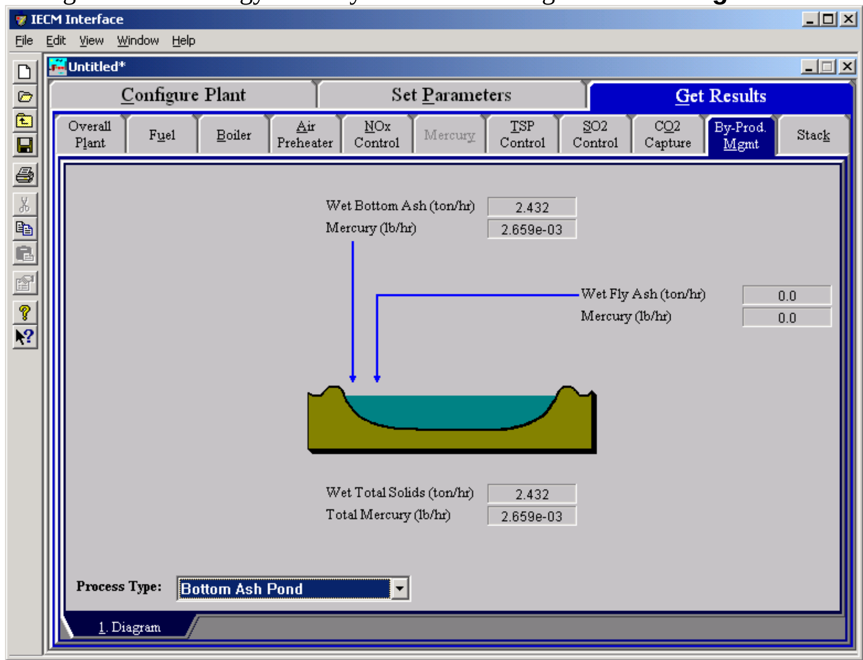
By Product Management – Sequestration input screen.

If the user has selected **CO_2 Capture** in the **Configure Plant** program area this input screen will also be available. Its parameter is described briefly below.

Sequestration Power Requirement: The energy requirement is zero by default.

By Products Management Bottom Ash Pond Diagram

The **By Product Management** Technology Navigation Tab screens displays the flow rates of solid and liquid substances collected which require management (disposal or recovery). There are three **By Product Management** areas, **Bottom Ash Pond**, **Flue Gas Treatment** and **Fly Ash Disposal**. If **CO_2** Capture has been configured for the plant by the user then a **Geological Reservoir** is also available. These are accessed by the **Process Type** drop-down menu. Each management technology has only one Result Navigation Tab: **Diagram**.



By Products Management Bottom Ash Pond—Diagram result screen

The **Bottom Ash Pond Diagram** result screen displays an icon for the **Pond** and values for major flows into it. Each result is described briefly below:

Bottom Ash Pond Inputs

Solids mixed with sluice water that are collected in the bottom of the boiler and by the particulate removal technologies are transported to the Pond for treatment. The IECM currently provides no additional treatment or consideration of these substances, and therefore simply reports the quantities entering the technology.

Wet Bottom Ash: Mass flow rate of bottom ash solids on a wet basis.

Mercury (contained in Bottom Ash): Mass flow rate of mercury present in the bottom ash solids on a wet basis.

Wet Fly Ash: Mass flow rate of total fly ash solids on a wet basis. This value is zero when the fly ash is disposed in a landfill.

Mercury (contained in Fly Ash): Mass flow rate of mercury present in the fly ash solids on a wet basis.

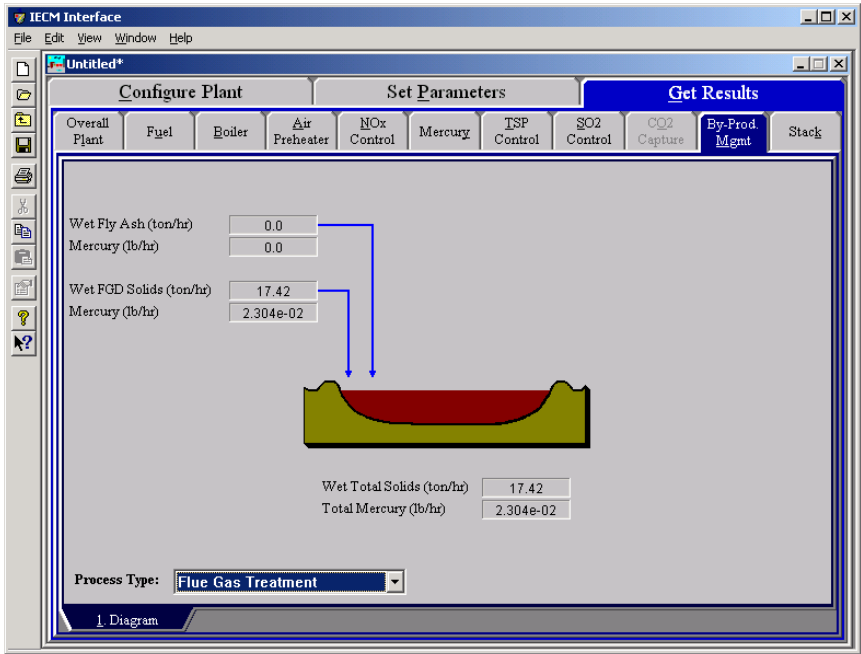
Bottom Ash Pond – Totals

Wet Total Solids: The sum of the fly ash and bottom ash solids on a wet basis.

Total Mercury: Mass flow rate of mercury present in the combined bottom ash and fly ash solids on a wet basis.

By Products Management Flue Gas Treatment Diagram

The **By Product Management** Technology Navigation Tab screens displays the flow rates of solid and liquid substances collected which require management (disposal or recovery). There are three **By Product Management** areas, **Bottom Ash Pond**, **Flue Gas Treatment** and **Fly Ash Disposal**. If CO_2 capture has been configured for the plant by the user then a **Geological Reservoir** is also available. These are accessed by the **Process Type** drop-down menu. Each management technology has only one Result Navigation Tab: **Diagram**.



By Products Management Bottom Ash Pond—Diagram result screen

The **Flue Gas Treatment Diagram** result screen displays an icon for the **Landfill** and values for major flows into it. Each result is described briefly below:

Flue Gas Treatment Inputs

Solids mixed with sluice water that are collected in the bottom of the boiler and by the particulate removal technologies are transported to the Pond for treatment. The IECM currently provides no additional treatment or consideration of these substances, and therefore simply reports the quantities entering the technology.

Wet FGD Solids: Mass flow rate of wet FGD solids.

Mercury (contained in Wet FGD Solids): Mass flow rate of mercury present in the Wet FGD solids.

Wet Fly Ash: Mass flow rate of total fly ash solids on a wet basis. This value is zero when the fly ash is disposed in a landfill.

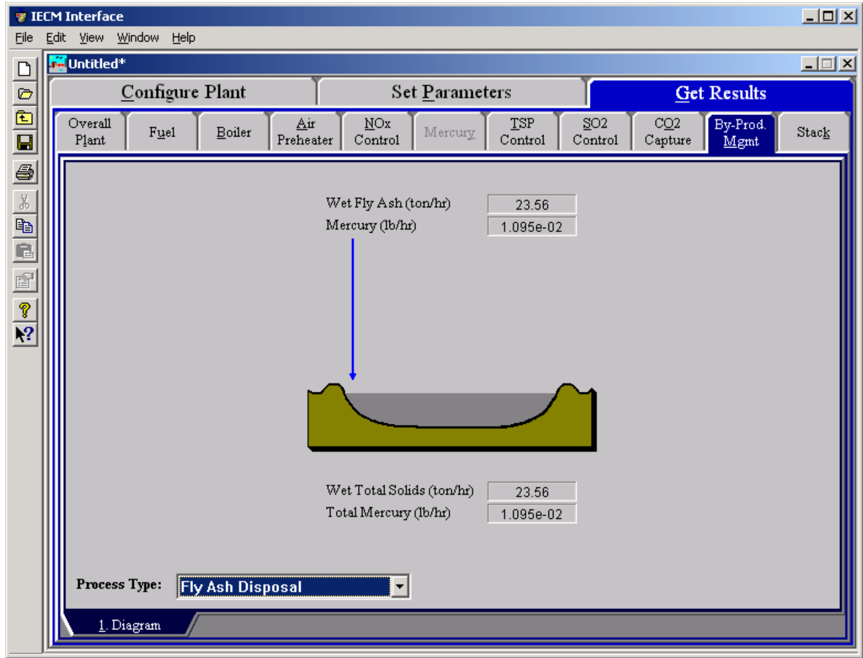
Mercury(contained in Fly Ash): Mass flow rate of mercury present in the fly ash solids on a wet basis.

Flue Gas Treatment – Totals

Wet Total Solids: The sum of the wet FGD solids and the fly ash on a wet basis.

Total Mercury: Mass flow rate of mercury present in the combined wet FGD solids and fly ash solids on a wet basis.

By Products Management Fly Ash Disposal Diagram



By Products Management Fly Ash Disposal—Diagram result screen

The **By Products Management Fly Ash Disposal Diagram** result screen displays an icon for the **Landfill** and values for major flows into it. This screen is only an option if **CO_2 Capture** has been configured for the plant by the user. Each result is described briefly below:

Fly Ash Disposal Inputs

Solids mixed with sluice water are collected in the particulate removal technologies and may be transported to the Landfill for treatment. The IECM currently provides no additional treatment or consideration of these substances, and therefore simply reports the quantities entering the technology.

Wet Fly Ash: Mass flow rate of total fly ash solids on a wet basis.

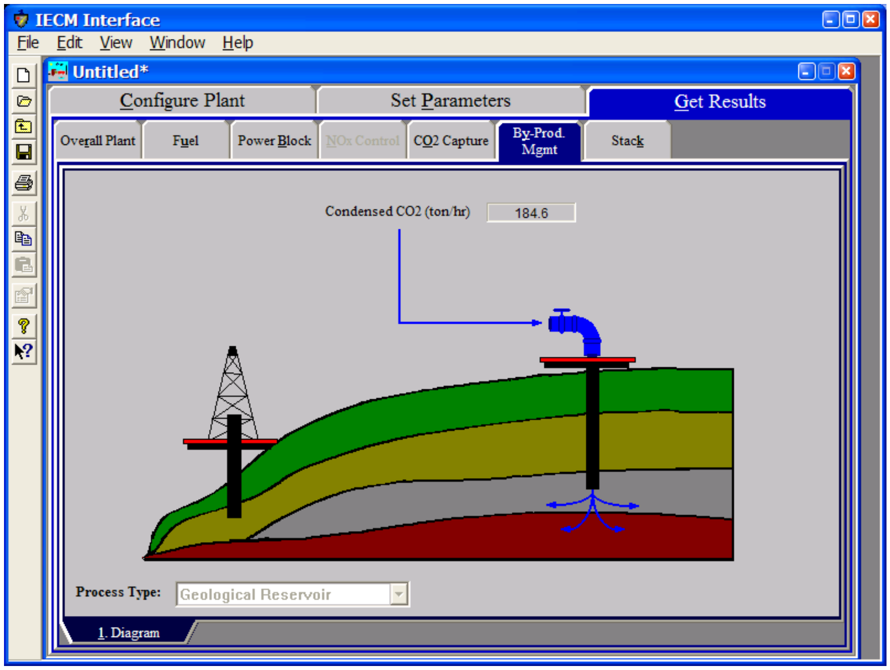
Mercury: Mass flow rate of mercury present in the fly ash solids on a wet basis.

Fly Ash Disposal Totals

Wet Total Solids: The sum of the fly ash and FGD solids on a wet basis.

Total Mercury: Mass flow rate of mercury present in the combined fly ash and FGD solids on a wet basis.

By Products Management Geological Resevoir Diagram



By Product Management – Geological Reservoir diagram.

The **By Products Management Geological Reservoir Diagram** result screen displays an icon for the **Geological Reservoir** and values for the concentrated CO_2 that flows into it. The result is described briefly below:

Condensed CO_2: Mass flow rate of CO_2.

CO_2 Transport System

The CO_2 Transport System models the transport via pipeline of carbon dioxide (CO_2) captured at a power plant from plant site to sequestration site. It may be used in all of the plant type configurations.

CO_2 Transport System Configuration

This screen is available for all plant types. The screens under the **CO_2 Capture** Technology Navigation Tab display and design flows and data related to the **CO_2 Transport System**.

CO_2 Transport System – Config. input screen.

Each configuration parameter is described briefly below.

Total Pipeline Length: This is the total length of the pipe between the plant site and the sequestration site.

Net Pipeline Elevation Change (Plant->Injection): The pipeline may traverse hilly terrain; this is the overall elevation change from plant site to injection site.

Number of Booster Stations: The cost of CO_2 transport may be lowered by adding booster stations for longer pipeline lengths. This is the number of those stations that are to be modeled.

Compressor/Pump Driver: This is the type of motor that drives the compressor or pump; electric, diesel or natural gas.

Booster Pump Efficiency: This is the efficiency of the pump, and accounts for all frictional losses.

Design Pipeline Flow (% plant cap): This is the flow of liquid CO_2 that the pipeline has been designed to handle as a percent of the total that the plant is capable of producing.

Actual Pipeline Flow: This is the amount of liquid CO_2 that flows through the pipeline in tons per year.

Inlet Pressure (@ power plant): The inlet pressure is shown here for reference only and may be modified in the parameters for the CO_2 capture device (e.g., amine scrubber, selexol scrubber)

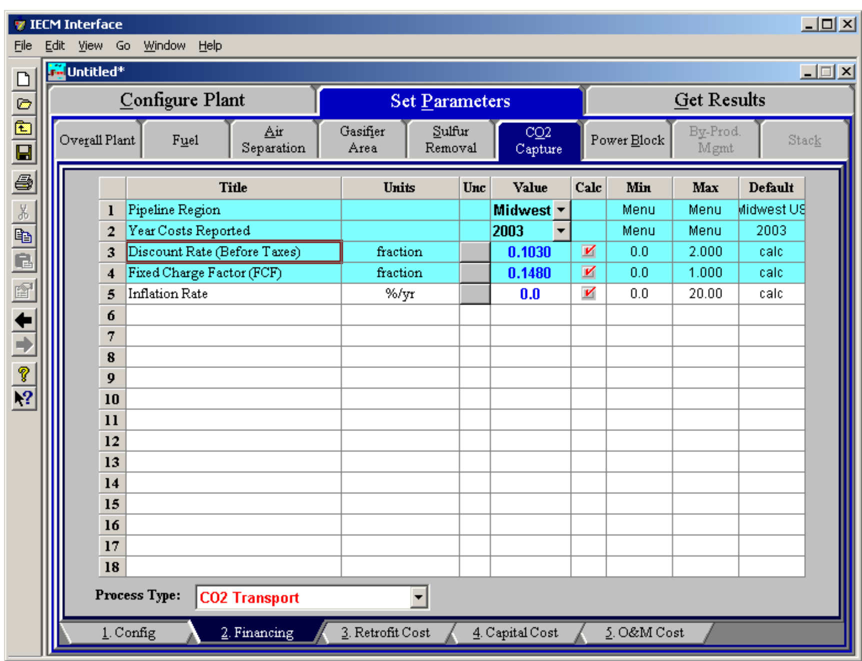
Min. Outlet Pressure (@ storage site): This the minimum outlet pressure of the CO_2 at the storage site

Average Ground Temperature: This is the average temperature of the ground where the pipeline will traverse.

Pipe Material Roughness: The roughness measure is the average size of the bumps on the pipe wall, for commercial pipes this is usually a very small number. Note that perfectly smooth pipes would have a roughness of zero.

CO_2 Transport System Financing Inputs

This screen is available for all plant types.



CO_2 Transport System –Financing input screen.

Pipeline Region: This is the region of the U.S. where the project will be built; central, mid-west, northeast, southeast or western. These regions are based on the EIA natural gas pipeline regions.

Year Costs Reported: This is the year in which all costs are given or displayed, both in the input screens and the results. A cost index is used by the IECM to scale all costs to the cost year specified by this parameter.

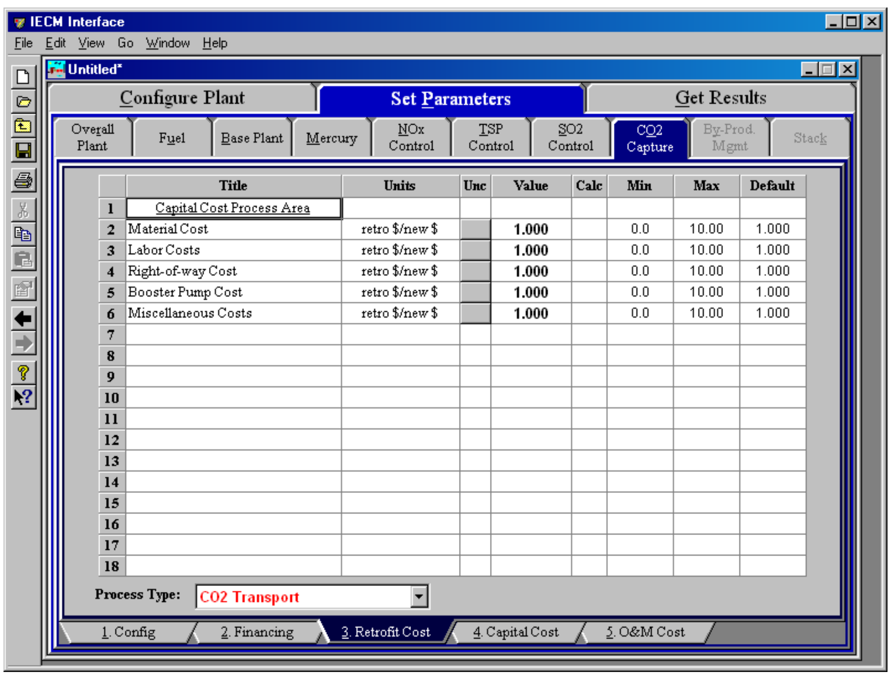
Discount Rate (Before Taxes): This is also known as the cost of money. Discount rate (before taxes) is equal to the sum or return on debt plus return on equity, and is the time value of money used in before-tax present worth arithmetic (i.e., levelization).

