AECI AFFECTED SYSTEM IMPACT STUDIES

GIA-61 STUDY

SOUTHWEST POWER POOL, INC.

MAY 4, 2022

NOTE: This Affected System Impact Study for GIA-61 was conducted in response to the order issued by the Federal Energy Regulatory Commission ("Commission") on December 16, 2021, in Docket No. EL21-77. The results contained herein are subject to further action by the Commission.

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Document Revisions

NO.	Revision	Date	PRD	CHK	APV
1	Draft Report Issued for Review	1/27/2022	FO/EM	WB	WB
2	Final Report Issued from Posting	5/4/2022	WB	WB	WB

Introduction

Associated Electric Cooperative Inc. (AECI) requested a definitive affected system impact study (ASIS) from Southwest Power Pool (SPP) for the AECI GIA-61 project. The purpose of this analysis was to determine the impact of one AECI generator interconnection request on the SPP transmission system. Additionally, the analysis looked to identify the amount of Interconnection Service available to the project resulting in no constraints requiring mitigation. This analysis evaluated one AECI interconnection requests in SPP cluster group 13 with a total generation capacity of 242 MW. While results from this analysis will be considered final, a restudy may be required should significant changes to the study assumptions occur[1].

The generator interconnection requests analyzed in this ASIS are listed in **Appendix A** by queue number, amount, requested interconnection service type, area, and proposed interconnection point.

The Siemens Power Technologies International PSS/E Version 33.11.0 and PowerGem's TARA 2102.1 were used for this analysis. SPP provided the following DISIS-2016-002 BASE case models:

- Year 1 (2017) Winter Peak (17WP)
- Year 2 (2018) Spring (18G)
- Year 2 (2018) Summer Peak (18SP)
- Year 5 (2021) Summer Peak (21SP)
- Year 5 (2021) Light Load (21L)
- Year 5 (2021) Winter Peak (21WP)
- Year 10 (2026) Summer Peak (26SP)

EPE updated power flow cases to reflect the groups under study and developed a total of 28 cases, specifically 14 Base Cases (BC) and 14 Transfer Cases (TC). The power flow analysis was performed to determine if the transmission system could accommodate the injection from the current study cluster generator interconnection requests without violating SPP's transmission planning criteria outlined below in the Study Methodology Criteria Section.

The ASIS has been conducted consistent with Attachment V of the SPP Open Access Transmission Tariff (OATT), the SPP-MISO Joint Operating Agreement (JOA), and SPP Business Practices to determine impacts to the SPP transmission system.

It should be noted that although this ASIS analyzed many of the most probable contingencies, it is not an all-inclusive list that can account for every operational situation. Additionally, the generator may not be able to inject any power onto the Transmission System due to constraints that fall below the threshold of mitigation for a generator interconnection request. Because of this, the Customer may be required by the Transmission Provider to reduce their generation output to 0 MW under certain system conditions to allow system operators to maintain the reliability of the transmission network.

Nothing in this study should be construed as a guarantee of delivery or transmission service within SPP's transmission system. If the customer wishes to sell power from the facility, a separate request for transmission service must be requested on SPP's OASIS by the Customer.

[1] Significant changes to study assumptions include but are not limited to interconnection request withdrawals and/or changes to higher-queued Network Upgrades included in the Base Case.

Base Case Model Build and Dispatch

Base Case Model Review and Grouping

SPP provided the following information to EPE:

1. List of interconnection requests for consideration in the analysis
2. List of all higher-queued interconnection requests and associated required upgrades
3. DISIS-2016-002 BASE cases
4. Current study Network Upgrades previously identified by SPP for consideration in the analysis

The AECI GIA-61 ASIS included 1 generator interconnection request in the AECI footprint. **Appendix A** lists the current study cluster generator interconnection requests included in the study. The DISIS-2016-002 BASE models are based on modified version of the 2017 ITP cases and served as the starting point for the AECI GIA-61 analysis. The BASE models were derived by adding higher-queued interconnection requests not already existing in the model and their associated Network Upgrades[2]. The AECI study generators, including all available collector system data, were added, and kept offline in the following BASE models:

