7.0 Sensitivity Analysis

A sensitivity analysis was conducted to identify the parameters that had the largest effects on the results of the study and to minimize the impact of incorrect data on the conclusions. Each parameter was changed independent of all others so that the magnitude of its effect on the base case could be assessed. One variable may affect several factors and thus several process steps or it may affect only one block in the overall life cycle assessment. For instance, changing the biomass yield affects the acreage required to grow the biomass, which in turn affects the amount of fertilizer, pesticides, and herbicides used, and the average distance to deliver the biomass to the plant. However, varying the amount of materials used to build the power plant affects only the emissions associated with plant construction and decommissioning. These affects were taken into account automatically in the LCA model.

Most of the sensitivity cases are shown in Table 29. Additionally, the amount of materials used to construct the power plant was reduced by 25% (case L), the distance that the biomass was transported was increased by 46% (case M), and the amount of materials recycled after decommissioning was decreased by one-third (case N).

A summary of the effects on the major emissions, energy use, and resource consumption relative to the base case for several of the parameters varied is shown in Table 30. The percentages shown represent the deviation from the base case values when comparing the results on a per unit of energy produced (i.e., MWh) basis. The positive numbers indicate a percent increase while the negative numbers signify a decrease. The cases that had little effect on the life cycle assessment results are excluded from this table but are discussed in the following text. For easier interpretation, Figures 30 and 31 are graphical representations of the CO_2 and energy sensitivity results. The sensitivity cases that result in the largest change from the base case values are highlighted in these figures.

Table 29: Sensitivity Analysis Cases

Parameter	Base Case	Low Case	Case Letter	% Change from Base Case	High Case	Case Letter	% Change from Base Case
Yield (bone dry Mg/ha/yr)	13.5	9.0	A	-33.3%	15.7	B	16.3%
Amount of nitrogen fertilizer applied (kg nitrate/ha)	100 in year 4	56 in year 4	C	-44%	100 in years 2,4, and 6	D	200%
Amount of phosphorus fertilizer applied (kg P/ha)	22 in year 1	0	E	-100%	44 in year 1	F	100%
Amount of potassium fertilizer applied (kg K/ha)	39 in year 1	0	G	-100%	56 in year 1	H	43.6%
Type of nitrogen fertilizer applied	50% ammonium nitrate, 50% urea	100% Urea	J	N/A	100% Ammonium nitrate	I	N/A
Amount of herbicide applied (cm^3/ha)	36.5 in years 1 and 2	36.5 in years 1 and 2	Same as base case	0%	54.75 in years 1 and 2	K	50%
Amount of fossil fuel use in feedstock production	Average of 82.8 liters/ha/yr	Average of 49.7 liters/ha/yr	O	-40%	Average of 124.2 liters/ha/yr	P	50%
Power plant efficiency	37.2%	32.2%	Q	-5 percentage points	42.2%	R	5 percentage points
Power plant operating capacity	40% in year 1, 80% in years 2-29, 60% in year 30	32.5% in year 1, 65% in years 2-29, 48.75% in year 30	S	-15 percentage points in normal operating years	42.5% in year 1, 85% in years 2-29, 63.75% in year 30	T	5 percentage points in normal operating years

Note: The case letters in this table correspond to the letters in Table 30 and Figures 30-34.

Table 30: Sensitivity Analysis Condensed Results

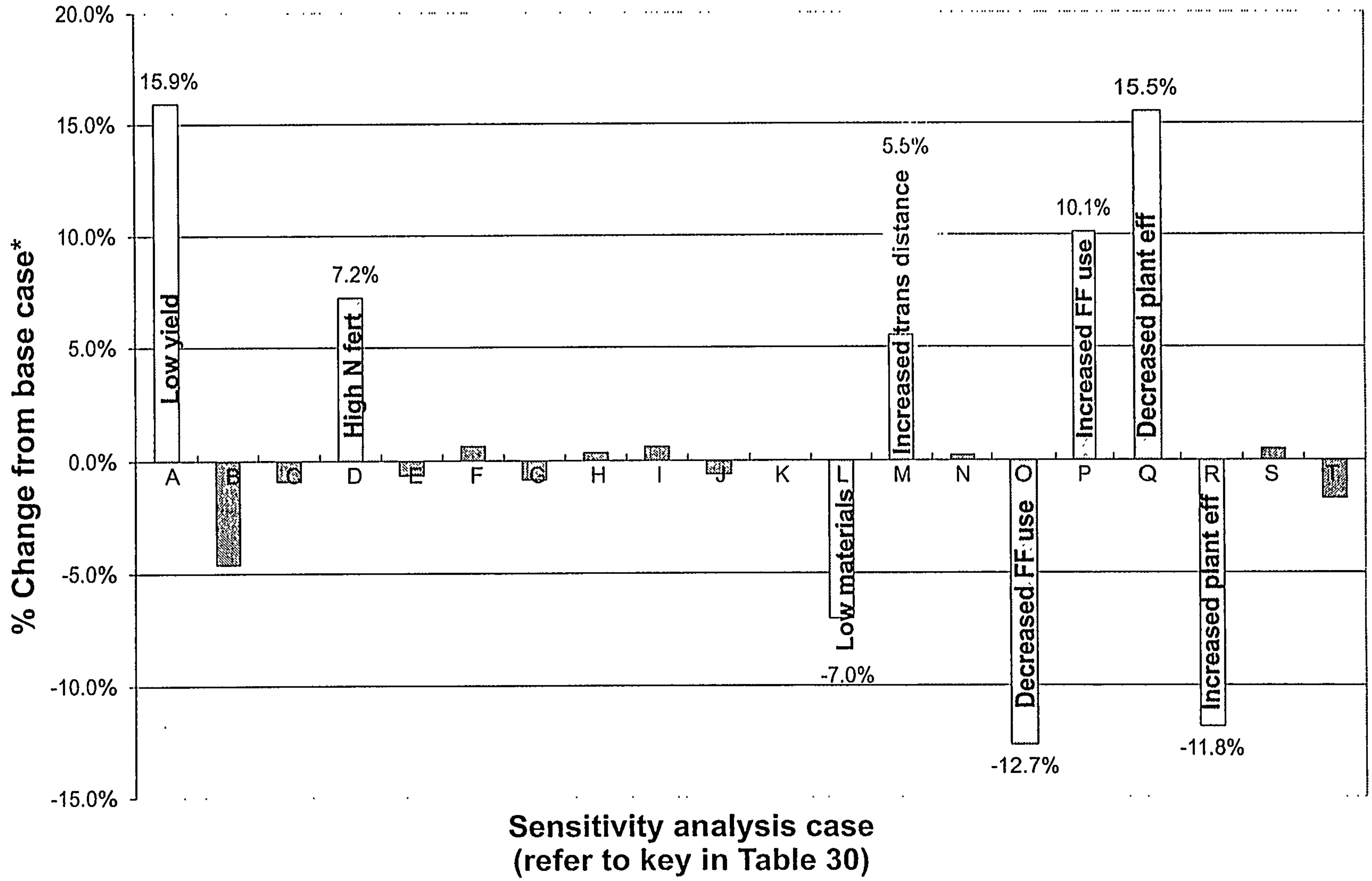
% change from the base case (on a per unit of energy (e.g., MWh) produced basis)

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R	S	T
r: Coal	34.2%	-9.8%	-10.7%	109.0%	-12.9%	12.9%	-17.1%	7.3%	2.5%	-2.5%	0.2%	-27.9%	0.7%	4.3%	-1.4%	1.1%	15.5%	-11.8%	7.8%	-2.0%
r: Natural gas	47.9%	-13.7%	-37.2%	176.2%	-1.5%	1.5%	-2.0%	0.9%	23.3%	-23.3%	0.2%	-2.9%	1.3%	0.6%	-2.7%	2.2%	15.5%	-11.8%	1.9%	-0.5%
r: Oil	43.6%	-12.7%	-0.3%	2.9%	-0.3%	0.3%	-0.4%	0.2%	0.1%	-0.1%	0.0%	-0.5%	18.3%	0.0%	-38.7%	31.0%	15.5%	-11.8%	1.1%	-0.3%
a: CO2	15.9%	-4.6%	-0.9%	7.2%	-0.7%	0.7%	-0.9%	0.4%	0.6%	-0.6%	0.0%	-7.0%	5.5%	0.2%	-12.7%	10.1%	15.5%	-11.8%	0.5%	-1.7%
a: CO	43.3%	-12.5%	-1.5%	8.6%	-0.4%	0.4%	-0.5%	0.2%	-0.1%	0.1%	0.0%	-3.2%	12.8%	0.0%	-38.1%	30.5%	15.5%	-11.8%	1.8%	-0.5%
a: NMHC (including VOCs)	5.8%	-1.7%	-0.6%	4.5%	-0.4%	0.4%	-0.5%	0.2%	0.2%	-0.2%	0.0%	-0.8%	1.2%	0.1%	-4.2%	3.4%	15.5%	-11.8%	0.3%	-0.1%
a: CH4	45.3%	-13.0%	-20.1%	93.0%	-0.4%	0.4%	-0.6%	0.2%	4.4%	-4.4%	0.1%	-0.7%	4.0%	0.2%	-20.9%	16.7%	15.5%	-11.8%	1.3%	-0.3%
a: NO x	13.0%	-3.8%	-0.2%	1.2%	-0.1%	0.1%	-0.1%	0.1%	0.1%	-0.1%	0.0%	-1.4%	3.8%	0.0%	-11.8%	9.5%	15.5%	-11.8%	0.6%	-0.2%
a: Particulate matter	29.9%	-8.7%	-5.2%	45.9%	-4.5%	4.5%	-6.0%	2.6%	4.4%	-4.4%	0.0%	-24.2%	7.4%	3.0%	-15.8%	12.7%	15.5%	-11.8%	6.6%	-1.7%
a: SO x	5.8%	-1.7%	-0.4%	4.0%	-0.4%	0.4%	-0.6%	0.2%	0.1%	-0.1%	0.0%	-2.8%	2.1%	0.0%	-4.1%	3.3%	15.5%	-11.8%	0.7%	-0.3%
w: NH4+	50.0%	-14.3%	-44.4%	199.8%	0.0%	0.0%	0.0%	0.0%	100.0%	-100.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	15.5%	-11.8%	1.2%	-0.3%
w: Dissolved matter	43.7%	-12.7%	-0.2%	2.2%	-0.3%	0.3%	-0.3%	0.1%	0.1%	-0.1%	0.0%	-0.3%	18.4%	0.0%	-38.9%	31.2%	15.5%	-11.8%	1.1%	-0.3%
Energy consumption	41.8%	-12.1%	-3.3%	23.6%	-1.8%	1.8%	-2.4%	1.0%	1.5%	-1.5%	0.0%	-3.8%	15.0%	0.5%	-31.8%	25.5%	15.5%	-11.8%	1.8%	-0.5%
Solid Waste	30.6%	-8.7%	-8.5%	87.2%	-10.4%	10.4%	-13.8%	5.9%	2.5%	-2.5%	0.1%	-34.6%	0.2%	27.3%	-0.4%	0.3%	15.5%	-11.8%	9.3%	-2.4%

r = resource
a = air emission
w = water emission

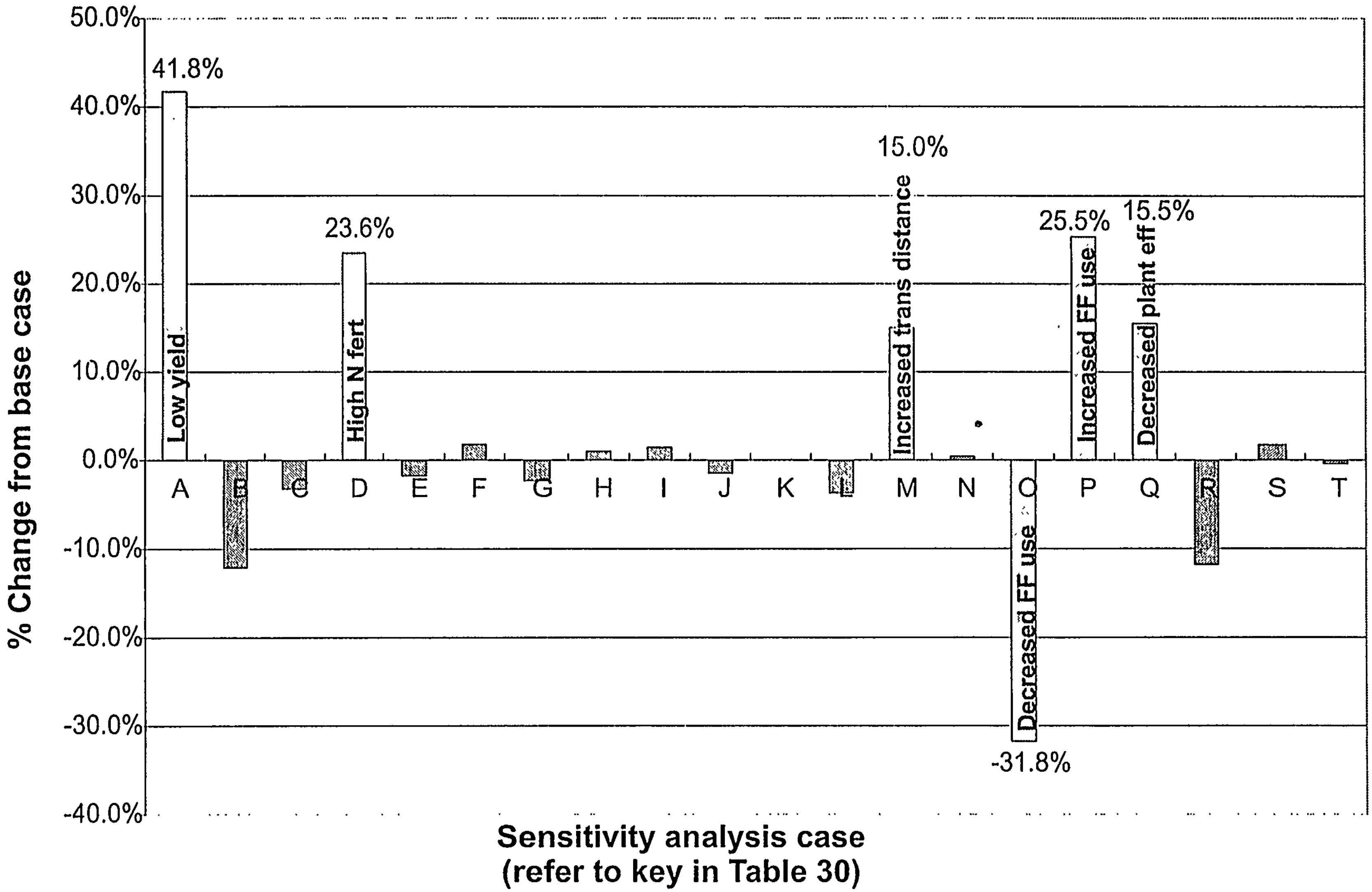
CASE LETTER	SENSITIVITY CASE
A	Yield of 9 Dry Tonnes / Hectare / Year (4 tons/acre/yr)
B	Yield of 15.7 Dry Tonnes / Hectare / Year (7 tons/acre/yr)
C	Nitrogen Fertilizer Low Case
D	Nitrogen Fertilizer High Case
E	Phosphorous Fertilizer Low Case
F	Phosphorous Fertilizer High Case
G	Potassium Fertilizer Low Case
H	Potassium Fertilizer High Case
I	Ammonium Nitrate as Sole Nitrogen Fertilizer
J	Urea as Sole Nitrogen Fertilizer
K	Herbicide Application High Case
L	Construction Materials Low Case
M	Biomass Transportation Distance Increased by 46%
N	Decrease in Recycle of Materials by 1/3
O	Decrease in Feedstock Fuel Use by 50%
P	Increase in Feedstock Fuel Use by 40%
Q	Decrease plant efficiency by 5 points
R	Increase plant efficiency by 5 points
S	Plant operating capcity factor = 65% in normal years
T	Plant operating capcity factor = 85% in normal years

Figure 30: Sensitivity Analysis Results of Net CO_2 Emissions per MWh of Energy Produced



*See Figure 32 for absolute changes in carbon closure

Figure 31: Sensitivity Analysis Results of System Energy Consumption per MWh of Energy Produced



*See Figures 33 and 34 for absolute changes in energy measures

Figure 32 shows the effect of the sensitivity cases on carbon closure, defined to be the amount of CO_2 emitted to the atmosphere divided by that recycled to the biomass. Additional cases, showing the carbon closure as a function of the amount of carbon sequestered in the soil, were given in Figure 8. Effects on the life cycle efficiency and fossil fuel energy ratio (see section 5.3) are shown in Figures 33 and 34. It's important to note that the scales shown on Figures 32 and 33 (carbon closure and life cycle efficiency) are very narrow, indicating that for even the most drastic values of the parameters changed, the overall results of the study remain the same. That is, carbon closure is very high (greater than 94%) and the life cycle efficiency is not significantly less than the power plant efficiency. Additionally, the fossil fuel energy ratio does not drop below 11, indicating that the amount of energy the system produces as electricity will always be significantly greater than the fossil energy it consumes.

7.1 Feedstock Sensitivity Analysis

Of the parameters related to feedstock production, lowering the yield by one-third has the largest effect on the results, causing a 16% increase in CO_2 emissions and a 42% increase in system energy consumption. Additionally, yield most affects carbon closure (94%) and the fossil fuel energy ratio (11). As expected, changing the amount of fossil fuel used in farming operations had a large impact in relation to the base case results. However, as noted above, carbon closure and life cycle efficiency are still very high.

The amount of fertilizers applied also has a large effect on emissions and energy consumption. In particular, nitrogen fertilizer, used at the rate in the high case, will increase overall system energy consumption by nearly 24%, and increase overall CO_2 emissions by 7%. Although it was found that using only ammonium nitrate or urea to supply nitrogen to the soil will affect some emissions and resources, the overall effect on energy and CO_2 is small. Increasing the amount of herbicide applied has very little impact on overall emissions and energy use.

7.2 Transportation Sensitivity Analysis

7.2.1 Mode of Transportation

The split of wood transported by truck and train was varied in the sensitivity analysis. For the high train transport case, the percentage of wood carried by truck was decreased from 70% to 50% with the remaining 50% of the wood being delivered by train. The low case examined wood transport solely by trucks. Having a case of all-truck transport is a reasonable assumption since many of today's existing biomass power plants use trucks only. In both of these cases, since the truck and rail transport is such a small portion of the overall resources required, energy used, and emissions generated, the distribution of the type of transport does not have a large effect on the overall life cycle assessment. For the 50% truck and 50% train transport case the average decrease in resources, energy, and emissions from the transportation sector was 12% but overall this made a difference of

