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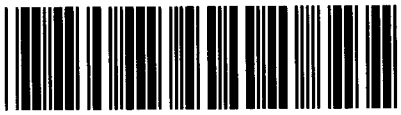

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SOAH DOCKET NO. 473-12-2979
PUC DOCKET NO. 39896

APPLICATION OF ENTERGY	§	
TEXAS, INC. FOR AUTHORITY TO	§	BEFORE THE
CHANGE RATES, RECONCILE	§	STATE OFFICE OF
FUEL COSTS, AND OBTAIN	§	ADMINISTRATIVE HEARINGS
DEFERRED ACCOUNTING	§	
TREATMENT	§	

REBUTTAL TESTIMONY

OF

KAREN D. MCILVOY

ON BEHALF OF

ENTERGY TEXAS, INC.

APRIL 2012

637

ENTERGY TEXAS, INC.
REBUTTAL TESTIMONY OF KAREN D. MCILVOY
DOCKET NO. 39896

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EXHIBITS

I. INTRODUCTION

A. Introduction and Qualifications

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Karen D. McIlvoy. My business address is 10055 Grogan's Mill Road, Parkwood II Building, Suite 300, The Woodlands, Texas 77380.

Q. DID YOU PREVIOUSLY FILE DIRECT TESTIMONY ON BEHALF OF ENTERGY TEXAS, INC. ("ETI" OR "THE COMPANY") IN THIS PROCEEDING?

A. Yes, I did.

Q. DO YOU SPONSOR ANY EXHIBITS OR SCHEDULES TO YOUR TESTIMONY?

A. I sponsor the Exhibits listed in the Table of Contents.

B. Purpose of Rebuttal Testimony

Q. WHAT IS THE PURPOSE OF THIS TESTIMONY?

A. My testimony addresses issues raised by Cities witness Karl Nalepa. Specifically, I address Mr. Nalepa's testimony that the Company's Spindletop gas storage facility is not useful or needed, and that Spindletop should therefore be removed from base rates and that the fuel costs and fuel-related operating costs incurred by the Company during the Reconciliation Period should be excluded from eligible fuel.

II. SPINDLETOP GAS STORAGE FACILITY

Q. PLEASE IDENTIFY THE ISSUES RAISED BY MR. NALEPA THAT YOU WILL ADDRESS.

A. Mr. Nalepa testifies that "ETI does not use or need the Spindletop facility"[1] and that therefore approximately $7.7 million of base rate costs relating to the facility should be removed from rates and the facility itself should be removed from regulated service.[2] Mr. Nalepa further testifies that the supply reliability and flexibility provided by the Spindletop facility can be provided by less-costly options, and that approximately $5.4 million of fuel costs relating to the facility's operation should be excluded as an eligible fuel expense.

Q. UPON WHAT DOES MR. NALEPA BASE HIS CONCLUSIONS?

A. Mr. Nalepa testifies that (1) since other Entergy Operating Companies are able to operate their gas-fired plants without the benefits of natural gas storage, ETI should be able to do so as well; (2) the reliability and swing flexibility provided by Spindletop far exceeds the needs of ETI, and therefore the Company is paying for services beyond what is required; and (3) the reliability and swing flexibility provided by Spindletop can be

[1] Nalepa Direct Testimony at page 20, line 6-7.

[2] *Id.* at page 5, lines 18-19.

provided at a lower cost through other mechanisms, such as are used by other Entergy Operating Companies.

Q. DO YOU AGREE WITH MR. NALEPA'S CONCLUSIONS?

A. No. Mr. Nalepa attempts to argue that the Company agreed that it could obtain either the same or a sufficient level of supply reliability and flexibility from less costly options than Spindletop.[3] Mr. Nalepa is correct in stating that other Entergy Operating Companies do not own or operate natural gas storage facilities to support their gas-fired generating units, and that they must therefore rely upon a variety of other mechanisms to provide the reliability and flexibility required by their plants. However, Mr. Nalepa incorrectly assumes that the conditions that exist in those other Operating Companies, specifically in EGSL, also exist in ETI, and that the level of service supplied to gas-fired plants in those locations would be sufficient for ETI's plants. This is simply not the case.

