Hydrogen to Provide Flexibility in The Canadian Energy System

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Abstract

Assessing new technologies, such as Power to Gas (P2G) with hydrogen storage, for the Canadian energy system will aid the transition to a low carbon future. Based on the country's emission reduction policy, Canada has pledged to strengthen its climate plan to meet the 2030 emission reduction and net-zero emissions by 2050. In this project, we use the OSeMOSYS Energy System Model to evaluate the potential of different technologies to contribute to these emissions reductions. Specifically, the ability of P2G, in conjunction with flexible hydro energy, to meet Canada's low carbon electricity demand is evaluated. The results provide electricity infrastructure pathways from 2020 through 2050 under differing emission penalties, hydro generation flexibility and P2G costs. Overall, increasing emission penalties are required to meet the pledged emission reduction strategy. Furthermore, allowing flexibility in the production of hydro significantly reduces the value of P2G for energy storage, but P2G does provide benefits when emission penalties are high.

Table of Contents

List of Tables

Table of Figures

List of Abbreviations

P2G .... Power to Gas
FC .... Fuel Cell
PEM .... Proton Exchange Membrane
WN........ WIND
PV........ SOLAR
HYD........ HYDRO
BIO........ BIOMASS
GS........ GAS
CL........ COAL
NUC........ NUCLEAR
ID........ Intermediate Day
IN........ Intermediate Night
SD........ Summer Day
SN........ Summer Night
WD........ Winter Day
WN........ Winter Night
W........ West
MW........ Mid-West
ME........ Mid-East
E........ East

Introduction

The Canadian Government adopted the Canadian Net-Zero Emissions Accountability Act in 2020 [1] which requires Canada to reach Net-Zero by 2050. To assess potential paths towards Net-Zero emissions, modelling of the Canadian energy system, and technology potential, can aid in ensuring that the most sustainable solutions are adopted. One significant challenge in meeting Net Zero goals is enabling the system to use low carbon intermittent renewables to meet demand during periods of low renewable production. One technology that has been proposed to address this challenge is the use of power conversion to hydrogen, subsequent storage, and then re-generation of electricity to allow time shifting of the produced energy. Referred to as Power to Gas (P2G), such conversion can enable variable renewable energy sources to contribute more fully to the electricity system.

Renewable energy sources are often identified as a potential resource to reduce emissions and improve environmental sustainability [2]. However, renewable energies are intermittent and in order to use these resources effectively, energy storage is critical [3]. Prior studies have found that techno-economic viability of P2G is highly dependent on regions' resources and the existing energy market characteristics [4]. These dependencies play a key role in determining cost competitiveness. Evaluating P2G for the Canadian landscape, as done in this report, provides policymakers with guidance as to the benefits and challenges in support of the comprehensive hydrogen strategy Canada is pursuing [5], [6].

We apply the OSeMOSYS Open-Source Energy Modelling System, a linear programming cost optimization model, to the Canadian electricity system to evaluate the costs and benefits of incorporating P2G, and specifically hydrogen technologies to the power system. Benefits expected from P2G technologies include system flexibility in support of integrating renewable resources. In particular, the use of PEM electrolysis for conversion of electricity into hydrogen is tested with the model. Furthermore, flexible and restricted hydro production in each region is applied to analyze the variation in energy production. The results highlight the cost and benefits of the P2G processes in Canada for policy makers to invest in P2G facilities and hydrogen storage in the future.

Literature Review

Power to Gas Technology (P2G) has received increased attention in the literature as a method to enhance the flexibility of energy systems through converting excess electricity into stored hydrogen; incorporating P2G into a system with large shares of intermittent renewable energy has the potential to significantly benefit from this technology [7]–[9]. Renewable energies are continually invested in year over year to meet future electrification and emission goals, however, the intermittent production from sources such as wind and solar can cause serious system balancing issues. The impact of the intermittency issue can be seen in California where policies and initiatives have significantly increased solar production in the state, this has led to a net energy load curve that has been coined the "Duck Curve"[10]–[12]. The Duck Curve shows the imbalance between peak demand and peak energy production. For example, during early evening as people arrive home from work the demand ramps up, however, solar energy has already passed its peak production and is staring to diminish at this time. This puts significant strain on the system as other energy producers need to quickly ramp up production to meet the demand spike, while solar energy was possibly curtailed or wasted earlier in the day. P2G could alleviate this strain by storing the excess solar energy as hydrogen, and then help meet the evening demand spike by converting the hydrogen back into electricity at the appropriate time.

Incorporating P2G technology and hydrogen into the energy system requires three steps; hydrogen production, hydrogen storage, and hydrogen use. The widely accepted method of hydrogen production through renewable energy sources is water electrolysis, with proton exchange membrane water electrolysis (PEM) being a subset of this group. Water electrolysis works by allowing electricity to flow through an electrolyser which splits water into hydrogen gas and oxygen gas. PEM is a leading technology choice due to its efficient hydrogen production, compact design, fast response, and ability to operate under non-extreme temperatures (20-80 °C). Furthermore, although PEM technology currently suffers from relatively high costs of components, a large amount of research is underway to make it commercially viable in the future [13]–[15]. Two options exist for the storage of hydrogen, it can either be blended into the natural gas supply or it can be stored in pressurized vessels and converted back into electricity when required by the electricity demand [6], [16]. Stored hydrogen can then be converted back into usable electricity using fuel cells. Hydrogen fuel cells work by generating electricity, heat, and water through an electrochemical reaction when supplied with hydrogen and oxygen. While hydrogen fuel cells do not need to be charged like their electrical battery counterpart, their electrical efficiency is much lower (30-60% depending on the type of fuel cell) [17], [18].

The operational challenges of balancing the energy gird through intermittent energy sources with short- and long-term storage solutions needs to be addressed; P2G technology offers distinct advantages over other storage mediums such as batteries and pumped hydroelectric storage. Batteries are an effective and common short-term energy storage solution, however, their relatively low storage density, environmental sensitivity, and self-discharge do not make them suitable for long-term bulk energy storage applications [9], [19]. Another discussed method of dealing with periods of excess electricity is using pumped hydroelectric storage; this solution has strict geographic requirements, must be evaluated on a case-by-case basis, and is not suitable for a generalized solution [9], [20].

Recent pilot projects are now assessing the technical capabilities and the economic feasibility of P2G and hydrogen storage on a large scale. The concept of using hydrogen as a commercial fuel is not new, and literature from the 2000s and earlier clearly lists advantages for using hydrogen that still hold true today, including that it is a viable source of energy [21]–[23]. The pilot projects discussed below are now showing the widespread acknowledgement of the technology as a method to combat climate change through coupling hydrogen with renewable energy sources. First, the HyDeploy project will be discussed as an example of hydrogen blending and a method to transport renewable hydrogen. Secondly, the Hydrogen Valley project will be reviewed as it represents a major hydrogen focused project with significant resource investments. Lastly, smaller projects and studies in North America will be used to understand the state of P2G for the Canadian geography and landscape.

HyDeploy is a project investigating the potential for blending up to 20% hydrogen (by volume) into the normal gas supply to reduce carbon dioxide emissions [24]. In 2016, the Office of Gas and Electricity Markets in Great Britain announced funding for the project and the 16 month long experiment is set to end in March 2021. Keele University was selected for this project as it operates on its own private gas network, has a population similar to a small town, and can support the hydrogen research. The project is currently operating at full capacity and is heating 100 homes and 30 faculty buildings with customers reporting no difference in their heating needs. Although the study is not over and results have not been published, the project is providing evidence on the commercial viability of injecting hydrogen into natural gas lines to provide customers with an environmentally friendly heating alternative [25]. The HyDeploy project will prove that the existing natural gas infrastructure can be used to offset the capital costs of adding P2G into an existing energy system and that blending hydrogen into the natural gas supply is a valid hydrogen distribution method. Providing the option to either blend hydrogen into the gas lines or to store it and convert it back into electricity will add additional flexibility to the system both in terms of cost and load balancing.

The Hydrogen Valley project is aiming to improve the storage and infrastructure for hydrogen, improve the availability of hydrogen for industry, use hydrogen to heat and power residential homes, and incorporate hydrogen into the transportation network on a large scale [26]. The project is based in the Northern Netherlands as it is surrounded by developing hydrogen demand hubs, has significant offshore wind potential, contains the physical space required for infrastructure improvements, and has committed to creating self-sustaining hydrogen businesses. Moreover, the project has more than 30 public and private partners financially backing it. The Northern Netherlands Hydrogen Investment Plan Report [27] outlines a two-phase road map for the project; Phase One (2020-2050) includes heavy research into the technology and scaling up the infrastructure to support the ambitious hydrogen production goals. Phase Two (2025 to 2030) includes a Northwestern European Expansion, where the valley will be able to supply neighboring regions with hydrogen. These two phases have major action items related to them, including ensuring regulatory frameworks are in place to incentivize hydrogen demand, increasing offshore wind development dedicated to hydrogen production, transferring knowledge from the Natural Gas industry to the hydrogen industry, and ensuring the hydrogen ecosystem is scaled up accordingly in other regions. If the 2030 hydrogen production targets are met, the report states that up to 25,000 hydrogen related jobs will be generated, and CO_2 emissions will drop by 5 to 10 Mt.

The objectives and action items laid out in the Hydrogen Valley project will play a significant role in understanding the impact hydrogen adoption can have on Canada's emission and electrification goals, including how to develop hydrogen policies to ensure the sector will produce long term economic growth. The Canadian Government has noted that in order to meet the emission targets laid out in the Canadian Net-Zero Emissions Accountability Act, long-term jobs need to be created and long-term investments that support low-carbon projects need to be obtained [28]. If Hydrogen Valley is successful, the techniques and methods used on the project can be transferred to Canada to expedite the hydrogen adoption process. Analyzing how other nations are handling hydrogen policy development will help ensure Canada can meet the emission and economic goals outlines in the Net-Zero Emissions Accountability Act.

