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P. 11 for review of Low-Ld + Exp

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EXPLORATION AND NATURAL GAS

Joan S. Chasan

EVENTS IN NATURAL GAS AND INVESTMENT IDEAS

The demand for natural gas far exceeds available supplies at current prices. Through 1975 this shortfall is expected to amount to several trillion cubic feet per year but will subsequently increase to 10 trillion cubic feet and more annually by around 1980. Because natural gas is inherently pollution-free and the supply of other practical energy sources short, we would expect the demand for natural gas to be strong even at sharply higher prices.

As a result of the current overall shortage of usable pollution-free fuels, the energy industry as a whole, fragmented as it is, will be very much in the news throughout 1973. We expect a major government program in the area and sharp battles from consumer interests in Congress.

Gas is at the bottom of the price scale. The price of this commodity has been held down historically, owing to its by-product status and the timing of Federal Power Commission wellhead price controls, particularly in relation to the prices of alternate fuels, which are not price-regulated. In constant dollars, the 1970 average wellhead price of $0.17 per thousand cubic feet (mcf) was a decline from the 1963 peak of $0.185 during the early period of FPC price restrictions. The highest long-term federally allowed wellhead price off-shore Louisiana is still only $0.26 per mcf. This is roughly one-third the price for the same heat energy provided by a barrel of oil.

Rising wellhead prices are strongly expected for all new gas supplies, particularly those in interstate markets. Upside potential could be at least to the $0.80 per mcf area versus $0.20–0.26 now, considering the proposed delivered prices of liquefied natural gas (LNG) at seaboard markets.

Major price changes in gas have already occurred in intrastate markets, where gas prices have remained free of federal regulation. Upside potential in intrastate markets is to $0.60–0.70 per million BTU's – if not more, depending on the supply of alternate fuels – versus $0.30–0.50 now. The higher prices in these markets have already resulted in nearly a 30% increase in exploratory gas wells to date in 1972.

While there is recognition of the need for gas price increases at the White House, the Federal Power Commission, and in most of the gas pipeline and distribution industry, there is much less in Congress and among consumers. We therefore anticipate major battles, the results of which cannot be foreseen. For example, it would be economically desirable to deregulate all producer gas sales in interstate markets; the result would be better capital formation in the industry. However, we doubt that this is politically possible. Consequently, only "new" gas discoveries will be able

to sell at the full market price. Flowing gas sales may not.

Since the geologic resource base is very ample, we expect other incentives to domestic exploration, such as somewhat higher crude-oil prices, investment tax credits for exploration investment, depletion tax advantages tied to exploration, more offshore lease sales, and so on. The purpose will be to produce a major surge in domestic U.S. exploration for both oil and gas reserves in an effort to reduce the high levels of energy imports that now seem inevitable. Imports already provided 29% of our petroleum needs in 1972.

We also expect large base-load imports of LNG into the U.S. East and West Coasts, amounting to several trillion cubic feet by the end of the decade. Two factors have made this possible: rising wellhead prices in the U.S. and spectacular advances in the technology of tanker transportation. LNG is already a reality in North America, where it is handled safely in over 100 peak-shaving plants. Europe has been importing LNG from Algeria for over a decade, and Japan, which is about to start importing it from Brunei, has received LNG from Alaska since 1969. While there are only about 11 LNG tankers currently operating, projections for LNG tankers to serve total world markets are between 100 to 200, with at least 24 on order already. These forecasts are entirely believable, since much of the industrialized world, namely Europe and Japan, is virtually completely dependent on energy imports, and major unutilized gas reserves exist in distant locations.

The U.S. provides about 64% of the world's gas market. Western Europe burns about 7%; Japan, still negligible; and the Communist bloc, 22%. Nevertheless, gas consumption has been growing at extremely high rates – well over 30% or more annually – in recent years in the major European countries. Gas consumption could boom in Japan, where use of locally manufactured town gas is growing at 10% per year and where pollution problems at electric power plants are formidable (even though there are no major gas transmission lines).

Consequently, new gas prices for fields serving these growing markets are already considerably higher than U.S. interstate prices, which, admittedly, are below world market levels. For example, Ekofisk gas is apparently going to Continental Europe at an initial wellhead price of around the middle $0.50's per million BTU's, a price that will escalate with the cost of alternate low-sulfur fuels. Large new gas reserves in distant parts of the world will have attractive markets for the first time, and we expect a huge LNG trade from areas such as the Mideast and Indonesia.

We also expect the development, in time, of synthetic supplies of crude oil and gas. Higher energy prices will certainly help make such projects feasible, and government programs will probably call for further research in this area.

Investment opportunities are not as obvious as they would seem because of the complexity of "energy" and the petroleum industry. In the natural-gas equity area, we recommend integrated, intrastate companies such as *Texas Oil and Gas, Houston Natural Gas, Lone Star Gas,* and *Pioneer Natural Gas*, which are increasing their onshore exploration. All offer sound, logical, fairly low-risk participation in the improving economics of the industry. All but one of these stocks are at historical highs, and we expect all to go higher in price with relatively little downside risk.

In the exploration area, where one seeks downside protection plus exploration exposure both U.S. and worldwide, as well as good management, we would recommend *Louisiana Land & Exploration Company* at a price level around $40 for the intermediate term. We recognize that the company's future is clearly not the same as its past and that if the company's current exploration efforts are not successful, downside risk could be increased to $30 or below. Also in the exploration area, but generally more speculative, are many of the new offshore companies such as *POGO, PLATO, Louisiana Land Offshore*, and others. We cannot make wholesale recommendations in these stocks and would tend to look at each company individually in relation to tracts gained, monies spent, and so forth. *POGO* appears to be fully priced near term, however, and we would be inclined to sell it on strength.

Onshore drilling programs are an obvious area of direct investment. *Inexco* is an example of a successful oil and gas exploration company that raises the bulk of its funds through public drilling programs offering tax advantages. The investor in this company may participate in both the fund and the stock, since each is a partner with the other. This assumes he has investigated all the conditions and disadvantages of drilling funds and is aware of their problems as well as benefits in his own case.

NATURAL GAS AS PART OF THE TOTAL ENERGY SCENE

The concept of energy is an amorphous one, since there are really many different types of energy being found and supplied by many different types of public and private companies to many different types of users worldwide. Besides the many overlapping relationships among these, there are equally important economic and geological factors. Further complicating this picture is the fact that some of these fuels are transformed at different stages of the production/consumption process. The U.S. electric utility industry, for example, is both a major supplier of energy to consumers – 25% of all energy – and simultaneously a major consumer of primary fossil fuels – 83% of its fuel needs comes from coal, oil, and natural gas.

It follows, then, that there is no one way to play energy. There are a variety of ways. And because oil and gas, merely different arrangements of carbon and hydrogen atoms, both occupy the same habitat and are found by about the same means by the same people, the entire oil and gas industry is one way of participating in energy investments.

Within the petroleum industry and among its regulatory authorities, there is a major debate as to the concept of "directionality." That is, can the explorer specifically drill for gas rather than oil and be successful? To the extent that gas tends to predominate below 15,000 feet, the answer is "yes." And to the extent that certain structures, or areas, are found to be gas-prone after drilling, the answer is also "yes." But most of the time, and especially in wildcat areas, the answer is "no." The explorer is looking for hydrocarbons and he will not know what he finds until he drills. Actually, 21.5% of net domestic U.S. gas production in 1971 (22.1 trillion cubic feet) was a direct consequence of finding oil wells that had gas associated with them. Alaska's North Slope has proved reserves of 26 trillion cubic feet of gas, virtually all of which is in the crude-oil reservoirs.

The petroleum industry has found it much more profitable to search for oil than for gas. One obvious reason is price. At $0.20–0.50 per mcf, 5.6 thousand cubic feet of gas is worth about $1.12 to $2.50; whereas a barrel of oil, yielding the same amount of heat energy and found by the same costly exploration techniques, is worth roughly $3.40 to $3.50, and usually less time is lost developing means of transportation. Moreover, an integrated company can refine that same barrel of oil into gasoline, petrochemicals, and other products, which further increase the final realization on the original barrel of crude.

The opportunity for functional integration and greater revenue from final products has not been generally available in the gas industry. Natural gas cannot be as easily gathered and transported as crude oil. In fact, the major cost component to most consumers of gas has frequently been permanent transportation to the site of the user. In most cases, a separate, nonredundant transmission and distribution industry has developed. It is frequently government-regulated as a public utility. In Europe most transmission networks have been state-owned. This regulatory situation, along with the historically low wellhead price and other factors, has generally discouraged the kind of functional integration found in oil production. Consequently, natural gas is an almost negligible revenue source to the major integrated petroleum companies, which produce well over 70% of domestic gas. Even if the gas price were to double or triple, it would have only minor impact on most large-capitalization companies.

The only exceptions to this lack of meaningful integration are certain intrastate gas pipeline and distribution companies; these have a twofold advantage. First, they attempt to supply an increasing proportion of their gas needs through

their own exploration efforts, while selling natural gas to the homeowner for around $1.00 per mcf or more, versus the $0.20 to $0.50 realization at the wellhead. If they have refineries, the gas can also be valuable both as a feedstock and as a source of ethane, propane, and butane which, after extraction, bring additional revenues. Propane (contract prices) can yield $0.05 –0.07 per gallon, for example, and ethane, $0.02–0.03. Second, companies closest to the gas source have the lowest transportation cost. This means they can afford to outbid others who are at much greater distances from the wellhead and have significantly larger transportation costs. Because of the transportation factor, then, gas has a local or regional aspect to it that oil does not.

CRUDE-OIL PRICES

From an exploration point of view, the major point is that crude-oil prices are equally important, if not more important, to the overall level of exploration and the profitability of most oil and gas exploration companies. Unfortunately, U.S. crude-oil prices in constant dollars have not provided any drilling incentive. This situation is very much like that of gas, even if unrecognized, and is a major reason for the decline of drilling in the U.S. since the peak levels of 1956. The 1967 price of oil, in constant 1954 dollars, was below post-World-War-II levels of around $2.90 –3.00 per barrel and even below the $2.51 per barrel average of the past 80 years, according to data presented by H. J. Gruy, a well-known independent petroleum consultant. Moreover, this constant-dollar price of $2.31 per barrel was nearly as low as the rock-bottom levels experienced in the crude surplus periods of 1905–15 and 1930–40. The result has been that exploration in the U.S. has declined steadily and drastically over the past 15 years to levels similar to those seen just after World War II. There were about 16,000 exploratory wells drilled in 1956 but only 6,922 in 1971, the fewest since 1947. While there is some evidence that the reserves of oil and gas found per exploratory well in attractive areas have held up rather well, a 50% drop in exploratory activity, consistent with declining real prices, does not help us find more oil or gas.

Accordingly, economic logic suggests that prospects for significant crude-oil price increases are now quite good, perhaps better than at any other time since the mid-1950's. Reason number one is the current peaking of U.S. crude oil, condensate, and gas-plant liquid production at about 11.2 million barrels per day (with crude oil slipping to around 9.0 million). But current consumption is already high enough so that we are importing about 29% of our total petroleum liquids – crude oil, fuel oil, and so forth – or around 4.7 million barrels per day (about 2.2 million barrels per day of crude, up 30% over 1971, and 2.5 million barrels per day of finished products, up 12% over 1971). These imports are costing over $4 billion annually, whereas total yearly U.S. exports in 1971 amounted to only $2 billion.

Moreover, all projections for near-term petroleum demand show a staggering further need for imports. The four projections presented in the December, 1972, National Petroleum Council *U.S. Energy Outlook* see crude-oil and product imports, including feedstocks for synthetic gas, in a range of 7.2 to 9.7 million barrels per day in 1975 – possibly more than double current levels. They would then be 41% to 50% of total projected oil supply needs, which are forecast at 17.5–19.3 million barrels per day at that time. By 1985 imports could range from only 3.6 million barrels per day to an astronomical 19.2 million barrels per day to serve projected total U.S. oil supply needs in a range of 20.5–29.7 million barrels per day, nearly all depending on policies now under consideration by Congress and the Nixon Administration. Any shortfall in gas, coal, nuclear energy, or other sources will have to be made up by oil imports.

Reason number two is the price impact of "participation" by Middle East and other OPEC countries. The delivered (landed) price of Indonesian and sweet Mideast and African crude oil to U.S. markets is already more or less the same as domestic crudes and is slated to go higher as a result of the agreements signed in the last few weeks. "Participation" may add $0.05 to $0.10 in costs in the initial year alone compared to about $3.40 per barrel received in the U.S. in 1971 and 1972. Indonesian oil was already

$2.96 per barrel, FOB Indonesia: i.e., before transportation to the U.S. and before the latest round of currency realignments. Obviously, at $4–5 per barrel, the level expected by some key government individuals, oil imports in 1975–80 could have a devastating effect on the U.S. balance of payments – the outflow could reach $15 billion by 1975, and by 1985, $30 billion. Foreign oil is no longer "cheap," as incorrectly surmised by the 1970 Cabinet Committee report on Oil Imports, which projected 1980 crude-oil prices at $3.30 per barrel and total U.S. oil needs at only 18 million barrels of oil per day. The U.S. was already consuming about 16.2 million barrels per day of crude oil and other liquid hydrocarbons in 1972.

In addition, few realize that delivered base-load prices for LNG of $1.00 per mcf are equivalent to importing crude oil at around $6.00 per barrel, and a $1.25 per mcf price is equivalent to $7.50 per barrel. Yet it is obvious that the U.S. hopes to be importing several trillion cubic feet of LNG annually at such prices by the end of this decade.

Reason number three for higher crude prices is the fact that U.S. exploration, whether in Alaska, offshore, or at greater onshore depths, is extremely costly relative to the declining real price of what is being found. The average cost of drilling oil and gas wells in 1971 in the U.S. hit a new peak of $19.03 per foot, up 48% over the 1961 figure. Each dollar invested in the U.S. oil industry would ultimately return only $1.77 before taxes and present-value discounts, according to a Chase Manhattan Bank study in March, 1971. The figure for gas was far worse, only $0.83.

The most attractive virgin area for oil and gas exploration – offshore, where geologic structures are simple in form and easy to find – has not been very economic for the industry as a whole. (We are not even considering Alaska's Prudhoe Bay, where nearly $1 billion in lease costs alone will not begin to earn any return for over five years.) The higher costs of merely working offshore, such as special rigs, platforms, pipelines, and personnel, are forecast at about $1.60 per barrel. This figure includes operating costs but excludes royalty and acreage charges. The balance primarily consists of extremely large acreage costs, a result of sporadic offshore lease sales providing uneconomically small blocks and the generally meagre reserves found offshore the U.S. compared to those in other areas of the world. For example, an oilfield containing 100 million to 200 million recoverable barrels is considered quite good offshore the U.S. but is extremely small compared to the billion-barrel-plus Ekofisk, Forties, and Brent fields recently discovered in the North Sea. For gas fields, a one-to-two-trillion-cubic-foot field would be extremely good offshore Louisiana, but it is also small in contrast to the gas at Ekofisk or Frigg (North Sea).

Assuming a $50–100 million acreage cost for a choice block, the lease cost alone on a 100- to 200-million-barrel offshore oilfield could be as high as $1.00 per barrel, if not more, or as low as $0.25. Adding these to the $1.60 per barrel mentioned earlier, a company's costs can range from $2.00 per barrel up to $2.60, all pre-royalty. Subtraction of the royalty interest to arrive at net cost per barrel would result in even higher costs and lower net per-barrel profit figures. The net return, undiscounted and pretax, is probably less than $1.00 per barrel, versus $1.00 or more in the North Sea.

There are a number of other ways to derive offshore profitability, or the lack thereof. Foster Associates published a study for the Department of the Interior in May, 1970, showing total costs for offshore Gulf Coast oil, excluding return on capital, royalties, and income taxes, as $1.93–1.98 per barrel. The figure for gas was $0.11 to $0.12 per mcf. (Continental U.S. costs outside onshore South Louisiana were higher, $1.85 per barrel and $0.13 per mcf.) Estimated offshore Gulf Coast discounted cash flow return ranged from 5.0% to 5.4% on oil reservoirs and 5.7% to 6.6% on gas. Return on book capital was estimated at 7.2% to 8.0% on oil and 8.3% to 10.4% on gas. These levels are extraordinarily low considering the risks involved in exploration.

Humble Oil stated this past October that industry's ultimate offshore profit will be only 7%. Moreover, the industry was in a negative net

income position at the end of 1970 and payments to government would be twice as large as "net cash profit." We think it constructive to note that in the most recent lease sale, several of those most experienced with tracts from the December, 1970, lease sale did not appear to put in many winning bids in the $50–100 million category relative to newcomers.

With returns so low, it would be wiser for the exploration industry to put its money in the bank. Therefore, it seems inescapable that crude-oil – as well as gas – prices will have to rise one way or another if domestic exploration is to be encouraged. Permitting this may prove even more difficult politically than deregulation of new gas prices. However, economic logic supports a crude price of at least $4 to $5 per barrel. In the next several years, with "new" gas possibly at $0.50 per mcf and crude oil at $4.50 per barrel, the total revenue per barrel would be $7.00, up markedly from a current level of around $4.60.

Looking near term for a moment, Phase III of President Nixon's battle with inflation has to be regarded as primarily neutral and perhaps positive for the oil and gas industry. By that we mean events or agencies over and above the controls machinery – the forthcoming Nixon energy message, the Federal Power Commission, and eventually Congress – have already been and will continue to be the key determinants of prices in this vital industry. Further, the position of the Cost of Living Council (COLC) is itself contradictory. The COLC appears to be allowing increases in the price of home heating oil, which had been frozen at seasonally low prices, while calling for countervailing reductions on other petroleum prices. Yet the COLC has also issued a regulation permitting price increases . . . "as necessary for efficient allocation of resources or to maintain adequate levels of supply." We do not understand why this regulation would not apply to crude oil as well as to gas, thus overruling the countervailing price approach. Nevertheless, we believe these positions are somewhat more positive than those of the Price Commission. Finally, to the extent that some intrastate gas prices may have been frozen under Phase II controls, Phase III would appear to eliminate this situation.

With gas prices rising and oil prices about to rise, the outlook for exploration-related industries is of course relatively bright. Fortunately, very large unfound supplies of both oil and gas almost certainly exist in the U.S.

Many people are amazed that this is so. Take oil, for example: Most U.S. oil production onshore is from wells producing above 5,000 feet, and 36% of that total is from stratigraphically entrapped or structurally complex reservoirs found almost accidentally through continuous drilling, not in the easy-to-find anticlinal structures that are the first choice of a logical exploration effort.

A major work (parts of which were first released in July, 1970) prepared for the National Petroleum Council by the American Association of Petroleum Geologists and containing much hitherto-unpublished information, has estimated that there exist in the U.S., onshore and offshore, an additional 436.5 billion barrels of oil-in-place. If this oil is recovered at rates known to be typical (30% or so), recoverable reserves could be 141 billion barrels, a 74-year supply at the current rate of use. At recovery rates of 42% and 60%, recoverable reserves might be, respectively, 185 and 262 billion barrels. Current proved U.S. oil reserves are around 36.8 billion barrels, including ten billion in Alaska; obviously, the potential is many times greater than proved reserves.

Among the bases for these estimates are prospective areas of sedimentary rock (above "basement," or 30,000 feet) as large as six million square miles, 3.4 million onshore and 2.6 million on the continental shelf and slope. (These figures ex Alaska are 4.6 million square miles total: 3.2 million onshore and 1.4 million off.) While no area of the U.S. is considered adequately explored, geologists think the offshore area has hardly been touched and will remain attractive. "Structure-hunting" will continue to be the exploration target there. Other high-potential areas, such as the Rocky Mountains and deeper Gulf Coast onshore salt structures, simply need more drilling. Because so many of the easy-to-find structures have already been found, petroleum discoveries in the area east of

the Mississippi River and north of the Gulf Coast will be dependent on deeper discoveries in older rocks, particularly in the more difficult stratigraphic and complex traps. Areas with the highest estimated potential oil-in-place include Alaska, the Pacific Coast, Rocky Mountains, Gulf Coast, and West Texas/New Mexico.

For recoverable gas potential, the most widely used estimate is 1,178 trillion cubic feet, the one prepared by the industry's Potential Gas Committee (December, 1970) and used by the Federal Power Commission. The PGC has access to proprietary company information. Its estimate may be compared to the considerably lower level of existing U.S. proved gas reserves at the beginning of 1972 of 278.8 trillion cubic feet, including 31.4 trillion cubic feet in Alaska. A July, 1972, publication of the U.S. Geological Survey, however, estimated undiscovered but recoverable gas reserves in the U.S. at 2,100 trillion cubic feet, almost twice the PGC figure. (Recovery factors are not a reason for the difference, since 80% of a gas reservoir is usually recovered. Instead, it is mainly the application of a gas/oil ratio to its crude-oil estimate, which is 450 billion barrels recoverable, including gas liquids, and also higher than that of the AAPG.)

The most interesting point about potential gas-reserve locations is that the largest amounts onshore in the "lower 48" lie within the states with strong intrastate gas markets, namely Texas, Louisiana, and Oklahoma. Nearly 400 trillion cubic feet of the 613 trillion cubic feet onshore potential (PGC) is in these regions. Most of the gas onshore is above 15,000 feet but still considerably below the 5,924-foot average depth per 1971 exploratory well. The Texas Gulf Coast, with 103 trillion cubic feet of potential reserves, is claimed by the FPC staff to have more unfound gas than any other domestic area with the exception of Alaska. The latter is said to have 851 trillion cubic feet of gas potential, and the total U.S. offshore area, primarily in water depth to 600 feet, should have some 238 trillion (PGC).

INVESTMENT OPPORTUNITIES

Intrastate Companies

The rationale for investing in intrastate companies is fairly clear. The companies whose stocks we recommend produce, gather, transport, and sell natural gas primarily within the state of Texas and within the borders of adjoining states. All have favorable gas reserve/sales ratios. Not only are they relatively free of regulation at federal levels, but state and local regulation for the three firms that are organized as utilities is considered fairly liberal. All four companies have dramatically increased gas exploration around their pipelines in response to rising intrastate gas prices.

As mentioned earlier, Texas, Oklahoma, and Louisiana have particularly large unfound gas supplies. These states consume about 29% of total U.S. gas (63.5% of this amount is used in Texas); they are considered saturated as residential and commercial markets. However, growth in industry and electric-power generation is continuing at high rates. We would expect gas to maintain a strong supply position to these markets in this area, not only because gas transportation costs are quite low but also because there is no equipment for using other fuels such as oil (as noted by the Federal Trade Commission in April, 1972, in a study on interfuel relationships for electric utilities). Also, significant supplies of low-sulfur fuel oil have been historically unavailable in this region and would have to be imported from abroad. In fact, residual fuel oil, which was driven out of many markets by the low price of competing natural gas, is not easily available in most parts of the country and, where used, is virtually totally imported.

In July a Mobil Oil manager gave the cost of low-sulfur residual fuel oil and crude (domestic and foreign) at $3.50–4.00 per barrel on the Gulf Coast. This equates to a price of $0.56–0.68 per mcf for gas, or some $0.30 to $0.45 more than the price of gas being delivered to Gulf Coast refineries. Current intrastate new-gas prices have already reached the $0.40–0.50 per mcf range, and may be expected to move to $0.60–0.70, the price of alternate fuels.

The major risk in these companies is possible end-use control of intrastate gas, primarily by passage of an act of Congress. Judicially and administratively, there is very slight precedent for this kind of action: several cases argued in the formation of administrative practice for the National Labor Relations Act and an incident concerning railroads. We doubt this will occur in gas since the Natural Gas Act is not a new act, but dates back to 1938. Further, the 1954 Hinshaw Amendment to the Natural Gas Act, confirming a 1950 Supreme Court decision, exempted intrastate companies, which sell to public utilities, from Federal Power Commission jurisdiction on two conditions: purchase of gas and ultimate consumption occur within the same state and the company is regulated by a state agency. (Direct sales to industry, of course, have not been regulated on either a federal or state utility level other than conservation-type regulations.) In addition, the chairman of the FPC has stated he prefers market prices for natural gas as a possible solution to the supply shortage rather than applying controls to the intrastate market, the legality of which we do not think is clear.

The threat of end-use control would therefore seem strongest in Congress, which will not be an easy forum for any energy bill granting higher petroleum prices. We can only say that, while a controls bill was introduced on June 30, 1972, there have also been recent bills introduced to grant sanctity of contract (on January 1 and August 6, 1972) and to deregulate gas altogether (on August 5, 1972). These bills are favorable to the industry. Several deregulation bills have been introduced in Congress since the 1940's. One was vetoed by President Eisenhower because of a scandal involving lobbying on the bill, even though the President stated that he was in accord with its objectives.

In our view, what stands out today is the overwhelming economic logic in favor of freeing-up gas prices and markets, the strong proindustry positions of the Nixon Administration and the Federal Power Commission, and the confluence of events in the world energy market as a whole. We think the odds are at least 50/50, if not better, that such congressional controls over intrastate gas will not occur. Any move in that direction would be sure to encounter congressional opposition from the states involved and time-consuming constitutional appeals to the Supreme Court based on states' rights.

Also, the question is asked whether an improving federal price picture for interstate gas will harm these intrastate companies. Again, we do not see this happening. Higher prices for all producers should expand onshore exploration, which should result in more gas being found. These companies should be able to get their share and continue supplying intrastate residential/commercial and industrial markets. Should they find themselves with surplus gas, they could sell it at higher prices to interstate pipelines once prices are decontrolled or under current FPC emergency certificates until that time.

Interstate pipelines, in our judgment, remain unattractive as gas pipeline operations alone. These companies will need reserve additions nearly double the low levels of the past few years just to continue serving existing customers in view of current firm curtailments and the expected 3–4% annual decline in existing deliverable supplies. We do not see growth in pipeline unit volumes, the key to their past success. Nor do we see rising gas prices, rates, and earnings on lower volumes improving this situation. Moreover, with all the pipelines more or less full at present, unit growth can only come through construction of new lines. The new lines will be serving smaller markets, not new ones as in the past, and partially empty pipelines are not economical. Some future opportunities for expanding sales include production activities, LNG, and synthetic gas plants. But most are several years from fruition. However, certain interstate pipeline companies may be attractive for the other businesses they have gotten into, such as North Sea and Canadian exploration, LNG ships, and the like.

Texas Oil and Gas is an intrastate company selling to other intrastate distribution companies as well as directly to industry and electric utilities. Gas-gathering operations provided 76% of fiscal

1972 revenues; oil and gas production, 20.5%. This firm specializes in gathering small volumes of gas in the major Gulf Coast exploration areas and reselling them to nearby distribution lines or to individual factories and electric generating plants under contracts fitted to the lives of the reservoirs. The company receives a minimum fee per unit of gas sold, with no lag problem between rising gas-purchase costs and selling-price realizations. The "spread" has been increasing somewhat.

With rising gas prices, the company is now attempting to develop about half the reserves needed for future growth through its own exploration – a relatively high proportion of self-developed throughput for any pipeline system. The company appears on schedule in developing the reserves that will be needed to support targeted gas-gathering sales of 600 million cubic feet per day (cf/d) by 1975 or sooner. Gas-gathering sales in 1972 averaged 400 million cf/d and in 1973's first quarter, 450 million cf/d. The growth rate is anticipated at about 25% annually for the next few years, based on existing gas-sale contracts.