[3] *Id.* at page 5, lines 12-14, and page 21, lines 24-25.

Q. PLEASE EXPLAIN HOW THE EGSL GAS-FIRED GENERATING PLANTS ARE OPERATED IN COMPARISON TO ETI'S SABINE AND LEWIS CREEK PLANTS.

A. Table 1, below, shows the gas-fired generating plants owned by EGSL and ETI respectively, their maximum generating capacity and the total gas burn at each plant during the Reconciliation Period.

TABLE 1

COMPANY	PLANT	MAXIMUM CAPACITY	MMBTU BURN (1)
EGSL	Nelson	414	31,580,804
	Willow Glen	835	20,830,168
	Total EGSL Legacy Plants	1,249	52,410,972
	Calcasieu	322	5,476,221
	Ouachita	807	5,533,361
	Total EGSL CCGT	1,129	11,009,582
	Total EGSL Fleet	**2.378**	**63,420,554**
ETI	Lewis Creek	460	41,166,137
	Sabine	1835	103,372,398
	Total ETI Fleet	**2,295**	**144,538,535**

(1) EGSL burn data taken from Company's response to Cities 18-12; ETI burn data taken from Schedule I-16.1.

Although EGSL's total gas-fired generating capacity is similar in size to that of ETI, it is quite evident that the ETI plants are operated at a much higher capacity factor than the EGSL plants. The ETI gas plants, for example, burned more than twice the amount of gas that was burned by the EGSL plants. Furthermore, it is important to note that of the 2378 MW of gas-fired generating capacity owned by EGSL, nearly half (Calcasieu and Ouachita) consists of combined cycle gas turbine ("CCGT")

technology. These CCGTs, because of their quick-start and shut-down capability are operated primarily as peaking units. These can be started up when needed to meet peak load for the day and then shut down during off-peak hours. The ETI plants do not have this capability. The remaining EGSL plants (Nelson and Willow Glen) were part of the legacy fleet that, together with Lewis Creek and Sabine, made up EGSI system prior to the jurisdictional separation of the Companies. When only the legacy plants are considered, the differences in the two systems become even more pronounced. ETI's legacy plant capacity is approximately 84% greater than the legacy plant capacity of EGSL, but the gas burn at the ETI legacy plants was approximately 176% greater than that of the EGSL legacy plants. Even a cursory examination of the gas generating capacity and gas burns between EGSL and ETI is sufficient to demonstrate that, contrary to Mr. Nalepa's assumptions, there are fundamental differences between the EGSL and ETI systems that make any attempts to extrapolate the operation of one (EGSL) to the other (ETI) problematic, at best. Moreover, the data in the preceding table supports the Company's position that ETI requires a much higher level of service than does EGSL.

Q. PLEASE EXPLAIN WHAT YOU MEAN BY THE TERM LEGACY PLANTS.

A. By "legacy plants," I am referring to those generating plants that were owned by Entergy Gulf States, Inc. (EGSI), the utility that was separated

into two distinct utilities, ETI and EGSL, on December 31, 2007, based on EGSI's former respective retail jurisdictions of Texas and Louisiana.

Q. WHAT ALTERNATIVES TO STORAGE DOES MR. NALEPA BELIEVE COULD PROVIDE THE FUEL SUPPLY RELIABILITY AND FLEXIBILITY THAT ARE PRESENTLY PROVIDED BY SPINDLETOP?

