Portachuelo Field—Peru
Talara Basin

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FIELD CLASSIFICATION

BASIN: Talara
BASIN TYPE: Forearc
RESERVOIR ROCK TYPE: Sandstone and Quartzite
RESERVOIR AGE: Eocene and Pennsylvanian
PETROLEUM TYPE: Oil
TRAP TYPE: Faulted Anticline
RESERVOIR ENVIRONMENT OF DEPOSITION: Distal Facies of Submarine Fan Sequence
TRAP DESCRIPTION: Anticline with numerous low-angle normal faults; faulting occurred after oil and gas accumulated

LOCATION

Portachuelo field is one of only two fields found to date on the south flank of the Talara basin (Figure 1(A)). The basin lies within the northern part of the Sechura Desert, which is itself the northernmost sector of the great coastal desert that stretches over 2000 mi (3218 km) from central Chile.

Extending from near the mouth of the Chira River northward about 4 mi (6.5 km), Portachuelo is only 17 mi (27 km) southeast of Punta Balcones, the westernmost point in South America.

Geologically the field is located near the crest of the Portachuelo high (Figure 1B). This is a spur off the basement high that separates the Talara basin from the younger Sechura basin to the south (Figure 1C). The great Neogene graben known as the Lagunitos trough, with a structural relief exceeding 15,000 ft (4575 m), in effect separates the two southern oil fields from the rest of the prolific Talara basin.

HISTORY

Portachuelo field is a good example of the Talara geologist's complaint: "In this basin, every [expletive] well is a wildcat." The following record is not only a chronology of field development in the mechanical sense, but also a history of the evolution of geologic thought *about* the field and about subsurface geologic techniques developed in response to the surprises that came with the drilling of most of the wells (Travis, 1953; Youngquist, 1958).

For professionals in the detective work known as subsurface geology, Portachuelo field in northwest Peru has three aspects of special interest:

- *Entrapment history:* Fluid data (including pressures) from many of the rather closely spaced wells provided indispensable clues to the history of oil-trapping in the Eocene Salina pool. (Also described in Hay-Roe et al., 1983, on which the present study is partially based.)
- *Successful infill drilling:* The spectacularly complex faulting obliged reservoir geologists who worked in the Talara basin to develop special correlating and mapping techniques. Within Portachuelo field these techniques enabled us to locate undrained blocks that were economically attractive for infill wells on a spacing of only 13 ac (5 ha).
- *Evolving geologic picture:* Some fields are developed quickly and routinely, with few surprises as drilling proceeds. Portachuelo was not like that. It was developed over a period of more than 40 years, during which the subsurface picture (the geologic model) changed dramatically—not only because new information continued to be generated, but also because geologic interpretations became more sophisticated, reflecting the rapid advances in every area of earth science.

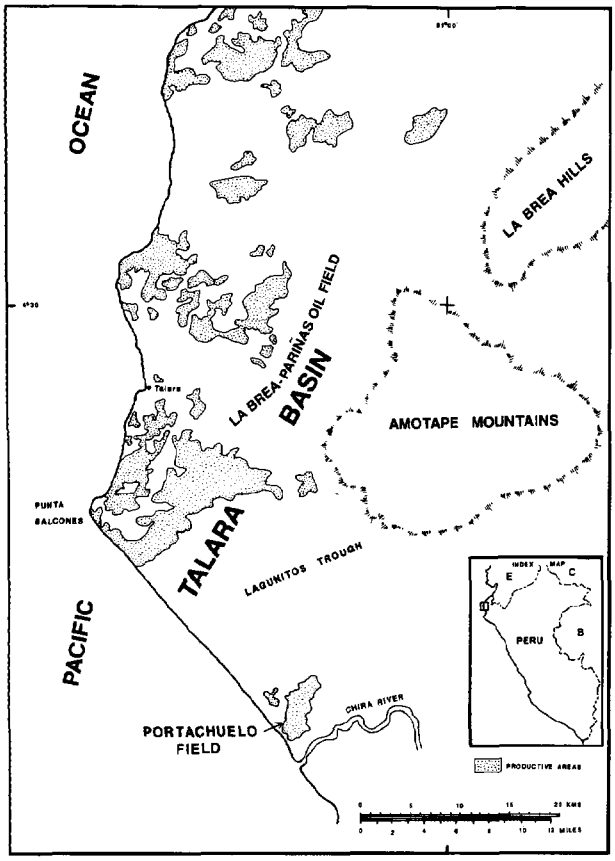

Figure 1A. Location map: southern Talara basin showing Portachuelo field, adjacent West Portachuelo pool, and pools of the LaBrea-Pariñas oil field. B, Brazil; C, Colombia; E, Ecuador.

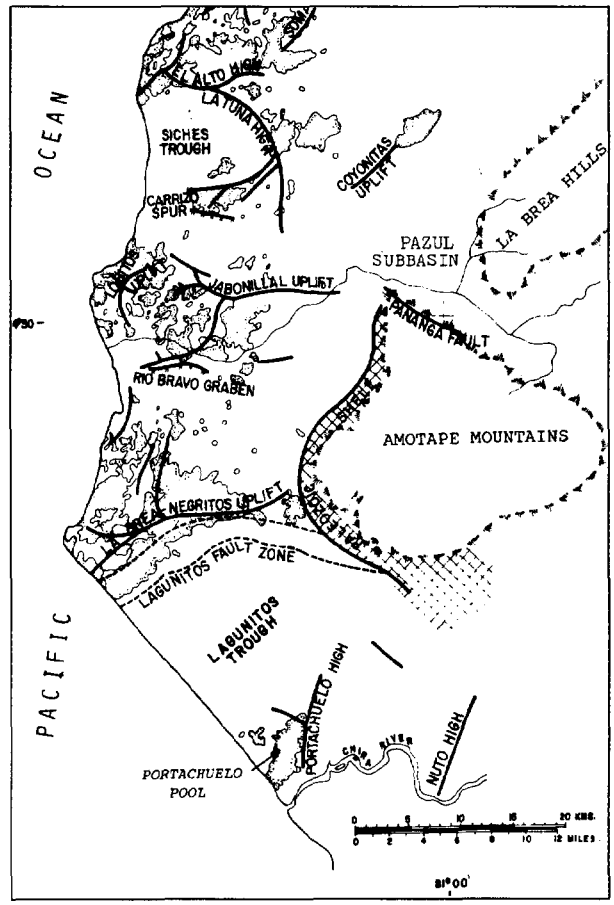

Figure 1B. Tectonic map of southern Talara basin. (After Hay-Roe et al., 1983, with permission of Journal of Petroleum Geology.)

This study is therefore presented as a case history in the use of (1) electric logs restored to the pre-fault sequence; dipmeters; detailed true-scale cross sections together with "straight-line" contour mapping to interpret the intensely faulted structure; and (2) pressure data and fluid-production data to reconstruct the general outlines of entrapment history in the Salina.

Early History

Portachuelo was discovered in 1931, but it is not an old field by Talara standards: The first oil wells in the basin were drilled in 1875. In fact, oil has been known and used there since prehistoric times. When the Spaniards under one of Pizarro's lieutenants arrived early in the sixteenth century, they found the natives mummifying their ancestors and waterproofing their containers with "brea" (pitch) from seeps that were given that name. The La Brea seeps are located some 10 mi (16 km) north of Portachuelo, near the foothills of the Amotape Mountains (Figure 1A).

The modern oil era in this basin began in 1914, when Toronto-based International Petroleum Co. (IPC) acquired the rights of a British firm, London and Pacific Petroleum. That firm had obtained a 99-year lease in 1888 from two Englishmen who had purchased outright both surface and subsurface rights in the "La Brea-Pariñas Estate"—essentially the southern half of the Talara basin—from a local citizen.

The correct taxes to be paid on this property, and even title to the property itself, were never fully agreed on by all parties. Whenever elements of the local or national government reached a settlement with the oil operator, there were always others who disputed the settlement. In 1922 the matter was submitted to an international tribunal headed by a Swiss jurist, and in 1924 that tribunal upheld IPC's right to La Brea-Pariñas.

Standard Oil of New Jersey (Exxon) became operator by acquiring IPC, although the Peruvian Congress never ratified the decision of the tribunal. Ongoing disagreement led eventually to the expropriation of all of IPC's operations in Peru (production,

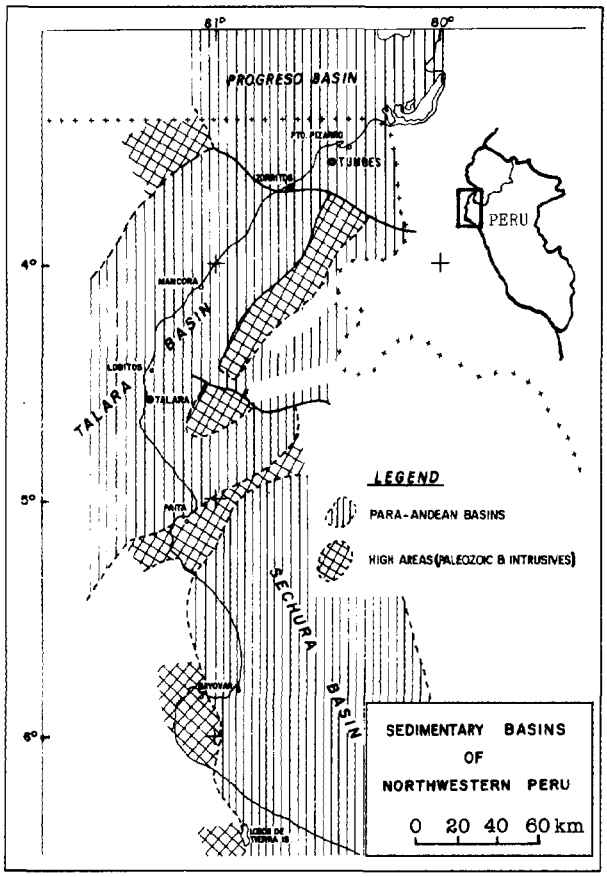

Figure 1C. Sedimentary basins of northwestern Peru. (After Hay-Roe et al., 1983, with permission of Journal of Petroleum Geology.)

refining, and marketing) by a socialist-oriented military government in 1968–1969.

The Discovery of Portachuelo

The discovery well, IPC No. 2570 (Figure 2), was located on a faulted anticlinal nose delineated by surface geologic mapping and subsurface data from a nearby dry hole (IPC No. 980). The discovery well, drilled in 1931, came in for 262 BOPD from sands in the Salina Formation (Figure 3).

But, except for a 7 ac (2.8 ha) south offset drilled in 1932, there was no follow-up for two decades. During the 1930s and 1940s, priorities for Talara geologists and development engineers were allocated through the concept of "rich areas" and "lean areas." In comparison with reservoirs in the "rich" central part of the basin (where wells in the Pariñas sandstone—stratigraphically between the Talara Shale and Pale Greda Formation but missing at Portachuelo—could produce up to 15,000 BOPD), Portachuelo was "lean." Further, there was no pipeline to the refinery, 25 mi (40 km) to the north, and the little wood-burning train ran only twice a week. In any case, more prolific fields closer to the refinery supplied all it could handle.

Ongoing Development

In the early 1950s, IPC returned to Portachuelo, prompted in part by the government's announcement that it was going to open the adjacent area on the south to applications. Seismic, gravity, and photogeologic work helped outline the Portachuelo high. A wildcat to the Pennsylvanian basement was drilled, but despite peaks on the gas detector, the well was not deemed worthy of testing. No reservoir rocks appeared to be present.

