

STATE OF NEW MEXICO
ENERGY, MINERALS AND NATURAL RESOURCES DEPARTMENT
OIL CONSERVATION DIVISION
CASES 10341 and 10342 (Consolidated)

EXAMINER HEARING

IN THE MATTER OF:

Application of Marathon Oil Company
for Statutory Unitization, Eddy
County, New Mexico.

Application of Marathon Oil Company
for Pressure Maintenance Project,
Eddy County, New Mexico

TRANSCRIPT OF PROCEEDINGS

BEFORE: MICHAEL E. STOGNER, EXAMINER

STATE LAND OFFICE BUILDING

SANTA FE, NEW MEXICO

June 27, 1991

A P P E A R A N C E S

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1 EXAMINER STOGNER: At this time I'll call
2 both Cases 10341 and 10342, both to be consolidated.

3 MR. STOVALL: 10341 is the application of
4 Marathon Oil Company for statutory unitization, Eddy
5 County, New Mexico.

6 10342 is the application of Marathon Oil
7 Company for pressure maintenance project, Eddy County,
8 New Mexico.

9 EXAMINER STOGNER: Call for appearances in
10 both these matters at this time.

11 MR. KELLAHIN: Mr. Examiner, I'm Tom
12 Kellahin of the Santa Fe Law Firm of Kellahin,
13 Kellahin and Aubrey, appearing on behalf of the
14 Applicant, and I have three witnesses to be sworn.

15 EXAMINER STOGNER: If there are no other
16 appearances, will the witnesses please stand to be
17 sworn.

18 [Thereupon, the witnesses were sworn.]

19 EXAMINER STOGNER: Mr. Kellahin?

20 DANIEL D. TAIMUTY
21 the witness herein, after having been first duly sworn
22 upon his oath, was examined and testified as follows:

23 EXAMINATION

24 BY MR. KELLAHIN:

25 Q. Mr. Taimuty, for the record, would you

1 please state your name and occupation?

2 A. My name is Daniel D. Taimuty, and I'm an
3 engineer for Marathon Oil Company.

4 Q. Mr. Taimuty, on prior occasions, have you
5 testified as an engineer before the Division?

6 A. No, sir.

7 Q. Summarize for us your education.

8 A. I received a Bachelor of Science from the
9 University of Pittsburgh, Pennsylvania, in chemical
10 engineering in 1980. I received a Master of Science
11 in petroleum engineering from the University of
12 Pittsburgh in 1982, and I'm also a registered
13 professional engineer in the State of Pennsylvania.

14 Q. Summarize for us your employment experience
15 as a petroleum engineer.

16 A. I have worked for Marathon Oil Company
17 since 1982 in Midland, Texas. I've spent four years
18 in the reservoir department, one year in special
19 projects, two years in the operations group, and in
20 June of 1989 I was transferred back into the reservoir
21 group, and I've been there ever since.

22 Q. Marathon has requested approval under the
23 statutory unitization procedures of a pressure
24 maintenance project called the Tamano Bone Springs
25 Second Carbonate Unit. They've abbreviated that, but

1 it's the Tamano Unit?

2 A. Yes, sir.

3 Q. What did you do for that project?

4 A. I did most of the reservoir evaluation to
5 determine if secondary reserves existed in the Bone
6 Springs Second Carbonate, and if they could be
7 commercially recovered.

8 Q. Have you finished that reserve study and
9 that engineering evaluation?

10 A. Yes, sir, I have.

11 Q. Based upon that study, do you have
12 conclusions about the feasibility of this pressure
13 maintenance project for this particular portion of the
14 Tamano Bone Springs Pool?

15 A. Yes, sir.

16 MR. KELLAHIN: We tender Mr. Taimuty as an
17 expert petroleum engineer.

18 EXAMINER STOGNER: Mr. Taimuty is so
19 qualified. And I must say, this must be a record
20 number of Pennsylvania people we've had today at this
21 hearing. Mr. Kellahin?

22 MR. KELLAHIN: We have an index map, Mr.
23 Examiner, that is also in the exhibit book, but it
24 serves as an easy reference. Let me hand you one of
25 those now.

1 Q. Before we talk about the specific
2 conclusions that you personally have made and that
3 have subsequently been adopted by your company for
4 this project, let's talk in general terms about what
5 you were trying to study.

6 A. Okay.

7 Q. Tell us a little something about this Bone
8 Springs reservoir.

9 A. As far as the geologic aspects?

10 Q. Some of the geologic aspects of it, and
11 give us some of the engineering characteristics that
12 you're finding in the Tamano Bone Springs Pool.

13 A. The Bone Springs Second Carbonate is part
14 of the Bone Springs formation recognized by the State
15 of New Mexico. The productive portion of the Second
16 Carbonate is located at approximately 8,000 feet.

17 It had an initial reservoir pressure of
18 3,000 pounds and estimated bubble point pressure of
19 2,500 pounds. We've determined it to be a solution
20 gas drive reservoir with some bottom water, but I
21 would hesitate to refer to it as an aquifer because we
22 do not believe it's lending any pressure support to
23 the reservoir.

24 Q. What is the current spacing applied by the
25 Oil Conservation Division to the production from the

1 Tamano Bone Springs?

2 A. It's 40 acres per well.

3 Q. What is the maximum daily oil producing
4 rate that the Division allows for production from the
5 pool?

6 A. 460 barrels per day, per well.

7 Q. You're seeking the approval of a pressure
8 maintenance project?

9 A. Yes, sir.

10 Q. Pursuant to that request, have you been
11 involved in preparing the C-108 documents to justify
12 the integrity of the water injection procedures to be
13 utilized for the project?

14 A. Yes, sir.

15 Q. Let's look at the handout, which is simply
16 a locator map, if you will. What's the significance
17 of the red dashed line Mr. Taimuty?

18 A. That is the proposed unit area or the unit
19 boundary for the unit.

20 Q. When we look at the circled numbers, what
21 does that represent?

22 A. Those are our proposed tract designations.

23 Q. The wells identified on this display are
24 only the Bone Springs penetrations?

25 A. The black circles indicate Bone Springs

1 Second Carbonate producers, and the X's indicate wells
2 that have penetrated the Bone Springs Second Carbonate
3 that are not productive.

4 Q. When we look at the current status of
5 development of the pool at this time, what is that
6 status? Has it been fully developed on 40 acres?

7 A. Yes, sir, we believe it has been fully
8 developed.

9 Q. You have a couple of open locations,
10 however, within the proposed boundary of the unit when
11 you look at the south half of Tract 3?

12 A. Right.

13 Q. Those with that exception is the only tract
14 not fully developed on 40 acres?

15 A. That's right. Well, in Tract 1 there's a
16 40-acre location on Tract 1 also.

17 Q. As part of the unitization process, you and
18 the other working interest owners have resolved what
19 to do with the undeveloped tracts that would be within
20 the unit, have you not, sir?

21 A. Yes, sir.

22 Q. Give us a short summary of what your major
23 conclusions are that you have reached. And perhaps
24 the easiest way to do that is to direct the Examiner's
25 attention to the second book, which is marked as

1 Marathon Exhibit 2. Do you have that?

2 A. Yes, sir.

3 Q. This engineering study is, in fact,
4 authored by you, is it not?

5 A. Yes.

6 Q. Before we get to your conclusions--

7 MR. KELLAHIN: Mr. Examiner, Exhibit 2 is
8 the package of documents that we will spend most of
9 our time with Mr. Taimuty on.

10 Q. Before we talk about the conclusions, let's
11 turn behind the cover sheet and look at the table of
12 contents. Summarize how you have organized your study
13 for presentation?

14 A. We have initially included or at the
15 beginning included a list of all the tables and
16 figures that we have used to refer to in the report.

17 Following that, we have listed our
18 conclusions that we've drawn from our evaluation of
19 the Bone Springs Second Carbonate reservoir, and
20 recommendations based on those conclusions.

21 We have then provided a history of the Bone
22 Springs Second Carbonate Pool. We've described the
23 unitized interval in a vertical sense, and have
24 supplied some geology that pertained to that unitized
25 interval. We've then addressed the proposed unitized

1 area and discussed its primary performance.

2 We used a computer model to help us in our
3 evaluation of secondary recovery, so the next section
4 supplies most of the data that we used to construct
5 our computer model. And also a discussion of the
6 history match, showing that we believe the model is
7 doing a very good job of describing the reservoir
8 behavior.

9 We then went into a discussion of the
10 enhanced recovery evaluation, using the model and
11 using our available data. We have summarized our
12 results and then we have listed the tables and the
13 figures at the end of the report.

14 Q. If the Examiner desired to do so, he could
15 take the figures and tables along with the written
16 narrative in the engineering study book and have a
17 reference, then, that will track your oral testimony
18 today?

19 A. Yes, sir.

20 Q. Let's talk about some of the general
21 conclusions you have reached with regards to studying
22 this project, and turn then to page 3. And without
23 having you read them to us, Mr. Taimuty, give us the
24 general sense of your major conclusions with regards
25 to the feasibility of this project.

1 A. The first conclusion is that we have
2 reasonably delineated the Bone Springs Second
3 Carbonate reservoir. After we have delineated it, we
4 determined that the original oil in place was 15
5 million barrels of oil, and the gross primary recovery
6 would be 2,167,000 barrels of oil, which represents
7 14.4 percent of the oil in place.

8 Based on our evaluation, we believe that a
9 peripheral waterflood yields the maximum incremental
10 recovery due to a secondary project, and that these
11 reserves can be developed economically. Also, that if
12 the waterflood project is deferred, there may be a
13 loss of reserves.

14 Q. When you characterize this as a waterflood
15 project, I'm going to use, interchangeably with that,
16 the phrase pressure maintenance. If I ask you about
17 pressure maintenance I'm asking you about this
18 waterflood project. So don't let that confuse you. I
19 intend to mean it the same thing.

20 A. Okay.

21 Q. When we look at the first conclusion,
22 you've talked about the reservoir being reasonably
23 delineated?

24 A. Yes, sir.

25 Q. Let's talk about how the reservoir was

1 delineated and then how you have determined the
2 reasonable vertical, as well as horizontal boundaries
3 for the unit itself.

4 A. Okay.

5 Q. To do that, let me direct your attention to
6 Figure No. 1, which corresponds to the same handout we
7 just gave the Examiner. Have you found that?

8 A. Yes.

9 Q. Let's relate that now to the type log, Mr.
10 Taimuty, and that's easiest to find as Figure No. 3?

11 A. Yes, sir.

12 Q. So that we can understand the proposed
13 vertical interval for the unit as well as what is
14 being developed as the Second Bone Springs Carbonate,
15 will you take the type log, tell us what well it's
16 taken from, and then describe for us the vertical
17 interval that you want to unitize?

18 A. Okay. The type log is taken from the
19 Johnson "B" Federal Well #4 by Marathon Oil Company.
20 For practical purposes, we consider this to be the
21 discovery well in the Bone Springs Second Carbonate of
22 the Tamano Field.

23 The type log we have listed there has a
24 gamma ray curve on the first tract, then a depth
25 tract. The second tract contains density and neutron

1 porosity estimates, and the fourth tract contains the
2 resistivity profile.

3 The interval we're proposing to unitize is
4 located, in Johnson "B" Federal #4, is from
5 approximately 7,905 feet to 8,190 feet. It is a
6 dolomitized carbonate interval that is overlain by the
7 Bone Springs 1st Sand and underlain by the Bone
8 Springs 2nd Sand.

9 If you look on the far right track or the
10 fourth track of that type log, you'll notice that the
11 resistivity is off scale throughout most of the upper
12 portion, approximately 150 feet of that interval.
13 This is a hard dolomite or tight dolomite. It's
14 general unproductive throughout the interval, although
15 there are some porosity streaks that are productive.

