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Technical Specification 4.12.E

U S Nuclear Regulatory Commission
Attn: Document Control Desk
Washington, DC 20555

PRAIRIE ISLAND NUCLEAR GENERATING PLANT
Docket No. 50-282 License No. DPR-42

2001 Unit 1 Steam Generator Category C-3 Inspection Results 30 Day Report

In accordance with Technical Specification 4.12.E.3, this special report due to Category C-3 inspection results of the Unit 1 steam generator tubing is provided for the information of the NRC Staff:

Following the recent inservice inspection of the Unit 1 steam generators, 44 tubes were plugged for the first time. The percentage of tubes plugged is 5.1% in 11 steam generator and 12.3% (equivalent) in 12 steam generator. Details of the inspections and repairs are provided in Attachment 1.

The results of the inspection of 11 Steam Generator and 12 Steam Generator were classified as Category C-3 in accordance with Technical Specification 4.12 because more than 1% of the inspected tubes in each Steam Generator were defective. The NRC Staff was informed of the Category C-3 classification by telephone on January 29, 2001. In accordance with Technical Specification 4.12.E.3, the 30 day special report on the Category C-3 steam generator inspection results is provided as Attachment 2 to this letter.

Attachment 3 lists the tubes pressure tested in situ to support the condition monitoring assessment.

Steam generator tubing examination and repairs were conducted from January 23, 2001 through February 15, 2001.

In this letter we have made no new Nuclear Regulatory Commission commitments.

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Please contact Richard Pearson (651-388-1121) if you have any questions related to this letter.

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Attachments:
1. Steam Generator Plugged Tube and F* / EF* Tube Summary
2. Prairie Island Unit 1 Steam Generator Category C-3 Tube Inspection Special Report
3. Prairie Island Unit 1 January 2001 In Situ Pressure Tests

ATTACHMENT 1

STEAM GENERATOR PLUGGED TUBE AND F*/EF* TUBE SUMMARY

11 and 12 Steam Generator Inspection Scope Summary

Inspection Scope

All open tubes were examined full length with the bobbin coil, except for Row 1 and 2 U-bends and the sleeve sections of sleeved tubes. A twenty-five percent (instead of the previous 100 percent) sample inspection of the sleeves in 12 steam generator was done with the rotating coil probe.

All Row 1 and 2 U-bends were examined with the Standard Mid Range Frequency +Point™ Coil (PP11A) prior to U-bend heat treatment.

All Row 1 and 2 U-bends which exceeded noise criteria equal to the average of the EPRI U-bend examination qualification data set were examined with the High Frequency +Point™ Coil (PP9A).

All open tubes were examined full length with the bobbin coil, except for Rows 1 and 2 U-bends and the sleeve region in tubes that contained sleeves.

All hot leg tubes were examined with rotating probe technology (including the +Point™ coil) from tube end hot to 3 inches above the top of the tubesheet.

All non-quantifiable bobbin coil indications, including all distorted tube support plate indications, were examined with rotating probe technology (including the +Point™ coil).

Twenty percent of the cold leg tubes were examined with rotating probe technology (including the +Point™ coil) from tube end cold to 1 inch above the top of the tubesheet with no need for expansion.

Following U-bend heat treatment, the rows1 and 2 U-bends were reexamined with rotating coil technology and the bobbin coil.

A visual examination was performed on 100% of the tube and sleeve plugs and sleeve ends.

An eddy current examination was performed on 25% of the ABB Alloy 690 hot leg tube and sleeve plugs with rotating coil technology. An eddy current examination was performed on 100% of the tubes following in situ pressure testing.

11 Steam Generator Plugged Tube and F*/EF* Tube Summary

As a result of the visual and eddy current inspections, 10.7% (346 of 3232) of the inspected tubes in 11 Steam Generator contained defects requiring repair. Fifteen of these tubes were plugged and the remaining 331 tubes were left in service using previous and new Additional Roll Expansions and the F-Star (F*) and Elevated F-Star (EF*) alternate repair criteria.

