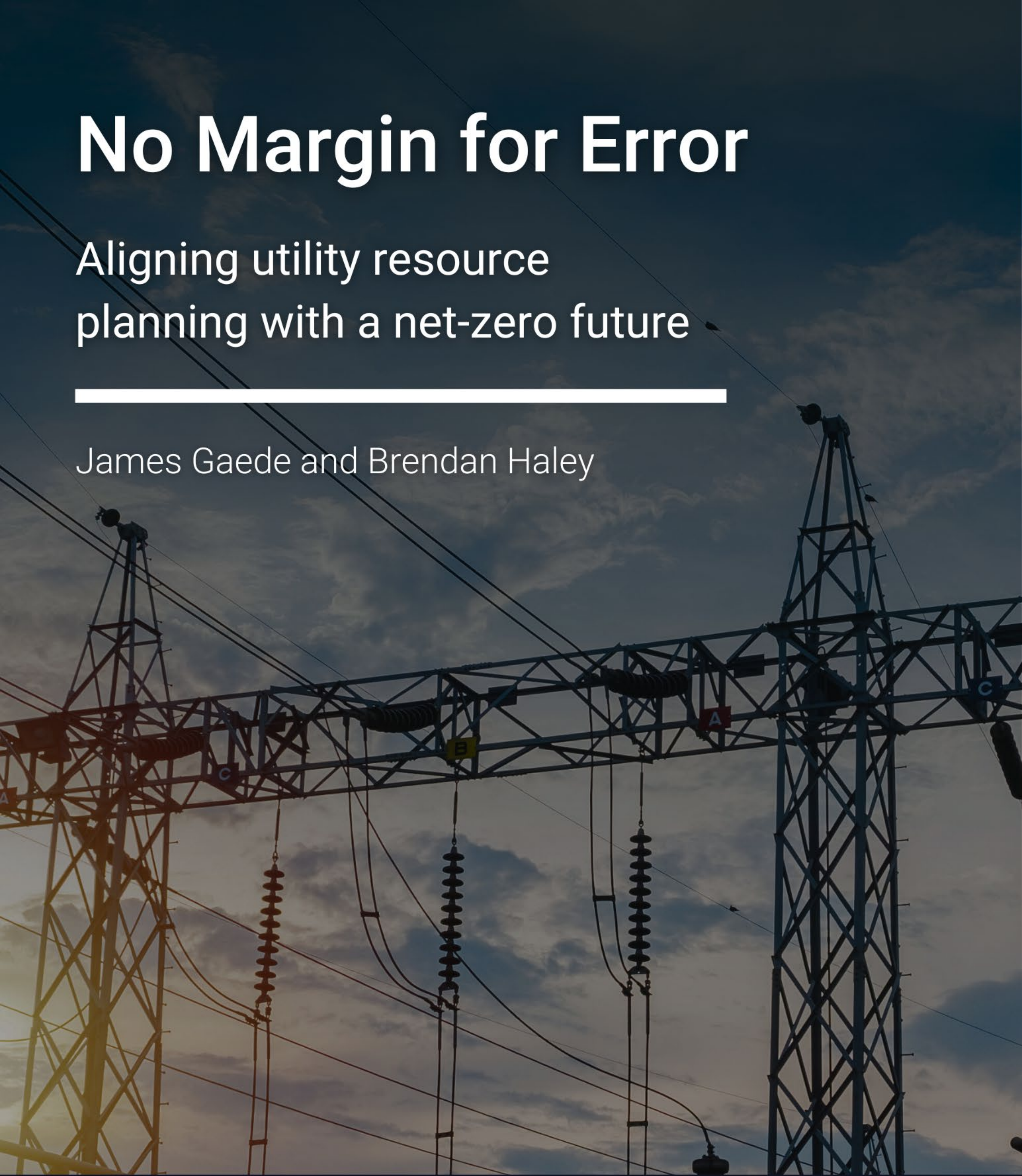
No Margin for Error

Aligning utility resource planning with a net-zero future

James Gaede and Brendan Haley



Efficiency Canada

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About Efficiency Canada

Efficiency Canada is the national voice for an energy-efficient economy. Our mission is to create a sustainable environment and better life for all Canadians by making our country a global leader in energy efficiency policy, technology, and jobs. Efficiency Canada is housed at Carleton University's Sustainable Energy Research Centre, which is located on the traditional unceded territories of the Algonquin nation.

The views expressed, as well as any errors or omissions, are the sole responsibility of the authors.

Summary

This study aims to identify essential procedural, substantive, and instrumental elements of utility resource planning in the context of reaching net zero by 2050 and evaluate Canadian resource planning practices in this light. Planning helps to define and attain goals and objectives in the future. Utility resource planning thus needs to account for risks and uncertainties about the future if it is to successfully lead us to the goal of a net-zero future. This study reviews literature on utility planning best practices, national net-zero pathway studies, and recent examples of utility resource planning to identify challenges that inhibit stronger alignment with a net-zero future. Our focus is specifically on the treatment of demand-side resources and largely in electricity system planning.

Integrated resource planning is a multi-step process for assessing and addressing future energy system requirements that should include all available resources (i.e., supply and demand). The practice of integrated resource planning, wherein planning is conducted publicly and incorporates both supply and demand-side solutions to future system requirements, emerged from a period of slowing demand growth but increasing systems costs and associated affordability concerns in the 1980s. A core principle of integrated resource planning is to treat all resources (including 'demand-side' resources like energy efficiency or demand response programs) equally. One implication is to include such resources in system expansion modelling "endogenously", meaning they can be selected by the optimization model based on their characteristics and influence or be influenced by other elements in the model as a scenario plays out.

Utility resource planning is essential to managing three types of risk: business/affordability risks, resource/system risks, and societal risks. Business and affordability risks relate to the cost of the utility system and the utility's ability to recover the costs of their investments, both in the short and long term. Generally speaking, utilities need to demonstrate "prudence" in their investment strategies, i.e., showing that an investment was reasonable given the information available when it was made. Planning must also manage risks associated with specific resources (e.g., costs, capacity factors, construction lead times) and the overall system reliability (i.e., ensuring that there will be adequate resources to meet demand). Finally, utility resource planning must also manage societal risks, stemming the uncertainty around current and future government policy objectives and the utility's ability to meet them.

A future net-zero energy system requires major structural and behavioural changes in how we produce and use energy. International and national net-zero pathway studies have highlighted the scale and scope of the challenge in reducing energy use greenhouse gas emissions. Canadian net-zero pathway studies show a highly electrified future – particularly in buildings and transportation – with some residual emissions, moderate demand reduction, and roughly 2x the growth in electricity demand and 2.5x in electricity capacity requirements. In the context of a net-zero transition, there are clear societal risks associated with a failure to adequately plan for electricity systems to support the decarbonization needs of other sectors, which will, at best make it more difficult and costly to hit national or international policy goals by 2050, or at worst make it nearly impossible.

Our review of recent Canadian integrated resource plans focuses on three main elements: alignment, demand-side resources, and risks. To assess alignment, we looked at the degree of coordination in utility planning across the electric and natural gas systems and the extent to which load forecasting in utility plans aligns with national net-zero pathway studies forecasts. On the treatment of demand-side resources, we reviewed the general methodology taken by utilities to include them, as well as the impact energy efficiency and demand response initiatives have on cumulative system requirements. Finally, to evaluate risk management practices, we looked at the treatment of demand-side resources in sensitivity analysis and the processes by which utilities compared and evaluated different resource portfolios and developed action plans.

There is little coordination in utility resource planning between Canada's electricity and natural gas systems. Most utility planning takes place in relative silos, with low levels of coordination among electric and natural gas utilities. Efforts are ongoing in B.C. to encourage utilities to coordinate on scenario assumptions, though they appear to have had minimal impact on the resource plans investigated here. Manitoba Hydro is responsible for delivering electricity and natural gas and sought to incorporate energy use outside of the electricity system in its resource plan (though in a limited way). Quebec recently introduced a bill that would make the government responsible for conducting economy-wide resource planning, and the Electrification and Energy Transition Panel in Ontario has recommended the government play a more active role in guiding utility planning.

While electrification is a common theme in scenario construction, electricity load forecasts used in utility resource planning are generally conservative. While the range in load forecasts across all plans and scenarios was quite broad, most utilities are not modelling scenarios with electricity load growth approximating those in net-zero pathway studies. In FortisBC's long-term electricity plan, the scenario closest to this was intended to show the theoretical maximum requirements if all drivers of demand were maxed out. Manitoba Hydro's accelerated electrification scenario forecasted energy and capacity requirements in line with net-zero pathway studies. However, the utility noted it would be challenging to realize this scenario in practice. Where utilities made a clear choice on their preferred resource portfolio (e.g., BC Hydro, Nova Scotia Power), they were based on scenarios with low load growth.

No utility in Canada treats demand-side resources "on par" with alternatives in their planning practices. This report found no utility plan in which all demand-side resources were made fully available to system expansion modelling as selectable resources. Most utilities subtract energy efficiency or demand response potential estimates from their load forecast, drawing from prior potential studies, as an input assumption to modelling. The partial exception is Manitoba Hydro, which made some portfolios of energy efficiency selectable in its main scenarios and tested sensitivities that included making all energy efficiency selectable. However, demand response was neither modelled nor included in the utility's main scenario analysis.

The potential of demand-side resources is systematically undervalued through modelling methodology, outdated assessments of avoided costs, and the use of total resource costs to screen measures. The range of demand-side resources that provide capacity varied significantly across plans, with some utilities identifying few, if any, such resources. Most, if not all, utilities use the total resource cost test to screen demand-side resources in potential studies, incorporating non-utility costs into the analysis and may use outdated avoided cost information. The impact of demand-side resources to provide capacity in utility plans may thus be understated (averaging 11 to 14 per cent of peak load across the plans reviewed here). A result of understating the potential for demand-side solutions to meet peak demand needs is that several scenarios increase natural gas generation under more aggressive load forecasts.

Utilities tend to consider the downside risks of demand-side resources more than supply-side alternatives and treat the latter bluntly in a sensitivity analysis. While methods differed across each plan, general testing of supply-side sensitivities was simplistic – the resource was either available or not. In contrast, in several plans, sensitivities around demand-side resources were given far more thorough consideration. For example, BC Hydro's evaluation of demand-side resource potential was the only example we found of a utility utilizing probabilistic methods to evaluate resource uncertainty. We did not find evidence to suggest utilities are deploying the same level of scrutiny to supply side resources a model may adopt in the future.

While several utilities identified multiple criteria by which to compare and evaluate different scenarios, total system costs and rate impacts figure more prominently. Full decision-making criteria are not always clearly specified in utility resource plans. However, the traditional goals of minimizing system costs, ensuring reliability, and reducing greenhouse gas emissions are commonly identified. Where societal risk factors were identified as decision-making criteria, they appear to take a back seat to system costs and short-term rate impacts. Both BC Hydro and NS Power explicitly discuss the rate impacts associated with different DSM portfolios, and there is no evidence of a broader consideration of bill impacts associated with demand-side resources in any plan. Manitoba Hydro ruled out consideration of broader social or environmental impacts and risk analysis of resource cost uncertainties as outside the "high-level scope" of its IRP.

Overall, present utility resource planning practices in Canada demonstrate a fundamentally reactive approach to managing risks associated with a net-zero transition. The typical approach is to assume a low or moderate level of demand growth, coupled with low or moderate levels of demand reduction, and model the least cost pathway to meeting future requirements – simply meeting (and rarely exceeding) policy goals for emissions reductions while minimizing short-term rate impacts. Recent developments in several provinces, including British Columbia, Ontario, Quebec, and Nova Scotia, have led planners to revise their earlier plans to accommodate unexpected demand growth or increased supply-side uncertainty. Planning is thus primarily reactive, working to minimize disruptive change instead of managing it.

Utility planning practices can better align with a net-zero future by working to centre what is possible in such a transition instead of what historical trends suggest is probable. This does not require a dramatic overhaul of planning practices. Governments and utilities should more seriously plan for increased electrification and take steps to conduct multi-fuel or economy-wide resource planning. To treat demand-side resources more fairly, utilities can incorporate them as selectable resources and adjust modelling practices to allow demand-side resources to influence and be influenced by model developments. More balanced and transparent consideration of the costs and benefits of all resources would help better manage resource and system risks and uncertainties. Finally, planners must be more aware of the dangers of locking-in emissions-intensive energy systems, thereby reducing our future manoeuvrability that results from a failure to front-load the known and proven demand-side solutions available today.

Résumé

Cette étude vise à déterminer les éléments procéduraux, fondamentaux et instrumentaux essentiels de la planification des ressources des services publics dans le contexte de l'atteinte de la carboneutralité d'ici 2050 et à évaluer les pratiques canadiennes de planification des ressources à cet égard. La planification aide à définir et à atteindre les buts et les objectifs à l'avenir. La planification des ressources des services publics doit donc tenir compte des risques et des incertitudes à l'égard de l'avenir pour nous permettre d'atteindre l'objectif d'un avenir carboneutre. Cette étude passe en revue la documentation sur les pratiques exemplaires en matière de planification des services publics; les études nationales sur les voies d'accès à la carboneutralité et les exemples récents de planification des ressources des services publics afin de cerner les défis qui nuisent au renforcement de l'harmonisation avec un avenir carboneutre. Nous mettons particulièrement l'accent sur le traitement des ressources du côté de la demande et surtout sur la planification du réseau électrique.

La planification intégrée des ressources est un processus en plusieurs étapes visant à évaluer et à répondre aux besoins futurs du système énergétique qui devrait comprendre toutes les ressources disponibles (c.-à-d. l'offre et la demande). La pratique de planification intégrée des ressources, dans le cadre de laquelle la planification est effectuée publiquement et intègre à la fois des solutions du côté de l'offre et de la demande aux besoins futurs du système, a émergé d'une période de ralentissement de la croissance de la demande, mais d'augmentation des coûts des systèmes et des préoccupations connexes en matière d'abordabilité dans les années 1980. L'un des principes fondamentaux de la planification intégrée des ressources consiste à traiter toutes les ressources (y compris les ressources « du côté de la demande » comme les programmes d'efficacité énergétique ou de réponse à la demande) sur un pied d'égalité. L'une des implications consiste à inclure ces ressources dans la modélisation de l'expansion du système « endogène », ce qui

signifie qu’elles peuvent être sélectionnées par le modèle d’optimisation en fonction de leurs caractéristiques et de leur influence ou être influencées par d’autres éléments du modèle au fur et à mesure qu’un scénario se déroule.

La planification des ressources des services publics est essentielle à la gestion de trois types de risques : risques pour les entreprises et l’abordabilité, risques liés aux ressources et au système, et risques sociétaux. Les risques pour les entreprises et l’abordabilité liés au coût du réseau de services publics et à la capacité de ceux-ci de recouvrer les coûts de ses investissements, tant à court qu’à long terme. En général, les services publics doivent faire preuve de « prudence » dans leurs stratégies d’investissement, c.-à-d. montrer qu’un investissement était raisonnable compte tenu des renseignements disponibles au moment où il a été fait. De son côté, la planification doit aussi tenir compte de la gestion des risques associés à des ressources particulières (p. ex. coûts, facteurs de capacité, délais de construction) de la fiabilité globale du système (c.-à-d. veiller à ce qu’il y ait suffisamment de ressources pour répondre à la demande). Enfin, la planification des ressources des services publics doit également gérer les risques sociétaux, en éliminant l’incertitude entourant les objectifs actuels et futurs de la politique gouvernementale et la capacité des services publics à les atteindre.

Un futur système énergétique carboneutre nécessite des changements structurels et comportementaux majeurs dans notre façon de produire et d’utiliser l’énergie. Des études internationales et nationales sur la voie de la carboneutralité ont mis en évidence l’ampleur et la portée du défi que représente la réduction de la consommation d’énergie par rapport aux émissions de gaz à effet de serre (GES). Les études canadiennes sur la voie de la carboneutralité montrent un avenir très électrifié – en particulier dans les bâtiments et les transports – avec certaines émissions résiduelles, une réduction modérée de la demande et environ 2 fois la croissance de la demande d’électricité et 2,5 fois les besoins en capacité électrique. Dans le contexte d’une transition vers la carboneutralité, il existe des risques sociétaux clairs associés à l’incapacité de planifier adéquatement les réseaux électriques pour répondre aux besoins des autres secteurs en matière de décarbonisation. Au mieux, il sera plus difficile et coûteux d’atteindre les objectifs stratégiques nationaux ou internationaux d’ici 2050, ou, au pire, cela le rendra presque impossible.

Notre examen des récents plans intégrés de ressources du Canada porte sur trois éléments principaux : l’harmonisation, les ressources axées sur la demande et les risques. Pour évaluer l’harmonisation, nous avons examiné le degré de coordination de la planification des services publics dans les réseaux d'électricité et de gaz naturel et la mesure dans laquelle les prévisions de charge dans les plans des services publics s'harmonisent avec les prévisions des études nationales sur la voie vers la carboneutralité. En ce qui concerne le traitement des ressources du côté de la demande, nous avons examiné la méthodologie générale adoptée par les services publics pour les inclure, ainsi que les répercussions de ces initiatives d'efficacité énergétique et de réponse à la demande sur les besoins cumulatifs du réseau. Enfin, pour évaluer les pratiques de gestion des risques, nous avons examiné le traitement des ressources du côté de la demande dans l'analyse de sensibilité et les processus par lesquels les services publics ont comparé et évalué différents portefeuilles de ressources et élaboré des plans d'action.