In addition, sums of money that are large relative to the size of the company are available for reinvestment. Total recent annual return on investment is about 9–10%; on equity, 17–18%. Over the past five years, net income has grown at a compound rate of 27% and net income per share at 20%, despite a 33% increase in average common and equivalent shares. This is a typical "growth" stock with a high, but deserved, multiple.

The three other intrastate companies we follow are distribution utilities: i.e., the gas they sell to residential and commercial consumers is regulated at the municipal and/or state level. These regulated volumes vary from a low 6% of total volume for Houston Natural Gas to 18% for Pioneer Natural Gas and 22% for Lone Star Gas. While these sales are subject to the vagaries of weather, and usually face at least a six-month lag with respect to rising gas-purchase costs, they provide a sound basis for secular growth. We estimate residential sales provide about 40% to 50% of Houston's gas earnings, the same or a slightly higher percentage for Pioneer, and considerably more for Lone Star. Both Houston and Lone Star have 65% pass-on of gas-purchase costs, the balance being made up through rate cases before the Texas Railroad Commission and other bodies. Pioneer is fortunate in having 100% pass-on of gas-purchase costs.

Industrial and electric-utility sales constitute major portions of current gas volumes at these companies – 63% for Houston, 70% for Pioneer, and 58% for Lone Star. But they are much smaller proportions of revenues and eventually of profits. However, all three companies will have major opportunities for upward price renegotiation and an improved spread on existing industrial and electric-utility contracts from the extremely low selling prices of $0.20 to $0.35 per mcf. Moreover, none of the three has a large outstanding volume of fixed-price contracts at this time.

Houston Natural Gas, operating primarily in the Houston area, has been one of the best-managed gas utilities in the state, with a consistent ten-year record of increasing earnings per share. Among the company's major, foresighted acts were the building up of exploration activity in the late 1960's and the organization of the second major intrastate pipeline to new West Texas gas reserves. The combination of warm winter weather, delays in rate increases, and a jump of about 33% since 1969 in average gas-purchase costs has held back the company's pretax gas earnings to the $20.1–20.8 million level for the past three years.

However, this situation is about to change for the better, and other developments are in the offing; we foresee continued 8% to 10% annual volume growth in industrial sales. Fixed-priced contracts, which accounted for 10% of total volume in fiscal 1972 (ended July 31), will virtually disappear over the next few years. Construction will start on the company's uranium project with Ranchers Exploration this year. The balance of the company is an industrial gas-supply business that contributed 34% of 1972 revenues and 27% of profit before taxes ($7.4 million in fiscal 1972), which the company purchased from General Dynamics in 1969. That operation

has enjoyed increases in sales and earnings since its acquisition; we expect it to expand about 10% annually in both categories.

Pioneer Natural Gas is a small, highly profitable utility serving the Western and Panhandle regions of Texas. Although the company had a static earnings record in the 1960's, the past two years have seen a remarkable improvement, a result in large part of applications for rate increases and the disposal of an unprofitable non-natural-gas subsidiary. Natural gas contributed about 73% of 1971 revenues, and oil and gas production, 12%. Most of the balance comes from a franchised heavy-construction-equipment dealer operation.

With a 15-year gas-supply position, opportunities to make a large volume of additional industrial and electric-generation sales pending acquisition of sufficient gas, and with a uranium-milling joint venture with Continental Oil already selling uranium concentrate to an eastern electric utility, we anticipate a significant increase in revenues and earning power and a return of the company's historical multiple range. Earnings may not increase consistently on a year-to-year basis, however, because of weather. Not only does the company, like other Texas utilities, face the uncertainties of winter heating seasons, but a great deal of its volume gas sales in summer to industry depend on rainfall levels, since a substantial portion of industrial revenues are for gas-fired pumps for irrigation purposes. Fixed-price contracts will drop to a nominal percentage of the total from the 1971 level of 25% over the next few years.

Lone Star Gas is the intrastate utility among these three that has been changing the most relative to its past, which was admittedly lackluster through 1968. However, in 1969 the company broke out of its no-growth earnings record and has continued to grow steadily in terms of earnings per share ever since. Among the steps taken to accomplish this have been a major change in management and accounting policies, rate increases, renegotiation of industrial contracts, acquisition of well service and supply companies, a dramatically expanded exploration program both domestically and abroad, a new pipeline to West Texas, and entry into the rich industrial Gulf Coast gas market, though not all of these steps have yet impacted the company's earnings. Moreover, warm weather can have a more severe impact on Lone Star than on the other intrastate companies because of the greater volume of residential sales.

Unlike Houston and Pioneer, the company continues to face a severe pretax operating squeeze – pretax operating earnings (before other net deductions) were nearly $5 million lower for the 12 months ended September, 1972, than for the year 1971 – due to the timing of rate increases vis-a-vis hikes in gas-purchase costs and the inability to effect price increases in the Nipak fertilizer operation. As a result, Nipak is still losing up to $2 million annually, and 1972 earnings levels for the company will depend mainly on lower income taxes. With the Phase III modifications of President Nixon's wage/price policies, this situation might be ameliorated assuming clarification of the new regulations. Nipak contributed 10% of 1971 revenues; natural gas, 78%; and oil and gas production, 10%. Nonetheless, the company has substantial unrealized earnings potential to at least the $3.00 to $3.25 area, and we believe its multiple will return to historical levels when, as, and if this potential is realized.

Exploration Companies

Exploration is a difficult and risky equity investment area. First, the largest discovery impact is usually on small-capitalization companies. Second, information about U.S. exploration results is quite poor in offshore areas for competitive reasons. Third, the U.S. is somewhat less attractive geologically and economically compared to the North Sea, Indonesia, and other areas. Fourth, any investment in this field must be considered extremely hazardous owing to the unpredictability of finding oil and gas, even though some companies do appear to have better records than others. Fifth, stock prices can be highly volatile, going to extremes of popularity or unpopularity and being greatly subject to the presence or absence of news. Sixth, investors must attempt to protect themselves against downside risk by buying close to the appraised value, if possible, while allowing for significant

upside opportunity in the case of major discoveries. Unfortunately, information on which to make such judgments is frequently lacking.

Louisiana Land & Exploration around $40 seems to us a good example of a stock with both a foreseeable intermediate-term earnings base and a call on exploration in the U.S., the North Sea, Indonesia, and Kenya. Downside risk is limited in the short to intermediate term, although it could increase to $30 or below later pending certain events. In the meantime, there are several pluses for this major domestic crude-oil and natural-gas-producing company.

First, Louisiana has an excellent domestic exploration record that is probably unequaled in the industry. Over the past 20 years, oil working interest production grew steadily from a nominal 5,740 barrels per day (bpd), or 2.1 million barrels per year (bbls/yr), to 40,900 bpd in 1971 (14.9 million bbls/yr), which is a compound growth rate of about 11%. The Jay Field, a large onshore Florida oil field, will be increasing liquid production still further by about 18,000–20,000 bpd net through 1973. Gas working interest has grown from about 12 million cf/d (4.4 billion cf/yr) to 164 million cf/d (59.7 billion cf/yr) in the same period, a compound annual growth rate of about 14.5%. Among the fields contributing to this growth in gas are some of the largest onshore gas fields in South Louisiana. We are also impressed by the company's record in offshore lease sales: i.e., not spending excessively on productive leases bought in 1967, 1970, and 1972. (Nevertheless, the company's reserve/production ratio, including our estimate of probable reserves – about 9.7 years for oil and 11.5 years for gas as of the end of 1972 – is not above the average for the industry as a whole.)

Second, the September, 1972, sale to the public of a major part of the company's new offshore U.S. exploration company for $75 million raised new funds for costly domestic offshore exploration without diluting parent-company equity over the next three to five years. And with Louisiana Land consolidating 80% of the new company onto its own books, a significant reduction in income taxes from 30% of pretax income in 1971 seems in prospect for each of the next several years. Moreover, a sizable percentage of the company's future annual exploration budget is now freed up for equally, if not substantially more attractive areas of the world. Longer term the 3% management fee earned on all cash receipts of the new company would benefit Louisiana if the new company is successful.

This budget, previously generated internally, has been running between $29 to $38 million since 1969, exclusive of lease acquisitions, a very large allocation in the domestic exploration industry. For the future, Louisiana Land won a 20% interest in about 287,000 acres in March, 1972, in the U.K. portion of the North Sea, although how attractive the acreage may be is unknown; the company was a newcomer to the U.K. portion of the North Sea. In addition, this firm is pursuing Indonesian exploration through a 20% interest on 3.9 million acres on the Bomberai peninsula of West Irian through participation in a Gulf Oil production-sharing contract with Pertamina and the investigation of other possible projects. A program covering 32,000 square kilometers in Kenya was announced last month. All this is in addition to the interests in nine offshore leases the new company won last month, three of which are considered "Class A" prospects (100 million barrels of oil or one trillion cubic feet of gas) by the parent.

Third, any crude-oil price increase will impact Louisiana Land more than most production companies, since in addition to the working interest production it has another 30,560 bpd (11.2 million bbls/yr) of oil production net to its interest as royalty oil on its fee-owned lands. (It also has another 208 million cf/d, or 76.3 billion cf/yr, of royalty gas production.) A $1.00 per barrel price increase over the $3.58 average revenue per barrel received in 1971 could mean an additional $33 million in revenues on a forecasted 1975 total of 33.3 million total barrels of oil (including 7.3 million barrels annually from the Jay Field) and $0.60 to $0.90 per share in additional earning power (36.3 million shares assumed outstanding), at the current tax rate or with no increase in taxes, owing to increased exploration expenditures and the resulting tax deductions. This would put 1974–75 earning power in the $2.50–2.90 per share area on foreseeable production.

Fourth, higher gas prices will spur deep gas exploration on the company's royalty acreage (fee lands) in extreme South Louisiana. The Potential Gas Committee has estimated future gas reserves to be found onshore South Louisiana at 45 trillion cubic feet, nearly half as much as the 99 trillion offshore. Gas production on the company's royalty acreage has already shown sharp growth over the past 20 years, reaching 76.3 billion cf/yr in 1971 versus 1.4 billion cubic feet in 1952. This represents a compound annual growth rate of 23–24%, whereas that for royalty oil was only about 6% over the same period. The company has nearly 360,000 additional royalty acres in South Louisiana and has already noted a pickup in leasing on these lands this year. About 305,000 acres are already under lease to Texaco and others.

Now we turn to the negatives. Louisiana Land has been a highly regarded stock since the late 1940's, when Texaco finally began exploring on the company's fee-owned acreage leased out under previous contracts. At that time the stock's multiple jumped from the 9–11 area to the 15–20 area and soon to the 20–30 area, where it has stayed more or less for 15 years. Earnings growth was erratic but moving upward on higher production volume in the 1950's and has shown uninterrupted growth in every year since 1960. The basic reason for this high, stable multiple was the highly visible assured earnings growth derived from increasing royalty production on which there were no real capital costs. That means that on each $3.00 barrel of oil, costs would be limited to taxes (severance and ad valorem) of various kinds. There were no capital, operating, and financing costs. The percentage of this highly profitable royalty oil to total oil production was 64.5% in 1952, though it declined slowly to 42.8% in 1971. The crossover below 50% in the proportion of royalty oil to total output occurred in 1970, when the figure fell to 48.2% from 55.8% primarily because working interest production jumped over 30% while royalty remained flat. The 1971 proportion was 42.8%, with royalty oil again flat. In gas, royalty production was a small 24.1% of the total in 1952 and increased fairly steadily through 1967 to 71.8%. It stayed at this proportion for two more years, but in 1970 royalty gas dropped to 64% of the total and declined further to 56.1% in 1971. While royalty gas production continued to increase, working interest production grew much more.

In the last two years investors have begun to perceive the importance of the relative decline in this assured, less risky source of earnings and have been according the stock multiples in the 15–20 area. The company's volume-related earnings growth is at least 57%-dependent on its own exploration for oil and 59.7% on its own gas as of 1971. While past results have been very good, exploration entails risks, and the company must pay the full share of costs on each barrel. For example, costs might be $1.50–2.00 per barrel versus only a hypothetical $0.30 to $0.50 on royalty acreage.

Further, with the downward reduction in reserves that occurred in 1971 because of the production behavior of older properties, volume growth in oil is now totally dependent on the company's exploration activities. Unfortunately, there is little foreseeable volume growth beyond 1973, since the Jay Field will be fully on stream in that year. In addition, investors are questioning the company's ability to sustain existing oil volumes. Besides the downgrading of royalty reserves, which were reported in 1971 as "somewhat lower" than the previous year, there was also the publication of proved reserve figures in August, 1972, that were much lower than many investors' expectations, even though they did not include "probable" reserves such as the Jay Field and others.

A continuation of the foregoing situation with no new discoveries should mean the stock at best could stagnate in the $40–50 area for some time. This range results primarily from a multiple of 20 applied to $2.00 earnings in 1973–74 and a multiple of 15 applied to $3.00 earnings (based mainly on crude oil price increases) in 1974–75. Should the multiple range fall further in the event of no discoveries, downside risk could be increased dramatically from the $40 area we see now to $30 or below. Moreover, appraised value sans reasonable discoveries is only about $23. While such a scenario is unlikely, it is possible. At the moment,

though, we do not see these possibilities as a near-term risk and suggest Louisiana Land and Exploration as a good stock relative to other available exploration vehicles. In other words, we are taking a positive point of view toward the change in the company's profile rather than a negative one.

There are many other small exploration companies that should have strong stock prices as a result of their U.S. exploration activities and the changing economics of exploration. *Inexco Oil* is such a company. It attracts our interest because of steadily increasing reserves being found at low cost through a sizable ongoing exploration program. The company finances a great deal of its activities through public drilling funds.

However, the most visible exploration companies, from an equity viewpoint, seem to be the new domestic offshore companies such as *Pennzoil Offshore Gas Operators (POGO), Pennzoil Louisiana & Texas Offshore (PLATO), Louisiana Land Offshore Exploration Company (LLOECO)*, and others. Because of their stronger ability to raise capital for gas exploration relative to other companies, some of these seem destined to become major companies if successful.

Most of these new companies have to be considered purely speculative, since they have no assets other than cash or wildcat leases and because reserve information is not usually disclosed for several years. Given the foregoing discussion on the economics of offshore production, though, it is obvious that these companies are expecting gas prices offshore to be at least $0.40 per mcf with some apparently expecting $1.00, judging by the amount of money they have spent on leases. Crude oil price expectations two to three years out appear to be in the $4.50 to $5.00 per barrel area: i.e., increases of about 10% annually after 1972. Higher petroleum prices are essential to profitability, since one to two trillion cubic feet of gas, or 100–200 million barrels of oil, would not generally support the offering prices of many of these securities, considering the cost of the leases. There is some indication, in the form of increasingly favorable offering terms, that investors in 1972 were decreasingly receptive to the later new exploration issues. After all, offshore gas prices are still only $0.26 per mcf, and it is only at the end of January, 1973, that the FPC will hold hearings on applications to sell new offshore gas at $0.45 per mcf by Texaco, Tenneco, and Belco. Nevertheless, we believe investors can do well in these issues if the securities are accumulated mainly in periods of price weakness and if the various kinds of debentures offering some downside protection are bought.

POGO is one new issue in which some information can be found to attempt some sort of reserve estimate, although this information may yet prove inaccurate as actual production details are made public in the near future. Basing our judgment on pipeline applications and testimony to the FPC by (1) a Pennzoil Company subsidiary, (2) Sea Robin Pipeline, and (3) Humble Oil (Exxon Corp.), as well as on our own guesses, we have arrived at the following estimate of net POGO reserves from offshore blocks won at the 1970 lease sale: 0.820 trillion cf of gas and 30.2 million barrels of oil and liquids. Also included is an estimate for the oil discovery on an offshore block acquired in September, 1972. What remains unaccounted for in our projection is any oil and gas found on still more offshore blocks acquired in 1972 lease sales, namely those bought in September and December, and the gas on the productive oil block from September, 1972. POGO's cash available for later lease sales at this time is about zero.

Obviously, the valuation of POGO's reserves, which are themselves a guess, is very difficult. But approaching the problem either from the angle of total field costs or present value per mcf of gas or barrel of oil leads to the conclusion that POGO's market price is about equal to the appraised value we have derived, even using very high oil and gas prices. (The addition of POGO's 20% equity interest in PLATO would add about $0.50 per share to all per-share calculations following.)

For example, our estimate of gas reserves at $0.20 per mcf and our estimate of liquid reserves at $1.50 per barrel, present value, would result in about $209.3 million in total pretax

income ($164.0 million from gas and $45.3 million from liquids), or $4.80 per potentially outstanding 43.3 million POGO shares. These present values correspond to wellhead prices of $0.40 per mcf for gas and $3.00–3.50 for oil, discounted at 8% over about ten years once production begins. If we use $0.30 per mcf present value, corresponding to a $0.60 per mcf gas selling price, and $2.00 per barrel present value for the liquids, corresponding to $4.00–4.50 per barrel selling price, then $306.4 per million ($246 million gas and $60.4 million liquids) would be the total pretax income and $7.10 the per-share pretax earnings. Only if we use $0.50 per mcf present value for gas and $2.50 per barrel for oil, corresponding to wellhead prices of $1.00 per mcf and $5.00 per barrel, can we derive a per-share value supporting the current stock price: i.e., $11.30 per share ($410 million net pretax for gas, $75.5 million net pretax for oil).

Looking at the valuation problem on a field-cost basis produces lower results. POGO showed capitalized costs (9/26/72) of $132.7 million, and adding the total of $24.5 million spent at the recent lease sales results in $157.2 million in capitalized costs. We will raise capitalized costs to a total of $200 million to account for full development of all properties and will add a round $50 million for finance and operating charges.

Subtracting $250 million from 0.82 trillion cubic feet of gas sold at $0.60 per mcf and 30.2 million barrels of liquids sold at $4.25 per barrel results in net pretax revenues of $620.5 million ($492 million gas, $128.5 million oil), or $8.70 per each of 43.3 million shares. Cutting this in half to allow for the time value of money produces $4.35 per share. If we use selling prices of $0.40 per mcf and $3.50 per barrel of oil, the calculations after discounting result in $2.13 per share. Again, only if we use $1.00 per mcf for gas and $5.00 per barrel of liquids can we derive a per-share value figure near the current stock price. In this case, the calculation works out to $8.30 per share pretax.

Many faults can probably be found with these approaches. Humble's testimony, in view of the Chandeleur case at the FPC, may prove too conservative. This may become obvious, if it is the case, as actual production details are announced this January and March. Wellhead prices may rise even higher than we now imagine. New discoveries may be made. We have not deducted income taxes because of the complications of filing consolidated tax returns involving Pennzoil Company and PLATO, as well as POGO, and because of the possibility that further offshore exploration can effectively postpone such taxes for a long time.

The point is, however, that we cannot come up with figures proving POGO drastically undervalued in the near term. And to double our highest reserve valuations of $8.30 to $11.30 per share on $1.00 per mcf gas and $5.00 per barrel oil, POGO would have to double its reserves over our estimate. But because the limited funds available to the company for the last two lease sales have also limited POGO's participation, this may not be possible near term – although the possibility always exists for discovery surprises.

There is no doubt that the company has been geologically successful in its offshore ventures. For example, data are on file at the FPC showing proved and potential reserve additions in South Louisiana related to advance payments for the past few years as 14.3 trillion cubic feet. Most of this we would guess lies in offshore Louisiana. Our estimate of POGO's gross gas reserves of 1.97 trillion would be 38% of this total and probably consistent with the fact that POGO performed about 20–26% of the drilling and installed about 35% of the platforms on all blocks in the December, 1970, lease sale as of late April, 1972.

But economic success is something else. Two further points seem worthy of mention here. Both the United Gas and Sea Robin affiliates of Pennzoil Company were and still are among the pipeline firms most actively seeking gas. From the point of view of POGO's semi-integrated parent, Pennzoil Company, production economics would be secondary to merely getting the gas through its pipeline. Second, we note that the POGO/PLATO group did not appear to go all out at the

December, 1972, lease sale for gas-prone tracts. Neither did TransOcean, another big winner at the December, 1970, lease sale. Those that did also had gas-short pipeline affiliations. We suggest that POGO and PLATO's own management team did not evaluate these blocks as highly, based on their own experience.

JSC
1/24/73

Additional information on companies mentioned in this report is available on request. The information and data in this report were obtained from sources considered reliable. Their accuracy or completeness is not guaranteed, and the giving of the same is not to be deemed an offer or solicitation on our part with respect to the sale or purchase of any securities or commodities.
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NATURAL-GAS INDUSTRY
COMPANY STATISTICS

Dean Witter Rating	Symbol	Company Name	1/24/73 Price	1972-73 Price Range	Growth Rates (a) Revenues 1966–71	Revenues 1971–76E	Earnings per Share 1966–71	Earnings per Share 1971–76E	Earnings per Share Fiscal 1971	Fiscal 1972E	Fiscal 1973E	Calendarized(b) 1971	Calendarized(b) 1972E	Calendarized(b) 1973E	Ind. Div'd.	Yield
2A	HNG	Houston Natural Gas (7/31)	65	65–39	26.8%	20.0%	11.4%	13.0%	2.32	2.68A	3.00	NA	NA	3.10	0.64	1.0%
1B	LSG	Lone Star Gas	36	40–27	6.1	15.0	9.4	10.0	2.26	2.50	2.75	–	–	–	1.40	3.9
1A	PNA	Pioneer Natural Gas	21	22–14	11.8	15.0	3.0	10.0	1.20	1.30	1.40	–	–	–	0.84	4.0
1A	TXO	Texas Oil & Gas (8/31)	35	39–28	26.7	45.0	18.6	25.0	0.58	0.72A	0.90	NA	NA	1.00	0.02	0.1

Symbol	1/24/73 Price/1973 EPS	P/E, 4 of Last 5 Yrs. Avg. High	Avg. Low	P/E Relative to S&P 500 Average 1969	1970	1971	Current 1972(c)	Future Value Expectation – 12 Mos. Value Target	Interquartile Trading Range	Value Target Related to Calendarized EPS(b) 1972E	1973E	1/24/73 Price	Market Sensitivity Measure Beta Factor	Correlation	Common Stock Outstanding (Mils.) Number	Market Value
HNG	21.7	22.5	17.8	1.14	1.13	1.03	0.37	65	70–58	NA	21.0	1.00	NA	NA	6.8	442.0
LSG	13.1	17.3	13.0	0.87	0.71	0.62	0.79	51	50–38	20.4	18.5	1.42	0.67	0.38	14.9	536.4
PNA	15.0	21.0	15.0	1.28	0.87	0.71	0.88	28	32–22	21.5	20.0	1.33	NA	NA	7.5	157.5
TXO	38.9	29.8	20.3	1.58	1.62	1.81	2.66	44	50–38	NA	44.0	1.26	1.05	0.44	17.4	609.0

Note: Fiscal years ending other than 12/31 noted after names. Data based on fiscal years except as noted. For fiscal years ending 3/31 or earlier, data under prior years.

(a) Historical data calculated by least-squares method; adjusted for acquisition when possible. Estimates for 1971–76 are secular.

(b) Based on four fiscal quarters ending nearest to 12/31.

(c) Based on $6.37 1972 estimate for S&P 500.

OIL AND GAS EXPLORATION

COMPANY STATISTICS

Dean Witter Rating	Symbol	Company Name	1/24/73 Price	1972-73 Price Range	Latest Appraised Value (Per Share)(a)	Appraised Value / 1/24/73 Price	Total Potential Asset Value (Per Share)(a)	Total Potential Asset Value / 1/24/73 Price	Earnings per Share 1971	1972E	1973P	1/24/73 Price/ 1973 EPS	Common Stock Outstanding (Mils.) Number	Market Value
2C	AOC	Austral Oil	24	36–16	21–25	0.88–1.04	32–36	1.33–1.50	0.56	0.70	0.85	28.2	3.4	81.6
3C	AOG	(b)Aztec Oil & Gas	25	27–17	21	0.84	29	1.16	0.46	0.45	0.50	50.0	5.3	132.5
(c)		(g)Energy Ventures, Inc.	11Ask	11–10	(c)	(c)	(c)	(c)	NA	NA	NA	NA	2.8	30.8
1D	HEXP	(g)Hamilton Bros. Exp. Co.	17Ask	25–14	13	0.76	32–55	1.88–3.24	NA	0	0	NM	2.5	42.5
2C	INX	Inexco Oil	14	14–6	10	0.71	18	1.29	0.39	0.55	0.70	20.0	9.3	130.2
2A	LLX	(f)Louisiana Land & Expl.	42	58–39	23	0.55	26–27	0.62–0.64	1.65	1.75	1.85	22.7	36.2	1,520.4

Company	Comments on Latest Approximate Appraised Value Ex Exploration (a)	Comments on Additional Asset Value (per Share) if Reasonable or Hypothetical Find(a)	Latest Estimated Probability of Reasonable Find(a)
Austral Oil	$9.35 for conventional domestic exploration on 1970 reserves plus $11.60-15.40 for Indonesian gas at Badak at $0.10 per mcf profit, 15 to 20 trillion cubic feet, 80% probability; Rulison Gas fracturing by nuclear explosives would add at least $59.00 per share in reserves at $0.10 per mcf present value but is not presently included.	$11.10 for Indonesian crude and/or condensate field at $2.60 profit per barrel after payout – 550 million barrels.	20%
		Condensate production would have to await gas-field production and may therefore be ignored by many. Indicated amount of condensate associated with the gas and not included in the gas reserves is 405 to 540 million barrels.	70%
Aztec Oil & Gas	$21.80 for proved and proved undeveloped reserves and gas price rise to $0.28-0.30 per mcf. No acreage.	$0.31 for 2% interest in 100 million barrels of oil at $4.00/barrel, pretax and discounted, from five blocks acquired in December, 1972, lease sale.	10%
		$6.45 for probable and possible gas reserves including gas price rise to $0.40 and oil price rise.	95%
Hamilton Bros. Expl.	$12.70 book value (available cash) per 2.5 million shares.	$19.90-40.00 for 7.5% interest in one to two billion barrel oilfield in North Sea at $0.75 per barrel present value. Includes possible $9.85 to $19.70 for 1.875% interest in two to four billion barrels recoverable oil on block 20/10, still drilling. Results on 20/10 by February at earliest.	30%
		$0.40-2.70 for 4% interest, pretax, in 100-200 million barrel oilfield on two blocks just won at December 19, 1972 lease sale at $4.00/barrel and discounted. Results possible in mid-March.	30%
Inexco Oil Co.	$9.64 as of 6/30/72 including proved and probable reserves, Canadian and domestic acreage, and mining properties at book value. Secondary recovery at Hilight following waterflooding.	$7.90 for 50% interest in one trillion cubic foot gas reserve find in West Texas or Oklahoma, using gas at $0.50/mcf selling price and discounting. Pretax only.	20%
Louisiana Land & Exp.	$22.80 including proved reserves plus probable reserves at Jay Field of 75 million bls. oil and 90 billion cf. gas. No values for Indonesian, Kenyan, North Sea acreage. Excludes 80% interest in LLOECO, Inc. Excludes two offshore U.S. blocks acquired September, 1972.	$0.36-0.72 for 20% interest in one to two billion barrel oilfield in North Sea at $0.75/barrel present value.	20%
		$0.41-1.52 for 80% equity interest in assumed 25% interest of LLOECO in 100-200 million barrels of oil at $4.00 per barrel, pretax and discounted, from nine offshore U.S. blocks acquired by LLOECO in December, 1972.	30%
		$2.20 for present value of $1.00/barrel price increase over 1971 average on 85 million barrels of royalty oil and 75 million barrels of Jay Field oil.	40%
		Nothing included at this time for Kenya, Indonesia or increased royalty gas potential.	NA

(over)

(a) Based on analyst's best estimate given latest available information. Not a price forecast. Judgements as to relevant discoveries are those of the analyst and must be considered fairly subjective.
(b) Stock dividend.
(c) Company is in registration.
(f) Cash dividend of $1.00.
(g) Dean Witter & Co. Incorporated and/or its stockholders may in the normal course of business have a position in this security.