Summary

New Tubes Plugged this Outage:	15
Total Plugged Tubes:	171
Total F* Tubes:	313
Total EF* Tubes:	18
11 Steam Generator % Plugged:	5.05%

Indications of Defective Tubes

Three hundred forty-six defective tubes were identified with the following types of degradation:

1. Wastage

   Zero tubes were plugged for thinning at the cold leg tube support plate.

2. Secondary Side IGA/SCC in Hot Leg Tubesheet Region

   Seven tubes contained single or multiple indications in the tubesheet crevice region indicative of secondary side IGA/SCC occurring in the tubesheet region. Two tubes were successfully repaired using elevated rerolls and the EF* criteria. One tube was successfully repaired with a reroll at the second elevation and the F* criteria. Four tubes were plugged when ODSCC indications appeared in the new elevated reroll region.

3. Secondary Side IGA/SCC at Tube Support Plates

   Two tubes contained single volumetric indications at the hot leg tube support plates indicative of outside diameter wastage, possibly in combination with secondary side IGA/SCC. (In addition to the normal GL 95-05 requirements, volumetric indications at tube support plates, not associated with sized cold leg tube support plate thinning indications, are plugged due to the discovery of wastage type indications in one of the intersections removed in 1997). Single

axial indications were identified at hot leg tube support plates, but remain in service since the DSI indication associated with these indications is less than 2 volts.

4. Primary Water Stress Corrosion Cracking (PWSCC) at the Hot Leg Roll Transition Zone

   Nine tubes contained single or multiple inside diameter axial indications at the Roll Transition Zone. Nine tubes were repaired using rerolls and the F* criterion. Four tubes were repaired using elevated rerolls and the EF* criterion.

5. Primary Water Stress Corrosion Cracking (PWSCC) at the Rows 1 and 2 U-bends

   There were no indications of tube degradation or excessive noise in the rows 1 and 2 U-bends.

6. Possible PWSCC Near the Tube End

   Two hundred ninety five tubes (48 new, one of which contained a circumferential indication near the tube end) contained short axial indications near the hot leg tube end. These tubes were all classified as F*0 tubes (tubes with tube end cracks that meet F* requirements).

7. Other

   One tube contained a single outside diameter volumetric indication in the upper part of the original hard roll region in the tubesheet. This tube was repaired using a reroll and the F* criterion.

   One tube contained a single outside diameter volumetric indication at the top of the tubesheet. It did not require in situ testing.

8. Previous F/EF Star Criteria Indications

   Two hundred forty-seven of the previous 250 F*0 tubes with tube end indications remain in service. Two tubes required new repairs and one tube no longer had an indication in the tube end.

   Six of the previous six F*1 tubes remain in service.

   Twelve of the previous nineteen elevated rerolls (EF*) remained in service. Nine EF* tubes were plugged due to inside diameter axial indications in the lower roll transition zone of the elevated reroll.

Visual Tube Plug Inspection

A visual inspection was done of all installed tube plugs. No unusual conditions were found.

Visual Tube Leak Inspection

A visual inspection for tube leakage was conducted following the reroll repairs with the secondary side pressurized to greater than 100 psig following repairs. There were no signs of leakage.

Circumferential Indications

One tube contained a circumferential indication in the lower region of the hard roll. This tube met the F* requirements without rerolling.

12 Steam Generator Plugged Tube and F*/EF* Tube Summary

As a result of the visual and eddy current inspection, 4.7% (144 of 3040) of the inspected tubes in 12 Steam Generator contained defects requiring repair. Twenty-nine of these tubes were plugged, 107 tubes were sleeved, and 8 tubes were left in service using previous Additional Roll Expansions and the (F*) alternate repair criteria.

