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DUKE POWER

September 15, 1994

U. S. Nuclear Regulatory Commission
Washington, D. C. 20555

Attention: Document Control Desk

Subject: McGuire Nuclear Station
Docket Numbers 50-369 and -370
Catawba Nuclear Station
Docket Numbers 50-413 and -414
Technical Specification Revision to Change Method of Measuring Reactor Coolant System Flow Rate; Supplemental Information

By letter dated January 10, 1994, Duke Power Company submitted a license amendment application to change the method by which reactor coolant flow is measured for Technical Specification surveillances at McGuire and Catawba Nuclear Stations. The Staff responded with a request for additional information (Reference letter, May 3, 1994, R. E. Martin to M. S. Tuckman). Enclosed are responses to the questions presented in the RAI.

Please note that Attachment 1 to the Enclosure contains information which is proprietary to Westinghouse Electric Corporation. This information, together with affidavits supporting the proprietary designation, was originally submitted in support of license amendments to remove the RTD Bypass System at McGuire (submittal dated October 25, 1985) and Catawba (submittal dated July 22, 1987). This present calculation, to support the change of RCS flow rate measurement technique, uses many of the same data, which are considered to remain proprietary. These data are indicated by brackets. Those numbers which were developed by Duke to support this submittal need not be considered proprietary. Attachment 1a of the Enclosure contains a non-proprietary version of Attachment 1.

Please note also that margin to the Technical Specification minimum flow limit at McGuire and Catawba remains small; Catawba Unit 1 has already failed to meet minimum flow as measured by the present method, and has received approval to use the proposed method for the current cycle; this approval allowed the unit to reach 100% power after being restricted to 98% for several weeks at the beginning of the cycle. Both of these units will face RCS flow measurements in the upcoming months. It is requested, therefore,

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that review of this amendment request proceed as expeditiously as Staff resources will permit, to minimize potential derating caused by inadequate measured flow.

If any additional information is required, please call Scott Gewehr at (704) 382-7581.

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REQUEST FOR ADDITIONAL INFORMATION
REACTOR COOLANT SYSTEM (RCS) FLOW MEASUREMENT METHODOLOGY

(1) **How are the elbow tap transmitters calibrated? What is the elbow tap transmitter calibration experience at Catawba and McGuire? The question pertains to changes found during calibrations, the condition of the transmitters and connecting tubing, and procedures pertinent to the calibration.**

Response to Question 1:

The reactor coolant flow transmitters at Catawba and McGuire are calibrated each 18 months per Technical Specification 3/4.3, typically each refueling outage. The method used for calibration is a standard technique which is used for all I&C equipment. Two techniques are available for use in calibration of the transmitters, the wet rig (wet calibration) or the dry calibration (evacuation of all liquid in transmitter cell and apply direct pressure). Standard calibration procedures and practices are followed to ensure transmitter calibration accuracy. Transmitter calibration and data collection requires the disconnecting of instrument tubing from the transmitter for the connection of calibration equipment. This may allow small amounts of air to be introduced to the impulse lines and transmitter when using either of the above techniques. This small amount of air will not affect the accuracy of the calibration since the air will rapidly be absorbed by the highly pressurized (>2000 psia) reactor coolant system.

The experience at McGuire and Catawba with the elbow tap transmitter drift shows that the transmitter drift from cycle to cycle is generally very small. Since "as found" and "as left" data is recorded during each calibration of these transmitters, excessive drift in individual transmitters can be detected and evaluated to determine if a transmitter should be repaired or replaced. To date, no excessive transmitter drift has been noted. Some minor adjustments are made during the calibration to "tighten up" the transmitter output even though it may not be out of tolerance; and relatively few failures have occurred which have required transmitter replacement.

(2) **What is the uncertainty associated with the indicated differential pressure, including tubing run influence, the transmitter, and any other data processing that is used in the management of data between the transmitter and the point-of-use.**

Response to Question 2:

Since no coolant flow is occurring in the instrument tubing between the taps and the transmitter, tubing run influences have little if any effect and are not a concern. As discussed in the response to question 1 above, small amounts of air which may be introduced into the instrument tubing will not affect the calibration accuracy. The uncertainties associated with the flow measurement channels are provided as a response to questions 14 & 15 below.

(3) **In regard to hot leg temperature nonuniformities:**

- **Please provide whatever information is available to the licensee regarding the expected temperature distribution in the hot leg as a function of power and as a function of core loading (including burnup).**

- **What is the experience of "thermal/flow" switching in the upper plenum as it affects hot leg temperatures? What is understood regarding this phenomenon?**

- **How are differences between true average temperature and indicated temperature considered in using temperature data as indicated by the RTDs during operation? For example, what is done to compensate for changes between indicated temperature and average temperature with respect to reactor trip and the other uses of hot leg temperature for plant operation?**

Response to Question 3:

The only information available regarding the temperature distribution in the hot leg is from the hot leg RTDs themselves. This information does not provide enough data points to give an accurate temperature profile. The RTD temperature data indicates that the temperature in the upper section of the hot leg pipe is hotter than the lower section. This is interpreted to indicate that the hotter water exiting from the central region of the core is turning without significant mixing and entering the hot leg upper half. Similarly, the colder water in the periphery regions of the core is turning without significant mixing and entering the lower half of the hot leg. The calorimetrics which have been performed at the end of a cycle indicate, as expected, that the flattening of the temperature profile due to burnup does cause a change in the hot leg streaming such that the calculated flows increase from the beginning of cycle calculated flows. This confirms the expectation that changes in the hot leg temperature profile are related to changes in the core exit temperature profile.

The phenomenon of thermal/flow switching in the upper plenum has occurred at McGuire Unit 1 and Catawba Unit 2. What is understood about this phenomenon is that for whatever reason hot and cold water is "switched" between adjacent loops causing a spike in temperature indications from one or more RTDs in the adjacent hot legs. This phenomenon has been observed primarily in Westinghouse plants with inverted top hat upper internals assemblies and is an aperiodic short lived phenomenon, usually lasting only a few seconds to a minute in duration. The upper plenum thermal/flow switching is characterized by a short lived increase in the indicated Thot average in one loop of an adjacent loop pair and a simultaneous decrease in the indicated Thot average of the other loop in the pair. In addition, similar but smaller temperature changes are observed by the cold leg RTDs after the appropriate loop transit time. This indicates that the temperature changes caused by this anomaly are real and caused by the actual change in hot leg water temperatures resulting from the thermal/flow switching.

No changes or corrections to the indicated RTD temperatures is made to compensate for the potential difference between indicated Tavg and actual Tavg during plant operation. The other primary uses for temperature data as indicated by the RTDs during plant operation is the reactor control system and the overtemperature ΔT (OTΔT) and

overpower ΔT (OPΔT) trip setpoints. The reactor control system uses an indicated auctioneered high Tavg to control the movement of the control rods. Thus, rod control will be conservatively performed utilizing the loop with the highest indicated Tavg. An increase in hot leg streaming will likely cause an increase in indicated Tavg for a particular loop resulting in the plant being controlled to an indicated Tavg which is higher than the actual plant Tavg. This is conservative with respect to DNB and fuel centerline temperature protection events. Events where low Tavg may be a concern have been evaluated and found to be sufficiently conservative for an indicated Tavg $\leq$ 1.0 °F higher than the actual Tavg. A higher indicated Tavg and lower actual Tavg is conservative with respect to the OTΔT and OPΔT trip functions since during a transient, when the indicated Tavg reaches the trip setpoint, the actual Tavg will be less than the setpoint, providing additional margin to DNB.

(4) **What is the licensee's experience regarding cold leg temperature nonuniformities? If cold leg temperature differences have been observed, what is the source of those differences?**

Response to Question 4:

McGuire and Catawba have one cold leg RTD located in the top and one spare RTD located at various angles, depending on the particular unit and coolant loop, from the top of each cold leg pipe downstream of the reactor coolant pump. These RTDs generally indicate cold leg temperatures within ± 1.0 °F of the cold leg average temperature as calculated from the average of the two RTDs. This small difference in temperature is probably attributable to some small temperature gradient, originating from the different steam generator tube lengths in the bundle, passing through the reactor coolant pump, or possibly some gradient attributable to the pump itself such as pump heating or centrifugal force on water with varying densities. Generally, for an individual loop, these cold leg temperatures change in unison with one another, usually related to actual temperature changes. Any streaming effect in the cold leg is small and the temperature differences between RTDs do not appear to change significantly from cycle to cycle.

(5) **Are there any performance data regarding before/after cleaning of the feedwater venturis? What is the basis for assuming the venturi characteristics do not change with time, assuming the venturis are clean? What is the quantitative effect of crud buildup?**

Response to Question 5:

Duke has never done any precision testing just before and then just after cleaning. The feedwater venturis are inspected during each outage before and after they are cleaned. The inspections have never detected any erosion around the upstream taps or on the venturi itself. The venturis have thus far been found to be smooth and unmarred by wear or corrosion, which would likely show up as pits and surface irregularities. As long as the venturis stay smooth and free of erosion, the flow characteristics will remain unchanged.

Crud buildup or venturi fouling results in an indication of higher than actual feedwater flow, which results in an indication of higher than actual secondary power, which results in

an indication of higher than actual RCS flow Since this is non-conservative with respect to RCS flow, corrections or allowances for venturi fouling are used to ensure the RCS flow is conservative. ASME flow nozzles are used as a standard to normalize the process feedwater venturi flow measurement and correct for fouling. These nozzles are periodically cleaned (typically once per fuel cycle depending on run time) and maintained in a clean condition by valving these nozzles out of service when not in use for testing. Confidence in our ASME flow nozzle characteristics/flow measurement is based on MNS & CNS nozzle calibration histories (which provide evidence that the nozzle discharge coefficient will return to its original value following cleaning), periodic cleaning/inspection of the nozzles and the fact that the nozzles are only placed in-service for testing purposes.

Fouling levels on the feedwater venturis have resulted in small increases (typically less than 0.5%) in calculated flow over the last couple of cycles. This low level of fouling accumulation is attributed to improvements in feedwater chemistry including the use of a reverse-osmosis filtering system.

(6) What data are used for determination of power level with respect to operation and plant control?

Response to Question 6:

Power level is determined by continuously performing a secondary side calorimetric on the plant computer. This is calculated using inlet feedwater flow, inlet feedwater temperature, and outlet steam pressure. Corrections are made for S/G blowdown and cycle heat losses and heat gains such as insulation losses and reactor coolant pump heat addition.

Feedwater venturi fouling is determined by trending various parameters such as turbine first stage pressure, main steam flowrate, feedwater pump suction flows and primary calculated power vs. secondary calculated power. When trends show an excessive amount of fouling, a fouling test is performed. This consists of valving in a precision set of ASME nozzles and comparing their reading with the feedwater venturi readings corrected for any inlet and outlet flows that occur in between. The amount of fouling measured by this test is input to the plant computer to correct the power calculation.

(7) What data are available to support a conclusion that the components exposed to water in the elbow tap differential pressure instrumentation do not change over the life of the plant? (The question does not apply to transmitters.)

Response to Question 7:

As discussed in the Technical Specification change submittal, specific phenomena which might affect the elbow meter repeatability were examined. These phenomena were found to have little if any short or long term effects on the repeatability of the elbow tap flow indications. Fouling as experienced with venturi meters is not a concern since the process which causes this fouling is not present in the cold leg elbow. Deposits in the RCS from impurities in the reactor coolant are expected to be small or nonexistent. Most deposits of impurities in the reactor coolant are expected to occur in the hottest portions of the RCS and in regions experiencing the lowest flow. Any deposits in the RCS piping willaffect the interior of all the RCS piping and not just the region of the elbow taps. This will cause a

real flow change and will be reflected in the elbow tap ΔPs. If preferential deposits were to occur in the region of the taps, the reduction in pipe diameter would be extremely small in comparison to the diameter of the cold leg elbow (31"). Fouling or deposits within the instrument tubing between the elbow tap and the differential pressure instrument is not a concern since no flow is transmitted within the tubing. In addition, erosion (flow accelerated corrosion) is not a concern since the velocity of the RCS fluid is small relative to velocities known to cause erosion in stainless steel. Erosion of the RCS piping will be small or nonexistent during plant life. Any changes in elbow diameter as a result of small amounts of erosion will not be significant with regard to the 31" diameter of the cold leg pipe. The elbow taps have been positioned on the elbow in such a manner that velocity pressure components and turbulence effects are minimized while not impacting the differential pressure indications. Since the piping between the elbow tap and the differential pressure instrument is used to transmit the pressure signal only, any velocity component of the turbulent RCS flow which is imparted to the tap location will result in random noise in the pressure signal.

Every attempt will be made to check for effects which may affect the calibration of the elbow meter. However, unless these effects are large, such as a plugged elbow tap, detec' on of small changes which will affect the calibration of the elbow taps will continue to be difficult since the effect on flow will be small and nearly undetectable. Comparisons to the analytical flow model prediction of flow will be used to determine the extent to which the elbow tap calculated flow reflects actual flow changes.

(8) Please provide a comparison of analyses and observed RCS loop/total flow rate behavior as determined from elbow tap differential pressure indications and from calorimetric testing for both Catawba and both McGuire units. Sufficient data should be used to establish that:

- **Changes during refueling outages, such as steam generator (SG) tube plugging, SG tube sleeving, and core changes are fully compared for the operating history of the plants.**

- **Behavior during operation is fully described.**

Use of differential pressure information of the type previously provided for parts of two cycles for Catawba Unit 1 to calculate flow rates for purposes of the comparison is acceptable. However, the staff requests a more extensive comparison for Catawba Unit 1 and also requests that the comparison be done for the other affected Duke plants. The flow rate comparison should be done on a "best estimate" basis.

In addition, please provide:

- **a description of the analysis used for the comparisons,**

- **discussion of differences between analysis and behavior based upon plant data, and**

- **discussion of differences in what appear to be identical loops, if such differences are observed.**

Response to Question 9:

Analytic RCS Flow Model Description

An accurate RCS flow prediction requires a model which can determine flow without relying on hot and cold leg temperature inputs. The reactor coolant flow may be calculated by first determining the system head loss curve for a reactor coolant loop with a given configuration. Once the system head loss curve has been established it is compared to the reactor coolant pump performance curve to determine the intersection of the two curves. The intersection of the two head curves will define the system operating point, the point where the loop system head loss matches the head produced by the reactor coolant pump. The flow is then obtained from the pump flow/head curve. By establishing the system head losses for each loop and accounting for changes in these system losses due to plant changes over time, e.g., steam generator tube plugging, modifications and different fuel designs, a reasonably accurate RCS flow, and therefore the change in flow due to system changes, may be calculated for each plant configuration.

The first step in calculating the RCS flow is to determine the system head loss for a given assumed flow. Table 1 lists the pressure drops for the RCS except for the steam generators.

Table 1
RCS Loop Pressure Drops

Loop Section	ΔP, psi	Reference Flow
Hot Leg	2.09	10,277 lbm/sec/loop
Pump Suction 40° Elbow	1.18	10,277 lbm/sec/loop
Pump Suction Straight Pipe	0.31	10,277 lbm/sec/loop
Elbow Tap 90° Elbow	1.28	10,277 lbm/sec/loop
Pump Suction 90° Elbow	1.28	10,277 lbm/sec/loop
RCP Weir Plate	2.0	100,900 gpm/loop
Cold Leg	2.54	10,277 lbm/sec/loop
Inlet Nozzle	10.01	10,277 lbm/sec/loop
Downcomer	0.36	39,587 lbm/sec
Downcomer exit	2.68	39,587 lbm/sec
Core Support	2.20	39,587 lbm/sec
Lower Core Plate	7.24	39,587 lbm/sec
Bottom Nozzle	3.2	101,700 gpm/loop
Core	17.3	101,700 gpm/loop
Top Nozzle	1.1	101,700 gpm/loop
Upper Core Plate	3.99	39,587 lbm/sec
Outlet Nozzle	2.33	10,277 lbm/sec/loop
Thermal Driving Head	-1.30	10,277 lbm/sec/loop

These pressure drops are adjusted to account for the flow differences between an assumed flow and the reference flow by multiplying a ratio of the flows squared to the above pressure drops as shown below.

Since $\Delta P \propto \text{Flow}^2$

$$\Delta P_{new} = \Delta P_{old}\left(\frac{\text{New Flow}}{\text{Reference Flow}}\right)^2$$

This adjustment of the pressure drops is made for all the above pressure drops except the thermal driving head, which is assumed to be relatively constant for full power operation.

In addition to the above adjustments to the primary side pressure drops, adjustments are also made to account for changes in plant configurations, i.e., barrel baffle region downflow to upflow modification, converting from Westinghouse OFA to Mark BW fuel, etc.

McGuire Units 1 & 2 were originally designed with downward RCS coolant flow in the barrel baffle region. This downward flow parallels the downcomer and produced undesirable baffle jetting due to the differential pressures between the barrel baffle region and the core region. The core barrels were modified such that the flow in the barrel baffle region is in the upward direction parallel to the core flow. The changes in the ΔPs as a result of this modification were largely due to the changes in flow distribution in the downcomer and core regions. The plugging of holes in the upper core barrel might have changed the pressure drop in the downcomer region slightly, but since the pressure drop in the downcomer is small (0.18 psi), the change in pressure drop due to plugging these holes is therefore not significant and the change in pressure drop is neglected. Holes plugged in the lower core plate are in the barrel baffle region around the periphery of the lower core plate and do not change the geometry of the plate in the core flow path. Therefore, changes in the ΔPs for the lower core plate are made by adjustments to the core flow fraction. The flow fractions used to adjust the ΔPs in the downcomer and the core regions are given in Table 2 below for McGuire Units 1 & 2.

Modification of the McGuire Units 1 & 2 reactor vessel core barrels from an upflow configuration to a downflow configuration were accounted for after the Unit 1 end of cycle 7 refueling outage and Unit 2 end of cycle 6 refueling outage.

Table 2
McGuire RCS Flow Fractions

	Downflow Configuration Flow Fraction		**Upflow Configuration Flow Fraction**	
Unit	**Downcomer**	**Core Region**	**Downcomer**	**Core Region**
McGuire Unit 1	0.963	0.925	0.964	0.931
McGuire Unit 2	0.963	0.925	0.963	0.930

Catawba Units 1 & 2 were designed with an upflow barrel baffle region and therefore no adjustment to the downcomer and core region ΔPs is necessary. The flow fractions for Catawba Units 1 & 2 are given in Table 3 below.

Table 3
Catawba RCS Flow Fractions

	Downcomer	Core Region
Catawba Units 1 & 2	0.966	0.943

Adjustments to the ΔPs in the core region are also made to account for different fuel designs. A new fuel vendor (B&W) is providing fuel for McGuire and Catawba Nuclear Stations which has replaced the original Westinghouse fuel. Since approximately 1/3rd of the core is replaced during a refueling outage, the cores consist of 1/3rd, 2/3rds, and full cores of B&W fuel as the new fuel is introduced. The B&W Mark-BW fuel with debris-trapping bottom nozzles (DTBN) has an approximately 2.4% lower pressure drop than the Westinghouse Standard and OFA fuel. The pressure drops for each fuel type at 101,700 gpm/loop are given in Table 4 below.

Table 4
Core Region Pressure Drops (Full Cores)

	Westinghouse Std & OFA ΔP, psi (from Table 1)	B&W Mark-BW w/DTBNs ΔP, psi
Bottom Nozzle	3.2	3.12
Core	17.3	16.88
Top Nozzle	1.1	1.07
Total	21.6	21.07

For cores with 1/3rd and 2/3rds Mark-BW fuel a weighted average of the pressure drops for each fuel type is used. The pressure drops used for each core configuration are given in Table 5 below.

Table 5
Core Region Pressure Drops (Partial Cores)

	1/3rd Mark-BW fuel ΔP, psi	2/3rds Mark-BW fuel ΔP, psi
Bottom Nozzle	3.17	3.15
Core	17.16	17.02
Top Nozzle	1.09	1.08
Total	21.42	21.25

The steam generator pressure drops are then calculated using the following input information and equations.

Table 6
Steam Generator Input For Pressure Drop Calculation

Flow rate, w	Assumed, gpm
ID of steam generator tube, D_{tube}	0.664 inches
Coolant average temperature	590.70 °F
Average fluid density, ρ_{avg}	43.94 lbm/ft^3 @2250 psia
Coolant inlet temperature	620.00 °F
Steam generator inlet fluid density, ρ_{in}	41.29 lbm/ft^3 @2250 psia
Coolant outlet temperature	561.30 °F
Steam generator outlet fluid density, ρ_{out}	46.12 lbm/ft^3 @2250 psia
Inlet nozzle ID, D_{inoz}	31.00 inches
Outlet nozzle ID, D_{onoz}	31.00 inches
Percent steam generator tube plugging	Initially 0.0
Number of steam generator tubes, n_{tube}	4,674 MNS-1, MNS-2, CNS-1 4,570 CNS-2
Friction factor, f	0.014
Average tube length, l_{tube}	55.9 ft MNS-1, MNS-2, CNS-1 686.64 in. CNS-2

The steam generator pressure drops are calculated using forms of the continuity equation and Darcy's formula given below.

Tube water velocity,

$$v_{tube} = 0.408\left(\frac{w/n_{tube}}{D_{tube}^{\ 2}}\right) ft/\sec$$

Inlet nozzle water velocity,

$$v_{inoz} = 0.408\left(\frac{w}{D_{inoz}^{\ 2}}\right) ft/\sec$$

Outlet nozzle water velocity,

$$v_{onoz} = 0.408\left(\frac{w}{D_{onoz}^{\ 2}}\right) ft/\sec$$

Pressure drop in tubes,

$$\Delta P_{tube} = 0.000216 \times f \times l_{tube} \times \rho_{avg} \times \frac{(w/n_{tube})^2}{D_{tube}^{5}} \ psi$$

The friction factor, f, is obtained from a friction factor chart utilizing the information below:

$\varepsilon(\text{drawn tubing}) = 0.000005$

$$\frac{\varepsilon}{D} = \frac{0.000005}{0.664\ in./12\ in/ft} = 9.0 \times 10^{-5}$$

f = 0.012 for completely turbulent flow

Tube entrance & exit pressure drop,

$$\Delta P_{ent} = (K_{in} \times 0.0001078 \times \rho_{in} \times v_{tube}^{2}) + (K_{out} \times 0.0001078 \times \rho_{out} \times v_{tube}^{2}) \ psi$$

where $K_{in} = 0.50$ and $K_{out} = 1.0$

SG nozzles pressure drop,

$$\Delta P_{sgnoz} = (K_{in} \times 0.0001078 \times \rho_{in} \times v_{inoz}^{2}) + (K_{out} \times 0.0001078 \times \rho_{out} \times v_{onoz}^{2}) \ psi$$

where $K_{in} = 0.427$ and $K_{out} = 0.266$

The steam generator tube pressure drops are affected by the number of tubes plugged and/or sleeved during each outage. Plugging and sleeving of tubes in the steam generators causes a reduction in the flow area which results in an increased pressure drop across the steam generator tubes. The number of tubes plugged and/or sleeved expressed as a percentage of steam generator tubes (4674 for McGuire Units 1 & 2 and Catawba Unit 1 and 4570 for Catawba Unit 2) is used to calculate the flow area through the steam generators in each loop. The calculated steam generator tube plugging percentage assumes that 18 sleeves are equivalent to 1 plugged tube. The steam generator tube plugging performed through the Technical Specification revision submittal date for McGuire and Catawba are given in Tables 7 - 10 below.