16 The main pay interval which is at
17 approximately 8,050 feet, is indicated by the fact
18 that the resistivity comes back on scale, suggesting
19 better effective porosity and permeability, and this
20 is the interval that we concentrated our efforts on,
21 and that is the most prolific and productive portion
22 of the Bone Springs Second Carbonate.

23 Q. When you, as a reservoir engineer, evaluate
24 the feasibility of this Second Bone Springs Carbonate
25 to determine the integrity vertically, so that you

1 could see if you can flood that zone in a feasible
2 fashion, what did you find?

3 A. Actually that we could flood this zone and
4 recover our oil and do it commercially.

5 Q. Let's talk now about the horizontal
6 boundaries of the container, and let's do the Figure 4
7 following the type log, and have you take that
8 schematic and give us a general view of the geology
9 and the characteristics of the reservoir.

10 A. Okay. What Figure 4 shows, and it's easier
11 to understand if you turn it sideways, this is a
12 characterization of the Bone Springs Second
13 Carbonate. It is a debris flow and it's located at
14 the bottom of the shelf margin. Geologists just refer
15 to that as toe-of-slope. It is not a single-debris
16 flow but a series of debris flows.

17 If you turn to the next page, which is
18 Figure 5, this is a structure map on top of the main
19 pay interval. The shelf margin is approximately one
20 mile north of here, and coincidentally runs across the
21 31 East range line, so the Tamano Bone Springs field
22 is approximately one mile from the shelf margin and
23 what I indicated as the toe-of-slope.

24 Q. Let me have you go to the cross-section up
25 on the wall, Mr. Taimuty. That would be found as an

1 appendix in the feasibility study, as the last display
2 in the plastic folder at the end?

3 A. What we would like to show from the
4 cross-section, this is the top of the Bone Springs
5 Second Carbonate interval, and we have indicated the
6 top of the main pay. Within the main pay our
7 geologists have defined 11 layers that seem to be
8 correlatable across the field. They have their own
9 types of characteristics.

10 The important point here is that, of the 11
11 layers, we refer to the odd numbered layers as
12 low-flow units and the layers here in purple as the
13 high-flow units. The significance of that is that the
14 high-flow units most likely occur during violent,
15 geologic times where larger debris flows, such as
16 clasts, were dumped over the shelf edge and deposited
17 in this nature.

18 In between, there were long periods of
19 dormant times where just mud stones were deposited
20 over. The mud stones have very low permeability and
21 are very fine grain, more difficult for the fluids to
22 move through the reservoir. Most of the production
23 occurs in the high-flow units or the purple units, and
24 they just happen to be numbered as all the even
25 numbered intervals.

1 Q. Can you use the cross-section to help us
2 understand the concept by which you're going to
3 introduce water into the reservoir to help you
4 maintain pressure of the reservoir?

5 A. I'm not sure I--

6 Q. We have 11 zones potentially in this Second
7 Bone Springs Carbonate. How are you going to do it?

8 A. Actually, we're just going to go in and we
9 may have to add some perfs at some intervals, but
10 we're going to perforate and try to introduce water
11 into the entire main pay interval on the peripheral of
12 the reservoir, and hope to flood it that way.

13 Q. What's the concept behind opening up all 11
14 zones or however many zones you can find in each of
15 the wells, and for those wells selected for
16 injectivity, use those for maintaining pressure of the
17 reservoir?

18 A. Well, we hope to maximize our sweep
19 efficiency in a vertical sense by injecting into the
20 entire main pay interval.

21 Q. Does it make any sense to try to isolate
22 individual stringers within the Second Bone Springs
23 Carbonate to use for injectivity?

24 A. No, we don't believe so. Actually, that
25 would hurt your vertical efficiency.

1 Q. Okay. Let me have you return to your
2 seat.

3 Having identified the structural
4 relationship of these wells in the area of the unit,
5 having examined the cross-section, what then did you
6 and the geologists do in order to determine the
7 horizontal boundaries to be suitable for the unit
8 purposes?

9 A. I would like to refer to Figure 6 which may
10 help understand what we've done. Figure 6 is a map of
11 porosity, a map of the product of porosity,
12 permeability to oil, and thickness. The way we have
13 constructed this map was to determine permeability to
14 oil through transient testing data and then determine
15 porosity values from log analysis.

16 We have mapped the product of those three
17 parameters, and the result was Figure 6. As it shows,
18 the greatest porosity permeability thickness exists
19 within the west half of the south half of Section 11
20 and it extends into Section 10. We have a zero line
21 there that well defines our proposed unit boundary,
22 whereas you reach the limits of the reservoir you lose
23 your porosity and permeability.

24 Q. When we look at the display and find the
25 letters NA next to a well dot, what does that tell

1 you?

2 A. It indicates that we didn't have transient
3 test data on those wells and were unable to determine
4 an exact porosity value.

5 Q. Let's turn now to Figure No. 7. Having
6 constructed your porosity/permeability ranges in
7 values and contouring it on Figure 6, what then did
8 you do on Figure 7?

9 A. Figure 7 was just actually a test of Figure
10 6, to see if it made sense. The wells circled in red
11 on Figure 7 were wells that flowed when they were
12 initially completed. The wells circled in yellow on
13 Figure 7 were wells that pumped initially.

14 What we have contoured there is the initial
15 potential of each well. As you can see, Figure 7
16 agrees quite well with Figure 6, as far as the most
17 productive portions of the reservoir. So basically
18 what we've done is just put an oil production number
19 to the phi-K-H value and we have quite good agreement
20 between the two figures.

21 Q. What does that help tell you as a reservoir
22 engineer about the logic of the unit boundaries that
23 you're imposing upon this portion of the pool?

24 A. We feel that the entire productive portion
25 of the Bone Springs Second Carbonate is contained

1 within the proposed unit boundary.

2 Q. If the Examiner approves the unitization of
3 this configuration of acreage for the unit, will that
4 give Marathon, as the operator, effective and
5 efficient control of the reservoir to maximize the
6 opportunity for enhanced oil recovery through the
7 pressure maintenance project?

8 A. Yes, it will.

9 Q. Before we leave Figure 7, give us a quick
10 summary around the boundary, let's start with the
11 north boundary, and give us a little sense of the
12 available data that's caused you to conclude that the
13 northern boundary has got a good, justifiable,
14 engineering basis.

15 A. Okay. If you look at Figure 7, you'll see
16 along the top row, and from west to east, Wells #10
17 and #3, and Well #3 on the Heyco lease, and Well #5,
18 those are all marginal producers. Gross recovery to
19 date is something less than 30,000 barrels per well,
20 and in most cases less than 10,000 barrels. As
21 opposed to the well circled in red that have exceeded
22 100,000 barrels and some in cases 200,000 barrels of
23 recovery.

24 As you move north, into Section 2, there
25 have been some tests of the Bone Springs Second

1 Carbonate, and none of them were productive, so we
2 feel that our boundary clearly defines the productive
3 portion of the Bone Springs Second Carbonate to the
4 north.

5 As you move to the east side, we can use
6 the same argument. The wells along the eastern row,
7 as indicated by the yellow circles are all pump,
8 whereas the central portion of the reservoir the
9 well's plugged, or are just reservoir properties.
10 There are two dry holes in Section 12, and those are
11 numbered 5 in the north and to the south, right along
12 the unit boundary there.

13 A point I would like to make at this time
14 is that those wells had zero effective porosity. They
15 were not water productive and therefore uncommercial.
16 They actually did not have any porosity that would
17 contribute fluid at all. That emphasizes the
18 stratigraphic nature of the Bone Springs Second
19 Carbonate reservoir.

20 Another point I would like to make is that
21 the #1 AJ well and our #8 well--our #8 well is located
22 in Tract 5, and the AJ-1 is in Tract 2--those wells
23 produce most of the water in the field. That goes
24 back to my earlier testimony which we believe there's
25 bottom water there, but that we've not observed any

1 pressure support from those wells.

2 Moving along the south border, two wells
3 drilled in Section 14, both indicated by a 1 and the
4 X's, more Bone Springs Second Carbonate tests, as with
5 the wells in Section 12. Those wells in Section 14
6 had no effective porosity. One was plugged back and
7 completed in the Grayburg, and the other has been
8 abandoned since it was attempted to test the well.

9 Moving to the west, we feel that we have
10 the western boundary defined by the fact that the #2
11 well has been a poor producer to date, indicating a
12 pinch out of the porosity and permeability. Although
13 #3 flowed, the porosity and permeability values on the
14 #3 well were not as great as those in the central
15 portion of the reservoir, the well treated at a higher
16 pressure and the pressure behavior in that well has
17 declined rapidly in the last three months, which
18 suggests that that's an edge well. So we really
19 believe we have a good definition of the Bone Springs
20 Second Carbonate on all four sides.

21 Q. When we look at the property on the outside
22 of the proposed unit, immediately adjacent to that
23 outer boundary, do you see any engineering
24 justification for the inclusion of any more acreage or
25 any additional wells within the unit, in order to give

1 you effective and efficient control of this portion of
2 the reservoir for unitization purposes?

3 A. No, sir, nothing outside the proposed unit
4 area.

5 Q. Correspondingly, do you see any wells or
6 acreage inclusive of the proposed unit boundary that,
7 in your opinion, ought to be excluded?

8 A. No, sir. Everything we've included in here
9 we feel should be in here, for effective flooding of
10 the zone.

11 Q. Let's turn to Figure 27. Before we talk
12 about the details of Figure 27, let me have you lay
13 the foundation for how we got to the point of having
14 the computer generate this concept of the reservoir.

15 Go back and tell us why you thought it
16 necessary to simulate the performance of individual
17 wells and then to model that in terms of designing a
18 program for enhanced recovery.

19 A. We felt that by using the computer model it
20 would be the most powerful way of trying to describe
21 what has happened in the reservoir and what would
22 happen by going to some secondary type project. The
23 Bone Springs Second Carbonate is very stratified, as
24 I've indicated with the 11 zones on the cross-section;
25 therefore, conventional volumetric or material balance

1 calculations really don't hold well individually, but
2 some combination of material balance and volumetrics
3 would be the most powerful way and the best way to
4 describe the reservoir, and by using the model we felt
5 we could accomplish this.

6 Q. Were you able to use the model to help you
7 select the type of waterflood project that gave you
8 the greatest potential secondary oil recovery?

9 A. Actually it goes beyond even just water
10 injection. We also evaluated emissible gas injection
11 as a possible secondary project, and we varied the
12 amount of gas injected and we also varied the
13 waterflood pattern in an attempt to find the optimum
14 recovery.

15 Q. Did the model aid you, as a reservoir
16 engineer, then, in selecting this peripheral
17 waterflood pattern to maximize the oil recovery?

18 A. Yes, it did.

19 Q. In addition, the model helped you predict
20 the performance of the existing wells?

21 A. That's right. The first thing we did with
22 the model was to try and determine remaining primary
23 recovery.

24 Q. Why could you not do that without the
25 assistance of the simulation of the reservoir, the

1 individual well performance model?

2 A. Some wells had an established decline and
3 we could use conventional decline analysis to try and
4 determine remaining performance on primary recovery.
5 However, other wells were either very new or had
6 produced at the top allowable rate for their entire
7 life; therefore, there was no production history that
8 would assist us in conventional decline analysis.

9 Q. With the assistance of the reservoir
10 simulation by computer modeling, you were able to
11 quantify, within a certain range, your anticipated
12 secondary oil recovery from the waterflood project?

13 A. Yes, sir.

14 Q. And it also aided you in determining what
15 would be the primary oil production by well or by
16 tract, without the waterflood operation?

17 A. That's right.

18 Q. Anything else in a major conclusion that
19 the model was used for?

20 A. If I could summarize, we used the model for
21 primary depletion and then to evaluate both emissible
22 gas injection and various waterflood patterns, and
23 that's it.

