CAUSE NO. C-1-PB-14-001245

IN RE:	§	IN THE PROBATE COURT
	§	
	§	OF
	§	
TEL OFFSHORE TRUST	§	TRAVIS COUNTY, TEXAS

CORPORATE TRUSTEE OF THE TEL OFFSHORE TRUST'S MOTION FOR TRADITIONAL AND NO-EVIDENCE PARTIAL SUMMARY JUDGMENT ON THE AFFIRMATIVE DEFENSE OF STATUTE OF LIMITATIONS

Pursuant to Texas Rules of Civil Procedure 166a(b), 166a(e), 166a(i), The Bank of New York Mellon Trust Company, N.A., ("BNYM") as Corporate Trustee ("the Corporate Trustee") of the TEL Offshore Trust ("Trust") hereby moves for partial summary judgment on its affirmative defense of statute of limitations against Plaintiffs Attorney Ad Litem ("Ad Litem"), Albert Speisman and Joyce E. Speisman (the "Speismans"), and RNR Production Land and Cattle ("RNR") (collectively, "Plaintiffs"). In support thereof, BNYM would respectfully show the Court the following:

I. SUMMARY

Plaintiffs allege that the Corporate Trustee's misconduct giving rise to their claims began in 2009; however, Plaintiffs waited until 2016 to file suit. As demonstrated below, the applicable four-year statute of limitations bars Plaintiffs' breach-of-fiduciary-duty claims and RNR's fraud claim accruing before December 28, 2011, and the applicable two-year statute of limitations bars Plaintiffs' negligence and gross negligence claims. Plaintiffs have no evidence that would defer accrual of Plaintiffs' claims or toll the statutes of limitations. Accordingly, BNYM is entitled to summary judgment on its affirmative defense of statute of limitations as to Plaintiffs' claims for breach of fiduciary duty, fraud, negligence, and gross negligence.

II. SUMMARY-JUDGMENT EVIDENCE

In support of this motion, BNYM relies on the following summary-judgment evidence, all of which is incorporated herein by reference:

Exhibit A: Assessment of TEL Offshore Trust: Technical Expert Report prepared by Michael L. Wiggins (Jan. 31, 2017) ("Wiggins Report")

Exhibit B: Ad Litem's Amended Responses to Corporate Trustee's Request for Disclosure (Jan. 31, 2017) ("Ad Litem's Disclosures")

Exhibit C: Speismans' Responses to Corporate Trustee's and Individual Trustee's Requests for Disclosure (Nov. 14, 2016) ("Speismans' Disclosures")

Exhibit D: Affidavit of Michael J. Ulrich (February 21, 2017) ("Ulrich Affidavit")

Exhibit D-1: 10-K for the fiscal year ended December 31, 2008 (March 31, 2009)

Exhibit D-2: 8-K (March 25, 2009)

Exhibit D-3: 10-Q for the quarterly period ended June 30, 2009 (Aug. 7, 2009)

Exhibit D-4: 10-K for the fiscal year ended December 31, 2009 (March 31, 2010)

Exhibit D-5: 10-K for the fiscal year ended December 31, 2010 (March 31, 2011)

Exhibit D-6: Trust Agreement of TEL Offshore Trust ("Trust Agreement")

Exhibit E: Excerpts from Reporter's Record on Attorney Ad Litem's Motion to Compel Unredacted Attorney's Fees Statements and Additional Information about Materials Withheld as Privileged, Attorney Ad Litem's Motion to Realign the Parties or Alternatively Set Order of Proceedings at Trial, Attorney Ad Litem's Amended September 2016 Fee Application, Motion to Substitute Counsel & Individual Trustees' Special Exceptions and Plea to the Jurisdiction to Second Amended Counterclaim (Oct. 3, 2016) ("Reporter's Record")

Exhibit F: Excerpt from Ad Litem's Response to Petition for Writ of Mandamus (Feb. 13, 2017)

Exhibit G: Ad Litem's Responses to the Corporate Trustee's First Set of Interrogatories (Dec. 7, 2016) ("Ad Litem's Responses to Interrogatories")

III. UNDISPUTED MATERIAL FACTS

A. Plaintiffs seek to recover for conduct beginning in 2009.

Plaintiffs allege that the Corporate Trustee's misconduct giving rise to their claims began in 2009. *See, e.g.*, Ad Litem's Second Amended Petition as Realigned Plaintiff ¶¶ 30–33, 48, 52 (alleging misconduct beginning in 2009); RNR's First Amended Petition as Realigned Plaintiff ¶¶ 24, 26–27 (same); Speismans' First Amended Original Petition as Realigned Plaintiffs ¶ 50 (seeking damages for alleged breaches of trust beginning in 2009). Indeed, the report of Michael L. Wiggins—designated expert for the Ad Litem—confirms that the Ad Litem seeks damages for conduct that occurred more than four years before the Ad Litem filed his claims. *See* Ex. A, Wiggins Report; *see also* Ex. B, Ad Litem's Disclosures at 2 ("The economic damages are the loss or depreciation in value of the trust estate as a result of the BNYM's breaches of trust. Some of this loss or depreciation in value was due to the breaches of trust represented by the delay in the sale of the Trust's net profits interests ***beginning in 2009*** and continuing until the Trustees filed the termination and modification proceeding in 2014." (emphasis added)).

RNR and the Speismans also appear to seek damages for conduct dating back to 2009. The Speismans expressly state that their economic damages were caused by alleged breaches of trust "beginning in 2009." *See* Ex. C, Speismans' Disclosures at 4. Although RNR does not specify the time period for which it seeks damages, its First Amended Petition references alleged misconduct beginning in 2009. *See, e.g.*, RNR's First Amended Petition as Realigned Plaintiff ¶¶ 24, 26–27.

B. The Trustees fully disclosed the damage caused by Hurricane Ike and the Corporate Trustee's compensation in their SEC filings, thereby putting Plaintiffs on notice of their claims.

The Trustees fully disclosed the damage caused by Hurricane Ike in their SEC filings in March 2009. Specifically, in the Trust's 10-K for 2008 dated March 31, 2009, the Trustees disclosed to the unit holders the damage inflicted on the Trust's royalty properties by Hurricane Ike, the adverse effect such damages had on funds available for distribution in the fourth quarter of 2008, and the fact that future distributions are expected to be "severely negatively impacted because of the reduced production and increased expenditures required to remediate, repair, and, perhaps, restore platforms and wells." *See* Ex. D-1, 10-K for the fiscal year ended December 31, 2008. Additionally, on March 25, 2009, the Trust filed an 8-K and issued a press release which announced that there would be no distributions to the unit holders. *See* Ex. D-2, 8-K. The Trust also stated in its second quarter 2009 10-Q report that: "There are not likely to be sufficient Net Proceeds from the Royalty Properties for the Trust to make a regularly scheduled quarterly distribution to Unit holders for the foreseeable future." Ex. D-3, 10-Q for the quarterly period ended June 30, 2009. According to the Ad Litem's expert, "[w]ith this information, it was clear TEL Trust faced financial difficulties and the Royalty Properties (and the Trust) were approaching their economic life." Ex. A, Wiggins Report ¶ 58.

The Trustees continued to disclose the adverse effects of the damage caused by Hurricane Ike in subsequent SEC filings. *See, e.g.*, Ex. D-4, 10-K for the fiscal year ended December 31, 2009 ("Production from Eugene Island 339 and Ship Shoal 182 and 183, the two most significant Royalty Properties, ceased following damage inflicted by Hurricane Ike in September 2008. While oil and natural gas production at Ship Shoal 182 and 183 was restored in 2009, there can be no assurance that production will be restored at Eugene Island 339."); Ex. D-5, 10-K for the fiscal year ended December 31, 2010 ("The funds available for the fourth quarter distribution were severely negatively impacted by Hurricane Ike. On March 25, 2009, the Trust announced that there would be no trust distribution for the first quarter of 2009, and the Trust had not made a distribution since January 9, 2009."). Similarly, on June 26, 2009, September 25, 2009, December 23, 2009 and March 23, 2010, the Trust announced there would be no trust distributions for the second, third and fourth quarters of 2009 or the first quarter of 2010, respectively. Ex. D-4, 10-K for the fiscal year ended December 31, 2009.

In addition to disclosing the financial problems facing the Trust after Hurricane Ike, the Trust's annual 10-K reports disclosed the Corporate Trustee's compensation since 2009. *See* Ex. D-4, 10-K for the fiscal year ended December 31, 2009 ("During the year ended December 31, 2009, the Corporate Trustee received compensation from the Trust in an aggregate amount of $207,500."); Ex. D-5, 10-K for the fiscal year ended December 31, 2010 ("During the year ended December 31, 2010, the Corporate Trustee received compensation from the Trust in an aggregate amount of $229,478.").

C. Plaintiffs waited until 2016 to file their claims.

Despite being on notice of the Trustees' alleged misconduct in March 2009, Plaintiffs waited until 2016 to assert their claims. The first time the Ad Litem asserted his claims was in his First Amended Counterclaim filed on August 17, 2016, and the first time RNR asserted its claims was in its Original Petition filed on October 28, 2016. Similarly, the Speismans did not assert their claims until November 15, 2016.

IV. TRADITIONAL SUMMARY JUDGMENT

A. Summary-Judgment Standard

In Texas, traditional summary judgment is proper when the movant establishes that there is no genuine issue of material fact and that the movant is entitled to judgment as a matter of law. *Mann Frankfort Stein & Lipp Advisors, Inc. v. Fielding*, 289 S.W.3d 844, 848 (Tex. 2009). A moving party is entitled to judgment as a matter of law if it can negate at least one element of the claimant's theory of recovery or can conclusively establish each element of an affirmative defense. *Sci. Spectrum, Inc. v. Martinez*, 941 S.W.2d 910, 911 (Tex. 1997). "If summary judgment is not rendered upon the whole case or for all the relief asked and a trial is necessary, the judge may . . . make an order specifying the facts that are established as a matter of law, and directing such further proceedings in the action as are just." TEX. R. CIV. P. 166a(e).

B. Plaintiffs cannot recover damages for breach of fiduciary duty or fraud that occurred more than four years before suit, or damages for negligence or gross negligence that occurred more than two years before suit.

In Texas, claims for fraud and breach of fiduciary duty are governed by a four-year statute of limitations that begins to run at the time of the breach. TEX. CIV. PRAC. & REM. CODE ANN. § 16.004(a)(4) & (5). Claims for negligence and gross negligence are governed by a two-year statute of limitations. *See Meredith v. Rose*, No. 05-15-00054-CV, 2016 WL 4205686, at *4 (Tex. App.—Dallas Aug. 9, 2016, no pet.) (applying a two-year statute of limitations to negligence, gross negligence, and negligent misrepresentation claims); *Perez v. Gulley*, 829 S.W.2d 388, 390 (Tex. App.—Corpus Christi 1992, writ denied) ("The two-year statute of limitations governing actions for personal injury, Tex. Civ. Prac. & Rem. Code Ann. § 16.003 (Vernon 1986), is applicable to negligence and gross negligence causes of action."). Plaintiffs seek to recover for conduct beginning in 2009. *See* Ex. A, Wiggins Report; Ex. B, Ad Litem's

Disclosures at 2; Ex. C, Speismans' Disclosures at 4; *see also* RNR's First Amended Petition as Realigned Plaintiff ¶¶ 24, 26–27. However, Plaintiffs waited until 2016 to file their claims. Accordingly, Plaintiffs cannot recover damages for any breaches of fiduciary duty—including any allegedly improper compensation of the Corporate Trustee—or fraud that occurred before December 28, 2011. Likewise, Plaintiffs cannot recover damages for negligence and gross negligence that occurred before December 28, 2013.

C. Plaintiffs were on notice of their claims since March 2009; therefore, all fiduciary duty and fraud claims accruing before December 28, 2011 and all negligence and gross negligence claims accruing before December 28, 2013 are barred by the statute of limitations.

1. Plaintiffs' claims accrued in 2009.

Generally, a cause of action accrues when a party has been injured by the actions or omissions of another. *Meredith*, 2016 WL 4205686, at *4 (citing *Barker v. Eckman*, 213 S.W.3d 306, 311 (Tex. 2006)). Plaintiffs allege that the Corporate Trustee's misconduct giving rise to their claims began in 2009. *See, e.g.*, Ad Litem's Second Amended Petition as Realigned Plaintiff ¶¶ 30–33, 48, 52; RNR's First Amended Petition as Realigned Plaintiff ¶¶ 24, 26–27; Speismans' First Amended Original Petition as Realigned Plaintiffs ¶ 50. Taking these allegations as true, Plaintiffs' claims accrued in 2009—well before Plaintiffs first filed their claims in 2016.

2. Plaintiffs cannot defer accrual of their claims.

"The discovery rule is 'a very limited exception to statutes of limitations' that 'defers accrual of a cause of action until the plaintiff knew or, exercising reasonable diligence, should have known of the facts giving rise to the cause of action.'" *Meredith*, 2016 WL 4205686, at *4 (quoting *Computer Assocs. Int'l, Inc. v. Altai, Inc.*, 918 S.W.2d 453, 455 (Tex. 1996)). Here, Plaintiffs knew or should have known of the facts giving rise to their claims by March 2009.

The Trust's SEC filings put unit holders on notice of the Corporate Trustee's compensation as well as the financial problems faced by the Trust as a result of the damages inflicted by Hurricane Ike. *See Miller v. Nationwide Life Ins. Co.*, 391 F.3d 698, 700 (5th Cir. 2004) ("SEC filings are generally sufficient to place investors on constructive notice of their contents."); *see also* Ex. E, Reporter's Record at 72:9–11 (Ad Litem admitting that "if things were disclosed in the securities filings they were disclosed to the beneficiaries regardless of who they are."). Indeed, the Ad Litem admits that the Trustees' SEC filings going back to the 10-K for 2008 told a grim tale about the prospects for future payments:

> Q. Let me ask you the question and you tell me if you need something. Would you agree that by the – your investigation revealed by the end of 2009 at the latest if Chevron opted not to re-develop Eugene Island 339, that ***it was obvious that the royalty properties were in dire straits and could not provide distributions to the beneficiaries for the foreseeable future if ever?*** Do you agree with that?
>
> A. ***I believe I can prove that.***
>
> Q. ***And do you agree that indeed the trustees repeatedly said so in their SEC filings?***
>
> A. ***Yes.***
>
> Q. Okay. And then – go to another thing on that. ***Do you agree that the trustees' SEC filings going back to the 2008 Form 10-K told a grim tale?***
>
> A. ***A grim tale about the prospects for future payments, yes.***
>
> Q. Yeah. ***And the future distributions by the trust are expected to be severely negatively impacted and there may not be sufficient proceeds from the royalty properties to make one or more future distributions?***
>
> A. ***I believe that's true.***

Ex. E, Reporter's Record at 95:2–22 (emphasis added); *see also* Ad Litem's Second Amended

Petition as Realigned Plaintiff ¶ 22 ("BNYM's SEC filings told some of the grim tale. . . . In each Form 10-K since [March 2009] until the filing of this suit (2009 – 2014), BNYM said 'there are not likely to be sufficient Net Proceeds from the Royalty Properties for the Trust to make a regularly scheduled quarterly distribution to Beneficiaries for the foreseeable future,' or something substantially similar."). Similarly, the Ad Litem admits that the Trust's "10-K filings disclose significant 'general and administrative expenses,' trustee compensation and accounting fees." Ad Litem's Second Amended Petition as Realigned Plaintiff ¶ 60. With this knowledge, the unit holders could have sold their units at any time. *See* Ex. E, Reporter's Record at 96:3–7. Additionally, after being put on notice of the financial problems facing the Trust (as disclosed in the SEC filings), the unit holders had the opportunity to inspect all books and records, which included the reserve reports by DeGolyer & MacNaughton and the compensation to the Corporate Trustee. *See* Ex. D, Ulrich Affidavit ¶ 7; Ex. D-6, Trust Agreement § 11.01. At the latest, the unit holders knew or should have known of their potential claims by March 31, 2009.[1] *See* Ex. D-1, 10-K for the fiscal year ended December 31, 2008. Accordingly, Plaintiffs' claims accrued in 2009—and certainly no later than 2010 with respect to claims relating to the Corporate Trustee's compensation—and are barred by the applicable statutes of limitations as a matter of law.

V. NO-EVIDENCE SUMMARY JUDGMENT

A. No-Evidence Summary Judgment Standard

Texas Rule of Civil Procedure 166(a)(i) confers upon a trial court the ability to grant a no-evidence motion for summary judgment after an adequate time for discovery has passed and

[1] At the latest, unit holders knew or should have known of their potential claims relating to the Corporate Trustee's compensation by March 31, 2010. Ex. D-4, 10-K for the fiscal year ended December 31, 2009.

the non-moving party is unable to present evidence raising a genuine issue of material fact as to one or more elements of its claims:

> After adequate time for discovery, a party without presenting summary judgment evidence may move for summary judgment on the ground that there is no evidence of one or more essential elements of a claim or defense on which an adverse party would have the burden of proof at trial. The motion must state the elements as to which there is no evidence.

The mere filing of a no-evidence motion shifts the burden to the respondent to come forward with enough evidence to take the case to a jury. *Jackson v. Fiesta Mart, Inc.*, 979 S.W.2d 68, 71 (Tex. App.—Austin 1998, no pet.).

Rule 166a(i) requires Plaintiffs to produce more than a scintilla of evidence to raise a genuine issue of material fact on the challenged elements of their claims. Although Plaintiffs are not required to marshal all of their evidence, Plaintiffs must produce enough competent summary-judgment evidence that "rises to a level that would enable reasonable and fair-minded people to differ in their conclusions." *Isbell v. Ryan*, 983 S.W.2d 335, 338 (Tex. App.—Houston [14th Dist.] 1998, no pet.). Evidence that is so weak as to only create a suspicion of its existence has no legal effect and is considered "no evidence." *Ford Motor Co. v. Ridgway*, 135 S.W.3d 598, 601 (Tex. 2004); *Kindred v. Con/Chem, Inc.*, 650 S.W.2d 61, 63 (Tex. 1983) ("When the evidence offered to prove a vital fact is so weak as to do no more than create a mere surmise or suspicion of its existence, the evidence is no more than a scintilla and, in legal effect, is no evidence."). Thus, if Plaintiffs produce summary-judgment evidence that is "so weak as to do no more than create a mere surmise or suspicion"—or fail to produce any evidence at all—Plaintiffs fail to meet their burden, and the Court must grant BNYM's motion. TEX. R. CIV. P. 166(a)(i).

B. There is no evidence that would defer accrual of Plaintiffs' claims or toll the statute of limitations.

1. Plaintiffs have no evidence to show that the unit holders did not know, or, in the exercise of reasonable diligence, should not have known of their claims until December 28, 2011 or later.

The discovery rule is a plea in confession and avoidance and "[t]he party seeking to benefit from the discovery rule . . . bear[s] the burden of proving and securing favorable findings thereon." *Woods v. William M. Mercer, Inc.*, 769 S.W.2d 515, 517–18 (Tex. 1988). Accordingly, Plaintiffs have the burden of proving that each unit holder did not know, or, in the exercise of reasonable diligence, should not have known, of the Corporate Trustee's misconduct until December 28, 2011 or later. Plaintiffs cannot satisfy this burden.

The Ad Litem is adamant that he sues on behalf of over 2,700 individual unit holders that are before the Court. *See* Ex. F, Excerpt from Ad Litem's Response to Petition for Writ of Mandamus. As such, to benefit from the discovery rule, the Ad Litem must prove that each individual unit holder he represents did not know, or through the exercise of reasonable diligence, should not have known, of their potential claims prior to December 28, 2011. *See* Ex. E, Reporter's Record at 71:22–72:1 (Ad Litem admitting that the discovery rule is an inquiry into the knowledge of the plaintiff—in this case, the beneficiaries of the Trust). But the Ad Litem does not have a scintilla of evidence on this point.[2] In response to the Corporate Trustee's interrogatories, the Ad Litem refused to provide specific information as to the individual unit holders. *See* Ex. G, Ad Litem's Responses to Interrogatories at 1 (objecting "to the extent the Corporate Trustee purports to require individual answers from each of the over 2,700 AAL

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[2] In paragraph 54 of his Second Amended Petition as Realigned Plaintiff, the Ad Litem lists the "numerous material facts" omitted from the Trust's SEC filings. However, the Ad Litem has no evidence to show that the unit holders could not have discovered this information by exercising reasonable diligence.

Parties Ad Litem represents."). The Ad Litem responded to the interrogatories "based on the information in his possession" and "object[ed] to any requirement for him to obtain information from over-2,700 AAL Parties." *Id.* at 3. In fact, the Ad Litem admits that he does not even know the identity of the unit holders he purports to represent. Ex. E, Reporter's Record at 69:10–11. The Ad Litem's refusal to obtain information specific to the individual unit holders—and his inability to identify those unit holders—demonstrates that the Ad Litem has no evidence to show that the unit holders he represents were both not aware of claims and not aware of facts that would put a reasonable person on notice of claims prior to December, 2011.

2. Plaintiffs have no evidence of fraudulent concealment.

"A party asserting fraudulent concealment as an affirmative defense to the statute of limitations has the burden to raise it in response to the summary judgment motion and to come forward with summary judgment evidence raising a fact issue on each element of the fraudulent concealment defense." *KPMG Peat Marwick v. Harrison County Hous. Fin. Corp.*, 988 S.W.2d 746, 749 (Tex. 1999); *B. Mahler Interests, L.P. v. DMAC Constr., Inc.*, 503 S.W.3d 43, 54 (Tex. App.—Houston [14th Dist.] 2016, no pet.). The elements of fraudulent concealment are: (1) existence of the underlying tort; (2) the defendant's knowledge of the tort; (3) the defendant's use of deception to conceal the tort; and (4) the plaintiff's reasonable reliance on the deception. *Markwardt v. Texas Indus., Inc.*, 325 S.W.3d 876, 895 (Tex. App.—Houston [14th Dist.] 2010, no pet.). "Fraudulent concealment only tolls the running of limitations until the fraud is discovered or could have been discovered with reasonable diligence." *B. Mahler Interests, L.P.*, 503 S.W.3d at 54–55. Plaintiffs have no evidence of any of these elements. Accordingly, Plaintiffs cannot rely on the doctrine of fraudulent concealment to toll limitations.

VI. PRAYER

For the foregoing reasons, BNYM respectfully requests that the Court grant this Motion for Traditional and No-Evidence Partial Summary Judgment on the Affirmative Defense of Statute of Limitations and issue an order specifying that the applicable statutes of limitations bar Plaintiffs' breach-of-fiduciary duty and fraud claims accruing before December 28, 2011, as well as Plaintiffs' negligence and gross negligence claims accruing before December 28, 2013. BNYM further requests all other relief to which it may be justly entitled.

Respectfully submitted,

/s/ Craig A. Haynes

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ATTORNEYS FOR THE BANK OF NEW YORK MELLON TRUST COMPANY, N.A., as CORPORATE TRUSTEE OF THE TEL OFFSHORE TRUST

CERTIFICATE OF SERVICE

I hereby certify that, on February 27, 2017, a true and correct copy of the foregoing has been served via Texas e-filing and email on Ad Litem, counsel for Ad Litem, counsel for Albert and Joyce Speisman, and counsel for RNR Production Land and Cattle. I hereby certify that all other interested parties in this matter will be served in accordance with the Court's Order Directing Method of Service dated January 21, 2016.

/s/ Rachelle H. Glazer
Rachelle H. Glazer

EXHIBIT A

ASSESSMENT

OF

TEL OFFSHORE TRUST

Technical Expert Report

In Re: TEL Offshore Trust

Cause No. C-1-PB-14-001245
Cause No. C-1-PB-16-000096

Probate Court No. 1
Travis County, Texas

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Assessment of TEL Offshore Trust

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Assessment of TEL Offshore Trust

Executive Summary

1. TEL Offshore Trust (TEL Trust) was organized in 1983 as part of a plan to dissolve Tenneco Offshore Company, Inc. (Tenneco Offshore). The only asset of TEL Trust is a 99.99 percent interest in TEL Offshore Trust Partnership (TEL Partnership), which was created to hold a 25 percent net profits interest in 20 oil and gas properties (Royalty Properties) located in the Gulf of Mexico owned by Tenneco Exploration, Ltd. (Tenneco Exploration) for the benefit of TEL Trust Unit Holders.

2. The purposes of TEL Trust are to protect and conserve the net profits interest in the Royalty Properties for the benefit of the Unit Holders and to distribute all funds received by the Trust to the Unit Holders after paying any liabilities of the Trust. A Corporate Trustee and three Individual Trustees are responsible for administering TEL Trust, monitoring the Royalty Properties and TEL Partnership, distributing any net proceeds of the Trust to the Unit Holders, and making decisions to protect the net profits interest for the benefit of the Unit Holders.

3. By 2008, the Royalty Properties were in an advanced stage of development and had limited remaining life with only eight properties still contributing revenue to TEL Partnership. In September 2008, Hurricane Ike moved through the Gulf of Mexico disrupting production from and causing catastrophic damage to the Royalty Properties, the primary source of income for the TEL Trust. This damage to the Royalty Properties had a severe negative impact on the financial viability of TEL Trust, requiring the Trust to deplete its special cost escrow and expense reserve plus accumulating a significant net loss carryforward by the end of 2009. As a result of the damage caused by Hurricane Ike, TEL Trust has paid no distributions to its Unit Holders since January 2009.

4. The Corporate Trustee, the Bank of New York Mellon Trust Company, N.A. (BONY Trust), and the Individual Trustees filed a petition with Probate Court No. 1 of Travis County, Texas in July 2014 to modify and terminate TEL Trust. The Petitioner stated that due to damage caused to the assets benefitting TEL Trust by Hurricane Ike that it had become impossible to fulfill the purposes of TEL Trust and that liquidation and termination of the Trust was more likely to result in a distribution to the Unit Holders than continuing to operate TEL Trust.[1]

5. While BONY Trust and the Individual Trustees would need sufficient time to determine the extent of the damage to the Royalty Properties by Hurricane Ike and the financial impact on the Trust, they should have realized by May 2009 and no later than December 2009 that the viability of the Trust was threatened. It was at this point TEL Partnership had lost over 50 percent of its net quarterly profit, Chevron had announced plans not to redevelop one of the major Royalty Properties, and TEL Trust was accumulating a significant net loss carryforward, depleting its cash reserves, and announcing in its SEC filings that "there are not likely to be

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[1] Original Petition, 2014: "Original Petition for Modification and Termination of Trust," filed on behalf of the Corporate Trustee and the Individual Trustees of the TEL Offshore Trust in Probate Court No. 1 of Travis County, Cause No. C-1-PB-14-001245, 10 July 2014.

sufficient Net Proceeds from the Royalty Properties for the Trust to make a regularly scheduled quarterly distribution to Unit holders for the foreseeable future."

6. In my opinion, BONY Trust and the Individual Trustees had ample evidence by May 2009 and no later than December 2009 to determine the economic viability of TEL Trust and should have taken immediate steps to divest the 25 percent net profits interest in the Royalty Properties no later than year-end 2010. By its delayed action, BONY Trust and the Individual Trustees have damaged TEL Unit Holders by failing to protect the value of the net profits interest. It is my opinion that the Unit Holders suffered damages ranging from at least $8.1 million to $9.2 million (excluding interest due to any judgement) by the Trustees' failure to divest the 25 percent net profit interest no later than year-end 2010.

Assessment of TEL Offshore Trust

Introduction

7. TEL Offshore Trust (TEL Trust) and TEL Offshore Trust Partnership (TEL Partnership) were created effective 01 January 1983 as part of a plan to dissolve Tenneco Offshore Company, Inc. (Tenneco Offshore). At that time, an overriding royalty interest in certain oil and gas properties (Royalty Properties) located in the Gulf of Mexico and owned by Tenneco Exploration, Ltd. (Tenneco Exploration) was conveyed to TEL Partnership for the benefit of TEL Trust. In exchange, shareholders of Tenneco Offshore common stock were issued units in TEL Trust and their Tenneco Offshore stock was essentially liquidated and canceled.[2]

8. TEL Partnership was created to hold the Royalty Properties, to receive any proceeds from production, and pay out any profits to the owners of the Partnership. TEL Trust held a 99.99 percent ownership interest in the Partnership while Tenneco Oil Company (Tenneco) was named the general partner and owned the remaining 0.01 percent of TEL Partnership. As the general partner, Tenneco managed the operations of the TEL Partnership and had full authority to manage the interests held in the Royalty Properties as it deemed prudent.[3]

9. TEL Trust was created to protect and conserve the Trust's interest in TEL Partnership for the benefit of the Unit Holders, receive any cash due from the Partnership, pay the liabilities of the Trust, and distribute any remaining funds to the Unit Holders. The Trust Agreement provided for a Corporate Trustee and three Individual Trustees to manage the operations of TEL Trust for the benefit of the Unit Holders. Texas Commerce Bank N.A. was named Corporate Trustee and was responsible for day-to-day administration of TEL Trust.[4]

10. Through a variety of bank mergers and acquisitions, Bank of New York Mellon Trust Company, N.A. (BONY Trust) currently serves as the Corporate Trustee for TEL Trust. In late 1988, Chevron USA, Inc. (Chevron) acquired most of the offshore oil and gas properties of Tenneco including the Royalty Properties. As successor to Tenneco, Chevron became the general partner of TEL Partnership and operator of a number of the Royalty Properties.[5]

11. In September 2008, Hurricane Ike moved through the Gulf of Mexico disrupting production and causing extensive damage to the Royalty Properties. Eugene Island 339 (EI 339) suffered catastrophic damage where two platforms and all wells were destroyed. Ship Shoal 183 (SS 183) suffered minor surface damages; however, the wells had to be shut-in due to damage caused to pipelines and facilities that transport production from the field.[6] In addition, East Cameron 371 (EC 371) and West Cameron 643 (WC 643) suffered sufficient damage that these

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[2] TEL Trust, 1983: TEL Offshore Trust Agreement, 01 January 1983. TEL 0031407-0031435; TEL Partnership, 1983: Agreement of General Partnership of TEL Offshore Trust Partnership, 01 January 1983. TEL 0001047-0001075; Tenneco Exploration, 1983: Second Amendment to Articles of Limited Partnership, 01 January 1983. TEL0000946-0000952; Conveyance, 1983: Conveyance of Overriding Royalty Interests, 01 January 1983. TEL0031437-0031472.
[3] TEL Partnership, 1983; Conveyance, 1983.
[4] TEL Trust, 1983.
[5] TEL Trust 2015 10-K: TEL Offshore Trust SEC Form 10-K for Year Ended 31 December 2015, 30 March 2016.
[6] TEL Trust, 2008a: TEL Offshore Trust Announces Hurricane Damage to Properties, press release dated 07 October 2008.

properties never returned to production.[7] At the time of Hurricane Ike, EI 339 and SS 183 accounted for almost 97 percent of the total net proceeds for TEL Partnership.[8]

12. Due to the loss of revenue from EI 339 and costs associated with its abandonment, total revenues have not exceeded total costs for the Royalty Properties since Hurricane Ike as of January 2016.[9] As the Royalty Properties have not had a net profit, TEL Partnership has had no net income since Hurricane Ike to distribute to TEL Trust. As a result, TEL Trust has made no distributions to the Unit Holders since January 2009, which was for the period ending October 2008.

13. TEL Partnership, at the direction of the Trustees of TEL Trust, sold 40 percent of its 25 percent net profits interest in the Royalty Properties in two separate transactions effective August 2011 and August 2013. Proceeds from these sales were used solely to defray expenses of TEL Trust, including Trustee compensation. After the sales, TEL Trust owned its proportionate share of a 15 percent net profits interest in the Royalty Properties.[10]

14. In July 2014, BONY Trust and the Individual Trustees filed a petition with Probate Court No. 1 in Travis County, Texas requesting the TEL Trust Agreement be modified and the Trust terminated. The Trustees claimed TEL Trust had insufficient income or reserves to fund its liabilities and that future distributions from the Royalty Properties were unlikely in the foreseeable future. The Petitioner further stated that due to damage caused by Hurricane Ike that it had become impossible to fulfill the purposes of TEL Trust.[11]

15. In June 2015, the Court appointed Glenn M. Karisch as Attorney Ad Litem to represent the interests of TEL Trust Unit Holders who were served by publication and did not answer or appear in this proceeding. Following the request of the Attorney Ad Litem, the Court approved the engagement of William M. Cobb & Associates, Inc. (Cobb & Associates) in September 2015 to assist in the review and assessment of TEL Trust, TEL Partnership, and the Royalty Properties.[12]

16. In providing assistance to the Attorney Ad Litem and forming opinions expressed in this report, Cobb & Associates undertook a review of the information related to the Royalty Properties and TEL Trust. This included information provided by the Attorney Ad Litem, BONY Trust, and DeGoyler & MacNaughton (D&M), the reserve engineers for TEL Partnership. Public information reviewed included: TEL Trust SEC filings; TEL Trust documents posted on the Andrews Kurth LLP (A-K) website; and, historical production data. Documents provided by TEL Trust in discovery and the deposition of BONY Trust's representative were also reviewed. In addition, Cobb & Associates conducted in person or telephone meetings with the Attorney Ad Litem, representatives of BONY Trust, and representatives of D&M.

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[7] TEL Trust 2010 10-K: TEL Offshore Trust SEC Form 10-K for Year Ended 31 December 2010, 31 March 2011.
[8] Net Profit Statement, Q3 2008: TEL Offshore Trust Net Profit Statement for months of May, June, and July 2008.
[9] TEL Trust, 2016: TEL Offshore Trust Announces There Will Be No Fourth Quarter 2015 Distribution and Provides Update on Probate Proceedings, press release dated 21 January 2016.
[10] TEL Trust 2015 10-K.
[11] Original Petition, 2014.
[12] Order for Appointment of Attorney Ad Litem, Cause No. C-1-PB14-001245, 18 June 2015; Attorney Ad Litem's Motion to Retain and Compensate Consulting Expert, Cause No. C-1-PB14-001245, 18 August 2015.

17. This report has been prepared by Michael L. Wiggins, who holds a doctoral degree in petroleum engineering and is a registered professional engineer (see Appendix A). The report has been limited to those issues for which Cobb & Associates has the necessary experience or expertise to review, investigate, analyze or opine upon. In addition, we have made all the inquiries that are relevant and appropriate in forming the opinions offered in this report. In evaluating the available information during this review, the author has not attempted to provide any legal or accounting interpretation or guidance. To our knowledge, no significant matters have been withheld in preparing this report related to the scope of this investigation. Finally, this report has been based on data and information available to Cobb & Associates at the time the report was generated; however, we reserve the right to amend or supplement this report if additional facts or data comes to our attention relevant to our analyses and opinions.

18. This report is subject to a confidentiality order of the Travis County Probate Court No. 1 and/or a confidentiality agreement between TEL Trust and Glenn Karisch, Cobb & Associates, and Michael L. Wiggins, which may require approval from either the Court and/or BONY Trust prior to public release.

Status of TEL Trust

19. TEL Trust was created in January 1983 by Tenneco Offshore as part of a plan to dissolve Tenneco Offshore while TEL Partnership was created to hold an "overriding royalty interest" in the Royalty Properties for the benefit of TEL Trust. TEL Trust holds a 99.99 percent interest in the TEL Partnership while Tenneco held the remaining 0.01 percent interest as the general partner of the Partnership at the time of its creation.[13] Following its acquisition of Tenneco's offshore properties, Chevron became the general partner of TEL Partnership. TEL Trust is managed by BONY Trust, the Corporate Trustee responsible for day-to-day administrative duties, and three Individual Trustees.

20. TEL Trust was created for the purpose of distributing revenues obtained from the 25 percent net profits interest in the Royalty Properties to its Unit Holders. The Royalty Properties consisted of interests in 20 offshore Gulf of Mexico blocks totaling 92,632 gross acres. The Royalty Properties were in various stages of development with original lease assignments from the US Mineral Management Service (MMS) dating as far back as 1955. Tenneco Exploration had obtained its interest in these properties during the period from December 1974 through April 1977. As of 30 June 1982, 42 exploration wells and 151 development wells had been drilled on these 20 properties where Tenneco Exploration held ownership interests ranging from 0.3 percent to 100.0 percent. Table 1 provides a listing of the original Royalty Properties.[14]

21. The "overriding royalty interest" in the Royalty Properties conveyed to TEL Partnership was equivalent to a 25 percent net profits interest, which was not a traditional overriding royalty interest. TEL Partnership is liable for all costs associated with its interest in the Royalty Properties including capital expenditures, operating expenses, and management fees. If the net

[13] TEL Trust, 1983; TEL Partnership, 1983; Conveyance, 1983.
[14] Conveyance, 1983: Exhibit A; Ulrich, 2015: E-mail from Michael Ulrich to Michael Wiggins dated 27 October 2015 with an attachment titled "Offshore Lease Summary" as of 30 June 1982.

revenue for a particular period fails to exceed costs, TEL Partnership accumulates a net loss that is carried forward to be paid from future revenues. In addition, there are provisions for the general partner to accrue a special cost reserve to offset future capital costs including plugging, abandonment, and decommissioning costs (P&A) of all wells, platforms, and facilities associated with the Royalty Properties.[15] If the total revenue in any period exceeds the total costs including any net loss carryforward and special cost reserve accrual, then TEL Partnership distributes the net proceeds to the partners at their proportionate ownership.

22. TEL Trust receives 99.99 percent of any distribution of net proceeds from TEL Partnership while Chevron as general partner receives the remaining 0.01 percent of the distribution. In a like manner, if there is a negative distribution attributable to the Partnership for a given period, TEL Trust accrues a net loss carry forward of 99.99 percent of the negative distribution that must be reimbursed from future net proceeds before any cash distributions can be made by TEL Partnership to the Trust.

TABLE 1
Royalty Properties

Block/Lease	Date Acquired	Property Size Acres	Original WI, percent	First Production
East Cameron 354	12-1972	5,000	50.0	06-1980
East Cameron 370	01-1973	5,000	25.0	06-1980
East Cameron 371	01-1973	5,000	25.0	06-1980
Eugene Island 208	08-1973	1,250	100.0	11-1975
Eugene Island 339	12-1972	5,000	50.0	10-1973
Eugene Island 342	12-1972	5,000	50.0	11-1975
Eugene Island 343	12-1972	5,000	50.0	11-1975
Eugene Island 348	12-1972	5,000	50.0	08-1979
Eugene Island 367	03-1974	5,000	1.6	01-1977
High Island A-336	03-1974	5,760	15.0	10-1979
Ship Shoal 183	12-1973	3,125	66.7	09-1974
South Marsh Island 252	03-1974	4,997	1.6	01-1980
South Timbalier 29	03-1974	5,000	0.3	06-1980
South Timbalier 36	03-1974	5,000	0.3	03-1977
South Timbalier 37	03-1974	5,000	0.3	11-1976
South Timbalier 38	03-1974	5,000	0.3	02-1979
Vermilion 246	05-1973	5,000	100.0	02-1975
West Cameron 41	03-1974	2,500	0.3	08-1975
West Cameron 642	01-1973	5,000	25.0	01-1977
West Cameron 643	12-1972	5,000	50.0	01-1977

23. Hurricane Ike entered the Gulf of Mexico in September 2008 and slowly moved through the Gulf before making landfall near Galveston. This slow-moving hurricane disrupted oil and gas

[15] Conveyance, 1983.

production and caused extensive damage to oil and gas facilities to the east of its path. The MMS reported that approximately 99 percent of the oil and gas production from the Gulf of Mexico had been shut-in due to Hurricane Ike. In addition, 611 manned offshore platforms and 101 offshore rigs had been evacuated as a precaution. Later it was determined that Hurricane Ike destroyed 59 platforms and numerous oil and gas pipelines.[16]

24. The Royalty Properties did not escape the destruction caused by Hurricane Ike, which caused catastrophic damage to EI 339 where two platforms were destroyed along with all the wells. SS 183 suffered minor surface damages; however, the wells had to be shut-in due to damage caused to pipelines and facilities that transported production from the field. In addition, wells and facilities at EC 371 and WC 643 also sustained damages.[17] At this time, EI 339 and SS 183 accounted for slightly more than 98 percent of oil revenue and almost 88 of natural gas and natural gas revenue to TEL Partnership. Combined, these two properties represented approximately 97 percent of the Partnership's net profit.[18]

25. Chevron assessed the damage at EI 339 and moved forward with cleanup and abandonment operations. The costs associated with abandoning EI 339 depleted the special cost reserve set aside by TEL Partnership. In addition, the operators of EC 371 and WC 643 determined that these Royalty Properties contained insufficient reserves to justify restoration of production and proceeded to abandonment. Eventually, SS 183 was returned to full production in October 2009.[19]

26. Following review, Chevron decided not to re-develop EI 339 and entered into a farmout agreement with Arena Offshore, LP (Arena Offshore) in late 2009 to re-develop EI 339 subject to a reduction of 65 percent in Chevron's interest (and consequently TEL Partnership's interest) prior to the farmout.[20] Arena Offshore completed its obligations to earn its interest in EI 339 and production from the first well was realized during the fourth quarter of 2012.[21] By completing its obligations, Arena Offshore earned a 65 percent interest in EI 339 unburdened by the 25 percent net profits interest. Following the farmout, TEL Partnership had a significantly reduced net profits interest in EI 339. Since 2012, Arena Offshore drilled three additional wells at EI 339, two in 2013 and one in 2014.

27. Through 2008, revenues exceeded costs and special cost accruals for the Royalty Properties with excess revenue being distributed by TEL Partnership to TEL Trust according to its ownership (99.99 percent). From that income, TEL Trust recovered Trust expenses, set aside a cash reserve, and distributed $29.20 per unit since inception through January 2009. For the year ending 2008 (31 October 2008), TEL Trust distributed approximately $13.3 million

[16] MMS, 2008: Hurricane Gustav/Ike Activity Statistics Update, US Minerals Management Service press release 3865, 13 September 2008; Energo, 2010: Assessment of Damage and Failure Mechanisms for Offshore Structures and Pipelines in Hurricanes Gustave and Ike, Final Report, MMS Tar No. 642, Energo Engineering, Houston, TX, February 2010.
[17] TEL Trust 2008 10-K: TEL Offshore Trust SEC Form 10-K for Year Ended 31 December 2008, 31 March 2009.
[18] Net Profit Statement, Q3 2008.
[19] TEL Trust 2009 10-K: TEL Offshore Trust SEC Form 10-K for Year Ended 31 December 2009, 31 March 2010.
[20] TEL Trust 2010 10-K: TEL Offshore Trust SEC Form 10-K for Year Ended 31 December 2010, 31 March 2011; See also TEL0029264.
[21] TEL Trust 2012 10-K: TEL Offshore Trust SEC Form 10-K for Year Ended 31 December 2012, 01 April 2013.

($2.799 per unit) to the Unit Holders on $14.4 million of Royalty Income. In addition TEL Trust had approximately $2.2 million in cash reserves and $4.3 million in TEL Partnership's special escrow account.[22]

28. Due to the loss of revenue from EI 339 and its associated abandonment costs, total revenues have not exceeded the total costs for the Royalty Properties since late 2008. As a result, TEL Partnership has accumulated a net loss carryforward since that time. By July 2010, TEL Trust's share of the net loss carryforward was $6.3 million. In the fourth quarter of 2010, Chevron released TEL Trust's share of the special escrow account to reduce the net loss carryforward to $3.5 million.[23]

29. Lacking revenue from TEL Partnership, TEL Trust has been unable to pay any distributions to its Unit Holders since January 2009 and has depleted the Trust's cash reserves. In response, the Trustees sold part of the 25 percent net profits interest and borrowed funds from an affiliate of BONY Trust to pay TEL Trust expenses including Trustee compensation. At the direction of TEL Trustees, TEL Partnership sold 40 percent of its 25 percent net profits interest in two separate transactions effective August 2011 and August 2013 to RNR Production, Land and Cattle Company, Inc. (RNR).[24]

30. TEL Partnership closed the initial divestiture to RNR on 27 October 2011 whereby RNR acquired a five percent net profits interest in the Royalty Properties for $1,600,000. The effective date of the transaction was 01 August 2011. RNR closed its second acquisition of 5 percent of the net profits interest in the Royalty Properties on 31 October 2013 with the transaction being effective on 01 August 2013. This transaction grossed $1,200,000 for the TEL Partnership. The purchaser in these transactions acquired its proportionate share of any special cost escrow and net loss carryforward.[25] In both cases, TEL Trust received its proportionate share (99.99 percent) of the sale proceeds after paying sales commissions. Proceeds from these transactions were used solely to defray administrative expenses of TEL Trust. After the sales, TEL Trust owned its proportionate share of a 15 percent net profits interest in the Royalty Properties.

31. As of the 31 October 2015 reserve report for the Royalty Properties, only five of the properties were productive and contributing revenue to TEL Partnership. These properties were Eugene Island 339 (EI 339), Eugene Island 342 (EI 342), Ship Shoal 183 (SS 183), South Timbalier 36 (ST 36), and South Timbalier 37 (ST 37). Based on the reserve report, SS 183 is estimated to contribute approximately 84 percent of the estimated future net revenue of the Royalty Properties while EI 339 will contribute 15 percent of the total. The other three properties combined are estimated to contribute less than one percent of the future net revenue from the Royalty Properties.[26]

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[22] TEL Trust 2008 10-K.
[23] Net Profit Statement, Q3 2010; Net Profit Statement, Q4 2010.
[24] TEL Trust 2011 10-K: TEL Offshore Trust SEC Form 10-K for Year Ended 31 December 2011, 30 March 2012; TEL Trust 2013 10-K: TEL Offshore Trust SEC Form 10-K for Year Ended 31 December 2013, 31 March 2014.
[25] *Ibid.*
[26] D&M Report, 2015: TEL Offshore Trust Partnership Reserve Report as of 31 October 2015, dated 04 December 2015. This report was modified in a letter report dated 20 May 2016 for net interest errors in the Royalty Properties.

32. TEL Trust had a net loss carryforward of approximately $907,000 (for its 60 percent portion) as of October 2015 after reduction for its proportionate share of the quarterly net operating income of the Royalty Properties of approximately $130,000.[27] In addition, TEL Trust had an approximate negative cash balance of $730,000 after accounting for outstanding debt.[28] Based on this information, it was highly unlikely in October 2015 that the Royalty Properties would generate sufficient income to recoup the net loss carryforward, create the required special cost escrow, and make sufficient distributions to TEL Trust in the near future to fund its negative cash balance and create a cash reserve for future Trust expenses. Consequently, it was highly unlikely TEL Trust would be able to make any future distributions to its Unit Holders after repaying its outstanding liabilities as of October 2015.

33. In July 2014, BONY Trust and the Individual Trustees filed a petition in Travis County Probate Court No. 1 to modify the TEL Trust Agreement and terminate the Trust. This request was made due to the financial condition of the Trust. In January 2016, this request was granted in part where the Trust Agreement was modified and the Trustees ordered to sell TEL Trust's remaining 15 percent net profits interest in the Royalty Properties.[29]

34. TEL Partnership sold its remaining 15 percent net profits interest to Arena Energy, LP (Arena Energy) effective 1 February 2016 for $1,830,000. The transaction was closed on 24 June 2016 and netted $1,756,624 to TEL Trust's 99.99 percent interest after sales commission. As in the prior transactions, the purchaser acquired its proportionate share of any net loss carryforward and special escrow account.[30] After this divestiture, TEL Trust has no interest in the Royalty Properties and no obligation to pay any net loss carryforward on the Royalty Properties. By order of the Probate Court, TEL Trust is holding the proceeds from this divestment in a segregated account until final resolution of any remaining matters before the Court.[31]

Termination of TEL Trust

35. TEL Trust was created in January 1983 for the benefit of the stockholders of Tenneco Offshore who would become the initial Unit Holders of TEL Trust. The enabling document states the purposes of the Trust were: a) to protect and conserve, for the benefit of the Unit Holders, the net profits interest in the Royalty Properties, the Trust's interest in TEL Partnership, and any other assets held by the Trust; b) to receive cash from the Trust's interest in TEL Partnership and any other assets held by the Trust; and, c) to pay any liabilities incurred by the Trust in conduct of its business and to distribute the remaining amounts received by the Trust to the Unit Holders.[32]

Cobb & Associates made adjustments to the net revenue for the properties as TEL did not provide the detailed appendix to the revised report by assuming the major correction was with regard to EI 339.

[27] Net Profit Statement, Q4 2015.

[28] TEL Trust 2015 10-K.

[29] Original Petition, 2014; Final Judgement and Order, 2016: Cause No. C-1-PB-16-000096, In Re: TEL Offshore Trust, Travis County Probate Court No. 1, 15 January 2016.

[30] TEL Trust 8-K, 2016: TEL Offshore Trust SEC Form 8-K, 27 June 2016.

[31] Final Judgement and Order, 2016.

[32] TEL Trust, 1983.

36. The Trust Agreement called for the appointment of a Corporate Trustee and three Individual Trustees. The Trustees were responsible for administering the operations of TEL Trust and taking actions "to achieve the purposes of the Trust" with BONY Trust directing day-to-day operations of TEL Trust. As such, BONY Trust and the individual Trustees are responsible for operating TEL Trust in a manner that benefits the Unit Holders by protecting the value of the net profits interest in the Royalty Properties. As the only asset of TEL Trust was its 99.99 percent ownership in TEL Partnership and the only asset of TEL Partnership was its 25 percent net profits interest in the Royalty Properties, it was incumbent on BONY Trust to monitor the Royalty Properties (its source of revenue) and the finances of TEL Partnership.

37. While the general partner of TEL Partnership was given "full, exclusive and complete discretion in the operation of the Partnership," the Trustees were essentially serving in a role similar to that of a non-operating working interest owner in the Partnership.[33] As such, they should have acted in a manner similar to a "prudent operator" and monitored not only the current status of the Royalty Properties but also projections of future performance and estimates of future revenue for these properties, which had a direct impact on the financial condition of TEL Trust. In addition, they were responsible to monitor the annual cash flow and projections of future cash flow of TEL Trust in order to the optimize the value of the Trust's assets for the benefit of its Unit Holders.

38. By their nature, oil and gas interests are declining assets with a limited lifetime as there are finite oil and gas volumes associated with any oil and gas reservoir. As the oil and gas are produced, the future recoverable volumes decrease until the interest is no longer economic and the property is abandoned. In an effort to optimize the value of oil and gas properties, they are often divested several years prior to their economic limit.

39. In this case, TEL Partnership originally owned a 25 percent net profits interest in 20 oil and gas properties that have been subject to additional development and production over a 30 to 40 year period. During this period, a number of these properties reached their economic limit and were abandoned by their operators.[34] This process reduced the asset base and value of TEL Partnership as time progressed. In addition, the enabling documents for TEL Partnership and TEL Trust prohibited each entity from acquiring additional oil and gas interests on behalf of the Partnership or the Trust, which effectively limited the life of the Partnership and Trust to the interests in the 20 Royalty Properties.[35]

40. In early 2008, TEL Trust was in sound financial condition; however, the Royalty Properties were aging and annual production was declining. Only 8 of the original 20 Royalty Properties were producing in July 2008: EC 371, EI 339, EI 342, EI 343, SS 183, ST 36, ST 37, and WC 643. EI 339 and SS 183 each accounted for approximately 48.5 percent of the third quarter 2008 net profit from the Royalty Properties. The other six properties combined accounted for less than four percent of the total net profit for third quarter 2008.[36] At this time, cash flow for

[33] TEL Partnership, 1983.
[34] TEL Trust 2015 10-K.
[35] TEL Trust, 1983; TEL Partnership, 1983.
[36] Net Profit Statement, Q3 2008.

the Royalty Properties was highly concentrated in two properties making TEL Partnership and TEL Trust vulnerable to any major disruption to production at either asset.

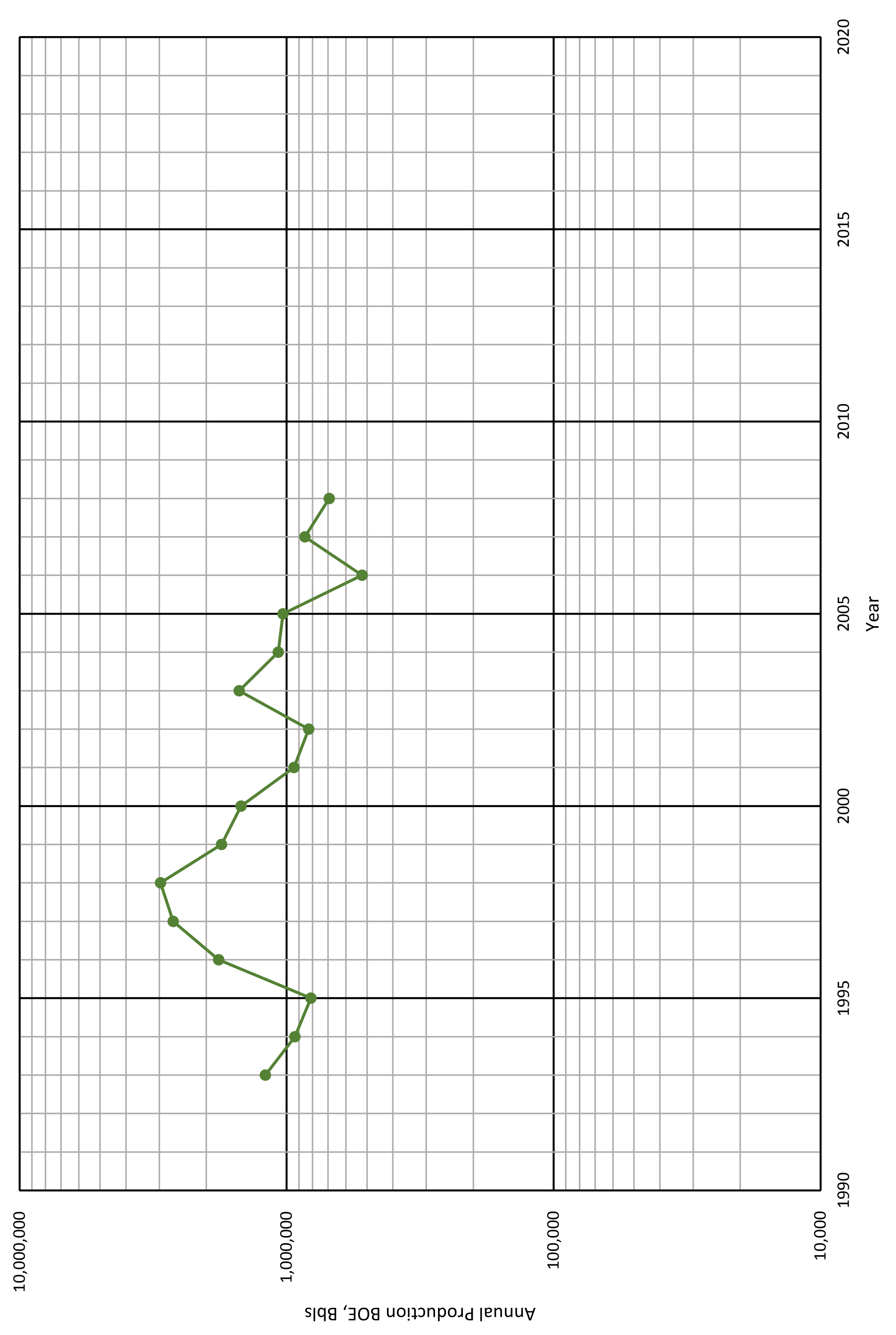
41. Table 2 tabulates the annual production from the Royalty Properties to the General Partner's interest from 1992 through 2015 on a barrel of oil equivalent (BOE) basis.[37] Fig. 1 presents the historical production for the period of 1992 through 2008, the historical production shows a downward trend as the properties age and the oil and gas resources are recovered. Peak production was achieved in 1998; however, by 2008 the production had declined to approximately one-quarter of the 1998 peak production representing a nominal decline rate of 15 percent per year. On a volume basis, annual production declined from 2,969,276 BOE in 1998 to 692,859 BOE in 2008.[38]

TABLE 2
Annual Production from Royalty Properties

Year	Oil, Bbls	Gas, Mcf	BOE, Bbls
1993	612,691	3,539,441	1,202,598
1994	548,669	2,300,991	932,168
1995	501,501	1,863,531	812,090
1996	769,722	6,164,224	1,797,093
1997	1,496,617	6,990,809	2,661,752
1998	1,301,651	10,005,749	2,969,276
1999	969,984	4,696,022	1,752,654
2000	794,154	4,126,774	1,481,950
2001	639,219	1,797,704	938,836
2002	664,323	975,639	826,930
2003	1,231,268	1,650,603	1,506,369
2004	589,647	2,907,514	1,074,233
2005	650,466	2,287,314	1,031,685
2006	421,763	600,477	521,843
2007	578,159	1,654,836	853,965
2008	421,958	1,625,408	692,859
2009	158,137	296,309	207,522
2010	168,985	327,444	223,559
2011	153,319	190,528	185,074
2012	114,704	153,133	140,226
2013	172,153	206,372	206,548
2014	136,141	235,790	175,439
2015	141,396	225,656	179,005

[37] BOE is a way to combine oil and gas volumes into one value for comparison purposes. Gas volumes are converted into oil-equivalent volumes by dividing the gas volume by 6 Mscf/BOE.
[38] TEL Trust Forms 10-K: Production data was compiled from TEL Offshore Trust's annual SEC Form 10-K for the years 1992 through 2015.

Fig. 1. Historical Production for Royalty Properties
1993 - 2008



42. Table 3 presents a similar tabulation of the annual reserve estimates from 1994 through 2015 for TEL Trust's net profits interest in the Royalty Properties. Volumes after the net profit sales in 2011 and 2013 have been reduced to account for the divestment of this interest to RNR. As shown in Fig. 2, historical reserve estimates had been declining since 1996 and by 2007 the reserve estimates were less than half the 1996 estimates, from 1,734 MBOE to 812 MBOE.[39]

TABLE 3
TEL Offshore Trust Net Reserves

Year	Oil, Bbls	Gas, Mcf	BOE, Bbls
1994	223,067	1,890,489	538,149
1995	335,975	1,439,323	575,862
1996	918,021	4,893,525	1,733,609
1997	716,389	3,623,357	1,320,282
1998	652,483	3,718,432	1,272,222
1999	613,052	3,349,524	1,171,306
2000	492,470	2,202,595	859,569
2001	405,863	2,419,142	809,053
2002	468,873	2,030,033	807,212
2003	538,444	2,060,267	881,822
2004	436,973	2,080,390	783,705
2005	407,804	1,940,162	731,164
2006	390,369	2,233,123	762,556
2007	442,004	2,217,654	811,613
2008	219,142	1,387,152	450,334
2009	137,464	868,505	282,215
2010	180,070	1,216,438	382,810
2011	100,424	513,096	185,940
2012	133,338	686,483	247,752
2013	64,050	495,045	146,558
2014	55,121	422,816	125,590
2015	22,920	221,323	59,807

43. While production and reserve decreases for the Royalty Properties are dramatic and an indicator of the Properties remaining life, annual cash flow projections for TEL Trust are more telling. Using the 2005, 2006, and 2007 D&M reserve reports and annual expenses for the Trust, cash flow projections by year were prepared for TEL Trust as shown in Tables 4-6.[40] The analysis indicates TEL Trust would go cash flow negative in 2011 for forecasts based on the 2005 and 2006 reports and 2012 based on the 2007 report. This analysis clearly indicates TEL Trust had limited remaining economic life in 2008.

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[39] D&M Reserve Reports: This information was compiled from D&M's annual letter reserve report contained in TEL Trust's annual SEC Form 10-K filing.

[40] The cash flows were prepared by using D&M's cash flow projections shown in the Appendix of the annual reserve reports and using a three-year average of Trust expenses obtained from TEL Trust's annual SEC Form 10-K.

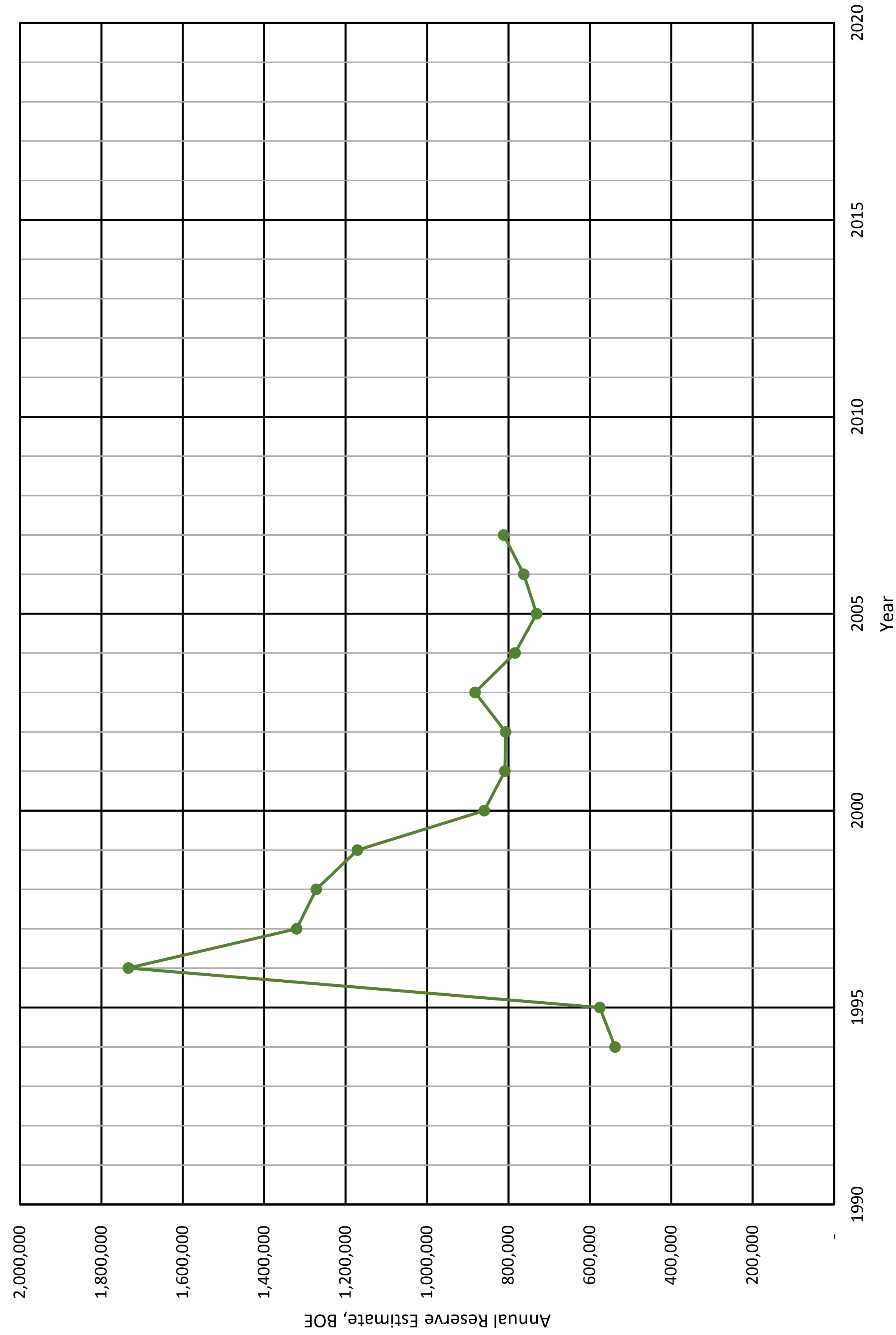

Fig. 2. TEL Trust's Net Reserve Estimates
1994 - 2007

TABLE 4 TEL Offshore Trust 2005 Net Cash Flow Estimate				
Year	**Partnership Revenue, $**	**TEL Trust Share, $**	**Trust Expenses, $**	**Trust NCF, $**
2006	8,018,048	8,017,246	454,734	7,562,512
2007	11,409,963	11,408,822	454,734	10,954,088
2008	13,957,619	13,956,223	454,734	13,501,489
2009	8,962,527	8,961,631	454,734	8,506,897
2010	4,604,865	4,604,405	454,734	4,149,671
2011	653,074	653,009	454,734	198,275
2012	197,478	197,458	454,734	(257,276)
2013	9,517	9,516	454,734	(445,218)
2014	144,053	144,039	454,734	(310,695)

Note: Partnership Revenue obtained from D&M's reserve report as of 31 October 2005 and Trust Expenses is one-third of Trust Reserve obtained from TEL Offshore Trust's SEC Form 10-K for calendar-year 2005. D&M's cash flow summary includes the special cost escrow.

TABLE 5 TEL Offshore Trust 2006 Net Cash Flow Estimate				
Year	**Partnership Revenue, $**	**TEL Trust Share, $**	**Trust Expenses, $**	**Trust NCF, $**
2007	8,456,995	8,456,149	541,288	7,914,861
2008	7,774,163	7,773,386	541,288	7,232,098
2009	11,416,872	11,415,730	541,288	10,874,442
2010	6,744,325	6,743,651	541,288	6,202,363
2011	3,374,639	3,374,302	541,288	2,833,014
2012	354,595	354,560	541,288	(186,728)
2013	124,235	124,223	541,288	(417,065)
2014	85,257	85,248	541,288	(456,040)

Note: Partnership Revenue obtained from D&M's reserve report as of 31 October 2006 and Trust Expenses is one-third of the Trust Reserve obtained from TEL Offshore Trust's SEC Form 10-K for calendar-year 2006. D&M's cash flow summary includes the special cost escrow.

TABLE 6 TEL Offshore Trust 2007 Net Cash Flow Estimate				
Year	**Partnership Revenue, $**	**TEL Trust Share, $**	**Trust Expenses, $**	**Trust NCF, $**
2008	15,316,356	15,314,824	627,908	14,686,916
2009	15,857,176	15,855,590	627,908	15,227,682
2010	11,706,733	11,705,562	627,908	11,077,654
2011	6,664,237	6,663,571	627,908	6,035,663
2012	4,072,916	4,072,509	627,908	3,444,601
2013	475,561	475,513	627,908	(152,395)
2014	375,289	375,251	627,908	(252,657)
2015	161,558	161,542	627,908	(466,366)
2016	121,394	121,382	627,908	(506,526)
2017	42,126	42,122	627,908	(585,786)

Note: Partnership Revenue obtained from D&M's reserve report as of 31 October 2007 and Trust Expenses is one-third of Trust Reserve obtained from TEL Offshore Trust's SEC Form 10-K for calendar-year 2007. D&M's cash flow summary includes the special cost escrow.

44. The production disruption and physical damage to the Royalty Properties caused by Hurricane Ike in September 2008 had a devastating impact on the Royalty Properties. In addition, it had a detrimental impact on the financial condition of TEL Partnership and TEL Trust.

45. The damage to EI 339 was catastrophic requiring the General Partner to completely abandon and clean up the property. After review, Chevron determined by December 2009 that it would not redevelop EI 339. As a result, Chevron farmed out EI 339 to Arena Offshore whereby Arena Offshore could earn a 65 percent interest in EI 339 unburdened by the net profits interest by completing its drilling obligations.[41] This would result in TEL Partnership losing 65 percent of its net profits interest in EI 339, if production was obtained and Arena earned its position in EI 339, which it eventually did in October 2012.[42]

46. The operators of EC 371 and WC 643 also reviewed their assets following Hurricane Ike and determined estimated reserves did not warrant redevelopment of these Royalty Properties. The underlying leases for these two Royalty Properties expired in the first half of 2010.[43] The loss of EC 371, EI 339, and WC 643 represented approximately 50 percent of the total net profit of the Royalty Properties just prior to Hurricane Ike.[44]

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[41] TEL Trust 2010 10-K.
[42] TEL Trust 2012 10-K:
[43] TEL Trust 2010 10-K:
[44] Net Profit Statement, Q3 2008.

47. In May 2009, D&M issued a reserve report for TEL Partnership's interest in the Royalty Properties.[45] The report as of 31 March 2009 indicated the Partnership was negatively impacted by the loss of EI 339 and the associated P&A costs. At this point in time after accounting for all costs and the special cost escrow, the reserve report projected the Royalty Properties would generate negative revenue, suggesting no future revenue to TEL Trust from TEL Partnership. This report served notice to BONY Trust and the Individual Trustees that TEL Trust was in a serious financial crisis requiring immediate action by the Trustees to protect the net profits interest for the benefit of TEL Trust Unit Holders.

48. By October 2009, only five of the Royalty Properties were producing oil and gas with SS 183 providing 97 percent of the net profit for the five properties.[46] Excluding any net loss carryforward, special cost escrow, Trust cash reserve, and the non-producing properties in process of being abandoned, the producing Royalty Properties generated $3.2 million of net operating income in the fourth quarter of 2009 resulting in a net operating income attributable to TEL Trust of approximately $800,000 for the quarter.[47] After adjusting for Trust expenses, the net distributable income would have been $556,000 (absent the net loss carryforward, special cost escrow, and Trust cash reserve) or less than 12 cents per unit. This income was only a small fraction (one-tenth) of the $5.5 million or $1.15 per unit the Trust distributed for the quarter prior to Hurricane Ike.[48] This contrast in potential distributions prior to and after Hurricane Ike emphasizes the negative impact the hurricane had on the financial condition of TEL Trust.

49. By the end of the Partnership's fourth quarter 2009 (31 October 2009), TEL Partnership had accumulated a net loss carryforward of $5,536,318 and $11.2 million net was yet to be spent for abandonment costs on EI 339 P&A.[49] If the producing Royalty Properties could continue to net $800,000 per quarter, it would take a little over five years (21 quarters) before TEL Partnership would become cash flow positive. TEL Trust would have no revenue during this period and would exhaust its cash reserves and the Trust would be cash deficient before TEL Partnership would begin making cash distributions to TEL Trust in early 2015. Based on TEL Trust's expenses for 2009, the Trust would have accumulated a deficit of approximately $3.6 million before receiving any revenue from TEL Partnership. This deficit would have to be repaid prior to any distributions to the Unit Holders requiring an additional 6 quarters for TEL Trust to recoup its deficit. Consequently, it would take over six years to mid-2016 before TEL Trust might be in a position to be cash flow positive and be able to make distributions to Unit Holders.

50. Table 7 details this basic exercise in projecting potential future cash flow for TEL Trust assuming the Royalty Properties continue to generate approximately $800,000 in quarterly revenue, which is optimistic. Fig. 3 graphically depicts the Trust's revenue and expenses by year along with its cumulative cash position from 2009 through 2016. As shown, it is mid-

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[45] D&M Report, 2009a: TEL Offshore Trust Partnership Report as of 31 March 2009, dated 15 May 2009.
[46] Net Profit Statement, Q4 2009.
[47] *Ibid*.
[48] TEL Trust 2008 10-K.
[49] Net Profit Statement, Q4 2009; TEL Trust, 2008b: TEL Offshore Trust Announces Fourth Quarter 2008 Distribution, press release dated 19 December 2008.

2016 before TEL Trust would be in a positive cash position to pay any distributions to Unit Holders. This simple exercise clearly indicates TEL Trust was severely damaged by Hurricane Ike and its potential to generate sufficient cash flow for distributions was years in the future. It also suggests that TEL Trust would become insolvent in early 2011, indicating BONY Trust and the Individual Trustees should have taken action no later than year-end 2009 to protect the value of TEL Trust for the benefit of the Unit Holders.

TABLE 7
TEL Offshore Trust
Cash Flow Projection as of Year-End 2009

Year	Trust Income, $	EI 339 P&A, $	Net Loss Carried, $	Trust Revenue, $	Trust Expenses, $	Trust Cash Position, $
2009			(5,228,528)			1,263,080
2010	3,195,156	5,600,000	(7,663,372)	---	971,545	291,535
2011	3,195,156	5,600,000	(10,038,215)	---	971,545	(680,010)
2012	3,195,156		(6,843,059)	---	971,545	(1,651,555)
2013	3,195,156		(3,647,902)	---	971,545	(2,623,100)
2014	3,195,156		(452,746)	---	971,545	(3,594,645)
2015	3,195,156		2,742,411	2,742,411	971,545	(1,823,779)
2016	3,195,156		3,195,156	3,195,156	971,545	399,832

Note: Trust Income estimated from Q4 2009 Net Profit Statement. EI 339 P&A costs estimated from 19 December 2008 press release less funds expended through Q4 2009. Net Loss Carryforward obtained from Q4 2009 Net Profit Statement and excludes non-Chevron properties to be abandoned. Trust Expenses and Trust cash position obtained from TEL Offshore Trust's SEC Form 10-K for calendar-year 2009.

51. The limited life of TEL Trust prior to Hurricane Ike, cleanup costs associated with EI 339, and the loss of 50 percent of the income from the Royalty Properties was an indication that the financial condition of TEL Trust was in jeopardy. Figs. 4 and 5 demonstrate the impact of Hurricane Ike on the Royalty Properties and TEL Partnership. As shown in Fig. 4, production from the Royalty Properties decreased by 70 percent from 2008 (pre-Hurricane Ike) to 2009 (post-Hurricane Ike) and has not recovered. Fig. 5 indicates the net TEL Trust reserves decreased by 45 percent for the same period and continue to decrease on an annual basis.

52. As the D&M reserve reports are limited to proved reserves, there was a possibility the Royalty Properties had potential upside value. In this regard, a meeting was held with D&M personnel who had evaluated the Royalty Properties for a number of years. In the process of this review, access to information supplied by Chevron in the preparation of the annual D&M reserve report was provided. This data included historical production, lease operating expenses, product differentials, and P&A costs. In addition, Chevron makes available engineering and geological information, well logs, wellbore schematics, and completion and well test data for recompletions or new wells drilled on the Royalty Properties. During the course of the project, D&M indicated that Chevron has been open with the exchange of information and responsive to its requests.

Fig. 3. TEL Trust's Projected Cash Position

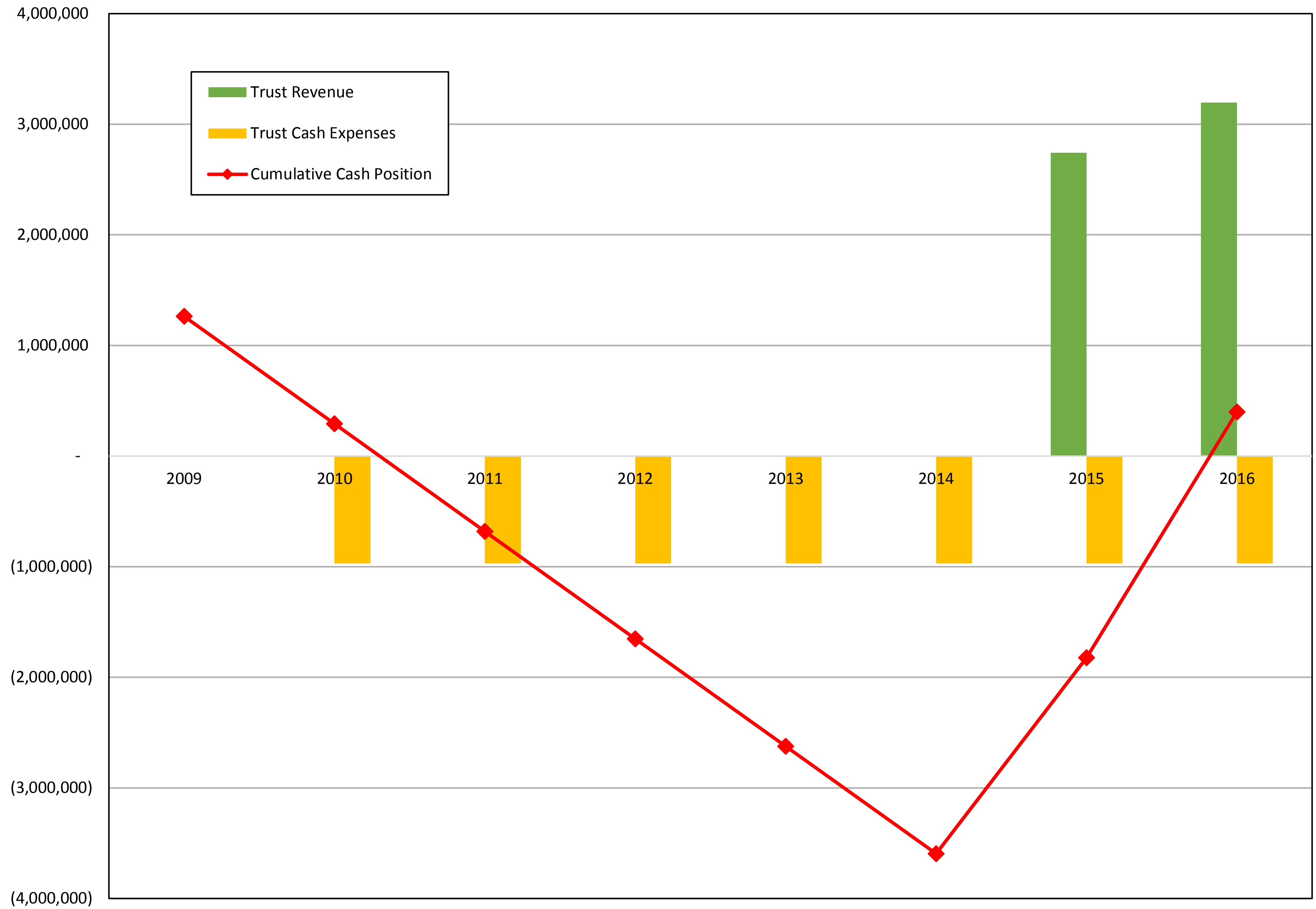


**Fig. 4. Historical Production for Royalty Properties
1993 - 2015**

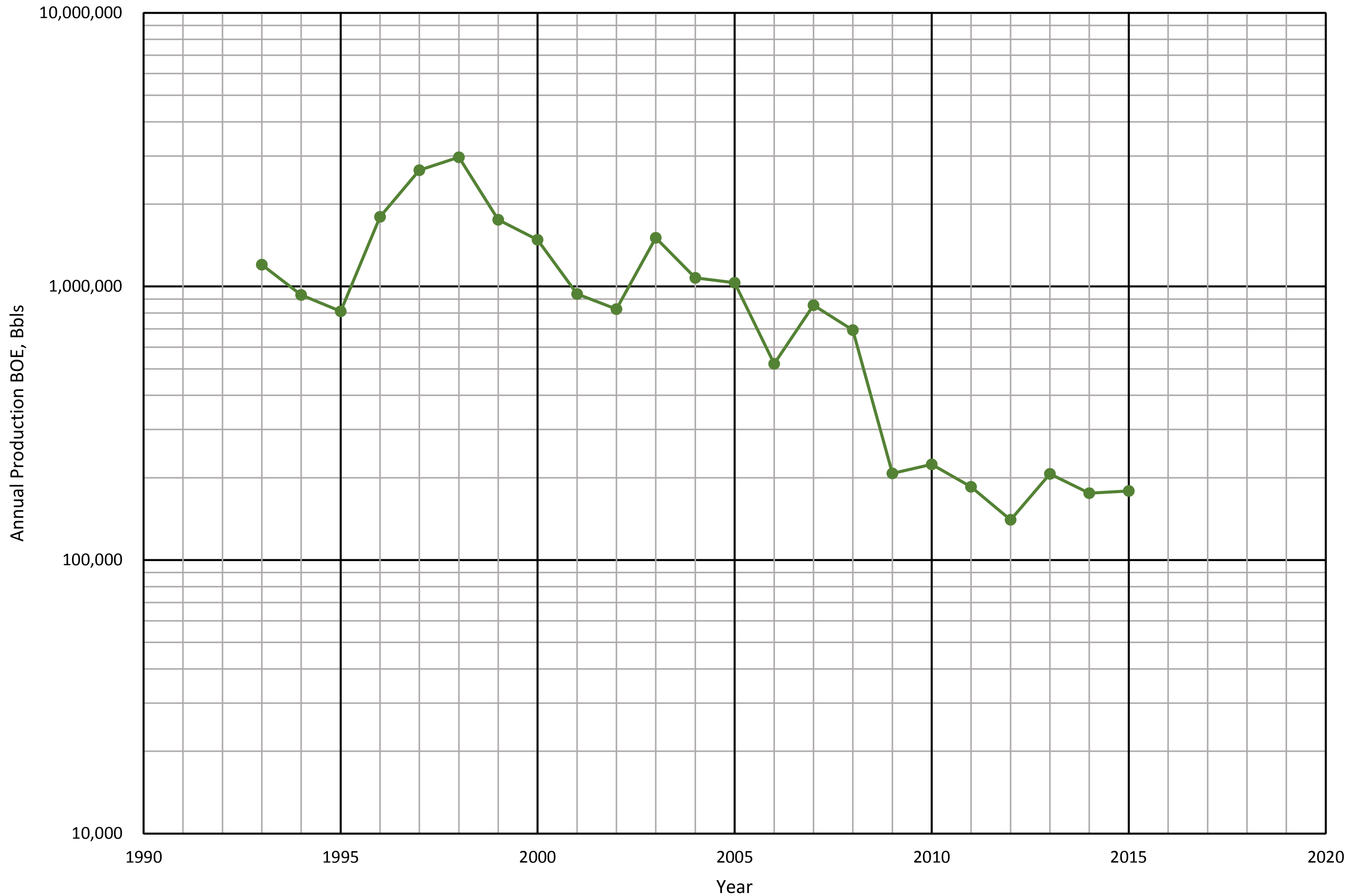
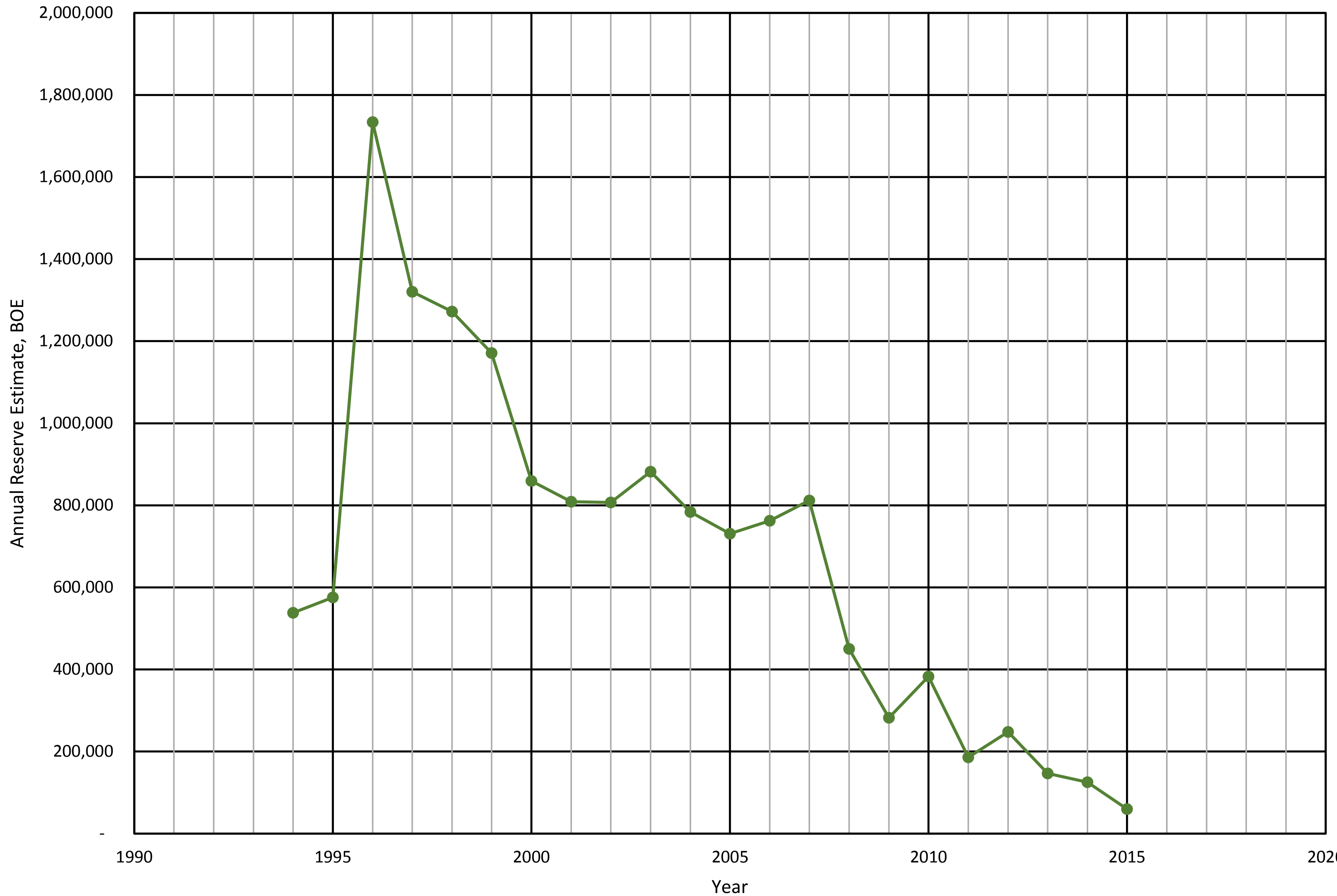


Fig. 5. TEL Trust's Net Reserve Estimates
1994 - 2015



53. In addition, D&M provided access to its geologic mapping, well logs, and analyses of potential resources associated with the remaining producing Royalty Properties, which was well documented and supported. While the reserve reports are limited to proved reserves, D&M's work papers have documented non-proved opportunities in the properties. For example, EI 339 had been well developed with a number of wells prior to Hurricane Ike; however, there appears to be limited upside potential for redevelopment. To support that observation, the development work undertaken by Arena Offshore under the farmout agreement has been the drilling of four wells that are essentially replacement wells in previously producing reservoirs. SS 183 is also a well-developed field with a number of producing wells. There appears to be some potential in behind pipe recompletions; however, these are not significantly large opportunities based on the geologic mapping.

54. The D&M reserve report effective as of 31 October 2008 (post-Hurricane Ike) did not include reserves attributed to EI 339, if any, nor cleanup and P&A costs for the property as Chevron was still evaluating the property for redevelopment.[50] Based on information provided to TEL Trust by Chevron regarding the estimated P&A costs for EI 339, an adjusted cash flow for TEL Trust was prepared based on the D&M reserve report and shown in Table 8.[51] D&M's report suggests the Royalty Properties had a seven year life based on cash flow; however, the first two years provide negative cash flow due to the EI 339 P&A cost burden. On a cumulative cash flow basis, it would take five years to recover the P&A costs with the last two years generating a positive cumulative cash flow for the seven year period of $839,000. This cash flow analysis indicates the precarious financial condition of TEL Trust following Hurricane Ike.

TABLE 8
TEL Offshore Trust
2008 Adjusted Net Cash Flow Forecast

Year	Partnership Revenue, $	TEL Trust Share, $	P&A Adjustment, $	Trust Expenses, $	Adjusted NCF, $	Cumulative NCF, $
2009	187,661	187,642	13,861,114	744,430	(14,417,902)	(14,417,902)
2010	1,116,511	1,116,399	4,312,069	744,430	(3,940,099)	(18,358,001)
2011	7,095,919	7,095,209		744,430	6,350,779	(12,007,222)
2012	7,511,914	7,511,163		744,430	6,766,733	(5,240,489)
2013	4,470,441	4,469,994		744,430	3,725,564	(1,514,925)
2014	2,493,016	2,492,767		744,430	1,748,337	233,412
2015	1,350,287	1,350,152		744,430	605,722	839,134

Note: Partnership Revenue obtained from D&M's reserve report as of 31 October 2008 and Trust Expenses is one-third of Trust Reserves obtained from TEL Offshore Trust's SEC Form 10-K for calendar-year 2008. D&M's report excludes reserves and costs associated with EI 339. D&M's cash flow summary includes the special cost escrow. P&A estimate was obtained from TEL Trust's press release on 19 December 2008 (See Reference 48).

[50] D&M Report, 2008: TEL Offshore Trust Partnership Reserve Report as of 31 October 2008, dated 16 March 2009.
[51] TEL Trust, 2008b: TEL Offshore Trust Announces Fourth Quarter 2008 Distribution, press release dated 19 December 2008.

55. During the cleanup of EI 339, TEL Partnership depleted the special cost escrow and incurred a significant net loss carry forward. As TEL Partnership had no revenue to distribute, TEL Trust received no income by which to pay its liabilities. As a result, TEL Trust depleted its cash reserves following Hurricane Ike paying administrative costs and eventually sold a portion of its net profits interest to pay TEL Trust liabilities including Trustee compensation.

56. Table 9 provides a quarterly summary of the special cost escrow, cash reserve, and net loss carryforward for TEL Trust by quarter from 2008 through 2015.[52] As shown in the table, the special cost escrow was $5.4 million in Q1 2008 and was reduced to $1,000 in Q4 2010 when Chevron released $4.3 million to defray a portion of TEL Trust's P&A obligation for EI 339. The Trust's cash reserve went from $2.2 million to approximately $352,000 during the same period as TEL Partnership accumulated a net loss carryforward. TEL Trust's share of that net loss carryforward went from zero in Q1 2008 to $3.5 million in Q4 2010.

57. The financial condition of TEL Trust continued to deteriorate until the Trustees borrowed funds from an affiliate of BONY Trust to pay Trust expenses including Trustee compensation. Due to its financial condition, TEL Trust has been unable to make a distribution to its Unit Holders since January 2009 (Hurricane Ike) covering 28 quarters through January 2016.[53]

58. While it would take time to evaluate the long-term effects of Hurricane Ike on the Royalty Properties, it was soon clear that future TEL Trust distributions would be affected. In its 25 March 2009 press release, TEL Trust "announced there would be no trust distribution for the first quarter of 2009" and warned "there may not be sufficient net proceeds from the royalty properties to make a particular distribution" in the future.[54] The March 2009 D&M reserve report projected zero net proceeds from the Royalty Properties for distribution to TEL Partnership during the same time frame.[55] The Trust stated the following in its second quarter 2009 SEC Form 10-Q: "There are not likely to be sufficient Net Proceeds from the Royalty Properties for the Trust to make a regularly scheduled quarterly distribution to Unit holders for the foreseeable future."[56] With this information, it was clear TEL Trust faced financial difficulties and the Royalty Properties (and the Trust) were approaching their economic life.

59. To further emphasize this point, the Royalty Properties had experienced hurricanes in the past, most recently with Hurricanes Katrina and Rita in August and September 2005. These hurricanes disrupted production and caused damage to the Royalty Properties that resulted in no distributions from TEL Partnership and the suspension of distributions to TEL Trust Unit Holders. In this case, the suspension of TEL Trust distributions covered only three quarters.[57] During his deposition, the representative of BONY Trust stated that the Royalty Properties had

[52] Information summarized in this table have been obtained from TEL Trust's annual Forms 10-K, TEL Trust's quarterly Forms 10-Q, and quarterly Net Profit Statements.
[53] TEL Trust 2015 10-K; TEL Trust, 2016.
[54] TEL Trust, 2009: TEL Offshore Trust Announces There Will Be No First Quarter 2009 Distribution, press release dated 25 March 2009.
[55] D&M Report, 2009a.
[56] TEL Trust 10-Q, 2009: TEL Offshore Trust SEC Form 10-Q for Quarter Ended 30 June 2009, 07 August 2009.
[57] TEL Trust 2005 10-K: TEL Offshore Trust SEC Form 10-K for Year Ended 31 December 2005, 31 March 2006; TEL Trust 2006 10-K: TEL Offshore Trust SEC Form 10-K for Year Ended 31 December 2006, 02 April 2007.

Table 9
Summary of TEL Offshore Trust
Special Cost Escrow, Cash Reserve, and Net Loss Carryforward

Period-Year	Cost Escrow, $	Cash Reserve, $	Net Loss Carryforward, $
Q1-2008	5,395,376	2,245,447	---
Q2-2008	5,353,559	2,136,178	16,683
Q3-2008	4,335,777	2,148,774	17,065
Q4-2008	4,325,503	2,233,291	62,159
Q1-2009	4,305,190	1,902,275	1,174,900
Q2-2009	4,306,735	1,691,500	3,384,630
Q3-2009	4,306,985	1,456,936	4,946,810
Q4-2009	4,306,275	1,263,080	5,536,317
Q1-2010	4,306,084	1,078,726	6,066,485
Q2-2010	4,306,383	810,935	5,853,105
Q3-2010	4,306,846	573,151	6,336,608
Q4-2010	1,000	352,017	3,546,139
Q1-2011	1,000	67,459	3,503,431
Q2-2011	1,000	47,625	3,684,455
Q3-2011	1,000	6,580	4,167,984
Q4-2011	1,000	944,917	4,686,930
Q1-2012	1,000	778,115	5,444,265
Q2-2012	1,000	454,894	5,976,141
Q3-2012	1,000	326,494	6,738,912
Q4-2012	1,000	223,925	6,292,697
Q1-2013	1,000	47,565	5,552,002
Q2-2013	1,000	(28,441)	5,159,205
Q3-2013	1,000	(147,512)	4,443,633
Q4-2013	1,000	873,640	3,019,944
Q1-2014	1,000	384,715	2,955,982
Q2-2014	1,000	207,679	2,570,783
Q3-2014	1,000	19,721	2,160,733
Q4-2014	1,000	(244,354)	1,675,562
Q1-2015	1,000	(329,955)	1,383,495
Q2-2015	1,000	(472,844)	1,232,370
Q3-2015	1,000	(569,609)	1,036,443
Q4-2015	1,000	(728,845)	906,266

experienced hurricanes in the past that caused damage, disrupted production, and led to periods of no revenue from TEL Partnership; however, in those instances TEL Trust started receiving revenue in one or two quarters.[58] Once the Trustees observed that TEL Trust distributions would be suspended for more than four quarters (the end of 2009), BONY Trust and the Individual Trustees should have realized the impact of Hurricane Ike was more severe than previous hurricanes and that TEL Trust had reached its economic life and taken actions to "protect" the value of the net profits interest for the benefit of the Unit Holders.

60. Based on the analysis of historical production data, historical reserve estimates, upside potential of the Royalty Properties, estimates of TEL Trust's future cash flows, D&M's March 2009 reserve report reflecting zero future revenue for TEL Partnership, and Chevron's notice of its intent to farmout EI 339 with a 65 percent reduction in ownership, it should have been clear to BONY Trust and the Individual Trustees that TEL Trust had reached its economic life no later than year-end 2009. In my opinion, BONY Trust and the Individual Trustees should have taken action to monetize the value of TEL Partnership for the benefit of TEL Trust Unit Holders by selling the 25 percent net profits interest in the Royalty Properties by year-end 2010.

Damages

61. BONY Trust and the Individual Trustees should have divested the 25 percent net profits interest in 2010 as it was clear as early as May 2009 and no later than year-end 2009 the assets supporting TEL Trust were approaching their economic life. Hurricane Ike had a devastating impact on the Royalty Properties resulting in three of the eight producing properties being abandoned. This loss of revenue from the Royalty Properties and the associated net loss carryforward for P&A expenses negatively impacted the cash flow of TEL Trust. Any delay in monetizing the 25 percent net profits interest only exposed TEL Trust to additional administrative expenses incurred by the Trustees and to a reduced value of the net profits interest as the Royalty Properties continued to age.

62. By failing to monetize TEL Trust's net profits interest in a timely manner, the Unit Holders were negatively impacted and damaged by BONY Trust's and the Individual Trustees' failure to act in a timely manner. In estimating damages, it has been assumed the 25 percent net profits interest would have been divested during calendar-year 2010 with net proceeds distributed to the Unit Holders.

63. An estimate of value for TEL Trust can be based on D&M's annual reserve report, which reported annual reserves and the ten percent discounted cash flow associated with TEL Partnership's interest in the Royalty Properties as of 31 October. D&M's annual analysis incorporated interest credits on any special cost escrow and interest charges for any net loss carryforward. In addition, it included a special three-percent management fee allowed by the Conveyance and credit for the special cost escrow; however, it did not incorporate any net loss carryforward.[59]

[58] Ulrich, 2016: Deposition of the Bank of New York Mellon Trust Company, N.A. Corporate Representative Michael Ulrich, page 46, lines 4-11, 14 July 2016, Austin, TX.
[59] Conveyance, 1983.

64. While the D&M reserve report serves as the basis of this damage model, actual purchase offers for the net profits interest can vary between buyers based on their perception of the market. For example, the D&M report uses constant product prices and a potential purchaser would likely evaluate the net profits interest assuming a higher oil or gas price or escalate product prices over time resulting in a higher value for the net profits interest. While this analysis has focused on the ten percent discounted value of the net cash flow stream, purchasers sometime use lower discount rates when evaluating proved producing properties like the Royalty Properties or when evaluating royalty interests. In these examples the value of the net profits interest would be higher than those estimated in this analysis using the ten percent discount cash flow.

65. Assuming the net profits interest was sold in 2010, D&M's 2010 reserve report provides a base value for TEL Partnership's share of the Royalty Property at that time.[60] Based on proved reserves only and including P&A costs for EI 339, D&M estimated the ten percent discounted cash flow for the 25 percent net profits interest to be slightly more than $15.0 million. After adjusting for the three percent management fee, interest on the net loss carryforward and special cost escrow, the Trust's ten percent discounted cash flow is almost $16 million. This value needs to be adjusted for any net loss carryforward and a four percent marketing commission in divesting the Royalty Properties. In addition, TEL Trust had a cash reserve of $352,017 at the end of the year.

66. Making these adjustments using information available contained in TEL Trust's 2010 10-K results in a damage estimate of $12.3 million.[61] However, there appears to be some inconsistencies in the 10-K relative to D&M's report with the special cost escrow and the net loss carryforward provided in the Trust's net profit statement for the period ending October 2010.[62] In particular, the D&M report includes the special escrow account in its analysis while the 10-K indicates a net cash loss carryforward after adjusting for the special cost escrow. This discrepancy results in an elevated ten percent discounted cash flow reported in the 10-K compared to the discounted cash flow determined using the proper special cost escrow and net loss carryforward values. Using information consistent with D&M's reserve report results in a damage estimate of $8.1 million to TEL Trust Unit Holders as of 2010.

67. If the net profits interest was not sold in 2010, a similar damage estimates can be made for any given year using the same procedure. Assuming the net profits interest in the Royalty Properties were sold in 2011 or 2012, one would use D&M's reserve report for those years.[63] During these two years, D&M's report reduced TEL Partnership's net profits interest from 25 percent to 20 percent to account for the sale of a five percent interest to RNR that occurred effective 01 August 2011. In this sale, as with two additional net profits interest divestments,

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[60] D&M Report, 2010: TEL Offshore Trust Partnership Reserve Report as of 31 October 2010, dated 21 January 2011.
[61] TEL Trust 2010 10-K.
[62] Net Profit Statement, Q4 2010.
[63] D&M Report, 2011: TEL Offshore Trust Partnership Reserve Report as of 31 October 2011, dated 31 January 2012; D&M Report, 2012: TEL Offshore Trust Partnership Reserve Report as of 31 October 2012, dated 26 February 2013.

the assignment of the net profits interest to the purchasers included the assignment of its proportional interest in any special cost escrow and any net loss carryforward.[64]

68. Assuming the entire 25 percent net profits interest was owned by the TEL Partnership in both 2011 and 2012, the ten percent discounted cash flow attributable to TEL Trust after making the required adjustments to the D&M analysis was $11.6 million and $15.5 million, respectively. These values must be adjusted for any net loss carryforward, the anticipated marketing commission, and any cash reserve held by TEL Trust. The Trust had cash deficits of approximately $542,100 and $1,263,200 for 2011 and 2012, respectively, ignoring the RNR acquisition. After accounting for these additional costs, damages to the Unit Holders are estimated to be $5.0 million in 2011 and $6.1 million in 2012. If one assumes the net profits interest was sold in 2009, the damage estimate would be $6.3 million based on D&M's October 2009 reserve report.[65]

69. As noted earlier, the Trustees sold five percent of the 25 percent net profits interest to RNR in late 2011. The purchaser paid $1.6 million for its five percent net profits interest, which when adjusted to reflect a purchase price for the entire net profits interest results in an $8.0 million purchase price for the 25 percent net profits interest. This purchase price is consistent with the estimated value of the net profits interest using the 2010 D&M report after the adjustments and a premium to the estimated value reflected using the 2011 D&M reserve report.

70. The damage estimates presented in the preceding paragraphs were based on the underlying annual cash flow projections prepared by D&M that corresponds to its annual letter report summary included in TEL Trust's annual SEC 10-K filings for the Chevron operated properties only. The special cost escrow was incorporated as a credit against the annual capital expenditures anticipated during the life of the Royalty Properties distorting the annual cash flow projection, resulting in a modified cash flow compared to the cash flow obtained if these costs were included as they were actually spent during the life of the project.

71. Using D&M's actual cash flow projections for the properties and removing those costs and revenues associated with the non-Chevron operated properties, annual cash flows were recalculated and a revised ten percent discounted cash flow determined for TEL Trust's share of the Partnership. This discounted value was then adjusted for any special cost escrow, net loss carryforward, and Trust cash reserves (or deficit). Performing these calculations results in a damage estimate of $9.2 million if the net profits interest was divested in 2010. The damage estimates total $6.9 million for 2009, $5.2 million for 2011, and $6.7 million for 2012 assuming the net profits interest were divested in 2009, 2011, or 2012, respectively. It should be noted that damage estimates made with this approach using the 2010 D&M report and the TEL's 2010 10-K without correcting for the proper net loss carryforward results in a damage estimate of $13.3 million.

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[64] Partial Assignment of ORRI, 2011: TEL Partnership to RNR dated 27 October 2011; Partial Assignment of ORRI, 2013: TEL Partnership to RNR dated 29 October 2013; Assignment of ORRI, 2016; TEL Partnership to Arena Energy dated 22 June 2016.

[65] D&M Report, 2009b: TEL Offshore Trust Partnership Reserve Report as of 31 October 2009, dated 01 February 2010.

72. In my opinion, TEL Trust Unit Holders suffered damages ranging from at least \$8.1 million to \$9.2 million caused by BONY Trust's and the Individual Trustees' failure to divest the 25 percent net profits interest during 2010. This estimate of damages does not include interest on the damages for the period from 2010 to date and it would not be subject to any reduction due to Trust expenses (or loans to pay liabilities) incurred after 2010. The market valued TEL Trust at \$12.4 in the third quarter and \$8.5 million in the fourth quarter of 2010 after applying a four percent discount for a sales commission. These market values are consistent with the damage estimates determined from D&M's reserve report for 2010.[66]

73. Assuming the net profits interest was not divested in 2010, damages have been estimated for 2009, 2011, and 2012. Damages range from \$6.3 million to \$6.9 million in 2009, \$5.0 million to \$5.2 million in 2011, and \$6.1 million to \$6.7 million in 2012.

Summary of Opinions

74. TEL Trustees had an obligation to protect the net profits interest in the Royalty Properties for the benefit of TEL Trust Unit Holders. This required active management of TEL Trust and regular monitoring of the condition of the Royalty Properties and the future financial condition of TEL Partnership and TEL Trust by BONY Trust and the Individual Trustees.

75. The Royalty Properties were approaching their economic life in 2008 based on their production performance, reserve evaluation, and future cash flow forecasts. Following the disruption to production and loss of several Royalty Properties to Hurricane Ike, it was clear by May 2009 and no later than December 2009 that TEL Partnership and TEL Trust were in precarious financial condition. It is my opinion, based on the status of the Royalty Properties and the financial condition of TEL Trust, BONY Trust and the Individual Trustees should have made the decision no later than year-end 2009 to sell the 25 percent net profits interest.

76. In my opinion, TEL Trust Unit Holders were damaged by BONY Trust's and the Individual Trustees' delay in divesting the 25 percent net profits interest. Based on my analysis, the damages suffered by the Unit Holders range from at least \$8.1 million to \$9.2 million if the net profits interest was sold in 2010. Assuming the net profits interest was sold in 2009, 2011, or 2012, damages range from \$5.0 million to \$6.9 million depending on the year the 25 percent net profits interest was sold.

[66] NASDAQ Historical Price Data: TELOZ (TEL Offshore Trust) data obtained from website accessed on 02 August 2016, http://www.nasdaq.com/symbol/teloz/historical. Using historical sales volume and closing price data from NASDAQ, a volume weighted average closing price (VWAP) can be determined for any period of time. Market value was determined by multiplying the VWAP for the third quarter (\$2.7232/unit) and fourth quarter of 2010 (\$1.8559/unit) by the outstanding units (4,751,510).

Documents Reviewed

The following list of documents includes documents available for my inspection or review. However, not all the documents have been consulted, reviewed, or considered in reaching my opinions. The documents used as references in this report were used to support my report, conclusions, and opinions.

Legal Filings: Cause No. C-1-PB-14-001245 and Cause No. C-1-PB-16-000096

Original Petition for Modification and Termination of Trust, filed on behalf of the Corporate Trustee and the Individual Trustees of the TEL Offshore Trust in Probate Court No. 1 of Travis County, Cause No. C-1-PB-14-001245, 10 July 2014.

Order for Appointment of Attorney Ad Litem, Cause No. C-1-PB14-001245, 18 June 2015.

Attorney Ad Litem’s Motion to Retain and Compensate Consulting Expert, Cause No. C-1-PB14-001245, 18 August 2015.

Attorney Ad Litem's First Amended Answer and Counterclaim for Order to Sell Royalty Interests and for Accounting, Cause No. C-1-PB14-001245, 16 November 2015.

Attorney Ad Litem's Motion to Sever, Cause No. C-1-PB14-001245, 16 November 2015.

Final Judgement and Order, Cause No. C-1-PB16-000096, 15 January 2016.

Order Protecting Confidentiality, Cause No. C-1-PB14-001245 and Cause No. C-1-PB16-000096, 19 June 2016.

Additional legal filings and documents were available through a public website hosted by Andrews Kurth LLP on behalf of TEL Offshore Trust, https://www.andrewskurth.com/teloffshoretrust.

Discovery Documents

Scott, Douglass & McConnico LLP provided the following discovery documents. The documents were provided as PDF images or in native format.

TEL0000001 – TEL0002068
TEL0002070 – TEL0002132
TEL0010000 – TEL0031404
TEL0031450 – TEL0094572

Depositions and Exhibits

Deposition of the Bank of New York Mellon Trust Company, N.A. Corporate Representative Michael Ulrich, taken 14 July 2016, Austin, TX.

SEC Documents

TEL Offshore Trust SEC filings were available through the SEC EDGAR website for the period of May 1995 through January 2017. https://www.sec.gov/edgar/searchedgar/companysearch.html

TEL Offshore Trust – Annual Forms 10-K
TEL Offshore Trust – Quarterly Forms 10-Q
TEL Offshore Trust – Significant Event Forms 8-K

Appendix A

Resume - Michael L. Wiggins

Michael L. Wiggins, Ph.D., P.E.
William M. Cobb & Associates, Inc.
12770 Coit Road, Suite 907
Dallas, Texas 75379
972-385-0354 – Office
mwiggins@wmcobb.com

EDUCATION:

Ph.D., Petroleum Engineering
Texas A&M University, May 1991

M.Eng., Petroleum Engineering
Texas A&M University, August 1988

B.S., Petroleum Engineering
Texas A&M University, May 1979

WORK EXPERIENCE:

2006 - 2013; 2016 - Present
William M. Cobb & Associates, Inc. (Dallas, Texas)

Senior Vice President	***2016 – Present***
President	***2011 – 2013***
Senior Vice President	***2006 – 2010***

- Perform technical and economic studies of oil and gas reservoirs for reservoir management, waterflood and EOR assessment and design, reserve determination, and production optimization

- Provide expert witness testimony involving petroleum engineering functions and industry practices

- Teach petroleum engineering industry courses in the areas of reservoir management, reservoir engineering, waterflooding, well completions and performance, and economic evaluations.

3/2013 – 6/2015
Mid-Con Energy Operating, LLC (Dallas, Texas)

President	***8/2014 – 6/2015***
Executive Vice President	***3/2013 – 7/2014***

- Served as chief engineer and chief operating officer for an independent upstream E&P company. Duties included supervising management staff, technical evaluation of waterflood and improved oil recovery projects, reserve determination and reporting, and reservoir management programs.

- Provided management direction for company that resulted in growing net production by 60 percent from 3100 BOEPD to 5000 BOEPD and net reserves by 60 percent to 28 MMBOE during this period. Led efforts that resulted in over $300 million in acquired properties.

1991 - 2006
The University of Oklahoma (Norman, Oklahoma)
Professor, School of Petroleum and Geological Engineering

- Taught undergraduate and graduate level petroleum engineering classes in areas of reservoir management, reservoir and production engineering, and petroleum economics

- Conducted research in the areas of flow through porous media, reservoir recovery processes, well performance, reservoir and production engineering, artificial lift, and environmental management

1987 - 1991
Texas A&M University (College Station, Texas)
Graduate Assistant, Petroleum Engineering Department

- Conducted research in the areas of well performance and reservoir management

- Assisted in teaching an introductory course on engineering and computers

1986 - 1987
Independent Consulting Engineer (Liberty, Texas)

- Performed reservoir projections and economic analysis on oil and gas properties under consideration for acquisition and divestment

1985 - 1986
ITR Petroleum, Inc. (Houston, Texas)
Petroleum Engineer

- Performed duties of a production engineer for operated and non-operated properties in South Texas and Oklahoma

1981 - 1985
Templeton Energy, Inc (Houston, Texas)
Petroleum Engineer

- Prepared drilling and completion programs for company operated properties primarily in Kansas, Oklahoma, Louisiana, and Texas

- Managed all production operations in Texas, Louisiana, Mississippi, Oklahoma and Kansas

- Supervised engineering, technical, clerical and field personnel

1980 – 1981
The Bertman Companies (Liberty, Texas)
Petroleum Engineer

- Supervised the operations of a small independent on the upper Texas Gulf Coast

1979 – 1980
Sun Gas Company (Lafayette, Louisiana)
Production Engineer

- Performed production engineering and field duties on properties in the upper Texas Gulf Coast, North Louisiana, and Mississippi

RESEARCH FUNDING:

Secured funding for and participated in 13 externally funded research projects while at the University of Oklahoma. Total external funding was 2.5 million dollars. Served as Project Director and Principal Investigator for 11 of these projects. Projects were funded by the U.S. Department of Energy, U.S. Environmental Protection Agency, Sandia National Laboratories, and various exploration and production companies including Phillips Petroleum, Marathon, Kerr-McGee, Devon Energy, and Anadarko Petroleum.

