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SUSITNA TRANSMISSION SYSTEM
STATUS SUMMARY

VOLUME TWO
APPENDICES

DRAFT

DECEMBER 1983

HARZA-EBASCO
SUSITNA JOINT VENTURE

ALASKA POWER AUTHORITY

SUSITNA TRANSMISSION SYSTEM

STATUS SUMMARY

VOLUME TWO
APPENDICES

DRAFT

DECEMBER 1983

HARZA-EBASCO
SUSITNA JOINT VENTURE

VOLUME 2

TECHNICAL AND ECONOMIC APPENDICES

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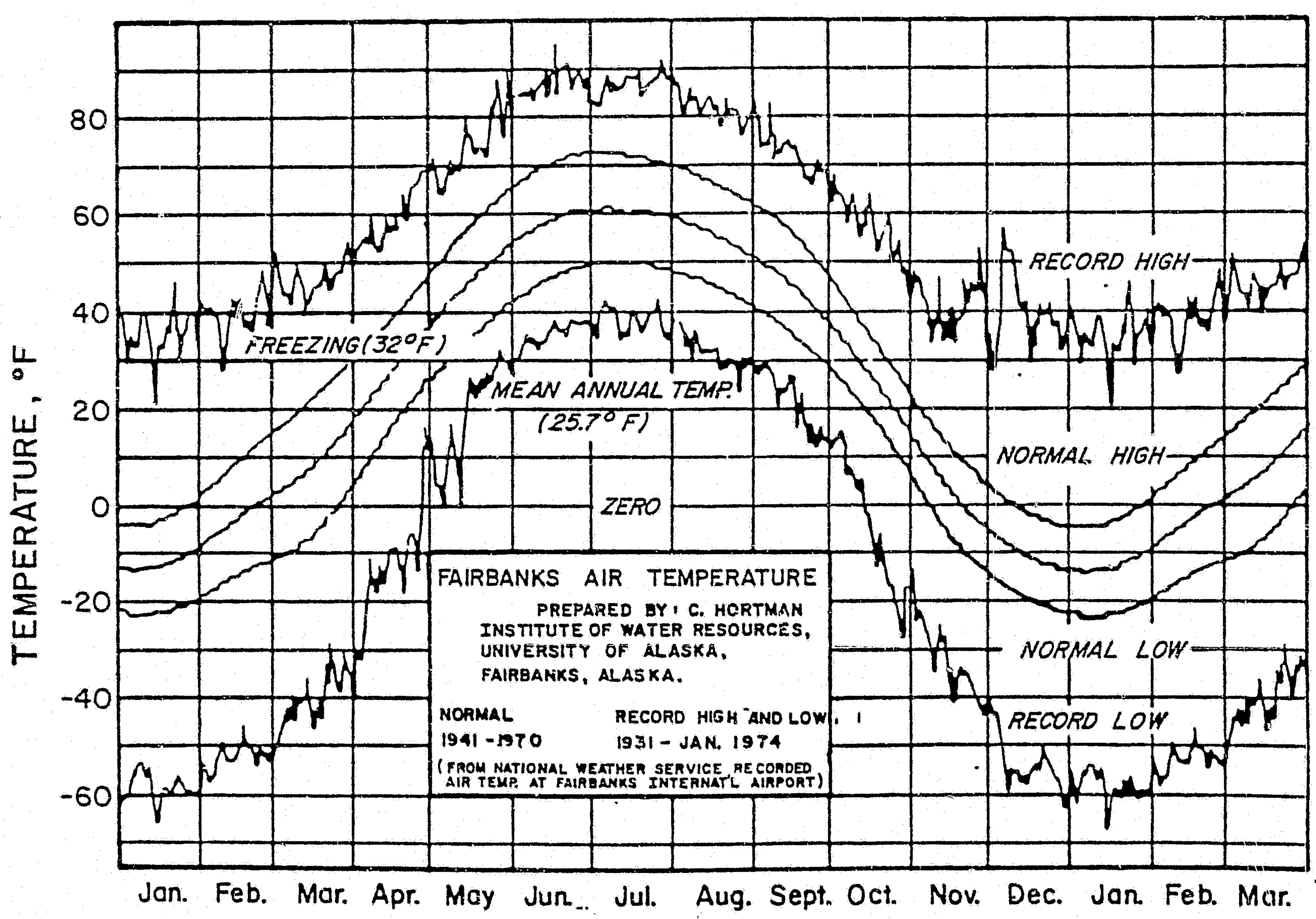
REVIEW OF ESTABLISHED METEROLOGICAL DESIGN PARAMETERS

1.0 METEROLOGICAL DESIGN PARAMETERS

A. Temperature

Temperatures experienced in Alaska exhibit an extreme range. Temperatures encountered along the northern sections of the transmission line corridor are illustrated by the curves shown in the figure below presenting data observed at Fairbanks.



The recorded range of temperature is from a record low of -65°F in winter to a record high of 95°F in summer.

The extremes of temperature in any month are observed by noting, for example, that in January there is a record low of -65°F and a record high of 46°F.

The following table based on a Northern Technical Services Study Report published in October, 1980 presents results of the temperature study tabulating maximum and minimum projected temperatures for Anchorage, Fairbanks, Summit and Talkeetna.

	Maximum Temperature (°F)			Minimmum Temperature (°F)		
Location	25 Year Period	50 Year Period	100 Year Period	25 Year Period	50 Year Period	100 Year Period
Anchorage	97.1	99.0	100.5	-54.9	-58.4	-61.9
Fairbanks	108.9	111.2	112.9	-84.3	-87.8	-91.3
Summit	104.3	107.0	109.1	-64.8	-67.8	-70.7
Talkeetna	100.9	102.6	103.9	-87.1	-92.4	-97.6

Data bases for these temperatures were annual temperatures over a 27 year span for Anchorage, 31 years for Fairbanks, 8 years for Summit and 12 years for Talkeetna.

Based on the 50 year recurrence temperatures, a minimum extreme temperature of -80°F and a minimum mean annual temperature of -40°F have been selected as acceptable levels. The following limiting criteria is selected for conductor tensions for design against aeolian vibrations:

- 25% Rated conductor strength initial at minimum mean annual temperature of -40°F;

- 20% Rated conductor strength final, at 40°F based on the analysis of 5 to 15 MPH wind occurrence, and

- Maximum 120°F conductor temperature is assumed for ground conductor clearance.

B. Heavy Wind

Key stations for wind data are located in Anchorage, Talkeetna, Summit, Healy and Fairbanks. These stations have fairly lengthy records of wind observations. None have recorded unusually severe winds. It is known that severe winds occur through and at the mouth of the Nenana Canyon in the vicinity of Healy. During initial operations of the Healy-Fairbanks 138 kV line, three towers in the vicinity of Healy were lost due to high winds.

To gain additional data, Northern Technical Services (NORTEC), set up four wind-recording stations to gather short-term data on wind and weather conditions. Computer analysis of long-term readings was used to extrapolate the more detailed short-term wind data available into long-term expected wind-velocity extremes. Results of the study submitted recommended design wind velocities.

The following table summarizes these heavy wind studies conducted by NORTEC showing the computer extrapolated extreme one minute average wind.

WIND SPEED (MPH)

Location	25 Year Period	50 Year Period	100 Year Period
Anchorage	87.0	92.0	95.7
Fairbanks	70.9	75.0	78.1
Healy	114.4	118.2	124.9
Summit	69.2	72.0	74.2

Data bases for these wind speeds were annual extreme winds over a 27 year period for Anchorage, 31 years for Fairbanks, 2-1/2 years for Healy and 7 years for Summit. The confidence limits are 99% for three locations and 95% for Healy.

The table shows extreme wind speeds of 118.2 MPH at Healy and 92.0 at Anchorage at 33 feet above the ground surface for a 50 year mean recurrence. These wind speeds can be adjusted for an average conductor height of 60 feet by using the following relationship:

$$V_X = V_{BASE} \left[\frac{\text{Height } X}{\text{Height Base}}\right]^{1/7} \text{ Thus:}$$

For Anchorage $\quad 92 \left[\frac{60}{33}\right]^{1/7} = 100.2$ MPH

For Healy $\quad 118.2 \left[\frac{60}{33}\right]^{1/7} = 128.7$ MPH

Therefore, the transmission lines should be designed for a heavy wind of 100 MPH along the whole corridor except Nenana Gorge and Windy Pass areas where the design wind speed will approach 130 MPH. A design speed of 140 MPH has been adapted for additional reliability and difficult maintenance operations in this area.

The wind pressures on towers based on these speeds will be further increased by a gust factor of 1.3.

C. Ice

Existing transmission lines in the Matanuska-Susitna Valley and from Healy to Fairbanks have not experienced any unusual icing problems. Climate and topography generally do not favor formation of heavy glaze or rime ice since during most of the year it is either too hot, too cold or too dry for heavy icing to occur. This is markedly different from conditions in some mountainous areas along the Gulf of Alaska where temperature and moisture conditions favorable to heavy icing are quite common.

The available data also indicates that possibilities are remote for simultaneous occurrence of maximum wind and maximum icing. Heaviest winds occur from November to March when air temperatures are well below freezing. NORTEC's study estimates a maximum annual extreme accumulation of radial ice for a 50 year recurrence period of 0.59 inches in the Anchorage area and 0.3 inches along the line route up to Fairbanks. Therefore, a heavy radial ice criteria of 0.75 inches is recommended. This loading will develop enough vertical and longitudinal structure capability for construction and stringing.

D. Wind and Ice

A review of the NORTEC study, considering maximum wind speeds at 33 feet above ground occurring simultaneously with freezing precipitation for a 50 year recurrence, shows a maximum wind speed of 74 MPH at Summit. Therefore, structures designed in accordance with National Electric Safety Code (NESC), heavy load conditions with the appropriate overload factors will be adequate for maximum wind and ice combination.

E. Snow

Annual precipitation in Alaska varies greatly from five inches per year in the high arctic regions to 200 inches per year in some coastal areas. Much of the precipitation is in the form of snow. Based on snow data available, maximum snow accumulation well under 10 feet is expected over the entire route, except for occasional areas subject to drifting. Guyed steel X-frame type structures selected as the standard 345 kV tangent structure will be structurally adequate to handle snow depths up to 10 feet.

F. Avalanche Exposure

A reconnaissance study of snow avalanche exposure was prepared for the Anchorage-Fairbanks Intertie in September, 1981 by Arthur I. Mears, Inc. The transmission alignment studied parallels the Susitna, Chulitna and Nenana River Valleys extending 150 miles northward from southcentral to interior Alaska and is therefore applicable to this project. The avalanche-prone areas occur primarily on the west side of the Talkeetna Mountains and north through Nenana Gorge, Moody and Montana Creeks. Clear evidence for avalanche activity in the form of destroyed or damaged trees is visible on photographs within the mountains along these areas. Conclusion of the study indicates that all types of avalanches are possible within this area, ranging from high velocity avalanches of dry snow, to slow moving wet snow avalanches. Therefore, total avoidance of all high exposure levels is most desirable, but this may not be possible at all locations. An acceptable level of risk based on safety and economics must be determined in areas where avoidance is not possible.

2.0 CONCLUSIONS

No specific recommendations have been provided by ACRES on meterological conditions to be used for Susitna transmission lines' design, except that zones related to climatic loading were suggested which are: Normal, Heavy Ice and Heavy Wind. The following meterological criteria which recognize Normal and Heavy Wind Zones is recommended for Susitna transmission lines based on previous related studies. These criteria are consistent with that used on the Intertie line outlined by Commonwealth Associated in their 1981 report on design criteria and are as follows:

A. Design Criteria

1. Temperatures

- Maximum for checking ground clearances............120°F
- Maximum extreme....................................100°F
- Minimum extreme....................................-80°F
- Minimum annual mean................................-40°F
- Everyday..40°F

2. Heavy Wind

A heavy wind of 100 MPH is recommended as the loading condition on the lines based on the maximum recorded wind along the major portion of the proposed routes with adjustments to average conductor heights.

This wind load translates to 25 lbs. per square foot of pressure for conductors, and approximately to the same value for the structures because of their tubular shape.

2A. Extra Heavy Wind

An extra heavy wind of 140 MPH is recommended for the section around Nenana Gorge and Windy Pass. The actual design (whether the special heavier structures or standard structures with reduced spans will be used in these areas) will be based upon the results of an economic study to be made during the design phase.

3. Ice

Because no heavy ice has been recorded in the area, only a moderate ice condition will be considered. For this loading criteria, 0.75 inches radial ice without wind is recommended.

4. Wind & Ice

The NESC Heavy (1/2 inch ice, 4# Wind) loading conditions shall be used for ice loading criteria. This criteria is substantiated by the Nortec study since the maximum wind speed with freezing precipitation is in the range of up to 40-44 MPH and ice accumulation in a range of 0.5 - 0.6 inches.

B. Load Combinations

Load Combinations for Each Zone will be:

Normal Case - Loads 1, 2, 3, 4
Heavy Wind Case - Loads 1, 2A, 3, 4

REFERENCES

1. Terrain Analysis of the North and South Intertie Power Transmission Corridors, R&M Consultants, Inc., November 1981.

2. Electric Power Engineering in an Arctic Environment, J.R. Eaton, R.P. Merritt, E.F. Rice, IEEE Publication F75 523-1.

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6. Anchorage-Fairbanks Transmission Intertie - Structure Study, Commonwealth Associates, Inc., September 1981.

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11. Anchorage-Fairbanks Transmission Intertie, Basic Design Criteria, Commonwealth Associates Inc., September 1981.

APPENDIX B

REVIEW OF ESTABLISHED
STRUCTUE AND FOUNDATION
DESIGN PARAMETERS

REVIEW OF ESTABLISHED STRUCTURE AND FOUNDATION DESIGN PARAMETERS

1.0 STRUCTURES

A. Loadings

The loading types to be considered can be divided into the following eight categories:

1. Combined wind and ice loading (NESC Heavy Load).
2. Extreme wind loading in any direction.
3. Heavy vertical loading due to ice.
4. Longitudinal loads due to tension in wires.
5. Construction and maintenance loads.
6. Longitudinal capability to resist cascading failure.
7. Permafrost considerations.
8. Seismic loading.

B. Structure Types - Design Considerations

Alaska has extensive regions of muskeg and permafrost where seasonal changes in the active layers of soils cause large earth movements. In the subarctic regions, freezing to considerable depths followed by thawing contributes to soil instability and results in large displacements of foundations. Thus, conventional self-supporting rigid towers are not suitable for Alaska.

Ten basic structure types were analyzed for the Intertie for life-cycle costs, constructability, reliability and visual impact. The type of structure selected as most suitable to meet the requirements of the Intertie was the hinged-guyed steel X-tower. Tangent towers of this X design frame were developed specifically for Alaska and have performed satisfactorily during the last ten years. However, the previous structures until the Intertie were designed for lower voltage levels than 345 kV.

The design features include hinged connections between the leg members and the foundations which together with the longitudinal guy system provide for necessary flexibility to accommodate foundation movement due to soil conditions. Transverse stability is provided by the wide leg base which also results in low foundation loads. The structures can withstand transverse forces without the aid of the guys.

Additional advantages of the X-type structure are the following:

- The X-type structure provides for less visual and environmental impacts than other structures. Therefore, the line blends in better with its surrounding than lattice towers;

- Towers could be stored in remote areas with less concern for vandalism or deterioration;

- The structures selected need a minimum of field labor. A typical tangent structure consists of only six major components with bolted connections. This is a big advantage as construction and maintenance labor costs are very high in Alaska. Access with machinery to most areas is only possible during winter days with short daylight periods, but while the surface is firmly frozen; and

- The X-towers are relatively insensitive to guy and foundation heaving. Fore and aft guys are attached in pairs to a yoke arrangement located about 4 feet above ground which is attached to the anchor through a single guy. Heaving of any combination of foundations or guy anchors can be identified by the inclination of the guy yoke plate and insulator strings or changes in sag. Whenever excessive heaving occurs, which may be around 1 foot in a season, the foundations and guys can be easily adjusted.

Self-supporting single-pole structures will be used for a section of the line and where the steep slopes require extreme leg differential length and very long guys. Three-pole guyed structures are used for heavy angle and dead-end applications. All towers will be built of unpainted, corrosion-resistant weathering steel. Weathering steel over several years turns to a dark brown color which is aesthetically more appealing than galvanized steel.

2.0 FOUNDATIONS

A. Geologic Conditions and Foundation Materials

Available soils and foundation data include:

- Detailed soil surveys from the Soil Conservation Service for part of the lower Susitna Valley and the immediate Fairbanks area;

- General geologic and permafrost maps from the USGS: 1:250,000 scale reconnaissance level interpretation of soil types prepared by the Resources Planning Team of the Land Use Planning Commission;

- Data from route studies for existing transmission lines and highways; and

- An environmental assessment including a regional permafrost map and strip maps showing general soil types for the corridors.

A generalized terrain analysis was conducted to collect geologic and geotechnical materials data for the transmission line corridors for the Intertie between Willow and Healy and described qualitatively. When evaluating the suitability of a terrain unit for a specific use, the actual properties of that unit were verified by on site subsurface investigation, sampling and laboratory testing. The geotechnical investigation of the Intertie Transmission Line Route was carried out by Commonwealth Associates and Shannon & Wilson, Inc., and submitted to the Power Authority in August, 1982. The material types encountered were grouped into the following classifications:

- Peat - Soft, compressible material containing greater than 50% organic material by volume;

- Fines - Fine-grained soils, predominantly soft silt with some clay;

- Gravel - Silty sand, gravel and in places amounts of cobbles and boulders;

- <u>Till</u> - Sand or gravel with cobbles and boulders up to 10 feet in diameter;

- <u>Talus</u> - Unsorted or poorly sorted rock waste at the base of a cliff or steep slope, commonly broken out of the bedrock by frost action; and

- <u>Bedrock</u> - Highly fractured and closely jointed bedrock.

The main three types of materials along the transmission line are designated as:

- <u>Good material</u>, which is defined as materials which permits augered excavation and allows installation of concrete without special form work;

- <u>Wetland and permafrost material</u>, which requires additional design details providing additional depth; and

- <u>Rock material</u>, is defined as material in which drilled-in anchors and concrete footings can be used.

Based on aerial, topographic and terrain unit maps, the following foundation conditions were noted:

- <u>For the Southern Study Area</u> - Mostly wetland, some rock and good foundation materials are present in this area in a very small proportion. Silty loamy loess over thick deposits of very gravelly and stony glacial drift. Generally free of permafrost. A few small isolated masses of permafrost occur at high altitudes.

- For the Central Study Area - Rock foundation and good materials were observed in most of this study area. Rough mountainous land with rocky slopes, deep mountain valleys in very gravelly drift with thin layer of loamy and silty loess. Generally underlain by discontinuous permafrost.

- For the Northern Study Area - The major part of this area is the wetland and permafrost materials. Some areas have good soil and rock materials, silt loam and micaceous loess over shattered bedrock of mica schist. Generally underlain by numerous isolated masses of permafrost.

B. Slope Stability Considerations

Discontinuities in the bedrock, combined with the steep topography create the potential for slope failures in mountainous locations of the line route. The effects of guy and tower loading on slope stability will have to be considered in tower location selection and detailed foundation design on a one-to-one basis.

C. Permafrost

Discontinuous permafrost underlies most of the route north of about the Talkeetna River. Permafrost and seasonal frost require special foundation considerations. Structures in permafrost areas will be supported below the annual frost zone, in the underlying permafrost zone using piles to transmit structure loads through the annual frost zone. The danger caused by deep seasonal frost is frost jacking forces which result in large vertical movements during freeze-thaw cycles. Permafrost causes excessive settlements caused by thawing of foundation materials. Foundations will be designed to withstand these frost jacking forces and excessive settlements.

3.0 SOIL INVESTIGATIONS

To select and detail design the most economical type of foundation for a specific tower location, soil conditions at that site must be known. A soils investigation program will furnish this needed information. Soil borings will be performed which will define the type of soil present and its strength in resisting the forces on the tower. The cost of a soil boring program is small compared to the line cost per mile. The primary purpose of soil borings is to assure an adequate and safe foundation. It is intended that geotechnical exploration and design services necessary will be completed in two phases:

A. Phase I - Preliminary Investigation

In Phase I, test boring and geophysical survey locations will be selected using existing subsurface data. A limited number of boring locations will be initially selected along the transmission line corridors to verify the terrain units.

B. Phase II - Detailed Investigation

In Phase II, additional borings will be selected to provide specific design information and to provide additional data for terrain unit mapping. Borings will average depths of 35 to 40 feet and drilling geologic logging and sampling will be carried out. In addition, geophysical surveys will verify permafrost conditions at selected locations established by the Mapping and Boring Programs. Eventually, a comprehensive laboratory testing program will be performed using field samples and a detailed geotechnical report will be prepared. This report will show graphic logs of borings, boring location plans, subsurface profiles, and define the foundation materials and design criteria.

4.0 FOUNDATION TYPES

The foundation types that can be used along the transmission line are divided into four basic types:

A. Pile Foundation

Most of the tubular steel, hinged-guyed tower and three-pole design dead-end structures will be supported by pile-type foundations, consisting of heavy H-pile beams driven to variable depths depending upon the soil conditions. This type of footing is considered when a good bearing stratum does not occur at normal footing depth, or at a reasonable distance below. Piling will be cut to suitable lengths around 20 to 25 feet and then driven with a vibratory hammer with welds used to splice the piling when necessary. Pile minimum driving resistance will be specified by the foundation report and driving continued with additional splices until an adequate bearing is achieved. Selected piles will be tested to verify that sufficient bearing capacity and uplift resistance have been achieved. Guy anchors used will be of the hydraulically installed screw-type anchor.

B. Rock Anchor

This type of footing is specified whenever good quality rock is encountered near the ground surface. A hole is drilled into the rock material and the concrete piers are grouted into the rock hole with reinforcing bars. Permissible bearing values with this type of footing are found to be high. The entire hole can be drilled using the small diameter drill bit without casing. This type of hole is easy and quick to drill and presents little or no problems. The minimum depth of these holes is approximately 8 feet and the entire hole is grouted to ensure adequate anchoring below the maximum frost depth. Guy anchors will use a similar type of grouted anchors in rock.

C. Grillages

Piles will not be driven into frozen gravel or till. In these frost zones, if bedrock is fragmented and not suitable for use of rock anchors, then a grillage type foundation will be used. The grillage type used will consist of a fabricated pedestal grillage made up of steel shapes such as angles, channels, etc. The grillage foundation will be placed deep enough to be founded below the active frost zone and will be placed on a bedding layer of gravel.

D. Pole Foundations

Foundations for cantilever pole-type structures will be required to resist high overturning moments, therefore, a large diameter cast-in place reinforced concrete augered piers can be used when the terrain is generally free of permafrost. It is possible that only angle and terminal poles with highest overturning moments may require this type of foundations. For tangent poles, closely driven 4 or 5 steel "H" piles under each pole working as a unit will resist the acting moments. These piles may be field welded to a base plate which, in turn, can be bolted to the bottom base plate of the pole to produce a moment resistant connection.

5.0 CONSTRUCTION CONSIDERATIONS

It is intended that most construction activity which will take place in winter will be performed using special winter Off-Road Vehicles (ORV). Environmental restrictions prohibit heavy construction vehicles on the fragile vegetation and tundra unless the ground is frozen and covered with a compacted snow base. In addition, many wet locations will not be accessible by vehicle at all. It is therefore considered that construction activity will be supported by heavy load carrying capacity helicopters like Boeing Vertol A-107 that can lift up to 10,000 or 11,000 pounds.

Hydraulic vibratory hammers on tracked vehicles can be used to drive the 8 or 10 inch steel "H" piles 20 to 25 feet with additional pile sections welded until necessary driving resistance is obtained. The connection of the structure with the foundation piles is considered to be a friction type, enabling to make height adjustment for frost heaving. Structures can be assembled horizontally on the ground and then pulled into vertical position using a hinged connection between the piling and structure legs. The tower can be erected with greater ease using the waist section as the attachment point. At inaccessible locations the foundation can be prepared as required and a heavy load carrying helicopter can fly the assembled structure to the site where a 4 or 5 man crew can bolt it to the piles in a relatively short time.

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1. Terrain Analysis of the North and South Intertie Power Transmission Corridors, R&M Consultants, Inc., November 1981.

2. Electric Power Engineering in an Arctic Environment, J.R. Eaton, R.P. Merritt, E.F. Rice, IEEE Publication F75 523-1.

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APPENDIX C

230 KV ENVIRONMENTAL EFFECTS
AND PERFORMANCE

<u>230 kV ENVIRONMENTAL EFFECTS AND PERFORMANCE</u>

1.0 INTRODUCTION

This report discusses the environmental effects of a 230 kV transmission system constructed on corridors with one and two 230 kV circuits.

The following are considered in the analysis:

- Ground Gradients
- Electrostatic Induction Effects
- Electromagnetic Effects
- Radio Noise
- Television Interference
- Audible Noise

All calculations were done considering the following circuit configuration:

- Phase Configuration . . . . Flat
- Phase spacing . . . . 22 ft.
- Shield wire spacing from ℄ of tower . . 17 ft.

- Minimum conductor height above ground . . . 25 ft.
- Mean conductor height above ground. . . . . 40 ft.
- Conductor and shield wire separation. . . . 27 ft.
- Separation of two circuits in parallel. . . 90 ft.
- Right-of-way for one circuit. . . . . . . 120 ft.
- Right-of-way for two circuits in parallel.................................210 ft.
- Conductor . . . . 1-954-Kcmil 45/7 ACSR
- Shield wire . . . . 3/8 EHS

Because of the circuit separation, coupling effects of the second circuit are insignificant, and values calculated within, and at the edge of ROW for the single circuit corridors, will be the same for the two circuit corridors.

2.0 CALCULATED RESULTS AND ANALYSIS

A. Ground Gradients

- The ground gradients were calculated considering the 25 ft. NESC minimum conductor height.

- The calculated results are:

  Single Circuit

  - Maximum under the line.........3.78 kV (rms)/m
  - Edge of ROW...................0.85 kV (rms)/m

Double Circuit

- Phase sequence.................ABC ABC
- Maximum under the line.........3.84 kV (rms)/m
- Edge of ROW....................0.88 kV (rms)/m

o Gradient guidelines as accepted by many states are as follows [13]:

- Maximum gradient.............7.0 to 9.0 kV (rms)/m
- Edge of ROW..................1.0 to 1.6 kV (rms)/m

o Calculated results are well below listed guidelines.

B. Electrostatic Induction Effects

o Induced currents and discharge energy were computed with phase conductors at 25 feet height.

o Maximum calculated values within ROW and values at the edge of ROW were very close for both single and double circuit configurations.

o Vehicles considered, their sizes in feet and capacitance to ground in picofarads are:

Vehicle	Size	Capacitance
Automobile	5.8x4.5x15	1000.0
Panel Truck	7.8x10.75x25	2000.0
Tractor Trailer	8.0x13.5x39	2500.0

o Calculated results are as follows:

	Induced Currents in ma (rms) Maximum within ROW
Automobile	0.361
Panel Truck	1.384
Trailer Truck	2.490

	Discharge Energy in mJ (millijoules)	
	Maximum within ROW	Edge of ROW
Automobile	0.92	0.04
Panel Truck	6.73	0.45
Trailer Truck	17.55	1.05

o National Electrical Safety Code allows 5 ma (rms) of induced current on any vehicle or object under the line. Calculated induced currents are within NESC limit [8].

o Tests have shown that a minimum energy of 0.25 mJ is sufficient to ignite gasoline vapors during a vehicle refueling process. Vehicles should not be refueled within right-of-way.

C. Electromagnetic Effects

- The electromagnetic field at the center line of the 230 kV circuit was calculated to be 0.090 Gauss which is too small to have any effect or be of any concern. The calculations were done assuming a 300 MVA line load.

D. Radio Noise

- Transmission radio noise was calculated considering the 40 feet mean conductor height above ground, one MHz frequency and 100 ohm-m average soil resistivity.

- Only AM radio reception having a broadcast band of 0.6 to 1.6 MHz is affected by transmission line radio noise.

- The calculated conductor surface gradients are as follows:

Phase	Surface Gradient - kV (rms)/m
A	14.844
B	15.730
C	14.844

o The calculated transmission radio noise for heavy rain, wet conductor and fair weather conditions are as follows:

	Transmission radio noise in dB above 1 uVm	
	Maximum within ROW	Edge of ROW
Heavy Rain	72.83	67.49
Wet Conductor	61.57	55.10
Fair Weather	44.57	38.10

o Reception quality is a relative term and depends on both signal strength and line noise level and is defined as follows [15, 3, 1]:

Radio Reception Quality	Signal/Noise Ratio (dB)
Excellent	>32
Very Good	27-32
Good	22-27
Poor	16-22
Very Poor	6-16
Intolerable	>7

o For primary area coverage FCC recommended signal levels are as follows:

Business City Area	80-94 dB above 1 uV/m
Residential District	66-80 dB above 1 uV/m
Rural Area	40-54 dB above 1 uV/m

- On the above basis the maximum line noise levels for "good" reception are:

Residential District	44-58 dB above 1 uV/m
Rural Area	18-32 dB above 1 uV/m

- From AM radio signal measurements carried out for the Anchorage-Fairbanks Intertie line it is evident that signal strengths, in far out areas, are of low level and some interference is expected at least in close proximity to the line during wet conductor condition [1,2]. The wet conductor condition is used for evaluating the line performance; the heavy rain condition represents the absolute maximum noise level, with 1% probability of occurrence.

- In far out remote areas the existing reception quality is preserved at a distance 500 feet away from the ROW. For wet conductor condition the radio noise at 500 feet from center phase is calculated to be 16.15 dB above 1 uV/m.

- For areas close to large cities where signal strengths are much stronger, no objectionable interference is anticipated at the edge of ROW for most of the time.

E. Television Interference (TVI)

- o Similar to radio noise, TV reception quality depends on both TV signal strength and noise level and is defined as follows [15, 3]:

TV Reception Quality	Signal/Noise Ratio (dB)
Excellent	> 36
Very Good	27-36
Good	17-26
Poor	4-16
Very Poor	-10-3
Intolerable	< -10

- o Channel 2 (54-60 MHz frequency band) is the channel most susceptible to line interference.

- o FCC required minimum TV signal strengths for a principal community service, are as follows:

Channels	2-6	74 dB above 1 uV/m
Channels	7-13	77 dB above 1 uV/m
Channels	14-83	80 dB above 1 uV/m

- o The calculated TVI at the edge of ROW during wet conductor condition for channel 2 (broadcast frequency 60 MHz) is 24.6 dB above 1 uV/m. For TV signals as low as 52 dB the reception quality will be "Very Good".

- For far out areas the criteria adopted for RI will eliminate even the slightest TV interference.

F. Audible Noise

- The calculated audible noise levels are as follows:

	Audible Noise Levels in dB(A) Above 20 uPA (micro-pascals)	
	Maximum	Edge of ROW
Heavy Rain	53.01	50.42
Wet Conductor	43.77	41.13

- Wet conductor condition, because it generates significant noise at relative low ambient, is the criterion of line performance.

- It is generally accepted that the audible noise for wet conductor condition should not be more than 52 dB(A) above 20 uPA at the edge of ROW [3].

- The calculated wet conductor audible noise levels for the 230 kV system are below the generally accepted maximum levels.

3.0 CONCLUSIONS

- From the calculated results it can be concluded that all electrical environmental effects resulting from operating the 230 kV system will be negligible.

- No interference to FM radio reception from the proposed 230 kV lines is expected.

- No interference to AM radio reception is expected at distances greater than 500 feet from the edge of the right-of-way, even in remote areas with weak radio signals.

- Electric and magnetic field strengths produced by the 230 kV system will be harmless.

- No shock hazards from induced currents are expected.

- No interference to TV reception is expected in areas with good reception.

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APPENDIX D

345 KV ENVIRONMENTAL EFFECTS AND PERFORMANCE

345 kV ENVIRONMENTAL EFFECTS AND PERFORMANCE

1.0 INTRODUCTION

This report discusses the environmental effects of the 345 kV transmission lines associated with Alaska Power Authority's Susitna Hydroelectric Project. The lines will deliver the power generated at the Susitna River basin plants to the major load centers of Anchorage and Fairbanks. The environmental effects were calculated for corridors with one circuit, 170 feet ROW width, and corridors with two circuits, 275 feet ROW width.

The following were considered in the analysis:

- Radio Noise
- Television Interference
- Audible Noise
- Electric and Magnetic Field Effects

For each one of the effects, a criterion was established defining acceptable levels of interference. For radio noise (RI), television interference (TVI) and audible noise (AN), the criteria were based on the interference being annoying. For the electrostatic and electromagnetic effects, primarily induced current, an upper level of current is defined beyond which physical injury could result.

Evaluation of the corona discharge phenomena such as radio noise, TVI and audible noise, requires knowledge of the conductor surface gradient whose magnitude entirely depends on the line configuration and voltage. Line configuration and calculated conductor surface gradients are as follows

Transmission Line Configuration

- Structure - guyed steel pole . . . . X-type
- Phase spacing . . . . 33 ft
- Conductor . . . . 2-954 kcmil 45/7ACSR
- Conductor diameter . . . . 1.165 inch
- Bundle spacing . . . . 18 inches
- Shield wire . . . . 3/8 inch EHS
- Shield wire spacing at each structure . . . . 52 feet
- Minimum ground clearance . . . . 30 feet
- Mean conductor height above ground . . . . 40 feet
- Voltage . . . . 345 kV with 1.05 pu. overvoltage
- Circuit separation . . . . 105 feet

Conductor Surface Gradients

Conductor surface gradients were calculated by using the multiple images method. For multiple circuits, the Maxwell's coefficient matrix was formed considering all circuit phases and all shield wires. The calculated average and maximum gradients are as follows:

A. Corridors with one 345 kV circuit

Phase	Surface Gradients kV (rms)/cm	
	Average	Maximum
A	14.389	15.320
B	15.161	16.142
C	14.389	15.320

B. Corridors with two 345 kV circuits

Phase Sequence: ABC ABC

Circuit #1

Phase	Surface Gradients kV (rms) /cm	
	Average	Maximum
A	14.301	15.227
B	15.221	16.206
C	15.245	16.232

Circuit #2

Phase	Surface Gradients kV (rms) /cm	
	Average	Maximum
A	15.245	16.232
B	15.221	16.206
C	14.301	15.227

2.0 RADIO NOISE

One of the by-products of transmission line corona discharge process is radio noise, which by definition means "any unwanted disturbance within the radio frequency band". Radio frequency band extends from 3#KHz to 30,000 MHz. Transmission line noise produced by corona discharge could, in the lower frequency band, interfere with the radio frequency communications. The interference level depends on the radio signal strength and the intensity of the line generated noise. The magnitude of the line noise decreases with increasing frequency and is negligible at frequencies above 10 MHz. Interference is generally noticed only with AM radio reception which has a broadcast band of 0.6 to 1.6 MHz. FM radios are immune to interference from line generated radio noise because the magnitude of the line noise is quite small in the FM broadcast band (88-108 MHz) and interference rejection properties inherent in FM radio systems makes them virtually immune to static type disturbance.

Reception quality quantitatively is expressed by the signal-to-noise ratio (SNR):

$$SNR = 20 \log \frac{V\ (\text{signal})}{V\ (\text{noise})}$$

Where V is in Volts/meter

High SNR is indicative of better quality reception. SNR and corresponding reception quality as defined by IEEE is as follows [15, 3, 1]:

Grade	SNR (dB)	Reception Quality
A	>32	Entirely satisfactory
B	27 - 32	Very good, background unobtrusive
C	22 - 27	Fairly satisfactory, background plainly evident
D	16 - 22	Background very evident, speech easily understood
E	6 - 16	Speech understandable only with severe concentration
F	< 7	Speech unintelligible

Signal strength is affected by station power, distance from the station, antenna height, soil conductivity, and frequency. Line noise is a function of line configuration, conductor surface gradient and weather condition.

Primary coverage area as defined by FCC requires a signal strength of 0.1 mV/m for daytime and 0.5 mV/m for nighttime. Recommended signal strengths in primary coverage area are as follows [3, 16]:

Business City Area	80 - 94 dB above 1 uV/m
Residential District	66 - 80 dB above 1 uV/m
Rural Areas	40 - 54 dB above 1 uV/m

On the above basis, for a "fairly satisfactory" grade C reception quality, the maximum line noise at the edge of ROW should be:

Residential District	44 - 58 dB above 1 uV/m
Rural Areas	18 - 32 dB above 1 uV/m

A. Signal Strength

No specific measurements of signal strengths have been carried out at this time for the proposed lines. However, preconstruction measurements carried out for the 345 kV Anchorage-Fairbanks Intertie line are applicable for the proposed lines because of proximity to each other and general similarities (away from large cities).

Quality of reception measurements of radio stations at different locations on the Intertie line are shown in Table 1.

AM radio stations servicing the area in the vicinity of Intertie line are shown in Table 2. The quality of reception from all 13 standard broadcast AM radio stations was not better than quality grade C.

Most signal strengths were measured around 20 dB above 1 uV/m with the strongest near Willow at 37 dB above 1 uV/m, which is below the minimum 40 dB above 1 uV/m required by FCC for primary service in rural areas. Therefore, only intermittent service is presently provided by radio stations to areas away from cities which by FCC definition is subject to fading and some interference from atmospheric and man-made noise [1, 2, 3, 13].

For areas close to Anchorage and Fairbanks the radio strengths are expected to be much stronger and the quality of reception to be grade A or B with an anticipated signal strength of at least 66 dB above 1 uV/m.

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B. Transmission Line RI Characteristics

The calculation of radio noise is based on determining the corona-generated currents and their propagation along the line. All RI calculations were done using methods developed at Project UHV. For corridors with two circuits, all phase wires were considered in forming the model transformation matrix and Maxwell's coefficient matrix. Shield wires were neglected as their effect in RI generation was negligible. RI profiles for corridors with one and two circuits are shown on Figures 1 and 2 respectively.

The calculations were based on the following:

(1) Line geometry and conductor surface gradients as described above

(2) Frequency - 1 MHz

(3) Soil resistivity - 100 Ohm-m

(4) Mean conductor height above ground - 40 ft.

At the low frequency end of the broadcast band (0.55 MHz) the line generated noise will be 4.5 dB greater than the one calculated at 1 MHz and at the high frequency end (1.6 MHz) it will be 5 dB lower.

Higher soil resistivity reduces the magnitude of RI generation. Over a range from 10 to 1,000 Ohm-m, a 10 dB difference in RI generation could occur. However, because signal strength would also decrease with increased soil resistivity, the expected effect on SNR would be very small.

Calculated maximum values of RI under the line and values at the edge of ROW are shown in Table 3.

Calculated RI values at extended lateral distances from the corridor are shown in Table 4.

C. Interference Levels

The interference levels of the Susitna lines will depend on the signal-to-noise-ratio. From the RI calculated results and signal strength measurements made for the Intertie line, the following are concluded:

(1) For areas away from cities the existing reception quality of the very weak AM radio signals is preserved at 600 feet away from the edge of ROW. The wet conductor RI at that distance was calculated to be 14.67 dB above 1 uV/m, which is within grade C reception quality in rural areas.

(2) No interference to FM reception is expected.

(3) For areas close to large cities where signal strengths are high, no interference is anticipated at the edge of ROW for most of the times. The maximum possible line noise is generated during heavy rain and the probability of occurrance is only 1%. An all weather RI statistical distribution curve for the edge of ROW is shown in Figure 3.

(4) Interference to CB communication near the 345 kV lines is not anticipated. At CB broadcast band of 27 MHz, the line generated noise will be very low.

(5) Any possible interference to other communication facilities will be alleviated by maintaining the clearances from each facility as shown in Table 5.

3.0 TELEVISION INTERFERENCE (TVI)

Interference to TV reception, when it happens, affects the received picture only. The audio portion of a TV signal is in the FM broadcast band and not subject to static types of interference. Channel 2, because of its lowest broadcast frequency band (54-60 MHz) will have the worst performance. The broadcast frequency band for each TV channel is listed in Table 6.

A. Criteria

TV reception quality is defined by the SNR similarly to Radio Noise and is as follows [15, 3]:

Grade	SNR (dB)	TV Reception Quality
A	> 36	Excellent
B	27 - 36	Very good
C	17 - 26	Good
D	4 - 16	Poor
E	-10 - 3	Very Poor
F	< - 10	Intolerable

B. Signal Strength and Performance

The FCC required minimum TV signal strengths for a principal community to be served are as follows:

Channels	2-6	74 dB above 1 uV/m
Channels	7-13	77 dB above 1 uV/m
Channels	14-83	80 dB above 1 uV/m

It is recognized that in many areas outside the principal community, useable signals are received with strength considerably lower than the above. In the same FCC regulations, reference is made to grade A and grade B service contours of signal strength. Bonneville Power Administration has gone further in defining grades C and D service contours. Signal strengths for each grade as defined by FCC and BPA are as follows [3, 16]:

TV SERVICE GRADES

(signal levels in dB above 1 uVm)

TV	FCC Signal Level		BPA Signal Level	
Channel	Grade A	Grade B	Grade C	Grade D
2 - 6	68	47	46 - 34	33 - 20
7 - 13	71	56	55 - 42	41 - 33
14 - 83	74	64		

A survey of received TV station, conducted for the Anchorage-Fairbanks Intertie line preconstruction measurements, is shown in Table 7.

On the basis of criteria for RI, a 600 feet separation was suggested between edge of ROW and houses. At that distance the TVI for channel 2 with 60 MHz broadcast frequency was calculated to be 6.75 dB above 1 uV/m which is very low for any TV interference. TVI at the edge of ROW during wet conductor condition (channel 2, 60 MHz) was calculated to be 44 dB above 1 uV/m which does not interfere with TV reception, in a principal community serviced in accordance with the FCC.

For areas receiving relatively weak TV signals, as is the case with many Alaska areas, TV translators are utilized to boost and rebroadcast the video and audio signals. A TV translator is licensed to provide service to a small geographical area. The rebroadcasted signal is much stronger and therefore, will be less susceptible to interference from the proposed 345 kV lines.

Reception of TV signals reflected from large structures can cause delayed or "ghost" images in the TV picture. The tubular steel structures proposed for the 345 kV lines are not expected to reflect sufficient TV signals to cause ghost images.

In conclusion, no TV reception problems are expected to result from the proposed 345 kV lines in locations where present TV reception is good.

4.0 AUDIBLE NOISE

During fair weather (dry conditions), the audible noise generated by a line is insignificant. However, during wet conductor and heavy rain conditions, audible noise generation increases drastically and can create serious problems.

Noise generated during heavy rain is in the order of 6 to 9 dB higher than that experienced for wet conductor. During heavy rain however, the ambient noise effectively masks the noise generated by the line. Following the rain, while the ambient noise is much lower, the noise generated by wet conductors is significant and therefore, it is used as the criterion for line performance.

Transmission line audible noise consists of a random component as well as a 120 Hz component. Human ear sensitivity is a function of

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Transmission line audible noise consists of a random component as well as a 120 Hz component. Human ear sensitivity is a function of frequency and consequently, there is no simple way to exactly relate a combination of noise to human response. There are numerous "frequency weighing networks" which can approximate human ear response. The one mostly used for transmission noise analysis is known as network "A". The noise level for this approach is usually identified as dB(A). All dB(A) levels will be given in dB(A) above the reference sound pressure of 20 uPa [3, 15, 16].

A. Criteria

Although no existing noise ordinance in the United States refers to transmission lines as noise sources, nonetheless, by virtue of their generality may implicity include transmission lines. Bonneville Power Administrations general guideline, based on public response to AC transmission audible noise, indicates that for audible noise levels below 52 dB(A), no complaints will be received. Between 52 and 58 dB(A), there is a very high probability of receiving complaints [3]. Therefore, based on these results, the audible noise level at the edge of the ROW during wet conductor condition should not exceed 52 dB(A).

B. Characteristics and Performance

Audible noise is generated by corona and is, therefore, related to many of the same line characteristics as RI generation. However, while RI is important both during dry and wet conditions, audible noise (AN) is usually insignificant except during wet conductor conditions.

The calculations were done in accordance with the methods developed at project UHV for a mean conductor height of 40 feet. Audible noise profiles for corridors with one and two circuits are shown in Figures 10 and 11.

Calculated maximum, and at the edge of ROW, audible noise levels are as follows:

ONE CIRCUIT PER CORRIDOR

	Audible Noise Levels in dB(A) Above 20 uPA	
	Maximum	Edge of Row
Heavy Rain	55.07	52.00
Wet Conductor	46.33	43.00

TWO CIRCUITS PER CORRIDOR

	Maximum	Edge of Row
Heavy Rain	57.75	53.95
Wet Conductor	49.37	45.05

The results indicate that the proposed Susitna 345 kV lines will meet all audible noise criteria for wet conductor anywhere in the vicinity of the lines.

5.0 ELECTRIC AND MAGNETIC FIELD EFFECTS

Both electrostatic and electromagnetic fields are generated by a transmission line during operation. Magnetic fields in the proximity of transmission lines is more than 10 times smaller than the magnetic fields generated from common household tools and appliances, and is considered harmless. There is no evidence that ground gradients have any biological effects on animals or plants. Electric fileds will induce a charge on an insulated object and when a person comes in contact with the object, current will flow from the object through the person to the ground. The shock from the discharge may or may not be serious, however, the magnitude of the charge and therefore the severity of the shock is related to parameters associated with the transmission line design and voltage, size and dimensions of the object, the proximity of the object to the line, and degree of insulation of the object from the ground. The insulation quality between a person coming in contact with such an object and the earth will effect the severity of the shock.

A. Criteria

Body-passage currents caused by contact with a charged object may range from barely detectable to those resulting in lethal effects. It has been reported by Dalziel [3, 4, 5, 11] that currents less than 1 ma produce little or no measurable physiological response, therefore, they are not classified as shock currents. Shock currents have been classified into two groups according to the degree of severity of the effects they produce. A limit of 5 mA (National Electrical Safety Code) is considered by the Underwriter's Laboratory as the maximum safe let-go current for the general population, including children. Currents of 6 mA or larger are considered primary currents. The most dangerous possible consequence of primary shock is ventricular fibrillation, resulting in immediate arrest of blood circulation. The current at which fibrillation begins varies with the weight of the person shocked and with the shock duration.

In addition to the above hazards of induced currents, if sufficient charge is placed on a vehicle and re-fueling is attempted, it is possible for discharges occurring between the spout of a fueling can and the vehicle to ignite gasoline vapors. Test at project UHV have indicated the minimum energy necessary for ignition to be in the order of 0.25 mJ [3, 15].

In light of all the above, many states have established recommended levels for Maximum Ground Gradient within and at the Edge of ROW. A list of the recommended guidelines for each state is given in Table 8 [13].

B. Electrostatic Effects - Calculations and Results

The Electrostatic Effects calculations were done in accordance with methods developed at project UHV. Induced current and discharge energy were calculated for three different vehicles having the following sizes:

Vehicle Type	Size in feet	Capacitance in pF
Automobile	5.8 x 4.50 x 15	1000.0
Panel Truck	7.8 x 10.75 x 25	2000.0
Tractor Trailer	8.0 x 13.50 x 39	2500.0

All conductors and shield wires were considered in forming the necessary matrixes for either one or two circuits.

The results indicated that there was no significant difference in maximum values at the edge of ROW, irrespectively whether one or two circuits were considered. This was true because of the large separation between the circuits and phase sequence considered.

Profiles for Induced Currents, Ground Gradients and Discharge Energy are shown in Figures 4, 5 and 7 respectively. The effects of ground clearance and maximum values of Induced Currents, Ground Gradient and Discharge Energy is shown in Figures 6, 7 and 9 respectively.

On the basis of calculations and presented criteria, the following are concluded:

(1) Induced currents are below the 5 ma required by NESC for all vehicles considered. At the edge of ROW the induced current even for the largest vehicle considered is less than 1.5 ma, therefore below maximum levels recommended in many states (Table 8).

(2) The maximum Electric Field under the ROW is calculated to be 6.6 kV (rms)/m which is below the maximum recommended in

many states. The maximum Electric Field at the edge of ROW is 1.5 kV (rms)/m which is within the guidelines accepted by many states [13]. The calculated Electric Field levels will have no adverse effects on people or animals.

(3) The calculated Discharge Energy is higher than the minimum required to cause fuel ignition. Therefore, precautions shall be taken to avoid fueling under or near the lines, or that steps be taken to insure that the vehicle is adequately grounded to remove any charge prior to any fueling operation.

C. Electromagnetic Effects

The Magnetic Field under the line was calculated considering 600 MVA load and 40 foot conductor height. The maximum Magnetic Field was calculated to be 0.14024 Gauss which is considered negligible.

6.0 CONCLUSIONS

- From the calculated results it can be concluded that all electrical environmental effects that will result from operating the Susitna 345 kV lines will be negligible.

- No interference to CB, microwave or other communication facilities is expected.

- No interference to FM radio reception is expected.

- Some interference to AM reception is expected, however, this is due to very weak signals that reach these remote areas. At a distance of 600 feet from the edge at the ROW, the existing reception quality will be maintained.

- No interference to TV reception is expected in areas with good reception. Areas with weak TV signals are generally serviced with TV translators which are utilized to boost and rebroadcast the video and audio signals, and will therefore be less susceptible to interference from the proposed 345 kV lines.

- The audible noise levels generated by the Susitna 345 kV lines will be within acceptable limits.

- No shock hazards from currents are expected. The maximum induced current is less than the 5 ma required by NESC.

- The maximum Electric Fields under the line and at the edge of ROW are within levels acceptable by many states (see Table 8).

- The calculated Discharge Energy is higher than the minimum required for fuel ignition. Therefore, refueling under or near the lines should be avoided unless the vehicle is grounded to remove any charges prior to any refueling operati n.

- Magnetic fields produced by operating the 345 kV system will be negligible and harmless.