A. It is Mr. Nalepa's position that the Company does not need the level of service that is provided by Spindletop. He argues that because EGSL is able to reliably operate its gas-fired generating plants without gas storage, ETI should therefore be able to do so as well. Mr. Nalepa argues that the supply reliability and swing flexibility that is required by ETI can be provided through a combination of the following: (1) the long-term gas supply agreement with Enbridge Marketing serving Sabine and Lewis Creek and the transportation agreement with Copano Pipeline at Lewis Creek; (2) utilizing the swing flexibility available on the TETCO and Copano pipelines; and (3) using call options to provide additional supply reliability.

Q. DO YOU AGREE WITH MR. NALEPA'S ARGUMENTS?

A. No, I do not. ETI's gas-fired generating plants require a significantly greater degree of reliability and swing flexibility than its EGSL-owned counterparts. As discussed previously in my testimony, and as shown in Table 1, ETI's gas-fired generating plants burn significantly greater

quantities of gas than do those belonging to EGSL. Exhibit KDM-R-1 shows the monthly gas burn during the Reconciliation Period for each of the legacy plants. As that Exhibit illustrates, not only do the ETI plants burn significantly more gas in every month than do the EGSL plants, but there are a number of months in which one or both of the EGSL legacy plants run very little or not at all. With significantly lower fuel requirements at the EGSL plants, there is a commensurate reduction in the level of supply reliability and swing flexibility that is required.

Moreover, it is important to note that the potential load swing on the EGSL legacy plants is significantly less than that of the ETI plants. Table 2, below, shows the approximate daily burn rate of natural gas at each of the EGSL and ETI legacy plants when operated at minimum and maximum load.

TABLE 2

Plant	Approximate MMBtu/Day Burn Rate		
	Minimum Load	Maximum Load	Maximum Swing
Nelson Station	44,000/day	105,000/day	61,000/day
Willow Glen	77,000/day	210,000/day	133,000day
Total EGSL Plants	121,000/day	315,000/day	194,000/day
Lewis Creek	30,000/day	120,000/day	90,000/day
Sabine Station	110,000/day	460,000/day	350,000/day
Total ETI Plants	140,000/day	580,000/day	440,000/day

As Table 2 illustrates, the maximum swing on the ETI plants is significantly greater than that of the EGSL plants. In fact, the maximum

swing potential at Sabine Station alone is greater than the rate of burn of both EGSL plants, combined, when running a maximum load. Thus, Mr. Nalepa's suggestion that operating methods used at EGSL can be extrapolated and employed at ETI is overly simplistic and, as a practical matter, infeasible.

Q. PLEASE ADDRESS MR. NALEPA'S ASSERTION THAT THE LONG-TERM GAS SUPPLY CONTRACT WITH ENBRIDGE COULD PROVIDE ADEQUATE RELIABILITY NEEDS FOR ETI'S GAS-FIRED GENERATING UNITS

A. The Enbridge contract is certainly an important and valuable component of the Company's overall portfolio. However, the Enbridge contract cannot replace the service provided by Spindletop. Moreover, the Enbridge contract expires in .

Q. PLEASE EXPLAIN.

A. The maximum contract quantity deliverable under the Enbridge contract is insufficient to run the ETI plants even at minimum load. By contrast, the Spindletop facility is capable of supplying gas to all five units at Sabine Station and one unit at Lewis Creek for four days at a 70% capacity factor. In the event of a severe weather event in which all gas supplies were curtailed, the Enbridge gas would continue to be a reliable supply to the plants. However, if that were the only gas that could be delivered, it would

supply less than 20% of the gas requirements for the ETI plants. Furthermore, when the Enbridge contract expires, there is no guarantee that the Company would be able to negotiate another long-term contract, or what the volume or pricing terms of the new contract might be.

Q. MR. NALEPA ASSERTS THAT IT WOULD BE POSSIBLE TO SUPPLEMENT THE ENBRIDGE CONTRACT WITH CALL OPTIONS TO SUPPLY THE BALANCE OF THE FUEL SUPPLY NEEDS OF THE PLANTS. DO YOU AGREE?