Il y a peu de coordination dans la planification des ressources entre les réseaux d'électricité et de gaz naturel du Canada. La planification des services publics se fait en grande partie en vase clos, avec de faibles niveaux de coordination entre les services publics d'électricité et de gaz naturel. Des efforts sont en cours en Colombie-Britannique pour encourager les services publics à coordonner leurs activités en fonction de scénarios hypothétiques, bien qu'ils semblent avoir eu une incidence minime sur les plans de ressources examinés ici. Manitoba Hydro est responsable de la distribution d'électricité et de gaz naturel et a cherché à intégrer la consommation d'énergie en dehors du réseau électrique dans son plan des ressources (quoique de façon limitée). Le Québec a récemment déposé un projet de loi qui rendrait le gouvernement responsable de la planification des ressources à l'échelle de l'économie, et le groupe d'experts sur l'électrification et la transition énergétique en Ontario a recommandé que le gouvernement joue un rôle plus actif dans l'orientation de la planification des services publics.

Bien que l'électrification soit un thème commun dans la construction de scénarios, les prévisions de charge d'électricité utilisées dans la planification des ressources des services publics sont généralement prudentes. Bien que la fourchette des prévisions de charge pour l'ensemble des plans et scénarios ait été assez large, la plupart des services publics ne modélisent pas de scénarios où la croissance de la charge d'électricité se rapproche de celle des études sur les voies à consommation carboneutre. Dans le plan d'électricité à long terme de FortisBC, le scénario qui se rapproche le plus de celui-ci visait à montrer les exigences théoriques maximales si tous les facteurs de la demande étaient maximisés. Le scénario d'électrification accélérée de Manitoba Hydro prévoyait des besoins en énergie et en capacité conformes aux études sur les voies à consommation carboneutre. Cependant, l'entreprise a fait remarquer qu'il serait difficile de réaliser ce scénario dans la pratique. Lorsque les services publics ont fait un choix clair quant à leur portefeuille de ressources privilégié (p. ex. BC Hydro et Nova Scotia Power), ils se sont fondés sur des scénarios où la croissance de la charge était faible.

Aucun service public au Canada ne traite les ressources du côté de la demande « sur un pied d'égalité » avec les solutions de rechange dans ses pratiques de planification. Ce rapport n'a révélé aucun plan de services publics dans lequel toutes les ressources du côté de la demande étaient entièrement disponibles pour la modélisation de l'expansion des systèmes en tant que ressources sélectionnables. La plupart des services publics soustraient les estimations de l'efficacité énergétique ou du potentiel de réponse à la demande de leurs prévisions de charge, en s'appuyant sur des études de potentiel antérieures, comme hypothèse d'entrée pour la modélisation. L'exception partielle est Manitoba Hydro, qui a rendu certains portefeuilles d'efficacité énergétique sélectionnables dans ses principaux scénarios et a testé des sensibilités, notamment en rendant toute l'efficacité énergétique sélectionnable. Toutefois, la réponse à la demande n'a pas été modélisée ni incluse dans l'analyse du scénario principal de l'entreprise.

Le potentiel des ressources du côté de la demande est systématiquement sous-évalué au moyen d'une méthodologie de modélisation, d'évaluations désuètes des coûts évités et de l'utilisation des coûts totaux des ressources pour filtrer les mesures. L'éventail des ressources du côté de la demande qui fournissent une capacité variait considérablement d'un plan à l'autre, et certains services publics en désignaient peu, voire aucune. La plupart des services publics, sinon tous, utilisent le test de coût total des ressources pour évaluer les ressources du côté de la demande dans des études potentielles, en intégrant les coûts non liés à la consommation dans l'analyse et peuvent utiliser des renseignements périmés sur les coûts évités. L'incidence des ressources du côté de la demande pour fournir une capacité dans les plans des services publics peut donc être sous-estimée (en moyenne de 11 à 14 % de la charge de pointe dans l'ensemble des plans examinés ici). En sous-évaluant le potentiel de solutions axées sur la demande pour répondre aux besoins de pointe, plusieurs scénarios augmentent la production d'électricité au gaz naturel selon des prévisions de charge plus audacieuses.

Les services publics ont tendance à tenir davantage compte des risques à la baisse liés aux ressources du côté de la demande que des solutions de rechange du côté de

l’offre et à traiter ce dernier sans ménagement dans une analyse de sensibilité. Bien que les méthodes différaient d’un plan à l’autre, la mise à l’essai générale des sensibilités du côté de l’offre était simpliste : la ressource était disponible ou non. En revanche, dans plusieurs plans, les sensibilités relatives aux ressources du côté de la demande ont fait l’objet d’un examen beaucoup plus approfondi. Par exemple, l’évaluation du potentiel de ressources du côté de la demande effectuée par BC Hydro est le seul exemple que nous avons trouvé d’un service public utilisant des méthodes probabilistes pour évaluer l’incertitude relative aux ressources. Nous n’avons pas trouvé de preuves indiquant que les services publics appliquent le même niveau d’examen aux ressources du côté de l’approvisionnement qu’un modèle pourrait adopter à l’avenir.

Bien que plusieurs services publics aient défini de multiples critères pour comparer et évaluer différents scénarios, les coûts totaux du système et les répercussions tarifaires occupent une place plus importante. Les critères complets d’examen des décisions ne sont pas toujours clairement précisés dans les plans des ressources des services publics. Cependant, les objectifs traditionnels de réduction des coûts du système, d’assurance de la fiabilité et de réduction des émissions de GES sont souvent définis. Lorsque les facteurs de risque sociétaux ont été désignés comme des critères décisionnels, ils semblent être relégués au second plan par rapport aux coûts du système et aux répercussions à court terme sur les tarifs. BC Hydro et NS Power discutent explicitement des répercussions tarifaires associées aux différents portefeuilles de gestion axée sur la demande (GAD), et il n’y a aucune preuve d’une prise en compte plus large des incidences du projet de loi liées aux ressources liées à la demande dans un plan. Manitoba Hydro a écarté l’examen des répercussions sociales ou environnementales plus vastes et de l’analyse des risques liés aux incertitudes liées au coût des ressources, car cela dépassait la « portée générale » de sa planification intégrée des ressources (PIR).

Dans l’ensemble, les pratiques actuelles de planification des ressources des services publics au Canada démontrent une approche fondamentalement réactive de la gestion des risques associés à une transition vers la carboneutralité. L’approche typique consiste à supposer un niveau faible ou modéré de croissance de la demande, conjugué à des niveaux faibles ou modérés de réduction de la demande, et à modéliser la voie la moins coûteuse pour répondre aux besoins futurs – en se contentant d’atteindre (et rarement de dépasser) les objectifs stratégiques en matière de réduction des émissions tout en réduisant au minimum les répercussions sur les tarifs à court terme. Les développements récents dans plusieurs provinces, dont la Colombie-Britannique, l'Ontario, le Québec et la Nouvelle-Écosse, ont amené les planificateurs à réviser leurs plans antérieurs pour tenir compte de la croissance imprévue de la demande ou de l'incertitude accrue du côté de l'offre. La planification est donc principalement réactive et vise à réduire au minimum les changements perturbateurs au lieu de les gérer.

Les pratiques de planification des services publics peuvent être mieux harmonisées avec un avenir carboneutre en travaillant à centrer ce qui est possible dans une telle transition au lieu de ce que les tendances historiques suggèrent comme étant probables. Cela ne nécessite pas une refonte en profondeur des pratiques de planification. Les gouvernements et les services publics devraient planifier plus sérieusement l'électrification accrue et prendre des mesures pour mener une planification des ressources multicombustibles ou à l'échelle de l'économie. Pour traiter plus équitablement les ressources du côté de la demande, les entreprises d'électricité peuvent les intégrer en tant que ressources sélectionnables et adapter les pratiques de modélisation afin de permettre aux ressources du côté de la demande d'influencer l'évolution des modèles. Un examen plus équilibré et transparent des coûts et des avantages de toutes les ressources aiderait à mieux gérer les risques et les incertitudes liés aux ressources et au système. Enfin, les planificateurs doivent être plus conscients des dangers liés au blocage de systèmes énergétiques à forte intensité d'émissions, ce qui réduit notre manœuvrabilité future résultant du fait que nous ne chargeons pas en amont les solutions connues et éprouvées du côté de la demande offertes aujourd'hui.

Introduction

In December 2015, the 21st UN Climate Change Conference (COP21) concluded the "Paris Agreement," committing signatories to pursue efforts to limit global warming in this century to 1.5 degrees Celsius. To achieve this, global greenhouse gas emissions need to be reduced by 45 per cent by 2030 and reach net zero (no more emissions are produced than can and are captured by engineered and environmental mechanisms) by 2050.[1] The magnitude of energy system changes necessary to hit this target is immense – the best modelling suggests it is possible will require heroic levels of effort, investment, and commitment. Even so, it will be tight; many things could go wrong. There is no margin for error.

In this context, what constitutes good planning? Ideally, a plan helps to achieve some desirable future state or thing (and avoid less desirable ones). A young couple might develop a savings plan to buy their first house. An organization may create a strategic plan to focus and guide its work over a set period. A government may establish a climate change plan to identify and highlight actions needed to achieve a targeted level of emissions reduction. In these examples, a good plan is one that successfully leads to its end goal and fulfills its purpose and reason for being – whatever difficulties arise.

Therefore, we may be tempted to assume that a good plan for a net-zero future successfully guides us to a net-zero future. But if that's all, we won't know if it is successful (or what made it so) until we arrive at that point. Absent clairvoyance, we would thus have little guidance on planning for net zero; not every contingency can be foreseen and accounted for at the outset. The best laid such plan would falter on the first instance of novelty. We can't fully know a good plan simply by what is in it.

Of course, a plan is rarely created once and never revisited. To manage change and uncertainty, a good plan needs to evolve and adjust as its objective becomes nearer (or further) and more or better information becomes available. This is true of each substantive element of a plan, its understanding of the critically important facts about the world, and its proposed mechanisms or strategies to manage action toward a goal, even perhaps its expectations for and definitions of future states or things – they all may need to change and adapt to new circumstances, if planning is to be successful.

[1] United Nations, "Net Zero Coalition."

Good planning is, in short, a process, the quality of which should be defined by a combination of procedural and instrumental (i.e., as a tool to accomplish some purpose) considerations. While it seems obvious that procedural aspects of good planning may contribute to a plan's usefulness, what about the substantive components — the content of its vision (and strategy) for the future? It seems reasonable to assume there must be some boundaries that define what should or should not be included in a plan to reach net zero by 2050 if stakeholders are to consider it feasible and realistic and if the plan is to have some likelihood of succeeding.

This study seeks to answer what it means for utility resource planning to be "aligned" with a net-zero future. To answer this, we identify the critical procedural, substantive, and instrumental elements of utility resource planning in reaching net zero by 2050. We also evaluate whether these elements are realized in current Canadian utility resource planning practices. Our focus is primarily on resource planning for electricity utilities. However, we also incorporate some examples from natural gas resource planning (indeed, the two should not be separated in truly 'aligned' planning). We pay particular attention to the representation of demand-sided resources and the treatment of risks in resource characterization, modelling, and portfolio analysis.

We argue that the core, instrumental purpose of utility resource planning is to manage the risks associated with a transition to net zero. Crucially, this includes the societal risks that stem from failing to plan for net zero. Substantively, we argue that, although no one can predict the exact constitution of a future net-zero energy system, resource planning must seriously consider and plan for extensive electrification — even where the policy does not require it or historical trends do not justify it. Finally, we develop an abbreviated 'checklist' of procedural considerations that suggest resource plans sufficiently and appropriately treat all available resource options fairly in the planning process. Treating resources equally, particularly demand-side resources, is integral to successfully managing the risks inherent in a transition to net zero.

The importance of utility resource planning

There are many ways to plan for a net-zero future, many different organizations that do so, and many different reasons why they want to. This paper focuses on the long-term, integrated resource planning that is traditionally carried out by utilities. In this section, we review the historical origins of integrated resource planning, the core principles that guide it, its importance in managing risks associated with a transition to net zero, and the ways in which it might be improved.

What is integrated resource planning?

“Utility resource planning” refers to the broad set of practices that energy utilities (electric and natural gas) use to estimate future energy requirements, identify available resources to meet these requirements, and evaluate these resources to determine which combination thereof would best meet the utility’s “planning objectives.” These practices are rooted in the historical development of utility regulatory and market structures in the early to mid-20th century and continue to evolve today. Yet, the core planning objectives have remained more-or-less the same over this time – to ensure affordable, reliable, and safe energy services to their customers.

Utility systems evolved around large, vertically integrated public utility companies (in Canadian electricity systems, often crown corporations), which were granted a monopoly to operate in a given jurisdiction in exchange for accepting regulatory oversight by a utility board that aimed to balance the often-competing interests of the utility, its investors, and its customers.[2] Under this arrangement, utilities are allowed to earn a reasonable rate of return on capital investments and recover the costs of providing those services through rates that are reasonable, affordable, non-discriminatory, and stable.[3] Utilities thus periodically identify their “revenue requirements” to sustain and operate the system, and regulators evaluate proposals based on core public interest objectives (such as affordability).

Resource planning is separate but related to this process. Resource planning is long-term (15–20 years), while revenue requirement applications typically are much shorter (one to three years). Yet, the arrangement by which utility revenue is governed

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[2] Swartwout, “Current Utility Regulatory Practice from a Historical Perspective.”

[3] James C. Bonbright, *Principles of Utility Regulation*.

incentivizes the utility to reduce operational costs in favour of capital assets on which it can earn a return on its investment. Traditionally, utility resource planning thus tended to focus mainly on utility-owned assets and what supply-side resources the utility itself could acquire to meet future demand.[4] Planning was also mainly internal to the utility (i.e., not public), without substantial intervention from external stakeholders.

These rules, coupled with rapid growth in energy demand in the 20th century, led to the extensive build-out of large-scale, centralized supply-side energy resources and the infrastructure necessary to deliver that energy to customers. However, as energy demand growth slowed in the 1980s, many utilities found themselves “caught in the whipsaw” of increasing rates to cover the cost of new, large-scale generation projects and falling demand, which they had failed to foresee.[5] At the same time, global energy system disruptions and increasing concern for the environment led to more interest in “soft energy” pathways comprising smaller-scale renewable energy sources and energy efficiency improvements.[6] Market restructuring and deregulation in the 1980s and 1990s sought to introduce more competition in different parts of the utility system and to the dismantling (in some jurisdictions) of large monopoly utilities into separate entities.[7]

In short, the era in which utilities could conduct resource planning entirely internally, focusing primarily on supply-side resources they owned or controlled, was gradually coming to an end (though not entirely or universally throughout North America). Increasing experience with and growing sophistication of tools and institutions to assess the potential of, deliver, and evaluate the impact of demand-side resources like energy efficiency demonstrated their strong cost-effectiveness and favourable risk profile vis-a-vis supply-side options or infrastructure investments. To counter barriers inherent in the core principles underpinning utility regulation and the disincentive of reduced energy sales, many jurisdictions introduced policies to require utilities to

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[4] Hirst and Goldman, “Creating the Future.”

[5] “Northwest Conservation and Electric Power Plan.”

[6] Lovins, *Soft Energy Paths*.

[7] For overviews of this dynamic in a Canadian context, see Doern, “Canadian Energy Policy and the Struggle for Sustainable Development: Political-Economic Context.”

conduct regular integrated resource planning and to introduce targets for improving energy efficiency that utilities are required to meet.[8]

The fundamental goal of integrated resource planning remains an affordable, reliable, and safe energy system. However, a core principle of integrated resource planning is to consider *all* available resources on the supply and demand side (i.e., energy efficiency and load management) and accurately and fairly represent their costs and benefits. This includes resources that may not be under the utilities' control, like procuring power from independent producers or importing electricity from neighbouring jurisdictions. Additionally, integrated resource planning should incorporate explicit consideration of the policy context (e.g., environmental impacts) and the direct economic costs, allow for public participation in planning, and evaluate the uncertainties and risks posed by different resource portfolios and external factors. In other words, integrated utility resource planning aims to be comprehensive, aligned, and transparent.[9]

Why is it important?

Utility resource planning is among many types of planning essential to guiding society toward a net-zero future. Government climate and energy plans and policies provide milestones and policy constraints on the scenarios used in utility planning. Similarly, there is a close relationship between resource potential studies (which assess a given resource's cost-effective potential) and utility resource planning. Potential estimates inform what is available to resource planning but are also informed by load forecasting and estimates of avoided costs produced through resource planning. Finally, there are studies on decarbonization pathways, often produced by organizations external to the utility system. These may be focused on a particular aspect of the energy system (e.g., the electricity system) or economy-wide. These pathway studies are instructive in identifying possible characteristics of a future net-zero energy system.