Figure 32: Sensitivity Analysis Results for Carbon Closure

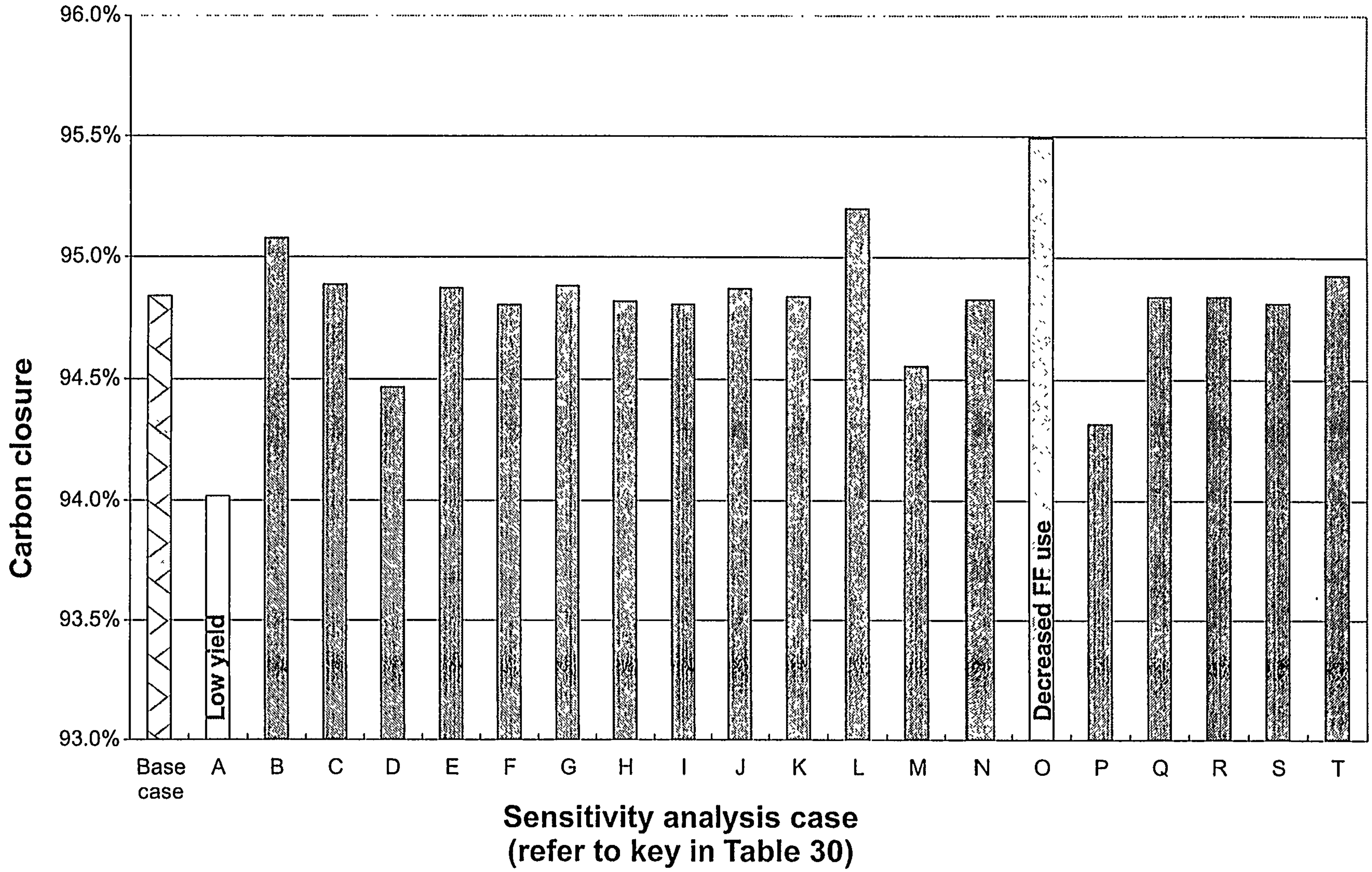


Figure 33: Sensitivity Results for Life Cycle Efficiency

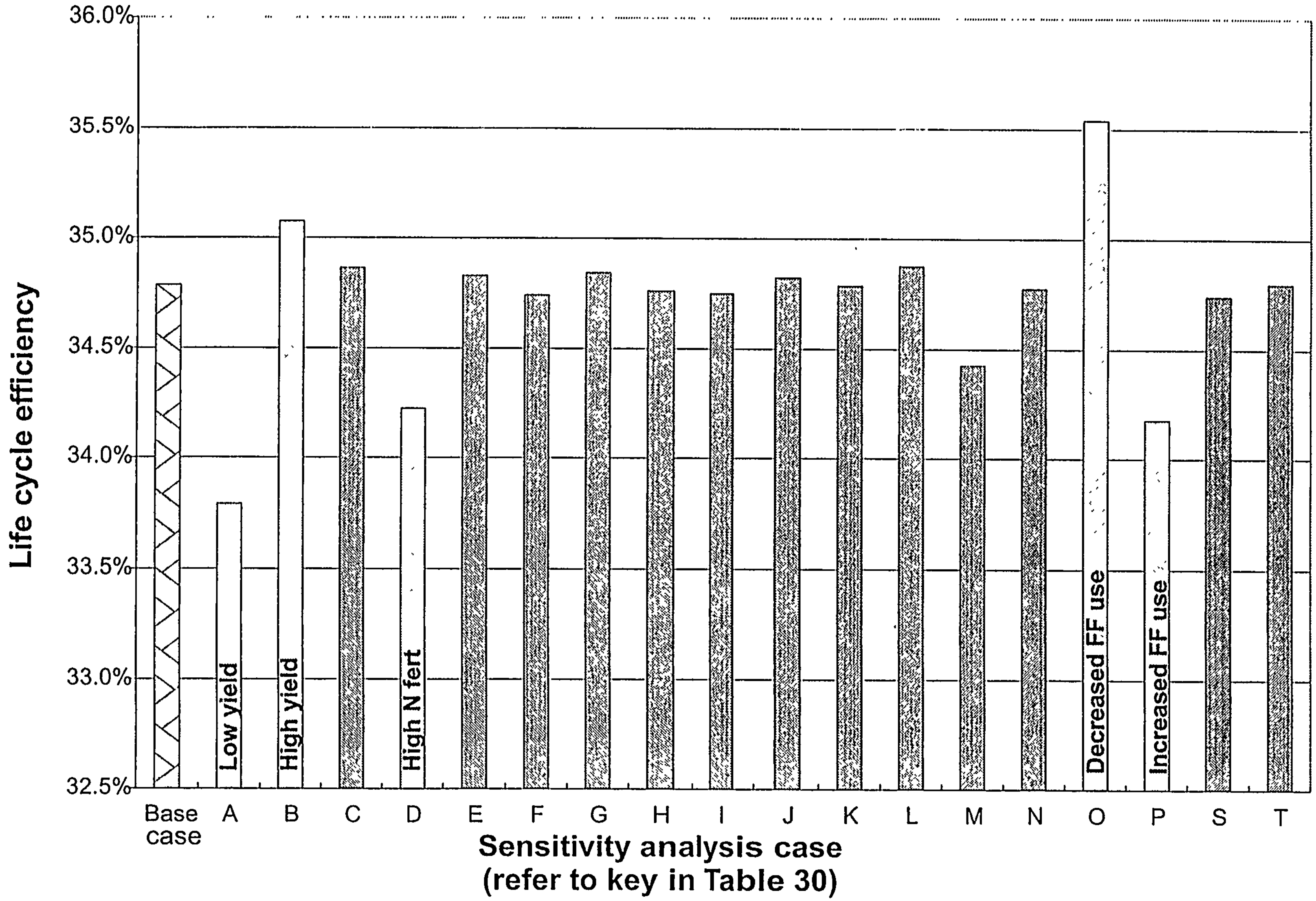
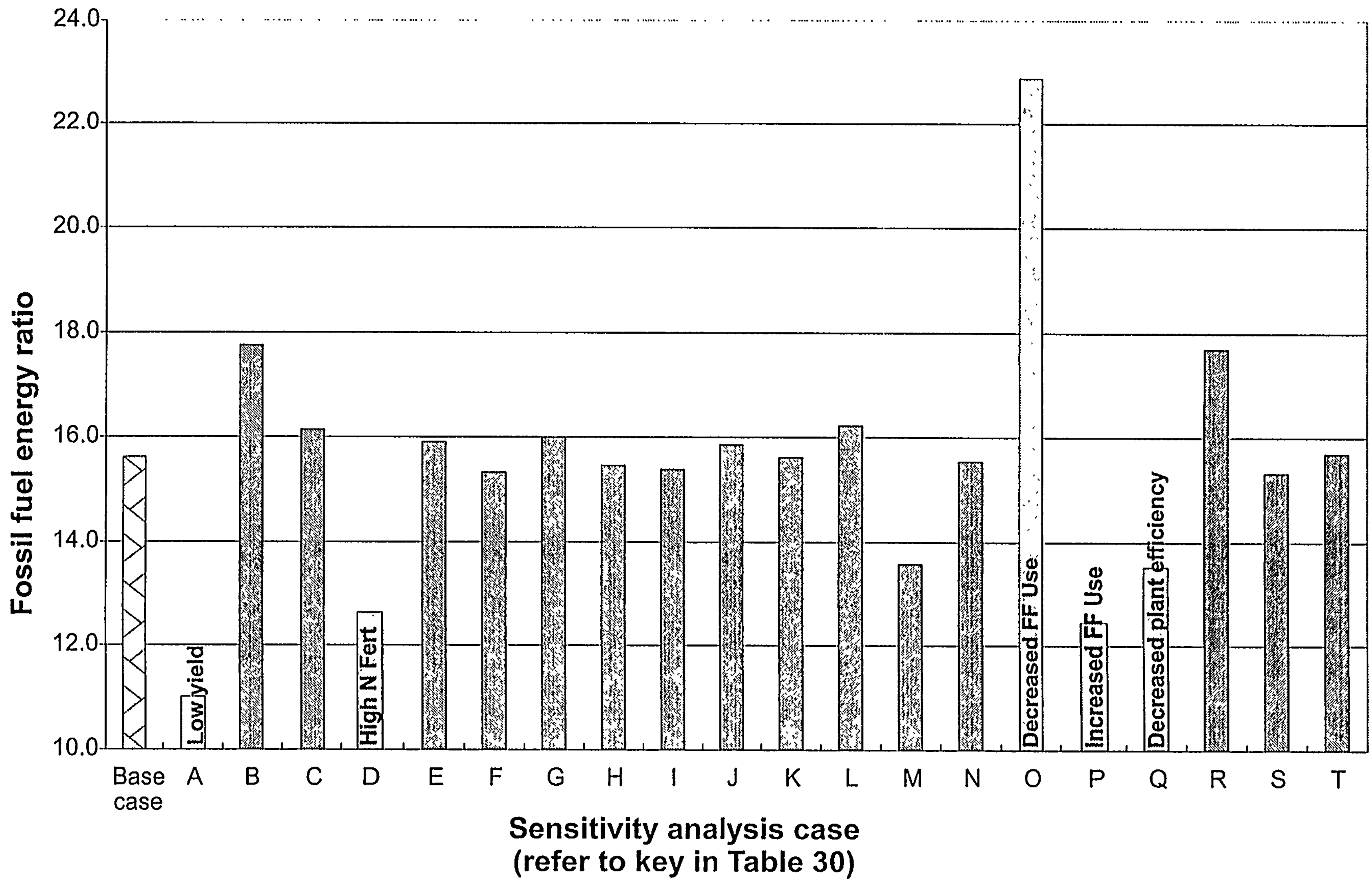


Figure 34: Sensitivity Results for Fossil Fuel Energy Ratio



less than 2% in the overall life cycle assessment. On the same note, even though train transport is more efficient, the 100% truck case increased the resources, energy, and emissions in the overall analysis by less than 2%.

7.2.2 Transportation Distance

Another variable examined was the average biomass transportation distance to the plant. In the base case, the average distance traveled, 27.6 km, was calculated based on the assumption that 10% of the land around the power generation facility was available for crop production and that the land had a tortuosity factor of 1.3. In order to determine the effect of varying the percent of the land around the power generation facility available for crop production and varying the tortuosity factor, a separate test was conducted. A matrix was set up and the percent of the land around the power generation facility available for crop production was varied from 10-25% and the tortuosity factor was varied from 1.0-2.0. The average haul distance ranged from 13.4 to 42.5 km. As would be expected the oil consumption increases for the high case, and thus the amount taken from the ground goes up by 18% for the overall analysis. Air emissions of CH_4, NOx, and CO_2 increase by less than 6%, while particulate matter and CO increase by 7% and 13%, respectively. System energy consumption increases by 15%. Further evidence of the effect on the overall system impacts can be seen in Table 30. To minimize the environmental effects the biomass should be grown within a reasonable distance from the plant and not hauled over a distance several states away.

7.3 Power Plant Construction & Decommissioning Sensitivity Analysis

Because there were two literature sources containing very different plant construction material requirements, the material requirements for concrete, steel, aluminum and iron were varied in one of the sensitivity analyses. The variation in these numbers can be seen in Table 31. The larger numbers were used as the base case for this analysis for several reasons. In both studies the IGCC plant had an operating capacity similar to the BIGCC in this life cycle assessment; however, the study with the larger numbers was specifically for a biomass plant whereas the other study was for a coal plant. Also, the study with the higher numbers was more rigorous, being derived from an in-depth report that examined the material requirements for many different operating systems (U.S. Department of Energy, 1983).

Table 31: Plant Material Requirements Used in Sensitivity

Material	Base case (kg/GWh)	Sensitivity (kg/GWh)
concrete	22,299	794
steel	8,341	103
aluminum	65	34
iron	97	49

The amount of materials used affects the emissions for both construction and decommissioning. A change in the materials of construction has a large effect on the life cycle assessment. Many of the resources decrease by over 30% causing many of the emissions to decrease by a similar order of magnitude. Some emissions, such as CO, CH_4, NMHC, SOx, and NOx, are slightly affected, with percent decreases of less than 6%. The total energy requirement decreases by only 3.8%.

7.4 Landfilling versus Recycling Sensitivity Analysis

Another sensitivity analysis involved changing the amount of materials landfilled versus recycled after disassembly of the trucks, trains, farm equipment, and power plant. The base case assumes that 75% of all materials is recycled and that the remaining 25% is landfilled. These numbers were changed to 50% each. Reducing the amount of metals recycled results in large increases in some of the resources and wastes, but has a relatively minor effect on energy requirements and most of the emissions.

7.5 Power Generation Sensitivity Analysis

7.5.1 NOx Produced

Most of the operating plant emissions are set by material balances from the ASPEN Plus™ simulation, and are not likely to vary significantly in an actual plant. However, NOx can be produced by two different mechanisms (formation of fuel-bound NOx and thermal NOx), making the possible range much broader. For the base case, it was very conservatively assumed that all of the nitrogen in the biomass was converted to NOx and emitted to the atmosphere from the stack. Because thermal NOx is difficult to predict, a sensitivity case assuming that the amount formed will be equal to the fuel NOx was run. This was based on the variation shown in the literature (Dyncorp, 1995, Delucchi, 1993, and U.S. EPA, 1995). Because 71.8% of the NOx emissions come from the power plant subsystem, doubling the NOx emissions in each operating year increases the overall NOx in the life cycle assessment by 69.8%.

7.5.2 Power Plant Efficiency

Another sensitivity analysis was conducted to examine both a decrease and an increase in the power plant efficiency. The base case IGCC system was found to have a power plant efficiency of 37.2% (higher heating value basis). This is defined as the fraction of energy in the feedstock to the power plant that is delivered to the grid. The power plant efficiency was changed by plus and minus five points to 42.2% and 32.2%. When comparing the results on a per unit of energy produced (i.e., MWh) basis, this resulted in a percent change from the base case resources, emissions, and energy of +15.5% and -11.8%.

7.5.3 Operating Capacity Factor

The amount of time that the power plant operates was also varied in the sensitivity analysis. For the low case, the power plant operating capacity factor was reduced from 80% to 65% during the normal operating years. On a per unit of energy produced basis, this resulted in an average percent increase from the base case resources, emissions, and energy of +6.3%. For the high case, the operating capacity factor was increased from 80% to 85%, resulting in an average decrease of about 1.6% on a per unit of energy produced basis.

8.0 Impact Assessment

Life cycle impact assessment is an evolving technique used to characterize the possible consequences of a process. It links the results of the life cycle inventory with potential environmental and human health effects by defining relationships between activities resulting in emissions, energy use, and material consumption (stressors) with likely environmental effects (stressor categories). Examples of stressor categories are photochemical oxidants, climate change gases, and loadings that alter habitat. Two important aspects of this method of classification are that a single stressor is often associated with multiple impacts, and that not all stressors within a category result in equal amounts of damage to the environment.

The scope of impact assessment for this study involved classification of inventory data into stressor categories that are potentially linked to ecological and human health. It should be recognized that discovering and establishing a causal relationship between an emission identified in the inventory and an impact on the environment is not a component of this work or of life cycle assessment in general. The intent is not to prove or disprove that biomass power production via gasification is responsible for any degradation of the environment, but to index expected emissions, energy use, and material consumption with known consequences. This type of impact assessment is qualitative rather than quantitative, and uses the premise that less is better when examining the potential impacts of each stressor. More complete means of assessing the possible impacts of this process on the environment require fate modeling and concentration estimates. The major stressors identified in this LCA and the associated stressor categories are shown in Table 32.

Table 32: Stressor Categories Associated with Biomass Power Production

Stressor Category	Stressors	Major Impact Category H = Human health E = Ecological health Area Impacted L = Local (county) R = Regional (state) G = Global
Toxicants	Pesticides, herbicides, fertilizers Tars, diesel fuel, and other hydrocarbons SO_2, SO_3, H_2S, NH_3 Fluorine and fluorides	H, E; L H, E; L H, E; L, R, G H, E; L, R
Photochemical oxidant precursors and photochemical oxidants	Hydrocarbons, non-methane hydrocarbons, VOCs Ozone (O_3)	H, E; L, R H, E, L H, E; L, R
Particulates	Wood dust Construction, cement, road dust Microorganisms, spores, fungi	H, E; L H, E; L H, E; L, R
Air pollutants	CO, O_3, NO_x, SO_2, SO_3, H_2S, hydrocarbons, NH_3 Chlorinated compounds wood dust, sand dust	H, E; L H; L H; L
Solid waste	Catalysts Char Gypsum Sand	H, E; L, R H, E; L, R H, E; L, R H, E; L, R
Physical trauma	Accidents Noise Odor	H; L H; L L
Climate change	CO_2, CH_4, nitrates, sulfates, changes in plant growth	E; G E, L, G
Acidification precursors	SO_2 (H_2SO_4), NO_2 (HNO_3), CO_2 (HCO_3-)	E; R, G
Nutrients	Nitrates, sulfates	H, E; L, R
Habitat effects	Monoculture, non-native species, flora kill, animal and insect kill	E; L, R
Resource depletion	Fossil fuel use Water use Mineral and ore use Groundwater pollution Topsoil erosion	E; R, G E; R E; R, G E; L, R E; L

9.0 Summary of Results and Discussion

Given that electric power production from biomass has considerable potential to contribute to energy supplies in the United States, it's important to assess the environmental consequences up-front, while system components are still being defined. By analyzing the emissions, resource consumption, and energy use of the entire system, including biomass production, transportation, and electricity generation, the dominant sources of environmental impacts can be determined and the resulting effects can be reduced. For these reasons, a life cycle assessment of a biomass power plant, including all upstream production and downstream disposal processes, was conducted.

General trends can be seen when examining the resources, emissions, and energy over the life of the biomass-to-electricity system described in this report. In years preceding power plant construction and operation, all of the stressors are associated with feedstock production, and as expected, there is a yearly increase as the number of fields in production is increased. A majority of the stressors are highest in the two years before plant operation due to activities associated with plant construction. The impacts then tend to be level during plant operation even with the construction and decommissioning activities associated with the farm equipment and truck transportation. Finally, a gradual decrease is seen, starting in year 23 when biomass production tapers off, leading up to a rapid decrease in impacts during final decommissioning.

Of all air emissions from the system, CO_2 is emitted in the greatest quantity. Feedstock production, primarily the use of fossil fuels in farming operations, is responsible for greater than half of all net CO_2 emissions. Other emissions commonly described as greenhouse gases, specifically methane and nitrous oxide, are emitted in very small quantities and add a minimal amount to the global warming potential of this system.

Because carbon dioxide emitted from the power plant is recycled back to the biomass as it grows, biomass power systems have the ability to reduce the overall amount of CO_2 added to the atmosphere. The system studied was found to have a 95% carbon closure, with 100% representing total recycle, i.e., no net addition of CO_2 to the atmosphere. The amount of carbon that is sequestered by the soil at the plantation most strongly affects the carbon closure of the system. If the range of literature values for soil carbon sequestration is applied, carbon closure may be as low as 83% or as high as 200% (i.e., a net reduction in the amount of atmospheric CO_2). Conducting sensitivity analyses on other assumptions used in this study predicts carbon closures greater than 94%.

The base case analysis assumed that there would be no net accumulation or loss in soil carbon, with a sensitivity analysis showing that if 1.9 Mg/ha over the seven year crop rotation could be sequestered, the carbon cycle could be closed. In other words the system would be a zero-net CO_2 process. Literature values for soil carbon build-up ranged from a loss of 4.5 to a gain of 40.3 Mg/ha/seven years.

Isoprene, the compound used to model biogenic emissions from the trees, is released to the air in the second highest amount. However, its impact on the environment cannot be directly assessed from this result without further study. NOx and NMHCs are the next highest emitted, followed by SOx. NOx, SOx, and particulates are released from the power plant at rates one-fifth, one-tenth, and 1/28th of those required by the New Source Performance Standards (NSPS) for fossil-fueled plants. Particulate emissions, although not found to be released in significant quantities overall, are greater than six times higher during the two years of plant construction than during normal operation. NMHC emissions, primarily from operating the power plant, represent only 0.9% of all air emissions. The majority of air emissions produced in the feedstock production section are typical of those from diesel-fueled farm equipment. However, the total amount of these emissions is small in comparison to air emissions from the power plant.

A previous technical and economic analysis on this system was revisited in the context of this life cycle assessment. To reduce the emissions of VOCs from the power plant, a slipstream of the dryer exhaust gas is recycled to the char combustor. This configuration is a change from the original design and technoeconomic analysis given in Craig and Mann (1996). The cost of an additional blower and its electricity consumption result in a minimal increase in the selling price of electricity to 6.75 ¢/kWh in current dollars or 5.25 ¢/kWh in constant dollars.

Emissions to water occurred mostly in the feedstock production system since the power plant treats a significant quantity of its water prior to discharge. It's important to note, however, that the total amount of water pollutants was found to be small compared to other emissions. In addition to the air and water emissions, non-hazardous solid waste was produced, but in small quantities.

Water is the resource consumed in the largest quantity by this system. Because rainfall was assumed to be adequate for water requirements at the plantation, water is consumed only in upstream manufacturing operations, and especially by the power plant itself. Excluding water, oil, iron, and coal account for 95% by weight of the other resources consumed. As expected, the majority of fossil fuels are consumed by farming operations in feedstock production. By weight of substance, the percentage of the total consumption of natural gas, oil, and coal used in the feedstock subsystem equals 95%, 79%, and 67%, respectively. Because of equipment construction, the power plant was found to require more electricity, and thus more coal and natural gas, than biomass transportation. However, the amount of oil consumed by transportation is higher than by the power plant subsystem.

In addition to quantifying emissions, a key aspect of this work was to evaluate the energy flows within the system boundaries to assess the net energy produced. The net energy production of the system was found to be highly positive. One unit of fossil fuel energy is required to produce 15.6 units of biomass-generated electricity. The worst case tested in the sensitivity analyses gave a ratio of no less than 11. Additionally, the life cycle efficiency (34.9%), which includes all energy consumed within the system, is not substantially less than the power plant efficiency (37.2%). Not including power plant parasitic losses, feedstock production accounts for 77% of the total system energy consumption.

Transporting the biomass to the power plant required fewer resources and less energy than both feedstock production and power plant operations. Additionally, air and water emissions are lowest from this subsystem. Changing the mode and/or emissions of transportation will not greatly affect the overall impact of this system on the environment.

Apart from the impact soil carbon sequestration has on the carbon closure, biomass yield was found to have the largest effect on the amount of resource consumption, net emissions, and energy use for the system. Changing the amount of fossil fuel used at the plantation and changing the power plant efficiency also had noticeable effects. Most importantly, however, the conclusions drawn remain the same for all sensitivity cases studied. That is, carbon closure and life cycle efficiency are very high for this system. Additionally, the fossil fuel energy ratio does not decrease substantially, indicating that the electric energy the system produces will always be far more than the fossil fuel energy it consumes.

10.0 Future Work

To complement this work, we will extend the life cycle study of biomass processes and expand the developed methodology to other systems. The next set of studies will seek to answer the question of how this process measures up environmentally against fossil-based systems. Life cycle assessments will be performed on three coal-fired power plants, one which incorporates new emissions control technologies, one which meets the New Source Performance Standards, and one which represents a plant in operation today. Another power generation option that is likely to be examined is co-firing of biomass in coal- or oil-fired boilers. This option of retrofitting existing power plants will likely be the first step for utilizing biomass in commercial, large-scale electricity systems. Finally, an assessment of a natural gas-fired IGCC plant may be conducted.

A system similar to that studied in this analysis but which uses other biomass feedstocks may also be examined. An herbaceous feedstock such as switchgrass, a feed from which co-products can be generated, such as alfalfa, and agricultural and forest waste wood are examples.

An interesting extension of this study would be the incorporation of biomass-derived diesel fuels into farming operations. Theoretically, this would close the carbon balance further, although the emissions related to growing biomass would be increased. Additionally, it would be useful to study the environmental effects of biomass crops compared to traditional agriculture crops.

11.0 Related Studies

A brief summary of some of the previous studies that relate to this work is given in this section. Data from many of these studies were used in this assessment, and referenced elsewhere in the text. Although this list is not all-inclusive, it serves to illustrate the nature of past efforts.

DynCorp EENSP, Inc. (1995).	A life cycle assessment of CO_2 and methane emissions from different renewable and non-renewable technologies, including a slightly different version of the same biomass technology assessed here. Energy use and other stressors were not assessed. Emissions factors from a modified version of the TEMIS model was used. Different capacity addition scenarios were addressed.
Ellington and Meo, 1990-91, 1993	A life cycle assessment showing the carbon dioxide emissions from using biomass from tree farms to produce methanol for reformulated gasoline. Presented a useful means of tracking the accumulated amount of CO_2 in the atmosphere. Did not include power production as a use for the biomass.
Graham et al (1992)	Assessment of the CO_2 released in producing biomass in a specific short rotation woody crop scenario. Contains a cursory glance at what the net CO_2 would be for different uses of the biomass. Did not include all upstream processes and transportation. However, the CO_2 released in producing biomass was found to be very close to that reported for the current study.
Gustavsson et al (1996)	Assumed that the only CO_2 inputs into the process were from energy use, and could thus be displaced with biomass-based products. Did not include the upstream processes that use fossil fuels as chemical inputs. CO_2 was the only stressor studied.
OTA Background Paper (1993)	Cursory discussion of the issues involved in establishing bioenergy in the U.S. Does not report an analysis.
Perlack et al (1992)	Excellent source of information on the environmental consequences of producing biomass fuel. According to ORNL, however, some data are now outdated given experience gained in the last few years. Did not discuss upstream processes.
Pimentel et al (1981)	General approach taken to evaluate the energy balance of producing energy from crop and forest residues. Few environmental effects discussed.

Ranney and Mann (1994)	Good summary of what has been learned about the environmental impacts of growing biomass. Issues discussed include previous land use, farm chemical requirements and fates, water quality, air emissions, sustainability, and biodiversity.
Ranney *et al* (1991)	Assessment of the total carbon flows involved in producing biomass as a fuel. Very useful discussion on how above- and below-ground biomass will affect soil carbon. Some data are now considered to be outdated.
Schlamadinger and Marland, 1996	A life cycle assessment showing the carbon dioxide emissions from using conventional and short-rotation forestry to produce biofuels and long- and short-term wood products to displace fossil fuels. Showed cumulative benefits over periods of time ranging from zero to 100 years. Did not include upstream processes or power production as a use for the biomass.
Turhollow and Perlack, 1991	An analysis of the CO_2 emissions from biomass and fossil fuels. Based on conversion factors for each technology. Does not include upstream processes. Assumptions on farming inputs are now considered by ORNL to be outdated.

12.0 Acknowledgments

We would like to acknowledge the Department of Energy's Biomass Power Program for funding this work, and Dr. Richard Bain, Dr. Ralph Overend and Kevin Craig for extensive technical guidance and review. Also, our thanks to the many people outside of NREL who have contributed their time and effort in assisting us, specifically, Bruce Vigon of Battelle for providing ideas on how best to conduct this study, ORNL's Environmental Sciences Division for supplying an extensive amount of information on the logistics and environmental consequences of producing biomass as a dedicated energy crop, and Vince Camobreco of Ecobalance for his many hours of technical support for the TEAM and TEAM Plus software.