Table 7
McGuire Unit 1 SG Tube Plugging Percentages

OUTAGE	EOC	Equiv Cum Plug A %	Equiv Cum Plug B %	Equiv Cum Plug C %	Equiv Cum Plug D %	Equiv Cum Plug % Tubes
Aug-81		0.428	0.449	0.428	0.428	0.433
Mar-82		0.471	0.449	0.428	0.428	0.444
Jul-82		0.492	0.449	0.428	0.428	0.449
Nov-82		0.599	0.449	0.449	0.428	0.481
Feb-83	1	0.642	0.449	0.449	0.428	0.492
May-85	2	0.642	0.492	0.471	0.449	0.513
May-86	3	2.696	2.546	2.567	3.231	2.760
Sep-87	4	3.252	3.659	2.931	4.044	3.471
Oct-88	5	3.851	4.236	3.594	4.878	4.140
Mar-89		4.172	4.750	3.937	5.285	4.536
Jan-90	6	4.516	6.005	5.991	6.062	5.643
Sep-91	7	5.281	6.585	6.384	6.610	6.215
Jan-92		6.133	7.651	7.560	7.270	7.153
May-92		7.841	8.079	8.330	8.253	8.126
Apr-93	8	8.587	9.382	9.269	9.833	9.268
Aug-93		9.528	9.874	9.739	10.67	9.953

Table 8
McGuire Unit 2 SG Tube Plugging Percentages

OUTAGE	EOC	Equiv Cum Plug A %	Equiv Cum Plug B %	Equiv Cum Plug C %	Equiv Cum Plug D %	Equiv Cum Plug % Tubes
May-83		0.021	0.000	0.000	0.000	0.005
Jan-85	1	0.021	0.000	0.000	0.000	0.005
Dec-85		0.021	0.000	0.000	1.070	0.273
Mar-86	2	2.460	2.439	2.482	2.503	2.471
May-87	3	3.209	3.338	3.124	3.231	3.225
Jun-88	4	4.086	4.086	4.236	3.487	3.974
Jul-89	5	5.327	4.792	4.942	4.536	4.899
Aug-90	6	5.512	5.079	5.229	4.710	5.132
Jan-92	7	5.874	6.023	5.616	5.450	5.741
May-92		6.128	6.279	5.872	5.705	5.996
Jul-93	8	7.305	7.306	6.621	6.754	6.996
Sep-93		7.669	8.141	6.941	7.075	7.456

Table 9
Catawba Unit 1 SG Tube Plugging Percentages

OUTAGE	EOC	Equiv Cum Plug A %	Equiv Cum Plug B %	Equiv Cum Plug C %	Equiv Cum Plug D %	Equiv Cum Plug % Tubes
Jun-85	0	0.064	0.150	0.043	0.064	0.080
Jan-86	1	0.064	0.150	0.043	0.064	0.080
Nov-87	2	0.064	0.150	0.043	0.064	0.080
Aug-88		0.064	0.150	0.043	0.107	0.091
Dec-88	3	0.492	0.385	0.300	0.513	0.423
Feb-90	4	2.204	0.471	1.284	1.626	1.396
Apr-91	5	2.598	0.941	4.151	2.884	2.643
Aug-92	6	4.438	1.562	6.025	4.104	4.032
Nov-93	7	6.953	3.466	11.168	10.056	7.911

Table 10
Catawba Unit 2 SG Tube Plugging Percentages

OUTAGE	EOC	Equiv Cum Plug A %	Equiv Cum Plug B %	Equiv Cum Plug C %	Equiv Cum Plug D %	Equiv Cum Plug % Tubes
Aug-86		0.175	0.175	0.175	0.175	0.175
Sep-86		0.197	0.328	0.197	0.284	0.252
Feb-88	1	0.284	0.350	0.197	0.328	0.290
Feb-89	2	0.328	0.460	0.219	0.328	0.334
Jun-90	3	0.525	0.481	0.263	0.481	0.438
Oct-91	4	0.678	0.481	0.350	0.503	0.503
Feb-93	5	0.985	0.613	0.635	0.722	0.739

The pressure drops calculated for each loop and steam generator are converted to a head loss using the equation:

$$Head,\ ft = \frac{\left(\Delta P\ psi \times 144 \dfrac{in^2}{ft^2}\right)}{\rho \dfrac{lbm}{ft^3}}.$$

The loop and steam generator head losses are then summed together to obtain a total system head loss around each loop. This total head loss is then used to calculate the flow at the point where the system head curve crosses the reactor coolant pump curve. The

point at which the two curves cross establishes the system operating flow for the given configuration.

The reactor coolant pump head/flow curves developed from hot performance data are given in Table 11 below. An equation for the pump curve is determined by fitting a curve to the data in the region of 50,000 to 130,000 gpm.

Table 11
Reactor Coolant Pump Head Curves

	McGuire Units 1 & 2 and Catawba Unit 1	Catawba Unit 2
Flow, gpm	Head, feet	Head, feet
0	516	519
10,000	495	509
20,000	470	484
30,000	437	447
40,000	409	410
50,000	391	395
60,000	380	382
70,000	384	387
80,000	366	371
90,000	329	339
100,000	284	292
101,000	279	286
110,000	234	240
120,000	184	181
130,000	127	122

A fourth-order curve fit was performed for each of the sets of data above in the region of 50,000 to 130,000 gpm and the resulting equations are:

McGuire Units 1 & 2 and Catawba Unit 1

$$y = 2231.8399x - 16.60783x^2 + 0.0486987x^3 - 0.0000519092x^4 + 28109.989$$

Catawba Unit 2

$$y = 1811.4992x - 14.082053x^2 + 0.0425535x^3 - 0.0000465846x^4 + 51565.277$$

The equations for the reactor coolant pump curves are used to calculate the flow that the pump can provide at the head loss determined for the input assumed flow. Since the system head must match the head produced by the reactor coolant pump, the input assumed flow is compared with the calculated pump flow to determine whether they match. If the flows do not match, a new assumed flow, halfway between the previous assumed flow and the calculated pump flow, is selected and the process is repeated until

the loop flows are equal. This defines the point where the system head curve intersects the reactor coolant pump head curve and defines the system flow for a given plant configuration.

Plant Data and Analytical Model Comparisons

McGuire Unit 1:

McGuire Unit 1 is the one unit that thus far does not appear to be greatly affected by the hot leg streaming phenomenon. The RCS flow as measured by the calorimetric has trended very closely to the changes in full power ΔT, as can be seen in Figure 1. In addition, the changes in RCS flow as determined by the calorimetrics has generally trended with the elbow tap ΔPs with some small hot leg streaming effects. The trends in flow as determined from the indicated elbow tap ΔPs (Figure 2) and the analytical flow model (Figures 4 & 5) are in good agreement with one another (Figures 4 & 5 differ only in the Y-axis scale with the scale on Figure 5 matching the scale of Figure 2 for easy comparison). The individual loop flows given in Figure 2 indicate an unequal loop flow distribution at McGuire Unit 1 since plant startup. Generally, this is the case for the other three Westinghouse units as well, and is likely the result of differences among the as-installed loop components, e.g., piping, steam generators, and reactor coolant pumps. However, the average of the individual loop flows in Figure 2 trend very close to the individual loop flows as given in Figure 5. In addition, the individual loop flows in Figure 2 show good agreement with the changes in flow expected as the result of plant changes. The loop flows in Figure 5 are almost identical during early plant life since the analytical model loop flows were determined using the same reactor coolant pump curve and loop geometry for all loops.

All elbow tap transmitters were replaced during the September 1987 EOC 4 refueling outage. This resulted in a step increase in the elbow tap ΔP indications from those of the previous transmitters (Note: the ΔP flows in Figure 2 have a correction included for calorimetric ΔPs before September 1987). Once corrected, the elbow tap ΔP flow (Figure 2) for early plant operation agrees well with the analytical model (Figure 5) and calorimetric (Figure 1) flows.

The upflow modification was made during the September 1991 EOC 7 refueling outage along with the introduction of the first batch of B&W fuel. The upflow modification was expected to change the RCS flow distribution through the core region slightly and not effect the total flow result significantly. The B&W fuel was expected to increase flow slightly due the decreased flow resistance in the core. The increase in flow due to the new fuel was expected to be offset by steam generator tube plugging. The flow in the plant as indicated by the elbow tap ΔPs actually increased slightly after this outage. This is likely due to the new fuel having a greater effect on the flow than anticipated and partially due to the analytical flow model assumption that 1/3rd of the core would be replaced when slightly more was in fact replaced ($\approx$ 40%). The April 1993 EOC 8 refueling outage resulted in a flow decrease as indicated by the calorimetric, elbow tap ΔP flow and analytic flow model, due to any flow increase from the second batch of B&W fuel being more than offset by substantial steam generator tube plugging.

Figure 6 shows the daily average elbow tap ΔP data for McGuire Unit 1 back to June 20, 1992. This data covers cycles 8 & 9 and has been modified to eliminate bad data and data at off power days (<99% power). The data shows that the elbow tap ΔPs are very steady with no major drifting trends when the transmitters are operating properly. Channel 1, Loops 1 and 3, transmitters failed during cycle 9 and were replaced during the last outage. The elbow tap data in Figure 6 shows changes due to SG tube plugging following the three outages during this time frame. Unit 1 went through a refueling outage from March, 1993 through June 1993 and steam generator outages from August 1993 through November 1993 and February 1994. The changes in loop flow resistances are reflected in the elbow tap ΔP changes corresponding to these time periods, with the largest change occurring after the February 1994 outage where significant SG tube plugging occurred.

McGuire Unit 2:

McGuire Unit 2 has experienced a significant flow impact as a result of hot leg streaming. The RCS flow as measured by the calorimetric has trended very closely to the changes in full power ΔT as can be seen in Figure 7. The calorimetric performed February 1985, just after the EOC 1 refueling outage, indicated a large increase in RCS flow which was not accompanied by significant plant changes. The large increase in flow was the result of a decrease in indicated ΔT of approximately 1 °F as can be seen on Figure 7. This decrease in ΔT was investigated by Duke and Westinghouse and found to be caused primarily by hot leg streaming changes and a reduction in thermal power caused by feedwater venturi fouling. For the same calorimetric the individual loop flows as determined by the elbow tap ΔPs (Figure 8) and the analytical flow model (Figures 10 & 11) do not show a corresponding increase in flow. Note, Figures 10 & 11 differ only in the Y-axis scale with the scale on Figure 11 matching the scale of Figure 8 for easy comparison. In addition, no changes in plant geometry (SG tube plugging, etc.) were made prior to this calorimetric which would indicate a significant flow increase or decrease (Figures 9 & 10).

The calorimetric flows following the February 1985 calorimetric have basically trended downward consistent with the increasing trend in ΔT, but in excess of that expected by plant geometry changes. Since plant startup the calorimetrics have indicated that the total RCS flow has dropped approximately 11,000 gpm (Figure 7) whereas the elbow tap and analytical model flow has indicated a drop in total flow of approximately 4,500 gpm (Figures 8 & 10). This indicates a significant impact from hot leg streaming as it shows that 6,500 gpm of the calorimetric flow decrease can be attributed to this phenomenon.

The upflow modification was made during the August 1990 EOC 6 refueling outage. As mentioned in the discussion of the upflow modification at McGuire Unit 1, this modification was expected to change the RCS flow distribution through the core region and not effect the total flow result significantly. However, the calorimetric flow following this outage decreased approximately 7,500 gpm to just above the then Technical Specification minimum measured flow limit of 385, 000 gpm (Figure 7). Since the steam generator tube plugging percentage during the EOC 6 refueling outage was small this magnitude of flow decrease was not expected. The elbow tap and analytical flow model for the same time frame indicate a flow decrease of ≈ 500 gpm which is consistent with the percentage of steam generator tube plugging which occurred during the outage.

An end of cycle calorimetric was performed just prior to the January 1992 EOC 7 refueling outage to determine if core burnup resulting in the flattening of the core exit temperature profile would increase the calorimetric measured flow. As expected the flow determined from this calorimetric did increase (≈ 3,000 gpm). This indicates that the unsubstantiated flow decreases measured by the calorimetrics are the result of hot leg streaming changes, as suspected.

The first batch of B&W fuel was introduced during the January 1992 EOC 7 refueling outage. The B&W fuel was expected to increase flow slightly due the decreased flow resistance in the core. This increase in flow due to the new fuel was expected to be offset by steam generator tube plugging as shown in Figures 10 & 11. The flow in the plant as indicated by the elbow tap ΔPs actually increased slightly after this outage. This is likely due to the new fuel having a greater effect on the flow than anticipated and partially due to the analytical flow model assumption that 1/3rd of the core would be replaced when slightly more was in fact replaced (≈ 37%). The July 1993 EOC 8 refueling outage, which involved a second batch of B&W fuel and additional steam generator tube plugging resulted in a flow decrease as measured by the calorimetric. The elbow tap ΔPs and analytic model flows indicate no decrease and a slight decrease respectively.

Figure 12 shows the daily average elbow tap ΔP data for McGuire Unit 2 back to September 22, 1993. This data covers cycle 8 and has been modified to eliminate bad data and data at off power days (<99% power). The data shows that the elbow tap ΔPs are very steady with no major drifting trends when the transmitters are operating properly. The elbow tap data in Figure 12 shows changes in loop flow resistances due to SG tube plugging performed during the SG tube leak outage which ended in October 1993.

Catawba Unit 1:

Catawba Unit 1 has experienced substantial flow impact as a result of hot leg streaming in recent calorimetrics. The RCS flow as measured by the calorimetric has trended very closely to the changes in full power ΔT as can be seen in Figure 13. The calorimetrics performed between plant startup and February 1986, following the EOC 1 refueling outage, indicate an unsubstantiated increase in RCS flow which was not accompanied by significant plant changes. The increase in flow was largely the result of ΔP transmitters which drifted excessively. This increase in flow was indicated by the calorimetric (Figure 13) and the elbow tap ΔP flow (Figure 14) since the drift in elbow tap ΔP transmitters affects both methods of flow measurement. The analytical flow model does not predict any flow changes during this period as no changes to plant geometry were made (Figures 15, 16 & 17). Note, Figures 16 & 17 differ only in the Y-axis scale with the scale on Figure 17 matching the scale of Figure 14 for easy comparison

The calorimetric flows following the November 1987 calorimetric have basically trended downward consistent with the increasing trend in ΔT, but in excess of that expected by plant geometry changes. Since plant startup the calorimetrics have indicated that the total RCS flow has dropped approximately 21,000 gpm (Figure 13) whereas the elbow tap and analytical model flow have indicated a drop in total flow of approximately 9,000 gpm and 5,000 gpm respectively (Figures 14 & 16). The difference between these flow indications is the excess elbow tap ΔP transmitter drift during the early calorimetrics which caused the

unsubstantiated indicated flow increase This indicates a significant impact from hot leg streaming as it shows that 12,000 to 16,000 gpm of the calorimetric flow decrease can be attributed to this phenomenon.

The first batch of B&W fuel was introduced during the April 1991 EOC 5 refueling outage. The B&W fuel was expected to increase flow slightly due the decreased flow resistance in the core. This increase in flow due to the new fuel was expected to be offset by steam generator tube plugging as shown in Figures 16 & 17. In fact, the flow in the plant as indicated by the elbow tap ΔPs and the calorimetric actually increased slightly after this outage. This is likely due to the new fuel having a greater effect on the flow than anticipated and partially due to the analytical flow model assumption that 1/3rd of the core would be replaced when slightly more was in fact replaced (≈ 37%). The August 1992 EOC 6 and November 1993 EOC 7 refueling outages, which include the second and third batch of B&W fuel and additional steam generator tube plugging, resulted in substantial flow decreases as measured by the calorimetric. The elbow tap ΔP flows indicate a slight flow increase resulting from the EOC 6 and a decrease in flow from the EOC7 refueling outages. The analytic model flows, however, indicate a slight decrease in flow after both outages.

Figures 18 and 19 show the daily average elbow tap ΔP data for Catawba Unit 1 back to January 1, 1992. This data covers cycles 6 & 7 and has been modified to eliminate bad data and data at off power days (<99% power). The data shows that the elbow tap ΔPs are very steady with no major drifting trends when the transmitters are operating properly. Channels A1, C2, and C3 did have drift problems during cycle 7 and were replaced during the last outage. In addition, the OAC scanner was recalibrated on August 5, 1993 which resulted in decrease in ΔP of approximately 0.3% in each channel. The numerous random small dips in the ΔP indications are the result of a bad data point in the daily average. Occasionally a point will read invalid by the computer and this will be recorded as a zero reading for the 5 minute period in question. This causes the daily average for that day to read slightly low resulting in the small dips in the elbow tap ΔPs.

Catawba Unit 2:

Catawba Unit 2 has experienced a substantial flow impact as a result of hot leg streaming in early calorimetrics. The RCS flow as measured by the calorimetric has trended very closely to the changes in full power ΔT as can be seen in Figure 20. The calorimetrics performed between plant startup and the June 1990, EOC 3 refueling outage, indicate unsubstantiated decreases in RCS flow which were not accompanied by significant plant changes. Between October 1990 and January 1992 five calorimetrics were performed. The October 1990 calorimetric was performed with a feedwater pressure transmitter of the wrong range, therefore, the calculated elbow tap coefficients for this calorimetric were not used. Another calorimetric was performed in November 1990, but due to questions concerning the amount of feedwater venturi fouling present, the calculated elbow tap coefficients for this calorimetric were also not used. Following the cleaning of the feedwater venturis the third calorimetric was performed in January 1991. The calculated elbow tap coefficients for this calorimetric were used for the remainder of Cycle 4. The calorimetric performed following the EOC 4 refueling outage in December 1991 was not used to establish the new elbow tap coefficients since it was discovered that a drain valve

on a transmitter installed for the calorimetric was leaking. The calorimetric performed January 1992 was used to calculate the elbow tap coefficients for Cycle 5. When using these two "good'" calorimetrics (January 1991 and January 1992) the calorimetric flow, as indicated by the dashed line on Figure 20, after the June 1989 calorimetric trend slightly downward consistent with the increasing trend in ΔT, but in excess of that expected by the very small amount of steam generator tube plugging (Figure 22). In the period between plant startup and the October 1990 calorimetric, the calorimetric flows have indicated that the total RCS flow has dropped approximately 13,000 gpm (Figure 20) whereas the elbow tap and analytical model flow have indicated a drop in total flow of approximately 150 gpm (Figures 21, 23 & 24). Note, Figures 23 & 24 differ only in the Y-axis scale with the scale on Figure 24 matching the scale of Figure 21 for easy comparison This indicates a significant impact from hot leg streaming as it shows that 12,850 gpm of the calorimetric flow decrease in this time frame can be attributed to this phenomenon.

The first batch of B&W fuel was introduced during the February 1993 EOC 5 refueling outage. The B&W fuel was expected to increase flow slightly due the decreased flow resistance in the core. The flow in the plant as indicated by the elbow tap ΔPs and the analytical flow model did not change appreciably, i. e., a very small increase in flow, while the calorimetric flow also showed a slight increase after this outage.

Figures 25 and 26 show the daily average elbow tap ΔP data for Catawba Unit 2 back to May 1, 1992. This data covers cycles 5 & 6 and has been modified to eliminate bad data and data at off power days (<99% power). The data shows that the elbow tap ΔPs are very steady with no major drifting trends when the transmitters are operating properly. Channel B2 did have drift problems during cycle 6 and was replaced during the last outage. The numerous random small dips in the ΔP indications are the result of a bad data point in the daily average. Occasionally a point will read invalid by the computer and this will be recorded as a zero reading for the 5 minute period in question. This causes the daily average for that day to read slightly low resulting in the small dips in the elbow tap ΔPs.

Summary:

As discussed above, the RCS flow measured at McGuire Unit 2 and Catawba Units 1 & 2 using the calorimetric method have been greatly affected by the hot leg streaming phenomenon. Calorimetrics affected by hot leg streaming have exhibited large decreases in the measured RCS flow which are not consistent with changes in plant geometry (steam generator tube plugging, fuel changes, etc.). The flow changes determined by the flow calorimetric have been shown to trend the increases in ΔT as indicated by the hot and cold leg RTDs. With unpredictable hot leg streaming patterns, the flows determined by the calorimetric become highly unpredictable. At the same time the flows as indicated by the elbow tap ΔP transmitters trend extremely well with an analytical flow model and produce predictable and reliable flow results.

(9) Please discuss the use of "on-line" differential pressure indications with respect to the observed behavior as opposed to the averaged data used for comparisons and evaluations.

Response to Question 9:

The use of "on line" ΔP data would provide calculated RCS loop flows much as those already plotted in Figures 2, 8, 14 and 21 with the additional points between calorimetrics and the noise associated with measuring the process ΔPs. This noise in this "instantaneous" data is due to the ΔP fluctuations caused by the turbulent RCS loop flow in the cold leg elbow. The data used for comparisons and evaluations is only averaged to the extent necessary to provide useful data for use in calculations. Much of the data used for these comparisons and evaluations (ΔPs, temperatures, etc.) comes from past calorimetrics used to perform the Technical Specification flow surveillances. Averaged data is primarily used to get a more representative parameter value (a value not at a momentary extreme) and reduce the process noise and error associated with the measurement of the parameter.

(10) Please discuss proposed future conduct of calorimetric tests and use of the results.

Response to Question 10:

Future calorimetric tests for the purpose of flow determination are not planned. Changes in RCS flow will be predicted for changes in plant geometry primarily by the analytical model. These predictions will be compared to the indicated elbow tap ΔP flow to determine if the expected flow changes correspond to the plant changes. If predictions of RCS flow do not correspond to the indicated elbow tap flow, further investigation into the source of the difference will be performed.

(11) Discuss known information on the degree of fouling on or in the RTD scoops. Discuss any plans for inspection of the scoops and RTDs in forthcoming outages.