HyDeploy and Hydrogen Valley discuss the feasibility of adopting hydrogen on a commercial scale in Europe, however, prior studies have found that the viability of P2G is highly dependent on a regions' resources and the existing energy market characteristics; these dependencies play a key role in determining cost competitiveness [29]. Evaluating P2G for the Canadian landscape, with consideration of provincial jurisdictional differences, will provide policymakers with guidance as to the benefits and challenges associated with P2G and support the comprehensive hydrogen strategy Canada is pursuing [30].

Throughout Canada and the United States, numerous hydrogen production and blending facilities are in development or have been completed, showing the interest from the governments and energy companies to pursue hydrogen projects. SoCalGas, a major United States natural gas company, in partnership with the University of California at Irvine (UCI) and the National Renewable Energy Laboratory have begun developing a P2G system for California to convert excess (predominantly solar) electricity into hydrogen. Hydrogenics, a subsidiary of Cummins, in partnership with Enbridge completed a 2.5 MW P2G facility in Markham Ontario in 2018; this facility is not only an example of a large-scale PEM electrolyser, but it will also supply hydrogen to a new blending facility to be built in Ontario through a partnership with Enbridge and Cummins. This blending facility pilot project is a first of its kind in North America and will be used to evaluate and plan how to scale up hydrogen blending into Enbridge's existing distribution system [4]–[6]. Finally, Mitsubishi Hitachi Power Systems and Magnum Developer are currently developing the Advanced Clean Energy Storage Project in Utah, which will produce 1000MW of clean energy storage with renewable hydrogen being one of the four types of storage [31]. The variety of projects highlighted in Canada and the United States show that the energy sector has committed to developing hydrogen in North America; as the number of projects increases, proper planning, resource management, and policy development needs to be done to ensure sustained growth of this industry.

In addition to the North American pilot projects, feasibility studies are also being completed to further assess P2G and hydrogen adoption in Canada; such studies include looking at seasonal underground hydrogen storage, evaluating Canada's natural gas pipeline infrastructure to allow for hydrogen transport, and the socio-economic benefits of becoming a hydrogen importer/exporter. While above ground hydrogen storage facilities are already being built in Canada, such as the Markham facility, a study conducted by Lemieux et al. researched seasonal underground hydrogen storage solutions in geological formations for Ontario [32]. The study investigated storing hydrogen in salt and hard rock caverns, aquifers, and depleted oil and natural gas deposits, and discussed the advantages that underground storage solutions offer, including occupying smaller surface area and allowing for increased storage pressure; these advantages also match up with similar articles discussing underground hydrogen storage [33]. The dangers of such storage mediums were also considered in the Ontario study completed by Lemieux et al. when assessing specific storage locations, such as seismic hazards. The findings showed that Ontario could use a variety of seasonal underground storage solutions and recommended specific salt caverns. Lemieux et al. showed that Ontario (as a subset of Canada) has the means for multiple hydrogen storage solutions and can allow for increased hydrogen infrastructure flexibility.

Canada has previously made significant investments in its natural gas pipeline infrastructure, being able to utilize these pipelines to transfer hydrogen within a region, and import/export hydrogen to neighboring region will result in a quicker and cheaper hydrogen infrastructure development period. Although there are technical challenges remaining before natural gas pipelines can be used to carry large amounts of hydrogen, such as investigating the impact of hydrogen embrittlement on the steel pipes and welds, and the need for lower cost hydrogen compression technology, research is currently going into solving these problems; as demonstrated by the HyDeploy project and Cummins/Enbridge blending facility previously discussed [34], [35]. Allowing hydrogen to be stored and transported through natural gas pipelines offers increased system flexibility through providing the option to blend hydrogen with the natural gas if the fuel cell facility is down or storage is at a premium, as well as providing a means to transport energy if electrical transmission lines are operating at capacity.

To offset the capital expenditures from hydrogen infrastructure development, understanding the feasibility of importing and exporting hydrogen to generate revenue is an important consideration. ITM Power PLC completed a hydrogen feasibility study to showcase the potential for British Columbia to become a hydrogen exporter to other jurisdictions, with options for blending hydrogen into the natural gas distribution system. The results from this study highlight BC's potential to become a producer and exporter of renewable electrolytic hydrogen and the resulting socio-economic benefits such as business development and job growth for the community [36]. This study further demonstrates that hydrogen can be incorporated into existing infrastructure to allow for a profitable gradual adoption and expansion into Canada.

The technical overview and presented case studies of hydrogen power to gas systems highlighted the technologies ability to aid Canada in reaching its Paris Agreement goal of reducing greenhouse gas emissions by 30% below 2005 levels [37]. Through conducting macro scale energy modeling, different scenarios can be run to prioritize reducing emissions, increasing hydrogen production, promoting hydrogen trade, or numerous other situations. The results from these scenarios will allow researchers and policy makers to visualize the impact P2G will have on Canada when coupled with intermittent renewable energy sources; these results can be used to help guide policy development and ensure P2G is invested in at the correct moments to maximize its effect and reduce Canada's environmental impact.

Methods

This study uses the open-source OSeMOSYS energy system model to evaluate the potential for Power to Gas to contribute to the Canadian electricity system. In this section we highlight the model structure and scope, regional representation, data and scenarios evaluated.

OSeMOSYS Open-source Energy Modelling System

We utilize the OSeMOSYS Open-Source Energy Modelling System to evaluate the impact of hydrogen P2G technology on the Canadian Energy System over the next 30 years. OSeMOSYS is an open-source modelling framework used for long-run integrated assessment and energy planning [38]–[40]. The benefit of utilizing an open-source software, opposed to commercial energy planning software, is that it does not require any financial investment and is supported by an active user community to help troubleshoot model issues. Since the inception of OSeMOSYS in 2008, it has been used to develop energy systems for regions as large as continents and countries down to systems as small as cities and villages. Examples of its use includes Jayadev et al. [41] who utilized a Python implementation of OSeMOSYS to develop a least-cost optimization model to perform emission policy scenario analysis on the United States electricity sector, and English et al. [42] who utilized a GNU Math Prog implementation of OSeMOSYS to study how interregional transmission can help provide flexibility to systems with large amounts of renewable energies. We selected the OSeMOSYS framework as it is freely available, offers a quick turnaround time to build a functioning model, allows for the addition of P2G technology and associated data with relative ease, and has an active online support community.

The version of OSeMOSYS we implemented was a least-cost linear optimization model written in GNU MathProg and solved using the free GNU linear programming kit (GLPK). The linear optimization model functions through minimizing an objective equation that gives the total cost of the scenario. The results of the optimization yield a unique set of values that specify how much of each energy type must be produced in order to meet energy demand in every time segment. This type of modelling allows us to perform sensitivity analysis to visually see how much an input parameter can change with the output results remaining relatively unchanged. The benefit of this type of analysis, specifically with P2G technology, is that we will be able to vary emission penalties and see at what carbon tax value will P2G begin to make economic sense. Moreover, since the price of hydrogen P2G systems are still an area of concern, performing sensitivity analysis to see at what cost P2G systems will become viable can help guide appropriately timed policies to spur investment. An advantage of using OSeMOSYS to perform this analysis is its ability to quickly swap in different capital costs, fixed costs, and variable costs associated with each component in the hydrogen chain (PEM electrolyzer, storage tanks, and fuel cells). This flexibility will allow us to see what component in the hydrogen supply chain is the financial bottleneck and can help guide research investment into commercializing the technology at a target price.

In order to efficiently implement P2G hydrogen storage and format all input data, a modified version of OSeMOSYS created by Dr. Taco Niet [43] was implemented and the python package otoole was used to process data and setup an efficient workflow. Niet modified the basis MathProg OSeMOSYS model to simplify the storage representation and reduce the runtime [44]. Otoole is a command-line python package that aids the user in pre- and post-processing OSeMOSYS data [45]. We utilized otoole's CSV formatting to assemble our input parameter data as it allowed us to automate our workflow and easily filter data to check for errors.

Energy System Structure

The model structure, as replicated for each region of the country, is presented in Figure 1. The structure allows the model to either directly meet the electricity demand, or to utilize Power to Gas, storage and a fuel cells, to meet the demand.

The energy sources used for every region are presented as wind, solar, hydro, nuclear, coal, natural gas and biomass. In each region, the generation capacity for each energy source is calculated and the resulting energy produced either goes directly into meeting the electricity demand or is pushed through the P2G process and converted into hydrogen. The P2G option then converts the hydrogen from storage to electricity through the fuel cell operation. Therefore, through varying parameters, such as emission penalty and availability factor, the resulting energy production from each technology will update accordingly.