For example, surveying national-level, net-zero pathway studies for Canada reveals some common findings. For one, there will almost always be residual emissions in energy end-use sectors in a net-zero future. Scenarios from the Canadian Energy Regulator (CER) and the Institut de l'Ènergie Trottier (IET) show a total economy-wide

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[8] Hirst and Goldman, “Creating the Future”; Haley et al., “From Utility Demand Side Management to Low-Carbon Transitions: Opportunities and Challenges for Energy Efficiency Governance in a New Era.”

[9] Dyson, Shwisberg, and Stephan, “Reimagining Resource Planning.”

reduction in emissions between 73 and 80 per cent from 2021 levels.[10] The CER scenarios result in roughly a 90 per cent reduction in emissions in transportation and a 72 per cent reduction in buildings, however. In comparison, the IET study resulted in a 66 per cent reduction in transport and a 97 per cent reduction in buildings. Generally, net-zero scenarios get to net-zero through negative emissions technologies in the electricity sector (e.g., hydrogen, carbon capture and storage), land-use changes, and forestry.

Understanding the relative difference between sectoral emissions reductions in different studies is complicated but generally has to do with the extent of electrification and the make-up of future electricity systems. Total reductions in energy demand (both economy-wide and in electricity systems) also play an important role. Across the three aforementioned scenarios, total final energy demand (versus the business-as-usual reference scenario in each study) averaged 72 per cent, suggesting a 28 per cent reduction in demand through energy efficiency improvements. The share of total end-use demand met by electricity averaged 2.35 times levels in 2021, 1.95 times in the buildings sector, and 248 times in the transportation sector (indicating near complete transportation electrification). There were still discrepancies between studies; the CER scenarios retained fossil fuel use in buildings at about 40 per cent of current levels, while it was virtually eliminated in the IET study.

Nevertheless, electrification is a common theme of net-zero pathway studies. Changes within electricity systems are, accordingly, quite significant as well. Studies by both the Canadian Climate Institute and the Transition Accelerator surveyed a wide range of pathway studies to evaluate the extent of electricity system changes necessary to support electrification.[11] The results suggest between 1.6 and 2.1 times (i.e., 60 to 110 per cent) more electricity will need to be produced in 2050, and electricity systems will require 2.2 to 3.4 times more capacity to meet demand. Assuming a 28-year forecast period (2022-2050), these figures equate to a range of 1.7 to 2.7 per cent annual growth in electricity and 2.9 to 4.5 per cent annual growth in capacity requirements. While energy efficiency may be mitigating some of the growth in generation and capacity requirements, the Transition Accelerator report found that none of the studies reviewed

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[10] Langlois-Bertrand et al., "Canadian Energy Outlook 2021 - Horizon 2060"; Canada Energy Regulator, "Canada's Energy Future 2023: Energy Supply and Demand Projections to 2050."

[11] Jason Dion et al., "The Big Switch: Powering Canada's Net Zero Future"; The Transitions Accelerator, "Putting Canadian Deep Decarbonization Electricity Modeling Studies to Use."

explicitly reported on peak demand findings or provided data on the impact of energy efficiency.

These pathway studies are useful in providing some general contours of a future net-zero emission energy system, but utility resource plans are very different. Utility resource planning is generally much “closer to the ground” than the higher-level, typically national pathway studies. Utilities also have far greater insight into the operation of their systems, the available resources and their expected costs, and — presumably – trends in energy consumption and demand growth. Utility plans extrapolate from observed trends; net-zero pathway studies assess what trends need to be to hit a goal. While both may consider pathways to reducing emissions, utility resource planning is directed and constrained by such policy goals while they motivate net-zero pathway studies.

Fundamentally, the difference is that utility resource planning is reactive to anticipated change, while pathway studies are generative of it (or aim to be). A lot is riding on utility resource plans, and costly, long-lasting decisions with significant societal impacts are made based on their findings. Unlike pathway studies, utility resource plans must *manage* the transition to a net-zero future – not only envision it – while ensuring core objectives for reliability, affordability, and safety are met. This must be accomplished under conditions of considerable uncertainty, with significant consequences..

As such, utility resource planning is essentially about identifying, assessing, understanding, making decisions, and communicating *risk*.[12] In the context of a transition to net zero, we can consider three overlapping categories of risks and risk management: business risks (and affordability implications), risks to energy systems (i.e., to reliability or safety), and societal risks concerning broader public policy goals.

Utilities are businesses and thus face both short— and long-term business risks, largely associated with recovering the costs of their investments. The existing regulatory compact that governs utility rate-setting and the ability to earn revenue biases utilities toward capital investments (e.g., supply-side resources and infrastructure) from which they can earn a return on equity.[13] The main organizational risk to utilities, as such, is that it cannot recover the costs of such investments. In the short term, this could be due to unexpected expenses, regulatory lag, addition/departure of large customers, or

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[12] Treasury Board of Canada Secretariat, “Guide to Integrated Risk Management.”

[13] Utils Consulting, “Back to Bonbright: Economic Regulation Fundamentals Can Enable Net-Zero.”

external events like severe weather or natural disasters. In the long-term, this may result if an asset ceases to be "used and useful," which is generally necessary to be included in a utility's revenue requirements.[14] In such a case, the asset becomes "stranded."

While the matter is complex and varies in practice across Canada, the principle underlying determining who bears the cost in these situations is known as the 'prudence test' — was the original investment reasonable given the available information when it was made? Generally speaking, an asset determined to be prudent remains so over its depreciable lifetime (and thus part of the rate base) even if it is no longer used / unused, though there are exceptions.[15] However, the question of what is or is not 'reasonable' in the context of observable and known trends, policy, and other information at the time can be ambiguous. Even though certain things may be possible characteristics of the future, this doesn't mean they are necessary characteristics.

The evolution of utility planning, rate and revenue regulation has, accordingly, resulted in a system biased toward "business-as-usual" in its approach to managing organizational and affordability risks. In the context of an energy transition, this arrangement presents serious challenges. When does a possibility pass into the realm of necessity? Without clear trends or explicit policy requirements, how should utilities and regulators decide what is prudent or imprudent to invest in? A recent controversy in Ontario is instructive. In 2023, the provincial natural gas utility proposed to amortize the cost of building new gas distribution infrastructure over 40 years, which the regulatory board rejected because this infrastructure may not be used or useful over that period due to electrification. The provincial government intervened to overturn the decision, citing new housing construction affordability concerns.

The second category of risks to manage in resource planning concerns risks to the system itself, mainly in terms of system reliability. This kind of risk has at least two closely related dimensions: ensuring sufficient capacity to meet demand when and where it is needed (i.e., resource adequacy) and the intrinsic risks associated with different resources and resource portfolios.

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[14] Asa S. Hopkins, "Summary of Evidence on Business Risk."

[15] Cusano et al., "Prudence, Stranded Assets, and the Regulation of Utilities." Several Supreme Court of Canada cases have weakened the "no-hindsight" principle in some circumstances, like in the case of an "extraordinary" pre-mature retirement of an asset, or in cases where prudence should be based on what is reasonable when the costs are recovered. A forthcoming paper from the Canadian Climate Institute explores the implications of the no-hindsight and prudence test principles in greater detail.

Aspects of the energy transition (e.g., rapid growth in electricity demand, proliferation of distributed energy resources and intermittent renewable energy; phasing out large coal and natural gas generation) can complicate conventional approaches to managing system risks.[16] The conventional approach to resource adequacy and system reliability has been to assess whether the total envisioned capacity (across the whole system) would be sufficient to meet projected annual peak demand, plus a reserve margin to provide a buffer against unexpected events. The changing resource profiles in a decarbonizing electricity system, coupled with increases in both the scale and variability of load from increased electrification, may necessitate a more granular consideration of the possible size, frequency, duration and timing of capacity shortfalls or energy surpluses.[17]

While system reliability tends to be assessed at an aggregate level, planners must also consider the risks intrinsic to the resources. Assessing the risk associated with existing and potential new resources often hinges on the cost of that resource, and whether it will be available at the time it is needed.[18] Cost and time-related risks stem from both the intrinsic characteristics of the resource (project size and lead times, costs, whether it provides firm/dispatchable capacity) and the inherent uncertainty regarding future conditions (e.g., the pace and location of load growth, market and fuel prices, or policy/regulatory or technology change). Different resources and portfolios of resources can similarly be compared and assessed under varying sets of conditions, provided planners can define and quantify standard metrics. In practice, comparing relative resource risks often relies on a mix of subjective assessment and known data or historical evidence.

A robust comparison of different resource portfolios might also consider the interactive effects between resources within the portfolio for mitigating cost and time-related risks, using stochastic or probabilistic analysis to quantify resource risks.[19] Unlike scenario analysis with deterministic models, this approach allows for random variation and can test resource portfolios against hundreds or thousands of possible future conditions. In its most advanced form, optimization does not assume or rely on perfect foresight (i.e.,

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[16] Stenclik, "Redefining Resource Adequacy for Modern Power Systems."

[17] Williams Jagdmann et al., "Resource Adequacy Primer for State Regulators."

[18] Binz et al., "Practicing Risk-Aware Electricity Regulation."Binz et al., (2012);

[19] Frick et al., "Methods to Incorporate Energy Efficiency in Electricity System Planning and Markets," app. B.

fixed input parameters on fuel prices, load growth, etc.), thus more closely reflecting the conditions under which actual decisions are made. The future, in the model, can vary from what the original input assumptions presumed it to be, which helps to demonstrate the risks associated with uncertainty even when a resource addition would have been optimal under original conditions or assumptions.[20]

A final category of risks associated with resource planning, which often go unrecognized or unformalized in utility plans, might be called "societal risks." Utilities and utility energy systems are embedded within a broader socio-political context, and as such, their actions (or inactions) have ramifications for society at large (not just ratepayers and investors). For the purposes of this report, we define societal risk as the possibility that a) political or public policy goals assigned to utility systems are not achieved and/or are made more difficult to achieve, or b) new or existing problems are created or reinforced through second-order effects of actions or inactions within utility systems.

In the transition context, there is a clear societal risk that a failure to adequately plan for decarbonization — both in utility systems and economy-wide — will, at best, make it more difficult and costly to hit national or international net-zero goals by 2050 and at worst make it nearly impossible barring drastic actions that will have serious second and third-order impacts on other utility system and societal goals. Key issues to consider are the risk of following dead-end pathways and "lock-in" — the winnowing of manoeuvrability or flexibility in future actions due to decisions made today.[21]

Many utility resource decisions have long lifetimes. The useful life of a natural gas generation plant built today could stretch 30 or 40 years. If that plant is not built with carbon capture technology (or cannot be retrofitted later), it will produce greenhouse gas emissions over that lifetime. Building houses with 100 amp service, replacing transformers without considering future EV charging requirements, neglecting energy efficiency improvements that could help defer riskier capital investments — all of these actions may restrict our future range of options for decarbonizing energy systems while maintaining reliability and affordability.

Second-order effects may also be associated with good faith efforts to electrify or decarbonize energy systems, though the situation may differ across electricity and

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[20] See Frick et al., Appendix B.

[21] Meadowcroft and Rosenbloom, "Accelerating Low-Carbon Energy Transitions."

natural gas systems. In a situation with high fixed costs in electricity and natural gas systems, electrification could lead to increased sales revenue for electricity utilities and reduce the potential rate impacts of system expansion. Still, it could also lead to ever smaller numbers of natural gas customers (typically those less financially able to electrify) footing the bill for fixed system costs. Similarly, a strategy to support electrification that relies heavily on large, centralized supply-side generation projects may increase the downside system risks of underperforming assets, leading to increased GHG emissions. These risks could be mitigated by prioritizing demand-side resources to meet additional generation or capacity requirements.

These are hypothetical risks that may arise from different strategies to manage a net-zero transition without necessary consequences. The critical point is that because decisions made through utility resource planning can have such consequences, these risks should be considered in that planning. A core question is whether utility planning practices, as they have evolved to date, can or do adequately consider such risks and, if not, what it would take to improve them.

How can it be improved?

Given the changing context and scale of the challenge associated with managing a transition to a net-zero future, is utility integrated resource planning up to the task? There are two separate aspects to answering this question: How does the transition context change the meaning of "aligned, comprehensive and trusted" planning, and how do current practices in Canada measure up? In this section, we address the first question. The following section will review current practices in Canada.

To successfully manage a transition to a net-zero future, there are necessary considerations to make across all phases of utility resource planning. Though specific practices vary across jurisdictions and utilities, integrated resource plans generally contain similar components and follow a similar process. There are roughly four main phases: setting the stage; exploring pathways, evaluating risks, and making decisions.[22]

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[22] NARUC-NASEO Task Force on Comprehensive Electricity Planning, "Aligning Integrated Resource Planning and Distribution Planning - Standard Building Blocks of Electricity System Planning Processes"; Dyson, Shwisberg, and Stephan, "Reimagining Resource Planning."

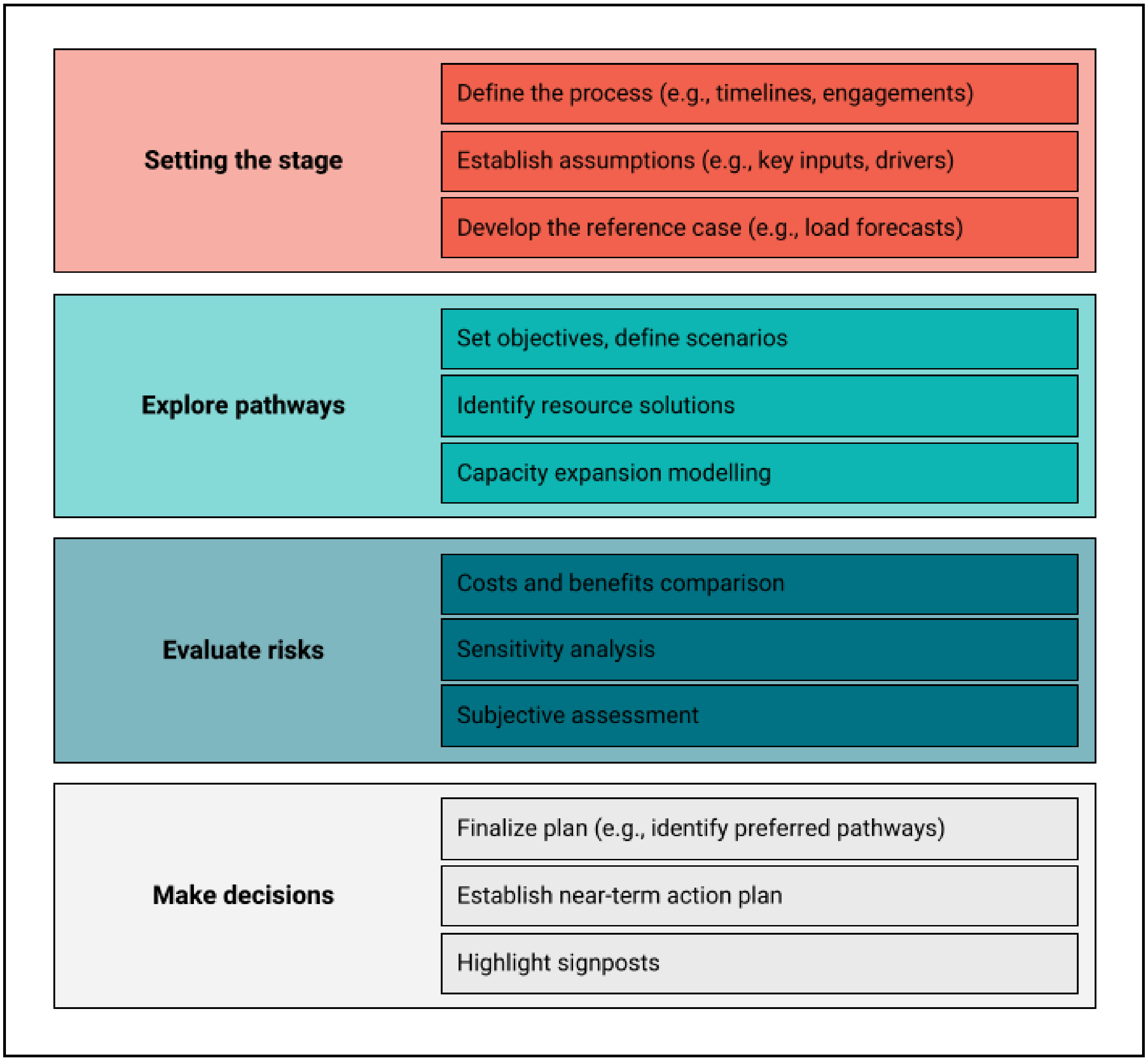

Figure 1. Building blocks of integrated resource planning, adapted from NARUC-NASEO (2019) and Dyson et al., (2023)

At the outset, planning often begins by outlining a process, determining planning objectives, and identifying 'key inputs.' Key inputs often include known drivers of change like economic and population growth, which may be used to inform a reference energy demand/load forecast that serves as the focal point for comparing different scenarios. Once a reference case has been established, the planning process typically explores alternative pathways to realizing certain objectives or addressing potential future challenges. This often involves outlining a series of plausible scenarios shaped by broader policy objectives (e.g., hitting government emissions targets) or perceived trends in key inputs or drivers (e.g., electrification) and estimating load under these conditions.

