Area-Level Assessment of Hourly Variability of Reliability: A Transmission Planning Perspective

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***Abstract*—Amid rising electricity demand and growing uncertainty around spatio-temporal evolution for extreme scenarios in the grid, transmission expansion planning has emerged as a critical priority for the energy sector. More granular visibility into the system reliability has become primal for ensuring robust performance of the planning solutions. This paper develops a novel algorithm called RECAP (*Reliability Evaluation from Case Analysis of PROMOD*) for building hourly DC load flow snapshots of large transmission system to demonstrate the variability of area-level reliability through comprehensive analysis on critical line flows and contingency events. The central framework of this methodology is designed to operate autonomously as a standalone tool which can systematically map ISO-level PROMOD-based production cost optimized database to power flow cases of the system. The algorithmic process leverages established industry practices on future load forecasts using an interpretable *Distribution Factor*-based bus load shaping formulation. Simulation case studies using the 2029 PROMOD output database from the 24264 bus PJM system, with a focused analysis of the 796 bus *Dominion Energy Virginia* area, showcase the tool's effectiveness in evaluating the reliability performance for future snapshots with enhanced granularity, thereby facilitating a more rigorous planning process.**

***Index Terms*—Reliability, Production Cost Modeling, Transmission Planning, FERC order 1000, DC Load Flow, PROMOD.**

I. Introduction

In recent times, the need to grow the transmission infrastructure is unprecedented because of the load growth and integration of diverse types of energy resources scattered across the grid. Several system-level studies are performed in electric transmission planning for optimal expansion of the transmission network to ensure system reliability while also maintaining the affordability of engineering solutions. The Federal Energy Regulatory Commission (FERC) order 1000 [1] requires independent system operators (ISOs) to provide opportunities through a competitive solicitation process for both incumbent transmission owners and non-incumbent transmission developers to propose transmission planning projects. Therefore, developers perform extensive analysis to solve for network congestion while planning for future expansions following ISO recommended processes such as the market efficiency open window (MEOW) guidelines from Pennsylvania-New Jersey-Maryland (PJM) interconnection [2]. In addition, ISOs also conduct separate competitive process for enhancing system reliability through regional transmission expansion planning (RTEP) approach [3].

RTEP solutions typically address seasonal peak conditions, i.e., summer peak, winter peak, spring minimum loads of the future snapshots of the system to give worst case guarantees for system reliability [3]. With the increasingly diverse scope for future interconnection projects, it has been crucial to assess the transmission planning solutions for wider range of snapshots capturing the edge cases. In this regard, the existing literature [4], [5] used *Monte Carlo* method in probabilistic assessment for network expansion planning. However, Monte Carlo generated power flow cases limit the representation of distinct characteristics of resource variability for diverse set of generation fleet, and are incapable of accurately capturing the forced outage rates of equipments for a wide range of operating points [6]. Authors in [7] used Monte Carlo technique enhanced with k-means clustering to capture the evolving constraints of probabilistic planning. However, the inherent convexity of k-means clusters in linearly separable feature space effectively limits the representation of non-linear correlation that may exist between system planning snapshots over the study year. In addition, grid planners face challenges in collecting, preparing and maintaining the system-level dataset needed for applying such probabilistic methods.

With the above challenges in reliability-oriented transmission planning, it has also been crucial to assess the interplay of reliability solutions with economical rationale behind transmission planning decisions. Hitachi Energy [8] developed a production cost optimization tool within their proprietary PROMOD software to address system congestion for MEOW. This involves optimization of system-wide operational costs over an entire future year, considering all relevent hourly constraints including the network-level DC load flow (DCLF) boundaries cumulatively accounted for that year. The system-level granular details needed for PROMOD's optimization is collected and maintained by the corresponding ISO during regular intervals of MEOW process. Therefore, PROMOD-based output solution database holds the potential for analyzing transmission planning solutions by coupling two main drivers: *Reliability* and *Economy*. However, as per authors' knowledge, there is no existing standalone tool for interpreting the reliability performance of PROMOD output database. With the above motivation, this paper develops a novel algorithm called RECAP (i.e., *Reliability Evaluation from Case Analysis*

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979-8-3315-8138-1

of PROMOD) to derive the hourly DCLF snapshots of a realistically large transmission system with flexibility to perform focused area-level analysis. It can assist system planners in the subsequent steps of solving the identified reliability concerns with more granular detail than simply planning infrastructure expansion for seasonal peaks. Accordingly, the reliability of hourly system equilibria is evaluated under critical contingency scenarios to assess performance risks in terms of (N-1) and (N-1-1) security limits for the utility area under study.

