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# TransCanada's Use of Technology to Meet Changing Demands on Measurement

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## Abstract

Daily supply/demand management of over 12,000,000 GJ's/day of natural gas commodity allocated to 350+ shippers/connecting pipeline operator accounts presents a significant challenge to management of TransCanada's 1300+ meter stations. New technology, hourly measurement, automated validation, exception based problem reporting and energy impact based prioritization is used to meet customer demands and "Near Time" deadlines.

## TransCanada

We are a leading North American energy company, focused on natural gas transmission and power services. Our employees are experts in these businesses. Our network of approximately 38,000 kilometers of pipeline transports the majority of western Canada's natural gas production to the fastest growing markets in Canada and the United States. TransCanada also owns, controls, or has under construction approximately 4000 megawatts of power. An equal amount of power can meet the needs of three million average households.

## Measurement and Customer Allocation Processes

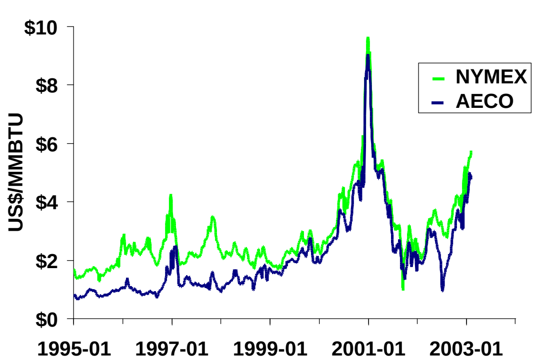
TransCanada receives natural gas at 950+ major receipt meter stations and delivers at 400+ major delivery stations, 950+ Gas Coop/tap stations, 250+ compressor fuel facilities on its Alberta, Mainline and BC systems. The Gas Measurement System (GMS) hourly validation and material balance identifies in "near time" measurement and imbalance problems. Once an hour ~99% receipt and delivery measurement is collected, validated and finalized. The remaining sites, heating fuel/operating losses and linepack change are estimated along with any sites with significant measurement or communication problems. At the start of each workday field technicians review any stations that haven't been finalized and analyze the reported problems. In the majority of cases the primary or check measurement can be selected, corrective action scheduled and any data related problems managed with-in a working day.

The second part of this process is to allocate the energy measured at each facility to one or more of the 350+ customers transporting natural gas on TransCanada's systems. Each customer or operator's receipt and delivery energy is accounted for at each location they participate in. Energy inventory ("paper gas") transfer between customers is also accounted for. The difference between all of the receipt and delivery transactions determines the supply/demand imbalance. It should be noted that the quantity of "paper gas" business has grown in Alberta over the past few years. On a typical day it accounts for 1-3 times as much energy custody transfer as the physical receipts.

## Market Conditions

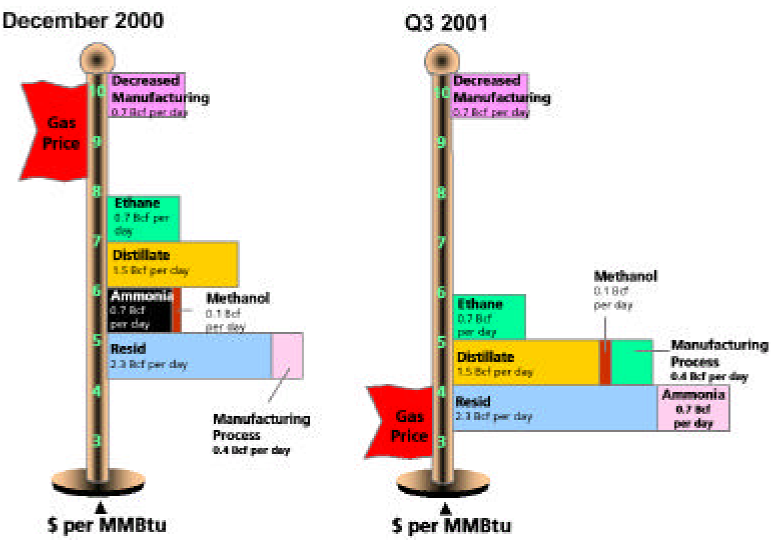
Supply and demand volatility in the energy and petrochemical sectors has created significant price fluctuations. The temperature related trend of prices increasing for the winter heating season has always existed. The size of the change has ranged from undetectable to double the average price for a two or three month period.

The 2000/2001 winter heating season changed all that. It experienced month to month price changes that were 2 times the historical commodity price and the monthly price peaked at 5 times the historical average.




The fall-out from this significant change to historical prices - **Increased need to match customer supply to demand daily.** Knowing how much production is available to sell, finding buyers and matching the timeframes for all of the remaining business transactions until it reaches its final destination is impossible if the measurement is not accurately known in a timely manner. Buying gas at $6/GJ and selling it a $8/GJ may be good but buying it a $9/JG and selling it at $7/GJ causes some real customer concern. An even bigger concern is customers thinking they have sold gas at $10/GJ, only to find out later that the measurement is lower and they didn't sell what they thought.

If that wasn't enough, in December 2000 the relationship between the price of Natural Gas and Ethane/Natural Gas Liquids (NGL) changed to substantively favor Natural Gas energy. The result, a large number of gas plants significantly changed their process to maximize the production of natural gas energy over NGL.




This resulted in - **Added complexity of gas composition determination.** Gas sampling methodology relies on historical gas plant operation and the commodity value of the estimate gas sampling error. If the estimated gas sampling error is +/- $500/month, it is very hard to spend real money to increase gas sampling or install gas chromatographs. However, when natural gas price increases by a factor of 5 or the average price over a month is equal to the historical average price, then the value of this error changes significantly.

## Supply/Demand Balancing to Manage Daily Operating Conditions

All pipelines face the Supply/Demand imbalance dilemma – **If Supply doesn't equal Demand, then the difference is made up from linepack change, storage or pipeline to pipeline OBA's (Operating Balance Agreements).** Because supply/demand is the responsibility of the customers transporting gas on each transmission systems, both the Alberta and Mainline systems have established Supply/Demand Balancing processes.

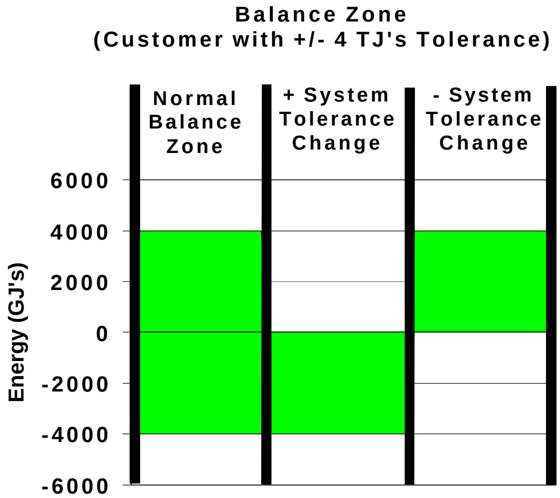
### *The Alberta System Supply/Demand Process*

The objective of the Alberta System Supply/Demand process is two-fold: to balance the total system's supply to demand, staying with-in the pipeline's operating linepack range and to balance each customer's supply to demand, minimizing the impact of one customer's imbalance on other customers. Sounds simple enough, but there are 300+ customers who transport gas on the Alberta System, each with different business models. Customers fit into one or more categories of producers, marketers, LDC's, aggregators, government sponsored agencies and petrochemical plants, with some defying typical categorization. As a result each customer has varying amounts of physical and "paper" supply and demand.

"Paper gas" is transferred from one customer to another and is like writing a check on one bank account and depositing it to another. These transactions must balance out on the day and are not used in calculating each customer's balance zone. Storage is another account management tools, it isn't used to determine balance zone. What is used to determine the allowable imbalance limits

| | Example 1 | Example 2 | Example 3 | Example 4 |
|---|---|---|---|---|
| Physical Receipts | 0 TJ's/d | 100 TJ's/d | 50 TJ's/d | 100 TJ's/d |
| Physical Deliveries | 0 TJ's/d | 0 TJ's/d | 50 TJ's/d | 50 TJ's/d |
| Balance Zone | +/- 2 TJ's | +/- 4 TJ's | +/- 4 TJ's | +/- 6 TJ's |

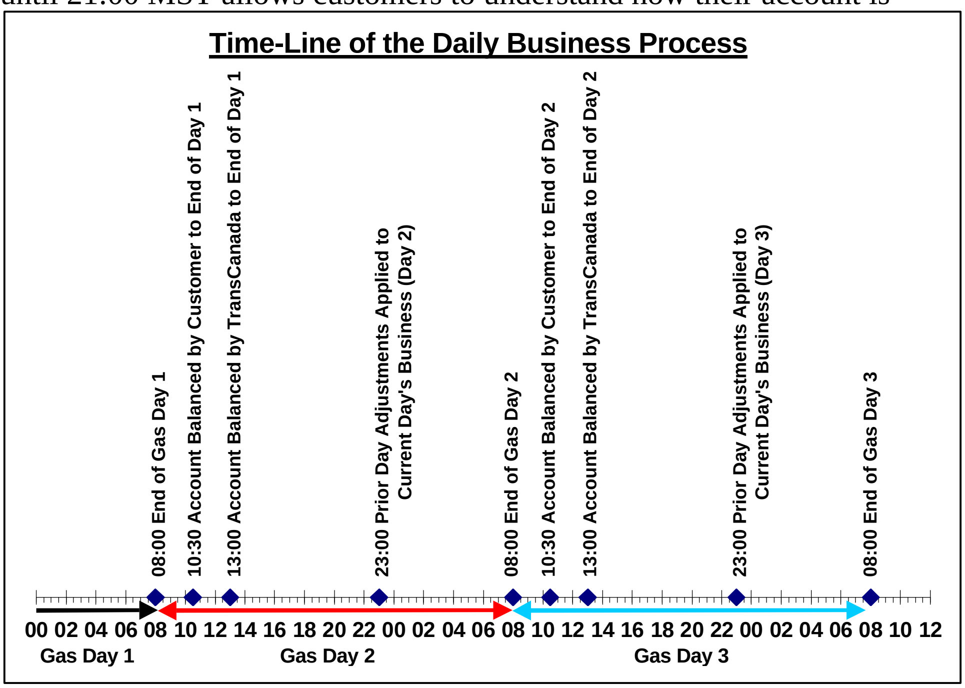
are physical receipts and physical deliveries. The upper limit of the balance zone is the larger of 2 TJ's or 4% of daily average of the physical receipts plus 4% of daily average of the physical deliveries. The lower limit is the negative of the upper limit.




