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Northeast America (NEA) Electricity Profile: Proposal of a Free Trade Area

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[†] I would like to thank Thomas Boyer and Owen Skoda for their valuable research assistance.

Abstract

The government of Quebec should formally propose to the governments of neighboring American states (CT, ME, MA, NH, RI, VT, NJ, NY, PA, IL, IN, MI, OH, WI, DE, MD, WV, KY) and the provinces of eastern Canada (NL, NS, NB, ON) an integrated common market in electricity with appropriate commonly owned and shared interconnections and regulatory institutions allowing effective, efficient, transparent and fluid exchanges. The important technological complementarities between the regional production capacities and technologies and the high value added of integration, in particular with the massive arrival of renewable but intermittent energies, are likely to create a win-win situation for all participants. But the game is not only complex, but also demands from the regional leaders, Premiers and Governors, a long-term vision based on strategic complementarities and open competition. Major enabling features revolve around opening the ownership structure of regional producers, integrating the independent system operators (ISO), implementing appropriate mechanisms to adequately face the "not in my backyard (NIMBY)" syndrome.

Keywords: Electricity Production, Free Trade, Economic Integration, NIMBY

Résumé

Le gouvernement du Québec devrait proposer officiellement aux gouvernements des États américains voisins (CT, ME, MA, NH, RI, VT, NJ, NY, PA, IL, IN, MI, OH, WI, DE, MD, WV, KY) et des Provinces de l'est du Canada (NL, NS, NB, ON) un marché commun intégré de l'électricité avec propriété commune et partagée des interconnexions et des institutions réglementaires permettant une efficacité, efficience, transparence et des échanges fluides. Les complémentarités importantes entre les technologies de production régionales et la forte valeur ajoutée de l'intégration, en particulier avec l'arrivée massive d'énergies renouvelables mais intermittentes, sont susceptibles de créer une situation gagnant-gagnant pour tous les participants. Mais le jeu est non seulement complexe, mais il exige également des dirigeants régionaux, Premiers Ministres et Gouverneurs, une vision à long terme fondée sur des capacités complémentaires stratégiques et une concurrence ouverte et transparente. Trois facteurs critiques : l'ouverture de la structure de propriété des producteurs régionaux, l'intégration des gestionnaires de réseaux indépendants ISO), la mise sur pied de mécanismes appropriés pour répondre adéquatement au syndrome « pas dans ma cour (NIMBY) ».

Mots-clés : Production d'électricité, Libre échange, Intégration économique, NIMBY

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1. INTRODUCTION – THE CHALLENGES AND THE DATA

Quebec's energy potential is phenomenal, not only because of its many indigenous sources, but also because of the experience and competency it has acquired (and thanks to visionary leaders such as former Premier Robert Bourassa). However, an uninformed and misguided coalition of legislators, business and union leaders exercise inordinate control over Québec's energy resources. The result is a directionless resource-development policy, based on price manipulation, that benefits only the groups directly involved, while squandering the potential welfare gains for all citizens from a socially optimal resource-exploitation plan. The current low-price policy — financed by higher public debt and taxes, and possibly leading to a deterioration of social services — is not only an inefficient subsidy to big energy consumers, including both individuals and corporations, but also a regressive transfer from the poor to the wealthy.

Commentators often hail the relatively low level of electricity prices in Quebec as helping achieve a high level of economic development. What that hides, however, is the real social cost of the policy. The real price of electricity is not its production cost, particularly low in Quebec because of plentiful hydro-electric power, but its opportunity cost. That opportunity cost is significantly higher because it equals the maximum competitive price at which electricity can be exported. The traditional response of customer and consumer groups that gain from this policy is: *Everybody benefits from low prices*. *Nothing could be further from the truth.*

The Government of Quebec together with governments of neighbouring American states and neighbouring Canadian provinces should promote the creation of an integrated common market in electricity with appropriate competitive rules and appropriate interconnections and system management institutions (ISO) allowing effective, efficient, transparent and fluid exchanges for the benefit of all their respective population. The important technological complementarities between the regional production capacities and technologies and the high value added of integration, in particular with the massive arrival of renewable but intermittent energies, are likely to create a win-win situation for all participants. But the game is complex. Above all, rules would be defined to counter the real danger of crony interventions in electricity markets.

In the next sections, I look at the total electricity supply levels and sources (including imports) as well as total disposition (including exports) first of Canada as a whole and the five NEA electricity producing provinces (NL, NS, NB, QC, ON) in Section 2 and of the US as a whole and the eighteen NEA electricity producing states in Section 3. I tackle in Section 4 the discussion of a free trade zone in electricity, namely the con and pro arguments, the benefits of free trade even under higher electricity prices (mainly in Québec), and the long term impact of such a free trade agreement. In the concluding Section 5, I develop three propositions or recommendations on the major enabling features that revolve around opening the ownership structure of regional producers, integrating the independent system operators (ISO), and implementing appropriate compensation mechanisms to adequately face the "not in my backyard (NIMBY)" syndrome.

The data I used in this document comes from different sources, which do not always present the same numbers and figures. In some cases, I had to dig under the numbers to get a truer picture of the underlying phenomena. One example is the treatment of Québec's important interprovincial import of electricity from Newfoundland-Labrador, which is curiously treated by Hydro-Québec as a local in-province production.

Three significant and credible data sources, Statistics Canada, the Canada Energy Regulator, and the HEC-Montréal Chair in Energy Sector Management, among others, were misled.

CANADA

Source: Canada Energy Regulator, Provincial and Territorial Energy Profiles.
https://www.cer-rec.gc.ca/nrg/ntgrtd/mrkt/nrgsstmprfls/index-eng.html
https://apps.cer-rec.gc.ca/CommodityStatistics/Statistics.aspx?language=english

Source : Chaire de gestion du secteur de l'énergie (HEC Montréal), L'État de l'énergie au Québec, 2020.
https://energie.hec.ca/wp-content/uploads/2020/03/EEQ2020_WEB.pdf

Source: Hydro-Québec, Annual Report 2018.
http://www.hydroquebec.com/data/documents-donnees/pdf/annual-report-2018.pdf

Source: Statistics Canada, Electric power generation, monthly receipts, deliveries and availability,
Table 25-10-0016-01. https://www150.statcan.gc.ca/t1/tbl1/en/tv.action?pid=2510001601

Source: Statistics Canada, Electric power generation, monthly generation by type of electricity
Table 25-10-0016-01. https://www150.statcan.gc.ca/t1/tbl1/en/tv.action?pid=2510001501

The Annual Reports of provincial electricity producers (NALCOR, NSPI, NB power, Hydro-Québec, OPG) and independent system operators (NYISO, ISO-NE, IESO, MISO)

USA

Source: Net Generation by State by Type of Producer by Energy Source (EIA-906, EIA-920, and EIA-923), 1990-2018. https://www.eia.gov/electricity/data/state/

Source for the different states: U.S. Energy Information Administration, Form EIA-861, "Annual Electric Power Industry Report." For Connecticut for instance, the source is
https://www.eia.gov/electricity/state/Connecticut/ Tables 2B, 7, 9 and 10. And similarly for the other states.

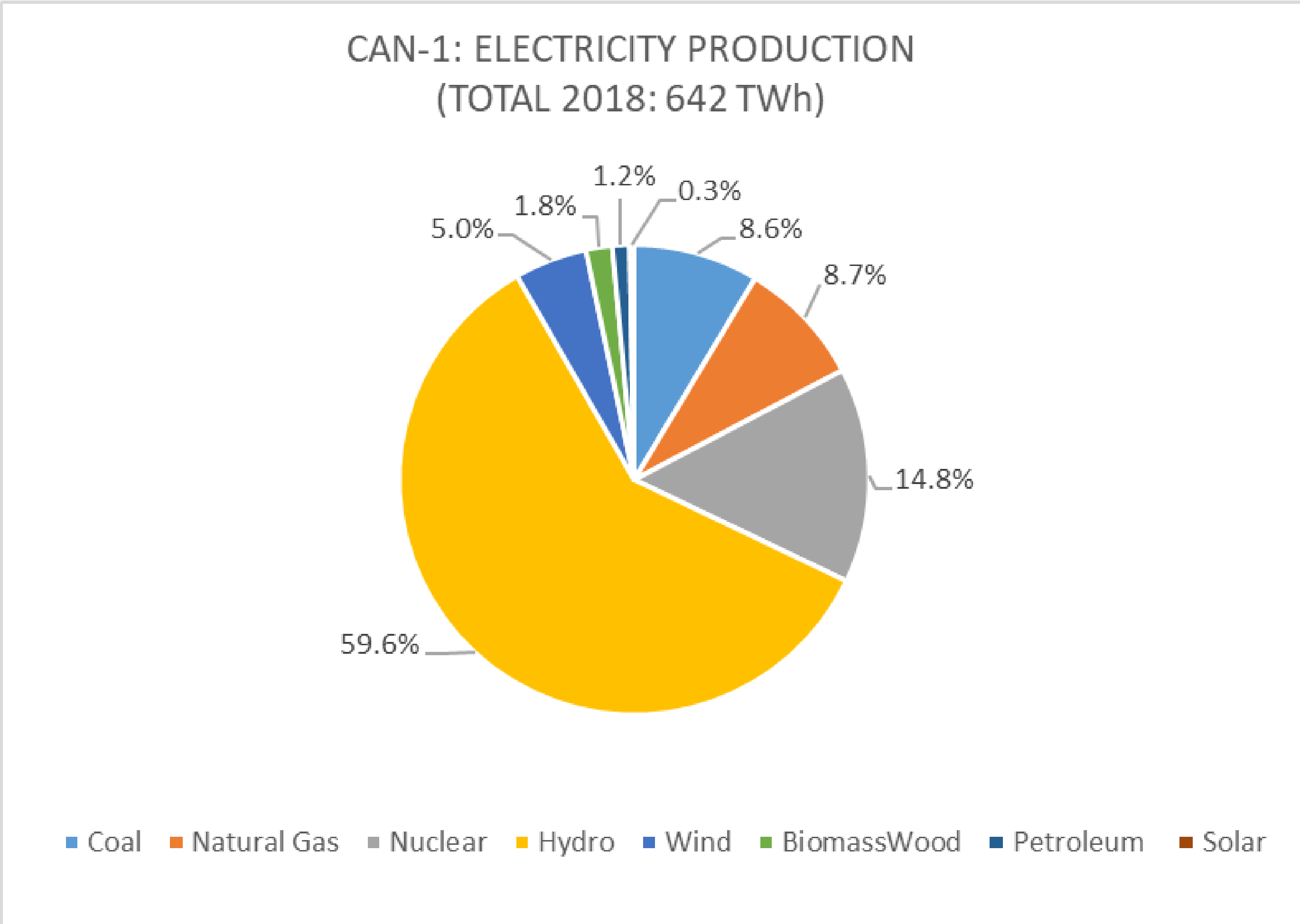
The source for the evolution of electricity production between 2001 and 2019 is:
Nadja Popovich and Brad Plumer, "How Does Your State Make Electricity?", *New York Times*, October 28, 2020

REFERENCES

Numerous additional references are provided in footnotes.

2. THE CANADIAN OUTLOOK: CANADA AS A WHOLE AND THE 5 NEA PROVINCES

In Canada (Figure CAN-1), electricity is produced mainly from hydroelectric power sources (59.6%), followed by nuclear power (14.8%), Natural gas (8.7%), coal (8.6%), Wind (5.0%). Less important sources of electricity were biomass and wood (1.8%), petroleum (1.2%) and solar (0.3%).

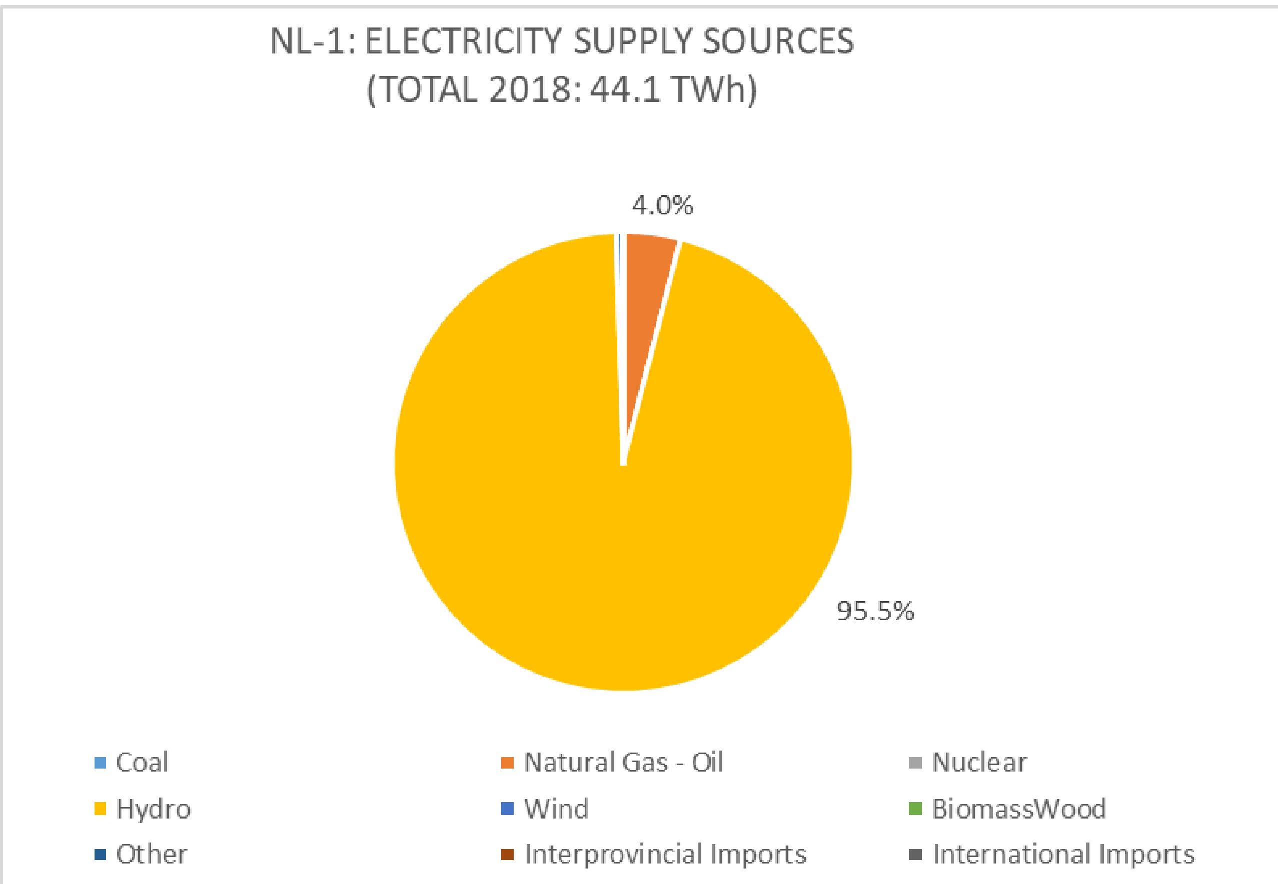


Canada exports to the US (2018) totaled 61 TWh, while imports from the US reached 13 TWh, for a net exports total of 48 TWh. Exports represented 9.4% of total production while imports reached 2.0% for a net exports share of 7.4% of total production.

The structure of electricity production varies significantly across provinces. In the next pages, we present the production, supply and disposition of electricity for each of the eastern provinces except Prince Edward Island, namely Newfoundland and Labrador (NL), Nova Scotia (NS), New Brunswick (NB), Québec (QC), and Ontario (ON).

NEWFOUNDLAND AND LABRADOR (NL)

Newfoundland and Labrador generates some 44.1 TWh (2018) of electricity, of which 95.5% is generated from hydro sources, 4.0% from natural gas and petroleum sources, and 0.5% from wind farms. This includes the 5,428 MW Churchill Falls generating station, which is one of the largest power plants in Canada. The provincial energy corporation NALCOR, a crown corporation, owns 65.8% of the Churchill Falls generating station and Hydro-Québec owns the remaining 34.2%. The energy from Churchill Falls is sold to Hydro-Québec under a long-term contract that expires in 2041 (see below in the Québec section). NALCOR's Lower Churchill Falls power generation facilities at Gull Island and Muskrat Falls will have a combined capacity of over 3,000 MW and provide 16.7 Terawatt hours of electricity per year. At the end of 2019, construction of the 824 MW Muskrat Falls generating facility is nearly complete, with first power expected in 2020. The Gull Island project is a proposed 2,250 MW generation facility has not yet been sanctioned for construction.

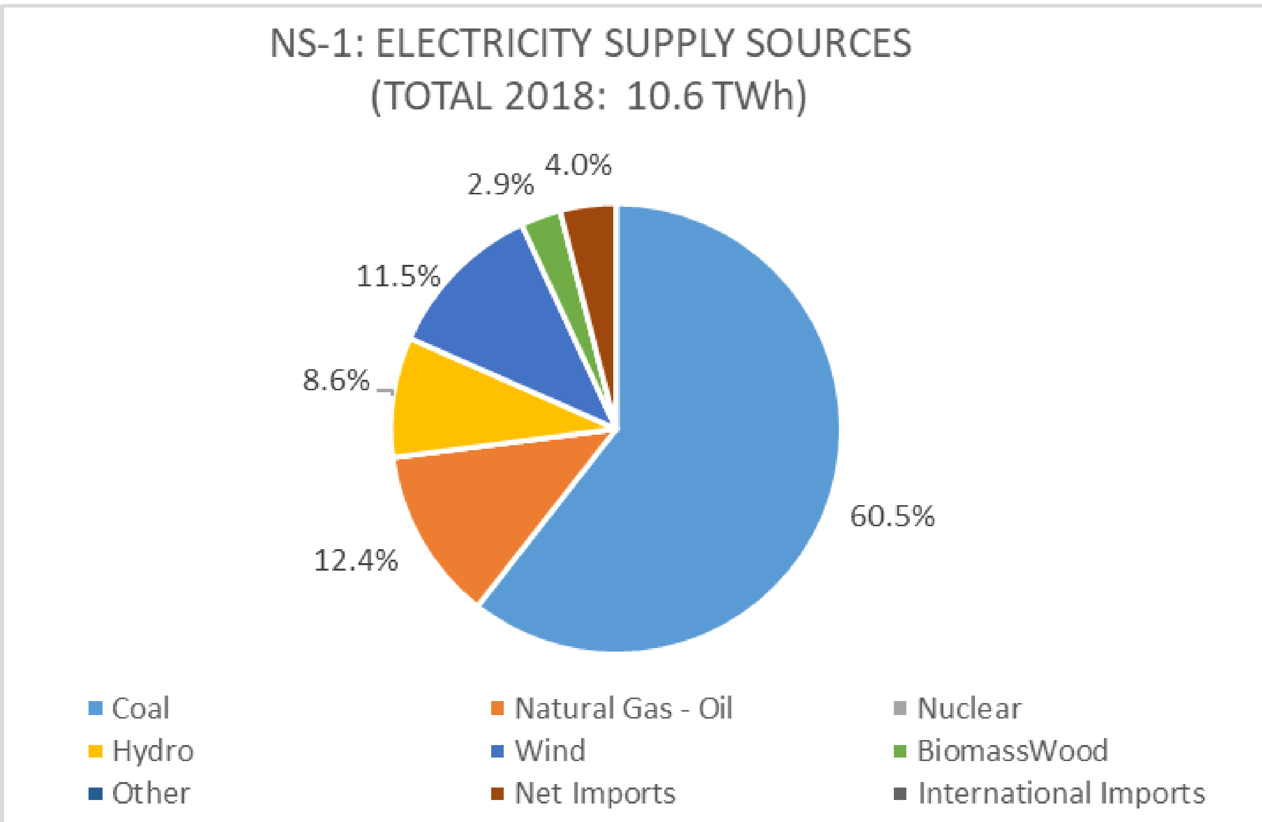


Newfoundland and Labrador is a significant net exporter of electricity. In 2018, total interprovincial and international electricity outflows reached 32.2 TWh, or about 75% of generation. Inflows were insignificant. Construction of the Labrador-Island Link was completed in late 2017, and will deliver electricity from Muskrat Falls in Labrador to the island over a 1,100 km transmission line. First power delivery from Muskrat falls is expected in 2020. The Maritime Link between NL and NS in service in January 2018 gives NL access to the North American bulk electricity network system.

