ALO/3987-1/3

SOLAR TOTAL ENERGY SYSTEM

LARGE SCALE EXPERIMENT
SHENANDOAH, GEORGIA

MASTER

FINAL
TECHNICAL PROGRESS REPORT

VOLUME III

APPENDIX

CONTRACT NO. EG-77-C-04-3987

ERDA
ALBUQUERQUE OPERATIONS OFFICE
ALBUQUERQUE, NEW MEXICO

C-19650
17 OCTOBER 1977

STEARNS-ROGER
McDONNELL DOUGLAS

SOLAR TOTAL ENERGY SYSTEM

LARGE SCALE EXPERIMENT
SHENANDOAH, GEORGIA

ENERGY RESEARCH & DEVELOPMENT ADMINISTRATION
USA

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APPENDIX A-1

HOURLY TEMPERATURES

(Ref. Section 2.1)

APPENDIX A-1-1

AVERAGE MONTHLY TEMPERATURES (1975)

Time	JANUARY					FEBRUARY				
	DBT		DPT		WBT	DBT		DPT		WBT
	°C	°F	°C	°F	°F	°C	°F	°C	°F	°F
1 am	6.3	43.3	2.3	36.1	39.7	6.5	43.7	2.6	36.9	40.5
3 am	6.0	42.8	2.3	36.1	39.5	5.7	42.3	2.6	36.7	39.6
5 am	5.5	41.9	2.1	35.8	39.0	5.2	41.4	2.5	36.5	39.0
7 am	5.4	41.7	1.8	35.2	38.9	5.3	41.5	2.3	36.1	39.0
8 am	4.9	40.8	1.8	35.2	38.4	6.4	43.5	3.0	37.4	40.5
10 am	7.6	45.7	2.5	36.5	41.4	7.6	45.7	3.6	38.5	42.1
12 noon	10.4	50.7	3.2	37.8	44.3	10.5	50.9	4.1	39.4	45.0
2 pm	12.1	53.8	3.1	37.6	45.8	12.3	54.1	4.1	39.4	46.7
4 pm	12.5	54.5	3.0	37.8	46.4	12.6	54.7	3.8	38.8	46.8
6 pm	10.3	50.5	2.5	36.5	43.8	11.3	52.3	3.4	38.1	45.3
8 pm	8.5	47.3	2.6	36.7	42.2	9.0	48.2	3.0	37.4	43.0
10 pm	7.2	45.0	2.5	36.5	41.0	7.7	45.9	2.7	36.9	41.6
12 midnight	6.5	43.7	2.1	35.8	39.9	6.8	44.2	2.7	36.9	40.8

DBT = DRY BULB TEMPERATURE
DPT = DEW POINT TEMPERATURE
WBT = WET BULB TEMPERATURE
°C = DEGREES CELCIUS (FROM WEATHER TAPE)
°F = DEGREES FAHRENHEIT (CONVERTED FROM °C)
WBT IS READ FROM PSYCHROMETRIC CHART CORRESPONDING TO GIVEN DBT & DPT.

APPENDIX A-1-2

AVERAGE MONTHLY TEMPERATURES (1975)

Time	MARCH					APRIL				
	DBT		DPT		WBT	DBT		DPT		WBT
	°C	°F	°C	°F	°F	°C	°F	°C	°F	°F
1 am	8.2	46.8	2.5	36.5	41.8	12.7	54.9	6.6	43.9	49.0
3 am	7.4	45.3	2.5	36.5	40.2	11.2	52.2	6.5	43.7	47.7
5 am	6.5	43.7	2.3	36.1	39.8	10.4	50.7	6.1	43.0	46.7
7 am	5.9	42.6	2.4	36.3	39.4	10.4	50.7	6.5	43.7	47.0
8 am	6.6	43.9	2.7	36.9	40.6	12.1	53.8	6.9	44.4	48.7
10 am	9.2	48.6	3.0	37.4	43.2	15.8	60.4	6.8	44.2	51.5
12 noon	11.6	52.9	3.0	37.4	45.2	18.1	64.6	6.5	43.7	53.2
2 pm	13.4	56.1	3.5	38.3	47.2	19.9	67.8	6.7	44.1	54.6
4 pm	14.5	58.1	3.5	38.3	48.1	20.2	68.4	6.6	43.9	55.0
6 pm	13.4	56.1	3.3	37.9	47.0	19.3	66.7	6.3	43.3	53.8
8 pm	11.4	52.5	3.2	37.8	45.0	16.4	61.5	6.6	43.9	52.0
10 pm	9.7	49.5	2.7	36.9	43.4	14.6	58.3	7.2	45.0	49.0
12 midnight	8.5	47.3	2.3	36.1	42.0	12.9	55.2	6.4	43.5	48.5

DBT = DRY BULB TEMPERATURE
DPT = DEW POINT TEMPERATURE
WBT = WET BULB TEMPERATURE
°C = DEGREES CELCIUS (FROM WEATHER TAPE)
°F = DEGREES FAHRENHEIT (CONVERTED FROM °C)
WBT IS READ FROM PSYCHROMETRIC CHART CORRESPONDING TO GIVEN DBT & DPT.

APPENDIX A-1-3

AVERAGE MONTHLY TEMPERATURES (1975)

Time	MAY					JUNE				
	DBT		DPT		WBT	DBT		DPT		WBT
	°C	°F	°C	°F	°F	°C	°F	°C	°F	°F
1 am	18.7	65.7	15.6	60.1	62.0	20.1	68.2	17.4	63.3	65.0
3 am	17.9	64.2	15.6	60.1	61.6	19.5	67.1	17.3	63.1	64.4
5 am	17.6	63.7	15.4	59.7	61.0	18.9	66.0	17.0	62.6	63.8
7 am	18.3	64.9	16.0	60.8	62.2	20.2	68.4	17.4	63.3	65.0
8 am	19.7	67.5	16.5	61.7	63.7	21.9	71.4	17.8	64.0	66.4
10 am	22.5	72.5	16.4	61.5	65.3	24.8	76.6	18.4	65.1	68.8
12 noon	24.1	75.4	16.2	61.2	66.0	26.8	80.2	18.1	64.6	68.7
2 pm	24.8	76.6	15.8	60.4	65.8	27.9	82.2	17.9	64.2	69.9
4 pm	25.3	77.5	15.6	60.1	64.4	27.7	81.9	17.8	64.0	69.7
6 pm	24.5	76.1	15.9	60.6	66.0	26.4	79.5	17.7	63.9	68.8
8 pm	22.1	71.8	15.9	60.6	64.5	23.6	74.5	17.9	64.2	65.8
10 pm	20.1	68.2	16.2	61.2	63.7	21.8	71.2	17.9	64.2	66.4
12 midnight	19.1	66.4	15.7	60.3	62.4	20.7	69.3	17.6	63.7	65.5

DBT = DRY BULB TEMPERATURE
DPT = DEW POINT TEMPERATURE
WBT = WET BULB TEMPERATURE
°C = DEGREES CELCIUS (FROM WEATHER TAPE)
°F = DEGREES FAHRENHEIT (CONVERTED FROM °C)

WBT IS READ FROM PSYCHROMETRIC CHART CORRESPONDING TO GIVEN DBT & DPT.

APPENDIX A-1-4

AVERAGE MONTHLY TEMPERATURES (1975)

	JULY					AUGUST				
Time	DBT		DPT		WBT	DBT		DPT		WBT
	°C	°F	°C	°F	°F	°C	°F	°C	°F	°F
1 am	21.6	70.9	20.4	68.7	69.4	22.2	72.0	21.3	70.3	70.8
3 am	21.1	70.0	20.1	68.2	68.7	21.7	71.1	21.2	70.2	70.4
5 am	20.9	69.6	19.9	67.8	68.4	21.4	70.5	20.8	69.4	69.7
7 am	21.3	70.3	20.3	68.5	69.1	21.8	71.2	21.1	70.0	70.3
8 am	23.3	73.9	20.7	69.3	70.7	23.1	73.6	21.6	70.9	71.7
10 am	24.5	76.1	20.7	69.3	71.4	25.9	78.6	21.9	71.4	73.5
12 noon	26.4	79.5	20.9	69.6	72.4	27.7	81.9	21.9	71.4	74.3
2 pm	27.6	81.7	20.6	69.1	72.2	28.7	83.7	21.5	70.7	74.3
4 pm	27.6	81.7	20.2	68.4	72.3	28.8	83.8	21.4	70.5	72.2
6 pm	25.7	78.3	20.4	68.7	71.6	27.4	81.3	21.7	71.1	74.1
8 pm	23.7	74.7	20.3	68.5	75.3	24.8	76.6	21.7	71.1	72.7
10 pm	22.4	72.3	20.5	68.9	69.9	23.5	74.3	21.9	71.4	72.1
12 midnight	21.8	71.2	20.4	68.7	69.5	22.9	73.2	21.6	70.9	71.5

DBT = DRY BULB TEMPERATURE

DPT = DEW POINT TEMPERATURE

WBT = WET BULB TEMPERATURE

°C = DEGREES CELCIUS (FROM WEATHER TAPE)

°F = DEGREES FAHRENHEIT (CONVERTED FROM °C)

WBT IS READ FROM PSYCHROMETRIC CHART CORRESPONDING TO GIVEN DBT & DPT.

APPENDIX A-1-5

AVERAGE MONTHLY TEMPERATURES (1975)

	SEPTEMBER					OCTOBER				
Time	DBT		DPT		WBT	DBT		DPT		WBT
	°C	°F	°C	°F	°F	°C	°F	°C	°F	°F
1 am	18.5	65.3	16.7	62.6	63.6	14.7	58.5	12.3	54.1	55.9
3 am	17.7	63.9	16.2	61.2	62.0	13.8	56.8	11.7	53.1	54.5
5 am	17.5	63.5	16.1	61.0	61.9	13.4	56.1	11.5	52.7	54.1
7 am	17.5	63.5	16.1	61.0	61.9	13.0	55.4	11.3	52.3	53.5
8 am	18.6	65.5	16.4	61.5	62.8	14.2	57.6	11.9	53.4	55.2
10 am	21.5	70.7	16.9	62.4	64.8	17.6	63.7	12.9	55.2	58.4
12 noon	23.7	74.7	17.5	63.5	67.1	20.2	68.4	13.2	55.8	60.4
2 pm	24.6	76.3	17.4	63.3	67.5	21.6	70.9	12.7	54.9	60.3
4 pm	24.2	75.6	17.6	63.7	67.5	21.7	71.1	12.2	54.0	58.8
6 pm	22.9	73.2	17.2	63.0	66.4	19.1	66.4	12.6	54.7	58.8
8 pm	20.8	69.4	17.0	62.6	64.7	17.1	62.8	12.6	54.7	57.2
10 pm	19.4	66.9	16.7	62.1	63.8	15.5	59.9	12.3	54.1	56.4
12 midnight	18.9	66.0	16.7	62.1	63.5	15.2	59.4	12.6	54.7	56.5

DBT = DRY BULB TEMPERATURE

DPT = DEW POINT TEMPERATURE

WBT = WET BULB TEMPERATURE

°C = DEGREES CELCIUS (FROM WEATHER TAPE)

°F = DEGREES FAHRENHEIT (CONVERTED FROM °C)

WBT IS READ FROM PSYCHROMETRIC CHART CORRESPONDING TO GIVEN DBT & DPT.

APPENDIX A-1-6

AVERAGE MONTHLY TEMPERATURES (1975)

Time	NOVEMBER					DECEMBER				
	DBT		DPT		WBT	DBT		DPT		WBT
	°C	°F	°C	°F	°F	°C	°F	°C	°F	°F
1am	10.0	50.0	5.4	41.7	45.8	4.5	40.1	-0.9	30.4	36.0
3am	9.0	48.2	5.3	41.7	45.0	3.7	38.7	-1.0	30.2	34.9
5am	8.1	46.6	4.8	40.6	43.8	3.6	38.5	-1.0	30.2	34.7
7 am	8.0	46.4	4.9	40.8	43.5	3.1	37.6	-1.2	29.8	34.0
8 am	8.3	46.9	5.1	41.2	44.0	3.1	37.6	-1.4	29.5	33.9
10 am	12.0	53.6	6.3	43.3	48.2	5.6	42.1	-0.6	30.9	37.2
12 noon	15.3	59.5	6.6	43.9	56.0	8.3	46.9	-0.4	31.3	40.2
2 pm	16.7	62.1	6.2	43.2	51.8	10.0	50.0	-0.2	31.6	41.5
4 pm	16.6	61.9	6.3	43.3	51.6	10.2	50.4	-0.6	30.9	41.5
6 pm	14.1	57.4	6.4	43.5	50.0	7.7	45.9	-0.8	30.6	39.2
8 pm	12.3	54.1	6.4	43.5	48.5	6.5	43.7	-1.1	30.0	37.5
10 pm	11.4	52.5	6.2	43.2	47.5	5.3	41.5	-1.2	29.8	36.2
12 midnight	10.3	50.5	5.5	41.9	46.0	4.8	40.6	-0.8	30.6	36.2

DBT = DRY BULB TEMPERATURE

DPT = DEW POINT TEMPERATURE

WBT = WET BULB TEMPERATURE

°C = DEGREES CELCIUS (FROM WEATHER TAPE)

°F = DEGREES FAHRENHEIT (CONVERTED FROM °C)

WBT IS READ FROM PSYCHROMETRIC CHART CORRESPONDING TO GIVEN DBT & DPT.

APPENDIX A2

APPENDIX A-2

DISPLACEMENT

(Ref. Section 2.2)

APPENDIX A2

DISPLACEMENT

Displacements were calculated for a number of other collector/field options. The methodology for calculating the displacement was basically the same as that described for the baseline system in Section 2.2 of this report. Figures A2-1 through A2-5 present field performance data for several combinations of collectors and field orientations and spacing. These figures compare the initial collector/field options which were limited to two types of collectors: parabolic trough and linear fresnel lens. Field performance was determined for several different parabolic collector orientations (North-South and East-West horizontal and North-South tilted at latitude) and two different packing factors (ground cover ratio - GCR) for the North-South tilted and the fresnel. All of these collector/field options were limited to 17,199 m^2 (4.25 acres) field size, as compared to the 14,694 m^2 (3.631 acre) field in the baseline.

The facility demand was based on an initial estimate of demand as shown in Table A2-1 This demand differs somewhat from the baseline demand in that it does not utilize an economizer cycle during the spring, fall and winter seasons for reduction of air conditioning load. Also, shown in this table are the pertinent power conversion system parameters. This data also differs from the baseline in that the baseline power conversion meets all of the electrical demand by rejecting a portion of the cycle heat in an air cooled condenser while the initial system relied entirely on the process heat and absorption cooling as a condenser load. Thus, less than 100 percent of the electric load was produced as noted in the table. For this reason, the calculation of facility demand used in determining displacement differed slightly for the baseline case as follows:

Baseline

demand = Power conversion load x 16 hrs

Initial

demand = Power conversion load x 16 hrs + nonproduced electricity for 16 hrs

DAC 7/5/77 7/6/77 7/11/77

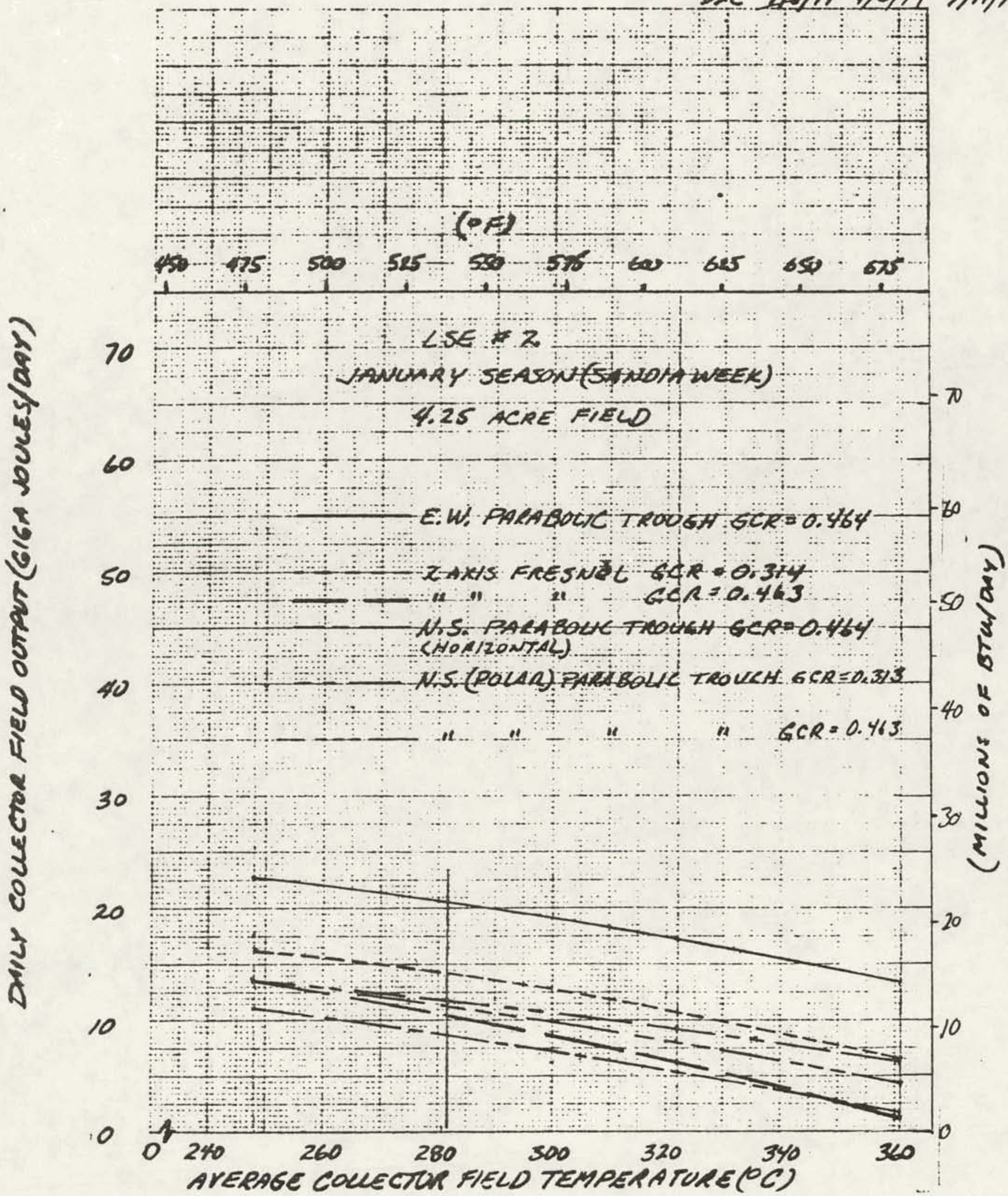


FIG. A2-1

DAC 7/5/77 7/6/77 7/11/77

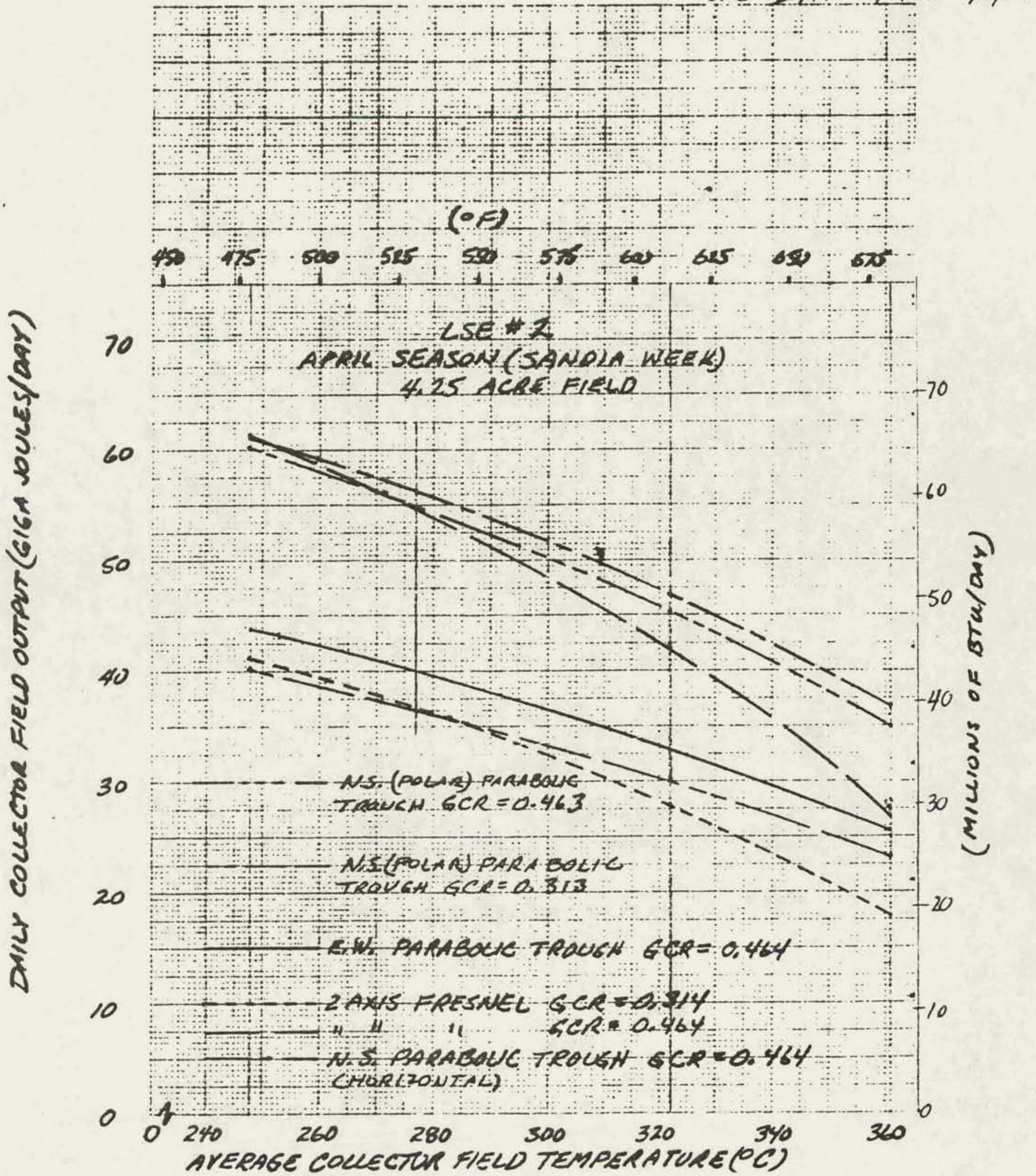


FIG. A2-2

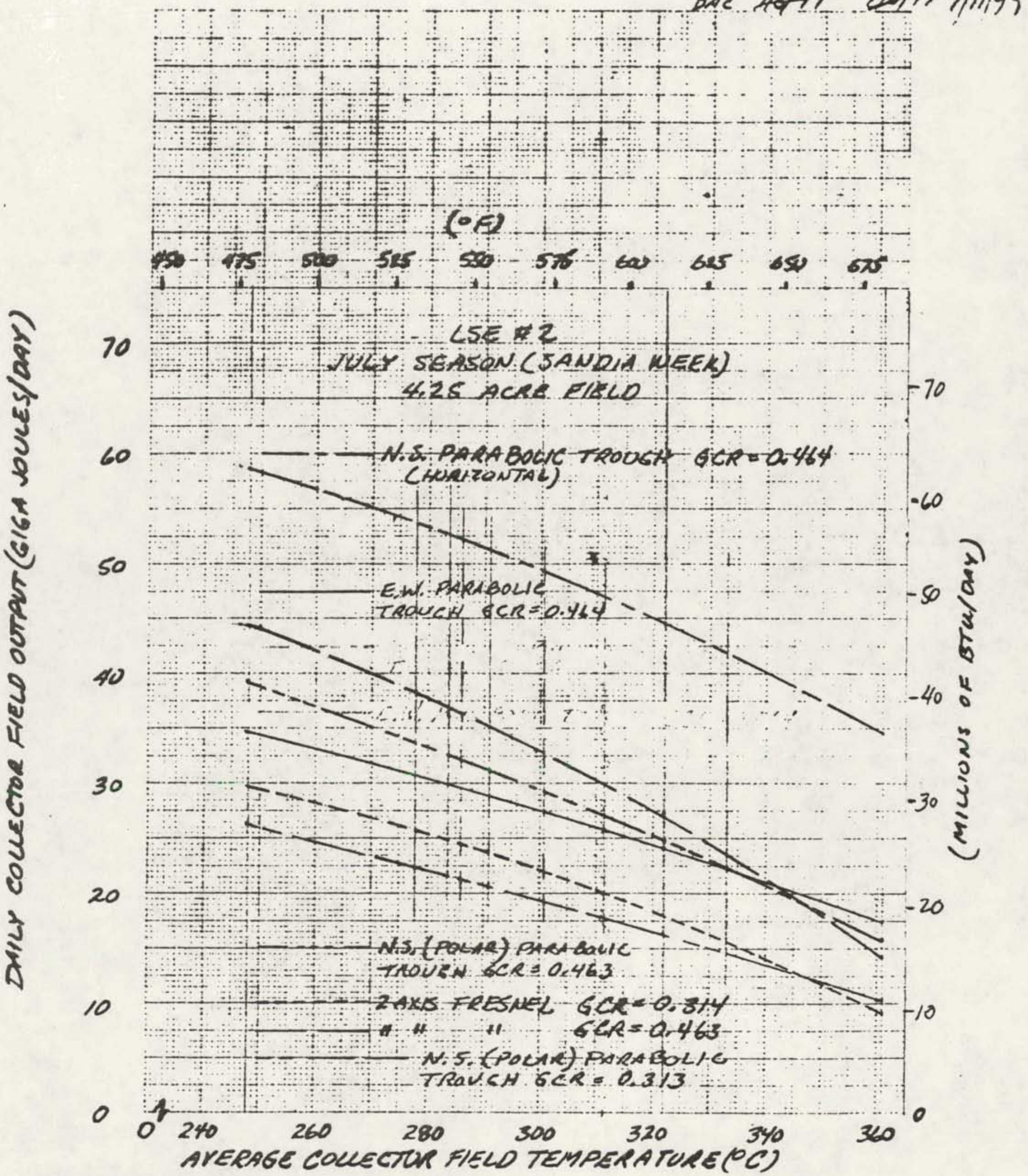

(°F)
450 475 500 525 550 575 600 625 650 675
LSE #2
JULY SEASON (SANDIA WEEK)
4.25 ACRE FIELD
N.S. PARABOLIC TROUGH GCR=0.464 (HORIZONTAL)
E.W. PARABOLIC TROUGH GCR=0.464
N.S. (POLAR) PARABOLIC TROUGH GCR=0.463
2 AXIS FRESNEL GCR=0.314
" " " GCR=0.463
N.S. (POLAR) PARABOLIC TROUGH GCR=0.313
DAILY COLLECTOR FIELD OUTPUT (GIGA JOULES/DAY)
70
60
50
40
30
20
10
0
(MILLIONS OF BTU/DAY)
70
60
50
40
30
20
10
0
0 240 260 280 300 320 340 360
AVERAGE COLLECTOR FIELD TEMPERATURE (°C)

FIG. A2-3

DAC 7/8/77 7/6/77 7/11/77

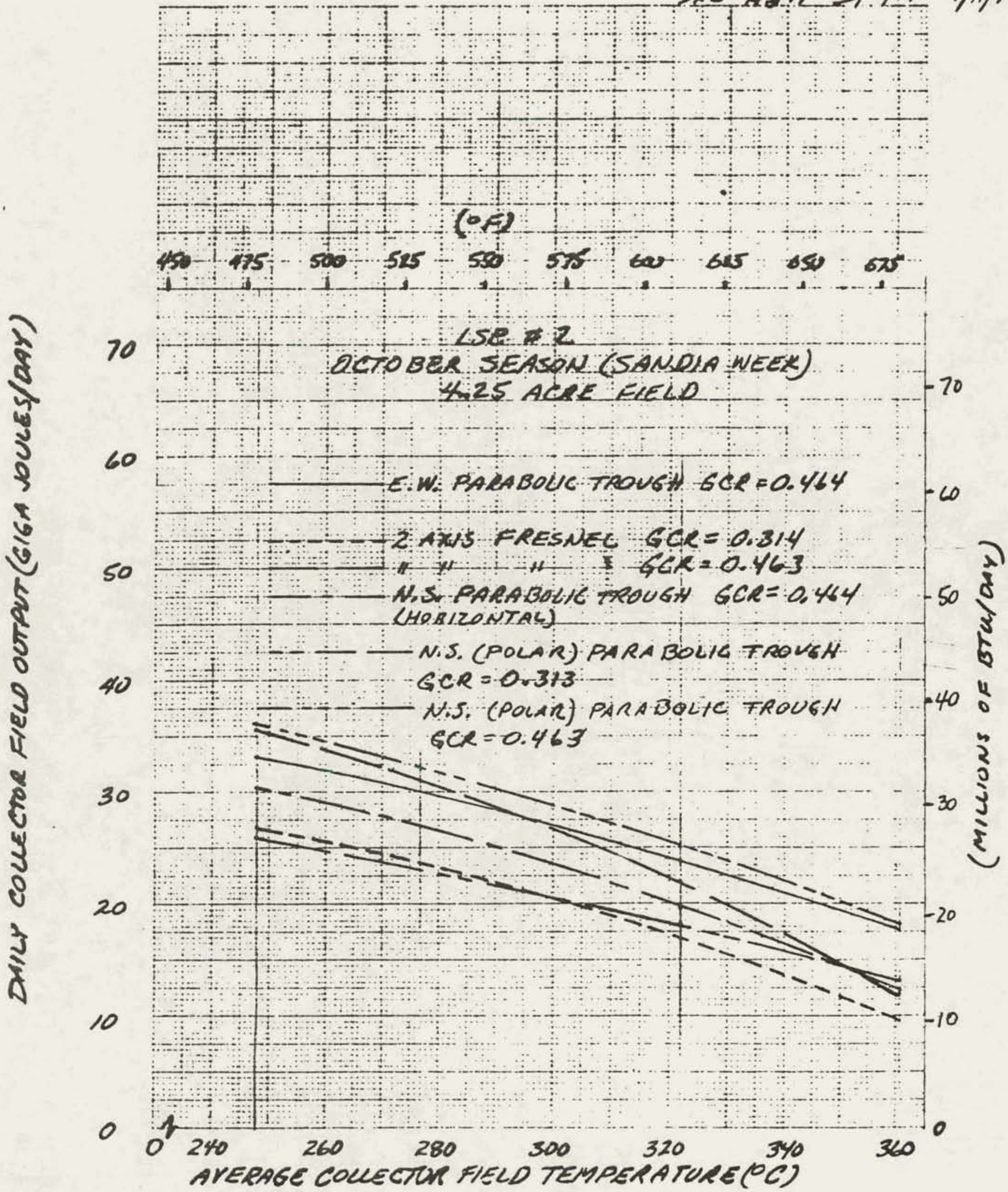


FIG A2-4

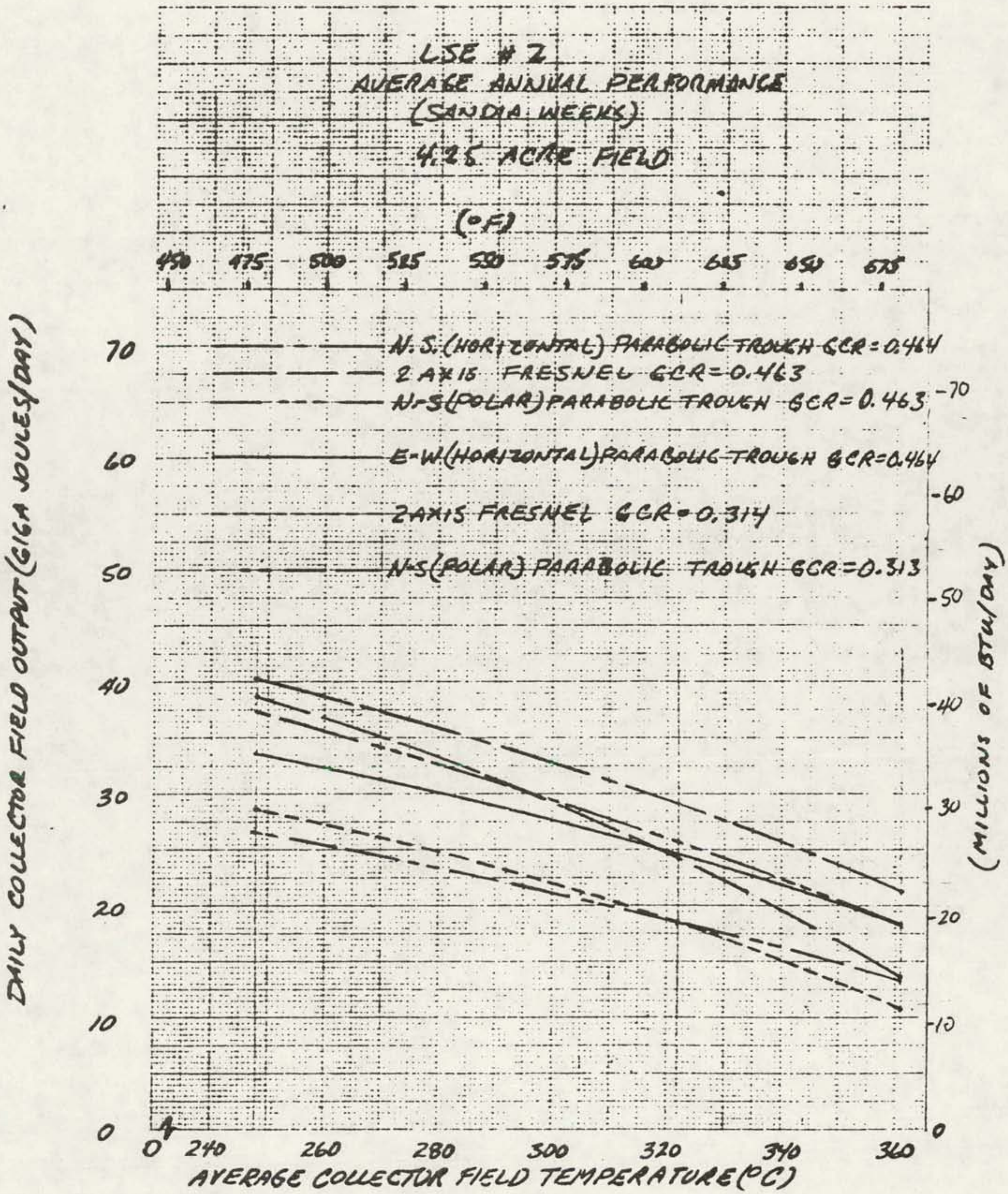

LSE # 2
AVERAGE ANNUAL PERFORMANCE
(SANDIA WEEKS)
4.25 ACRE FIELD
(°F)
450 475 500 525 550 575 600 625 650 675
N.S. (HORIZONTAL) PARABOLIC TROUGH GCR=0.464
2 AXIS FRESNEL GCR=0.463
N-S (POLAR) PARABOLIC TROUGH GCR=0.463
E-W (HORIZONTAL) PARABOLIC TROUGH GCR=0.464
2AXIS FRESNEL GCR=0.314
N-S (POLAR) PARABOLIC TROUGH GCR=0.313
DAILY COLLECTOR FIELD OUTPUT (GIGA JOULES/DAY)
0 10 20 30 40 50 60 70
(MILLIONS OF BTU/DAY)
0 -10 -20 -30 -40 -50 -60 -70
0 240 260 280 300 320 340 360
AVERAGE COLLECTOR FIELD TEMPERATURE (°C)

FIG A2-5

TABLE A2-1

INITIAL

SIZING LOADS

FACILITY	JULY	OCT-APRIL	DEC
ELECTRICAL	383.4 KW	383.4 KW	383.4 KW
NIGHT HEATING	0	31.21 KW	97.55 KW
		(106,500 BTU/HR)	(332,900 BTU/HR)
AIR CONDITIONING	220.05 TONS	213 TONS	65.57 TONS
PROCESS STEAM	0.2772 KG/SEC @ 786,000 PA (2,200 LB/HR @ 114 PSIA)		
POWER CONVERSION			
DAILY LOADS - GIGA JOULES	125.92	124.73	75.65
(10^6 BTU)	(119.36)	(118.24)	(71.71)
AVERAGE COLLECTOR TEMPERATURE °C/(°F)	281.7 (539.1)	277 (530.6)	277 (530.6)
PERCENT ELECTRICAL DEMAND FURNISHED	51.6	96.5	96.7

where nonproduced electricity equals

(1- percent electricity produced) x ELECTRICITY required

in consistent energy units

The seasonal and annual displacement for each of the initial collection/field options is shown in Figures A2-6 through A2-11. The electrical and process-absorption heating displacements differ numerically from the overall seasonal displacements because of the power conversion system's varying electrical output (always less than facility electrical demand). As in the baseline, the annual displacement is the numerical average of the seasonal displacements. The displacement, along with the required fuel oil energy and purchased electricity to bring the total output up to the facility demand, is summarized in Table A2-2. On the basis of this initial comparison, the N-S horizontal parabolic trough was selected as the baseline collector/field system.