TEACHING ACTIVITY:

Academic teaching experience includes petroleum engineering courses at both the graduate and undergraduate level in reservoir engineering, production engineering, and petroleum economic evaluation. Industry short course teaching activity includes courses in petroleum reservoir management, basic reservoir engineering, well completions and performance, and petroleum economic evaluation.

GRADUATE STUDENT ACTIVITY:

Supervised 18 graduate students through degree completion, four doctoral students, and 14 masters students. Theses encompassed a range of topics related to fluid flow in porous media, reservoir engineering, production engineering, well performance, artificial lift, and environmental issues.

TECHNICAL AND PROFESSIONAL SOCIETIES:

- Society of Petroleum Engineers

- General Chairman, 2016 Improved Oil Recovery Conference 2014-2016
- Carll, Lucas, and Uren Award Committee, 2010-2012
- 2010 Annual Technical Conference and Exhibition Program Committee
- Member of Reservoir Monitoring Technical Program Subcommittee, Annual Technical Conference and Exhibition, 2008-2010
- Board of Directors, 2004 - 2006
- Executive Editor, SPE Production and Facilities, 2001-2004
- Elected Distinguished Member by Board of Directors, 2003
- General Chairman, 2003 Production and Operations Symposium 2001-2003
- Recipient of the Mid-Continent Region Service Award, 2002
- Program Chairman, Oklahoma City Chapter, Reservoir Engineering and Economic Study Group, 2001-2002
- Member of the Waterflooding Subcommittee, SPE Reprint Series, 2000-2002
- Program Chairman, 2001 Production Operations Symposium, 2000-2001
- Director, Oklahoma City Chapter, 1999-2001
- Review Chairman, SPE Production and Facilities, 1998-2001
- Served on the Engineering Registration Committee, 1996-1999
- Member of the Reservoir Management Subcommittee, SPE Reprint Series, 1996-1998
- Program Committee, SPE Production Operations Symposiums, 2009, 2007, 2005, 2003, 2001, 1999, 1997, 1995, 1993
- Recipient of the Outstanding Technical Editor Award, 1996, 1997, 2009
- Technical Editor, SPE Production and Facilities, 1995 to present
- Member, Petroleum Computer Conference Committee, 1995 - 1997
- Approved ABET Petroleum Engineering Visitor, 1993 to present
- PI EPSILON TAU, The National Petroleum Engineering Honor Society, 1978

- Society of Petroleum Evaluation Engineers

- American Society for Engineering Education

- Network of Excellence in Training (NExT)
  - Petroleum Engineering Peer Review Board, 2000 – 2010

- University of Oklahoma, Norman
  - General Chairman, Conference on Naturally Fractured Reservoirs
  - Recipient, Petroleum and Geological Engineering Distinguished Achievement Award, 2000
  - College of Engineering Dean’s Senior Advisory Committee, 1999 – 2000
  - Student Chapter Faculty Advisor, 1991-1996

REGISTRATION:

- Registered Professional Engineer, States of Texas and Oklahoma

PUBLICATIONS:

- Akhimiona, N. and Wiggins, M.L.: “An Inflow Performance Relationship for Horizontal Gas Wells,” paper SPE 97627 presented at the 2005 SPE Eastern Regional Meeting, Morgantown, WV, 14-16 September.

- Wiggins, M.L. and Wang, H-S.: “A Two-Phase IPR for Horizontal Oil Wells,” paper SPE 94302 presented at the 2005 SPE Production & Operations Symposium, Oklahoma, OK, 16-19 April.

- Anklam, E.G. and Wiggins, M.L.: “Horizontal Well Productivity and Wellbore Pressure Behavior Incorporating Wellbore Hydraulics,” paper SPE 94316 presented at the 2005 SPE Production & Operations Symposium, Oklahoma, OK, 16-19 April.

- Ogunsina, O.O. and Wiggins, M.L.: “A Review of Downhole Separation Technology,” paper SPE 94276 presented at the 2005 SPE Production & Operations Symposium, Oklahoma, OK, 16-19 April.

- Anklam, E.G. and Wiggins, M.L.: “A Review of Horizontal Wellbore Pressure Equations,” paper SPE 94314 presented at the 2005 SPE Production & Operations Symposium, Oklahoma, OK, 16-19 April.

- Gallice, F. and Wiggins, M.L.: “Comparison of Two-Phase Inflow Performance Relationships,” SPEPF (May 2004) 100-104.

- Brown, R.L., Wiggins, M.L. and Gupta, A.: “Seismic Determination of Saturation in Fractured Reservoirs,” SPE Journal (September 2002) 237-242.

- Penuela, G., Hughes, R.G., Civan, F. and Wiggins, M.L: “Elongated-Slab Models for Interporosity Flow in Naturally Fractured Reservoirs,” paper NFR-003 presented at the 2002 Conference on Naturally Fractured Reservoirs, 3-4 June 2002.

- Penuela, G., Civan, F., Hughes, R.G., and Wiggins, M.L.: "Time-Dependent Shape Factors for Interporosity Flow in Naturally Fractured Gas-Condensate Reservoirs," paper SPE 75524 presented at the SPE Gas Technology Symposium held in Calgary, 30 April - 2 May 2002.

- Penuela, G., Hughes, R.G., Civan, F., and Wiggins, M.L.: "Time-Dependent Shape Factors for Secondary Recovery in Naturally Fractured Reservoirs," paper SPE 75234 presented at the SPE/DOE Improved Oil Recovery Symposium, Tulsa, April 13-17, 2002.

- Striz, E.A. and Wiggins, M.L.: "A Coupled Model to Predict Interformation Flow Through an Abandoned Wellbore," SPE Production and Facilities (February 2002) 11-22.

- Gasbari, S. and Wiggins, M.L.: "A Dynamic Plunger Lift Model for Gas Wells," SPE Production and Facilities (May 2001) 89-96.

- Goel, N., Wiggins, M.L. and Shah, S.: "Analytical Modeling of Gas Recovery from In Situ Hydrates Dissociation," Journal of Petroleum Science and Engineering (April 2001) 113-125.

- Brown, R.L., Wiggins, M.L. and Gupta, A.: "Seismic Determination of Saturation in Fractured Reservoirs," paper SPE 67278, Proceedings 2001 SPE Production and Operations Symposium, Oklahoma City, OK, March 25-28.

- Brown, R.L., Wiggins, M.L. and Gupta, A.: "Problems Calibrating Production and Seismic Data for Fractured Reservoirs," paper SPE 67317, Proceedings 2001 SPE Production and Operations Symposium, Oklahoma City, OK, March 25-28.

- Wiggins, M.L.: "Analytical Inflow Performance Relationships," ASME Journal of Energy Resources Technology (March 1999) 24-30.

- Wiggins, M.L., Nguyen, S.H., and Gasbarri, S.: "Optimizing Plunger Lift Operations in Oil and Gas Wells," paper SPE 52119, Proceedings 1999 SPE Mid-Continent Operations Symposium, Oklahoma City, OK, March 28-31.

- Wiggins, M.L. and Startzman, R.A.: "An Approach to Reservoir Management," Reservoir Management, Reprint Series No. 48, SPE, Richardson, TX (1998) 9-15.

- Gallice, F. and Wiggins, M.L.: "Comparison of Two-Phase Inflow Performance Relationships," paper SPE 52171, Proceedings 1999 SPE Mid-Continent Operations Symposium, Oklahoma City, OK, March 28-31.

- Striz, E.A. and Wiggins, M.L.: "A Coupled Model to Predict Interformation Flow Through an Abandoned Wellbore," paper SPE 49151, Proceedings 1998 SPE Annual Technical Meeting and Exhibition, New Orleans, LA, Sept. 27-30.

- Wiggins, M.L., Broussard, N.J., and Rieke, H.H.: "Advisory Boards: Leveraging Industry Resources," paper SPE 39491, Proceedings 1997 SPE Annual Technical Conference and Exhibition, San Antonio, TX, Oct. 5-8.

- Lee, W.J., et al.: "Enhancing Partnerships Between Engineering and Education: Roles for SPE," paper SPE 39492, Proceedings 1997 SPE Annual Technical Conference and Exhibition, San Antonio, TX, Oct. 5-8.

- Sabins, F. and Wiggins, M.L.: "Parametric Study of Gas Entry into Cemented Wellbores," SPE Drilling and Completion, (Sept. 1997) 180-187.

- Sabins, F. and Wiggins, M.L.: "Supplement to SPE 28472, Parametric Study of Gas Entry into Cemented Wellbores," paper SPE 39494, SPE, Richardson, TX.

- Gasbarri, S., Gupta, A.J., and Wiggins, M.L.: "Inflow Performance of Reservoirs Produced by Intermittent Lift Methods," paper 97-135, Proceedings 48th Annual Technical Meeting of The Petroleum Society, Calgary, Alberta, Canada, June 8-11, 1997.

- Gasbarri, S. and Wiggins, M.L.: "A Dynamic Plunger Lift Model for Gas Wells," paper SPE 37422, Proceedings 1997 SPE Production Operations Symposium, Oklahoma City, OK, March 9-11, 1997.

- Wiggins, M.L., Russell, J.E., and Jennings, J.W.: "Analytical Development of Vogel-Type Inflow Performance Relationships," SPE Journal (Dec. 1996) 355-362.

- Almisned, O.A. and Wiggins, M.L.: "Utilization of Software Engineering in Modeling a Petroleum Engineering Problem," paper SPE 36003, Proceedings 1996 SPE Petroleum Computer Conference, Dallas, TX, June 2-5, 1996.

- Wiggins, M.L. and Evans, R.D.: "Reserves and Resources of Oil and Gas," Encyclopedia of Earth Sciences, E.J. Dasch (ed.) MacMillian Library Reference, New York, NY (1996).

- Wiggins, M.L.: "Generalized Inflow Performance Relationships for Three-Phase Flow," 1994 SPE Annual Transactions, Richardson, TX (1995).

- Anklam, E.G. and Wiggins, M.L.: "E&P Waste Management Practices," Proceedings 1995 International Petroleum Environmental Conference, New Orleans, LA, Sept. 25-27.

- Anklam, E.G. and Wiggins, M.L.: "Waste Trends in Oil and Gas Operations," Proceedings 1995 WERC Technology Development Conference, Las Cruces, NM.

- Han, D., Wiggins, M.L. and Menzie, D.E.: "An Approach to the Optimum Design of Sucker-Rod Pumping Systems," paper SPE 29535, Proceedings 1995 SPE Production Operations Symposium, Oklahoma City, OK, April 2-4.

- Poe, B.D., Elbel, J.L., Wiggins, M.L. and Spath, J.B.: "Prediction of Future Well Performance Including Reservoir Depletion Effects," paper SPE 29465,

Proceedings 1995 SPE Production Operations Symposium, Oklahoma City, OK, April 2-4.

- Sabins, F. and Wiggins, M.L.: "Parametric Study of Gas Entry into Cemented Wellbores," paper SPE 28472, Proceedings 1994 SPE Annual Technical Conference and Exhibition, New Orleans, LA, Sept. 26-28.
- Wiggins, M.L. and Anklam, E.G.: "Managing E&P Waste Lessens Impact," American Oil & Gas Reporter (Aug. 1994) 78-83.
- Wiggins, M.L.: "Generalized Inflow Performance Relationships for Three-Phase Flow," SPE Reservoir Engineering (Aug. 1994) 181-182
- Wiggins, M.L. and Zhang, X.: "Using PCs and Monte Carlo Simulation for Assessing Risk in Workover Evaluations," SPE Computer Applications (June 1994) 19-23.
- Wiggins, M.L. and Zhang, X.: "Using PCs and Monte Carlo Simulation for Assessing Risk in Workover Evaluations," paper SPE 26243, Proceedings 1993 SPE Petroleum Computer Conference, New Orleans, LA, July 11-14.
- Wiggins, M.L.: "Generalized Inflow Performance Relationships for Three-Phase Flow," paper SPE 25458, Proceedings 1993 SPE Production Operations Symposium, Oklahoma City, OK, March 21-23.
- Wiggins, M.L., Choe, J. and Juvkam-Wold, H.C.: "Single Equation Simplifies Horizontal, Directional Drilling Plans," Oil & Gas Journal (Nov. 2, 1992) 74-79.
- Wiggins, M.L., Russell, J.E. and Jennings, J.W.: "Analytical Inflow Performance Relationships for Three-Phase Flow in Bounded Reservoirs," paper SPE 24055, Proceedings 1992 SPE Western Regional Meeting, Bakersfield, CA, Mar. 30-Apr. 1.
- Wiggins, M.L., Russell, J.E. and Jennings, J.W.: "Analytical Development of Vogel-Type Inflow Performance Relationships," paper SPE 23580, Proceedings 1992 SPE Permian Basin Oil and Gas Recovery Conference, Midland, TX, Mar. 18-20.
- Wiggins, M.L.: "Methods Predict Oil Well Performance," American Oil & Gas Reporter (Sept. 1991) 64-67.
- Wiggins, M.L., Jochen, V.A. and Jennings, J.W.: "Prediction of Oilwell Performance in Bounded Reservoirs," Proceedings 1991 Southwestern Petroleum Short Course, Lubbock, TX, Apr. 17-18.

- Mukerji, P., Wiggins, M.L. and Jennings, J.W.: "Inflow Performance Relationships for Oil-Water Systems Above the Bubble Point," Proceedings 1991 Southwestern Petroleum Short Course, Lubbock, TX, Apr. 17-18.

- Wiggins, M.L. and Juvkam-Wold, H.C.: "Simplified Equations for Planning Directional and Horizontal Wells," paper SPE 21261, Proceedings 1990 Eastern Regional Meeting, Columbus, OH, Oct. 31-Nov. 2.

- Wiggins, M.L. and Startzman, R.A.: "An Approach to Reservoir Management," paper SPE 20747, Proceedings 1990 SPE Annual Technical Conference and Exhibition, New Orleans, LA, Sept. 23-26.

- Wiggins, M.L. (ed.): A Manual for Petroleum Reservoir Management, Crisman Institute for Petroleum Reservoir Management, Petroleum Engineering Department, Texas A&M U., College Station, TX (May 1989).

01/2016

EXHIBIT B

NO. C-1-PB-14-001245

In Re:	**§**	**In the Probate Court No. 1**
	§	
	§	**of**
	§	
TEL Offshore Trust	**§**	**Travis County, Texas**

ATTORNEY AD LITEM'S AMENDED RESPONSES TO CORPORATE TRUSTEE'S REQUEST FOR DISCLOSURE

To: The Bank of New York Mellon Trust Company, N.A., by and through its attorneys of record, Craig A. Haynes and Rachelle H. Glazer, Thompson & Knight LLP, One Arts Plaza, 1722 Routh Street, Suite 1500, Dallas, Texas 75201, and James E. Cousar, Thompson & Knight LLP, 98 San Jacinto Boulevard, Suite 1900, Austin, Texas 78701.

Pursuant to Texas Rule of Civil Procedure 194.2, Glenn M. Karisch, as Attorney Ad Litem for the beneficiaries of TEL Offshore Trust who were served by publication and did not answer or appear ("Ad Litem"), serves these responses to the Corporate Trustee's Request for Disclosure to Ad Litem as follows:

REQUEST FOR DISCLOSURE (a):

The correct names of the parties to the lawsuit.

RESPONSE:

Ad Litem is correctly named and believes that the Individual Trustees, the Corporate Trustee, RNR Production Land and Cattle Company, Inc. and Albert and Joyce Speisman are correctly named.

Ad Litem does not have personal knowledge of the correct names of all the unit holders TEL Offshore Trust.

REQUEST FOR DISCLOSURE (b):

The name, address, and telephone number of any potential parties.

RESPONSE:

None known at this time.

REQUEST FOR DISCLOSURE (c):

The legal theories and, in general, the factual bases of the responding party's claims or defenses (the responding party need not marshal all evidence that may be offered at trial).

RESPONSE:

Ad Litem incorporates the factual bases for his claims set forth in Attorney Ad Litem's Second Amended Petition as Realigned Plaintiff and any subsequent amendments thereto.

REQUEST FOR DISCLOSURE (d):

The amount and any method of calculating economic damages.

RESPONSE:

The economic damages are the loss or depreciation in value of the trust estate as a result of the BNYM's breaches of trust. Some of this loss or depreciation in value was due to the breaches of trust represented by the delay in the sale of the Trust's net profits interests beginning in 2009 and continuing until the Trustees filed the termination and modification proceeding in 2014. *See* Assessment of TEL Offshore Trust, dated January 31, 2017, attached. In addition to these damages, Ad Litem is asking the Court to order the return of the compensation and profits the Trustees received during this time as a result of breaches of trust. Compensation is approximately $1.2 million, not including insurance premiums on the trustees' liability insurance which should also be repaid to the Trust. In addition, the Ad Litem seeks to recover his fees and his outside counsel's and expert's fees and to require that the Trustees and not the Trust bear their own attorneys' fees and costs.

Ad Litem will supplement this disclosure as discovery progresses.

REQUEST FOR DISCLOSURE (e):

The name, address, and telephone number of persons having knowledge of relevant facts, and a brief statement of each identified person's connection with the case.

RESPONSE:

Michael Ulrich
Sarah Newell
Derek Kettel
The Bank of New York Mellon Trust Company, N.A.
Corporate Trustee of the TEL Offshore Trust
c/o Craig A. Haynes
Thompson & Knight LLP
One Arts Plaza
1722 Routh Street, Suite 1500
Dallas, Texas 75201

The Bank of New York Mellon is the Corporate Trustee of the TEL Offshore Trust.

Gary C. Evans
Individual Trustee of the TEL Offshore Trust
c/o Paul Trahan
Norton Rose Fulbright US, L.L.P.
98 San Jacinto Boulevard, Suite 1100
Austin, Texas 78701-4255

Jeffrey S. Swanson
Individual Trustee of the TEL Offshore Trust
c/o Paul Trahan
Norton Rose Fulbright US, L.L.P.
98 San Jacinto Boulevard, Suite 1100
Austin, Texas 78701-4255

Thomas H. Owen Jr.
Individual Trustee of the TEL Offshore Trust
c/o Paul Trahan
Norton Rose Fulbright US, L.L.P.
98 San Jacinto Boulevard, Suite 1100
Austin, Texas 78701-4255

Daniel O. Conwill, IV
Individual Trustee of the TEL Offshore Trust

c/o Paul Trahan
Norton Rose Fulbright US, L.L.P.
98 San Jacinto Boulevard, Suite 1100
Austin, Texas 78701-4255

Messrs. Evans, Swanson, Owen and Conwill are/were Individual Trustees of the TEL Offshore Trust.

Roy T. Rimmer, Jr., President
RNR Production Land and Cattle Company, Inc.
c/o Shannon Ratliff
Ratliff Law Firm PLLC
600 Congress Ave., Suite 3100
Austin, Texas 78701

RNR Production Land and Cattle Company, Inc. is a unit holder of the TEL Offshore Trust.

Albert and Joyce Speisman, Unit Holders
c/o Jim George
George Brothers Kincaid & Horton, LLP
114 W. 7th Street, Ste. 1100
Austin, TX 78701

Mr. and Ms Speisman are unit holders of the TEL Offshore Trust.

Jesse Myers
Lance Schuler
David Buck
Craig Stahl
Philip Haines
Bill McDonald
Custodian of records
Andrews Kurth LLP
P.O. Box 201785
Houston, Texas 77216-1785

These attorneys and others represented the Corporate and Individual Trustees of the TEL Offshore Trust.

Todd J. Attalla
Roger Gann
Pat Martindale
Debra Fuentes
Martindale Consultants, Inc.
4242 N. Meridian Ave.

Oklahoma City, OK 73112

Martindale Consultants performed audits for the TEL Offshore Trust and its properties.

Marilou Tojino
Dian Miller
Yesenia Cruz-Partido
Robert Poindexter
Pravin Dayaldasani
Michael Lemen
Alex Kuiper
Linda Ratto
Chevron U.S.A., Inc.
Joint Interest Audits and Analysis
Accounting
Finance Share Services
2003 Diamond Blvd. Room 32255
Concord, CA 94520-5738

Chevron USA, Inc. is the general partner of the TEL Offshore Trust Partnership.

George Wilson
Paul J. Szatkowski, P.E.
DeGolyer and MacNaughton
5001 Spring Valley Road, Suite 800 East
Dallas, Texas 75244

DeGolyer and MacNaughton provided reserve estimates for TEL Offshore Trust Partnership.

Dustin Oslund
Tatsiana B. Bender
Wyn Smith
Brandy Smith
Walter Powell
Justin R. Smith
Deloitte & Touche LLP
333 Clay Street, Ste 2300
Houston, Texas 77002-4196

Deloitte & Touche LLP performed audits for the TEL Offshore Trust.

Bob Rudolph
704-996-7005

Mr. Rudolph is a unit holder of the TEL Offshore Trust.

See also the testifying experts identified below.

REQUEST FOR DISCLOSURE (f):

For any testifying expert:

(1) the expert's name, address, and telephone number;

(2) the subject matter on which the expert will testify;

(3) the general substance of the expert's mental impressions and opinions and a brief summary of the basis for them, or if the expert is not retained by, employed by, or otherwise subject to your control, documents reflecting such information;

(4) if the expert is retained by, employed by, or otherwise subject to your control:

(A) all documents, tangible things, reports, models, or data compilations that have been provided to, reviewed by, or prepared by or for the expert in anticipation of the expert's testimony; and

(B) the expert's current resume and bibliography.

RESPONSE:

Glenn M. Karisch Law Firm, PLLC
The Karisch Law Firm, PLLC
301 Congress Avenue, Suite 1910
Austin, TX 78701
(512) 328-6346 – Telephone

Mr. Karisch has testified and will testify as to the reasonable and necessary attorneys' fees and costs incurred, and expected to be incurred, in this matter and the compensation of the attorney ad litem in this matter. His testimony will be based upon his experience as a probate and trust attorney in Texas, including Travis County, Texas and the factors for determining the reasonableness of a fee set forth in Rule 1.04(b) of the Rules of Professional Conduct and Texas case law. His testimony also will be based on the standards for compensating attorneys ad litem in trust cases under Sections 114.064 and 115.014 of the Texas Trust Code. Specifically, Mr. Karisch is expected to testify that the attorneys' fees and costs that he has incurred in this action are reasonable and necessary and are consistent with the fees customarily charged for the type of services provided in Travis County, Texas.

Mr. Karisch's resume and bibliography have been previously produced.

Daniel C. Bitting
Cynthia L. Saiter
SCOTT DOUGLASS & McCONNICO LLP
303 Colorado, Suite 2400
Austin, Texas 78701-2589
(512) 495-6300 – Telephone

Mr. Bitting has testified and may testify and Ms. Saiter and may testify as to the reasonable and necessary attorneys' fees and costs incurred, and expected to be incurred, in this matter. Their testimony will be based upon their experience as litigation attorneys in Texas, including Travis County, Texas and the factors for determining the reasonableness of a fee set forth in Rule 1.04(b) of the Rules of Professional Conduct and Texas case law. Specifically, Mr. Bitting and Ms. Saiter are expected to testify that the attorneys' fees that the Ad Litem incurred in this action are reasonable and necessary and are consistent with the fees customarily charged for the type of services provided in Travis County, Texas.

Mr. Bitting's resume and biographical information is available at http://www.scottdoug.com/lawyers/daniel-c-bitting.

Ms. Saiter's resume and biographical information is available at http://www.scottdoug.com/lawyers/cindy-saiter.

Michael L. Wiggins, Ph.D., P.E.
Senior Vice President
William M. Cobb & Associates, Inc.
12770 Coit Road, Suite 907
Dallas, TX 75251
(972) 385-0354 – Telephone

The subject matter and general substance of Mr. Wiggins' mental impressions and opinions and the basis for them are set forth in his Assessment of TEL Offshore Trust, dated January 31, 2017 ("Wiggins Report"), attached. The Wiggins report identifies the documents and other materials provided to or reviewed by Mr. Wiggins, which will be produced at a reasonable time and location upon Defendant's written request.

R. Bruce Wallace, Jr.
Eggleston & Briscoe, LLP
4800 Three Allen Center 333 Clay Street
Houston, Texas 77002
(713) 659-5100 – Telephone

The subject matter and general substances of Mr. Wallace's mental impressions and opinions and the basis for them are set forth in his Letter to Dan Bitting, dated January 31, 2017 ("Wallace Report"), attached. The Wallace report identifies the documents and other materials provided to or reviewed by Mr. Wallace, which will be produced at a reasonable time and location upon Defendant's written request.

REQUEST FOR DISCLOSURE (g):

Any discoverable indemnity and insuring agreements described in Rule 192.3(f).

RESPONSE:

None as to Ad Litem.

REQUEST FOR DISCLOSURE (h):

Any discoverable settlement agreements described in Rule 192.3(g).

RESPONSE:

The settlement agreement between the Plaintiffs and the Individual Trustees has been produced, filed and approved by the Court.

REQUEST FOR DISCLOSURE (i):

Any discoverable witness statements described in Rule 192.3(h).

RESPONSE:

None other than the deposition(s) taken in this action and except as may be in the documents produced by the parties or third parties.

REQUEST FOR DISCLOSURE (l):

The name, address and telephone number of any person who may be designated as a responsible third party.

RESPONSE:

Ad Litem is not aware of any responsible third party at this time.

Ad Litem reserves the right to supplement or amend these responses at any time as appropriate or necessary.

Respectfully submitted,

SCOTT DOUGLASS & McCONNICO LLP
303 Colorado Street, Suite 2400
Austin, Texas 78701
(512) 495-6300 Telephone
(512) 495-6399 Facsimile

By: */s/ Daniel C. Bitting*
Daniel C. Bitting
State Bar No. 02362480
dbitting@scottdoug.com
Cynthia L. Saiter
State Bar No. 00797367
csaiter@scottdoug.com

Attorneys for Ad Litem

THE KARISCH LAW FIRM, PLLC

By: */s/ Glenn M. Karisch*
Glenn M. Karisch
State Bar No. 11098950
301 Congress Avenue, Suite 1910
Austin, TX 78701
(512) 328-6346 (telephone)
(512) 597-4062 (fax)
karisch@texasprobate.com

Attorney Ad Litem

CERTIFICATE OF SERVICE

I hereby certify that a true and correct copy of the foregoing has been served on counsel of record on January 31, 2017 and will be served in accordance with the Court's orders regarding service dated September 28, 2015 and January 21, 2016.

/s/ Cynthia L. Saiter
Cynthia L. Saiter

EXHIBIT C

CAUSE NO. C-1-PB-14-001245

IN RE:	**§**	**IN THE PROBATE COURT NO. 1**
	§	
TEL OFFSHORE TRUST	**§**	**OF**
	§	
	§	**TRAVIS COUNTY, TEXAS**

DEFENDANT ALBERT SPEISMAN'S RESPONSES TO CORPORATE TRUSTEE'S AND INDIVIDUAL TRUSTEE'S REQUESTS FOR DISCLOSURE

TO: The Bank of New York Mellon Trust Company, N.A., as Corporate Trustee of the TEL Offshore Trust, by and through its attorneys, Craig A. Haynes and Rachelle H. Glazer, Thompson & Knight LLP, One Arts Plaza, 1722 Routh Street, Suite 1500, Dallas, Texas 75201, and James E. Cousar, Thompson & Knight LLP, 98 San Jacinto Blvd., Suite 1900, Austin, Texas 78701.

Individual Trustees, Gary C. Evans, Jeffrey S. Swanson, and Thomas H. Owens, Jr., by and through their attorneys, Paul Trahan and Peter Stokes, Norton Rose Fulbright US, L.L.P., 98 San Jacinto Boulevard, Suite 1100, Austin, Texas 78701-4255, and Daniel M. McClure, Norton Rose Fullbright US, L.L.P., 1301 McKinney, Suite 5100, Houston, Texas 77010.

Pursuant to Rule 194 of the Texas Rules of Civil Procedure, Defendant Albert Speisman submits his Responses to Corporate Trustee's and Individual Trustees' Requests for Disclosure.

Respectfully submitted,

/s/R. James George, Jr.

R. James George, Jr.
State Bar No. 07810000
114 West 7th Street, Suite 1100
Austin, Texas 78701
(512) 495-1400
(512) 499-0094 *facsimile*
rjgeorge@gbkh.com

ATTORNEY FOR DEFENDANT
ALBERT SPEISMAN

CERTIFICATE OF SERVICE

I hereby certify that a true and correct copy of the foregoing has been served or will be served in accordance with the Court's orders regarding service dated September 28, 2015 and January 21, 2016.

/s/R. James George, Jr.

RESPONSE TO REQUESTS FOR DISCLOSURE

<u>REQUEST FOR DISLOSURE (a)</u>: The correct names of the parties to the lawsuit.

<u>RESPONSE</u>: Albert Speisman believes the parties that have made an appearance have been named correctly. Albert Speisman is a party to the lawsuit. Albert Speisman does not have personal knowledge of the correct names of all the unit holders of TEL Offshore Trust.

<u>REQUEST FOR DISCLOSURE (b)</u>: The name, address, and telephone number of any potential parties.

<u>RESPONSE</u>: Joyce E. Speisman should be a party to this lawsuit. Albert Speisman is unaware of the identity of any other potential parties at this time.

<u>REQUEST FOR DISCLOSURE (c)</u>: The legal theories and, in general, the factual bases of the responding party's claims or defenses.

<u>RESPONSE</u>: Albert Speisman believes the Trustees of the TEL Offshore Trust have failed in their obligations to Albert Speisman as follows:

1. The TEL Offshore Trustees intentionally, in bad faith, with gross negligence, fraud or with reckless indifference to the interests of the beneficiaries failed to disclose that the Trust had terminated by its own provisions no later than May, 2009;

2. The Trustees of the TEL Offshore Trust intentionally, in bad faith, with gross negligence, fraud or with reckless indifference to the interests of the beneficiaries failed to act in accordance with the express provisions of the Trust Agreement to take steps to terminate the Trust in or shortly after May, 2009;

3. Despite the acknowledged limited ability of the Trust to generate future revenues sufficient to provide for distributions to unit holders, subsequent to May, 2009, the Trustees of the TEL Offshore Trust intentionally, in bad faith, with gross negligence, fraud or with reckless indifference to the interests of the beneficiaries took no steps to terminate the Trust;

4. The Trustees of the TEL Offshore Trust intentionally, in bad faith, with gross negligence, fraud or with reckless indifference to the interests of the beneficiaries continued to incur trustees' fees and administrative expenses and other costs well beyond such time as it was apparent that the Trust would not be able to make any distributions to unit holders and prudent for the Trust to continue to exist.

Albert Speisman incorporates the factual bases for his claims as set forth in Ad Litem's First Amended Original Petition as Realigned Plaintiff.

Discovery in this matter is ongoing and Albert Speisman reserves the right to amend or otherwise supplement these responses as discovery proceeds and in accordance with the Scheduling Order that it anticipates will be entered in this matter.

REQUEST FOR DISCLOSURE d): The amount and any method of calculating economic damages.

RESPONSE: Albert Speisman is entitled to his proportionate share of the proceeds from the sale of the net profits interest attributable to the Trust that would have been realized had the Trustees not intentionally postponed acting in accordance with the provisions of the TEL Offshore Trust Agreement, plus interest. In addition, Albert Speisman is entitled to his proportionate share of the fees incurred by the Trustees and other administrative expenses, including Directors and Officers insurance, plus interest, that would have been unnecessary had the Trustees of the TEL Offshore Trust acted in a timely manner in accordance with the Trust Agreement. Albert Speisman is also entitled to his proportionate share of the Reserve for Future Trust Expense established by the Trustees that would have otherwise been in place had the Trustees acted timely in terminating the Trust, plus interest. Albert Speisman is also entitled to his proportionate share of the management fee that was charged by Chevron to the Trust that would have terminated had the Trust been terminated in a timely manner, plus interest and such other relief as Albert Speisman may show himself to be entitled. The exact dollar amounts have not yet been determined and discovery is ongoing.

Albert Speisman is also entitled to his pro-rata share of damages due to the individual trustees and corporate trustees breach of fiduciary duty.

The economic damages are the loss or depreciation in value of the trust estate as a result of the Trustees' breaches of trust. Some of this loss or depreciation in value was due to the breaches of trust represented by the Trustees' delay in the sale of the Trust's net profits interests beginning in 2009 and continuing until the Trustees filed the termination and modification proceeding in 2014. For example, had the Trustees sold the net profits interest during 2010, they could have received over $20 million in sales proceeds based on publicly-traded market values, or if they sold at the end of 2010 they could have received around $15 million in sales proceeds based on their own engineer's calculation. In addition to these damages, Albert Speisman is entitled to his pro-rata share of the return of the compensation and profits the Trustees received during this time as a result of breaches of trust. Compensation is approximately $1.2 million, which does not include insurance premiums on trustee liability insurance. In addition, Albert Speisman seeks to recover his attorney's fees and costs and to require that the Trustees bear their own attorneys' fees and costs, not the Trust.

Albert Speisman will supplement his answer as discovery continues and in accordance with the Scheduling Order.

REQUEST FOR DISCLOSURE e): The name, address, and telephone number of persons having knowledge of relevant facts, and a brief statement of each identified person's connection with the case.

<u>RESPONSE</u>:

1. Roy Rimmer
Paul Willingham
Custodian of Records, Employees and/or Representatives of RNR Production Land and Cattle
c/o Shannon H. Ratliff
Ratliff Law Firm, PLLC
600 Congress Avenue, Suite 3100
Austin, Texas 78701
512-493-9601

2. Michael Ulrich
Sarah Newell
James Favola
Mary Jo Davis
Custodian of Records, Employees and/or Representatives of The Bank of New York Mellon, Trust Company N.A., Corporate Trustee
c/o Craig Haynes
Thompson & Knight LLP
One Arts Plaza
1722 Routh Street, Suite 1500
Dallas, Texas 75201
214-969-1239

   Albert Speisman believes these individuals have knowledge of facts and activities surrounding the operation of the TEL Offshore Trust including the bank's role as corporate trustee, the manner in which it calculated its fees to the Trust for serving as a corporate trustee and the actions and inactions of the bank, as corporate trustee, and the other trustees in administering the TEL Offshore Trust.

3. Gary C. Evans
c/o Paul Trahan
Peter Stokes
Norton Rose Fulbright US, LLP
98 San Jacinto Boulevard, Suite 1100
Austin, Texas 78701-4255
512- 474-5201

   Albert Speisman believes Mr. Evans has knowledge of facts and activities surrounding the operation of the TEL Offshore Trust including the actions and inactions of the trustees in administering the TEL Offshore Trust.

4. Jeffrey S. Swanson
c/o Paul Trahan
Peter Stokes
Norton Rose Fulbright US, LLP
98 San Jacinto Boulevard, Suite 1100
Austin, Texas 78701-4255
512- 474-5201

Albert Speisman believes Mr. Swanson has knowledge of facts and activities surrounding the operation of the TEL Offshore Trust including the actions and inactions of the trustees in administering the TEL Offshore Trust.

5. Thomas H. Owen, Jr.
c/o Paul Trahan
Peter Stokes
Norton Rose Fulbright US, LLP
98 San Jacinto Boulevard, Suite 1100
Austin, Texas 78701-4255
512- 474-5201

6. Lance Schuler
Custodian of Records, Employees and/or Representatives of Andrews Kurth LLP
600 Travis, Suite 4200
Houston, Texas 77002
(713) 220-4200

Albert Speisman believes Mr. Schuler and potentially others with the Andrews Kurth firm have knowledge regarding the facts and activities surrounding the operation of the TEL Offshore Trust including the actions and inactions of the trustees in administering the TEL Offshore Trust. Additionally, Mr. Schuler may have information relating to the discussions and activities at the quarterly meetings of the Trustees of the TEL Offshore Trust.

7. Wyn Smith
Dustin Oslund
Custodian of Records, Employees and/or Representatives of Deloitte Touche

Albert Speisman believes Mr. Smith, Mr. Oslund and potentially others with Deloitte Touche may have knowledge regarding the facts and activities surrounding the operation of the TEL Offshore Trust including the actions and inactions of the trustees in administering the TEL Offshore Trust.

8. Ms. Crus-Partida
Custodian of Records, Employees and/or Representatives of Chevron

Albert Speisman believes the individuals from Chevron may have knowledge regarding the information provided or otherwise available to the trustees of the TEL Offshore Trust including information relating to the operations of the interests held by the Trust as well as information provided to DeGolyer and MacNaughton in conjunction with their assessments of the Trust properties. Additionally, Ms. Cruz-Partida may have information relating to the discussions and activities at the quarterly meetings of the Trustees of the TEL Offshore Trust.

9. Paul J. Szatkowski
Custodian of Records, Employees and/or Representatives of DeGolyer and MacNaughton
5001 Spring Valley Road, Suite 800 East
Dallas, Texas 75244

Albert Speisman believes that DeGolyer and MacNaughton and Mr. Szatkowski may have knowledge regarding the analysis performed by DeGolyer and MacNaughton regarding their assessment of the Trust properties. Additionally, Mr. Szatkowski may have knowledge of discussions and information between DeGolyer and MacNaughton, representatives of Chevron and one or more Trustees or representatives of Trustees of the TEL Offshore Trust.

10. Albert Speisman

Albert Speisman reserves the right to supplement this list as discovery continues and designate any other witnesses with knowledge listed by any other party to this litigation and not objected to by Defendant Albert Speisman

<u>REQUEST FOR DISCLOSURE (f)</u>: For any testifying expert:

(1) the expert's name, address and telephone number;

(2) the subject matter on which the expert will testify;

(3) the general substance of the expert's mental impressions and opinions and a brief summary of the basis for them, or if the expert is not retained by, employed by, or otherwise subject to the control of the responding party, documents reflecting such information;

(4) if the expert is retained by, employed by, or otherwise subject to the control of the responding party:

(A) all documents, tangible things, reports, models, or data compilations that have been provided to, reviewed by, or prepared by or for the expert in anticipation of the expert's testimony; and,

(B) the expert's current resume and bibliography.

RESPONSE: Discovery is currently ongoing and Albert Speisman has not made a final determination of its expert(s) in this matter. Albert Speisman will supplement this answer in accordance with the Scheduling Order that it anticipates will be entered in this matter.

REQUEST FOR DISCLOSURE (g): Any indemnity and insuring agreements described in Rule 192.3(f);

RESPONSE: None.

REQUEST FOR DISCLOSURE (h): Any settlement agreements described in Rule 192.3(g);

RESPONSE: None.

REQUEST FOR DISCLOSURE (i): Any witness statements described in Rule 192.3(h);

RESPONSE: The deposition of Michael Ulrich, the representative of Bank of New York Mellon, the corporate trustee, has been taken. Additionally, he has testified in at least one hearing on this matter.

REQUEST FOR DISCLOSURE (l): The name, address, and telephone number of any person who may be designated as a responsible third party.

RESPONSE: None at this time.

Defendant Albert Speisman's investigation and discovery in this matter are ongoing. Defendant Albert Speisman reserves the right to amend or supplement this disclosure as may be necessary.

EXHIBIT D

CAUSE NO. C-1-PB-14-001245

IN RE:	§	IN THE PROBATE COURT
	§	
	§	OF
	§	
TEL OFFSHORE TRUST	§	TRAVIS COUNTY, TEXAS

AFFIDAVIT OF MICHAEL J. ULRICH

STATE OF TEXAS	§
	§
COUNTY OF TRAVIS	§

Before me, the undersigned notary, on this day personally appeared Michael J. Ulrich, the affiant, a person whose identity is known to me. After I administered an oath to affiant, affiant testified:

1. "My name is Michael J. Ulrich. I am over twenty-one years of age, am of sound mind, and am capable of making this affidavit. In my capacity as a Vice President of The Bank of New York Mellon Trust Company, N.A. ("BNYM"), as Corporate Trustee of the TEL Offshore Trust (the "Trust"), I have personal knowledge of the facts stated in this Affidavit, which are all true and correct.

2. Since 2006, I have been a Vice President of BNYM. BNYM serves as Corporate Trustee of the Trust. Since 2000, I have served as the Trust officer for Corporate Trustee. In that capacity, I manage and administer the Trust income and expenses. I make distributions of any net profits from the Trust royalty properties to holders of interests in the Trust on a quarterly basis. I also manage the administrative expenses for the Trust, including costs related to the Trust's federal securities law obligations, financial audits, tax filings, and fees for professional services necessary for Trust administration. I also prepare quarterly (10-Q) and annual (10-K) reports for the Trust

that are publicly filed with the U.S. Securities and Exchange Commission and prepare all press releases (8-K) for the Trust.

3. A true and correct copy of the Trust's 10-K for the fiscal year ended December 31, 2008, filed with the SEC on March 31, 2009, is attached hereto as Exhibit 1.

4. A true and correct copy of the Trust's 8-K dated March 25, 2009 is attached hereto as Exhibit 2.

5. A true and correct copy of the Trust's 10-Q for the quarterly period ended June 30, 2009, filed with the SEC on August 7, 2009, is attached hereto as Exhibit 3.

6. A true and correct copy of the Trust's 10-K for the fiscal year ended December 31, 2009, filed with the SEC on March 31, 2010, is attached hereto as Exhibit 4.

7. A true and correct copy of the Trust's 10-K for the fiscal year ended December 31, 2010, filed with the SEC on March 31, 2011, is attached hereto as Exhibit 5.

8. I am familiar with the provisions of the TEL Offshore Trust Agreement (the "Trust Agreement"), a true and correct copy of which is attached hereto as Exhibit 6. I understand that Section 11.01 of the Trust Agreement permits unit holders to inspect the books and records of the Trust. This would include all reserve reports by DeGolyer & MacNaughton and the compensation to the Corporate Trustee.

FURTHER AFFIANT SAYETH NOT."

Michael J. Ulrich

SUBSCRIBED AND SWORN TO before me, the undersigned official, on the 21 day of February, 2017, to certify which witness my hand and official seal of office.

SARAH NEWELL
Notary Public, State of Texas
My Commission Expires
February 16, 2018

Sarah Newell

Notary Public, State of Texas

EXHIBIT D-1

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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

(Mark One)

☒ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(D) OF THE SECURITIES EXCHANGE ACT OF 1934**

for the fiscal year ended December 31, 2008

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(D) OF THE SECURITIES EXCHANGE ACT OF 1934**

for the transition period from to

Commission File Number 0-6910

TEL OFFSHORE TRUST

(Exact name of registrant as specified in its charter)

Texas (State or other jurisdiction of incorporation or organization)	**76-6004064** (I.R.S. Employer Identification No.)

The Bank of New York Mellon Trust Company, N.A., Trustee **919 Congress Avenue** **Austin, Texas** (Address of principal executive offices)	**78701** (Zip Code)

Registrant's telephone number, including area code: **(800) 852-1422**

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Name of each exchange on which registered
None	None

Securities registered pursuant to Section 12(g) of the Act:

(Title of class)
Units of Beneficial Interest

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ☐ No ☒.

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes ☐ No ☒.

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the Registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☒ No ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☒

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer ☐	Accelerated filer ☒	Non-accelerated filer ☐ (Do not check if a smaller reporting company)	Smaller reporting company ☐

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act). Yes ☐ No ☒

The aggregate market value of the 4,751,510 Units of Beneficial Interest in TEL Offshore Trust held by non-affiliates as of the last business day of the registrant's most recently completed second fiscal quarter was $126,817,802 based on a June 30, 2008 closing sales price of $26.69.

Indicate the number of shares outstanding of each of the registrant's classes of common stock, as of the latest practicable date.

As of March 27, 2009, there were 4,751,510 Units of Beneficial Interest in TEL Offshore Trust outstanding.

Documents Incorporated By Reference: None

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Note Regarding Forward-Looking Statements

This Form 10-K includes "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. All statements other than statements of historical facts included in this Form 10-K are forward-looking statements. Although the Managing General Partner of the Partnership (as defined below) has advised the Trust that the Managing General Partner believes that the expectations reflected in the forward-looking statements contained herein are reasonable, no assurance can be given that such expectations will prove to have been correct. Important factors that could cause actual results to differ materially from expectations ("Cautionary Statements") are disclosed in this Form 10-K, including without limitation in conjunction with the forward-looking statements included in this Form 10-K. Risks factors that may affect actual results and Trust distributions include, without limitation:

- Commodity price fluctuations;
- Uncertainty of estimates of oil and gas production;
- Uncertainty of future production and development costs;
- Operating risks for Working Interest Owners, including drilling and environmental risks;
- Delays and costs in connection with repairs and replacements of hurricane-damaged facilities and pipelines, including third-party transportation systems;
- Regulatory changes;
- Decisions by and at the discretion of Working Interest Owners not to perform additional development projects, not to replace hurricane-damaged facilities, or to abandon properties; and
- Uncertainties inherent in estimating proved oil and natural gas reserves and in projecting future rates of production and timing of development expenditures.

Should any event or circumstances contemplated by the risks or uncertainties described above or elsewhere in this Form 10-K occur, or should any material underlying assumptions prove incorrect, actual results may differ materially from future results expressed or implied by the forward-looking statements. All subsequent written and oral forward-looking statements attributable to the Trust or persons acting on its behalf are expressly qualified in their entirety by the Cautionary Statements. See "Item 1A—Risk Factors" below in this Form 10-K for a summary description of principal risk factors.

PART I

Item 1. *Business.*

DESCRIPTION OF THE TRUST

General

The TEL Offshore Trust ("Trust"), created under the laws of the State of Texas, maintains its offices at the office of the Corporate Trustee, The Bank of New York Mellon Trust Company, N.A. ("Corporate Trustee"), 919 Congress Avenue, Austin, Texas 78701. The telephone number of the Corporate Trustee is 1-800-852-1422. The Bank of New York Mellon Trust Company, N.A. succeeded JPMorgan Chase Bank, N.A. as the Corporate Trustee effective October 2, 2006 pursuant to an agreement under which The Bank of New York Mellon Trust Company acquired substantially all of JPMorgan Chase's corporate trust business. JPMorgan Chase Bank was formerly known as The Chase Manhattan Bank and is the successor by mergers to the original corporate trustee, Texas Commerce Bank National Association. Daniel O. Conwill, IV, Gary C. Evans and Jeffrey S. Swanson serve as individual trustees ("Individual Trustees") of the Trust. The Individual Trustees and the Corporate Trustee may be referred to hereinafter collectively as the "Trustees."

The Corporate Trustee does not maintain a website for filings by the Trust with the U.S. Securities and Exchange Commission ("SEC"). Electronic filings by the Trust with the SEC are available free of charge through the SEC's website at *www.sec.gov* and at *www.businesswire.com/cnn/tel-offshore.htm*.

The principal asset of the Trust consists of a 99.99% interest in the TEL Offshore Trust Partnership ("Partnership"). Chevron U.S.A., Inc. ("Chevron") owns the remaining .01% interest in the Partnership. The Partnership owns an overriding royalty interest ("Royalty"), equivalent to a 25% net profits interest, in certain oil and gas properties (the "Royalty Properties") located offshore Louisiana.

On October 31, 1986, Tenneco Exploration Ltd. ("Exploration I") was dissolved and the oil and gas properties of Exploration I were distributed to Tenneco Oil Company ("Tenneco") subject to the Royalty. Tenneco, who was then serving as the Managing General Partner of the Partnership, assumed the obligations of Exploration I, including its obligations under the instrument conveying the Royalty to the Partnership (the "Conveyance"). The dissolution of Exploration I had no impact on future cash distributions to holders of units of beneficial interests in the Trust.

On November 18, 1988, Chevron acquired most of the Gulf of Mexico offshore oil and gas properties of Tenneco, including all of the Royalty Properties. As a result of the acquisition, Chevron replaced Tenneco as the Working Interest Owner and Managing General Partner of the Partnership. Chevron also assumed Tenneco's obligations under the Conveyance.

On October 30, 1992, PennzEnergy Company ("PennzEnergy") (which merged with and into Devon Energy Production Company L.P. effective January 1, 2000) acquired certain oil and gas producing properties from Chevron, including four of the Royalty Properties. The four Royalty Properties acquired by PennzEnergy were East Cameron 354, Eugene Island 348, Eugene Island 367 and Eugene Island 208. As a result of such acquisition, PennzEnergy replaced Chevron as the Working Interest Owner of such properties on October 30, 1992. PennzEnergy also assumed Chevron's obligations under the Conveyance with respect to these properties.

On December 1, 1994, Texaco Exploration and Production Inc. ("TEPI") acquired two of the Royalty Properties from Chevron. The Royalty Properties acquired by Texaco were West Cameron 643 and East Cameron 371. As a result of such acquisitions, TEPI replaced Chevron as the Working Interest Owner of such properties on December 1, 1994. TEPI also assumed Chevron's obligations under the Conveyance with respect to these properties.

On October 1, 1995, SONAT Exploration Company ("SONAT") acquired the East Cameron 354 property from PennzEnergy. In addition, on October 1, 1995, Amoco Production Company ("Amoco") acquired the Eugene Island 367 property from PennzEnergy. As a result of such acquisitions, SONAT and Amoco replaced PennzEnergy as the Working Interest Owners of the East Cameron 354 and Eugene Island 367 properties, respectively, on October 1, 1995 and also assumed PennzEnergy's obligations under the Conveyance with respect to these properties.

Effective January 1, 1998, Energy Resource Technology, Inc. ("ERT") acquired the East Cameron 354 property from SONAT. As a result of such acquisition, ERT replaced SONAT as the Working Interest Owner of the East Cameron 354 property effective January 1, 1998, and also assumed SONAT's obligations under the Conveyance with respect to such property. In October 1998, Amerada Hess Corporation ("Amerada") acquired the East Cameron 354 property from ERT effective January 1, 1998. As a result of such acquisition, Amerada replaced ERT as the Working Interest Owner of the East Cameron 354 property effective January 1, 1998, and also assumed ERT's obligations under the Conveyance with respect to this property.

Effective January 1, 2000, PennzEnergy and Devon Energy Corporation (Nevada) merged into Devon Energy Production Company L.P. ("Devon"). As a result of such merger, Devon replaced PennzEnergy as the Working Interest Owner of Eugene Island 348 and Eugene Island 208 properties effective January 1, 2000, and also assumed PennzEnergy's obligations under the Conveyance with respect to these properties. The abandonment obligations for Eugene Island 348 have been assumed by Maritech Resources, Inc. effective January 1, 2005.

On October 9, 2001, a wholly owned subsidiary of Chevron Corporation, a Delaware corporation, merged (the "Merger") with and into Texaco Inc., a Delaware corporation ("Texaco"), pursuant to an Agreement and Plan of Merger, dated as of October 15, 2000. As a result of the Merger, Texaco Inc. became a wholly owned subsidiary of Chevron Corporation, and Chevron Corporation changed its name to "ChevronTexaco Corporation" in connection with the Merger. Effective May 9, 2005, ChevronTexaco Corporation changed its name to Chevron Corporation. Accordingly, the properties referred to herein by Chevron and Texaco are each now controlled by subsidiaries of Chevron Corporation.

On May 1, 2002, TEPI assigned all of its interests in West Cameron 643 and East Cameron 371 to Chevron. Chevron sold its interest in East Cameron 371 to Energy Resource Technology, Inc. effective July 1, 2007. On July 18, 2008, Chevron sold its interest in West Cameron 643 to Hilcorp Energy GOM, LLC ("Hilcorp"). Effective August 1, 2008, Hilcorp assumed operations, reporting and payment responsibilities for West Cameron 643.

On June 6, 2003, Anadarko Petroleum Corporation ("Anadarko") acquired, among other interests, a 25% Working Interest in the East Cameron 354 field subject to the Royalty from Amerada effective April 1, 2003. As a result of such transaction, Anadarko replaced Amerada as the Working Interest Owner of East Cameron 354 effective July 1, 2003 and also assumed Amerada's obligations under the Conveyance with respect to this property.

Effective October 1, 2004, Apache Corporation ("Apache") acquired Anadarko's interest in East Cameron 354 and assumed Anadarko's obligations under the Conveyance with respect to this property.

All of the Royalty Properties continue to be subject to the Royalty, and it is anticipated that the Trust and Partnership, in general, will continue to operate as if the above-described sales of the Royalty Properties had not occurred. Chevron, as the managing general partner of the Partnership, calculates the Net Proceeds from the Royalty Properties owned by Chevron and collects financial information relating to the other Royalty Properties from the Working Interest Owners other than Chevron for presentation to the Trust.

Unless the context in which such terms are used indicates otherwise, the terms "Working Interest Owner" and "Working Interest Owners" generally refer to the owner or owners of the Royalty Properties (Exploration I through October 31, 1986; Tenneco for periods from October 31, 1986 until November 18, 1988; Chevron with respect to all Royalty Properties for periods from November 18, 1988 until October 30, 1992, and with respect to all Royalty Properties except East Cameron 354, Eugene Island 348, Eugene Island 367 and Eugene Island 208 for periods from October 30, 1992 until December 1, 1994, and with respect to the same properties except West Cameron 643 thereafter; PennzEnergy/Devon with respect to East Cameron 354, Eugene Island 348, Eugene Island 367 and Eugene/Devon Island 208 for periods from October 30, 1992 until October 1, 1995, and with respect to Eugene Island 348 and Eugene Devon Island 208 thereafter; TEPI with respect to West Cameron 643 and East Cameron 371 for periods beginning on or after December 1, 1994 until May 1, 2002; SONAT with respect to East Cameron 354 for periods on or after October 1, 1995; Amoco with respect to Eugene Island 367 for periods beginning on or after October 1, 1995; Amerada with respect to East Cameron 354 for periods beginning on or after January 1, 1998 until July 1, 2003; Chevron with respect to West Cameron 643 on and after May 1, 2002 until August 1, 2008; Chevron with respect to East Cameron 371 on and after May 1, 2002 until July 1, 2007; Anadarko with respect to East Cameron 354 on and after July 1, 2003 until October 1, 2004, Apache with respect to East Cameron 354 after October 1, 2004; Energy Resource Technology, Inc. with respect to East Cameron 371 on and after July 1, 2007; and Hilcorp with respect to West Cameron 643 on and after August 1, 2008).

As of March 27, 2009, a total of 4,751,510 units of beneficial interest in the Trust ("Units") are issued and outstanding. The Units have been traded on the Nasdaq SmallCap Market since August 31, 2001. Previously the Units were traded on the OTC Bulletin Board. The Units were also traded on pink sheets. From inception of the Trust to December 31, 2008, distributions to Unit holders totaled approximately $138,742,000 or approximately $29.20 per Unit. See "Management's Discussion and Analysis of Financial Condition and Results of Operation-Liquidity and Capital Resources" in Item 7 of this Form 10-K and Note 4 to the Notes to Financial Statements under Item 8 of this Form 10-K for a discussion regarding certain uncertainties of distributions.

The terms of the TEL Offshore Trust Agreement (the "Trust Agreement") provide, among other things, that: (1) the Trust is a passive entity whose activities are generally limited to the receipt of revenues attributable to the Trust's interest in the Partnership and the distribution of such revenues, after payment of or provision for Trust expenses and liabilities, to the owners of the Units; (2) the Trustees may sell all or any part of the Trust's interest in the Partnership or cause the sale of all or any part of the Royalty by the Partnership with the approval of a majority of the Unit holders; (3) the Trustees can establish cash reserves and can borrow funds to pay liabilities of the Trust and can pledge the assets of the Trust to secure payment of such borrowings; (4) to the extent cash available for distribution exceeds liabilities or reserves therefore established by the Trust, the Trustees will cause the Trust to make quarterly cash distributions to the Unit holders in January, April, July and October of each year; and (5) the Trust will terminate upon the first to occur of the following events: (i) total future net revenues attributable to the Partnership's interest in the Royalty, as determined by independent petroleum engineers, as of the end of any year, are less than $2 million or (ii) a decision to terminate the Trust by the affirmative vote of Unit holders representing a majority of the Units. Total future net revenues attributable to the Partnership's interest in the Royalty were estimated at $24.2 million as of October 31, 2008 based on the reserve study of DeGolyer and MacNaughton, independent petroleum engineers. (See "Termination of the Trust" and Note 9 of the Notes to Financial Statements under Item 8 of this Form 10-K for further information regarding estimated future net revenues.) Upon termination of the Trust, the Trustees will sell for cash all the assets held in the Trust estate and make a final distribution to Unit holders of any funds remaining after all Trust liabilities have been satisfied.

The terms of the Agreement of General Partnership of the Partnership (the "Partnership Agreement") provide that the Partnership will dissolve upon the occurrence of any of the following: (1) December 31, 2030, (2) the election of the Trust to dissolve the Partnership, (3) the termination of the Trust, (4) the bankruptcy of the Managing General Partner of the Partnership, or (5) the dissolution of the Managing General Partner or its election to dissolve the Partnership; however, the Managing General Partner has agreed not to dissolve or to elect to dissolve the Partnership and shall be liable for all damages and costs to the Trust if it breaches this agreement.

Under the Conveyance and the Partnership Agreement, the Trust is entitled to its share (99.99%) of 25% of the Net Proceeds, as hereinafter defined, realized from the sale of the oil, gas and associated hydrocarbons when produced from the Royalty Properties. See "Description of Royalty Properties." The Conveyance provides that the Working Interest Owners will calculate, for each quarterly period commencing the first day of February, May, August and November, an amount equal to 25% of the Net Proceeds from its oil and gas properties for the period. "Net Proceeds" means for each quarterly period, the excess, if any, of the Gross Proceeds, as hereinafter defined, for such period over Production Costs, as hereinafter defined, for such period. "Gross Proceeds" means the amounts received by the Working Interest Owners from the sale of oil, gas and associated hydrocarbons produced from the properties burdened by the Royalty, subject to certain adjustments. Gross Proceeds do not include amounts received by the Working Interest Owners as advance gas payments, "take-or-pay" payments or similar payments unless and until such payments are extinguished or repaid through the future delivery of gas. "Production Costs" means, generally, costs incurred on an accrual basis by the Working Interest Owners in operating the Royalty Properties, including capital and non-capital costs. In general, Net Proceeds are computed on an aggregate basis and consist of the aggregate proceeds to the Working Interest Owners from the sale of oil and gas from the Royalty Properties less (1) all direct costs, charges and expenses incurred by the Working Interest Owners in exploration, production, development, drilling and other operations on the Royalty Properties (including secondary recovery operations); (2) all applicable taxes (including severance and ad valorem taxes) excluding income taxes; (3) all operating charges directly associated with the Royalty Properties; (4) an allowance for costs, computed on a current basis at a rate equal to the prime rate of JPMorgan Chase Bank plus 0.5% on all amounts by which, and for only so long as, costs and expenses for the Royalty Properties incurred for any quarter have exceeded the proceeds of production from such Royalty Properties for such quarter; (5) applicable charges for certain overhead expenses as provided in the Conveyance; (6) the management fees and expense reimbursements owing the Working Interest Owners; and (7) a special cost reserve for the future costs to be incurred by the Working Interest Owners to plug and abandon wells and dismantle and remove platforms, pipelines and other production facilities from the Royalty Properties and for future drilling projects and other estimated future capital expenditures on the Royalty Properties. The Trustees are not obligated to return any royalty income received in any period, but future amounts otherwise payable will be reduced by the amount of any prior overpayments of such royalty income. The Working Interest Owners are required to maintain books and records sufficient to determine amounts payable under the Royalty. The Working Interest Owners are also required to deliver to the Managing General Partner on behalf of the Partnership a statement of the computation of Net Proceeds no later than the tenth business day prior to the quarterly record date.

The Royalty Properties are required to be operated in accordance with standards applicable to a prudent oil and gas operator. The Working Interest Owners are free to transfer their working interest in any of the Royalty Properties (burdened by the Royalty) to third parties. The Working Interest Owners are also free to enter into farm-out agreements whereby a Working Interest Owner would transfer a portion of its interest (unburdened by the Royalty) while retaining a lesser interest (burdened by the Royalty) in return for the transferee's obligation to drill a well on the Royalty Properties. The Working Interest Owners have the right to abandon any well or lease, and upon termination of any lease, the part of the Royalty relating thereto will be extinguished. The Royalty Properties are primarily operated by the Working Interest Owners although certain other parties operate some of the Royalty Properties.

The discussions of terms of the Trust Agreement, Partnership Agreement and Conveyance contained herein are qualified in their entirety by reference to the Trust Agreement, Partnership Agreement and Conveyance themselves, which are exhibits to this Form 10-K and are available upon request from the Corporate Trustee.

The Trust has no employees. Administrative functions of the Trust are performed by the Corporate Trustee.

History of the Trust

Tenneco Offshore Company, Inc. ("Tenneco Offshore") created the Trust effective January 1, 1983, pursuant to a Plan of Dissolution ("Plan"), which was approved by Tenneco Offshore's stockholders on December 22, 1982. In accordance with the Plan, the assets of Tenneco Offshore were transferred to the Trust as of January 1, 1983, and Units were exchanged for shares of common stock of Tenneco Offshore on the basis of one Unit for each share of common stock held by stockholders of record on January 14, 1983. Additionally, the Partnership was formed, in which the Trust owned a 99.99% interest and Tenneco initially owned a .01% interest. The Partnership was formed solely for the purpose of owning the Royalty, receiving the proceeds from the Royalty, paying the liabilities and expenses of the Partnership and disbursing remaining revenues to the Trust and the Managing General Partner of the Partnership in accordance with their interests. The Plan was effected by transferring an overriding royalty interest equivalent to a 25% net profits interest in the oil and gas properties of Exploration I located offshore Louisiana to the Partnership, contributing the common stock of Tenneco Offshore II Company ("Offshore II") to the Trust, and issuing certificates evidencing Units in liquidation and cancellation of Tenneco Offshore's common stock.

On October 31, 1986, Exploration I was dissolved and the oil and gas properties of Exploration I were distributed to Tenneco subject to the Royalty. Tenneco, who was then serving as the Managing General Partner of the Partnership, assumed the obligations of Exploration I, including its obligations under the Conveyance. The dissolution of Exploration I had no impact on future cash distributions to holders of units of beneficial interest.

As discussed above, on November 18, 1988, Chevron replaced Tenneco as the Working Interest Owner and Managing General Partner of the Partnership and assumed Tenneco's obligations under the Conveyance. On October 30, 1992, PennzEnergy acquired certain oil and gas producing properties from Chevron, including four of the Royalty Properties. The four Royalty Properties acquired by PennzEnergy were East Cameron 354, Eugene Island 348, Eugene Island 367 and Eugene Island 208. As a result of such acquisition, PennzEnergy replaced Chevron as the Working Interest Owner of such properties and assumed Chevron's obligations under the Conveyance with respect to such properties on October 30, 1992. On December 1, 1994, TEPI acquired two of the Royalty Properties from Chevron. The Royalty Property acquired by TEPI is West Cameron 643 and East Cameron 371. As a result of such acquisition, TEPI replaced Chevron as the Working Interest Owner of such property and assumed Chevron's obligations under the Conveyance with respect to such property on December 1, 1994. On October 1, 1995, SONAT and Amoco acquired the East Cameron 354 and Eugene Island 367 properties, respectively, from PennzEnergy. As a result of such acquisitions, SONAT and Amoco replaced PennzEnergy as the Working Interest Owners of the East Cameron 354 and Eugene Island 367 properties, respectively, and also assumed PennzEnergy's obligations under the Conveyance with respect to such properties on October 1, 1995. Effective January 1, 1998 ERT acquired the East Cameron 354 property from SONAT. As a result of such acquisition, ERT replaced SONAT as the Working Interest Owner of the East Cameron 354 property and also assumed SONAT's obligations under the Conveyance with respect to such property effective January 1, 1998. In October 1998, Amerada acquired the East Cameron 354 property from ERT effective January 1, 1998. As a result of this acquisition, Amerada replaced ERT as the Working Interest Owner of the East Cameron 354 property effective January 1, 1998, and also assumed ERT's obligations under the Conveyance with respect to this property. Effective January 1, 2000, PennzEnergy and Devon Energy Corporation (Nevada) merged into Devon. As a result of such merger, Devon replaced PennzEnergy as the Working Interest Owner of Eugene Island 348 and Eugene Island 208 properties effective January 1, 2000, and also assumed PennzEnergy's obligations under the Conveyance with respect to these properties. On October 9, 2001, a wholly owned subsidiary of Chevron Corporation, a Delaware corporation, merged with and into Texaco, pursuant to an Agreement and Plan of Merger, dated as of October 15, 2000. As a result of the Merger, Texaco Inc. became a wholly owned subsidiary of Chevron Corporation, and Chevron Corporation changed its name to "ChevronTexaco Corporation" in connection with the Merger. Accordingly, the properties referred to herein by Chevron and Texaco are each now controlled by subsidiaries of Chevron Corporation. Effective May 9, 2005, ChevronTexaco Corporation changed its name to Chevron Corporation. On May 1, 2002, TEPI assigned all of its interests in West Cameron 643 and East Cameron 371 to Chevron. Chevron sold its interest in East Cameron 371 to Energy Resource Technology, Inc. effective July 1, 2007. Chevron sold its interests in West Cameron 643 to Hilcorp effective August 1, 2008. On June 6, 2003, Anadarko acquired, among other interests, a 25% Working Interest in the East Cameron 354 field subject to the Royalty from Amerada effective April 1, 2003. As a result of this transaction, Anadarko replaced Amerada as the Working Interest Owner of East Cameron 354 effective July 1, 2003 and also assumed Amerada's obligation under the Conveyance with respect to this property. Effective October 1, 2004, Apache acquired Anadarko's interest in East Cameron 354 and assumed Anadarko's obligations under the Conveyance with respect to this property.

DESCRIPTION OF THE UNITS

Each Unit is evidenced by a transferable certificate issued by the Corporate Trustee. Each unit ranks equally as to distributions, has one vote on any matter submitted to Unit holders and represents an undivided interest in the Trust, which in turn owns a 99.99% interest in the Partnership.

Distributions

The Trustees distribute the Trust's income pro rata for each calendar quarter within 10 days after the end of each calendar quarter. Distributions of the Trust's income are made to Unit holders of record on the Quarterly Record Date, which is the last business day of each quarterly period, or such later date as the Trustees determine is required to comply with legal requirements. The Trustees determine for each quarterly period the amount available for distribution. Such amount (the "Quarterly Income Amount") consists of the cash received from the Royalty during the quarterly period plus any other cash receipts of the Trust, less the obligations of the Trust paid during the quarterly period, and adjusted for changes made by the Trust during the quarter in any cash reserves established for the payment of contingent or future obligations of the Trust. For a discussion of the cash reserves being established by the Trust, see "Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources" in Item 7 of this Form 10-K.

Within 90 days of the close of each year, the net federal taxable income of the Trust for each quarterly period ending in such year is reported by the Trustees for federal tax purposes to the Unit holder of record to whom the Quarterly Income Amount was distributed.

Possible Requirement That Units Be Divested

The Trust Agreement imposes no restrictions based on nationality or other status of the persons or other entities who are eligible to hold Units. However, the Trust Agreement provides that if at any time the Trust or any of the Trustees are named as a party in any judicial or administrative or other governmental proceeding which seeks the cancellation or forfeiture of any interest in any property located in the United States in which the Trust has an interest because of the nationality or any other status of any one or more owners of Units, or if at any time the Trustees in their reasonable discretion determine that such a proceeding is threatened or likely to be asserted and the Trust has received an opinion of counsel stating that the party asserting or likely to assert the claims has a reasonable probability of succeeding in such claim, the following procedures will be applicable:

(a) The Trustees, in their discretion, may seek from an investment banking firm to be selected by the Trustees an opinion as to whether it is in the Trust's best interest for the Trustees to take the actions permitted by (b)(i) through (iii) below.

(b) The Trustees may take no action with respect to the potential cancellation or forfeiture or may seek to avoid such cancellation or forfeiture by the following procedure:

(i) The Trustees will promptly give written notice ("Notice") to each record owner of Units as to the existence of or probable assertion of such controversy. The Notice will contain a reasonable summary of such controversy, will include materials which will permit an owner of Units to promptly confirm or deny to the Trustees that such owner is a person whose nationality or other status is or would be an issue in such a proceeding ("Ineligible Holder") and will constitute a demand to each Ineligible Holder that he dispose of his Units, to a party who would not be an Ineligible Holder, within 30 days after the date of the Notice.

(ii) If an Ineligible Holder fails to dispose of his Units as required by the Notice, the Trustees will have the right to redeem and will redeem, during the 90 days following the termination of the 30-day period specified in the Notice, any Unit not so transferred for a cash price equal to the mean between the closing bid and ask prices of the Units in the over-the-counter market or, if the Units are then listed on a stock exchange, the closing price of the Units on the largest stock exchange on which the Units are listed, on the last business day prior to the expiration of the 30-day period stated in the Notice. The procedures for any such purchase are more fully described in the Trust Agreement. The Trustees will cancel any Units acquired in accordance with the foregoing procedures thereby increasing the proportionate interest in the Trust of other holders of Units.

(iii) The Trustees may, in their sole discretion, cause the Trust to borrow any amounts required to purchase Units in accordance with the procedures described above.

Liability of Unit Holders

It is the intention of the Working Interest Owners and the Trustees that the Trust be an "express trust" under the Texas Trust Act. Under Texas law, beneficiaries of an express trust are not personally liable for the obligations of the trust, even if the assets of the trust are insufficient to discharge its obligations. However, it is unclear under Texas law whether the Trust will be held to constitute an express trust and, if it is not held to be an express trust, whether the holders of Units would be jointly and severally liable for the obligations of the Trust as would general partners of a partnership.

Under current judicial decisions, the Federal Energy Regulatory Commission ("FERC") is not considered to be empowered to compel refunds from overriding royalty interest owners with respect to gas price overcharges. However, future laws, regulations or judicial decisions might permit the FERC or other governmental agencies to require such refunds from overriding royalty interest owners or create filing, reporting or certification obligations with respect to a trust created for such overriding royalty interest owners. Moreover, other parties, such as oil or gas purchasers, may be able to instigate private lawsuits or other legal action to compel refunds from overriding royalty interest owners with respect to oil or gas pricing overcharges.

The Working Interest Owners have agreed that they will not seek to recover from the Unit holders the amount of any refunds they are required to make except out of future revenues payable to the

Trust. The Trustees will be liable to the Unit holders if the Trustees allow any liability to be incurred without taking any and all action necessary to ensure that such liability will be satisfiable only out of the Trust assets (regardless of whether the assets are adequate to satisfy the liability) and will be non-recourse to the Unit holders. However, the Trustees will not be liable to the Unit holders for state or federal income taxes or for refunds, fines, penalties or interest relating to oil or gas pricing overcharges under state or federal price controls. The Trustees will be indemnified from the Trust assets, to the extent that the Trustees' actions do not constitute gross negligence, bad faith or fraud.

Each Unit holder should consider, in weighing the possible exposure to liability in the event the Trust were not classified as an express trust, (1) the substantial value and passive nature of the Trust assets, (2) the restrictions on the power of the Trustees to incur liabilities on behalf of the Trust and (3) the limited activities to be conducted by the Trustees.

Federal Income Tax Matters

This section is a summary of federal income tax matters of general application which addresses the material tax consequences of the ownership and sale of the Units. Except where indicated, the discussion below describes general federal income tax considerations applicable to individuals who are citizens or residents of the United States. Accordingly, the following discussion has limited application to domestic corporations and persons subject to specialized federal income tax treatment, such as regulated investment companies and insurance companies. It is impractical to comment on all aspects of federal, state, local and foreign laws that may affect the tax consequences of the transactions contemplated hereby and of an investment in the Units as they relate to the particular circumstances of every Unit holder. **Each Unit holder is encouraged to consult his own tax advisor with respect to his particular circumstances.**

This summary is based on current provisions of the Internal Revenue Code of 1986, as amended (the "Code"), existing and proposed Treasury Regulations thereunder and current administrative rulings and court decisions, all of which are subject to changes that may be retroactively applied. Some of the applicable provisions of the Code have not been interpreted by the courts or the Internal Revenue Service ("IRS"). No assurance can be provided that the statements set forth herein (which do not bind the IRS or the courts) will not be challenged by the IRS or will be sustained by a court if so challenged.

Classification of the Trust

The IRS has ruled that the Trust is a grantor trust and that the Partnership is a partnership for federal income tax purposes. Thus, the Trust will incur no federal income tax liability and each Unit holder will be treated as owning an interest in the Partnership.

The Trustees assume that some Units are held by a middleman as such term is broadly defined in applicable Treasury Regulations (and includes custodians, nominees, certain joint owners, and brokers holding an interest for a custodian in street name.) Therefore, the Trustees consider the Trust to be a widely held fixed investment trust ("WHFIT") for federal income tax purposes. The Corporate Trustee, 919 Congress Avenue, Austin, Texas 78701, telephone number 1-800-852-1422, is the representative of the Trust that will provide tax information in accordance with applicable Treasury Regulations governing the information reporting requirements of the Trust as a WHFIT.

Income and Depletion

Each Unit holder of record as of the last business day of each quarter will be allocated a share of the income and deductions of the Trust, including the Trust's share of the income and deductions of the Partnership, computed on an accrual basis, for that quarter. Royalty income is portfolio income. Since all income from the Partnership is royalty income, this amount, net of depletion and severance taxes, is portfolio income and, subject to certain exceptions and transitional rules, this royalty income cannot be offset by passive losses. Additionally, interest income is portfolio income. Administrative expense is an investment expense.

The IRS has also ruled that the Royalty is a non-operating economic interest giving rise to income subject to depletion. The Trustees will treat the Royalty as a single property giving rise to income subject to depletion, although the computation of depletion will be made by each Unit holder based upon information provided by the Trustees. Each Unit holder will be entitled to compute cost depletion with respect to his share of income from the Royalty based on his basis in the Royalty. A Unit holder will have a basis in the Royalty equal to the basis in his Units less any amount allocable to his share of any cash reserve account. Transferees of Units transferred after October 11, 1990, may be eligible to use the percentage depletion deduction on oil and gas income thereafter attributable to such Units, if the percentage depletion deduction would exceed cost depletion. Unlike cost depletion, percentage depletion is not limited to a Unit holder's depletable tax basis in the Units. Rather, a Unit holder may be entitled to a percentage depletion deduction as long as the Royalty generates gross income.

Backup Withholding

Distributions from the Trust are generally subject to backup withholding at a rate of 28% of these distributions. Backup withholding generally will not apply to distributions to a Unit holder unless the Unit holder fails to properly provide to the Trust his taxpayer identification number or the IRS notifies the Trust that the taxpayer identification number provided by the Unit holder is incorrect.

Sale of Units

Generally, except for recapture items, the sale, exchange or other disposition of a Unit will result in capital gain or loss measured by the difference between the tax basis in the Unit and the amount realized. Effective for property placed in service after December 31, 1986, the amount of gain, if any, realized upon the disposition of oil and gas property is treated as ordinary income to the extent of the intangible drilling and development costs incurred with respect to the property and depletion claimed with respect to the property to the extent it reduced the taxpayer's basis in the property. Under this provision, depletion attributable to a Unit acquired after 1986 will be subject to recapture as ordinary income upon disposition of the Unit or upon disposition of the oil and gas property to which the depletion is attributable. The balance of any gain or any loss will be capital gain or loss if the Unit was held by the Unit holder as a capital asset, either long-term or short-term depending on the holding period of the Unit. This capital gain or loss will be long-term if a Unit holder's holding period for the Unit exceeds one year at the time of sale or exchange. Capital gain or loss will be short-term if the Unit has not been held for more than one year at the time of sale on exchange. Long-term capital gain generally will be subject to a maximum U.S. federal income tax rate of 15%, which maximum tax rate currently is scheduled to increase to 20% for dispositions occurring during taxable years beginning on or after January 1, 2011. The deductibility of capital losses are subject to certain limitations.

Non-U.S. Unit holders

In general, a Unit holder who is a nonresident alien individual or which is a foreign corporation, each a "non-U.S. Unit holder" for purposes of this discussion, will be subject to tax on the gross income (without taking into account any deductions, such as depletion) produced by the Royalty at a rate equal to 30%, or if applicable, at a lower treaty rate. This tax will be withheld by the Trustees and remitted directly to the United States Treasury. A non-U.S. Unit holder may elect to treat the income from the Royalty as effectively connected with the conduct of a United States trade or business under provisions of the Code, or pursuant to any similar provisions of applicable treaties. Upon making this election a non-U.S. Unit holder is entitled to claim all deductions with respect to that income, but he must file a United States federal income tax return to claim those deductions. This election once made is irrevocable, unless an applicable treaty allows the election to be made annually. However, that effectively connected taxable income is subject to withholding at the highest applicable tax rate, 35% for individual non-U.S. Unit holders.

The Code and the Treasury Regulations thereunder treat the publicly traded Trust as if it were a United States real property holding corporation. Accordingly, non-U.S. Unit holders may be subject to United States federal income tax on any gain from the disposition of their Units.

Federal income taxation of a non-U.S. Unit holder is a highly complex matter which may be affected by many other considerations. Therefore, each non-U.S. Unit holder is encouraged to consult its own tax advisor with respect to its ownership of Units.

Tax-exempt Organizations

Investments in publicly traded grantor trusts are treated the same as investments in partnerships for purposes of the rules governing unrelated business taxable income. The Royalty and interest income should not be unrelated business taxable income so long as, generally, a Unit holder did not incur debt to acquire a Unit or otherwise incur or maintain a debt that would not have been incurred or maintained if that Unit had not been acquired. Legislative proposals have been made from time to time which, if adopted, would result in the treatment of Royalty income as unrelated business taxable income. Each tax-exempt Unit holder is encouraged to consult its own tax advisor with respect to its ownership of Units and the treatment of Royalty income.

State Law Considerations

The Trust and the Partnership have been structured so as to cause the Units to be treated for certain state law purposes essentially the same as other securities, that is, as interests in intangible personal property rather than as interests in real property. However, in the absence of controlling legal precedent, there is a possibility that under certain circumstances a Unit holder could be treated as owning an interest in real property under the laws of Louisiana. In that event, the tax, probate, devolution of title and administration laws of Louisiana or other states applicable to real property may apply to the Units, even if held by a person who is not a resident thereof. Application of these laws could make the inheritance and related matters with respect to the Units substantially more onerous than had the Units been treated as interests in intangible personal property. Unit holders are encouraged to consult their legal and tax advisors regarding the applicability of these considerations to their individual circumstances.

Texas does not impose an income tax. Therefore, no part of the income produced by the Trust is subject to an income tax in Texas. However, effective January 1, 2008, Texas imposes a margin tax at a rate of 1% on gross revenues less certain deductions, as specifically set forth in the Texas margin tax statute. The Texas margin tax is a significant change in Texas tax law. The tax generally will be imposed on gross revenues generated in 2007 and thereafter. Entities subject to tax generally include trusts unless otherwise exempt, and most other types of entities having limited liability protection. Trusts and partnerships that receive at least 90% of their federal gross income from designated passive sources, including royalties from mineral properties and other non-operated mineral interest income, and do not receive more than 10% of their income from operating an active trade or business, are generally exempt from the Texas margin tax as "passive entities." The Trust should be exempt from Texas margin tax as a "passive entity." Since the Trust should be exempt from Texas margin tax at the Trust level as a passive entity, each Unit holder that is considered a taxable entity under the Texas margin tax would generally be required to include its Texas portion of Trust revenues in its own Texas margin tax computation. Each unitholder is urged to consult its own tax advisor regarding its possible Texas state franchise tax liability.

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TERMINATION OF THE TRUST

The terms of the TEL Offshore Trust Agreement provide that the Trust will terminate upon the first to occur of the following events: (1) total future net revenues attributable to the Partnership's interest in the Royalty, as determined by independent petroleum engineers, as of the end of any year, are less than $2 million or (2) a decision to terminate the Trust by the affirmative vote of Unit holders representing a majority of the Units. Total future net revenues attributable to the Partnership's interest in the Royalty were estimated at $24.2 million as of October 31, 2008, based on the reserve study of DeGolyer and MacNaughton, independent petroleum engineers, discussed herein. Such reserve study does not include any reserves or values attributable to Eugene Island 339, nor does it include the Trust's percentage share of the total plugging and abandonment costs related to Eugene Island 339, with costs for 2009 alone estimated to be approximately $61 million. Based on the DeGolyer and MacNaughton reserve study, as of October 31, 2008, in order to correspond with distributions to the Trust, it is estimated that approximately 40% of future net revenues from the Royalty Properties are expected to be received by the Trust during the next 3 years. Because the Trust will terminate in the event estimated future net revenues fall below $2.0 million, it would be possible for the Trust to terminate even though some or all of the Royalty Properties continued to have remaining productive lives. Upon termination of the Trust, the Trustees will sell for cash all of the assets held in the Trust estate and make a final distribution to Unit holders of any funds remaining after all Trust liabilities have been satisfied. The estimates of future net revenues discussed above are subject to the limitations described in the summary of the DeGolyer and MacNaughton reserve study included in Item 1 of this Form 10-K. The reserve study is limited to reserves classified as proved; therefore, future capital expenditures for recovery of reserves not classified as proved by DeGolyer and MacNaughton are not included in the calculation of estimated future net revenues nor are any capital expenditures included for any redevelopment of Eugene Island 339. In addition, the estimates of future net revenues discussed above are subject to large variances from year to year and should not be construed as exact. There are numerous uncertainties present in estimating future net revenues for the Royalty Properties. The estimate may vary depending on changes in market prices for crude oil and natural gas, the recoverable reserves, annual production and costs assumed by DeGolyer and MacNaughton. In addition, future economic and operating conditions as well as results of future drilling plans may cause significant changes in such estimate. The discussion set forth above is qualified in its entirety by reference to the Trust Agreement itself, which is an exhibit to this Form 10-K and is available upon request from the Corporate Trustee.

In addition, in the event of a dissolution of the Partnership (which could occur under the circumstances described above under "Description of the Trust") and a subsequent winding up and termination thereof, the assets of the Partnership (*i.e.*, the Royalty) could either (1) be distributed in kind ratably to the Trust and the Managing General Partner or (2) be sold and the proceeds thereof distributed ratably to the Trust and the Managing General Partner. In the event of a sale of the Royalty and a distribution of the cash proceeds thereof to the Trust and the Managing General Partner, the Trustees would make a final distribution to Unit holders of the Trust's portion of such cash proceeds plus any other cash held by the Trust after payment of or provision for all liabilities of the Trust, and the Trust would be terminated.

ROYALTY INCOME, DISTRIBUTABLE INCOME AND TOTAL ASSETS

Reference is made to Items 6, 7 and 8 of this Form 10-K for financial information relating to the Trust.

DESCRIPTION OF ROYALTY PROPERTIES

Producing Acreage and Wells

The Partnership's interest consists of an overriding royalty interest, equivalent to a 25% net profits interest, in the Royalty Properties as follows:

					Gross Wells Drilled as of October 31, 2008			
					Wells Drilled(1)		Successful (2)(3)	
Property	**Acquisition Date (Mo.-Yr.)**	**Current Working Interest Owner**	**Working Interest Owner's Ownership Interest(%) (4)**	**Gross Acres**	**Expl.**	**Dev.**	**Oil**	**Gas**
East Cameron 354(5)	12-72	Apache	11.14	5,000	2	4	0	5
West Cameron 643 unit(6)	12-72	Hilcorp	35.86	5,000	3	17	0	14
Eugene Island 339 non-unit(2)	12-72	Chevron	50.00	5,000	2	33(7)	19(7)	0
Eugene Island 339 5500' unit(2)	12-72	Chevron	42.05	5,000	0	5	5	0
Eugene Island 339 4500' unit(2)	12-72	Chevron	38.50gas 24.44oil	5,000	0	20	16	0
Eugene Island 342 SW/4	12-72	Chevron	.06	5,000	4	5	0	7
Eugene Island 342 NW/4	12-72	Chevron	0.18	5,000	2	4	0	4
Eugene Island 348(8)	12-72	Devon	50.00	5,000	4	5	0	7
West Cameron 642	12-72	Chevron	25.00	5,000	4	7	0	8
East Cameron 370(9)	1-73	N.A.	25.00	5,000	3	1	0	4
East Cameron 371(10)	1-73	ERT	7.50	5,000	7	2	0	4
Vermilion 246(11)	1-73	Chevron	33.37	5,000	3	3	0	4
West Cameron 41 E/2(12)	3-74	N.A	.30	2,500	0	0	0	0
Ship Shoal 183 N/2	7-88	Chevron	66.67	2,500	1	11	8	4
Ship Shoal 183 unit	7-88	Chevron	34.29	1,875	1	22	20	3
Ship Shoal 183 F-3	7-88	Chevron	100.0	5,000	1	0	0	1
Ship Shoal 183 F-1	7-88	Chevron	50.00	5,000	1	0	1	0
Eugene Island 208	8-73	Devon	100.00	1,250	0	3	0	3
Eugene Island 367(13)	3-74	N.A.	1.60	5,000	2	9	0	9
South Marsh Island 252	3-74	Chevron	3.00	4,997	2	0	0	1
South Timbalier 36(14)	3-74	Chevron	.26	5,000	2	20	9	11
South Timbalier 37	3-74	Chevron	.26	5,000	13	41	39	3
Total				98,122	57	212	117	92

(1) As of October 31, 2008, there were no wells in the process of being drilled.

(2) As of October 31, 2008, there were 75 producing completions (34 associated with Ship Shoal, 4 associated with South Timbalier 36 and 37 associated with South Timbalier 37). All Eugene Island 339 wells were destroyed by Hurricane Ike in September 2008.

(3) Multiple completions are counted as one well. South Timbalier 37 has 5 multiple completion wells and Ship Shoal 182/183 has 2 multiple completion wells.

(4) These percentages represent the working interest owner's interest subject to the Partnership's net proceeds.

(5) Apache purchased this working interest from Anadarko effective October 1, 2004. This lease expired in 2005. Wells were plugged and abandoned in 2006. The platforms to which the wells were connected were abandoned in July 2008.

(6) West Cameron 643 was sold to Hilcorp Energy Company, effective August 1, 2008.

(7) Eugene Island 339 C-17 and C-18 wells are producing in this property but are not included here; they are not subject to the Partnership's net proceeds until they pay out.

(8) This lease expired in 2004. Abandonment work was completed in May 2006.

(9) This lease expired in 1996.

(10) East Cameron 371 was sold to Energy Resource Technology, Inc., effective July 1, 2007.

(11) This lease (Vermillion 246 Block, OCS-G 1147) was terminated in 2002. Abandonment work was completed mid 2005.

(12) This lease expired in November 2002, and all wells on the lease had been abandoned as of November 2003.

(13) This lease expired on May 30, 1996. It was leased again as OCS-G 19800 effective July 1, 1998. Neither Chevron nor any affiliates of Chevron have an interest in OCS-G-19800.

(14) South Timbalier 36 well number 2 working interest owner's ownership interest is .013 percent.

During 2006, there was one development gas well drilled, which was completed at Ship Shoal 183. During 2007, there were three development oil wells drilled, all of which were completed and were associated with South Timbalier 37. During 2008, one development oil well was drilled, which was completed and was associated with South Timbalier 37, and there was one workover of a gas well at South Timbalier 36.

Reserves

A study of the proved oil and gas reserves attributable to the Partnership, in which the Trust has a 99.99% interest, has been made by DeGolyer and MacNaughton, independent petroleum engineering consultants, as of October 31, 2008. The following is a summary of such reserve study. Such study reflects estimated production, reserve quantities and future net revenue based upon estimates of the future timing of actual production without regard to when received by the Trust, which differs from the manner in which the Trust recognizes its royalty income. See Notes 2 and 9 in the Notes to Financial Statements under Item 8 of this Form 10-K.

On October 7, 2008, the Trust announced that production from the two most significant oil and gas properties associated with the Trust had ceased following damage inflicted by Hurricane Ike in September 2008. The platforms and wells on Eugene Island 339 were completely destroyed by the hurricane. In order to restore production at Eugene Island 339, Chevron expects that it would need to redevelop the facility and drill new wells. The Trust had expected Chevron to make a decision in the first quarter of 2009 whether to proceed with any such development; however, Chevron is still assessing its alternatives and the economic feasibility for restoring production at the property. See "Management's Discussion and Analysis of Financial Condition and Results of Operation—Operations." Chevron's decisions regarding Eugene Island 339 impact the treatment of Eugene Island for purposes of preparing a reserve report for the Partnership. Solely for purposes of being able to complete the reserve report so that the Trust could file this Form 10-K, DeGolyer and MacNaughton assumed that Eugene Island 339 will not be redeveloped. As such, the reserve study does not include any reserves or values attributable to Eugene Island 339, nor does it include the Trust's percentage share of the total plugging and abandonment costs related to Eugene Island 339, with costs for 2009 alone estimated to be approximately $61 million. At this point in time, there can be no assurance as to how or when, or if at all, production may be restored at Eugene Island 339. Based on the reserve study of DeGolyer and MacNaughton for the oil and gas reserves attributable to the Partnership as of October 31, 2007, Eugene Island 339 accounted for approximately 34% of the total future net revenues attributable to the Partnership's interest in the Royalty as of October 31, 2007.

There are numerous uncertainties inherent in estimating quantities of proved reserves and in projecting the future rates of production and timing of development expenditures, including many factors beyond the control of the producer. The reserve data in the DeGolyer and MacNaughton study represent estimates only and should not be construed as being exact. The discounted present values shown by the DeGolyer and MacNaughton study should not be construed as the current market value of the estimated gas and oil reserves attributable to the Royalty Properties or the costs that would be incurred to obtain equivalent reserves, since a market value determination would include many additional factors. Estimates were prepared in accordance with guidelines established by the SEC and the Financial Accounting Standards Board. Accordingly, the estimates are based on existing economic and operating conditions in effect at October 31, 2008, with no provision for future increases or decreases except for periodic price redeterminations in accordance with existing gas contracts. Actual future prices and costs may be materially greater or less than the assumed amounts in the reserve study. Because the reserve study is limited to proved reserves, future capital expenditures for recovery of reserves not classified as proved by DeGolyer and MacNaughton are not included in the calculation of estimated future net revenues nor are any capital expenditures for any redevelopment of Eugene Island 339. Reserve assessment is a subjective process of estimating the recovery from underground accumulations of gas and oil that cannot be measured in an exact way, and estimates of other persons might differ materially from those of DeGolyer and MacNaughton. Accordingly, reserve estimates are often different from the quantities of hydrocarbons that are ultimately recovered.

Estimated net proved reserves attributable to the net profits interest owned by the Partnership, as of October 31, 2008 (excluding Eugene Island 339), are summarized as follows, expressed in barrels (bbl) and thousands of cubic feet (Mcf):

	Oil and Condensate (bbl)	Natural Gas (Mcf)
Proved Developed Reserves		
Reserves as of October 31, 2007	442,004	2,217,654
Revisions of Previous Estimates(2)	(126,491)	(210,967)
Improved Recovery	0	0
Purchases of Minerals in Place	0	0
Extensions, Discoveries, and Other Additions	58	3,131
Production(1)	(96,429)	(622,666)
Sales of Minerals in Place	0	0
Reserves as of October 31, 2008	219,142	1,387,152

(1) Production was estimated based on the ratio as of October 31, 2007, of the Partnership's net profits interest in net reserves to the net reserves associated with the Partnership's net profits interest and the interests retained in the Royalty Properties by the Working Interest Owners. This ratio was then applied to the production net to the combined interests of the Partnership and the Working Interest Owners for the period from November 1, 2007, through October 31, 2008.

(2) The revisions also take into account the assumption, solely for purposes of being able to complete the related reserve study, that no reserves are attributable to Eugene Island 339.

Information used in the preparation of the reserve study was obtained from the Working Interest Owners. All of the reserve estimates are classified as proved developed reserves.

The Partnership's share of gas sales are recorded by the Working Interest Owners on the cash method of accounting or based on actual production. When revenues are reported on actual production, there is no gas imbalance created. Under the cash method, revenues are recorded based on actual gas volumes sold, which could be more or less than the volumes the Working Interest Owners are entitled to based on their ownership interests. Total future net revenues attributable to the Partnership's interest in the Royalty were estimated at $24.2 million as of October 31, 2008 based on the reserve study of DeGolyer and MacNaughton. The Partnership's Royalty income for a period reflects the actual gas sold during the period.

While estimates of reserves attributable to the Royalty are shown in order to comply with requirements of the SEC, there is no precise method of allocating estimates of physical quantities of reserves to the Partnership and the Trust, since the Royalty is not a working interest and the Partnership does not own and is not entitled to receive any specific volume of reserves from the Royalty. Reserve quantities in the DeGolyer and MacNaughton reserve study have been allocated based on a revenue formula and such quantities can be affected by future changes in various economic factors utilized in estimating future gross and net revenues from the Royalty Properties. Therefore, the estimates of reserves set forth in the DeGolyer and MacNaughton study are to a large extent hypothetical and differ in significant respects from estimates of reserves attributable to a working interest. For a further discussion of reserves, reference is made to Note 9 in the Notes to Financial Statements under Item 8 of this Form 10-K.

The future net revenues contained in the DeGolyer and MacNaughton reserve study have not been reduced for future costs and expenses of the Trust, which are expected to approximate $883,000 annually, plus the Trust's percentage share of the total plugging and abandonment costs related to Eugene Island 339, with costs for 2009 alone estimated to be approximately $61 million. The costs and expenses of the Trust may increase in future years, depending on increases in accounting, engineering, legal and other professional fees, as well as other factors.

Revenue values in the reserve study were estimated using the initial costs provided by Chevron and prices as of October 31, 2008 of $67.81 per barrel of oil and $6.75 per Mcf of natural gas. The future net revenue value was calculated by deducting operating expenses and capital costs from future gross revenue of the combined interests of the Partnership and the Working Interest Owners in the Royalty Properties. Current estimates of operating expenses were used for the life of the properties with no increases in the future based on inflation. The values were reduced by a trust overhead charge furnished by Chevron. Capital and abandonment costs for longer-life properties were accrued at the end of each quarter in amounts specified by Chevron beginning in January 2009. The future accrual or escrow amounts for the Royalty Properties were deducted from the future net revenue at the end of each quarter, as specified by Chevron. Interest on the balance of the accrued capital and abandonment costs at the rate of 2.0% per year as specified by Chevron was credited monthly. The adjusted revenue resulting from subtracting the overhead charge and accrued capital and abandonment costs was multiplied by a factor of 25% to arrive at the future net revenue attributed to the Partnership's net profits interest. Interest was charged monthly on the net profits deficit balances (costs not recovered currently) at the rate of 2.0% per year as specified by Chevron. Future income tax expenses were not taken into account in estimating future net revenue.

In addition, because the DeGolyer and MacNaughton reserve study is limited to proved reserves, future capital expenditures for recovery of reserves not classified as proved by DeGolyer and MacNaughton are not included in the calculation of future net revenues nor are any capital expenditures for any redevelopment of Eugene Island 339. These capital expenditures could have a significant effect on the actual future net revenues attributable to the Partnership's interest in the Royalty.

The Trust Agreement provides that the Trust will terminate in the event total future net revenues attributable to the Partnership's interest in the Royalty as determined by independent petroleum engineers, as of the end of any year, are less than $2.0 million. See "Business—Termination of the Trust".

The Managing General Partner of the Partnership has advised the Trust that there have been no events (other than the treatment of Eugene Island, solely for purposes of preparing the reserve study) subsequent to October 31, 2008 that have caused a significant change in the estimated proved reserves referred to in the DeGolyer and MacNaughton study.

Operations and Production

Reference is made to the Section entitled "Operations" under Item 7 of this Form 10-K for information concerning operations and production.

Distributions

During 2005, Hurricane Katrina and Hurricane Rita caused significant damage to various platforms and third-party transportation systems, which resulted in oil and gas production delays in the Royalty Properties. During 2006, several of the platforms and facilities on the Royalty Properties were restored, and by the third quarter of 2007 all but one of the platforms and facilities had been restored. One of the platforms and facilities on Eugene Island was destroyed and has not been restored. Since those hurricanes, overall production slowly returned to normal production levels, until production ceased at Eugene Island 339 and Ship Shoal 182 and 183 following damages inflicted by Hurricane Ike in September 2008. Future Net Proceeds may take into account the Trust's share of project costs and other related expenditures that are not covered by insurance of the operator of the Royalty Properties. The extensive damage caused by hurricanes Katrina and Rita led to significant demand for services and supplies for repairs in the offshore Gulf of Mexico, which increased levels of expenditures. The reduced oil and gas production and increased costs reduced the cash income distributions to unitholders significantly during 2006 and affected the first and second quarters of 2007. During the fourth quarter 2006, the Trust resumed distributions. The fourth quarter distribution of $1.7 million was paid on January 11, 2007. On March 30, 2007, the Trust announced its first quarter distribution of approximately $1.2 million. On June 27, 2007, the Trust announced its second quarter distribution of approximately $2.1 million, which was paid on July 9, 2007. On September 27, 2007, the Trust announced its third quarter distribution of approximately $2.8 million, which was paid on October 9, 2007. On December 21, 2007, the Trust announced its fourth quarter distribution of approximately $3.3 million, which was paid on January 10, 2008. On March 26, 2008, the Trust announced its first quarter distribution of approximately $4.5 million, which was paid on April 10, 2008. On June 27, 2008, the Trust announced its second quarter distribution of approximately $2.6 million, which was paid on July 10, 2008. On September 26, 2008, the Trust announced its third quarter distribution of approximately $5.5 million, which was paid on October 10, 2008. On December 19, 2008, the Trust announced its fourth quarter distribution of approximately $0.7 million, which was paid on January 9, 2009. The funds available for the fourth quarter distribution were severely negatively impacted by Hurricane Ike. On March 25, 2009, the Trust announced that there would be no trust distribution for the first quarter of 2009. Future distributions by the Trust are expected to be severely negatively impacted because of both reduced production and increased expenditures required to remediate, repair and, perhaps, restore platforms and wells. See "Management's Discussion and Analysis of Financial Condition and Results of Operations—Operations."

MARKETING

The amount of cash distributions by the Trust is dependent on, among other things, the sales prices for oil and gas produced from the Royalty Properties and the quantities of oil and gas sold.

It should be noted that substantial uncertainties exist with regard to future oil and gas prices, which are subject to material fluctuations due to changes in production levels and pricing and other actions taken by major petroleum producing nations, as well as the regional supply and demand for gas, weather, industrial growth, conservation measures, competition and other variables.

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Gas Marketing

During the years ended December 31, 2006, 2007 and 2008, approximately 99% of Chevron's natural gas and natural gas liquids relative to the Trust's Royalty Properties were committed and sold to Chevron Natural Gas at spot market prices.

It should be noted that the Conveyance provides that amounts received by the producer pursuant to "take-or-pay" provisions are not included within the Royalty payable to the Trust unless and until gas is actually delivered pursuant to the "make-up" provisions, if any, of the applicable contract. Accordingly, amounts received by the Working Interest Owners as "take-or-pay" payments are not included in the calculation of the Royalty payable, and the income received by the Trust is restricted to amounts paid for gas actually delivered.

Due to the seasonal nature of demand for natural gas and its effects on sales prices and production volumes, the amount of gas sold with respect to the Royalty Properties may vary. Generally, production volumes and prices are higher during the first and fourth quarters of each calendar year. Because of the time lag between the date on which the Working Interest Owners receive payment for production from the Royalty Properties and the date on which distributions are made to Unit holders, the seasonality that generally affects production volumes and prices is generally reflected in distributions to the Trust in later periods.

The following paragraphs discuss the marketing of gas from the principal Royalty Properties.

West Cameron 643. West Cameron 643 contributed approximately 18% of the revenues from natural gas sales from the Royalty Properties in 2008. The average price received for natural gas from all of the Working Interest Owners' purchasers on West Cameron 643 during 2008 was $9.46 per Mcf.

East Cameron 371. East Cameron 371 contributed a little over 2% of the revenues from natural gas sales from the Royalty Properties in 2008. The average price received for natural gas from all of the Working Interest Owners' purchasers on East Cameron 371 during 2008 was $7.79 per Mcf.

Ship Shoal 182/183. Ship Shoal 182/183 contributed approximately 42% of the revenues from gas sales from the Royalty Properties in 2008. The average price received for natural gas from all of the Working Interest Owners' purchasers on Ship Shoal 182/183 during 2008 was $9.29 per Mcf, before prior period audit adjustments.

Eugene Island 339. Eugene Island 339 contributed approximately 37% of the revenues from natural gas sales from the Royalty Properties in 2008. The average price received for natural gas from all of the Working Interest Owners' purchasers on Eugene Island 339 during 2008 was $9.60 per Mcf, before prior period audit adjustments.

South Timbalier 36/37. South Timbalier 36/37 contributed approximately 1% of the revenues from natural gas sales from the Royalty Properties in 2008. The average price received for natural gas from all of the Working Interest Owners' purchasers on South Timbalier 36/37 during 2008 was $10.39 per Mcf, before prior period audit adjustments.

Oil Marketing

Crude oil purchases by Chevron accounted for approximately 99% of total crude oil revenues from the Royalty Properties during 2006, 2007 and 2008.

Chevron purchases the crude oil at prices based on a market index for the applicable grade of crude oil, as adjusted for gravity and transportation charges, if applicable. Average monthly prices for fiscal year 2008 ranged from $80.86 per barrel to $137.32 per barrel.

COMPETITION AND REGULATION

Competition

The Working Interest Owners experience competition from other oil and gas companies in all phases of its operations. Numerous companies participate in the exploration for and production of oil and gas. The Working Interest Owners have advised the Trust that they believe that their competitive positions are affected by price and contract terms. Business is affected not only by such competition, but also by general economic developments, governmental regulations and other factors.

Regulation—General

The production of oil and gas by the Working Interest Owners is affected by many state and federal regulations with respect to allowable rates of production, drilling permits, well spacing, marketing, environmental matters and pricing. Future regulations could change allowable rates of production or the manner in which oil and gas operations may be lawfully conducted. Sales of natural gas in interstate commerce for resale and the transportation of natural gas in interstate commerce are subject to regulation by the Federal Energy Regulatory Commission ("FERC") under the Natural Gas Act of 1938, as amended (the "Natural Gas Act").

The operations of the Working Interest Owners under federal oil and gas leases offshore the United States are subject to regulations of the United States Department of Interior which currently impose absolute liability upon lessees for the cost of cleanup of pollution resulting from their operations.

FERC Regulation

In general, the FERC regulates the transportation of natural gas in interstate commerce by interstate pipelines. The FERC has adopted regulations resulting in a restructuring of the natural gas industry. The principal elements of this restructuring were the requirement that interstate pipelines separate, or "unbundle," into individual components the various services offered on their systems, with all transportation services to be provided on a non-discriminatory basis, and the prohibition against an interstate pipeline providing gas sales services except through separately- organized affiliates. In various rulemaking proceedings following its initial unbundling requirement, the FERC has refined its regulatory program applicable to interstate pipelines in various respects, and it has announced that it will continue to monitor these regulations to determine whether further changes are needed. In addition to rulemaking proceedings, the FERC establishes new policies and regulations through policy statements and adjudications of individual pipeline matters. Further, additional changes to regulations may occur based on actions taken by the United States Congress and/or the courts. As to these various developments, the working interest owners have advised the Trust that the on-going and evolving nature of these regulatory initiatives makes it impossible to predict their ultimate impact on the prices, markets or terms of sale of natural gas related to the Trust.

State and Other Regulation

State regulation of gathering facilities generally includes various safety, environmental, and in some circumstances, non-discriminatory take requirements. Some states have implemented more stringent legislation in recent years to regulate gathering rates charged by gas gathering companies, but to date the effect on the Working Interests Owners in connection with the Trust has been minimal.

Natural gas pipeline facilities used for the transportation of natural gas in interstate commerce are subject to Federal minimum safety requirements. These requirements, however, are not applicable to, *inter alia*: (1) onshore gathering facilities outside: (i) the limits of any incorporated or unincorporated city, town, or village; and (ii) any designated residential or commercial area; or (2) pipeline facilities on the Outer Continental Shelf ("OCS") upstream of the point at which operating responsibility transfers from a producing operator to a transporting operator. *See* 49 C.F.R. § 192.1(b). The Corporate Trustee has been informed that the Royalty Properties are located in Federal waters on the OCS. The standards governing pipeline safety have undergone recent changes and it is possible that future changes in the regulations and statutes may occur which may increase the stringency of the standards or expand the applicability of the standards to facilities not currently covered.

Environmental Regulations

General

The Working Interest Owners' oil and gas activities on the Royalty Properties are subject to existing and evolving federal, state and local environmental laws and regulations. The Managing General Partner of the Partnership has advised the Trust that the Working Interest Owners believe that their operations and facilities are in general compliance with applicable health, safety, and environmental laws and regulations that have taken effect at the federal, state and local levels. In addition, events in recent years have heightened environmental concerns about the oil and gas industry generally, and about offshore operations in particular. The Working Interest Owners' operation of federal offshore oil and gas leases is subject to extensive governmental regulation, including regulations that may, in certain circumstances, impose absolute liability upon lessees for cost of removal of pollution and for pollution damages resulting from their operations, and require lessees to suspend or cease operations in the affected areas.

Under the Oil Pollution Act of 1990, as amended by the Coast Guard Authorization Act of 1996, (collectively, "OPA"), parties responsible for offshore facilities must establish and maintain evidence of oil-spill financial responsibility ("OSFR") for costs attributable to potential oil spills. OPA requires a minimum of $35 million in OSFR for offshore facilities located on the OCS. This amount is subject to upward regulatory adjustment up to $150 million. Responsible parties for more than one offshore facility are required to provide OSFR only for their offshore facility requiring the highest OSFR. In 1998, the Minerals Management Service adopted regulations for establishing the amount of OSFR required for particular facilities. The amount of OSFR increases as the volume of a facility's worst-case oil spill increases. Accordingly, for facilities with worst-case spills of less than 35,000 barrels, only $35 million in OSFR is required; for worst-case spills of over 35,000 barrels, $70 million is required; for worst-case spills of over 70,000 barrels, $105 million is required; and for worst-case spills of over 105,000 barrels, $150 million is required. In addition, all OSFR below $150 million remains subject to upward regulatory adjustment if warranted by the particular operational, environmental, human health or other risks involved with a facility. The Working Interest Owners are currently maintaining their required OSFR. Although the Managing General Partner of the Partnership has advised the Trust that current environmental regulation has had no material adverse effect on the Working Interest Owners' present method of operations, future environmental regulatory developments such as stricter environmental regulation and enforcement policies cannot presently be quantified.

The Working Interest Owners' operations are subject to regulation, principally under the following federal statutes, along with their analogous state statutes.

Water

The Federal Water Pollution Control Act of 1972, as amended, and the Oil Pollution Act of 1990 impose certain liabilities and penalties upon persons and entities, such as the Working Interest Owners, for any discharges of petroleum products in reportable quantities, for the costs of removing an oil spill, and for natural resource damages. State laws for the control of water pollution also provide varying civil and criminal penalties and liabilities in the case of a release of petroleum or its derivatives in surface waters.

The federal NPDES permits prohibit the discharge of produced water, sand and other substances related to the oil and gas industry to coastal waters of Louisiana and Texas. The Working Interest Owners have advised the Trust that these costs have not had a material adverse impact on their operations.

Air Emissions

Amendments to the federal Clean Air Act were enacted in late 1990 and require most industrial operations in the United States, including offshore operations, to incur capital expenditures for air emission control equipment in connection with maintaining and obtaining operating permits and approvals addressing other air emission related issues. The Environmental Protection Agency ("EPA") and state environmental agencies have been developing regulations to implement these requirements. Some of the Working Interest Owners' facilities are included within the categories of hazardous air pollutant sources which will be affected by these regulations and these regulations could make operation of the Royalty Properties more costly.

Solid Waste

The Working Interest Owners' operations may generate wastes that are subject to the federal Resource Conservation and Recovery Act ("RCRA") and comparable state statutes. The EPA has limited disposal options for certain hazardous wastes and may adopt more stringent disposal standards for nonhazardous wastes. Furthermore, it is possible that some wastes that are currently classified as nonhazardous, perhaps including wastes generated during drilling and production operations, may in the future be designated as "hazardous wastes." Such changes in the regulations would result in more rigorous and costly disposal requirements which could result in increased operating expenses on the Royalty Properties.

Norm

Oil and gas exploration and production activities have been identified as generators of low-level naturally-occurring radioactive materials ("NORM"). The generation, handling and disposal of NORM in the course of offshore oil and gas exploration and production activities is currently regulated in federal and state waters. These regulations could result in an increase in operating expenses on the Royalty Properties.

Superfund

The Comprehensive Environmental Response, Compensation and Liability Act ("CERCLA"), also known as the "Superfund" law, imposes liability, without regard to the fault or the legality of the original conduct, on certain classes of persons that contributed to the release of a "hazardous substance" into the environment. These persons include the current or previous owner and operator of a facility and companies that disposed or arranged for the disposal of the hazardous substance found at a facility. CERCLA also authorizes the EPA and, in some cases, private parties to take actions in response to threats to the public health or the environment and to seek recovery from such responsible classes of persons of the costs, which can be substantial, of such action. Although "petroleum" is excluded from CERCLA's definition of a "hazardous substance", in the course of their operations, the Working Interest Owners may generate wastes that fall within CERCLA's definition of "hazardous substances." The Working Interest Owners may be responsible under CERCLA for all or part of the costs to clean up facilities at which such substances have been disposed. Such clean-up costs may make operation of the Royalty Properties more expensive for the Working Interest Owners.

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Offshore Operations

Offshore oil and gas operations are subject to regulations of the United States Department of the Interior, including regulations promulgated pursuant to the Outer Continental Shelf Lands Act, which impose liability upon a lessee, such as the Working Interest Owners, under a federal lease for the cost of clean-up of pollution resulting from a lessee's operations. In the event of a serious incident of pollution, the Department of the Interior may require a lessee under federal leases to suspend or cease operations in the affected areas.

