EXHIBIT 2

Summary of 191 Account Audit Procedures and Results for CY 2010

1 SCOPE

The Division conducted an audit of Questar Gas' 191 account for calendar year 2010. The majority of the Division's work focused on the net costs (costs offset by miscellaneous revenues) included in the 191 account although limited testing was performed on the reported revenues. The purpose of this audit was to determine if the costs and revenues presented in the 191 account are fairly presented and free of material misstatement.

2 DEFINITIONS

Various terms or abbreviations are used in the following sections. Those terms or abbreviations are described below.

1) QGC: Questar Gas Company
2) QPC: Questar Pipeline Company
3) QGM: Questar Gas Management
4) QEP: Questar Exploration and Production Resources
5) ABS: Account Balance Summary. A spreadsheet consisting of individual accounting entries to the various accounts in the 191 account.
6) GL: General Ledger or "Accounting Works". A QGC spreadsheet report produced monthly that originates from the Company's general ledger.
7) GB: Gray Back. The monthly gray back financial reports.
8) 191 SUM: 191 Summary. The monthly 191 summary sheet produced by QGC. This sheet shows the 191 account calculations including a breakdown by account, interest calculations and adjustments to the 191 account.

3 AUDIT PROCEDURES

The Division's audit procedures of the 191 account for calendar year 2010 consisted of the following procedures:

1) Risk Assessment – This assessment was performed to determine if certain areas of the 191 account were at greater risk of misstatement.

2) High Level Reconciliations
   a) Reconcile the summary vouchers (ABS, GL, GB) for each 191 net gas cost account to the 191 SUM.
   b) Reconcile Questar's 10K report and GB to the 191 SUM.

3) Net Cost Review
   a) Accuracy
      i) Verify that the Commodity percentage was calculated correctly.
      ii) Verify that the Demand percentage was calculated correctly.
      iii) Verify that the Commodity and Demand percentages were appropriately applied to total Company costs and that the result ties to the 191 SUM.
      iv) Recalculate the ending 191 balance and compare to the 191 SUM.
   b) Completeness/Occurrence
      i) Review supporting documentation for Wexpro costs.
      ii) Review supporting documentation for purchased gas costs.
      iii) Review supporting documentation for storage gas costs.
      iv) Review supporting documentation for gathering costs.
      v) Review supporting documentation for transportation costs.
      vi) Review supporting documentation for overriding royalty revenues.
      vii) Review supporting documentation for the 191 account adjustments shown in the 191 SUM.

4) Revenue Review
   a) Occurrence/Completeness
      i) Trace the billed amounts for two industrial customers to the 191 SUM.
      ii) Reconcile the GB decatherms with the decatherms reported in the 191 SUM.
   b) Accuracy
      i) Recalculate the 191 account revenues (excluding miscellaneous revenues and credits) and tie the result to the 191 SUM.

4 RISK ASSESMENT

A risk assessment was performed to determine if certain areas of the 191 account were at greater risk of misstatement. The Division's consideration of risk during the audit revolved around three main areas. These areas are discussed below.

4.1 RISK - INTERNAL AUDIT REPORTS

In a data request to the Company the Division requested any Questar internal audit reports (operational or financial/internal control) that had been performed on 191 components for CY 2010. The Company provided the internal audit reports and they were reviewed by the Division. The internal audits reviewed did not identify any particular issues or areas of concern. This review indicates lower risk and therefore less testing than would otherwise be required.

4.2 RISK - STORAGE GAS RELATED COSTS

During the audit, it was determined that the greatest likelihood of misstatement was with storage gas costs (withdrawal value/charges, injection value/charges, return on storage gas) This is due to 1) the complexity of the storage inventory calculations and 2) the use of an estimated company owned gas rate for determining storage injection values and therefore also subsequent withdrawal value changes. However, it was determined that the magnitude of a misstatement was likely small. Net storage gas costs constitute only 3.12% of total gas costs. Due to the complexity of the storage gas calculations the Division's 2009 191 audit report stated that future audits may not include a review of every month of storage gas calculations. The Division's audit for 2010 included a review of storage costs for January, February, August, and December 2010.