A. No. Mr. Nalepa's recommended disallowance, which is based in part on his assumption that call options in conjunction with the Enbridge contract could be used in lieu of Spindletop, should be rejected because they are based on fundamentally flawed assumptions and analysis.

Q. PLEASE EXPLAIN.

A. Certainly. First, Mr. Nalepa's recommendation is based on the assumption that the Company would purchase a single five-day call option each month (with the exception of October – December and April – May) for 35,000 MMBtu/day. In the event of a severe weather event in which all non-firm gas is curtailed, Mr. Nalepa's recommended plan, which includes the Enbridge contract gas and 35,000 MMBtu/day of call option gas, would allow the Company to run less than 25% of the ETI plants' combined capacity. As Table 2 illustrates, in order to run the ETI plants at

full load, approximately 580,000 MMBtu/day would have to be purchased and delivered to the plants. In order to achieve this level of reliable supply under Mr. Nalepa's proposal, the Company would have to purchase the equivalent of approximately fourteen such call options each month to supplement the gas deliverable under the Enbridge contract. And this is a "best case" scenario, because it assumes that only one severe weather event will occur in any given month. In reality, however, if such an event occurred early in the month and the Company called for delivery of all its option gas to serve the load during the event, it would be necessary to replace those exercised options with new options for the remainder of the month. An additional factor that would have to be considered is that call options are subject to force majeure.

Q. WHAT OTHER FLAWS HAVE YOU IDENTIFIED IN MR. NALEPA'S RECOMMENDATION TO REPLACE THE RELIABILITY AND FLEXIBILITY PROVIDED BY SPINDLETOP WITH A COMBINATION OF CALL OPTIONS AND THE ENBRIDGE SUPPLY AGREEMENT?

A. Mr. Nalepa's analysis also ignores the costs that would be incurred in the exercise of the call options. The call option gas, like gas delivered under the Enbridge contract, must be delivered ratably. That is, it is delivered at a constant, even rate throughout the delivery period. In order to have gas available to meet peak loads, the Company would have to exercise all of its call options and nominate maximum delivery under the Enbridge

contract. Unfortunately, the plants do not operate at maximum load throughout the day. Consequently, as system loads decline so do the system's gas requirements. This means that the Company would have to find an alternative use for the gas that is being delivered under the call options and the Enbridge contract, but that is no longer needed during the low-load hours of the day.

Currently, the Company is able to inject this gas into Spindletop storage during off-peak hours and withdraw gas from storage across the peak hours. During the Reconciliation Period, approximately 8.1 million MMBtu's were injected into inventory in order to allow the Sabine plant to follow load requirements.[4] If the Commission were to accept Mr. Nalepa's proposal, and deny the Company the use and cost recovery associated with Spindletop, the Company would be required to either (1) continue to run the gas plants at full load in order to burn the gas; or (2) sell the excess gas back into the market.

Both of these options carry significant costs that are not considered in Mr. Nalepa's analysis. Option 1, for example, would mean that during the off-peak hours the Company would be continuing to operate its gas plants at full load, displacing much more economical options such as purchased power or even coal or nuclear power available through Schedule MSS-4 of the Entergy System Agreement. Option 2 would put

[4] Direct Testimony of Karen D. McIlvoy, Exhibit KDM-12.

the Company completely at the mercy of the marketplace. During off-peak hours, when the Company would be trying to sell excess gas back into the market, potential buyers would, of course, be experiencing the same off-peak load conditions. The resulting low demand would obviously translate into a lower price for the gas being sold. It is not possible to determine what the magnitude of the price discount might be, but considering that the volumes of gas being sold would likely be significant, it is reasonable to expect that the discount would be significant as well. In any case, these costs – whatever they might be – were ignored or not considered at all by Mr. Nalepa.