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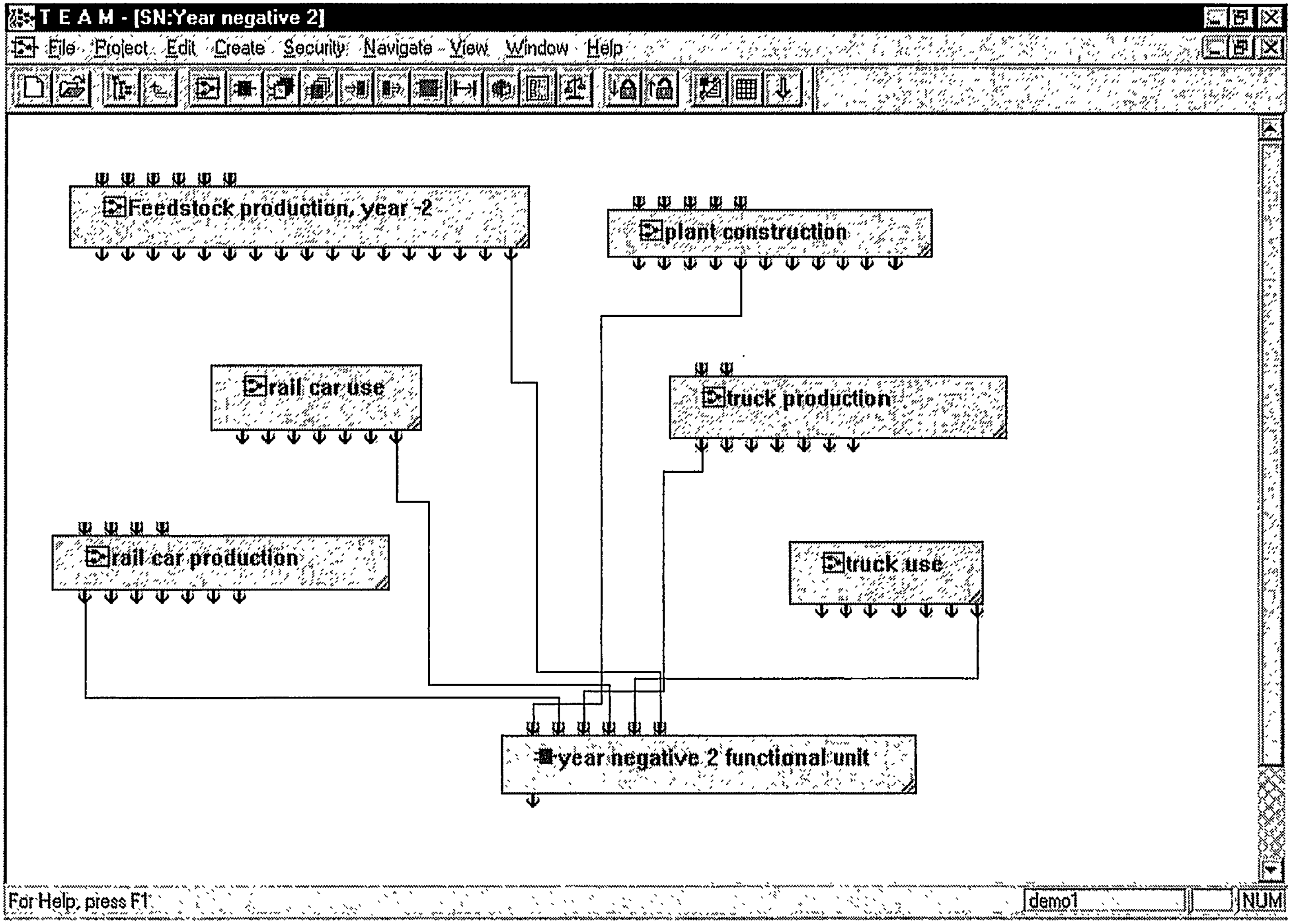
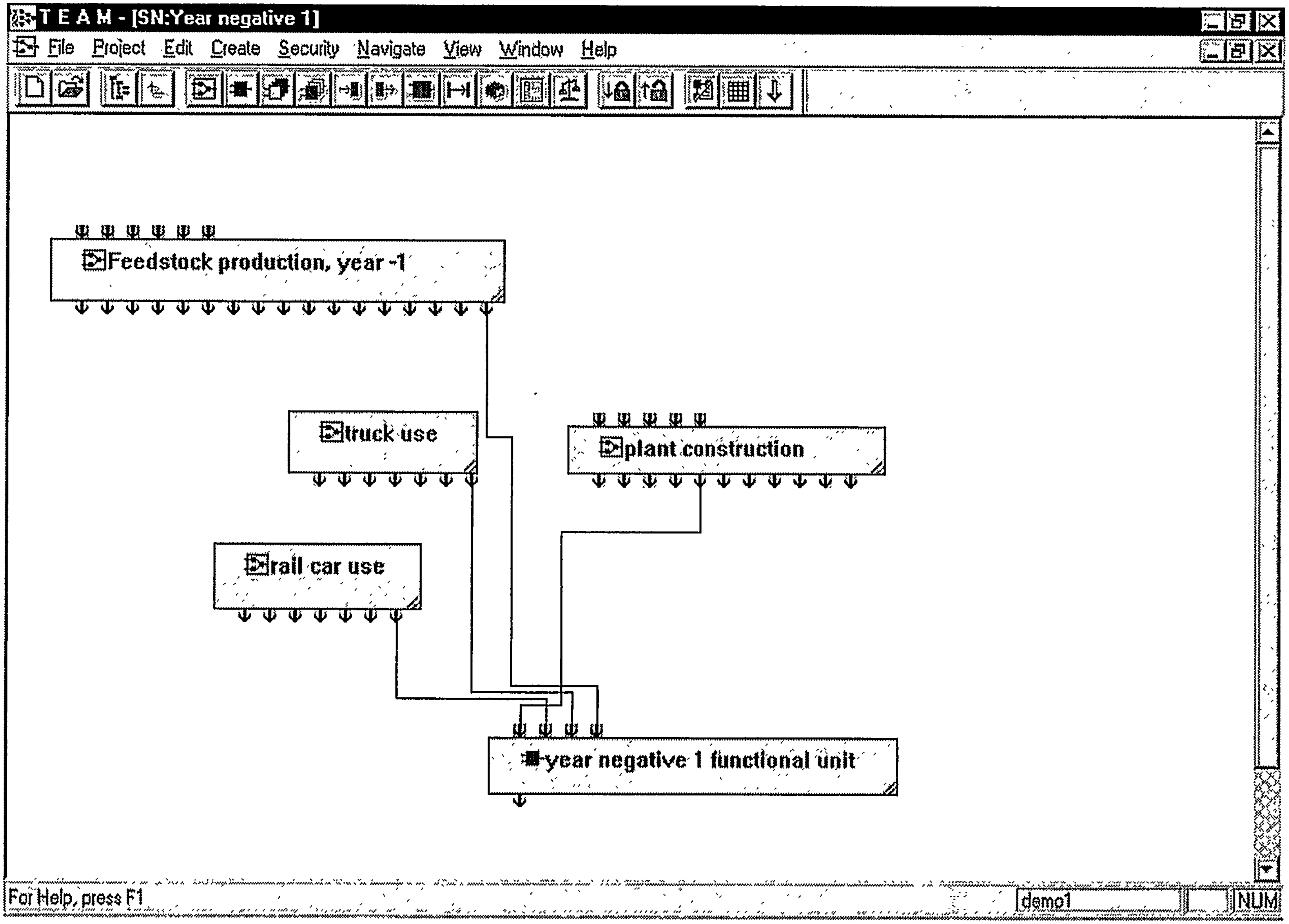
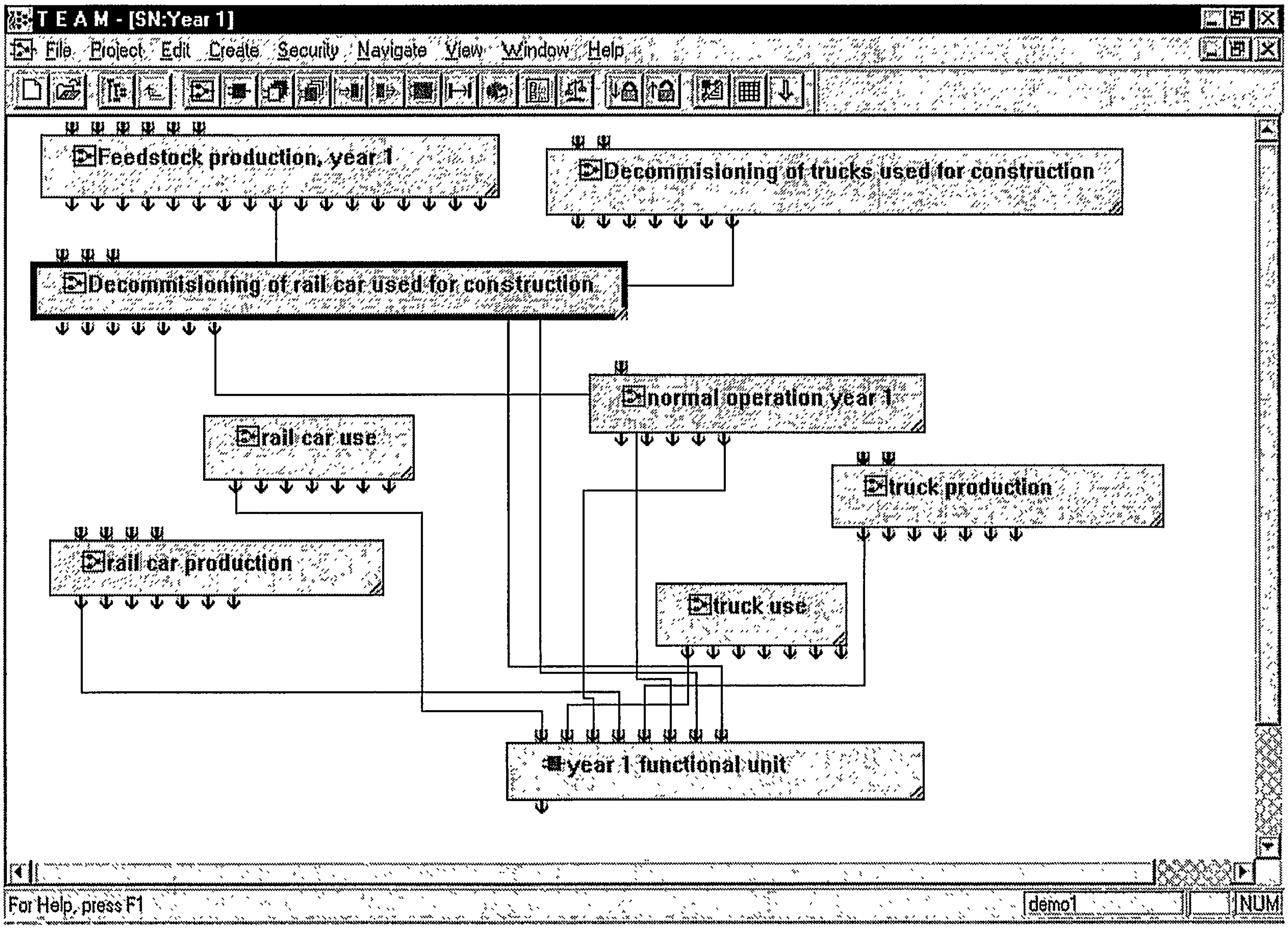
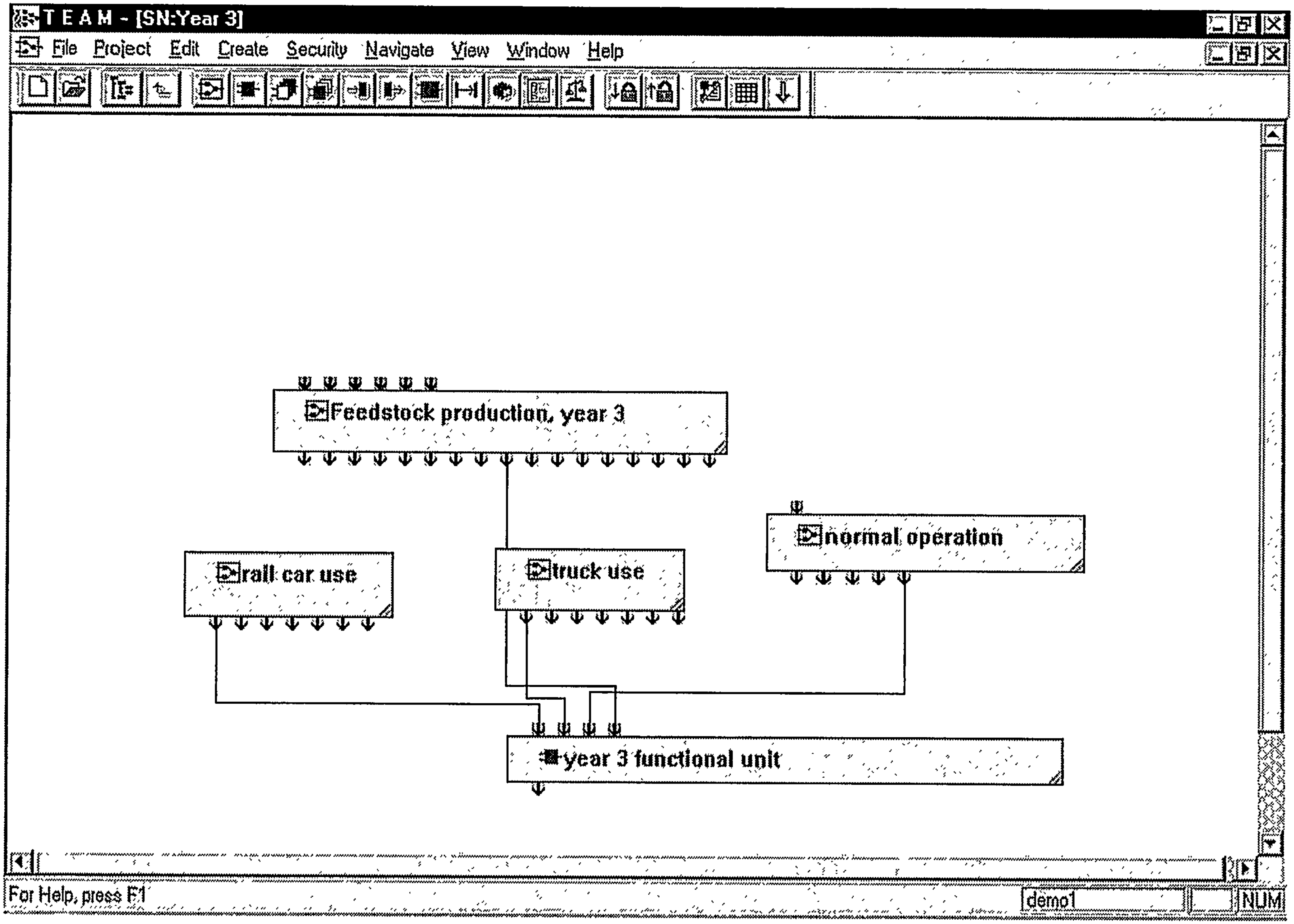
Appendix A: Graphical Representation of the LCA System in TEAM

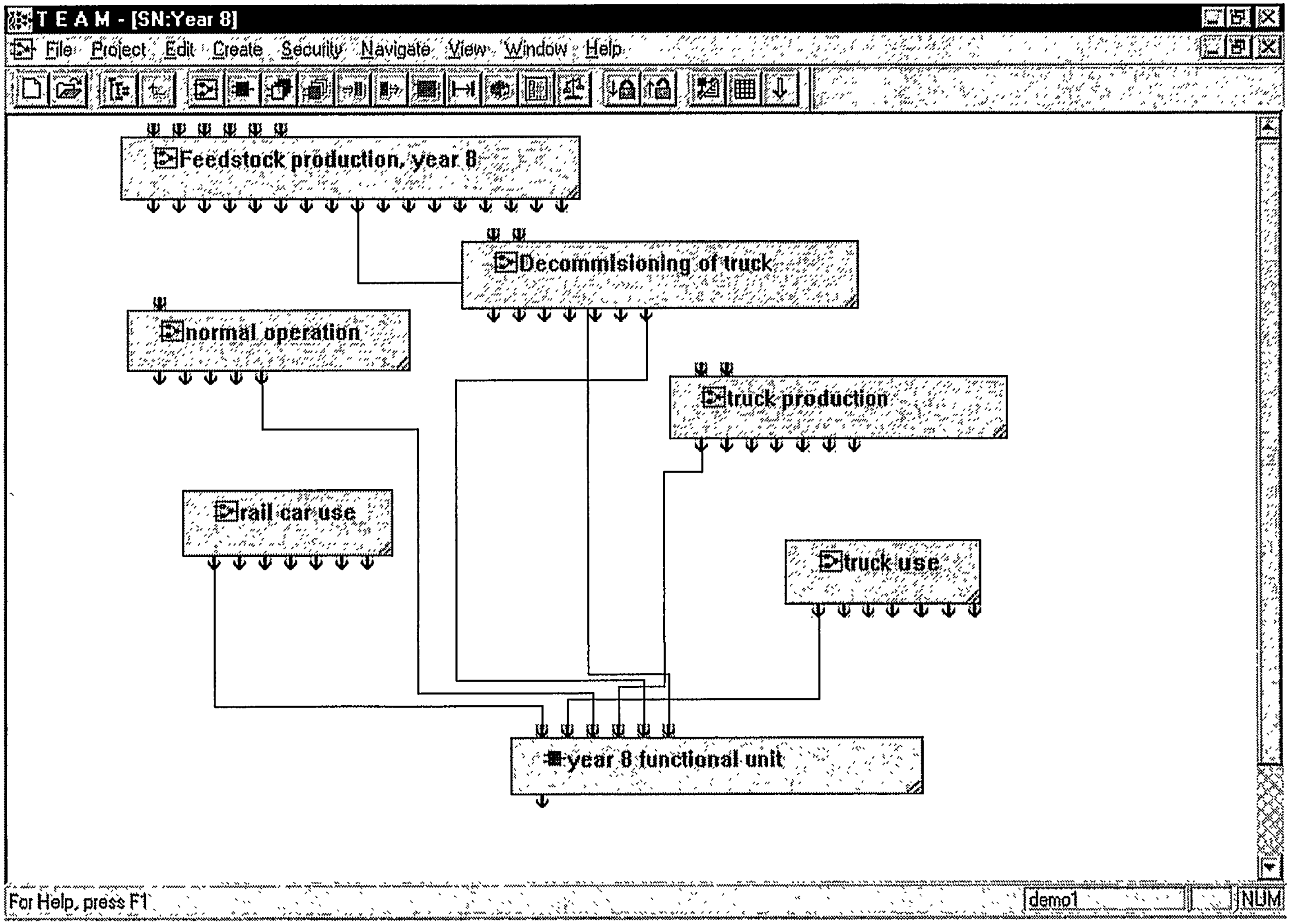

T E A M - [SN:Year negative 2]
File Project Edit Create Security Navigate View Window Help
Feedstock production, year -2
plant construction
rail car use
truck production
rail car production
truck use
year negative 2 functional unit
For Help, press F1
demo1
NUM

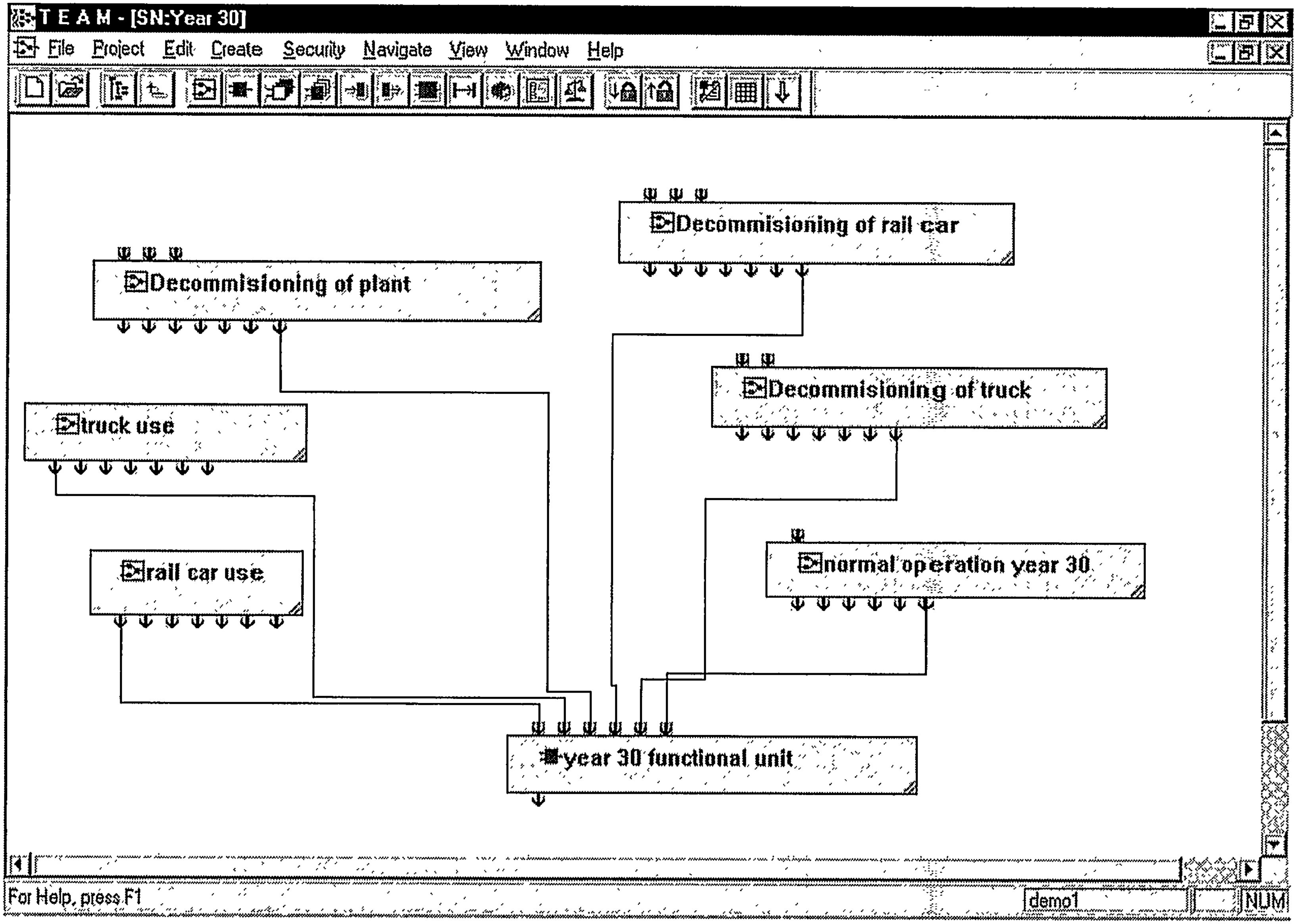

T E A M - [SN:Year negative 1]
File Project Edit Create Security Navigate View Window Help
Feedstock production, year -1
truck use
plant construction
rail car use
year negative 1 functional unit
For Help, press F1
demo1
NUM