Fixed Charge Factor (FCF): This parameter, also known as the *capital recovery factor*, is used to find the uniform annual amount needed to repay a loan or investment with interest. It is one of the most important parameters in the IECM. 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.

Inflation Rate: 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.

CO_2 Transport System Retrofit Costs Inputs

This screen is available for all plant types.



CO_2 Transport System – Retrofit Cost input screen.

Capital Cost Process Area

The retrofit cost factor of each process is a multiplicative cost adjustment, which considers the cost of retrofitted capital equipment relative to similar equipment installed in a new plant. These factors affect the capital costs directly and the operating and maintenance costs indirectly.

Direct capital costs for each process area are calculated in the IECM. These calculations are reduced form equations derived from more sophisticated models and reports. The sum of the direct capital costs associated with each process area is defined as the process facilities capital (PFC). The retrofit cost factor provided for each of the process areas can be used as a tool for adjusting the anticipated costs and uncertainties across the process area separate from the other areas.

Uncertainty can be applied to the retrofit cost factor for each process area in each technology. Thus, uncertainty can be applied as a general factor across an entire process area, rather than as a specific uncertainty for the particular cost on the capital or O&M input screens. Any uncertainty applied to a process area through the retrofit cost factor compounds any uncertainties specified later in the capital and O&M cost input parameter screens.

The following are the **Capital Cost Process Areas** for the CO_2 Transport System:

Material Cost: This includes the cost of line pipe, pipe coatings, and cathodic protection.

Labor Costs: This covers the cost of labor during pipeline construction.

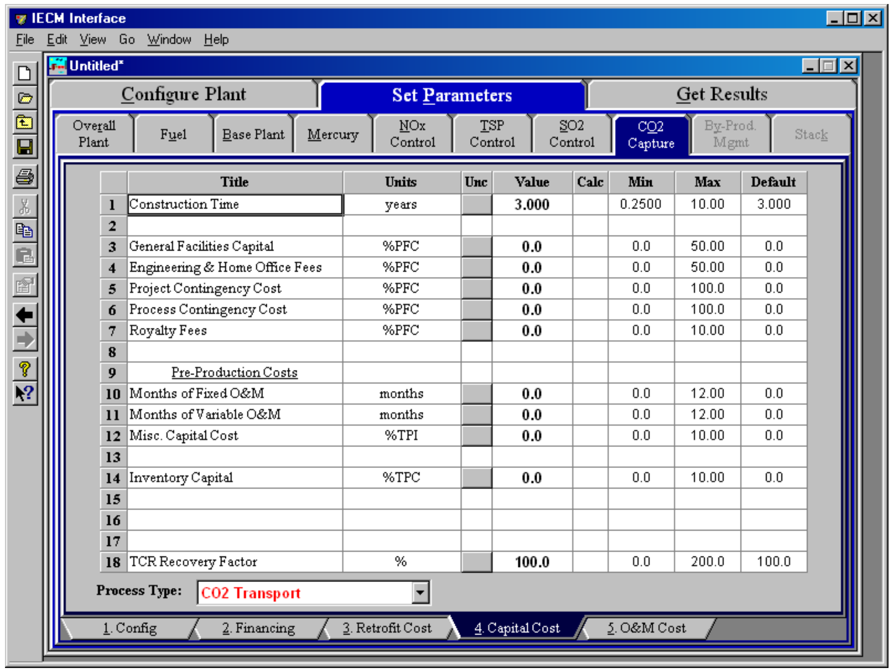
Right-of-way Cost: This is the cost of obtaining right-of-way for the pipeline. This cost not only includes compensating landowners for signing easement agreements but landowners may be also be paid for loss of certain uses of the land during and after construction, loss of any other resources, and any damage to property.

Booster Pump Cost: This is the total capital cost of a booster pump.

Miscellaneous Cost: This includes the costs of: surveying, engineering, supervision, contingencies, telecommunications equipment, freight, taxes, allowances for funds used during construction (AUFDC), administration and overheads, and regulatory filing fees.

CO_2 Transport System Capital Cost Inputs

This screen is available for all of the plant types; the **Combustion (Boiler)**, the **Combustion (Turbine)** and IGCC.



CO_2 Transport System –Capital Cost input screen

Inputs for capital costs are entered on the **Capital Cost** input screen.

Construction Time: This is the idealized construction period in years. It is used to determine the allowance for funds used during construction (AFUDC).

General Facilities Capital (GFC): 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%.

Engineering & Home Office Fees: The engineering & home office fees are a percent of total direct capital cost. This is an overhead fee paid to the architect/engineering company. These fees typically range from 7-15%.

Project Contingency Cost: This is 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.

Process Contingency Cost: 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.

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

Pre-Production Costs: 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 applied to the O&M costs over a specified period of time (months). The two time periods for fixed and variable O&M costs are described below with the addition of a miscellaneous capital cost factor.

- **Months of Fixed O&M:** Time period of fixed operating costs used for preproduction to cover training, testing, major changes in equipment, and inefficiencies in start-up. This includes operating, maintenance, administrative and support labor. It also considers maintenance materials.

- **Months of Variable O&M:** Time period of variable operating costs used for preproduction to cover chemicals, water, consumables, and solid disposal charges in start-up, assuming 100% load. This excludes any fuels.

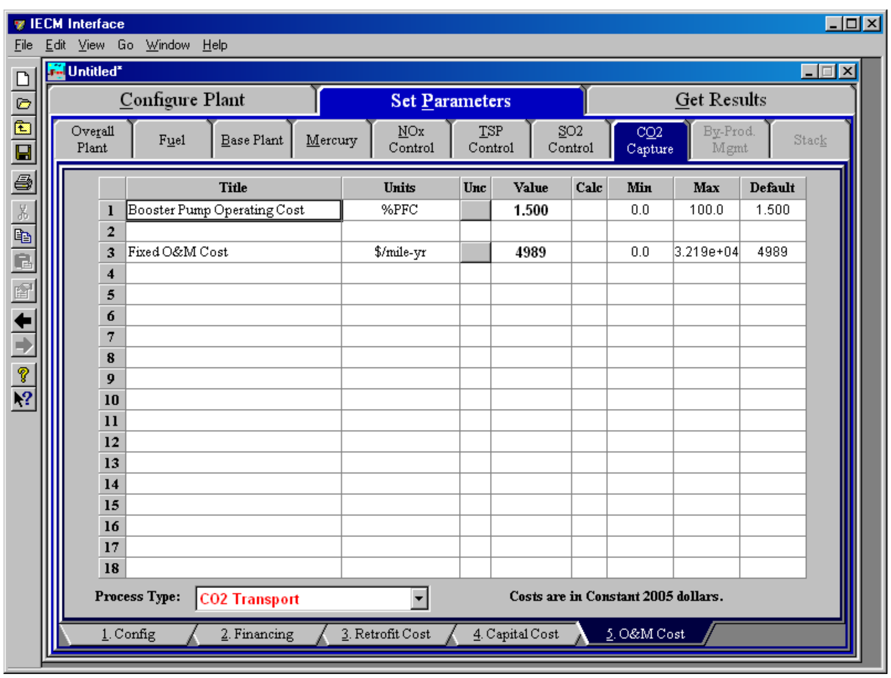
- **Misc. Capital Cost:** This is a percent of total plant investment (sum of TPC and AFUDC) to cover expected changes to equipment to bring the system up to full capacity.

Inventory Capital: Percent of the total direct capital for raw material supply based on 100% capacity during a 60 day period. These materials are considered storage. The inventory capital includes fuels, consumables, by-products, and spare parts. This is typically 0.5%.

TCR Recovery Factor: The actual total capital required (TCR) as a percent of the TCR in a new power plant. This value is 100% for a new installation and may be set as low as 0% for a fabric filter that has been paid off.

CO_2 Transport System O&M Cost Inputs

This screen is available for all plant types.



CO_2 Transport System – O&M Cost input screen.

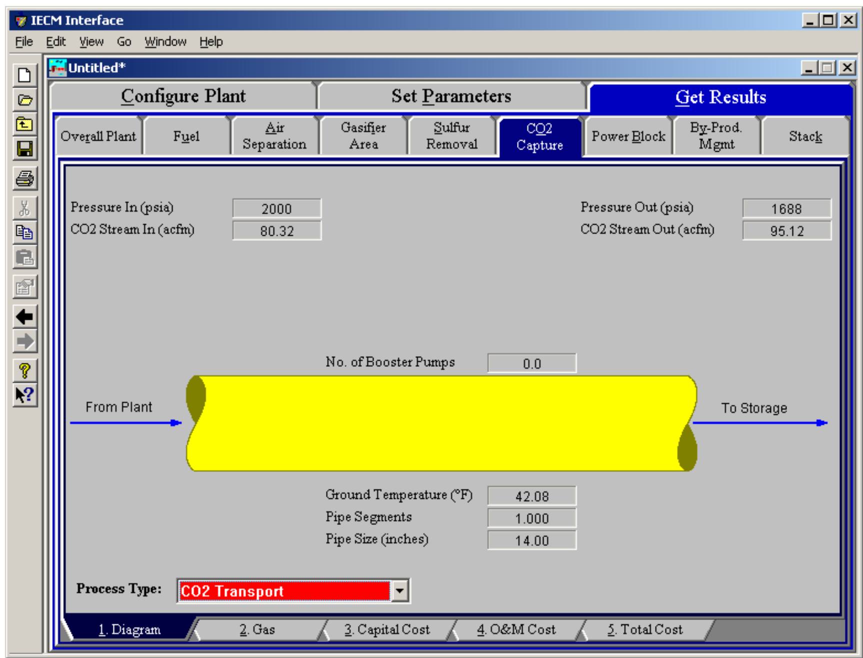
Inputs for operation and maintenance are entered on the **O&M Cost** input. O&M costs are typically expressed on an average annual basis and are provided in either constant or current dollars for a specified year, as shown on the bottom of the screen. Each parameter is described briefly below:

Booster Pump Operating Cost: This is the cost of operating a booster pump as a percent of the process facilities capital

Fixed O&M Cost: These are the operating and maintenance fixed costs including all maintenance materials and all labor costs and is given in dollars per mile of pipeline per year.

CO_2 Transport System Diagram

This screen is available for all plant types.



CO_2 Transport System – Diagram.

From Plant

Pressure In: This is the pressure of the CO_2 from the plant into the pipeline in absolute pounds per square inch.

CO_2 Stream In: This is the flow of the CO_2 from the plant into the pipeline in actual cubic feet per minute.

To CO_2 Transport System

No. of Booster Pumps: This is the number of booster pumps used (if any).

Ground Temperature: Average ground temperature that the pipeline traverses.

Pipe Segments: Total number of pipe segments from plant to injection site.

Pipe Size: Outer diameter of the pipe in inches.

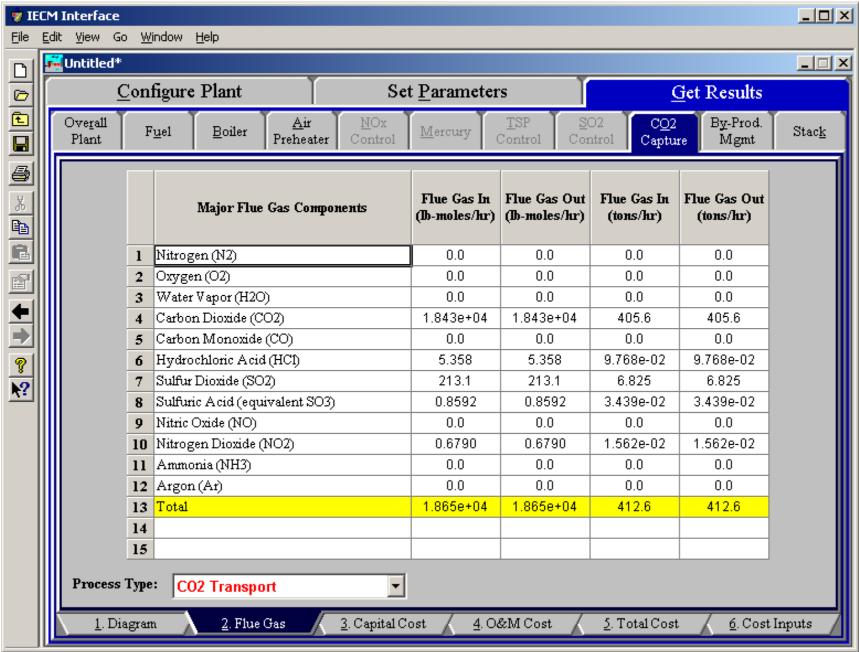
To Storage

Pressure Out: This is the pressure of the CO_2 when it enters the storage site in absolute pounds per square inch.

CO_2 Stream Out: This is the flow of the CO_2 from the pipeline into the storage site in actual cubic feet per minute.

CO_2 Transport System Flue Gas Results

This screen is only available for the **Combustion (Boiler)** and **Combustion (Turbine)** plant types.



CO_2 Transport System – Flue Gas result screen

Major Flue Gas Components

Each result is described briefly below:

Nitrogen (N_2): Total mass of nitrogen.

Oxygen (O_2): Total mass of oxygen.

Water Vapor (H_2O): Total mass of water vapor.

Carbon Dioxide (CO_2): Total mass of carbon dioxide.

Carbon Monoxide (CO): Total mass of carbon monoxide.

Hydrochloric Acid (HCl): Total mass of hydrochloric acid.

Sulfur Dioxide (SO_2): Total mass of sulfur dioxide.

Sulfuric Acid (equivalent SO_3): Total mass of sulfuric acid.

Nitric Oxide (NO): Total mass of nitric oxide.

Nitrogen Dioxide (NO_2): Total mass of nitrogen dioxide.

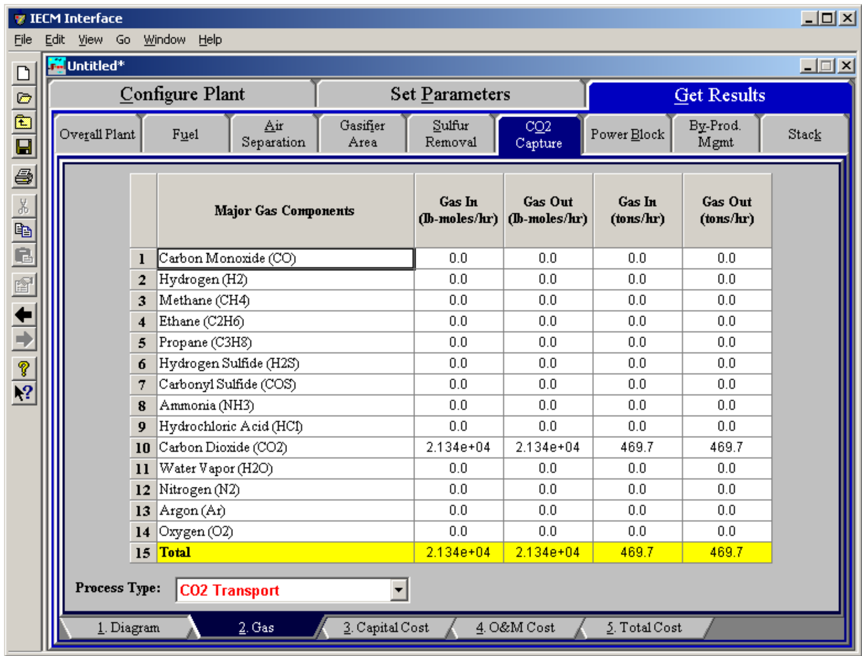
Ammonia (NH_3): Total mass of ammonia.

Argon (Ar): Total mass of argon.

Total: Total of the individual components listed above. This item is highlighted in yellow.

CO_2 Transport System Gas Results

This screen is only available for the IGCC plant type.



CO_2 Transport System – Gas result screen

Major Gas Components

Each result is described briefly below:

Carbon Monoxide (CO): Total mass of carbon monoxide.

Hydrogen (H): Total mass of hydrogen.

Methane (CH_4): Total mass of methane.

Ethane (C_2H_6): Total mass of ethane.

Propane (C_3H_8): Total mass of propane.

Hydrogen Sulfide (H_2S): Total mass of hydrogen sulfide.

Carbonyl Sulfide (COS): Total mass of carbon dioxide.

Ammonia (NH_3): Total mass of ammonia.

Hydrochloric Acid (HCl): Total mass of hydrochloric acid.

Carbon Dioxide (CO_2): Total mass of carbon dioxide.

Water Vapor (H_2O): Total mass of water vapor.

Nitrogen (N_2): Total mass of nitrogen.

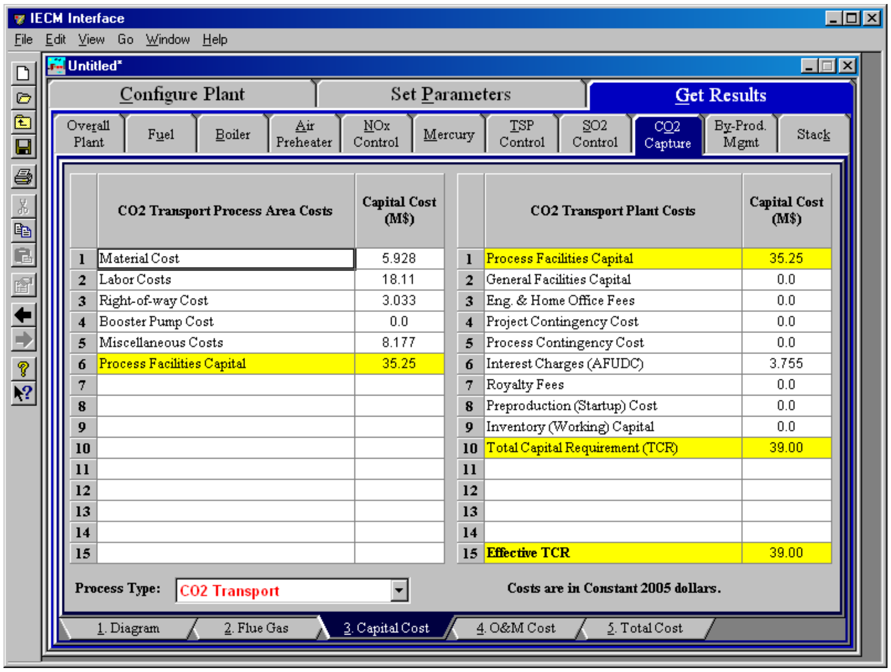
Argon (Ar): Total mass of argon.