4.3 RISK - COMPANY ADJUSTMENTS TO THE 191 ACCOUNT

Adjustments to the 191 account were also considered to be of greater risk due to their nature of being outside the normal operating expenses and revenues that are booked to the 191 account. In calendar year 2010 there were approximately $4.4 million in net adjustments to the 191 account. The results of the adjustment review is discussed in section 5.3.7 below.

In addition to the risks considered above, the Division also reviewed trends related to the various components of the 191 account such as Wexpro costs, gathering costs and others. This review showed considerable increases to Wexpro costs and Gathering costs over the past several years. In May 2009, the Division contracted with Williams Consulting Inc. to review the costs in the systems-wide gathering agreement. The final report was received in November 2009, a copy of the report was submitted to the Commission as an attachment to the DPU comments filed in Docket No. 10-057-06. The investigation found the costs charged were following the terms of the contract and no adjustments to the 191 account were recommended.

5 AUDIT PROCEDURES AND RESULTS

In addition to the items identified in the risk assessment, the Division tested many other key areas of the 191 account. The majority of the Division's audit procedures focused on the costs included in the 191 account for calendar year 2010 although limited testing was also performed on the reported revenues. The audit procedures described below as well as the results of those tests are summarized in the sections that follow. The Division notes that the procedures and tests discussed below are summaries of the work performed by the Division. Many of the procedures, particularly with storage gas related costs, required extensive review and calculations. The Division also issued data requests and held meetings with the Company to discuss certain aspects of the 191 account.

5.1 HIGH LEVEL RECONCILIATIONS - COMPLETENESS

5.1.1 SUMMARY VOUCHER RECONCILIATION

The purpose of this procedure was to verify that the summary vouchers (ABS, GL, GB) for gas costs tie to the 191 SUM. The results of this reconciliation are shown below.

Total NET differences for the audit year (total Company).		
GB vs 191 SUM	$	5
ABS vs 191 SUM	$	21,522
GL vs 191 SUM	$	5

The $21,522 difference between the ABS and the 191 SUM is the result the Company creating a new subaccount (492005). Since this new account was not part of the Division's reconciliation workpapers in the past and for the current audit, the ABS total for account 492 was $21,572 lower than what was reported in the 191 SUM. The two entries ($11,084 -Aug, $10,488-Oct) under 492005 are liquid revenue from the ONeal regulating station. Per the Company's tariff, it appears these types of revenues can be included in this account. It therefore appears that the four high level summary vouchers to tie to each other with a few minor immaterial exceptions. Since the amounts are immaterial and the Division has no other process or reconciliation concerns no further action is needed.

5.1.2 RECONCILE 191 ACCOUNT TO 2009 10K AND GRAY BACK FINANCIALS

The purpose of this procedure was to verify that the amounts included in the 191 account tie to the amounts reported in the 2010 10K report and GB reports. If amounts differed, these differences were investigated. The results of this procedure are shown below.

Revenues	**Amount (Millions)**	**Diff with DPU Compiled Revenues (Millions)**
DPU Compiled Revenues*	902.91	-
GB Revenues	902.91	(0.00)
10K Revenues (Rounded)	902.90	(0.01)
DPU Compiled Expenses*	592.24	-
GB Expenses	592.24	0.00
10K Expenses (Rounded)	592.20	(0.04)
*DPU Revenues and Expenses are a compilation of revenues from the 191 account, QGC's Rev Run Report, and revenues and expenses from the the Gray Backs.		

The differences noted above are immaterial and were not investigated further. Based on the Division's review it appears the costs and revenues reported in the 191 account were the same costs and revenues reported in the Company's 10K report.

