FROM: Northern States Power Company
Minneapolis, Minnesota 55401
R. O. Duncanson

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TO:

Dr. Peter A. Morris

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ACTION NECESSARY ☐

NO ACTION NECESSARY ☐

CONCURRENCE ☐

COMMENT ☐

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ENCLOSURES:

REPORT: Turbine Lockout Following Generator Trip Test frmm 15% Power and Subsequent Events.

(3 cys rec'd)

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NSP

NORTHERN STATES POWER COMPANY
Minneapolis, Minnesota 55401

March 22, 1971

Dr. Peter A. Morris, Director
Division of Reactor Licensing
United States Atomic Energy Commission
Washington, D.C. 20545

Dear Dr. Morris:

MONTICELLO NUCLEAR GENERATING PLANT
Docket No. 50-263 License No. DPR-22

Turbine Lockout Following Generator Trip Test
from 15% Power and Subsequent Events

A condition occurred at the Monticello Nuclear Generating Plant on March 10, 1971 which we are reporting to your office in accordance with the reporting requirements of Section 6.6.A and 6.6.B of Appendix A, Technical Specifications, of the Provisional Operating License DPR-22. The Region III Compliance office has been notified in accordance with the reporting requirements of Section 6.6.A of the Technical Specification.

The attached report, "Turbine Lockout Following Generator Trip Test from 15% Power and Subsequent Events" describes the details of the occurrence and the corrective actions taken as a result of the occurrence.

Yours very truly,

R O Duncanson Jr

R.O. Duncanson, Jr., P.E.
Gen. Supt. of Power Plants - Mechanical
Chairman - Monticello Safety Audit Committee

ROD/CEL/caf

1437

DL

March 23, 1971

MONTICELLO NUCLEAR GENERATING PLANT

Subject: Turbine Lockout Following Generator Trip Test from 15% Power and Subsequent Events

1. Summary Description of the Occurrence

Following a generator trip test from approximately 15% power, at 0255 on March 10, a turbine lockout occurred resulting in a loss of plant auxiliary power and a reactor scram. The emergency buses properly transferred to the 1AR reserve transformer and the remaining buses were manually re-energized through the 1R reserve transformer. Following restoration of auxiliary power, the reactor recirculation pumps could not be restarted. A failure of the seals on the No. 12 pump occurred at approximately 3:20 A.M. and the pump could not be isolated until approximately 4:20 A.M. The drywell pressure increased approximately 1 psi and was vented through the Standby Gas Treatment System. Reactor conditions remained normal during the occurrence and the stack release rate remained below 100 microcuries per second.

2. Detailed Description of the Occurrence

a. Description of Generator Trip Test

The generator trip test (load rejection) is initiated by opening the generator output breakers 8N4 and 8N5. When this sudden load rejection occurs, the turbine-generator begins to accelerate. As speed increases, the turbine governor closes the control valves. If the rate of acceleration is high, as it would be if the rejection was from a high load, an acceleration relay causes a fast closure of the control valves (faster than the governor). If turbine first stage pressure is above 30% of rated, on acceleration relay trip also initiates a reactor scram.

The expected plant response for the load rejection test at 15% power was as follows:

1) The turbine governor was expected to initially close the control valves and then to regulate speed, with the generator continuing to carry plant auxiliary loads through the No. 11 auxiliary transformer, at a frequency slightly above 60 Hz.

2) The main steam bypass valves were expected to open to pass the excess steam previously being supplied to the turbine. The bypass valves would then restore and maintain steam pressure under the control of the pressure regulator.

3) The reactor was expected to go through a mild pressure and neutron flux transient caused by the initial closure of the control valves and the increase in recirculation pump speed due to the increase in auxiliary power frequency.

Recovery was expected to merely require resynchronizing with the NSP system and reclosure of the generator breakers.

Prior to the test it was recognized that a loss of auxiliary power would occur if some turbine or generator protective device were to trip the turbine lockout relay while breakers 8N4 and 8N5 were open. Under these unique conditions of the test the normal automatic transfer of auxiliary power to the 1R reserve transformer does not occur, resulting in a loss of power to all auxiliary buses except the essential buses, which automatically transfer to the 1AR transformer or the diesel generators. The operators were prepared to re-establish auxiliary power by manually closing the 1R reserve transformer 4 KV breakers in the event that a turbine lockout trip was initiated, even though there was no known reason to expect it.

b. <u>Summary of Conditions Prior to Generator Trip Test</u>

Prior to the generator trip test, the reactor was in the RUN mode at rated pressure and temperature with power at 235 MWT. Reactor water level was 36 inches and the electrical pressure regulator was controlling.