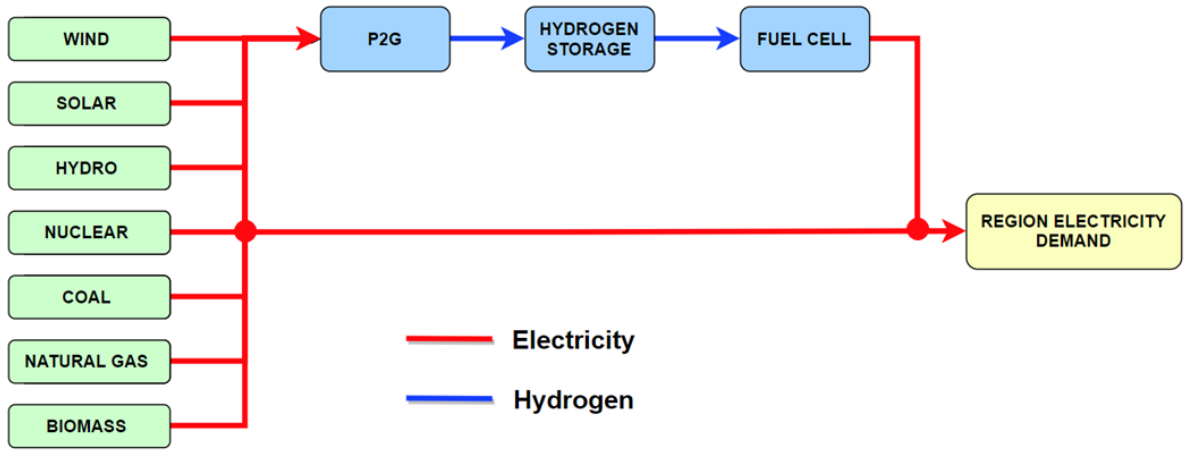

Figure 1 – RES Regional Diagram

Regional Representation

We divide the country into four regions to account for differences in the electricity generation mix, renewable resource availability, and existing interconnections, with consideration given to the NERC electricity coordinating areas and existing government policies. The Canadian regions are outlined in Table 1. The Northern provinces have not been added to the list due to their current limited transmission to other provinces. This is due to the high cost of transmission which is based on the long distance between the regions and the addition of transmission lines will not be cost effective [46], [47]. Canada is divided into different regions to better illustrate the ability of P2G technologies to act as energy carriers between regions. The regionalization is described below, summarized in Table 1, and is largely based on the NERC regions in [48]:

West (W): British Columbia and Alberta have been placed in region West (W) due to their renewable energy production plans and location. They are both located in the same NERC region (Western Electricity Coordinating Council (WECC)) and have a high capacity of geothermal resources.

Mid-West (MW): Saskatchewan and Manitoba have been placed in region Mid-West (MW) because they are in the same NERC region (Midwest Reliability Organization (MRO)) and have a high capacity of solar resources. Furthermore, both provinces are responsible for their central electricity company.

Mid-East (ME): Ontario and New Brunswick have been placed in region Mid-East (ME). Both provinces are located in the same NERC region (Northeast Power Coordinating Council (NPCC)). In addition, both provinces have the same electricity generation dominance of Uranium and a high capacity of solar.

East (E): Quebec, Nova Scotia, Prince Edward Island and Newfoundland have been placed in region East (E). They are all located in the same NERC region (Northeast Power Coordinating Council (NPCC)). Quebec shares electricity generation dominance of hydro with Newfoundland. Additionally, Prince Edward Island, Nova Scotia and Quebec produce electricity through wind resources.

Table 1 - Canadian Regions

Model region	**Abbreviation**	**Provinces Included**
West	W	British Columbia (BC) & Alberta (AB)
Mid-West	MW	Saskatchewan (SAS) & Manitoba (MAN)
Mid-East	ME	New Brunswick (NB) & Ontario (ONT)
East	E	Quebec (QC), Nova Scotia (NS), Prince Edward Island (PEI) & Newfoundland & Labrador (NL)

Data

The data sources used in our base model, with a brief description of each source, are provided in Table 2.

Table 2 – Data Source Documentation

Parameters	**Source**	**Description**
Output Activity Ratio	[41], [49]	Cost and performance characteristics – EIA
Input Activity Raito	[9], [41], [50]	Cost and performance characteristics – EIA and hydrogen performance research
Emission Penalty	[51], [52]	Federal climate plan
Canadian demand	[53]–[55]	Government and Utility Websites
Capital, Fixed and Variable Cost	[56], [57]	Cost and performance summary – ATB
Residual Capacity	[58]	Government of Canada
Capacity Factor	[41], [59]	System Advisor Model (SAM)

The time horizon of 2020-2050 is selected based on the Canadian Net-Zero Emissions Accountability Act [1] which was initiated in 2020 and requires a zero emission in the country by 2050. The timeslice descriptions used in our model are presented in Table 3 and represent the split of each year in the model and the demand in this division [39]. The timeslices have been created based on seasons and represent the energy demand for one day and night cycle. This separation increases the calculation accuracy based on the variances in the energy demand and production seen between days and nights. The spring and fall seasons have been combined into one season (intermediate) due to their commonalities in energy demand and production.

Table 3 – Canada P2GModel Time-slices

Time-slice Title	Description
ID	Intermediate Day – Presents the addition of Spring and Fall day hours (7:00 – 19:00)
IN	Intermediate Night – Presents the addition of Spring and Fall night hours (19:00 – 7:00)
SD	Summer Day – Presents the Summer days hours (7:00 – 19:00)
SN	Summer Night – Presents the Summer night hours (19:00 – 7:00)
WD	Winter Day – Presents the Winter day hours (7:00 – 19:00)
WN	Winter Night – Presents the Winter night hours (19:00 – 7:00)

Scenarios

The base model and the three scenarios to be evaluated are described in Table 4. The base model represents the current Canadian energy system with limited emission penalties which remain constant from 2022, representing the situation where a new government halts the current trend towards increased carbon prices. Scenario #1 and #3 present an increase in emission penalties until 2030 to meet the emission reduction goals set by the current government.

Scenarios #2 and #3 test the benefits of flexible operation of hydro generation. While the base model allows full flexibility in the operation of hydro generation, these scenarios restrict hydro operation to represent the minimum flow operations required. We evaluate hydro at its extreme conditions (constant, inflexible and full flexibility) to highlight the benefits of hydro flexibility, although in reality a mixture of flexible and fixed operation is generally required.

Table 4 - Scenarios

Scenario #	Scenario name	Description
-	Base Model	Includes the Canadian input data including constant emission penalty from 2022 ($50/tonne) and hydro at availability factor
1	Increase Emission Penalties	Emission penalties are increased and remain constant from 2030 ($170/tonne)
2	Hydro Restricted	Hydro is operating at capacity factor and constant emission penalty from 2022 ($50/tonne)
3	Hydro Restricted and increased penalties	Hydro is operating at capacity factor and constant emission penalty from 2030 ($170/tonne)

Results

In this section we first provide the base model results and then continue with a comparison of the base model with the different scenarios.

Base Model

The base model results highlight three main points; the constant emission penalty after 2022 is not high enough to phase out all emission producing technologies, the regionalized emission levels increase or remain constant in three of the four regions, and the flexibility of hydro power makes P2G financially viable only in the last year of the model period, and even then, only in one region.

Figure 2, Figure 3, and Figure 4 show the emission trends, generated power for years 2020, 2030, 2040 and 2050, and the installed generation capacity for all years in the model run, respectively. The W and MW regions behave similarly in the base model, with both opting to replace coal production with a combination of solar and natural gas within the first 10 years. As can be seen in Figure 3, the W and MW regions heavily utilize coal in 2020 before the maximum emission penalty is reached in 2022; after this point coal production has been predominantly replaced by natural gas and solar. To understand what is happening to coal production, Figure 4 illustrates that the W and MW's coal capacity is gradually declining but remains present throughout the entire model run. This signifies that coal capacity is available to the system to meet the reserve margin. However, it is not being used as it is more economical to replace the majority of coal production with natural gas and solar due to the lower fuel cost with the $50/tonne emission penalty applied. The 2050 energy production snapshot for the MW region (Figure 3) shows that coal is reintroduced to the generation mix in 2050. At this point the economics have switched to rely on the now substantial solar capacity, invest in a small amount of new natural gas, and utilize the existing high emitting coal capacity, rather than financing a complete natural gas replacement.

The W and MW regions also utilize the flexibility of hydro power to offset the intermittency of solar power. Both regions in Figure 3 show solar contributing significantly during the day timeslices (ID, SD, WD) and hydro contributing significantly during the night timeslices (IN, SN, WN) for 2030, 2040 and 2050. Since the model has the flexibility to run hydro as much or as little as it wants in each timeslice (without exceeding its capacity limit shown in Figure 4), it opts to store water in its reservoir and will often shut down during the day cycles to offset the high generation of solar during this time. This flexibility allows the model to heavily invest in solar and enables it to mostly avoid installation of P2G.

The only region that showed substantial emission reductions was the E region; these reductions are due to the large capacity of flexible hydro and a significant build out of wind. Figure 4 shows the E region heavily investing in expanding its solar capacity around the 2022 mark when the max emission limit is reached; this is in line with when the W and MW regions also switch to lower emitting technologies. The other important feature of this graph is that when the natural gas investment reaches the end of its operational life, around the 2044 mark, it is replaced with wind power. This switch to wind generation is seen in Figure 3 where all the natural gas generation in 2040 has been replaced with wind generation in 2050. Moreover, when the emissions of the E region suddenly drop to zero, the switch from natural gas to wind has occurred as natural gas was the only CO2 producing technology at this point. If the E region was to switch to a natural gas and solar combination as seen in the other regions instead of wind, it would require roughly double the natural gas capacity when compared to the W and MW regions to account for its larger demand. This signifies a trade off point has been passed in the E when it becomes more economical to build wind, which has a higher capital cost and fixed cost, over natural gas which has a higher variable cost and emissions cost. Since the E region has large shares of hydro capacity, as seen in Figure 4, it also has the resources for hydro to efficiently work in tandem with the intermittent sources of wind and solar to meet all demands. Finally, in 2049 and 2050 for the E region, P2G is invested in as shown in Figure 3. To see why, the first timeslice in the 2050 year shows that solar and wind are overproducing; since these production numbers are results of the capacity factor, instead of curtailing this power, a small amount of P2G was built to store this extra energy as hydrogen to be used in the second timeslice.