Pennsylvanian production was discovered in 1954 by wildcat No. 4610, on the northeast edge of the field (Figure 2). It had an initial producing rate of 26 BOPD from fractured Amotape quartzite (Figure 3).

Information from development wells of the early 1950s in the Salina sand yielded a very sketchy geologic picture. Geologists of that period quickly recognized that stratigraphically the Salina on the southern flank of the basin was different from that farther north: For one thing, it was only one-third as thick. Correlations from well to well proved difficult—with some wells, impossible. Geologists also recognized that fluid content of the sands was largely independent of present-day structural position.

An IPC in-house report written in 1952 stated:

> . . . The [Salina] sands change thickness so rapidly laterally that it is difficult to correlate them from well to well . . . The 1400-ft spacing of the wells is probably a greater length than the longest diameter of the sand bodies, with the result that a given sand may appear in only one well . . . Sand lenses tend to achieve an average thickness, so that many of them look quite similar on the electric log, adding further to correlation difficulties.

On this basis, IPC's geologists developed a model (Youngquist, personal communication, April 1987) involving extremely lenticular sands, presumed to be deltaic, with very local hydrocarbon sources and very short range migration. Exploration largely consisted of guided mapping of sand/shale ratios. Seismic and gravity interpretations on the basin flank supported the concept of a small high area that helped localize the accumulation of hydrocarbons. Some geologists considered that the high had been present at the time of Salina deposition. Drilling established that the pool had a north-northeast trend, not east-west as was previously believed.

Breakthrough: The Composite Log and Detailed Mapping

In the early to mid-1950s, Portachuelo development gained momentum. John D. Tuohy (personal communication, April 1987) recalls, "When I got there a steam rig with a standard derrick was drilling

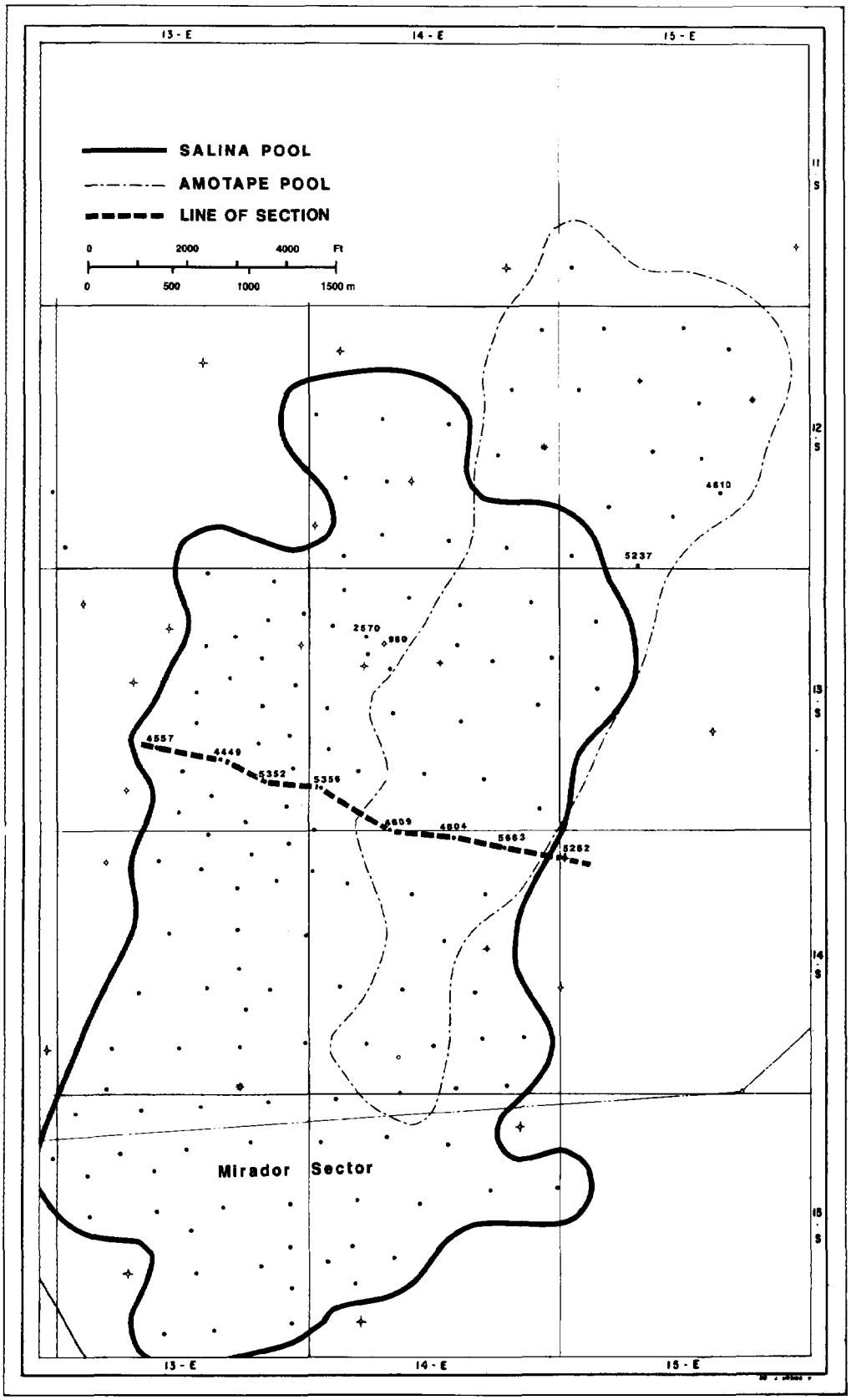

Figure 2. Pool outlines, Portachuelo field. Well numbers shown are those of wells mentioned in the text. Dashed line is cross section, Figure 6. Well 2570 is Salina discovery well, and 4610 is Amotape discovery well. (After Hay-Roe et al., 1983, with permission of Journal of Petroleum Geology.)

SYSTEM	SERIES	GROUP	FORMATION	THICKNESS feet
QUAT.	PL.		TABLAZO	
TERTIARY	EOCENE	LAGUNITOS	MIRADOR	1200+
			CHIRA-VERDUN	3800
		TALARA	TALARA SHALE	50-250
			PALE GREDA	200-1100
		SALINA	SALINA	1600
	PALEOCENE	MAL PASO	BALCONES	500-1500
CRET.	UPPER		REDONDO	100-1100
PENN.	MIDDLE	TARMA	AMOTAPE	6000

Figure 3. Generalized stratigraphic column of the Portachuelo area. (After Hay-Roe et al., 1983, with permission of Journal of Petroleum Geology.)

almost full-time. A couple of wells on the eastern edge of the field had production from the Amotape (Pennsylvanian) as well as from the Salina." In 1956 the field averaged 2678 BOPD from the Salina and 271 BOPD from the Amotape.

About this time a very powerful geologic tool was introduced: the *composite well log* (Figure 4). In the terminology of Talara geologists, this was not the kind of log showing a composite of several curves from the same well, but rather a composite of several wells using the same curves to restore a full stratigraphic section for the vicinity. This "restored" log represented a normal drilled sequence as it would have looked prior to fault shortening. It was used to identify individual lithologic units in other wells in the vicinity and thus to detect both the depths at which faults intersect any particular well in question and the resulting amount of section missing.

The area over which such a log can be used depends, of course, on the lateral persistence of distinctive curve characteristics. In Portachuelo, composite logs of the Salina Formation are most reliable within a radius of a mile or so, but individual stratal sequences with distinctive log features can be correlated over the entire field. For greater reliability, Talara geologists have worked with logs at 2 in. per 100 ft, laying a film transparency of one log over a paper copy of the other. In many areas of the basin the bed-by-bed agreement of curves is so precise (especially in shaly rocks) that the correlation is unchallengeable.

The first composite log developed in Portachuelo by Manuel Paredes (personal communication, March 1987), in the northwestern part of the field, led to new insights into the structural complexity of the area. It became apparent that at least some of the abrupt lateral variations in logged sequences were due *not* to lenticularity, as previously considered, but to fault-shortening.

In the late 1950s, R. B. Travis (personal communication, March 1987) set out to reassemble this three-dimensional jigsaw puzzle. He had to work without benefit of dipmeter surveys, for none were available in Portachuelo. It cost him two full years of complex and painstaking work with a close network of true-scale cross sections interlocked with structure contour maps at different levels within the Salina, but he succeeded in making it all fit together.

One factor that made this task even possible was the lack of any need for correlation above and below the Salina; Travis did not have to attempt to extend the mapping into the pre- and post-Salina intervals, because there was no effective control for mapping. (At the same time, that "advantage" made it impossible to confirm the suspected presence of growth faults or deeper faults.) This meticulous work not only demonstrated that lateral variations between wells were due mainly to faulting, but also guided the development drilling and served as an example for detailed studies elsewhere in the basin.

Subsurface mapping techniques used in the Talara basin involve simplifying assumptions, some of which would be hard to justify from strict conventional geological techniques. But the techniques have remained in use for one good reason: They work. Fault-blocks are treated as rigid and uncurved; contours on top of each block can thus be represented by straight lines (Figure 5), although both strike and dip can vary from one block to the next. Normal faults are likewise assumed to be uncurved planes unless evidence to the contrary is available. Drag on beds next to a fault is usually ignored (again, this assumption evidently works for mapping in this basin).

Both these assumptions permit the use of contour templates, referred to in Spanish as "la guitarra" because the series of evenly spaced, straight parallel lines look like the strings of a guitar. Using one transparent template for bedding dip and another for the plane of a fault, the geologist can quickly plot the trace of these intersecting surfaces. Another extremely handy tool is the apparent dip protractor, which permits rapid graphic solutions of the apparent dip. Cross sections are always constructed with no exaggeration (horizontal and vertical scales the same) so that dips and dip components are correct as shown.