Oxygen (O_2): Total mass of oxygen.

Total: Total of the individual components listed above. This item is highlighted in yellow.

CO_2 Transport System Capital Cost Results

This screen is available for all plant types.



CO_2 Transport System – Capital Cost result screen.

The **Capital Cost** result screen displays tables for the capital costs. Capital costs are typically expressed in either constant or current dollars for a specified year, as shown on the bottom of the screen. Each result is described briefly below:

CO_2 Transport Process Area Costs

Material Cost: This includes the cost of line pipe, pipe coatings, and cathodic protection.

Labor Costs: This covers the cost of labor during pipeline construction.

Right-of-way Cost: This is the cost of obtaining right-of-way for the pipeline. This cost not only includes compensating landowners for signing easement agreements but landowners may be also be paid for loss of certain uses of the land during and after construction, loss of any other resources, and any damage to property.

Booster Pump Cost: This is the total capital cost of a booster pump.

Miscellaneous Cost: This includes the costs of: surveying, engineering, supervision, contingencies, telecommunications equipment, freight, taxes, allowances for funds used during construction (AUFDC), administration and overheads, and regulatory filing fees.

Process Facilities Capital: The process facilities capital is the total constructed cost of all on-site processing and generating units listed above, including all direct and indirect construction costs. All sales taxes and freight costs are included where applicable implicitly. This result is highlighted in yellow.

CO_2 Transport Plant Costs

Process Facilities Capital: (see definition above).

General Facilities Capital: The general facilities include construction costs of roads, office buildings, shops, laboratories, etc. Sales taxes and freight costs are included implicitly.

Eng. & Home Office Fees: The engineering & home office fees are a percent of total direct capital cost. This is an overhead fee paid to the architect/engineering company.

Project Contingency Cost: Capital cost contingency factor covering the cost of additional equipment or other costs that would result from a more detailed design of a definitive project at the actual site.

Process Contingency Cost: Capital cost contingency factor applied to a new technology in an effort to quantify the uncertainty in the technical performance and cost of the commercial-scale equipment.

Interest Charges (AFUDC): Allowance for funds used during construction, also referred to as interest during construction, is the time value of the money used during construction and is based on an interest rate equal to the before-tax weighted cost of capital. This interest is compounded on an annual basis (end of year) during the construction period for all funds spent during the year or previous years.

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

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.

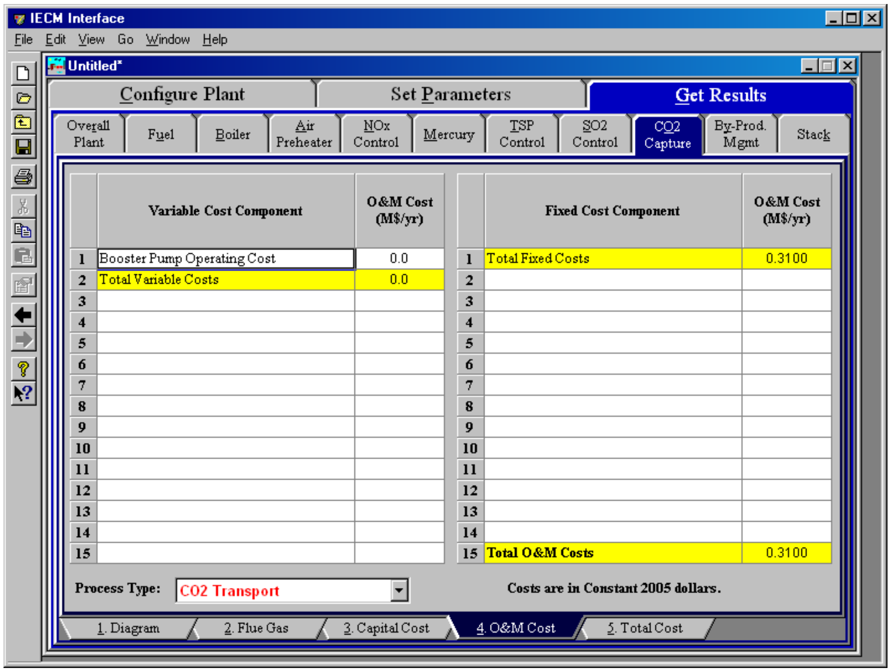
Inventory (Working) Capital: The raw material supply based on 100% capacity during a 60 day period. These materials are considered storage. The inventory capital includes fuels, consumables, by-products, and spare parts.

Total Capital Requirement (TCR): Money that is placed (capitalized) on the books of the utility on the service date. TCR includes all the items above. This result is highlighted in yellow.

Effective TCR: The TCR of the pipeline transport system that is used in determining the total power plant cost. The effective TCR is determined by the “TCR Recovery Factor”.

CO_2 Transport System O&M Cost Results

This screen is available for all plant types.



CO_2 Transport System – O&M Cost result screen.

The **O&M Cost** result screen displays tables for the variable and fixed operation and maintenance costs involved with the **CO_2 Capture** technology. O&M costs are typically expressed on an average annual basis and are provided in either constant or current dollars for a specified year, as shown on the bottom of the screen. Each result is described briefly below:

Variable Cost Components

Variable operating costs and consumables are directly proportional to the amount of kilowatts produced and are referred to as incremental costs. All the costs are subject to inflation.

Booster Pump Operating Cost: This is the total capital cost of a booster pump.

Total Variable Costs: This is the sum of all the variable O&M costs listed above. This result is highlighted in yellow.

Fixed Cost Components

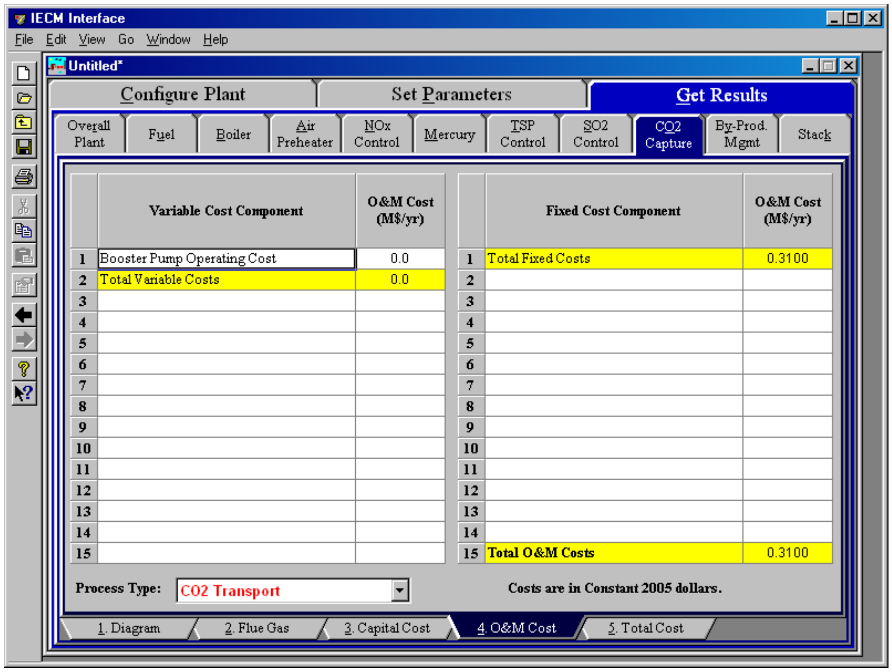
Fixed operating costs are essentially independent of actual capacity factor, number of hours of operation, or amount of kilowatts produced. All the costs are subject to inflation.

Total Fixed Costs: This is the sum of all the fixed O&M costs listed above. This result is highlighted in yellow.

Total O&M Costs: This is the sum of the total variable and total fixed O&M costs. It is used to determine the base plant total revenue requirement. This result is highlighted in yellow.

CO_2 Transport System Total Cost Results

This screen is available for all plant types.



CO_2 Transport System – Total Cost result screen.

The **Total Cost** result screen displays a table which totals the annual fixed, variable, operations and maintenance, and capital costs associated with the **CO_2 Transport System CO_2 Control** technology. Total costs are typically expressed in either constant or current dollars for a specified year, as shown on the bottom of the screen. Each result is described briefly below.

Annual Fixed Cost: The operating and maintenance fixed costs are given as an annual total. This number includes all maintenance materials and all labor costs.

Annual Variable Cost: The operating and maintenance variables costs are given as an annual total. This includes all reagent, chemical, steam, and power costs.

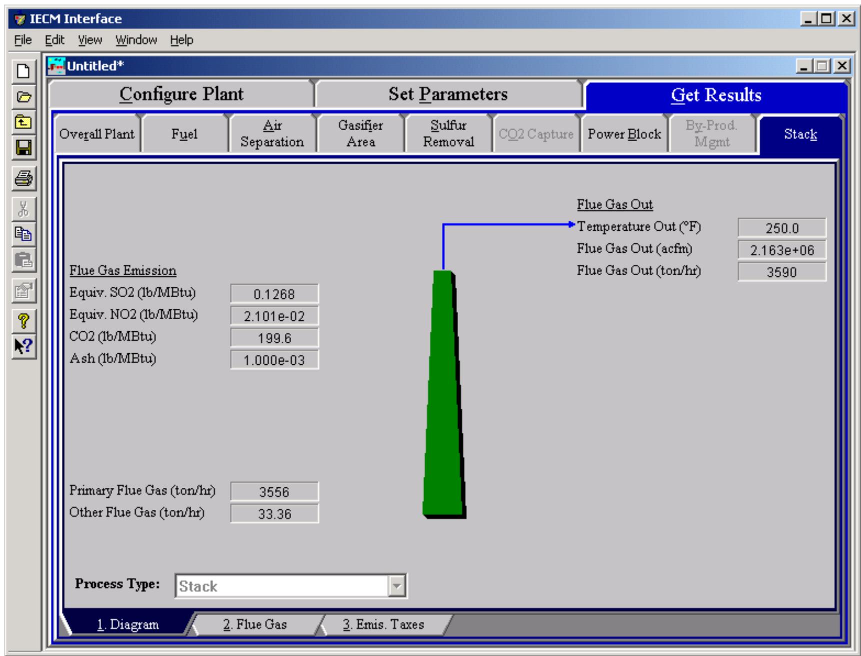
Total Annual O&M Cost: This is the sum of the annual fixed and variable operating and maintenance costs above. This result is highlighted in yellow.

Annualized Capital Cost: This is the total capital cost expressed on an annualized basis, taking into consideration the levelized carrying charge factor, or fixed charge factor, over the entire book life.

Total Levelized Annual Cost: The total annual cost is the sum of the total annual O&M cost and annualized capital cost items above. This result is highlighted in yellow.

Stack

Stack Diagram



Stack – Diagram.

The **Diagram** result screen displays an icon for the stack and values for major flows out of it. Each result is described briefly below.

Flue Gas Out

Temperature Out: Temperature of the flue gas exiting the stack.

Flue Gas Out: Volumetric flow rate of flue gas exiting the stack, based on the flue gas temperature exiting the stack and atmospheric pressure.

Fly Ash Out: Mass flow rate of solids in the flue gas exiting the stack.

Flue Gas Emission

CO_2: This is the number of pounds of **CO_2** vented to the air for every MBtu.

Equivalent SO_2: This is the number of pounds of **Equivalent SO_2** vented to the air for every MBtu.

Equivalent NO_2 : This is the number of pounds of **Equivalent NO_2** vented to the air for every MBtu.

Particulate: This is the number of pounds of **Particulate** vented to the air for every MBtu.

Mercury Emission

Elemental: This is the number of pounds of **Elemental Mercury** vented to the air for every MBtu.

Oxidized: This is the number of pounds of **Oxidized Mercury** vented to the air for every MBtu.

Total: This is the number of pounds of **Total Mercury** vented to the air for every MBtu.

Mercury Exiting Stack

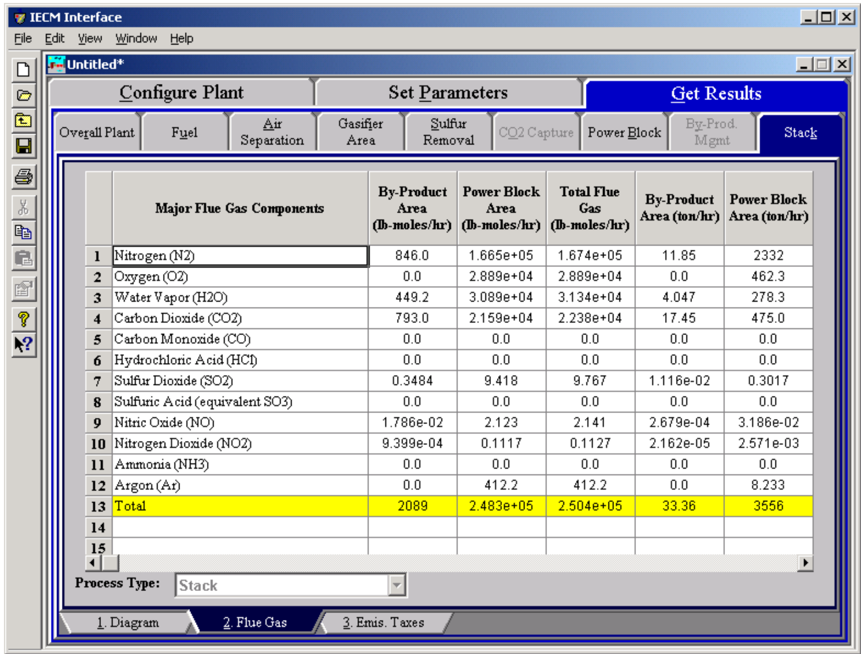
Elemental Mercury: Mass flow rate of elemental mercury (Hg^0) in the flue gas exiting the stack.

Oxidized Mercury: Mass flow rate of oxidized mercury (Hg^{+2}) in the flue gas exiting the stack.

Total Mercury: Mass flow rate of total mercury in the flue gas exiting the stack (elemental, oxidized, and particulate).

Stack Flue Gas Results

The **FlueGas** result screen displays a table of quantities of flue gas components exiting the stack. For each component, quantities are given in both moles and mass per hour.



Stack Flue Gas result screen.

Major Flue Gas Components

Each result is described briefly below

Nitrogen (N_2): Total mass of nitrogen.

Oxygen (O_2): Total mass of oxygen.

Water Vapor (H_2O): Total mass of water vapor.

Carbon Dioxide (CO_2): Total mass of carbon dioxide.

Carbon Monoxide (CO): Total mass of carbon monoxide.

Hydrochloric Acid (HCl): Total mass of hydrochloric acid.

Sulfur Dioxide (SO_2): Total mass of sulfur dioxide.

Sulfuric Acid (equivalent SO_3): Total mass of sulfuric acid.

Nitric Oxide (NO): Total mass of nitric oxide.

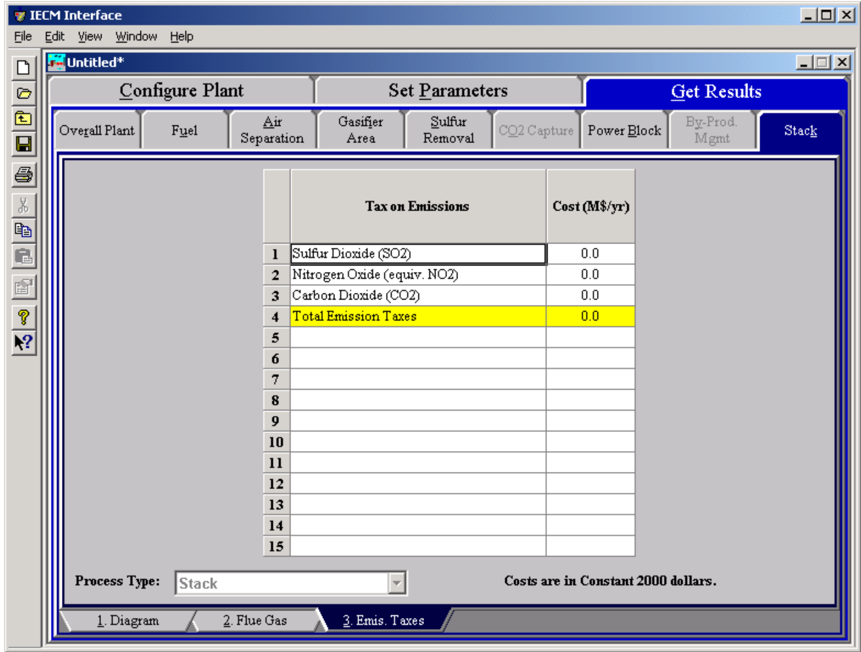
Nitrogen Dioxide (NO_2): Total mass of nitrogen dioxide.

Ammonia (NH_3): Total mass of ammonia.

Argon(Ar): Total mass ofargon.

Total: Total of the individual components listed above. This item is highlighted in yellow.

Stack Emission Taxes Results



Stack – Emis. Taxes result screen

The **Stack Emis. Taxes** results screen shows the cost of to the plant for emissions. The **Taxes on Emissions** are entered by the user in dollars per ton.

Tax on Emissions

Sulfur Dioxide (SO_2): The cost (as a result of user entered data) to the plant of emitting sulfur dioxide in dollars per ton.

Nitrogen Oxide (equiv. NO_2): The cost (as a result of user entered data) to the plant of emitting nitrogen oxide in dollars per ton.

Carbon Dioxide (CO_2): The cost (as a result of user entered data) to the plant of emitting carbon dioxide in dollars per ton.

Total Emission Taxes: This is the sum of the emission taxes displayed above. It is highlighted in yellow.