Two additional collectors (the SLATS and the fresnel rotary array) were analyzed. The SLATS performance was determined using two different optical efficiencies. The rotary array was analyzed at two different ground cover ratios (GCR). The performance of these collector/field options is shown in Figures A2-12 through A2-16. Also shown, for comparison, is the performance of the baseline collector field (N-S horizontal parabolic trough GCR - 0.464). The displacement for these collector/field options are summarized in Table A2-3 along with the fossil fuel energy and purchased electricity. These displacements are also based on the initial estimates of facility demand and the power conversion system parameters shown in Table A2-1.

LSE #2 STES #1 SOLAR DISPLACEMENT

EAST-WEST-HORIZONTAL PARABOLIC TROUGH GCR = 0.464

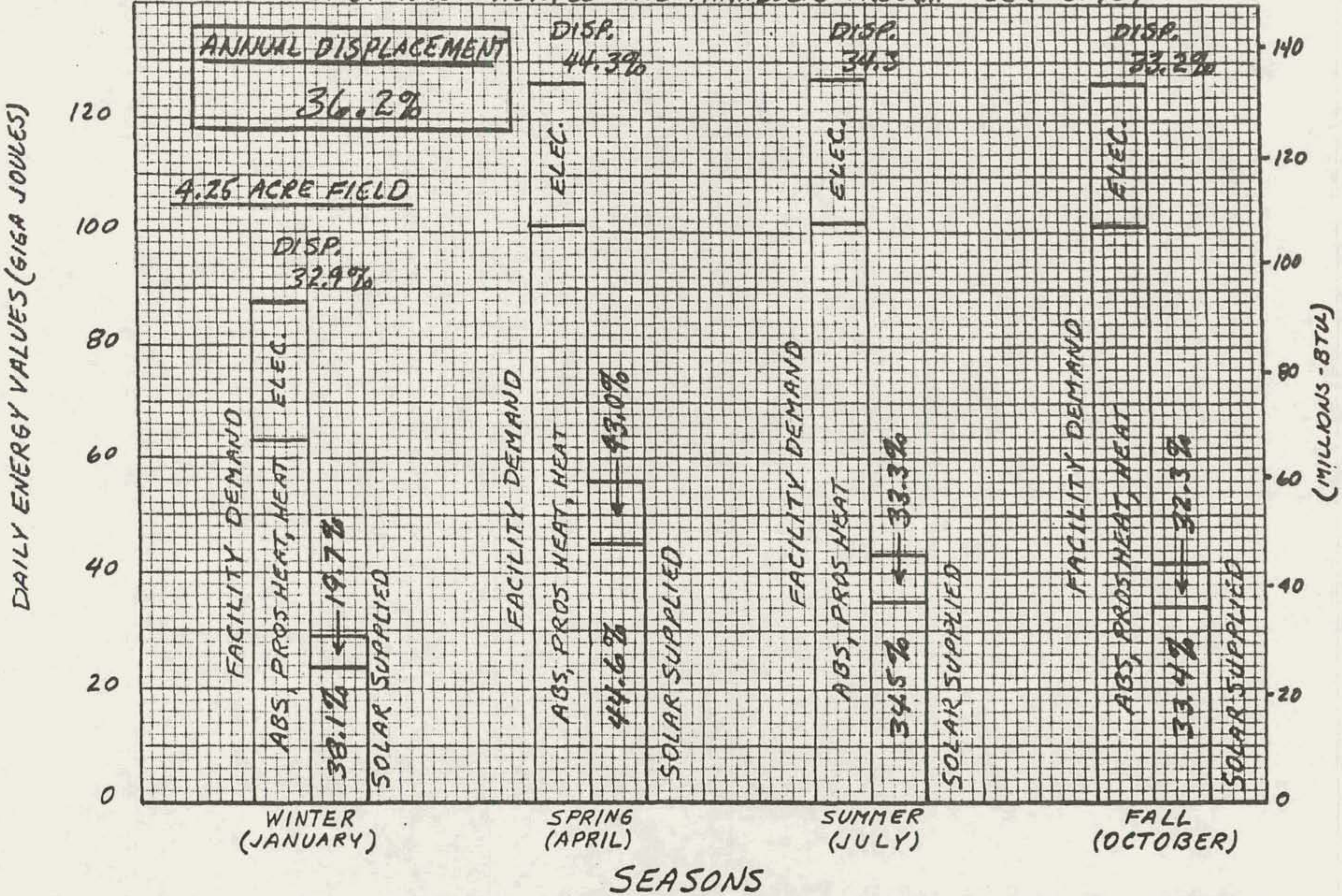


FIG. A2-6

LSE #2 STES #1 SOLAR DISPLACEMENT

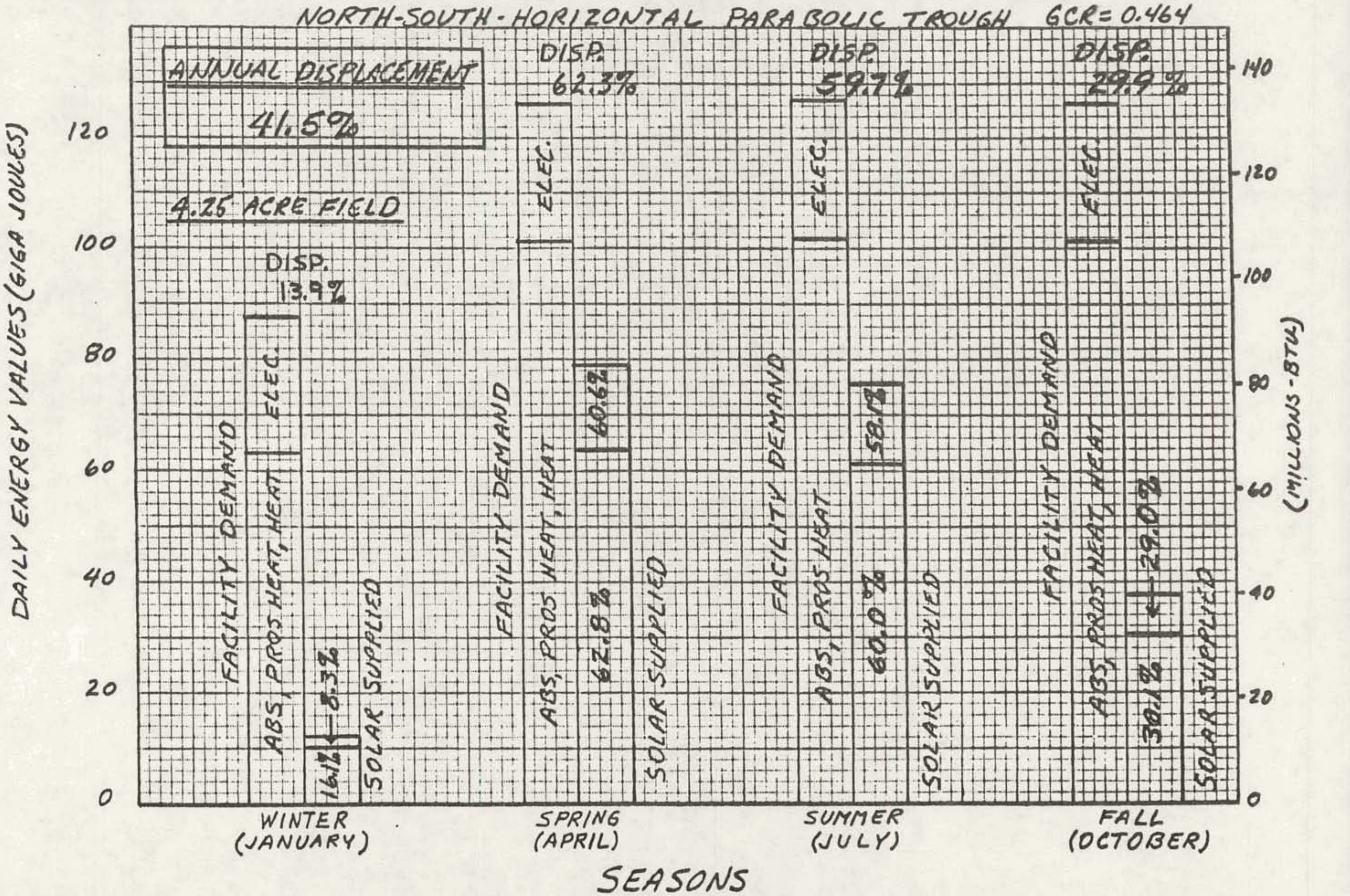


FIG. A2-7

LSE #2 STES #1 SOLAR DISPLACEMENT

NORTH-SOUTH-POLAR PARABOLIC TROUGH GCR = 0.463

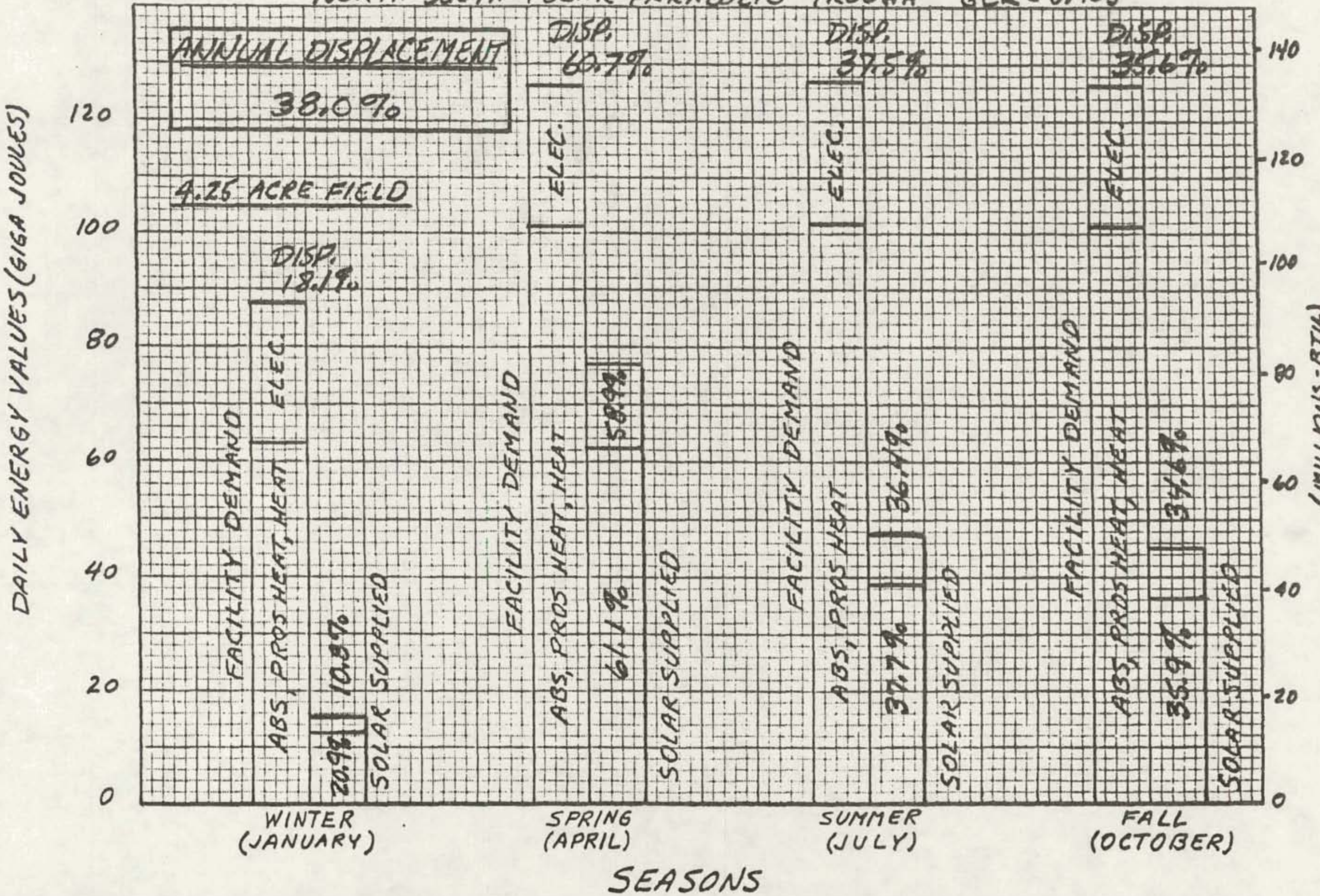


FIG. A2-8

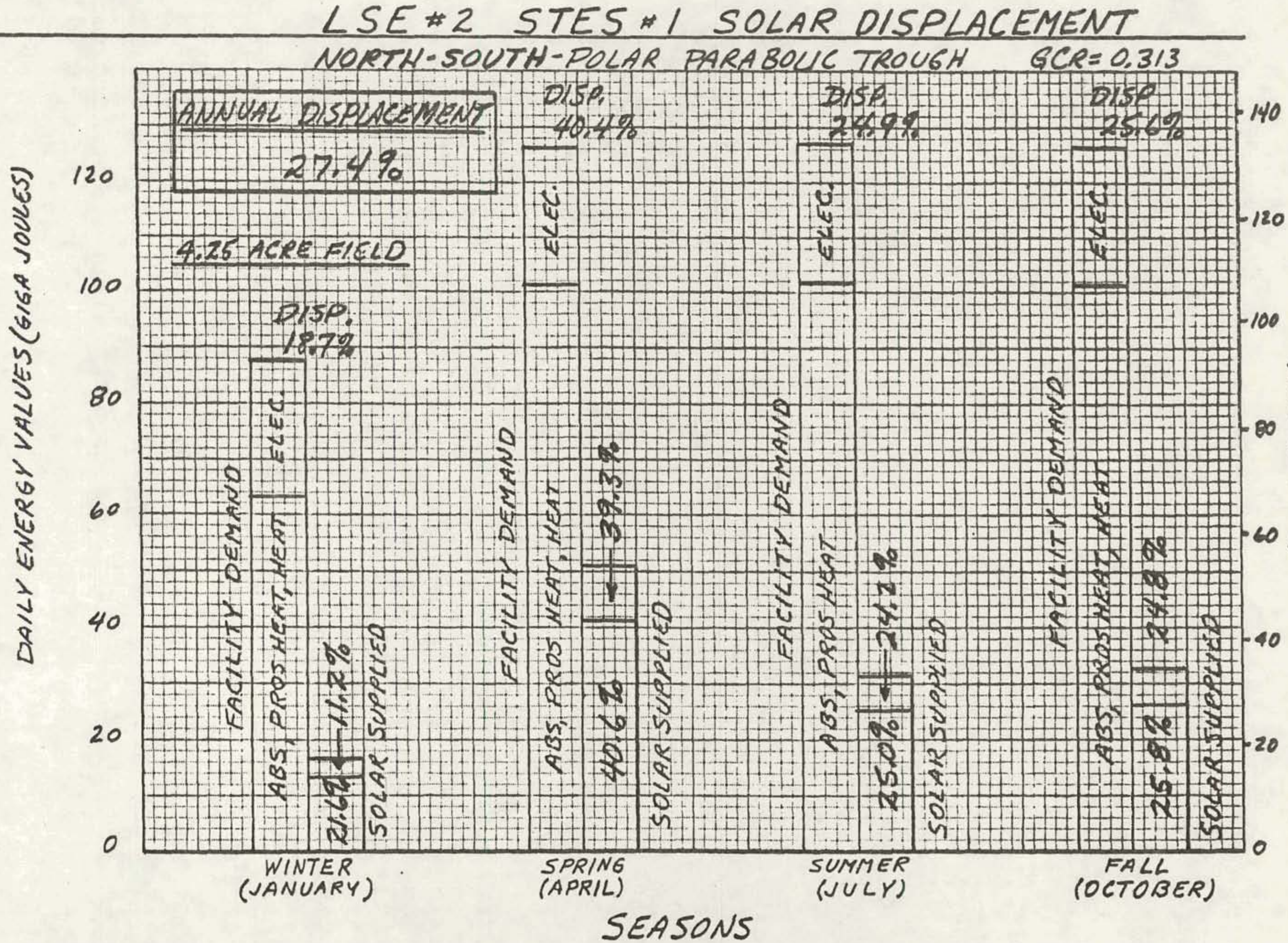

LSE #2 STES #1 SOLAR DISPLACEMENT
NORTH-SOUTH-POLAR PARABOLIC TROUGH GCR= 0.313
ANNUAL DISPLACEMENT
27.4%
4.25 ACRE FIELD
DAILY ENERGY VALUES (GIGA JOULES)
(MILLIONS - BTU)
DISP. 18.7%
DISP. 40.4%
DISP. 24.9%
DISP 25.6%
FACILITY DEMAND
ABS, PROS HEAT, HEAT
ELEC.
SOLAR SUPPLIED
21.6%
11.7%
40.6%
39.3%
25.0%
24.1%
25.8%
24.8%
WINTER (JANUARY)
SPRING (APRIL)
SUMMER (JULY)
FALL (OCTOBER)
SEASONS

FIG. A2-9

LSE #2 STES #1 SOLAR DISPLACEMENT

2-AXIS FRESNEL GCR=0.463

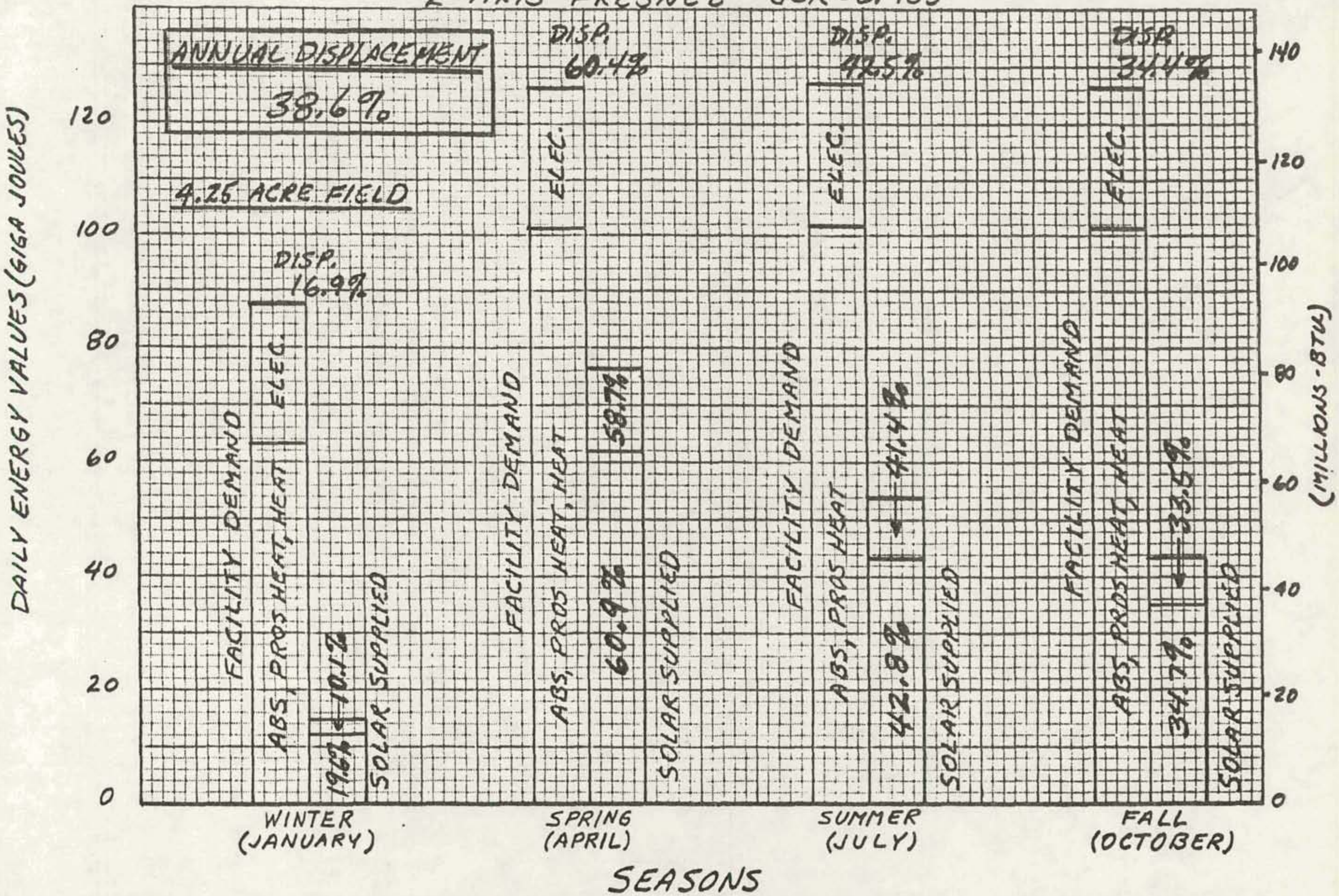
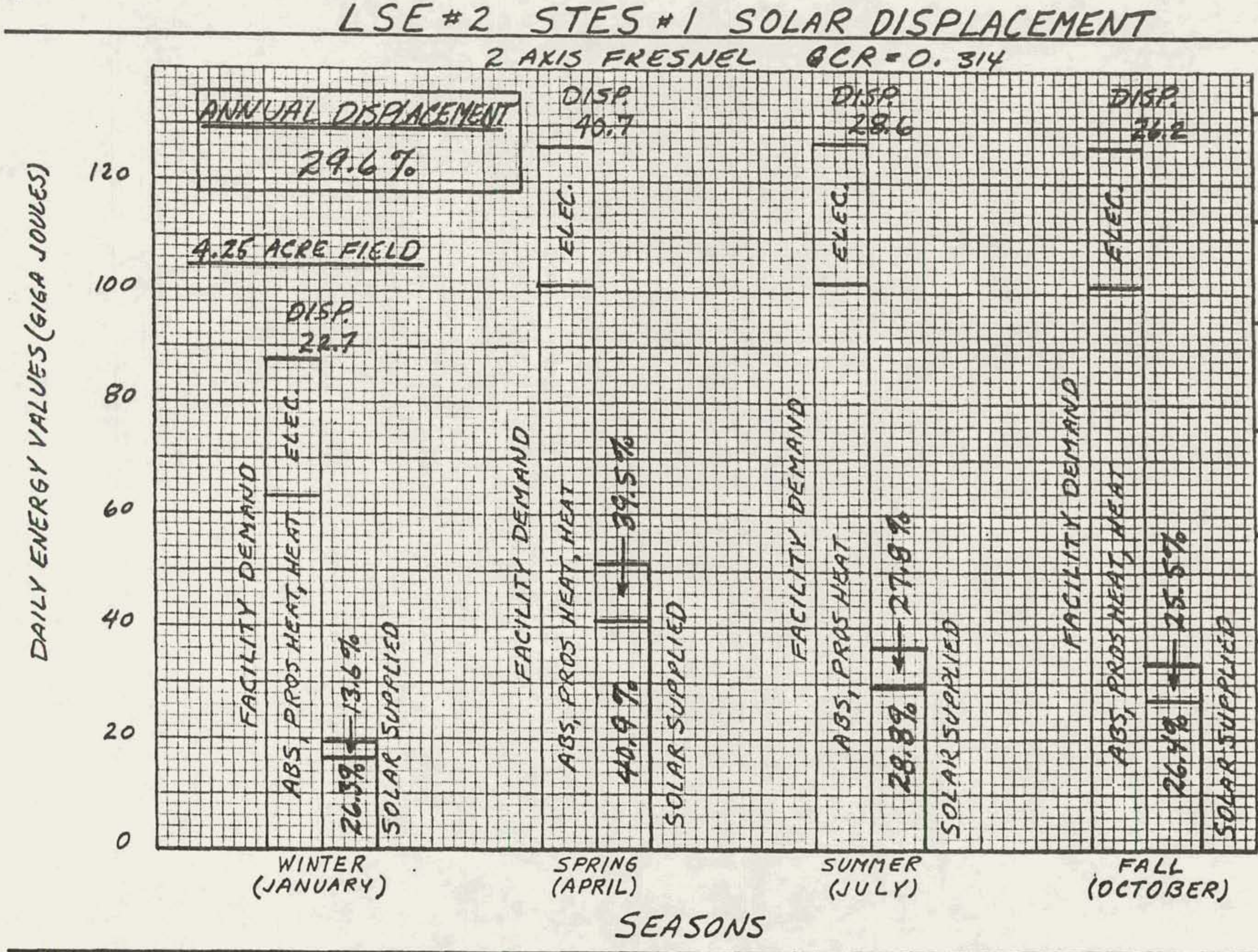


FIG A2-10



LSE #2 STES #1 SOLAR DISPLACEMENT
2 AXIS FRESNEL GCR = 0.314
ANNUAL DISPLACEMENT
29.6 %
4.25 ACRE FIELD
DISP. 22.7
DISP. 40.7
DISP. 28.6
DISP. 26.2
FACILITY DEMAND
ELEC.
ABS, PROS HEAT, HEAT
SOLAR SUPPLIED
13.6 %
26.3 %
39.5 %
40.9 %
27.8 %
28.8 %
25.5 %
26.4 %
DAILY ENERGY VALUES (GIGA JOULES)
(MILLIONS - BTU)
0
20
40
60
80
100
120
140
WINTER (JANUARY)
SPRING (APRIL)
SUMMER (JULY)
FALL (OCTOBER)
SEASONS

FIG A2-11

TABLE A2-2

INITIAL

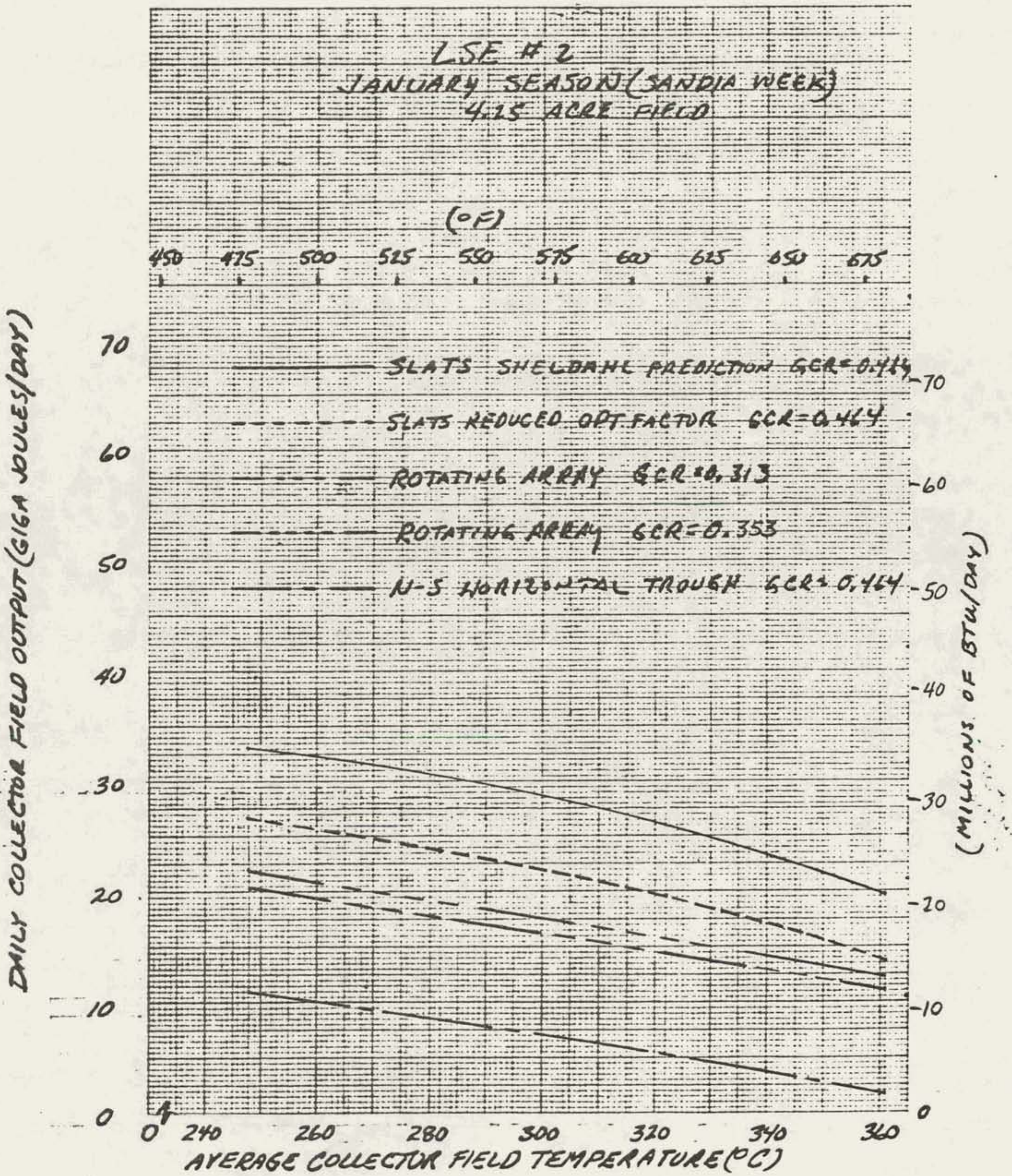
SOLAR DISPLACEMENT SUMMARY

COLLECTOR FIELD	ANNUAL DISPLACEMENT	SEASONAL DISPLACEMENT (PERCENT OF FACILITY DEMAND)			
		WINTER	SPRING	SUMMER	FALL
1. E-W HORIZONTAL PARABOLIC TROUGH GCR = 0.464	22,953[1] 234[2] 36.2[3]	3,803 193 32.9	5,654 14 44.3	6,704 13 34.3	6,792 14 33.2
2. N-S HORIZONTAL PARABOLIC TROUGH GCR = 0.464	20,178 234 41.5	5,157 193 13.9	3,800 14 62.3	4,088 13 59.7	7,133 14 29.9
3. N-S POLAR PARABOLIC TROUGH GCR = 0.463	21,747 234 38.0	4,861 193 18.1	3,971 14 60.7	6,374 13 37.5	6,541 14 35.6
4. N-S POLAR PARABOLIC TROUGH GCR = 0.313	26,116 234 27.4	4,816 193 18.7	6,052 14 40.4	7,671 13 24.9	7,577 14 25.6
5. TWO AXIS NORTH-SOUTH FRESNEL GCR = 0.463	21,452 234 38.6	4,941 193 16.9	3,993 14 60.4	5,851 13 42.5	6,667 14 34.4
6. TWO AXIS NORTH-SOUTH FRESNEL GCR = 0.313	25,341 234 29.6	4,531 193 22.7	6,018 14 40.7	7,284 13 28.6	7,508 14 26.2