5.2 NET GAS COST REVIEW – ACCURACY

5.2.1 COMMODITY % RECONCILIATION

The Division verified that the commodity percentages used to allocate costs to Utah were calculated correctly. The DPU calculated percentages shown in the table below were calculated from the decatherms reported in the GB reports. The results of this procedure are shown below.

Commodity % Reconciliation					
Month	QGC Reported Commodity %	DPU Calculated Commodity %	Difference	Total Company Net Commodity Gas Costs*	UT Allocated Dollar
Jan-10	96.609%	96.609%	0.000%	94,672,580	-
Feb-10	96.303%	96.302%	0.001%	75,697,530	757
Mar-10	96.586%	96.585%	0.001%	59,546,202	595
Apr-10	96.107%	96.106%	0.001%	40,738,503	407
May-10	95.876%	95.876%	0.000%	27,811,231	-
Jun-10	95.661%	95.659%	0.002%	16,802,835	336
Jul-10	97.239%	97.238%	0.001%	10,665,983	107
Aug-10	97.118%	97.117%	0.001%	9,883,247	99
Sep-10	96.552%	96.551%	0.001%	17,646,223	176
Oct-10	96.717%	96.716%	0.001%	26,322,720	263
Nov-10	96.023%	96.022%	0.001%	52,047,765	520
Dec-10	96.435%	96.435%	0.000%	75,339,715	-
Total				507,174,533	3,262
* Excludes return on storage gas, capacity release credit, and accounts specific to just Wyoming.					

As can be seen from the table above the DPU recalculated Utah Commodity percentages tied (with some small immaterial exceptions) to the amounts reported by the Company.

5.2.2 DEMAND % RECONCILIATION

The percentages used to allocated demand costs to Utah originate from Questar's pass through filings. The Division found that the demand percentages used for CY 2010 tied back to the percentages shown in the applicable pass through filings (Docket Nos. 09-057-12 and 10-057-09) with only a few insignificant differences. It appears the demand percentages used by Questar for 2010 are appropriate and no further action is needed.

5.2.3 APPLICATION OF COMMODITY AND DEMAND PERCENTAGES

The Division verified that the demand and commodity percentages were appropriately applied to total Company amounts and that the Utah allocated net gas costs were correct. The results of this procedure is shown below.

191 Summary Utah allocated gas costs	$ 578,504,446
DPU Calculated Utah allocated gas costs	$ 578,500,513
Difference	$ 3,933

The Division's recalculated Utah net gas costs tied back to (with some minor immaterial exceptions) the amounts reported in the 191 SUM. From an allocation perspective the Division believes the net gas costs shown in the 191 SUM to be stated correctly. Whether the total Company net gas costs are appropriately supported by invoices and other documentation is discussed later on in Section 5.3.

5.2.4 RECALCULATION OF MONTHLY 191 ACCOUNT BALANCE

In this audit procedure, the Division allocated total Company costs to Utah, added DPU calculated gas revenues, applied the applicable interest costs, bad debt percentages and other QGC 191 Adjustments to arrive at monthly 191 account balances. These amounts were then compared to the amounts reported by Questar in the 191 SUM. The results of this procedure are shown below.

Month	DPU CALCULATED 191 BALANCE	QGC REPORTED 191 BALANCE	Difference
1/31/2010	(14,601,188)	(14,601,171)	(18)
2/28/2010	642,550	643,345	(795)
3/31/2010	2,807,094	2,808,508	(1,414)
4/30/2010	7,839,292	7,840,871	(1,579)
5/31/2010	11,399,133	11,400,999	(1,867)
6/30/2010	21,757,869	21,760,832	(2,964)
7/31/2010	25,560,084	25,563,182	(3,098)
8/31/2010	27,527,675	27,530,989	(3,314)
9/30/2010	35,987,197	35,990,806	(3,610)
10/31/2010	37,650,867	37,654,864	(3,997)
11/30/2010	33,004,199	33,008,838	(4,639)
12/31/2010	10,375,062	10,379,820	(4,758)

As can be seen in the table above, each monthly balance ties closely to the amounts reported by QGC. The differences noted above are primarily the result of slightly different gas costs calculated by the Division when compared to the Company. Based on this recalculation it appears the Company's 191 account balances are stated accurately.