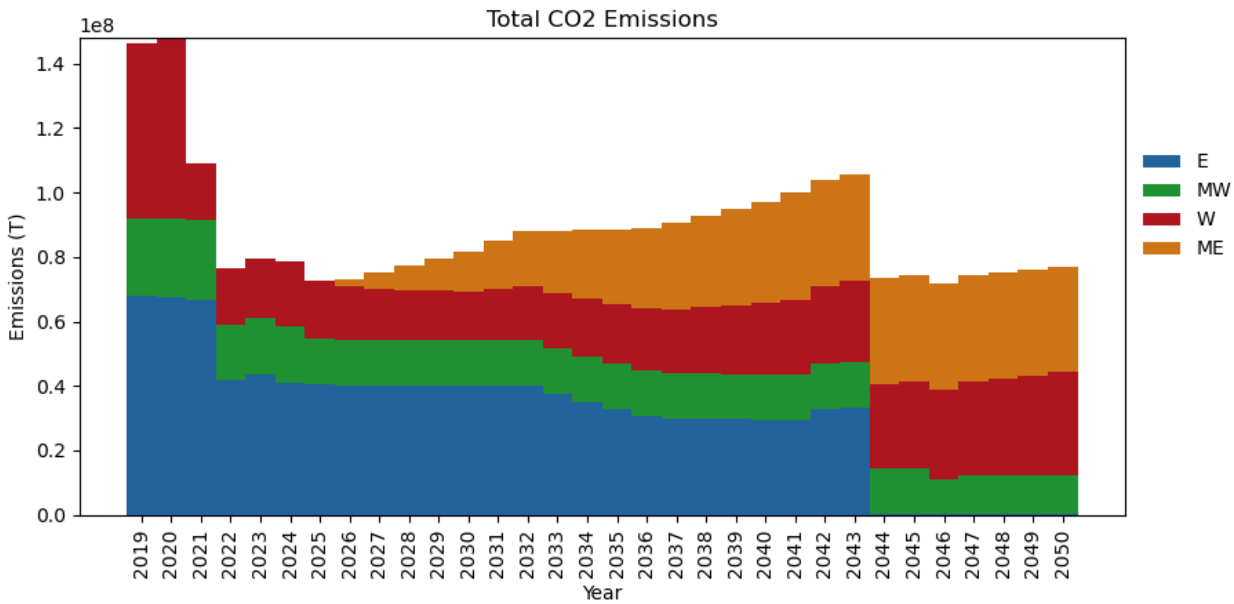

Figure 2– Base Scenario Emission Forecast

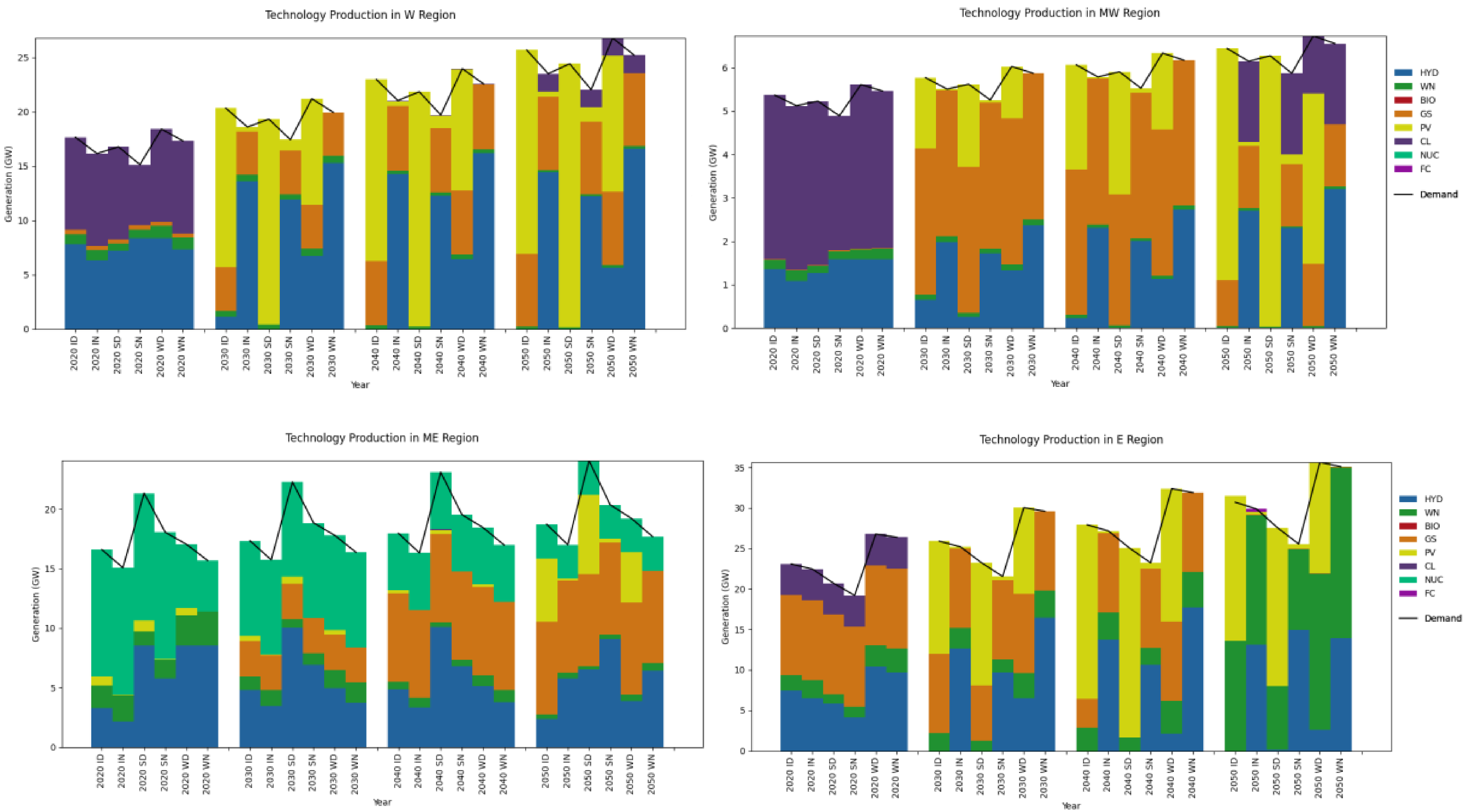

Figure 3 –Base Scenario Energy Production by Technology

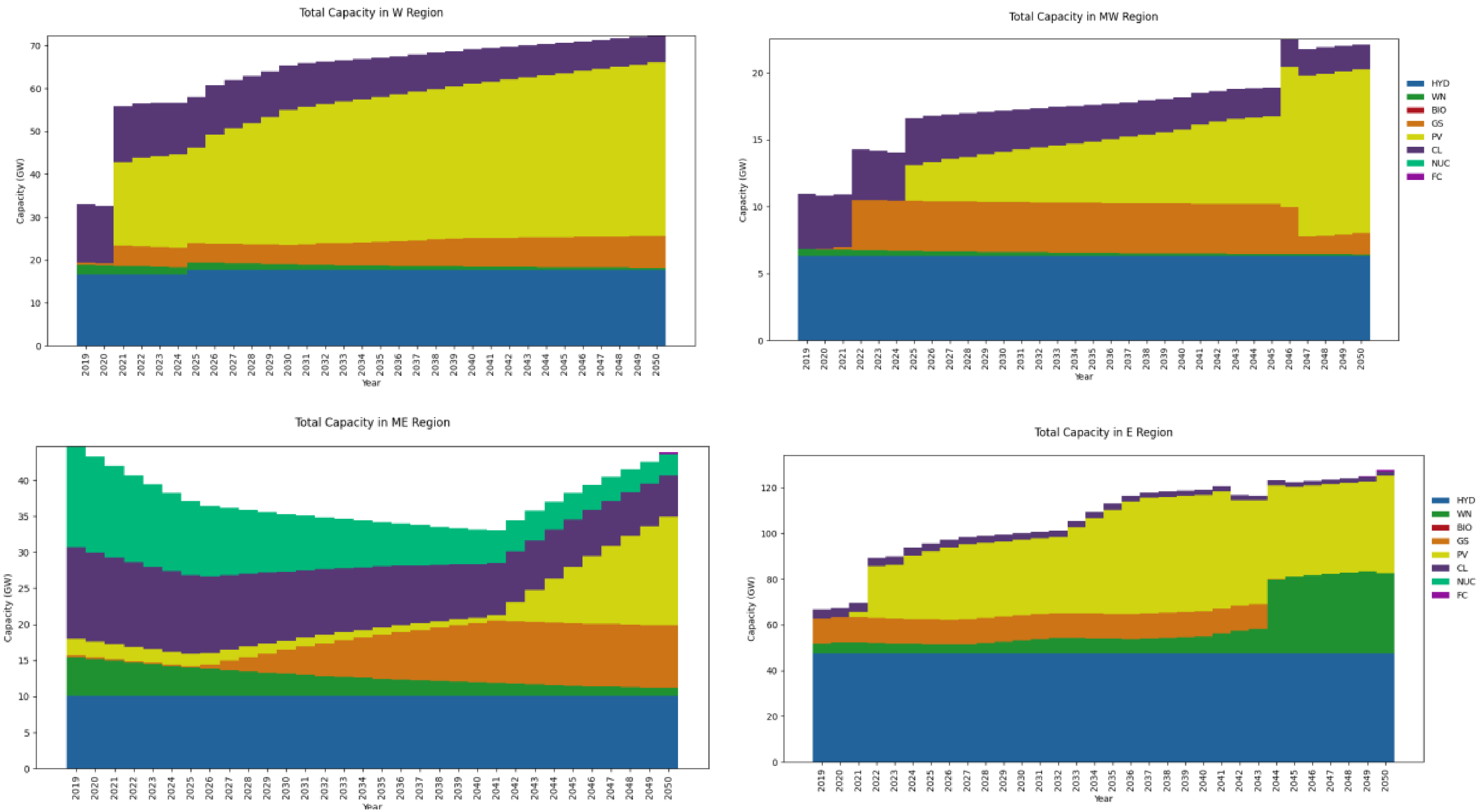

Figure 4– Base Scenario Energy Capacity by Technology

Scenario #1 – Increased Emission Penalties

Scenario #1 entails increasing the emission penalty to $170/tonne by 2030. This increase removes the emission producing energy sources and eliminates the emission in every region by 2025, as seen in Figure 5. In this scenario an increase in the production of renewable energy sources is seen in all regions as evident in Figure 6. Furthermore, the W, ME, and E Regions have begun installing noticeable amount of P2G, partly to meet the reserve margin in the model. However, the first use of P2G is not seen until 2050 in the ME Region due to that region's significant reliance on renewables and decreasing nuclear energy supply. P2G is implemented into this region because it is more economical to use the existing stable nuclear coupled with new hydrogen storage rather than investing in a complete solar/wind replacement.

Figure 6 shows each regions' energy production per technology for the first year of each decade starting from 2020. Comparing these graphs with the ones from our base scenario in Figure 3 we see that as a general trend the model choses to move heavily towards renewable energy sources; mainly wind and solar to address the increase in cost associated with our CO2 emitting technologies as a result of increasing the emission penalty. In the E, W, and MW regions, this involves phasing out coal production that was largely utilized in the beginning of our modelling years due to its significant residual capacity. The emissions penalty is enough to push this generation out of the mix even though there is still some residual capacity that is mothballed as seen in Figure 7.