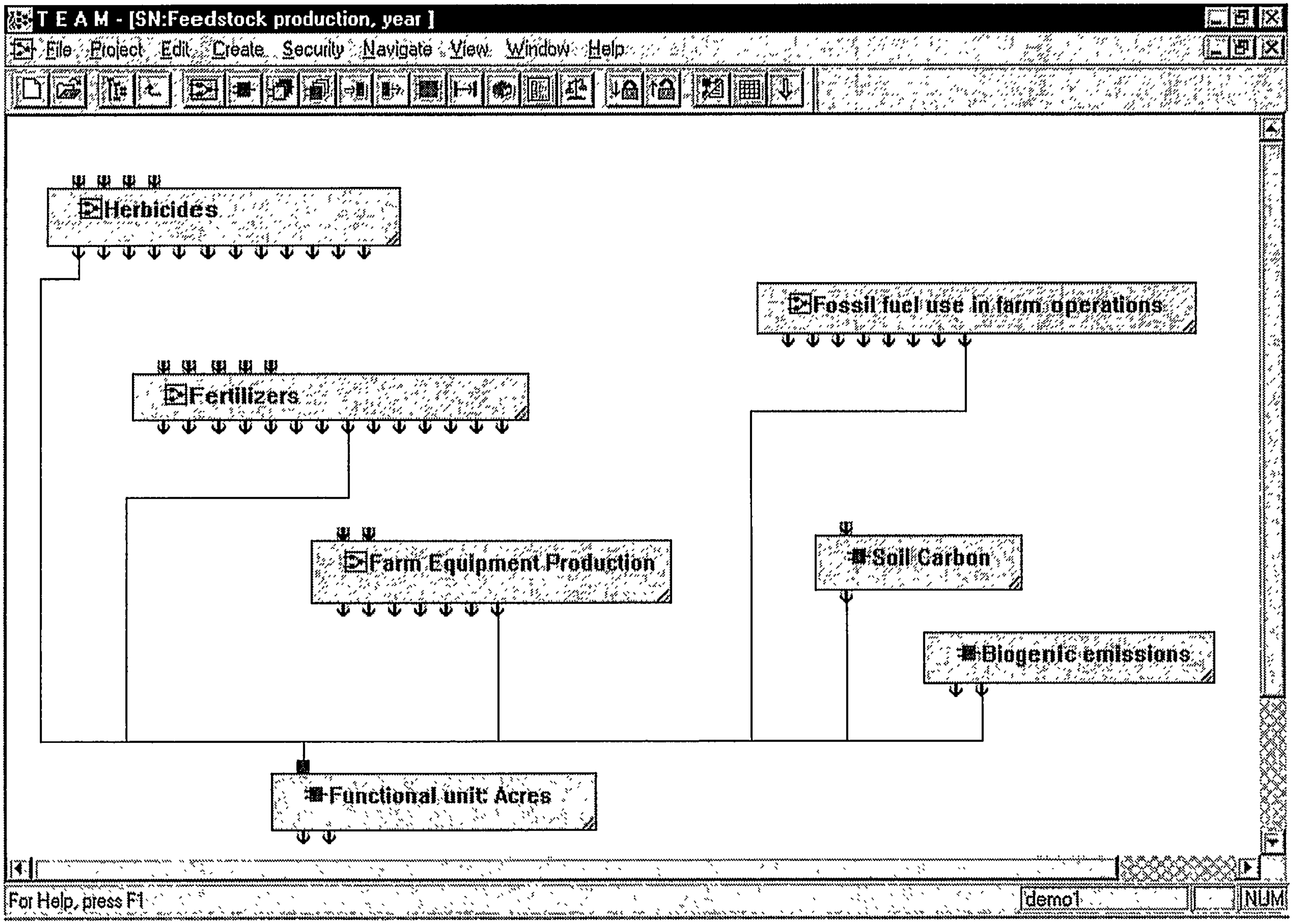


T E A M - [SN:Year 1]
File Project Edit Create Security Navigate View Window Help
Feedstock production, year 1
Decommisioning of trucks used for construction
Decommisioning of rail car used for construction
normal operation year 1
rail car use
truck production
rail car production
truck use
year 1 functional unit
For Help, press F1
demo1
NUM

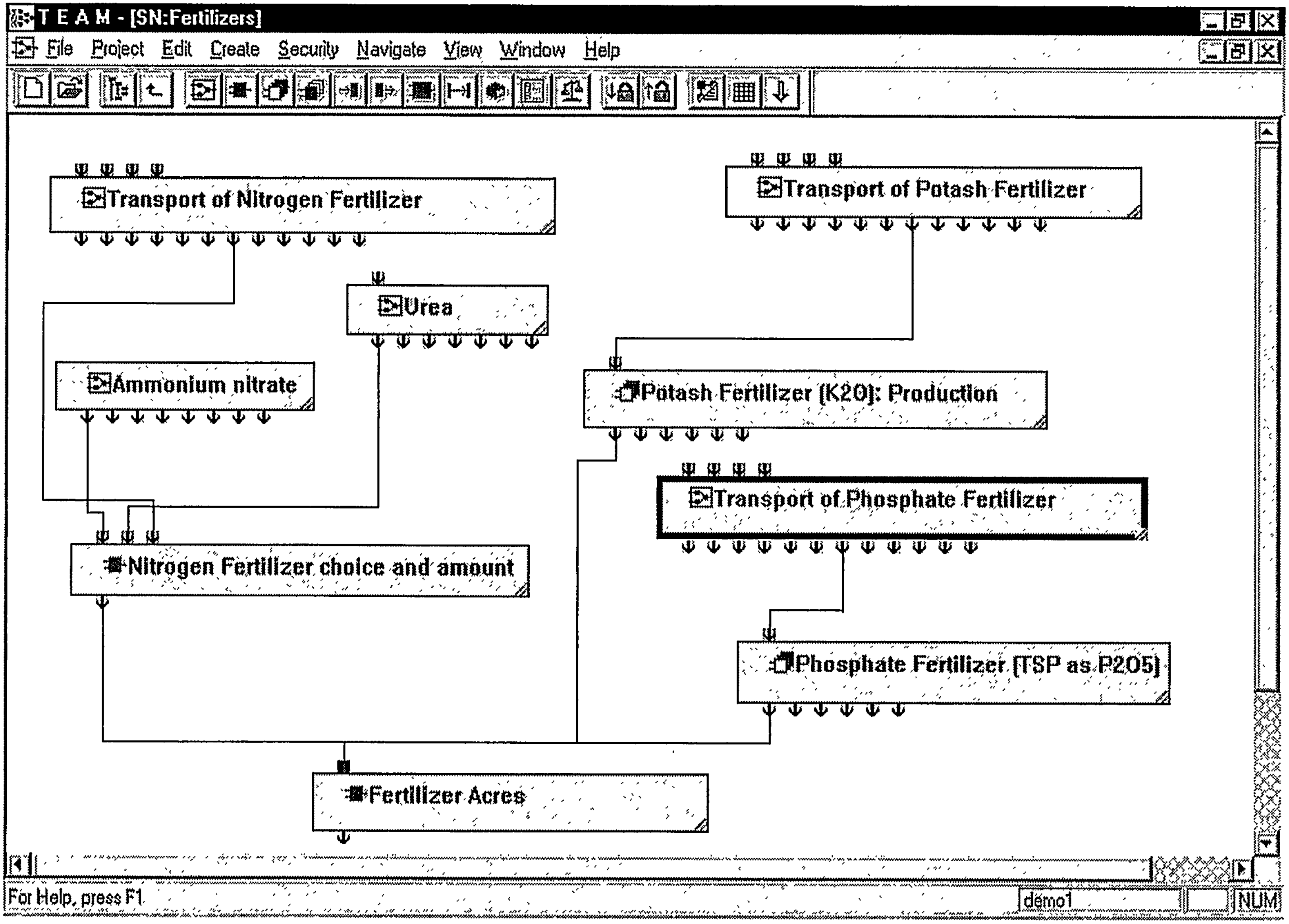

T E A M - [SN:Year 3]
File Project Edit Create Security Navigate View Window Help
Feedstock production, year 3
normal operation
rail car use
truck use
year 3 functional unit
For Help, press F1
demo1
NUM

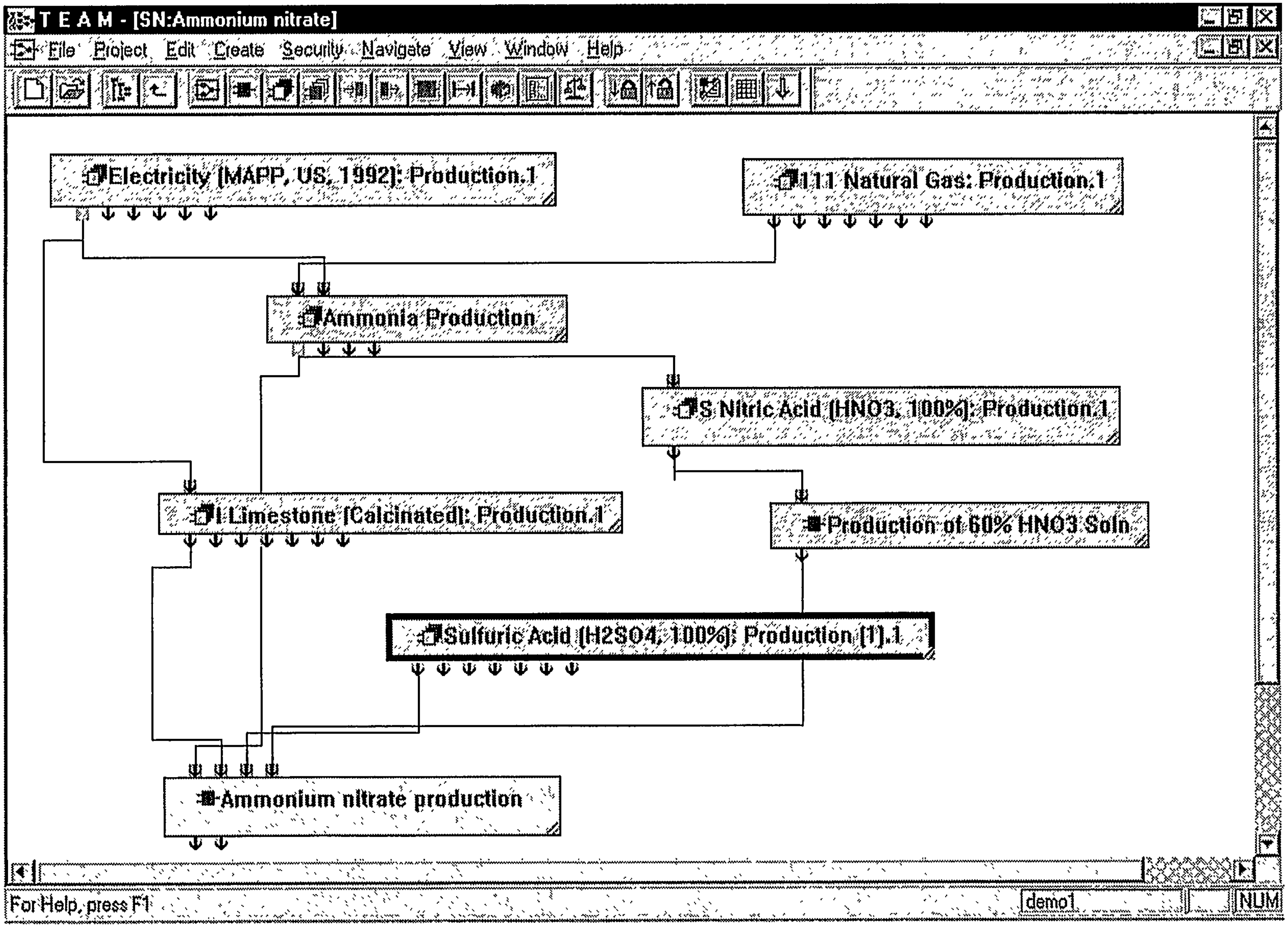

T E A M - [SN:Year 8]
File Project Edit Create Security Navigate View Window Help
Feedstock production, year 8
Decommisioning of truck
normal operation
truck production
rail car use
truck use
year 8 functional unit
For Help, press F1
demo1
NUM

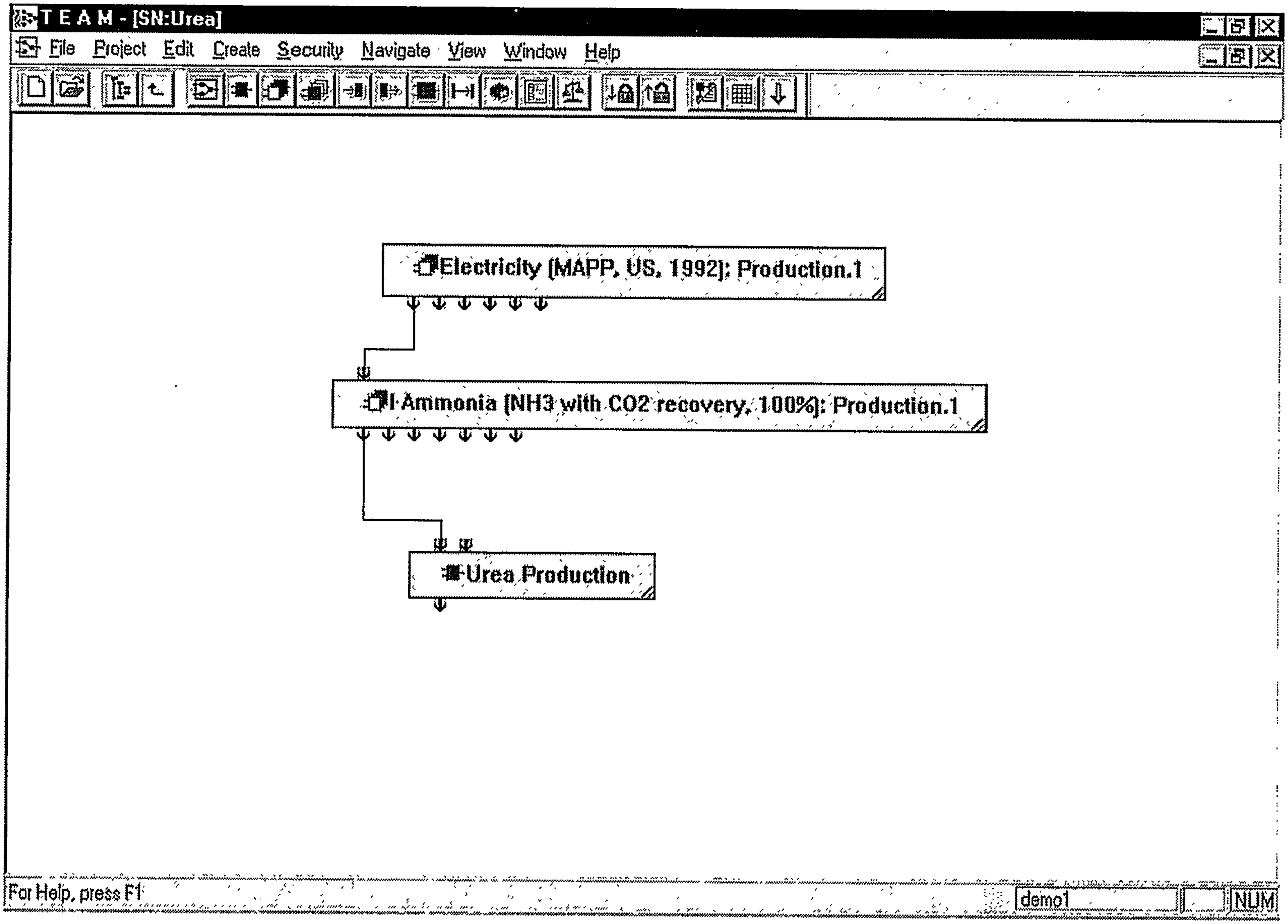

T E A M - [SN:Year 30]
File Project Edit Create Security Navigate View Window Help
Decommisioning of rail car
Decommisioning of plant
Decommisioning of truck
truck use
rail car use
normal operation year 30
year 30 functional unit
For Help, press F1
demo1
NUM

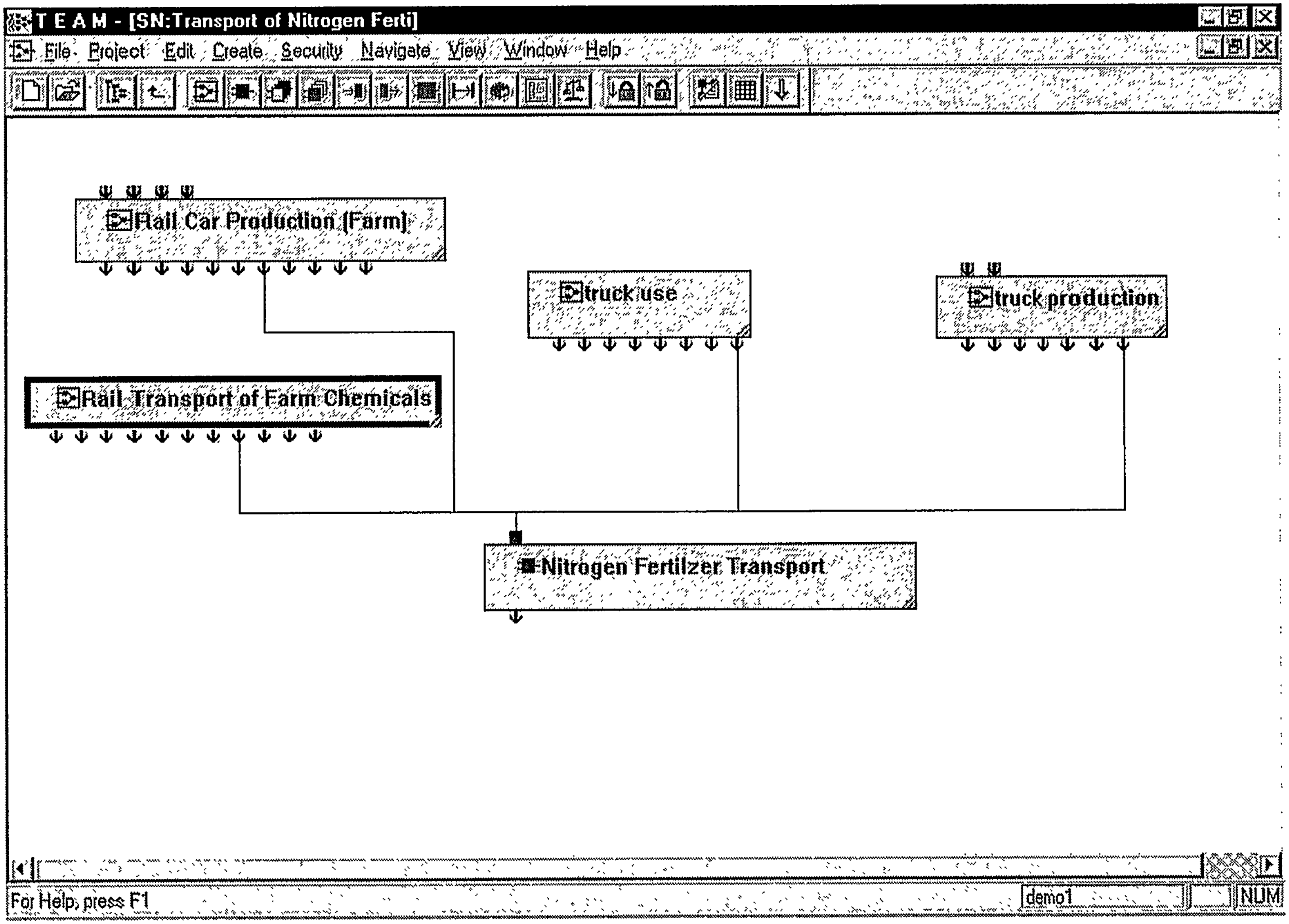


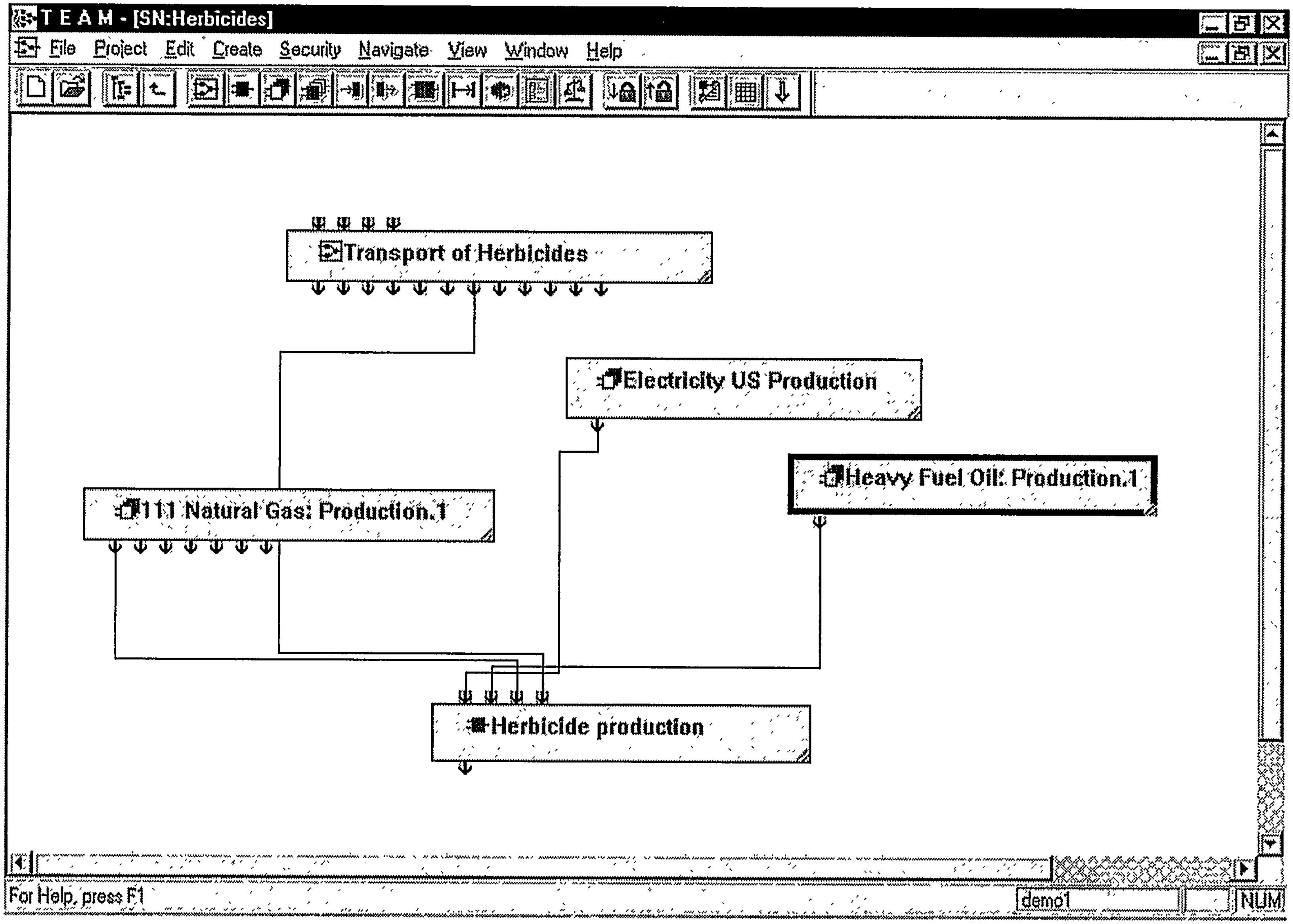
T E A M - [SN:Feedstock production, year]
File Project Edit Create Security Navigate View Window Help
Herbicides
Fossil fuel use in farm operations
Fertilizers
Farm Equipment Production
Soil Carbon
Biogenic emissions
Functional unit: Acres
For Help, press F1
demo1
NUM