5.3 NET GAS COST REVIEW – COMPLETENESS/OCCURENCE

The Division performed several review procedures to ensure that the total Company expenses and Utah revenues reported in the 191 SUM are in fact supported by invoices, billing statements, checks, inventory calculations and other documentation. The 191 account net gas costs can be broken down into the following components; Wexpro operating costs, purchased gas, storage gas, gathering costs, transportation costs and overriding royalties. The proportion of each component related to the total net gas costs as a whole is shown below.

Total Company Net Gas Cost		
	CY 2010	
Gas Cost	Amount	% of Total
Wexpro Costs	263,720,410	43.94%
Purchased Gas	245,378,406	40.89%
Storage Gas Costs	18,740,965	3.12%
Gathering Costs	23,566,231	3.93%
Transportation Costs	64,108,114	10.68%
Overridding Royalties	(15,342,555)	-2.56%
Gas Managment (WY Only)	53,275	0.01%
Non Core Customer Revenue (WY Only)	(103,383)	-0.02%
Total Net Gas Costs	600,121,463	100.00%

Each of these components, with the exception of the Wyoming accounts, are discussed in the sections that follow.

5.3.1 WEXPRO COSTS

Wexpro related costs constitutes a considerable portion of the net Utah gas costs. These costs, which are spread to approximately 10 different 191 accounts, were tied back to the monthly Wexpro invoices sent to QGC.

The Division reviewed the various Wexpro related 191 accounts and was able to tie the amounts included those accounts back to the Wexpro invoices provided by the Company.

5.3.2 PURCHASED GAS COSTS

Purchased gas constitutes a major portion of the net Utah gas costs. The Division totaled the purchased gas amounts shown on QGC's Purchased Gas Summary (PGS) statement and then tied those amounts to the 191 SUM. The PGS statements include line item detail of the purchases made by the Company. The Division also reviewed and tied supporting documentation (invoices and contracts) to the purchased gas summary statements.

5.3.2.1 PURCHASED GAS SUMMARY (PGS) RECALCULATION AND RECONCILIATION

The Division reconciled the PGS sheets with the 191 SUM. The Division found the reported purchased gas amounts in the 191 SUM to tie to the amounts reported in the PGS sheets.

5.3.2.2 PGS CONTRACT/INVOICE REVIEW

Through the invoices provided by QGC the Division was able to tie the 191 SUM to the QPC invoices for purchased gas costs. The Division reviewed all contracts for purchased gas and found that purchased gas invoices were consistent with contract terms.

Based on the information reviewed by the Division it appears the purchased gas amounts stated in the 191 SUM tie to the supporting documentation provided by the Company.

5.3.3 STORAGE GAS COSTS

Storage related costs consist of injection and withdrawal charges, injection and withdrawal value changes and return on storage gas. The calculation of these costs constitute the most complicated part of the 191 account audit. While the net storage gas costs constitutes only 3.12% of the total Company gas costs, it is important to note that two components of the storage gas costs are the value of gas injected into storage ($73.4 million) and the value of gas withdrawn from storage ($72.7 million). These two components largely offset each other but are significant in and of themselves. In the current audit (CY 2010) the Division recalculated the storage costs for the accounting or “voucher” months of January, February, August and December 2010 based on information from invoices to QGC, QGC provided decatherm injections and withdrawals, and other QGC reports. The results of the Division’s calculations compared to the Company’s reported amounts are shown below.