24 Q. From those conclusions, then, you were also
25 able to assign values to each individual tracts?

1 A. In terms of--

2 Q. Relative value for each tract by which,
3 then, participation parameters can be selected for
4 participation and production from the unit?

5 A. Right. We did use the model to some extent
6 for that, to estimate reserves for our tracts where we
7 did not have established decline. So we did.

8 Q. Let's go back and build the model. What
9 model did you use? what software program?

10 A. The software name is Eclipse.

11 Q. How many phases in this software program to
12 model this reservoir?

13 A. There are three fluid phases, oil, gas and
14 water.

15 Q. Was this a single porosity model or dual
16 porosity model?

17 A. It's a single porosity model.

18 Q. Why did you select a single porosity model?

19 A. We've looked at a single and a dual
20 porosity model. In a fractured reservoir, which is
21 what we believe the Bone Springs Carbonate to be, you
22 would normally use a dual porosity model. However,
23 through our evaluation we've determine that most, if
24 not all of the storage capacity and the flow
25 capability of the reservoir is contained within the

1 vugs and fractures of the reservoir. Therefore, even
2 though it may be a dual porosity model, by normal
3 convention it behaved as a single porosity model
4 because the vugs or fractures were so dominated. We
5 went ahead and ran both types of models and found that
6 we got almost identical results with both a single
7 porosity model and a dual porosity model, and
8 obviously a single porosity model was more efficient
9 in describing the reservoir. So we opted for the
10 single porosity model.

11 Q. How many layers did you integrate into the
12 model?

13 A. All 11 geologic layers that we described by
14 the cross-section.

15 Q. When we look at the horizontal pattern or
16 the grid size for the model, what was the grid size?

17 A. The grid size was 264 feet on the side in
18 Section 11 and 528 feet by 264 feet in Section 10.

19 Q. Were you satisfied that you got reliable
20 results from reservoir simulation with a grid size of
21 that configuration?

22 A. Yes, I am.

23 Q. At this point, then, you have to select
24 reservoir parameters or values to input into the
25 computer, do you not?

1 A. That's right.

2 Q. Do we have a reference sheet or some way to
3 tell the Examiner what the input was into the model,
4 in terms of that data?

5 A. Not necessarily one reference sheet, but
6 there's an entire chapter in the report, and
7 everything that we used within the model is described
8 within that section.

9 Q. The Examiner will find it, starting on page
10 16, running all the way through page 23?

11 A. That's right.

12 Q. Having input all the reservoir data that
13 you are satisfied, as an engineer, would give you an
14 accurate reservoir description, what then did you do?

15 A. Okay. We first history-matched the model
16 to determine the accuracy or the comfort level the
17 model was giving us as far as predicting reservoir
18 behavior.

19 Q. You're doing that on an individual well
20 basis or for a selected number of wells?

21 A. We did it for every well.

22 Q. What are you history-matching against?

23 A. Four things; oil production, gas
24 production, water production and reservoir pressure.

25 Q. Can you direct our attention to those

1 portions of the engineering book that will give us
2 your history matches, first of all, on oil?

3 A. That would be, Figure 37 would be the oil
4 history match.

5 Q. Figure 37 represents an oil history match
6 for what wells?

7 A. Actually for all of the wells that are to
8 be included in the unit, all 19 wells.

9 Q. What do you find when you examine the
10 match?

11 A. The model predictions are indicated by the
12 solid line and the actual production are indicated by
13 the plus signs, and they overlay identically. They're
14 exact.

15 Q. In order to get a history match on oil,
16 what reservoir parameters did you have to adjust or
17 fine-tune in order to get the history match?

18 A. Probably the parameter we adjusted the most
19 was permeability. I don't mean to mislead you by
20 saying "the most," because there were just basically
21 some minor adjustments in permeability to get a match
22 that we were comfortable with.

23 Q. Where is the base data derived from that
24 gives you your permeability value?

25 A. Okay. I would have to refer to the

1 technical report.

2 Q. Is that from core information?

3 A. Oh, yes, sir. We plotted the core data,
4 core porosity versus core permeability, and we were
5 able to derive three correlations that we used to
6 determine permeability. One were all of the low-flow
7 units seemed to have the same characteristics. In
8 addition, our high-flow Unit No. 2 had the same flow
9 characteristics. So there was one correlation for
10 those zones.

11 Zones 4, 6 and 8 had another set of data
12 that seemed to fit quite nicely together, and we
13 generated a second permeability/porosity correlation
14 from that data, and Zone 10 stood alone. It had its
15 own correlation.

16 So, after determining porosity from logs,
17 we then assigned a permeability value based on the
18 three sets of correlations.

19 Q. From the analysis of the core information
20 on permeability for the various zones, does that give
21 you a range of permeability, or is it an absolute
22 value based upon that core?

23 A. We found a range of permeabilities.

24 Q. Can you approximate for us, based upon your
25 recollection, what is the range of permeability

1 derived from the core analysis?

2 A. Less than one hundredths of a millidarcy to
3 a thousand millidarcies.

4 Q. In order to adjust the history match of the
5 reservoir simulation to the actual oil producing rates
6 shown in the wells, to what degree did you have to
7 adjust the permeability?

8 A. Most of it was just minor. If the zone was
9 10 millidarcies, I may have increased it to 20
10 millidarcies to get a better match on the production.
11 So I guess, maybe, in that case, that would be
12 doubled. But again, it was on a millidarcy basis, and
13 maybe 10 to 20 millidarcies on any particular layer to
14 get a good match.

15 Q. Were you satisfied, as a reservoir
16 engineer, that you were adjusting the permeability so
17 that it stayed within the reasonable range of
18 permeabilities derived from the core data?

19 A. Yes, sir.

20 Q. Let's go and see what the history match is
21 on the gas production. That's Figure 38?

22 A. Yes, the very next figure. Again, as you
23 can see, the solid line would be the gas direction
24 determined from the model, and the plus sign would be
25 the actual gas production. We were very happy with

1 the fit. They track each other very well.

2 Q. Let's go to Figure 39. That's the history
3 match on the water production?

4 A. Yes, sir. Again it's the same convention,
5 the solid being the model prediction and the pluses
6 being the actual. The match here doesn't look as good
7 as the oil or gas, but we do believe we have a good
8 match on the water.

9 Q. The history match is not as close here.
10 Have you examined why it has occurred, and is there an
11 explanation that satisfies you about this occurrence?

12 A. Yes, there is.

13 Q. What is the answer?

14 A. One reason that the match may not agree as
15 closely is that, if you'll notice, there's only
16 100,000 barrels maximum on the axis, so that's not a
17 large volume of water. Therefore spin acid water from
18 our treatments would tend to skew the curve, and the
19 actual data would be somewhat greater than the model
20 predictions because of the spin acid.

21 Another reason is that some of the wells
22 are commingled in the Bone Springs Second Sand, and
23 there's water production associated with the Second
24 Sand that our the model wouldn't be predicting. Our
25 model is confined solely to the Second Carbonate. So,

1 for those two reasons, the actual production is
2 somewhat higher than model predictions.

3 Q. The actual water production is not
4 exclusively confined to the Second Bone Springs
5 Carbonate to formation waters?

6 A. That's right.

7 Q. Have you attempted to exclude the elements
8 of air and reported water production to see what
9 current formation water rates are and how they compare
10 to what the model has predicted?

11 A. That's what gives us our confidence level
12 because the current projected water production for the
13 model matches quite well with the actual production.
14 The Bone Springs Second Sand is producing a minimal
15 amount of water at this time, and we feel like we've
16 recovered most of the spin acid. So our current rates
17 and our production model are quite close.

18 Q. Let's go to Figure 40 and have you describe
19 that.

20 A. Figure 40 is a plot of the reservoir
21 pressure. The solid line is average reservoir
22 pressure throughout the Bone Springs Second Carbonate
23 as determined from the computer, and the pluses are
24 actual data points. I would like to point out at this
25 time that although some of the pluses fall below the

1 average reservoir pressure for the entire unit, that's
2 not alarming because those pluses represent reservoir
3 pressure from any one individual well and are not
4 representative of the entire pressure, which is what
5 the model is plotting.

6 Q. When we turn to Figure 41, what are we
7 looking at with this figure?

8 A. Figure 41 was really the first test of the
9 model. Most of the model was built in January of this
10 year when we were doing our history match. We
11 completed this Stedco 10 #3 in January of 1991. After
12 measuring the reservoir pressure in that well, we
13 plotted the reservoir pressure of just that well in
14 the model. As you can see, we had an excellent
15 agreement between the estimated pressure from the
16 model and actual pressure observed in the well.

17 Q. At this point, then, you were satisfied, as
18 a reservoir engineer, that you have a good, reliable
19 working simulation of the performance of the reservoir
20 and these wells?

21 A. Yes, sir.

22 Q. Did you use the model, then, to help you
23 construct the optimum waterflood configuration to get
24 you the greatest amount of oil recovery?

25 A. Yes, we did.

1 Q. Turn your attention to Figure 42. Tell us
2 how you to read that display.

3 A. This is a plot of four different types of
4 secondary recovery projects that we evaluated, and a
5 dip curve that is just straight primary depletion.
6 The primary depletion curve is in black and it would
7 level off at somewhere around two million barrels of
8 oil, something greater than two million barrels of
9 oil.

10 The four color plots, then, are the four
11 scenarios that we've evaluated; those being a downdip
12 waterflood, a peripheral waterflood and gas injection,
13 both at 10 million cubic feet a day of methane, and 20
14 million cubic feet a day of methane. And these are
15 the projected ultimate recoveries inclusive of
16 primarily for all four scenarios.

17 Q. In each instance the pressure maintenance
18 waterflood projects exceed depletion without secondary
19 recovery?

20 A. Yes, sir, all four do.

21 Q. The best one is the peripheral waterflood
22 that you've ultimately adopted and proposed to the
23 Examiner?

24 A. That's correct.

25 Q. Having determined that the peripheral

1 waterflood is the best or the optimum configuration of
2 the project, did you make a study to determine what is
3 the optimum time in which to commence the project?

4 A. Yes, we did.

5 Q. Is that shown on Figure 44?

6 A. Figure 44 are the results of what we are
7 proposing today. Water injection would begin on
8 January 1, 1992. We plot oil, gas and water
9 production, oil being indicated by the curve with the
10 squares, gas production by the triangles, and water by
11 the circles.

12 As you can see, we're projecting a decline
13 in production through about 1994, at which point we
14 start seeing the benefits of our waterflood project.
15 The production peaks at around 900 barrels per day,
16 and then goes on an ultimate decline.

17 Q. What is your recommendation for an actual
18 commencement date of water injection for pressure
19 maintenance purposes into the project?

20 A. January 1, 1992.

21 Q. Have you examined the possibility of
22 delaying the initiation of injection until the working
23 interest owners in the three 40-acre tracts that yet
24 do not have Bone Springs wells on them, until those
25 wells are drilled, completed and produced, and then

1 initiating waterflood?

2 A. Yes, we've done that evaluation.

3 Q. What did you find out?

4 A. If I could refer you to Figure 46, what we
5 found out is that if we delay water production for two
6 years, until January 1, 1994, the estimated secondary
7 recovery is somewhat less than if we begin injection
8 in January 1, 1992.

9 Q. How did you resolve or attempt to resolve,
10 then, the fact that you've got undrilled tracts in the
11 unit, in terms of how you handle those and the timing
12 of the project?

13 A. I'm not sure I understand the question.

14 Q. You've got three undrilled tracts.

15 A. Right.

16 Q. Those tracts are going to be committed to
17 the unit?

18 A. Yes, sir.

19 Q. Have you satisfied yourself that under the
20 participation formula those tracts are not going to
21 receive more than their contributing value from
22 participation in the unit?

23 A. Yes, we've satisfied ourselves that it's
24 been handled equitably.

25 Q. So you have overcome any obstacles in your

1 mind about having any undrilled tracts in your
2 waterflood?