If the pipeline balance is outside of its operating linepack range and is not being managed by the supply/demand process, then a system wide tolerance change will be made. This change adjusts the balance zone of all customers and makes their upper or lower balance zone limit 0 to offset the system's packed or drafted state.

All customers are required to be with-in their balance zone by 10:30 MST for the previous gas day that ends at 08:00 MST. If the customer has not managed their previous day business by 10:30, TransCanada must ensure compliance by either canceling "paper gas" transactions, decreasing receipt or delivery nominations and/or decreasing receipt or delivery allocations. These changes are made by 13:00 MST and reported to the customer.

At this point business is already 5 hours into today's Supply/Demand management process and customers are focusing on how the current day is shaping up. Measurement for the current day is being collected, the Gas Measurement System is estimating measurement to the end of the gas day and field technicians and the Data Integrity group in Calgary have been busy fixing measurement problems. The corrections for the current gas day are applied as they are fixed, while corrections for previously completed gas days are held and applied at 21:00 MST. Holding the historical changes until 21:00 MST allows customers to understand how their account is changing. They work from 06:00 MST to 10:30 MST buying and selling gas to balance their account for the "just closing" gas day.




The historical changes are also identified as discretionary changes, allowing them to be managed in the mornings trading or as part of the next days business.

### *The Mainline System Supply/Demand Process*

The objective of the Mainline System Supply/Demand process is to enable operators to manage supply to match market demand. As with the Alberta System process, it is the operator's responsibility to manage their imbalance to acceptable levels.

There are three main differences between the Mainline System and the Alberta System. The first difference is that the majority of the supply is managed via Operating Balance Agreements (OBA's) with the inter-connecting pipelines. (OBA's manage the differences between measurements and nominations by allowing the pipeline operators to adjust future business to match the cumulative nominations.) These agreements result in the customer getting what they nominate at pipeline inter-connects, eliminating any imbalance at these locations. The second difference is deliveries are managed to each delivery area or physical accounting location. The delivery area is a group of meter stations that are managed as a group, are assigned a single accounting location and have a single operator. The third difference is the services offered by the pipeline such as Short Term Firm Service and Park and Loan enable the operator to manage each location.

Operators are required to manage imbalances at each accounting location on a daily basis to a maximum +/- 2% of the location's throughput. The total cumulative imbalance must also not exceed +/- 4%. Failure of the operator to manage their imbalance results in an imbalance charge being assessed to their bill. These charges are not designed to generate revenue. Their intent is to encourage the operator to manage their imbalances with-out pipeline intervention.

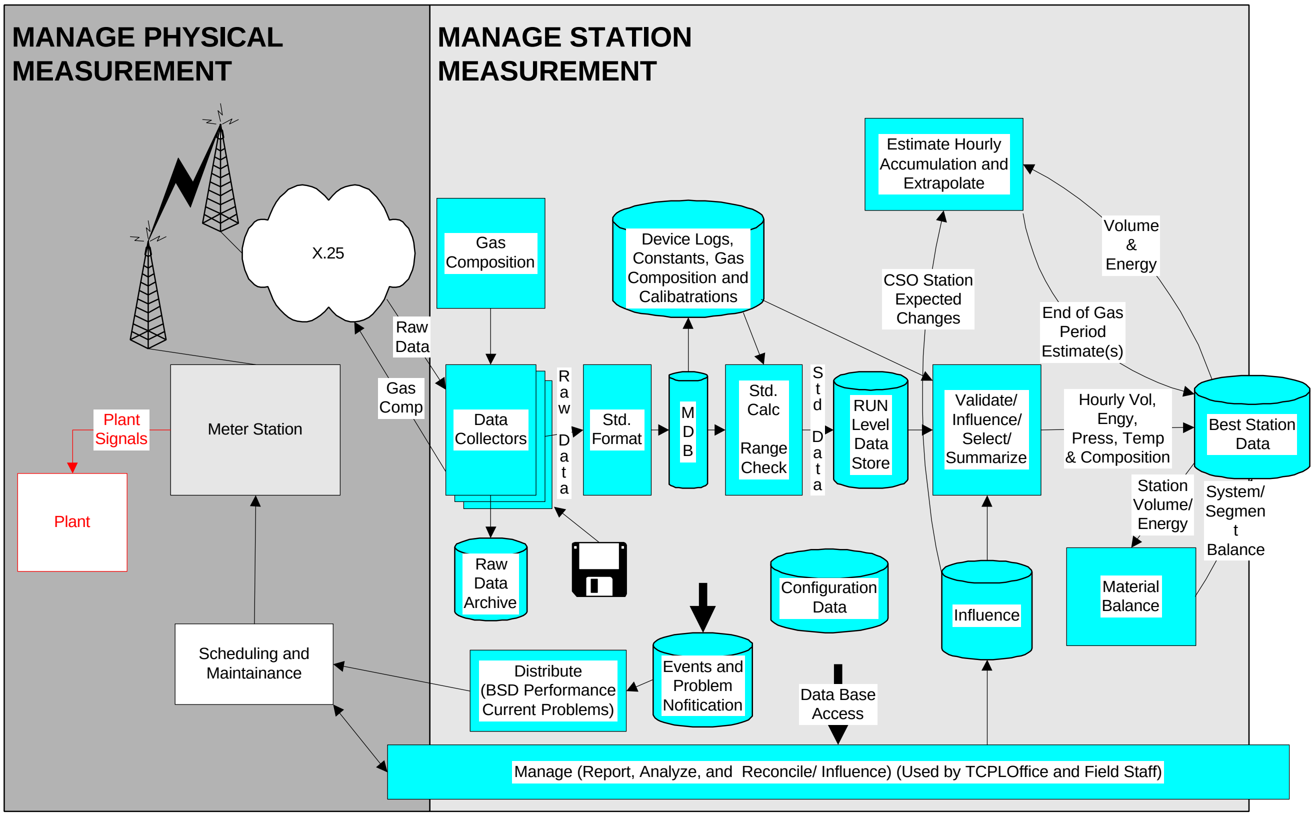
## The Business Processes Required for Measurement to Meet Demands for Timeliness and Accuracy

Market Conditions and Supply/Demand processes clearly identify the need for measurement to be accurate and available in "near time". TransCanada meets these demands through the use of Data Collection Systems and the Gas Measurement System. These systems provide validated volume, energy, pressure, temperature and gas composition information. The data is update hourly, with-in an hour after the EFM systems have completed their measurement transactions. The data is made available for use by all of TransCanada's business processes from a database that is commonly referred to as Best Station Data (BSD). This process operates 24 hours a day, 365 $^{1}/_{4}$ days a year.

The next sections provide a brief description of the major gas measurement and management components. The data flow and components are also summarized in the figure below.

### *Estimation*

The Gas Measurement System estimates all facilities to the end of the current gas day and for future gas days based on historical measurement and flow confirmations received from the Customer account management process. A side benefit of the estimation process is that any missing measurements, due to communication problems, facilities that are too small to justify communications or stations with major validation problems, automatically use these previously generated station estimates. The process ensures that timely measurement from all facilities is available to the Gas Management System for allocation to the customer accounts on an hourly basis.




Gas Measurement System Components

## *Hourly Data Collection*

The Data Collector Systems collect measurement on an hourly basis from approximately 99% (by Energy) of TransCanada's measurement facilities. These hourly measurement transaction records, along with any event and user change logs, are passed to the Gas Measurement System for processing and validation.

## *Standardization of Calculation Methods and Range/Recalculation Checks*

The next step in the management process converts all volume and energy calculation into 24 hourly records for each run. Any flow computer not using the latest calculation standard is also corrected by using the correction methodology below. (This methodology was described in the paper "Real Time Measurement, Coordination of Information Processing from the Field Meter to the Bill" presented at the 2nd International Symposium on Fluid Flow Measurement in 1989.)

$$V_{\text{STANDARD}} = \frac{V_{\text{RECALCULATED USING THE CURRENT STANDARD}}}{V_{\text{RECALCULATED USING THE FLOW COMPUTER STANDARD}}} * V_{\text{REPORTED}}$$

A side benefit of this process identifies significant measurement problems by comparing the recalculated volume and energy to the original reported volume and energy.

## *Validation*

Validation exploits the redundant instrumentation design by performing a primary to check percent difference calculation for volume, energy, differential pressure/frequency, temperature and pressure. This check is also done between runs on multi-run facilities to enhance identification of the specific transmitter requiring maintenance or when the multiple runs provide the transmitter redundancy.

To round out the validation checking and finalization process a number of additional operating characteristics are identified.

**System Level** - Checks for station and run configuration.

**Station Level** - Checks for gas composition, orifice plate sizes and communication problems.

**Run Level** - Primary to check and/or run to run comparisons of volume, energy, pressure, temperature and differential pressure/frequency done at hourly and daily intervals. The hourly checks use the daily limits times a system $k_{factor}$. In addition both modify their limits to account for EFM time and sampling differences.