- Year 1 (2017) Winter Peak (17WP)
- Year 2 (2018) Spring (18G)
- Year 2 (2018) Summer Peak (18SP)
- Year 5 (2021) Summer Peak (21SP)
- Year 5 (2021) Light Load (21L)
- Year 5 (2021) Winter Peak (21WP)
- Year 10 (2026) Summer Peak (26SP)

Higher-queued interconnection requests were included in the models, including the DISIS-2016-002 cluster and prior. If the interconnection request did not already exist in the model, it was modeled as out of service. Otherwise, the interconnection request was modified as necessary to reflect the nameplate capacity requested in the Generator Interconnection Agreement. Updates were also made to external interconnection requests, such as those in the MISO queue, to align the modeled capacity with the requested queue capacity. The higher-queued requests added or modified to the study models are listed in **Appendix B**.

Grouping

The interconnection requests listed in **Appendix A** and **Appendix B** are grouped into sixteen active regional groups. Grouping is determined by engineering judgement and electrical connectivity to SPP transmission. The SPP groupings are listed in **Table 1** below. Please note that groups five and eleven are inactive. The interconnection requests provided in the interconnection request database have been identified as being potentially impactful to the SPP transmission system due to electrical proximity to SPP facilities.

[2] Previously assigned Network Upgrades from those clusters were added to the transfer cases as needed to resolve violations which met mitigation criteria. Previously-assigned Network Upgrades from clusters equal to and higher than the DISIS-2016-002 cluster were already included in the BASE cases.

Table 1: All SPP Groupings

Group #	Area	Group #	Area
1	Woodward, OK	10	Southeast OK/Northeast TX
2	Hitchland, OK	12	Northwest AR
3	Spearville, KS	13	Northwest MO
4	Northwest KS	14	South Central OK
6	South TX Panhandle/New Mexico	15	East SD
7	Southwest OK	16	West ND
8	North OK/South Central KS	17	West SD
9	Nebraska	18	East ND

Development of Base Cases (BC)

The number of Base Cases (BC) and Transfer Cases (TC) required for each impact study depends on the service requested and fuel type of the study units. **Table 2** outlines the number of cases required per seasonal case for each dispatch scenario. **Table 4** describes SPP dispatch criteria used for this analysis.

Table 2: SPP Seasons and Cases per Dispatch

Seasonal Case	ERIS HVER	ERIS LVER	NRIS
+1 Winter Peak (i.e. 17WP)	1 per group	1 per study	1 per study
+2 Spring (i.e. 18G)	1 per group	--	1 per group
+2 Summer Peak (i.e. 18SP)	1 per group	1 per study	1 per study
+5 Light Load (i.e. 21L)	1 per group	--	1 per group
+5 Summer Peak (i.e. 21SP)	1 per group	1 per study	1 per study
+5 Winter Peak (i.e. 21WP)	1 per group	1 per study	1 per study
+10 Summer Peak (i.e. 26SP)	1 per group	1 per study	1 per study

Four BASE power flow cases were provided as the starting point for this analysis. The SPP regional group (Group 13) had two types of dispatch for their local generation: High-Variable Energy Resource (HVER) and Network Resource Interconnection Service (NRIS). The groups and the dispatch resulted in 28 cases with unique dispatches, as shown in **Table 3**. All in-scope higher-queued SPP and MISO generators listed in **Appendix B** were added and dispatched per criteria listed in **Table 4**.

Table 3: AECI GIA-61 Study Cases

Seasonal Case	ERIS HVER	NRIS
+1 Winter Peak (i.e. 17WP)	1 per group	1 per study
+2 Spring (i.e. 18G)	1 per group	1 per group
+2 Summer Peak (i.e. 18SP)	1 per group	1 per study
+5 Light Load (i.e. 21L)	1 per group	1 per group
+5 Summer Peak (i.e. 21SP)	1 per group	1 per study
+5 Winter Peak (i.e. 21WP)	1 per group	1 per study
+10 Summer Peak (i.e. 26SP)	1 per group	1 per study
AECI GIA-61	**28 Cases (14 BC/14 TC)**	

SPP region generation offset caused by the prior-queued generators' dispatch was balanced using the load ratio share (LRS) and uniform scale. The LRS determined where generation adjustments were required.

The generation offset was sunk using a uniform scale across all non-queue and non-nuclear units in each area.