Climate Change

A variety of regulatory developments, proposals or requirements have been introduced that are focused on restricting the emission of carbon dioxide, methane and other greenhouse bases. Among these developments is the Kyoto Protocol to the United Nations Framework Convention on Climate Change that became effective in February 2005. Under the Protocol, participating nations are required to implement programs to reduce emissions of certain gases, generally referred to as greenhouse gases, that are suspected of contributing to global warming. The United States is not currently participating in the Protocol though the Protocol may impact oil and gas markets generally. In addition, Congress has considered recent proposed legislation directed at reducing greenhouse gas emissions. There has been support in various regions of the country for legislation that requires reductions in greenhouse gas emissions, and some states have already adopted legislation addressing greenhouse gas emissions from various sources. In 2007, the U.S. Supreme Court held in *Massachusetts, et al. v. EPA* that greenhouse gases are an "air pollutant" under the federal Clean Air Act and, thus, subject to future regulation. The oil and natural gas industry is a direct source of certain greenhouse gas emissions, namely carbon dioxide and methane, and future restrictions on such emissions could impact the future operations of the Royalty Properties. The operations of the Royalty Properties are not adversely impacted by the current state and local climate change initiatives and, at this time, it is not possible to accurately estimate how potential future laws or regulations addressing greenhouse gas emissions would impact the operations of the properties.

Item 1A. *Risk Factors.*

Although risk factors are described elsewhere in this Form 10-K together with specific forward-looking statements, the following is a summary of the principal risks associated with an investment in Units in the Trust.

Natural gas and oil prices fluctuate due to a number of factors, and lower prices will reduce net proceeds available to the Trust and distributions to Trust Unit holders.

The Trust's quarterly distributions are highly dependent upon the prices realized from the sale of natural gas and oil, and a material decrease in such prices could reduce the amount of Trust distributions. Natural gas and oil prices can fluctuate widely on a month-to-month basis in response to a variety of factors that are beyond the control of the Trust and the Working Interest Owners. Factors that contribute to price fluctuation include, among others:

- political conditions worldwide, in particular political disruption, war and other armed conflict in oil producing regions such as Iraq;
- worldwide economic conditions;
- weather conditions;
- the supply and price of foreign natural gas;
- the level of consumer demand;

- the price and availability of alternative fuels;
- the proximity to, and capacity of, transportation facilities; and
- the effect of worldwide energy conservation measures.

Moreover, government regulations, such as regulation of natural gas and oil transportation and price controls, can affect product prices in the long term.

During recent months, there has been a substantial downturn in general business activity and in the worldwide credit and capital markets that has led to a worldwide economic recession. Recent oil prices have been low compared to historical prices. The current sustained decline in oil prices, particularly in combination with the constrained capital markets and overall economic downturn, has resulted in a decline in activity by participants in the oil and gas industry. The Trust cannot predict the timing or the duration of this or any other economic downturn in the economy and if the current conditions continue, the financial condition of the Trust could be materially adversely affected.

When natural gas and oil prices decline, the Trust is affected in two ways. First, net royalties are reduced. Second, exploration and development activities on the underlying properties may decline as some projects may become uneconomic and are either delayed or cancelled. The volatility of energy prices reduces the predictability of future cash distributions to Unit holders. Substantially all of the natural gas and natural gas liquids produced from the Royalty Properties is being sold to Chevron Natural Gas at spot market prices. Substantially all of the crude oil produced by the Royalty Properties is being sold to subsidiaries of Chevron Corporation based on pricing bulletins.

Production from Eugene Island 339 and Ship Shoal 182 and 183, the two most significant Royalty Properties, ceased following damage inflicted by Hurricane Ike in September 2008. At this point in time, there can be no assurance as to how or when, or if at all, production may be restored at either of the oil and gas properties. Based on the damage caused by Hurricane Ike, the Trust's scheduled distribution for the fourth quarter of 2008 was severely negatively impacted and there will be no distribution for the first quarter of 2009. Future distributions are also expected to be severely negatively impacted, and there may not be sufficient Net Proceeds from the Royalty Properties to make one or more future distributions.

The platforms and wells on Eugene Island 339 were destroyed by Hurricane Ike in September 2008. Chevron is assessing its alternatives and the economic feasibility for restoring production at the property. At this point in time, there can be no assurance as to how or when, or if at all, production may be restored at Eugene Island 339. While Hurricane Ike caused limited surface damage to the facilities at Ship Shoal 182/183, all of the wells at Ship Shoal 182/183 were shut-in following hurricane-related damage to a third-party transporter's natural gas pipeline. A limited volume of oil production was restored at Ship Shoal 182/183 in November 2008, with an average rate of daily oil production from November 20, 2008 through January 31, 2009 of approximately 831 barrels per day. The volume of oil production that can be produced is limited by the amount of gas that is also produced by the oil wells. Production is expected to remain limited until the natural gas pipeline is fully repaired and tested, which is anticipated to occur in the second quarter of 2009, but which is also in the control of the pipeline owner. There may also be related regulatory approval requirements that must be satisfied before gas transportation may commence. At this point in time, there can be no assurance as to when, or if at all, gas production may be restored at Ship Shoal 182/183. Based on the damage caused by Hurricane Ike, the Trust's scheduled distribution for the fourth quarter of 2008 was severely negatively impacted and there will be no distribution for the first quarter of 2009. Future distributions are also expected to be severely negatively impacted, and there may not be sufficient Net Proceeds from the Royalty Properties to make one or more future distributions. At this time, the ultimate outcome of these various matters cannot be determined.

In addition, production from West Cameron 643 and East Cameron 371 ceased following damage inflicted by Hurricane Ike in September 2008 to third-party transporters' pipelines. The Managing General Partner of the Partnership understands that the pipelines are in the process of being restored; however, the pipeline for West Cameron 643 is not expected to be able to take production until at least the end of 2009. At this point in time, there can be no assurance as to when, or if at all, production may be restored at West Cameron 643 or East Cameron 371. For additional information, see "Management's Discussion and Analysis of Financial Condition and Results of Operations—Operations."

Increased production and development costs for the Royalty will result in decreased or no Trust distributions.

Production and development costs attributable to the Royalty are deducted in the calculation of the Trust's share of net proceeds. Production and development costs are impacted by increases in commodity prices both directly and indirectly, through commodity-price dependent costs such as electricity, and indirectly, as a result of demand-driven increases in costs of oilfield goods and services. Accordingly, higher or lower production and development costs, without concurrent increases in revenues, directly decrease or increase the amount received by the Trust for the Royalty.

During 2005, Hurricane Katrina and Hurricane Rita caused significant damage to various platforms and third-party transportation systems. The extensive damage caused by these hurricanes led to significant demand for services and supplies for repairs in the offshore Gulf of Mexico. These incurred costs reduced Royalty income.

In September 2008, Hurricane Ike completely destroyed the platforms and wells on Eugene Island 339. Chevron is proceeding to plug and abandon the existing wells, to clear debris and otherwise to deal with the remaining infrastructure, with estimated costs relating thereto of approximately $61 million for 2009. In order to restore production, Chevron expects that it would need to redevelop the facility and drill new wells. There can be no assurance that production at Eugene Island 339 will be restored. For additional information, see "Management's Discussion and Analysis of Financial Condition and Results of Operations—Operations."

If development and production costs of the Royalty exceed the proceeds of production from the Royalty Properties, the Trust will not receive Net Proceeds until future proceeds from production exceed the total of the excess costs plus accrued interest, at a rate equal to one-fourth of (i) one-half of one percent plus (ii) the median between the prime interest rate at the end of a quarterly period in which there are excess costs and the prime interest rate at the end of the preceding quarterly period, during the deficit period. Development activities may not generate sufficient additional revenue to repay the costs. Accordingly, there may not be sufficient Net Proceeds to make a particular distribution.

Trust reserve estimates depend on many assumptions that may prove to be inaccurate, which could cause both estimates of reserves and estimated future revenues to be too high or too low.

The value of the Units depends upon, among other things, the amount of reserves attributable to the Royalty and the estimated future value of the reserves. Estimating reserves is inherently uncertain. Ultimately, actual production, revenues and expenditures for the underlying properties will vary from estimates and those variations could be material. Petroleum engineers consider many factors and make assumptions in estimating reserves. Those factors and assumptions include:

- historical production from the area compared with production rates from similar producing areas;
- the assumed effect of governmental regulation;
- assumptions about future commodity prices, production and development costs, severance and excise taxes, and capital expenditures;

- the availability of enhanced recovery techniques; and
- relationships with landowners, working interest partners, pipeline companies and others.

Changes in these factors and assumptions can materially change reserve estimates and future net revenue estimates.

The reserve quantities attributable to the Royalty and revenues are based on estimates of reserves and revenues for the Royal Properties. The method of allocating a portion of those reserves to the Trust is complicated because the Trust, indirectly through the Partnership, holds an interest in the Royalty and does not own a specific percentage of the natural gas reserves. Ultimately, actual production, revenues and expenditures for the Royalty Properties, and therefore actual net proceeds payable to the Trust, will vary from estimates and those variations could be material. Results of drilling, testing and production after the date of those estimates may require substantial downward revisions or write-downs of reserves.

The Trustees also rely entirely on reserve estimates and related information prepared by Chevron and the independent reserve engineer engaged by the Partnership. While the Trustees have no reason to believe the reserve estimates included in this report are not accurate, to the extent additional information exists that could affect their reserve estimates, the estimated reserves in these reports could also be too low.

Operating risks for the Working Interest Owners' interests in the Royalty Properties can adversely affect Trust distributions.

There are operational risks and hazards associated with the production and transportation of natural gas, including without limitation natural disasters, blowouts, explosions, fires, leakage of natural gas, releases of other hazardous materials, mechanical failures, cratering and pollution. Any of these or similar occurrences could result in the interruption or cessation of operations, personal injury or loss of life, property damage, damage to productive formations or equipment, damage to the environment of natural resources, or cleanup obligations. The occurrence of drilling, production or transportation accidents and other natural disasters at any of the Royalty Properties will reduce Trust distributions by the amount of uninsured costs. Offshore activities are also subject to a variety of additional operating risks, such as hurricanes and other weather disturbances. These accidents may result in personal injuries, property damage, damage to productive formations or equipment and environmental damages. Any uninsured costs would be deducted as a production cost in calculating net proceeds payable to the Trust.

As described in this report, Hurricanes Katrina and Rita caused significant damage during 2005. All but one of the platforms and facilities on the Royalty Properties were restored during 2006 and 2007. As also described in the report, production from the two most significant oil and gas properties associated with the Trust ceased following damage inflicted by Hurricane Ike in September 2008. The platforms and wells on Eugene Island 339 were completely destroyed. While Hurricane Ike caused limited damage to the facilities at Ship Shoal 182 and 183, all of the wells at Ship Shoal 182 and 183 were shut-in following hurricane related damage to a third-party transporter's natural gas pipeline.

Terrorism and continued hostilities in the Middle East could decrease Trust distributions or the market price of the units of beneficial interest of the Trust.

Terrorist attacks and the threat of terrorist attacks, whether domestic or foreign, as well as military or other actions taken in response, cause instability in the global financial and energy markets. Terrorism, the war in Iraq and other sustained military campaigns could adversely affect Trust distributions or the market price of the Units in unpredictable ways, including through the disruption of fuel supplies and markets, increased volatility in natural gas prices, or the possibility that the infrastructure on which the operators developing the underlying properties rely could be a direct target or an indirect casualty of an act of terror.

The operators of the working interests are subject to extensive governmental regulation.

Offshore oil and gas operations have been, and in the future will be, affected by federal, state and local laws and regulations and other political developments, such as price or gathering rate controls and environmental protection regulations. These regulations and changes in regulations could have a material adverse effect on Royalty income payable to the Trust.

The Trustees and the Unit holders have no control over the operation or development of the Royalty Properties and have little influence over operation or development.

Neither the Trustees nor the Unit holders can influence or control the operation or future development of the underlying properties. The Royalty Properties are owned by independent Working Interest Owners. The Working Interest Owners manage the underlying properties and handle receipt and payment of funds relating to the Royalty Properties and payments to the Trust for the Royalty.

Information regarding operations provided by the Working Interest Owners has been subject to errors and adjustments, some of which have been significant. Accordingly, the Trustees cannot assure Unit holders that other errors or adjustments by Working Interest Owners, whether historical or future, will not affect future Royalty income and distributions by the Trust.

The current Working Interest Owners are under no obligation to continue operating the properties. The failure of an operator to conduct its operations, discharge its obligations, deal with regulatory agencies or comply with laws, rules and regulations, including environmental laws and regulations, in a proper manner could have an adverse effect on the net proceeds payable to the Trust. Neither the Trustees nor the Unit holders have the right to replace an operator.

The Trustees rely upon the Working Interest Owners and Managing General Partner for information regarding the Royalty Properties.

The Trustees rely on the Working Interest Owners and the Managing General Partner of the Partnership for information regarding the Royalty Properties. The Working Interest Owners alone control (i) historical operating data, including production volumes, marketing of products, operating and capital expenditures, environmental and other liabilities, effects of regulatory changes and the number of producing wells and acreage, (ii) plans for future operating and capital expenditures, (iii) geological data relating to reserves, as well as related projections regarding production, operating expenses and capital expenses used in connection with the preparation of the reserve report, (iv) forward-looking information relating to production and drilling plans and (v) information regarding the Royalty Properties responsive to litigation claims. While the Trustees request material information for use in periodic reports as part of its disclosure controls and procedures, the Trustees do not control this information and rely entirely on the Working Interest Owners to provide accurate and timely information when requested for use in the Trust's periodic reports. The Trustees also rely on the Managing General Partner of the Partnership to collect certain information from the Working Interest Owners and do not have any direct contact with the Working Interest Owners other than the Managing General Partner. Under the terms of the Trust Indenture, the Trustees are entitled to rely, and in fact rely, on certain experts in good faith. While the Trustees have no reason to believe their reliance on experts is unreasonable, this reliance on experts and limited access to information may be viewed as a weakness as compared to the management and oversight to entity forms other than trusts.

The owner of any Royalty Property may abandon any property, terminating the related Royalty.

The Working Interest Owners may at any time transfer all or part of the Royalty Property to another unrelated third party. Unit holders are not entitled to vote on any transfer, and the Trust will not receive any proceeds of any such transfer. Following any transfer, the Royalty Properties will continue to be subject to the Royalty, but the net proceeds from the transferred property would be calculated separately and paid by the transferee. The transferee would be responsible for all of the obligations relating to calculating, reporting and paying to the Trust the Royalty on the transferred portion of the Royalty Properties, and the current owner of the Royalty Properties would have no continuing obligation to the Trust for those properties.

The current Working Interest Owners or any transferee may abandon any well or property if it reasonably believes that the well or property can no longer produce in commercially economic quantities. This could result in termination of the Royalty relating to the abandoned well.

Generally, if production ceases from an outer continental shelf lease, like that for Eugene Island 339, production must be restored or drilling operations must commence within 180 days of the cessation (which was in early March 2009 with respect to Eugene Island 339 given the ceasing of production in September 2008 resulting from Hurricane Ike), or the lease will be terminated. A lease operator may seek approval from the regional supervisor of the Mineral Management Service to allow additional time to restore production. Chevron has submitted such a request with respect to Eugene Island 339. There can be no assurance that production at Eugene Island 339 will be restored, or that such requested extension will be granted.

The Royalty can be sold and the Trust can be terminated.

The Trust will be terminated and the Trustees must sell the Royalty if holders of a majority of the Units approve the sale or vote to terminate the Trust, or if the total future net revenues attributable to the Royalty, determined by the independent reserve engineer as of December 31 of the prior year, are less than $2 million. Following any such termination and liquidation, the net proceeds of any sale will be distributed to the Unit holders and Unit holders will receive no further distributions from the Trust. We cannot assure you that any such sale will be on terms acceptable to all Unit holders. For a more complete description of these matters, see "—Termination of the Trust" under Item 1 of this Form 10-K.

Trust assets are depleting assets and, if the Working Interest Owners or other operators of the Royalty Properties do not perform additional development projects, the assets may deplete faster than expected.

The net proceeds payable to the Trust are derived from the sale of depleting assets. Accordingly, the portion of the distributions to Unit holders attributable to depletion may be considered a return of capital. The reduction in proved reserve quantities is a common measure of depletion. Future maintenance and development projects on the Royalty Properties will affect the quantity of proved reserves. The timing and size of these projects will depend on the market prices of natural gas. If operators of the Royalty Properties do not implement additional maintenance and development projects, the future rate of production decline of proved reserves may be higher than the rate currently expected by the Trust. For federal income tax purposes, depletion is reflected as a deduction, which is dependent upon the purchase price of a Units. Please see the section entitled "—Description of the Units—Federal Income Tax Matters" under Item 1 of this Form 10-K.

Because the net proceeds payable to the Trust are derived from the sale of depleting assets, the portion of distributions to Unit holders attributable to depletion may be considered a return of capital as opposed to a return on investment. Distributions that are a return of capital will ultimately diminish the depletion tax benefits available to the Unit holders, which could reduce the market value of the Units over time. Eventually, properties underlying the Trust's Royalty will cease to produce in commercial quantities and the Trust will, therefore, cease to receive any distributions of net proceeds therefrom.

Unit holders have limited voting rights.

Voting rights as a Unit holder are more limited than those of stockholders of most public corporations. For example, there is no requirement for annual meetings of Unit holders or for an annual or other periodic re-election of the Trustees. Additionally, Unit holders have no voting rights in the Working Interest Owners. Unlike corporations which are generally governed by boards of directors elected by their equity holders, the Trust is administered by a Corporate Trustee and three Individual Trustees in accordance with the Trust Agreement and other organizational documents. The Trustees have extremely limited discretion in their administration of the Trust.

Unit holders have limited ability to enforce the Trust's rights against the current or future owners of the Royalty Properties.

The Trust Agreement and related trust law permit the Trustees and the Trust to sue the Working Interest Owners to compel them to fulfill the terms of the Conveyance of the Royalty. If the Trustees do not take appropriate action to enforce provisions of the Conveyance, the recourse of a Unit holder would likely be limited to bringing a lawsuit against the Trustees to compel the Trustees to take specified actions. Unit holders probably would not be able to sue the Working Interest Owners directly.

Item 1B. *Unresolved Staff Comments.*

There were no unresolved Securities and Exchange Commission comments as of December 31, 2008.

Item 2. *Properties.*

Reference is made to Item 1 of this Form 10-K.

Item 3. *Legal Proceedings.*

Currently, there are not any legal proceedings pending to which the Trust is a party or of which any of its property is the subject.

Item 4. *Submission of Matters to a Vote of Security Holders.*

There were no matters submitted to a vote of security holders during the fourth quarter of 2008.

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PART II

Item 5. ***Market for the Registrant's Common Equity, Related Stockholder Matters and Issuer Purchasers of Equity Securities.***

The Trust Units are traded on the Nasdaq SmallCap Market under the symbol "TELOZ". At March 26, 2009, the 4,751,510 Units outstanding were held by 1,931 Unit holders of record. The high and low sales price as reported by the Nasdaq SmallCap Market, and distributions for each quarter for the years ended December 31, 2008 and 2007, were as follows:

Quarter	High	Low	Distribution
2008:			
Fourth	$18.64	$ 3.87	$ .155708
Third	26.63	13.72	1.151294
Second	42.87	20.60	.551272
First	25.98	13.80	.940552
2007:			
Fourth	$32.95	$13.70	$ .684564
Third	15.44	10.00	.597051
Second	10.88	9.21	.432270
First	11.05	9.12	.245727

See "Management's Discussion and Analysis of Financial Condition and Results of Operations—Operations" and Note 4 to Notes to Financial Statements under Item 8 of this Form 10-K for a discussion regarding uncertainty of distributions.

Item 6. ***Selected Financial Data.***

	Year Ended December 31,				
	2008	2007	2006	2005	2004
Royalty income	$14,451,252	$10,257,485	$2,510,936	$9,854,531	$5,987,936
Distributable income	$13,298,654	$ 9,311,113	$1,697,721	$9,239,617	$5,344,207
Distributions per Unit	$ 2.798827	$ 1.959611	$ 0.357301	$ 1.944564	$ 1.124739
Total assets	$ 3,004,478	$ 5,176,634	$3,375,093	$3,239,290	$3,901,263

Item 7. ***Management's Discussion and Analysis of Financial Condition and Results of Operation.***

On the last business day of each calendar quarter, the Working Interest Owners pay to the Partnership 25% of the Net Proceeds for the immediately preceding Quarterly Period. A Quarterly Period is each period of three months commencing on the first day of February, May, August and November. In turn, the Partnership distributes funds to its partners on the last business day of each calendar quarter. Cash distributions from the Trust are made in January, April, July and October of each year, and are payable to Unit holders of record as of the last business day of each calendar quarter. Thus, the cash conveyed to the Trust from the Royalty during the quarter ended December 31, 2008 substantially represents the revenues and expenses from the Royalty Properties from August through October 2008. The financial and operating information included in this Form 10-K for the 12 months ended December 31, 2008 represents financial and operating information with respect to the Royalty Properties for the months of November 2007 through October 2008. As such, the impact of Hurricane Ike will not be fully reflected in the discussion of 2008 operations, as such discussion does not include a discussion of operations of the Royalty Properties in November or December 2008. Similarly, the financial and operating information included in this Form 10-K for the 12 months ended December 31, 2007 represents financial and operating information with respect to the Royalty

Properties for the months of November 2007 through October 2008. Income from the Royalty is recorded by the Trust on a cash basis, when it is received by the Trust from the Partnership.

Critical Accounting Policies

The financial statements of the Trust are prepared on the following basis:

(a) Royalty income is recorded when received, including the effect of overtaken or undertaken positions and negative or positive adjustments, by the Corporate Trustee on the last business day of each calendar quarter. In addition, Royalty income includes amounts related to funds deposited or released from the Special Cost Escrow account—see (c);

(b) Trust general and administrative expenses are recorded when paid, except for the cash reserved for future general and administrative expenses; and

(c) The funds deposited or released from the Special Cost Escrow account are recorded at the time of payment or receipt. The Special Cost Escrow account is an account of the Working Interest Owners and is not reflected in the financial statements of the Trust.

This manner of reporting income and expenses is considered to be the most meaningful because the quarterly distributions to Unit holders are based on net cash receipts received from the Working Interest Owners. The financial statements of the Trust differ from financial statements prepared in accordance with generally accepted accounting principles, because, under such principles, Royalty income and Trust general and administrative expenses for a quarter would be recognized on an accrual basis. In addition, amortization of the net overriding royalty interest, calculated on a units-of-production basis, is charged directly to Trust corpus since such amount does not affect distributable income.

The Trustees, including the Corporate Trustee, have no authority over, have not evaluated and make no statement concerning, the internal control over financial reporting of any of the Working Interest Owners.

Liquidity and Capital Resources

The Trust's source of capital is the Royalty Income received from its share of the Net Proceeds from the Royalty Properties. Reference is made to Note 9 in the Notes to Financial Statements under Item 8 of this Form 10-K, which contains certain unaudited supplemental reserve information, for an estimate of future Royalty income attributable to the Partnership, of which the Trust has a 99.99% interest.

On October 7, 2008, the Trust announced that production from the two most significant oil and gas properties associated with the Trust had ceased following damage inflicted by Hurricane Ike in September 2008. The platforms and wells on Eugene Island 339 were completely destroyed by Hurricane Ike. Crude oil revenues from Eugene Island 339 represented approximately 48% of the crude oil and condensate revenues for the Royalty Properties in 2007. While Hurricane Ike caused limited surface damage to the facilities at Ship Shoal 182/183, all of the wells at Ship Shoal 182/183 were shut-in following hurricane-related damage to a third-party transporter's natural gas pipeline. The more productive wells on the properties produce both oil and gas, and there is currently no downstream transmission available for any gas produced from the wells. Crude oil revenues from Ship Shoal 182/183 represented approximately 50% of the crude oil and condensate revenues for the Royalty Properties in 2007. There can be no assurance that production at Eugene Island 339 will be restored. While production is expected to remain limited at Ship Shoal 182/183 until the natural gas pipeline is fully repaired and tested, which is anticipated to occur in the second quarter of 2009, there can be no assurance as to when, or if at all, meaningful production may be restored at Ship Shoal 182/183. See "—Operations."

In addition, production from West Cameron 643 and East Cameron 371 ceased following damage inflicted by Hurricane Ike in September 2008 to third-party transporters' pipelines. The Managing General Partner of the Partnership understands that the pipelines are in the process of being restored; however, the pipeline for West Cameron 643 is not expected to be able to take production until at least the end of 2009. At this point in time, there can be no assurance as to when, or if at all, production may be restored at West Cameron 643 or East Cameron 371. For additional information, see "—Operations."

On December 19, 2008, the Trust announced its fourth quarter distribution of approximately $0.7 million, which was paid on January 9, 2009. Based on the damage caused by Hurricane Ike, the Trust's scheduled distribution for the fourth quarter of 2008 was severely negatively impacted, although there were funds available for distribution given that there was some production from Eugene Island 339 and Ship Shoal 182/183 in August and September 2008. On March 25, 2009, the Trust announced that there would be no trust distribution for the first quarter of 2009. There are no Net Proceeds expected to be distributed to the Trust for the first quarter of 2009. Future distributions by the Trust are expected to be severely negatively impacted, and there may not be sufficient Net Proceeds from the Royalty Properties to make one or more future distributions. At this time, the ultimate outcome of these various matters cannot be determined.

Future Net Proceeds may take into account the Trust's share of project costs and other related expenditures that are not covered by insurance of the operator of the Royalty Properties. If development and production costs of the Royalty exceed the proceeds of production from the Royalty Properties, the Trust will not receive Net Proceeds until future proceeds from production exceed the total of the excess costs plus accrued interest, at a rate equal to one-fourth of (i) one-half of one percent plus (ii) the median between the prime interest rate at the end of a quarterly period in which there are excess costs and the prime interest rate at the end of the preceding quarterly period, during the deficit period. Development activities may not generate sufficient additional revenue to repay the costs. Accordingly, there may not be sufficient Net Proceeds to make a particular distribution.

Substantial uncertainties exist with regard to future oil and gas prices, which are subject to material fluctuations due to changes in production levels and pricing and other actions taken by major petroleum producing nations, as well as the regional supply and demand for gas, weather, industrial growth, conservation measures, competition, economic conditions generally and other variables.

In accordance with the provisions of the Trust Agreement, generally all Net Proceeds received by the Trust, net of Trust general and administrative expenses and any cash reserves established for the payment of contingent or future obligations of the Trust, are distributed currently to the Unit holders. In 1994, in anticipation of future periods when the cash received from the Royalty may not be sufficient for payment of Trust expenses, the Trust determined, in accordance with the Trust Agreement, to begin further increasing the Trust's cash reserve each quarter. In the first quarter of 1998, the Trust determined that the Trust's cash reserve was then sufficient to provide for future administrative expenses in connection with the winding up of the Trust. The Trust determined that a cash reserve equal to three times the average expenses of the Trust during each of the past three years was sufficient at such time to provide for future administrative expenses in connection with the winding up of the Trust.

The calculated reserve amount at December 31, 2008 and 2007 was $2,233,291 and $1,883,726, respectively.

Operations

The following operational information has been based on information provided to the Corporate Trustee by Chevron as the Managing General Partner of the Partnership. The Trustees have no control over these operations or internal controls relating to this information.

During 2005, Hurricane Katrina and Hurricane Rita caused significant damage to various platforms and third-party transportation systems, which resulted in oil and gas production delays in the Royalty Properties. At the end of October 2005, approximately half of Chevron oil-equivalent production in the Gulf of Mexico remained shut-in due to damages from hurricanes in the third quarter. During 2006, several of the platforms and facilities on the Royalty Properties were restored, and by the third quarter of 2007 all but one of the platforms and facilities had been restored. One of the platforms and facilities on Eugene Island was destroyed from hurricanes in the third quarter of 2005 and was never restored. Eugene Island 339 oil production increased during the second half of 2006 and the first quarter of 2007 as the B-5 well gas injection project, which allows the operator to increase oil production and to limit flaring of gas, was completed. On Ship Shoal 182/183, gas production and sales resumed in July 2006 following the hurricanes in the third quarter of 2005, and full production resumed in the fourth quarter of 2006. On West Cameron 643, production was shut in from September 2005 following Hurricane Rita's major damage to various platforms, but limited gas production resumed in late July 2006 before the wells loaded up and additional repairs were required thus requiring the well to be shut in again during the second quarter 2006. Production at West Cameron 643 resumed May 2007.

The platforms and wells on Eugene Island 339 were completely destroyed by Hurricane Ike in September 2008. Crude oil revenues from Eugene Island 339 represented approximately 48% of the crude oil and condensate revenues for the Royalty Properties in 2007 and approximately 47% of such revenues for the nine months ended September 30, 2008. Eugene Island 339 contributed approximately 12% of the revenues from natural gas sales from the Royalty Properties in 2007 and approximately 41% of such revenues for the nine months ended September 30, 2008. Based on a prior reserve study of DeGolyer and MacNaughton, independent petroleum engineering consultants, Eugene Island 339 accounted for approximately 34% of the total future net revenues attributable to the Partnership's interest in the royalty as of October 31, 2007. Chevron is proceeding to plug and abandon the existing wells, to clear debris and otherwise to deal with the remaining infrastructure, with estimated costs relating thereto for 2009 alone of approximately $61 million. In order to restore production, Chevron expects that it would need to redevelop the facility and drill new wells. Chevron is still assessing its alternatives and the economic feasibility for restoring production at the property. At this point in time, there can be no assurance as to how or when, or if at all, production may be restored at Eugene Island 339. Generally, if production ceases from an outer continental shelf lease, like that for Eugene Island 339, production must be restored or drilling operations must commence within 180 days of the cessation (which was in early March 2009), or the lease will be terminated. A lease operator may seek approval from the regional supervisor of the Mineral Management Service to allow additional time to restore production. Chevron has submitted such a request with respect to Eugene Island 339. There can be no assurance that production at Eugene Island 339 will be restored or that such requested extension will be granted.

Production at Ship Shoal 182/183 ceased following damage inflicted by Hurricane Ike in September 2008. While the hurricane caused limited surface damage to the facilities at Ship Shoal 182/183, all of the wells at Ship Shoal 182/183 were shut-in following hurricane-related damage to a third-party transporter's natural gas pipeline. The more productive wells on the properties produce both oil and gas, and there was no downstream transmission available for any gas produced from the wells. Crude oil revenues from Ship Shoal 182/183 represented approximately 50% of the crude oil and condensate revenues for the Royalty Properties in 2007 and approximately 51% of such revenues for the nine months ended September 30, 2008. Ship Shoal 182/183 contributed approximately 77% of the revenues from natural gas sales from the Royalty Properties in 2007 and approximately 42% of such revenues for the nine months ended September 30, 2008. A limited volume of oil production was restored in November 2008, with an average rate of daily oil production from November 20, 2008 through January 31, 2009 of approximately 831 barrels per day. The volume of oil production that can be produced is limited by the amount of gas that is also produced by the oil wells. Production is expected to remain limited until the natural gas pipeline is fully repaired and tested, which is anticipated to occur in the second quarter of 2009, but which is also in the control of the pipeline owner. There may also be related regulatory approval requirements that must be satisfied before gas transportation may commence. At this point in time, there can be no assurance as to when, or if at all, gas production may be restored at Ship Shoal 182/183.

In addition, production from West Cameron 643 and East Cameron 371 ceased following damage inflicted by Hurricane Ike in September 2008 to third-party transporters' pipelines. The Managing General Partner of the Partnership understands that the pipelines are in the process of being restored; however, the pipeline for West Cameron 643 is not expected to be able to take production until at least the end of 2009. At this point in time, there can be no assurance as to when, or if at all, production may be restored at West Cameron 643 or East Cameron 371.

The Trust has engaged an outside auditor for the purpose of reviewing the books and records of certain Working Interest Owners with respect to the Royalty Properties and the related payments to the Trust. Based on the initial report of this auditor, the Trustees believe that certain errors have occurred and are involved in ongoing discussions with such Working Interest Owners to resolve these items. As part of this ongoing process, certain adjustments resulted in an additional cash distribution to the Trust during the first quarter of 2008. These amounts are comprised of a one-time increase of approximately $31,716 in gas revenues, a one-time increase of approximately $43,287 in oil revenues, and a one-time credit of approximately $123,900 in capital expenditures. An additional $127,973 related to the outside audit was included in the second quarter 2008 distribution. An additional $135,551 related to the outside audit was included in the third quarter 2008 distribution. An additional credit adjustment of $352,317 related to the outside audit was made in the fourth quarter of 2008. No assurance can be provided as to the ultimate outcome of the remaining items under discussion.

Years 2008 and 2007

Royalty income increased approximately 41% from $10,257,485 in 2007 to $14,451,252 in 2008 primarily due to an increase in gas revenues and crude oil and condensate revenues as discussed below.

For 2008, the Trust had a collection of prior undistributed net income of $33,169. For 2007, the Trust had undistributed net loss of $9,297. An increase in undistributed net income represents revenues generated during the respective period, but not distributed by the Working Interest Owners. Collection of undistributed net income is the subsequent receipt in future periods from the related Working Interest Owner(s) of revenues generated in prior periods but not yet distributed.

Volumes and dollar amounts discussed below represent amounts recorded by the Working Interest Owners unless otherwise specified.

Natural Gas and Gas Products

Natural gas revenues and gas products increased 21% from $11,820,973 in 2007 to $14,248,644 in 2008, partially offset by a slight decrease in natural gas and gas products volumes from 1,654,836 Mcf equivalents in 2007 to 1,625,408 Mcf equivalents in 2008. The average price received for natural gas increased 19% from $7.11 per Mcf in 2007 to $8.45 Mcf in 2008.

Crude Oil and Condensate

Crude oil and condensate revenues increased 12% from $37,732,678 in 2007 to $42,424,601 in 2008, due primarily to a 54% increase in the average price received for crude oil and condensate from $65.26 in 2007 to $100.54 in 2008. This increase was partially offset by a decrease of 27% in crude oil and condensate volumes from 578,159 barrels in 2007 to 421,958 barrels in 2008.

The decrease in crude oil and condensate volumes during 2008 was related in part to a three day field shut-in for repairs at Eugene Island 339 and to an entire production shut-in at Ship Shoal 182/183, platforms C and E, due to pipeline obstruction. Oil production ceased at Eugene Island 339 and Ship Shoal 182/183 in September 2008 after damages inflicted by Hurricane Ike.

Operating and Capital Expenditures

Operating expenses paid by the Working Interest Owners increased 6% from $6,598,909 in 2007 to $7,012,792 in 2008. The increase in operating expenses is primarily due to the increased production during 2008.

Capital expenditures paid by the Working Interest Owners decreased 87% from $1,716,676 in 2007 to $228,959 in 2008. The higher amount of capital expenditures during 2007 related primarily to damages caused by Hurricanes Rita and Katrina.

Special Cost Escrow Account

The special cost escrow account is an account of the Working Interest Owners, and it is described herein for information purposes only. The Conveyance provides for the reserve of funds for estimated future "Special Costs" of plugging and abandoning wells, dismantling platforms and other costs of abandoning the Royalty Properties, as well as for the estimated amount of future drilling projects and other capital expenditures on the Royalty Properties. As provided in the Conveyance, the amount of funds to be reserved is determined based on factors, including estimates of aggregate future production costs, aggregate future Special Costs, aggregate future net revenues and actual current net proceeds. Deposits into this account reduce current distributions and are placed in an escrow account and invested in short-term certificates of deposit. Such account is herein referred to as the "Special Cost Escrow" account. The Trust's share of interest generated from the Special Cost Escrow Account, $155,152 and $255,443 in 2008 and 2007, respectively, serves to reduce the Trust's share of allocated production costs. Special Cost Escrow funds will generally be utilized to pay Special Costs to the extent there are not adequate current net proceeds to pay such costs. Special Costs that have been paid are no longer included in the Special Cost Escrow calculation. Deposits to the Special Cost Escrow Account will generally be made when the balance in the Special Cost Escrow Account is less than 125% of future Special Costs and there is a Net Revenues Shortfall (a calculation of the excess of estimated future costs over estimated future net revenues pursuant to a formula contained in the Conveyance). When there is not a Net Revenues Shortfall, amounts in the Special Cost Escrow account will generally be released, to the extent that Special Costs have been incurred. Amounts in the Special Cost Escrow account will also be released when the balance in such account exceeds 125% of estimated future Special Costs. The discussion of the terms of the Conveyance and Special Cost Escrow account contained herein is qualified in its entirety by reference to the Conveyance itself, which is an exhibit to this Form 10-K and is available upon request from the Corporate Trustee.

Chevron, in its capacity as Managing General Partner of the Partnership, has advised the Trust that additional deposits to the Special Cost Escrow account may be required in future periods in connection with other production costs, other abandonment costs, other capital expenditures and changes on the estimates and factors described above. Such deposits could result in a significant reduction on Royalty income on the periods in which such deposits are made, including the possibility that no Royalty income would be received in such periods.

In 2008, the Working Interest Owners refunded a net amount to the Trust of $2,388,061 from the Special Cost Escrow Account. As of December 31, 2008, approximately $4,325,503 remained in the Special Cost Escrow Account. In 2007, the Working Interest Owners refunded a net amount to the Trust of $125,391 from the Special Cost Escrow Account. As of December 31, 2007, approximately $6,713,564 remained in the Special Cost Escrow Account. The net refund for 2008 compared to the net refund for 2007 was primarily due to a revision to the Special Cost Escrow Account related to the outside audit commenced by the Trust as discussed above. See"—Operations".

Summary By Property

Listed below is a summary of 2008 operations as compared to 2007 of the five principal Royalty Properties based on gross revenues generated during these periods combined.

Eugene Island 339

Eugene Island 339 crude oil revenues increased $1,519,790, from $18,179,707 in 2007 to $19,699,497 in 2008, primarily due to an increase in average price of crude oil received. The average price of crude oil increased from $63.22 per barrel in 2007 to $104.60 per barrel in 2008. This increase was partially offset by a decrease in crude oil production from 287,539 barrels in 2007 to 188,337 barrels in 2008. Gas revenues increased $2,960,096, from $1,222,807 in 2007 to $4,182,903 in 2008, primarily due to an increase in gas production from 194,633 Mcf in 2007 to 435,583 Mcf in 2008 as a result of completion in July 2007 of the pipeline connection to the sales point on the Eugene Island 361 platform. The average price received for natural gas increased from $6.28 per Mcf in 2007 to $9.60 per Mcf in 2008. Capital expenditures increased from $190,093 in 2007 to $518,385 in 2008 due to the conversion to a water injector. Operating expenses increased from $2,214,130 in 2007 to $2,868,686 in 2008 primarily due to increased production.

Production from Eugene Island 339 ceased following damage inflicted by Hurricane Ike in September 2008, as the platforms and wells on Eugene Island 339 were completely destroyed. At this point in time, there can be no assurance that production will restored at Eugene Island 339. See "—Operations."

Ship Shoal 182/183

Ship Shoal 182/183 crude oil revenues increased from $18,924,236 in 2007 to $21,775,671 in 2008, due to an increase in crude oil prices from $67.35 per barrel in 2007 to $107.70 per barrel in 2008. This increase was partially offset by a decrease in crude oil production from 280,996 barrels in 2007 to 202,185 barrels in 2008. This production decline is related in part to a three day field shut-in for repairs at Ship Shoal 182/183. Gas revenues decreased from $8,013,970 in 2007 to $4,726,292 in 2008 due to a decrease in gas volumes from 1,089,709 Mcf in 2007 to 508,781 Mcf in 2008. The decrease in gas volumes was due to a shut-in as a result of an obstructed pipeline and the natural decline of production. The average natural gas sales price increased from $7.35 per Mcf in 2007 to $9.29 per Mcf in 2008. Capital expenditures decreased from $701,753 in 2007 to ($419,971) in 2008 primarily due to an audit credit adjustment for prior periods. Operating expenses decreased from $3,204,308 in 2007 to $2,471,185 in 2008 due to decreased production during 2008.

Production from Ship Shoal 182 and 183 ceased following damage inflicted by Hurricane Ike in September 2008. While Hurricane Ike caused limited surface damage to the facilities at Ship Shoal 182/183, all of the wells at Ship Shoal 182/183 were shut-in following hurricane-related damage to a third-party transporter's natural gas pipeline. A limited volume of oil production was restored in November 2008, with an average rate of daily oil production from November 20, 2008 through January 31, 2009 of approximately 831 barrels per day. The volume of oil production that can be produced is limited by the amount of gas that is also produced by the oil wells. Production is expected to remain limited until the natural gas pipeline is fully repaired and tested, which is anticipated to occur in the second quarter of 2009, but which is also in the control of the pipeline owner. At this point in time, there can be no assurance as to when, or if at all, production may be restored at Ship Shoal 182/183. See "—Operations."

West Cameron 643

West Cameron 643 gas revenues increased from $802,575 in 2007 to $2,024,841 in 2008 due primarily to an increase in gas volumes from 126,971 Mcf in 2007 to 214,130 Mcf in 2008. The increase in gas volumes resulted from increased production for the last three quarters of 2008, compared to the last three quarters of 2007. The average natural gas sales price increased from $6.32 per Mcf in 2007 to $9.46 per Mcf in 2008. Operating expenses decreased from $942,457 in 2007 to $1,233,887 in 2008. Capital expenditures increased from $0 in 2007 to $27,953 in 2008.

Production from West Cameron 643 ceased following damage inflicted by Hurricane Ike in September 2008 to a third-party transporter's pipeline. The Managing General Partner of the Partnership understands that the pipeline is in the process of being restored; however, the pipeline is not expected to be able to take production until at least the end of 2009. At this point in time, there can be no assurance as to when, or if at all, production may be restored at West Cameron 643.

East Cameron 371

East Cameron 371 gas revenues increased from $150,500 in 2007 to $252,992 in 2008. Oil revenues increased from $30,164 in 2007 to $47,962 in 2008. Capital expenditures were $0 in 2007 and 2008 and operating expenses increased from $174,559 in 2007 to $298,413 in 2008.

Production from East Cameron 371 ceased following damage inflicted by Hurricane Ike in September 2008 to a third-party transporter's pipeline. The Managing General Partner of the Partnership understands that the pipeline is in the process of being restored; however, there can be no assurance as to when, or if at all, production may be restored at East Cameron 371.

South Timbalier 36/37

South Timbalier 36/37 oil revenues decreased from $595,442 in 2007 to $592,068 in 2008, due to a decrease in production from 9,229 barrels in 2007 to 5,802 barrels in 2008, offset by an increase in crude oil prices from $64.52 per barrel in 2007 to $102.05 per barrel in 2008. Capital expenditures decreased from $109,901 in 2007 to $43,345 in 2008. Operating expenses increased $78,730 from $61,780 in 2007 to $140,510 in 2008.

Years 2007 and 2006

Royalty income increased approximately 309% from $2,510,936 in 2006 to $10,257,485 in 2007 primarily due to an increase in gas revenues and crude oil and condensate revenues as discussed below.

For 2007, the Trust had undistributed net loss of $9,297. For 2006, the Trust had undistributed net loss of $2,092. An increase in distributed net income represents revenues generated during the respective period but not distributed by the Working Interest Owners. Collection of undistributed net income is the subsequent receipt in future periods from the related Working Interest Owner(s) of revenues generated in prior periods but not yet distributed.

Volumes and dollar amounts discussed below represent amounts recorded by the Working Interest Owners unless otherwise specified.

Natural Gas and Gas Products

Natural gas and gas products revenues increased 195% from $4,003,561 in 2006 to $11,820,973 in 2007, primarily due to a 176% increase in natural gas and gas products volumes from 600,477 Mcf equivalents in 2006 to 1,654,836 Mcf equivalents in 2007. The average price received for natural gas increased 6% from $6.70 per Mcf in 2006 to $7.11 Mcf in 2007.

Crude Oil and Condensate

Crude oil and condensate revenues increased 40% from $26,869,007 in 2006 to $37,732,678 in 2007, due primarily to a 37% increase in crude oil and condensate volumes from 421,763 barrels in 2006 to 578,159 barrels in 2007. The average price received for crude oil and condensate increased by 2% from $63.71 in 2006 to $65.26 in 2007.

The increase in crude oil and condensate volume, as well as natural gas volumes and gas products production volumes, for 2007, compared to 2006, resulted primarily from repairs of certain damages caused by Hurricanes Rita and Katrina.

Operating and Capital Expenditures

Operating expenses paid by the Working Interest Owners increased 12% from $5,876,944 in 2006 to $6,598,909 in 2007. The increase in operating expenses is primarily due to the increased production during 2007.

Capital expenditures paid by the Working Interest Owners decreased 82% from $9,443,605 in 2006 to $1,716,676 in 2007. The higher amount of capital expenditures during 2006 related primarily to damages caused by Hurricanes Rita and Katrina.

Special Cost Escrow Account

In the first quarter of 2008, there was a net release of funds from the Special Cost Escrow Account of approximately $1,318,188.

In 2007, the Working Interest Owners refunded a net amount to the Trust of $125,391 from the Special Cost Escrow Account. As of December 31, 2007, approximately $6,713,564 remained in the Special Cost Escrow Account. In 2006, the Working Interest Owners deposited a net amount to the Trust of $1,188,000 from the Special Cost Escrow Account. As of December 31, 2006, approximately $6,839,000 remained in the Special Cost Escrow Account. The net refund for 2007 compared to net deposit for 2006 was primarily due to a decrease in the estimate of projected capital expenditures, production costs and abandonment costs of the Royalty Properties due to hurricane related damages.

Summary By Property

Listed below is a summary of 2007 operations as compared to 2006 of the five principal Royalty Properties based on gross revenues generated during these periods combined.

Eugene Island 339

Eugene Island 339 crude oil revenues increased $8,959,469, from $9,220,238 in 2006 to $18,179,707 in 2007, primarily due to an increase in production. Crude oil production increased from 149,887 barrels in 2006 to 287,539 barrels in 2007. The average price of crude oil increased from $61.51 per barrel in 2006 to $63.22 per barrel in 2007. Gas revenues increased $674,988, from $547,819 in 2006 to $1,222,807 in 2007, primarily due to an increase in gas production from 83,101 Mcf in 2006 to 194,633 Mcf in 2007 as a result of completion in July 2007 of the pipeline connection to the existing sales point on the Eugene Island 361 platform. The average price received for natural gas decreased from $6.59 per Mcf in 2006 to $6.28 per Mcf in 2007. Capital expenditures decreased from $3,524,145 in 2006 to $190,093 in 2007. The capital expenditures incurred during 2006 were due to hurricane-related damages. Operating expenses decreased from $2,584,319 in 2006 to $2,214,130 in 2007 primarily due to a decrease in workover expenses.

Ship Shoal 182/183

Ship Shoal 182/183 crude oil revenues increased from $17,107,346 in 2006 to $18,924,236 in 2007, due to an increase in crude oil prices from $64.93 per barrel in 2006 to $67.35 per barrel in 2007 and an increase in crude oil production from 263,486 barrels in 2006 to 280,996 barrels in 2007. Gas revenues increased from $3,044,766 in 2006 to $8,013,970 in 2007 due to an increase in gas volumes from 453,910 Mcf in 2006 to 1,089,709 Mcf in 2007. The increase in gas volumes resulted from no gas being produced until the third quarter of 2006 due to hurricane-related damages. The average natural gas sales price increased from $6.71 per Mcf in 2006 to $7.35 per Mcf in 2007. Capital expenditures decreased from $5,718,239 in 2006 to $701,753 in 2007 primarily due to hurricane-related repairs having been made in 2006. Operating expenses increased from $2,782,327 in 2006 to $3,204,308 in 2007 due to increased production during 2007.

West Cameron 643

West Cameron 643 gas revenues increased from $33,587 in 2006 to $802,575 in 2007 due primarily to an increase in gas volumes from 6,628 Mcf in 2006 to 126,971 Mcf in 2007. The increase in gas volumes resulted from no gas being produced until the third quarter of 2006 at which time only a limited amount of production had begun. The average natural gas sales price increased from $5.07 per Mcf in 2006 to $6.32 per Mcf in 2007. Operating expenses increased from $404,380 in 2006 to $942,457 in 2007 due to the increased production during 2007. Capital expenditures decreased from $46,156 in 2006 to $0 in 2007.

East Cameron 371

East Cameron 371 gas revenues were $770 in 2006 and $150,500 in 2007. Oil revenues were $0 in 2006 and $30,164 in 2007. Capital expenditures decreased from $315 in 2006 to $0 in 2007 and operating expenses increased from $31,917 in 2006 to $174,559 in 2007.

South Timbalier 36/37

South Timbalier 36/37 oil revenues increased from $527,183 in 2006 to $595,442 in 2007, due to an increase in crude oil production from 8,142 barrels in 2006 to 9,229 barrels in 2007, offset by a slight decrease in crude oil prices from $64.75 per barrel in 2006 to $64.52 per barrel in 2007. Capital expenditures increased from $34,316 in 2006 to $109,901 in 2007.

Production and Price Review

The following schedule provides a summary of the volumes and weighted average prices for crude oil and condensate and natural gas recorded by the Working Interest Owners for the Royalty Properties, as well as the Working Interest Owners' calculations of the net proceeds and royalties paid

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to the Trust during the periods indicated. Net proceeds due to the Trust are calculated for each three month period commencing on the first day of February, May, August and November.

	Royalty Properties Year Ended December 31,(1)		
	2008	2007	2006
Crude oil and condensate (bbls)	421,958	578,159	421,763
Natural gas and gas products (Mcfe)	1,625,408	1,654,836	600,477
Crude oil and condensate average price, per bbl	$ 100.54	$ 65.26	$ 63.71
Natural gas average price, per Mcf (excluding gas products)	$ 8.45	$ 7.11	$ 6.70
Crude oil and condensate revenues	$42,424,601	$37,732,678	$26,869,007
Natural gas and gas products revenues	$14,248,644	$11,820,973	$ 4,003,561
Production expenses	(8,939,036)	(8,363,502)	(7,277,259)
Capital expenditures	(228,959)	(1,716,676)	(9,443,605)
Undistributed Net Income—collection of (increase in)(2)	$ 132,688	37,226	8,368
Refund of/(Provision for) Special Cost Escrow	$10,172,852	1,523,341	(4,115,324)
Net Proceeds	$57,810,788	$41,034,042	$10,044,748
Royalty interest	x25%	x25%	x25%
Partnership share	$14,452,697	$10,258,511	$ 2,511,187
Trust interest	x99.99%	x99.99%	x99.99%
Trust share of Royalty Income(3)	$14,451,252	$10,257,485	$ 2,510,936

(1) Amounts represent actual production for the 12-month period ended on October 31 of each year, respectively.

(2) An increase in undistributed net income represents revenues generated during the respective period but not distributed by the Working Interest Owners. Collection of undistributed net income is the subsequent receipt in future periods from the related Working Interest Owner(s) of revenues generated in prior periods but not yet distributed. For the twelve months ended December 31, 2008, the collection of prior undistributed net income was $132,688.

(3) See "Management's Discussion and Analysis of Financial Condition and Results of Operations—Operations" and Note 4 to the Notes to the Financial Statements under Item 8 of this Form 10-K for a discussion regarding uncertainty of distributions.

Off-Balance Sheet Arrangements

The Trust has no off-balance sheet arrangements.

Contractual Obligations

As of December 31, 2008, the Trust had no obligations or commitments to make future contractual obligations except for administrative fees owed to the Trustee pursuant to the Trust Agreement. In 2008, the Trust paid the Trustee an administrative fee of $182,500.

Item 7A. *Quantitative and Qualitative Disclosures About Market Risk*

Reference is made to Item 1 of this Form 10-K.

Item 8. ***Financial Statements and Supplementary Data***

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Trustees and Unit Holders of
TEL Offshore Trust
Austin, Texas

We have audited the accompanying statements of assets, liabilities and trust corpus of TEL Offshore Trust (the "Trust") as of December 31, 2008 and 2007, and the related statements of distributable income and changes in trust corpus for each of the three years in the period ended December 31, 2008. These financial statements are the responsibility of the Corporate Trustee. Our responsibility is to express an opinion on the financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by the Corporate Trustee, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

As described in Note 3 to the financial statements, these financial statements were prepared on a comprehensive basis of accounting other than accounting principles generally accepted in the United States of America.

In our opinion, such financial statements present fairly, in all material respects, the assets, liabilities and trust corpus of TEL Offshore Trust as of December 31, 2008 and 2007, and its distributable income and changes in trust corpus for each of the three years in the period ended December 31, 2008, on the comprehensive basis of accounting described in Note 3 to the financial statements.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Trust's internal control over financial reporting as of December 31, 2008, based on the criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated March 31, 2009 expressed an unqualified opinion on the Trust's internal control over financial reporting.

Deloitte & Touche LLP

Houston, Texas
March 31, 2009

TEL OFFSHORE TRUST

STATEMENTS OF ASSETS, LIABILITIES AND TRUST CORPUS

	December 31, 2008	December 31, 2007
Assets		
Cash and cash equivalents	$2,973,140	$5,136,437
Net overriding royalty interest in oil and gas properties, net of accumulated amortization of $28,236,317 and $28,227,458 at December 31, 2008 and 2007, respectively	31,338	40,197
Total assets	$3,004,478	$5,176,634
Liabilities and Trust Corpus		
Distribution payable to Unit holders	$ 739,849	$3,252,711
Reserve for future Trust expenses	$2,233,291	1,883,726
Trust corpus (4,751,510 Units of beneficial interest authorized and outstanding at December 31, 2008 and 2007)	31,338	40,197
Total liabilities and Trust corpus	$3,004,478	$5,176,634

STATEMENTS OF DISTRIBUTABLE INCOME

	Year Ended December 31, 2008	2007	2006
Royalty income	$14,451,252	$10,257,485	$2,510,936
Interest income	37,422	77,565	25,516
	14,488,674	10,335,050	2,536,452
General and administrative expenses	(840,455)	(259,861)	(579,069)
Increase in reserve for future Trust expenses	(349,565)	(764,076)	(259,662)
Distributable income	13,298,654	9,311,113	1,697,721
Distributions per Unit (4,751,510 Units)	$ 2.798827	$ 1.959611	$ .357301

STATEMENTS OF CHANGES IN TRUST CORPUS

	Year Ended December 31, 2008	2007	2006
Trust corpus, beginning of year	$ 40,197	$ 53,506	$ 64,069
Distributable income	13,298,654	9,311,113	1,697,721
Distributions to Unit holders	(13,298,654)	(9,311,113)	(1,697,721)
Amortization of net overriding royalty interest	(8,859)	(13,309)	(10,563)
Trust corpus, end of year	$ 31,338	$ 40,197	$ 53,506

The accompanying notes are an integral part of these financial statements

TEL OFFSHORE TRUST

NOTES TO FINANCIAL STATEMENTS

(1) Trust Organization and Provisions

Tenneco Offshore Company, Inc. ("Tenneco Offshore") created the TEL Offshore Trust ("Trust") effective January 1, 1983, pursuant to the Plan of Dissolution ("Plan") approved by Tenneco Offshore's stockholders on December 22, 1982. In accordance with the Plan, the TEL Offshore Trust Partnership ("Partnership") was formed in which the Trust owns a 99.99% interest and Tenneco Oil Company initially owned a .01% interest. In general, the Plan was effected by transferring an overriding royalty interest ("Royalty") equivalent to a 25% net profits interest in the oil and gas properties (the "Royalty Properties") of Tenneco Exploration, Ltd. located offshore Louisiana to the Partnership and issuing certificates evidencing units of beneficial interest in the Trust in liquidation and cancellation of Tenneco Offshore's common stock.

On January 14, 1983, Tenneco Offshore distributed units of beneficial interest ("Units") in the Trust to holders of Tenneco Offshore's common stock on the basis of one Unit for each common share owned on such date.

The terms of the Trust Agreement, dated January 1, 1983, provide, among other things, that:

(a) the Trust is a passive entity and cannot engage in any business or investment activity or purchase any assets;

(b) the interest in the Partnership can be sold in part or in total for cash upon approval of a majority of the Unit holders;

(c) the Trustees, as defined below, can establish cash reserves and borrow funds to pay liabilities of the Trust and can pledge the assets of the Trust to secure payments of the borrowings. At December 31, 2008 the reserve amount was $2,233,291;

(d) the Trustees will make cash distributions to the Unit holders in January, April, July and October of each year as discussed in Note 4; and

(e) the Trust will terminate upon the first to occur of the following events: (i) total future net revenues attributable to the Partnership's interest in the Royalty, as determined by independent petroleum engineers, as of the end of any year, are less than $2.0 million or (ii) a decision to terminate the Trust by the affirmative vote of Unit holders representing a majority of the Units. Future net revenues attributable to the Royalty were estimated at approximately $24.2 million (unaudited) as of October 31, 2008. Upon termination of the Trust, the Corporate Trustee will sell for cash all assets held in the Trust estate and make a final distribution to the Unit holders of any funds remaining, after all Trust liabilities have been satisfied.

The Trust is currently administered by The Bank of New York Mellon Trust Company, N.A., which succeeded JPMorgan Chase Bank, N.A. as the Corporate Trustee, effective October 2, 2006 pursuant to an agreement under which The Bank of New York acquired substantially all of the Corporate Trust business of JPMorgan Chase (formerly known as The Chase Manhattan Bank), and Daniel O. Conwill, IV, Gary C. Evans and Jeffrey S. Swanson ("Individual Trustees"), as trustees ("Trustees").

(2) Net Overriding Royalty Interest

The Royalty entitles the Trust to its share (99.99%) of 25% of the Net Proceeds attributable to the Royalty Properties. The Conveyance, dated January 1, 1983, provides that the Working Interest Owners will calculate, for each period of three months commencing the first day of February, May, August and November, an amount equal to 25% of the Net Proceeds from their oil and gas properties for the

(2) Net Overriding Royalty Interest (Continued)

period. Generally, "Net Proceeds" means the amounts received by the Working Interest Owners from the sale of minerals from the Royalty Properties less operating and capital costs incurred, management fees and expense reimbursements owing to the Managing General Partner of the Partnership, applicable taxes other than income taxes, and the Special Cost Escrow account. The Special Cost Escrow account is established for the future costs to be incurred to plug and abandon wells, dismantle and remove platforms, pipelines and other production facilities, and for the estimated amount of future capital expenditures on the Royalty Properties. Net proceeds do not include amounts received by the Working Interest Owners as advance gas payments, "take-or-pay" payments or similar payments unless and until such payments are extinguished or repaid through the future delivery of gas.

As of October 9, 2001, Chevron Corporation merged with Texaco, and the Royalty Properties owned by Texaco Exploration and Production Inc. ("TEPI") were assigned to Chevron U.S.A. Inc. ("Chevron") on May 1, 2002. Crude oil sales from the Chevron and TEPI properties added together accounted for approximately 99% for 2008, 2007 and 2006 of crude oil revenues from the Royalty Properties. Sales to Chevron Corporation accounted for approximately 99% of total gas revenues from the Royalty Properties during 2008, 2007 and 2006.

The Trust's share of Royalty income was reduced by approximately $481,561, $441,148 and $350,927 in 2008, 2007 and 2006, respectively, for management fees paid to the Working Interest Owners as reimbursement for expenses incurred by them on behalf of the Trust. Such management fees were calculated as 3% of the Trust's share of the sum of revenues, production expenses and capital expenditures attributable to the Royalty Properties in each of the three years above.

(3) Basis of Accounting

The financial statements of the Trust are prepared on the following basis:

(a) Royalty income is recorded when received, including the effect of overtaken or undertaken positions and negative or positive adjustments, by the Corporate Trustee on the last business day of each calendar quarter. In addition, Royalty Income includes amounts related to funds deposited or released from the Special Cost Escrow account—see (c);

(b) Trust general and administrative expenses are recorded when paid, except for the cash reserved for future general and administrative expenses; and

(c) The funds deposited or released from the Special Cost Escrow account are recorded at the time of payment or receipt. The Special Cost Escrow account is an account of the Working Interest Owners and is not reflected in the financial statements of the Trust.

This manner of reporting income and expenses is considered to be the most meaningful because the quarterly distributions to Unit holders are based on net cash receipts received from the Working Interest Owners. The financial statements of the Trust differ from financial statements prepared in accordance with generally accepted accounting principles, because, under such principles, Royalty income and Trust general and administrative expenses for a quarter would be recognized on an accrual basis. In addition, amortization of the net overriding royalty interest, calculated on a units-of-production basis, is charged directly to Trust corpus since such amount does not affect distributable income.

TEL OFFSHORE TRUST

NOTES TO FINANCIAL STATEMENTS (Continued)

(3) Basis of Accounting (Continued)

Cash and cash equivalents include all highly liquid short-term investments with original maturities of three months or less.

The changes in reserve for future Trust expenses includes both changes of amounts deemed necessary by the Trustees and related distributions, as well as amounts paid from the reserve during periods when the Trust has insufficient income to pay Trust expenses.

The Trust reviews net overriding royalty interests in oil and gas properties for possible impairment whenever events or circumstances indicate the carrying amount of the asset may not be recoverable. If there is an indication of impairment, the Trust prepares an estimate of future cash flows (undiscounted and without interest charges) expected to result from the use of the asset and its eventual disposition. If these cash flows are less than the carrying amount of the asset, an impairment loss is recognized to write down the asset to its estimated fair value. Preparation of estimated expected future cash flows is inherently subjective and is based on the Corporate Trustee's best estimate of assumptions concerning expected future conditions. There were no write downs taken in the periods presented.

The Special Cost Escrow account (see Note 5) is established for future costs to be incurred to plug and abandon wells, dismantle and remove platforms, pipelines and other production facilities, and for the estimated amount of future capital expenditures on the Royalty Properties. The funds held in the Special Cost Escrow account are not reflected in the financial statements of the Trust. However, funds deposited to or released from the Special Cost Escrow account are included in Royalty income.

The preparation of financial statements requires the Trustees to make use of estimates and assumptions that affect amounts reported in the financial statements as well as certain disclosures. Actual results could differ from those estimates.

The amount of cash distributions by the Trust is dependent on, among other things, the sales prices for oil and gas produced from the Royalty Properties and the quantities of oil and gas sold. It should be noted that substantial uncertainties exist with regard to future oil and gas prices, which are subject to material fluctuations due to changes in production levels and pricing and other actions taken by major petroleum producing nations, as well as the regional supply and demand for gas, weather, industrial growth, conservation measures, competition and other variables. The Trust does not enter into any hedging transactions on future production.

(4) Distributions to Unit Holders

In accordance with the provisions of the Trust Agreement, generally all Net Proceeds received by the Trust, net of Trust general and administrative expenses and any cash reserves established for the payment of contingent or future obligations of the Trust, are distributed currently to the Unit holders. These distributions are referred to as "distributable income". The amounts distributed are determined on a quarterly basis and are payable to Unit holders of record as of the last business day of each calendar quarter. However, cash distributions are made in January, April, July and October and include interest earned from the quarterly record date to the date of distribution.

During 2005, Hurricane Katrina and Hurricane Rita caused significant damage to various platforms and third-party transportation systems, which resulted in oil and gas production delays in the Royalty Properties. During 2006, several of the platforms and facilities on the Royalty Properties were restored, and by the third quarter of 2007 all but one of the platforms and facilities had been restored. One of the platforms and facilities on Eugene Island was destroyed and has not been restored. Since

TEL OFFSHORE TRUST

NOTES TO FINANCIAL STATEMENTS (Continued)

(4) Distributions to Unit Holders (Continued)

those hurricanes, overall production slowly returned to normal production levels, until production ceased at Eugene Island 339 and Ship Shoal 182 and 183 following damages inflicted by Hurricane Ike in September 2008. Future Net Proceeds may take into account the Trust's share of project costs and other related expenditures that are not covered by insurance of the operator of the Royalty Properties. The extensive damage caused by hurricanes Katrina and Rita led to significant demand for services and supplies for repairs in the offshore Gulf of Mexico, which increased levels of expenditures. The reduced oil and gas production and increased costs reduced the cash income distributions to unitholders significantly during 2006. During the fourth quarter 2006, the Trust resumed distributions.

Set forth below are the quarterly distributions made by the Trust for 2008 and 2007.

	Distribution	
Quarter	2008	2007
Fourth	$ 739,849	$3,252,711
Third	5,470,387	2,836,895
Second	2,619,375	2,053,933
First	4,469,043	1,167,574

Future distributions are expected to be severely negatively impacted as a result of Hurricane Ike, and there may not be sufficient Net Proceeds to make one or more scheduled distributions.

(5) Special Cost Escrow Account

The Special Cost Escrow is an account of the Working Interest Owners and it is described herein for informational purposes only. The Conveyance provides for reserving funds for estimated future "Special Costs" of plugging and abandoning wells, dismantling platforms and other costs of abandoning the Royalty Properties, as well as for the estimated amount of future drilling projects and other capital expenditures on the Royalty Properties. As provided in the Conveyance, the amount of funds to be reserved is determined based on certain factors, including estimates of aggregate future production costs, aggregate future Special Costs, aggregate future net revenues and actual current net proceeds. Deposits into this account reduce current distributions and are placed in an escrow account and invested in short-term certificates of deposit. Such account is herein referred to as the "Special Cost Escrow" account. The Trust's share of interest generated from the Special Cost Escrow account, approximately $155,152, $255,443 and $150,109 for 2008, 2007 and 2006, respectively, serves to reduce the Trust's share of allocated production costs. As of December 31, 2008, 2007 and 2006, approximately $4,325,503, $6,714,000 and $6,839,000, respectively, remained in the Special Cost Escrow account. Special Cost Escrow account funds will generally be utilized to pay Special Costs to the extent there are not adequate current net proceeds to pay such costs. Special Costs that have been paid are no longer included in the Special Cost Escrow calculation. Deposits to the Special Cost Escrow account will generally be made when the balance in the Special Cost Escrow account is less than 125% of estimated future Special Costs and there is a Net Revenues Shortfall (a calculation of the excess of estimated future costs over estimated future net revenues pursuant to a formula contained in the Conveyance). When there is not a Net Revenues Shortfall, amounts in the Special Cost Escrow account will generally be released, to the extent that Special Costs have been incurred. Amounts in the Special Cost Escrow account will also be released when the balance in such account exceeds 125% of future Special Costs.

TEL OFFSHORE TRUST

NOTES TO FINANCIAL STATEMENTS (Continued)

(5) Special Cost Escrow Account (Continued)

The discussion of the terms of the Conveyance and Special Cost Escrow Account contained herein is qualified in its entirety by reference to the Conveyance.

Deposits to the Special Cost Escrow Account may be required in future periods in connection with other production costs, other abandonment costs, other capital expenditures and changes in the estimates and factors described above. Such deposits could result in a significant reduction in Royalty income in the periods in which such deposits are made.

In 2008, the Working Interest Owners refunded a net amount of approximately $2,388,061 from the Special Cost Escrow Account. In 2007, the Working Interest Owners refunded a net amount of approximately $125,391 from the Special Cost Escrow Account. In 2006, the Working Interest Owners deposited a net amount of approximately $1,188,239 into the Special Cost Escrow Account. The net deposits were made primarily due to changes in the estimate of projected capital expenditures, production costs and abandonment costs of the Royalty Properties.

(6) Reserve For Future Trust Expenses

The Trust made a determination in 1998 to maintain a cash reserve equal to approximately three times the average expenses of the Trust during each of the past three years to provide for future administrative expenses in connection with the winding up of the Trust. During 2008, the Trust increased its reserve by $349,565 for a reserve balance of $2,233,291 as of December 31, 2008. The reserve amount at December 31, 2007 was $1,883,726.

(7) Federal Income Tax Matters

The IRS has ruled that the Trust is a grantor trust and that the Partnership is a partnership for federal income tax purposes. Thus, the Trust will incur no federal income tax liability and each Unit holder will be treated as owning an interest in the Partnership.

(8) Commitments and Contingencies

The Managing General Partner of the Partnership has advised the Trust that, although the Working Interest Owners believe that they are in general compliance with applicable health, safety and environmental laws and regulations that have taken effect at the federal, state and local levels, costs may be incurred to comply with current and proposed environmental legislation which could result in increased operating expenses on the Royalty Properties.

(9) Supplemental Reserve Information (Unaudited)

Estimates of the proved oil and gas reserves attributable to the Partnership's royalty interest are based on a report prepared by DeGolyer and MacNaughton, independent petroleum engineering consultants. Estimates were prepared in accordance with guidelines established by the Securities and Exchange Commission and the Financial Accounting Standards Board. Accordingly, the estimates are based on existing economic and operating conditions in effect at October 31, 2008, with no provision for future increases or decreases except for periodic price redeterminations in accordance with existing gas contracts.

On October 7, 2008, the Trust announced that production from the two most significant oil and gas properties associated with the Trust had ceased following damage inflicted by Hurricane Ike in

TEL OFFSHORE TRUST

NOTES TO FINANCIAL STATEMENTS (Continued)

(9) Supplemental Reserve Information (Unaudited) (Continued)

September 2008. The platforms and wells on Eugene Island 339 were completely destroyed by the hurricane. In order to restore production at Eugene Island 339, Chevron expects that it would need to redevelop the facility and drill new wells. The Trust had expected Chevron to make a decision in the first quarter of 2009 whether to proceed with any such development; however, Chevron is still assessing its alternatives and the economic feasibility for restoring production at the property. Chevron's decisions regarding Eugene Island 339 impact the treatment of Eugene Island for purposes of preparing a reserve report for the Partnership. Solely for purposes of being able to complete the reserve report so that the Trust could file its Form 10-K for the year ended December 31, 2008, DeGolyer and MacNaughton assumed that Eugene Island 339 will not be redeveloped. As such, the reserve study does not include any reserves or values attributable to Eugene Island 339, nor does it include the Trust's percentage share of the total plugging and abandonment costs related to Eugene Island 339, with costs for 2009 alone estimated to be approximately $61 million. At this point in time, there can be no assurance as to how or when, or if at all, production may be restored at Eugene Island 339. Based on the reserve study of DeGolyer and MacNaughton for the oil and gas reserves attributable to the Partnership as of October 31, 2007, Eugene Island 339 accounted for approximately 34% of the total future net revenues attributable to the Partnership's interest in the Royalty as of October 31, 2007.

The reserve volumes and revenue values attributable to the Partnership's royalty interest were estimated from projections of reserves and revenue attributable to the combined interests consisting of the Partnership's royalty interest and the retained interest of the Working Interest Owners in the Royalty Properties. Net reserves attributable to the Partnership's royalty interest were estimated by allocating to the Partnership a portion of the estimated combined net reserves of the subject properties based on the ratio of the Partnership's interest in future net revenues to combined future gross revenues. Because the net reserve volumes attributable to the Partnership's royalty interest are estimated using an allocation of reserves based on estimates of future revenue, a change in prices or costs will result in changes in the estimated net reserves. Therefore, the estimated net reserves attributable to the Partnership's royalty interest will vary if different future price and cost assumptions are used. All reserves attributable to the Partnership's royalty interest are located in the United States. Total future net revenues attributable to the Partnership's interest in the Royalty were estimated at $24.2 million as of October 31, 2008 based on the reserve study of DeGolyer and MacNaughton.

The Partnership's share of gas sales can be recorded by the Working Interest Owner on the cash method of accounting or based on actual production. When revenues are reported based on actual production, there is no gas imbalance created. Under the cash method, revenues are recorded based on actual gas volumes sold, which could be more or less than the volumes the Working Interest Owners are entitled to based on their ownership interests. The Partnership's Royalty income for a period reflects the actual gas sold during the period.

Distributable income for the Partnership for the periods ended December 31, 2008, 2007 and 2006 included net proceeds relating to production of reserves from the Royalty Properties for the twelve months ended October 31, 2008, 2007 and 2006, respectively.

TEL OFFSHORE TRUST

NOTES TO FINANCIAL STATEMENTS (Continued)

(10) Selected Quarterly Financial Data (Unaudited)

Summarized quarterly financial data is as follows:

	First	Second	Third	Fourth
2008*:				
Royalty income	$5,067,521	$2,750,990	$5,627,452	$1,005,289
Distributable income	$4,469,043	$2,619,375	$5,470,387	$ 739,849
Distributions per Unit	$ 0.940552	$ 0.551272	$ 1.151294	$ 0.155708
2007*:				
Royalty income	$1,516,684	$2,415,521	$2,924,013	$3,401,267
Distributable income	$1,167,574	$2,053,933	$2,836,895	$3,252,711
Distributions per Unit	$ 0.245727	$ 0.432270	$ 0.597051	$ 0.684564

* Royalty income and distributable income were decreased or increased in certain quarters due to deposits to or releases from the Special Cost Escrow Account as discussed in Note 5 above.

See Note 4 for a discussion regarding uncertainty of distributions.

*****

Item 9. ***Changes in and Disagreements with Accountants on Accounting and Financial Disclosure.***

None.

Item 9A. ***Controls and Procedures.***

Evaluation of disclosure controls and procedures.

The Corporate Trustee maintains disclosure controls and procedures designed to ensure that information to be disclosed by the Trust in the reports that it files or submits under the Securities Exchange Act of 1934, as amended, is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and regulations. Disclosure controls and procedures include controls and procedures designed to ensure that information required to be disclosed by the Trust is accumulated and communicated by Chevron as the managing general partner of the Partnership, and the working interest owners to The Bank of New York Mellon Trust Company, N.A., as Corporate Trustee of the Trust, and its employees who participate in the preparation of the Trust's periodic reports as appropriate to allow timely decisions regarding required disclosure.

As of the end of the period covered by this report, the Corporate Trustee carried out an evaluation of the Trust's disclosure controls and procedures. Mike Ulrich, as Trust Officer and Corporate Trustee, has concluded that the disclosure controls and procedures of the Trust are effective.

Due to the contractual arrangements of (i) the Trust Agreement, (ii) the Partnership Agreement and (iii) the rights of the Partnership under the Conveyance regarding information furnished by the working interest owners, the Trustees rely on (A) information provided by the Working Interest Owners, including historical operating data, plans for future operating and capital expenditures, reserve information and information relating to projected production, (B) information from the Managing General Partner of the Partnership, including information that is collected from the Working Interest Owners, and (C) conclusions and reports regarding reserves by the Trust's independent reserve engineers. See Item 1A. Risk Factors "—The Trustees and the Unit holders have no control over the operation or development of the Royalty Properties and have little influence over operation or development" in the Trust's Form 10-K and "Management's Discussion and Analysis of Financial Condition and Results of Operation" included in this Form 10-K, for a description of certain risks relating to these arrangements and reliance and applicable adjustments to operating information when reported by the Working Interest Owners to the Corporate Trustee and recorded in the Trust's results of operation.

Changes in Internal Control Over Financial Reporting

In connection with the evaluation by the Corporate Trustee of changes in internal control over financial reporting of the Trust, no change in the Trust's internal control over financial reporting was identified that has materially affected, or is reasonably likely to materially affect, the Trust's internal control over financial reporting.

Trustee's Report on Internal Control over Financial Reporting

A registrant's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A registrant's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the registrant; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the registrant are being made

only in accordance with authorizations of management and directors of the registrant; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the registrants assets that could have a material effect on the financial statements.

The Corporate Trustee is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Rule 13a-15(f) promulgated under the Securities and Exchange Act of 1934, as amended. The Corporate Trustee conducted an evaluation of the effectiveness of the Trust's internal control over financial reporting based on the criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on the Corporate Trustee's evaluation under the framework in *Internal Control—Integrated Framework*, the Corporate Trustee concluded that the Trust's internal control over financial reporting was effective as of December 31, 2008.

Deloitte & Touche, LLP, the Trust's independent registered public accounting firm that audited the financial statements included in this Form 10-K, has issued an attestation report on the effectiveness of the Trust's internal control over financial reporting.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

March 31, 2009

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Trustees and Unit Holders of
TEL Offshore Trust
Austin, Texas

We have audited the internal control over financial reporting of TEL Offshore Trust (the "Trust") as of December 31, 2008 based on criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Corporate Trustee is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Trustee's Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the Trust's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A trust's internal control over financial reporting is a process designed by, or under the supervision of, the trust's trustee, and effected by the trustees and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with the comprehensive basis of accounting described in Note 3 to the financial statements. A trust's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the trust; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with the comprehensive basis of accounting described in Note 3 of the financial statements, and that receipts and expenditures of the trust are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the trust's assets that could have a material effect on the financial statements.

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper trustee override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the Trust maintained, in all material respects, effective internal control over financial reporting as of December 31, 2008, based on the criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the financial statements as of and for the year ended December 31, 2008 of the Trust and our report dated March 31, 2009 expressed an unqualified opinion on those financial statements.

Deloitte & Touche LLP

Houston, Texas
March 31, 2009

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Item 9B. ***Other Information.***

None.

PART III

Item 10. ***Directors, Executive Officers and Corporate Governance.***

There are no directors or executive officers of the Registrant. The Trustees consist of a Corporate Trustee and three Individual Trustees. The Bank of New York Mellon Trust Company, N.A. serves as the Corporate Trustee, and Daniel O. Conwill, IV, Gary C. Evans and Jeffrey S. Swanson serve as the three Individual Trustees. Any Trustee may be removed by the affirmative vote of two Individual Trustees or by the affirmative vote of a majority of the Units at a meeting of Unit holders of beneficial interest in the Trust at which a quorum is present.

The Trust does not have a principal executive officer, principal financial officer, principal accounting officer or controller and, therefore, has not adopted a code of ethics applicable to such persons. However, employees of the Corporate Trustee must comply with the bank's code of ethics.

The Trust does not have a board of directors, and therefore does not have an audit committee, an audit committee financial expert, or a nominating committee.

Section 16(a) Beneficial Ownership Reporting Compliance.

The Trust has no directors or officers. Accordingly, only holders of more than 10% of the Trust's Units are required to file with the SEC initial reports of ownership of Units and reports of changes in such ownership pursuant to Section 16 under the Securities Exchange Act of 1934. Based solely on a review of these reports, the Trust believes that the applicable reporting requirements of Section 16(a) of the Securities Exchange Act of 1934 were complied with for all transactions that occurred in 2008.

Item 11. ***Executive Compensation.***

Not applicable.

Item 12. ***Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters.***

(a) Security Ownership of Certain Beneficial Owners.

The Trust has no officers or directors. Accordingly, only holders of more than 5% of the Trust's Units are required to file reports with the SEC on Schedule 13D or Schedule 13G and holders of 10% or more of the Trust's Units are required to file initial and other reports with the SEC pursuant to Section 16 of the Securities Exchange Act of 1934. Based solely on a review of reports, the Trust is not aware of such holders as of the date of this report.

(b) Security Ownership of Management.

Not applicable.

(c) Changes in Control.

The Trust knows of no arrangements, including the pledge of securities of the Trust, the operation of which may at a subsequent date result in a change in control of the Trust.

Item 13. ***Certain Relationships and Related Transactions, and Director Independence.***

Each of the Working Interest Owners owns interests, for its own account, in leases which are in the same area as leases in which the Partnership has acquired or may acquire an interest. Such relationships may give rise to potential conflicts of interests in, among other things, the operation of such leases and in the acquisition and operation of any drainage leases acquired by a Working Interest Owner for its own account. Additionally, the Working Interest Owners and their affiliates are not prohibited from purchasing oil and gas produced from or attributable to any leases in which the Partnership has an interest.

Crude oil sales to Chevron Corporation accounted for approximately 99% of total crude oil revenues from the Royalty Properties during 2008, 2007 and 2006. During such years, approximately 99% of Chevron's natural gas and natural gas liquids relative to the Royalty Properties were committed and sold to Chevron Texaco Natural Gas.

The Trust's share of Royalty income was reduced by approximately $482,000, $441,000 and $351,000 in 2008, 2007 and 2006, respectively, for management fees paid to the Working Interest Owners as reimbursement for expenses incurred by them on behalf of the Trust. The aggregate amount of management fees paid to the Working Interest Owners was calculated as 3% of the Trust's share of the sum of revenues, production expenses and capital expenditures attributable to the Royalty Properties in 2008, 2007 and 2006.

Item 14. ***Principal Accountant Fees and Services.***

The Trust does not have an audit committee. Any pre-approval and approval of all services performed by the principal auditor or any other professional service firms and related fees are granted by the Trustees. The Trustees have appointed Deloitte & Touche, LLP, the member firm of Deloitte & Touche Tohmatsu, and their respective affiliates (collectively "Deloitte") as the independent registered public accounting firm to audit the trust's financial statements for the fiscal year ending December 31, 2009. During fiscal 2008, Deloitte served as the Trust's independent registered public accounting firm and also provided certain tax services.

The following table presents the aggregate fees billed to the Trust for the fiscal years ended December 31, 2008 and 2007 by Deloitte:

	2008	2007
Audit fees(1)	$210,000	$163,000
Audit-related fees	—	—
Tax fees(2)	$ 10,500	7,000
All other fees	—	—
Total fees	$220,500	$170,000

(1) Fees for audit services in 2008 and 2007 consisted of the audit of the Trust's annual financial statements and reviews of the Trust's quarterly financial statements. Services in 2008 also included the attestation on the effectiveness of the Trust's internal control over financial reporting.

(2) Fees for tax services billed in 2008 and 2007 consisted of tax compliance services.

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PART IV

Item 15. ***Exhibits, Financial Statement Schedules.***

(a)(1) Financial Statements

The following financial statements are set forth under Part II, Item 8 of this Annual Report on Form 10-K on the pages as indicated:

(a)(2) Schedules

Schedules have been omitted because they are not required, not applicable or the information required has been included elsewhere herein.

(a)(3) Exhibits

(Asterisk indicates exhibit previously filed with the Securities and Exchange Commission and incorporated herein by reference. The Bank of New York Mellon Trust Company, N.A. succeeded JPMorgan Chase Bank as Corporate Trustee. JPMorgan Chase Bank is successor by mergers to the original corporate trustee, Texas Commerce Bank National Association.)

		SEC File or Registration Number	Exhibit Number
4(a)*	Trust Agreement dated as of January 1, 1983, among Tenneco Offshore Company, Inc., Texas Commerce Bank National Association, as corporate trustee, and Horace C. Bailey, Joseph C. Broadus and F. Arnold Daum, as individual trustees (Exhibit 4(a) to Form 10-K for year ended December 31, 1992 of TEL Offshore Trust)	0-6910	4(a)
4(b)*	Agreement of General Partnership of TEL Offshore Trust Partnership between Tenneco Oil Company and the TEL Offshore Trust, dated January 1, 1983 (Exhibit 4(b) to Form 10-K for year ended December 31, 1992 of TEL Offshore Trust)	0-6910	4(b)
4(c)*	Conveyance of Overriding Royalty Interests from Exploration I to the Partnership (Exhibit 4(c) to Form 10-K for year ended December 31, 1992 of TEL Offshore Trust)	0-6910	4(c)
4(d)*	Amendments to TEL Offshore Trust Agreement, dated December 7, 1984 (Exhibit 4(d) to Form 10-K for year ended December 31, 1992 of TEL Offshore Trust)	0-6910	4(d)
4(e)*	Amendment to the Agreement of General Partnership of TEL Offshore Trust Partnership, effective as of January 1, 1983 (Exhibit 4(e) to Form 10-K for year ended December 31, 1992 of TEL Offshore Trust)	0-6910	4(e)

		SEC File or Registration Number	Exhibit Number
10(a)*	Purchase Agreement, dated as of December 7, 1984 by and between Tenneco Oil Company and Tenneco Offshore II Company (Exhibit 10(a) to Form 10-K for year ended December 31, 1992 of TEL Offshore Trust)	0-6910	10(a)
10(b)*	Consent Agreement, dated November 16, 1988, between TEL Offshore Trust and Tenneco Oil Company (Exhibit 10(b) to Form 10-K for year ended December 31, 1988 of TEL Offshore Trust)	0-6910	10(b)
10(c)*	Assignment and Assumption Agreement, dated November 17, 1988, between Tenneco Oil Company and TOC-Gulf of Mexico Inc. (Exhibit 10(c) to Form 10-K for year ended December 31, 1988 of TEL Offshore Trust)	0-6910	10(c)
10(d)*	Gas Purchase and Sales Agreement Effective September 1, 1993 between Tennessee Gas Pipeline Company and Chevron U.S.A. Production Company (Exhibit 10(d) to Form 10-K for year ended December 31, 1993 of TEL Offshore Trust)	0-6910	10(d)
31	Certification furnished pursuant to Section 302 of the Sarbanes-Oxley Act of 2002		
32	Certification furnished pursuant to Section 906 of the Sarbanes-Oxley Act of 2002		

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized on this 31st day of March, 2009.

TEL OFFSHORE TRUST

By: THE BANK OF NEW YORK MELLON TRUST COMPANY, N.A., Corporate Trustee

By: /s/ MIKE ULRICH

Mike Ulrich
Vice President

Signature		Date
THE BANK OF NEW YORK MELLON TRUST COMPANY, N.A., Corporate Trustee		
By:	/s/ MIKE ULRICH Mike Ulrich, *Vice President & Trust Officer*	March 31, 2009
INDIVIDUAL TRUSTEES		
/s/ DANIEL O. CONWILL, IV Daniel O. Conwill, IV, *Individual Trustee*		March 31, 2009
/s/ GARY C. EVANS Gary C. Evans, *Individual Trustee*		March 31, 2009
/s/ JEFFREY S. SWANSON Jeffrey S. Swanson, *Individual Trustee*		March 31, 2009

The Registrant, TEL Offshore Trust, has no principal executive officer, principal financial officer, board of directors or persons performing similar functions. Accordingly, no additional signatures are available and none have been provided. In signing the report above, neither the Corporate Trustee nor the Individual Trustees imply that they perform any such function or that such function exists pursuant to the terms of the Trust Agreement under which they serve.

EXHIBIT D-2

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 8-K

CURRENT REPORT
Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934

Date of Report (Date of earliest event reported): **March 25, 2009**

TEL Offshore Trust
(Exact name of registrant as specified in its charter)

Texas	**1-6910**	**76-6004064**
(State or other jurisdiction of incorporation)	(Commission File Number)	(IRS Employer Identification No.)

The Bank of New York Mellon Trust Company, N.A., Trustee **Global Corporate Trust** **919 Congress Avenue** **Austin, Texas**	**78701**
(Address of principal executive offices)	(Zip Code)

Registrant's telephone number, including area code: **(800) 852-1422**

Not Applicable
(Former name or former address, if changed since last report.)

Check the appropriate box below if the Form 8-K filing is intended to simultaneously satisfy the filing obligation of the registrant under any of the following provisions:

☐ Written communications pursuant to Rule 425 under the Securities Act (17 CFR 230.425)

☐ Soliciting material pursuant to Rule 14a-12 under the Exchange Act (17 CFR 240.14a-12)

☐ Pre-commencement communications pursuant to Rule 14d-2(b) under the Exchange Act (17 CFR 240.14d-2(b))

☐ Pre-commencement communications pursuant to Rule 13e-4(c) under the Exchange Act (17 CFR 240.13e-4(c))

Item 2.02 Results of Operation and Financial Condition.

On March 25, 2009, the Registrant issued a press release announcing that there will be no trust distributions for the first quarter of 2009 for unitholders of record on March 31, 2009. The press release is attached hereto as Exhibit 99.1 and incorporated herein by reference.

Pursuant to General Instruction B.2 of Form 8-K and Securities and Exchange Commission Release No. 33-8176, the press release attached as Exhibit 99.1 is not “filed” for purposes of Section 18 of the Securities Exchange Act of 1934, as amended, is not subject to the liabilities of that section and is not deemed incorporated by reference in any filing under the Securities Act of 1933, as amended, but is instead furnished for purposes of that instruction.

Item 9.01 Financial Statements and Exhibits.

(c) Exhibits.

Exhibit 99.1	TEL Offshore Trust’s Press Release dated March 25, 2009.

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned hereunto duly authorized.

TEL Offshore Trust
By: The Bank of New York Mellon Trust Company, N.A.,
as Trustee

Date: March 25, 2009

By: /s/ Mike Ulrich
Mike Ulrich
Vice President and Trust Officer

EXHIBIT INDEX

Exhibit	Description
99.1	TEL Offshore Trust's Press Release dated March 25, 2009.

Exhibit 99.1

TEL OFFSHORE TRUST

THE BANK OF NEW YORK MELLON TRUST COMPANY, N.A., CORPORATE TRUSTEE
919 CONGRESS AVENUE / (800) 852-1422 / AUSTIN, TEXAS 78701

TEL OFFSHORE TRUST ANNOUNCES THERE WILL BE NO FIRST QUARTER 2009 DISTRIBUTION

AUSTIN, TEXAS March 25, 2009—TEL OFFSHORE TRUST announced that there will be no trust distribution for the first quarter of 2009 for unitholders of record on March 31, 2009. The financial and operating information included herein for the Trust's first quarter of 2009 reflects financial and operating information with respect to the royalty properties for the months of November and December 2008 and January 2009 and includes prior period adjustments associated therewith.

Gas revenues recorded by the Working Interest Owners on the royalty properties increased approximately 30% to $827,661 in the first quarter of 2009 from $638,250 in the fourth quarter of 2008. Natural gas volumes during the first quarter of 2009 decreased approximately 23% to 130,986 Mcf from 169,621 Mcf during the fourth quarter of 2008, primarily due to damages caused by Hurricane Ike in September 2008. The average price received for natural gas decreased approximately 34% to $7.14 per Mcf in the first quarter of 2009 as compared to $10.81 per Mcf received in the fourth quarter of 2008. After taking into account prior period pricing adjustments, including adjustments to reflect alternative pricing contracts, the average price received for natural gas for the first quarter of 2009 was effectively $6.32 per Mcf and the average price received for natural gas for the fourth quarter of 2008 was effectively $3.76 per Mcf; thus, gas revenues actually increased quarter to quarter.

Crude oil revenues recorded by the Working Interest Owners on the royalty properties decreased approximately 80% to $1,009,282 in the first quarter of 2009 from $4,939,538 in the fourth quarter of 2008. Oil volumes during the first quarter of 2009 decreased approximately 49% to 18,510 barrels, compared to 36,270 barrels of oil produced in the fourth quarter of 2008. The decrease in revenue was primarily due to decreases in production resulting from damages caused by Hurricane Ike. The average price received for oil decreased to $54.53 per barrel in the first quarter of 2009 from $136.19 per barrel in the fourth quarter of 2008 (after taking into account minor prior period pricing adjustments in both quarters).

The Trust's share of capital expenditures increased by $166,417 in the first quarter of 2009 to $276,425, as compared to $110,008 in the fourth quarter of 2008. The increase in capital expenditures was primarily due to higher expenditures for Eugene Island 339 that were classified as capital expenditures. The Trust's share of operating expenses increased by $4,208,634 in the first quarter of 2009 to $5,937,665 as compared to $1,729,031 for the fourth quarter of 2008. The increase in operating expenses was primarily due to expenditures associated with the plugging and abandonment of the existing wells at Eugene Island 339 and related matters.

No funds were released or escrowed from the Trust's Special Cost Escrow in the first quarter of 2009. The Trust's Special Cost Escrow balance was $4,305,190 as of the end of the Trust's first quarter.

On October 7, 2008, the Trust announced that production from the two most significant oil and gas properties associated with the Trust had ceased following damage inflicted by Hurricane Ike in

September 2008. The principal asset of the Trust consists of a 99.99% interest in TEL Offshore Trust Partnership. The Partnership owns an overriding royalty interest, equivalent to a 25% net profits interest, in certain oil and gas properties, including the working interest ownership interest of Chevron U.S.A. Inc. in Eugene Island 339 and Ship Shoal 182 and 183.

The platforms and wells on Eugene Island 339 were completely destroyed by Hurricane Ike in September 2008. Crude oil revenues from Eugene Island 339 represented approximately 48% of the crude oil and condensate revenues for the royalty properties in 2007 and approximately 47% of such revenues for the nine months ended September 30, 2008. Eugene Island 339 contributed approximately 12% of the revenues from natural gas sales from the royalty properties in 2007 and approximately 41% of such revenues for the nine months ended September 30, 2008. Based on a prior reserve study of DeGolyer and MacNaughton, independent petroleum engineering consultants, Eugene Island 339 accounted for approximately 34% of the total future net revenues attributable to the Partnership's interest in the royalty as of October 31, 2007. Chevron is proceeding to plug and abandon the existing wells, to clear debris and otherwise to deal with the remaining infrastructure. In order to restore production, Chevron expects that it would need to redevelop the facility and drill new wells. Chevron is still assessing its alternatives and the economic feasibility for restoring production at the property. At this point in time, there can be no assurance as to how or when, or if at all, production may be restored at Eugene Island 339. Generally, if production ceases from an outer continental shelf lease, like that for Eugene Island 339, production must be restored or drilling operations must commence within 180 days of the cessation (which was in early March 2009), or the lease will be terminated. A lease operator may seek approval from the regional supervisor of the Mineral Management Service to allow additional time to restore production. Chevron has submitted such a request with respect to Eugene Island 339. There can be no assurance that production at Eugene Island 339 will be restored or that such requested extension will be granted.

Production at Ship Shoal 182/183 ceased following damage inflicted by Hurricane Ike in September 2008. While the hurricane caused limited surface damage to the facilities at Ship Shoal 182/183, all of the wells at Ship Shoal 182/183 were shut-in following hurricane-related damage to a third-party transporter's natural gas pipeline. The more productive wells on the properties produce both oil and gas, and there was no downstream transmission available for any gas produced from the wells. Crude oil revenues from Ship Shoal 182/183 represented approximately 50% of the crude oil and condensate revenues for the royalty properties in 2007 and approximately 51% of such revenues for the nine months ended September 30, 2008. Ship Shoal 182/183 contributed approximately 77% of the revenues from natural gas sales from the royalty properties in 2007 and approximately 42% of such revenues for the nine months ended September 30, 2008. A limited volume of oil production was restored in November 2008, with an average rate of daily oil production from November 20, 2008 through January 31, 2009 of approximately 831 barrels per day. The volume of oil production that can be produced is limited by the amount of gas that is also produced by the oil wells. Production is expected to remain limited until the natural gas pipeline is fully repaired and tested, which is anticipated to occur in the second quarter of 2009, but which is also in the control of the pipeline owner. There may also be related regulatory approval requirements that must be satisfied before gas transportation may commence. At this point in time, there can be no assurance as to when, or if at all, gas production may be restored at Ship Shoal 182/183.

Future distributions are likely to be severely impacted, by both reduced production and increased expenditures required to remediate, repair and, perhaps, restore platforms and wells. Future net proceeds from the royalty properties may take into account the Trust's share of project costs and other related expenditures that are not covered by insurance of the operators of the royalty properties. If development and production costs of the royalty exceed the proceeds of production from the royalty properties, the Trust will not receive net proceeds until future proceeds from production exceed the total of the excess costs plus accrued interest. Development activities may not generate sufficient additional revenue to repay the costs. Accordingly, there may not be sufficient net proceeds from the royalty properties to make a particular distribution. At this time, the ultimate outcome of these matters cannot be determined.

This press release contains forward-looking statements. Although the Managing General Partner of the TEL Offshore Trust Partnership has advised the Trust that the Managing General Partner believes that the expectations contained in this press release are reasonable, no assurances can be given that such expectations will prove to be correct. The Working Interest Owners alone control historical operating data, and handle receipt and payment of funds relating to the royalty properties and payments to the Trust for the related royalty. The Trustees of the Trust cannot assure that errors or adjustments by the Working Interest Owners, whether historical or future, will not affect future royalty income and distributions by the Trust. Other important factors that could cause these statements to differ materially include delays and costs in connection with repairs or replacements of hurricane-damaged facilities and pipelines, including third-party transportation systems, the actual results of drilling operations, risks inherent in drilling and production of oil and gas properties, and other factors described in the Trust's Form 10-K for 2007 under "Item 1A. Risk Factors" and in the Trust's Form 10-Q for the quarterly period ended September 30, 2008 under "Item 1A. Risk Factors." Statements made in this press release are qualified by the cautionary statements made in these risk factors. The Trust does not intend, and assumes no obligations, to update any of the statements included in this press release.

The Bank of New York Mellon Trust Company, N.A.
AS CORPORATE TRUSTEE
CONTACT: Mike Ulrich
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www.businesswire.com/cnn/tel-offshore.htm

EXHIBIT D-3

QuickLinks -- Click here to rapidly navigate through this document

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q

☒ **Quarterly Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934 for the quarterly period ended June 30, 2009**

Or

☐ **Transition Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934 for the transition period from to**

Commission File Number: 0-6910

TEL OFFSHORE TRUST

(Exact name of registrant as specified in its charter)

Texas (State or other jurisdiction of incorporation or organization)	**76-6004064** (I.R.S. Employer Identification No.)
The Bank of New York Mellon Trust Company, N.A. **919 Congress Avenue** **Austin, Texas** (Address of principal executive offices)	**78701** (Zip Code)

(800) 852-1422
(Registrant's telephone number, including area code)

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☒ No ☐

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ☐ No ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer ☐ Accelerated filer ☒ Non-accelerated filer ☐ (Do not check if a smaller reporting company) Smaller reporting company ☐

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes ☐ No ☒

As of August 6, 2009, 4,751,510 Units of Beneficial Interest in TEL Offshore Trust were outstanding.

NOTE REGARDING FORWARD LOOKING STATEMENTS

This Form 10-Q includes "forward looking statements" within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. All statements other than statements of historical facts included in this Form 10-Q are forward looking statements. Although the Managing General Partner of the TEL Offshore Trust Partnership has advised the Trust that the Managing General Partner believes that the expectations reflected in the forward looking statements contained herein are reasonable, no assurance can be given that such expectations will prove to have been correct. Important factors that could cause actual results to differ materially from expectations ("Cautionary Statements") are disclosed in this Form 10-Q, including, without limitation, in conjunction with the forward looking statements included in this Form 10-Q. A summary of certain principal risks and Cautionary Statements is also included in the Trust's Annual Report on Form 10-K for the year ended December 31, 2009 under Part I, Item 1A. "Risk Factors." All subsequent written and oral forward looking statements attributable to the Trust or persons acting on its behalf are expressly qualified in their entirety by the Cautionary Statements.

PART I—FINANCIAL INFORMATION

Item 1. Financial Statements.

TEL OFFSHORE TRUST
STATEMENTS OF ASSETS, LIABILITIES AND TRUST CORPUS

(Unaudited)

	June 30, 2009	December 31, 2008
Assets		
Cash and cash equivalents	$1,691,500	$2,973,140
Net overriding royalty interest in oil and gas properties, net of accumulated amortization of $28,237,686 and $28,236,317, respectively	29,969	31,338
Total assets	$1,721,469	$3,004,478
Liabilities and Trust Corpus		
Distribution payable to Unit holders	$ —	$ 739,849
Reserve for future Trust expenses	1,691,500	2,233,291
Trust corpus (4,751,510 Units of beneficial interest authorized and outstanding)	29,969	31,338
Total liabilities and Trust corpus	$1,721,469	$3,004,478

STATEMENTS OF DISTRIBUTABLE INCOME

(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2009	2008	2009	2008
Royalty income	$ —	$2,750,990	$ —	$7,818,511
Interest income	379	8,929	955	20,189
	379	2,759,919	955	7,838,700
(Increase) decrease in reserve for future Trust expenses	210,775	109,269	541,791	(252,452)
General and administrative expenses	(211,154)	(249,813)	(542,746)	(497,830)
Distributable income	$ —	$2,619,375	$ —	$7,088,418
Distributions per Unit (4,751,510 Units)	$ .000000	$ .551272	$ .000000	$ 1.491824

STATEMENTS OF CHANGES IN TRUST CORPUS

(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2009	2008	2009	2008
Trust corpus, beginning of period	$30,636	$ 37,609	$31,338	$ 40,197
Distributable income	—	2,619,375	—	7,088,418
Distribution payable to Unit holders	—	2,619,375	—	7,088,418
Amortization of net overriding royalty interest	(667)	(2,007)	(1,369)	(4,595)
Trust corpus, end of period	$29,969	$ 35,602	$29,969	$ 35,602

The accompanying notes are an integral part of these financial statements.

TEL OFFSHORE TRUST
NOTES TO FINANCIAL STATEMENTS
(Unaudited)

Note 1—Trust Organization

Tenneco Offshore Company, Inc. ("Tenneco Offshore") created the TEL Offshore Trust ("Trust") effective January 1, 1983, pursuant to the Plan of Dissolution ("Plan") approved by Tenneco Offshore's stockholders on December 22, 1982. In accordance with the Plan, the TEL Offshore Trust Partnership ("Partnership") was formed in which the Trust owns a 99.99% interest and Tenneco Oil Company initially owned a .01% interest. In general, the Plan was effected by transferring an overriding royalty interest ("Royalty") equivalent to a 25% net profits interest in the oil and gas properties (the "Royalty Properties") of Tenneco Exploration, Ltd. located offshore Louisiana to the Partnership and issuing certificates evidencing units of beneficial interest in the Trust ("Units") in liquidation and cancellation of Tenneco Offshore's common stock. The terms "Working Interest Owner" and "Working Interest Owners," as used herein, refer to the owner or owners of the various Royalty Properties, which owners have changed from time to time since the original ownership of the Royalty Properties by Tenneco Exploration, Ltd.

On January 14, 1983, Tenneco Offshore distributed Units to holders of Tenneco Offshore's common stock on the basis of one Unit for each common share owned on such date.

The terms of the Trust Agreement, dated January 1, 1983, provide, among other things, that:

(a) the Trust is a passive entity and cannot engage in any business or investment activity or purchase any assets;

(b) the interest in the Partnership can be sold in part or in total for cash upon approval of a majority of the Unit holders;

(c) the Trustees, as defined below, can establish cash reserves and borrow funds to pay liabilities of the Trust and can pledge the assets of the Trust to secure payments of the borrowings; at December 31, 2008, the reserve amount was $2,233,291;

(d) the Trustees will make cash distributions to the Unit holders in January, April, July and October of each year as discussed in Note 4; and

(e) the Trust will terminate upon the first to occur of the following events: (i) total future net revenues attributable to the Partnership's interest in the Royalty, as determined by independent petroleum engineers, as of the end of any year, are less than $2.0 million or (ii) a decision to terminate the Trust by the affirmative vote of Unit holders representing a majority of the Units. Future net revenues attributable to the Royalty were estimated at approximately $24.2 million (unaudited) as of October 31, 2008 (such future net revenues do not include any reserves or values attributable to Eugene Island 339, nor does it include the Trust's percentage share of the total plugging and abandonment costs related to Eugene Island 339, with costs for 2009 alone estimated to be approximately $61 million). Upon termination of the Trust, the Corporate Trustee will sell for cash all assets held in the Trust estate and make a final distribution to the Unit holders of any funds remaining, after all Trust liabilities have been satisfied.

The Trust is currently administered by The Bank of New York Mellon Trust Company, N.A. (the "Corporate Trustee"), which succeeded JPMorgan Chase Bank, N.A. as the corporate trustee, effective

October 2, 2006 pursuant to an agreement under which The Bank of New York acquired substantially all of the corporate trust business of JPMorgan Chase (formerly known as The Chase Manhattan Bank), and Daniel O. Conwill, IV, Gary C. Evans and Jeffrey S. Swanson (the "Individual Trustees"), as trustees (the "Trustees").

Note 2—Basis of Accounting

The accompanying unaudited financial information has been prepared by the Corporate Trustee. The accompanying financial information is prepared on a comprehensive basis of accounting other than accounting principles generally accepted in the United States of America ("generally accepted accounting principles"). The Corporate Trustee and the Individual Trustees believe that the information furnished reflects all adjustments that are, in the opinion of the Trustees, necessary for a fair presentation of the results for the interim periods presented. Such adjustments are of a normal and recurring nature. The financial information should be read in conjunction with the financial statements and notes thereto included in the Trust's Annual Report on Form 10-K for the year ended December 31, 2008.

The financial statements of the Trust are prepared on the following basis:

(a) Royalty income is recorded when received, including the effect of overtaken or undertaken positions and negative or positive adjustments, by the Corporate Trustee on the last business day of each calendar quarter. In addition, Royalty income includes amounts related to funds deposited or released from the Special Cost Escrow account—see (c); and

(b) Trust general and administrative expenses are recorded when paid, except for the cash reserved for future general and administrative expenses; and

(c) The funds deposited or released from the Special Cost Escrow account are recorded at the time of payment or receipt. The Special Cost Escrow account is an account of the Working Interest Owners and is not reflected in the financial statements of the Trust.

This manner of reporting income and expenses is considered to be the most meaningful because the quarterly distributions to Unit holders are based on net cash receipts received from the Working Interest Owners. The financial statements of the Trust differ from financial statements prepared in accordance with generally accepted accounting principles, because, under such principles, Royalty income and Trust general and administrative expenses for a quarter would be recognized on an accrual basis. In addition, amortization of the net overriding royalty interest, which is calculated on a units-of-production basis, is charged directly to Trust corpus since such amount does not affect distributable income.

On the last business day of each calendar quarter, the Working Interest Owners pay to the Partnership 25% of the Net Proceeds for the immediately preceding Quarterly Period. A Quarterly Period is each period of three months commencing on the first day of February, May, August and November. In turn, the Partnership distributes funds to its partners on the last business day of each calendar quarter. Cash distributions from the Trust are made in January, April, July and October of each year, and are payable to Unit holders of record as of the last business day of each calendar quarter. Thus, the cash conveyed to the Trust from the Royalty during the quarter ended June 30, 2008 substantially represents the revenues and expenses from the Royalty Properties from February 2008 through April 2008. There was no cash conveyed to the Trust from the Royalty Properties from

November 2008 through April 2009. The financial and operating information included in this Form 10-Q for the three months ended June 30, 2009 and June 30, 2008 represent financial and operating information with respect to the Royalty Properties for the months of February, March and April 2009 and 2008, respectively. Similarly, financial and operating information with respect to the Royalty Properties for the six months ended June 30, 2009 and June 30, 2008 represent financial and operating information with respect to the Royalty Properties for the immediately preceding months of November through April. Income from the Royalty is recorded by the Trust on a cash basis, when it is received by the Trust from the Partnership.

Cash and cash equivalents include all highly liquid, short-term investments with original maturities of three months or less.

The changes in reserve for future Trust expenses include both changes of amounts deemed necessary by the Trustees and related distributions, as well as amounts paid from the reserve during periods when the Trust has insufficient income to pay Trust expenses.

The Trust reviews the net overriding royalty interest in oil and gas properties for possible impairment whenever events or circumstances indicate the carrying amount of the asset may not be recoverable. If there is an indication of impairment, the Trust prepares an estimate of future cash flows (undiscounted and without interest charges) expected to result from the use of the asset and its eventual disposition. If these cash flows are less than the carrying amount of the asset, an impairment loss may be recognized to write down the asset to the lower of its estimated fair value or net book value. Preparation of estimated expected future cash flows is inherently subjective and is based on the Corporate Trustee's best estimate of assumptions concerning expected future conditions. There were no write downs taken in the periods presented.

The Special Cost Escrow account (Note 5) is established for the future costs to be incurred to plug and abandon wells, dismantle and remove platforms, pipelines and other production facilities and for the estimated amount of future capital expenditures on the Royalty Properties. The funds held in the Special Cost Escrow account are not reflected in the financial statements of the Trust. However, funds deposited to or released from the Special Cost Escrow account are included in the Royalty income.

The preparation of financial statements requires the Trustees to make use of estimates and assumptions that affect amounts reported in the financial statements as well as certain discounts. Actual results could differ from those estimates.

The amount of cash distributions by the Trust is dependent on, among other things, the quantities of oil and gas produced from the Royalty Properties and the sales prices therefor. As described herein, production ceased at Eugene Island 339 and Ship Shoal 182 and 183 following damages inflicted by Hurricane Ike in September 2008, and substantial uncertainties exist with regard to future production from such Royalty Properties. It should be noted that substantial uncertainties exist with regard to future oil and gas prices, which are subject to material fluctuations due to changes in production levels and pricing and other actions taken by major petroleum producing nations, as well as the regional supply and demand for gas, weather, industrial growth, conservation measures, competition, economic conditions generally and other variables. The Trust does not enter into any hedging transactions on future production.

In May 2009, the Financial Accounting Standards Board (FASB) issued SFAS No. 165, Subsequent Events ("SFAS 165"). SFAS 165 establishes principles and standards related to the accounting for and disclosure of events that occur after the date of the balance sheet included in financial statements being presented, but before such financial statements are issued. SFAS 165 requires an entity to recognize, in the financial statements, subsequent events that provide additional information regarding conditions that existed at the balance sheet date. Subsequent events that provide information about conditions that did not exist at the balance sheet date are not to be recognized in the financial statements under SFAS 165. SFAS 165 is effective for interim and annual reporting periods ending after June 15, 2009. The Trust adopted this standard effective as of June 30, 2009. The adoption of SFAS 165 did not have a material effect on the Trust's financial statements. Subsequent events were evaluated through August 7, 2009, the date that these financial statements were issued.

Note 3—Net Overriding Royalty Interest

The Royalty entitles the Trust to its share (99.99%) of 25% of the Net Proceeds attributable to the Royalty Properties. The Conveyance dated January 1, 1983, conveying the Royalty Properties to the Partnership (the "Conveyance"), provides that the Working Interest Owners will calculate, for each period of three months commencing the first day of February, May, August and November, an amount equal to 25% of the Net Proceeds from their oil and gas properties for the period. Generally, "Net Proceeds" means the amounts received by the Working Interest Owners from the sale of minerals from the Royalty Properties less operating and capital costs incurred, management fees and expense reimbursements owing to the Managing General Partner of the Partnership, applicable taxes other than income taxes, and a Special Cost Escrow account. The Special Cost Escrow account (See Note 5) is established for the future costs to be incurred to plug and abandon wells, dismantle and remove platforms, pipelines and other production facilities, and for the estimated amount of future capital expenditures on the Royalty Properties. Net Proceeds do not include amounts received by the Working Interest Owners as advance gas payments, "take-or-pay" payments or similar payments unless and until such payments are extinguished or repaid through the future delivery of gas.