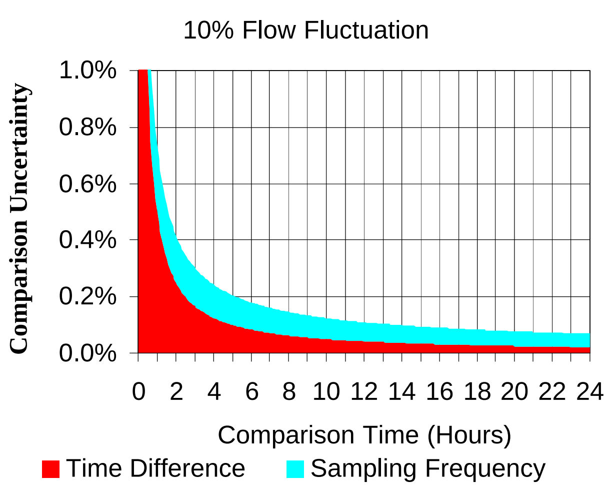
The time difference uncertainty is estimated by:

$$\text{Time Uncertainty} = \frac{\text{\% Fluctuation} * \text{Allowable Time Difference}}{\text{Comparison Time Interval}}$$

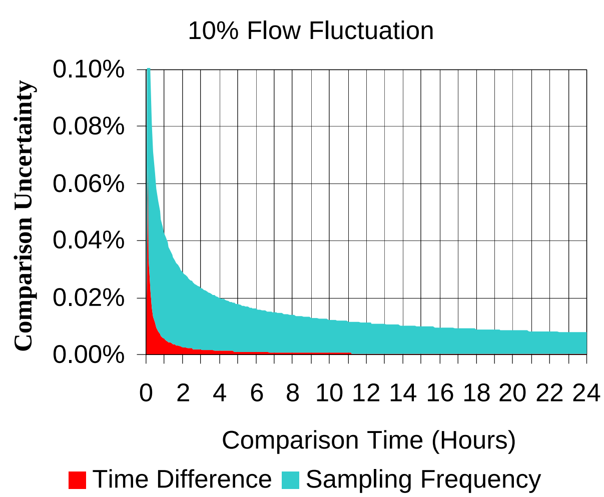
and the EFM device sampling frequency estimated by:

$$\text{Sampling Uncertainty} = \frac{\text{\% Fluctuation}}{\sqrt{\text{\# Samples for the Comparison Interval}}}$$

These uncertainties add together to limit the size of detectable operating problems. The Barton flow computer time and sampling uncertainty is estimated in the lower left figure. It requires a comparison interval of 24 hours to reduce the 10% flow fluctuation comparison uncertainty to <0.1%. The Datek flow computer system uncertainty is estimated in the lower right figure. It is able to achieve 0.1% comparison performance in <5 minutes for the same flow fluctuation.




2 Second Sampling < 3 Minutes Time Dif.




20 Samples/Second <2 Second Time Dif.

In addition to primary to check % difference comparisons, run level checks are done for:

- over-range conditions,
- gas composition update frequency,
- plate change validity,
- configuration changes and
- missing information.

## *Select Provides Accurate "Final" Measurement or "Needs Work" Identified*

TransCanada's Gas Measurement System performs station and run level validation checks on all of the measurement it receives. The results of this validation are indicated on all of the hourly measurement records which enables the state of the measurement to be displayed with the measurement. Problem reports are generated for any failed rule. All measurements that pass the validation process are considered final, with the remainder being prioritized and cued for action by the field technician.

### EFM Data Selection

The worst validity level for the run and run use (primary or check) is added to the hourly measurement record and is used to select the "best" run level data. (1 best to 4 worst) The table below summarizes the selection process. If there is "best" run level data selected for all of the runs at a station, then the data is summarized to create an hourly station record.

| | Check Validity 1 | Check Validity 2 | Check Validity 3 | Check Validity 4 |
|---|---|---|---|---|
| Primary Validity 1 | Primary Selected | Primary Selected | Primary Selected | Primary Selected |
| Primary Validity 2 | Check Selected | Primary Selected | Primary Selected | Primary Selected |
| Primary Validity 3 | Check Selected | Check Selected | Primary Selected | Primary Selected |
| Primary Validity 4 | Check Selected | Check Selected | Check Selected | **Neither Selected** |

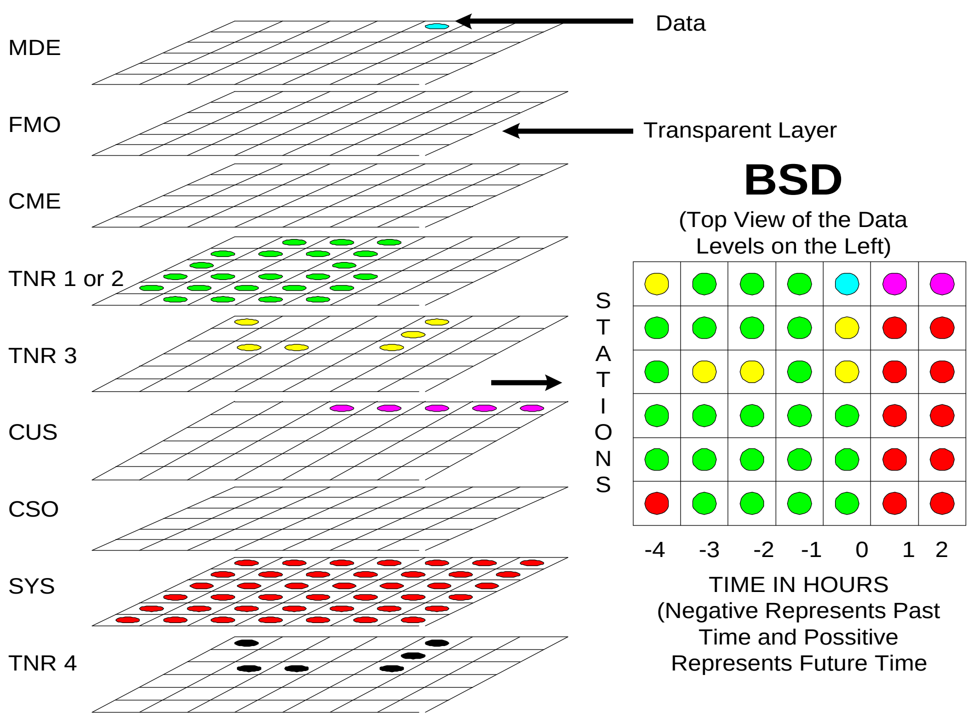
Measurement Selection Matrix

## *Influence Management Provides "Near Time" Accuracy*

This run level EFM data selection process is then enhanced by introducing a multi-level management hierarchy (Table 1) which enables different business process to co-operatively manage best data selection. All measurement start of as station estimates (SYS) which are calculated for up to 14 days into the future. The estimates are then "over-written" with EFM (TNR) data as long as it has a validity levels of 1, 2 or 3 when it is collected. Various influences (MDE, CME, FMO, CUS, CSO etc.) can be applied at any time base on business need. The highest measurement or influence, based on the data management hierarchy, is used to select the measurement provide in the "best station data" database.

| Influence / Data Type | Name | Description | Applied at | Validity |
|---|---|---|---|---|
| Override | MDE | Measurement Data Estimate | Station/Run | 1 |
| | FMO | Forward Measurement Override. An instruction to use Check over Primary or Primary over Check for a particular run | Run | 2 |
| | CME | Customer Manage Estimate | Station/Run | 4 |
| Measured | TNR-1 or TNR-2 | TAMI selected EFM data | Run | 1 or 2 |
| | TNR-3 | TAMI selected EFM data | Run | 3 |
| Estimate | CUS | Customer Manage Estimate. | Station/Run | 4 |
| | CSO | Common Stream Operator Estimate | Station | N/A |
| | SYS | System Calculated Estimate based on ¾ filter station history | Station | N/A |
| Measured | TNR-4 | TAMI rejected EFM data | Run | 4 |