NOVA SCOTIA (NS)

Nova Scotia supplies some 10.6 TWh (2018) of electricity, of which 60.5% is generated from coal power plants, 12.4% form natural gas/ petroleum plants, 11.5% from wind power, 8.6% from hydroelectric power plants, 2.9% from biomass and wood plants, and 4.0% represents net imports.

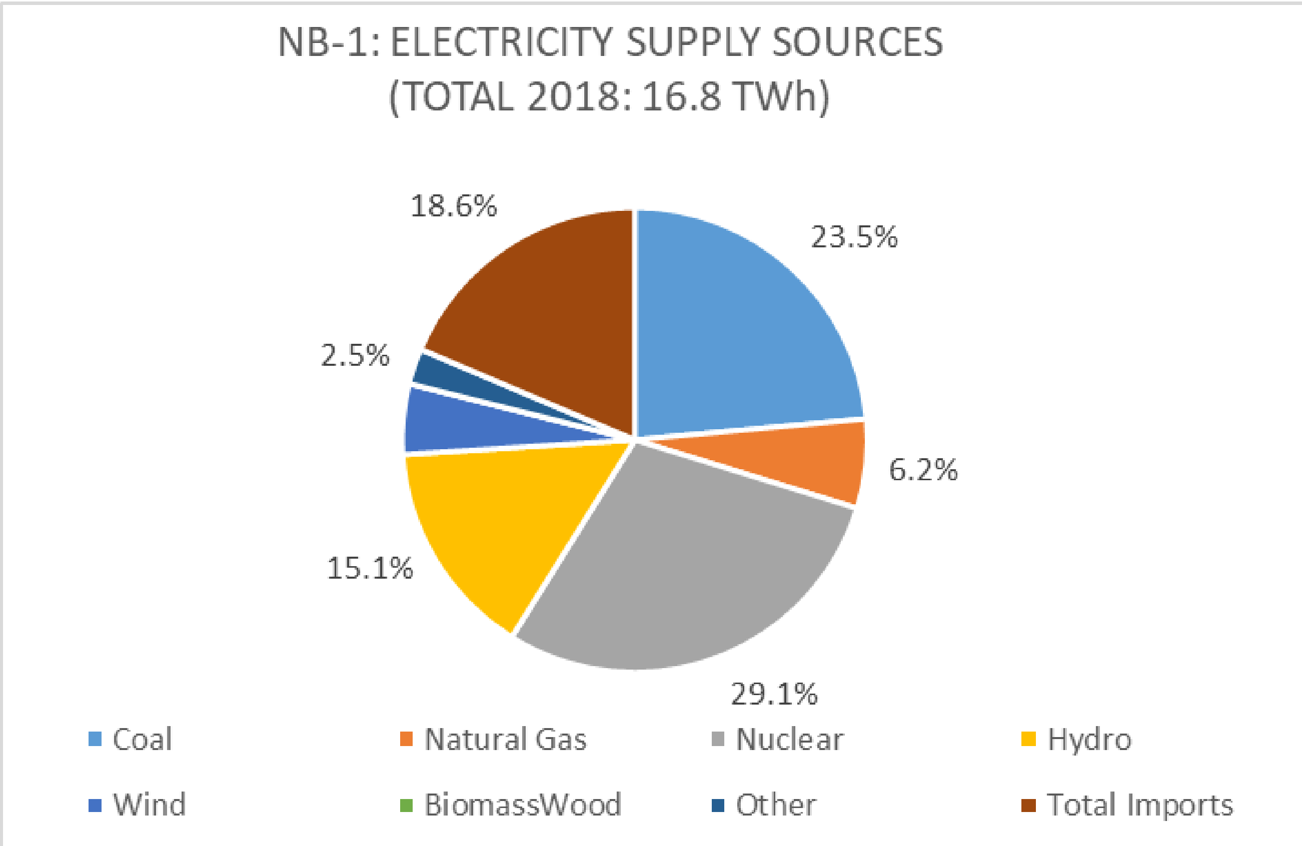
Nova Scotia Power Inc. (NSPI) supplies most of the electricity in Nova Scotia and owns over 95% of the province's electricity systems. It is a vertically-integrated utility, which means that it generates, transmits and distributes electricity. Besides NSPI, six municipal electric utilities serve customers in their regions. The NS production capacity is completed by a group of Independent Power Producers (IPPs) supplying a large amount of the province's renewable energy, such as wind and biomass, to NSPI and municipal utilities through a competitive wholesale market.



The Maritime Link between NL and NS, developed by Emera Inc., NSPI's parent company, will allow NS to import about 20% of electricity produced at Muskrat Falls NL. Before the Maritime Link, NS had only one limited transmission connection to another energy market – a link to New Brunswick that allows exports from Nova Scotia.

NEW BRUNSWICK (NB)

New Brunswick supplies some 16.8 TWh (2018) of electricity, of which 18.6% is imported from Québec and New England. NB has a generating capacity of 4,521 megawatts (MW). In 2018, approximately 35.7% of NB electricity generation was from nuclear, representing 29.1% of total supply; 36.5% was from fossil fuels (natural gas, coal, and petroleum), representing a total of 29.7% of supply; 18.6% was from hydroelectricity, representing 15.1% of supply; and 6.0% from wind farms, representing 4.9% of supply.



New Brunswick Power Corporation (NB Power) operates a total of 13 hydro, nuclear, coal, oil, and diesel powered stations with an installed net capacity of 3,790 MW comprised of 1,716 MW of thermal, 889 MW of hydro and 525 MW of combustion turbine capacity. Because NB has limited natural resources to generate electricity in the province, it has developed one of the most diverse generating systems in North America. NB is the only province outside of Ontario with nuclear power. The Point Lepreau Nuclear Generating Station, located near the Bay of Fundy, has a capacity of 705 MW.

NB imports some 3.1 TWh (94.4% from other Canadian provinces) and exports 2.8 TWh (56.8% to other Canadian provinces). In-province sales are close to 14 TWh, with industrial customers representing 37%, residential customers 43% and commercial 19%.

QUÉBEC (QC)

Québec's electricity total supply in 2018 totaled some 214 TWh, 95% of which came from hydroelectric sources, 4.7% from wind sources and less than 1% from biomass, solar energy and diesel (Chaire HEC 2020, Statistics Canada). Hydro-Québec (HQ) produces and buys most of Québec's hydroelectricity (there are some 46 other producers of hydroelectricity), that is, nearly 90% of total production.

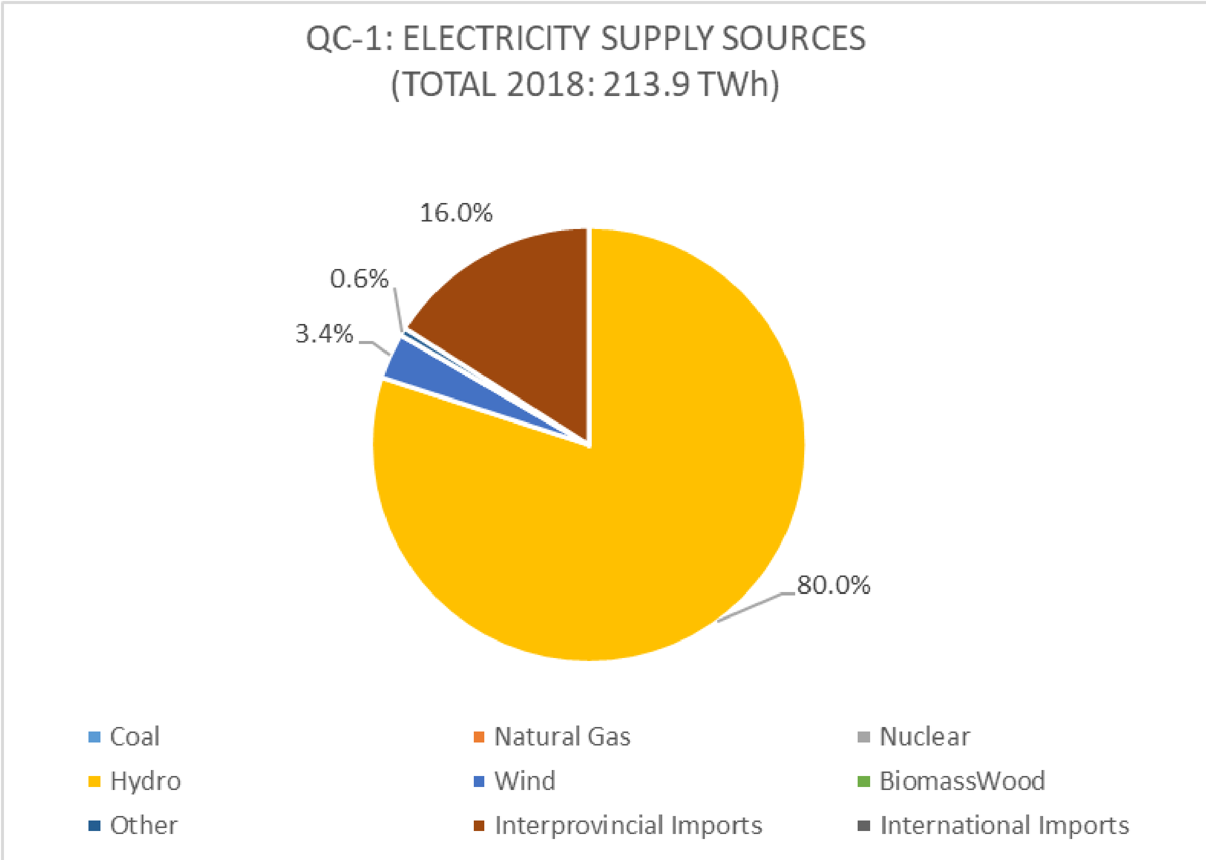
HQ is involved in imports and exports, together with other players, such as Brookfield Renewable Energy, Quebec's second largest exporter of electricity. Some companies are also involved in the distribution, brokerage or export of electricity. Most have contracts with Hydro-Québec Distribution (HQD), to whom they sell their production from wind farms, cogeneration plants or small hydroelectric plants. The province has ten redistributors of electricity (nine municipalities and one cooperative) that manage small electricity distribution networks, separate from that of Hydro-Québec. They buy about 4.5 TWh of energy from HQD annually.

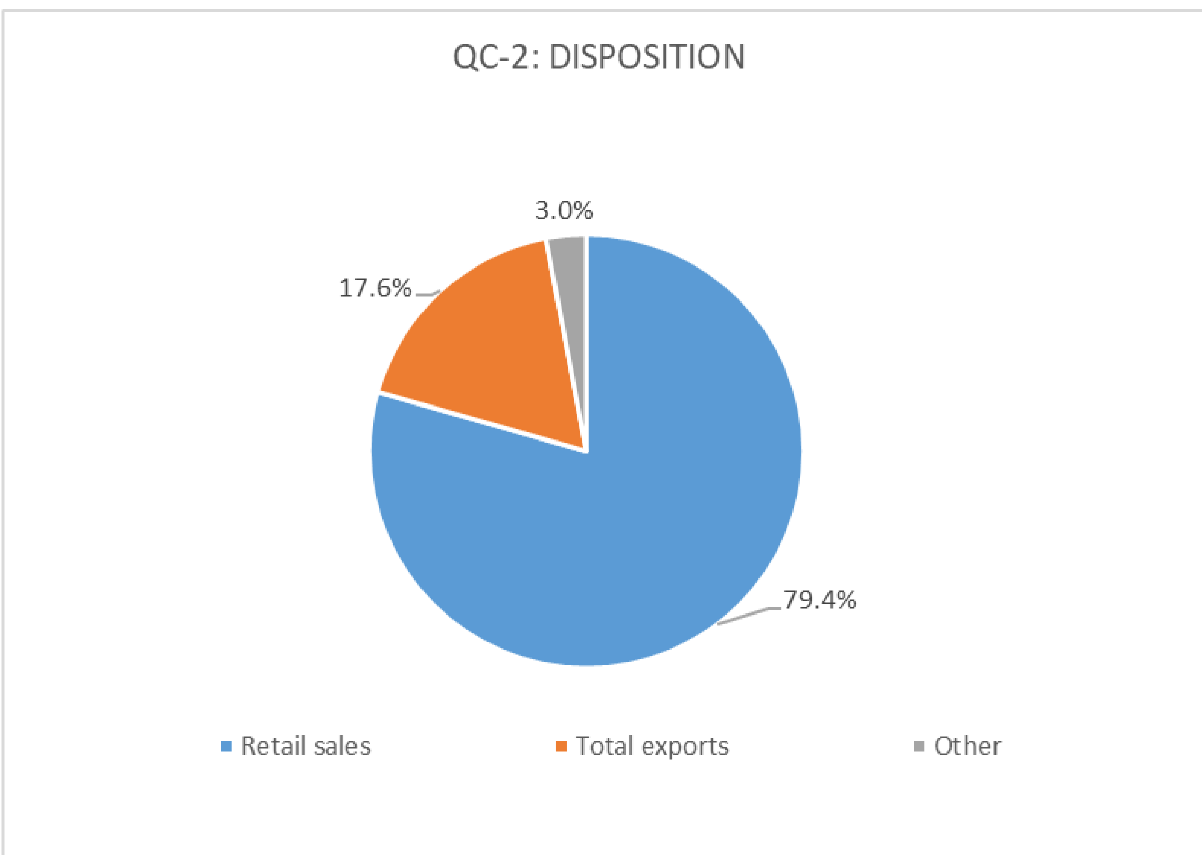
Hydro-Québec (Annual Report 2018) is the largest supplier of electricity in Canada, with a total generating capacity of 46,176 megawatts (MW), of which 40,853 MW is hydroelectric, representing some 95% of Quebec's electricity production. **This generating capacity includes Canada's largest power plant, the 5,616 MW Robert-Bourassa power plant in the municipality of Eeyou Istchee Baie-James, and also the 5,428 MW Churchill Falls power plant in NL (see below)**.

In terms of total electricity supply (Figure QC-1), interprovincial imports from NL and ON represent some 16.0%, while in-province production is dominated by Hydro with 80.0% of supply or 95.0% of in-province production. Figure QC-2 shows that in-province sales represent 79.4 of the total (with the industrial sector accounting for 48.4%, the residential sector 38.3%, and the commercial sector 13.2%), exports to the US and other provinces about 17.6%, and other (losses) some 3.0%.

Statistics Canada and the Canada Energy Regulator report that QC is a net exporter (provincial and international) of some 3.4 TWh in 2018, with total exports of 37.6 TWh (Figure QC-3) of which 71.8% (27.0 TWh) goes to US (61.0% to New England, 38.9% to New York, 0.1% to other) and 28.2% (10.6 TWh) to other provinces (71.7% to Ontario and 28.3% to NB). They report that total imports reached 34.2 TWh (Figure QC-4), of which 99.5% came from other provinces (mainly NL Churchill Falls, but also from ON and marginally from NB). Significant projects are being developed with Massachusetts. In 2018, Quebec was the largest exporter of electricity to the U.S. of all Canadian provinces.

There is an awkward aspect in the reporting of production capacity, imports and exports by Hydro-Québec. In its 2018 Annual Report, HQ claims that its net electricity sales reached 208.9 TWh in 2018, of which a net 172.8 TWh amount was sold in Québec and a net 36.1 TWh amount (17%) was exported to neighboring markets, namely 19% to Ontario, 7% to New Brunswick, 24% to New York, 47% to New England, and 3% to other.


QC-1: ELECTRICITY SUPPLY SOURCES
(TOTAL 2018: 213.9 TWh)
16.0%
0.6%
3.4%
80.0%
Coal
Natural Gas
Nuclear
Hydro
Wind
BiomassWood
Other
Interprovincial Imports
International Imports


QC-2: DISPOSITION
3.0%
17.6%
79.4%
Retail sales
Total exports
Other

Curiously, HQ considers the production of the Churchill Falls complex in NL as an in-Québec production, not as an interprovincial import.

The reasoning of HQ is that Churchill Falls huge power plant production is 100% bought by HQ under a "power contract", signed on May 12 1969 and renewed/extended on September 1 2016, which will last till 2041.

The NL crown corporation NALCOR owns 65.8% of Churchill Falls (Labrador) Corporation CF(L)Co and Hydro-Québec 34.2%. Historically, CF(L)Co needed this long term contract with HQ in order to secure financing for the project: HQ was clearly the only possible buyer (monopsonist) of the project's output. NL agreed to sell and HQ agreed to buy essentially 100% of Churchill Falls production through a contract which would expire in 2041. The integration of this huge amount of electricity into its own network meant that HQ assumed significant risks, which may appear ridiculously low today (ex post), but were significant at the time of signing the contract (ex ante).

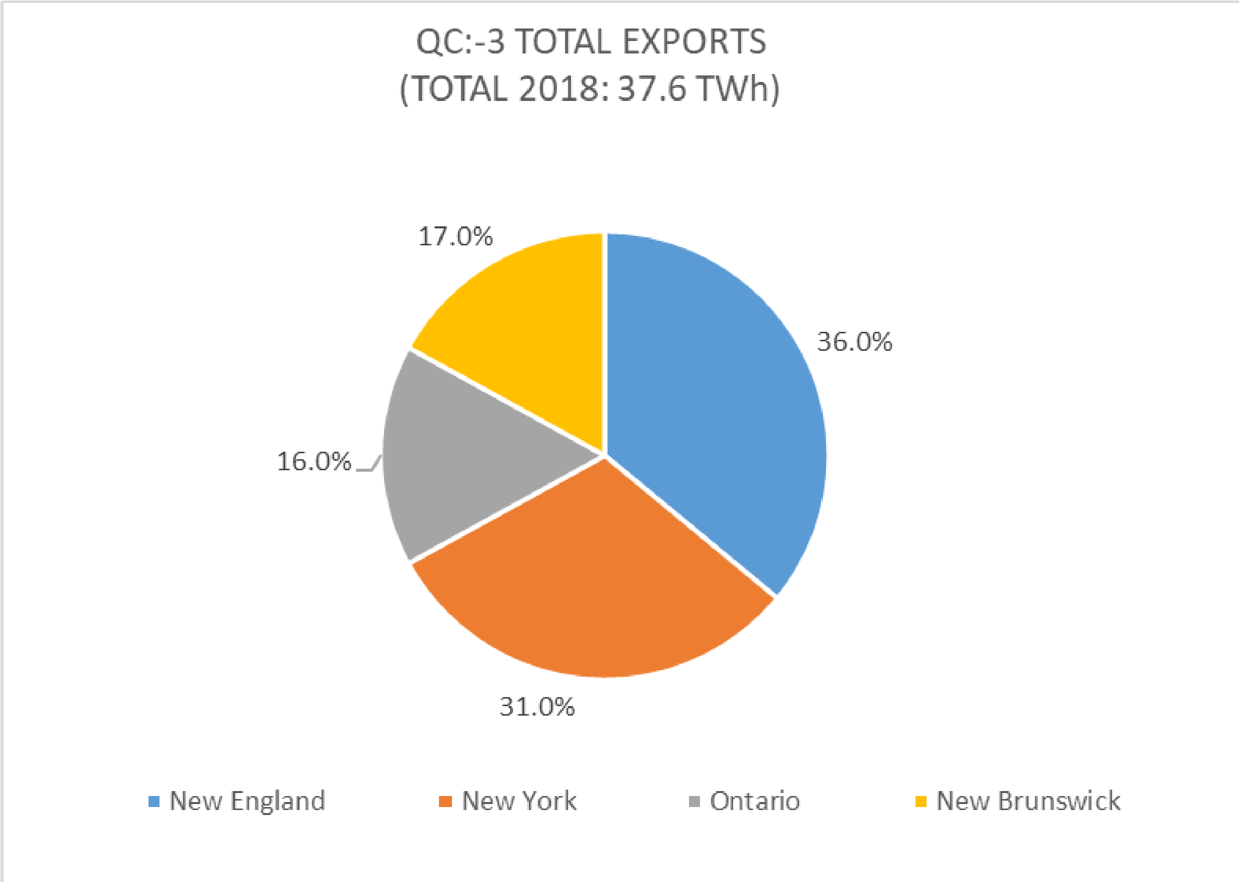
If we apply the accounting norms on imports and exports that prevail elsewhere in North America, the total QC <u>supply</u> reached some 213.9 TWh in 2018. Total imports were 34.2 TWH, of which 97.6% or some 33.4 TWh from CF(L)Co, for $97M or 0.29¢/kWh. Hence, total in-Québec production totaled about 179.7 TWh.