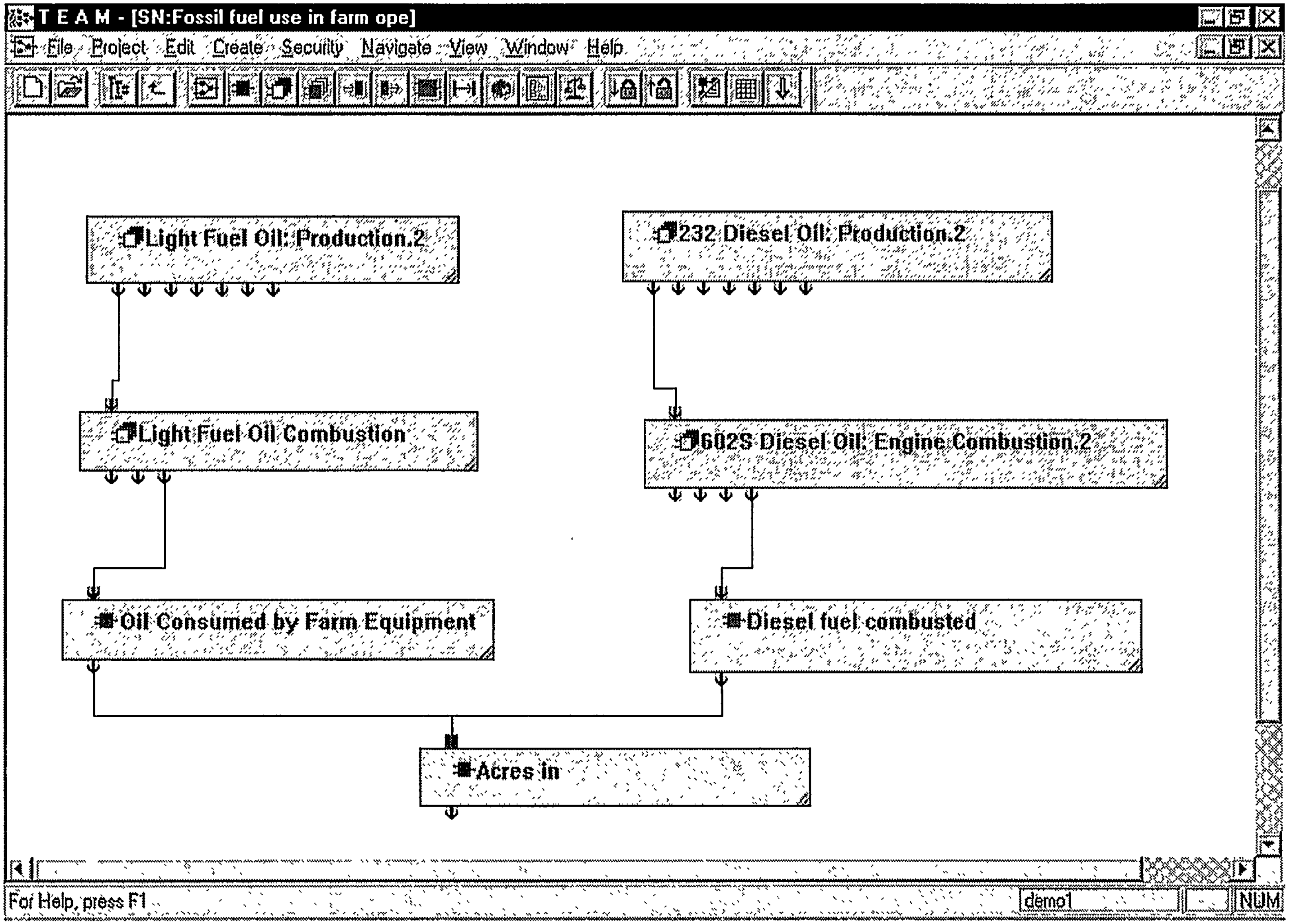

T E A M - [SN:Fertilizers]
File Project Edit Create Security Navigate View Window Help
Transport of Nitrogen Fertilizer
Transport of Potash Fertilizer
Urea
Ammonium nitrate
Potash Fertilizer (K2O): Production
Transport of Phosphate Fertilizer
Nitrogen Fertilizer choice and amount
Phosphate Fertilizer (TSP as P2O5)
Fertilizer Acres
For Help, press F1
demo1
NUM

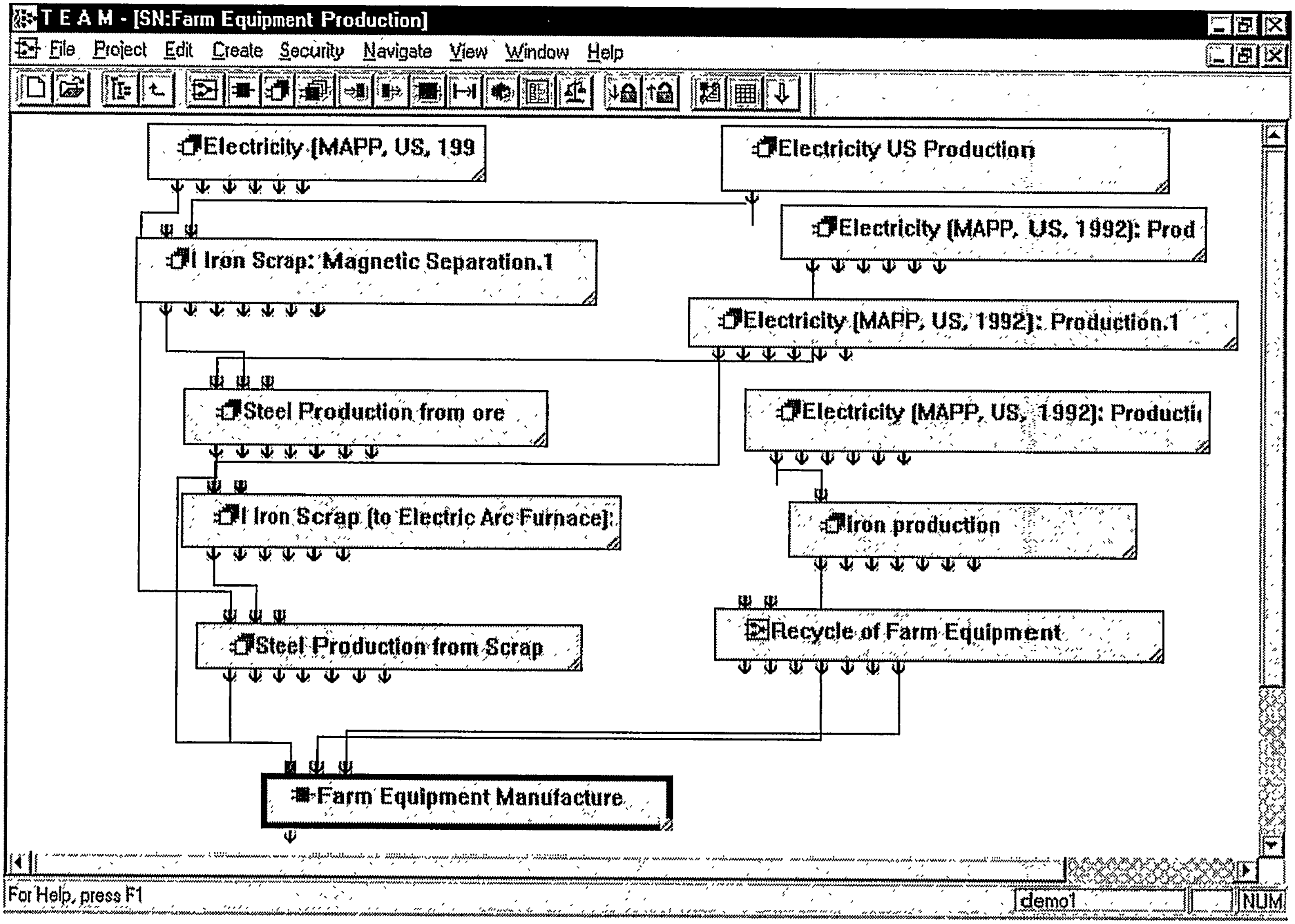

T E A M - [SN:Ammonium nitrate]
File Project Edit Create Security Navigate View Window Help
Electricity [MAPP, US, 1992]: Production.1
111 Natural Gas: Production.1
Ammonia Production
S Nitric Acid [HNO3, 100%]: Production.1
I Limestone [Calcinated]: Production.1
Production of 60% HNO3 Soln
Sulfuric Acid [H2SO4, 100%]: Production [1].1
Ammonium nitrate production
For Help, press F1
demo1
NUM

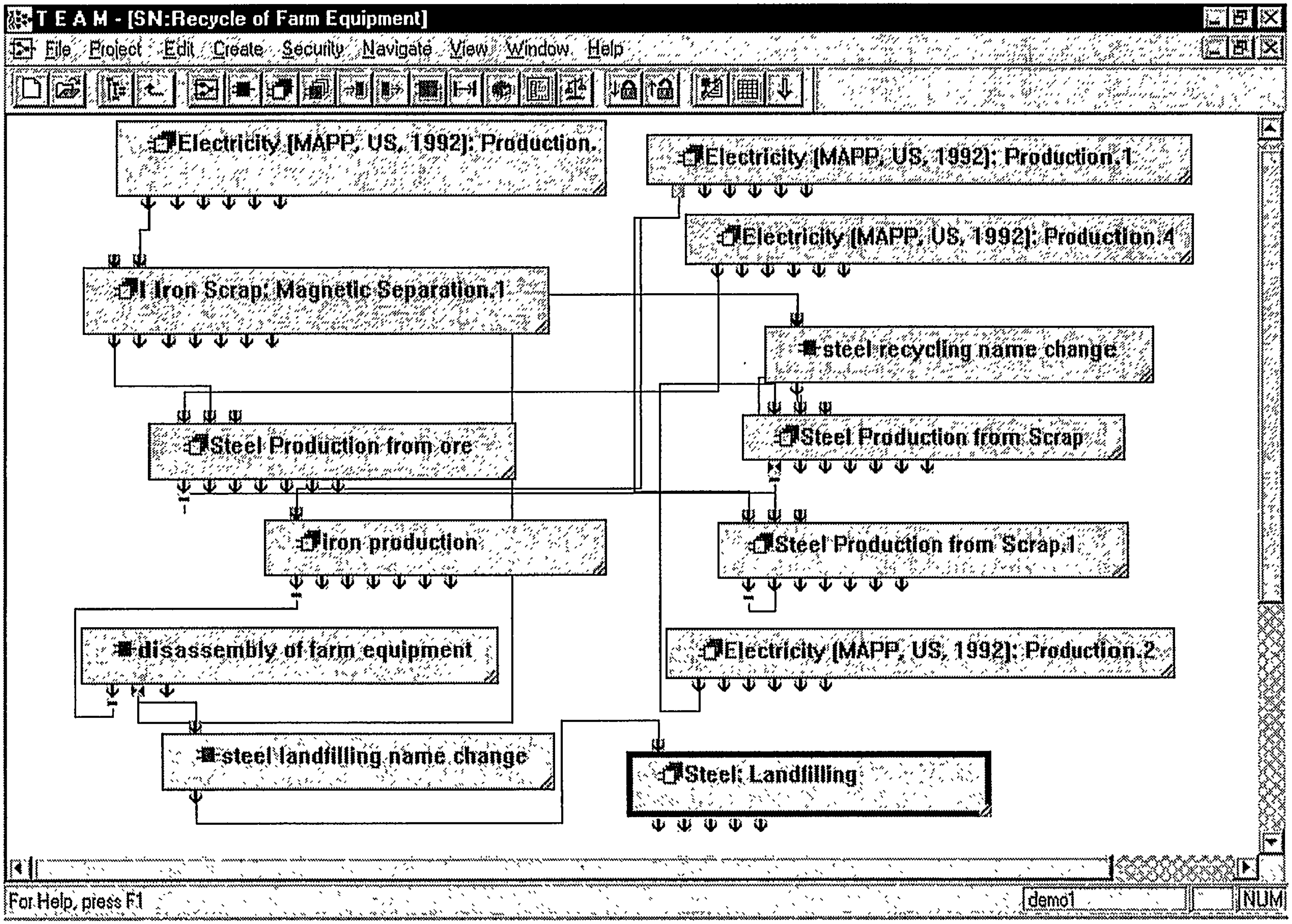

T E A M - [SN:Urea]
File Project Edit Create Security Navigate View Window Help
Electricity [MAPP, US, 1992]: Production.1
I Ammonia [NH3 with CO2 recovery, 100%]: Production.1
Urea Production
For Help, press F1
demo1
NUM


T E A M - [SN:Transport of Nitrogen Ferti]
File Project Edit Create Security Navigate View Window Help
Rail Car Production (Farm)
truck use
truck production
Rail Transport of Farm Chemicals
Nitrogen Fertilzer Transport
For Help, press F1
demo1
NUM

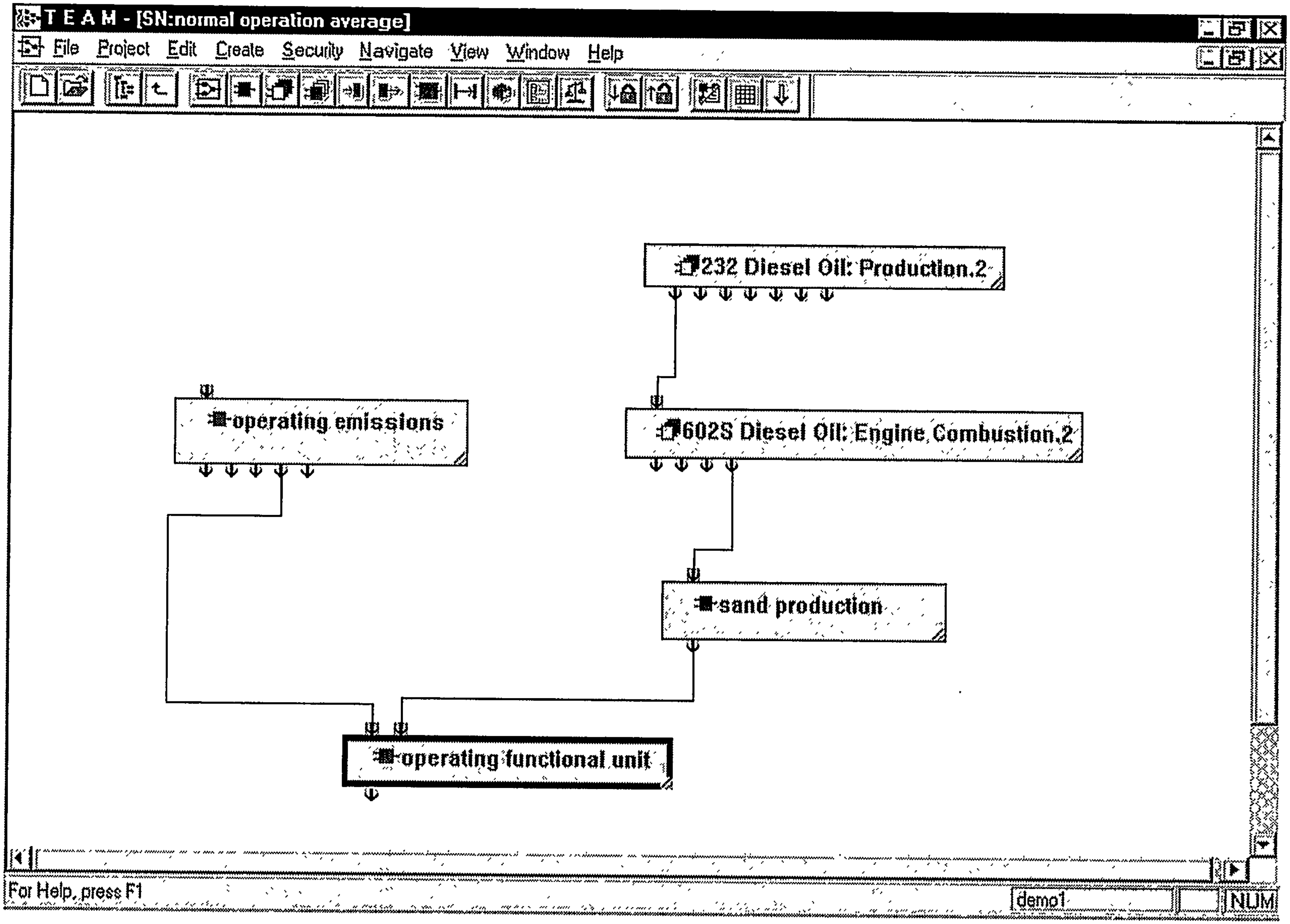

T E A M - [SN:Herbicides]
File Project Edit Create Security Navigate View Window Help
Transport of Herbicides
Electricity US Production
Heavy Fuel Oil: Production.1
111 Natural Gas: Production.1
Herbicide production
For Help, press F1
demo1
NUM

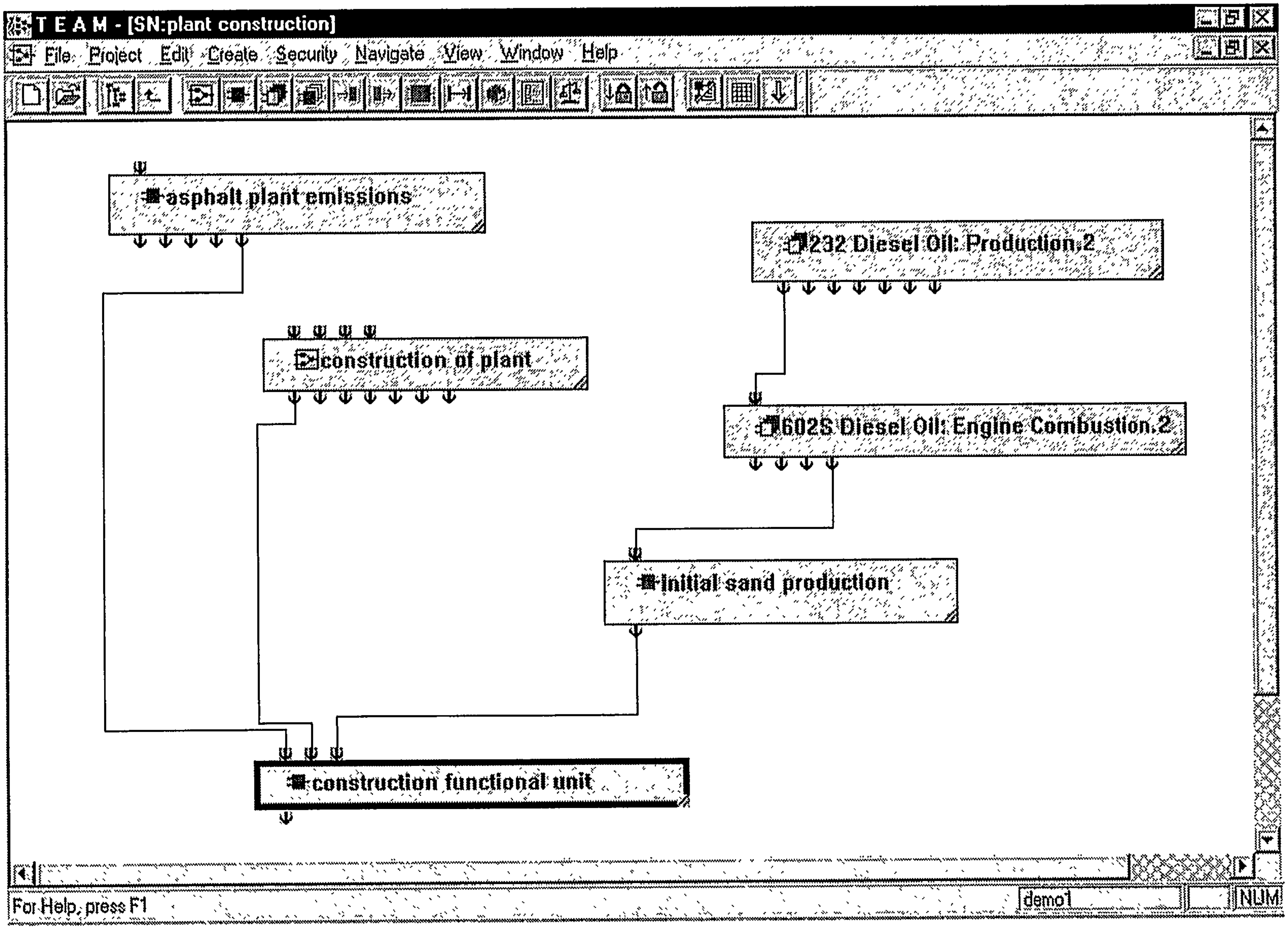

T E A M - [SN:Fossil fuel use in farm ope]
File Project Edit Create Security Navigate View Window Help
Light Fuel Oil: Production.2
232 Diesel Oil: Production.2
Light Fuel Oil Combustion
602S Diesel Oil: Engine Combustion.2
Oil Consumed by Farm Equipment
Diesel fuel combusted
Acres in
For Help, press F1
demo1
NUM

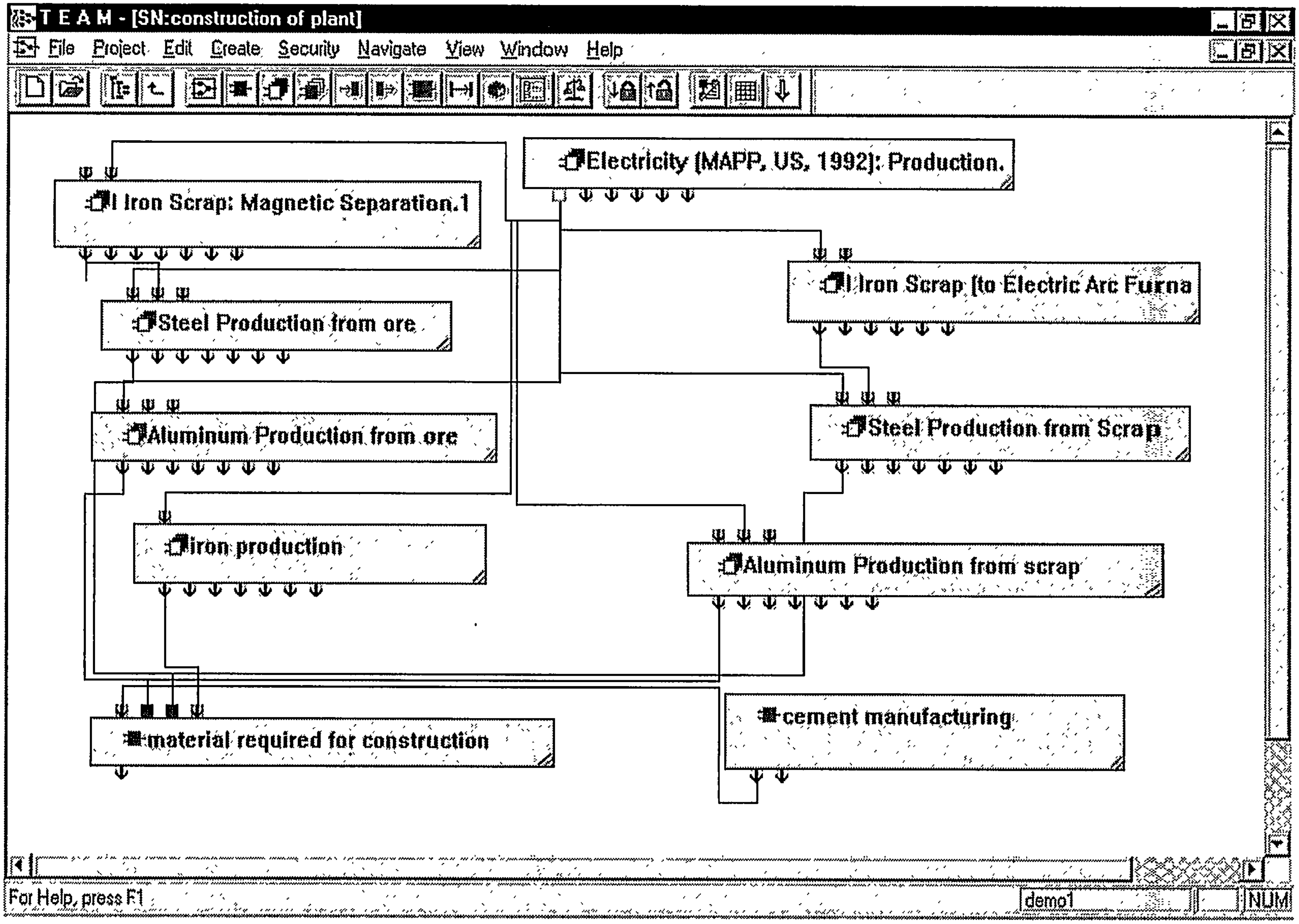

T E A M - [SN:Farm Equipment Production]
File Project Edit Create Security Navigate View Window Help
Electricity [MAPP, US, 199
Electricity US Production
Electricity (MAPP, US, 1992): Prod
I Iron Scrap: Magnetic Separation.1
Electricity (MAPP, US, 1992): Production.1
Steel Production from ore
Electricity (MAPP, US, 1992): Producti
I Iron Scrap (to Electric Arc Furnace):
Iron production
Steel Production from Scrap
Recycle of Farm Equipment
Farm Equipment Manufacture
For Help, press F1
demo1
NUM