Summary

New Indications Plugged this Outage:	29
New Indications Sleeved this Outage	107
Total Plugged Tubes:	377
Total Sleeved Tubes	1076
Total F* Tubes:	8
Total EF* Tubes:	0
12 Steam Generator % Equivalent Plugged:	12.26%

Indications of Defective Tubes

One hundred forty-four defective tubes were identified with the following types of degradation:

1. Wastage

   One tube was plugged for a single volumetric indication at the cold leg tube support plate.

2. Secondary Side IGA/SCC in Hot Leg Tubesheet Region

   Thirty tubes contained single or multiple indications in the tubesheet crevice region representative of continuing secondary side IGA/SCC occurring in the tubesheet region. Two of these tubes also contained an indication of primary water stress corrosion cracking at the roll transition zone. One tube with a nine inch long and 0.1 volt indication was leak tested in situ with zero leakage. There was an increase in the voltage of the eddy current signal obtained in post in situ testing by eddy current testing. All of these tubes were plugged or sleeved.

   No tubes had indications at the elevation just above the tubesheet.

3. Secondary Side IGA/SCC at Tube Support Plates

   One tube contained a single volumetric indication at the first tube support plate on the hot leg side indicative of secondary side IGA/SCC and/or wastage. Since this morphology can not be determined to meet the requirements of GL 95-05, this tube was plugged.

   Three tubes contained axial indications at the first tube support plate on the hot leg side indicative of secondary side IGA/SCC. Since this morphology and bobbin voltage meet the requirements of GL 95-05, these tubes were left in service.

   All of the tube support plate intersections with distorted bobbin coil indications (regardless of voltage) or with dents greater than 5.0 volts were examined by rotating coil probes. There were no other confirmed indications of degradation at the tube support plates.

4. Primary Water Stress Corrosion Cracking (PWSCC) at the Hot Leg Roll Transition Zone

   Ninety-five tubes contained single or multiple axial indications at the Roll Transition Zone. All indications in 12 steam generator were repaired by sleeving or plugging.

5. Primary Water Stress Corrosion Cracking (PWSCC) at the Rows 1 and 2 U-bends

   One row 1 U-bend contained two circumferential indications on the intradose about one inch from the apex. The tube was pressure tested in situ to greater than 5000 psig with no leakage and no change in the post testing eddy current signal. A special letter report on this indication was sent to the NRC on February 28, 2001.

6. Possible PWSCC Near the Tube End

   Three tubes contained short axial or circumferential indications near the hot leg tube end. These tubes were all classified as F*0 tubes (tubes with tube end cracks that meet F* requirements).

7. Previously Installed Sleeves

   No anomalous indications or indications of degradation were found in the sleeve examination.

8. Previously Installed Rerolls

Five tubes meeting F* criteria with previously installed rerolls remain in service. One of the previous six F* criteria tubes developed PWSCC at the new lower hardroll transition.

9. Other

Eight tubes were plugged due to mechanical damage that occurred during tube sample removal in 1999. Non-quantifiable bobbin coil indications at about 47 inches above the top of the tubesheet on the hot leg side were examined by rotating coil technology and characterized as volumetric. The tubes with these indications are located adjacent to two different locations from which sleeved tubes were removed in 1999. The height corresponded to the height at which the tube samples were cut just below the first tube support plate. One of these adjacent tube indications was estimated to be near structural integrity limits. This indication plus the next two largest were pressure tested in situ and met structural integrity requirements (Attachment 3).

<u>Visual Tube Plug, Sleeve Plug and Sleeve End Inspection</u>

A visual inspection was done of all installed tube plugs and sleeves. One sleeve plug was found to be leaking. Upon removal of the plug, a through wall defect was found in the plug near the top end. This occurred due to an unnoticed error in machining of the plug. Extensive investigation into the scope and root cause of the problem found no further non-conforming plugs. The plug was replaced. The wall thickness of all new plugs was measured prior to installation. All of the installed suspect sleeve plugs were measured with UT and were acceptable.