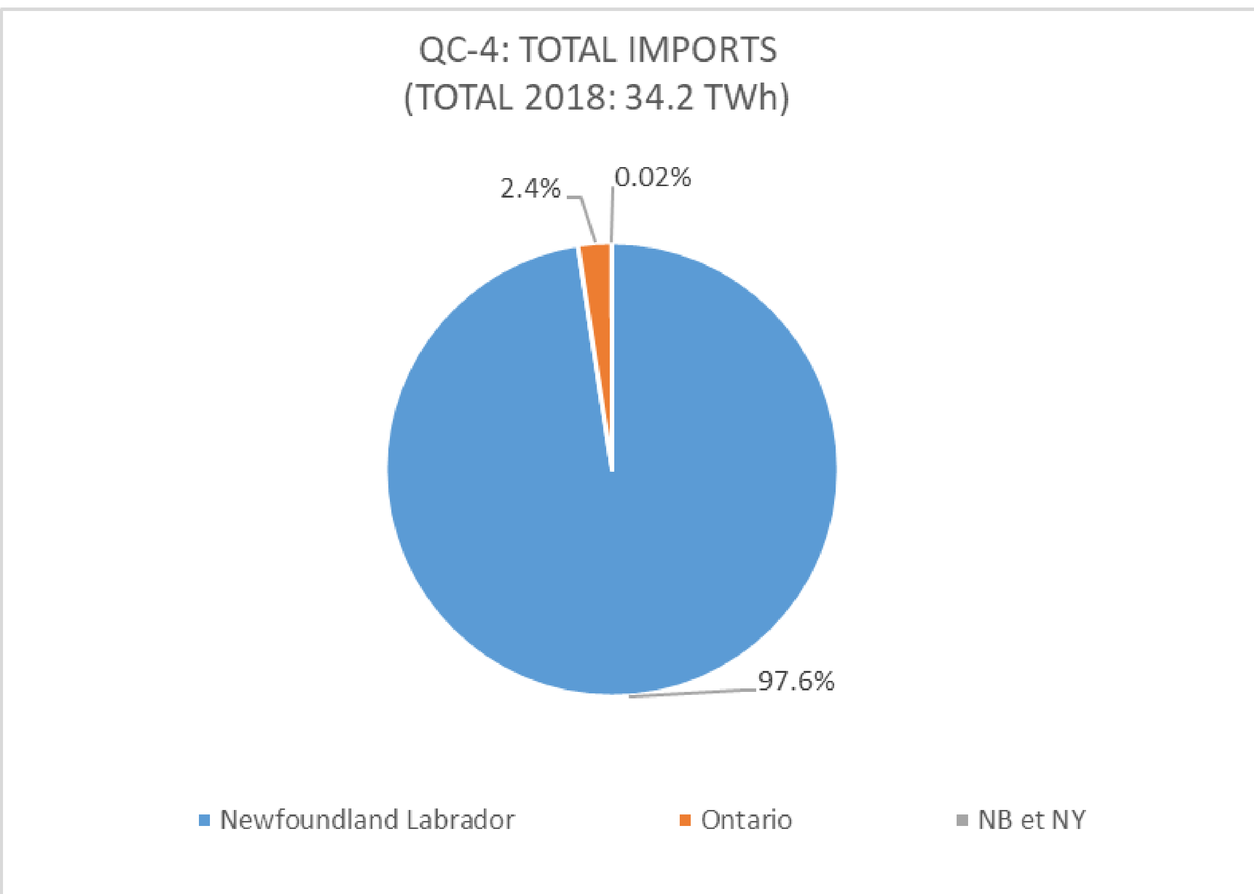
Statistics Canada and the Canada Energy Regulator website both overestimate QC electricity production, maybe on the basis of the data reported by HQ. Although HQ reports in-province sales of about 172.8 TWh, Statistics Canada reports a total electricity amount available for use within Québec (total production as measured plus imports minus exports) of 210.5 TWh in 2018. The difference of 37.7 TWh is significant. Proper accounting of electricity production, imports and exports, both interprovincial and international, would give us:

Total supply = production (179.7 TWh) + total imports (34.2 TWh) = 213.9 TWh;
Total electricity available for in-province uses = total supply – total exports =
production (179.7 TWh) + total imports (34.2 TWh) – total exports (37.6 TWh) = 176.3 not 210.5 TWh!

The history of the Churchill Falls project and of the contract(s) between HQ and CF(L)Co and other parties is a long saga of political and judicial conflicts. Globally, a win-win agreement between HQ and NALCOR to develop the Lower Churchill Falls (Muskrat Falls and Gull Island) would have made much more economic and business sense that the Maritime Link project between NL and NS.

This is a textbook example of a potentially significant value adding bargaining gone wrong: political and bureaucratic egos prevailed, at the expense of sound economics and citizens' well being.


QC:-3 TOTAL EXPORTS
(TOTAL 2018: 37.6 TWh)
17.0%
36.0%
16.0%
31.0%
New England
New York
Ontario
New Brunswick


QC-4: TOTAL IMPORTS
(TOTAL 2018: 34.2 TWh)
2.4%
0.02%
97.6%
Newfoundland Labrador
Ontario
NB et NY

ONTARIO (ON)

In 2018, Ontario generated approximately 23% of total Canadian generation. Ontario is the 2nd largest producer of electricity in Canada and has a generating capacity of 40 671 megawatts (MW). Three nuclear power plants with a combined 12 633 MW of installed capacity provide the bulk of Ontario's baseload generation. Bruce Power on the east shore of Lake Huron is the largest, with eight generation units and a capacity of about 6 600 MW. It is one of the largest nuclear power plants currently operating in the world.

The Independent Electricity System Operator (IESO) works at the heart of Ontario's power system as the system operator—directing the flow of electricity across the grid and administering the wholesale electricity market. It sets the hourly Ontario electricity price and ensures there is enough power to meet the province's energy needs in real time.

OPG (Ontario Power Generation) is the largest utility in Ontario's competitive electricity market, with over 16 600 MW of capacity (40.8% of total Ontario capacity). It is wholly owned by the Province.

OPG receives regulated prices for electricity generated from most of its hydroelectric facilities (40% of its capacity) and all of the nuclear facilities (35% of capacity), the rest falling under its contracted generation portfolio.

Ontario has over 200 hydroelectricity generation facilities with a total capacity of 9 251 MW. Ontario leads Canada in wind capacity as about 5 061 MW of wind capacity was added between 2005 and 2018 and in solar capacity with a capacity of 2 871 MW in 2018, which represents 98% of wind capacity in Canada.

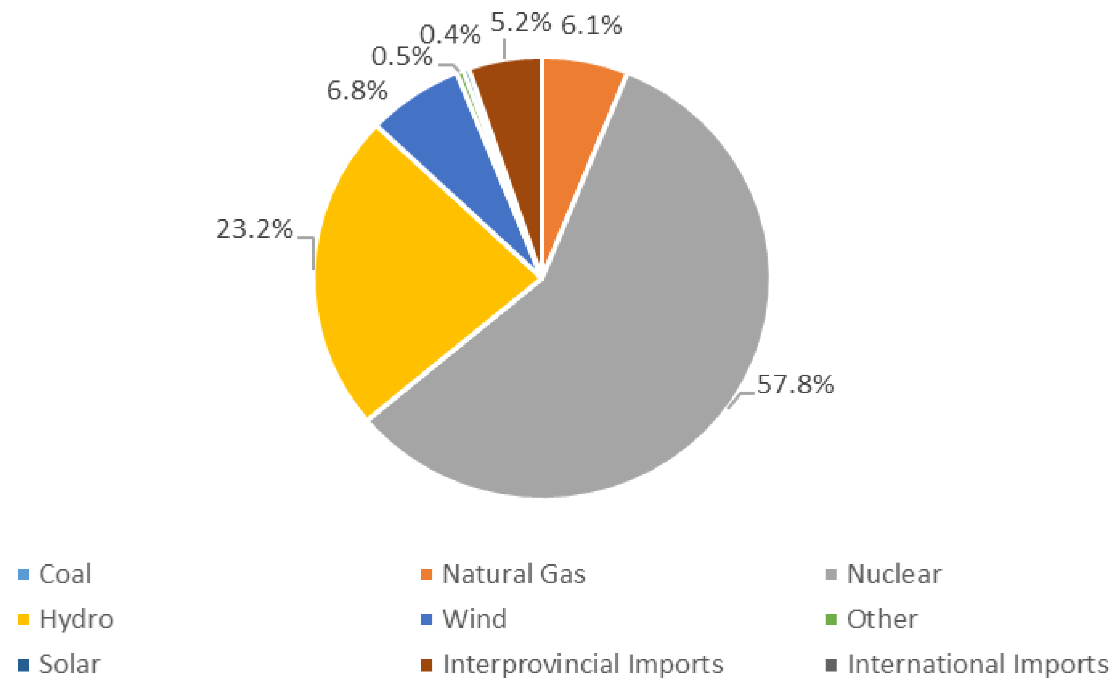
Hydro One is Ontario's largest electricity transmission and distribution service provider with nearly 1.4 million or approximately 26% of the total number of customers in Ontario. It became a publicly traded company on the Toronto Stock Exchange in November 2015.

Total exports to US and other provinces reached 18.6 TWh in 2018 (11.9% of its disposition - IESO), of which 84.8% was exported to the US and 11.1% was exported to Québec, while total imports from the US and other provinces reached 8.4 TWh (5.2% of its supply), of which 3.2% came from the US and 90.2% from Québec.

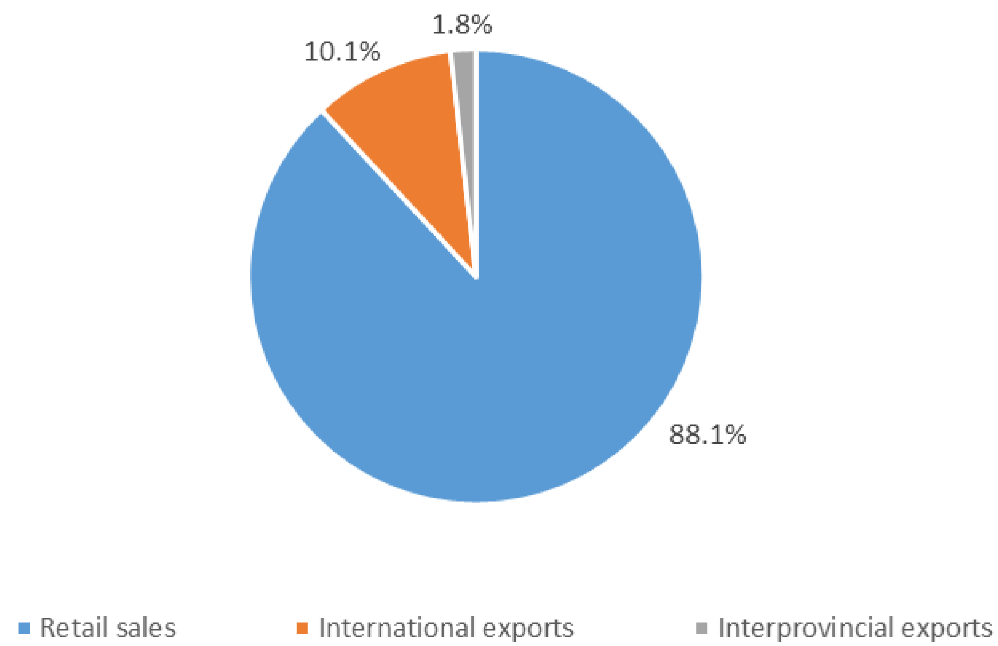
Exports (TWh) to	US	15,759	84.8%
	CAN (QC)	2,831 (2,055)	15.2% (11.1%)
Imports (TWh) from	US	0,274	3.2%
	CAN (QC)	8,165 (7,615)	96.8% (90.2%)

Data reported by IESO differ slightly from those from Statistics Canada. The latter report Total Supply and Disposition at 163.4 TWh, total exports to US and other provinces at 20.5 TWh in 2018 (12.5% of its disposition), while total imports from the US and other provinces reached 8.8 TWh (5.4% of its supply). Figures ON-1 and ON-2 are based on IESO data.

ON-1: ELECTRICITY SUPPLY SOURCES (TOTAL 2018: 156.0 TWh)



ON-2: DISPOSITION

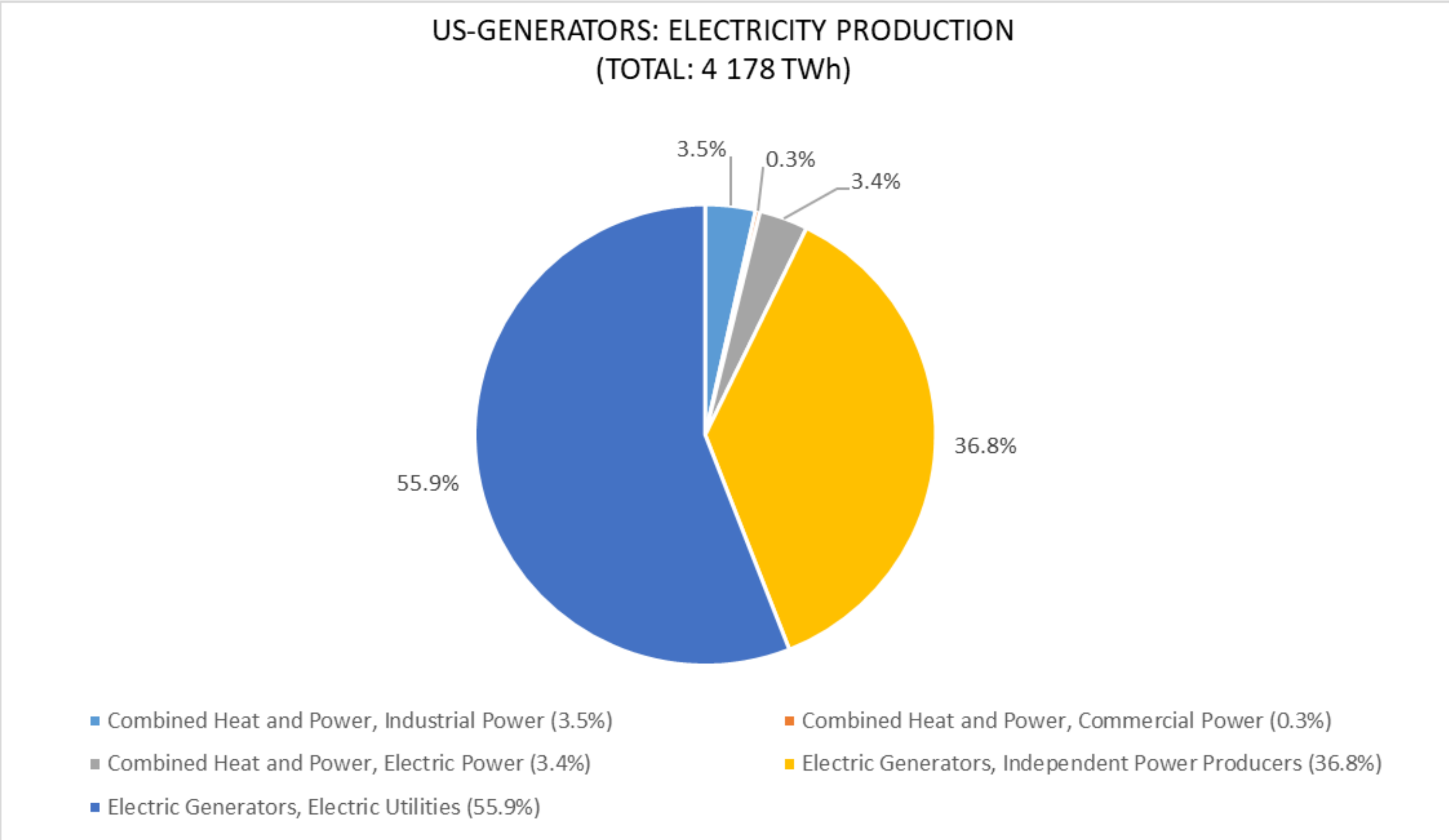


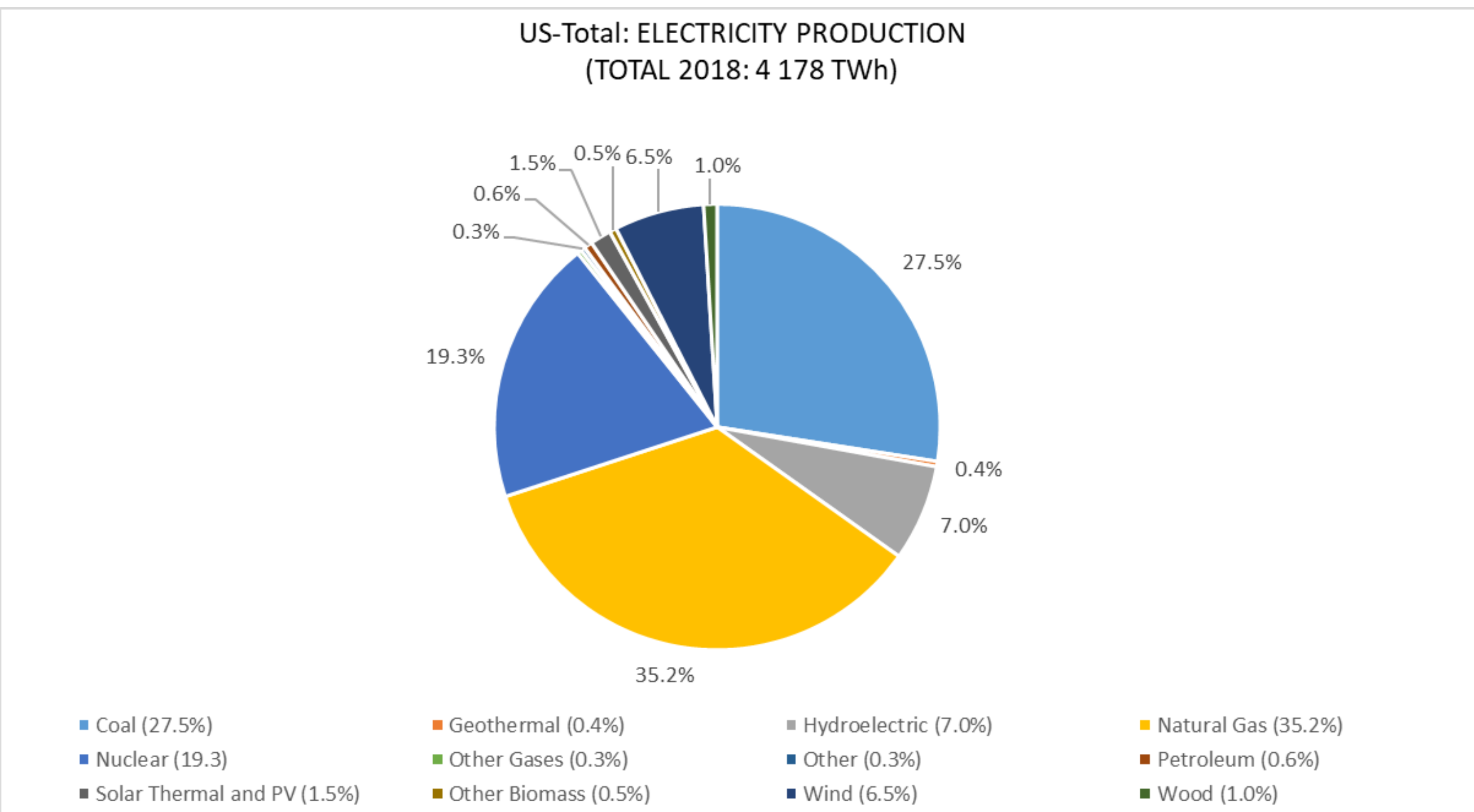
3. THE US OUTLOOK: THE US AS A WHOLE AND THE 18 NEA STATES

From the US Energy Information administration (EIA) website, we learn that combined heat and power (CHP), also known as cogeneration, includes central of distributed production plants that produces concurrently electricity or mechanical power and useful thermal energy from a single source of energy and “a suite of technologies that can use a variety of fuels to generate electricity or power at the point of use, allowing the heat that would normally be lost in the power generation process to be recovered to provide needed heating and/or cooling.” Moreover, “CHP may not be widely recognized outside industrial, commercial, institutional, and utility circles, but it has quietly been providing highly efficient electricity and process heat to some of the most vital industries, largest employers, urban centers, and campuses in the United States.” CHP technologies are responsible for 7.2% of electricity produced in the US.