Response to Question 11:

No inspections for fouling of the RTD scoops have been performed since the installation of the RTD thermowells during the RTD bypass removal outages at each plant. Fouling of the RTD scoops is expected to be small and have little impact on the temperature sensing function of the RTD. Major fouling of the RTD scoops would only affect the thermal response time of the RTDs and no significant change in the response time of the RTDs has been observed. Currently, inspections of the scoops and RTDs for fouling are not planned for future outages.

(12) Discuss any considerations underway for a redesign of the RTD and/or its scoop, both in terms of geometry, placement, and number to be used.

Response to Question 12:

There are no plans for a redesign of the RTD/scoop configuration. No practical, cost effective redesign of this configuration could be made which would provide adequate temperature indication and not negatively impact the RCS flow resistance and ALARA. Since ALARA concerns were a major factor in the elimination of the RTD bypass system, a redesign of the RTD/scoop configuration would have to mimimize the ALARA impact.

A new design of this system could have considerable present and future impact on ALARA. Any plant modification to change this configuration could involve a considerable one time ALARA impact. In addition, designs which incorporate more RTDs and/or scoops may result more potential crud traps which will have significant future ALARA impact. Therefore, since no practical redesign of the RTD/scoop configuration can be made, which adequately addresses the above concerns and provides an adequate temperature indication, efforts focused on the measurement of RCS flow by the more direct method of elbow tap ΔP indications.

(13) **The data presented on the handouts in the February 10, 1994, meeting shows that the flow rate indicated by the calorimetric heat balance method approximates that indicated by the elbow taps except for the McGuire Unit 2 in 1985, Catawba Unit 2 up until 1990 and Catawba Unit 1 in October 1992 and January 1994. Provide an assessment for each of these divergencies.**

Response to Question 13:

The large increase in flow for McGuire Unit 2 in 1985 is the result of a decrease in indicated ΔT of approximately 1 °F. This decrease in ΔT was investigated by Duke and Westinghouse and found to be caused primarily by hot leg streaming changes and a reduction in thermal power caused by feedwater venturi fouling. As can be seen in Figure 5 the RCS total flow was largely the result of this change in ΔT. For the same calorimetric the individual loop flows as determined by the elbow tap ΔPs (Figure 6) do not show a corresponding increase in flow. In addition, no changes in plant geometry (SG tube plugging, etc.) were made prior to this calorimetric which would indicate a flow increase or decrease (Figures 7 & 8).

The decrease in RCS flow for Catawba Unit 1 during the October 1992 and January 1994 calorimetrics was the result of hot leg streaming changes which resulted in an increased indicated ΔT. The Catawba Unit 1 plot of indicated full power ΔT in Figure 9 shows that the indicated ΔT for the October 1992 and the January 1994 calorimetric increased approximately 1 °F each. These two increases in ΔT represent a decrease in flow of approximately 12,750 gpm while the changes in elbow tap ΔP indicate a flow decrease of approximately 2,100 gpm. Steam generator tube plugging was performed during the outages prior to these calorimetrics (Figures 11 & 12), however, the magnitude of the elbow tap ΔP flow changes is consistent with the analytical model predicted flows which indicates that $\approx$ 10,650 gpm of the calorimetric decrease is attributable to hot leg streaming.

The decreases in RCS flow for Catawba Unit 2 prior to 1990 were the result of increases in indicated ΔT caused by changes in hot leg streaming patterns. The Catawba Unit 2 plot of indicated full power ΔT in Figure 13 shows that the indicated ΔT up to 1990 increased approximately 2 °F. This increase in ΔT represents a decrease in flow of approximately 13,000 gpm while the changes in elbow tap ΔP indicate a flow decrease of approximately 150 gpm. Very little steam generator tube plugging was performed during this time frame as indicated in Figure 15, therefore, very little decrease in the RCS flowrate should have been observed.

(14) **The February 10, 1994, meeting handouts provided an RCS Flow Uncertainty Analysis. That information is requested to be submitted by a DPC letter with the appropriate non-proprietary and proprietary versions and accompanied by an affidavit, consistent with the requirements of 10 CFR 2.790.**

Response to Question 14:

Included with response to question 15 below. See Attachment 1.

(15) **Duke Power's approach to the issue appears to assume that, notwithstanding the greater variability in hot leg temperature, the uncertainty in the measurement of RCS flow rate for surveillance purposes decreases from the present value of 2.1% to 1.9%. Please submit the complete derivations of these values consistent with the format of previous submittals, identified by DPC, in September 1987 and in Catawba FSAR question 492.7 for the surveillance flow rate. This should also be done relative to the McGuire submittal of October 8, 1981, and the Catawba submittal of July 30, 1984, for the reactor protection system trip flow measurement.**

Response to Question 15:

The present uncertainty value of 2.2% flow (2.1% flow measurement uncertainty plus 0.1% feedwater venturi fouling penalty), stated in Figure 3.2.1 of the Catawba Technical Specifications is an uncertainty allowance and not a calculated uncertainty value. The present calculated flow measurement uncertainty value is 1.83% flow, therefore, the calculated flow measurement uncertainty is increasing by 0.07% to 1.9% flow. The calorimetric and flow uncertainties for the time period after the RTD bypass removal at McGuire and Catawba are given in Attachment 1. In addition, the flow surveillance and loss of flow setpoint uncertainties for the elbow tap flow method are also included in Attachment 1.

(16) **The DPC topical report DPC-NE-2004P-A, on core thermal hydraulic methodology, states in Section 6.4, that the flow uncertainty standard deviation is 1.337% and that the uncertainty is 2.2%. Please discuss the comparability of this methodology of arriving at a flow uncertainty relative to the methodology identified as the McGuire and Catawba licensing basis methodology in the handouts (numbers 35, 36, 37, etc.) in the meeting on February 10, 1994.**

Response to Question 16:

The flow uncertainty of 2.2% stated in topical report DPC-NE-2004P-A is identical to the licensing basis methodology identified in the February 10, 1994 handouts. The standard deviation is determined from the 2.2% uncertainty allowance by assuming a normal distribution and a 95% one-sided probability level. The probability factor of 1.645 is obtained from normal distribution tables. Dividing the uncertainty of 2.2% by the probability factor of 1.645 results in a standard deviation of 1.337%.

(17) **To support the proposed Technical Specification amendment, the loss of flow trip measurement uncertainty has been revised to include the following sensor uncertainty allowances:**

- **Sensor calibration accuracy**
- **Sensor temperature effect**
- **Sensor pressure effect**

However, should a measurement, test, and equipment accuracy term for the sensor also be included in the revised loss of flow Channel Statistical Allowance calculation?

Response to Question 17:

The current Duke setpoint methodology for McGuire and Catawba includes measurement and test equipment accuracy terms (M&TE) for the sensor when the calibration accuracy to measurement and test equipment accuracy exceed a 4 to 1 ratio. A review of the calibration procedure and the measurement and test equipment used to calibrate the elbow tap ΔP transmitters indicate that the ratio of sensor calibration accuracy to sensor M&TE do not meet the 4 to 1 criteria. Therefore, a conservative sensor M&TE term is included in the McGuire and Catawba uncertainty calculations in Attachment 1.

The result of the additional term for McGuire is that the calculated value for the RCS flow uncertainty is increased from the present calculated value of 1.7% flow to 1.76% flow instead of the 1.74% flow indicated in the November 16, 1993, Technical Specification submittal. This does not change the proposed Technical Specification change which increases the present value of 1.7% flow plus 0.1% feedwater venturi fouling penalty to 1.8% flow plus 0.1% feedwater venturi fouling penalty.

The result of the additional term for Catawba is that the calculated value for the RCS flow uncertainty is increased from the present calculated value of 1.83% flow to 1.88% flow instead of the 1.87% flow indicated in the November 16, 1993, Technical Specification submittal. This does not change the proposed Technical Specification change which decreases the present value of 2.1% flow plus 0.1% feedwater venturi fouling penalty to 1.9% flow plus 0.1% feedwater venturi fouling penalty.

The additional sensor M&TE term for the McGuire low reactor coolant flow setpoint uncertainty does not change the setpoint of 91% of minimum measured flow per loop and the allowable value of 90% of minimum measured flow per loop as presented in the November 16, 1993, Technical Specification submittal. However, the channel statistical allowance (CSA) will increase from 3.72% flow given in the November 16, 1993, submittal to 3.79% flow.

The additional sensor M&TE term for the Catawba low reactor coolant flow setpoint uncertainty does not change the setpoint of 91% of minimum measured flow per loop and the allowable value of 89.7% of minimum measured flow per loop as presented in the November 16, 1993, Technical Specification submittal. However, the channel statistical allowance (CSA) will increase from 3.37% flow given in the November 16, 1993, submittal to 3.42% flow.

MNS-1 Comparison Between Full Power Delta T and RCS Flow As Determined By Flow Calorimetric

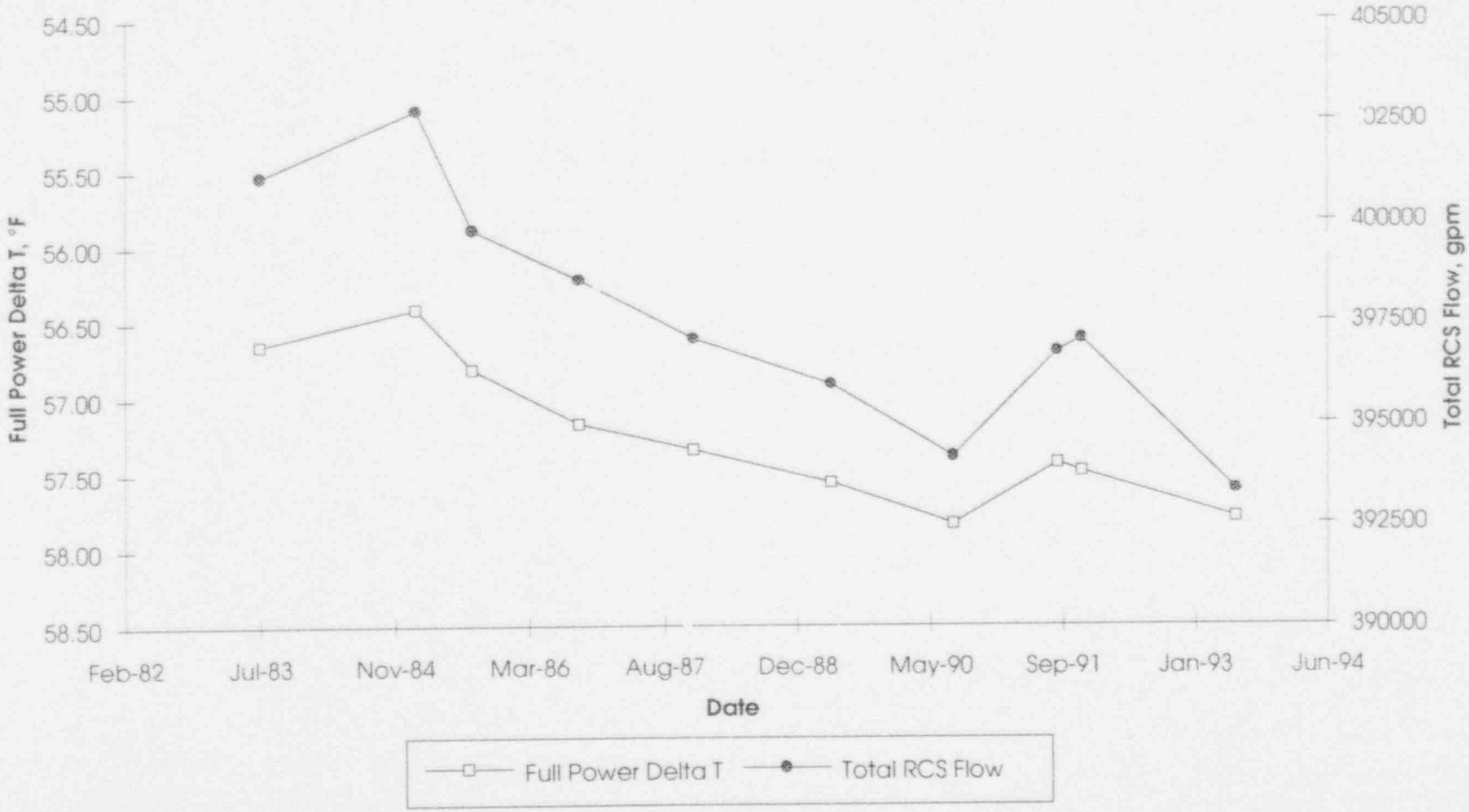


Figure 1

MNS-1 Individual Loop Flows As Determined By Elbow Tap Delta Ps

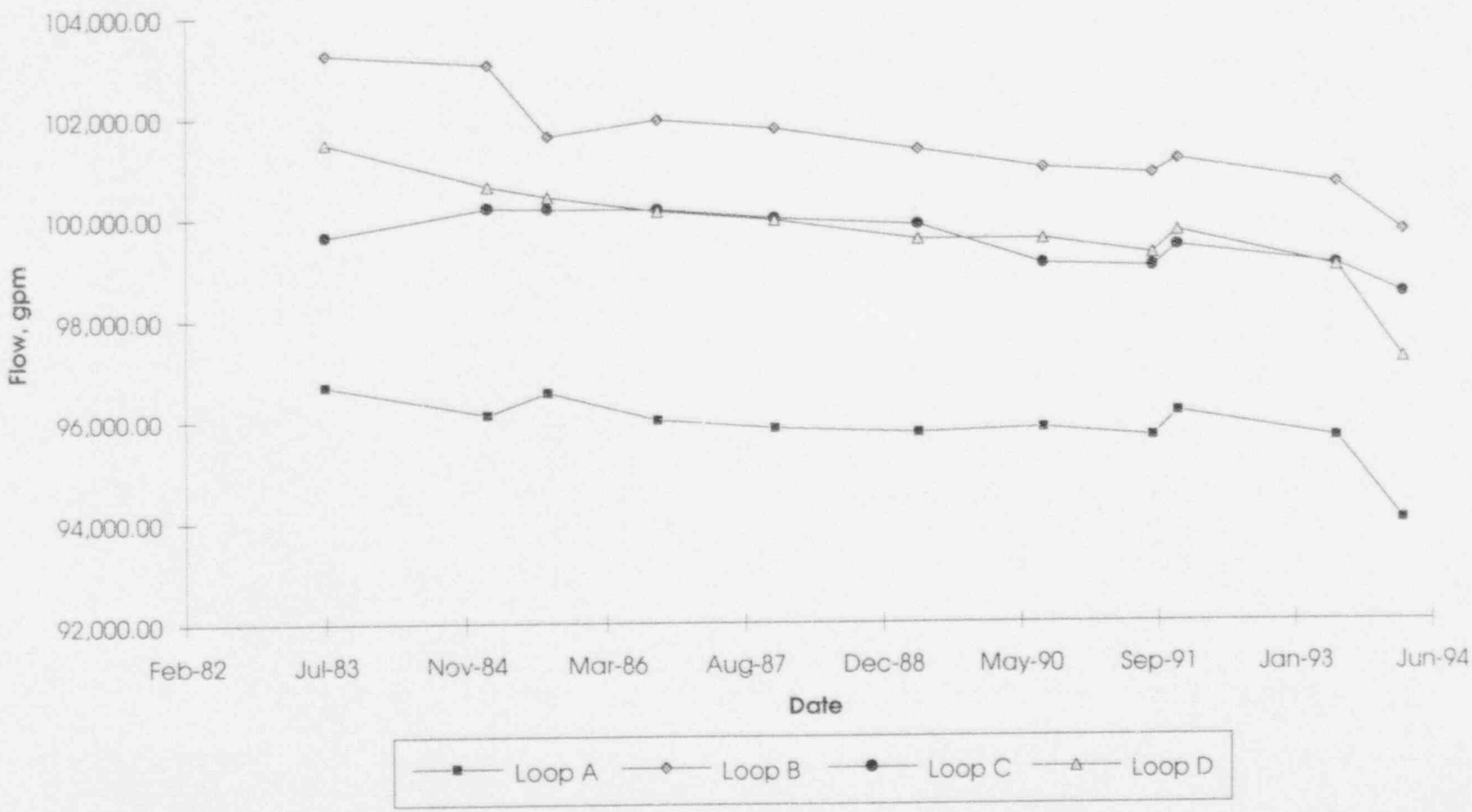


Figure 2

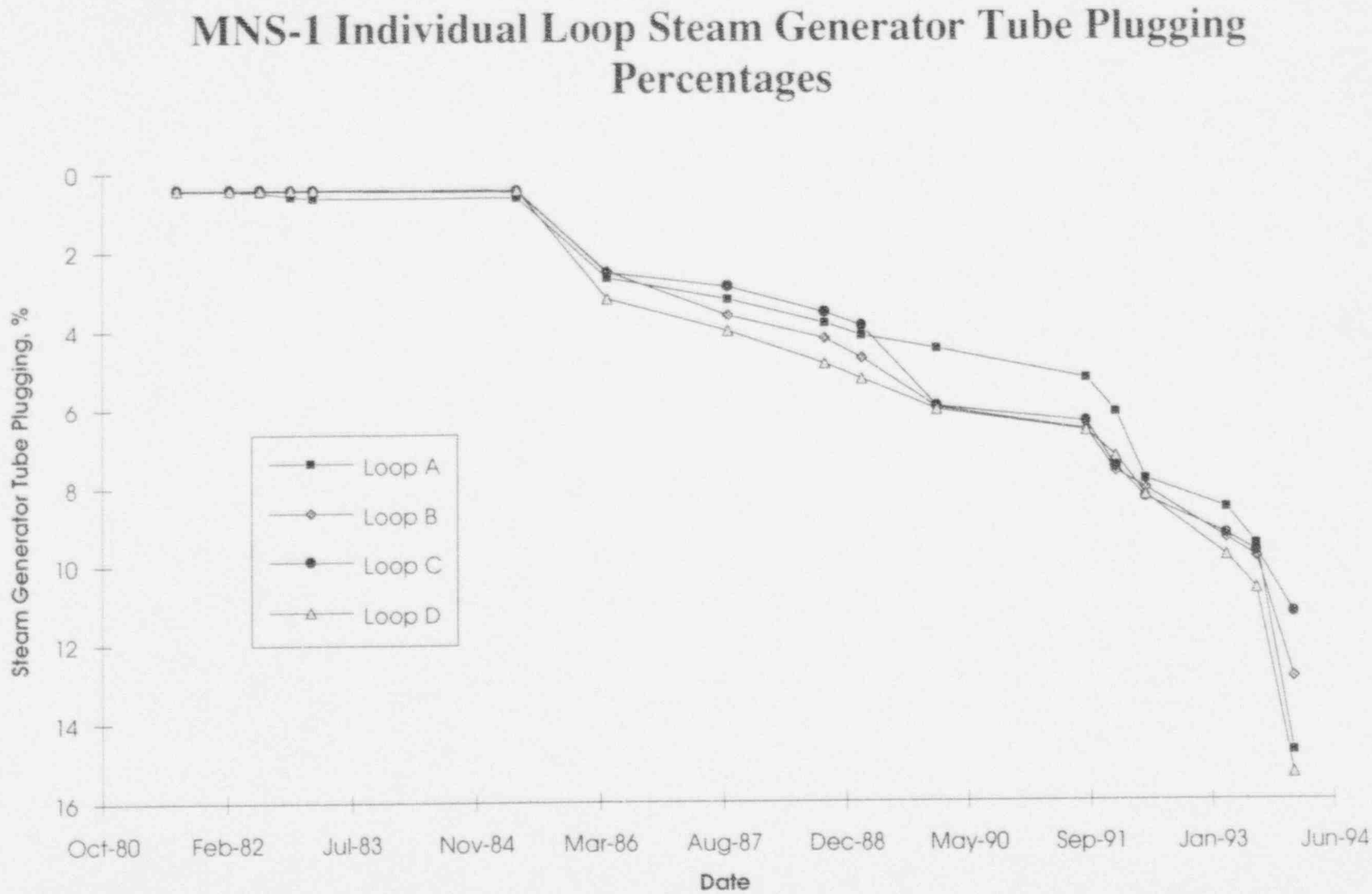

MNS-1 Individual Loop Steam Generator Tube Plugging Percentages
Steam Generator Tube Plugging, %
0
2
4
6
8
10
12
14
16
Oct-80
Feb-82
Jul-83
Nov-84
Mar-86
Aug-87
Dec-88
May-90
Sep-91
Jan-93
Jun-94
Date
Loop A
Loop B
Loop C
Loop D

Figure 3

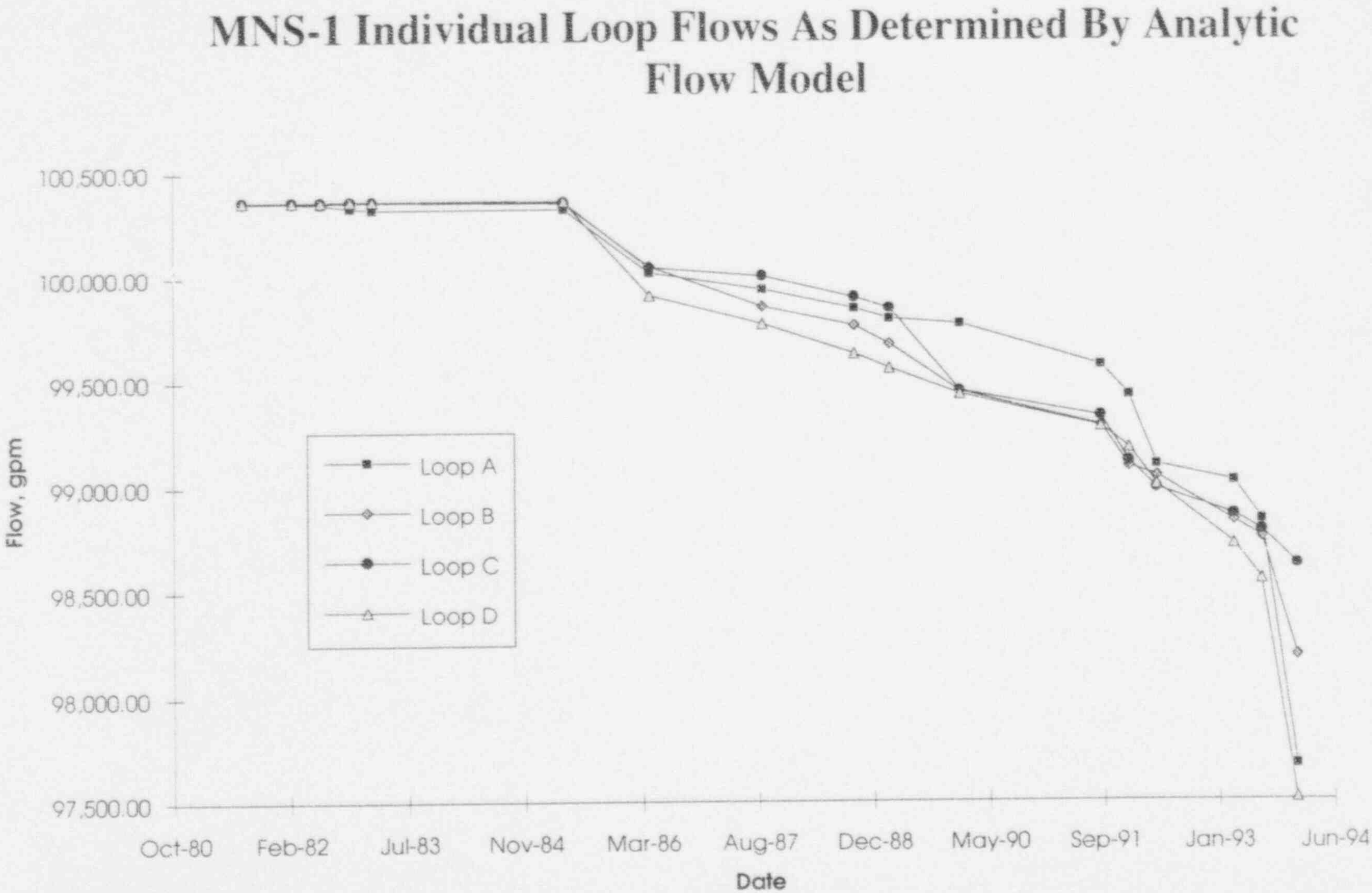

MNS-1 Individual Loop Flows As Determined By Analytic Flow Model
100,500.00
100,000.00
99,500.00
99,000.00
98,500.00
98,000.00
97,500.00
Flow, gpm
Loop A
Loop B
Loop C
Loop D
Oct-80
Feb-82
Jul-83
Nov-84
Mar-86
Aug-87
Dec-88
May-90
Sep-91
Jan-93
Jun-94
Date