3 A. Yes, sir.

4 Q. Summarize for us the secondary recovery
5 potential that you've assigned, then, to the
6 waterflood project.

7 A. The amount of reserves we believe we can
8 recover are 2,261,000 barrels through our peripheral
9 waterflood.

10 Q. Let's go and have you give us the
11 economics, then, for the investment, and the schedule
12 of investment for the working interest owners in the
13 project.

14 A. If I may refer to Table 8, Table 8
15 summarizes our projected investments.

16 Q. It's on page 44 of your engineering book?

17 A. Yes, sir. The field is relatively new.
18 Discovery occurred in 1987, so most of the equipment
19 we have on hand is in very good shape and we can use
20 this equipment for the waterflood.

21 Most of the initial investments will be for
22 consolidation of a main battery and for our injection
23 facilities. We're also proposing the conversion of
24 five wells initially to water injection, and we have
25 two wells in the proposed unit area that are currently

1 commingled in the Bone Springs Second Carbonate and
2 Bone Springs Second Sand.

3 We'll set cast-iron bridge plugs between
4 the two zones and dump cement on top of the bridge
5 plugs, which should effectively isolate the two
6 zones. The total cost as outlined in Table 8, is
7 1,125,000 gross to the working interest partners.

8 Beyond that, we are proposing the
9 conversion of two additional wells to injection in
10 1994, at an incremental cost of \$140,000. Also, based
11 on our estimation, we'll require larger lift equipment
12 beyond the existing broad pumps. We need to acquire
13 three submersible pumps, one in 1997, one in 1998 and
14 one in the year 2002, for a total investment in the
15 waterflood of \$1,511,000.

16 Q. Turn now to Table 10 on page 46 and
17 summarize that for me.

18 A. These are the key economic parameters that
19 suggest how the waterflood project will work. We have
20 our initial investments of \$1,125,000, and future
21 anticipated investments of \$386,000. What this is a
22 summary of are our incremental economics, or economics
23 above and beyond what we would realize through just
24 straight primary depletion. We'll pay the investment
25 out in roughly three and a half years, at an annual

1 rate of return of 60 percent.

2 The net present value of the secondary
3 project is roughly \$9.4 million, using a discount
4 factor of 15 percent. Incremental net profit would be
5 \$26,284,000, and as you can see, suggested incremental
6 reserves net to the working interest owners, would be
7 \$1,979,000, and the difference would go to the royalty
8 owners, the difference between that number and the
9 total of 2,261,000 barrels that we've estimated.

10 We feel these are very good economic
11 parameters and the flood should be very successful.

12 Q. Let's go back to the chronology of the
13 efforts to complete the study, and then to share it
14 with the other working interest owners in the proposed
15 unit. In that regard, identify for me what is marked
16 as Exhibit 1?

17 A. This is the feasibility study that we put
18 together between January of 1991 and March of 1991.
19 When we had that completed, we called for a meeting of
20 all the working interest owners in the proposed unit
21 area, at which time we submitted the feasibility study
22 to them and discussed it.

23 Q. Give us a quick summary of the major
24 differences, if any, between the March 91 feasibility
25 study and the engineering book you've discussed, which

1 is dated June of 1991?

2 A. The technical report dated June of 1991 is
3 a more complete report from a geologic and engineering
4 standpoint. The feasibility study was designed to
5 just hit the highlights of the results of our
6 evaluation, and to let the partners know what our
7 conclusions were, and to discuss with them any merits
8 or how to proceed about unitizing this area. So the
9 feasibility study may be more geared toward the
10 economics and what Marathon was proposing, whereas the
11 technical report would supply most of the actual
12 factual data.

13 Q. When we compare the June 1991 engineering
14 report to the March 1991 feasibility study, are there
15 any major conclusions or recommendations in the March
16 91 report that should be changed?

17 A. No.

18 Q. Who are the major working interest owners?
19 You don't have to name them all, but give us a general
20 idea of the major companies or individuals that you
21 were dealing with on a voluntary basis to formulate
22 this unit.

23 A. Actually there are, I believe, eight major
24 partners. In addition to Marathon Oil Company there
25 was Hudson and Hudson, the Harvey E. Yates Company, or

1 Heyco, Yates Energy, Pennzoil, Winoco, Arco, and Kerr
2 McGee.

3 Q. Were there various meetings called by your
4 company, as the initiator of this proposed unit, to
5 meet with the working interest owners and give them an
6 opportunity to hear your presentation and then to
7 comment on the feasibility of the project?

8 A. Actually, we had three working interest
9 owner meetings to discuss the merits of the project.
10 In addition to the three meetings, we had several
11 individual meetings. Several companies came in to
12 review our data, our logs, and the model runs.

13 In addition, we traveled to both Hudson and
14 Hudson and Heyco to discuss the data. So several
15 meetings, I guess three formal.

16 Q. Ultimately, did the working interest owners
17 vote on an equity participation formula for unit
18 production?

19 A. Yes, they did.

20 Q. Describe for us the parameters that they
21 had to select from.

22 A. We tried to review all possible parameters.
23 We used various rate parameters, and we were focusing
24 on an average six-month oil rate. Surface acres,
25 wellbores, cumulative production, remaining primary

1 production and ultimate production.

2 Q. Did the working interest owners finally
3 vote on and adopt a final participation formula to
4 share production in the unit?

5 A. Yes, we did.

6 Q. Do you have a reference by which we can see
7 that participation formula?

8 A. Actually, I don't have one handy.

9 Q. Will we find that in the Unit Agreement?

10 A. Yeah, it's in the Unit Agreement,.

11 Q. Let's take a moment and find that.

12 MR. KELLAHIN: Mr. Examiner, if I can
13 direct your attention to Exhibit 44, that will be the
14 Unit Agreement.

15 Q. If you'll turn to page 14 of that
16 agreement, describe for us the participation formula
17 that was ultimately selected by the majority of the
18 working interest owners.

19 A. It's based five percent on number of
20 service acres contributed by any one working interest
21 owner, compared to the total acreage in the unit, six
22 percent on wellbores, 56 percent on a six-month
23 average oil rate, and 33 percent on the remaining
24 primary recovery from April 1, 1991.

25 Q. This acreage is, in fact, all federal BLM

1 acreage, is it not?

2 A. Yes, it is.

3 Q. Has the BLM giving you preliminary approval
4 for this unit, including this participation formula?

5 A. Yes, they have.

6 Q. Have a majority of the working interest
7 owners adopted and approved this participation
8 formula?

9 A. Yes, they have.

10 Q. In your opinion, as a reservoir engineer,
11 is this final participation formula one that is fair
12 and equitable to each of the interest owners in each
13 of the tracts?

14 A. Yes, sir.

15 Q. Can you think of another participation
16 formula that is better than this one?

17 A. None come to mind.

18 Q. Have you concluded, as a reservoir
19 engineer, Mr. Taimuty, that the unitized management
20 and operation, development of this unit, in fact, is
21 feasible?

22 A. Yes.

23 Q. Have you determined that it will result in
24 a reasonable profit to the working interest owners
25 that have to contribute the investment required to

1 obtain the additional oil recovery?

2 A. Yes, sir.

3 Q. In your opinion, is the participation
4 formula fair and reasonable?

5 A. Yes, sir.

6 Q. Have you also determined and satisfied in
7 your own judgment that the procedures for allocating
8 units expenses to the various separately owned tracts,
9 is fair, reasonable and equitable?

10 A. Yes, sir.

11 Q. Will this project, if approved by the
12 Commission, benefit each of the working interest
13 owners and the royalty owners in the affected unit?

14 A. Yes, sir.

15 Q. And under the unit operations and with this
16 proposed participation formula, does each tract
17 receive its relative value when compared to its
18 contributing value?

19 A. Yes, sir.

20 Q. In your opinion, will the granting of this
21 application prevent waste?

22 A. Yes.

23 Q. Afford you an opportunity, as a company, on
24 the behalf of all these interest owners, to recover
25 additional oil that might not otherwise be recovered?

1 A. That's right.

2 Q. In your opinion, will it protect the
3 correlative rights of all the interest owners
4 involved?

5 A. Yes, it will.

6 Q. In your opinion, is the unitized management
7 and operation development of this portion of the
8 Tamano Bone Springs Pool, necessary in order to carry
9 on the pressure maintenance or to implement pressure
10 maintenance in order to increase ultimate oil
11 recovery?

12 A. Yes.

13 Q. Will the estimated additional cost of this
14 operation exceed the estimated value of the additional
15 oil?

16 A. No.

17 Q. It, in fact, will recover a reasonable
18 profit for the working interest owners?

19 A. Yes, sir.

20 MR. KELLAHIN: That concludes our portion
21 of this part of the presentation, Mr. Examiner. Mr.
22 Taimuty needs to talk to us about the C-108
23 procedures. There is a request in the application for
24 an increase surface injection pressure that exceeds
25 the .2 PSI guideline.

1 If we need a five-minute break, this is a
2 convenient place. If you would like us to continue,
3 we're prepared to go on.

4 EXAMINER STOGNER: How much longer with
5 this witness?

6 MR. KELLAHIN: It will probably take at
7 least another 30 minutes or so.

8 EXAMINER STOGNER: Let's take about a
9 five-minute break right now.

10 (Thereupon, a recess was taken.)

11 EXAMINER STOGNER: Mr. Kellahin?

12 MR. KELLAHIN: Thank you, Mr. Examiner.

13 EXAMINATION RESUMED

14 BY MR. KELLAHIN:

15 Q. Mr. Taimuty, the last item before we leave
16 your Exhibit No. 2 is to direct your attention to page
17 33, Table 1. For benefit of the interest owners as
18 well as for reference by the Examiner, what have you
19 shown on that page?

20 A. Table 1 includes estimated remaining
21 primary reserves as of April 1, 1991, and secondary
22 reserves that would be attributed to each tract based
23 on the equity formula.

24 In addition to that, we've provided
25 economics or the net present value of the remaining

1 primary reserves--

2 EXAMINER STOGNER: Where are you at?

3 MR. KELLAHIN: Table 1.

4 EXAMINER STOGNER: Thank you, Mr. Kellahin.

5 Q. What have you summarized on this table, Mr.
6 Taimuty?

7 A. Remaining primary reserves as of April 1,
8 1991, and secondary reserves attributed to each tract
9 based on the equity formula, the net present value of
10 both remaining reserves, and incremental secondary
11 remaining reserves and then the total secondary net
12 present value.

13 Q. And on a tract-by-tract basis, then, what
14 do you conclude about each tract receiving secondary
15 credit?

16 A. That each tract would indeed benefit from
17 implementation of the peripheral waterflood, and that
18 it would be done in an economic fashion.

19 Q. Is there an explanation as to what
20 assumptions went into price in order to get the dollar
21 amount of the value of secondary reserves?

22 A. There's a summary-- With regard to price,
23 yes, there is, on Table 11 on page 47. There's a
24 total summary of the incremental economics, and it
25 lists reserves, operating revenue, operating expense

1 and investment. It also lists various parameters that
2 we've already discussed in Table 10, and in the bottom
3 left-hand corner it gives initial product prices.
4 \$20.96 per barrel of oil, \$2.01 per Mcf of gas. We
5 included no inflation factors in our economics. We
6 were going to leave that to the individual working
7 interest owners.

8 Q. Let's turn now, Mr. Taimuty, to the C-108
9 package of documents. Are you familiar with the C-108
10 procedures?

11 A. Yes, sir.

12 Q. Attached to the end of Exhibit No. 3 is an
13 area map, if you will. Do you have a copy of that?

14 A. Yes.

15 Q. Have you complied, to the best of your
16 ability, with the requirements of the C-108 filings by
17 the Oil Conservation Division?

18 A. Yes, sir.

19 Q. When we look at the half-mile area of
20 review around each of the proposed injection wells,
21 how have you identified that area on your area map?