OIL AND GAS EXPLORATION

COMPANY STATISTICS

Dean Witter Rating	Symbol	Company Name	1/24/73 Price	1972-73 Price Range	Latest Appraised Value (Per Share)(a)	Appraised Value / 1/24/73 Price	Total Potential Asset Value (Per Share)(a)	Total Potential Asset Value / 1/24/73 Price	Earnings per Share 1971	1972E	1973P	1/24/73 Price/ 1973 EPS	Common Stock Outstanding (Mils.) Number	Market Value
2D	LLOEB	(b)Louisiana Land Offshore	6Ask	9–6	2	0.33	3–6	0.50–1.00	NA	NA	NA	NA	15.0(c)	90.0
4D	PLATB	(b)PLATO	4Ask	5–4	3	0.75	3	0.75	NA	NA	NA	NA	54.2(c)	216.8
3D	POGOB	(f)POGO	9Ask	12–8	3	0.33	4	0.44	NA	NA	NA	NA	43.3(c)	389.7
(g)	TOFF	(b)Tenneco Offshore Co.	5Ask	7–5	(g)	(g)	(g)	(g)	NA	NA	NA	NA	14.3(c)	71.5
2C	TSO	Tesoro Petroleum (9/30)	40	54–31	24	0.60	34–44	0.85–1.10	2.03	2.65A	3.25	12.3	5.6(c)	224.0
1C	TOCN	(f)TransOcean Oil (3/31)	21Ask	24–16	16	0.76	23–31	1.10–1.48	0.22	0.35	0.47	44.7	12.7	266.7

Company	Comments on Latest Approximate Appraised Value Ex Exploration(a)	Comments on Additional Asset Value (per Share) if Reasonable or Hypothetical Find(a)	Latest Estimated Probability of Reasonable Find (a)
PLATO	$2.45 in approximate unspent cash now on hand. $0.21-0.64 for 10% interest in possible 100-200 million barrel oilfield on offshore block acquired in September, 1972 at $4.00/barrel, pretax and discounted, and 0.5 to 1.0 trillion of gas on same block, at $0.50/mcf.	$0.27-0.98 for 26% interest in 100-200 million barrel oilfield at $4.00/barrel, pretax and discounted, from four blocks acquired in December, 1972 lease sale.	20%
POGO	$3.25 for net 0.82 trillion cubic feet of gas and net 30.2 million barrels of oil at $4.00/parrel and $0.50/mcf, pretax and discounted, for blocks acquired in December, 1970 lease sale and oil (gas excluded) on block from September, 1972 lease sale. Increase in gas price to $1.00/mcf would add $4.74 but is not included.	$0.08 to 0.28 for 6% interest in 100-200 million barrel oilfield at $4.00/barrel, pretax and discounted, from four blocks acquired in December, 1972 lease sale. $0.50 for 20% equity interest in PLATO, which is carried on POGO's books at $21.7 million.	20% 100%
Tesoro Petroleum	$24.00 fully diluted including reserves and refining and marketing properties. No values for wildcat acreage such as 1.5% interest in 1.5 million gross acres in Panarctic Drake Point and King Christian gas hits.	$10 to $20 fully dilluted for about 25% share after payout in 0.5 to 1.0 billion barrel oilfield in Indonesia (ten million acres in contract area), discounted at 20%. Drilling should begin end of January with first results around end of March.	20%
TransOcean Oil	$16.40 includes estimate of 0.570 trillion cubic feet of gas and 8.8 million barrels of liquids from blocks acquired in December, 1970 lease sale. Gas selling price is $0.26-0.32/mcf. Canada acreage (2.5 million acres) is 150% of cost.	$5.15-10.35 for 10% interest in 1 to 2 billion barrel oilfield in North Sea at $0.75 per barrel present value. $1.28-4.38 for 16.3% interest in 100-200 million barrels of oil and 0.5 to 1.0 trillion cubic feet of gas from two blocks acquired at December, 1972 lease sale at $4.00/barrel and $0.50/mcf, respectively. Pretax and discounted.	30% 30%

Note: Fiscal years ending other than 12/31 noted after names. For fiscal years ending 3/31 or earlier, data under prior years.

(a) Based on analyst's best estimate given latest available information. Not a price forecast. Judgments as to relevant discoveries are those of the analyst and must be considered fairly subjective.

(b) Dean Witter & Co. Incorporated and/or its stockholders may in the normal course of business have a position in this security.

(c) Potentially outstanding.

(f) Dean Witter & Co. Incorporated makes a market in this over-the-counter security.

(g) Company is in registration.

Gene Mear
Minerals Exp. Office
Louisiana Land + Exp. Co.
Suite 2340
Colo. State Bank Bldg.
1600 Broadway
Denver, Colo.
80202
Tel. 303-893-1060

SIPC
SECURITIES INVESTOR PROTECTION CORPORATION

FEB 26 '73
ARIZ.
U.S. POSTAGE
.16
PB METER 885398

from

DEAN WITTER & CO.
INCORPORATED
MEMBER NEW YORK STOCK EXCHANGE
4400 EAST BROADWAY, TUCSON, ARIZONA 85711

To

Mr. Dennis C. Temple
6656 Sesame Lane
Tucson, Arizona 85704

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E.G.B.

BERTRAM B. BENEVILLE
MERRILL LYNCH,
PIERCE,
FENNER & SMITH INC
135 NORTH STONE AVE.
TUCSON, ARIZONA 85701
602-TEL: 792-3750

9999 NL 0 OPN 030273-0332

5364 LOUISIANA LAND AND EXPLORATION

SXM
MAR 5 - 1973
RECEIVED

DIV 1.00
GOOD QUAL SUIT FOR GROWTH
INTR T APREC HOLD
L .T .APREC HOLD
SLFD FOR INCOME
EARNS EST 1973 NOESTIMA VS 1.74
RR 3/6 2/3

THE INFORMATION SET FORTH HEREIN WAS OBTAINED FROM SOURCES WHICH WE BELIEVE RELIABLE, BUT WE DO NOT GUARANTEE ITS ACCURACY. NEITHER THE INFORMATION, NOR ANY OPINION EXPRESSED, CONSTITUTES A SOLICITATION BY US OF THE PURCHASE OR SALE OF ANY SECURITIES OR COMMODITIES.

LLX DERIVES A MAJOR PORTION OF ITS INCOME FROM OIL AND GAS PRODUCION AND ROYALITY INCOME FROM LARGE LOUISIANA ACREAGE . SHOULD HAVE EXPANDING PRODUCTION FROM DISCOVERIES BEING DEVELOPED IN FLORIDA AND OFFSHORE LOUISIANA . IN OUR OPINION THE OPERATING OUTLOOK CONTINUES FAVORABLE . HOWEVER . WE BELIEVE THIS IS ADEQUATELY REFLECTED IN THE CURRENT PRICE . WE WOULD HOLD THE STOCK . BUT WOULD DEFER PURCHASE .

5/2/73

from

Dick Goehrig

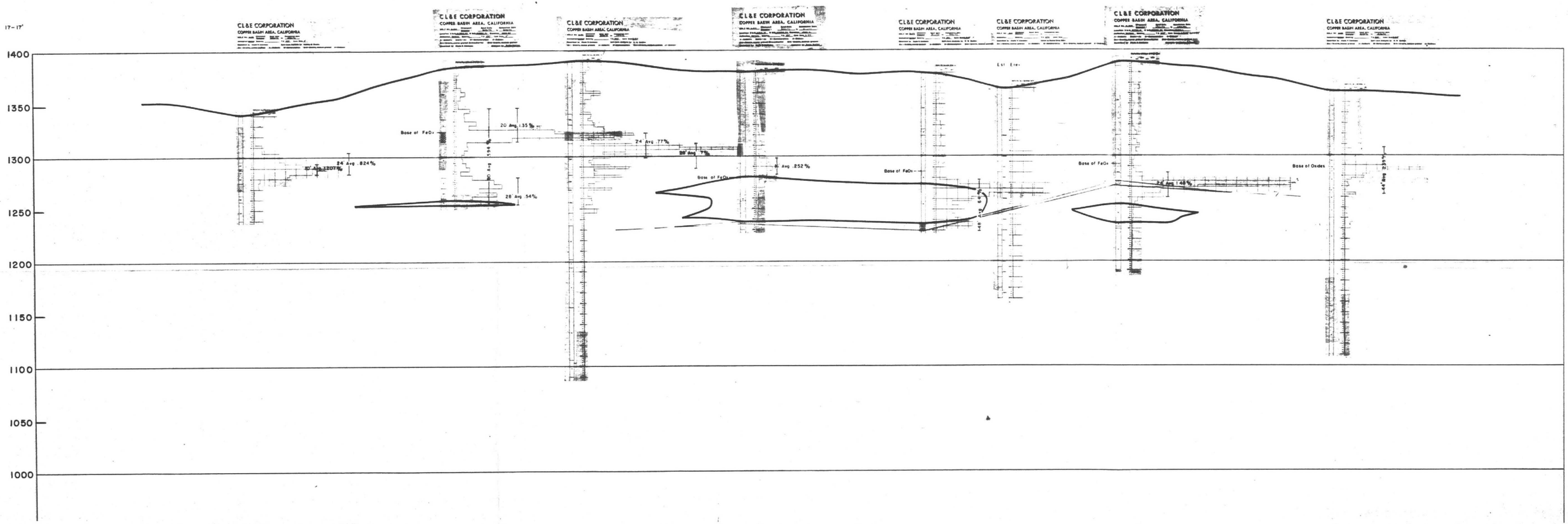
Dear Mr. Temple,
Thought this new item would be of interest to you.

DEAN WITTER & CO.
INCORPORATED
4400 East Broadway / Tucson 85711 / (602) 795-5770

Price Dec. 27'72 Dividend Yield

INCOME STATISTICS (Million $) AND PER SHARE ($) DATA

Information has been obtained from sources believed to be reliable, but its accuracy and completeness, and that of the opinions based thereon, are not guaranteed. Printed in U. S. A.


17-17'
C L & E CORPORATION
COPPER BASIN AREA, CALIFORNIA
1400
1350
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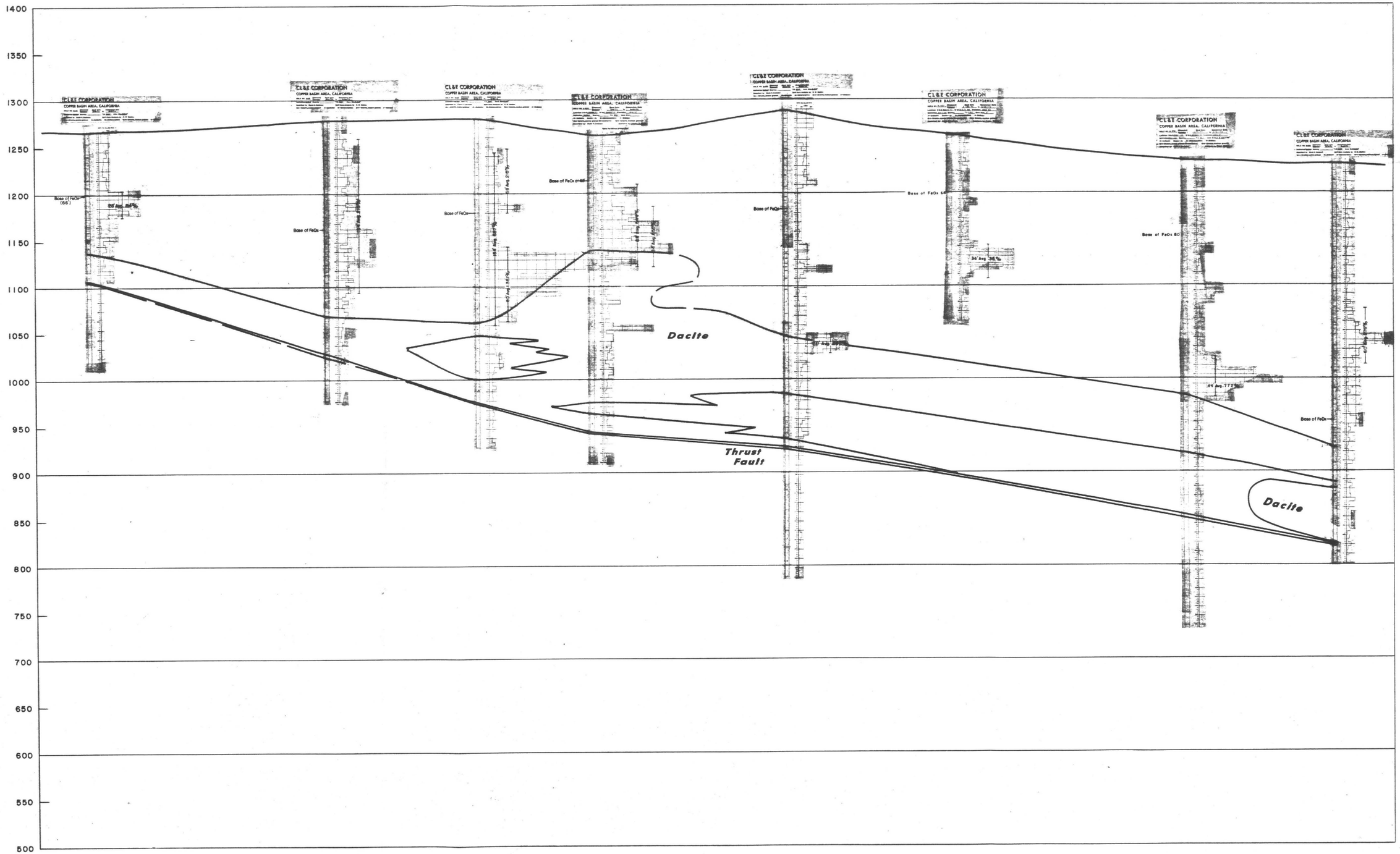
1000
Base of FeOx
20 Avg .35%
24 Avg .77%
28 Avg .7%
24 Avg .824%
20' Avg .1207%
28 Avg .54%
16 Avg .252%
Base of FeOx
Base of FeOx
Est Elev
Base of FeOx
24 Avg .48%
Base of Oxides
1-44' Avg 2.59%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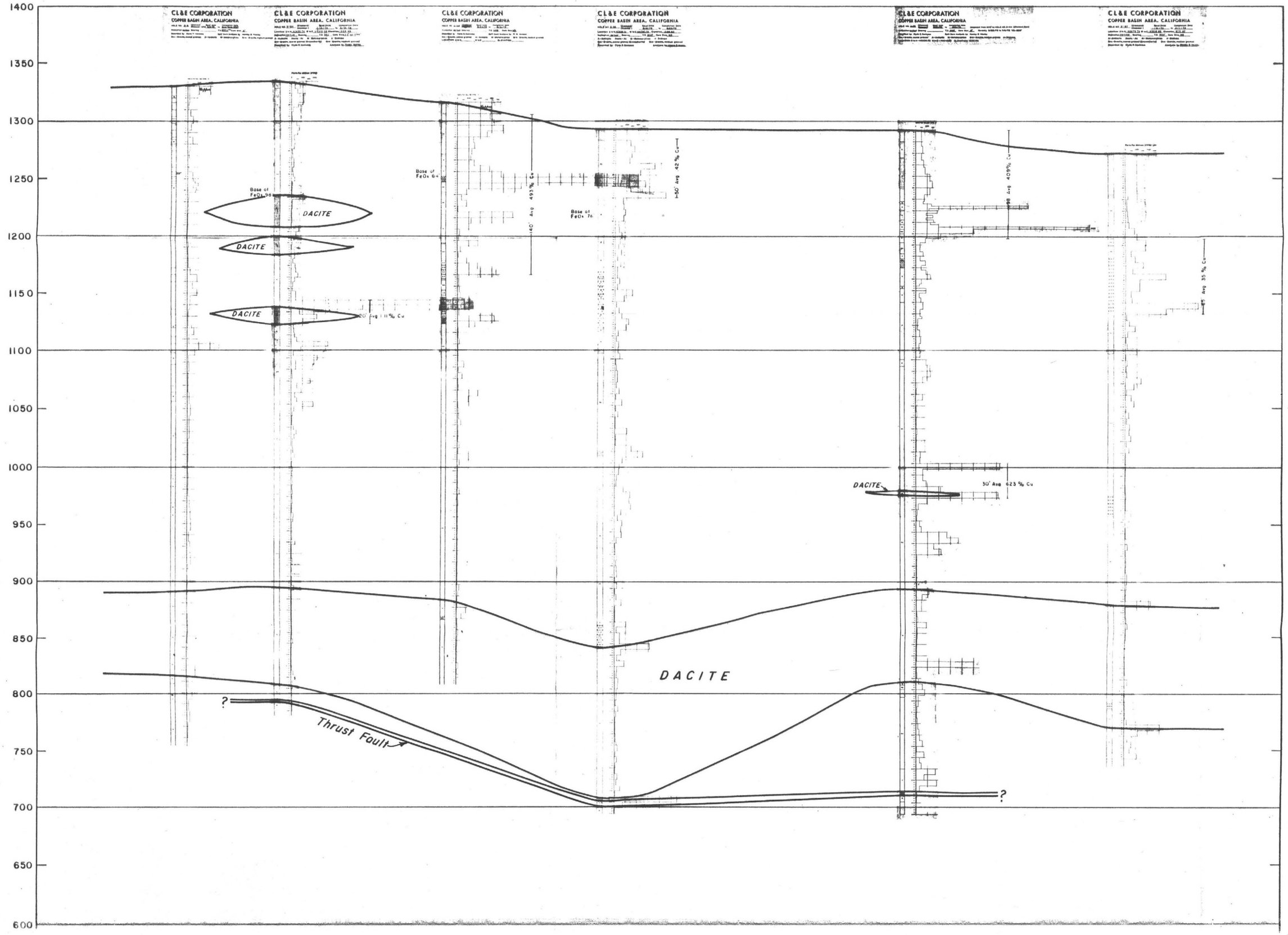
CL&E CORPORATION
COPPER BASIN AREA, CALIFORNIA
Base of FeOx (66')
Base of FeOx
Base of FeOx
Base of FeOx
Base of FeOx
Base of FeOx
Base of FeOx
Dacite
Thrust Fault
Dacite

15-15'


CL&E CORPORATION
COPPER BASIN AREA, CALIFORNIA
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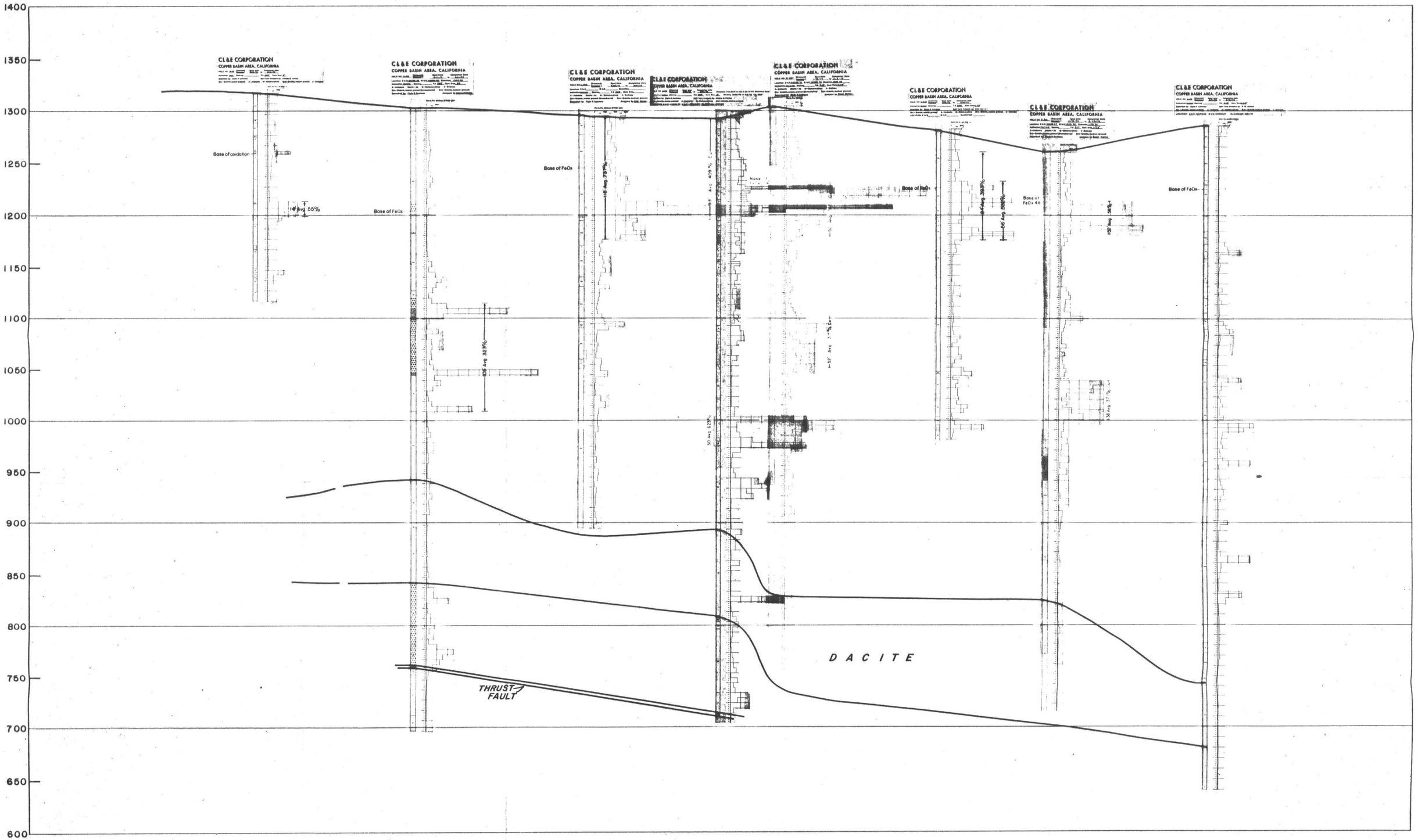
Base of FeOx 98
DACITE
DACITE
DACITE
20' Avg 1.11% Cu
Base of FeOx 64
140' Avg 4.93% Cu
Base of FeOx 76
150' Avg 4.2% Cu
Avg 4.09% Cu
Avg 3.5% Cu
DACITE
30' Avg 6.23 % Cu
DACITE
?
Thrust Fault
?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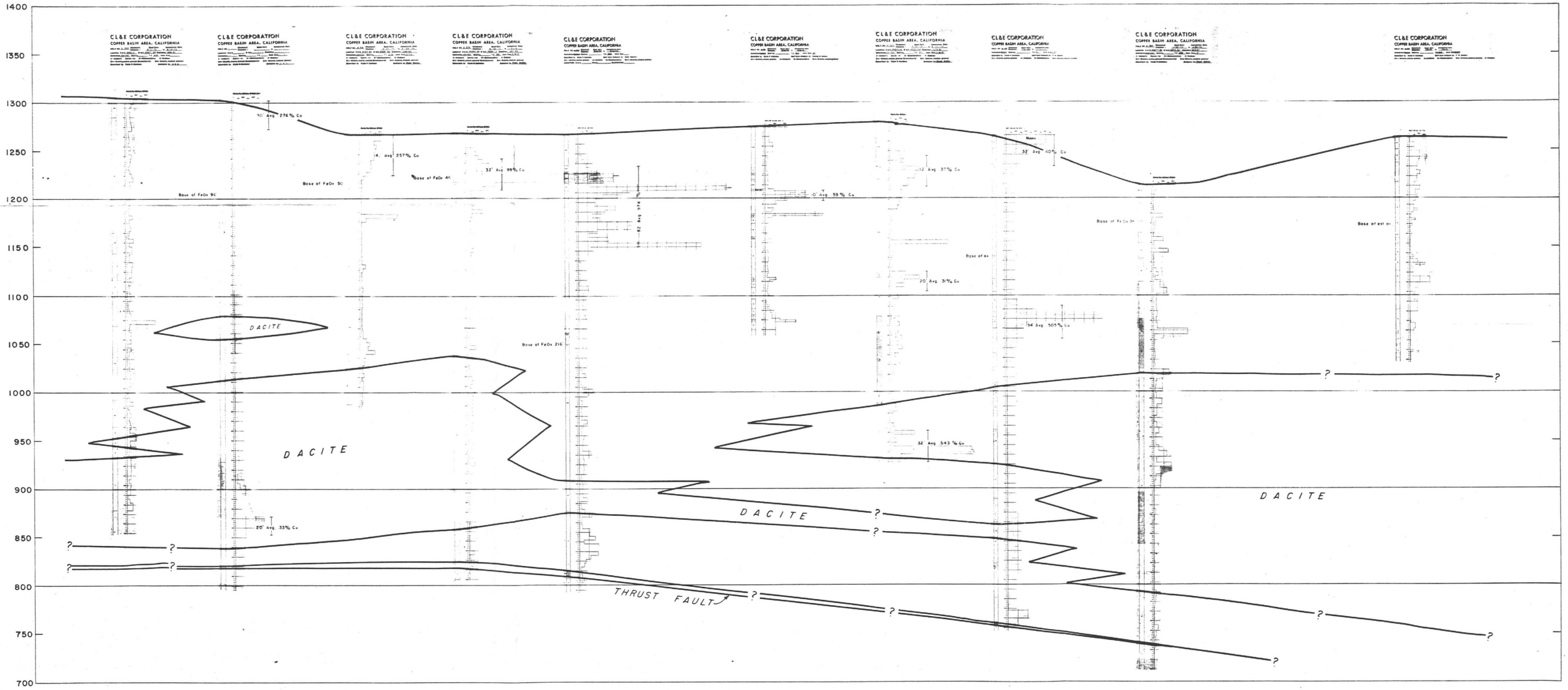
C L & E CORPORATION
COPPER BASIN AREA, CALIFORNIA
Base of oxidation
Base of FeOx
Base of FeOx
Base of FeOx
Base of FeOx
Base of FeOx
Base of FeOx
THRUST FAULT
D A C I T E

12-12'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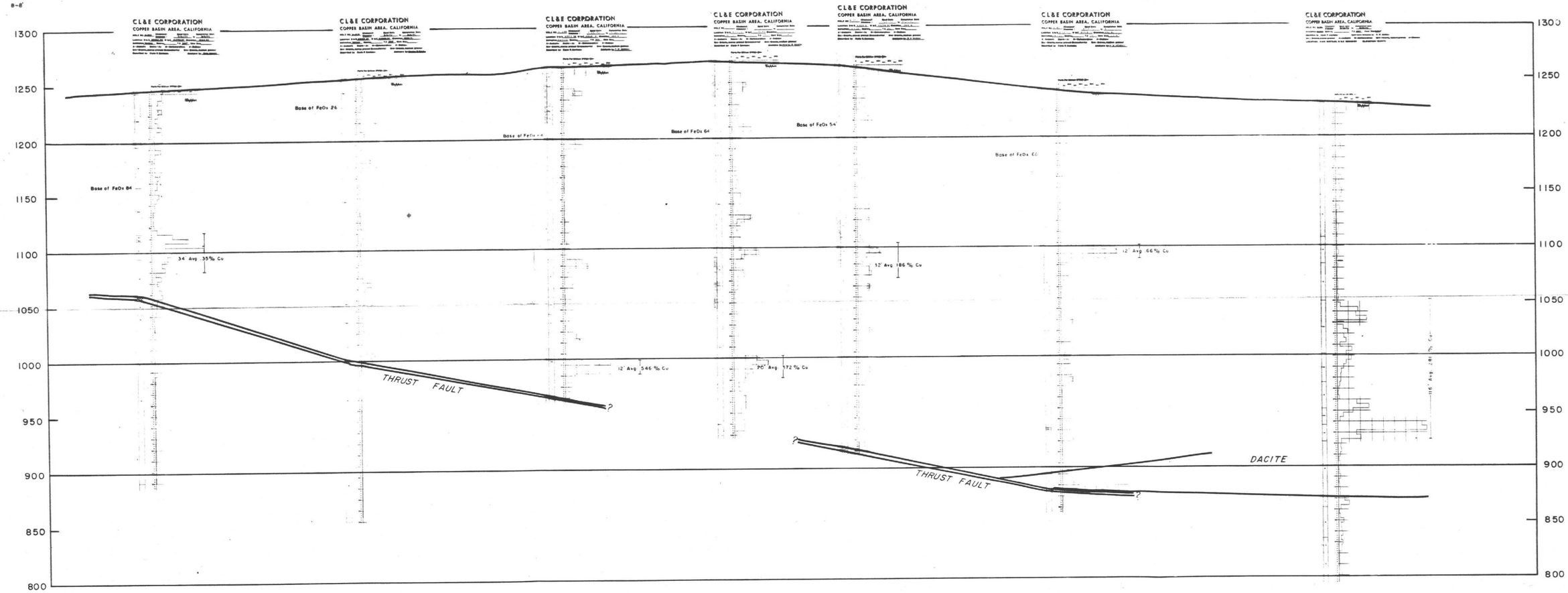
CL&E CORPORATION
COPPER BASIN AREA, CALIFORNIA
Base of FeOx 9C
Base of FeOx 5C
Base of FeOx 4C
Base of FeOx 216
Base of FeOx 3
Base of ox
Base of ext o
10' Avg 276% Cu
14' Avg 257% Cu
32' Avg 99% Cu
82' Avg 91%
10' Avg 59% Cu
12' Avg 37% Cu
20' Avg 31% Cu
32' Avg 40% Cu
34' Avg 505% Cu
32' Avg 543 % Cu
20' Avg 33% Cu
DACITE
DACITE
DACITE
DACITE
THRUST FAULT
?