Q. WOULD THERE BE ANY EFFECT ON ETI'S CUSTOMERS RESULTING FROM BEING REQUIRED TO RESELL EXCESS GAS INTO THE MARKETPLACE DURING OFF-PEAK HOURS?

A. Yes. ETI's retail customers would ultimately be required to absorb the difference between gas purchased for peak operations and gas sold at off-peak prices, absent a finding of imprudence by the Commission.

Q. ARE THERE ANY ADDITIONAL FLAWS IN MR. NALEPA'S ANALYSIS?

A. Yes. Mr. Nalepa's analysis assumes a cost of a five-day 35,000 MMBtu/day call option of $26,250. Even if the Company were to agree that Mr. Nalepa's estimate of the price of single call option is reasonable,

it is highly unlikely that the cost of fourteen such options each month would be at that same price.

Q. PLEASE EXPLAIN.

A. First, the simple laws of supply and demand would suggest that the price per option would increase because of the higher demand for call options. Second, the fact that a call option places a greater burden upon the counterparty will also tend to raise the cost. Remember, a call option represents a firm promise by the counterparty to deliver. When that option is backed by storage – as is the case for options purchased by the Company – then the counterparty must be certain to have sufficient gas in storage to satisfy the obligations under the option contract. Having such an obligation for 35,000 MMBtu/day represents a significantly lower level of risk on the part of the counterparty than an obligation to be ready to deliver up to 400,000 – 500,000 MMBtu/day. The higher the risk to the counterparty, the higher the price that would likely be demanded to purchase the call options.

Q. ARE THERE POLICY ISSUES FOR THE COMMISSION TO CONSIDER REGARDING MR. NALEPA'S RECOMMENDATION TO REPLACE SPINDLETOP IN PART WITH CALL OPTIONS?

A. Yes, there are. Mr. Nalepa has failed to address the regulatory treatment of the cost of unexercised call options. One of the elements of a call

option is the "strike price," which is the price the Company would pay for gas purchased upon the exercise of the option. Generally, the strike price is defined in the option contract as some market index (such as the Houston Ship Channel GDA) plus an adder. The amount of the adder can vary greatly with market conditions, but, during normal conditions, gas purchased under a call option would typically be more expensive than gas purchased in the spot market. The reason for this premium, of course, is because call options are not intended to be a spot market alternative, but are intended to ensure a firm, reliable supply when spot gas may not be available in the market. The significance of this is that during normal operations, the Company would not exercise the call options that it purchased, but would instead opt to purchase lower-priced gas in the spot market, thus resulting in lower fuel costs for its customers. As a result, the Company could spend hundreds of thousands of dollars per month to purchase call options that it never exercises.

Q. WHY IS THIS A POLICY ISSUE FOR THE COMMISSION?

A. According to the Commission's Fuel Rule, these costs are not considered to be reconcilable. In Dockets 34800 and 37744, the Company did incur such costs and sought and was granted the right to seek recovery of these costs under a "special circumstances" clause. Notably, Mr. Nalepa does not address this issue at all. However, in Docket No. 34800, the Cities opposed such special circumstances recovery. Mr. Nalepa is silent

with regard to whether Cities would continue to oppose recovery of such costs through fuel if the Company were to follow his proposals.

Q. YOU MENTIONED IN THE PREVIOUS DISCUSSION THAT THE ENBRIDGE AND CALL OPTION GAS IS DELIVERED RATABLY. MR. NALEPA TESTIFIES THAT THE COMPANY COULD CONVERT THESE RATABLE FLOWS TO MATCH HOURLY LOADS BY TAKING ADVANTAGE OF SWING ON THE TETCO NATURAL GAS PIPELINE AT SABINE STATION. DO YOU AGREE?

A. No. As Schedule I-6 shows, the maximum capacity on the TETCO line at Sabine Station is 130,000 MMBtu/day. The Sabine plant will burn approximately 460,000 MMBtu/day at full load and can swing approximately 350,000 MMBtu/day from minimum to maximum load. TETCO's capacity of 130,000 MMBtu/day would supply less than 30% of the plant's requirements at full load and even if it were able to swing from zero to 130,000 MMBtu/day, it would still satisfy less than 40% of the maximum swing requirements of the plant.