These first steps ensure aligned, comprehensive and trusted integrated resource planning in a net-zero transition. Perhaps foremost, resource planning needs to be truly "all-in," meaning that it focuses not only on utility system requirements but also the needs of customers, communities, climate requirements and environmental justice in order to manage societal risks.[23] In this respect, increasing the degree of coordination between natural gas and electric utilities could help align scenarios with policy goals (which also improves transparency to stakeholders), as well as break down "fuel silos" in utility demand-side management offerings.[24] This could entail increasing the separation of planning activities from the "owners" of the utility system (i.e., utilities) and the planners, for instance, by establishing independent planning authorities empowered to look for solutions beyond the traditional boundaries of utilities and across fuels (i.e., economy-wide planning).

To improve transparency, policymakers can introduce rules regarding what types of data are shared and how frequently, and planners could look toward open-access models that allow stakeholders to see how scenarios were configured and enable other parties to model scenarios of their own.[25] Even with greater data and modelling transparency, there remain barriers to the meaningful engagement of stakeholders. Time, resource constraints, and technical knowledge may prohibit some groups of stakeholders from participating in planning processes despite having interest in the outcomes. Ensuring that all stages of the process are communicated early and in an accessible manner, in plain language, via publicly available websites or other channels can help to address some of these constraints.

On alignment, resource planning should, at a minimum, be based upon existing and committed federal and provincial policy that impacts utility systems, with no assumptions that such policy will be revoked. A more challenging issue concerns load forecasting – a key input to resource planning. As noted above, net-zero pathway studies consistently find electrification essential to reaching net-zero, with substantial

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[23] Boyd and Tully, "RESPECT: Reforming Energy System Planning for Equity and Climate Transformation."

[24] Haley, Gaede, and Nippard, "Breaking Fuel Silos in Demand-Side Management: Policy Options to Align Energy Efficiency with Net-Zero Emissions across All Fuels."

[25] For instance, Dyson et al. note the case of New Mexico as a case study, which requires utilities to produce specific cost data, including capital, operating and maintenance costs, in the IRP process.

growth in electricity production and capacity necessary to meet future requirements. Yet, utilities may be constrained in their ability or capacity to base planning on levels of electrification that are not justified by observable trends. Furthermore, in Canada, most utilities provide electricity or natural gas services, rarely both, and may have different visions of reducing emissions. Increased coordination in planning assumptions may help to mitigate these challenges, but exactly how to accomplish this in a way that respects different visions of decarbonization while providing clarity and direction to all stakeholders remains an issue to be solved. At the very least, utilities should incorporate at least one scenario in which electrification (and electricity system expansion) aligns with levels found in net-zero pathway studies and treating the challenges that scenario poses seriously.

The transition context also has implications for the phases that follow these first steps. Identifying the potential and estimated costs of new and existing resources is a complex endeavour, often outside the IRP process. Utilities typically maintain a resource options database (usually proprietary and confidential) that includes this information for supply-side resources. Still, they may periodically conduct studies to estimate the technical, economic, and achievable potential of other resources, like energy efficiency or demand response programming. Resource potential and characteristics are key inputs into system expansion modelling, which aims to optimize the resource portfolio mix to minimize costs while retaining reliability within the scenario's constraints.

The principle of comprehensiveness requires that all resources should be able to compete in the planning process based on their particular costs and performance characteristics. This “parity in planning” entails symmetry in the model resource acquisition process, where models pursue all resources up to the cost that is equal to their value to the utility system with symmetrical assumptions regarding “willingness-to-pay” across supply and demand-side resources and; equality in cost-benefit analyses, where all relevant resource characteristics (e.g., construction lead times, scheduling flexibility, load shapes, dispatch ability, reliability, forced-outages, carbon emissions, fuel/market price risks) are included in the evaluation.[26] In practice, parity implies that all resources (including demand-side resources) should be treated endogenously in

[26] Frick et al., “Methods to Incorporate Energy Efficiency in Electricity System Planning and Markets.”

system modelling, where they are influenced by and can influence other elements in the model as a scenario plays out.[27]

For demand-side resources, this practice is not widespread. A recent ACEEE study found that the “vast majority” energy system modelling treats efficiency as an input assumption (i.e., subtracting it from load forecasts before modelling), precluding it from directly competing with supply-side resources.[28] A separate Resources for the Future study reviewed eight integrated utility resource plans in the U.S. to evaluate how they represented demand-side resources. The study found that plans typically did not adequately investigate the demand-side potential, most often using a predetermined DSM portfolio as an input assumption and not fully accounting for the demand flexibility and non-energy benefits of demand-side resources in their cost-effectiveness screening.[29] The consequence is that energy efficiency is treated as a price-taker, not a price-maker.[30]

Instead of using predetermined portfolios of demand-side resources to reduce forecasted system requirements, the economic potential of demand-side resources should be optimized during the system expansion modelling. The logic of the model should account for specific characteristics that can complement system requirements and impact prior input assumptions (e.g., load growth).[31] Since the planning period often exceeds the useful life of many measures, model logic should also be able to capture the cost-effectiveness of acquiring savings each time they come up for replacement. For example, an appliance with an average useful life of eight years may be replaced twice during a twenty-year planning period. Resource modelling should be able to select savings from such “lost opportunity” resources at every turnover (if cost-effective). For example, the first turnover period might not have high energy savings or

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[27] This is generally true of the treatment of energy efficiency in economy-wide decarbonization pathway studies, reviewed in the next section of the report. See The Transitions Accelerator, “Putting Canadian Deep Decarbonization Electricity Modeling Studies to Use.”

[28] Specian and Bell-Pasht, “Energy Efficiency in a High Renewable Future.”

[29] Duncan and Burtraw, “Does Integrated Resource Planning Effectively Integrate Demand-Side Resources?”

[30] Frick et al., “Methods to Incorporate Energy Efficiency in Electricity System Planning and Markets,” 14.

[31] Frick et al., 14.

avoided costs to justify savings acquisition, but the cost-benefit equation might change eight years later and thus be included as a renewed resource option.[32]

Given the high probability of widespread electrification, comprehensive consideration of the potential for demand-side resources to provide flexibility to grids is of critical importance. This involves both a broad definition of available demand-response measures and an extended analysis of where they provide value. Traditional assessments of demand-side resource potential to provide flexibility focused on a narrow range of options, and typically on demand reductions system-wide during narrow peak windows. Technological development coupled with advances in modelling practices enable a broader perspective. This could include demand-response options in space and water heating, EV charging, energy storage, and value streams deriving from more granular targeting of transmission and distribution capacity deferral or ancillary services. According to research by the Brattle Group, a more fulsome understanding of demand flexibility suggests it could account for 20 per cent of peak load in the U.S. by 2030, and $15 billion saved annually in avoided system costs.[33]

While the goal of optimization modelling is to identify resource portfolios that satisfy the planning criteria, multiple different portfolios may do so, with different cost/benefit tradeoffs, which planners need to evaluate. A subsequent phase of testing sensitivities around model inputs, assumptions, and technological characteristics (such as costs and availability) can inform the evaluation of different portfolios, which helps to evaluate risks associated with each portfolio under certain conditions.

The result of these final stages is one or more long-term technological or resource pathways the utility can use as the basis for a shorter-term (e.g., five-year) action plan (often, the utility will select one scenario/portfolio as its preferred basis for planning, which regulators must assess and rule upon). Action plans guide utility investment and operational strategies to help ensure the realization of preferred pathways and minimize risks associated with these strategies. Action plans may also include initiatives related to future planning processes (e.g., identifying areas where more information or research is required to bolster analysis) or to identify ‘signposts’ which — if coming to pass — might suggest a need to pivot in the strategy. For example, a

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[32] Frick et al., 15–16 and Appendix A.

[33] Hledik and Higham, “Brattle Study.”

‘signpost’ might be the passage of an anticipated policy change or a variance in a key trend from what was expected in the modelling (e.g., faster / slower electrification).

These final stages are critical to managing risks associated with a transition to net zero. The principle of parity suggests that the evaluation of sensitivities and risks for different resources and resource portfolios should be comprehensive and transparent, using metrics of costs and benefits that put resources on an equal footing and that are commensurate with the importance of the resource. In comparing and evaluating different resource portfolios, planners may need to move beyond traditional, utility system-centric measures to consider broader societal impacts. The pace and scale of change in the context of a net-zero transition may also require adjustments in planning frequency, which has traditionally followed a schedule of every three to five years.

Table 1 below summarizes resource planning characteristics that suggest sufficient management of risks inherent in a net-zero transition. We note, however, that there are likely many other elements that could be added to this list, both to provide more technical specifics on modelling choices or techniques or performance or reliability metrics or to expand it to include factors pertinent to transparency or stakeholder engagement.

Net-zero alignment
Includes scenario(s) which comply with federal/provincial policy
Includes scenario(s) which incorporate known but yet-to-be-implemented policy and/or a scenario that works back from net zero
Includes scenario(s) with aligned assumptions regarding energy demand between natural gas and electric utilities
Includes scenario(s) with levels of electrification approximating estimates from national pathway studies
Independent, economy-wide planning

Resource characterization
Comprehensive consideration of demand flexibility potential
Demand-side resources are incorporated as selectable resources in modelling
Market potential of demand-side resources not artificially constrained outside of optimization modelling
All relevant resource characteristics (e.g., construction lead times, scheduling flexibility, etc.) considered
Parity in treatment of utility and non-utility costs and benefits
Risk management
Parity in sensitivity analysis of supply/demand-side resource risk
Transparent, multi-criteria assessment evaluation of competing resource portfolios that includes societal factors
Both rate and bill impacts are considered
Bias toward early action to avoid lock-in, maintain maneuverability
Preferred resource plan derived from scenario that meets alignment criteria for net-zero
Action plan includes clear signposts, schedule for renewing plan is accelerated (i.e., < three years)

Table 1. Characteristics of net-zero aligned utility resource planning

To conclude, utility resource planning is critically important to managing risks associated with a net-zero transition. It should thus aim to be aligned with policy, comprehensive in its resource characterization, and trusted by stakeholders. While net-zero pathway studies can help identify characteristics of a net-zero future, they are not constrained in the way that utility resource planning is. Furthermore, significant decisions are made based on utility resource plans. Given the changing context and the potential scale and pace of change associated with a net-zero transition, resource planning will need to be aligned with policy and the likely shape of a net-zero energy system, explore greater coordination between electricity and natural gas systems, work to ensure equal consideration and accurate representation of demand-side resources, and pay more attention to the interconnections between different types of risk, particularly societal risks.

Resource planning in Canada

In this section of the report, we provide a high-level overview of select utility integrated resource plans in Canada, paying particular attention to the following:

1) The **degree of alignment** with provincial and federal climate and energy policy, including coordination between natural gas and electric utility systems, electrification in load forecasting and scenario development, and GHG emissions.

2) The **treatment of demand-side resources**, both in load forecasting and expansion modelling and the contribution of demand-side resources to meeting future system requirements.

3) The consideration and treatment of **utility, system and social risks** in resource characterization, scenario development and modelling practices, including sensitivity testing, action plans, and recent developments necessitating adjustments to plans.

Utilities in several provinces have recently completed integrated resource plans, including BC Hydro and FortisBC/FortisBC Energy in British Columbia, New Brunswick Power, Manitoba Hydro, and Nova Scotia Power. These are the primary focus of this analysis.[34] However, resource planning is carried out in other provinces as well, and we will occasionally reference these plans and planning processes. This includes net-zero pathway reports, annual planning outlooks by the Alberta and Ontario electric system operators, and recent resource planning developments (and implications for demand-side management) in Quebec.

Alignment

For utility resource planning to remain comprehensive, aligned, and trusted in the context of a net-zero transition, we should expect to find significant coordination across

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[34] Resource planning has continued in these provinces as well, and in at least one case (Nova Scotia Power), the plan reviewed in this study may not be the most recent plan. We selected these cases because the planning process had been entirely completed, and for which we could review developments that followed afterward. While planning techniques and methodologies may continue to evolve, the broader findings concerning institutional capacity — and what are good practices to follow — to plan for net-zero, remain relevant.

electricity and natural gas planning processes, consideration of the economy-wide implications of resource strategies, and load forecasts that roughly align with the scale and pace of electrification suggested by net-zero pathway studies. Our review finds this not to be the case. With few exceptions, utility resource planning remains siloed by energy type, load forecasts generally fall short of electrification levels seen in other studies, and emissions reductions are not as seriously problematized as other core planning objectives.

Coordination

There is little formal coordination in resource planning across Canada's natural gas and electric utilities. In 2021, while BC Hydro and FortisBC were carrying out their respective integrated resource planning processes, the British Columbia Utilities Commission (BCUC) initiated a proceeding to encourage the utilities to coordinate and align their scenarios.[35] The utilities agreed to develop load forecasts in coordination across six scenarios from their respective energy plans. These included FortisBC's "Deep electrification," "Diversified energy," and "Economic stagnation" scenarios, which were roughly equivalent to BC Hydro's "Accelerated electrification," "Reference load," and "Low load" scenarios. The two utilities also are members of each other's technical advisory committees.

The exercise appears not to have led to meaningful impacts on each utility's respective plan – neither utility selected an electrification pathway for the basis of their action plan, and both utilities raised concerns regarding assumptions of alternative fuels (BC Hydro about hydrogen supply in FortisBC's planning; FortisBC about the low levels of renewable natural gas in BC Hydro's electrification scenario). In its final submission to the proceeding, FortisBC called for a more complete collaborative assessment before the province embarked on a single decarbonization pathway.

The framework for long-term energy planning in Ontario does not require any coordination between electricity and natural gas utilities. The last long-term energy plan was carried out by the Ministry of Energy in 2017, which issued implementation directions to the IESO and the Ontario Energy Board (which then were required to submit separate implementation plans to the Minister for approval).[36] While the IESO conducts annual bulk system planning, there is no comparable independent planner for

[35] BC Utilities Commission, Energy Scenarios for BC Hydro and FEI.

[36] Ministry of Energy, "Delivering Fairness and Choice: Ontario's Long-Term Energy Plan."

fuels or electricity distribution grids. The government described this approach as "bespoke coordinated planning" in a presentation to the Electrification and Energy Transition Panel in 2023, indicating less coordination than in BC.[37] In Quebec, Bill 69 was tabled in June 2024, which would make the Ministry of Energy responsible for conducting economy-wide, cross-fuel integrated resource planning.[38] Presently, Hydro Quebec and Energir carry out their supply outlooks independently.

Unlike most other provinces, Manitoba Hydro is responsible for the delivery of both electricity and natural gas and presented its 2023 IRP as a first effort to carry out planning across both energy sources.[39] Nevertheless, scenario-specific inputs for customer gas demand, gas transmission, and distribution infrastructure were not inputs in the optimization process. Instead, the interactions between electricity and natural gas were explored via the scenario assumptions and sensitivity analysis. Manitoba Hydro determined this was the "most feasible" approach, given it was the first IRP for both electricity and natural gas.[40] A basic assumption across scenarios is that the existing system can meet that future gas demand.

Resource plans are thus predominantly focused on specific energy types (i.e., either electric or natural gas) and offer a wide range of scenarios for the future of their respective provincial systems. While the general intent of these plans is similar – ascertain what the range of future needs could be and identify options to meet them – the specific approach of each utility varies. More often than not, the scenario that most closely aligns with the broad contours of the net-zero pathways discussed above is not selected as the basis for near-term action planning.

Energy and capacity

The resource plans reviewed for this report offer a wide range of scenarios. Scenarios are typically constructed by modifying a reference load or energy demand forecast (often produced annually by utilities) based on varying assumptions regarding trends in key inputs or uncertainties, usually identified through stakeholder consultation and informed by provincial and federal climate and energy policies. Resource portfolio

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[37] Collie, "Ontario's Clean Energy Opportunity: Report of the Electrification and Energy Transition Panel."

[38] Frechette, An Act to ensure the responsible governance of energy resources and to amend various legislative provisions.

[39] Manitoba Hydro, "2023 Integrated Resource Plan."

[40] Manitoba Hydro, 52.

modelling is run separately for each scenario, with system greenhouse gas emissions as an output and/or constraint in the modelling process.