In addition to the normal shift complement of five persons, including a senior licensed NSP Shift Supervisor, the following persons were on site.

- an additional NSP control room operator
- an additional NSP plant operator
- senior licensed G.E. Shift Superintendent
- senior licensed G.E. Operations Superintendent
- NSP engineer (Results Crew)
- G.E. engineer (G.E. TD&A startup group)
- NSP radiation protection man.

The following operations had taken place in preparation for opening the generator output breakers.

1) The RCIC had been started and was running in the TEST mode. This precaution was taken to provide reactor water makeup capability in the event the test was unsuccessful.

2) The plant load had been transferred to the No. 11 auxiliary transformer.

3) The speed load changer setpoint had been set to the point just above system frequency to minimize turbine generator over speed following the generator trip. (It had been previously determined that a load rejection from 55 MWe to 5 MWe could be controlled by the bypass valves.)

4) As a precaution, operators had been dispatched to strategic points within the plant in anticipation of actions that might be necessary to recover from the test if plant response to the trip test did not go as expected.

c. <u>Account of the Occurrence</u>

025527 Generator output breaker 8N5 opened manually.

025530 Generator output breaker 8N4 opened manually.

025530 to 025617 The plant response to the load rejection test was proceeding as expected. One alarm, UNINTERRUPTIBLE MG SET DC MOTOR RUNNING was received. This action apparently resulted because of a slight frequency increase due to an expected increase in turbine generator speed.

025617 Turbine lockout occurred, causing loss of plant auxiliary power. This properly resulted in the trip of
- #11 recirc pump and MG set
- #12 recirc pump and MG set
- #11 circulating water pump
- #12 CRD pump
- #11 reactor feedwater pump
- #11 Reactor Protection System MG set
- #12 Reactor Protection System MG set

The emergency diesel generators started when power was lost, but their output breakers did not close because the essential buses were properly re-energized automatically via the 1AR transformer.

025641 Scram occurred as Reactor Protection System MG sets' output breakers were automatically tripped by their underfrequency relays. The MG sets had been coasting down for about 24 seconds following the loss of power. Because of the loss of power to the protection system, all the scram relays de-energized and primary containment isolation occurred.

0257 The RCIC system was operated to inject water into the vessel. The lowest reactor water level recorded was +14" (scram = +9") at approximately 0257, 20-30 seconds after the scram.

0258 IRMs were downranged to follow the decay of reactor power.

0258 Operator verified that the uninterruptible MG set had switched back to a-c power. #12 RPS MG set was returned to operation. (The #11 RPS MG set output breaker was reset approximately six minutes after scram. Operator in the reactor biilding apparently failed to reset the #11 RPS MG set output breaker when #12 RPS MG set was properly reset.)

0258 The #11 feedwater pump and #12 CRD pump were restarted. The RCIC system was transferred back to the TEST condition. Water level in the vessel was increasing at the rate of approximately 2 inches per minute.

0257 to 0303 An attempt to start both recirculation pumps failed; the #12 pump was started twice but tripped from a lockout each time, the #11 pump could not be restarted because of the apparent failure of a permissive interlock to operate properly. Operators were also unsuccessful in closing the suction valves to isolate each pump in an effort to protect the seals of the shutdown pumps.

(Due to the known potential damage to the pump seals, the operators had been instructed to isolate a pump within eight minutes if the pump could not be restarted after a trip.)

(See Section 4 of the report for more details.)

0310 Drywell pressure had risen from 14.65 to 15.25 psia. Observation of the recirc pump seal pressure indicators confirmed that the seals on the #12 pump had failed.

0312 Torus temperature had risen slightly as a result of dumping RCIC exhaust steam into the torus. The #11 RHR pump and #11 RHRSW pump were started to cool the torus. The RHR heat exchanger service water outlet control valve, CV-1728, failed to open. #11 RHRSW pump was tripped and restarted twice without the valve opening. Following the third start, the operator switched the valve controller to manual and the valve opened. After flow was established the controller was returned to AUTO and the valve operated properly.

031502 The reactor feedpump was taken out of service because water level had risen to 50 inches. Water was also being added to the vessel by the CRD pump.

0318 The CRD flow to the vessel was decreased by shutting off the charging water header. The RCIC (in the TEST mode) had tripped off due to high water level, but was subsequently restarted and operated in the TEST mode.