An independent power producer (IPP) is “a corporation, person, agency, authority, or other legal entity or instrumentality that owns or operates facilities for the generation of electricity for use primarily by the public, and that is not an electric utility.” An electric utility generator is “a generator that is owned by an electric utility, defined as a corporation, person, agency, authority, or other legal entity or instrumentality aligned with distribution facilities for delivery of electric energy for use primarily by the public, or a jointly owned generator with the greatest share of the generator being electric utility owned.” They are responsible for the production 36.8% and 55.9% respectively of total US electricity.

Coal includes anthracite, bituminous coal, subbituminous coal, lignite, waste coal, and synthetic coal. Other includes non-biogenic municipal solid waste, batteries, chemicals, hydrogen, pitch, purchased steam, sulfur, tire-derived fuels, and miscellaneous technologies. Other Biomass includes biogenic municipal solid waste, landfill gas, sludge waste, agricultural by-products, other biomass solids, other biomass liquids, and other biomass gases (including digester gases and methane). Other Gases includes blast furnace gas, propane gas, and other manufactured and waste gases derived from fossil fuels. Petroleum includes distillate fuel oil (all diesel and No. 1, No. 2, and No. 4 fuel oils), residual fuel oil (No. 5 and No. 6 fuel oils and bunker C fuel oil), jet fuel, kerosene, petroleum coke, and waste oil. Wood (and Wood Derived Fuels) includes paper pellets, railroad ties, utility poles, wood chips, bark, red liquor, sludge wood, spent sulfite liquor, and black liquor, with other wood waste solids and wood-based liquids.


US-GENERATORS: ELECTRICITY PRODUCTION
(TOTAL: 4 178 TWh)
3.5%
0.3%
3.4%
36.8%
55.9%
Combined Heat and Power, Industrial Power (3.5%)
Combined Heat and Power, Commercial Power (0.3%)
Combined Heat and Power, Electric Power (3.4%)
Electric Generators, Independent Power Producers (36.8%)
Electric Generators, Electric Utilities (55.9%)


US-Total: ELECTRICITY PRODUCTION
(TOTAL 2018: 4 178 TWh)
1.5%
0.5%
6.5%
1.0%
0.6%
0.3%
27.5%
19.3%
0.4%
7.0%
35.2%
Coal (27.5%)
Geothermal (0.4%)
Hydroelectric (7.0%)
Natural Gas (35.2%)
Nuclear (19.3)
Other Gases (0.3%)
Other (0.3%)
Petroleum (0.6%)
Solar Thermal and PV (1.5%)
Other Biomass (0.5%)
Wind (6.5%)
Wood (1.0%)

CONNECTICUT (CT)

In 2018, Connecticut total electricity supply sources totalled 40.0 TWh, of which 98.7% was produced within the state and 1.3% was imported from international sources (Figure CT-1). The state depends mainly on nuclear energy and natural gas to produce its electricity, respectively accounting for 42.2% and 50.0% of the state's total supply of 40.0 TWh, that is, 42.8% and 50.7% of the state's total production of 39.5 TWh.

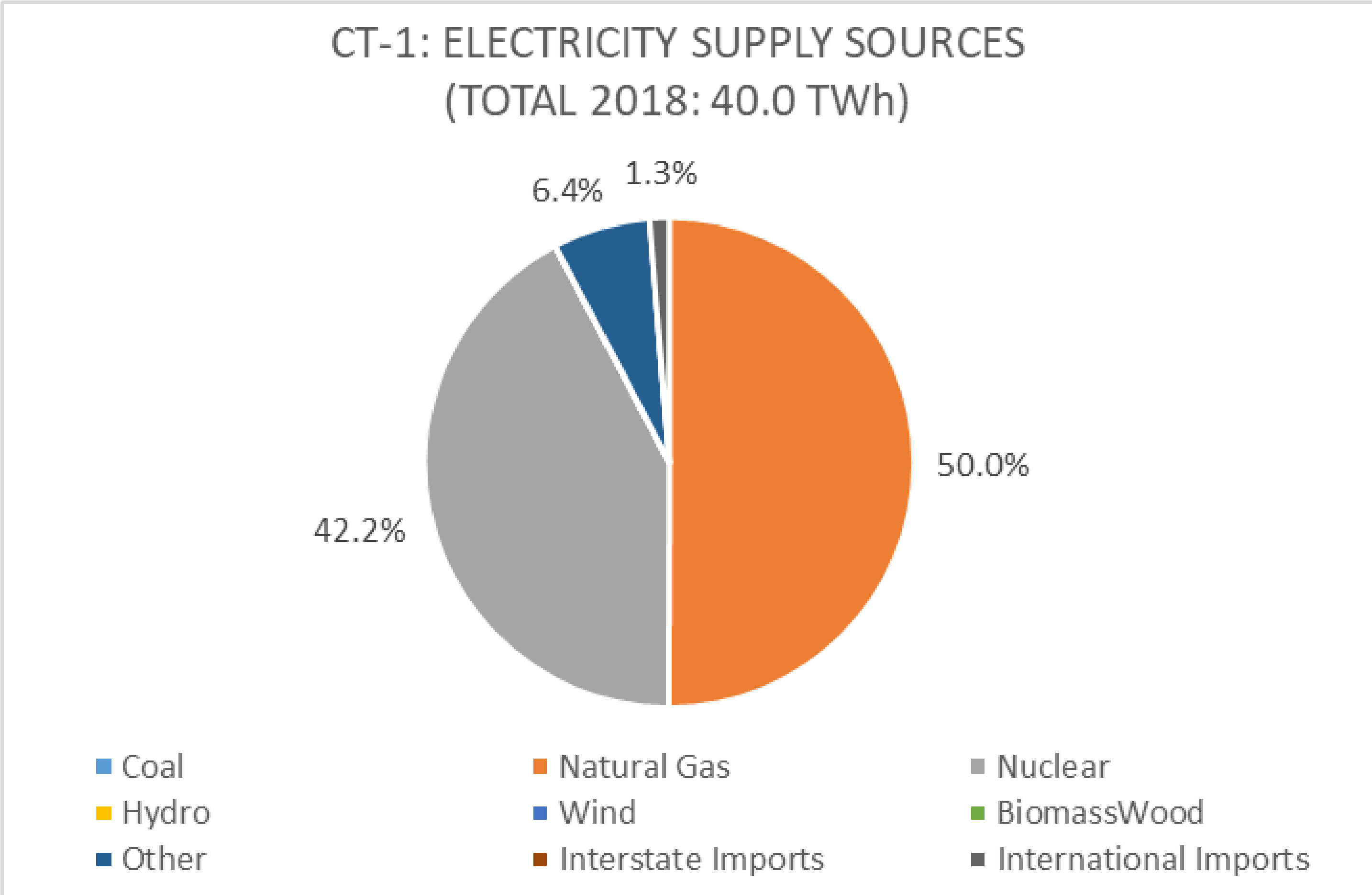
Renewables constitute a small percentage of total supply in 2018, with biomass wood (1.89%), hydro (1.39%) and solar (0.26%) being the most prominent. Coal and petroleum accounts for small percentages of electricity supply (0.82% and 0.85% respectively). In terms of disposition, Connecticut exports a sizeable 21.3% of its electricity supply to other states (Figure CT-2).

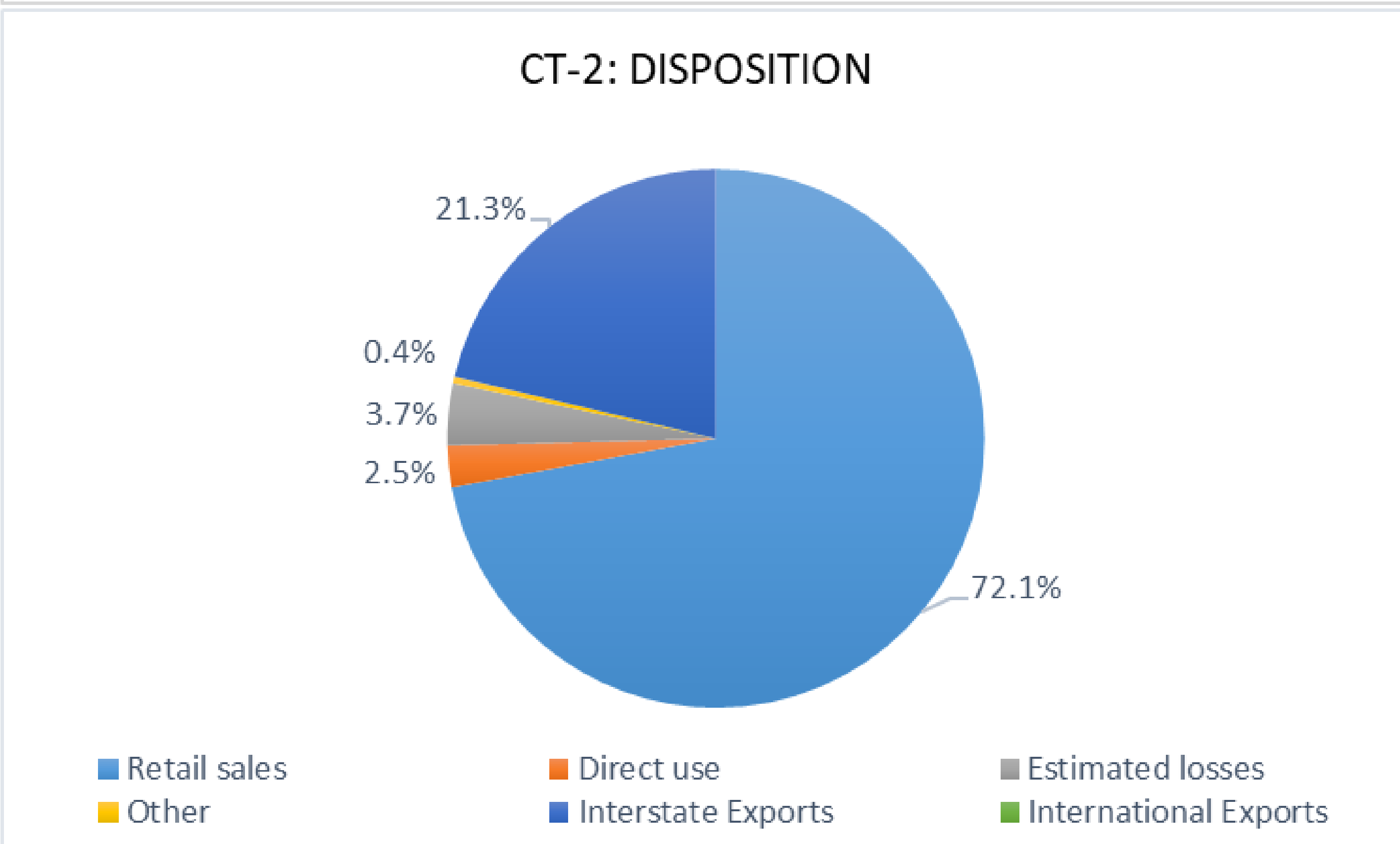
Connecticut has undergone significant changes in its electricity production profile since 2001. Nuclear power represented about 51% of the electricity produced in the state in 2001 and has come down to 41% in 2019, while the share of natural gas power has increased significantly reaching 52% in 2019 compared with just 13% in 2001, its most important surge occurring around 2011-2012. The strong increase of reliance on natural gas has been fueled by the abandonment of traditional fossil fuels such as Coal and Petroleum, which in 2001 occupied a relatively significant proportion of the electricity profile, respectively clocking in at 12% and 17% while in 2018 both fuels are practically nonexistent in the electricity landscape of Connecticut. A mild, yet noticeable rise in the importance of renewable energy is observable (5% in 2019) with Solar energy rapidly growing as the third most important source of power in the state in 2019. The objective is that 40% of electricity consumed in 2030 come from renewable sources.

The largest Connecticut plant by generation is the nuclear Milestone plant (16.9 TWh or 42.7% of total in-state production of 39.5 TWh). It is followed by the natural gas Lake Road Generating plant (5.2 TWh or 13.2% of total in-state production) and four other natural gas plants totaling 12.9 TWh or 32.6% of total in-state production.

Connecticut electricity production compact was responsible for CO_2 emissions of 535 lbs/MWh in 2018, that is, some 29.5% less than in 1990 with 758 lbs/MWh. The progression is noteworthy: Connecticut emitted some 844 lbs/MWh in 2000 and 607 lbs/MWh in 2010. The worst years were 1996, 1997 and 1998 with 1230 lbs/MWh, 1804 lbs/MWh and 1490 lbs/MWh respectively.

Full service providers of electricity (full service providers sell bundled electricity services e.g., both energy and delivery, to end users) are responsible for servicing some 73.1% of the total number of customers, generating 47.9% of total sales in MWh and 49.7% of total revenues. Of those full service providers, investor-owned ones represent 85.4% of retail sales and 90.2% of revenues. The average retail price of investor-owned full Service providers reached 20.18 cents/kWh in 2018 compared with 12.38 cents/kWh public owned providers and 10.23 cents/kWh for cooperatives, for statewide all providers price of 18.41 cents/kWh.


CT-1: ELECTRICITY SUPPLY SOURCES
(TOTAL 2018: 40.0 TWh)
6.4%
1.3%
50.0%
42.2%
Coal
Natural Gas
Nuclear
Hydro
Wind
BiomassWood
Other
Interstate Imports
International Imports


CT-2: DISPOSITION
21.3%
0.4%
3.7%
2.5%
72.1%
Retail sales
Direct use
Estimated losses
Other
Interstate Exports
International Exports

MAINE (ME)

In 2018, Maine's total electricity supply sources reached 15.6 TWh, of which 27.8% was imported internationally (Figure ME-1). The remaining 72.2% (11.3 TWh) was produced within the state, of which Hydroelectricity was the main source with more than 29.0% of the state's total production or 20.9% of the state's total supply.

Renewables constituted a very important source electricity, accounting for more than 53.3% of the state's total supply with hydro (20.9%), wind (15.3%), and biomass wood (17.1%) being the main contributors. Natural gas accounted for 14.9% of total supply, while coal and nuclear were nonexistent.

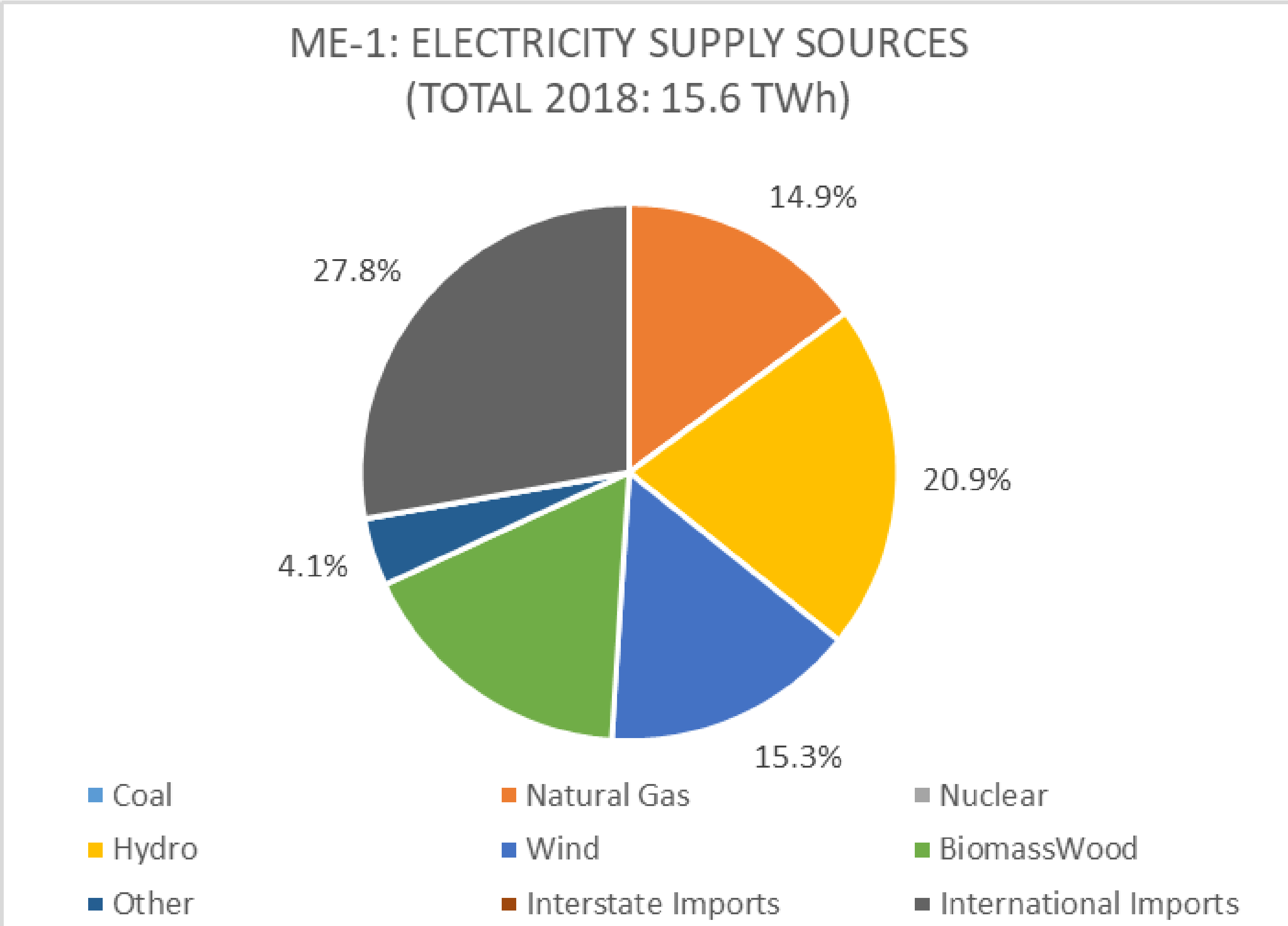
The state does not export much of its electricity supply with interstate exports amounting to only 2.8% of its supply and international exports being almost negligible with only 0.7% of the total supply (Figure ME-2).