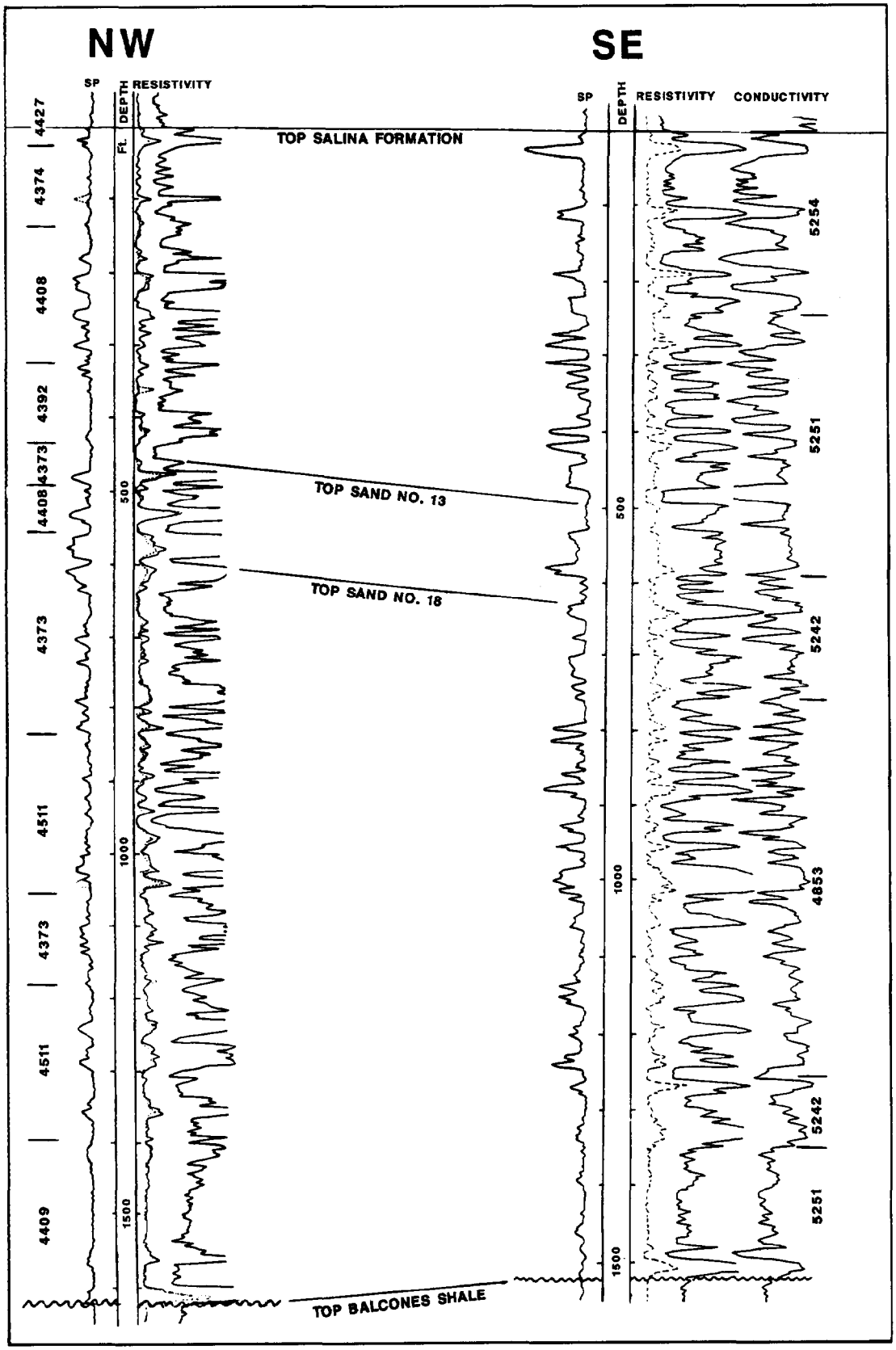

Figure 4. Examples of Talara-style composite logs (restored Salina sequence) from northwestern and southeastern sectors of Portachuelo pool. Numbers along left and right margins are well numbers of logs used to make up the composite. Depths in feet.

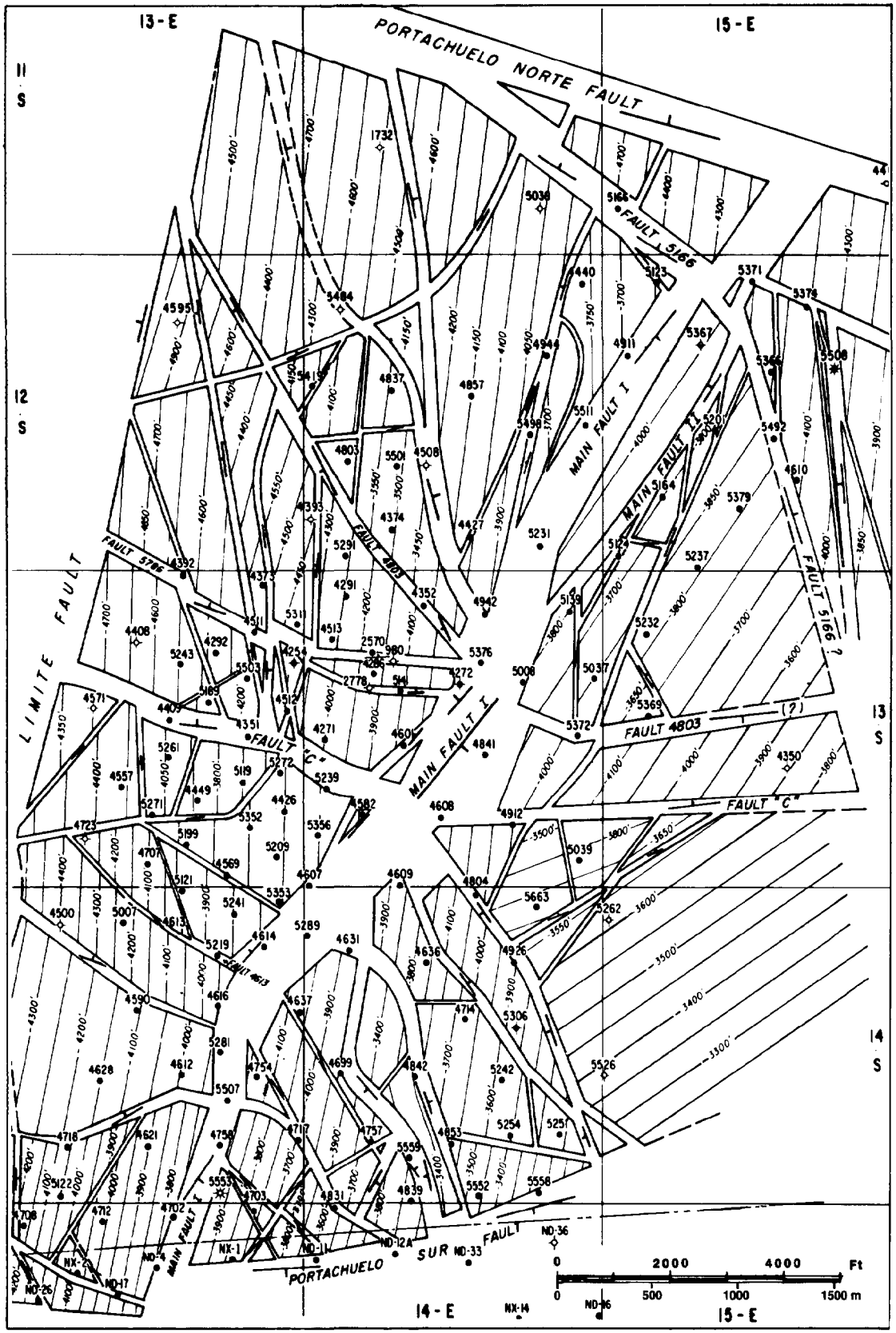

Figure 5. "Straight-line" structure contour map on top of Salina Sand No. 13, prepared by Petroleos del Peru. Contour interval 50 ft. (After Hay-Roe et al., 1983, with permission of Journal of Petroleum Geology.)

Still, because of the lack of wells on the east side of Portachuelo, problems of stratigraphic interpretation remained. A 1960 IPC internal report stated:

> . . . Eastward [in] Portachuelo pool the Salina remains about the same thickness as over the higher parts of the structure. It is . . . logical . . . to explain the thinning [relative to the section along the western edge of the pool] by non-deposition over the eastern [i.e., now the central] part of the pool, due to contemporaneous activity of the Portachuelo High.

To illustrate this concept the report contained a "restored Salina isopach" that showed the original Salina thickness along the crest as only 800 ft, implying that the maximum thinning due to faulting still left 55% of the total original section.

Late Development

During the 1960s, data from the ongoing drilling, together with information from palynology and oil source studies, added new elements to the geologic picture of Portachuelo. The apparent eastward thinning of the Salina, once thought to be depositional, proved to be due to drastic fault-shortening (Figure 6). Beyond this former axial trend the faulting is again less intense, and the drilled Salina sequence is correspondingly thicker (Figure 7). This realization opened up a new area for profitable development on the east side of the field.

In the southernmost part of the field, Belco's (Belco Petroleum Corporation of Peru, which developed the southern sector of the field) drilling showed that the Salina sands were grading into shale southward, in what is now a structurally higher area. In the early 1960s the Salina sequence had been interpreted as thin, fluvial sheet sandstones alternating with shallow marine shales, but later work indicated that the Portachuelo Salina actually represents the distal part of a submarine fan sequence whose sediment source was to the north. Thus the increase in shaliness to the south would be expected.

Additional composite logs helped refine the Salina mapping, but dipmeters triggered a truly major overhaul by providing reliable dips. It turned out that in the previous comprehensive mapping described above, the assumed dip direction was actually 180° off. However, this did not mean that the two years' earlier work was wasted; the stratigraphic correlations and nearly all the fault "picks" in wells were still valid.

The increasingly detailed mapping made it possible to detect undrilled fault blocks with possible commercial size reservoirs, which could then be exploited by infill wells on 13 ac (5 ha) spacing. The tight control in areas of infill wells allowed increasing refinement of the mapping, leading to still more infill drilling and to an arrest of the decline in production. But the logging program of that period was never sophisticated enough to define fluid content with perfect reliability; some sands continued to provide a surprise when perforated.

As feasible sites for infill and edge wells were finally used up, the production from Portachuelo began to decline again. In the fault block fields of the Talara basin, all wells drain reservoir blocks of limited size. It is not unusual for a well to produce half its total reserves in the first 12 months (thereafter the decline is, of course, less drastic).

STRUCTURE

The extreme complexity of the Portachuelo field, like that of other fields in the basin, is due largely to normal faulting. Low-angle gravitational slide faults, while common in post-lower Eocene strata, are not evident in the reservoir units of Portachuelo. Lateral changes in lithology add to the complexity, but their effect is minor compared to the effect of the faulting.

Tectonic History

The Talara basin is predominantly an Eocene feature. In most parts of the basin Eocene strata account for more than 80% of the total thickness of post-Paleozoic sediments.

Since the early Mesozoic, the tectonic history of the coastal sector of northwestern Peru has been governed by its position near the leading edge of the South America plate. The entire basin, only 100 mi (160 km) long and about 30 mi (50 km) wide, represents a minor dimple in the upraised edge of the plate adjacent to the Peru-Chile trench, which marks the subduction zone of the Nazca plate.

Presumably this plate-edge position led to alternating periods of tension and compression in response to the nonhomogeneous westward movement of the plate. Evidence of at least one period of early Tertiary folding was largely erased subsequently by intense normal faulting. During the Oligocene or later time, instability of the upper Eocene sediments led to low-angle gravitational slide-faulting throughout the basin.

As might be expected, shorelines shifted frequently during Eocene deposition in this small basin. Continental, fluviodeltaic, and marine environments followed one another in quick succession. Neogene and Quaternary times have seen predominantly vertical movement, reflected in the multiple terrace deposits now uplifted along the coast.