Figure 4

MNS-1 Individual Loop Flows As Determined By Analytic Flow Model

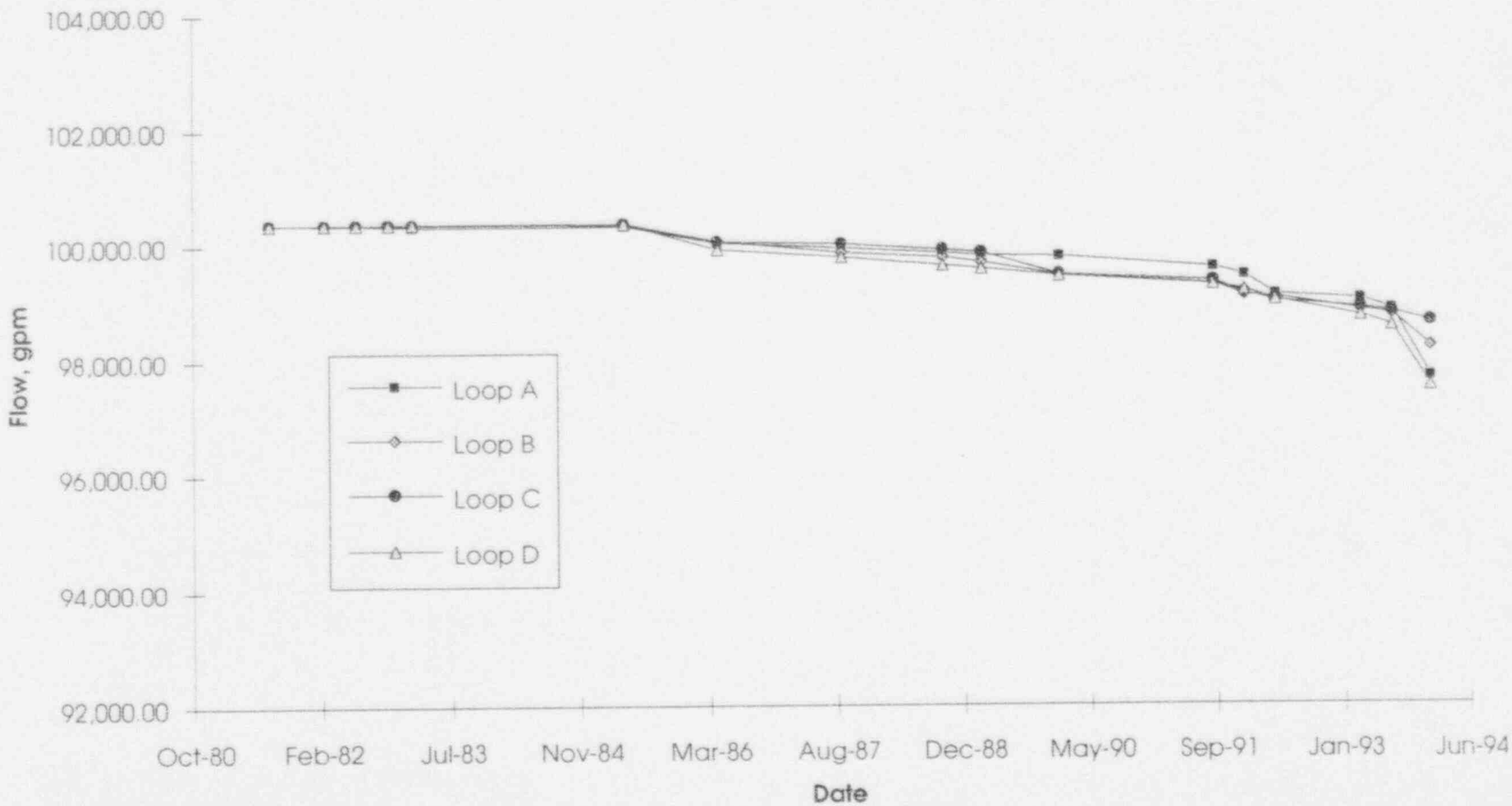
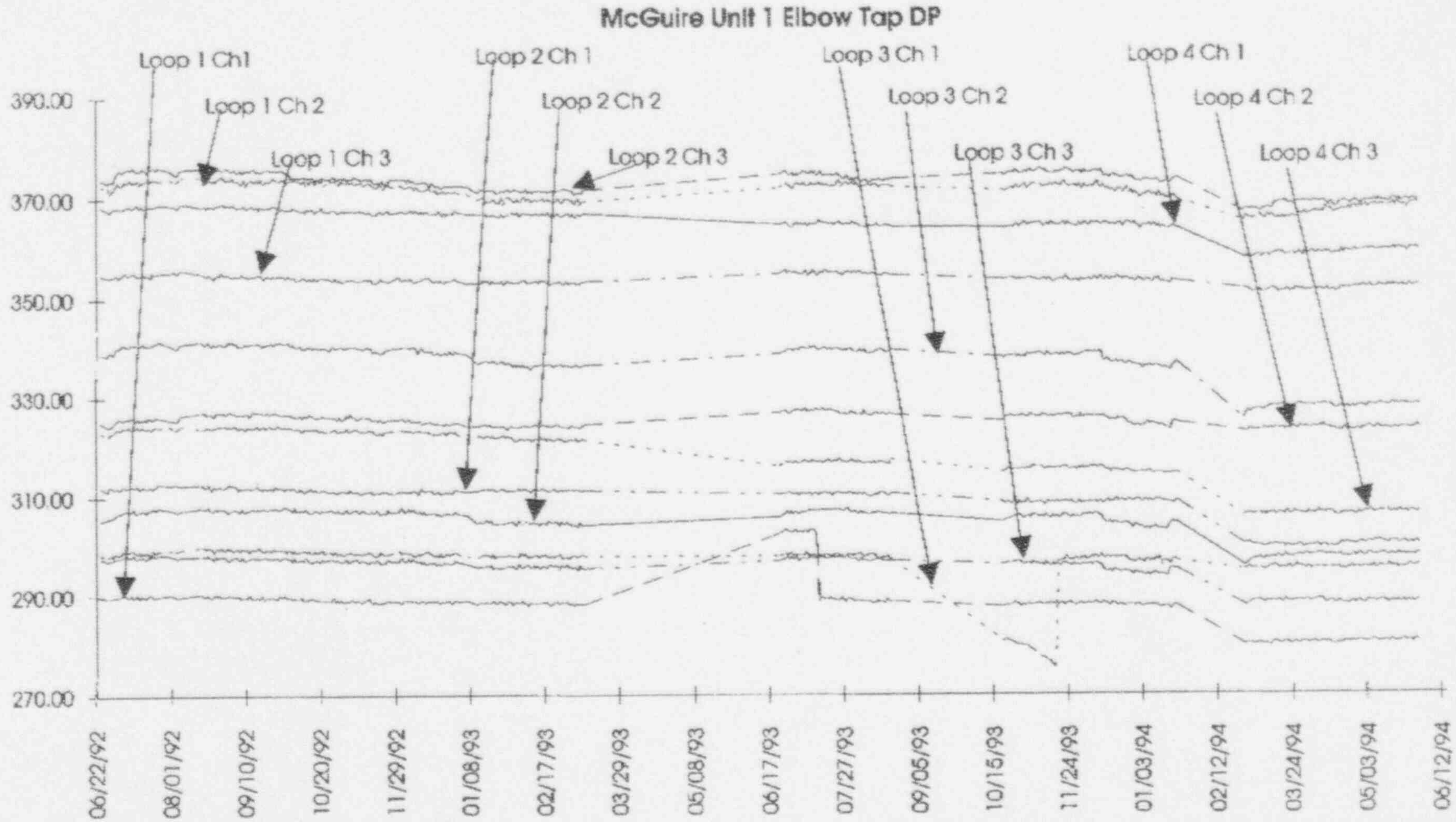


Figure 5



McGuire Unit 1 Elbow Tap DP
Loop 1 Ch1
Loop 1 Ch 2
Loop 1 Ch 3
Loop 2 Ch 1
Loop 2 Ch 2
Loop 2 Ch 3
Loop 3 Ch 1
Loop 3 Ch 2
Loop 3 Ch 3
Loop 4 Ch 1
Loop 4 Ch 2
Loop 4 Ch 3
390.00
370.00
350.00
330.00
310.00
290.00
270.00
06/22/92
08/01/92
09/10/92
10/20/92
11/29/92
01/08/93
02/17/93
03/29/93
05/08/93
06/17/93
07/27/93
09/05/93
10/15/93
11/24/93
01/03/94
02/12/94
03/24/94
05/03/94
06/12/94

Figure 6

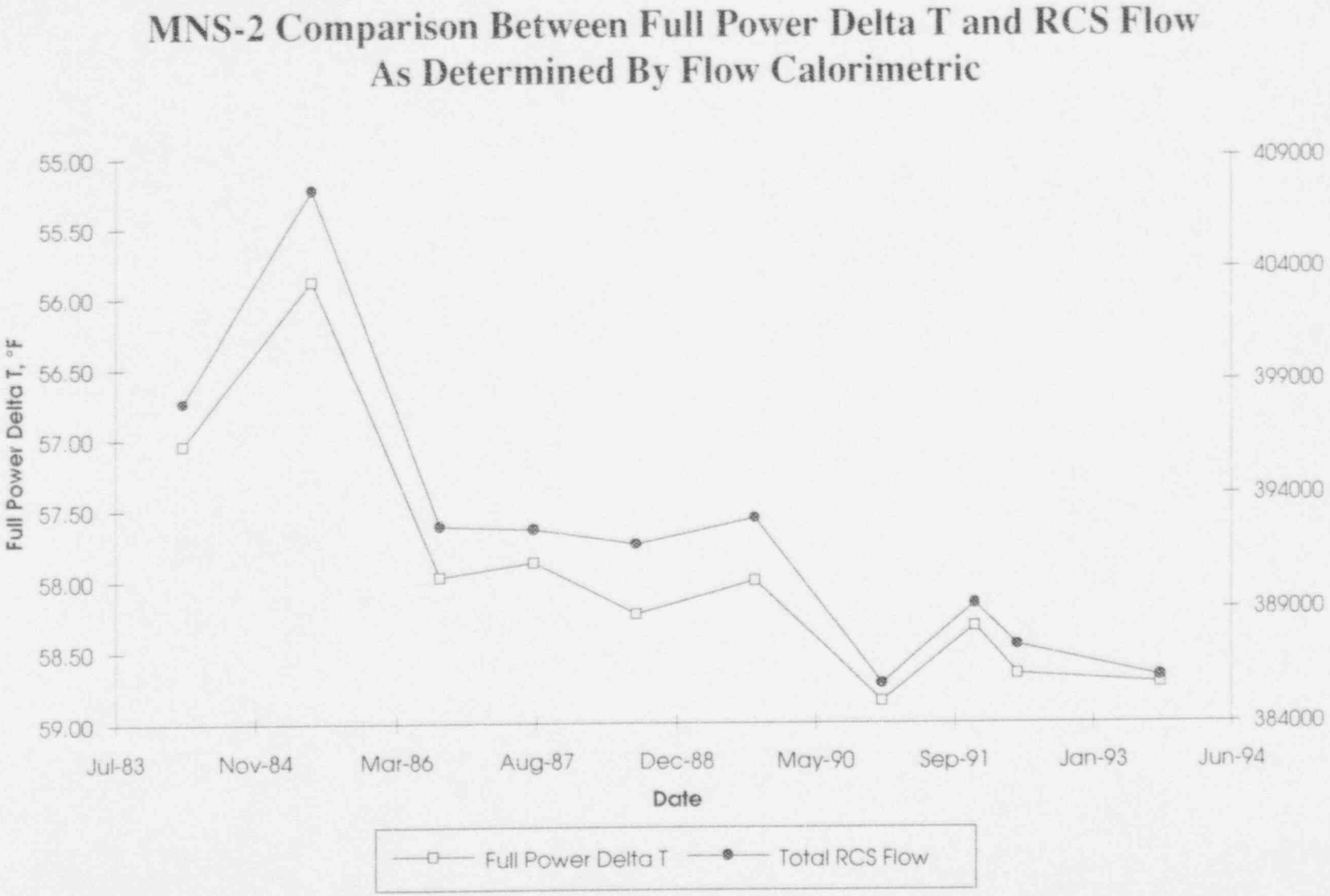

MNS-2 Comparison Between Full Power Delta T and RCS Flow
As Determined By Flow Calorimetric
Full Power Delta T, °F
Total RCS Flow, gpm
55.00
55.50
56.00
56.50
57.00
57.50
58.00
58.50
59.00
409000
404000
399000
394000
389000
384000
Jul-83
Nov-84
Mar-86
Aug-87
Dec-88
May-90
Sep-91
Jan-93
Jun-94
Date
Full Power Delta T
Total RCS Flow

Figure 7

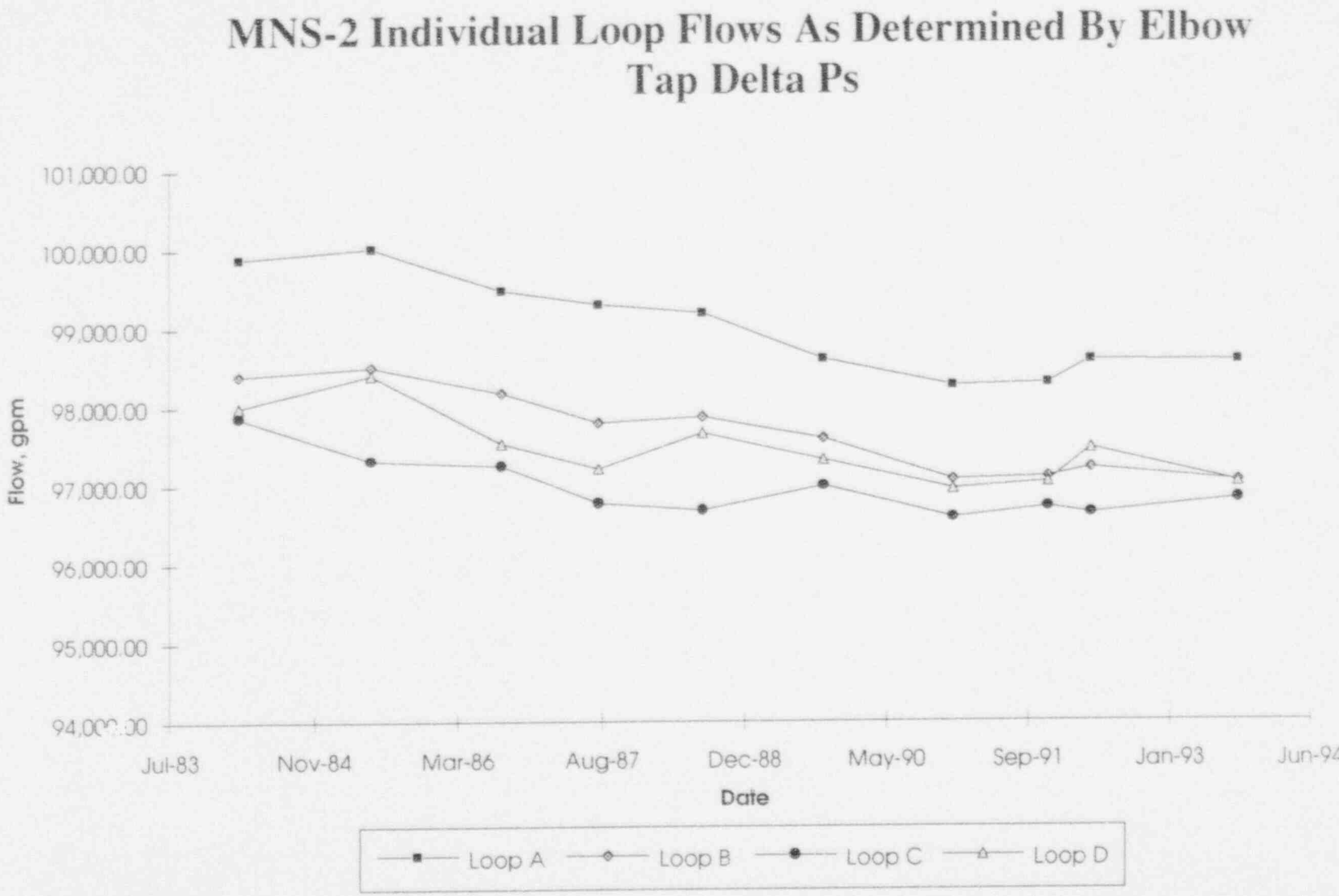
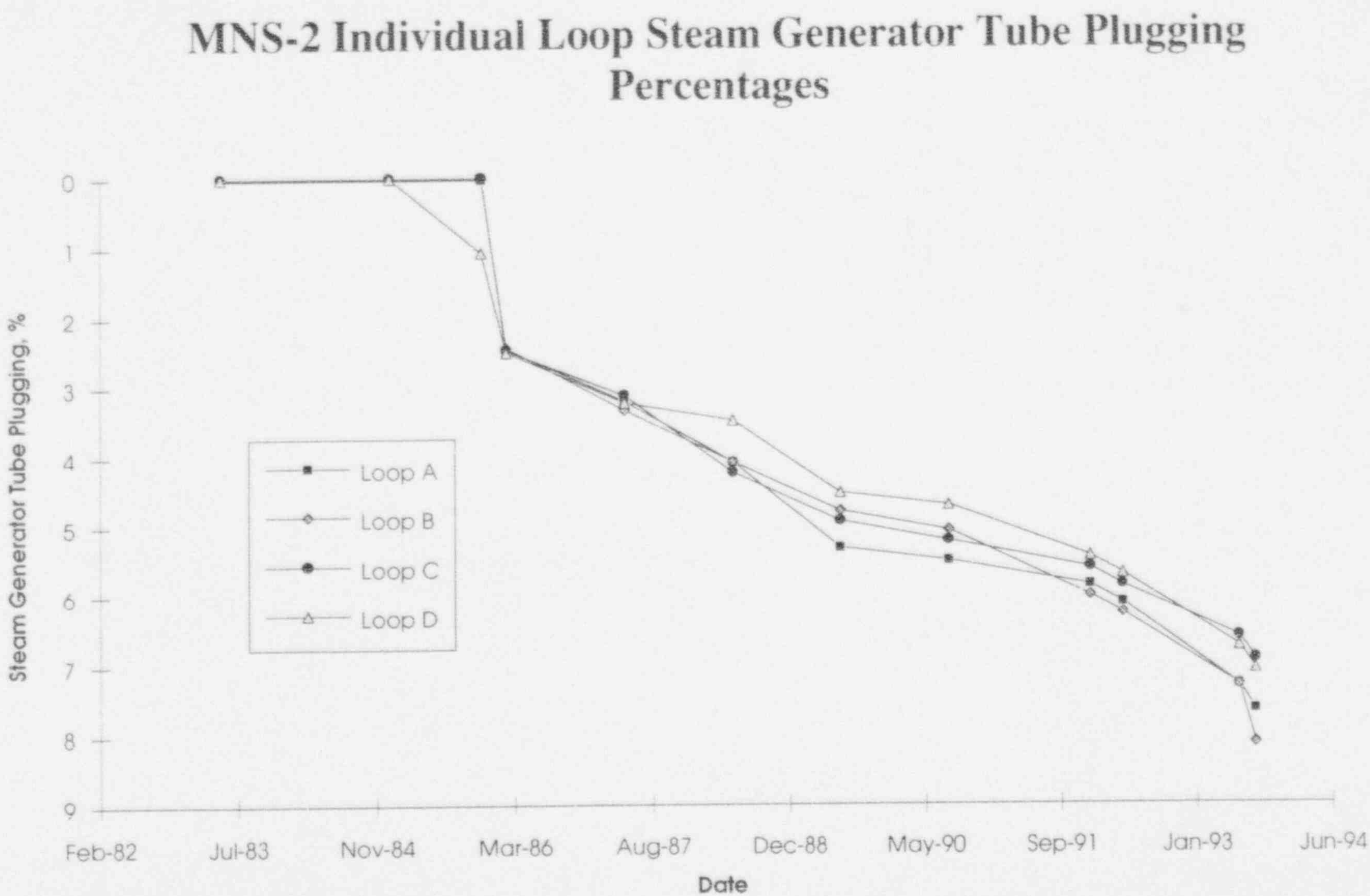
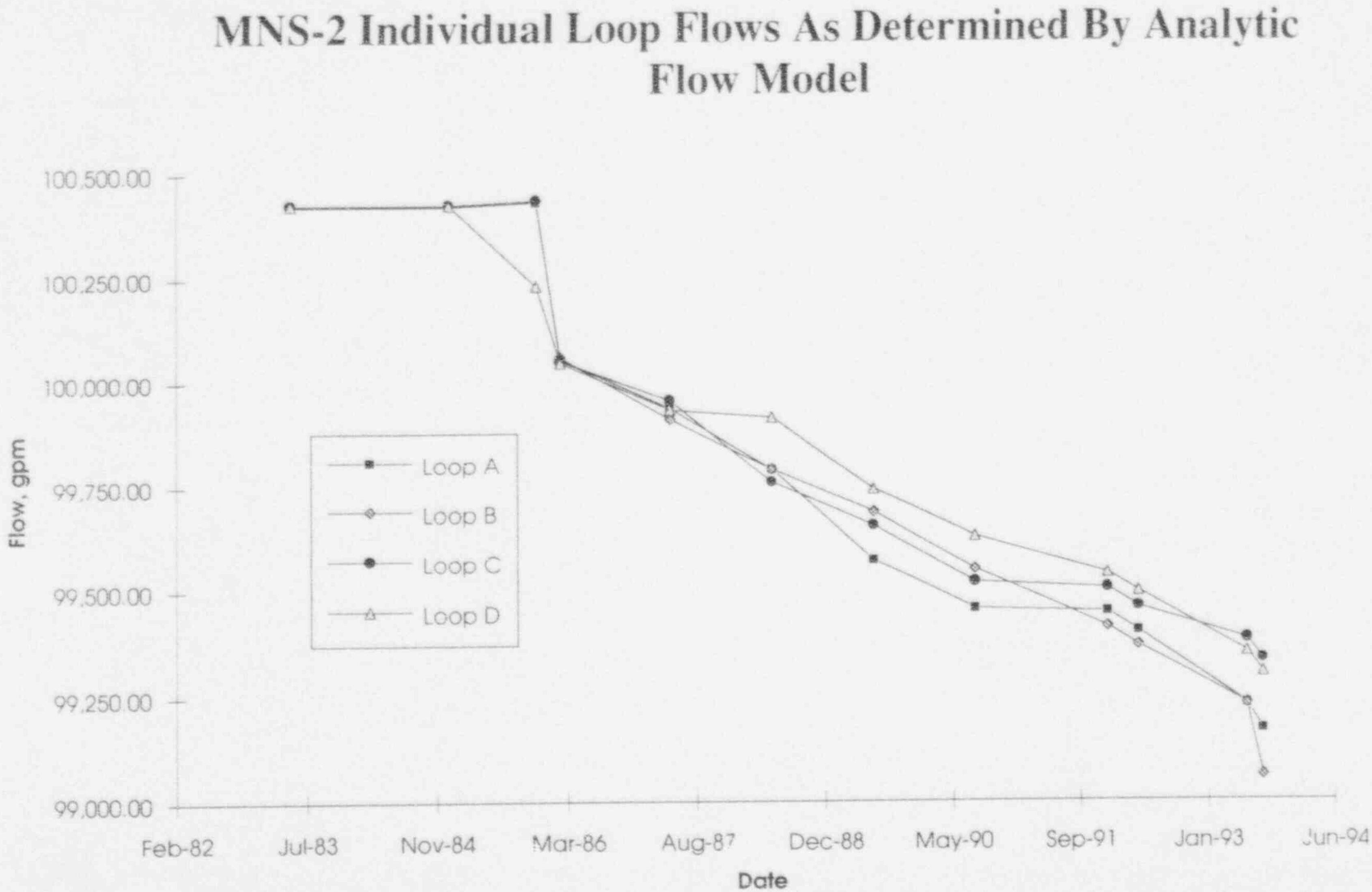