0325 Drywell pressure was increasing at the rate of about 2 psi per hour. Attempts to close the suction valves to the recirc pumps were still not successful. (At this time, it was found that the drywell sample isolation valves would not open.)

0334 The Standby Diesel Generators were stopped.

0340 The drywell pressure continued to increase and indicated 15.4 psia. It was decided to vent the drywell through the Standby Gas Treatment System. The SGTS had automatically started when power was lost and was drawing its suction from the reactor building. The 2" vents from the drywell and torus were opened to the SGTS for about two minutes; however, this was apparently not adequate and the drywell pressure indicated 15.6 psia. The 18 inch vent line was opened for approximately one minute and the pressure decreased rapidly to 14.1 psia in the drywell and 13.9 psia in the torus. Stack gas activity during venting was approximately 15 uc/sec. No additional venting of the drywell through the SGTS system occurred until approximately 0920 after drywell air sample were analyzed. (Lower level drywell temperatures had increased approximately twenty to twenty five degrees to a maximum of 101°F. Midlevel drywell temperature had increased about thirty five degrees to 106°F and the top level drywell temperature had increased about ten degrees to 120°.)

0355 The plant chief electrician was called to assist in getting the recirculation pump suction valves closed.

0355 to 0415 Reactor pressure remained steady at 920 psig. Water was being added to the vessel with the CRD pump. Water was being extracted through the cleanup system and RCIC steam was being extracted from the vessel with the RCIC in TEST.

0410 The suction valve to the #11 recirculation pump closed while an operator was continuing his attempts to close the valve from the control room. (Apparently a limit switch problem cleared to allow this action)

0410 Observation of the pump seal pressure indicated that the inner seal on the #11 pump might have failed.

0410 In preparation for re-establishing condenser vacuum, the outboard MSIV's were opened, and it was attempted to pressurize between the inboard MSIV's and the turbine stop valves by using the main steamline drain line. However, it was found that valve MO-2374, the inner drain line outboard isolation valve, would not open.

0415 The chief electrician arrived on site. After a quick briefing of the situation, the #12 recirc pump suction valve was closed by manually holding in the closing contactor on the valve motor.

0420 NSP Plant Superintendent was notified. He proceeded to the site.

0425 NSP Plant Results Engineer was notified. He proceeded to the site.

0425 to 0430 The chief electrician assisted in opening the main steam line drain isolation valves. This was accomplished by manually holding in the opening contactors at the motor control centers.

0430 NSP Radiation Protection Engineer was notified. He proceeded to the site.

0433 Turbine sealing steam was established.
The condenser vacuum pump was started.
Reactor depressurization was begun.

0445 G.E. Operations Manager arrived on site.

0500 The NSP engineer began recording the reactor pressure readings every three minutes to determine the reactor saturation temperatures. This data was being taken as part of a cooldown rate study; however, an additional purpose was accomplished since normal indication of reactor temperature is not available with both recirculation loops isolated.

0610 The final scram trip from low condenser vacuum was cleared (at approximately 570 psig reactor pressure) and the scram was reset. The scram reset cleared the drywell sampling system isolation signal.

0700 Reactor temperature was 433^{o}F.

0745 Drywell sample showed total activity (particulate) of 3.26×10^{-9} uci/ml. No iodine was detected.

0830 The cooldown rate study was terminated at approximately 365^{o}F.

0920 Dyrwell venting through the SGTS was initiated.

1135 Shutdown cooling was begun with #11 RHR pump.

1200 Drywell sample showed total activity of 3.61×10^{-11} uci/ml.

1430 Entry was made into the drywell by radiation protection man and two others for general survey of the drywell. No unusual conditions were found. Drywell temperature and humidity were normal and no moisture or moisture damage was evident. Air sample taken near the #12 recirc pump showed 3.39×10^{-10} uci/ml.

1600 Reactor vessel pressure was 15 psig and the reactor temperature was 250^{o}F.

1622 SGTS taken out of service (Subsequent DOP tests of the HEPA filters showed greater than 99.9% efficiency.)

1628 Containment was purged with normal ventilation flow discharged through the reactor building ventilation stack after the reactor water temperature had decreased below 212^{o}F.