Regional Structure

The Talara basin straddles the Pacific coastline, with nearly half of its 2800 mi^2 (7200 km^2) offshore (Figure 1C). It is bounded by Paleozoic uplifts on the

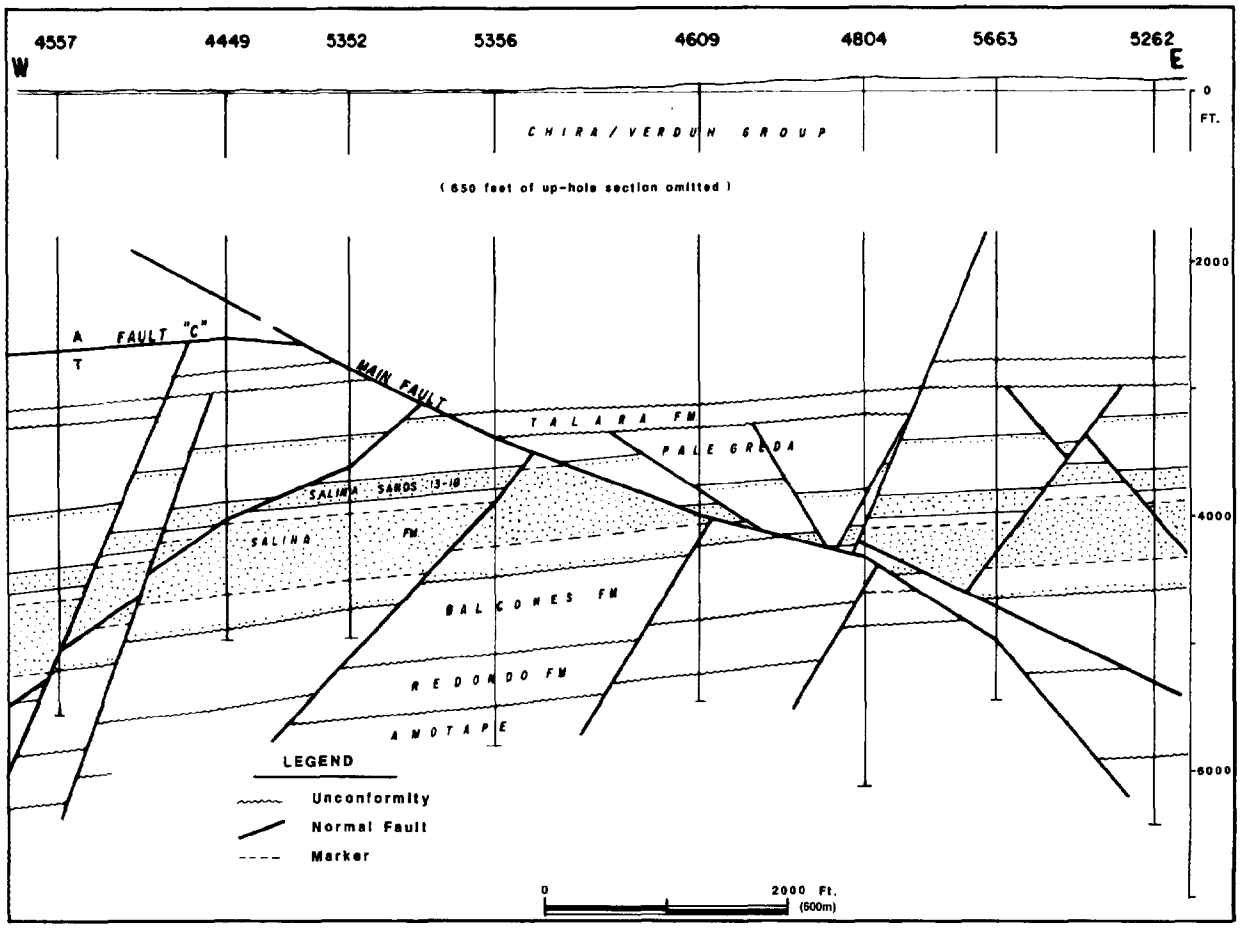

Figure 6. Structure cross section, Portachuelo Salina pool, prepared by Petroleos del Peru. No vertical exaggeration. See Figure 2 for location. Subsurface control inadequate to locate faults at or in the Amotape Formation. (After Hay-Roe et al., 1983, with permission of Journal of Petroleum Geology.)

north, east, and south, and presumably on the seaward side as well. This small, narrow basin is also quite deep: Pre-Tertiary rocks are interpreted to lie below 20,000 ft (6000 m) in the deepest parts.

Portachuelo field is located on a positive feature in the subsurface called the Portachuelo high (Figure 1B). This high is a spur off the major basement ridge to the south, the Paita uplift, which separates the Talara basin from the younger Sechura basin (Figure 1C). A major zone of normal faulting separates the raised southern flank of the Talara basin from the Lagunitos trough, a deep east-west graben to the north. The total relief between the upraised strata of the Portachuelo high and the deepest part of the trough is on the order of 15,000 ft (4600 m).

These two features—the Lagunitos trough and the Portachuelo high—are unusual in that they do not fit the pattern of the major transverse highs and lows of the Talara basin, all of which have a geographic expression: the highs are marked by coastal promontories, the lows by coastal embayments. In contrast, the coastline by the Lagunitos trough and Portachuelo high is remarkably straight (Figures 1A and 1B).

Local Structure

A discussion of the local structure associated with the Portachuelo field necessarily focuses on structure within the 1600 ft (490 m) Salina sequence, since that is where all detailed mapping was concentrated.

Portachuelo field formed as a simple north-plunging anticline, whose crestal area collapsed during intense normal faulting, while the flank areas were (relatively) raised. The resultant present-day structure, contoured conventionally and with faults omitted, is that of a west-dipping homocline with local closures of up to 400 ft (120 m) in parts of the field (Figure 8). The present-day axis at the top of the Pennsylvanian basement underlies the eastern part of the pool, but the crest at the Salina level, shifted by faulting and tilting, actually lies east of the study area.

Conventional contouring gives only a generalized configuration at the level of the mapping horizon—a smoothed average through the real, highly irregular surface, variously tilted and offset by faults.

The main characteristics of the normal faults cutting the Salina are these:

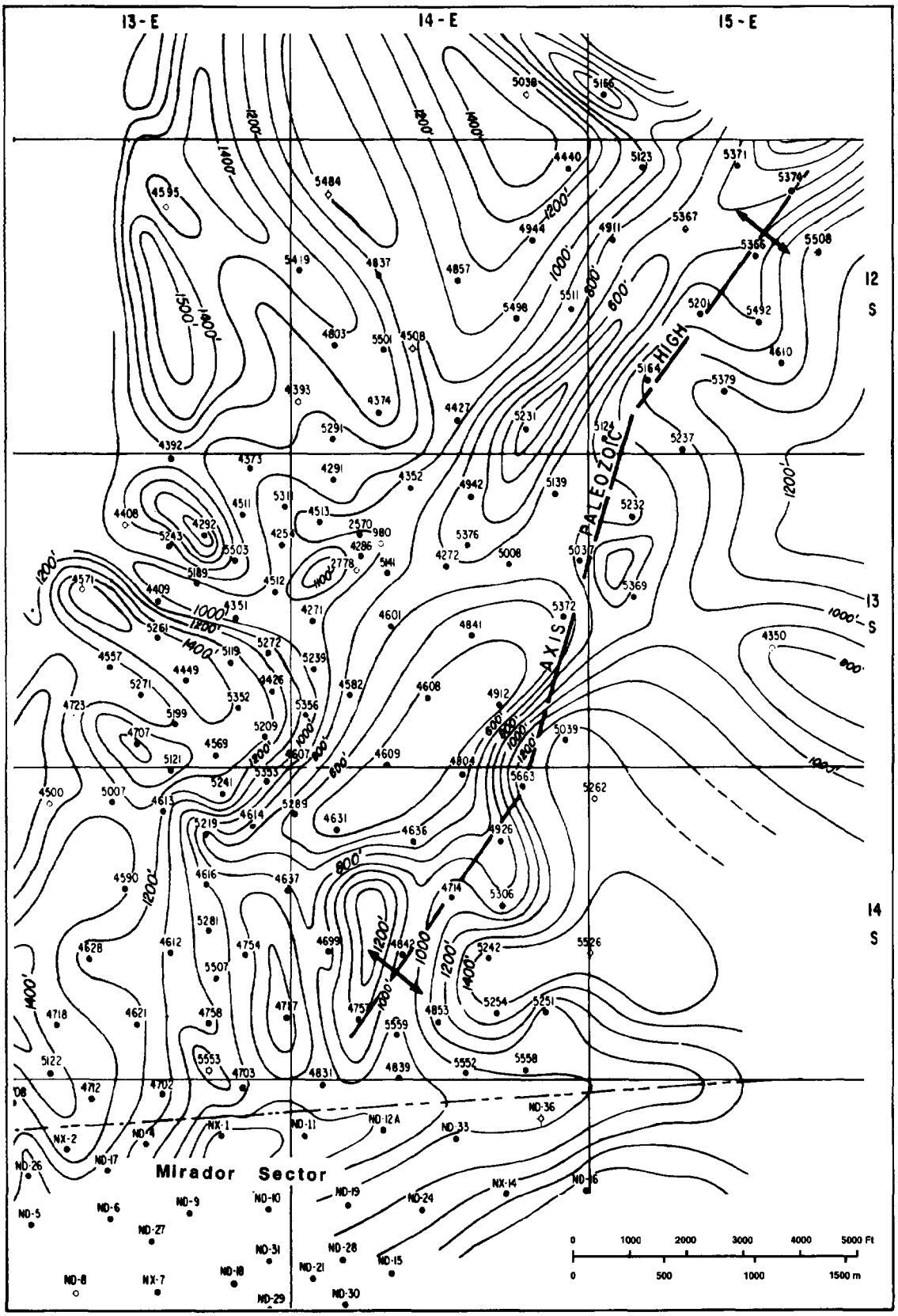

Figure 7. Isochore map, Salina Formation. Contour interval 100 ft. (After Hay-Roe et al., 1983, with permission of Journal of Petroleum Geology.)