[1] Fossil fuel energy in giga Joules (80% heater efficiency) 1 BBL #2 fuel oil contains 6.145 giga Joules

[2] Purchased electricity (MW-HR)

[3] Solar displacement


LSE # 2
JANUARY SEASON (SANDIA WEEK)
4.25 ACRE FIELD
(°F)
450 475 500 525 550 575 600 625 650 675
SLATS SHELBAHL PREDICTION GCR=0.464
SLATS REDUCED OPT FACTOR GCR=0.464
ROTATING ARRAY GCR=0.313
ROTATING ARRAY GCR=0.353
N-S HORIZONTAL TROUGH GCR=0.464
DAILY COLLECTOR FIELD OUTPUT (GIGA JOULES/DAY)
(MILLIONS OF BTU/DAY)
0 10 20 30 40 50 60 70
0 240 260 280 300 320 340 360
AVERAGE COLLECTOR FIELD TEMPERATURE (°C)
FIG. A2-12

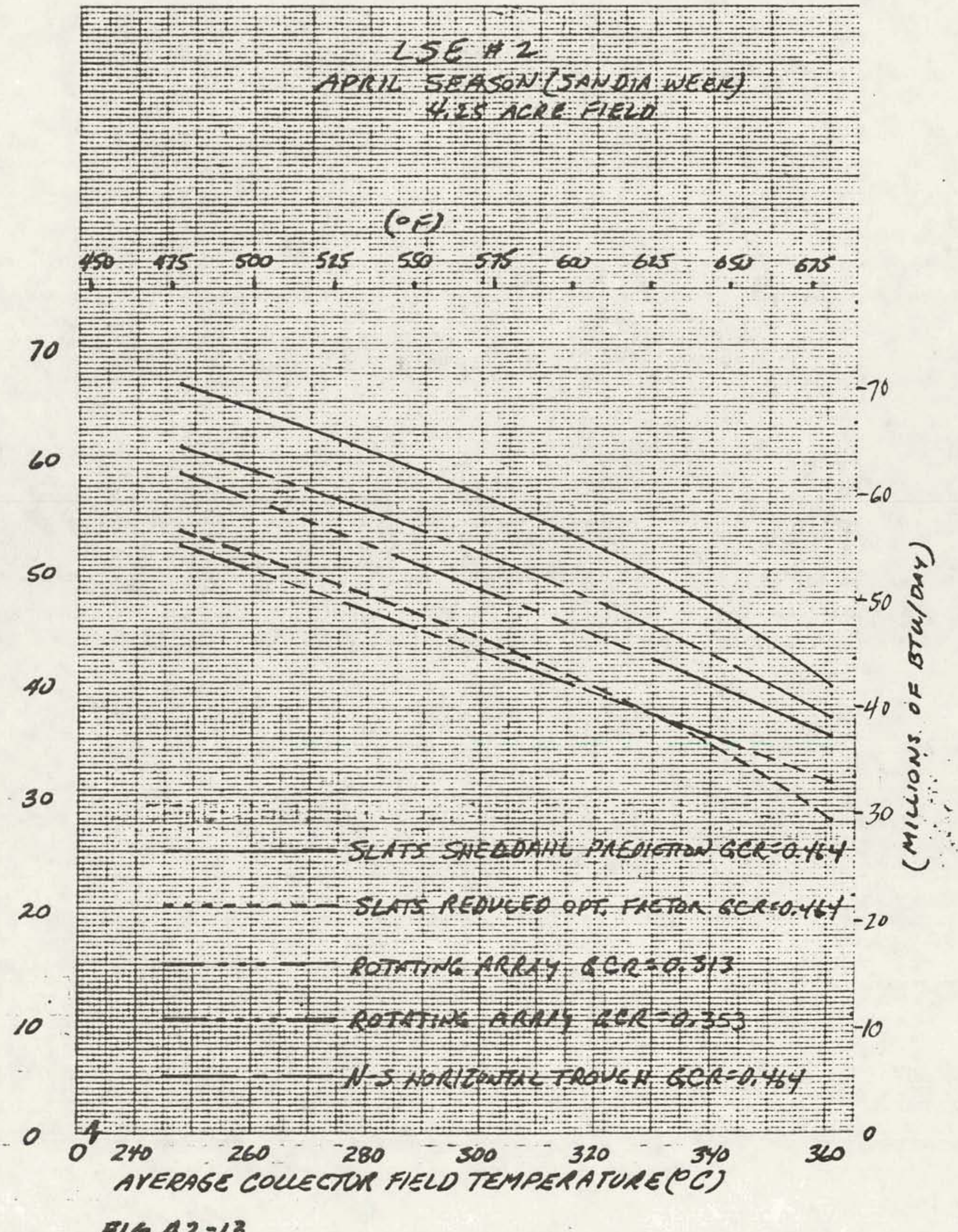

LSE #2
APRIL SEASON (SANDIA WEEK)
4.25 ACRE FIELD
(°F)
450 475 500 525 550 575 600 625 650 675
DAILY COLLECTOR FIELD OUTPUT (GIGA JOULES/DAY)
70 60 50 40 30 20 10 0
(MILLIONS OF BTU/DAY)
70 60 50 40 30 20 10 0
0 240 260 280 300 320 340 360
AVERAGE COLLECTOR FIELD TEMPERATURE (°C)
SLATS SHEDDAHL PREDICTION GCR=0.464
SLATS REDUCED OPT. FACTOR GCR=0.464
ROTATING ARRAY GCR=0.313
ROTATING ARRAY GCR=0.353
N-S HORIZONTAL TROUGH GCR=0.464

FIG. A2-13

DOUGLAS

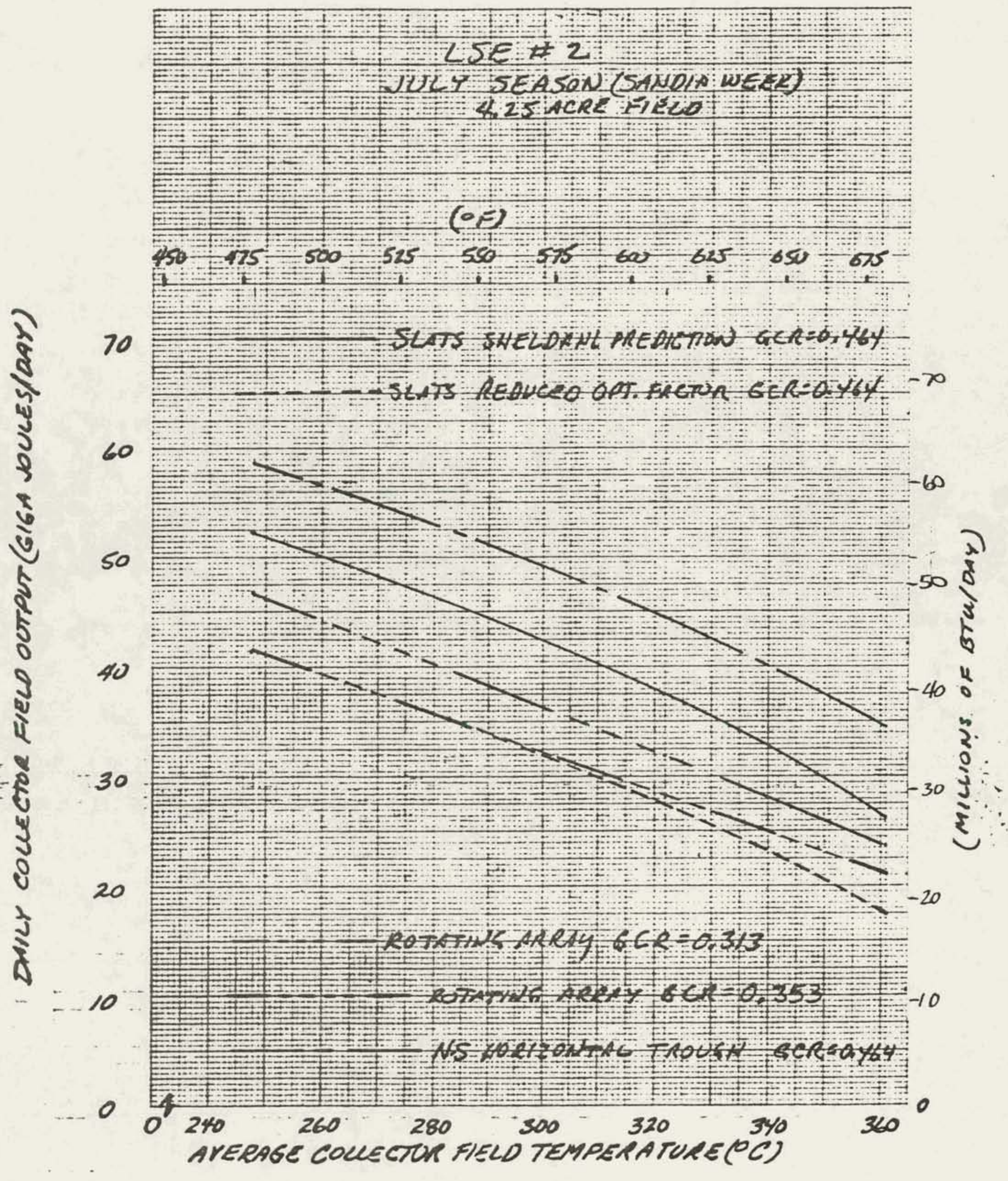


FIG A2-14

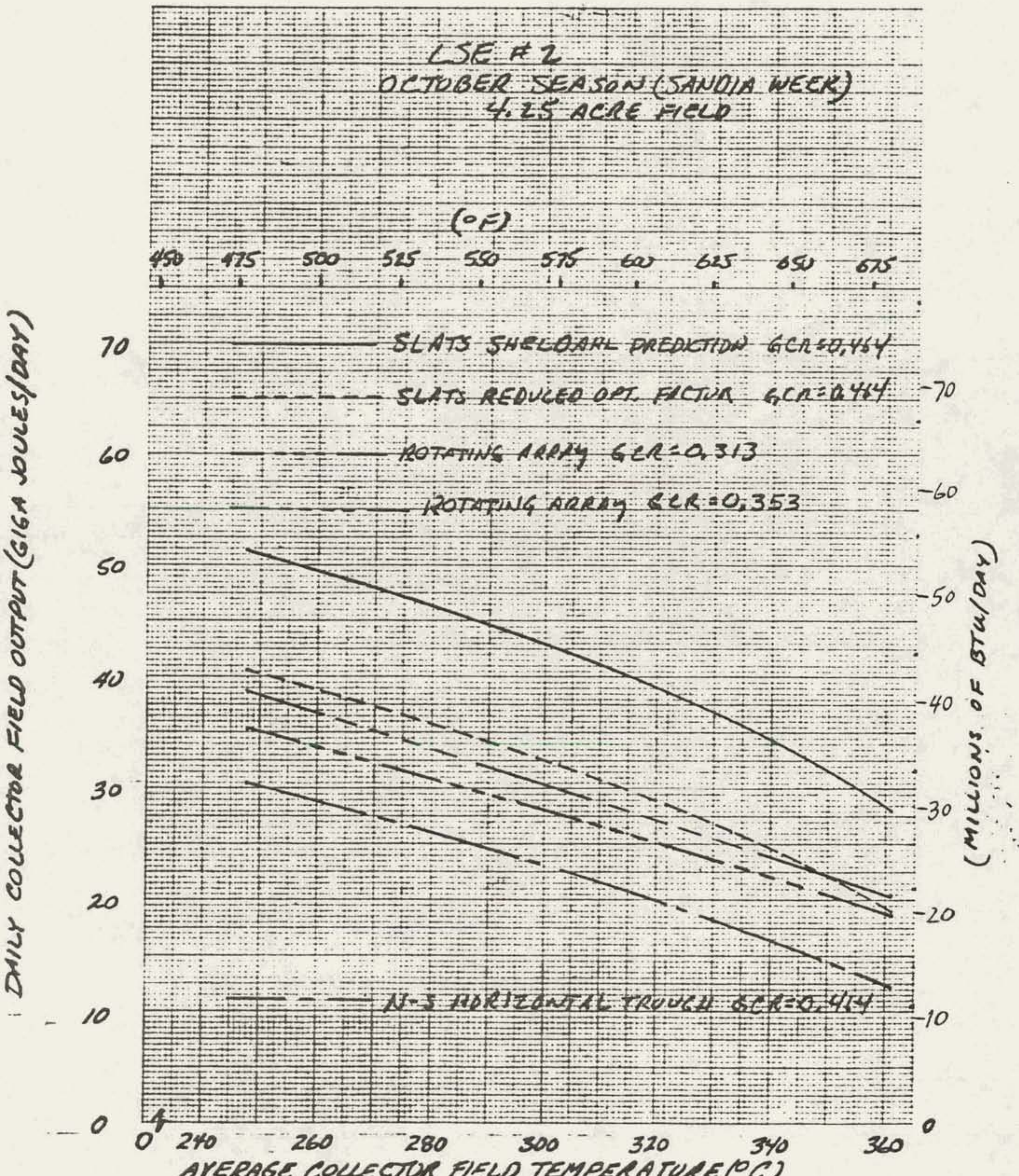
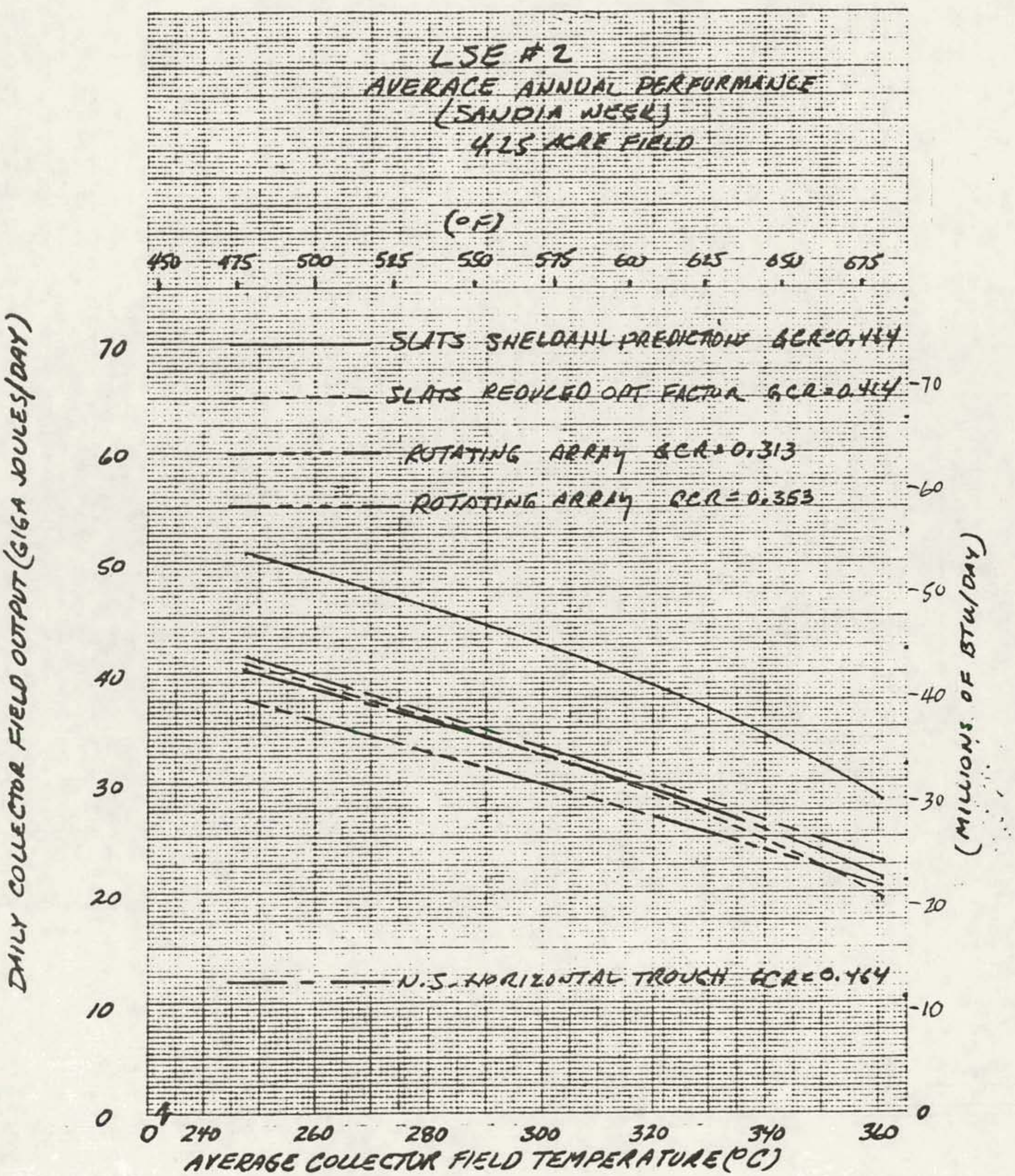

LSE #2
OCTOBER SEASON (SANDIA WEEK)
4.25 ACRE FIELD
(°F)
450 475 500 525 550 575 600 625 650 675
SLATS SHELDAHL PREDICTION GCR=0.464
SLATS REDUCED OPT. FACTOR GCR=0.464
ROTATING ARRAY GCR=0.313
ROTATING ARRAY GCR=0.353
N-S HORIZONTAL TROUGH GCR=0.414
DAILY COLLECTOR FIELD OUTPUT (GIGA JOULES/DAY)
0 10 20 30 40 50 60 70
(MILLIONS OF BTU/DAY)
0 10 20 30 40 50 60 70
0 240 260 280 300 320 340 360
AVERAGE COLLECTOR FIELD TEMPERATURE (°C)

FIG. A2-15



LSE #2
AVERAGE ANNUAL PERFORMANCE
(SANDIA WEEK)
4.25 ACRE FIELD
(°F)
450 475 500 525 550 575 600 625 650 675
SLATS SHELDAHL PREDICTION GCR=0.464
SLATS REDUCED OPT FACTOR GCR=0.464
ROTATING ARRAY GCR=0.313
ROTATING ARRAY GCR=0.353
N.S. HORIZONTAL TROUGH GCR=0.464
DAILY COLLECTOR FIELD OUTPUT (GIGA JOULES/DAY)
0 10 20 30 40 50 60 70
(MILLIONS OF BTU/DAY)
0 10 20 30 40 50 60 70
0 240 260 280 300 320 340 360
AVERAGE COLLECTOR FIELD TEMPERATURE (°C)

FIG A2-16

TABLE A2-3

ALTERNATE COLLECTORS

SOLAR DISPLACEMENT SUMMARY
(4.25 ACRE FIELD)

PERCENT OF FACILITY DEMAND

COLLECTOR FIELD	ANNUAL DISPLACEMENT		SEASONAL DISPLACEMENT WINTER		SPRING		SUMMER		FALL	
1. N-S Horizontal Trough GCR = 0.464	41.5		13.9		62.3		59.7		29.9	
	20,178[1]	234[2]	5,157	193	3,800	14	4,088	13	7,133	14
2. Rotating Array GCR = 0.313	38.8		28.1		52.0		40.1		34.8	
	21,736	234	4,145	193	4,858	14	6,101	13	6,632	14
3. Rotating Array GCR = .353	43.0		30.4		58.7		45.3		37.6	
	20,062	234	3,985	193	4,175	14	5,566	13	6,336	14
4. SLATS Reduced Opt. Factor GCR = 0.464	42.9		37.8		53.6		40.1		40.1	
	20,343	234	3,457	193	4,699	14	6,101	13	6,086	14
(5. SLATS Sheldahl Predictions GCR = 0.464)	55.1		48.9		67.8		51.9		51.8	
	15,675	234	2,666	193	3,243	14	4,884	13	4,882	14

Purchased fossil fuel and electricity to meet portion of facility demand not supplied by solar.

1. Fossil fuel in giga Joules (assumes 80 percent heater η) 1BBL #2 fuel oil contains 6.145 giga Joules
2. Electricity in MW-hr

APPENDIX A3

APPENDIX A-3

UTILITY RATES

(Ref. Section 2.2)

GEORGIA POWER COMPANY

SCHEDULE GS-3

kWh Range	Correction Factor		¢/kWh
0 - 25	$ 3.05	+	.00¢, plus F.A.
26 - 100	1.30	+	7.0 ¢, plus F.A.
101 - 1500	3.12	+	5.18¢, plus F.A.
1501 - 10000	15.87	+	4.33¢, plus F.A.
10001 - 200000	148.87	+	3.0 ¢, plus F.A.
200001 - Over	1148.87	+	2.5 ¢, plus F.A.

Add Sales Tax and Excess Reactive Charge of $0.20/RKVA When Applicable

Over 200 Hours Use

kW Range	Correction Factor		$/kW		¢/kWh
5 - 7	$ 3.12	+	$8.64	+	.86¢, plus F.A.
8 - 50	15.87	+	6.94	+	.86¢, plus F.A.
51 - 1000	148.87	+	4.28	+	.86¢, plus F.A.
1001 - Over	1148.87	+	3.28	+	.86¢, plus F.A.

Add Sales Tax and Excess Reactive Charge of $0.20/RKVA When Applicable

Over 400 Hours Use

kW Range	Correction Factor		$/kW		¢/kWh
5 - 7	$ 3.12	+	$9.60	+	.62¢, plus F.A.
8 - 50	15.87	+	7.90	+	.62¢, plus F.A.
51 - 1000	148.87	+	5.24	+	.62¢, plus F.A.
1001 - Over	1148.87	+	4.24	+	.62¢, plus F.A.

Add Sales Tax and Excess Reactive Charge of $0.20/RKVA When Applicable

Minimum Bill: $3.05 per kW of billing demand less $12.20 plus fuel adjustment

GEORGIA POWER COMPANY

Schedule of Fuel Adjustment Rates (FA-1)

(Cents Per KWH)

1977

Sales Month	Fuel Adjustment Rate
January 1977	1.113
February 1977	1.048
March 1977	0.860
April 1977	0.932
May 1977	0.863
June 1977	0.698
July 1977	0.887
August 1977	1.056
September 1977	0.799*
October 1977	0.803*
November 1977	0.801*
December 1977	0.848*

*Estimated

E.T.H.
8/3/77

ATLANTA GAS LIGHT COMPANY

APPENDIX A-3c

N-2 SHORTCUT
(12-9-76)

T_A = AIR COND THERMS T_O = OTHER THERMS $T = T_A + T_O$ = TOTAL THERMA

I. GAS AIR COND. CUSTOMERS

A. IF TOTAL THERMS = 50 USE SCHEDULE II.

B. OCTOBER - APRIL (INCLUSIVE):

RANGE (T)	corr FACTOR		$/T		ADJ		ST
0-4	2.50	+	0	+	ADJ	+	ST
4-20	1.916	+	.146	+	ADJ	+	ST
20-600	2.736	+	.105	+	ADJ	+	ST
OVER 600	13.536	+	.087	+	ADJ	+	ST

C. MAY - SEPTEMBER (INCLUSIVE):

RANGE(TO)	CORR FACTOR		$/$T_O$		$/(50-$T_O$)		$/(T-50)		S/T_A		ADJ		ST
0-50	2.736	+	.105	+	.105	+	.076	+	0		ADJ	+	ST
50-600	2.736	+	.105	+	0	+	0	+	.076	+	ADJ	+	ST
OVER 600	13.536	+	.087	+	0	+	0	+	.076	+	ADJ	+	ST

II. NON GAS AIR COND CUSTOMERS

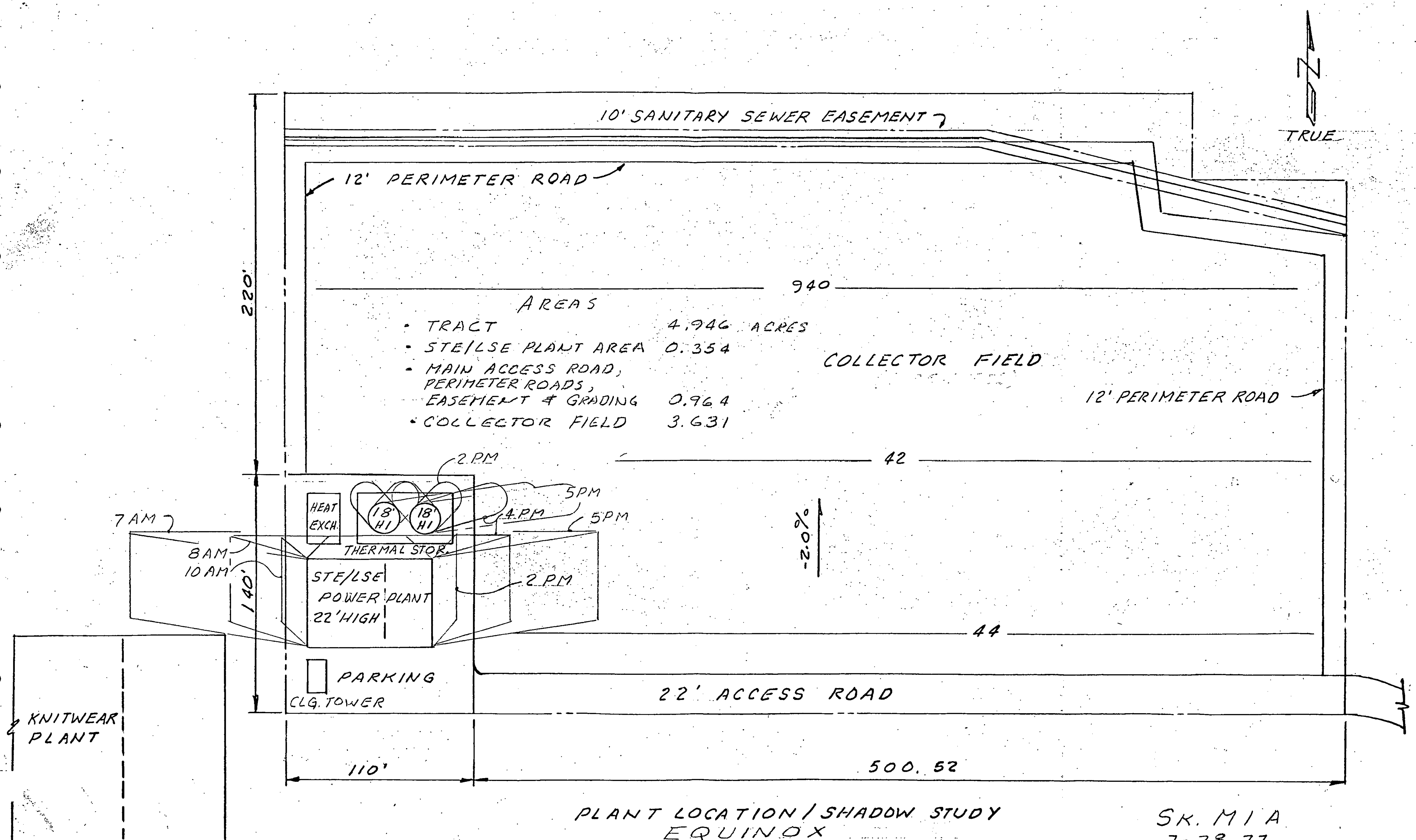
RANGE(T)	CORR FACTOR		$/T		ADJ		ST
0-4	2.50	+	0	+	ADJ	+	ST
4-20	1.916	+	.146	+	ADJ	+	ST
20-600	2.736	+	.105	+	ADJ	+	ST
OVER-600	13.536	+	.087	+	ADJ	+	ST

GAS USED FOR SPACE HEATING ONLY SHALL NOT AVERAGE LESS THAN $0.13 PER THERM PLUS GAS ADJUSTMENT PLUS SALES TAX.