8-8'
C L & E CORPORATION
COPPER BASIN AREA, CALIFORNIA
1300
1250
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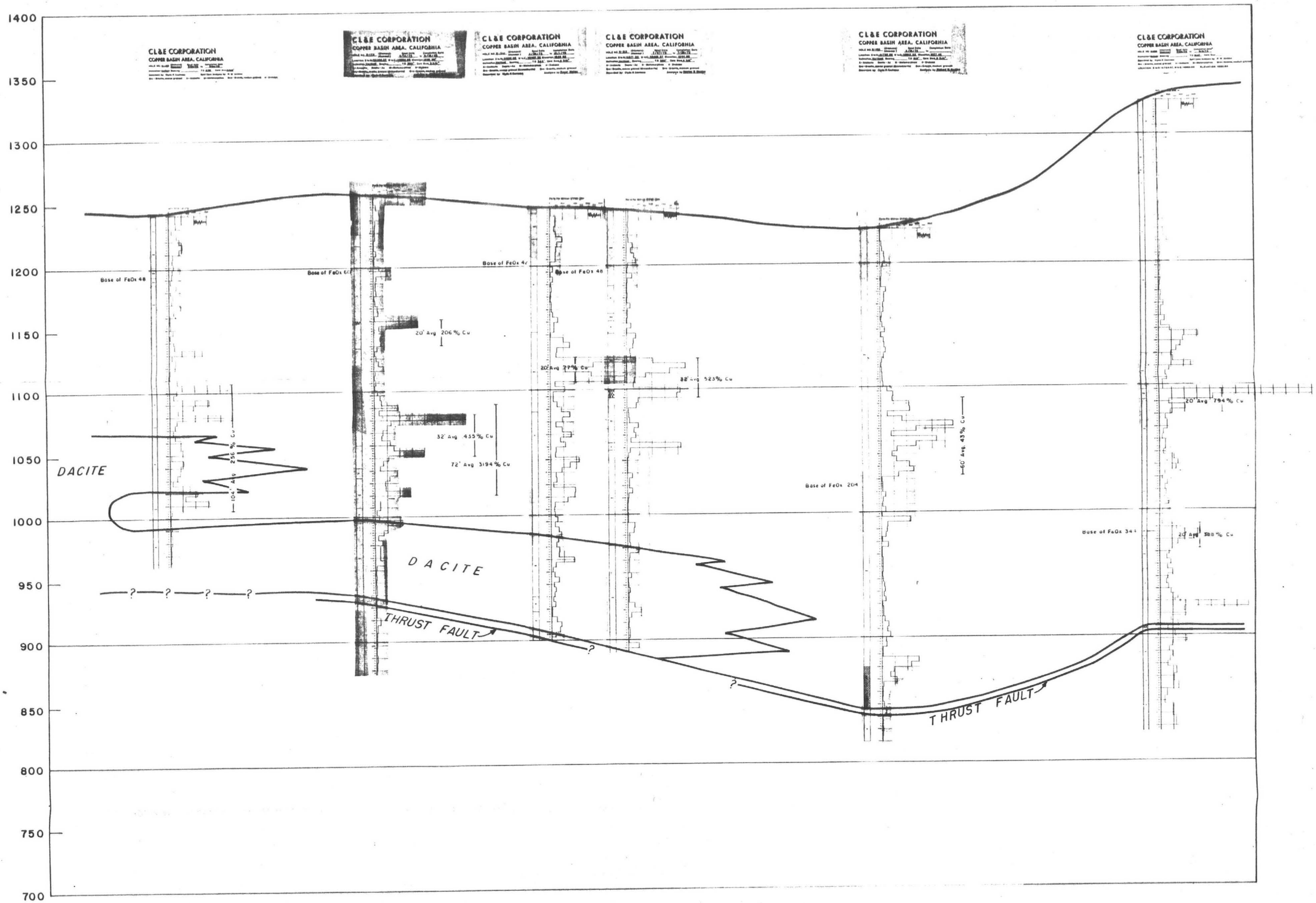
800
Base of FeOx 26
Base of FeOx 64
Base of FeOx 54'
Base of FeOx 84
34' Avg .35% Cu
12' Avg .546 % Cu
20' Avg .372 % Cu
12' Avg .186 % Cu
12' Avg .66% Cu
THRUST FAULT
THRUST FAULT
DACITE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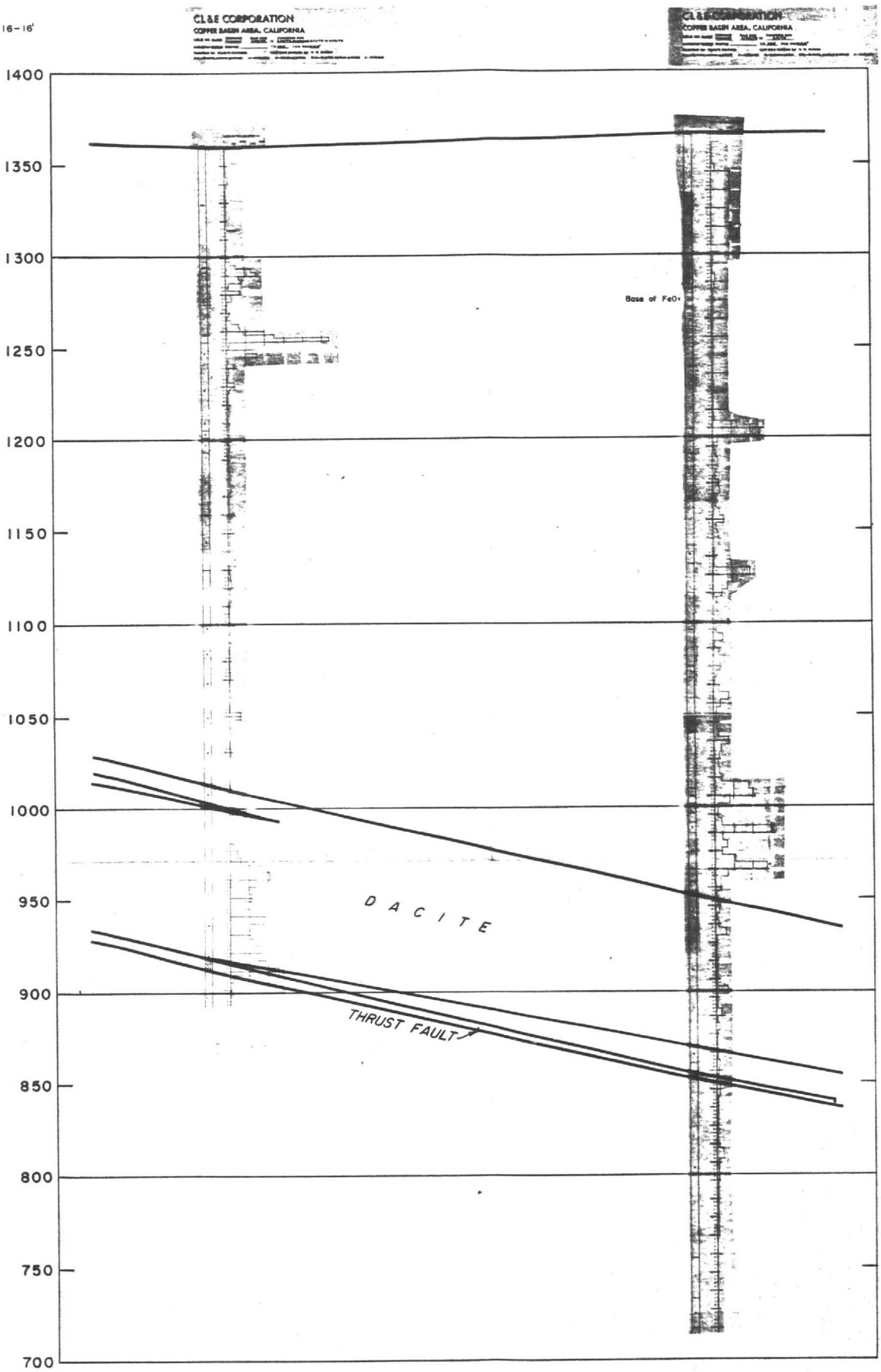
C L & E CORPORATION
COPPER BASIN AREA, CALIFORNIA
Base of FeOx 48
Base of FeOx 204
Base of FeOx 341
20' Avg 206 % Cu
20' Avg 279% Cu
88' Avg 523% Cu
32' Avg 455% Cu
72' Avg 3194% Cu
104' Avg 256 % Cu
60' Avg. 43% Cu
20' Avg 794 % Cu
DACITE
DACITE
THRUST FAULT
THRUST FAULT
?

16-16'


CL&E CORPORATION
COPPER BASIN AREA, CALIFORNIA
CL&E CORPORATION
COPPER BASIN AREA, CALIFORNIA
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1200
1150
1100
1050
1000
950
900
850
800
750
700
Base of FeO+
DACITE
THRUST FAULT

CHARLES E. MEAR
Exploration Supervisor

THE LOUISIANA LAND AND EXPLORATION COMPANY
MINERALS DIVISION

Suite 2340 Colorado State Bank Bldg.
1600 BROADWAY
DENVER, COLORADO 80202
303 893-1060

February 27, 1974

Mr. Glen L. Evans, Vice President
The Louisiana Land & Exploration Co.
Minerals Division
Suite 2340 Colorado State Bank Bldg.
1600 Broadway
Denver, Colorado 80202

Re: Copper Basin
San Bernardino County, Calif.

Dear Mr. Evans:

During the course of exploration work in the region I visited Mr. Clyde Caviness at your Copper Basin property on Feb. 19, 1974. He suggested that I again contact you for further discussions concerning the property.

The primary need for assured copper supplies by Essex remains, so we would consider participation in almost any phase of a project. Essex is considering the feasibility of building a smelter and Copper Basin could be a factor. On a date that is convenient for you I can travel to Denver for discussions concerning possible Essex involvement.

Since our last communication, Essex has merged with United Aircraft Corporation and is a wholly owned subsidiary of that company. This merger has not caused any changes in our exploration activities, but will probably create greater demands for assured sources of metal supplies.

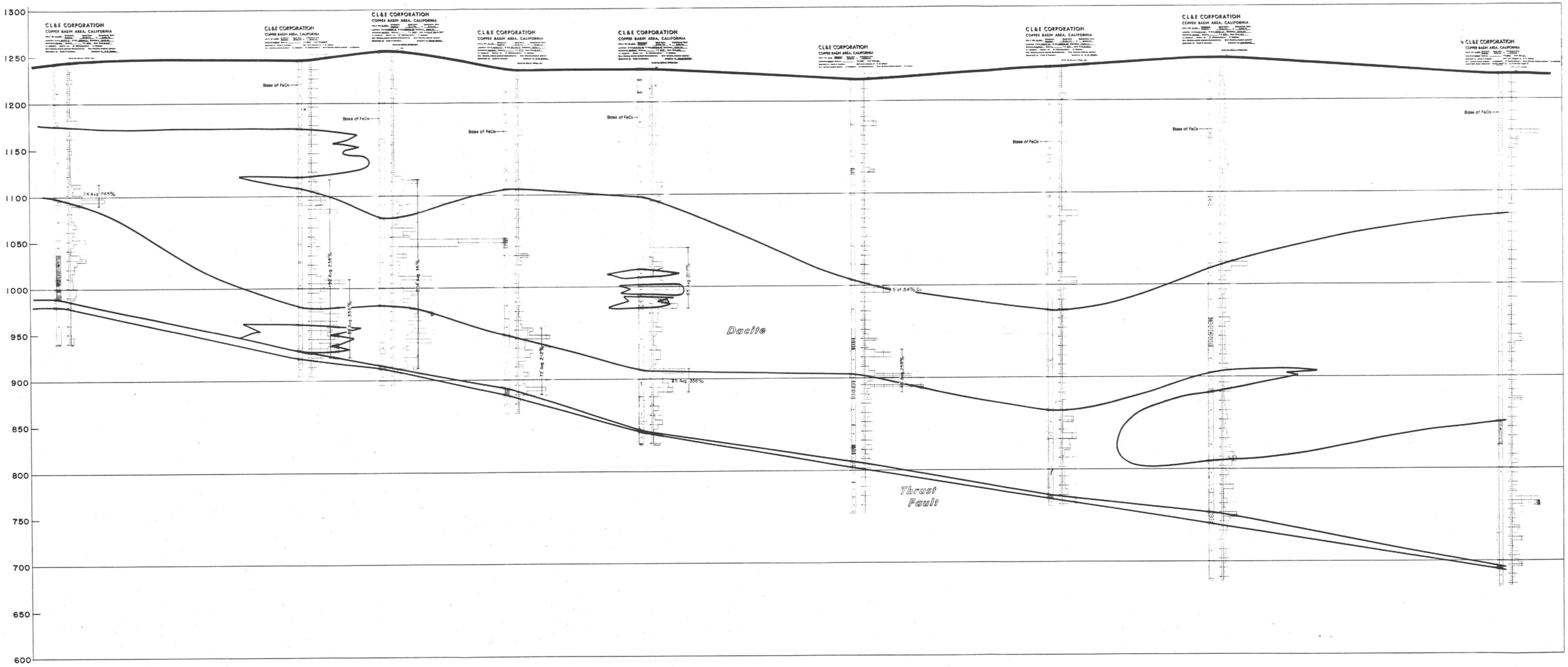
Very truly yours,

Dennis C. Temple
Senior Geologist

ESSEX INTERNATIONAL, INC.

DCT:td
attachment

5-5'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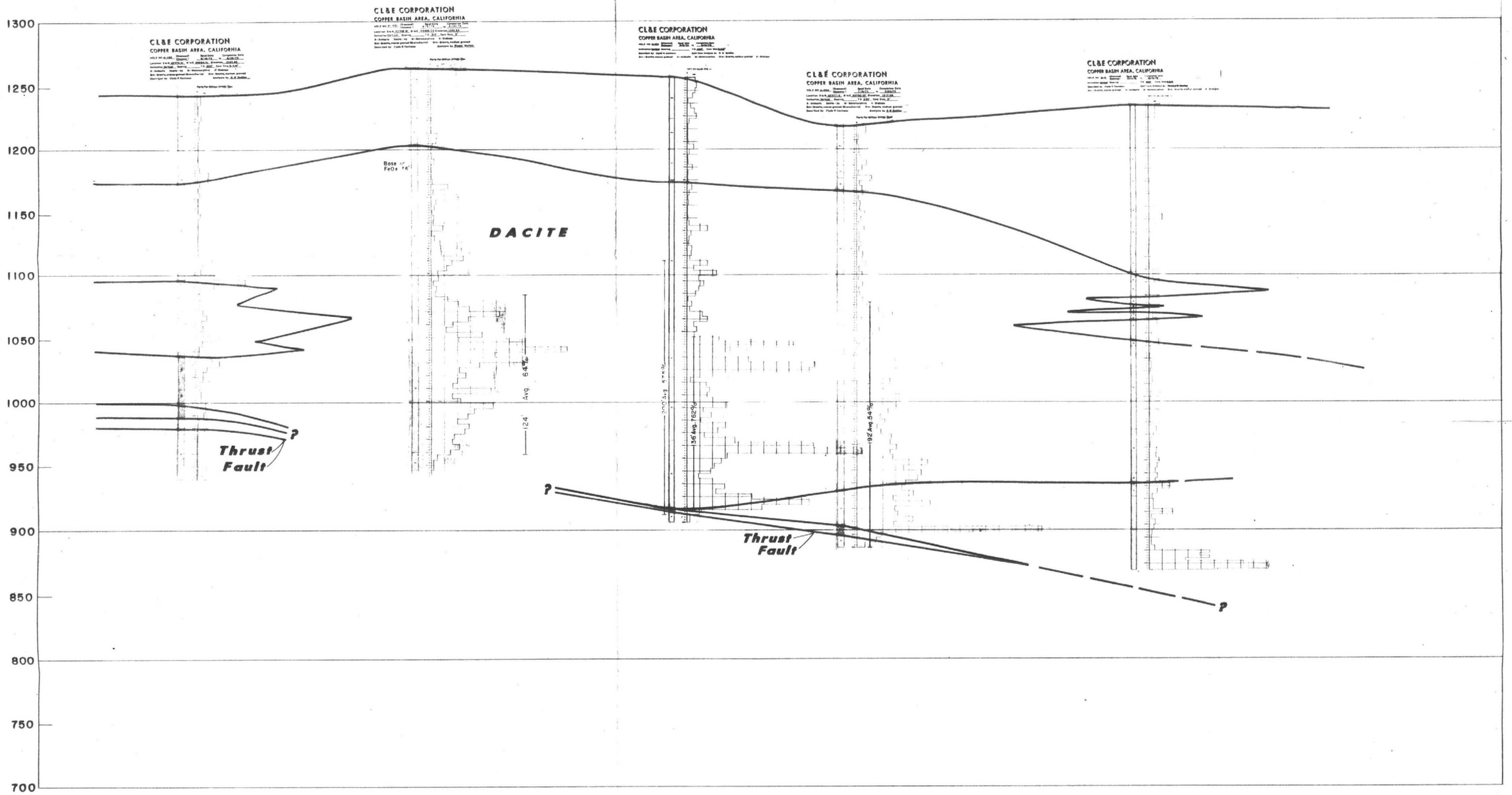
C L & E CORPORATION
COPPER BASIN AREA, CALIFORNIA
Base of FeOx
74 Avg 265%
Dacite
Thrust Fault

4-4'


C L & E CORPORATION
COPPER BASIN AREA, CALIFORNIA
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COPPER BASIN AREA, CALIFORNIA
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C L & E CORPORATION
COPPER BASIN AREA, CALIFORNIA
C L & E CORPORATION
COPPER BASIN AREA, CALIFORNIA
1300
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850
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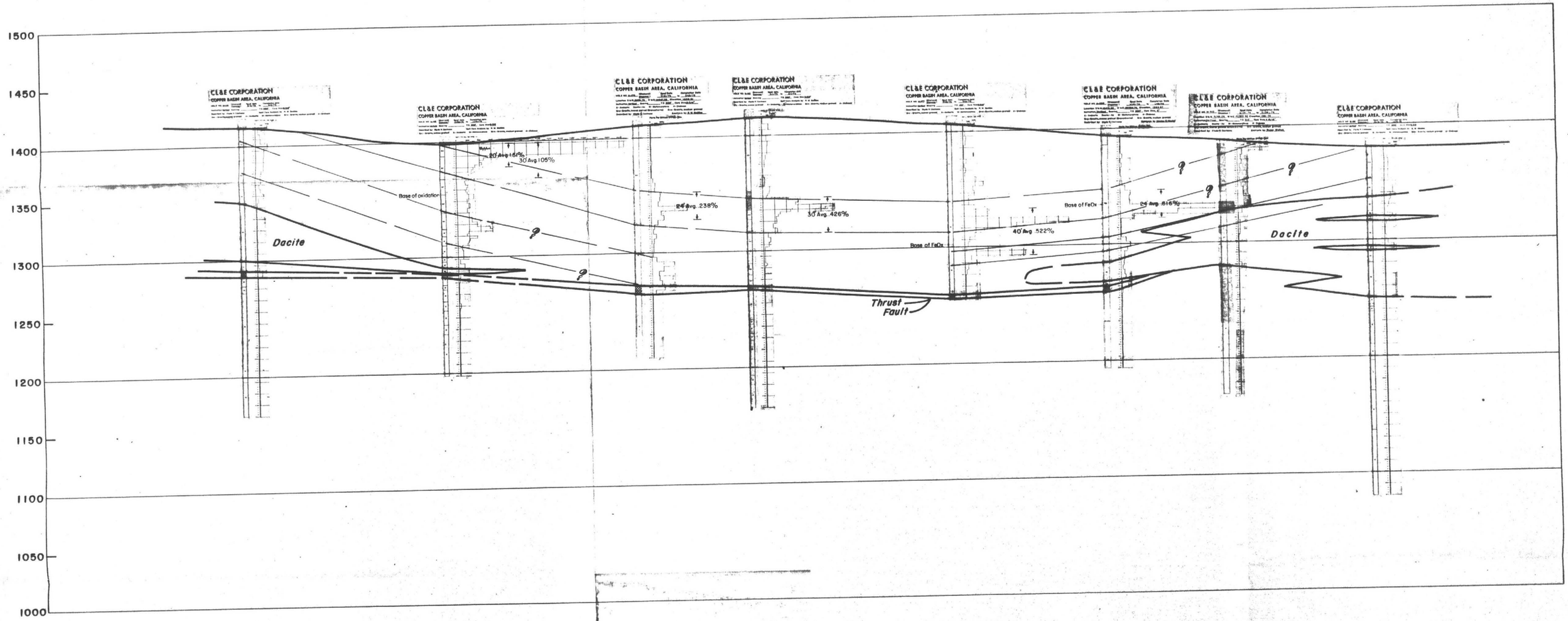
750
700
Base of FeOx 14'
DACITE
Avg 64%
124'
136' Avg 76.2%
192' Avg 54%
Thrust Fault
?
Thrust Fault
?
?