1800 Radiation protection personnel entered the drywell and completed a contamination level survey.
#11 recirc pump (seal area) - 131,415 dpm/cm^2
#12 recirc pump (seal area) - 566,156 dpm/cm^2
Lower level from 46 to 9449 dpm/100cm^2
Upper level from 2 to 1565 dpm/100cm^2

1900 Reactor pressure was 0 psig.

2140 Reactor temperature at 100^{o}F.

March 11

0828 Drywell air sample taken near the #12 recirculation pump seal showed total activity of 5.16×10^{-11} uci/ml. No iodine was detected.

0900 Work was begun in the drywell on the #11 recirc pump seal after the pump seal area was decontaminated.

3. Response to the Occurrence

Three aspects of personnel response to the occurrence merit comment.

a. The general response of supervisors and operators to the occurrence was excellent. Priorities of action concerning the reactor conditions, restoration of plant auxiliary power, recirculation pump considerations, turbine-generator considerations and general plant conditions were proper and correct. The initial improper resetting of the #12 RPS MG set output breaker and the relatively late callout of the electrician to analyze and complete the work required to close the recirculation pump suction valves are the only apparent actions which could or should have been completed more promptly.

b. The decision to vent the drywell through the Standby Gas Treatment System, without an air sample analysis, is considered as proper action consistent with the procedural responsibilities afforded to senior licensed personnel as described in Volume A of the Operations Manual. Momentary venting of the drywell approximately 40 minutes after the shutdown was decided with the knowledge and understanding of existing plant conditions.

c. The Reactor Log entries (late entries) describing operator actions in response to the occurrence understandably cannot provide a detailed timely account of all operator actions. Recognizing this, consideration is being given to furnish the control room with a tape recorder to allow the operators to maintain an account of their actions during extremely busy times and provide the means for more accurate and complete late entries in the Reactor Log.

4. Corrective Actions Required

The following aspects of the occurrence required investigative or corrective actions.

a. Cause of Turbine Lockout

The cause of the turbine trip cannot be absolutely established but the most probable cause was a high water level trip from a moisture separator tank. Moisture separator drain tank high levels are alarmed; however, the moisture separator high level trips which operate the turbine lockout relay directly are not alarmed. No other possible initiating conditions are known to have existed at the time of the turbine lockout.

The four moisture separator drain tank drain valves and controls were checked out and one drain valve was found to operate improperly. The valve was repaired.

The moisture separator tank high level switches have been connected to the computer and will initiate a sequence of vents log entry for any future moisture separator tank high level condition.

b. Failure of the Recirculation Pumps to Restart

When the turbine lockout occurred, both recirculation pumps were tripped directly from the turbine lockout relays. The turbine lockout bypass switches were placed in the "bypass" position; however, the pump drive motor breakers would not close. Further investigation revealed that the loss of power to the RPS MG sets causes primary isolation which also trips the recirculation pumps. Following the return of the RPS MG sets to service, the No. 12 recirculation pump was started but tripped from a lockout approximately 5 seconds following the generator field application. A second attempt to start the No. 12 pump resulted in a similar lockout trip. Attempts to restart the No. 11 recirculation pump were unsuccessful because of the failure of a valve position permissive interlock to operate properly.

The failure of the No. 12 pump to start has been traced to an incorrect setting on the pump differential pressure time delay relay installed in the auto start sequencing logic and a zero shift in the pump differential pressure transmitter at 1000 psig. The differential pressure transmitters for both pumps have been calibrated to eliminate the zero shift problem and the entire auto start sequencing logic for both pumps has been checked for proper time delay settings.

Recirculation pumps are started with the suction valve open, discharge valve closed and the discharge bypass valve open. These valve positions are interlocked to the pump start circuit and if they are not properly set, the pump motor breaker is prevented from closing. All recirculation system valve interlocks have been checked and readjusted where necessary to assure proper interlock operation.

Proper operation of the recirculation pumps and valves has been verified by testing in the cold condition. Hot restarts of the pumps and proper operations of the system valves will be completed in conjunction with 25% power level testing (loss of power test) scheduled to occur within approximately one week.

c. Failure of the Recirculation Pump Suction Valves to Close and the Main Steam Line Drain Valves to Open

The failure of the recirculation system suction valves to close and the main steam line drain valves to open was caused by improperly set torque limit switches. Torque switch settings on all recirculation system valves and on the steam line drain valves have been checked and properly reset where required. Testing of the valves has been completed under cold system conditions to verify proper operation.

The problem encountered with the torque switch settings has prompted a review of the torque switch setting practices and the operational testing of the related valves under their normal operating temperatures.