In the ME however, looking at Figure 6, we see a significant initial production of nuclear supported by the initial residual capacity (Figure 7), and since nuclear does not produce emissions, the level at which nuclear is phased out from the ME region is much less severe compared to phasing out Coal from the W and MW regions. Nuclear is however phased out eventually and replaced by other renewable energy sources such as wind and solar due to its higher fixed and capital costs. Moreover, we see some utilization of our P2G system in this region towards the end of our modeling period. This happens because our combined nuclear and renewable energies are no longer able to meet the increasing demand in the summer night timeslices. This forces the model to use P2G to store the extra energy produced in the other timeslices (primarily ID, WD, and WN) to meet the demand in the summer night. While that might not reflect a completely realistic scenario, as the model is allowed phase out stable nuclear generation with vast amounts of variable solar and wind, and hydro is given full flexibility, it serves the purpose of outlining the potential conditions for making P2G an effective energy storage medium in a given energy system.

Looking the Energy Capacity graphs (Figure 7), we see a similar trend towards increasing investment in wind and solar in the E, W and MW regions during the first quarter of our modeling period; after which the total capacity for these technologies increases only gradually to meet our increasing demand in the future. Similar patterns are observed in the ME Region with the difference of gradually phasing out nuclear and replacing it by wind and solar. Moreover, we observe that capacity for P2G is added to the system around the end of the second quarter of the modeling period in the ME Region and soon after in the W and MW regions. They start building capacity for P2G, indicating its potential use in future timeslices not presented in this model when renewables are unable to meet demand.