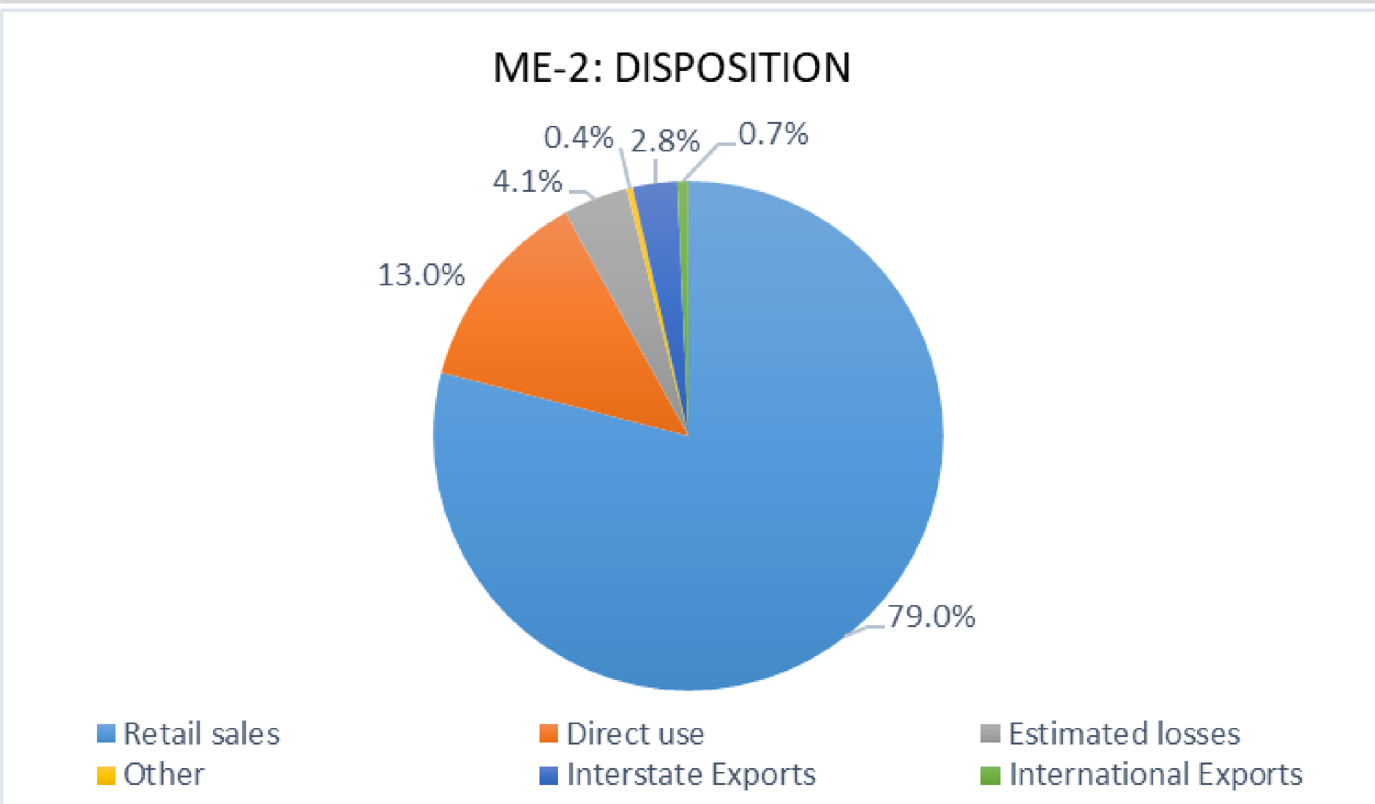
Maine has undergone a thorough and powerful reform of its electricity production since 2001. At the beginning of the millennium, natural gas was the state's main source of energy with more than 51% of the total production. This proportion has gradually decreased until reaching 16% of the state's production total in 2019. Petroleum followed a similar trajectory falling from 11% in 2001 to a negligible amount in 2019. On the contrary, hydro and wind both gained considerably more importance with hydro growing from 14.0% in 2001 to 31% in 2019 and wind growing from 0% in 2001 to more than 24% of the state's total production in 2019. Biomass, while having some considerable volatility throughout the years, didn't change much from 20.0% in 2001 to 25% in 2019. The objective is that 100% of electricity consumed in Maine come from renewable in 2050.

The state's biggest plant by energy production is the Westbrook Energy Center Power plant which uses natural gas to generate 1.49 TWh (or 13.23% of the state's 11.26 TWh production). It is then followed by the Great Lakes Hydro American plant which produces 0.65 TWh (or 5.77% of the state's production). The Rumford Cogeneration, Somerset Plant, Bingham Wind, and Domtar-Woodland Mill are the state's next biggest generating plants accounting for 0.59 TWh (or 5.24% of the state's production), 0.54 TWh (or 4.80% of the state's production), 0.50 TWh (or 4.44% of the state's production), and 0.41 TWh (or 3.64% of the state's production) respectively.

Maine's electricity production compact generated more than 429 lbs/MWh of carbon dioxide in 2018, which is 32.9% less than in 2010 and 58.5% less than in 2000. The state's worst years in terms of total emission rate were 1999 (1 200 lbs/MWh), 1998 (1 118 lbs/MWh), 1995 (1 104 lbs/MWh), 2000 (1 034 lbs/MWh) and 1997 (1 007 lbs/MWh).

In 2018, full service providers of electricity (full service providers sell bundled electricity services e.g., both energy and delivery, to end users) were responsible for servicing 85.9% of the state's total number of customers, generating 53.1% of total sales in MWh and 60.4% of total revenues. Of those full service providers, investor-owned ones accounted for 93.6% of retail sales and 95.2% of revenues. The average retail price of these investor-owned full service providers was 15.53 cents/kWh, while it was 12.55 cents/kWh for public-owned providers and 17.01 cents/kWh for cooperatives. The average price for all providers was 13.44 cents/kWh.


ME-1: ELECTRICITY SUPPLY SOURCES
(TOTAL 2018: 15.6 TWh)
14.9%
27.8%
20.9%
4.1%
15.3%
Coal
Natural Gas
Nuclear
Hydro
Wind
BiomassWood
Other
Interstate Imports
International Imports


ME-2: DISPOSITION
0.4%
2.8%
0.7%
4.1%
13.0%
79.0%
Retail sales
Direct use
Estimated losses
Other
Interstate Exports
International Exports

MASSACHUSETTS

In 2018, Massachusetts total electricity supply sources amounted to 57.1 TWh. Of this, 50.7% (29.0 TWh) were imported from other states, 1.7% (1.0 TWh) was imported from Canada, and 47.6% (27.2 TWh) were produced within the state (Figure MA-1). Natural gas accounted for more than 67.7% of the state's total production (32.2% of total supply) while nuclear was the only other important source with more than 16.4% of the state's production.

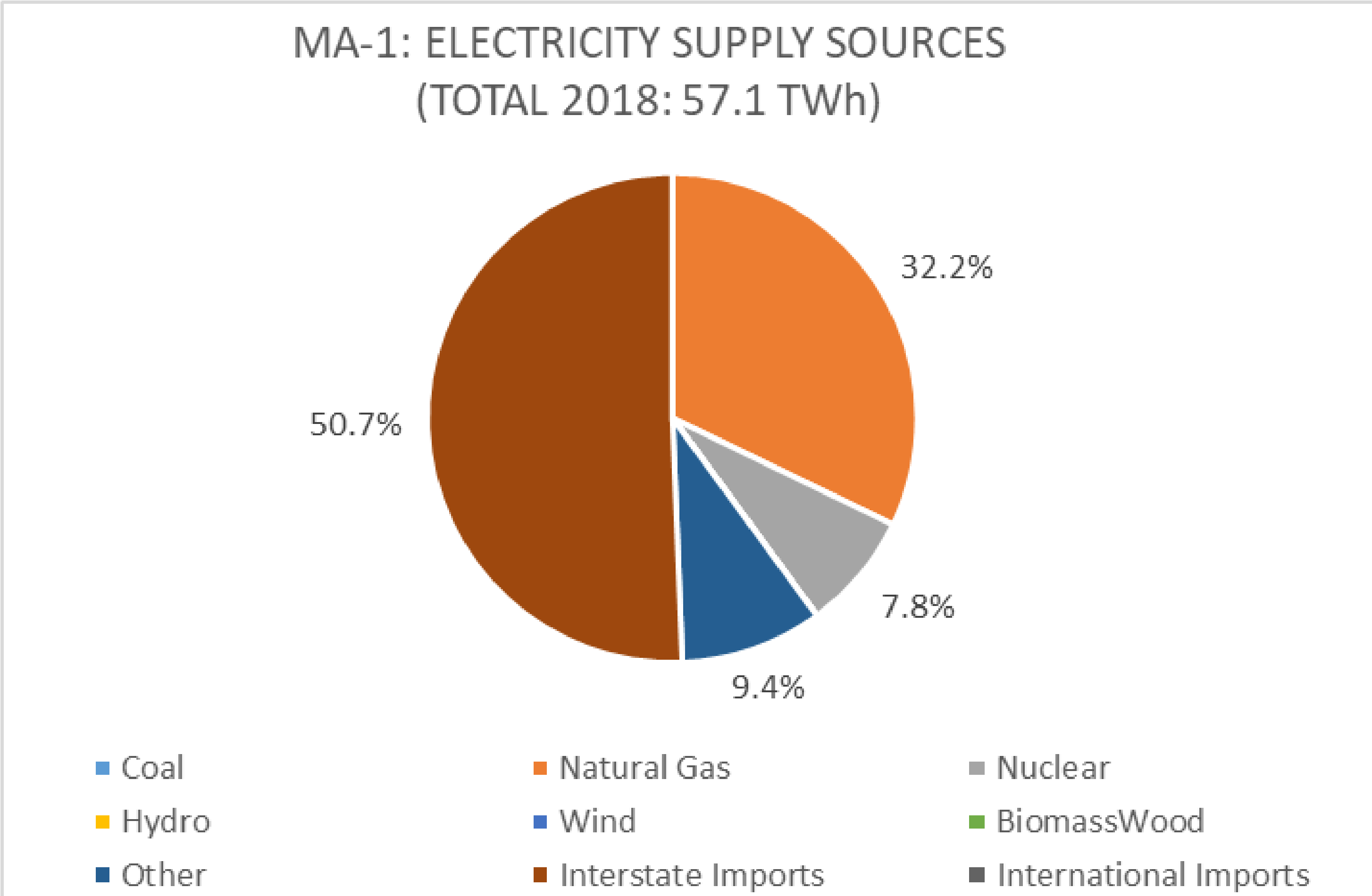
Being such a big importer, Massachusetts exports no electricity (Figure MA-2).

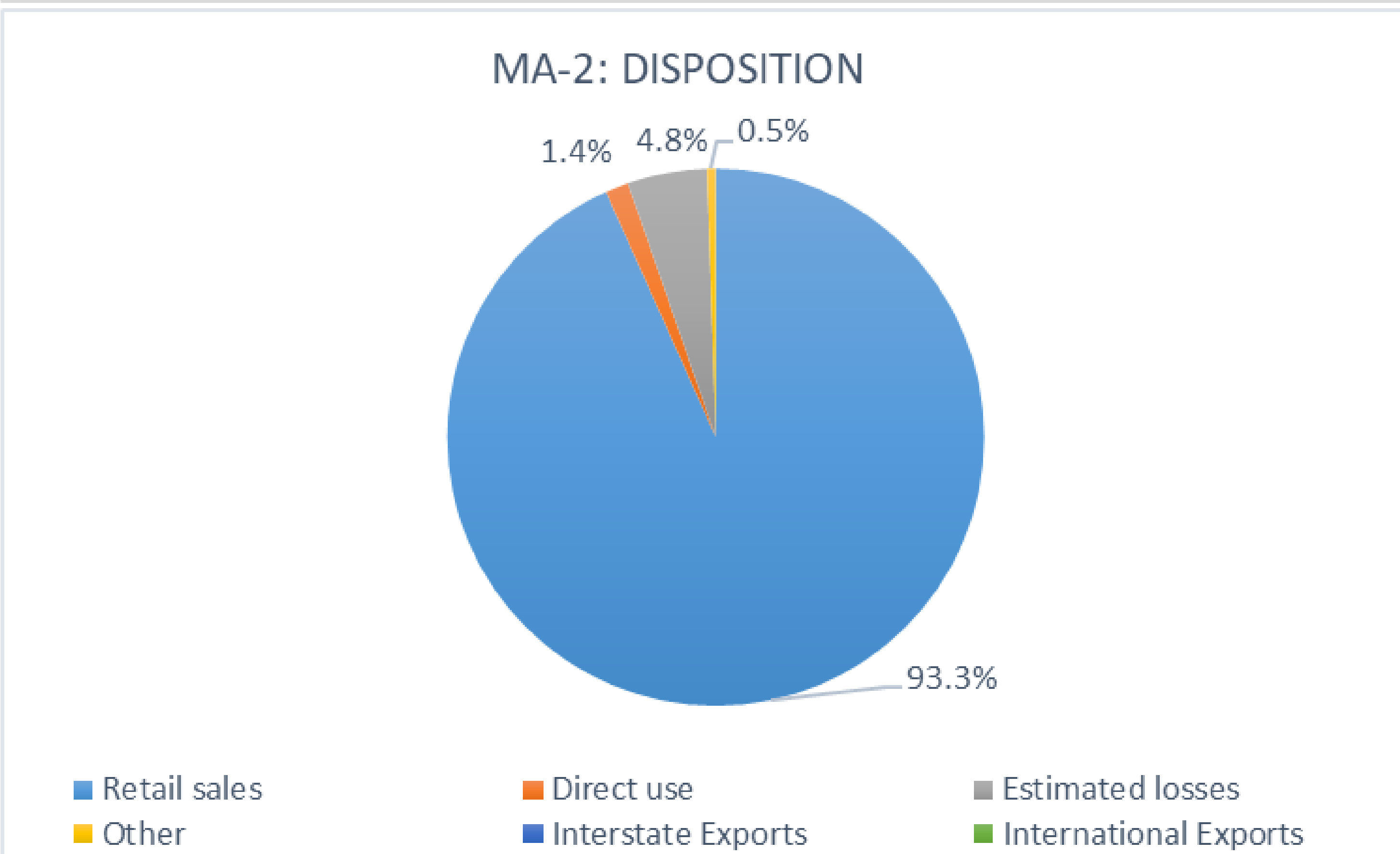
In 2001, natural gas, coal, and petroleum accounted for more than 81% of the state's total production. That number has fallen to around 64% in 2019. This dramatic change can be explained by the gradually decreasing importance of both coal and petroleum within the state. Despite accounting for 29% and 22% respectively in 2001, both energy sources have almost completely disappeared in 2019. Natural gas, on the other hand, has gained tremendous importance, moving from 30% in 2001 to 64% in 2019. Nuclear has gradually gained but recently lost importance, moving from 13% 2001 to 16.4% in 2018 and down to 9% in 2019. It is also important to note that despite being inexistent in 2001, renewable energy has taken a considerable importance in the state's production with Solar energy leading the way at 7% in 2017 and 13% in 2019. The objective is to get 35 percent of total electricity consumed in Maine from renewable sources by 2030.

More than 75% of the state's total production was made within the state's 10 largest plants. The biggest one, the Mystic Generation Station which is powered by natural gas, accounted for more than 4.7 TWh or 16.7% of the state's 27.2 TWh production. In close second came the Pilgrim Nuclear Power Station which generated more than 4.4 TWh or 16.3% of the state's production of electricity in 2018. The next eight plants were all powered by natural gas and accounted for a combined 11.4 TWh or 40.5% of the state's production.

In 2018, the state emitted more than 808 lbs/MWh which was 22.53% less than in 2010 and a whopping 42.74% less than in 2000. However, it is interesting to note than ever since 1990, the state's total emission rate has been gradually diminishing until reaching 2018's low. The state emitted more than 1 500 lbs/MWh on two occasions: 1990 and 1991 with 1 537 lbs/MWh and 1 538 lbs/MWh respectively.

The state's full service providers (full service providers sell bundled electricity services e.g., both energy and delivery, to end users) were responsible for servicing more than 58.7% of the total number of customers within the state, generating 40.3% of total sales in MWh and 41.0% of total revenues. Of those full service providers, investor-owned ones accounted for 62.8% of retail sales while also generating 72.2% of revenues. Those investor-owned full service providers had an average retail price of 21.68 cents/kWh in 2018 compared with 14.01 cents/kWh for public-owned providers and 13.67 cents for non-utilities. The average retail price for all providers within the state was 18.50 cents/kWh.


MA-1: ELECTRICITY SUPPLY SOURCES
(TOTAL 2018: 57.1 TWh)
32.2%
50.7%
7.8%
9.4%
Coal
Natural Gas
Nuclear
Hydro
Wind
BiomassWood
Other
Interstate Imports
International Imports


MA-2: DISPOSITION
1.4%
4.8%
0.5%
93.3%
Retail sales
Direct use
Estimated losses
Other
Interstate Exports
International Exports

NEW HAMPSHIRE

In 2018. New Hampshire's total electricity supply sources amounted to 17.3 TWh, all of which was produced within the state (Figure NH-1). Nuclear and natural gas are the main drivers behind this production, accounting for more than 58.2% and 17.3% of the state's total production.

Biomass wood (8%), hydro (7.8%), and coal (3.8%) were the remaining main sources of production within the state.

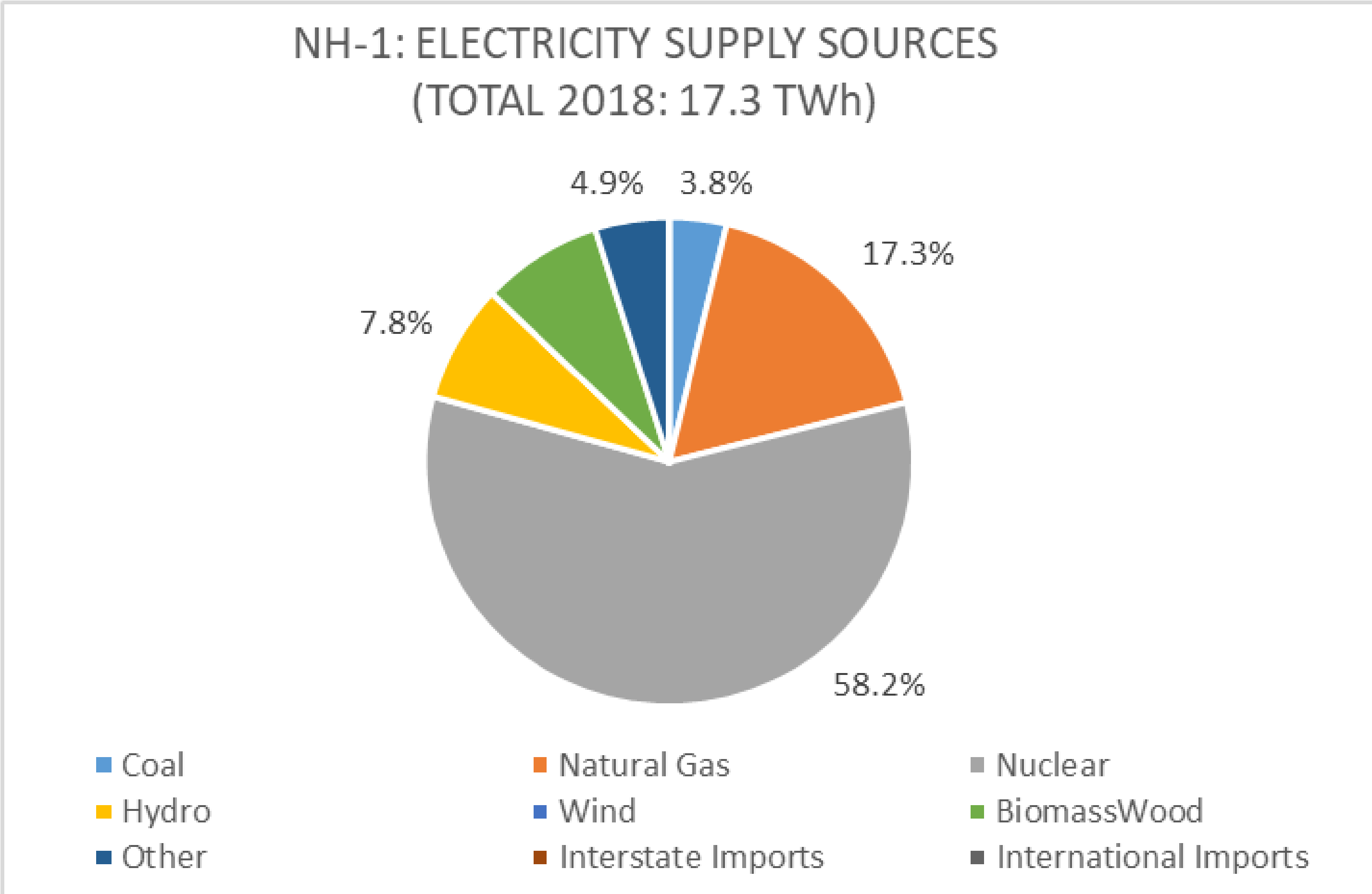
In terms of its disposition, it is interesting to note that the state exports more than 31.8% of its electricity production to other American states (Figure NH-2).