MNS-2 Individual Loop Flows As Determined By Elbow Tap Delta Ps
101,000.00
100,000.00
99,000.00
98,000.00
97,000.00
96,000.00
95,000.00
94,000.00
Flow, gpm
Jul-83
Nov-84
Mar-86
Aug-87
Dec-88
May-90
Sep-91
Jan-93
Jun-94
Date
Loop A
Loop B
Loop C
Loop D

Figure 8



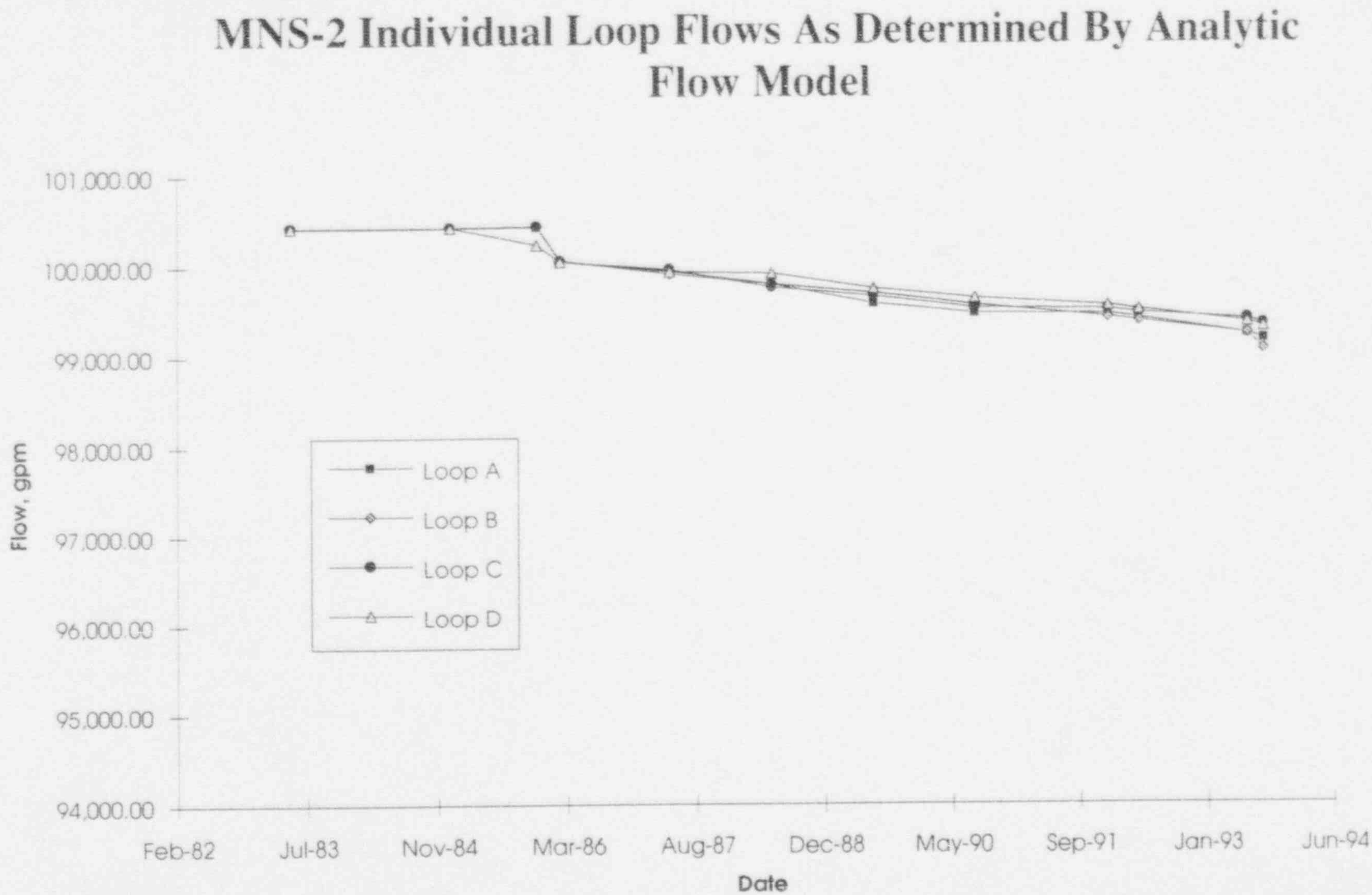
MNS-2 Individual Loop Steam Generator Tube Plugging Percentages
Steam Generator Tube Plugging, %
0
1
2
3
4
5
6
7
8
9
Loop A
Loop B
Loop C
Loop D
Feb-82
Jul-83
Nov-84
Mar-86
Aug-87
Dec-88
May-90
Sep-91
Jan-93
Jun-94
Date

Figure 9



MNS-2 Individual Loop Flows As Determined By Analytic Flow Model
100,500.00
100,250.00
100,000.00
99,750.00
99,500.00
99,250.00
99,000.00
Flow, gpm
Loop A
Loop B
Loop C
Loop D
Feb-82
Jul-83
Nov-84
Mar-86
Aug-87
Dec-88
May-90
Sep-91
Jan-93
Jun-94
Date

Figure 10



MNS-2 Individual Loop Flows As Determined By Analytic Flow Model
101,000.00
100,000.00
99,000.00
98,000.00
97,000.00
96,000.00
95,000.00
94,000.00
Flow, gpm
Loop A
Loop B
Loop C
Loop D
Feb-82
Jul-83
Nov-84
Mar-86
Aug-87
Dec-88
May-90
Sep-91
Jan-93
Jun-94
Date

Figure 11

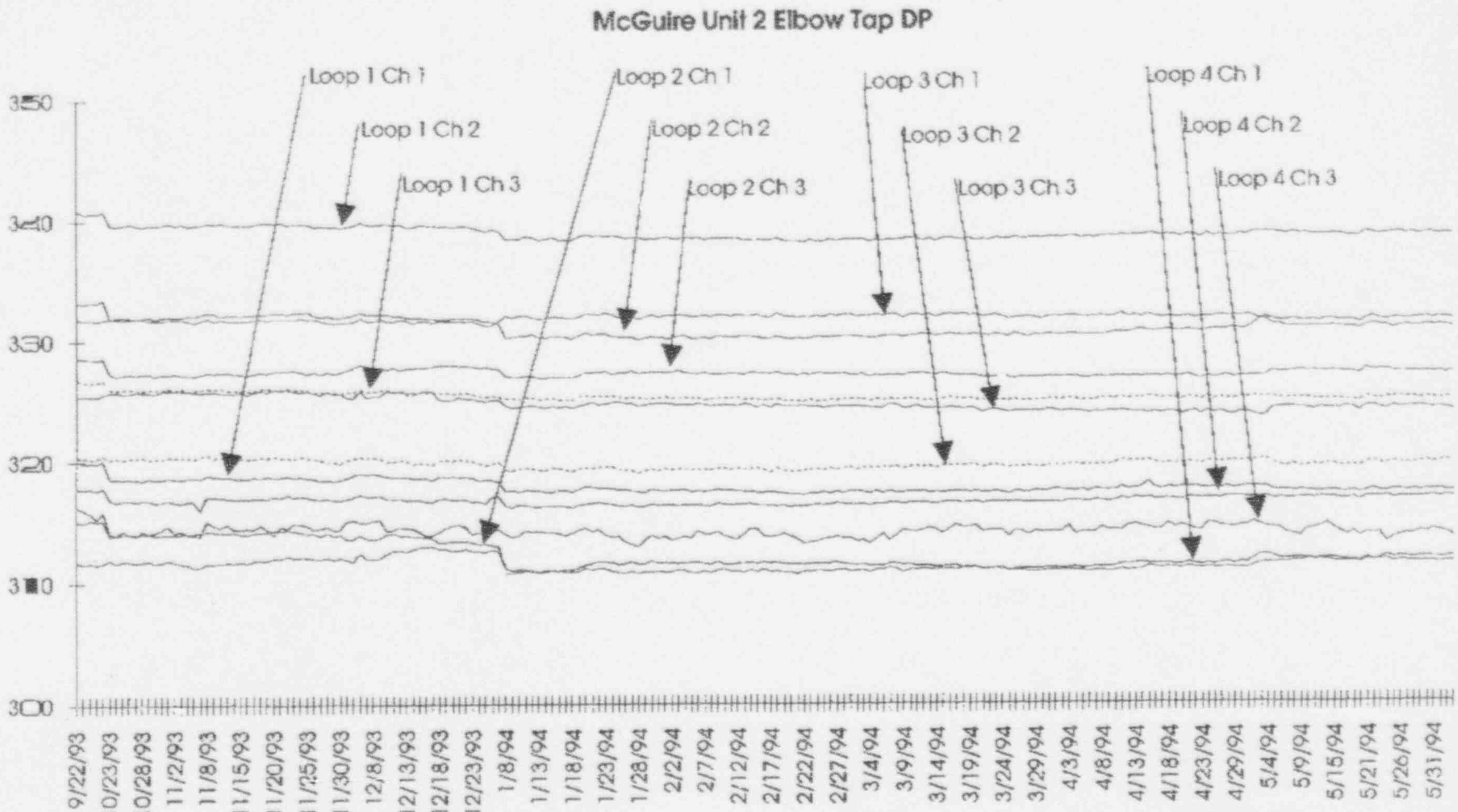

McGuire Unit 2 Elbow Tap DP
Loop 1 Ch 1
Loop 1 Ch 2
Loop 1 Ch 3
Loop 2 Ch 1
Loop 2 Ch 2
Loop 2 Ch 3
Loop 3 Ch 1
Loop 3 Ch 2
Loop 3 Ch 3
Loop 4 Ch 1
Loop 4 Ch 2
Loop 4 Ch 3
350
340
330
320
310
300
9/22/93
10/23/93
10/28/93
11/2/93
11/8/93
11/15/93
11/20/93
11/25/93
11/30/93
12/8/93
12/13/93
12/18/93
12/23/93
1/8/94
1/13/94
1/18/94
1/23/94
1/28/94
2/2/94
2/7/94
2/12/94
2/17/94
2/22/94
2/27/94
3/4/94
3/9/94
3/14/94
3/19/94
3/24/94
3/29/94
4/3/94
4/8/94
4/13/94
4/18/94
4/23/94
4/29/94
5/4/94
5/9/94
5/15/94
5/21/94
5/26/94
5/31/94

Figure 12

CNS-1 Comparison Between Full Power Delta T and RCS Flow As Determined By Flow Calorimetric

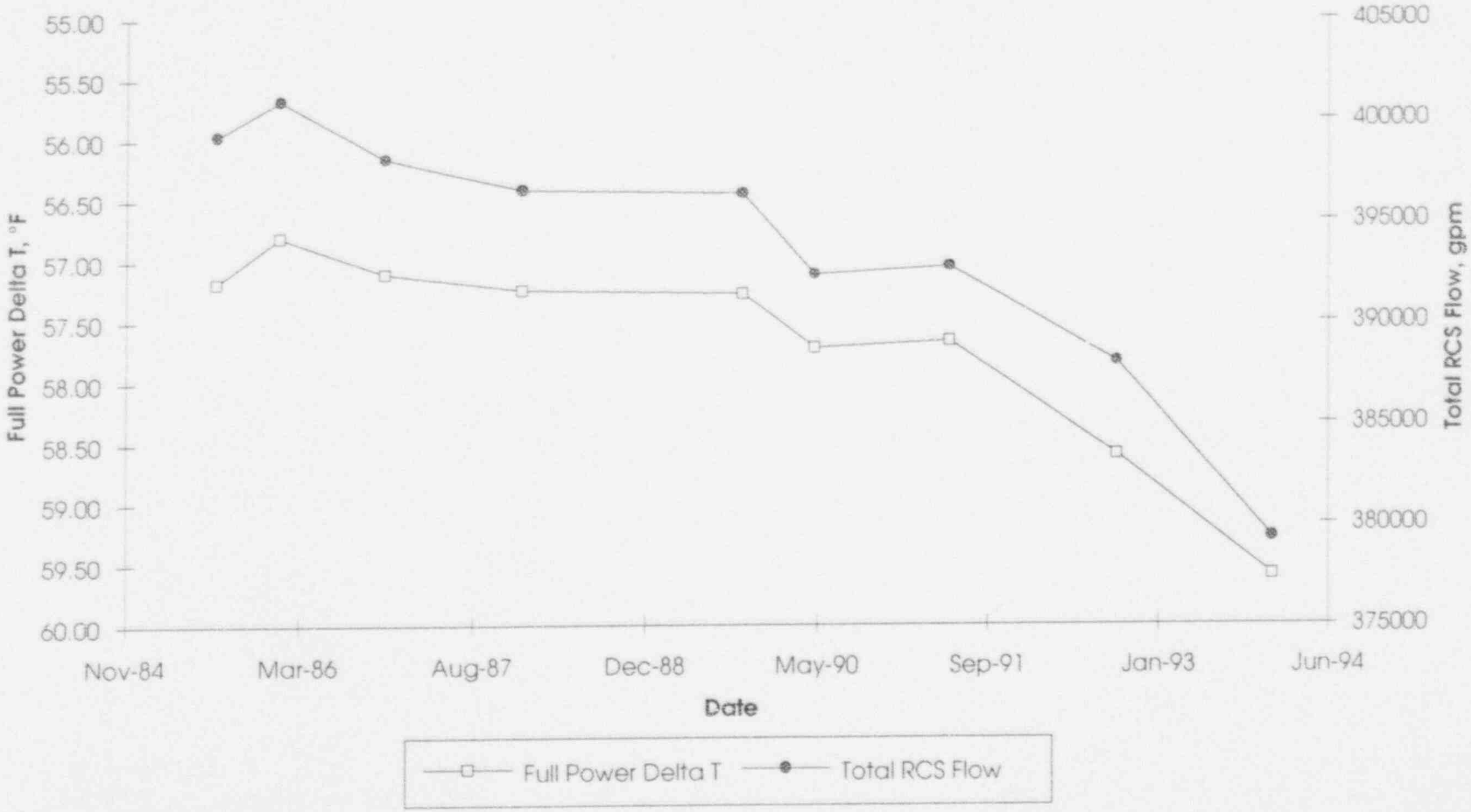


Figure 13

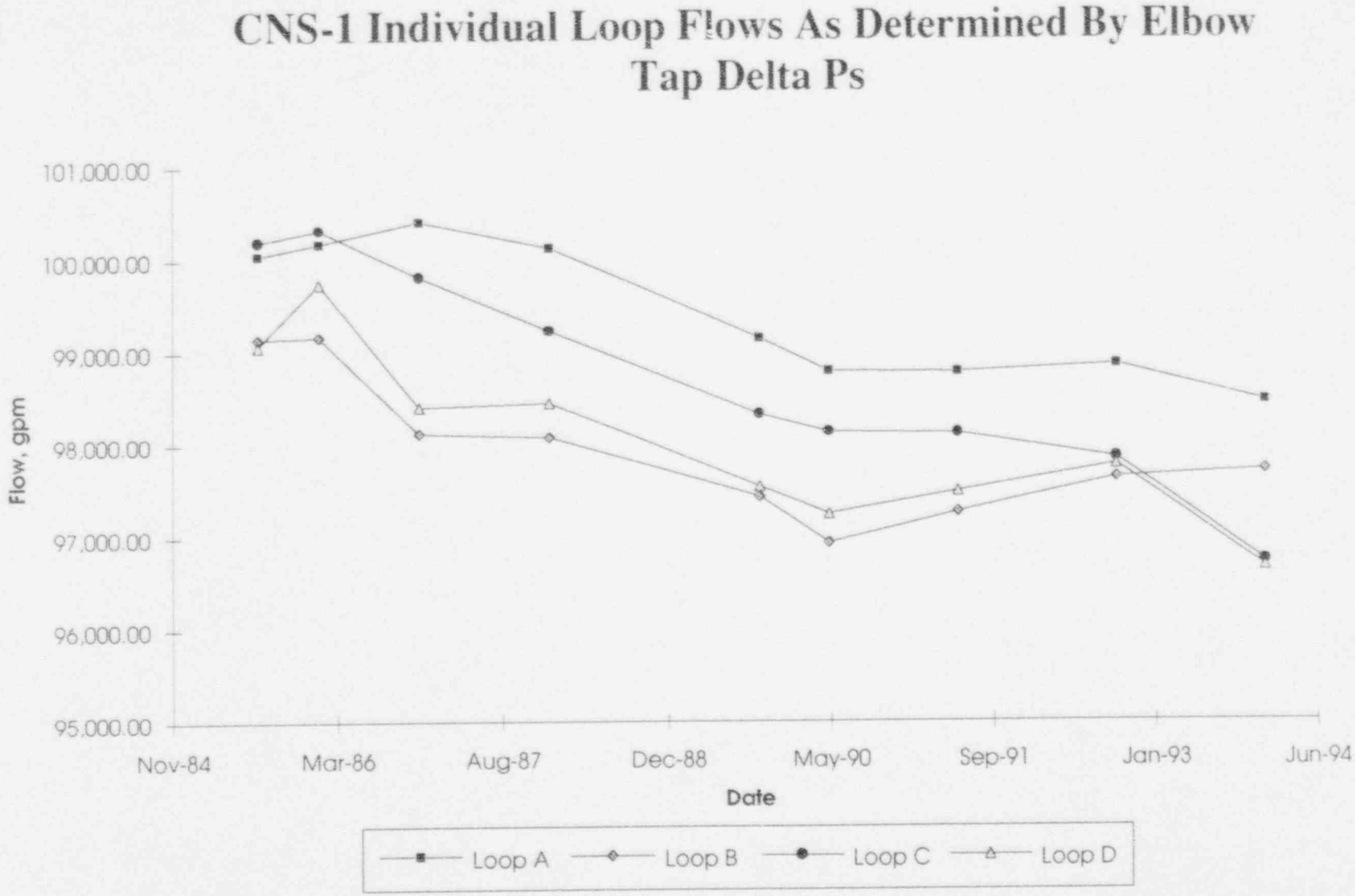

CNS-1 Individual Loop Flows As Determined By Elbow Tap Delta Ps
101,000.00
100,000.00
99,000.00
98,000.00
97,000.00
96,000.00
95,000.00
Flow, gpm
Nov-84
Mar-86
Aug-87
Dec-88
May-90
Sep-91
Jan-93
Jun-94
Date
Loop A
Loop B
Loop C
Loop D