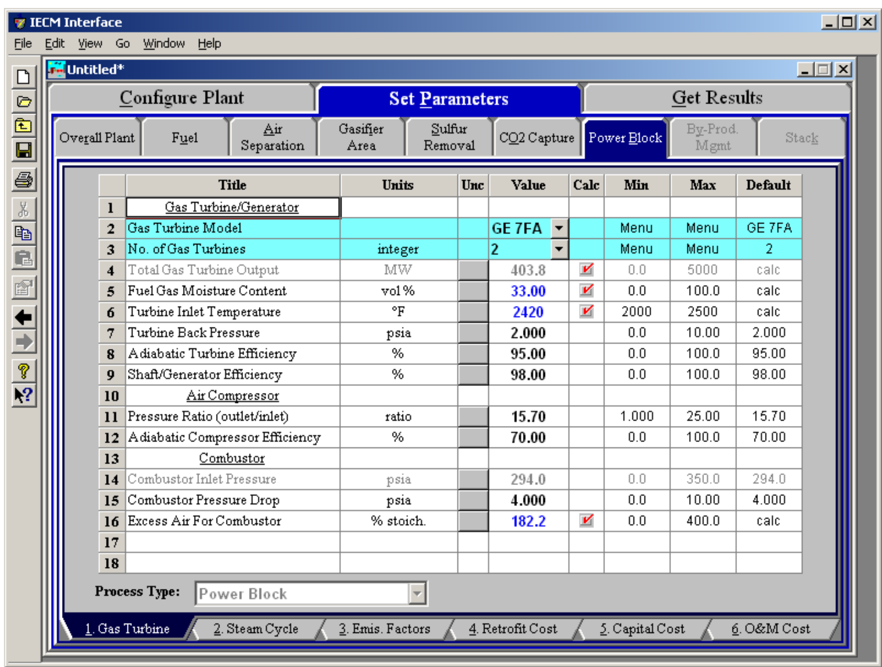
Power Block

The power block technology area includes all the equipment necessary to convert the potential and kinetic energy of natural gas or syngas fuels into steam and electricity.

The process equipment is divided into several areas: the gas turbine/generator, the air compressor, the combustor, the steam turbine, and the heat recovery steam generator. These are all available in the **Combustion (Turbine)** and **IGCC** plant types.

Power Block Gas Turbine Inputs

This screen is only available for the Combustion (Turbine) and IGCC plant types.



Power Block – Gas Turbine input screen.

Gas Turbine/Generator

Gas Turbine Model: This is a selection of the type of turbine model used (manufacturer types currently include only the "7FA"). The type determines the inlet temperature, pressure ratio, and size parameters. This parameter list will be expanded in future versions.

No. of Gas Turbines: This is the number of gas turbines. Since each turbine is able to produce a fixed output, the number of turbines will determine the plant size (e.g., gross plant size).

Total Gas Turbine Output: This parameter is provided for reference purposes only. It provides the gross power generated from the gas turbines alone.

Fuel Gas Moisture Content: Steam is typically added to the fuel gas prior to being combusted. This increases the volume of the fuel gas and results in a higher power output in the gas turbine.

Turbine Inlet Temperature: The turbine inlet temperature is carefully controlled to prevent damage or fatigue of the first stage stator and rotor blades. This temperature is one of the two most important parameters that impacts system efficiency.

Turbine Back Pressure: The turbine exit pressure must be higher than atmospheric pressure to provide a positive pressure on the flue gas exiting the turbine.

Adiabatic Turbine Efficiency: The adiabatic turbine efficiency adjusts for inefficiencies in real turbines. The ratio is an estimate of real to ideal performance.

Shaft/Generator Efficiency: The combined shaft/generator efficiency adjusts for inefficiencies in generator and shaft between the compressor and the generator. The ratio is an estimate of real to ideal performance.

Air Compressor

Pressure Ratio (outlet/inlet): This is the ratio of the compressor exit pressure to the inlet ambient air pressure. Compression takes place approximately adiabatically.

Adiabatic Compressor Efficiency: The adiabatic compressor efficiency adjusts for inefficiencies in real compressors. The ratio is an estimate of real to ideal performance.

Combustor

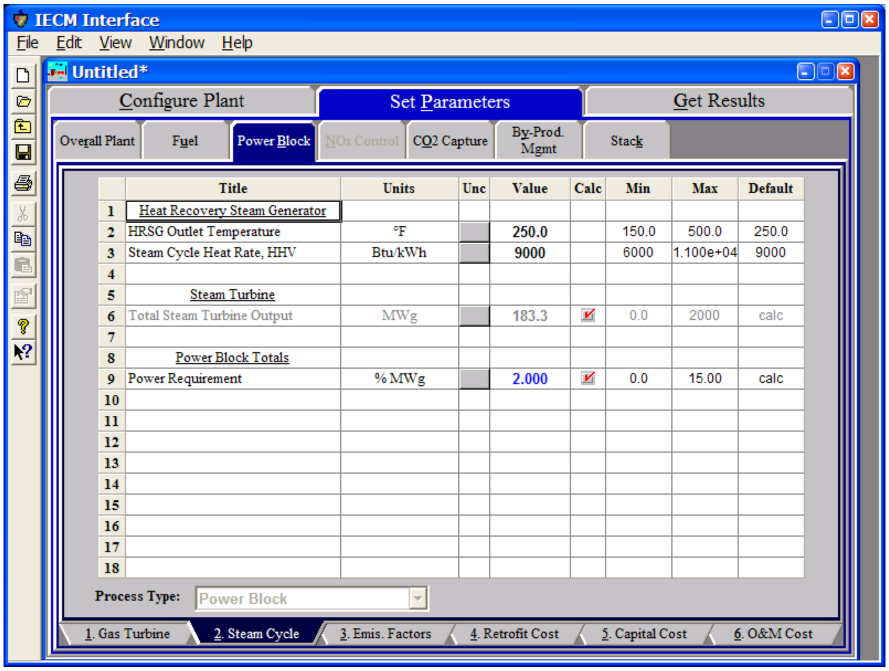
Combustor Inlet Pressure: The combustor inlet pressure is currently fixed at a single value. It is provided for reference purposes only.

Combustor Pressure Drop: Although the combustor operates at essentially constant pressure, a small pressure drop is typically observed in the combustor exit from the compressor exit.

Excess Air For Combustor: This is the excess theoretical air used for combustion. It is added to the stoichiometric air requirement calculated by the model. This value is based on the required mass flow rate of syngas through the combustor, the heat content of the syngas, and the flame temperature of the combustor.

Power Block Steam Cycle Inputs

This screen is only available for the Combustion (Turbine) and IGCC plant types.



Power Block – Steam Cycle input screen

Heat Recovery Steam Generator

HRSG Outlet Temperature: This is the desired output temperature from the heat recovery steam generator (HRSG).

Steam Cycle Heat Rate, HHV: This is the steam cycle heat rate for the heat recovery steam generator.

Steam Turbine

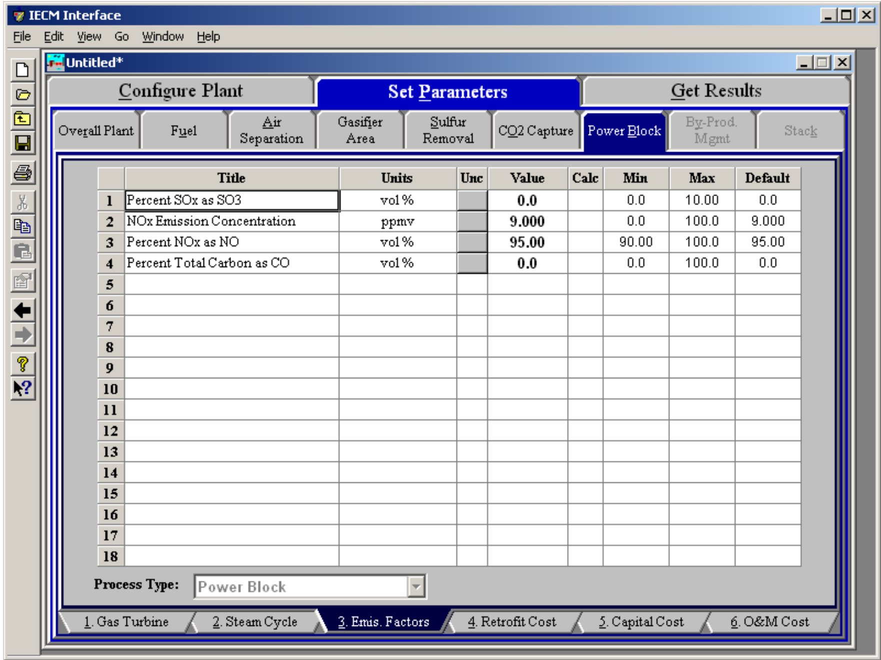
Total Steam Turbine Output: This is the net electricity produced by the steam turbine associated with the HRSG (steam cycle). This value cannot be edited. It is provided for reference only.

Power Block Totals

Power Requirement: This is the electricity for internal use. It is expressed as a percent of the gross plant capacity.

Power Block Emission Factors

This screen is only available for the Combustion (Turbine) and IGCC plant types.



Power Block – Emission Factors input screen.

Emission Factors Input Parameters

Percent SO_x as SO_3: This is the volume percent of SO_x that is SO_3. The remainder is SO_2.

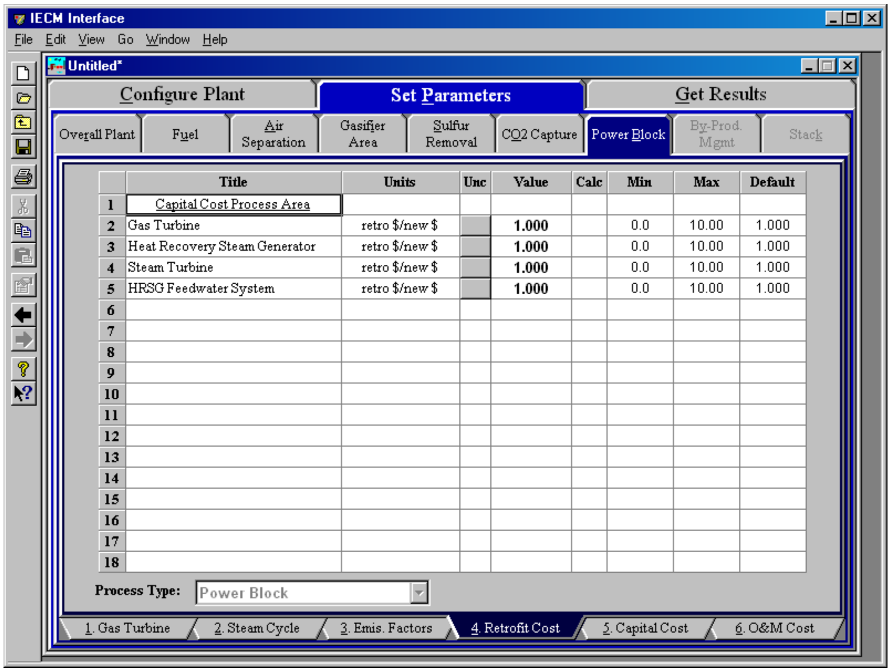
NO_x Emission Concentration: This is the concentration of NO_x emitted from the gas turbine after combustion.

Percent NO_x as NO: This is the volume percent of NO_x that is NO. The remainder is NO_2.

Percent Total Carbon as CO: This is the volume percent of the total carbon in the syngas entering the combustor that is emitted from the gas turbine as CO.

Power Block Retrofit Cost

This screen is only available for the Combustion (Turbine) and IGCC plant types.



Power Block – Retrofit Cost input screen.

Power Block Retrofit Cost Input Parameters

Gas Turbine: The Gas Turbine retrofit factor is a ratio of the costs of retrofiting an existing facility versus a new facility, using the same equipment.

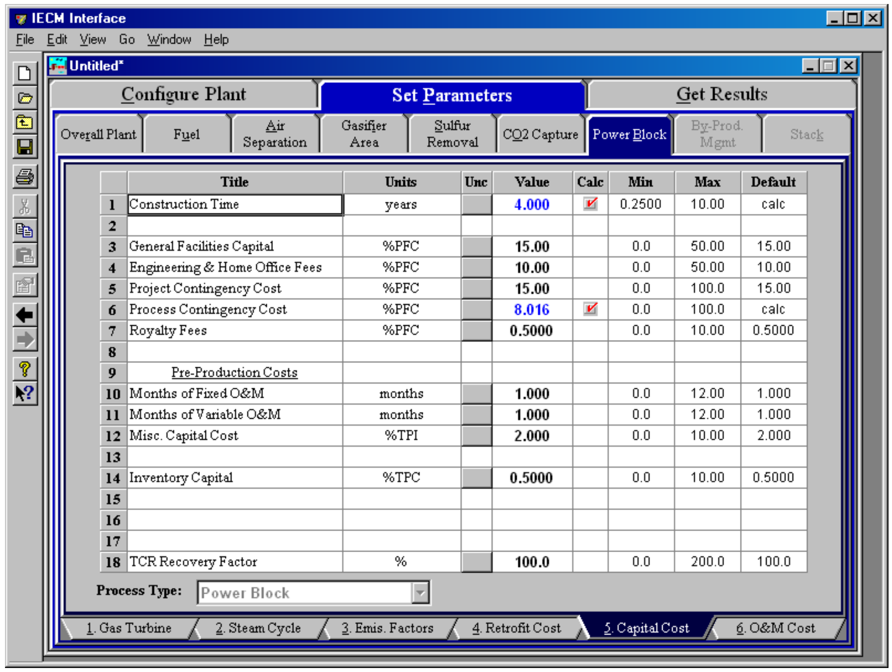
Heat Recovery Steam Generator: The Heat Recovery Steam Generator retrofit factor is a ratio of the costs of retrofiting an existing facility versus a new facility, using the same equipment.

Steam Turbine: The Steam Turbine retrofit factor is a ratio of the costs of retrofiting an existing facility versus a new facility, using the same equipment.

HRSG Feedwater System: The Boiler Feedwater retrofit factor is a ratio of the costs of retrofiting an existing facility versus a new facility, using the same equipment.

Power Block Capital Cost Inputs

This screen is only available for the Combustion (Turbine) and IGCC plant types.



	Title	Units	Unc	Value	Calc	Min	Max	Default
1	Construction Time	years		4.000	✓	0.2500	10.00	calc
2								
3	General Facilities Capital	%PFC		15.00		0.0	50.00	15.00
4	Engineering & Home Office Fees	%PFC		10.00		0.0	50.00	10.00
5	Project Contingency Cost	%PFC		15.00		0.0	100.0	15.00
6	Process Contingency Cost	%PFC		8.016	✓	0.0	100.0	calc
7	Royalty Fees	%PFC		0.5000		0.0	10.00	0.5000
8								
9	Pre-Production Costs							
10	Months of Fixed O&M	months		1.000		0.0	12.00	1.000
11	Months of Variable O&M	months		1.000		0.0	12.00	1.000
12	Misc. Capital Cost	%TPI		2.000		0.0	10.00	2.000
13								
14	Inventory Capital	%TPC		0.5000		0.0	10.00	0.5000
15								
16								
17								
18	TCR Recovery Factor	%		100.0		0.0	200.0	100.0

Power Block – Capital Cost input screen.

Inputs for capital costs are entered on the **Capital Cost** input screen.

Construction Time: This is the idealized construction period in years. It is used to determine the allowance for funds used during construction (AFUDC).

General Facilities Capital (GFC): 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%.

Engineering & Home Office Fees: The engineering & home office fees are a percent of total direct capital cost. This is an overhead fee paid to the architect/engineering company. These fees typically range from 7-15%.

Project Contingency Cost: This is 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.

Process Contingency Cost: 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.

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

Pre-Production Costs: 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 applied to the O&M costs over a specified period of time (months). The two time periods for fixed and variable

O&M costs are described below with the addition of a miscellaneous capital cost factor.

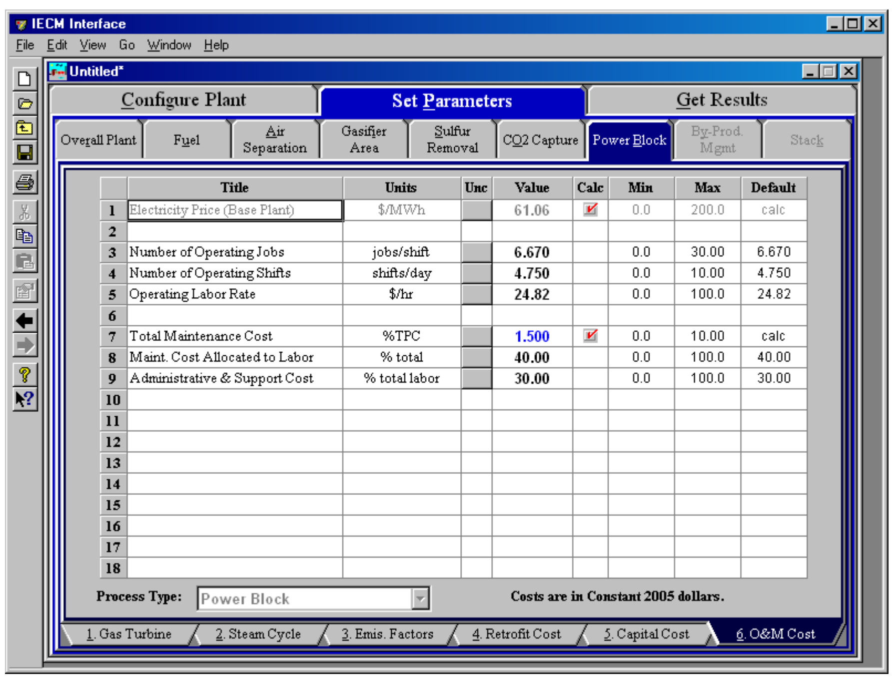
- **Months of Fixed O&M:** Time period of fixed operating costs used for preproduction to cover training, testing, major changes in equipment, and inefficiencies in start-up. This includes operating, maintenance, administrative and support labor. It also considers maintenance materials.
- **Months of Variable O&M:** Time period of variable operating costs used for preproduction to cover chemicals, water, consumables, and solid disposal charges in start-up, assuming 100% load. This excludes any fuels.
- **Misc. Capital Cost:** This is a percent of total plant investment (sum of TPC and AFUDC) to cover expected changes to equipment to bring the system up to full capacity.