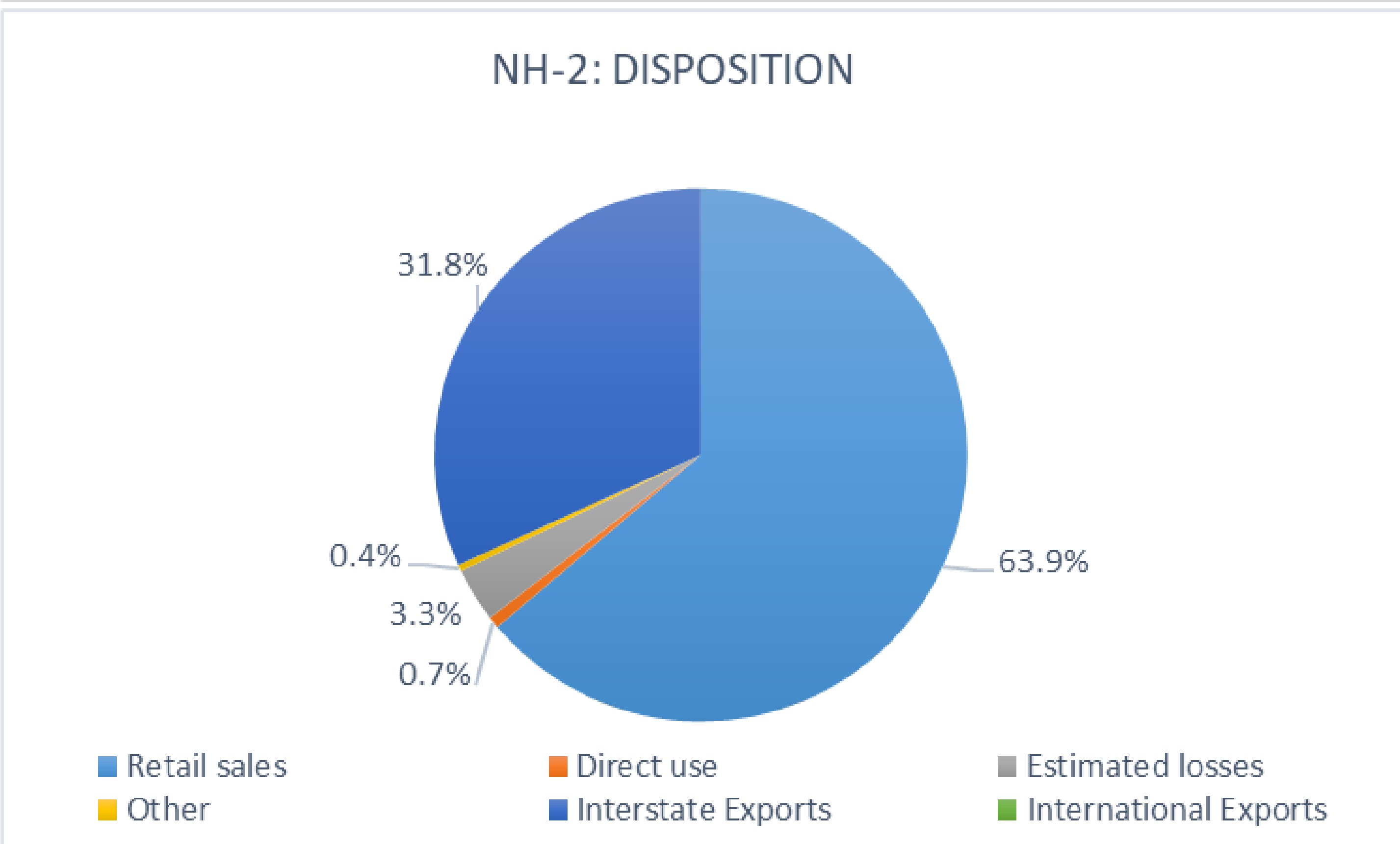
While nuclear energy has been the state's primary energy contributor since before 2001 (coming manly from the Seabrook Power plant) with 58% of total production in 2001 and 60% in 2019, the rise of natural gas has been significant. In 2001, natural gas was practically inexistent within the state, before dramatically increasing in the early 2000s to reach 20% of the total production in 2019. Coal has gradually lost importance from 25% in 2001 to being practically inexistent in 2019 and renewable energy has more or less remained at a constant percentage (18% in 2019) of total production throughout the years with hydro leading the group. The objective is that by 2025, 25% of electricity consumed come from renewable sources.

The Seabrook nuclear plant is by far the state's largest plant generating more than 10.1 TWh (or 58.4% of the state's 17.3 TWh production). It is followed by the Granite Ridge natural gas plant which accounted for almost 2.2 TWh (or 12.7% of the state's production) and the Essential Power Newington LLC natural gas plant which generated 0.81 TWh (or 4.7% of the state's production). Of the seven following plants, three use wood, two are hydro-based, one uses coal, and one uses wind; they accounted for a combined 2.39 TWh (or 13.8% of the state's production).

New Hampshire electricity production compact was responsible for 282 lbs/MWh of carbon dioxide emissions in 2018. The state saw its total emission rate fall by a whopping 60.7% from 2000 to 2018, by 48.7% from 2010 to 2018. The state experienced important fluctuations from 1990 to 2003. After reaching 782 lbs/MWh in 2003, the state's worst year since 1991, the emission rate started stabilizing and gradually dropped to reach 2018's 282 lbs/MWh low.

In 2018, full service providers (full service providers sell bundled electricity services e.g., both energy and delivery, to end users) were responsible for servicing more than 79.5% of the state's total number of customers, generating 48.3% of total sales in MWh and 51.9% of total revenues. Of those full service providers, investor-owned ones accounted for 84.1% of retail sales in MWh while generating more than 83.6% of the revenues. Those same investor-owned full service providers had an average retail price of 18.20 cents/kWh compared to the 13.78 cents/kWh for publicly owned full service providers and 20.14 cents/kWh for cooperatives. The state's total average for both full service providers and other providers was 17.01 cents/kWh.


NH-1: ELECTRICITY SUPPLY SOURCES
(TOTAL 2018: 17.3 TWh)
4.9%
3.8%
17.3%
7.8%
58.2%
Coal
Natural Gas
Nuclear
Hydro
Wind
BiomassWood
Other
Interstate Imports
International Imports


NH-2: DISPOSITION
31.8%
0.4%
3.3%
0.7%
63.9%
Retail sales
Direct use
Estimated losses
Other
Interstate Exports
International Exports

RHODE ISLAND

In 2018, Rhode Island electricity supply sources totalled 8.5 TWh, which was all produced within the state (Figure RI-1). A significant 92.7% of this total production came from natural gas.

The rest of production was mainly attributed to biomass wood which produced 2.5% of the state's total production while other sources amounted to 4.8%.

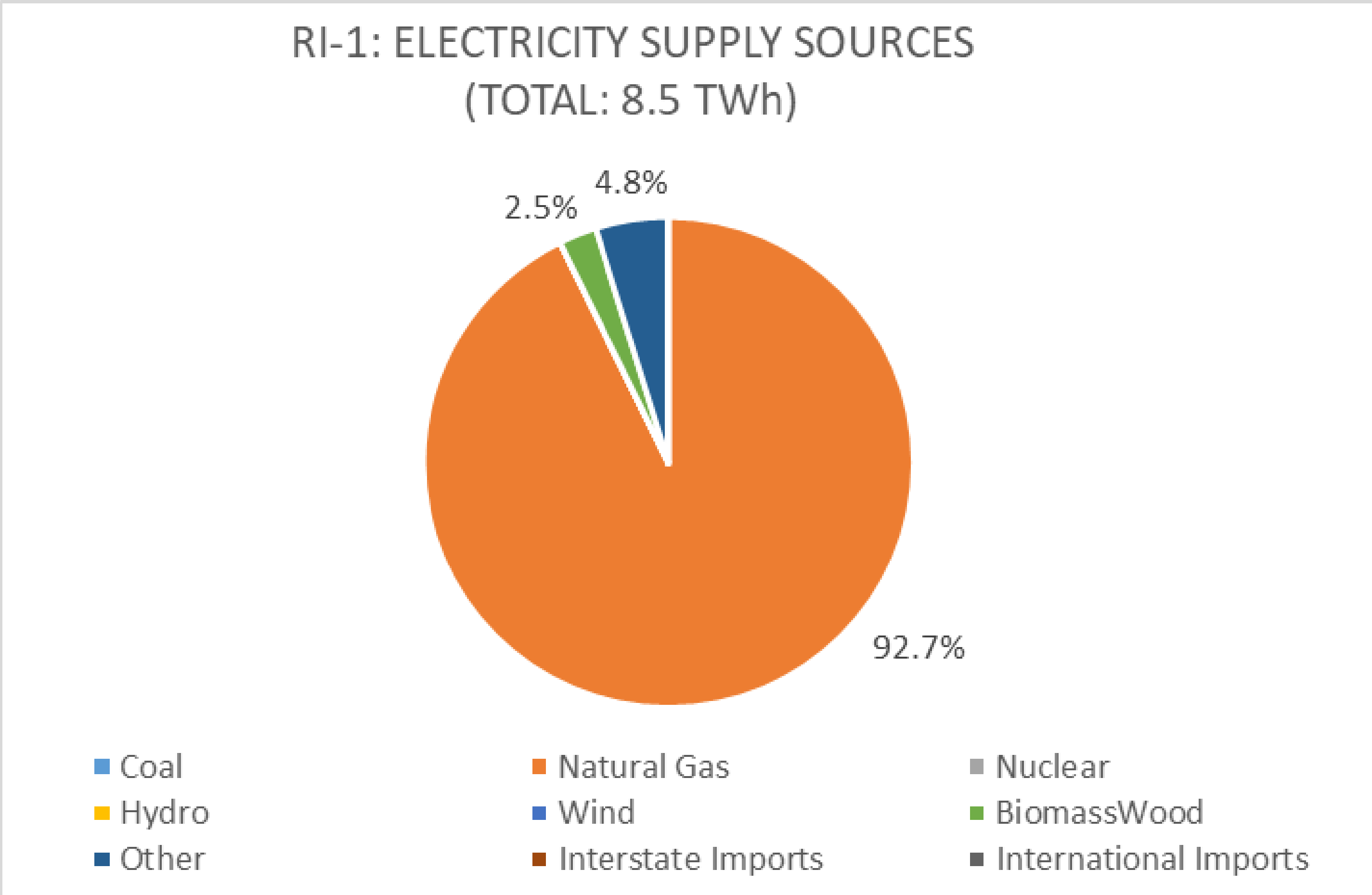
In terms of its disposition, the state's used 96.7% of its supply within the state while 3.3% of was exported to other states (Figure RI-2).

Rhode Island is highly dependant on natural gas and has been for decades. In 2001, natural gas amounted to more than 98% of the state's total production and it has kept the same level of importance throughout the years although it fell to 91% in 2019. Since 2013, biomass wood, wind and solar energy have gradually expanded their importance in the state's total production profile at the expense of the natural gas industries. That trend seemed to accelerate in 2019 with solar energy rapidly expanding throughout the state. The objective for 2035 is that 38% of electricity consumed in Rhode Island come from renewable sources.

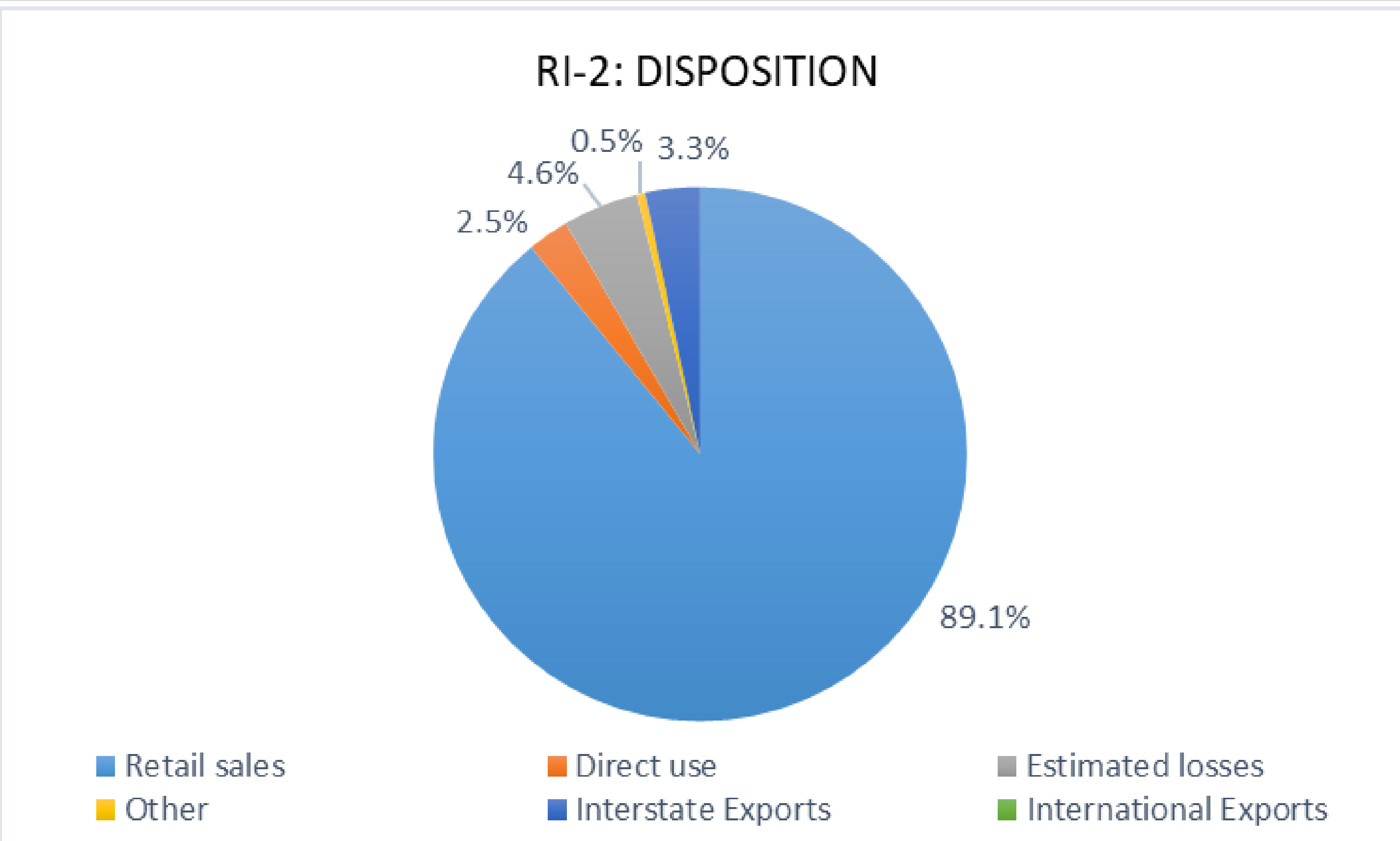
The state's top five plants were all operating on natural gas and accounted for a combined 7.75 TWh (or 91.2% of the state's 8.5 TWh production). Most of that was generated within the Rhode Island State Energy Center which produced more than 2.82 TWh (or 33.2% of the state's production) and the Manchester Street plant which accounted for 1.87 TWh (or 22.0% of the state's production). The Tiverton Power plant and Ocean State Power 2 and Ocean State Power 1 plants also accounted for noticeable amounts of electricity produced with 1.56 TWh (or 18.4% of the state's production), 0.83 TWh (or 9.8% of the state's production), and 0.7 TWh (or 8.0% of the state's 8.5 TWh production) respectively.

Rhode Island's electricity production compact was responsible for the emission of more than 879 lbs/MWh of carbon dioxide in 2018. This is only a 3.93% decrease since 2010 and a 17.15% decrease since 2000. It is also interesting to note that in 2013, the state emitted 999 lbs/MWh which was the most since 2001. Unlike other states, Rhode Island hasn't achieved substantial improvement in its total emission rate.

In 2018, full service providers (full service providers sell bundled electricity services e.g., both energy and delivery, to end users) were responsible for servicing more than 87.1% of the state's total number of retail customers, generating 54.2% of total sales in MWh and 58.4% of total revenues. Of those full service providers, investor-owned ones accounted for 98.7% of retail sales in MWh while generating more than 98.9% of the total revenues. The average retail price of the investor-owned full service providers was 19.58 cents/kWh while it was 14.86 cents/kWh for publicly owned full service providers and 14.98 cents/kWh for non-utilities. The total average retail price for both full service providers and others was 18.10 cents/kWh.



RI-1: ELECTRICITY SUPPLY SOURCES
(TOTAL: 8.5 TWh)
2.5%
4.8%
92.7%
Coal
Natural Gas
Nuclear
Hydro
Wind
BiomassWood
Other
Interstate Imports
International Imports



RI-2: DISPOSITION
0.5%
3.3%
4.6%
2.5%
89.1%
Retail sales
Direct use
Estimated losses
Other
Interstate Exports
International Exports

VERMONT

In 2018, Vermont's total electricity supply sources was estimated at 11.9 TWh, 18.3% (2.18 TWh) of which was produced within the state (Figure VT-1). Hydro was the state's main production technology, amounting to 58.47% (1.27 TWh) of the state's total production. More than 81.7% (9.72 TWh) of the state's total electricity supply was imported from Canada.

While Vermont imported a tremendous amount of electricity, the one it did produce was almost completely provided by renewable energy. Biomass wood amounted to almost 3.6% of the state's total electricity supply while wind was responsible for more than 3.1%. Other sources represented 0.9% of the state's supply.

Despite importing 81.7% of its electricity supply from Canada, Vermont actually exports more than half (50.7%) of its total electricity supply to other American states (Figure VT-2).