APPENDIX B1

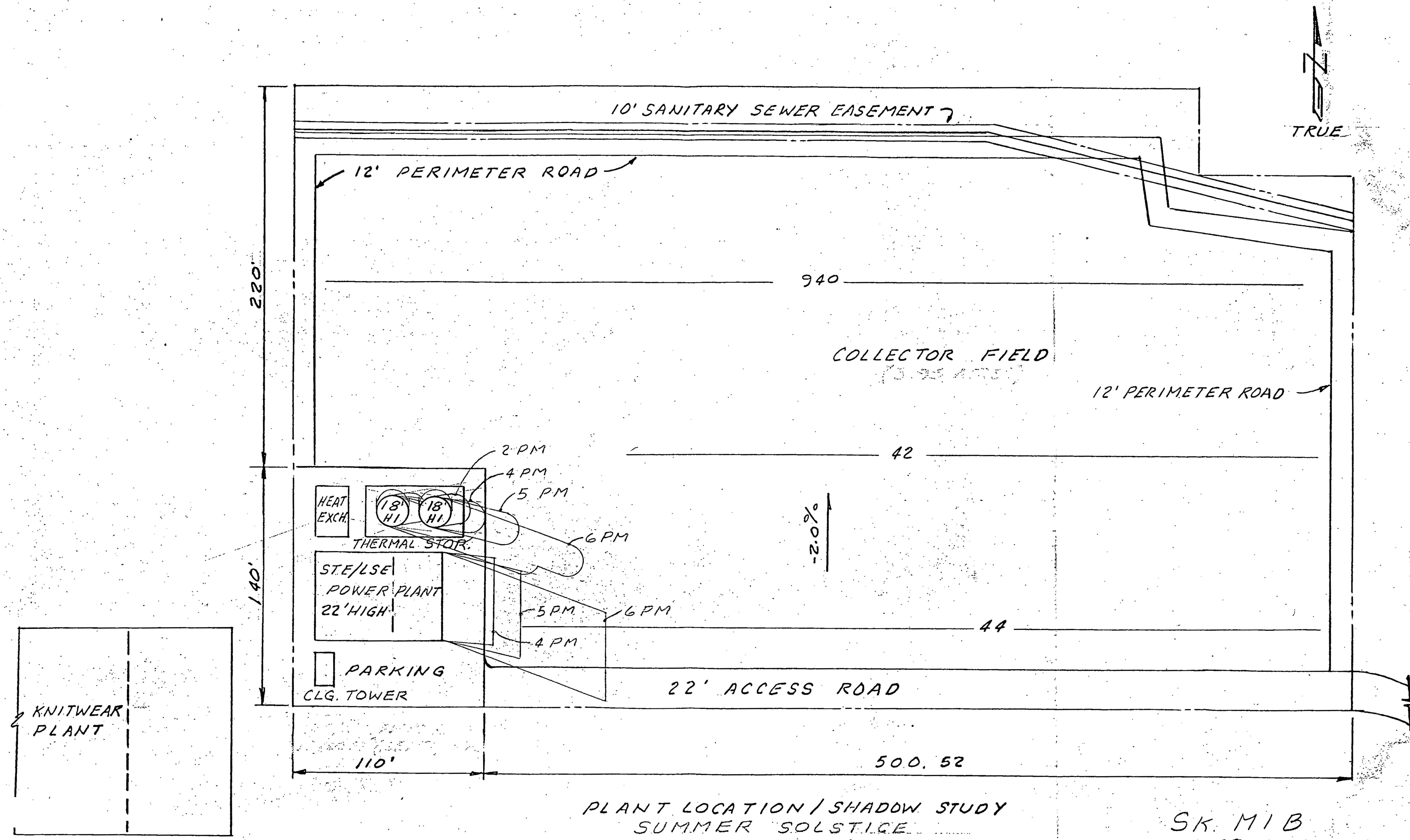
APPENDIX B1

DRAWINGS (SHADOW STUDIES)
(Ref. Section 3.1)



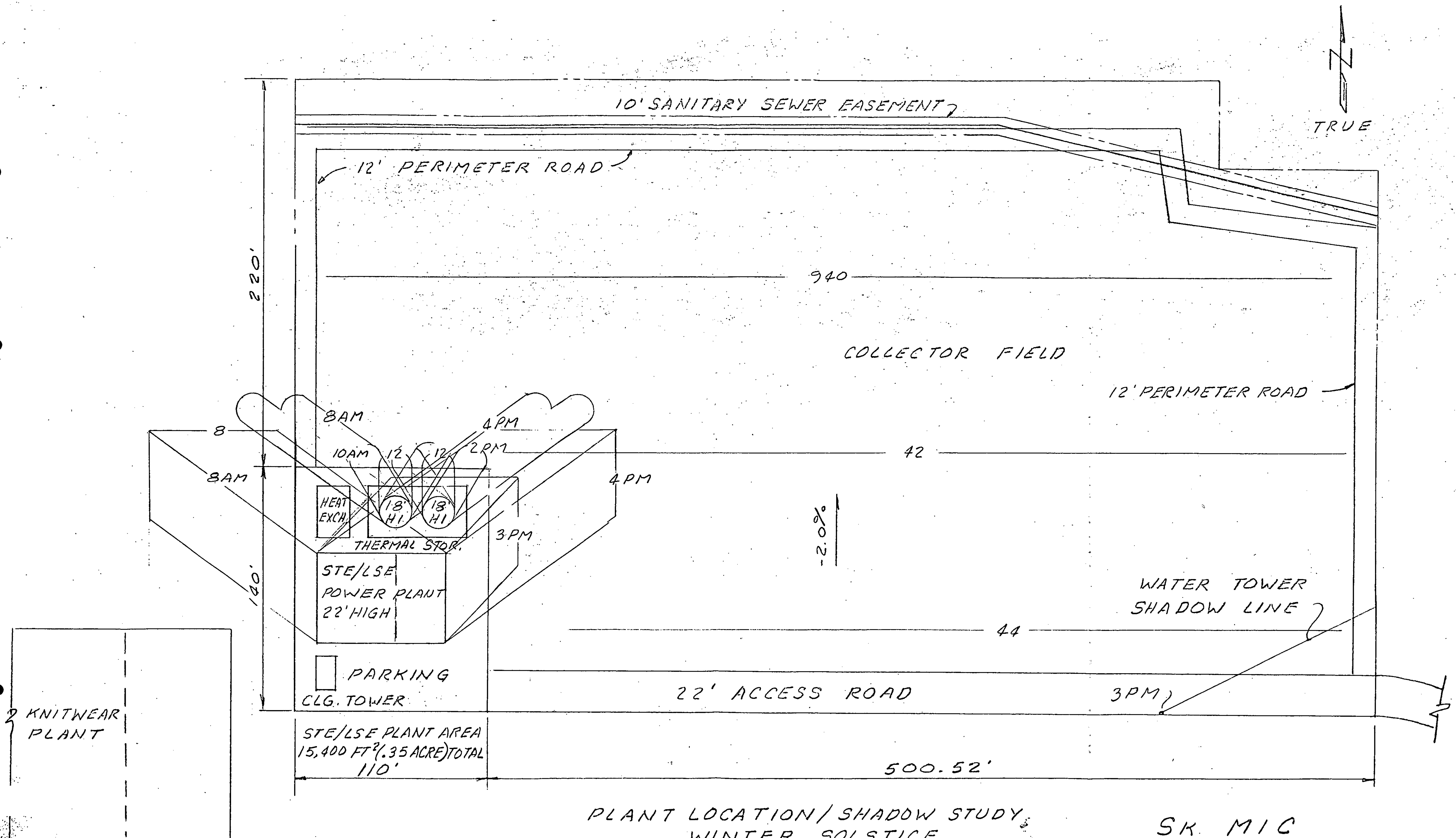
PLANT LOCATION / SHADOW STUDY
EQUINOX
SCALE: 1" = 50'

SK. M1A
7-28-77



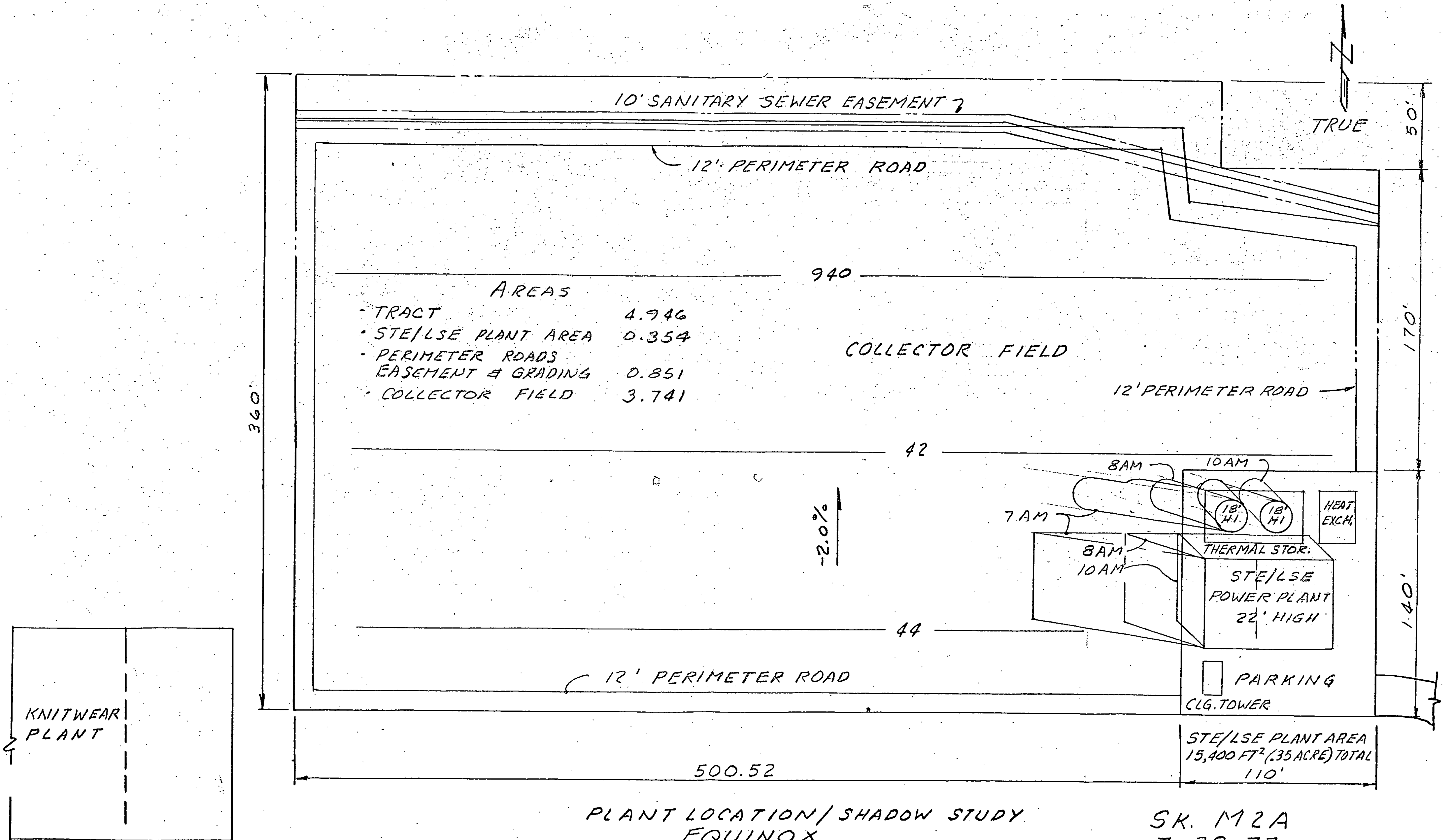
PLANT LOCATION / SHADOW STUDY
SUMMER SOLSTICE
SCALE: 1' = 50'

SK. M1B
7-28-77



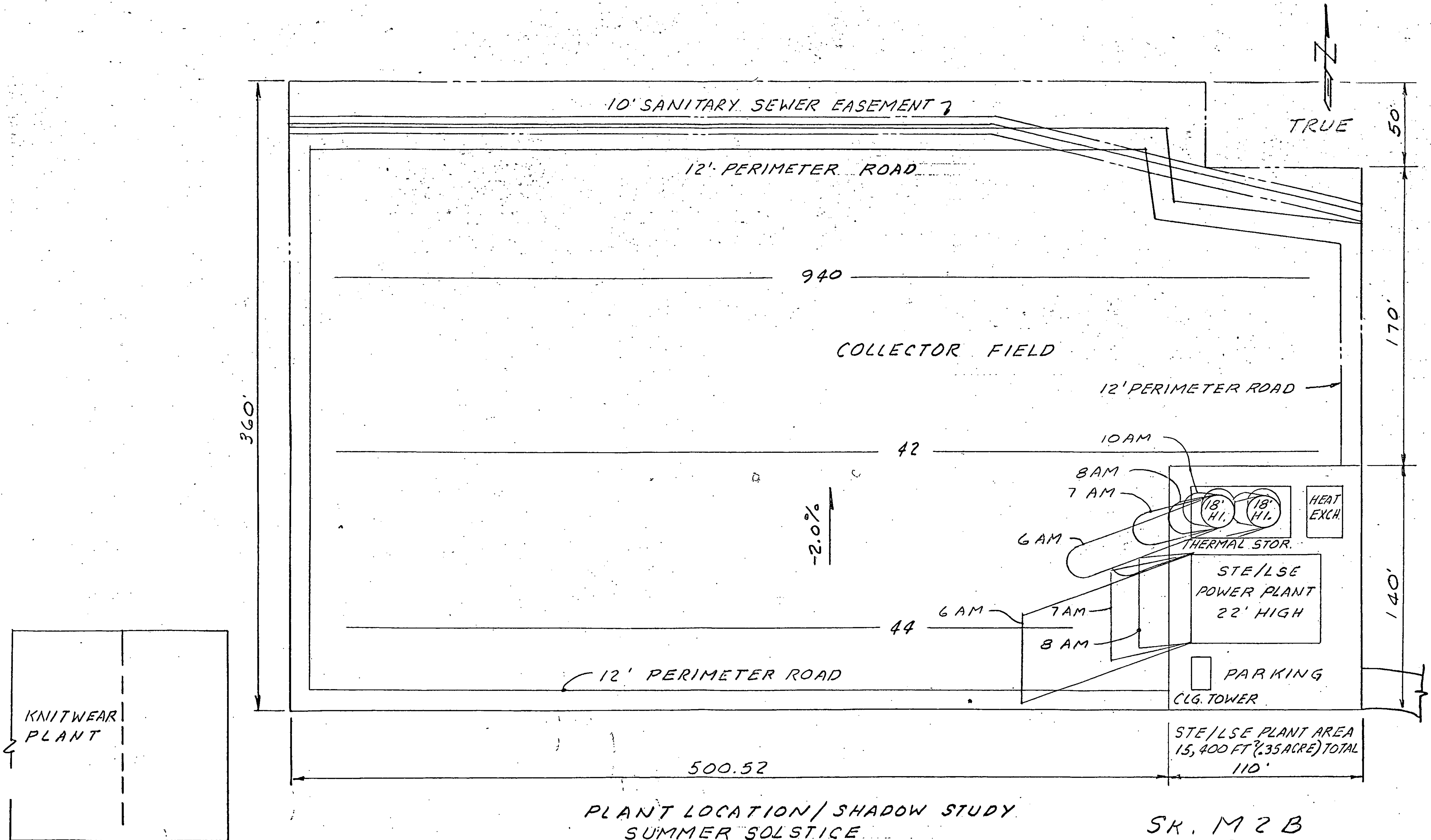
PLANT LOCATION/ SHADOW STUDY
WINTER SOLSTICE
SCALE: 1" = 50'

SK. MIC
7-28-77



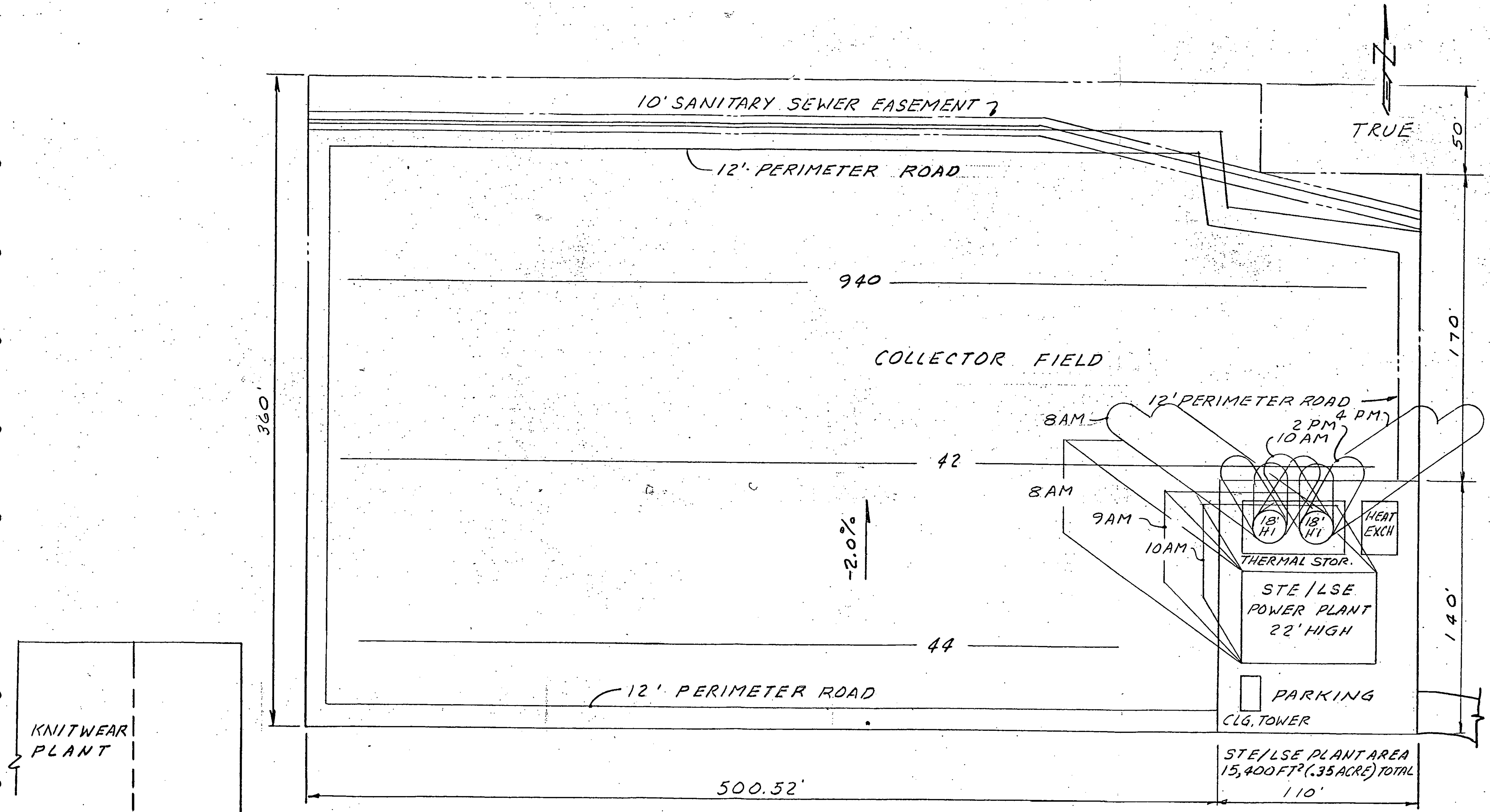
PLANT LOCATION/SHADOW STUDY
EQUINOX
SCALE: 1" = 50'

SK. M2A
7-28-77



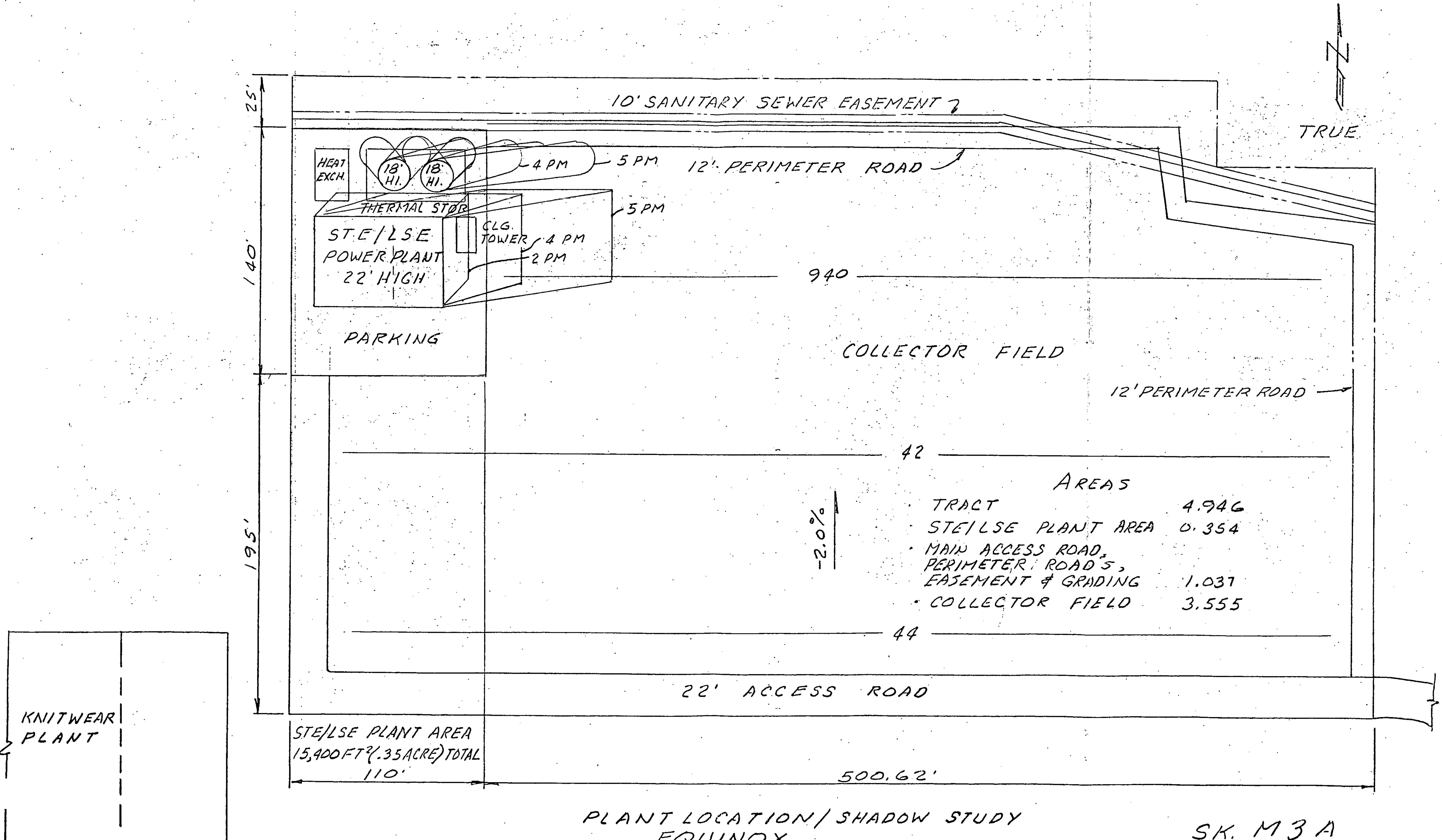
PLANT LOCATION/SHADOW STUDY
SUMMER SOLSTICE
SCALE: 1" = 50'

SK. M2B
7-28-77



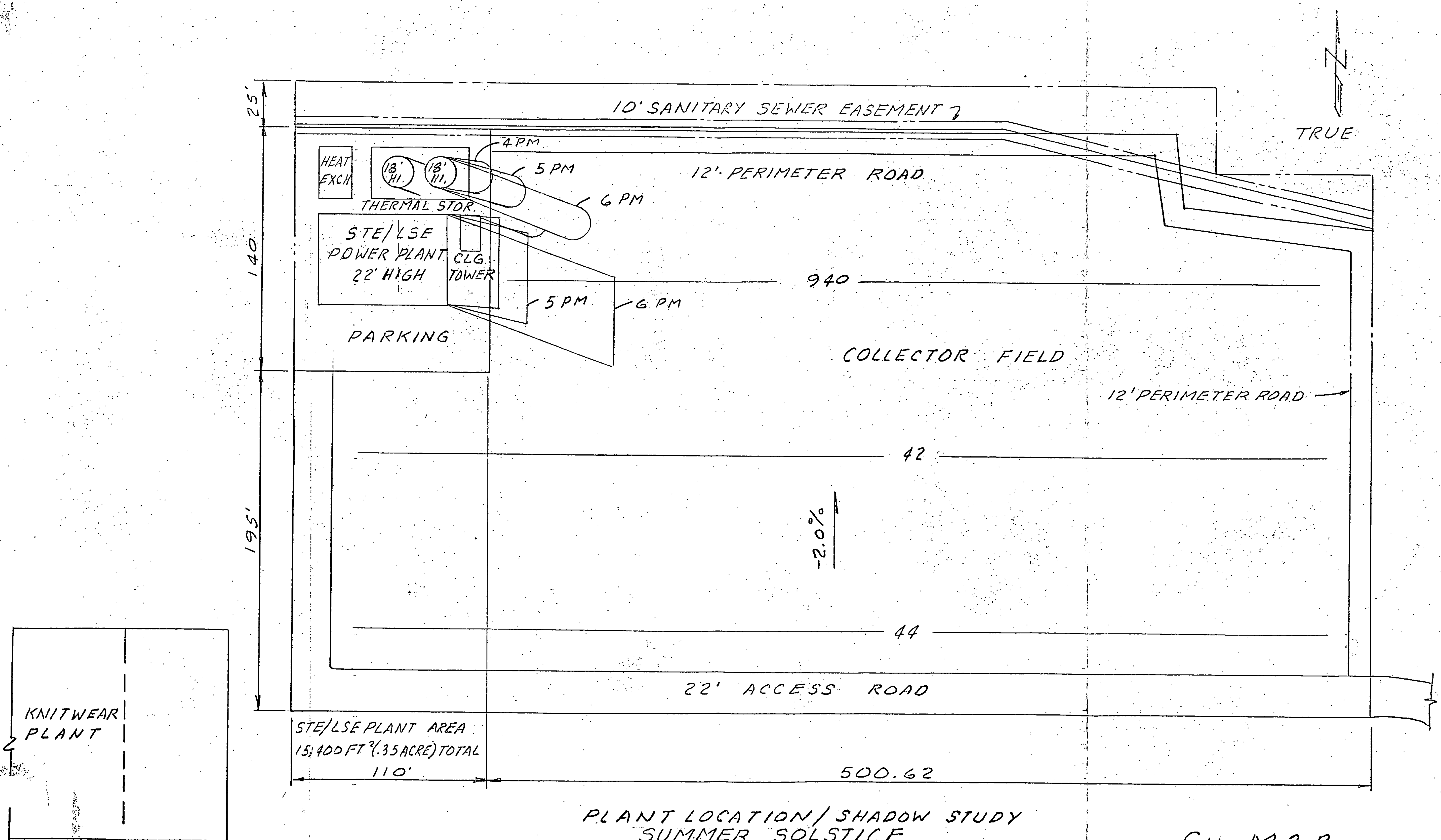
PLANT LOCATION/ SHADOW STUDY
WINTER SOLSTICE
SCALE: 1" = 50'

SK. M2C
7-28-77



PLANT LOCATION/ SHADOW STUDY
EQUINOX
SCALE: 1" = 50'

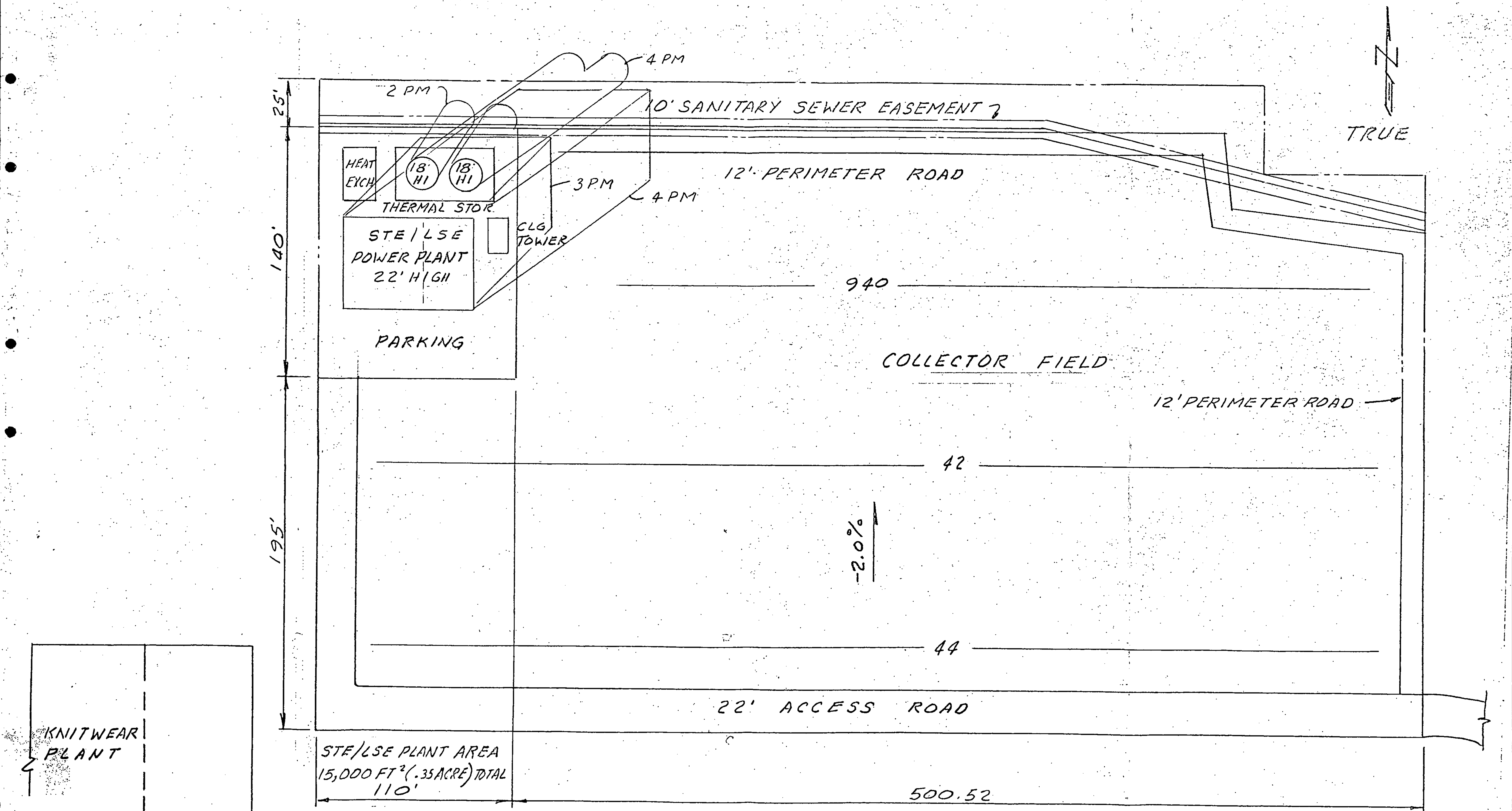
SK. M3A
7-28-77



PLANT LOCATION/ SHADOW STUDY
SUMMER SOLSTICE
SCALE: 1" = 50'

SK. M3B
7-28-77

B1-8



PLANT LOCATION/SHADOW STUDY
WINTER SOLSTICE
SCALE: 1" = 50'

SK. M3C
7-28-77

APPENDIX B2

APPENDIX B2

POWER CONVERSION SYSTEM SEASONAL DESIGN LOAD SUMMARY

The following is the analysis resulting in the loads used to size the power conversion system. The results of this analyses were used in Section 3.2.3 of the report.

Power Conversion System Seasonal Design Load Summary

The following is the analysis resulting in the loads used to size the power conversion system. The results of this analysis were used in Section 3.7.3 of the report.

LSE #2 LOAD SUMMARY 8-2-77 (1)

JANUARY

NIGHT HEATING LOAD = 105195 BTU/HR
COOLING LOAD W/ECONIMIZER = 0
✓ ✓ W/O ✓ = 150.78 TONS = 1.809×10^6 BTU/HR
ELECT LOAD (NET = 383.4 KW = 1.308×10^6 BTU/HR
✓ ✓ @ TURBINE = 429.3 KW = 1.465×10^6 BTU/HR
PROCESS STEAM = 2.27×10^6 BTU/HR

APRIL

[illegible] HEATING LOAD = 34650 [illegible]
COOLING LOAD W/ ECONIMIZER = 35 TONS = 420000 [illegible]
COOLING LOAD W/O ECONIMIZER = 16[illegible] TONS = 2.02[illegible]
ELECT LOAD NET = 383.4 KW = 1.308×10^6 BTU/HR
✓ ✓ @ TURBINE = 429.3 KW = 1.465×10^6 BTU/HR
PROCESS STEAM = 2.27×10^6 BTU/HR

JULY

NIGHT HEATING LOAD = 0
COOLING LOAD W/ ECONIMIZER = 215.78 TONS = [illegible]
COOLING LOAD W/O ECONIMIZER = 215.78 TONS = 2.5893×10^6 BTU/HR
ELECTRICAL LOAD NET = 383.4 KW = [illegible] BTU/HR
✓ ✓ @ TURBINE = 429.3 KW = 1.465×10^6 BTU/HR
PROCESS STEAM LOAD = 2.27×10^6 BTU/HR

(2)

OCTOBER

NIGHT HEATING LOAD = 54850 BTU/HR

COOLING LOAD W/ ECONOMIZER = 48.44 TONS = 581333 BTU/HR

" " W/O " = 171.33 TONS = 2.056×10^6 BTU/HR

ELECT LOAD NET = [illegible] KW = $1.30[illegible] \times 10^6$ BTU/HR

" @ TURBINE = 429.3 KW = $1.4[illegible] \times 10^6$ BTU/HR

PROCESS STEAM = [illegible] BTU/HR

DECEMBER

[illegible] HEATING LOAD [illegible] 142985 BTU/HR

COOLING LOAD W/ ECONOMIZER = 0

COOLING LOAD W/O ECONOMIZER = 147.67 TONS = [illegible]

ELECT LOAD NET = 383.4 KW = 1.308×10^6 BTU/HR

" " @ TURBINE = 429.3 KW = 1.465×10^6 BTU/HR

PROCESS STEAM LOAD = [illegible] $\times 10^6$ BTU/HR

NIGHT HEATING LOAD

[illegible] JANUARY = $\frac{107 + 112 + 120 + [illegible]}{4}$ = 115250 BTU/HR
8 HRS/NIGHT

APRIL = $\frac{92 + 72 + 40 + 4[illegible]}{4}$ = 49500 BTU/HR

JULY = 0

[illegible] = [illegible] = 66500 [illegible]

DECEMBER = [illegible] + 160 = 149750 BTU/HR

WEEK ENDS =

(DAYTIME) JAN = [illegible] + 4[illegible] + 4.6 + 70.6 = 61300 BTU/HR

APRIL = 0
JULY = 0
OCTOBER = 20750 BTU/HR

DECEMBER = 95250 BTU/HR

[illegible] FOR CYCLE

JANUARY = $\frac{115250 \times 8 \times 5 + 61300 \times 16 \times 2 + 115250 \times 8 \times 2}{5 \times 16}$ = 105195[illegible]

APRIL - $\frac{49500 \times 5 \times 8 + 49500 \times 2 \times 8}{5 \times 16}$ = 34650 [illegible]

JULY = 0

OCTOBER = $\frac{66500 \times 5 \times 8 + 20750 \times 16 \times 2 + [illegible]}{5 \times 16}$ [illegible]

DECEMBER = $\frac{149750 \times 5 \times 8 + 95250 \times 16 \times 2 + 149750 \times 8 \times 2}{5 \times 16}$ = 14295[illegible] / HR

COOLING LOAD WITH ECONOMIZER

JANUARY = 0

APRIL = 35 TONS = 420000 BTU/HR

JULY = 215.78 TONS = 2.5893×10^6 BTU/HR

OCTOBER = 48.44 TONS = 581333 BTU/HR

DECEMBER = 0

COOLING LOAD W/O ECONOMIZER

JANUARY = 150.78 TONS = 1.809×10^6 BTU/HR
APRIL = 169.11 TONS = 2.029×10^6 BTU/HR
JULY = 215.78 TONS = 2.5893×10^6 BTU/HR
OCTOBER = 171.33 TONS = 2.056×10^6 BTU/HR
DECEMBER = 147.67 TONS = 1.772×10^6 BTU/HR

ELECTRICAL LOAD (REQUIREMENT)
NET = 383.4 KW
AT TURBINE $\frac{383.4}{.95 \times .94}$ = 429.3 KW = 1.465×10^6 BTU/HR

PROCESS STEAM LOAD = 2.27×10^6 BTU/HR

APPENDIX B3

APPENDIX B3

APPENDIX B3

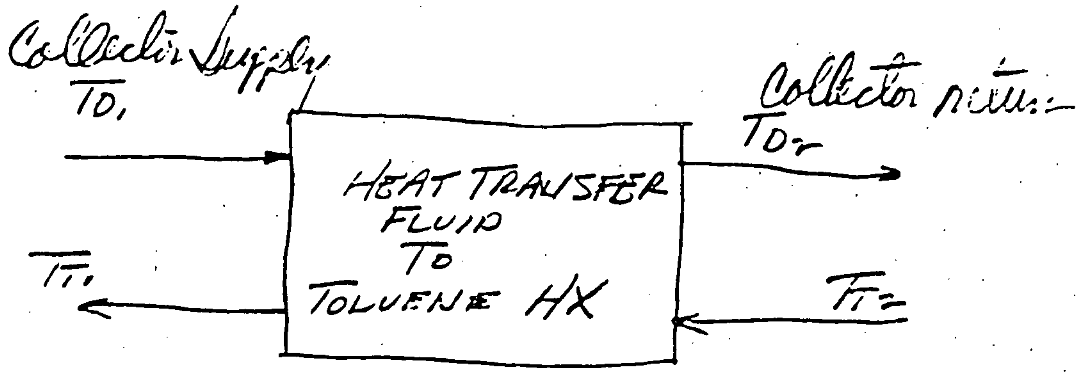
AVERAGE COLLECTOR TEMPERATURE OPTIMIZATION STUDY

The following is the analysis used in a study to determine optimum flow rate ratios across the Therminol 66 to toluene heat exchanger to minimize the average collector temperature. The results of this analysis are presented in Section 3.2.3.