<u>Post Maintenance Visual Tube Leak Inspection</u>

A visual inspection for tube leakage was conducted following the sleeve installations with the secondary side pressurized to greater than 100 psig following repairs. There were no signs of leakage.

<u>Circumferential Indications</u>

Circumferential indications were found in one row 1 U-bend and in one tube end near the seal weld. The U-bend indication was plugged. The tube end indication was left in service using the F* criterion.

ATTACHMENT 2

PRAIRIE ISLAND UNIT 1 STEAM GENERATOR CATEGORY C-3 TUBE INSPECTION SPECIAL REPORT

Purpose

This report fulfills the special reporting requirements of Prairie Island Technical Specification 4.12.E.3. This report is required whenever the steam generator tube inservice inspection finds more than 10% of the total tubes inspected are degraded tubes or more than 1% of the inspected tubes are defective. This report summarizes the inspection results, the causes of tube degradation, the condition monitoring assessment, and the operational assessment. Corrective measures to prevent recurrence of Category C-3 inspections are discussed. It is acknowledged that steam generator inspection results continue to exceed the category C-3 limits and that remedial actions do not prevent recurrence. However, careful inspections and repairs coupled with chemistry controls and low operating temperature provide assurance of safe and reliable steam generator operation. Unit 1 steam generator replacement is scheduled for the fall of 2004.

Summary

An inservice inspection consisting of inspection of 100% of the full length of tubing with the bobbin coil and 100% of the hot leg tubesheet region, 20% of the cold leg tubesheet region and the row 1 and 2 u-bends with mechanical rotating probes with + Point^{TM} coil was conducted in Unit 1 Steam Generators from January 23, 2001 through February 15, 2001.

As a result of the visual and eddy current inspections, 10.7% (346 of 3232) of the inspected tubes in 11 Steam Generator contained defects requiring repair. Fifteen of these tubes were plugged and the remaining 331 tubes were left in service using previous and new Additional Roll Expansions and the F-Star (F*) and Elevated F-Star (EF*) alternate repair criteria.

As a result of the visual and eddy current inspection, 4.7% (144 of 3040) of the inspected tubes in 12 Steam Generator contained defects requiring repair. Twenty-nine of these tubes were plugged, 107 tubes were sleeved, and 8 tubes were left in service using previous Additional Roll Expansions and the (F*) alternate repair criteria.

Background

Table 1 provides data on the Prairie Island Nuclear Generating Plant which is significant for the steam generators.

Table 1: PRAIRIE ISLAND PLANT DATA

Location:	On Mississippi River near Red Wing Minnesota
Nuclear Steam Supply System:	Westinghouse 2-Loop 560 MWE
Steam Generators:	Westinghouse Model 51 Mill-Annealed Alloy 600 Tubing Open Tubesheet Crevices - 2.75 inch hard roll at bottom of tube
Circulating Water:	Mississippi River/Cooling Towers
Secondary Systems Tubing:	Stainless Steel/Carbon Steel
Startup Dates :	Unit 1 - December 16, 1973 Unit 2 - December 21, 1974
Effective Full Power Years as of End of Previous Cycle:	Unit 1 (EOC 18) - 20.8 EFPY's Unit 2 (EOC 17) - 20.3 EFPY's
Hot Leg Temperature:	590 degrees Fahrenheit

Causes of Major Tube Degradation

There are two major causes of the degradation of tubes in Unit 1 steam generators. Secondary side intergranular attack and stress corrosion cracking (IGA/SCC or ODSCC) is occurring in the lower portion of the hot leg tubesheet crevice region, at the top of the hot leg tubesheet, and in the hot leg tube support plate intersections. This cause was identified by metallurgical examination of three hot leg tubesheet region sections of the Inconel 600 tubing removed from Steam Generator 12 in January 1985. This was confirmed by examination of a parent tube section removed during the sleeve pulls in 1996. The degradation is characterized as single or multiple axial indications. In addition, three tubes were removed for GL 95-05 Voltage Based Repair Criteria in 1997 and ODSCC along with apparent old wastage was identified at the hot leg tube support plates.