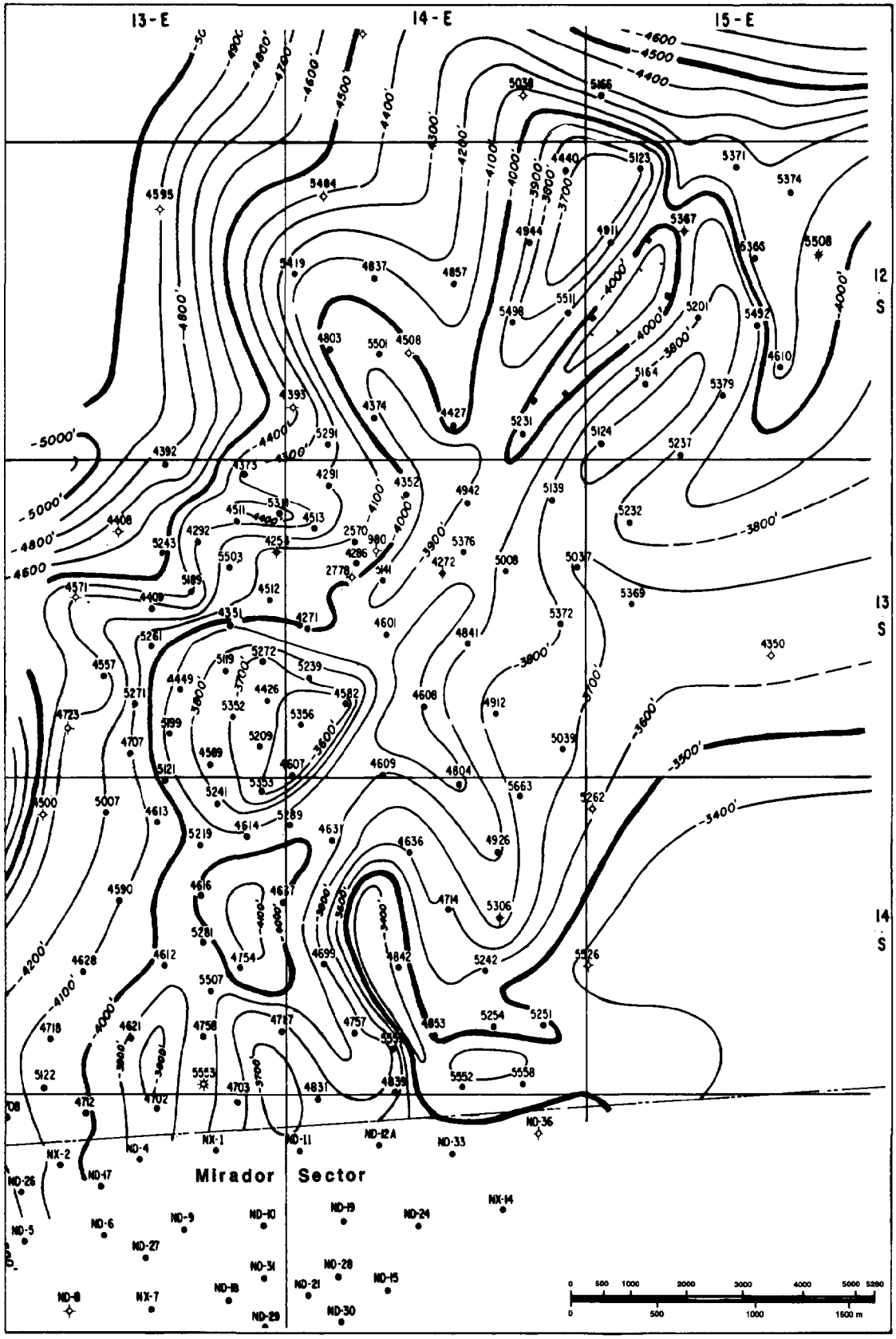

Figure 8. Conventional structure contour map on top of Salina Sand No. 13, prepared by Petroleos del Peru. Contour interval 100 ft. Faults omitted. (After Hay-Roe et al., 1983, with permission of Journal of Petroleum Geology.)

- Faults are normal, with dips mostly in the range of 50–60°.
- Stratigraphic throws range from less than 10 ft to about 1000 ft (300 m). In routine mapping, faults of less than 50 ft (15 m) have been ignored. This cutoff was supported by the next observation.
- Faults with throws of more than 50 ft appear to be effective barriers to fluid communication, whereas smaller faults may or may not be.
- A majority of the bigger faults (throws over 100 ft or 30 m) have a dip component opposite in direction to the prevailing dip of the Salina, thus compensating for the effect of bedding dip on the subsea elevation of any given stratum.
- The age of the main period of normal faulting has not been pinned down with any precision but is evidently latest Eocene or younger.

Compared with conventional mapping (Figure 8), structure mapping "Talara style" (Figure 5) gives a very different picture. The field now appears as an intricate mosaic of west- to northwest-dipping blocks separated by normal faults, including a major one (over 1000 ft or 300 m displacement) roughly parallel to the field axis, with another beyond the northern edge of the productive area.

Variations in the intensity of faulting are clearly reflected in the gross Salina thickness (Figure 7). In places along the east and west flanks of the basement high, where more than 1300 ft (400 m) of Salina is present, the faulting is minor; but near the axis of the basement high, the Salina has been reduced to only a third of its normal thickness, reflecting an increase in both the number and magnitude of normal faults.

From detailed east-west cross sections (such as Figure 6), it is possible to estimate the thinning and stretching of the Salina caused by normal faulting. The calculation is simplified by assuming no north-south component of the extension. If all the thinning and stretching takes place in the plane of the cross section, the cross-sectional area will be proportional to the volume of rock, which remains constant. On this basis the extension works out to an astonishing 52%; the *average* thinning is about 34%. As just mentioned, thinning is much less on the flanks and much more near the crest of the basement high.

STRATIGRAPHY

A stratigraphic column for the field (Figure 3) reflects Portachuelo's position close to the southern basin margin. Most Eocene units are thinned, and some that are present further north (Travis, 1953; Youngquist, 1958) are completely absent here.

The oldest rocks known in Portachuelo are the argillites, quartzites, and (less common) dark limestones of the Pennsylvanian Amotape Formation, which is considered basement throughout the Talara basin. The level of metamorphism has been characterized as "incipient to nonexistent" (Montoya, 1985, p. 153), although older units studied in outcrop do show higher levels.

The true thickness of the Amotape is unknown; it is complexly folded and may also be repeated by thrusting. As overturned sections are present in outcrop, they presumably prevent reliable thickness calculations in the subsurface as well. One Portachuelo deep test, No. 5237, penetrated 6025 ft (1835 m) of Amotape Formation without encountering different or older strata.

Above the major post-Amotape unconformity are two shale units: the Redondo shale of Campanian age, and—separated from it by another unconformity—the Paleocene Balcones shale. The Redondo, considered to be the source of both Salina and Amotape oil, varies in thickness from 100 to 1100 ft (30 to 335 m). Part of this variation may be due to faulting. Upper Cretaceous limestone units known elsewhere in the basin are almost entirely absent around Portachuelo. The Balcones in this area ranges from 500 to 1500 ft (150 to 455 m).

The lower Eocene Salina, which is discussed in the following section, is conformably overlain by a silty shale sequence of light gray color, known as the Pale Greda. In the field area it is 200 to 1100 ft (60 to 335 m) thick.

The post-Pale Greda hiatus in the field area is represented further north, in the central Talara basin fields, by close to 5000 ft (1525 m) of clastics—the prolific Pariñas sandstone and an overlying shale. These two units are entirely missing south of the Lagunitos trough. The succeeding middle Eocene Talara Shale, also nearly 5000 ft thick in the central part of the basin, is scarcely present in the report area, being only 50 to 250 ft (15 to 75 m) thick.

In the central part of the basin the Talara Shale is succeeded by about 2000 ft (610 m) of sand and shale; these units also are completely absent south of the Lagunitos trough. Directly on top of the post-Talara Shale unconformity the Portachuelo drilled sequence has around 3800 ft (1160 m) of late Eocene Chira and Verdun clastics, undifferentiated. They are conformably overlain by the youngest pre-Quaternary strata in the area, the fine-grained clastics of the Mirador Formation (locally over 1200 ft or 365 m thick).

HYDROCARBON TRAP

Like nearly all the oil pools in the Talara basin, the Portachuelo Salina pool has fault-trapping associated with a structural high. The deeper Amotape pool is considered a combination trap (a sub-unconformity accumulation on a structural high, modified by normal faulting).

Reservoirs

Reservoir Strata: Salina

If a reservoir is defined as a volume of permeable oil- or gas-bearing rock that is in pressure commu-

nication, then the Salina of Portachuelo is not a reservoir but, instead, hundreds of separate reservoirs, many of which will never be drained (untapped by existing wells, they are too small to develop). In this section we will, nevertheless, follow conventional usage in referring to "the Salina reservoir."

The 1600 ft (490 m) Salina sequence contains up to 45 sandstone units (Figure 4) that constitute the individual reservoirs of the Salina pool. They are predominantly fine-grained, pale gray to greenish gray quartzose sandstones. Some units are friable, others are calcite-cemented and fossiliferous, and still others are shaly and finely laminated or cross-laminated. Medium-grained to pebbly sandstones are less common; they also can be friable or calcite-cemented and fossiliferous. Glauconite is common.

Shales, which predominate in the section, are dark gray to black, silty to sandy, fissile in places, less commonly calcareous. Siltstone units ranging from 6 in. to 3 ft (0.15 to 1 m) in thickness (as seen in cores) are scattered throughout the section. The Salina of the study area is now interpreted as the distal portion of a submarine fan sequence. This interpretation accounts for the fact that floral zonules representing 5000 ft (1525 m) of the proximal section farther north are compressed into only 1600 ft (490 m) around Portachuelo.

Reflecting the lithologic variations mentioned above, sandstone reservoir characteristics also vary markedly, and the available averages do not give the whole picture. As an example, the average permeability of 20 md gives no hint that friable sands can reach values of 1000 md. The average porosity calculated from logs (20%) is one-third greater than the average measured in cores (15%).

During drilling, reservoir fluid content was monitored by cuttings fluorescence, supplemented by chromatography of the gas extracted from the drilling mud with a steam still. As a general rule, even the best producers never displayed spectacular cuttings fluorescence, but complete absence of fluorescence was a fairly reliable sign that the sand was wet.

The detailed geometry of the Salina reservoirs is extraordinarily complex. Since the 45 sands have been divided by faulting into blocks and smaller mini-blocks, the number of individual, separate reservoirs runs into the hundreds. Some have gas-oil contacts; some have oil-water contacts; some have neither, and some may have both. The actual picture becomes even more complicated when one realizes that faults acting as barriers under natural (pre-exploitation) conditions can leak when their entry pressure is exceeded under the high artificial pressure gradients created by flowing and pumping wells.

Reservoir Strata: Amotape

The Amotape Formation in the Portachuelo area consists of argillites and quartzites of Pennsylvanian age. Although the degree of metamorphism is very slight, intergranular porosity is commonly below the commercial range. Production from the Amotape is mostly associated with the highly fractured ortho-quartzite facies, although there are a few zones of argillite sufficiently competent to sustain the open fractures that can store and give up oil. Core studies also revealed some secondary vug porosity related to the fracturing, especially near the post-Amotape unconformity.

Total porosity in the quartzite is reported to average 10% (intergranular and fracture porosity combined); intergranular porosity in cores ranges from 0.7 to 5%. The higher figures were measured in essentially unmetamorphosed quartzitic sandstones. Silica is the most common cement, but calcite is also present in some medium to coarse sandstones. Calcite is likewise the most commonly observed fracture filling.

The average permeability is reported as 4 md, but initial producing rates (reflecting variations in effective transmissibility, as well as variations in bottom-hole pressure from 1250 to 3270 psi [8620 to 22,550 kPa]) range all the way from 20 to 1381 BOPD (Montoya, 1985).

Factors controlling the areal distribution of the quartzite facies (which is relatively local compared to the argillite) were never adequately determined. In the southern sector of the pool, Belco was not able to establish commercial production from the Amotape, in part because of the difficulty of finding the quartzite facies, but probably also because of the presence of limestone between the Amotape and the Redondo Shale (see following section).

Inferred Source Rocks

The inferred source of both Salina and Amotape oil is the Upper Cretaceous Redondo Shale, although Salina hydrocarbons could come in part from younger source rocks as well. Modern geochemical studies have never been stressed in the Talara basin. The few early studies, relatively unsophisticated by the latest standards, suggested that (1) hydrocarbons from the many different Eocene producing units all belonged to the same general family, and (2) the sedimentary section did not include any rocks consistently rich in organic matter (>2 to 3% TOC).

One empirical observation is important in working out the source and migration of oil now stored in the Amotape Formation: The Amotape produces commercially in the basin only where it is directly overlain by the Redondo Shale. For example, there is no commercial production from the Amotape in the southern sector of the pool, where it is separated from the Redondo by about 100 ft (30 m) of limestone.

The metamorphism of Amotape rocks presumably did not have any effect on the contained hydrocarbons. Thin-section study of argillite and quartzite from IPC No. 5237, which penetrated 6025 ft (1838 m) of Amotape, did not reveal any downward increase in the degree of metamorphism, which was only incipient despite the implication in the use of "argillite." In any case, indigenous hydrocarbons would presumably have leaked out during the great post-Pennsylvanian hiatus or would have been

destroyed well before the metamorphic grade became high enough to visibly affect minerals seen in thin-section. It thus seems certain that the oil produced from the Amotape was not emplaced there until latest Cretaceous or early Tertiary time.