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TABLES

Table D-1

EXISTING QUALITY OF RECEPTION FOR AM RADIO STATIONS
(BASED ON FIELD MEASUREMENTS OF RADIO STATION
SIGNAL STRENGTHS JULY 9-15, 1981) [1, 2]

Site Number	Location	Number of Radio Stations Judged to have the following Quality of Radio Reception				
		A	B	C	D	E
10	Willow	-	-	3	3	-
20	Trapper Creek	-	-	2	2	3
30	Chase	-	-	-	1	4
40	Lane Creek	-	-	1	1	4
50A	Curry	-	-	-	-	1
60	Cantwell	-	-	-	-	1
70	Carlo Creek	-	-	-	-	1
80	Deneki Lake	-	-	-	1	3
90	McKinley Village	-	-	-	-	-
100	McKinley Park	-	-	-	-	-
110A	Healy	-	-	-	1	1

LEGEND:

A - Entirely Satisfactory
B - Very Good, Background Unobtrusive
C - Fairly Satisfactory, Background Plainly Evident
D - Background Very Evident, Speech Understandable With Concentrating
E - Speech Unintelligible

TABLE D-2

AM RADIO STATIONS [1, 2]

Freq. KHz	Station Call	Location	Power kW	Antenna Limitation	Station Class
550	KENI	Anchorage	5	-	III
560	KOVK	Kodiak	1	-	III
580	KYUK	Bethel	5	-	III
590	KHAR	Anchorage	5	-	III
650	KYAR	Anchorage	50	DA-2	II
660	KFAR	Fairbanks	10	-	II
700	KBYR	Anchorage	LS-1, N-.5	-	II
750	KFQD	Anchorage	LS-50, N-10	-	II
900	KFRB	Fairbanks	10	-	II
970	KIAK	Fairbanks	5	-	III
1080	KANC	Anchorage	10	-	II
1150	KABN	Long Island (Big Lake)	5	-	III
1170	KJNP	North Pole	50	DA-N	II

Key:

DA-2 - Directional Antenna, different patterns day and night
DA-N - Directional Antenna, during night only
LS - Local Sunset
N - Night

Stations # Class II are licensed by FCC to operate on a clear channel render primary service over wide areas.

Stations # Class III are licensed by FCC to operate on a regional channel and render primary service to large cities (municipalities) and surrounding areas.

Table D-3

CALCULATED MAXIMUM RI LEVELS UNDER THE 345 KV LINE AND AT THE EDGE OF ROW

Corridors with One Circuit

	RI values in dB above $1\mu V/m$	
	Max. under the line	At the edge of ROW
Heavy Rain	78.80	67.82
Wet Conductor	70.20	59.00
Fair Weather	53.20	42.00

Corridors with Two Circuit

Heavy Rain	86.68	68.40
Wet Conductor	78.07	59.90
Fair Weather	61.07	42.90

Table D-4

CALCULATED 345 KV RI LEVELS - ONE CIRCUIT PER CORRIDOR

Lateral Distance from Centerline (ft)	Corridors with One Circuit* RI levels in dB above 1μV/m Heavy Rain (L_1)	Wet Conductor (L_{50})	Fair Weather (L_{50})
100	64.25	55.44	38.44
200	48.22	39.40	22.40
300	39.56	30.76	13.76
400	33.85	25.07	8.07
500	29.61	20.84	3.84
600	26.24	17.47	-
700	23.43	14.67	-
800	21.02	12.27	-
900	18.92	10.10	-
1000	17.00	8.29	-

* Corridors with two circuits will have the same values with lateral distances measured from the center line of each circuit.

Table D-5

POSSIBLE EHV LINE EFFECTS ON COMMUNICATIONS FACILITIES AND RECOMMENDED MINIMUM CLEARANCES [1, 2]

Communication Facility	Reflection	Diffraction	Absorption	Ghosting	No Reported Effects	Recommended Minimum Clearance to EHV Lines	Criterion
FM Translator					X	Antenna Height plus 200 feet	Antenna Toppling Guy Anchor Maintenance
TV Translator	X	X		X		Antenna Height plus 20 feet	Antenna Toppling Guy Anchor Maintenance
Earth Stations						10 Tower Height	
NAVAIDS (En route)							
NDB					X	1000 feet	FAA
RCAG					X	1000 feet	FAA
SFO					X	1000 feet	FAA
SSFO					X	1000 feet	FAA
NAVAIDS (At Airports)							
VOR	X					1.5°	DOT/FAA
Unicom						1.5°	Ref. B-2
					X		Airport, Criterion
RCO					X		Airport Criterion
FSS					X		Airport Criterion
AAS					X		Airport Criterion
ALAS					X		Airport Criterion
Point-to-Point Microwave	X	X	X			Antenna Height plus 200 feet	Antenna Toppling Guy Anchor Maintenance 0.6 First Fresnel Zone

Table D-6

FREQUENCY BAND FOR EACH TELEVISION CHANNEL [16]

Television Channel	Frequency Band (MHz)
2	54 - 60
3	60 - 66
4	66 - 72
5	76 - 82
6	82 - 88
7	174 - 180
8	180 - 186
9	186 - 192
10	192 - 198
11	198 - 204
12	204 - 210
13	210 - 216
14 - 83	470 - 890

Table D-7

TV STATIONS RECEIVED [1, 2]

TV Channel		Location	Operating Power-KW Visual/ Aural	Antenna Height-feet At/AG
2	KENI	Anchorage	26.9/2.69	70/173
2	KFAR	Fairbanks Cantwell Translator at Earth Station Operated by Alaska Department of Highways	5.37/.676	45/200
4	K04CO	Healy Translator (Primary Ch. 11 KTVF Fairbanks)		
4	K04DO	Talkeetna Translator (Primary Ch. 11 Anchorage)		
6	K06KG	Talkeetna Translator (Primary Ch. 13 Anchorage)		
*7	KAKM	Anchorage	105/20.90	143/250
7	K07ND	Healy Translator (Primary Ch. 9 Fairbanks)		
9	KUAC	Fairbanks	46.7/1.16	200/255
9	K0900	Talkeetna Translator (Primary Ch. 2 Anchorage)		
11	KTVA	Anchorage	26.3/5.35	300/391
13	KIMO	Anchorage	30/6.17	90/347
13		Healy Translator		

AT - Above average terrain
AG - Above ground
* - Non-commercial educational station

Table D-8

STATE RECOMMENDED ELECTRIC FIELD LEVELS [13]

State	Recommending Regulatory Agency	Maximum Electric Field Within The ROW (kV/m)	Electric Field at Edge of ROW (kV/m)	Maximum Short Circuit Current (mA)
California	California Energy Commission/Public Utility Commission		1.0 (See text)	
Minnesota	Environmental Quality Board	8 (ac) 12 (HVdc) steady state)	-	5 (ac)
New Jersey	Department of Environmental Protection	(no requirement)	3*	
New York	Public Service Commission	7.0 - public roads 11.0 - private roads 11.8 - over other terrain	1.6 or less	4.5 (ac)
North Dakota	Public Service Commission	8 (ac) 33 (HVdc)	-	5 (ac) 34 (Hvdc)
Oregon	Energy Facility Siting Council	9	-	5 (ac)
South Dakota	Public Utilities Commission	7.1 at ground level	1.4	5 (ac)

(HVdc) = High voltage direct current transmission
(ac) = Alternating current

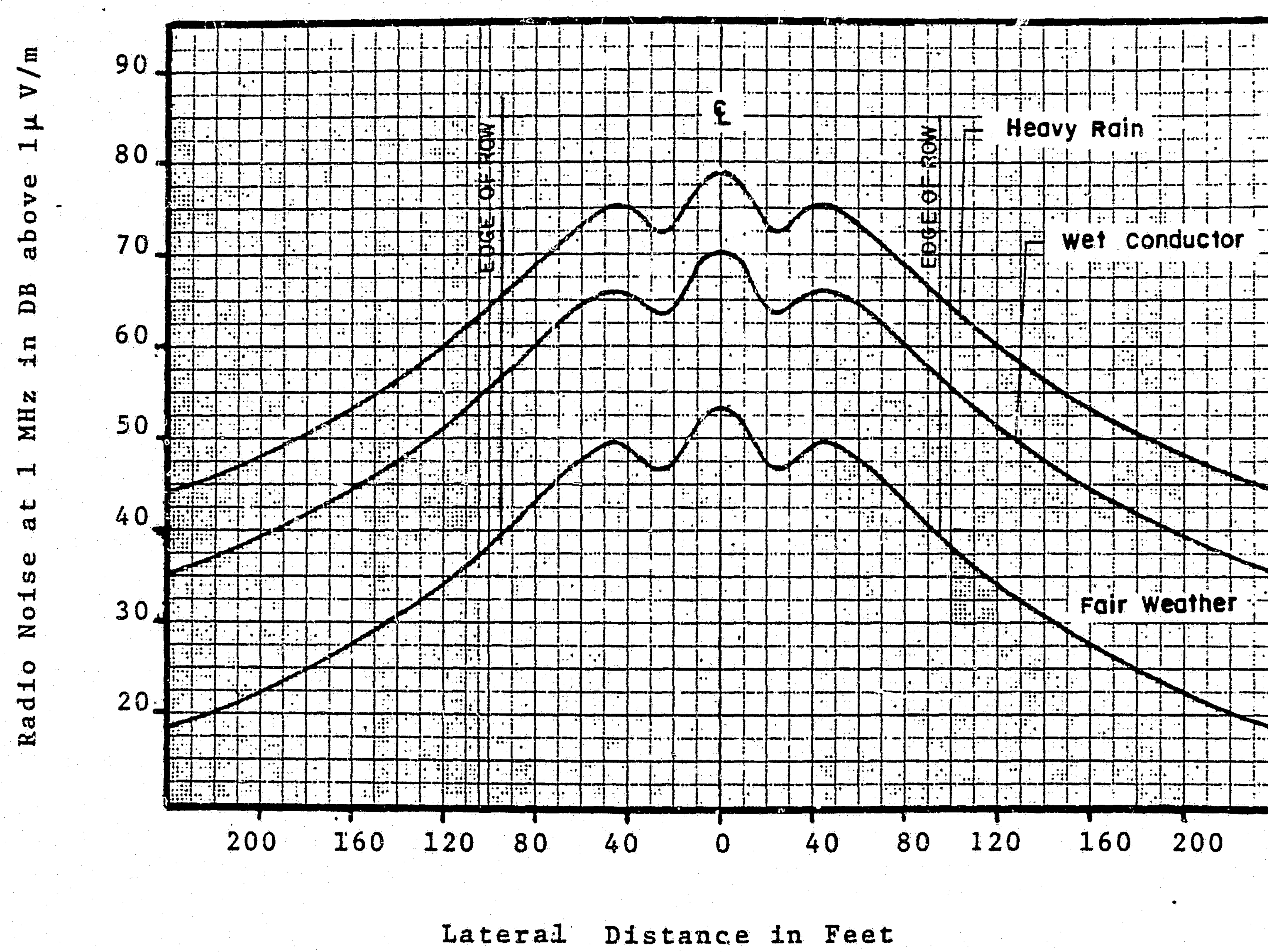
* From Guidelines for High Voltage Lines Adopted, Resolution by New Jersey Commission on Radiation Protection, June 4, 1981.

FIGURES

ALASKA POWER AUTHORITY

345 Kv System

RI Profiles for Corridors with One Circuit



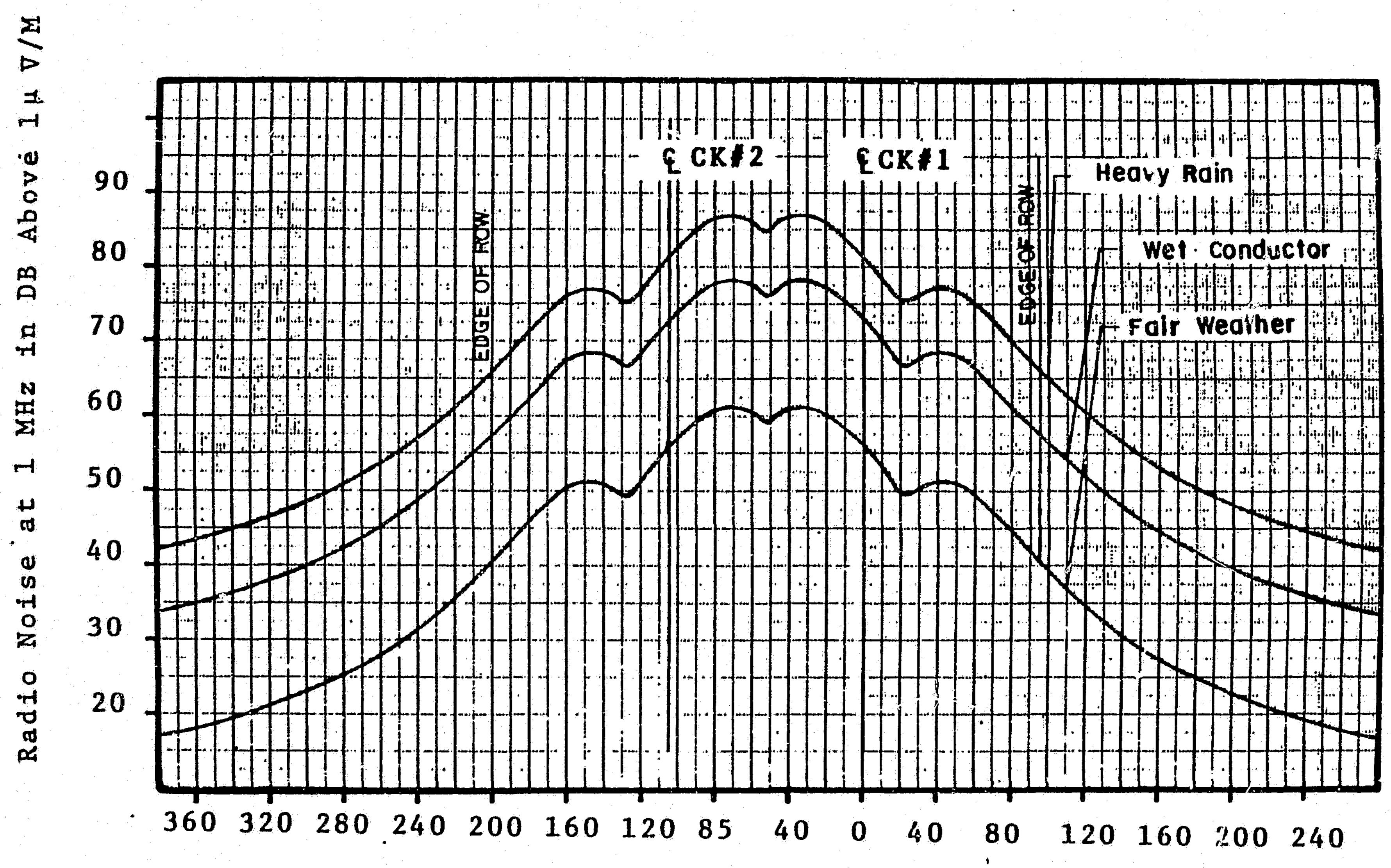
Heavy Rain, Wet Conductor and Fair Weather
RI Profiles with Mean Conductors Height of 40 Feet

Figure D-1

ALASKA POWER AUTHORITY

345 Kv System

RI Profiles for Corridors with Two Circuits



Heavy Rain, Wet Conductor and Fair Weather

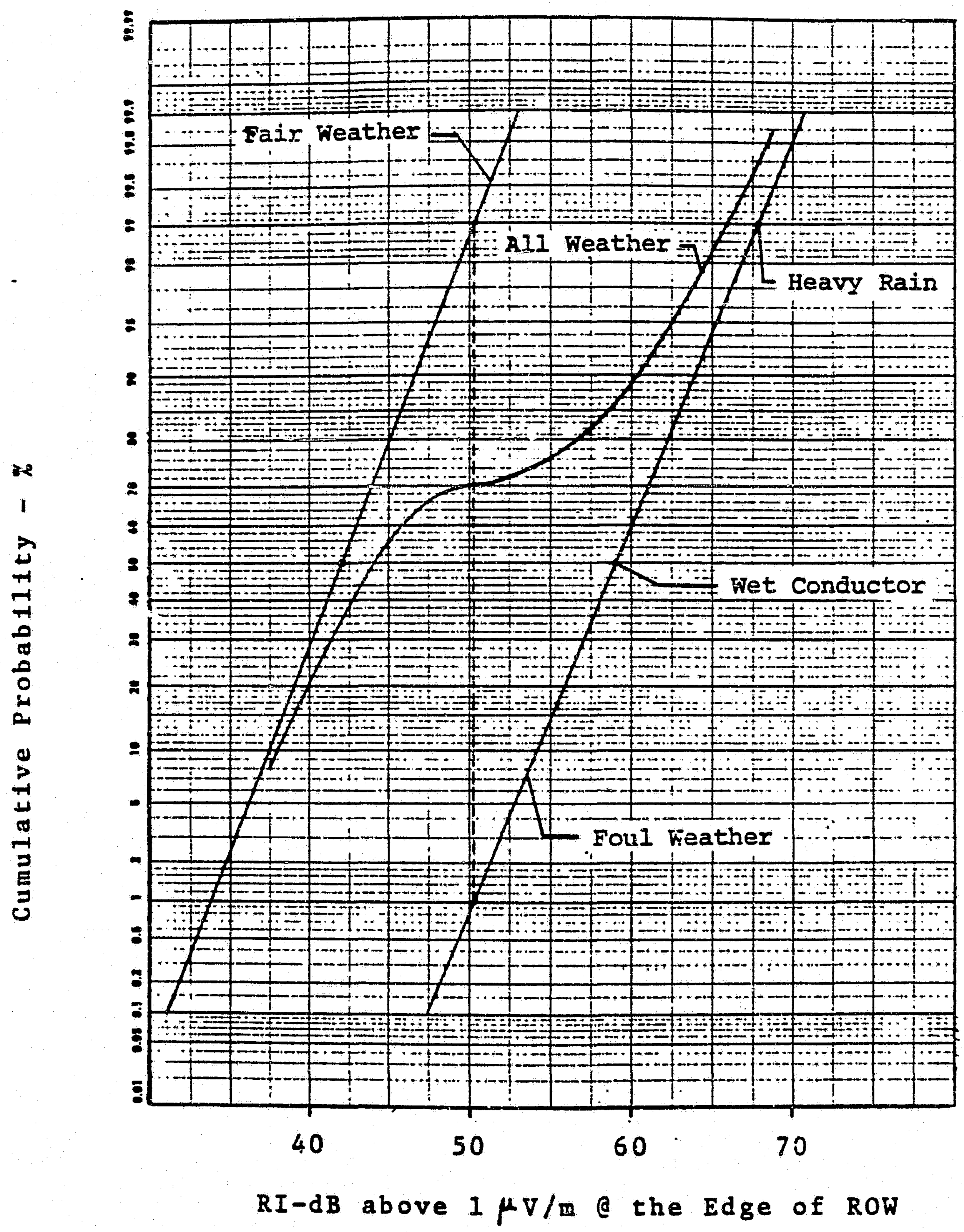
RI Profiles with Mean Conductor Height of 40 Feet

Figure D-2

ALASKA POWER AUTHORITY

345 Kv System

All Weather RI Statistical Distribution



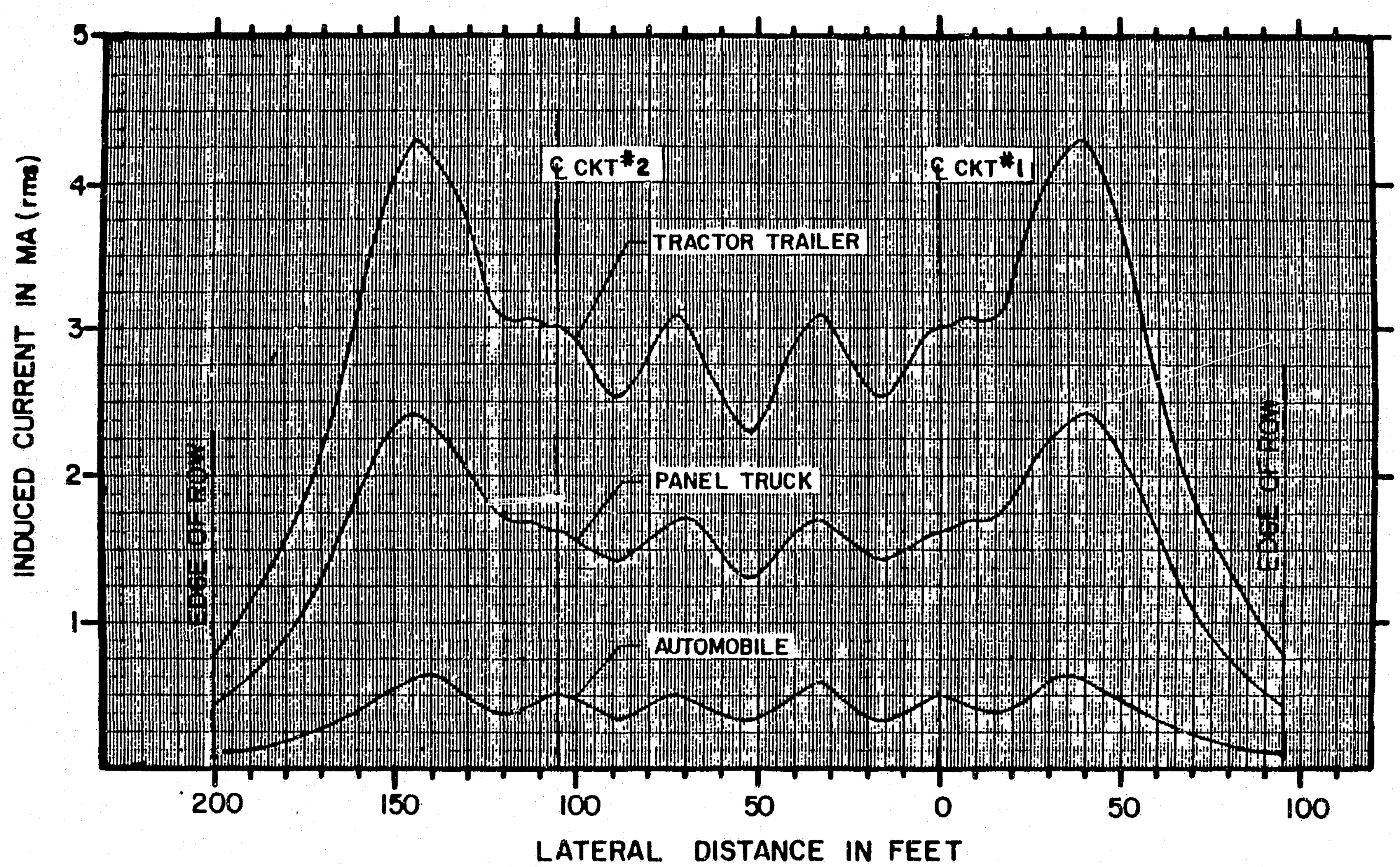
RI Statistical Distribution Curve at the Edge of ROW with 71%/29% Fair to Foul Weather Distribution

Figure D-3

ALASKA POWER AUTHORITY

345 kV System

Electrostatic Induction on Vehicles

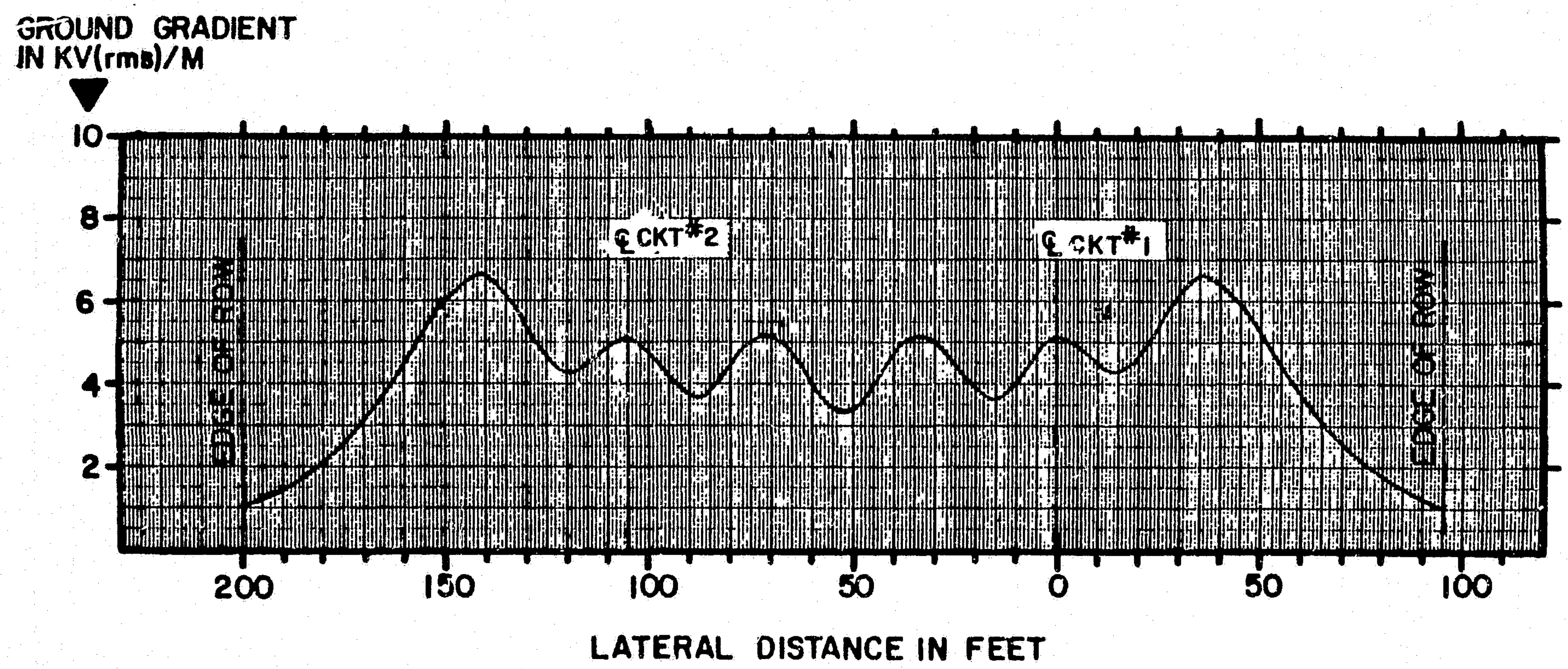


Electrostatically Induced Current Profiles with two circuits in one corridor and phase conductors at 30 ft. above ground with CBA CBA phase sequence.

Figure D-4

ALASKA POWER AUTHORITY

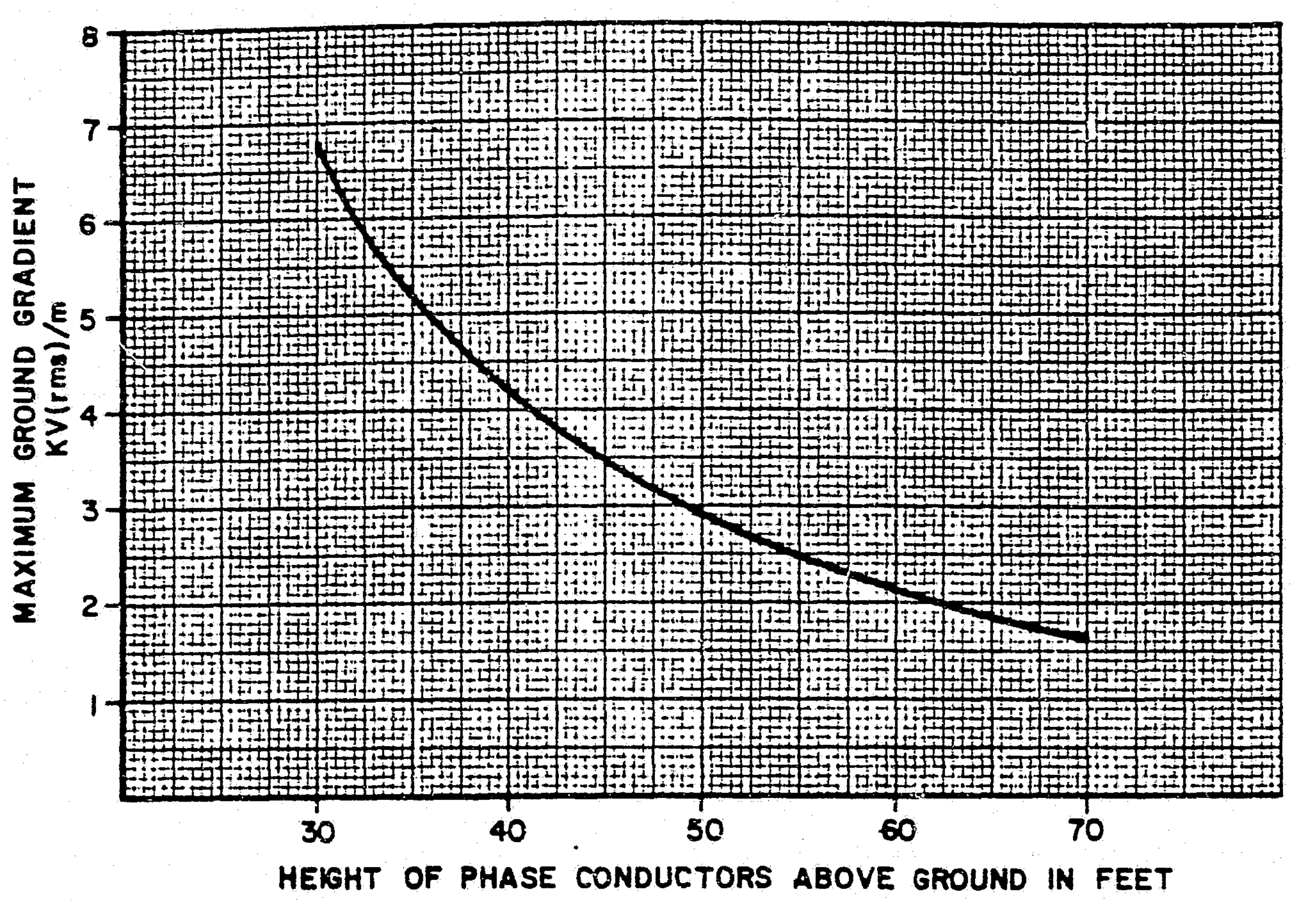
345 Kv System



Ground Gradient Profiles with two circuits in one corridor and phase conductors at 30 ft. above ground with CBA CBA phase sequence.

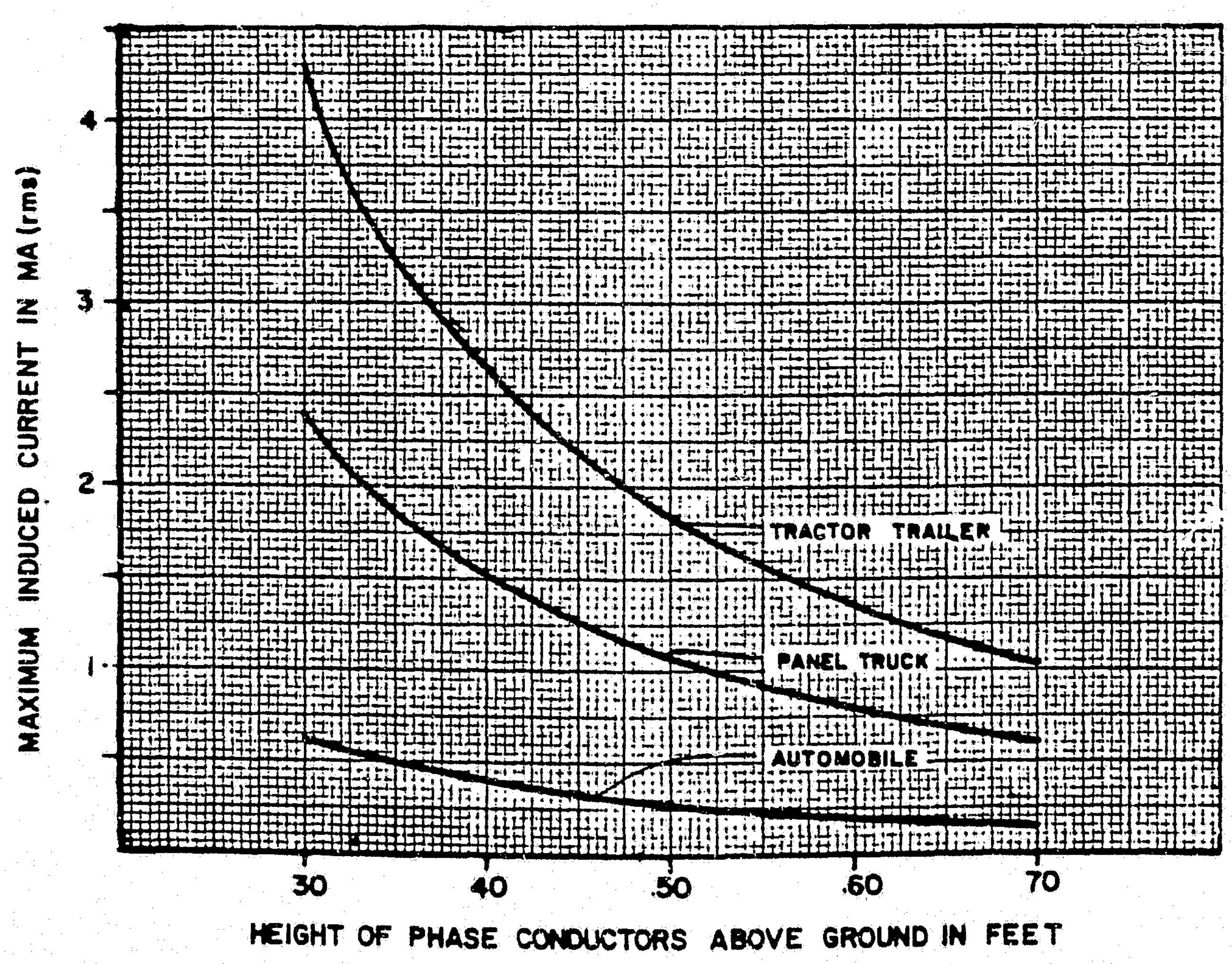
Figure D-5

ALASKA POWER AUTHORITY
345 KV SYSTEM



Maximum Ground Gradient VS Ground Clearance

Figure D-6



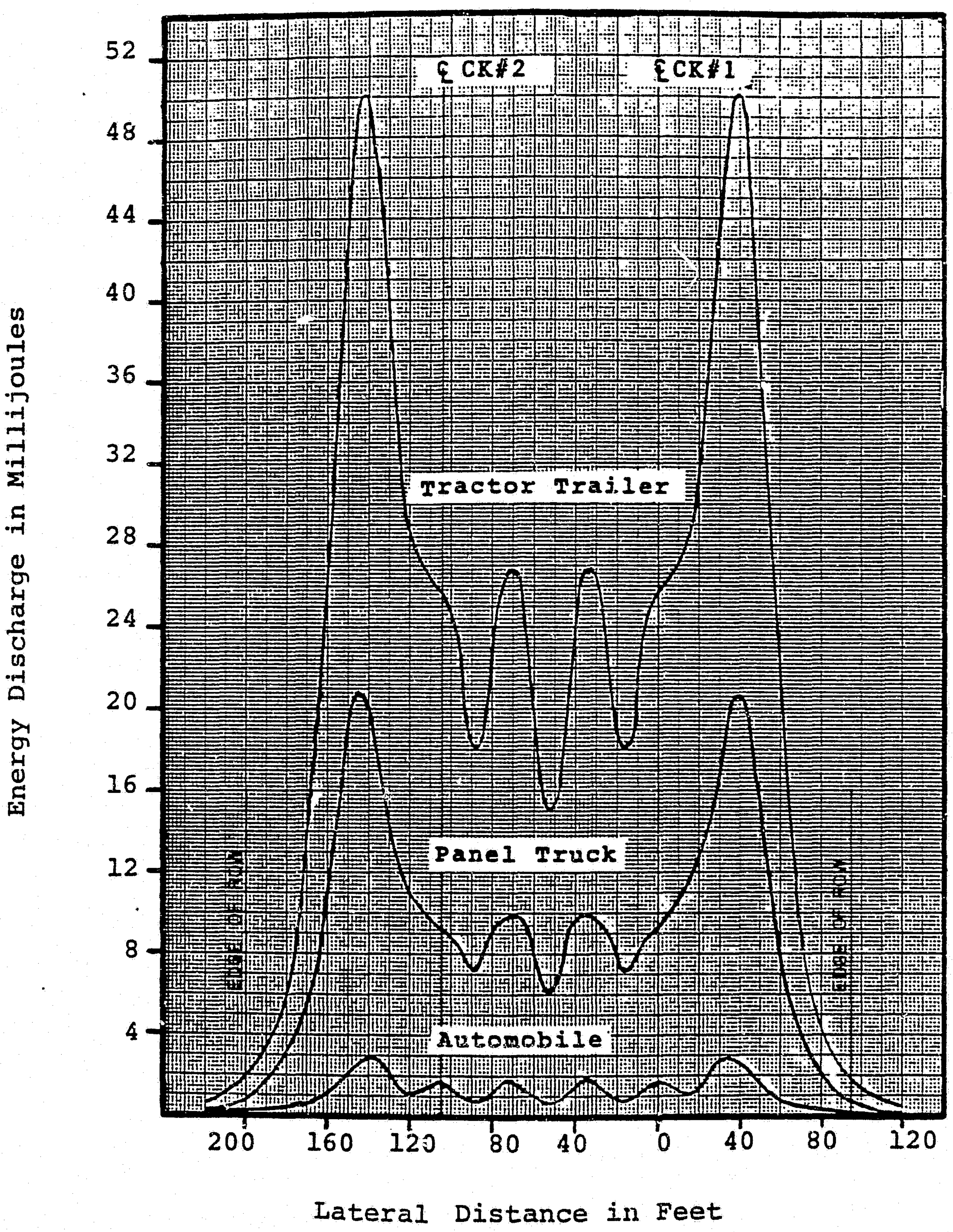
Maximum Vehicle Induced Current VS Ground Clearance

Figure D-7

ALASKA POWER AUTHORITY

345 Kv System

Discharge Energy on Vehicles



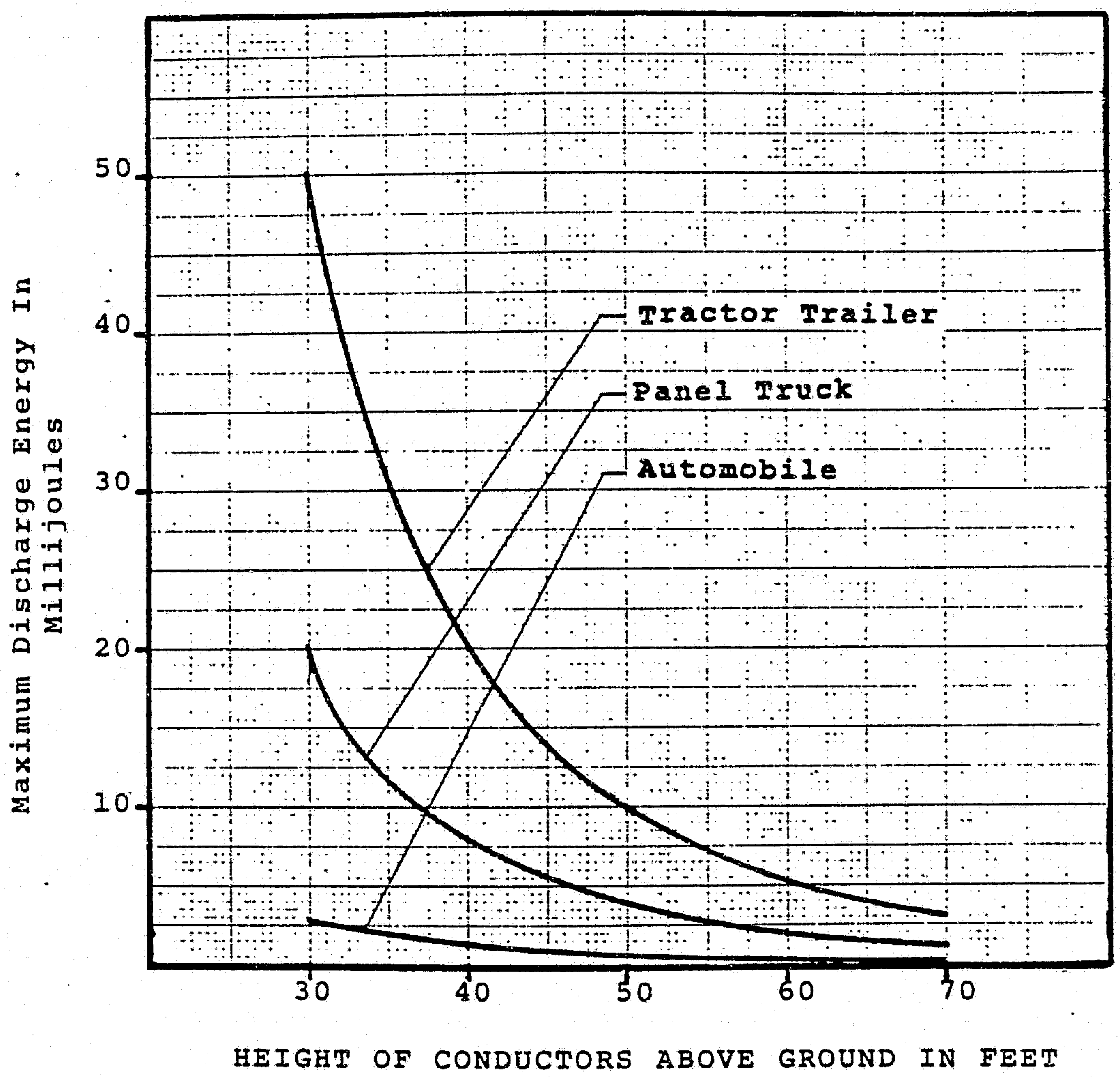
Vehicles Discharge Energy Profiles

Figure D-8

ALASKA POWER AUTHORITY

345 Kv System

Discharge Energy on Vehicles



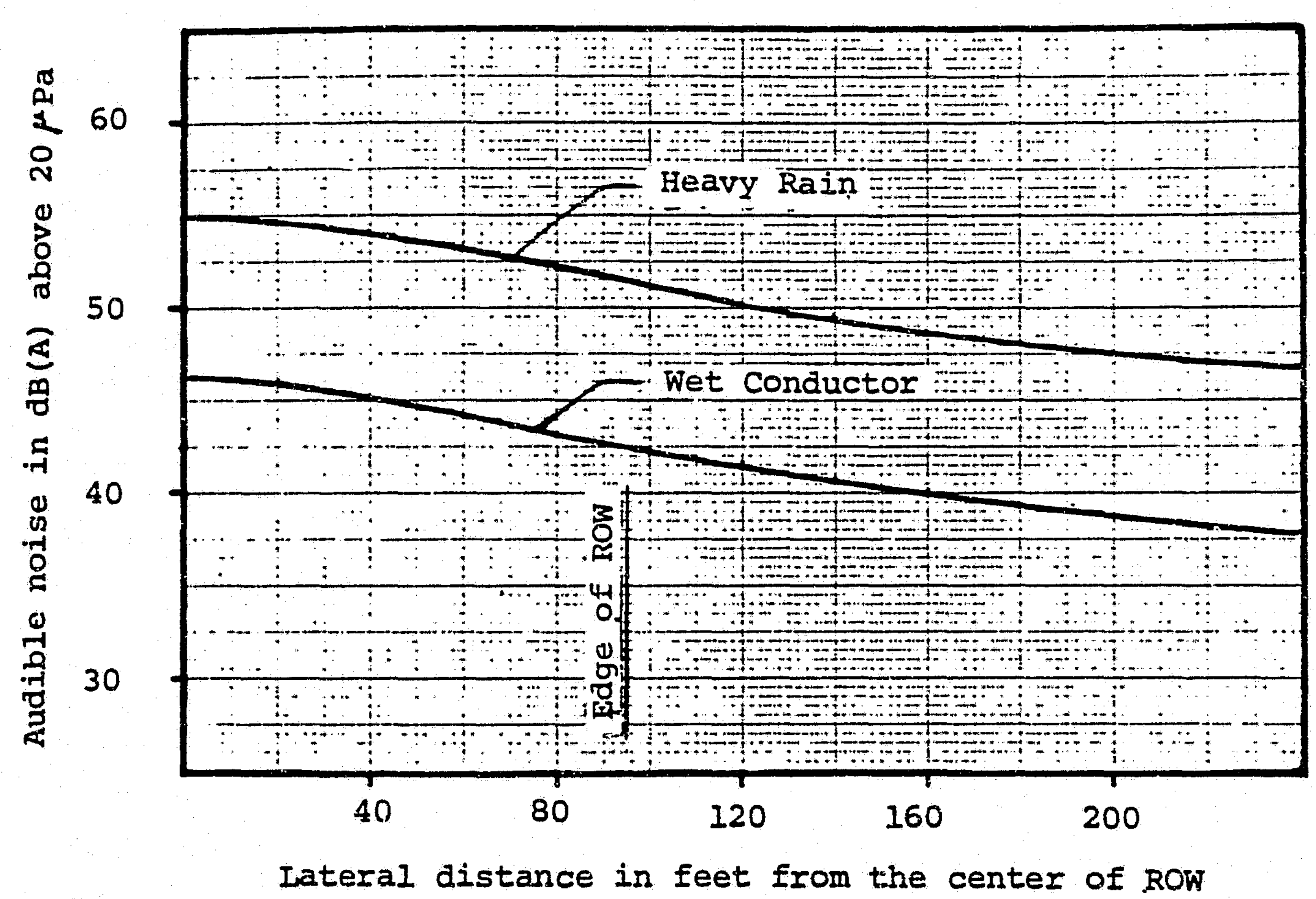
Maximum Discharge Energy on Vehicles VS Ground Clearance

Figure D-9

ALASKA POWER AUTHORITY

345 KV SYSTEM

AUDIBLE NOISE - ONE CIRCUIT PER CORRIDOR



Audible Noise Profiles for Heavy Rain and Wet Conductor for corridors with one 345 Kv circuit.

Figure D-10

APPENDIX E

230 KV AND 345 KV RIGHT-OF-WAY AND

CLEARING DIAGRAMS

230 KV AND 345#KV RIGHT-OF-WAY
AND CLEARING DIAGRAMS

1.0 INTRODUCTION

Studies were carried out to consider the mode and effects of structure failure to determine the proper distance between the two parallel transmission lines on the same ROW. Only one mode of structure failure (i.e. falling in the transverse direction toward the adjacent line), will cause interference with the parallel line.

Based on proposed separation between the lines (105 and 90 feet for 345 and 230 kV respectively) in order to reach the adjacent line, the structure should fall in a direction normal (90°) to the line axis. A decrease of this angle diminishes this possibility considerably and falling at 75° to the axis, the structure will not interfere with the parallel line.

2.0 SUSPENSION STRUCTURES

It was assumed that for transverse falling, the suspension structure will be rotated around the pivot at the base of one leg, as shown in Figure E-1 dated October 31, 1983 attached. Pivoting with respect to the leg closest to the parallel line is not likely. Transverse forces acting in the direction of the adjacent parallel line must exist for the occurrence of conflict. Under this loading condition the structure leg closest to the adjacent line will be under compressive stress. Because the leg under compression is the weakest, it will buckle and fail. Immediately upon failure of the compressed leg all the load imposed on the structure will be transferred to the other leg, under which condition large bending moments at the base of this leg will cause the structure to collapse.

However, the feasibility of assumed falling trajectory in reality is contingent not only on loss of support from buckled structure leg, but also on the complete balance or absence of all longitudinal loads. This condition is unlikely for any loading combination. Therefore, everyday conditions rather than heavy loading are more proper for this study on the assumption that the failure is due to vandalism, external forces, or other unusual occurrences.

Furthermore, since the width of the structures (made of tubular elements) is negligibly small, the probability of hitting an adjacent structure is so extremely small that for all practical purposes it can be ignored.

3.0 ANGLE STRUCTURES

The angle and strain structures consist of three separate guyed poles with single phases attached to each pole. They are considered to rotate at their base in the case of failure. However, the direction of falling trajectory is not expected to be in the transverse direction or in the direction of the bisector of the deflection angle. This is due to the fact that the transverse component at the normal direction basically exists only for intact line condition when longitudinal components are balanced. As soon as a pole moves away from the intact position during failure, highly unbalanced longitudinal loads will appear and the vector of transverse component will change its direction, which phenomenon normally makes angle structures fail more longitudinally rather than in the direction of bisector. Only in the case of simultaneous and instant release of the guyes on angle structures, thus essentially preserving the intact balanced conditions, the structure can fall in direction of transverse component (i.e. normal to the line). A failure occurring under heavy loading conditions will definitely result in the angle structure falling close to the longitudinal direction.

4.0 EVALUATION

In view of the above, for evaluation purposes the following assumptions were adopted:

(1) Everyday loading condition is considered rather than heavy loading.

(2) Suspension structures fall at 90° to axis of the line, rotating around the pivot at the base of the leg away from the parallel line.

(3) Angle structures are considered to fall closer to longitudinal and not in transverse direction.

(4) The structures made of tubular elements cannot be hit by falling structures, because of very small target areas involved.

(5) Conductors of parallel line can be hit by falling structures, thus creating conflict.

Based on the above assumptions and proposed separation between lines, Figure E-1 showing transverse structure falling trajectories were prepared. These sketches are based on structure heights corresponding to 1200 feet spans.

From these sketches it appears that: a) for the structures of both lines located in the vicinity of each other (i.e. 360 and 520 feet distance for 345 and 230 kV lines repectively) no conflict exists, even in the worst case of 90° transverse trajectory; and b) a decrease in structure height of 5 to 10 feet will eliminate this conflict regardless of tower location.

5.0 CONCLUSIONS

The conclusion is that no increase of separation is justified for the subject lines as it is very unlikely that in actuality conflicts will occur. This is based on the following:

- The failure occurrence is most probable for tangent structures because they normally are designed to be relatively weaker than strain structures, and because of the fact 90% of the line structures are of this type.