Utility	Forecast coverage	Scenarios
BC Hydro, 2021 Integrated Resource Plan / 2023 Update	2020–2040	Four main scenarios, defined by assumptions about end-use consumption, electrification and EV adoption: Accelerated electrification (high load); Reference (mid-level); Low load; North Coast LNG & Mining.
FortisBC Energy, 2022 Long-term gas resource plan	2022–2042	Six scenarios: A 'price-based regulation' scenario, a 'deep electrification' case, an 'economic stagnation' case, the 'diversified energy' scenario, and upper and lower bound demand scenarios.
FortisBC, 2021 Long-term electric resource plan	2021–2040	Five scenarios: Upper and lower bounds; Deep electrification; Diversified energy; Distributed energy.
Manitoba Hydro, 2023 Integrated resource plan	2022–2042	Four scenarios, defined by assumptions on decarbonization and decentralization (i.e., 1. slow/slow, 2. modest/modest, 3. steady/modest, and 4. accelerated/steady).
Nova Scotia Power, Powering a green Nova Scotia, together: 2020 Integrated resource plan	2021–2045	Six "key" scenarios, defined by varying assumptions on GHG reduction and coal phase-out timelines, levels of electrification and DSM, and degree of regional integration: 1.0 Comparator; 2.0 Net-zero 2050-low electrification; 2.1 Net-zero 2050-mid electrification; 2.2 Net-zero 2050-high electrification; 3.1 Net-zero 2045-mid electrification; 3.2 Net-zero 2045-high electrification.
New Brunswick Power, 2023 Integrated Resource Plan: Pathways to a net-zero electricity system	2024–2043	Four main scenarios, defined by high/low electrification and moderate/rapid technological development, with 16 separate pathways across these scenarios.
AESO, Net-zero emissions pathways	2022–2041	Three scenarios: "Dispatchable dominant" (carbon capture and hydrogen); "First-mover advantage" (high

report*		renewables and moderate storage); “Renewables and storage rush” (highest renewables, high energy storage).
IESO, 2022 Pathways to decarbonization*; 2019–2024 Annual Planning Outlooks	2019–2050	Two scenarios: “Moratorium” (focuses on 2035, impact of moratorium on new natural gas generation); “Pathways” (focuses on 2050, and decarbonization of electricity system).

** The AESO and IESO Pathways studies are not resource plans per se but are included here to provide context on how planning is being carried out in these two provinces and contrast with the annual planning outlooks produced by the system operators.*

Table 2. Utility resource plans, timelines, and scenarios

As can be seen in the names of the scenarios listed above, electrification is universally understood to be a trend of primary importance. Economic/population growth, government decarbonization policy (e.g., limits on the use of fossil fuel generation, emissions reduction targets and carbon pricing, policies/mandates for building energy efficiency, etc.), growth in customer self-generation (i.e., decentralization or distributed energy resources), regional integration, and “technological development” (i.e., changes in availability and costs of certain technologies) were also common drivers of scenarios.

Most of the plans listed in the table above are based on a reference load forecast, which is modified by varying the key driver input assumptions (e.g., EV penetration, space/water electrification, etc) to produce different load scenarios. Exceptions include Manitoba Hydro and New Brunswick Power’s IRPs, which did not include an explicit “reference” load forecast, and for which scenarios are based more explicitly on certain technological assumptions (e.g., availability of SMRs in NB Power’s scenarios; customer behaviour in MB Hydro’s plan). Nevertheless, it is possible to roughly estimate the range in gross load forecasts (for both energy and peak demand) across all modelled scenarios for each plan.[41]

[41] It is difficult to ensure that load forecasts compared here are fully comparable (in terms of the scope of end-use, domestic versus total system requirements), and prior to the anticipated impact of demand-side management activities. Many utilities subtract some amount of DSM from their load forecasts prior to

Utility	Forecast length	Total growth, energy (percentage)	Total growth, capacity (percentage)	Est. annual growth rate, energy (percentage)	Est. annual growth rate, capacity (percentage)
BC Hydro	20 years	-4 - 55	-5 - 59	-0.2 - 2.2	-0.3 - 2.3
FortisBC (Electric)	20	21 - 113	45 - 141	1.0 - 3.9	1.9 - 4.5
Manitoba Hydro	20 years	21 - 100	13 - 151	1.0 - 3.5	0.6 - 4.7
Nova Scotia Power	24 years	21 - 41	30 - 65	0.8 - 1.4	1.1 - 2.1
NB Power	20 years	18 - 88	-2 - 36	0.8 - 3.2	-0.1 - 1.5
IESO	20 years (2022 APO); 28 years (Pathways)	41 - 80	39 - 128	1.7 - 2.1	1.7 - 3.0
AESO	20 years	6 - 23	9 - 35	0.3 - 1.0	0.4 - 1.5

Table 3. Summary of energy and capacity forecast range by utility resource plan

As this table demonstrates, the range of forecasted energy and peak demand requirements is generally quite broad across the scenarios considered by each utility. While the upper bound of some load forecasts (e.g., Manitoba Hydro, NB Power) approximate the total energy growth rates estimated by reviews of net-zero pathway studies (60 to 110 per cent), none approach the high-end growth estimate for capacity from the Canadian Climate Institute's survey, on either a total percentage growth (~240 per cent) or annualized growth rate (4.5 per cent) basis.

This data shows that few utilities include scenarios that forecast load requirements roughly in line with an electrified, net-zero future. However, these scenarios are typically not used as the basis for developing action plans. For example, the upper bound in FortisBC's electric IRP is constructed by only including drivers that would increase demand and are, as such, basically a thought exercise about the theoretical maximum

portfolio modelling. For these charts, we have endeavoured to estimate forecasted gross load, excluding impacts from yet-to-be implemented demand-side measures.

amount of load growth. System requirements in that plan's "deep electrification" scenario were less aggressive (67 per cent increased energy requirements, 98 per cent more capacity requirements). FortisBC's selected planning scenario ('Diversified') has approximately equivalent forecasted additional capacity requirements in 2040 (97 per cent) and slightly more expected energy requirements (75 per cent) than the electrification scenario.

The upper bounds in Manitoba Hydro's IRP are found in Scenario 4 – "accelerated decarbonization and steady decentralization." It is the only scenario the utility described as "trending toward" net zero by 2050, had the most aggressive assumptions about electrification and the lowest residual GHG emissions (though only marginally less than 'steady decarbonization, modest decentralization' Scenario 3, due to increased use of natural gas generation to provide capacity in Scenario 4).[42] It was also found to have considerably higher net system costs (electricity and natural gas combined) than Scenario 3, and Manitoba Hydro noted that it would be difficult to pursue due to the early requirements for additional energy and capacity and the long lead time of the projects it determined would be necessary to provide them.[43] Also of note: Scenario 3 and 4 were the only scenarios where assumptions about EV penetration were aligned with current federal mandates (and only for light-duty vehicles in Scenario 3).

More recent load forecasts tend to show continually increasing future requirements. Some utilities (BC Hydro, NS Power) have recently revised their IRPs to account in part for higher-than-expected load growth. The 2024 Annual Planning Outlook from the IESO estimates 75 per cent more electricity by 2050 (still less than the 80 per cent estimated in the 2022 Pathways to Decarbonization report), and Hydro Quebec forecasts the need for an additional 200 TWh of electricity by 2050. The 'Actions and Consequences' section below discusses these revisions and updates in more detail.

GHG emissions

As noted above, utility resource plans differ from net-zero pathway studies in several ways. In principle, a utility resource plan should minimally demonstrate compliance with government climate policy. However, regulators may need to only 'consider' policy objectives that are not present in legislation or regulation in their review of plans. In the absence of provincial GHG targets, especially for interim 'milestone' years or for the

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[42] Manitoba Hydro, "2023 Integrated Resource Plan," app. 3, p.12.

[43] Manitoba Hydro, app. 5, p. 5.

utility specifically, compliance thus occurs mainly in the input assumptions (e.g., coal phase-out dates, federal clean electricity regulation requirements). Even where provincial GHG targets exist, compliance can be achieved relatively painlessly if load growth forecasts are moderate. Also, utilities are generally not held responsible for delivering economy-wide emissions reductions, only for responding to anticipated energy/capacity requirements and addressing emissions from their system.

The consequence is that GHG impacts are not seriously problematized in the IRPs reviewed here, despite being reported as an outcome of scenario modelling in almost all plans, and more often, informally serving to bolster an argument in favour of the utility's preferred resource strategy. BC Hydro's IRP is the only one that did not report the GHG impacts of its preferred resource portfolio but did describe its "accelerated electrification" scenario as the scenario that is aligned with interim provincial GHG emission reduction targets.[44] The reference case, which forms the basis for the utility's action plan, is more conservative in its assumptions about load growth. FortisBC also did not report GHG impacts in its long-term electricity plan.

NS Power, NB Power, MB Hydro, and FortisBC Energy's long-term plans reported the GHG emissions implications of their scenarios. NS Power reported them for Scenarios 2.0c and 2.1c (the former of which was selected as the utility's preferred planning scenario) in the IRP, both characterized by coal phase-out by 2040, regional integration via the Atlantic Loop and low/mid electrification, respectively. Both scenarios "meet the GHG emission requirement," reducing emissions in the electricity sector from five to 1/4 MT by 2045 – equivalent to roughly a 72 per cent reduction in emissions from the plan's base year.[45]

There was very little differentiation between emissions impacts in NB Power's four main scenarios. Each exceeds the policy target of a 98 per cent reduction from 2005 levels by 2035, and only Scenario B (high electrification, moderate technological development) grows after that to approach the threshold again by 2043.[46] Notably, NB Power's scenarios all include a prominent role for nuclear SMRs (not modelled, but rather as

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[44] "2021 Integrated Resource Plan Application," chap. 5, p. 9.

[45] NS Power did model emissions results for all scenarios, which are contained in Appendix F to the 2020 IRP. Only the results for Scenarios 2.0c and 2.1c were discussed in the IRP itself. See Nova Scotia Power, "Powering a Green Nova Scotia, Together," app. F.

[46] NB Power, "2023 Integrated Resource Plan: Pathways to a Net-Zero Electricity System," 64.

scenario input assumptions) before 2035, so the emissions implications of SMRs not being available by this date are not considered in the primary analysis.

MB Hydro's IRP is unique in its consideration of something closer to 'economy-wide' emissions impacts, reporting on the emissions implications of their scenarios for stationary (non-electric) energy consumption, transportation, and electricity generation. While Scenario 4 has the most substantial emissions reductions in the first two categories, these are partially offset by the final plan year by growth in emissions from electricity generation (because of anticipated additional natural gas generation requirements associated with more widespread and aggressive electrification). Even still, Scenario 4 only achieves an approximate 40 per cent reduction in provincial GHG emissions from 2023 levels, ending at an annual emission output of 8 MtCO2e in 2041.[47] The case is explicitly made that, given much lower anticipated net system costs in Scenario 3 – but roughly equivalent net emissions reductions as in Scenario 4 – a less aggressive approach to electrification is the preferred scenario.

Both FortisBC's natural gas and electric IRPs emphasize the utility's proposed "clean growth pathway," represented by the "diversified energy" scenario in both plans.[48] In anticipation of a GHG cap on natural gas utilities in B.C. equivalent to 5.7MtCO2e for FortisBC by 2030, the natural gas plan includes some discussion of how that pathway meets these targets, hitting an annual emission level of about 4 MtCO2e in 2041 (roughly a 63 per cent reduction from base year). The modelling suggests that the diversified pathway exceeds the emissions reductions in the electrification scenario, principally due to reliance on RNG and other low-carbon gases in the former scenario.[49]

All of the utility IRPs reviewed for this study were produced prior to the federal Clean Electricity Regulations (CERs) coming into force (though the intention to develop such regulations was evident by the time the more recent IRPs were underway). Both NB Power and MB Hydro's IRPs recognize these impending policy developments. MB Hydro only notes that the CERs may restrict how the utility can operate existing and potential future natural gas generation stations. NB Power represents the impact of potential CERs by limiting unabated (i.e., no carbon capture and storage) thermal plants to a five

[47] Manitoba Hydro, "2023 Integrated Resource Plan," app. 5, pp. 15–16.

[48] "2022 Long-Term Gas Resource Plan Application"; "2021 Long-Term Electric Resource Plan and Long-Term Demand-Side Management Plan."

[49] "2022 Long-Term Gas Resource Plan Application," chap. 9, p. 4.

per cent capacity factor or less after 2035 and replacing the industrial output-based carbon pricing system with a simplified price on all carbon of $170/tonne.

The fact that most utilities are not modelling economy-wide energy system changes and that load forecasts generally fall short of the growth in energy and capacity expected by net-zero pathway studies suggests that emissions reductions are not core planning objectives of these plans. If they were, we would expect to see more rigorous consideration of the risks and uncertainties in managing emissions reductions that could be associated with preferred resource pathways.

Treatment of demand-side resources

Utility resource planning should treat all resources equally. Treating demand-side resources fairly has implications across the entire process of producing an integrated resource plan, from load forecasting to resource potential studies to expansion modelling and sensitivity analysis. Load forecasting, which is a key input in potential estimates and system modelling, should only include anticipated efficiency impacts from stock turnover and existing codes and standards – not efficiency improvements that can be changed by programs and policies and thus considered as an option in managing energy systems. Estimates of the market potential of energy efficiency should be limited only by non-financial market barriers, such as product availability or delivery infrastructure limits, and not by assumptions about customer willingness to adopt efficient technologies. Demand-side resource supply curves should reflect the unique qualities of these resources, showing the quantity of efficiency reliably obtained at a range of costs in sets of measures/groups with similar characteristics (e.g., load shapes).

On the general treatment of demand-side resources in utility plans, our review finds that most utilities do not include these resources as selectable within their modelling. There thus appears to be little, if any, interplay between demand-side resources and the other modelling input parameters or outputs (i.e., endogeneity), suggesting that the real potential benefits of demand-side resources (particularly at granular spatial or temporal scales) are not represented or captured by the analysis.

Basic methodology

Of the plans reviewed for this study, only Manitoba Hydro incorporated some energy efficiency as selectable and scalable resources in its capacity expansion modelling.

The plan began by extrapolating out Efficiency Manitoba's current planned savings over the 20-year planning horizon and subtracting these from their gross load forecast, with the assumption that these savings are fully realized. Then, based on the latest available efficiency potential study, two separate cases for selectable demand-side resources were created: a mid-level "enhanced" scenario and a maximized scenario. For both potential scenarios, Manitoba Hydro established two groupings of measures — one for heat pumps only and another for other efficiency measures, including distributed solar generation.[50] Only the higher maximized potential scenario was included in the analysis (based on total resource cost estimates), while the mid-level enhanced potential estimates were included in a sensitivity analysis. The heat pump measures were assumed to have zero contribution to winter peak demand, which was the peaking period Manitoba Hydro focused on in its analysis (province-wide). The heat pump measures were not included in the main scenario analysis, and thus, the electrification of home heating in the main scenarios was done via electric resistance heating.

Manitoba Hydro provided little information on the exact nature of the demand flexibility resources considered in its plan. Three broad classes of resources were noted (direct load control of EV charging and thermostats for residential, Interruptible rates/curtailment for commercial and industrial, and dynamic rates), but specific incentive or participation settings were not provided. The utility did not include any demand response options in its main scenario modelling, opting instead to modify load forecasts in sensitivity analysis.

The remaining studies did not incorporate energy efficiency as selectable in the modelling process. BC Hydro, FortisBC (electric) and Nova Scotia Power all followed a similar approach, using different levels of potential from recent potential studies to establish different demand-side scenarios, which were used as inputs during the modelling process. BC Hydro had four scenarios for energy efficiency (None, Base, Higher, and Higher+) and multiple settings for three different manifestations of demand response: time of use rates (none, voluntary, or default); EV peak reduction (with participation rates of zero per cent, 35 per cent, 50 per cent, and 75 per cent); and industrial load curtailment (available or not available).[51] The utility modelled a total of 33 resource portfolios under different configurations of energy efficiency and demand response assumptions (e.g., high energy efficiency with 50 per cent EV participation,

[50] Manitoba Hydro, "2023 Integrated Resource Plan," app. 2, pp. 29–33.

[51] "2021 Integrated Resource Plan Application," app. B, pp. 16–18.

voluntary rates, and no industrial curtailment). Only two of the 33 portfolios were based on the utility's "accelerated electrification" load forecast.[52]

While Nova Scotia Power followed a similar approach for including energy efficiency (i.e., running multiple scenario models under different assumptions of energy efficiency potential, subtracted from the input load forecast), they treated demand response as a resource option in the modelling process. Six different demand-response options were modelled, including direct load control, business/industrial load curtailment, behind-the-meter battery control, EV charging control, critical peak pricing, and behaviour demand response.[53] FortisBC's electric long-term plan also considered five different demand-side potential scenarios as inputs to their modelling process.

FortisBC's natural gas long-term plan has a different context than the electricity IRPs. The plan explains that since FortisBC doesn't construct its own natural gas 'generation' resources, its demand-side management resources are not weighed against the cost of alternative supply sources. Instead, its DSM analysis is intended "to establish adequate and cost-effective" levels of DSM, with consideration of the implications of downstream infrastructure deferral from peak demand savings.[54] The plan evaluated multiple DSM potential cases across the main scenarios based on incentive levels, economic screening results, and budget limitations.[55]

Within FortisBC's "diversified pathway" scenario, the inclusion of DSM was tailored to prioritize reducing conventional gas demand for GHG reductions instead of renewable natural gas or low-carbon fuels. The potential benefits of DSM in reducing requirements for these fuels were noted as something to consider in future long-term plans. As a result, the model curtailed DSM post-2030, as more alternative fuels became available with which the utility could meet emissions targets. While the utility included varying levels of EV charging shifting as an input assumption for modelling, it was at the time only piloting demand response programs and did not include them in its IRP.

NB Power's IRP noted that government policy has set a target of 0.75 per cent savings (of annual sales) by 2028/9 and assumes this target persists over the remaining planning period, subtracting the resulting energy savings from its business-as-usual and

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[52] "2021 Integrated Resource Plan Application," app. N, p. 6.