The rest of the paper is organized as follows. Section II introduces the conceptual formulations and algorithmic computation process for RECAP tool. Section III demonstrates the implementation framework for RECAP. Section IV presents an extensive simulation based analysis on Dominion Energy Virginia's transmission grid. Section V concludes the paper including directions for future work.

II. RECAP: Formulation and Methodology

A. Problem Setup

Consider, a power system that represents a *Balancing Authority* or ISO whose region is divided into m number of distinct control areas operated by different utilities. Accordingly, any area in the system is denoted as A_α indicating that it is the α^{th} area. Let $\mathbb{N}_\alpha$, ref, and ξ_α denote the set of buses, reference bus, and set of branches respectively for A_α. Let $\mathbb{N}'_\alpha = \mathbb{N}_\alpha \setminus ref$ represent the set of buses excluding the reference bus. The cardinality of $\mathbb{N}_\alpha$ is n_α. Given the ISO-level PROMOD output database being denoted as $\mathbf{X}$ and the corresponding database of network-level hourly power flow snapshots of A_α being denoted as $\mathbf{Y}^\alpha$, our RECAP algorithm aims to develop $\mathbf{Y}^\alpha$ with high-fidelity representations of A_α grid through the functional mapping $f : \mathbf{X} \rightarrow \mathbf{Y}^\alpha$. The following subsections describe the computational process for the structural mapping f from different data fragments of $\mathbf{X}$.

B. Bus Mapping

First, the buses need to be mapped to build the power flow case for the system of interest A_α. It involves bus-level information such as bus number, bus name, base kV, bus type (P-V, P-Q, V-θ), voltage angle ($\theta_i, \forall i \in \mathbb{N}_\alpha$), associated owner, zone, and area. Since the ISO-level networked topology related information embedded in PROMOD output database provides all the above mentioned bus parameters in scattered structure, the information had to be collated through coordinated mapping of the database. Please note that the bus voltage magnitude is taken as 1 p.u. to maintain power flow equivalence with DCLF constraints embedded in PROMOD.

C. Network Topology Mapping

Networked topology is represented in DCLF formulation by the bus connectivity, branch susceptances and line ratings. Usually, ISO-level PROMOD output database has fragmented segments of branch information linked through unique IDs for the buses. Therefore, RECAP builds the network-level DC power flow for A_α at k^{th} hour of the study year by mapping the topology using the bus IDs of that area as follows:

$$\mathbf{P}_k^{A_\alpha}\Big|_{\text{DC}} = (diag(\mathbf{b}^{A_\alpha})\,.\,\mathcal{I}^{A_\alpha}\,.\,\theta_k^{A_\alpha}), \tag{1}$$

$$\text{where } \mathbf{P}_k^{A_\alpha}\Big|_{\text{DC}} \in \mathbb{R}^{|\xi_\alpha|\times 1},\ \mathbf{b}^{A_\alpha} \in \mathbb{R}^{|\xi_\alpha|\times 1},$$
$$\mathcal{I}^{A_\alpha} \in \mathbb{Z}^{|\xi_\alpha|\times(n_\alpha-1)},\ \theta_k^{A_\alpha} \in \mathbb{R}^{(n_\alpha-1)\times 1}.$$

Here, $\mathbf{P}_k^{A_\alpha}\Big|_{\text{DC}}$ is the vector of active power flows from all branches $(i \leftrightarrow j) \in \xi_\alpha$ during k^{th} hour. Branch susceptances are in the $\mathbf{b}^{A_\alpha}$ vector with $diag(.)$ being the diagonal matrix with the argument on the diagonal. $\mathcal{I}^{A_\alpha}$ is the incidence matrix [9] describing the connections between the buses and branches of the network. As planned outages of the transmission network are not trackable in scenarios of long-term planning, we do not consider topology variation over the study year. $\theta_k^{A_\alpha}$ is the vector of voltage angles for buses $i \in \mathbb{N}'_\alpha$ at k^{th} hour. $\mathbb{R}$ and $\mathbb{Z}$ are the set of real numbers and set of integers respectively. In addition to the above network-level power balance, RECAP tracks the following thermal limits of line flows for individual elements $\left(p_{ij}^{A_\alpha}\right)_{\text{DC}}^k$ of vector $\mathbf{P}_k^{A_\alpha}\Big|_{\text{DC}}$.