EXPLORATION AND DEVELOPMENT CONCEPTS

While Portachuelo field does not offer any great lessons for wildcatters (apart from the obvious one that a 21 million bbl field need not be left undeveloped for 20 years), for subsurface geologists its Salina pool provides important insights in two areas: determining optimum well spacing in discontinuous reservoirs and using reservoir-fluid data to work out the history of an accumulation.

In focusing almost entirely on the rocks, subsurface geologists may miss important clues provided by the contained fluids. A useful focus for reservoir studies is to consider the hydrocarbon reservoir as analogous to a plumbing system in which the rocks are the pipes and tanks, and the pressures recorded in the different fluids (including gases) are a measure of the system's stored energy. The payoff from applying this approach to the Portachuelo Salina pool is described in a following section.

Optimum Well-Spacing in a Highly Faulted Reservoir

A highly faulted sequence of thin sands separated by shales is inherently inefficient for recovery of stored oil. The inefficiency can be partly overcome by careful mapping to get an idea of optimum well spacing and to locate undrained fault blocks. Both these approaches were successfully applied in the Portachuelo Salina pool. The following discussion neglects possible reservoir limits caused by facies change, and considers only those limits resulting from faulting.

The average Salina fault-block has an area of much less than 40 ac (16 ha). For more economic drainage, closer well-spacing was required. This was accomplished in two ways. In the prolific western part of the field, already developed on 40 ac triangular spacing, infill wells were drilled on 13 ac (5 ha) centers to tap virgin blocks between the old wells. In the undrilled southeastern part of the field, the development grid was changed to 20 ac (8 ha) rectangular. A good indication of fault-block size is the average area enclosed by faults on a "straight-line" structure map of some horizon in the Salina (for example, Figure 5). Within the pool proper, the average block area is under 30 ac (12 ha) and drops further as smaller faults are included. The most detailed maps, not included in this paper, show an average block size of about 10 ac (4 ha).

The effective size of individual reservoirs does not depend on *all* of the faults, but only on those that act as seals. The kind of information that would be needed to determine precisely which faults are barriers to flow and which are permeable—such as detailed flowmeter and pressure surveys—has never been available. At most it seems feasible to make a few inferences indirectly. On the basis of structure mapping and production histories it appears that most of the faults that cut the Salina with more than 50 ft (15 m) of displacement act as seals, whereas smaller faults may or may not be effective barriers. The problem is not only that of the geometry of each individual fault (i.e., whether sand is faulted against shale to make a seal), but also whether the fault plane itself is cemented by calcite or sealed by tar.

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Actual results confirmed the inefficiency of 40 ac spacing in two ways: First, original per-acre recoveries were too low; second, excellent production was obtained from infill wells on 13 ac (5 ha) spacing. Despite unpleasant surprises with certain wells, the overall program of infill drilling in the Salina pool was a commercial success. The program yielded one outstanding well for every three drilled—the same ratio found in the pool as a whole—and those outstanding infill wells added enough production to pay out the costs of the overall program (Figure 9). As an example, one infill well was located in the center of a triangle whose corner wells had collectively produced over 900,000 bbl and had declined to an average of less than 100 BOPD per well. The infill well came in for 1269 BOPD, paying out its own costs in three months. It produced 187,000 bbl in the first 12 months.

Fluid Distribution

A map of accumulated water production from the Salina (Figure 10) shows the distribution typical of an anticlinal trap: an axial trend of water-free producers, flanked by zones of intermediate water production, with the highest water-cut along the edges. High water production was seldom a problem, even in edge wells. It was often noted that a well starting out with high water-cut would clean up and

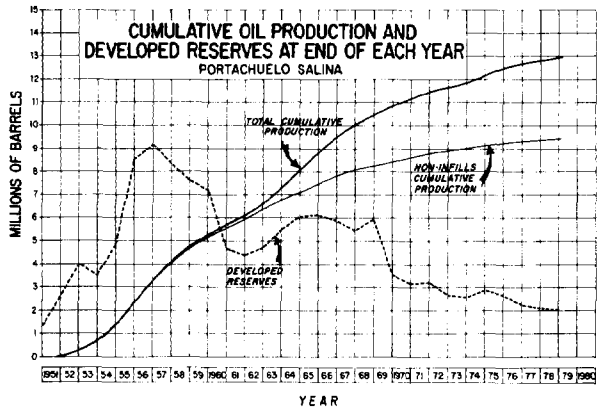

Figure 9. Production curves, Salina reservoir. "Developed reserves" = remaining reserves for sands that are open to production. (After Hay-Roe et al., 1983, with permission of Journal of Petroleum Geology.)

produce less water after continued flowing or pumping. The salinity of Salina formation-water is uniform within Portachuelo. It ranges from 15,000 to 18,000 ppm dissolved solids, with no apparent trends, either lateral or vertical.

Gas sands are more likely to be encountered near the top of the section (Salina sands 1 to 3 are commonly gassy), but there is no consistent level of gas-oil contacts anywhere in the pool. As would be expected, gassy Salina is more common within the trend of water-free oil production, and wells with a very low initial gas/oil ratio (IGOR) are mostly located near the western edge of the field. But maps of IGOR and initial gas production do not show a clear-cut picture like that of water production and are omitted from this report.

The authors consider that the more irregular distribution of gas is due to its higher mobility. At the time of faulting it was more widely redistributed than were oil and water. Also, since both known and presumed gas sands were always avoided in Salina well completions, initial gas production also depended on technical factors such as log-analysis results and inferences of fluid content from correlations with nearby producers.

Reservoir Pressures

Treated from a geologic rather than an engineering perspective, pressure data strongly support the conclusion that Salina hydrocarbons originally accumulated in an anticline.

The engineering treatment of initial pressures is shown in Figure 11—a standard plot of static BHP (bottom-hole pressure, adjusted to an arbitrary depth datum) vs. the time of measurement. Analysis of these values is greatly complicated by the fact that a well can penetrate up to 45 sands (each of which would, in an unfaulted field, be a separate reservoir) cut up into numerous fault-blocks. Some of the hundreds of resulting minireservoirs were drained by earlier wells, others not. Thus each data-point represents some kind of rough average for *all the sands, whether virgin or depleted, that were opened during the initial completion* of the well in question. The sloping dashed lines in Figure 11 enclose a trend that seems to suggest poolwide communication, with later wells coming in at lower initial pressures than early wells. However, four wells on regular spacing plot are above the "trend," and all but three of the infill wells are above it—many are far above. Clearly some other control is at work here.

A suite of maps of exploitation chronology (unpublished, Hay-Roe, 1965) provide a clue. They show how Salina development began near the northern end of the pool and proceeded southward and southeastward. But the mystery is still not cleared up until initial pressure distribution is displayed *geographically* (Figure 12). This map—a geological treatment of pressure data—has the distribution of values that would exist if an anticlinal accumulation were flattened by faulting, with *minimal readjustment of the pressures to their new depths.* The dozen wells marked by crosses had initial pressures 200 to 300 psi (1380 to 2070 kPa) lower than the normal pressure indicated for the vicinity and are judged to have been opened in one or more depleted or partly depleted sands.

Blocks located high on the former anticline (where the *absolute* pressure was less) were dropped to a lower position. Flank areas, which started off with a higher absolute pressure by virtue of their depth, were raised. Although some sands undoubtedly suffered pressure adjustment (i.e., fluid loss) during faulting, the majority still reflect the "fossil" pressure-distribution of a collapsed anticline.

In conjunction with this pressure distribution map, the exploitation chronology can now explain the apparent trend of initial bottom-hole pressures in Figure 11. Purely by chance, the discovery well for Portachuelo was in the north end of the pool, where initial pressures are high. Drilling proceeded south-southeastward toward the low pressure area whose center is well No. 4839. Thus, the *chronological* arrangement of wells completed through 1957 shown on Figure 11 indicates a consistent downward trend. Wells 4628 and 4804 are off the trend precisely because they are located on the higher-pressure east and west flanks, respectively.

Now it is clear why the wells drilled after 1960 do not fit the "trend" of Figure 11: They did not follow the geographic pattern of development. For example, well No. 5242 (right side of Figure 11) came in more than 1000 psi (7000 kPa) *above* that "trend." The fact that the initial pressure of No. 5242 is 350 psi (2450 kPa) *below* that predicted by Figure 12 suggests that some sands must have been partly drained by earlier wells.

Inferred History of Accumulation

The foregoing evidence supports the concept of an anticlinal accumulation in the Salina Formation of

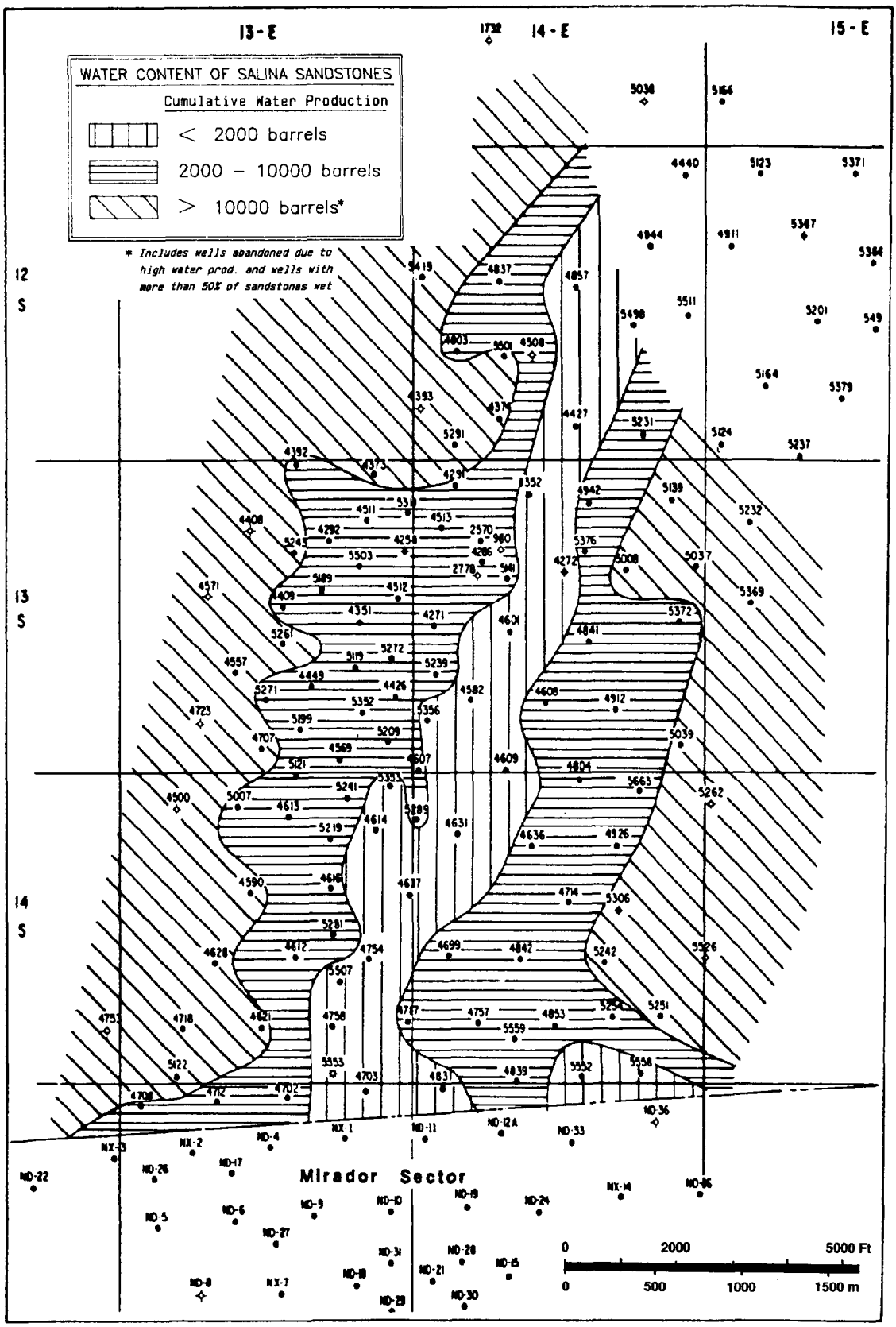

Figure 10. Cumulative water production, Portachuelo Salina pool. (After Hay-Roe et al., 1983, with permission of Journal of Petroleum Geology.)