Rotating pancake coil (MRPC) of the tube samples and experience gained from other utilities provides tools to confirm the type of degradation occurring in the tubesheet region. MRPC examinations of all tubes with non-quantifiable indications in the tubesheet region have been done routinely since February, 1987. The MRPC results have confirmed the type of degradation as secondary side IGA/SCC.

Also, tubes with indications representative of primary water stress corrosion cracking (PWSCC) at the roll transition region have been identified by MRPC and by metallurgical examination of one roll transition zone removed during the sleeve pulls in 1996.

Comparison of Number of Defective Tubes in Unit 1 Steam Generators, April 1999 to January 2001.

The number of new defective tubes identified in Unit 1 Steam Generators decreased. In both steam generators, roll transition zone PWSCC is more dominant than ODSCC. In 11 steam generator, tube end cracking is a dominant mode of degradation. In 12 steam generator, no indications of weld anomalies or sleeve joint degradation were found in existing sleeves.

Indications at hot leg tube support plates due to ODSCC occurring remained similar. Of the combined total of ~500 distorted indications detected at TSP intersections in both SGs, only 14 indications exceed 1 volt and none exceed 2 volts. Further details will be provided in the 90 day report for the voltage based repair criteria.

New Sleeve Installation Data

Twelve of the 119 new sleeves installed required plugging due to welds, which failed the ultrasonic testing requirements for new sleeves.

Condition Monitoring

Condition Monitoring evaluates the as found condition of the steam generator tubing against leakage and structural integrity criteria. There were no tubes identified, which exceeded the structural integrity requirement of no tube burst at three times the normal operating differential pressure. Degradation mechanisms located in the tubesheet crevice region can not burst due to the constraints of the tubesheet. Axial degradation mechanisms are not expected to burst unless the indication is greater than 0.38 inches long in the free span. There were no tubes identified by in situ pressure testing which exceeded leakage limits at main steam line break conditions. There were no tubes identified with qualified sizing techniques, which approach structural integrity limits.

In Situ Tests

To demonstrate adequate leakage and structural integrity, twelve tubes were pressure tested in situ. Tubes were selected based on largest extent and voltage of the eddy current indications and each type of degradation was tested. Tests were done at Main Steam Line Break (MSLB) conditions for indications in the tubesheet crevice region. Tests were done at Main Steam Line Break pressure and at three times normal operating differential pressure (3dp) for indications in free span regions. The test pressure for Main Steam Line Break conditions was 2816 psig and for 3dp conditions was a maximum of 5550 psig. The list of tubes tested in situ is in Attachment 3. No tubes challenged the structural integrity criteria of 3 times normal operating differential pressure. No tubes leaked at Main Steam Line Break or 3dp pressures.

Summary of Operational Assessment

An evaluation of all indications of degradation confirms that none of the forms of degradation occurring presents a structural or leakage integrity concern for the next cycle of operation.

Remedial Actions

Northern States Power has participated in utility funded research on steam generator related issues beginning with the Steam Generator Owners Group II in 1982 and continuing to the present EPRI funded Steam Generator Management Project. Remedial actions to reduce and/or prevent tube degradation due to primary water stress corrosion cracking and secondary side IGA/SCC have been used by the industry with only limited success. Prairie Island has evaluated, and in most cases, implemented the following remedial actions:

Reduced Operating Temperature: Prairie Island has been a low temperature plant having operated with Thot at 590 °F since startup. This has slowed, but not eliminated, growth of PWSCC and IGA/SCC in the Prairie Island steam generators. Additional temperature reduction has not been warranted.