Average Collector Temperature Minimization Study.

The following is the analysis used in a study to determine optimum flow rate ratios across the Therminol 66 to Toluene heat exchanger to minimize the average collector temperature. The results of this analysis is [illegible] in Section 3.2.3

AVERAGE COLLECTOR TEMPERATURE
OPTIMIZATION STUDY



WHERE

T_{D1} = COLLECTOR SUPPLY TEMP

T_{D2} = COLLECTOR RETURN TEMP

T_{T1} = TURBINE INLET TEMPERATURE

T_{T2} = FEEDWATER RETURN TEMP

$$T_{DAV} = \frac{T_{D1} + T_{D2}}{2}$$

WHEN C_{MIN} = TOLUENE

$$E_{TOT} = \frac{T_{T1} - T_{T2}}{T_{D1} - T_{T2}} \quad \& \quad C_{rat} = \frac{T_{D1} - T_{D2}}{T_{T1} - T_{T2}}$$

$$T_{D1} = T_{T2} + \frac{(T_{T1} - T_{T2})}{E_{TOT}}$$

$$T_{D2} = T_{D1} - (T_{T1} - T_{T2})\,C_{rat}$$

$$T_{D2} = T_{T2} + \frac{(T_{T1} - T_{T2})}{E_{TOT}} - C_{rat}(T_{T1} - T_{T2})$$

$$T_{D2} = T_{T2} + \left[\frac{1 - E_{TOT}C_{rat}}{E_{TOT}}\right](T_{T1} - T_{T2})$$

$$T_{DAV} = \frac{(T_{D1} + T_{D2})}{2} = T_{T2} + \left[\frac{2 - E_{TOT}C_{RAT}}{2E_{TOT}}\right](T_{T1} - T_{T2})$$

WHEN C_{MIN} = HT FLUID

$$E_{TOT} = \frac{T_{D1} - T_{D2}}{T_{D1} - T_{T2}} \quad \& \quad C_{rat} = \frac{T_{T1} - T_{T2}}{T_{D1} - T_{D2}}$$

$$T_{D1} = T_{D2} + \frac{(T_{T1} - T_{T2})}{C_{RAT}}$$

$$T_{D2} = T_{D1} - (T_{D1} - T_{T2})E_{TOT}$$

$$\cancel{T_{D2}} = \cancel{T_{D2}} + \frac{(T_{T1} - T_{T2})}{C_{rat}} - (T_{D1} - T_{T2})E_{TOT}$$

$$T_{D1} = T_{T2} + \frac{(T_{T1} - T_{T2})}{E_{TOT}C_{RAT}}$$

$$T_{D2} = T_{T2} + \frac{(T_{T1} - T_{T2})}{E_{TOT}C_{RAT}} - \left[\cancel{T_{T2}} + \frac{(T_{T1} - T_{T2})}{E_{TOT}C_{rat}} - \cancel{T_{T2}}\right]E_{TOT}$$

$$T_{D2} = T_{T2} + \left[\frac{1 - E_{TOT}}{E_{TOT}C_{RAT}}\right](T_{T1} - T_{T2})$$

$$T_{DAV} = \left(\frac{T_{D1} + T_{D2}}{2}\right) = T_{T2} + \left[\frac{2 - E_{TOT}}{2E_{TOT}C_{RAT}}\right](T_{T1} - T_{T2})$$

NTU = 2 3 PASS HX

$\frac{W_t C_{pt}}{W_{ht} C_{ph}}$	$\frac{T_{DAV} - T_{T2}}{T_{T1} - T_{T2}}$	E_{TOT}	E_{PASS}
.2	.9086	.9915	.8160
.4	.8243	.9762	.7646
.6	.7577	.9454	.7130
.8	.7173	.8950	.6629
1	.7083	.8276	.6154
1.2	.75630	.8848	.6548
1.4	.8234	.9190	.6841
1.6	.9018	.9402	.7066
1.8	.9870	.9539	.72[illegible]
2	1.0765	.9631	.7388
2.2	1.1688	.9696	.7505
2.4	1.2652	.9744	.7603

NTU=3 3 PASS HX

.2	.9011	.9999	.9086
.4	.8063	.9938	.8567
.6	.7743	.9762	.7993
.8	.6694	.9351	.7408
1.0	.6587	.8630	.6842
1.2	.6967	.9254	.7311
1.4	.7642	.9562	.7458
[illegible]	.8451	.9726	.7720
1	.9333	.9818	.8123
2.0	1.0752	.9873	.8284
2.2	1.1[illegible]7	.9907	.8411
2.4	1.2171	.9929	.8521

NTU = 4 3 PASS

$\frac{W_t C_{pt}}{W_{ht} C_{ph}}$	$\frac{T_{DAV} - T_{T2}}{T_{T1} - T_{T2}}$	E_{TOT}	E_{PASS}
.2	.9002	.9998	.9513
.4	.8020	.9980	.9045
.6	.7125	.9877	.8467
.8	.6480	.9542	.7846
1	.6282	.8864	.7235
1.2	.6694	.9153	.7743
1.4	.7397	.9724	.8114
1.6	.[illegible]	.9851	.8391
1.8	.9157	.9914	.8[illegible]
2.0	1.[illegible]	.9981	.9150
2.4	1.2057	.9976	.9000

NTU = 5 3 PASS

.2	.9000	.9999	.9775
.4	.8008	.9992	.9319
.6	.7073	.9927	.8758
.8	.6564	.9649	.8[illegible]
1.0	.6149	.8969	.7590
1.2	.6542	.9568	.8017
1.4	.7274	.9808	.8399
1.6	.8147	.9909	.8651
1.8	.9085	.9953	.8892
2.0	1.0052	.9973	.9053
2.2	1.1054	.9985	.9178
2.4	1.2023	.9990	.9277

APPENDIX B4

APPENDIX B4

SYSTEM OPERATING TEMPERATURE OPTIMIZATION STUDY

The following is the analysis, from the power conversion system side, used in conjunction with a similar study for the solar collector system to determine the optimum temperature for operating the collector/power conversion system to maximize total system performance.

The results of this study are discussed in Section 3.2.3.

System Operating Temperature Optimization Study.

The following is the analysis, from the power conversion system side, used in conjunction with a similar study for the solar collector system to determine the optimum temperature for operating the collector/power conversion system to maximize total system performance.

The results of this study are discussed in section 3.4.2

SYSTEM OPERATING TEMP
OPTIMIZATION STUDY
(POWER CONVERSION)

[illegible]	T_{T1} °F	Gross EFF η_e	Net EFF (Including [illegible])	[illegible] HP	T_{D1} °F	T_{D2}	T_{coll} Av	[illegible]	% [illegible] 499.3 KW [illegible]	Required 220.05 [illegible] VC Tons	Abs Tons	Total Elect (Gen) Sep Elect + VC	Q_{SYS} BTU (10^6)	W_{SYS} #/HR
[illegible]PER	725	LT .155 ST .276	.159 .256	24.62 30.54	750	515.5	632.8		100%	2.875	191.8	457.09	2.118	32072
[illegible]	650	LT .169 ST .256	.241 .235	26.24 35.08	671.2	441.8	556.5		100%	2.39	212.66	436.56	2.404	35674
	625	LT .159 ST .244	.130 .222	26.79 36.80	646.2	411.8	532.0		96.7%	0	220.05	415.32	2.480	37200
B4-4	625	LT .157 ST .248	.134 .230	21.86 30.90	646.1	629.1	572.9		100%	1.50	218.55	430.77	2.49	40891
B4-4	550	LT .145 ST .226	.126 .214	16.95 20.49	568	567.66	546.9		92.6%	0	220.5	379.59	2.46	38587

SMALL TURBINE

$T_{COND} = 200\ ^\circ F$ $P_{cond} = 8.70878\ psia$

$T_{S_2} = 478.9$ $h_{S_2} = 3.4173\ BTU/\#$ $\eta_T = .74$ $N_{STAGE} = 4$ 3 PASS

$T_r = 530.06\ ^\circ F$ $h_r = 29.01777\ BTU/\#$ $C_{out} = .79$ $E_{PASS} = .57888$

$E_{TOT} = .85082$ $P_{in} = 50\ \#/in^2$ $\Delta P_{PUMP} = 700\ psid$

$T_3 = 757.18\ ^\circ F$ $T_5 = \ldots$ $h_5 = -151.1458\ BTU/\#$ $T_6 = 427.524$ $h_6 = -116.54\ldots$

$T_{P\ldots} = 205.79\ ^\circ F$ $h_{P\ldots} = -266.5277\ BTU/\#$ $\Delta h_{PUMP} = 4.3188\ BTU/\#$

$\eta_c = .27566$ $\Delta h_{PUMP} @ TURBINE = \frac{4.3188}{.95 \times .94} = 4.8363\ BTU/\#$

$\eta_{C\,NET} = .25595$ (INCLUDING PUMP)

... STATE

... $= 4$ @ TURBINE $= 4 \times .95 \times .94 = 5.57\ldots$

LARGE TURBINE

SEP ELECT GENERATED $= 514934\ BTU/HR = 150.88\ KW$ @ TURBINE

$Q_{SYS} = 2.785 \times 10^6\ BTU/HR$ $W_{SYS} = 1451\ldots\ \#/HR$

SMALL TURBINE

SEP ELECT REQ'D $= 4\ldots - 150.88 = 278.\ldots\ KW = 950164\ BTU/HR$

SEP ELECT GEN $= 950164\ BTU/HR = 268.44\ KW$ @ TURBINE

ELECTRICAL GEN FOR VC REF $= 165008\ BTU/HR = 48.35$

$R_{\ldots} = 49.12$ TON $Q_{ABS} = 2.950 \times 10^6\ BTU/HR$ $R_{\ldots} = 170.93$ TON

$W_{ABS} = 16483\ \#/HR$ $Q_{SYS} = 4.045 \times 10^6\ BTU/HR$ $W_{SYS} = 16483\ \#/HR$

CALCULATE $T_{6\,MIX}$ & $h_{6\,MIX}$

$h_{6\,MIX} = -118.1459\ BTU/\#$ $\ldots = 37185\ \#/HR$ $T_{6\,MIX} = 47\ldots$

$Q_{TOT} = 6.83 \times 10^6\ BTU/HR$

$\ldots\ \eta_c = \frac{Q_{ELEC} + Q_{REF}}{Q_{TOT}} = \frac{514934 + 1.115 \times 10^6}{6.83 \times 10^6} = \ldots$

LARGE TURBINE

$T_1 = 650°F$ $P_1 = 700$ PSIA $h_1 = 41.773560$ $S_1 = .037772$

$T_{COND} = 350°F$ $P_{COND} = 76.019547$

$T_{S2} = 477.36°F$ $h_{S2} = 1.43768$ BTU/#

$T_2 = 499.89°F$ $h_2 = 11.9750$ $E_{PASS} = .57888$ $E_{TOT} = .85082$

$T_3 = 375.12°F$ $T_5 = 446.87°F$ $h_5 = -137.1494$ BTU/# $T_6 = 451.31°F$ $h_6 = -134.17528$ BTU/#

$T_P = 353.24°F$ $h_P = -190.7980$ BTU/# $\Delta h_{pump} = 4.4559$ BTU/#

$\eta_c = .16955$ GROSS Δh_{pump} @ TURBINE $= \frac{4.4559}{.9...4} = 4.9698$ BTU/#

$\eta_{c_{NET}} = .14104$ (PUMP INCLUDED)

SMALL TURBINE

$T_1 = 650°F$ $P_1 = 700$ PSIA $h_1 = 41.7735605$ BTU/# $S_1 = .037272$

$T_{COND} = 200°F$ $P_{COND} = 8.70878$ PSIA

$T_{S2} = 379.69°F$ $h_{S2} = -37.76.16$ BTU/#

$T_2 = 428.32°F$ $h_2 = -...$ BTU/# $E_T = .5...$ $E_{TOT} = .85920$

$T_3 = 239.89°F$ $T_5 = 352.64°F$ $h_5 = -191.1208$ $T_6 = 357.35°F$ $h_6 = -18...$ BTU/#

$T_P = 205.79°F$ $h_P = -266.5277$ BTU/# $\Delta h_{pump} = 4.3188$

$\eta_c = .25556$ Δh_{pump} @ TURBINE $= \frac{4.3188}{.95x.94} = 4.8362$ BTU/#

$\eta_{c_{NET}} = .23455$ (PUMP INCLUDED)

$T_1 = 625°F$ (4)

LARGE TURBINE

$T_1 = 625°F$ $P_1 = 700$ PSIA $h_1 = 22.3389$ BTU/# $v_1 = .020116$

$T_{COND} = 350°F$ $P_{COND} = 71.019547$ PSIA

$T_{5r} = 442.71°F$ $h_{5r} = -14.3207$ BTU/#

$T_r = 465.73°F$ $h_r = -4.7892$ BTU/# $E_P = .57888$ $E_{TOT} = .85082$

$T_3 = 369.75°F$ $T_5 = 423.75°F$ $h_5 = -150.7621$ BTU/# $T_6 = 420.31°F$ $h_6 = -145.1586$ BTU/#

$T_P = 355.71°F$ $h_P = -190.7810$ BTU/# $\Delta h_{pump} = 4.4559$ BTU/#

$\eta_e = .15918$ Δh_{pump} @ TURBINE $= \frac{4.4559}{.9544} = 4.9808$ BTU/#

$\eta_{e,NET} = .12993$ (PUMP INCLUDED)

SMALL TURBINE

$T_1 = 625°F$ $P_1 = 700$ PSIA $h_1 = 22.3389$ BTU/# $v_1 = .020116$

$T_{COND} = 200°F$ $P_{COND} = 8.70897$

$T_{5r} = 346.33°F$ $h_{5r} = -51.38512$ BTU/#

$T_r = 392.81°F$ $h_r = -32.7152$ BTU/# $E_P = .57122$ $E_{TOT} = .83910$

$T_3 = 234.70°F$ $T_5 = 329.19°F$ $h_5 = -203.5720$ BTU/# $T_6 = 320°F$ $h_6 = -201.2807$ BTU/#

$T_P = 205.79°F$ $h_P = -266.5297$ BTU/# $\Delta h_{pump} = 4.819$ BTU/#

$\eta_e = .24396$ Δh_{pump} @ TURBINE $= \frac{4.819}{.9544} = 4.836$

$\eta_{e,NET} = .22233$ (INCLUDES PUMP)

SMALL TURBINE (SUBCRITICAL) (4A)

$T_1 = 625^\circ F$ $P = 500$ psia $h_1 = 49.791$ BTU/# $S_1 = .048101$

$T_{COND} = 200^\circ F$ $P_{cond} = 8.70878$

$T_{S_2} = 402.84^\circ F$ $h_{S_2} = -25.0418$ BTU/#

$T_2 = 449.19^\circ F$ $h_2 = -7.9553$ BTU/# $E_P = .57172$ $E_{TOT} = .85970$

$T_3 = 242.86^\circ F$ $T_5 = 366.50^\circ F$ $h_5 = -185.4503$ BTU/# $T_6 = 372.51^\circ F$ $h_6 = -181.15$ BTU/#

$T_P = 203.77^\circ F$ $h_P = -266.2599$ BTU/# $\Delta h_{PUMP} = 3.7756$ BTU/#

$\eta_e = .24826$ Δh_{PUMP} @ TURBINE $= \frac{3.7756}{.95 \times .94} = 4.172$ BTU/#

$\eta_{e\,NET} = .23016$

LARGE TURBINE

$T_1 = 650^\circ F$ $P = 500$ psia $h_1 = 49.791$ BTU/# $S_1 = .048101$

$T_{COND} = 350^\circ F$ $P_{COND} = 71.019547$ psia

$T_{S_2} = 499.52^\circ F$ $h_{S_2} = 11.7757$ BTU/#

$T_2 = 520.10^\circ F$ $h_2 = 21.5$ BTU/# $E_P = .57888$ $E_{TOT} = .85082$

$T_3 = 377.70^\circ F$ $T_5 = 459.55^\circ F$ $h_5 = -172.54851$ BTU/# $T_6 = 462.78^\circ F$ $h_6 = -171.7751$ BTU/#

$T_P = 352.75^\circ F$ $h_P = -191.0726$ BTU/# $\Delta h_{PUMP} = 3.7518$ BTU/#

$\eta_e = .15752$ Δh_{PUMP} @ TURBINE $= \frac{3.7518}{.94 \times .95} = 4.2014$ BTU/#

$\eta_{e\,NET} = .13358$ (INCLUDES PUMP)

(4D)

LARGE TURBINE

$T_1 = 550°F$ $P = 400$ psia $h_1 = 14.2791427$ BTU/# $S_1 = .017975$

$T_{COND} = 350°F$ $P_{COND} = 71.019547$ PSIA

$T_{S2} = 438.41°F$ $h_{S2} = -16.21707$ BTU/#

$T_2 = 485.70$ $h_2 = -8.3065$ BTU/# $E_P = .57882$ $E_{TOT} = .8508$

$T_3 = 371.86°F$ $T_5 = 457.?°F$ $h_5 = -147.8076$ BTU/# $T_6 =$ [illegible] $h_6 = -147.8076$ BTU/#

$T_P = 351.00°F$ $h_P = -191.5501$ BTU/# $\Delta h_{pump} = 2.6079$ BTU/#

$\eta_C = .1452$ Δh_{pump} @ TURBINE $= \frac{2.6079}{.95 \times .94} = 2.9204$ BTU/#

$\eta_{CNET} = .12645$ (INCLUDING PUMP)

SMALL TURBINE

$T_1 = 550°F$ $P = 400$ psia $h_1 = 14.2791427$ BTU/# $S_1 = .017975$

$T_{COND} = 200°F$ $P_{COND} = 8.70878$ PSIA

$T_{S2} = 342.52$ $h_{S2} = -52.?56$ BTU/#

$T_2 = 385.?°F$ $h_2 = -35.4561$ BTU/# $E_T = .5712?$ $E_{TOT} = .839.0$

$T_3 = 231.55°F$ $T_5 = 323.51$ $h_5 = -2?6.?71$ BTU/# $T_6 = ?.19°F$ $h_6 = -265.?79$ BTU/#

$T_P = 202.10°F$ $h_P = -267.7949$ BTU/# $\Delta h_{pump} = 2.3881$ BTU/#

$\eta_C = .22623$ Δh_{pump} @ TURBINE $= \frac{2.3881}{.95 \times .94} = 2.6743$ BTU/#

$\eta_{CNET} = .21420$ (INCLUDING PUMP)

T = [illegible] °F

REF SITE

LARGE TURBINE

SEPARATE ELECTRICAL GENERATED = 428847 BTU/HR = 125.66 KW

Q_{SYST} = 2.699 x 10^6 BTU/HR $\dot{W}_{SYS}$ = 14066 #/HR

SMALL TURBINE

Q_{ELECT} REQ'D = 1.036 x 10^6 BTU/HR = 303.62 KW @ TURBINE

SEP ELEC GEN = 1.036 x 10^6 BTU/HR = 303.62 KW @ TURBINE

TOTAL ELECT = 1.131 x 10^6 BTU/HR = 331.43 KW @ TURBINE (INC. VC REF)

Q_{VC} = [illegible] BTU/HR R_{VC} = 28.25 TONS

Q_{ABS} = 3.7[illegible] x 10^6 BTU/HR R_{ABS} = 191.80 TONS

$\dot{W}_{ABS}$ = 18006 #/HR Q_{SYS} = 4.419 x 10^6 BTU/HR $\dot{W}_{SYS}$ = 18006

$T_1 = 650°F$

REF SPLIT

LARGE TURBINE

SEPARATE ELECTRIC GENERATED = 377731 BTU/HR = 109.77 KW

$Q_{SYST} = 7.643 \times 10^6$ BTU/HR $W_{SYST} = 14994$ #/HR

SMALL TURBINE

$Q_{ELECT\ RQD} = 1.0973 \times 10^6$ BTU/HR

SEP ELECT GEN [illegible] 1.0973×10^6 BTU/HR = [illegible] KW

TOTAL ELECT = 1.117×10^6 BTU/HR = 327.[illegible] KW (INC. H.C. [illegible]

$Q_{HC} = 74814$ BTU/HR $P_{HC} = 7.39$ TONS

$Q_{ABS} = 3.646 \times 10^6$ BTU/HR $P_{ABS} = 717.[illegible]$ TONS

$\dot{W}_{ABS} = 20680$ #/HR $Q_{SYS} = 4.763 \times 10^6$ BTU/HR $W_{SYS} = 20680$ #/HR

$T_1 = 675°F$

(1)

REF SPLITS

LARGE TURBINE

SEPARATE ELECTRICAL GEN = 33889 BTU/HR = 9930 KW

$Q_{SYS} = 2.609 \times 10^6$ BTU/HR $\dot{W}_{SYS} = 15308$ #/HR

SMALL TURBINE

OFFSET [illegible] = 1.17 [illegible] BTU [illegible]

OFFSET ELECT GEN = 1. [illegible] BTU/HR = [illegible] KW

$\dot{W}_{VC} = 0$

[illegible] 3.772 × 10^6 BTU/HR P_{ABS} = 220.05 Tons.

$\dot{W}_{abs}$ = 2169 #/HR $Q_{SYS} = 4.651 \times 10^6$ BTU/HR $\dot{W}_{SYS}$ = 2169 #/HR

675°F (8)

REF SPLITS (SEQUENTIAL)

LARGE TURBINE

SEPARATE ELECTRICAL GENERATED = 349976 BTU/HR = 102.55 KW

Q_{SYS} = 26.20 x10^6 BTU/HR $\dot{W}_{SYS}$ = 14837 #/HR

SMALL TURBINE

[illegible] – REF [illegible] 1.115 x [illegible]^6 BTU/HR = [illegible] TURBINE

[illegible] ELECT [illegible] = 1.[illegible] BTU/HR = 326.75 KW @ TURBINE

TOTAL [illegible] = 1.120 [illegible] BTU/HR = [illegible] KW @ TURBINE (incl

Q_{VC} = 5034 BTU/HR R_{VC} = 1.50 TONS

Q_{ABS} = 3.747 x10^6 BTU/HR $R_{[illegible]}$ = 218.55 TONS

$\dot{W}_{ABS}$ = 21113 #/HR $Q_{S[illegible]}$ = [illegible] BTU/HR $\dot{W}_{SYS}$ = 21113 #/HR

550 °F (SUBCRITICAL)
LARGE TURBINE
SEPARATE ELECTRICAL GENERATED = 328597 BTU/HR = 96.3 KW

Q_{SYS} = 2.598 X 10^6 BTU/HR W_{SYS} = 1654.2 #/HR

o

SMALL TURBINE

QELEC EQUIV = 1.136 X 10^6 BTU/HR = 330.01 KW

SEP ELECT GEN = 1.028 X 10^6 BTU/HR = 301.3 KW

Que = 0

QABS = 3.772 X 10^6 BTU/HR RACS = 220.05 TONS

WABS = 2184.5 #/HR QSYS = 4.501 X 10^6 BTU/HR WSYS = 2184.5 #/HR [illegible]: h_{6MIX}, T_{6MIX}, $\dot{W}_{MIX}$ & $\eta_{OVERALL}$, Q_{TOT}

$T_1 = 725$ =

LARGE TURBINE $\dot{W}_{SYS} = 14066$ #/HR $h_6 = -95.00$ BTU/# $T_6 = 515.91$ °F

$Q_{SYS} = 2.699 \times 10^6$ BTU/HR

SMALL TURBINE $\dot{W}_{SYS} = 18006$ #/HR $h_6 = -148.52$ BTU/# $T_6 = 427.52$ °F

$Q_{SYS} = 4.419 \times 10^6$ BTU/HR

$h_{6MIX} = -125.$ [illegible] BTU/# $\dot{W}_{MIX} = 32072$ #/HR $Q_{TOT} =$ [illegible] $\times 10^6$

$T_{6MIX} = 466.79$ °F

$$\eta_{OVERALL} = \frac{428847 + 1.131 \times 10^6}{7.118 \times 10^6} = .21900$$

$T_1 = 650$ °F

LARGE TURBINE $\dot{W}_{SYS} = 14$ [illegible] #/HR $h_6 =$ [illegible] BTU/# $T_6 = 451.31$ °F

$Q_{SYS} = 2.643 \times 10^6$ BTU/HR

SMALL TURBINE $\dot{W}_{SYS} = 20680$ #/HR $h_6 = -188.$ [illegible] BTU/# $T_6 = 33$[illegible] °F

$Q_{SYS} = 4.763 \times 10^6$ BTU/HR

$h_{6MIX} = -15$[illegible] BTU/# $\dot{W}_{MIX} = 35674$ #/HR $Q_{TOT} = 7.406 \times 10^6$ BTU/HR

$T_{6MIX} = 391.84$ °F

$$\eta_{OVERALL} = \frac{372734 + 1.117 \times 10^6}{7.406 \times 10^6} = .20115$$

$T_1 = 625$ °F

LARGE TURBINE $\dot{W}_{SYS} = 15308$ #/HR $h_6 = -148.055$ BTU/# $T_6 = 4$[illegible] °F

$Q_{SYS} = 2.609 \times 10^6$ BTU/HR

SMALL TURBINE $\dot{W}_{SYS} = 216$[illegible] #/HR $h_6 = -201.$[illegible] BTU/# $T_6 = 334$ °F

$Q_{SYS} = 4.871 \times 10^6$ BTU/HR

$h_{6MIX} = -179.7735$ BTU/# $\dot{W}_{MIX} = 370$[illegible] #/HR $Q_{TOT} = 7.480 \times 10^6$ BTU/HR

$T_{6MIX} = 373.02$ °F

$$\eta_{OVERALL} = \frac{3[illegible] + 1.0785 \times 10^6}{7.48 \times 10^6} = .189[illegible]$$

$T_1 = 625°F$ (SUBCRITICAL) (11)

LARGE TURBINE $\dot{W}_{SYS} = 14837$ #/HR $h_L = -172.2975$ BTU/HR $T_6 = 463.37°F$

$Q_{SYS} = 2.62 \times 10^6$ BTU/HR

SMALL TURBINE $\dot{W}_{SYS} = 27560$ #/HR $h_L = -181.2258$ BTU/HR $T_6 = 370.51°F$

$Q_{SYS} = 4.867 \times 10^6$ BTU/HR

$h_{SHIV} = -167.3463$ BTU/# $\dot{W}_{HIV} = 42397$ #/HR $Q_{TOT} = 7.487 \times 10^6$ BTU/HR

$T_{6HIV} = 402.97°F$ $\eta_{OVERALL} = \dfrac{349976 + 1.120 \times 10^6}{7.487 \times 10^6} = .19634$

$T_1 = 550°F$ (SUBCRITICAL)

LARGE TURBINE $\dot{W}_{SYS} = 16540$ #/HR $h_L = 143.8076$ BTU/# $T_6 = 439.92°F$

$Q_{SYS} = 2.$ [illegible] BTU/HR

SMALL TURBINE $\dot{W}_{SYS} = 21845$ #/HR $h_L = 205.4792$ BTU/# $T_6 = 326.19°F$

$Q_{SYS} = 4.801 \times 10^6$ BTU/HR

$h_{6HIV} = -178.[illegible]3$ BTU/# $\dot{W}_{SYS} = 38[illegible]7$ #/HR $Q_{TOT} = 7.399 \times 10^6$ BTU/HR

$T_{6HIV} = 355.01°F$ $\eta_{OVERALL} = \dfrac{328592 + 1.028 \times 10^6}{7.399 \times 10^6} = .18[illegible]5$

HX PERFORMANCE (SUPERCRITICAL CYCLE)

SUPERCRITICAL $E_{TOT} = .92253$ PASS 4NTU/PASS HX

725°F

$$T_{D1} = T_{T2} + \frac{(T_{T1} - T_{T2})}{E_{TOT}} = 427.52 + \frac{(725-427.52)}{.9225} = 750°F$$

$h_{T1} = 96.872$ BTU/# $h_{T2} = -175.0674$ $\dot{W}_{STM} = 37072$

$T_{T2} = 466.29°F$

$T_{D2} = 565.55°F$ $W_D/W_T = 1.50375$ $W_{D/HR} = 55770$ #/HR

$E_P = .7577$ $E_{TOT} = .92253$ $C_{rat} = .90630$

$T_{DAV} = 632.77$

650°F

$$T_{D1} = 396.84 + \frac{(650-396.84)}{.92253} = 671.26°F$$

$h_{T1} = 41.7550$ BTU/# $h_{T2} = 165.81623$ BTU/# $\dot{W}_{STM} = 35674$

$T_{T2} = 396.8$ °F

$T_{D2} = 441.82°F$ $W_D/W_T = 1.50152$ $W_{D/HR} = 53565$ #/HR

$E_P = .7572$ $E_{TOT} = .92253$ $C_{rat} = .90630$

$T_{DAV} = 556.54°F$

625°F

$$T_{D1} = 373.02 + \frac{(625-373.02)}{.92253} = 646.16°F$$

$h_{T1} = 22.3389$ BTU/# $h_{T2} = -179.22351$ BTU/# $\dot{W}_{STM} = 3700$ #/HR

$T_{T2} = 373.02°F$

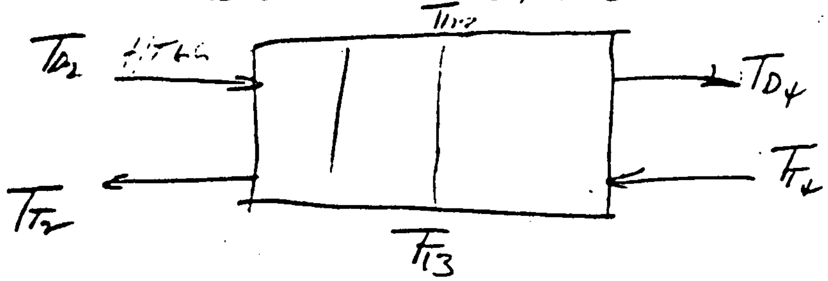
$T_{D2} = 417.79°F$ $W_D/W_T = 1.48784$ $W_{D/HR} = 55050$ #/HR

$E_P = .75178$ $E_{TOT} = .92253$ $C_{rat} = .90630$

$T_{DAV} = 531.97°F$

HX PERFORMANCE (SUBCRITICAL CYCLE)