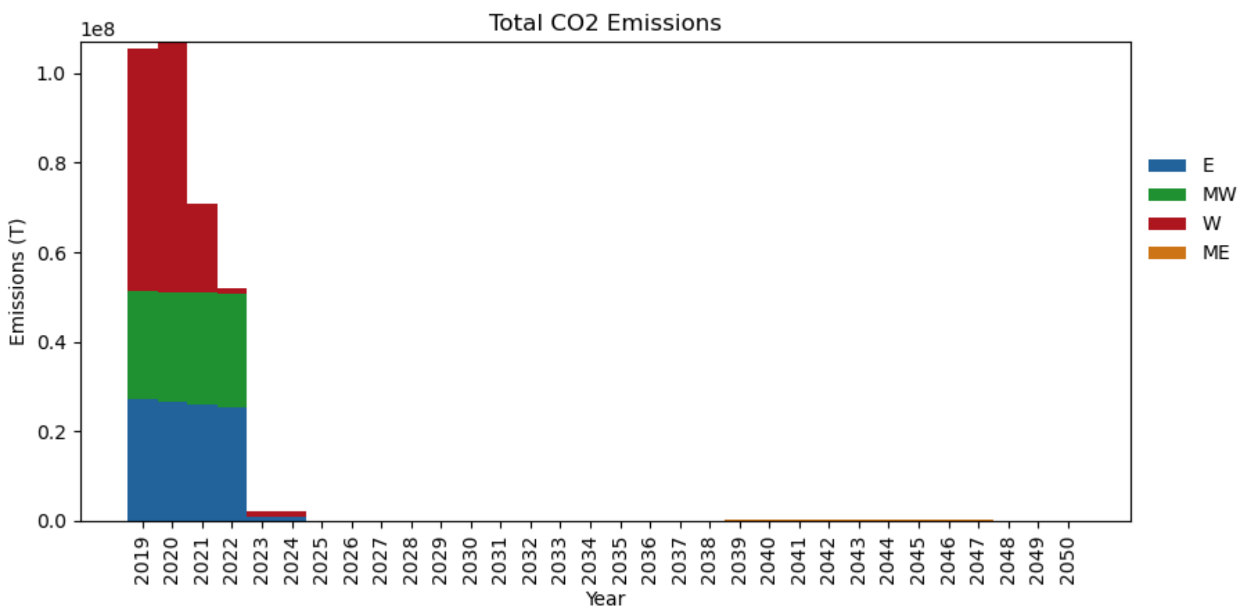

Figure 5– Increased Emission Penalties Emission Forecast

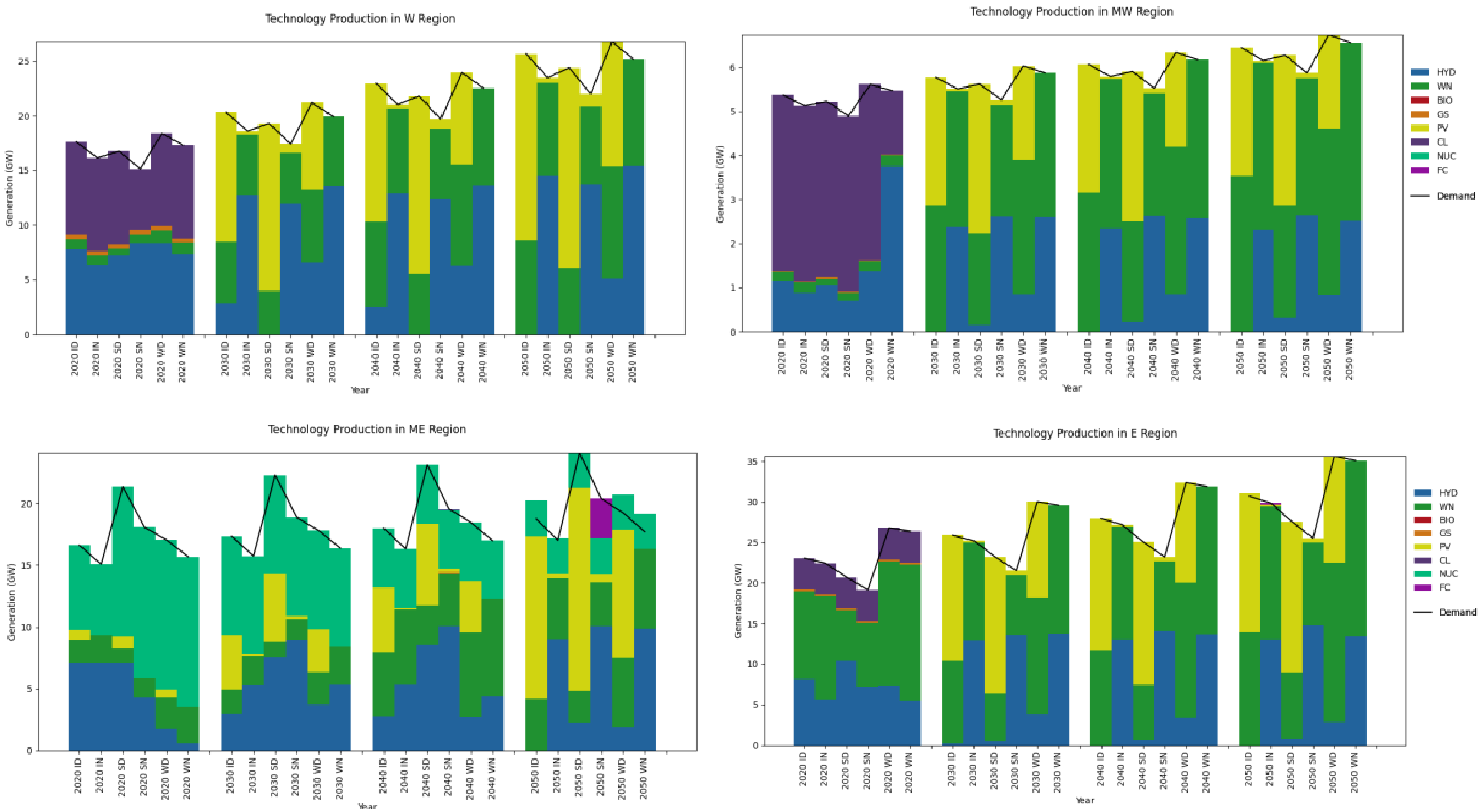

Figure 6– Increased Emission Penalties Scenario Energy Production by Technology

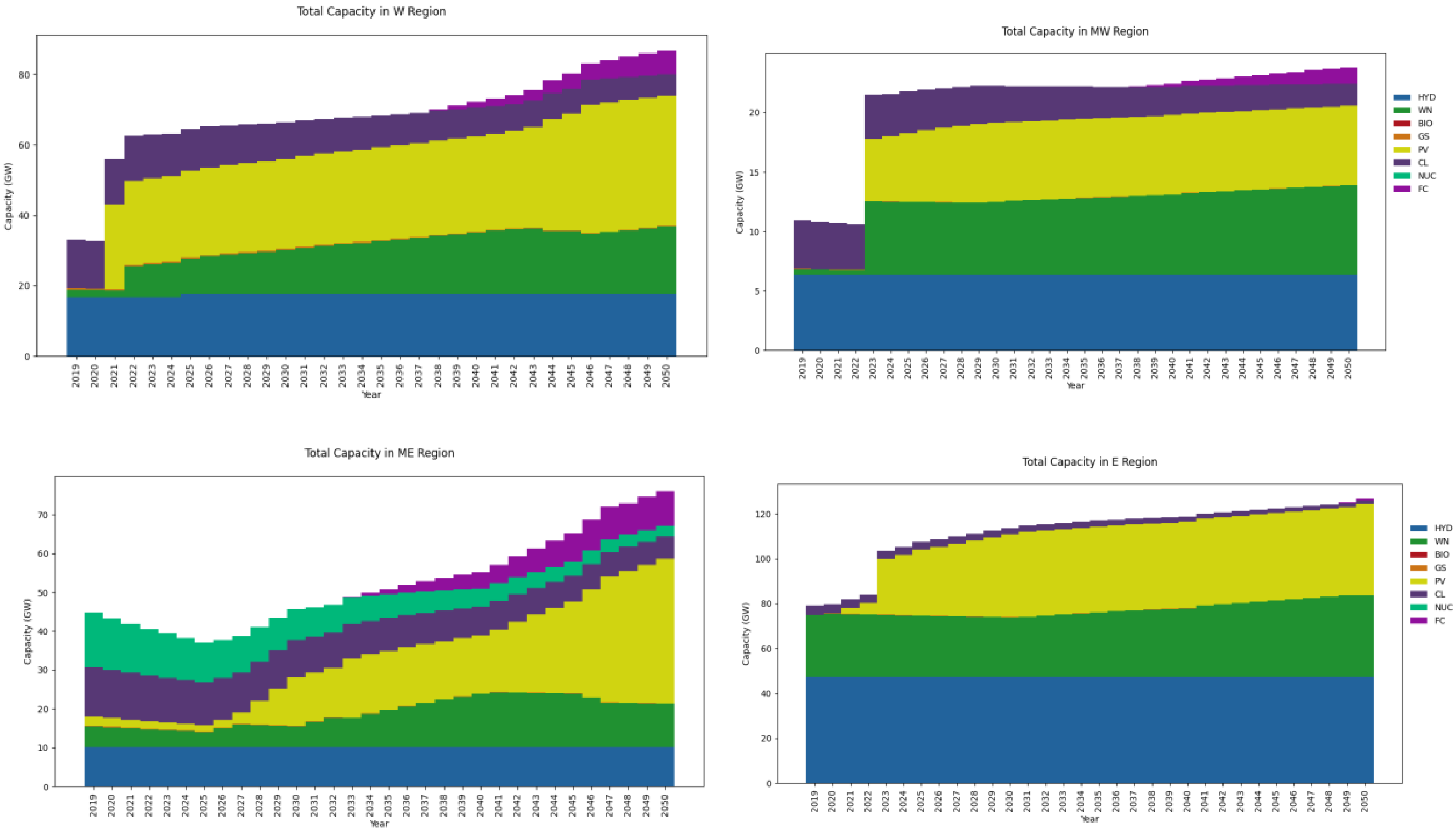

Figure 7 – Increased Emission Penalties Energy Capacity

Scenario #2 – Hydro Restricted

The impact of restricting hydro flexibility is shown in Figure 9 where hydro cannot shift generation between time periods in all regions; this requires the model to find other flexibility generation options, including P2G, when compared to the base model. In the base model, (Figure 4) solar is heavily invested in because it can interplay with flexible hydro; during the day cycle energy is heavily produced by solar and hydro production reduces, then during the night cycle hydro ramps up to cover the demand when solar is not available. However, in Scenario #2 hydro is not flexible and a portion of the large solar investment seen in the base scenario is replaced by natural gas and wind (Figure 10). The emissions in this scenario presented in Figure 8 show an increase compared to the base scenario and illustrate that hydro flexibility may be a significant contributor to Canada meeting its emissions targets. In addition, Figure 10 shows that the W and E region install P2G and Figure 9 shows that P2G is used to meet demand requirements in 2050 for the E which was covered by flexible hydro in the base model. In the ME Region, we see a significant initial production of nuclear that gets phased out slowly and replaced largely by natural gas which proves a more cost-effective approach when dealing with a relatively low emission penalty.