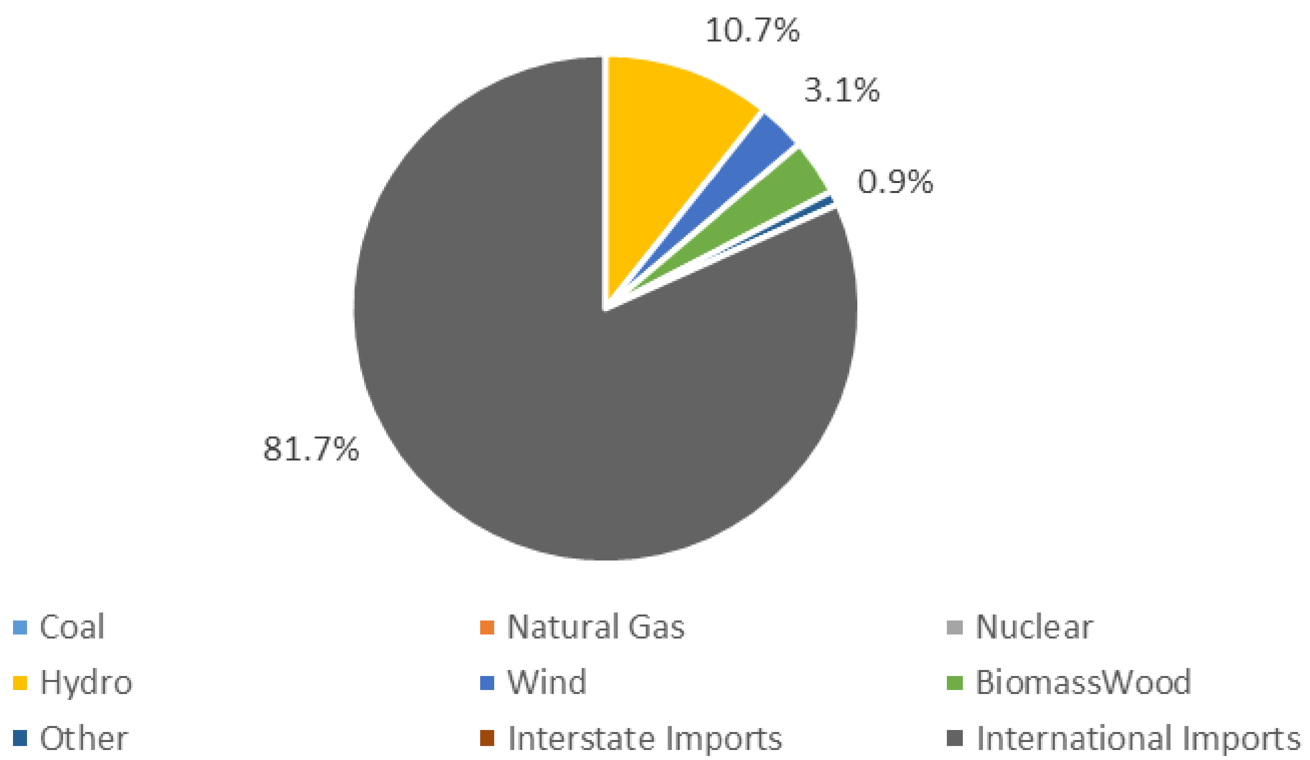
Vermont has undergone tremendous changes in its electricity production profile since 2001. Nuclear was a prominent source in the state's production profile in 2001, amounting to more than 76% of the state's internal production value while hydro (16%) and biomass wood (7%) took care of the rest. This remained the case until 2014 when the state decided its dependence on Nuclear energy wasn't sustainable and shifted towards renewable and cleaner energy. Nuclear energy was abandoned, and its plants shut down. Wind (16%) and solar (14%) energy carved a significant role within the state while biomass wood (18%) and hydro (51%) both rose dramatically to replace the lost electricity output. Vermont imports most of its electricity (81.7%) from Canada. The objective that by 2032, more than 75% of its consumption come from renewable sources.

The state produced only 2.18 TWh of electricity in 2018. The Bellows Falls hydroelectric plant was responsible for 0.25 TWh (or 11.5% of the state's production) while the J C McNeil wood plant accounted for 0.24 TWh (or 11.0% of the state's production).

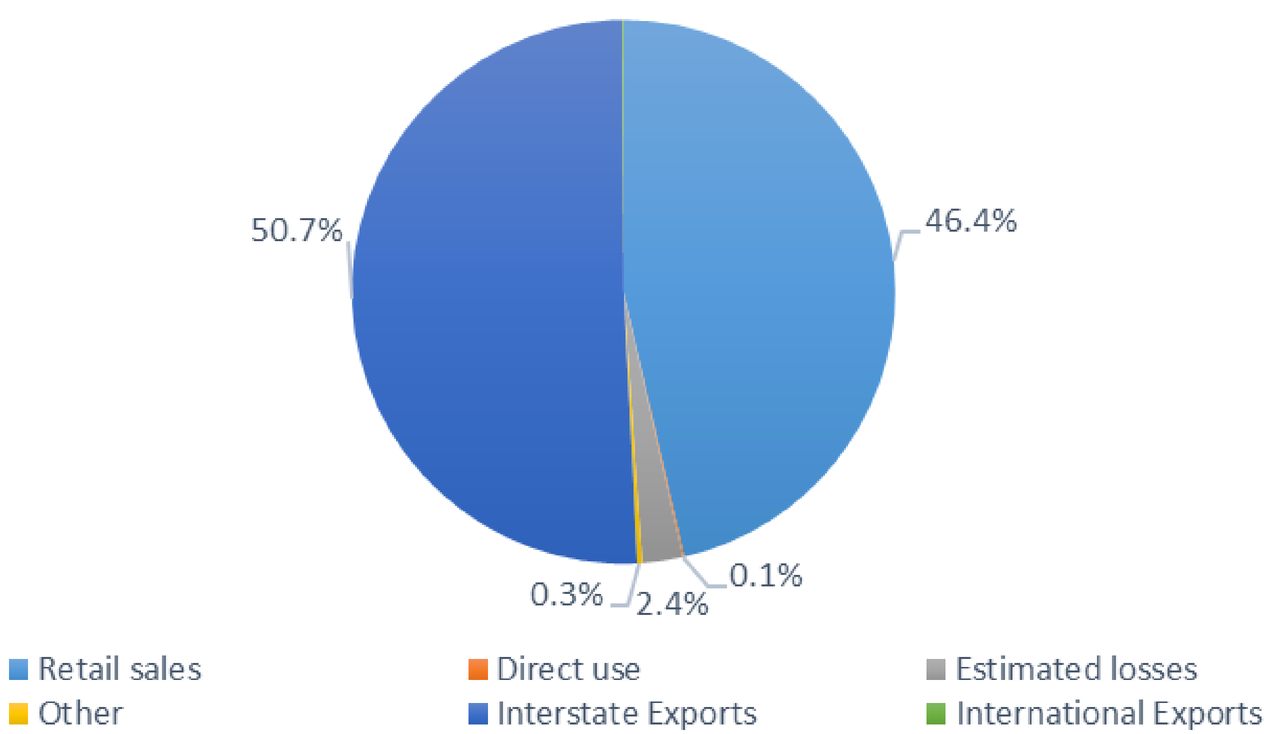
Vermont was responsible for the emission of only 10 lbs/MWh of carbon dioxide in 2018, an incredibly low number compared to the others 18 states we analyze. The state has been a very low producer of carbon dioxide for decades which is understandable considering how little electricity it produces.

In 2018, full service providers (full service providers sell bundled electricity services e.g., both energy and delivery, to end users) were responsible for servicing all of the retail customers within the state. Investor-owned providers accounted for 76.6% of retail sales in MWh while generating 75.6% of total revenues at an average retail price of 14.92 cents/kWh. Publicly owned providers had an average retail price of 15.04 cents/kWh, while cooperatives had 16.93 cents/kWh. The average price for all providers was 15.13 cents/kWh.

VT-1: ELECTRICITY SUPPLY SOURCES (TOTAL: 11.9 TWh)



VT-2: DISPOSITION



NEW JERSEY

In 2018, New Jersey's total electricity supply sources amounted to 81.6 TWh, 91.7% (74.83 TWh) of which was produced internally (Figure NJ-1) through natural gas technology which produced 51.8% (38.76 TWh) of total production and nuclear which produced 42.64% (31.91 TWh). The state imported 8.3% of it's total supply sources from other states.

Other sources of energy such as solar energy and coal represented 5.1% of the state's total supply.

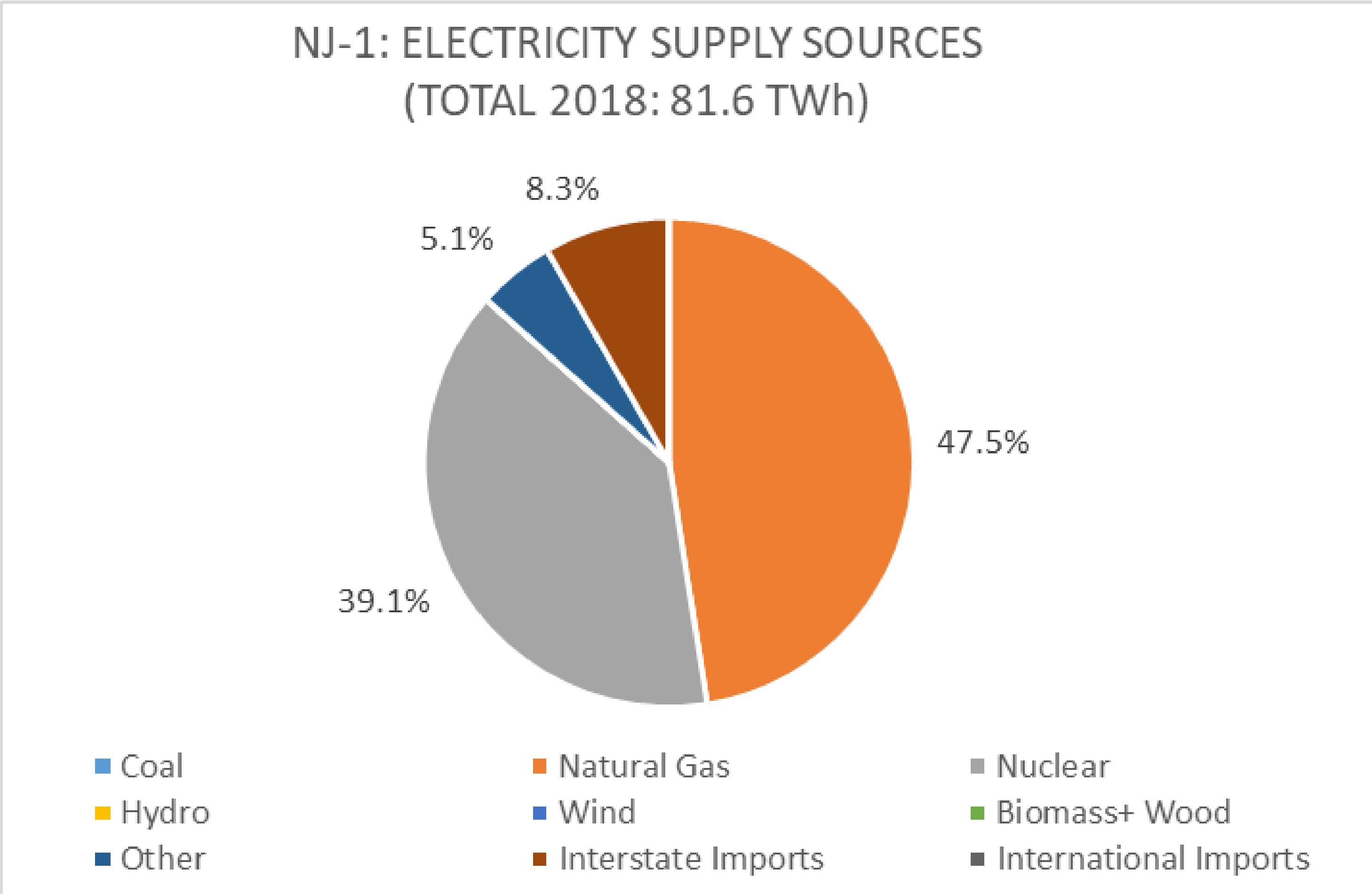
New Jersey does not export any electricity to other states as the totality of its supply is consumed within the state (Figure NJ-2).

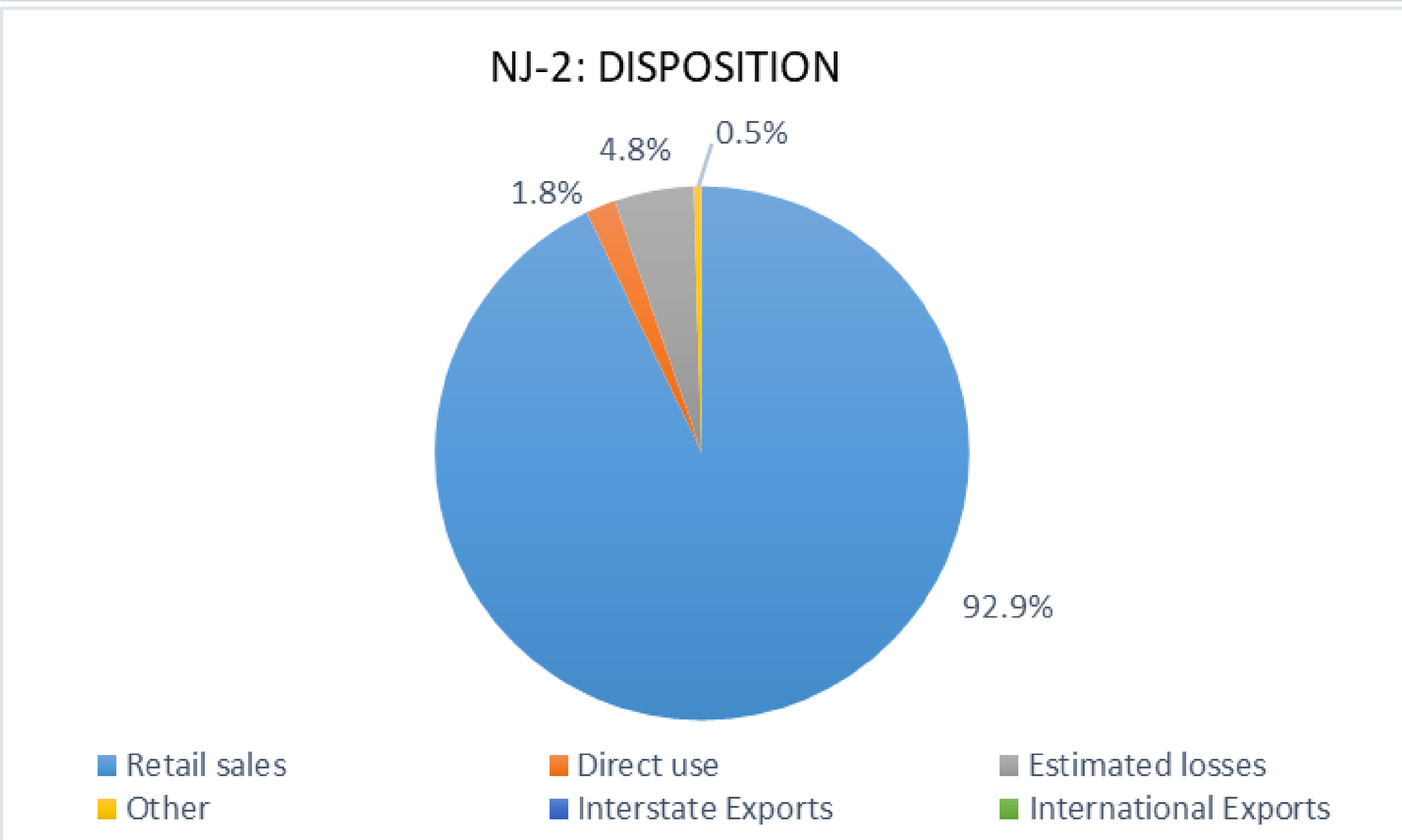
The state's energy production profile has changed significantly since 2001 as Nuclear went from 51% to 36% and Natural Gas from 28% to 55%. Therefore, the two main sources accounted for 79% of the state's total production of electricity in 2001 and 91% in 2019. The other main change regards the gradually diminishing importance of coal within the state falling from 16% in 2001 to an insignificant 1% of the state's total production profile in 2019. This came as solar energy gained some importance within the state. The objective is that 50% of electricity consumed in New Jersey come from renewable sources by 2030.

New Jersey is a rather large producer of electricity. The PSEG Salem Generation Station nuclear plant and the PSEG Hope Creek Generating Station nuclear plant generated a combined 28.43 TWh (or 38.0% of the state's 74.83 TWh production). The following seven plants in terms of generated electricity were all operating on natural gas and combined for a total of 32.24 TWh (or 43.1% of the state's production).

In 2018, the state's electricity production compact was responsible for the emission of 554 lbs/MWh of carbon dioxide which represented a 13.7% decrease from 2010 and a 33.49% decrease from 2000. In 1996, the state emitted more than 1 115 lbs/MWh, the state's worst year. Ever since, the emission rate has been gradually diminishing until 2018 which was the state's best year.

Full service providers (full service providers sell bundled electricity services e.g., both energy and delivery, to end users) are responsible for servicing more than 86.1% of all the total number of retail customers within the state, generating 53.2% of sales in MWh and 56.5% of all revenues. Of the full service providers, investor-owned ones accounted for more than 95.6% of retail sales in MWh while generating 95.5% of revenues. The average retail price for those investor-owned full service providers was 14.06 cents/kWh compared to 15.60 cents/kWh for publicly owned full service providers, 12.53 cents/kWh for cooperatives, and 11.50 cents/kWh for non-utilities. The total average for both full service providers and others was 13.23 cents/kWh.


NJ-1: ELECTRICITY SUPPLY SOURCES
(TOTAL 2018: 81.6 TWh)
8.3%
5.1%
47.5%
39.1%
Coal
Natural Gas
Nuclear
Hydro
Wind
Biomass+ Wood
Other
Interstate Imports
International Imports


NJ-2: DISPOSITION
4.8%
0.5%
1.8%
92.9%
Retail sales
Direct use
Estimated losses
Other
Interstate Exports
International Exports

NEW YORK

In 2018, New York's total electricity supply amounted to 160.5 TWh, 82.5% (132.41 TWh) of which was produced within the state (figure NY-1). Natural gas was the main producer in the state being responsible for more than 38.4% (50.87 TWh) of the state's total production while nuclear (32.4% or 42.85 TWh) and hydro (22.4% or 29.69 TWh) came in not far behind in the state's production profile. Importations amounted to 17.5% (28.09 TWh) of the state's electricity supply, from international sources for 9.8% and national sources for 7.7%. Other sources of energy amounted to 5.7% of the state's total.