$$\underbrace{\left|\left(p_{ij}^{A_\alpha}\right)_{\text{DC}}^k\right|}_{\forall \text{ line } (i\leftrightarrow j)\in\xi_\alpha} \leq \begin{cases} \bar{p}_{ij}^{A_\alpha}\Big|_{s_k}^n, & \text{for } normal \text{ operation,} \\ \bar{p}_{ij}^{A_\alpha}\Big|_{s_k}^e, & \text{for short-term } emergency. \end{cases} \tag{2}$$

Where n and e are associated with *normal* operation and short-term *emergency* (STE) limits respectively for the corresponding branch during the season s_k. Typically, following a contingency event, if the grid operates in STE band, grid operators are supposed to make system readjustments to bring the network back within the limits of normal operation [10]. Therefore, these thermal limits are used later to evaluate the system reliability from the DCLF solutions of the hourly power flow cases generated by RECAP.

D. Load Mapping: Area-level to Bus-level Disaggregation

The feasibility of network-level DC power flow solution has strong sensitivity towards the individual bus-level active power loads. Therefore, the hourly variability of bus loads needs to be rigorously represented to closely match the load forecast of the area A_α under study. The RECAP tool performs the *Load Mapping* from PROMOD output database to power flow case by maintaining the consistency between area-level aggregated load envelopes and bus-level allocation of loads. The RECAP *Load Shaping Formulation* is described as follows:

As per PROMOD convention, the total load associated with an entire area is represented by a *Demand Group*. Area-level demand includes two types of loads, namely (1) *Conforming Load* which varies with system conditions (e.g., residential, commercial), and (2) *Non-conforming Loads* which does not vary, usually fixed industrial or *Block Loads* [11]. Typically, an ISO has the visibility to the area-level load growth and can estimate the hourly load value for A_α. Therefore, the estimated total load of A_α can be expressed as:

$$\mathcal{P}_k^{A_\alpha} = \mathcal{P}_{b,k}^{A_\alpha} + \mathcal{P}_{c,k}^{A_\alpha}, \tag{3}$$

where $\mathcal{P}_k^{A_\alpha}$ is the area-level load forecasted for the k^{th} hour of the year for A_α. $\mathcal{P}_{b,k}^{A_\alpha}$ and $\mathcal{P}_{c,k}^{A_\alpha}$ are the *Block Load* and *Conforming Load* respectively for that area at the same hour. Usually, ISO-Utility partnership brings visibility to the seasonal peak values of the bus-level conforming and non-conforming load components from the load interconnection process during transmission planning phase. By definition, $\mathcal{P}_{b,k}^{A_\alpha}$ stays constant for a particular season. Therefore, the ISO-level PROMOD database readily uses the bus-level $BlockLoad$ values from future year planning cases to build *Non-conforming* load information in the production cost modeling framework. Consequently, RECAP can calculate the area-level *Block Load* as:

$$\mathcal{P}_{b,k}^{A_\alpha} = \sum_{j=1}^{n_\alpha} \mathrm{p}_{b,s_k}^{j^{A_\alpha}}, \tag{4}$$

where $\mathrm{p}_{b,s_k}^{j^{A_\alpha}}$ is the non-conforming load component at j^{th} bus of *Demand Group* A_α for k^{th} hour belonging to the season s_k in PROMOD database. Therefore, RECAP can use Eq. (3)-(4) to calculate the area-level *Conforming Load* as:

$$\mathcal{P}_{c,k}^{A_\alpha} = \mathcal{P}_k^{A_\alpha} - \sum_{j=1}^{n_\alpha} \mathrm{p}_{b,s_k}^{j^{A_\alpha}}, \tag{5}$$