- The study has shown, that for 1200 feet span, tangent structures placed near each other will not interfere with the parallel line when falling even at 90° angle to the line axis. For structures located at random, the conflict will be eliminated if the spans are in range of 1100-1150 feet. Inasmuch as the Intertie average span is 1150 feet, their values are expected to be closer to actual span lengths. Furthermore, for visual appearance, parallel lines are generally spotted, locating the structures of the two lines as close to each other as possible, practically in pairs, which effectively eliminates the possibility of conflicts.

- Tangent structure transverse falling trajectories normal to the direction of the line axis are not likely in actuality. One of the conditions for this trajectory is balanced longitudinal loads which is true only during conductor stringing. Longitudinal loads will be unbalanced for all other conditions and especially during a structure failure. This alone will prevent the tangent structure from falling at a trajectory close enough to 90° to reach the adjacent line.

- The failure of strain structures is less probable since they are designed for containment of failures on the line. The falling modes and trajectories of strain structures are determined by large unbalanced longitudinal loads imposed on them, and existing during normal and abnormal conditions. Therefore, the probability of interference due to their transverse fall is even less than that for tangent structures. It is also apparent that since parallel lines have common deflection points, angle structures of the two lines will be located close to each other.

Right-Of-Way Width

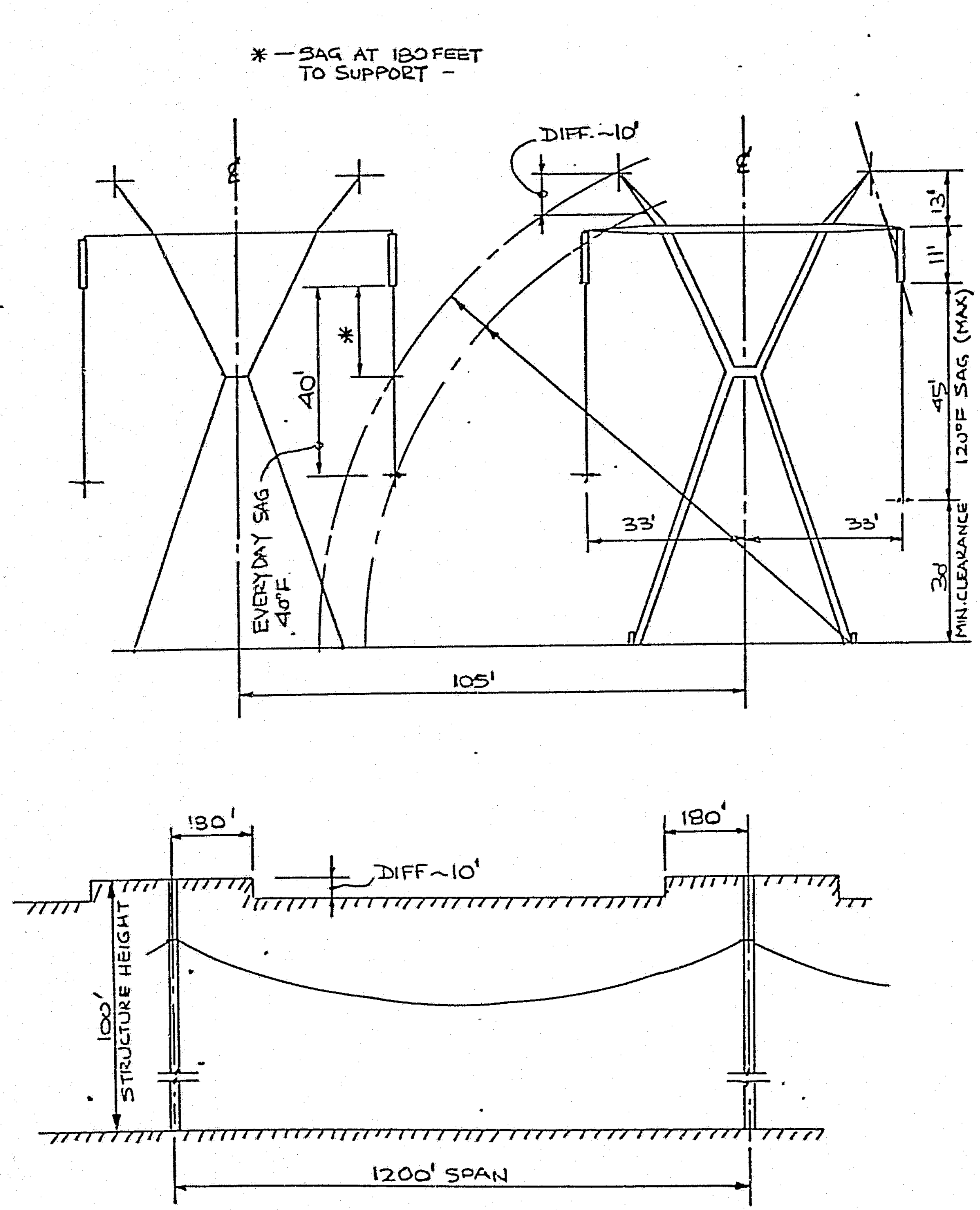
ROW widths for 230 kV and 345 kV lines shown on sketches have been determined based on the results of electrical environmental study and analysis of the conflicts for parallel lines. For specific conditions encountered and different terrain characteristics, the dimensions indicated will be adjusted during design phase, as required.

Clearing diagrams are typical and actual vegetation cutting should be selective. The vegetation shall be topped rather than removed. The area between transmission lines designated as "access, construction road area" if not used for this purpose can be left with vegetation up to 10 to 12 feet high for the width of 30-35 feet. Required ROW area for different widths will be as follows:

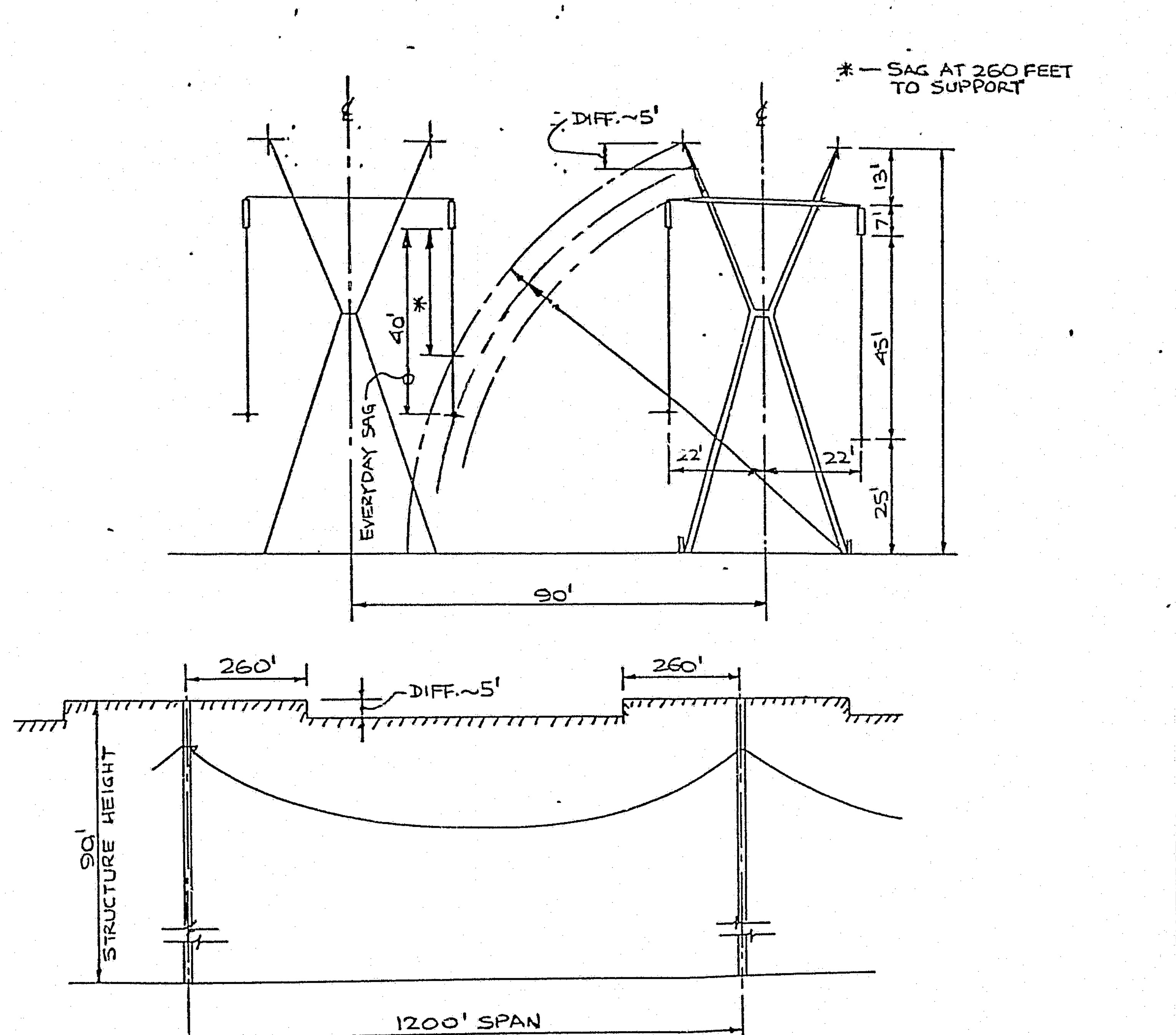
Structure Type and Voltage	No. of Circuits on ROW	ROW Width Feet	Area Acres/Mile
X-frame 345 kV	1	170	20.63
X-frame 345 kV	2	275	33.38
X-frame 345 kV	3	380	46.12
X-frame 345 kV	4	485	58.87
X-frame 230 kV	1	120	14.57
X-frame 230 kV	2	210	25.49
X-frame 345 kV & 230 kV	2	250	30.35
Steel Pole 345 kV Double Circuit	1	130	15.78
Steel Pole 345 kV Single Circuit	1	125	15.17
Steel Pole 345 kV Single Circuit	2	230	27.92
Steel Pole 230 kV Single Circuit	1	100	12.14
Steel Pole 230 kV Single Circuit	2	190	23.06

FIGURES

345 kV SUSPENSION STRUCTURE



230 kV SUSPENSION STRUCTURE

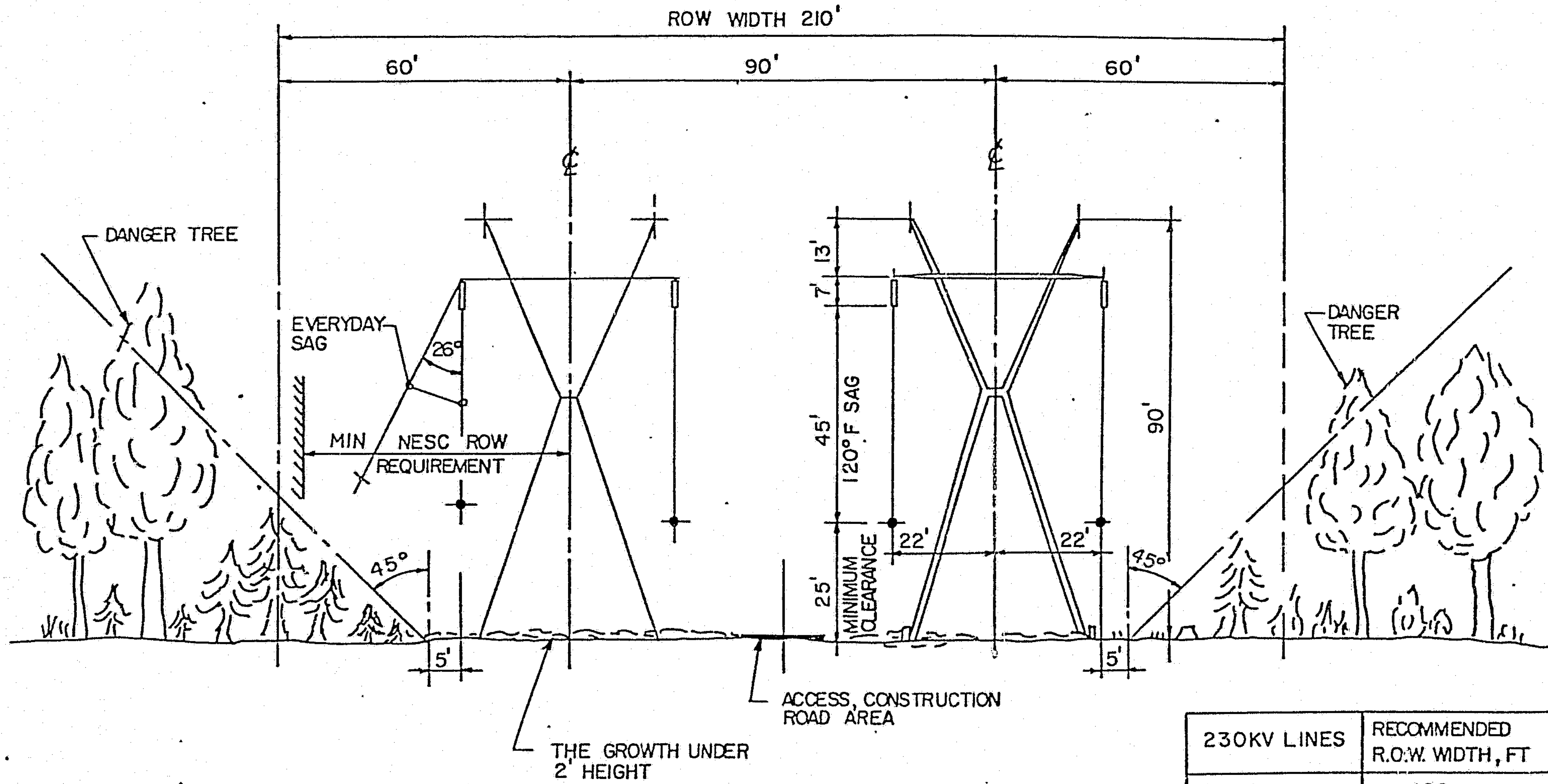


ASSUMPTION:

SPAN—1200 FEET
EVERYDAY SAG—40 FEET
MAXIMUM SAG—45 FEET

ALASKA POWER AUTHORITY SUSITNA HYDROELECTRIC PROJECT	
PARALLEL LINE SEPARATION STUDY	
HARZA – EBASCO	
DATE OCT 31.83	DWG. NO. FIGURE E-1

TYPICAL ROW WIDTH AND CLEARING DIAGRAM
230KV X-TYPE STRUCTURES



ASSUMPTION:

954KCM "RAIL" CONDUCTORS
1200FT SPAN
MAX 120°F SAG-45 FT
EVERYDAY SAG - 40 FT

230KV LINES	RECOMMENDED R.O.W. WIDTH, FT
1	120
2	210

NOTE:

RIGHT OF WAY WIDTH FOR TWO SINGLE CIRCUIT 230KV POLE LINES (900FT SPAN) WILL BE 50+ 90+50=190 FT

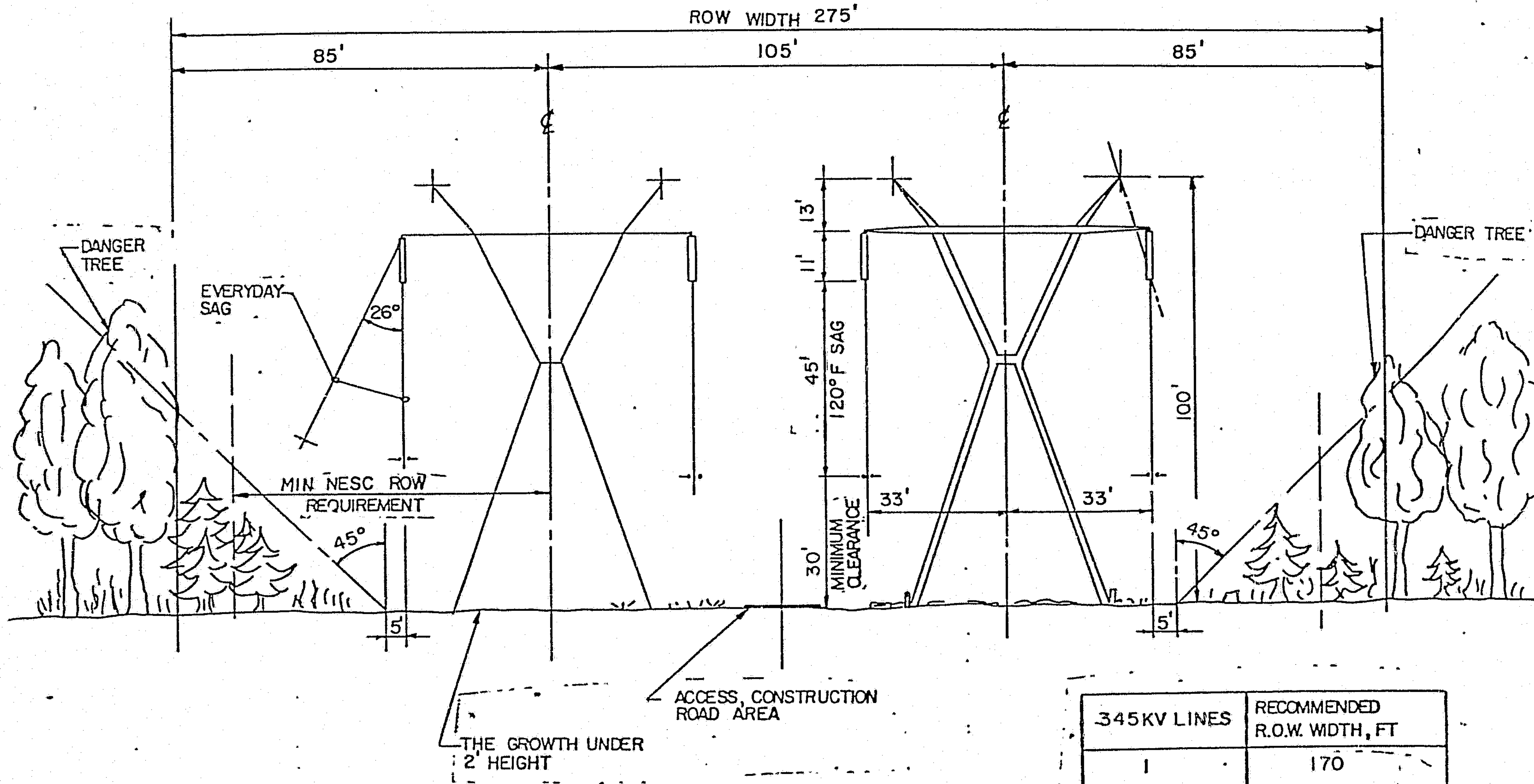
ALASKA POWER AUTHORITY
SUSITNA HYDROELECTRIC PROJECT

230 KV TRANSMISSION LINES
RIGHT-OF- WAY

HARZA - EBASCO

DATE: November 9, 1983 DWG. NO. FIGURE E-2

TYPICAL ROW WIDTH AND CLEARING DIAGRAM
345KV X-TYPE STRUCTURES



ASSUMPTION:

954KCM RAIL CONDUCTORS
1200FT SPAN
MAX 120°F SAG-45 FT
EVERYDAY SAG - 40 FT

345KV LINES	RECOMMENDED R.O.W. WIDTH, FT
1	170
2	275
3	380
4	485

NOTE:

RIGHT OF WAY WIDTH FOR TWO LINES, 345KV AND 230KV IN PARALLEL WILL BE 85+105+60=250FT.

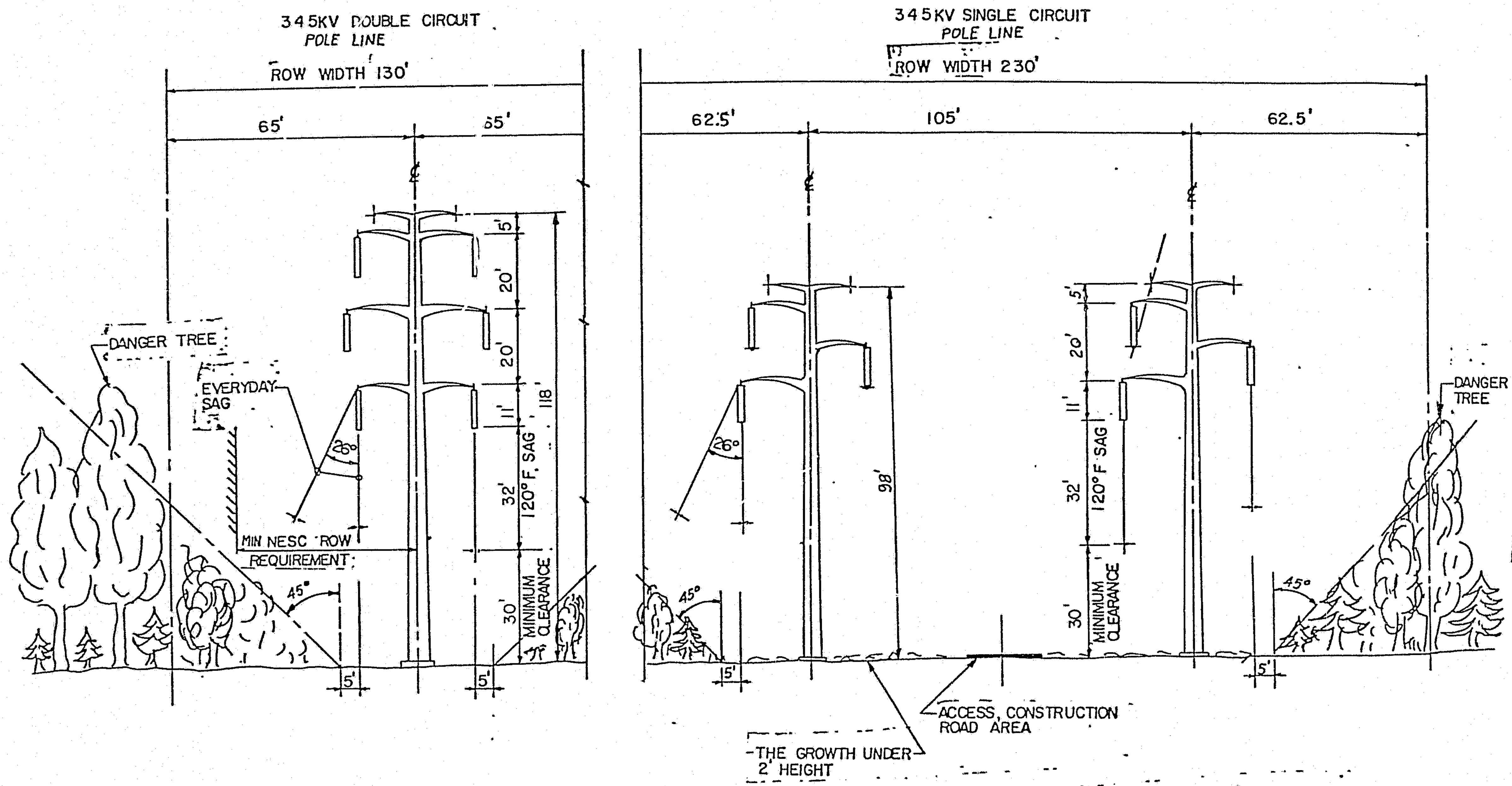
ALASKA POWER AUTHORITY
SUSITNA HYDROELECTRIC PROJECT

345KV TRANSMISSION LINES RIGHT-OF-WAY

HARZA - EBASCO

DATE: November 9, 1983 | DWG. NO. FIGURE E-3

TYPICAL ROW WIDTH AND CLEARING DIAGRAM



ASSUMPTION:
954KCM "RAIL" CONDUCTORS
900 FT SPAN
MAX 120°F SAG - 32 FT
EVERYDAY SAG - 26 FT

LINES	RECOMMENDED R.O.W. WIDTH, FT
1	125
2	230

ALASKA POWER AUTHORITY
SUSITNA HYDROELECTRIC PROJECT
345KV SINGLE POLE TRANSMISSION LINE RIGHT-OF-WAY
HARZA - EBASCO
DATE OCT 31, 83 | DWG. NO. FIGURE E-4

APPENDIX F

COST DATA FOR POTENTIAL TRANSMISSION SYSTEM REFINEMENTS

COST DATA FOR POTENTIAL TRANSMISSION SYSTEM REFINEMENTS

1.0 INTRODUCTION

The total installed cost of the Susitna Transmission System as shown in the FERC License Application is in the order of 575 million dollars, measured in terms of January, 1983 dollars and excluding Alaska Power Authority and Harza-Ebasco charges. This figure also excludes carrying charges and interest during construction.

In order to obtain an understanding of the most significant elements of cost related to potential Susitna Transmission System project development, the cost data on the following pages were prepared during the last week of August, 1983.

2.0 COSTS ASSOCIATED WITH POTENTIAL PROJECT REFINEMENTS*

INDEX

Category 1	Identifier
Change Voltage from Gold Creek to Fairbanks	CIT
Category 2	
Route One Circuit Overland Around Knik Arm From Willow to University	C2T1
Utilize Existing Anchorage Area Transmission Network As Much As Possible	C2T2
Revise Fairbanks Susitna Power Delivery From Ester to Fort Wainwright	C2T3
Relocate Willow Substation to "W/T"	C2T4
Change Voltage from Healy to Fairbanks	C2T5

*This cost data, should not be used in the future, because it was modified. The land acquisition costs provided by Land Field Services was obtained on October 26, 1983 and is included in Appendix G. In addition, the cost data should be modified by the ROW widths shown on page E-7 of Appendix E. Modified cost data is shown in Appendix H, Table H-2.

3.0 POTENTIAL PROJECT REFINEMENTS

Drawing No. T-1	South Study Area Anchorage Subarea Preliminary Corridor Alternatives
Drawing No. T-6	North Study Area Fairbanks Subarea Preliminary Corridor Alternatives
Exhibit No. 2	Transmission Line - Cost Per Mile
Sketch No. 3	Lorraine Single Line
Sketch No. 4	Knik Arm Single Line
Sketch No. 5	Single Line - Potential Refinements and Transmission Corridors
Sketch No. 7	Gold Creek - Ester at 345 kV
Sketch No. 8	Gold Creek - Ester at 138 kV
Exhibit 3-3	Plate F81 - 345 kV System Single Line Diagram and Transmission Corridor
Exhibit 6-10	Gold Creek - Ester at 230 kV

TASK 41 - SUSITNA TRANSMISSION SYSTEM

C2T1 PROPOSED PROJECT REFINEMENTS

Change route of one 345 kV transmission line from Willow to University Substation, overland around Knik Arm instead of using a submarine cable crossing under Knik Arm.

C2T1	Represents Watana 1993 installation
C2T1.S	Represents Susitna 2002 installation
C2T1.A	Represents Watana 1993 installation with route from Nancy Lake to Knik Arm (Fossil Creek Area)
C2T1.A.S	Same as C2T1.A except Susitna 2002 installation

TASK 41 - SUSITNA TRANSMISSION SYSTEM

CIT COST COMPARISON

Change voltage of the transmission system from Gold Creek to Fairbanks, Ester Substation from 345 Kv to 230 Kv.

COST COMPARISON

	345 Kv SYSTEM (Million $)	230 Kv SYSTEM (Million $)
Gold Creek Substation	10.200	17.410
Transmission Lines Gold Creek to Healy (93 Miles)	40.548	22.971
Transmission Lines Healy to Ester (94 Miles)	81.028	45.778
Ester Substation	23.950	20.600
Totals	155.726	106.759

Difference: 345 Kv system minus 230 Kv system = $48.97 Million or approximately $49 Million dollars.

TASK 41 - SUSITNA TRANSMISSION SYSTEM

CIT COST COMPARISON

Change transmission line route of one 345 kV line from Willow to University Substation, overland around Knik Arm instead of using a submarine cable crossing under Knik Arm.

COST COMPARISON (YEAR 1993)

	ORIGINAL	REFINEMENT
345 kV "X" (2 circuits)	38.750 (43.2 Miles)	18.299 (20.4 Miles)
345 kV "X" (1 circuit)	--	16.663 (345.5 Miles)
Submarine Cable (1 circuit)	69.100 (3.5 Miles-2 circuits)	38.600 (3.5 Miles-1 circuit)
345 kV Pole (2 circuit)	18.340 (18.6 Miles-2 circuits)	11.635 (11.8 Miles-1 circuit)
345 kV Pole (1 circuit)	--	23.025 (37.5 Miles)
Knik Arm Substation	13.650	5.100
Totals	139.840	113.322

Difference: Original minus Refinement = $26.518 million or approximately $26.5 Million.

C2T1.S COST COMPARISON

Change transmission line route of one 345 kV line from Willow to University Substation, overland around Knik Arm instead of using a submarine cable crossing under Knik Arm.

COST COMPARISON (YEAR 2002)
(Million $)

	ORIGINAL	REFINEMENT
345 kV "X" Type 3 circuits	$59.616 (43.2 Miles)	--
345 kV "X" Type 2 circuits	--	$18.299 (20.4 Miles)
345 kV "X" Type 1 circuit	--	16.663 (34.5 Miles)
345 kV Submarine Cable	99.600 (3.5 Miles)	38.600 (3.5 Miles)
345 kV Steel Pole 3 circuits	11.973 (7.5 Miles)	--
345 kV Steel Pole 2 circuits	10.945 (11.1 Miles)	11.635 (11.8 Miles)
345 kV Steel Pole 1 circuit	--	23.025 (37.5 Miles)
Knik Arm Substation	16.550	5.100
Totals	198.684	113.322

Difference: Original minus Refinement = $85.361 million or approximately $85.4 million.

TASK 41 - SUSITNA TRANSMISSION SYSTEM

C2T1.A COST COMPARISON

Change transmission line route of one 345 kV line from Willow to University Substation, overland around Knik Arm instead of using a submarine cable crossing under Knik Arm. Using alternative line route from Nancy Lake to Knik Arm.

COST COMPARISON (YEAR 1993)
(Million $)

	ORIGINAL	REFINEMENT
345 kV "X" (2 circuits)	$38.750 (43.2 Miles)	5.741 (6.4 Miles)
345 kV "X" (1 circuit) 2 circuits	--	36.177 (74.9 Miles)
Submarine Cable 1 circuit	69.100 (3.5 Miles 2 circuits)	38.600 (3.5 Miles)
345 kV Pole (2 circuits)	18.340 (18.6 Miles 2 circuits)	10.945 (11.1 Miles)
345 kV Pole (1 circuit)	--	23.025 (37.5 Miles)
Knik Arm Substation	13.650	5.100
Totals	139.840	119.588

Difference: Original minus Refinement = $20.252 million or approximately $20.2 million.

C2T1.A.S COST COMPARISON

Change transmission line route of one 345 kV line from Willow to University Substation, overland around Knik Arm instead of using a submarine cable crossing under Knik Arm, and using alternative line route from Nancy Lake to Knik Arm.

COST COMPARISON (YEAR 1993)
(Million $)

	ORIGINAL	REFINEMENT
345 kV "X" Type 3 circuits	$59.616 (43.2 Miles)	--
345 kV "X" Type 2 circuits	--	5.741 (6.4 Miles)
345 kV "X" Type 1 circuit	--	36.177 (74.9 Miles)
345 Submarine Cable	99.600 (3.5 Miles)	38.600 (3.5 Miles)
345 kV Steel Pole 3 circuits	11.973 (7.5 Miles)	--
345 kV Steel Pole 2 circuits	10.945 (11.1 Miles)	10.945 (11.1 Miles)
345 kV Steel Pole 1 circuit	--	23.025 (37.5 Miles)
Knik Arm Substation	16.550	5.100
Totals	$198.684	$119.588

Difference: Original minus Refinement = $79.096 million or approximately $79.1 million.

TASK 41 - SUSITNA TRANSMISSION STSTEM

C2T2 PROPOSED PROJECT REFINEMENTS

Change transmission system in Anchorage area to utilize existing transmission network as much as practical. To do so, set-up substation on west side of Knik Arm opposite Anchorage called "Lorraine" (see Sketch No. 3). Modify Knik Arm Substation to incorporate a 230 kV breaker and one-half scheme in addition to the 345 kV breaker and one-half arrangement. See Sketch No. 4.

C2T2	Represents Watana 1993 installation
C2T2.S	Represents Susitna 2002 installation
C2T2.A	Represents Watana 1993 installation with route from Nancy Lake to Knik Arm (Fossil Creek Area)
C2T2.A.S	Same as C2T1.A except Susitna 2002 installation

TASK 41 - SUSITNA TRANSMISSION SYSTEM

C2T2 COST COMPARISON

Change transmission system in Anchorage area to utilize existing network as much as possible.

	COST COMPARISON (YEAR 1993) (Million $) ORIGINAL	REFINEMENT
345 kV "X" Type 2 circuits	$38.750 (43.2 Miles)	18.299 (20.4 Miles)
345 kV "X" Type 1 circuit	--	15.698 (32.5 Miles)
345 kV Submarine Cable	69.100 (3.5 Miles)	--
345 kV Steel Pole 2 circuits	18.340 (18.6 Miles)	--
345 kV Steel Pole 1 circuit	--	18.420 (30.0 Miles)
230 kV "X" Tower 2 circuits	--	--
230 kV "X" Tower 1 circuit	--	0.544 (2.0 Miles)
230 Submarine Cable	--	24.00 (3.5 Miles)
230 kV Steel Pole 2 circuits	--	6.360 (11.1 Miles)
230 kV Steel Pole 1 circuit	--	2.670 (7.5 Miles)
Lorraine Substation	--	21.290
Knik Arm Substation	13.650	22.140
University Substation	25.143	2.400
Totals	$164.983	$131.821

Difference: Original minus Refinement = $33.162 million or approximately $33.2 million.

TASK 41 - SUSITNA TRANSMISSION SYSTEM

C2T2.S COST COMPARISON

Change transmission system in Anchorage area to utilize existing network as much as possible.

COST COMPARISON (YEAR 2002)
(Million $)

	ORIGINAL	REFINEMENT
345 kV "X" Type 3 circuits	$59.616 (43.2 Miles)	--
345 kV "X" Type 2 circuits	--	18.299 (20.4 Miles)
345 kV "X" Type 1 circuit	--	15.698 (32.5 Miles)
345 kV Submarine Cable	99.600 (3.5 Miles)	--
345 kV Steel Pole 3 circuits	11.973 (7.5 Miles)	--
345 kV Steel Pole 2 circuits	10.945 (11.1 Miles)	--
345 kV Steel Pole 1 circuit	--	18.420 (30.0 Miles)
230 kV "X" Tower 2.0 Miles) 1 circuit	--	0.544 1 circuit
230 Submarine Cable	--	24.0 (3.5 Miles)
230 kV Steel Pole 2 circuits	--	6.360 (11.1 Miles)
230 kV Steel Pole 1 circuit	--	2.670 (7.5 Miles)
Lorraine Substation	--	21.290
Knik Arm Substation	16.550	22.140
University Substation	33.266	2.400
Totals	$231.950	$131.821

Difference: Original minus Refinement = $100.129 million or approximately $100. million.

C/41/7F

C2T2.A COST COMPARISON

Change transmission system in Anchorage area to utilize existing network as much as possible using alternative line route from Nancy Lake to Knik Arm.

COST COMPARISON (YEAR 1993)
(Million $)

	ORIGINAL	REFINEMENT
345 kV "X" Type 2 circuits	$38.700 (43.2 Miles)	5.741 (6.4 Miles)
345 kV "X" Type 1 circuit	--	35.211 (72.9 Miles)
345 kV Submarine Cable	69.100 (3.5 Miles)	--
345 kV Steel Pole 2 circuits	18.340 (18.6 Miles)	--
345 kV Steel Pole 1 circuit	--	18.420 (30.0 Miles)
230 kV "X" Tower 2 circuits	-----	
230 kV "X" Tower 1 circuit	--	0.544 (2.0 Miles)
230 kV Submarine Cable	--	24.0000 (3.5 Miles)
230 kV Steel Pole 2 circuits	--	6.360 (11.1 Miles)
230 kV Steel Pole 1 circuit	--	2.670 (7.5 Miles)
Lorraine Substation	--	21.290
Knik Arm Substation	13.650	22.140
University Substation	25.143	2.400
Totals	$164.983	$138.776

Difference: Original minus Refinement = $26.207 million or approximately $26.2 million.

C/41/7F

C2T2.A.S COST COMPARISON

Change transmission system in Anchorage area to utilize existing network as much as possible using alternative line route from Nancy Lake to Knik Arm.

COST COMPARISON (YEAR 2002)
(Million $)

	ORIGINAL	REFINEMENT
345 kV "X" Type 3 circuits	$59.616 (43.2 Miles)	--
345 kV "X" Type 2 circuits	--	5.741 (6.4 Miles)
345 kV "X" Type Miles	--	35.211 1 circuit(72.9
345 kV Submarine Cable	99.600 (3.5 Miles)	--
345 kV Steel Pole 3 circuits	11.973 (7.5 Miles)	--
345 kV Steel Pole 2 circuits	10.945 (11.1 Miles	--
345 kV Steel Pole Miles)	--	18.420 1 circuit(30.0
230 kV "X" Tower 2.0 Miles) 1 circuit	--	0.544 1 circuit
230 kV Submarine Cable	--	24.0000 (3.5 Miles)
230 kV Steel Pole 2 circuits	--	6.360 (11.1 Miles)
230 kV Steel Pole 1 circuit	--	2.670 (7.5 Miles)
Lorraine Substation	--	21.290
Knik Arm Substation	16.550	22.140
University Substation	33.266	2.400
Totals	$231.950	$138.776

Difference: Original minus Refinement = $93.174 million or approximately $93.2 million.

C/41/7F

TASK 41 - SUSITNA TRANSMISSION SYSTEM

C2T3 COST COMPARISON

Relocate Fairbanks area Susitna power delivery location from Ester to Fort Wainwright.

	ADDITIONAL COST (Million $)
2-230 kV Lines "X" Type Structures 6 Miles additional length	$ 2.922
River Crossings	11.650
Total	$ 14.572

Difference: Original minus Refinement = $14.572 million or approximately $14.6 million.

C2T4 COST COMPARISON

Change location of Willow Substation approximately 15 miles southeast to location designated as "W/T".

COST COMPARISON
(Million $)

	ORIGINAL	REFINEMENT
345 kV "X" Type 2 Lines	$38.750 (43.2 Miles)	37.135 (41.4 Miles)
345 Submarine Cable 2 circuits	69.100	69.100
345 kV Steel Pole 2 circuits	18.340	18.340
Totals	$126.190	$124.576

Difference: Original minus Refinement = $1.614 million or approximately $1.6 million.

TASK 41 - SUSITNA TRANSMISSION SYSTEM

C2T4.S COST COMPARISON

Change location of Willow Substation approximately 15 miles southeast to location designated as "W/T".

COST COMPARISON (YEAR 2002)
(Million $)

	ORIGINAL	REFINEMENT
345 kV "X" Type 3 circuits	$59.617 (43.2 Miles)	--
345 kV "X" Type	--	37.136 (2 circuits) (41.4 Miles)
345 kV Submarine Cable 2 circuits	--	69.1 (3.5 Miles)
345 kV Submarine Cable 3 circuits	99.6 (3.5 Miles)	--
345 kV Steel Pole 3 circuits	11.973 (7.5 Miles)	
345 kV Steel Pole	10.945 (11.1 Miles)	18.340 (18.6 Miles)
Totals	$182.135	$124.559

Difference: Original minus Refinement = $57.559 million or approximately $57.6 million.

TASK 41 - SUSITNA TRANSMISSION SYSTEM

C2T5 COST COMPARISON

Change voltage from Healy Substation to Ester Substation to 138 kV.

COST COMPARISON (Million $)

230 kV SYSTEM	138 kV SYSTEM	
230 kV "X" Type 2 Lines	$45.778	--
138 kV "X" Type	--	37.224 2 Lines
Ester Substation	17.150	9.5
Healy Substation	--	11.56
Totals	$ 62.928	$ 58.284

Difference: 230 kV System minus 138 kV = $4.644 million or approximately $4.6 million.

TABLES

Task 41 - Transmission Line - Cost per mile
Revised August 31, 1983
All dollars adjusted to January, 1983

Structure Type & KV	Conduct's No./Size	CKTS/ ROW	Cost: Mat'l & Labor (2) (Dollars)	ROW/Width Cleared (Feet)	ROW Cost (Dollars) Gold Creek - FBX	ROW Cost (Dollars) Gold Creek-Anch
X-frame 345	2 x 954	2(lines)	822,000	300/	40,000	75,000
X-frame 345	2 x 954	1	(1)436,000	190/	25,000	47,000
Steel Pole 345	2 x 954	1	567,000	100/	25,000	47,000
Steel Pole 345	2 x 954	2(CKTS)	939,000	100/	25,000	47,000
X-frame 230	1 x 954	1	247,000	100/	13,000	25,000
Steel Pole 230	1 x 954	1	331,000	80/	13,000	25,000
X-frame 230	1 x 954	2(lines)	466,000	160/	21,000	40,000
Steel Lattice pole with guyes 138	1 x 556	1	181,000	70/	10,000	18,000
Same 138	1 x 556	2	344,000	120/	16,000	30,000
138	1 x 954	1	200,000	70/	10,000	18,000
Steel Pole 230	1 x 954	2(CKTS)	548,000	80/	13,000	25,000
230 SCSC(3)	3 x 2000	1	24 million	--	--	--
230 SCSC(3)	4 x 2000	1	29.2 million	--	--	--
345 SCSC(3)	3 x 2000	1	30.5 million	--	--	--
345 SCSC(3)	4 x 2000	1	38.6 million	--	--	--

ROW Width	Acres/mile
300' x 0.12138	36.4
190'	23.1
100'	12.1
80'	9.7
70'	8.5

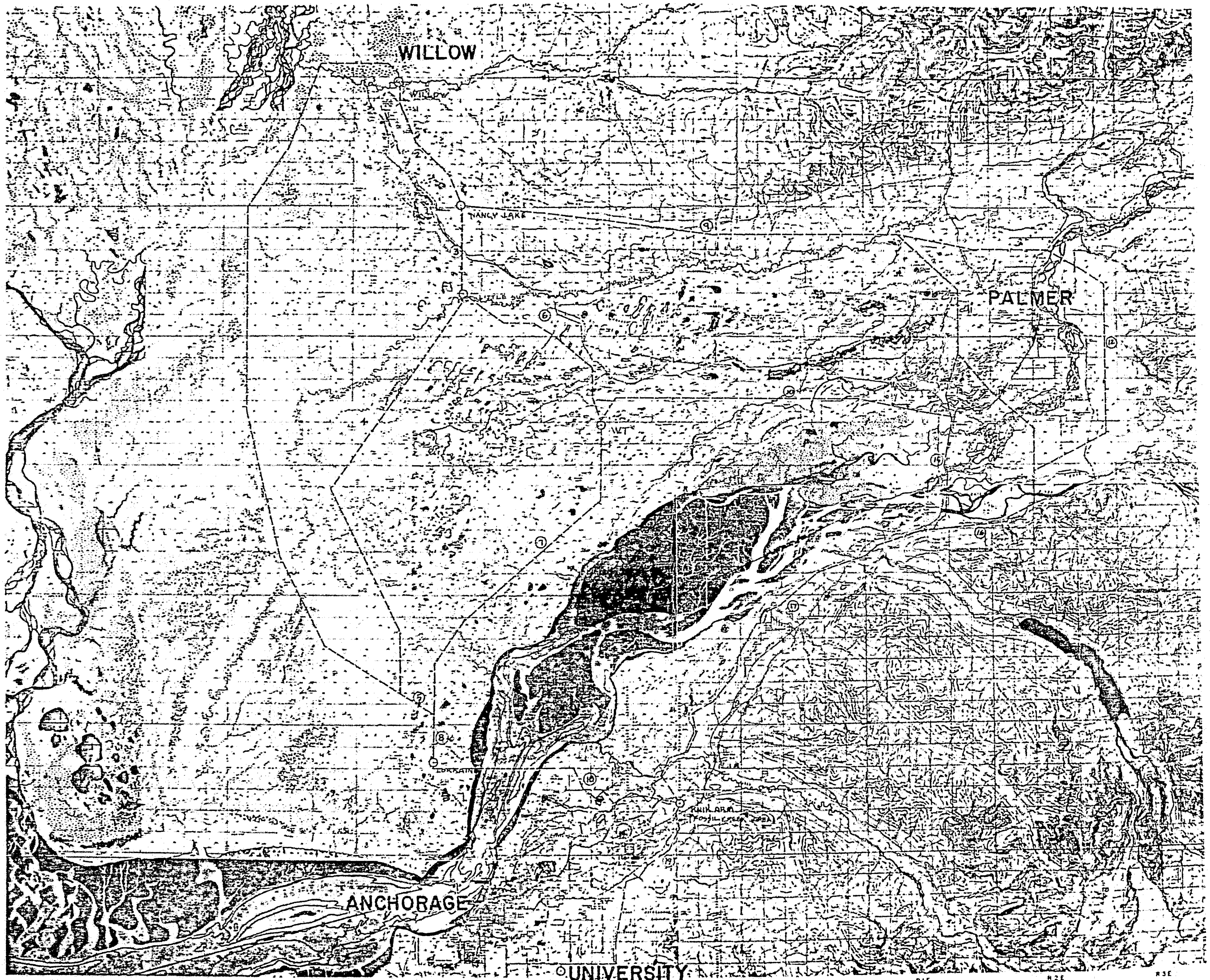
(1)Bid data for Intertie Construction (Average of 3 lowest bidders)
(2)Includes Line survey and clearing costs
(3)SCSC - Self-Contained Submarine Cable - Dollars are estimated total installed cost with all accessories in Anchorage, Alaska for 3.5 miles under Knik Arm.

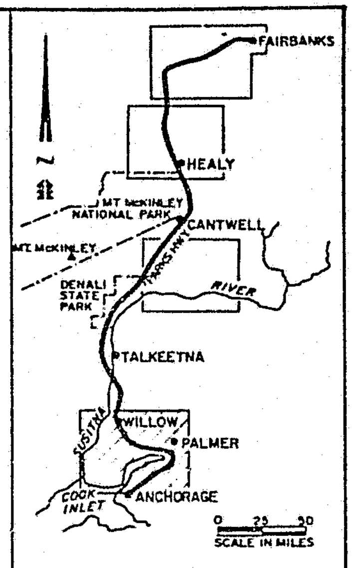
C/41/7F.3

EXHIBIT NO. 2

FIGURES

Frank Moolin & Associates, Inc.