Note 4—Distributions to Unit Holders

In accordance with the provisions of the Trust Agreement, generally all Net Proceeds received by the Trust, net of Trust general and administrative expenses and any cash reserves established for the payment of contingent or future obligations of the Trust, are distributed currently to the Unit holders. Such distributions are referred to as "distributable income." The amounts distributed are determined on a quarterly basis and are payable to Unit holders of record as of the last business day of each calendar quarter. However, cash distributions are made in January, April, July and October and include interest earned from the quarterly record date to the date of distribution.

Set forth below are the quarterly distributions made by the Trust for 2009 and 2008.

Quarter	Distribution
2009:	
Second	$ 0
First	0
2008:	
Fourth	$ 739,849
Third	5,470,387
Second	2,619,375
First	4,469,043

Production ceased at Eugene Island 339 and Ship Shoal 182 and 183 following damages inflicted by Hurricane Ike in September 2008. On March 25, 2009, the Trust announced there would be no first quarter distribution. Similarly, on June 26, 2009, the Trust announced there would be no second quarter distribution.

There are not likely to be sufficient Net Proceeds from the Royalty Properties for the Trust to make a regularly scheduled quarterly distribution to Unit holders for the foreseeable future. As a result of the damage inflicted by Hurricane Ike, Net Proceeds will continue to be severely impacted by reduced production, from historical levels, and the amount of expenditures incurred that are associated with such damages, including the expenditures required to plug and abandon the wells on Eugene Island 339, and, perhaps, to redevelop the facility at Eugene Island 339. Future Net Proceeds from the Royalty Properties may take into account the Trust's share of project costs and other related expenditures that are not covered by the insurance of the operators of the Royalty Properties. The Trust's net portion of the aggregate cost to plug and abandon the wells subject to the royalty on Eugene Island 339 is currently estimated to be approximately $13 million. If development and production costs of the Royalty exceed the proceeds of production from the Royalty Properties, the Trust will not receive Net Proceeds until future proceeds from production exceed the total of the excess costs plus accrued interest. Development activities may not generate sufficient additional revenue to repay such costs. Accordingly, there will not be sufficient Net Proceeds from the Royalty Properties to make distributions for some period of time in the future. At this time, the ultimate outcome of these matters cannot be determined with any degree of certainty.

Note 5—Special Cost Escrow Account

The Special Cost Escrow is an account of the Working Interest Owners, and it is described herein for informational purposes only. The Conveyance provides for the reserve of funds for estimated future "Special Costs" of plugging and abandoning wells, dismantling platforms and other costs of abandoning the Royalty Properties, as well as for the estimated cost of future drilling projects and other capital expenditures on the Royalty Properties. As provided in the Conveyance, the amount of funds to be reserved is determined based on certain factors, including estimates of aggregate future production costs, aggregate future Special Costs, aggregate future net revenues and actual current net profits interest. Deposits into this account reduce current distributions and are placed in an escrow account and invested in short-term certificates of deposit. Such account is herein referred to as the "Special Cost Escrow" account. The Trust's share of interest generated from the Special Cost Escrow account serves to reduce the Trust's share of allocated production costs. Special Cost Escrow funds will generally be utilized to pay Special Costs to the extent there are not adequate current net profits to pay such costs. Special Costs that have been paid are no longer included in the Special Cost Escrow calculation. Deposits to the Special Cost Escrow account will generally be made when the balance in the Special Cost Escrow account is less than 125% of estimated future Special Costs and there is a Net Revenues Shortfall (a calculation of the excess of estimated future costs over estimated future net revenues pursuant to a formula contained in the Conveyance). When there is not a Net Revenues Shortfall, amounts in the Special Cost Escrow account will generally be released, to the extent that Special Costs have been incurred. Amounts in the Special Cost Escrow account will also be released when the balance in such account exceeds 125% of estimated future Special Costs. In the second quarter of 2009 there were no funds released or escrowed from the Special Cost Escrow account. As of June 30, 2009, $4,306,735 remained in the Special Cost Escrow account. The funds held in the Special Cost Escrow account are not reflected in the financial statements of the Trust.

Chevron U.S.A. Inc. ("Chevron"), in its capacity as the Managing General Partner of the Partnership, has advised the Trust that additional deposits to the Special Cost Escrow account may be required in future periods in connection with other production costs, other abandonment costs, other capital expenditures and changes in the estimates and factors described above. Such deposits could result in a significant reduction in Royalty income in the periods in which such deposits are made, including the possibility that no Royalty income would be received in such periods.

Note 6—Reserve For Future Trust Expenses

The Trust maintains a cash reserve, equal to approximately three times the average expenses of the Trust during each of the past three years, to provide for future administrative expenses in connection with the winding up of the Trust. During the second quarter of 2009, the Trust used $210,775 from the reserve account for current expenses, leaving a reserve balance of $1,691,500 as of June 30, 2009. The reserve amount at December 31, 2008 was $2,233,291.

Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations.

Critical Accounting Policies

The financial statements of the Trust are prepared on the following basis:

(a) Royalty income is recorded when received, including the effect of overtaken or undertaken positions and negative or positive adjustments, by the Corporate Trustee on the last business day of each calendar quarter. In addition, Royalty income includes amounts related to funds deposited or released from the Special Cost Escrow account—see (c); and

(b) Trust general and administrative expenses are recorded when paid, except for the cash reserved for future general and administrative expenses; and

(c) The funds deposited or released from the Special Cost Escrow account are recorded at the time of payment or receipt. The Special Cost Escrow account is an account of the Working Interest Owners and is not reflected in the financial statements of the Trust.

This manner of reporting income and expenses is considered to be the most meaningful because the quarterly distributions to Unit holders are based on net cash receipts received from the Working Interest Owners. The financial statements of the Trust differ from financial statements prepared in accordance with generally accepted accounting principles, because, under such principles, Royalty income and Trust general and administrative expenses for a quarter would be recognized on an accrual basis. In addition, amortization of the net overriding royalty interest, calculated on a units-of-production basis, is charged directly to Trust corpus since such amount does not affect distributable income.

The Trustees, including the Corporate Trustee, have no authority over, have not evaluated and make no statement concerning, the internal control over financial reporting of the Working Interest Owners.

Financial Review

In May 2007, the Trust engaged an independent oil and gas accounting firm for the purpose of reviewing the books and records of certain Working Interest Owners with respect to the Royalty Properties and the related payments to the Trust. As part of this ongoing audit review process, certain adjustments to revenues, production volumes, prices and capital expenditures have occurred, and references below to a prior period audit adjustment, or an audit of prior periods, refers to the audit described in this paragraph. The adjustments resulting from such audit review have now been completed. See "—Operational Review".

Three Months Ended June 30, 2009 and 2008

There were no distributions to the Unit holders for the three months ended June 30, 2009 as compared to distributions of $2,619,375 or $0.551272 per Unit to the Unit holders for the same period in 2008.

Crude oil and condensate revenues decreased $8,266,970, or 82%, to $1,813,293 in the second quarter of 2009 as compared to $10,080,263 in the second quarter of 2008, due primarily to decreases in production resulting from damages caused by Hurricane Ike. Oil volumes decreased 66% to 35,475 barrels in the second quarter of 2009 from 103,147 barrels in the second quarter of 2008. The revenues for the second quarter of 2009 reflect a credit of $186,806 associated with an audit for prior periods. The revenues and volumes for the second quarter of 2008 reflect a net debit for $22,361 in revenues and a credit of 53 barrels associated with an audit for prior periods and certain other adjustments. The average price received for crude oil and condensate decreased 48%, or $46.62, to $51.11 per barrel in the second quarter of 2009 from $97.73 per barrel in the second quarter of 2008. Prior to taking into account such adjustments to revenues and volumes, the average price received for crude oil and condensate would have been $97.99 per barrel in the second quarter of 2008.

Gas revenues decreased $3,065,947, or 99%, to $8,701 in the second quarter of 2009 from $3,074,648 in the second quarter of 2008, due primarily to decreases in production resulting from damages caused by Hurricane Ike in September 2008. Gas volumes decreased 99% to 1,384 Mcf in the second quarter of 2009 from 353,503 Mcf in the second quarter of 2008. The revenues and volumes for the second quarter of 2009 reflect debits to correct an error in revenue allocation in August 2008 for $4,603 in revenues and 1,234 Mcf of gas; the revenues and volumes for the second quarter of 2008 reflect credits associated with an audit of prior periods for $534,253 in revenues and 66,577 Mcf of gas. The average price received for natural gas decreased 28%, or $2.41, to $6.29 per Mcf in the second quarter of 2009 from $8.70 per Mcf in the second quarter of 2008. Prior to taking into account such adjustments to revenues and volumes, the average price received for natural gas would have been $5.08 per Mcf in the second quarter of 2009 and $8.85 per Mcf in the second quarter of 2008. Gas products revenue decreased $605,693, or 98%, to $13,060 in the second quarter of 2009 from $618,753 in the second quarter of 2008, due primarily to a decrease in production volume of 488,231 gallons, or 99%, to 2,920 gallons in the second quarter of 2009 from 491,151 gallons in the second quarter of 2008.

Capital expenditures decreased $300,541, or 96%, from $311,505 in the second quarter of 2008 to $10,964 in the second quarter of 2009. The capital expenses were much lower in the second quarter of 2009 given the operational status of the Royalty Properties resulting from the damages caused by Hurricane Ike. The capital expenditures in 2008 primarily relate to field workovers at Ship Shoal 182/183 and Eugene Island 339 necessary to help improve production performance.

Operating expenses increased by $7,990,458, or 288%, from $2,773,442 in the second quarter of 2008 to $10,763,900 in the second quarter of 2009, primarily as a result of well and platform abandonment costs at Eugene Island 339 as a result of Hurricane Ike. Reflected within the operating expenses for the second quarter 2009 is a cost allocation refund of $78,260 for certain prior period audit adjustments. Reflected within the operating expenses are management fees to Chevron, as Managing General Partner of the Partnership, of $499,426 and $361,725 for the second quarter of 2008 and the second quarter of 2009, respectively.

The Royalty Properties had undistributed net loss of $8,936,312 in the second quarter of 2009.

In the second quarter of 2009, no funds were released or escrowed from the Special Cost Escrow account. As of June 30, 2009, $4,306,735 remained in the Special Cost Escrow account. In the second quarter of 2008, there was a net release of funds from the Special Cost Escrow account. The Trust's share of the funds released was $41,817. As of June 30, 2008, $5,353,559 remained in the Special Cost Escrow account. The funds held in the Special Cost Escrow account are not reflected in the financial statements of the Trust. The Special Cost Escrow account is set aside for estimated abandonment costs and future capital expenditures, as provided for in the Conveyance. For additional information relating to the Special Cost Escrow account, see "—Special Cost Escrow Account" below.

Six Months Ended June 30, 2009 and 2008

There were no distributions to the Unit holders for the six months ended June 30, 2009 as compared to distributions of $7,088,418 or $1.491824 per Unit to the Unit holders for the same period in 2008.

Crude oil and condensate revenues decreased $19,220,510, or 87%, to $2,822,575 in the first six months of 2009 as compared to $22,043,085 for the same period in 2008, due primarily to decreases in production resulting from damages caused by Hurricane Ike. Oil volumes decreased 77% to 53,985 barrels in the first six months of 2009 from 236,562 barrels in the first six months of 2008. The revenues and volumes for the first six months of 2009 reflect credits associated with an audit for prior periods for $224,511 in revenues and 311 barrels; the revenues and volumes for the first six months of 2008 reflect credits associated with an audit for prior periods for $150,787 in revenues and 1,002 barrels. The average price received for crude oil and condensate decreased 44%, or $40.90, to $52.28 per barrel in the first six months of 2009 from $93.18 per barrel in the first six months of 2008. Prior to taking into account such adjustments to revenues and volumes, the average price received for crude oil and condensate would have been $48.40 per barrel in the first six months of 2009 and $92.94 per barrel in the first six months of 2008.

Gas revenues decreased $5,471,464, or 87%, to $836,362 in the first six months of 2009 from $6,307,826 for the same period in 2008, due primarily to damages caused by Hurricane Ike in September 2008. Gas volumes decreased 84% to 132,370 Mcf in the first six months of 2009 from 807,263 Mcf for the same period in 2008. The revenues and volumes for the first six months of 2009 reflect net credits of $808,484 in revenues and 127,711 Mcf of gas for prior adjustments; the revenues and volumes for the first six months of 2008 reflect credits associated with an audit of prior periods for $661,117 in revenues and 86,975 Mcf of gas. The average price received for natural gas decreased 19%, or $1.49, to $6.32 per Mcf in the first six months of 2009 from $7.81 per Mcf in the same period of 2008. Prior to taking into account such adjustments to revenues and volumes, the average price received for natural gas would have been $5.98 per Mcf in the first six months of 2009 and $7.84 per Mcf in the first six months of 2008. Gas products revenue decreased $1,590,561, or 89%, to $195,626 in the first six months of 2009 from $1,786,187 in the same period of 2008, primarily due to an decrease in production volume of 1,176,611 gallons, or 87%, to 172,910 gallons in the first six months of 2009 from 1,349,521 gallons in the same period of 2008.

Capital expenditures increased $401,560, or 352%, from ($114,172) in the first six months of 2008 to $287,388 in the same period of 2009. The negative capital expenditures number for the first six months of 2008 resulted from a prior period audit adjustment. Reflected in the capital expenditures for the first six months of 2009 is a refund of $59,794 for certain prior period audit adjustments.

Operating expenses increased by $12,211,074, or 258%, from $4,736,015 in the first six months of 2008 to $16,947,089 in the first six months of 2009, primarily as a result of well abandonment costs at Eugene Island 339 as a result of Hurricane Ike. Reflected in the operating expenses for the first six months of 2009 are cost allocation refunds of an aggregate of $115,252 for certain prior period adjustments. Reflected within the operating expenses are management fees to Chevron, as Managing General Partner of the Partnership, of $1,030,241 and $607,249 for the first six months of 2008 and the first six months of 2009, respectively.

The Royalty Proprieties had undistributed net loss of $13,291,668 for the six months ended June 30, 2009.

In the first six months of 2009, no funds were released or escrowed from the Special Cost Escrow account. In the first six months of 2008, there was a net release of funds into the Special Cost Escrow account. The Trust's share of the net funds released was $1,360,005.

Reserve for Future Trust Expenses

In accordance with the provisions of the Trust Agreement, generally all Royalty income received by the Trust, net of Trust general and administrative expenses and any cash reserves established for the payment of contingent or future obligations of the Trust, is distributed currently to the Unit holders. The Trust has previously determined that a cash reserve equal to approximately three times the average expenses of the Trust during each of the past three years was sufficient to provide for future administrative expenses in connection with the winding up of the Trust. During the second quarter of 2009, the Trust used $541,791 from the reserve for current expenses, leaving a reserve balance of $1,691,500 as of June 30, 2009.

Other

The amount of cash distributions by the Trust is dependent on, among other things, the quantities of oil and gas produced from the Royalty Properties and the sales prices therefor, as well as expenditures by the Working Interest Owners that may or may not be included in the Special Cost Escrow account. As described herein, production ceased at Eugene Island 339 and Ship Shoal 182 and 183 following damages inflicted by Hurricane Ike in September 2008, and substantial uncertainties exist with regard to future production from such Royalty Properties. It should be noted that substantial uncertainties exist with regard to future oil and gas prices, which are subject to material fluctuations due to changes in production levels and pricing and other actions taken by major petroleum producing nations, as well as the regional supply and demand for gas, weather, industrial growth, conservation measures, competition, economic conditions generally and other variables. The Trust does not enter into any hedging transactions on future production.

Operational Review

The platforms and wells on Eugene Island 339 were completely destroyed by Hurricane Ike in September 2008. Crude oil revenues from Eugene Island 339 represented approximately 48% of the crude oil and condensate revenues for the Royalty Properties in 2007 and approximately 47% of such revenues for the nine months ended September 30, 2008. Eugene Island 339 contributed approximately 12% of the revenues from natural gas sales from the Royalty Properties in 2007 and approximately 41% of such revenues for the nine months ended September 30, 2008. Based on a prior year reserve study prepared by DeGolyer and MacNaughton, independent petroleum engineering consultants, Eugene Island 339 accounted for approximately 34% of the total future net revenues attributable to the Partnership's interest in the royalty as of October 31, 2007. Chevron is working on the plugging and abandonment of the existing wells, clearing debris and otherwise dealing with the remaining infrastructure. This will be a multi-year project. In order to restore production, Chevron would need to redevelop the facility, including a new platform with production processing equipment, and to drill new wells. Chevron is still assessing its alternatives and the economic feasibility of restoring production at Eugene Island 339. At this point in time, there can be no assurance as to how or when, or if at all, production may be restored at Eugene Island 339. Generally, if production ceases from an outer continental shelf lease, like that for Eugene Island 339, production must be restored or drilling operations must commence within 180 days of the cessation (which was in early March 2009), or the lease will be terminated. A lease operator may seek approval from the regional supervisor of the Mineral Management Service to allow additional time to restore production. Chevron submitted such a request with respect to Eugene Island 339 and, like other lessees dealing with the effects of Hurricane Ike, was granted an extension until September 6, 2009 to submit a commitment to restore production. If Chevron elects to pursue the restoration of production from Eugene Island 339, Chevron must submit a request for a Suspension of Operations ("SOP") prior to September 6, 2009. The SOP must include an estimated date for the restoration of production and must be approved by the Mineral Management Service. As stated above, Chevron is still assessing its alternatives, and Chevron has not made a decision whether to submit an SOP to commit to restore production.

Production at Ship Shoal 182/183 ceased following damage inflicted by Hurricane Ike in September 2008. While the hurricane caused limited surface damage to the facilities at Ship Shoal 182/183, all of the wells at Ship Shoal 182/183 were shut-in following hurricane-related damage to a third-party transporter's natural gas pipeline. Crude oil revenues from Ship Shoal 182/183 represented approximately 50% of the crude oil and condensate revenues for the Royalty Properties in 2007 and approximately 51% of such revenues for the nine months ended September 30, 2008. Ship Shoal 182/183 contributed approximately 77% of the revenues from natural gas sales from the Royalty Properties in 2007 and approximately 42% of such revenues for the nine months ended September 30, 2008. A limited volume of oil production was restored in November 2008. During the second quarter of 2009, net crude oil production was 34,065 barrels. The volume of oil production that can be produced is limited by the amount of gas that is also produced by the oil wells. The third-party transporter's natural gas pipeline repairs were completed and gas sales at Ship Shoal 182/183 were restored on June 26, 2009. Chevron has been informed by the gas transporter that an estimated 30 day shut-in of the gas line will be required to make further repairs. Once those repairs are completed, Chevron expects the oil and natural gas production and sales at Ship Shoal 182/183 to return to normal.

In addition, production from West Cameron 643 and East Cameron 371 ceased following damage inflicted by Hurricane Ike in September 2008 to third-party transporters' pipelines. The Managing General Partner of the Partnership understands that the pipelines are in the process of being restored. The pipeline for West Cameron 643 is not expected to be able to take production until at least the end of 2009; there is no available estimate for when the pipeline for East Cameron 371 will be able to take production. At this point in time, there can be no assurance as to when, or if at all, production may be restored at West Cameron 643 or East Cameron 371.

In May 2007, the Trust engaged an independent oil and gas accounting firm for the purpose of reviewing the books and records of certain Working Interest Owners with respect to the Royalty Properties and the related payments to the Trust. Based on the initial report of the accounting firm, the Trustees believed that certain errors in the books and records had occurred and have been involved in ongoing discussions with such Working Interest Owners to resolve these items. As part of this ongoing process, certain adjustments to revenues, production volumes, prices and capital expenditures have occurred, and references herein to an audit of prior periods refers to the audit described in this paragraph. Such audit resulted in an additional cash distribution to the Trust during the first quarter of 2008. These amounts are comprised of a one-time increase of approximately $31,716 in gas revenues, a one-time increase of approximately $43,287 in oil revenues, and a one-time credit of approximately $123,900 in capital expenditures. Additional amounts related to the audit were included in later distributions to the Trust during 2008. Additional credits were made for the benefit of the Trust in the first quarter of 2009, consisting of approximately $203,272 in gas revenues, approximately $9,426 in oil revenues, approximately $14,948 in capital expenditures and approximately $9,248 in operating expenditures. All remaining audit adjustments were completed during the second quarter of 2009. The Trust's proportionate interest in the various audit adjustments for the second quarter of 2009 included a one-time credit of $1,151 in gas revenues, an increase of $46,702 in crude oil revenues related to Eugene Island 354 and a one-time credit adjustment of $19,625 in operating expenses.

Three Months Ended June 30, 2009 and 2008

The following operational information has been based on information provided to the Corporate Trustee by Chevron, as the Managing General Partner of the Partnership, who received operational information from the other Working Interest Owners. The Trustees have no control over these operations or internal controls relating to this information.

Volumes and dollar amounts discussed below represent amounts recorded by the Working Interest Owners unless otherwise specified.

Ship Shoal 182/183 crude oil revenues decreased from $5,197,061 in the second quarter of 2008 to $1,564,170 in the second quarter of 2009, primarily due to a decrease in net crude oil production from 52,448 barrels in the second quarter of 2008 to 34,065 barrels in the second quarter of 2009. The average crude oil price also decreased from $99.09 per barrel in the second quarter of 2008 to $45.92 per barrel for the same period in 2009. Gas revenues decreased from $941,566 in the second quarter of 2008 to $0 in the second quarter of 2009 due to cessation of gas production since September 2008 resulting from damages caused by Hurricane Ike compared to production of 101,823 Mcf in the second quarter of 2008. The average gas sales price realized during the second quarter of 2009 was $0 per Mcf compared to $9.25 during the second quarter of 2008. Capital expenditures increased from $1,727 in the second quarter of 2008 to $6,982 in the second quarter of 2009. Operating expenses increased from $945,438 in the second quarter of 2008 to $698,827 for the same period in 2009 due to an increase in operating and repair costs related to damages inflicted by Hurricane Ike, and after taking into account in the second quarter of 2009 a credit of $78,260 associated with an audit of a prior period.

Eugene Island 339 net crude oil revenues decreased from $4,755,226 in the second quarter of 2008 to $0 for the same period in 2009 due to a decrease in volumes from 49,114 barrels in the second quarter of 2008 to 0 barrels in the second quarter of 2009. The average crude oil price was $96.82 per barrel in the second quarter of 2008 and $0 per barrel in the second quarter of 2009. Gas revenues decreased from $1,469,332 in the second quarter of 2008 to $0 in the second quarter of 2009 due to a decrease in volumes from 174,483 Mcf in the second quarter of 2008 to 0 Mcf in the second quarter of 2009. The gas revenues and volumes for 2008 reflect credits of $324,129 and 43,623 Mcf associated with an audit of prior periods. Capital expenditures decreased from $284,321 in the second quarter of 2008 to $3,795 in the second quarter of 2009. There were limited capital expenditures during the second quarter of 2009 and the capital expenditures in the second quarter of 2008 primarily relate to repairs associated with a conversion to a water injector. Operating expenses increased from $1,070,845 in the second quarter of 2008 to $9,274,930 in the second quarter of 2009 due to well abandonment costs incurred as a result of Hurricane Ike.

West Cameron 643 gas revenues were $624,351 in the second quarter of 2008 and ($4,603) in the second quarter of 2009. Gas production was 79,244 Mcf in the second quarter of 2008 and (1,234) Mcf in the second quarter of 2009. There was no actual gas production during the second quarter of 2009 and the revenues and volumes for the second quarter 2009 reflect debits to correct an error in revenue allocation in August 2008. The revenues and volumes for the second quarter of 2008 reflect credits of $200,133 and 28,402 Mcf associated with an audit of prior periods. Operating expenses increased from $181,924 in the second quarter of 2008 to $417,432 for the same period in 2009 due primarily to repairs of damages caused by Hurricane Ike. Capital expenditures were $0 in the second quarter of 2008 and $231 for the same period in 2009.

East Cameron 371 crude oil revenues were $346 in the second quarter of 2008 and $0 in the second quarter of 2009 as a result of the field being shut-in following Hurricane Ike in September 2008. Gas revenues were $4,659 for the second quarter of 2008 and $0 for the second quarter of 2009, also due to the shut-in of the field. Capital expenditures were $0 for the second quarter 2008 and for the second quarter 2009. Operating expenses decreased from $12,792 in the second quarter of 2008 to $0 for the same period in 2009.

South Timbalier 37/27 crude oil revenues decreased from $115,325 in the second quarter of 2008 to $62,297 for the same period in 2009 due to a four-day field shut-in related to compressor problems. There was a decrease in crude oil production volumes to 1,409 barrels in the second quarter of 2009 from 1,445 barrels in the second quarter of 2008. Gas revenues decreased from $34,602 in the second quarter 2008 to $13,215 in the second quarter of 2009. There was an increase in natural gas volumes from (2,611) Mcf in the second quarter of 2008 to 2,604 Mcf in the second quarter of 2009. Gas volumes for the second quarter of 2008 reflect a debit of 5,464 Mcf related to revised volume allocations for the years 2004 through 2007. Capital expenditures decreased from $3,439 in the second quarter of 2008 to $(45) in the second quarter of 2009 after taking into account a $45 credit primarily related to workover cost adjustments for wells at South Timbalier 37. Operating expenses decreased from $62,988 in the second quarter of 2008 to $11,226 in the second quarter of 2009 after taking into account a $220 credit in 2009 for a prior period adjustment.

Six Months Ended June 30, 2009 and 2008

Volumes and dollar amounts discussed below represent amounts recorded by the Working Interest Owners unless otherwise specified.

Ship Shoal 182/183 crude oil revenues decreased from $11,367,638 in the first six months of 2008 to $2,473,541 in the same period in 2009, primarily due to a decrease in net crude oil production from 120,163 barrels in the first six months of 2008 to 51,189 in the same period of 2009. Included in the revenues and production for the first six months of 2008 was an upward adjustment of $46,630 associated with an additional 178 barrels that were included from 2007 production. There was also a decrease in the average crude oil price from $94.60 per barrel in the first six months of 2008 to $48.32 per barrel for the same period in 2009. Gas revenues decreased from $2,614,285 in the first six months of 2008 to $725,720 in the same period of 2009. Gas production decreased from 336,697 Mcf in the first six months of 2008, which included an upward adjustment of 19,999 Mcf relating to 2007 production, to 0 Mcf in the same period of 2009. However, there was an audit adjustment made in the first quarter of 2009, which resulted in the recognition of $725,720 in gas revenues associated with 107,416 Mcf of gas from a prior period. The inclusion of such adjustment for the 19,999 Mcf in 2008 resulted in an increase in revenues for 2008 of $123,946. The natural gas sales price was $7.76 per Mcf in the first six months of 2008 compared to $0 per Mcf in the first six months of 2009. Capital expenditures increased from ($466,499) in the first six months of 2008 to $27,443 in the same period of 2009 primarily due to a credit of $495,600 in the first six months of 2008 from an audit adjustment for prior periods. Operating expenses decreased from $1,511,393 in the first six months of 2008 to $1,398,596 for the same period in 2009 due to a decrease in production, but offset by an increase in operating and repair costs related to damages inflicted by Hurricane Ike.

Eugene Island 339 net crude oil revenues decreased from $10,282,800 in the first six months of 2008 to $38,544 for the same period in 2009, due to a decrease in volumes from 111,572 barrels in the first six months of 2008 to 318 barrels in the first six months of 2009. However, there was no actual crude oil production during the first six months of 2009 and such crude oil revenues and production volumes are entirely from an audit adjustment made in the first quarter of 2009 and associated with a prior period. The oil revenues for the first six months of 2008 reflect a $81,750 credit relating to prior periods. The average crude oil price was $92.16 per barrel in the first six months of 2008. Gas revenues decreased from $2,461,106 in the first six months 2008 to $170,231 for the same period in 2009, due to a decrease in natural gas volumes from 316,092 Mcf in the first six months of 2008 to 33,296 Mcf for the same period in 2009. However, there was no actual gas production during the first six months of 2009 and such gas revenues and volumes are entirely from an audit adjustment made in the first quarter of 2009 and associated with a prior period. The gas revenues and volumes for the first six months of 2008 reflect credits of $324,129 and 43,623 Mcf associated with an audit of prior periods. Capital expenditures decreased from $290,380 in the first six months of 2008 to $180,089 in the same period in 2009. There were limited capital expenditures during the second quarter of 2009 and the capital expenditures in the first six months of 2008 primarily relate to repairs associated with a conversion to a water injector. Operating expenses increased from $1,463,934 in the first six months of 2008 to $14,220,452 in the same period in 2009 due to well abandonment costs incurred as a result of Hurricane Ike.

West Cameron 643 gas revenues decreased from $921,625 in the first six months of 2008 to ($4,603) for the same period in 2009. This is due to a decrease in gas volumes from 121,432 Mcf in the first six months of 2008 to (1,234) Mcf for the same period in 2009. There was no actual gas production during the first six months of 2009 and the revenues and volumes for the first six months of 2009 are a result of debits to correct an error in revenue allocation in August 2008. Operating expenses increased from $348,423 for the first six months of 2008 to $740,330 for the same period in 2009, and capital expenditures were $0 for the first six months of 2008 and $135,291 for the first six months of 2009.

East Cameron 371 crude oil revenues were $48,087 for the first six months of 2008 and $0 for the first six months of 2009 as a result of the field being shut-in following Hurricane Ike in September 2008. Production decreased from 531 barrels in the first six months of 2008 to 0 barrels for the same period in 2009. Gas revenues decreased from $252,605 for the first six months of 2008 to $0 for the same period in 2009 as a result of a decrease in gas volumes from 32,412 Mcf in the first six months of 2008 to 0 Mcf for the same period in 2009. Capital expenditures were $0 in the first six months of 2008 and 2009. Operating expenses decreased from $292,982 in the first six months of 2008 to $0 for the same period in 2009.

South Timbalier 37/27 crude oil revenues decreased from $285,366 in the first six months of 2008 to $116,021 for the same period in 2009 due to a four-day field shut-in related to compressor problems. There was a decrease in crude oil production volumes to 2,409 barrels in the first six months of 2009 from 3,365 barrels in the first six months of 2008. Gas revenues decreased from $56,790 in the first six months of 2008 to $23,341 in the first six months of 2009. There was an increase in natural gas volumes from 536 Mcf in the first six months of 2008 to 4,046 Mcf in the first six months of 2009. Gas volumes for the first six months of 2008 reflect a debit of 5,464 Mcf related to revised volume allocations for the years 2004 through 2007. Capital expenditures decreased from $40,369 in the first six months of 2008 to $(55,435) in the first six months of 2009 after taking into account a $56,263 credit in 2009 for a prior period audit adjustment. Operating expenses decreased from $89,012 in the first six months of 2008 to $(19,298) in the first six months of 2009 after taking into account a $36,992 credit in 2009 for a prior period audit adjustment.

Liquidity and Capital Resources

The Trust's source of capital is the Royalty income received from its share of the Net Proceeds from the Royalty Properties.

On October 7, 2008, the Trust announced that production from the two most significant oil and gas properties associated with the Trust had ceased following damage inflicted by Hurricane Ike in September 2008. The platforms and wells on Eugene Island 339 were completely destroyed by Hurricane Ike. While Hurricane Ike caused limited surface damage to the facilities at Ship Shoal 182/183, all of the wells at Ship Shoal 182/183 were shut-in following hurricane-related damage to a third-party transporter's natural gas pipeline. The more productive wells on the properties produce both oil and gas, and there is no downstream transmission available for any gas produced from the wells. There can be no assurance that production at Eugene Island 339 will be restored. While production is expected to remain limited at Ship Shoal 182/183 until the natural gas pipeline is fully repaired and tested, which is anticipated to occur in the third quarter of 2009, there can be no assurance as to when, or if at all, meaningful production may be restored at Ship Shoal 182/183.

In addition, production from West Cameron 643 and East Cameron 371 ceased following damage inflicted by Hurricane Ike in September 2008 to third-party transporters' pipelines. The Managing General Partner of the Partnership understands that the pipelines are in the process of being restored. The pipeline for West Cameron 643 is not expected to be able to take production until at least the end of 2009; there is no available estimate for when the pipeline for East Cameron 371 will be able to take production. At this point in time, there can be no assurance as to when, or if at all, production may be restored at West Cameron 643 or East Cameron 371.

On December 19, 2008, the Trust announced its fourth quarter distribution of approximately $0.7 million, which was paid on January 9, 2009. Based on the damage caused by Hurricane Ike, the Trust's scheduled distribution for the fourth quarter of 2008 was severely negatively impacted, although there were funds available for distribution given that there was some production from Eugene Island 339 and Ship Shoal 182/183 in August and September 2008. On March 25, 2009, the Trust announced that there would be no trust distribution for the first quarter of 2009. Similarly, on June 26, 2009, the Trust announced that there would be no trust distribution for the second quarter of 2009. There were no Net Proceeds distributed to the Trust for the first or second quarter of 2009.

There are not likely to be sufficient Net Proceeds from the Royalty Properties for the Trust to make a regularly scheduled quarterly distribution to Unit holders for the foreseeable future. As a result of the damage inflicted by Hurricane Ike, Net Proceeds will continue to be severely impacted by both reduced production, from historical levels, and the amount of expenditures incurred that are associated with such damages, including the expenditures required to plug and abandon the wells on Eugene Island 339, and, perhaps, to redevelop the facility at Eugene Island 339.

Future Net Proceeds from the Royalty Properties may take into account the Trust's share of project costs and other related expenditures that are not covered by the insurance of the operators of the Royalty Properties. The Trust's net portion of the aggregate cost to plug and abandon the wells subject to the royalty on Eugene Island 339 is currently estimated to be approximately $13 million. If development and production costs of the Royalty exceed the proceeds of production from the Royalty Properties, the Trust will not receive Net Proceeds until future proceeds from production exceed the total of the excess costs plus accrued interest, at a rate equal to one-fourth of (i) one-half of one percent plus (ii) the median between the prime interest rate at the end of a quarterly period in which there are excess costs and the prime interest rate at the end of the preceding quarterly period, during the deficit period. Development activities may not generate sufficient additional revenue to repay the costs. Accordingly, there will not be sufficient Net Proceeds from the Royalty Properties to make distributions for some period of time in the future. At this time, the ultimate outcome of these matters cannot be determined with any degree of certainty.

For the second quarter of 2009, under the terms of the Conveyance, production costs for the Royalty Properties exceeded gross proceeds thereof, with the Trust's portion of such excess equal to approximately $2.2 million. For the first six months of 2009, the Trust's portion of the amount by which production costs exceeded gross proceeds is approximately $3.1 million.

Substantial uncertainties exist with regard to future oil and gas prices, which are subject to material fluctuations due to changes in production levels and pricing and other actions taken by major petroleum producing nations, as well as the regional supply and demand for gas, weather, industrial growth, conservation measures, competition, economic conditions generally and other variables.

In accordance with the provisions of the Trust Agreement, generally all Net Proceeds received by the Trust, net of Trust general and administrative expenses and any cash reserves established for the payment of contingent or future obligations of the Trust, are distributed currently to the Unit holders.

Future Net Revenues and Termination of the Trust

Based on a reserve study provided to the Trust by DeGolyer and MacNaughton, independent petroleum engineers, as of October 31, 2008 future net revenues attributable to the Trust's royalty interests were estimated at $24.2 million. Estimates of proved oil and gas reserves attributable to the Partnership's royalty interest are based on existing economic and operating conditions in effect at October 31, 2008 in order to correspond with distributions to the Trust. Such reserve study also indicates that approximately 40% of the future net revenues from the Royalty Properties are expected to be received by the Trust during the next three years. Solely for purposes of being able to complete the reserve study so that the Trust could file its Form 10-K for the year ended December 31, 2008, DeGolyer and MacNaughton assumed that Eugene Island 339 will not be redeveloped. As such, the reserve study does not include any reserves or values attributable to Eugene Island 339, nor does it include the Trust's net portion of the aggregate cost to plug and abandon the wells subject to the royalty on Eugene Island 339, which net portion is currently estimated to be approximately $13 million. The assumption was made by DeGolyer and MacNaughton because Chevron had not made a decision regarding any redevelopment of Eugene Island 339 and such decision would impact the treatment of Eugene Island 339 for purposes of preparing a reserve study for the Partnership. Because the Trust will terminate in the event estimated future net revenues fall below $2.0 million, it would be possible for the Trust to terminate even though some or all of the Royalty Properties continued to have remaining productive lives. Upon termination of the Trust, the Trustees will sell for cash all of the assets held in the Trust estate and make a final distribution to Unit holders of any funds remaining after all Trust liabilities have been satisfied. The estimates of future net revenues discussed above are subject to large variances from year to year and should not be construed as exact. There are numerous uncertainties present in estimating future net revenues for the Royalty Properties. The estimate may vary depending on changes in market prices for crude oil and natural gas, the recoverable reserves, annual production and costs assumed by DeGolyer and MacNaughton. In addition, future economic and operating conditions as well as results of future drilling plans may cause significant changes in such estimate. The discussion set forth above is qualified in its entirety by reference to the Trust's Annual Report on Form 10-K for the year ended December 31, 2008. The Trust's Form 10-K is available at the website of the Securities and Exchange Commission ("SEC") at www.sec.gov or upon request from the Corporate Trustee.

Special Cost Escrow Account

The Conveyance provides for reserving funds for estimated future "Special Costs" of plugging and abandoning wells, dismantling platforms and other costs of abandoning the Royalty Properties, as well as for the estimated amount of future drilling projects and other capital expenditures on the Royalty Properties. As provided in the Conveyance, the amount of funds to be reserved is determined based on factors including estimates of aggregate future production costs, aggregate future Special Costs, aggregate future net revenues and actual current net proceeds. Deposits into this account reduce current distributions and are placed in an escrow account and invested in short-term certificates of deposit. Such account is herein referred to as the "Special Cost Escrow" account. The Trust's share of interest generated from the Special Cost Escrow account serves to reduce the Trust's share of allocated production costs.

Special Cost Escrow funds will generally be utilized to pay Special Costs to the extent there are not adequate current net proceeds to pay such costs. Special Costs that have been paid are no longer included in the Special Cost Escrow calculation. Deposits to the Special Cost Escrow account will generally be made when the balance in the Special Cost Escrow account is less than 125% of estimated future Special Costs and there is a Net Revenues Shortfall (a calculation of the excess of estimated future costs over estimated future net revenues pursuant to a formula contained in the Conveyance). When there is not a Net Revenues Shortfall, amounts in the Special Cost Escrow account will generally be released, to the extent that Special Costs have been incurred. Amounts in the Special Cost Escrow account will also be released when the balance in such account exceeds 125% of estimated future Special Costs. In the first six months of 2009, there were no funds released or escrowed from the Special Cost Escrow account. As of June 30, 2009, $4,306,735 remained in the Special Cost Escrow account. The funds held in the Special Cost Escrow account are not reflected in the financial statements of the Trust. The discussion of the terms of the Conveyance and Special Cost Escrow account contained herein is qualified in its entirety by reference to the Conveyance itself, which is an exhibit to this Form 10-Q and is available upon request from the Corporate Trustee.

Chevron, in its capacity as the Managing General Partner of the Partnership, has advised the Trust that additional deposits to the Special Cost Escrow account may be required in future periods in connection with other production costs, other abandonment costs, other capital expenditures and changes in the estimates and factors described above. Such deposits could result in a significant reduction in Royalty income in the periods in which such deposits are made, including the possibility that no Royalty income would be received in such periods.

Overview of Production, Prices and Royalty Income

The following schedule provides a summary of the volumes and weighted average prices for crude oil and condensate and natural gas recorded by the Working Interest Owners for the Royalty Properties, as well as the Working Interest Owners' calculations of the Net Proceeds and the royalties paid to the Trust during the periods indicated. Net Proceeds due to the Trust are calculated for each three month period commencing on the first day of February, May, August and November.

	Royalty Properties Three Months Ended June 30,(1) 2009	2008
Crude oil and condensate (bbls)	35,475	103,147
Natural gas and gas products (Mcfe)	1,801	423,667
Crude oil and condensate average price, per bbl	$ 51.11	$ 97.73
Natural gas average price, per Mcf (excluding gas products)	$ 6.29	$ 8.70
Crude oil and condensate revenues	$ 1,813,293	$10,080,263
Natural gas and gas products revenues	21,761	3,693,401
Production expenses	(10,763,900)	(2,773,442)
Capital expenditures	(10,964)	(311,505)
Undistributed net loss (income)(2)	8,936,312	27,704
Refund of (provision for) Special Cost Escrow	3,498	288,640
Net Proceeds	—	$11,005,061
Royalty interest	x25%	x25%
Partnership share	—	$ 2,751,265
Trust interest	x99.99%	x99.99%
Trust share of Royalty Income	$ —	$ 2,750,990

(1) Amounts are based on actual production for the three-month period ended April 30 of each year, respectively.

(2) Undistributed net loss represents the amount of development and production costs associated with the Royalty that exceed the proceeds of production from the Royalty Properties during the period. An undistributed net loss is carried forward and offset, in future periods, by positive proceeds earned by the related Working Interest Owner(s). The Trust will not receive Net Proceeds until future proceeds from production exceed the total of the excess costs plus applicable accrued interest. Undistributed net income represents positive Net Proceeds, generated during the respective period, but not distributed by the Working Interest Owners. As of June 30, 2009, the undistributed net loss was $8,936,312.

	Royalty Properties Six Months Ended June 30, 2009	2008
Crude oil and condensate (bbls)	53,999	236,562
Natural gas and gas products (Mcfe)	157,071	1,000,051
Crude oil and condensate average price, per bbl	$ 52.27	$ 93.18
Natural gas average price, per Mcf (excluding gas products)	$ 6.32	$ 7.81
Crude oil and condensate revenues	$ 2,822,575	$22,043,085
Natural gas and gas products revenues	1,031,988	8,094,013
Production expenses	(16,947,089)	(4,736,015)
Capital expenditures	(287,388)	114,172
Undistributed net loss (income)(1)	13,291,668	(88,115)
Refund of (provision for) Special Cost Escrow	88,247	5,850,032
Net Proceeds	—	$31,277,172
Royalty interest	x25%	x25%
Partnership share	—	$ 7,819,293
Trust interest	x99.99%	x99.99%
Trust share of Royalty Income	$ —	$ 7,818,511

(1) Undistributed net loss represents the amount of development and production costs associated with the Royalty that exceed the proceeds of production from the Royalty Properties during the period. An undistributed net loss is carried forward and offset, in future periods, by positive proceeds earned by the related Working Interest Owner(s). The Trust will not receive Net Proceeds until future proceeds from production exceed the total of the excess costs plus applicable accrued interest. Undistributed net income represents positive Net Proceeds, generated during the respective period, but not distributed by the Working Interest Owners. As of June 30, 2009, the undistributed net loss was $13,291,668.

Item 3. Quantitative and Qualitative Disclosures About Market Risk.

The only assets of and sources of income to the Trust are cash and the Trust's interest in the Partnership, which is the holder of the Royalty. Consequently, the Trust is exposed to market risk associated with the Royalty from fluctuations in oil and gas prices. Reference is also made to Note 2 of the Notes to Financial Statements included in Item 1 of this Form 10-Q.

Item 4. Controls and Procedures.

Evaluation of disclosure controls and procedures. The Corporate Trustee maintains disclosure controls and procedures designed to ensure that information required to be disclosed by the Trust in the reports that it files or submits under the Securities Exchange Act of 1934, as amended, is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and regulations. Disclosure controls and procedures include controls and procedures designed to ensure that information required to be disclosed by the Trust is accumulated and communicated by Chevron, as the Managing General Partner of the Partnership, and the Working Interest Owners to the

Corporate Trustee of the Trust, and its employees who participate in the preparation of the Trust's periodic reports as appropriate to allow timely decisions regarding required disclosure.

As of the end of the period covered by this report, the Corporate Trustee carried out an evaluation of the Trust's disclosure controls and procedures. Mike Ulrich, as Trust Officer of the Corporate Trustee, has concluded that the disclosure controls and procedures of the Trust are effective.

Due to the contractual arrangements of (i) the Trust Agreement, (ii) the Partnership Agreement and (iii) the rights of the Partnership under the Conveyance regarding information furnished by the Working Interest Owners, the Trustees rely on (A) information provided by the Working Interest Owners, including historical operating data, plans for future operating and capital expenditures, reserve information and information relating to projected production, (B) information from the Managing General Partner of the Partnership, including information that is collected from the Working Interest Owners, and (C) conclusions and reports regarding reserves by the Trust's independent reserve engineers. See Item 1A. Risk Factors "—The Trustees and the Unit holders have no control over the operation or development of the Royalty Properties and have little influence over operation or development" and "The Trustees rely upon the Working Interest Owners and Managing General Partner for information regarding the Royalty Properties" in the Trust's Annual Report on Form 10-K for the year ended December 31, 2008 for a description of certain risks relating to these arrangements and reliance on and applicable adjustments to operating information when reported by the Working Interest Owners to the Corporate Trustee and recorded in the Trust's results of operation.

Changes in Internal Control Over Financial Reporting. During the three months ended June 30, 2009, there has been no change in the Trust's internal control over financial reporting that has materially affected, or is reasonably likely to materially affect, the Trust's internal control over financial reporting. The Corporate Trustee notes for purposes of clarification that it has no authority over, and makes no statement concerning, the internal control over financial reporting of the Working Interest Owners or the Managing General Partner of the Partnership.

PART II—OTHER INFORMATION

Item 1A. Risk Factors.

There have not been any material changes from risk factors previously disclosed in the Trust's response to Item 1A of Part 1 of the Trust's Annual Report on Form 10-K for the year ended December 31, 2008.

Item 6. Exhibits.

(Asterisk indicates exhibit previously filed with the Securities and Exchange Commission and incorporated herein by reference.)

		SEC File or Registration Number	Exhibit Number
4(a)*—	Trust Agreement dated as of January 1, 1983, among Tenneco Offshore Company, Inc., Texas Commerce Bank National Association, as corporate trustee, and Horace C. Bailey, Joseph C. Broadus and F. Arnold Daum, as individual trustees (Exhibit 4(a) to Form 10-K for the year ended December 31, 1992 of TEL Offshore Trust)	0-6910	4(a)
4(b)*—	Agreement of General Partnership of TEL Offshore Trust Partnership between Tenneco Oil Company and the TEL Offshore Trust, dated January 1, 1983 (Exhibit 4(b) to Form 10-K for year ended December 31, 1992 of TEL Offshore Trust)	0-6910	4(b)
4(c)*—	Conveyance of Overriding Royalty Interests from Exploration I to the Partnership (Exhibit 4(c) to Form 10-K for year ended December 31, 1992 of TEL Offshore Trust)	0-6910	4(c)
4(d)*—	Amendments to TEL Offshore Trust Agreement, dated December 7, 1984 (Exhibit 4(d) to Form 10-K for year ended December 31, 1992 of TEL Offshore Trust)	0-6910	4(d)
4(e)*—	Amendment to the Agreement of General Partnership of TEL Offshore Trust Partnership, effective as of January 1, 1983 (Exhibit 4(e) to Form 10-K for the year ended December 31, 1992 of TEL Offshore Trust)	0-6910	4(e)
10(a)*—	Purchase Agreement, dated as of December 7, 1984 by and between Tenneco Oil Company and Tenneco Offshore II Company (Exhibit 10(a) to Form 10-K for year ended December 31, 1992 of TEL Offshore Trust)	0-6910	10(a)
10(b)*—	Consent Agreement, dated November 16, 1988, between TEL Offshore Trust and Tenneco Oil Company (Exhibit 10(b) to Form 10-K for year ended December 31, 1988 of TEL Offshore Trust)	0-6910	10(b)

		SEC File or Registration Number	Exhibit Number
10(c)* —	Assignment and Assumption Agreement, dated November 17, 1988, between Tenneco Oil Company and TOC-Gulf of Mexico Inc. (Exhibit 10(c) to Form 10-K for year ended December 31, 1988 of TEL Offshore Trust)	0-6910	10(c)
10(d)* —	Gas Purchase and Sales Agreement Effective September 1, 1993 between Tennessee Gas Pipeline Company and Chevron U.S.A. Production Company (Exhibit 10(d) to Form 10-K for year ended December 31, 1993 of TEL Offshore Trust)	0-6910	10(d)
31 —	Certification furnished pursuant to Section 302 of the Sarbanes Oxley Act of 2002		
32 —	Certification furnished pursuant to Section 906 of the Sarbanes Oxley Act of 2002		

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

TEL OFFSHORE TRUST

By: The Bank of New York Mellon Trust
Company, N.A.
Corporate Trustee

By: /s/ MIKE ULRICH

Mike Ulrich
Vice President

Date: August 7, 2009

The Registrant, TEL Offshore Trust, has no principal executive officer, principal financial officer, board of directors or persons performing similar functions. Accordingly, no additional signatures are available and none have been provided.

QuickLinks

EXHIBIT D-4

Use these links to rapidly review the document
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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

(Mark One)

☒ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(D) OF THE SECURITIES EXCHANGE ACT OF 1934**

for the fiscal year ended December 31, 2009

or

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(D) OF THE SECURITIES EXCHANGE ACT OF 1934**

for the transition period from to

Commission File Number 0-6910

TEL OFFSHORE TRUST

(Exact name of registrant as specified in its charter)

Texas (State or other jurisdiction of incorporation or organization)	**76-6004064** (I.R.S. Employer Identification No.)
The Bank of New York Mellon Trust Company, N.A., Trustee **919 Congress Avenue** **Austin, Texas** (Address of principal executive offices)	**78701** (Zip Code)

Registrant's telephone number, including area code: **(800) 852-1422**

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Name of each exchange on which registered
None	None

Securities registered pursuant to Section 12(g) of the Act:

Units of Beneficial Interest
(Title of class)

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ☐ No ☒.

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes ☐ No ☒.

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the Registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☒ No ☐

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Website, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the proceeding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ☐ No ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§229.405 of this chapter) is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☒

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer ☐	Accelerated filer ☐	Non-accelerated filer ☒ (Do not check if a smaller reporting company)	Smaller reporting company ☐

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act). Yes ☐ No ☒

The aggregate market value of the 4,751,510 Units of Beneficial Interest in TEL Offshore Trust held by non-affiliates as of the last business day of the registrant's most recently completed second fiscal quarter was $19,908,827 based on a June 30, 2009 closing sales price of $4.19.

Indicate the number of shares outstanding of each of the registrant's classes of common stock, as of the latest practicable date.

As of March 26, 2010, there were 4,751,510 Units of Beneficial Interest in TEL Offshore Trust outstanding.

Documents Incorporated By Reference: None

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Note Regarding Forward-Looking Statements

This Form 10-K includes "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. All statements other than statements of historical facts included in this Form 10-K are forward-looking statements. Although the Managing General Partner of the Partnership (as defined below) has advised the Trust that the Managing General Partner believes that the expectations reflected in the forward-looking statements contained herein are reasonable, no assurance can be given that such expectations will prove to have been correct. Important factors that could cause actual results to differ materially from expectations ("Cautionary Statements") are disclosed in this Form 10-K, including without limitation in conjunction with the forward-looking statements included in this Form 10-K. Risks factors that may affect actual results and Trust distributions include, without limitation:

- Commodity price fluctuations;
- Uncertainty of estimates of oil and gas production;
- Uncertainty of future production and development costs;
- Operating risks for Working Interest Owners, including drilling and environmental risks;
- Delays and costs in connection with repairs and replacements of hurricane-damaged facilities and pipelines, including third-party transportation systems;
- Regulatory changes;
- Decisions by and at the discretion of Working Interest Owners not to perform additional development projects, not to replace hurricane-damaged facilities, or to abandon properties; and
- Uncertainties inherent in estimating proved oil and natural gas reserves and in projecting future rates of production and timing of development expenditures.

Should any event or circumstances contemplated by the risks or uncertainties described above or elsewhere in this Form 10-K occur, or should any material underlying assumptions prove incorrect, actual results may differ materially from future results expressed or implied by the forward-looking statements. All subsequent written and oral forward-looking statements attributable to the Trust or persons acting on its behalf are expressly qualified in their entirety by the Cautionary Statements. See "Item 1A—Risk Factors" below in this Form 10-K for a summary description of principal risk factors.

PART I

Item 1. Business.

DESCRIPTION OF THE TRUST

General

The TEL Offshore Trust, which we refer to herein as the "Trust", created under the laws of the State of Texas, maintains its offices at the office of The Bank of New York Mellon Trust Company, N.A., whom we refer to as the "Corporate Trustee", 919 Congress Avenue, Austin, Texas 78701. The telephone number of the Corporate Trustee is 1-800-852-1422. The Bank of New York Mellon Trust Company, N.A. succeeded JPMorgan Chase Bank, N.A. as the Corporate Trustee effective October 2, 2006 pursuant to an agreement under which The Bank of New York Mellon Trust Company acquired substantially all of JPMorgan Chase's corporate trust business. JPMorgan Chase Bank was formerly known as The Chase Manhattan Bank and is the successor by mergers to the original corporate trustee, Texas Commerce Bank National Association. Daniel O. Conwill, IV, Gary C. Evans and Jeffrey S. Swanson serve as individual trustees of the Trust and are referred to herein as the "Individual

Trustees". The Individual Trustees and the Corporate Trustee may be referred to hereinafter collectively as the "Trustees."

The Corporate Trustee does not maintain a website for filings by the Trust with the U.S. Securities and Exchange Commission, which we refer to herein as the "SEC". Electronic filings by the Trust with the SEC are available free of charge through the SEC's website at *www.sec.gov* and at *www.businesswire.com/cnn/tel-offshore.htm*.

The principal asset of the Trust consists of a 99.99% interest in the TEL Offshore Trust Partnership, which we refer to herein as the "Partnership". Chevron U.S.A., Inc., or "Chevron", owns the remaining .01% interest in the Partnership. The Partnership owns an overriding royalty interest, or "Royalty", equivalent to a 25% net profits interest, in certain oil and gas properties, which we refer to herein as the "Royalty Properties", located offshore Louisiana.

On October 31, 1986, Tenneco Exploration Ltd. ("Exploration I") was dissolved and the oil and gas properties of Exploration I were distributed to Tenneco Oil Company ("Tenneco") subject to the Royalty. Tenneco, who was then serving as the Managing General Partner of the Partnership, assumed the obligations of Exploration I, including its obligations under the instrument conveying the Royalty to the Partnership (the "Conveyance"). The dissolution of Exploration I had no impact on future cash distributions to holders of units of beneficial interest in the Trust.

On November 18, 1988, Chevron acquired most of the Gulf of Mexico offshore oil and gas properties of Tenneco, including all of the Royalty Properties. As a result of the acquisition, Chevron replaced Tenneco as the Working Interest Owner and Managing General Partner of the Partnership. Chevron also assumed Tenneco's obligations under the Conveyance.

On October 30, 1992, PennzEnergy Company ("PennzEnergy") (which merged with and into Devon Energy Production Company L.P. effective January 1, 2000) acquired certain oil and gas producing properties from Chevron, including four of the Royalty Properties. The four Royalty Properties acquired by PennzEnergy were East Cameron 354, Eugene Island 348, Eugene Island 367 and Eugene Island 208. As a result of such acquisition, PennzEnergy replaced Chevron as the Working Interest Owner of such properties on October 30, 1992. PennzEnergy also assumed Chevron's obligations under the Conveyance with respect to these properties.

On December 1, 1994, Texaco Exploration and Production Inc. ("TEPI") acquired two of the Royalty Properties from Chevron. The Royalty Properties acquired by TEPI were West Cameron 643 and East Cameron 371. As a result of such acquisitions, TEPI replaced Chevron as the Working Interest Owner of such properties on December 1, 1994. TEPI also assumed Chevron's obligations under the Conveyance with respect to these properties.

On October 1, 1995, SONAT Exploration Company ("SONAT") acquired the East Cameron 354 property from PennzEnergy. In addition, on October 1, 1995, Amoco Production Company ("Amoco") acquired the Eugene Island 367 property from PennzEnergy. As a result of such acquisitions, SONAT and Amoco replaced PennzEnergy as the Working Interest Owners of the East Cameron 354 and Eugene Island 367 properties, respectively, on October 1, 1995 and also assumed PennzEnergy's obligations under the Conveyance with respect to these properties.

Effective January 1, 1998, Energy Resource Technology, Inc. ("ERT") acquired the East Cameron 354 property from SONAT. As a result of such acquisition, ERT replaced SONAT as the Working Interest Owner of the East Cameron 354 property effective January 1, 1998, and also assumed SONAT's obligations under the Conveyance with respect to such property. In October 1998, Amerada Hess Corporation ("Amerada") acquired the East Cameron 354 property from ERT effective January 1, 1998. As a result of such acquisition, Amerada replaced ERT as the Working Interest Owner of the East Cameron 354 property effective January 1, 1998, and also assumed ERT's obligations under the Conveyance with respect to this property.

Effective January 1, 2000, PennzEnergy and Devon Energy Corporation (Nevada) merged into Devon Energy Production Company L.P. ("Devon"). As a result of such merger, Devon replaced PennzEnergy as the Working Interest Owner of Eugene Island 348 and Eugene Island 208 properties effective January 1, 2000, and also assumed PennzEnergy's obligations under the Conveyance with respect to these properties. The abandonment obligations for Eugene Island 348 have been assumed by Maritech Resources, Inc. effective January 1, 2005.

On October 9, 2001, a wholly owned subsidiary of Chevron Corporation merged (the "Merger") with and into Texaco Inc. ("Texaco"), pursuant to an Agreement and Plan of Merger, dated as of October 15, 2000. As a result of the Merger, Texaco became a wholly owned subsidiary of Chevron Corporation, and Chevron Corporation changed its name to "ChevronTexaco Corporation" in connection with the Merger. Effective May 9, 2005, ChevronTexaco Corporation changed its name to Chevron Corporation. Accordingly, the properties referred to herein as controlled by Chevron and Texaco are each now controlled by subsidiaries of Chevron Corporation.

On May 1, 2002, TEPI assigned all of its interests in West Cameron 643 and East Cameron 371 to Chevron. Chevron sold its interest in East Cameron 371 to ERT effective July 1, 2007. On July 18, 2008, Chevron sold its interest in West Cameron 643 to Hilcorp Energy GOM, LLC ("Hilcorp"). Effective August 1, 2008, Hilcorp assumed operations, reporting and payment responsibilities for West Cameron 643.

On June 6, 2003, Anadarko Petroleum Corporation ("Anadarko") acquired, among other interests, a 25% Working Interest in the East Cameron 354 field subject to the Royalty from Amerada effective April 1, 2003. As a result of such transaction, Anadarko replaced Amerada as the Working Interest Owner of East Cameron 354 effective July 1, 2003 and also assumed Amerada's obligations under the Conveyance with respect to this property.

Effective October 1, 2004, Apache Corporation ("Apache") acquired Anadarko's interest in East Cameron 354 and assumed Anadarko's obligations under the Conveyance with respect to this property.

All of the Royalty Properties continue to be subject to the Royalty, and it is anticipated that the Trust and Partnership, in general, will continue to operate as if the above-described sales of the Royalty Properties had not occurred. Chevron, as the managing general partner of the Partnership, calculates the Net Proceeds (as defined below) from the Royalty Properties owned by Chevron and collects financial information relating to the other Royalty Properties from the Working Interest Owners other than Chevron for presentation to the Trust.

Unless the context in which such terms are used indicates otherwise, the terms "Working Interest Owner" and "Working Interest Owners" generally refer to the owner or owners of the Royalty Properties (Exploration I through October 31, 1986; Tenneco for periods from October 31, 1986 until November 18, 1988; Chevron with respect to all Royalty Properties for periods from November 18, 1988 until October 30, 1992, and with respect to all Royalty Properties except East Cameron 354, Eugene Island 348, Eugene Island 367 and Eugene Island 208 for periods from October 30, 1992 until December 1, 1994, and with respect to the same properties except West Cameron 643 thereafter; PennzEnergy/Devon with respect to East Cameron 354, Eugene Island 348, Eugene Island 367 and Eugene/Devon Island 208 for periods from October 30, 1992 until October 1, 1995, and with respect to Eugene Island 348 and Eugene Devon Island 208 thereafter; TEPI with respect to West Cameron 643 and East Cameron 371 for periods beginning on or after December 1, 1994 until May 1, 2002; SONAT with respect to East Cameron 354 for periods on or after October 1, 1995; Amoco with respect to Eugene Island 367 for periods beginning on or after October 1, 1995; Amerada with respect to East Cameron 354 for periods beginning on or after January 1, 1998 until July 1, 2003; Chevron with respect to West Cameron 643 on and after May 1, 2002 until August 1, 2008; Chevron with respect to East Cameron 371 on and after May 1, 2002 until July 1, 2007; Anadarko with respect to East Cameron 354 on and after July 1, 2003 until October 1, 2004, Apache with respect to East Cameron 354 after

October 1, 2004; ERT with respect to East Cameron 371 on and after July 1, 2007; and Hilcorp with respect to West Cameron 643 on and after August 1, 2008).

As of March 26, 2010, a total of 4,751,510 units of beneficial interest in the Trust, which we refer to herein as "Units", were issued and outstanding. The Units have been traded on the Nasdaq SmallCap Market since August 31, 2001. Previously the Units were traded on the OTC Bulletin Board. The Units were also traded on pink sheets. From inception of the Trust to December 31, 2009, distributions to Unit holders totaled approximately $138,742,000 or approximately $29.20 per Unit. See "Management's Discussion and Analysis of Financial Condition and Results of Operation—Liquidity and Capital Resources" in Item 7 of this Form 10-K and Note 4 to the Notes to Financial Statements under Item 8 of this Form 10-K for a discussion regarding certain uncertainties of distributions.

The terms of the TEL Offshore Trust Agreement, which we refer to herein as the "Trust Agreement", provide, among other things, that: (1) the Trust is a passive entity whose activities are generally limited to the receipt of revenues attributable to the Trust's interest in the Partnership and the distribution of such revenues, after payment of or provision for Trust expenses and liabilities, to the owners of the Units; (2) the Trustees may sell all or any part of the Trust's interest in the Partnership or cause the sale of all or any part of the Royalty by the Partnership with the approval of a majority of the Unit holders; (3) the Trustees can establish cash reserves and can borrow funds to pay liabilities of the Trust and can pledge the assets of the Trust to secure payment of such borrowings; (4) to the extent cash available for distribution exceeds liabilities or reserves therefore established by the Trust, the Trustees will cause the Trust to make quarterly cash distributions to the Unit holders in January, April, July and October of each year; and (5) the Trust will terminate upon the first to occur of the following events: (i) total future net revenues attributable to the Partnership's interest in the Royalty, as determined by independent petroleum engineers, as of the end of any year, are less than $2 million or (ii) a decision to terminate the Trust by the affirmative vote of Unit holders representing a majority of the Units. Total future net revenues attributable to the Partnership's interest in the Royalty were estimated at $13.1 million as of October 31, 2009 based on the reserve study of DeGolyer and MacNaughton, independent petroleum engineers. (See "Termination of the Trust" and Note 9 of the Notes to Financial Statements under Item 8 of this Form 10-K for further information regarding estimated future net revenues.) Upon termination of the Trust, the Trustees will sell for cash all the assets held in the Trust estate and make a final distribution to Unit holders of any funds remaining after all Trust liabilities have been satisfied.

The terms of the Agreement of General Partnership of the Partnership, which we refer to herein as the "Partnership Agreement," provide that the Partnership will dissolve upon the occurrence of any of the following: (1) December 31, 2030, (2) the election of the Trust to dissolve the Partnership, (3) the termination of the Trust, (4) the bankruptcy of the Managing General Partner of the Partnership, or (5) the dissolution of the Managing General Partner or its election to dissolve the Partnership; however, the Managing General Partner has agreed not to dissolve or to elect to dissolve the Partnership and will be liable for all damages and costs to the Trust if it breaches such agreement.

Under the Conveyance and the Partnership Agreement, the Trust is entitled to its share (99.99%) of 25% of the Net Proceeds, as hereinafter defined, realized from the sale of the oil, gas and associated hydrocarbons when produced from the Royalty Properties. See "Description of Royalty Properties." The Conveyance provides that the Working Interest Owners will calculate, for each quarterly period commencing the first day of February, May, August and November, an amount equal to 25% of the Net Proceeds from their oil and gas properties for the period. "Net Proceeds" means for each quarterly period, the excess, if any, of the Gross Proceeds, as hereinafter defined, for such period over Production Costs, as hereinafter defined, for such period. "Gross Proceeds" means the amounts received by the Working Interest Owners from the sale of oil, gas and associated hydrocarbons produced from the properties burdened by the Royalty, subject to certain adjustments. Gross Proceeds do not include amounts received by the Working Interest Owners as advance gas payments, "take-or-pay" payments or similar payments unless and until such payments are extinguished or repaid through the future delivery of gas. "Production Costs" means, generally, costs incurred on an accrual basis by the Working Interest Owners in operating the Royalty Properties, including capital and non-capital costs. In general, Net Proceeds are computed on an aggregate basis and consist of the aggregate proceeds to the Working Interest Owners from the sale of oil and gas from the Royalty Properties less (1) all direct costs, charges and expenses incurred by the Working Interest Owners in exploration, production, development, drilling and other operations on the Royalty Properties (including secondary recovery operations); (2) all applicable taxes (including severance and ad valorem taxes) excluding income taxes; (3) all operating charges directly associated with the Royalty Properties; (4) an allowance for costs, computed on a current basis at a rate equal to the prime rate of JPMorgan Chase Bank plus 0.5% on all amounts by which, and for only so long as, costs and expenses for the Royalty Properties incurred for any quarter have exceeded the proceeds of production from such Royalty Properties for such quarter; (5) applicable charges for certain overhead expenses as provided in the Conveyance; (6) the management fees and expense reimbursements owing the Working Interest Owners; and (7) a special cost reserve for the future costs to be incurred by the Working Interest Owners to plug and abandon wells and dismantle and remove platforms, pipelines and other production facilities from the Royalty Properties and for future drilling projects and other estimated future capital expenditures on the Royalty Properties. The Trustees are not obligated to return any royalty income received in any period, but future amounts otherwise payable will be reduced by the amount of any prior overpayments of such royalty income. The Working Interest Owners are required to maintain books and records sufficient to determine amounts payable under the Royalty. The Working Interest Owners are also required to deliver to the Managing General Partner on behalf of the Partnership a statement of the computation of Net Proceeds no later than the tenth business day prior to the quarterly record date.

The Royalty Properties are required to be operated in accordance with standards applicable to a prudent oil and gas operator. The Working Interest Owners are free to transfer their working interest in any of the Royalty Properties (burdened by the Royalty) to third parties. The Working Interest Owners are also free to enter into farm-out agreements whereby a Working Interest Owner would transfer a portion of its interest (unburdened by the Royalty) while retaining a lesser interest (burdened by the Royalty) in return for the transferee's obligation to drill a well on the Royalty Properties. The Working Interest Owners have the right to abandon any well or lease, and upon termination of any lease, the part of the Royalty relating thereto will be extinguished. The Royalty Properties are primarily operated by the Working Interest Owners although certain other parties operate some of the Royalty Properties.

The discussions of terms of the Trust Agreement, Partnership Agreement and Conveyance contained herein are qualified in their entirety by reference to the Trust Agreement, Partnership Agreement and Conveyance themselves, which are exhibits to this Form 10-K and are available upon request from the Corporate Trustee.

The Trust has no employees. Administrative functions of the Trust are performed by the Corporate Trustee.

History of the Trust

Tenneco Offshore Company, Inc. ("Tenneco Offshore") created the Trust effective January 1, 1983, pursuant to a Plan of Dissolution ("Plan"), which was approved by Tenneco Offshore's stockholders on December 22, 1982. In accordance with the Plan, the assets of Tenneco Offshore were transferred to the Trust as of January 1, 1983, and Units were exchanged for shares of common stock of Tenneco Offshore on the basis of one Unit for each share of common stock held by stockholders of record on January 14, 1983. Additionally, the Partnership was formed, in which the Trust owned a 99.99% interest and Tenneco initially owned a .01% interest. The Partnership was formed solely for the purpose of owning the Royalty, receiving the proceeds from the Royalty, paying the liabilities and expenses of the Partnership and disbursing remaining revenues to the Trust and the Managing General Partner of the Partnership in accordance with their interests. The Plan was effected by transferring an overriding royalty interest equivalent to a 25% net profits interest in the oil and gas properties of Exploration I located offshore Louisiana to the Partnership, contributing the common stock of Tenneco Offshore II Company to the Trust, and issuing certificates evidencing Units in liquidation and cancellation of Tenneco Offshore's common stock.

On October 31, 1986, Exploration I was dissolved and the oil and gas properties of Exploration I were distributed to Tenneco subject to the Royalty. Tenneco, who was then serving as the Managing General Partner of the Partnership, assumed the obligations of Exploration I, including its obligations under the Conveyance. The dissolution of Exploration I had no impact on future cash distributions to holders of units of beneficial interest.

As discussed above, on November 18, 1988, Chevron replaced Tenneco as the Working Interest Owner and Managing General Partner of the Partnership and assumed Tenneco's obligations under the Conveyance. On October 30, 1992, PennzEnergy acquired certain oil and gas producing properties from Chevron, including four of the Royalty Properties. The four Royalty Properties acquired by PennzEnergy were East Cameron 354, Eugene Island 348, Eugene Island 367 and Eugene Island 208. As a result of such acquisition, PennzEnergy replaced Chevron as the Working Interest Owner of such properties and assumed Chevron's obligations under the Conveyance with respect to such properties on October 30, 1992. On December 1, 1994, TEPI acquired two of the Royalty Properties from Chevron. The Royalty Properties acquired by TEPI were West Cameron 643 and East Cameron 371. As a result of such acquisition, TEPI replaced Chevron as the Working Interest Owner of such properties and assumed Chevron's obligations under the Conveyance with respect to such properties on December 1, 1994. On October 1, 1995, SONAT and Amoco acquired the East Cameron 354 and Eugene Island 367 properties, respectively, from PennzEnergy. As a result of such acquisitions, SONAT and Amoco replaced PennzEnergy as the Working Interest Owners of the East Cameron 354 and Eugene Island 367 properties, respectively, and also assumed PennzEnergy's obligations under the Conveyance with respect to such properties on October 1, 1995. Effective January 1, 1998 ERT acquired the East Cameron 354 property from SONAT. As a result of such acquisition, ERT replaced SONAT as the Working Interest Owner of the East Cameron 354 property and also assumed SONAT's obligations under the Conveyance with respect to this property effective January 1, 1998. In October 1998, Amerada acquired the East Cameron 354 property from ERT effective January 1, 1998. As a result of this acquisition, Amerada replaced ERT as the Working Interest Owner of the East Cameron 354 property effective January 1, 1998, and also assumed ERT's obligations under the Conveyance with respect to this property. Effective January 1, 2000, PennzEnergy and Devon Energy Corporation (Nevada) merged into Devon. As a result of such merger, Devon replaced PennzEnergy as the Working Interest Owner of the Eugene Island 348 and Eugene Island 208 properties effective January 1, 2000, and also assumed PennzEnergy's obligations under the Conveyance with respect to these properties. On October 9, 2001, a wholly owned subsidiary of Chevron Corporation merged with and into Texaco, pursuant to an Agreement and Plan of Merger, dated as of October 15, 2000. As a result of the Merger, Texaco Inc. became a wholly owned subsidiary of Chevron Corporation, and Chevron Corporation changed its name to "ChevronTexaco Corporation" in connection with the Merger. Accordingly, the properties referred to herein as controlled by Chevron and Texaco are each now controlled by subsidiaries of Chevron Corporation. Effective May 9, 2005, ChevronTexaco Corporation changed its name to Chevron Corporation. On May 1, 2002, TEPI assigned all of its interests in West Cameron 643 and East Cameron 371 to Chevron. Chevron sold its interest in East Cameron 371 to ERT effective July 1, 2007. Chevron sold its interests in West Cameron 643 to Hilcorp effective August 1, 2008. On June 6, 2003, Anadarko acquired, among other interests, a 25% Working Interest in the East Cameron 354 field, subject to the Royalty, from Amerada effective April 1, 2003. As a result of this transaction, Anadarko replaced Amerada as the Working Interest Owner of East Cameron 354 effective July 1, 2003 and also assumed Amerada's obligations under the Conveyance with respect to this property. Effective October 1, 2004, Apache acquired Anadarko's interest in East Cameron 354 and assumed Anadarko's obligations under the Conveyance with respect to this property.

DESCRIPTION OF THE UNITS

Each Unit is evidenced by a transferable certificate issued by the Corporate Trustee. Each unit ranks equally as to distributions, has one vote on any matter submitted to Unit holders and represents an undivided interest in the Trust, which in turn owns a 99.99% interest in the Partnership.

Distributions

The Trustees distribute the Trust's income pro rata for each calendar quarter within 10 days after the end of each calendar quarter. Distributions of the Trust's income are made to Unit holders of record on the Quarterly Record Date, which is the last business day of each quarterly period, or such later date as the Trustees determine is required to comply with legal requirements. The Trustees determine for each quarterly period the amount available for distribution. Such amount (the "Quarterly Income Amount") consists of the cash received from the Royalty during the quarterly period plus any other cash receipts of the Trust, less the obligations of the Trust paid during the quarterly period, and adjusted for changes made by the Trust during the quarter in any cash reserves established for the payment of contingent or future obligations of the Trust. For a discussion of the cash reserves being established by the Trust, see "Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources" in Item 7 of this Form 10-K.

Within 90 days of the close of each year, the net federal taxable income of the Trust for each quarterly period ending in such year is reported by the Trustees for federal tax purposes to the Unit holder of record to whom the Quarterly Income Amount was distributed.

Possible Requirement That Units Be Divested

The Trust Agreement imposes no restrictions based on nationality or other status of the persons or other entities who are eligible to hold Units. However, the Trust Agreement provides that if at any time the Trust or any of the Trustees are named as a party in any judicial or administrative or other governmental proceeding that seeks the cancellation or forfeiture of any interest in any property located in the United States in which the Trust has an interest because of the nationality or any other status of any one or more owners of Units, or if at any time the Trustees in their reasonable discretion determine that such a proceeding is threatened or likely to be asserted and the Trust has received an opinion of counsel stating that the party asserting or likely to assert the claims has a reasonable probability of succeeding in such claim, the following procedures will be applicable:

> (a) The Trustees, in their discretion, may seek from an investment banking firm to be selected by the Trustees an opinion as to whether it is in the Trust's best interest for the Trustees to take the actions permitted by (b)(i) through (iii) below.
>
> (b) The Trustees may take no action with respect to the potential cancellation or forfeiture or may seek to avoid such cancellation or forfeiture by the following procedure:
>
>> (i) The Trustees will promptly give written notice ("Notice") to each record owner of Units as to the existence of or probable assertion of such controversy. The Notice will contain a reasonable summary of such controversy, will include materials which will permit an owner of Units to promptly confirm or deny to the Trustees that such owner is a person whose nationality or other status is or would be an issue in such a proceeding ("Ineligible Holder") and will constitute a demand to each Ineligible Holder that he dispose of his Units, to a party who would not be an Ineligible Holder, within 30 days after the date of the Notice.

(ii) If an Ineligible Holder fails to dispose of his Units as required by the Notice, the Trustees will have the right to redeem and will redeem, during the 90 days following the termination of the 30-day period specified in the Notice, any Unit not so transferred for a cash price equal to the mean between the closing bid and ask prices of the Units in the over-the-counter market or, if the Units are then listed on a stock exchange, the closing price of the Units on the largest stock exchange on which the Units are listed, on the last business day prior to the expiration of the 30-day period stated in the Notice. The procedures for any such purchase are more fully described in the Trust Agreement. The Trustees will cancel any Units acquired in accordance with the foregoing procedures thereby increasing the proportionate interest in the Trust of other holders of Units.

(iii) The Trustees may, in their sole discretion, cause the Trust to borrow any amounts required to purchase Units in accordance with the procedures described above.

Liability of Unit Holders

It is the intention of the Working Interest Owners and the Trustees that the Trust be an "express trust" under the Texas Trust Act. Under Texas law, beneficiaries of an express trust are not personally liable for the obligations of the trust, even if the assets of the trust are insufficient to discharge its obligations. However, it is unclear under Texas law whether the Trust will be held to constitute an express trust and, if it is not held to be an express trust, whether the holders of Units would be jointly and severally liable for the obligations of the Trust as would general partners of a partnership.

Under current judicial decisions, the Federal Energy Regulatory Commission, which we refer to herein as the "FERC", is not considered to be empowered to compel refunds from overriding royalty interest owners with respect to gas price overcharges. However, future laws, regulations or judicial decisions might permit the FERC or other governmental agencies to require such refunds from overriding royalty interest owners or create filing, reporting or certification obligations with respect to a trust created for such overriding royalty interest owners. Moreover, other parties, such as oil or gas purchasers, may be able to instigate private lawsuits or other legal action to compel refunds from overriding royalty interest owners with respect to oil or gas pricing overcharges.

The Working Interest Owners have agreed that they will not seek to recover from the Unit holders the amount of any refunds they are required to make, except out of future revenues payable to the Trust. The Trustees will be liable to the Unit holders if the Trustees allow any liability to be incurred without taking any and all action necessary to ensure that such liability will be satisfiable only out of the Trust assets (regardless of whether the assets are adequate to satisfy the liability) and will be non-recourse to the Unit holders. However, the Trustees will not be liable to the Unit holders for state or federal income taxes or for refunds, fines, penalties or interest relating to oil or gas pricing overcharges under state or federal price controls. The Trustees will be indemnified from the Trust assets, to the extent that the Trustees' actions do not constitute gross negligence, bad faith or fraud.

Each Unit holder should consider, in weighing the possible exposure to liability in the event the Trust were not classified as an express trust, (1) the substantial value and passive nature of the Trust assets, (2) the restrictions on the power of the Trustees to incur liabilities on behalf of the Trust and (3) the limited activities to be conducted by the Trustees.

Federal Income Tax Matters

This section is a summary of federal income tax matters of general application which addresses the material tax consequences of the ownership and sale of the Units. Except where indicated, the discussion below describes general federal income tax considerations applicable to individuals who are citizens or residents of the United States. Accordingly, the following discussion has limited application to domestic corporations and persons subject to specialized federal income tax treatment, such as regulated investment companies and insurance companies. It is impractical to comment on all aspects of federal, state, local and foreign laws that may affect the tax consequences of the transactions contemplated hereby and of an investment in the Units as they relate to the particular circumstances of every Unit holder. **Each Unit holder is encouraged to consult his own tax advisor with respect to his particular circumstances.**

This summary is based on current provisions of the Internal Revenue Code of 1986, as amended (the "Code"), existing and proposed Treasury Regulations thereunder and current administrative rulings and court decisions, all of which are subject to changes that may be retroactively applied. Some of the applicable provisions of the Code have not been interpreted by the courts or the Internal Revenue Service ("IRS"). No assurance can be provided that the statements set forth herein (which do not bind the IRS or the courts) will not be challenged by the IRS or will be sustained by a court if so challenged.

Classification of the Trust

The IRS has ruled that the Trust is a grantor trust and that the Partnership is a partnership for federal income tax purposes. Thus, the Trust will incur no federal income tax liability and each Unit holder will be treated as owning an interest in the Partnership.

The Trustees assume that some Units are held by a middleman as such term is broadly defined in applicable Treasury Regulations (and includes custodians, nominees, certain joint owners, and brokers holding an interest for a custodian in street name).

Therefore, the Trustees consider the Trust to be a non-mortgage widely held fixed investment trust ("WHFIT") for federal income tax purposes. The Corporate Trustee, 919 Congress Avenue, Austin, Texas 78701, telephone number 1-800-852-1422, is the representative of the Trust that will provide tax information in accordance with applicable Treasury Regulations governing the information reporting requirements of the Trust as a WHFIT.

Income and Depletion

Each Unit holder of record as of the last business day of each quarter will be allocated a share of the income and deductions of the Trust, including the Trust's share of the income and deductions of the Partnership, computed on an accrual basis, for that quarter. Royalty income is portfolio income. Since all income from the Partnership is royalty income, this amount, net of depletion and severance taxes, is portfolio income and, subject to certain exceptions and transitional rules, this royalty income cannot be offset by passive losses. Additionally, interest income is portfolio income. Administrative expense is an investment expense.

The IRS has also ruled that the Royalty is a non-operating economic interest giving rise to income subject to depletion. The Trustees will treat the Royalty as a single property giving rise to income subject to depletion, although the computation of depletion will be made by each Unit holder based upon information provided by the Trustees. Each Unit holder will be entitled to compute cost depletion with respect to his share of income from the Royalty based on his basis in the Royalty. A Unit holder will have a basis in the Royalty equal to the basis in his Units less any amount allocable to his share of any cash reserve account. Transferees of Units transferred after October 11, 1990, may be eligible to use the percentage depletion deduction on oil and gas income thereafter attributable to such Units, if the percentage depletion deduction would exceed cost depletion. Unlike cost depletion, percentage depletion is not limited to a Unit holder's depletable tax basis in the Units. Rather, a Unit holder may be entitled to a percentage depletion deduction as long as the Royalty generates gross income.

Backup Withholding

Distributions from the Trust are generally subject to backup withholding at a rate of 28% of these distributions. Backup withholding generally will not apply to distributions to a Unit holder unless the Unit holder fails to properly provide to the Trust his taxpayer identification number or the IRS notifies the Trust that the taxpayer identification number provided by the Unit holder is incorrect.

Sale of Units

Generally, except for recapture items, the sale, exchange or other disposition of a Unit will result in capital gain or loss measured by the difference between the tax basis in the Unit and the amount realized. Effective for property placed in service after December 31, 1986, the amount of gain, if any, realized upon the disposition of oil and gas property is treated as ordinary income to the extent of the intangible drilling and development costs incurred with respect to the property and depletion claimed with respect to the property to the extent it reduced the taxpayer's basis in the property. Under this provision, depletion attributable to a Unit acquired after 1986 will be subject to recapture as ordinary income upon disposition of the Unit or upon disposition of the oil and gas property to which the depletion is attributable. The balance of any gain or any loss will be capital gain or loss if the Unit was held by the Unit holder as a capital asset, either long-term or short-term depending on the holding period of the Unit. This capital gain or loss will be long-term if a Unit holder's holding period for the Unit exceeds one year at the time of sale or exchange. Capital gain or loss will be short-term if the Unit has not been held for more than one year at the time of sale on exchange. Long-term capital gain generally will be subject to a maximum U.S. federal income tax rate of 15%, which maximum tax rate currently is scheduled to increase to 20% for dispositions occurring during taxable years beginning on or after January 1, 2011. The deductibility of capital losses are subject to certain limitations.

Non-U.S. Unit holders

In general, a Unit holder who is a nonresident alien individual or which is a foreign corporation, each a "non-U.S. Unit holder" for purposes of this discussion, will be subject to tax on the gross income (without taking into account any deductions, such as depletion) produced by the Royalty at a rate equal to 30%, or if applicable, at a lower treaty rate. This tax will be withheld by the Trustees and remitted directly to the United States Treasury. A non-U.S. Unit holder may elect to treat the income from the Royalty as effectively connected with the conduct of a United States trade or business under provisions of the Code, or pursuant to any similar provisions of applicable treaties. Upon making this election a non-U.S. Unit holder is entitled to claim all deductions with respect to that income, but he must file a United States federal income tax return to claim those deductions. This election once made is irrevocable, unless an applicable treaty allows the election to be made annually. However, that effectively connected taxable income is subject to withholding at the highest applicable tax rate, currently 35% for individual non-U.S. Unit holders.

The Code and the Treasury Regulations thereunder treat the publicly traded Trust as if it were a United States real property holding corporation. Accordingly, non-U.S. Unit holders may be subject to United States federal income tax on any gain from the disposition of their Units.

Federal income taxation of a non-U.S. Unit holder is a highly complex matter which may be affected by many other considerations. Therefore, each non-U.S. Unit holder is encouraged to consult its own tax advisor with respect to its ownership of Units.

Tax-exempt Organizations

Investments in publicly traded grantor trusts are treated the same as investments in partnerships for purposes of the rules governing unrelated business taxable income. Royalty income and interest income should not be unrelated business taxable income so long as, generally, a Unit holder did not incur debt to acquire a Unit or otherwise incur or maintain a debt that would not have been incurred or maintained if that Unit had not been acquired. Legislative proposals have been made from time to time which, if adopted, would result in the treatment of Royalty income as unrelated business taxable income. Each tax-exempt Unit holder is encouraged to consult its own tax advisor with respect to its ownership of Units and the treatment of Royalty income.

State Law Considerations

The Trust and the Partnership have been structured so as to cause the Units to be treated for certain state law purposes essentially the same as other securities, that is, as interests in intangible personal property rather than as interests in real property. However, in the absence of controlling legal precedent, there is a possibility that under certain circumstances a Unit holder could be treated as owning an interest in real property under the laws of Louisiana. In that event, the tax, probate, devolution of title and administration laws of Louisiana or other states applicable to real property may apply to the Units, even if held by a person who is not a resident thereof. Application of these laws could make the inheritance and related matters with respect to the Units substantially more onerous than had the Units been treated as interests in intangible personal property. Unit holders are encouraged to consult their legal and tax advisors regarding the applicability of these considerations to their individual circumstances.

Texas does not impose an income tax. Therefore, no part of the income produced by the Trust is subject to an income tax in Texas. However, effective January 1, 2008, Texas imposes a margin tax at a rate of 1% on gross revenues less certain deductions, as specifically set forth in the Texas margin tax statute. The Texas margin tax is a significant change in Texas tax law. The tax generally will be imposed on gross revenues generated in 2007 and thereafter. Entities subject to tax generally include trusts unless otherwise exempt, and most other types of entities having limited liability protection. Trusts and partnerships that receive at least 90% of their federal gross income from designated passive sources, including royalties from mineral properties and other non-operated mineral interest income, and do not receive more than 10% of their income from operating an active trade or business, are generally exempt from the Texas margin tax as "passive entities." The Trust should be exempt from Texas margin tax as a "passive entity." Since the Trust should be exempt from Texas margin tax at the Trust level as a passive entity, each Unit holder that is considered a taxable entity under the Texas margin tax would generally be required to include its Texas portion of Trust revenues in its own Texas margin tax computation. Each Unit holder is urged to consult its own tax advisor regarding its possible Texas state franchise tax liability.

TERMINATION OF THE TRUST

The terms of the TEL Offshore Trust Agreement provide that the Trust will terminate upon the first to occur of the following events: (1) total future net revenues attributable to the Partnership's interest in the Royalty, as determined by independent petroleum engineers, as of the end of any year, are less than $2 million or (2) a decision to terminate the Trust by the affirmative vote of Unit holders representing a majority of the Units. Total future net revenues attributable to the Partnership's interest in the Royalty were estimated at $13.1 million as of October 31, 2009, based on the reserve study of DeGolyer and MacNaughton, independent petroleum engineers, discussed herein. Such reserve study does not include any reserves or volumes attributable to Eugene Island 339; however, it does include estimated costs of approximately $13 million, which represent the Partnership's percentage share of the total plugging and abandonment costs related to Eugene Island 339. Based on the DeGolyer and MacNaughton reserve study, as of October 31, 2009, in order to correspond with distributions to the Trust, it is estimated that approximately 65% of future net revenues from the Royalty Properties are expected to be received by the Trust during the next 3 years. Because the Trust will terminate in the event estimated future net revenues fall below $2.0 million, it would be possible for the Trust to terminate even though some or all of the Royalty Properties continued to have remaining productive lives. Upon termination of the Trust, the Trustees will sell for cash all of the assets held in the Trust estate and make a final distribution to Unit holders of any funds remaining after all Trust liabilities have been satisfied. The estimates of future net revenues discussed above are subject to the limitations described in the summary of the DeGolyer and MacNaughton reserve study included in Item 1 of this Form 10-K. The reserve study is limited to reserves classified as proved; therefore, future capital expenditures for recovery of reserves not classified as proved by DeGolyer and MacNaughton are not included in the calculation of estimated future net revenues, nor are any capital expenditures included for any redevelopment of Eugene Island 339. In addition, the estimates of future net revenues discussed above are subject to large variances from year to year and should not be construed as exact. There are numerous uncertainties present in estimating future net revenues for the Royalty Properties. The estimate may vary depending on changes in market prices for crude oil and natural gas, the recoverable reserves, annual production and costs assumed by DeGolyer and MacNaughton. In addition, future economic and operating conditions as well as results of future drilling plans may cause significant changes in such estimate. The discussion set forth above is qualified in its entirety by reference to the Trust Agreement itself, which is an exhibit to this Form 10-K and is available upon request from the Corporate Trustee.

In addition, in the event of a dissolution of the Partnership (which could occur under the circumstances described above under "Description of the Trust") and a subsequent winding up and termination thereof, the assets of the Partnership (*i.e*., the Royalty) could either (1) be distributed in kind ratably to the Trust and the Managing General Partner or (2) be sold and the proceeds thereof distributed ratably to the Trust and the Managing General Partner. In the event of a sale of the Royalty and a distribution of the cash proceeds thereof to the Trust and the Managing General Partner, the Trustees would make a final distribution to Unit holders of the Trust's portion of such cash proceeds plus any other cash held by the Trust after payment of or provision for all liabilities of the Trust, and the Trust would be terminated.

Royalty Income, Distributable Income and Total Assets

Reference is made to Items 6, 7 and 8 of this Form 10-K for financial information relating to the Trust.

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Description of Royalty Properties

Properties and Wells

The Partnership's interest consists of an overriding royalty interest, equivalent to a 25% net profits interest, in the Royalty Properties as follows:

Property	Acquisition Date (Mo.-Yr.)	Current Working Interest Owner	Working Interest Owner's Ownership Interest(%)(4)	Gross Acres	Gross Wells Drilled as of October 31, 2009 — Wells Drilled(1) Expl.	Dev.	Successful(2)(3) Oil	Gas
East Cameron 354(5)	12-72	Apache	11.14	5,000	2	4	0	5
West Cameron 643 unit(6)	12-72	Hilcorp	35.86	5,000	3	17	0	14
Eugene Island 339 non-unit(2)	12-72	Chevron	50.00	5,000(18)	2	33(7)	19(7)	0
Eugene Island 339 5500' unit(2)	12-72	Chevron	42.05		0	5	5	0
Eugene Island 339 4500' unit(2)	12-72	Chevron	38.50 gas 24.44 oil		0	20	16	0
Eugene Island 342/343 SW/4	12-72	Chevron	.06	5,000(19)	4	5	0	7
Eugene Island 342/343 NW/4	12-72	Chevron	0.18		2	4	0	4
Eugene Island 348(8)	12-72	Devon	50.00	5,000	4	5	0	7
West Cameron 642(9)	12-72	Chevron	25.00	5,000	4	7	0	8
East Cameron 370(10)	1-73	N.A.	25.00	5,000	3	1	0	4
East Cameron 371(11)	1-73	ERT	7.50	5,000	7	2	0	4
Vermilion 246(12)	1-73	Chevron	33.37	5,000	3	3	0	4
West Cameron 41 E/2(13)	3-74	N.A	.30	2,500	0	0	0	0
Ship Shoal 183 N/2	7-88	Chevron	66.67	5,000(20)	1	11	8	4
Ship Shoal 183 unit	7-88	Chevron	34.29		1	22	20	3
Ship Shoal 183 F-3	7-88	Chevron	100.0		1	0	0	1
Ship Shoal 183 F-1	7-88	Chevron	50.00		1	0	1	0
Eugene Island 208(14)	8-73	Devon	100.00	1,250	0	3	0	3
Eugene Island 367(15)	3-74	N.A.	1.60	5,000	2	9	0	9
South Marsh Island 252(16)	3-74	Chevron	3.00	4,997	2	0	0	1
South Timbalier 36(17)	3-74	Chevron	.26	5,000	2	20	9	11
South Timbalier 37	3-74	Chevron	.26	5,000	13	41	39	3
Total				73,747	57	212	117	92

(1) As of both October 31, 2009 and December 31, 2009, there were no wells in the process of being drilled.

(2) As of both October 31, 2009 and December 31, 2009, there were 50 producing wells: 1 gas well and 11 oil wells associated with Ship Shoal, 2 gas wells and 2 oil wells associated with South Timbalier 36, and 4 gas wells and 30 oil wells associated with South Timbalier 37. All Eugene Island 339 wells were destroyed by Hurricane Ike in September 2008.

(3) Multiple completions are counted as one well. South Timbalier 37 has 4 multiple completion wells and Ship Shoal 182/183 has 2 multiple completion wells.

(4) These percentages represent the working interest owner's interest subject to the Partnership's net proceeds.

(5) Apache purchased this working interest from Anadarko effective October 1, 2004. This lease expired in 2005. Wells were plugged and abandoned in 2006. The platforms to which the wells were connected were abandoned in July 2008.

(6) West Cameron 643 was sold to Hilcorp Energy Company, effective August 1, 2008.

(7) Eugene Island 339 C-17 and C-18 wells are not included here; they are not subject to the Partnership's net proceeds until they pay out. Such wells were also destroyed by Hurricane Ike in September 2008.

(8) This lease expired in 2004. Abandonment work was completed in May 2006.

(9) Hilcorp has informed the Managing General Partner of the Partnership that, while the wells at West Cameron 642 have not been plugged and abandoned, such wells are depleted and no more production is

anticipated from such wells. The Managing General Partner understands that plugging and abandonment will not occur until all wells in the area are depleted.

(10) This lease expired in 1996.

(11) East Cameron 371 was sold to ERT, effective July 1, 2007. Included in this sale was East Cameron 381, in which the Partnership does not own an interest. The Royalty includes East Cameron A1 and A3 wells, which are located on East Cameron 381 but were produced from East Cameron 371. As previously stated, the wells at East Cameron 371 have been depleted.

(12) This lease (Vermillion 246 Block, OCS-G 1147) was terminated in 2002. Abandonment work was completed mid 2005.

(13) This lease expired in November 2002, and all wells on the lease had been abandoned as of November 2003.

(14) The wells at Eugene Island 208 were plugged and the surface cleaned over 20 years ago.

(15) This lease expired on May 30, 1996. It was leased again as OCS-G 19800 effective July 1, 1998. Neither Chevron nor any affiliates of Chevron have an interest in OCS-G-19800.

(16) The wells at South Marsh Island 252 have been inactive since 2006.

(17) South Timbalier 36 well number 2 working interest owner's ownership interest is .013 percent.

(18) Represents the total gross acreage for all properties subject to the lease at Eugene Island 339.

(19) Represents the total gross acreage for all properties subject to the lease at Eugene Island 342/343.

(20) Represents the total gross acreage for all properties subject to the lease at Ship Shoal 183.

The following is a summary of the number of developmental and exploratory wells drilled on the Royalty Properties during the last 3 years:

	Year Ended December 31,					
	2007		2008		2009	
	Gross	Net	Gross	Net	Gross	Net
Developmental:						
Oil wells	3(1)	.8	1(2)	.3	0	0
Natural gas wells	0	0	1(3)	.3	0	0
Non-productive	0	0	0	0	0	0
Exploratory:						
Oil wells	0	0	0	0	0	0
Natural gas wells	0	0	0	0	0	0
Non-productive	0	0	0	0	0	0
Total	3	.8	2	.6	0	0

(1) All such developmental oil wells were associated with South Timbalier 37.

(2) Associated with South Timbalier 37.

(3) During 2008, there was also one workover of a gas well at South Timbalier 36.

Reserves

A study of the proved oil and gas reserves attributable to the Partnership, in which the Trust has a 99.99% interest, has been made by DeGolyer and MacNaughton, independent petroleum engineering consultants, as of October 31, 2009. A copy of the reserve study has been filed as an exhibit to this Form 10-K. The following is a summary of such reserve study. Such study reflects estimated production, reserve quantities and future net revenue based upon estimates of the future timing of actual production without regard to when received by the Trust, which differs from the manner in which the

Trust recognizes its royalty income. See Notes 2 and 9 in the Notes to Financial Statements under Item 8 of this Form 10-K.

On the last business day of each calendar quarter, the Working Interest Owners pay to the Partnership 25% of the Net Proceeds for the immediately preceding Quarterly Period. A Quarterly Period is each period of three months commencing on the first day of February, May, August and November. In turn, the Partnership distributes funds to its partners on the last business day of each calendar quarter. Cash distributions from the Trust are made in January, April, July and October of each year, and are payable to Unit holders of record as of the last business day of each calendar quarter. Thus, the cash conveyed to the Trust from the Royalty during the quarter ended December 31, 2009 substantially represents the revenues and expenses from the Royalty Properties from August through October 2009. The financial and operating information included in this Form 10-K for the 12 months ended December 31, 2009 represents financial and operating information with respect to the Royalty Properties for the months of November 2008 through October 2009. Thus, DeGolyer and MacNaughton's reserve study was made as of October 31, 2009. As such, the reserve study bases proved developed reserves on oil and gas prices as of October 31, 2009. In future periods, pursuant to new rules adopted by the SEC relating to disclosures of estimated reserves, the proved developed reserves attributable to the net profits interest owned by the Partnership will be based on the 12-month unweighted arithmetic average of the first-day-of-the-month prices of oil and gas for the preceding 12 months. In this Form 10-K, we provide a sensitivity analysis to show the effects of the new rules adopted by the SEC on the estimated proved reserves attributable to the Partnership had such rules been applied in the reserve study as of October 31, 2009. Additionally, in this Form 10-K, proved reserve estimates do not include any value for probable or possible reserves that may exist, categories that the new SEC rules would for the first time permit the Trust to disclose in its public reports.

During September 2008, the platforms and wells associated with the Eugene Island 339 field were completely destroyed by Hurricane Ike. Chevron is proceeding with the work required to clear the remaining infrastructure and abandon existing wells. A cost estimate for this work was not available during the preparation of the October 31, 2008 report. Solely for purposes of being able to complete the October 31, 2008 reserve study so that the Trust could file its Form 10-K for the year ended December 31, 2008, DeGolyer and MacNaughton assumed that Eugene Island 339 would not be redeveloped. The reserve study prepared as of October 31, 2009 does not include reserves attributable to Eugene Island 339 or any capital expenditures for any redevelopment of Eugene Island 339. However, such reserve study does include the Trust's share of the estimated total plugging and abandonment costs related to Eugene Island 339, with costs to the Trust relating thereto estimated to be approximately $13 million, $7.9 million of which had been incurred through December 31, 2009.

The reserve study notes that there were four productive Royalty Properties, which consist of Eugene Island 342/343, Ship Shoal 182/183, South Timbalier 36 and South Timbalier 37. West Cameron 643 is not included as a productive Royalty Property as production ceased from West Cameron 643 following damage inflicted by Hurricane Ike in September 2008 to a third-party transporter's pipeline. The Managing General Partner of the Partnership understands that the pipeline for West Cameron 643 is in the process of being restored, although such pipeline is not expected to be able to take production until at least the third quarter of 2010. During the year ended December 31, 2009, there were 228 barrels of oil and 927 Mcf of natural gas produced from Eugene Island 342/343 with revenues associated therewith of $17,545 and $5,951, respectively. Such volumes and dollar amounts represent amounts recorded by the Working Interest Owner at Eugene Island 342/343. For a discussion of the remaining productive Royalty Properties, see "Management's Discussion and Analysis of Financial Condition and Results of Operation—Operations."

There are numerous uncertainties inherent in estimating quantities of proved reserves and in projecting the future rates of production and timing of development expenditures, including many factors beyond the control of the producer. The reserve data in the DeGolyer and MacNaughton study represent estimates only and should not be construed as being exact. The discounted present values shown by the DeGolyer and MacNaughton study should not be construed as the current market value of the estimated gas and oil reserves attributable to the Royalty Properties or the costs that would be incurred to obtain equivalent reserves, since a market value determination would include many additional factors. Estimates were prepared in accordance with guidelines established by the SEC and the Financial Accounting Standards Board. Accordingly, the estimates are based on existing economic and operating conditions in effect at October 31, 2009, with no provision for future increases or decreases except for periodic price redeterminations in accordance with existing gas contracts. Actual future prices and costs may be materially greater or less than the assumed amounts in the reserve study. Because the reserve study is limited to proved reserves, future capital expenditures for recovery of reserves not classified as proved by DeGolyer and MacNaughton are not included in the calculation of estimated future net revenues. Reserve assessment is a subjective process of estimating the recovery from underground accumulations of gas and oil that cannot be measured in an exact way, and estimates of other persons might differ materially from those of DeGolyer and MacNaughton. Accordingly, reserve estimates are often different from the quantities of hydrocarbons that are ultimately recovered.

Estimated net proved reserves attributable to the net profits interest owned by the Partnership, as of October 31, 2009, are summarized as follows, expressed in barrels (bbl) and thousands of cubic feet (Mcf):

	Oil and Condensate (bbl)	Natural Gas (Mcf)
Proved Developed Reserves(1)		
Reserves as of October 31, 2008(2)	219,142	1,387,152
Revisions of Previous Estimates	(53,050)	(477,499)
Improved Recovery	0	0
Purchases of Minerals in Place	0	0
Extensions, Discoveries, and Other Additions	0	0
Production(3)	(28,628)	(41,148)
Sales of Minerals in Place	0	0
Reserves as of October 31, 2009(4)	137,464	868,505

(1) There are no proved undeveloped reserves for the Royalty Properties.

(2) Estimated Eugene Island 339 abandonment costs were not included.

(3) Production was estimated based on the ratio as of October 31, 2008, of the Partnership's net profits interest in net reserves to the net reserves associated with the Partnership's net profits interest and the interests retained in the Royalty Properties by the Working Interest Owners. This ratio was then applied to the production net to the combined interests of the Partnership and the Working Interest Owners for the period from November 1, 2008, through October 31, 2009.

(4) Estimated Eugene Island 339 abandonment costs were included.

Information used in the preparation of the reserve study was obtained from the Working Interest Owners. All of the reserve estimates are classified as proved developed reserves. There are no proved undeveloped reserves for the Royalty Properties.

The Partnership's share of gas sales are recorded by the Working Interest Owners on the cash method of accounting or based on actual production. When revenues are reported on actual production, there is no gas imbalance created. Under the cash method, revenues are recorded based on actual gas volumes sold, which could be more or less than the volumes the Working Interest Owners are entitled to based on their ownership interests. The Partnership's Royalty income for a period reflects the actual gas sold during the period.

While estimates of reserves attributable to the Royalty are shown in order to comply with requirements of the SEC, there is no precise method of allocating estimates of physical quantities of reserves to the Partnership and the Trust, since the Royalty is not a working interest and the Partnership does not own and is not entitled to receive any specific volume of reserves from the Royalty. Reserve quantities in the DeGolyer and MacNaughton reserve study have been allocated based on a revenue formula and such quantities can be affected by future changes in various economic factors utilized in estimating future gross and net revenues from the Royalty Properties. Therefore, the estimates of reserves set forth in the DeGolyer and MacNaughton study are to a large extent hypothetical and differ in significant respects from estimates of reserves attributable to a working interest. For a further discussion of reserves, reference is made to Note 9 in the Notes to Financial Statements under Item 8 of this Form 10-K.

The future net revenues contained in the DeGolyer and MacNaughton reserve study have not been reduced for future costs and expenses of the Trust, which are expected to approximate $972,000 annually. The costs and expenses of the Trust may increase in future years, depending on increases in accounting, engineering, legal and other professional fees, as well as other factors.

Total future net revenues attributable to the Partnership's interest in the Royalty were estimated in the reserve study at $13.1 million as of October 31, 2009. The present value of the total future net revenues attributable to the Partnership's interest in the Royalty, discounted at 10 percent, were estimated in the reserve study at $9.4 million as of October 31, 2009. Revenue values in the reserve study were estimated using the initial costs provided by Chevron and prices of $69.55 per barrel of oil and $4.02 per Mcf of natural gas. The future net revenue value was calculated by deducting operating expenses and capital costs from future gross revenue of the combined interests of the Partnership and the Working Interest Owners in the Royalty Properties. Current estimates of operating expenses were used for the life of the properties with no increases in the future based on inflation. The values were reduced by a trust overhead charge furnished by Chevron. Capital and abandonment costs for longer-life properties were accrued at the end of each quarter in amounts specified by Chevron beginning in January 2010. The future accrual or escrow amounts for the Royalty Properties were deducted from the future net revenue at the end of each quarter, as specified by Chevron. Interest on the balance of the accrued capital and abandonment costs at the rate of 0.18% per year as specified by Chevron was credited monthly. The adjusted revenue resulting from subtracting the overhead charge and accrued capital and abandonment costs was multiplied by a factor of 25% to arrive at the future net revenue attributed to the Partnership's net profits interest. Interest was charged monthly on the net profits deficit balances (costs not recovered currently) at the rate of 0.18% per year as specified by Chevron. Future income tax expenses were not taken into account in estimating future net revenue.

If, pursuant to the new rules promulgated by the SEC, the reserve study had based proved developed reserves attributable to the net profits interest owned by the Partnership on the 12-month unweighted arithmetic average of the first-day-of-the-month prices of oil and natural gas for the 12 months ended October 31, 2009, the estimated proved developed reserves attributable to the net profits interest owned by the Partnership as of October 31, 2009 would have been 110,978 barrels of oil and condensate and 690,969 Mcf of natural gas, and the future net revenues attributable to the Partnership's interest in the Royalty would have been $8.6 million. In deriving the estimated proved developed reserves and future net revenues using the SEC's new pricing rules, no changes were made to cost or other assumptions upon which such reserves and revenues are based.

Because the DeGolyer and MacNaughton reserve study is limited to proved reserves, future capital expenditures for recovery of reserves not classified as proved by DeGolyer and MacNaughton are not included in the calculation of future net revenues nor are any capital expenditures for any redevelopment of Eugene Island 339. These capital expenditures could have a significant effect on the actual future net revenues attributable to the Partnership's interest in the Royalty.

The Trustees rely on DeGolyer and MacNaughton to prepare the reserve study of the oil and gas reserves attributable to the Partnership, in which the Trust has a 99.99% interest. The Trustees do not control the information provided by the Working Interest Owners or the assumptions made or methodologies used by the third-party reserve engineer. Accordingly, such information is outside the scope of the internal controls of the Trust and the Trustees.

Chevron, as the Managing General Partner of the Partnership, maintains oversight and compliance responsibility for the internal reserve estimate process and, in accordance with internal policies and procedures, provides appropriate data to independent third party engineers for the annual estimation of year-end reserves. Chevron accumulates historical production data for the Royalty Properties, calculates historical lease operating expenses and differentials, updates working interests and net revenue interests, and obtains logs, 3-D seismic and other geological and geophysical information. This data is forwarded to DeGolyer & MacNaughton, thereby allowing DeGolyer & MacNaughton to prepare estimated proved reserves in their entirety based on such data.

Estimates of the proved oil and gas reserves attributable to the Partnership as of October 31, 2008 and 2009 are based on reports of DeGolyer & MacNaughton. DeGolyer and MacNaughton is a Delaware corporation with offices in Dallas, Houston, Calgary, and Moscow. The firm's more than 80 professionals include engineers, geologists, geophysicists, petrophysicists, and economists engaged in the appraisal of oil and gas properties, evaluation of hydrocarbon and other mineral prospects, basin evaluations, comprehensive field studies, equity studies and studies of supply and economics related to the domestic and international energy industry. These services have been provided for over 70 years. DeGolyer and MacNaughton restricts its activities exclusively to consultation; it does not accept contingency fees, nor does it own operating interests in any oil, gas, or mineral properties. The firm subscribes to a code of professional conduct, and its employees support their related technical and professional societies.

The technical person at DeGolyer and MacNaughton primarily responsible for overseeing the preparation of the reserve study is a Registered Professional Engineer in the State of Texas with more than 35 years of experience in oil and gas reservoir studies and reserve evaluations. He graduated with a Bachelor of Science degree in Petroleum Engineering from Texas A&M University in 1974 and he is a member of the International Society of Petroleum Engineers and the American Association of Petroleum Geologists.

The Trust Agreement provides that the Trust will terminate in the event total future net revenues attributable to the Partnership's interest in the Royalty as determined by independent petroleum engineers, as of the end of any year, are less than $2.0 million. See "Business—Termination of the Trust".

The Managing General Partner of the Partnership has advised the Trust that there have been no events subsequent to October 31, 2009 that have caused a significant change in the estimated proved reserves referred to in the DeGolyer and MacNaughton study.

Operations and Production

Reference is made to the Section entitled "—Operations" under Item 7 of this Form 10-K for information concerning operations and production.

Distributions

As previously discussed, production ceased at Eugene Island 339 and Ship Shoal 182 and 183 following damages inflicted by Hurricane Ike in September 2008. Future Net Proceeds may take into account the Trust's share of project costs and other related expenditures that are not covered by insurance of the operator of the Royalty Properties. On December 19, 2008, the Trust announced its fourth quarter distribution of approximately $0.7 million, which was paid on January 9, 2009. The funds available for the fourth quarter distribution were severely negatively impacted by Hurricane Ike. On March 25, 2009, the Trust announced that there would be no trust distribution for the first quarter of 2009. Similarly, on June 26, 2009, September 25, 2009, December 23, 2009 and March 23, 2010, the Trust announced there would be no trust distributions for the second, third and fourth quarters of 2009 or the first quarter of 2010, respectively.