$\mathcal{P}_{c,k}^{A_\alpha}$ needs to be disaggregated to bus-level load values for building the hourly power flow cases. As stated above, PROMOD database has the seasonal peak forecast of bus-level loads which can be used to distribute the total load from *Demand Group* to its buses. The corresponding *Distribution Factor* (*DF*) can be expressed as:

$$DF_{c,s_k}^{i^{A_\alpha}} = \frac{p_{s_k}^{i^{A_\alpha}} - p_{b,s_k}^{i^{A_\alpha}}}{\sum_{j=1}^{n_\alpha} p_{s_k}^{j^{A_\alpha}} - \sum_{j=1}^{n_\alpha} p_{b,s_k}^{j^{A_\alpha}}}, \qquad \forall i \in \mathbb{N}'_\alpha, \tag{6}$$

where $DF_{c,s_k}^{i^{A_\alpha}}$ is the distribution factor for the conforming load at the i^{th} bus of A_α during the season s_k. $p_{s_k}^{i^{A_\alpha}}$ and $p_{b,s_k}^{i^{A_\alpha}}$ are the total load and the block load component respectively at the same bus during the peak scenario of the same season as reflected in the PROMOD database. Therefore, RECAP can calculate the total load $\mathrm{p}_k^{i^{A_\alpha}}$ at i^{th} bus of A_α at k^{th} hour as:

$$\mathrm{p}_k^{i^{A_\alpha}} = \mathcal{P}_{c,k}^{A_\alpha} \,.\, DF_{c,s_k}^{i^{A_\alpha}} + \mathrm{p}_{b,s_k}^{i^{A_\alpha}}, \qquad \forall i \in \mathbb{N}'_\alpha. \tag{7}$$

This method ensures that the area-level load for *Demand Group* A_α is distributed across individual buses of the area in proportion to their seasonal forecast, while respecting the fixed non-conforming load values for that season.

E. Tie-Line Representation for External Area Equivalencing

The power flows of tie-lines need to be accurately represented in the DCLF formulation for capturing the inter-area coupling between A_α and its neighbors. Consider the set of boundary buses corresponding to the tie-lines of A_α is $\mathbb{B}_\alpha$ (where $\mathbb{B}_\alpha \subseteq \mathbb{N}_\alpha$). To capture the net effect of interchanges with the external system, RECAP represents the tie-line flows at bus i (where $i \in \mathbb{B}_\alpha$) as equivalent load with positive (or negative) value indicating export to (or import from) corresponding neighboring areas. Consequently, appropriate branch data and corresponding bus IDs are utilized from PROMOD output database to map the DCLF-constrained directional values of feasible hourly flows for tie-lines of A_α.

F. Generation Mapping

RECAP needs to incorporate the details on hourly generator dispatch in the DCLF. Unlike loads, ISOs have full observability to the energization timelines of the upcoming generation interconnection projects for the future year under study. In addition, ISOs incorporate generation retirements and generation maintenance related planned outage information while preparing the production cost modeling database. Also, ISOs determine the dispatch of available generators for transmission planning cases using a range of processes such as uniform dispatch, block dispatch etc. [3], [12]. Therefore, generation setpoints are compiled for the area A_α through direct mapping of the ISO-level PROMOD output data segments. Appropriate data integration is performed at bus-level by processing different segments of information such as week-to-hour mapping of the generation dispatch, creating per hour transaction based compact generator ID, incorporating the owner information and the power limits as the following inequality constraint:

$$\underline{P}_g^{i^{A_\alpha}} \le P_{g,k}^{i^{A_\alpha}} \le \bar{P}_g^{i^{A_\alpha}}, \qquad \forall i \in \mathbb{N}'_\alpha, \tag{8}$$

where $P_{g,k}^{i^{A_\alpha}}$ is the generation dispatch at i^{th} bus of A_α at k^{th} hour with $\underline{P}_g^{i^{A_\alpha}}$ and $\bar{P}_g^{i^{A_\alpha}}$ as lower and upper bounds.

Bus-level power conservation [9] at k^{th} hour with generation (or load) as positive (or negative) injection is given as:

$$\mathscr{P}_{inj,k}^{A_\alpha} = \left(\left[\mathcal{I}^{A_\alpha}\right]^T . \, diag(\mathbf{b}^{A_\alpha}) \,.\, \mathcal{I}^{A_\alpha}\right) . \, \theta_k^{A_\alpha}, \tag{9}$$

with $\mathscr{P}_{inj,k}^{A_\alpha} \in \mathbb{R}^{(n_\alpha - 1)\times 1}$ as the vector of power injections. Therefore, RECAP constructs the DCLF hourly snapshots with Eq. (1) and (9) to analyze system reliability rigorously.