Additional valves have been checked for proper operation and, if necessary, additional valve testing will be conducted at rated temperature and pressure prior to further power testing. A program for continual surveillance of torque switch settings and the operation of their related valves will be established.

d. Failure of the Recirculation Pump Seals

On March 5, 1971, the No. 11 recirculation pump was inadvertently tripped at rated pressure and temperature conditions but was successfully restarted on the second attempt. During this pump trip, the seal temperature had increased to the point of concern. Discussions with Bingham pump personnel on March 8th revealed that seal leakoff isolation valves are required in the seal leakoff lines (following the upper seal pressure breakdown coil - see attached figure) to prevent seal damage following a pump trip unless the pump can be restarted within 10 to 15 minutes. Tripping a recirculation pump without the isolation valves results in primary system water leaking past the pump bearing and lower seal resulting in a failure of the lower and upper tungsten carbide seals due to thermal shock conditions.

On the basis of the information received from the pump manufacturer, the operators were instructed to isolate a recirculation pump within eight minutes after it tripped if the pump could not be restarted. Also, the installation of the seal leakoff isolation valves was planned for the next shutdown.

On March 10th, after the plant shutdown occurred, unsuccessful attempts were made to isolate the recirculation pumps after the attempts to restart the pumps were unsuccessful. Several minutes after the shutdown, the inner seal temperatures on both pumps were greater than the 300°F range of the indicator. The No. 12 pump inner seal cavity pressure dropped from a normal operating pressure of approximately 500 psi to approximately 300 psi indicating a failure of the inner and outer seals. The No. 11 pump inner seal cavity pressure increased to approximately 750 psi indicating an inner seal failure but no outer seal failure.

Following the shutdown on March 10th, the seals for both recirculation pumps were replaced. The lower bearing on the No. 11 pump was damaged and was also replaced. The seal leakoff isolation valves were installed and the controls checked out. These valves are operated from auxiliary contacts on the drive motor breaker. When the drive motor breaker trips, the isolation valves close to prevent seal leakage from the upper seal breakdown coil. By blocking the seal leakoff path, the cooled water is trapped in the seals preventing hot primary system water from entering along the pump shaft through the pump bearing and lower seal.

e. Failure to be Able to Open the Drywell Sampling Isolation Valves from the Control Room

Following the turbine trip and reactor scram, the primary containment sampling system valves isolated properly; however, after the plant auxiliary power was restored, the sampling system valves could not be opened. No electrical or control system problems could be found. The valves opened when the scram was reset.

Investigation of the situation revealed that the instrument air supply to the sample valves was from the CRD scram air header which is depressurized by the backup scram solenoid valves following a scram. The air supply to the sampling system valves has been changed and now comes directly from the reactor building air supply header.

f. Effects or Possible Effect of Drywell Moisture on Nuclear Instrumentation

Following the plant shutdown on March 10th, the nuclear instrumentation responded properly. Subsequent checks of the LPRM channels showed that nine detectors were reading high. Cable resistance measurements were made on all LPRM cables and the nine suspect channels were found to have low resistance. The cable connectors in the drywell were cleaned and the resistance values returned to normal.