LOCATION MAP

BASE MAP SOURCE USGS

0 1 2 3 4 5
SCALE IN MILES

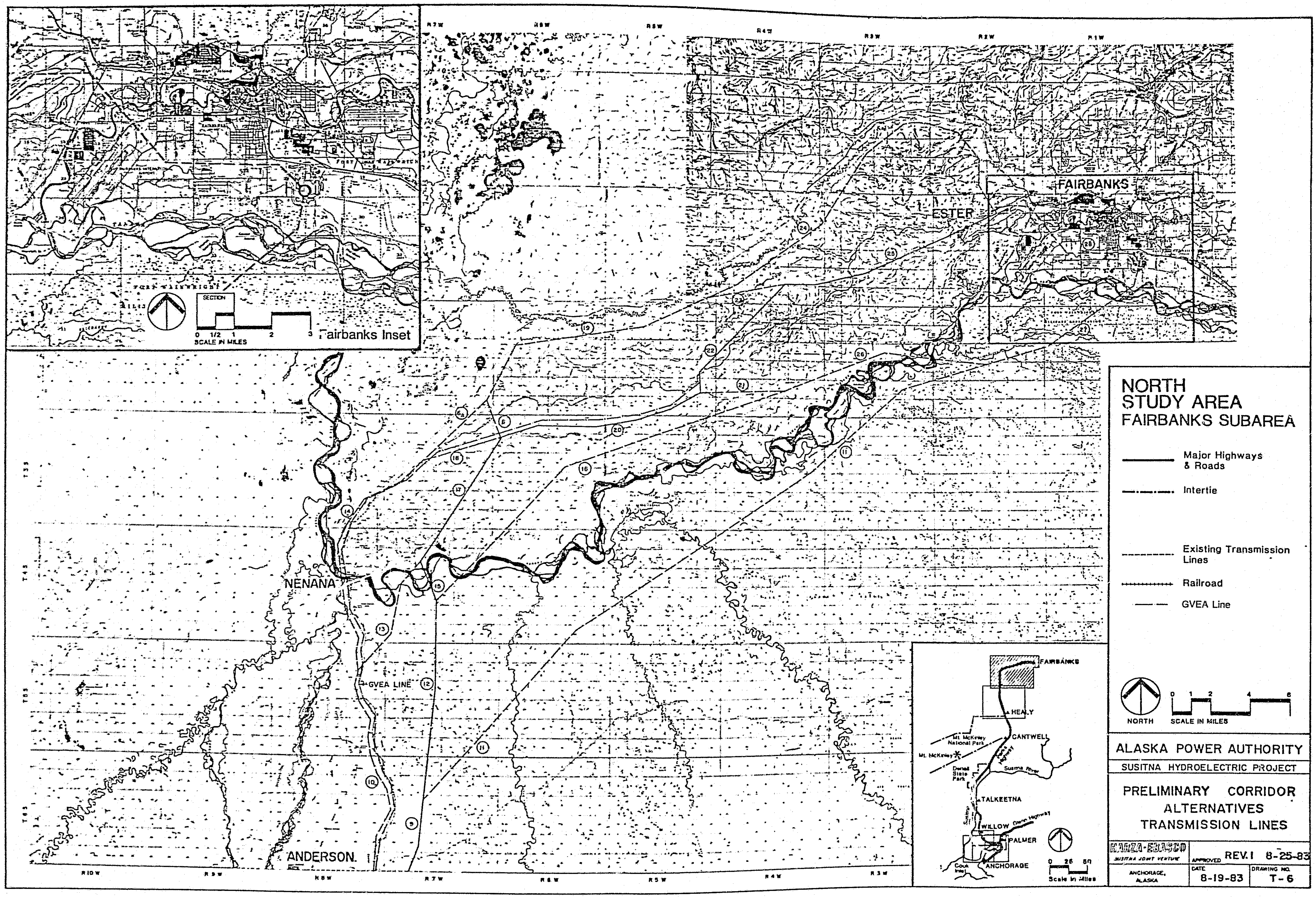
ALASKA POWER AUTHORITY

SUSITNA HYDROELECTRIC PROJECT

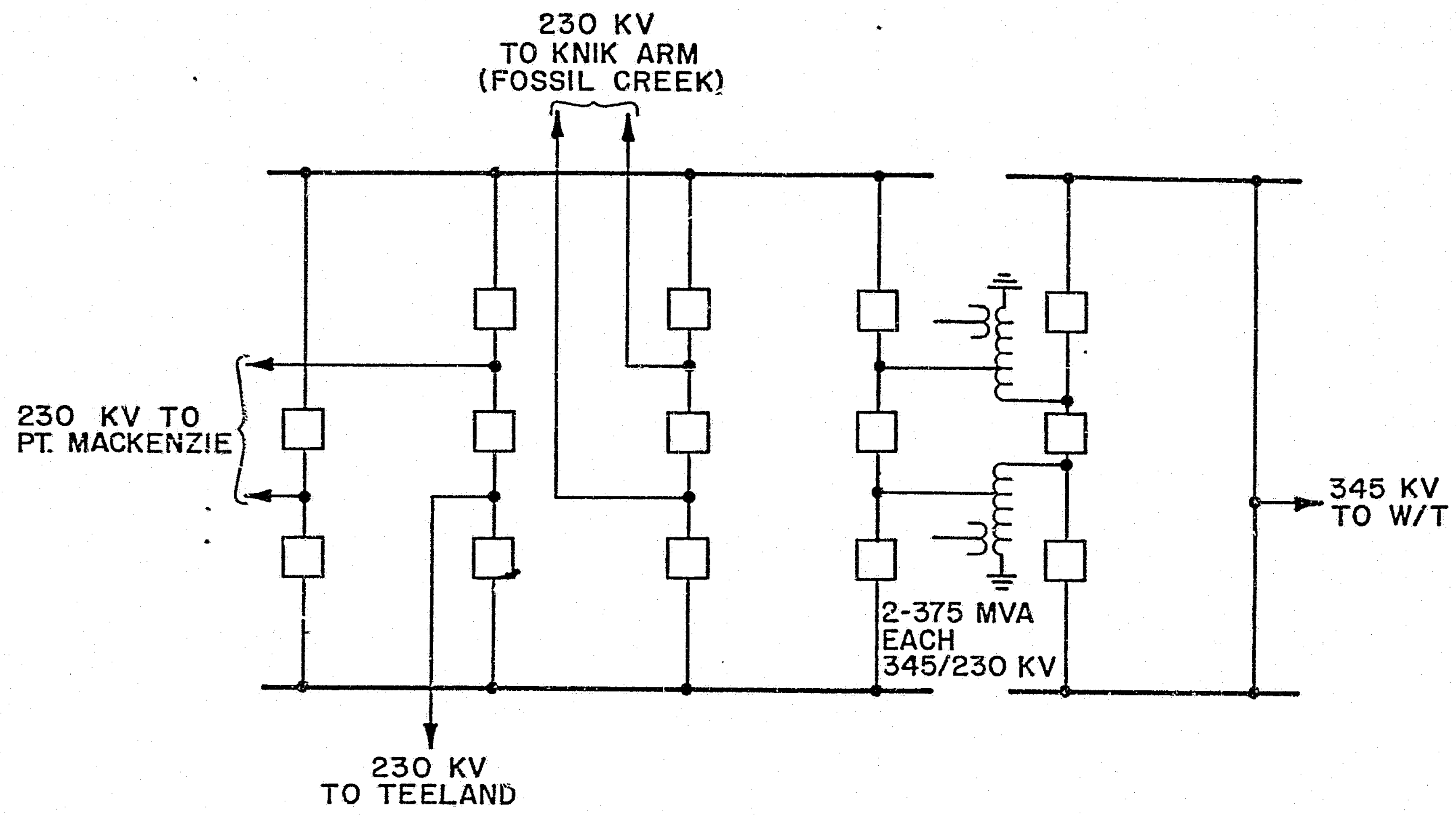
PRELIMINARY CORRIDOR ALTERNATIVES TRANSMISSION LINES

SUSITNA JOINT VENTURE
ANCHORAGE, ALASKA

APPROVED	REV. 1	8-25-83
DATE 8-19-83	DRAWING NO. T-1	



Fairbanks Inset
SCALE IN MILES
FAIRBANKS
ESTER
NENANA
GVEA LINE
ANDERSON
NORTH
STUDY AREA
FAIRBANKS SUBAREA
Major Highways & Roads
Intertie
Existing Transmission Lines
Railroad
GVEA Line
NORTH
SCALE IN MILES
FAIRBANKS
HEALY
CANTWELL
TALKEETNA
WILLOW
PALMER
ANCHORAGE
Scale in Miles
ALASKA POWER AUTHORITY
SUSITNA HYDROELECTRIC PROJECT
PRELIMINARY CORRIDOR ALTERNATIVES TRANSMISSION LINES
HARZA-EBASCO
SUSITNA JOINT VENTURE
ANCHORAGE, ALASKA
APPROVED
REV. 1 8-25-83
DATE 8-19-83
DRAWING NO. T-6



LORRAINE SUBSTATION

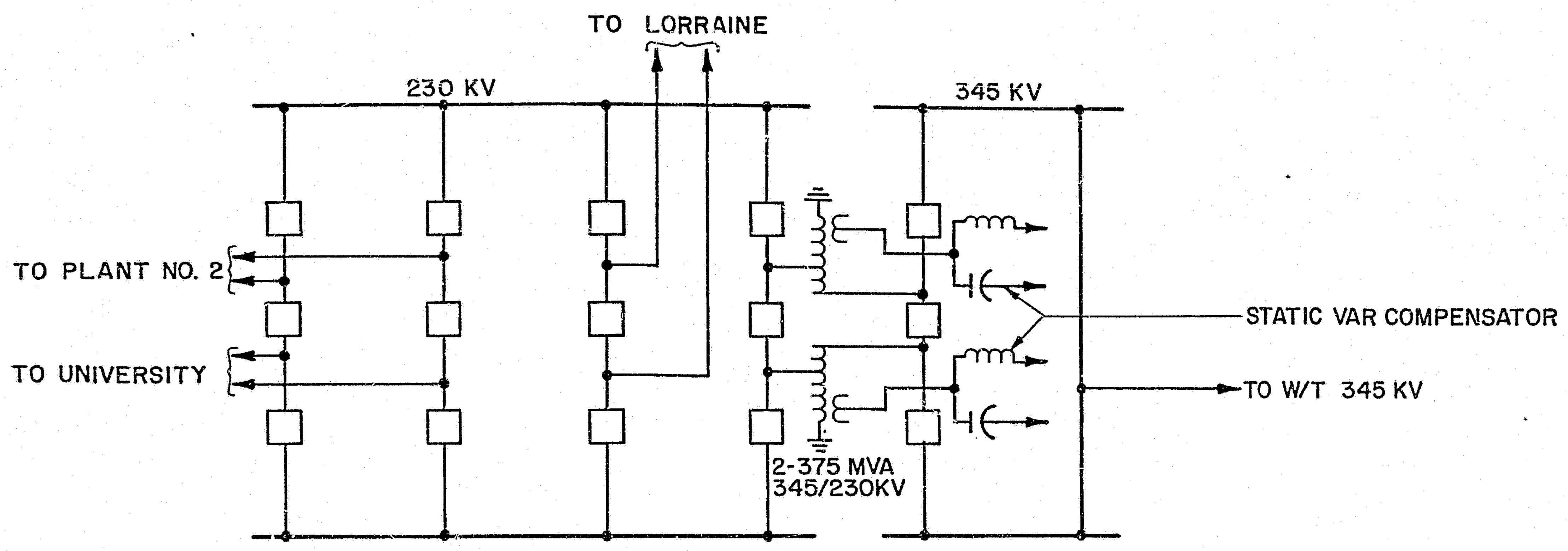
ALASKA POWER AUTHORITY

SUSITNA HYDROELECTRIC PROJECT

SUSITNA TRANSMISSION SYSTEM
SINGLE LINE DIAGRAM
POTENTIAL REFINEMENTS
LORRAINE SUBSTATION

HARZA – EBASCO SKETCH NO. 3

00 2576



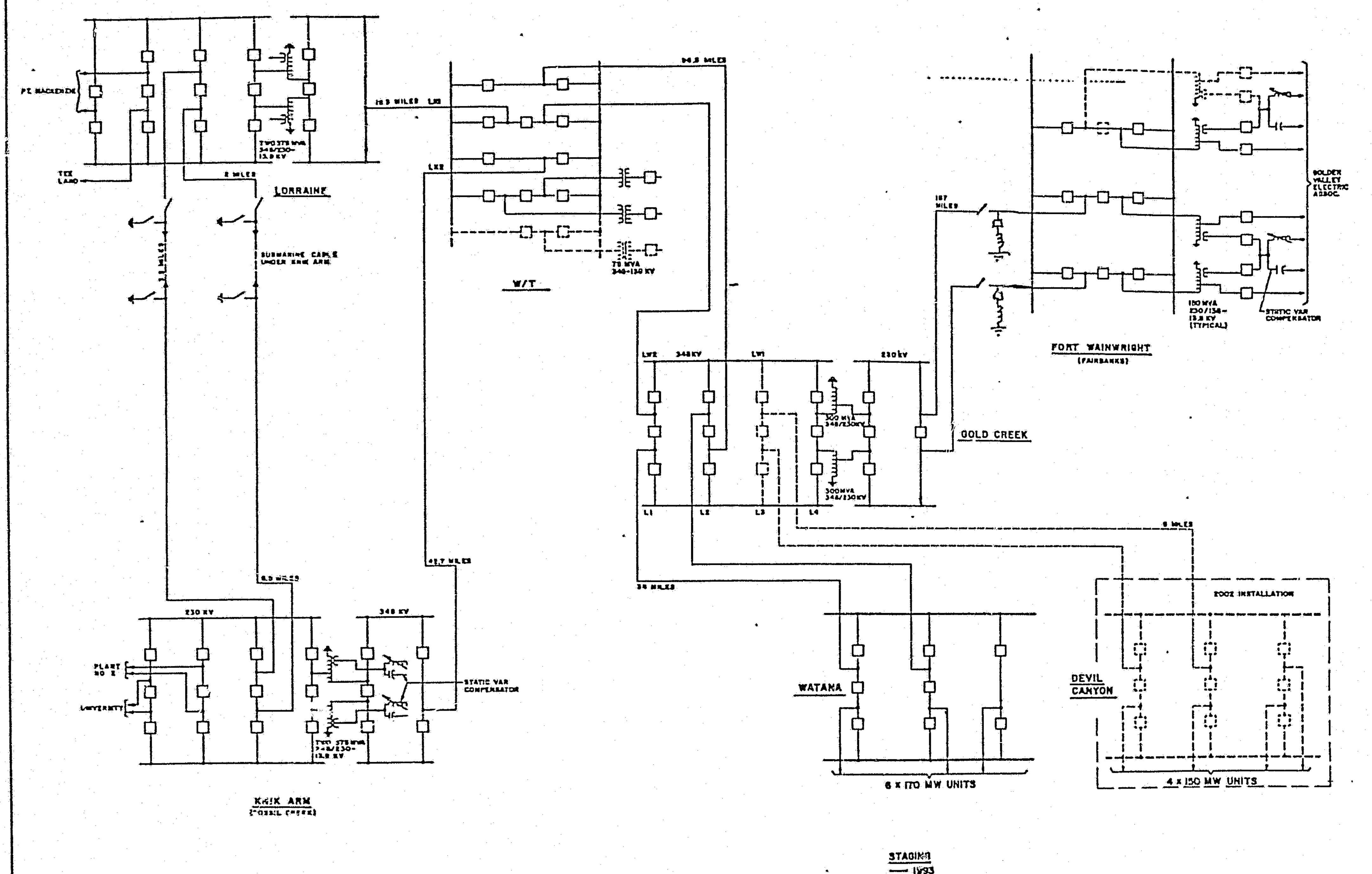
KNIK ARM
(FOSSIL CREEK)

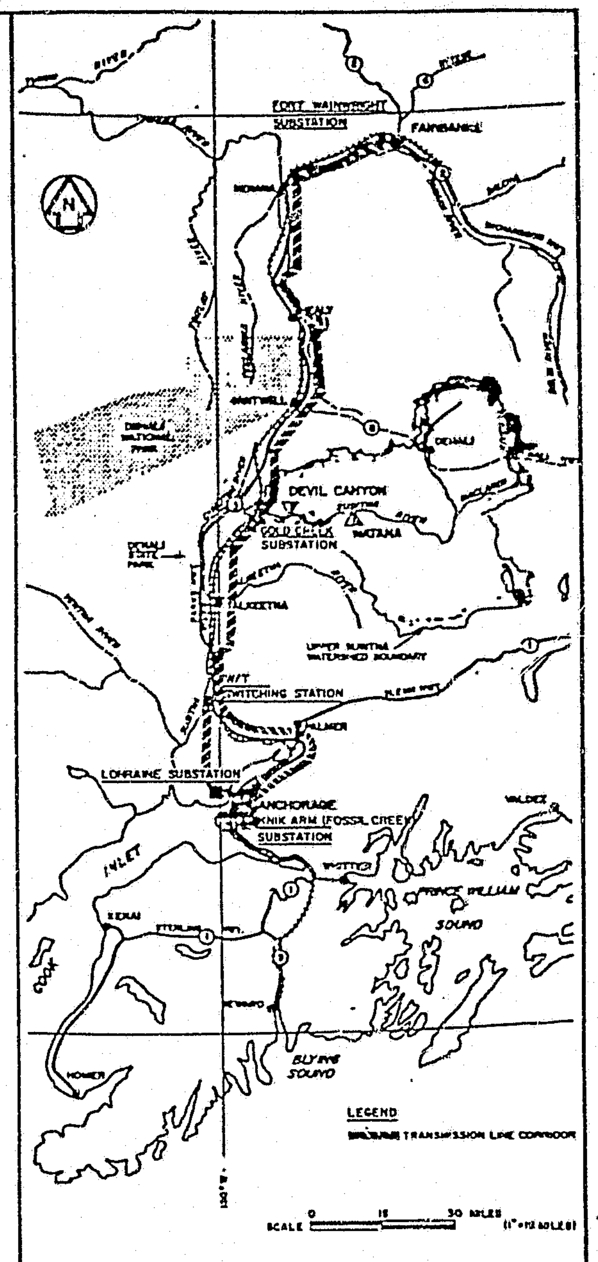
ALASKA POWER AUTHORITY

SUSITNA HYDROELECTRIC PROJECT

SUSITNA TRANSMISSION SYSTEM
SINGLE LINE DIAGRAM
POTENTIAL REFINEMENTS
FOSSIL CREEK SUBSTATION

HARZA – EBASCO SKETCH NO. 4





TRANSMISSION LINE CORRIDOR

NUMBER OF LINES	WIDTH OF R.O.W. (FT)	DISTANCE BETWEEN LINES (FT)	DISTANCE FROM LINE TO EDGE OF R.O.W. (FT)
1	190	—	[illegible]
2	300	108.[illegible]	96
3	400	108.[illegible]	96
4	510	108.[illegible]	96

NOTE:

1. ESTIMATED GROUND RESISTIVITY FOR DESIGN IS 50 OHMS.

ALASKA POWER AUTHORITY

SUSITNA HYDROELECTRIC PROJECT

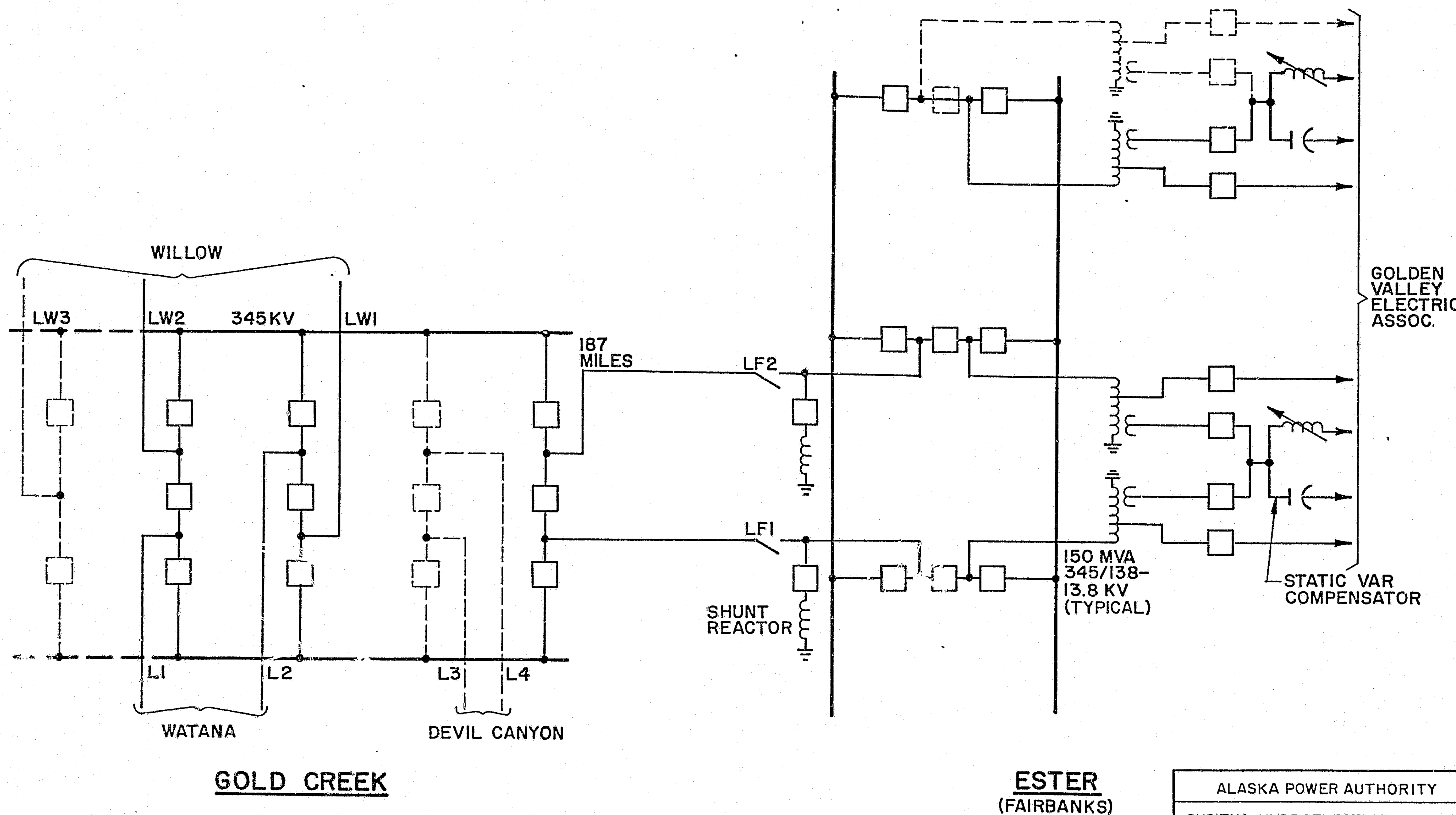
SUSITNA TRANSMISSION SYSTEM
SINGLE LINE DIAGRAM
POTENTIAL REFINEMENTS

HARZA-EBASCO
SUSITNA JOINT VENTURE
ANCHORAGE, ALASKA

APPROVED

DATE	CONTRACT NUMBER	DRAWING NUMBER
		SKETCH NO. 5

00 2576

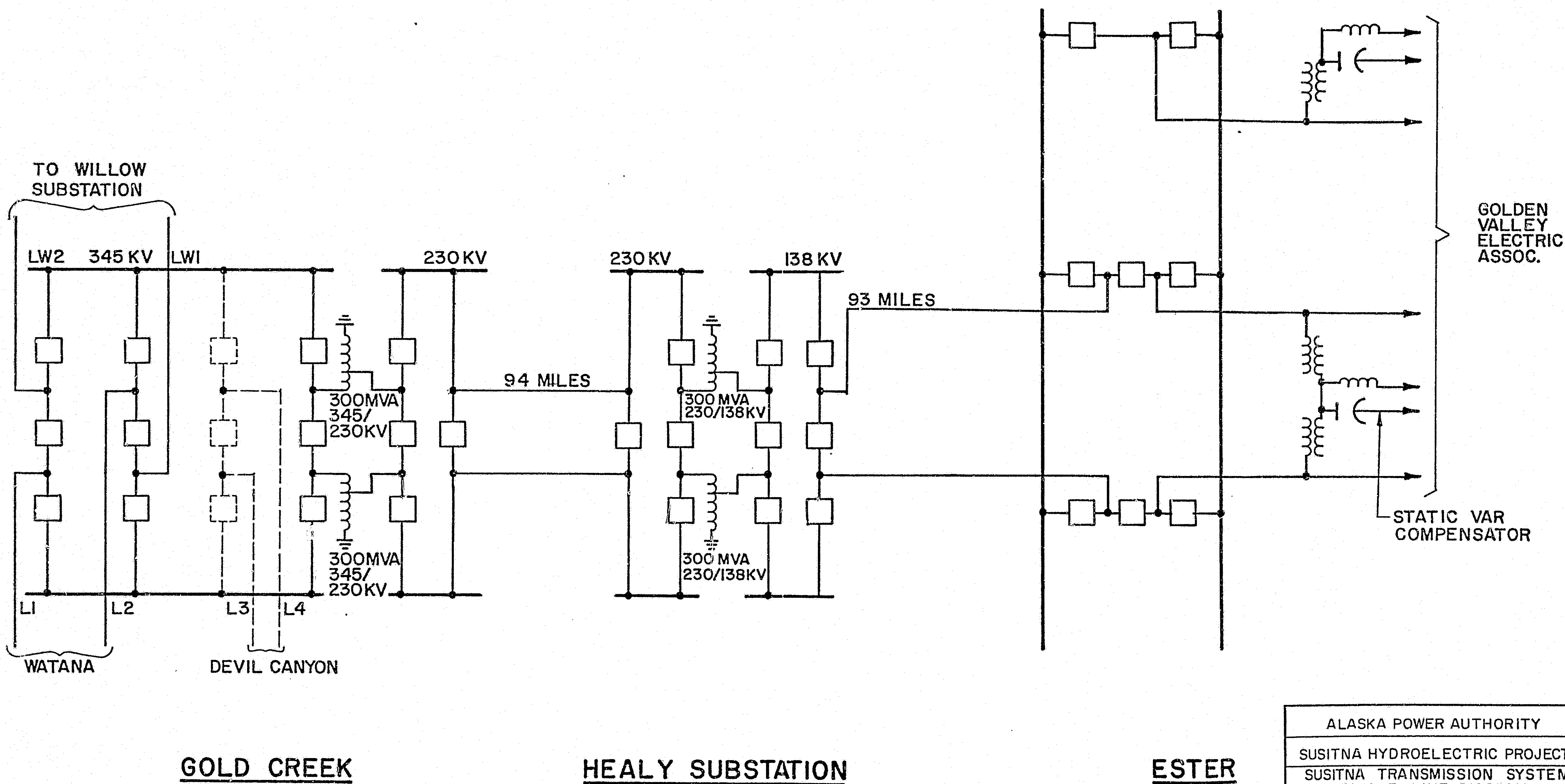


ALASKA POWER AUTHORITY

SUSITNA HYDROELECTRIC PROJECT

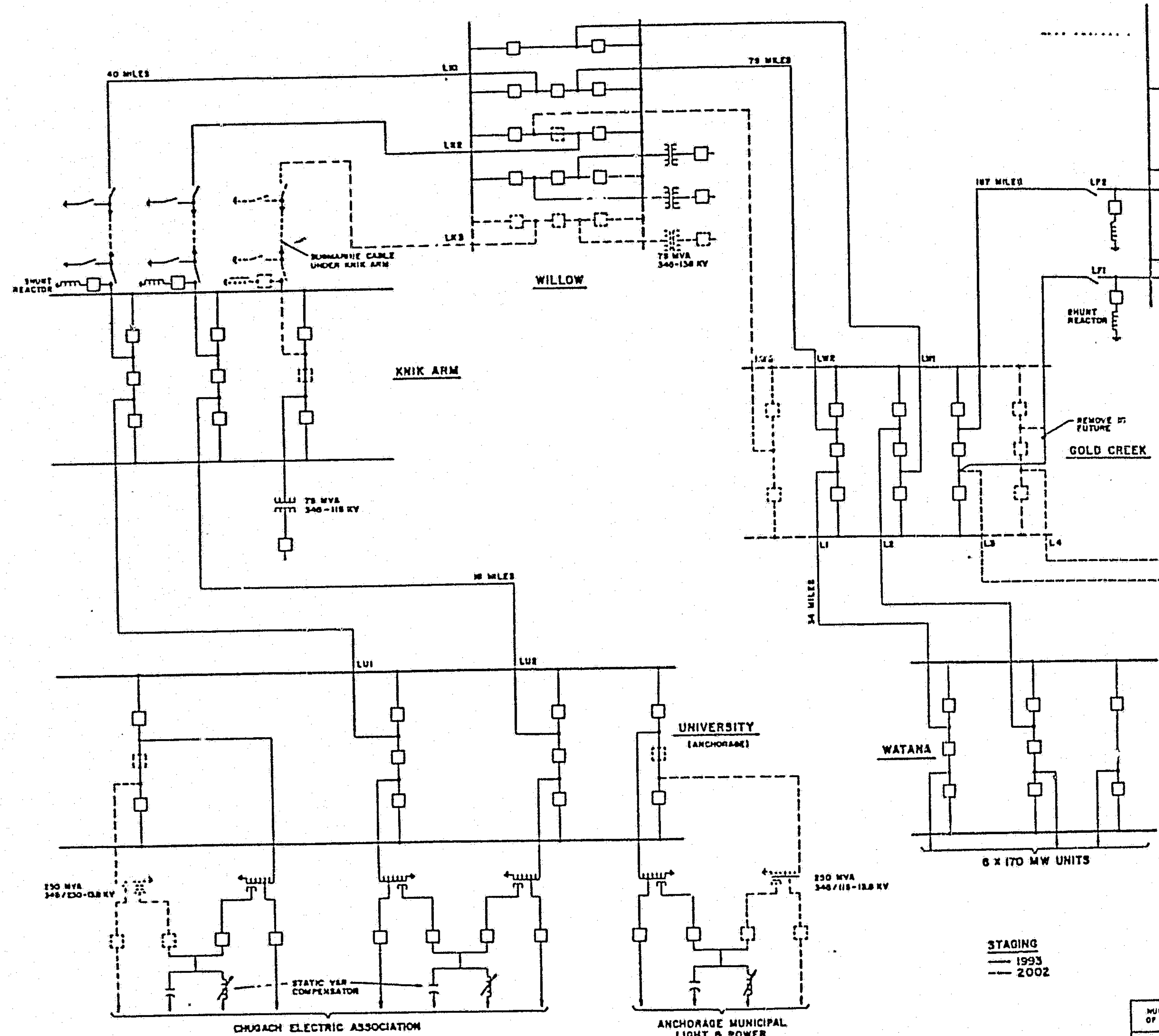
SUSITNA TRANSMISSION SYSTEM
SINGLE LINE DIAGRAM
POTENTIAL REFINEMENTS
GOLD CREEK-ESTER SYSTEM AT 345KV

HARZA – EBASCO SKETCH NO. 7



ALASKA POWER AUTHORITY
SUSITNA HYDROELECTRIC PROJECT
SUSITNA TRANSMISSION SYSTEM SINGLE LINE DIAGRAM POTENTIAL REFINEMENTS HEALY–ESTER SYSTEM AT 138 KV
HARZA – EBASCO SKETCH NO. 8

0 0 2 5 7 6



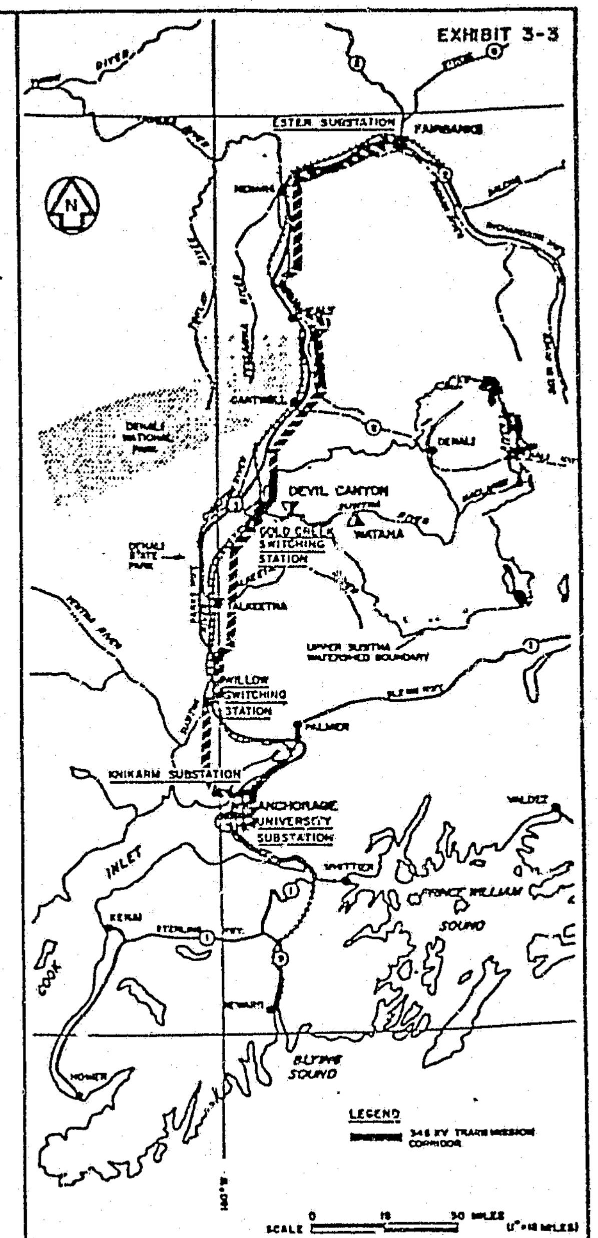
345 KV TRANSMISSION SYSTEM SINGLE LINE DIAGRAM

NUMBER OF LINES	WIDTH OF R.O.W. (FT)	DISTANCE BETWEEN LINES (FT)	DISTANCE FROM LINE TO EDGE OF R.O.W. (FT)
1	190	—	95
2	300	105 ±	98
3	400	105 ±	96
4	510	105 ±	98

NOTE:

1. ESTIMATED GROUND RESISTIVITY FOR DESIGN IS 50 OHMS.

EXHIBIT 3-3



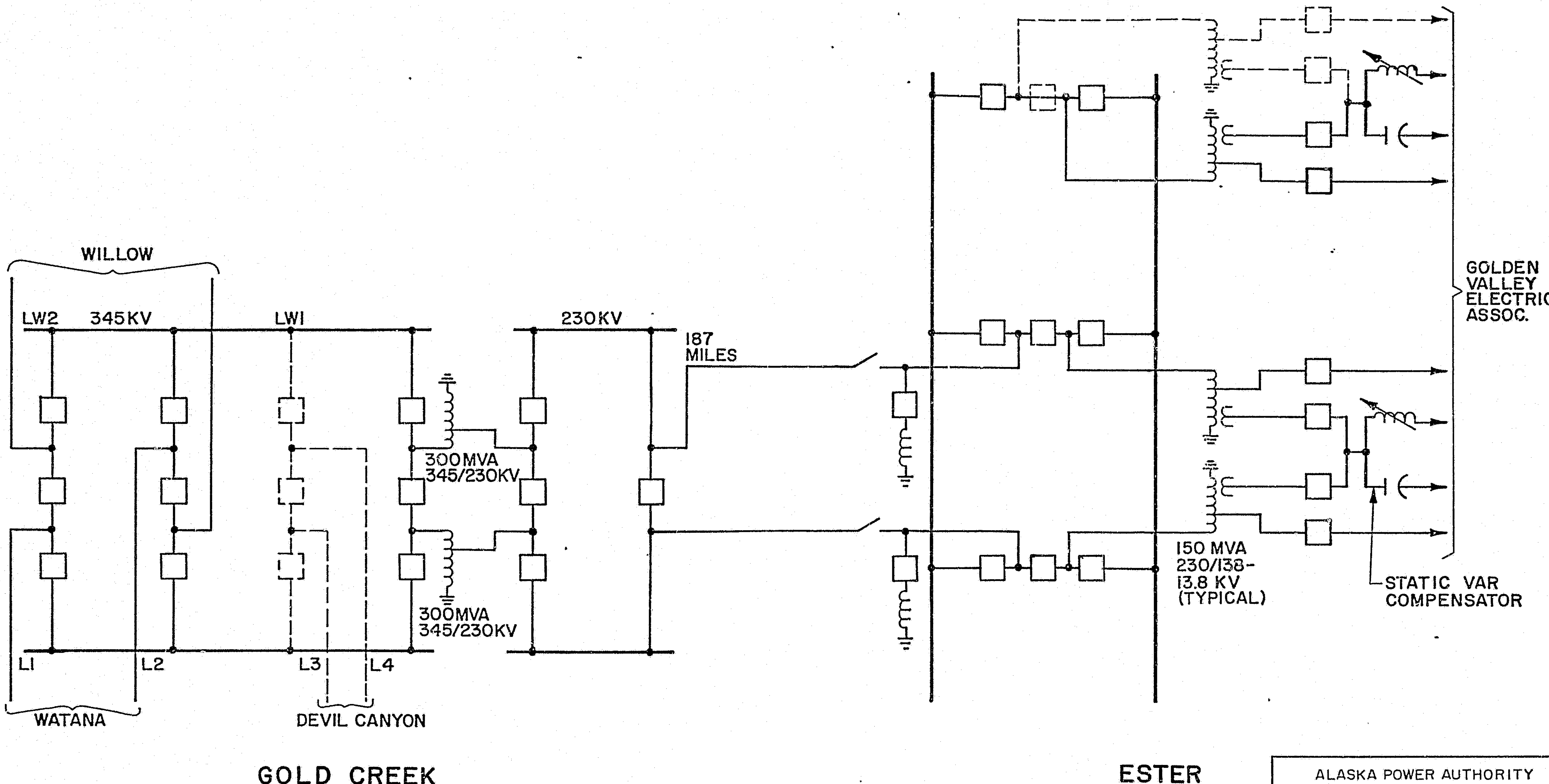
345 KV TRANSMISSION CORRIDOR

ALASKA POWER AUTHORITY

SUSITNA HYDROELECTRIC PROJECT

345 KV SYSTEM SINGLE LINE DIAGRAM AND TRANSMISSION CORRIDOR

HARZA-EBASCO SUSITNA JOINT VENTURE	APPROVED		
ANCHORAGE, ALASKA	DATE	CONTRACT NUMBER	DRAWING NUMBER EXHIBIT 3-3



ALASKA POWER AUTHORITY

SUSITNA HYDROELECTRIC PROJECT

SUSITNA TRANSMISSION SYSTEM
SINGLE LINE DIAGRAM
RECOMMENDED REFINEMENTS
GOLD CREEK-ESTER SYSTEM AT 230KV

HARZA – EBASCO

EXHIBIT 6-10

APPENDIX G

LAND FIELD SERVICES REPORT ON
DIRECT AND INDIRECT LAND ACQUISITION COSTS

October 26, 1983

LAND FIELD SERVICES, INC.

P.O. Box 111705
Anchorage, Alaska 99511
561-1671

P.O. Box 2510
Fairbanks, Alaska 99707
452-1208

October 26, 1983

Harza-Ebasco
Susitna Joint Venture
711 H Street
Anchorage, Alaska 99501

Attention: Mr. William J. Rom

Subject: Susitna Transmission Line Routing Studies
North Alternatives

Dear Bill:

The following report addresses the land acquisition costs, both direct and indirect, in terms of January 1983 dollars for the various numbered alternatives to the Fairbanks Stub of the Susitna FERC transmission line application. Also included is a parcel count for the number of private owners affected by the various routes, and evaluation of alternate routes in Fairbanks from Gold Hill to the Municipal Utilities System Plant and the Fort Wainwright substation.

Costs are based on a per line mile times a 200-foot wide right-of-way. Direct costs include direct payment to private land owners, including agricultural, remote, mining and native interests; the indirect costs are cumulative of preliminary contacts, title work, surveying, application preparation, appraisal, administration, negotiations and eminent domain proceedings. The direct and indirect costs are estimated as follows:

Route 1, 2, 5, 8, 9, 12, 15, 17, 20, 22, 25 (FERC Application)

Direct Costs: $1,099,500.00

Indirect Costs: $ 337,000.00

Alternate Routes:

Route 11, 27A

Direct Costs: -0-

Indirect Costs: $ 32,450.00

Route 24, 19, 6A, 14, 10

Direct Costs: $1,768,250.00

Indirect Costs: $ 859,025.00

Route 23

Direct Costs: -0-

Indirect Costs: $ 9,850.00

Route 6

Direct Costs: $ 66,000.00

Indirect Costs: $ 34,200.00

Route 18

Direct Costs: $ 16,500.00

Indirect Costs: $ 9,900.00

Route 13

Direct Costs: $102,000.00

Indirect Costs: $ 32,075.00

Route 26, 16

Direct Costs: $ 77,000.00

Indirect Costs: $ 61,000.00

Route 21

Direct Costs: -0-

Indirect Costs: $ 5,750.00

Route 7, 3

Direct Costs: -0-

Indirect Costs: $ 32,775.00

Route 4

Direct Costs: -0-

Indirect Costs: $ [illegible],600.00

An analysis of alternative tie-in locations to the existing systems is shown on the attached plat. There is a new alternative route on the east side of Fairbanks numbered 27A. This route would be preferable to 27 because it will bypass a private airport, gravel dredging operations and a trailer court. Additionally, it would be on military lands and so minimize the direct costs.

Another alternative is to go from Gold Hill to the Municipal Utilities System power plant or the Fort Wainwright plant through town. There is a great deal of expensive private property to get to either place. One possibility is to utilize existing rights-of-way such as the old Ester Road right-of-way and the Alaska Railroad right-of-way (if ownership is transferred to the State of Alaska). In the case of going to the Municipal Utilities System plant, it would involve crossing the Chena River from the Railroad Reserve area to the plant at the existing coal conveyor. To get to Fort Wainwright, it is possible to follow the railroad around Fairbanks and onto the base through Trainor Gate. Using this route would involve burying aportion of the line where it crosses the clear zone for the runway.

At this time there are plans to extend Geist Road easterly to the Steese Highway through portions of the railroad yard. The exact routing has not been determined, so it may be possible to coordinate with this project. There is a planned extension of the Parks Highway around the southern part of town to meet up with the Richardson Highway. A portion of this project is already under way.

We endorse the FERC application route. Route 24 impacts great numbers of private land holders. Route 16/26 makes two Tanana River crossings and ends in a flood zone; also, there is a great deal of low-flying aircraft traffic over the river area. Route 11/27 is in an area of no ground access and is partially in a flood plain.

Some of the routes may impact future disposals by the State of Alaska. Some of these are just in the planning stages and we could be involved in the planning to include the transmission line easement. Some are already platted and scheduled for disposal. A conversation with the State Division of Land and

Water Management revealed that Harza-Ebasco has current disposal information graphically depicted on maps (see attached letter).

We have backup figures for this analysis in our files and will be happy to discuss them with you at your convenience.

Very truly yours,

LAND FIELD SERVICES, INC.

P. J. Sullivan /ns

P. J. Sullivan

PJS/ns

Enclosures

NORTH STUB-ESTIMATED PRIVATE PARCEL COUNT

Route 27:	2 private
Route 26:	2 private
Route 25:	25 private
Route 24:	65 private, future ag disposal
Route 23:	future ag disposal
Route 22:	future ag disposal
Route 21:	0 private
Route 20:	6 sections native corporation
Route 19:	4 private
Route 18:	1 native, future ag disposal
Route 17:	1 native
Route 16:	1 native corp, 2 private (native allotments), 4 Min. Cl.
Route 15:	1 native
Route 14:	20 private, 2 native
Route 13:	3 private, 2 native, future disposal area (5 parcels)
Route 12:	0 private
Route 11:	0 private
Route 10:	45 private, 2 native, future disposal area
Route 9:	0 private, future disposal area
Route 8:	4 private, open remote area
Route 7:	1 private, 1 proposed private, open remote area
Route 6:	4 private, 2 native
Route 6A:	6 private, future ag disposal
Route 5:	4 private
Route 4:	0 private
Route 3:	11 mining claim
Route 2:	5 private, future ag disposal
Route 1:	1 (or 2) private

LAND FIELD SERVICES, INC.

P.O. Box 111705
Anchorage, Alaska 99511
561-1671

P.O. Box 2510
Fairbanks, Alaska 99707
452-1208

October 26, 1983

Harza-Ebasco
Susitna Joint Venture
711 H Street
Anchorage, Alaska 99501

Attention: Mr. William J. Rom

Subject: Susitna Transmission Line Routing Studies
South Alternatives

Dear Bill:

The following report addresses the land acquisition costs, both direct and indirect, in terms of January 1983 dollars, for the various numbered alternatives to the Anchorage Stub of the Susitna FERC transmission line application.

The direct land acquisition costs were developed from use of the assessing records of the Matanuska-Susitna Borough, as tempered by a Sales Ratio Study based on the Borough's 1983 assessments which indicates that the assessed values supported 80 to 85% of the market value of the properties assessed.

Route 1, 5, 8, 18 (FERC Application)

The direct acquisition cost for this route is estimated to be $1,832,000.00, broken down as follows:

Route 1:	$1,375.000.00
Route 5:	$ 145,000.00
Route 8:	$ 312,000.00
Route 18:	-0-

These figures include direct payments to private owners (including agricultural and remote interests) and the Matanuska-Susitna Borough. State of Alaska lands and military lands do not entail direct land cost considerations.

Indirect costs for this route are estimated at $290,750.00, broken down as follows:

Route 1:	$ 196,750.00
Route 5:	$ 57,375.00
Route 8:	$ 17,875.00
Route 18:	$ 18,750.00

These indirect costs are cumulative of preliminary contacts, title work, surveying, application preparation, appraisal, administration, negotiations and eminent domain proceedings.

The direct costs for this entire report are based on acreage figures calculated by using line miles times 200 foot wide right-of-way.

The direct and indirect costs for the alternative routes are estimated as follows:

Route 2

Direct Cost	$ 36,000.00
Indirect Cost	$ 61,750.00

Route 3

Direct Cost	$215,000.00
Indirect Cost	$ 59,550.00

Route 4

Direct Cost	$940,000.00
Indirect Cost	$199,125.00

Route 6

Direct Cost	$1,121,500.00
Indirect Cost	$ 163,875.00

Route 7

Direct Cost	$1,183,500.00
Indirect Cost	$ 177,875.00

Route 9

Direct Cost	$368,500.00
Indirect Cost	$252,875.00

These indirect costs are cumulative of preliminary contacts, title work, surveying, application preparation, appraisal, administration, negotiations and eminent domain proceedings.

The direct costs for this entire report are based on acreage figures calculated by using line miles times 200 foot wide right-of-way.

The direct and indirect costs for the alternative routes are estimated as follows:

Route 2

Direct Cost	$ 36,000.00
Indirect Cost	$ 61,750.00

Route 3

Direct Cost	$215,000.00
Indirect Cost	$ 59,550.00

Route 4

Direct Cost	$940,000.00
Indirect Cost	$199,125.00

Route 6

Direct Cost	$1,121,500.00
Indirect Cost	$ 163,875.00

Route 7

Direct Cost	$1,183,500.00
Indirect Cost	$ 177,875.00

Route 9

Direct Cost	$368,500.00
Indirect Cost	$252,875.00

<u>Route 10</u>

Direct Cost	$3,273,000.00
Indirect Cost	$ 548,825.00

<u>Route 11</u>

Direct Cost	$ 918,000.00
Indirect Cost	$ 291,750.00

<u>Route 12</u>

Direct Cost	$1,338,500.00
Indirect Cost	$ 571,000.00

<u>Route 13/15</u>

Direct Cost	$ 318,000.00
Indirect Cost	$ 150,500.00

<u>Route 14</u>

Direct Cost	$1,035,000.00
Indirect Cost	$ 153,375.00

<u>Route 16</u>

Direct Cost	$1,062,000.00
Indirect Cost	$ 76,500.00

<u>Route 17</u>

Direct Cost	$5,495,000.00
Indirect Cost	$ 190,250.00

While these direct costs reflect the market as it existed January 1, 1983, these indirect costs represent worst case situations and can be, with good prior planning and coordination, reduced by 25%.

From a land standpoint, the Route 2, 9, 11, 13, 15, 17, route appears to be the most desirable for an overland routing alternative. We recommend that Route 9 be moved approximately one-half mile northerly from its present location and traverse easterly to a point near the Little Susitna River then turn southerly and join Route 11 near the Section 23 P.I. This move would save approximately 50% of both the direct and indirect costs for Route 9. Route 17 should be realigned to use both the existing Alaska Power Administration line from Eklutna and the Alaska Railroad Right-of-Way (assuming transfer of that right-of-way to the State of Alaska) thus eliminating the majority of the direct cost for Route 17.

We cannot recommend Route 3-6-10, as this route effects a great number of private tracts, with their attendant high direct and indirect costs. On Route 6 and 10, there are 12 existing subdivisions. The market indicates that subdivided one-half acre lots are selling for $20,000 per lot in this area. Furthermore, the Matanuska-Susitna Borough has a platting and zoning ordinance whereby off-right-of-way buffer zones may be required between transmission lines and subdivided property. This can cause a very expensive off-right-of-way damage factor which must be included in both direct and indirect costs.

If you decide to "bite the bullet" on Route 6, then Route 7-8 using the existing Chugach right-of-way, looks very attractive, both from a direct and indirect cost standpoint.

We have no particular recommendation on Route 4, except to point out that there is a potential for effecting 43 private ownerships (many of which are recreation oriented) on this route while affecting 15 private ownerships on Route 1.

Route 12 is unattractive from a land standpoint because of the number of private parcels and their attendant high direct and indirect costs.

Because of the change in character, i.e., from rural to urban, we strongly recommend that an advance acquisition program be commenced for whatever routes are chosen within the Matanuska-Susitna Borough. Although the property values in the Willow area are probably stable the growth in the Palmer-Wasilla-Big Lake area will make a long line acquisition program more expensive as time goes on.

We have back-up figures for this analysis in our files and will be happy to discuss them with you at your convenience.

Very truly yours,

LAND FIELD SERVICES, INC.

P.J. Sullivan/MS

P. J. Sullivan
President

PJS/cf

APPENDIX H

SUMMARY OF SUSITNA TRANSMISSION SYSTEM COSTS FOR FERC APPLICATION SCHEME

SUMMARY OF SUSITNA TRANSMISSION SYSTEM COSTS
FOR FERC APPLICATION SCHEME

1.0 INTRODUCTION

Using the land acquisition costs from Appendix G and the right-of-way widths as indicated in Appendix E, Exhibit No. 2 from Appendix F was revised as shown in the following tables:

TABLES

TABLE H-1

TASK 41 - SUSITNA TRANSMISSION SYSTEM

SUMMMARY OF SUSITNA 345 KV TRANSMISSION SYSTEM COSTS FOR 2002 FERC APPLICATION SCHEME AS SHOWN ON PLATE F81 (IN MILLIONS OF JANUARY 1983 DOLLARS)

OCTOBER 29, 1983

ITEM	WATANA TRANSMISSION	WATANA SUBSTATIONS	DEVIL CANYON TRANSMISSION	DEVIL CANYON SUBSTATIONS	TOTALS
1. Ester Substation	-	22.31	-	3.25	25.56
2. Ester to Healy Transmission Lines	81.028	-	-	-	81.028
3. Healy to Gold Creek Transmission Lines (Excluding Row Costs)	40.548	-	-	-	40.548
4. Gold Creek Switching Station	-	10.20	-	5.6	15.80
5. Gold Creek to Willow Transmission Line (Add one line in 1993 excluding Row Costs)	33.136	-	-	-	33.136
6. Gold Creek to Willow Transmission Line (Add on line in 2002)	-	-	35.036	-	35.036
7. Willow Switching Station	-	13.10	-	5.55	18.65
8. Willow to Submarine Cable Potheads Transmission Lines	38.664	-	20.866	-	59.530
9. Submarine Cable Crossing Under Knik Arm	66.400	-	33.200	-	99.600
10. Knik Arm Switching Station	-	14.08	-	3.08	17.16
11. Knik Arm to University Transmission Lines	22.918	-	-	-	22.918
12. University Substation	-	34.69	-	7.19	41.88
13. Watana Switching Station	-	9.0	-	-	9.0
14. Watana to Gold Creek Transmission Lines	29.308	-	-	-	29.308
15. Devil Canyon Switching Station	-	-	-	10.2	10.2
16. Devil Canyon to Gold Creek Transmission Lines	-	-	6.896	-	6.896
TOTALS	312.002	103.38	95.998	34.87	546.25
17. Wilow Energy Management System	-	22.4	-	4.0	26.4
GRAND TOTAL	312.002	125.78	95.998	38.87	572.65

TABLE H-2

Task 41 - Transmission Line - Cost per mile
Revised November 30, 1983
All costs adjusted to January, 1983

Structure Type & kV	Conduct's No./Size, kcm	CKTS/ ROW	Cost: Mat'l & Labor (2) (Dollars)
X-frame 345	2 x 954	2	822,000
X-frame 345	2 x 954	1	(1)436,000
Steel Pole 345	2 x 954	1	614,000
Steel Pole 345	2 x 954	2	939,000
X-frame 230	1 x 954	2	331,000
X-frame 230	1 x 954	1	459,000
Steel Pole 230	1 x 954	1	628,000
Steel Pole 230	1 x 954	2(4)	673,000
230 SCSC(3)	3 x 2000	1	24 million
230 SCSC(3)	4 x 2000	1	29.2 million
345 SCSC(3)	3 x 2000	1	30.5 million
345 SCSC(3)	4 x 2000	1	38.6 million

ROW Width	Acres/mile
300' x 0.12138	36.4
190'	23.1
100'	12.1
80'	9.7
70'	8.5

(1) Bid data for Intertie Construction (Average of 3 lowest bidders)
(2) Includes Line survey and clearing costs
(3) SCSC - Self-Contained Submarine Cable - Dollars are estimated total installed cost with all accessories in Anchorage, Alaska for 3.5 miles under Knik Arm.
(4) Double circuit pole line.