III. Implementation Framework for RECAP

Fig. 1 illustrates the architecture of the RECAP tool. The system planners can define specific hours of interest for analyzing *Demand Group* of area A_α. Accordingly, the proposed algorithm performs multifaceted acquisition of information to build hourly power flow snapshots from the fragmented *data lake* of PROMOD database. A wide array of clustered datasets showing network topology, hourly line flows, flow limits, hourly generation dispatches, and load forecasts at different spatio-temporal scale are embedded in the centralized repository of the output files generated by PROMOD. The standard file formats (e.g., `.PFF`, `.TRN`, `.FLO` etc.) of various PROMOD files are shown for reference. These datasets are categorized into time-variant and time-invariant data clusters as per 8,760 hours of the year, with the time-variant data further segmented into sub-clusters capturing variations for each quarter of the future year of interest for planning purposes. In addition to compiling the necessary data, the tool can also evaluate system reliability through comprehensive contingency analysis.

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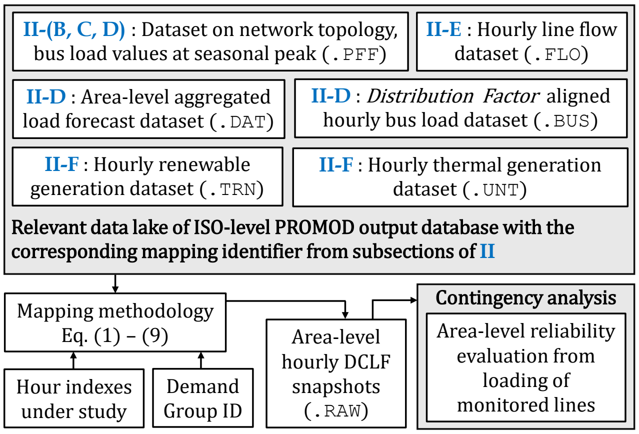

Fig. 1: Implementation architecture of RECAP tool.

IV. Simulation Results

The RECAP algorithm has been evaluated using the PROMOD output database of the PJM system from plan of year 2029 developed during the 2024-25 PJM market efficiency cycle. This database contains 24264 buses, 31126 branches, 4556 load buses, and 21954 generator buses of PJM system. From this database, RECAP generates the hourly power flow snapshots with 796 buses, 1456 branches, 514 load buses, and 130 generator buses to represent the *Demand Group* equivalent to *Dominion Energy Virginia* (DEV)'s transmission network. 11 tie-lines from 4 neighboring areas of DEV are also incorporated using load equivalencing from section II-E.

A. Evaluation of Accuracy of RECAP Tool

First, we evaluate the accuracy of RECAP in developing the faithful representation of DEV area in .RAW format of PSS/E. The 8 AM snapshot of February 26th 2029 is taken as a representative system equilibrium. Fig. 2 shows the histogram of percentage error representing line flow mismatches between the RECAP-based DCLF branch flows derived from PSS/E for that hour and the DEV branch flows in the .FLO data cluster of PROMOD output database.

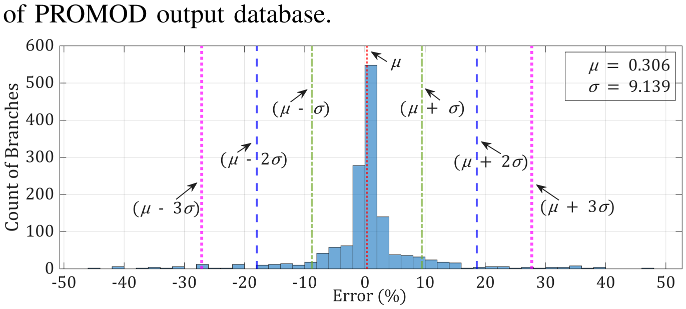

Fig. 2: Histogram of errors in line flows for RECAP wrt PROMOD for the snapshot of 8 AM from February 26th 2029.