LRS was not used in non-SPP regions. Instead, generation offset was adjusted using a uniform scale across all non-queue and non-nuclear units in the region. Dispatched cases were solved without area interchange, and the system swing generation was kept as close as possible between the BASE case, BC case, and TC case.

Development of Analysis Cases (TC)

All in-scope higher-queued and current study interconnection requests were dispatched as per criteria listed in **Table 4**. For existing SPP interconnection requests included in the scope, if the existing generation dispatch (P_{GEN}) was greater than the expected GI dispatch criteria, the generation was left as-is. If the existing generation dispatch (P_{GEN}) was less than the expected GI dispatch criteria, it was dispatched up to the defined amount.

Generation adjustments are dispatched against legacy[3] conventional generation[4] in the host TO footprint. For the HVER dispatch scenario, all renewable generation facilities are dispatched to 100% within the studied group and at 20% outside of the study group if the unit was offline or dispatched below the assigned dispatch setpoint. Legacy resources and higher-queued conventional units are used to balance generation changes in the HVER scenarios. The HVER dispatch scenario was used with all cases including Winter, Summer, Spring, and Light Load DISIS BASE cases.

For the Low-Variable Energy Resource (LVER) dispatch scenario, all conventional generation facilities are dispatched to 100%. The code 00 for this scenario represents that the entire SPP footprint is included as being in-group. Legacy resources are used to balance generation changes. The LVER dispatch scenario is utilized in Winter and Summer DISIS BASE cases but only used if there is a conventional resource in the current study.

For the Network Resource (NR) dispatch scenario, the dispatch levels for the renewable and conventional generation facilities are determined based upon the level of system integration being requested (ERIS and NRIS). For Spring and Light Load, dispatches are group based. For Winter and Summer, the entire SPP footprint is considered “in-group” for the study (like the LVER dispatch scenario). Legacy resources are used to balance generation changes.

For this analysis, MISO’s partial NRIS was taken into account for the NR dispatch, where ERIS only capacity was not dispatched in the NR dispatch scenarios.

The study interconnection request was included in the power flow analysis models as an equivalent generator dispatched at the applicable percentage of the requested service amount with 0.95 power factor capability. The facility modeling includes explicit representation of equivalent generator step-up (GSU) and main project transformer(s) with impedance data provided in the interconnection request. All equivalent collector system branches and transmission tie-lines shorter than 20 miles in length are modeled as zero-impedance branches.

[3] Generators that are found in the SPP footprint in the DISIS BASE cases that do not map to the SPP generator mapping sheet are considered “legacy.”

[4] The conventional units included in the sink excluded non-adjustable generation such as hydro/run-of-river.

Table 4: SPP Dispatch Criteria

Dispatch Type	Season	Service Type	Renewable in group	Renewable out of group	Conventional in group	Conventional out of group
ERIS HVER	Winter, Summer, Spring, and Light Load	Both	100%	20%[5]	n/a	n/a
ERIS LVER	Winter and Summer	All	20%	20%	100%	100%
NRIS	Spring and Light Load	ERIS	80%	20%	n/a	n/a
		NRIS	100%	20%	100%	20%
	Winter and Summer	ERIS	20%[6]	20%[6]	80%	80%
		NRIS	100%	100%	100%	100%

[5] For light 10% for DISIS-2016-002 or 0% for DISIS-2017-001 forward.

[6] Solar 80% in Summer Peak

Study Methodology Criteria

Solve Parameters

The following solution parameters were used:

- Fixed slope decoupled Newton-Raphson
- Tap adjustment – stepping
- Switch shunt adjustments – enable all
- Area interchange disabled
- Adjust phase shift
- Adjust DC taps
- VAR limits – apply immediately
- Must solve within five iterations, three or less is preferred

Thermal Overloads

Network constraints are identified using PowerGEM TARA AC Contingency Calculation (ACCC) analysis on the entire cluster grouping dispatched at the various levels.

For Energy Resource Interconnection Service (ERIS):

For ERIS, thermal overloads are determined for system intact (n-0) (greater than or equal to 100% of Rate A/normal) and for contingency (N-1) (greater than or equal to 100% of Rate B/emergency) conditions.

The overloads are then screened to determine which generator interconnection requests have at least:

- 3% DFAX for system intact conditions (N-0),
- 20% DFAX upon outage-based conditions (N-1), or
- 3% DFAX on contingent elements that resulted in a non-converged solution.