There are not likely to be sufficient Net Proceeds from the Royalty Properties for the Trust to make a regularly scheduled quarterly distribution to Unit holders for the foreseeable future. As a result of the damage inflicted by Hurricane Ike, Net Proceeds will continue to be severely impacted by reduced production, from historical levels, and the amount of expenditures incurred that are associated with such damages, including the expenditures required to plug and abandon the wells on Eugene Island 339, and, as currently expected, to redevelop the facility at Eugene Island 339. Future Net Proceeds from the Royalty Properties will take into account the Trust's share of project costs and other related expenditures that are not covered by the insurance of the operators of the Royalty Properties. The Trust's net portion of the aggregate cost to plug and abandon the wells subject to the royalty on Eugene Island 339 is estimated to be approximately $13 million, $7.9 million of which had been incurred through December 31, 2009. If development and production costs of the Royalty exceed the proceeds of production from the Royalty Properties, the Trust will not receive Net Proceeds until future proceeds from production exceed the total of the excess costs plus accrued interest. As of December 31, 2009, development and production costs of the Royalty exceeded the proceeds of production from the Royalty Properties by approximately $5.5 million. Significant development and production costs will continue to be incurred as Eugene Island 339 is redeveloped. Development activities may not generate sufficient additional revenue to repay such costs. Accordingly, there will not be sufficient Net Proceeds from the Royalty Properties to make distributions for some period of time in the future. At this time, the ultimate outcome of these matters cannot be determined with any degree of certainty. See "Management's Discussion and Analysis of Financial Condition and Results of Operations—Operations."

MARKETING

The amount of cash distributions by the Trust is dependent on, among other things, the sales prices for oil and gas produced from the Royalty Properties and the quantities of oil and gas sold.

It should be noted that substantial uncertainties exist with regard to future oil and gas prices, which are subject to material fluctuations due to changes in production levels and pricing and other actions taken by major petroleum producing nations, as well as the regional supply and demand for gas, weather, industrial growth, conservation measures, competition and other variables.

Gas Marketing

During the year ended December 31, 2009, 100% of Chevron's natural gas and natural gas liquids relative to the Trust's Royalty Properties were committed and sold to Chevron Natural Gas at spot market prices. During the years ended December 31, 2008 and 2007, approximately 99% of Chevron's natural gas and natural gas liquids relative to the Trust's Royalty Properties were committed and sold to Chevron Natural Gas at spot market prices.

It should be noted that the Conveyance provides that amounts received by the producer pursuant to "take-or-pay" provisions are not included within the Royalty payable to the Trust unless and until gas is actually delivered pursuant to the "make-up" provisions, if any, of the applicable contract. Accordingly, amounts received by the Working Interest Owners as "take-or-pay" payments are not included in the calculation of the Royalty payable, and the income received by the Trust is restricted to amounts paid for gas actually delivered.

Due to the seasonal nature of demand for natural gas and its effects on sales prices and production volumes, the amount of gas sold with respect to the Royalty Properties may vary. Generally, production volumes and prices are higher during the first and fourth quarters of each calendar year. Because of the time lag between the date on which the Working Interest Owners receive payment for production from the Royalty Properties and the date on which distributions are made to Unit holders, the seasonality that generally affects production volumes and prices is generally reflected in distributions to the Trust in later periods.

The following paragraphs discuss the marketing of gas from the principal Royalty Properties.

West Cameron 643. West Cameron 643 contributed 0% of the revenues from natural gas sales from the Royalty Properties in 2009, as there was no natural gas production.

East Cameron 371. East Cameron 371 contributed 0% of the revenues from natural gas sales from the Royalty Properties in 2009, as there was no natural gas production.

Ship Shoal 182/183. Ship Shoal 182/183 contributed approximately 90% of the revenues from gas sales from the Royalty Properties in 2009. The average price received for natural gas from all of the Working Interest Owners' purchasers on Ship Shoal 182/183 during 2009 was $3.46 per Mcf, before prior period audit adjustments.

Eugene Island 339. Eugene Island 339 contributed 0% of the revenues from natural gas sales from the Royalty Properties in 2009, as there was no natural gas production.

South Timbalier 36/37. South Timbalier 36/37 contributed approximately 10% of the revenues from natural gas sales from the Royalty Properties in 2009. The average price received for natural gas from all of the Working Interest Owners' purchasers on South Timbalier 36/37 during 2009 was $4.67 per Mcf, before prior period audit adjustments.

Oil Marketing

Crude oil purchases by Chevron accounted for approximately 99% of total crude oil revenues from the Royalty Properties during 2007 and 2008, and approximately 98% of the total crude oil revenues from the Royalty Properties during 2009.

Chevron purchases the crude oil at prices based on a market index for the applicable grade of crude oil, as adjusted for gravity and transportation charges, if applicable. Average monthly prices for fiscal year 2009 ranged from $41.11 per barrel to $83.14 per barrel.

COMPETITION AND REGULATION

Competition

The Working Interest Owners experience competition from other oil and gas companies in all phases of their operations. Numerous companies participate in the exploration for and production of oil and gas. The Working Interest Owners have advised the Trust that they believe that their competitive positions are affected by price and contract terms. Business is affected not only by such competition, but also by general economic developments, governmental regulations and other factors.

Regulation—General

The production of oil and gas by the Working Interest Owners is affected by many state and federal regulations with respect to allowable rates of production, drilling permits, well spacing, marketing, environmental matters and pricing. Future regulations could change allowable rates of production or the manner in which oil and gas operations may be lawfully conducted. Sales of natural gas in interstate commerce for resale and the transportation of natural gas in interstate commerce are subject to regulation by the Federal Energy Regulatory Commission ("FERC") under the Natural Gas Act of 1938, as amended (the "Natural Gas Act").

FERC Regulation

In general, the FERC regulates the sale of natural gas in interstate commerce for resale and the transportation of natural gas in interstate commerce by interstate pipelines. The FERC has issued orders and adopted regulations resulting in a restructuring of the natural gas industry. The principal elements of this restructuring were the requirement that interstate pipelines separate, or "unbundle," into individual components the various services offered on their systems, with all transportation services to be provided on a non-discriminatory basis, and the prohibition against an interstate pipeline providing gas sales services except through separately-organized affiliates. In various rulemaking proceedings following its initial unbundling requirement, the FERC has refined its regulatory program applicable to interstate pipelines in various respects, and it has announced that it will continue to monitor these regulations to determine whether further changes are needed. In addition to rulemaking proceedings, the FERC establishes new policies and regulations through policy statements and adjudications of individual pipeline matters. Further, additional changes to regulations may occur based on actions taken by the United States Congress and/or the courts. As to these various developments, the working interest owners have advised the Trust that the on-going and evolving nature of these regulatory initiatives makes it impossible to predict their ultimate impact on the prices, markets or terms of sale of natural gas related to the Trust.

State and Other Regulation

State regulation of gathering facilities generally includes various safety, environmental, and in some circumstances, non-discriminatory take requirements. Some states have implemented more stringent legislation in recent years to regulate gathering rates charged by gas gathering companies, but to date the effect on the Working Interests Owners in connection with the Trust has been minimal.

Environmental Regulations

General

The Working Interest Owners' oil and gas activities on the Royalty Properties are subject to existing and evolving federal, state and local environmental laws and regulations. The Managing General Partner of the Partnership has advised the Trust that the Working Interest Owners believe that their operations and facilities are in general compliance with applicable health, safety, and environmental laws and regulations that have taken effect at the federal, state and local levels. In addition, events in recent years have heightened environmental concerns about the oil and gas industry generally, and about offshore operations in particular. The Working Interest Owners' operation of federal offshore oil and gas leases is subject to extensive governmental regulation, including regulations that may, in certain circumstances, impose absolute liability upon lessees for cost of removal of pollution and for pollution damages resulting from their operations, and require lessees to suspend or cease operations in the affected areas.

Under the Oil Pollution Act of 1990, as amended by the Coast Guard Authorization Act of 1996, (collectively, "OPA"), parties responsible for offshore facilities must establish and maintain evidence of oil-spill financial responsibility ("OSFR") for costs attributable to potential oil spills. OPA requires a minimum of $35 million in OSFR for offshore facilities located on the OCS. This amount is subject to upward regulatory adjustment up to $150 million. Responsible parties for more than one offshore facility are required to provide OSFR only for their offshore facility requiring the highest OSFR. In 1998, the Minerals Management Service, which we refer to herein as the "MMS", adopted regulations for establishing the amount of OSFR required for particular facilities. The amount of OSFR increases as the volume of a facility's worst-case oil spill increases. Accordingly, for facilities with worst-case spills of less than 35,000 barrels, only $35 million in OSFR is required; for worst-case spills of over 35,000 barrels, $70 million is required; for worst-case spills of over 70,000 barrels, $105 million is required; and for worst-case spills of over 105,000 barrels, $150 million is required. In addition, all OSFR below $150 million remains subject to upward regulatory adjustment if warranted by the particular operational, environmental, human health or other risks involved with a facility. The Working Interest Owners are currently maintaining their required OSFR. Although the Managing General Partner of the Partnership has advised the Trust that current environmental regulation has had no material adverse effect on the Working Interest Owners' present method of operations, future environmental regulatory developments such as stricter environmental regulation and enforcement policies cannot presently be quantified.

The Working Interest Owners' operations are subject to regulation, principally under the following federal statutes, along with their analogous state statutes.

Water

The Federal Water Pollution Control Act of 1972, as amended, and the Oil Pollution Act of 1990 impose certain liabilities and penalties upon persons and entities, such as the Working Interest Owners, for any discharges of petroleum products in reportable quantities, for the costs of removing an oil spill, and for natural resource damages. State laws for the control of water pollution also provide varying civil and criminal penalties and liabilities in the case of a release of petroleum or its derivatives in surface waters.

The federal NPDES permits prohibit the discharge of produced water, sand and other substances related to the oil and gas industry to coastal waters of Louisiana and Texas. The Working Interest Owners have advised the Trust that these costs have not had a material adverse impact on their operations.

Air Emissions

Amendments to the federal Clean Air Act were enacted in late 1990 and require most industrial operations in the United States, including offshore operations, to incur capital expenditures for air emission control equipment in connection with maintaining and obtaining operating permits and approvals addressing other air emission related issues. The Environmental Protection Agency ("EPA") and state environmental agencies have been developing regulations to implement these requirements. Some of the Working Interest Owners' facilities are included within the categories of hazardous air pollutant sources that will be affected by these regulations and these regulations could make operation of the Royalty Properties more costly.

Climate Change

A variety of regulatory developments, proposals or requirements have been introduced that are focused on restricting the emission of carbon dioxide, methane and other greenhouse gases. Among these developments is the Kyoto Protocol to the United Nations Framework Convention on Climate Change that became effective in February 2005. Under the Protocol, participating nations are required to implement programs to reduce emissions of certain gases, generally referred to as greenhouse gases, that are suspected of contributing to global warming. The United States is not currently participating in the Protocol though the Protocol may impact oil and gas markets generally. In addition, Congress has considered recent proposed legislation directed at reducing greenhouse gas emissions and President Obama has indicated his support of legislation aimed at reducing greenhouse gases. There has been support in various regions of the country for legislation that requires reductions in greenhouse gas emissions, and some states have already adopted legislation addressing greenhouse gas emissions from various sources. In 2007, the U.S. Supreme Court held in *Massachusetts, et al. v. EPA* that greenhouse gases are an "air pollutant" under the federal Clean Air Act and, thus, subject to future regulation. The Environmental Protection Agency (the "EPA") is moving forward to regulate greenhouse gases. To date, the EPA has issued (i) a "Mandatory Reporting of Greenhouse Gases" final rule, effective December 29, 2009, which establishes a new comprehensive scheme requiring operators of stationary sources in the United States emitting more than established annual thresholds of carbon dioxide-equivalent greenhouse gases to inventory and report their greenhouse gas emissions annually; and (ii) an "Endangerment Finding" final rule, effective January 14, 2010, which states that current and projected concentrations of six key greenhouse gases in the atmosphere, as well as emissions from new motor vehicles and new motor vehicle engines, threaten public health and welfare, allowing the EPA to finalize motor vehicle greenhouse gas standards (the effect of which could reduce demand for motor fuels refined from crude oil). Finally, according to the EPA, the final motor vehicle greenhouse gas standards will trigger construction and operating permit requirements for stationary sources. As a result, the EPA has proposed to tailor these programs such that only large stationary sources will be required to have air permits that authorize greenhouse gas emissions.

Laws, regulations, treaties or international agreements related to greenhouse gases and climate change, including incentives to conserve energy or use alternative energy sources, could have a negative impact on the future operations of the Royalty Properties if such laws, regulations, treaties or international agreements reduce the worldwide demand for oil and natural gas or otherwise result in reduced economic activity generally. In addition, such laws, regulations, treaties or international agreements could result in increased compliance costs or additional operating restrictions, which may have a negative impact on the Royalty Property operations. In addition to potential impacts on the Royalty Property operations directly or indirectly resulting from climate-change legislation or regulations, the Royalty Property operations also could be negatively affected by climate-change related physical changes or changes in weather patterns. At this time, it is not possible to accurately estimate how potential future laws or regulations addressing greenhouse gas emissions would impact the operations of the Royalty Properties.

Solid Waste

The Working Interest Owners' operations may generate wastes that are subject to the federal Resource Conservation and Recovery Act ("RCRA") and comparable state statutes. The EPA has limited disposal options for certain hazardous wastes and may adopt more stringent disposal standards for nonhazardous wastes. Furthermore, it is possible that some wastes that are currently classified as nonhazardous, perhaps including wastes generated during drilling and production operations, may in the future be designated as "hazardous wastes." Such changes in the regulations would result in more rigorous and costly disposal requirements that could result in increased operating expenses on the Royalty Properties.

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Norm

Oil and gas exploration and production activities have been identified as generators of low-level naturally-occurring radioactive materials ("NORM"). The generation, handling and disposal of NORM in the course of offshore oil and gas exploration and production activities is currently regulated in federal and state waters. These regulations could result in an increase in operating expenses on the Royalty Properties.

Superfund

The Comprehensive Environmental Response, Compensation and Liability Act ("CERCLA"), also known as the "Superfund" law, imposes liability, without regard to the fault or the legality of the original conduct, on certain classes of persons that contributed to the release of a "hazardous substance" into the environment. These persons include the current or previous owner and operator of a facility and companies that disposed or arranged for the disposal of the hazardous substance found at a facility. CERCLA also authorizes the EPA and, in some cases, private parties to take actions in response to threats to the public health or the environment and to seek recovery from such responsible classes of persons of the costs, which can be substantial, of such action. Although "petroleum" is excluded from CERCLA's definition of a "hazardous substance", in the course of their operations, the Working Interest Owners may generate wastes that fall within CERCLA's definition of "hazardous substances." The Working Interest Owners may be responsible under CERCLA for all or part of the costs to clean up facilities at which such substances have been disposed. Such clean-up costs may make operation of the Royalty Properties more expensive for the Working Interest Owners.

Offshore Operations

Offshore oil and gas operations are subject to regulations of the United States Department of the Interior, including regulations promulgated pursuant to the Outer Continental Shelf Lands Act, which impose liability upon a lessee, such as the Working Interest Owners, under a federal lease for the cost of clean-up of pollution resulting from a lessee's operations. In the event of a serious incident of pollution, the Department of the Interior may require a lessee under federal leases to suspend or cease operations in the affected areas.

Item 1A. Risk Factors.

Although risk factors are described elsewhere in this Form 10-K together with specific forward-looking statements, the following is a summary of the principal risks associated with an investment in Units in the Trust.

Natural gas and oil prices fluctuate due to a number of factors, and lower prices will reduce Net Proceeds available to the Trust and distributions to Trust Unit holders.

The Trust's quarterly distributions are highly dependent upon the prices realized from the sale of natural gas and oil, and a material decrease in such prices could reduce the amount of Trust distributions. Natural gas and oil prices can fluctuate widely on a month-to-month basis in response to a variety of factors that are beyond the control of the Trust and the Working Interest Owners. Factors that contribute to price fluctuation include, among others:

- political conditions worldwide, in particular political disruption, war and other armed conflict in oil producing regions such as Iraq;
- worldwide economic conditions;
- weather conditions;

- the supply and price of foreign natural gas;
- the level of consumer demand;
- the price and availability of alternative fuels;
- the proximity to, and capacity of, transportation facilities; and
- the effect of worldwide energy conservation measures.

Moreover, government regulations, such as regulation of natural gas and oil transportation and price controls, can affect product prices in the long term.

Given the recent economic downturn, crude oil prices have been volatile and, in 2009, ranged from a high of $81.37 to a low of $33.98. The Trust cannot predict the timing or the duration of this or any other economic downturn in the economy and if the current conditions continue, the financial condition of the Trust could be materially adversely affected.

When natural gas and oil prices decline, the Trust is affected in two ways. First, net royalties are reduced. Second, exploration and development activities on the underlying properties may decline as some projects may become uneconomic and are either delayed or cancelled. The volatility of energy prices reduces the predictability of future cash distributions to Unit holders. Substantially all of the natural gas and natural gas liquids produced from the Royalty Properties is being sold to Chevron Natural Gas at spot market prices. Substantially all of the crude oil produced by the Royalty Properties is being sold to subsidiaries of Chevron Corporation based on pricing bulletins.

Production from Eugene Island 339 and Ship Shoal 182 and 183, the two most significant Royalty Properties, ceased following damage inflicted by Hurricane Ike in September 2008. While oil and natural gas production at Ship Shoal 182 and 183 was restored in 2009, there can be no assurance that production will be restored at Eugene Island 339. Chevron's failure or inability to pursue redevelopment of Eugene Island 339, and on the timeframes approved by the MMS, could result in a loss of the lease. Based on the damage caused by Hurricane Ike, the Trust's scheduled distribution for the fourth quarter of 2008 was severely negatively impacted and there were no distributions during 2009 or the first quarter of 2010. If development and production costs of the Royalty exceed the proceeds of production from the Royalty Properties, the Trust will not receive Net Proceeds until future proceeds from production exceed the total of the excess costs plus accrued interest. Development activities may not generate sufficient additional revenue to repay such costs. Accordingly, there will not be sufficient Net Proceeds from the Royalty Properties to make distributions for some period of time in the future. As of December 31, 2009, development and production costs of the Royalty exceeded the proceeds of production from the Royalty Properties by approximately $5.5 million. Significant development and production costs will continue to be incurred as Eugene Island 339 is redeveloped. See "Management's Discussion and Analysis of Financial Condition and Results of Operations—Operations."

The platforms and wells on Eugene Island 339 were destroyed by Hurricane Ike in September 2008. Chevron is working on the plugging and abandonment of the existing wells, clearing debris and otherwise dealing with the remaining infrastructure, which activities are not expected to be completed until the first quarter of 2012. Chevron has informed the Corporate Trustee that Chevron presently intends to pursue the redevelopment of platforms and wells at Eugene Island 339 in accordance with the terms and conditions established by the MMS in response to Chevron's submission to the MMS of a program to restore production at Eugene Island 339. The activity schedule approved by the MMS contemplates, among other things, commencement of front-end engineering and design work by the end of January 2010, which was so commenced, completion of the front-end engineering and design work by the end of July 2010, an awarding of fabrication contracts for platform, substructure and equipment by the end of November 2010, and commencement of production ultimately occurring by the end of October 2012. Chevron is required to provide the MMS with periodic updates on Chevron's progress on such redevelopment. The approval by the MMS expires by its terms on November 30, 2010, and Chevron would need to request an extension of such approval from the MMS in order to complete the proposed redevelopment, given that the activity schedule contemplates activity through October 2012. Chevron recently entered into an agreement with a third party for the redevelopment of Eugene Island Blocks 338 and 339. Chevron is the operator of Eugene Island Block 338; however, this property is not a Royalty Property. Three wells are planned to be commenced from a common open water location at Eugene 338 in the second quarter of 2010. The information derived from these wells will be used, in part, to determine the size of the platform and topside facilities (production processing equipment) that are to cover both Eugene Island 338 and Eugene Island 339 as a common facility. If a platform is set, the current plan is to drill additional wells in Eugene Island 338 and Eugene Island 339. If Chevron determines that it is warranted, and the redevelopment plans are successful, first production at Eugene Island 339 is anticipated in the fourth quarter of 2012. Restoration of production at Eugene Island 338 and 339 is a complex process and cannot be assured at this time. If the initial three well drilling program is not successful, Chevron intends to reevaluate the redevelopment of Eugene Island 338 and 339. The costs for such a redevelopment would be significant. While Chevron has stated that it intends to pursue such a redevelopment, there is no obligation for Chevron to continue to pursue such redevelopment. Failure or inability to pursue such a redevelopment, and on the timeframes approved by the MMS, could result in a loss of the lease. At this time, there can be no assurance that production will be restored at Eugene Island 339.

Production at Ship Shoal 182/183 ceased following damage inflicted by Hurricane Ike in September 2008. While the hurricane caused limited surface damage to the facilities at Ship Shoal 182/183, all of the wells at Ship Shoal 182/183 were shut-in following hurricane-related damage to a third-party transporter's natural gas pipeline. A limited volume of oil production was restored in November 2008. The volume of oil production that can be produced is limited by the amount of gas that is also produced by the oil wells. The third-party transporter's natural gas pipeline repairs were completed and gas sales at Ship Shoal 182/183 were restored on June 26, 2009. However, the pipeline was shut down in mid-September for additional repairs. Production sales for both oil and natural gas at Ship Shoal 182 and 183 were restored on October 8, 2009 following completion of such additional repairs.

In addition, production from West Cameron 643 and East Cameron 371 ceased following damage inflicted by Hurricane Ike in September 2008 to third-party transporters' pipelines. Chevron, as the Managing General Partner of the Partnership, understands that, as a result of the cessation of production at West Cameron 643 due to the damages inflicted by Hurricane Ike to a third-party transporter's pipeline, Hilcorp submitted to the MMS a program to restore production at West Cameron 643 and that such request has been granted. Chevron also understands that the pipeline for West Cameron 643 is in the process of being restored, although such pipeline is not expected to be able to take production until at least the third quarter of 2010. At this point in time, there can be no assurance as to when, or if at all, production may be restored at West Cameron 643. The field operator for East Cameron 371 has reported to Chevron that a review of the remaining reserves for East Cameron 371 has been conducted, and that the wells at East Cameron 371 have been depleted. At this time, the field operator for East Cameron 371 has not made a decision regarding field abandonment, including the related wells, equipment platforms and any field infrastructure.

For additional information, see "Management's Discussion and Analysis of Financial Condition and Results of Operations—Operations." Based on the damage caused by Hurricane Ike, the Trust's scheduled distribution for the fourth quarter of 2008 was severely negatively impacted and there were no distributions made to Unit holders during 2009 or the first quarter of 2010. Future distributions are also expected to be severely negatively impacted, and there may not be sufficient Net Proceeds from the Royalty Properties to make one or more future distributions. At this time, the ultimate outcome of the various matters cannot be determined with any degree of certainty.

Increased production and development costs for the Royalty will result in decreased or no Trust distributions.

Production and development costs attributable to the Royalty are deducted in the calculation of the Trust's share of Net Proceeds. Production and development costs are impacted by increases in commodity prices both directly and indirectly, through commodity-price dependent costs such as electricity, and indirectly, as a result of demand-driven increases in costs of oilfield goods and services. Accordingly, higher or lower production and development costs, without concurrent increases in revenues, directly decrease or increase the amount received by the Trust for the Royalty.

In September 2008, Hurricane Ike completely destroyed the platforms and wells on Eugene Island 339. Chevron is proceeding to plug and abandon the existing wells, to clear debris and otherwise to deal with the remaining infrastructure, with estimated costs to the Trust relating thereto of approximately $13 million. Chevron has informed the Corporate Trustee that Chevron presently intends to pursue the redevelopment of platforms and wells at Eugene Island 339 in accordance with the terms and conditions established by the MMS in response to Chevron's submission to the MMS of a program to restore production at Eugene Island 339. At this time, there can be no assurance that production at Eugene Island 339 will be restored. For additional information, see "Management's Discussion and Analysis of Financial Condition and Results of Operations—Operations."

If development and production costs of the Royalty exceed the proceeds of production from the Royalty Properties, the Trust will not receive Net Proceeds until future proceeds from production exceed the total of the excess costs plus accrued interest, at a rate equal to one-fourth of (i) one-half of one percent plus (ii) the median between the prime interest rate at the end of a quarterly period in which there are excess costs and the prime interest rate at the end of the preceding quarterly period, during the deficit period. Development activities may not generate sufficient additional revenue to repay the costs. Accordingly, there may not be sufficient Net Proceeds to make a particular distribution.

Trust reserve estimates depend on many assumptions that may prove to be inaccurate, which could cause both estimates of reserves and estimated future revenues to be too high or too low.

The value of the Units depends upon, among other things, the amount of reserves attributable to the Royalty and the estimated future value of the reserves. Estimating reserves is inherently uncertain. Ultimately, actual production, revenues and expenditures for the underlying properties will vary from estimates and those variations could be material. Petroleum engineers consider many factors and make assumptions in estimating reserves. Those factors and assumptions include:

- historical production from the area compared with production rates from similar producing areas;
- the assumed effect of governmental regulation;
- assumptions about future commodity prices, production and development costs, severance and excise taxes, and capital expenditures;
- the availability of enhanced recovery techniques; and
- relationships with landowners, working interest partners, pipeline companies and others.

Changes in these factors and assumptions can materially change reserve estimates and future net revenue estimates.

The reserve quantities attributable to the Royalty and revenues are based on estimates of reserves and revenues for the Royal Properties. The method of allocating a portion of those reserves to the Trust is complicated because the Trust, indirectly through the Partnership, holds an interest in the Royalty and does not own a specific percentage of the natural gas reserves. Ultimately, actual production, revenues and expenditures for the Royalty Properties, and therefore actual net proceeds payable to the Trust, will vary from estimates and those variations could be material. Results of drilling, testing and production after the date of those estimates may require substantial downward revisions or write-downs of reserves.

The Trustees also rely entirely on reserve estimates and related information prepared by Chevron, the other Working Interest Owners and the independent reserve engineer engaged by the Partnership. While the Trustees have no reason to believe the reserve estimates included in this Form 10-K are inaccurate, to the extent additional information exists that could affect the reserve estimates of Chevron, the other Working Interest Owners and the independent reserve engineer, the estimated reserves in this Form 10-K could also be too low.

Operating risks for the Working Interest Owners' interests in the Royalty Properties can adversely affect Trust distributions.

There are operational risks and hazards associated with the production and transportation of natural gas, including without limitation natural disasters, blowouts, explosions, fires, leakage of natural gas, releases of other hazardous materials, mechanical failures, cratering and pollution. Any of these or similar occurrences could result in the interruption or cessation of operations, personal injury or loss of life, property damage, damage to productive formations or equipment, damage to the environment of natural resources, or cleanup obligations. The occurrence of drilling, production or transportation accidents and natural disasters at any of the Royalty Properties will reduce Trust distributions by the amount of uninsured costs. These accidents may result in personal injuries, property damage, damage to productive formations or equipment and environmental damages. Offshore activities are also subject to a variety of additional operating risks, such as hurricanes and other weather disturbances. Any uninsured costs would be deducted as a production cost in calculating net proceeds payable to the Trust.

As described in this report, Hurricanes Katrina and Rita caused significant damage during 2005. All but one of the platforms and facilities on the Royalty Properties were restored during 2006 and 2007. As also described in the report, production from the two most significant oil and gas properties associated with the Trust ceased following damage inflicted by Hurricane Ike in September 2008. The platforms and wells on Eugene Island 339 were completely destroyed. While Hurricane Ike caused limited damage to the facilities at Ship Shoal 182 and 183, all of the wells at Ship Shoal 182 and 183 were shut-in following hurricane related damage to a third-party transporter's natural gas pipeline.

Terrorism and continued hostilities in the Middle East could decrease Trust distributions or the market price of the units of beneficial interest of the Trust.

Terrorist attacks and the threat of terrorist attacks, whether domestic or foreign, as well as military or other actions taken in response, cause instability in the global financial and energy markets. Terrorism and other sustained military campaigns could adversely affect Trust distributions or the market price of the Units in unpredictable ways, including through the disruption of fuel supplies and markets, increased volatility in natural gas prices, or the possibility that the infrastructure on which the operators developing the underlying properties rely could be a direct target or an indirect casualty of an act of terror.

The operators of the working interests are subject to extensive governmental regulation.

Offshore oil and gas operations have been, and in the future will be, affected by federal, state and local laws and regulations and other political developments, such as price or gathering rate controls and environmental protection regulations. These regulations and changes in regulations could have a material adverse effect on Royalty income payable to the Trust.

Regulation of greenhouse gases and climate change could adversely affect Trust distributions

Some scientific studies have suggested that emissions of certain gases, commonly referred to as greenhouse gases and including carbon dioxide and methane, may be contributing to the warming of the Earth's atmosphere and other climatic changes. In response to such studies, the issue of climate change and the effect of greenhouse gas emissions, in particular emissions from fossil fuels, is attracting increasing attention worldwide. Legislative and regulatory measures to address concerns that emissions of greenhouse gases are contributing to climate change are in various phases of discussions or implementation at the international, national, regional and state levels.

In 2005, the Kyoto Protocol to the 1992 United Nations Framework Convention on Climate Change, which establishes a binding set of emission targets for greenhouse gases, became binding on the countries that had ratified it. In the United States, federal legislation imposing restrictions on greenhouse gases is under consideration. Proposed legislation has been introduced that would establish an economy-wide cap on emissions of greenhouse gases and would require more sources of greenhouse gas emissions to obtain greenhouse gas emission "allowances" corresponding to their annual emissions. In addition, the EPA is taking steps that would result in the regulation of greenhouse gases as pollutants under the Clean Air Act. To date, the EPA has issued (i) a "Mandatory Reporting of Greenhouse Gases" final rule, effective December 29, 2009, which establishes a new comprehensive scheme requiring operators of stationary sources in the United States emitting more than established annual thresholds of carbon dioxide-equivalent greenhouse gases to inventory and report their greenhouse gas emissions annually and (ii) an "Endangerment Finding" final rule, effective January 14, 2010, which states the current and projected concentrations of six key greenhouse gases in the atmosphere, as well as emissions from new motor vehicles and new motor vehicle engines, threaten public health and welfare, allowing the EPA to finalize motor vehicle greenhouse gas standards (the effect of which could reduce demand for motor fuels refined from crude oil). Finally, according to the EPA, the final motor vehicle greenhouse gas standards will trigger construction and operating permit requirements for stationary sources. As a result, the EPA has proposed to tailor these programs such that only large stationary sources will be required to have air permits that authorize greenhouse gas emissions.

Existing or future laws, regulations, treaties or international agreements related to greenhouse gases and climate change, including incentives to conserve energy or use alternative energy sources, could have a negative impact on the Royalty Property operations if such laws, regulations, treaties or international agreements reduce the worldwide demand for oil and natural gas or otherwise result in reduced economic activity generally. In addition, such laws, regulations, treaties or international agreements could result in increased compliance costs or additional operating restrictions, which may have a negative impact on the Royalty Property operations. In addition to potential impacts on the Royalty Property operations directly or indirectly resulting from climate-change legislation or regulations, the Royalty Property operations also could be negatively affected by climate-change related physical changes or changes in weather patterns.

The Trustees and the Unit holders have no control over the operation or development of the Royalty Properties and have little influence over operation or development.

Neither the Trustees nor the Unit holders can influence or control the operation or future development of the underlying properties. The Royalty Properties are owned by independent Working Interest Owners. The Working Interest Owners manage the underlying properties and handle receipt and payment of funds relating to the Royalty Properties and payments to the Trust for the Royalty.

Information regarding operations provided by the Working Interest Owners has been subject to errors and adjustments, some of which have been significant. Accordingly, the Trustees cannot assure

Unit holders that other errors or adjustments by Working Interest Owners, whether historical or future, will not affect future Royalty income and distributions by the Trust.

The current Working Interest Owners are under no obligation to continue operating the properties. The failure of an operator to conduct its operations, discharge its obligations, deal with regulatory agencies or comply with laws, rules and regulations, including environmental laws and regulations, in a proper manner could have an adverse effect on the net proceeds payable to the Trust. Neither the Trustees nor the Unit holders have the right to replace an operator.

The Trustees rely upon the Working Interest Owners and Managing General Partner for information regarding the Royalty Properties.

The Trustees rely on the Working Interest Owners and the Managing General Partner of the Partnership for information regarding the Royalty Properties. The Working Interest Owners alone control (i) historical operating data, including production volumes, marketing of products, operating and capital expenditures, environmental and other liabilities, effects of regulatory changes and the number of producing wells and acreage, (ii) plans for future operating and capital expenditures, (iii) geological data relating to reserves, as well as related projections regarding production, operating expenses and capital expenses used in connection with the preparation of the reserve study, (iv) forward-looking information relating to production and drilling plans and (v) information regarding the Royalty Properties responsive to litigation claims. While the Trustees request material information for use in periodic reports as part of its disclosure controls and procedures, the Trustees do not control this information and rely entirely on the Working Interest Owners to provide accurate and timely information when requested for use in the Trust's periodic reports. The Trustees also rely on the Managing General Partner of the Partnership to collect certain information from the Working Interest Owners and do not have any direct contact with the Working Interest Owners other than the Managing General Partner. Under the terms of the Trust Indenture, the Trustees are entitled to rely, and in fact rely, on certain experts in good faith. While the Trustees have no reason to believe their reliance on experts is unreasonable, this reliance on experts and limited access to information may be viewed as a weakness as compared to the management and oversight of entity forms other than trusts.

The owner of any Royalty Property may abandon any property, terminating the related Royalty.

The Working Interest Owners may at any time transfer all or part of the Royalty Properties to another unrelated third-party. Unit holders are not entitled to vote on any transfer, and the Trust will not receive any proceeds of any such transfer. Following any transfer, the Royalty Properties will continue to be subject to the Royalty, but the Net Proceeds from the transferred property would be calculated separately and paid by the transferee. The transferee would be responsible for all of the obligations relating to calculating, reporting and paying to the Trust the Royalty on the transferred portion of the Royalty Properties, and the current owner of the Royalty Properties would have no continuing obligation to the Trust for those properties.

The current Working Interest Owners or any transferee may abandon any well or property if it reasonably believes that the well or property can no longer produce in commercially economic quantities. This could result in termination of the Royalty relating to the abandoned well.

Generally, if production ceases from an outer continental shelf lease, like that for Eugene Island 339, production must be restored or drilling operations must commence within 180 days of the cessation (which was in early March 2009 with respect to Eugene Island 339 given the cessation of production in September 2008 resulting from Hurricane Ike), or the lease will be terminated. A lease operator may seek approval from the regional supervisor of the MMS to allow additional time to restore production. Chevron has submitted such a request with respect to Eugene Island 339. Chevron has informed the Corporate Trustee that Chevron presently intends to pursue the redevelopment of platforms and wells at Eugene Island 339 in accordance with the terms and conditions established by the MMS in response to Chevron's submission to the MMS of a program to restore production at Eugene Island 339. The activity schedule approved by the MMS contemplates, among other things, commencement of front-end engineering and design work by the end of January 2010, which was so commenced, completion of the front-end engineering and design work by the end of July 2010, an awarding of fabrication contracts for platform, substructure and equipment by the end of November 2010, and commencement of production ultimately occurring by the end of October 2012. Chevron is required to provide the MMS with periodic updates on Chevron's progress on such redevelopment. The approval by the MMS expires by its terms on November 30, 2010, and Chevron would need to request an extension of such approval from the MMS in order to complete the proposed redevelopment, given that the activity schedule contemplates activity through October 2012. The costs for such a redevelopment would be significant. While Chevron has stated that it intends to pursue such a redevelopment, there is no obligation for Chevron to continue to pursue such redevelopment. Failure or inability to pursue such a redevelopment, and on the timeframes approved by the MMS, could result in a loss of the lease. At this time, there can be no assurance that production will be restored at Eugene Island 339. For a more complete description of Chevron's current plans for the restoration of production at Eugene Island 339, see "Management's Discussion and Analysis of Financial Condition and Results of Operation—Operations" under Item 7 of this Form 10-K.

The Royalty can be sold and the Trust can be terminated.

The Trust will be terminated and the Trustees must sell the Royalty if holders of a majority of the Units approve the sale or vote to terminate the Trust, or if the total future net revenues attributable to the Royalty, determined by the independent reserve engineer as of December 31 of the prior year, are less than $2 million. Following any such termination and liquidation, the net proceeds of any sale will be distributed to the Unit holders and Unit holders will receive no further distributions from the Trust. We cannot assure you that any such sale will be on terms acceptable to all Unit holders. For a more complete description of these matters, see "—Termination of the Trust" under Item 1 of this Form 10-K.

Trust assets are depleting assets and, if the Working Interest Owners or other operators of the Royalty Properties do not perform additional development projects, the assets may deplete faster than expected.

The Net Proceeds payable to the Trust are derived from the sale of depleting assets. Accordingly, the portion of the distributions to Unit holders attributable to depletion may be considered a return of capital. The reduction in proved reserve quantities is a common measure of depletion. Future maintenance and development projects on the Royalty Properties will affect the quantity of proved reserves. The timing and size of these projects will depend on the market prices of natural gas. If operators of the Royalty Properties do not implement additional maintenance and development projects, the future rate of production decline of proved reserves may be higher than the rate currently expected by the Trust. For federal income tax purposes, depletion is reflected as a deduction, which is dependent upon the purchase price of a Units. Please see the section entitled "—Description of the Units—Federal Income Tax Matters" under Item 1 of this Form 10-K.

Because the Net Proceeds payable to the Trust are derived from the sale of depleting assets, the portion of distributions to Unit holders attributable to depletion may be considered a return of capital as opposed to a return on investment. Distributions that are a return of capital will ultimately diminish the depletion tax benefits available to the Unit holders, which could reduce the market value of the Units over time. Eventually, properties underlying the Trust's Royalty will cease to produce in commercial quantities and the Trust will, therefore, cease to receive any distributions of Net Proceeds therefrom.

Unit holders have limited voting rights.

Voting rights as a Unit holder are more limited than those of stockholders of most public corporations. For example, there is no requirement for annual meetings of Unit holders or for an annual or other periodic re-election of the Trustees. Additionally, Unit holders have no voting rights in the Working Interest Owners. Unlike corporations which are generally governed by boards of directors elected by their equity holders, the Trust is administered by a Corporate Trustee and three Individual Trustees in accordance with the Trust Agreement and other organizational documents. The Trustees have extremely limited discretion in their administration of the Trust.

Unit holders have limited ability to enforce the Trust's rights against the current or future owners of the Royalty Properties.

The Trust Agreement and related trust law permit the Trustees and the Trust to sue the Working Interest Owners to compel them to fulfill the terms of the Conveyance of the Royalty. If the Trustees do not take appropriate action to enforce provisions of the Conveyance, the recourse of a Unit holder would likely be limited to bringing a lawsuit against the Trustees to compel the Trustees to take specified actions. Unit holders probably would not be able to sue the Working Interest Owners directly.

Item 1B. Unresolved Staff Comments.

There were no unresolved Securities and Exchange Commission comments as of December 31, 2009.

Item 2. Properties.

Reference is made to Item 1 of this Form 10-K.

Item 3. Legal Proceedings.

Currently, there are not any legal proceedings pending to which the Trust is a party or of which any of its property is the subject.

Item 4. [Reserved]

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PART II

Item 5. **Market for the Registrant's Common Equity, Related Stockholder Matters and Issuer Purchasers of Equity Securities.**

The Trust Units are traded on the Nasdaq SmallCap Market under the symbol "TELOZ". At March 26, 2010, the 4,751,510 Units outstanding were held by 1,879 Unit holders of record. The high and low sales price as reported by the Nasdaq SmallCap Market, and distributions for each quarter for the years ended December 31, 2009 and 2008, were as follows:

Quarter		High	Low	Distribution
2009:				
Fourth	&sbsp;	$ 5.60	$ 4.36	$ .000000
Third		5.75	3.75	.000000
Second		6.50	3.92	.000000
First		7.87	4.70	.000000
2008:				
Fourth		$ 18.64	$ 3.87	$ .155708
Third		26.63	13.72	1.151294
Second		42.87	20.60	.551272
First		25.98	13.80	.940552

See "Management's Discussion and Analysis of Financial Condition and Results of Operations—Operations" and Note 4 to Notes to Financial Statements under Item 8 of this Form 10-K for a discussion regarding uncertainty of distributions.

Item 6. **Selected Financial Data.**

	Year Ended December 31,				
	2009	2008	2007	2006	2005
Royalty income	$ 0	$ 14,451,252	$ 10,257,485	$ 2,510,936	$ 9,854,531
Distributable income	$ 0	$ 13,298,654	$ 9,311,113	$ 1,697,721	$ 9,239,617
Distributions per Unit	$ 0.000000	$ 2.798827	$ 1.959611	$ 0.357301	$ 1.944564
Total assets	$ 1,290,266	$ 3,004,478	$ 5,176,634	$ 3,375,093	$ 3,239,290

Item 7. **Management's Discussion and Analysis of Financial Condition and Results of Operation.**

On the last business day of each calendar quarter, the Working Interest Owners pay to the Partnership 25% of the Net Proceeds for the immediately preceding Quarterly Period. A Quarterly Period is each period of three months commencing on the first day of February, May, August and November. In turn, the Partnership distributes funds to its partners on the last business day of each calendar quarter. Cash distributions from the Trust are made in January, April, July and October of each year, and are payable to Unit holders of record as of the last business day of each calendar quarter. Thus, the cash conveyed to the Trust from the Royalty during the quarter ended December 31, 2009 substantially represents the revenues and expenses from the Royalty Properties from August through October 2009. The financial and operating information included in this Form 10-K for the 12 months ended December 31, 2009 represents financial and operating information with respect to the Royalty Properties for the months of November 2008 through October 2009. Similarly, the financial and operating information included in this Form 10-K for the 12 months ended December 31, 2008 represents financial and operating information with respect to the Royalty Properties for the months of November 2007 through October 2008. As such, the impact of Hurricane Ike is not fully reflected in the discussion of 2008 operations, as such discussion does not include a discussion of operations of the

Royalty Properties in November or December 2008. Similarly, the financial and operating information included in this Form 10-K for the 12 months ended December 31, 2007 represents financial and operating information with respect to the Royalty Properties for the months of November 2006 through October 2007. Income from the Royalty is recorded by the Trust on a cash basis, when it is received by the Trust from the Partnership.

Critical Accounting Policies

The financial statements of the Trust are prepared on the following basis:

(a) Royalty income is recorded when received, including the effect of overtaken or undertaken positions and negative or positive adjustments, by the Corporate Trustee on the last business day of each calendar quarter. In addition, Royalty income includes amounts related to funds deposited or released from the Special Cost Escrow account—see (c);

(b) Trust general and administrative expenses are recorded when paid, except for the cash reserved for future general and administrative expenses; and

(c) The funds deposited or released from the Special Cost Escrow account are recorded at the time of payment or receipt. The Special Cost Escrow account is an account of the Working Interest Owners and is not reflected in the financial statements of the Trust.

This manner of reporting income and expenses is considered to be the most meaningful because the quarterly distributions to Unit holders are based on net cash receipts received from the Working Interest Owners. The financial statements of the Trust differ from financial statements prepared in accordance with generally accepted accounting principles, because, under such principles, Royalty income and Trust general and administrative expenses for a quarter would be recognized on an accrual basis. In addition, amortization of the net overriding royalty interest, calculated on a units-of-production basis, is charged directly to Trust corpus since such amount does not affect distributable income.

The Trustees, including the Corporate Trustee, have no authority over, have not evaluated and make no statement concerning, the internal control over financial reporting of any of the Working Interest Owners.

Liquidity and Capital Resources

The Trust's source of capital is the Royalty Income received from its share of the Net Proceeds from the Royalty Properties. Total future net revenues attributable to the Partnership's interest in the Royalty were estimated at $13.1 million as of October 31, 2009. However, there are not likely to be sufficient Net Proceeds from the Royalty Properties for the Trust to make a regularly scheduled quarterly distribution to Unit holders for the foreseeable future. On October 7, 2008, the Trust announced that production from the two most significant oil and gas properties associated with the Trust had ceased following damage inflicted by Hurricane Ike in September 2008. As a result of the damage inflicted by Hurricane Ike, Net Proceeds will continue to be severely impacted by reduced production, from historical levels, and the amount of expenditures incurred that are associated with such damages, including the expenditures required to plug and abandon the wells on Eugene Island 339, and, as currently expected, to redevelop the facility at Eugene Island 339. Accordingly, there will not be sufficient Net Proceeds from the Royalty Properties to make distributions for some period of time in the future.

The platforms and wells on Eugene Island 339 were completely destroyed by Hurricane Ike. Chevron is working on the plugging and abandonment of the existing wells, clearing debris and otherwise dealing with the remaining infrastructure, which activities are not expected to be completed until the first quarter of 2012. Chevron has informed the Corporate Trustee that Chevron presently intends to pursue the redevelopment of platforms and wells at Eugene Island 339 in accordance with the terms and conditions established by the MMS in response to Chevron's submission to the MMS of a program to restore production at Eugene Island 339; however, there is no obligation for Chevron to pursue such redevelopment. The costs for such a redevelopment would be significant. Failure or inability to pursue such a redevelopment, and on the timeframes approved by the MMS, could result in a loss of the lease. At this time, there can be no assurance that production will be restored at Eugene Island 339. See "—Operations" below for a more detailed discussion of Eugene Island 339.

Production at Ship Shoal 182/183 ceased following damage inflicted by Hurricane Ike in September 2008. While the hurricane caused limited surface damage to the facilities at Ship Shoal 182/183, all of the wells at Ship Shoal 182/183 were shut-in following hurricane-related damage to a third-party transporter's natural gas pipeline. The third-party transporter's natural gas pipeline repairs were completed and gas sales at Ship Shoal 182/183 were restored on June 26, 2009. However, the pipeline was shut down in mid-September for additional repairs. Production sales for both oil and natural gas at Ship Shoal 182 and 183 were restored on October 8, 2009 following completion of such additional repairs. See "—Operations" below for a more detailed discussion of Ship Shoal 182/183.

In addition, production from West Cameron 643 and East Cameron 371 ceased following damage inflicted by Hurricane Ike in September 2008 to third-party transporters' pipelines. Chevron understands that the pipeline for West Cameron 643 is in the process of being restored, although such pipeline is not expected to be able to take production until at least the third quarter of 2010. At this point in time, there can be no assurance as to when, of if at all, production may be restored at West Cameron 643. The field operator for East Cameron 371 has reported to Chevron that a review of the remaining reserves for East Cameron 371 has been conducted, and that the wells at East Cameron 371 have been depleted. See "—Operations" below for a more detailed discussion of West Cameron 643 and East Cameron 371.

On December 19, 2008, the Trust announced its fourth quarter distribution of approximately $0.7 million, which was paid on January 9, 2009. Based on the damage caused by Hurricane Ike, the Trust's scheduled distribution for the fourth quarter of 2008 was severely negatively impacted, although there were funds available for distribution given that there was some production from Eugene Island 339 and Ship Shoal 182/183 in August and September 2008. On March 25, 2009, the Trust announced that there would be no trust distribution for the first quarter of 2009. Similarly, on June 26, 2009, September 25, 2009, December 23, 2009 and March 23, 2010, the Trust announced there would be no trust distributions for the second, third and fourth quarters of 2009 or the first quarter of 2010, respectively. There are not likely to be sufficient Net Proceeds from the Royalty Properties for the Trust to make a regularly scheduled quarterly distribution to Unit holders for the foreseeable future. As a result of the damage inflicted by Hurricane Ike, Net Proceeds will continue to be severely impacted by reduced production, from historical levels, and the amount of expenditures incurred that are associated with such damages, including the expenditures required to plug and abandon the wells on Eugene Island 339, and, as currently expected, to redevelop the facility at Eugene Island 339. Future Net Proceeds from the Royalty Properties will take into account the Trust's share of project costs and other related expenditures that are not covered by the insurance of the operators of the Royalty Properties. The Trust's net portion of the aggregate cost to plug and abandon the wells subject to the royalty on Eugene Island 339 is estimated to be approximately $13 million, $7.9 million of which had been incurred through December 31, 2009. If development and production costs of the Royalty exceed the proceeds of production from the Royalty Properties, the Trust will not receive Net Proceeds until future proceeds from production exceed the total of the excess costs plus accrued interest. As of December 31, 2009, development and production costs of the Royalty exceeded the proceeds of production from the Royalty Properties by approximately $5.5 million. Significant development and production costs will continue to be incurred as Eugene Island 339 is redeveloped. Development activities may not generate sufficient additional revenue to repay such costs. Accordingly, there will not be sufficient Net Proceeds from the Royalty Properties to make distributions for some period of time in the future. At this time, the ultimate outcome of these various matters cannot be determined. See "—Operations."

Future Net Proceeds will take into account the Trust's share of project costs and other related expenditures that are not covered by insurance of the operator of the Royalty Properties. If development and production costs of the Royalty exceed the proceeds of production from the Royalty Properties, the Trust will not receive Net Proceeds until future proceeds from production exceed the total of the excess costs plus accrued interest, at a rate equal to one-fourth of (i) one-half of one percent plus (ii) the median between the prime interest rate at the end of a quarterly period in which there are excess costs and the prime interest rate at the end of the preceding quarterly period, during the deficit period. Development activities may not generate sufficient additional revenue to repay the costs. As of December 31, 2009, development and production costs of the Royalty exceeded the proceeds of production from the Royalty Properties by approximately $5.5 million. Significant development and production costs will continue to be incurred as Eugene Island 339 is redeveloped. Accordingly, there may not be sufficient Net Proceeds to make a particular distribution.

Substantial uncertainties exist with regard to future oil and gas prices, which are subject to material fluctuations due to changes in production levels and pricing and other actions taken by major petroleum producing nations, as well as the regional supply and demand for gas, weather, industrial growth, conservation measures, competition, economic conditions generally and other variables.

In accordance with the provisions of the Trust Agreement, generally all Net Proceeds received by the Trust, net of Trust general and administrative expenses and any cash reserves established for the payment of contingent or future obligations of the Trust, are distributed currently to the Unit holders. In 1994, in anticipation of future periods when the cash received from the Royalty may not be sufficient for payment of Trust expenses, the Trust determined, in accordance with the Trust Agreement, to begin further increasing the Trust's cash reserve each quarter. In the first quarter of 1998, the Trust determined that the Trust's cash reserve was then sufficient to provide for future administrative expenses in connection with the winding up of the Trust. The Trust determined that a cash reserve equal to three times the average expenses of the Trust during each of the past three years was sufficient at such time to provide for future administrative expenses in connection with the winding up of the Trust.

The reserve amount at December 31, 2009 and 2008 was $1,263,080 and $2,233,291, respectively. However, given that there are not likely to be sufficient Net Proceeds from the Royalty Properties for the Trust to make distributions to Unit holders for the foreseeable future, the Trust may not have sufficient funds to pay the liabilities of the Trust in the future. As such, the Trustees may take certain actions, discussed below, permitted under the Trust Agreement. At this time, there can be no assurance that the Trust will have sufficient funds in the future to pay the liabilities of the Trust.

Pursuant to the terms of the Trust Agreement, the Trustees are authorized to borrow funds, and pledge the assets of the Trust to secure payments of such borrowings, in the event that cash on hand is not sufficient to pay the liabilities of the Trust. In the event that the Trustees borrow funds to pay the liabilities of the Trust, no further distributions will be made to the Unit holders until the indebtedness created by such borrowings has been paid in full.

The Trust Agreement further provides that, if necessary to provide for the payment of specific liabilities of the Trust then due, the Trustees may without a vote of the Unit holders (a) sell all or a portion of the Trust's interest in the Partnership or any other assets of the Trust for such cash consideration as the Trustees shall deem appropriate, (b) exercise their rights under the Partnership Agreement to dissolve the Partnership, or (c) cause a sale by the Partnership of the overriding royalty interest owned by the Partnership.

Operations

The following operational information has been based on information provided to the Corporate Trustee by Chevron as the Managing General Partner of the Partnership. The Trustees have no control over these operations or internal controls relating to this information.

During 2005, Hurricane Katrina and Hurricane Rita caused significant damage to various platforms and third-party transportation systems, which resulted in oil and gas production delays in the Royalty Properties. During 2006, several of the platforms and facilities on the Royalty Properties were restored, and by the third quarter of 2007 all but one of the platforms and facilities had been restored. One of the platforms and facilities on Eugene Island was destroyed from hurricanes in the third quarter of 2005 and was never restored.

The platforms and wells on Eugene Island 339 were completely destroyed by Hurricane Ike in September 2008. Crude oil revenues from Eugene Island 339 represented approximately 48% of the crude oil and condensate revenues for the Royalty Properties in 2007 and approximately 47% of such revenues for the nine months ended September 30, 2008. Eugene Island 339 contributed approximately 12% of the revenues from natural gas sales from the Royalty Properties in 2007 and approximately 41% of such revenues for the nine months ended September 30, 2008. Based on a prior year reserve study prepared by DeGolyer and MacNaughton, independent petroleum engineering consultants, Eugene Island 339 accounted for approximately 34% of the total future net revenues attributable to the Partnership's interest in the royalty as of October 31, 2007. Chevron is working on the plugging and abandonment of the existing wells, clearing debris and otherwise dealing with the remaining infrastructure, which activities are not expected to be completed until the first quarter of 2012. The Trust's net portion of the aggregate cost to plug and abandon the wells subject to the royalty on Eugene Island 339 is estimated to be approximately $13 million, $7.9 million of which had been incurred through December 31, 2009. Generally, if production ceases from an outer continental shelf lease, like that for Eugene Island 339, production must be restored or drilling operations must commence within 180 days of the cessation (which was in early March 2009 with respect to Eugene Island 339 given the cessation of production in September 2008 resulting from Hurricane Ike), or the lease will be terminated. A lease operator may seek approval from the regional supervisor of the MMS to allow additional time to restore production. Chevron has informed the Corporate Trustee that Chevron presently intends to pursue the redevelopment of platforms and wells at Eugene Island 339 in accordance with the terms and conditions established by the MMS in response to Chevron's submission to the MMS of a program to restore production at Eugene Island 339. The activity schedule approved by the MMS contemplates, among other things, commencement of front-end engineering and design work by the end of January 2010, which was so commenced, completion of the front-end engineering and design work by the end of July 2010, an awarding of fabrication contracts for platform, substructure and equipment by the end of November 2010, and commencement of production ultimately occurring by the end of October 2012. Chevron is required to provide the MMS with periodic updates on Chevron's progress on such redevelopment. The approval by the MMS expires by its terms on November 30, 2010, and Chevron would need to request an extension of such approval from the MMS in order to complete the proposed redevelopment, given that the activity schedule contemplates activity through October 2012. Chevron recently entered into an agreement with a third party for the redevelopment of Eugene Island Blocks 338 and 339. Chevron is the operator of Eugene Island Block 338; however, this property is not a Royalty Property. Three wells are planned to be commenced from a common open water location at Eugene 338 in the second quarter 2010. The information derived from these wells will be used, in part, to determine the size of the platform and topside facilities (production processing equipment) that are to cover both Eugene Island 338 and Eugene Island 339 as a common facility. If a platform is set, the current plan is to drill additional wells in Eugene Island 338 and Eugene Island 339. If Chevron determines that it is warranted, and the redevelopment plans are successful, first production at Eugene Island 339 is anticipated in the fourth quarter of 2012. Restoration of production at Eugene Island 338 and 339 is a complex process and cannot be assured at this time. If the initial three well drilling program is not successful, Chevron intends to reevaluate the redevelopment of Eugene Island 338 and 339. The costs for such a redevelopment would be significant. While Chevron has stated that it intends to pursue such a redevelopment, there is no obligation for Chevron to continue to pursue such redevelopment. Failure or inability to pursue such a redevelopment, and on the timeframes approved by the MMS, could result in a loss of the lease. At this time, there can be no assurance that production will be restored at Eugene Island 339.

Production at Ship Shoal 182/183 ceased following damage inflicted by Hurricane Ike in September 2008. While the hurricane caused limited surface damage to the facilities at Shop Shoal 182/183, all of the wells at Ship Shoal 182/183 were shut-in following hurricane-related damage to a third-party transporter's natural gas pipeline. Crude oil revenues from Ship Shoal 182/183 represented approximately 50% of the crude oil and condensate revenues for the Royalty Properties in 2007 and approximately 51% of such revenues for the nine months ended September 30, 2008. Ship Shoal 182/183 contributed approximately 77% of the revenues from natural gas sales from the Royalty Properties in 2007 and approximately 42% of such revenues for the nine months ended September 30, 2008. A limited volume of oil production was restored in November 2008. The volume of oil production that can be produced is limited by the amount of gas that is also produced by the oil wells. The third-party transporter's natural gas pipeline repairs were completed and gas sales at Ship Shoal 182/183 were restored on June 26, 2009. However, the pipeline was shut down in mid-September for additional repairs. Production sales for both oil and natural gas at Ship Shoal 182 and 183 were restored on October 8, 2009 following completion of such additional repairs.

In addition, production from West Cameron 643 and East Cameron 371 ceased following damage inflicted by Hurricane Ike in September 2008 to third-party transporters' pipelines. Chevron, as the Managing General Partner of the Partnership, understands that, as a result of the cessation of production at West Cameron 643 due to the damages inflicted by Hurricane Ike to a third-party transporter's pipeline, Hilcorp submitted to the MMS a program to restore production at West Cameron 643 and that such request has been granted. Chevron also understands that the pipeline for West Cameron 643 is in the process of being restored, although such pipeline is not expected to be able to take production until at least the third quarter of 2010. At this point in time, there can be no assurance as to when, or if at all, production may be restored at West Cameron 643. The field operator for East Cameron 371 has reported to Chevron that a review of the remaining reserves for East Cameron 371 has been conducted, and that the wells at East Cameron 371 have been depleted. At this time, the field operator at East Cameron 371 has not made a decision regarding field abandonment, including the related wells, equipment platforms and any field infrastructure.

In May 2007, the Trust engaged an independent oil and gas accounting firm for the purpose of reviewing the books and records of certain Working Interest Owners with respect to the Royalty Properties and the related payments to the Trust. As part of this audit review process, certain adjustments to revenues, production volumes, prices and capital expenditures have occurred, and references below to a prior period audit adjustment, or an audit of prior periods, refers to the audit described in this paragraph. We include discussions of audit adjustments in the comparison of years 2009 and 2008 because, as a result of such audit adjustments, certain of the Royalty Properties, including Eugene Island 339, have positive oil and gas volumes for 2009 (and the revenues associated therewith), despite there being no actual oil or gas production at such properties due to damages inflicted by Hurricane Ike in September 2008. The adjustments resulting from such audit review were completed in the second quarter of 2009.

Years 2009 and 2008

Royalty income decreased 100% from $14,451,252 in 2008 to $0 in 2009 because there were no positive Net Proceeds attributable to the Royalty Properties due to damages inflicted to the Royalty Properties by Hurricane Ike in September 2008.

For 2009, the Trust had undistributed net loss of $5,469,255. For 2008, the Trust had undistributed net loss of $33,169. Undistributed net loss represents the amount of development and production costs associated with the Royalty that exceed the proceeds of production from the Royalty Properties during the period. An undistributed net loss is carried forward and offset, in future periods, by positive proceeds earned by the related Working Interest Owner(s). The Trust will not receive Net Proceeds until future proceeds from production exceed the total of the excess costs plus applicable accrued interest. Undistributed net income represents positive Net Proceeds, generated during the respective period, but not distributed by the Working Interest Owners.

Volumes and dollar amounts discussed below represent amounts recorded by the Working Interest Owners unless otherwise specified.

Natural Gas and Gas Products

Natural gas revenues and gas products decreased 89% from $14,248,644 in 2008 to $1,538,011 in 2009, due primarily to decreases in production resulting from damages caused by Hurricane Ike in September 2008. Gas and gas products volumes decreased from 1,625,408 Mcf equivalents in 2008 to 296,309 Mcf equivalents in 2009. The revenues and volumes for 2009 reflect net credits of $808,484 in revenues and 127,711 Mcf of gas for prior period adjustments; the revenues and volumes for 2008 reflect a net debit associated with an audit of prior periods of $310,032 in revenues and a credit of 99,117 Mcf of gas. The average price received for natural gas decreased 42% from $8.45 per Mcf in 2008 to $4.90 Mcf in 2009. Prior to taking into account such adjustments to revenues and volumes, the average price received for natural gas would have been $9.43 per Mcf in 2008 and $3.55 per Mcf in 2009.

Crude Oil and Condensate

Crude oil and condensate revenues decreased 77% from $42,424,601 in 2008 to $9,564,082 in 2009, due primarily to decreases in production resulting from damages caused by Hurricane Ike in September 2008. Oil volumes decreased 63% from 421,958 barrels in 2008 to 158,137 barrels in 2009. The revenues and volumes for 2009 reflect a credit associated with an audit for prior periods for $224,511 in revenues and 311 barrels; the revenues and volumes for 2008 reflect a credit associated with an audit for prior periods for $225,823 in revenues and 24,573 barrels. The average price received for crude oil and condensate decreased 40% from $100.54 in 2008 to $60.48 in 2009. Prior to taking into account such adjustments to revenues and volumes, the average price received for crude oil and condensate would have been $106.19 per barrel in 2008 and $59.18 per barrel in 2009.

Operating and Capital Expenditures

Operating expenses paid by the Working Interest Owners increased 341% from $7,012,792 in 2008 to $30,944,828 in 2009, primarily as a result of well abandonment costs at Eugene Island 339 as a result of Hurricane Ike. Reflected in the operating expenses for 2009 are cost allocation refunds of a net aggregate of $115,253 for certain prior period adjustments. Reflected within the operating expenses are management fees to Chevron, as Managing General Partner of the Partnership, of $1,926,245 and $1,281,318 for 2008 and 2009, respectively.

Capital expenditures paid by the Working Interest Owners increased 286% from $228,959 in 2008 to $883,470 in 2009. The higher amount of capital expenditures during 2009 related primarily to repair of damages caused by Hurricane Ike in September 2008. Reflected within the capital expenditures line item for 2008 is a refund of $495,600 from the Working Interest Owners for certain prior period adjustments. Reflected in the capital expenditures for 2009 is a refund of $59,794 for certain prior period audit adjustments.

Special Cost Escrow Account

The special cost escrow account is an account of the Working Interest Owners, and it is described herein for information purposes only. The Conveyance provides for the reserve of funds for estimated future "Special Costs" of plugging and abandoning wells, dismantling platforms and other costs of abandoning the Royalty Properties, as well as for the estimated amount of future drilling projects and other capital expenditures on the Royalty Properties. As provided in the Conveyance, the amount of funds to be reserved is determined based on factors, including estimates of aggregate future production costs, aggregate future Special Costs, aggregate future net revenues and actual current net proceeds. Deposits into this account reduce current distributions and are placed in an escrow account and invested in short-term certificates of deposit. Such account is herein referred to as the "Special Cost Escrow" account. The Trust's share of interest generated from the Special Cost Escrow Account, $7,923 and $155,152 in 2009 and 2008, respectively, serves to reduce the Trust's share of allocated production costs. Special Cost Escrow funds will generally be utilized to pay Special Costs to the extent there are not adequate current Net Proceeds to pay such costs. Special Costs that have been paid are no longer included in the Special Cost Escrow calculation. Deposits to the Special Cost Escrow Account will generally be made when the balance in the Special Cost Escrow Account is less than 125% of future Special Costs and there is a Net Revenues Shortfall (a calculation of the excess of estimated future costs over estimated future net revenues pursuant to a formula contained in the Conveyance). When there is not a Net Revenues Shortfall, amounts in the Special Cost Escrow account will generally be released, to the extent that Special Costs have been incurred. Amounts in the Special Cost Escrow account will also be released when the balance in such account exceeds 125% of estimated future Special Costs. The discussion of the terms of the Conveyance and Special Cost Escrow account contained herein is qualified in its entirety by reference to the Conveyance itself, which is an exhibit to this Form 10-K and is available upon request from the Corporate Trustee.

Chevron, in its capacity as Managing General Partner of the Partnership, has advised the Trust that additional deposits to the Special Cost Escrow account may be required in future periods in connection with other production costs, other abandonment costs, other capital expenditures and changes to the estimates and factors described above. Such deposits could result in a significant reduction to Royalty income for the periods in which such deposits are made, including the possibility that no Royalty income would be received in such periods.

In 2009, no funds were released from or deposited into the Special Cost Escrow account. As of December 31, 2009, approximately $4,306,275 remained in the Special Cost Escrow Account. In 2008, the Working Interest Owners refunded a net amount to the Trust of $2,388,061 from the Special Cost Escrow Account. As of December 31, 2008, approximately $4,325,503 remained in the Special Cost Escrow Account. The net refund for 2008 was primarily due to a revision to the Special Cost Escrow Account related to the outside audit commenced by the Trust as discussed above. See "—Operations".

Summary By Property

Listed below is a summary of 2009 operations as compared to 2008 of the five principal Royalty Properties based on gross revenues generated during these periods combined.

Eugene Island 339

Eugene Island 339 crude oil revenues decreased $19,660,953, from $19,699,497 in 2008 to $38,544 in 2009, due to a decrease in crude oil production from 188,337 barrels in 2008 to 318 barrels in 2009. However, there was no actual crude oil production during 2009 and such crude oil revenues and production volumes are entirely from an audit adjustment made in the first quarter of 2009 and associated with a prior period. The oil revenues for 2008 reflect a $207,194 credit relating to an audit of prior periods. The average price of crude oil was $93.79 per barrel in 2008. Prior to taking into account such adjustments in 2008, the average crude oil price would have been $104.60 per barrel in 2008. Gas revenues decreased $4,012,672, from $4,182,903 in 2008 to $170,231 in 2009, due to a decrease in gas production from 435,583 Mcf in 2008 to 33,296 Mcf in 2009. However, there was no actual gas production during 2009 and such gas revenues and volumes are entirely from an audit adjustment made in the first quarter of 2009 and associated with a prior period. The gas revenues and volumes for 2008 reflect debits of $867,840 and 31,130 Mcf associated with an audit of prior periods. The average price received for natural gas during 2008 was $7.10 per Mcf . Prior to taking into account such adjustments in 2008, the average gas sales price realized in 2008 would have been $9.60 per Mcf. Capital expenditures decreased from $518,385 in 2008 to $246,729 in 2009. There were limited capital expenditures during the second, third and fourth quarter of 2009 and the capital expenditures in the 2008 primarily relate to repairs associated with a conversion to a water injector. Operating expenses increased from $2,868,686 in 2008 to $26,866,150 in 2009 due to well abandonment costs incurred as a result of Hurricane Ike.

Production from Eugene Island 339 ceased following damage inflicted by Hurricane Ike in September 2008, as the platforms and wells on Eugene Island 339 were completely destroyed. Chevron is working on the plugging and abandonment of the existing wells, clearing debris and otherwise dealing with the remaining infrastructure, which activities are not expected to be completed until the first quarter of 2012. Chevron has informed the Corporate Trustee that Chevron presently intends to pursue the redevelopment of platforms and wells at Eugene Island 339 in accordance with the terms and conditions established by the MMS in response to Chevron's submission to the MMS of a program to restore production at Eugene Island 339. At this point in time, there can be no assurance that production will be restored at Eugene Island 339. See "—Operations."

Ship Shoal 182/183

Ship Shoal 182/183 crude oil revenues decreased from $21,775,671 in 2008 to $9,052,477 in 2009, primarily due to a decrease in net crude oil production from 202,185 barrels in 2008 to 152,725 in 2009 and a decrease in average crude oil prices received. Included in the revenues and production for 2008 was a debit adjustment of $5,657 and 135 barrels associated with prior period adjustments. Average crude oil prices decreased from $107.70 per barrel in 2008 to $59.27 per barrel in 2009, excluding the immaterial audit adjustment made during 2008. Gas revenues decreased from $4,726,292 in 2008 to $1,160,602 in 2009. Gas production decreased from 508,781 Mcf in 2008, which included an upward adjustment of 44,360 Mcf and $347,713 in revenues relating to an audit of prior periods, to 233,142 Mcf in 2009. The revenues and volumes for 2009 reflect an audit adjustment made in the first quarter of 2009, which resulted in the recognition of $725,720 in gas revenues associated with 107,416 Mcf of gas from a prior period. The average natural gas sales price decreased from $9.29 per Mcf in 2008 to $3.46 in 2009, excluding the audit adjustment made during 2009. Capital expenditures increased from a balance of ($419,971) in 2008 to $556,872 in 2009 primarily due to a credit of $495,600 in 2008 related to an audit adjustment for prior periods. Operating expenses increased from $2,471,185 in 2008 to $3,076,853 in 2009 due to an increase in operating and repair costs related to damages inflicted by Hurricane Ike.

Production from Ship Shoal 182 and 183 ceased following damage inflicted by Hurricane Ike in September 2008. While Hurricane Ike caused limited surface damage to the facilities at Ship

Shoal 182/183, all of the wells at Ship Shoal 182/183 were shut-in following hurricane-related damage to a third-party transporter's natural gas pipeline. A limited volume of oil production was restored in November 2008. The volume of oil production that can be produced is limited by the amount of gas that is also produced by the oil wells. The third-party transporter's natural gas pipeline repairs were completed and gas sales at Ship Shoal 182/183 were restored on June 26, 2009. However, the pipeline was shut down in mid-September for additional repairs. Production sales for both oil and natural gas at Ship Shoal 182/183 were restored on October 8, 2009 following completion of such additional repairs. See "—Operations."

West Cameron 643

West Cameron 643 gas revenues decreased from $2,024,841 in 2008 to ($87,518) in 2009, due primarily to a decrease in gas volumes from 214,130 Mcf in 2008 to (13,001) Mcf in 2009. There was no gas production during 2009 and the revenues and volumes for 2009 are a result of debits to correct an error in revenue allocation in August 2008. Revenues and volumes for 2008 reflect credits of $200,133 and 28,402 Mcf related to an audit of prior periods. The average natural gas sales price during 2008 was $9.17 per Mcf. Prior to taking into account such adjustments in 2008, the average gas sales price realized in 2008 would have been $9.46 per Mcf. Operating expenses decreased from $1,233,887 in 2008 to $1,006,626 in 2009. Capital expenditures increased from $27,953 in 2008 to $135,291 in 2009, due primarily to work related to the installation of piping, fittings and valves.

Production from West Cameron 643 ceased following damage inflicted by Hurricane Ike in September 2008 to a third-party transporter's pipeline. The Managing General Partner of the Partnership understands that the pipeline for West Cameron 643 is in the process of being restored, although such pipeline is not expected to be able to take production until at least the third quarter of 2010. At this point in time, there can be no assurance as to when, or if at all, production may be restored at West Cameron 643. See "—Operations."

East Cameron 371

East Cameron 371 gas revenues decreased from $252,992 in 2008 to $0 in 2009 as a result of the field being shut-in following Hurricane Ike in September 2008. Gas volumes decreased from 32,463 Mcf in 2008 to 0 Mcf for 2009. The average gas sales price realized during 2008 was $7.79 per Mcf. Oil revenues decreased from $47,962 in 2008 to $0 in 2009 as a result of the field being shut-in. Production decreased from 531 barrels in 2008 to 0 barrels for in 2009. The average crude oil price was $90.26 per barrel in 2008. Capital expenditures were $0 in 2008 and 2009 and operating expenses decreased from $298,413 in 2008 to $0 in 2009 as a result of the field being shut-in.

Production from East Cameron 371 ceased following damage inflicted by Hurricane Ike in September 2008 to a third-party transporter's pipeline. The field operator for East Cameron 371 has reported to Chevron that a review of the remaining reserves for East Cameron 371 has been conducted, and that the wells at East Cameron 371 have been depleted. At this time, the field operator at East Cameron 371 has not made a decision regarding field abandonment, including the related wells, equipment platforms and any field infrastructure. See "—Operations."

South Timbalier 36/37

South Timbalier 36/37 oil revenues decreased from $592,068 in 2008 to $269,554 in 2009 primarily due to a decrease in realized prices and a four-day field shut-in related to compressor problems and equipment issues that have been repaired. There was a decrease in crude oil production from 5,802 barrels in 2008 to 4,859 barrels in 2009. The average crude oil price was $102.05 per barrel in 2008 compared to $55.48 per barrel in 2009. Gas revenues decreased from $110,111 in 2008 to $40,425 in 2009 primarily due to a decrease in realized prices and a four-day field shut-in related to compressor problems and equipment issues that have been repaired. There was an increase in natural gas volumes from 5,351 Mcf in 2008 to 9,024 Mcf in 2009. Gas volumes for 2008 reflect a debit of 4,870 Mcf related to revised volume allocations for the years 2004 through 2007 and a debit of 164 Mcf in 2009.] The average gas sales price realized was $9.58 per Mcf in 2008, excluding such adjustment, and $4.49 per Mcf in 2009. Capital expenditures decreased from $43,345 in 2008 to $(55,422) in 2009 after taking into account a $56,263 credit in 2009 for a prior period audit adjustment. Operating expenses decreased $145,073 from $140,510 in 2008 to $(4,563) in 2009 after taking into account a $36,992 credit in 2009 for a prior period audit adjustment.

Years 2008 and 2007

As stated above, the Trust engaged an outside auditor for the purpose of reviewing the books and records of certain Working Interest Owners with respect to the Royalty Properties and the related payments to the Trust. As a result of this process, certain adjustments resulted in an additional cash distribution to the Trust during the first quarter of 2008. These amounts were comprised of a one-time increase of approximately $31,716 in gas revenues, a one-time increase of approximately $43,287 in oil revenues, and a one-time credit of approximately $123,900 in capital expenditures. An additional $127,973 related to the outside audit was included in the second quarter 2008 distribution. An additional $141,709 related to the outside audit was included in the third quarter 2008 distribution. An additional credit adjustment of $352,317 related to the outside audit was made in the fourth quarter of 2008. During 2008, there were aggregate adjustments consisting of a $77,508 decrease in gas revenues, a $56,456 increase in oil revenues and a credit of $110,479 in capital expenditures.

Royalty income increased approximately 41% from $10,257,485 in 2007 to $14,451,252 in 2008 primarily due to an increase in gas revenues and crude oil and condensate revenues as discussed below.

For 2008, the Trust had undistributed net loss of $33,169. For 2007, the Trust had undistributed net loss of $9,297. Undistributed net loss represents the amount of development and production costs associated with the Royalty that exceed the proceeds of production from the Royalty Properties during the period. An undistributed net loss is carried forward and offset, in future periods, by positive proceeds earned by the related Working Interest Owner(s). The Trust will not receive Net Proceeds until future proceeds from production exceed the total of the excess costs plus applicable accrued interest. Undistributed net income represents positive Net Proceeds, generated during the respective period, but not distributed by the Working Interest Owners.

Volumes and dollar amounts discussed below represent amounts recorded by the Working Interest Owners unless otherwise specified.

Natural Gas and Gas Products

Natural gas revenues and gas products increased 21% from $11,820,973 in 2007 to $14,248,644 in 2008, partially offset by a slight decrease in natural gas and gas products volumes from 1,654,836 Mcf equivalents in 2007 to 1,625,408 Mcf equivalents in 2008. The average price received for natural gas increased 19% from $7.11 per Mcf in 2007 to $8.45 Mcf in 2008.

Crude Oil and Condensate

Crude oil and condensate revenues increased 12% from $37,732,678 in 2007 to $42,424,601 in 2008, due primarily to a 54% increase in the average price received for crude oil and condensate from $65.26 in 2007 to $100.54 in 2008. This increase was partially offset by a decrease of 27% in crude oil and condensate volumes from 578,159 barrels in 2007 to 421,958 barrels in 2008.

The decrease in crude oil and condensate volumes during 2008 was related in part to a three day field shut-in for repairs at Eugene Island 339 and to an entire production shut-in at Ship Shoal 182/183, platforms C and E, due to pipeline obstruction. Oil production ceased at Eugene Island 339 and Ship Shoal 182/183 in September 2008 after damages inflicted by Hurricane Ike.

Operating and Capital Expenditures

Operating expenses paid by the Working Interest Owners increased 6% from $6,598,909 in 2007 to $7,012,792 in 2008. The increase in operating expenses is primarily due to the increased production during 2008.

Capital expenditures paid by the Working Interest Owners decreased 87% from $1,716,676 in 2007 to $228,959 in 2008. The higher amount of capital expenditures during 2007 related primarily to damages caused by Hurricanes Rita and Katrina in 2005.

Special Cost Escrow Account

In 2008, the Working Interest Owners refunded a net amount to the Trust of $2,388,061 from the Special Cost Escrow Account. As of December 31, 2008, approximately $4,325,503 remained in the Special Cost Escrow Account. In 2007, the Working Interest Owners refunded a net amount to the Trust of $125,391 from the Special Cost Escrow Account. As of December 31, 2007, approximately $6,713,564 remained in the Special Cost Escrow Account. The net refund for 2008 compared to the net refund for 2007 was primarily due to a revision to the Special Cost Escrow Account related to the outside audit commenced by the Trust as discussed above. See "—Operations".

Summary By Property

Listed below is a summary of 2008 operations as compared to 2007 of the five principal Royalty Properties based on gross revenues generated during these periods combined.

Eugene Island 339

Eugene Island 339 crude oil revenues increased $1,519,790, from $18,179,707 in 2007 to $19,699,497 in 2008, primarily due to an increase in average price of crude oil received. The average price of crude oil increased from $63.22 per barrel in 2007 to $104.60 per barrel in 2008. This increase was partially offset by a decrease in crude oil production from 287,539 barrels in 2007 to 188,337 barrels in 2008. Gas revenues increased $2,960,096, from $1,222,807 in 2007 to $4,182,903 in 2008, primarily due to an increase in gas production from 194,633 Mcf in 2007 to 435,583 Mcf in 2008 as a result of completion in July 2007 of the pipeline connection to the sales point on the Eugene Island 361 platform. The average price received for natural gas increased from $6.28 per Mcf in 2007 to $9.60 per Mcf in 2008. Capital expenditures increased from $190,093 in 2007 to $518,385 in 2008 due to the conversion to a water injector. Operating expenses increased from $2,214,130 in 2007 to $2,868,686 in 2008 primarily due to increased production.

Production from Eugene Island 339 ceased following damage inflicted by Hurricane Ike in September 2008, as the platforms and wells on Eugene Island 339 were completely destroyed. At this point in time, there can be no assurance that production will restored at Eugene Island 339. See "—Operations."

Ship Shoal 182/183

Ship Shoal 182/183 crude oil revenues increased from $18,924,236 in 2007 to $21,775,671 in 2008, due to an increase in crude oil prices from $67.35 per barrel in 2007 to $107.70 per barrel in 2008. This increase was partially offset by a decrease in crude oil production from 280,996 barrels in 2007 to 202,185 barrels in 2008. This production decline is related in part to a three day field shut-in for repairs at Ship Shoal 182/183. Gas revenues decreased from $8,013,970 in 2007 to $4,726,292 in 2008 due to a decrease in gas volumes from 1,089,709 Mcf in 2007 to 508,781 Mcf in 2008. The decrease in gas volumes was due to a shut-in as a result of an obstructed pipeline and the natural decline of production. The average natural gas sales price increased from $7.35 per Mcf in 2007 to $9.29 per Mcf in 2008. Capital expenditures decreased from $701,753 in 2007 to ($419,971) in 2008 primarily due to an audit credit adjustment for prior periods. Operating expenses decreased from $3,204,308 in 2007 to $2,471,185 in 2008 due to decreased production during 2008.

Production from Ship Shoal 182 and 183 ceased following damage inflicted by Hurricane Ike in September 2008. While Hurricane Ike caused limited surface damage to the facilities at Ship Shoal 182/183, all of the wells at Ship Shoal 182/183 were shut-in following hurricane-related damage to a third-party transporter's natural gas pipeline. A limited volume of oil production was restored in November 2008, with an average rate of daily oil production from November 20, 2008 through January 31, 2009 of approximately 831 barrels per day. The volume of oil production that can be produced is limited by the amount of gas that is also produced by the oil wells. The third-party transporter's natural gas pipeline repairs were completed and gas sales at Ship Shoal 182/183 were restored on June 26, 2009. However, the pipeline was shut down in mid-September for additional repairs. Production sales for both oil and natural gas at Ship Shoal 182 and 183 were restored on October 8, 2009 following completion of such additional repairs. See "—Operations."

West Cameron 643

West Cameron 643 gas revenues increased from $802,575 in 2007 to $2,024,841 in 2008 due primarily to an increase in gas volumes from 126,971 Mcf in 2007 to 214,130 Mcf in 2008. The increase in gas volumes resulted from increased production for the last three quarters of 2008, compared to the last three quarters of 2007. The average natural gas sales price increased from $6.32 per Mcf in 2007 to $9.46 per Mcf in 2008. Operating expenses decreased from $942,457 in 2007 to $1,233,887 in 2008. Capital expenditures increased from $0 in 2007 to $27,953 in 2008.

Production from West Cameron 643 ceased following damage inflicted by Hurricane Ike in September 2008 to a third-party transporter's pipeline. The Managing General Partner of the Partnership understands that the pipeline for West Cameron 643 is in the process of being restored, although such pipeline is not expected to be able to take production until at least the third quarter of 2010. At this point in time, there can be no assurance as to when, or if at all, production may be restored at West Cameron 643. See "—Operations."

East Cameron 371

East Cameron 371 gas revenues increased from $150,500 in 2007 to $252,992 in 2008. Oil revenues increased from $30,164 in 2007 to $47,962 in 2008. Capital expenditures were $0 in 2007 and 2008 and operating expenses increased from $174,559 in 2007 to $298,413 in 2008.

Production from East Cameron 371 ceased following damage inflicted by Hurricane Ike in September 2008 to a third-party transporter's pipeline. The field operator for East Cameron 371 has reported to the Managing General Partner of the Partnership that a review of the remaining reserves for East Cameron 371 has been conducted, and that the wells at East Cameron 371 have been depleted. At this time, the field operator at East Cameron 371 has not made a decision regarding field abandonment, including the related wells, equipment platforms and any field infrastructure. See "—Operations."

South Timbalier 36/37

South Timbalier 36/37 oil revenues decreased from $595,442 in 2007 to $592,068 in 2008, due to a decrease in production from 9,229 barrels in 2007 to 5,802 barrels in 2008, offset by an increase in crude oil prices from $64.52 per barrel in 2007 to $102.05 per barrel in 2008. Capital expenditures decreased from $109,901 in 2007 to $43,345 in 2008. Operating expenses increased $78,730 from $61,780 in 2007 to $140,510 in 2008.

Production and Price Review

The following schedule provides a summary of the volumes and weighted average prices for crude oil and condensate and natural gas recorded by the Working Interest Owners for the Royalty Properties, as well as the Working Interest Owners' calculations of the Net Proceeds and Royalties paid to the Trust during the periods indicated. Net proceeds due to the Trust are calculated for each three month period commencing on the first day of February, May, August and November.

	Royalty Properties Year Ended December 31,(1)		
	2009	2008	2007
Crude oil and condensate (bbls)	158,137	421,958	578,159
Natural gas and gas products (Mcfe)	296,309	1,625,408	1,654,836
Crude oil and condensate average price, per bbl	$ 60.48	$ 100.54	$ 65.26
Natural gas average price, per Mcf (excluding gas products)	$ 4.90	$ 8.45	$ 7.11
Crude oil and condensate revenues	$ 9,564,082	$ 42,424,601	$ 37,732,678
Natural gas and gas products revenues	$ 1,538,011	$ 14,248,644	$ 11,820,973
Production expenses	(32,226,146)	(8,939,036)	(8,363,502)
Capital expenditures	(883,471)	(228,959)	(1,716,676)
Undistributed Net Loss (income)(2)	$ 21,898,918	$ 132,688	$ 37,226
Refund of/(Provision for) Special Cost Escrow	$ 108,606	$ 10,172,852	$ 1,523,341
Net Proceeds	$ —	$ 57,810,788	$ 41,034,042
Royalty interest	x25%	x25%	x25%
Partnership share	$ —	$ 14,452,697	$ 10,258,511
Trust interest	x99.99%	x99.99%	x99.99%
Trust share of Royalty Income(3)	$ —	$ 14,451,252	$ 10,257,485

(1) Amounts represent actual production for the 12-month period ended on October 31 of each year, respectively.

(2) Undistributed net loss represents the amount of development and production costs associated with the Royalty that exceed the proceeds of production from the Royalty Properties during the period. An undistributed net loss is carried forward and offset, in future periods, by positive proceeds earned by the related Working Interest Owner(s). The Trust will not receive Net Proceeds until future proceeds from production exceed the total of the excess costs plus applicable accrued interest. Undistributed net income represents positive Net Proceeds, generated during the respective period, but not distributed by the Working Interest Owners.

(3) See "Management's Discussion and Analysis of Financial Condition and Results of Operations—Operations" and Note 4 to the Notes to the Financial Statements under Item 8 of this Form 10-K for a discussion regarding uncertainty of distributions.

Off-Balance Sheet Arrangements

The Trust has no off-balance sheet arrangements.

Contractual Obligations

As of December 31, 2009, the Trust had no obligations or commitments to make future contractual obligations except for administrative fees owed to the Trustee pursuant to the Trust Agreement.

Item 7A. **Quantitative and Qualitative Disclosures About Market Risk**

The only assets of and sources of income to the Trust are cash and the Trust's interest in the Partnership, which is the holder of the Royalty. Consequently, the Trust is exposed to market risk associated with the Royalty from fluctuations in oil and gas prices. Reference is also made to Item 1 of this Form 10-K.

The Trust may borrow money to pay expenses of the Trust. Additionally, if development and production costs of the Royalty exceed the proceeds of production from the Royalty Properties, the Trust will not receive Net Proceeds until future proceeds from production exceed the total of the excess costs plus accrued interest, at a rate equal to one-fourth of (i) one-half of one percent plus (ii) the median between the prime interest rate at the end of a quarterly period in which there are excess costs and the prime interest rate at the end of the preceding quarterly period, during the deficit period. Consequently, the Trust will be exposed to interest rate market risk should it borrow money to pay expenses and to the extent that development and production costs of the Royalty exceed the proceeds of production from the Royalty Properties.

Item 8. **Financial Statements and Supplementary Data**

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Trustees and Unit Holders of
TEL Offshore Trust
Austin, Texas

We have audited the accompanying statements of assets, liabilities and trust corpus—modified cash basis of TEL Offshore Trust (the "Trust") as of December 31, 2009 and 2008, and the related statements of distributable income and changes in trust corpus—modified cash basis for each of the three years ended December 31, 2009. These financial statements are the responsibility of the Corporate Trustee. Our responsibility is to express an opinion on the financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by the trustee, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

As described in Note 3 to the financial statements, these financial statements were prepared on the modified cash basis of accounting, which is a comprehensive basis of accounting other than accounting principles generally accepted in the United States of America.

In our opinion, such financial statements present fairly, in all material respects, the assets, liabilities and trust corpus of TEL Offshore Trust as of December 31, 2009 and 2008, and its distributable income and changes in trust corpus for each of the three years ended December 31, 2009, on the comprehensive basis of accounting described in Note 3 to the financial statements.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Trust's internal control over financial reporting as of December 31, 2009, based on the criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated March 31, 2010 expressed an unqualified opinion on the Trust's internal control over financial reporting.

/s/ Deloitte & Touche LLP

Houston, Texas
March 31, 2010

TEL OFFSHORE TRUST

STATEMENTS OF ASSETS, LIABILITIES AND TRUST CORPUS

	December 31, 2009	December 31, 2008
Assets		
Cash and cash equivalents	$ 1,263,080	$ 2,973,140
Net overriding royalty interest in oil and gas properties, net of accumulated amortization of $28,240,469 and $28,236,317 at December 31, 2009 and 2008, respectively	27,186	31,338
Total assets	$ 1,290,266	$ 3,004,478
Liabilities and Trust Corpus		
Distribution payable to Unit holders	$ —	$ 739,849
Reserve for future Trust expenses	1,263,080	2,233,291
Trust corpus (4,751,510 Units of beneficial interest authorized and outstanding at December 31, 2009 and 2008)	27,186	31,338
Total liabilities and Trust corpus	$ 1,290,266	$ 3,004,478

STATEMENTS OF DISTRIBUTABLE INCOME

	Year Ended December 31, 2009	2008	2007
Royalty income	$ —	$ 14,451,252	$ 10,257,485
Interest income	1,334	37,422	77,565
	1,334	14,488,674	10,335,050
General and administrative expenses	(971,545)	(840,455)	(259,861)
Decrease (Increase) in reserve for future Trust expenses	970,211	(349,565)	(764,076)
Distributable income	—	13,298,654	9,311,113
Distributions per Unit (4,751,510 Units)	$ 0.000000	$ 2.798827	$ 1.959611

STATEMENTS OF CHANGES IN TRUST CORPUS

	Year Ended December 31, 2009	2008	2007
Trust corpus, beginning of year	$ 31,338	$ 40,197	$ 53,506
Distributable income	—	13,298,654	9,311,113
Distributions to Unit holders	—	(13,298,654)	(9,311,113)
Amortization of net overriding royalty interest	(4,152)	(8,859)	(13,309)
Trust corpus, end of year	$ 27,186	$ 31,338	$ 40,197

The accompanying notes are an integral part of these financial statements.

TEL OFFSHORE TRUST

NOTES TO FINANCIAL STATEMENTS

(1) Trust Organization and Provisions

Tenneco Offshore Company, Inc. ("Tenneco Offshore") created the TEL Offshore Trust ("Trust") effective January 1, 1983, pursuant to the Plan of Dissolution ("Plan") approved by Tenneco Offshore's stockholders on December 22, 1982. In accordance with the Plan, the TEL Offshore Trust Partnership ("Partnership") was formed in which the Trust owns a 99.99% interest and Tenneco Oil Company initially owned a .01% interest. In general, the Plan was effected by transferring an overriding royalty interest ("Royalty") equivalent to a 25% net profits interest in the oil and gas properties (the "Royalty Properties") of Tenneco Exploration, Ltd. located offshore Louisiana to the Partnership and issuing certificates evidencing units of beneficial interest in the Trust in liquidation and cancellation of Tenneco Offshore's common stock.

On January 14, 1983, Tenneco Offshore distributed units of beneficial interest ("Units") in the Trust to holders of Tenneco Offshore's common stock on the basis of one Unit for each common share owned on such date.

The terms of the Trust Agreement, dated January 1, 1983, provide, among other things, that:

(a) the Trust is a passive entity and cannot engage in any business or investment activity or purchase any assets;

(b) the interest in the Partnership can be sold in part or in total for cash upon approval of a majority of the Unit holders;

(c) the Trustees, as defined below, can establish cash reserves and borrow funds to pay liabilities of the Trust and can pledge the assets of the Trust to secure payments of the borrowings. At December 31, 2009, the reserve amount was $1,263,080;

(d) the Trustees will make cash distributions to the Unit holders in January, April, July and October of each year as discussed in Note 4; and

(e) the Trust will terminate upon the first to occur of the following events: (i) total future net revenues attributable to the Partnership's interest in the Royalty, as determined by independent petroleum engineers, as of the end of any year, are less than $2.0 million or (ii) a decision to terminate the Trust by the affirmative vote of Unit holders representing a majority of the Units. Future net revenues attributable to the Royalty were estimated at approximately $13.1 million (unaudited) as of October 31, 2009. Upon termination of the Trust, the Corporate Trustee will sell for cash all assets held in the Trust estate and make a final distribution to the Unit holders of any funds remaining, after all Trust liabilities have been satisfied.

The Trust is currently administered by The Bank of New York Mellon Trust Company, N.A., which succeeded JPMorgan Chase Bank, N.A. as the Corporate Trustee, effective October 2, 2006 pursuant to an agreement under which The Bank of New York acquired substantially all of the Corporate Trust business of JPMorgan Chase (formerly known as The Chase Manhattan Bank), and Daniel O. Conwill, IV, Gary C. Evans and Jeffrey S. Swanson ("Individual Trustees"), as trustees ("Trustees").

(2) Net Overriding Royalty Interest

The Royalty entitles the Trust to its share (99.99%) of 25% of the Net Proceeds attributable to the Royalty Properties. The Conveyance, dated January 1, 1983, provides that the Working Interest Owners will calculate, for each period of three months commencing the first day of February, May, August and November, an amount equal to 25% of the Net Proceeds from their oil and gas properties for the

(2) Net Overriding Royalty Interest (Continued)

period. Generally, "Net Proceeds" means the amounts received by the Working Interest Owners from the sale of minerals from the Royalty Properties less operating and capital costs incurred, management fees and expense reimbursements owing to the Managing General Partner of the Partnership, applicable taxes other than income taxes, and the Special Cost Escrow account. The Special Cost Escrow account is established for the future costs to be incurred to plug and abandon wells, dismantle and remove platforms, pipelines and other production facilities, and for the estimated amount of future capital expenditures on the Royalty Properties. Net Proceeds do not include amounts received by the Working Interest Owners as advance gas payments, "take-or-pay" payments or similar payments unless and until such payments are extinguished or repaid through the future delivery of gas.

As of October 9, 2001, Chevron Corporation merged with Texaco Inc. and the Royalty Properties owned by Texaco Exploration and Production Inc. ("TEPI") were assigned to Chevron U.S.A. Inc. ("Chevron") on May 1, 2002. Crude oil sales from the Chevron and TEPI properties added together accounted for approximately 98% of crude oil revenues from the Royalty Properties during 2009, and approximately 99% of crude oil revenues from the Royalty Properties during 2008 and 2007. Sales to Chevron Corporation accounted for 100% of total gas revenues from the Royalty Properties during 2009, and approximately 99% of total gas revenues from the Royalty Properties during 2008 and 2007.

The Trust's share of Royalty income was reduced by approximately $320,329, $481,561 and $441,148 in 2009, 2008 and 2007, respectively, for management fees paid to the Working Interest Owners as reimbursement for expenses incurred by them on behalf of the Trust. Such management fees were calculated as 3% of the Trust's share of the sum of revenues, production expenses and capital expenditures attributable to the Royalty Properties in each of the three years above.

(3) Basis of Accounting

The financial statements of the Trust are prepared on the following basis:

(a) Royalty income is recorded when received, including the effect of overtaken or undertaken positions and negative or positive adjustments, by the Corporate Trustee on the last business day of each calendar quarter. In addition, Royalty income includes amounts related to funds deposited or released from the Special Cost Escrow account—see (c);

(b) Trust general and administrative expenses are recorded when paid, except for the cash reserved for future general and administrative expenses; and

(c) The funds deposited or released from the Special Cost Escrow account are recorded at the time of payment or receipt. The Special Cost Escrow account is an account of the Working Interest Owners and is not reflected in the financial statements of the Trust.

This manner of reporting income and expenses is considered to be the most meaningful because the quarterly distributions to Unit holders are based on net cash receipts received from the Working Interest Owners. The financial statements of the Trust differ from financial statements prepared in accordance with generally accepted accounting principles, because, under such principles, Royalty income and Trust general and administrative expenses for a quarter would be recognized on an accrual basis. In addition, amortization of the net overriding royalty interest, calculated on a units-of-production basis, is charged directly to Trust corpus since such amount does not affect distributable income.

TEL OFFSHORE TRUST

NOTES TO FINANCIAL STATEMENTS (Continued)

(3) Basis of Accounting (Continued)

Cash and cash equivalents include all highly liquid short-term investments with original maturities of three months or less.

The changes in reserve for future Trust expenses includes both changes of amounts deemed necessary by the Trustees and related distributions, as well as amounts paid from the reserve during periods when the Trust has insufficient income to pay Trust expenses.

The Trust reviews net overriding royalty interests in oil and gas properties for possible impairment whenever events or circumstances indicate the carrying amount of the asset may not be recoverable. If there is an indication of impairment, the Trust prepares an estimate of future cash flows (undiscounted and without interest charges) expected to result from the use of the asset and its eventual disposition. If these cash flows are less than the carrying amount of the asset, an impairment loss is recognized to write down the asset to its estimated fair value. Preparation of estimated expected future cash flows is inherently subjective and is based on the Corporate Trustee's best estimate of assumptions concerning expected future conditions. There were no write downs taken in the periods presented.

The Special Cost Escrow account (see Note 5) is established for future costs to be incurred to plug and abandon wells, dismantle and remove platforms, pipelines and other production facilities, and for the estimated amount of future capital expenditures on the Royalty Properties. The funds held in the Special Cost Escrow account are not reflected in the financial statements of the Trust. However, funds deposited to or released from the Special Cost Escrow account are included in Royalty income.

The preparation of financial statements requires the Trustees to make use of estimates and assumptions that affect amounts reported in the financial statements as well as certain disclosures. Actual results could differ from those estimates.

The amount of cash distributions by the Trust is dependent on, among other things, the sales prices for oil and gas produced from the Royalty Properties and the quantities of oil and gas sold. It should be noted that substantial uncertainties exist with regard to future oil and gas prices, which are subject to material fluctuations due to changes in production levels and pricing and other actions taken by major petroleum producing nations, as well as the regional supply and demand for gas, weather, industrial growth, conservation measures, competition and other variables. The Trust does not enter into any hedging transactions on future production.

(4) Distributions to Unit Holders

In accordance with the provisions of the Trust Agreement, generally all Net Proceeds received by the Trust, net of Trust general and administrative expenses and any cash reserves established for the payment of contingent or future obligations of the Trust, are distributed currently to the Unit holders. These distributions are referred to as "distributable income". The amounts distributed are determined on a quarterly basis and are payable to Unit holders of record as of the last business day of each calendar quarter. However, cash distributions are made in January, April, July and October and include interest earned from the quarterly record date to the date of distribution.

Production ceased at Eugene Island 339 and Ship Shoal 182 and 183 following damages inflicted by Hurricane Ike in September 2008. Future Net Proceeds may take into account the Trust's share of project costs and other related expenditures that are not covered by insurance of the operator of the Royalty Properties. On December 19, 2008, the Trust announced its fourth quarter distribution of approximately $0.7 million, which was paid on January 9, 2009. The funds available for the

TEL OFFSHORE TRUST

NOTES TO FINANCIAL STATEMENTS (Continued)

(4) Distributions to Unit Holders (Continued)

fourth quarter distribution were severely negatively impacted by Hurricane Ike. On March 25, 2009, the Trust announced that there would be no trust distribution for the first quarter of 2009. Similarly, on June 26, 2009, September 25, 2009, December 23, 2009 and March 23, 2010, the Trust announced there would be no trust distributions for the second, third and fourth quarters of 2009 or the first quarter of 2010, respectively.

Set forth below are the quarterly distributions made by the Trust for 2009 and 2008.

	Distribution	
Quarter	2009	2008
Fourth	$ 0	$ 739,849
Third	0	5,470,387
Second	0	2,619,375
First	0	4,469,043

There are not likely to be sufficient Net Proceeds from the Royalty Properties for the Trust to make a regularly scheduled quarterly distribution to Unit holders for the foreseeable future. As a result of the damage inflicted by Hurricane Ike, Net Proceeds will continue to be severely impacted by reduced production, from historical levels, and the amount of expenditures incurred that are associated with such damages, including the expenditures required to plug and abandon the wells on Eugene Island 339, and, as currently expected, to redevelop the facility at Eugene Island 339. Future Net Proceeds from the Royalty Properties will take into account the Trust's share of project costs and other related expenditures that are not covered by the insurance of the operators of the Royalty Properties. The Trust's net portion of the aggregate cost to plug and abandon the wells subject to the royalty on Eugene Island 339 is estimated to be approximately $13 million, $7.9 million of which had been incurred through December 31, 2009. If development and production costs of the Royalty exceed the proceeds of production from the Royalty Properties, the Trust will not receive Net Proceeds until future proceeds from production exceed the total of the excess costs plus accrued interest. As of December 31, 2009, development and production costs of the Royalty exceeded the proceeds of production from the Royalty Properties by approximately $5.5 million. Significant development and production costs will continue to be incurred as Eugene Island 339 is redeveloped. Development activities may not generate sufficient additional revenue to repay such costs. Accordingly, there will not be sufficient Net Proceeds from the Royalty Properties to make distributions for some period of time in the future.

(5) Special Cost Escrow Account

The Special Cost Escrow is an account of the Working Interest Owners and it is described herein for informational purposes only. The Conveyance provides for reserving funds for estimated future "Special Costs" of plugging and abandoning wells, dismantling platforms and other costs of abandoning the Royalty Properties, as well as for the estimated amount of future drilling projects and other capital expenditures on the Royalty Properties. As provided in the Conveyance, the amount of funds to be reserved is determined based on certain factors, including estimates of aggregate future production costs, aggregate future Special Costs, aggregate future net revenues and actual current net proceeds. Deposits into this account reduce current distributions and are placed in an escrow account and invested in short-term certificates of deposit. Such account is herein referred to as the "Special Cost

TEL OFFSHORE TRUST

NOTES TO FINANCIAL STATEMENTS (Continued)

(5) Special Cost Escrow Account (Continued)

Escrow" account. The Trust's share of interest generated from the Special Cost Escrow account, approximately $7,923, $155,152 and $255,443 for 2009, 2008 and 2007, respectively, serves to reduce the Trust's share of allocated production costs. As of December 31, 2009, 2008 and 2007, approximately $4,306,275, $4,325,503 and $6,714,000, respectively, remained in the Special Cost Escrow account. Special Cost Escrow account funds will generally be utilized to pay Special Costs to the extent there are not adequate current net proceeds to pay such costs. Special Costs that have been paid are no longer included in the Special Cost Escrow calculation. Deposits to the Special Cost Escrow account will generally be made when the balance in the Special Cost Escrow account is less than 125% of estimated future Special Costs and there is a Net Revenues Shortfall (a calculation of the excess of estimated future costs over estimated future net revenues pursuant to a formula contained in the Conveyance). When there is not a Net Revenues Shortfall, amounts in the Special Cost Escrow account will generally be released, to the extent that Special Costs have been incurred. Amounts in the Special Cost Escrow account will also be released when the balance in such account exceeds 125% of future Special Costs.

The discussion of the terms of the Conveyance and Special Cost Escrow Account contained herein is qualified in its entirety by reference to the Conveyance.

Deposits to the Special Cost Escrow Account may be required in future periods in connection with other production costs, other abandonment costs, other capital expenditures and changes in the estimates and factors described above. Such deposits could result in a significant reduction in Royalty income in the periods in which such deposits are made.

In 2009, there were no funds released from or deposited into the Special Cost Escrow account. In 2008, the Working Interest Owners refunded a net amount of approximately $2,388,061 from the Special Cost Escrow Account. In 2007, the Working Interest Owners refunded a net amount of approximately $125,391 from the Special Cost Escrow Account. The net deposits were made primarily due to changes in the estimate of projected capital expenditures, production costs and abandonment costs of the Royalty Properties.

(6) Reserve For Future Trust Expenses

The Trust made a determination in 1998 to maintain a cash reserve equal to approximately three times the average expenses of the Trust during each of the past three years to provide for future administrative expenses in connection with the winding up of the Trust. During 2009, the Trust decreased its reserve by $970,211, to pay current expenses, for a reserve balance of $1,263,080 as of December 31, 2009. The reserve amount at December 31, 2008 was $2,233,291.

Pursuant to the terms of the Trust Agreement, the Trustees are authorized to borrow funds, and pledge the assets of the Trust to secure payments of such borrowings, in the event that cash on hand is not sufficient to pay the liabilities of the Trust. In the event that the Trustees borrow funds to pay the liabilities of the Trust, no further distributions will be made to the Unit holders until the indebtedness created by such borrowings has been paid in full.

The Trust Agreement further provides that, if necessary to provide for the payment of specific liabilities of the Trust then due, the Trustees may without a vote of the Unit holders (a) sell all or a portion of the Trust's interest in the Partnership or any other assets of the Trust for such cash consideration as the Trustees shall deem appropriate, (b) exercise their rights under the Partnership

(6) Reserve For Future Trust Expenses (Continued)

Agreement to dissolve the Partnership, or (c) cause a sale by the Partnership of the overriding royalty interest owned by the Partnership.

(7) Federal Income Tax Matters

The IRS has ruled that the Trust is a grantor trust and that the Partnership is a partnership for federal income tax purposes. Thus, the Trust will incur no federal income tax liability and each Unit holder will be treated as owning an interest in the Partnership.

(8) Commitments and Contingencies

The Managing General Partner of the Partnership has advised the Trust that, although the Working Interest Owners believe that they are in general compliance with applicable health, safety and environmental laws and regulations that have taken effect at the federal, state and local levels, costs may be incurred to comply with current and proposed environmental legislation that could result in increased operating expenses on the Royalty Properties.

(9) Supplemental Reserve Information (Unaudited)

Estimates of the proved oil and gas reserves attributable to the Partnership's royalty interest are based on a reserve study prepared by DeGolyer and MacNaughton, independent petroleum engineering consultants. The reserve study prepared by DeGolyer and MacNaughton as of October 31, 2009 does not include reserves attributable to Eugene Island 339 or any capital expenditures for any redevelopment of Eugene Island 339. However, such reserve study does include the Trust's share of the estimated total plugging and abandonment costs related to Eugene Island 339, with costs to the Trust relating thereto estimated to be approximately $13 million. Estimates were prepared in accordance with guidelines established by the Securities and Exchange Commission and the Financial Accounting Standards Board. Accordingly, the estimates are based on existing economic and operating conditions in effect at October 31, 2009, with no provision for future increases or decreases except for periodic price redeterminations in accordance with existing gas contracts.

TEL OFFSHORE TRUST

NOTES TO FINANCIAL STATEMENTS (Continued)

(9) Supplemental Reserve Information (Unaudited) (Continued)

Estimated net proved reserves attributable to the net profits interest owned by the Partnership, as of October 31, 2009, are summarized as follows, expressed in barrels (bbl) and thousands of cubic feet (Mcf):

	Oil and Condensate (bbl)	Natural Gas (Mcf)
Proved Developed Reserves(1)		
Reserves as of October 31, 2008(2)	219,142	1,387,152
Revisions of Previous Estimates	(53,050)	(477,499)
Improved Recovery	0	0
Purchases of Minerals in Place	0	0
Extensions, Discoveries, and Other Additions	0	0
Production(3)	(28,628)	(41,148)
Sales of Minerals in Place	0	0
Reserves as of October 31, 2009(4)	137,464	868,505

(1) There are no proved undeveloped reserves for the Royalty Properties.

(2) Estimated Eugene Island 339 abandonment costs were not included.

(3) Production was estimated based on the ratio as of October 31, 2008, of the Partnership's net profits interest in net reserves to the net reserves associated with the Partnership's net profits interest and the interests retained in the Royalty Properties by the Working Interest Owners. This ratio was then applied to the production net to the combined interests of the Partnership and the Working Interest Owners for the period from November 1, 2008, through October 31, 2009.

(4) Estimated Eugene Island 339 abandonment costs were included

On October 7, 2008, the Trust announced that production from the two most significant oil and gas properties associated with the Trust had ceased following damage inflicted by Hurricane Ike in September 2008. The platforms and wells on Eugene Island 339 were completely destroyed by the hurricane. Chevron has informed the Corporate Trustee that Chevron presently intends to pursue the redevelopment of the platforms and wells at Eugene Island 339 in accordance with the terms and conditions established by the Mineral Management Service (the "MMS") in response to Chevron's submission to the MMS of a program to restore production at Eugene Island 339. Chevron recently entered into an agreement with a third party for the redevelopment of Eugene Island Blocks 338 and 339. Chevron is the operator of Eugene Island Block 338; however, this property is not a Royalty Property. Three wells are planned to be commenced from a common open water location at Eugene 338 in the second quarter 2010. The information derived from these wells will be used, in part, to determine the size of the platform and topside facilities (production processing equipment) that are to cover both Eugene Island 338 and Eugene Island 339 as a common facility. If a platform is set, the current plan is to drill additional wells into Eugene Island 338 and Eugene Island 339. If Chevron determines that it is warranted, and the redevelopment plans are successful, first production at Eugene Island 339 is anticipated in the fourth quarter of 2012. Restoration of production at Eugene Island 338 and 339 is a complex process and cannot be assured at this time. If the initial three well drilling program is not successful, Chevron intends to reevaluate the redevelopment of Eugene

(9) Supplemental Reserve Information (Unaudited) (Continued)

Island 338 and 339. At this point in time, there can be no assurance as to how or when, or if at all, production may be restored at Eugene Island 339. Based on the reserve study of DeGolyer and MacNaughton for the oil and gas reserves attributable to the Partnership as of October 31, 2007, Eugene Island 339 accounted for approximately 34% of the total future net revenues attributable to the Partnership's interest in the Royalty as of October 31, 2007.

The reserve volumes and revenue values attributable to the Partnership's royalty interest were estimated from projections of reserves and revenue attributable to the combined interests consisting of the Partnership's royalty interest and the retained interest of the Working Interest Owners in the Royalty Properties. Net reserves attributable to the Partnership's royalty interest were estimated by allocating to the Partnership a portion of the estimated combined net reserves of the subject properties based on the ratio of the Partnership's interest in future net revenues to combined future gross revenues. Because the net reserve volumes attributable to the Partnership's royalty interest are estimated using an allocation of reserves based on estimates of future revenue, a change in prices or costs will result in changes in the estimated net reserves. Therefore, the estimated net reserves attributable to the Partnership's royalty interest will vary if different future price and cost assumptions are used. All reserves attributable to the Partnership's royalty interest are located in the United States. Total future net revenues attributable to the Partnership's interest in the Royalty were estimated at $13.1 million as of October 31, 2009 based on the reserve study of DeGolyer and MacNaughton.

The Partnership's share of gas sales can be recorded by the Working Interest Owner on the cash method of accounting or based on actual production. When revenues are reported based on actual production, there is no gas imbalance created. Under the cash method, revenues are recorded based on actual gas volumes sold, which could be more or less than the volumes the Working Interest Owners are entitled to based on their ownership interests. The Partnership's Royalty income for a period reflects the actual gas sold during the period.

Distributable income for the Partnership for the periods ended December 31, 2009, 2008 and 2007 included Net Proceeds relating to production of reserves from the Royalty Properties for the twelve months ended October 31, 2009, 2008 and 2007, respectively.

(10) Related Party Transactions

Each of the Working Interest Owners owns interests, for its own account, in leases that are in the same area as leases in which the Partnership has acquired or may acquire an interest. Such relationships may give rise to potential conflicts of interests in, among other things, the operation of such leases and in the acquisition and operation of any drainage leases acquired by a Working Interest Owner for its own account. Additionally, the Working Interest Owners and their affiliates are not prohibited from purchasing oil and gas produced from or attributable to any leases in which the Partnership has an interest.