Definition of Influence and Data Types

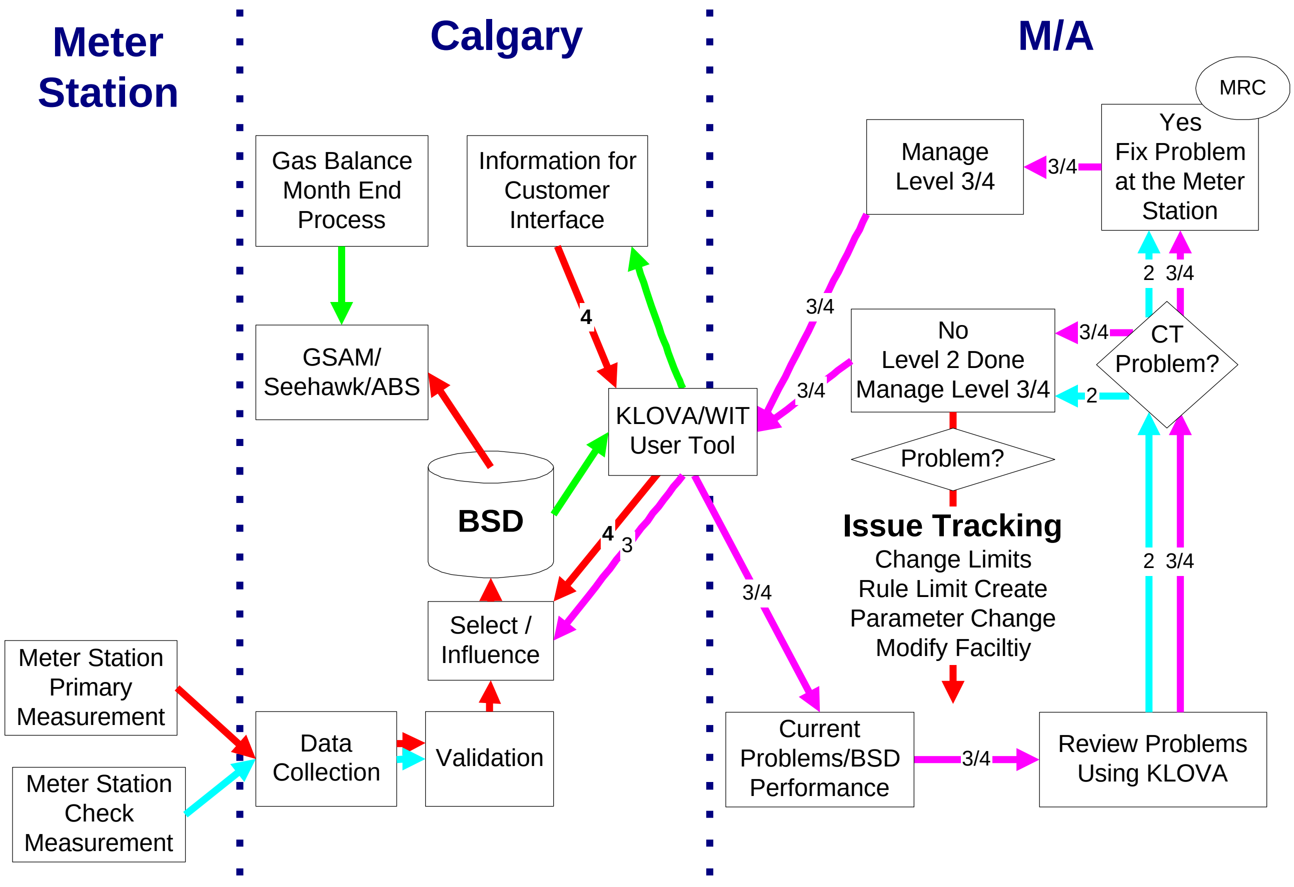



Best Station Data Management Hierarchy

For data to be considered “Final” it must be EFM sourced data with a validity of 1 or 2 or have been influenced to a validity of 1 or 2 by an MDE, FMO or other validity 1/2 influence. Data that is validity 3 or 4, such as CME, TNR-3, CUS, etc., is still considered “Best Station Data” but is not “final”. The data must be managed with-in its maintenance window to meet the need of “Timely Accurate Measurement Information” for use by the business processes of supply/demand balancing and gas balance/billing.

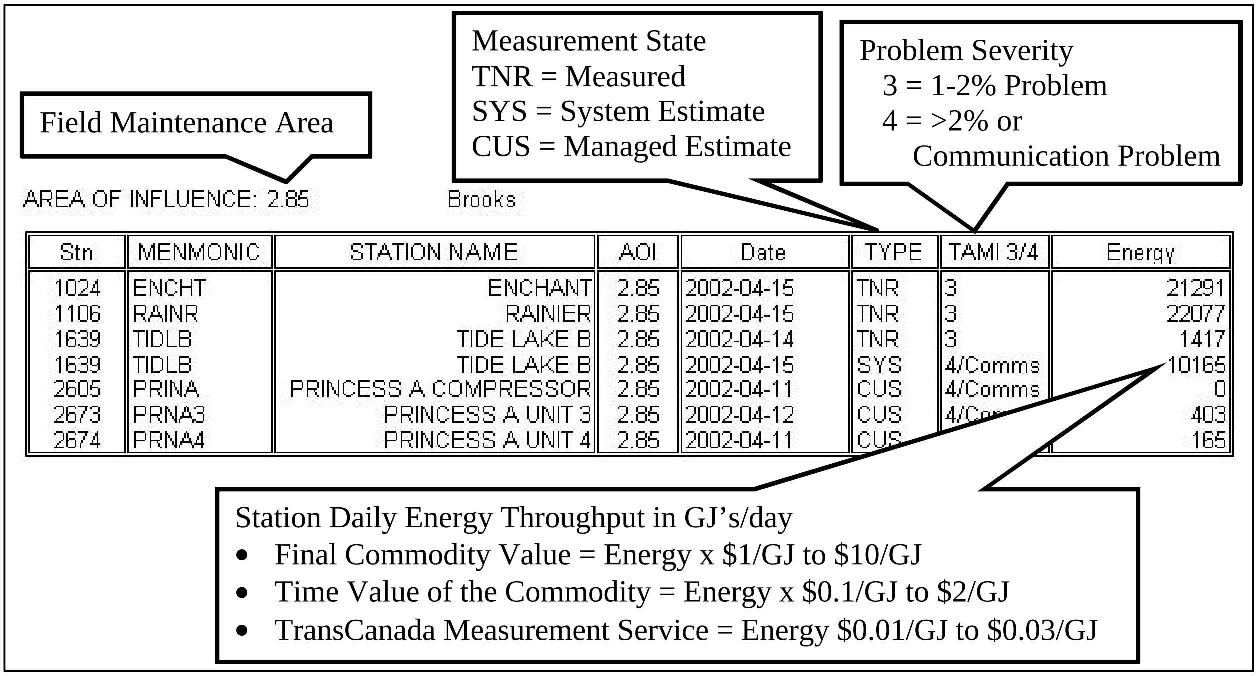
### *Analysis and Management of Measurement Problems*

Field technicians review the measurement state and validation information for their facilities at the start of each workday. (See *“TransCanada Experience With Redundant Electronic Instrumentation”* below for details of the validation process and problem categorization.) They mitigate the impact of the identified measurement problems on the business process by using the influence process to select available redundant measurement to finalize it or manage the measurement estimate to an acceptable value until the measurement can be finalized.



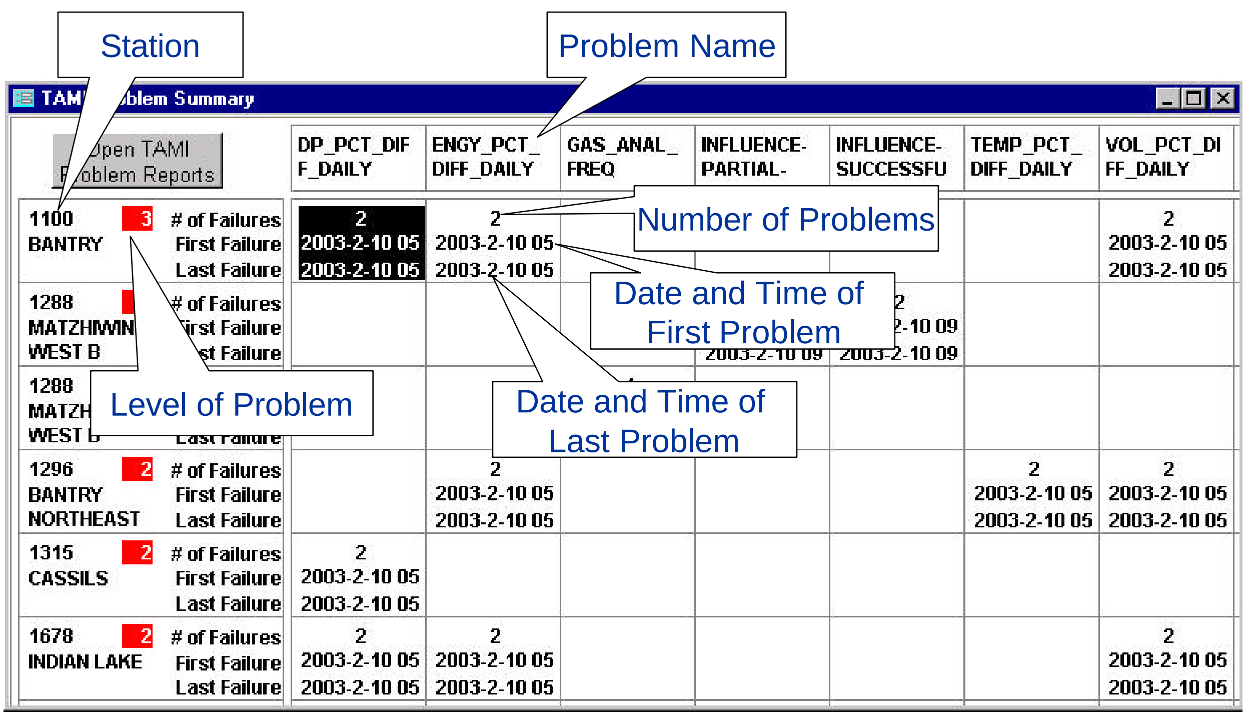

The Data Management Process

Their next task is to prioritize and schedule any required corrective action. (ie as plate changes or transmitter calibration) This prioritization is based on the size of the facility (daily energy) and the severity of the validation problem.




| Stn | MENMONIC | STATION NAME | AOI | Date | TYPE | TAMI 3/4 | Energy |
|---|---|---|---|---|---|---|---|
| 1024 | ENCHT | ENCHANT | 2.85 | 2002-04-15 | TNR | 3 | 21291 |
| 1106 | RAINR | RAINIER | 2.85 | 2002-04-15 | TNR | 3 | 22077 |
| 1639 | TIDLB | TIDE LAKE B | 2.85 | 2002-04-14 | TNR | 3 | 1417 |
| 1639 | TIDLB | TIDE LAKE B | 2.85 | 2002-04-15 | SYS | 4/Comms | 10165 |
| 2605 | PRINA | PRINCESS A COMPRESSOR | 2.85 | 2002-04-11 | CUS | 4/Comms | 0 |
| 2673 | PRNA3 | PRINCESS A UNIT 3 | 2.85 | 2002-04-12 | CUS | 4/Co | 403 |
| 2674 | PRNA4 | PRINCESS A UNIT 4 | 2.85 | 2002-04-11 | CUS | | 165 |