SUBCRITICAL CYCLE   BOILER $E_{BOIL} = .9$



T_{T_1} 625°F

$T_{D_1} = 646.16$ °F

$Q_{T_1} = 49.291$[illegible] $Q_{T_2} = 19.485$[illegible] $Q_{T_3} = -45.31381$ BTU/# $Q_{T_4} =$

$T_{T_1} = 625$ °F $T_{T_2} = 5$[illegible] °F $T_{T_4} = 335.01$ °F

$T_{D_2} = 6$[illegible] °F $T_{D_3} = 5$[illegible] °F $T_{D_4} =$ [illegible]

$E_I =$ [illegible] $E_{II} = .9$ $E_{III} = .97$[illegible] $W_D/W_S = 7.$[illegible]

$W_{D_{TOT}} = 98222$ #/HR

$T_{AV} = 572.93$ °F

$T_{T_1} = 550$ °F $T_{D_1} = 568$

$Q_{T_1} = 14.279142$ BTU/# $Q_{T_2} = 17.6994$ BTU/# $Q_{T_3} = -71.6785$ BTU/# $Q_{T_4} = -178.$[illegible] BTU/#

$T_{T_1} = 550$ °F $T_{T_2 . 3} = 547.35$ °F $T_{T_4} = 335.01$ °F

$T_{D_2} = 567.66$ $T_{D_3} =$ [illegible] $T_{D_4} =$ [illegible] °F

$E_I = .1$[illegible] $E_{II} = .9$ $E_{III} = .97$[illegible] $W_D/W_S = 7.6085$

$W_{D_{TOT}} = 292069$ #/HR

$T_{AV} = 546.91$ °F

7-1?-?? [illegible] TO SYSTEM [illegible] (POWER CONVERSION)

LARGE TURBINE

$T_1 = 500°F$ $P_1 = 200°F$ $h_1 = 4.413356$ BTU/# $S_1 = .01924$

$T_{cond} = 350°F$ $P_{cond} = 71.019547$ PSIA

$T_{S1} = 440.80$ $h_{S1} = -151753$

$T_2 = 457.12°F$ $h_2 = -10.08226$ BTU/# $E_P = .57313$ $E_{TOT} = .84214$

$T_3 = 566.71°F$ $T_5 = 417.32°F$ $h_5 = -154.5101$ BTU/# $T_6 = 418.31°F$ $h_6 = -153.93081$ BTU/#

$T_P = 350.70°F$ $h_P = -197.1875$ BTU/# $\Delta h_{pump} = .96509$ BTU/#

$\eta_c = .09154$ Δh_{pump} @ TURBINE $= \frac{.96509}{.9[illegible]} = 1.0807$

$\eta_{c\,NET} = .08472$ (INCLUDING PUMP)

[illegible]

$T_1 = 500°F$ $P_1 = [illegible]°F$ $h_1 = 4.413356$ BTU/# $S_1 = .019164$

$T_{cond} = [illegible]°F$ $P_{cond} = 8.70578$

$T_{S1} = 344.[illegible]°F$ $h_{S1} = -57.1123$ BTU/#

$T_2 = 312.[illegible]°F$ $h_2 = -37.1[illegible]$ $E_P = .573[illegible]$ $E_{TOT} = .84214$

$T_3 = 718.68°F$ $T_5 = 2[illegible].34°F$ $h_5 = -252.[illegible]899$ BTU/# $T_6 = 257.79°F$ $h_6 = -251.35691$ BTU/#

$T_P = 201.07°F$ $h_P = -267.7615$ BTU/# $\Delta h_{pump} = 1.2217$

$\eta_c = .17721$ Δh_{pump} @ TURBINE $= \frac{1.2217}{.[illegible]} = 1.3681$ BTU/#

$\eta_{c\,NET} = .17141$ (INCLUDING PUMP

LOADS

Q_{COOL} = 2640612 BTU/HR = 220.05 tons

Q_{HEAT} = 0

$Q_{AIR\ CFCC}$ = 2.77 X 10^6 BTU/HR

$Q_{SEP\ ELECT}$ = 1465072 BTU/HR @ Turbine = 4293 KW

[illegible]
LARGE TURBINE

Q_{ELECT} GENERATED = 210115 BTU/HR = 61.5 KW

Q_{SYS} = 7.480 X 10^6 BTU/HR W_{STM} = 15664 #/HR

h_L = −153.9208 BTU/# T_L = 416.21 °F

SMALL TURBINE

Q_{SEP} ELECT REQD = 367.73 KW = 1254952 BTU/HR @ TURBINE

Q_{ELECT} GEN = 780374 BTU/HR = 228.67 KW @ TURBINE

h_L = −231.7569 BTU/# T_L = 275.79 °F

Q_{ABS} = 3.77 X 10^6 BTU/HR Q_{ABS} = 220.05 Tons

W_{ABS} = [illegible] #/HR Q_{SYS} = 4.553 X 10^6 BTU/HR W_{SYS} = 19177 #/HR

h_L mix = −196.8676 BTU/# W_{MIX} = 3[illegible] #/HR Q_{TOT} = 7.033 X 10^6 BTU/HR

T_L mix = 339.68 °F $P_{overall}$ = $\frac{99.0 \times E9}{7.033 \times 10^6}$ = .14083

APPENDIX B5

APPENDIX B5

POWER CONVERSION SYSTEM SEASONAL PERFORMANCE

Attached is the analysis for the final conceptual design for the power conversion system. The results of this analysis are discussed in Section 3.2.3 of the report.

Power Conversion System Seasonal Performance

Attached is the analysis for the final conceptual design for the power conversion system. The results of this analysis is discussed in section 3.2.3 of the ~~final~~ report.

SECOND STAGE

$T_{COND} = 175^{\circ}F$ $\quad P_{Cond} = 1.878$ #/in

$T_1 = 463.73^{\circ}F$ $\quad h_1 = -4.7892$ BTU/# $\quad P_1 = 71.01954$ psia $\quad S_1 = .03054$

$T_{5r} = 300.95^{\circ}F$ $\quad h_{5r} = -68.6575$ BTU/#

$T_2 = 348.52^{\circ}F$ $\quad h_2 = -57.0517$ BTU/# $E_T = .57$ $\quad E_{TOT} = .8392$

$T_3 = 163.63^{\circ}F$ $T_5 = 271.28^{\circ}F$ $h_5 = -734.035$ BTU/# $T_6 = 276.11^{\circ}F$ $h_6 = -731.594$

$T_P = 129.16^{\circ}F$ $\quad h_P = -798.579$ BTU/# $\quad \Delta h_{pump} = 4.069$ $\quad \eta_{STAGE} = .7083$

$$\eta_{e\,overall} = \frac{22.3389. + 52.0717 - 4.069}{22.3389. + 231.594} = .27698$$

JANUARY

FIRST STAGE (PROCESS HEAT + NIGHT HEATING)

$Q_{PROCESS} = 2.27 \times 10^6$ BTU/HR

Q_{HEAT} = 105195 BTU/HR

Q_{ELECT} REQ'D @ TURBINE = 429.3 KW = 1465077 BTU/HR

Q_{ELECT} GENERATED = 354600 BTU/HR = 103.9 BTU/HR

T_6 = 428.31 °F h_6 = -148.0586 BTU/#

$Q_{SYS} = 2.73 \times 10^6$ BTU/HR W_{SYSTEM} = 16017 #/HR

SECOND STAGE (CONDENSE @ 125°F THROW AWAY)

Q_{ELECT} REQ'D = 429.3 - 103.9 = 325.4 KW = 1110495 BTU/HR

n = 2.6104

Q_{REJ} = 2.6104 × 1110495 = 2.898831 BTU/HR

Q_{ELECT} GENERATED = 325.4 KW = 1.11×10^6 BTU/HR

$Q_{SYS} = 4.01 \times 10^6$ BTU/HR W_{SYS} = 15789 #/HR

T_6 = 276.11 °F h_6 = -231.594 BTU/#

h_{MIX} = -189.542 BTU/# $T_{6\,MIX}$ = 354.52 °F [illegible]

$\dot{W}_{MIX}$ = 31806 #/HR

HX 3 PASS 4 NTU/PASS C_{MT} = .984 OR T_{D1} = 650°F MAX

T_{D1} = 650°F T_{D2} = 399.31°F T_{DAV} = 524.66°F C_{MT} = .977

$\dot{W}_{D\,HX}$ = 45508 #/HR W_D/W_T = 1.431

APRIL

FIRST STAGE (PROCESS HEAT ONLY)

$Q_{PROCESS} = 2.27 \times 10^6$ BTU/HR

Q_{ELECT} REQ'D = 429.3 KW = 1465072 BTU/HR

Q_{ELECT} GENERATED = 338895 BTU/HR = 99.30 KW

$Q_{SYST} = 2.609 \times 10^6$ BTU/HR $\dot{W}_{SYS}$ = 15308 #/HR

T_6 = 478.31 °F h_6 = -148.0886 BTU/#

SECOND STAGE (Q_{COOL} + NIGHT HEATING + THROW AWAY COOLING)

Q_{ELECT} REQ'D = 429.3 − 99.30 = 330 KW = 1126191 BTU/HR

$Q_{COOLING}$ = 35 TON = 420000 BTU/HR
Q_{HEAT} = 34650 BTU/HR
$n = 3.4978$

$Q_{REJ} = 3.4978 \times 1126191 - 34650 - \frac{420000}{.7} = 3.304 \times 10^6$ BTU/HR

Q_{ELECT} GENERATED = 1126191 BTU/HR = 330 KW

$Q_{SYS} = 5.065 \times 10^6$ BTU/HR $\dot{W}_{SYS}$ = 22652 #/HR

Q_{ABS} = 599996 BTU/HR R_{ABS} = 35 TONS $\dot{W}_{ABS}$ = 3450 #/HR

$\dot{W}_{PROC}$ = 19201 #/HR

T_6 = 334 °F h_6 = -201.7507 BTU/#

h_{6MIX} = -179.530 BTU/# T_{6MIX} = 377.31 °F $Q_{TOT} = 7.674 \times 10^6$ BTU/HR

$\dot{W}_{MIX}$ = 37960 #/HR

HX 3 PASS 4 NTU/PASS C_{RAT} = .982 $C_R T_{D1}$ = 650 °F/HR

T_{D1} = 650 °F T_{D2} = 412.10 °F T_{DAV} = 531.06 °F η_{EFF} = .9415

$\dot{W}_{DHX}$ = 57018 #/HR

JULY

(4)

FIRST STAGE (PROCESS HEAT ONLY)

$Q_{PROCESS}$ = 7.27 x 10^6 BTU/HR

Q_{ELECT} REQ'D = 429.3 KW = 1465072 BTU/HR

Q_{ELECT} GENERATED = 338895 BTU/HR = 99.30 KW

Q_{SYST} = 2.609 x 10^6 BTU/HR $\dot{W}_{SYS}$ = 15308 #/HR

SECOND STAGE (Q_{COOL} + THROWAWAY COND @ 200 °F)

Q_{ELECT} REQ'D = 429.3 − 99.3 = 330 KW = 1126191 BTU/HR

Q_{COOL} = 215.78 TONS = 2589360 BTU/HR

Q_{HEAT} = 0

λ = 3.4978

Q_{REJ} = 3.4978 x 1126191 − 2589360 = 2400 58 BTU/HR

Q_{ELECT} GEN = 1126191 BTU/HR = [illegible] KW

Q_{SYST} = 5.065 x 10^6 BTU/HR $\dot{W}_{SYS}$ = 22652 #/HR

Q_{ABS} = [illegible].9 x 10^6 BTU/HR C_{ABS} = 215.78 TONS

$\dot{Q}_{LOSS}$ = −179.530 BTU/H $T_{6\,mix}$ = 372.31 °F Q_{TOT} = 7.674 x 10^6 BTU/HR

$\dot{W}_{mix}$ = 37960 #/HR

HX   3 PASS   4 NTU/PASS C_{rat} = .98202 T_{D1} = 650 °F/HR

T_{D1} = 650 °F T_{D2} = 412.10 °F T_{AV} = 531.06 °F C_{rat} = .9[illegible]

$\dot{W}_{MAX}$ = 37018 #/HR

OCTOBER.

FIRST STAGE (PROCESS HEAT ONLY)

$Q_{PROCESS} = 2.77 \times 10^6$ BTU/HR

Q_{ELECT} REQ'D = 429.3 KW = 1465072 BTU/HR

Q_{ELECT} GENERATED = 338895 BTU/HR = 99.30 KW

$Q_{SYS} = 2.609 \times 10^6$ BTU/HR $\dot{W}_{SYS} = 15308$ #/HR

SECOND STAGE (Q_{COOL} + Q_{HEAT} + THROW AWAY @ 200 °F)

Q_{ELECT} REQ'D = 330 KW = 1126191 BTU/HR

Q_{COOL} = 48.44 TONS = 581333 BTU/HR

Q_{HEAT} = 54850 BTU/HR

λ = 3.4978

$Q_{RES} = 3.4978 \times 1126191 - 54850 - \underset{?}{581333} = 3.053818$ BTU/HR

Q_{ELECT} GENERATED = 1126191 BTU/HR = 330 KW

Q_{SYS} = 5.065734 BTU/HR $\dot{W}_{SYS}$ = 22152 #/HR

Q_{ABS} = 830472 BTU/HR $\dot{W}_{ABS}$ = 4276 #/HR

$\dot{W}_{PROC}$ = 17876 #/HR

$\dot{H}_{6mix}$ = -179,830 BTU/H T_{6mix} = 377.31°F Q_{TOT} = 7.674 $\times 10^6$ BTU/HR

$\dot{W}_{mix}$ = 31960 #/HR

HX 3 PASS 4 NTU/PASS C_{mult} = .982 OR T_{D1} = 650 °F MAX.

T_{D1} = 650°F T_{D2} = 412.10°F T_{DAV} = 531.06°F C_{mult} = .9815

$\dot{W}_{DTH}$ = 57018 #/HR

(6)

LEAVE JANUARY & JULY THE SAME

FOR APRIL & OCTOBER CONDENSE AT 125°F WITH THIRD AWAY CONDENSER & MAKE ALL COOLING VAPOR CYCLE & LET PROCESS HEAT DO NIGHT HEATING

APRIL

FIRST STAGE $\eta_2 = .1?$

$Q_{PROC} = 2.77 \times 10^6$ BTU/HR

$Q_{HEAT} = 34150$ BTU/HR

$Q_{ELECT\ REQ} = 429.? KW = 1466072$ BTU/HR

$Q_{ELECT\ GEN} = 100.52$ KW $= 343058$ BTU/HR

$Q_{SYS} = 2.6894 \times 10^6$ BTU/HR $\dot{W}_{SYS} = 15542$ #/HR

$T_6 = 478.31$°F $h_6 = -148.0786$ BTU/#

SECOND STAGE

$Q_{COOL} = 35$ TONS $= 420000$ BTU/HR (ALL VAPOR CYCLE)

$Q_{SEP\ ELECT} = 429.3 - 100.52 = 328.48$ KW $= 1.121 \times 10^6$ BTU/HR

$Q_{REJ} = 2.6104 \left(\frac{420000}{3.572} + 1.121 \times 10^6 \right) = 3.233 \times 10^6$ BTU/HR

$Q_{TOT\ ELECTRIC\ GEN} = 1.4662 \times 10^6$ BTU/HR $= 429.63$ KW (INC A/C)

$Q_{SEP\ ELECT\ GEN} = 1.121 \times 10^6$ BTU/HR $= 328.48$ KW

$Q_{VAPOR\ CYCLE} = 34.45$ KW $= 117.6 \times 10^3$ BTU/HR $R_{VC} = 35$ TONS.

$Q_{SYS} = 4.472 \times 10^6$ BTU/HR $\dot{W}_{SYS} = 19997$ #/HR

$Q_{TOT} = 7.721 \times 10^6$ BTU/HR

$h_{6\,min} = -178.019$ BTU/# $T_{6\,min} = 375.61$°F $\dot{W}_{min} = 35539$ #/HR

$T_{D1} = 650$°F $T_{D2} = 414.49$°F $T_{DAVG} = 532.25$°F $C_{mft} = .9144$

$\dot{W}_{DHX} = 50948$ #/HR

OCTOBER

FIRST STAGE

$Q_{PRBC} = 2.27 \times 10^6$ BTU/HR

$Q_{HEAT} = 54850$ BTU/HR

$Q_{ELECT\ GENERATED} = 347084$ BTU/HR $= 101.70$ KW

$Q_{SYST} = 2.672 \times 10^6$ BTU/HR $\dot{W}_{SYS} = 15678$ #/HR

$T_C = 428.31\ °F$ $h_6 = -148.0886$ BTU/#

SECOND STAGE

$Q_{ELECT\ REQ'D} = 429.3 - 101.70 = 327.6$ KW $= 1.118 \times 10^6$ BTU/HR

$Q_{COOL} = 48.44$ TONS $= 581333$ BTU/HR

$r = 2.6104$

$$Q_{REQ} = 2.6104 \left(\frac{581333}{3.572} + 1.118 \times 10^6 \right) = 3.343 \times 10^6$$

$Q_{TOT\ ELECT\ GENERATED} = 1.281 \times 10^6$ BTU/HR $= 375.29$ KW

$Q_{SEP\ ELECT\ GENERATED} = 1.118 \times 10^6$ BTU/HR $= 327.6$ KW

$Q_{VAP\ CYCLE} = 47.69$ KW $= .162752$ BTU/HR $R_{VAP\ CYCLE} = 48.44$ TONS

$Q_{SYS} = 4.624 \times 10^6$ BTU/HR $\dot{W}_{SYS} = 20678$ #/HR

$Q_{TOT} = 7.296 \times 10^6$ BTU/HR

$T_C = 334\ °F$ $h_6 = -201.2807$ BTU/#

$h_{6\ mix} = -178.342$ BTU/# $T_{mix} = 375.[illegible]\ °F$ $\dot{W}_{mix} = 36336$ #/HR

$T_{D1} = 650\ °F$ $T_{D2} = 414.08\ °F$ $T_{DAV} = 532.04\ °F$ [illegible] $= .9437$

$W_{DHX} = 50951$ #/HR

APPENDIX B6

APPENDIX B6

THERMAL STORAGE/FLUID LOOP

This appendix discusses the baseline concepts for the ullage and fluid maintenance units. A detailed description of the other major components of the Thermal Storage System (TSS) appears in Section 3.2.4 of this report.

ULLAGE MAINTENANCE UNIT

The basic requirement of this unit is to provide a controlled-pressure, inert gas atmosphere above the fluid in the thermal storage system. It is necessary to have an inert gas above the heat transfer fluid surface to prevent fire hazards and long-term oxidation of the fluid. The ullage pressure must be controlled within a moderately narrow band to avoid underpressurizing or overpressurizing the tank. When the heat transfer fluid is heated over the operating temperature range, the volume expands by about six percent. If the inert gas in the ullage in the reservoir tank were not released, the pressure would rise above the allowable upper limit. The gas released must be replaced or stored and returned to the ullage space during the cooling cycle since an equal amount of gas is required to prevent the pressure from going below the allowable lower limit as the fluid cools and contracts.

These functions must be accomplished in as simple a manner as possible with minimum capital, maintenance, and operating costs. The design also must permit reliable operational control and have the flexibility and measurement capabilities needed for the STES.

The major specific requirements on the ullage maintenance unit are as follows:

A. The gas in the ullage space must not react with the fluid. Therefore, oxygen and air must be excluded from the entire system and an inert gas such as nitrogen or carbon dioxide must be substituted.

B. A control system with suitable backups must be provided to ensure that the pressure in the ullage space will remain within the proper gage pressure range. A pressure below this range is not tolerable since this might permit collapse of the tank.

C. Since the emerging gases will be hot and will carry with them vapors given off by the fluid, they must be cooled and the condensate must be returned to the tank. Cooling the gas is required to accommodate storage of the gas in one form or another. Those gases which do not condense when cooled to near ambient temperature will be considered undesirable and will be removed from the inert gas, while the latter will be stored and used to refill the ullage space during the cooling cycle.

Several types of ullage maintenance units have been identified in previous MDAC studies. The following alternatives have been examined and evaluated during these studies:

A. Nonrecovered gas systems

- o Using GN_2
- o Using CO_2

B. Condensible Vapor Systems

- o Using water
- o Using a hydrocarbon such as heptane or hexane
- o Using other compounds

C. Recovered gas systems

- o Storage at TSU pressure (gas holder)
- o Storage of compressed gas

As a result of these studies, a recovered gas (N_2) system utilizing storage of compressed gas has been selected for analysis in this study.

The ullage maintenance unit is shown in conceptual form in Figure B6-1. The unit controls the pressure and vapor quality in the ullage space of the tank. Air is excluded since it will accelerate the heat transfer fluid degradation rate, and could in extreme instances create a hazardous condition. An inert ullage gas is added and vented as the fluid in the system expands and contracts

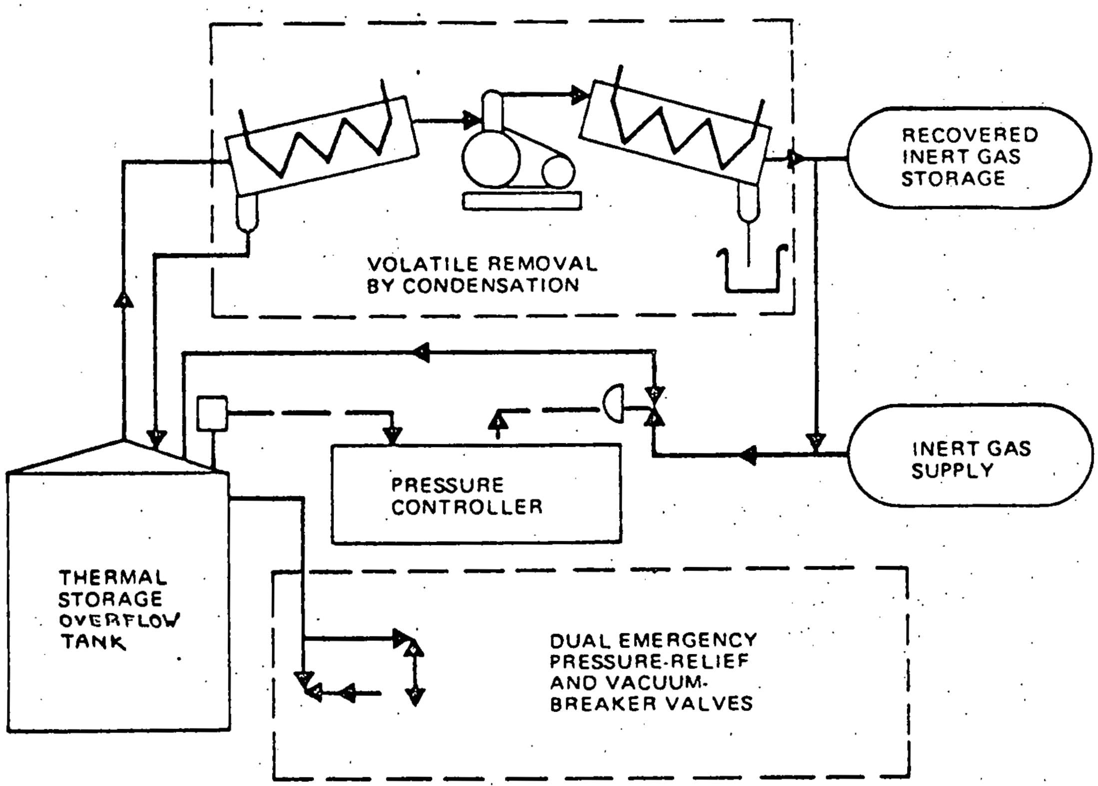


FIGURE B6-1 CONCEPTUAL SCHEMATIC OF
BASELINE ULLAGE MAINTENANCE SUBSYSTEM

during thermal cycling. Nitrogen was selected as the ullage gas for its economy and ready availability.

The baseline ullage control unit has the following features:

A. Ullage pressure automatically maintained at a few centimeters of water above ambient atmospheric pressure.

B. Low boiling condensable gases removed from expelled ullage gas so that the gas can be reused for subsequent repressurization; simultaneously the unit provides a low-boiler stripping operation for the fluid.

C. A redundant system of emergency pressure and vacuum relief valves to protect the tank in case the pressure control system is unable to handle the necessary reduction or increase in gas flow into the ullage space.

D. A liquid alarm (which also shuts off the compressor used to remove ullage gas) in case the liquid should overflow to the top of the tank.

E. Nitrogen storage at a working pressure of 1 MNg/m^2 (150 psig) and with a nitrogen volume of approximately 45.5 m^3 (1,605 ft^3) at 0°C and 1 atm, which is sufficient gas to provide one complete filling of the reservoir tank.

F. Measurement of inert gas flow into the tank for monitor and record of proper system operation; tank pressure and liquid level are also measured and recorded.

G. An explosive mixture detector/indicator and alarm with its sensor located in the upper ullage space to guard against the possibility that accumulations of noncondensable gases such as hydrogen do not reach a dangerous level should a sudden expulsion to the atmosphere occur. (If such gases accumulate over a period of time, they can be vented to the atmosphere or mixed with natural gas and torched. Make-up gas will automatically come in from the reserve with nitrogen storage providing the required inert gas dilution.)

FLUID MAINTENANCE UNIT

The general requirement imposed on the fluid maintenance unit is that it maintain the heat transfer fluid in satisfactory condition for continual operation of the Thermal Storage Subsystem. Some of the detailed requirements to be met by the unit related to fluid stability, degradation products, and degradation rates are as follows.

The fluid maintenance unit will be required to:

A. Maintain the level of high-boilers (polymerized materials) below a given value. There are indications that 20 to 40 percent is acceptable; 20 percent was used as a requirement on this design.

B. Remove suspended solids from the circulating fluid, both during normal operations and during initial start-up with an unconditioned rock bed in the thermal storage unit.

C. Provide fresh heat transfer fluid to make up for materials removed from the circulating fluid.

D. Provide virtually automatic operation using a simple direct method which requires relatively inexpensive equipment.

E. Use existing state-of-the-art technology and, as far as practicable, use existing commercial components.

F. Use only a modest quantity of parasitic electrical power and thermal energy.

The analysis and design of the fluid maintenance unit depends critically on the thermal stability characteristics of the heat transfer fluid. Discussions were held with suppliers and users of the baseline heat transfer fluids in order to obtain information about the characteristics of the fluids.

Commercial experience with lubricating oils shows that routine cleanup procedures will permit reuse of the oil almost indefinitely. Experience with rehabilitation and cleanup of lubricating oils and fuels utilized in large commercial and jet engines facilities is directly applicable to the cleanup of the thermal storage fluid. These processes use distillation to remove low-boiling-point fractions in combination with filtration to remove solids. The lubrication-oil reclaiming industry recently developed several new processes which utilize solvent extraction to extract various additives and metals. Another new method adds recycled naphtha combined with a mild caustic (sodium carbonate) to the oil, causing the carbonaceous material to separate. After centrifugation, the oil is vacuum fraction distilled.

From the standpoint of the fluid maintenance unit, increasing the allowable concentration of high boilers which can be tolerated decreases the size of the clean-up limit. However, the following considerations affect the upper value of the concentration:

A. The viscosity increase at working temperatures requires greater pumping power.

B. If system shutdown and cooling are required, the room temperature viscosity should not be so great as to make a restart impossible.

C. High concentration may increase or decrease the degradation rate; however, the effect of high boiler concentration on decomposition is unknown.

The baseline fluid maintenance unit for the STES TSS is shown schematically in Figure B6-2. It performs three functions to maintain fluid stably within its operating range: filtration to remove suspended solids, distillation of a side stream to remove high boiling compounds, and addition of fresh make-up fluid to replace the material removed. The unit is designed to use existing commercial components.

A screen of about 20-mesh is provided at the entrance to each pump. This removes trash and large particles which are prevalent primarily at startup or immediately after repairs have been made. Once the system has been cycled a number of times, the likelihood of large particles being carried along is very highly reduced. The TSS bed acts as an effective filtration bed, and only the smallest particles can be picked up by the fluid because its velocity is extremely low. At typical fluid design velocities, particles of spherical shape and of the same density as rock will gradually settle back down to the

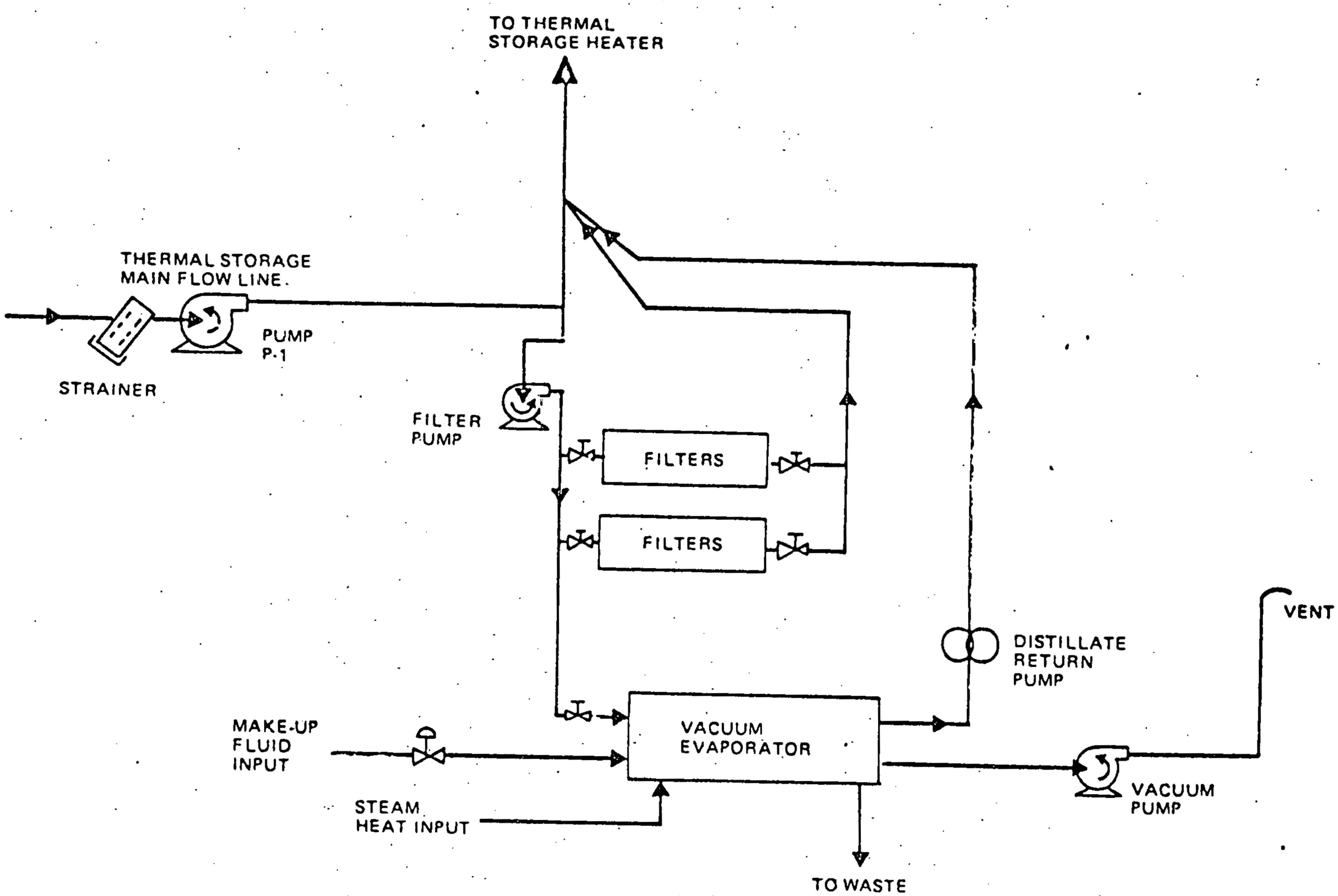


FIGURE B6-2 CONCEPTUAL SCHEMATIC OF BASELINE FLUID MAINTENANCE UNIT.

bed if the diameter of the particle is greater than 16 micron (0.0016 cm); only particles smaller than this could be carried along with the fluid. This particle size is so small, however, that as long as their concentration is low they will not harm the system. Nevertheless, filtration equipment capable of removing particles down to 10-micron diameter is being provided for the following reasons:

A. The material collected by several filters haveing different pore sizes is valuable for determining the extent and source of system contamination and will be of great value in system design scale-up.

B. The solid material found in the fluid may be a product of polymerization and carburization of the fluid itself, and is therefore expected to have a density close to that of the fluid. Hence, it will not settle out by gravity in the TSS as is the case for relatively dense particles of sand or rock. This light material may prove to be detrimental from a chemical standpoint in that it may be found to catalyze polymerization of the fluid producing even more high boilers. Thus, its removal is considered desirable until further confirmation is available.