APPENDIX I

POWER SALES AGREEMENT

Letter Of Intent

November 14, 1983

ALASKA POWER AUTHORITY
334 West 5th Avenue
Anchorage, Alaska 99501

Gentlemen:

Re: Intentions concerning the Purchase of Susitna Project Power

The Alaska Power Authority (the "Authority") intends to construct the "Susitna Project" which will consist of power generation and transmission facilities. This letter is a statement of intention of ______________________________________ (the Purchaser) to purchase a portion of the electric power and energy to be generated and transmitted by these facilities. It is understood that certain terms and conditions will be applicable to the sale of this power and energy and that the terms and conditions herein described will be subject to modification and amplification before being included in the agreement that succeeds and replaces this letter of intent.

W I T N E S S E T H:

The Authority recites, agrees, represents and covenants as follows:

(1) The Authority is a public corporation of the State of Alaska duly created, organized and existing pursuant to AS 44.83; and

(2) The Authority fully intends, according to the Constitution and laws of the State of Alaska and the regulations and by-laws of the Authority, to fully comply with the terms thereof; and

(3) The Authority desires to fulfill its legislatively established duty of acquiring and constructing power projects to provide residents of the State of Alaska with long-term, stable, and economic sources of energy and an adequate, economic, and reliable long-term supply of power and energy.

The Purchaser recites, agrees, represents and covenants as follows:

(1) The Purchaser is a Home Rule Municipality or a non-profit electric cooperative membership corporation of the State of Alaska, duly created, organized and existing under the Constitution and laws of the State; and

(2) The Purchaser is authorized, and has taken all steps necessary pursuant to the Constitution and laws of the State of Alaska and the charter and ordinances of the Purchaser, to enter into this Agreement and to fully comply with the terms thereof; and

(3) The Purchaser needs to secure an adequate, economical and reliable long-term supply of power and energy; and

(4) The Purchaser performs the functions of a utility and is a wholesale power customer eligible to purchase power produced from a project pursuant to AS 44.83; and

The Authority and the Purchaser recite, agree, represent and covenant as follows:

(1) As consideration for Purchaser's entry into this Agreement, the Authority will use its reasonable best efforts to complete construction of the Project so as to be able to provide power and energy from the Project to the Purchaser; and

(2) As consideration for the Authority's entry into this Agreement, the Purchaser will pay the amounts provided for under this Agreement for power and energy and the rights to such power and energy from the Project; and

(3) This Agreement is entered into in furtherance of the Act, including AS 43.83.010, to promote the general welfare of the people of the State, including the users of the power and energy of the Project; for public purposes; and for the promotion of the long-term economic growth of the State and the development of its natural resources; and

(4) In order to enable the Authority to begin discussions with financiers concerning the funds necessary to acquire and construct projects in the Energy Program for Alaska and specifically meet its obligations under the Act and the Indenture to be entered into with the holders of Bonds, it is necessary for the Authority to enter into this Agreement with the Purchaser and agreements with other purchasers and to pledge the moneys to be received as security for the payment of the Authority's bonds.

(5) This Statement of Intent will be succeeded by a formal "Power Sales Agreement" or other agreement that will include all of the terms and conditions necessary for a proper and workable contract.

NOW, THEREFORE, the parties agree as follows:

<u>Section 1. Definitions.</u> For the purposes of this Agreement, definitions are specified in Exhibit "A" attached hereto and incorporated herein.

<u>Section 2. Term of Agreement.</u>

(a) This Agreement shall be effective immediately.

(b) This Agreement shall remain in effect until such time as it is replaced by a formal "Power Sales Agreement" or other document. It is anticipated that the terms of the final agreement will be 40 years.

Section 3. Electric Service to be Furnished.

(a) Delivery. The service will be taken from the Authority as it becomes available, realizing that not all phases of the project are likely to be completed at the same time. The power and energy that is available during construction will be allocated to each utility in the same manner as indicated in Section 5. The Authority may enter into agreements with other parties for operation and maintenance of the Project.

(b) Continuity of Service. The Authority may interrupt or reduce deliveries of electric power and energy to the Purchaser if it determines that such interruption or reduction is necessary or desirable in cases of system emergencies, or in order to install equipment in, make repairs, replacements, investigations, and inspections of, or perform other maintenance work on, the Project or the Purchaser's own equipment. In order that the Purchaser's operations will not be unreasonably interfered with, the Authority will give (except in the case of an emergency) the Purchaser reasonable notice of any such interruption or reduction, the reason therefor and the probable duration thereof.

(c) Duty to Participate in Development of System Operating Criteria. Purchaser agrees to participate in development of interconnected operating and safety criteria not addressed by this Agreement but which may be required from time to time. To this end Purchaser agrees to the formulation of an operating committee to include parties or utilities interconnected with Project facilities.

(d) Additional or Improved Facilities. If additional facilities must be constructed or installed by the Authority to enable the Authority to supply any increase in the Purchaser's demand or to maintain the reliability or operation of the Project, the Authority may in its discretion construct such additional facilities or improvements. The Authority will consider (1) the reasonable utilization of existing facilities; (2) circumstances demonstrating that reasonable utilization of the additional facilities will be assured; and (3) the financial feasibility of the additions including the impact upon the Wholesale Power Rate. Any such additional facilities shall, to the extent required by the Act, be considered as part of the Project for purposes of calculating the Wholesale Power Rate for the Project.

(e) Delivery Through One Purchaser's System to Another Purchaser. In those instances where the facilities of one Purchaser must be used for transfer of power and energy to another Purchaser, the Authority shall have the right to contract with both Purchasers. There shall be an agreement between the two Purchasers that shall set forth the terms and conditions for the transfer of power and energy over one Purchaser's system. The rate that may be charged for the transfer shall be based on cost plus an adequate margin.

Section 4. Obligations Under Indenture. The Authority intends to assign its rights under this Agreement to receive payments as security for the payment of the Bonds and that the rates charged for energy and power from the Project and the rights thereto are based in part on debt service costs incurred in the acquisition, construction, and financing of projects in the Energy Program for Alaska. As such the parties recognize that the amounts paid monthly by the Purchaser under this Agreement shall be calculated as provided herein, but shall in no event be less than the amounts necessary to meet the Debt Service requirements of the Indenture as such amounts are apportioned to the Purchaser pursuant to this Agreement.

Section 5. Purchase Obligation; Allocation of Project Capability.

(a) Purchase Requirement. The Authority intends to supply and the Purchaser intends to purchase its Entitlement (as hereinafter defined) with respect to the Project of ________ kilowatts of Project Capacity each month. The Purchaser also intends to purchase its Entitlement of energy generated by the project each month in the amount as hereinafter defined.

(b) Purchaser's Entitlement Share. As used herein a Purchaser's Entitlement Share shall be equal to the ratio of the summation of the Purchaser's peak system demand for the previous 2 years to the summation of all Purchaser's peak system demand for the previous 2 years. This determination shall be based on the demand recorded in each of the 24 months ending in December prior to the fiscal year beginning July 1 the following year. The Purchaser's Entitlement shall be equal to the result of multiplying the Purchaser's Entitlement Share times the total Project Capacity properly adjusted for transmission line loss. This determination is to be calculated annually.

A Purchaser's monthly energy shall be equal to the result of multiplying the Purchaser's entitlement share times the actual generation for that month properly adjusted for transmission line loss.

(c) Purchase Rights. Each Purchaser shall have the right to purchase capacity and energy which is in excess of its Entitlement on a when, as, and if available basis. The Authority or its operating agent shall be solely responsible for determining the availability of power and energy in excess of entitlements.

(d) Cost Determination. The Authority will set the wholesale power rate for each fiscal year to collect those funds necessary to meet the annual costs of owning, operating and maintaining the project including an adequate margin.

Cost shall be defined as the following:

i. Annual debt service expenses, plus

ii. Annual operation and maintenance expense related to the Project, plus

iii. That portion of the Authority's annual administrative and general expense allocable to the Project, plus

iv. Other annual expenses which result from the ownership, operation, maintenance or termination of the Project, plus

v. An adequate margin.

(e) Billings - The monthly bill shall be determined by application of the wholesale power rate shown below.

(f) Wholesale Power Rate - The monthly wholesale power rate shall have a three-part structure - a customer charge, a capacity charge and an energy charge. The rate for the first year of operation is as follows:

Monthly Rate

Customer Charge	$________	per Delivery Point
Capacity Charge	________	$ per KW
Energy Charge	________	cents/KWH

Capacity Determination: The capacity to be billed shall be equal to the highest one hour KW demand reading occurring during the month but in no case shall be less than the Entitlement as herein defined.

Energy: The energy to be billed shall be equal to the kilowatt hour consumption recorded by the meter for the month, but in no case shall be less than the entitlement as herein defined.

(g) Payment of Amounts Due

(1) On or before the 15th day of each month, the Authority shall render the Purchaser a billing statement indicating the payment due.

(2) The Purchaser shall pay the amount shown on the Billing Statement to the Authority by the 10th of the month after receipt of the billing statement.

(h) Adjustments to Billings

(1) As soon as practicable after the end of each fiscal year, the billings for each Purchaser will be adjusted to reflect actual cost, any overpayment being refunded, and any underbilling being paid within 30 days.

(i) The Purchaser shall make the payments to the Authority whether or not the Project is operating and shall expect the Power Authority to make every effort to operate the Project in a safe and responsible manner in keeping with prudent utility practice.

Section 6. Metering

(a) The Authority shall design, purchase and install at its own expense all required revenue metering equipment at the specified delivery points. Metering of electric energy delivered shall be accomplished by a totalizing watt-hour meter of standard accuracy, adequate capability, and reliable manufacture. Additional metering and instrumentation may be installed at Delivery Points by the Authority as required to meet the requirements of the Authority and this Agreement.

(b) Revenue metering shall be subject to the Purchaser's consent to the make and type thereof, which consent shall not be unreasonably withheld.

Section 7. Source of Payment.

(a) The obligations of the Purchaser to make the payments under this Agreement shall be an operating expense of Purchaser's System and be payable solely from the revenues of Purchaser's System and other moneys legally available therefor.

(b) In order to afford, permit, and make timely payments as specified in this Agreement, the Purchaser agrees that it will establish, charge and collect rates, fees, and charges for its sales of Project power and energy so as to provide revenues sufficient to meet its obligations including those under this Agreement.

Section 8. Obligations in the Event of Default.

(a) Upon failure of the Purchaser to make any payment in full when due under this Agreement or to perform any other obligation herein, the Authority shall make demand upon the Purchaser, and if said failure is not cured within fifteen (15) days from the date of such demand it shall constitute a default at the expiration of such period. Notice of such demand shall be provided other purchasers by the Authority.

(b) In the event of any default by the Authority under any covenant, agreement or obligation of this Agreement, the Purchaser may, upon fifteen (15) days written notice to the Authority, bring any suit, action or proceeding, at law or in equity, including mandamus, injunction and action for specific performance, as may be necessary or appropriate to enforce any covenant, agreement or obligation of this Agreement against Authority, but the same shall not make the Authority liable in damages to the Purchaser nor give the Purchaser the right to discontinue the performance of its obligations under this Agreement.

(c) Upon the failure of a Power Purchaser with a Power Sales Agreement to make a payment which failure constitutes a default under that Power Sales Agreement, the Wholesale Power Rate will be increased to the extent that Debt Service allocated to the defaulting Power Purchaser is apportioned among all other Power Purchasers with Power Sales Agreements, including the Purchaser as Allocated Debt Service. The increase in the Allocated Debt Service shall not reduce the defaulting Power Purchaser's obligations under its Power Sales Agreement, and any subsequent payments made by defaulting Power Purchaser shall be credited to Debt Service obligations of non-defaulting Power Purchasers with Power Sales Agreements, including the Purchaser as an adjustment to the Allocated Debt Service. The obligations of a defaulting Power Purchaser will be apportioned among other Power Purchasers with Power Sales Agreements pursuant to this subsection for a maximum period of one calendar year following the default of that defaulting Power Purchaser. A defaulting Power Purchaser's rights to delivery of power and energy may be terminated or suspended by the Authority. In the event of a default the Authority will exercise its best efforts to recover amounts owed by the defaulting Power Purchaser.

(d) No remedy conferred upon or reserved to the parties hereto is intended to be exclusive of any other remedy or remedies available hereunder or now or hereafter existing at law, in equity, by statue or otherwise, but each and every such remedy shall be cumulative and shall be in addition to every other such remedy. The pursuit by either party of any specific remedy shall not be deemed to be an election of that remedy to the exclusion of any other or others, whether provided hereunder or by law, equity or statute.

(e) Any waiver at any time by either party to this Agreement of its rights with respect to any default of the other party hereto, or with respect to any other matter arising in connection with this Agreement, shall not be considered a waiver with respect to any subsequent default, right or matter.

Section 9. Limitation on New Projects. (a) The Authority will not issue Bonds to finance new projects in the Energy Program for Alaska unless a nationally-recognized consultant selected pursuant to (b) of this Section 9 renders an opinion in writing that (i) the specified new project is economically and financially feasible under reasonable standards for such determinations and consistent with the Act; and (ii) that the issuance of Bonds therefor will not cause an increase in rates or other obligations under the Power Sales Agreements such that the rates or other obligations are economically or financially unfeasible.

(b) The Authority will notify Power Purchasers who have executed Power Sales Agreements of the name of a nationally-recognized consultant deemed qualified to render an opinion as specified in (a) of this Section 9. The Power Purchasers shall have thirty (30) days in which to object to the consultant so named. If objections are raised by Power Purchasers, then if within forty-five (45) days after the Authority's notice, Power Purchasers, which in the aggregate are assigned two-thirds of more of the Debt Service apportioned to them by law as an element of their respective wholesale power rates under Power Sales Agreements, agree to an alternative consultant similarly qualified and submit that name to the Authority, the consultant recommended by the Power Purchasers will be selected. If the Power Purchasers cannot agree upon an alternative consultant within the time prescribed, the Authority's recommendation will be selected. Selection made under this Section must comply with applicable provisions of State law.

Section 10. Exchange of Energy. The Purchaser may exchange energy purchased under this Agreement with energy available from other sources to the extent that the Purchaser may determine that such an exchange is in its best interests, and does not contravene applicable provisions as determined in good faith by the Authority.

Section 11. Assignment.

(a) This Agreement shall inure to the benefit of, and shall be binding upon the respective successors and assigns of the parties to this Agreement; provided, however, that neither such agreement nor any interest therein shall be transferred or assigned by the Purchaser to any other person unless prior consent of the Authority has been obtained and the assignee or successor in interest complies with the statutory requirements for a purchaser of power under this Act.

(b) The Authority may assign its rights to receive payments under this Agreement to a trustee under the Indenture for the benefit of holders of Bonds issued by the Authority.

IN WITNESS WHEREOF, the Purchaser has caused this Letter of Intent to be executed the day and year first above written.

____
Purchaser

By ______________________
Title ______________________
Date ______________________

(SEAL)

A T T E S T:

____

EXHIBIT A

SUSITNA PROJECT
DEFINITIONS

(a) "Act" means Title 44, Chapter 83 of the Alaska Statutes (AS 44.83), including the Energy Program for Alaska, as such provisions may be amended by Senate Bill 168 in the First Session of the Thirteenth Legislature in the form originally introduced, or legislation substantially similar thereto.

(b) "Agreement" means this Statement of Intent.

(c) "Allocated Debt Service" means that portion of the Authority's Debt Service allocated to the Project and determined in a manner consistent with the Energy Program for Alaska pursuant to the Act.

(d) "Annual Project Budget" means the budget adopted, and amended from time to time, by the Authority pursuant to Section 5 with respect to the Project and which itemizes the estimated annual expenses of the Project for each Fiscal Year, commencing with the Commencement Month, exclusive of costs of construction as defined in the Indenture.

(e) "Authority" means the Alaska Power Authority as established by the Act, and any successor agency thereto and, unless the context otherwise requires, such officers of the Authority as may from time to time be delegated responsibilities and duties under this Agreement.

(f) "Billing Statement" means the written statement prepared by the Authority and delivered monthly to the Purchaser that shows the monthly amount to be paid to the Authority by the Purchaser for the Purchaser's Entitlement Share as defined in Section 5 in a Fiscal Year (or the remainder of such Fiscal Year in the case of an amended Billing Statement adopted to reflect an amended Annual Project Budget) and including any year-end adjustments for over-billing or under-billing made pursuant to Section 5.

(g) "Bonds" means bonds, notes or other evidences of indebtedness (including refunding bonds) issued pursuant to an Indenture, the proceeds of which will be used to finance, or to refund bonds, notes or other evidences of indebtedness so issued to finance, a project or projects in the Energy Program for Alaska.

(h) "Commencement Month" means that calendar month which is designated by the Authority upon 90 days' prior written notice to the Purchaser as the first month during which the Purchaser will make monthly payments under this Agreement, and said month will be the later of (i) the Project Completion Date or (ii) the date of commencement of the Agreement as provided in Section 2.

(i) "Debt Service" means the amounts convenanted to be charged in the Indenture to pay principal (including any mandatory sinking fund installments), as it becomes due and not by acceleration, and interest on Bonds and such additional amounts as are convenanted to be charged under the Indenture including, without limitation, amounts to provide debt service coverage and maintain reserves.

(j) " Delivery Point" means the point or points where

(1) the amount of electric power and energy is actually metered or, if no meter exists at that point, the equivalent point adjusted mathematically for line losses from the nearest point of actual metering; and

(2) delivery occurs.

(k) "electric energy" or "energy" means the amount of electric power delivered over time measured in kilowatt hours.

(l) "electric power" or "power" means the rate of flow of electric energy measured in terms of kilowatts or megawatts.

(m) "Energy Program for Alaska" means the program for acquisition, construction, operation and maintenance, and sale of power from power projects pursuant to AS 44.83.-380-425, as such provisions may be amended by Senate Bill 168 in the First Session of the Thirteenth Alaska State Legislature in the form originally introduced, or legislation substantially similar thereto.

(n) "Entitlement Share" or "Purchaser's Entitlement Share" means the percent of an Annual Project Budget for which the Purchaser is obligated and the percent of Project Capability and output to which the Purchaser is entitled to receive as provided in Section 5.

(o) "Fiscal Year" means that twelve-month fiscal year starting July 1 of a particular year through and including June 30 of the succeeding calendar year. If this Agreement becomes effective on a date between July 1 and the succeeding June 30, the initial Fiscal Year for purposes of this Agreement is that portion of the twelve-month period remaining thereafter or such other period of time as is mutually agreeable to the parties.

(p) "Indenture" means a trust indenture, trust agreement, secured loan agreement, or other instrument or resolution consitituting a contract with bondholders to secure Bonds.

(q) "Operations Agreement" means that agreement between the Authoirity and Purchaser which sets forth the procedures for delivery of energy and power and executed on even date with this Agreement.

(r) "Outstanding" means Outstanding Bonds as defined in the Indenture.

(s) "Power Purchasers" means Initial Power Purchasers and Subsequent Power Purchasers.

(t) "Power Sales Agreements" means agreements for the sale of power from projects in the Energy Program for Alaska which will replace this letter of intent.

(u) "Project" means the Susitna Hydro Electric Project.

(v) "Project Capability" means the amounts of electric power and energy, if any, as determined by the Authority, which the Project is capable at any time of generating whether or not the Project is actually generating power and energy, less Project station use and losses.

(w) "Project Completion Date" means the date as established by the Authority when the Project construction and testing is demonstrated to be complete and the Project can begin commercial service.

(x) "Prudent Utility Practice" shall mean at a particular time any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry at such time, or which, in the exercise of reasonable judgment in light of facts known at such time, could have been expected to accomplish the desired results at the lowest reasonable cost consistent with good business practices, reliability, safety and reasonable expedition. Prudent Utility Practice is not intended to be limited to the optimum practice,method or act or the exclusion of all others, but rather to be a spectrum of possible practices, methods and the acts, having due regard for manufacturers' warranties and the requirements of governmental agencies of competent jurisdiction.

(y) "Purchase Requirement" means, with respect to a particular project (including the Project) in the Energy Program of Alaksa, the amount of Power in kilowatts and the energy in kilowatt hours which a Project Power Purchaser is obligated to purchase from this project.

(z) "Purchaser means ____________________, Alaska, a Home Rule Municipality of the State of Alaska duly organized and existing under and pursuant to the laws of the State of Alaska, or any successor municipality or ____________________ Electric Association, Inc., a non-profit electric cooperative membership corporation of the State of Alaska.

(aa) "Purchaser's System" means the Purchaser's public utility system for the distribution, transmission, and generation of electrical power and energy, other than the Project, and which is owned and operated by the Purchaser.

(bb) "Wholesale Power Rate" for the Project means the rate (or rates) charged to the Purchaser per kilowatt of capacity and per kilowatt hour of electrical energy from the Project.

APPENDIX J

ELECTRIC POWER SYSTEM STUDY, TASK 7, VOLUME ONE SUPPLEMENT
SYSTEM DEVELOPMENT AND STEADY STATE ANALYSIS

ALASKA POWER AUTHORITY

SUSITNA HYDROELECTRIC PROJECT
ELECTRIC POWER SYSTEM STUDY

TASK 7

VOLUME 2

SYSTEM DEVELOPMENT
AND
STEADY STATE ANALYSIS

PRELIMINARY REPORT

Prepared by: R. Meredith
J. Szablya, Task Leader

HARZA-EBASCO
SUSITNA JOINT VENTURE
DECEMBER 1983

TRANSMISSION PLANS FOR 1620 MW SUSITNA
GENERATION, REVISED LOADS AND LOAD ALLOCATION

Introduction

This study summarizes the results of studies conducted subsequent to the Volume 1 study on "System Development and Steady State Analysis" of Harza-Ebasco. It evaluates the impact of increasing the total installed generating capacity at Susitna and of requiring the transmission system to be able to transmit 85 percent and 25 percent of its highest possible output to Anchorage and Fairbanks, respectively. Additional constraints relating to rights-of-way have been introduced and are discussed in the text.

The generating capacities assumed for this study are as follows: Watana would be installed in 1993 with six units totaling 1020 MW nominal winter capability. With high head summer conditions it is assumed to be able to generate 1170 MW. Devil Canyon would have four units installed in 2002 with winter nominal and summer maximum capabilities of 600 MW and 716 MW, respectively.

Because of the higher generating capacities and the revised allocation assumptions, transmission loadings in this study are about 50% higher than those in Volume 1.

Criteria Interpretation

The criteria used in this study are nominally the same as those outlined in the FERC License Application for the Susitna Project. However, some notable exceptions have been made in interpreting them to avoid unwarranted or premature transmission expenditures.

The first of the exceptions is that transmission capability requirements have been timed based on transfer capability requirements to the Anchorage and Fairbanks area, rather than on when generating capacity is expected to be installed.

The transfer capability requirements to either Anchorage or Fairbanks have been defined as the lesser of the projected area peak load or the appropriate maximum (25 percent or 85 percent) share of Susitna's then-installed generating capacity. Both loads and generating capacity limits have been applied on a seasonal basis. For example, either the appropriate share of the winter generating capability or the winter peak load has defined winter transmission requirements. The fact that summer line ratings are lower, or that summer generating capability is higher, is of concern.

The basis for the load estimate is the DOR mean forecast provided in Appendix A of Volume 1. When particular load levels were found to occur beyond the years covered in Appendix A, the growth patterns between years 2000 and 2020 were extrapolated to provide an estimate of the date a future load would occur.

A direct result of these interpretations of the criteria is that the need to transmit an appropriate share of the summer maximum generating capacity will not become a significant factor until summer peak loads nearly equal Susitna's winter generating capability. Based on the extrapolation of the DOR mean forecast, this will occur sometime in the 2040s. At so distant a date, even if revised by different load forecasts, that particular part of the criteria in the FERC license has little current economic impact. Thus, except for right-of-way considerations or other non-economic factors, the need to transmit Susitna's maximum summer output is unimportant at this time.

A third variation is that estimates of normal loading patterns and reasonable operating practices have been assumed for purposes of loss evaluation and for determining the suitability of post-contingency operating procedures.

As an example, although the maximum transfer capability to Anchorage may be required to equal the winter peak load in a particular year, that does not mean that one would expect such a transfer level to being maintained indefinitely after losing one of two supply circuits. A prudent system operator can be expected to increase local generation to replace Susitna generation and to reduce the risk to area security.

If such redispatch is done immediately following a contingency, it can allow the use of smaller transformers and lower cable capacities, since both of these elements have long thermal time constants. Cost savings from appropriate use of operating procedures could be significant. Transient stability requirements would not be affected by such measures.

A related conclusion from the analysis of expected system operations is that, in average hydro years, both before Devil Canyon is completed and near the study horizon, significant amounts of local (thermal) generation will be required to supplement Susitna's energy output. The thermal generation will be operated most likely during winter peak load periods. This will mean that design conditions of maximum transmission loading can be expected only when the local generation is not operating for some reason.

It also means that should operation of thermal generation avoid a contingency loading problem, little incremental operating cost would be entailed. Thermal energy generated during contingency conditions would just replace energy generation otherwise required at another time.

Considering the lack of cost involved with use of thermal generation to relieve transmisson loading problems, this is economically preferable to transmission reinforcement. These instances are noted in the text.

SUSITNA AREA SUBSYSTEM

Discussion

The Susitna area transmission system continues to perform as a means of collecting the generated power and transmitting it to the Gold Creek Station. The main change from Volume 1 is the elimination of the Reregulation Dam and the increase in generated power levels. Neither of these changes is sufficient to cause a revision to the Volume 1 configuration, other than conductor sizes.

Since the writing of Volume 1, two new constraints have been raised. They are the need to use the rights-of-way shown in the FERC License Application as much as possible; and the possible desirability of providing Watana and Devil Canyon switching in underground stations.

These latter constraints have led to a return to a configuration comparable to the one in the FERC License Application (Figure 1). In it both Watana and Devil Canyon would have two 345-kV circuits to Gold Creek. The restoration of independent circuitry from Devil Canyon would avoid the need to bring Watana's circuitry near Devil Canyon and possibly into an underground switching station. It would also facilitate use of lower voltage switchgear and transformer terminated lines, if economically desirable.

Load flows of this configuration are included in the appendices relating to the Fairbanks and Anchorage transmission systems.

SUSITNA TO FAIRBANKS SUBSYSTEM

Discussion

In the Susitna-Fairbanks area, forecast loadings have not changed from Volume 1, since the maximum loadings can still only equal the Fairbanks load. The major change has been a need to consider loading levels as high as 25% of Susitna's 1886 MW summer capability.

Three alternatives were considered:

- Plan I - an expansion of the recommended alternative of Volume 1 with an additional 230-kV circuit

- Plan J2 - a modification of the configuration of the FERC License Application

- Plan DD - a hybrid configuration involving two 345-kV circuits to Healy and eventually three 230-kV circuits between Healy and Fairbanks.

These alternatives are shown in Figures 2, 3 and 4, respectively.

Comparison of Alternatives

Timing of facility additions is important in ranking the three alternatives. At one extreme, if all the transmission facilities were required initially, Plan J2 would be the least costly. Three 230-kV circuits, which comprise parts of the other two plans, would cost nearly as much as two 345-kV circuits and would have loss penalties significant enough to make them more expensive. The need for an intermediate station at Healy would also penalize Plans I and DD.

If timing of facilities is based upon the DOR mean load forecast (and extrapolations of it), a different result is obtained. Plan I remains the one with the lowest present worth, since the third 230-kV circuit added to that plan would not be required until power transfers to Fairbanks exceed the estimated 350+ MW stability limit of that plan. The capital cost savings of Plan I more than offset its loss penalty, compared to the Plan J2 or, to a lesser degree, Plan DD.

If economics and performance were the sole basis of selecting the preferred plan, Plan I for serving Fairbanks would continue to be recommended. However, since Volume 1 was prepared, it has been suggested that getting right-of-way for a third circuit between Gold Creek and Healy could be difficult and that the extra environmental impact of a third circuit would be an undesirable aspect of this plan.

To cope with these considerations the hybrid Plan DD has been developed. It would use the same rights-of-way between Gold Creek and Healy as described in the FERC License Application. It could use the existing 138-kV circuit's right-of-way, when required, for the third 230-kV circuit between Healy and Ester. Its present worth is higher than Plan I, but it is still significantly lower than the plans which use only 345-kV transmission.

The exact timing for the addition of the third 230-kV circuit in Plan DD has not been determined. That will depend upon whether or not thermal generation is added in Fairbanks before the third line is needed. If thermal generation is added, one can assume that it will be operating during winter peak periods to supply some of the energy deficit which Susitna can not supply. In that case the need for the third line will be delayed until the Fairbanks summer load levels exceed the estimated 350-400 MW thermal and stability limits of the initial transmission system. If the thermal generation is added at Healy or a point further south, winter power transfers associated with this additional generation could determine the timing of the third 230-kV circuit.

Load flow performance of Plan DD is shown in Appendix A for both 390 MW and 453 MW load levels. These load levels represent 25% of Susitna's nominal winter and maximum summer generating capabilities, respectively. The initial development is judged capable of handling the winter output, but an augmented system is required to carry the maximum summer output. The magnitudes of SVC requirements have not yet been refined but are expected to be comparable to those of the plan in the FERC License Application.

SUSITNA TO ANCHORAGE SUBSYSTEM

Discussion

The main changes from Volume 1's assumptions regarding the system between Susitna and Anchorage are that more generation will be available to serve Anchorage both initially and ultimately. It is also desired that the FERC License Application configuration be followed as closely as possible.

Three alternatives are discussed in this study. They are:

- Plan Y - from Volume 1 with additional circuitry
- Plan J2 - a modification of the plan in the FERC License Application
- Plan SS - a modified Plan S from Volume 1.

Plan Y is shown in Figure 5; Plan J2 in Figures 6 through 8B; and Plan SS in Figures 9 through 11. Each of these plans is presented in turn. Only the latter two are discussed in detail.

Augmentation of Plan Y

As indicated in Volume 1, several possible plans are competitive to serve Anchorage. Plan Y (Figure 5) offers a fortuitous combination of adequate capability, and reasonable cost. It is adequate for a transfer to Anchorage of just over 1100 MW. However, it is not capable of handling 85% of 1886 MW (= 1603 MW) or even 85% of 1620 (= 1377 MW) without modification.

To handle a 1600 MW transfer these studies, in concert with those supporting the original FERC License Application, indicate that plans with three 345-kV circuits and one intermediate switching station are preferred. While it may be possible to use a system of two 345-kV circuits and two intermediate switching stations, losses and thermal capability requirements would dictate a much larger conductor size than is now being installed on the Intertie. Therefore, a two circuit plan would not coordinate with on-going construction and is not considered further.

Plan Y could be augmented by addition of another 345-kV circuit between Gold Creek and Lorraine. At Lorraine a 345/230-kV switching/transformation station would be desirable to defer or eliminate the need to install a second 345-kV cable under Knik Arm. To the north of W/T it even may be desirable to add a 345-kV switching station to reduce the lengths of the circuits between Gold Creek and W/T.

With all of these modifications it becomes apparent that 345-kV switching at W/T does not add to the system's capabilities or that W/T is not an optimal location for a "middle of the line" station between Lorraine and Gold Creek. It was its ability to serve as a compromise "middle of the line", "service to load center" and "access to existing cables" station which made it attractive in Volume 1.

For significantly higher transfers, the trade-offs involved in the Plan Y compromise are no longer acceptable. The most notable weaknesses of Plan Y are that it does not provide access for Susitna transfers to all of the existing cable capacity in its later stages and that the W/T switching location is not optimally located between Gold Creek and Anchorage. It appears that switching stations are required both at Lorraine and at a "middle of the line" point north of W/T. Each of these can be economically justified by delaying a cable, a third circuit, or SVC capacity.

With this conclusion, it can be shown that Plan S of Volume 1, which would use Willow and Lorraine switching stations, is preferable to Plan Y. No detailed studies of expanding Plan Y have been conducted because of this. Expansion of Plan S, called Plan SS, is discussed later in this study.

Plan J2

One of the constraints for this study is to stay as close to the FERC License Application configuration as possible. This alternative was designed to use only rights-of-way indicated in the FERC License Application, but it has been modified to reduce costs.

Its initial development is shown in Figure 6. It consists of two 345-kV circuits between Gold Creek and Lorraine. A mid-point switching station would be located about 15-20 miles north of Willow, to minimize SVC requirements.

Since Willow is no longer expected to be a major load center, no offsetting savings would result from using the less desirably located Willow site. Double breaker switching would be used at the midpoint station to eliminate loss of two circuits for a breaker failure.

At Gold Creek the Anchorage circuits would be switched in the same bays as the future Devil Canyon circuits. A breaker and a half layout could be used because a breaker failure, which could affect another eight mile long circuit, is not of large concern.

At Lorraine one 345-kV circuit would connect to a 345-kV cable to Fossil Creek. The other would terminate in a transformer to the 230-kV station, which would connect to the existing cables and also serve the Teeland area load. An SVC system would also be installed.

This plan requires another 345-kV cable when the capabilities of those already existing and initially installed are exceeded. Appropriate operating procedures can delay the need for extra cable capacity; however, it will probably be required by the time Devil Canyon is installed.

Because of the less than ten year span (1993 to 2002) between the need for the first and second sets of 345-kV cables, it is more economical to install both sets initially. At this stage it is advantageous to use the second set of cables temporarily at 230-kV in order to augment the 230-kV system. This has a triple advantage in that it (1) reinforces the weaker of the two Susitna terminations at Lorraine; (2) defers costs of 345-kV switching, transformation and shunt reactors needed to use it at 345-kV, and (3) increases 230-kV system capabilities for times when Beluga's output is high.

At Fossil Creek, which is a much preferred location over University, 230-kV switching would be provided for the transformer-terminated 345-kV cable, the 345-kV cable operating at 230-kV, the existing 230-kV cable and the station exits into Anchorage. An SVC system would also be provided.

The stage of development with only two 345-kV lines would be expected to be able to transfer about 1000 MW without a stability problem. Approximately two-thirds of the SVC required for that transfer would be installed initially at Lorraine and at Fossil Creek. The remainder would be installed about 5 years later at the mid-point station. The total SVC requirement is roughly estimated to be 700 MVAR of dynamic range, but can be better sized as part of the stability studies.

An outage of the 345-kV line terminating at Lorraine would limit sustained power transfers from Susitna at the estimated 800 MW capability of the 345-kV cable. An outage of the circuit containing the 345-kV cable would be less restrictive because the 230-kV and 138-kV cable capacities are higher. The total transfer capability of the paralleled 230-kV and 138-kV cables will depend upon what measures are taken to apportion cable loadings, including the application of phase shifters, series reactors or bundled conductors on overhead lines. With careful balance over 1100 MW capacity could be made available. The combination of Susitna and Beluga can transfer at least 300 MW more than Susitna alone could during single contingency outages.

If it becomes desirable to transfer more than 800 MW from Susitna without the use of post-contingency operating procedures, it will become necessary to operate the second 345-kV cable at its rated voltage. This would require 345-kV switching at Lorraine and addition of a second transformer at Fossil Creek. Shunt reactors would also be added to the cable circuit. These changes are shown in Figure 7.

It appears that this upgrade will not be economically attractive before loads in Anchorage exceed 1000 MW. The reason for this is that an outage of the Lorraine transformer, or its source circuit, would produce only about a 25% overload on the 800 MW cable, which should be well within its short term thermal capability. It would not be prudent to continue to serve all of Anchorage on one circuit even if its capability were 1000 MW. The proper response will be to bring as much thermal generation on line as quickly as possible. The cable capability, whether 800 MW or 1000 MW, plays no important role as long as the system remains stable and the cable's thermal time constant is long enough to allow local generation to be brought on line.

Switching for the next stage of development, shown in Figures 8A and 8B, depends upon whether or not the cable capacity upgrade is implemented before or concurrently with a third 345-kV circuit from Susitna. Figure 8A is the logical successor to Figure 7 and assumes that cable upgrading occurs before addition of a third 345-kV circuit. Figure 8B shows that 345-kV switching at Lorraine can be eliminated if the cable upgrading and the third 345-kV circuit addition are coordinated. Figure 7 would not apply to this latter development sequence.

The question of whether or not coordination is possible depends on when the third 345-kV circuit is desired and how long operational procedures can delay the need for greater cable capacity. Initial conclusions suggest that both needs would occur at the same time at about the 1000 MW load level in Anchorage.

Two factors lead to this load level as a critical indicator. First the total capacity of the cables (the 345-kV cable operating at 230-kV, and the existing 230-kV and 138-kV cables) would exceed 1000 MW; consequently, no restrictions on local generation would exist before that load level is reached. Second, the annual energy surplus from Susitna is expected to disappear at about that load level which would significantly increase the loss benefits of a third 345-kV circuit and help to justify the latter.

Between the addition of Devil Canyon and the end of the hydro energy surplus, the losses on the transmission system are not important. They just reduce water spillage at Susitna and have negligible cost. However, after that time incremental losses may require incremental thermal generation at significant expense. At that time advancing a third 345-kV circuit is more economical than to operate with higher losses and installing additional amounts of SVC.

This approach is in contrast to that proposed in Volume 1, where SVC was used to extend an even weaker system (longer circuit segments) to the 1100 MW level. The present study is based on the premise that Anchorage's share of Susitna will reach as high as 1600 MW. At this level a third circuit is inevitable.

Load flow studies of Plan J2 at the 1000 MW and 1330 MW load levels are shown in Appendix B. The former represents the limit by design of the two circuit plan. The latter represents an 85% share of Susitna's 1620 MW winter capability. The system could also be upgraded with additional SVCs, and possibly new cables, to carry at least 85% of 1886 MW when required to do so.

Plan SS

The final alternative studied for the Anchorage area can be considered as a variation on either Plan J2 or on Plan S of Volume 1. It is shown in Figures 9 through 11.

It differs from Plan J2 by routing one 345-kV circuit around Knik Arm, thus avoiding one of the 345-kV cables and providing a system more immune to common-mode cable failures, such as could be caused by earthquakes, tidal waves, ice scour, and anchoring. Like the plan in the FERC License Application and Plan S, it would have a switching station at Willow. In most respects it resembles Plan S with the eventual addition of a third 345-kV circuit between Gold Creek and Lorraine.

The initial configuration would be similar to that of Plan S in Volume 1 and is shown in Figure 9. The main change from Plan S would be the earlier addition of the Willow switching station. The Willow switching station will allow a cost-effective reduction in initial SVC requirements. As in Plan J2, additional SVC would be added (at Willow) about five years later to cope with increased transfers from Susitna.

One of the main advantages of this plan over Plan J2 is its ability to defer all new Knik Arm cable installations. As in Volume 1, the existing cables are assumed to have just over 600 MW of capability. Any outage of the overhead circuit into Anchorage would exceed the existing cables' long term capability, but operation of Anchorage or Kenai generation instead of Beluga or Susitna could relieve the problem. However, the likelihood that such operational condition will occur is small because it anticipates a double contingency at an inopportune time; namely, it assumes that a single cable failure reduces Susitna's transfer capability to Anchorage to 600 MW and that simultaneously no thermal generation is available at Anchorage (or south of it), while winter peak load is in progress.

Delaying the need for any new cables has a large economic advantage. First, cables are expensive, relative to all other parts of the transmission system. Second, the longer the cable is delayed, the more likely it might be able to be added inexpensively to the highway bridge proposed to span Knik Arm. Third, the longer the decision is put off, the more likely future generation plans can be integrated into the Susitna system. If new Beluga generation were to be added or existing cables need to be replaced, two 345-kV cables could be added at once to take advantage of shared installation costs.

When extra cable capacity must be added, the preferred mode is to operate it initially at 230-kV as shown in Figure 10. Just as in Plan J2, there are several advantages to initial operation at 230-kV, despite the need to install an extra circuit breaker at Lorraine.

The Figure 10 configuration could operate up to the 1000 MW level, just as Plan J2 could. However, the longer circuitry of this plan would require additional SVC. It may be desirable to add the third 345-kV circuit to this plan before loadings reach 1000 MW. Figure 11 shows the recommended configuration after the third 345-kV circuit is added and the cable is uprated to 345-kV.

It should be noted that this configuration avoids the need for a 345-kV switching station at Lorraine. Later generation development at Beluga or cable retirements could dictate 345-kV switching as a means of controlling cable loading balance, but it is not required when the third circuit goes into service.

Load flow studies for Plan SS are included in Appendix C for 900 MW and 1330 MW load levels. The 900 MW level represents a reasonable limit before adding a third circuit to this configuration, just as the 1000 MW level was reasonable for Plan J2. More detailed studies would be required to refine either limit. The 1330 MW level again represents a transfer of 85% of 1620 MW. SVC requirements for this alternative are estimated to be 850 MVAR. Higher transfers are possible with additional SVC and possibly more cable capacity.

CONCLUSIONS

Based on the results of these studies and the rights-of-way restrictions between Gold Creek and Healy, it appears desirable to modify the configuration for service to Fairbanks to that shown in Figure 4 of this study.

For the Anchorage area it appears that the configuration shown as Plan S in Volume 1 and Plan SS in this study is preferable to the previously recommended Plan Y for servicing Anchorage. The desirability of considering an alternative plan was already noted in Volume 1 and was done in this case to make expansion to higher than expected power transfers, and the installation of a third 345-kV circuit, more economical.

In any event, the results of these studies should be considered tentative. They were based on many long range operational assumptions which could change. They were conducted over a period of only a few days and required many approximations. The timing of a third circuit is highly dependent upon loss reduction benefits and transient stability enhancement relative to alternative use of SVC. Neither of these could be evaluated accurately without extensive studies.

Despite these disclaimers, the general conclusions are believed to be valid for planning purposes.