The mean (μ) and variance (σ) of error values are utilized to provide a statistical visualization in Table I that quantitatively represents RECAP's accuracy for that hour. 3σ boundaries of Fig. 2 are used to form error buckets $\Re_1, \Re_2, \Re_3, \Re_4$. Count of branches showcases that 84.75% of all lines are in bucket $\Re_1$ depicting high accuracy with respect to the benchmark flows in .FLO data segment. Further investigation on all error ranges reveal that a higher percentage error does not necessarily indicate a larger MW difference. The reason being the actual branch flow value which can be very small, and thereby, a minor MW difference can make the percentage error appear disproportionately large. For example, in the range $\Re_4$, the highest error recorded is 47.45%, but the corresponding MW difference is only 4.98 MW. The accuracy pattern observed for this hourly snapshot remains consistent for other hours of the year 2029 demonstrating the tool's capability to generate accurate hourly snapshot files in .RAW format.

TABLE I: Visualization of MW mismatches and percentage errors corresponding to the histogram of errors in line flows.

Error range	Count of branches	MW mismatch visualization		Error visualization	
		Highest gap (MW)	Error (%)	Highest error (%)	MW mismatch
$\Re_1$	1234	13.24	7.82	9.27	1.84
$\Re_2$	124	28.27	15.08	17.49	10.93
$\Re_3$	42	17.31	-22.83	26.56	-8.02
$\Re_4$	56	40.91	-44.32	47.45	4.98

$\Re_1 = [(\mu-\sigma),(\mu+\sigma)]$, $\Re_2 = [(\mu-2\sigma),(\mu-\sigma)) \cup ((\mu+\sigma),(\mu+2\sigma)]$, $\Re_3 = [(\mu-3\sigma),(\mu-2\sigma)) \cup ((\mu+2\sigma),(\mu+3\sigma)]$, and range beyond $\pm 3\sigma$ is $\Re_4 = (-\infty,(\mu-3\sigma)) \cup ((\mu+3\sigma),+\infty)$.

B. Evaluation of Hourly Variability of Power Flow

RECAP generated .RAW snapshots are subsequently utilized for reliability analysis, enabling the evaluation of line flow variability at any given hour. This level of granularity is unobtainable within conventional planning process using RTEP snapshots showing seasonal peaks only. Consequently, RTEP 2029 summer peak snapshot with DEV area load 31426 MW is considered as base case for comparative analysis. Top 10 lines are identified in the base case based on the ranking from the highest to the lowest line flows. Now, from all the RECAP snapshots derived for 2029 summer, $Set1 = \{1_{\mathrm{M}}, 2_{\mathrm{M}}, \ldots, 10_{\mathrm{M}}\}$ represents the top 10 high load hourly snapshots ranked from the highest to the lowest DEV area load, $Set2 = \{1_{\mathrm{m}}, 2_{\mathrm{m}}, \ldots, 10_{\mathrm{m}}\}$ represents the top 10 light load hourly snapshots ranked from the lowest to the highest DEV area load as shown in the Table II. Fig. 3 shows the comparison of flows in critical corridors for the selected snapshots in the consistent direction of calculated line flows. Both $Set1$ and $Set2$ snapshots portray deviations from RTEP.

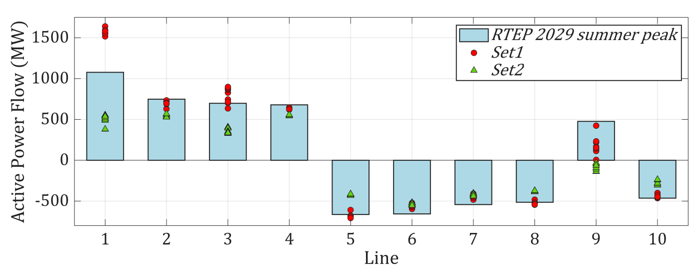

Fig. 3: Flows in top 10 highly loaded lines in 2029 summer with variability from snapshots $Set1$, $Set2$ wrt the peak case.

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TABLE II: DEV area load for snapshots generated by RECAP algorithm for summer of 2029.