Non-converged contingencies shall also be considered for Limited Operation.

For Network Resource Interconnection Service (NRIS):

Interconnection Requests that requested NRIS are also studied in a separate NRIS analysis to determine if any constraint measured greater than or equal to a 3% DFAX. If so, these constraints are also considered for transmission reinforcement under NRIS.

Contingencies

The contingency set includes all SPP control area branches and ties 69 kV and above, first-tier non-SPP control area branches and ties 115 kV and above, any defined contingencies for these control areas, and generation unit outages for the SPP control areas with SPP reserve share program redispatch.

- All branches, ties, shunts, and generators within the following areas:
  - SPP Internal Areas for 65 kV – 999 kV facilities:
    - 515 – 546, 640, 641, 642, 645, 650, 652, 659
  - SPP External Areas for 100 kV – 999 kV facilities:
    - 327, 330, 351, 356, 502-504, 600, 615, 620, 627, 635, 661, 672, 680
- NERC, SPP, and Tier 1 Permanent Contingent Flowgates
- SPP TO Specific P1, P2, P4, and P5 TPL-004-1 Contingencies
- SPP TO Specific Op-Guide Implementation

Monitored Facilities

The monitored elements include all SPP control area branches, ties, and buses 69 kV and above, and all first-tier non-SPP control area branches and ties 69 kV and above. NERC Power Transfer Distribution Factor (PTDF) Flowgates for SPP and first-tier non-SPP control areas are monitored. Additional NERC Flowgates are monitored in second-tier or greater non-SPP control areas. Voltage monitoring was performed for SPP control area buses 69 kV and above.

- All branches (thermal)/buses (voltage) and ties within the following areas:
  - SPP Internal Areas for 65 kV – 999 kV facilities:
    - 515 – 546, 640 – 659
- NERC, SPP, and Tier 1 Permanent Monitor Flowgates (thermal)

Voltage

For non-converged power flow solutions that are determined to be caused by a lack of voltage support, appropriate transmission support will be determined to mitigate the constraint.

After all thermal overload and voltage support mitigations are determined; a full ACCC analysis is then performed to determine voltage constraints. The following voltage performance guidelines are used in accordance with the Transmission Owner local planning criteria.

SPP Areas (69 kV+)

<table>
<tr><th>Transmission Owner</th><th>Voltage Criteria (System Intact)</th><th>Voltage Criteria (Contingency)</th></tr>
<tr><td>AEPW</td><td rowspan="15">0.95 – 1.05 p.u.</td><td>0.92 – 1.05 p.u.</td></tr>
<tr><td>GRDA</td><td rowspan="12">0.90 – 1.05 p.u.</td></tr>
<tr><td>SWPA</td></tr>
<tr><td>OKGE</td></tr>
<tr><td>OMPA</td></tr>
<tr><td>WFEC</td></tr>
<tr><td>SWPS</td></tr>
<tr><td>MIDW</td></tr>
<tr><td>SUNC</td></tr>
<tr><td>KCPL</td></tr>
<tr><td>INDN</td></tr>
<tr><td>SPRM</td></tr>
<tr><td>NPPD</td></tr>
<tr><td>WAPA</td></tr>
<tr><td>WERE LV</td><td>0.93 – 1.05 p.u.</td></tr>
<tr><td>WERE HV</td><td>0.95 – 1.05 p.u.</td></tr>
</table>

EMDE LV		0.90 – 1.05 p.u.
EMDE HV		0.92 – 1.05 p.u.
LES		0.90 – 1.05 p.u.
OPPD		

SPP Buses With More Stringent Voltage Criteria

Bus Name/Number	Voltage Criteria (System Intact)	Voltage Criteria (Contingency)
TUCO 230 kV 525830	0.925 – 1.05 p.u.	0.925 – 1.05 p.u.
Wolf Creek 345 kV 532797	0.985 – 1.03 p.u.	0.985 – 1.03 p.u.
FCS 161 kV 646251	1.001 – 1.047 p.u.	1.001 – 1.047 p.u.