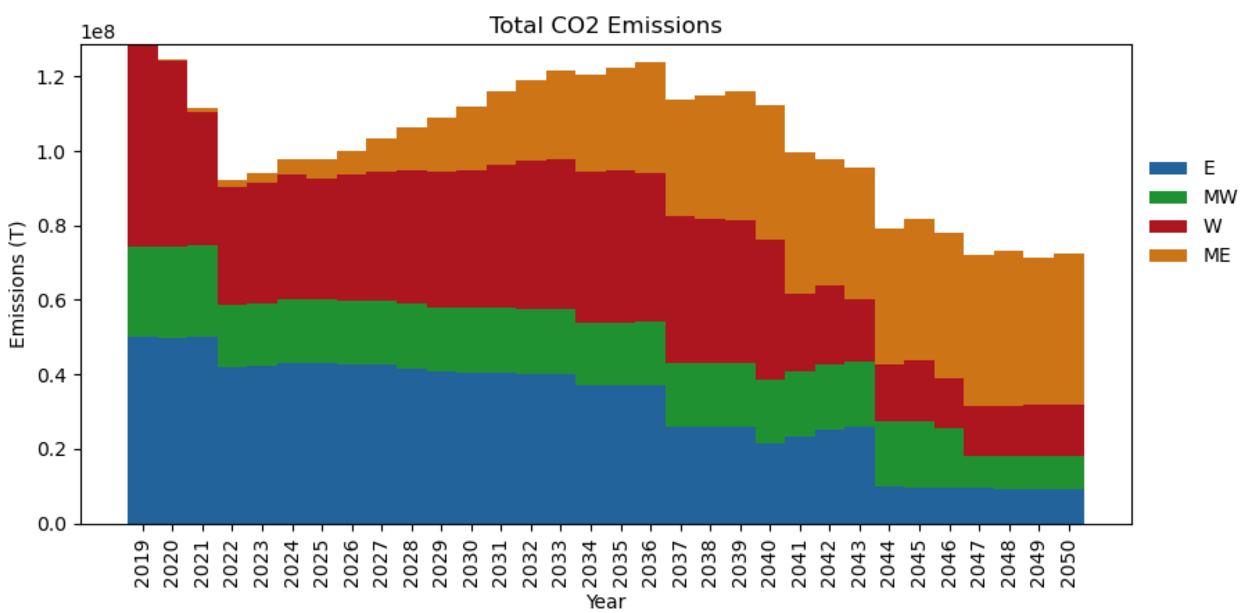

Figure 8– Restricted Hydro Emission Forecast

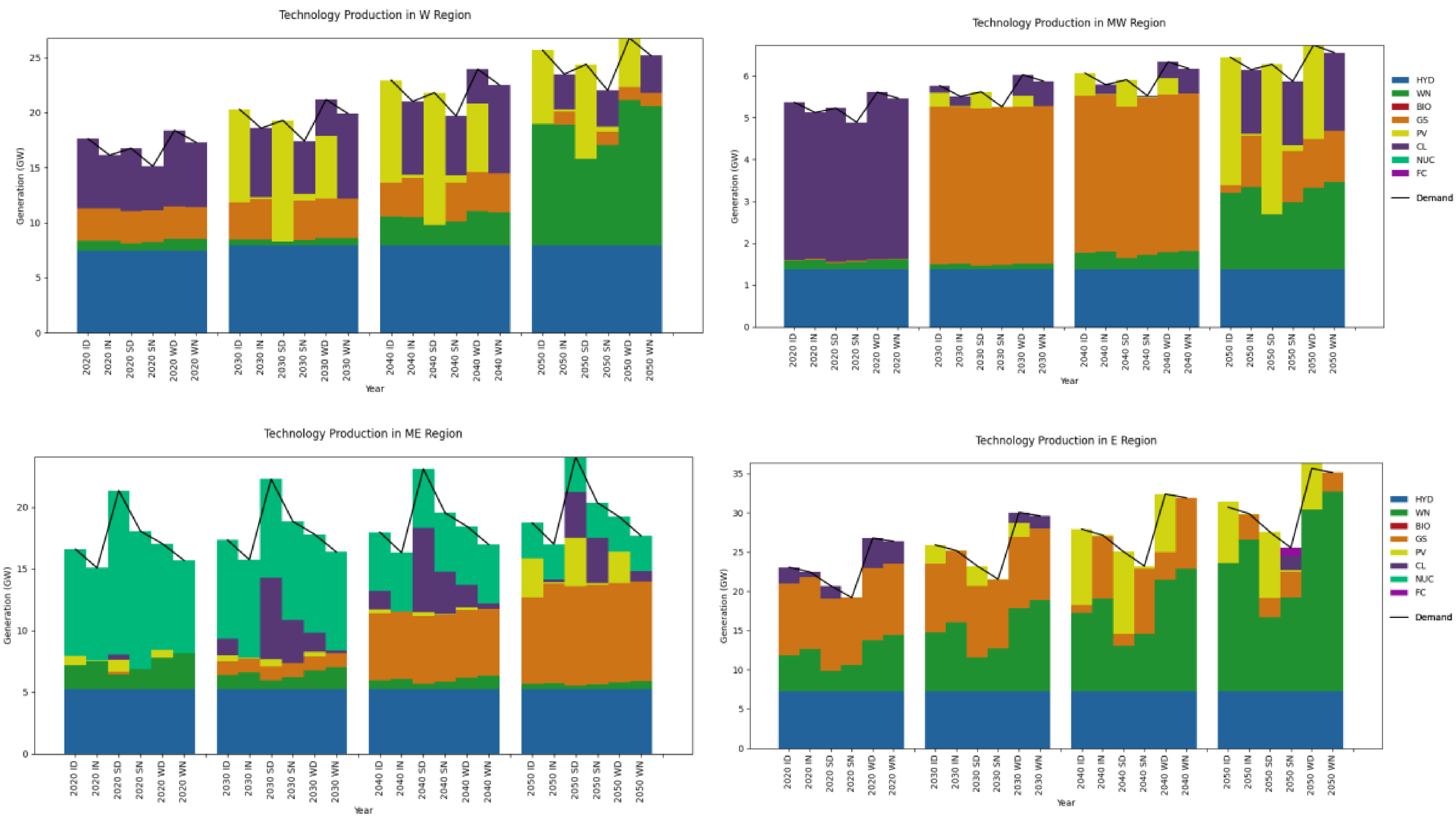

Figure 9 –Restricted Hydro Energy Production by Technology

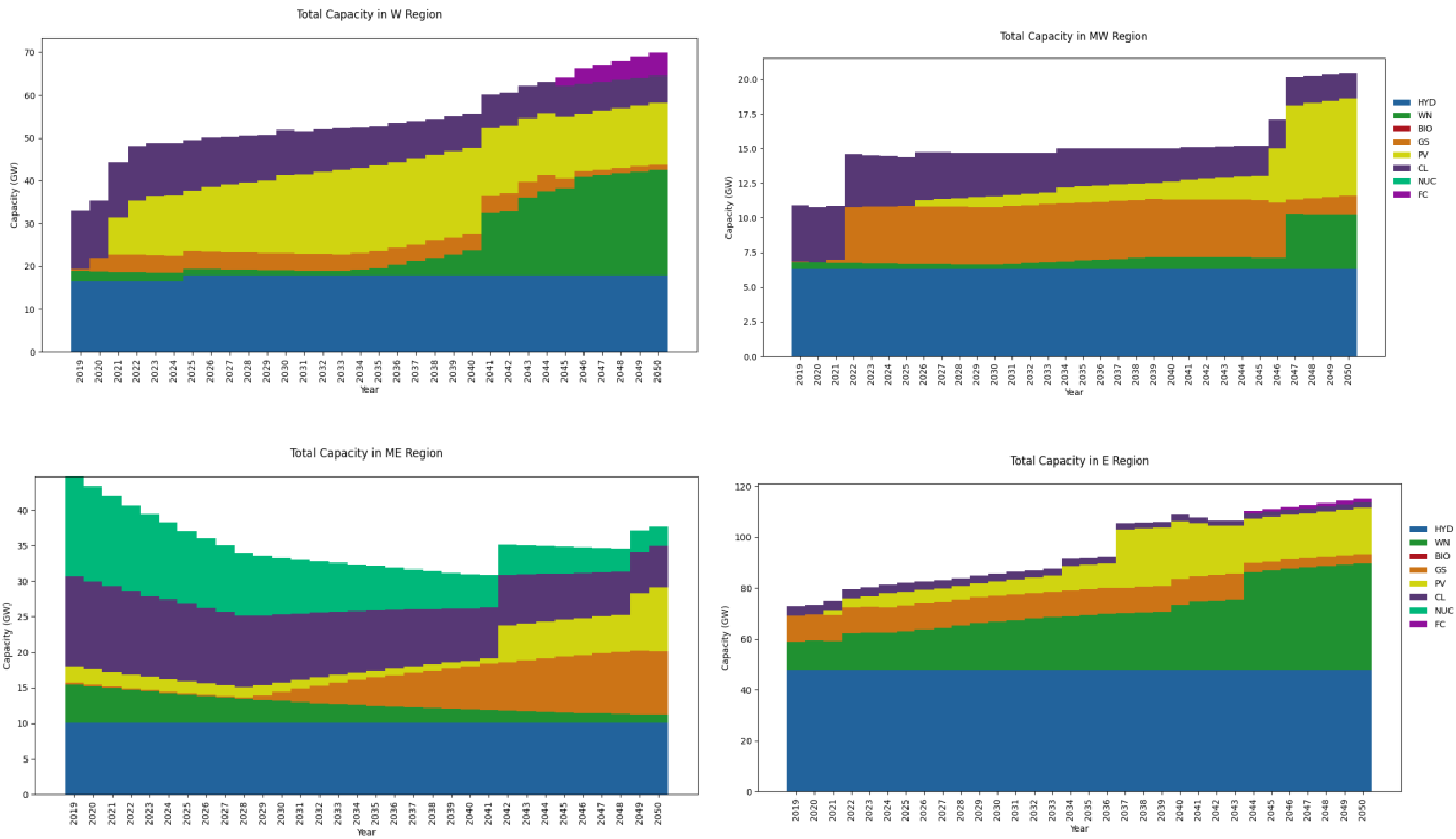

Figure 10 – Restricted Hydro Energy Capacity

Scenario #3 – Increased Emission Penalties + Hydro Restricted

The production of electricity through P2G has increased in this scenario showing that flexibility in the production of hydro significantly reduces the need for P2G as an energy storage system in this model. In all regions the investment in variable renewable energy sources increase yearly due to the high emission penalty; since hydro is not flexible, P2G systems are invested in to account for the variable renewables not being able to consistently meet the demand. In the E region, natural gas is still used to meet the demand up to 2040 due to insufficient renewable energy production preceding and during the summer night-cycle demand. That explains the increase in emissions past 2025 seen in Figure 11 relative to scenario #1 that has similar emission penalties but does not restrict hydro production. Thus, it is evident that restricting the flexibility of hydro production along with imposing a higher emission penalty is the scenario that favors P2G energy storage the most. Much like in the previous scenarios, although the model may not reflect a completely realistic scenario, as hydro does allow for some operational flexibility in energy production, the results highlight the conditions where P2G can have the most impact on the system.