21-21'


1500
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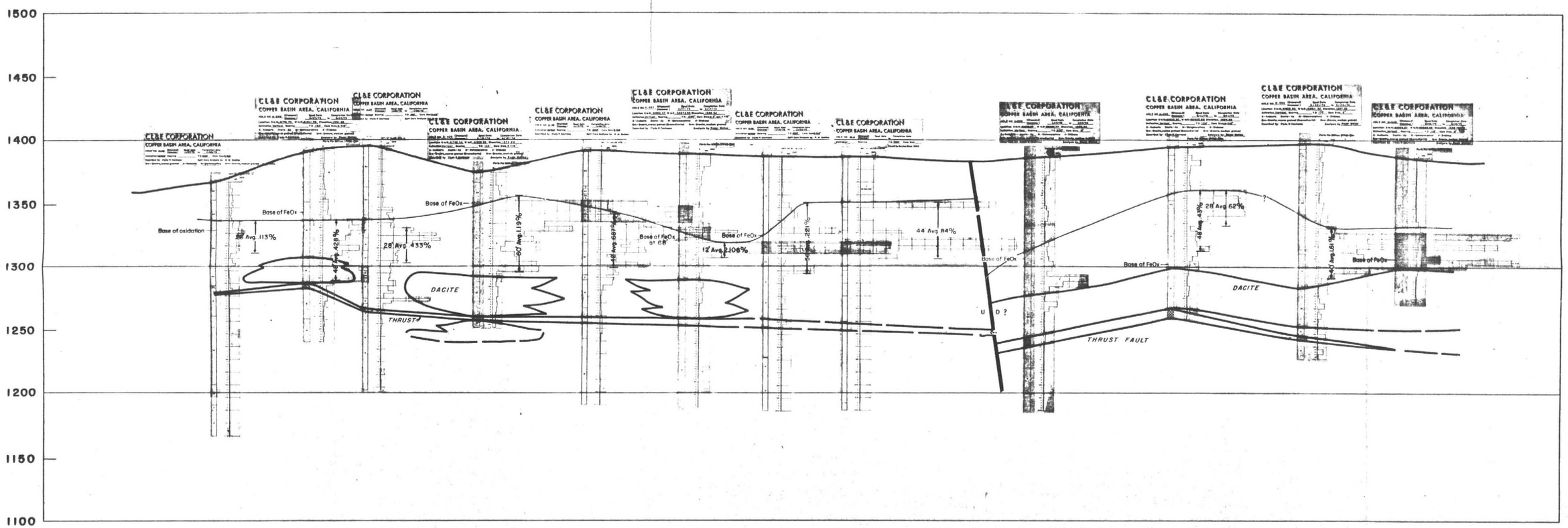
CL&E CORPORATION
COPPER BASIN AREA, CALIFORNIA
Base of oxidation
Dacite
30' Avg 105%
24' Avg .238%
30' Avg .426%
Base of FeOx
40' Avg .522%
24' Avg .816%
Thrust Fault
Dacite

20-20'


1500
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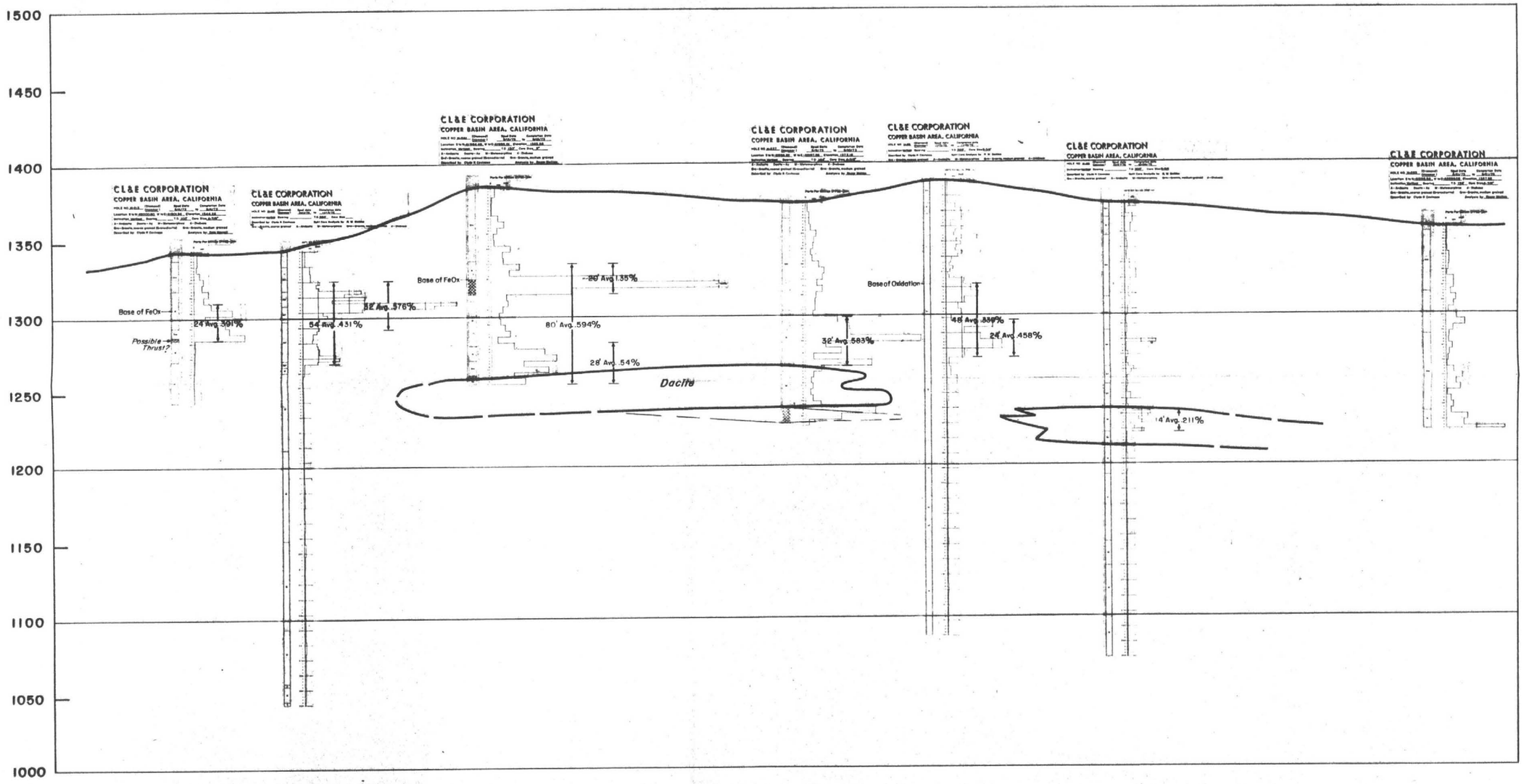
CL&E CORPORATION
COPPER BASIN AREA, CALIFORNIA
Base of FeOx
Base of oxidation
28' Avg. 113%
46' Avg. 428%
28' Avg. 433%
DACITE
THRUST
50' Avg. 119%
28' Avg. 687%
Base of FeOx at 68'
12' Avg. 2108%
Base of FeOx
50' Avg. 281%
44 Avg. 84%
Base of FeOx
U D ?
THRUST FAULT
Base of FeOx
DACITE
46' Avg. 43%
28' Avg. 62%
50' Avg. 161%
Base of FeOx

19-19'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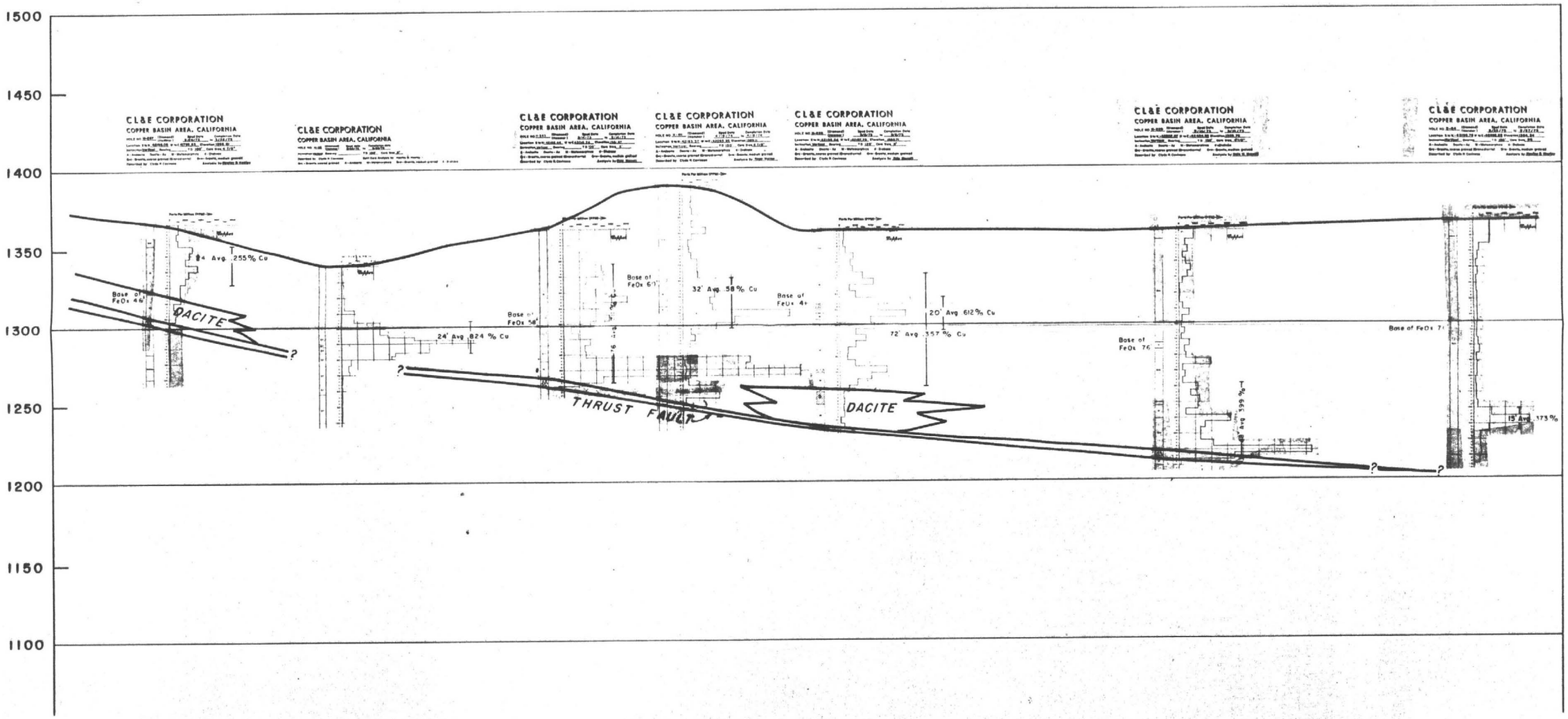
CL&E CORPORATION
COPPER BASIN AREA, CALIFORNIA
Base of FeOx
Possible Thrust?
24' Avg .391%
54' Avg .431%
52' Avg .576%
20' Avg 1.35%
80' Avg .594%
28' Avg .54%
Dacite
Base of Oxidation
32' Avg .583%
48' Avg .334%
24' Avg .458%
14' Avg .211%

18-18'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CL&E CORPORATION
COPPER BASIN AREA, CALIFORNIA
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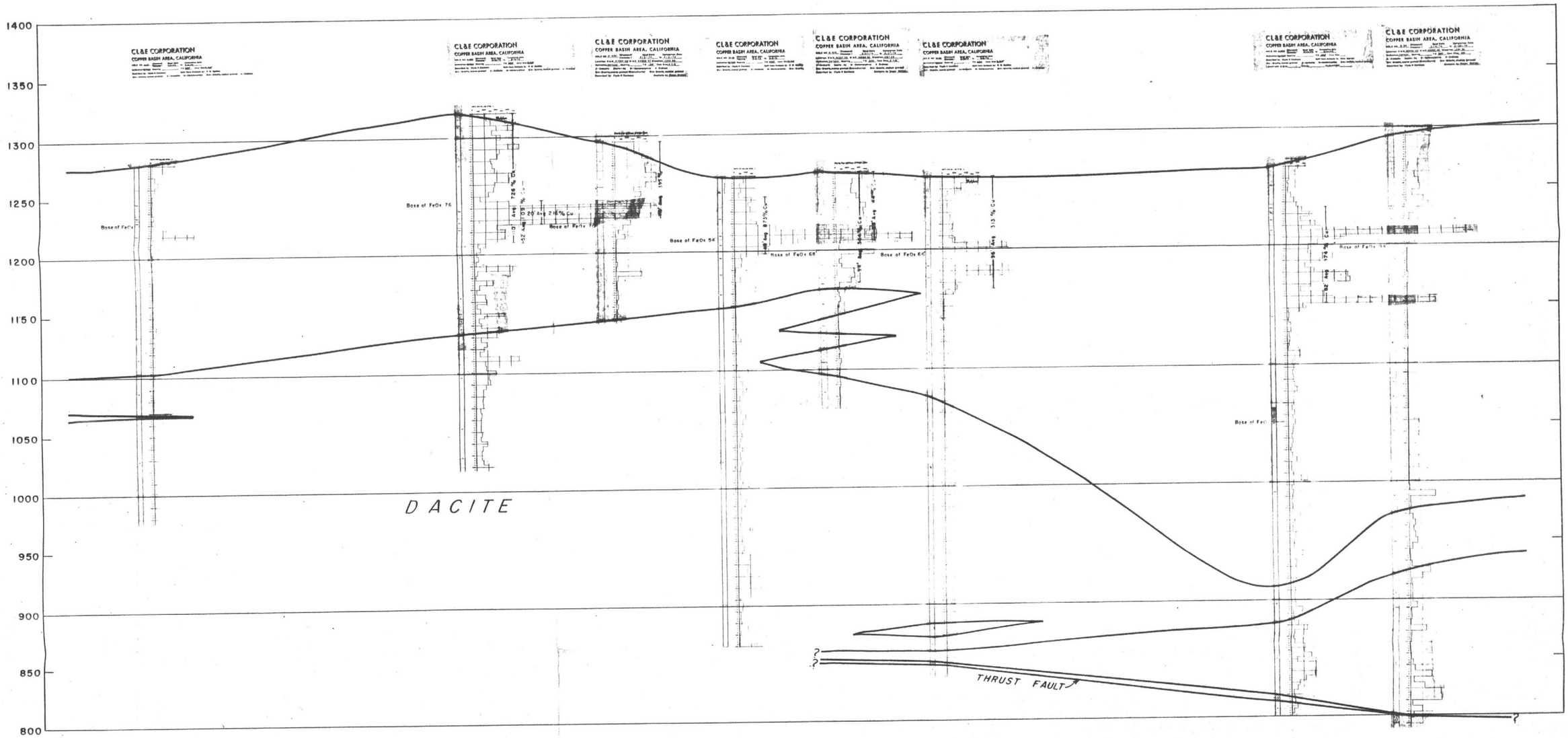
CL&E CORPORATION
COPPER BASIN AREA, CALIFORNIA
CL&E CORPORATION
COPPER BASIN AREA, CALIFORNIA
Base of FeOx 46'
DACITE
24' Avg .255% Cu
24' Avg .824 % Cu
Base of FeOx 58'
Base of FeOx 61'
32' Avg .58% Cu
Base of FeOx 4+
THRUST FAULT
DACITE
20' Avg 612% Cu
72' Avg .357 % Cu
Base of FeOx 76
Base of FeOx 7
15' Avg .173%

11-11'


CL&E CORPORATION
COPPER BASIN AREA, CALIFORNIA
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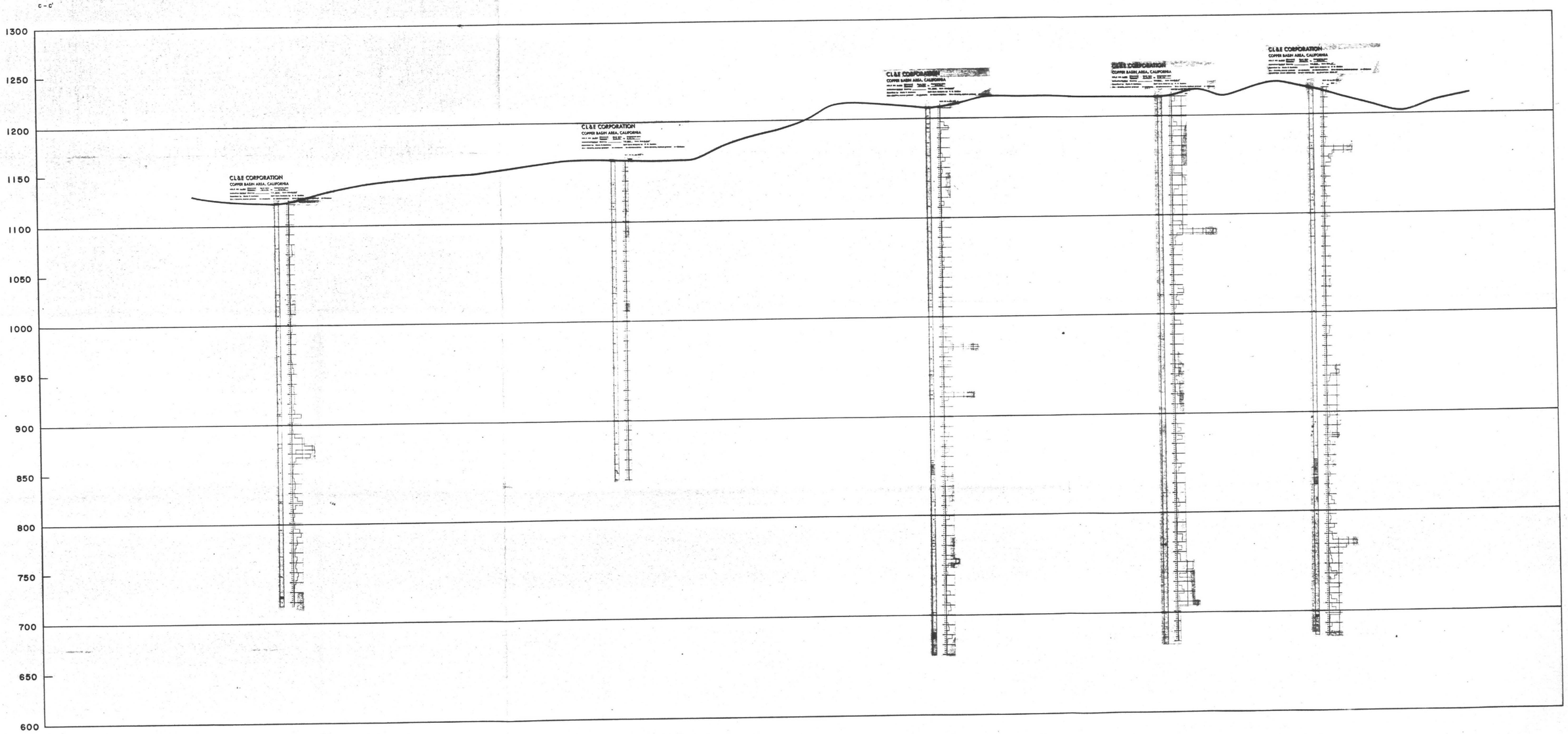
Base of FeOx 76
Base of FeOx 54
Base of FeOx 68'
Base of FeOx 61'
DACITE
THRUST FAULT

C - C'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C L & E CORPORATION
COPPER BASIN AREA, CALIFORNIA
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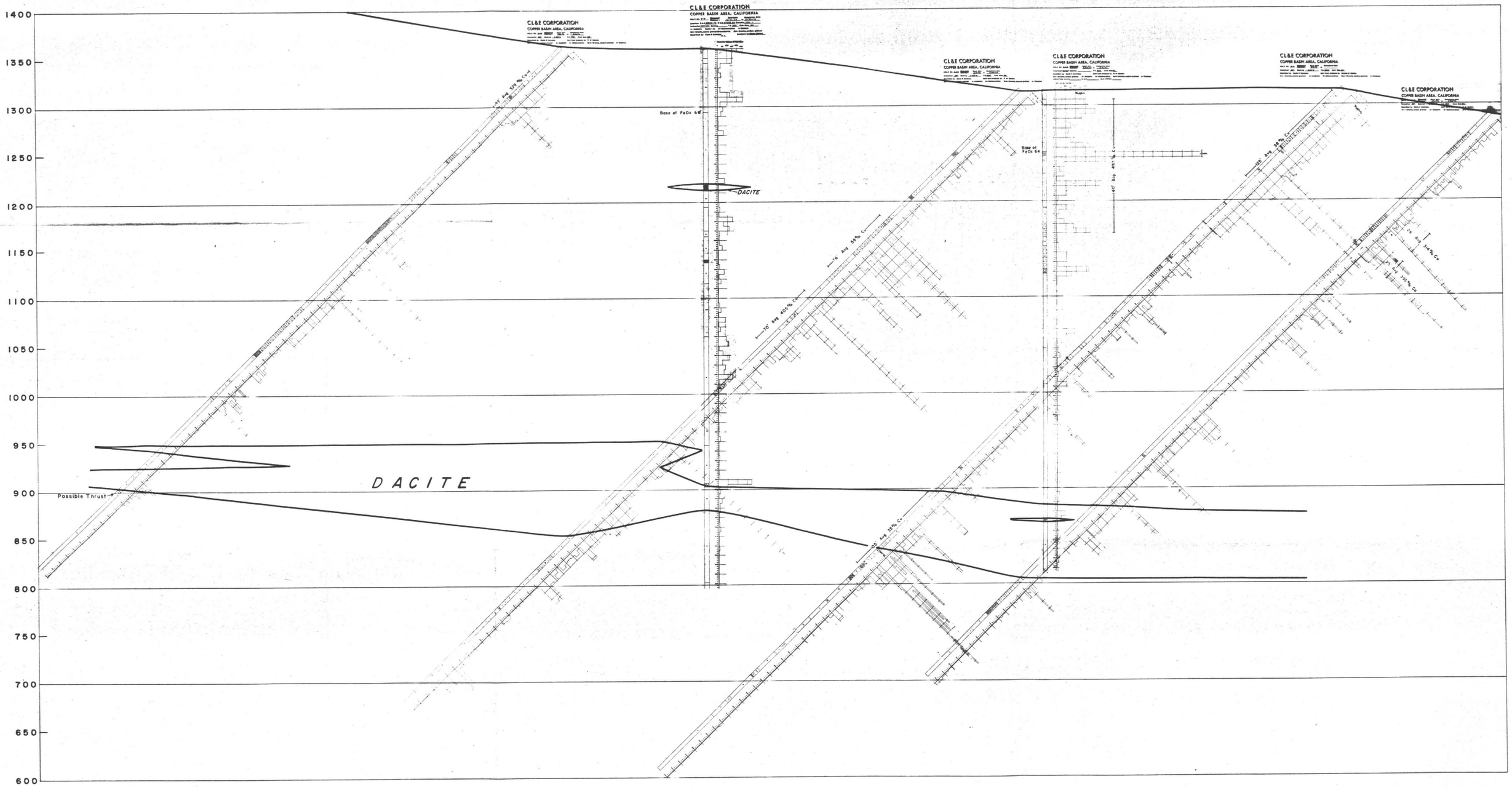
C L & E CORPORATION
COPPER BASIN AREA, CALIFORNIA

E-E'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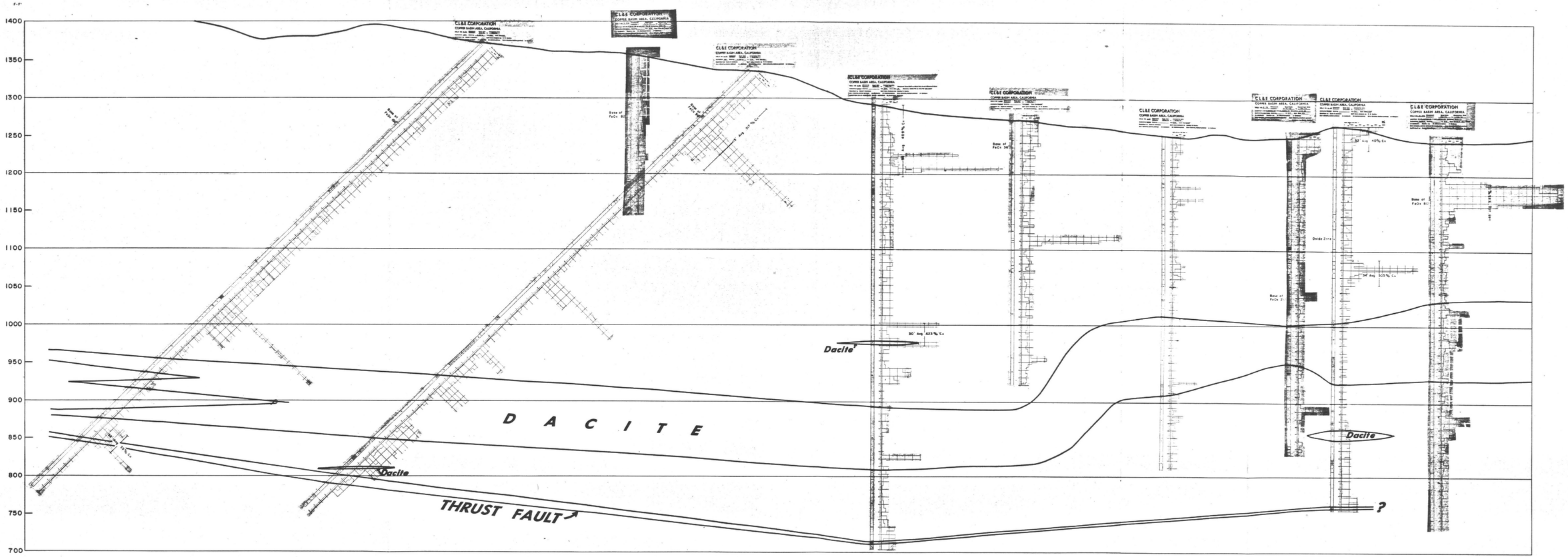
CL&E CORPORATION
COPPER BASIN AREA, CALIFORNIA
Base of FeOx 64
DACITE
Possible Thrust
DACITE
Base of FeOx 64


F-F'
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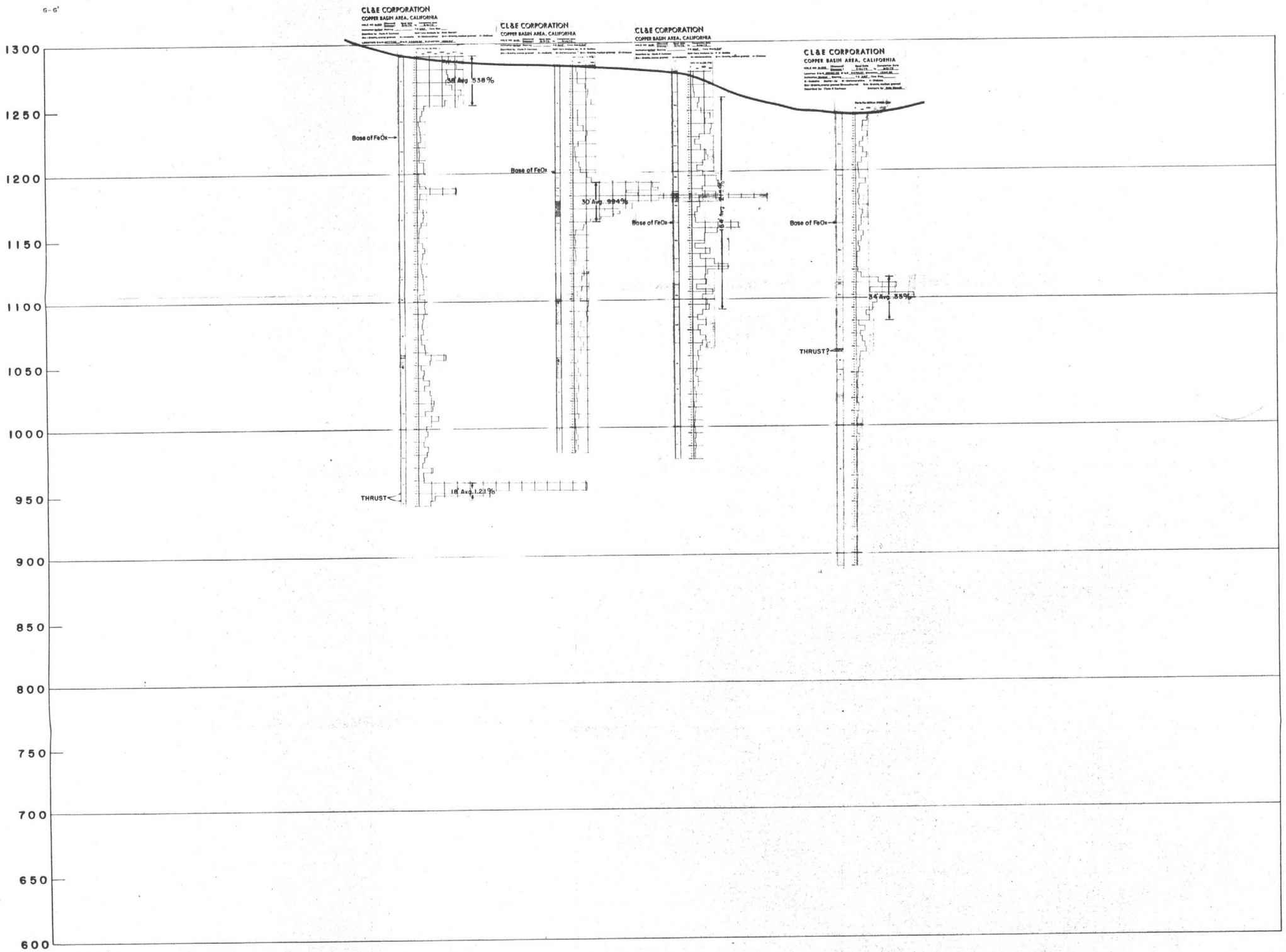
C L & E CORPORATION
COPPER BASIN AREA, CALIFORNIA
Base of FeOx 80
Base of FeOx 34
Base of FeOx 2
Oxide Zone
Avg 30% Cu
Avg 32% Cu
Avg 34% Cu
Avg 30% Cu
Dacite
D A C I T E
THRUST FAULT
?