Chemistry Control: Prairie Island has used state of the art analytical equipment since startup and has followed both the original equipment manufacturer's water chemistry guidelines as well as the EPRI secondary water chemistry guidelines. The amounts of material found from hideout return tests during shutdowns have been small. Steam generators are sludge lanced every other outage on a cycling basis with less than 50 pounds of sludge removed from the steam generator per outage. Plasticor repairs of the condenser tubesheets has reduced circulating water in leakage to a very low level. The PWSCC degradation is relatively independent of chemistry and occurs in regions of high residual stress.

High Hydrazine Control: Prairie Island maintains a hydrazine control band of 125 +/- 25 ppb.

Molar ratio control to reduce secondary side corrosion: Molar ratio control has been attempted by adjustments to steam generator blowdown resin ratios during recent operating cycles. Operating molar ratios are normally less than 1. The object of molar ratio control is to maintain the cation to anion ratio (sodium to chloride plus sulfate) at less than one so that free sodium hydroxide can not form in the crevice regions.

Conduct Crevice Flushing Operations with Boric Acid: Prairie Island started crevice flushing in 1986. Boric acid was used in the crevice flushing procedure. Crevice flushing was discontinued in 1999.

On-line addition of Boric Acid: Following the report of favorable laboratory results in 1986, Prairie Island began on-line addition of boric acid in Unit 1 in March 1987. The effectiveness of this remedial action remains controversial within the industry (EPRI IGA/SCC workshops in May 1991 and December 1992). Prairie Island will continue to use boric acid until such time as an inhibitor of equal or greater effectiveness is justified for on-line use. One of the recommended boric acid practices, low power soaks, has not been implemented at Prairie Island.

Use of other chemical inhibitors: At the present time, NSP supports EPRI research for other chemical inhibitors. Our current evaluations centers around the use of titanium compounds to inhibit the growth of IGA/SCC. A titanium chelate, TYZOR LA Titanate has been added since January 1994.

Preventive sleeving: Sleeving is one method of reducing the probability of tube leak outages. The down side of preventive sleeving is the inability to follow the degradation mechanism and the reduction in the ability to examine tube support plate intersections above the sleeves. NSP has made the strategic decision to sleeve on an as-needed basis, to insure that we are able to best follow the tube support plate problems and to reduce our overall cost of steam generator repair and maintenance.

F* and EF* Repair Criteria: The F-Star and EF-Star Alternate Repair Criteria allow tubes to remain in service with indications below the F* or EF* distance. Additional Roll Expansion adds a new F* or EF* distance to the steam generator tubing and allows additional tubes to remain in service which have degradation in the lower tubesheet crevice region.

Detailed Inspection Plans: Although not a recommendation for remedial actions, but rather a current inspection guideline, 100% of the full length of all tubes in service are routinely examined at Prairie Island. This was started in 1982. In addition, all tubes with indications which can not be quantified, such as NQI's, DSI's, MBM's (in the tubesheet) are examined with the rotating coil probe due to its higher sensitivity. Repair decisions, in those cases, are based on the RPC results.

ATTACHMENT 3

PRAIRIE ISLAND 12 SG IN SITU PRESSURE TEST DETAILS, JAN 2001

Results: ZERO Leakage and NO Burst at Final Pressure for all Tubes

	ROW 1	COL 52	
	Target Pressure	Actual Pressure	Hold Time
Normal Operating Delta P	1787	1850	5 min
Main Steam Line Break	2872	2950	5 min
1st Intermediate	3372	3450	5 min
2nd Intermediate	3872	3950	5 min
3rd Intermediate	4372	4450	5 min
4th Intermediate	4872	5000	5 min
3 x Normal Operating Delta P	5466	5550	5 min

	ROW 10	COL 9	
	Target Pressure	Actual Pressure	Hold Time
Normal Operating Delta P	1752	1800	5 min
Main Steam Line Break	2816	2900	5 min
3 x Normal Operating Delta P	N/A	N/A	N/A