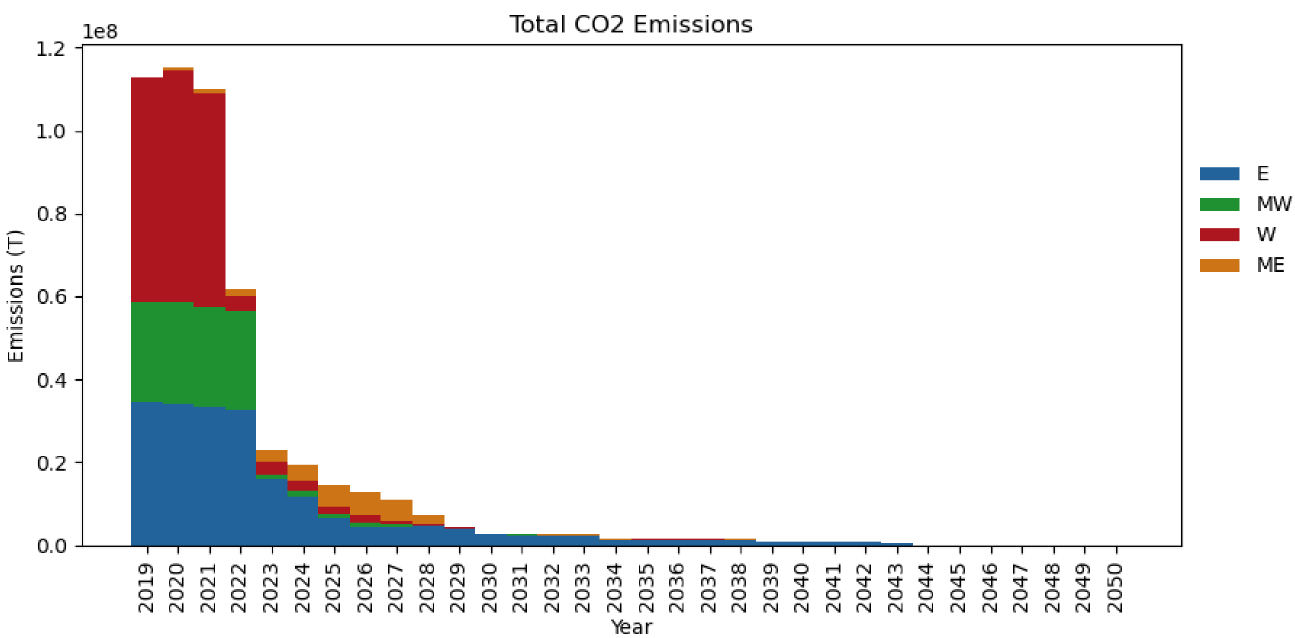

Figure 11– Increased Emission Penalties with Restricted Hydro Emission Forecast

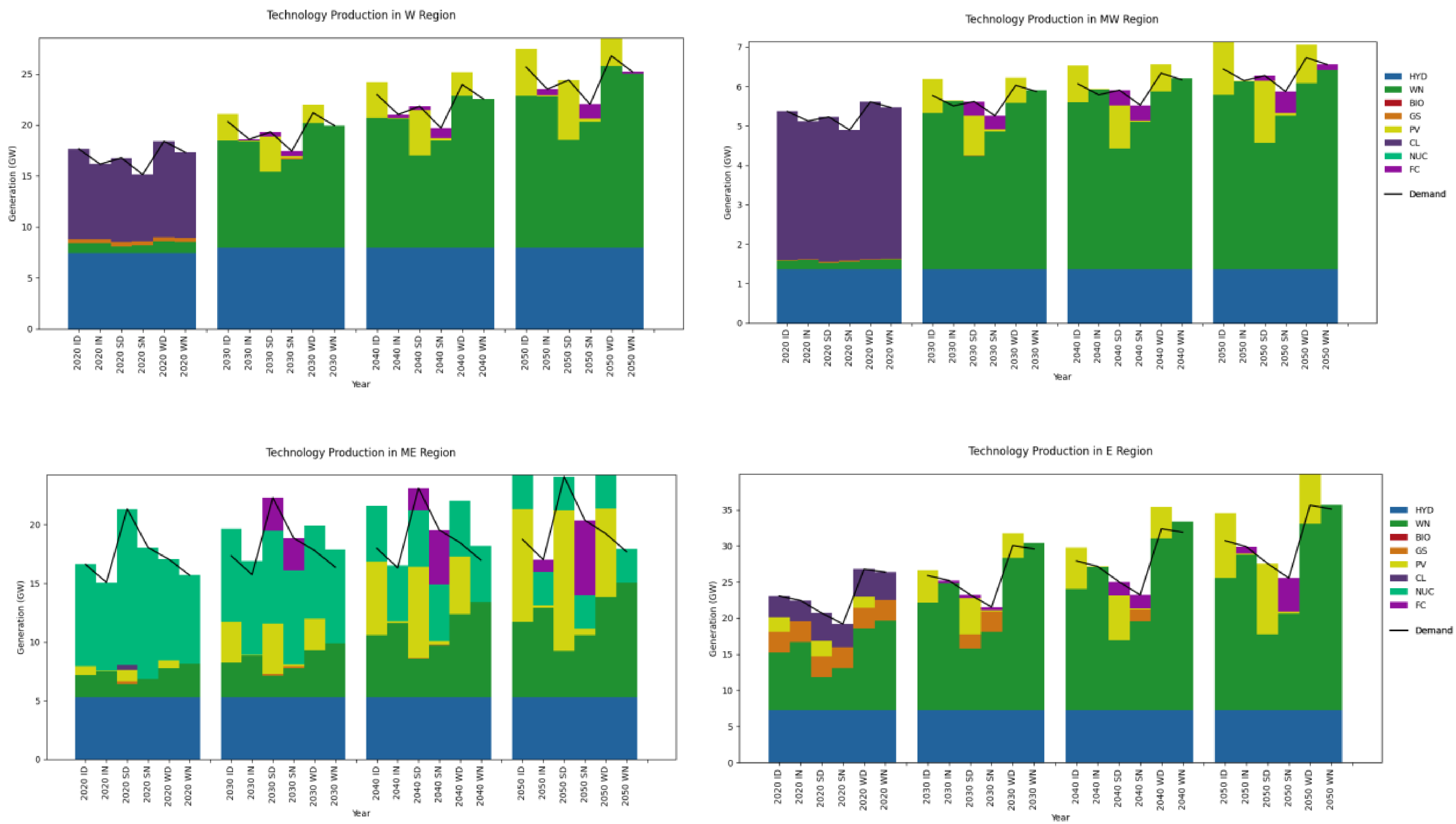

Figure 12 – Increased Emission Penalties with Restricted Hydro Energy

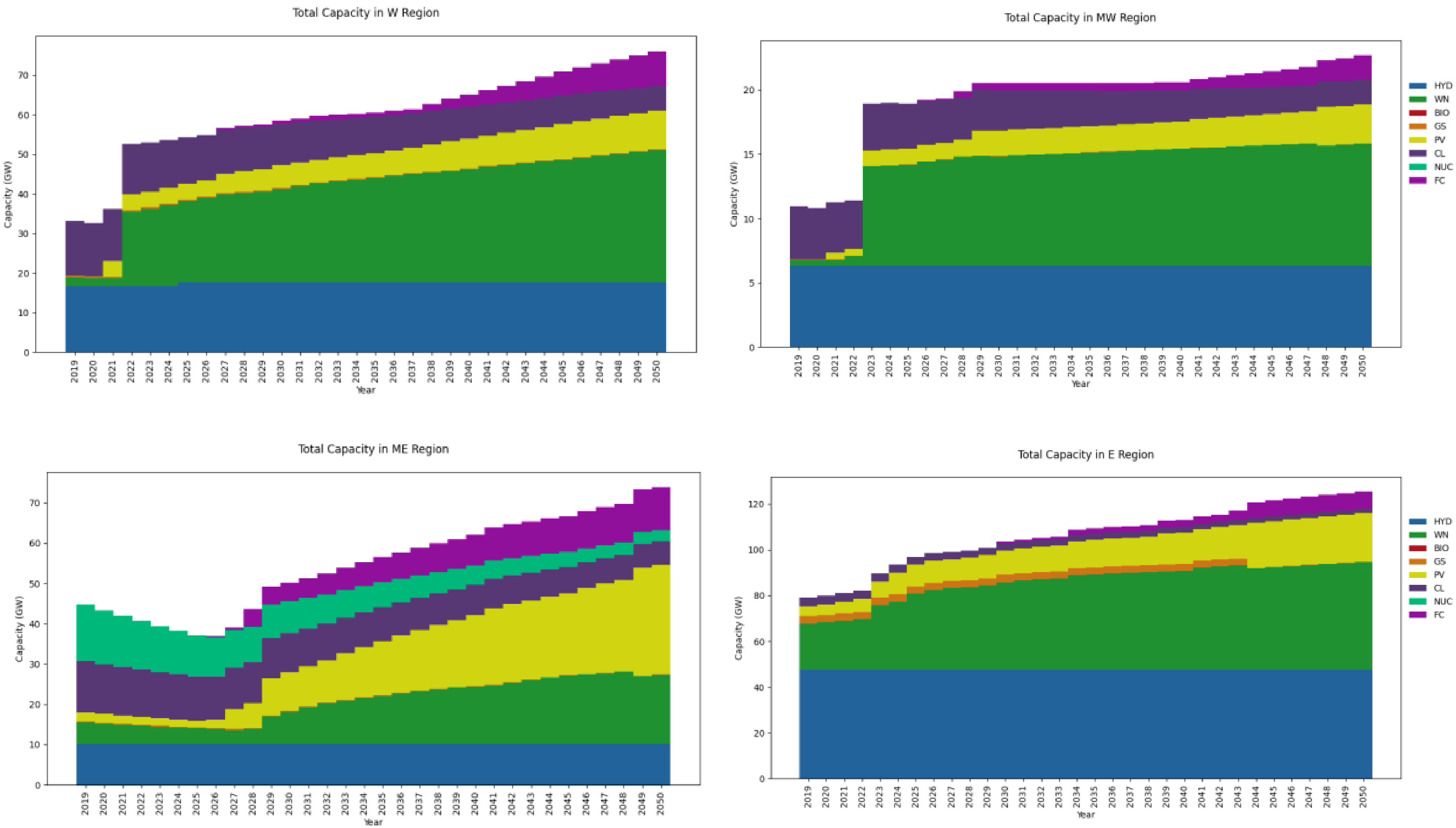

Figure 13 – Increased Emission Penalties with Restricted Hydro Energy

Conclusions

Two main conclusions are evident. First, the flexibility of Hydro provides significant flexibility to the Canadian electricity system and contributes to the ability of the system to meet emission targets. The Canadian and provincial governments should consider this when developing energy policy, potentially encouraging development of hydro assets where possible. Second, P2G has the ability to contribute to the electricity system to help reduce emissions, but this is limited by costs and the existing flexibility of the hydro system. Governments should consider encouraging research and development on low-cost P2G technologies as well as evaluating alternate paths for P2G technologies to see if there are more beneficial value chains. Meeting emissions targets, in all cases, requires adhering to the pledged carbon tax increases to $170/tonne by 2050.

Future work to address limitations of the current study include obtaining better demand data for provinces where hourly data was not readily available, adding more realistic restrictions to the installation and production of renewable generation, including trade, developing methods to model semi-flexible hydro energy production and providing upper limits to restrict the max capacity of the energy sources. Expanding the temporal resolution of the model to evaluate the short-term P2G potential could also highlight the benefits of P2G. Finally, performing some sensitivity analysis on the input data, especially on the P2G pathway component specifications, would provide potential cost targets for P2G.

Once the above limitations are addressed, the intent is to expand the study by integrating the model with an existing OSeMOSYS model of the United States ([41]). This will allow more accurate representation of trade in the Canadian system and will enable the model to represent the impact of the significant north-south connections in the Canadian electricity system. Some of the extra capacity evident in the ME region in this study will likely be utilized more fully if these north-south connections are available to the model.

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