APPENDIX B7

APPENDIX B7

SYSTEM INTEGRATION

The system operating temperature trade study was discussed in Section 3.2.5 of this report using the baseline collector/field option. The trade study was also performed using the performance of several other collector/field options. The candidate collector fields used in the trade are listed in Table C-2-1.

The season collector performances for the five other candidate fields are shown in Figures C-2-1 through C-2-5. Their performances, along with the baseline collector field, are summarized in Table C-2-2.

System efficiencies were calculated, using the methodology discussed in Section 3.2.5 for all of the collector field options using both organic rankine and steam power conversion cycles. This data is presented in Figures C-2-6 through C-2-7. The results of the trade study and its conclusions are discussed in Sections 1.4.1 and 3.2.5 of the main report.

B7-2

TABLE C2-1

CANDIDATE COLLECTOR FIELDS

1.	EAST WEST HORIZONTAL PARABOLIC TROUGH	GCR* = 0.464
2.	NORTH SOUTH HORIZONTAL PARABOLIC TROUGH	GCR = 0.464
3.	NORTH SOUTH POLAR PARABOLIC TROUGH	GCR = 0.463
4.	NORTH SOUTH POLAR PARABOLIC TROUGH	GCR = 0.313
5.	TWO AXIS NORTH SOUTH FRESNEL	GCR = 0.463
6.	TWO AXIS NORTH SOUTH FRESNEL	GCR = 0.313

GCR = GROUND COVER RATIO

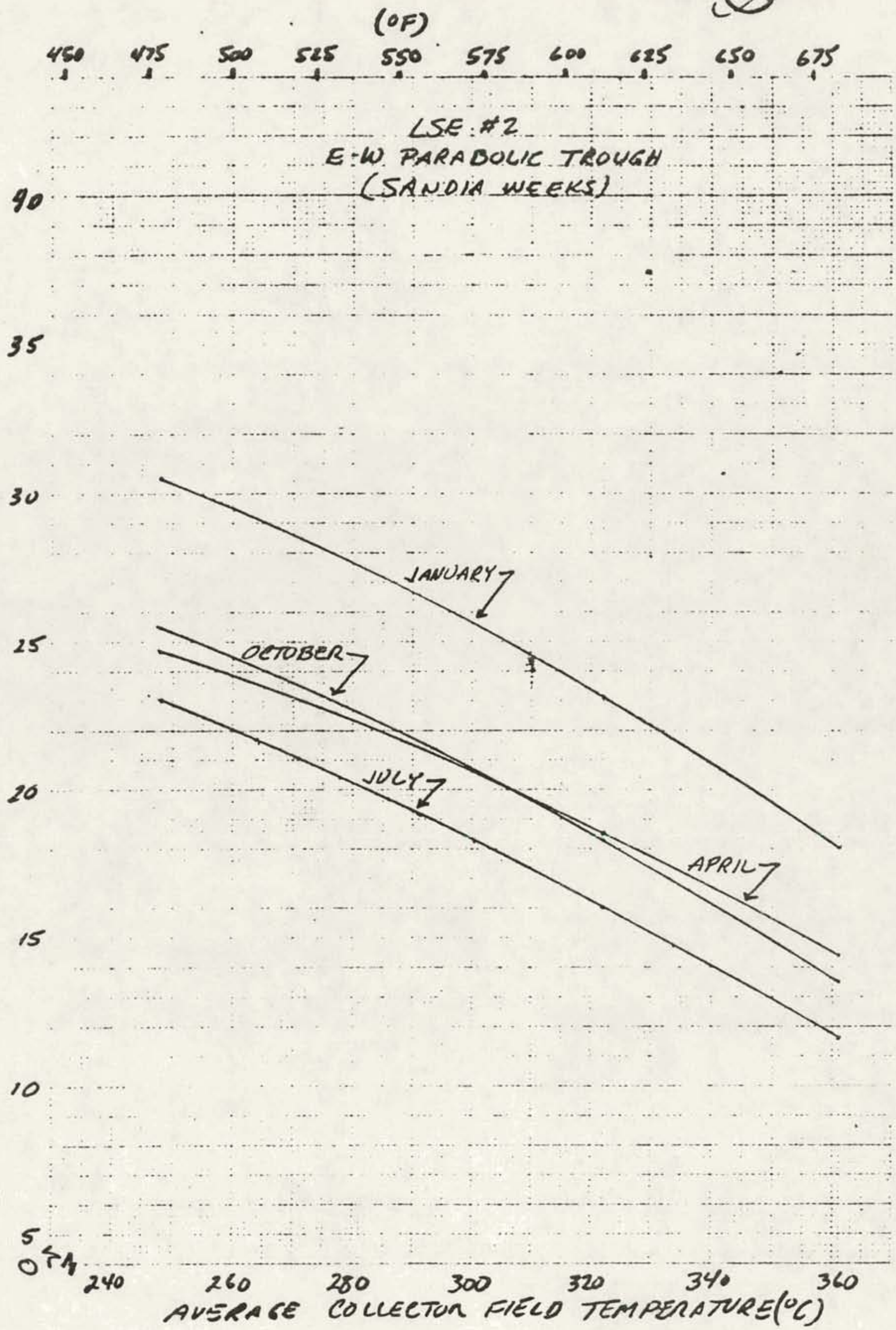


FIGURE C-2-1

51

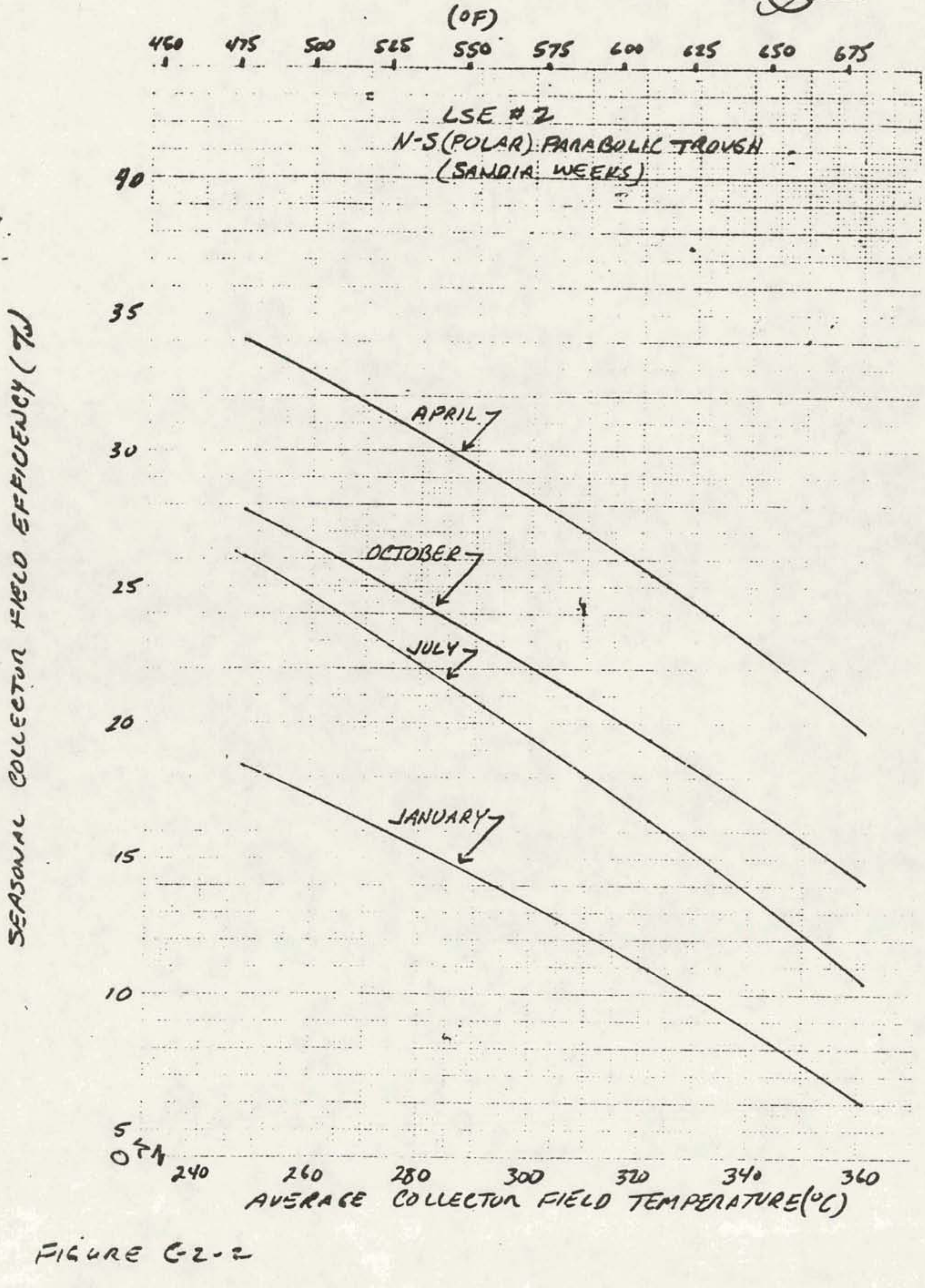


FIGURE C-2-2

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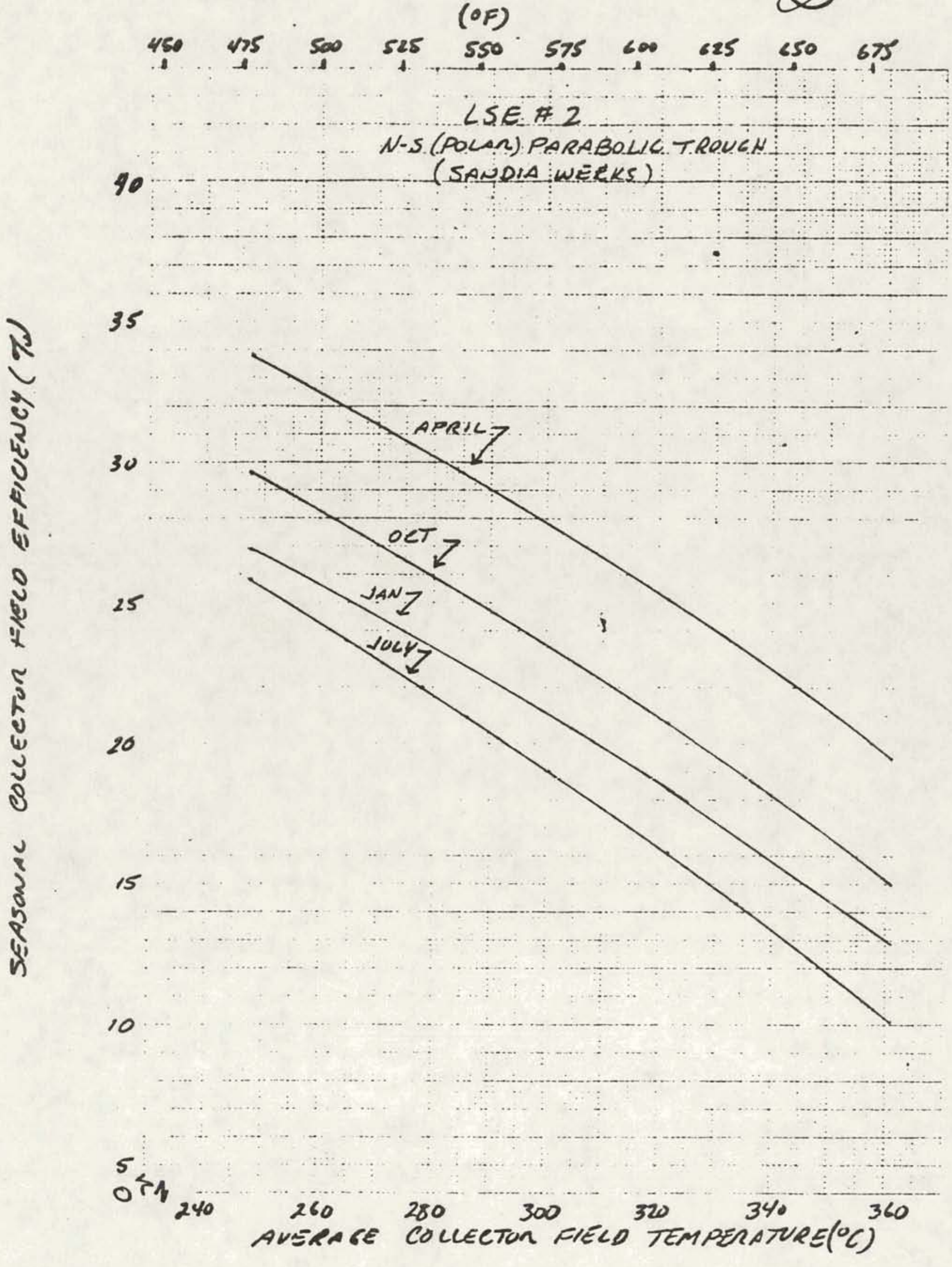
(°F)
450 475 500 525 550 575 600 625 650 675
LSE #2
N-S (POLAR) PARABOLIC TROUGH
(SANDIA WERKS)
SEASONAL COLLECTOR FIELD EFFICIENCY (%)
40
35
30
25
20
15
10
5
0
APRIL
OCT
JAN
JULY
240 260 280 300 320 340 360
AVERAGE COLLECTOR FIELD TEMPERATURE (°C)

FIGURE C-2-3

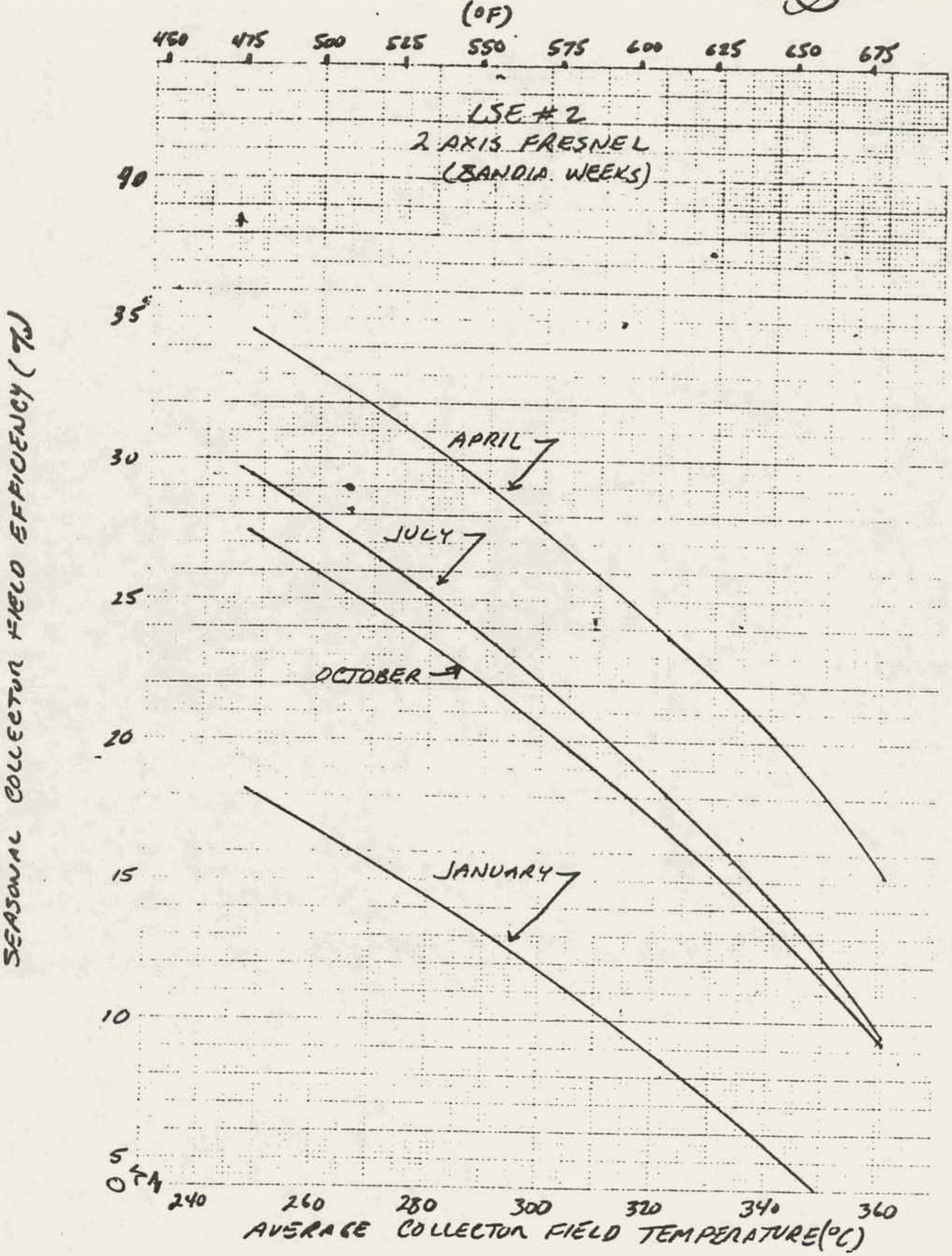

FIGURE C-2-4

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DOUGLAS

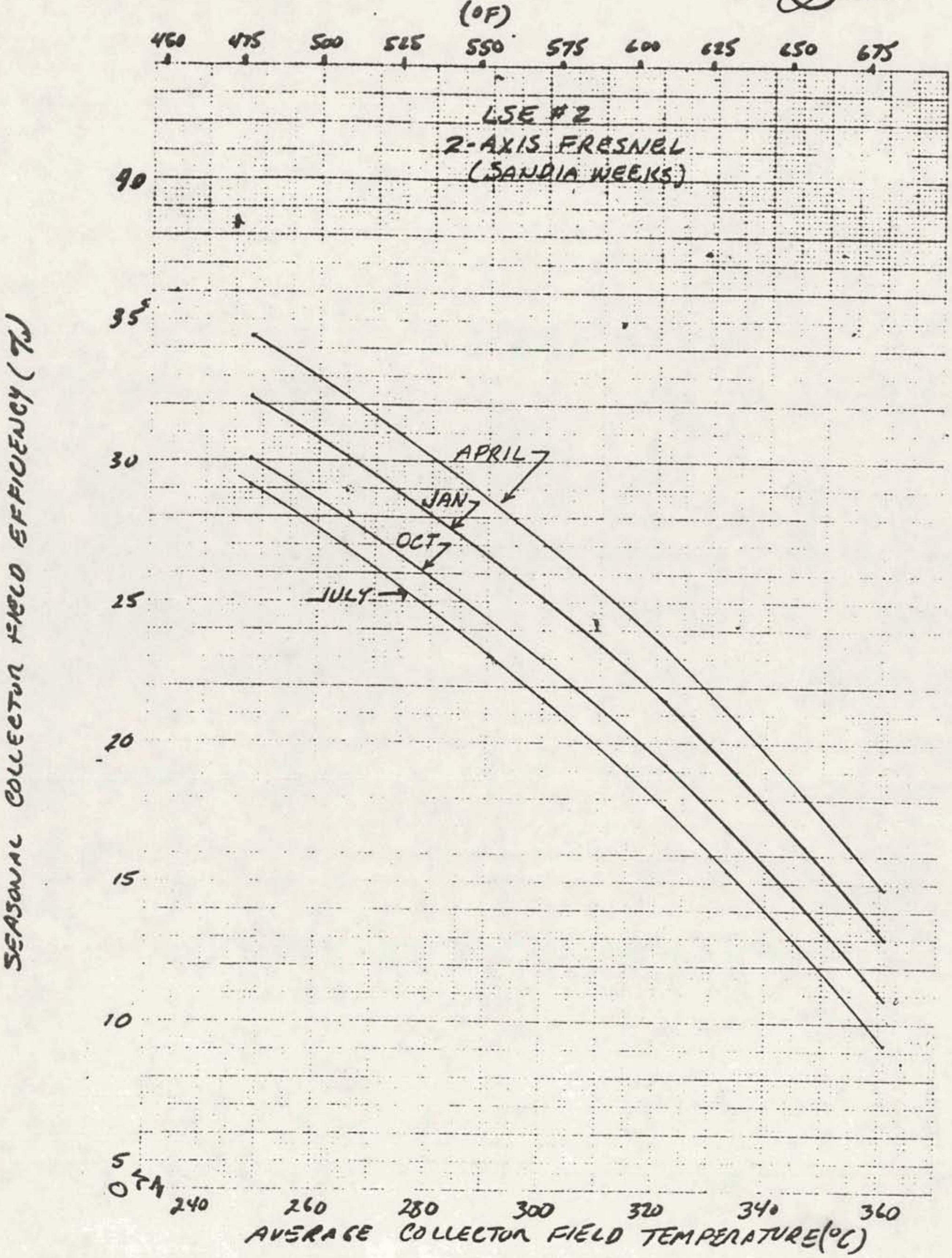

FIGURE C-2-5

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TABLE C-2-2

COLLECTOR FIELD EFFICIENCY

SUMMARY

COLLECTOR	SEASONAL ORDER OF PERFORMANCE BEST → POOREST	BEST SEASON PERFORMANCE @ 300°C (%)	SEASONAL VARIATION $\Delta\ \eta_c$ @ 300°C (Δ%)
1. E-W HORIZONTAL PARABOLIC TROUGH GCR = 0.464	JAN, OCT-APR, JULY	25.6	7.3
2. N-S HORIZONTAL PARABOLIC TROUGH GCR = 0.464	JULY, APR, OCT, JAN	32.7	22.9
3. N-S POLAR PARABOLIC TROUGH GCR = 0.464	APR, OCT, JULY, JAN	28.2	14.9
4. N-S POLAR PARABOLIC TROUGH GCR = 0.313	APR, OCT, JAN, JULY	27.8	8.7
5. TWO AXIS N-S FRESNEL GCR = 0.463	APR, JULY, OCT, JAN	27.5	15.7
6. TWO AXIS N-S FRESNEL GCR = 0.313	APR, JAN, OCT, JULY	27.1	5.6

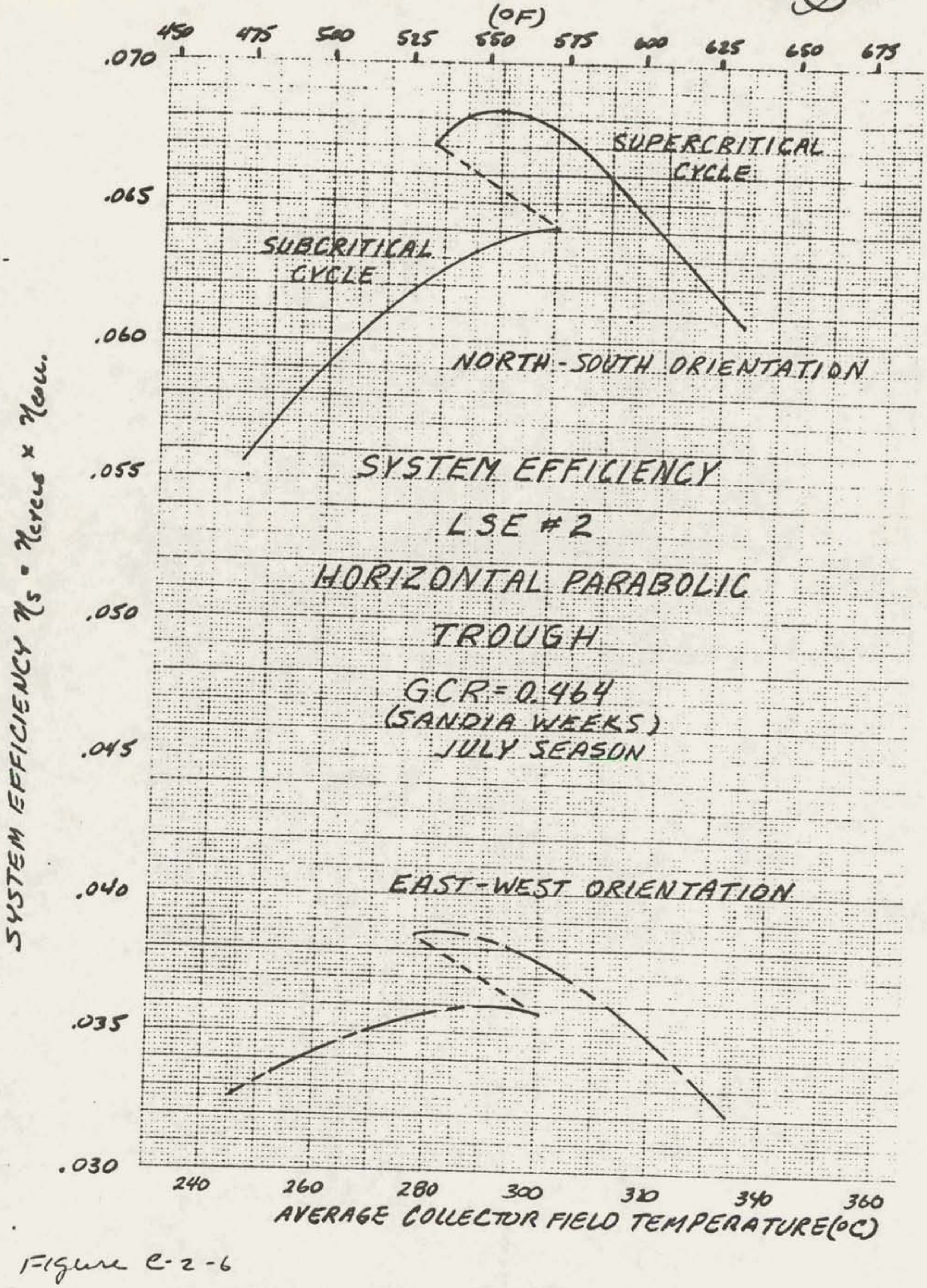

Figure C-2-6

60

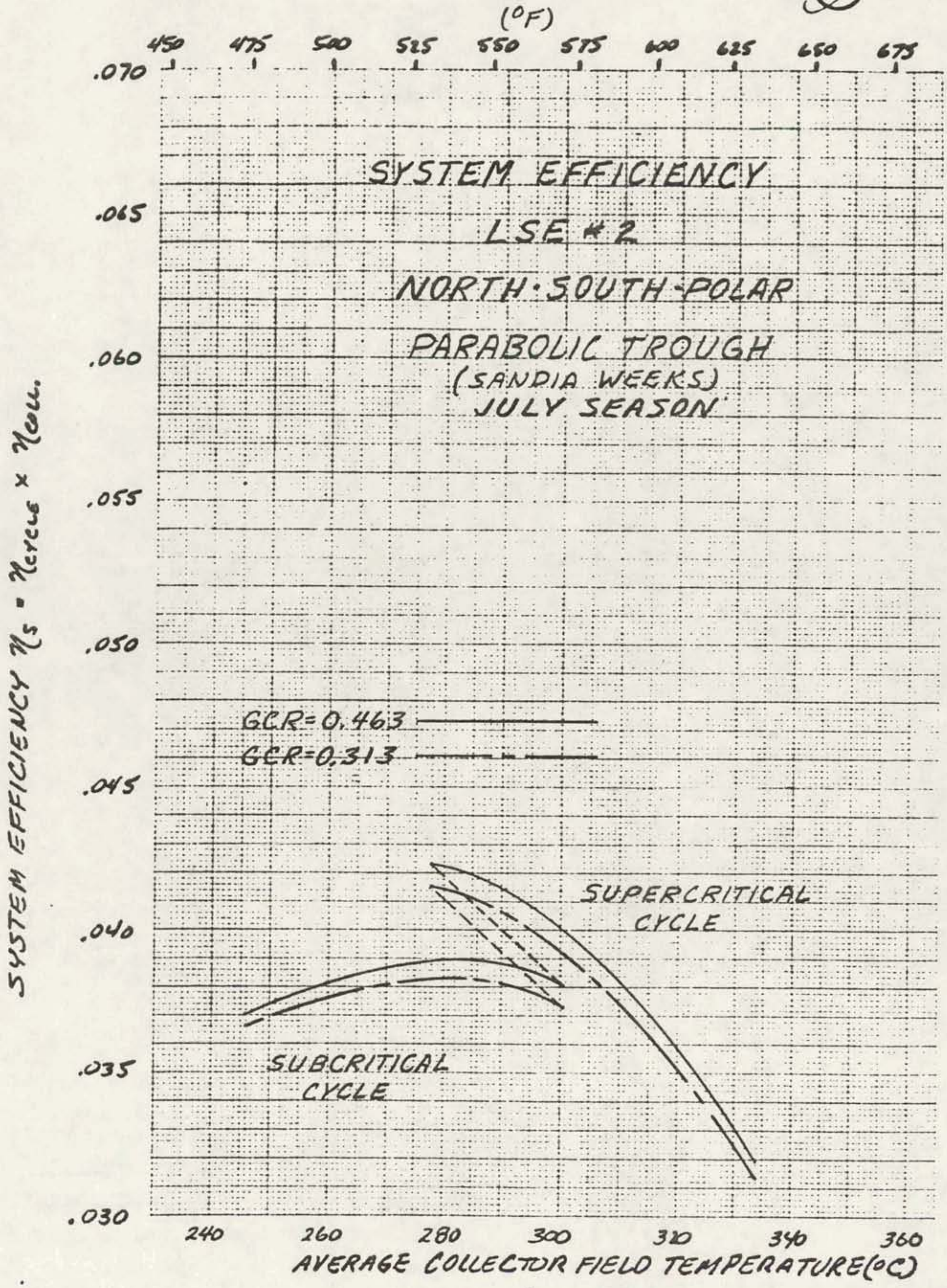

FIGURE C2-7

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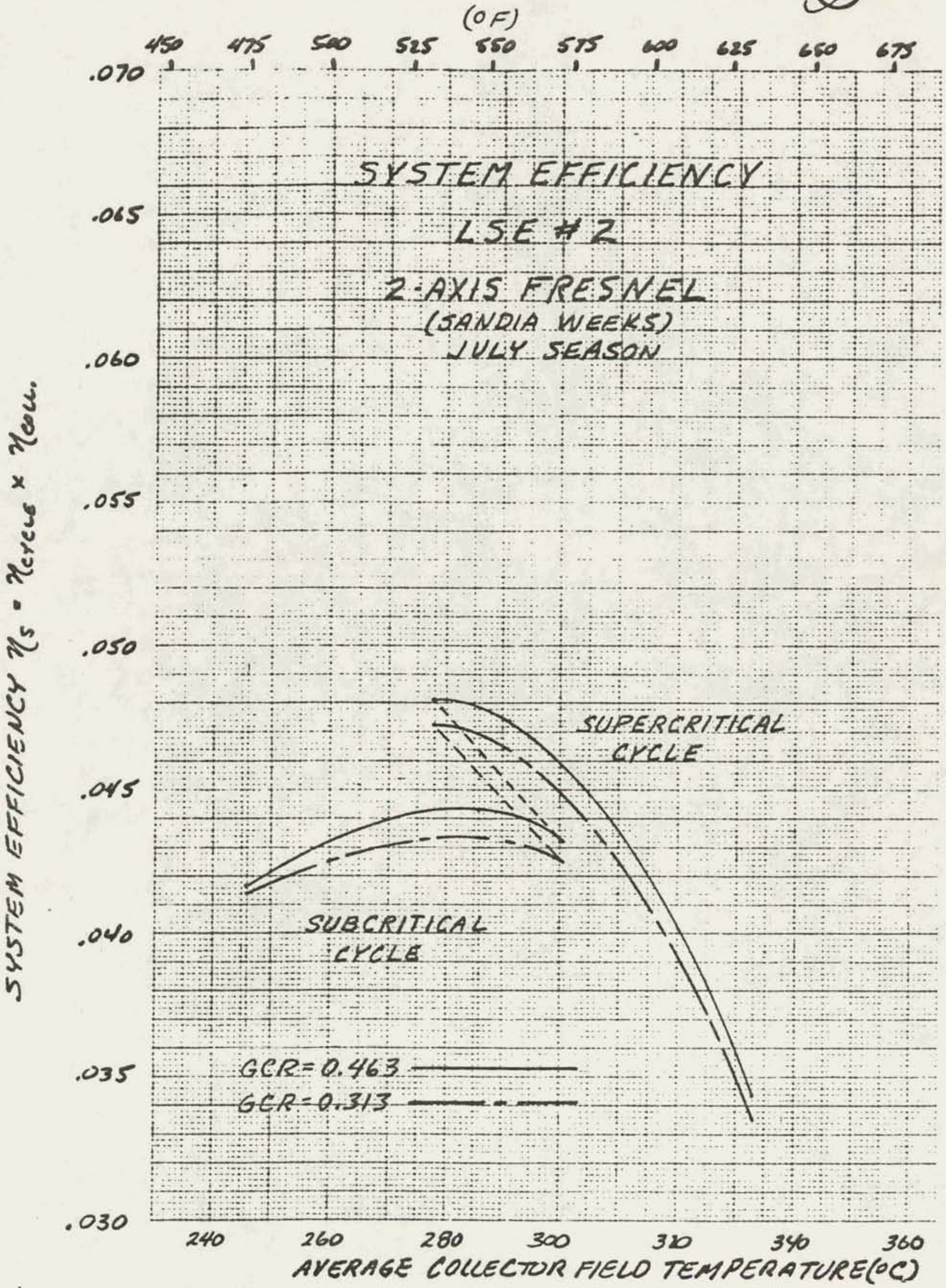