Figure 14

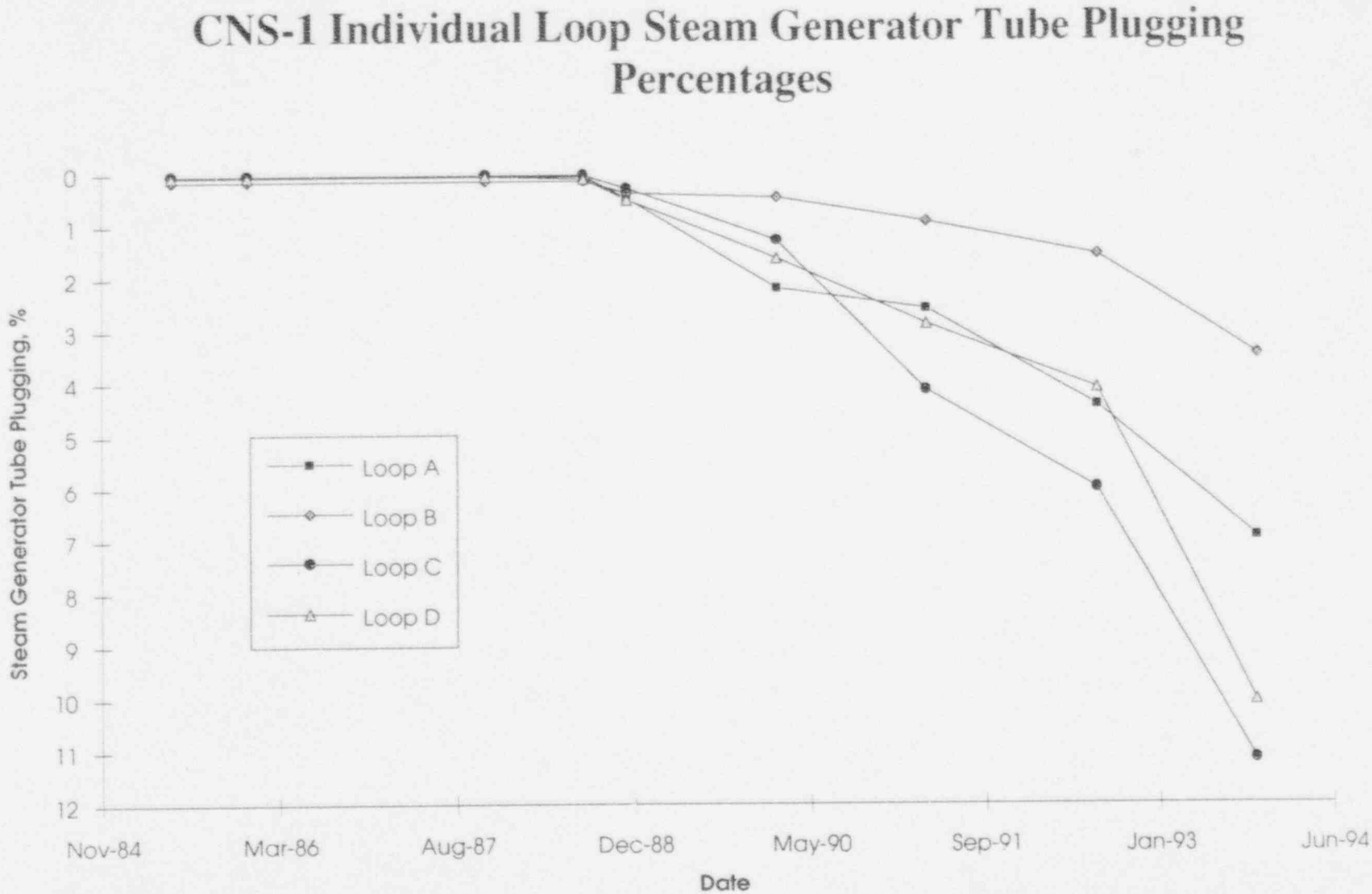

CNS-1 Individual Loop Steam Generator Tube Plugging Percentages
Steam Generator Tube Plugging, %
0
1
2
3
4
5
6
7
8
9
10
11
12
Nov-84
Mar-86
Aug-87
Dec-88
May-90
Sep-91
Jan-93
Jun-94
Date
Loop A
Loop B
Loop C
Loop D

Figure 15

CNS-1 Individual Loop Flows As Determined By Analytic Flow Model

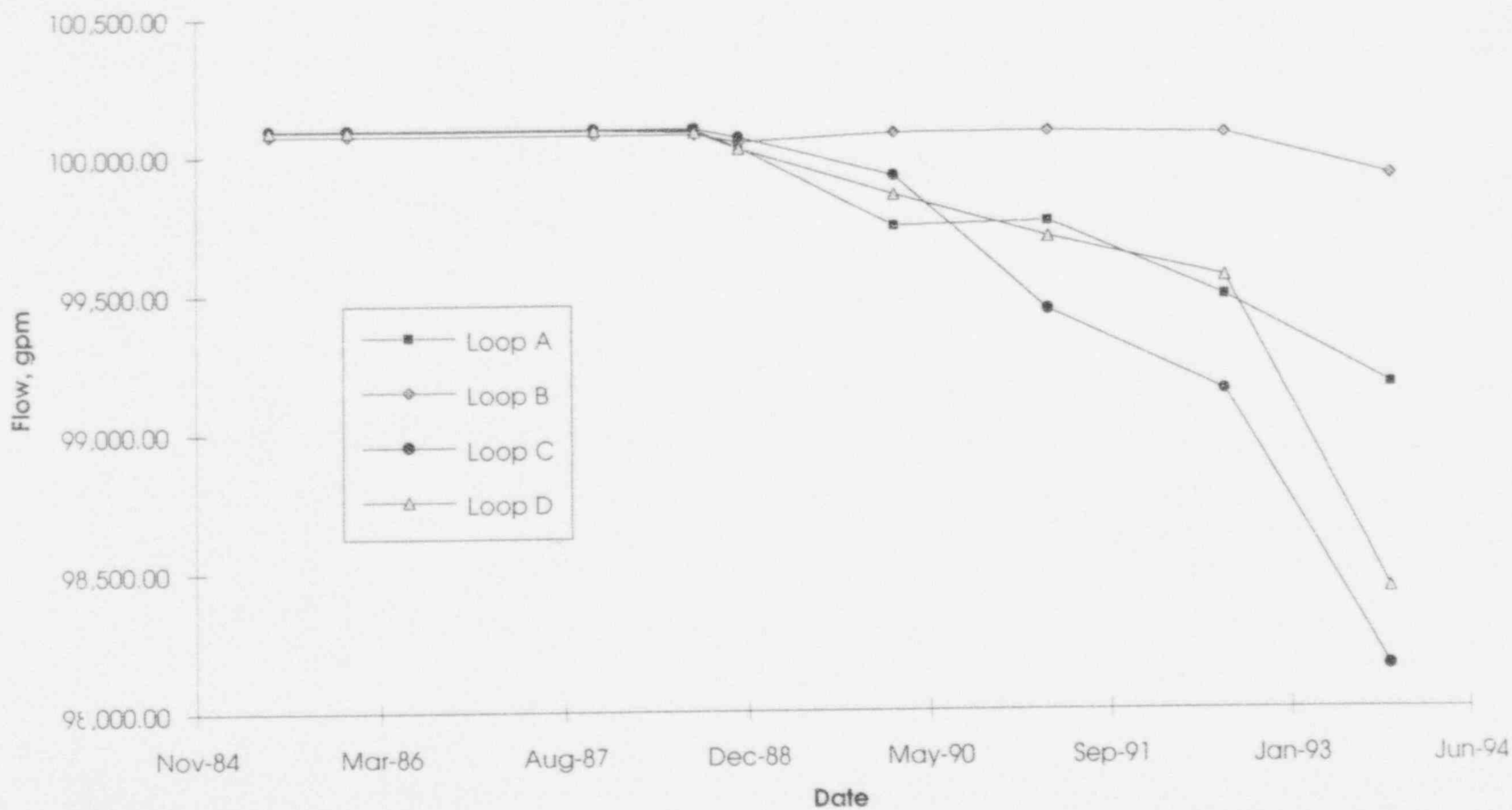


Figure 16

CNS-1 Individual Loop Flows As Determined By Analytic Flow Model

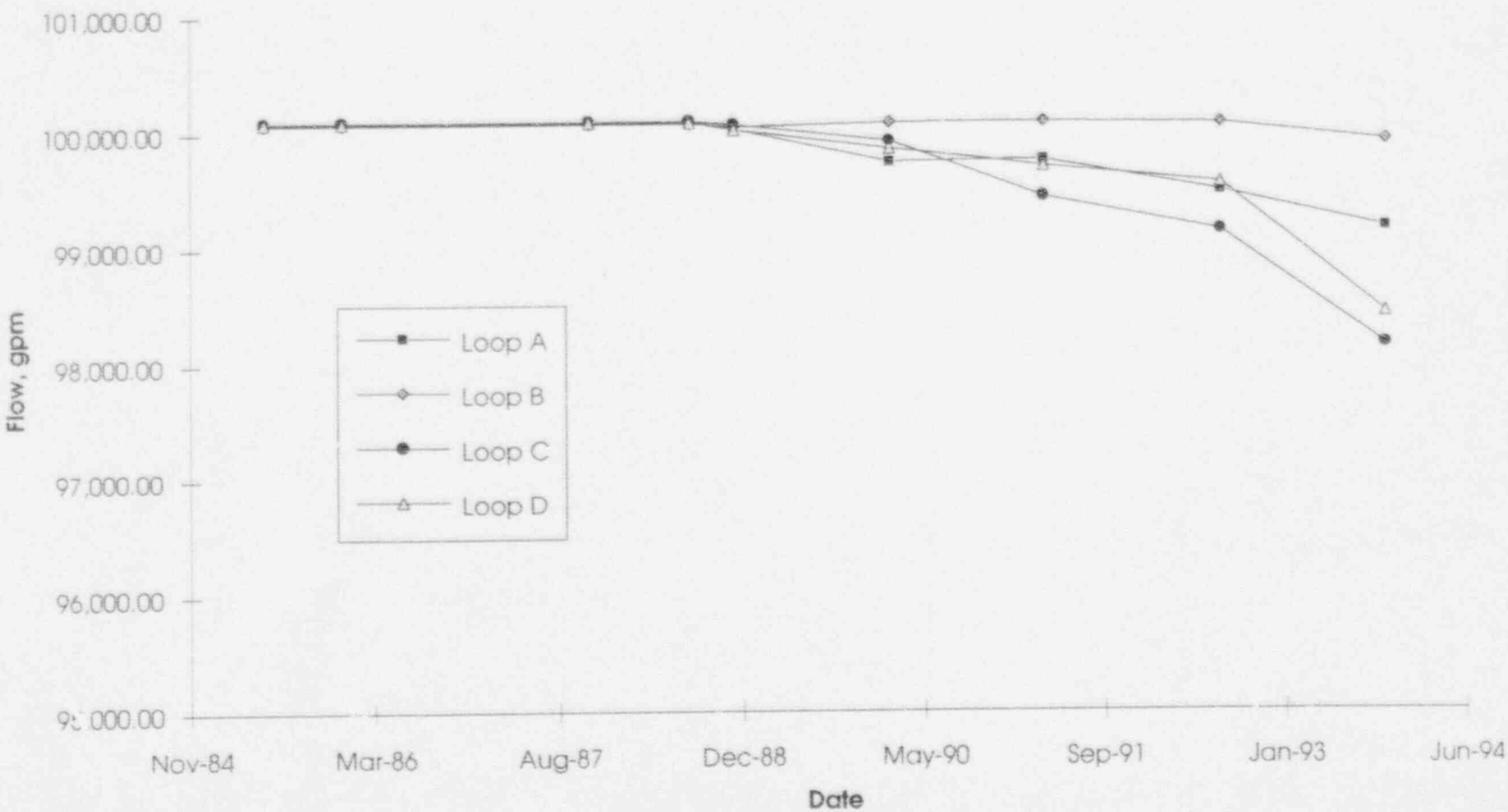


Figure 17

Catawba Unit 1 Elbow Tap DP (1/1/92 to EOC6)

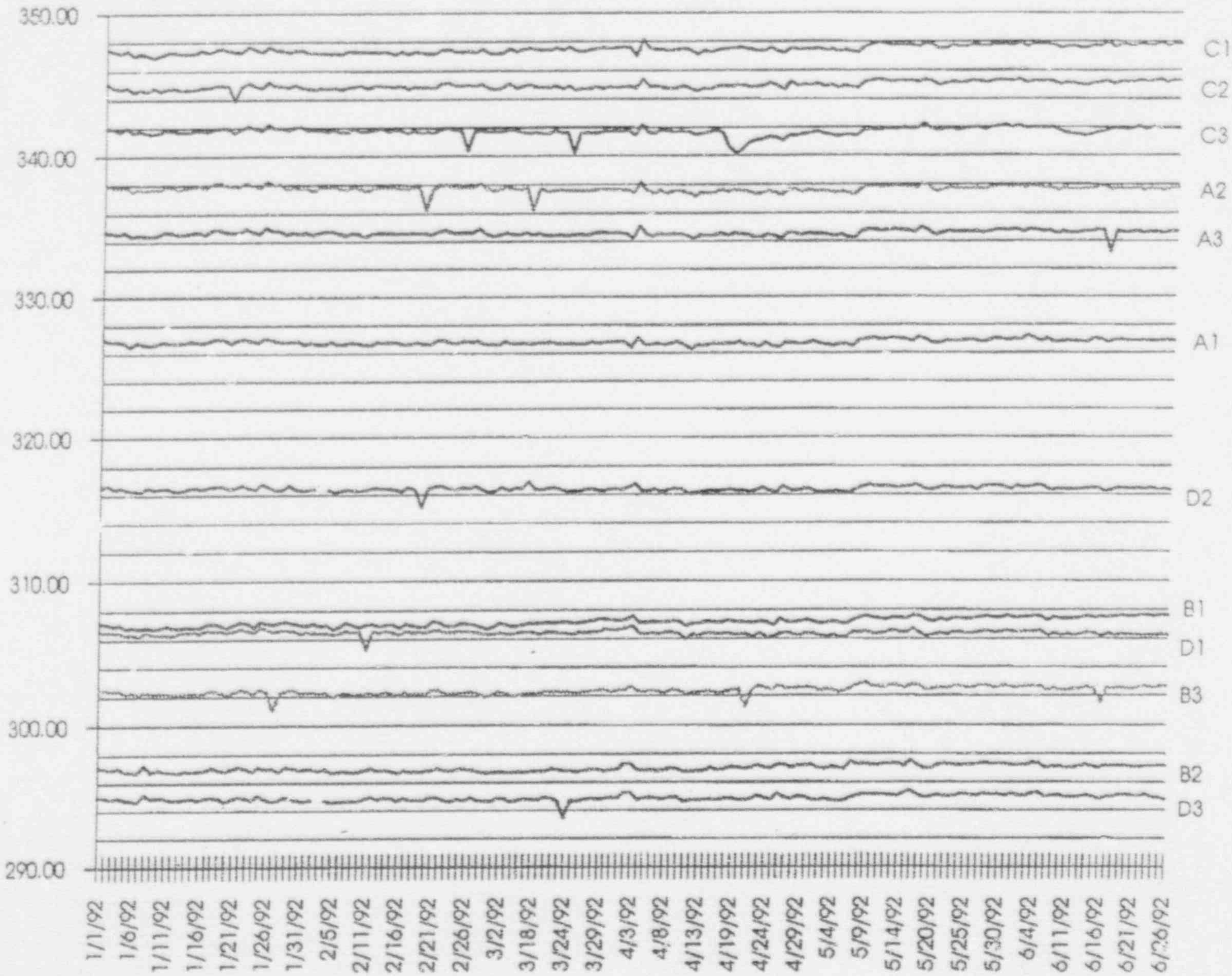


Figure 18

Catawba Unit 1 Elbow Tap DP (Cycle 7)

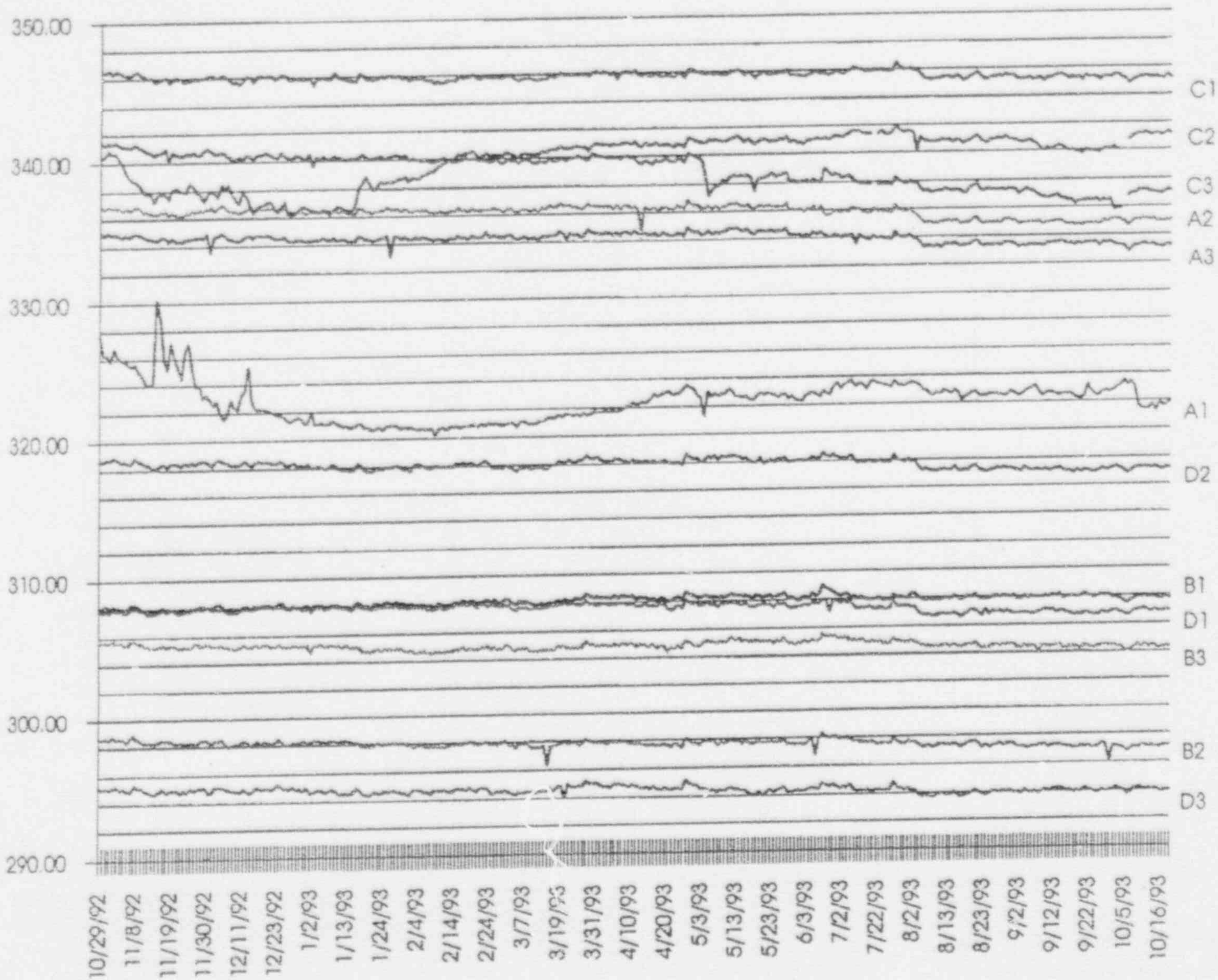


Figure 19

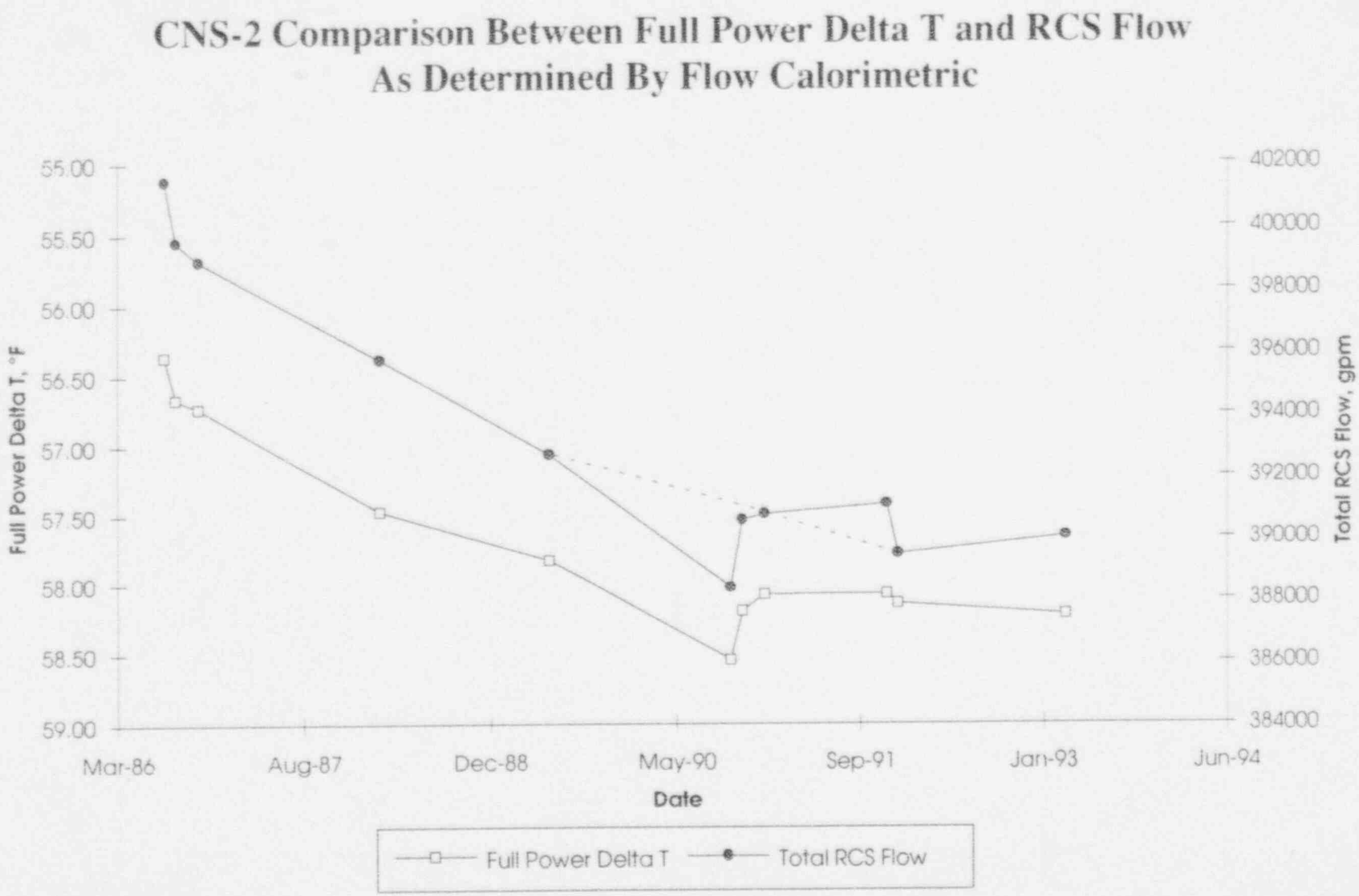

CNS-2 Comparison Between Full Power Delta T and RCS Flow
As Determined By Flow Calorimetric
55.00
55.50
56.00
56.50
57.00
57.50
58.00
58.50
59.00
Full Power Delta T, °F
402000
400000
398000
396000
394000
392000
390000
388000
386000
384000
Total RCS Flow, gpm
Mar-86
Aug-87
Dec-88
May-90
Sep-91
Jan-93
Jun-94
Date
Full Power Delta T
Total RCS Flow