Summary Report for One Maintenance Area, With Problem Type, Severity and Impact




Summary Crosstab of GMS Problems by Station and Validity

## TransCanada Experience With Redundant Electronic Instrumentation

Analysis of monthly routine electronic re-calibration and detection of calibration problems based on Primary to Check comparison identified four significant findings:

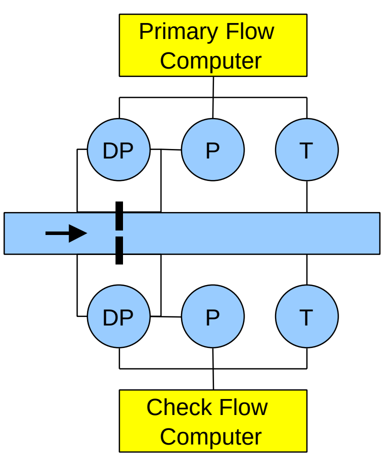
- electronic calibrations enabled tracking calibration drift over time (The original calibration table of engineering values to A/D values can be compared to future calibrations done over the entire life of the facility unless the transmitter or transmitter range is changed)
- analysis of calibrations over a three year time-frame indicated no significant calibration drift as long as there was no mechanical adjustment of the transmitter, no calibration problems caused by liquid or hydrocarbon contamination of the transmitter cell and no transmitter failure
- routine monthly re-calibration caused more calibration problems that they fixed (The majority of re-calibrations didn't cause a problem, but ones that created a calibration problem exceed those correcting a calibration problem by a factor of between 2:1 and 10:1)
- primary to check comparisons identified all significant calibration problems

These findings enabled TransCanada to transition in 1997/98 from routine re-calibration and manual validation to exception based maintenance comprised of primary to check comparisons and automated validation. Each hourly measurement is validated and categorized into one of the following four levels:

- Level 1 - Data is good and considered "Final" (Primary to Check within +/- 0.5% on energy)
- Level 2 - Data is good but is approaching the maintenance threshold and requires investigation. It is considered "Final" (Primary to Check > +/- 0.5% but < +/- 1% on energy)
- Level 3 - Data may change because it exceeds the maintenance threshold and requires remedial maintenance with-in 1 working day. It is "not Final" (Primary to Check > +/- 1% but < +/- 2% on energy) but is better than an estimate.
- Level 4 - Data will change because it exceeds the maintenance threshold, requires interim management immediate and remedial maintenance with-in 1 working day. It is "not Final" (Primary to Check > +/- 2% on energy) and a station estimate is used as "Best Station Data" (BSD).

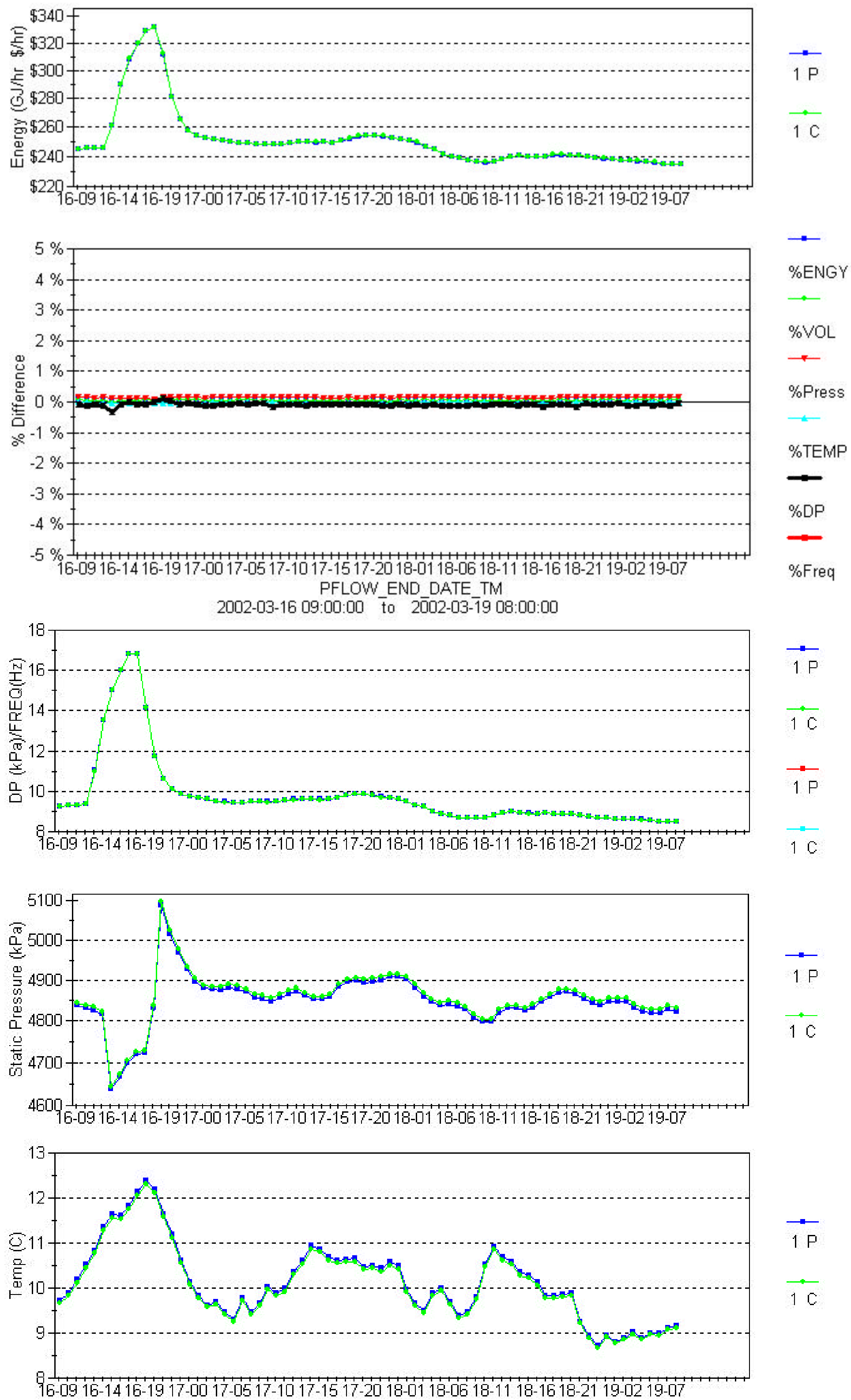
### *Primary to Check Validation of Orifice Check Measurement Systems*

TransCanada employs automated check measurement systems at its orifice meter stations. At these stations, one set of pressure transmitters is connected to each of the two pressure taps located on each side of the orifice meter. The transmitters in turn are connected to their own flow computer to perform independent flow calculations. This information is communicated hourly to TransCanada's central Gas Measurement System where comparisons are performed to validate energy, volume, pressure, temperature and differential pressure on an hourly/daily basis. (See figure below for hourly % and process comparisons.)



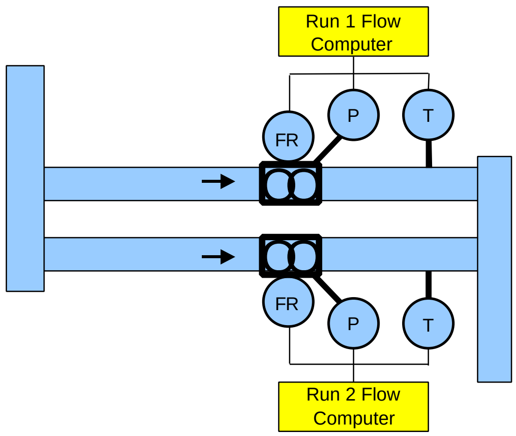
Monday, February 24, 2003 Hourly % Difference Page 1