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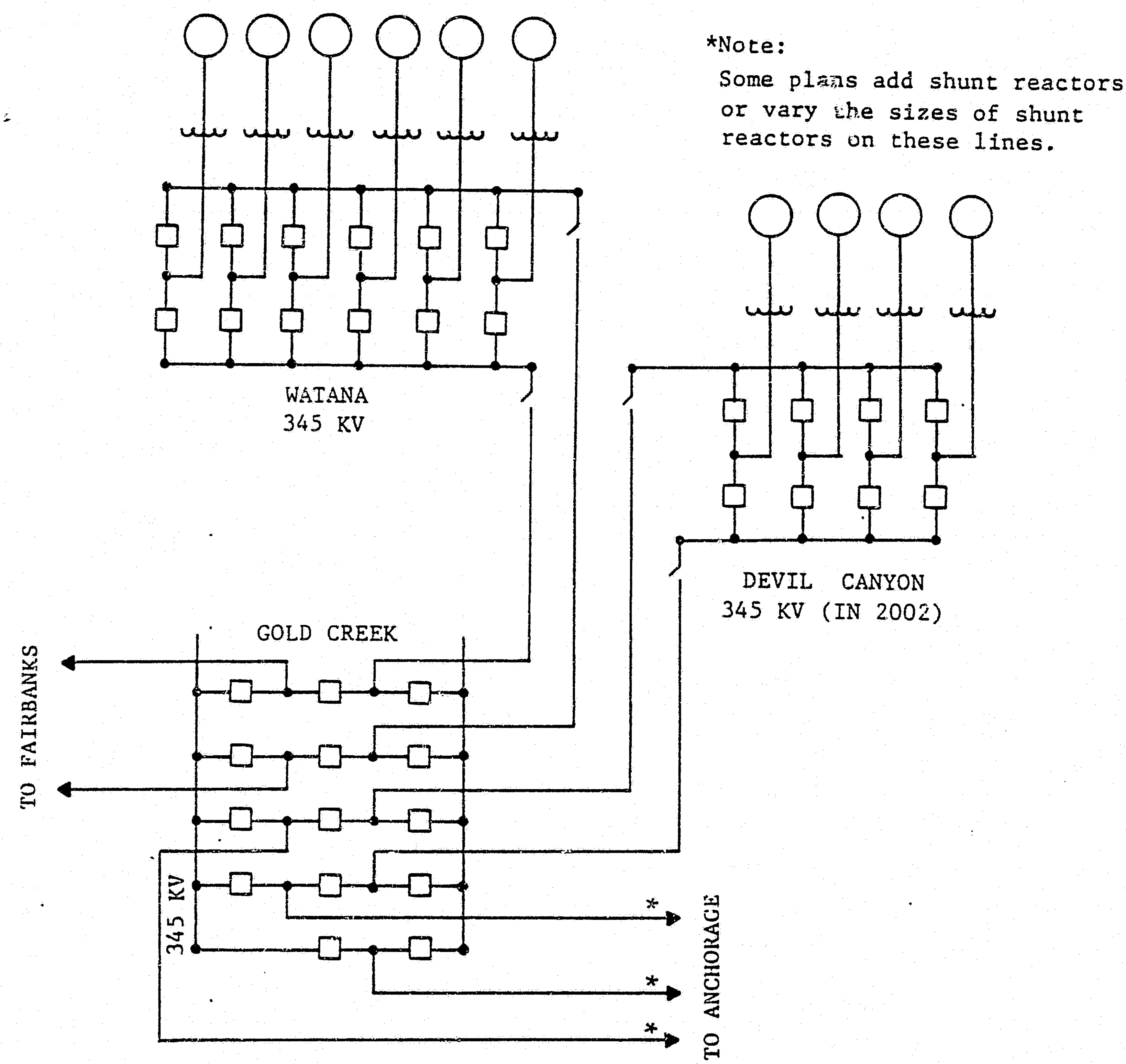


ALASKA POWER AUTHORITY

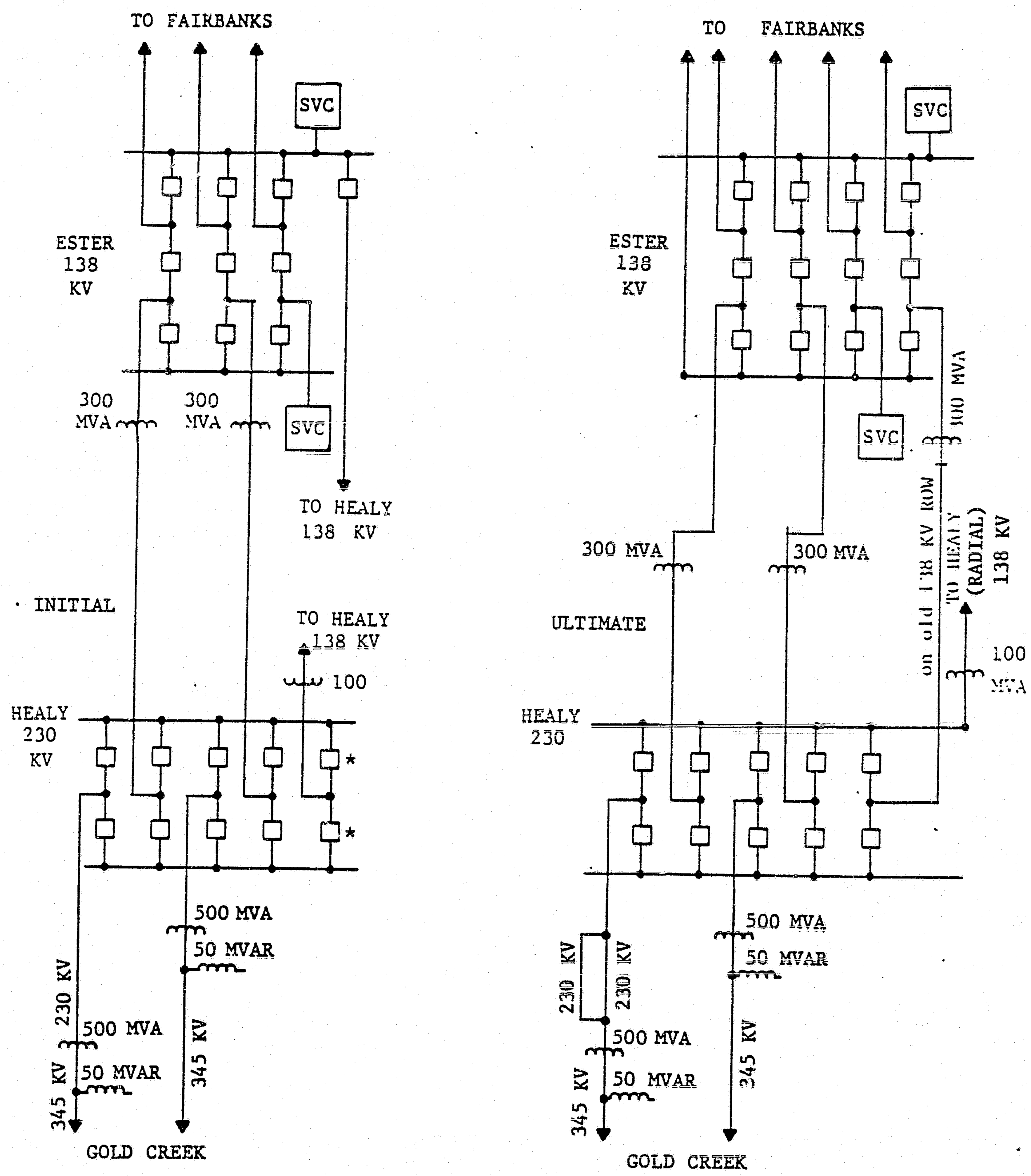
SUSITNA HYDROELECTRIC PROJECT

SUSITNA AREA SWITCHING
WITH INDEPENDENT
DEVIL CANYON CIRCUITRY

HARZA-EBASCO

ANCHORAGE ALASKA

FIGURE 1



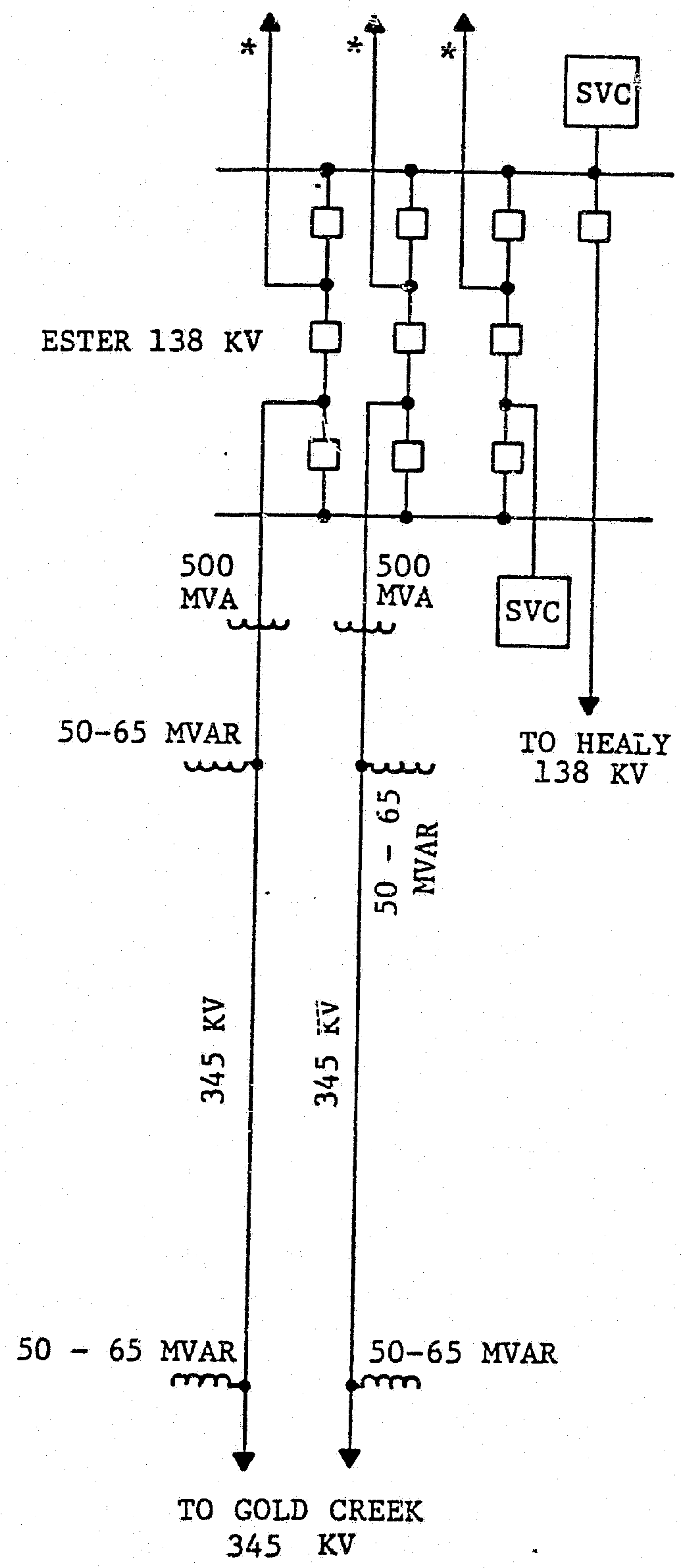
ALASKA POWER AUTHORITY

SUSITNA HYDROELECTRIC PROJECT

SUSITNA - FAIRBANKS SWITCHING

230 - KV PLAN I

FIGURE 2



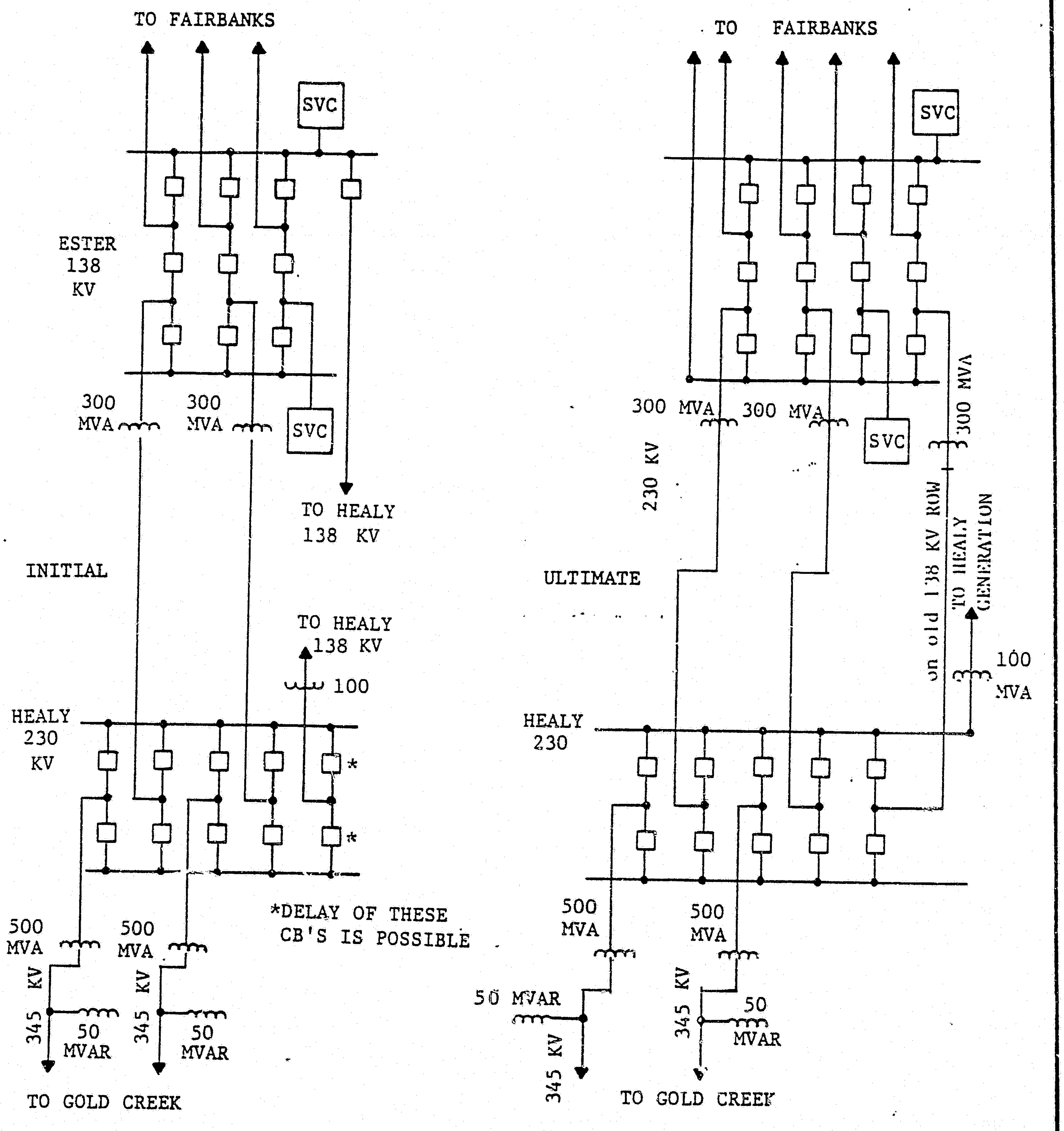
*TO FAIRBANKS LOCAL SYSTEM, FUTURE LINES NOT SHOWN.