22 A. With a solid dashed line.

23 Q. You simply squared off what would otherwise
24 have been circles around these injection wells?

25 A. Actually we've gone maybe a little further

1 than a half mile. We extended it one-half mile beyond
2 the unit boundaries in all directions.

3 Q. Have you inventoried, within that half-mile
4 radius, all the wellbore data for individual wells,
5 whether producing or plugged and abandoned, that
6 penetrate to or through the Second Bone Springs
7 Carbonate?

8 A. Yes, we have.

9 Q. When we go through all the data you've
10 assimilated, do you, as a reservoir engineer, find any
11 plugged and abandoned wells that can be characterized
12 as problem wells?

13 A. No, none.

14 Q. Are all the plugged and abandoned wells
15 within this area of review, properly plugged and
16 abandoned so that the Second Bone Springs interval is
17 isolated out from any other interval?

18 A. Yes, sir.

19 Q. Did you have any plugged and abandoned
20 wells?

21 A. Yes, we did. We had a few.

22 Q. When we look at producing wells, other than
23 those you'll utilize for production here, do we have
24 deeper wells that penetrate through this Second Bone
25 Springs Carbonate?

1 A. Yes, we do.

2 Q. You find that each of those is completed in
3 such a way to isolate out the Second Bone Springs
4 Carbonate so it will not be intrusive onto the casing
5 or the tubing of those wells?

6 A. Yes, sir.

7 Q. No problem wells?

8 A. No problem wells.

9 Q. The source of water to inject into the
10 Second Bone Springs comes from where?

11 A. Three sources we propose to use. One will
12 be actual produced water from the Bone Springs Second
13 Carbonate. That's only approximately 100 barrels per
14 day right now, so it will not fill all of our needs.

15 We also proposed to use City of Carlsbad
16 water, which I believe they acquire from the Ogallala,
17 and also local Grayburg production in and around the
18 area. It is Marathon's intent to inject as much salt
19 water as we can or as much produced water from the
20 Grayburg and the Bone Springs Second Carbonate, and
21 minimize, if not eliminate, all the fresh water or any
22 fresh water requirements from the City of Carlsbad.

23 Q. Have you provided any compatibility tests
24 thus far with regards to the types of waters that
25 might be introduced into the Bone Springs?

1 A. Actually, attached to the C-108 are all of
2 the compatibility tests of the various combinations I
3 just discussed. Both the fresh water with the
4 Grayburg, and the Bone Springs produced water.

5 Q. We have fresh water, Grayburg and Bone
6 Springs. Any other potential combinations of waters
7 from other zones at this point?

8 A. No. We reviewed the entire area and found
9 that there's just no other feasible source of water to
10 inject.

11 Q. What are the results of the compatibility
12 tests, integrating those three sources of water into
13 the Bone Springs?

14 A. There's a mild tendency to form calcium
15 carbonate scale, but it's very mild and easily
16 treatable, so we're not anticipating any problems at
17 all.

18 Q. Do you find sources of fresh water in this
19 immediate vicinity?

20 A. There are no sources of fresh water.

21 Q. How have you made that determination?

22 A. We visited with Ken Fresquez from the State
23 Engineer's Office, and he had given us some insight
24 into what we might review. And in conversations with
25 him, and our best known analysis, we found no other

1 possible sources.

2 Q. Has there been field inspections of the
3 surface to see if there was any undocumented windmills
4 or fresh water sources that were not of record with
5 the State Engineer's Office?

6 A. We reviewed the area, and we didn't find
7 any.

8 Q. What is the range of anticipated volumes
9 that you think you'll need for this project in terms
10 of barrels of water per day?

11 A. Initially we will inject 3,500 barrels, is
12 what we're estimating, with a maximum of 5,000 barrels
13 once we have all seven conversions to injection.

14 Q. In providing the data for the Examiner, do
15 you have schematics of the injection wells, either for
16 each one or by type or example?

17 A. Yes, we have them all included.

18 Q. Give me a general summary of how you
19 propose to complete these wells for injection.

20 A. It would just be, we would use
21 plastic-coated tubing and inject under a packer, put
22 such packer above all Bone Springs Second Carbonate
23 first, and inject with a coated tubing.

24 Q. Is the annular space between the tubing and
25 the casing filled with some type of fluid?

1 A. I'm sure we'll use KCL inhibitors.

2 Q. And is there some way to monitor the
3 annular space, between the casing and tubing, to see
4 if you've got any tubing leaks or other failures that
5 might require action on the part of the operator?

6 A. Yes, sir. We'll been able to tie into the
7 casing and pressure up to determine if there are any
8 leaks.

9 Q. The request in the application is for a
10 maximum surface injection pressure up to 2,300 pounds
11 surface?

12 A. Yes, sir.

13 Q. That will be greater than the Division
14 guidelines of .2 PSI per foot of depth to the top
15 perforation?

16 A. Yes, sir.

17 Q. If you applied the .2 guidelines, what
18 pressure surface limitation will that be?

19 A. Approximately 1,600 pounds.

20 Q. So you want an additional 700-pound
21 flexibility?

22 A. Yes, sir.

23 Q. Let's turn to the package of exhibits that
24 are identified with the No. 4. If you'll find all
25 those, Mr. Taimuty, they're identified as Exhibit 4(a)

1 and they run through 4(f).

2 I marked, as Marathon Exhibit 4(a), a step
3 rate test?

4 A. Yes, sir.

5 Q. On what well is that taken?

6 A. Marathon Shugart "B" No. 1.

7 Q. I have to go back to my index. The Shugart
8 "B" No. 1?

9 A. It's located in tract 6. It's the southern
10 well in tract 6.

11 Q. What was the purpose of the step rate test?

12 A. To determine the parting pressure of the
13 Bone Springs Second Carbonate.

14 Q. What does this test show you?

15 A. That the Bone Springs Second Carbonate will
16 part at a pressure of 5,371 pounds bottom-hole.
17 Actually, the pressures there are not mid-perf
18 pressures, they're somewhat higher. The corrected
19 bottom-hole pressure would be 5,474 pounds.

20 Q. What is the parting pressure within the
21 formation, then? This is a surface pressure?

22 A. No, sir, these are bottom-hole pressures.

23 Q. On this well, the "B" 1 well, the
24 bottom-hole pressure is what? The parting pressure
25 within the formation breaks over at what pressure

1 point?

2 A. 5,474 pounds.

3 Q. Translate that to surface pressure for me.

4 A. That's indicated on the very next page or
5 exhibit, around 2,150 pounds, approximately.

6 Q. Do you have any other step rate tests other
7 than the Shugart "B" 1?

8 A. Yes, sir. We ran one also on the Johnson
9 "B" Federal No. 10. That's the No. 10 indicated on
10 tract 4.

11 Q. You have a step rate test on the north side
12 and a step rate test on the south side. When I look
13 at the Johnson "B" Federal 10, what is my surface
14 pressure at the breakover point?

15 A. 1,928 pounds.

16 Q. If we're increasing pressure above the .2
17 gradient, which is 1,600 surface pounds, we can find
18 that we can do that without fracturing the Bone
19 Springs Carbonate up to a range of between 1,928 and
20 2,147 pounds?

21 A. Yes, sir.

22 Q. What does that tell you, as an engineer?

23 A. That we're able to inject at higher than
24 the 1,600 pounds indicated by the .2 gradient, and
25 still not fracture the reservoir.

1 Q. Your request, however, is to go up to 2,300
2 pounds?

3 A. That's right.

4 Q. Knowing that we've fractured a formation at
5 a certain step rate test, what then have you done to
6 derive data to give you confidence that the fractures
7 you're now propagating in the Second Bone Springs are
8 going to remain confined to the Second Bone Springs
9 Carbonate?

10 A. We reviewed the unit area to try and
11 determine the fracture gradient properties, to see how
12 consistent they were, and we evaluated a fracture log
13 and after-frac survey and two injectivity profiles, to
14 see where the fluids were going.

15 Q. Let me have you turn your attention now to
16 Exhibit 4(b). Identify and describe that.

17 A. These are the wells within the unit area
18 that Marathon operates. What we have listed there are
19 the estimated frac gradients as determined from acid
20 treatments. That would be taking the hydrostatic
21 pressure and the initial shut-in pressure, following
22 acid stimulation, and then dividing by the mid-perf
23 depth.

24 What we hope to illustrate by this are that
25 the frac gradients are all around the .72 average we

1 indicate at the bottom, and that we have good rock
2 properties that we can correlate across the unit area.

3 Q. Can you take 2,300 pounds at the surface
4 and convert that into a frac gradient?

5 A. Actually with the hydrostatic, that would
6 be .72.

7 Q. I would direct your attention to 4(c).
8 That's a frachite log. I have it on the Johnson "B"
9 Federal A/C 1 No. 7 well?

10 A. Yes, sir.

11 Q. Give us your conclusion about the frachite
12 log and then support your conclusion.

13 A. Okay. The conclusion from the frachite log
14 is that if we do initiate any fracture in the Bone
15 Springs Second Carbonate, it will remain totally
16 confined within that interval and we will not go out
17 of zone with it.

18 We base that conclusion on the Delta
19 pressure tract, which is really the fifth tract over
20 from the left of depth. Beyond depth the first three
21 tracts are just reservoir properties. The Delta
22 pressure tract, what it suggests is it ranges from
23 zero to a thousand pounds, and this tract shows you
24 what interval will begin to fracture initially when
25 the external pressure is applied.

1 If you look at that, the depth of 8,062 to
2 -64, that has the lowest Delta pressure, and we would
3 expect that to frac first. The line, then, as it
4 increases to roughly 100 pounds, as your surface
5 injection pressure increases by 100 pounds over the
6 pressure that's required to frac the formation, that
7 zone will also fracture. As that line gets greater,
8 to 500 pounds, then you would have to increase your
9 reservoir pressure or your injection pressure by 500
10 pounds to propagate a fracture in that interval.

11 If you'll notice, at the top and the bottom
12 of the Bone Springs Second Carbonate, it would require
13 a thousand pounds over the surface pressure to
14 propagate a fracture above or below the Bone Springs
15 Second Carbonate. Because, as you've indicated
16 already, our surface pressures range from 1,928 pounds
17 to 2,147 pounds before you even begin a fracture, and
18 we would have to increase our surface injection
19 pressure to over 3,000 pounds, therefore, to frac out
20 a zone.

21 So I feel our request of 2,300 pounds will
22 keep any fracture confined within the Bone Springs
23 Second Carbonate.

24 Q. You use the "B" 1 well step rate test at
25 1,928, add a thousand pounds to that step rate test,

1 that will give you close to 3,000 pounds in that well?

2 A. Yes, sir.

3 Q. At that point is the first point you're
4 going to begin to run the risk of propagating
5 fractures outside either the top or the bottom of the
6 Second Bone Springs Carbonate?

7 A. That's right.

8 Q. And your request, then, is at 2,300 pounds?

9 A. Right.

10 Q. Some 700 pounds less than that maximum
11 amount?

12 A. Yes, sir.

13 Q. Let's go to 4(d) and have you identify and
14 describe that exhibit.

15 A. This is our after frac survey. What we did
16 to stimulate the Stetco "10" Federal No. 2 was to sand
17 frac the well. We tagged the sand with a radioactive
18 material that we could follow through the reservoir
19 with a gamma ray to determine where our frac went.

20 As you observe on the log, we have a gamma
21 ray baseline above and below the main pay interval.
22 Our treating pressures reached 5,000 pounds, and as
23 the after frac survey indicates, all of the high gamma
24 ray activity, which would indicate where this sand
25 went, is confined within the main pay interval.

1 We have a minor fracture growth upward to
2 approximately 7,950 feet, but there's still a good
3 50-foot barrier above that before we got out of the
4 Bone Springs Second Carbonate.