[53] Nova Scotia Power, "Powering a Green Nova Scotia, Together," 72.

[54] "2022 Long-Term Gas Resource Plan Application," chap. 5, p. 2.

[55] "2022 Long-Term Gas Resource Plan Application," chap. 5, p. 11.

electrification load forecasts.[56] The utility did not explicitly describe or identify any demand response resources used in its planning. The IESO's 2022 Annual Planning Outlook, while not an integrated plan per se, subtracted estimates of future demand-side programs and codes and standards from its initial load forecast.[57] Estimates for demand-side resources were based on observed historical trends. The AESO Planning Report only incorporates general efficiency factors in its economic growth input assumptions, based on historic energy efficiency gains obtained in the absence of active demand side management initiatives.[58]

Demand-side resource potential and impacts

Most utilities use estimates of demand-side resource potential drawn from potential studies, often conducted separately from their integrated resource planning. It was not within the scope of this study to conduct a comprehensive and in-depth review of utility potential studies for all the cases examined here. Furthermore, some utilities do not make their potential studies public. Nevertheless, the potential of demand-side resources depends greatly on how utilities treat the costs and benefits of these resources, as well as the load forecasts on which they were based.

Estimates of demand-side resource potential typically include three variations: technical potential, economic potential, and market potential (sometimes referred to as 'achievable' potential). Technical potential is a theoretical maximum, assuming all applicable baseline measures are immediately replaced with the efficient alternative, regardless of turnover, costs or market acceptance. Economic potential introduces a cost-effectiveness screen to rule out measures that fail to meet it. Cost-effectiveness tests vary in form but generally involve dividing the present value of avoided costs (i.e., benefits, like deferred infrastructure investments) by some measure of costs (i.e., to the utility or to customers as well). Finally, market potential introduces further variables, such as natural turnover rates, incentive levels, or consumer willingness to adopt efficient technologies, as well as elements that might increase potential, like 'word of

[56] NB Power, "2023 Integrated Resource Plan: Pathways to a Net-Zero Electricity System," 33.

[57] Independent Electricity System Operator (IESO), "Annual Planning Outlook: Demand Forecast Module."

[58] AESO, "2021 Long-Term Outlook," 5.

mouth' effects that improve customer awareness, or the success rate of marketing activities.[59] Cost-effectiveness screening is also conducted in market potential analysis.

Our research suggests that most (if not all) utilities use the Total Resource Cost (TRC) test to screen demand-side measures in estimating economic and market potential. This includes BC Hydro, FortisBC, Manitoba Hydro, and Nova Scotia Power (we could not acquire a potential study for New Brunswick). The TRC consists of the incremental cost to the customer in the denominator of its analysis, in addition to the cost of the incentive provided to the customer by the program administrator. This is, in effect, bringing a non-utility cost into an analysis that is supposed to be focused on minimizing utility system costs, treating the fact that efficiency programs leverage private spending as a penalty, not a benefit, in the acquisition of resources.

On the benefits side, we were not able to find transparent information on avoided costs used in cost-effectiveness testing for any utility reviewed here. The relative separation of potential studies and integrated resource plans, coupled with the exclusion of demand-side resources from capacity expansion modelling, suggests that avoided costs from deferred investments in infrastructure or other resources are not a direct output of the resource planning itself. This means the costs and benefits used to estimate economic potential could be out of date or needlessly truncated. Indeed, in the case of Nova Scotia Power's potential study, estimates of avoided costs for generation and energy were drawn from the preceding, 2014 integrated resource plan, with estimated updates for transmission and distribution infrastructure from 2018.[60]

The potential of demand-side resources is generally presented as cumulative savings over the planning period, reaching a total savings amount in the terminal year. In most cases reviewed here, utilities used varying levels of market/achievable potential as input assumptions to modify the load forecast. As such, the range in cumulative impacts of energy efficiency and demand-response measures in the final year of the resource plan is largely fixed by the demand-side potential scenarios used as inputs.

In BC Hydro's IRP, demand-side resources contribute between 1,731 GWh in the 'Base' efficiency potential case (though some portfolios included no DSM at all) and 4,679

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[59] Navigant Consulting, 2019. "Nova Scotia Energy Efficiency and Demand Response Potential Study for 2021-2045", p. 52.

[60] Navigant Consulting, 2019. "Nova Scotia Energy Efficiency and Demand Response Potential Study for 2021-2045", p. 97.

GWh of energy in the 'Higher+' case.[61] Demand response varies based on the specific assumptions tested but ranges between 913 MW and 1,735 MW. These results are equivalent to an approximate range of 3.8 per cent to 5.6 per cent in energy savings (between the combinations of Base DSM potential scenario / low load forecast scenario and the Higher+ DSM potential scenario / Accelerated Electrification scenario) and 9.4 per cent to 10.1 per cent in capacity savings in 2040.[62]

Nova Scotia Power's approach to modelling resource portfolios was similar to BC Hydro's, though demand response options were selectable. Total market potential of energy efficiency ranged from 2,100 GWh and 375 MW in the 'Low' efficiency scenario to 3,450 GWh and 600 MW in the 'Max' scenario. This is approximately equivalent to a range of 15 per cent to 20.6 per cent energy savings and 13.5 per cent to 16 per cent capacity savings by 2045 (between the Low DSM / Business-as-usual load forecast and Max DSM / estimated high electrification load forecast combinations). Selected demand response ranged from 80 MW to 105 MW in 2027.[63]

There was little variation in total energy and capacity savings across NB Power's scenarios and FortisBC's electric scenarios. NB Power's assumptions ranged from 2,113 GWh and 466 MW savings in Scenario C (both 12 per cent of 2043 gross load) to 2,666 GWh and 595 MW in Scenario B (9.7 per cent and 12.4 per cent).[64] In FortisBC's electric plan, DSM contributions account for between 421 GWh / 61.6 MW energy and capacity savings in the 'Low' DSM scenarios, and 503 GWh / 72.7 MW in the 'Max' scenarios, equivalent to 9.7 per cent / 6.4 per cent and 8.3 per cent / 5.5 per cent of load requirements in the Low and Deep Electrification scenarios, respectively.[65] On the natural gas side, the 'High' energy efficiency savings in the Diversified scenario account

[61] See Appendix N for a summary of the resource optimization modelling portfolios, and Appendices N-1 through 33 for the results.

[62] It is possible that no portfolio modelled tested these exact parameters. Only two portfolios tested the low load growth scenario, but both assumed 'Higher' levels of DSM. Similarly, only two portfolios tested the accelerated electrification load growth scenario, both of which assumed 'Higher+' levels of DSM. A combination of higher load forecast with low or no DSM would obviously yield different results.

[63] See Nova Scotia Power, "Powering a Green Nova Scotia, Together," app. K.

[64] NB Power, "2023 Integrated Resource Plan: Pathways to a Net-Zero Electricity System," app. B.

[65] "2021 Long-Term Electric Resource Plan and Long-Term Demand-Side Management Plan," 151–52.

for a 13 per cent reduction in demand in 2042, while the 'Medium' DSM delivers an eight per cent reduction.[66]

The IESO's 2022 Annual Planning Outlook estimates a total of 24.2 to 26.5 TWh in annual savings over the outlook period (roughly equivalent to 11.3 per cent of gross demand in 2042). Savings from energy efficiency programs plateau after 2024 and decline through 2042 to 10.4 TWh, which is attributed to the 'decay' of savings from previous conservation frameworks over time.[67] Savings from codes and standards are estimated to account for 15.8 TWh in 2043. It is not possible to ascertain the impact of energy efficiency in the AESO's planning outlook.

Only Manitoba Hydro made both energy efficiency and demand response measures directly available in system modelling. The cumulative impacts of these resources differed from the estimated maximum potential, as no scenario in the IRP selected all energy efficiency and demand response options available to the model but did select some above the legislated target savings.

The total market potential of demand-side resources in Manitoba Hydro's IRP varied slightly across scenarios. In scenarios one through three, the total potential energy savings in 2042 was estimated at 4,750 GWh, but 6,000 GWh in scenario four. The 'base DSM' assumed to be realized (based on current Efficiency Manitoba targets) was 3,590 GWh. Savings above the base level acquired by the model ranged from 201 GWh in scenario one to 1,772 GWh in scenario four – equivalent to a range in energy savings of 3,791 to 5,362 GWh, thereby reducing annual demand in 2042 by between 13.6 per cent in scenario one to 11.7 per cent in scenario four. These figures exclude any potential energy savings from the selectable heat pump groupings, which were only included in a sensitivity analysis.[68] While figures for total market potential capacity contribution from demand-side measures were not provided, the model selections resulted in a range of 1,300MW to 1,600MW in scenarios one and four respectively (equivalent to 25 per cent and 14 per cent of total system requirements in 2024 in those scenarios).[69]

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[66] "2022 Long-Term Gas Resource Plan Application," chap. 5, pp. 14–15.

[67] Independent Electricity System Operator (IESO), "Annual Planning Outlook: Demand Forecast Module," 20.

[68] Appendix 5, page 9-10.

[69] Appendix 5, page 6.

Organization	Energy low	Energy high	Capacity low	Capacity high
NS Power	15%	20.6%	13.0%	16%
BC Hydro	3.8%	5.6%	9%	10.1%
IESO	n/a	11.3%		
NB Power	9.7%	12%	12%	12.4%
MB Hydro	11.7%	13.6%	14%	25%
FortisBC (Electric)	8.3%	9.7%	5.5%	6.4%
FortisBC (Natural Gas)	Unknown	13%	n/a	n/a
Average	**10%**	**12%**	**11%**	**14%**

Table 4. Summary of impact of demand-side resources

Table 4 above summarises the cumulative impact of demand-side resources against total final demand across the plans reviewed above in the final year. On average, demand-side resources contribute between 10 and 12 per cent of expected energy requirements and 11 per cent and 14 per cent of expected capacity requirements across the most conservative and aggressive load forecast scenarios in each plan. While this is far short of the estimated 28 per cent in demand reductions through efficiency suggested by national net-zero pathway studies, the impacts in resource plans are not economy-wide.

However, the methodology used to estimate potential and to incorporate demand-side resources into system modelling suggests potential is being systematically underestimated. First, few utilities model demand-side resources in the capacity expansion modelling. As such, these resources do not have a chance to influence (or be influenced by) developments in the model. Second, the costs and benefits of these resources are thus disconnected from what is happening in capacity expansion and are determined by preceding analysis that may be using outdated assumptions about energy or capacity value or the costs of transmission or distribution infrastructure.

Third, demand-side measures are generally screened using a TRC cost test, including the costs to consumers (a non-utility cost), which has no bearing on minimizing utility system costs.

Risk management

The final stages of an integrated plan tests sensitivities on scenario parameters, resource portfolios and other input assumptions. There may also be some comparative evaluation of different resource portfolios or scenarios that meet planning objectives in different ways. The result is an action plan highlighting the utility's near-term actions to ensure its objectives are met. These steps are critical to how utility planning manages risks inherent in an energy system transition.

In this final section, we review how utility resource planning practices in Canada incorporate and manage risk in sensitivity analysis. We also look at the criteria utilities used to arrive at their preferred planning scenario; the action plans they put forward, and developments since the plan was completed that have led some utilities to revise their strategy.

Our analysis finds that, in testing sensitivities around resource availability or capacity, utilities typically take a deterministic approach that fixes conditions with perfect foresight and little interplay with modelling (e.g., low versus high fuel costs). This is particularly true of supply-side resources, which may be available or not. In selecting preferred scenarios for decision-making, utilities often put forward many evaluation criteria but appear to be guided principally by objectives to reduce net system costs and short-term rate impacts – in no case did a utility select an electrification-focused scenario for action planning. Finally, recent developments in British Columbia, Ontario, Nova Scotia and Quebec highlight that planning for business-as-usual and relying on large, supply-side solutions is not a strong risk management approach in an energy transition context.

Sensitivity analysis

Utilities' primary way of managing risks associated with their plans is to conduct sensitivity analysis, though each utility approaches this somewhat differently. In principle, any plan that consists of multiple scenarios is already conducting some form of sensitivity analysis to evaluate what could happen under different assumptions and input settings. A plan that produced only one load forecast and one run of an optimization model would not have incorporated any uncertainty.

BC Hydro and Nova Scotia Power's plans followed a similar approach, wherein different combinations of input assumptions were used to produce a plethora of portfolios, and the optimization model was then used to solve. Consequently, while the table above lists only a handful of scenarios in each IRP, both plans were modelled over 30 different sets of assumptions. It is through the construction of these portfolios that BC Hydro and Nova Scotia Power tested the implications of some load, resource availability, policy, and market uncertainties.

For example, different portfolios in Nova Scotia Power's IRP could model the implications of whether regional integration was available or whether future needs would need to be met without new interconnections. Different portfolios in BC Hydro's modelling tested varying availability of renewing power purchase agreements. In both IRPs, further sensitivity analysis was conducted by imposing conditions – for example, assuming under-delivery of energy efficiency in BC Hydro's case or modelling lower wind and battery costs in Nova Scotia's IRP. Finally, levels of energy efficiency were another input assumption used to create portfolios, drawing from different levels of potential identified in recent potential studies. In Nova Scotia Power's IRP, the full range of DSM sensitivities was only explored for the low electrification scenarios.[70]

To inform its testing of sensitivities around demand-side resource performance, BC Hydro developed subjective probability distributions for energy and capacity savings for a year mid-way through its planning period (2030) based on program manager experience and a Monte Carlo simulation.[71] The result was a curve relating savings levels to a probability the utility would achieve that amount of less. BC Hydro's analysis found a 10 per cent chance of achieving 1050 GWh/yr or less and a 90 per cent chance of achieving less than 2200 GWh/yr. BC Hydro converted these into scaling factors to define "low performance" (i.e., the 10 per cent level), and "mid-performance" (the average of the middle section).[72]

A similar approach was used to estimate capacity savings from efficiency programs, demand response initiatives, and EV charging peak reduction initiatives. These were

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[70] Nova Scotia Power, "Powering a Green Nova Scotia, Together," app. K, p. 5.

[71] "2021 Integrated Resource Plan Application," app. M.

[72] "2021 Integrated Resource Plan Application," app. M p. 4.

combined to estimate an uncertainty band incorporated in BC Hydro's "contingency resource plans" (i.e., the scenarios/portfolios that used either accelerated electrification or low load forecasts) to test the impact of low performance on DSM. As BC Hydro notes, "the increasing uncertainties associated with ramping up demand-side measures was one of the considerations for not pursuing more savings from demand-side measures at this time."[73]

The scenario construction/sensitivity analysis approach used by Manitoba Hydro and New Brunswick was somewhat different. Rather than identifying a set of core inputs with different settings to produce a long list of portfolios to model capacity expansion, as was done by BC Hydro and Nova Scotia, Manitoba Hydro and NB Power established a handful of scenarios first and tested sensitivities (i.e., different assumptions) across them. The electric and natural gas IRPs from FortisBC followed a similar approach. In the natural gas IRP, FortisBC conducted some sensitivity analysis around different levels of DSM for the "diversified energy" scenario, producing cost-effectiveness results and conducting rate and bill impacts for each level of DSM.

Manitoba Hydro's sensitivity analysis was more comprehensive than NB Power's. Manitoba Hydro tested a range of sensitivities across four main categories: natural gas sensitivities (e.g., restricted use, requiring carbon capture and storage, no new turbines); a variety of demand-side sensitivities; energy prices and market interactions; and 'other' (climate change policy, availability of renewables, adoption rate of electric vehicles).[74] NB Power considered only three special conditions, all related to resource availability: not retiring the Mactaquac hydropower station, not including small-modular reactors, and a final condition where the Atlantic Loop is available.[75]

As Manitoba Hydro's IRP was the only one in which demand-side resources were included in optimization modelling, their approach to testing sensitivities around energy efficiency and demand response is worth discussing in more length (all other utilities just vary the level of DSM through modifications to the load forecast input). Several sensitivities were tested: availability of demand response (which was not modelled; load forecasts were modified); the availability of dual fuel heating systems; making all energy efficiency selectable by the model (in the main scenarios, current policy targets are assumed to be met for the duration of the planning period); requiring full

[73] "2021 Integrated Resource Plan Application," app. M p. 12.

[74] Manitoba Hydro, "2023 Integrated Resource Plan," apps. 5, Section 3.

[75] NB Power, "2023 Integrated Resource Plan: Pathways to a Net-Zero Electricity System," sec. 12.

development of all energy efficiency potential; adding ground and air source heat pump profiles as selectable resources in optimization; and, finally, testing the implications of the “enhanced” scenario for energy efficiency (lower than the “maximized” level used in the main scenarios).