Affected System Areas (115 kV+)

Transmission Owner	Voltage Criteria (System Intact)	Voltage Criteria (Contingency)
AECI	0.95 – 1.05 p.u.	0.90 – 1.05 p.u.
EES-EAI		
LAGN		
EES		
AMMO		
CLEC		
LAFA		
LEPA		
XEL		
MP		
SMMPA		
GRE		0.90 – 1.10 p.u.
OTP		0.90 – 1.05 p.u.
OTP-H (115 kV+)	0.97 – 1.05 p.u.	0.92 – 1.10 p.u.

<table>
<tr><td>ALTW</td><td rowspan="6">0.95 – 1.05 p.u.</td><td rowspan="3">0.90 – 1.05 p.u.</td></tr>
<tr><td>MEC</td></tr>
<tr><td>MDU</td></tr>
<tr><td>SPC</td><td>0.95 – 1.05 p.u.</td></tr>
<tr><td>DPC</td><td rowspan="2">0.90 – 1.05 p.u.</td></tr>
<tr><td>ALTE</td></tr>
</table>

The constraints identified through the voltage scan are then screened for the following for each interconnection request.

- 3% DFAX on the contingent element and
- 2% change in p.u. voltage

Identification of Network Constraints

ERIS Thermal Non-Converged Constraint Identification and Mitigation

There were no ERIS non-converged constraints observed for single contingency (N-1) conditions that require mitigation.

ERIS Thermal System Intact and Contingency Constraint Identification and Mitigation

One ERIS thermal constraint was identified for single contingency (N-1) conditions. **Table 5** below summarizes the ERIS thermal constraint and associated mitigation.

Table 5 : ERIS Thermal Constraints

Monitored Facility	Mitigation
Maryville to Creston 161 kV	Reconductor Maryville to Creston 161 kV

ERIS Voltage Constraint Identification and Mitigation

There were no voltage constraints identified for Group 13 ERIS interconnection request.

NRIS Thermal Non-Converged Constraint Identification and Mitigation

There were no NRIS non-converged constraints observed for single contingency (N-1) conditions that require mitigation.

NRIS Thermal System Intact and Contingency Constraint Identification and Mitigation

Five NRIS thermal constraints were identified for single contingency (N-1) and multiple contingency conditions. **Table 6** below summarizes the NRIS thermal constraints and associated mitigations.

Table 6 : NRIS Thermal Constraints

Monitored Facility	Mitigation
Nashua 345/161 kV Transformer	Build Second Nashua 345/161 kV Transformer
Avenue City to St Joseph 161 kV	Rebuild Avenue City to St Joseph 161 kV
Maryville to Midway 161 kV	Rebuild Maryville to Midway 161 kV
Midway to Avenue City 161 kV	Rebuild Midway to Avenue City 161 kV
Nashua to Roanridge 161 kV	Rebuild Nashua to Roanridge 161 kV

NRIS Voltage Constraint Identification and Mitigation

There were no voltage constraints identified for Group 13 NRIS interconnection request.

Network Upgrades

Cost Estimates

Preliminary cost estimates provided in this analysis are subject to change.

SPP utilizes the one-year-out spring seasonal model for Variable Energy Resources (VERs). The five-year-out summer peak seasonal model is used for conventional fuel type generators. If both fuel types are

being studied, both sets of models are utilized. Project distribution factors on the identified upgrades, under system intact conditions, are used to determine cost allocation. The impact each generator interconnection request has on each upgrade project is weighted by the size of each request. Finally, the costs due by each request for a particular project are then determined by allocating the portion of each request's impact over the impact of all affecting requests.

For example, assume that there are three generator interconnection requests, X, Y, and Z that are responsible for the costs of Upgrade Project '1'. Given that their respective PTDF for the project have been determined, the cost allocation for generator interconnection request 'X' for Upgrade Project 1 is found by the following set of steps and formulas:

- Request X, Upgrade Project 1 = PTDF (%)(X) * MW(X) = X1
- Request Y, Upgrade Project 1 = PTDF (%)(Y) * MW(Y) = Y1
- Request Z, Upgrade Project 1 = PTDF (%)(Z) * MW(Z) = Z1

Allocation of Cost for a particular project:

- Request X's Project 1 Cost Allocation ($) = $\frac{\text{Network Upgrade Project 1 Cost (\$)} * X1}{X1 + Y1 + Z1}$

Repeat previous for each responsible GI request for each Project.

If the current study interconnection request requires a Network Upgrade for full interconnection service, the study resource will determine the Limited Operation amount available to the request prior to all required Network Upgrades being in-service. **Table 7** lists the allocated costs for Network Upgrades assigned to current study projects.