Crude oil sales to Chevron Corporation accounted for approximately 98% of total crude oil revenues from the Royalty Properties during 2009, and approximately 99% of total crude oil revenues from the Royalty Properties during 2008 and 2007. During the year ended December 31, 2009, 100% of Chevron's natural gas and natural gas liquids relative to the Trust's Royalty Properties were committed and sold to Chevron Natural Gas at spot market prices. During the years ended December 31, 2008 and 2007, approximately 99% of Chevron's natural gas and natural gas liquids relative to the Trust's Royalty Properties were committed and sold to Chevron Natural Gas at spot market prices.

TEL OFFSHORE TRUST

NOTES TO FINANCIAL STATEMENTS (Continued)

(10) Related Party Transactions (Continued)

The Trust's share of Royalty income was reduced by approximately $320,000, $482,000 and $441,000 in 2009, 2008 and 2007, respectively, for management fees paid to the Working Interest Owners as reimbursement for expenses incurred by them on behalf of the Trust. The aggregate amount of management fees paid to the Working Interest Owners was calculated as 3% of the Trust's share of the sum of revenues, production expenses and capital expenditures attributable to the Royalty Properties in 2009, 2008 and 2007.

(11) Subsequent Events

On March 23, 2010, the Trust issued a press release announcing that there would be no trust distribution for the first quarter of 2010 for unitholders of record on March 31, 2010.

(12) Selected Quarterly Financial Data (Unaudited)

Summarized quarterly financial data is as follows:

	First	Second	Third	Fourth
2009:				
Royalty income	$ 0	$ 0	$ 0	$ 0
Distributable income	$ 0	$ 0	$ 0	$ 0
Distributions per Unit	$ 0.000000	$ 0.000000	$ 0.000000	$ 0.000000
2008*:				
Royalty income	$ 5,067,521	$ 2,750,990	$ 5,627,452	$ 1,005,289
Distributable income	$ 4,469,043	$ 2,619,375	$ 5,470,387	$ 739,849
Distributions per Unit	$ 0.940552	$ 0.551272	$ 1.151294	$ 0.155708

* Royalty income and distributable income were decreased or increased in certain quarters due to deposits to or releases from the Special Cost Escrow Account as discussed in Note 5 above.

See Note 4 for a discussion regarding uncertainty of distributions.

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Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure.

None.

Item 9A. Controls and Procedures.

Evaluation of disclosure controls and procedures.

The Corporate Trustee maintains disclosure controls and procedures designed to ensure that information to be disclosed by the Trust in the reports that it files or submits under the Securities Exchange Act of 1934, as amended, is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and regulations. Disclosure controls and procedures include controls and procedures designed to ensure that information required to be disclosed by the Trust is accumulated and communicated by Chevron as the Managing General Partner of the Partnership, and the working interest owners to The Bank of New York Mellon Trust Company, N.A., as Corporate Trustee of the Trust, and its employees who participate in the preparation of the Trust's periodic reports as appropriate to allow timely decisions regarding required disclosure.

As of the end of the period covered by this report, the Corporate Trustee carried out an evaluation of the Trust's disclosure controls and procedures. Mike Ulrich, as Trust Officer of the Corporate Trustee, has concluded that the disclosure controls and procedures of the Trust are effective.

Due to the contractual arrangements of (i) the Trust Agreement, (ii) the Partnership Agreement and (iii) the rights of the Partnership under the Conveyance regarding information furnished by the working interest owners, the Trustees rely on (A) information provided by the Working Interest Owners, including historical operating data, plans for future operating and capital expenditures, reserve information and information relating to projected production, (B) information from the Managing General Partner of the Partnership, including information that is collected from the Working Interest Owners, and (C) conclusions and reports regarding reserves by the Trust's independent reserve engineers. See Item 1A. Risk Factors "—The Trustees and the Unit holders have no control over the operation or development of the Royalty Properties and have little influence over operation or development" in the Trust's Form 10-K and "Management's Discussion and Analysis of Financial Condition and Results of Operation" included in this Form 10-K, for a description of certain risks relating to these arrangements and reliance and applicable adjustments to operating information when reported by the Working Interest Owners to the Corporate Trustee and recorded in the Trust's results of operation.

Changes in Internal Control Over Financial Reporting

In connection with the evaluation by the Corporate Trustee of changes in internal control over financial reporting of the Trust, no change in the Trust's internal control over financial reporting was identified that has materially affected, or is reasonably likely to materially affect, the Trust's internal control over financial reporting.

Trustee's Annual Report on Internal Control over Financial Reporting

A registrant's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A registrant's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the registrant; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the registrant are being made

only in accordance with authorizations of management and directors of the registrant; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the registrants assets that could have a material effect on the financial statements.

The Corporate Trustee is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Rule 13a-15(f) promulgated under the Securities Exchange Act of 1934, as amended. The Corporate Trustee conducted an evaluation of the effectiveness of the Trust's internal control over financial reporting based on the criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on the Corporate Trustee's evaluation under the framework in *Internal Control—Integrated Framework*, the Corporate Trustee concluded that the Trust's internal control over financial reporting was effective as of December 31, 2009.

Deloitte & Touche, LLP, the Trust's independent registered public accounting firm that audited the financial statements included in this Form 10-K, has issued an attestation report on the effectiveness of the Trust's internal control over financial reporting.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

March 31, 2010

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Trustees and Unit Holders of
TEL Offshore Trust
Austin, Texas

We have audited the internal control over financial reporting of TEL Offshore Trust (the "Trust") as of December 31, 2009 based on criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Corporate Trustee is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Trustee's Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the Trust's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A trust's internal control over financial reporting is a process designed by, or under the supervision of, the trust's trustee, and effected by the Corporate Trustee and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with the comprehensive basis of accounting described in Note 3 to the financial statements. A trust's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the trust; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with the comprehensive basis of accounting described in Note 3 of the financial statements, and that receipts and expenditures of the trust are being made only in accordance with authorization of the Corporate Trustee; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the trust's assets that could have a material effect on the financial statements.

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper trustee override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the Trust maintained, in all material respects, effective internal control over financial reporting as of December 31, 2009, based on the criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the financial statements as of and for the year ended December 31, 2009 of the Trust and our report dated March 31, 2010 expressed an unqualified opinion on those financial statements and included an explanatory paragraph regarding the Trust's basis of accounting.

/s/ Deloitte & Touche LLP

Houston, Texas
March 31, 2010

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Item 9B. **Other Information.**

None.

PART III

Item 10. **Directors, Executive Officers and Corporate Governance.**

There are no directors or executive officers of the Registrant. The Trustees consist of a Corporate Trustee and three Individual Trustees. The Bank of New York Mellon Trust Company, N.A. serves as the Corporate Trustee, and Daniel O. Conwill, IV, Gary C. Evans and Jeffrey S. Swanson serve as the three Individual Trustees. Any Trustee may be removed by the affirmative vote of two Individual Trustees or by the affirmative vote of a majority of the Units at a meeting of Unit holders of beneficial interest in the Trust at which a quorum is present.

The Trust does not have a principal executive officer, principal financial officer, principal accounting officer or controller and, therefore, has not adopted a code of ethics applicable to such persons. However, employees of the Corporate Trustee must comply with the bank's code of ethics.

The Trust does not have a board of directors, and therefore does not have an audit committee, an audit committee financial expert, a compensation committee or a nominating committee.

Section 16(a) Beneficial Ownership Reporting Compliance.

The Trust has no directors or officers. Accordingly, only holders of more than 10% of the Trust's Units are required to file with the SEC initial reports of ownership of Units and reports of changes in such ownership pursuant to Section 16 under the Securities Exchange Act of 1934. Based solely on a review of these reports, the Trust believes that the applicable reporting requirements of Section 16(a) of the Securities Exchange Act of 1934 were complied with for all transactions that occurred in 2009.

Item 11. **Executive Compensation.**

During the year ended December 31, 2009, the Corporate Trustee received compensation from the Trust in an aggregate amount of $207,500. During the year ended December 31, 2009, each of the Individual Trustees received compensation from the Trust in an aggregate amount of $31,349. The Trust does not have any executive officers.

Item 12. **Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters.**

(a) *Security Ownership of Certain Beneficial Owners.*

The Trust has no officers or directors. Accordingly, only holders of more than 5% of the Trust's Units are required to file reports with the SEC on Schedule 13D or Schedule 13G and holders of 10% or more of the Trust's Units are required to file initial and other reports with the SEC pursuant to Section 16 of the Securities Exchange Act of 1934. Based solely on a review of reports, the Trust is not aware of such holders as of March 30, 2010.

(b) *Security Ownership of Management.*

Not applicable.

(c) *Changes in Control.*

The Trust knows of no arrangements, including the pledge of securities of the Trust, the operation of which may at a subsequent date result in a change in control of the Trust.

Item 13. **Certain Relationships and Related Transactions, and Director Independence.**

Each of the Working Interest Owners owns interests, for its own account, in leases that are in the same area as leases in which the Partnership has acquired or may acquire an interest. Such relationships may give rise to potential conflicts of interests in, among other things, the operation of such leases and in the acquisition and operation of any drainage leases acquired by a Working Interest Owner for its own account. Additionally, the Working Interest Owners and their affiliates are not prohibited from purchasing oil and gas produced from or attributable to any leases in which the Partnership has an interest.

Crude oil sales to Chevron Corporation accounted for approximately 98% of total crude oil revenues from the Royalty Properties during 2009, and approximately 99% of total crude oil revenues from the Royalty Properties during 2008 and 2007. During the year ended December 31, 2009, 100% of Chevron's natural gas and natural gas liquids relative to the Trust's Royalty Properties were committed and sold to Chevron Natural Gas at spot market prices. During the years ended December 31, 2008 and 2007, approximately 99% of Chevron's natural gas and natural gas liquids relative to the Trust's Royalty Properties were committed and sold to Chevron Natural Gas at spot market prices.

The Trust's share of Royalty income was reduced by approximately $320,000, $482,000 and $441,000 in 2009, 2008 and 2007, respectively, for management fees paid to the Working Interest Owners as reimbursement for expenses incurred by them on behalf of the Trust. The aggregate amount of management fees paid to the Working Interest Owners was calculated as 3% of the Trust's share of the sum of revenues, production expenses and capital expenditures attributable to the Royalty Properties in 2009, 2008 and 2007. Chevron, as the Managing General Partner of the Partnership, was paid a management fee of $1,281,318 for 2009 by the Partnership.

Item 14. **Principal Accountant Fees and Services.**

The Trust does not have an audit committee. Any pre-approval and approval of all services performed by the principal auditor or any other professional service firms and related fees are granted by the Trustees. The Trustees have appointed Deloitte & Touche, LLP, the member firm of Deloitte & Touche Tohmatsu, and their respective affiliates (collectively "Deloitte") as the independent registered public accounting firm to audit the trust's financial statements for the fiscal year ending December 31, 2010. During fiscal 2009, Deloitte served as the Trust's independent registered public accounting firm and also provided certain tax services.

The following table presents the aggregate fees billed to the Trust for the fiscal years ended December 31, 2009 and 2008 by Deloitte:

	2009	2008
Audit fees(1)	$ 210,000	$ 210,000
Audit-related fees	—	—
Tax fees(2)	9,050	10,500
All other fees	—	—
Total fees	$ 219,050	$ 220,500

(1) Fees for audit services in 2009 and 2008 consisted of the audit of the Trust's annual financial statements and reviews of the Trust's quarterly financial statements. Services in 2009 and 2008 also included the attestation on the effectiveness of the Trust's internal control over financial reporting.

(2) Fees for tax services billed in 2009 and 2008 consisted of tax compliance services.

PART IV

***Item 15.* Exhibits, Financial Statement Schedules.**

(a) (1) Financial Statements

The following financial statements are set forth under Part II, Item 8 of this Annual Report on Form 10-K on the pages as indicated:

(a) (2) Schedules

Schedules have been omitted because they are not required, not applicable or the information required has been included elsewhere herein.

(a) (3) Exhibits

(Asterisk indicates exhibit previously filed with the Securities and Exchange Commission and incorporated herein by reference. The Bank of New York Mellon Trust Company, N.A. succeeded JPMorgan Chase Bank as Corporate Trustee. JPMorgan Chase Bank is successor by mergers to the original corporate trustee, Texas Commerce Bank National Association.)

		SEC File or Registration Number	Exhibit Number
4(a)*	Trust Agreement dated as of January 1, 1983, among Tenneco Offshore Company, Inc., Texas Commerce Bank National Association, as corporate trustee, and Horace C. Bailey, Joseph C. Broadus and F. Arnold Daum, as individual trustees (Exhibit 4(a) to Form 10-K for year ended December 31, 1992 of TEL Offshore Trust)	0-6910	4(a)
4(b)*	Agreement of General Partnership of TEL Offshore Trust Partnership between Tenneco Oil Company and the TEL Offshore Trust, dated January 1, 1983 (Exhibit 4(b) to Form 10-K for year ended December 31, 1992 of TEL Offshore Trust)	0-6910	4(b)
4(c)*	Conveyance of Overriding Royalty Interests from Exploration I to the Partnership (Exhibit 4(c) to Form 10-K for year ended December 31, 1992 of TEL Offshore Trust)	0-6910	4(c)
4(d)*	Amendments to TEL Offshore Trust Agreement, dated December 7, 1984 (Exhibit 4(d) to Form 10-K for year ended December 31, 1992 of TEL Offshore Trust)	0-6910	4(d)
4(e)*	Amendment to the Agreement of General Partnership of TEL Offshore Trust Partnership, effective as of January 1, 1983 (Exhibit 4(e) to Form 10-K for year ended December 31, 1992 of TEL Offshore Trust)	0-6910	4(e)
10(a)*	Purchase Agreement, dated as of December 7, 1984 by and between Tenneco Oil Company and Tenneco Offshore II Company (Exhibit 10(a) to Form 10-K for year ended December 31, 1992 of TEL Offshore Trust)	0-6910	10(a)

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		SEC File or Registration Number	Exhibit Number
10(b)*	Consent Agreement, dated November 16, 1988, between TEL Offshore Trust and Tenneco Oil Company (Exhibit 10(b) to Form 10-K for year ended December 31, 1988 of TEL Offshore Trust)	0-6910	10(b)
10(c)*	Assignment and Assumption Agreement, dated November 17, 1988, between Tenneco Oil Company and TOC-Gulf of Mexico Inc. (Exhibit 10(c) to Form 10-K for year ended December 31, 1988 of TEL Offshore Trust)	0-6910	10(c)
10(d)*	Gas Purchase and Sales Agreement Effective September 1, 1993 between Tennessee Gas Pipeline Company and Chevron U.S.A. Production Company (Exhibit 10(d) to Form 10-K for year ended December 31, 1993 of TEL Offshore Trust)	0-6910	10(d)
31	Certification furnished pursuant to Section 302 of the Sarbanes-Oxley Act of 2002		
32	Certification furnished pursuant to Section 906 of the Sarbanes-Oxley Act of 2002		
99.1	Reserve Study of DeGolyer & MacNaughton		

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SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized on this 30th day of March, 2010.

TEL OFFSHORE TRUST

By: THE BANK OF NEW YORK MELLON TRUST COMPANY, N.A., Corporate Trustee

By: /s/ MIKE ULRICH

Mike Ulrich
Vice President

Signature	Date
THE BANK OF NEW YORK MELLON TRUST COMPANY, N.A., Corporate Trustee	
By: /s/ MIKE ULRICH Mike Ulrich, *Vice President & Trust Officer*	March 31, 2010
INDIVIDUAL TRUSTEES	
/s/ DANIEL O. CONWILL, IV Daniel O. Conwill, IV, *Individual Trustee*	March 31, 2010
/s/ GARY C. EVANS Gary C. Evans, *Individual Trustee*	March 31, 2010
/s/ JEFFREY S. SWANSON Jeffrey S. Swanson, *Individual Trustee*	March 31, 2010

The Registrant, TEL Offshore Trust, has no principal executive officer, principal financial officer, board of directors or persons performing similar functions. Accordingly, no additional signatures are available and none have been provided. In signing the report above, neither the Corporate Trustee nor the Individual Trustees imply that they perform any such function or that such function exists pursuant to the terms of the Trust Agreement under which they serve.

EXHIBIT D-5

Use these links to rapidly review the document
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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

(Mark One)

☒ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(D) OF THE SECURITIES EXCHANGE ACT OF 1934**

for the fiscal year ended December 31, 2010

or

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(D) OF THE SECURITIES EXCHANGE ACT OF 1934**

for the transition period from to

Commission File Number 0-6910

TEL OFFSHORE TRUST

(Exact name of registrant as specified in its charter)

Texas (State or other jurisdiction of incorporation or organization)	**76-6004064** (I.R.S. Employer Identification No.)
The Bank of New York Mellon Trust Company, N.A., Trustee **919 Congress Avenue** **Austin, Texas** (Address of principal executive offices)	**78701** (Zip Code)

Registrant's telephone number, including area code: **(800) 852-1422**

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Name of each exchange on which registered
None	None

Securities registered pursuant to Section 12(g) of the Act:

Units of Beneficial Interest
(Title of class)

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ☐ No ☒.

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes ☐ No ☒.

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the Registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☒ No ☐

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Website, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the proceeding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ☐ No ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§229.405 of this chapter) is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☒

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer ☐	Accelerated filer ☐	Non-accelerated filer ☒ (Do not check if a smaller reporting company)	Smaller reporting company ☐

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act). Yes ☐ No ☒

The aggregate market value of the 4,751,510 Units of Beneficial Interest in TEL Offshore Trust held by non-affiliates as of the last business day of the registrant's most recently completed second fiscal quarter was $8,362,658 based on a June 30, 2010 closing sales price of $1.76.

Indicate the number of shares outstanding of each of the registrant's classes of common stock, as of the latest practicable date.

As of March 30, 2011, there were 4,751,510 Units of Beneficial Interest in TEL Offshore Trust outstanding.

Documents Incorporated By Reference: None

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Note Regarding Forward-Looking Statements

This Form 10-K includes "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. All statements other than statements of historical facts included in this Form 10-K are forward-looking statements. Although the Managing General Partner of the Partnership (as defined below) has advised the Trust that the Managing General Partner believes that the expectations reflected in the forward-looking statements contained herein are reasonable, no assurance can be given that such expectations will prove to have been correct. Important factors that could cause actual results to differ materially from expectations ("Cautionary Statements") are disclosed in this Form 10-K, including without limitation in conjunction with the forward-looking statements included in this Form 10-K. Risks factors that may affect actual results and Trust distributions include, without limitation:

- The Trust's utilization of its cash reserves to pay expenses and the lack of net proceeds received by the Trust;
- Commodity price fluctuations;
- Uncertainty of estimates of oil and gas production;
- Uncertainty of future production and development costs;
- Operating risks for Working Interest Owners, including drilling and environmental risks;
- Delays and costs in connection with repairs and replacements of hurricane-damaged facilities and pipelines;
- Regulatory changes;
- Decisions by and at the discretion of Working Interest Owners not to perform additional development projects, not to replace hurricane-damaged facilities, or to abandon properties; and
- Uncertainties inherent in estimating proved oil and natural gas reserves and in projecting future rates of production and timing of development expenditures.

Should any event or circumstances contemplated by the risks or uncertainties described above or elsewhere in this Form 10-K occur, or should any material underlying assumptions prove incorrect, actual results may differ materially from future results expressed or implied by the forward-looking statements. All subsequent written and oral forward-looking statements attributable to the Trust or persons acting on its behalf are expressly qualified in their entirety by the Cautionary Statements. See "Item 1A—Risk Factors" below in this Form 10-K for a summary description of principal risk factors.

PART I

Item 1. Business.

DESCRIPTION OF THE TRUST

General

The TEL Offshore Trust, which we refer to herein as the "Trust", created under the laws of the State of Texas, maintains its offices at the office of The Bank of New York Mellon Trust Company, N.A., whom we refer to as the "Corporate Trustee", 919 Congress Avenue, Austin, Texas 78701. The telephone number of the Corporate Trustee is 1-800-852-1422. The Bank of New York Mellon Trust Company, N.A. succeeded JPMorgan Chase Bank, N.A. as the Corporate Trustee effective October 2, 2006 pursuant to an agreement under which The Bank of New York Mellon Trust Company acquired substantially all of JPMorgan Chase's corporate trust business. JPMorgan Chase Bank was formerly known as The Chase Manhattan Bank and is the successor by mergers to the original corporate trustee, Texas Commerce Bank National Association. Gary C. Evans, Thomas H. Owen, Jr. and Jeffrey S. Swanson serve as individual trustees of the Trust and are referred to herein as the "Individual Trustees". The Individual Trustees and the Corporate Trustee may be referred to hereinafter collectively as the "Trustees."

The Corporate Trustee does not maintain a website for filings by the Trust with the U.S. Securities and Exchange Commission, which we refer to herein as the "SEC". Electronic filings by the Trust with the SEC are available free of charge through the SEC's website at *www.sec.gov* and at *www.businesswire.com/cnn/tel-offshore.htm*.

The principal asset of the Trust consists of a 99.99% interest in the TEL Offshore Trust Partnership, which we refer to herein as the "Partnership". Chevron U.S.A., Inc., or "Chevron", owns the remaining .01% interest in the Partnership. The Partnership owns an overriding royalty interest, or "Royalty", equivalent to a 25% net profits interest, in certain oil and gas properties, which we refer to herein as the "Royalty Properties", located offshore Louisiana.

On October 31, 1986, Tenneco Exploration Ltd. ("Exploration I") was dissolved and the oil and gas properties of Exploration I were distributed to Tenneco Oil Company ("Tenneco") subject to the Royalty. Tenneco, who was then serving as the Managing General Partner of the Partnership, assumed the obligations of Exploration I, including its obligations under the instrument conveying the Royalty to the Partnership (the "Conveyance"). The dissolution of Exploration I had no impact on future cash distributions to holders of units of beneficial interest in the Trust.

On November 18, 1988, Chevron acquired most of the Gulf of Mexico offshore oil and gas properties of Tenneco, including all of the Royalty Properties. As a result of the acquisition, Chevron replaced Tenneco as the Working Interest Owner and Managing General Partner of the Partnership. Chevron also assumed Tenneco's obligations under the Conveyance.

On October 30, 1992, PennzEnergy Company ("PennzEnergy") (which merged with and into Devon Energy Production Company L.P. effective January 1, 2000) acquired certain oil and gas producing properties from Chevron, including four of the Royalty Properties. The four Royalty Properties acquired by PennzEnergy were East Cameron 354, Eugene Island 348, Eugene Island 367 and Eugene Island 208. As a result of such acquisition, PennzEnergy replaced Chevron as the Working Interest Owner of such properties on October 30, 1992. PennzEnergy also assumed Chevron's obligations under the Conveyance with respect to these properties.

On December 1, 1994, Texaco Exploration and Production Inc. ("TEPI") acquired two of the Royalty Properties from Chevron. The Royalty Properties acquired by TEPI were West Cameron 643 and East Cameron 371. As a result of such acquisitions, TEPI replaced Chevron as the Working Interest Owner of such properties on December 1, 1994. TEPI also assumed Chevron's obligations under the Conveyance with respect to these properties.

On October 1, 1995, SONAT Exploration Company ("SONAT") acquired the East Cameron 354 property from PennzEnergy. In addition, on October 1, 1995, Amoco Production Company ("Amoco") acquired the Eugene Island 367 property from PennzEnergy. As a result of such acquisitions, SONAT and Amoco replaced PennzEnergy as the Working Interest Owners of the East Cameron 354 and Eugene Island 367 properties, respectively, on October 1, 1995 and also assumed PennzEnergy's obligations under the Conveyance with respect to these properties.

Effective January 1, 1998, Energy Resource Technology, Inc. ("ERT") acquired the East Cameron 354 property from SONAT. As a result of such acquisition, ERT replaced SONAT as the Working Interest Owner of the East Cameron 354 property effective January 1, 1998, and also assumed SONAT's obligations under the Conveyance with respect to such property. In October 1998, Amerada Hess Corporation ("Amerada") acquired the East Cameron 354 property from ERT effective January 1, 1998. As a result of such acquisition, Amerada replaced ERT as the Working Interest Owner of the

East Cameron 354 property effective January 1, 1998, and also assumed ERT's obligations under the Conveyance with respect to this property.

Effective January 1, 2000, PennzEnergy and Devon Energy Corporation (Nevada) merged into Devon Energy Production Company L.P. ("Devon"). As a result of such merger, Devon replaced PennzEnergy as the Working Interest Owner of Eugene Island 348 and Eugene Island 208 properties effective January 1, 2000, and also assumed PennzEnergy's obligations under the Conveyance with respect to these properties. The abandonment obligations for Eugene Island 348 have been assumed by Maritech Resources, Inc. effective January 1, 2005.

On October 9, 2001, a wholly owned subsidiary of Chevron Corporation merged (the "Merger") with and into Texaco Inc. ("Texaco"), pursuant to an Agreement and Plan of Merger, dated as of October 15, 2000. As a result of the Merger, Texaco became a wholly owned subsidiary of Chevron Corporation, and Chevron Corporation changed its name to "ChevronTexaco Corporation" in connection with the Merger. Effective May 9, 2005, ChevronTexaco Corporation changed its name to Chevron Corporation. Accordingly, the properties referred to herein as controlled by Chevron and Texaco are each now controlled by subsidiaries of Chevron Corporation.

On May 1, 2002, TEPI assigned all of its interests in West Cameron 643 and East Cameron 371 to Chevron. Chevron sold its interest in East Cameron 371 to ERT effective July 1, 2007. On July 18, 2008, Chevron sold its interest in West Cameron 643 to Hilcorp Energy GOM, LLC ("Hilcorp"). Effective August 1, 2008, Hilcorp assumed operations, reporting and payment responsibilities for West Cameron 643.

On June 6, 2003, Anadarko Petroleum Corporation ("Anadarko") acquired, among other interests, a 25% Working Interest in the East Cameron 354 field subject to the Royalty from Amerada effective April 1, 2003. As a result of such transaction, Anadarko replaced Amerada as the Working Interest Owner of East Cameron 354 effective July 1, 2003 and also assumed Amerada's obligations under the Conveyance with respect to this property.

Effective October 1, 2004, Apache Corporation ("Apache") acquired Anadarko's interest in East Cameron 354 and assumed Anadarko's obligations under the Conveyance with respect to this property.

All of the Royalty Properties continue to be subject to the Royalty, and it is anticipated that the Trust and Partnership, in general, will continue to operate as if the above-described sales of the Royalty Properties had not occurred. Chevron, as the Managing General Partner of the Partnership, calculates the Net Proceeds (as defined below) from the Royalty Properties owned by Chevron and collects financial information relating to the other Royalty Properties from the Working Interest Owners other than Chevron for presentation to the Trust.

Unless the context in which such terms are used indicates otherwise, the terms "Working Interest Owner" and "Working Interest Owners" generally refer to the owner or owners of the Royalty Properties (Exploration I through October 31, 1986; Tenneco for periods from October 31, 1986 until November 18, 1988; Chevron with respect to all Royalty Properties for periods from November 18, 1988 until October 30, 1992, and with respect to all Royalty Properties except East Cameron 354, Eugene Island 348, Eugene Island 367 and Eugene Island 208 for periods from October 30, 1992 until December 1, 1994, and with respect to the same properties except West Cameron 643 thereafter; PennzEnergy/Devon with respect to East Cameron 354, Eugene Island 348, Eugene Island 367 and Eugene/Devon Island 208 for periods from October 30, 1992 until October 1, 1995, and with respect to Eugene Island 348 and Eugene Devon Island 208 thereafter; TEPI with respect to West Cameron 643 and East Cameron 371 for periods beginning on or after December 1, 1994 until May 1, 2002; SONAT with respect to East Cameron 354 for periods on or after October 1, 1995; Amoco with respect to Eugene Island 367 for periods beginning on or after October 1, 1995; Amerada with respect to East Cameron 354 for periods beginning on or after January 1, 1998 until July 1, 2003; Chevron with respect to West Cameron 643 on and after May 1, 2002 until August 1, 2008; Chevron with respect to East Cameron 371 on and after May 1, 2002 until July 1, 2007; Anadarko with respect to East Cameron 354 on and after July 1, 2003 until October 1, 2004, Apache with respect to East Cameron 354 after October 1, 2004; ERT with respect to East Cameron 371 on and after July 1, 2007; and Hilcorp with respect to West Cameron 643 on and after August 1, 2008).

As of March 30, 2011, a total of 4,751,510 units of beneficial interest in the Trust, which we refer to herein as "Units", were issued and outstanding. The Units traded on the Nasdaq Capital Market, or "NASDAQ", from August 31, 2001 through January 2, 2011. Previously the Units were traded on the OTC Bulletin Board and on the pink sheets. On January 3, 2011, the Units were suspended from trading by the NASDAQ and the Trust filed a Form 25 with the SEC to announce the voluntary delisting of the Units. In an effort to reduce expenses, the Trustees determined that it was in the best interest of the Trust to voluntarily delist the Units and to cause the Units to no longer be traded on the NASDAQ. Since January 3, 2011, the Units have been quoted on the OTCQB™ Marketplace, which is an electronic quotation service operated by Pink OTC Markets Inc. for securities traded over-the-counter. From inception of the Trust to December 31, 2010, distributions to Unit holders totaled approximately $138,742,000 or approximately $29.20 per Unit; however, the Trust had not made a distribution to Unit holders since January 9, 2009. See "Management's Discussion and Analysis of Financial Condition and Results of Operation—Liquidity and Capital Resources" in Item 7 of this Form 10-K and Note 4 to the Notes to Financial Statements under Item 8 of this Form 10-K for a discussion regarding uncertainties of the Trust's future distributions.

The terms of the TEL Offshore Trust Agreement, which we refer to herein as the "Trust Agreement", provide, among other things, that: (1) the Trust is a passive entity whose activities are generally limited to the receipt of revenues attributable to the Trust's interest in the Partnership and the distribution of such revenues, after payment of or provision for Trust expenses and liabilities, to the owners of the Units; (2) the Trustees may sell all or any part of the Trust's interest in the Partnership or cause the sale of all or any part of the Royalty by the Partnership with the approval of a majority of the Unit holders or if necessary to provide for the payment of liabilities of the Trust; (3) the Trustees can establish cash reserves and can borrow funds to pay liabilities of the Trust and can pledge the assets of the Trust to secure payment of such borrowings; (4) to the extent cash available for distribution exceeds liabilities or reserves therefore established by the Trust, the Trustees will cause the Trust to make quarterly cash distributions to the Unit holders in January, April, July and October of each year; and (5) the Trust will terminate upon the first to occur of the following events: (i) total future net revenues attributable to the Partnership's interest in the Royalty, as determined by independent petroleum engineers, as of the end of any year, are less than $2 million or (ii) a decision to terminate the Trust by the affirmative vote of Unit holders representing a majority of the Units. Total future net revenues attributable to the Partnership's interest in the Royalty were estimated at $19.8 million as of October 31, 2010 based on the reserve study of DeGolyer and MacNaughton, independent petroleum engineers. (See "Termination of the Trust" and Note 9 of the Notes to Financial Statements under Item 8 of this Form 10-K for further information regarding estimated future net revenues.) Upon termination of the Trust, the Trustees will sell for cash all the assets held in the Trust estate and make a final distribution to Unit holders of any funds remaining after all Trust liabilities have been satisfied.

The terms of the Agreement of General Partnership of the Partnership, which we refer to herein as the "Partnership Agreement," provide that the Partnership will dissolve upon the occurrence of any of the following: (1) December 31, 2030, (2) the election of the Trust to dissolve the Partnership, (3) the termination of the Trust, (4) the bankruptcy of the Managing General Partner of the Partnership, or (5) the dissolution of the Managing General Partner or its election to dissolve the Partnership; however, the Managing General Partner has agreed not to dissolve or to elect to dissolve the Partnership and will be liable for all damages and costs to the Trust if it breaches such agreement.

Under the Conveyance and the Partnership Agreement, the Trust is entitled to its share (99.99%) of 25% of the Net Proceeds, as hereinafter defined, realized from the sale of the oil, gas and associated hydrocarbons when produced from the Royalty Properties. See "Description of Royalty Properties." The Conveyance provides that the Working Interest Owners will calculate, for each quarterly period commencing the first day of February, May, August and November, an amount equal to 25% of the Net Proceeds from their oil and gas properties for the period. "Net Proceeds" means for each quarterly period, the excess, if any, of the Gross Proceeds, as hereinafter defined, for such period over Production Costs, as hereinafter defined, for such period. "Gross Proceeds" means the amounts received by the Working Interest Owners from the sale of oil, gas and associated hydrocarbons produced from the properties burdened by the Royalty, subject to certain adjustments. Gross Proceeds do not include amounts received by the Working Interest Owners as advance gas payments, "take-or-pay" payments or similar payments unless and until such payments are extinguished or repaid through the future delivery of gas. "Production Costs" means, generally, costs incurred on an accrual basis by the Working Interest Owners in operating the Royalty Properties, including capital and non-capital costs. In general, Net Proceeds are computed on an aggregate basis and consist of the aggregate proceeds to the Working Interest Owners from the sale of oil and gas from the Royalty Properties less (1) all direct costs, charges and expenses incurred by the Working Interest Owners in exploration, production, development, drilling and other operations on the Royalty Properties (including secondary recovery operations); (2) all applicable taxes (including severance and ad valorem taxes) excluding income taxes; (3) all operating charges directly associated with the Royalty Properties; (4) an allowance for costs, computed on a current basis at a rate equal to the prime rate of JPMorgan Chase Bank plus 0.5% on all amounts by which, and for only so long as, costs and expenses for the Royalty Properties incurred for any quarter have exceeded the proceeds of production from such Royalty Properties for such quarter; (5) applicable charges for certain overhead expenses as provided in the Conveyance; (6) the management fees and expense reimbursements owing the Working Interest Owners; and (7) a special cost reserve for the future costs to be incurred by the Working Interest Owners to plug and abandon wells and dismantle and remove platforms, pipelines and other production facilities from the Royalty Properties and for future drilling projects and other estimated future capital expenditures on the Royalty Properties. The Trustees are not obligated to return any Royalty income received in any period, but future amounts otherwise payable will be reduced by the amount of any prior overpayments of such Royalty income. The Working Interest Owners are required to maintain books and records sufficient to determine amounts payable under the Royalty. The Working Interest Owners are also required to deliver to the Managing General Partner on behalf of the Partnership a statement of the computation of Net Proceeds no later than the tenth business day prior to the quarterly record date.

The Trust's source of capital is the Royalty income received from its share of the Net Proceeds from the Royalty Properties. Total future net revenues attributable to the Partnership's interest in the Royalty were estimated at $19.8 million as of October 31, 2010. However, there are not likely to be sufficient Net Proceeds from the Royalty Properties for the Trust to make a regularly scheduled quarterly distribution to Unit holders for the foreseeable future. The Trust has not received a distribution of Net Proceeds since December 2008. Chevron offered to the Trustees in February 2011 that, based on then present production forecasts, the possibility of distributions being made to the Partnership would likely begin in 2013. However, there can be no assurance by Chevron or anyone else as to the actual timing for any future distributions to the Partnership from the Royalty, and distributions could recommence some time before, during or after 2013, and there is no guarantee that any further distributions will be made. Absent the receipt of Net Proceeds or other actions being taken, at some time in the early part of the second quarter of 2011, the Trust will not have sufficient funds to pay the liabilities of the Trust. As such, the Trustees may take certain actions, on behalf of the Trust as permitted under the Trust Agreement, that could materially impact the Unit holders. Such actions include the potential borrowing of funds, which may be secured by the Trust's assets, or the sale of all or a part of the Trust's interests in the Partnership or causing the Partnership to sell all or a part of the Royalty. On March 11, 2011, the Trustees provided written notice to Chevron that, pursuant to the Trust Agreement, the Trust needs funds to pay for liabilities of the Trust and that the Trustees therefore instructed Chevron, as the Managing General Partner of the Partnership, to sell such portion, and only such portion, of the Royalty that will provide the Trust with a current distribution equal to $2,000,000 from the proceeds of such sale. The Trustees are also seeking a loan to the Trust to be able to pay liabilities of the Trust. There can be no assurance that such a loan will be obtained or that such a sale of interests in the Royalty can be consummated or that $2,000,000 in proceeds can be obtained, or as to the terms, conditions and timing of such a loan or of the sale of interests in the Royalty. For more information, see "Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources" in Item 7 of this Form 10-K.

The Royalty Properties are required to be operated in accordance with standards applicable to a prudent oil and gas operator. The Working Interest Owners are free to transfer their working interest in any of the Royalty Properties (burdened by the Royalty) to third parties. The Working Interest Owners are also free to enter into farm-out agreements whereby a Working Interest Owner would transfer a portion of its interest (unburdened by the Royalty) while retaining a lesser interest (burdened by the Royalty) in return for the transferee's obligation to drill a well on the Royalty Properties. The Working Interest Owners have the right to abandon any well or lease, and upon termination of any lease, the part of the Royalty relating thereto will be extinguished. The Working Interest Owners are primarily the operators of the respective Royalty Properties although certain other parties are, and have also been, operators for the Royalty Properties.

The discussions of terms of the Trust Agreement, Partnership Agreement and Conveyance contained herein are qualified in their entirety by reference to the Trust Agreement, Partnership Agreement and Conveyance themselves, which are exhibits to this Form 10-K and are available upon request from the Corporate Trustee.

The Trust has no employees. Administrative functions of the Trust are performed by the Corporate Trustee.

History of the Trust

Tenneco Offshore Company, Inc. ("Tenneco Offshore") created the Trust effective January 1, 1983, pursuant to a Plan of Dissolution ("Plan"), which was approved by Tenneco Offshore's stockholders on December 22, 1982. In accordance with the Plan, the assets of Tenneco Offshore were transferred to the Trust as of January 1, 1983, and Units were exchanged for shares of common stock of Tenneco Offshore on the basis of one Unit for each share of common stock held by stockholders of record on January 14, 1983. Additionally, the Partnership was formed, in which the Trust owned a 99.99% interest and Tenneco initially owned a .01% interest. The Partnership was formed solely for the purpose of owning the Royalty, receiving the proceeds from the Royalty, paying the liabilities and expenses of the Partnership and disbursing remaining revenues to the Trust and the Managing General Partner of the Partnership in accordance with their interests. The Plan was effected by transferring an overriding royalty interest equivalent to a 25% net profits interest in the oil and gas properties of Exploration I located offshore Louisiana to the Partnership, contributing the common stock of Tenneco Offshore II Company to the Trust, and issuing certificates evidencing Units in liquidation and cancellation of Tenneco Offshore's common stock.

On October 31, 1986, Exploration I was dissolved and the oil and gas properties of Exploration I were distributed to Tenneco subject to the Royalty. Tenneco, who was then serving as the Managing General Partner of the Partnership, assumed the obligations of Exploration I, including its obligations under the Conveyance. The dissolution of Exploration I had no impact on future cash distributions to holders of units of beneficial interest.

As discussed above, on November 18, 1988, Chevron replaced Tenneco as the Working Interest Owner and Managing General Partner of the Partnership and assumed Tenneco's obligations under the Conveyance. On October 30, 1992, PennzEnergy acquired certain oil and gas producing properties from Chevron, including four of the Royalty Properties. The four Royalty Properties acquired by PennzEnergy were East Cameron 354, Eugene Island 348, Eugene Island 367 and Eugene Island 208. As a result of such acquisition, PennzEnergy replaced Chevron as the Working Interest Owner of such properties and assumed Chevron's obligations under the Conveyance with respect to such properties on October 30, 1992. On December 1, 1994, TEPI acquired two of the Royalty Properties from Chevron. The Royalty Properties acquired by TEPI were West Cameron 643 and East Cameron 371. As a result of such acquisition, TEPI replaced Chevron as the Working Interest Owner of such properties and assumed Chevron's obligations under the Conveyance with respect to such properties on December 1, 1994. On October 1, 1995, SONAT and Amoco acquired the East Cameron 354 and Eugene Island 367 properties, respectively, from PennzEnergy. As a result of such acquisitions, SONAT and Amoco replaced PennzEnergy as the Working Interest Owners of the East Cameron 354 and Eugene Island 367 properties, respectively, and also assumed PennzEnergy's obligations under the Conveyance with respect to such properties on October 1, 1995. Effective January 1, 1998 ERT acquired the East Cameron 354 property from SONAT. As a result of such acquisition, ERT replaced SONAT as the Working Interest Owner of the East Cameron 354 property and also assumed SONAT's obligations under the Conveyance with respect to this property effective January 1, 1998. In October 1998, Amerada acquired the East Cameron 354 property from ERT effective January 1, 1998. As a result of this acquisition, Amerada replaced ERT as the Working Interest Owner of the East Cameron 354 property effective January 1, 1998, and also assumed ERT's obligations under the Conveyance with respect to this property. Effective January 1, 2000, PennzEnergy and Devon Energy Corporation (Nevada) merged into Devon. As a result of such merger, Devon replaced PennzEnergy as the Working Interest Owner of the Eugene Island 348 and Eugene Island 208 properties effective January 1, 2000, and also assumed PennzEnergy's obligations under the Conveyance with respect to these properties. On October 9, 2001, a wholly owned subsidiary of Chevron Corporation merged with and into Texaco, pursuant to an Agreement and Plan of Merger, dated as of October 15, 2000. As a result of the Merger, Texaco Inc. became a wholly owned subsidiary of Chevron Corporation, and Chevron Corporation changed its name to "ChevronTexaco Corporation" in connection with the Merger. Accordingly, the properties referred to herein as controlled by Chevron and Texaco are each now controlled by subsidiaries of Chevron Corporation. Effective May 9, 2005, ChevronTexaco Corporation changed its name to Chevron Corporation. On May 1, 2002, TEPI assigned all of its interests in West Cameron 643 and East Cameron 371 to Chevron. Chevron sold its interest in East Cameron 371 to ERT effective July 1, 2007. Chevron sold its interests in West Cameron 643 to Hilcorp effective August 1, 2008. On June 6, 2003, Anadarko acquired, among other interests, a 25% Working Interest in the East Cameron 354 field, subject to the Royalty, from Amerada effective April 1, 2003. As a result of this transaction, Anadarko replaced Amerada as the Working Interest Owner of East Cameron 354 effective July 1, 2003 and also assumed Amerada's obligations under the Conveyance with respect to this property. Effective October 1, 2004, Apache acquired Anadarko's interest in East Cameron 354 and assumed Anadarko's obligations under the Conveyance with respect to this property.

DESCRIPTION OF THE UNITS

Each Unit is evidenced by a transferable certificate issued by the Corporate Trustee. Each unit ranks equally as to distributions, has one vote on any matter submitted to Unit holders and represents an undivided interest in the Trust, which in turn owns a 99.99% interest in the Partnership.

Distributions

The Trustees distribute the Trust's income pro rata for each calendar quarter within 10 days after the end of each calendar quarter. Distributions of the Trust's income are made to Unit holders of record on the Quarterly Record Date, which is the last business day of each quarterly period, or such later date as the Trustees determine is required to comply with legal requirements. The Trustees determine for each quarterly period the amount available for distribution. Such amount (the "Quarterly Income Amount") consists of the cash received from the Royalty during the quarterly period plus any other cash receipts of the Trust, less the obligations of the Trust paid during the quarterly period, and adjusted for changes made by the Trust during the quarter in any cash reserves established for the payment of contingent or future obligations of the Trust. In 1994, in anticipation of future periods when the cash received from the Royalty may not be sufficient for payment of Trust expenses, the Trust determined, in accordance with the Trust Agreement, to begin further increasing the Trust's cash reserve each quarter. In the first quarter of 1998, the Trust determined that the Trust's cash reserve was then sufficient to provide for future administrative expenses in connection with the winding up of the Trust. The Trust determined that a cash reserve equal to three times the average expenses of the Trust during each of the past three years was sufficient at such time to provide for future administrative expenses in connection with the winding up of the Trust. The reserve amount at December 31, 2010 and 2009 was $352,017 and $1,263,080, respectively. The Trust has not received a distribution from the Partnership for Net Proceeds since December 2008; thus, the Trust has not made a distribution to Unit holders since January 9, 2009. As described herein, there are not likely to be positive Net Proceeds from the Royalty Properties for the foreseeable future. Chevron offered to the Trustees in February 2011 that, based on then present production forecasts, the possibility of distributions being made to the Partnership would likely begin in 2013. However, there can be no assurance by Chevron or anyone else as to the actual timing for any future distributions to the Partnership from the Royalty, and distributions could recommence some time before, during or after 2013, and there is no guarantee that any further distributions will be made. Absent the receipt of Net Proceeds or other actions being taken, at some time in the early part of the second quarter of 2011, the Trust will not have sufficient funds to pay the liabilities of the Trust. See "Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources" in Item 7 of this Form 10-K.

Within 90 days of the close of each year, the net federal taxable income of the Trust for each quarterly period ending in such year is reported by the Trustees for federal tax purposes to the Unit holder of record to whom the Quarterly Income Amount was distributed.

Possible Requirement That Units Be Divested

The Trust Agreement imposes no restrictions based on nationality or other status of the persons or other entities who are eligible to hold Units. However, the Trust Agreement provides that if at any time the Trust or any of the Trustees are named as a party in any judicial or administrative or other governmental proceeding that seeks the cancellation or forfeiture of any interest in any property located in the United States in which the Trust has an interest because of the nationality or any other status of any one or more owners of Units, or if at any time the Trustees in their reasonable discretion determine that such a proceeding is threatened or likely to be asserted and the Trust has received an opinion of counsel stating that the party asserting or likely to assert the claims has a reasonable probability of succeeding in such claim, the following procedures will be applicable:

(a) The Trustees, in their discretion, may seek from an investment banking firm to be selected by the Trustees an opinion as to whether it is in the Trust's best interest for the Trustees to take the actions permitted by (b)(i) through (iii) below.

(b) The Trustees may take no action with respect to the potential cancellation or forfeiture or may seek to avoid such cancellation or forfeiture by the following procedure:

(i) The Trustees will promptly give written notice ("Notice") to each record owner of Units as to the existence of or probable assertion of such controversy. The Notice will contain a reasonable summary of such controversy, will include materials which will permit an owner of Units to promptly confirm or deny to the Trustees that such owner is a person whose nationality or other status is or would be an issue in such a proceeding ("Ineligible Holder") and will constitute a demand to each Ineligible Holder that he dispose of his Units, to a party who would not be an Ineligible Holder, within 30 days after the date of the Notice.

(ii) If an Ineligible Holder fails to dispose of his Units as required by the Notice, the Trustees will have the right to redeem and will redeem, during the 90 days following the termination of the 30-day period specified in the Notice, any Unit not so transferred for a cash price equal to the mean between the closing bid and ask prices of the Units in the over-the-counter market or, if the Units are then listed on a stock exchange, the closing price of the Units on the largest stock exchange on which the Units are listed, on the last business day prior to the expiration of the 30-day period stated in the Notice. The procedures for any such purchase are more fully described in the Trust Agreement. The Trustees will cancel any Units acquired in accordance with the foregoing procedures thereby increasing the proportionate interest in the Trust of other holders of Units.

(iii) The Trustees may, in their sole discretion, cause the Trust to borrow any amounts required to purchase Units in accordance with the procedures described above.

Liability of Unit Holders

It is the intention of the Working Interest Owners and the Trustees that the Trust be an "express trust" under the Texas Trust Act. Under Texas law, beneficiaries of an express trust are not personally liable for the obligations of the trust, even if the assets of the trust are insufficient to discharge its obligations. However, it is unclear under Texas law whether the Trust will be held to constitute an express trust and, if it is not held to be an express trust, whether the holders of Units would be jointly and severally liable for the obligations of the Trust as would general partners of a partnership.

With respect to sales certificates issued by the Federal Energy Regulatory Commission, which we refer to herein as the "FERC", although the FERC has the power to compel refunds, it has not compelled refunds from overriding royalty interest owners with respect to gas price overcharges. However, future laws, regulations or judicial decisions might permit the FERC or other governmental agencies to require such refunds from overriding royalty interest owners or create filing, reporting or certification obligations with respect to a trust created for such overriding royalty interest owners. Moreover, other parties, such as oil or gas purchasers, may be able to instigate private lawsuits or other legal action to compel refunds from overriding royalty interest owners with respect to oil or gas pricing overcharges.

The Working Interest Owners have agreed that they will not seek to recover from the Unit holders the amount of any refunds they are required to make, except out of future revenues payable to the Trust. The Trustees will be liable to the Unit holders if the Trustees allow any liability to be incurred without taking any and all action necessary to ensure that such liability will be satisfiable only out of the Trust assets (regardless of whether the assets are adequate to satisfy the liability) and will be non-recourse to the Unit holders. However, the Trustees will not be liable to the Unit holders for state or federal income taxes or for refunds, fines, penalties or interest relating to oil or gas pricing overcharges under state or federal price controls. The Trustees will be indemnified from the Trust assets, to the extent that the Trustees' actions do not constitute gross negligence, bad faith or fraud.

Each Unit holder should consider, in weighing the possible exposure to liability in the event the Trust were not classified as an express trust, (1) the substantial value and passive nature of the Trust assets, (2) the restrictions on the power of the Trustees to incur liabilities on behalf of the Trust and (3) the limited activities to be conducted by the Trustees.

Federal Income Tax Matters

This section is a summary of federal income tax matters of general application which addresses the material tax consequences of the ownership and sale of the Units. Except where indicated, the discussion below describes general federal income tax considerations applicable to individuals who are citizens or residents of the United States. Accordingly, the following discussion has limited application to domestic corporations and persons subject to specialized federal income tax treatment, such as regulated investment companies and insurance companies. It is impractical to comment on all aspects of federal, state, local and foreign laws that may affect the tax consequences of the transactions contemplated hereby and of an investment in the Units as they relate to the particular circumstances of every Unit holder. **Each Unit holder is encouraged to consult his own tax advisor with respect to his particular circumstances.**

This summary is based on current provisions of the Internal Revenue Code of 1986, as amended (the "Code"), existing and proposed Treasury Regulations thereunder and current administrative rulings and court decisions, all of which are subject to changes that may be retroactively applied. Some of the applicable provisions of the Code have not been interpreted by the courts or the Internal Revenue Service ("IRS"). No assurance can be provided that the statements set forth herein (which do not bind the IRS or the courts) will not be challenged by the IRS or will be sustained by a court if so challenged.

Classification of the Trust

The IRS has ruled that the Trust is a grantor trust and that the Partnership is a partnership for federal income tax purposes. Thus, the Trust will incur no federal income tax liability and each Unit holder will be treated as owning an interest in the Partnership.

The Trustees assume that some Units are held by a middleman as such term is broadly defined in applicable Treasury Regulations (and includes custodians, nominees, certain joint owners, and brokers holding an interest for a custodian in street name).

Therefore, the Trustees consider the Trust to be a non-mortgage widely held fixed investment trust ("WHFIT") for federal income tax purposes. The Corporate Trustee, 919 Congress Avenue, Austin, Texas 78701, telephone number 1-800-852-1422, is the representative of the Trust that will provide tax information in accordance with applicable Treasury Regulations governing the information reporting requirements of the Trust as a WHFIT. Notwithstanding the foregoing, the middlemen holding Units on behalf of Unit holders, and not the Trustees of the Trust, are solely responsible for complying with the information reporting requirements under the Treasury Regulations with respect to such Units, including the issuance of IRS Forms 1099 and certain written tax statements. Unit holders whose Units are held by middlemen should consult with such middlemen regarding the information that will be reported to them by the middlemen with respect to the Units.

Income and Depletion

Each Unit holder of record as of the last business day of each quarter will be allocated a share of the income and deductions of the Trust, including the Trust's share of the income and deductions of the Partnership, computed on an accrual basis, for that quarter. Royalty income is portfolio income. Since all income from the Partnership is Royalty income, this amount, net of depletion and severance taxes, is portfolio income and, subject to certain exceptions and transitional rules, this Royalty income cannot be offset by passive losses. Additionally, interest income is portfolio income. Administrative expense is an investment expense.

The IRS has also ruled that the Royalty is a non-operating economic interest giving rise to income subject to depletion. The Trustees will treat the Royalty as a single property giving rise to income subject to depletion, although the computation of depletion will be made by each Unit holder based upon information provided by the Trustees. Each Unit holder will be entitled to compute cost depletion with respect to his share of income from the Royalty based on his basis in the Royalty. A Unit holder will have a basis in the Royalty equal to the basis in his Units less any amount allocable to his share of any cash reserve account. Transferees of Units transferred after October 11, 1990, may be eligible to use the percentage depletion deduction on oil and gas income thereafter attributable to such Units, if the percentage depletion deduction would exceed cost depletion. Unlike cost depletion, percentage depletion is not limited to a Unit holder's depletable tax basis in the Units. Rather, a Unit holder may be entitled to a percentage depletion deduction as long as the Royalty generates gross income.

Backup Withholding

Distributions from the Trust are generally subject to backup withholding at a rate of 28% of these distributions. Backup withholding generally will not apply to distributions to a Unit holder unless the Unit holder fails to properly provide to the Trust his taxpayer identification number or the IRS notifies the Trust that the taxpayer identification number provided by the Unit holder is incorrect.

Sale of Units

Generally, except for recapture items, the sale, exchange or other disposition of a Unit will result in capital gain or loss measured by the difference between the tax basis in the Unit and the amount realized. Effective for property placed in service after December 31, 1986, the amount of gain, if any, realized upon the disposition of oil and gas property is treated as ordinary income to the extent of the intangible drilling and development costs incurred with respect to the property and depletion claimed with respect to the property to the extent it reduced the taxpayer's basis in the property. Under this provision, depletion attributable to a Unit acquired after 1986 will be subject to recapture as ordinary income upon disposition of the Unit or upon disposition of the oil and gas property to which the depletion is attributable. The balance of any gain or any loss will be capital gain or loss if the Unit was held by the Unit holder as a capital asset, either long-term or short-term depending on the holding period of the Unit. This capital gain or loss will be long-term if a Unit holder's holding period for the Unit exceeds one year at the time of sale or exchange. Capital gain or loss will be short-term if the Unit has not been held for more than one year at the time of sale or exchange. Under law as of March 30, 2011, long-term capital gain generally will be subject to a maximum U.S. federal income tax rate of 15%. The deductibility of capital losses are subject to certain limitations.

Non-U.S. Unit holders

In general, a Unit holder who is a nonresident alien individual or which is a foreign corporation, each a "non-U.S. Unit holder" for purposes of this discussion, will be subject to tax on the gross income (without taking into account any deductions, such as depletion) produced by the Royalty at a rate equal to 30%, or if applicable, at a lower treaty rate. This tax will be withheld by the Trustees and remitted directly to the United States Treasury. A non-U.S. Unit holder may elect to treat the income from the Royalty as effectively connected with the conduct of a United States trade or business under provisions of the Code, or pursuant to any similar provisions of applicable treaties. Upon making this election a non-U.S. Unit holder is entitled to claim all deductions with respect to that income, but he must file a United States federal income tax return to claim those deductions. This election once made is irrevocable, unless an applicable treaty allows the election to be made annually. However, that effectively connected taxable income is subject to withholding at the highest applicable tax rate, currently 35% for individual non-U.S. Unit holders.

The Code and the Treasury Regulations thereunder treat the publicly traded Trust as if it were a United States real property holding corporation. Accordingly, non-U.S. Unit holders may be subject to United States federal income tax on any gain from the disposition of their Units.

Federal income taxation of a non-U.S. Unit holder is a highly complex matter which may be affected by many other considerations. Therefore, each non-U.S. Unit holder is encouraged to consult its own tax advisor with respect to its ownership of Units.

Tax-exempt Organizations

Investments in publicly traded grantor trusts are treated the same as investments in partnerships for purposes of the rules governing unrelated business taxable income. Royalty income and interest income should not be unrelated business taxable income so long as, generally, a Unit holder did not incur debt to acquire a Unit or otherwise incur or maintain a debt that would not have been incurred or maintained if that Unit had not been acquired. Legislative proposals have been made from time to time which, if adopted, would result in the treatment of Royalty income as unrelated business taxable income. Each tax-exempt Unit holder is encouraged to consult its own tax advisor with respect to its ownership of Units and the treatment of Royalty income.

State Law Considerations

The Trust and the Partnership have been structured so as to cause the Units to be treated for certain state law purposes essentially the same as other securities, that is, as interests in intangible personal property rather than as interests in real property. However, in the absence of controlling legal precedent, there is a possibility that under certain circumstances a Unit holder could be treated as owning an interest in real property under the laws of Louisiana. In that event, the tax, probate, devolution of title and administration laws of Louisiana or other states applicable to real property may apply to the Units, even if held by a person who is not a resident thereof. Application of these laws could make the inheritance and related matters with respect to the Units substantially more onerous than had the Units been treated as interests in intangible personal property. Unit holders are encouraged to consult their legal and tax advisors regarding the applicability of these considerations to their individual circumstances.

Texas does not impose an income tax. Therefore, no part of the income produced by the Trust is subject to an income tax in Texas. However, Texas imposes a tax at a rate of 1% on gross revenues less certain deductions, as specifically set forth in the Texas franchise tax statute. Entities subject to tax generally include trusts unless otherwise exempt, and most other types of entities having limited liability protection. Trusts and partnerships that receive at least 90% of their federal gross income from designated passive sources, including royalties from mineral properties and other non-operated mineral interest income, and do not receive more than 10% of their income from operating an active trade or business, are generally exempt from the Texas franchise tax as "passive entities." The Trust should be exempt from Texas franchise tax as a "passive entity." Since the Trust should be exempt from Texas franchise tax at the Trust level as a passive entity, each Unit holder that is considered a taxable entity under the Texas franchise tax would generally be required to include its Texas portion of Trust revenues in its own Texas franchise tax computation. Each Unit holder is urged to consult its own tax advisor regarding its possible Texas franchise tax liability.

TERMINATION OF THE TRUST

The terms of the TEL Offshore Trust Agreement provide that the Trust will terminate upon the first to occur of the following events: (1) total future net revenues attributable to the Partnership's interest in the Royalty, as determined by independent petroleum engineers, as of the end of any year, are less than $2 million or (2) a decision to terminate the Trust by the affirmative vote of Unit holders representing a majority of the Units. Total future net revenues attributable to the Partnership's interest in the Royalty were estimated at $19.8 million as of October 31, 2010, based on the reserve study of DeGolyer and MacNaughton, independent petroleum engineers, discussed herein. Such reserve study does not include any reserves or volumes attributable to Eugene Island 339; however, it does include estimated costs of approximately $13 million, which represent the Partnership's percentage share of the total plugging and abandonment costs related to Eugene Island 339, and without giving credit for an expected approximately $612,000 of insurance proceeds received by Chevron and to be allocated for the benefit of the Partnership with respect to Eugene Island 339. Based on the DeGolyer and MacNaughton reserve study, as of October 31, 2010, it is estimated that approximately 66% of future net revenues from the Royalty Properties are expected to be generated during the next three years. Because the Trust will terminate in the event estimated future net revenues fall below $2.0 million, it would be possible for the Trust to terminate even though some or all of the Royalty Properties continued to have remaining productive lives. Upon termination of the Trust, the Trustees will sell for cash all of the assets held in the Trust estate and make a final distribution to Unit holders of any funds remaining after all Trust liabilities have been satisfied. The estimates of future net revenues discussed above are subject to the limitations described in the summary of the DeGolyer and MacNaughton reserve study included in Item 1 of this Form 10-K. The reserve study is limited to reserves classified as proved; therefore, future capital expenditures for recovery of reserves not classified as proved by DeGolyer and MacNaughton are not included in the calculation of estimated future net revenues, nor are any capital expenditures included for any redevelopment of Eugene Island 339. In addition, the estimates of future net revenues discussed above are subject to large variances from year to year and should not be construed as exact. There are numerous uncertainties present in estimating future net revenues for the Royalty Properties. The estimate may vary depending on changes in market prices for crude oil and natural gas, the recoverable reserves, annual production and costs assumed by DeGolyer and MacNaughton. In addition, future economic and operating conditions as well as results of future drilling plans may cause significant changes in such estimate. The discussion set forth above is qualified in its entirety by reference to the Trust Agreement itself, which is an exhibit to this Form 10-K and is available upon request from the Corporate Trustee.

In addition, in the event of a dissolution of the Partnership (which could occur under the circumstances described above under "Description of the Trust") and a subsequent winding up and termination thereof, the assets of the Partnership (*i.e*., the Royalty) could either (1) be distributed in kind ratably to the Trust and the Managing General Partner or (2) be sold and the proceeds thereof distributed ratably to the Trust and the Managing General Partner. In the event of a sale of the Royalty and a distribution of the cash proceeds thereof to the Trust and the Managing General Partner, the Trustees would make a final distribution to Unit holders of the Trust's portion of such cash proceeds plus any other cash held by the Trust after payment of or provision for all liabilities of the Trust, and the Trust would be terminated.

Royalty Income, Distributable Income and Total Assets

Reference is made to Items 6, 7 and 8 of this Form 10-K for financial information relating to the Trust.

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Description of Royalty Properties

Properties and Wells

The Partnership's interest consists of an overriding royalty interest, equivalent to a 25% net profits interest, in the Royalty Properties as follows:

					Gross Wells Drilled as of October 31, 2010			
					Wells Drilled(1)		Successful(2)(3)	
Property	Acquisition Date (Mo.-Yr.)	Current Working Interest Owner	Working Interest Owner's Ownership Interest(%)(4)	Gross Acres	Expl.	Dev.	Oil	Gas
East Cameron 354(5)	12-72	Apache	11.14	5,000	2	4	0	5
West Cameron 643 unit(6)	12-72	Hilcorp	35.86	5,000	3	17	0	14
Eugene Island 339 non-unit(2)	12-72	Chevron	50.00	5,000(18)	2	33(7)	19(7)	0
Eugene Island 339 5500' unit(2)	12-72	Chevron	42.05		0	5	5	0
Eugene Island 339 4500' unit(2)	12-72	Chevron	38.50 gas		0	20	16	0
			24.44 oil					
Eugene Island 342/343 SW/4	12-72	Chevron	.06	5,000(19)	4	5	0	7
Eugene Island 342/343 NW/4	12-72	Chevron	0.18		2	4	0	4
Eugene Island 348(8)	12-72	Devon	50.00	5,000	4	5	0	7
West Cameron 642(9)	12-72	Chevron	25.00	5,000	4	7	0	8
East Cameron 370(10)	1-73	N.A.	25.00	5,000	3	1	0	4
East Cameron 371(11)	1-73	ERT	7.50	5,000	7	2	0	4
Vermilion 246(12)	1-73	Chevron	33.37	5,000	3	3	0	4
West Cameron 41 E/2(13)	3-74	N.A	.30	2,500	0	0	0	0
Ship Shoal 183 N/2	7-88	Chevron	66.67	5,000(20)	1	11	8	4
Ship Shoal 183 unit	7-88	Chevron	34.29		1	22	20	3
Ship Shoal 183 F-3	7-88	Chevron	100.0		1	0	0	1
Ship Shoal 183 F-1	7-88	Chevron	50.00		1	0	1	0
Eugene Island 208(14)	8-73	Devon	100.00	1,250	0	3	0	3
Eugene Island 367(15)	3-74	N.A.	1.60	5,000	2	9	0	9
South Marsh Island 252(16)	3-74	Chevron	3.00	4,997	2	0	0	1
South Timbalier 36(17)	3-74	Chevron	.26	5,000	2	20	9	11
South Timbalier 37	3-74	Chevron	.26	5,000	13	41	39	3
Total				73,747	57	212	117	92

(1) As of both October 31, 2010 and December 31, 2010, there were no wells in the process of being drilled.

(2) As of both October 31, 2010 and December 31, 2010, there were 53 producing wells: 1 gas well and 11 oil wells associated with Ship Shoal, 2 gas wells and 2 oil wells associated with South Timbalier 36, 4 gas wells and 30 oil wells associated with South Timbalier 37, one gas well at East Cameron 381, and one gas well and one oil well at Eugene Island 342/343. All Eugene Island 339 wells were destroyed by Hurricane Ike in September 2008.

(3) Multiple completions are counted as one well. South Timbalier 37 has 4 multiple completion wells and Ship Shoal 182/183 has 2 multiple completion wells.

(4) These percentages represent the working interest owner's interest subject to the Partnership's net proceeds.

(5) Apache purchased this working interest from Anadarko effective October 1, 2004. This lease expired in 2005. Wells were plugged and abandoned in 2006. The platforms to which the wells were connected were abandoned in July 2008.

(6) West Cameron 643 was sold to Hilcorp Energy Company, effective August 1, 2008. The lease for West Cameron 643 expired on May 31, 2010. Abandonment work remains to be completed.

(7) Eugene Island 339 C-17 and C-18 wells are not included here; they are not subject to the Partnership's net proceeds until they pay out. Such wells were also destroyed by Hurricane Ike in September 2008.

(8) This lease expired in 2004. Abandonment work was completed in May 2006.

(9) Hilcorp has informed the Managing General Partner of the Partnership that, while the wells at West Cameron 642 have not been plugged and abandoned, such wells are depleted and no more production is anticipated from such wells. The Managing General Partner understands that plugging and abandonment will not occur until all wells in the area are depleted.

(10) This lease expired in 1996.

(11) East Cameron 371 was sold to ERT, effective July 1, 2007. Included in this sale was East Cameron 381, in which the Partnership does not own an interest. The Royalty includes East Cameron A1 and A3 wells, which are located on East Cameron 381 but were produced from East Cameron 371. The wells at East Cameron 371 have been depleted. The lease for East Cameron 371 expired on March 31, 2010. Abandonment work remains to be completed.

(12) This lease (Vermillion 246 Block, OCS-G 1147) was terminated in 2002. Abandonment work was completed mid 2005.

(13) This lease expired in November 2002, and all wells on the lease had been abandoned as of November 2003.

(14) The wells at Eugene Island 208 were plugged and the surface cleaned over 20 years ago.

(15) This lease expired on May 30, 1996. It was leased again as OCS-G 19800 effective July 1, 1998. Neither Chevron nor any affiliates of Chevron have an interest in OCS-G-19800.

(16) The wells at South Marsh Island 252 have been inactive since 2006.

(17) South Timbalier 36 well number 2 working interest owner's ownership interest is .013 percent.

(18) Represents the total gross acreage for all properties subject to the lease at Eugene Island 339.

(19) Represents the total gross acreage for all properties subject to the lease at Eugene Island 342/343.

(20) Represents the total gross acreage for all properties subject to the lease at Ship Shoal 183.

The following is a summary of the number of developmental and exploratory wells drilled on the Royalty Properties during the last three years:

	Year Ended December 31,					
	2008		2009		2010	
	Gross	Net	Gross	Net	Gross	Net
Developmental:						
Oil wells	1(1)	.3	1(1)	.3	0	0
Natural gas wells	1(2)	.3	1	.3	0	0
Non-productive	0	0	0	0	0	0
Exploratory:						
Oil wells	0	0	0	0	0	0
Natural gas wells	0	0	0	0	0	0
Non-productive	0	0	0	0	0	0
Total	2	.6	2	.6	0	0

(1) Associated with South Timbalier 37.

(2) During 2008, there was also one workover of a gas well at South Timbalier 36. During 2010, there was also one workover of a well at South Timbalier 36/37.

Reserves

A study of the proved oil and gas reserves attributable to the Partnership, in which the Trust has a 99.99% interest, has been made by DeGolyer and MacNaughton, independent petroleum engineering consultants, as of October 31, 2010. A copy of the reserve study has been filed as an exhibit to this Form 10-K. The following is a summary of such reserve study. Such study reflects estimated production, reserve quantities and future net revenue based upon estimates of the future timing of actual production without regard to when received by the Trust, which differs from the manner in which the Trust recognizes its Royalty income. See Notes 2 and 9 in the Notes to Financial Statements under Item 8 of this Form 10-K.

On the last business day of each calendar quarter, the Working Interest Owners pay to the Partnership 25% of the Net Proceeds for the immediately preceding Quarterly Period. A Quarterly Period is each period of three months commencing on the first day of February, May, August and November. In turn, the Partnership distributes funds to its partners on the last business day of each calendar quarter. Cash distributions from the Trust are made in January, April, July and October of each year, and are payable to Unit holders of record as of the last business day of each calendar quarter. Thus, any cash conveyed to the Trust from the Royalty during the quarter ended December 31, 2010 would substantially represent the revenues and expenses from the Royalty Properties from August through October 2010. The financial and operating information included in this Form 10-K for the 12 months ended December 31, 2010 represents financial and operating information with respect to the Royalty Properties for the months of November 2009 through October 2010. Thus, DeGolyer and MacNaughton's reserve study was made as of October 31, 2010. The reserve study bases proved developed reserves on oil and gas prices based on a 12-month average price, calculated as the unweighted arithmetic average of the first-day-of-the-month price for each month within the 12-month period ended October 31, 2010. Proved reserve estimates do not include any value for probable or possible reserves that may exist, categories that SEC rules permit the Trust to disclose in its public reports.

During September 2008, the platforms and wells associated with the Eugene Island 339 field were completely destroyed by Hurricane Ike. Chevron is proceeding with the work required to clear the remaining infrastructure and abandon existing wells. Neither the reserve study prepared as of October 31, 2009 nor the reserve study prepared as of October 31, 2010 includes reserves attributable to Eugene Island 339 or any capital expenditures for any redevelopment of Eugene Island 339. However, each such reserve study does include the Trust's share of the estimated total plugging and abandonment costs related to Eugene Island 339, with costs to the Trust relating thereto estimated to be approximately $13 million, approximately $11.3 million of which had been incurred through December 31, 2010, and without giving credit for an expected approximately $612,000 of insurance proceeds received by Chevron and to be allocated for the benefit of the Partnership with respect to Eugene Island 339.

The reserve study notes that there were five productive Royalty Properties, which consist of Eugene Island 342/343, Ship Shoal 182/183, South Timbalier 36, South Timbalier 37 and the A1 well located on East Cameron 381, which is produced from East Cameron 371. For a discussion of Royalty Properties, see "Management's Discussion and Analysis of Financial Condition and Results of Operation—Operations."

There are numerous uncertainties inherent in estimating quantities of proved reserves and in projecting the future rates of production and timing of development expenditures, including many factors beyond the control of the producer. The reserve data in the DeGolyer and MacNaughton study represent estimates only and should not be construed as being exact. The discounted present values shown by the DeGolyer and MacNaughton study should not be construed as the current market value of the estimated gas and oil reserves attributable to the Royalty Properties or the costs that would be incurred to obtain equivalent reserves, since a market value determination would include many additional factors. Estimates were prepared in accordance with guidelines established by the SEC and the Financial Accounting Standards Board. Accordingly, the estimates are based on existing economic and operating conditions in effect at October 31, 2010, with no provision for future increases or decreases except for periodic price redeterminations in accordance with existing gas contracts. Actual future prices and costs may be materially greater or less than the assumed amounts in the reserve study. Because the reserve study is limited to proved reserves, future capital expenditures for recovery of reserves not classified as proved by DeGolyer and MacNaughton are not included in the calculation of estimated future net revenues. Reserve assessment is a subjective process of estimating the recovery from underground accumulations of gas and oil that cannot be measured in an exact way, and estimates of other persons might differ materially from those of DeGolyer and MacNaughton. Accordingly, reserve estimates are often different from the quantities of hydrocarbons that are ultimately recovered.

Estimated net proved reserves attributable to the net profits interest owned by the Partnership, as of October 31, 2010, are summarized as follows, expressed in barrels (bbl) and thousands of cubic feet (Mcf):

	Oil and Condensate (bbl)	Natural Gas (Mcf)
Proved Developed Reserves(1)		
Reserves as of October 31, 2009(2)	137,464	868,505
Revisions of Previous Estimates	64,795	405,351
Improved Recovery	0	0
Purchases of Minerals in Place	0	0
Extensions, Discoveries, and Other Additions	0	0
Production(3)	(22,189)	(57,418)
Sales of Minerals in Place	0	0
Reserves as of October 31, 2010(4)	180,070	1,216,438

(1) There are no proved undeveloped reserves for the Royalty Properties that are the subject of the report.

(2) Estimated Eugene Island 339 abandonment costs were included.

(3) Production was estimated based on the ratio as of October 31, 2009, of the Partnership's net profits interest in net reserves to the net reserves associated with the Partnership's net profits interest and the interests retained in the Royalty Properties by the Working Interest Owners. This ratio was then applied to the production net to the combined interests of the Partnership and the Working Interest Owners for the period from November 1, 2009, through October 31, 2010.

(4) Estimated Eugene Island 339 abandonment costs were included.

Information used in the preparation of the reserve study was obtained from Working Interest Owners. All of the reserve estimates are classified as proved developed reserves. There are no proved undeveloped reserves for the Royalty Properties subject to the report.

The Partnership's share of gas sales are recorded by the Working Interest Owners on the cash method of accounting or based on actual production. When revenues are reported on actual production, there is no gas imbalance created. Under the cash method, revenues are recorded based on actual gas volumes sold, which could be more or less than the volumes the Working Interest Owners are entitled to based on their ownership interests. The Partnership's Royalty income for a period reflects the actual gas sold during the period.

While estimates of reserves attributable to the Royalty are shown in order to comply with requirements of the SEC, there is no precise method of allocating estimates of physical quantities of reserves to the Partnership and the Trust, since the Royalty is not a working interest and the Partnership does not own and is not entitled to receive any specific volume of reserves from the Royalty. Reserve quantities in the DeGolyer and MacNaughton reserve study have been allocated based on a revenue formula and such quantities can be affected by future changes in various economic factors utilized in estimating future gross and net revenues from the Royalty Properties. Therefore, the estimates of reserves set forth in the DeGolyer and MacNaughton study are to a large extent hypothetical and differ in significant respects from estimates of reserves attributable to a working interest. For a further discussion of reserves, reference is made to Note 9 in the Notes to Financial Statements under Item 8 of this Form 10-K.

The future net revenues contained in the DeGolyer and MacNaughton reserve study does not take into account the approximately $3.5 million, as of December 31, 2010, by which aggregate Production Costs for the Royalty Properties have exceeded the related Gross Proceeds for the Royalty Properties since November 2008, or any required deposits to the Special Cost Escrow account. The future net revenues contained in the DeGolyer and MacNaughton reserve study have not been reduced for future costs and expenses of the Trust, which are expected to approximate $1,000,000 annually. The costs and expenses of the Trust may increase in future years, depending on increases in accounting, engineering, legal and other professional fees, as well as other factors. Increased legal fees may occur in connection with, among other things, any borrowing or sales effected by the Trust in order to provide liquidity to the Trust.

Total future net revenues attributable to the Partnership's interest in the Royalty were estimated in the reserve study at $19.8 million as of October 31, 2010. The present value of the total future net revenues attributable to the Partnership's interest in the Royalty, discounted at 10 percent, were estimated in the reserve study at $15.1 million as of October 31, 2010. Revenue values in the reserve study were estimated using the initial costs provided by Chevron and volume-weighted average prices of $79.05 per barrel of oil and $4.60 per Mcf of natural gas. The future net revenue value was calculated by deducting operating expenses and capital costs from future gross revenue of the combined interests of the Partnership and the Working Interest Owners in the Royalty Properties. Current estimates of operating expenses were used for the life of the properties with no increases in the future based on inflation. The values were reduced by a trust overhead charge furnished by Chevron. Capital and abandonment costs for longer-life properties were accrued at the end of each quarter in amounts specified by Chevron beginning in January 2011. The future accrual or escrow amounts for the Royalty Properties were deducted from the future net revenue at the end of each quarter, as specified by Chevron. Interest on the balance of the accrued capital and abandonment costs at the rate of 0.20% per year as specified by Chevron was credited monthly. The adjusted revenue resulting from subtracting the overhead charge and accrued capital and abandonment costs was multiplied by a factor of 25% to arrive at the future net revenue attributed to the Partnership's net profits interest. Interest was charged monthly on the net profits deficit balances (costs not recovered currently) at the rate of 0.20% per year as specified by Chevron. Future income tax expenses were not taken into account in estimating future net revenue.

Because the DeGolyer and MacNaughton reserve study is limited to proved reserves, future capital expenditures for recovery of reserves not classified as proved by DeGolyer and MacNaughton are not included in the calculation of future net revenues nor are any capital expenditures for any redevelopment of Eugene Island 339. These capital expenditures could have a significant effect on the actual future net revenues attributable to the Partnership's interest in the Royalty.

The Trustees rely on DeGolyer and MacNaughton to prepare the reserve study of the oil and gas reserves attributable to the Partnership, in which the Trust has a 99.99% interest. The Trustees do not control the information provided by the Working Interest Owners or the assumptions made or methodologies used by the third-party reserve engineer. Accordingly, such information is outside the scope of the internal controls of the Trust and the Trustees.

Chevron, as the Managing General Partner of the Partnership, maintains oversight and compliance responsibility for the internal reserve estimate process and, in accordance with internal policies and procedures, provides appropriate data to independent third party engineers for the annual estimation of year-end reserves. Chevron accumulates historical production data for the Royalty Properties, calculates historical lease operating expenses and differentials, updates working interests and net revenue interests, and obtains logs, 3-D seismic and other geological and geophysical information. This data is forwarded to DeGolyer & MacNaughton, thereby allowing DeGolyer & MacNaughton to prepare estimated proved reserves in their entirety based on such data.

Estimates of the proved oil and gas reserves attributable to the Partnership as of October 31, 2009 and 2010 are based on reports of DeGolyer & MacNaughton. DeGolyer and MacNaughton is a Delaware corporation with offices in Dallas, Houston, Calgary, and Moscow. The firm's more than 80 professionals include engineers, geologists, geophysicists, petrophysicists, and economists engaged in the appraisal of oil and gas properties, evaluation of hydrocarbon and other mineral prospects, basin evaluations, comprehensive field studies, equity studies and studies of supply and economics related to the domestic and international energy industry. These services have been provided for over 70 years. DeGolyer and MacNaughton restricts its activities exclusively to consultation; it does not accept contingency fees, nor does it own operating interests in any oil, gas, or mineral properties. The firm subscribes to a code of professional conduct, and its employees support their related technical and professional societies.

The technical person at DeGolyer and MacNaughton primarily responsible for overseeing the preparation of the reserve study is a Registered Professional Engineer in the State of Texas with more than 35 years of experience in oil and gas reservoir studies and reserve evaluations. He graduated with a Bachelor of Science degree in Petroleum Engineering from Texas A&M University in 1974 and he is a member of the International Society of Petroleum Engineers and the American Association of Petroleum Geologists.

The Trust Agreement provides that the Trust will terminate in the event total future net revenues attributable to the Partnership's interest in the Royalty as determined by independent petroleum engineers, as of the end of any year, are less than $2.0 million. See "Business—Termination of the Trust".

The Managing General Partner of the Partnership has advised the Trust that, as of March 30, 2011, there had been no events subsequent to October 31, 2010 that have caused a significant change in the estimated proved reserves referred to in the DeGolyer and MacNaughton study.

Operations and Production

Reference is made to the Section entitled "—Operations" under Item 7 of this Form 10-K for information concerning operations and production.

Distributions

Production ceased at Eugene Island 339 and Ship Shoal 182 and 183 following damages inflicted by Hurricane Ike in September 2008. Future Net Proceeds may take into account the Trust's share of project costs and other related expenditures that are not covered by insurance of the operator of the Royalty Properties. On December 19, 2008, the Trust announced its fourth quarter distribution of approximately $0.7 million, which was paid on January 9, 2009. The funds available for the fourth quarter distribution were severely negatively impacted by Hurricane Ike. On March 25, 2009, the Trust announced that there would be no trust distribution for the first quarter of 2009, and the Trust had not made a distribution since January 9, 2009.

There are not likely to be sufficient Net Proceeds from the Royalty Properties for the Trust to make a regularly scheduled quarterly distribution to Unit holders for the foreseeable future. As a result of the damage inflicted by Hurricane Ike, Net Proceeds will continue to be severely impacted by reduced production, from historical levels, and the amount of expenditures incurred that are associated with such damages, including the expenditures required to plug and abandon the wells on Eugene Island 339, and, as currently expected, to redevelop the facility at Eugene Island 339. Future Net Proceeds from the Royalty Properties will take into account the Trust's share of project costs and other related expenditures that are not covered by the insurance of the operators of the Royalty Properties. The Trust's net portion of the aggregate cost to plug and abandon the wells subject to the royalty on Eugene Island 339 is estimated to be approximately $13 million, $11.3 million of which had been incurred through December 31, 2010, and without giving credit for an expected approximately $612,000 of insurance proceeds received by Chevron and to be allocated for the benefit of the Partnership with respect to Eugene Island 339. If Production Costs of the Royalty exceed the Gross Proceeds of production from the Royalty Properties, the Trust will not receive Net Proceeds until future Gross Proceeds from production exceed the total of the Production Costs plus accrued interest. As of December 31, 2010, Production Costs of the Royalty exceeded the Gross Proceeds from the Royalty Properties since November 2008 by approximately $3.5 million. In the fourth quarter of 2010, Chevron withdrew $4,304,894 from the Special Cost Escrow account of the Working Interest Owners (a reserve fund for certain costs) to cover expenses incurred in connection with the plugging and abandonment of Eugene Island 339, which served to reduce the amount by which Production Costs exceeded the Gross Proceeds from production as of December 31, 2010; however, additional deposits to the Special Cost Escrow account would be required in future periods in accordance with the terms of the Conveyance if, and when, Net Proceeds would otherwise be payable on the Royalty. Significant development and production costs will continue to be incurred as Eugene Island 339 is redeveloped. Development activities may not generate sufficient additional revenue to repay such costs. Accordingly, there will not be sufficient Net Proceeds from the Royalty Properties to make distributions for some period of time in the future. At this time, the ultimate outcome of these matters cannot be determined with any degree of certainty. See "Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources" and also "—Operations."

MARKETING

The amount of cash distributions by the Trust is dependent on, among other things, the sales prices for oil and gas produced from the Royalty Properties and the quantities of oil and gas sold.

It should be noted that substantial uncertainties exist with regard to future oil and gas prices, which are subject to material fluctuations due to changes in production levels and pricing and other actions taken by major petroleum producing nations, as well as the regional supply and demand for gas, worldwide political conditions, weather, industrial growth, conservation measures, competition, economic conditions generally and other variables.

Gas Marketing

During the years ended December 31, 2010 and December 31, 2009, 100% of Chevron's natural gas and natural gas liquids relative to the Trust's Royalty Properties were committed and sold to Chevron Natural Gas at spot market prices. During the year ended December 31, 2008 approximately 99% of Chevron's natural gas and natural gas liquids relative to the Trust's Royalty Properties were committed and sold to Chevron Natural Gas at spot market prices. Prices for natural gas paid by Chevron Natural Gas in fiscal 2010 ranged from $3.87 to $6.18 per Mcf.

It should be noted that the Conveyance provides that amounts received by the producer pursuant to "take-or-pay" provisions are not included within the Royalty payable to the Trust unless and until gas is actually delivered pursuant to the "make-up" provisions, if any, of the applicable contract. Accordingly, amounts received by the Working Interest Owners as "take-or-pay" payments are not included in the calculation of the Royalty payable, and the income received by the Trust is restricted to amounts paid for gas actually delivered.

Due to the seasonal nature of demand for natural gas and its effects on sales prices and production volumes, the amount of gas sold with respect to the Royalty Properties may vary. Generally, production volumes and prices are higher during the first and fourth quarters of each calendar year. Because of the time lag between the date on which the Working Interest Owners receive payment for production from the Royalty Properties and the date on which distributions are made to Unit holders, the seasonality that generally affects production volumes and prices is generally reflected in distributions to the Trust in later periods.

Oil Marketing

Crude oil purchases by Chevron accounted for approximately 99% of total crude oil revenues from the Royalty Properties operated by Chevron during 2008, approximately 98% of the total crude oil revenues from the Royalty Properties operated by Chevron during 2009, and approximately 100% of the total crude oil revenues from the Royalty Properties operated by Chevron during 2010.

Chevron purchases the crude oil at prices based on a market index for the applicable grade of crude oil, as adjusted for gravity and transportation charges, if applicable. Prices for crude oil paid by Chevron in fiscal 2010 ranged from $73.36 per barrel to $86.25 per barrel.

COMPETITION AND REGULATION

Competition

The Working Interest Owners experience competition from other oil and gas companies in all phases of their operations. Numerous companies participate in the exploration for and production of oil and gas. The Working Interest Owners have previously advised the Trust that they believe that their competitive positions are affected by price and contract terms. Business is affected not only by such competition, but also by general economic developments, governmental regulations and other factors.

Regulation—General

The production of oil and gas by the Working Interest Owners is affected by many state and federal regulations with respect to allowable rates of production, drilling permits, well spacing, marketing, environmental matters and pricing. Future regulations could change allowable rates of production or the manner in which oil and gas operations may be lawfully conducted. Sales of natural gas in interstate commerce for resale and the transportation of natural gas in interstate commerce are subject to regulation by the Federal Energy Regulatory Commission ("FERC") under the Natural Gas Act of 1938, as amended (the "Natural Gas Act").

FERC Regulation

In general, under the Natural Gas Act, the FERC regulates the sale of natural gas in interstate commerce for resale and the transportation of natural gas in interstate commerce by interstate pipelines. The FERC has issued orders and adopted regulations resulting in a restructuring of the natural gas industry. The principal elements of this restructuring were the requirement that interstate pipelines separate, or "unbundle," into individual components the various services offered on their systems, with all transportation services to be provided on a non-discriminatory basis, and the prohibition against an interstate pipeline providing gas sales services except through separately-organized affiliates. In various rulemaking proceedings following its initial unbundling requirement, the FERC has refined its regulatory program applicable to interstate pipelines in various respects, and it has announced that it will continue to monitor these regulations to determine whether further changes are needed. In addition to rulemaking proceedings, the FERC establishes new policies and regulations through policy statements and adjudications of individual pipeline matters. Further, additional changes to regulations may occur based on actions taken by the United States Congress and/or the courts. As to these various developments, the Managing General Partner has advised the Trust that Working Interest Owners have advised that the on-going and evolving nature of these regulatory initiatives makes it impossible to predict their ultimate impact on the prices, markets or terms of sale of natural gas related to the Trust.

In the past, the federal government has regulated the prices at which natural gas could be sold. While sales by producers of natural gas can currently be made at market prices, Congress could reenact price controls in the future. Deregulation of wellhead natural gas sales began with the enactment of the Natural Gas Policy Act of 1978 and culminated in adoption of the Natural Gas Wellhead Decontrol Act that removed all price controls affecting wellhead sales of natural gas effective January 1, 1993.

Sales of crude oil, condensate, and natural gas liquids are not currently regulated and are made at negotiated prices. Nevertheless, Congress could reenact price controls in the future. Sales of crude oil are affected by the availability, terms and cost of transportation. The transportation of oil in common carrier pipelines is subject to rate and access regulation. The FERC regulates interstate oil pipeline transportation rates under the Interstate Commerce Act. In general, interstate oil pipeline rates must be just and reasonable and may be derived in a number of ways including, but not limited to, the FERC's indexing methodology.

As to these various types of regulation, the on-going and evolving nature of these regulatory initiatives makes it impossible to predict their ultimate impact on the prices, markets or terms of sale of natural gas related to the Trust.

State and Other Regulation

State regulation of gathering facilities generally includes various safety, environmental, and in some circumstances, non-discriminatory take requirements. Some states have implemented more stringent legislation in recent years to regulate gathering rates charged by gas gathering companies, but to date the effect on the Working Interests Owners in connection with the Trust has been minimal.

Environmental Regulations

General

The Working Interest Owners' oil and gas activities on the Royalty Properties are subject to existing and evolving federal, state and local environmental laws and regulations. The Managing General Partner of the Partnership has advised the Trust that, with respect to the Royalty Properties, the Working Interest Owners believe that their operations and facilities are in general compliance with applicable health, safety, and environmental laws and regulations that have taken effect at the federal, state and local levels. In addition, events in recent years have heightened environmental concerns about the oil and gas industry generally, and about offshore operations in particular. The Working Interest Owners' operation of federal offshore oil and gas leases is subject to extensive governmental regulation, including regulations that may, in certain circumstances, impose absolute liability upon lessees for cost of removal of pollution and for pollution damages resulting from their operations, and require lessees to suspend or cease operations in the affected areas.

Under the Oil Pollution Act of 1990, as amended by the Coast Guard Authorization Act of 1996, (collectively, "OPA"), parties responsible for offshore facilities must establish and maintain evidence of oil-spill financial responsibility ("OSFR") for costs attributable to potential oil spills. OPA requires a minimum of $35 million in OSFR for offshore facilities located on the OCS. This amount is subject to upward regulatory adjustment up to $150 million. Responsible parties for more than one offshore facility are required to provide OSFR only for their offshore facility requiring the highest OSFR. In 1998, the Minerals Management Service (which was renamed the Bureau of Ocean Energy Management, Regulation and Enforcement, which we refer to as the "BOEM") adopted regulations for establishing the amount of OSFR required for particular facilities. The amount of OSFR increases as the volume of a facility's worst-case oil spill increases. Accordingly, for facilities with worst-case spills of less than 35,000 barrels, only $35 million in OSFR is required; for worst-case spills of over 35,000 barrels, $70 million is required; for worst-case spills of over 70,000 barrels, $105 million is required; and for worst-case spills of over 105,000 barrels, $150 million is required. In addition, all OSFR below $150 million remains subject to upward regulatory adjustment if warranted by the particular operational, environmental, human health or other risks involved with a facility. The Managing General Partner of the Partnership has advised the Trust that the Working Interest Owners are currently maintaining their required OSFR. Although the Managing General Partner of the Partnership has advised the Trust that current environmental regulation has had no material adverse effect on the Working Interest Owners' present method of operations with respect to the Royalty Properties, future environmental regulatory developments such as stricter environmental regulation and enforcement policies cannot presently be quantified. However, drilling activity associated with the redevelopment of Eugene Island 339 was suspended, the drilling rig moved off location and the redevelopment plan modified given Chevron's inability to obtain drilling permits in a timely basis under the new guidelines issued by the BOEM on June 8, 2010 pursuant to NTL No. 2010-N05, "Increased Safety Measures for Energy Development on the OCS" following the *Deepwater Horizon* incident.

The Working Interest Owners' operations are subject to regulation, principally under the following federal statutes, along with their analogous state statutes.

Water

The Federal Water Pollution Control Act of 1972, as amended, and the Oil Pollution Act of 1990 impose certain liabilities and penalties upon persons and entities, such as the Working Interest Owners, for any discharges of petroleum products in reportable quantities, for the costs of removing an oil spill, and for natural resource damages. State laws for the control of water pollution also provide varying civil and criminal penalties and liabilities in the case of a release of petroleum or its derivatives in surface waters.

The federal NPDES permits prohibit the discharge of produced water, sand and other substances related to the oil and gas industry to coastal waters of Louisiana and Texas. The Managing General Partner of the Partnership has advised the Trust that these costs have not had a material adverse impact on the Working Interest Owners' operations with respect to the Royalty Properties.

Air Emissions

Amendments to the federal Clean Air Act were enacted in late 1990 and require most industrial operations in the United States, including offshore operations, to incur capital expenditures for air emission control equipment in connection with maintaining and obtaining operating permits and approvals addressing other air emission related issues. The Environmental Protection Agency ("EPA") and state environmental agencies have been developing regulations to implement these requirements. Some of the Working Interest Owners' facilities are included within the categories of hazardous air pollutant sources that will be affected by these regulations and these regulations could make operation of the Royalty Properties more costly.

Climate Change

A variety of regulatory developments, proposals or requirements have been introduced that are focused on restricting the emission of carbon dioxide, methane and other greenhouse gases. Among these developments is the Kyoto Protocol to the United Nations Framework Convention on Climate Change that became effective in February 2005. Under the Protocol, participating nations are required to implement programs to reduce emissions of certain gases, generally referred to as greenhouse gases, that are suspected of contributing to global warming. The United States is not currently participating in the Protocol though the Protocol may impact oil and gas markets generally. In addition, Congress has considered recent proposed legislation directed at reducing greenhouse gas emissions. There has been support in various regions of the country for legislation that requires reductions in greenhouse gas emissions, and some states have already adopted legislation addressing greenhouse gas emissions from various sources. In 2007, the U.S. Supreme Court held in *Massachusetts, et al. v. EPA* that greenhouse gases are an "air pollutant" under the federal Clean Air Act and, thus, subject to future regulation. The Environmental Protection Agency (the "EPA") is moving forward to regulate greenhouse gases. The EPA has issued an "Endangerment Finding" final rule, effective January 14, 2010, which states that current and projected concentrations of six key greenhouse gases in the atmosphere, as well as emissions from new motor vehicles and new motor vehicle engines, threaten public health and welfare, allowing the EPA to finalize motor vehicle greenhouse gas standards effective January 2, 2011 (the effect of which could reduce demand for motor fuels refined from crude oil). According to the EPA, the motor vehicle greenhouse gas standards will trigger construction and operating permit requirements for stationary sources. As a result, the EPA issued regulations to tailor these programs such that only large stationary sources will be required to have air permits that authorize greenhouse gas emissions.

In addition, the EPA issued a "Mandatory Reporting of Greenhouse Gases" final rule effective December 20, 2009, which established a new comprehensive scheme requiring operators of stationary sources in the United States emitting more than established annual thresholds of carbon dioxide equivalent greenhouse gases to inventory and report their greenhouse gas emissions annually. In November 2010, the EPA published a final rule expanding this reporting rule to onshore and offshore petroleum and natural gas systems.

Laws, regulations, treaties or international agreements related to greenhouse gases and climate change, including incentives to conserve energy or use alternative energy sources, could have a negative impact on the future operations of the Royalty Properties if such laws, regulations, treaties or international agreements reduce the worldwide demand for oil and natural gas or otherwise result in reduced economic activity generally. In addition, such laws, regulations, treaties or international agreements could result in increased compliance costs or additional operating restrictions, which may have a negative impact on the Royalty Property operations. In addition to potential impacts on the Royalty Property operations directly or indirectly resulting from climate- change legislation or regulations, the Royalty Property operations also could be negatively affected by climate-change related physical changes or changes in weather patterns. At this time, it is not possible to accurately estimate how potential future laws or regulations addressing greenhouse gas emissions would impact the operations of the Royalty Properties.

Solid Waste

The Working Interest Owners' operations may generate wastes that are subject to the federal Resource Conservation and Recovery Act ("RCRA") and comparable state statutes. The EPA has limited disposal options for certain hazardous wastes and may adopt more stringent disposal standards for nonhazardous wastes. Furthermore, it is possible that some wastes that are currently classified as nonhazardous, perhaps including wastes generated during drilling and production operations, may in the future be designated as "hazardous wastes." Such changes in the regulations would result in more rigorous and costly disposal requirements that could result in increased operating expenses on the Royalty Properties.

Norm

Oil and gas exploration and production activities have been identified as generators of low-level naturally-occurring radioactive materials ("NORM"). The generation, handling and disposal of NORM in the course of offshore oil and gas exploration and production activities is currently regulated in federal and state waters. These regulations could result in an increase in operating expenses on the Royalty Properties.

Superfund

The Comprehensive Environmental Response, Compensation and Liability Act ("CERCLA"), also known as the "Superfund" law, imposes liability, without regard to the fault or the legality of the original conduct, on certain classes of persons that contributed to the release of a "hazardous substance" into the environment. These persons include the current or previous owner and operator of a facility and companies that disposed or arranged for the disposal of the hazardous substance found at a facility. CERCLA also authorizes the EPA and, in some cases, private parties to take actions in response to threats to the public health or the environment and to seek recovery from such responsible classes of persons of the costs, which can be substantial, of such action. Although "petroleum" is excluded from CERCLA's definition of a "hazardous substance", in the course of their operations, the Working Interest Owners may generate wastes that fall within CERCLA's definition of "hazardous substances." The Working Interest Owners may be responsible under CERCLA for all or part of the costs to clean up facilities at which such substances have been disposed. Such clean-up costs may make operation of the Royalty Properties more expensive for the Working Interest Owners.

Offshore Operations

Offshore oil and gas operations are subject to regulations of the United States Department of the Interior, or "DOI", including regulations promulgated pursuant to the Outer Continental Shelf Lands Act, which impose liability upon a lessee, such as the Working Interest Owners, under a federal lease for the cost of clean-up of pollution resulting from a lessee's operations. More specifically, the BOEM, formerly the Minerals Management Service, regulates offshore operations, including engineering and construction specifications for production facilities, safety procedures, plugging and abandonment of wells and removal of facilities on the Outer Continental Shelf. On April 22, 2010, a deepwater U.S. Gulf of Mexico drilling rig, the *Deepwater Horizon*, sank after a blowout and fire at the Macondo wellsite. As a result, the DOI imposed a six-month moratorium on offshore deepwater drilling, which it lifted on October 12, 2010. Although the moratorium has been lifted, the *Deepwater Horizon* incident led to additional governmental regulation of the offshore exploration and production industry. The Department of the Interior may require a lessee under federal leases to suspend or cease operations in the affected areas.

Item 1A. **Risk Factors.**

Although risk factors are described elsewhere in this Form 10-K together with specific forward-looking statements, the following is a summary of the principal risks associated with an investment in Units in the Trust.

The Trust continues to utilize its cash reserves to pay expenses, and there are not likely to be Net Proceeds distributed to the Trust for the foreseeable future. Absent the receipt of Net Proceeds, or other actions being taken, at some time in the early part of the second quarter of 2011, the Trust will not have sufficient funds to pay the liabilities of the Trust. As such, the Trustees may take certain actions on behalf of the Trust that could materially impact the Unit holders, including borrowing money, causing the sale by the Partnership of the Royalty owned by the Partnership, selling all or a part of the Trust's interest in the Partnership or exercising the Trustees' rights to dissolve the Partnership.

The Trust's source of capital is the Royalty income received from its share of the Net Proceeds from the Royalty Properties. The Trust has not received a distribution of Net Proceeds since December 2008, and there are not likely to be positive Net Proceeds from the Royalty Properties for the foreseeable future. The Trust continues to utilize its cash reserves to pay expenses; however, as of December 31, 2010, those reserves were approximately 39% of the average annual expenses of the Trust during the three-year period ended December 31, 2010. Chevron offered to the Trustees in February 2011 that, based on then present production forecasts, the possibility of distributions being made to the Partnership would likely begin in 2013. However, there can be no assurance by Chevron or anyone else as to the actual timing for any future distributions to the Partnership from the Royalty, and distributions could recommence some time before, during or after 2013, and there is no guarantee that any further distributions will be made. Absent the receipt of Net Proceeds, or other actions being taken, at some time in the early part of the second quarter of 2011, the Trust will not have sufficient funds to pay the liabilities of the Trust. As such, the Trustees may take certain actions on behalf of the Trust that could materially impact the Unit holders. Such actions include borrowing money, causing a sale by the Partnership of all or a part of the Royalty owned by the Partnership, selling all or a part of the Trust's interest in the Partnership or exercising the Trustees' rights to dissolve the Partnership. On March 11, 2011, the Trustees provided written notice to Chevron that, pursuant to the Trust Agreement, the Trust needs funds to pay for liabilities of the Trust and that the Trustees therefore instructed Chevron, as the Managing General Partner of the Partnership, to sell such portion, and only such portion, of the Royalty that will provide the Trust with a current distribution equal to $2,000,000 from the proceeds of such sale. The Trustees are also seeking a loan to the Trust to be able to pay liabilities of the Trust. There can be no assurance that such a loan will be obtained or that such a sale of interests in the Royalty can be consummated or that $2,000,000 in proceeds can be obtained, or as to the terms, conditions and timing of such a loan or of the sale of interests in the Royalty. For more information, see "Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources" under Item 7 of this Form 10-K.

Production from Eugene Island 339 and Ship Shoal 182 and 183, the two most significant Royalty Properties, ceased following damage inflicted by Hurricane Ike in September 2008. While oil and natural gas production at Ship Shoal 182 and 183 was restored in 2009, there can be no assurance that production will be restored at Eugene Island 339. Chevron's failure or inability to pursue redevelopment of Eugene Island 339, and on the timeframes previously approved by the BOEM, could result in a loss of the lease. Based on the damage caused by Hurricane Ike, the Trust's scheduled distribution for the fourth quarter of 2008 was severely negatively impacted and there were no distributions during 2009, 2010 or the first quarter of 2011. If development and production costs of the Royalty exceed the proceeds of production from the Royalty Properties, the Trust will not receive Net Proceeds until future proceeds from production exceed the total of the excess costs plus accrued interest. Development activities may not generate sufficient additional revenue to repay such costs. Accordingly, there will not be sufficient Net Proceeds from the Royalty Properties to make

distributions for some period of time in the future. As of December 31, 2010, development and production costs of the Royalty exceeded the proceeds of production from the Royalty Properties by approximately $3.5 million. Significant development and production costs will continue to be incurred as Eugene Island 339 is redeveloped. See "Management's Discussion and Analysis of Financial Condition and Results of Operations—Operations and—Liquidity and Capital Resources" under Item 7 of this Form 10-K."

The platforms and wells on Eugene Island 339 were completely destroyed by Hurricane Ike in September 2008. Chevron is working on the plugging and abandonment of the existing wells, clearing debris and otherwise dealing with the remaining infrastructure, which activities are not expected to be completed until the second quarter of 2012. Chevron has informed the Corporate Trustee that Chevron presently intends to pursue the redevelopment of platforms and wells at Eugene Island 339 in accordance with the terms and conditions established by the BOEM in response to Chevron's submission to the BOEM of a program to restore production at Eugene Island 339. Chevron has informed the Corporate Trustee that Chevron has received a Suspension of Production, or "SOP", from the BOEM, for Eugene Island 339 through October 31, 2011, as long as certain SOP milestones are met. The SOP provides for the staged redevelopment of Eugene Island 339 and the adjacent lease, Eugene Island 338 (which is not a property subject to the overriding royalty interest held by the Partnership), as a single development project, contingent upon meeting certain obligations established in the SOP. Chevron is required to provide the BOEM with periodic updates on Chevron's progress and to meet each of the SOP activity schedule deadlines to maintain the SOP. Although the SOP formally expires on October 31, 2011, the BOEM has acknowledged that production is not scheduled to be restored at Eugene Island until October 2012. Therefore, Chevron must submit, and obtain approval by the regional supervisor of the BOEM of, an additional SOP request prior to October 31, 2011 to obtain BOEM authority for any redevelopment of Eugene Island 338 and 339 after October 31, 2011. While Chevron has stated that it intends to redevelop Eugene Island 338 and 339, and has met the activity schedule obligations under the SOP through December 31, 2010, there is no obligation upon Chevron to continue to pursue such redevelopment. Failure or inability to pursue such a redevelopment, or to satisfy the activity schedule approved by the BOEM, could result in a loss of the lease covering Eugene Island 339. At this time, there is and can be no assurance that each activity schedule date will be met or that an additional SOP will be approved by the BOEM or that production will be restored at Eugene Island 339. The costs for the redevelopment plan would be significant.

If Production Costs of the Royalty exceed the Gross Proceeds from the Royalty Properties, the Trust will not receive Net Proceeds until future Gross Proceeds exceed the total of the Production Costs plus accrued interest. Development activities may not generate sufficient additional revenue to repay such costs. Accordingly, there will not be sufficient Net Proceeds from the Royalty Properties to make distributions for some period of time in the future. As of December 31, 2010, Production Costs of the Royalty exceeded the Gross Proceeds from the Royalty Properties by approximately $3.5 million. In the fourth quarter of 2010, Chevron withdrew $4,304,894 from the Special Cost Escrow account of the Working Interest Owners (a reserve fund for certain costs) to cover expenses incurred in connection with the plugging and abandonment of Eugene Island 339, which served to reduce the amount by which production costs exceeded the proceeds from production as of December 31, 2010; however, additional deposits to the Special Cost Escrow account would be required in future periods in accordance with the terms of the Conveyance if, and when, Net Proceeds would otherwise be payable on the Royalty.

Production at Ship Shoal 182/183 ceased following damage inflicted by Hurricane Ike in September 2008. While the hurricane caused limited surface damage to the facilities at Ship Shoal 182/183, all of the wells at Ship Shoal 182/183 were shut-in following hurricane-related damage to a third-party transporter's natural gas pipeline. A limited volume of oil production was restored in November 2008. The volume of oil production that can be produced is limited by the amount of gas that is also produced by the oil wells. The third-party transporter's natural gas pipeline repairs were completed and gas sales at Ship Shoal 182/183 were restored on June 26, 2009. However, the pipeline was shut down in mid-September 2009 for additional repairs. Production sales for both oil and natural gas at Ship Shoal 182 and 183 were restored on October 8, 2009 following completion of such additional repairs. Oil and gas production at Ship Shoal 182/183 ceased in March 2010 due to a leak in the oil pipeline that services Ship Shoal 182/183. Such oil pipeline has since been repaired and Ship Shoal 182/183 was reopened on May 1, 2010 after a 36-day shut-in.

In addition, production from West Cameron 643 and East Cameron 371 ceased following damage inflicted by Hurricane Ike in September 2008 to third-party transporters' pipelines. Chevron, as the Managing General Partner of the Partnership, understands that, as a result of the cessation of production at West Cameron 643 due to the damages inflicted by Hurricane Ike to a third-party transporter's pipeline, Hilcorp submitted to the BOEM a program to restore production at West Cameron 643 and that such request was granted. The approval by the BOEM expired by its terms on May 31, 2010, and Chevron has been informed by Hilcorp that it submitted to the BOEM a request for an extension but that such request was denied. Accordingly, the lease for West Cameron 643 expired on May 31, 2010. Chevron has been informed by Hilcorp that there is a deadline of June 1, 2011 to plug and abandon the wells and related infrastructure at West Cameron 643. The field operator for East Cameron 371 has reported to Chevron that a review of the remaining reserves for East Cameron 371 has been conducted, and that the wells at East Cameron 371 have been depleted. The lease for East Cameron 371 expired on March 31, 2010 and the field operator has informed Chevron that field abandonment work, including the related wells, equipment platforms and any field infrastructure, is expected to commence mid 2011, after the operator received an extension of the one-year deadline to complete such abandonment work.

For additional information, see "Management's Discussion and Analysis of Financial Condition and Results of Operations—Operations." Based on the damage caused by Hurricane Ike, the Trust's scheduled distribution for the fourth quarter of 2008 was severely negatively impacted and no distributions have been made to Unit holders since January 9, 2009. There are not likely to be positive Net Proceeds from the Royalty Properties for the foreseeable future. Chevron offered to the Trustees in February 2011 that, based on then present production forecasts, the possibility of distributions being made to the Partnership would likely begin in 2013. However, there can be no assurance by Chevron or anyone else as to the actual timing for any future distributions to the Partnership from the Royalty, and distributions could recommence some time before, during or after 2013, and there is no guarantee that any further distributions will be made. At this time, the ultimate outcome of the various matters cannot be determined with any degree of certainty.

The Deepwater Horizon incident in the U.S. Gulf of Mexico and its consequences could have a material adverse effect on the Royalty income.

On April 22, 2010, a deepwater U.S. Gulf of Mexico drilling rig, the *Deepwater Horizon*, sank after a blowout and fire at the Macondo wellsite. In response to such incident, the BOEM, among other things, issued Notices to Lessees, or "NTLs," implementing additional safety and certification requirements applicable to drilling activities in the U.S. Gulf of Mexico, imposed additional requirements with respect to development and production activities in the U.S. Gulf of Mexico and has delayed the approval of applications to drill in both deep-water and shallow-water areas.

To the extent this incident has resulted in, or will result in, federal legislation, policy, restrictions, or regulations that cause delays or deter new drilling in the U.S. Gulf of Mexico, or that increase the costs of offshore production, the Royalty income could be materially adversely affected. We cannot predict at this time the impact, if any, that this incident may have on the operations of the Royalty Properties, particularly a redevelopment of Eugene Island 339, the Royalty income payable to the Trust or on the financial condition of the Trust. However, drilling activity associated with the redevelopment of Eugene Island 339 was suspended, the drilling rig moved off location and the redevelopment plan modified given Chevron's inability to obtain drilling permits in a timely basis under the new guidelines issued by the BOEM on June 8, 2010 pursuant to NTL No. 2010-N05, "Increased Safety Measures for Energy Development on the OCS" following the *Deepwater Horizon* incident.

Natural gas and oil prices fluctuate due to a number of factors, and lower prices will reduce Net Proceeds available to the Trust and distributions to Trust Unit holders.

Net Proceeds and the Trust's quarterly distributions are highly dependent upon the prices realized from the sale of natural gas and oil. Natural gas and oil prices can fluctuate widely on a month-to-month basis in response to a variety of factors that are beyond the control of the Trust and the Working Interest Owners. Factors that contribute to price fluctuation include, among others:

- political conditions worldwide, in particular political disruption, war and other armed conflict in oil producing regions such as North Africa and the Middle East;
- worldwide economic conditions;
- weather conditions;
- the supply and price of foreign oil and natural gas;
- the level of consumer demand;
- the price and availability of alternative fuels;
- the proximity to, and capacity of, transportation facilities; and
- the effect of worldwide energy conservation measures.

Moreover, government regulations, such as regulation of natural gas and oil transportation and price controls, can affect product prices in the long term.

Crude oil prices have been volatile the last several years and, in 2010, ranged from a high of approximately $91.50 to a low of approximately $68.00 The Trust cannot predict the timing or the duration of any economic cycle and, depending on the prices realized, the financial condition of the Trust could be materially adversely affected.

When natural gas and oil prices decline, the Trust is affected in two ways. First, net royalties are reduced. Second, exploration and development activities on the underlying properties may decline as some projects may become uneconomic and are either delayed or cancelled. The volatility of energy prices reduces the predictability of future cash distributions to Unit holders. Substantially all of the natural gas and natural gas liquids produced from the Royalty Properties operated by Chevron is being sold to Chevron Natural Gas at spot market prices. Substantially all of the crude oil produced by the Royalty Properties operated by Chevron is being sold to subsidiaries of Chevron Corporation based on pricing bulletins.