The original Scenario 4 (the high electrification scenario) assumed all resistance heating for electrification. Incorporating dual fuel heating systems thus substantially reduced annual electricity system costs (by 19 per cent), even as the consumer cost of the heat pumps was included in the estimation of system costs. When Manitoba Hydro made all energy efficiency resources available to the model (including the policy target levels assumed previously), it found the model adopted less efficiency across all scenarios than initially, and the model did not always select some measures (e.g., lighting). While forcing the full realization of all efficiency resources did reduce the need for natural gas, the analysis found cumulative net present value to be within 0.5 per cent difference from the original scenarios. Including ground source and air source heat pump measures in the optimization, modelling did not materially change the resource mix for any scenario. For its demand response and energy efficiency sensitivities, Manitoba Hydro noted it could not determine if the benefits in those analyses were due to something in the capacity expansion model and that further work would be required to “isolate” the benefits of these demand-side resources.[76]

Regardless of the slight difference in approaches to scenario construction, most utilities have taken a deterministic approach to testing sensitivities — varying input assumptions with more or less perfect foresight and letting the model optimize the resource portfolio accordingly. Assessment of supply-side resource risk is particularly blunt — a resource is either available or it is not; there is little explicit consideration of the risk that it may not be available at the time the model needs it or that its costs may be higher or lower than expected (with some exceptions), or that its capacity factor may be lower than expected. (Note: we did not review any sensitivity analysis utilities may have conducted for renewable generation).

Assessment of DSM-related sensitivities was also largely carried out deterministically, using varying potential levels as input assumptions. However, the number of sensitivity scenarios for demand-side resources (including low or underperforming scenarios) was relatively high. The exceptions were BC Hydro, which carried out a thorough probabilistic analysis of demand-side resource uncertainty, and MB Hydro, which ran

[76] Manitoba Hydro, “2023 Integrated Resource Plan,” app. 5, pp. 36, 44.

several modelling scenarios for different selectable energy efficiency portfolios. At least in the case of BC Hydro's IRP, it is not clear that all supply-side options were subjected to a similar degree of scrutiny.

It is worth noting that while resource risks are valid for demand-side resources, the risk of underperforming demand-side portfolios is of a different character than far larger, less flexible supply-side projects – if utilities fail to achieve demand-side targets due to customer participation, they might have also avoided spending out of its incentive budget (yet it might have spent on administration and marketing). So, while underperforming demand-side initiatives may require the utility to revise its broader resource plans, the direct financial risk could be minimal. Underperforming in energy savings is not necessarily equivalent to a cost overrun. Furthermore, demand-side resources are far more flexible, targetable to specific locations, and composed of many measures. The risk of falling short of planned targets is not as 'all-or-nothing' as it may be for supply-side projects.

Decision-making

Ultimately, producing scenarios, resource portfolios, and sensitivity analysis aims to compare results and draw conclusions about the best course forward. From those conclusions, the utility produces a near-term action plan (discussed in the following section). This evaluation/decision-making process is not always explicit but typically involves qualitative assessment and judgment.

Both BC Hydro and Nova Scotia Power clearly explained their methods for comparing amongst scenarios. BC Hydro's evaluation was guided by four overarching "decision objectives": keeping costs low for customers, limiting land and water impacts, reducing GHGs, and supporting the economy's growth. Keeping costs low implied minimizing net total resource and net utility costs, minimizing cost risk from demand-side measure under-delivery (measured as MW below 2030 planned estimates), minimizing cost risks from transmission upgrade uncertainty, minimizing rate impacts, and maximizing the ability for all to benefit from a rate.[77]

Based on these factors, BC Hydro then conducted a trade-off analysis between different levels of its primary portfolio resource variables (e.g., levels of DSM, renewals of power purchase agreements) using "consequence tables." This was not done for decisions

[77] "2021 Integrated Resource Plan Application," app. B, p. 25.

regarding renewing natural gas purchase agreements (assumed not to be renewed), transmission upgrades, and existing or future BC Hydro generating resources.

ABOUT THIS TABLE

Each column corresponds to a portfolio, or a bundle of resource options. Each portfolio was created by selecting a specific level of energy efficiency and then letting the optimization model fill in the rest of the resource choices. The table shows the consequences, or impacts, of these different portfolios on identified objectives and measures. Choosing one portfolio as a base of comparison against the alternatives lets us identify where a portfolio performs better or worse than the base for each objective (colour-coded for ease of reference).

Legend

- This portfolio is used as the basis of comparison
- This alternative is worse than the base portfolio
- This alternative is better than the base portfolio
- This alternative is roughly the same as the base portfolio

Planning Objective (measure)	What is better	No energy efficiency	Base energy efficiency	Higher energy efficiency	Higher plus energy efficiency
Net Total Resource Cost ($M PV)	Lower	$2,510	$1,280	$680	$110
Net Utility Cost ($M PV)	Lower	$2,510	$1,630	$1,410	$1,210
Cost risk from DSM under-delivery* (MW below plan by 2030)	Lower	0	80	130	140
Cost risk from transmission schedule uncertainty* (year in service, Step 1)	Later	2032	2032	2033	2033
Cost risk from transmission schedule uncertainty* (year in service, Step 2)	Later	2036	2037	2038	2039
Rate Impact (% change in F2030)	Lower	-1.0%	0.0%	1.0%	1.8%
Rate Impact (% change in F2041)	Lower	-0.8%	0.0%	1.5%	3.8%
Land and Water Impacts (Index)	Lower	5.0	3.5	2.7	1.5
Economic Development (provincial gross FTEs, annualized)	Higher	4,040	4,030	4,060	4,510

*These are not represented in dollars as they are a proxy for cost risk, not an assessment of financial risk.

Figure 2. BC Hydro's energy efficiency consequence table[78]

[78] "2021 Integrated Resource Plan Application," app. B, p. 33.

The figure above shows the consequence table BC Hydro created to evaluate which energy efficiency portfolio best fits its decision objectives. The “Higher” level was chosen as the comparator. Despite Higher and Higher plus exceeding the Base level portfolio on every parameter aside from under-delivery risk and rate impacts, BC Hydro chose the Base portfolio for its resource plan. The reasoning BC Hydro provided in the IRP was that there was little material difference between the Base and Higher plans until later in the planning period, and opting for the Base plan would minimize rate impacts while reserving the capacity to ramp up in the future if needed.[79]

Similarly, Nova Scotia Power evaluated scenarios on the basis of minimization of cumulative net-present value revenue requirements, rate impacts, reliability and supply adequacy, grid services, plan “robustness” (i.e., the ability of the plan to withstand plausible changes to assumptions, tested through sensitivity analysis), GHG reductions, and flexibility (i.e., a qualitative assessment of the timing of investments). When comparing the DSM sensitivities, the utility found that the Base profile was more economic (in terms of both the 25-year NPV revenue requirement and relative rate impact) than either the Mid or Max levels across all scenarios, though higher DSM levels resulted in earlier coal retirement, less new-built gas capacity, and lower CO2 emissions.[80] The analysis also found that higher levels of electrification mitigated rate impacts due to higher sales compensating for higher fixed system costs and that regional integration was a common component of lowest-cost portfolios. Consequently, Nova Scotia Power selected Scenario 2.0C (low electrification, regional integration, Base DSM, and an emissions target of net zero by 2050) as its preferred planning scenario.

Nova Scotia Power provided a summary of stakeholder consultation and feedback for each stage in the appendices to its IRP, and some stakeholders raised concerns about aspects of the analysis and decision-making as it pertained to risks.[81] For example, EfficiencyOne suggested more assessment of risks associated with large capital investments, such as a regional intertie, which NS Power noted was outside the scope of the IRP. They also noted that the rate impact analysis NS Power undertook differed substantially from the “more mature” Rate and Bill Impact assessment model in active use in Nova Scotia. Finally, EfficiencyOne raised several concerns about the approach

[79] “2021 Integrated Resource Plan Application,” app. B, p. 35.

[80] Nova Scotia Power, “Powering a Green Nova Scotia, Together,” 99.

[81] See Nova Scotia Power, app. M.

to estimating avoided costs of transmission and distribution infrastructure associated with DSM, arguing that these should be determined as part of the IRP process. NS Power noted that "as a generation-focused modelling exercise," the IRP did not specifically evaluate the optimization of such investments and that — upon approval by the utility board — the utility would use its preferred plan to calculate updated avoided costs for energy and capacity.

The analysis and decision-making Manitoba Hydro undertook as part of its IRP did not lead to the selection of a preferred scenario but was guided primarily by finding the lowest cost solution that met firm capacity and dependable energy needs. Costs were assessed as net system costs, excluding financing costs for new capital spending. They note that certain further analyses could be conducted on model outputs – for example, social or environmental impacts, or quantitative risk analysis on resource cost uncertainties, construction timelines, or policy that limits resource options – but that these did not align with the "high-level scope" of the IRP.[82] The "learnings" identified by Manitoba Hydro were generally quite high-level observations about energy transitions, the need for investment across all scenarios, and uncertainty around pathways forward. Managing peak demand was noted to be of particular importance, and leveraging existing natural gas assets was identified as a cost-effective way to do this. Energy efficiency investments that reduce peak demand were identified as most valuable to the system.[83]

Similarly, NB Power did not select one of its scenarios as preferred, but instead based its decisions and actions on minimizing system cost revenue requirements and reducing GHGs. Analysis of the three sensitivities reinforced the initial assumptions around these resources – continuing to include the Mactaquac station helped reduce costs associated with the integration of renewables, and excluding SMRs would increase risks associated with levels of intermittent generation from renewables the utility was not experienced with (though NB Power notes that the costs of SMRs are a "significant unknown").[84] Reliance on the Atlantic Loop, the utility found, would lead to higher system costs across all scenarios, mainly due to the expected capital and

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[82] Manitoba Hydro, "2023 Integrated Resource Plan," 52–53.

[83] Manitoba Hydro, 87.

[84] NB Power, "2023 Integrated Resource Plan: Pathways to a Net-Zero Electricity System," 78.

operating costs of the project and diminishing returns beyond the existing import capacity in the province.[85]

The above review shows that the rigour and transparency with which utilities evaluate and make decisions based on the results of analysis are not consistent across the cases examined. These IRPs are highly complicated, technical exercises, and decision-making parameters and critical data are not always clearly specified or made public. Consequently, it can be difficult to ascertain whether the scenario construction and sensitivity analysis addresses the full range of available pathways, or restricting the set of portfolios to lead to preferred results.

That said, there appears to be more consideration of downside risks associated with demand-side resources in several IRPs reviewed here than there is for other supply-side alternatives or for the implications of electrification and required transmission and distribution infrastructure. Furthermore, consideration of rate impacts (in the absence of bill impacts) provides only one-half of the picture and biases evaluation to short-term costs, not long-term benefits.

Actions and consequences

The final step of an IRP is to develop an action plan based on the analysis and evaluation of competing scenarios through the lens of the chosen decision-making objectives. Sometimes, this step also involves identifying signposts that could trigger a change in plans. While none of the IRPs reviewed here serve as formal resource acquisition applications, the direction of actions and signposts nevertheless indicate how the utility is managing risks, particularly business risks. Given that several of the IRPs reviewed for this report date back three years or more, this section will also review recent developments regarding resource planning that occurred post-publication of the final IRP.

Updates have already been made to both BC Hydro and NS Power's 2021 and 2020 IRPs. In BC Hydro's case, the update to the 2021 IRP was triggered by a revised load forecast in April 2023, before the original IRP had been approved by the provincial regulator.[86] The revised forecast anticipated both a higher load after 2030 than originally expected (mainly industrial and commercial load) and reduced energy and

[85] NB Power, 82.

[86] BC Hydro, "2021 Integrated Resource Plan: 2023 Update."

capacity contributions from existing or planned resources (primarily reduced generation from biomass owing to fuel supply risks). Consequently, BC Hydro revised its action plan to accelerate and expand its earlier resource strategies (including advancing the ramp-up from Base to Higher energy efficiency levels and retaining Higher+ levels for future years) and to move toward a new "living" long-term plan cycle with more regular filings. The revised IRP was approved by the BCUC on March 6, 2024.

In NS Power's case, one of the actions identified in the original plan was to move to an "evergreen" IRP process with more frequent updates and revisions. This was prompted in part by the provincial government introducing a policy in October 2021 to phase out coal power by 2030 (in 2020 IRP selected scenarios, coal was not phased out until 2040).[87] The utility initiated this process in 2022 and produced an updated plan in August 2023, with a number of changes to input assumptions, scenarios modelled, and the action plan.[88] While the 2020 IRP chose a low electrification scenario as its reference, the 2023 plan used updated load forecasts more in line with the original "mid" electrification scenario until 2030, and "high" electrification thereafter. The 2023 plan also included a new "hybrid peak mitigation" scenario, which tested the implications of hybrid heat pump-heating oil space heating, as well as modified "Base+" and "Modified-Mid" DSM assumptions, with increased potential over the original Base and Mid portfolios (though both were found to lead to higher system costs than the original Base portfolio).

FortisBC Energy's natural gas IRP was approved by the BCUC on March 20, 2024.[89] In it, the panel raised some concerns about the utility's "Clean Growth Pathway" (i.e., the diversified energy scenario), noting that the pathway is based on assumptions and assertions for which there is no certainty the future will unfold consistent with, and thus might not represent the lowest-cost pathway to reducing GHG emissions. The panel also recognized that, while there was some merit to the utility's arguments about a diversified energy future being resilient, there were conceivable alternative future energy system arrangements that would also provide resiliency (e.g., higher penetration of distributed generation, energy storage). A "full-scale commitment" to the Clean Growth Pathway might not be in the public interest at this point. The panel also noted that resiliency itself is not a stated policy objective, and thus, it was not able to make

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[87] Province of Nova Scotia, Environmental Goals and Climate Change Reduction Act.

[88] NS Power, "2022 Evergreen IRP: Updated Assumptions."

[89] "FortisBC Energy - 2022 Long-Term Gas Resource Plan - Decision and Order."

determinations regarding the relative importance of resiliency against GHG reductions or electrification pathways.[90]

In the decisions on BC Hydro's IRP and FortisBC Energy's natural gas IRP, there is some discussion of the need for collaboration between the utilities in future long-term planning exercises. As noted above, the BCUC called on the utilities to explore coordination earlier in this planning cycle, which highlighted the difficulties in bringing resource plans into closer alignment. In both decisions, the panels conclude that the level of collaboration sought by some intervenors to facilitate deep decarbonization would be resource-intensive and require considerable changes to both utility's models, assumptions and inputs. Furthermore, they note that "the BCUC cannot force the utilities to agree upon any given view of the future" and that they do not wish to be overly prescriptive on an issue that is more in the domain of government.[91] The ruling did support more coordination between BC Hydro and FortisBC on input assumptions common to each planning process in future IRPs, including customer growth rates, volume of fuel switching, low/zero carbon fuels facilities, and capture rates for new customers for major end-uses (such as space and water heating).

Both NB Power and MB Hydro's IRPs are more recent, and neither needed to be submitted to or approved by the provincial regulatory boards. The other two cases that received some attention in this report (the AESO and IESO annual planning activities) are not IRPs and are also not reviewed or approved by provincial regulators. However, in the latter case, some recent developments pertaining to resource planning are worth noting.

Budgets for electric demand-side management are formally set by the provincial government in Ontario, albeit in consultation with the IESO. The IESO's current conservation and demand-management plan began in January 2021 and runs to December 2024. Mid-way, the IESO conducted a review of the plan, drawing from updated load forecasts (which have steadily increased since 2019 but have yet to reach the levels estimated in the IESO's own "Pathways to Decarbonization" report).[92] As a result of the mid-term review and in recognition of the increasing load forecasts, the

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[90] "FortisBC Energy - 2022 Long-Term Gas Resource Plan - Decision and Order," 48.

[91] "British Columbia Hydro and Power Authority ~ 2021 Integrated Resource Plan ~ Final Order," 29.

[92] Independent Electricity System Operator (IESO), "2021-2024 Conservation and Demand Management Framework Mid-Term Review."

government increased the overall budget of the 2021-2024 plan by approximately 50 per cent.[93]

The government convened an Electrification and Energy Transition panel in 2022, which issued a report to the government in December 2023. Among other recommendations, the panel called upon the government to conduct integrated, long-term energy planning on a regular cycle to provide clear guidance and policy direction to regulators and utilities across the electric and natural gas systems, as well as on conservation and demand management.[94] In October 2024, the government released a series of consultation processes in response, including a proposed 12-year electricity demand-side management framework, proposed amendments to allow the IESO to offer beneficial electrification programs, and a proposed integrated energy resource planning process.[95] These policy developments were framed in part as a response to the latest Annual Planning Outlook from the IESO, which forecasted electricity demand 75 per cent higher by 2050.

Other provinces are beginning to recognize the implications of a net-zero transition for resource planning as well. According to Hydro-Quebec's most recent long-term forecasts of energy requirements, the utility estimates it will need an additional 150-200 TWh to meet electricity demand by 2050 — twice the electricity demand of 2023.[96] The utility released its "Action Plan 2035" in November 2023, outlining its priorities over the coming decade.[97] Under this plan, in recognition of the large increases in future demand, Hydro-Quebec committed to doubling its energy savings targets, aiming for 21 TWh of cumulative energy savings and freeing up 3,500 MW of capacity by 2035. In July 2024, the province introduced Bill 69, which would substantially change the resource planning practices in Quebec. Included in the bill are provisions to make the provincial

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[93] Independent Electricity System Operator (IESO), "Update to 2021-2024 Conservation and Demand Management Framework Program Plan."

[94] Collie, "Ontario's Clean Energy Opportunity: Report of the Electrification and Energy Transition Panel."