Furthermore, whereas TETCO does permit the Company a certain degree of latitude under its transportation contract, there is no contractual obligation or right for swing service under the contract at either Lewis Creek or Sabine Station. TETCO allows the Company to swing on an "if, as, and when" basis, subject to operating conditions on the pipeline at any given time. In other words, the Company has no contractual rights to

demand such swing. While the Company does utilize the TETCO line to swing when it is economical to do so, it would be imprudent and irresponsible for planning purposes to assume that this service would always be available, or that it would be available during a severe weather event when most needed.

Q. DO YOU HAVE ANY OTHER OBSERVATIONS REGARDING MR. NALEPA'S ANALYSIS OF SPINDLETOP COSTS VERSUS OTHER ALTERNATIVES?

A. Yes. In Mr. Nalepa's Table 10 he calculates a total test year cost relating to Spindletop storage of approximately $13.1 million. He also calculates what he considers to be an appropriate level of alternative costs of approximately $1.7 million, and then concludes that the Company overpaid for the services provided by Spindletop by $11.4 million. Mr. Nalepa asserts that these excess costs should be disallowed by the Commission. There are a number of serious problems with Mr. Nalepa's analysis, some of which have I have previously addressed:

First, as mentioned previously, Mr. Nalepa's alternative costs assume that a single five-day call option for 35,000 MMBtu/day would be sufficient to meet the additional reliability needs of the ETI plants beyond those which are provided under the Enbridge contract. I have shown in my earlier discussion that the Company would likely need as many as <u>fourteen</u> such contracts each month, and possibly more.

Second, Mr. Nalepa assumed a cost of each call option contract of $26,250. As I noted earlier in my testimony, this is very likely a low number.

Third, Mr. Nalepa assumed that no call options would be purchased in October – December or April – May. Although he did not offer any explanation for excluding those months, presumably he considered those months to be "low-risk" months and therefore no call options would be needed. However, it must be noted that major hurricanes have occurred as late as October, disrupting fuel supplies, and severe winter weather can occur as early as December. With respect to the remaining months (November, April, and May) that Mr. Nalepa excluded from his analysis, these are months in which planned maintenance is generally scheduled and performed. When base-load plants are on outage for planned maintenance, the gas-fired plants become more vital to meeting system energy requirements than they might otherwise be. Consequently, while these particular months might arguably be considered less risky with regard to fuel supply issues, the reliability of gas becomes more important. It would therefore be prudent to include those months in the analysis.

Fourth, as I discussed earlier, Mr. Nalepa's analysis does not take into account the cost associated with having to take delivery of gas ratably throughout the day, when generation requirements vary with load.

Fifth, with respect to Mr. Nalepa's calculation of Spindletop costs, he calculates a cost that is based only on storage withdrawals and adjustments during the test year. He completely ignored natural gas injections. His own Figure 2 illustrates that injections were approximately the same as withdrawals. My Exhibit KDM-12 in my Direct Testimony shows that total injections during the test year were 8,122,852 MMBtu's. When these injections are added to Mr. Nalepa's analysis at Table 10, the total MMBtu's increases from 8,560,604 to 16,683,456, essentially cutting in half all of his estimated "per MMBtu" costs relating to Spindletop. In addition, including the MMBtu's injected will have the effect of nearly doubling Mr. Nalepa's calculated "Alternative Transport Costs."

Sixth, Mr. Nalepa's analysis mixes fixed and variable costs to present a distorted comparison. The "Base Rate Storage Costs" shown in Table 10 are fixed costs that relate to costs that are in base rates. While I am not qualified to comment on the treatment of costs in base rates, in an analysis of this type, these costs should be considered "sunk" and should not be factored into the analysis.