G-G'
CL&E CORPORATION
COPPER BASIN AREA, CALIFORNIA
CL&E CORPORATION
COPPER BASIN AREA, CALIFORNIA
CL&E CORPORATION
COPPER BASIN AREA, CALIFORNIA
CL&E CORPORATION
COPPER BASIN AREA, CALIFORNIA
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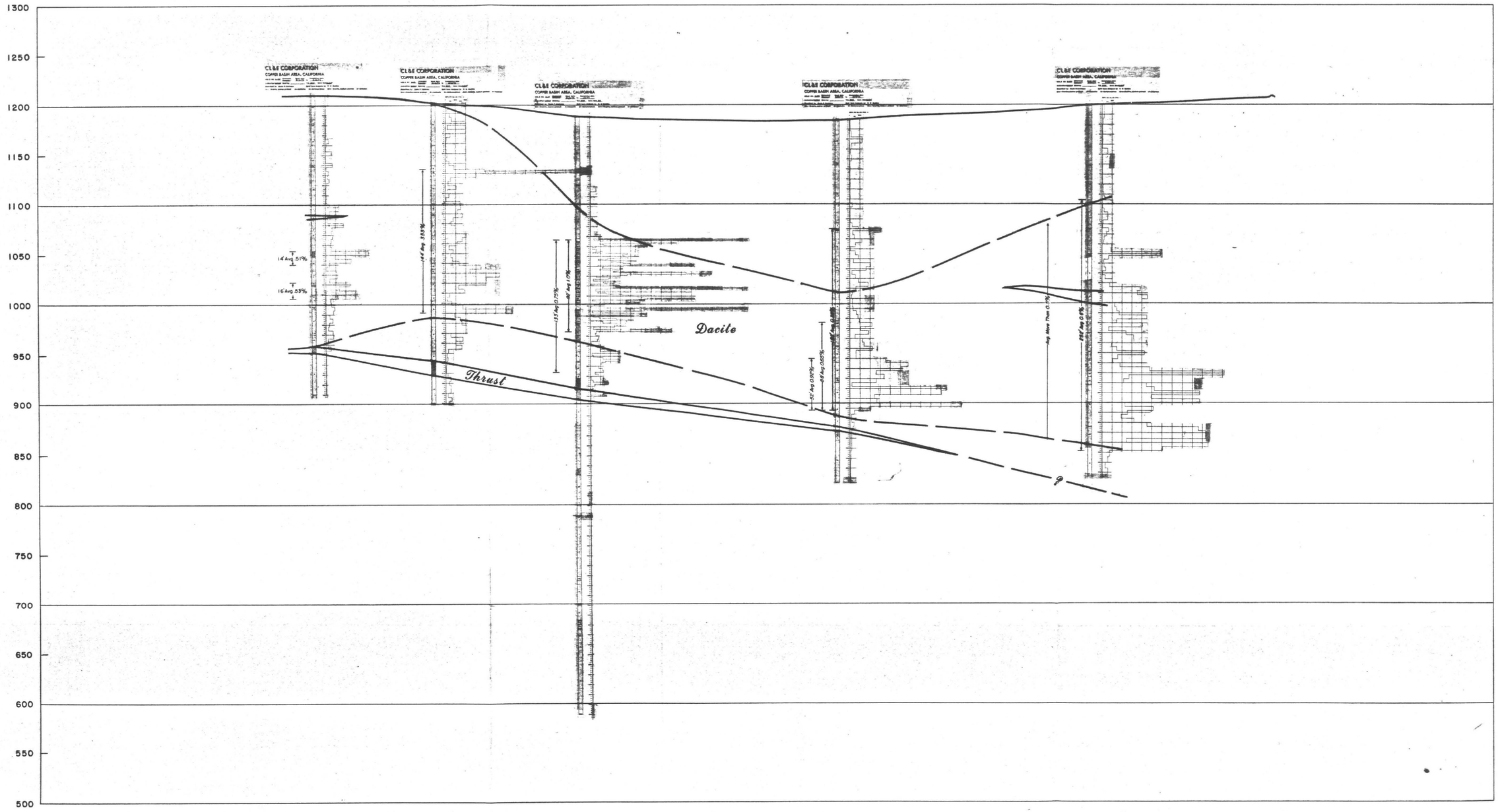
650
600
Base of FeOx
Base of FeOx
Base of FeOx
Base of FeOx
THRUST
THRUST?
36' Avg. 5.38%
30' Avg. 9.94%
18' Avg. 1.21%
34' Avg. .88%

H-H'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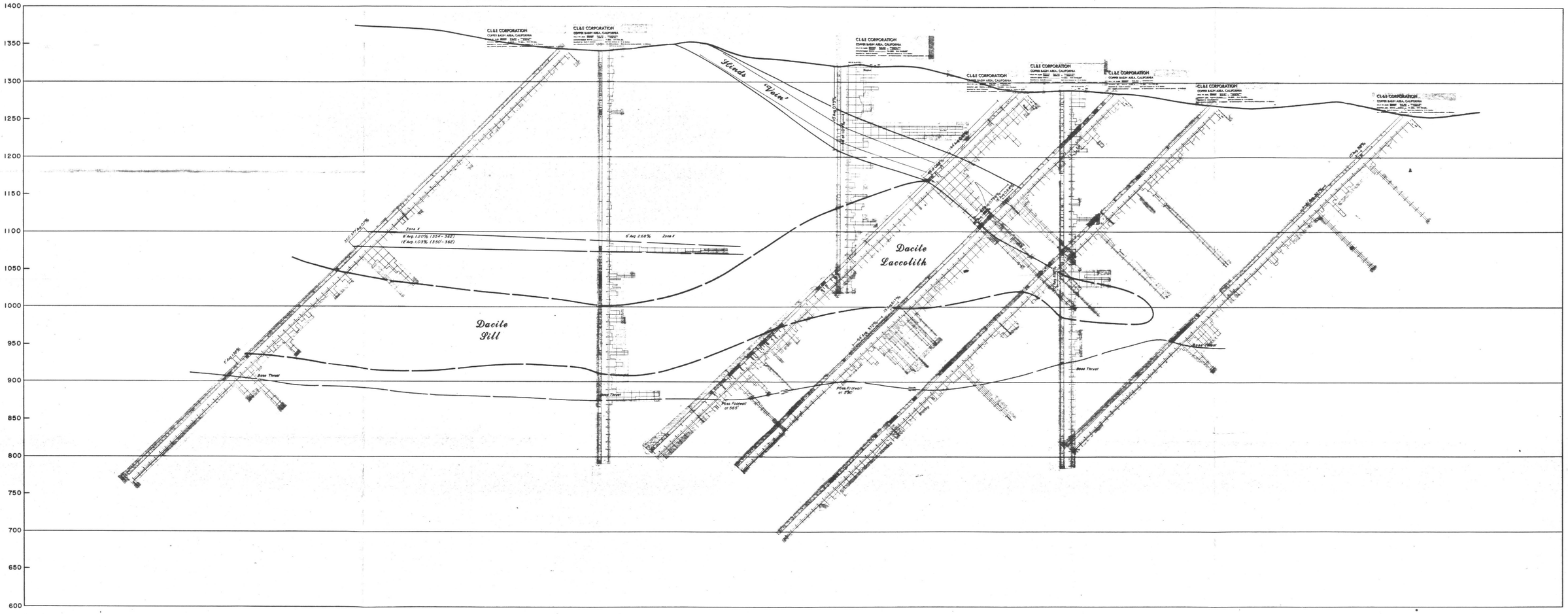
C L & E CORPORATION
COPPER BASIN AREA, CALIFORNIA
14' Avg .51%
16' Avg .53%
14' Avg .55%
13' Avg 0.75%
20' Avg 1.0%
Dacite
Thrust
Avg More Than 0.1%
194' Avg 0.0%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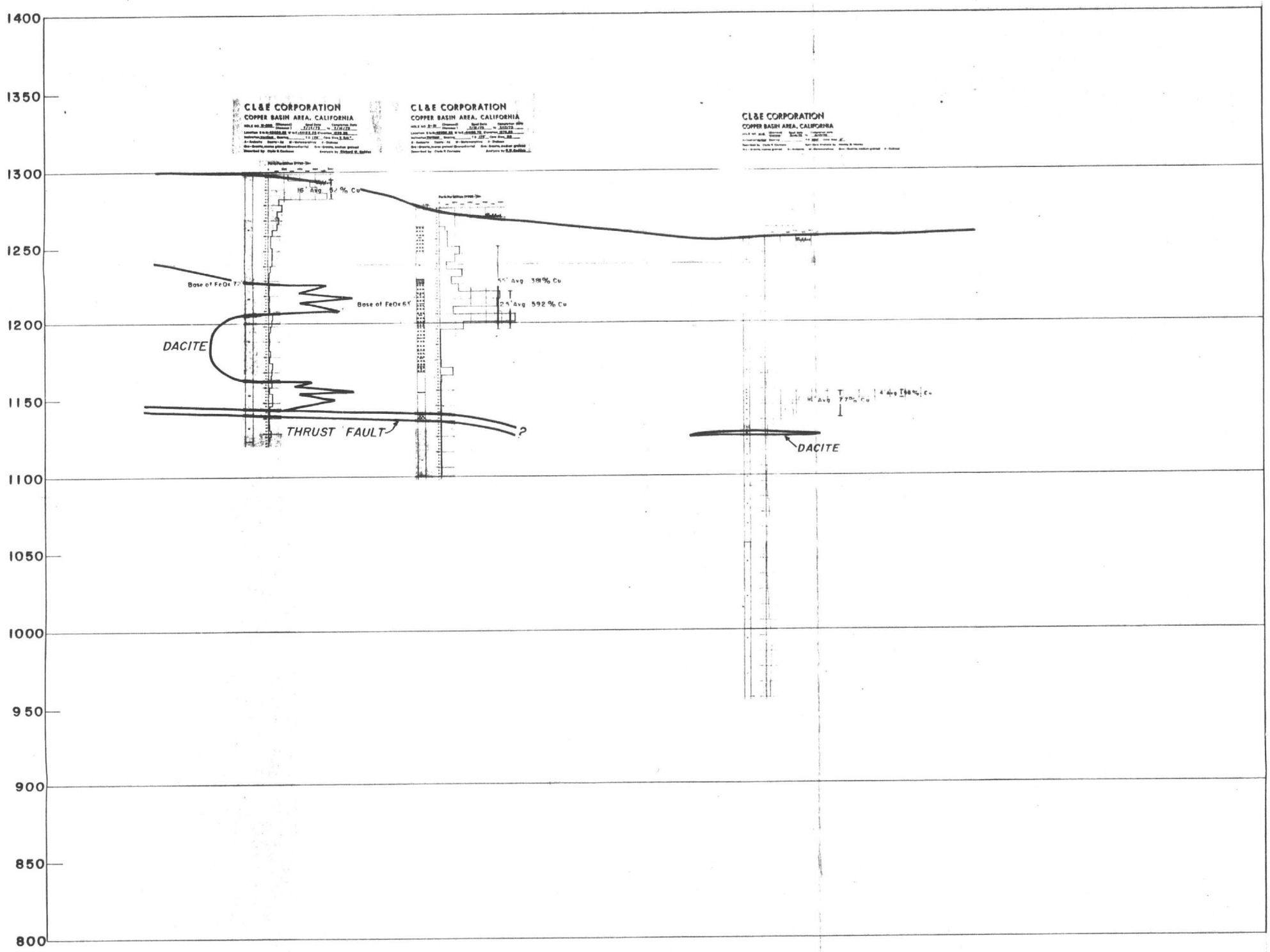
C L & E CORPORATION
COPPER BASIN AREA, CALIFORNIA
Hinds "Vein"
Zone X
6' Avg. 1.20% (354'-362')
18' Avg. 1.03% (350'-368')
6' Avg. 2.68%
Zone X
Dacite Sill
Dacite Laccolith
Base Thrust
Hole Footwall at 565'
Hole Footwall at 730'

J-J'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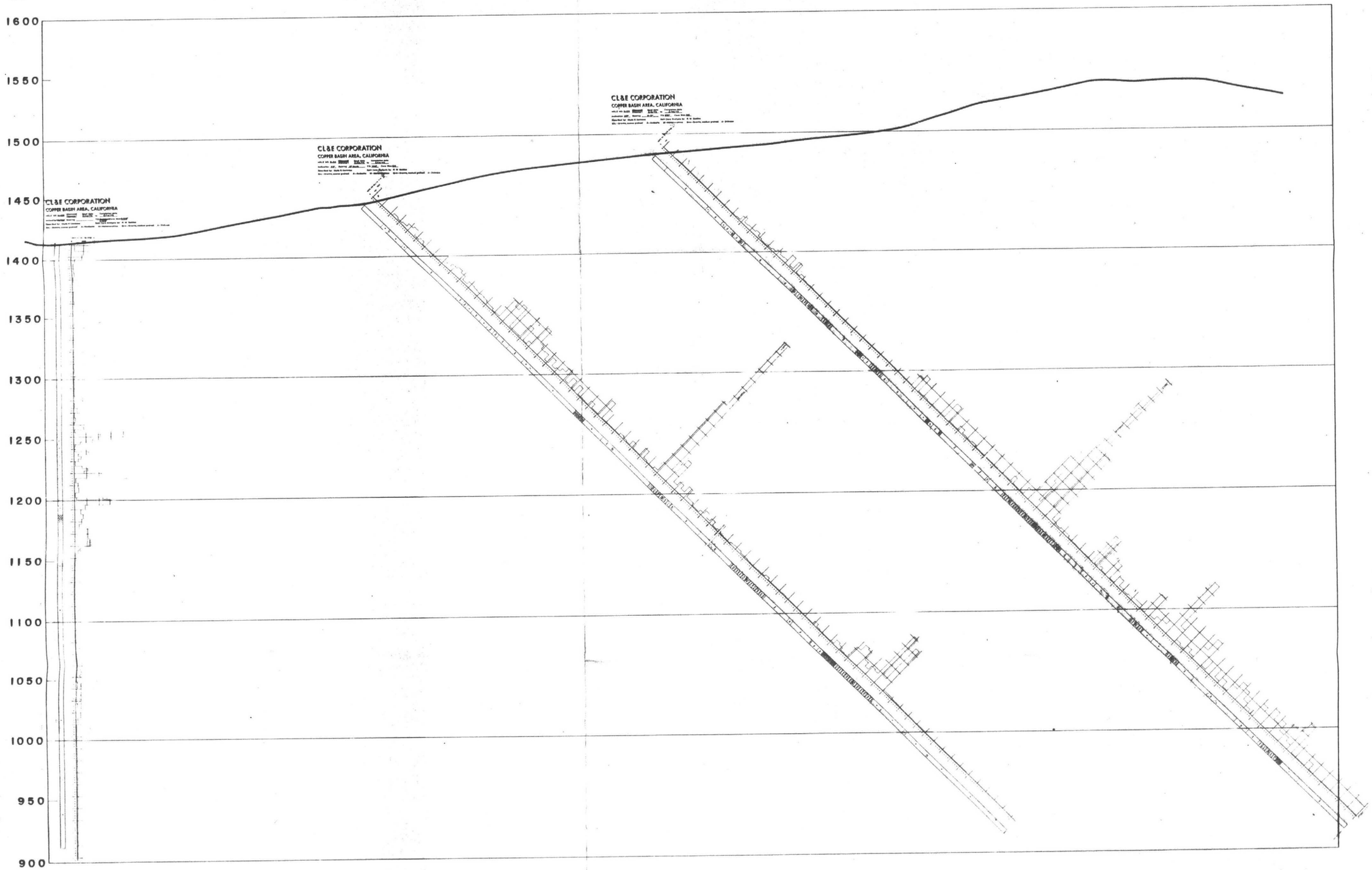
CL&E CORPORATION
COPPER BASIN AREA, CALIFORNIA
CL&E CORPORATION
COPPER BASIN AREA, CALIFORNIA
CL&E CORPORATION
COPPER BASIN AREA, CALIFORNIA
16' Avg. 5.7 % Cu
Base of FeOx 7.2'
Base of FeOx 6.1'
DACITE
THRUST FAULT
?
5.5' Avg 3.81 % Cu
2.5' Avg 5.92 % Cu
DACITE

K-K'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COPPER BASIN AREA, CALIFORNIA
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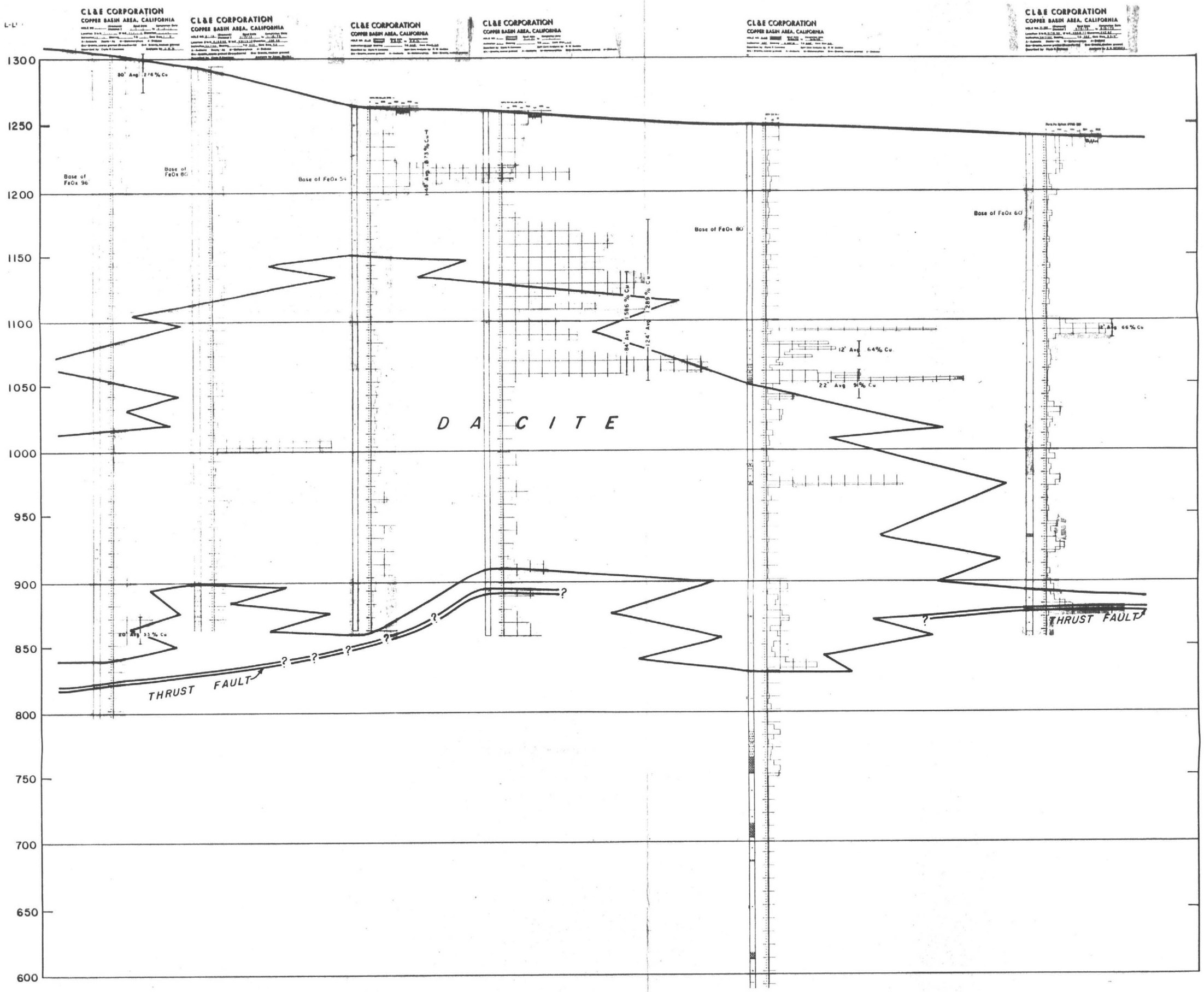
CL&E CORPORATION
COPPER BASIN AREA, CALIFORNIA


CL&E CORPORATION
COPPER BASIN AREA, CALIFORNIA
L-L'
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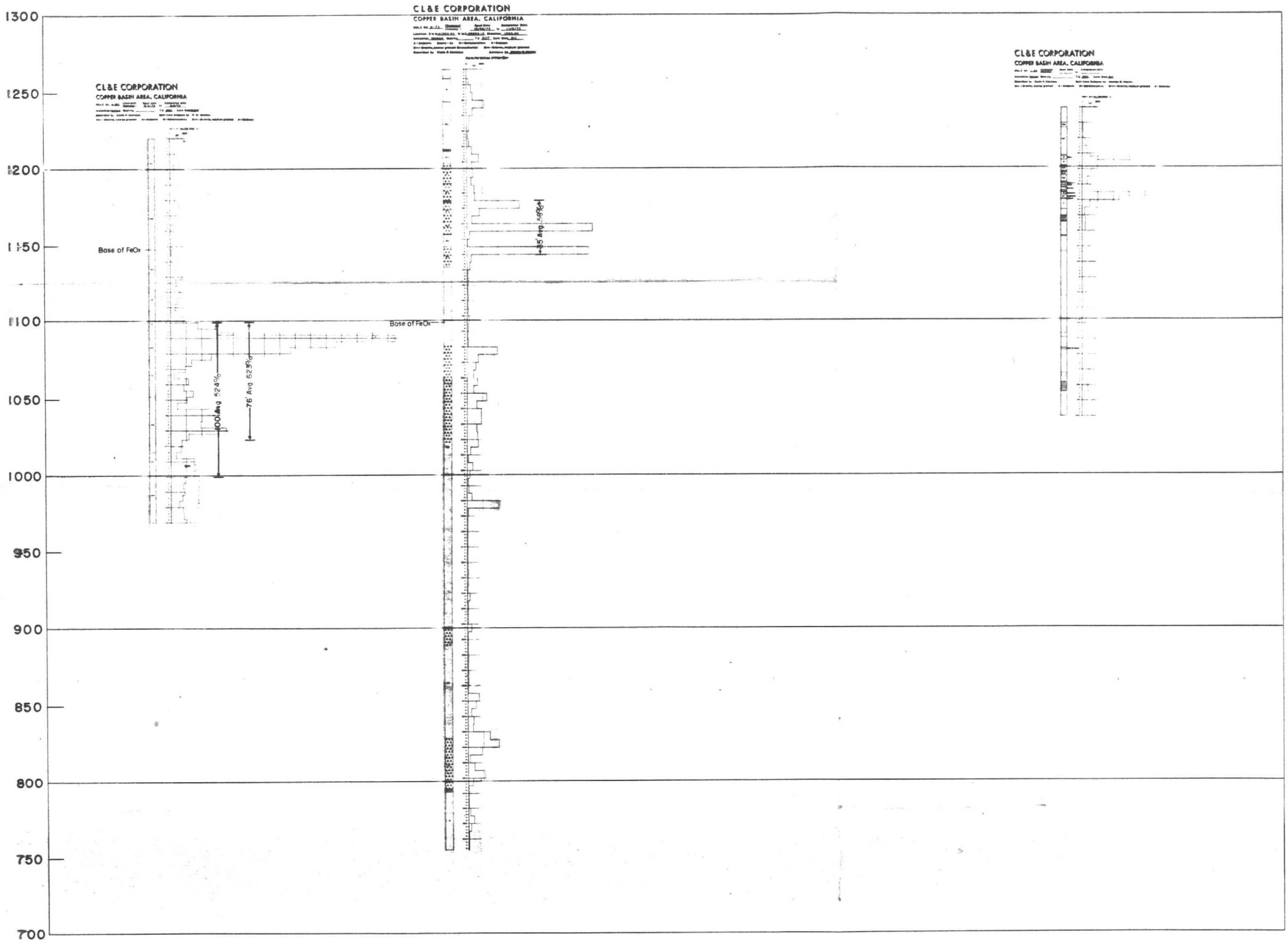
650
600
80' Avg 2.76 % Cu
Base of FeOx 96
Base of FeOx 80
Base of FeOx 54
148' Avg 1.73 % Cu
Base of FeOx 80
Base of FeOx 60
1.586 % Cu
2.89 % Cu
84' Avg
124' Avg
12' Avg 6.4% Cu
22' Avg 9.1% Cu
8' Avg 6.6% Cu
D A C I T E
THRUST FAULT
THRUST FAULT

M-M'


CL&E CORPORATION
COPPER BASIN AREA, CALIFORNIA
CL&E CORPORATION
COPPER BASIN AREA, CALIFORNIA
CL&E CORPORATION
COPPER BASIN AREA, CALIFORNIA
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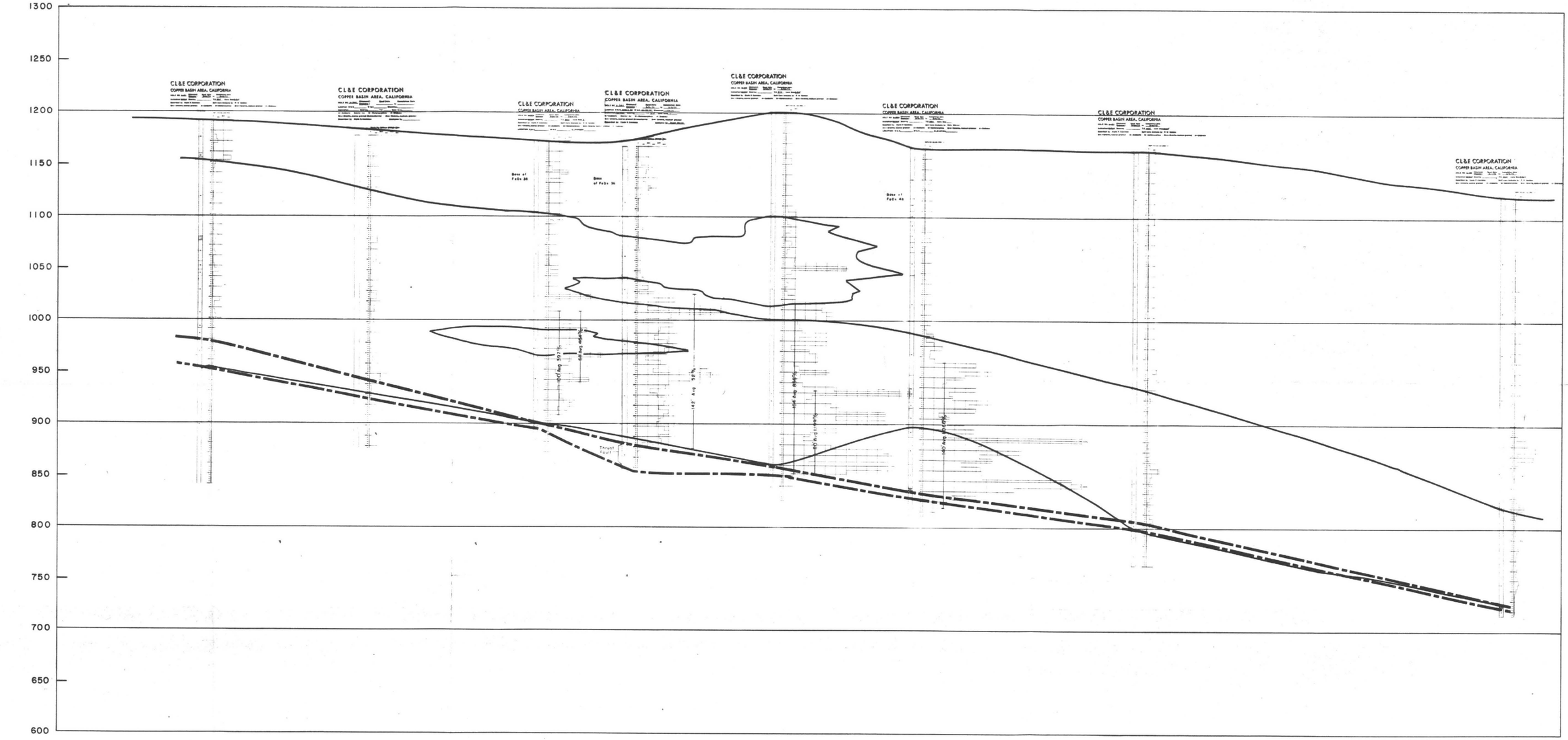
Base of FeOx
Base of FeOx
100' Avg 52%
76' Avg 52%
95' Avg 59%