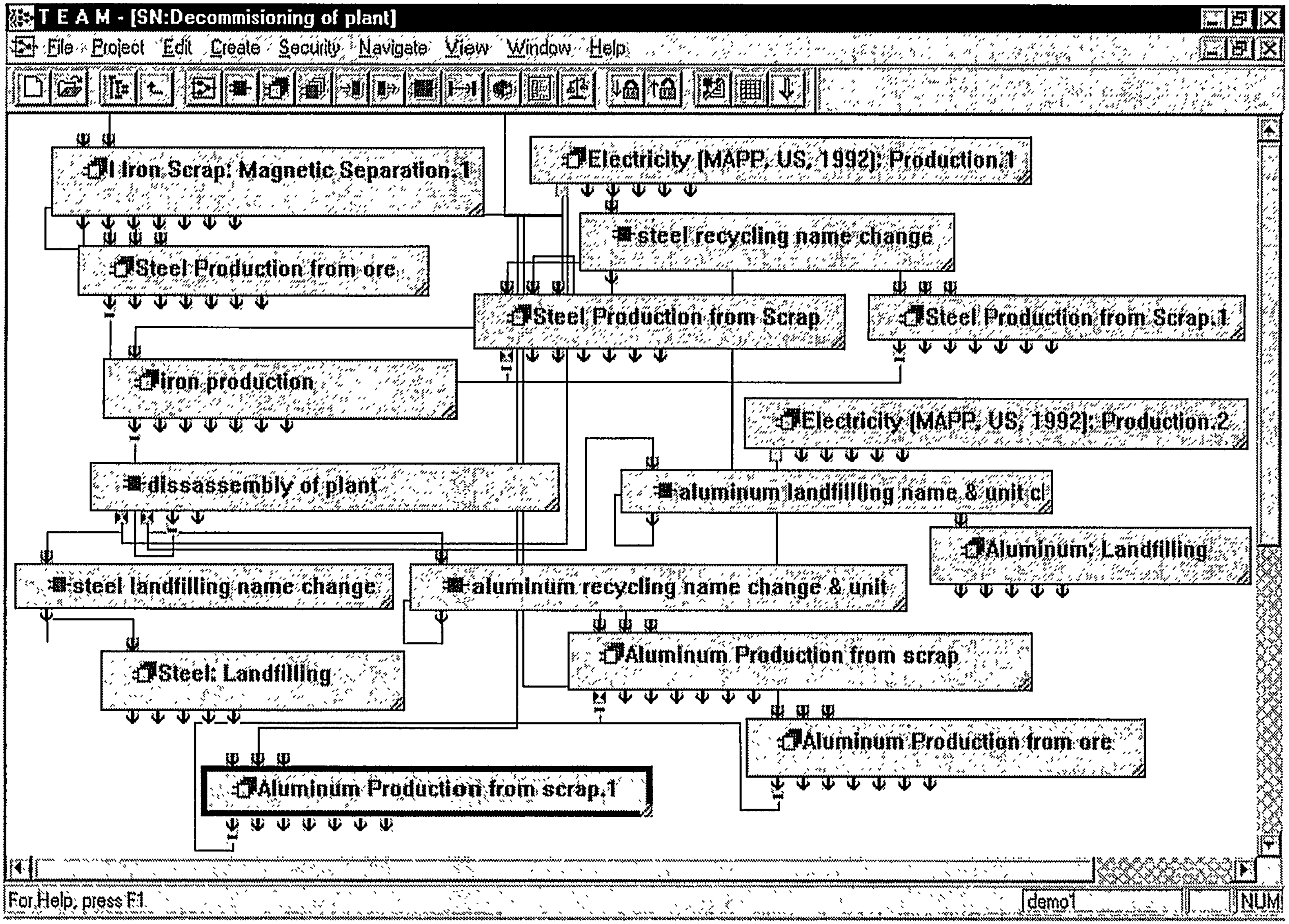
T E A M - [SN:Recycle of Farm Equipment]
File Project Edit Create Security Navigate View Window Help
Electricity [MAPP, US, 1992]: Production.
Electricity [MAPP, US, 1992]: Production.1
Electricity [MAPP, US, 1992]: Production.4
I Iron Scrap: Magnetic Separation.1
steel recycling name change
Steel Production from ore
Steel Production from Scrap
Iron production
Steel Production from Scrap.1
disassembly of farm equipment
Electricity [MAPP, US, 1992]: Production.2
steel landfilling name change
Steel: Landfilling
For Help, press F1
demo1
NUM


T E A M - [SN:normal operation average]
File Project Edit Create Security Navigate View Window Help
232 Diesel Oil: Production.2
operating emissions
602S Diesel Oil: Engine Combustion.2
sand production
operating functional unit
For Help, press F1
demo1
NUM

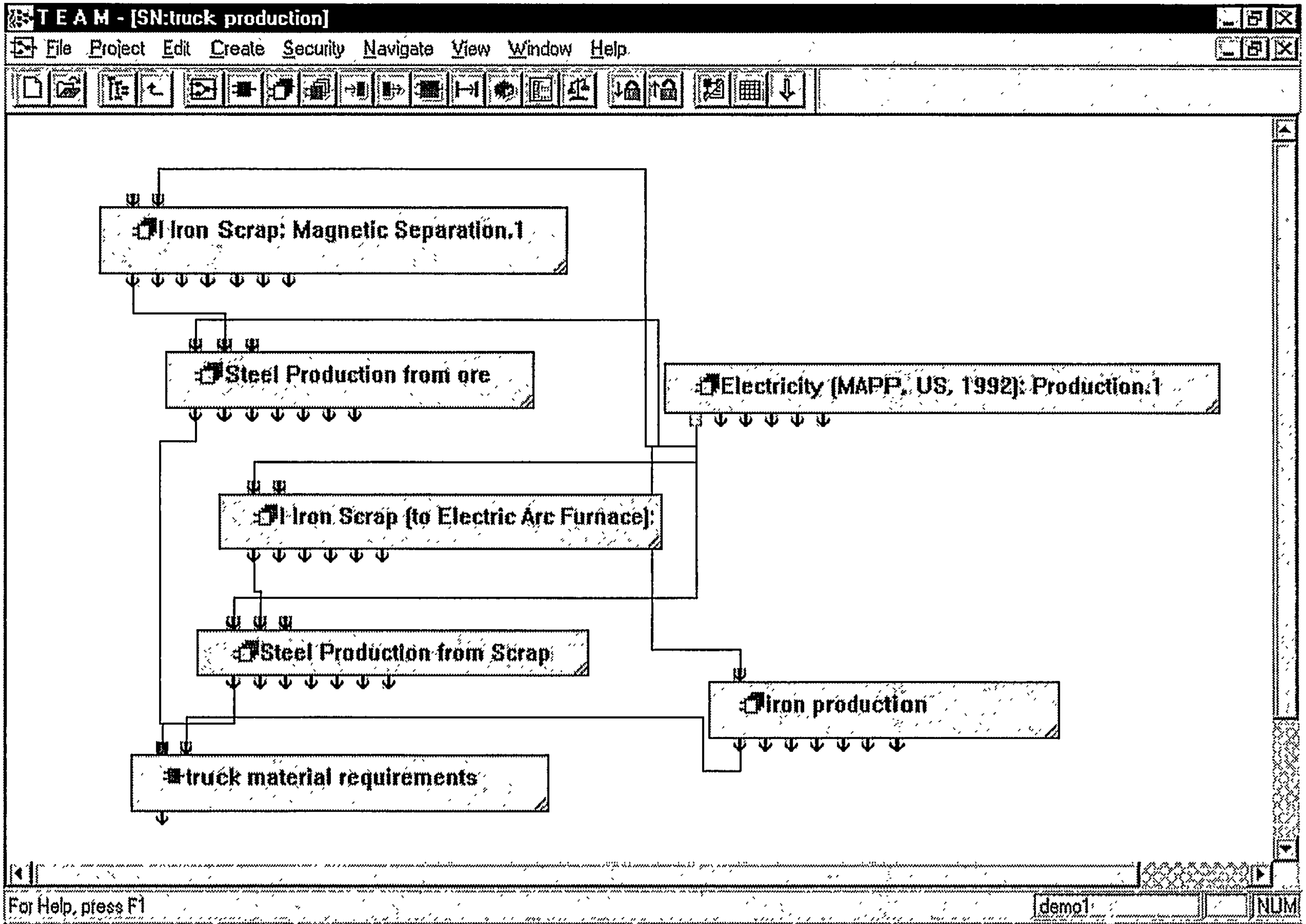

T E A M - [SN:plant construction]
File Project Edit Create Security Navigate View Window Help
asphalt plant emissions
232 Diesel Oil: Production.2
construction of plant
602S Diesel Oil: Engine Combustion.2
initial sand production
construction functional unit
For Help, press F1
demo1
NUM

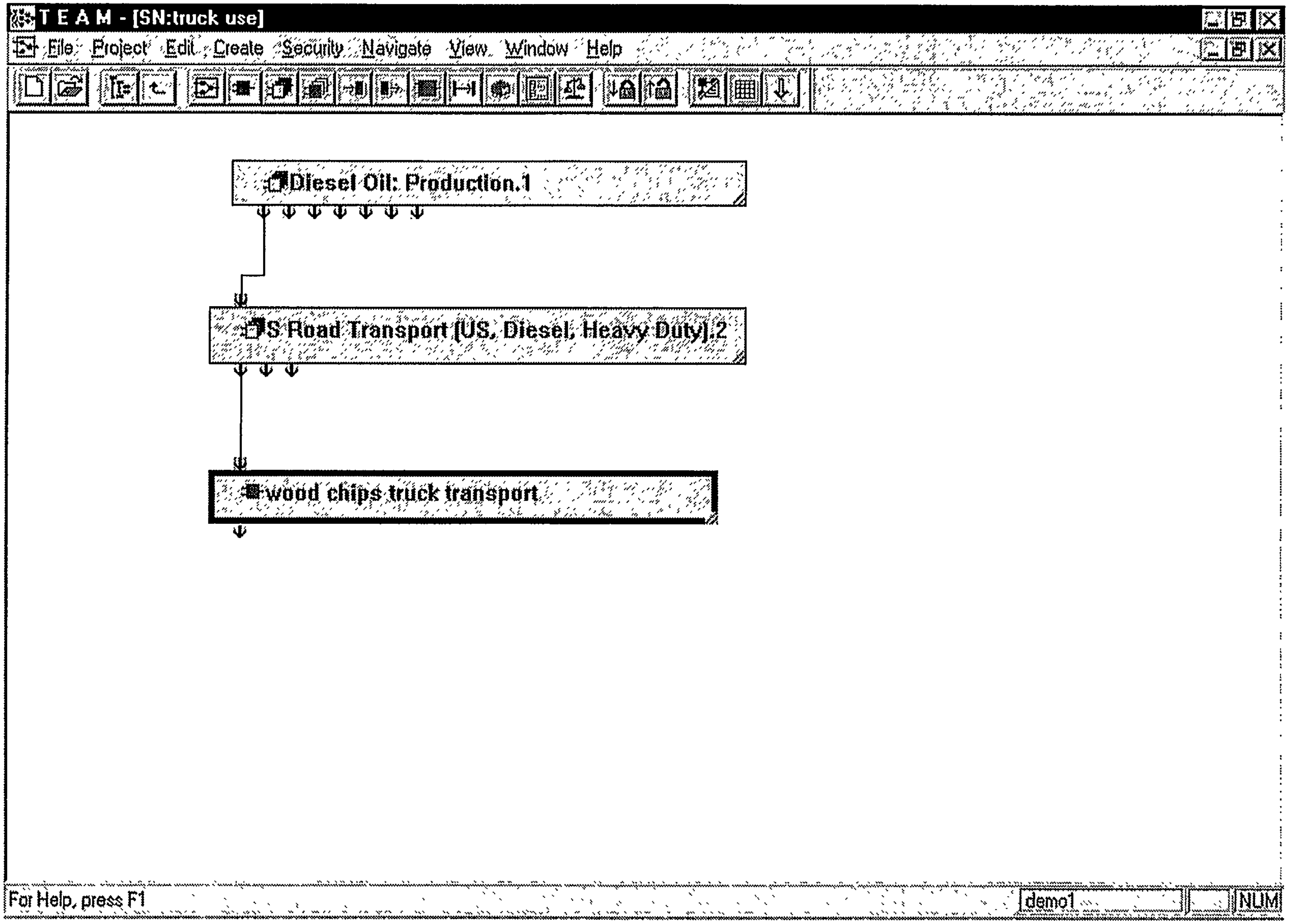


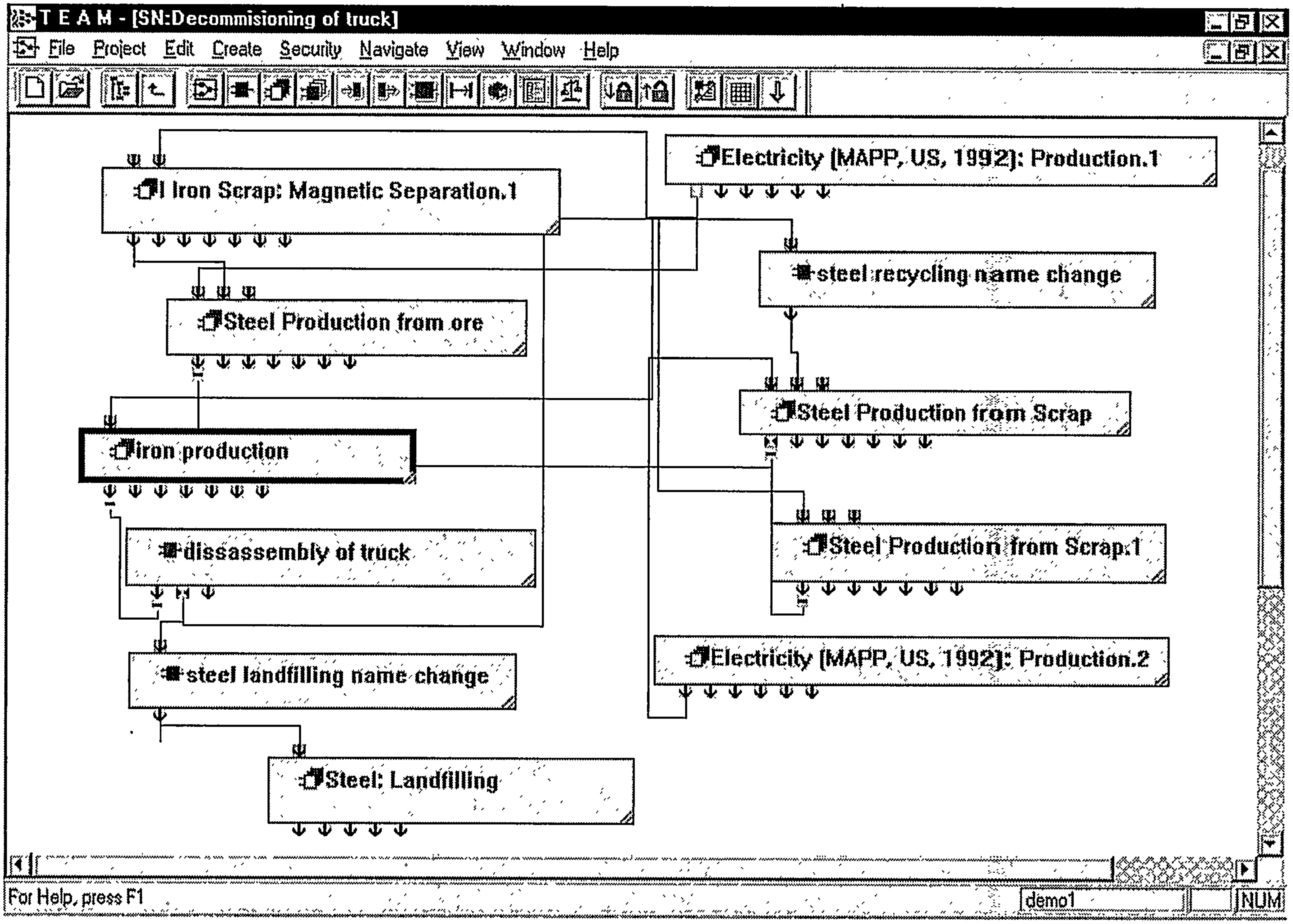
T E A M - [SN:construction of plant]
File Project Edit Create Security Navigate View Window Help
Electricity [MAPP, US, 1992]: Production.
I Iron Scrap: Magnetic Separation.1
I Iron Scrap [to Electric Arc Furna
Steel Production from ore
Aluminum Production from ore
Steel Production from Scrap
iron production
Aluminum Production from scrap
cement manufacturing
material required for construction
For Help, press F1
demo1
NUM

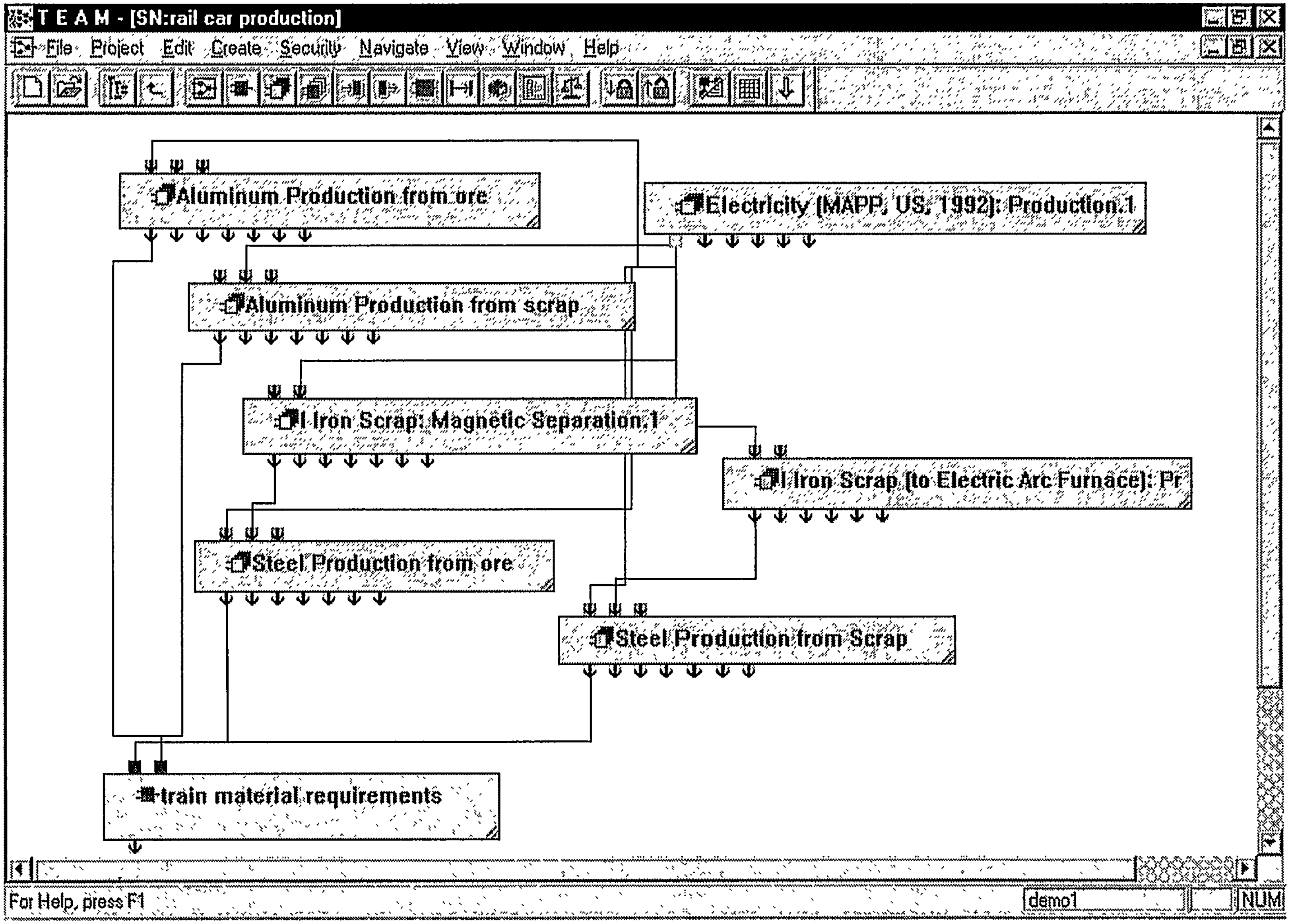


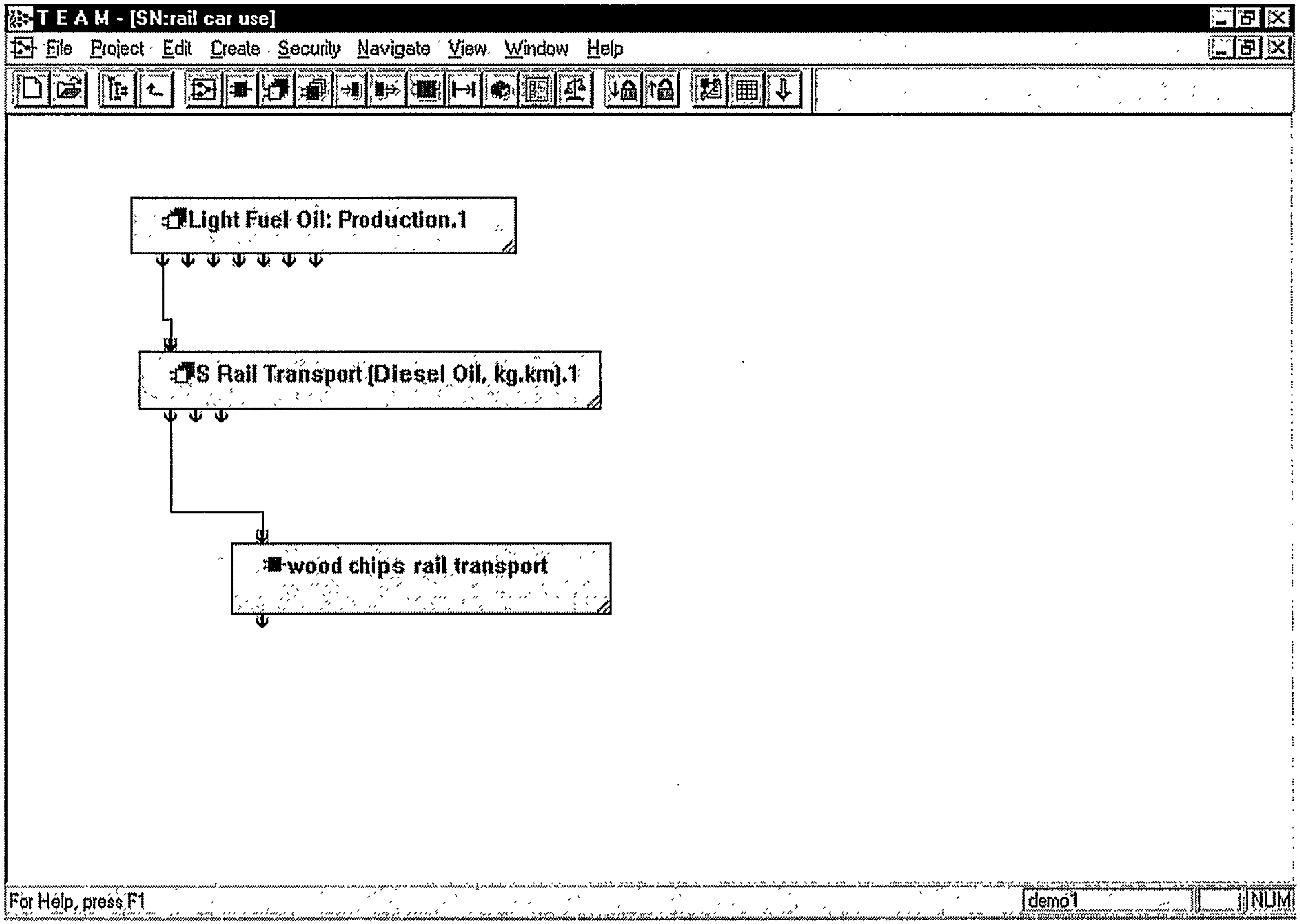
T E A M - [SN:Decommisioning of plant]
File Project Edit Create Security Navigate View Window Help
I Iron Scrap: Magnetic Separation.1
Electricity (MAPP, US, 1992): Production.1
steel recycling name change
Steel Production from ore
Steel Production from Scrap
Steel Production from Scrap.1
iron production
Electricity (MAPP, US, 1992): Production.2
dissassembly of plant
aluminum landfillling name & unit cl
Aluminum: Landfilling
steel landfilling name change
aluminum recycling name change & unit
Aluminum Production from scrap
Steel: Landfilling
Aluminum Production from ore
Aluminum Production from scrap.1
For Help, press F1
demo1
NUM