5 So, the after frac survey supports the
6 frachite conclusions that even at very high surface
7 treating pressures, that any fracture propagated is
8 confined within the Bone Springs Second Carbonate.

9 Q. Let's go to Exhibit 4(e). This is the same
10 well?

11 A. Yes, sir.

12 Q. What are we looking at here?

13 A. This is an injection profile, to determine
14 if we had any fluid movement up or down from the
15 perforated interval. What they do, they inject the
16 radioactive material again, and then they try and
17 trace it with a gamma ray.

18 What the top portion of this exhibit shows
19 is as you go down, as the intensity of the gamma ray
20 reading decreases, suggesting that you're losing more
21 and more of your radioactivity into the perforations.
22 Once you get below the indicated perforations, you
23 have absolutely no radioactive material present and
24 the gamma ray goes back to the baseline that has been
25 established. This suggests that there's no movement

1 of any fluids downward, or there have been no
2 fractures created beneath the Bone Springs Second
3 Carbonate.

4 If you go to the bottom portion, where it
5 says "Upward Channel Checks," they inject the
6 radioactive material, and then they try and trace it.
7 Their sensors are pulled above the perforations to see
8 if there's any radioactive material moving upward, and
9 as indicated on the log, no channels upward were
10 found.

11 So this, in addition to the frachite log
12 and the after frac survey, indicates that we've
13 confined our injection totally to within the main pay
14 interval.

15 Q. You have a similar display for Exhibit 4(f)
16 on another well?

17 A. Yes, sir. This is the Marathon
18 Shugart "B" 1. We ran this injection profile after we
19 ran our step rate test to determine where our injected
20 water was going, and exactly like with the Stetco 10
21 No. 2, we have found there were no channels either
22 downward or upward. Everything stays confined within
23 the perforated interval.

24 Q. The Division, on occasion, requires some
25 resolution of injection wells that might be

1 characterized as being lease line injection wells. On
2 occasion you'll see that in waterflood projects.
3 There are a couple of your proposed injector wells
4 that while they're not right on the lease line,
5 they're on the outer boundary.

6 Do you see any necessity to have any
7 contractual arrangements with the offsetting operators
8 with regards to what might be characterized as lease
9 line injection wells?

10 A. No, sir.

11 Q. Why not?

12 A. There's no productive Bone Springs Second
13 Carbonate outside the proposed unit area.

14 Q. In those instances, that has been verified
15 with actual wellbore data offsetting you, is that
16 right?

17 A. Yes, sir.

18 Q. Those wells have either been depleted or
19 have shown no opportunity for production?

20 A. I won't even say depleted. Just no
21 opportunity for production.

22 MR. KELLAHIN: That concludes my
23 examination of Mr. Taimuty, Mr. Examiner. We would
24 move the introduction of his Exhibits 1 through 4.

25 EXAMINER STOGNER: Exhibits 1 through 4

1 will be admitted into evidence.

2 EXAMINATION

3 BY EXAMINER STOGNER:

4 Q. In referring to your description of your
5 unitized interval, and to Figure 3 on Exhibit 1--

6 A. Yes, sir.

7 Q. --I would like to get the heading on this
8 log, or is it a composite of several logs?

9 A. It's a composite of several logs. I could
10 provide all the headings. I don't have them with me.

11 Q. I take it the one on the far right is of a
12 separate log and the two combined is of one log; so
13 we, essentially, have two logs?

14 A. Yes, sir. It would be a density neutron
15 log and a resistivity log.

16 Q. If you could give me a heading on that and
17 with the date shown and the pertinent information, I
18 would appreciate that.

19 A. Okay.

20 Q. In looking at your Figure 7 in Exhibit 1,
21 and with the remarks made before the end of the
22 testimony, and I'll also refer back to, I believe,
23 page 14 of the Unit Agreement.

24 EXAMINER STOGNER: Mr. Kellahin, that's the
25 participation formula?

1 MR. KELLAHIN: Participation formula?

2 EXAMINER STOGNER: Mr. Kellahin, help me
3 out. One of your last questions was about lease line
4 injection?

5 MR. KELLAHIN: Uh-huh.

6 Q. And, if I remember right, Mr. Taimuty, you
7 said that there was absolutely no flow outside the
8 unit area, is that correct?

9 A. Well, we don't believe there would be any
10 flow, sir.

11 Q. Maybe I'm not seeing that on Figure 7. How
12 do you explain the far right-hand corner?

13 A. Figure 7 is kind of difficult. It's an
14 initial potential well, so there's a zero line that
15 extrapolates outward but, as you can see, the wells
16 outside the line are dry-hole wells, and I think the
17 way things are mapped it would be difficult to put
18 contour lines on top of each other so we map it that
19 way. Figure 7 is more to verify Figure 6. Figure 6
20 is what is defining the productive portion and where
21 the fluid movement would occur, and Figure 7 is more
22 of just a support. It's difficult. Obviously we have
23 edge wells that are producing a minimum amount of oil,
24 but they would have something other than zero, so that
25 would require us to draw a zero line outside that

1 range.

2 Q. There are three 40-acre proration units
3 which essentially have no well on them, never had a
4 well on them, and your zero line on your Figure 6,
5 especially the, what is that, the southwest quarter of
6 the northeast quarter? but you still have it in the
7 unit. Has that been discussed, about taking that out,
8 and why didn't the BLM, perhaps, take it out?

9 A. Our reasons for keeping those in there are
10 that we're offsetting top allowable wells. We don't
11 feel that these wells are necessary for any primary
12 production, but it's possible that future evaluation
13 would suggest that we would need those to improve the
14 sweep efficiency of our flood.

15 We visited with our working interest
16 partners and with the BLM, to discuss that matter with
17 them.

18 Q. Did that have any bearing, with only five
19 percent being dedicated to the acres of the tract?

20 A. The BLM actually had given us some
21 guidelines on what they would consider acceptable as
22 far as surface acres, and that five percent is within
23 their guidelines and agreeable to all the working
24 interest partners.

25 EXAMINER STOGNER: Mr. Kellahin, help me

1 out on this one. In the beginning, this being a
2 pressure maintenance project and the current allowable
3 is 460 barrels of oil per day, I believe that was
4 established?

5 MR. KELLAHIN: Yes, sir. We had a special
6 hearing in which we got a special depth bracket
7 allowable for the Tamano Bone Springs, and it
8 increased it up to the 460 a day as a maximum.

9 EXAMINER STOGNER: Do you have an order
10 number on that?

11 MR. KELLAHIN: I do, and I'll have to look
12 it up and give it to you. It escapes me at the
13 moment.

14 EXAMINER STOGNER: Okay, if you will do
15 that. And as far as this particular pressure
16 maintenance project, would that allowable still be
17 sufficient or is there any request to amend that or
18 establish a new one just for the unit area? It wasn't
19 advertised, and that's the reason I'm bringing it up.

20 MR. KELLAHIN: I think the initial thought
21 was the maximum allowable under the rules would be
22 translated into a unit allowable that could then be
23 produced out of any combination of the producing
24 wells. But we're not asking for a waiver at this
25 point of the maximum 460 a day.

1 EXAMINER STOGNER: That's what I was
2 asking. I apologize.

3 MR. KELLAHIN: We'll stick with that until
4 we can determine that it's justifiable to ask that
5 that be withdrawn.

6 EXAMINER STOGNER: Okay. There's a lot of
7 information to digest here, and there's a need to move
8 on, so I have no further questions at this time.

9 MR. KELLAHIN: Mr. Examiner, that special
10 depth bracket oil allowable is by Order No. R-9354,
11 Case 10115. The order is dated November 7, 1990.
12 I'll give you a copy of that for your reference.

13 EXAMINER STOGNER: Thank you Mr. Kellahin.

14 GREGORY A. WILSON

15 the witness herein, after having been first duly sworn
16 upon his oath, was examined and testified as follows:

17 EXAMINATION

18 BY MR. KELLAHIN:

19 Q. Would you please state your name and
20 occupation.

21 A. My name is Gregory A. Wilson. I am
22 employed by Marathon Oil Company as a geologist.

23 Q. Mr. Wilson, on prior occasions have you
24 testified as a petroleum geologist?

25 A. Yes, I have.

1 Q. You reside in Midland, Texas?

2 A. That's correct.

3 Q. Summarize for us, Mr. Wilson, what has been
4 your involvement as a geologist in studying the Tamano
5 Bone Springs, and in participating in the feasibility
6 studies that Mr. Taimuty has just described.

7 A. I wasn't involved in the drilling and
8 development of the well. The geologist, Patty
9 Phillips, that was the geologist working on the
10 project, left Marathon Oil Company and moved to
11 Dallas, Texas, so I was taking over the project.

12 Subsequent to her leaving, I did some
13 additional examination of the cores, familiarized
14 myself with the previous core studies, and had done
15 some additional mapping in the area. I had also done
16 some thin section studies of samples in the area.

17 Q. Have you reviewed the Marathon feasibility
18 study that's dated March of 1981, as well as Mr.
19 Taimuty's engineering report of June of 1991, insofar
20 as it has geologic components to it?

21 A. Yes, I have.

22 Q. Based upon those studies, do you have
23 certain geologic conclusions about the feasibility of
24 this project?

25 A. Yes.

1 Q. I don't ask you for the conclusions now,
2 but did you have conclusions?

3 A. Yes, I did.

4 MR. KELLAHIN: We tender Mr. Wilson as an
5 expert petroleum geologist.

6 EXAMINER STOGNER: Mr. Wilson is so
7 qualified.

8 Q. Without trying to repeat what Mr. Taimuty
9 has testified, let me have you summarize your geologic
10 conclusions. First of all, in looking at the
11 feasibility of taking the Second Bone Springs
12 Carbonate, isolating that vertically and seeing
13 whether, as a geologist, you find it to be
14 sufficiently continuous that it may serve a suitable
15 environment in which you may introduce water and
16 recover additional oil, have you examined that topic?

17 A. Yes, I have. As to vertically containing a
18 waterflood within the carbonate, overlying the Second
19 Bone Sprins Carbonate is the First Bone Springs Sand,
20 which is predominantly a fine-grain sand and siltstone
21 with some dolomite stringers. It's a clay-rich sand,
22 where there is sand developed as opposed to siltstone,
23 and tends to be very low permeability and somewhat
24 water sensitive. In this area there are no productive
25 First Bone Springs Sand wells.

1 The base of the Second Bone Springs
2 Carbonate would be the Second Bone Springs Sand, which
3 is very similar, virtually identical in lithologic
4 properties. It's a quartz sand, very clay-rich, with
5 some stringers of dolomite. Again very low
6 permeability, very fine-grain and owing to the clays
7 within the matrix of the sand, usually some are water
8 sensitive. It would be very difficult, if not
9 impossible, to put a significant amount of water into
10 the Second Bone Springs Sand or First Bone Springs
11 Sand.

12 Q. Geologically, then, are you satisfied the
13 Second Bone Springs Carbonate can be isolated?

14 A. Yes.

15 Q. From the interval above and below that
16 carbonate?

17 A. Yes, I am.

18 Q. Let's talk about the horizontal extent.
19 Does this provide well-to-well continuity, if you
20 will, of the Second Bone Springs that you can map it
21 geologically?

22 A. Yes. As shown on the cross-section, which
23 was previously brought in evidence, there are specific
24 porosity intervals within the Second Bone Springs
25 Carbonate that can be correlated. In addition to

1 that, the top of what we call the main pay interval is
2 very correlatable through the area, and I don't think
3 there's really any question that what we are mapping
4 as the main pay interval is continuous across this
5 area.

6 Q. You can find, by mapping the log
7 information from each of the wells, that the Second
8 Bone Springs Carbonate can be correlated among all the
9 wells?

10 A. Yes.

11 Q. Within that zone, though, there are
12 individual lenses that may come and go within the
13 Second Bone Springs Carbonate?