STN NO: 1631 1P Compared to 1C MNEMONIC: ACADE ACADIA EAST



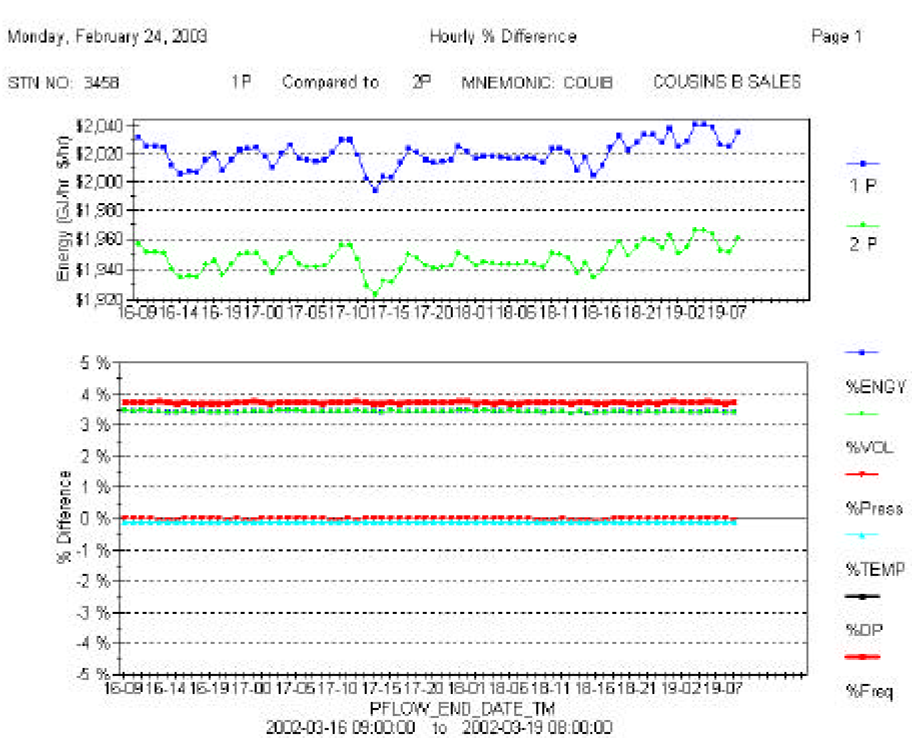

Primary to Check - % Difference/Process Comparison

## *Base Run Validated Against Other Runs on Multi-Run Stations*

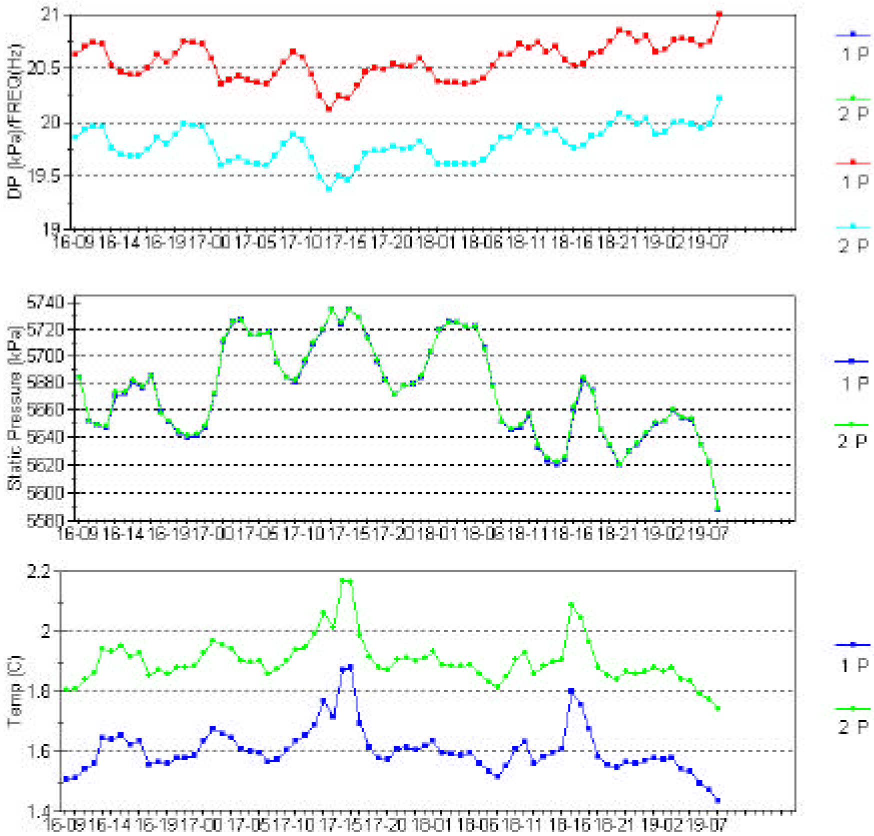



At multi-run Turbine and Ultrasonic meter stations, check measurement is based on automated Run to Base Run comparisons. One set of pressure and temperature transmitters is installed on each meter run. The transmitters and the pulse output from the meter are connected to a minimum of two independent flow computers. By maintaining a minimum of two runs in service, the flowing runs can be validated against the base run. The Gas Measurement System collects data from these facilities on an hourly basis and directly compares pressure and temperature readings. The volume, energy and frequency are compared between the flowing runs and the base run using the historical flow split for the meter station.

If one of the flow computers fails, the historical flow split is also used to estimate its flow. This practice increases the reliability of measurement for use in the “near time” business processes and provides for flexibility in scheduling equipment repair.



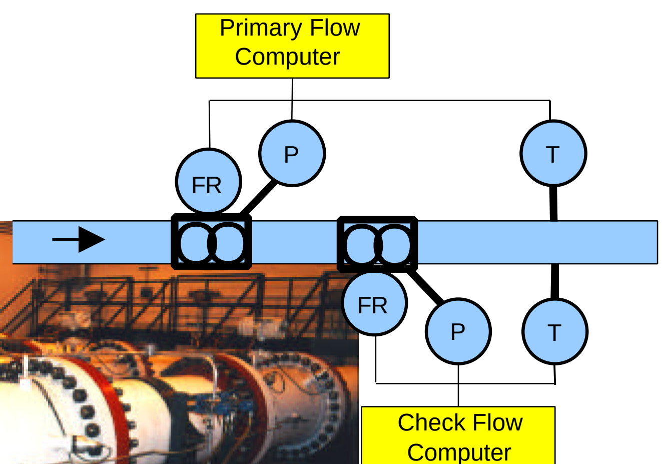

Run 1 to Run 2 % Difference Comparisons

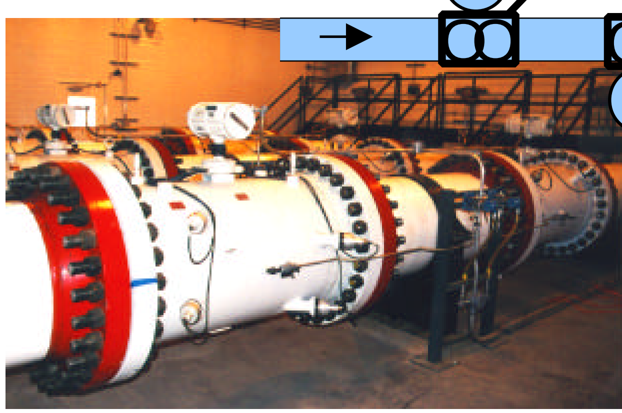


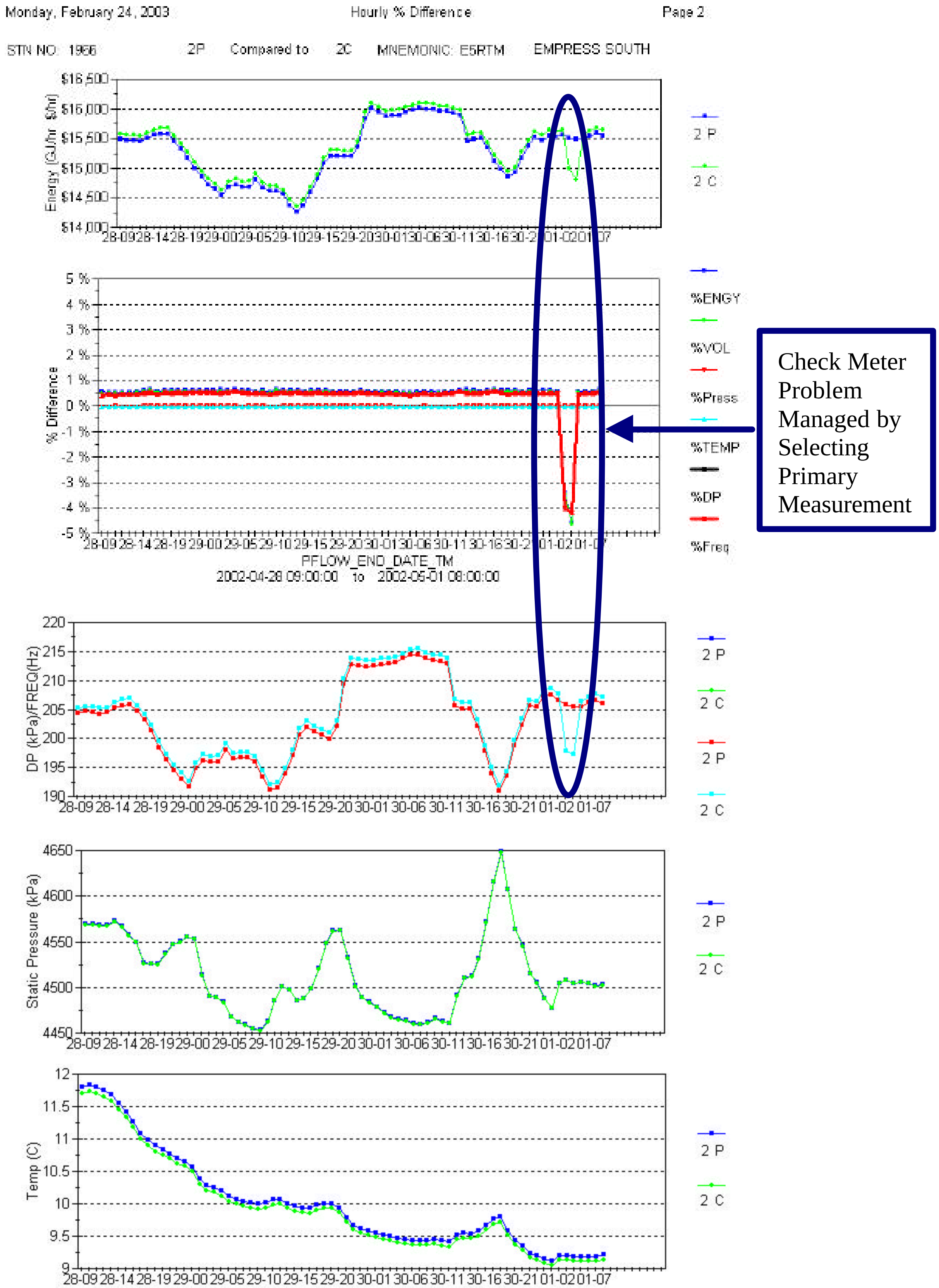

Base Run to Run Frequency/Pressure/Temperature Comparisons

### *Primary to Check Validation of Series Meter Check Measurement*

At large Ultrasonic meter stations, check measurement is based on series meter and instrumentation comparisons. One set of pressure and temperature transmitters is installed on each meter and connected, along with the pulse output from the meter, to two independent flow computers. The Gas Measurement System collects data from these facilities on an hourly basis and directly compares pressure, temperature, volume, energy and frequency.