Figure 20

CNS-2 Individual Loop Flows As Determined By Elbow Tap Delta Ps

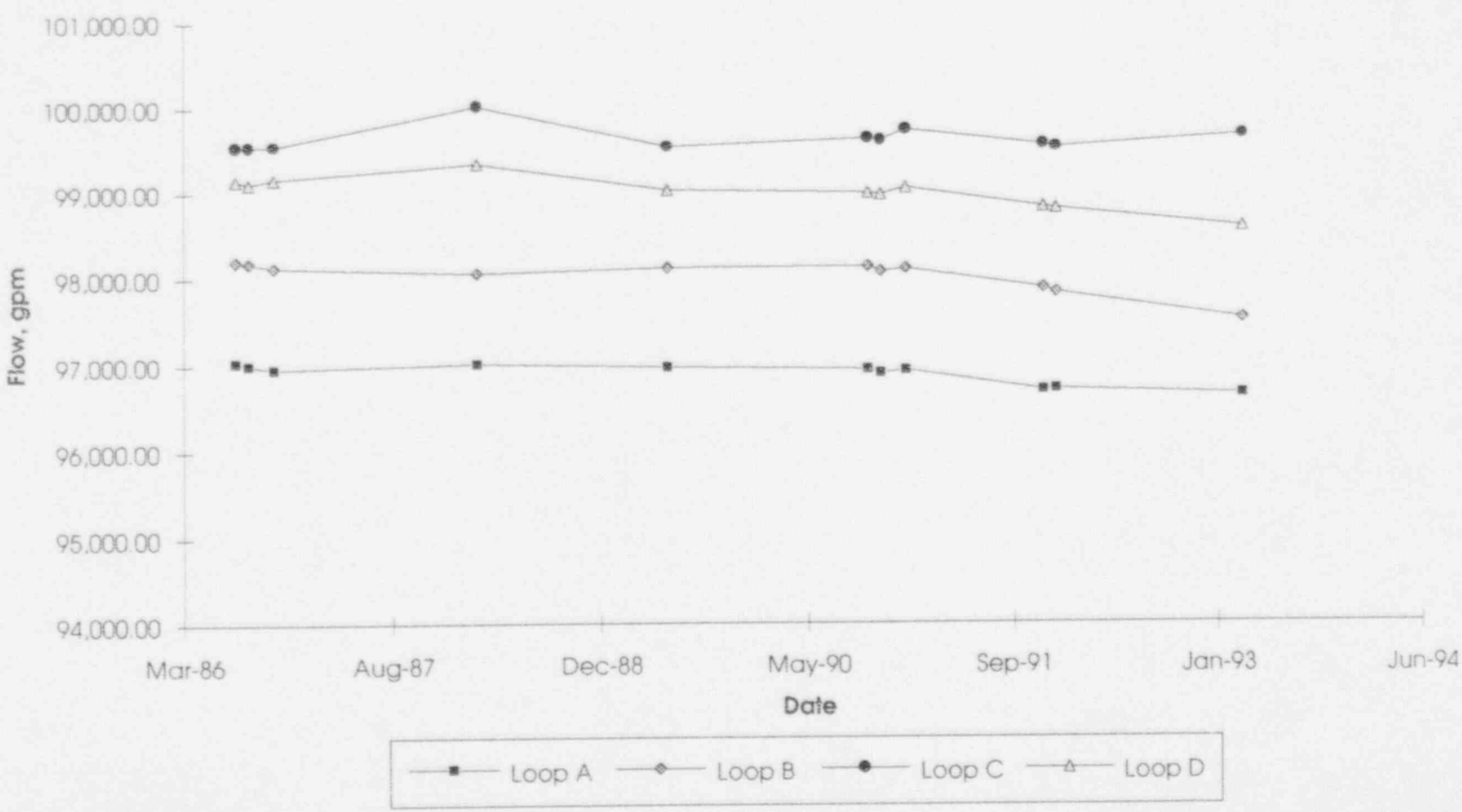


Figure 21

CNS-2 Individual Loop Steam Generator Tube Plugging Percentages

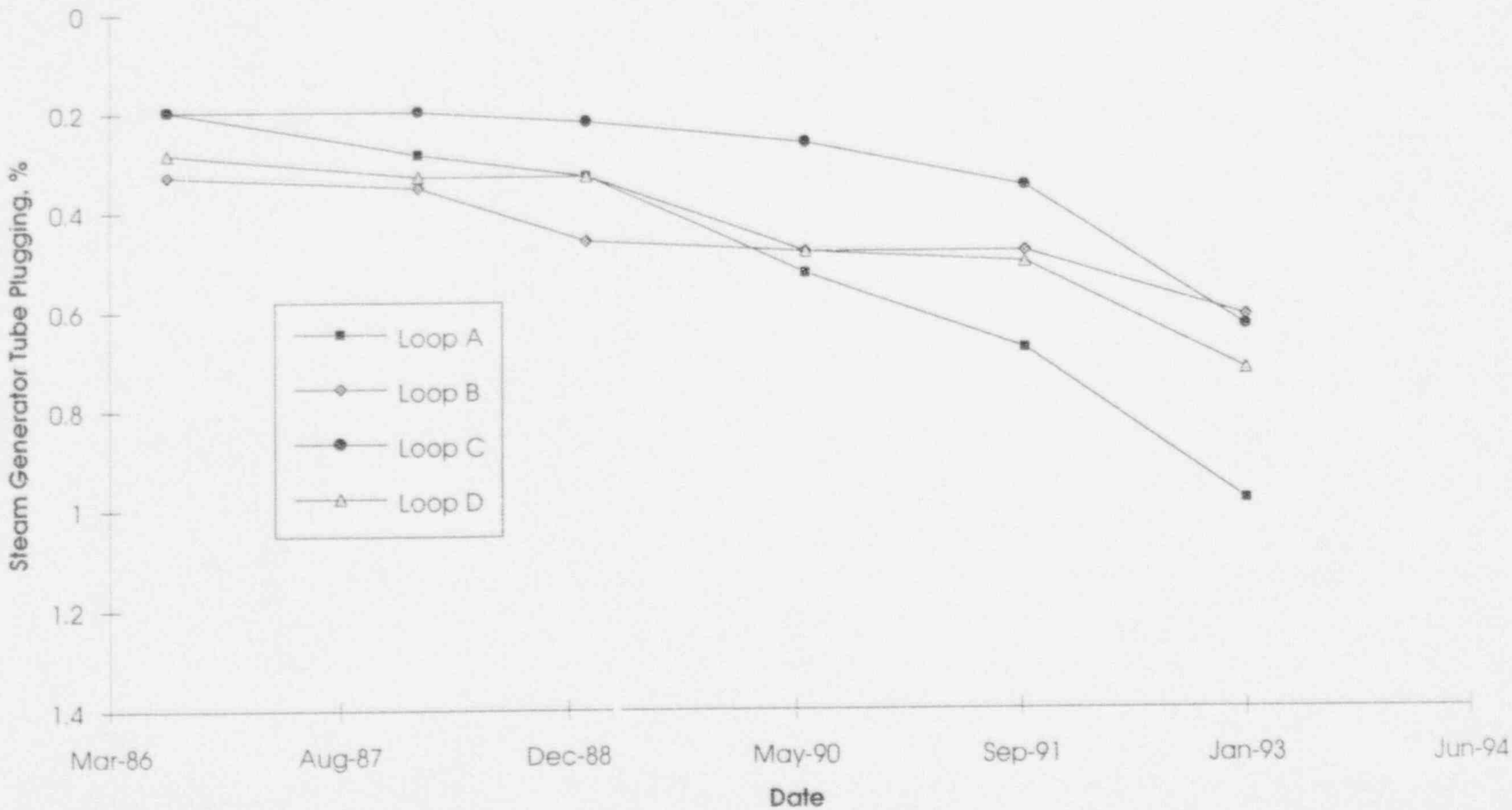


Figure 22

CNS-2 Individual Loop Flows As Determined By Analytic Flow Model

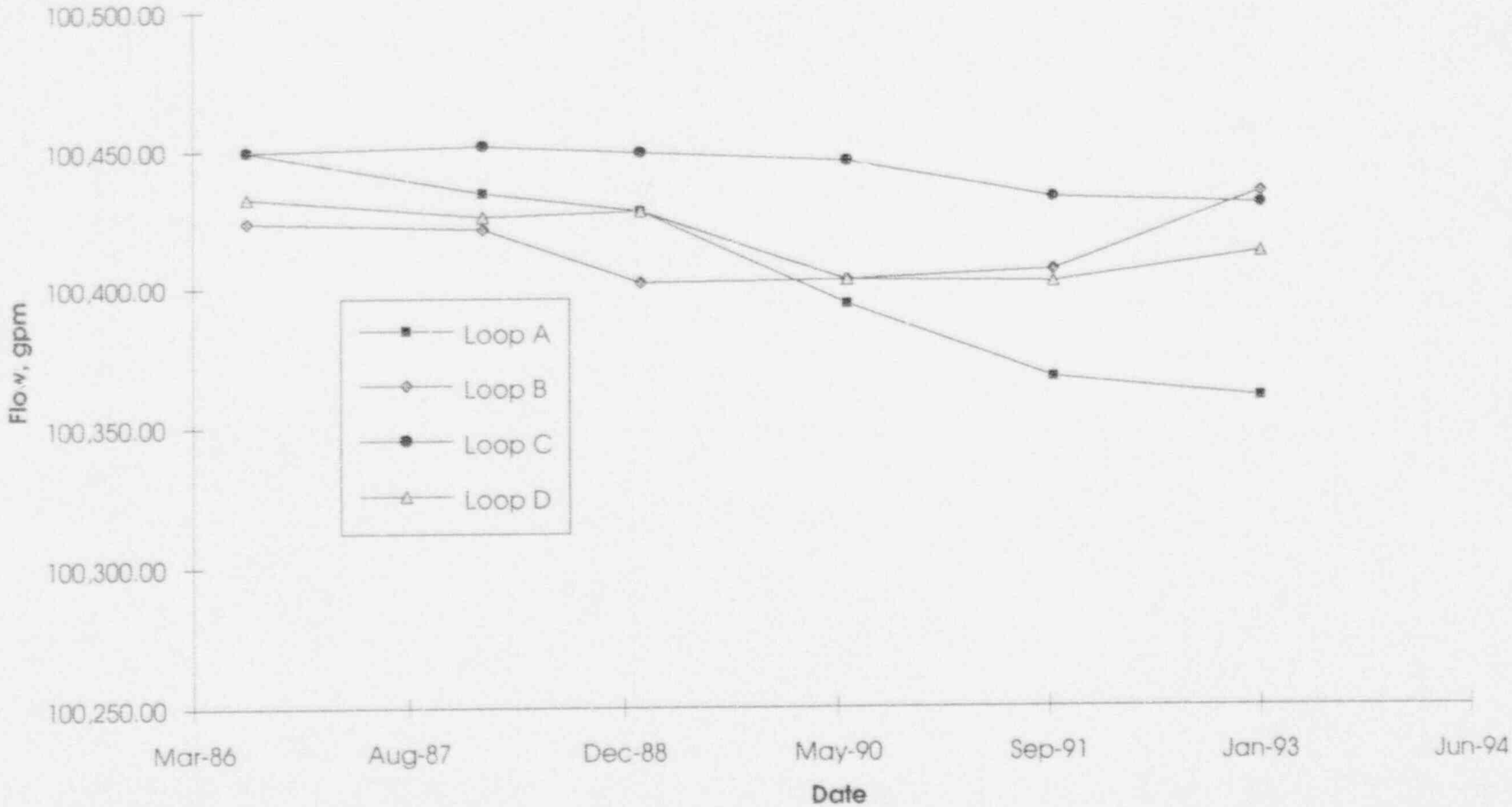


Figure 23

CNS-2 Individual Loop Flows As Determined By Analytic Flow Model

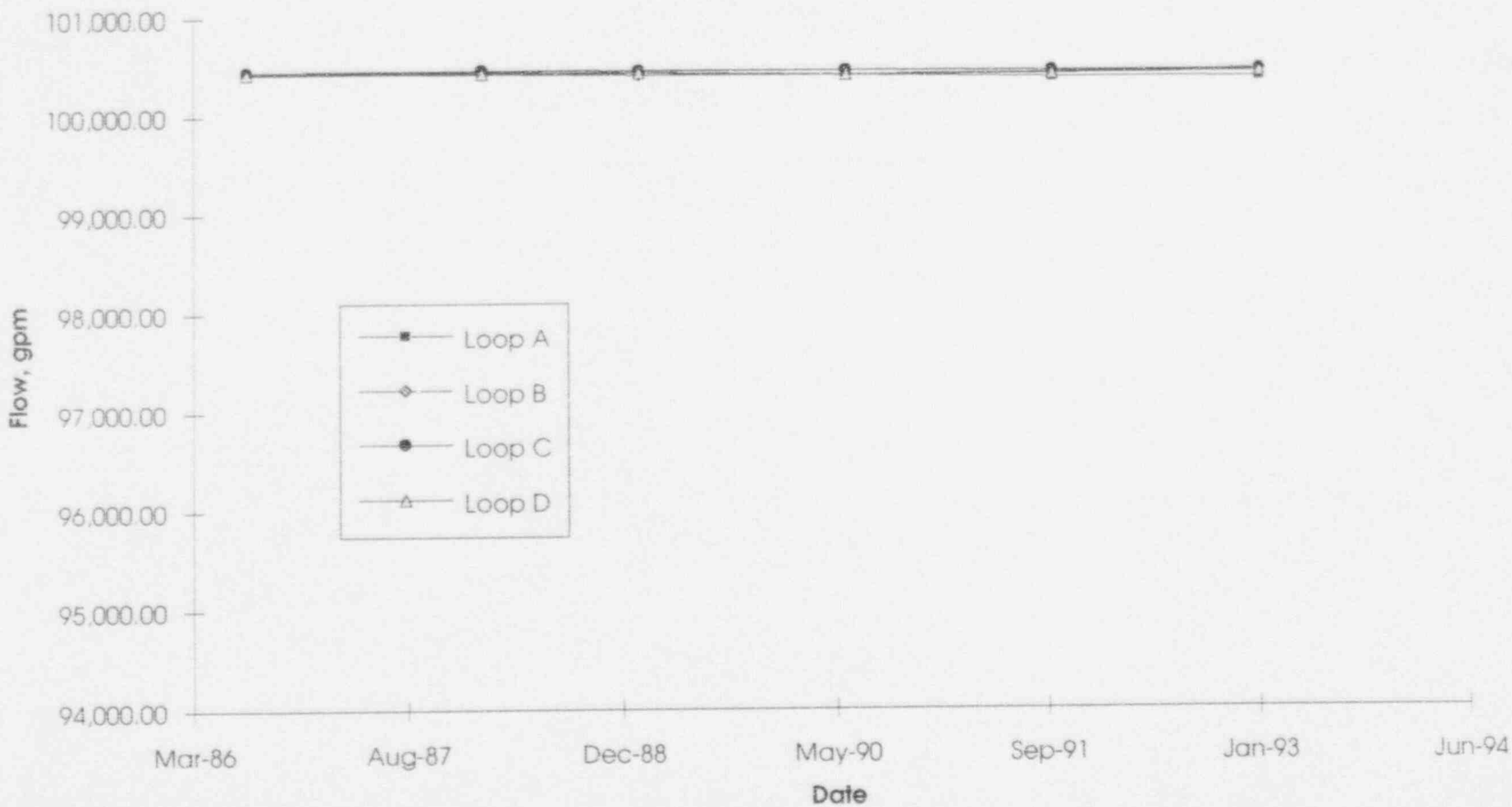


Figure 24

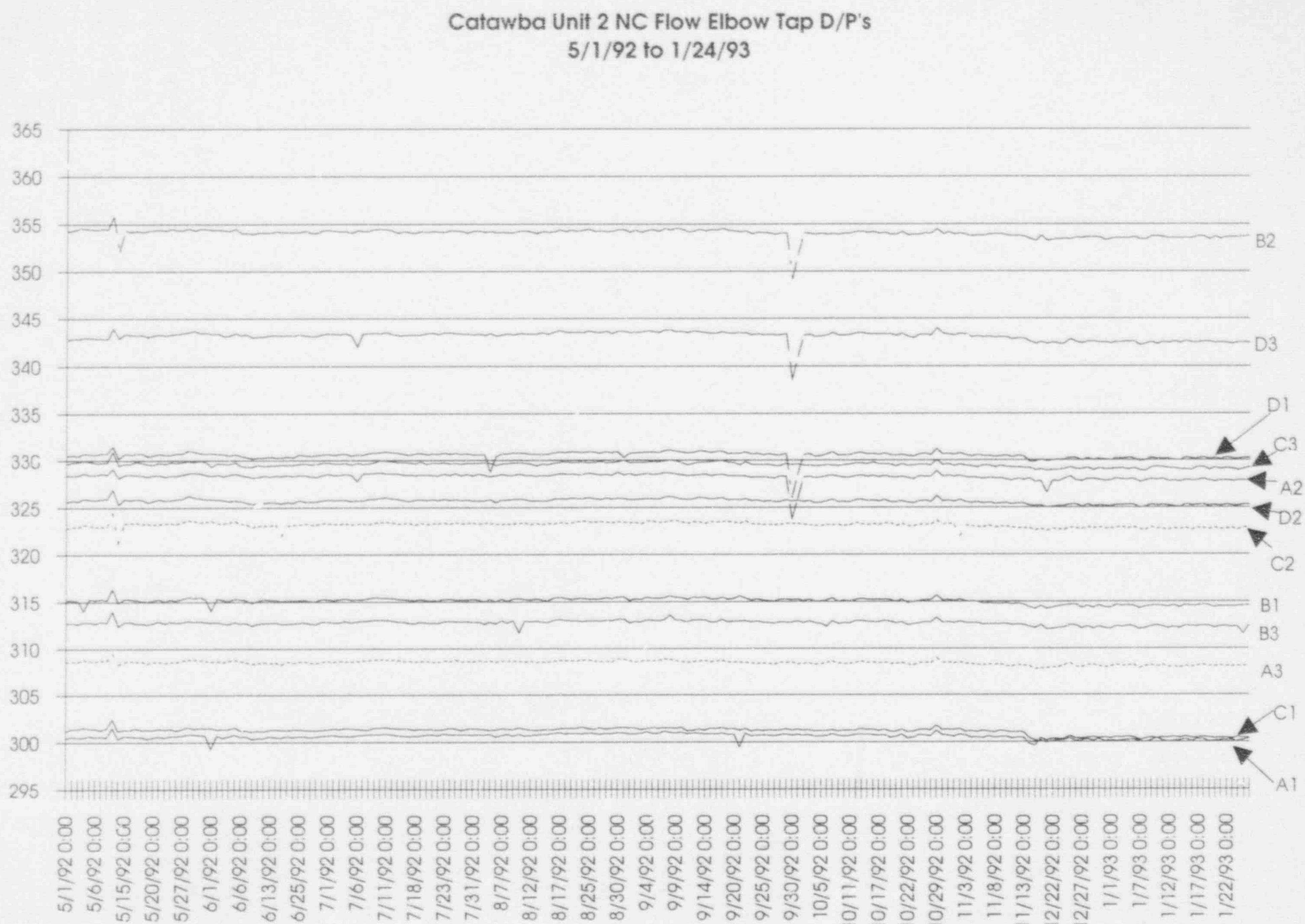

Catawba Unit 2 NC Flow Elbow Tap D/P's
5/1/92 to 1/24/93
365
360
355
350
345
340
335
330
325
320
315
310
305
300
295
B2
D3
D1
C3
A2
D2
C2
B1
B3
A3
C1
A1
5/1/92 0:00
5/6/92 0:00
5/15/92 0:00
5/20/92 0:00
5/27/92 0:00
6/1/92 0:00
6/6/92 0:00
6/13/92 0:00
6/25/92 0:00
7/1/92 0:00
7/6/92 0:00
7/11/92 0:00
7/18/92 0:00
7/23/92 0:00
7/31/92 0:00
8/7/92 0:00
8/12/92 0:00
8/17/92 0:00
8/25/92 0:00
8/30/92 0:00
9/4/92 0:00
9/9/92 0:00
9/14/92 0:00
9/20/92 0:00
9/25/92 0:00
9/30/92 0:00
10/5/92 0:00
10/11/92 0:00
10/17/92 0:00
10/22/92 0:00
10/29/92 0:00
11/3/92 0:00
11/8/92 0:00
11/13/92 0:00
12/22/92 0:00
12/27/92 0:00
1/1/93 0:00
1/7/93 0:00
1/12/93 0:00
1/17/93 0:00
1/22/93 0:00

Figure 25

Catawba Unit 2 NC Flow Elbow Tap D/P's
4/8/93 to 4/24/94

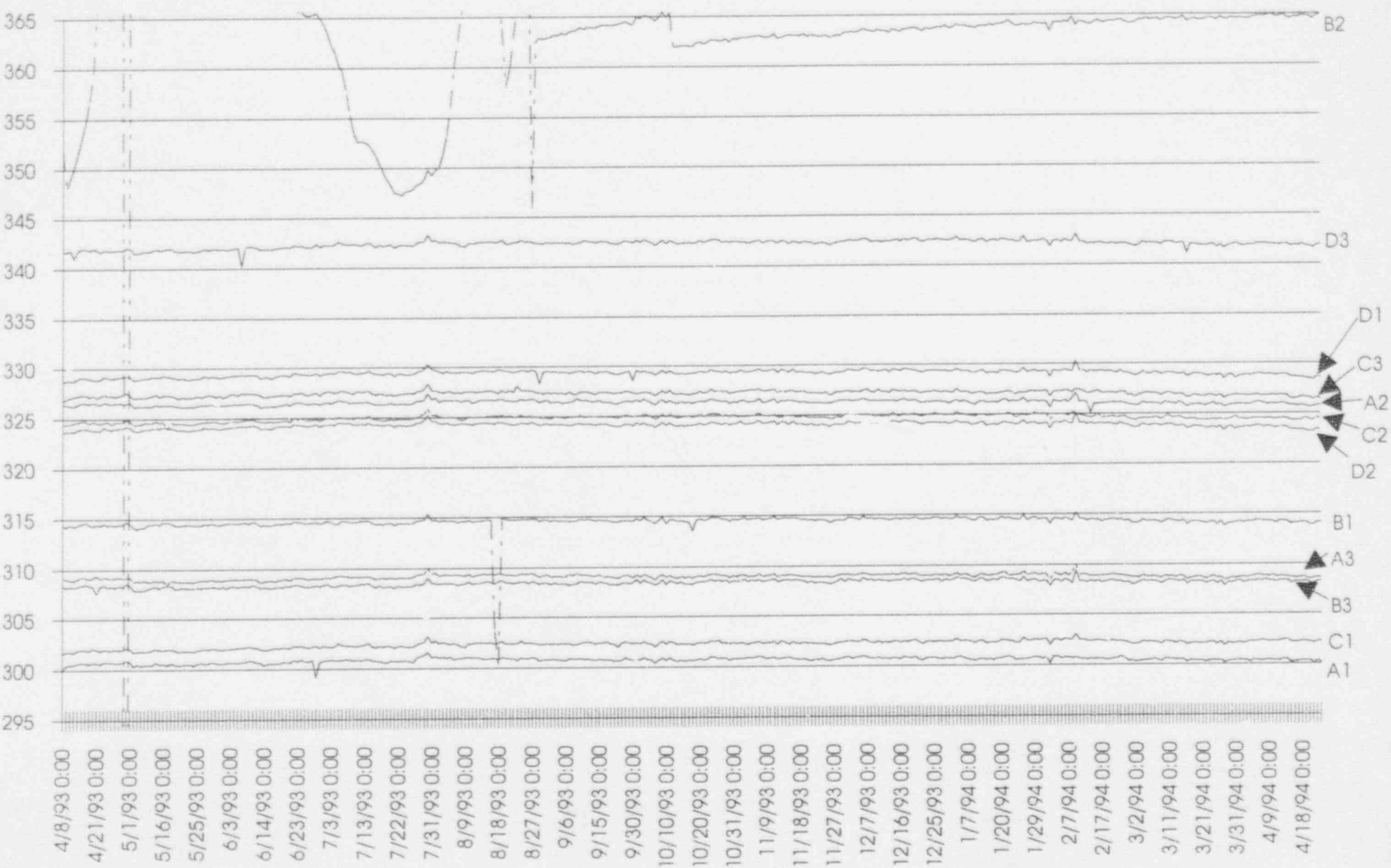


Figure 26

Attachment 1a
Non-Proprietary Version

I. Feedwater Venturi Flow Measurement Uncertainty for McGuire
(Post RTD Bypass Removal)

Parameter	Parameter Uncertainty	Sensitivity Factor	Loop Flow Uncertainty
Feedwater Flow			
Venturi (K)	Note 1	-	Note 1
Expansion			
Temperature*	3.2 °F	0.002%/°F	0.50%
Material	[		]
Density			
Temperature*	3.2 °F	0.042%/°F	0.13%
Pressure	20.7 psi	0.0005%/psi	0.01%
Differential Pressure			
Instrument	0.03%	0.5%/%	0.02%
Process Fluctuation	1.8%	0.5%/%	0.9%

* - indicate dependent parameters.