Inventory Capital: Percent of the total direct capital for raw material supply based on 100% capacity during a 60 day period. These materials are considered storage. The inventory capital includes fuels, consumables, by-products, and spare parts. This is typically 0.5%.

TCR Recovery Factor: The actual total capital required (TCR) as a percent of the TCR in a new power plant. This value is 100% for a new installation and may be set as low as 0% for a fabric filter that has been paid off.

Power Block O&M Cost Inputs

This screen is only available for the Combustion (Turbine) and IGCC plant types.



Power Block – O&M Cost input screen.

Inputs for operating and maintenance costs are entered on the **O&M Cost** input screen. O&M costs are typically expressed on an average annual basis and are provided in either constant or current dollars for a specified year, as shown on the bottom of the screen.

Electricity Price (Base Plant): This is the price of electricity and is calculated as a function of the utility cost of the base plant, where the base plant is the power block. This is provided for reference purposes only.

Number of Operating Jobs: This is the total number of operating jobs that are required to operate the plant per eight-hour shift.

Number of Operating Shifts: This is the total number of equivalent operating shifts in the plant per day. The number takes into consideration paid time off and weekend work (3 shifts/day * 7 days/5 day week * 52 weeks/(52 weeks - 6 weeks PTO) = 4.75 equiv. Shifts/day)

Operating Labor Rate: The hourly cost of labor is specified in the base plant O&M cost screen. The same value is used throughout the other technologies.

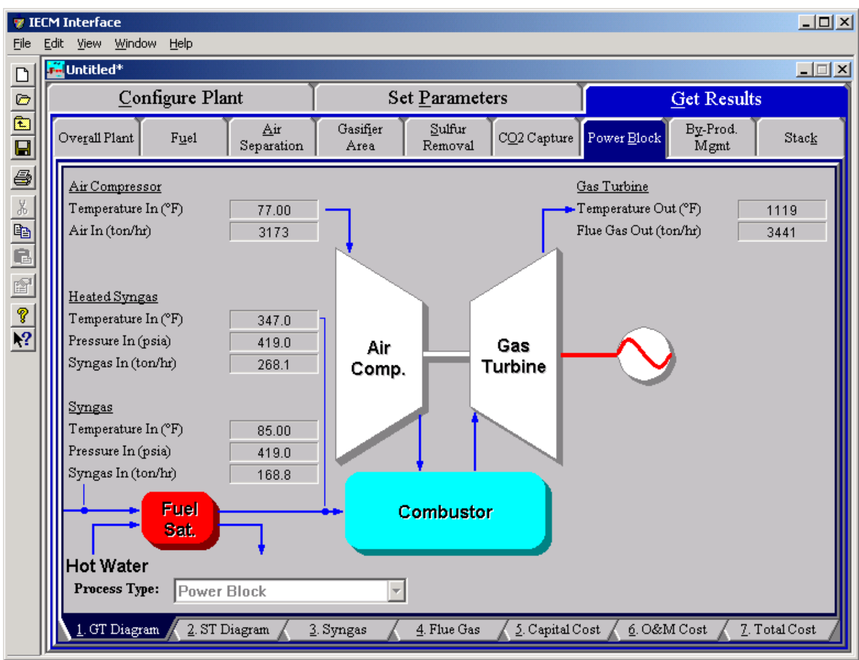
Total Maintenance Cost: This is the annual maintenance cost as a percentage of the total plant cost. Maintenance cost estimates can be developed separately for each process area.

Maint. Cost Allocated to Labor: Maintenance cost allocated to labor as a percentage of the total maintenance cost.

Administrative & Support Cost: This is the percent of the total operating and maintenance labor associated with administrative and support labor.

Power Block Gas Turbine Diagram

This screen is only available for the Combustion (Turbine) and IGCC plant types.



Power Block – Gas Turbine Diagram result screen.

Air Entering Compressor

Temperature In: Temperature of the atmospheric air entering the air compressor.

Air In: Volumetric flow rate of the air entering the air compressor.

Syngas Entering Combustor

Temperature In: Temperature of the syngas entering the fuel heater and saturator.

Pressure In: This is the pressure of the synas as it enters the fuel heater and saturator.

Syngas In: This is the mass flow rate of the syngas to the fuel heater and saturator.

Heated Syngas Entering Combustor

Temperature In: Temperature of the heated and saturated syngas entering the combustor.

Pressure In: This is the pressure of the heated and saturated syngas as it enters the combustor.

Syngas In: This is the mass flow rate of the heated and saturated syngas to the combustor.

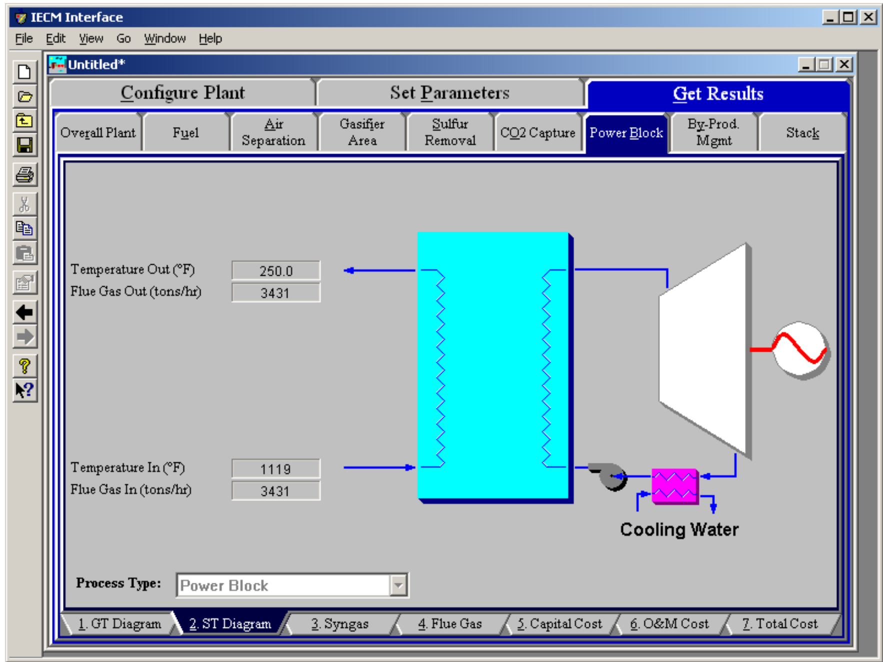
Flue Gas Exiting Gas Turbine

Temperature Out: Temperature of the flue gas exiting the gas turbine.

Flue Gas Out: Volumetric flow rate of the flue gas exiting the gas turbine.

Power Block Steam Diagram

This screen is only available for the **Combustion (Turbine)** and IGCC plant types.



Power Block – HRSG/ Steam Diagram results screen.

Flue Gas Exiting Steam Generator

Temperature Out: Temperature of the flue gas exiting the HRSG system.

Flue Gas Out: Volumetric flow rate of the flue gas exiting the HRSG.

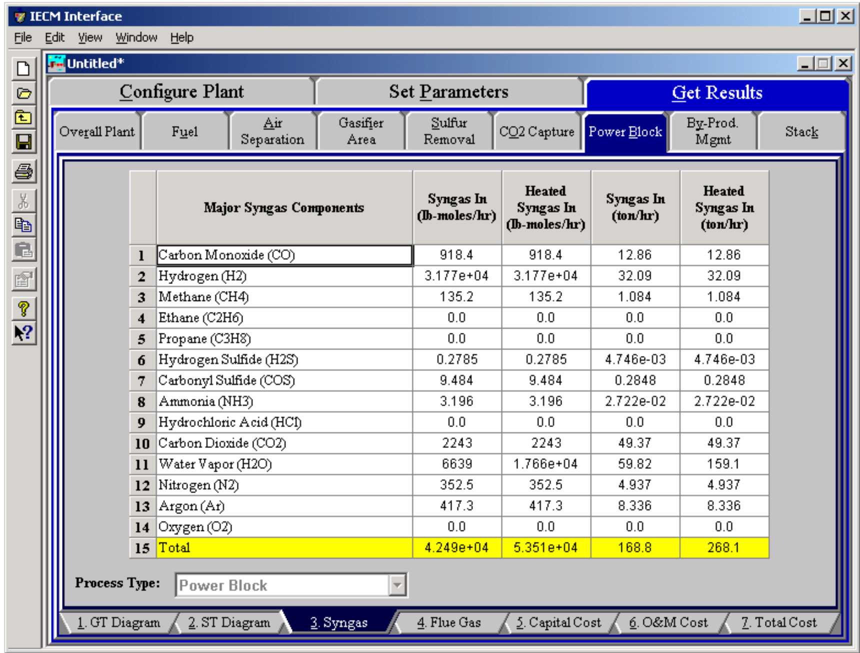
Flue Gas Entering Steam Generator

Temperature In: Temperature of the flue gas entering the HRSG.

Flue Gas In: Volumetric flow rate of flue gas entering the HRSG.

Power Block Syngas Results

This screen is only available for the **Combustion (Turbine)** and IGCC plant types.



Power Block – Syngas result screen.

Major Syngas Components

Carbon Monoxide (CO): Flow rate of carbon monoxide in the syngas.

Hydrogen (H_2): Flow rate of hydrogen in the syngas.

Methane (CH_4): Flow rate of methane in the syngas.

Ethane (C_2H_6): Flow rate of ethane in the syngas.

Propane (C_3H_8): Flow rate of propane in the syngas.

Hydrogen Sulfide (H_2S): Flow rate of hydrogen sulfide in the syngas.

Carbonyl Sulfide (COS): Flow rate of carbon sulfide in the syngas.

Ammonia (NH_3): Flow rate of ammonia in the syngas.

Hydrochloric Acid (HCl): Flow rate of hydrochloric acid in the syngas.

Carbon Dioxide (CO_2): Flow rate of carbon dioxide in the syngas.

Water Vapor (H_2O): Flow rate of water vapor in the syngas.

Nitrogen (N_2): Flow rate of nitrogen in the syngas.

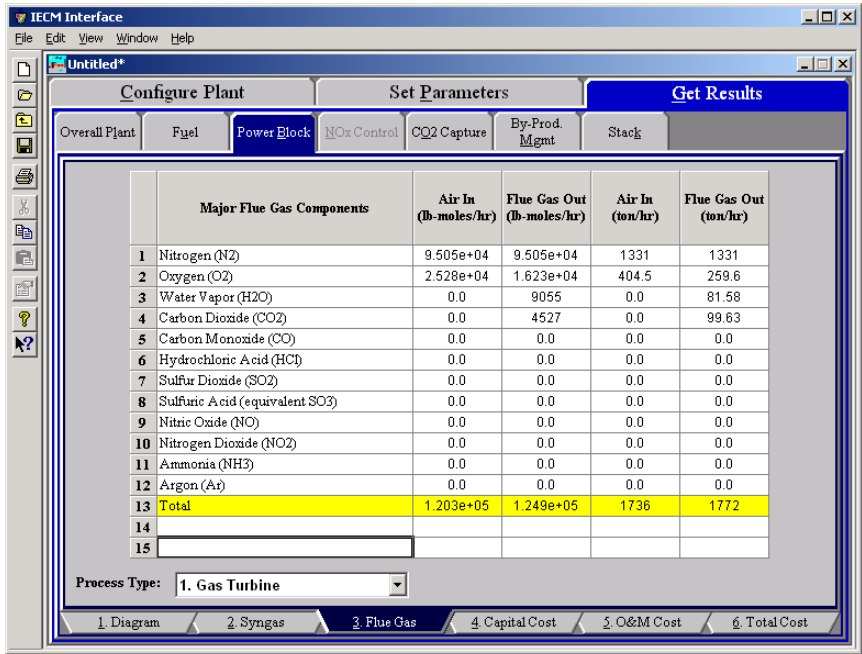
Argon (Ar): Flow rate of argon in the syngas.

Oxygen (O_2): Flow rate of oxygen in the syngas.

Total: Total flow rate of the syngas.

Power Block Flue Gas Results

This screen is only available for the Combustion (Turbine) and IGCC plant types.



Power Block – Flue Gas results screen.

Major Flue Gas Components

Each result is described briefly below:

Nitrogen (N_2): Total mass of nitrogen.

Oxygen (O_2): Total mass of oxygen.

Water Vapor (H_2O): Total mass of water vapor.

Carbon Dioxide (CO_2): Total mass of carbon dioxide.

Carbon Monoxide (CO): Total mass of carbon monoxide.

Hydrochloric Acid (HCl): Total mass of hydrochloric acid.

Sulfur Dioxide (SO_2): Total mass of sulfur dioxide.

Sulfuric Acid (equivalent SO_3): Total mass of sulfuric acid.

Nitric Oxide (NO): Total mass of nitric oxide.

Nitrogen Dioxide (NO_2): Total mass of nitrogen dioxide.

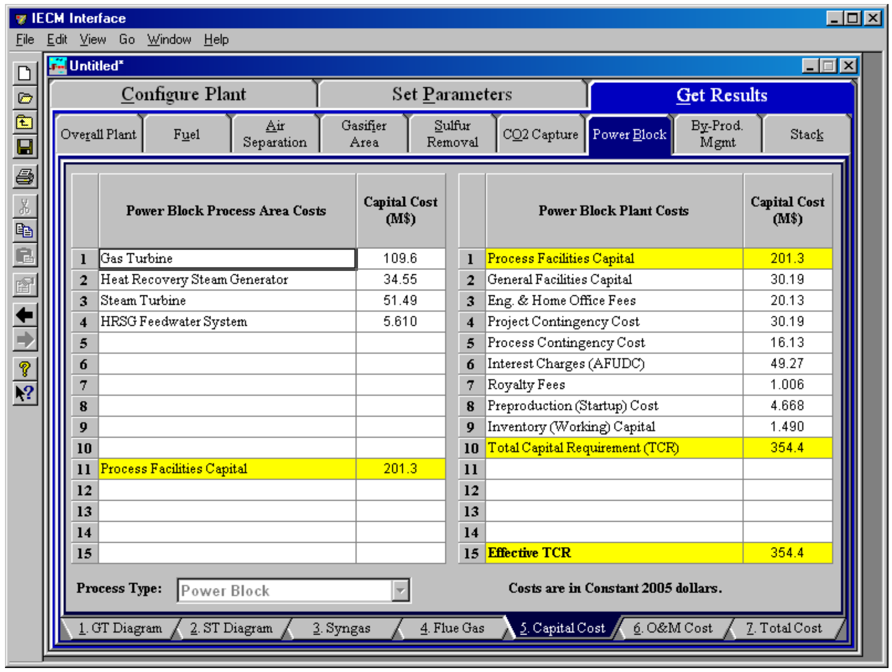
Ammonia (NH_3): Total mass of ammonia.

Argon (Ar): Total mass of argon.

Total: Total of the individual components listed above. This item is highlighted in yellow.

Power Block Capital Cost Results

This screen is only available for the Combustion (Turbine) and IGCC plant types.



Power Block – Capital Cost results screen.

This result screen displays tables containing the **Power Block Capital Costs**. Capital costs are typically expressed in either constant or current dollars for a specified year, as shown on the bottom of the screen. Each result is described briefly below:

Power Block Process Area Costs

Gas Turbine: The capital cost of the gas turbines, the air compressor, and the combustor.

Heat Recovery Steam Generator: The heat recovery steam generator is a set of heat exchangers in which heat is removed from the gas turbine exhaust gas to generate steam for the steam turbine.

Steam Turbine: The cost of a steam turbine is depends on the mass flow rate of steam through the turbine, the pressures in each stage, and the generator output.

HRSG Feedwater System: The boiler feedwater system consists of equipment for handling raw water and polished water in the steam cycle, including a water mineralization unit for raw water, a dimineralized water storage tank, a condensate water, a condensate polishing unit, and a blowdown flash drum.

Process Facilities Capital: The process facilities capital is the total constructed cost of all on-site processing and generating units listed above, including all direct and indirect construction costs. All sales taxes and freight costs are included where applicable implicitly. This result is highlighted in yellow.

Power Block Plant Costs

Process Facilities Capital: (see definition above)

General Facilities Capital: The general facilities include construction costs of roads, office buildings, shops, laboratories, etc. Sales taxes and freight costs are included implicitly.

Eng. & Home Office Fees: The engineering & home office fees are a percent of total direct capital cost. This is an overhead fee paid to the architect/engineering company.

Project Contingency Cost: Capital cost contingency factor covering the cost of additional equipment or other costs that would result from a more detailed design of a definitive project at the actual site.

Process Contingency Cost: Capital cost contingency factor applied to a new technology in an effort to quantify the uncertainty in the technical performance and cost of the commercial-scale equipment.

Interest Charges (AFUDC): Allowance for funds used during construction, also referred to as interest during construction, is the time value of the money used during construction and is based on an interest rate equal to the before-tax weighted cost of capital. This interest is compounded on an annual basis (end of year) during the construction period for all funds spent during the year or previous years.

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

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.

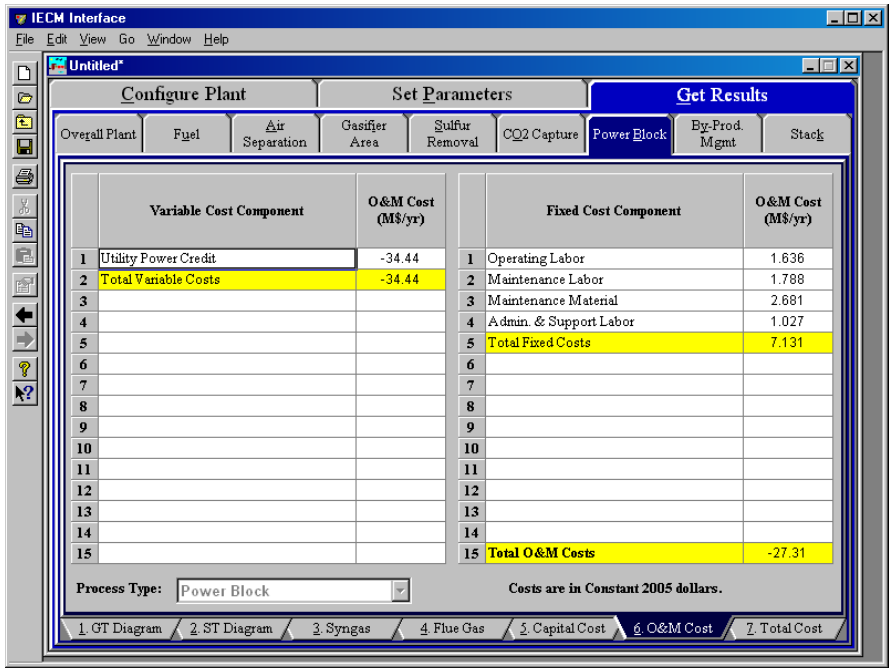
Inventory (Working) Capital: The raw material supply based on 100% capacity during a 60 day period. These materials are considered storage. The inventory capital includes fuels, consumables, by-products, and spare parts.