ALASKA POWER AUTHORITY

SUSITNA HYDROELECTRIC PROJECT

SUSITNA-FAIRBANKS SWITCHING
MODIFIED FERC PLAN J2

FIGURE 3



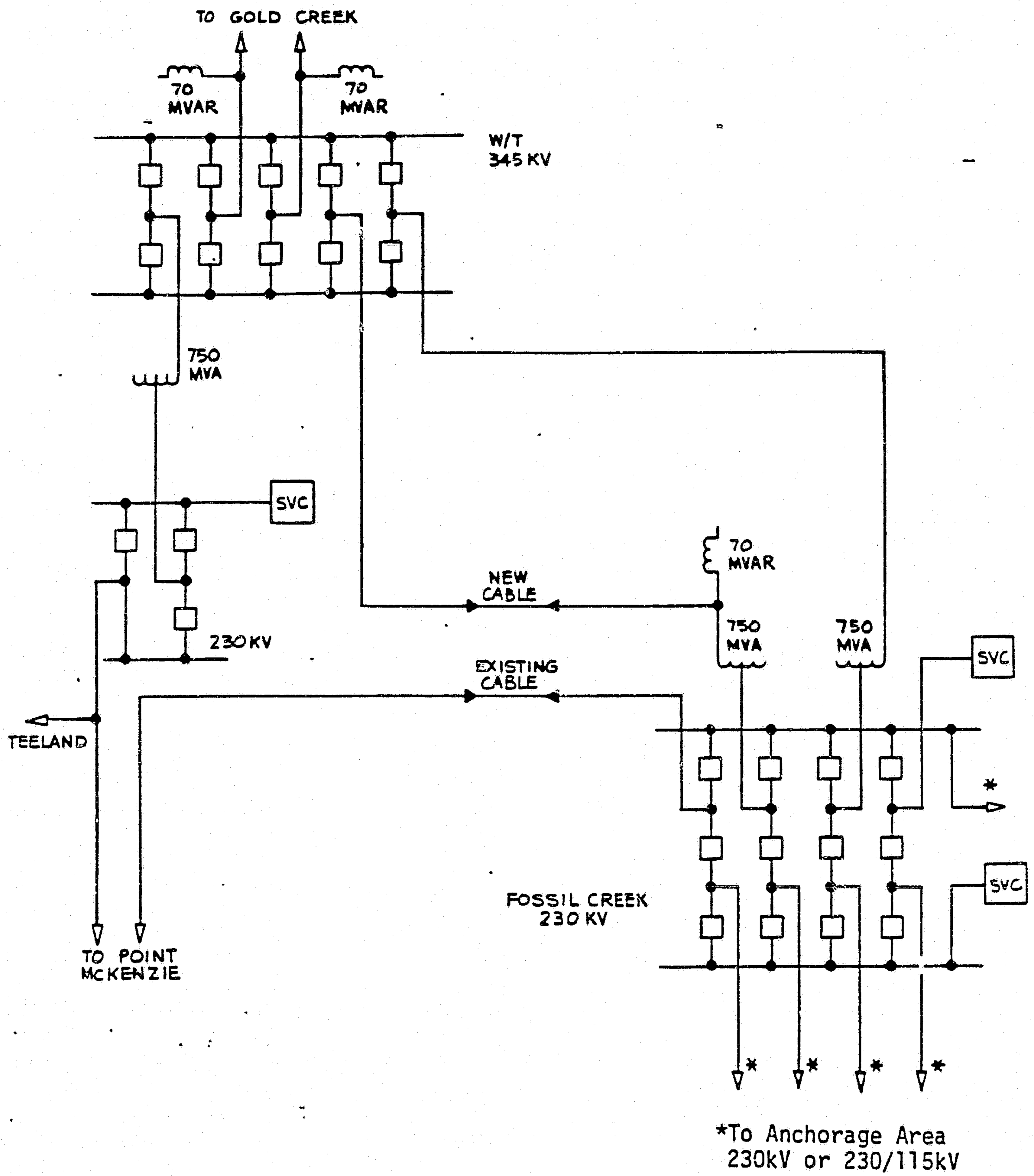
ALASKA POWER AUTHORITY

SUSITNA HYDROELECTRIC PROJECT

SUSITNA-FAIRBANKS SWITCHING
HYDRID PLAN DD

HARZA-EBASCO

FIGURE 4



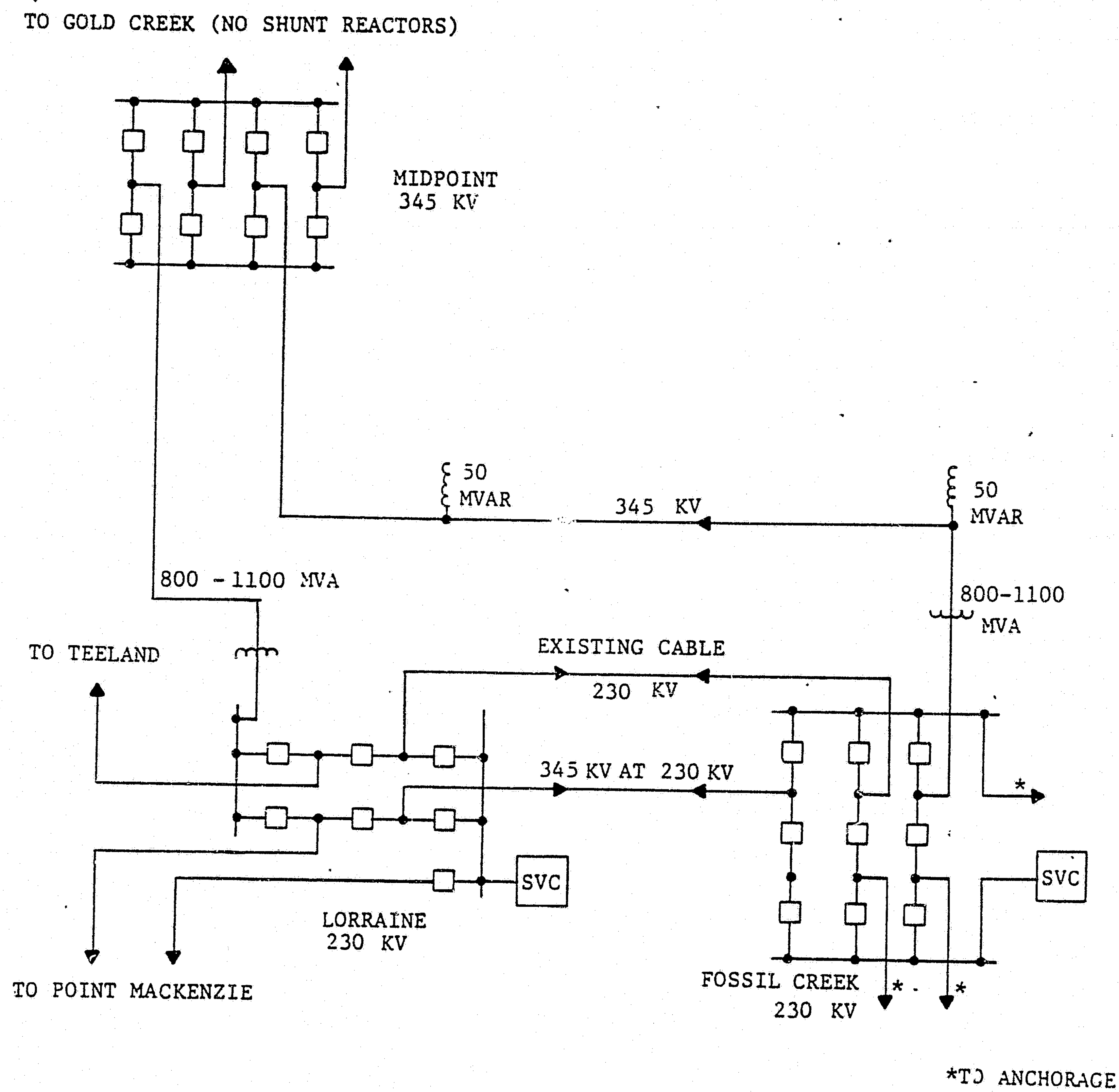
ALASKA POWER AUTHORITY

SUSITNA HYDROELECTRIC PROJECT

SUSITNA — ANCHORAGE SWITCHING
PLAN Y
TWO CIRCUIT STAGE

HARZA-EBASCO

FIGURE 5



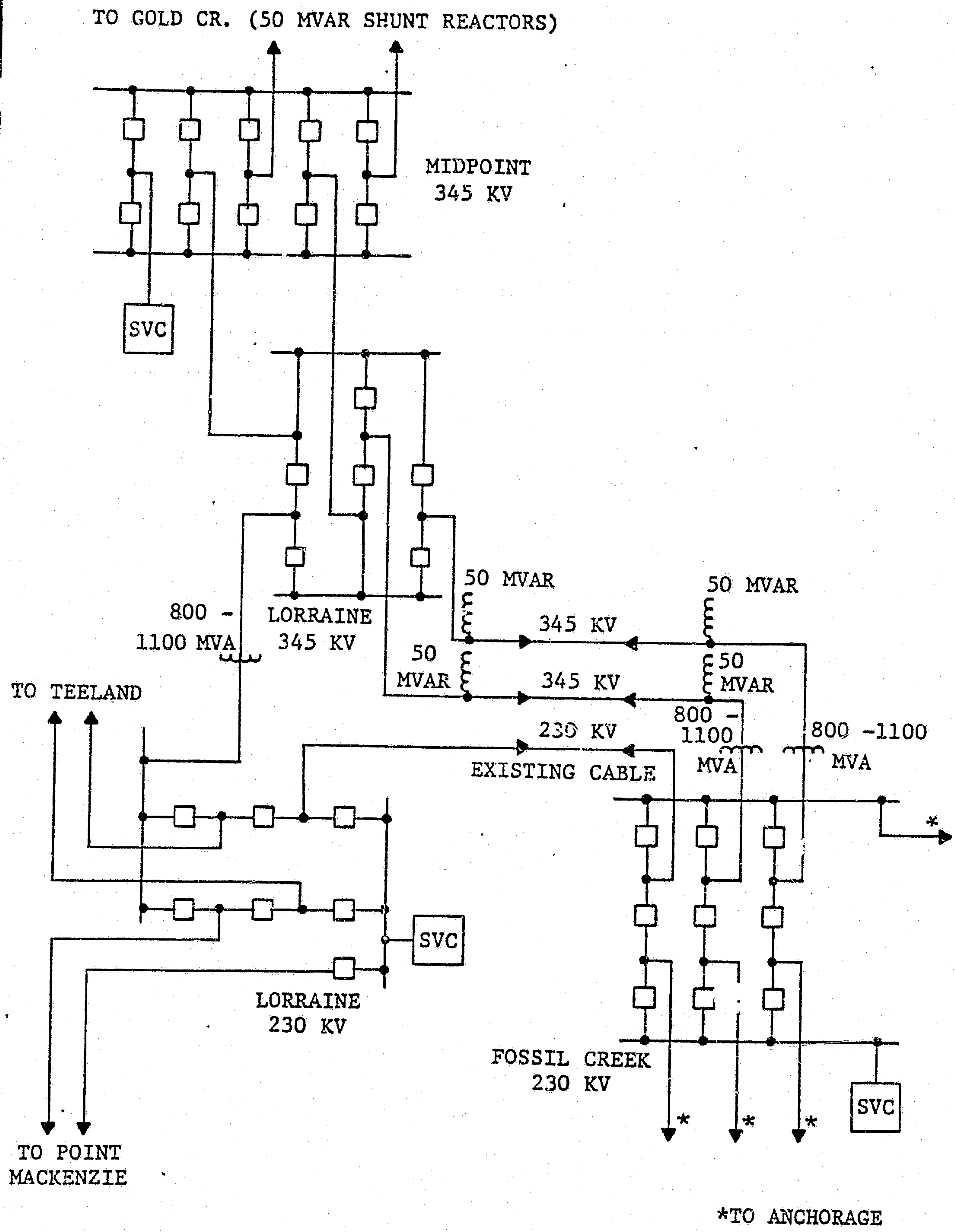
ALASKA POWER AUTHORITY

SUSITNA HYDROELECTRIC PROJECT

SUSITNA - ANCHORAGE SWITCHING
MODIFIED FERC PLAN J2
TWO CIRCUIT STAGE

HARZA-EBASCO

FIGURE 6

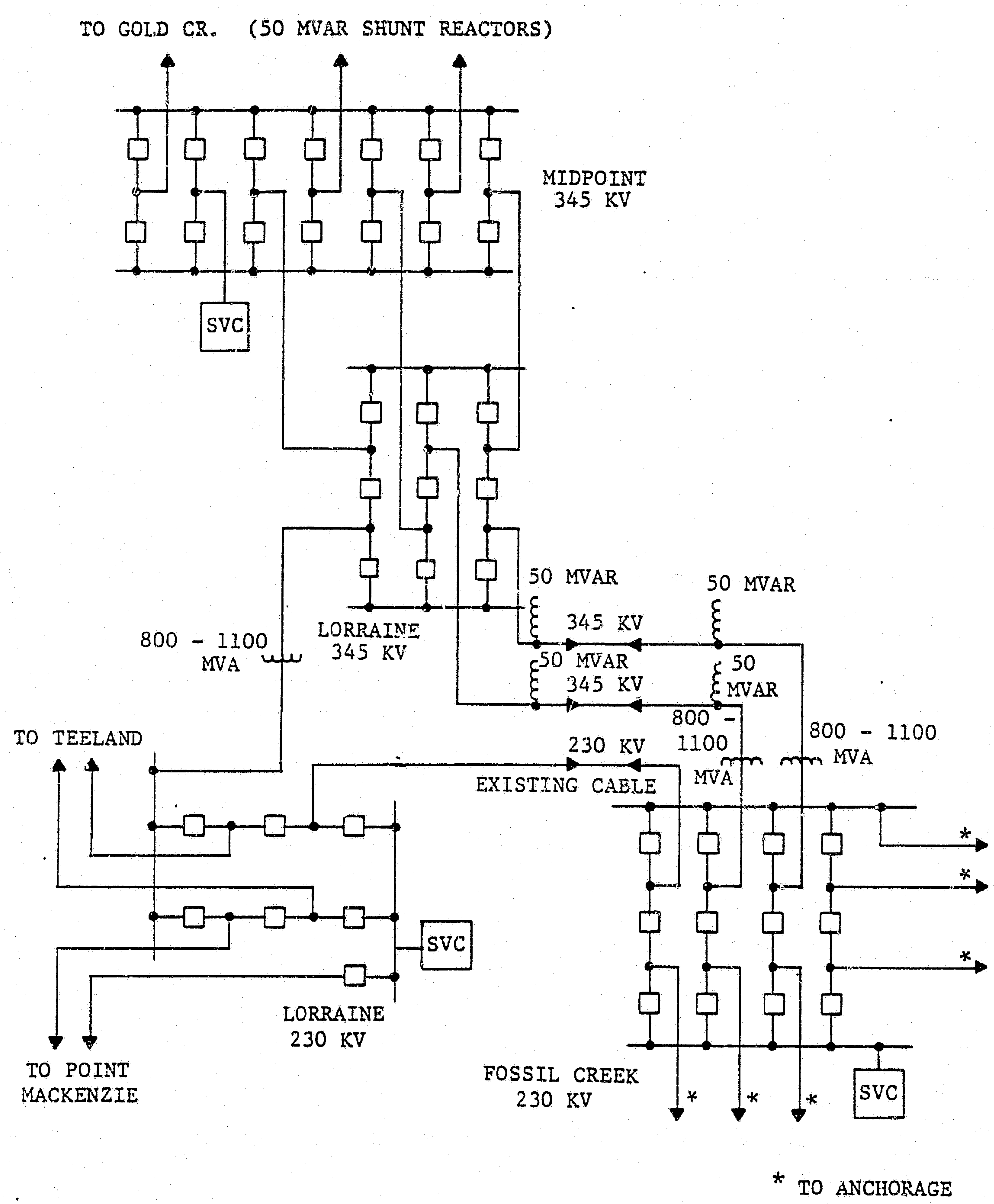


ALASKA POWER AUTHORITY

SUSITNA HYDROELECTRIC PROJECT

SUSITNA-ANCHORAGE SWITCHING
MODIFIED FERC PLAN J2
IF CABLE UPGRADE
PRECEDES THIRD CIRCUIT

FIGURE 7

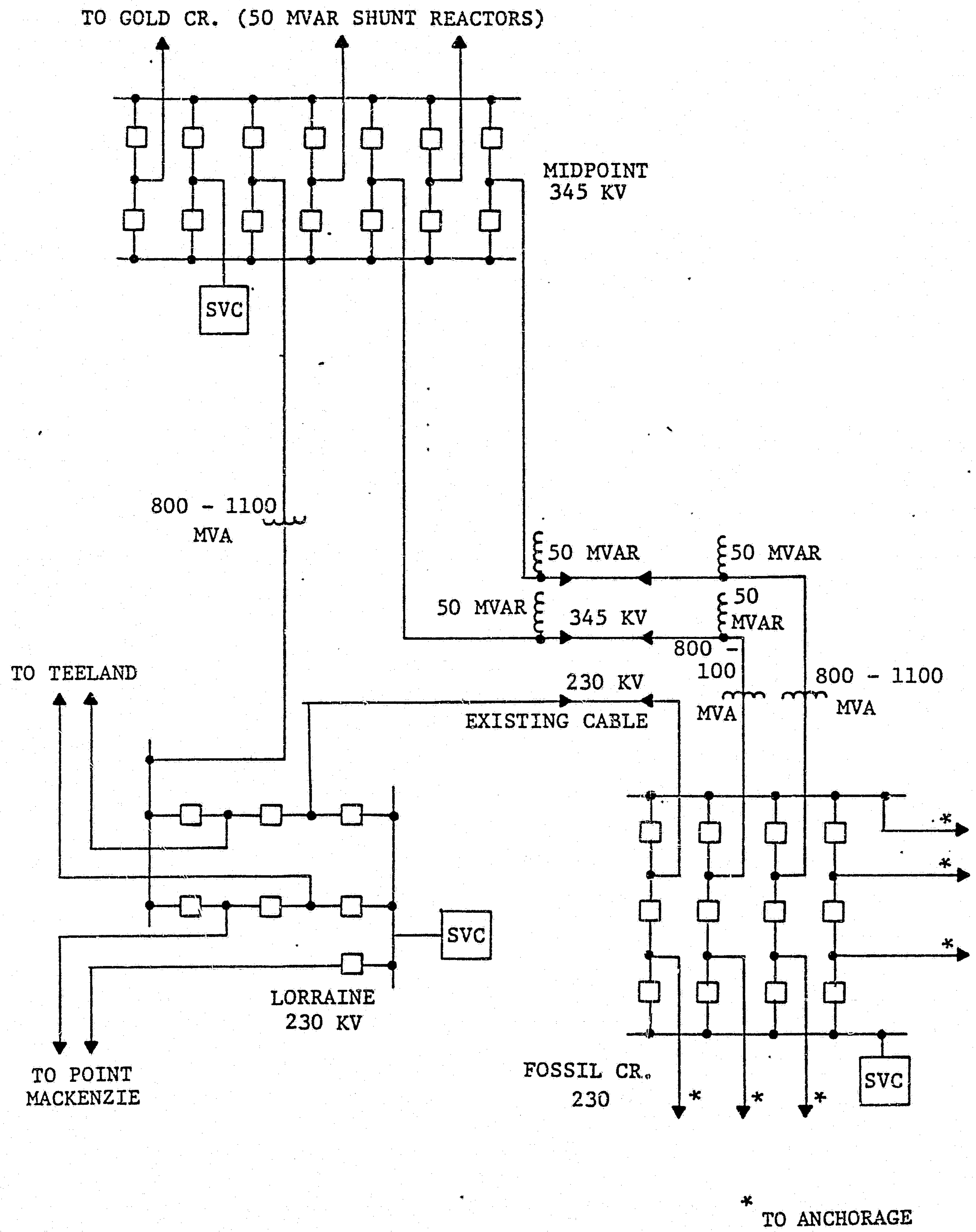


ALASKA POWER AUTHORITY

SUSITNA HYDROELECTRIC PROJECT

SUSITNA-ANCHORAGE SWITCHING
MODIFIED FERC PLAN J2
THREE CIRCUIT STAGE
IF PRECEDED BY CABLE UPGRADE

FIGURE 8A

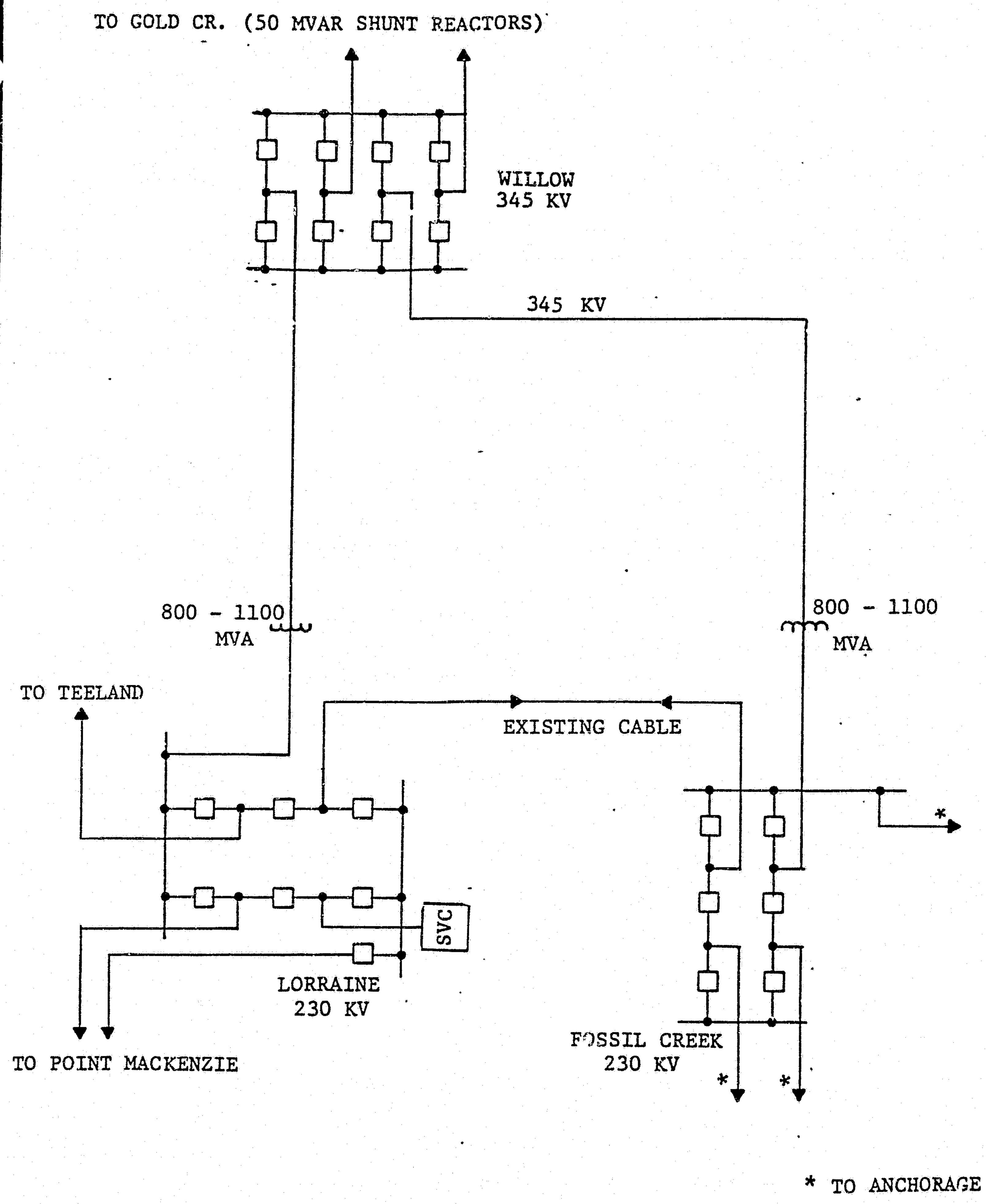


ALASKA POWER AUTHORITY

SUSITNA HYDROELECTRIC PROJECT

SUSITNA-ANCHORAGE SWITCHING
MODIFIED FERC PLAN J 2
THREE CIRCUIT STAGE
IF COORDINATED WITH CABLE UPGRADE

FIGURE 8B

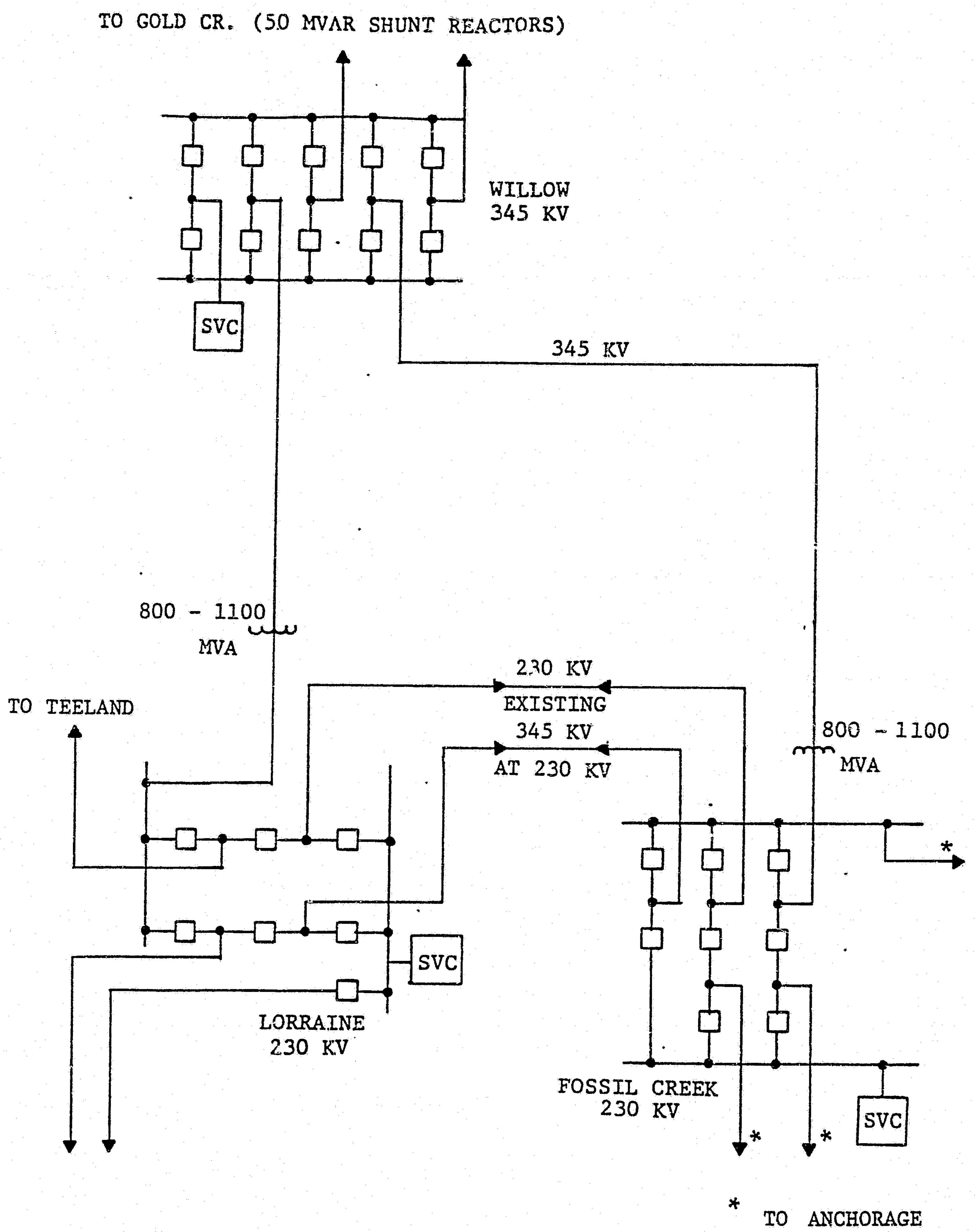


ALASKA POWER AUTHORITY

SUSITNA HYDROELECTRIC PROJECT

SUSITNA-ANCHORAGE SWITCHING
PLAN SS
TWO CIRCUIT STAGE

FIGURE 9

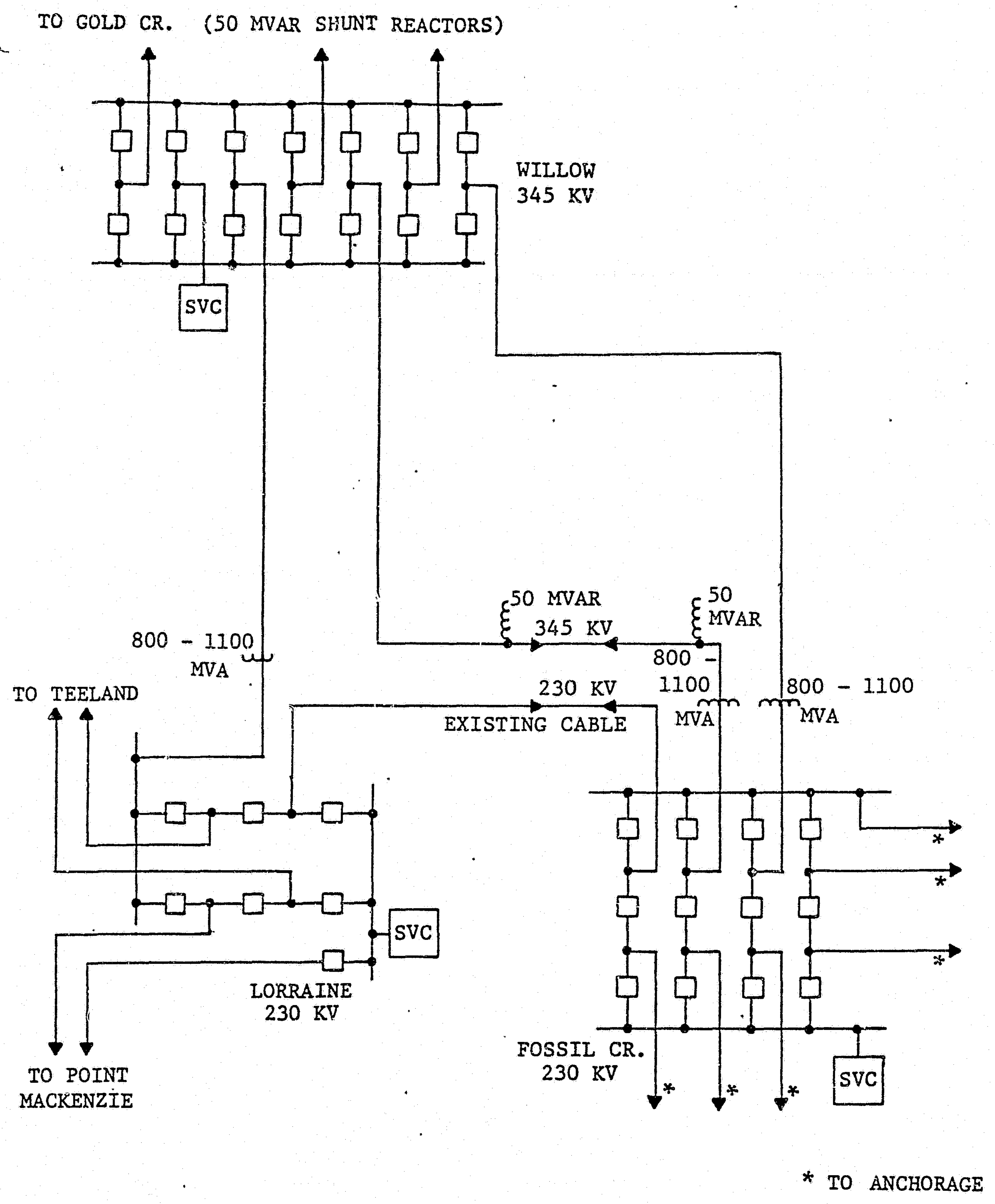


ALASKA POWER AUTHORITY

SUSITNA HYDROELECTRIC PROJECT

SUSITNA-ANCHORAGE SWITCHING PLAN SS WITH FIRST NEW CABLE

FIGURE 10



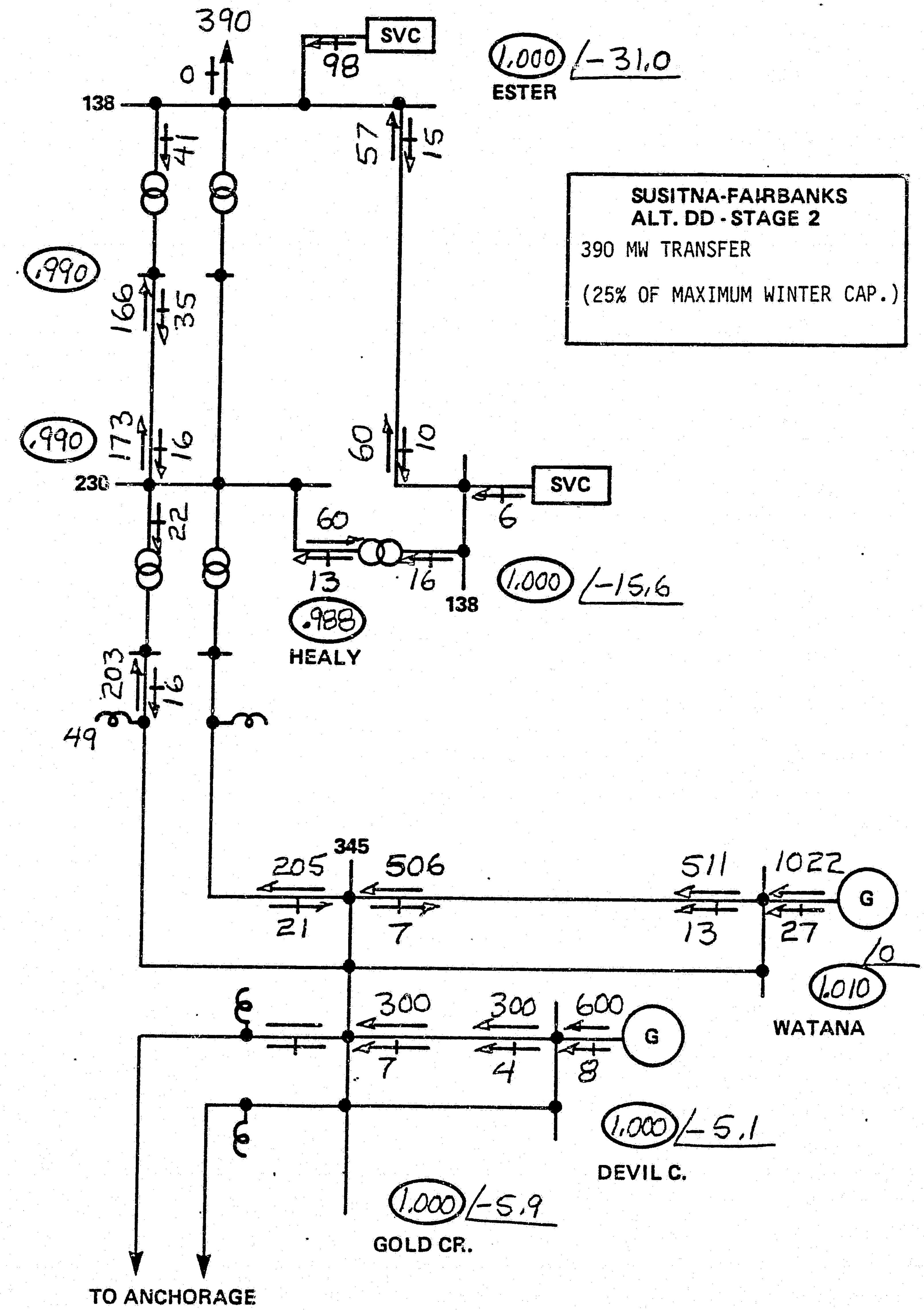
ALASKA POWER AUTHORITY

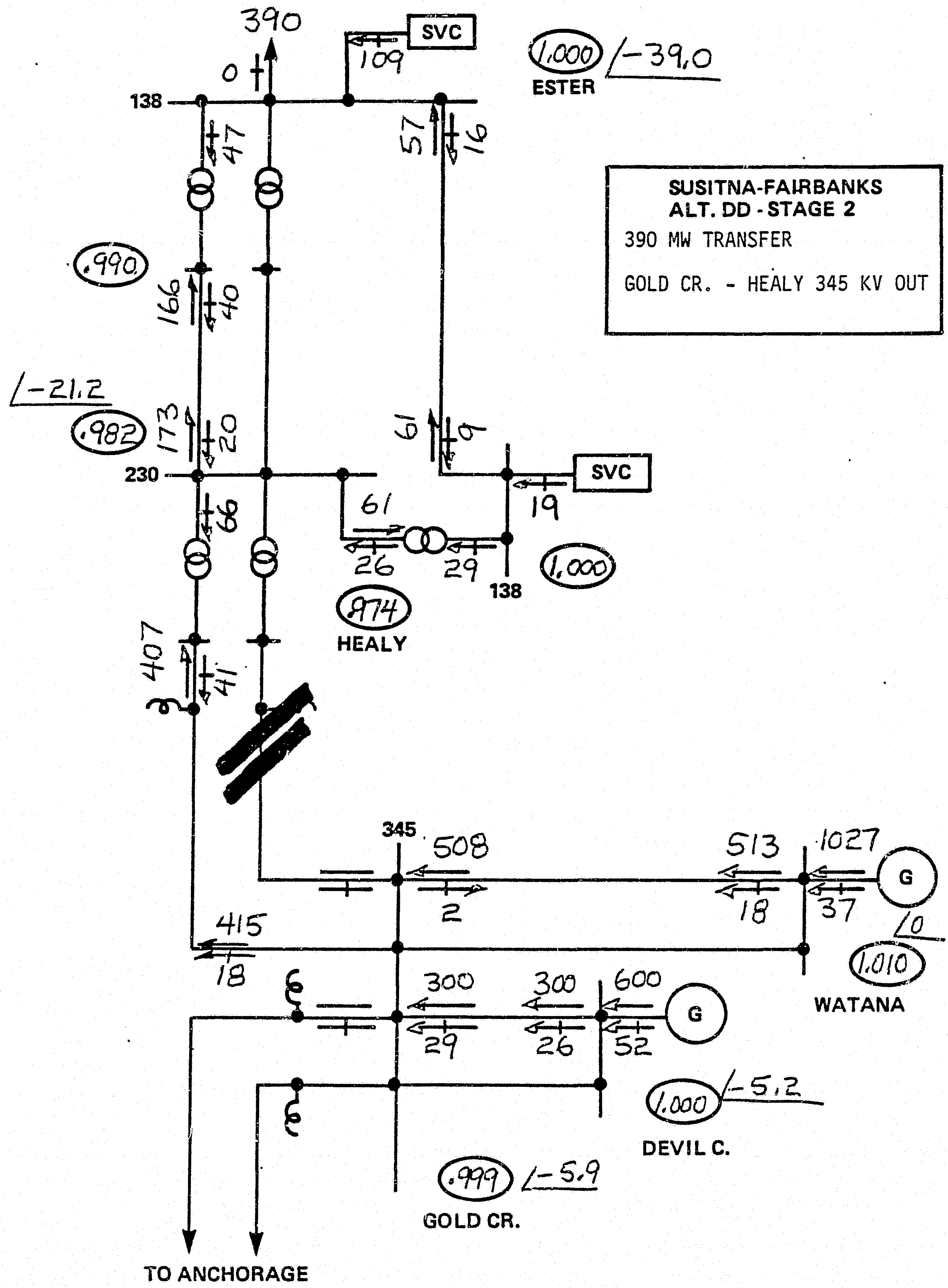
SUSITNA HYDROELECTRIC PROJECT

SUSITNA-ANCHORAGE SWITCHING
PLAN SS
THREE CIRCUIT STAGE

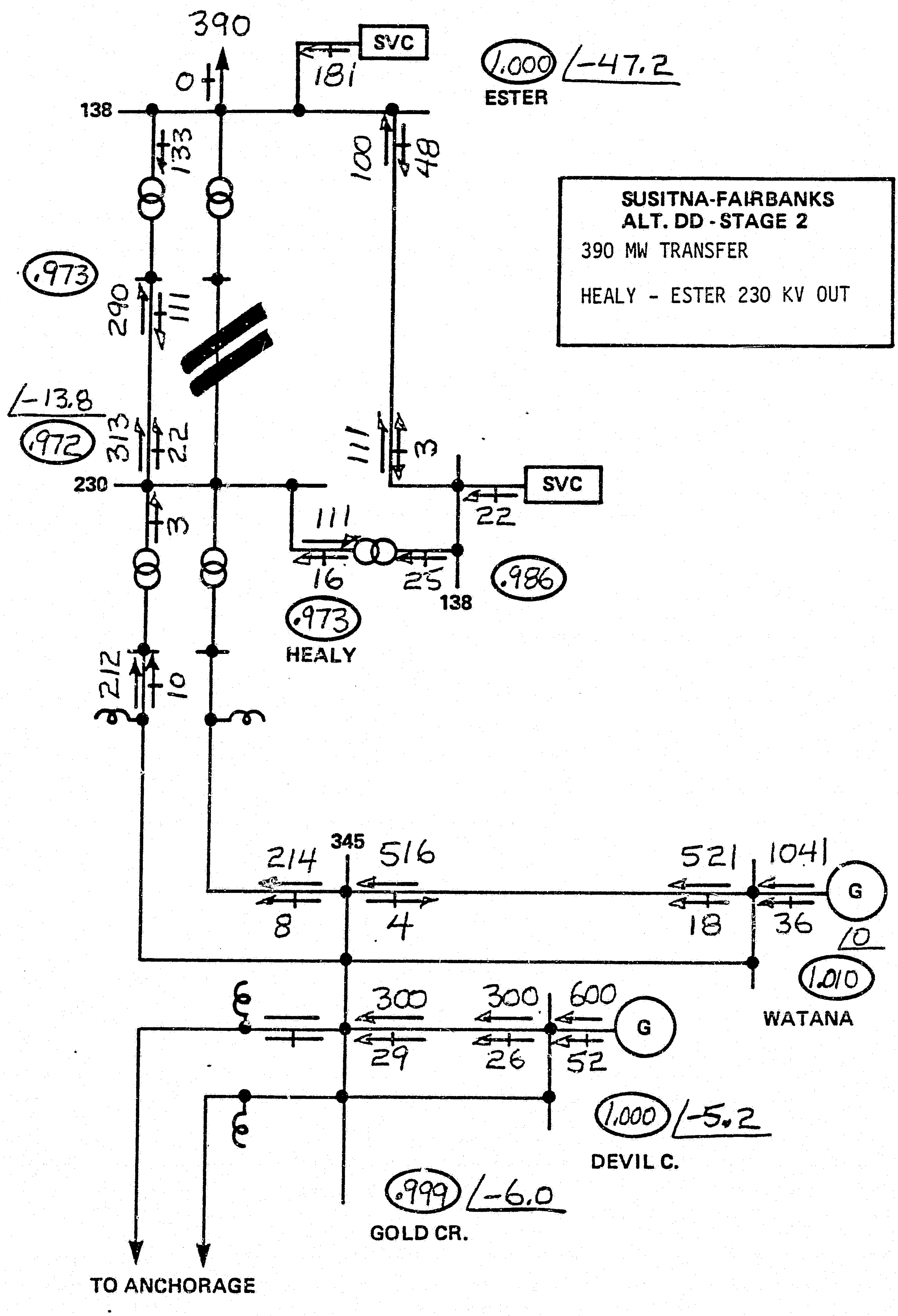
FIGURE 11

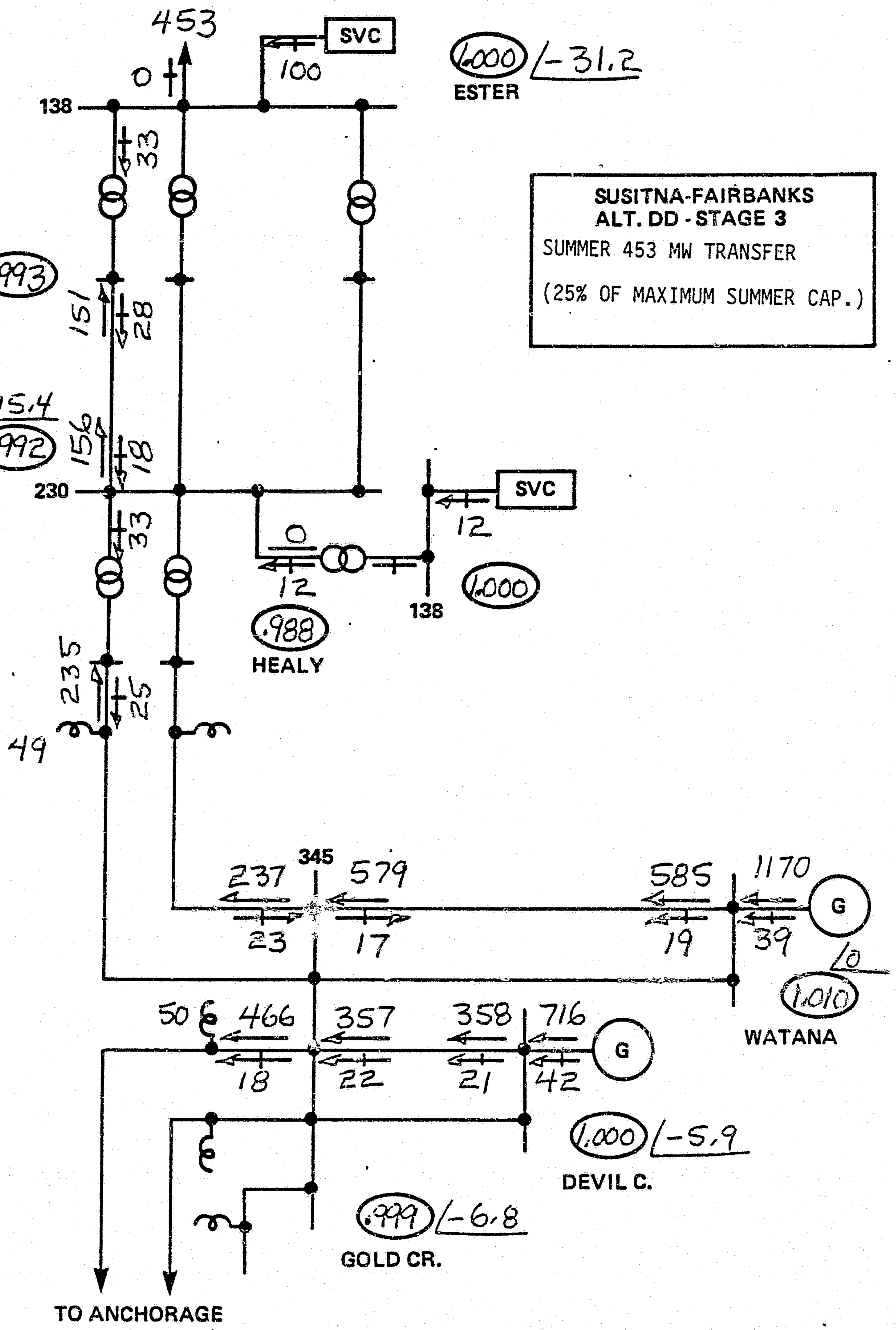
APPENDIX A

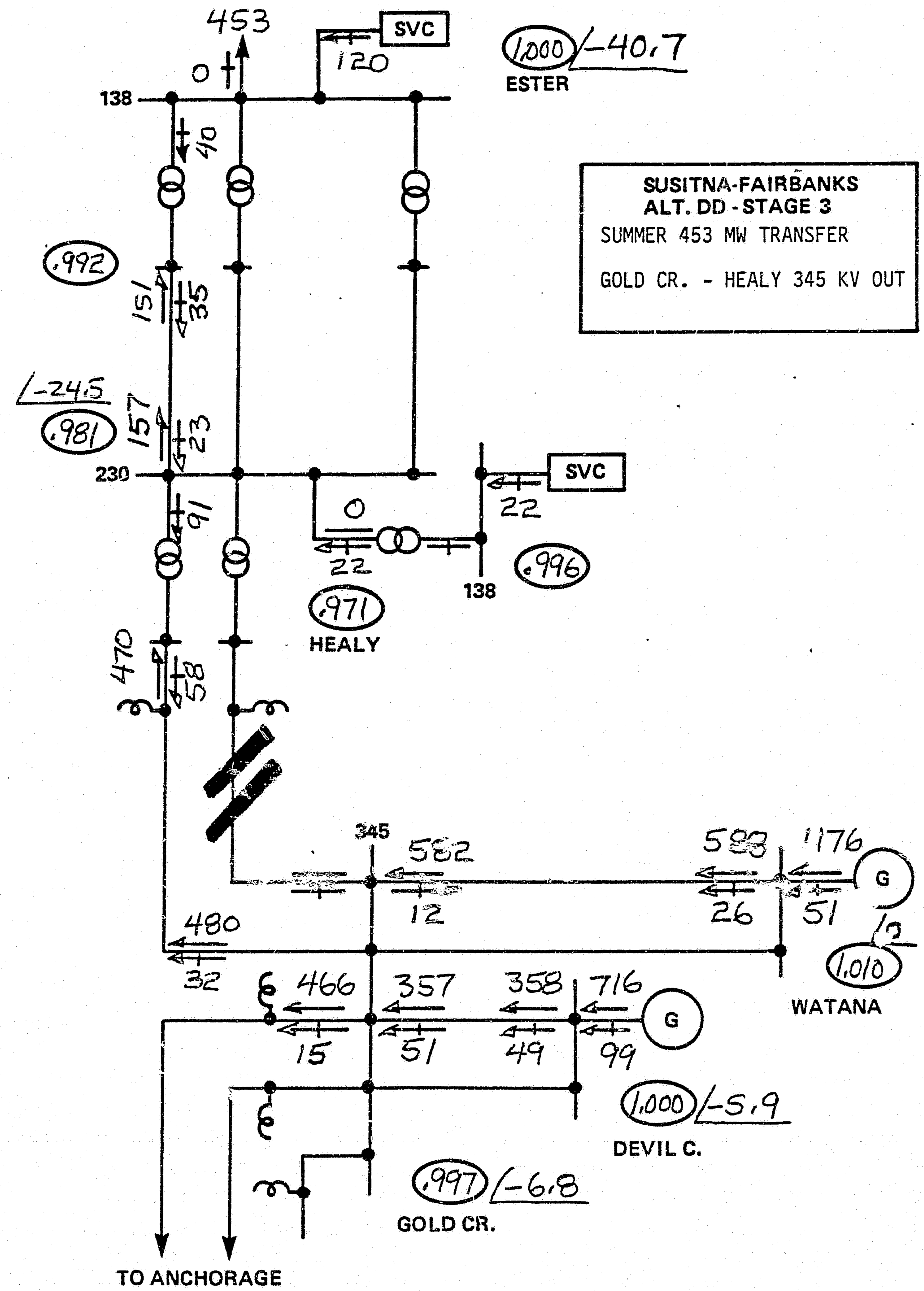

SUSITNA-FAIRBANKS
ALT. DD - STAGE 2
390 MW TRANSFER
(25% OF MAXIMUM WINTER CAP.)
390
0
SVC
98
1,000 /-31,0
ESTER
138
41
57
15
.990
166
35
.990
173
16
60
10
230
SVC
6
22
60
13
16
1,000 /-15,6
138
.988
HEALY
203
16
49
345
205
506
511
1022
G
21
7
13
27
/0
1.010
WATANA
300
300
600
G
7
4
8
1,000 /-5,1
DEVIL C.
1,000 /-5,9
GOLD CR.
TO ANCHORAGE

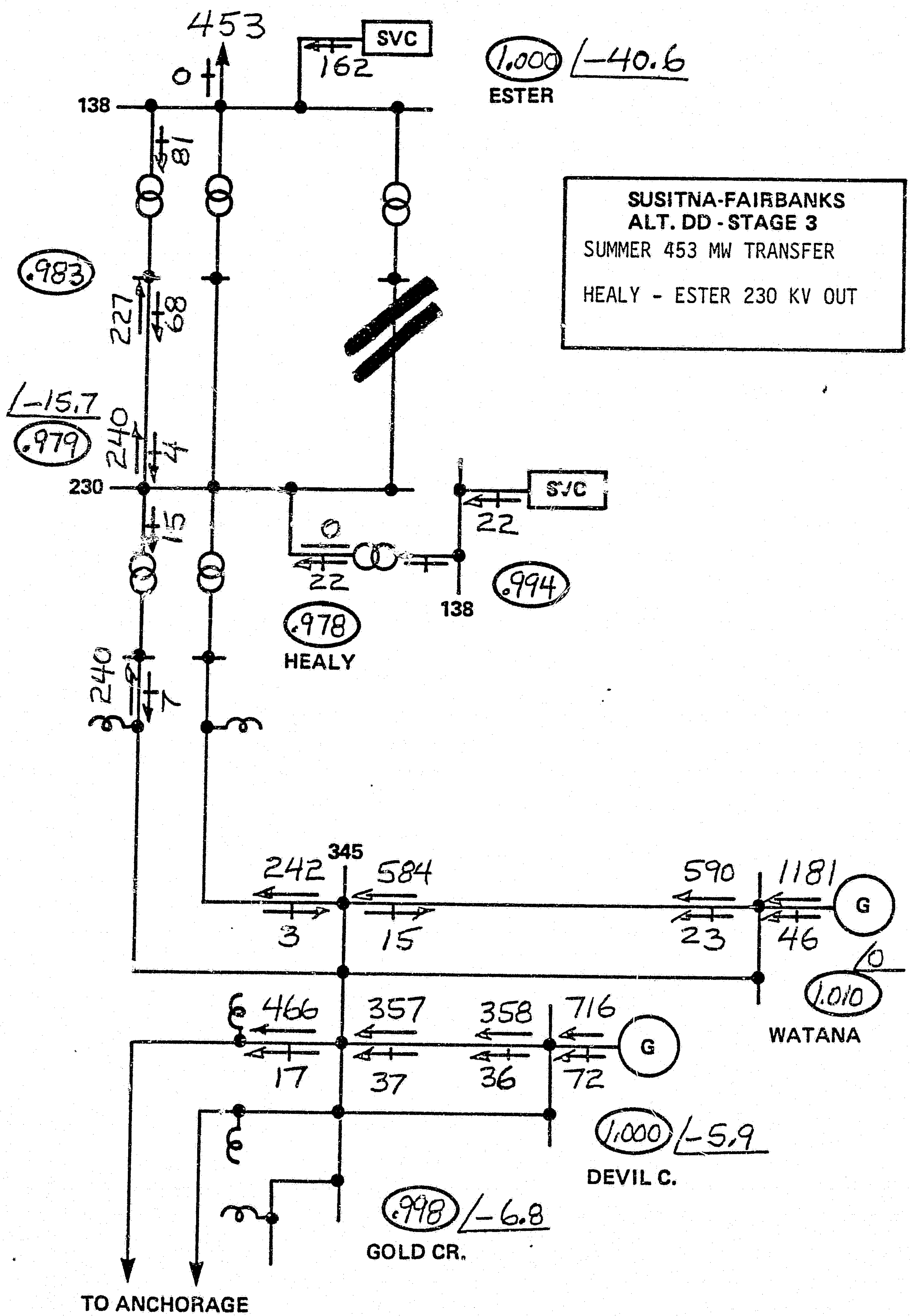


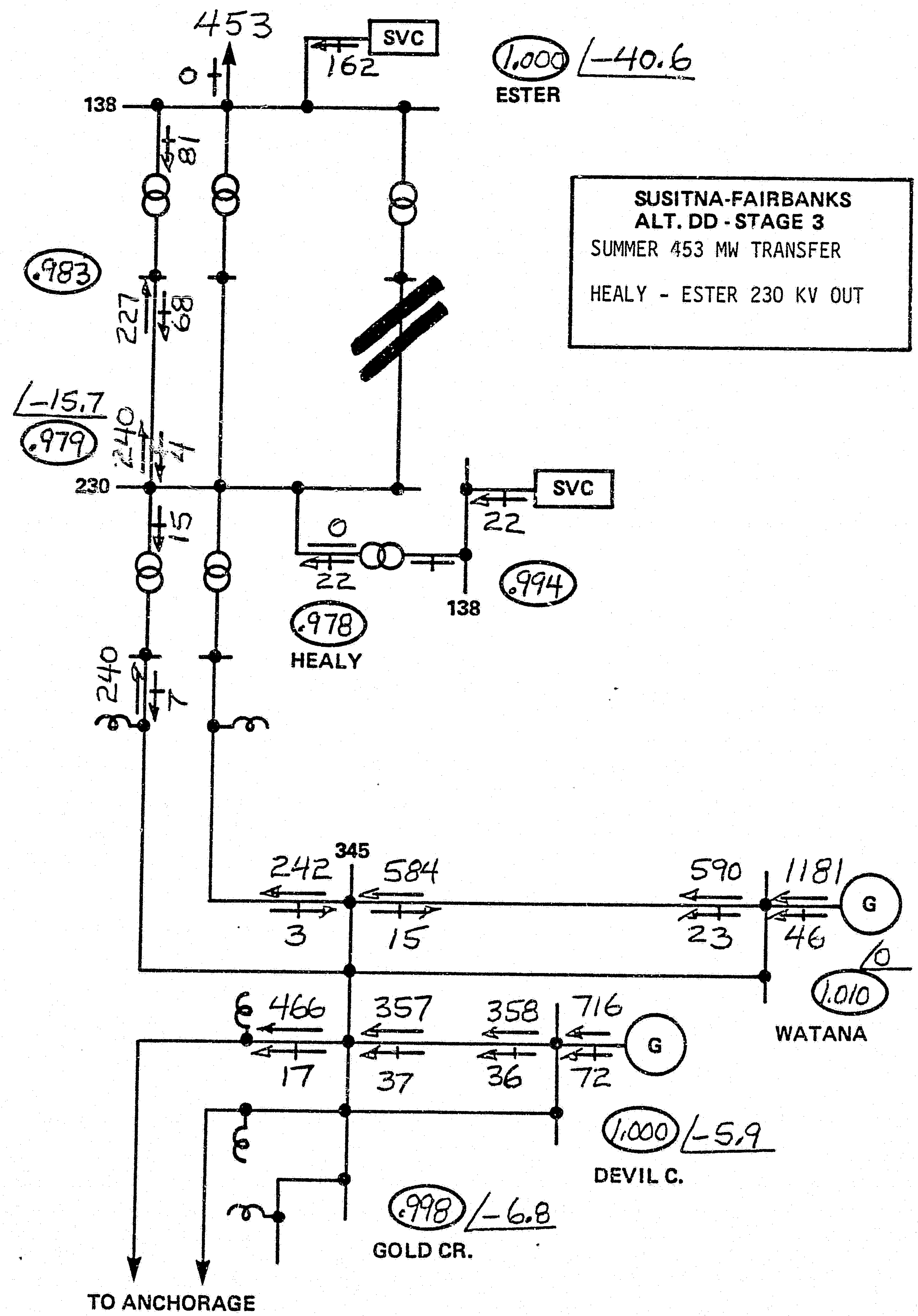
SUSITNA-FAIRBANKS
ALT. DD - STAGE 2
390 MW TRANSFER
GOLD CR. - HEALY 345 KV OUT
390
SVC
109
1.000
/-39.0
ESTER
138
47
57
16
.990
166
40
/-21.2
.982
173
20
61
9
230
SVC
19
66
61
26
29
1.000
138
.974
HEALY
407
41
345
508
513
1027
G
2
18
37
/0
1.010
WATANA
415
18
300
300
600
G
29
26
52
1.000
/-5.2
DEVIL C.
.999
/-5.9
GOLD CR.
TO ANCHORAGE


SUSITNA-FAIRBANKS
ALT. DD - STAGE 2
390 MW TRANSFER
HEALY - ESTER 230 KV OUT
ESTER
HEALY
WATANA
DEVIL C.
GOLD CR.
TO ANCHORAGE
SVC
SVC
G
G
138
230
138
345
390
0
181
1.000
-47.2
133
100
48
.973
290
111
-13.8
.972
313
22
111
3
3
22
111
16
25
.986
.973
212
10
214
516
521
1041
8
4
18
36
0
1.010
300
300
600
29
26
52
1.000
-5.2
.999
-6.0


SUSITNA-FAIRBANKS
ALT. DD - STAGE 3
SUMMER 453 MW TRANSFER
(25% OF MAXIMUM SUMMER CAP.)
453
0
SVC
100
1.000 ∠-31.2
ESTER
138
33
.993
151
28
∠-15.4
.992
156
18
230
33
SVC
12
0
12
1.000
138
.988
HEALY
235
25
49
345
237
579
585
1170
G
23
17
19
39
∠0
1.010
WATANA
50
466
357
358
716
G
18
22
21
42
1.000 ∠-5.9
DEVIL C.
.999 ∠-6.8
GOLD CR.
TO ANCHORAGE

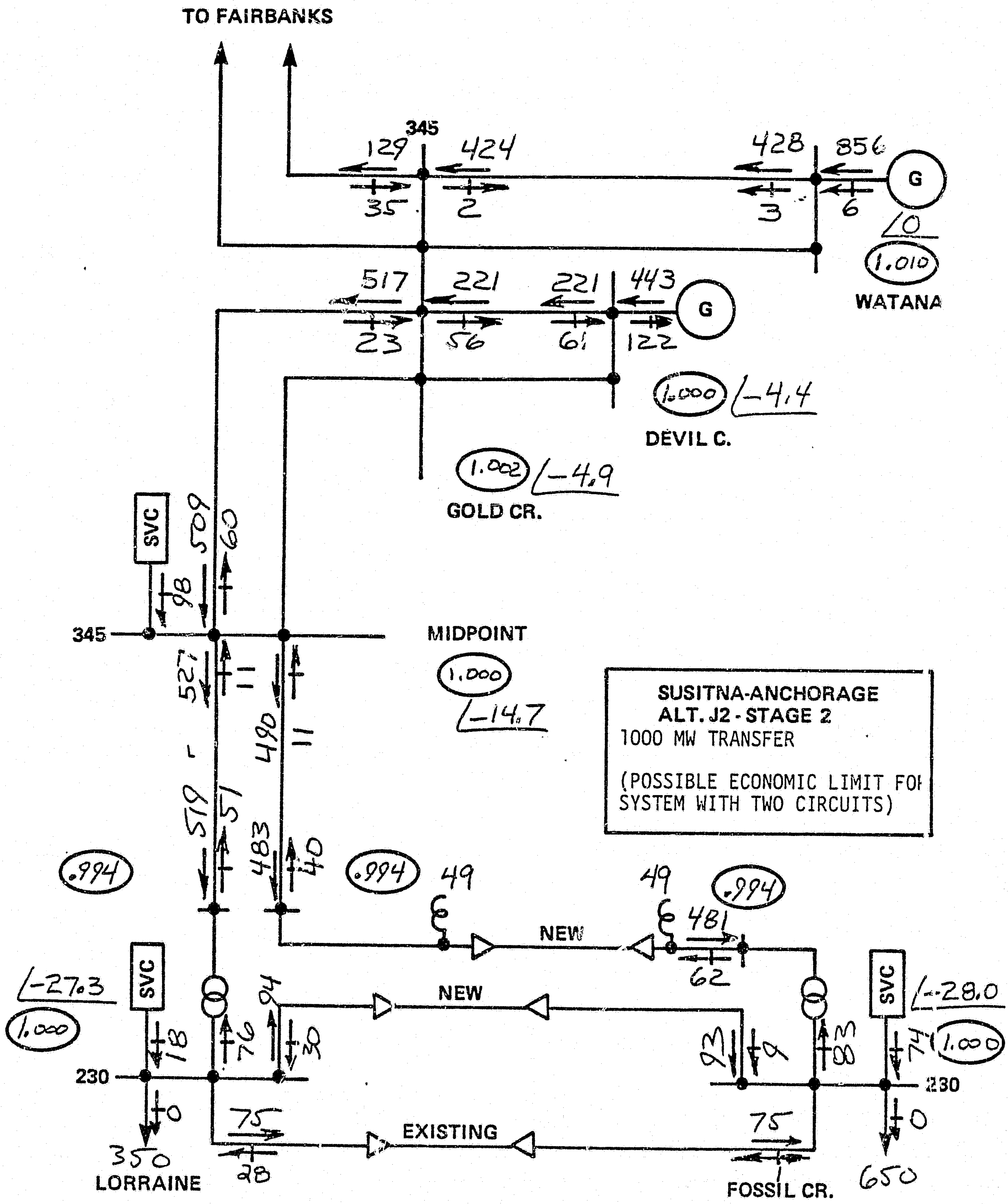

SUSITNA-FAIRBANKS
ALT. DD - STAGE 3
SUMMER 453 MW TRANSFER
GOLD CR. - HEALY 345 KV OUT
453
SVC
120
0
1.000 /-40.7
ESTER
138
40
.992
151
35
/-24.5
.981
157
23
230
91
SVC
22
0
22
138
.996
.971
HEALY
470
58
345
582
12
583
26
1176
51
G
480
32
1.010
WATANA
466
15
357
51
358
49
716
99
G
1.000 /-5.9
DEVIL C.
.997 /-6.8
GOLD CR.
TO ANCHORAGE

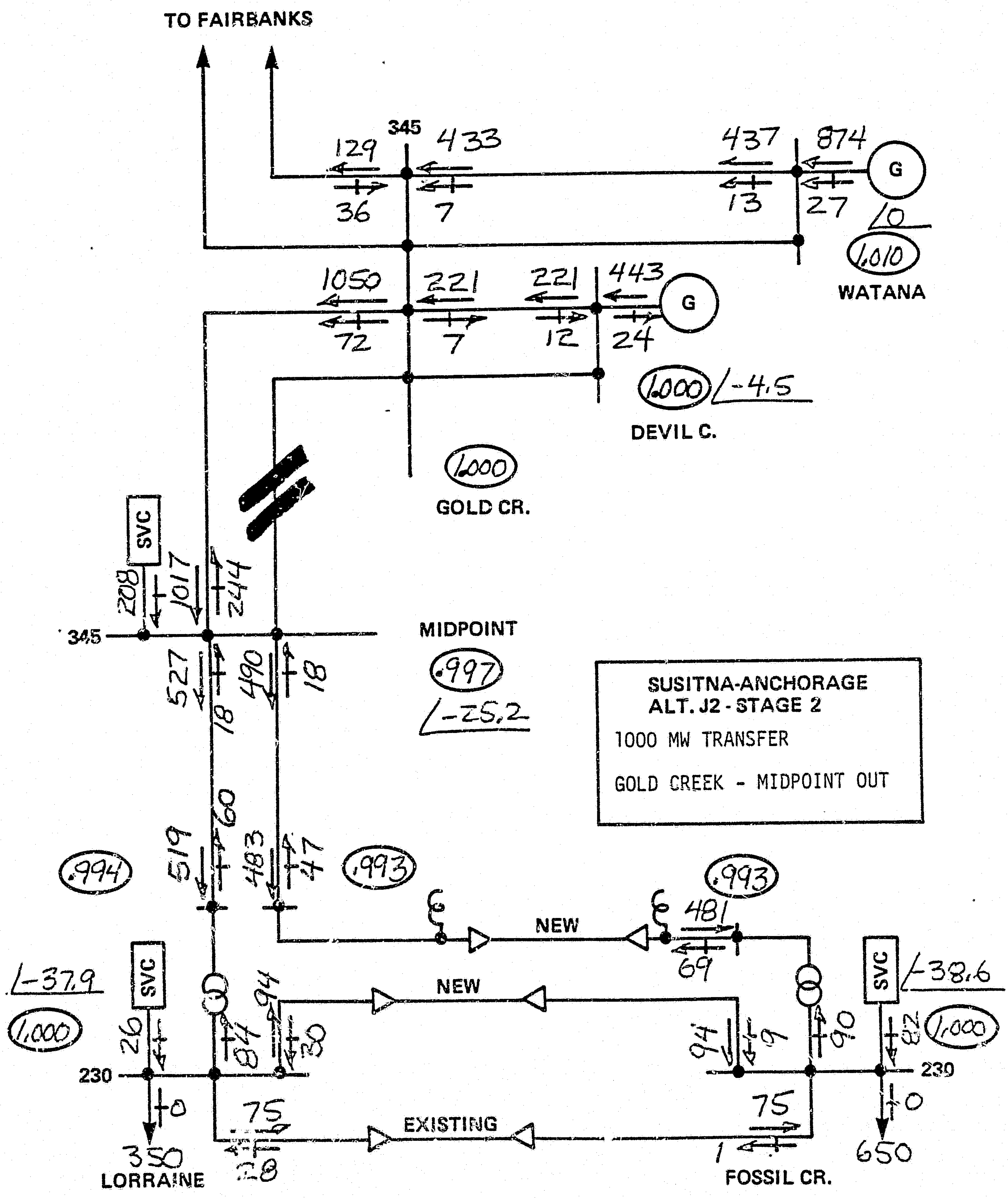

SUSITNA-FAIRBANKS
ALT. DD - STAGE 3
SUMMER 453 MW TRANSFER
HEALY - ESTER 230 KV OUT
453
SVC
162
1,000 /-40.6
ESTER
138
.983
227
68
81
/-15.7
.979
240
4
230
15
0
22
SVC
22
.994
138
.978
HEALY
240
7
345
242
584
590
1181
G
3
15
23
46
0
1.010
WATANA
466
357
358
716
G
17
37
36
72
1,000 /-5.9
DEVIL C.
.998 /-6.8
GOLD CR.
TO ANCHORAGE



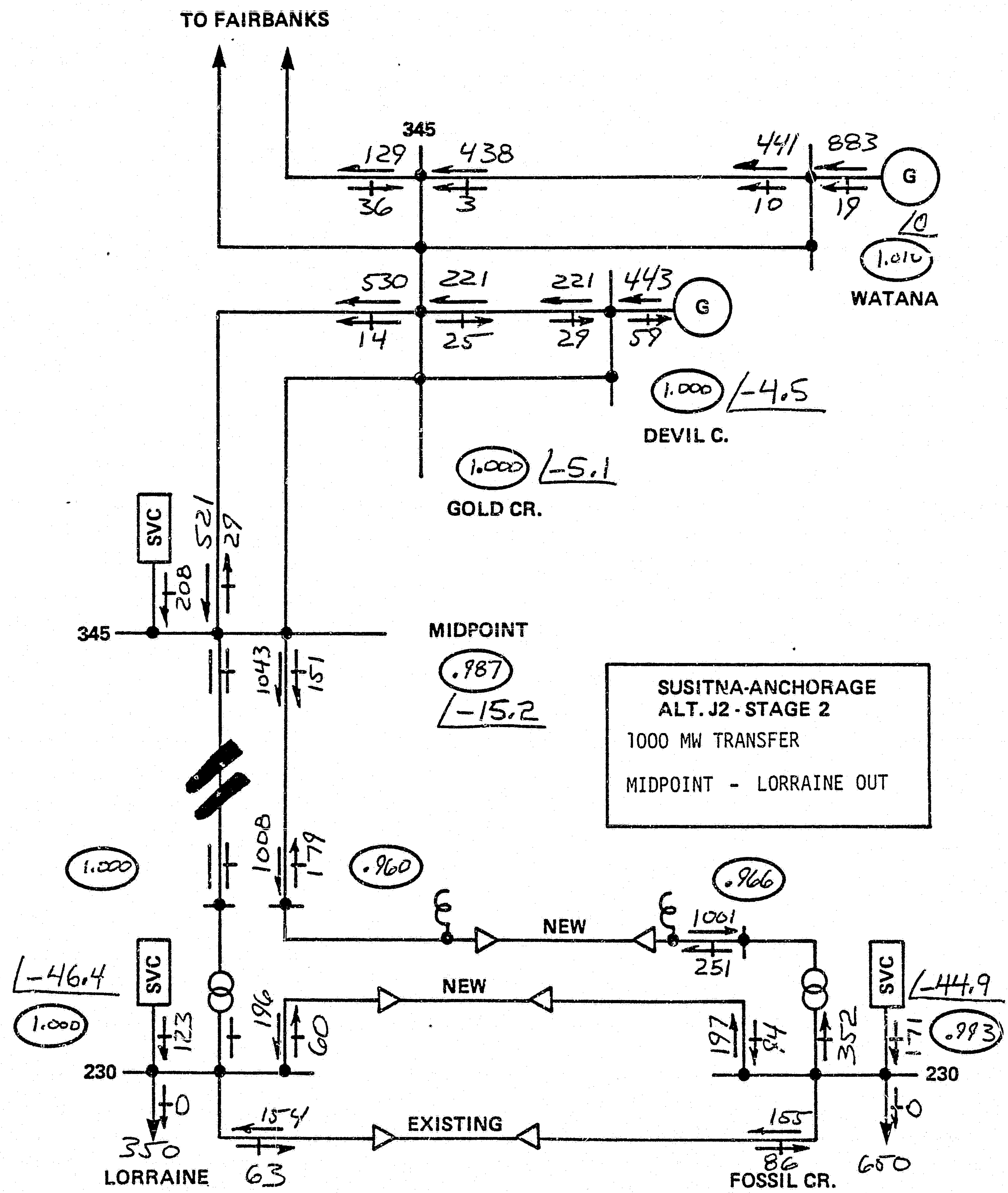
SUSITNA-FAIRBANKS
ALT. DD - STAGE 3
SUMMER 453 MW TRANSFER
HEALY - ESTER 230 KV OUT
453
SVC
162
1.000
-40.6
ESTER
138
0
81
.983
227
89
-15.7
.979
240
41
230
15
SVC
22
0
22
.994
138
.978
HEALY
240
7
345
242
584
590
1181
G
3
15
23
46
0
1.010
WATANA
466
357
358
716
G
17
37
36
72
1.000
-5.9
DEVIL C.
.998
-6.8
GOLD CR.
TO ANCHORAGE

APPENDIX B


TO FAIRBANKS
345
129
424
428
856
35
2
3
6
G
∠0
1.010
WATANA
517
221
221
443
23
56
61
122
G
1.000
∠-4.4
DEVIL C.
1.002
∠-4.9
GOLD CR.
SVC
509
60
98
345
MIDPOINT
1.000
∠-14.7
527
11
490
11
SUSITNA-ANCHORAGE
ALT. J2 - STAGE 2
1000 MW TRANSFER
(POSSIBLE ECONOMIC LIMIT FOR
SYSTEM WITH TWO CIRCUITS)
519
51
483
40
.994
.994
.994
49
49
481
62
NEW
NEW
SVC
∠-27.3
1.000
18
76
94
30
23
9
83
SVC
∠-28.0
74
1.000
230
230
0
75
EXISTING
75
0
350
28
LORRAINE
FOSSIL CR.
650


TO FAIRBANKS
345
129
433
36
7
437
874
13
27
G
/0
1.010
WATANA
1050
221
221
443
72
7
12
24
G
1.000
/-4.5
DEVIL C.
1.000
GOLD CR.
SVC
208
1017
244
345
MIDPOINT
.997
/-25.2
527
18
490
18
SUSITNA-ANCHORAGE
ALT. J2 - STAGE 2
1000 MW TRANSFER
GOLD CREEK - MIDPOINT OUT
60
519
483
47
.994
.993
.993
NEW
481
69
/-37.9
SVC
94
NEW
SVC
/-38.6
1.000
26
84
30
94
9
90
82
1.000
230
230
0
75
EXISTING
75
0
350
28
1
650
LORRAINE
FOSSIL CR.

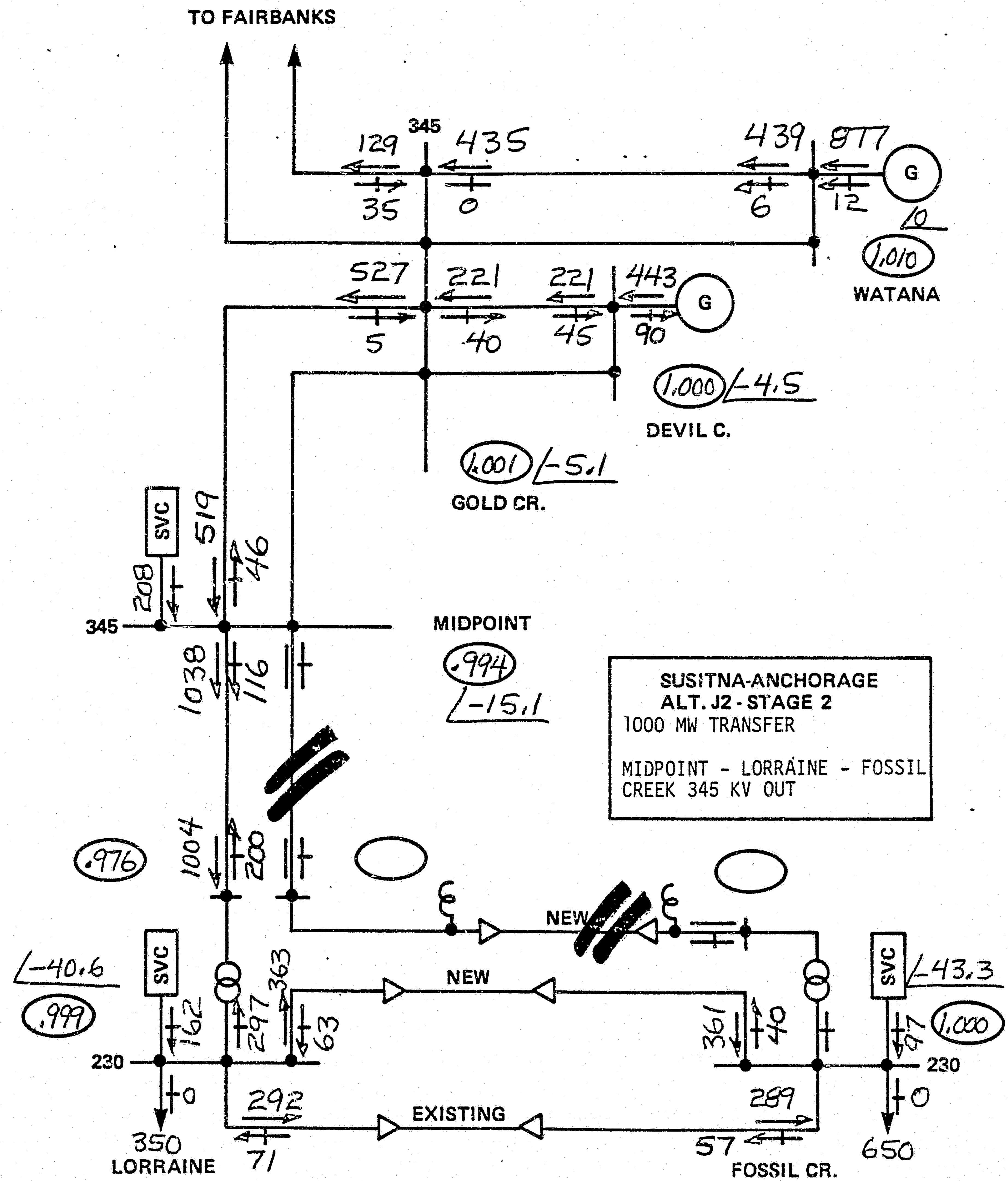
F-2

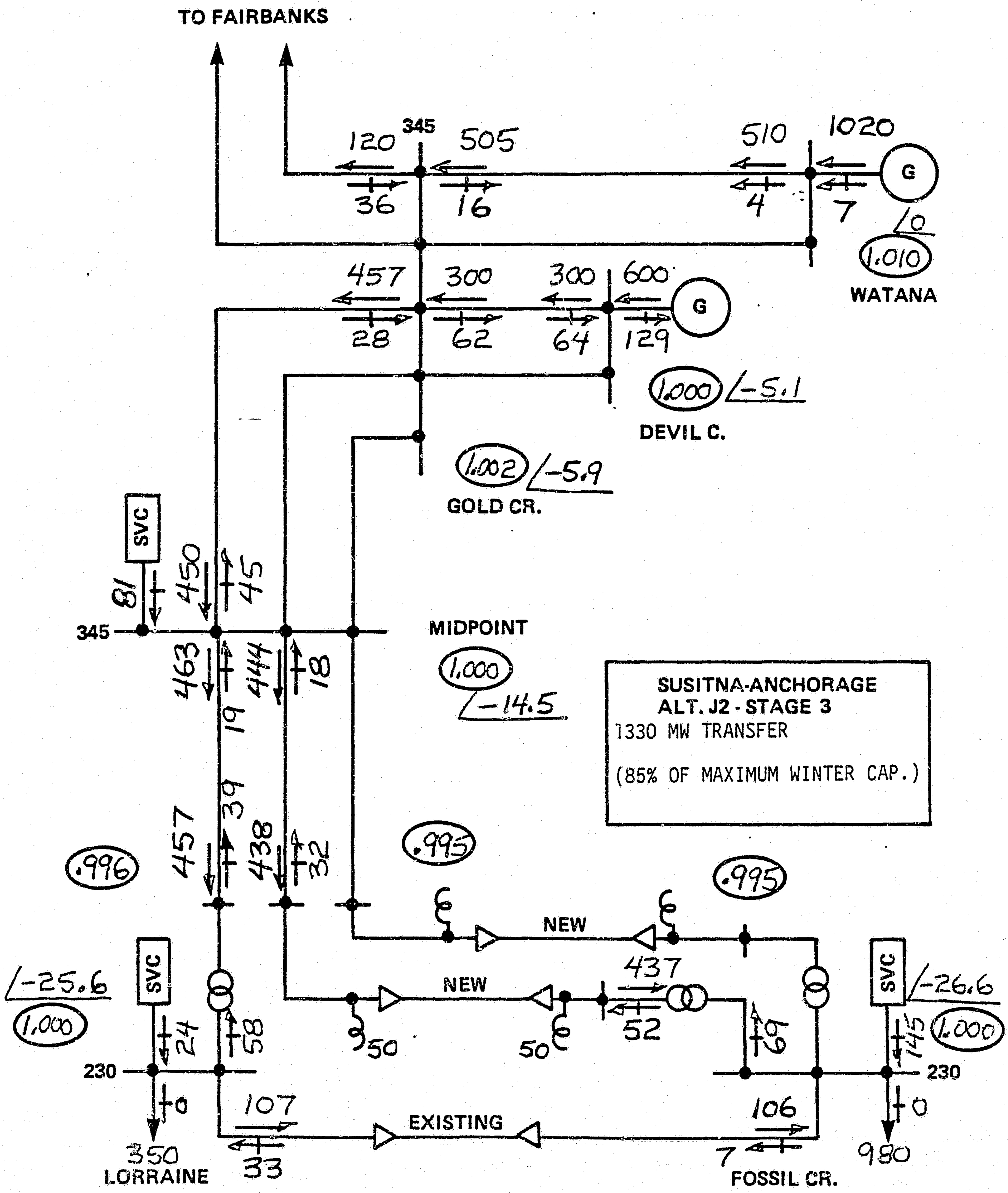


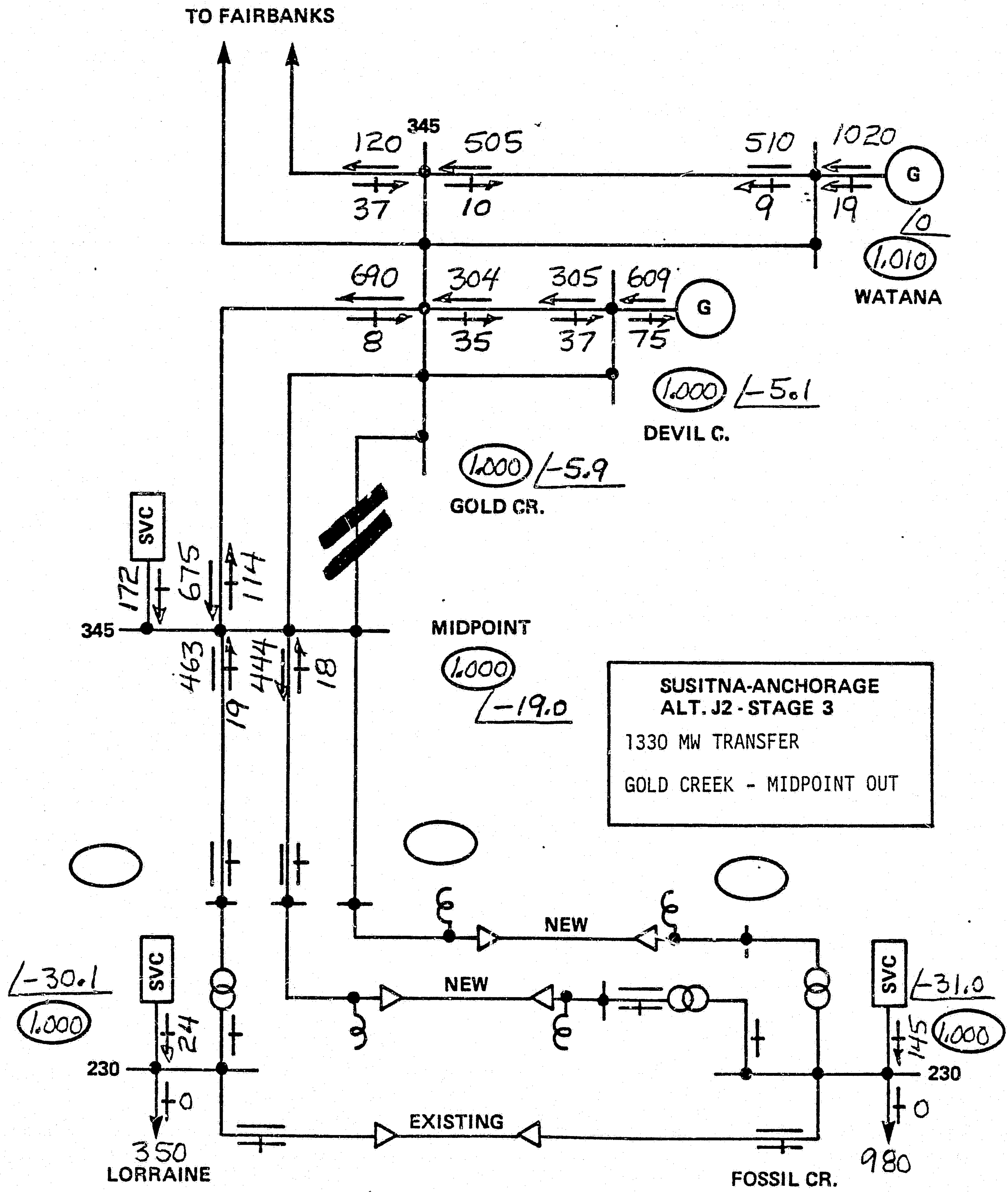
SUSITNA-ANCHORAGE
ALT. J2 - STAGE 2

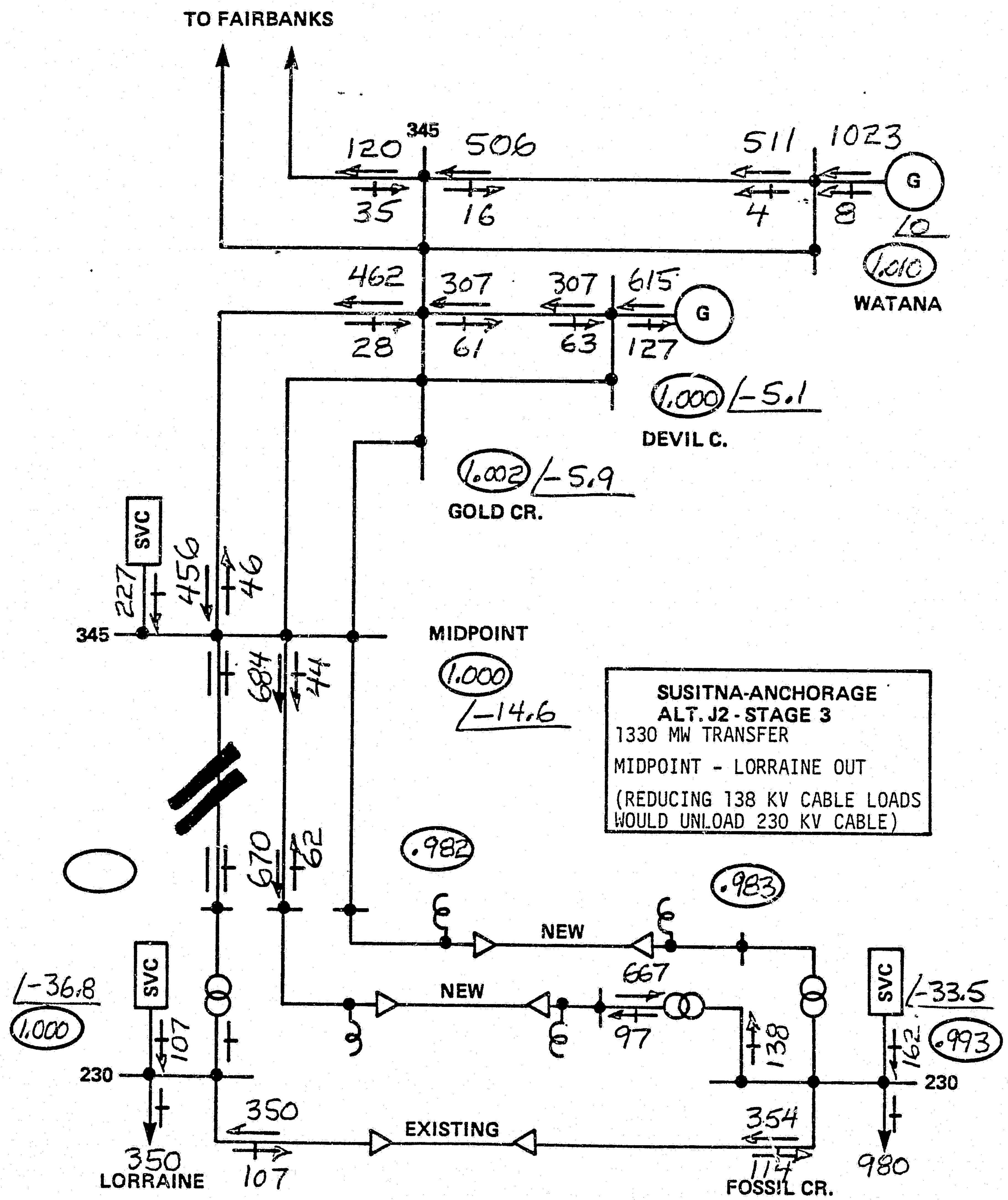
1000 MW TRANSFER

MIDPOINT - LORRAINE OUT

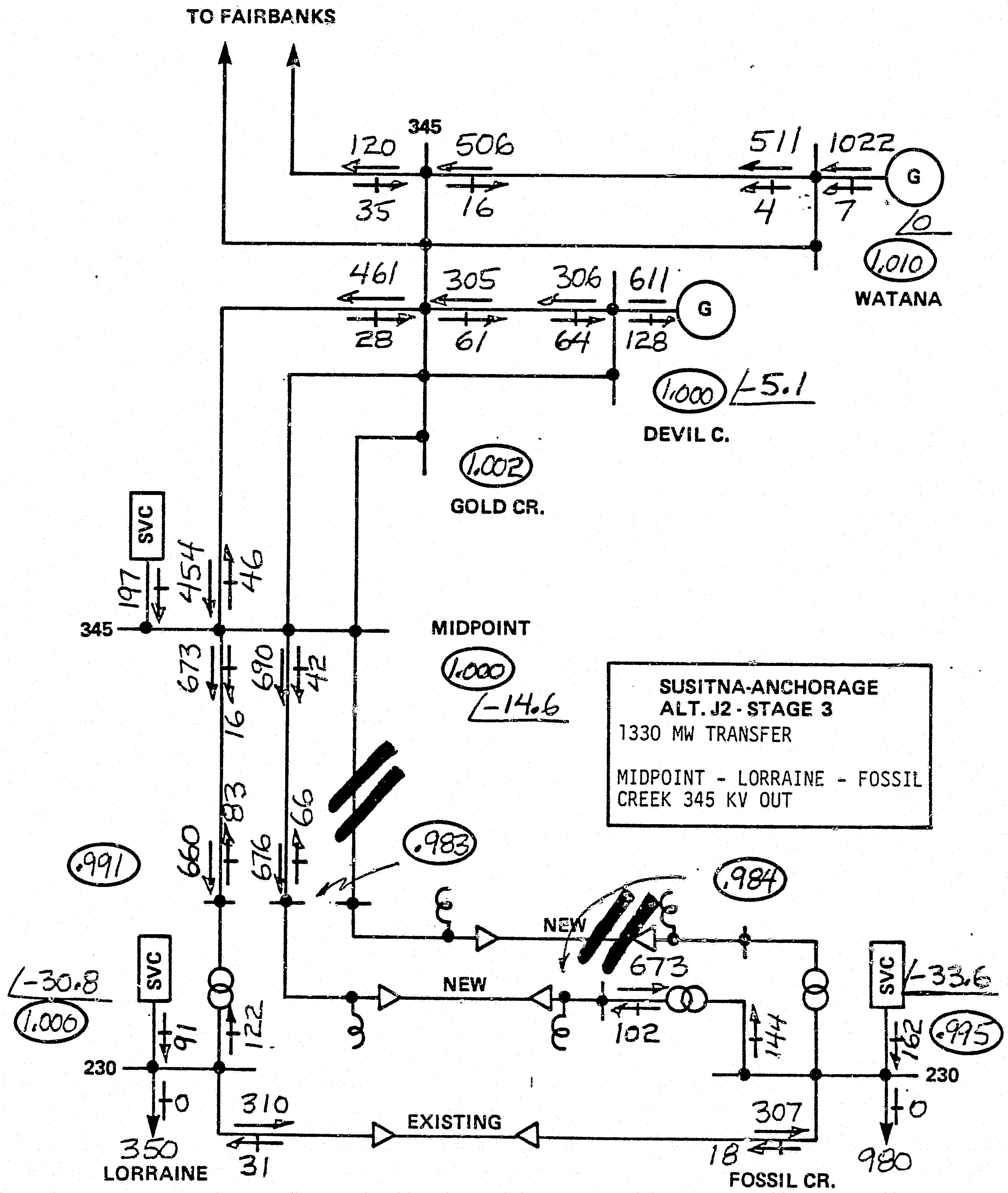

TO FAIRBANKS
345
129
435
439
877
35
0
6
12
G
/0
1.010
WATANA
527
221
221
443
G
5
40
45
90
1.000 /-4.5
DEVIL C.
1.001 /-5.1
GOLD CR.
SVC
519
46
208
345
MIDPOINT
.994
/-15.1
1038
116
SUSITNA-ANCHORAGE
ALT. J2 - STAGE 2
1000 MW TRANSFER
MIDPOINT - LORRAINE - FOSSIL
CREEK 345 KV OUT
.976
1004
200
NEW
SVC
/-40.6
.999
363
162
297
63
NEW
361
40
SVC
/43.3
97
1.000
230
230
0
292
EXISTING
289
0
350
LORRAINE
71
57
650
FOSSIL CR.