Increased production and development costs for the Royalty will result in decreased or no Trust distributions.

Production and development costs attributable to the Royalty are deducted in the calculation of the Trust's share of Net Proceeds. Production and development costs are impacted by increases in commodity prices both directly and indirectly, through commodity-price dependent costs such as electricity, and indirectly, as a result of demand-driven increases in costs of oilfield goods and services. Accordingly, higher or lower production and development costs, without concurrent increases in revenues, directly decrease or increase the amount received by the Trust for the Royalty.

In September 2008, Hurricane Ike completely destroyed the platforms and wells on Eugene Island 339. Chevron is proceeding to plug and abandon the existing wells, to clear debris and otherwise to deal with the remaining infrastructure, with estimated costs to the Trust relating thereto of approximately $13 million, and without giving credit for an expected approximately $612,000 of insurance proceeds received by Chevron and to be allocated for the benefit of the Partnership with respect to Eugene Island 339. Chevron has informed the Corporate Trustee that Chevron presently intends to pursue the redevelopment of platforms and wells at Eugene Island 339 in accordance with the terms and conditions established by the BOEM in response to Chevron's submission to the BOEM of a program to restore production at Eugene Island 339. The costs for the redevelopment would be significant. At this time, there can be no assurance that production at Eugene Island 339 will be restored. For additional information, see "Management's Discussion and Analysis of Financial Condition and Results of Operations—Operations."

If development and production costs of the Royalty exceed the proceeds of production from the Royalty Properties, the Trust will not receive Net Proceeds until future proceeds from production exceed the total of the excess costs plus accrued interest, at a rate equal to one-fourth of (i) one-half of one percent plus (ii) the median between the prime interest rate at the end of a quarterly period in which there are excess costs and the prime interest rate at the end of the preceding quarterly period, during the deficit period. Development activities may not generate sufficient additional revenue to repay the costs. Accordingly, there may not be sufficient Net Proceeds to make a particular distribution.

Trust reserve estimates depend on many assumptions that may prove to be inaccurate, which could cause both estimates of reserves and estimated future revenues to be too high or too low.

The value of the Units depends upon, among other things, the amount of reserves attributable to the Royalty and the estimated future value of the reserves. Estimating reserves is inherently uncertain. Ultimately, actual production, revenues and expenditures for the underlying properties will vary from estimates and those variations could be material. Petroleum engineers consider many factors and make assumptions in estimating reserves. Those factors and assumptions include:

- historical production from the area compared with production rates from similar producing areas;
- the assumed effect of governmental regulation;
- assumptions about future commodity prices, production and development costs, severance and excise taxes, and capital expenditures;
- the availability of enhanced recovery techniques; and
- relationships with landowners, working interest partners, pipeline companies and others.

Changes in these factors and assumptions can materially change reserve estimates and future net revenue estimates.

The reserve quantities attributable to the Royalty and revenues are based on estimates of reserves and revenues for the Royal Properties. The method of allocating a portion of those reserves to the Trust is complicated because the Trust, indirectly through the Partnership, holds an interest in the Royalty and does not own a specific percentage of the reserves. Ultimately, actual production, revenues and expenditures for the Royalty Properties, and therefore actual net proceeds payable to the Trust, will vary from estimates and those variations could be material. Results of drilling, testing and production after the date of those estimates may require substantial downward revisions or write-downs of reserves.

The Trustees also rely entirely on reserve estimates and related information prepared by Chevron, the other Working Interest Owners and the independent reserve engineer engaged by the Partnership. While the Trustees have no reason to believe the reserve estimates included in this Form 10-K are inaccurate, to the extent additional information exists that could affect the reserve estimates of

Chevron, the other Working Interest Owners and the independent reserve engineer, the estimated reserves in this Form 10-K could also be too low.

Operating risks for the Working Interest Owners' interests in the Royalty Properties can adversely affect the Royalty and Trust distributions.

There are operational risks and hazards associated with the production and transportation of natural gas, including without limitation natural disasters, blowouts, explosions, fires, leakage of natural gas, releases of other hazardous materials, mechanical failures, cratering and pollution. Any of these or similar occurrences could result in the interruption or cessation of operations, personal injury or loss of life, property damage, damage to productive formations or equipment, damage to the environment of natural resources, or cleanup obligations. The occurrence of drilling, production or transportation accidents and natural disasters at any of the Royalty Properties will reduce Trust distributions by the amount of uninsured costs. These accidents may result in personal injuries, property damage, damage to productive formations or equipment and environmental damages. Offshore activities are also subject to a variety of additional operating risks, such as hurricanes and other weather disturbances. Any uninsured costs would be deducted as a production cost in calculating net proceeds payable to the Trust.

As described in this report, Hurricanes Katrina and Rita caused significant damage during 2005. All but one of the platforms and facilities on the Royalty Properties were restored during 2006 and 2007. As also described in the report, production from the two most significant oil and gas properties associated with the Trust ceased following damage inflicted by Hurricane Ike in September 2008. The platforms and wells on Eugene Island 339 were completely destroyed. While Hurricane Ike caused limited damage to the facilities at Ship Shoal 182 and 183, all of the wells at Ship Shoal 182 and 183 were shut-in following hurricane related damage to a third-party transporter's natural gas pipeline.

Terrorism and hostilities in the Middle East could decrease Trust distributions or the market price of the units of beneficial interest of the Trust.

Terrorist attacks and the threat of terrorist attacks, whether domestic or foreign, as well as military or other actions taken in response, cause instability in the global financial and energy markets. Terrorism and other sustained military campaigns could adversely affect Trust distributions or the market price of the Units in unpredictable ways, including through the disruption of fuel supplies and markets, increased volatility in natural gas prices, or the possibility that the infrastructure on which the operators developing the underlying properties rely could be a direct target or an indirect casualty of an act of terror.

The operators of the working interests are subject to extensive governmental regulation.

Offshore oil and gas operations have been, and in the future will be, affected by federal, state and local laws and regulations and other political developments, such as price or gathering rate controls and environmental protection regulations. These regulations and changes in regulations could have a material adverse effect on Royalty income payable to the Trust.

Regulation of greenhouse gases and climate change could adversely affect Trust distributions

Some scientific studies have suggested that emissions of certain gases, commonly referred to as greenhouse gases and including carbon dioxide and methane, may be contributing to the warming of the Earth's atmosphere and other climatic changes. In response to such studies, the issue of climate change and the effect of greenhouse gas emissions, in particular emissions from fossil fuels, is attracting increasing attention worldwide. Legislative and regulatory measures to address concerns that emissions of greenhouse gases are contributing to climate change are in various phases of discussions or implementation at the international, national, regional and state levels.

The EPA is taking steps that would result in the regulation of greenhouse gases as pollutants under the Clean Air Act. The EPA has issued an "Endangerment Finding" final rule, effective January 14, 2010, which states the current and projected concentrations of six key greenhouse gases in the atmosphere, as well as emissions from new motor vehicles and new motor vehicle engines, that threaten public health and welfare, and allowed the EPA to finalize motor vehicle greenhouse gas standards effective January 2, 2011 (the effect of which could reduce demand for motor fuels refined from crude oil). According to the EPA, the final motor vehicle greenhouse gas standards trigger construction and operating permit requirements for stationary sources. As a result, the EPA has proposed to tailor these programs such that only large stationary sources will be required to have air permits that authorize greenhouse gas emissions. In addition, the EPA has issued a "Mandatory Reporting of Greenhouse Gases" final rule, effective December 29, 2009, which establishes a new comprehensive scheme requiring operators of stationary sources in the United States emitting more than established annual thresholds of carbon dioxide-equivalent greenhouse gases to inventory and report their greenhouse gas emissions annually. In November 2010, the EPA published a final rule expanding this reporting rule to onshore and offshore petroleum and natural gas systems beginning in 2012 for emissions in 2011.

Existing or future laws, regulations, treaties or international agreements related to greenhouse gases and climate change, including incentives to conserve energy or use alternative energy sources, could have a negative impact on the Royalty Property operations if such laws, regulations, treaties or international agreements reduce the worldwide demand for oil and natural gas or otherwise result in reduced economic activity generally. In addition, such laws, regulations, treaties or international agreements could result in increased compliance costs or additional operating restrictions, which may have a negative impact on the Royalty Property operations. In addition to potential impacts on the Royalty Property operations directly or indirectly resulting from climate- change legislation or regulations, the Royalty Property operations also could be negatively affected by climate-change related physical changes or changes in weather patterns.

The Trustees and the Unit holders have no control over the operation or development of the Royalty Properties and have little influence over operation or development.

Neither the Trustees nor the Unit holders can influence or control the operation or future development of the underlying properties. The Royalty Properties are owned by independent Working Interest Owners. The Working Interest Owners manage the underlying properties and handle receipt and payment of funds relating to the Royalty Properties and payments to the Trust for the Royalty.

Information regarding operations provided by the Working Interest Owners has been subject to errors and adjustments, some of which have been significant. Accordingly, the Trustees cannot assure Unit holders that other errors or adjustments by Working Interest Owners, whether historical or future, will not affect future Royalty income and distributions by the Trust.

The current Working Interest Owners are under no obligation to continue operating the properties. The failure of an operator to conduct its operations, discharge its obligations, deal with regulatory agencies or comply with laws, rules and regulations, including environmental laws and regulations, in a proper manner could have an adverse effect on the net proceeds payable to the Trust. Neither the Trustees nor the Unit holders have the right to replace an operator.

The Trustees rely upon the Working Interest Owners and Managing General Partner for information regarding the Royalty Properties.

The Trustees rely on the Working Interest Owners and the Managing General Partner of the Partnership for information regarding the Royalty Properties. The Working Interest Owners alone control (i) historical operating data, including production volumes, marketing of products, operating and capital expenditures, environmental and other liabilities, effects of regulatory changes and the number of producing wells and acreage, (ii) plans for future operating and capital expenditures, (iii) geological data relating to reserves, as well as related projections regarding production, operating expenses and capital expenses used in connection with the preparation of the reserve study, (iv) forward-looking information relating to production and drilling plans and (v) information regarding the Royalty Properties responsive to litigation claims. While the Trustees request material information for use in periodic reports as part of its disclosure controls and procedures, the Trustees do not control this information and rely entirely on the Working Interest Owners to provide accurate and timely information when requested for use in the Trust's periodic reports. The Trustees also rely on the Managing General Partner of the Partnership to collect certain information from the Working Interest Owners and do not have any direct contact with the Working Interest Owners other than the Managing General Partner. Under the terms of the Trust Indenture, the Trustees are entitled to rely, and in fact rely, on certain experts in good faith. While the Trustees have no reason to believe their reliance on experts is unreasonable, this reliance on experts and limited access to information may be viewed as a weakness as compared to the management and oversight of entity forms other than trusts.

The owner of any Royalty Property may abandon any property, terminating the related Royalty.

The Working Interest Owners may at any time transfer all or part of the Royalty Properties to another unrelated third-party. Unit holders are not entitled to vote on any transfer, and the Trust will not receive any proceeds of any such transfer. Following any transfer, the Royalty Properties will continue to be subject to the Royalty, but the Net Proceeds from the transferred property would be calculated separately and paid by the transferee. The transferee would be responsible for all of the obligations relating to calculating, reporting and paying to the Trust the Royalty on the transferred portion of the Royalty Properties, and the current owner of the Royalty Properties would have no continuing obligation to the Trust for those properties.

The current Working Interest Owners or any transferee may abandon any well or property if it reasonably believes that the well or property can no longer produce in commercially economic quantities. This could result in termination of the Royalty relating to the abandoned well.

Generally, if production ceases from an outer continental shelf lease, like that for Eugene Island 339, production must be restored or drilling operations must commence within 180 days of the cessation (which was in early March 2009 with respect to Eugene Island 339 given the cessation of production in September 2008 resulting from Hurricane Ike), or the lease will be terminated. Alternatively, an operator of a lease may seek an SOP, that, if approved by the regional supervisor of the BOEM, allows additional time to restore production in the event of certain circumstances, such as hurricanes and other events beyond the control of the operator. Chevron, as the operator of Eugene Island 339, sought and obtained an SOP for Eugene Island 339 for the period from December 1, 2010 through October 31, 2011. Chevron had previously sought and obtained a SOP providing for the staged redevelopment of Eugene Island 339 and the adjacent lease, Eugene Island 338 (which is not a property subject to the overriding royalty interest held by the Partnership), as a single development project, contingent upon meeting certain obligations established in the SOP. Such initial SOP extended the lease on Eugene Island 339 until November 30, 2010. The new December 1, 2010 through October 31, 2011 SOP extends the lease on Eugene Island 339 until October 31, 2011, as long as certain SOP milestones are met. Although the new December 1, 2010 through October 31, 2011 SOP formally expires on October 31, 2011, the BOEM has acknowledged that production is not scheduled to be restored at Eugene Island until October 2012. Therefore, Chevron must submit, and obtain approval by the regional supervisor of the BOEM of, an additional SOP request prior to October 31, 2011 to obtain BOEM authority for any redevelopment of Eugene Island 338 and 339 after October 31, 2011. While Chevron has stated that it intends to redevelop Eugene Island 338 and 339, there is no obligation upon Chevron to continue to pursue such redevelopment. Failure or inability to pursue such a redevelopment, or to satisfy the activity schedule approved by the BOEM, could result in a loss of the lease covering Eugene Island 339. At this time, there is and can be no assurance that each activity schedule date will be met or that an additional SOP will be approved by the BOEM or that production will be restored at Eugene Island 339.

The Royalty can be sold and the Trust can be terminated.

The Trust will be terminated and the Trustees must sell the Royalty if holders of a majority of the Units approve the sale or vote to terminate the Trust, or if the total future net revenues attributable to the Royalty, determined by the independent reserve engineer as of December 31 of the prior year, are less than $2 million. Following any such termination and liquidation, the net proceeds of any sale will be distributed to the Unit holders and Unit holders will receive no further distributions from the Trust. In addition, if the Trust does not have sufficient funds to pay the liabilities of the Trust, the Trustees may take certain actions on behalf of the Trust that could materially impact the Unit holders. Such actions include borrowing money, selling all or a part of the Trust's interest in the Partnership, exercising their rights to dissolve the Partnership or causing a sale by the Partnership of the Royalty owned by the Partnership. On March 11, 2011, the Trustees provided written notice to Chevron that, pursuant to the Trust Agreement, the Trust needs funds to pay for liabilities of the Trust and that the Trustees therefore instructed Chevron, as the Managing General Partner of the Partnership, to sell such portion, and only such portion, of the Royalty that will provide the Trust with a current distribution equal to $2,000,000 from the proceeds of such sale. The Trustees are also seeking a loan to the Trust to be able to pay liabilities of the Trust. There can be no assurance that such a loan will be obtained or that such a sale of interests in the Royalty can be consummated or that $2,000,000 in proceeds can be obtained, or as to the terms, conditions and timing of such a loan or of the sale of interests in the Royalty. For more information, see "—Termination of the Trust" under Item 1 of this Form 10-K and "Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources" under Item 7 of this Form 10-K.

Trust assets are depleting assets and, if the Working Interest Owners or other operators of the Royalty Properties do not perform additional development projects, the assets may deplete faster than expected.

The Net Proceeds payable to the Trust are derived from the sale of depleting assets. Accordingly, the portion of the distributions to Unit holders attributable to depletion may be considered a return of capital. The reduction in proved reserve quantities is a common measure of depletion. Future maintenance and development projects on the Royalty Properties will affect the quantity of proved reserves. The timing and size of these projects will depend on the market prices of natural gas. If operators of the Royalty Properties do not implement additional maintenance and development projects, the future rate of production decline of proved reserves may be higher than the rate currently expected by the Trust. For federal income tax purposes, depletion is reflected as a deduction, which is dependent upon the purchase price of a Units. Please see the section entitled "—Description of the Units—Federal Income Tax Matters" under Item 1 of this Form 10-K.

Because the Net Proceeds payable to the Trust are derived from the sale of depleting assets, the portion of distributions to Unit holders attributable to depletion may be considered a return of capital as opposed to a return on investment. Distributions that are a return of capital will ultimately diminish the depletion tax benefits available to the Unit holders, which could reduce the market value of the Units over time. Eventually, properties underlying the Trust's Royalty will cease to produce in commercial quantities and the Trust will, therefore, cease to receive any distributions of Net Proceeds therefrom.

Unit holders have limited voting rights.

Voting rights as a Unit holder are more limited than those of stockholders of most public corporations. For example, there is no requirement for annual meetings of Unit holders or for an annual or other periodic re-election of the Trustees. Additionally, Unit holders have no voting rights in the Working Interest Owners. Unlike corporations which are generally governed by boards of directors elected by their equity holders, the Trust is administered by a Corporate Trustee and three Individual Trustees in accordance with the Trust Agreement and other organizational documents. The Trustees have extremely limited discretion in their administration of the Trust.

Unit holders have limited ability to enforce the Trust's rights against the current or future owners of the Royalty Properties.

The Trust Agreement and related trust law permit the Trustees and the Trust to sue the Working Interest Owners to compel them to fulfill the terms of the Conveyance of the Royalty. If the Trustees do not take appropriate action to enforce provisions of the Conveyance, the recourse of a Unit holder would likely be limited to bringing a lawsuit against the Trustees to compel the Trustees to take specified actions. Unit holders probably would not be able to sue the Working Interest Owners directly.

Item 1B. Unresolved Staff Comments.

There were no unresolved Securities and Exchange Commission comments as of December 31, 2010.

Item 2. Properties.

Reference is made to Item 1 of this Form 10-K.

Item 3. Legal Proceedings.

Currently, there are not any legal proceedings pending to which the Trust is a party or of which any of its property is the subject.

Item 4. [Reserved]

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PART II

Item 5. Market for the Registrant's Common Equity, Related Stockholder Matters and Issuer Purchasers of Equity Securities.

Effective January 3, 2011, the Units have been quoted on the OTCQB™ Marketplace, which is an electronic quotation service operated by Pink OTC Markets Inc. for securities traded over-the-counter. Prior to January 3, 2011, the Trust Units were traded on the Nasdaq Capital Market under the symbol "TELOZ". At March 29 2011, the 4,751,510 Units outstanding were held by 1,801 Unit holders of record. The high and low sales price as reported by the Nasdaq Capital Market, and distributions for each quarter for the years ended December 31, 2010 and 2009, were as follows:

Quarter	High	Low	Distribution
2010:			
Fourth	$ 2.76	$ 1.12	$ .000000
Third	3.75	1.60	.000000
Second	4.94	1.75	.000000
First	5.40	4.43	.000000
2009:			
Fourth	$ 5.60	$ 4.36	$ .000000
Third	5.75	3.75	.000000
Second	6.50	3.92	.000000
First	7.87	4.70	.000000

See "Management's Discussion and Analysis of Financial Condition and Results of Operations—Operations" and "—Liquidity and Capital Resources" and Note 4 to Notes to Financial Statements under Item 8 of this Form 10-K for a discussion regarding uncertainty of distributions.

Item 6. Selected Financial Data.

	Year Ended December 31,				
	2010	2009	2008	2007	2006
Royalty income	$ 0	$ 0	$ 14,451,252	$ 10,257,485	$ 2,510,936
Distributable income	$ 0	$ 0	$ 13,298,654	$ 9,311,113	$ 1,697,721
Distributions per Unit	$ 0.000000	$ 0.000000	$ 2.798827	$ 1.959611	$ 0.357301
Total assets	$ 374,512	$ 1,290,266	$ 3,004,478	$ 5,176,634	$ 3,375,093

Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operation.

On the last business day of each calendar quarter, the Working Interest Owners pay to the Partnership 25% of the Net Proceeds for the immediately preceding Quarterly Period. A Quarterly Period is each period of three months commencing on the first day of February, May, August and November. In turn, the Partnership distributes funds to its partners on the last business day of each calendar quarter. Cash distributions from the Trust are made in January, April, July and October of each year, and are payable to Unit holders of record as of the last business day of each calendar quarter. Thus, any cash conveyed to the Trust from the Royalty during the quarter ended December 31, 2010 would substantially represent the revenues and expenses from the Royalty Properties from August through October 2010. The financial and operating information included in this Form 10-K for the 12 months ended December 31, 2010 represents financial and operating information with respect to the Royalty Properties for the months of November 2009 through October 2010. Similarly, the financial and operating information included in this Form 10-K for the 12 months ended December 31, 2009 represents financial and operating information with respect to the Royalty Properties for the months of November 2008 through October 2009. Similarly, the financial and operating information included in this Form 10-K for the 12 months ended December 31, 2008 represents financial and operating information with respect to the Royalty Properties for the months of November 2007 through October 2008. As such, the impact of Hurricane Ike is not fully reflected in the discussion of 2008 operations, as such discussion does not include a discussion of operations of the Royalty Properties in November or December 2008. Income from the Royalty is recorded by the Trust on a cash basis, when it is received by the Trust from the Partnership.

Critical Accounting Policies

The financial statements of the Trust are prepared on the following basis:

(a) Royalty income is recorded when received, including the effect of overtaken or undertaken positions and negative or positive adjustments, by the Corporate Trustee on the last business day of each calendar quarter. In addition, Royalty income includes amounts related to funds deposited or released from the Special Cost Escrow account—see (c);

(b) Trust general and administrative expenses are recorded when paid, except for the cash reserved for future general and administrative expenses; and

(c) The funds deposited or released from the Special Cost Escrow account are recorded at the time of payment or receipt. The Special Cost Escrow account is an account of the Working Interest Owners and is not reflected in the financial statements of the Trust.

This manner of reporting income and expenses is considered to be the most meaningful because the quarterly distributions to Unit holders are based on net cash receipts received from the Working Interest Owners. The financial statements of the Trust differ from financial statements prepared in accordance with generally accepted accounting principles, because, under such principles, Royalty income and Trust general and administrative expenses for a quarter would be recognized on an accrual basis. In addition, amortization of the net overriding royalty interest, calculated on a units-of-production basis, is charged directly to Trust corpus since such amount does not affect distributable income.

The Trustees, including the Corporate Trustee, have no authority over, have not evaluated and make no statement concerning, the internal control over financial reporting of any of the Working Interest Owners.

Liquidity and Capital Resources

The Trust's source of capital is the Royalty income received from its share of the Net Proceeds from the Royalty Properties. Total future net revenues attributable to the Partnership's interest in the Royalty were estimated at $19.8 million as of October 31, 2010. However, there are not likely to be sufficient Net Proceeds from the Royalty Properties for the Trust to make a regularly scheduled quarterly distribution to Unit holders for the foreseeable future. Chevron offered to the Trustees in February 2011 that, based on then present production forecasts, the possibility of distributions being made to the Partnership would likely begin in 2013. However, there can be no assurance by Chevron or anyone else as to the actual timing for any future distributions to the Partnership from the Royalty, and distributions could recommence some time before, during or after 2013, and there is no guarantee that any further distributions will be made. Absent the receipt of Net Proceeds or other actions being taken, at some time in the early part of the second quarter of 2011, the Trust will not have sufficient funds to pay the liabilities of the Trust. On October 7, 2008, the Trust announced that production from the two most significant oil and gas properties associated with the Trust had ceased following damage inflicted by Hurricane Ike in September 2008. On December 19, 2008, the Trust announced its fourth quarter distribution of approximately $0.7 million, which was paid on January 9, 2009. Based on the damage caused by Hurricane Ike, the Trust's scheduled distribution for the fourth quarter of 2008 was severely negatively impacted, although there were funds available for distribution given that there was some production from Eugene Island 339 and Ship Shoal 182/183 in August and September 2008. The Trust has not received a distribution of Net Proceeds since December 2008. Consequently, the Trust has not made a distribution to Unit holders for nine consecutive quarters, or since January 9, 2009. As a result of the damage inflicted by Hurricane Ike, Net Proceeds will continue to be severely impacted by reduced production, from historical levels, and the amount of expenditures incurred that are associated with such damages, including the expenditures required to plug and abandon the wells on Eugene Island 339 and to redevelop the facility at Eugene Island 339. While Chevron has stated that it intends to redevelop Eugene Island 339, there is no obligation for Chevron to continue to pursue such redevelopment.

The platforms and wells on Eugene Island 339 were completely destroyed by Hurricane Ike. Chevron is working on the plugging and abandonment of the existing wells, clearing debris and otherwise dealing with the remaining infrastructure, which activities are not expected to be completed until the second quarter of 2012. Chevron has informed the Corporate Trustee that Chevron presently intends to pursue the redevelopment of platforms and wells at Eugene Island 339 in accordance with the terms and conditions established by the BOEM in response to Chevron's submission to the BOEM of a program to restore production at Eugene Island 339; however, there is no obligation for Chevron to pursue such redevelopment. The costs for the redevelopment would be significant. Failure or inability to pursue such a redevelopment, and on the timeframes approved by the BOEM, could result in a loss of the lease. At this time, there can be no assurance that production will be restored at Eugene Island 339. See "—Operations" for a more detailed discussion of Eugene Island 339.

Production at Ship Shoal 182/183 ceased following damage inflicted by Hurricane Ike in September 2008. While the hurricane caused limited surface damage to the facilities at Ship Shoal 182/183, all of the wells at Ship Shoal 182/183 were shut-in following hurricane-related damage to a third-party transporter's natural gas pipeline. The third-party transporter's natural gas pipeline repairs were completed and gas sales at Ship Shoal 182/183 were restored on June 26, 2009. However, the pipeline was shut down in mid-September 2009 for additional repairs. Production sales for both oil and natural gas at Ship Shoal 182 and 183 were restored on October 8, 2009 following completion of such additional repairs. Production ceased at Ship Shoal 182/183 in late March 2010 due to a leak in the oil pipeline that services Ship Shoal 182/183. Such pipeline was repaired and Ship Shoal 182/183 was reopened on May 1, 2010 after a 36-day shut-in. See "—Operations" for a more detailed discussion of Ship Shoal 182/183.

In addition, production from West Cameron 643 and East Cameron 371 ceased following damage inflicted by Hurricane Ike in September 2008 to third-party transporters' pipelines. Chevron has been informed by the operator of West Cameron 643 that the operator submitted to the BOEM a request for an extension of the program to restore production but that such request was denied. Accordingly, the lease for West Cameron 643 expired on May 31, 2010. Chevron has been informed by the operator that there is a deadline of June 1, 2011 to plug and abandon the wells and related infrastructure at West Cameron 643. The field operator for East Cameron 371 has reported to Chevron that a review of the remaining reserves for East Cameron 371 has been conducted, and that the wells at East Cameron 371 have been depleted. The lease for East Cameron 371 expired on March 31, 2010 and the field operator has informed Chevron that field abandonment work, including the related wells, equipment platforms and any field infrastructure, is expected to commence mid 2011, after the operator received an extension of the one-year deadline to complete such abandonment work. See "—Operations" for a more detailed discussion of West Cameron 643 and East Cameron 371.

Future Net Proceeds from the Royalty Properties will take into account the Trust's share of project costs and other related expenditures that are not covered by the insurance of the operators of the Royalty Properties. Chevron has informed the Trustees that Chevron has reached settlements that provide Chevron with insurance proceeds associated with damages that Chevron's assets sustained from

Hurricane Ike, and that the allocated portion thereof with respect to the Partnership's interest in Eugene Island 339, as a Royalty Property, is approximately $612,000. Chevron applied $400,000 thereof in the first quarter of 2011 and has stated that the remaining approximately $212,000 is to be received by Chevron and allocated to the Partnership's interest upon completion of the abandonment work at Eugene Island, which is expected to occur in the second quarter of 2012. Chevron has stated that all such allocated insurance proceeds will be applied to the Partnership's portion of the aggregate cost to plug and abandon the wells subject to the Royalty on Eugene Island 339. The Trust's net portion of the aggregate cost to plug and abandon the wells subject to the Royalty on Eugene Island 339 is estimated to be approximately $13 million, approximately $11.3 million of which had been incurred through December 31, 2010, without taking into account the benefit of such allocated insurance proceeds. If Production Costs of the Royalty Properties exceed the Gross Proceeds from the Royalty Properties, the Trust will not receive Net Proceeds until future proceeds from production exceed the total of the excess costs plus accrued interest at a rate equal to one-fourth of (i) one-half of one percent plus (ii) the median between the prime interest rate at the end of a quarterly period in which there are excess costs and the prime interest rate at the end of the preceding quarterly period, during the deficit period. As a result of the damage inflicted by Hurricane Ike, the Trust has not received Net Proceeds since December 2008. As of December 31, 2010, aggregate development and production costs for the Royalty Properties since November 2008 have exceeded the related proceeds of production from the Royalty Properties by approximately $3.5 million. In the fourth quarter of 2010, Chevron withdrew $4,304,894 from the Special Cost Escrow account of the Working Interest Owners (a reserve fund for certain costs) to cover expenses incurred in connection with the plugging and abandonment of Eugene Island 339, which served to reduce the amount by which production costs exceeded the proceeds from production as of December 31, 2010; however, additional deposits to the Special Cost Escrow account would be required in future periods in accordance with the terms of the Conveyance if, and when, Net Proceeds would otherwise be payable on the Royalty. Significant development and production costs will continue to be incurred if Eugene Island 339 is redeveloped. Accordingly, there will not be sufficient Net Proceeds from the Royalty Properties to make distributions for some period of time in the future. At this time, the ultimate outcome of these various matters cannot be determined. See "—Operations."

Substantial uncertainties exist with regard to future oil and gas prices, which are subject to material fluctuations due to changes in production levels and pricing and other actions taken by major petroleum producing nations, as well as the regional supply and demand for oil and gas, worldwide political conditions, weather, industrial growth, conservation measures, competition, economic conditions generally and other variables.

In accordance with the provisions of the Trust Agreement, generally all Net Proceeds received by the Trust, net of Trust general and administrative expenses and any cash reserves established for the payment of contingent or future obligations of the Trust, are distributed currently to the Unit holders. In 1994, in anticipation of future periods when the cash received from the Royalty may not be sufficient for payment of Trust expenses, the Trust determined, in accordance with the Trust Agreement, to begin further increasing the Trust's cash reserve each quarter. In the first quarter of 1998, the Trust determined that the Trust's cash reserve was then sufficient to provide for future administrative expenses in connection with the winding up of the Trust. The Trust determined that a cash reserve equal to three times the average expenses of the Trust during each of the past three years was sufficient at such time to provide for future administrative expenses in connection with the winding up of the Trust.

The reserve amount at December 31, 2010 and 2009 was $352,017 and $1,263,080, respectively. As described herein, there are not likely to be positive Net Proceeds from the Royalty Properties for the foreseeable future. Absent the receipt of Net Proceeds or other actions being taken, at some time in the early part of the second quarter of 2011, the Trust will not have sufficient funds to pay the liabilities of the Trust. As such, the Trustees may take certain actions, discussed below, on behalf of the Trust as permitted under the Trust Agreement, which could materially impact the Unit holders.

Pursuant to the terms of the Trust Agreement, the Trustees, on behalf of the Trust, are authorized to borrow funds, and pledge the assets of the Trust to secure payments of such borrowings, in the event that cash on hand is not sufficient to pay the liabilities of the Trust. In the event that the Trustees borrow funds to pay the liabilities of the Trust, no distributions will be made to the Unit holders until the indebtedness created by such borrowings has been paid in full. However, there can be no assurance as to the terms and conditions of any such financing, or that any such financing can actually be obtained.

The Trust Agreement further provides that, if necessary to provide for the payment of specific liabilities of the Trust then due, the Trustees may without a vote of the Unit holders (a) sell all or a portion of the Trust's interest in the Partnership or any other assets of the Trust for such cash consideration as the Trustees shall deem appropriate, (b) exercise their rights under the Partnership Agreement to dissolve the Partnership, or (c) cause a sale by the Partnership of the overriding royalty interest owned by the Partnership.

On March 11, 2011, the Trustees provided written notice to Chevron that, pursuant to the Trust Agreement, the Trust needs funds to pay for liabilities of the Trust and that the Trustees therefore instructed Chevron, as the Managing General Partner of the Partnership, to sell such portion, and only such portion, of the Royalty that will provide the Trust with a current distribution equal to $2,000,000 from the proceeds of such sale. Such dollar amount represents the amount of funds that the Trust will need to cover its expected expenses, based on historical annual expenses, through the end of the second quarter of 2013. There can be no assurance as to the amount of expenses that will actually be incurred by the Trust. Chevron offered to the Trustees in February 2011 that, based on then present production forecasts, the possibility of distributions being made to the Partnership would likely begin in 2013. However, there can be no assurance by Chevron or anyone else as to the actual timing for any future distributions to the Partnership from the Royalty, and distributions could recommence some time before, during or after 2013, and there is no guarantee that any further distributions will be made. The Trustees are in ongoing discussions with Chevron regarding the sales process to be conducted by Chevron. In such written notification to Chevron, the Trustees reserved the right to withdraw, at any time, such instruction to sell interests in the Royalty. The Trustees are also seeking a loan to the Trust to be able to pay liabilities of the Trust. There can be no assurance that such a loan will be obtained or that such a sale of interests in the Royalty can be consummated or that $2,000,000 in proceeds can be obtained, or as to the terms, conditions and timing of such a loan or of the sale of interests in the Royalty.

The Trustees of the Trust have previously asked Chevron if it would be willing to advance funds to the Partnership against future payments to the Partnership on the Royalty, particularly in light of Chevron's withdrawal of $4,304,894 from the Special Cost Escrow account in the fourth quarter of 2010. Chevron declined to make any such advance of funds, though orally offered to the Corporate Trustee in December 2010 to buy the Royalty for $0. As discussed further below, under "—Operations", in January 2010, the Trust engaged an independent oil and gas accounting firm to review the books and records of certain Working Interest Owners with respect to the Royalty Properties and the related payments to the Trust. The Corporate Trustee has requested Chevron to pay any adjustments resulting from such audit directly to the Partnership; however, Chevron instead intends to credit any such adjustments against the Partnership's share of allocated expenses for the Royalty Properties. As a result, there will be no current payments to the Partnership resulting from such audit.

In March 2011, the Trustees unanimously determined to suspend further payments of fees to the Trustees, until a date to be determined in the future by the Trustees. Until a subsequent determination by the Trustees, such suspended fees will be accrued as an expense of the Trust, but will not be paid currently.

The accompanying financial statements have been prepared assuming that the Trust will continue as a going concern. The lack of Net Proceeds and the inability to maintain adequate cash reserves raise substantial doubt about the Trust's ability to continue as a going concern. Certain potential alternatives available to the Trustees are described in Note 6 to the financial statements. The financial statements do not include any adjustments that might result from the outcome of this uncertainty. See Notes 3 and 6 to the financial statements.

Operations

The following operational information has been based on information provided to the Corporate Trustee by Chevron as the Managing General Partner of the Partnership. The Trustees have no control over these operations or internal controls relating to this information.

The platforms and wells on Eugene Island 339 were completely destroyed by Hurricane Ike in September 2008. Crude oil revenues from Eugene Island 339 represented approximately 48% of the crude oil and condensate revenues for the Royalty Properties in 2007 and approximately 47% of such revenues for the nine months ended September 30, 2008. Eugene Island 339 contributed approximately 12% of the revenues from natural gas sales from the Royalty Properties in 2007 and approximately 41% of such revenues for the nine months ended September 30, 2008. Based on a prior year reserve study prepared by DeGolyer and MacNaughton, independent petroleum engineering consultants, Eugene Island 339 accounted for approximately 34% of the total future net revenues attributable to the Partnership's interest in the Royalty as of October 31, 2007. Chevron is still working on the plugging and abandonment of the existing wells, clearing debris and otherwise dealing with the remaining infrastructure, which activities are not expected to be completed until the second quarter of 2012. The Trust's net portion of the aggregate cost to plug and abandon the wells subject to the Royalty on Eugene Island 339 is estimated to be approximately $13 million, approximately $11.3 million of which had been incurred through December 31, 2010, and without giving credit for an expected approximately $612,000 of insurance proceeds received by Chevron and to be allocated for the benefit of the Partnership with respect to Eugene Island 339.

Generally, if production ceases from an outer continental shelf lease, like that for Eugene Island 339, production must be restored or drilling operations must commence within 180 days of the cessation of production (which was in early March 2009 with respect to Eugene Island 339 given the cessation of production in September 2008 resulting from Hurricane Ike), or the lease will be terminated. Alternatively, an operator of a lease may seek a Suspension of Production, or "SOP", that, if approved by the regional supervisor of the BOEM, allows additional time to restore production in the event of certain circumstances, such as hurricanes and other events beyond the control of the operator. Chevron, as the operator of Eugene Island 339, sought and obtained an SOP for Eugene Island 339 for the period from December 1, 2010 through October 31, 2011. Chevron had previously sought and obtained an SOP providing for the staged redevelopment of Eugene Island 339 and the adjacent lease, Eugene Island 338 (which is not a Royalty Property), as a single development project, contingent upon meeting certain obligations established in the SOP. Such initial SOP extended the lease on Eugene Island 339 until November 30, 2010. The new December 1, 2010 through October 31, 2011 SOP extends the lease on Eugene Island 339 until October 31, 2011, as long as certain SOP milestones are met. Such milestones include the issuance of jacket and pile material order drawings to the fabrication contractor by April 2011, the continuation of offshore deck refurbishment by May 2011 and the commencement of jacket and pile fabrication by October 2011. Chevron is required to provide the BOEM with periodic updates on Chevron's progress and to meet each of the SOP activity schedule deadlines to maintain the SOP. Although the new December 1, 2010 through October 31, 2011 SOP formally expires on October 31, 2011, the BOEM has acknowledged that production is not scheduled to be restored at Eugene Island until October 2012. Therefore, Chevron must submit, and obtain approval by the regional supervisor of the BOEM of, an additional SOP request prior to October 31, 2011 to obtain BOEM authority for any redevelopment of Eugene Island 338 and 339 after October 31, 2011. However, the BOEM would review Chevron's interim progress under the December 1, 2010 through October 31, 2011 SOP for each activity date before any review of a request for SOP approval until October of 2012. While Chevron has stated that it intends to redevelop Eugene Island 338 and 339, and has met the activity schedule obligations through December 31, 2010, there is no obligation upon Chevron to continue to pursue such redevelopment.

In December 2009, Chevron entered into a participation agreement with a third party to assist in the redevelopment of Eugene Island 338 and 339. The redevelopment plan provided that three wells were to be drilled from a common open water location in Eugene Island 338 in the second quarter of 2010. The first well of the three-well drilling program had been drilled; however, drilling activity was suspended and the drilling rig moved off location in July 2010. Chevron's inability to obtain related drilling permits in a timely basis under the new guidelines issued by the BOEM on June 8, 2010, following the oil spill in the U.S. Gulf of Mexico related to the sinking of the *Deepwater Horizon* drilling rig, pursuant to Notice to Lessees No. 2010-N05, "Increased Safety Measures for Energy Development on the OCS", caused the parties to such participation agreement to revise and amend the participation agreement. The revised redevelopment plan provides for setting a platform at Eugene Island 338 and drilling wells into Eugene Island 339 and Eugene Island 338 from such platform. The revised redevelopment plan retains the original estimate for first production from Eugene Island 339 of the fourth quarter of 2012. Restoration of production at Eugene Island 338 and 339 is a complex process, requires various governmental permits, and cannot be assured at this time. The costs for the redevelopment project would be significant. Failure or inability to pursue such a redevelopment, or to satisfy the activity schedule approved by the BOEM, could result in a loss of the lease covering Eugene Island 339. At this time, there is and can be no assurance that each activity schedule date will be met or that an additional SOP will be approved by the BOEM or that production will be restored at Eugene Island 339. Additionally, the Trust cannot predict at this time the further impact that the oil spill in the U.S. Gulf of Mexico related to the sinking of the *Deepwater Horizon* drilling rig may have on the redevelopment of Eugene Island 339. See "Risk Factors" under Item 1A of this Form 10-K.

Production at Ship Shoal 182/183 ceased following damage inflicted by Hurricane Ike in September 2008. While the hurricane caused limited surface damage to the facilities at Ship Shoal 182/183, all of the wells at Ship Shoal 182/183 were shut-in following hurricane-related damage to a third-party transporter's natural gas pipeline. Crude oil revenues from Ship Shoal 182/183 represented approximately 50% of the crude oil and condensate revenues for the Royalty Properties in 2007 and approximately 51% of such revenues for the nine months ended September 30, 2008. Ship Shoal 182/183 contributed approximately 77% of the revenues from natural gas sales from the Royalty Properties in 2007 and approximately 42% of such revenues for the nine months ended September 30, 2008. A limited volume of oil production was restored in November 2008. The volume of oil production that can be produced is limited by the amount of gas that is also produced by the oil wells. The third-party transporter's natural gas pipeline repairs were completed and gas sales at Ship Shoal 182/183 were restored on June 26, 2009. However, the pipeline was shut down in mid-September 2009 for additional repairs. Production sales for both oil and natural gas at Ship Shoal 182 and 183 were restored on October 8, 2009 following completion of such additional repairs. Oil and gas production at Ship Shoal 182/183 ceased in March 2010 due to a leak in the oil pipeline that services Ship Shoal 182/183. Such oil pipeline has since been repaired and Ship Shoal 182/183 was reopened on May 1, 2010 after a 36-day shut-in. In November 2010, the platform at Ship Shoal 182/183 was shut-in for a scheduled tank replacement.

In addition, production from West Cameron 643 and East Cameron 371 ceased following damage inflicted by Hurricane Ike in September 2008 to third-party transporters' pipelines. Chevron, as the

Managing General Partner of the Partnership, understands that, as a result of the cessation of production at West Cameron 643 due to the damages inflicted by Hurricane Ike to a third-party transporter's pipeline, Hilcorp submitted to the BOEM a program to restore production at West Cameron 643 and that such request was granted. The approval by the BOEM expired by its terms on May 31, 2010, and Chevron has been informed by Hilcorp that it submitted to the BOEM a request for an extension but that such request was denied. Accordingly, the lease for West Cameron 643 expired on May 31, 2010. Chevron has been informed by Hilcorp that there is a deadline of June 1, 2011 to plug and abandon the wells and related infrastructure at West Cameron 643. The field operator for East Cameron 371 has reported to Chevron that a review of the remaining reserves for East Cameron 371 has been conducted, and that the wells at East Cameron 371 have been depleted. The lease for East Cameron 371 expired on March 31, 2010 and the field operator has informed Chevron that field abandonment work, including the related wells, equipment platforms and any field infrastructure, is expected to commence mid 2011, after the operator received an extension of the one-year deadline to complete such abandonment work.

In May 2007, the Trust engaged an independent oil and gas accounting firm for the purpose of reviewing the books and records of certain Working Interest Owners with respect to the Royalty Properties and the related payments to the Trust. As part of this audit review process, certain adjustments to revenues, production volumes, prices and capital expenditures have occurred, and references below to a prior period audit adjustment, or an audit of prior periods, refers to the audit described in this paragraph. We include discussions of audit adjustments in the comparison of years 2009 and 2008 because, as a result of such audit adjustments, certain of the Royalty Properties, including Eugene Island 339, have positive oil and gas volumes for 2009 (and the revenues associated therewith), despite there being no actual oil or gas production at such properties due to damages inflicted by Hurricane Ike in September 2008.

In January 2010, the Trust engaged the same independent oil and gas accounting firm to review the books and records of certain Working Interest Owners with respect to the Royalty Properties and the related payments to the Trust. Such audit review process is currently on-going and may result in certain adjustments to revenues, production volumes, prices and expenditures. As part of such process, Chevron has already agreed that $22,197 in adjustments were appropriate, which were credited in the first quarter of 2011. Chevron did not pay this amount to the Partnership or the Trust, but credited such amount against the Partnership's share of allocated expenses for the Royalty Properties. No assurance can be provided as to the ultimate outcome of such audit review process.

Years 2010 and 2009

Royalty income was $0 in 2009 and 2010 because there were no positive Net Proceeds attributable to the Royalty Properties due to damages inflicted to the Royalty Properties by Hurricane Ike in September 2008.

For 2010, the Trust had undistributed net loss of $1,537,061, representing the Trust's portion of the aggregate undistributed net loss of $6,154,398 associated with the Royalty Properties for 2010. For 2009, the Trust had undistributed net loss of $5,469,255. Undistributed net loss represents the amount of development and production costs associated with the Royalty that exceed the proceeds of production from the Royalty Properties during the period. An undistributed net loss is carried forward and offset, in future periods, by positive proceeds earned by the related Working Interest Owner(s). The Trust will not receive Net Proceeds until future proceeds from production exceed the total of the excess costs plus applicable accrued interest. Undistributed net income represents positive Net Proceeds, generated during the respective period, but not distributed by the Working Interest Owners.

Volumes and dollar amounts discussed below represent amounts recorded by the Working Interest Owners unless otherwise specified.

Natural Gas and Gas Products

Natural gas revenues and gas products increased 14% from $1,538,011 in 2009 to $1,756,145 in 2010, due primarily to increased production at Ship Shoal 182/183. Gas and gas products volumes increased from 296,309 Mcf equivalents in 2009 to 327,444 Mcf equivalents in 2010. The revenues and volumes for 2009 reflect net credits of $808,484 in revenues and 127,711 Mcf of gas for prior period adjustments. The average price received for natural gas increased 3% from $4.90 per Mcf in 2009 to $5.05 Mcf in 2010. Prior to taking into account such adjustments to revenues and volumes, the average price received for natural gas would have been $3.55 per Mcf in 2009.

Crude Oil and Condensate

Crude oil and condensate revenues increased 37% from $9,564,082 in 2009 to $13,130,251 in 2010, due primarily to increased production at Ship Shoal 182/183 and increased realized prices. Oil volumes increased 6.86% from 158,137 barrels in 2009 to 168,985 barrels in 2010. The revenues and volumes for 2009 reflect a credit associated with an audit for prior periods for $224,511 in revenues and 311 barrels. The average price received for crude oil and condensate increased 28% from $60.48 in 2009 to $77.70 in 2010. Prior to taking into account such adjustments to revenues and volumes, the average price received for crude oil and condensate would have been $59.18 per barrel in 2009.

Operating and Capital Expenditures

Operating expenses paid by the Working Interest Owners decreased 26% from $30,944,828 in 2009 to $22,749,090 in 2010, due primarily to less well and platform abandonment work being conducted at Eugene Island 339 in 2010 as compared to 2009. Reflected in the operating expenses for 2009 are cost allocation refunds of a net aggregate of $115,253 for certain prior period adjustments. Reflected within the operating expenses are management fees to Chevron, as Managing General Partner of the Partnership, of $1,281,318 and $1,172,039 for 2009 and 2010, respectively.

Capital expenditures paid by the Working Interest Owners increased 58% from $883,470 in 2009 to $1,399,182 in 2010. The capital expenditures during 2009 related primarily to repair of damages caused by Hurricane Ike in September 2008. The capital expenditures during 2010 related primarily to platform upgrades and repairs at Ship Shoal 182/183. Reflected in the capital expenditures for 2009 is a refund of $59,794 for certain prior period audit adjustments.

Special Cost Escrow Account

The special cost escrow account is an account of the Working Interest Owners, and it is described herein for information purposes only. The Conveyance provides for the reserve of funds for estimated future "Special Costs" of plugging and abandoning wells, dismantling platforms and other costs of abandoning the Royalty Properties, as well as for the estimated amount of future drilling projects and other capital expenditures on the Royalty Properties. As provided in the Conveyance, the amount of funds to be reserved is determined based on factors, including estimates of aggregate future production costs, aggregate future Special Costs, aggregate future net revenues and actual current net proceeds. Deposits into this account reduce current distributions and are placed in an escrow account and invested in short-term certificates of deposit. Such account is herein referred to as the "Special Cost Escrow" account. The Trust's share of interest generated from the Special Cost Escrow Account, $7,946 and $7,923 in 2010 and 2009, respectively, serves to reduce the Trust's share of allocated production costs. Special Cost Escrow funds will generally be utilized to pay Special Costs to the extent there are not adequate current Net Proceeds to pay such costs. Special Costs that have been paid are no longer included in the Special Cost Escrow calculation. Deposits to the Special Cost Escrow Account will generally be made when the balance in the Special Cost Escrow Account is less than 125% of future Special Costs and there is a Net Revenues Shortfall (a calculation of the excess of estimated future costs over estimated future net revenues pursuant to a formula contained in the Conveyance). When there is not a Net Revenues Shortfall, amounts in the Special Cost Escrow account will generally be released, to the extent that Special Costs have been incurred. Amounts in the Special Cost Escrow account will also be released when the balance in such account exceeds 125% of estimated future Special Costs. The discussion of the terms of the Conveyance and Special Cost Escrow account contained herein is qualified in its entirety by reference to the Conveyance itself, which is an exhibit to this Form 10-K and is available upon request from the Corporate Trustee.

In 2009, no funds were released from or deposited into the Special Cost Escrow account. As of December 31, 2009, approximately $4,306,275 remained in the Special Cost Escrow Account. In the fourth quarter of 2010, Chevron withdrew $4,304,894 from the Special Cost Escrow Account to cover expenses incurred in connection with the plugging and abandonment of Eugene Island 339, leaving a balance of $1,000 in the Special Cost Escrow Account. After taking into account such withdrawal, aggregate development and production costs in excess of the related proceeds for the royalty Properties as of December 31, 2010 was approximately $3.5 million, net to the Royalty; however, additional deposits to the Special Cost Escrow account would be required in future periods in accordance with the Conveyance if, and when, Net Proceeds would otherwise be payable on the royalty.

Chevron, in its capacity as Managing General Partner of the Partnership, has advised the Trust that additional deposits to the Special Cost Escrow account may be required in future periods in connection with other production costs, other abandonment costs, other capital expenditures and changes to the estimates and factors described above. Such deposits could result in a significant reduction to Royalty income for the periods in which such deposits are made, including the possibility that no Royalty income would be received in such periods.

Summary By Property

Listed below is a summary of 2010 operations as compared to 2009 of the principal Royalty Properties based on gross revenues generated during these periods combined.

Eugene Island 339

Eugene Island 339 crude oil revenues increased $44,448, from $38,544 in 2009 to $82,992 in 2010, due to an increase in crude oil volumes from 318 barrels in 2009 to 797 barrels in 2010. However, there was no actual crude oil production during 2009 or 2010 and such crude oil revenues and production volumes are entirely from audit adjustments made in the first quarter of 2009 and the fourth quarter of 2010 and associated with prior periods. Gas revenues decreased $41,409, from $170,231 in 2009 to $128,822 in 2010. Gas production was 33,296 Mcf in 2009 and 15,055 Mcf in 2010. However, there was no actual gas production during 2009 or 2010 and such gas revenues and volumes are entirely from audit adjustments made in the first quarter of 2009 and the fourth quarter of 2010 associated with prior periods. Capital expenditures decreased from $246,729 in 2009 to $(8,582) in 2010. The higher capital expenditures during 2009 reflect costs associated with damages caused by Hurricane Ike. Capital expenditures for 2010 reflect credits of $8,582 associated with the workover of a well during a prior period and an invoice correction related to well abandonment. Operating expenses decreased from $26,866,150 in 2009 to $18,634,670 in 2010 due primarily to less well and platform abandonment work being conducted at Eugene Island 339 in 2010 as compared to 2009.

Production from Eugene Island 339 ceased following damage inflicted by Hurricane Ike in September 2008, as the platforms and wells on Eugene Island 339 were completely destroyed. Chevron is working on the plugging and abandonment of the existing wells, clearing debris and otherwise dealing with the remaining infrastructure, which activities are not expected to be completed until the second quarter of 2012. Chevron has informed the Corporate Trustee that Chevron presently intends to pursue the redevelopment of platforms and wells at Eugene Island 339 in accordance with the terms and conditions established by the BOEM in response to Chevron's submission to the BOEM of a program to restore production at Eugene Island 339. At this point in time, there can be no assurance that production will be restored at Eugene Island 339. See "—Operations."

Ship Shoal 182/183

Ship Shoal 182/183 crude oil revenues increased from $9,052,477 in 2009 to $12,590,657 in 2010, primarily due to an increase in net crude oil production from 152,725 barrels in 2009 to 162,121 in 2010 and an increase in average crude oil prices received. Average crude oil prices increased from $59.27 per barrel in 2009 to $77.66 per barrel in 2010. The revenues and volumes for 2010 reflect an audit adjustment made in the fourth quarter of 2010, which resulted in the recognition of $10,188 in oil revenues from a prior period. Gas revenues increased from $1,160,602 in 2009 to $1,296,622 in 2010. Gas production increased from 233,142 Mcf in 2009 to 265,508 Mcf in 2010. The revenues and volumes for 2009 reflect an audit adjustment made in the first quarter of 2009, which resulted in the recognition of $725,720 in gas revenues associated with 107,416 Mcf of gas from a prior period. The average natural gas sales price increased from $3.46 per Mcf in 2009, excluding the audit adjustment made during 2009, to $4.88 in 2010. Capital expenditures increased from a balance of $556,872 in 2009 to $1,329,005 in 2010 primarily due to platform upgrades and repairs during 2010. Operating expenses increased from $3,076,853 in 2009 to $3,904,099 in 2010 due to an unsuccessful well workover during the third quarter of 2010 and continuing repair costs related to damages inflicted by Hurricane Ike.

Production from Ship Shoal 182 and 183 ceased following damage inflicted by Hurricane Ike in September 2008. While Hurricane Ike caused limited surface damage to the facilities at Ship Shoal 182/183, all of the wells at Ship Shoal 182/183 were shut-in following hurricane-related damage to a third-party transporter's natural gas pipeline. A limited volume of oil production was restored in November 2008. The volume of oil production that can be produced is limited by the amount of gas that is also produced by the oil wells. The third-party transporter's natural gas pipeline repairs were completed and gas sales at Ship Shoal 182/183 were restored on June 26, 2009. However, the pipeline was shut down in mid-September for additional repairs. Production sales for both oil and natural gas at Ship Shoal 182/183 were restored on October 8, 2009 following completion of such additional repairs. Oil and gas production at Ship Shoal 182/183 ceased in March 2010 due to a leak in the oil pipeline that services Ship Shoal 182/183. Such oil pipeline has since been repaired and Ship Shoal 182/183 was reopened on May 1, 2010 after a 36-day shut-in. In November 2010, the platform at Ship Shoal 182/183 was shut-in for a scheduled tank replacement. See "—Operations."

South Timbalier 36/37

South Timbalier 36/37 oil revenues increased from $269,554 in 2009 to $346,870 in 2010 due to an increase in realized prices. There was a decrease in crude oil production from 4,859 barrels in 2009 to 4,526 barrels in 2010. The average crude oil price was $55.48 per barrel in 2009 compared to $76.64 per barrel in 2010. Gas revenues increased from $40,425 in 2009 to $48,391 in 2010 primarily due to increased production and an increase in realized prices. There was an increase in natural gas volumes from 9,024 Mcf in 2009 to 10,094 Mcf in 2010. Gas volumes for 2009 reflect a debit of 164 Mcf in 2009. The average gas sales price realized was $4.49 per Mcf in 2009 and $4.79 per Mcf in 2010. Capital expenditures increased from $(55,422) in 2009 to $78,759 in 2010. The capital expenditures in 2009 reflect a $56,263 credit related to a prior period audit adjustment. Operating expenses increased $41,731 from $(4,563) in 2009 to $37,168 in 2010. The operating expenses in 2009 reflect a $36,992 credit in 2009 related to a prior period audit adjustment.

Eugene Island 342/343

Eugene Island 342/343 oil revenues increased from $17,545 in 2009 to $109,729 in 2010 due to an increase in both production and realized prices. There was an increase in crude oil production from

228 barrels in 2009 to 1,541 barrels in 2010. Gas revenues increased from $5,951 in 2009 to $9,926 in 2010 primarily due to increased production and an increase in realized prices. Natural gas volumes increased from 927 Mcf in 2009 to 2,924 Mcf in 2010. On the date of this Form 10-K, Apache Corporation is the operator of Eugene Island 342/343.

West Cameron 643

Production from West Cameron 643 ceased following damage inflicted by Hurricane Ike in September 2008 to a third-party transporter's pipeline. The lease for West Cameron 643 expired on May 31, 2010. West Cameron 643 gas revenues were ($87,518) in 2009 as compared to $0 in 2010. There was no gas production during 2009 or 2010 and the revenues for 2009 (and the associated volumes of (13,001) Mcf) are a result of debits to correct an error in revenue allocation in August 2008. Operating expenses decreased from $1,006,626 in 2009 to $173,152 in 2010. Capital expenditures decreased from $135,291 in 2009 to $0 in 2010. See "—Operations."

East Cameron 371

Production from East Cameron 371 ceased following damage inflicted by Hurricane Ike in September 2008 to a third-party transporter's pipeline. The field operator for East Cameron 371 has reported to Chevron that a review of the remaining reserves for East Cameron 371 has been conducted, and that the wells at East Cameron 371 have been depleted. The lease for East Cameron 371 expired on March 31, 2010. There were no gas revenues or oil revenues during 2009 or 2010, as there was no production during these time periods. See "—Operations."

Years 2009 and 2008

Royalty income decreased 100% from $14,451,252 in 2008 to $0 in 2009 because there were no positive Net Proceeds attributable to the Royalty Properties due to damages inflicted to the Royalty Properties by Hurricane Ike in September 2008.

For 2009, the Trust had undistributed net loss of $5,469,255. For 2008, the Trust had undistributed net loss of $33,169. Undistributed net loss represents the amount of development and production costs associated with the Royalty that exceed the proceeds of production from the Royalty Properties during the period. An undistributed net loss is carried forward and offset, in future periods, by positive proceeds earned by the related Working Interest Owner(s). The Trust will not receive Net Proceeds until future proceeds from production exceed the total of the excess costs plus applicable accrued interest. Undistributed net income represents positive Net Proceeds, generated during the respective period, but not distributed by the Working Interest Owners.

Volumes and dollar amounts discussed below represent amounts recorded by the Working Interest Owners unless otherwise specified.

Natural Gas and Gas Products

Natural gas revenues and gas products decreased 89% from $14,248,644 in 2008 to $1,538,011 in 2009, due primarily to decreases in production resulting from damages caused by Hurricane Ike in September 2008. Gas and gas products volumes decreased from 1,625,408 Mcf equivalents in 2008 to 296,309 Mcf equivalents in 2009. The revenues and volumes for 2009 reflect net credits of $808,484 in revenues and 127,711 Mcf of gas for prior period adjustments; the revenues and volumes for 2008 reflect a net debit associated with an audit of prior periods of $310,032 in revenues and a credit of 99,117 Mcf of gas. The average price received for natural gas decreased 42% from $8.45 per Mcf in 2008 to $4.90 Mcf in 2009. Prior to taking into account such adjustments to revenues and volumes, the average price received for natural gas would have been $9.43 per Mcf in 2008 and $3.55 per Mcf in 2009.

Crude Oil and Condensate

Crude oil and condensate revenues decreased 77% from $42,424,601 in 2008 to $9,564,082 in 2009, due primarily to decreases in production resulting from damages caused by Hurricane Ike in September 2008. Oil volumes decreased 63% from 421,958 barrels in 2008 to 158,137 barrels in 2009. The revenues and volumes for 2009 reflect a credit associated with an audit for prior periods for $224,511 in revenues and 311 barrels; the revenues and volumes for 2008 reflect a credit associated with an audit for prior periods for $225,823 in revenues and 24,573 barrels. The average price received for crude oil and condensate decreased 40% from $100.54 in 2008 to $60.48 in 2009. Prior to taking into account such adjustments to revenues and volumes, the average price received for crude oil and condensate would have been $106.19 per barrel in 2008 and $59.18 per barrel in 2009.

Operating and Capital Expenditures

Operating expenses paid by the Working Interest Owners increased 341% from $7,012,792 in 2008 to $30,944,828 in 2009, primarily as a result of well abandonment costs at Eugene Island 339 as a result of Hurricane Ike. Reflected in the operating expenses for 2009 are cost allocation refunds of a net aggregate of $115,253 for certain prior period adjustments. Reflected within the operating expenses are management fees to Chevron, as Managing General Partner of the Partnership, of $1,926,245 and $1,281,318 for 2008 and 2009, respectively.

Capital expenditures paid by the Working Interest Owners increased 286% from $228,959 in 2008 to $883,470 in 2009. The higher amount of capital expenditures during 2009 related primarily to repair of damages caused by Hurricane Ike in September 2008. Reflected within the capital expenditures line item for 2008 is a refund of $495,600 from the Working Interest Owners for certain prior period adjustments. Reflected in the capital expenditures for 2009 is a refund of $59,794 for certain prior period audit adjustments.

Special Cost Escrow Account

In 2009, no funds were released from or deposited into the Special Cost Escrow account. As of December 31, 2009, approximately $4,306,275 remained in the Special Cost Escrow Account. In 2008, the Working Interest Owners refunded a net amount to the Trust of $2,388,061 from the Special Cost Escrow Account. As of December 31, 2008, approximately $4,325,503 remained in the Special Cost Escrow Account. The net refund for 2008 was primarily due to a revision to the Special Cost Escrow Account related to the outside audit commenced by the Trust as discussed above. See "—Operations".

Summary By Property

Listed below is a summary of 2009 operations as compared to 2008 of the five principal Royalty Properties based on gross revenues generated during these periods combined.

Eugene Island 339

Eugene Island 339 crude oil revenues decreased $19,660,953, from $19,699,497 in 2008 to $38,544 in 2009, due to a decrease in crude oil production from 188,337 barrels in 2008 to 318 barrels in 2009. However, there was no actual crude oil production during 2009 and such crude oil revenues and production volumes are entirely from an audit adjustment made in the first quarter of 2009 and associated with a prior period. The oil revenues for 2008 reflect a $207,194 credit relating to an audit of prior periods. The average price of crude oil was $93.79 per barrel in 2008. Prior to taking into account such adjustments in 2008, the average crude oil price would have been $104.60 per barrel in 2008. Gas revenues decreased $4,012,672, from $4,182,903 in 2008 to $170,231 in 2009, due to a decrease in gas production from 435,583 Mcf in 2008 to 33,296 Mcf in 2009. However, there was no actual gas production during 2009 and such gas revenues and volumes are entirely from an audit adjustment made in the first quarter of 2009 and associated with a prior period. The gas revenues and volumes for 2008 reflect debits of $867,840 and 31,130 Mcf associated with an audit of prior periods. The average price received for natural gas during 2008 was $7.10 per Mcf . Prior to taking into account such adjustments in 2008, the average gas sales price realized in 2008 would have been $9.60 per Mcf. Capital expenditures decreased from $518,385 in 2008 to $246,729 in 2009. There were limited capital expenditures during the second, third and fourth quarter of 2009 and the capital expenditures in the 2008 primarily relate to repairs associated with a conversion to a water injector. Operating expenses increased from $2,868,686 in 2008 to $26,866,150 in 2009 due to well abandonment costs incurred as a result of Hurricane Ike.

Production from Eugene Island 339 ceased following damage inflicted by Hurricane Ike in September 2008, as the platforms and wells on Eugene Island 339 were completely destroyed. Chevron is working on the plugging and abandonment of the existing wells, clearing debris and otherwise dealing with the remaining infrastructure, which activities are not expected to be completed until the second quarter of 2012. Chevron has informed the Corporate Trustee that Chevron presently intends to pursue the redevelopment of platforms and wells at Eugene Island 339 in accordance with the terms and conditions established by the BOEM in response to Chevron's submission to the BOEM of a program to restore production at Eugene Island 339. At this point in time, there can be no assurance that production will be restored at Eugene Island 339. See "—Operations."

Ship Shoal 182/183

Ship Shoal 182/183 crude oil revenues decreased from $21,775,671 in 2008 to $9,052,477 in 2009, primarily due to a decrease in net crude oil production from 202,185 barrels in 2008 to 152,725 in 2009 and a decrease in average crude oil prices received. Included in the revenues and production for 2008 was a debit adjustment of $5,657 and 135 barrels associated with prior period adjustments. Average crude oil prices decreased from $107.70 per barrel in 2008 to $59.27 per barrel in 2009, excluding the immaterial audit adjustment made during 2008. Gas revenues decreased from $4,726,292 in 2008 to $1,160,602 in 2009. Gas production decreased from 508,781 Mcf in 2008, which included an upward adjustment of 44,360 Mcf and $347,713 in revenues relating to an audit of prior periods, to 233,142 Mcf in 2009. The revenues and volumes for 2009 reflect an audit adjustment made in the first quarter of 2009, which resulted in the recognition of $725,720 in gas revenues associated with 107,416 Mcf of gas from a prior period. The average natural gas sales price decreased from $9.29 per Mcf in 2008 to $3.46 in 2009, excluding the audit adjustment made during 2009. Capital expenditures increased from a balance of ($419,971) in 2008 to $556,872 in 2009 primarily due to a credit of $495,600 in 2008 related to an audit adjustment for prior periods. Operating expenses increased from $2,471,185 in 2008 to $3,076,853 in 2009 due to an increase in operating and repair costs related to damages inflicted by Hurricane Ike.

Production from Ship Shoal 182 and 183 ceased following damage inflicted by Hurricane Ike in September 2008. While Hurricane Ike caused limited surface damage to the facilities at Ship Shoal 182/183, all of the wells at Ship Shoal 182/183 were shut-in following hurricane-related damage to a third-party transporter's natural gas pipeline. A limited volume of oil production was restored in November 2008. The volume of oil production that can be produced is limited by the amount of gas that is also produced by the oil wells. The third-party transporter's natural gas pipeline repairs were completed and gas sales at Ship Shoal 182/183 were restored on June 26, 2009. However, the pipeline was shut down in mid-September for additional repairs. Production sales for both oil and natural gas at Ship Shoal 182/183 were restored on October 8, 2009 following completion of such additional repairs. See "—Operations."

West Cameron 643

West Cameron 643 gas revenues decreased from $2,024,841 in 2008 to ($87,518) in 2009, due primarily to a decrease in gas volumes from 214,130 Mcf in 2008 to (13,001) Mcf in 2009. There was no gas production during 2009 and the revenues and volumes for 2009 are a result of debits to correct an error in revenue allocation in August 2008. Revenues and volumes for 2008 reflect credits of $200,133 and 28,402 Mcf related to an audit of prior periods. The average natural gas sales price during 2008 was $9.17 per Mcf. Prior to taking into account such adjustments in 2008, the average gas sales price realized in 2008 would have been $9.46 per Mcf. Operating expenses decreased from $1,233,887 in 2008 to $1,006,626 in 2009. Capital expenditures increased from $27,953 in 2008 to $135,291 in 2009, due primarily to work related to the installation of piping, fittings and valves.

Production from West Cameron 643 ceased following damage inflicted by Hurricane Ike in September 2008 to a third-party transporter's pipeline. The lease for West Cameron 643 expired on May 31, 2010. See "—Operations."

East Cameron 371

East Cameron 371 gas revenues decreased from $252,992 in 2008 to $0 in 2009 as a result of the field being shut-in following Hurricane Ike in September 2008. Gas volumes decreased from 32,463 Mcf in 2008 to 0 Mcf for 2009. The average gas sales price realized during 2008 was $7.79 per Mcf. Oil revenues decreased from $47,962 in 2008 to $0 in 2009 as a result of the field being shut-in. Production decreased from 531 barrels in 2008 to 0 barrels for in 2009. The average crude oil price was $90.26 per barrel in 2008. Capital expenditures were $0 in 2008 and 2009 and operating expenses decreased from $298,413 in 2008 to $0 in 2009 as a result of the field being shut-in.

Production from East Cameron 371 ceased following damage inflicted by Hurricane Ike in September 2008 to a third-party transporter's pipeline. The field operator for East Cameron 371 has reported to Chevron that a review of the remaining reserves for East Cameron 371 has been conducted, and that the wells at East Cameron 371 have been depleted. The lease for East Cameron 371 expired on March 31, 2010. See "—Operations."

South Timbalier 36/37

South Timbalier 36/37 oil revenues decreased from $592,068 in 2008 to $269,554 in 2009 primarily due to a decrease in realized prices and a four-day field shut-in related to compressor problems and equipment issues that have been repaired. There was a decrease in crude oil production from 5,802 barrels in 2008 to 4,859 barrels in 2009. The average crude oil price was $102.05 per barrel in 2008 compared to $55.48 per barrel in 2009. Gas revenues decreased from $110,111 in 2008 to $40,425 in 2009 primarily due to a decrease in realized prices and a four-day field shut-in related to compressor problems and equipment issues that have been repaired. There was an increase in natural gas volumes from 5,351 Mcf in 2008 to 9,024 Mcf in 2009. Gas volumes for 2008 reflect a debit of 4,870 Mcf related to revised volume allocations for the years 2004 through 2007 and a debit of 164 Mcf in 2009. The average gas sales price realized was $9.58 per Mcf in 2008, excluding such adjustment, and $4.49 per Mcf in 2009. Capital expenditures decreased from $43,345 in 2008 to $(55,422) in 2009 after taking into account a $56,263 credit in 2009 for a prior period audit adjustment. Operating expenses decreased $145,073 from $140,510 in 2008 to $(4,563) in 2009 after taking into account a $36,992 credit in 2009 for a prior period audit adjustment.

Production and Price Review

The following schedule provides a summary of the volumes and weighted average prices for crude oil and condensate and natural gas recorded by the Working Interest Owners for the Royalty Properties, as well as the Working Interest Owners' calculations of the Net Proceeds and Royalties paid to the Trust during the periods indicated. Net proceeds due to the Trust are calculated for each three month period commencing on the first day of February, May, August and November.

	Royalty Properties Year Ended December 31,(1)		
	2010	2009	2008
Crude oil and condensate (bbls)	168,985	158,137	421,958
Natural gas and gas products (Mcfe)	327,444	296,309	1,625,408
Crude oil and condensate average price, per bbl	$ 77.70	$ 60.48	$ 100.54
Natural gas average price, per Mcf (excluding gas products)	$ 5.05	$ 4.90	$ 8.45
Crude oil and condensate revenues	$ 13,130,251	$ 9,564,082	$ 42,424,601
Natural gas and gas products revenues	$ 1,756,145	$ 1,538,011	$ 14,248,644
Interest	(44,531)	—	—
Production expenses	(23,921,129)	(32,226,146)	(8,939,036)
Capital expenditures	(1,399,182)	(883,471)	(228,959)
Undistributed Net Loss (income)(2)	$ 6,154,398	$ 21,898,918	$ 132,688
Refund of/(Provision for) Special Cost Escrow	$ 4,324,048	$ 108,606	$ 10,172,852
Net Proceeds	$ —	$ —	$ 57,810,788
Royalty interest	x25%	x25%	x25%
Partnership share	$ —	$ —	$ 14,452,697
Trust interest	x99.99%	x99.99%	x99.99%
Trust share of Royalty Income(3)	$ —	$ —	$ 14,451,252

(1) Amounts represent actual production for the 12-month period ended on October 31 of each year, respectively.

(2) Undistributed net loss represents the amount of development and production costs associated with the Royalty that exceed the proceeds of production from the Royalty Properties during the period. An undistributed net loss is carried forward and offset, in future periods, by positive proceeds earned by the related Working Interest Owner(s). The Trust will not receive Net Proceeds until future proceeds from production exceed the total of the excess costs plus applicable accrued interest. Undistributed net income represents positive Net Proceeds, generated during the respective period, but not distributed by the Working Interest Owners.

(3) See "Management's Discussion and Analysis of Financial Condition and Results of Operations—Operations" and Note 4 to the Notes to the Financial Statements under Item 8 of this Form 10-K for a discussion regarding uncertainty of distributions.

Off-Balance Sheet Arrangements

The Trust has no off-balance sheet arrangements.

Contractual Obligations

As of December 31, 2010, the Trust had no obligations or commitments to make future contractual obligations except for administrative fees owed to the Trustees pursuant to the Trust Agreement.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

The only assets of and sources of income to the Trust are cash and the Trust's interest in the Partnership, which is the holder of the Royalty. Consequently, the Trust is exposed to market risk associated with the Royalty from fluctuations in oil and gas prices. Reference is also made to Item 1 of this Form 10-K.

The Trust may borrow money to pay expenses of the Trust. Additionally, if development and production costs of the Royalty exceed the proceeds of production from the Royalty Properties, the Trust will not receive Net Proceeds until future proceeds from production exceed the total of the excess costs plus accrued interest, at a rate equal to one-fourth of (i) one-half of one percent plus (ii) the median between the prime interest rate at the end of a quarterly period in which there are excess costs and the prime interest rate at the end of the preceding quarterly period, during the deficit period. Consequently, the Trust will be exposed to interest rate market risk should it borrow money to pay expenses and to the extent that development and production costs of the Royalty exceed the proceeds of production from the Royalty Properties.

Item 8. **Financial Statements and Supplementary Data**

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Trustees and Unit Holders of
TEL Offshore Trust
Austin, Texas

We have audited the accompanying statements of assets, liabilities and trust corpus—modified cash basis of TEL Offshore Trust (the "Trust") as of December 31, 2010 and 2009, and the related statements of distributable income and changes in trust corpus—modified cash basis for each of the three years ended December 31, 2010. These financial statements are the responsibility of the Corporate Trustee. Our responsibility is to express an opinion on the financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. The Trust is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Trust's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by the trustee, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

As described in Note 3 to the financial statements, these financial statements were prepared on the modified cash basis of accounting, which is a comprehensive basis of accounting other than accounting principles generally accepted in the United States of America.

In our opinion, such financial statements present fairly, in all material respects, the assets, liabilities and trust corpus of TEL Offshore Trust as of December 31, 2010 and 2009, and its distributable income and changes in trust corpus for each of the three years ended December 31, 2010, on the comprehensive basis of accounting described in Note 3 to the financial statements.

The accompanying financial statements have been prepared assuming that the Trust will continue as a going concern. As discussed in Note 4 to the financial statements, the Trust has not received any royalties or paid distributions since 2008, which raises substantial doubt about its ability to continue as a going concern. The Trustee's plans concerning these matters are also discussed in Note 6 to the financial statements. The financial statements do not include any adjustments that might result from the outcome of this uncertainty.

/s/ Deloitte & Touche LLP

Austin, Texas
March 31, 2011

TEL OFFSHORE TRUST

STATEMENTS OF ASSETS, LIABILITIES AND TRUST CORPUS

	December 31, 2010	December 31, 2009
Assets		
Cash and cash equivalents	$ 352,017	$ 1,263,080
Net overriding royalty interest in oil and gas properties, net of accumulated amortization of $28,245,160 and $28,240,469 at December 31, 2010 and 2009, respectively	22,495	27,186
Total assets	$ 374,512	$ 1,290,266
Liabilities and Trust Corpus		
Distribution payable to Unit holders	$ —	$ —
Reserve for future Trust expenses	352,017	1,263,080
Trust corpus (4,751,510 Units of beneficial interest authorized and outstanding at December 31, 2010 and 2009)	22,495	27,186
Total liabilities and Trust corpus	$ 374,512	$ 1,290,266

STATEMENTS OF DISTRIBUTABLE INCOME

	Year Ended December 31, 2010	2009	2008
Royalty income	$ —	$ —	$ 14,451,252
Interest income	181	1,334	37,422
	181	1,334	14,488,674
General and administrative expenses	(911,245)	(971,545)	(840,455)
Decrease (Increase) in reserve for future Trust expenses	911,064	970,211	(349,565)
Distributable income	$ —	$ —	$ 13,298,654
Distributions per Unit (4,751,510 Units)	$ 0.000000	$ 0.000000	$ 2.798827

STATEMENTS OF CHANGES IN TRUST CORPUS

	Year Ended December 31, 2010	2009	2008
Trust corpus, beginning of year	$ 27,186	$ 31,338	$ 40,197
Distributable income	—	—	13,298,654
Distributions to Unit holders	—	—	(13,298,654)
Amortization of net overriding royalty interest	(4,691)	(4,152)	(8,859)
Trust corpus, end of year	$ 22,495	$ 27,186	$ 31,338

The accompanying notes are an integral part of these financial statements.

TEL OFFSHORE TRUST

NOTES TO FINANCIAL STATEMENTS

(1) Trust Organization and Provisions

Tenneco Offshore Company, Inc. ("Tenneco Offshore") created the TEL Offshore Trust ("Trust") effective January 1, 1983, pursuant to the Plan of Dissolution ("Plan") approved by Tenneco Offshore's stockholders on December 22, 1982. In accordance with the Plan, the TEL Offshore Trust Partnership ("Partnership") was formed in which the Trust owns a 99.99% interest and Tenneco Oil Company initially owned a .01% interest. In general, the Plan was effected by transferring an overriding royalty interest ("Royalty") equivalent to a 25% net profits interest in the oil and gas properties (the "Royalty Properties") of Tenneco Exploration, Ltd. located offshore Louisiana to the Partnership and issuing certificates evidencing units of beneficial interest in the Trust in liquidation and cancellation of Tenneco Offshore's common stock.

On January 14, 1983, Tenneco Offshore distributed units of beneficial interest ("Units") in the Trust to holders of Tenneco Offshore's common stock on the basis of one Unit for each common share owned on such date.

The terms of the Trust Agreement, dated January 1, 1983 (as amended, the "Trust Agreement"), provide, among other things, that:

(a) the Trust is a passive entity and cannot engage in any business or investment activity or purchase any assets;

(b) the interest in the Partnership can be sold in part or in total for cash upon approval of a majority of the Unit holders;

(c) the Trustees, as defined below, can establish cash reserves and borrow funds to pay liabilities of the Trust and can pledge the assets of the Trust to secure payments of the borrowings. At December 31, 2010, the reserve amount was $352,017;

(d) the Trustees will make cash distributions to the Unit holders in January, April, July and October of each year as discussed in Note 4; and

(e) the Trust will terminate upon the first to occur of the following events: (i) total future net revenues attributable to the Partnership's interest in the Royalty, as determined by independent petroleum engineers, as of the end of any year, are less than $2.0 million or (ii) a decision to terminate the Trust by the affirmative vote of Unit holders representing a majority of the Units. Future net revenues attributable to the Royalty were estimated at approximately $19.8 million (unaudited) as of October 31, 2010. Upon termination of the Trust, the Corporate Trustee will sell for cash all assets held in the Trust estate and make a final distribution to the Unit holders of any funds remaining, after all Trust liabilities have been satisfied.

The Trust is currently administered by The Bank of New York Mellon Trust Company, N.A., which succeeded JPMorgan Chase Bank, N.A. as the Corporate Trustee, effective October 2, 2006 pursuant to an agreement under which The Bank of New York acquired substantially all of the Corporate Trust business of JPMorgan Chase (formerly known as The Chase Manhattan Bank), and Gary C. Evans, Thomas H. Owen, Jr. and Jeffrey S. Swanson ("Individual Trustees"), as trustees ("Trustees").

(2) Net Overriding Royalty Interest

The Royalty entitles the Trust to its share (99.99%) of 25% of the Net Proceeds attributable to the Royalty Properties. The Conveyance, dated January 1, 1983, provides that the Working Interest Owners will calculate, for each period of three months commencing the first day of February, May, August and

(2) Net Overriding Royalty Interest (Continued)

November, an amount equal to 25% of the Net Proceeds from their oil and gas properties for the period. Generally, "Net Proceeds" means the amounts received by the Working Interest Owners from the sale of minerals from the Royalty Properties less operating and capital costs incurred, management fees and expense reimbursements owing to the Managing General Partner of the Partnership, applicable taxes other than income taxes, and the Special Cost Escrow account. The Special Cost Escrow account is established for the future costs to be incurred to plug and abandon wells, dismantle and remove platforms, pipelines and other production facilities, and for the estimated amount of future capital expenditures on the Royalty Properties. Net Proceeds do not include amounts received by the Working Interest Owners as advance gas payments, "take-or-pay" payments or similar payments unless and until such payments are extinguished or repaid through the future delivery of gas.

As of October 9, 2001, Chevron Corporation merged with Texaco Inc. and the Royalty Properties owned by Texaco Exploration and Production Inc. ("TEPI") were assigned to Chevron U.S.A. Inc. ("Chevron") on May 1, 2002. Crude oil sales from the Chevron and TEPI properties added together accounted for approximately 100%, 98% and 99% of crude oil revenues from the Royalty Properties during 2010, 2009 and 2008, respectively. Sales to Chevron Corporation accounted for 100% of total gas revenues from the Royalty Properties during 2010 and 2009, and approximately 99% of total gas revenues from the Royalty Properties during 2008.

The Trust's share of Royalty income was reduced by approximately $293,010, $320,329 and $481,561 in 2010, 2009 and 2008, respectively, for management fees paid to the Working Interest Owners as reimbursement for expenses incurred by them on behalf of the Trust. Such management fees were calculated as 3% of the Trust's share of the sum of revenues, production expenses and capital expenditures attributable to the Royalty Properties in each of the three years above.

(3) Basis of Accounting and Going Concern

The financial statements of the Trust are prepared on the following basis:

(a) Royalty income is recorded when received, including the effect of overtaken or undertaken positions and negative or positive adjustments, by the Corporate Trustee on the last business day of each calendar quarter. In addition, Royalty income includes amounts related to funds deposited or released from the Special Cost Escrow account—see (c);

(b) Trust general and administrative expenses are recorded when paid, except for the cash reserved for future general and administrative expenses; and

(c) The funds deposited or released from the Special Cost Escrow account are recorded at the time of payment or receipt. The Special Cost Escrow account is an account of the Working Interest Owners and is not reflected in the financial statements of the Trust.

This manner of reporting income and expenses is considered to be the most meaningful because the quarterly distributions to Unit holders are based on net cash receipts received from the Working Interest Owners. The financial statements of the Trust differ from financial statements prepared in accordance with generally accepted accounting principles, because, under such principles, Royalty income and Trust general and administrative expenses for a quarter would be recognized on an accrual basis. In addition, amortization of the net overriding royalty interest, calculated on a units-of-production basis, is charged directly to Trust corpus since such amount does not affect distributable income.

TEL OFFSHORE TRUST

NOTES TO FINANCIAL STATEMENTS (Continued)

(3) Basis of Accounting and Going Concern (Continued)

Cash and cash equivalents include all highly liquid short-term investments with original maturities of three months or less.

The changes in reserve for future Trust expenses includes both changes of amounts deemed necessary by the Trustees and related distributions, as well as amounts paid from the reserve during periods when the Trust has insufficient income to pay Trust expenses.

The Trust reviews net overriding royalty interests in oil and gas properties for possible impairment whenever events or circumstances indicate the carrying amount of the asset may not be recoverable. If there is an indication of impairment, the Trust prepares an estimate of future cash flows (undiscounted and without interest charges) expected to result from the use of the asset and its eventual disposition. If these cash flows are less than the carrying amount of the asset, an impairment loss is recognized to write down the asset to its estimated fair value. Preparation of estimated expected future cash flows is inherently subjective and is based on the Corporate Trustee's best estimate of assumptions concerning expected future conditions. There were no write downs taken in the periods presented.

The Special Cost Escrow account (see Note 5) is established for future costs to be incurred to plug and abandon wells, dismantle and remove platforms, pipelines and other production facilities, and for the estimated amount of future capital expenditures on the Royalty Properties. The funds held in the Special Cost Escrow account are not reflected in the financial statements of the Trust. However, funds deposited to or released from the Special Cost Escrow account are included in Royalty income.

The preparation of financial statements requires the Trustees to make use of estimates and assumptions that affect amounts reported in the financial statements as well as certain disclosures. Actual results could differ from those estimates.

The amount of cash distributions by the Trust is dependent on, among other things, the sales prices for oil and gas produced from the Royalty Properties and the quantities of oil and gas sold. It should be noted that substantial uncertainties exist with regard to future oil and gas prices, which are subject to material fluctuations due to changes in production levels and pricing and other actions taken by major petroleum producing nations, as well as the regional supply and demand for gas, worldwide political conditions, weather, industrial growth, conservation measures, competition, economic conditions generally and other variables. The Trust does not enter into any hedging transactions on future production.

The accompanying financial statements have been prepared assuming that the Trust will continue as a going concern. The lack of Net Proceeds and the inability to maintain adequate cash reserves raise substantial doubt about the Trust's ability to continue as a going concern. Certain potential alternatives available to the Trustees are described in Note 6. The financial statements do not include any adjustments that might result from the outcome of this uncertainty.

(4) Distributions to Unit Holders

In accordance with the provisions of the Trust Agreement, generally all Net Proceeds received by the Trust, net of Trust general and administrative expenses and any cash reserves established for the payment of contingent or future obligations of the Trust, are distributed currently to the Unit holders. These distributions are referred to as "distributable income". The amounts distributed are determined on a quarterly basis and are payable to Unit holders of record as of the last business day of each

(4) Distributions to Unit Holders (Continued)

calendar quarter. However, cash distributions are made in January, April, July and October and include interest earned from the quarterly record date to the date of distribution.

Production ceased at Eugene Island 339 and Ship Shoal 182 and 183 following damages inflicted by Hurricane Ike in September 2008. Future Net Proceeds may take into account the Trust's share of project costs and other related expenditures that are not covered by insurance of the operator of the Royalty Properties. On December 19, 2008, the Trust announced its fourth quarter distribution of approximately $0.7 million, which was paid on January 9, 2009. The funds available for the fourth quarter distribution were severely negatively impacted by Hurricane Ike. On March 25, 2009, the Trust announced that there would be no trust distribution for the first quarter of 2009, and the Trust has not made a distribution since January 9, 2009.

There are not likely to be sufficient Net Proceeds from the Royalty Properties for the Trust to make a regularly scheduled quarterly distribution to Unit holders for the foreseeable future. As a result of the damage inflicted by Hurricane Ike, Net Proceeds will continue to be severely impacted by reduced production, from historical levels, and the amount of expenditures incurred that are associated with such damages, including the expenditures required to plug and abandon the wells on Eugene Island 339 and, as currently expected, to redevelop the facility at Eugene Island 339. While Chevron has stated that it intends to redevelop Eugene Island 339, there is no obligation for Chevron to continue to pursue such redevelopment. Chevron offered to the Trustees in February 2011 that, based on then present production forecasts, the possibility of distributions being made to the Partnership would likely begin in 2013. However, there can be no assurance by Chevron or anyone else as to the actual timing for any future distributions to the Partnership from the Royalty, and distributions could recommence some time before, during or after 2013, and there is no guarantee that any further distributions will be made. Future Net Proceeds from the Royalty Properties will take into account the Trust's share of project costs and other related expenditures that are not covered by the insurance of the operators of the Royalty Properties. The Trust's net portion of the aggregate cost to plug and abandon the wells subject to the Royalty on Eugene Island 339 is estimated to be approximately $13 million, $11.3 million of which had been incurred through December 31, 2010, and without giving credit for an expected approximately $612,000 of insurance proceeds received by Chevron and to be allocated for the benefit of the Partnership with respect to Eugene Island 339. If development and production costs of the Royalty Properties exceed the proceeds of production from the Royalty Properties, the Trust will not receive Net Proceeds until future proceeds from production exceed the total of the excess costs plus accrued interest. As a result of the damage inflicted by Hurricane Ike, the Trust has not received Net Proceeds since December 2008. As of December 31, 2010, aggregate development and production costs for the Royalty Properties since November 2008 have exceeded the related proceeds of production from the Royalty Properties by approximately $3.5 million. In the fourth quarter of 2010, Chevron withdrew $4,304,894 from the Special Cost Escrow account of the Working Interest Owners to cover expenses incurred in connection with the plugging and abandonment of Eugene Island 339, which served to reduce the amount by which development and production costs exceeded the related proceeds of production as of December 31, 2010. Significant development costs will be incurred if Eugene Island 339 is redeveloped. Accordingly, there will not be sufficient Net Proceeds from the Royalty Properties to make distributions for some period of time in the future. At this time, the ultimate outcome of these matters cannot be determined with any degree of certainty.

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(5) Special Cost Escrow Account

The Special Cost Escrow is an account of the Working Interest Owners and it is described herein for informational purposes only. The Conveyance provides for reserving funds for estimated future "Special Costs" of plugging and abandoning wells, dismantling platforms and other costs of abandoning the Royalty Properties, as well as for the estimated amount of future drilling projects and other capital expenditures on the Royalty Properties. As provided in the Conveyance, the amount of funds to be reserved is determined based on certain factors, including estimates of aggregate future production costs, aggregate future Special Costs, aggregate future net revenues and actual current net proceeds. Deposits into this account reduce current distributions and are placed in an escrow account and invested in short-term certificates of deposit. Such account is herein referred to as the "Special Cost Escrow" account. The Trust's share of interest generated from the Special Cost Escrow account, approximately $7,946, $7,923 and $155,152 for 2010, 2009 and 2008, respectively, serves to reduce the Trust's share of allocated production costs. As of December 31, 2010, 2009 and 2008, approximately $1,000, $4,306,275 and $4,325,503, respectively, remained in the Special Cost Escrow account. Special Cost Escrow account funds will generally be utilized to pay Special Costs to the extent there are not adequate current net proceeds to pay such costs. Special Costs that have been paid are no longer included in the Special Cost Escrow calculation. Deposits to the Special Cost Escrow account will generally be made when the balance in the Special Cost Escrow account is less than 125% of estimated future Special Costs and there is a Net Revenues Shortfall (a calculation of the excess of estimated future costs over estimated future net revenues pursuant to a formula contained in the Conveyance). When there is not a Net Revenues Shortfall, amounts in the Special Cost Escrow account will generally be released, to the extent that Special Costs have been incurred. Amounts in the Special Cost Escrow account will also be released when the balance in such account exceeds 125% of future Special Costs.

In the fourth quarter of 2010, Chevron withdrew $4,304,894 from the Special Cost Escrow account of the Working Interest Owners (a reserve fund for certain costs) to cover expenses incurred in connection with the plugging and abandonment of Eugene Island 339, leaving a balance of $1,000 in the Special Cost Escrow account. After taking into account such withdrawal, aggregate development and production costs in excess of the related proceeds for the royalty properties, as of December 31, 2010, was approximately $3.5 million, net to the royalty interest; however, additional deposits to the Special Cost Escrow account would be required in future periods in accordance with the underlying conveyance of the royalty if, and when, net proceeds would otherwise be payable on the royalty. In 2009, there were no funds released from or deposited into the Special Cost Escrow account. In 2008, the Working Interest Owners refunded a net amount of approximately $2,388,061 from the Special Cost Escrow Account. The net deposits were made primarily due to changes in the estimate of projected capital expenditures, production costs and abandonment costs of the Royalty Properties.

The discussion of the terms of the Conveyance and Special Cost Escrow Account contained herein is qualified in its entirety by reference to the Conveyance.

Deposits to the Special Cost Escrow Account will be required in future periods in connection with other production costs, other abandonment costs, other capital expenditures and changes in the estimates and factors described above. Such deposits could result in a significant reduction in Royalty income in the periods in which such deposits are made.

TEL OFFSHORE TRUST

NOTES TO FINANCIAL STATEMENTS (Continued)

(6) Reserve For Future Trust Expenses

The Trust made a determination in 1998 to maintain a cash reserve equal to approximately three times the average expenses of the Trust during each of the past three years to provide for future administrative expenses in connection with the winding up of the Trust. During 2010, the Trust decreased its reserve by $911,064, to pay current expenses, for a reserve balance of $352,017 as of December 31, 2010, or approximately 39% of the average annual expenses of the Trust during the three-year period ended December 31, 2010. During 2009, the Trust decreased its reserve by $970,211, to pay current expenses, for a reserve balance of $1,263,080 as of December 31, 2009, or approximately 1.7 times the average annual expenses of the Trust during the three-year period ended December 31, 2009.

There are not likely to be positive Net Proceeds from the Royalty Properties for the foreseeable future. Chevron offered to the Trustees in February 2011 that, based on then present production forecasts, the possibility of distributions being made to the Partnership would likely begin in 2013. However, there can be no assurance by Chevron or anyone else as to the actual timing for any future distributions to the Partnership from the Royalty, and distributions could recommence some time before, during or after 2013, and there is no guarantee that any further distributions will be made. Absent the receipt of Net Proceeds or other actions being taken, at some time in the early part of the second quarter of 2011, the Trust will not have sufficient funds to pay the liabilities of the Trust. As such, the Trustees may take certain actions, discussed below, on behalf of the Trust as permitted under the Trust Agreement, which could materially impact the Unit holders.

Pursuant to the terms of the Trust Agreement, the Trustees are authorized to borrow funds, and pledge the assets of the Trust to secure payments of such borrowings, in the event that cash on hand is not sufficient to pay the liabilities of the Trust. In the event that the Trustees borrow funds to pay the liabilities of the Trust, no distributions will be made to the Unit holders until the indebtedness created by such borrowings has been paid in full.

The Trust Agreement further provides that, if necessary to provide for the payment of specific liabilities of the Trust then due, the Trustees may without a vote of the Unit holders (a) sell all or a portion of the Trust's interest in the Partnership or any other assets of the Trust for such cash consideration as the Trustees shall deem appropriate, (b) exercise their rights under the Partnership Agreement to dissolve the Partnership, or (c) cause a sale by the Partnership of the overriding royalty interest owned by the Partnership.

On March 11, 2011, the Trustees provided written notice to Chevron that, pursuant to the Trust Agreement, the Trust needs funds to pay for liabilities of the Trust and that the Trustees therefore instructed Chevron, as the Managing General Partner of the Partnership, to sell such portion, and only such portion, of the Royalty that will provide the Trust with a current distribution equal to $2,000,000 from the proceeds of such sale. The Trustees are also seeking a loan to the Trust to be able to pay liabilities of the Trust. There can be no assurance that such a loan will be obtained or that such a sale of interests in the Royalty can be consummated or that $2,000,000 in proceeds can be obtained, or as to the terms, conditions and timing of such a loan or of the sale of interests in the Royalty.

(7) Federal Income Tax Matters

The IRS has ruled that the Trust is a grantor trust and that the Partnership is a partnership for federal income tax purposes. Thus, the Trust will incur no federal income tax liability and each Unit holder will be treated as owning an interest in the Partnership.

TEL OFFSHORE TRUST

NOTES TO FINANCIAL STATEMENTS (Continued)

(8) Commitments and Contingencies

The Managing General Partner of the Partnership has advised the Trust that, although the Working Interest Owners believe that they are in general compliance with applicable health, safety and environmental laws and regulations that have taken effect at the federal, state and local levels, costs may be incurred to comply with current and proposed environmental legislation that could result in increased operating expenses on the Royalty Properties.

(9) Supplemental Reserve Information (Unaudited)

Estimates of the proved oil and gas reserves attributable to the Partnership's royalty interest are based on a reserve study prepared by DeGolyer and MacNaughton, independent petroleum engineering consultants. The reserve study prepared by DeGolyer and MacNaughton as of October 31, 2010 does not include reserves attributable to Eugene Island 339 or any capital expenditures for any redevelopment of Eugene Island 339. However, such reserve study does include the Trust's share of the estimated total plugging and abandonment costs related to Eugene Island 339, with costs to the Trust relating thereto estimated to be approximately $13 million, and without giving credit for an expected approximately $612,000 of insurance proceeds received by Chevron and to be allocated for the benefit of the Partnership with respect to Eugene Island 339. Estimates were prepared in accordance with guidelines established by the Securities and Exchange Commission and the Financial Accounting Standards Board. Accordingly, the estimates are based on existing economic and operating conditions in effect at October 31, 2010, with no provision for future increases or decreases except for periodic price redeterminations in accordance with existing gas contracts.

Estimated net proved reserves attributable to the net profits interest owned by the Partnership, as of October 31, 2010, are summarized as follows, expressed in barrels (bbl) and thousands of cubic feet (Mcf):

	Oil and Condensate (bbl)	Natural Gas (Mcf)
Proved Developed Reserves(1)		
Reserves as of October 31, 2009(2)	137,464	868,505
Revisions of Previous Estimates	64,795	405,351
Improved Recovery	0	0
Purchases of Minerals in Place	0	0
Extensions, Discoveries, and Other Additions	0	0
Production(3)	(22,189)	(57,418)
Sales of Minerals in Place	0	0
Reserves as of October 31, 2010(4)	180,070	1,216,438

(1) There are no proved undeveloped reserves for the Royalty Properties.

(2) Estimated Eugene Island 339 abandonment costs were included.

(3) Production was estimated based on the ratio as of October 31, 2009, of the Partnership's net profits interest in net reserves to the net reserves associated with the Partnership's net profits interest and the interests retained in the Royalty Properties by the Working Interest Owners. This ratio was then applied to the production net to the combined

TEL OFFSHORE TRUST

NOTES TO FINANCIAL STATEMENTS (Continued)

(9) Supplemental Reserve Information (Unaudited) (Continued)

interests of the Partnership and the Working Interest Owners for the period from November 1, 2009, through October 31, 2010.

(4) Estimated Eugene Island 339 abandonment costs were included

On October 7, 2008, the Trust announced that production from the two most significant oil and gas properties associated with the Trust had ceased following damage inflicted by Hurricane Ike in September 2008. The platforms and wells on Eugene Island 339 were completely destroyed by the hurricane. Chevron has informed the Corporate Trustee that Chevron presently intends to pursue the redevelopment of the platforms and wells at Eugene Island 339 in accordance with the terms and conditions established by the Bureau of Ocean Energy Management, Regulation and Enforcement "BOEM", formerly the Minerals Management Service) in response to Chevron's submission to the BOEM of a program to restore production at Eugene Island 339. In December 2009, Chevron entered into a participation agreement with a third party to assist in the redevelopment of Eugene Island 338 and 339. The redevelopment plan provided that three wells were to be drilled from a common open water location in Eugene Island 338 in the second quarter of 2010. The first well of the three-well drilling program had been drilled; however, drilling activity was suspended and the drilling rig moved off location in July 2010. Chevron's inability to obtain related drilling permits in a timely basis under the new guidelines issued by the BOEM on June 8, 2010, following the oil spill in the U.S. Gulf of Mexico related to the sinking of the *Deepwater Horizon* drilling rig, pursuant to Notice to Lessees No. 2010-N05, "Increased Safety Measures for Energy Development on the OCS", caused the parties to such participation agreement to revise and amend the participation agreement. The revised redevelopment plan provides for setting a platform at Eugene Island 338 and drilling wells into Eugene Island 339 and Eugene Island 338 from such platform. The revised redevelopment plan retains the original estimate for first production from Eugene Island 339 of the fourth quarter of 2012. Restoration of production at Eugene Island 338 and 339 is a complex process, requires various governmental permits, and cannot be assured at this time. The costs for the redevelopment project would be significant. Failure or inability to pursue such a redevelopment, or to satisfy the activity schedule approved by the BOEM, could result in a loss of the lease covering Eugene Island 339. At this time, there is and can be no assurance that each activity schedule date will be met or that an additional SOP will be approved by the BOEM or that production will be restored at Eugene Island 339. While Chevron has stated that it intends to redevelop Eugene Island 338 and 339, there is no obligation for Chevron to continue to pursue such redevelopment. Additionally, the Trust cannot predict at this time the further impact that the oil spill in the U.S. Gulf of Mexico related to the sinking of the *Deepwater Horizon* drilling rig may have on the redevelopment of Eugene Island 339. Based on the reserve study of DeGolyer and MacNaughton for the oil and gas reserves attributable to the Partnership as of October 31, 2007, Eugene Island 339 accounted for approximately 34% of the total future net revenues attributable to the Partnership's interest in the Royalty as of October 31, 2007.

The reserve volumes and revenue values attributable to the Partnership's royalty interest were estimated from projections of reserves and revenue attributable to the combined interests consisting of the Partnership's royalty interest and the retained interest of the Working Interest Owners in the Royalty Properties. Net reserves attributable to the Partnership's royalty interest were estimated by allocating to the Partnership a portion of the estimated combined net reserves of the subject properties based on the ratio of the Partnership's interest in future net revenues to combined future gross revenues. Because the net reserve volumes attributable to the Partnership's royalty interest are estimated using an allocation of reserves based on estimates of future revenue, a change in prices or

(9) Supplemental Reserve Information (Unaudited) (Continued)

costs will result in changes in the estimated net reserves. Therefore, the estimated net reserves attributable to the Partnership's royalty interest will vary if different future price and cost assumptions are used. All reserves attributable to the Partnership's royalty interest are located in the United States. Total future net revenues attributable to the Partnership's interest in the Royalty were estimated at $19.8 million as of October 31, 2010 based on the reserve study of DeGolyer and MacNaughton.

The Partnership's share of gas sales can be recorded by the Working Interest Owner on the cash method of accounting or based on actual production. When revenues are reported based on actual production, there is no gas imbalance created. Under the cash method, revenues are recorded based on actual gas volumes sold, which could be more or less than the volumes the Working Interest Owners are entitled to based on their ownership interests. The Partnership's Royalty income for a period reflects the actual gas sold during the period.

Distributable income for the Partnership for the periods ended December 31, 2010, 2009 and 2008 included Net Proceeds relating to production of reserves from the Royalty Properties for the twelve months ended October 31, 2010, 2009 and 2008, respectively.

(10) Related Party Transactions

Each of the Working Interest Owners owns interests, for its own account, in leases that are in the same area as leases in which the Partnership has acquired or may acquire an interest. Such relationships may give rise to potential conflicts of interests in, among other things, the operation of such leases and in the acquisition and operation of any drainage leases acquired by a Working Interest Owner for its own account. Additionally, the Working Interest Owners and their affiliates are not prohibited from purchasing oil and gas produced from or attributable to any leases in which the Partnership has an interest.

Crude oil sales to Chevron Corporation approximately 100%, 98% and 99% of crude oil revenues from the Royalty Properties during 2010, 2009 and 2008, respectively. During the year ended December 31, 2010 and 2009, 100% of Chevron's natural gas and natural gas liquids relative to the Trust's Royalty Properties were committed and sold to Chevron Natural Gas at spot market prices. During the years ended December 31, 2008, approximately 99% of Chevron's natural gas and natural gas liquids relative to the Trust's Royalty Properties were committed and sold to Chevron Natural Gas at spot market prices.

The Trust's share of Royalty income was reduced by approximately $293,000, $320,000 and $482,000 in 2010, 2009 and 2008, respectively, for management fees paid to the Working Interest Owners as reimbursement for expenses incurred by them on behalf of the Trust. The aggregate amount of management fees paid to the Working Interest Owners was calculated as 3% of the Trust's share of the sum of revenues, production expenses and capital expenditures attributable to the Royalty Properties in 2010, 2009 and 2008.

(11) Subsequent Events

On March 30, 2011, the Trust issued a press release announcing that there would be no trust distribution for the first quarter of 2011 for unitholders of record on March 31, 2011.

TEL OFFSHORE TRUST

NOTES TO FINANCIAL STATEMENTS (Continued)

(12) Selected Quarterly Financial Data (Unaudited)

Summarized quarterly financial data is as follows:

	First	Second	Third	Fourth
2010:				
Royalty income	$ 0	$ 0	$ 0	$ 0
Distributable income	$ 0	$ 0	$ 0	$ 0
Distributions per Unit	$ 0.000000	$ 0.000000	$ 0.000000	$ 0.000000
2009:				
Royalty income	$ 0	$ 0	$ 0	$ 0
Distributable income	$ 0	$ 0	$ 0	$ 0
Distributions per Unit	$ 0.000000	$ 0.000000	$ 0.000000	$ 0.000000

See Note 4 for a discussion regarding uncertainty of distributions.

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Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure.

None.

Item 9A. Controls and Procedures.

Evaluation of disclosure controls and procedures.

The Corporate Trustee maintains disclosure controls and procedures designed to ensure that information to be disclosed by the Trust in the reports that it files or submits under the Securities Exchange Act of 1934, as amended, is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and regulations. Disclosure controls and procedures include controls and procedures designed to ensure that information required to be disclosed by the Trust is accumulated and communicated by Chevron as the Managing General Partner of the Partnership, and the Working Interest Owners to The Bank of New York Mellon Trust Company, N.A., as Corporate Trustee of the Trust, and its employees who participate in the preparation of the Trust's periodic reports as appropriate to allow timely decisions regarding required disclosure.

As of the end of the period covered by this report, the Corporate Trustee carried out an evaluation of the Trust's disclosure controls and procedures. Mike Ulrich, as Trust Officer of the Corporate Trustee, has concluded that the disclosure controls and procedures of the Trust are effective.

Due to the contractual arrangements of (i) the Trust Agreement, (ii) the Partnership Agreement and (iii) the rights of the Partnership under the Conveyance regarding information furnished by the Working Interest Owners, the Trustees rely on (A) information provided by the Working Interest Owners, including historical operating data, plans for future operating and capital expenditures, reserve information and information relating to projected production, (B) information from the Managing General Partner of the Partnership, including information that is collected from the Working Interest Owners, and (C) conclusions and reports regarding reserves by the Trust's independent reserve engineers. See Item 1A. Risk Factors "—The Trustees and the Unit holders have no control over the operation or development of the Royalty Properties and have little influence over operation or development" in the Trust's Form 10-K and "Management's Discussion and Analysis of Financial Condition and Results of Operation" included in this Form 10-K, for a description of certain risks relating to these arrangements and reliance and applicable adjustments to operating information when reported by the Working Interest Owners to the Corporate Trustee and recorded in the Trust's results of operation.

Changes in Internal Control Over Financial Reporting

In connection with the evaluation by the Corporate Trustee of changes in internal control over financial reporting of the Trust, no change in the Trust's internal control over financial reporting was identified that has materially affected, or is reasonably likely to materially affect, the Trust's internal control over financial reporting.

Trustee's Annual Report on Internal Control over Financial Reporting

A registrant's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A registrant's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the registrant; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the registrant are being made

only in accordance with authorizations of management and directors of the registrant; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the registrants assets that could have a material effect on the financial statements.

The Corporate Trustee is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Rule 13a-15(f) promulgated under the Securities Exchange Act of 1934, as amended. The Corporate Trustee conducted an evaluation of the effectiveness of the Trust's internal control over financial reporting based on the criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on the Corporate Trustee's evaluation under the framework in *Internal Control—Integrated Framework*, the Corporate Trustee concluded that the Trust's internal control over financial reporting was effective as of December 31, 2010.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Item 9B. **Other Information.**

None.

PART III

Item 10. **Directors, Executive Officers and Corporate Governance.**

There are no directors or executive officers of the Registrant. The Trustees consist of a Corporate Trustee and three Individual Trustees. The Bank of New York Mellon Trust Company, N.A. serves as the Corporate Trustee, and Gary C. Evans, Thomas H. Owen, Jr. and Jeffrey S. Swanson serve as the three Individual Trustees. Any Trustee may be removed by the affirmative vote of two Individual Trustees or by the affirmative vote of a majority of the Units at a meeting of Unit holders of beneficial interest in the Trust at which a quorum is present.

The Trust does not have a principal executive officer, principal financial officer, principal accounting officer or controller and, therefore, has not adopted a code of ethics applicable to such persons. However, employees of the Corporate Trustee must comply with the bank's code of ethics.

The Trust does not have a board of directors, and therefore does not have an audit committee, an audit committee financial expert, a compensation committee or a nominating committee.

Section 16(a) Beneficial Ownership Reporting Compliance.

The Trust has no directors or officers. Accordingly, only holders of more than 10% of the Trust's Units are required to file with the SEC initial reports of ownership of Units and reports of changes in such ownership pursuant to Section 16 under the Securities Exchange Act of 1934. Based solely on a review of these reports, the Trust believes that the applicable reporting requirements of Section 16(a) of the Securities Exchange Act of 1934 were complied with for all transactions that occurred in 2010.

Item 11. **Executive Compensation.**

During the year ended December 31, 2010, the Corporate Trustee received compensation from the Trust in an aggregate amount of $229,478. During the year ended December 31, 2010, each of the Individual Trustees received compensation from the Trust in an aggregate amount of $69,858. The Trust does not have any executive officers.

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters.

(a) Security Ownership of Certain Beneficial Owners.

The Trust has no officers or directors. Accordingly, only holders of more than 5% of the Trust's Units are required to file reports with the SEC on Schedule 13D or Schedule 13G and holders of 10% or more of the Trust's Units are required to file initial and other reports with the SEC pursuant to Section 16 of the Securities Exchange Act of 1934. Based solely on a review of reports, the Trust is not aware of such holders as of March 30, 2011.

(b) Security Ownership of Management.

Not applicable.

(c) Changes in Control.

The Trust knows of no arrangements, including the pledge of securities of the Trust, the operation of which may at a subsequent date result in a change in control of the Trust.

Item 13. Certain Relationships and Related Transactions, and Director Independence.

Each of the Working Interest Owners owns interests, for its own account, in leases that are in the same area as leases in which the Partnership has acquired or may acquire an interest. Such relationships may give rise to potential conflicts of interests in, among other things, the operation of such leases and in the acquisition and operation of any drainage leases acquired by a Working Interest Owner for its own account. Additionally, the Working Interest Owners and their affiliates are not prohibited from purchasing oil and gas produced from or attributable to any leases in which the Partnership has an interest.

Crude oil sales to Chevron Corporation accounted for approximately 100%, 98% and 99% of crude oil revenues from the Royalty Properties during 2010, 2009 and 2008, respectively. During the years ended December 31, 2010 and 2009, 100% of Chevron's natural gas and natural gas liquids relative to the Trust's Royalty Properties were committed and sold to Chevron Natural Gas at spot market prices. During the year ended December 31, 2008, approximately 99% of Chevron's natural gas and natural gas liquids relative to the Trust's Royalty Properties were committed and sold to Chevron Natural Gas at spot market prices.

The Trust's share of Royalty income was reduced by approximately $293,000, $320,000 and $482,000 in 2010, 2009 and 2008, respectively, for management fees paid to the Working Interest Owners as reimbursement for expenses incurred by them on behalf of the Trust. The aggregate amount of management fees paid to the Working Interest Owners was calculated as 3% of the Trust's share of the sum of revenues, production expenses and capital expenditures attributable to the Royalty Properties in 2010, 2009 and 2008. Chevron, as the Managing General Partner of the Partnership, was paid a management fee of $1,172,039 for 2010 by the Partnership.