Note 1 Venturis are normalized to ASME flow elements. The uncertainty in feedwater flow using the ASME flow elements is 0.59% flow.

The combination of the random components using SRSS is provided below:

[ ] = 0.913% flow per venturi tap set

The above feedwater flow uncertainty is conservatively rounded to 0.92% flow. This uncertainty is then converted to total feedwater flow uncertainty for 4 venturis with 2 tap sets per venturi using the following relationship:

[ ] = 0.33% total feedwater flow

Combining the this feedwater flow uncertainty with the uncertainty for the ASME flow elements above gives the following venturi flow constant uncertainty:

[ ] = 0.68% total feedwater flow

2. Calorimetric Contribution to McGuire Flow Measurement Uncertainty
(Post RTD Bypass Removal)

Parameter	Parameter Uncertainty	Sensitivity Factor	Loop Flow Uncertainty
Feedwater Flow			
Constant K	0.68%	2.0	1.36%
ΔP & Fluctuation	0.33%	2.0	0.66%
Tempering Flow	15%	0.0335%/%	0.50%
Feedwater Enthalpy			
Temperature	[		]
Pressure			
Steam Enthalpy			
Pressure	40 psi	0.0046%/psi	0.18%
Carryover	[		]
SG Blowdown	20%	0.0001%/%	0.002%
Hot Leg Enthalpy			
Temperature (RTD)	[		]
Temerature (DVM)	0.2 °F	1.905%/°F	0.381%
Pressure*	[		]
Streaming	1.[illegible] °F	1.905%/°F	2.286%
Pump Power	[		]
Heat Losses	20%	0.0004%/%	0.008%
Charging Flow	20%	0.0015%/%	0.030%
Letdown Flow	20%	0.0015%/%	0.030%
Cold Leg Enthalpy			
Temperature (RTD)**	0.5 °F	1.560%/°F	0.780%
Temerature (DVM)***	0.2 °F	1.560%/°F	0.312%
Pressure*	[		%]
Cold Leg Specific Volume			
Temperature (RTD)**	0.5 °F	0.145%/°F	0.073%
Temerature (DVM)***	0.2 °F	0.145%/°F	0.029%
Pressure*	[		]

*, **, *** - indicate dependent parameters.

The combination of the random components using SRSS is provided below:

[ ] = 3.13% flow per loop

The above loop flow uncertainty is converted to total RCS flow uncertainty for a four loop plant while also incorporating a [ ]psi or[ ]% flow Barton bias (pressurizer pressure) uncertainty.

[ ] = [ ] = 1.62% Total primary system flow

3. Current McGuire Total RCS Flow Technical Specification Surveillance Uncertainty

(Post RTD Bypass Removal)

Parameter	Allowance	% Flow
Process Measurement Accuracy (PMA)		
Primary Element Accuracy		
Sensor Calibration Accuracy (SCA)		
Sensor Drift (SD)		
Sensor Temperature Effects (STE)		
Sensor Pressure Effects (SPE)		
Rack Calibration Accuracy (RCA)		
Rack Drift (RD)		
Rack Temperature Effects (RTE)		
Computer Isolator Drift (ID)		
Allowance for noisy signal (RDOT)		
Analog to digital conversion accuracy (A/D)		

The above uncertainties are combined using the equation below:

CSA = [ ]

CSA = 1.47 % flow (Single elbow tap uncertainty)

The uncertainty associated with the precision calorimetric ([ ]% flow + [ ]% bias) is combined with the RCS flow process instrumentation uncertainty above. Assuming two out of the three elbow taps in a given loop are available to measure flow, the normalized elbow meter flow uncertainty is determined as follows:

[ ] = 1.70% RCS flow

4. Current McGuire Low RCS Loop Flow Reactor Trip Function Measurement Uncertainty
(Post RTD Bypass Removal)

Parameter	Allowance	% Flow span
Process Measurement Accuracy (PMA)		
Density effects on ΔP cell	0.40% flow	0.33
Precision flow calorimetric	1.60% flow	1.33
Noise		
Sensor Calibration Accuracy (SCA)		
Sensor Drift (SD)		
Sensor Temperature Effects (STE)		
Sensor Pressure Effects (SPE)		
Rack Calibration Accuracy (RCA)		
Rack Comparator Setting Accuracy (RCSA)		
Rack Drift (RD)		
Rack Temperature Effects (RTE)		
Bias, Barton transmitter, (Pressurizer pressure)		

The above uncertainties are combined using the equation below:

CSA = [ ]

CSA = 1.94 % flow span (2.33 % flow)

The Allowable Value is calculated below:

Total Allowance (TA) = 2.92 % flow span or 3.50 % flow.

T_1 = [ ] = 1.07 % flow span

T_2 = [ ] = 1.32% flow span

$T_1 < T_2$ therefore the limiting Trigger Value is 1.07 % flow span or 1.28 % flow

Since the Trigger Value in Tech. Specs. was already at a conservative value of 1.2 % flow at this time no change in the current Allowable Value was made. Therefore, with a McGuire loss of flow setpoint at 90 % flow, the Allowable Value was left at 88.8 % flow.

5. Feedwater Venturi Flow Measurement Uncertainty for Catawba

(Post RTD Bypass Removal)

Parameter	Parameter Uncertainty	Sensitivity Factor	Loop Flow Uncertainty
Feedwater Flow			
Venturi (K)	Note 1	-	Note 1
Expansion			
Temperature*	1.0 °F	0.002%/°F	0.002%
Material	[		]
Density			
Temperature*	1.0 °F	0.043%/°F	0.043%
Pressure	30 psi	0.00052%/psi	0.0156%
Differential Pressure			
Instrument	0.72%	0.72%/%	0.52%
Process Fluctuation	0.22%	0.5%/%	0.11%

* - indicate dependent parameters.

Note 1 Venturis are normalized to ASME flow elements. The uncertainty in feedwater flow using the ASME flow elements is 0.59% flow.

The combination of the random components using SRSS is provided below:

[ ] = 0.54% flow per venturi tap set

This uncertainty is then converted to total feedwater flow uncertainty, for 4 venturis using 1 tap set per venturi, with the following relationship:

[ ] = 0.27% total feedwater flow

Combining the this feedwater flow uncertainty with the uncertainty for the ASME flow elements above gives the following venturi flow constant uncertainty:

[ ] = 0.65% total feedwater flow

6. Calorimetric Contribution to Catawba Flow Measurement Uncertainty
(Post RTD Bypass Removal)

Parameter	Parameter Uncertainty	Sensitivity Factor	Loop Flow Uncertainty
Feedwater Flow			
Constant K	0.65%	2.0	1.30%
ΔP & Fluctuation	0.27%	2.0	0.54%
Tempering Flow	15%	0.0335%	0.50%
Feedwater Enthalpy			
Temperature	1.0 °F	0.143%/°F	0.143%
Pressure	30 psi	0.0001%/psi	0.003%
Steam Enthalpy			
Pressure	40 psi	0.0049%/psi	0.196%
Carryover	[		]
Hot Leg Enthalpy			
Temperature (RTD)			
Temerature (DVM)	0.0 °F	0.193%/°F	0.0%
Pressure*	30 psi	0.00923%/psi	0.28%
Streaming (random)	[		]
Streaming (systematic)			
Pump Power/Heat Losses	-	-	0.1%
Cold Leg Enthalpy			
Temperature (RTD)**	[		]
Temerature (DVM)***	0.2 °F	1.563%/°F	0.313%
Pressure*	30 psi	0.00258%/psi	0.077%
Cold Leg Specific Volume			
Temperature (RTD)**	[		]
Temerature (DVM)***	0.2 °F	0.146%/°F	0.029%
Pressure*	30 psi	0.00138%/psi	0.041%

*, **, *** - indicate dependent parameters.

No SG Blowdown uncertainty is listed above since the uncertainty is small and only affects the combination of the random components in the sixth decimal place.

The combination of the random components using SRSS is provided below:

[[

] = 2.45% flow per loop

Incorporation of the [ ]% Barton bias and [ ]% systematic streaming allowance results in the following total primary system flow uncertainty:

[ ] = [ ] = 1.75% Total primary system flow

7. Current Catawba Total RCS Flow Technical Specification Surveillance Uncertainty
(Post RTD Bypass Removal)

Parameter	Allowance	% Flow
Process Measurement Accuracy (PMA)		
Primary Element Accuracy		
Sensor Calibration Accuracy (SCA)		
Sensor Drift (SD)		
Sensor Temperature Effects (STE)		
Sensor Pressure Effects (SPE)		
Rack Calibration Accuracy (RCA)		
Rack Drift (RD)		
Rack Temperature Effects (RTE)		
Computer Isolator Drift (ID)		
Allowance for noisy signal (RDOT)		
Analog to digital conversion accuracy (A/D)		

The above uncertainties are combined using the equation below:

CSA = [ ]

CSA = 1.5 % flow (Single elbow tap uncertainty)

The uncertainty associated with the precision calorimetric ([1.69]% flow + [0.06]% bias) is combined with the RCS flow process instrumentation uncertainty above. Assuming two out of the three elbow taps in a given loop are available to measure flow, the normalized elbow meter flow uncertainty is determined as follows:

[ ] = 1.83% RCS flow

8. Current Catawba Low RCS Loop Flow Reactor Trip Function Measurement Uncertainty
(Post RTD Bypass Removal)

Parameter	Allowance	% Flow span
Process Measurement Accuracy (PMA)		
Density effects on ΔP cell	0.40% flow	0.33
Precision flow calorimetric	1.60% flow	1.33
Noise		
Sensor Calibration Accuracy (SCA)		
Sensor Drift (SD)		
Sensor Temperature Effects (STE)		
Sensor Pressure Effects (SPE)		
Rack Calibration Accuracy (RCA)		
Rack Comparator Setting Accuracy (RCSA)		
Rack Drift (RD)		
Rack Temperature Effects (RTE)		
Bias, Barton transmitter, (Pressurizer pressure)		

The above uncertainties are combined using the equation below:

$$CSA = \left[\qquad \right]$$

CSA = 1.96 % flow span (2.35 % flow)

The Allowable Value is calculated below:

Total Allowance (TA) = 2.92 % flow span or 3.50 % flow.

$T_1 = \left[\qquad \right] = 1.11$ % flow span

$T_2 = \left[\qquad \right] = 1.32$% flow span

$T_1 < T_2$ therefore the limiting Trigger Value is 1.11 % flow span or 1.33 % flow

Therefore, with a Catawba loss of flow setpoint at 90 % flow, a conservative Trigger Value of 1.2 % flow is assumed and results in an Allowable Value of 88.8 % flow.

9. Proposed McGuire Total RCS Flow Technical Specification Surveillance Uncertainty
(For Proposed Elbow Tap Flow Surveillance)

Parameter	Allowance	% Flow *
Process Measurement Accuracy (PMA)		
Density effects on ΔP cell		
Noise		
Sensor Calibration Accuracy (SCA)		
Sensor Measurement & Test Equipment (SMTE)		
Sensor Drift (SD)		
Sensor Temperature Effects (STE)		
Sensor Pressure Effects (SPE)		
Rack Calibration Accuracy (RCA)		
Rack Drift (RD)		
Rack Temperature Effects (RTE)		
Computer Isolator Drift (ID)		
Allowance for noisy signal (RDOT)		
Analog to digital conversion accuracy (A/D)		

$$\text{* Allowance in \%Flow} = \left(\frac{\text{Allowance in } \Delta P \text{ span}}{2}\right)\left(\frac{120\% \text{ Flow span}}{100\% \ \Delta P \text{ span}}\right)\left(\frac{120\% \text{ Flow}}{100\% \text{ Flow span}}\right)$$

The above uncertainties are combined using the equation below:

CSA =

CSA

CSA = 1.92 % flow (Single elbow tap uncertainty)

The uncertainty associated with the precision calorimetric [ ]% flow + [ ]% bias) is combined with the RCS flow process instrumentation uncertainty above. The total flow is

assumed to be calculated using only two of the three elbow taps per loop. Therefore, the single loop flow uncertainty expressed as a percent of loop flow may be expressed as a percent of total RCS flow by dividing by the [ ]. The resulting RCS flow uncertainty is:

[ ] = 1.76% flow (Total 4 Loop RCS flow uncertainty)

The flow uncertainties for the McGuire loss of flow setpoint are given in the table below.

10. Proposed McGuire Low RCS Loop Flow Reactor Trip Function Measurement Uncertainty

Parameter	Allowance	% Flow*
Process Measurement Accuracy (PMA)	[	]
Density effects on ΔP cell		
Precision flow calorimetric		3.13
Noise	[	]
Sensor Calibration Accuracy (SCA)	0.50% ΔP span	0.36
Sensor Measurement & Test Equipment (SMTE)	0.31% ΔP span	0.22
Sensor Drift (SD)	[	]
Sensor Temperature Effects (STE)	0.65% ΔP span	0.47
Sensor Pressure Effects (SPE)	0.50% ΔP span	0.36
Rack Calibration Accuracy (RCA)	[	]
Rack Comparator Setting Accuracy (RCSA)	0.35% ΔP span	0.25
Rack Drift (RD)	[	
Rack Temperature Effects (RTE)		
Bias, Barton transmitter, (Pressurizer pressure)		]

$$* \text{ Allowance in \%Flow} = \left(\frac{\text{Allowance in }\Delta P\text{ span}}{2}\right)\left(\frac{120\%\text{ Flow span}}{100\%\ \Delta P\text{ span}}\right)\left(\frac{120\%\text{ Flow}}{100\%\text{ Flow span}}\right)$$

The above uncertainties are combined using the equation below:

CSA [ ]

CSA = [ ]

CSA = 3.79 % flow

The Allowable Value is calculated below.

Safety Analysis Limit = 86.5% flow

Total Allowance (TA) = 4.50 % flow

An increase in the total allowance from 3.50% flow to 4.50% flow was made to maintain the allowable value at or near its current value. This will prevent the need for excessive transmitter calibrations resulting from an allowable value which is too close to the setpoint.

T_1 = [ ] = 1.33 % flow

T_2 = [ ]

T_2 = 1.0 % flow

$T_1 > T_2$ therefore T_2 is used to calculate the Allowable Value of 90 % flow

The table below summarizes the changes necessary to account for the additional uncertainty associated with using the unnormalized elbow taps for flow surveillance.

	CSA	TS Setpoint/Allowable Value	Margin	Total Allowance
Existing	2.33% flow	90%/88.8% flow	1.17% flow	3.50% flow
Proposed	3.79% flow	91%/90% flow	0.71% flow	4.50% flow

II. Proposed Catawba Total RCS Flow Technical Specification Surveillance Uncertainty
(For Proposed Elbow Tap Flow Surveillance)

Parameter	Allowance	% Flow *
Process Measurement Accuracy (PMA)		
Density effects on ΔP cell	0.50% ΔP span	0.36
Noise	[	]
Sensor Calibration Accuracy (SCA)	0.50% ΔP span	0.36
Sensor Measurement & Test Equipment (SMTE)	0.20% ΔP span	0.14
Sensor Drift (SD)	[	]
Sensor Temperature Effects (STE)	0.70% ΔP span	0.50
Sensor Pressure Effects (SPE)	0.50% ΔP span	0.36
Rack Calibration Accuracy (RCA)	[	
Rack Drift (RD)		
Rack Temperature Effects (RTE)		
Computer Isolator Drift (ID)		
Allowance for noisy signal (RDOT)		
Analog to digital conversion accuracy (A/D)		]

$$\text{* Allowance in \%Flow} = \left(\frac{\text{Allowance in } \Delta P \text{ span}}{2}\right)\left(\frac{120\% \text{ Flow span}}{100\% \ \Delta P \text{ span}}\right)\left(\frac{120\% \text{ Flow}}{100\% \text{ Flow span}}\right)$$

The above uncertainties are combined using the equation below:

CSA = [ ]

CSA = [ ]

CSA = 1.89 % flow (Single elbow tap uncertainty)

The uncertainty associated with the precision calorimetric ([ ]% flow + [ ]% bias) is combined with the RCS flow process instrumentation uncertainty above. The total flow is assumed to be calculated using only two of the three elbow taps per loop. The resulting RCS flow uncertainty is:

= 1.88% flow (Total 4 Loop RCS flow uncertainty)

The flow uncertainties for the Catawba loss of flow setpoint are given in the table below.

12. Proposed Catawba Low RCS Loop Flow Reactor Trip Function Measurement Uncertainty

Parameter	Allowance	% Flow*
Process Measurement Accuracy (PMA)		
Density effects on ΔP cell	[	]
Precision flow calorimetric		2.71
Noise	[	]
Sensor Calibration Accuracy (SCA)	0.50% ΔP span	0.36
Sensor Measurement & Test Equipment (SMTE)	0.20% ΔP span	0.14
Sensor Drift (SD)	[	]
Sensor Temperature Effects (STE)	0.70% ΔP span	0.50
Sensor Pressure Effects (SPE)	0.50% ΔP span	0.36
Rack Calibration Accuracy (RCA)	[	
Rack Comparator Setting Accuracy (RCSA)		
Rack Drift (RD)		
Rack Temperature Effects (RTE)		
Bias, Barton transmitter, (Pressurizer pressure)		]

$$* \text{ Allowance in \%Flow} = \left(\frac{\text{Allowance in } \Delta P \text{ span}}{2}\right)\left(\frac{120\% \text{ Flow span}}{100\% \ \Delta P \text{ span}}\right)\left(\frac{120\% \text{ Flow}}{100\% \text{ Flow span}}\right)$$

The above uncertainties are combined using the equation below:

CSA = [ ]

CSA = [ ]

CSA = 3.42 % flow

The Allowable Value is calculated below.

Safety Analysis Limit = 86.5% flow

Total Allowance (TA) = 4.50 % flow.

An increase in the total allowance from 3.50% flow to 4.50% flow was made to maintain the allowable value at or near its current value. This will prevent the need for excessive transmitter calibrations resulting from an allowable value which is too close to the setpoint.

T_1 = [ ] = 1.3 % flow

T_2 = [ ]

T_2 = 1.34 % flow

$T_1 < T_2$ therefore T_1 was used to calculate the Allowable Value of 89.7 % flow

The table below summarizes the changes necessary to account for the additional uncertainty associated with using the unnormalized elbow taps for flow surveillance.

	CSA	TS Setpoint/Allowable Value	Margin	Total Allowance
Existing	2.35% flow	90%/88.8% flow	1.15% flow	3.50% flow
Proposed	3.42% flow	91%/89.7% flow	1.08% flow	4.50% flow

Attachment 1

This attachment summarizes the following twelve uncertainty calculations:

1. Feedwater Venturi Flow Measurement Uncertainty for McGuire
2. Calorimetric Contribution to McGuire Flow Measurement Uncertainty
3. Current McGuire Total RCS Flow Technical Specification Surveillance Uncertainty
4. Current McGuire Low RCS Loop Flow Reactor Trip Function Measurement Uncertainty
5. Feedwater Venturi Flow Measurement Uncertainty for Catawba
6. Calorimetric Contribution to Catawba Flow Measurement Uncertainty
7. Current Catawba Total RCS Flow Technical Specification Surveillance Uncertainty
8. Current Catawba Low RCS Loop Flow Reactor Trip Function Measurement Uncertainty
9. Proposed McGuire Total RCS Flow Technical Specification Surveillance Uncertainty
10. Proposed McGuire Low RCS Loop Flow Reactor Trip Function Measurement Uncertainty
11. Proposed Catawba Total RCS Flow Technical Specification Surveillance Uncertainty
12. Proposed Catawba Low RCS Loop Flow Reactor Trip Function Measurement Uncertainty