1-1' (cont)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CL&E CORPORATION
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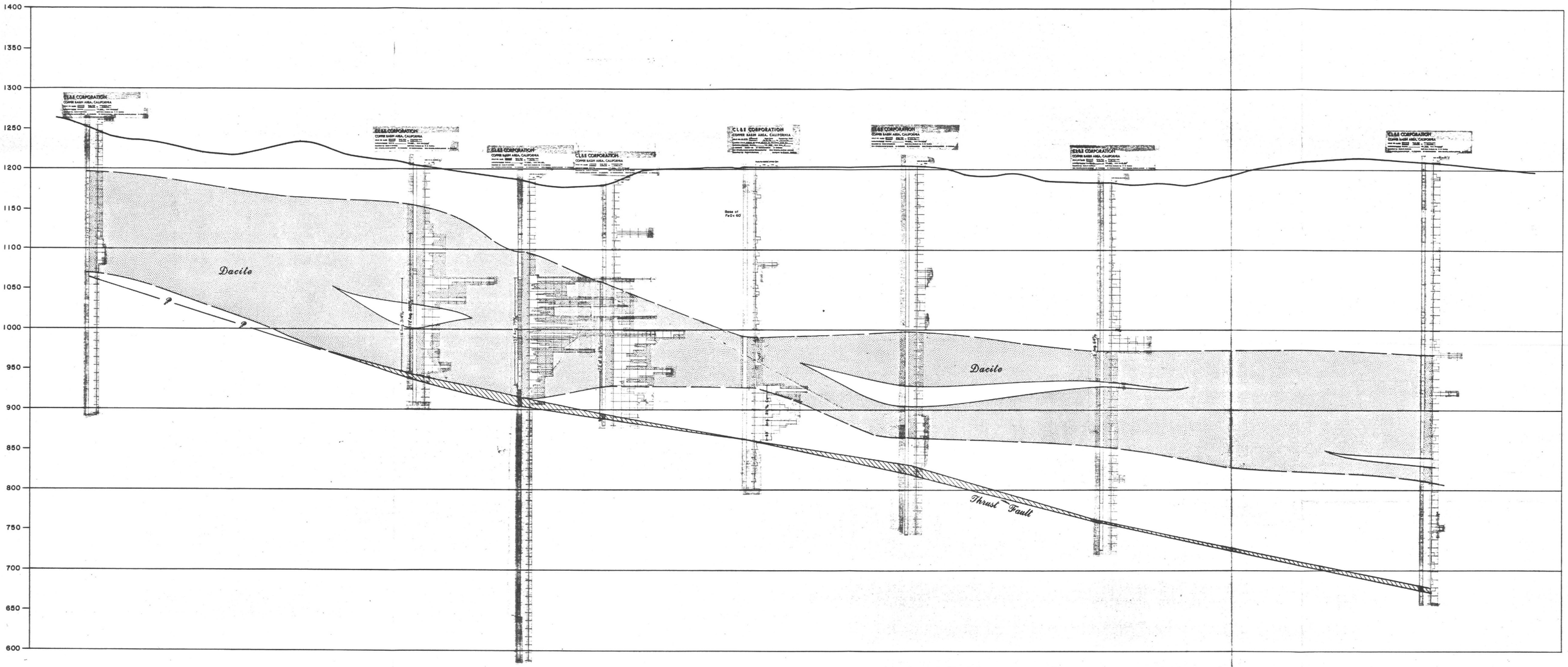
COPPER BASIN AREA, CALIFORNIA
CL&E CORPORATION
COPPER BASIN AREA, CALIFORNIA
CL&E CORPORATION
COPPER BASIN AREA, CALIFORNIA
Base of FeOx 38
Base of FeOx 36
Base of FeOx 46
Thrust fault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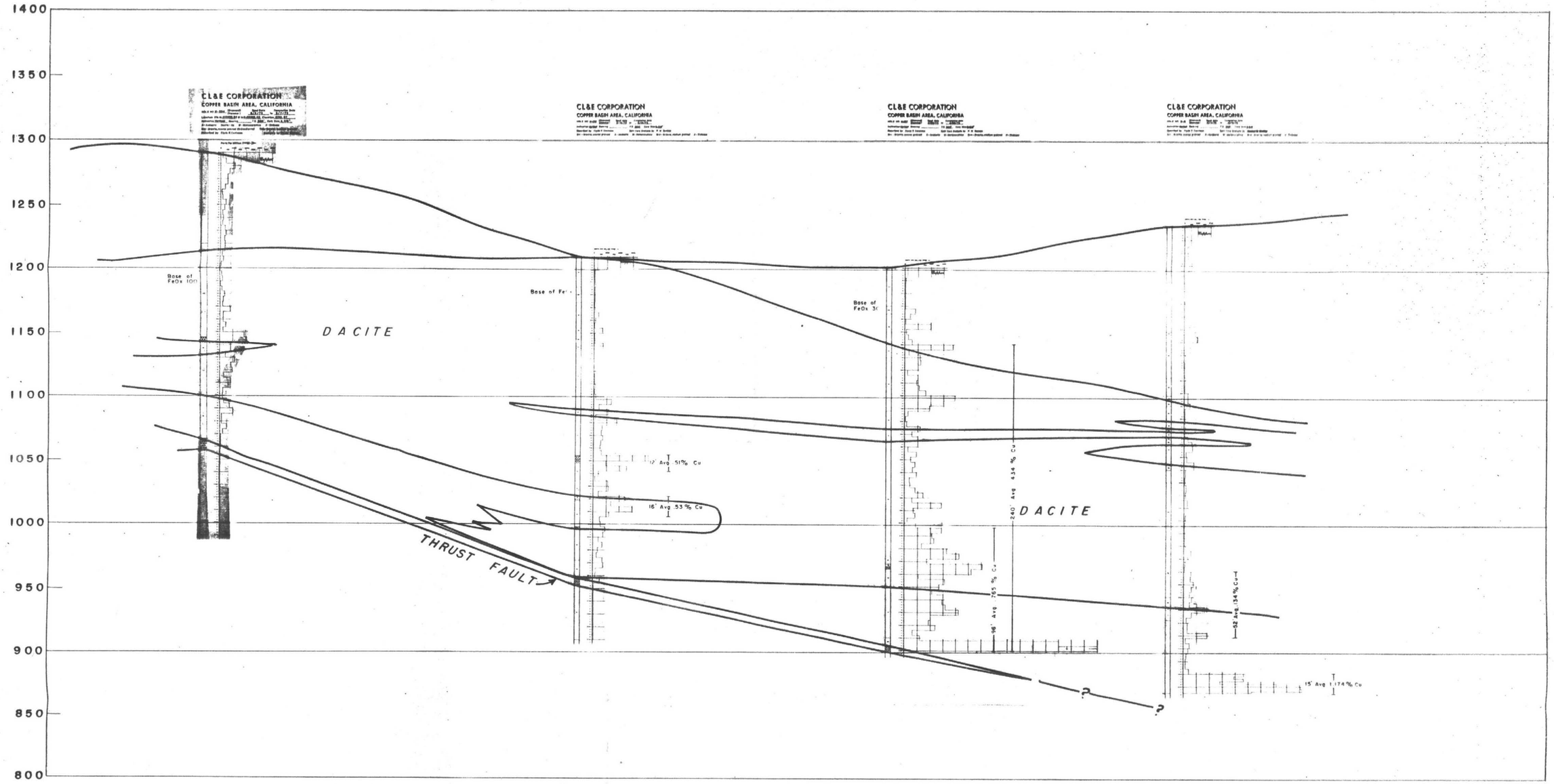
C L & E CORPORATION
COPPER BASIN AREA, CALIFORNIA
Dacite
Dacite
Thrust Fault
Base of
Fe O x 60

3-3'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CL&E CORPORATION
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CL&E CORPORATION
COPPER BASIN AREA, CALIFORNIA
CL&E CORPORATION
COPPER BASIN AREA, CALIFORNIA
CL&E CORPORATION
COPPER BASIN AREA, CALIFORNIA
Base of FeOx 100
Base of Fe
Base of FeOx 3
DACITE
DACITE
THRUST FAULT
12' Avg .51% Cu
16' Avg .53% Cu
240' Avg .434 % Cu
96' Avg .765 % Cu
52' Avg .134% Cu
15' Avg 1.174% Cu
?
?

DONALD G. BRYANT

MINING AND MINERAL EXPLORATION CONSULTANT

7060 SO. GRAY COURT
LITTLETON, COLORADO 80123
(303) 798-3192

November 20, 1974

TO:
Mr. Raymond E. Grant
CL&E Corporation
2340 Colorado State Bank Bldg.
Denver, Colorado 80202

SUBJECT: Suggested studies at Copper Basin, San Bernardino County, California, for determination of a geologic model for the copper mineralization

The purpose of this study was to devise a geologic model of the copper mineralization at Copper Basin for use in determining ore reserves. The Copper Basin deposit is located in eastern San Bernardino County within Precambrian rocks associated with Tertiary intrusives. The deposit has been explored by surface cuts, underground workings and over 600 hammer and core holes. The copper occurs as chalcopyrite with pyrite in chlorite, specular hematite and silica epidote veins. The mineralization is apparently bottomed at depth by a persistent low angle fault which dips about 8° to the south. The fault varies in thickness from less than one inch to several feet and is composed predominantly of dense red gouge-like material containing small rock fragments. The footwall of the fault is composed of unmineralized metamorphic Precambrian rocks of variable composition which give way at depth to a classic augen gneiss. The rocks of the upper plate containing the copper mineralization are mapped and logged as granodiorite, coarse-(grc) and medium-grained(grm) granite, schist, dacite and andesite. The dacite and andesite appear to be Tertiary intrusives whose form is sill-like and controlled by the flat fault. The ore is assumed to be controlled and related to these Tertiary intrusives.

Because the veins containing the copper are irregular, discontinuous and occur in isolated concentrations, efforts to develop an "accurate" ore estimate for feasibility studies and planning are very difficult and subject to significant error. In order to develop a model, I spent several days studying available geologic sections, plans, geophysical maps and the Dravo feasibility study which were available in the Denver office. Then two days were spent on the property with Ray Grant and Clyde Caviness examining the surface outcrops, drill cores and cuttings, and photographs. Several samples were collected for thin sectioning and additional petrographic study. On the

basis of these studies I have concluded that I cannot propose an adequate model for the mineralization without much more work on the geology. The major need for more geology arises from the many questions and apparent contradictions that have come from this brief appraisal. The thin sections indicate that the granite and schist are true cataclastites and probably were never intrusives; that the flat fault involved actual melting and is not typical of shallow gravity slides, and that more than one variety or facies of the dacite is present. Reconnaissance of the quartz monzonite to the south seems to indicate that this intrusive is on its side. The quartz monzonite adjacent to the ore bodies may actually be the top of the intrusive. The flat fault may be both pre- and post-ore and has probably been tilted since the period of ore deposition. The variations in the surface of the flat fault seem to control the distribution of ore, the configuration of the dacite and the distribution of the "granite" and "schists". Perusal of the cores with assay sheets in hand found many discrepancies between the visual estimate and the analytical value.

Assuming that the evaluation of the Dravo feasibility study by LL&E personnel indicates that further work is warranted, I recommend the following steps be taken to systematize the great amount of geologic data. Undistorted geologic sections should be prepared on 100-foot centers at a scale of 1"=200'. Both color-coded geologic and analytical information should be included at a standard elevation on an interval of 10 or 15 feet. Chip logs of, at least, 100 holes should be prepared with the grade and logged geology indicated by color-code. The holes should be selected to fall on the sections and to cover the area of interest. 30 of these holes should have an additional chip log prepared of washed chips from the +8-10 mesh portion of 10 or 15-foot intervals. Additional petrographic work is required on the rocks, cores, ores and selected washed cuttings. The internal granitic tectonic structures of the quartz-monzonite should be mapped. A more accurate regional map should be made of the flat surfaces surrounding the Copper Basin accompanied by long sections.

The model developed during this study should be valuable not only for additional feasibility studies but would be useful in major "grass-roots" exploration programs. One program should be designed to cover eastern San Bernardino County, California and Mojave County, Arizona.

Donald G. Bryant

DONALD G. BRYANT 7060 So. GRAY COURT LITTLETON, COLORADO 80123

November 21, 1974

TO: Raymond E. Grant
The Louisiana Land & Exploration Co.
2340 Colorado State Bank Bldg.
Denver, Colorado 80202

Subject: Manpower requirements for study of Copper Basin geology, Eastern San Bernardino County, California

Preparation of 60 section -- geology and assay

25 days, draftsman

Preparation of 100 chip logs

21 days, technician
5 days, jr. geologist for supervision

Preparation of 30 washed +8-10 mesh chip logs

14 days, technician
10 days, jr. geologist for chip selection and supervision

Geologic mapping

10 days, flat faults, jr. geologist
10 days, igneous tectonics, quartz monzonite, jr. geologist

Petrography

5 days, sr. geologist
10 days, jr. geologist

Evaluation of data

15 days, sr. geologist

Recommendations for further work

5 days, sr. geologist

Detailed IP analysis

3 days, Joe Anzman

DONALD G. BRYANT 7060 So. GRAY COURT LITTLETON, COLORADO 80123

April 10, 1973

Mr. Glen L. Evans
Vice President
The Louisiana Land & Exploration Co.
Minerals Division
Suite 2340 Colorado State Bank Bldg.
1600 Broadway
Denver, Colorado 80202

Dear Mr. Evans:

Thank you for your letter of March 19, 1973.

Mr. Paul I. Eimon, Exploration Manager, will be in the Denver area on April 18, 1973 and would like to visit with you, if it is convenient.

Enclosed is a copy of the Essex 1972 annual report.

Very truly yours,

Dennis C. Temple
Senior Exploration Geologist

DCT:td
enclosure

March 12, 1973

Mr. Gene Mear
Minerals Exploration Office
Louisiana Land and Exploration Co.
Suite 2340
Colorado State Bank Bldg.
1600 Broadway
Denver, Colorado 80202

Dear Mr. Mear:

During the course of geological work in the Whipple Mountains of San Bernardino County, California, your drilling activity in Copper Basin was noted. Clyde Caviness, your geologist on the job, referred me to you for further information.

Essex International, Inc. is a major consumer of copper and has been active for several years in copper exploration. If your work on this or other copper exploration projects reaches the stage where participation by other parties is being considered we would appreciate being kept in mind as a possible joint venture partner. Essex' primary need is for assured copper supplies, so we would consider participation in almost any phase of a project from early exploration to mine development.

In connection with our continued exploration program in San Bernardino County, I will maintain contact with Clyde and hope to meet you in the future. For further information on Essex please contact me, Kenneth Jones, Chief Geologist, or Paul Eimon, Manager of Exploration, through the above address.

Sincerely,

Dennis C. Temple
Senior Exploration Geologist

DCT:td

LOUISIANA LAND AND EXPLORATION CO.

Copper Basin, San Bernardino County, Calif.

Feb. 27, 1974

A visit was made to Copper Basin on Feb. 19, 1974 and discussions held with Mr. Clyde Caviness, Project Manager.

Some observations were made during the visit.

1. The main access road has been widened to two lanes on Louisiana Land Property.
2. Drilling is now in progress filling in the pattern at 100 foot spacings, using three drills.
3. The lumber and supplies seen one year ago have been used to improve and enlarge core processing and storage facilities.
4. Approximately ten people are working at the property, excluding drilling contractors.
5. Completed drill holes now total approximately 350.
6. Several 6" and 8" cores have been recovered for metalurgical tests.

Mr. Caviness furnished the following information:

1. Interviews are ni progress for an assistant project manager.
2. The holes are not deep and a small (?) orebody amenable to open pit extraction.
3. Native gold is visible in the rocks.
4. Now would be a good time to visit Mr. Glan L. Evans, Vice President, for Minerals Division in Denver.

5. Mr. Evans is probably not interested in sharing the announcement of a discovery, but may be agreeable to Essex participation in some form.
6. Environmental impact statements are being prepared and satisfactory relations are being maintained with the Metropolitan Water District, who have a reservoir and aqueduct below the property.

The following conclusions have been derived from the above:

1. Drilling is nearing completion.
2. A test facility of the mine is being planned.
3. Louisiana Land may be interested in participation after they make the discovery announcement.
4. A market for concentrates may be needed.

An attempt is being made to meet with Mr. Evans and discuss the possibilities of Essex participation or purchase of the concentrates.

D.C. Temple

File: Copper Basin
San Bernardino Co.
California

MEMO March 14, 1973

TO: Bud Temple, Ken Jones, Paul Eimon

FROM: Grover Heinrichs

SUBJECT: Jim Sharp
6512 W. Van Buren
Phoenix, Arizona 85009
Phone (602) 936-1326

Information on Louisiana Land & Exploration
Property in Cu Basin, San Bernardino County, Calif.

Jim Sharp claims he promoted property to L.L.&E. Co. (80+ claims) and they have optioned other land and control several square miles in area.

Depth of drilling: Est. 700'-800'
Mineralization: Chalcopyrite, bornite, some oxides to 80' depth.

Three drill rigs drilling 2 shifts have been drilling for almost 2 years.

Has other property near by in Sec. 35, 36, 24, 25, 26 T.10N., R.16W. near Swanson in Yuma County, Arizona.

EGH:td

THE LOUISIANA LAND AND EXPLORATION COMPANY
MINERALS DIVISION
Suite 2340 Colorado State Bank Building
1600 Broadway
Denver, Colorado 80202

GLEN L. EVANS
VICE PRESIDENT

Area Code 303
893-1060

SXM
MAR 21 1973
RECEIVED

March 19, 1973

Mr. Dennis C. Temple, Senior Exploration Geologist
Essex International, Inc.
Metallurgical and Mining Division
1704 West Grant Road
Tucson, Arizona 85704

Dear Mr. Temple:

Gene Mear referred your letter of March 12, 1973 to me for consideration.

We are not planning, at least for the present, a joint venture exploration program in the Copper Basin Area of the Whipple Mountains. There is a definite possibility at a later time that we would want to consider joint venturing on this project and possibly on some of the other areas we are working in the western states. I appreciate your expression of interest in this possibility.

If you are in Denver, I would like to invite you to stop in to get acquainted with members of our staff.

Very truly yours,

Glen L. Evans

Glen L. Evans,
Vice-President

GLE:dk

MEMO March 14, 1973

TO: Bud Temple, Ken Jones, Paul Eimon

FROM: Grover Heinrichs

SUBJECT: Jim Sharp
6512 W. Van Buren
Phoenix, Arizona 85009
Phone (602) 936-1326

Information on Louisiana Land & Exploration
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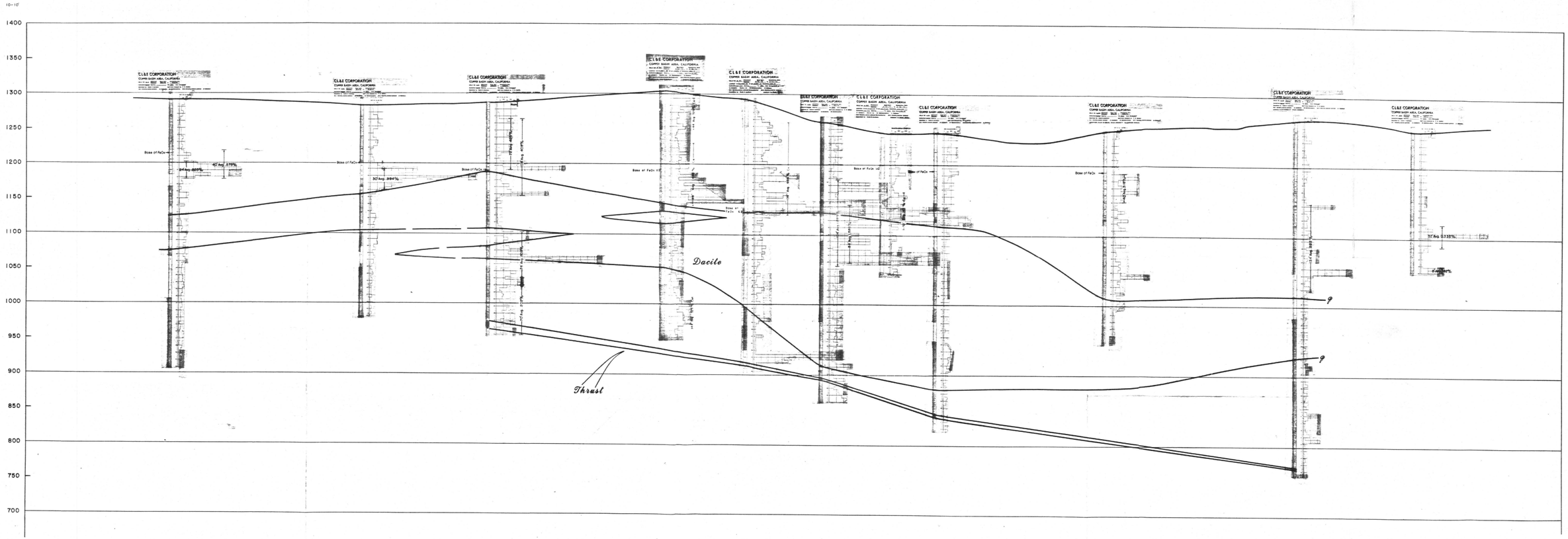
Depth of drilling: Est. 700'-800'
Mineralization: Chalcopyrite, bornite, some oxides to 80' depth.

Three drill rigs drilling 2 shifts have been drilling for almost 2 years.

Has other property near by in Sec. 35, 36, 24, 25, 26 T.10N., R.16W. near Swansea in Yuma County, Arizona.

EGH:td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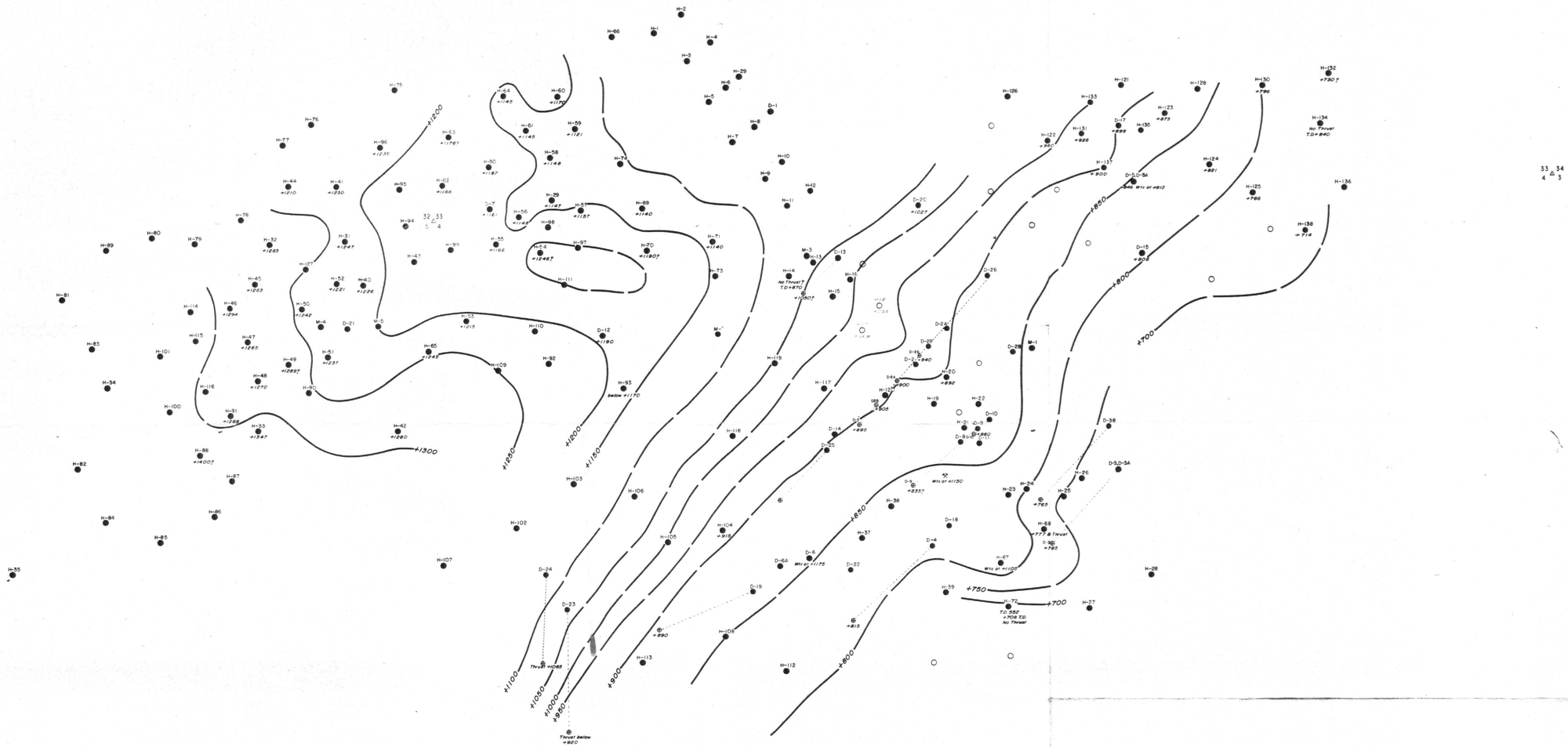
C L & E CORPORATION
COPPER BASIN AREA, CALIFORNIA
Base of FeOx
Dacite
Thrust
?
?