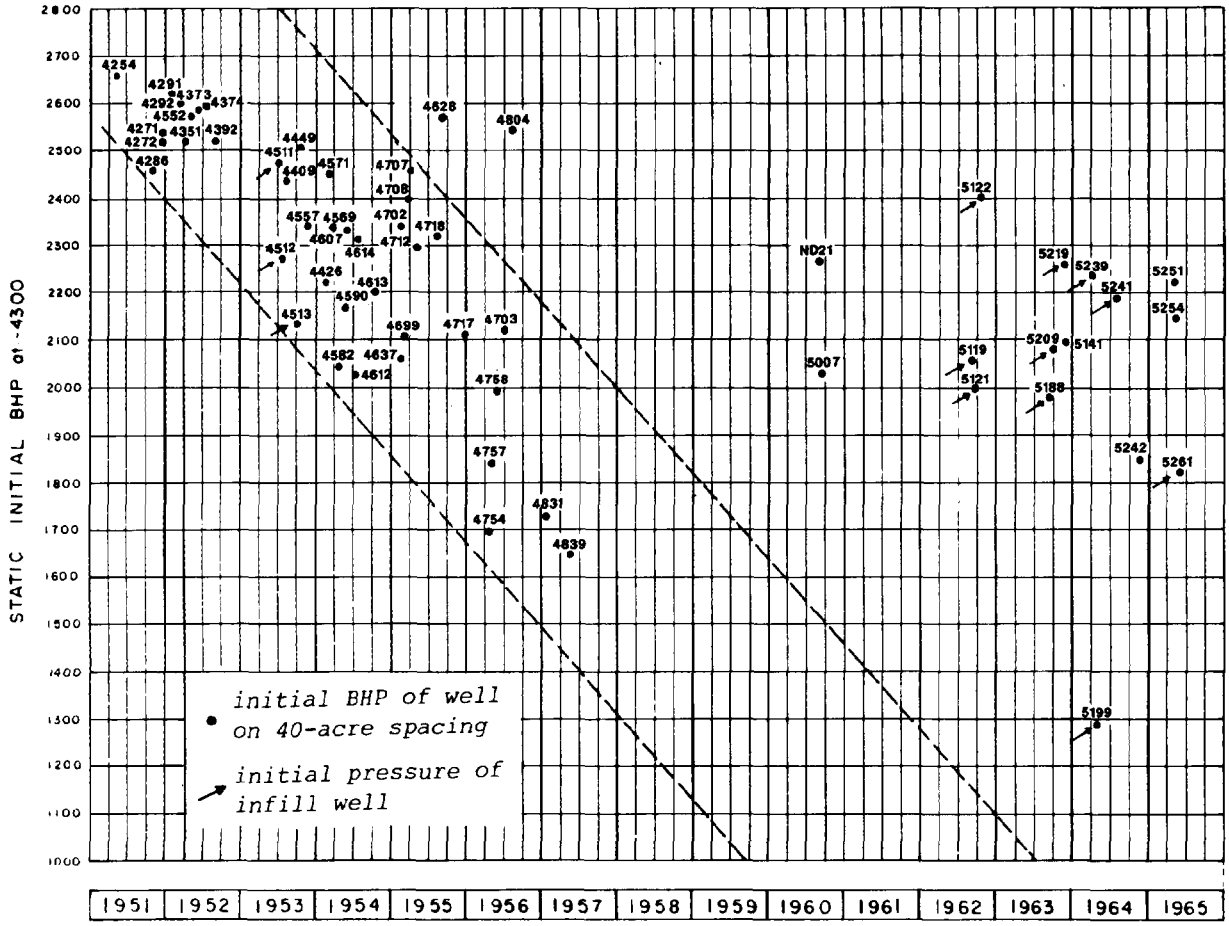

Figure 11. Initial bottom-hole pressures (psi), Salina Formation, vs. time of measurement. (After Hay-Roe et al., 1983, with permission of Journal of Petroleum Geology.)

Portachuelo (Figure 13A). The anticline, genetically related to the Paleozoic high, plunged north-northeast. By the time hydrocarbon migration into this structure took place, the shales separating the reservoir sands must have been sufficiently compacted to prevent appreciable vertical migration of the oil phase.

With cross-formational migration blocked, each of the 45 sands would act as a separate reservoir, having independent gas-oil and oil-water contacts whose positions would depend on the relative abundance of oil and gas that happened to migrate into that particular sand on the structure. The end result would be something like that represented in Figure 13A, which for simplicity portrays only a portion of the total Salina sequence.

This comparatively simple fluid distribution was enormously complicated by the post-early Eocene extensional faulting that flattened the Salina anticline until it was unrecognizable, although it did not totally eliminate the Portachuelo high. Presumably there was some escape of oil and gas (as well as water) along temporarily permeable fault planes, or directly across faults from one sand to another, during and immediately after each phase of the faulting. A very rough volumetric calculation suggests that approximately 40% of the original oil may have been lost from the reservoir. The redistribution of fluids into the present complex arrangement is suggested schematically in Figure 13B.

ACKNOWLEDGMENTS

Portachuelo's subsurface geology has been an ongoing challenge, a three-dimensional jigsaw puzzle with which many talented geoscientists have struggled. We particularly benefited from the work of former colleagues R. B. (Russ) Travis, Manuel Paredes, Lizardo Munoz, and Adolfo Perret; we also picked the brains of "old Talara hands" George H. Tappan, J. Fernando Zuñiga-Rivero, J. Roger Palomino, W. L. (Walt) Youngquist, John D. Tuohy,

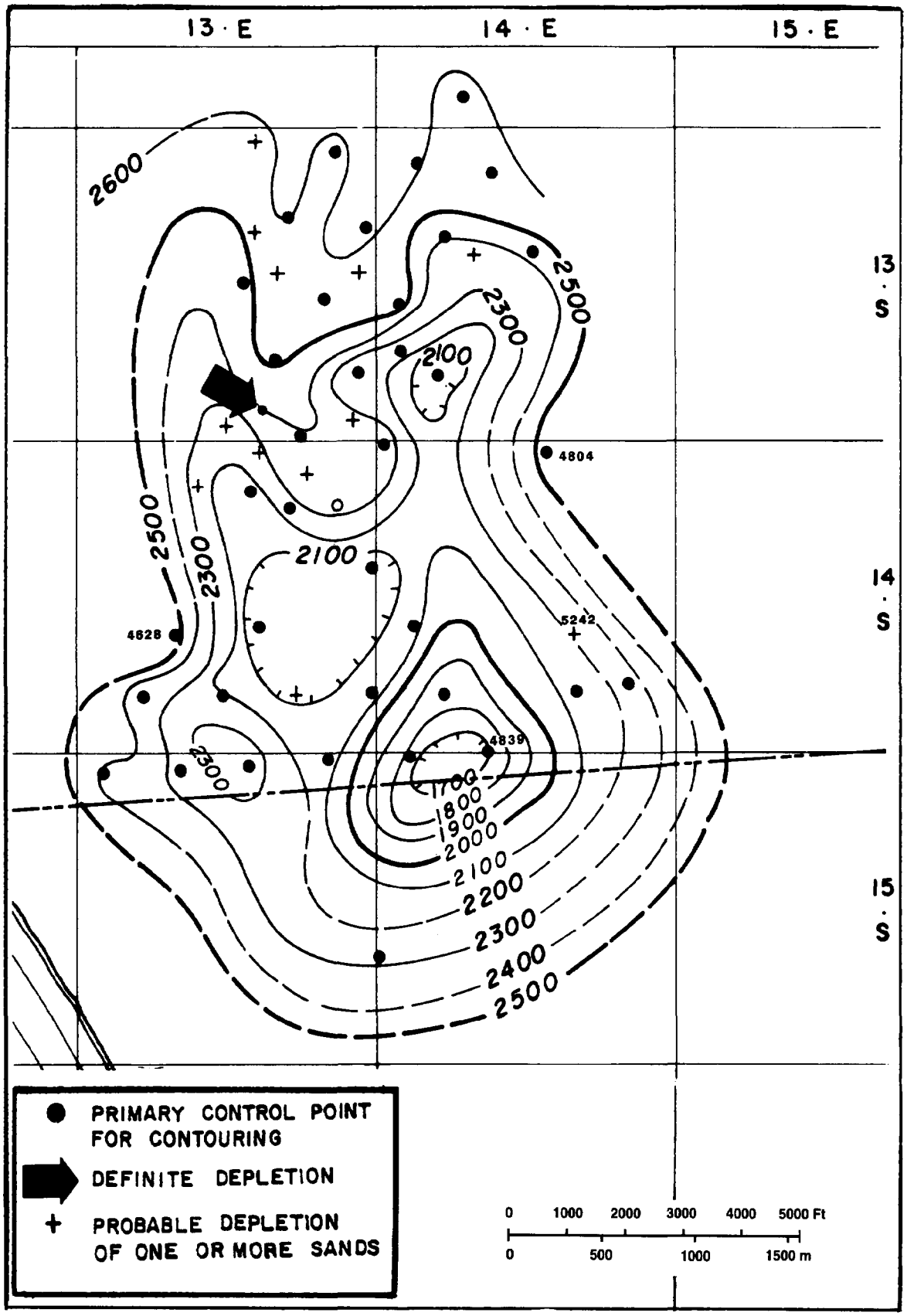

Figure 12. Initial bottom-hole pressure map, Salina Formation. Contour interval 100 psi (dashed where inferred). (After Hay-Roe et al., 1983, with permission of Journal of Petroleum Geology.)