Total Capital Requirement (TCR): Money that is placed (capitalized) on the books of the utility on the service date. TCR includes all the items above. This result is highlighted in yellow.

Effective TCR: The TCR of the power block that is used in determining the total power plant cost. The effective TCR is determined by the "TCR Recovery Factor".

Power Block O&M Cost Results

This screen is only available for the Combustion (Turbine) and IGCC plant types.



Power Block – O&M Cost results screen.

O&M costs are typically expressed on an average annual basis and are provided in either constant or current dollars for a specified year, as shown on the bottom of the screen.

Variable Cost Component

Utility Power Credit: Power consumed by abatement technologies result in lower net power produced and lost revenue. The IECM charges each technology for the internal use of electricity and treats the charge as a credit for the base plant. When comparing individual components of the plant, these utility charges are taken into consideration. For total plant costs they balance out and have no net effect on the plant O&M costs.

Total Variable Costs: This is the sum of all the variable O&M costs listed above. This result is highlighted in yellow.

Fixed Cost Component

Fixed operating costs are essentially independent of actual capacity factor, number of hours of operation, or amount of kilowatts produced. All the costs are subject to inflation.

Operating Labor: Operating labor cost is based on the operating labor rate, the number of personnel required to operate the plant per eight-hour shift, and the average number of shifts per day over 40 hours per week and 52 weeks.

Maintenance Labor: The maintenance labor is determined as a fraction of the total maintenance cost.

Maintenance Material: The cost of maintenance material is the remainder of the total maintenance cost, considering the fraction associated with maintenance labor.

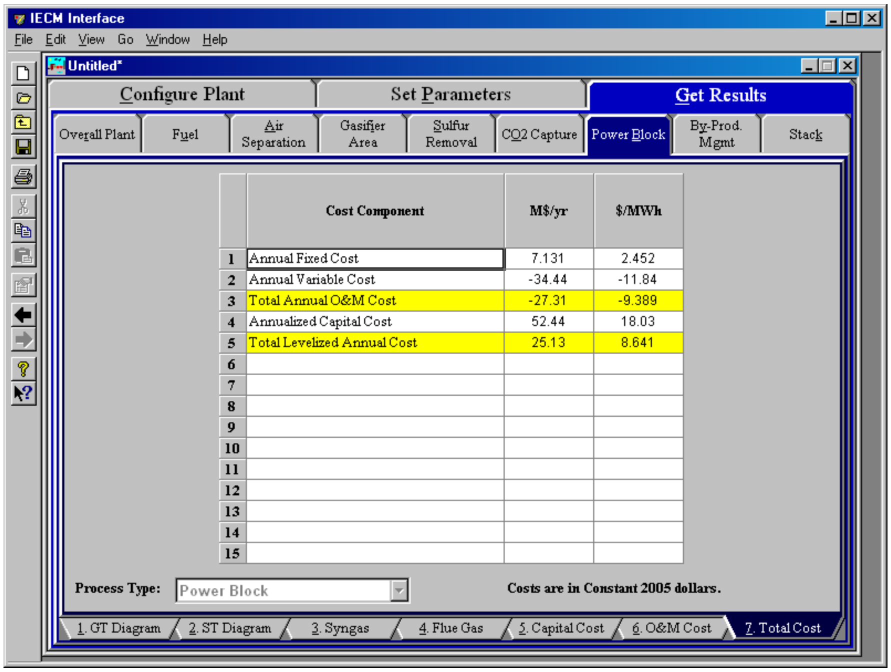
Admin. & Support Labor: The administrative and support labor is the only overhead charge. It is taken as a fraction of the total operating and maintenance labor costs.

Total Fixed Costs: This is the sum of all the fixed O&M costs listed above. This result is highlighted in yellow.

Total O&M Costs: This is the sum of the total variable and total fixed O&M costs. It is used to determine the base plant total revenue requirement. This result is highlighted in yellow.

Power Block Total Cost Results

This screen is only available for the Combustion (Turbine) and IGCC plant types.



Power Block – Total Cost results screen.

The **Total Cost** result screen displays a table which totals the annual fixed, variable, operations, maintenance, and capital costs. Total costs are typically expressed in either constant or current dollars for a specified year, as shown on the bottom of the screen. Each result is described briefly below.

Cost Component

Annual Fixed Cost: The operating and maintenance fixed costs are given as an annual total. This number includes all maintenance materials and all labor costs.

Annual Variable Cost: The operating and maintenance variables costs are given as an annual total. This includes all reagent, chemical, steam, and power costs.

Total Annual O&M Cost: This is the sum of the annual fixed and variable operating and maintenance costs above. This result is highlighted in yellow.

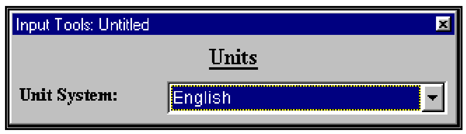
Annualized Capital Cost: This is the total capital cost expressed on an annualized basis, taking into consideration the levelized carrying charge factor, or fixed charge factor, over the entire book life.

Total Levelized Annual Cost: The total annual cost is the sum of the total annual O&M cost and annualized capital cost items above. This result is highlighted in yellow.

Units

Units Inputs

Inputs may be entered using different units. Changing the units in which inputs are entered using the **Input Tools** floating palette is described in *Getting Started*. This section will describe the various unit settings in detail



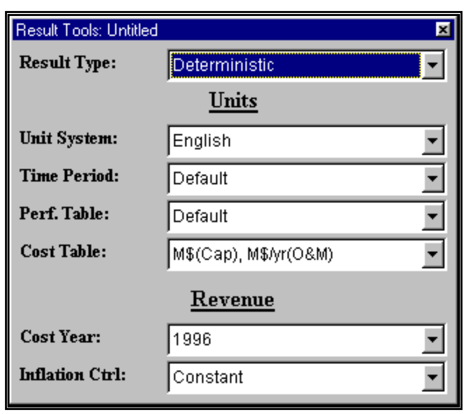
The Input Tools Floating Palette

Unit System

The **Unit System** option determines the unit system in which input values are entered. The choices are **English** and **Metric**. The default setting is **English**.

Units Results

Results may be displayed in different units. Changing the units in which results are displayed using the **Result Tools** floating palette is described in *Getting Started.* This section will describe the various unit settings in detail.



The Result Tools floating palette

Result Type

The **Result Type** option determines the type of values displayed in the result tables. The choices available are **Deterministic**, **Mean**, **Median (50th percentile)**, **2.5 percentile**, **97.5 percentile**, and **Standard Deviation**. The default setting is **Deterministic**.

Unit System

The **Unit System** option determines the unit system in which result values are displayed. The choices available are **English** and **Metric**. The default setting is **English**.

Time Period

The **Time Period** option determines the time period for which result values are displayed. The choices available are **Default**, **Max Hourly** and **Annual Avg.** The default setting is **Default**.

Performance Table

The **Perf. Table** option determines the units in which values are displayed on performance result screens**.** The choices available are **Default**, **% Total**, **mass/kWh**, and **mass/Btu in.** The default setting is **Default**.

NOTE: The **% Total** unit change can be used to determine the volume percent and weight percent of the components of the flue gas. This is possible when viewing the "Gas Summary" result table for any control technology.

Cost Table

The **Cost Table** option determines the units in which values are displayed on cost result screens**.** The choices available are **M$(Cap), M$/yr(O&M)** and **$/kW(Cap), mills/kWh(O&M).** The default setting is **M$(Cap), M$/yr(O&M)**.

Cost Year

The **Cost Year** option determines the year for which values are displayed on cost result screens**.** You may choose any year between 1977 and 1998**.** The default setting is **1996**.

Inflation Control

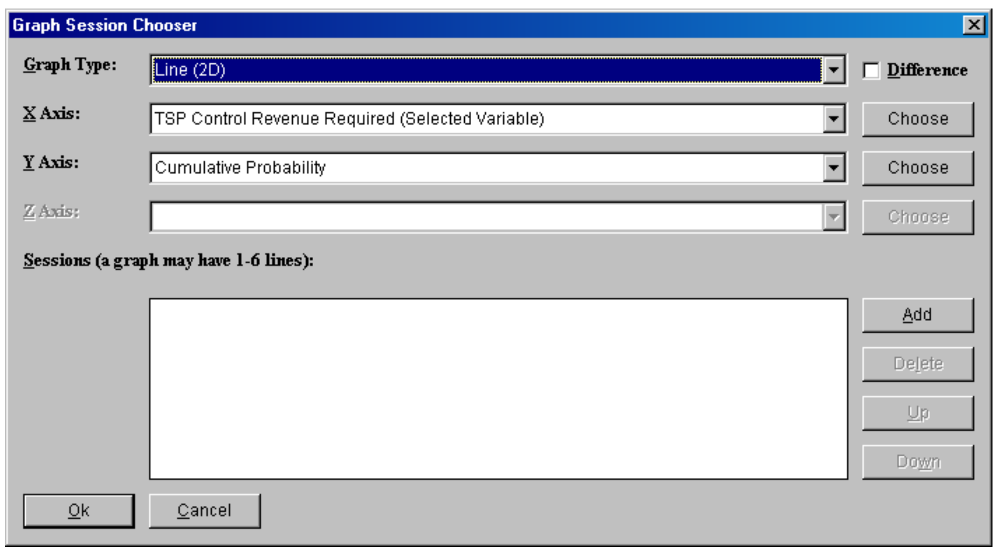
The **Inflation Ctrl** option determines the method by which inflation is calculated for cost result screens**.** The choices available are **Constant** and **Current.** The default setting is **Constant**.

Working with Graphs

Graph Chooser

The table and diagram results displayed on the **Get Results** screens are all deterministic values; that is, uncertainties are not taken into consideration. Probabilistic results (with uncertainties taken into consideration) can be displayed in graphical format as a supplement to every deterministic value shown.

The graph chooser window opens when any value displayed on a result screen is double-clicked. The figure below shows the initial graph window.



The graph chooser window

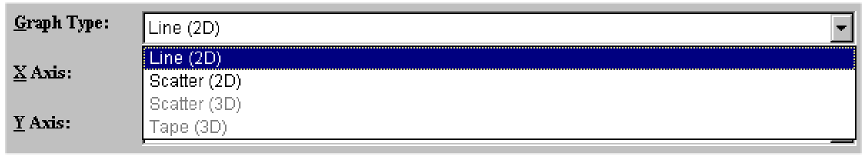
The graph chooser window contains several drop-down menus, a check box, and a few buttons. Each menu begins in a default state, producing a cumulative probability distribution (CDF) graph of the particular result variable double-clicked. These drop-down menus can be modified to produce many different types of graphs. These will be described in the following sections.

To view the standard CDF graph, select the menu items as they appear in the figure above:

- Graph Type: Line (2D)
- X Axis: (Selected Variable)
- Y Axis: Cumulative Probability

The graph type and details that will be displayed can be modified later if the initial graph is not what was desired.

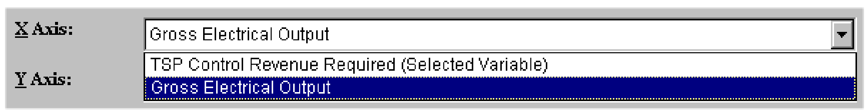
Graph Type



Graph type selection menu

The **Graph Type** drop-down menu contains multiple types of graphs. **Line (2D)** and **Scatter (2D)** can be selected initially with the line graph as the default option. Additional options are available after the graph opens. The line graph connects the x-y data points consecutively with line segments. The scatter graph displays the x-y data points with markers instead of line segments. Because the IECM generates sorted x-y data with x values always increasing, the two graphs will appear very similar. The only difference is the use of line segments and data markers.

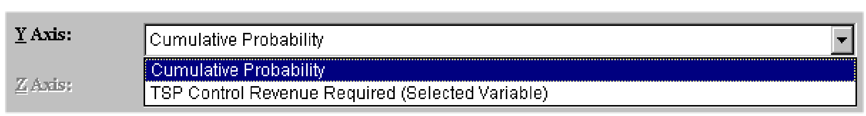
X Axis



X Axis variable selection menu

The **X Axis** drop-down menu allows you to select the independent variable. The menu initially contains only one item – the variable you double-clicked. This is the "selected variable" as shown in the figure above. If the **Choose** button immediately to the right of the drop-down menu is clicked, any input or result variable that exists in the IECM can be selected (see Variable Chooser on page 395).

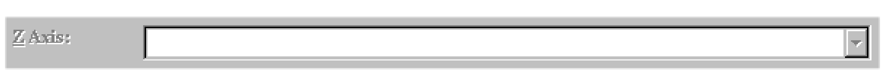
Y Axis



Y Axis variable selection menu

The **Y Axis** drop-down menu allows you to select the dependent variable. The menu initially contains only two items – "Cumulative Probability" and the variable you double-clicked. The second item is the "selected variable" as shown in the figure above. "Cumulative Probability" is the default option. If the **Choose** button immediately to the right of the drop-down menu is clicked, any input or result variable that exists in the IECM can be selected (see Variable Chooser).

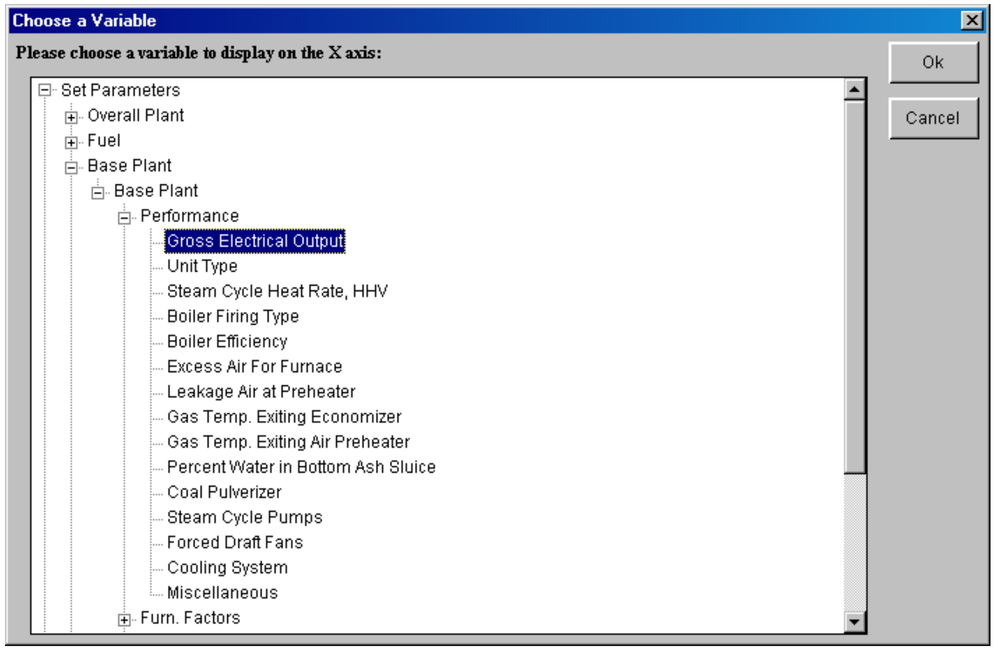
Z Axis



Z Axis variable selection menu

The **Z Axis** drop-down menu allows you to select an additional variable. This option is currently unavailable.

Variable Chooser

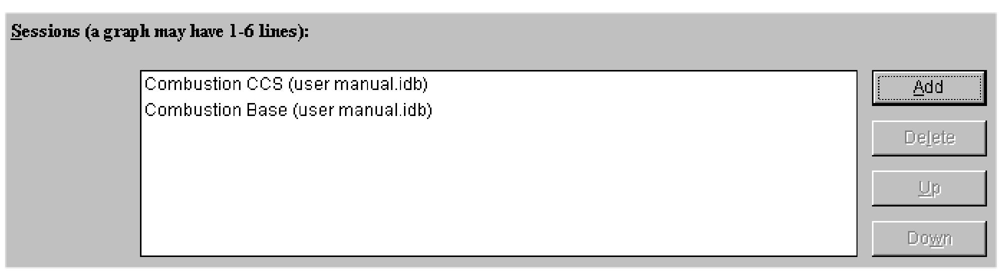


All the IECM variables are available through the **Choose** *buttons.*

Clicking the **Choose** button immediately to the right of the axis drop down menus in the graph chooser window opens the variable chooser window, as shown above. All the input variables listed in the IECM are included in this window. The variables are nested according to input or result variable, technology type, and technology sub-option. These match the navigation tabs used in the IECM. Every variable is present in the same pattern as the IECM screens themselves.

Select a variable and click **Ok** to place the variable in the X-axis drop-down list. The variable chosen will be added to the drop down menu. For best results, select a variable that has a probabilistic function defined; in other words; the variable must be probabilistic in order to represent multiple values. Input variables in the IECM can be associated with uncertainty functions. Result variables must be a direct result of one or more input variables with uncertainty functions assigned. For more information on assigning uncertainty functions to input variables, see Uncertainty Distributions .