[95] Ontario Ministry of Energy, "2025–2036 Electricity Energy Efficiency Framework"; Ontario Ministry of Energy, "Integrated Energy Resource Plan Consultation"; Ontario Ministry of Energy, "Proposed Amendments to the Electricity Act, 1998, Ontario Energy Board Act, 1998 and the Energy Consumer Protection Act, 2010 to Enable an Affordable Energy Future."

[96] Hydro-Québec, "Hydro-Québec's Plan to Decarbonize the Economy, Contribute to Québec's Prosperity and Meet Customer Expectations."

[97] Hydro-Québec, "Action Plan 2035."

government responsible for carrying out integrated resource planning every three years across electricity and natural gas systems.[98]

These developments demonstrate that there is considerably more uncertainty around the future growth of electricity systems than five years ago and that utility plans are struggling to adapt. Moving toward more continuous planning cycles, as witnessed in BC and NS, shows that the situation is changing faster than can be managed effectively under three year or longer planning cycles. Revisions to load forecasts have led several provinces to substantially ramp up DSM plans set only two years prior, and there are increasing calls for provincial governments to play a more active role in conducting truly integrated energy planning.

The approach to date in utility resource planning demonstrates a fundamentally business-as-usual approach to managing business risk — assume low to moderate growth in anticipated system requirements, assume a low to moderate level of continued demand-side savings, and model the least-cost pathway to meeting future requirements that only just meet, but rarely exceeds, policy goals for emissions reductions or other non-utility system objectives while minimizing short-run rate impacts. This is not solely a consequence of utility decisions; it is a product of a policy and regulatory framework for resource planning that is stuck in the past. Yet, the possible second-order consequence is that, in seeking to minimize risks to utilities and ratepayers, resource planning practices are heightening societal risks associated with climate change and a net-zero transition.

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[98] Frechette, An Act to ensure the responsible governance of energy resources and to amend various legislative provisions.

Review and evaluation

As noted in the introduction, the goal of this report was to identify the important procedural, substantive, and instrumental aspects that characterize net-zero-aligned utility resource planning practices and assess whether current practices in Canada reflect these considerations.

Based on the findings above, we believe the answer to the latter question is no. Recent utility-integrated resource plans do not appear to be aligned with an energy system trajectory characteristic of the net-zero future envisaged by prominent, national-level net-zero pathway studies. No utility is truly planning for the level of electrification modelled in these studies, and though some demonstrate compliance with emissions reduction objectives, most have made decisions and developed action plans on more business-as-usual forecasts of electric load growth. In terms of the procedural aspects of integrated resource planning, this study finds that utilities in Canada do not treat demand-side resources on par with other alternatives. Primarily, this comes to how demand-side resources are incorporated (or, rather, not incorporated) in system modelling, though utility planning practices also seem to focus more on downside risks associated with demand-side resources than they do the supply-side and treat costs and benefits differently.

Instrumentally, however, it is more difficult to determine whether current utility resource planning practices are aligned with net zero by 2050. The question, as we suggested at the outset, is not whether these plans successfully chart a course toward net zero (which we cannot truly know until we get there) nor whether they check off all the procedural boxes (which this report finds, is not the case). Both are certainly relevant to the instrumental value of utility planning but insufficient on their own. Rather, the question is, is utility resource planning effectively managing risk associated with a net-zero transition?

It should not be surprising that utilities across Canada and within provinces are advancing different visions of decarbonization. We should expect the future to be contested; a lot is riding on it. And, as much as utility resource planning aims to bring a cool-headed, rational approach to risk management, it is also about projecting a vision of the future that one has reason to value. While this study finds that, in many ways, utility planning practices are rigorous, comprehensive, transparent and technical, this does not mean they are objective. Based on our research, we therefore believe that current utility resource planning practices tend to minimize disruptive change, not manage it.

Below, we review in brief how the utility resource plans covered here meet or do not meet the criteria for net-zero aligned planning we developed in the first section of the report. We will also reflect on some of the institutional and methodological challenges that constrain the alignment of utility resource planning with net zero.

Net-zero alignment

In the sections above, we discussed how utility resource planning differs in fundamental ways from net-zero pathway studies. We argued a core difference is that utility resource planning is reactive to change, while pathway studies are generative of it (or aim to be). This is a constraint imposed on resource planning by the historical evolution of utility regulation – because decisions need to be considered prudent based on information available at the time, there tends to be a business-as-usual bias in utility system governance. Speculation about possible or likely future events is not sturdy grounds for action.

	BC Hydro	FortisBC/ FortisBC Energy	Manitoba Hydro	NB Power	Nova Scotia Power	IESO	AESO
Includes scenario(s) which comply with federal/provincial policy	●	●	●	●	●	●	●
Includes scenario(s) which incorporate known but yet-to-be-implemented policy and/or a scenario that works back from net zero	-	-	-	-	-	○	○
Includes scenario(s) with aligned assumptions regarding energy demand between natural gas and electric utilities	○	○	○	-	n/a	-	-
Includes scenario(s) with levels of electrification approximating estimates from national pathway studies	-	○	○	-	-	-	-
Independent, economy-wide planning	-	-	○	-	-	-	-

Table 5. Evaluation of net-zero alignment of Canadian resource planning

Our research finds that utility IRPs do exhibit this 'business-as-usual' bias. Few utilities developed scenarios in which electric load growth approached the levels envisaged by national net-zero pathway studies. For the few utilities that did, such scenarios were either theoretical maximums (e.g., FortisBC) or treated as a practical impossibility (e.g., Manitoba Hydro). Furthermore, not all scenarios developed comply with provincial or federal policies – only the 'Accelerated Electrification' scenario in BC Hydro's plan was noted as being in line with provincial policy targets, and it was not selected as the basis for action planning.

While we found some limited attempts at coordinating planning assumptions between natural gas and electric utilities, these appear not to have substantially influenced scenarios developed in the plans examined for this study. Only one utility (Manitoba Hydro) conducted something closer to an economy-wide analysis. While its most climate-friendly scenario may have been deemed on track to net zero by 2050, it still had some way to go in the eight years that remained after its planning horizon.

Finally, at the time of writing, there are no examples of economy-wide integrated resource planning in Canada, but this may change. Ontario and Quebec have recently taken steps to centralize resource planning in government. Greater policy clarity and direction from governments may help align utility planning practices toward a common future, but too much centralization of government planning may also be risky. While it may improve "coordination," it might also reduce transparency (absent sufficient opportunities for public intervention and oversight of government planning practices). Also, government policy is liable to change, get stuck on flagship initiatives, pick winners, or avoid hard choices for political reasons.[99]

'Policy clarity' cannot descend to the level of which model to use, what assumptions to make, or what the avoided costs are of demand-side resources, etc. In other words, the existence of policy alone may be insufficient to resolve all questions about how to plan for the future nor to remove the need for planners' discretion and judgment in weighing competing priorities. Net-zero-aligned utility resource planning must do more to centre the contrast between where we need to be and where present trends appear to be leading us. Doing so would lead to better management of electricity system costs and risks while supporting the societal benefits of electrification.

Resource characterization

The dominant way of treating demand-side resource potential in utility resource planning in Canada is to reduce load growth and then select supply-side resources. This effectively excludes demand-side management from integrated planning because the model cannot select demand-side solutions, even if they are at a lower cost than supply-side alternatives. Making energy savings internal to the planning process involves estimating the market potential of DSM resources at each period and allowing the model to select demand-side solutions as a resource option over supply-side alternatives.

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[99] Haley et al., "From Utility Demand Side Management to Low-Carbon Transitions: Opportunities and Challenges for Energy Efficiency Governance in a New Era."

Resource characterization	BC Hydro	FortisBC/ FortisBC Energy	Manitoba Hydro	NB Power	Nova Scotia Power	IESO	AESO
Comprehensive consideration of demand flexibility potential	●	-	○	-	●	n/a	n/a
Demand-side resources are incorporated as selectable resources in modelling	-	-	●	-	○	-	-
Market potential of demand-side resources not artificially constrained outside of optimization modelling	-	-	-	?	-	?	?
All relevant resource characteristics (e.g., construction lead times, scheduling flexibility, etc.) considered	?	?	?	?	?	?	?
Parity in treatment of utility and non-utility costs and benefits	-	-	-	?	-	-	-

Table 6. Evaluation of treatment of demand-side resources in Canadian resource planning

A separate but related issue concerns how the costs and benefits of demand-side resources are accounted for. This review found that the standard practice is to use total resource costs of demand-side resources to screen measures in potential studies and then to use varying levels of potential as input assumptions to system modelling. This unfairly biases analysis against demand-side resources by introducing constraints on market potential before optimization and incorporating non-utility costs for only one type of resource. Analysis should be restricted to utility system costs only or undertake a much more systemic and society-wide modeling exercise that includes all non-utility and non-energy costs and benefits for all resources.

Planning processes without fully considering demand flexibility resource options will rely on traditional solutions like natural gas peaking plants. For example, many IRPs reviewed here fall back on natural gas generation in scenarios with higher load forecasts to provide the additional firm capacity required for reliability. Consideration of demand-side resources to provide such flexibility is rather limited. While some plans incorporate a range of flexible resources in their analysis, these solutions are rarely incorporated into modelling. Furthermore, the potential of these resources generally reflects experience and aging potential studies and may be artificially limited by assumptions around customer behaviour. Digital technologies now enable a much broader range of "demand response" or demand flexible options. In no IRP reviewed here, demand-side resources came close to accounting for the 20 per cent of forecasted peak demand found possible in a Brattle Group study that comprehensively considered demand response potential up to 2030.

This research also found that the avoided costs of demand-side resources assumed in utility resource plans are often inscrutable, and the methodology used to incorporate demand-side resources in planning neglects to fully account for avoided transmission and distribution costs. This stems partly from the sequencing in some planning processes, where avoided costs are taken from prior planning efforts or outdated load forecasts. Other utility costs that can fail to be considered include transmission and distribution line losses, ancillary services, credit and collection costs, avoided costs of compliance with renewable energy requirements, environmental compliance, and achieving reliability standards. In some cases, utilities might not have a high-quality assessment of the potential to save on transmission and distribution costs due to a lack of location-specific planning processes and data collection.

A plausible consequence of these findings is that the potential of demand-side resources is being artificially constrained, particularly in a condition where system requirements may grow rapidly or change unpredictably. Since the potential of demand-side resources is partly a function of the expected load growth and associated avoided costs, using historical and/or business-as-usual values for those parameters will lead to lower potential estimates for demand-side resources.

Risk management

Planning for net zero will involve several uncertainties. These can include a planned resource not being available, extreme weather conditions, technology cost reductions, or increased availability of flexible demand resources as customers seek greater independence by investing in on-site energy generation, efficiency, and storage. A core challenge of resource planning is to accurately characterize risks and compare and evaluate competing future pathways under these conditions of uncertainty.

Risk management	BC Hydro	FortisBC / FortisBC Energy	Manitoba Hydro	NB Power	Nova Scotia Power	IESO	AESO
Parity in sensitivity analysis of supply/demand-side resource risk	-	-	-	-	-	-	-
Transparent, multi-criteria assessment evaluation of competing resource portfolios that includes societal factors	○	○	○	-	○	-	-
Both rate and bill impacts are considered	-	-	-	-	-	n/a	n/a
Bias toward early action to avoid lock-in, maintain maneuverability	-	-	-	-	-	n/a	n/a
Preferred resource plan derived from scenario that meets alignment criteria for net-zero	-	-	-	-	-	n/a	n/a
Action plan includes clear signposts, schedule for renewing plan is accelerated (i.e., < 3 years)	●	○	-	-	○	n/a	n/a

Table 7. Evaluation of risk management practices in Canadian resource planning

Uncertainties on the demand and supply side and their consequences should be fully articulated. There is considerable evidence that large supply-side projects experience cost overruns and delays. Bent Flyvbjerg's database of megaprojects finds that nuclear power plants have a mean cost overrun of 120 per cent, and hydroelectric dams have a cost overrun of 75 per cent.[100] However, utility planning practices in Canada give more consideration to downside risks associated with demand-side resources than they do for supply-side alternatives. For example, BC Hydro opted against an aggressive level of DSM due to the risk of underdelivery, even though underdelivery would not have triggered a resource availability emergency. Achieving higher levels of DSM would have been cost-effective and better prepared the province for more electrification. In general, supply-side resource risks are treated bluntly – a particular resource is either available or not, and if it is, it's available when needed.

In comparing and evaluating competing resource strategies, several utilities put forward a comprehensive list of criteria to weigh different approaches. In practice, however, resource plans often focus on a decision point between plans that deliver lower long-term costs but have higher short-term rates impacts and plans that prioritize lower rates in the short-term but have higher long-term costs. This trade-off can occur with significant demand reductions that lower overall costs, yet it can result in higher rates if costs are large and spread over fewer sales. While rate impacts are important, they should not be considered without including bill impacts. The potential distributional problem of customers paying higher rates can be mitigated by ensuring DSM strategies reach more customers – particularly low and moderate-income customers, who are more at risk from rate impacts when not participating in DSM programming. Combined rate and bill impact assessments put this in perspective by showing the distribution of bill savings across different customer groups.

We also found little thorough consideration of societal risk factors in evaluating and comparing resource portfolios. A multi-criteria assessment of resource planning should present project indicators such as environmental benefits beyond legislated requirements and economic development. The growth of distributed energy resources will create resilience benefits for people using on-site generation and/or storage as backup generation. Meeting core societal goals like GHG reductions with an additional buffer can ultimately lower risk given real-world conditions. Though some plans

[100] Flyvbjerg and Gardner, *How Big Things Get Done*, 192.

reviewed did include broader societal benefits in their decision-making criteria (e.g., BC Hydro, NS Power), it isn’t clear that these are given the same prominence as system costs and rate impacts.

The construction of scenarios and testing of sensitivities across all IRPs reviewed here follows a deterministic approach, setting input assumptions out at the outset and with ostensibly perfect foresight (e.g., low fuel prices; accelerated electrification) — thus establishing fixed conditions in which fixed sets of resources compete to produce the lowest-cost system. While time and modelling resources present limitations on what can be accomplished in carrying out a timely IRP, this approach fails to adequately make the underlying uncertainty of results transparent and accessible to readers. The resource mix in future energy systems will be far different from those in the past, and the effects of climate change will be more severe. Together, this will add more variability and unpredictability to how systems operate. Supplementing scenario-based analysis with probabilistic methods to characterize uncertainty of conditions and resource availability and performance will provide more information on managing risks.

Under heightened uncertainty, early actions that increase future flexibility should be prioritized over those that could lock utility systems into a resource that can be difficult to exit. This review does not find evidence of utilities taking such early action. Rather, most IRPs did not develop an action plan that included higher levels of demand-side management earlier in the plan. A common argument against maximizing near-term demand-side resources is that the short-term rate impacts outweigh the resource benefit when the resource is not immediately needed. We submit that this brings a “just-in-time” supply-side mentality to a fundamentally different resource. In the context of a transition to net zero, but perhaps in any context, this forgoes the true, cumulative risk management benefits of highly flexible, multi-purpose demand-side resources.

The recent move in several provinces toward ‘evergreen’ resource planning practices, where planning occurs more frequently, may help to mitigate some of the risks associated with heightened uncertainty. However, supposing the primary stance of utility resource planning remains reactive and “generation-focused,” we will still be putting a lot of faith in procurement processes playing out according to plan, project lead times staying on course, and market conditions remaining favourable and in line with other planning assumptions. Electricity system planning accounts for operational reliability risks by building a capacity buffer, yet there is no commensurate security buffer to hedge against planners being wrong. The best thing utilities — and governments — can do to manage risks in a net-zero transition is to take all no-regrets actions on demand-side resources and build more margin against error.

Conclusion

The objective of this study was to identify and evaluate the important procedural, substantive, and instrumental elements of utility resource planning in the context of reaching net zero by 2050; evaluate and assess the extent to which current planning practices in Canada are aligned with a net-zero future; and to identify challenges to and opportunities for improvement. Our focus was specifically on the treatment of demand-side resources and largely on electricity system resource planning.

Our findings suggest that current utility resource planning practices in Canada are not aligned with a net-zero future. However, many plans claim they offer a feasible pathway to emissions reductions. Indeed, whether plans are aligned with a net-zero future is broader than simply reducing emissions. Good utility planning appropriately manages the risks associated with an unavoidable and necessary energy system transition. Current utility planning in Canada is not managing disruptive change but minimizing it.

The basis for this claim is ultimately that utility plans and planning practices are fundamentally conservative – not in a political sense, but rather that institutional and societal factors constrain them from going beyond what is realistic to say or prudent to do about the future, based on experience and observable trends. This arrangement results from a particular, historical solution to managing utility planning and investment risks. We believe it is no longer adequate to effectively manage risks in the context of a net-zero transition.

If the net-zero pathway studies reviewed in this study tell us one thing, there is almost no margin for error in successfully transitioning to a net-zero energy system future. The downside risk of failure is immense, and yet so many plans and studies arrive at this end-state just in time (if they do at all) and rely on highly uncertain assumptions to do so. Why would we also be conservative on known and proven solutions in such a condition?

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