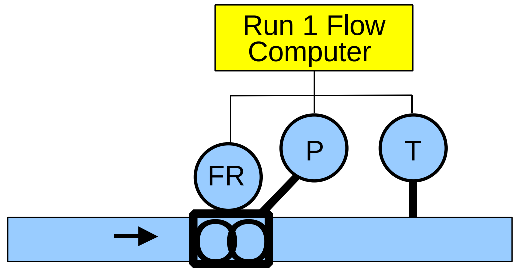



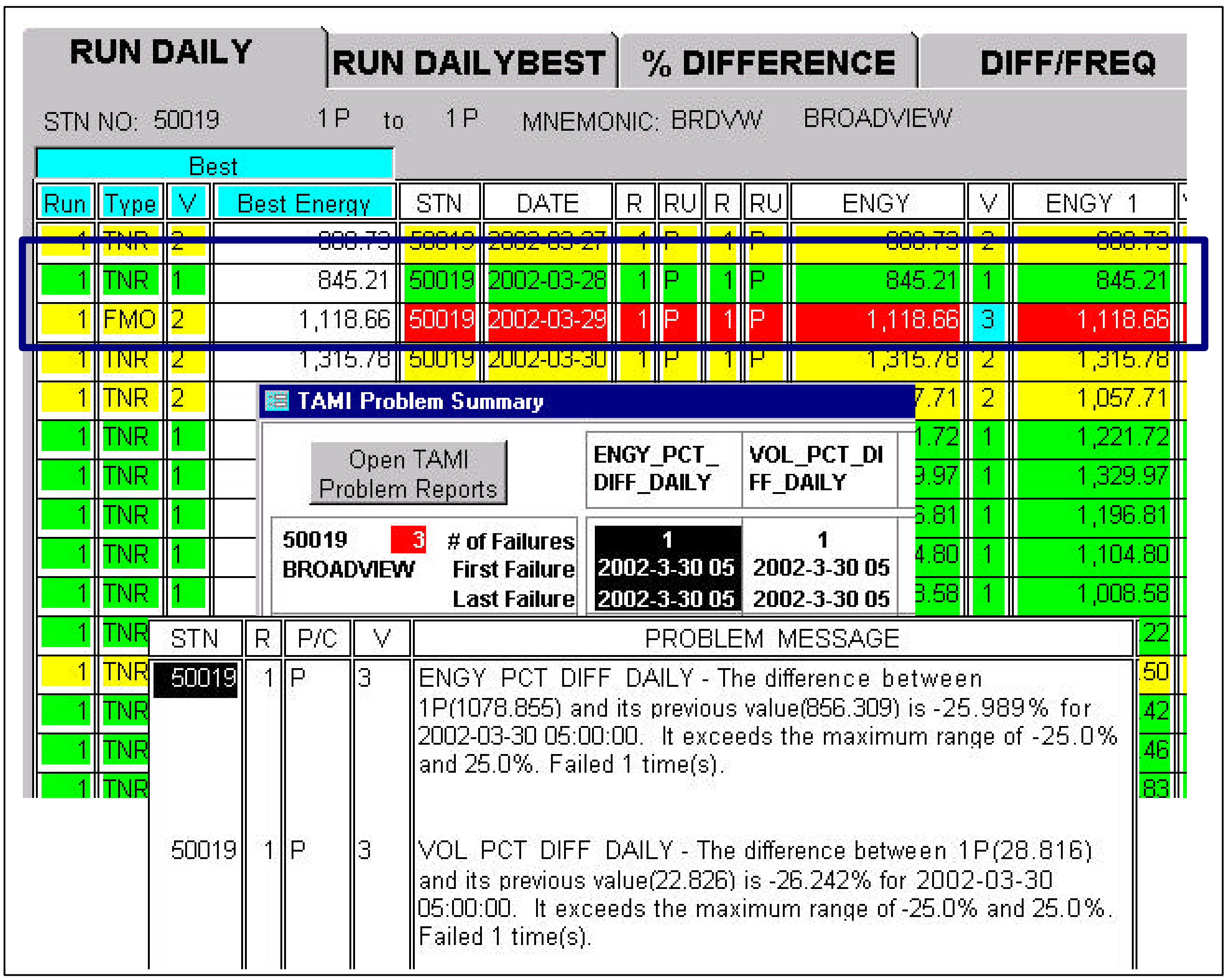



Primary to Check Ultrasonic Meter Comparison Data

## *Validation Single-Run Previous Day Check Measurement Systems*

At small volume meter stations, the expense of additional transmitters and flow computers is not economical. Validation checks are still done based on comparison of the current hour and day pressure, temperature, volume, energy and frequency values to the previous hour and day values.



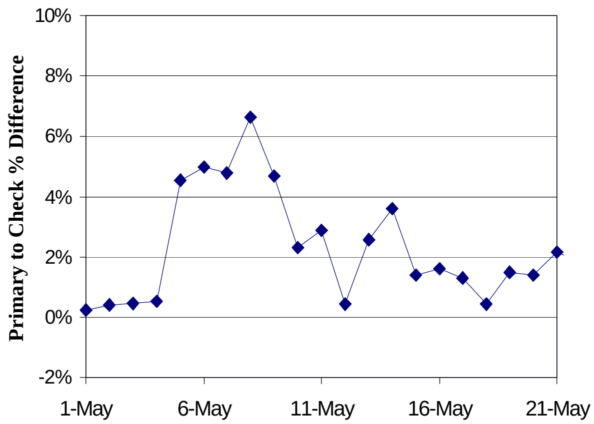




Validation Reports for a Single Run – Previous Day Measurement Check

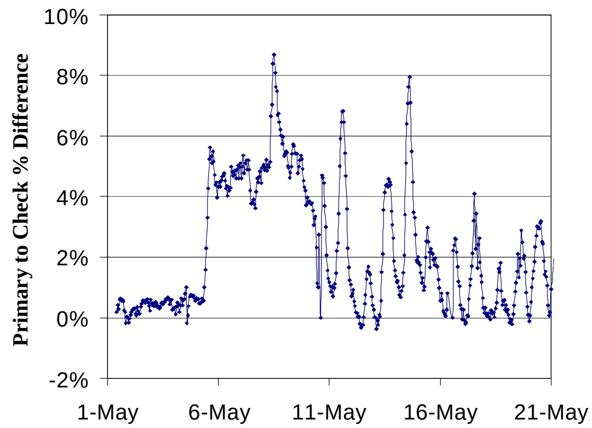
## *Examples of Problems Identified by Primary to Check Validation and Their Diagnoses*

### Pulsation

The figures below are daily/hourly energy comparisons for an NPS 8 single run orifice facility located in close proximity to the producer. Comparison of the primary to check measurement identified an intermittent measurement problem caused by the gas plant compression and gauge line amplification of the flow pulsation.



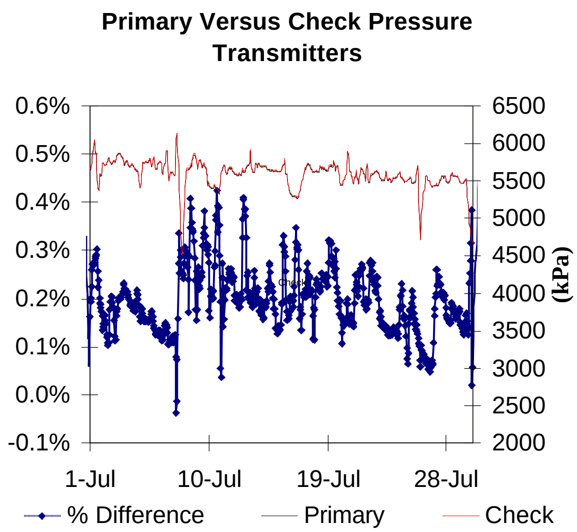

Daily Energy Comparisons

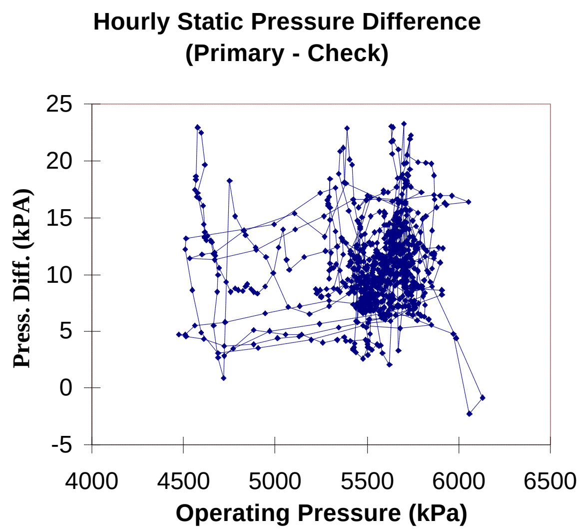



Hourly Energy Comparisons

### Identification of Static Pressure Transmitter Manufacturing Defects

A per cent difference comparison between a primary and check static pressure transmitter along with the static pressure. The per cent difference comparison fluctuated significantly even during periods of stable static pressure. This difference could not be attributed to calibration problems. Graphing the same data as an X-Y plot of the pressure difference versus operating pressure shows some interesting characteristics. Note the large build-up of pressure difference for a small pressure excursion on the left hand side of the “Differences Vs Pressure” graph below. Analysis of this problem resulted in the identification of Static Pressure Transmitters with manufacturing defects.