Item 14. Principal Accountant Fees and Services.

The Trust does not have an audit committee. Any pre-approval and approval of all services performed by the principal auditor or any other professional service firms and related fees are granted by the Trustees. The Trustees have appointed Deloitte & Touche, LLP and its affiliates (collectively "Deloitte") as the independent registered public accounting firm to audit the trust's financial statements for the fiscal year ending December 31, 2011. During fiscal 2010, Deloitte served as the Trust's independent registered public accounting firm and also provided certain tax services.

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The following table presents the aggregate fees billed to the Trust for the fiscal years ended December 31, 2010 and 2009 by Deloitte:

	2010	2009
Audit fees(1)	$ 203,500	$ 210,000
Audit-related fees	—	—
Tax fees(2)	9,050	9,050
All other fees	—	—
Total fees	$ 212,550	$ 219,050

(1) Fees for audit services in 2010 and 2009 consisted of the audit of the Trust's annual financial statements and reviews of the Trust's quarterly financial statements. Services in 2009 also included the attestation on the effectiveness of the Trust's internal control over financial reporting.

(2) Fees for tax services billed in 2010 and 2009 consisted of tax compliance services.

PART IV

Item 15. Exhibits, Financial Statement Schedules.

(a)(1) Financial Statements

The following financial statements are set forth under Part II, Item 8 of this Annual Report on Form 10-K on the pages as indicated:

(a)(2) Schedules

Schedules have been omitted because they are not required, not applicable or the information required has been included elsewhere herein.

(a)(3) Exhibits

(Asterisk indicates exhibit previously filed with the Securities and Exchange Commission and incorporated herein by reference. The Bank of New York Mellon Trust Company, N.A. succeeded JPMorgan Chase Bank as Corporate Trustee. JPMorgan Chase Bank is successor by mergers to the original corporate trustee, Texas Commerce Bank National Association.)

		SEC File or Registration Number	Exhibit Number
4(a)*	Trust Agreement dated as of January 1, 1983, among Tenneco Offshore Company, Inc., Texas Commerce Bank National Association, as corporate trustee, and Horace C. Bailey, Joseph C. Broadus and F. Arnold Daum, as individual trustees (Exhibit 4(a) to Form 10-K for year ended December 31, 1992 of TEL Offshore Trust)	0-6910	4(a)

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		SEC File or Registration Number	Exhibit Number
4(b)*	Agreement of General Partnership of TEL Offshore Trust Partnership between Tenneco Oil Company and the TEL Offshore Trust, dated January 1, 1983 (Exhibit 4(b) to Form 10-K for year ended December 31, 1992 of TEL Offshore Trust)	0-6910	4(b)
4(c)*	Conveyance of Overriding Royalty Interests from Exploration I to the Partnership (Exhibit 4(c) to Form 10-K for year ended December 31, 1992 of TEL Offshore Trust)	0-6910	4(c)
4(d)*	Amendments to TEL Offshore Trust Agreement, dated December 7, 1984 (Exhibit 4(d) to Form 10-K for year ended December 31, 1992 of TEL Offshore Trust)	0-6910	4(d)
4(e)*	Amendment to the Agreement of General Partnership of TEL Offshore Trust Partnership, effective as of January 1, 1983 (Exhibit 4(e) to Form 10-K for year ended December 31, 1992 of TEL Offshore Trust)	0-6910	4(e)
10(a)*	Purchase Agreement, dated as of December 7, 1984 by and between Tenneco Oil Company and Tenneco Offshore II Company (Exhibit 10(a) to Form 10-K for year ended December 31, 1992 of TEL Offshore Trust)	0-6910	10(a)
10(b)*	Consent Agreement, dated November 16, 1988, between TEL Offshore Trust and Tenneco Oil Company (Exhibit 10(b) to Form 10-K for year ended December 31, 1988 of TEL Offshore Trust)	0-6910	10(b)
10(c)*	Assignment and Assumption Agreement, dated November 17, 1988, between Tenneco Oil Company and TOC-Gulf of Mexico Inc. (Exhibit 10(c) to Form 10-K for year ended December 31, 1988 of TEL Offshore Trust)	0-6910	10(c)
10(d)*	Gas Purchase and Sales Agreement Effective September 1, 1993 between Tennessee Gas Pipeline Company and Chevron U.S.A. Production Company (Exhibit 10(d) to Form 10-K for year ended December 31, 1993 of TEL Offshore Trust)	0-6910	10(d)
31	Certification furnished pursuant to Section 302 of the Sarbanes-Oxley Act of 2002		
32	Certification furnished pursuant to Section 906 of the Sarbanes-Oxley Act of 2002		
99.1	Reserve Study of DeGolyer & MacNaughton		

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized on this 31st day of March, 2011.

TEL OFFSHORE TRUST

By: THE BANK OF NEW YORK MELLON TRUST COMPANY, N.A., Corporate Trustee

By: /s/ MIKE ULRICH

Mike Ulrich
Vice President

Signature	Date
THE BANK OF NEW YORK MELLON TRUST COMPANY, N.A., Corporate Trustee	
By: /s/ MIKE ULRICH Mike Ulrich, *Vice President & Trust Officer*	March 31, 2011
INDIVIDUAL TRUSTEES	
/s/ GARY C. EVANS Gary C. Evans, *Individual Trustee*	March 31, 2011
/s/ THOMAS H. OWEN, JR. Thomas H. Owen, Jr., *Individual Trustee*	March 31, 2011
/s/ JEFFREY S. SWANSON Jeffrey S. Swanson, *Individual Trustee*	March 31, 2011

The Registrant, TEL Offshore Trust, has no principal executive officer, principal financial officer, board of directors or persons performing similar functions. Accordingly, no additional signatures are available and none have been provided. In signing the report above, neither the Corporate Trustee nor the Individual Trustees imply that they perform any such function or that such function exists pursuant to the terms of the Trust Agreement under which they serve.

EXHIBIT D-6

5

TEL OFFSHORE TRUST
TRUST AGREEMENT

TRUST AGREEMENT, made as of the 1st day of January, 1983, by and between TENNECO OFFSHORE COMPANY, INC., a Delaware corporation having its principal offices in Houston, Texas (the "Company") acting on behalf of the owners of Units as "Trustor", and Texas Commerce Bank National Association, a national banking association organized under the laws of the United States and having its principal trust office in Houston, Texas ("Corporate Trustee") and Horace C. Bailey, Joseph C. Broadus and F. Arnold Daum, individuals ("Individual Trustees") as "Trustees".

WHEREAS, the Company is the sole limited partner of Tenneco Exploration, Ltd., a limited partnership engaged in the production of crude oil and natural gas from certain federal leases located in the Gulf of Mexico offshore the States of Texas and Louisiana; and

WHEREAS, Tenneco Exploration, Ltd. is to distribute Overriding Royalty Interest in and to such leases (as hereinafter defined) in partial liquidation of the Company's interest in such partnership; and

WHEREAS, in connection with the liquidation of the Company, the Company desires to distribute to its stockholders the Overriding Royalty Interest; and

WHEREAS, it would not be in the best interest of the Company's stockholders to own directly undivided interests in such Overriding Royalty Interest; and

WHEREAS, the Company's objectives may be accomplished through the creation of an express trust to hold directly or indirectly such Overriding Royalty Interest and through the distribution to the Company's stockholders of interests in such trust; and

WHEREAS, it is in the best interests of the stockholders who will own beneficial interests in such Trust that the Overriding Royalty Interest relating to such properties be contributed to a partnership of which the Trust is a general partner and Tenneco Oil Company is a managing general partner (the "Partnership"); and

WHEREAS, at, prior to or as of the Effective Time (as hereinafter defined), the following shall occur in chronological order:

(1) the Company will adopt a plan to liquidate and dissolve;

(2) Tenneco Exploration, Ltd. will execute and deliver to the Partnership the Conveyance of Overriding Royalty Interest attached as Exhibit I hereto as the Trust's contribution to the capital of the Partnership;

(3) Tenneco Oil Company will agree to contribute its management services to the Partnership;

(4) Tenneco Offshore II Company, a wholly-owned subsidiary of the Company, will be substituted for the Company as the sole limited partner of Tenneco Exploration, Ltd.;

(5) the Company, acting on behalf of its stockholders, will transfer to the Trust the Tenneco Offshore II Stock (as hereinafter defined);

(6) the Trustees will distribute to the Company the initial certificates evidencing the ownership of Units of Beneficial Interest registered in such names and denominations as requested by the Company (the number of Units to equal one Unit for each share of common stock of the Company outstanding at the time of the distribution of Units); and

(7) the Corporate Trustee, on behalf of the Company, will distribute such certificates to or for the benefit of the Company's shareholders.

NOW, THEREFORE, Trustor has granted, assigned, and delivered unto the Trustees hereunder One Hundred Dollars ($100.00) receipt of which is hereby acknowledged and accepted by the Trustees, to have and to hold, in trust as hereinafter set out, such property and all other properties, real or personal, which may hereafter be received by the Trustees as additions to the Trust pursuant to this Trust Agreement. To accomplish the purposes of the Trust, the Company and Trustees agree as follows:

ARTICLE I

DEFINITIONS

As used herein, the following terms have the meanings indicated:

1.01 "Bank" means Texas Commerce Bank National Association.

1.02 "Beneficial Interest" means the rights of ownership in a Unit including the rights to share in the benefits, obligations and detriments resulting from the accomplishment of the purposes of the Trust as expressly set out in this Trust Agreement, which includes, without limitation, the rights to share in distributions during the term of the Trust, to share in the final distributions from the Trust, to participate in decisions affecting the Trust only to the extent expressly provided herein, and all other rights of beneficiaries of express trusts created under the Texas Trust Act, subject to the limitations set forth in this Trust Agreement and the Texas Trust Act.

1.03 "Business Day" means any day which is not a Saturday, Sunday, or any other day on which national banking institutions in the City of Houston, Texas (or the City where the principal trust office of the Corporate Trustee is located) are closed as authorized or required by law.

1.04 "Certificate" means a certificate issued by the Trustees pursuant to Section 2.03 and Article III hereof evidencing the ownership of one or more Units.

1.05 "Certificate Holder" means the owner of a Certificate as reflected on the records of the Corporate Trustee pursuant to the provisions of Article III hereof.

1.06 "Code" means the Internal Revenue Code of 1954, as amended.

1.07 "Conveyance" means the Conveyance of Overriding Royalty Interest attached as Exhibit I to this Trust Agreement.

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1.08 "Distribution Date" means the date of any distribution pursuant to Section 4.02 hereof.

1.09 "Effective Time" shall have the meaning attributed to it in Section 2.01 hereof.

1.10 "Interest Bearing Account" shall mean an account or certificates of the Bank or any successor bank serving as Corporate Trustee and shall bear interest at a rate which shall be the interest rate which the Bank or its successor pays in the normal course of business on amounts placed with it, taking into account the amounts involved, the period held and other relevant factors.

1.11 "Issue" of a person means such person's children and the descendants in any degree of such children, and includes any such descendant who is legally adopted.

1.12 "Overriding Royalty Interest" means the interest or interests in and to minerals in and under and produced, saved and sold from Subject Interests (as defined in the Conveyance) which interests have been conveyed to the Partnership. References in this Trust Agreement to Overriding Royalty Interest shall refer to the Trust Partnership Interest except where the context otherwise requires.

1.13 "Offshore II Overriding Royalty Interest" means any mineral interests conveyed to the Trust or the Partnership as a result of the liquidation of Tenneco Offshore II Company.

1.14 "Person" means an individual, corporation, partnership, unincorporated organization, trust, estate, or any other organization.

1.15 "Partnership" means the general partnership to be governed by the Partnership Agreement.

1.16 "Partnership Agreement" means the Agreement of General Partnership of the TEL Offshore Trust Partnership, dated as of January 1, 1983, to be entered into by Tenneco Oil Company, as general partner, and the Trust, as general partner.

1.17 "Properties" means (i) the properties located in the Gulf of Mexico offshore the States of Texas and Louisiana described in the Conveyance and (ii) any properties subject to any future conveyances of overriding royalties to the Trust or the Partnership resulting from the liquidation of Tenneco Offshore II Company.

1.18 "Proxy Statement" means the Proxy Statement which is part of the amended Registration Statement of the Company (File No. 2-80512) on file with the Securities and Exchange Commission at the time the Registration Statement became effective and which was distributed to the shareholders of the Company in connection with their vote on the liquidation of the Company and creation and distribution of Units in the Trust, except that if the Proxy Statement filed by the Company pursuant to Rule 424(b) or (c) under the Securities Act of 1933 differs from the Proxy Statement on file at the time the Registration Statement became effective, the term Proxy Statement shall refer to the Proxy Statement filed pursuant to Rule 424(b) or (c).

1.19 "Quarterly Cash Amount" for any Quarterly Period means the sum of (a) the cash received during the Quarterly Period which cash is directly attributable to the Overriding Royalty Interest, (b) the cash received during the Quarterly Period attributable to the Tenneco Offshore II Stock, (c) any cash available for distribution as a result of the reduction or elimination during the Quarterly Period of any existing cash reserve created pursuant to Section 6.06 hereof and (d) any other cash receipts of the Trust during the Quarterly Period, including without limitation any interest earned on reserves established pursuant to Section 6.06 but not including any interest earned on the Quarterly Cash Amount for the prior Quarterly Period which is being held for distribution pursuant to Section 4.02, such sum to be reduced by the sum of (x) all liabilities of the Trust paid during the Quarterly Period and (y) the amount of any cash used in the Quarterly Period to establish or increase a cash reserve pursuant to Section 6.06 hereof. In the case of sales or dispositions pursuant to Section 6.04, distributions of cash received from such sales or dispositions shall be deferred until the distribution for the next succeeding Quarterly Period if the Trustees shall determine that a distribution of such amount for the Quarterly Period in which such sales or dispositions occur would prevent the Trust from complying with any regulation or policy of the National Association of Securities Dealers or any securities exchange on which the Units may then be listed. In the case of sales or dispositions pursuant to Sections 6.08 or 9.02, however, no distributions of such cash shall be made until all related liabilities have been paid, discharged or provided for. If the Quarterly Cash Amount determined in accordance with the foregoing provisions of this Section 1.19 shall for any Quarterly Period be a negative number ("Excess Quarterly Liabilities"), then the amount distributed as the Quarterly Cash Amount shall be zero and the Excess Quarterly Liabilities shall be carried forward to reduce the Quarterly Cash Amount for the next succeeding Quarterly Period or Periods until such Excess Quarterly Liabilities have been offset against such Quarterly Cash Amount or Amounts on a dollar for dollar basis. For purposes of the foregoing, amounts received, reserved and disbursed by the Partnership shall be deemed, to the extent of the Trust's sharing ratio in the Partnership, to have been received, reserved and disbursed by the Trust.

1.20 "Quarterly Period" means each calender quarter.

1.21 "Quarterly Record Date" means the last Business Day of each Quarterly Period unless the Trustees determine that a different date is required to comply with applicable law or the rules or regulations of any stock exchange on which the Units may then be listed, if any, in which event, it means such different date.

1.22 "Tenneco Offshore II Stock" shall mean all of the issued and outstanding common stock, par value $1 per share, of Tenneco Offshore II Company, a Delaware corporation.

1.23 "Trust" means the express trust under the Texas Trust Act created by and administered under the terms of this instrument and includes any ancillary trust created pursuant to Section 7.10 hereof.

1.24 "Trust Agreement" means this instrument, as originally executed, or, if amended pursuant to the provisions of Section 10.02, as so amended.

1.25 "Trust Estate" means all assets, however and whenever acquired (including without limitation the property to be acquired pursuant to Section 2.03), which may belong to the Trust at any designated time, and shall include both income and principal if separate accounts or records are kept therefor.

1.26 "Trust Partnership Interest" means the interest of the Trust in the Partnership.

1.27 "Trustees" means (except as provided in Section 8.03) the initial Corporate Trustee and Individual Trustees under this instrument or any successor corporate Trustee or Individual Trustees during the period it is serving in such capacity and "Corporate Trustee" means the initial Corporate Trustee under the instrument or any successor Corporate Trustee.

1.28 "Unit" means an undivided interest in the Beneficial Interest in the Trust equal to the number one divided by the number of shares of common stock of the Company outstanding at the time of the distribution of Units, as increased by cancellation of Units in accordance with the provisions of Section 6.10 hereof.

ARTICLE II

CREATION AND PURPOSE OF TRUST AND ACQUISITION OF OVERRIDING ROYALTIES INTEREST AND TRUST PARTNERSHIP INTEREST

2.01 Creation of Trust. There is hereby created, effective as of January 1, 1983 (the "Effective Time"), an irrevocable Trust for the benefit of the stockholders of the Company. The Trust herein created shall be known as the TEL OFFSHORE TRUST, and the Trustees may conduct all affairs of the Trust in such name. The property described herein as being placed in trust shall constitute the initial Trust Estate of such Trust.

2.02 Purposes. The purposes of the Trust are:

(a) to protect and conserve, for the benefit of the owners of the Units, the Overriding Royalty Interest, the Trust Partnership Interest, the Tenneco Offshore II Stock and any other assets held in the Trust Estate;

(b) to receive cash attributable to the Trust Partnership Interest and the Tenneco Offshore II Stock and any other assets held in the Trust Estate; and

(c) to pay or provide for the payment of any liabilities incurred in carrying out the purposes of the Trust, and thereafter to distribute the remaining amounts received by the Trust pro rata to the owners of the Units.

It is the intention and agreement of the Company and the Trustees to create an express trust within the meaning of Section 2 of the Texas Trust Act, for the benefit of the owners of Units, and a grantor trust for federal income tax purposes of which the owners of Units are the grantors. As set forth above and amplified herein, the Trust is intended to be a passive entity whose activities are limited to the receipt of revenues attributable to (i) the Trust Partnership Interest, and (ii) the Tenneco Offshore II Stock and any substitute interest for such stock resulting from implementation of Section 6.15 hereof, and the distribution of such revenues, after payment of or provision for Trust expenses and liabilities, to the owners of Units. It is neither the purpose nor the intention of the parties hereto to create, and nothing in this Trust Agreement shall be construed as creating, a partnership, joint venture, joint stock company or business association between or among owners of Units hereunder, present or future, or among or between the owners of Units, or any of them, and the Trustees.

2.03 Assignment of the Overriding Royalties and Transfer of the Tenneco Offshore II Stock. At, prior to or as of the Effective Time, the Trustees:

(i) shall execute and deliver on behalf of the Trust the Partnership Agreement with Tenneco Oil Company;

(ii) shall cause the Partnership to accept the Conveyance of the Overriding Royalty Interest from Tenneco Exploration, Ltd. in exchange for the Trust receiving a 99.99% interest in the Partnership;

(iii) shall accept the transfer of the Tenneco Offshore II Stock from the Company; and

(iv) shall issue to or for the benefit of the owners of Units, the identity of which shall be determined by reference to the certificate provided by the Company pursuant to Section 3.01 hereof, the initial Certificates evidencing ownership of the Units.

ARTICLE III

CREATION OF UNITS AND CERTIFICATES

3.01 Creation and Distribution of Units. The entire Beneficial Interest in the Trust Estate is hereby divided into separate, equal and distinct Units. The number of Units shall be one Unit for each share of common stock of the Company outstanding at January 14, 1983. The ownership of the Units shall be evidenced by Certificates in substantially the form set forth in Exhibit III attached hereto. Initially, the Company shall own all of the Units. However, the Corporate Trustee, on behalf of the Company, shall distribute to each shareholder of record as of January 14, 1983 one Unit for each share of the Company so owned of record by such shareholder. The Company shall certify the identity and address of such shareholders and such number of shares to the Trustees at the Effective Time.

The Corporate Trustee shall act as exchange agent to effect the distribution of Certificates evidencing ownership of Units to such stockholders only upon surrender of such stockholder of certificates representing shares of the Company in accordance with the instructions set forth in Exhibit IV. In addition, any distributions being held by the Corporate Trustee pursuant to Section 4.02 shall be paid, without interest, at the time of surrender of the certificates representing shares of the Company. The Corporate Trustee will cancel on behalf of the Company such certificates representing shares of the Company so surrendered. The Corporate Trustees obligations hereunder shall be subject to the requirements of escheat laws of the various states which may be applicable

3.02 Certificates as Evidence of Ownership of Units. In addition to Section 3.08 hereof and notwithstanding anything else stated herein, the Trustees may for all purposes set forth in this Trust Agreement, including without limitation the making of distributions and voting, treat the holder of any certificate as shown on the Trustees' records as the owner of the Units evidenced thereby.

3.03 Rights of Owners of Units. An owner of a Unit by assignment or otherwise shall take and hold the Unit subject to all the terms and provisions of this Trust Agreement, the Partnership Agreement and the Conveyance, which shall be binding

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upon and inure to the benefit of the successors, assigns, legatees, heirs and personal representatives of such owner. By an assignment or transfer of one or more Units, the assignor thereby shall, with respect to such assigned or transferred Unit or Units which are transferred and recorded by the Trustee in accordance with Section 3.06, part with, (a) all of his rights in, to and under such Unit; and (b) all interests, rights and benefits under this Trust Agreement of an owner of a Unit which are attributable to such Unit or Units. As to the Trustees, the rights of the owner of a Unit hereunder shall be subject to the terms of this Article III with respect to Certificate Holders.

3.04 Character of Rights. The sole interest of each owner of a Unit shall be his pro rata portion of the Beneficial Interest and the obligations of the Trustees expressly created under this Trust Agreement with respect to the Beneficial Interest. Such interest of an owner of a Unit is and shall be construed for all purposes to be intangible personal property as of the date hereof. No Certificate Holder as such shall have any title, legal or equitable, in or to any real property interest which is a part of the Trust Estate, including, without limiting the foregoing, the Overriding Royalty Interest or any part thereof, but the sole interest of each Certificate Holder shall be his pro rata portion of the Beneficial Interest and the obligation of the Trustees to hold, manage and dispose of the Trust Estate and to account for the same as in this Trust Agreement provided. No owner of a Unit or Certificate Holder shall have the right to seek or secure any partition during the term of the Trust or during the period of liquidation and winding up under Section 9.02 hereof.

3.05 Form, Execution and Dating of Certificates. The Certificates may contain such changes of form, but not substance, as the Trustees, from time to time in their discretion, may deem necessary or desirable. In addition, the Certificates shall contain such changes (not inconsistent with the provisions of this Trust Agreement) as from time to time may be required to comply with any rule or regulation of any securities exchange on which the Certificates may then be listed. Each Certificate shall be dated the date of issuance of the Certificate. Each Certificate shall be signed by two authorized officers of the Corporate Trustee (which signatures may be on or affixed to the Certificate) and may be sealed with the seal of the Corporate Trustee or a facsimile thereof. Where any such Certificate is countersigned by the Transfer Agent, the signatures of any such authorized officers of the Corporate Trustee may be facsimiles.

Pending the preparation of definitive Certificates, the Corporate Trustee may execute and the Transfer Agent shall record, countersign and register temporary Certificates (printed, lithographed or typewritten). Temporary Certificates shall be issuable as registered Certificates and substantially in the form of the definitive Certificates, but with such omissions, insertions and variations as may be appropriate for temporary Certificates, all as may be determined by the Corporate Trustee. Temporary Certificates may contain such references to any provisions of this Trust Agreement as may be appropriate. Every temporary Certificate shall be executed by the Corporate Trustee and be recorded, countersigned and registered upon the same conditions and in substantially the same manner, and with like effect, as the definitive Certificates. As promptly as practicable, the Corporate Trustee shall execute and furnish definitive Certificates, and thereupon temporary Certificates may be surrendered in exchange therefor without charge at offices or agencies to be maintained by the Corporate Trustee for the purpose pursuant to this Section 3.05, and the Transfer Agent shall record, countersign and register in exchange for such temporary

Certificates a like aggregate amount of definitive Certificates. Until so exchanged the temporary Certificates shall be entitled to the same benefits under this Trust Agreement as definitive Certificates.

3.06 Registration and Transfer of Units. With respect to the issuance of the initial Certificates representing ownership of the Units and upon subsequent transfers of such Certificates in accordance with the provisions of this Section, the Corporate Trustee shall maintain records which reflect the name and address of the holder of each Certificate, the number of Units represented by each such Certificate, the date of issuance and/or transfer of each Certificate, the name of each transferee of a Certificate and any other such information as the Trustees shall deem necessary or advisable; provided, that, except for information elicited pursuant to Section 6.10, the Corporate Trustee shall not be required to maintain any records as to the citizenship or national origin of any holder of Certificates. All Units shall be freely transferable, but no transfer of any Unit shall be effective as against the Trustees prior to entry on the records of the Corporate Trustee upon the surrender of the Certificate or Certificates evidencing ownership of such Unit or Units (or upon compliance with the provisions of Section 3.07 hereof) and compliance with such reasonable regulations as the Trustees may prescribe. Certificates may be presented for transfer on such date at the principal trust office of the Corporate Trustee or at such office of the Corporate Trustee as the Corporate Trustee shall maintain (and hereby agrees to maintain) in the City of Houston.

The Company and the Trustees hereby appoint the Bank as Transfer Agent for the transfer and registration of Certificates of all Units. The Trustees may in their sole discretion remove the Bank as Transfer Agent, and appoint such other Transfer Agents as it deems appropriate. No service charge shall be made by the Trustees to the transferor or transferee of a Certificate for any transfer of a Unit evidenced by the transferred Certificate, but the Trustees may require payment of a sum sufficient to cover any tax or other governmental charge that may be imposed in relation to such transfer.

Until any such transfer and the recording of such transfer by the Corporate Trustee as provided in this Section 3.06, the Trustees may treat the holder of any Certificate as shown by the Corporate Trustee's records as the owner of the Units evidenced thereby and shall not be charged with notice of any claim or demand respecting such Certificate or the interest represented thereby by any other party. Any such transfer of a Unit as evidenced by a transfer of a Certificate in accordance with the provisions of this Section 3.06 shall, as to the Trustees, transfer to the transferee of the Certificate as of the close of business on the date of transfer all of the undivided right, title and interest of the transferor in and to the Beneficial Interest; provided that as to the Trustees, a transfer of a Certificate shall not transfer to the transferee of such Certificate the right of the transferor of the Certificate to any sum payable to the transferor as the holder of the Certificate until such transfer is recorded by the Corporate Trustee as provided in this Section 3.06. However, nothing stated herein shall affect the right of the Trustees to act in accordance with Section 3.09 and Section 6.11 hereof.

As to matters affecting the title, ownership, warranty or transfer of Certificates, Article 8 of the Uniform Commercial Code, the Texas Uniform Act for Simplification of Fiduciary Security Transfers under Chapter 33 of the Texas Business and Commerce Code and other statutes and rules with respect to the transfer of securities, each as adopted and then in force in the State of Texas, shall govern and apply. The death of any Certificate Holder or owner of a Unit shall not entitle such owner's or Certificate Holder's transferee to an accounting or valuation for any purpose, but as to the Trustees the transferee of a deceased Certificate Holder shall succeed to all rights of the deceased Certificate Holder under this Trust Agreement upon proper proof of title, satisfactory to the Trustees.

3.07 Mutilated, Destroyed, Lost or Stolen Certificates. In the event that any Certificate is mutilated, destroyed, lost or stolen, the Corporate Trustee in its discretion may issue to the holder of such Certificate as shown by the records of the Corporate Trustee a new Certificate in exchange and substitution for the mutilated Certificate, or in lieu of and substitution for the Certificate so destroyed, lost or stolen. In every case, the applicant for a substituted Certificate shall furnish to the Trust and the Trustees such security or indemnity as the Trustees may reasonably require to save the Trust and the Trustees harmless, and, in every case of destruction, loss or theft, the applicant shall also furnish to the Trustees evidence to the Trustees' satisfaction of the destruction, loss or theft of such Certificate. Upon the issuance of any substituted Certificate, the Trustees may require the payment of a sum sufficient to cover any tax or other governmental charge that may be imposed in relation thereto and any other reasonable expenses incurred in connection therewith.

3.08 Protection of Trustees. The Trustees shall be protected in acting upon any notice, credential, certificate, assignment or other document or instrument believed by the Trustees to be genuine and to be signed by the proper party or parties. The Trustees are specifically authorized to rely upon the application of Article 8 of the Uniform Commercial Code, the application of the Texas Uniform Act for Simplification of Fiduciary Security Transfers under Chapter 33 of the Texas Business and Commercial Code and the application of other statutes and rules with respect to the transfer of securities, each as adopted and then in force in the State of Texas, as to all matters affecting title, ownership, warranty, or transfer of the Certificates and the Units represented thereby, without any personal liability for such reliance, and the indemnity granted pursuant to Section 7.03 shall specifically extend to any matters arising as a result thereof.

3.09 Determination of Ownership of Certificates. In the event of any disagreement between persons claiming to be the person entitled to be the Certificate Holder with respect to any Unit or Units or claiming to be the transferee of any Certificate Holder, the Corporate Trustee shall be entitled at its option to refuse to recognize any such claims so long as such disagreement shall continue. In so refusing, the Corporate Trustee may elect to make no delivery or other disposition of the interest represented by the Certificate involved, or any part thereof, or of any sum or sums of money, accrued or accruing thereunder, and, in so doing, the Corporate Trustee shall not be or become liable to any Person for the failure or refusal of the Corporate Trustee to comply with such conflicting claims, and the Corporate Trustee shall be entitled to continue so to refrain and refuse so to act, until

(a) the rights of the adverse claimants have been adjudicated by a final judgment of a court assuming and having jurisdiction of the parties and the interest and money involved and the time within which appellate relief may be requested has expired or final appellate relief has been denied, or

(b) all differences have been adjusted by valid agreement between said parties and the Corporate Trustee shall have been notified thereof in writing signed by all of the interested parties.

In addition, the Corporate Trustee may bring an interpleader action against the interested parties in an appropriate court and ask such court for a declaration as to the resolution of such adverse claims.

3.10 Transfer Agent. Any references in this Article III to the rights and duties of the Corporate Trustee with respect to the transfer or registration of Certificates shall also be deemed to be references to the Transfer Agent acting hereunder.

ARTICLE IV

ACCOUNTING AND DISTRIBUTIONS

4.01 Fiscal Year and Accounting Method. [redacted] be the calendar year. The Trustees shall maintain the books of the Trust on a cash basis except to the extent that such books must be kept on any other basis pursuant to requirements for reporting to the Securities and Exchange Commission, any other governmental regulatory body, any national securities exchange on which the Units may become listed, if any, or to the Certificate Holders.

4.02 Distributions. [redacted] provided, however, that the Corporate Trustee shall withhold such amounts from such distributions, make such deposits with depositary institutions and file such reports with governmental agencies as is customary or appropriate for disbursing agents with respect to such distributions.

No distributions shall be paid to a Certificate Holder until such Certificate Holder has surrendered for exchange pursuant to Section 3.01 his certificate representing shares of the Company. Until such surrender all distributions shall be held by the Corporate Trustee pursuant to Section 3.01.

4.03 Income Tax Reporting. For federal and state income tax purposes, the Trustees shall file such returns and statements as in their judgment are required to comply with applicable provisions of the Code and regulations thereunder and any state laws and regulations thereunder and to permit each Certificate Holder to correctly report his share of the income and deductions of the Trust. Unless otherwise advised by counsel, the Trustees intend to treat all income and deductions of the Trust for each Quarterly Period as having been realized on the Quarterly Record Date for such Quarterly Period and to allocate to the Certificate Holders on such Quarterly Record Date such income and deductions.

4.04 Reports to Certificate Holders. [redacted] which shall show in reasonable detail the assets and liabilities and receipts and disbursements of the Trust for such quarter.

Within 90 days following the end of the Trust's fiscal year the Trustees will cause the Corporate Trustee to mail to each Certificate Holder who was a Certificate Holder on the Quarterly Record Date for any Quarterly Period in such year a report which will show in reasonable detail the assets and liabilities, the receipts and disbursements, and, for state and federal tax purposes, the income and expenses of the Trust as well as sufficient information to permit a calculation of any depletion deduction for each Quarterly Period (or portion thereof, if any) during the year. In such report, the Trustee shall, if required, report separately with respect to each property (within the meaning of Section 614 of the Code) held in the Trust Estate during such year. Within 120 days following the end of each fiscal year, the Trustees shall cause the Corporate Trustee to mail to Certificate Holders, as of a record date to be determined by the Trustees, an annual report (which may be the Trust's Annual Report on Form 10-K to the Securities and Exchange Commission) containing financial statements audited by a nationally recognized firm of independent public accountants selected by the Trustees and a summary oil and gas reserve report with respect to the Overriding Royalty Interest, which, pursuant to the terms of the Conveyance, will be prepared by the working interest owner of the Properties.

ARTICLE V

MEETINGS OF CERTIFICATE HOLDERS

5.01 Purpose of Meetings. A meeting of the Certificate Holders may be called at any time pursuant to the provisions of this Article V to act with respect to any matter regarding which the Certificate Holders are authorized to act by the express terms of this Trust Agreement.

5.02 Call and Notice of Meetings. Any such meeting of the Certificate Holders may be called at any time by the Trustees in their discretion. The Trustees also shall call a meeting of the Certificate Holders within twenty days after receipt of a written request which sets forth in reasonable detail the action proposed to be taken at such meeting and is signed by Certificate Holders representing the ownership of at least twenty-five percent in number of the Units then outstanding. Except as may be otherwise required by any national securities exchange on which the Units may then be listed, written notice signed by the Corporate Trustee (which signature may be a facsimile) of every meeting of the Certificate Holders setting forth the time and place of the meeting and in general terms the matters proposed to be acted upon at such meeting shall be given in person or by mail, not more than sixty nor less than twenty days before such meeting is to be held to all of the Certificate Holders of record on a date ("Voting Record Date") selected by the Corporate Trustee, which date shall be not more than sixty days before the date of such meeting. Notice to any Certificate Holder shall be mailed to him at his last address as shown by the records of the Corporate Trustee and shall be deemed to have been duly given when so addressed and deposited in the United States mail, postage prepaid. No matter other than that stated in the notice shall be acted upon at any meeting. Any such meeting shall be held at such time and at such place as the notice of such meeting may designate in the city where the principal trust office of the Corporate Trustee is located.

5.03 Voting. Except as set forth in this Section 5.03, only a person who was a Certificate Holder on the Voting Record Date ("Record Date Certificate Holder") shall be entitled to speak or vote at any such meeting. A person appointed by an instrument in writing as a proxy for such Record Date Certificate Holder shall be entitled at such meeting to exercise all rights exercisable by such Record Date Certificate Holder as if such Record Date Certificate Holder attended such meeting and exercised such right in person. In addition, a general partner of the Partnership and any Trustee or Trustees' representatives shall be entitled to be present, speak and generally to participate in any such meeting. All references to a Record Date Certificate Holder shall mean either such Record Date Certificate Holder or his duly appointed proxy. At any such meeting, the presence in person or by proxy of Record Date Certificate Holders holding Certificates representing a majority of the Units outstanding on the Voting Record Date shall constitute a quorum, and, unless otherwise provided in this Trust Agreement (including those instances where although the meeting is to be duly called and held in accordance with the provisions of this Article V a different number of votes is required for the taking of any action), any matter shall be deemed to have been approved if it is approved by the vote of Record Date Certificate Holders holding on the Voting Record Date Certificates representing a majority of the Units represented at the meeting. Each Record Date Certificate Holder shall be entitled to one vote for each Unit represented by the Certificate or Certificates held by him. The Trustees, subject to all applicable laws, may solicit from, and vote proxies of, Certificate Holders entitled to vote at any meeting of owners of Units.

5.04 Conduct of Meetings. The Trustees may make such reasonable regulations as they may deem advisable governing the conduct of any such meeting including, without limitation, provisions governing the appointment of proxies, the appointment and duties of inspectors of votes, the submission and examination of proxies, certificates and other evidences of the right to vote, the preparation and use at the meeting of a list of the Persons entitled to vote at the meeting, the appointment of a Chairman and Secretary of the meeting and such other matters concerning the conduct of the meeting as it shall deem advisable.

ARTICLE VI

ADMINISTRATION OF TRUST AND POWERS OF THE TRUSTEES

6.01 General Authority. Subject to the limitations set forth in this Trust Agreement, the Trustees are authorized to and shall take such actions as in their judgment are necessary, desirable or advisable to achieve the purposes of the Trust, including the solicitation and voting of proxies at meetings of the owners of Units and the taking of appropriate action to enforce the terms of the Partnership Agreement and to enforce, or to cause the Partnership to enforce, the terms of the Conveyance (including the institution of any actions or proceedings at law or in equity necessary to the foregoing). Unless otherwise provided, whenever any provision hereunder empowers the Trustees to act herein, such action shall be considered to be the action of the Trustees when done upon the authority of the Corporate Trustee and any two of the Individual Trustees or upon the authority of all of the Individual Trustees.

If any legislation exempting owners of nonoperating interests from the provisions of the Crude Oil Windfall Profit Tax Act of 1980 is enacted, the Trustees are authorized to and shall use all reasonable efforts to collect any required certificate or other document from any person whose certification with regard to the amount of production from Properties or with respect to any other information is required to perfect such exemption for the owners of the Units and shall use all reasonable efforts to transmit, if necessary, such documents or certificates to the working interest owners of the Properties. The Trustees are authorized to, and shall cause the Corporate Trustee (with the Company to the extent the Company is required to be a party to the Trust's filings), to make all filings on behalf of the Trust with the Securities and Exchange Commission and other governmental authorities required by applicable law or regulation.

It is the intention of the Company that the Units not be registered on a securities exchange, provided that the Trustees shall have the discretion to apply for the listing of the Units on a securities exchange if they deem such listing to be in the best interest of the Unit holders.

6.02 Limitations on Actions of Trustees. Subject to the limitations set forth in this Trust Agreement, the Trustees may agree to modify the terms of the Partnership Agreement and to settle disputes with respect thereto. In no event, however, shall a modification or settlement be agreed to by the Trustees which (a) alters the nature of the Overriding Royalty Interest or (b) alters the powers of the partners of the Partnership, the Sharing Ratio (as defined in the Partnership Agreement) of the Trust, the purposes and scope of activities of the Partnership, or the manner of amending the Partnership Agreement, from that set forth in the Partnership Agreement.

6.03 Consent by Trust to Dissolution of Partnership. The Trustees shall not agree to the dissolution of the Partnership or (except as otherwise provided in Section 6.04) to the sale of all or any portion of the Overriding Royalty Interest owned by the Partnership without the affirmative vote at a meeting duly called and held in accordance with Article V hereof of the Record Date Certificate Holders holding Certificates representing a majority of the Units.

6.04 Limited Power to Dispose of the Overriding Royalties and of the Trust Partnership Interest. Except as otherwise provided in Sections 6.04, 6.08 and 9.02, if, and only if, approved by the affirmative vote at a meeting duly called and held in accordance with the provisions of Article V hereof of the Record Date Certificate Holders holding Certificates representing a majority of the Units, the Trustees may sell all or any part of the Trust Partnership Interest or the Offshore II Overriding Royalty Interest, or cause the sale of all or any part of the Overriding Royalty Interest by the Partnership in such manner as they deem in the best interest of the owners of Units provided, that the Trustees shall use their reasonable efforts to consummate such sale on a Quarterly Record Date. Except as provided in Section 6.15, the Trustees may not sell or otherwise dispose of all or any part of the Trust Partnership Interest or the Offshore II Overriding Royalty Interest or any other assets of the Trust or consent to the sale by the Partnership of the Overriding Royalty Interest for any consideration other than cash. The Trustees shall distribute any cash received by the Trust as a result of any such sale, subject to the need to pay any liabilities or to establish or increase any cash reserves pursuant to Section 6.06 hereof, to Certificate Holders as part of the Quarterly Cash Amount as set forth in Section 1.19. Notwithstanding the foregoing, if necessary to provide for the payment of specific liabilities of the Trust then due, the Trustees may without a vote of the owners of Units (a) sell all or a portion of the Trust Partnership Interest or the Offshore II Overriding Royalty Interest or any other assets of the Trust for such cash consideration as they shall deem appropriate, (b) exercise their rights under the Partnership Agreement to dissolve the Partnership or (c) cause a sale by the Partnership of the Overriding Royalty Interest owned by the Partnership.

6.05 No Power to Engage in Business or Make Investments. The Trustees shall not, in their capacity as Trustees under the Trust, acquire any oil and gas lease, royalty or other mineral interest other than the Overriding Royalty Interest or the Offshore II Overriding Royalty Interest, including such portion thereof as may be held indirectly through ownership of the Trust Partnership Interest or the Tenneco Offshore II Stock or directly upon a distribution from the Partnership, whether upon liquidation of the Partnership or otherwise, nor engage in any business or investment activity, except as permitted in Section 6.09, of any kind whatsoever. Nothing contained in this Section 6.05 shall prevent the Trustees from taking those actions as are expressly permitted by other portions hereof or are reasonably related thereto, including the dissolution of the Trust or the Partnership and holding and/or disposing of distributions from the Partnership.

6.06 Payment of Liabilities of Trust. The Trustees are authorized to and shall use all money received by the Trust for the payment of all liabilities of the Trust, including but not limited to all expenses, taxes, and liabilities incurred of all kinds, compensation to the Trustees for their services pursuant to Sections 7.04 and 7.05 hereof, and compensation to such parties as may be consulted pursuant to Section 7.06 hereof. With respect to any liability which is contingent or uncertain in amount or which otherwise is not currently due and payable, the Trustees in their sole discretion may, but are not obligated to, establish a cash reserve for the payment of such liability.

6.07 Timing of Trust Expenses. The Trustees will use all reasonable efforts to cause the Trust and the owners of Units, as grantors thereof for federal income tax purposes, to recognize income (including any income from interest earned on reserves established pursuant to Section 6.06 hereof or any sale of the Offshore II Overriding Royalty Interest or the Trust Partnership Interest) and expenses on Quarterly Record Dates. The Trustees will use all reasonable efforts to invoice the Trust for services rendered by the Trustees only on a Quarterly Record Date and will use all reasonable efforts to cause the Trust to pay any such invoices only on the Quarterly Record Date and to cause the Trust to pay all other liabilities of the Trust on the Quarterly Record Date for the Quarterly Period in which such liability is invoiced. Nothing in this Section 6.07 shall be construed as requiring the Trustees to cause payment to be made for Trust liabilities on any date other than on such date as in their sole discretion they shall deem to be in the best interests of the owners of the Units.

6.08 Limited Power to Borrow. If at any time the cash on hand is not sufficient to pay liabilities of the Trust then due or to redeem Units as required by Section 6.10 of this Trust Agreement, the Trustees are authorized, but not required, to borrow from the Corporate Trustee in its capacity as a bank, or from another Person, on a secured or unsecured basis, such amounts as are required after use of any available Trust funds to pay such liabilities as have become due or to make such purchases. The borrowing costs to the Trust of any loan from the Bank shall not exceed the prime rate of the Bank. Borrowings from any other Person shall be on such terms as the Trustees shall deem advisable. To secure payment of such indebtedness, the Trustees are authorized to mortgage, pledge, grant security interests in or otherwise encumber the assets of the Trust, or any portion thereof, including all or any part of the Trust Partnership Interest or the Offshore II Overriding Royalty Interest, and to carve out and convey production payments. In securing payment of any indebtedness, the Trustees are specifically authorized to include any and all terms, powers, remedies, covenants and provisions deemed necessary or advisable in the Trustee's discretion, including, without limitation, confession of judgment and the power of sale without the approval of the Certificate Holders and with or without judicial proceedings.

In the event of such borrowings, the Trustees shall suspend further Trust distributions (except in respect of previously announced Quarterly Cash Amounts) until the indebtedness created by such borrowing has been paid in full.

6.09 Interest on Cash on Hand. Cash being held by the Trustees as a reserve for liabilities or for distribution shall, to the extent not prohibited by Section 11 of the Texas Trust Act, be placed in an Interest Bearing Account. Any amount which may not by law be so placed shall be placed with a bank which is not an affiliate of the Trustees on term and conditions acceptable to the Trustees.

6.10 Divestiture of Units. If at any time the Trust or the Trustees are named a party in any judicial or administrative or other governmental proceeding which seeks the cancellation or forfeiture of any interest in any Property located in the United States in which the Trust has an interest because of the nationality, or any other status of any one or more owners of Units, or if at any time the Trustees in their reasonable discretion determine that such a proceeding is threatened or likely to be asserted and the Trust has received an opinion of counsel stating that the party or parties threatening or asserting the claim have a reasonable probability of succeeding in such claim, in order to preserve the sound investment character of the Trust, the following procedures will be applicable:

(a) The Trustees, in their discretion, may seek from an investment banking firm to be selected by the Trustees an opinion as to whether it is in the Trust's best interest for the Trustees to take the actions permitted by subparagraphs (b)(1)-(3) of this Section 6.10. In reaching its opinion, the investment banking firm shall consider: (i) the value of the interest subject to potential forfeiture or cancellation; (ii) the likelihood of the forfeiture or cancellation; (iii) the number of Units involved in, and the cost to the Trust of the Trustees' acting pursuant to, subparagraphs (b)(1) through (b)(3) of this Section 6.10; and (iv) such other matters as the investment banking firm shall deem relevant.

(b) The Trustees may (1) take no action with respect to the potential cancellation or forfeiture or (2) seek to avoid such cancellation or forfeiture by the following procedure:

(1) The Trustees will promptly give written notice ("Notice") to each record owner of Units as to the existence of or probable assertion of such controversy. The Notice will contain a reasonable summary of such controversy, will include materials which will permit an owner of Units to promptly confirm or deny to the Trustees that such owner is a Person whose nationality or other status is or would be an issue in such a proceeding ("Ineligible Holder") and will constitute a demand to each Ineligible Holder that he dispose of his Units, to a party which would not be an Ineligible Holder, within 30 days after the date of the Notice.

(2) If an Ineligible Holder fails to dispose of his Units as required by the Notice, the Trustees will have the right to redeem and will redeem, any such Units at any time during the 90 days after the expiration of the 30-day period specified in the Notice. The redemption price on a per Unit basis will be determined as of the last Business Day

("determination day") preceding the end of the 30 day period specified in the Notice and will equal the following per Unit amount: (i) the mean between the closing bid and asked prices for the Units in the over-the-counter market on the determination day if quotations for such prices on such day are available or, if not, on the last preceding day for which such quotations are available, or (ii) if the Units are then listed on a securities exchange, the price will equal the closing price of the Units on such exchange (or, if the Units are then listed on more than one exchange, as quoted in any composite index of trading on such exchanges, or if not quoted in any such index, on the largest such exchange in terms of the volume of Units traded thereon during the preceding twelve months) on the determination day if any Units were sold on such exchange on such day or, if not, on the last preceding day on which any Units were sold on such exchange, or (iii) if Units are not then traded in the over-the-counter market or listed on a securities exchange, at a price per Unit as determined by the Trustees, which may be based on an opinion of a recognized firm of independent investment bankers as to the value of the Units. Such redemption will be accomplished by tender of the above cash price to the Ineligible Holder at his address as shown on the records of the Corporate Trustee, either in person or by mail as provided in Section 11.04, accompanied by notice of cancellation. Concurrently with such tender the Corporate Trustee shall cancel or cause to be cancelled all Certificates representing Units then owned by such Ineligible Holder and for which tender has been made. In the event the tender is refused by the Ineligible Holder or if he cannot be located after reasonable efforts to do so, the tendered sum shall be held by the Corporate Trustee in an Interest Bearing Account for the benefit of such Ineligible Holder, until proper claim for same (together with interest accrued thereon) has been made by such Ineligible Holder, but subject to applicable laws concerning unclaimed property, and such Ineligible Holder's Certificates representing Units shall be deemed for all purposes cancelled except to the extent such Certificates evidence the ownership of or the right to receive the tendered sum being held by the Corporate Trustee for the benefit of such Ineligible Holder.

(3) The Trustees may, in their sole discretion, borrow any amounts required to redeem Units pursuant to this Section 6.10.

Nothing herein shall prevent the Trustees from maintaining such legal and other related actions as shall be recommended by counsel to the Trustees.

(c) The Trustees in relying on the opinion of an investment banking firm or in connection with the matters subject to this Section 6.10 shall have the full authorization and be entitled to the full protection provided by Section 7.06 hereof. If the Trustees desire but cannot obtain an opinion from an investment banking firm which in the Trustees' sole discretion is competent to render such opinion, then the Trustees may obtain (and rely on) for the opinion referred to in subparagraph (a) of this Section 6.10 the opinion of any other adviser or expert which the Trustees in their sole discretion believe to have sufficient competence to render such opinion.

The Trustees may agree with any such investment banking firm or other adviser or expert in connection with such opinion that it will not assert against the investment banking firm, adviser or expert on behalf of itself, the Trust or any owner of Units any claim unless such claim is based on such investment banking firm, adviser or expert failing to act in good faith.

In no event shall the Trustee or the Transfer Agent have any responsibility for monitoring the citizenship or residence of the Certificate Holders, except as made necessary by the procedures described in subsection (b) above, after such procedures have been invoked, or in any other respect to insure compliance with such federal oil and gas lease requirements.

6.11 Settlement of Claims. The Trustees are authorized to maintain and defend, and to settle, in the Trust's name any claim or controversy by or against the Trust without the joinder or consent of any Certificate Holder or owner of a Unit.

6.12 Income and Principal. The Trustees may but shall not be required to keep separate accounts or records for income and principal. To the extent that such separate accounts or records are kept, the Trustees may allocate the receipts, disbursements and reserves of the Trust between income and principal in the discretion of the Trustees, and the Trustees' discretion need not accord with the provisions of any requirement of applicable law. Regardless of any such characterization, however, the Trustees shall not make any distribution, accumulate any funds, or maintain any reserve except as expressly provided in this Trust Agreement. The Trustees shall not maintain a reserve for depletion of the mineral assets represented in the Trust corpus.

6.13 Effect of Trustees' Powers on Trust Property. The powers granted the Trustees under this Trust Agreement may be exercised upon such terms as the Trustees deem advisable and may affect Trust properties for any length of time regardless of the duration of the Trust.

6.14 No Requirement of Diversification. The Trustees shall be under no obligation to diversify the Trust's assets or to dispose of any wasting assets.

6.15 Liquidation of Tenneco Offshore II Company. As soon as feasible after satisfaction of Tenneco Offshore II Company's ("Offshore II") obligations under Note Purchase Agreements dated April 15, 1974, between Offshore II and certain purchasers named therein as secured by an Indenture and Security Agreement, dated April 1, 1974, from Offshore II and the Company to First National City Bank, as Trustee, but not later than December 31, 1984 (provided such obligations have been satisfied), the Trustees shall take, or cause to be taken, all action necessary to convert all of Offshore II's assets into cash, distribute such cash, subject to any unsatisfied claims, in complete cancellation of the Offshore II Stock outstanding, and to cause Offshore II to dissolve, subject to the following:

(a) The Trustees may cause the dissolution of Offshore II to be postponed until Offshore II's obligations under the Assignment of Partnership Distributions, dated as of April 1, 1974, between the Company, Tenneco Exploration, Ltd. and Tenneco Oil Company have been satisfied if the Internal Revenue Service, on or before July 1, 1984, has ruled to the effect that such postponement will not cause the distribution of Units by the Company to its stockholders to be treated as something other than a distribution pursuant to a plan of complete liquidation.

(b) In lieu of causing Offshore II to convert its assets into cash, the Trustees may cause Offshore II to convert its assets into nonoperating mineral interests and distribute such interests in complete cancellation of the Offshore II Stock, if, prior to such distribution, the Internal Revenue Service has ruled to the effect that such distribution will not cause the Trust to be classified as a corporation for federal income tax purposes.

The Trustees may cause the dissolution of Offshore II to occur earlier than above provided or to distribute cash even if the ruling provided in paragraph (b) is obtained, but they shall have no authority to postpone the liquidation or to distribute property other than cash except as provided in paragraphs (a) and (b) above.

The Trustees are authorized to execute and deliver an agreement with the holders of the obligations referred to in this Section 6.15 or with Citibank, N.A. (formerly First National City Bank), as trustee, and take such other action as they may deem appropriate to bind the Trust not to sell or otherwise dispose of any of the outstanding capital stock of Offshore II so long as the obligations of Offshore II referred to in this Section 6.15 remain outstanding.

ARTICLE VII

RIGHTS AND LIABILITIES OF TRUSTEES

7.01 General Liability of Trustees. The Trustees are empowered to act in their discretion and shall not be personally or individually liable for any act or omission except in the case of gross negligence, bad faith or fraud and except for any liability the Trustees may have vis-a-vis the owners of Units as provided in Section 7.02 hereof.

Neither the Trustees nor the Certificate Holders shall have any liability with respect to any contract or agreement where such contract or agreement includes language substantially to the following effect, provided that failure to include such language, or language substantially to the same effect, shall not imply any such liability:

> "Any liability hereunder is the liability of the Trust alone and is in no respect whatsoever the obligation of the Trustees or of the Certificate Holders. Any person dealing with the Trust is doing so in reliance solely upon the assets of the Trust and not upon the Trustees or the Certificate Holders and neither the Trustees nor the Certificate Holders shall have any personal liability to any such person."

7.02 Limitation of Liability of Certificate Holder. In authorizing any transaction which results or could result in any kind of liability, the Trustees shall take such action as may be necessary to ensure that such liability shall be satisfiable in all events (including the exhaustion of the Trust Estate) only out of the Trust Estate, that such liability shall not be satisfiable out of any amounts at any time distributed to any Certificate Holder or other assets owned by a Certificate Holder, and that no Certificate Holder shall have any personal liability therefor. In the event of failure by the Trustees to take any such action, the Trustees shall be fully and exclusively liable for any resulting liability (other than liability for state and Federal taxes or liabilities for refunds, fines, penalties or interest relating to oil or gas pricing overcharges under state or federal price controls) vis-a-vis the Certificate Holder; but the Trustees shall be entitled to be indemnified and reimbursed from the Trust

Estate; provided, however, that nothing herein shall result in the imposition of any liability on the Trustees for state or federal taxes or for refunds, fines, penalties or interest relating to oil or gas pricing overcharges under state or federal price controls and provided further that failure to include the language in any contract or agreement as set forth in Section 7.01 shall not imply any such liability. Notwithstanding anything in this Trust Agreement to the contrary, neither the Trustees nor any Trustee shall be required to take any action that the Trustees or any such Trustee, as the case may be, believe in good faith could result in the imposition of liability on them or him or it under this Section 7.02.

7.03 Indemnification of Trustees. The Trustees shall be indemnified by, and receive reimbursement from, the Trust Estate against and from any and all liability, expense (including counsel fees and expenses incurred in preparing for and defending claims or suits), claim, damage, or loss incurred by them individually or as Trustees in the administration of the Trust and the Trust Estate or any part or parts thereof, or in the performance or omission to perform any act under this Indenture, except [redacted] and (b) any loss resulting from Trustees' costs (direct or indirect) in carrying out the administrative tasks required hereunder exceeding the compensation and reimbursement provided for pursuant to Sections 7.04 and 7.05 hereof. The Trustees shall have a lien upon the Trust Estate to secure them for such indemnification and reimbursement and for compensation to be paid to the Trustees. Except as provided in Section 3.07, neither the Trustees nor any agent or employee of the Trustees shall be entitled to any reimbursement or indemnification from any owner of Units for any liability, expense, claim, damage, or loss incurred by the Trustees or any such agent or employee; and the rights of the Trustees or any employee or agent of the Trustees to reimbursement and indemnification, if any, shall be limited solely to the Trust Estate, whether or not the Trust Estate is exhausted without full reimbursement or indemnification of the Trustees or any such agent or employee.

7.04 Compensation of Corporate Trustee. The Corporate Trustee shall receive from the Trust compensation for its services as Corporate Trustee and Transfer Agent of the Trust as set forth in Exhibit II, attached hereto. In the event that any Person serving as Corporate Trustee is not also Transfer Agent, the compensation to be paid to the Corporate Trustee and Transfer Agent shall be allocated to the Corporate Trustee and Transfer Agent as the Trustees shall determine. Charges for performing any services not contemplated or specifically covered in Exhibit II will be charged to the Trust on the basis of the prevailing rate for such services in the community in which the Corporate Trustee maintains its principal trust office.

7.05 Other Services and Expenses. Each of the Individual Trustees shall receive from the Trust compensation for his services as an Individual Trustee $15,000 per annum, such amount to be adjusted prospectively for inflation based on the producers price index, adjusted in the same manner as the Transfer Agent fee as set forth in Exhibit II, upon the prior written notification to Certificate Holders. The out-of-pocket costs incurred by the Trustees in the discharge of their duties, including but not limited to fees and expenses incurred for experts hired pursuant to Section 7.06, the costs of insurance deemed advisable by the Trustees and printing additional Certificates, are to be reimbursed to the Trustees by the Trust at actual cost. The

Trustees shall be reimbursed by the Trust for actual expenditures made on account of any unusual duties in connection with matters pertaining to the Trust. In the event of litigation involving the Trust, audits or inspection of the records of the Trust pertaining to the transactions affecting the Trust or any other unusual or extraordinary services rendered in connection with the administration of the Trust, the Trustees shall be entitled to receive reasonable compensation from the Trust for the services rendered. The initial organizational costs of the Trust, including the printing of the initial Certificates and fees of legal counsel of the Trustees and fees of the Corporate Trustee in its capacity as exchange agent under Section 3.01, will be paid by the Company.

7.06 Reliance on Experts. To perform any act required or permitted by this Trust Agreement, the Trustees may, but shall not be required to, consult with counsel, including their own counsel, accountants, geologists, engineers and other parties deemed by the Trustees to be qualified as experts on the matters submitted to them, who may be employees of any of the Trustees, and the opinion or written advice of any such parties on any matter submitted to them by the Trustees shall be full and complete authorization and protection in respect of any action taken or suffered by them hereunder in good faith and in accordance with the opinion or advice of any such party. The Trustees are authorized to make payments of all reasonable fees for services or expenses thus incurred out of the Trust Estate.

7.07 No Security Required. No bond or other security shall be required of the Trustees.

7.08 Transactions in Multiple Capacities. To the extent allowed by applicable law, the Trustees shall not be prohibited in any way in exercising their powers or from dealing with any Trustees in any other capacity, fiduciary or otherwise.

7.09 Relief of Trustees from Certain Duties, Restrictions, and Liabilities. Pursuant to Article 7425b-22 of the Texas Trust Act, the Company, as Trustor, hereby relieves the Trustees from any or all duties, restrictions, and liabilities otherwise imposed upon the Trustees by the Texas Trust Act except for such duties, restrictions, and liabilities as are imposed (a) by Sections 10, 11 and 12 of the Texas Trust Act, (b) by the terms and conditions of this Trust Agreement or (c) by any other applicable law, rule or regulation.

7.10 Appointment of Ancillary Trustees, etc. If at any time it becomes necessary under the laws of any jurisdiction for a trustee qualified under such laws to take any action with respect to any assets held in the Trust Estate, or if at any time in their discretion the Trustees determine that it would be useful or desirable in connection with the administration of the Trust Estate, the individual, bank or trust company legally qualified to act in such jurisdiction appointed in writing by the Trustees then serving hereunder shall serve as ancillary trustee for such purposes. Any such ancillary trustee shall have all rights, privileges, powers, responsibilities and duties as are delegated in writing by the appointing Trustees, subject to such limitations and directions as shall be specified by the Trustees in the instrument evidencing such appointment. Any such ancillary trustee shall be responsible to the Trustees for all assets with respect to which such ancillary trustee is so empowered to act. To the extent permitted under the laws of such jurisdiction, the Trustees may remove an ancillary trustee at any time, without cause and without the necessity of any court proceeding, and may or may not appoint a successor or substitute ancillary trustee from time to time and at any time.

ARTICLE VIII

OFFICE OF THE TRUSTEES

8.01 <u>Removal of Trustees</u>. The Trustees or any one or more of them may be removed from the Trust by the affirmative vote of two Individual Trustees or the affirmative vote at a meeting duly called and held in accordance with the provisions of Article V hereof of the Record Date Certificate Holders holding Certificates representing a majority of the Units; provided that no such removal shall be effective as to the Corporate Trustee unless a successor Corporate Trustee is appointed by the Individual Trustees or at such meeting by such Record Date Certificate Holders.

8.02 <u>Resignation of Trustees</u>. Any one or more of the Trustees may at any time resign from the Trust without cause and without the necessity of any court proceeding after giving written notice ("Resigning Trustees' Notice") to each of the Certificate Holders by registered mail addressed to each such Certificate Holder at his last address on the records of the Corporate Trustee at the time such notice is given and, in the event of the resignation of the Corporate Trustee, by accounting to its successor for the administration of the Trust Estate as may be required by the successor Corporate Trustee. Any and all successors to such resigning Corporate Trustee shall be fully protected in relying upon such accounting. Such resignation shall be effective as of a date to be specified in such notice which shall be a Business Day not less than one hundred twenty days after the date on which the last such notice is mailed ("Resignation Notice Date") unless, in the event of the resignation of the Corporate Trustee, a successor Corporate Trustee shall not have been named pursuant to Section 8.03 in which case such resignation shall become effective upon the appointment of such successor Corporate Trustee.

8.03 <u>Appointment of Successor Trustees</u>. In the event the Corporate Trustee has given notice of its intention to resign, a successor Corporate Trustee shall be appointed by the Individual Trustees as of the effective date of the resignation of the Corporate Trustee within sixty days of the Resignation Notice Date. Notice of the appointment of a successor Corporate Trustee shall be given by the Individual Trustees (within ten days of the appointment of the successor Corporate Trustee) to each Certificate Holder on the Resignation Notice Date at each Certificate Holder's last address on the records of the Corporate Trustee. In the event that a successor Corporate Trustee has not been appointed within sixty days after the Resignation Notice Date or the occurrence of a vacancy in the position of Corporate Trustee, a successor Corporate Trustee may be appointed by any Texas or United States District Court holding terms in Houston, Harris County, Texas, upon the application of any Certificate Holder (and if no Certificate Holder has so applied within seventy-five days after the Resignation Notice Date or occurrence of a vacancy, then the Trustees will so apply prior to the eighty-fifth such day). In the event any such application is filed, such court may appoint a temporary successor Corporate Trustee at any time after any such application is filed with it which shall, pending the final appointment of a successor Corporate Trustee, have such powers and duties as the court appointing such temporary Corporate Trustee shall provide in its order of appointment, consistent with the provisions of this Trust Agreement. In the event such Court shall deem it necessary, the Court may appoint such temporary successor Corporate Trustee or successor Corporate Trustee on such terms as to compensation as the Court shall deem necessary and reasonable notwithstanding any provision herein to the contrary. A Corporate Trustee appointed under the provisions of this Section shall be a national banking association domiciled in the United States which has a capital, surplus and undivided profits of at least One Hundred Million Dollars ($100,000,000).

In the event an Individual Trustee has given notice of his intention to resign, or has already resigned or has died, a successor Individual Trustee shall, except as otherwise provided in this Section 8.03, be appointed by the remaining Individual Trustees within sixty days of the Resignation Notice Date. Notice of the appointment of a successor Individual Trustee shall be given by the remaining Trustees (within ten days of the appointment of a successor Individual Trustee) to each Certificate Holder on the Resignation Notice Date at each Certificate Holder's last address on the records of the Corporate Trustee. In the event that a successor Individual Trustee has not been appointed within sixty days after the Resignation Notice Date or the occurrence of a vacancy in the position of Corporate Trustee, a successor Individual Trustee may be appointed by any Texas or United States District Court holding terms in Houston, Harris County, Texas, upon the application of any Certificate Holder (and if no Certificate Holder has so applied within seventy-five days after the Resignation Notice Date or occurrence of a vacancy, then the Trustees will so apply prior to the eighty-fifth such day). In the event any such application is filed, such court may appoint a temporary successor Individual Trustee at any time after any such application is filed with it which shall, pending the final appointment of a successor Individual Trustee, have such powers and duties as the court appointing such temporary Individual Trustee shall provide in its order of appointment, consistent with the provisions of this Trust Agreement. In the event such Court shall deem it necessary, the Court may appoint such temporary successor Individual Trustee or successor Individual Trustee on such terms as to compensation as the Court shall deem necessary and reasonable notwithstanding any provision herein to the contrary.

All of the Individual Trustees may, with the consent of the Corporate Trustee, elect to resign and not to appoint successor Individual Trustees, in which case, the Corporate Trustee shall be the sole Trustee under this Trust Agreement. In such event, the term "Trustees" under this Trust Agreement shall mean the Corporate Trustee and any action taken by the Corporate Trustee shall be considered the action of the Trustees.

8.04 <u>Rights of Successor Trustee</u>. Immediately upon the appointment of any successor Trustee (including a temporary successor Corporate or Individual Trustee), all rights, titles, duties, powers and authority of the succeeded Trustee hereunder shall be vested in and undertaken by the successor Trustee and the Successor Corporate Trustee shall be entitled to receive from the Corporate Trustee which it succeeds, in addition to the accounting referred to in Section 8.02, all of the Trust Estate held by it hereunder and all records and files in connection therewith. No successor Corporate Trustee shall be obligated to examine or seek alteration of any accounting of any preceding Corporate Trustee, nor shall any successor Corporate Trustee be liable personally for failing to do so or for any act or omission of any preceding Corporate Trustee. The preceding sentence shall not prevent any successor Corporate Trustee or anyone else from taking any action otherwise permissible in connection with any such accounting.

8.05 <u>Merger or Consolidation of Corporate Trustee</u>. Neither a change of name of the Corporate Trustee nor any merger or consolidation of its corporate powers with another bank or with a trust company shall affect its right or capacity to act hereunder.

ARTICLE IX

TERM OF TRUST AND FINAL DISTRIBUTION

9.01 Termination. The Trust shall terminate upon the first to occur of the following events or times:

(a) at such time as the total future net revenues attributable to the Overriding Royalty Interest, as determined by independent petroleum engineers as of the end of any year, are less than $2 million;

(b) a decision to terminate the Trust by the affirmative vote at a meeting duly called and held in accordance with Article V hereof of the Record Date Certificate Holders holding Certificates representing a majority of the Units; or

(c) the expiration of twenty-one (21) years after the death of the last to die of all of the Issue living at the date of execution of this Trust Agreement of JOHN D. ROCKEFELLER, JR., late father of the late former Vice President of the United States, NELSON A. ROCKEFELLER.

9.02 Disposition and Distribution of Assets Upon Termination. Upon termination of the Trust, the Trustees shall sell for cash in one or more sales all the assets other than cash then held in the Trust Estate. Any such sale shall be upon such terms as the Trustees, in their sole discretion, deem to be in the best interests of owners of Units; provided, however, the Trustees shall use their reasonable efforts to consummate such sale on a Quarterly Record Date. The Trustees shall pay, satisfy and discharge all of the existing liabilities of the Trust including fees of the Trustees, or, if necessary, setting up reserves in such amounts as the Trustees in their discretion deem appropriate to provide for payment of contingent liabilities. In the event that any asset which the Trustees are required to sell is not sold by the Trustees within three years after the event causing termination of the Trust, the Trustees shall cause such property to be sold at public auction to the highest cash bidder. Notice of such sale by auction shall be mailed at least thirty days prior to such sale to each Certificate Holder's last address as it appears on the books of the Corporate Trustee. The Trustees shall not be required to obtain approval of the Certificate Holders prior to selling assets pursuant to this Section 9.02. Upon making final distribution to the Certificate Holders, the Trustees shall be under no further liability except as provided in Sections 7.01 and 7.02 hereof. For the purposes of liquidating and winding up the affairs of the Trust at its termination, the Trustees shall continue to act as Trustees and may exercise each power until their duties have been fully performed and the Trust Estate has been finally distributed.

ARTICLE X

IRREVOCABILITY AND AMENDMENT

10.01 Irrevocability. This Trust Agreement and the Trust are intended to be and are irrevocable. No person shall have the right or power to terminate, revoke, alter, amend or change this Trust Agreement or any provisions hereof except as expressly provided in Article IX or in this Article X.

10.02 Limited Amendment. Any provision of this Trust Agreement may be amended by the vote at a meeting duly called and held in accordance with the provisions of Article V hereof of the Record Date Certificate Holders holding Certificates representing a majority of the Units, but no such amendment shall be effective unless and until consented to in writing by the Trustees (provided, however, that the Trustees will so consent unless such amendment affects the Trustees' own rights, duties or immunities under this Trust Agreement or otherwise, in which case the Trustees may in their discretion, but shall not be obligated to, agree to such amendment), and in no event may an amendment be made which would

(a) alter the rights of the Certificate Holders as against each other;

(b) reduce or delay the distributions to the Certificate Holders provided for in Sections 4.02, 6.04 and 9.02 hereof;

(c) provide the Trustees with the power to engage in business or investment activities not specifically authorized herein;

(d) adversely affect the characterization of the Trust as an express trust under the Texas Trust Act and as a grantor trust for federal income tax purposes;

(e) alter the voting requirements set forth in Sections 6.03, 6.04, 8.01, 9.01(b) and 10.02 hereof; or

(f) alter the number of Units in the Trust (except by authorized cancellation of Units as provided in Section 6.10);

unless such amendment is approved (i) by the vote at a meeting duly called and held in accordance with the provisions of Article V hereof of the Record Date Certificate Holders holding Certificates representing one hundred percent (100%) of the Units and (ii) by the Trustees, it being understood that nothing herein shall permit the amendment of this Trust Agreement to provide the Trustees with the power to engage in business or investment activities not specifically authorized herein.

If any ruling has at any time been issued by the Internal Revenue Service, or if any opinion of counsel has been rendered with respect to the classification or treatment of the Trust for federal income tax purposes, no amendment permitted by this Section 10.02 shall be effective unless and until a supplemental ruling or opinion has been obtained indicating that the proposed amendment shall not affect the continued applicability of such existing ruling or opinion.

ARTICLE XI

MISCELLANEOUS

11.01 Inspection of Trustees' Books. Each Certificate Holder and his duly authorized agents, attorneys and auditors shall have the right during reasonable business hours at their own cost and expenses to examine, inspect and make audits of the Trust and records of the Corporate Trustee in reference thereto.

11.02 Filing of Trust Agreement. Except as otherwise required by law, neither this Trust Agreement nor any executed copy hereof need be filed in any county, parish or other jurisdiction in which any of the properties comprising the Trust Estate are located, but the same may be filed for record in any county, parish or other jurisdiction by the Trustees. In order to avoid the necessity of filing this Trust Agreement for record, the Trustees agree that for the purpose of vesting the record title in any successor to the Corporate Trustee, the retiring Corporate Trustee will, upon appointment of any successor Corporate Trustee, execute and deliver to such successor Corporate Trustee appropriate assignments or conveyances.

11.03 Saving Clause. If any provision of this Trust Agreement should be held illegal or invalid, such invalidity or illegality shall not affect the remaining provisions, or any other property interests, and each provision of this Trust Agreement shall exist separately and independently, and shall be applied to property interests separately and independently, of every other provision, and this Trust Agreement shall be construed as if such illegal or invalid provision had never existed.

11.04 Notices. Any notice or demand which by any provision of this Trust Agreement is required or permitted to be given or served upon the Trustees by any Certificate Holder may be given or served by being deposited, postage prepaid and by registered or certified mail, in a post office or letter box addressed (until another address is designated by notice given by the Trustees to the Certificate Holders and the Company) or by hand delivery to the Trustees at the following address:

Corporate Trustee:

Texas Commerce Bank National Association
600 Travis
Houston, Texas 77002
Attention: W. C. Rosson
Senior Vice President and
Trust Officer

Individual Trustees:

Horace C. Bailey
K P Exploration, Inc.
20 Exchange Place-8th Floor
New York, New York 10005

Joseph C. Broadus
169 East 69th Street
Suite 4-D
New York, New York 10021

F. Arnold Daum
Cahill, Gordon & Reindel
80 Pine Street
New York, New York 10005

Any notice or other communication by the Trustees to any Certificate Holder shall be deemed to have been sufficiently given, for all purposes, when deposited, postage prepaid, in a post office or letter box addressed to said holder at its address as shown on the records of the Corporate Trustee.

11.05 Notice and Reports. Whenever any notice, communication or report is given by the Trustees to Certificate Holders pursuant to the provisions of this Trust Agreement or is otherwise required to be provided to Certificate Holders pursuant to the provisions of this Trust Agreement, the Trustees shall provide, by in-hand delivery or as set forth in Section 11.04 hereof, such notice, communication or report to the Partnership at the following address:

TEL Offshore Trust Partnership
c/o Tenneco Oil Company, General Partner
1100 Milam
Houston, Texas 77002
Attention: Secretary

or at such other address as the Partnership may from time to time advise the Trustees in writing.

11.06 Situs of Trust. The situs of the Trust hereby created is Texas, and wherever possible the laws of Texas shall control with respect to the construction, administration and validity of the Trust.

11.07 Acceptance by Trustees. The Trustees, by joining in the execution of this Trust Agreement, accepts the Trust herein created and provided for and accepts all of the rights, powers, privileges, duties and responsibilities of the Trustees hereunder and agrees to exercise and perform the same in accordance with the terms and provisions contained herein.

11.08 Counterparts. This Trust Agreement may be executed in a number of counterparts, each of which shall constitute an original, but such counterparts shall together constitute but one and the same instrument.

11.09 Headings. The headings of the Sections and Articles of this Agreement are inserted for convenience only and shall not constitute a part hereof.

11.10 Independent Conduct. The Company, the Trustees and the Company on behalf of all future owners of Units hereby reserve and retain the right to engage in all businesses and activities of any kind whatsoever (irrespective of whether the same may be in competition with the Trust), and to acquire and own all assets however acquired and whenever situated, and to receive compensation or profit thereof, for their own respective accounts and without in any manner being obligated to disclose or offer such business and activities or assets or compensation or profit to each other or to the Trust.

IN WITNESS WHEREOF, Trustor and Trustees hereunto set their hands effective as of the day and year first above written.

ATTEST: Carl A. Stutt
(Seal) Assistant Secretary

TENNECO OFFSHORE COMPANY, INC.

By E. J. Snel
Vice President

Trustor

WITNESSES:

William S. Collins Jr.

Rita L. Harris

ATTEST: W. C. Rowan
(Seal)

TEXAS COMMERCE BANK NATIONAL ASSOCIATION

By R. L. Melton

Corporate Trustee

WITNESSES:

Geraldine A. Turner

William G. Allen

By [illegible]

[illegible]

[illegible]

Individual Trustees

WITNESSES:

John Schuyler

Rita L. Harris

7821A

THE STATE OF TEXAS §
§
COUNTY OF HARRIS §

On this 13th day of January, 1983, before me appeared E. J. Milan, to me personally known, who, being duly sworn, did say that he is a Vice President of TENNECO OFFSHORE COMPANY, INC., and that the instrument was signed and delivered in behalf of the Corporation by authority of its Board of Directors and that he acknowledged the instrument to be the free act and deed of the Corporation.

Laverne Fisher
Notary Public in and for
Harris County, T E X A S

(SEAL)

LAVERNE FISHER
Notary Public in and for the State of Texas
My Commission Expires March 26, 1984

My Commission expires:

____

THE STATE OF TEXAS §
§
COUNTY OF HARRIS §

On this 14th day of January, 1983, before me appeared R. L. Nelton, to me personally known, who, being duly sworn, did say that he is an Senior Vice President & Trust Officer of TEXAS COMMERCE BANK, NATIONAL ASSOCIATION, and that the instrument was signed and delivered in behalf of the national banking association in its capacity therein stated, by authority of its Board of Directors or pursuant to its bylaws and that he acknowledged the instrument to be the free act and deed of the national banking association.

Laverne Fisher
Notary Public in and for
Harris County, T E X A S

(SEAL)

LAVERNE FISHER
Notary Public in and for the State of Texas
My Commission Expires March 26, 1984

My Commission expires:

____

THE STATE OF NEW YORK

ss.

COUNTY OF NEW YORK

On this 11th day of January, 1983, before me personally came Horace C. Bailey, Joseph C. Broadus and F. Arnold Daum, to me known to be the persons described in and who executed the foregoing instrument and acknowledged that they executed the same.

Katherine H W Swift

Notary Public, in and for
New York County, New York

My Commission expires:

KATHERINE H. W. SWIFT
Notary Public, State of New York
No. 31-[illegible]
Qualified in New York County
Commission Expires March 30, 1984

EXHIBIT A

AMENDMENTS TO TEL OFFSHORE TRUST TRUST AGREEMENT

1.10 "Interest Bearing Account" shall mean either an account payable on demand without penalty or a certificate of deposit which matures prior to the Distribution Date immediately following the purchase of the certificate of deposit and which will be held until maturity. Such accounts or certificates of deposit shall bear interest at a rate which shall be the interest rate which the Bank or its successor pays in the normal court of business on amounts placed with it, taking into account the amounts involved, the period held and other relevant factors.

6.09 Interest on Cash on Hand. Cash being held by the Trustees as a reserve for liabilities or for distribution shall, to the extent not prohibited by Section 11 of the Texas Trust Act, be placed in an Interest Bearing Account of the Bank or any successor bank serving as Corporate Trustee. Any amount which may not by law be so placed shall be placed in an Interest Bearing Account of a bank which is not an affiliate of the Trustees.

EXHIBIT II

TEL OFFSHORE TRUST

CORPORATE TRUSTEE'S COMPENSATION

1. Administrative: For all administrative services, preparation of quarterly and annual statements with attention to tax and legal matters, $7,500 annually plus an hourly charge at the Trustee's standard rate for officer time in excess of 150 hours annually.

2. Transfer Agency:

   (a) $4.50 annually per account for maintaining computer records of each Certificate Holder, name and address of record, tax ID number, outstanding Unit balances, alternative payee, various coded fields of pertinent information; for processing change of address and/or social security number; posting each Certificate cancelled or issued; issuance of 8,000 Certificates; processing request and documentation required for replacement of lost or destroyed Certificates; for placing and/or removing stop transfer orders; registering Certificates; disbursing cash distributions; preparing and mailing required IRS forms; mailing of proxies and other related material; tabulation of proxies; and printing of Certificate Holder list.

   (b) For Certificates issued, registered and posted in excess of 8,000 annually, $1.00 for each Certificate.

   (c) The transfer agency fees stated above will be subject to an escalator based upon the general rise in prices in the economy. The index used will be the Producers Price Index as published by the Department of Labor, Bureau of Labor Statistics. All transfer agency fees will be adjusted annually by the percentage rise in this index on a December-to-December basis beginning December 31, 1983.

   (d) In addition to the fees quoted, a charge will be made for all out-of-pocket expenses, such as postage, envelopes, insurance, long distance telephone calls, overtime necessitated by rush orders, checks, binders and similar items.

3. Termination: A fee will be charged upon termination of the Trust Commensurate with the amount of work and responsibility involved which shall not exceed 10% of the value of the assets distributed provided that termination is accomplished under Section 9.01(a). Under any other method of termination, fees will be charged on an hourly basis only.

8798A

EXHIBIT E

REPORTER'S RECORD
VOLUME 2 OF 3 VOLUMES
TRIAL COURT CAUSE NO. C-1-PB-14-001245

IN RE:	*	IN THE PROBATE COURT
	*	
	*	NO. 1 OF
	*	
TEL OFFSHORE TRUST	*	TRAVIS COUNTY, TEXAS

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ATTORNEY AD LITEM'S MOTION TO COMPEL UNREDACTED ATTORNEY'S FEES STATEMENTS AND ADDITIONAL INFORMATION ABOUT MATERIALS WITHHELD AS PRIVILEGED, ATTORNEY AD LITEM'S MOTION TO REALIGN THE PARTIES OR ALTERNATIVELY SET ORDER OF PROCEEDINGS AT TRIAL, ATTORNEY AD LITEM'S AMENDED SEPTEMBER 2016 FEE APPLICATION, MOTION TO SUBSTITUTE COUNSEL & INDIVIDUAL TRUSTEES' SPECIAL EXCEPTIONS AND PLEA TO THE JURISDICTION TO THE SECOND AMENDED COUNTERCLAIM

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On the 3rd day of October, 2016, the following Attorney Ad Litem's Motion to Compel Unredacted Attorney's Fees Statements and Additional Information about Materials Withheld as Privileged, Attorney Ad Litem's Motion to Realign the Parties or Alternatively Set Order of Proceedings at Trial, Attorney Ad Litem's Amended September 2016 Fee Application, Motion to Substitute Counsel & Individual Trustees' Special Exceptions and Plea to the Jurisdiction to Second Amended Counterclaim came on to be heard outside the presence of a jury, in the above-entitled and numbered cause before the Honorable Guy Herman, Judge Presiding, held in Austin, Travis County, Texas.

Proceedings reported by Computerized Stenotype Machine; Reporter's Record produced by Computer-Assisted Transcription.

MELISSA VOIGT
Official Court Reporter
C.S.R. Certification No. 4886
Probate Court No. 1, Travis County
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Austin, Texas 78701
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VOLUME 2

ATTORNEY AD LITEM'S MOTION TO COMPEL UNREDACTED ATTORNEY'S FEES STATEMENTS AND ADDITIONAL INFORMATION ABOUT MATERIALS WITHHELD AS PRIVILEGED, ATTORNEY AD LITEM'S MOTION TO REALIGN THE PARTIES OR ALTERNATIVELY SET ORDER OF PROCEEDINGS AT TRIAL, ATTORNEY AD LITEM'S AMENDED SEPTEMBER 2016 FEE APPLICATION, MOTION TO SUBSTITUTE COUNSEL & INDIVIDUAL TRUSTEES' SPECIAL EXCEPTIONS AND PLEA TO THE JURISDICTION TO THE SECOND AMENDED COUNTERCLAIM

October 3, 2016

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P R O C E E D I N G S

October 3, 2016

THE COURT: I will call Cause No. C-1-PB-14-001245 in the matter of the TEL Offshore Trust. We have a number of things to be heard today. I'm just going to read them out and then you all can tell me which order you want to go.

We have an ad litem's motion to compel un-redacted attorneys fees statements and additional information about materials withheld as privileged, we have a trustee's joint response to that. We have the attorney ad litem's motion to realign the parties or in alternative set orders for proceedings of trial. We have a fee application by the attorney ad litem. We have a motion for substitution of counsel for the Bank of New York Mellon Trust Company, N.A. as the corporate trustee. We have individual trustee special exceptions, a plea to the jurisdiction. And we have an objection to the attorneys fees of the ad litem and then we have the individual trustees' joinder and the corporate trustees' objections to those fees.

Anything else that you all are aware of that I'm missing?

MR. HAYNES: Well, the corporate trustee also has special exceptions too that mirror those of the individual trustees.

this trust operates because there are people who bought in and sold and so forth and that -- that the -- that the money that's recovered has to be divided on some other formula then that's fine. It's -- it's irrelevant to what's happening right now. What's happening right now is he's appointed me to represent the interests of these 2,700 beneficiaries and I'm pursuing claims that will inure to their benefit and to the benefit of whatever group of beneficiaries the Court determines are entitled to recover.

Q. Do you know who those people are, the 2,700?

A. No.

Q. Have you gotten their consent to go ask to be paid out of these -- out of these funds in real time, not at the end of the case but in real time as the case goes on?

A. No.

Q. Do you know if they all agree to it?

A. I -- represented by the Court and my basis of compensation is what's in the Trust Code. The Trust Code says I'm entitled to compensation, it doesn't say I have to get the permission of everybody I represent to be compensated.

Q. It doesn't say you get compensated as the case goes on in real time, it could be at the end of the case, right?

A. No, it says I'm entitled to compensation in an amount set by the Court in the manner prescribed in

Section 114.064 of the Trust Code.

Q. Right. Which means it has to be just and equitable?

A. Yes.

Q. And it would be taxed as costs?

A. Yes.

Q. But it doesn't say that you have to get paid in real time, does it?

A. No.

Q. That's up to the Court?

A. That's up to the Court.

Q. That's why we're having this hearing?

A. I don't know why we're -- I mean, we're having this hearing because I'm asking the Court to approve my fees and order that they be paid from the segregated fund.

Q. Now, just one other thing and then I'll move to a different sort of topic. But just again, getting back to the difference between an individual claim, which as you can see I think I'm saying you have to prove individually each of these peoples' claims. It's different than a derivative action. You can't just sort of -- all right. One thing you mentioned on your direct examination was that on -- Mr. Bitting I think asked you if these claims weren't barred by limitations on their face and you said the discovery rule would apply, right?

A. I think the discovery rule applies.

Q. Actually you haven't pled the discovery rule, have you?
A. I haven't needed to plead the discovery rule, that's a response to an affirmative defense that you may raise.
Q. We pled limitations?
A. Well, I haven't had a chance to respond to your -- to your answer which was filed maybe a week ago.
Q. You filed your third amended and second amended counterclaim after our answer, right?
A. Yes.
Q. So you did have a chance to respond and you didn't plead -- didn't plead the discovery rule, right?
A. Not yet.
Q. Now, under the discovery rule how long does the tolling last?
A. The discovery rule is based on being able to bring a claim for breach of fiduciary duty or fraud within four years of the time that the -- the person bringing the claim knew or should have known through the exercise of reasonable discretion of the claim.
Q. Right. And that's an individual inquiry into each person as to when they knew or should have known of their claim, right?
A. It's an inquiry into the knowledge of the -- of

the plaintiff. In this case the beneficiaries.

A. Depends on what you're going to ask me I guess.
Q. Let me ask you the question and you tell me if you need something. Would you agree that by the -- your investigation revealed by the end of 2009 at the latest if Chevron opted not to re-develop Eugene Island 339, that it was obvious that the royalty properties were in dire straits and could not provide distributions to the beneficiaries for the foreseeable future if ever? Do you agree with that?
A. I believe I can prove that.
Q. And do you agree that indeed the trustees repeatedly said so in their SEC filings?
A. Yes.
Q. Okay. And then -- go to another thing on that. Do you agree that the trustees' SEC filings going back to the 2008 Form 10K told a grim tale?
A. A grim tale about the prospects for future payments, yes.
Q. Yeah. And the future distributions by the trust are expected to be severely negatively impacted and there may not be sufficient proceeds from the royalty properties to make one or more future distributions?
A. I believe that's true.
Q. And by the way, any -- any unit holder receiving that can sell their units if they want to, right?
A. I'm not sure what you mean. I mean, if they

received my counterclaim -- I guess they can sell the units for any reason that they want.

Q. Could have sold it in 2008 when they did the SEC filing?

A. They could have sold it at any time as far as I -- I don't know much about the securities laws but I think that's right.

THE STATE OF TEXAS)
COUNTY OF TRAVIS)

I, MELISSA VOIGT, Official Court Reporter in and for the Probate Court No. 1 of Travis County, State of Texas, do hereby certify that the above and foregoing contains a true and correct transcription of all portions of evidence and other proceedings requested in writing by counsel for the parties to be included in this volume of the Reporter's Record, in the above-styled and numbered cause, all of which occurred in open court or in chambers and were reported by me.

I further certify that this Reporter's Record of the proceedings truly and correctly reflects the exhibits, if any, offered by the respective parties.

I further certify that the total cost for the preparation of this Reporter's Record is $__________________ and was paid by ________________________.

WITNESS MY OFFICIAL HAND this the __________ day of _____________, 2016.

____
MELISSA VOIGT, CSR #4886
Official Court Reporter
Probate Court No. 1
Travis County, Texas
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Austin, Texas 78701
(512) 854-9258
C.S.R. Certification No. 4886
Expires: 12/16

EXHIBIT F

NO. 16-0994

IN THE SUPREME COURT OF TEXAS

IN RE TRUSTEES OF THE TEL OFFSHORE TRUST

RESPONSE TO PETITION FOR WRIT OF MANDAMUS

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ATTORNEYS FOR REAL PARTY IN INTEREST
GLENN M. KARISCH, AD LITEM

ORAL ARGUMENT CONDITIONALLY REQUESTED

- An "interested person" may sue a trustee to determine the liability of the trustee. TEX. TRUST CODE §§115.001 and 115.011(a).

- As beneficiaries of the Trust, each of the AAL Parties is an "interested person." TEX. TRUST CODE §111.004(7).

- The Court may appoint an attorney ad litem to represent any interest that the Court considers necessary. TEX. TRUST CODE §115.014(b).

- As a fiduciary for the AAL Parties, Ad Litem is an "interested person" who may sue Trustees to hold them liable. TEX. TRUST CODE §111.004(7) and (10)(J).

The AAL Parties are persons interested in the Trust who by statute are permitted to sue to hold Trustees liable for their breaches of fiduciary duty. Tex. Trust Code §§111.004(7), 115.001 and 115.011(a). As the fiduciary representing the AAL Parties, Ad Litem is entitled (and, indeed, required) to bring these claims on their behalf. Tex. Trust Code §§111.004(10)(J), 115.014(b); *see also Cahill v. Lyda*, 826 S.W.2d 932, 933 (Tex. 1992) (appointment under Rule 244 requires attorney ad litem to "exhaust all remedies available to his client").

Ad Litem sues on behalf of the AAL Parties he represents. He does not assert claims on behalf of a class of non-parties. A class action is used to represent persons who have not been joined as parties. *See* Tex. R. Civ. P. 42(a). No class is needed here because the AAL Parties are before the court, something Trustee took great pains to accomplish.

Trustee notes that Trust Code § 111.004(7) recognizes that whether someone is an interested person "must be determined according to the particular purposes of

EXHIBIT G

NO. C-1-PB-14-001245

In Re:	**§**	**In the Probate Court No. 1**
	§	
	§	**of**
	§	
TEL Offshore Trust	**§**	**Travis County, Texas**

ATTORNEY AD LITEM'S RESPONSES TO
THE CORPORATE TRUSTEE'S FIRST SET OF INTERROGATORIES

To: The Bank of New York Mellon Trust Company, N.A., by and through its attorneys of record, Craig A. Haynes, Thompson & Knight LLP, One Arts Plaza, 1722 Routh Street, Suite 1500, Dallas, Texas 75201.

Pursuant to Texas Rule of Civil Procedure 197, Glenn M. Karisch, as Attorney Ad Litem for the Unit Holders of TEL Offshore Trust who were served by publication and did not answer or appear ("Ad Litem"), serves these responses to The Corporate Trustee's First Set of Interrogatories as follows:

Objections to Definitions and Instructions

Ad Litem objects to the Corporate Trustee's purported service on each unit holder of the TEL Offshore Trust who was served by publication and did not answer or appear in this proceeding ("AAL Parties") by and through their attorney ad litem to the extent the Corporate Trustee purports to require individual answers from each of the over 2,700 AAL Parties Ad Litem represents. Such an attempt is overly broad and unduly burdensome. Ad Litem will respond to the discovery with the information in his possession.

Ad Litem objects to the general instruction that "if the answer to interrogatory is not within the personal knowledge of the person answering, include within such answer the name and address of each person to whom the information is a matter of personal knowledge or from whom the information was obtained" as overly broad and unduly burdensome, irrelevant and not reasonably calculated to lead to the discovery of admissible evidence and as is causing the interrogatories to exceed the number of interrogatories allowed by the Discovery Control Plan.

Ad Litem objects to the general instruction to specify the reasons that a complete answer cannot be given and state whatever information, knowledge or belief is available concerning the unanswered portion. This instruction is overly broad, unduly burdensome, not reasonably calculated to lead to the discovery of admissible evidence and irrelevant. Further, it causes the number of interrogatories to exceed the numbers allowed by the Discovery Control Plan.

Ad Litem objects to the instruction concerning privilege claims to the extent it exceeds and conflicts with the requirements for handling privileged information under Tex. R. Civ. P. 193.3. Ad Litem will comply with Rule 193.3.

Ad Litem objects to the inclusion of electronically stored information ("ESI") in the definition of "Document" to the extent that ESI is not obtainable without undue burden or expense.

Ad Litem objects to the definition of "Petition" because the Ad Litem's original petition has been superseded by amendment. Ad Litem will treat the term "Petition" as referring to his live pleading at the time of these answers.

Ad Litem objects to the definition of "You" or "Your" as meaning the "unit holders of the TEL Offshore Trust who were served by publication and did not answer or appear in this proceeding, and their representatives" as overly broad, unduly burdensome, irrelevant and not reasonably calculated to lead to the discovery of admissible evidence.

Ad Litem will respond to this discovery based on the information in his possession but objects to any requirement for him to obtain information from over-2,700 AAL Parties.

INTERROGATORIES

INTERROGATORY NO. 1: Please provide Your name and address if You are a Unit Holder client of the Attorney Ad Litem in this proceeding.

RESPONSE:

Ad Litem incorporates his objections to instructions and definitions, including his objections to the defined terms used in this interrogatory. Ad Litem objects that this request calls for information that is, or should be, in the possession of the Trustees. Ad Litem objects to any requirement that he provide to the Trustees information he received from the Trustees.

Subject to objections, Ad Litem does not have any responsive information other than any information he may have received from the Trustees. Ad Litem's name and address is Glenn M. Karisch, The Karisch Law Firm, PLLC, 301 Congress Avenue, Suite 1910, Austin, Texas 78701.

INTERROGATORY NO. 2: For each Unit Holder client identified in response to interrogatory no. 1, please state when the Unit Holder first bought units in the Trust and when the Unit Holder sold all his, her, or its units in the Trust.

RESPONSE:

Ad Litem incorporates his objections to instructions and definitions, including his objections to the defined terms used in this interrogatory. Ad Litem objects that this request calls for information that is, or should be, in the possession of the Trustees. Ad Litem objects to any requirement that he provide to the Trustees information he received from the Trustees. Ad Litem further objects that the Corporate Trustee has refused to provide the information sought in this interrogatory in response to Ad Litem's discovery requests and any effort to force Ad Litem to provide information that should be in the Trustees' possession but which they have failed to provide is overly broad, unduly burdensome and harassing, irrelevant and not reasonably calculated to lead to the discovery of admissible evidence.

Subject to objections, Ad Litem does not have any responsive information other than any information he may have received from the Trustees.

INTERROGATORY NO. 3: For each Unit Holder client identified in response to Interrogatory No. 1, please state when the Unit Holder's spouse first bought units in the Trust and when the Unit Holder's spouse sold all of his or her units in the Trust.

RESPONSE:

Ad Litem incorporates his objections to instructions and definitions, including his objections to the defined terms used in this interrogatory. Ad Litem objects that this request calls for information that is, or should be, in the possession of the Trustees. Ad Litem objects to any requirement that he provide to the Trustees information he received from the Trustees. Ad Litem further objects that the Corporate Trustee has refused to provide the information sought in this interrogatory in response to Ad Litem's discovery requests and any effort to force Ad Litem to provide information that should be in the Trustees possession but which they have failed to provide is overly broad, unduly burdensome and harassing, irrelevant and not reasonably calculated to lead to the discovery of admissible evidence.

Subject to objections, Ad Litem does not have any responsive information other than any information he may have received from the Trustees.

INTERROGATORY NO. 4: If You are claiming a fiduciary relationship outside the period in which You owned units in the Trust, list for each such person Your name and the time period in which such a fiduciary relationship existed, the nature of the fiduciary relationship, and why You claim it existed.

RESPONSE:

Ad Litem incorporates his objections to instructions and definitions, including his objections to the defined terms used in this interrogatory. Ad Litem objects to the extent this interrogatory would require him to marshal his evidence on this issue.

Subject to objections, Ad Litem contends that the Trustees owed fiduciary duties to each of the AAL Parties—and for that matter, all unit holders—throughout the periods in which those unit holders owned units. Ad Litem does not understand what Corporate Trustee means by the "nature of the fiduciary relationship." The relationship arose from an express Texas trust and was governed by the terms of that trust and Texas common and statutory law on fiduciary duties and relationships.

Discovery has not been completed, and Ad Litem reserves the right to supplement or amend this response as the case progresses and new facts come to light.

INTERROGATORY NO. 5: Please identify (a) each damage You claim to the AAL Parties (as used in the Petition) and to the Trust estate; (b) the amount of each damage; and (c) the basis for each such damage sought by You in this proceeding.

RESPONSE:

Ad Litem incorporates his objections to instructions and definitions, including his objections to the defined terms used in this interrogatory. Ad Litem objects to the extent this interrogatory would require him to marshal his evidence on this issue.

Subject to objections, at this time Ad Litem seeks to recover two categories of actual damages. In the first category are the damages resulting from the Trustees' failure to take appropriate action in response to the devastation wrought by Hurricane Ike. These damages are the amounts that the Trustees could have realized from a sale of the net profits interest had they timely pursued such a sale. Based on the Corporate Trustee's own admission, the Trustees were aware of the dire situation by the end of 2009. Thus, they should have pursued a sale in the first quarter of 2010. Had they done so, they could have realized around $22.3 million for the benefit of the trust estate and all the beneficiaries. The basis for this calculation is as follows.

For most of the times covered by this request, units of the Trust were publicly traded on NASDAQ. Using historical sales volumes and closing price data from NASDAQ, one can determine a volume weighted average closing price ("VWAP") for any particular time. For the first quarter of 2010 the VWAP was $4.8121 per unit. Multiplying that price by the number of outstanding units yields the total value of the trust estate, as determined by the open market. That value was approximately $22.9 million. Assuming a 4% sales commission, the trust portion of that value that could have been realized had the Trustees sold the Net Profits Interest in the first quarter of 2010 was approximately $22 million. In addition, at the end of 2010 the Trust had cash reserve of $352,017. That reserve could have been returned to the Beneficiaries had the net profits interest been sold and the Trust terminated. Thus, the damages to the Trust estate from the Trustees' decision not to sell the net profits interest in the first quarter of 2010 is approximately $22.3 million. Ad Litem has not done those calculations for other times.

The Trust expenses for each year are shown in Ad Litem's First Amended Petition as Realigned Plaintiff. They are also shown in the Trustees' SEC filings. Ad Litem reserves the right to modify or supplement this answer as additional discovery and information becomes available.

The failure to pursue such a sale was a continuing breach of fiduciary duty. One can calculate damage amount for sales at other points in time, using the same methodology as discussed above. For any particular quarter one can determine the VWAP, multiply it by the outstanding units and subtract a 4% sales commission to determine the proceeds that could have been received from the sale of the net profits interest. To those proceeds one would add the amount of the trust cash reserve at that time to determine the total damages to the Trust estate due to the Trustees' failure to sell the net profits interest at that particular time.

The second category of damages is the compensation that the Corporate Trustee paid to itself contrary to the compensation formula in the trust agreement. *See* Ad Litem's motion for summary judgment and response to the Corporate Trustee's motion for summary judgment on this issue for further explanation.

Finally, although it does not fall in the category of actual damages, Ad Litem will ask the Court to order that the Trustees forfeit some or all of the compensation they received as a result of their clear and serious breaches of fiduciary duty. And the Ad Litem seeks recovery of his costs and expenses, including expert expenses and attorneys' fees to outside counsel.

Discovery has not been completed, and Ad Litem reserves the right to supplement or amend this response as the case progresses and new facts come to light.

INTERROGATORY NO. 6: Please state what "appropriate action" within what "reasonable time" the Trustees should have taken after the September 2008 Hurricane Ike, as alleged in paragraph 11 of the Petition.

RESPONSE:

Ad Litem incorporates his objections to instructions and definitions, including his objections to the defined terms used in this interrogatory. Ad Litem objects to the extent this interrogatory would require him to marshal his evidence on this issue.

Subject to objections, Ad Litem contends that even before Hurricane Ike, the Trustees should have known that due to the nature of these aging properties, their economic lifespan was limited and the Trustees should have been considering what steps to take to maximize the value from these depleting properties for the benefit of all unit holders. Hurricane Ike should have greatly accelerated this process. The Trustees should have evaluated the destruction caused by Hurricane Ike, its effect on the revenue-generating potential of the Net Profits Interest, the likelihood that pre-Ike revenue levels could be obtained and the option for selling the Net Profits Interest while it still had value. In fact, the Corporate Trustee admitted to considering selling the Net Profits Interest as one of the options it considered by the end of 2009. Certainly by the end of 2009, the dire situation was obvious and the Trustees should have taken steps to sell the Net Profits Interest while it still had value, by calling for a vote of all the unit holders, seeking court approval or selling the Net Profits Interest without a vote or court approval.

Discovery has not been completed, and Ad Litem reserves the right to supplement or amend this response as the case progresses and new facts come to light.

INTERROGATORY NO. 7: Please state the actions You contend in the Petition amount to "gross negligence" and the factual basis for contending each such action is gross negligence.

RESPONSE:

Ad Litem incorporates his objections to instructions and definitions, including his objections to the defined terms used in this interrogatory. Ad Litem objects to the extent this interrogatory would require him to marshal his evidence on this issue.

Subject to objections, Ad Litem contends that even before Hurricane Ike, the Trustees should have known that due to the nature of these aging properties, their economic lifespan was limited and the Trustees should have been considering what steps to take to maximize the value from these depleting properties for the benefit of all unit holders. Hurricane Ike should have greatly accelerated this process. The Trustees should have evaluated the destruction caused by Hurricane Ike, its effect on the revenue generating potential of the Net Profits Interest, the likelihood that pre-Ike revenue levels could be obtained and the option for selling the Net Profits Interest while it still had value. In fact, the Corporate Trustee admitted to considering selling the Net Profits Interest as one of the options it considered. Certainly by the end of 2009, the dire situation was obvious and the Trustees should have taken steps to sell the Net Profits Interest while it still had value, by calling for a vote of all the unitholders, seeking court approval or selling the Net Profits Interest without a vote or court approval.

Rather than taking action to preserve value for the beneficiaries, the Trustees took actions designed solely to benefit themselves at the expense of the beneficiaries. They did not call a vote to give the beneficiaries the right to decide how they wanted to proceed in light of Hurricane Ike's devastation. They did not pursue a sale of all the Net Profits Interest when such a sale could have generated millions of dollars in value. Instead, they continued on with the trust, incurring administrative fees, including substantial Trustee compensation, of close to a million dollars a year. When the reserve for trust expenses was depleted to the point that the Trustees could not pay themselves, they sold off a portion of the Net Profits Interest. While this generated money to pay the Trustees and their outside accountants, engineers and other vendors, it simply made the financial situation worse. Now there was even less revenue with which to pay the substantial administrative expenses. Though the revenue decreased; those expenses did not decrease. The Trustee pursued such sales twice. The Corporate Trustee also borrowed money from its affiliated bank to ensure that the Trustees and their accountants, lawyers and engineers got paid. This action too made the situation worse, as now the Trust had additional debt that would have to be paid before any possibility of a distribution to the beneficiaries.

Further, from 2009 if not earlier, to the present, the Corporate Trustee did not follow the compensation formula in the Trust Agreement. *See* Answer to Interrogatory No 14.

For further explanation of the facts see the Ad Litem's live petition as realigned plaintiff in this case. Ad Litem contends that these acts constitute gross negligence and that this gross negligence was continuing from at the latest, late 2009 until the Trustees finally effected a sale of the Net Profits Interest in 2016.

Discovery has not been completed, and Ad Litem reserves the right to supplement or amend this response as the case progresses and new facts come to light.

INTERROGATORY NO. 8: Please state the actions You contend in the Petition amount to "bad faith" and the factual basis for contending each such action is bad faith.

RESPONSE:

Ad Litem incorporates his objections to instructions and definitions, including his objections to the defined terms used in this interrogatory. Ad Litem objects to the extent this interrogatory would require him to marshal his evidence on this issue.

Subject to objections, *see* Answer to Interrogatory No. 7. Ad Litem contends that facts set forth in that answer constitute bad faith and that this bad faith was from continued, from late 2009 at the latest until the Trustees finally effected a sale of the Net Profits Interest in 2016.

Discovery has not been completed, and Ad Litem reserves the right to supplement or amend this response as the case progresses and new facts come to light.

INTERROGATORY NO. 9: Please state the factual basis for Your contention that the Trustees have breached their fiduciary duties, as alleged in paragraphs 11 and 61-74 of the Petition, listing every alleged act that You contend breached a fiduciary duty and when it occurred.

RESPONSE:

Ad Litem incorporates his objections to instructions and definitions, including his objections to the defined terms used in this interrogatory. Ad Litem objects to the extent this interrogatory would require him to marshal his evidence on this issue.

Subject to objections, *see* Answer to Interrogatory No. 7. Ad Litem contends that facts set forth in that answer constitute breaches of fiduciary duty and that these breaches of fiduciary duty continued from at the latest, late 2009 until the Trustees finally effected a sale of the Net Profits Interest in 2016.

Discovery has not been completed, and Ad Litem reserves the right to supplement or amend this response as the case progresses and new facts come to light.

INTERROGATORY NO. 10: With respect to each act You contend breached a fiduciary duty in response to Interrogatory No. 9, please say what action should have been done instead or differently.

RESPONSE:

Ad Litem incorporates his objections to instructions and definitions, including his objections to the defined terms used in this interrogatory. Ad Litem objects to the extent this interrogatory would require him to marshal his evidence on this issue.

Subject to objections, *see* Answer to Interrogatory No. 7. Rather than pursuing the course of action described in that answer, the Trustees should have taken steps to sell the Net Profits interest in the first quarter of 2010 if not earlier. And they had a continuing obligation to pursue such a sale up until they finally sold the remaining proportion of the interest in 2016. Finally the Corporate Trustee should have complied with the Trust Agreement in calculating its compensation.

Discovery has not been completed, and Ad Litem reserves the right to supplement or amend this response as the case progresses and new facts come to light

INTERROGATORY NO. 11: Identify each action by the Trustees that You contend constituted self-dealing and the factual basis for Your contention as to each such action.

RESPONSE:

Ad Litem incorporates his objections to instructions and definitions, including his objections to the defined terms used in this interrogatory. Ad Litem objects to the extent this interrogatory would require him to marshal his evidence on this issue.

Subject to objections, the self-dealing transactions by the Trustees of which Ad Litem is aware include the Corporate Trustee's borrowing money from its affiliated bank to pay its compensation and the Corporate Trustee's calculating its compensation and paying itself in violation of the formula set forth in the Trust Agreement. The Individual Trustees were aware of these actions but took no steps to prevent them or to remedy them once they occurred.

Discovery has not been completed, and Ad Litem reserves the right to supplement or amend this response as the case progresses and new facts come to light.

INTERROGATORY NO. 12: Identify each action by the Trustees that You contend breached a duty to administer the Trust in good faith and the factual basis for Your contention as to each such action.

RESPONSE:

Ad Litem incorporates his objections to instructions and definitions, including his objections to the defined terms used in this interrogatory. Ad Litem objects to the extent this interrogatory would require him to marshal his evidence on this issue.

Subject to objections, *see* Answer to Interrogatory No. 7. Ad Litem contends that facts set forth in that answer constitute breaches of the duty to administer the Trust in good faith and that such breaches continued from at the latest, late 2009 until the Trustees finally effected a sale of the Net Profits Interest in 2016.

Discovery has not been completed, and Ad Litem reserves the right to supplement or amend this response as the case progresses and new facts come to light.

INTERROGATORY NO. 13: Please provide the name and address of just those Unit Holders of the Trust who the Attorney Ad Litem represents who were served by publication and did not answer or appear in this Suit.

RESPONSE:

Ad Litem incorporates his objections to instructions and definitions, including his objections to the defined terms used in this interrogatory. Ad Litem objects that this request calls for information that is, or should be, in the possession of the Trustees. Ad Litem objects to any requirement that he provide to the Trustees information he received from the Trustees.

Subject to objections, Ad Litem does not have any responsive information other than any information he may have received from the Trustees.

INTERROGATORY NO. 14: State the factual basis for Your contention in Your Petition that the Corporate Trustee paid itself compensation contrary to the terms of the Trust Agreement and identify what language of the Trust Agreement You contend was not followed.

RESPONSE:

Ad Litem incorporates his objections to instructions and definitions, including his objections to the defined terms used in this interrogatory. Ad Litem objects to the extent this interrogatory would require him to marshal his evidence on this issue.

Subject to objections, the Trust Agreement provides that the Corporate Trustee should be compensated at $7,500 a year and then at its "standard rate for officer time" for all hours above 150 hours. The $7,500 for the first 150 hours reflects an hourly rate of $50. Rather than follow this formula, the Corporate Trustee arbitrarily determined that it worked an additional 500 hours over the 150 hours and paid itself $400 an hour for those hours. It did not keep records to show exactly how much work it actually did. And it is not reasonable to think that anywhere close to a total of 650 hours were needed to administer this Trust, which was a passive-income receiving trust with only one asset that it did not operate. For further explanation of the Ad Litem's position on this issue, see the Ad Litem's motion for summary judgment and response to the Corporate Trustee's motion for summary judgment on this issue.

Discovery has not been completed, and Ad Litem reserves the right to supplement or amend this response as the case progresses and new facts come to light.

Respectfully submitted,

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Attorney Ad Litem

CERTIFICATE OF SERVICE

I hereby certify that a true and correct copy of the foregoing has been served to counsel of record on December 7, 2016 and will be served in accordance with the Court's orders regarding service dated September 28, 2015 and January 21, 2016.

<u>/s/ Daniel C. Bitting</u>
Daniel C. Bitting

VERIFICATION

STATE OF TEXAS §
§
COUNTY OF TRAVIS §

BEFORE ME, the undersigned Notary Public, on this day personally appeared GLENN M. KARISCH, as Attorney Ad Litem for the beneficiaries of TEL Offshore Trust who were served by publication and did not answer or appear, who, having been by me duly sworn, on his oath deposed and said that he is duly qualified and authorized in all respects to make this verification; that he has read the above Attorney Ad Litem's Responses to the Corporate Trustee's First Set of Interrogatories; and the factual statements, either based on his personal knowledge or based upon information obtained from other persons, are true and correct.

By:__________________________
GLENN M. KARISCH,
ATTORNEY AD LITEM

SUBSCRIBED AND SWORN TO before me on this the 7th day of December, 2016, to certify which witness my hand and official seal.

LINDA SHERIDAN
Notary Public, State of Texas
Comm. Expires 01-27-2019
Notary ID 128503555

Linda Sheridan
Notary Public in and for the State of Texas

Linda Sheridan
Printed or typed name

My Commission Expires: 01/27/2019

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