14 A. Yes. The lenses, or the high-flow units,
15 as they've been called, were originally identified
16 using core data, looking at the porosity and
17 permeability to rock, and also using some of the
18 production logs which determine where the greatest
19 amount of fluid was coming into the wellbore, and
20 applying that to the neutron density logs where that
21 information was available, and correlating those
22 high-flow units in the wells where the core
23 information was available, to the wells where there
24 was no core information. And the correlations are
25 always open to some interpretation, but these are very

1 high degree of probability correlations.

2 Q. Justify geologically the conclusions about
3 the boundary of the unit. Is it a logical and
4 reasonable boundary, from a geologist's point of view?

5 A. Because of the nature of these debris
6 flows, they tend to be somewhat limited in size in one
7 event. They're basically a cohesive mud flow which
8 will pick up and carry larger clasts and grain stones,
9 usually shelf-dried material, and they're basically
10 going to be a pile of mud at the base of the slope,
11 where you have a steeper slope that grades to a less
12 steep slope and you lose sufficient slope for the mud
13 to continue to flow.

14 They tend to be either elongate, parallel
15 to the shelf edge, or somewhat round in shape. As you
16 move away from the debris flow, you start going from
17 the shelf drive, a nice clean carbonate, into the
18 slope drive, a more clay-rich, deep water deposited
19 muds, therefore losing any original porosity and
20 permeability. So the configuration and size of the
21 field is consistent with the depositional model.

22 Q. As a geologist, do you see any need to
23 include additional acreage that is not already
24 included in the proposed unit?

25 A. No. The surrounding well data which shows

1 no porosity and permeability, there are some wells
2 with porosity but very poorly developed permeability,
3 which is related to the postdepositional diagenesis in
4 the rock, the well data, I think, very clearly defines
5 where the limits of the effective porosity in the
6 reservoir are.

7 Q. When we get to the western side, there are
8 three tracts, if you will, 40-acre tracts, that do not
9 yet have wells?

10 A. That's correct.

11 Q. They are in an area where there is some
12 well control?

13 A. Uh-huh.

14 Q. Give us your geologic opinions about the
15 reliability of that boundary of the unit in terms of
16 what acreage has been included or excluded?

17 A. As far as what has been excluded, which
18 would be the acreage west of the Stetco 10 #3 well, I
19 think that's reasonable because the amount of porosity
20 found in the formation was greatly decreased, the
21 thickness of the formation was decreasing, which
22 suggested that we're moving towards the edge of the
23 reservoir.

24 The acreage that was included, as can be
25 seen in--let's see, it would be Figure 6 of Exhibit 2,

1 and Figure 7, it can very abruptly go from a porous,
2 permeable reservoir to a very impermeable portion of
3 the formation, or if you can't tail out to where
4 you'll have a marginal well before finding an
5 impermeable, nonproductive section. So there's really
6 no way of determining whether one location away from a
7 top allowable well you may have a productive location
8 or not.

9 So, I think including the additional
10 undrilled acreage is reasonable, as was stated
11 earlier, for possibly increasing the efficiency of the
12 sweep. There may be porous, permeable rock in those
13 locations.

14 Q. From a geologic aspect, though, can you
15 reach a geologic conclusion that the proposed boundary
16 for this unit is reasonable and fair?

17 A. Yes, I think it is.

18 MR. KELLAHIN: That concludes my
19 examination of Mr. Wilson.

20 EXAMINATION

21 BY EXAMINER STOGNER:

22 Q. Several quick and basic questions. I'm
23 referring to Figure 6. Are there any Bone Springs
24 sand producing intervals anywhere within the map
25 area? I'm looking at the nine-section area.

1 A. Yes. On Figure 7, the map of the initial
2 potential, there are two wells in which the initial
3 potential reflect a production from both the second
4 sand and the second carbonate. They were perforated
5 and treated separately, but the initial potential was
6 put together, so we didn't have figures broken out
7 individually for the two zones.

8 Those are the two numbers that are in
9 parenthesis. It would be Well #3 in the northeast of
10 the northwest quarter, and Well #3 in the northwest of
11 the northeast quarter. In addition, the five wells in
12 Section 2 on the Mesquite Unit are Second Bone Springs
13 Sand producers.

14 Q. So is it really reflecting some Bone
15 Springs sand production, or is it just reflecting that
16 the sand was open?

17 A. You mean, the initial potential, or--

18 Q. Yes.

19 A. In the case of the Heyco #3 in the
20 northwest of the northeast, that was believed to be,
21 on the initial potential, primarily Second Bone
22 Springs Sand production. That well is not on the
23 cross-section. That well falls between the 50 and 0
24 barrels of oil per day lines. The initial potential
25 is about 248 barrels per day. That's only an

1 estimate. We know that the quality of the reservoir,
2 from log data in the second carbonate, did not look
3 very good. In looking at the surrounding wells, we
4 assumed it was one of the four wells from the
5 carbonate, and they did have a very good second sand
6 section. So, that is an estimate as far as where that
7 well falls within the contour lines.

8 Q. I assume all of these intervals, wells that
9 will be taken over that have perforated intervals into
10 the sand, will be plugged back?

11 A. Yes. I think Mr. Taimuty mentioned that
12 there will be a cast-iron bridge plug set between the
13 perfs in the Second Bone Springs Sand and second
14 carbonate, with cement on top of the plug to
15 effectively separate them.

16 Q. And as Mr. Taimuty said, and I'm sure you
17 will probably agree, even the injection into those
18 wells or near those wells will not spread into the
19 sand zone?

20 A. I couldn't address the fracture properties
21 of the Bone Springs carbonates, but the sands, where
22 they are well developed, tend to be very low
23 permeability. The low from some sidewalk core studies
24 that we've done at Marathon and from studies I've read
25 done by Heyco, below a porosity of eight percent,

1 there is effectively all microporosity in the clay
2 matrix. There is no effective porosity that could
3 contain oil or move fluid.

4 Even where there's greater than eight
5 porosity developed, there can be very low
6 permeability. And due to the movement of fines, the
7 clays within the core spaces, it's very difficult to
8 move water through those sands. So, because of the
9 very low permeability of the sands and water
10 sensitivity of the clays within the matrix, I can't
11 imagine that a significant amount of water, if any,
12 could be put into the second sand.

13 Q. And the information you reviewed or worked
14 was included in the Unit Agreement?

15 A. It was included in the Exhibit 2, the
16 engineering study.

17 Q. How about the geologic information in the
18 Unit Agreement?

19 A. Yes, I believe that was the same
20 information that was taken from the study.

21 Q. And you reviewed it?

22 A. I did not review the agreement myself, but
23 I believe the same exhibits were used from the
24 engineering study.

25 EXAMINER STOGNER: I have no further

1 questions of Mr. Wilson, Mr. Kellahin.

2 MR. KELLAHIN: Thank you. Mr. Wilson?

3 RANDAL PAUL WILSON

4 the witness herein, after having been first duly sworn
5 upon his oath, was examined and testified as follows:

6 EXAMINATION

7 BY MR. KELLAHIN:

8 Q. Sir, could you please state your name and
9 occupation.

10 A. My name is Randal, R-A-N-D-A-L, Paul
11 Wilson. I'm a landman with Marathon Oil Company in
12 Midland, Texas.

13 Q. Mr. Wilson, on prior occasions, have you
14 testified as a petroleum landman before the Division?

15 A. No, I haven't.

16 Q. Summarize your educational and employment
17 experience that qualifies you to be a petroleum
18 landman.

19 A. I graduated from the University of Texas at
20 Austin in 1981 and worked for one year in Abilene,
21 Texas, as a landman, before being hired by Marathon in
22 May of 82. I have been with Marathon since that time,
23 and have recently completed certain requirements,
24 successfully completed certain requirements so I can
25 be considered as a certified professional landman in

1 my field.

2 Q. Describe the kinds of activities you've
3 performed with regards to the Tamano Bone Springs
4 unit?

5 A. I compiled the list of owners, overriding
6 royalty interest owners, a search of their records and
7 titles, to determine what where there's federal or
8 state acreage, prepared the initial documents, came up
9 with the address lists and so forth.

10 Q. Do you also maintain, as part of your
11 duties in the land department, the correspondence
12 files that deal with the unitization efforts of your
13 company in dealing with others?

14 A. For those unitization efforts that I'm
15 involved in, yes.

16 Q. Does that include this Tamano Bone Springs?

17 A. Yes, it does.

18 Q. Have you satisfied yourself that to the
19 best of your ability you have an accurate list of the
20 working interest owners by tract, and you know what
21 you believe to be the percentage in which they have
22 the interest for those tracts?

23 A. Yes, I do.

24 Q. Have you performed the same function with
25 regards to the royalty or overriding royalty owners?

1 A. Yes, I have.

2 Q. And, to the best of your ability, do you
3 have a reliable list of the names and addresses of
4 those parties or individuals?

5 A. Yes, I do.

6 MR. KELLAHIN: We tender Mr. Wilson as an
7 expert petroleum landman.

8 EXAMINER STOGNER: Mr. Wilson is so
9 qualified also.

10 Q. Let's go through the correspondence file
11 here rather briefly, Mr. Wilson, and then we'll get
12 down to the ultimate status of your efforts to obtain
13 voluntary participation in your unit. Let's look
14 first of all, so we can identify them for the record.

15 Have you had a chance to review the
16 chronology shown as Exhibit No. 5 to determine whether
17 it lists, in chronological fashion the major items of
18 interest in your efforts to obtain voluntarily
19 participation?

20 A. Yes, I have.

21 Q. I don't ask you to read the list, but it's
22 simply a compilation taken from your files of those
23 major events, in chronological order?

24 A. That's correct.

25 Q. When we look at the correspondence package,

1 starting with Exhibit No. 6, do we find individual
2 copies of letters and correspondence that can be
3 matched with the chronology, so that if the Examiner
4 desired to do so, he can see individual pieces of
5 communication?

6 A. That's correct.

7 Q. Let me ask you to turn your attention to
8 Exhibit No. 42, if you'll find that in the package of
9 documents. What is Exhibit 42?

10 A. That's the letter from the BLM basically
11 accepting our application to unitize the field.

12 Q. This was after a series of conferences,
13 discussions with the BLM, on the topic of acreage and
14 participation formulas?

15 A. That's correct.

16 Q. Ultimately you have received in your files,
17 this letter, Exhibit No. 42, giving you a preliminary
18 approval on behalf of the BLM for this project?

19 A. Yes.

20 Q. Did they attach any conditions or
21 qualifications to their preliminary letter of
22 approval?

23 A. Yes, sir, they had certain changes they
24 wanted to make within the, I believe that's the unit.

25 Q. Have those proposed conditions and

1 contingencies been circulated and approved by Marathon
2 for inclusion?

3 A. Yes, sir.

4 Q. And have you shared those with the other
5 working interest owners?

6 A. Yes.

7 Q. Go back and find Exhibit 38.

8 A. Okay.

9 Q. What is Exhibit 38?

10 A. That is a letter written by Tom Lowry, an
11 attorney, to the lessees of records, overriding
12 royalty interest owners and owners of royalty,
13 notifying them of the hearing.

14 Q. Have you compiled, in response to that
15 letter, the green return receipt cards for
16 notification purposes?

17 A. Yes, sir.

18 Q. Are they appended to that letter?

19 A. Yes, they are.

20 Q. So the best of your knowledge, information
21 and belief, did you attempt to notify all the working
22 interest owners that might be affected by this
23 project?

24 A. Yes, we did.

25 Q. In addition, did Marathon undertake to

1 notify the offsetting operators within the half-mile
2 area of review, that might be affected by any of these
3 injection wells?