Q. DO YOU HAVE ANY FINAL COMMENTS WITH REGARD TO THE RECOMMENDED DISALLOWANCE PROPOSED BY MR. NALEPA?

A. Yes. Mr. Nalepa's calculations and recommended disallowance assumes that all of the Spindletop costs are borne by ETI. This is not the case. Although ETI is the owner of the Spindletop facilities, it is my

understanding that 57.5% of the costs are passed through to EGSL through the MSS-4 agreement. Of the remaining 42.5% retained by ETI, 2.4% was passed to other Entergy Operating Companies through the MSS-3 agreement. In effect, then, only 40.1% of the Spindletop fuel costs during the Reconciliation Period actually stayed in ETI.

Secondly, with regard to base rate costs, Mr. Nalepa's assertion that the Company does not "use or need" Spindletop defies logic. The Company's Spindletop facility is regularly used to provide reliable and flexible gas supply to its Texas gas plants. It is my understanding that the Commission has repeatedly arrived at this conclusion in response to Cities' arguments in Commission proceedings going back to the time that the facility was placed into service.

III. CONCLUSION

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes.

	EGSL LEGACY PLANTS (1)			ETI LEGACY PLANTS (2)		
	Nelson	Willow Glen	Total EGSL	Lewis Creek	Sabine	Total ETI
7/1/2009	2,003,393	1,185,066	3,188,459	2,608,808	5,042,538	7,651,346
8/1/2009	2,394,630	1,787,670	4,182,300	2,685,893	6,046,204	8,732,097
9/1/2009	557,491	687,631	1,245,122	1,864,425	5,140,879	7,005,304
10/1/2009	1,046,481	0	1,046,481	1,011,789	4,080,479	5,092,268
11/1/2009	10,326	3,534	13,860	787,709	2,270,031	3,057,740
12/1/2009	61,039	4,890	65,929	955,265	3,256,767	4,212,032
1/1/2010	752,339	169,713	922,052	1,628,474	3,658,429	5,286,903
2/1/2010	160,810	5,902	166,712	1,030,933	2,680,265	3,711,198
3/1/2010	1,027,094	60,541	1,087,635	1,555,739	2,130,268	3,686,007
4/1/2010	2,107,656	1,382	2,109,038	1,786,838	2,932,593	4,719,431
5/1/2010	2,150,343	594,811	2,745,154	2,008,631	4,513,467	6,522,098
6/1/2010	2,255,095	1,591,555	3,846,650	2,320,646	5,520,997	7,841,643
7/1/2010	1,987,604	2,560,394	4,547,998	2,379,486	6,272,254	8,651,740
8/1/2010	2,283,377	2,155,760	4,439,137	2,369,530	6,614,399	8,983,929
9/1/2010	1,658,754	0	1,658,754	1,900,465	4,456,847	6,357,312
10/1/2010	801,369	0	801,369	1,556,227	4,797,985	6,354,212
11/1/2010	9,302	2,400	11,702	1,138,663	3,767,921	4,906,584
12/1/2010	923,141	6,194	929,335	1,418,140	3,885,348	5,303,488
1/1/2011	1,498,468	1,314,970	2,813,438	1,624,790	3,843,256	5,468,046
2/1/2011	1,276,596	1,602,721	2,879,317	1,545,013	3,152,675	4,697,688
3/1/2011	1,842,114	75	1,842,189	1,524,921	4,197,198	5,722,119
4/1/2011	1,774,121	2,587,388	4,361,509	1,071,688	4,866,237	5,937,925
5/1/2011	741,802	2,397,128	3,138,930	2,180,638	5,243,585	7,424,223
6/1/2011	2,257,459	2,110,443	4,367,902	2,211,426	5,001,776	7,213,202

(1) Data derived from Company's attachment to Cities 18-12.
(2) Data taken from Schedule I-16.1.