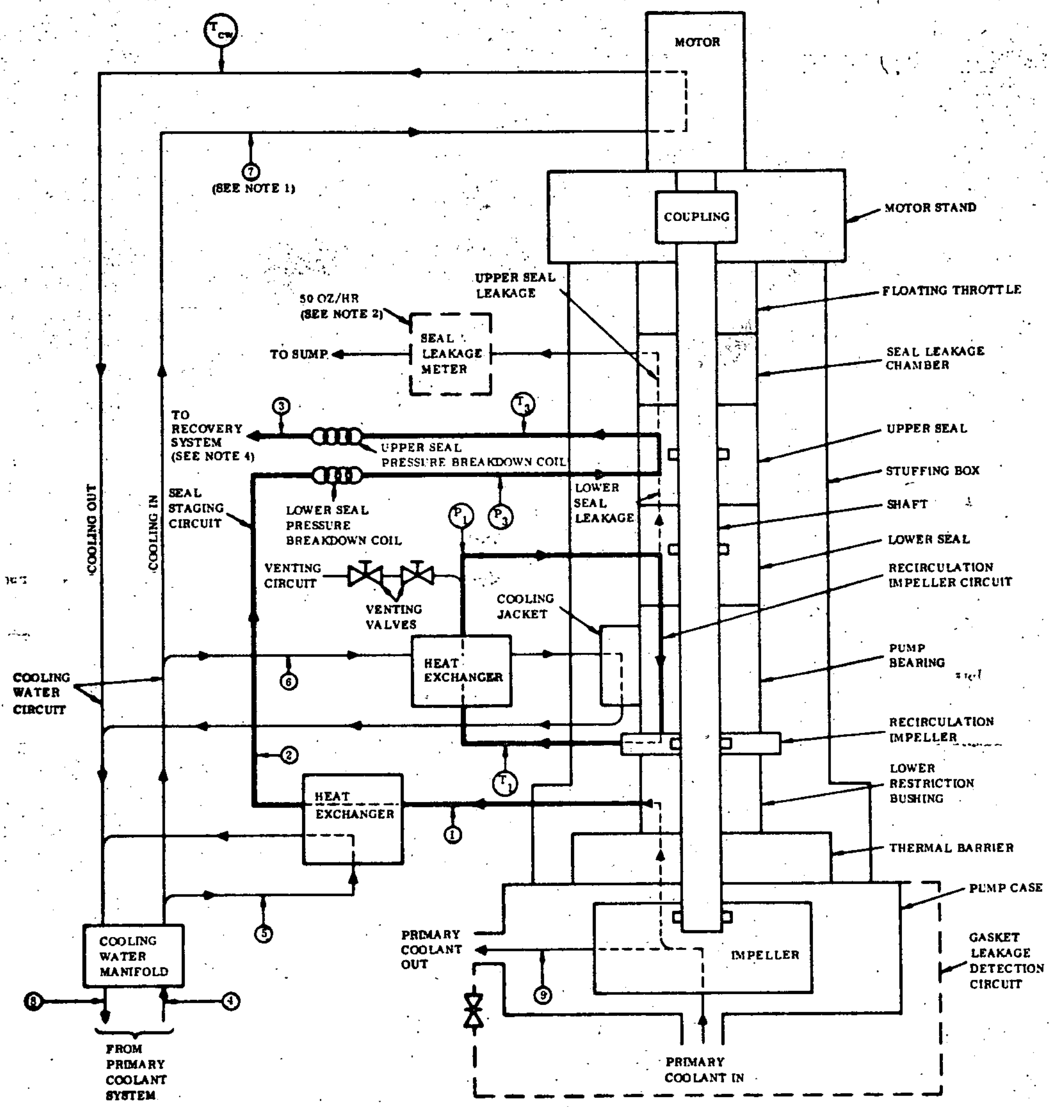
Prior to the plant shutdown, one IRM channel had been noisy. During the shutdown, the detector and preamp were replaced to eliminate the noise problem.

Presently, all nuclear instrumentation is operating properly.

DETAIL A PRESSURE, TEMPERATURE, AND FLOW DATA

	POINT	PRESSURE (psig)	TEMPERATURE (°F)	FLOW (GALLONS/MINUTE)
GAGE POINTS	P_1	1025 (AVERAGE)	—	—
	P_3	510 (AVERAGE)	—	—
	T_1	—	120 (MAX)	—
	T_3	—	120 (MAX)	—
	T_{cw}	—	120 (MAX)	—
	1	1025 (AVERAGE)	510 (AVERAGE)	0.75
	2	1025 (AVERAGE)	118 (AVERAGE)	0.75
	3	ATMOSPHERE	120 (MAX)	0.75 SEE NOTES
	4	150	95 (MAX)	66.5
	5	150	95 (MAX)	30
	6	150	95 (MAX)	25
	7	150	95 (MAX)	11.5 (SEE NOTE 1)
	8	140	115 (MAX)	66.5
	9	1025 (AVERAGE)	530 (AVERAGE)	32,500 (RATED FLOW)

NOTES:
1. FLOW TO MOTOR IS DIVIDED 10 GPM TO UPPER THRUST AND JOURNAL BEARING, 1.5 GPM TO LOWER JOURNAL BEARING.
2. IF UPPER SEAL FAILS, LEAKAGE INCREASES TO 1.1 GPM. IF BOTH SEALS FAIL, LEAKAGE INCREASES TO 20 GPM.
3. IF UPPER SEAL FAILS, LEAKAGE INCREASED TO 1.1 GPM.
4. A SOLENOID-OPERATED BLEED-OFF BLOCK VALVE IS PROVIDED IN THE RECOVERY CIRCUIT.



Reactor Recirculating Pump, Functional Diagram