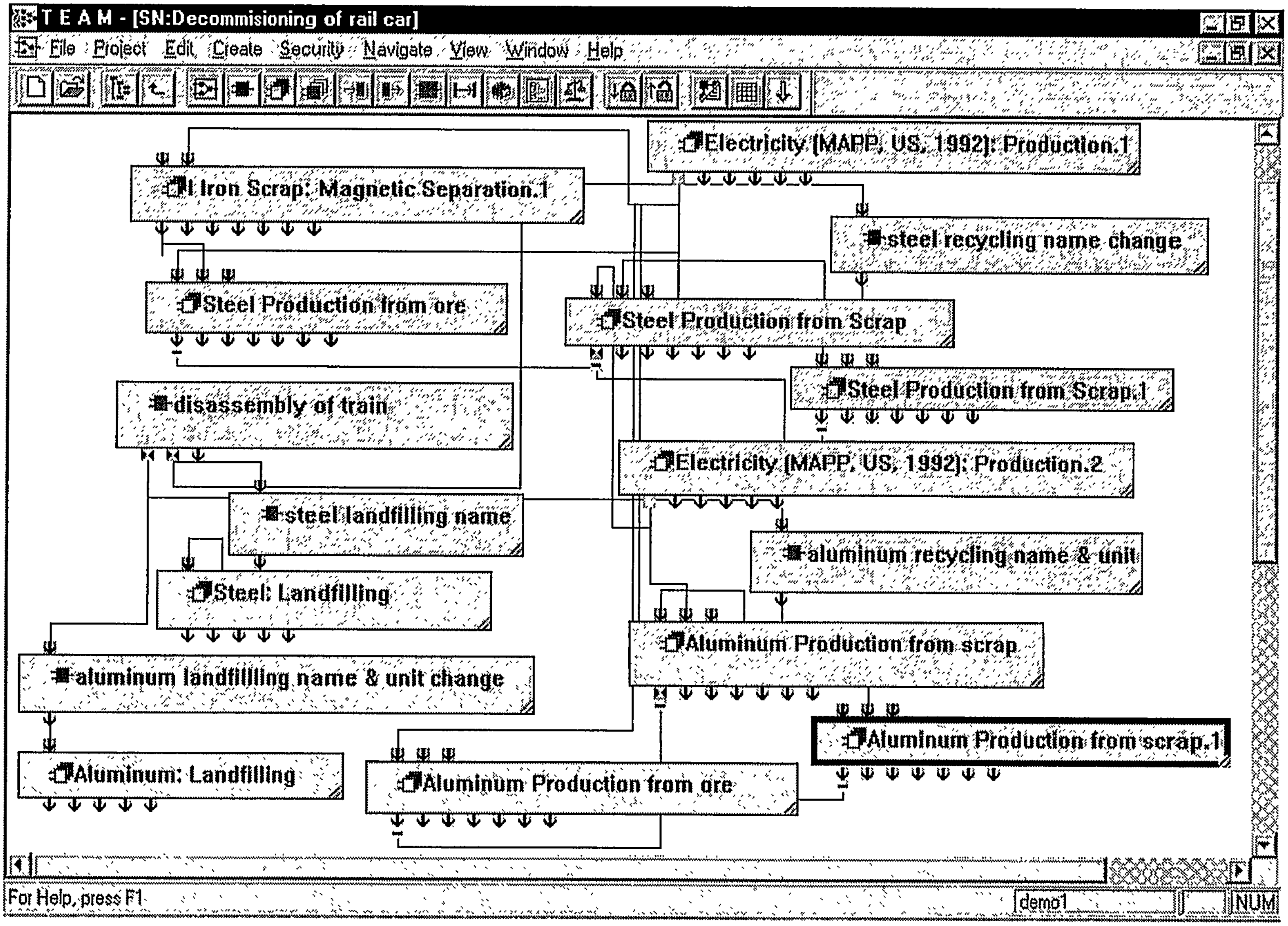

T E A M - [SN:truck production]
File Project Edit Create Security Navigate View Window Help
I Iron Scrap: Magnetic Separation.1
Steel Production from ore
Electricity (MAPP, US, 1992): Production.1
I Iron Scrap (to Electric Arc Furnace):
Steel Production from Scrap
Iron production
truck material requirements
For Help, press F1
demo1
NUM


T E A M - [SN:truck use]
File Project Edit Create Security Navigate View Window Help
Diesel Oil: Production.1
S Road Transport (US, Diesel, Heavy Duty).2
wood chips truck transport
For Help, press F1
demo1
NUM


T E A M - [SN:Decommisioning of truck]
File Project Edit Create Security Navigate View Window Help
I Iron Scrap: Magnetic Separation.1
Electricity (MAPP, US, 1992): Production.1
steel recycling name change
Steel Production from ore
Steel Production from Scrap
iron production
Steel Production from Scrap.1
dissassembly of truck
Electricity (MAPP, US, 1992): Production.2
steel landfilling name change
Steel: Landfilling
For Help, press F1
demo1
NUM


T E A M - [SN:rail car production]
File Project Edit Create Security Navigate View Window Help
Aluminum Production from ore
Electricity (MAPP, US, 1992): Production.1
Aluminum Production from scrap
I Iron Scrap: Magnetic Separation.1
I Iron Scrap (to Electric Arc Furnace): Pr
Steel Production from ore
Steel Production from Scrap
train material requirements
For Help, press F1
demo1
NUM


T E A M - [SN:rail car use]
File Project Edit Create Security Navigate View Window Help
Light Fuel Oil: Production.1
S Rail Transport (Diesel Oil, kg.km).1
wood chips rail transport
For Help, press F1
demo1
NUM


T E A M - [SN:Decommisioning of rail car]
File Project Edit Create Security Navigate View Window Help
Electricity (MAPP, US, 1992): Production.1
I Iron Scrap: Magnetic Separation.1
steel recycling name change
Steel Production from ore
Steel Production from Scrap
Steel Production from Scrap.1
disassembly of train
Electricity (MAPP, US, 1992): Production.2
steel landfilling name
aluminum recycling name & unit
Steel: Landfilling
Aluminum Production from scrap
aluminum landfilling name & unit change
Aluminum Production from scrap.1
Aluminum: Landfilling
Aluminum Production from ore
For Help, press F1
demo1
NUM

Appendix B: Details of Some DEAM Database Modules

Material	Source	Content of the Module	Comment
Steel (cold rolled)	Swiss Federal Office of Environment, Forests and Landscape (FOEFL or BUWAL) Environmental Series No. 132. p. A80, A83, A86, A89, A92, A94.	Iron ore mining. Coal carbonization (distillation in the absence of air). Hot metal production, includes sinter plant and blast furnace. Oxygen converter steel plant. Hot rolling of slabs. Cold rolling of coils.	Data representative of the 1975-1980 period. US electricity model.
Steel (secondary)	See cold rolled steel	Detinning of steel scrap. Magnetic separation of steel scrap from mixed waste. Steel slab production from the Electric Arc Furnace (EAF). Includes the production of graphite electrodes (3 kg per metric ton of raw steel).	Data representative of the 1975-1980 period. US electricity model.
Iron (Fe)	See cold rolled steel	Iron ore mining. Coal carbonization (distillation in the absence of air). Hot metal production, includes sinter plant and blast furnace.	Data representative of the 1975-1980 period. US electricity model.
Steel(electro-galvanized)	See cold rolled steel	Same as cold rolled. Electrogalvanization is not modeled.	
Steel (stainless)	See cold rolled steel	Same as secondary steel (Electric Arc Furnace). None of the alloys added to produce stainless steel are accounted for.	.

Table 1: Source of Data for Ferrous Metals

Material	Source	Content of the Module	Comment
Aluminum (Al, casting alloy)	One OEM casting plant. In order to preserve the confidentiality of the data, the initial data have been aggregated with secondary data describing the production of ancillary materials and energy carriers consumed by the plant	Refinery of aluminum. 80% secondary, 20% primary	Primary data: water emissions are missing not included in emission numbers are the releases called: "Recycle/Recovery/Reuse"
Aluminum (Al, 30% secondary)	1.) Swiss Federal Office of Environment, Forests and Landscape (FOEFL or BUWAL) Environmental Series No. 250 Bern, 1996. Page 83, 87-88. 2.) EAA (European Aluminium Association) (primary source in Buwal)	A mixture of 30% secondary 70% primary aluminum, no further processing. For primary, Bauxite from Guinea, Australia and Europe Bayer Process	Primary: Transport by sea (Bauxite: 7917 km, Aluminum Oxide: 4587), barge (Limestone: 500), rail (AlF3: 300) and road (NaOH: 500) is included. Electricity is included. Secondary: includes transport
Aluminum (Al, primary)	1) Swiss Federal Office of Environment, Forests and Landscape (FOEFL or BUWAL) Environmental Series No. 250 Bern, 1996. Page 83. 2) EAA (European Aluminium Assocation) (primary source in Buwal)	Bauxite from Guinea, Australia and Europe Bayer Process Electricity model from European Aluminum Association: - 66.3% hydro - 14.8 % nuclear - 13.6 % coal - 3.2 % natural gas - 2.1 % oil	Transport by sea (Bauxite: 7917 km, Aluminum Oxide: 4587), barge (Limestone: 500), rail (AlF3: 300) and road (NaOH: 500) is included. Electricity is included.

Table 2: Source of Data for Non Ferrous Metals

COAL PRE-COMBUSTION

Coal pre-combustion includes extraction of coal from the ground, then cleaning and preparation of the coal for use. Transportation to the point of use is not included at this stage.

COAL MINING:

Materials and energy consumed in mining and cleaning of coal comes from 1987 Census Bureau data (DeLuchi, Emissions of Greenhouse Gases from the Use of Transportation Fuels and Electricity, 1993. Volume 2. Appendix F. Table F-2).

Emissions due to mining coal are from the combustion of diesel oil of mining equipment (except methane which is released directly from the mine). All emissions factors come from AP-42 Mobile Sources Volume II, January 1991.

In terms of water effluents, DOE states that water effluents due to mining are unquantifiable, however water effluents from this type of operation generally do not cause global impacts[1].

CLEANING AND PREPARATION:

Cleaning and preparing coal may involve many processes, including beneficiation, which removes sulfur and mineral matter so that stringent Federal emissions limits during combustion are met. However,

- there are not enough specific data as to the percentage of coal that goes through these processes; and
- the amount of energy consumed in these processes is negligible compared to the amount of energy that is generated from coal combustion[2].

Therefore, coal cleaning and preparation steps are omitted from the model.

Water Effluents:

Water effluents coming from pre-combustion processes are considered negligible for this study. In general, the only water effluents coming from pre-combustion are those from mining (and refining) the fuels that are used to transport materials.

[1] DOE, March 1983. Energy Technology Characterizations Handbook section on "Coal Technologies."
[2] DeLuchi, 1993. *Emissions of Greenhouse Gases from the Use of Transportation Fuels and Electricity*, Appendix F.

COAL ELECTRICITY PRODUCTION

Production of electricity from coal includes coal pre-combustion, transportation of the coal to the utility, coal combustion (including control technologies) and coal ash management. Data on coal pre-combustion is listed separately, therefore, this section only describes the coal transport, combustion, and ash management.

TRANSPORTATION OF COAL FROM SITE OF EXTRACTION TO POWER PLANT

Coal may be transported by different transportation means, including rail, road, pipeline, and river. The expression used to describe the energy intensity of transporting coal (or any other material) is Btu per ton-mile. This is calculated as:

$$\boxed{\frac{E}{T * M}}$$ (see note 3)

where:
E is total Btu used by the mode of transport and the energy used for the backhaul (assuming the return trip is empty);
T is total tonnage of the transported material; and
M is the distance the material was carried.

It is safe to assume that for the most part, the carrier returns empty. For example, 91% of the unit train cars that carry coal return empty to the mine (DeLuchi, 1993), and trucks return empty unless they can find a similar product to transport back. Therefore, all transportation data will assume a one-way haul.

Rail:

The 1987 national average length of haul for coal by means of rail is 490 miles[4]. It is assumed that diesel fuel is used for rail transportation[5]. DeLuchi (1993) presents energy consumed in coal transportation by rail from a few sources (U.S. Department of Energy (1983), U.S. Congressional Research Service (CRS) (1977), and Argonne National Laboratory (ANL) (1982)). The energy consumed is averaged out to be 589 Btu per ton-mile.

Truck:

DeLuchi (1993) is in accordance with the DOE *Energy Technology Characterizations Handbook* (1983) on an average haul distance of 60 miles for a round trip of coal delivery. It is assumed that diesel fuel is used for truck transportation. DeLuchi (1993) estimates energy consumed in coal transportation by truck from a few sources (U.S. Department of Energy (1983), U.S. Congressional Research Service (CRS) (1977), and Argonne National Laboratory (ANL) (1982), and Rose (1979)). The energy consumed is averaged out to be 2349 Btu per ton-mile.

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[3] DeLuchi, 1993. *Emissions of Greenhouse Gases from the Use of Transportation Fuels and Electricity*, Appendix E.
[4] DeLuchi, 1993. *Emissions of Greenhouse Gases from the Use of Transportation Fuels and Electricity*. EIA, 1988. *Coal Distribution.*
[5] DeLuchi, 1993. *Emissions of Greenhouse Gases from the Use of Transportation Fuels and Electricity*, Appendix F.

Ship:

The national average length of haul for coal by means of water is 450 miles[6]. DeLuchi (1993) estimates energy consumed in coal transportation by ship from a few sources (U.S. Department of Energy (1983), U.S. Congressional Research Service (CRS) (1977), and Argonne National Laboratory (ANL) (1982), and Rose (1979)). The energy consumed is averaged 539 Btu per ton-mile.

Slurry Pipeline:

In general, coal slurry pipeline is a highly reliable (99%) source of transportation, and can last longer than 20 or 30 years. It is the cleanest and safest coal delivery system to power plants. Data for energy consumed in coal transportation by slurry pipeline was presented in *Emissions of Greenhouse Gases from the Use of Transportation Fuels and Electricity*[7] (1993) over a few sources: U.S. Department of Energy (1983), Banks (1977) and Argonne National Laboratory (ANL) (1982). The energy consumed for this mode of transport is averaged out to be 668 Btu-power per ton-mile. Included in this average is energy used for slurry preparation, pipeline pumping, dewatering facilities, and specifically, energy used in the Black Mesa Pipeline, which runs 273 miles from the Black Mesa Coal Mine in Arizona to the Mohave Power Plant in Laughlin, Nevada. DeLuchi (1993) estimates that the average length of haul for a pipeline is 300 miles, including the pipeline itself, tramway transportation, and conveyor belts.

Transportation Emissions:

Emissions from all of the different types of transportation methods are included in the model. The emission factors for the different transportation methods are shown elsewhere.

COAL COMBUSTION

Energy consumed and emissions associated with combustion of coal in utility boilers comes from a variety of sources. Emissions and total coal burned were obtained from the 1994 Interim Inventory based on the Form EIA-767 data[8] (the Interim Inventory 1994). Emissions factors for pollutants not provided in the Interim Inventory (1994) are obtained from AP-42 (1995).

Emissions are presented for each individual firing configuration. Because firing configurations have varying combustion requirements (coal burning temperatures, firing methods, and emissions control equipment, etc.), they emit varying amounts of pollutants.

The firing configurations included in the model are:

- pulverized coal fired, dry bottom and wall fired;
- pulverized coal fired, dry bottom and tangentially-fired;
- pulverized coal-fired and wet bottom;
- spreader stoker;
- fluidized bed combustor; and
- cyclone furnace.

[6] DeLuchi, 1993. *Emissions of Greenhouse Gases from the Use of Transportation Fuels and Electricity.* U.S. Department of Army, 1988, 1989. *Waterborne Commerce of the United States,*

[7] DeLuchi, 1993. *Emissions of Greenhouse Gases from the Use of Transportation Fuels and Electricity.*

[8] Database provided by EPA.

The Interim Inventory (1994) provides actual air emissions (VOC's, NOx, CO, SOx, and PM-10) by specific type of coal (bituminous, subbituminous, and lignite) and by furnace type. The firing types provided are also identified by a Source Classification Code (SCC). Each firing type was placed into a broader category of firing configurations (identified in AP-42), using SCC numbers. The following table presents the firing types provided by the Interim Inventory (1994), and how they were placed in the firing configuration category, based on SCC numbers.

Firing Configuration (AP-42 1995)	Firing Types (Interim Inventory 1994)
Pulverized coal fired, dry bottom, wall fired	Front Furnace Arch Furnace (50%)[9] Rear Furnace Spreader Stoker (80%)[10] Opposed Furnace Vertical Furnace
Pulverized coal fired, dry bottom and tangentially-fired	Tangential Furnace
Pulverized coal-fired, wet bottom	Arch Furnace (50%)
Spreader stoker	Spreader Stoker (20%)
Fluidized bed combustor	Fluidized Bed
Cyclone furnace	Cyclone

Several steps were made to obtain actual emissions in pounds per ton of each type of coal. The tonnage for each emission provided by the Interim Inventory (1994) database was summed for each firing configuration. This number was divided by the total amount of coal consumed for each firing configuration, to obtain actual emissions per firing configuration, per type of coal.

Where actual emissions data were not available, such as N_2O, methane, and trace elements, emissions factors were obtained from AP-42 (1995) and a weighted average was used for each firing configuration.

The model also takes into account all carbon dioxide emissions, which are calculated by multiplying 36.7 by the percent weight of carbon content in coal. Fixed carbon content percentages of different coal samples are given in provided Babcock and Wilcox[11] for anthracite, bituminous coal, subbituminous coal, and lignite. Averaged values, and CO_2 emissions factors (in g/kg coal) are provided in the table below:

	Fixed Carbon Content %	CO2 Emissions Factor (g/kg)
Anthracite	(see footnote 12)	2,840
Bituminous	85	3,120
Subbituminous	75	2,753
Lignite	70	2,569

Finally, the model takes the weighted average of each of the firing configurations for each type of coal. For example, the emissions from the spreader stoker for bituminous coal combustion are omitted from the model, since bituminous coal combusted in the spreader stoker is a negligible representation of all of the bituminous coal fed into the firing configurations.

Emissions Control Technology:

[9] About half of the arch furnace boilers had SCC numbers for dry-bottom wall-fired units and the other half for wet-bottom units.

[10] An estimated 80% of the spreader stoker boilers had SCC numbers for dry-bottom wall-fired units and the other 20% belonged in the spreader stoker category of firing configurations.

[11] Babcock & Wilcox, 1992. **Steam**, 40th ed. Babcock & Wilcox Company, Barberton, OH.

[12] Carbon content for anthracite is not needed for the calculation since the EPA Air Emissions Factors provided the emission factor directly.

Because there is actual plant data for VOCs, NOx, CO, SO2, and particulate matter, emission control technologies for some of the major pollutants of concern, such as NOx and SOx, are already taken into account.

Lime and limestone, used for flue gas desulfurization (FGD), are modeled. Coal utility plants use different methods for scrubbing, such as limestone slurries and dry spraying, and use as the primary FGD materials lime and limestone. Quantities of lime and limestone vary, depending on the type of coal, the molar ratio needed to scrub the SOx, and the percentage of SOx (by weight) in the coal. Each type of coal was modeled according to the general scrubbing material for that type of coal and based on its percentage by weight of SOx. Data on scrubbing, molar ratios, and technologies were collected from a source at a coal utility plant in North America (1996), a source at American Electric Power Company (1997) and from the DOE Energy Information Administration *Electric Power Annual* 1994, Vol. II, November 1995.

Water Effluents:

Coal combustors use water for boiler makeup, treatment of fumes, and slag cooling. However, it is assumed that most of the water is recycled in the facility. Therefore, water effluents generated as a result of combustion of coal are negligible in this model.

POST-COMBUSTION OF COAL

The coal combustion process produces waste that must be disposed of off-site, including coal ash, resulting from coal combustion, and sludge, resulting from flue gas desulfurization (FGD). In 1984, 69 x 10^6 tons and 16 x 10^6 tons of coal ash and FGD sludge, respectively, were generated from electrical facilities[13]. Energy and emissions to remove coal ash and FDG sludge are modeled. Since the quantity of FDG sludge is approximately 25% the amount of coal ash, all energy and emissions to remove and dispose of FDG sludge are considered to be about 25% of those found for the disposal of coal ash.

Energy to transport FDG sludge and coal ash from the plant to their respective storage locations is modeled. The moisture content of coal ash (in % weight of ash) at the point it is removed from the silo is assumed to be approximately 17% (moisture content may be anywhere from 8% to 25%)[14]. The average energy consumed to place ash from the silo into the truck, 0.143 kilowatt hours[15] per ton, is very minimal, as most of the work is due to gravitational force (ash falling from the shoot).

The distance from the power plant to the coal ash and FGD sludge landfills is assumed to be one mile[16].

The trucks used to transport the materials are tandem trucks, filled based on weight of the material. The tandem truck carries an actual payload of about 27.6 short tons, and consumes 0.038 gallons of diesel fuel per short ton[17] of material.

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[13] U.S. EPA, October 1987. *Wastes from the Combustion of Coal by Electric Utility Power Plants (from* DeLuchi, 1993. *Emissions of Greenhouse Gases from the Use of Transportation Fuels and Electricity*, Appendix F*)*.

[14] From American Power Plant Data, 1996. Power plant information is confidential data collected by Ecobalance.

[15] From American Power Plant Data, 1996.

[16] From American Power Plant Data, 1996.

[17] At an average of 4 L of diesel fuel to transport 28 metric tons per load to the coal ash monofill, from American Power Plant Data, 1996.

REFINED PETROLEUM PRODUCTS PRE-COMBUSTION

This section includes pre-combustion data for the refined petroleum products heavy fuel oil, diesel oil, and gasoline. The pre-combustion steps includes extraction of crude oil from the ground, transportation of the crude oil to a refinery, and refining the crude oil into finished refinery products. Transportation of the finished refinery products to the point of use is not included at this stage.

GEOGRAPHICAL BOUNDARIES

The modeling of refined petroleum products production includes worldwide crude oil extraction and U.S. refinery operations. Foreign crude oil extraction and transportation to the United States is modeled because half of the U.S. supply of crude oil is imported. The transport of finished refinery products into the U.S. is not studied because foreign refinery products only accounts for a small percent of the total finished refinery products used in the U.S. in 1994[18], and may be accounted for under domestic refinery production. In addition, domestic refinery data are more accurate and reliable.

CRUDE OIL EXTRACTION

There are three separate methods for crude oil extraction and recovery: onshore production, offshore production, and thermal enhanced recovery, which entails the underground injection of carbon dioxide or steam produced by natural gas boilers[19]. All of these methods are modeled.

Heater treater separators are used to separate the crude oil, natural gas, and water mixture that is extracted. As natural gas is produced as a co-product of crude oil production, emissions will be allocated between gross natural gas and crude oil production on a mass based method. The emissions associated with the venting and flaring of some of the natural gas extracted from the well will also be accounted for.

The inflows associated with the three different methods of crude oil extraction include electricity used in pumping, and natural gas used as fuel to run the heater treater systems. Outflows include air emissions, water effluents, and solid waste.

TRANSPORTATION

The United States is broken up into Petroleum Administration for Defense Districts (PADDs) in order to insure that each region or PADD is supplied with enough petroleum for strategic defense reasons. The transportation distances used in this report will be averaged across all of the PADDs. The amount of foreign and domestic crude oil transported into each PADD will be estimated from refinery receipts of crude oil which is known for each PADD[20].

[18] EIA, May 1995, Petroleum Supply Annual 1994 Volume 1.