Table 7: Network Upgrade Cost Estimates

Interconnection Request	Size	ERIS Total	NRIS Total	Total
GIA-61	242	$14,900,000	$64,381,170	$79,281,170

It should be noted that Network Upgrades associated with higher-queued projects are also considered as Contingent Facilities. These facilities have been included in the models for this study and are assumed to be in service. This list may not be all-inclusive. **While current study interconnection customers do not have cost responsibility for contingent facilities, they may later be assigned cost if higher-queued customers terminate their interconnection request.** The Network Upgrades assumed in-service in the BASE models associated with higher-queued projects are listed in **Appendix C.**

Limited Operation Availability

The results of the power flow identified the system constraints that require mitigation. The Limited Operation analysis identifies an amount of available interconnection service based on the most limiting of these constraints for each current study request. **As the Limited Operation amount is calculated using the transfer cases developed for this analysis, the amount available is dependent upon all higher queued interconnection requests and Network Upgrades being in-service.**

Power flow analysis results included the thermal overload amount, circuit rating, size, and TDF of each current study request. An initial Limited Operation amount is calculated by identifying the impact of each request on each constraint and identifying a reduced size of each request proportional to the thermal

constraint that would result in a circuit loading within the applicable rating. The Limited Operation amount is calculated according to the following equation:

$$\text{Limited Operation amount} = \text{Request MW} - \frac{\text{MVA Rating} * (\text{Overload p.u.} - 1)}{\text{Request TDF}}$$

With the initial Limited Operation amount request sizes applied to the study cases, ACCC is repeated to verify that the thermal constraints are not observed, or the calculation and verification are repeated until all thermal constraints are mitigated.

Power flow analysis results for voltage violations are then further mitigated by identifying the contribution of each request and determination of the required impact reduction is conducted and verified through ACCC to determine the Limited Operation amount for each request.

Limited Operation results are listed below in **Table 8**. While these results are based on the criteria listed in GIP 8.4.3, the Interconnection Customers may request additional scenarios for Limited Operation based on higher-queued interconnection requests not being placed in service.

Table 8: Limited Operation Results

Interconnection Request	Group	Service Type	Available MW Before Mitigation	Most Limiting Constraint
GIA-61	13 NE-KS & NW-MO	ERIS	161	Maryville to Creston 161 kV
		NRIS	0	Nashua to Roanridge 161 kV

Power Flow Analysis Results

The results of the power flow analysis for interconnection requests under study are embedded in **Table 9**.

Table 9: Power Flow Analysis Results

Results	
Thermal Constraints	AECI-GIA-61_Thermal Constraints CEII.xl
Voltage Constraints	AECI-GIA-61_Voltage Violations CEII.xlsx
Network Upgrades and Cost Allocation Calculation	AECI-GIA-61_Network Upgrades and Co

Conclusion

A power flow analysis was performed to determine the impact of one AECI generator interconnection request on the SPP transmission system. The results of the power flow analysis identified six system constraints that require mitigation. The minimum cost of interconnecting the new generator interconnection request included in this analysis is estimated at $79,281,170. Allocated costs for Network Upgrades are listed in **Table 7**.

The study results identified one ERIS constraint. Generator project GIA-61 requires one ERIS upgrades to be in service before interconnection service is available. In addition, project GIA-61 requires the identified ERIS upgrades and five NRIS upgrades to be in service before NRIS interconnection service is available.

It should be noted that although this ASIS analyzed many of the most probable contingencies, it is not an all-inclusive list that can account for every operational situation. Additionally, the generator may not be able to inject any power onto the Transmission System due to constraints that fall below the threshold of mitigation for a generator interconnection request. Because of this, the Customer may be required by the Transmission Provider to reduce their generation output to 0 MW under certain system conditions to allow system operators to maintain the reliability of the transmission network.

Nothing in this study should be construed as a guarantee of delivery or transmission service within SPP's transmission system. If the customer wishes to sell power from the facility, a separate request for transmission service must be requested on SPP's OASIS by the Customer.

Appendix A

Appendix A -
Current Study Interc

Appendix B

Appendix B -
Higher Queued Inte

Appendix C

Appendix C -
Higher Queued Netv