⟵ $Set1$: High load hours' snapshots ⟶										⟵ $Set2$: Light load hours' snapshots ⟶									
1_M	2_M	3_M	4_M	5_M	6_M	7_M	8_M	9_M	10_M	1_m	2_m	3_m	4_m	5_m	6_m	7_m	8_m	9_m	10_m
32472	**32385**	**32310**	**32223**	**32170**	**32133**	**32132**	**32127**	**32098**	**32077**	**14493**	**14507**	**14528**	**14544**	**14551**	**14557**	**14657**	**14675**	**14712**	**14775**
⟵ $\mathcal{P}_k^{A\alpha}$: **Area load (MW)** where $k \in$ Set of hours for snapshots $Set1$ & $Set2$ ⟶																			

Compared to RTEP flows, line 1 and 3 are loaded substantially more in $Set1$. The flow pattern of line 3 is shown in Fig. 4 as an illustrative example to portray the variability with respect to the monotonicity of area load in RECAP snapshots. With decreasing area load in $Set1$, the flow in line 3 does not decrease monotonically because the individual bus-level consumptions that alter the power flow, may not have consistent gradient like area load. A similar pattern is evident under increasing area load conditions for $Set2$. Therefore, RECAP can effectively capture line flow variability, which is typically overlooked in conventional reliability planning processes that rely on only seasonal peak snapshots.

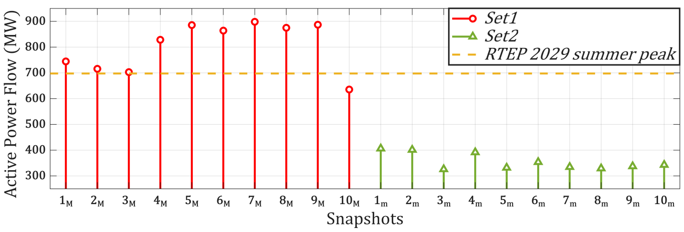

Fig. 4: Flows in line 3 for 2029 summer with variability from snapshots $Set1$, $Set2$ wrt the peak case.

C. Reliability Evaluation using Contingency Analysis

In this subsection, we evaluate 5 critical (N-1) contingencies and 5 critical (N-1-1) contingencies of DEV area to further showcase the capability of RECAP algorithm in the assessment of system reliability. Fig. 5 shows the percentage loading of the monitored branch for each contingency scenario with respect to the STE rating of the branch. As per DEV's planning criteria [10], thermal loading of any line needs to be limited to 94% of STE rating during (N-1) condition to keep marginal flexibility around 100% STE loading. The monitored flows in RTEP case satisfy this criteria because the case is devised to serve reliability bounds for seasonal peaks. However, RECAP is able to capture the spread of loading values for each of the critical (N-1) contingencies highlighting risky loading points at 93.56% and 93.67% for monitored branch during (N-1) scenario 2 for snapshots 2_M and 3_M respectively from $Set1$. In addition, (N-1-1) scenario results from $Set1$ and $Set2$ reveal more severe overloads beyond 100% that are not identified in the summer peak case.

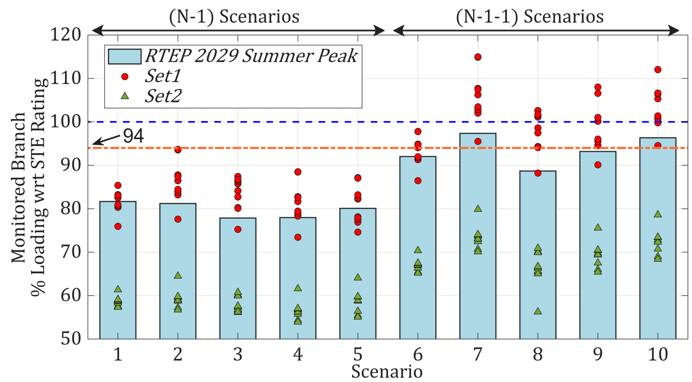

Fig. 5: Loading variation for monitored branches for seasonal peak case vs $\{Set1, Set2\}$ for 10 critical contingencies.

V. Conclusions and Future Work

We developed a novel algorithm to perform transmission planning studies capturing the variability of system reliability with higher granularity. The area-level network snapshots are methodically and accurately mapped at hourly scale from exclusive mapping of PROMOD output database embedded with DCLF constraints. Assumptions on generation dispatch and load forecast are considered in the hourly power balance respecting data availability and information sharing framework of planning process. The comprehensive analyses on critical line flows and contingency scenarios are presented across diverse operating points, highlighting potential thermal violations beyond the limited insights provided by seasonal peak cases. Future research directions could include the extension of the developed hourly DC power flow case to AC while handling the sparsity in information on reactive power variables, augmenting reliability evaluation with additional functionalities such as area-to-area power deliverability analyses.

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