[19] Shares of each production type were obtained from the Oil & Gas Journal Database, using numbers obtained in 1994. Note that the Other Enhanced/Advanced category includes all advanced crude oil extraction techniques except water flooding. It will be assumed that the emissions associated with thermal advanced recovery as listed by Tyson et al. (November 1993, Fuel Cycle evaluations of Biomass-Ethanol and Reformulated Gasoline) will apply to the percentage of wells operating with the other Enhanced/Advanced techniques obtained from the Oil & Gas Journal Database.

[20] Source: EIA Petroleum Supply Annual 1993, Vol. 1. 1993 data was used because that was the latest year for which information used to calculate transportation distances could be found (see Section 3.3.2).

Distances used to model transportation of are based on national averages, obtained from the following types of data and methods of calculation:

Domestic Tanker and Domestic Barge[21]:

Army report lists tons and ton-miles of crude oil transported by tanker and barge on all United States waterways. Average miles are calculated by dividing total ton-miles traveled by total tons transported. This is done separately for both tanker and barge.

Domestic Pipeline[22]:

Association of Oil Pipelines lists total ton-miles of crude oil carried in domestic pipelines. Average miles are calculated by dividing total ton-miles of crude oil, carried in domestic pipelines, by tons of crude oil received at refineries via pipeline. Foreign pipeline is calculated the same way.

Domestic Rail[23]:

Association of Oil Pipelines lists total ton-miles of crude oil carried by rail in the United States. Average miles are calculated by dividing total ton-miles of crude oil, carried by rail, by tons of crude oil received at refineries via railroad tank cars.

Domestic Truck[24]:

Association of Oil Pipelines lists estimated total ton-miles of crude oil transported by motor carriers in the United States. Average miles are calculated by dividing total ton-miles of crude oil, transported by motor carriers, by tons of crude oil received at refineries via truck.

Foreign Tanker[25]:

The Petroleum Supply Annual lists imports of crude oil by country for each PADD (in barrels). PADD I crude oil is assumed to all arrive at New York. PADD II and III oil is assumed to arrive at Houston. PADD V oil is assumed to arrive at Los Angeles. PADD IV does not receive any foreign oil other than Canada.

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[21] Source: Waterborne Commerce of the United States, Calendar Year 1993, Part 5 - National Summaries. Department of the Army, Corps of Engineers.

[22] Source: Association of Oil Pipelines, using data from Annual Report (Form 6) of oil pipeline companies to the Federal Energy Regulatory Commission. Energy Information Administration, Petroleum Supply Annual, 1993, Vol. 1.

[23] Source: Association of Oil Pipelines, using data from Carload Way Bill Statistics, Report TD-1, Department of Transportation, Federal Railroad Administration, annual, and Freight Commodity Statistics, Association of American Railroads, annual. Energy Information Administration, Petroleum Supply Annual, 1993, Vol. 1.

[24] Source: Association of Oil Pipelines, using data from Financial and Operating Statistics, American Trucking Association, Inc. Energy Information Administration, Petroleum Supply Annual, 1993, Vol. 1.

[25] Source: DeLuchi, M. A., Emissions of Greenhouse Gases from the Use of Transportation Fuels and Electricity, Vol. 2 Argonne National Laboratory, 1993. Energy Information Administration, Petroleum Supply Annual, 1994, Vol. 1.

Nautical miles between ports of origin and United States ports (New York, Houston, and Los Angeles) are given in DeLuchi's study, based on information from the Defense Mapping Agency[26]. From this information a weighted average is calculated, for each PADD, by multiplying barrels imported from each country by the distance from that country to the specified United States port of entry. These results, in barrel-miles for each PADD, are added together and then divided by the total number of barrels imported to get an average distance in miles traveled by the foreign tankers.

CRUDE OIL REFINING

The inflows associated with refining include crude oil, natural gas, LPG, steam, electricity, and coal[27]. Outflows for this process include air emissions[28], water effluents, and solid waste.

Allocation of refining processes must be addressed. Petroleum refineries produce a number of different products from the amount of crude oil that they receive. Additional complexity is introduced by the fact that the refinery product mix is variable, both among refineries and even with time for a given integrated refinery.

The methodology used in order to allocate total refinery energy consumption and total refinery emissions to the production of different refinery products is described as follows:

1. Calculate the percent of total refinery energy used by each different process within the refinery.
2. Calculate the refinery products share of each process' energy consumption.
3. Multiply the two results in order to get the percent of total refinery energy allocated to the refinery product production for each individual process. Adding the results of each process gives the percent of total refinery energy allocated to the total refinery product production.
4. Emissions are allocated based on the percent of total refinery energy allocated to the total refinery product production (from step 3 above).

CAPITAL EQUIPMENT

Life cycle environmental flows associated with the production of the capital equipment and facilities used in the extraction, transportation and refining of crude oil are excluded from the fuel model since the energy used in the construction of large energy facilities and other equipment used in fuel cycles (including electric power plants, oil wells, oil tankers and hydroelectric plants) is negligible (less than 1%) compared with the energy produced or carried by that equipment over its useful life[29] (DeLuchi, 1993).

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[26] Defense Mapping Agency, Hydrographic/Topographic Center, Distance Between Ports, Fifth edition, Publication 151, Washington, D.C. (1995)
[27] EIA, May 1995, Petroleum Supply Annual 1994 Volume 1.
[28] Environmental Protection Agency, July 1995. AP-42 Emission Factors.
[29] DeLuchi, M.A., 1993. Emissions of Greenhouse Gases from the Use of Transportation Fuels and Electricity.

Heavy Fuel Oil Electricity Production

Production of electricity from heavy fuel oil includes heavy fuel oil pre-combustion, transportation of the heavy fuel oil to the utility and heavy fuel oil combustion (including control technologies). Data on heavy fuel oil pre-combustion is listed separately, therefore, this section only describes the heavy fuel oil transport and combustion.

Transportation of Heavy Fuel Oil from Refinery to Power Plant

The transportation of heavy fuel oil from the refinery to a utility plant is assumed to be through the use of pipelines and road transport.

Of all the heavy fuel oil transported, 85% is assumed to be transported by pipeline an average distance of 800 miles. The remaining 15% is assumed to be transported by diesel truck an average (one-way distance of 75 miles[30].

Emissions from the two different types of transportation methods are included in the model. The emission factors for the different transportation methods are shown elsewhere.

Heavy Fuel Oil Combustion

The major source of data for the combustion of fuel oil is EPA AP42. As described in detail for the coal combustion, different technologies of fuel combustion have been averaged, according to their relative weight on the market.

Lime and limestone, used for flue gas desulfurization (FDG), are modeled. The average heavy fuel oil utility plants use different methods for scrubbing, such as limestone slurries and dry spraying, and use as the primary FGD materials lime and limestone. The quantities of lime and limestone needed are based on, the molar ratio needed to scrub the SOx, and the percentage of SOx (by weight) in the heavy fuel oil[31]. About 1.01 moles of FDG material are used to scrub 1 mole of SO_2[32].

[30] DeLuchi, M.A., 1993. *Emissions of Greenhouse Gases from the Use of Transportation Fuels and Electricity,* Volume 2: Table E1a and Appendix H (specifically, EIA Petroleum Supply Annual data).
[31] EPA, July 1995. AP-42 air emissions factors.
[32] Source at coal utility plant.

NATURAL GAS PRE-COMBUSTION

Natural gas pre-combustion includes extraction of natural gas from the ground, then processing of the natural gas for use. Transportation to the point of use is not included at this stage.

NATURAL GAS EXTRACTION

Raw natural gas is a mixture of hydrocarbons, N_2, CO_2, sulfur compounds, and water. It may have any range of compounds from mostly methane to inert gases, such as nitrogen, carbon dioxide, and helium, and smaller amounts of ethane, propane, and butane. Natural gas may be mined onshore, offshore, and in conjunction with petroleum processes.

The energy used to mine natural gas is provided by EIA Natural Gas Annual[33] and U.S. Bureau of Census[34]. The process energy is apportioned out among petroleum, natural gas, and natural gas liquids based on the following assumptions:

- Almost all the of natural gas consumed that the Census Bureau reports goes toward field operations—natural gas lifting and reinjecting. This data correspond with data provided by EIA;
- Any energy used to reinject natural gas into wells is excluded from the natural gas pre-combustion processes, since reinjection is mainly used in oil wells; and
- The amount of electricity used for field equipment and processing plants is little relative to the amount of gas they produce[35].

Thus, energy in this model excludes gas reinjection energy requirements.

NATURAL GAS PROCESSING (SWEETENING)

The amine process, or gas sweetening removes and recovers H_2S. The recovered hydrogen sulfide gas is either (1) vented, (2) flared in waste gas flares or modern smokeless flares, (3) incinerated, or (4) utilized for the production of elemental sulfur or sulfuric acid. Emissions due to only venting the gas into the environment are covered in the model. Vented gas is usually passed to a tail gas incinerator in which the H_2S is oxidized to SO_2 and is then passed to the atmosphere out a stack. Emissions are mostly SO_2 due to the 100% conversion of H_2S to SO_2. Very little particulate and NOx emissions are generated from this process. Emissions factors for the amine process come from AP-42 (1995).

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[33] EIA, 1990. *Natural Gas Annual 1989, Volume 1.*

[34] US Department of Commerce, 1990. *Census of Mineral Industries, Fuels, and Electrical Energy Consumed.*

[35] DeLuchi, M.A., 1993. *Emissions of Greenhouse Gases from the Use of Transportation Fuels and Electricity,* Volume 2.

NATURAL GAS ELECTRICITY PRODUCTION

Production of electricity from natural gas includes natural gas pre-combustion, transportation of the natural gas to the utility, and natural gas combustion. Data on natural gas pre-combustion is listed separately, therefore, this section only describes the natural gas transport, and combustion.

TRANSPORTATION OF NATURAL GAS FROM SITE OF EXTRACTION TO POWER PLANT

Natural gas is transported by way of high-pressure transmission lines. Compressors along these lines may be powered from different sources: gas-fueled reciprocating engines and gas turbines, and electric motors. Emissions are all different due to the different sources of power in the compressors: the turbines, the engines, and the electric motors, so all of these sources will be modeled.

The total amount of gas that is consumed in the compressors is averaged over the different sources of power. It is known, however, that most pipeline compressor units are reciprocating engines, since reciprocating engines are more efficient when they operate under a large load. And since many of the compressors do operate under a large load, it may be assumed that there are more reciprocating engines in the compressors than turbines (DeLuchi, 1993). To obtain a breakdown of energy sources for compressors in transmission pipelines, actual pipeline company data was used. Averaging out the percent horsepower for each type of power source for the pipeline, it was found that:

% Horsepower in 1989[36]:

Turbines:	24.2%
Engines:	73.4%
Electric:	2.5%

Horsepower hours by type of compressor and the associated fuel combustion per horsepower-hour is used to obtain a weighted percent of energy and emissions due to each type of compressor in transmission pipelines. Since electric power is so little relative to the other compressors (2.5%), it is neglected.

AP-42 (1995) provides emissions data for gas turbines and reciprocating engines. Emission factors for controlled (i.e., with NOx reduction technologies in place) for NOx, CO, TOC, total non-methane organic compounds, CH4, and PM-10. The control technology is assumed to be in place due to increasingly stricter NOx control standards. For gas turbines, uncontrolled emissions factors are provided for NOx, CO, TOC, total non-methane organic compounds, CH4, and PM-10 in AP-42 (1995).

NATURAL GAS COMBUSTION

Natural gas is combusted in gas boilers. Emissions from combustion of natural gas are mainly due to improper operating conditions, such as inefficient mixing of fuel and air in the boiler, or an insufficient amount of air, etc. Emissions vary by the type and size of combustor and operating conditions.

Emissions factors for gas boilers were obtained from EPA AP-42 (1995) for NOx, CO, SOx, particulate matter, CO, and TOC's. NOx control technologies are required for many boilers to comply with strict NOx emissions standards, so it is assumed that most boilers have NOx control technologies. Therefore, emissions factors for NOx in AP-42 (1995) use the factors for boilers with NOx control technologies.

[36] DeLuchi, Emissions of Greenhouse Gases from the Use of Transportation Fuels and Electricity, Volume 2:, Appendix G.

NUCLEAR ENERGY ELECTRICITY PRODUCTION

Uranium contains two different isotopes, of uranium—238U and 235U. 235U is used as a fuel for nuclear reactors because it is fissionable, so the atoms can be split, releasing large amounts of heat. However, natural uranium consists of more than 99 percent 238U and less than 1 percent 235U. To be used as a fuel, its 235U content must be enriched to 3-5 percent.

The data included in the model is uranium hexafluoride (UF6) manufacturing, enrichment of 235U, and fuel rods manufacturing[37]. There is no available data on disposal of waste, plant construction, or emissions of radionucleides.

[37] Swiss Federal Office of Environment, Forests and Landscape (FOEFL or BUWAL). Environmental Series No. 132. p A15. Berne, February 1991, and E.E. El-Hinnawi: Environmental Impacts of Production and Use of Energy. Tycooli International 1981.

HYDRO POWER ELECTRICITY PRODUCTION

Hydroelectric power generation refers to water used to generate electricity at plants in which turbine generators are driven by falling water.

Included in the hydroelectric power production model are greenhouse gas emissions (CO_2 and CH_4) from operation of a hydroelectric plant (flooded biomass decomposition). The Federal Energy Regulatory Commission38 provides US hydroelectric plant information such as average annual generation, plant capacity, and reservoir area and depth.

Construction of the facility (steel and concrete production and transportation to the reservoir plus construction energy) is excluded from the model. Capital equipment in hydroelectric power production has been raised to be a potential source of burdens for hydroelectricity[39] (it has been shown that capital equipment was negligible for fossil fuel combustion). However, in order to be consistent with the other energy production methods, capital equipment is excluded.

The data obtained on greenhouse gases emissions does not distinguish flooded biomass decomposition from new biomass decomposition and is assumed to refer only to flooded biomass.

[38] FERC database, 1996.

[39] Data from Chamberland, Andre and Levesque, S. Hydroelectricity, an Option to Reduce Greenhouse Gas Emissions from Thermal Power Plants. Energy Cons. Mgmt Vol. 37, Nos. 6-8, pp. 885-890. Chamberland's life cycle study is based on a group of facilities in northern Canada whose average lifespan is 100 years and produces annually 62,200 GWh of electricity.

COMBUSTION EMISSIONS

This section lists the emission factors for the following fuel combustion modules:

- Natural Gas Industrial Boilers (> 100 10^6 Btu/hr heat input)
- Heavy Fuel Oil Industrial Boilers
- Coal Industrial Boilers
- Diesel Industrial Engines
- Gasoline Industrial Engines

Most of the emission factors were obtained from the EPA document, "Compilation Of Air Pollutant Emission Factors", Volume I, Fifth Edition, Point Sources AP-42 (1995). These numbers were compared with a project done by Argonne National Laboratory[40], to verify and expand on the EPA emission factors.

All the factors reported are for uncontrolled emissions. If control technologies are used, the emission factors should be reduced by the efficiencies of the control devices.

[40] Wang, M.Q., GREET 1.0 - Transportation Fuel Cycles Model: Methodology and Use, Center for Transportation Research, Energy Systems Division, Argonne National Laboratory, Argonne, Illinois.

TRANSPORTATION EMISSIONS

Diesel Barge:

The barge was assumed to be a ship transporting generic goods, with a Btu/tonmile of 402 (source - *Emissions of Greenhouse Gases from the Use of Transportation Fuels and Electricity*, M. DeLuchi)
Emission factors for CO, NOx and HC are for a 2500 hp diesel engine cruising speed (source - *AP-42*, US EPA). The deadweight tons for the ship are assumed to be under 15,000.
The diesel fuel consumed is assumed to have 0.2% sulfur, converted completely to SO_2 during combustion.
The fuel density for the diesel fuel is assumed to be 3173.83 grams/gallon (source -*Ecobalance of Packaging Materials State of 1990*, BUWAL)

Diesel Truck:

The truck is assumed to be an 18-ton heavy-duty truck, fully loaded; 5.5 miles/gallon is assumed.
The emission factors are for 1991-1997 trucks operated at low altitude (source - *AP-42*, US EPA).
CO_2 and SOx emissions are calculated using the diesel fuel's carbon content and sulfur content respectively.
Diesel fuel is assumed to be 0.2% sulfur and 85.8% carbon.

Diesel Train:

Data for average annual freight ton miles and gallons of diesel fuel consumed come from the Bureau of Transportation Statistics. The values are an average of six years worth of data (1990-1995).
Emission factors are for Class I railroads (source - *Procedures for Emission Inventory Preparation - Vol. IV: Mobile Sources*, Bureau of Transportation Statistics).
CO_2 emissions are calculated using the assumption of 85.8% carbon in diesel fuel. Diesel fuel density is given as 3173.83 grams/gallon (source -*Ecobalance of Packaging Materials State of 1990*, BUWAL).

Heavy Fuel Oil Ocean Tanker:

The tanker is assumed to be an international oil tanker averaged over different deadweight ton sizes, transporting crude oil or petroleum products. The fuel oil density is given as 3575 grams/gallon and the btu/ton mile is calculated as 114 (source -*Emissions of Greenhouse Gases from the Use of Transportation Fuels and Electricity*, M. DeLuchi).
CO_2 and SOx emissions are calculated using the heavy fuel oil's carbon content and sulfur content respectively. Heavy fuel oil is assumed to be 2.2% sulfur and 85.8% carbon.
Emissions are calculated using general fuel oil tanker emission in grams/10^6 btu of fuel (source -*Emissions of Greenhouse Gases from the Use of Transportation Fuels and Electricity*, M. DeLuchi)

ELECTRICITY PRODUCTION PER GEOGRAPHICAL ZONE

The following tables show the electricity *production* percentages for the different North American Electric Reliability Council (NERC) regions in the North America[41].

			NERC Region		
Fuel Type	***NPCC***	***ECAR***	***WSCC***	***ERCOT***	***SERC***
HFO	10.7 %	0.3 %	0.1 %	0.1 %	3.4 %
Hydro	15.4 %	0.5 %	40.6 %	0.3 %	4.6 %
NG	18.3 %	0.5 %	10.2 %	37.4 %	5.9 %
Nuclear	35.1 %	10.4 %	12.8 %	17.1 %	29.5 %
Coal	20.5 %	88.3 %	36.3 %	45.2 %	56.6 %

			NERC Region		
Fuel Type	***MAAC***	***MAPP***	***MAIN***	***SPP***	***US Average***
HFO	3.1 %	0.5 %	0.5 %	0.3 %	2 %
Hydro	0.8 %	8.4 %	1.4 %	2.9 %	9.8 %
NG	5.3 %	0.9 %	1.7 %	28.3 %	10.2 %
Nuclear	40.8 %	15.9 %	42.4 %	15.7 %	23 %
Coal	50 %	74.3 %	54 %	52.8 %	55 %

Note that the percentages are given for the United States portion of the region listed. Some regions are split between Canada and the United States (WSCC for example), however, the electricity production percentages are given for only the United States portion.

The different NERC regions are described on the figure below.

[41] Electricity source percentages from: EIA-759, U.S. Department of Energy, 1995 Electric Utility Net Generation by NERC Region and Fuel Type.

Map of the NERC regions in the United States and in Canada

LIMESTONE PRODUCTION

Production of limestone includes quarrying of the limestone. Transportation of the limestone to the point of use is not included at this stage.

Limestone quarrying is modeled as diesel fuel, natural gas and electricity use. The amount of fuel and electricity used is based on Swiss Federal Office of Environment, Forests and Landscape (FOEFL or BUWAL) data[21].

Diesel fuel, natural gas and electricity production are based on Ecobalance's energy carrier LCI data.

Diesel fuel combustion emissions are based on United States Environmental Protection Agency (US EPA) data. The AP-42 mobile source emissions factors for miscellaneous heavy duty construction equipment are used to model the emissions form the combustion of the diesel fuel used in limestone quarrying.

Natural gas combustion emissions are based on Ecobalance's energy carrier LCI data for combustion of natural gas in an industrial boiler and in industrial engines[22]. It is assumed that 50 % of the natural gas used is combusted in an industrial boiler and 50 % is combusted in an industrial engine.

Other LCI flows from limestone quarrying include solid waste production, and particulate emissions from quarrying operations. These additional LCI flows are also based on Swiss Federal Office of Environment, Forests and Landscape (FOEFL or BUWAL) data[23].

Water effluents coming from limestone quarrying are considered negligible for this study. In general, the only water effluents coming from limestone production are those from mining (and refining) the fuels and producing the electricity that are used to quarry the limestone.

[21] Environmental Series No. 132, Bern, February 1991. energy requirements page A35
[22] Based on US EPA AP-42 data.
[23] Environmental Series No. 132, Bern, February 1991. air/water/waste page A36

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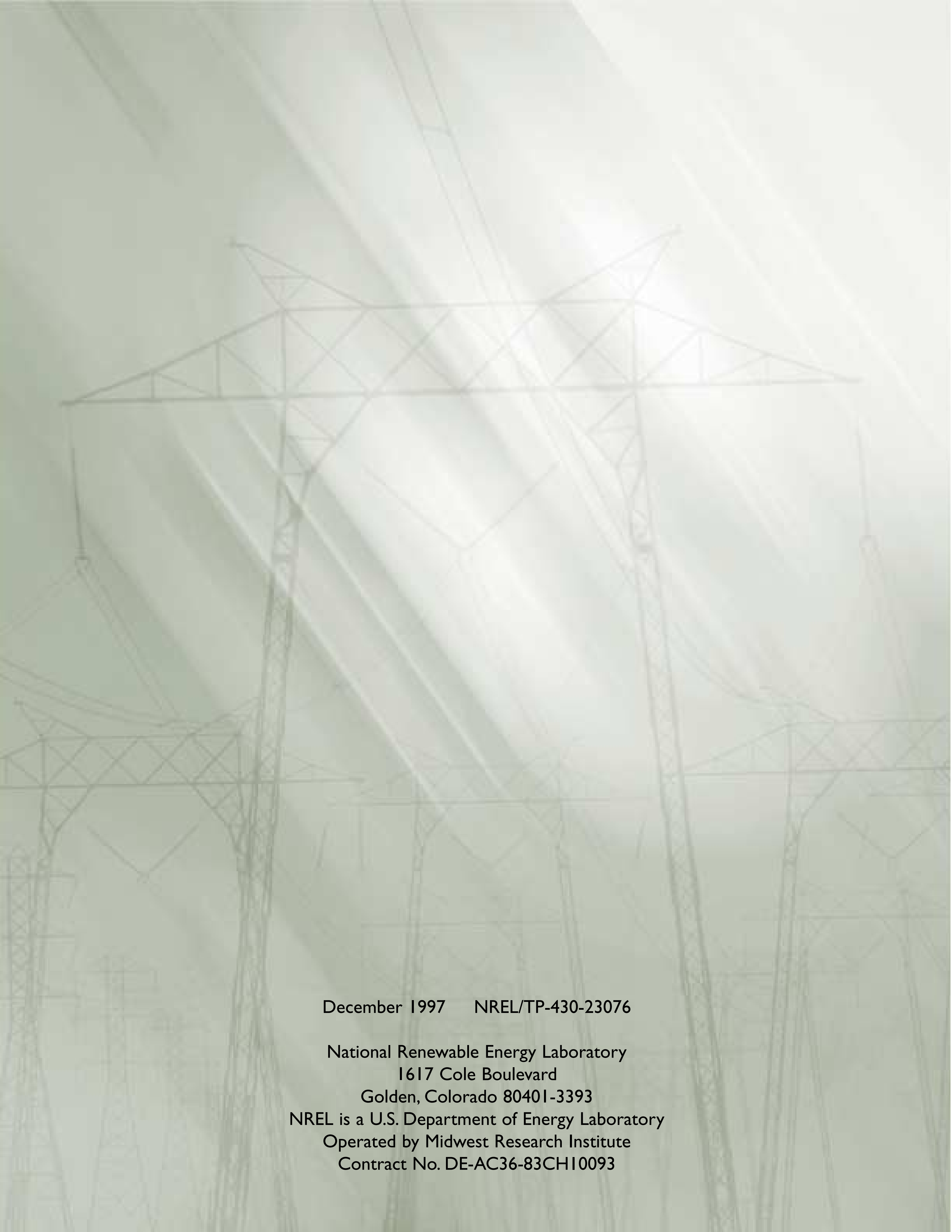

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