TO FAIRBANKS
345
120
505
36
16
510
1020
4
7
G
1.010
WATANA
457
300
300
600
28
62
64
129
G
1.000
-5.1
DEVIL C.
1.002
-5.9
GOLD CR.
SVC
81
450
45
345
MIDPOINT
463
444
18
19
1.000
-14.5
SUSITNA-ANCHORAGE
ALT. J2 - STAGE 3
1330 MW TRANSFER
(85% OF MAXIMUM WINTER CAP.)
39
457
438
32
.996
.995
.995
NEW
NEW
437
52
50
50
69
SVC
-25.6
1.000
24
58
230
SVC
-26.6
145
1.000
230
0
107
EXISTING
106
0
350
LORRAINE
33
7
980
FOSSIL CR.


TO FAIRBANKS
345
120
505
37
10
510
1020
9
19
G
0
1.010
WATANA
690
304
305
609
8
35
37
75
G
1.000
-5.1
DEVIL C.
1.000
-5.9
GOLD CR.
SVC
172
675
114
345
463
19
444
18
MIDPOINT
1.000
-19.0
SUSITNA-ANCHORAGE
ALT. J2 - STAGE 3
1330 MW TRANSFER
GOLD CREEK - MIDPOINT OUT
NEW
NEW
-30.1
1.000
SVC
24
230
0
350
LORRAINE
EXISTING
SVC
-31.0
145
1.000
230
0
980
FOSSIL CR.



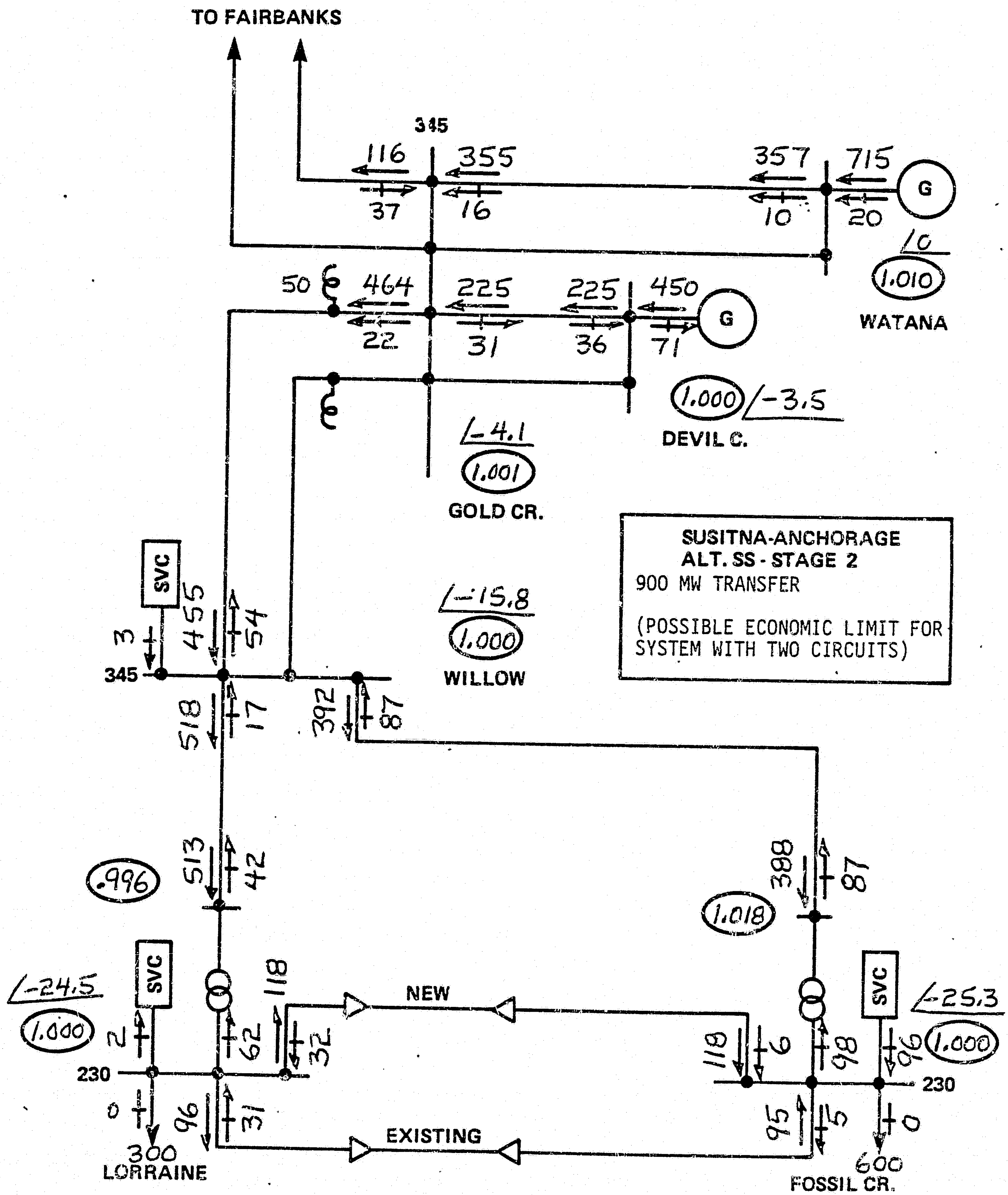
TO FAIRBANKS
345
120
506
511
1023
G
35
16
4
8
1.010
WATANA
462
307
307
615
G
28
61
63
127
1.000
-5.1
DEVIL C.
1.002
-5.9
GOLD CR.
SVC
227
456
46
345
MIDPOINT
1.000
-14.6
684
44
SUSITNA-ANCHORAGE
ALT. J2 - STAGE 3
1330 MW TRANSFER
MIDPOINT - LORRAINE OUT
(REDUCING 138 KV CABLE LOADS
WOULD UNLOAD 230 KV CABLE)
670
62
.982
.983
NEW
NEW
667
97
138
SVC
-36.8
1.000
107
230
SVC
-33.5
162
.993
230
350
EXISTING
354
350
LORRAINE
107
114
FOSSIL CR.
980

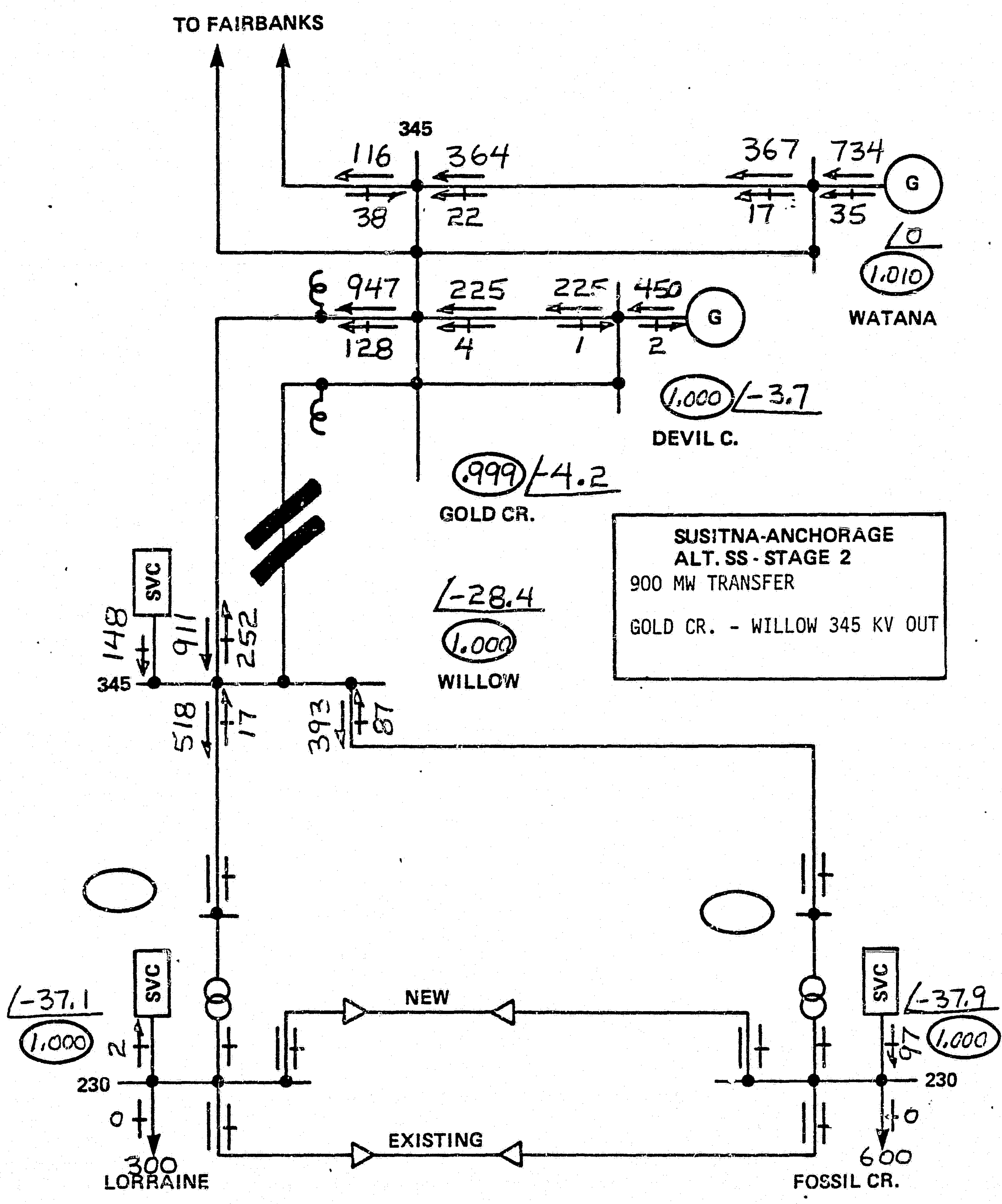


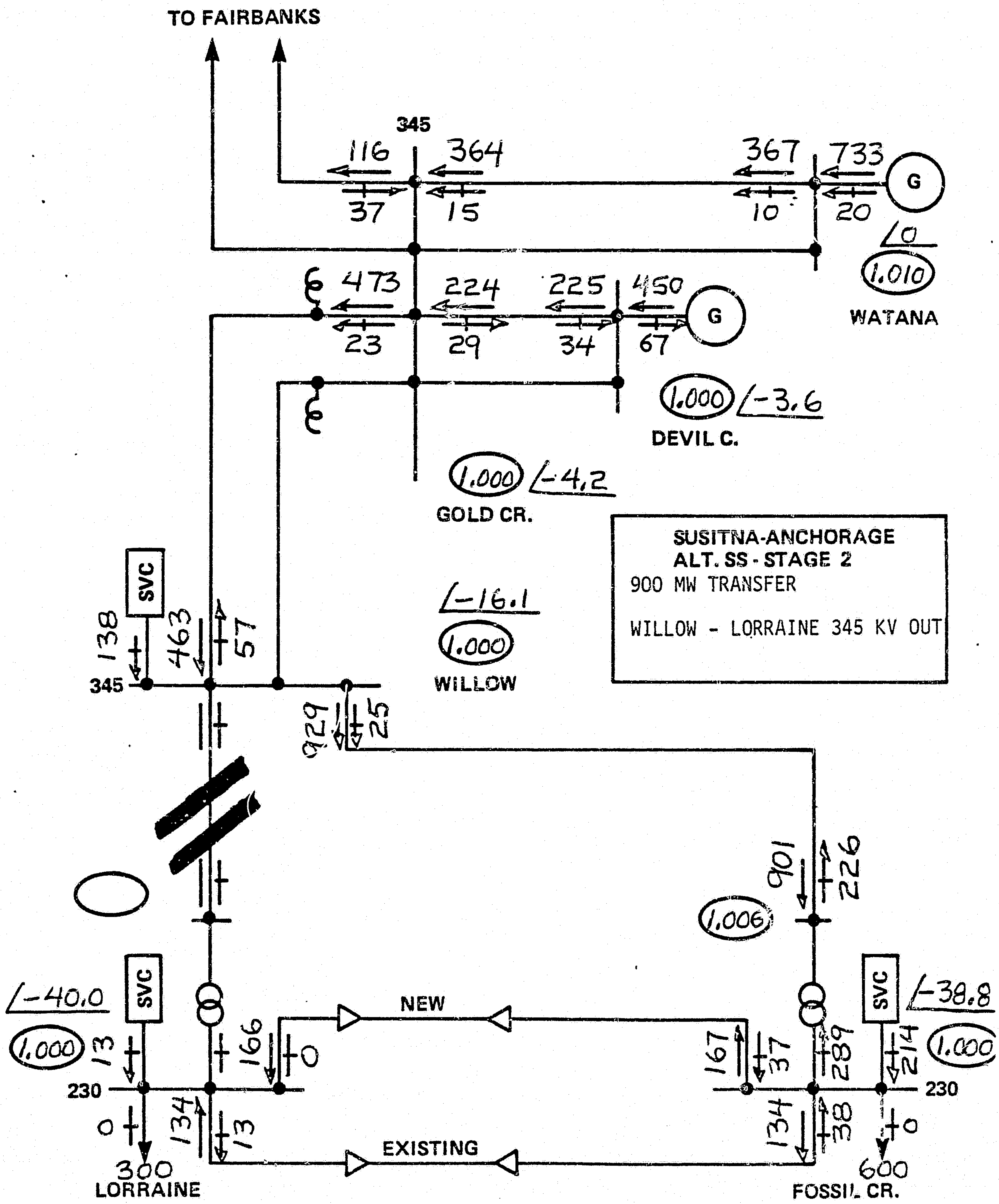
SUSITNA-ANCHORAGE
ALT. J2 - STAGE 3
1330 MW TRANSFER

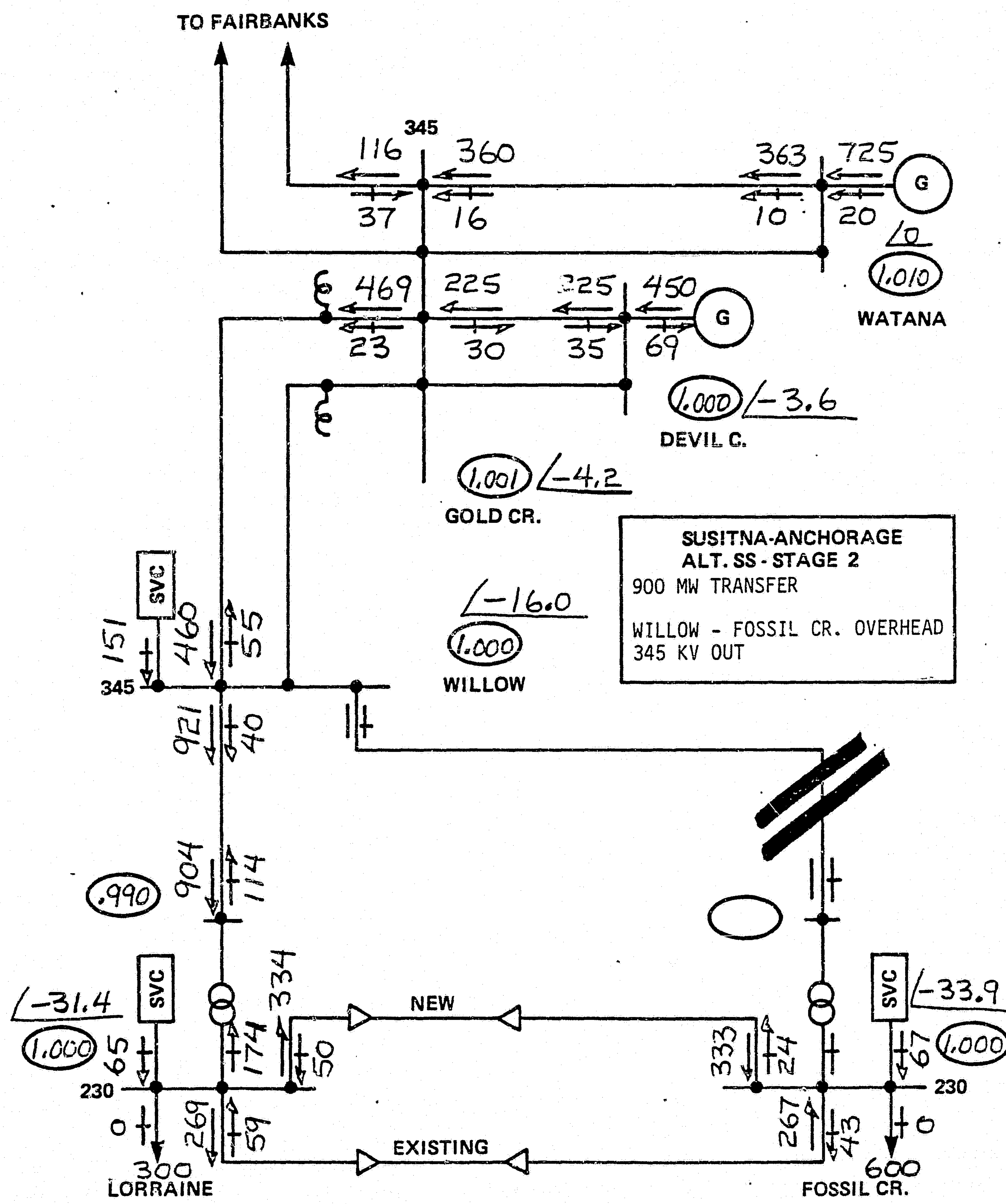
MIDPOINT - LORRAINE - FOSSIL CREEK 345 KV OUT

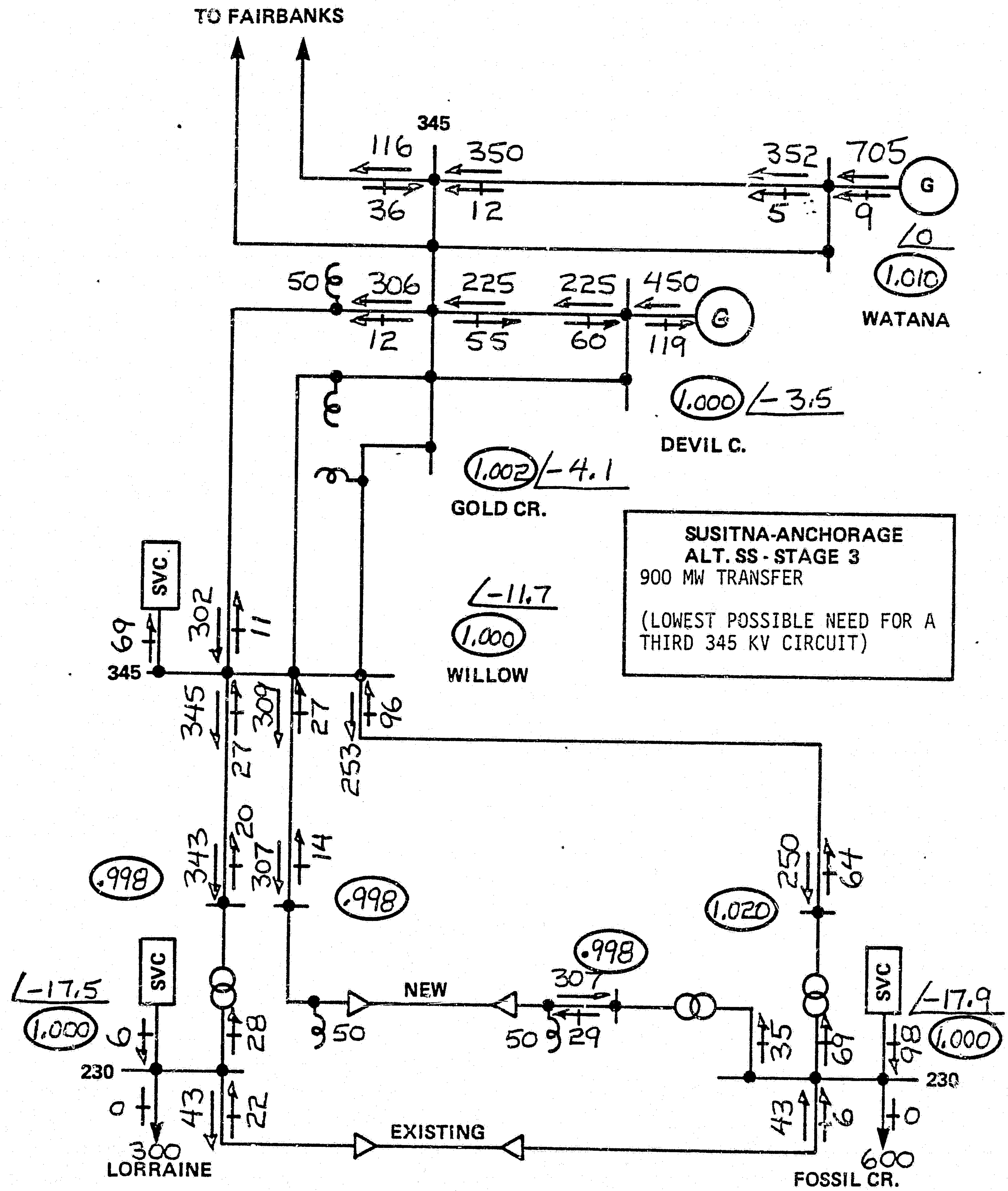
APPENDIX C


TO FAIRBANKS
345
116
355
357
715
G
37
16
10
20
/_0
1.010
WATANA
50
464
225
225
450
G
22
31
36
71
1.000
/_-3.5
DEVIL C.
/_-4.1
1.001
GOLD CR.
SUSITNA-ANCHORAGE
ALT. SS - STAGE 2
900 MW TRANSFER
(POSSIBLE ECONOMIC LIMIT FOR SYSTEM WITH TWO CIRCUITS)
SVC
3
455
54
345
/_-15.8
1.000
WILLOW
518
17
392
87
513
42
.996
388
87
1.018
/_-24.5
1.000
SVC
2
62
118
32
NEW
118
6
98
SVC
96
/_-25.3
1.000
230
230
0
96
31
300
LORRAINE
EXISTING
95
5
0
600
FOSSIL CR.

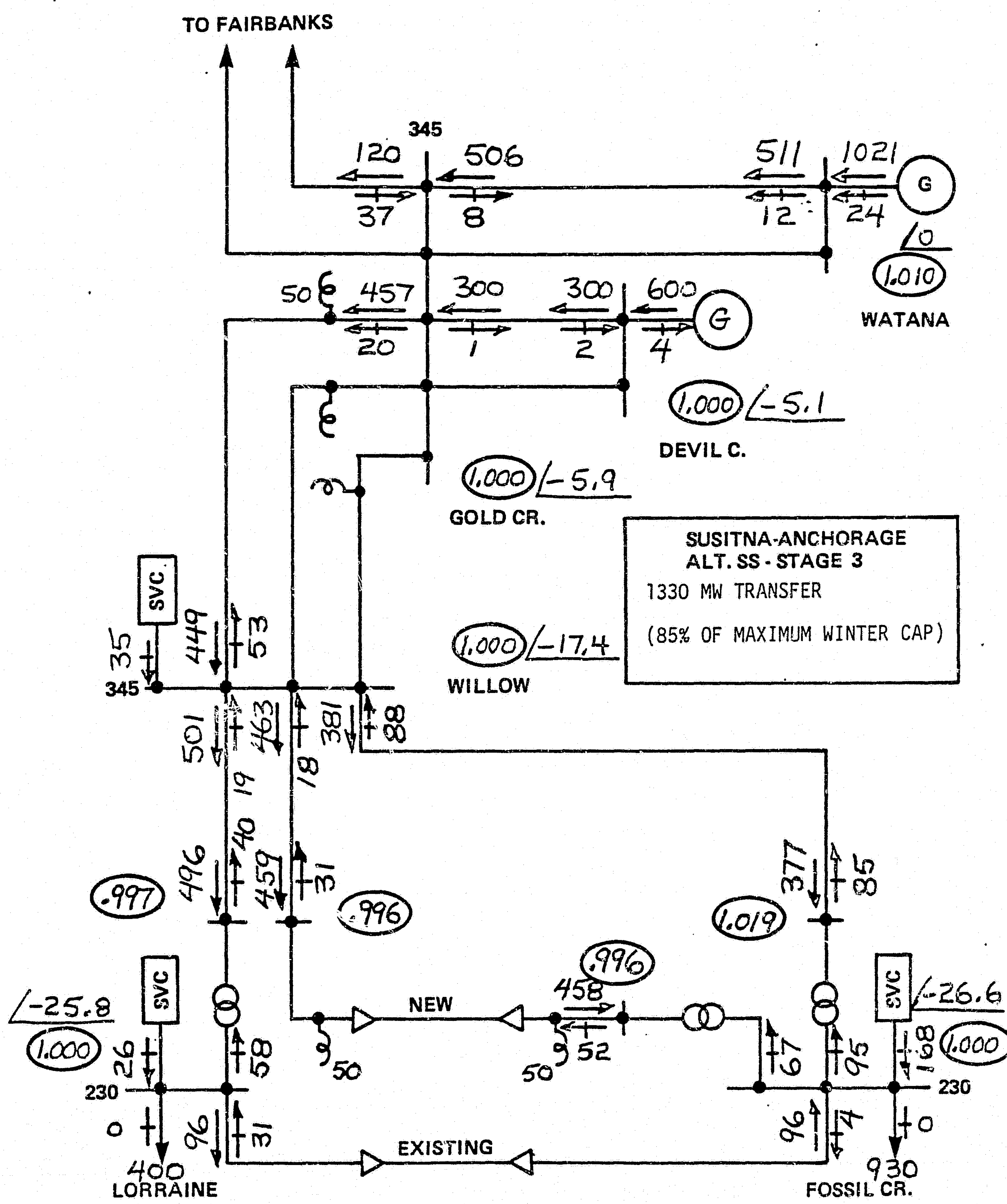

TO FAIRBANKS
345
116
364
38
22
367
734
17
35
G
/0
1.010
WATANA
947
225
225
450
128
4
1
2
G
1.000 /-3.7
DEVIL C.
.999 /-4.2
GOLD CR.
SUSITNA-ANCHORAGE
ALT. SS - STAGE 2
900 MW TRANSFER
GOLD CR. - WILLOW 345 KV OUT
SVC
148
911
252
/-28.4
1.000
WILLOW
345
518
17
393
87
SVC
/-37.1
1.000
2
NEW
SVC
/-37.9
97
1.000
230
230
0
0
EXISTING
300
LORRAINE
600
FOSSIL CR.


TO FAIRBANKS
345
116
364
37
15
367
733
10
20
G
/0
1.010
WATANA
473
224
225
450
23
29
34
67
G
1.000 /-3.6
DEVIL C.
1.000 /-4.2
GOLD CR.
SUSITNA-ANCHORAGE
ALT. SS - STAGE 2
900 MW TRANSFER
WILLOW - LORRAINE 345 KV OUT
SVC
138
463
57
345
/-16.1
1.000
WILLOW
929
25
901
226
1.006
/-40.0
1.000
SVC
13
166
0
230
NEW
167
37
289
SVC
214
/-38.8
1.000
230
0
134
13
EXISTING
134
38
0
300
LORRAINE
600
FOSSIL CR.

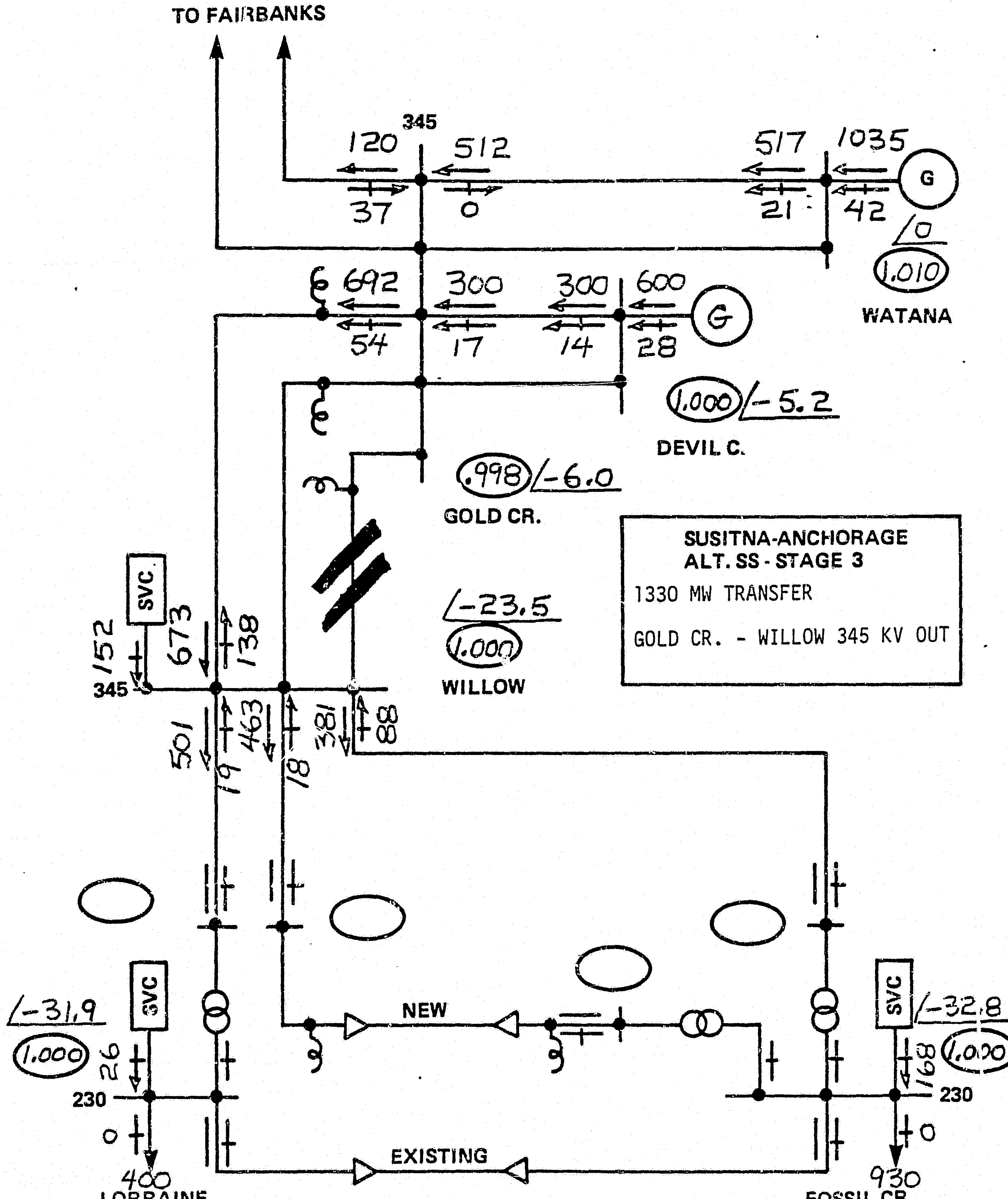

TO FAIRBANKS
345
116
360
37
16
363
725
10
20
G
1.010
WATANA
469
225
225
450
23
30
35
69
G
1.000
-3.6
DEVIL C.
1.001
-4.2
GOLD CR.
SUSITNA-ANCHORAGE
ALT. SS - STAGE 2
900 MW TRANSFER
WILLOW - FOSSIL CR. OVERHEAD
345 KV OUT
-16.0
1.000
WILLOW
SVC
151
460
55
345
921
40
904
114
.990
SVC
-31.4
1.000
65
174
334
50
NEW
333
24
SVC
-33.9
67
1.000
230
0
269
59
EXISTING
267
43
0
230
300
LORRAINE
600
FOSSIL CR.

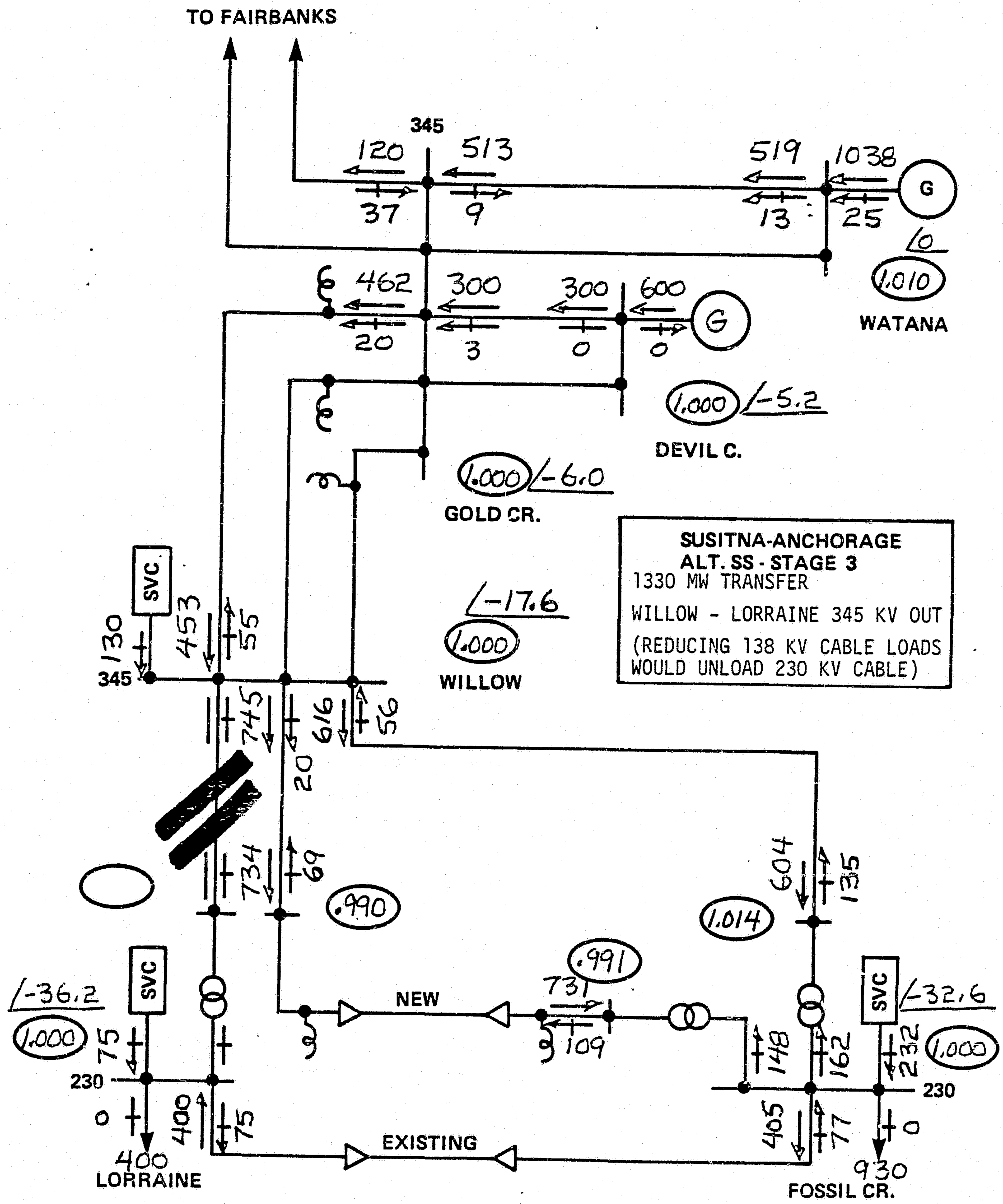


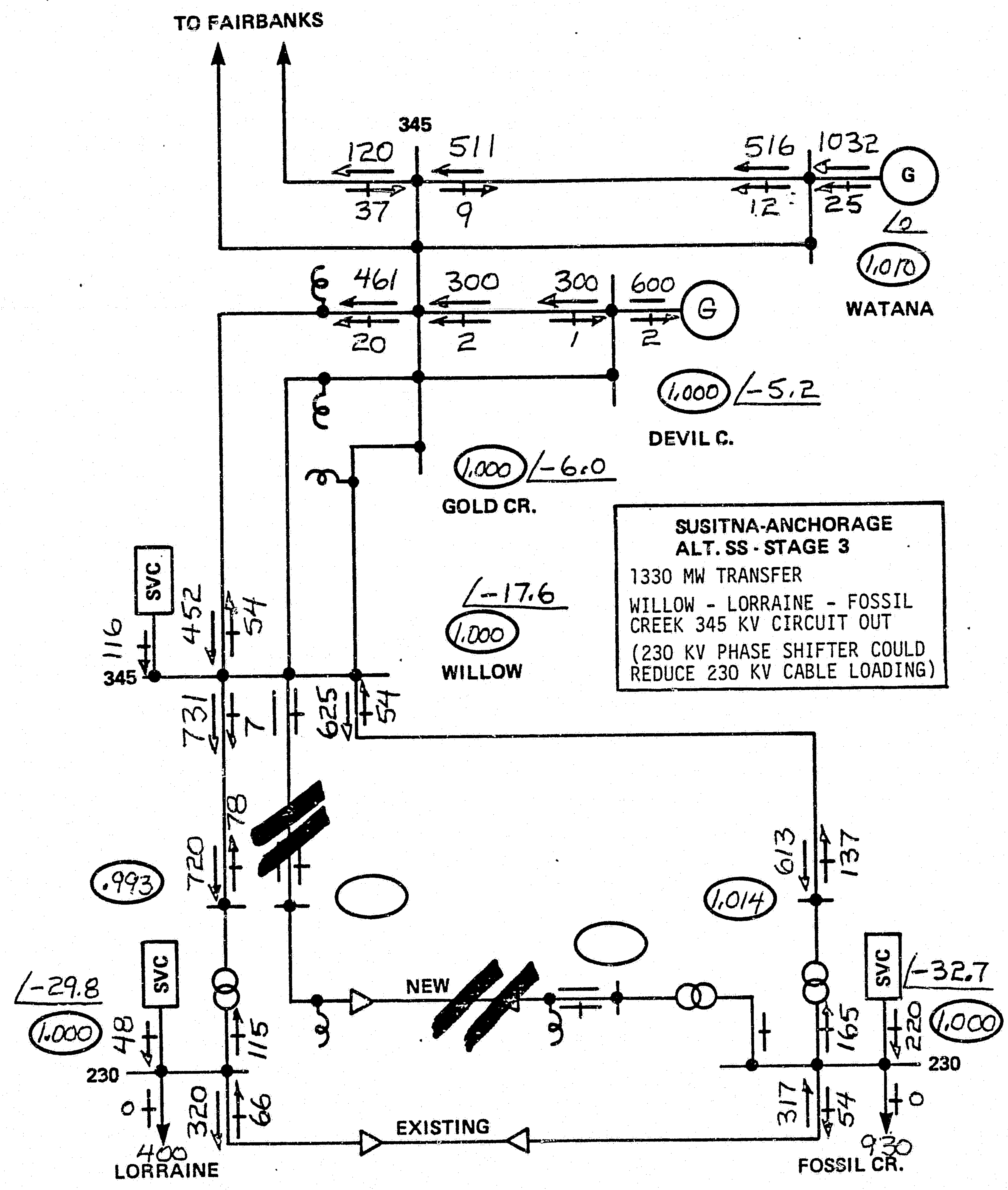
TO FAIRBANKS
345
WATANA
1.010
DEVIL C.
1.000
-3.5
GOLD CR.
1.002
-4.1
SUSITNA-ANCHORAGE
ALT. SS - STAGE 3
900 MW TRANSFER
(LOWEST POSSIBLE NEED FOR A THIRD 345 KV CIRCUIT)
WILLOW
1.000
-11.7
SVC
345
NEW
EXISTING
230
LORRAINE
1.000
-17.5
FOSSIL CR.
1.000
-17.9
1.020
.998

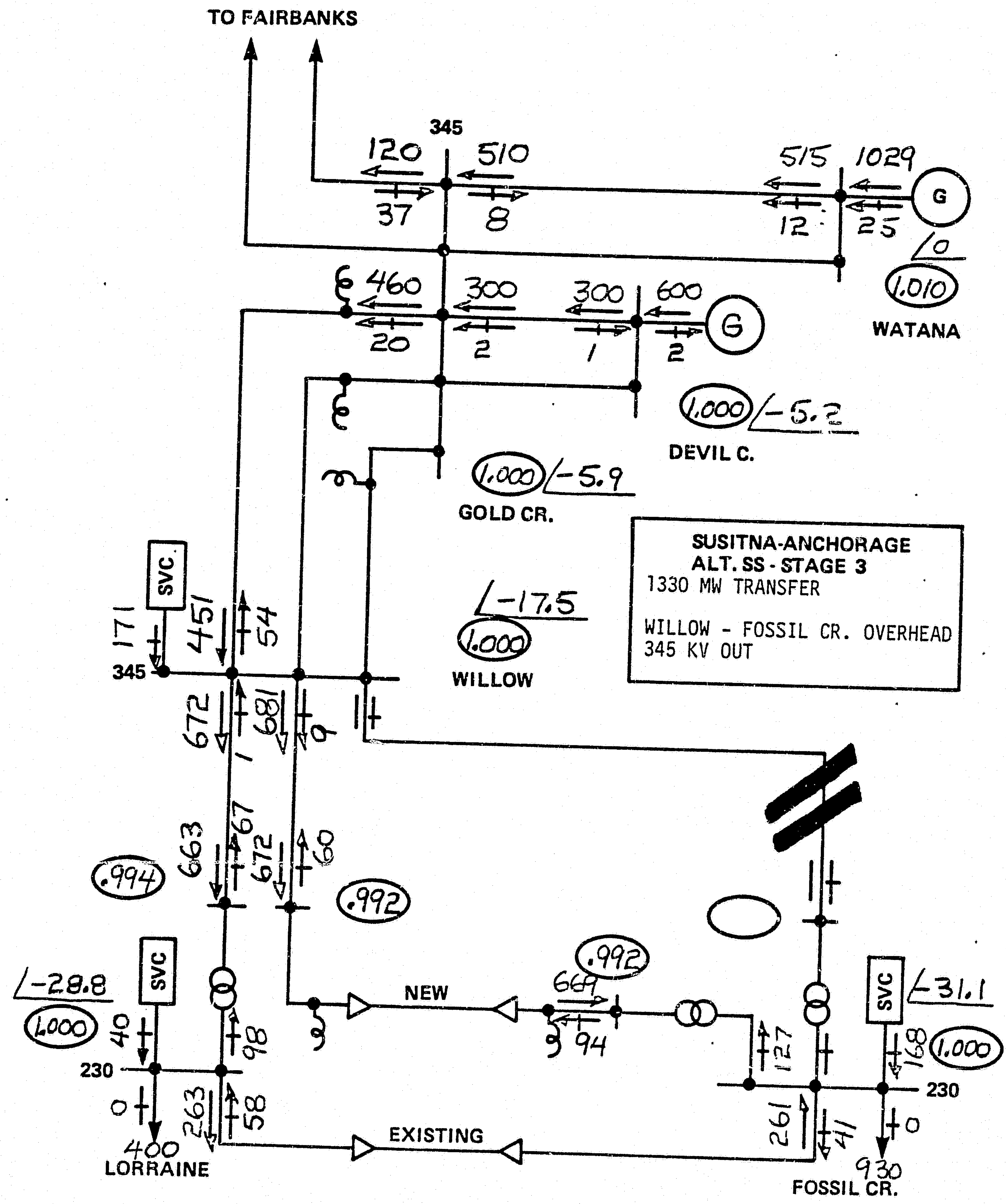


TO FAIRBANKS
345
120
506
511
1021
G
37
8
12
24
/0
1.010
WATANA
50
457
300
300
600
G
20
1
2
4
1.000 /-5.1
DEVIL C.
1.000 /-5.9
GOLD CR.
SUSITNA-ANCHORAGE
ALT. SS - STAGE 3
1330 MW TRANSFER
(85% OF MAXIMUM WINTER CAP)
1.000 /-17.4
WILLOW
SVC
35
449
53
345
501
463
381
88
19
18
496
40
459
31
377
85
.997
.996
1.019
.996
458
SVC
/-25.8
1.000
26
58
NEW
50
52
50
67
95
SVC
/-26.6
168
1.000
230
230
0
96
31
96
4
0
EXISTING
400
LORRAINE
930
FOSSIL CR.


TO FAIRBANKS
345
120
512
517
1035
G
37
0
21
42
/0
1.010
WATANA
692
300
300
600
G
54
17
14
28
1.000 /-5.2
DEVIL C.
.998 /-6.0
GOLD CR.
SUSITNA-ANCHORAGE
ALT. SS - STAGE 3
1330 MW TRANSFER
GOLD CR. - WILLOW 345 KV OUT
/-23.5
1.000
WILLOW
SVC
152
673
138
345
501
19
463
18
381
88
SVC
/-31.9
1.000
26
230
0
400
LORRAINE
NEW
EXISTING
SVC
/-32.8
1.000
168
230
0
930
FOSSIL CR.


TO FAIRBANKS
345
120
513
519
1038
G
37
9
13
25
/0
1.010
WATANA
462
300
300
600
G
20
3
0
0
1.000
/-5.2
DEVIL C.
1.000
/-6.0
GOLD CR.
SUSITNA-ANCHORAGE
ALT. SS - STAGE 3
1330 MW TRANSFER
WILLOW - LORRAINE 345 KV OUT
(REDUCING 138 KV CABLE LOADS
WOULD UNLOAD 230 KV CABLE)
SVC
130
453
55
345
/-17.6
1.000
WILLOW
745
616
56
20
734
69
.990
604
135
1.014
.991
731
109
NEW
/-36.2
SVC
1.000
75
230
0
400
75
400
LORRAINE
EXISTING
SVC
/-32.6
148
162
232
1.000
230
405
77
0
930
FOSSIL CR.


TO FAIRBANKS
345
120
511
516
1032
G
37
9
12
25
1,010
WATANA
461
300
300
600
G
20
2
1
2
1,000
-5.2
DEVIL C.
1,000
-6.0
GOLD CR.
SUSITNA-ANCHORAGE
ALT. SS - STAGE 3
1330 MW TRANSFER
WILLOW - LORRAINE - FOSSIL CREEK 345 KV CIRCUIT OUT
(230 KV PHASE SHIFTER COULD REDUCE 230 KV CABLE LOADING)
SVC
116
452
54
345
-17.6
1,000
WILLOW
731
7
625
54
78
720
.993
613
137
1,014
SVC
-32.7
-29.8
SVC
NEW
1,000
48
115
165
220
1,000
230
230
0
320
66
317
54
0
EXISTING
400
LORRAINE
930
FOSSIL CR.


SUSITNA-ANCHORAGE
ALT. SS - STAGE 3
1330 MW TRANSFER
WILLOW - FOSSIL CR. OVERHEAD
345 KV OUT
TO FAIRBANKS
345
WATANA
DEVIL C.
GOLD CR.
WILLOW
LORRAINE
FOSSIL CR.
NEW
EXISTING
SVC
230