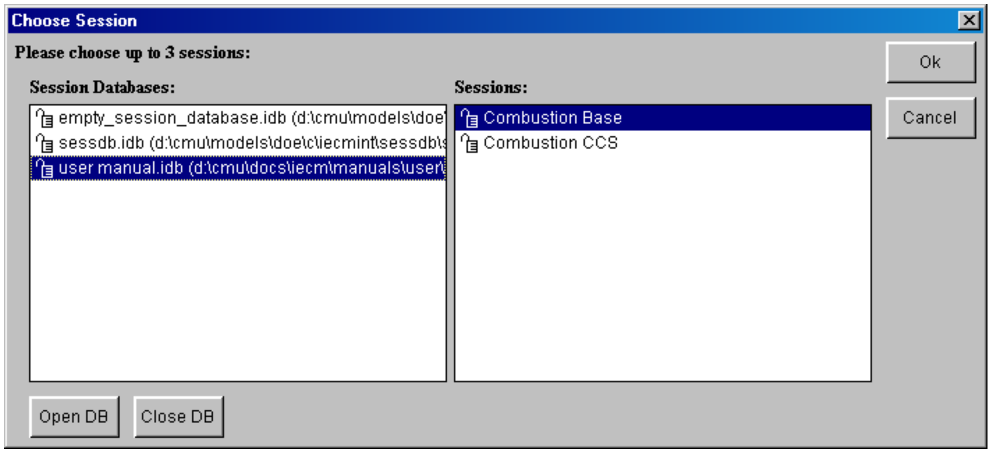
Selecting Multiple Sessions



Multiple session selection area

The graph chooser window allows the same variable(s) from multiple sessions to be displayed on the same graph. The sessions you may select to graph simultaneously are listed in the graph chooser window. The order of these can be changed by using the **Up** and **Down** buttons on the right side of the window. Database files listed can be removed by using the **Delete** button on the right side of the window.

The default is to display only the variable(s) from the current session. As demonstrated in the figure above, only additional sessions are listed in the white area. All graphs displayed will use the X, Y, and Z variables selected in the graph selection window.

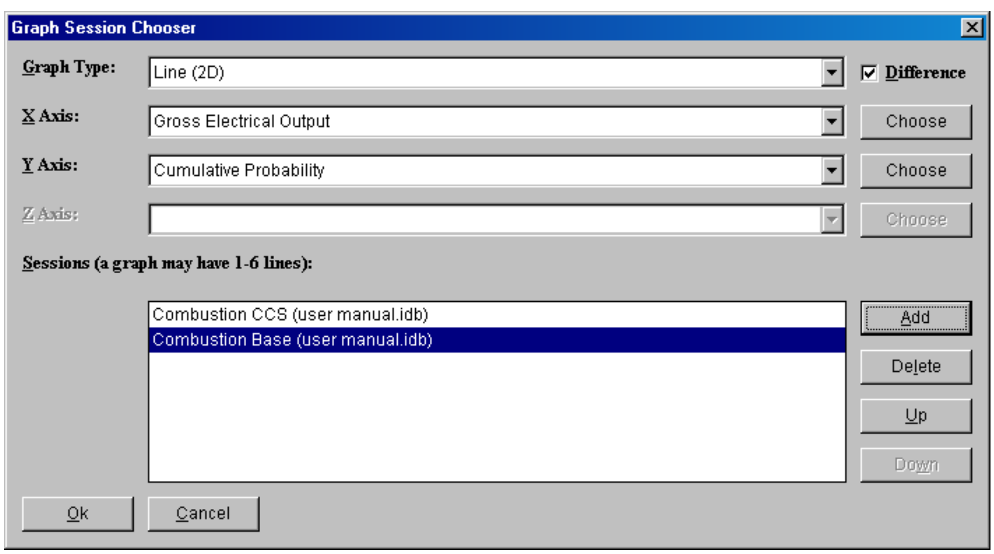


Choose session window

To add additional session to your graph, use the **Add** button immediately to the right of this area. A session chooser window will be displayed as shown in the figure above. Up to five additional sessions can be selected. The sessions may come from multiple session database files. For more information on session databases, see [Session Database Files](#) .

The sessions you add will be reflected in the graph chooser window. All those shown will be displayed in a graph when you click the **Ok** button on the graph chooser window.

Difference Graphs

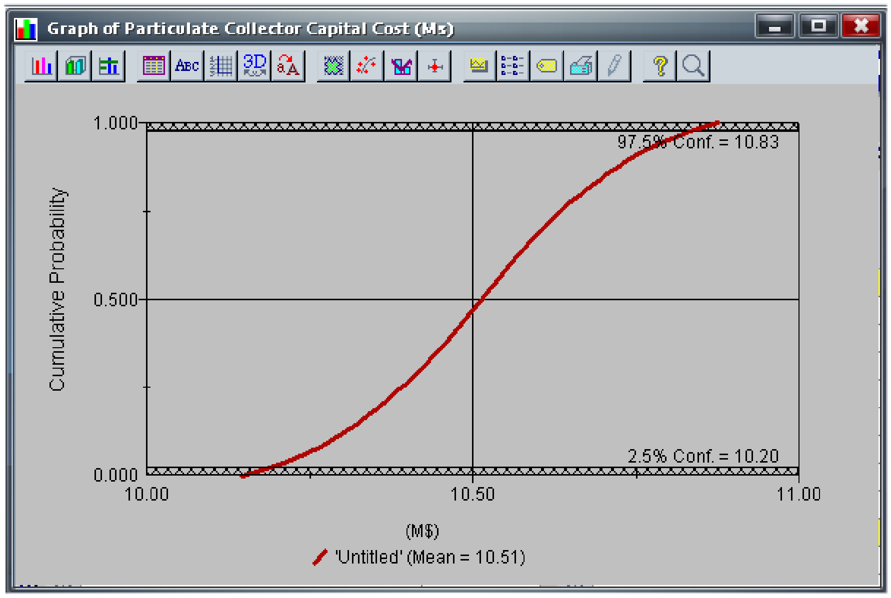


The graph chooser window can be used to display the difference in a variable across multiple sessions

The graphing window can also display the difference between the currently selected variable and the same variable in one to five other sessions. The result is a unique method of examining differences between key results across different modeling sessions.

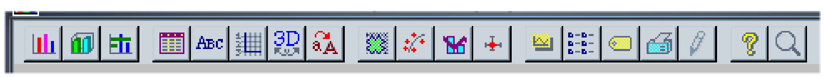
The first step to graphing difference graphs is the click the **Difference** check box at the top of the graph chooser window. The next step is to select other sessions to compare with the current session. This is described in Selecting Multiple Sessions on page 395. Finally, click the **Ok** button at the bottom of the graph chooser window.

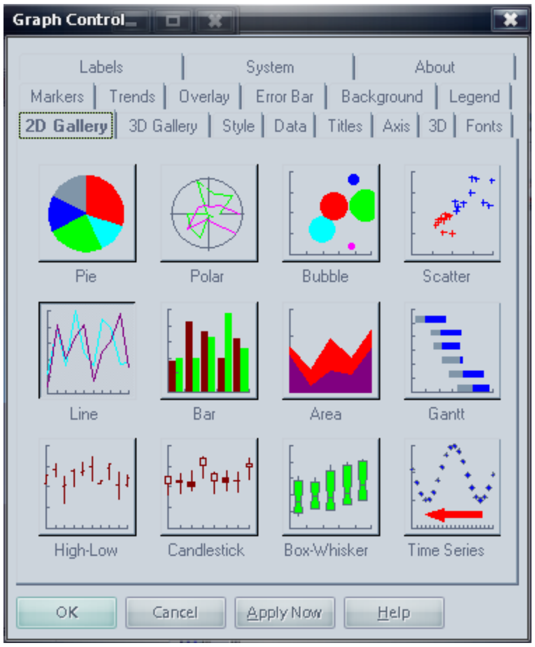
Graph Window



Graph window using all default conditions

The graph window is a very powerful and versatile tool for viewing data results. The variables selected earlier are represented on the axes. Graph option buttons are provided above the graph, allowing you to change the appearance and style of the variables being graphed. These are described in a separate help document distributed with the IECM.





Graph controls can be accessed from any button on the graph window, or any tab from within the graph control window itself. The two methods are synonymous.

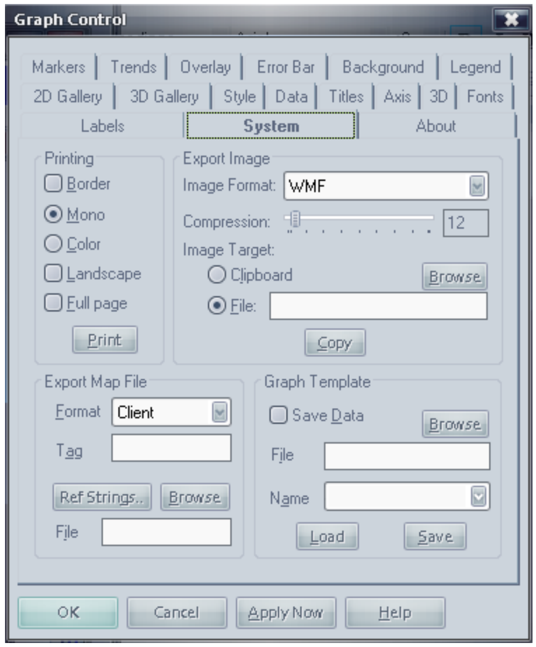
Each button at the top of the graph window opens the same graph control window, but with a particular tab selected. The figure above shows the row of buttons in the graph window and the graph control window that opens when one of the buttons is clicked. Consult the graphing help file for more detailed descriptions of the graph option buttons. The graphing help file is distributed with the IECM software and is accessible from the graph control window (see the help button on the lower right of the figure above).

NOTE: Right-clicking the graph window will also open the graph control window.

Importing and Exporting Graphs

If a graph window is active, you may use the Windows copy function (press **Ctrl-C**) to copy the graph to the clipboard. Both the data and the graph will be placed on the clipboard at the same time.

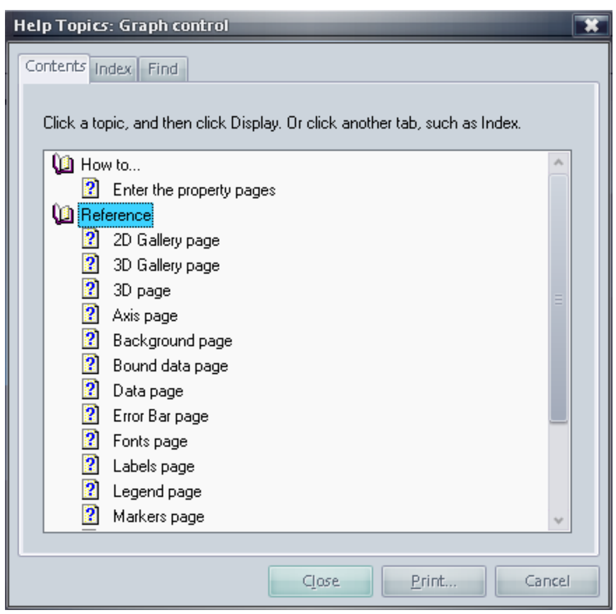
Because the clipboard contains both data and graph information, it is not certain in which format Windows will paste the graph into an application. Windows may paste a Bitmap image, a Windows Metafile image, or a data list of x-y values taken from the graph. By default, graphics programs will typically paste the graph information and word processing programs will paste the data information. To determine how the graph will be pasted, use the **Paste As** function in your target application to paste the graph.



The “System” tab in the graph control window allows data to be imported and saved in any method.

Full control of importing and exporting is accomplished through the “System” tab in the graph control window, as shown in the figure above. For more detailed information, please consult the graph window help file.

Graph Window Help



Detailed Help File Window

Detailed graph help is available by clicking the  button on the graph window. Clicking this button brings up the help file as shown in the figure above. This detailed help is not reproduced here.

Running a Probabilistic Analysis

Uncertainty Analysis

As noted in the introduction, a unique feature of the IECM is its ability to analyze uncertainties probabilistically. You may assign probability distributions to any input parameter, including calculated parameters. The combined effect of all uncertain parameters is then calculated. This chapter describes again how to specify input probability distributions, and how to set several additional parameters needed to conduct a probabilistic analysis.

Even after probabilistic values have been set you do *not* have to use them. Probabilistic analysis can be turned on or off individually for technologies or input types or all at once. Turning the probabilistic calculations on and off for particular portions of the plant allows you to evaluate the major sources of uncertainty.

Uncertainty Distributions

The entry of uncertainty distributions is covered briefly in *Getting Started* This section gives a more detailed description of the process.

Uncertainty Parameters

Each uncertainty distribution requires one or more parameters. The table below lists the parameters and numerical value limits required for each distribution type.

Function	Operator	min or mean	mode	max or sdev
Normal, Half-normal(s)	*	x >= 0	N/A	x > 0
	+	x	N/A	x > 0
LogNormal	*	x > 0	N/A	x >= 1
	+	x > 0	N/A	x >= 1
Uniform	*	x >= 0	N/A	x >= 0
	+	x	N/A	x
Triangular	*	x >= 0	x >= 0	x >= 0
	+	x	x	x
Fractiles	*	x >= 0	N/A	N/A
	+	N/A	N/A	N/A

Wedge	* +	x >= 0 x	N/A N/A	x >= 0 x

Distribution Types

Several types of probability distributions are provided with the IECM. Brief descriptions of each uncertainty distribution are included in the model when the uncertainty editor is selected; the information required, and additional notes, appear below. Distributions that are easiest to use are designated with a dagger (†). Consult a standard statistics reference for additional information.

None

None represents no uncertainty.

Normal Distributions

†Normal (**mean, stddev**) returns a continuous, normal Gaussian probability distribution with the specified **mean** and the standard deviation, **stddev**.

†Neghalf_Normal (**mean, stddev**) returns the lower half of a normal Gaussian probability distribution with the specified **mean** and the standard deviation, **stddev**.

†Half_Normal (**mean, stddev**) returns the upper half of a normal Gaussian probability distribution with the specified **mean** and the standard deviation, **stddev**.

This bell-shaped distribution is often assumed in statistical analysis as the basis for unbiased measurement errors. The normal distribution has infinite tails; however, over 99 percent of all values of the normal distribution lie within plus or minus three standard deviations of the mean. Thus, when used to represent uncertainty in physical quantities which much be greater than zero, the standard deviation should not be more than about 20 or 30 percent of the mean.

Lognormal Distribution

Lognormal (**median, gsdev**) returns a continuous lognormal probability distribution with the specified **median** and the geometric standard deviation, **gsdev**. The geometric standard deviation must be 1 or greater.

This distribution is usually used to represent uncertainty in physical quantities which must be positive values that are positively skewed, such as the ambient concentration of a pollutant. This distribution may be appropriate when uncertainties are expressed on a multiplicative order-of-magnitude basis (e.g., factor of 2) or when there is a probability of obtaining extreme large values.

Uniform Distribution

†Uniform (**min, max**) returns a continuous probability distribution in which every value between **min** and **max** has an equal chance of occurring.

Use this when you are able to specify a finite range of possible values, but are unable to decide which values in the range are more likely to occur than others. The use of the uniform distribution is also a signal that the details about uncertainty in the variable are not known. It is useful for screening studies.

Triangular Distribution

†Triangular (**min, mode, max**) returns a continuous, triangular probability distribution bounded by **min** and **max** and with the specified **mode**.

Use this when you are able to specify both a finite range of possible values and a "most likely" (mode) value. The triangle distribution may be symmetric or skewed. Like the uniform distribution, this distribution indicates that additional details about uncertainty are not yet known. The triangle distribution is excellent for screening studies.

Fractiles

Fractiles. If n is the number of elements in the list L, **Fractiles** (**L**) returns a continuous probability distribution where the first element is the 0% fractile, the second is the 1/(n-1) fractile, the third is the 2/(n-1) fractile, and so on. (The values must be enclosed in square-brackets to register as a "list.")

This distribution looks like a histogram for large sample sizes and can be used to represent any arbitrary data or judgment about uncertainties in a parameter, when the parameter is continuous. It explicitly shows detail of the uncertainties. It is used in the IECM Model to represent all trace species data in the default databases. The finite range of possible values is divided into subintervals. Within each subinterval, the values are sampled uniformly according to a specified frequency for each subinterval.

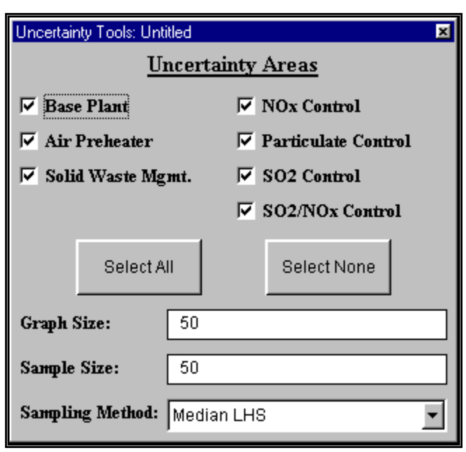
Wedge Distribution

†Wedge (**min, max**) returns a continuous wedge-shaped probability distribution increasing linearly from **min** to **max**.

Use this when you are able to specify a finite range of possible values. The wedge distribution increases linearly from zero probability at the minimum value to the maximum probability at the maximum value. Like the uniform distribution, this distribution indicates that additional details about uncertainty are not yet known. This is a special case of the triangular distribution described below.

Configuring Uncertainty in Results

Some uncertainty parameters may be changed while results are displayed. These are modified using the Uncertainty Tools Floating Palette



The Uncertainty Tools floating palette

Uncertainty Areas

You may choose technology or technologies for which you would like results with uncertain values by clicking the box to the left of each technology. You may select all or none by clicking the buttons at the bottom of the palette.

Graph Size

The sample size determines the number of possible data points used to draw a graph. This parameter determines how many of the total samples to use for the graph. This value cannot exceed the sample size.

Sample Size

You can also specify the number of samples used with the sampling method. This is the number of iterations performed in a probabilistic analysis. The appropriate sample size depends on the number and types of uncertainty distributions that are specified, and on the accuracy with which the distribution is to be estimated (especially the tails of the distribution). A sample size of 100 is the default. The maximum is 200. The calculation time and memory requirements are proportional to this value.

Sampling Methods

Input and output variables are related to each other by model definitions defined for each variable. These relationships are generally referred to as the “decision tree.” The model uses this decision tree to determine which input variables must be calculated to specify the output variable. Only those input variables necessary to specify the output variable value are calculated.

Since each input variable can be expressed as a non-singular distribution, a method of sampling the inputs must be determined. Several methods are available in the model, ranging from a deterministic or single “best guess” value to a completely random sampling of each input distribution. The sampling methods all produce sets of values for the inputs. These sets together form the “sampling space.”