Storage Gas Item	DPU Calculated Costs Jan,Feb,Aug,Dec	QG Reported Costs Jan, Feb, Aug, Dec	Difference
Inj/WD Charges (Acct 813000/3)	5,402,507	5,402,510	(3)
Injection Value Changes (808200)	(18,037,266)	(18,034,799)	(2,467)
Withdrawal Value Changes (808100)	41,813,141	41,813,322	(181)
Working Gas Charges (808300)	3,706,856	3,707,530	(674)
Total	32,885,238	32,888,563	(3,325)

As shown above, the only differences found between the Company and the Division were immaterial. Based on the Division’s review it appears the storage gas costs were properly calculated and that the pricing assumptions used therein tied back to QPC tariffs, QGC semiannual pass through filings, equity receipt and imbalance statements, and purchased gas statements.

5.3.4 GATHERING COSTS

The gathering costs in the 191 SUM can be traced to accounting estimates in QGC's accounting journals and invoices from third parties. Since QGM/QEP invoices and accounting estimates constitute 96% of the gathering costs, invoices from other third parties such as Williams and Mountain Res were not requested from QGC.

The Division was able to tie the QGM/QEP invoices and accounting estimates to the amounts included in the 191 SUM and as such it appears the gathering costs are properly stated and tie to the supporting documentation.

5.3.5 TRANSPORTATION COSTS

Transportation costs constitute approximately 11% of the net gas costs. Of the 11%, approximately 91% is from QPC charges. The Division attempted to tie the Demand, Commodity and ACA charges from the 191 SUM to the QPC invoices. Almost the entirety of the remaining transportation costs are from Kern River. The Division then tied the Kern River invoices to the amounts included in the 191 SUM.

Through the invoices originally provided by QGC and additional invoices requested in Division data requests, the Division was able to tie the 191 SUM to the QPC invoices for transportation costs. Any differences identified were immaterial. The Division requested Kern River invoices for CY 2010. The Division was able to tie the Kern River invoices to the amounts included in the 191 account.

5.3.6 OVERRIDING ROYALTY

Overriding royalty revenues constitute a small portion of total net gas costs. The Division did however request supporting payment documentation for approximately $11.2 million of the total $15.3 million royalty revenue.

The Division was able to tie the amounts shown in the 191 ABS/191 SUM to the supporting payment documentation, no exceptions were noted.

5.3.7 QGC ADJUSTMENTS TO 191 ACCOUNT

In addition to the net costs and revenues reported in the QGC 191 SUM, Questar made several adjustments to Utah's 191 account balance that had the net impact of reducing the balance by $4.4 million. These adjustments are shown below.

Month	Amount
3/31/2010	(57,590)
4/30/2010	(30,323)
10/31/2010	(66,582)
12/31/2010	(4,230,308)
Various	(3,336)
Total 2010 Adjustments	(4,388,139)

With the exception of the "Various" adjustments totaling only $3,336, the Division requested the Company explain the adjustments shown above. A Summary of the Company's response is shown below.

Month	Amount	Adjustment
3/31/2010	(57,590)	Payments received from Questar
4/30/2010	(30,323)	Pipeline for Interruptible Storage
10/31/2010	(66,582)	Service (ISS)/Cash Out Sharing.
Total	(154,495)	

12/31/2010	46,381	UT and WY Allocation Adjustment
12/31/2010	(4,276,689)	Kern River Refund with Interest
Various	(3,336)	Other Adjustments

Total 2010 Adjustments	(4,388,139)

With regards to the payments received from Questar Pipeline for Interruptible Storage Service, the Company provided copies of the checks received with represent the total Company receipts. When the applicable commodity percentages are applied to the payments the resulting totals match the amounts reported by the Company.

5.4 REVENUE REVIEW – OCCURRENCE/COMPLETENESS

5.4.1 TRACE CUSTOMER BILLS TO 191 SUM

The Division selected two Questar industrial customers for the month of August 2010 and traced the billing amounts from the invoices to various billing reports/reconciliations and the gray back financial statements. The gray backs were reconciled to the 191 SUM as noted in a procedure above.

The Division held a meeting with Company personnel in which the supporting documentation for the two customer billings was provided. The Division has reviewed the supporting documentation and was able to trace the billed amounts to the gray back financials and the 191 SUM.