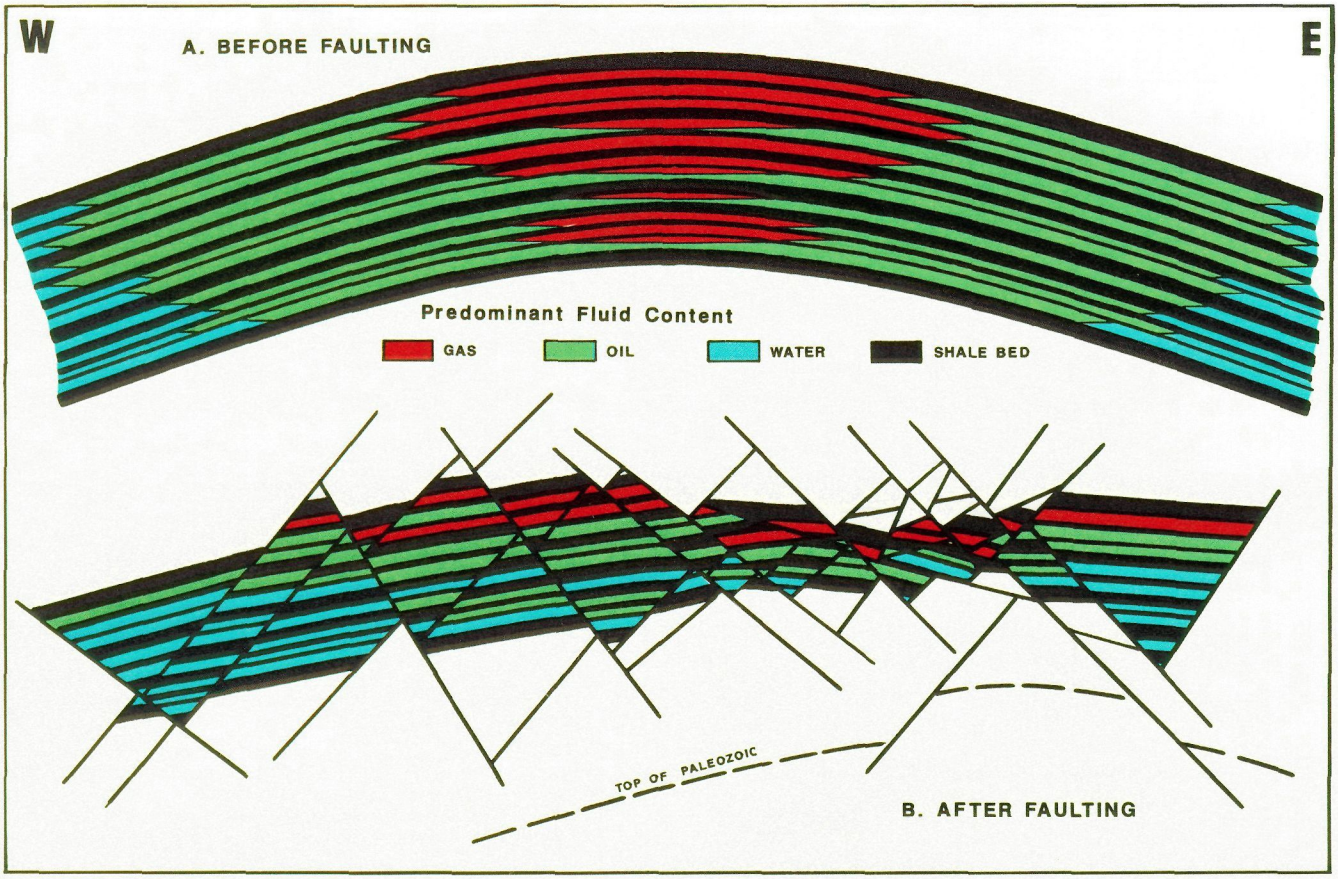

Figure 13. (A) Highly generalized schematic cross section of a portion of the Salina Formation of Portachuelo pool, prior to faulting. No scale. (B) Same strata as in A, after faulting and redistribution of fluids. No scale. Subsurface control inadequate to locate faults at or in the Amotape Formation.

Viktor Petters, Paul M. Tucker, and J. M. (Jim) Dorreen. Marco Antonio Raez provided valuable information on the southern sector of the field, developed in the late 1950s and 1960s by Belco Petroleum Corporation of Peru. To all these geoscientists, our thanks for their generous help.

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Appendix 1. Field Description

Field name ..... *Portachuelo field*
Ultimate recoverable reserves ..... *21 million bbl*

Field location:

Country ..... *Peru*
State ..... *Department of Piura, northwestern Peru*
Basin/Province ..... *Talara basin*

Field discovery:

Year first pay discovered ..... *Salina Formation 1931*
Year second pay discovered ..... *Amotape Formation 1954*

Discovery well name and general location:

First pay ..... *IPC #2570, sq. mi 13S-14E, La Brea-Parinas sector; 20 mi SSE of port of Talara*

Discovery well operator ..... *International Petroleum Co. (IPC) (Exxon)*

IP

First pay ..... *262 BOPD*
Second pay ..... *26 BOPD*

All other zones with shows of oil and gas in the field:

Age	*Formation*	*Type of Show*
Paleocene	*Balcones Formation*	*Oil*
Campanian	*Redondo Formation*	*Oil*

Geologic concept leading to discovery and methods used to delineate prospect

The 1931 discovery well, 2570, was based on surface geologic mapping plus limited subsurface data from IPC well #980, an early (pre-1920) abandonment. After the drilling of one 7 ac (2.8 ha) offset to the discovery well, development was suspended for 20 years. By the time it was resumed in 1951, gravimetry and photogeology had aided in outlining the structure. The second (deeper) pay was suspected from shows in bit cuttings and was confirmed by the drilling of well 4610 after the structural high was further delineated by seismic.

Structure:

Province/basin type ..... *III Rift (Bally); III B b Transform rifted convergent margin (Klemme)*

Tectonic history

The Talara basin developed during the Paleogene near the leading edge of the South America plate where it overrides the Nazca plate. The main cycle of subsidence/deposition was in the Eocene. The Neogene and Pleistocene were marked by normal faulting and uplift.

Regional Structure

The productive structure lies on the southern flank of the Talara basin, separated from the main part of the basin by the major transverse graben called the Lagunitos trough (Figure 1).

Local Structure

The field lies high on the west flank of a highly faulted, asymmetric, northward-plunging nose.

Trap:

Trap Types

The original trap was a simple anticline, subsequently broken up by intense normal faulting into numerous fault-block reservoirs that, for the most part, are not in pressure communication with one another.

Basin stratigraphy (major stratigraphic intervals from surface to deepest penetration in field):

Chronostratigraphy	Formation	Depth to Top in ft (m)
Upper Eocene	*Lagunitos Group*	*0*
Middle Eocene	*Talara Shale*	*2700 (825)*
Lower Eocene	*Pale Greda (shale)*	*2900 (885)*
	Salina (shale/sand)	*3300 (1005)*
Paleocene	*Balcones Shale*	*4600 (1400)*
Upper Cretaceous	*Campanian Redondo Shale*	*5000 (1525)*
Pennsylvanian	*Amotape (quartzite/argillite)*	*5300 (1615)*

Reservoir characteristics:

Number of reservoirs

Formations ..... *Salina, Amotape*

Ages ..... *Salina, early Eocene; Amotape, Pennsylvanian*

Depths to tops of reservoirs ..... *Salina, 2800-3800 ft (855-1160 m); Amotape, 4900-5800 ft (1495-1770 m)*

Gross thickness (top to bottom of producing interval) ..... *Salina, 1000 ft (305 m) (highly variable); Amotape, 500± ft (150± m)*

Effective net thickness ..... *Salina, variable; Amotape, variable*

Lithology ..... *Salina, friable, fine- to coarse-grained quartzose sandstones Amotape, highly fractured orthoquartzite (some argillite)*

Porosity type ..... *Salina, intergranular; Amotape, fracture porosity (minor intergranular)*

Average porosity ..... *Salina, 15% from cores, 18-23% from logs; Amotape, less than 5% intergranular porosity*

Average permeability ..... *Salina, 15-25 md, locally up to 1000 md; Amotape, matrix perm. less than 0.5 md, no data on fracture perm.*

Seals:

Upper

Formation, fault, or other feature ..... *Salina, Pale Greda and intra-Salina shales; Amotape, Redondo shale*

Lateral

Formation, fault, or other feature ..... *Salina, normal faults; Amotape, normal faults*

Source:

Formation and age ..... *Salina, Redondo, Campanian; Amotape, Redondo, Campanian*

Lithology ..... *Shale*

Average total organic carbon (TOC) ..... *NA*

Maximum TOC ..... *NA*

Kerogen type (I, II, or III) ..... *NA*

Vitrinite reflectance (maturation) ..... *NA*

Time of hydrocarbon expulsion ..... *NA*

Present depth to top of source ..... *5000 ft (1525 m)*

Thickness ..... *300 ft (90 m)*

Appendix 2. Production Data

Field name ..... *Portachuelo field*

Field size:

Proved acres ..... *Salina, 3500 ac (1415 ha); Amotape, 1800 ac (730 ha)*

Number of wells all years ..... *Salina, 103; Amotape, 18; Dual Zone, 24 (includes shut-in wells; total wells in field, including 19 dry holes: 164)*

Current number of wells ..... *NA*
Well spacing ..... *40 ac triangular, with infill wells on 13 ac spacing*
Ultimate recoverable ..... *21,000,000 bbl (both reservoirs)*
Cumulative production ..... *Salina, 11,400,000; Amotape, 5,200,000; Dual Zone, 2,200,000 (exact figures not available)*
Annual production ..... *1,000,000 bbl (both reservoirs)*
Decline rates of individual wells ..... *Highly variable (a function of fault-block size, number of individual reservoirs perforated, and pressure in each reservoir)*
Annual water production ..... *NA*
In place, total reserves ..... *NA*
Primary recovery ..... *2,200,000 (both reservoirs)*
Secondary recovery ..... *No estimate*
Enhanced recovery ..... *No estimate*
Cumulative water production ..... *Salina, 450,000 bbl; Amotape, NA; Dual Zone, NA*

Formation evaluation:

Logging suites ..... *Induction electric log; sonic log with caliper; cased-hole neutron and casing/collar locator; logs supplemented by sidewall cores in sands of uncertain fluid content*
Testing practices ..... *Drillstem tests rare; zones to be completed normally determined from log analysis*
Mud logging techniques ..... *Drilling fluid samples in sealed containers taken in to lab for steam-still extraction and gas chromatography*

Oil characteristics:

API gravity ..... *Salina, 36° (range 29-39°); Amotape, 23° (range 19-30°)*
Base ..... *Salina, paraffin; Amotape, paraffin*
Initial GOR ..... *Salina, 300 to 3000; Amotape, NA*
Sulfur, wt% ..... *Salina, 0.06; Amotape, NA*
Viscosity, SUS ..... *NA*
Pour point ..... *Salina, 80°F; Amotape, NA*
Gas composition ..... *Methane, 96.0%; ethane, 2.2%; propane, 0.7%; butane, 0.2%; pentane, 0.7%; CO_2, 0.2%*

Field characteristics:

Average elevation ..... *40 ft (12 m)*
Initial pressure ..... *Salina, 2660 psi at datum -4300 ft (18,300 kPa at -3110 m); Amotape, 3270 psi at datum -5000 ft (22,500 kPa at -1525 m)*
Present pressure ..... *Salina, highly variable; Amotape, NA*
Temperature ..... *Salina, 135°F (57°C); Amotape, 145°F (63°C) (variable)*
Geothermal gradient ..... *0.015°F/ft (0.027°C/m)*
Drive ..... *Solution gas (both reservoirs)*
Oil column thickness ..... *Highly variable (both reservoirs)*
Oil-water contact ..... *Salina, multiple; Amotape, -5200 to -6100 ft (-1585 to -1860 m)*
Connate water ..... *Salina, 50% (est.); Amotape, highly variable*
Water salinity, TDS ..... *Salina, 15,000-19,000 ppm; Amotape, 15,000-17,000 ppm*

Transportation method and market for oil and gas:

Crude oil and produced gas move by company-owned pipeline 20 mi (32 km) north to company-owned refinery/petrochemical complex; products go to the domestic market..