	ROW 22	COL 21	
	Target Pressure	Actual Pressure	Hold Time
Normal Operating Delta P	1752	1850	2 min
Main Steam Line Break	2816	2850	2 min
1st Intermediate	3316	3350	2 min
2nd Intermediate	3816	3850	2 min
3rd Intermediate	4316	4350	2 min
4th Intermediate	4816	4850	2 min
3 x Normal Operating Delta P	5256	5300	2 min

	ROW 22	COL 20	
	Target Pressure	Actual Pressure	Hold Time
Normal Operating Delta P	1752	1850	2 min
Main Steam Line Break	2816	2850	2 min
1st Intermediate	3316	3350	2 min
2nd Intermediate	3816	3850	2 min
1.43 x Main Steam Line Break	4027		2 min
3rd Intermediate	4527	4600	2 min
4th Intermediate	5027	5050	2 min
3 x Normal Operating Delta P	5256	5300	2 min

	ROW 23 Target Pressure	COL 20 Actual Pressure	Hold Time
Normal Operating Delta P	1752	1800	2 min
Main Steam Line Break	2816	2900	2 min
1st Intermediate	3316	3350	2 min
2nd Intermediate	3816	3900	2 min
1.43 x Main Steam Line Break	4027	4100	2 min
3rd Intermediate	4227	4300	2 min
4th Intermediate	4427	4450	2 min
5th Intermediate	4627	4650	2 min
6th Intermediate	4827	4900	2 min
7th Intermediate	5027	5100	2 min
3 x Normal Operating Delta P	5256	5300	2 min

sg	row	tube	volts	degree	ind	channel	location	reelcal	probe
12	1	52	0.58	20	SCI	P 2	07H +7.50 TO+7.67	SG12HCAL00042	650PR
12	1	52	1.06	22	SCI	P 2	07H +7.78 TO+8.15	SG12HCAL00042	650PR
12	1	52	0.81	18	SCI	P 2	07H +7.51 TO+7.64	SG12HCAL00128	650PR
12	1	52	1.53	22	SCI	P 2	07H +7.75 TO+8.11	SG12HCAL00128	650PR
12	10	9	0.09	123	MAI	3	TRH +0.52 TO+9.69	SG12HCAL00004	700PR
12	10	9	0.20	141	MAI	3	TRH +0.42 TO+9.91	SG12HCAL00127	720PR
12	22	21	7.36	121	NQI	P 1	TSH +46.84	SG12CCAL00078	720ZU
12	22	21	1.13	91	SVI	3	TSH +46.24 TO+46.97	SG12HCAL00118	720PR
12	22	21	1.23	93	SVI	3	TSH +46.24 TO+46.97	SG12HCAL00130	700PR
12	22	21	1.30	85	SVI	3	TSH +46.24 TO+46.97	SG12HCAL00131	700PR
12	22	20	4.60	106	NQI	P 1	TSH +46.78	SG12CCAL00078	720ZU
12	22	20	0.74	79	SVI	3	TSH +46.66 TO+47.14	SG12HCAL00114	720PR
12	22	20	1.10	92	SVI	3	TSH +46.66 TO+47.14	SG12HCAL00130	700PR
12	22	20	0.88	91	SVI	3	TSH +46.66 TO+47.14	SG12HCAL00131	700PR
12	23	20	16.00	94	NQI	P 1	TSH +46.70	SG12CCAL00079	720ZU
12	23	20	19.48	79	NQI	P 1	TSH +46.70	SG12CCAL00080	720ZU
12	23	20	2.53	47	SVI	3	TSH +46.56 TO+47.05	SG12HCAL00114	720PR
12	23	20	3.12	54	SVI	3	TSH +46.56 TO+47.05	SG12HCAL00130	700PR
12	23	20	3.28	43	SVI	3	TSH +46.56 TO+47.05	SG12HCAL00131	700PR