5.4.2 RECONCILE THE 191 SUM AND GB REPORTED DECATHERMS

The Division verified the decatherm amounts reported in the 191 SUM were the same as the decatherms included in the gray back financial statements. The results of this procedure are shown below.

Reconcile the 191 SUM Decatherms with the GB Decatherms	
GB Decatherms (Commodity)	106,329,886
191 SUM Decatherms (Commodity)	106,329,883
Difference	3
GB Decatherms (SNG)	106,358,679
191 SUM Decatherms (SNG)	106,358,675
Difference	4

As shown above, the Division was able to tie the GB decatherms to the 191 SUM decatherms for each month with very minor exceptions.

5.5 REVENUE REVIEW – ACCURACY

5.5.1 RECALCULATE 191 REVENUES

In past 191 Audits the Division multiplied Commission approved tariff rates by the decatherms shown in the gray back financial statements to arrive at total revenue values for each class. These DPU calculated revenues were then compared to the reported revenues in the 191 SUM. This same task was performed in the 2010 audit but unlike previous audits, differences were found for each month in 2010. These differences were the result of differences between the Commission approved tariff rate and the rate shown on the 191 SUM. The rates shown on the 191 SUM differ from the Commission approved rate because they are a value calculated as:

$$\frac{As\ Billed\ Bililngs + As\ Billed\ Adjustments + Unbilled\ Estimate\ Reversal + Unbilled\ Estimate}{Total\ Decatherms\ for\ the\ Month}$$

The Company's response to DPU FDR 1.12b states:

> The methodology of calculating unbilled revenues changed in January 2010 to a monthly estimate and reversal pattern. Prior to that, it was a rolling balance with a yearly true-up. Because of this, a reconciliation of the rates used in the calculation of unbilled revenue was necessary to show why unbilled wasn't simply volumes times the current rates but rather a blend of as billed, the estimate and the reversal.

An example of the reconciliation referred to in the Company's response is shown below.

January 2010

GS	Dth	SNG Amount	SNG Rate Per Dth	SNG Tariff Rate	Commodity Amount	Commodity Rate Per Dth	Commodity Tariff Rate *
As Billed - Billings	19,461,136	$21,545,744	$1.10712	$1.10696	$76,437,873	$3.92772	$3.92696
As Billed - Adjustments	-	-	-	-	-	-	-
Unbilled Estimate Revers	(10,306,095)	(11,408,435)	1.10696	1.10696	(40,471,624)	3.92696	3.92696
Unbilled Estimate	8,310,726	9,199,642	1.10696	1.10696	32,635,891	3.92696	3.92696
Final Financial Pages	**17,465,767**	**$19,336,951**	**$1.10713**	**$1.10696**	**$68,602,140**	**$3.92781**	**$3.92696**

* I.S. Customers are billed @ two different monthly rates

As can be seen above, the "Rate Per Dths" for "As-Billed Billings" are different than the tariff rates. The Company's response to DPU FDR 1.12a states:

> The rate is calculated by dividing the revenue by the decatherms. There are several reasons the rate may be different from the tariff rate. One reason would be if there was a rate change in the middle of a billing cycle. Some billing adjustments would also cause a different rate. The rates shown are calculated as a check to ensure the revenue collected is close to the tariff rates.

The Division has reviewed and is satisfied with the Company's explanations and revenue reconciliations. The Division found a few material differences between Commission approved rates and the "As Billed-Billings" rates but they all appear to be from rate changes that occurred between months. Thus, some billings were done with the new rates and the others within the same month were done with previous rates. The Company provided revenue reconciliations did show an incorrect decatherm value for the SNG-NGV calculation for June 2010. However, this error was only within the revenue reconciliation and did not flow through to the 191 SUM. Based on the explanations provided from the Company and the reviews performed, it appears the QGC reported revenues are accurately stated.

6 CONCLUSION

As can be seen from the procedure results above, the differences found between Company reports or between Company reports and Division determined amounts were immaterial. No adjustments are proposed for calendar year 2010.