Deterministic Evaluation

Output values can be determined by using the most probable value for each input. This method is frequently referred to as the “best guess.”

Input variables can be treated deterministically either by specifying only a single value, or by selecting the “Off” option for the “Uncertainty Distribution” pane. This option forces all uncertain parameters to be evaluated deterministically. Selecting the “Off” option forces each uncertainty function used in the decision tree to be evaluated using its expected value. This option overrides any particular uncertainty distribution types.

Monte Carlo

Monte Carlo is the simplest and best-known sampling method. It draws values at random from the uncertainty distribution of each input variable in the decision tree. For a particular sampling run, each input variable is randomly sampled once. The random samples from each input result in one final output value. This process is repeated *m* times and results in a final solution set. This set can then be evaluated with standard statistical techniques to determine the mean, precision, and confidence.

This method has the advantage of providing an easy method of determining the precision for a specific number of samples using standard statistical techniques. However, it suffers from requiring a large number of samples for a given precision. It also has the drawback of substantial noise in the resulting distribution. For these reasons, Latin Hypercube sampling is preferred as the model default.

Latin Hypercube

Latin Hypercube is a stratified sampling method that divides the sampling space into equally probable intervals, or strata. For each input variable, the method samples each interval in a random order. When the samples from each input variable are combined, one resultant output is determined. This process is repeated *m* times, forming a final result of *m* output values. These *m* output values contain the uncertainty of the output variable, based on all the uncertainties of the entire set of input variables. The value *m* is referred to as the sample size.

The model contains two variations of Latin Hypercube sampling: Random and Median. **Random Latin Hypercube** (RLH) samples each strata randomly, while the **Median Latin Hypercube** (MLH) samples each strata by its median value. (See: Diwekar, U.M. and J.R. Kalagnanam, (1997) "Efficient Sampling Technique for Optimization under Uncertainty," *AIChE Journal*, Vol. 43, No. 2, pp. 440-7.) Median Latin Hypercube is the default sampling method.

Both forms of Latin Hypercube have the advantage of sampling more uniformly over the input distributions relative to Monte Carlo sampling, resulting in less noise in the final distribution. Another advantage is the reduced number of samples that must be taken to satisfy a given precision. Latin Hypercube has the drawback that the precision is more difficult to calculate using statistical methods. Finally, the output is random but not independent.

Hammersley

A new sampling technique has been added to the IECM which is more efficient than either the Monte Carlo or Latin-Hypercube sampling techniques. It is called the Hammersley sequence sampling technique. (See: Diwekar, U.M. and J.R. Kalagnanam, (1997) "Efficient Sampling Technique for Optimization under Uncertainty," *AIChE Journal*, Vol. 43, No. 2, pp. 440-7.) The sampling method is loosely based on the Monte Carlo method. However, instead of using a random number generator, it uses a quasi-random number generator based on Hammersley points to uniformly sample a unit hypercube. These points are an optimal design for placing n points on a k-dimensional hypercube. The sample points are then inverted over a cumulative probability distribution to define the sample set for any uncertainty variable.

Hammersley has the advantage of high precision and consistent behavior in addition to better computational efficiency. The method reduces the number of samples required relative to the other sampling methods for calculating uncertainty by a factor of 2 to 100. The actual sample reduction varies with the uncertainty function being sampled.

Appendix A - Introduction to Uncertainty Analysis

Uncertainty Analysis

The following section is provided as a means of introducing uncertainty analysis as a tool for model design and operation. However, you should consult standard statistical and other texts (e.g., Morgan and Henrion, Uncertainty, Cambridge Press, 1990) to develop a more complete understanding of the subject.

Introduction

Nearly all analyses of energy and environmental control technologies involve uncertainties. The most common approach to handling uncertainties is either to ignore them or to use simple sensitivity analysis. In sensitivity analysis, the value of one or a few model input parameters are varied, usually from low to high values, and the effect on a model output parameter is observed. Meanwhile, all other model parameters are held at their nominal values. In practical problems with many input variables which may be uncertain, the combinatorial explosion of possible sensitivity scenarios (e.g., one variable "high," another "low," and so on) becomes unmanageable. Furthermore, sensitivity analysis provides no insight into the *likelihood* of obtaining any particular result.

A more robust approach is incorporated in the IECM to represent uncertainties in model parameters using probability distributions. Using probabilistic simulation techniques, uncertainties in any number of model input parameters can be propagated through the model simultaneously to determine their combined effect on model outputs. The result of a probabilistic simulation includes both the possible range of values for model output parameters and information about the likelihood of obtaining various results. You may have seen probabilistic analysis referred to elsewhere as "range estimating" or "risk assessment."

The development of ranges and probability distributions for model input parameters can be based either on statistical data analysis and/or engineering judgments. The approaches to developing probability distributions for model parameters are similar in may ways to the approach you might take to pick a single "best guess" number for deterministic (point-estimate) analysis, or to select a range of values to use in sensitivity analysis.

Philosophy of Uncertainty Analysis

The classical approach to probability theory requires that estimates for probability distributions be based on empirical data. However, in many practical cases, the available data may not be available or relevant to the problem at hand. Thus, statistical manipulation of data may be an insufficient basis for estimating uncertainty. Engineering analysis or judgments about the data may be required.

An alternative approach is the “Bayesian” view. It differs in how probability distributions are interpreted. The probability of an outcome is your “degree of belief” that the outcome will occur, based on all of the relevant information you currently have about the system. Thus, the probability distribution may be based on empirical data and/or other considerations, such as your own technically-informed judgments. The assessment of uncertainties requires thought about all possible outcomes and their likelihood, not just the “most likely” outcome. The advantage to thinking systematically and critically about uncertainties is the likelihood of anticipating otherwise overlooked problems, or identifying potential payoffs that might otherwise be overlooked.

Types of Uncertain Quantities

There are a number of types of uncertainty to consider when developing a probability distribution for a variable. Some of these are summarized briefly here.

Statistical error is associated with imperfections in measurement techniques. Statistical analysis of test data is thus one method for developing a representation of uncertainty in a variable.

Empirical measurements also involve *systematic error*. The mean value of a quantity may not converge to the “true” mean value because of biases in measurement and procedures. Such biases may arise from imprecise calibration, faulty reading of meters, and inaccuracies in the assumptions used to infer the actual quantity of interest from the observed readings of other quantities. Estimating the possible magnitude of systematic error may involve an element of engineering judgment.

Variability can be represented as a probability distribution. Some quantities are variable over time. For example, the composition of a coal (or perhaps a sorbent) may vary over time.

Uncertainty may also arise due to lack of actual experience with a process. This type of uncertainty often cannot be treated statistically, because it requires predictions about something that has yet to be built or tested. This type of uncertainty can be represented using technical estimates about the range and likelihood of possible outcomes. These judgments may be based on a theoretical foundation or experience with analogous systems.

Encoding Uncertainties as Probability Distributions

As indicated in the previous sections, there are two fundamental approaches for encoding uncertainty in terms of probability distributions. These include statistical estimation techniques and engineering judgments. A combination of both methods may be appropriate in many practical situations. For example, a statistical analysis of measured test data for a new emission control technology may be a starting point for thinking about uncertainties in a hypothetical commercial scale system. You must then consider the effect that systematic errors, variability, or uncertainties about scaling-up the process might have on interpreting test results for commercial-scale design applications.

Statistical Techniques

Statistical estimation techniques involve estimating probability distributions from available data. The fit of data to a particular probability distribution function can be evaluated using various statistical tests. For example, the cumulative probability distribution of a set of data may be plotted on "probability" paper. If the data plot as a straight line, then the distribution is normal. Procedures for fitting probability distribution functions are discussed in many standard texts on probability and are not reviewed here.

Such procedures can be utilized to obtain distribution functions for many of the power plant parameters in the IECM when data are available for operating plants. In other cases, especially where data are limited, expert technical judgments may be necessary to develop appropriate distribution functions for model parameters. The emphasis of the discussion below is on the situations where statistical analysis alone may be insufficient.

Judgments about Uncertainties

In making judgments about a probability distribution for a quantity, there are a number of approaches (heuristics) that people use which psychologists have observed. Some of these can lead to biases in the probability estimate. Three of the most common are briefly summarized.

Availability: The probability experts assign to a particular possible outcome may be linked to the ease (availability) with which they can recall past instances of the outcome. For example, if tests have yielded high sorbent utilization, it may be easier to imagine obtaining a high sorbent utilization in the future than obtaining lower utilization. Thus, one tends to expect experts to be biased toward outcomes they have recently observed or can easily imagine, as opposed to other possible outcomes that have not been observed in tests.

Representativeness: has also been termed the "law of small numbers." People may tend to assume that the behavior they observe in a small set of data must be representative of the behavior of the system, which may not be completely characterized until substantially more data are collected. Thus, one should be cautious in inferring patterns from data with a small number of samples.

Anchoring and adjustment: involves using a natural starting point as the basis for making adjustments. For example, an expert might choose to start with a "best guess" value, which represents perhaps an average or most likely (modal) value, and then make adjustments to the best guess to achieve "worst" and "best" outcomes as bounds. The "worst" and "best" outcomes may be intended to represent a 90 percent probability range for the variable. However, the adjustment from the central "best guess" value to the extreme values is often insufficient, with the result that the probability distribution is too tight and biased toward the central value. This phenomenon is overconfidence, because the expert's judgment reflects less uncertainty in the variable than it should. The "anchor" can be any value, not just a central value. For example, if an expert begins with a "worst" case value, the entire distribution may be biased toward that value.

Motivational Bias: Judgments also may be biased for other reasons. One common concern is *motivational bias*. This bias may occur for reasons such as:

- a person may want to influence a decision to go a certain way;
- the person may perceive that they will be evaluated based on the outcome and might tend to be conservative in their estimates;
- the person may want to suppress uncertainty that they actually believe is present in order to appear knowledgeable or authoritative; and
- the expert has taken a strong stand in the past and does not want to appear to contradict himself by producing a distribution that lends credence to alternative views.

Designing an Elicitation Protocol

Studies of uncertainty judgment show that the most frequent problem encountered is overconfidence. Knowledge of how people make judgments about probability distributions can be used to design a procedure for eliciting these judgments. The appropriate procedure depends on the background of the expert and the quantity for which the judgment is being elicited. For example, if you have some prior knowledge about the shape of the distribution for the quantity, then it may be appropriate to ask you to think about extreme values of the distribution and then to draw the distribution yourself. On the other hand, if you have little statistical background, it may be more appropriate to ask you a series of questions. For example, you might be asked the probability of obtaining a value less than or equal to some value x, and then the question is repeated for a few other values of x. Your judgment can then be graphed by an elicitor, who would review the results of the elicitation with you to see if you are comfortable with your answers.

To overcome the typical problem of overconfidence, consider extreme high or low values before asking about central values of the distribution. In general, experts' judgments about uncertainties tend to improve when:

- the expert is forced to consider how things could turn out differently than expected (e.g., high and low extremes); and
- the expert is asked to list reasons for obtaining various outcomes.

While the development of expert judgments may be flawed in some respects, it does permit a more robust analysis of uncertainties in a process when limited data are available. Furthermore, in many ways, the assessment of probability distributions is qualitatively no different than selecting single "best guess" values for use in a deterministic estimate. For example, a "best guess" value often represents a judgment about the single most likely value that one expects to obtain. The "best guess" value may be selected after considering several possible values. The types of heuristics and biases discussed above may play a similar role in selecting the value. Thus, even when only a single "best guess" number is used in an analysis, a seasoned engineer usually has at least a "sense" for "how good that number really is." This may be why engineers are usually able to make judgments about uncertainties, because they implicitly make these types of judgments routinely.

A Non-technical Example

To illustrate the process of defining a subjective probability distribution, let's turn to a simple example of eating lunch in a cafeteria. How long does it take from the time you enter the cafeteria to the time you pay the cashier? Assume that you enter at 12:05 p.m. on a weekday and that you purchase your entire meal at the cafeteria. The answer you give may depend on your recent experiences in the cafeteria. Think about the shortest possible time that it could take (suppose nobody else is getting lunch) or the longest possible time (everyone shows up at the same time). What is the probability that it will take 2 minutes or less? 45 minutes or less? Is the probability that it takes 10 minutes or less greater than 50 percent? etc. After asking yourself a number of questions such as these, it should be possible to draw a distribution for your judgment regarding the time require to obtain and purchase lunch at the cafeteria. Such a distribution might take the form of a fractile distribution giving the probabilities of different waiting times to purchase lunch. For example, your evaluation may conclude that there is only a 1 percent (1 in 100) chance it will take one minute or less, a 60 percent chance of 1 to 10 minutes, a 25 percent likelihood of 10 to 15 minutes, and a 14 percent chance of up to 25 minutes. These probability intervals can be drawn as a histogram and translated into a fractile distribution for a probabilistic analysis.

A Technical Example

A second example focuses on a performance parameter for an advanced pollution control system. This parameter has an important effect on system performance and cost.

The example focuses on an assessment of uncertainty in the performance of an innovative emission control system for coal-fired power plants. In this system, a chemical sorbent circulates between a fluidized bed reactor, where SO_2 in the flue gas is removed by chemical reaction with the sorbent, and a regenerator, in which SO_2 is evolved in a reaction of the sulfated sorbent with methane. There is no commercial experience with this system; the largest test unit has been sized to handle 100 scfm of flue gas. Furthermore, the test units have used batch, rather than continuous, regeneration.

One of the key parameters affecting the performance and cost of this system is the regeneration efficiency, which is defined as the fraction of the spent sorbent which is converted for reuse. In small-scale tests in which the regeneration efficiency has been estimated, the efficiency was found to be roughly 30 to 50 percent. In a more recent test, the regeneration efficiency was not measured due to instrumentation difficulties; however, it may have been lower than the previously obtained values. Regeneration residence times were typically greater than 30 minutes.

A detailed modeling study of the regenerator estimated that a properly sized and designed unit, coupled with heating of the sorbent to a sufficiently high reaction temperature, would result in a regeneration efficiency of just over 99 percent at a 30 minute residence time.

A potential problem that may be occurring in the test units is that regenerated sorbent in the regenerator may be reabsorbing some of the evolved SO_2. However, this was not considered in the modeling study of the regenerator.

Based on this information, it appears that it may be possible to achieve the design target of over 99 percent regeneration efficiency. Clearly, however, it is possible that the actual efficiency may be substantially less than this target value. As a worst case, we might consider the known test results as a lower bound. Thus, there is a small chance the regeneration efficiency may be less than 50 percent. We expect the regeneration efficiency to tend toward the target value of 99.2 percent. Thus, to represent the expectation that the efficiency will be near the target value, but may be substantially less, we can use a negatively skewed distribution. In this case, we assume a triangle with a range from, say, 50 to 99.2 percent with a mode also at 99.2 percent. The triangle in this case gives us a distribution with a mean of about 83 percent and a median of about 85 percent. This type of triangular distribution, in which a minimum, maximum, and modal value are specified, is often a convenient way of expressing uncertainty distributions when a little information is available.

Appendix B - Technical Support

Reaching Technical Support

Questions, issues or concerns regarding the Integrated Environmental Control Model should be directed to:

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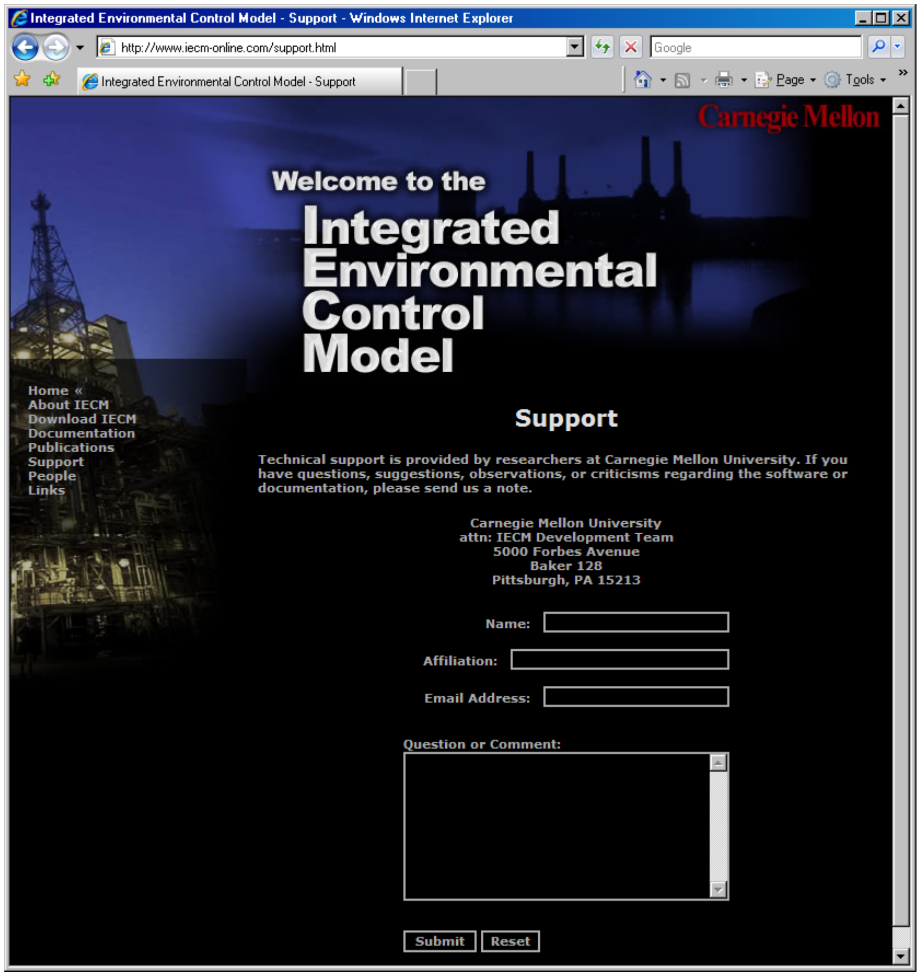
Questions can also be directed through the IECM web site. The web site distributes the question to a team of engineers that will address your question and reply to you.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