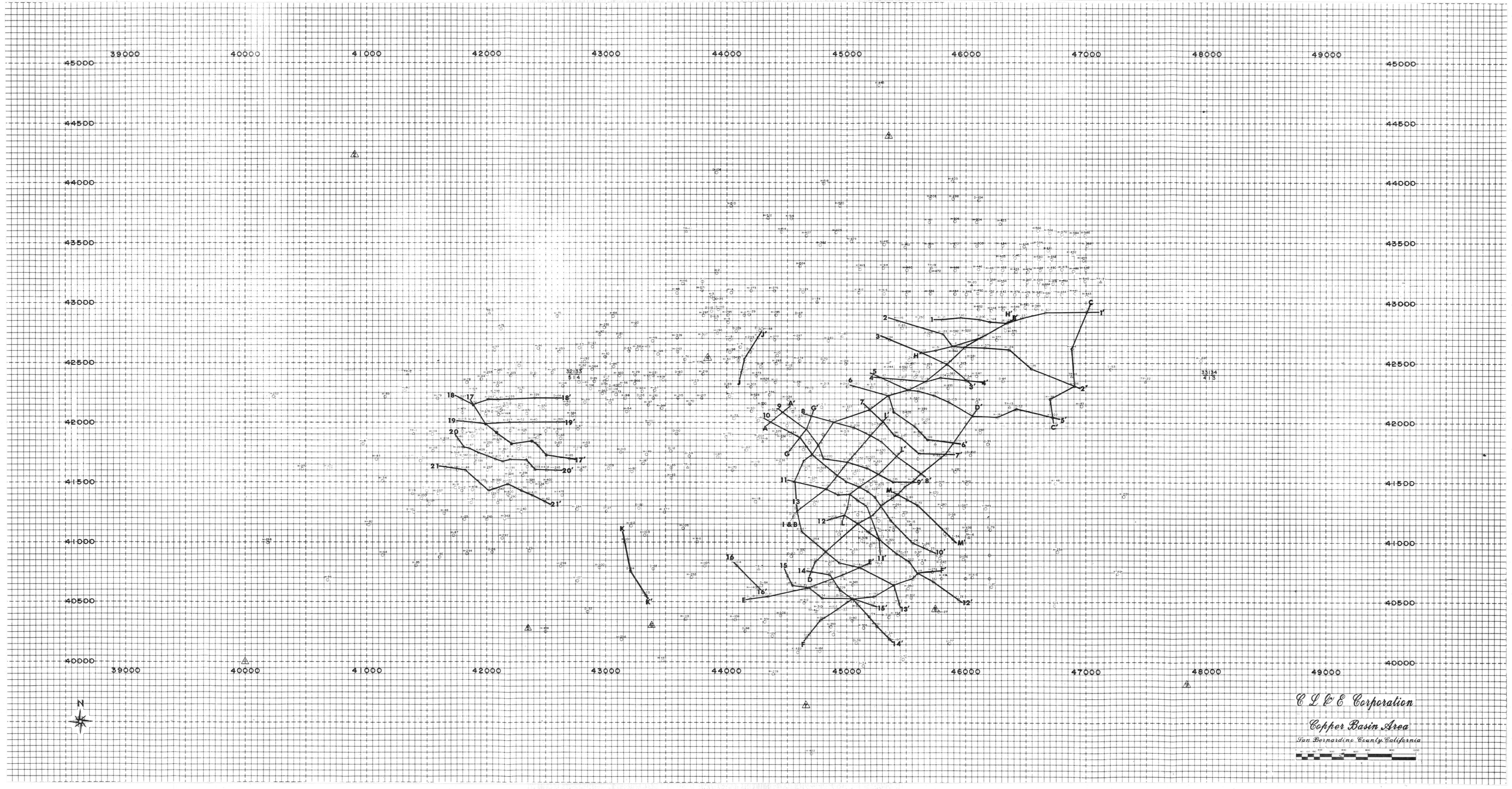


C L & E Corporation

Copper Basin Area

San Bernardino County, California

DATUM
BASE OF THRUST
Scale: 1" = 200'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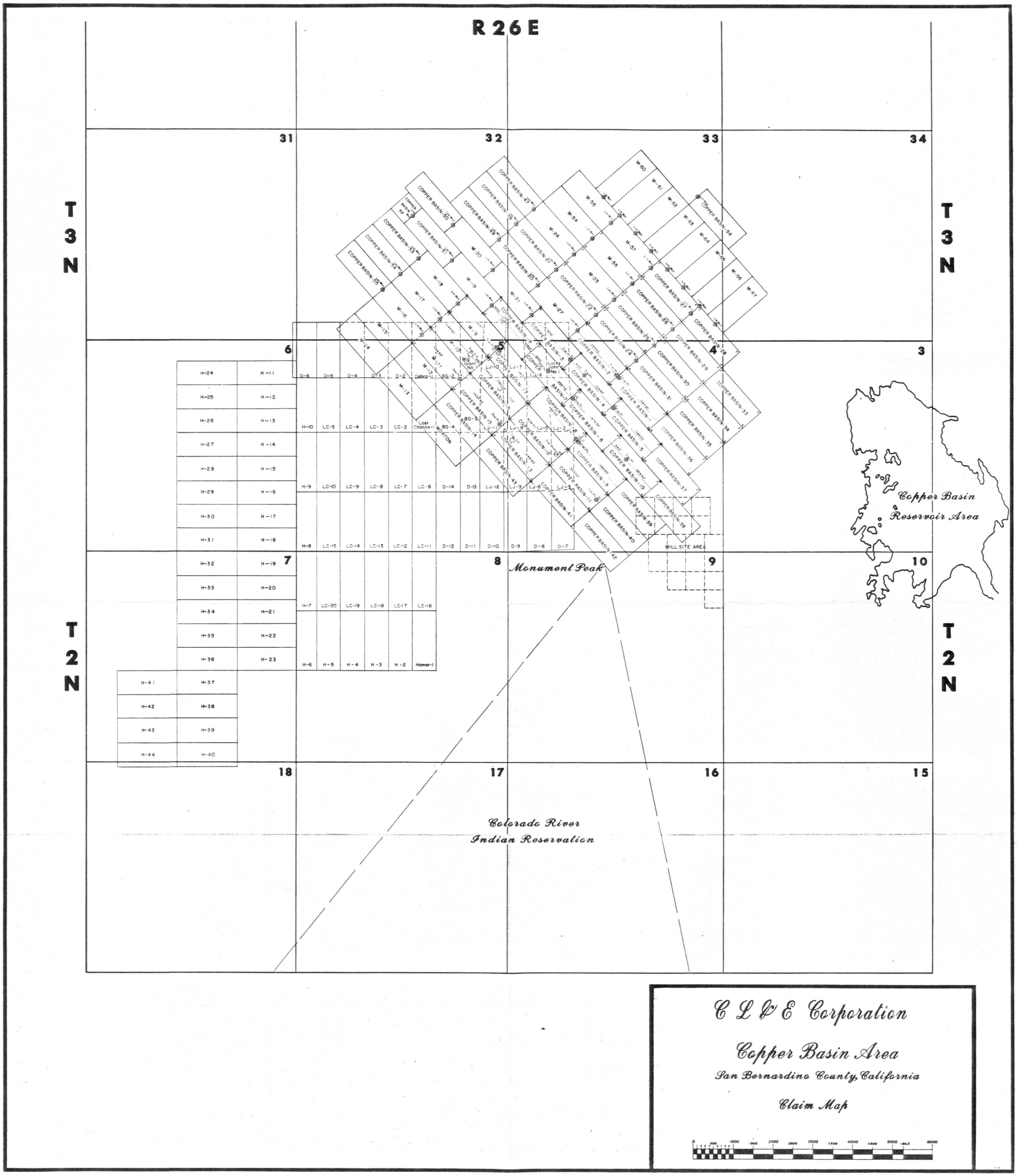
C L & E Corporation
Copper Basin Area
San Bernardino County California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16
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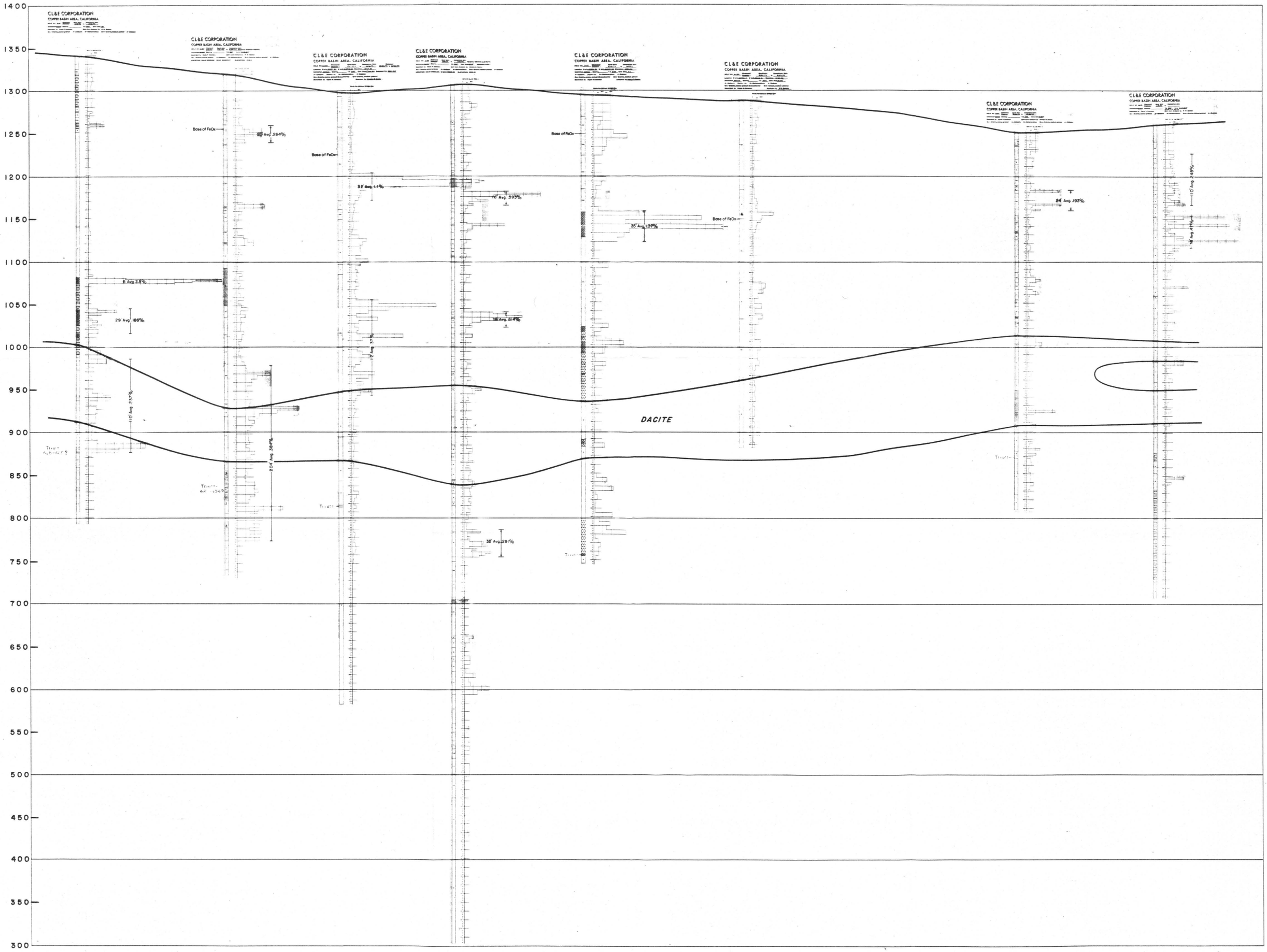
Monument Peak
Colorado River
Indian Reservation
MILL SITE AREA
Copper Basin
Reservoir Area
C L & E Corporation
Copper Basin Area
San Bernardino County, California
Claim Map

13-13'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COPPER BASIN AREA, CALIFORNIA
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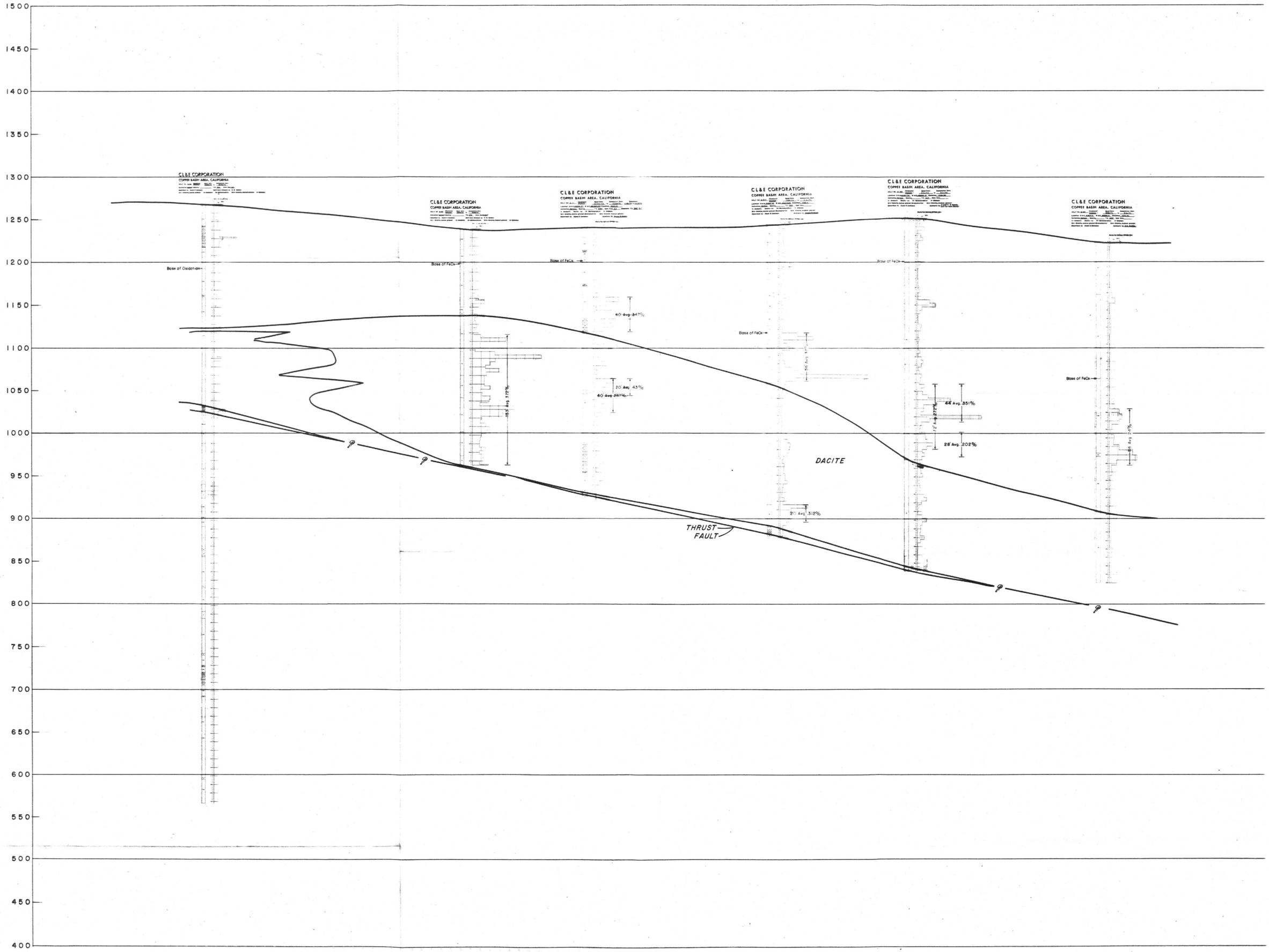
Base of FeOx
DACITE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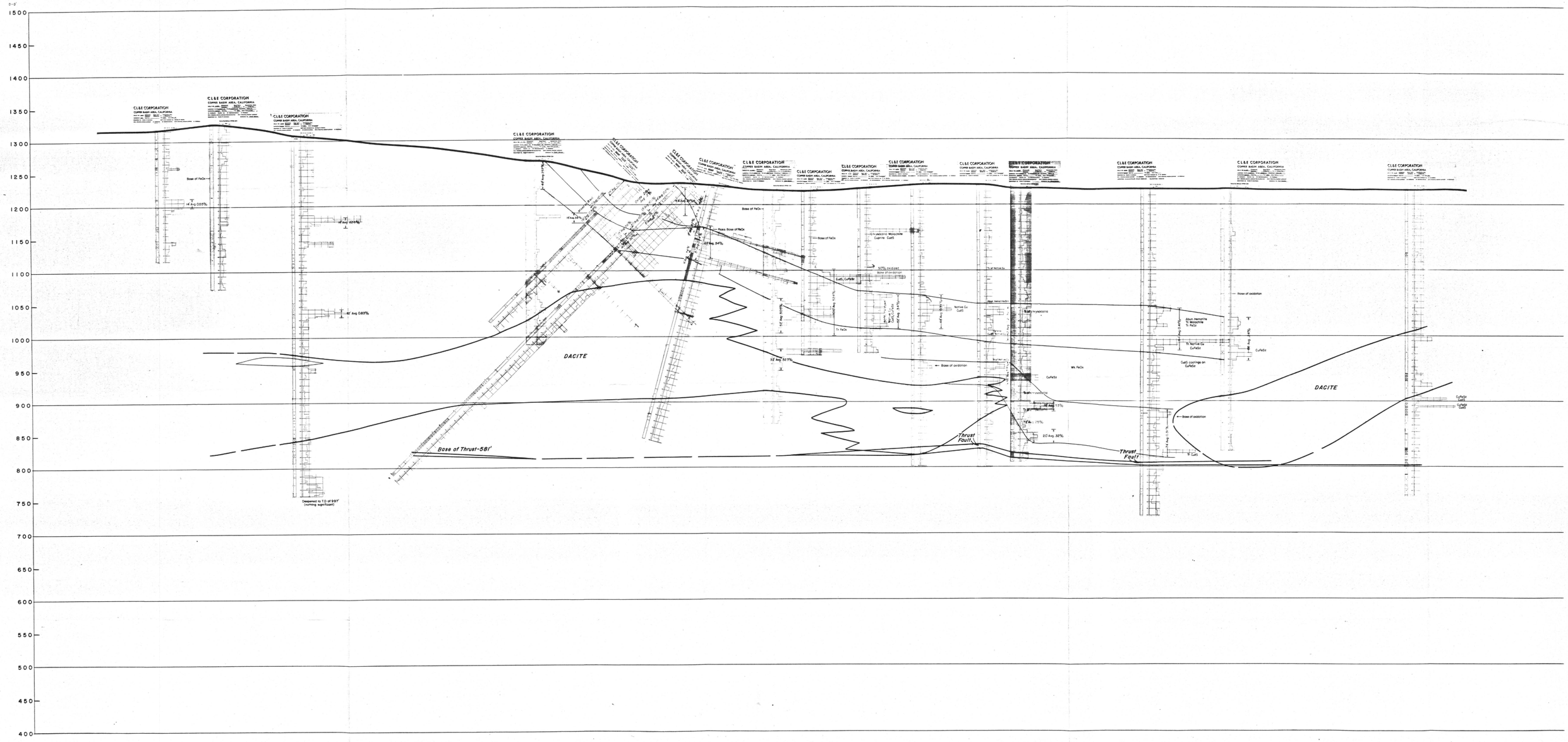
C L & E CORPORATION
COPPER BASIN AREA, CALIFORNIA
Base of Oxidation
Base of FeOx
40' Avg. .847%
20' Avg. .43%
40' Avg. .287%
185' Avg. .372%
56' Avg. .57%
20' Avg. .312%
72' Avg. .272%
44' Avg. .351%
28' Avg. .202%
16' Avg. .28%
DACITE
THRUST FAULT


D-D'
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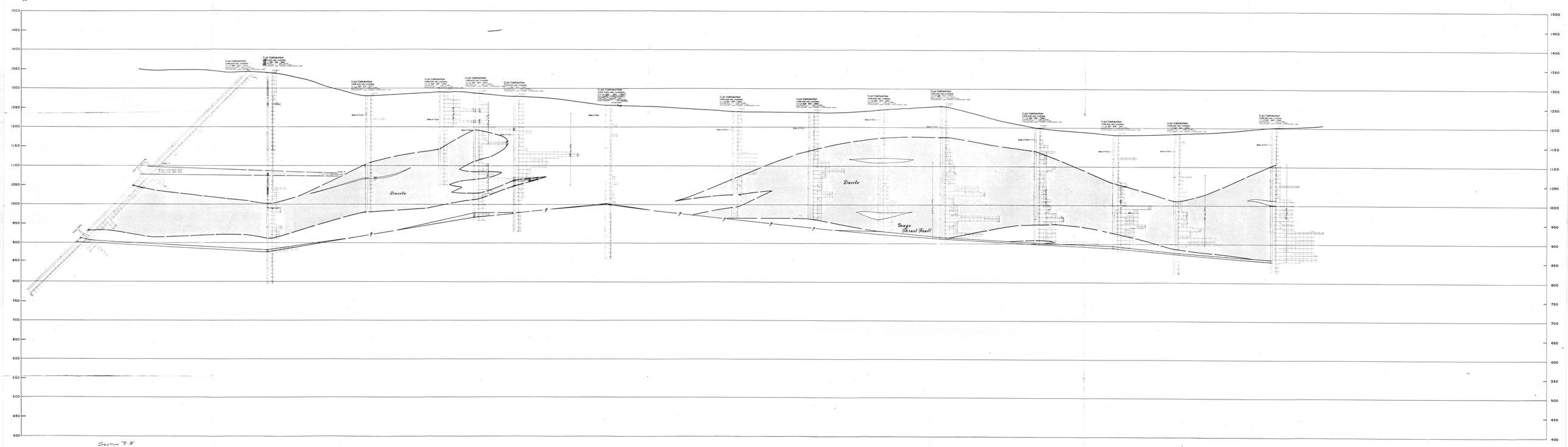
C L & E CORPORATION
COPPER BASIN AREA, CALIFORNIA
Base of FeOx
14' Avg 0.85%
18' Avg 0.83%
DACITE
Base of Thrust-581'
Deepened to T.D. of 997'
(nothing significant)
Base of FeOx
Rock Base of FeOx
Base of FeOx
Chrysocolla Malachite
Cuprite CuO
50% oxidized
Base of oxidation
CuO, CuFeSi
Native Cu
CuO
Base of oxidation
Wk. FeOx
CuFeSi
Thrust Fault
Thrust Fault
Base of oxidation
Alum. Hematite
To Malachite
To FeSi2
To Native Cu
CuFeSi
CuO coatings on
CuFeSi
Base of oxidation
DACITE
CuFeSi
CuFeSi
CuO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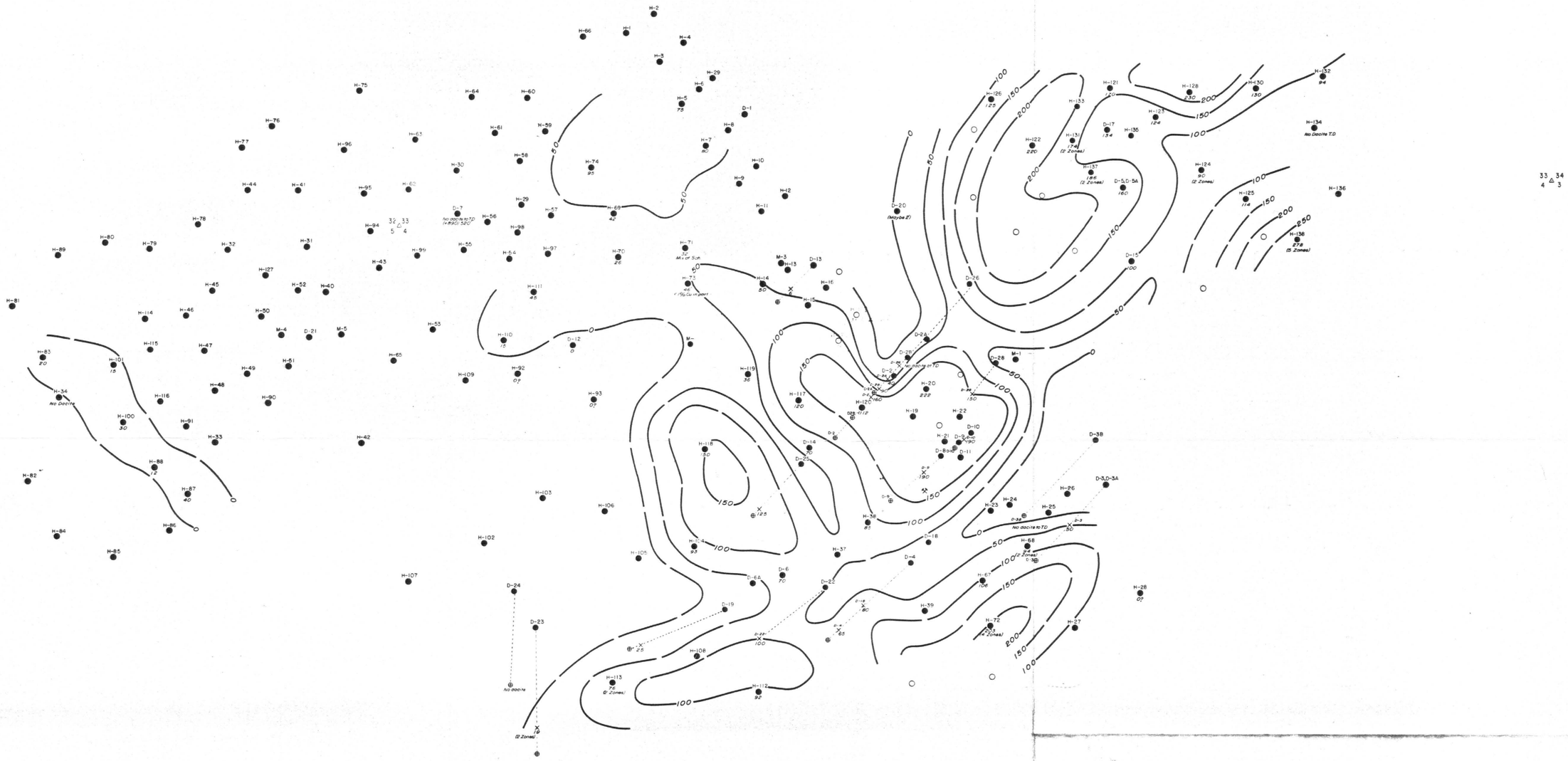
Davile
Davile
Gouge
Thrust Fault

Section B-B'



C L & E Corporation

Copper Basin Area

San Bernardino County, California

TOTAL THICKNESS DACITE

Scale: 1" = 200'

C L & E Corporation

Copper Basin Area

San Bernardino County, California

Geology by: C.E. Mear

Base–Aerial Photograph