Figure C-2-8

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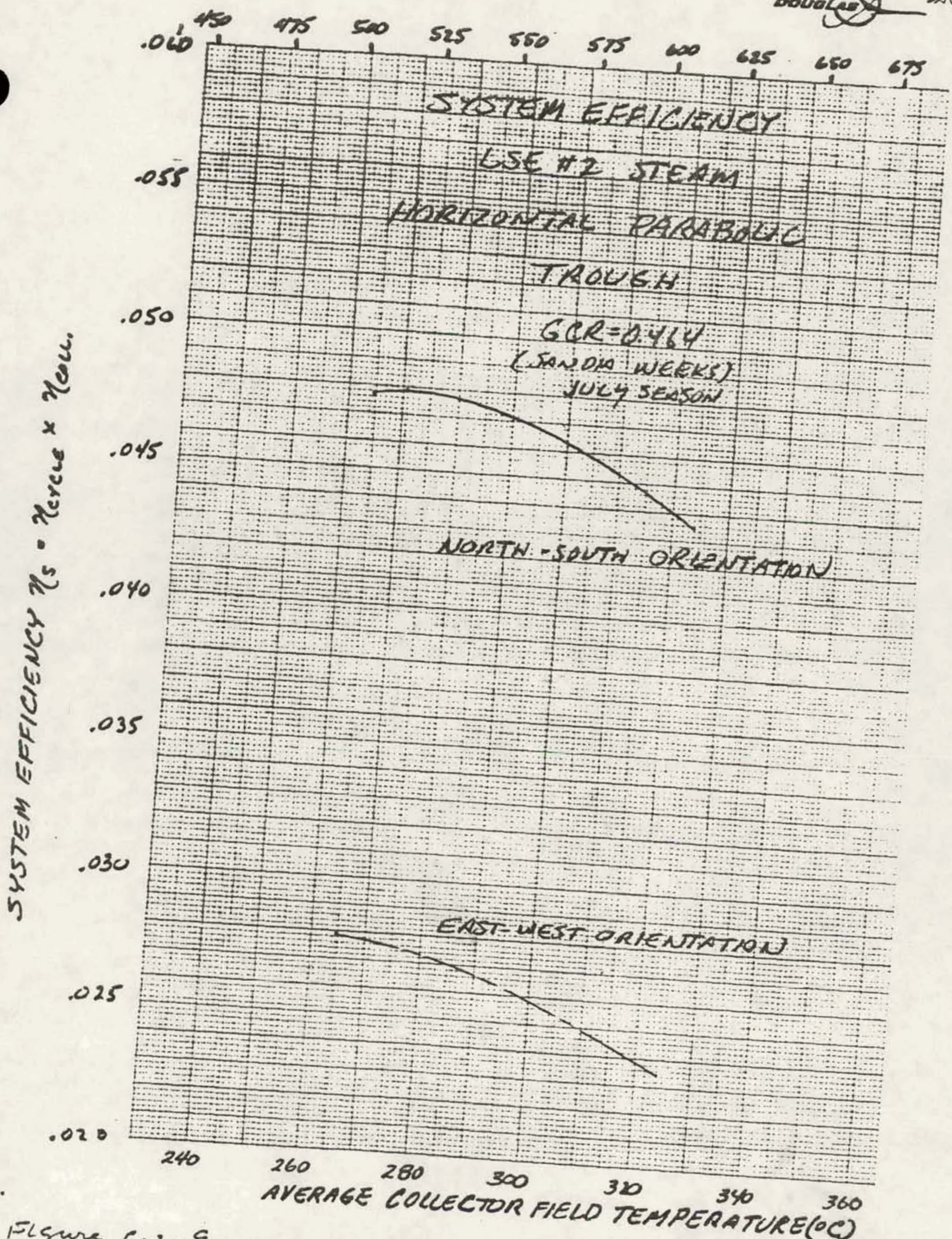

450 475 500 525 550 575 600 625 650 675
SYSTEM EFFICIENCY
LSE #2 STEAM
HORIZONTAL PARABOLIC
TROUGH
GCR=0.464
(SANDIA WEEKS)
JULY SEASON
NORTH-SOUTH ORIENTATION
EAST-WEST ORIENTATION
.060
.055
.050
.045
.040
.035
.030
.025
.020
SYSTEM EFFICIENCY $\eta_s = \eta_{cycle} \times \eta_{coll.}$
240 260 280 300 320 340 360
AVERAGE COLLECTOR FIELD TEMPERATURE(°C)

Figure C-2-9

DOUGLAS [signature] DAC 7/26/77

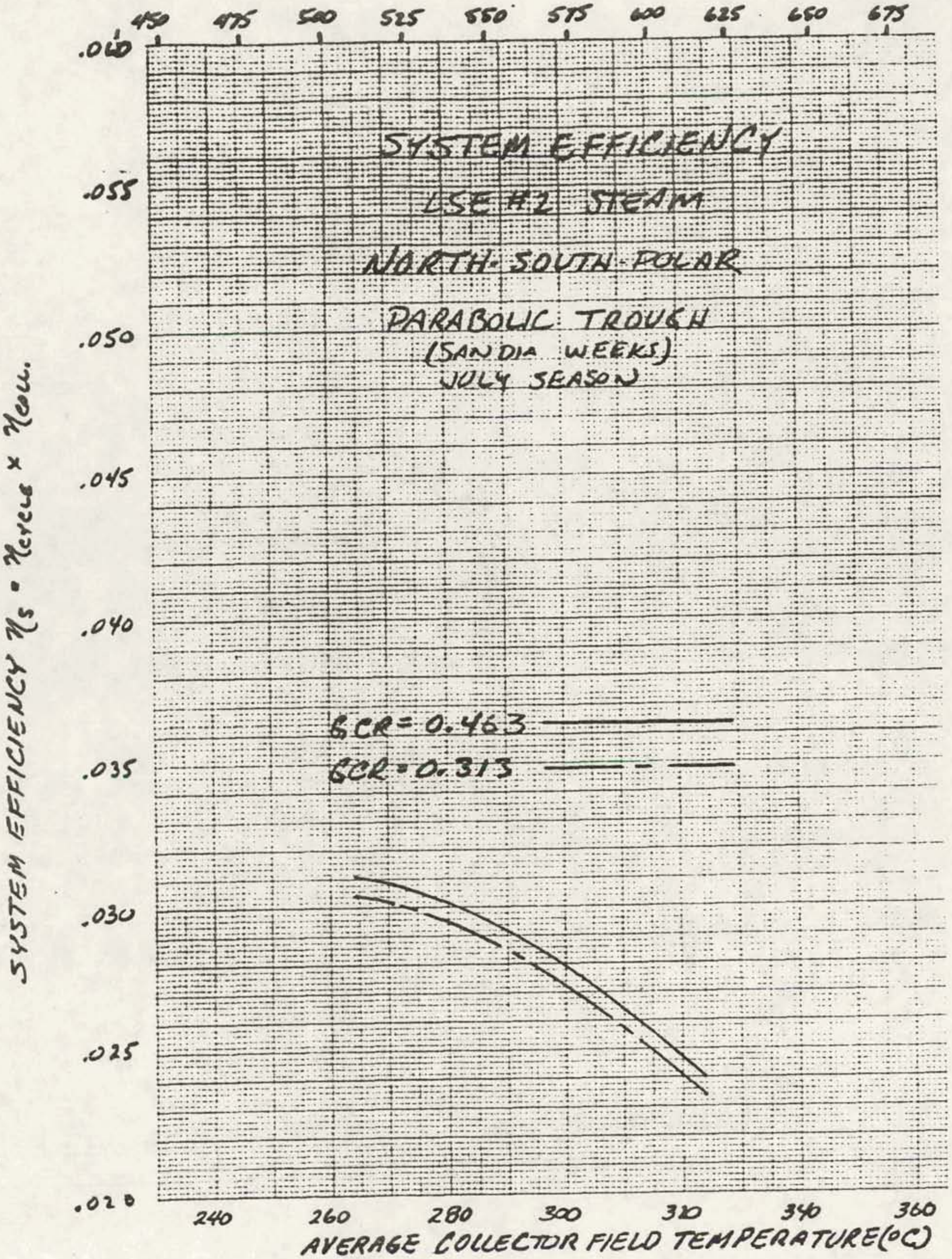

FIGURE C-2-10

DOUGLAS — DAC 7/26/77

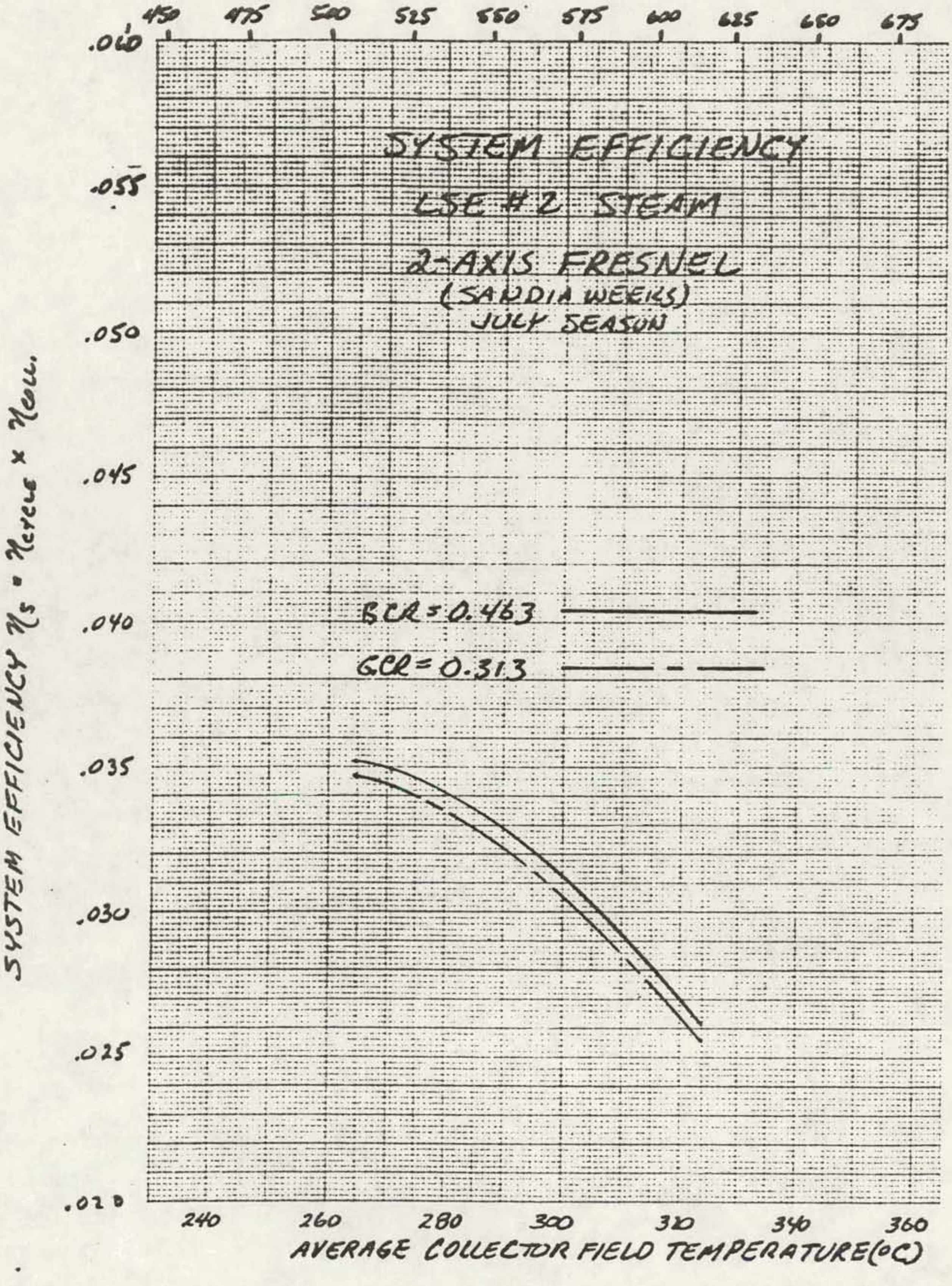

FIGURE C-2-11

APPENDIX B8

APPENDIX B8

BACKUP COST ESTIMATES
(Ref. Section 3.7)

Stearns-Roger SHEET NO. 1/7

JOB STES #2 CAPITAL COST FOR 1ST UNIT ESTIMATE

ORDER NO. C-19650 | CUSTOMER ERDA/ALO | LOCATION SHENANDOAH, GEO | BY | DATE 9/15/77

AREA AND ACCOUNT	DESCRIPTION	TYPE UNIT	WEIGHT OR QUANTITY	HOURS	LABOR ($000)	MATERIAL ($000)	OTHER ($000)	TOTAL ($000)
1101	COLLECTORS							
	COLLECTOR MODULES	m^2	9683		194.0	733.6	—	927.6
	COLLECTOR FNDN MATERIAL				—	—	41.8	41.8
	TOTAL COLLECTORS				194.0	733.6	41.8	969.4
1102	PIPING							
	2.5" ϕ				1.9	2.6	—	4.5
	3.5" ϕ				1.5	1.7	—	3.2
	4.0" ϕ				2.3	2.5	—	4.8
	4.5" ϕ				1.0	1.0	—	2.0
	PIPING INSULATION				—	—	41.2	41.2
	MANUAL VALVE				2.6	45.1	—	47.7
	HANGERS & SUPPORTS				8.0	138.0		146.0
	FLUID				—	401.6	—	401.6
	MISC. FITTINGS				14.3	1.5	—	15.8
	TOTAL PIPING				31.6	594.0	41.2	666.8
1103	SITE CONST. MATERIALS							
	SITE GRADING	CY	26000		45.6	—	—	45.6
	PAVING COLLECTOR AREA	SY	23300		21.0	64.2	—	85.2
	CHAIN LINK FENCING	L.F.	1900		—	—	13.6	13.6
	CONC. (MODULE FNDN)	CY	575		63.0	21.0	—	84.0
	MODULE SUPPORTS (PIPE, 3½)	Ea	1400		19.0	110.0	—	129.0
	MISC PIPING & GRADING	—	—		2.5	2.4		4.9
					151.1	197.6	13.6	362.3

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Stearns-Roger

SHEET NO. 2/7

JOB STES #2 CAPITAL COST, 1ST UNIT ESTIMATE

ORDER NO. C-19650 | CUSTOMER | LOCATION | BY | DATE 9/15/77

AREA AND ACCOUNT	DESCRIPTION	TYPE UNIT	WEIGHT OR QUANTITY	HOURS	LABOR ($000)	MATERIAL ($000)	OTHER ($000)	TOTAL ($000)
1104	PACKING, SHIPPING & INSPECT							
					—	75.2	~~75~~	75.2
	TOTAL PACK, SHIP, ECT					75.2	~~75~~	75.2
	TOTAL ITEMS 1101 THRU 1104				376.7	1600.4	96.6	2073.7
ENERGY PLANT								
1201	TURBINE GENERATOR SYSTEM							
	Fossil Fuel Heater	BTU/HR	10×10^6		11.3	75.0	—	86.3
	Toluene Vapor Turbine, incl all following equip.:							
	Speed Reducer							
	Generator (600KVA, 480V)							
	Vaporizer							
	1st & 2nd Stage Regenerator							
	" & " " Condenser/Boiler							
	" & " " Vapor Feed Pumps	GPM	55					
	Reciever	Gal	370					
	Hot well tank	Gal	415		90.0	600.0		690.0
	Condensate Feed Pump	GPM	5		0.2	0.7		0.9
	Deaerating Feed H_2O Heater	Gal	50		0.2	1.0		1.2
	TOTAL TURBINE GEN. SYS.				101.7	676.7	-0-	778.4

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Stearns-Roger

SHEET NO. 3/7

JOB STES #2 CAPITAL COST, 1ST UNIT ESTIMATE

ORDER NO.	CUSTOMER	LOCATION	BY	DATE
C-19650				9/15/77

AREA AND ACCOUNT	DESCRIPTION	TYPE UNIT	WEIGHT OR QUANTITY	HOURS	LABOR ($000)	MATERIAL ($000)	OTHER ($000)	TOTAL ($000)
1202	PIPING & MISC. EQUIP							
	ABSORP. CHILLER	TON	220		2.0	8.0		10.0
	CHILLER HOT H_2O CIRC. PUMP	GPM	550		0.9	9.0		9.9
	CHILLER COOLING TOWER				2.0	20.0		22.0
	CHILLER COOLING H_2O PUMPS (2)	GPM	800		0.9	7.1		8.0
	CHILLED H_2O CIRC. PUMPS (2)	GPM	440		0.8	5.4		6.2
	CHILLED H_2O EXP. TANK	Ea	1		0.5	1.5		2.0
	" " CHEM FEED (18 gal)	Ea	1		0.1	0.3		0.4
	BLDG. HEAT PUMPS (60 GPM)	Ea	2		0.4	1.6		2.0
	DOM. H_2O HEATER PUM (5 GPM)	Ea	1		0.2	0.6		0.8
	DOM. H_2O HEATER (40 GAL)	Ea	1		0.8	2.2		3.0
	HOT H_2O CIRC. PUMPS (180 GPM)	Ea	2		0.4	2.1		2.5
	H_2O EXPAN. TANK (CIR. H_2O)	Ea	1		0.8	2.2		3.0
	Heat EXPAN. TANK	Ea	1		0.5	1.5		2.0
	AIR COOL HEAT EXCHGR.	Ea	1		1.5	7.5		9.0
	ANTI-FREEZE / CHEM FEEDER				0.5	2.5		3.0
	CO_2 FIRE PROTECT. SYS.				5.0	3.0		8.0
	HYDROCARBON LEAK DETECTOR	Ea	1		0.2	0.8		1.0
	AIR COMPRESSOR (INSTRUMENT)	Ea	1		0.4	3.2		3.6
	" " (SERVICE)	Ea	1		0.6	9.3		9.9
	CRANE - 5 TON BRIDGE, ELEC.	Ea	1		2.5	10.0		12.5
	CONDENSATE STOR. TANK (5000 GAL)	Ea	1		1.5	3.5		5.0
	FUEL OIL STOR. TANK (15000 GAL)	Ea	1		5.0	12.0		17.0
	" " TRANS. PUMP	Ea	1		0.2	0.4		0.6
	SODIUM ION EXCH. UNIT (10 GAL)	Ea	1		0.1	0.6		0.7

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Stearns-Roger

SHEET NO. 4/7

JOB STES CAPITAL COST, 1ST UNIT

ESTIMATE

ORDER NO.	CUSTOMER	LOCATION	BY	DATE
C-19650				9/15/77

AREA AND ACCOUNT	DESCRIPTION	TYPE UNIT	WEIGHT OR QUANTITY	HOURS	LABOR ($000)	MATERIAL ($000)	OTHER ($000)	TOTAL ($000)
1202 (CONT'D)								
	COOLING TOWER FEED UNITS	EA.	2		0.4	1.8		2.2
	CHEM. FEED UNITS	EA.	3		2.0	10.0		12.0
	PIPING, VALVES & FITTINGS	L.S.			35.4	53.1		88.5
	TOTAL PIPING & MISC. EQUIP.				65.6	179.2	-0-	244.8
1203	THERMAL STORAGE							
	PUMPS				1.0	3.6		4.6
	FILTER				0.4	12.0		12.4
	COMB. HEATER				0.3	2.5		2.8
	REGULATOR				0.5	1.3		1.8
	THERMAL STORAGE TANK						358.0	358.0
	" " RESERVOIR						97.0	97.0
	BLENDING TANK						60.0	60.0
	TOTAL THERMAL STORAGE				2.2	19.4	515.0	536.6
1204	T.S. PIPING & MISC. EQUIP.							
	PIPING, FITTINGS & MISC. EQUIP.				8.0	24.0	9.8	41.8
	TOTAL PIPING & MISC. EQUIP.				8.0	24.0	9.8	41.8

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Stearns-Roger SHEET NO. 5/7

JOB STES #2 CAPITAL COST - 1ST UNIT ESTIMATE

ORDER NO.	CUSTOMER	LOCATION	BY	DATE
C-19650	ERDA			9/15/77

AREA AND ACCOUNT	DESCRIPTION	TYPE UNIT	WEIGHT OR QUANTITY	HOURS	LABOR ($000)	MATERIAL ($000)	OTHER ($000)	TOTAL ($000)
1205	BUILDINGS & MISC.							
	EXCAV. FOR BLDG FND'N	CY	900		1.2	—	—	1.2
	REIN. CONC. BLDG FND'N	CY	70		8.0	7.7		15.7
	STRUCT CONC. FLOOR SLAB	CY	260		17.2	23.4	—	40.6
	96'x72' BLOCK w/BRICK FACE BLDG. INCL. ALL FINISHED PARTITIONS & INTERIOR	L.S.			79.8	89.9		169.7
	BLDG. PLUMBING & ELEC	L.S			2.0	43.8		45.8
	TOTAL BLDGS & MISC.				108.2	164.8		273.0
1206	YARD WORK							
	ROADWAY PAVING	SY	1100		2.6	5.7		8.3
	PARKING AREA PAVING	SY	100		0.3	0.5		0.8
	MACHINE EXC. & TRENCHING	CY	3800		8.3			8.3
	EROSION CONTROL	L.S			6.0			6.0
	LANDSCAPING	L.S					10.0	10.0
	SAN. SEWER MANHOLES	Ea	2		0.4	0.8		1.2
	8" H_2O MAIN	L.F	5000				55.0	55.0
	8" GATE VALVE	Ea	1				0.7	0.7
	8" DRAIN LINE	L.F	200		0.3	1.7		2.0
	FIRE HYDRANTS	Ea	2		0.4	0.8		1.2
	TRENCHING BACKFILL	CY	3000		15.9			15.9
	TOTAL YARD WORK				34.2	9.5	65.7	109.4

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Stearns-Roger

SHEET NO. 6/7

JOB STES #2 CAPITAL COST - 1ST UNIT ESTIMATE

ORDER NO.	CUSTOMER	LOCATION	BY	DATE
C-19650	ERDA			9/15/77

AREA AND ACCOUNT	DESCRIPTION	TYPE UNIT	WEIGHT OR QUANTITY	HOURS	LABOR ($000)	MATERIAL ($000)	OTHER ($000)	TOTAL ($000)
1207	PACKING, SHIPPING & INSPECTION				-0-	50.0	-0-	50.0
	TOTAL					50.0		50.0
	TOTAL - ITEMS 1201 THRU 1207				319.9	1,123.6	590.5	2,034.0
	INTERFACE EQUIP., CONTROL & DISPLAY SYSTEMS							
1301	ELECTRICAL EQUIP. & SYSTEMS							
	POWER & CONTROL CABLING	LOT			25.0	270.5	-0-	295.5
	CONDUIT, RGS	LOT			43.8	122.8	-0-	166.6
	CONTROL BLDG, ELEC. (INCLUDES SUB STATION)	L.S.			35.2	24.3	-0-	59.5
	480V. POWER CRKT. BREAKER	Ea	5		2.4	22.0	-0-	24.4
	LOAD CENTER	Ea	1		1.0	11.3	-0-	12.3
	MOTOR CONTROL CTR.	Ea	1		1.2	8.4	-0-	9.6
	DISTRIBUTION TRANSFORMER	Ea	1		0.5	1.7	-0-	2.2
	750 KVA TRANS.	Ea	1		1.3	13.3	-0-	14.6
	480 V. BUS	Ea	1		0.8	10.1	-0-	10.9
	BATTERIES, BATT. CHARGER & 30KW DC/AC CONVERTER	LOT	1		4.2	38.7	-0-	42.9
	TOTAL ELEC. EQUIP. & SYSTEMS				115.4	523.1	-0-	638.5

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Stearns-Roger

SHEET NO. 7/7

JOB STES #2 CAPITAL COST · 1ST UNIT ESTIMATE

ORDER NO.	CUSTOMER	LOCATION	BY	DATE
C-19650	ERDA			9/15/77

AREA AND ACCOUNT	DESCRIPTION	TYPE UNIT	WEIGHT OR QUANTITY	HOURS	LABOR ($000)	MATERIAL ($000)	OTHER ($000)	TOTAL ($000)
1302	INSTRUMENTATION & CONTROLS							
	MINI COMPDER				10.0	65.0		75.0
	MISC. INST. & CONTROLS				80.0	145.0		225.0
	TOTAL INSTRU. & CONTROLS				90.0	210.0		300.0
	TOTAL ITEMS 1301 & 1302				205.4	733.1		938.5

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FORM 43-135 REV. 9-75

Stearns-Roger

SHEET NO. 1/3

JOB STES #2 CAPITAL COST - 100TH UNIT ESTIMATE

ORDER NO.	CUSTOMER	LOCATION	BY	DATE
C-19650	ERDA/ALO			9/15/77

AREA AND ACCOUNT	DESCRIPTION	TYPE UNIT	WEIGHT OR QUANTITY	HOURS	LABOR ($000)	MATERIAL ($000)	OTHER ($000)	TOTAL ($000)
COLLECTOR FIELD								
1101	MODULES							
	COLLECTORS				194.0	643.4	-0-	837.4
	COLLECTOR FND'N MAT'LS				—	—	41.8	41.8
	TOTAL MODULES				194.0	643.4	41.8	879.2
1102	PIPING (same as 1ST unit except reduction in pipe & valves)				31.6	570.2	41.2	643.0
1103	SITE CONST'N MAT'L (same as 1ST unit).				151.1	197.6	13.6	362.3
1104	PACKING & SHIPPING (same as 1ST unit).				-0-	75.2	-0-	75.2
	TOTAL ITEMS 1101 THRU 1104				376.7	1486.4	96.6	1959.7
ENERGY PLANT								
1201	TURBINE GENERATOR							
	FOSSIL FUEL HEATER				11.3	73.8	-0-	85.1
	TOLUENE TURBINE W/ MISC. EQUIP. (SEE 1ST UNIT LIST)				90.0	567.7	-0-	657.7
	CONDENSATE FEED PUMP				0.2	0.7	-0-	0.9
	DEAERATING				0.2	1.0	-0-	1.2
	TOTAL TURBINE GENERATOR				101.7	643.2		744.9

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Stearns-Roger

SHEET NO. 2/3

JOB STES #2 CAPITAL COST - 100TH UNIT ESTIMATE

ORDER NO.	CUSTOMER	LOCATION	BY	DATE
C-19650	ERDA/ALO			9/15/77

AREA AND ACCOUNT	DESCRIPTION	TYPE UNIT	WEIGHT OR QUANTITY	HOURS	LABOR	MATERIAL	OTHER	TOTAL
1202	PIPING & MISC EQUIP. (same as 1st unit except slight reduction on major equip. items)				65.6	172.8	-0-	238.4
1203	THERMAL STORAGE (T.S.)							
	PUMPS				1.0	3.6	-0-	4.6
	FILTER				0.4	12.0	-0-	12.4
	COMB. HEATER				0.3	2.5	-0-	2.8
	REGULATOR				0.5	1.3	-0-	1.8
	THERMAL STORAGE TANK				-0-	-0-	304.3	304.3
	" " RESERVOIR				-0-	-0-	82.4	82.4
	BLENDING TANK				-0-	-0-	51.0	51.0
	TOTAL THERMAL STORAGE				2.2	19.4	437.7	459.3
1204	T.S. PIPING & MISC. EQUIP.				8.0	21.6	9.1	38.7
1205	BLDGS & MISC. (same as 1st unit)				108.2	164.8	-0-	273.0
1206	YARDWORK (same as 1st Unit)				34.2	9.5	65.7	109.4

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FORM 43-135 REV. 9-75

Stearns-Roger

SHEET NO. 3/3

JOB STES #2 CAPITAL COST - 100th UNIT ESTIMATE

ORDER NO.	CUSTOMER	LOCATION	BY	DATE
C-19650	ERDA/ALO			9/15/77

AREA AND ACCOUNT	DESCRIPTION	TYPE UNIT	WEIGHT OR QUANTITY	HOURS	LABOR	MATERIAL	OTHER	TOTAL
1207	PACK. SHIP. & INSPECT. (same as 1st unit)				-0-	50.0	-0-	50.0
	TOTAL ITEMS 1201 THRU 1207				319.9	1081.3	512.7	1913.7
	INTERFACE EQUIP., CONTROL & DISPLAY SYSTEMS							
1301	ELEC. EQUIP. (same as 10th unit)				115.4	523.1	-0-	638.5
1302	INSTRU. & CONTROL (same as 10th unit)				90.0	206.2	-0-	296.2
	TOTAL ITEMS 1301 & 1302				205.4	729.3	-0-	934.7

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Stearns-Roger SHEET NO. 1/3

JOB STES #2 CAPITAL COST - 10th UNIT ESTIMATE

ORDER NO.	CUSTOMER	LOCATION	BY	DATE
19650	ERDA/ALO			9/15/77

AREA AND ACCOUNT	DESCRIPTION	TYPE UNIT	WEIGHT OR QUANTITY	HOURS	LABOR	MATERIAL	OTHER	TOTAL
	COLLECTOR FIELD							
1101	COLLECTORS (same as 1st plant)				194.0	733.6	41.8	969.4
1102	PIPING (same as 1st except reduction in pipe & valves)				31.6	583.4	41.2	656.3
1103	SITE CONST'N MAT'L (same as 1st)				151.1	197.6	13.6	362.3
1104	PACKING & SHIPPING (same as 1st)				-0-	75.2	-0-	75.2
	TOTAL ITEMS 1101 THRU 1104				376.8	1589.8	96.6	2063.2
	ENERGY PLANT							
1201	TURBINE GENERATOR							
	FOSSIL FUEL HEATER				11.3	74.3	-0-	85.6
	TOLUENE TURBINE w/ MISC. EQUIP. (see 1st unit list)				90.0	581.4	-0-	671.4
	CONDENSATE FEED PUMP				0.2	0.7	-0-	0.9
	DEAERATING				0.2	1.0	-0-	1.2
	TOTAL, TURBINE GEN. SYSTEM				101.7	657.4	-0-	759.1
1202	PIPING & MISC. EQUIP. (same as 1st unit, except a slight reduction on major items of equip.)				65.6	176.7	-0-	242.3

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Stearns-Roger

SHEET NO. 2/3

JOB CAPITAL COST 10TH UNIT

ESTIMATE

ORDER NO.	CUSTOMER	LOCATION	BY	DATE
C-19650	ERDA/IACO			9/15/77

AREA AND ACCOUNT	DESCRIPTION	TYPE UNIT	WEIGHT OR QUANTITY	HOURS	LABOR	MATERIAL	OTHER	TOTAL
1203	THERMAL STORAGE							
	PUMPS				1.0	3.6	-0-	4.6
	FILTER				0.4	12.0	-0-	12.4
	COMB. HEATER				0.3	2.5	-0-	2.8
	REGULATOR				0.5	1.3	-0-	1.8
	THERMAL STORAGE TANK				-0-	-0-	340.1	340.1
	" " RESERVOIR				-0-	-0-	92.2	92.2
	BLENDING TANK				-0-	-0-	57.0	57.0
	TOTAL THERMAL STORAGE				2.2	19.4	489.3	510.9
1204	T.S. PIPING & MISC. EQUIP.				8.0	21.8	9.1	38.9
1205	BLDG & MISC. (same as 1ST Unit)				108.2	164.8	-0-	273.0
1206	YARD WORK (same as 1ST Unit)				34.2	9.5	65.7	109.4
1207	PACK. SHIP. & INSPECT. (same as 1ST Unit)				-0-	50.0	-0-	50.0
	TOTAL ITEMS 1201 THRU 1207				319.9	1099.6	564.1	1983.6

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Stearns-Roger

SHEET NO. 3/3

JOB STES #2 CAPITAL COST - 10th Unit ESTIMATE

ORDER NO.	CUSTOMER	LOCATION	BY	DATE
C-19650	ERDA/ALO			9/15/77

AREA AND ACCOUNT	DESCRIPTION	TYPE UNIT	WEIGHT OR QUANTITY	HOURS	LABOR	MATERIAL	OTHER	TOTAL
	INTERFACE EQUIP., CONTROL & DISPLAY SYS.							
1301	ELEC. EQUIP & SYS. (same as for 1 unit).				115.4	523.1	-0-	638.5
1302	INSTRU. & CONTROLS							
	Mini Computer				10.0	61.2		71.2
	Misc. Inst. & Controls				80.0	145.0		225.0
	TOTAL INSTRU. & CONTROLS				90.0	206.2	-0-	296.2
	TOTAL ITEMS 1301 & 1302				205.4	729.3	-0-	934.7

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