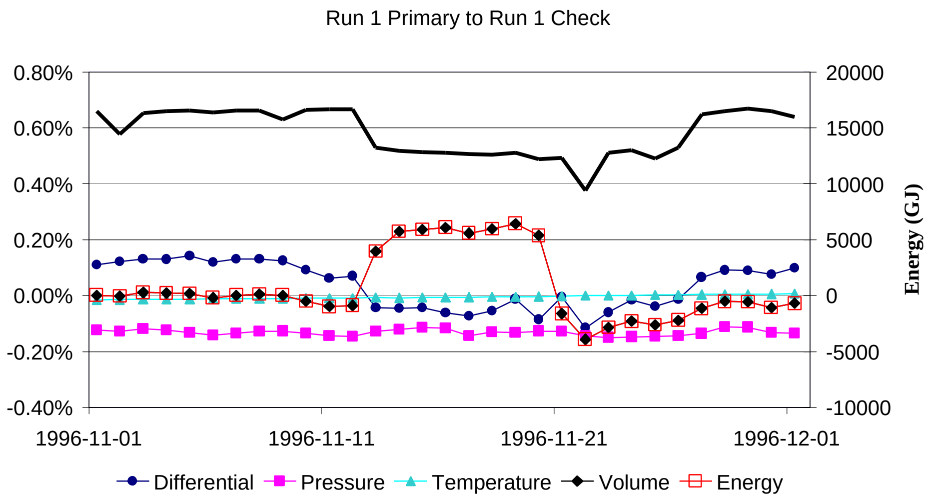



## Flow Computer Compressibility Algorithm Calculation Error

In normal operation the primary to check volume and energy comparisons can be estimated from the differential, pressure and temperature comparisons with the formula

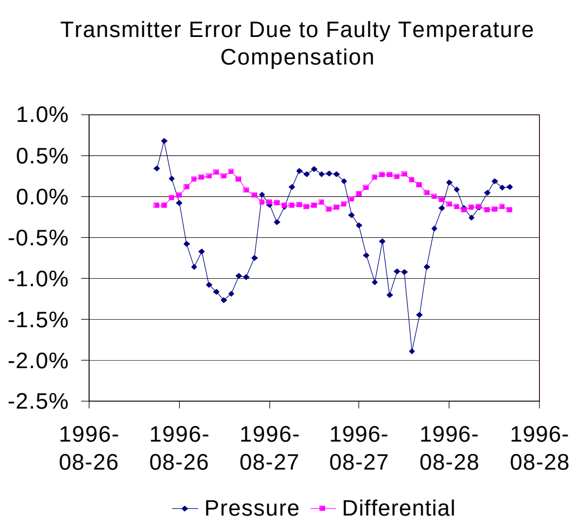
$$\% \text{ Volume or Energy} = \tfrac{1}{2}\,\% \text{ Differential} + \tfrac{1}{2}\,\% \text{ Pressure} - \tfrac{1}{2}\,\% \text{ Temperature}$$

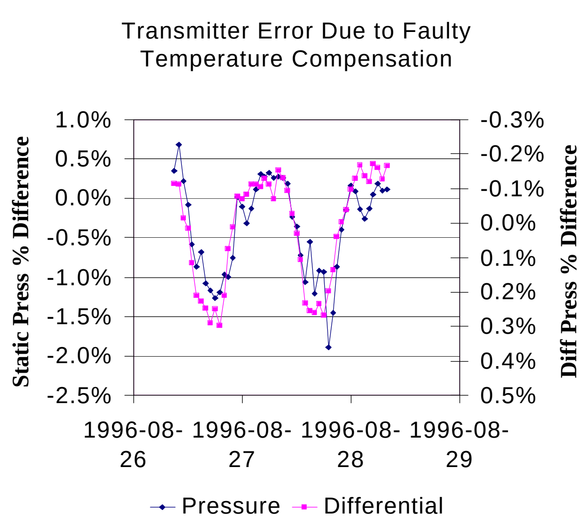
The above figure displays the % difference comparison between primary and check volume, energy, differential pressure, temperature and pressure. Note that from the 13th to the 21st the volume and energy didn't follow the expected pattern. This problem was traced to the compressibility calculation algorithm that didn't correctly re-calculate the coefficients unless temperature changed by >0.1 $^oC$ in 5 minutes.




## Faulty Temperature Compensation

Investigation of hourly comparison problems at a number of sites during a Fall cold snap identified significant correlation of transmitter primary to check comparison with temperature cycling. The figure below on the left shows the correlation in both pressure and differential pressure transmitter a one facility. By scaling differential pressure and plotting the comparison in reverse order the correlation is more evident in the figure below on the right. The problem was tracked to a temperature compensation manufacturing problem.

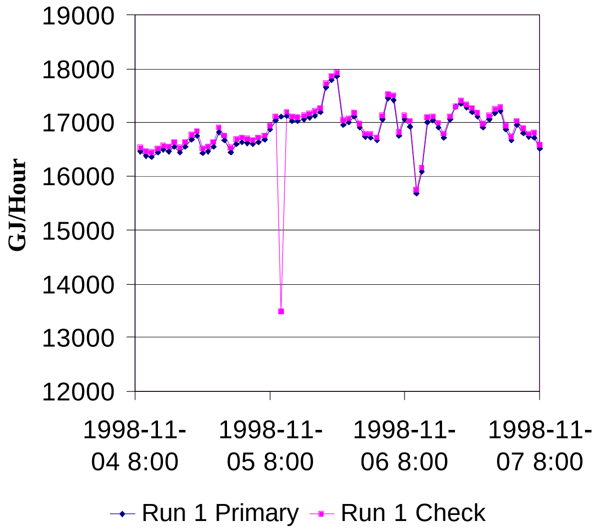


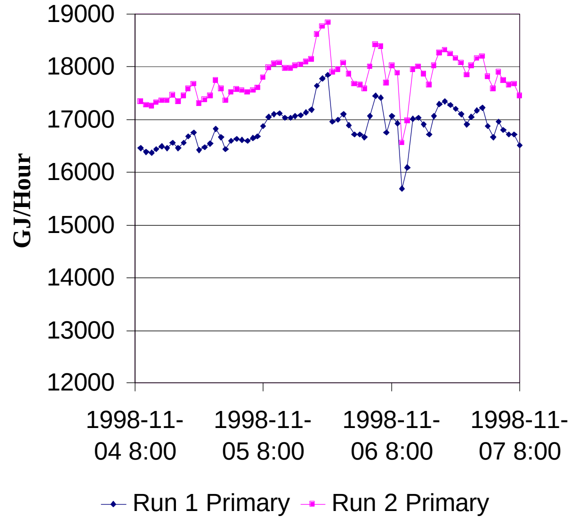
## Single Path Ultrasonic Operating Problem

To minimize the risk of installing a three run NPS 30 multi-path ultrasonic measurement facility with daily metering capacity of 1,500 TJ/day, series single path ultrasonic meters were installed and configured as check measurement.

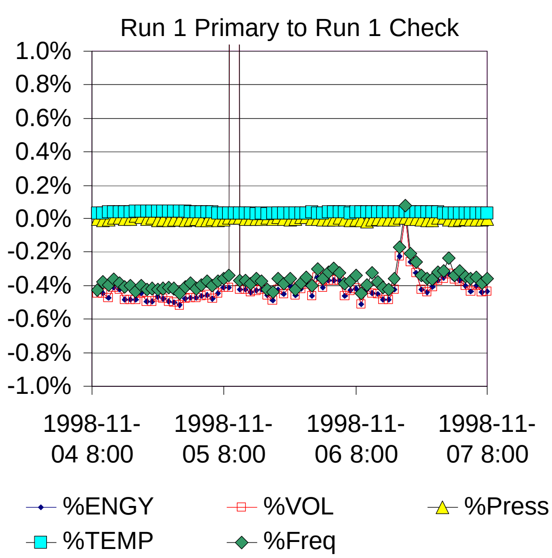
This design identified a periodic failure of each of the three single path ultrasonic meters due to electronic rejection of a low strength signal for a portion of an hour. The raw Run 1 Primary to Check comparison shows a significant drop in the check energy which is confirmed by the Run 1 Primary to Check % difference comparisons below it. The two figures on the right show the same information for the primary measurement on runs 1 & 2. Notice that the flow in run 1 follows run 2 for the hour in question, confirming a run 1 check meter problem.



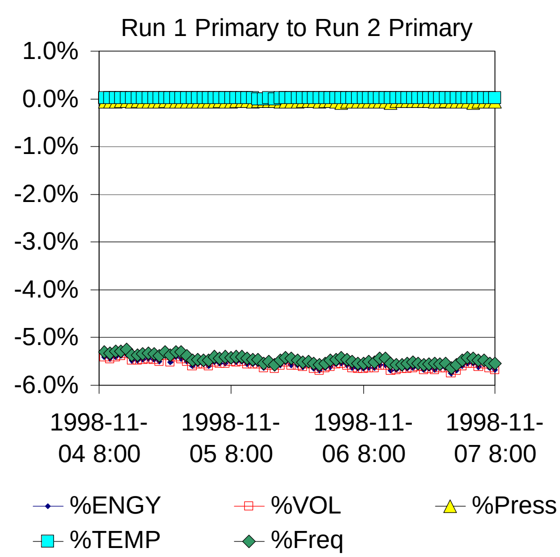

Primary to Check Energy Comparison




Run to Run Energy Comparison




Run 1 Primary to Check % Comparison




Run 1 to 2 Primary % Comparisons

## Conclusion

Measurement plays a key role in TransCanada’s daily operation and the custody transfer of over 11,000 TJ’s of gas on a daily basis. It’s “near time” availability and accuracy enables the 350+ customers on our system to track and manage their gas transportation 24 hours/day $365^{1}/_{4}$ days/year, to meet the demanding energy market needs. Producers, transporters, consumers and government also use this custody transfer information to account for billions of dollars of natural gas transfer annually.

### References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