4 A. We did.

5 Q. And did you also attempt to notify the BLM,
6 as the owner of the surface of each of these injection
7 wells?

8 A. We did.

9 Q. Let's turn now to Exhibit 44. What is that
10 Mr. Wilson?

11 A. That is a copy of the Unit Agreement.

12 Q. Is that Unit Agreement on a form that's
13 approved by the Bureau of Land Management for
14 unitization of production such as this?

15 A. Yes, sir.

16 Q. Have you circulated that Unit Agreement to
17 all the proposed working interest owners?

18 A. Yes, sir.

19 Q. In addition, have you prepared an Operating
20 Agreement?

21 A. Yes, we have.

22 Q. Has that also been circulated to the
23 potential working interest owners?

24 A. It has.

25 Q. I am going to direct your attention to what

1 is marked as Exhibit 47, and I'm going to share with
2 you, Mr. Examiner, a substitute copy of both 47 and
3 48. They have been color-coded to assist you in
4 understanding what the status is of participation in
5 both categories of interest owners.

6 If we start off with 47, first of all, Mr.
7 Wilson, the color codes I've shown to the Examiner
8 represent what, in terms of the participation of the
9 working interest owners in the unit?

10 A. I did that a couple of days ago. The
11 fluorescent yellow colors are the signature pages that
12 I had received in the office at that time. The pink
13 would represent companies that had indicated that they
14 were mailing it back. The day before we left I
15 received two more in, so I circled those in yellow. I
16 believe the only one that has indicated they would
17 send it back, but has not, is Yates Energy.

18 Q. With the assumption that Yates will be
19 sending you the signed ratifications to the unit, what
20 percentage of working interest owner participation is
21 now committed to the unit?

22 A. Excluding Yates right now, it's 75.01322
23 percent. Including Yates--

24 Q. I think you wrote that on the bottom of one
25 of the displays?

1 A. It is on the bottom--I don't have a copy
2 with me--but it would approach over 76 percent.

3 Q. How have you tabulated the responses from
4 the overriding royalty interest owners?

5 A. I used a copy of Exhibit B of the Unit
6 Operating Agreement that has the listing by tracts of
7 all royalty owners.

8 Q. If I asked the Examiner to compare it to
9 Exhibit No. 48, appended to the back of that series of
10 correspondence, then you have highlighted in yellow
11 what?

12 A. Actually, I put red check marks by the
13 parties that I have actually received the ratification
14 and joinders from. At the time I started this, I
15 highlighted in yellow the parties that indicated they
16 would be mailing them in. You might have a check mark
17 and a yellow highlight by a same name.

18 At the time I believe there's only two
19 parties that have indicated that they would be mailing
20 in, that I have not received.

21 Q. Do you have an estimate for us of the
22 percentage of royalty participation that you have at
23 this point in the unit, including both the federal
24 royalty and then the overriding royalties into that
25 category?

1 A. Yes, sir. It's approaching 86 percent.
2 It's 85.7 percent.

3 Q. Ask you to go back and identify some of the
4 components of the Operating Agreement and the Unit
5 Agreement, to see where we can reference those
6 documents and find the corresponding requirements out
7 of the Statutory Unitization Act. Have you
8 accomplished that review?

9 A. Yes, sir.

10 Q. Let me ask you, is there a provision in the
11 Unit Agreement where the operating expenses and
12 capital investments have been allocated to the various
13 separately owned tracts?

14 A. Yes, sir. It's Article 11 of the Unit
15 Operating Agreement. It's on page 15.

16 Q. It's on page what?

17 A. 15.

18 Q. Of the--

19 A. Unit Operating Agreement. And, of course,
20 the COPAS also deals with accounting procedures.
21 That's Exhibit D.

22 Q. The COPAS attachment in Exhibit D, is it?

23 A. Yes, sir.

24 Q. From your perspective, is the language used
25 to accomplish those provisions, can that be

1 characterized or considered to be a fair allocation of
2 cost between the parties that have to bear those
3 expenses?

4 A. Yes, sir. The parties will receive revenue
5 based on the same percentage as they will be billed,
6 so I believe that's a fair and equitable situation.

7 Q. Is there a procedure in the Unit Agreement
8 for taking care of credits and charges for equipment,
9 machinery or anything contributed to the unit?

10 A. Yes, sir, it's Article 10 of the Unit
11 Operating Agreement.

12 Q. Okay. How is that to be accomplished?

13 A. Article 10 provides that we will have an
14 inventory committee, and if we can't decide on a
15 committee, there will be an independent authority that
16 will propose the inventory to the working interest
17 owners.

18 Charges and credits will be given to each
19 working interest owner. If charges exceed credits,
20 they will receive a bill. If credits exceed charges,
21 then they will receive a check in payment from the
22 operator.

23 Q. Are there provisions made in the agreements
24 in the event a working interest owner does not pay his
25 share of unit expenses?

1 A. Yes, sir. That's also in Article 11 of the
2 Unit Operating Agreement. The COPAS provides that you
3 can charge interest after 30 days if you've not
4 received payment. Article 11 provides that after 60
5 days, the nondefaulting working interest owners can't
6 pay their proportionate share of the defaulted
7 payment, at that time the operator can pay them back
8 with the interest attributable to the defaulting
9 party.

10 Q. Do the agreements provide for a risk factor
11 penalty to be assessed against any nonconsenting
12 working interest owner?

13 A. No, sir.

14 Q. Is there a procedure provided for in the
15 Agreements for the designation of successor operator
16 or procedure for removing of a current operator?

17 A. Yes, sir. Section 6 and 7 of the Unit
18 Agreement and Article 6 of the Operating Agreement
19 provide for the resignation and designation of
20 operator; Marathon Oil Company being designated as the
21 initial unit operator.

22 Q. Does the agreement provide for a method of
23 voting on unit matters?

24 A. Yes, sir. That's Article 4 of the Unit
25 Operating Agreement, and that provides for voting

1 procedures, I believe 80 percent and three parties.

2 Q. Does the agreement provide for a method in
3 which to implement the unit, a starting time as well
4 as a procedure for termination of the unit?

5 A. Yes, sir. The effective date of the unit
6 is either going to be the latter of January 1, 1992,
7 or the first day of the next month succeeding approval
8 of the unit by the State, BLM and the working interest
9 owners. As far as termination, they can terminate on
10 January 1st of 93 if it hasn't been approved by that
11 date. That date can be extended by a vote of 75
12 percent or more of the working interest owners. And
13 the term, the unit will say in effect for as long as
14 there's unitized substitutes being produced from the
15 unit area.

16 Q. Are there provisions in the Agreement to
17 effectively describe the unitized interval and the
18 unitized substance?

19 A. That's in the definition portion of the
20 Unit Agreement. I believe it's subparagraph W on page
21 5.

22 Q. Are you satisfied, Mr. Wilson, as a
23 petroleum landman, that you have the appropriate
24 contractual documentation approved by the various
25 parties and the agencies involved, would give Marathon

1 as the unit operator, effective and efficient control
2 over this portion of the Tamano Bone Springs Pool?

3 A. Yes, sir.

4 Q. Were Exhibits 5 through 48 either compiled
5 with your assistance or under your direction, or
6 copies of documents taken out of Marathon's file
7 derived in the ordinary course of doing business on
8 this project?

9 A. Yes.

10 MR. KELLAHIN: Mr. Examiner, we tender
11 Exhibits 5 through 48.

12 EXAMINER STOGNER: Exhibits 5 through 48
13 will be admitted into evidence at this time.

14 MR. KELLAHIN: That concludes my
15 examination of Mr. Wilson

16 EXAMINATION

17 BY MR. STOVALL:

18 Q. Mostly as a point of clarification, looking
19 at Section 11, and I've just only skimmed through it--

20 MR. KELLAHIN: Of the Operating Agreement?

21 MR. STOVALL: Yes.

22 Q. --that is what you referred to in response
23 to Mr. Kellahin as a method for allocating costs and
24 charges, is that correct?

25 A. Yes, sir, I believe that's correct.

1 Q. Would it be more accurate to say that the
2 Unit Agreement itself, and it appears just looking at
3 the Table of Contents, it talks about, I believe,
4 Sections 13 and 14 establish the formula?

5 A. Yes.

6 Q. And then the Section 11 that you're talking
7 about says, what do you do with that formula now that
8 you've got it?

9 A. That's correct. 11 deals with costs, and
10 the articles you're talking about are the tract
11 participation formula.

12 Q. And then Exhibit C, then, I assume, to the
13 Operating Agreement, is the working interest tract
14 participation, is that correct?

15 A. Yes, sir. That's the summary of the
16 working interest owners' interest.

17 Q. As it stands now, at this point in time,
18 based upon the formula you've used and the interest
19 held by the other parties?

20 A. That's correct.

21 Q. And the statute, Mr. Kellahin was tracking
22 you through the statute there to make sure your
23 agreement addressed all the issues, has a specific
24 provision which allows for treatment of nonconsent
25 interests? It appears you don't really have anything

1 which you would call nonconsent, it's just failure to
2 pay your share when due?

3 A. That's correct.

4 Q. You're not really treating anybody as a
5 nonconsent with a nonconsent penalty attached to it?

6 A. No, sir, not planning to.

7 EXAMINER STOGNER: What did he say?

8 MR. STOVALL: He said "no."

9 Q. You talked about joinder, and your 86
10 percent royalty was all of the noncost-bearing
11 interest. When you refer to royalty, you're referring
12 to the combination of basic royalty and overriding
13 royalties?

14 A. That's right. There are some owners that
15 own overrides that are also working interest owners.
16 When you add those parties in, it increases that by a
17 minimal--about one and a half percent.

18 Q. In doing your calculation, did you separate
19 those parties? Did you put them--you know, Mr. Jones
20 is in the working interest column and here's how his
21 interest is there, and here it is?

22 A. Yes. Right now we have 85.7 percent of the
23 royalty committed, and that's not including any of the
24 working interest owners own overrides.

25 Q. I think I understand what you said, but I

1 don't think it matters because you're in excess of the
2 statutory requirement. But your working interest
3 calculation is based upon 100 percent of the working
4 interest?

5 A. That's correct.

6 MR. STOVALL: I don't think I have any
7 other questions.

8 EXAMINER STOGNER: Neither do I.

9 MR. STOVALL: You did get him to state that
10 all those numerous exhibits regarding correspondence,
11 you've verified their authenticity as either being to
12 or from Marathon?

13 THE WITNESS: Yes, sir.

14 MR. STOVALL: Okay. That's it. Now I'm
15 through.

16 EXAMINER STOGNER: Thank you, Mr. Stovall.
17 Thank you, Mr. Wilson. Mr. Kellahin, anything
18 further?

19 MR. KELLAHIN: No, sir.

20 EXAMINER STOGNER: Does anybody else have
21 anything further in either of these two cases?

22 If not, Case Nos. 10341 and 10342 will be
23 taken under advisement.

24

25

1 CERTIFICATE OF REPORTER

2

3 STATE OF NEW MEXICO)
4 COUNTY OF SANTA FE) ss.

5

6 I, Carla Diane Rodriguez, Certified
7 Shorthand Reporter and Notary Public, HEREBY CERTIFY
8 that the foregoing transcript of proceedings before
9 the Oil Conservation Division was reported by me; that
10 I caused my notes to be transcribed under my personal
11 supervision; and that the foregoing is a true and
12 accurate record of the proceedings.

13 I FURTHER CERTIFY that I am not a relative
14 or employee of any of the parties or attorneys
15 involved in this matter and that I have no personal
16 interest in the final disposition of this matter.

17 WITNESS MY HAND AND SEAL July 3, 1991.

18

19 CARLA DIANE RODRIGUEZ
20 CSR No. 91

21 My commission expires: May 25, 1995

22 I do hereby certify that the foregoing is
23 a correct record of the proceedings in
24 the Executive Hearing of the 18-1034A/10342
25 heard by me on 27 June 1991.

Michael J. Sloan, Examiner
Oil Conservation Division