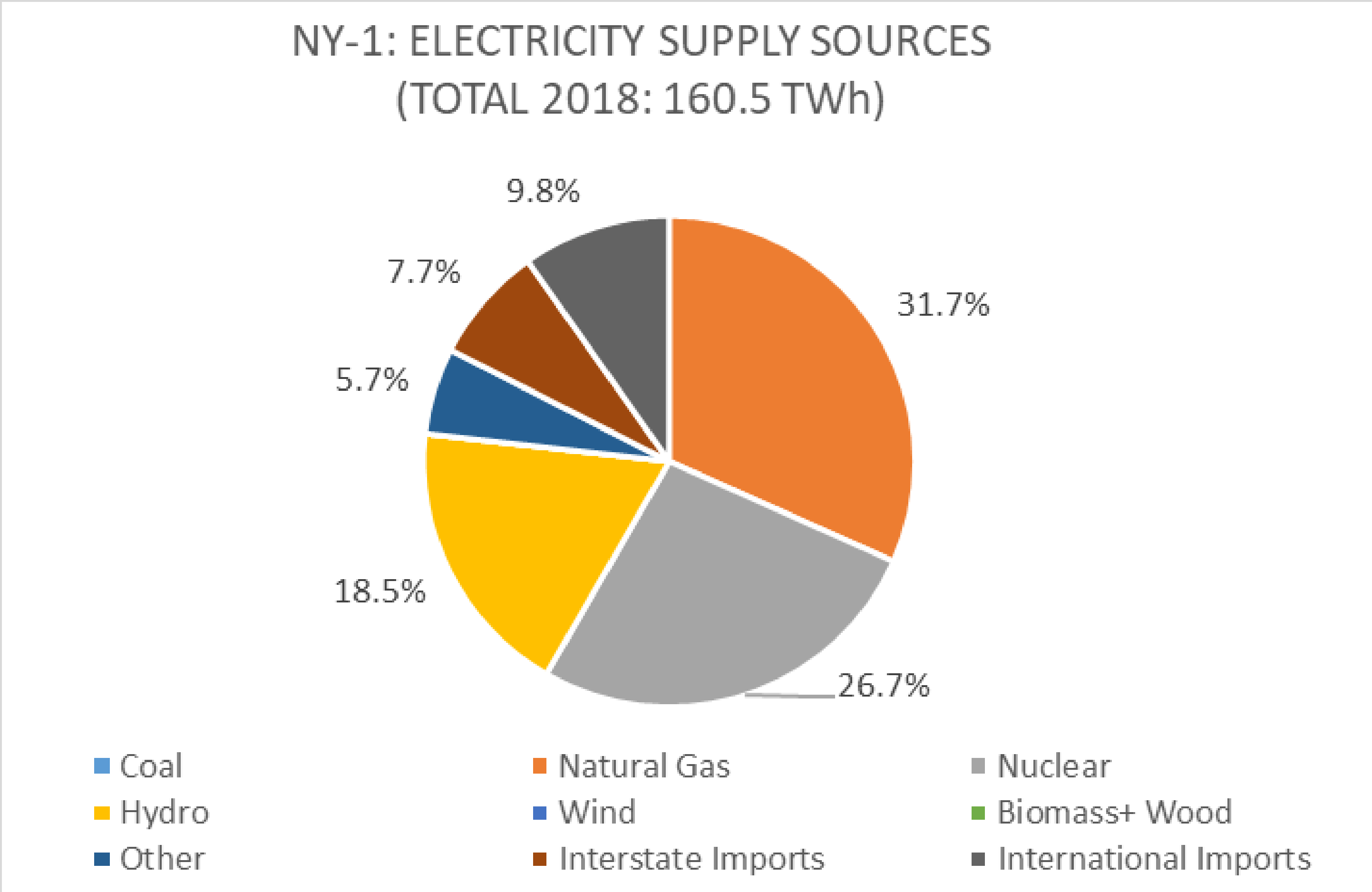
New York did not export electricity as the totality of its supply was consumed within the state (Figure NY-2).

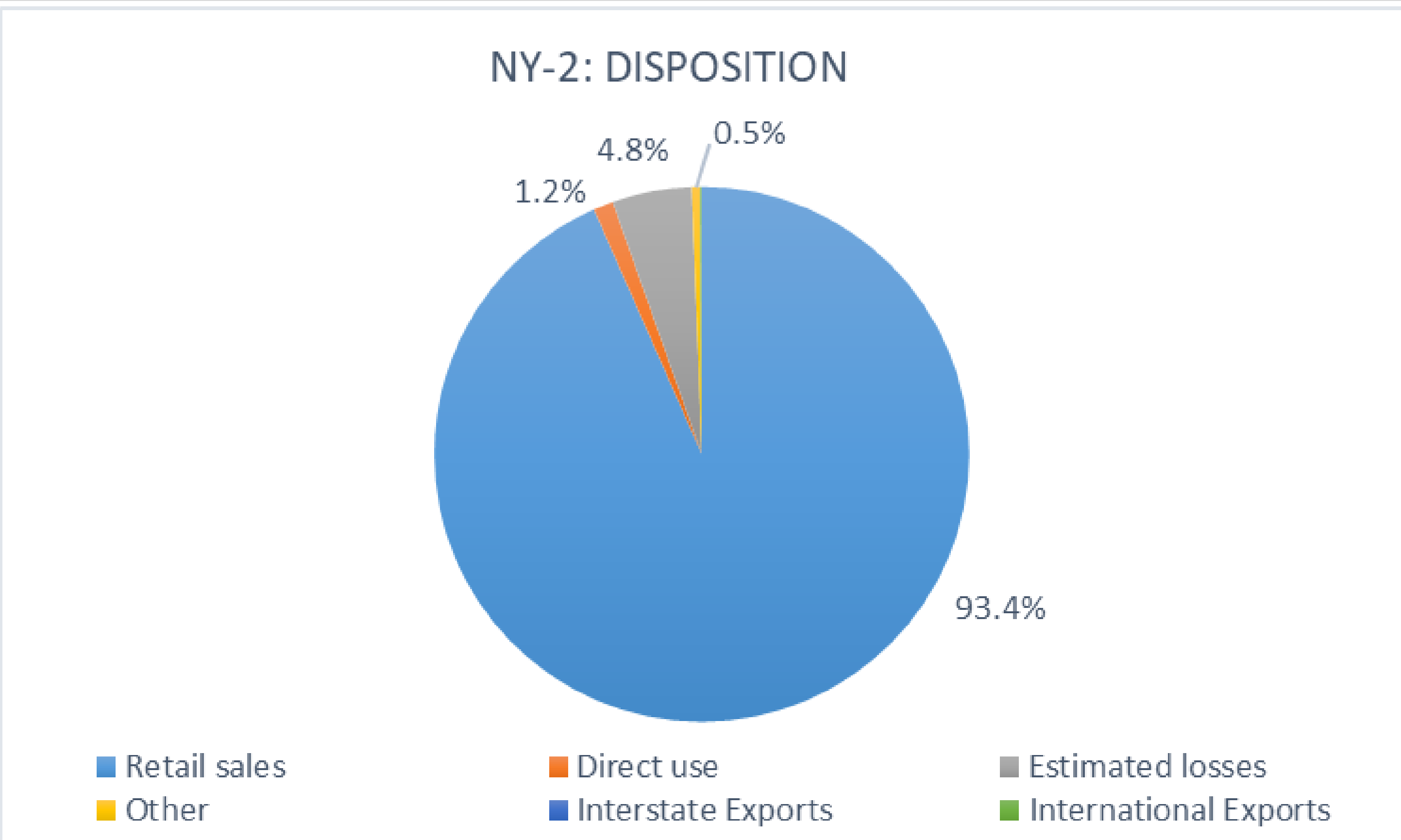
The state has seen important changes in its electricity output. While natural gas (27% to 37%), nuclear (28% to 33%) and hydro (16% to 22%) have seen their market share increase between 2001 and 2019, coal and petroleum, both important players in 2001 with a combined 27% of the total production, have been wiped out from the state's production profile. The objective is that no less than 70% of consumption of electricity come from renewable sources by 2013.

New York is a big producer of electricity but it doesn't have very big plants. Instead it has a large number of medium sized and smaller plants. However, the Roberts Moses Niagara Hydroelectric plant and the Nine Mile Point Nuclear Station are the two biggest plants in terms of generated electricity with 16.77 TWh (or 12.7% of the state's 132.41 TWh production) and 15.38 TWh (or 11.6% of the state's production). They are followed by the Indian Point 3 and Indian Point 2 nuclear plants which generated 8.3 TWh (or 6.3% of the state's production) and 8.01 TWh (or 6.1% of the state's production) of electricity in 2018. The following six largest plants accounted for a combined 32.85 TWh (or 24.8% of the state's production).

In 2018, New York's electricity production compact was responsible for the emission of 464 lbs/MWh of carbon dioxide, which is a 30.5% decrease since 2010 and a 52.9% decrease since 2000. The state has made effort to diminish its carbon dioxide emission since 1990 and it shows as the total emission rate has been gradually decreasing since 1990 when it topped 1 123 lbs/MWh.

The state's full service providers (full service providers sell bundled electricity services e.g., both energy and delivery, to end users) were responsible for servicing more than 82.5% of the total number of retail customers within the state, generating 48.9% of sales in MWh and 55.7% of all revenues. Of those full service providers, investor-owned ones accounted for 68.0% of retail sales in MWh while generating 68.7% of revenues at an average price of 17.04 cents/kWh. Publicly owned full service providers had an average retail price of 16.86 cents/kWh while it was 12.16 cents/kWh for cooperatives and 8.58 cents/kWh for non-utilities. The total average retail price for both full service providers and others was 14.83 cents/kWh.


NY-1: ELECTRICITY SUPPLY SOURCES
(TOTAL 2018: 160.5 TWh)
9.8%
7.7%
31.7%
5.7%
18.5%
26.7%
Coal
Natural Gas
Nuclear
Hydro
Wind
Biomass+ Wood
Other
Interstate Imports
International Imports


NY-2: DISPOSITION
4.8%
0.5%
1.2%
93.4%
Retail sales
Direct use
Estimated losses
Other
Interstate Exports
International Exports

PENNSYLVANIA

Pennsylvania's electricity supply totalled 215.4 TWh in 2018, all of it produced within the state through (Figure PA-1) nuclear at 83.36 TWh or 38.7% of total. production, natural gas at 76.47 TWh or 35.5%, and coal at 44.16 TWh or 20.5%.

Renewable energy is negligible for now, but the state has undertaken concrete actions to increase and encourage cleaner electricity supply sources.

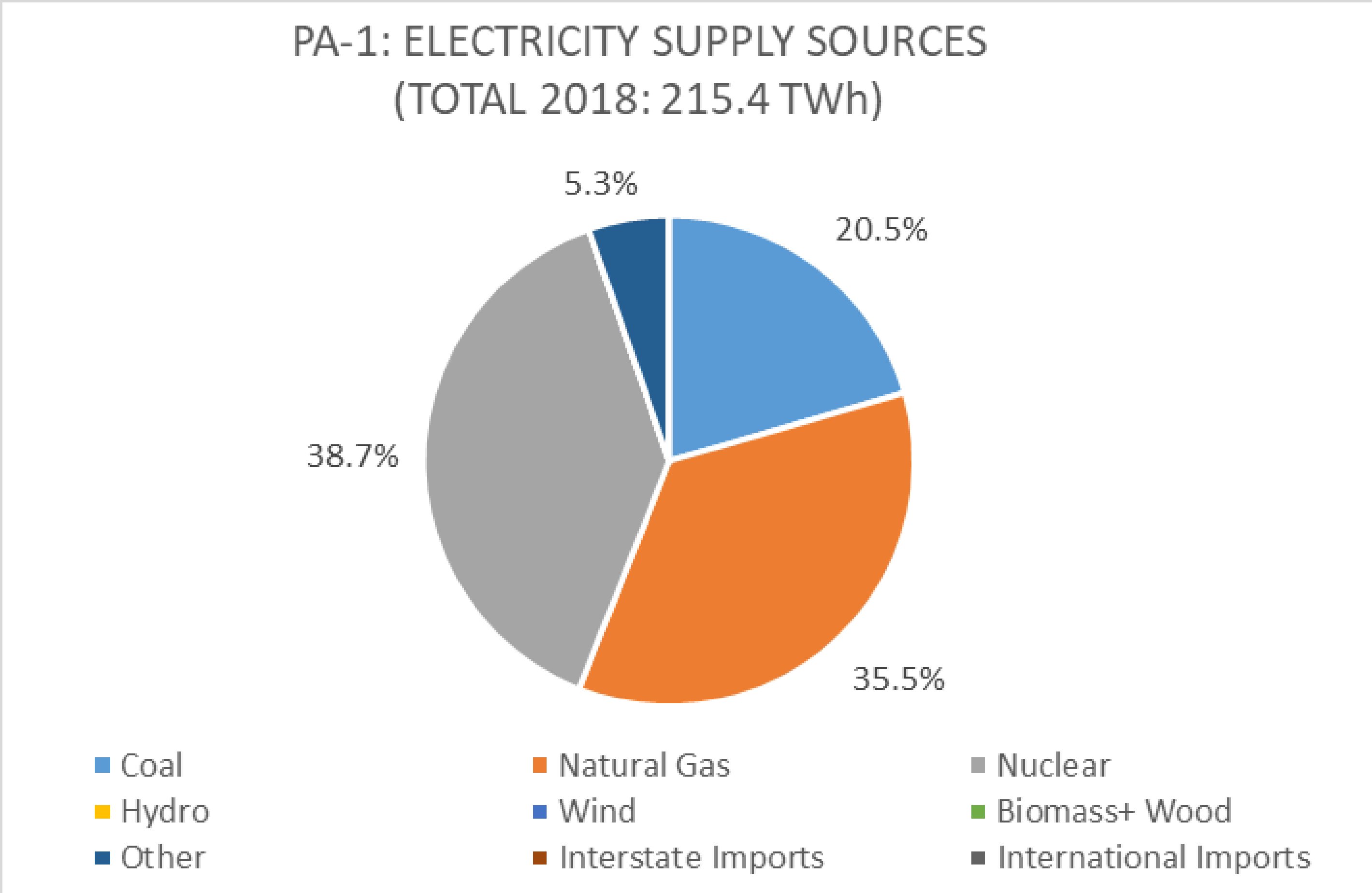
Being such a big producer, it is unsurprising that the state exports almost a quarter (24.4%) of its total supply while the rest is consumed within the state (Figure PA-2).

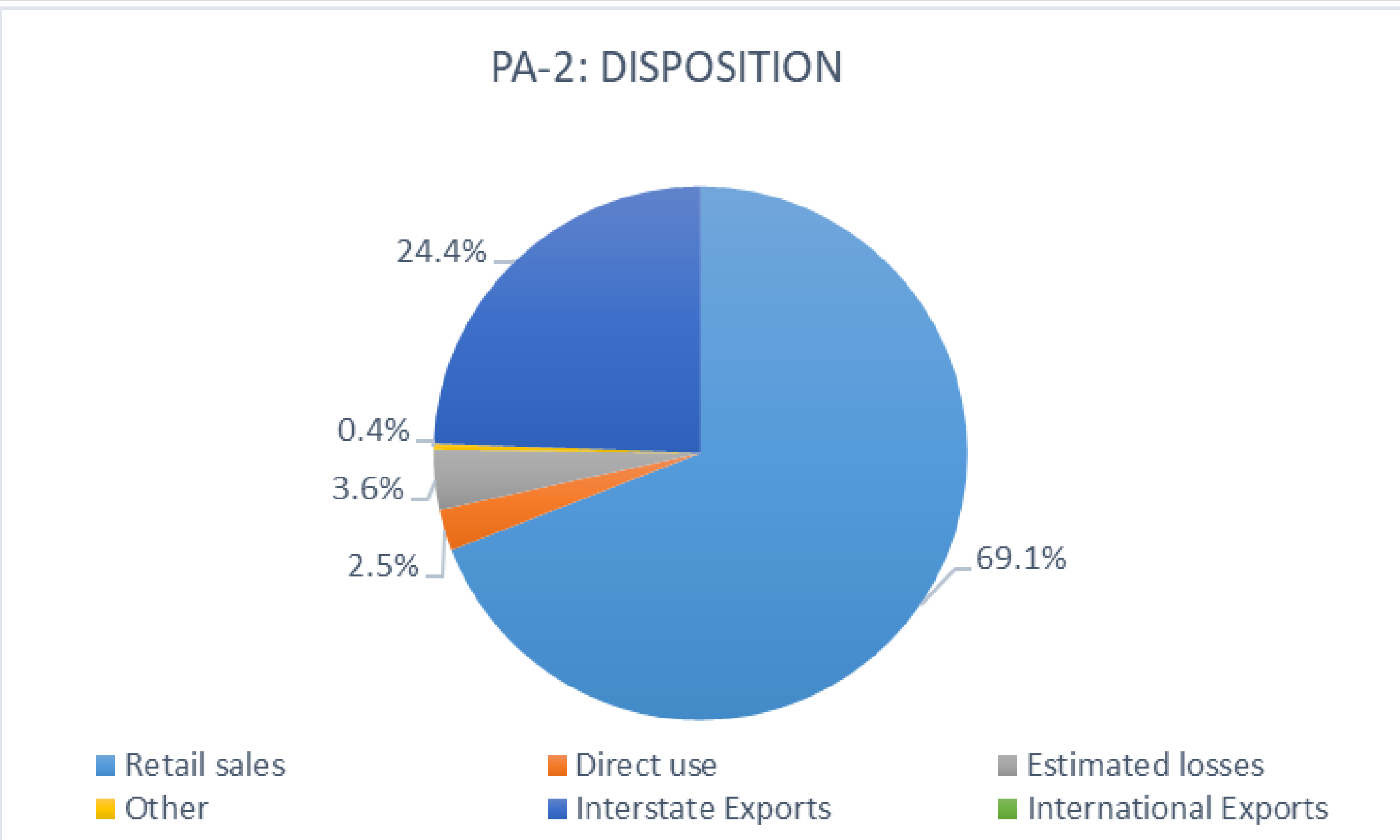
Coal, nuclear, and natural gas were the main supply drivers in 2001 (98%) as they are in 2019 (95%). However, the state has drifted away from coal which produced 57% of the state's output in 2001, but is responsible for 17% of the production in 2019. Natural gas has risen from 4% to 42% of the state's output. Nuclear has remained steady throughout the years going from 38% to 36% of total production. The objective is that renewable sources be responsible for 18% of consumption by 2021.

Pennsylvania is one of the country's biggest electricity producer. It operates five big nuclear plants. The Peach Bottom nuclear plant is the biggest one as it accounted for more than 21.68 TWh or 10.1 % of the state's 215.4 TWh production, but it is very closely followed by the Talen Energy Susquehanna nuclear plant which totaled 20.47 TWh or 9.5% of the state's production, and the Limerick nuclear Plant which produced 19.34 TWh or 9.0% of the state's production; the Beaver Valley nuclear plant which produced 14.65 TWh or 6.8% of the state's production and the Three Mile Island nuclear plant which totaled 7.34 TWh or 3.4% of the state's production were the two other main nuclear plants. The Keystone and Conemaugh plants, both operating on coal, accounted for a combined 23.86 TWh (or 11.1% of the state's production).

The state emitted more than 787 lbs/MWh of carbon dioxide in 2018. However, that number represents a 33.1% decrease since 2010 and a 41.9% decrease since 2000. The state's total emission rate has been constant from 1990 to 2008. Since then, it has been gradually diminishing until reaching its lowest point in 2018.

In 2018, the state's full service providers (full service providers sell bundled electricity services e.g., both energy and delivery, to end users) were responsible for servicing some 68.0% of the total number of retail customers within the state, generating 33.4% of sales in MWh and 41.3% of all revenues. Of those full service providers, investor-owned ones were responsible for 90.6% of retail sales in MWh while generating more than 90.8% of total revenues at an average price of 12.48 cents/kWh. Publicly owned full service providers had an average retail price of 12.91 cents/kWh while it was 11.97 cents/kWh for cooperatives and 10.60 cents/kWh for non-utilities. The total average retail price for both full service providers and others was 10.10 cents/kWh.


PA-1: ELECTRICITY SUPPLY SOURCES
(TOTAL 2018: 215.4 TWh)
5.3%
20.5%
38.7%
35.5%
Coal
Natural Gas
Nuclear
Hydro
Wind
Biomass+ Wood
Other
Interstate Imports
International Imports


PA-2: DISPOSITION
24.4%
0.4%
3.6%
2.5%
69.1%
Retail sales
Direct use
Estimated losses
Other
Interstate Exports
International Exports

ILLINOIS

In 2018, Illinois' total electricity supply amounted to 188 TWh (Figure IL-1), all of which was produced internally. Nuclear and coal were the main production technologies with 98.14 TWh or 52.2% of total production and 59.6 TWh or 31.7% of total production respectively.

Natural gas was also present in the state's production profile with 9.2% of total production while wind represented 6.3% of the state's total output. Other energy sources amounted to only 0.6% of the total production.

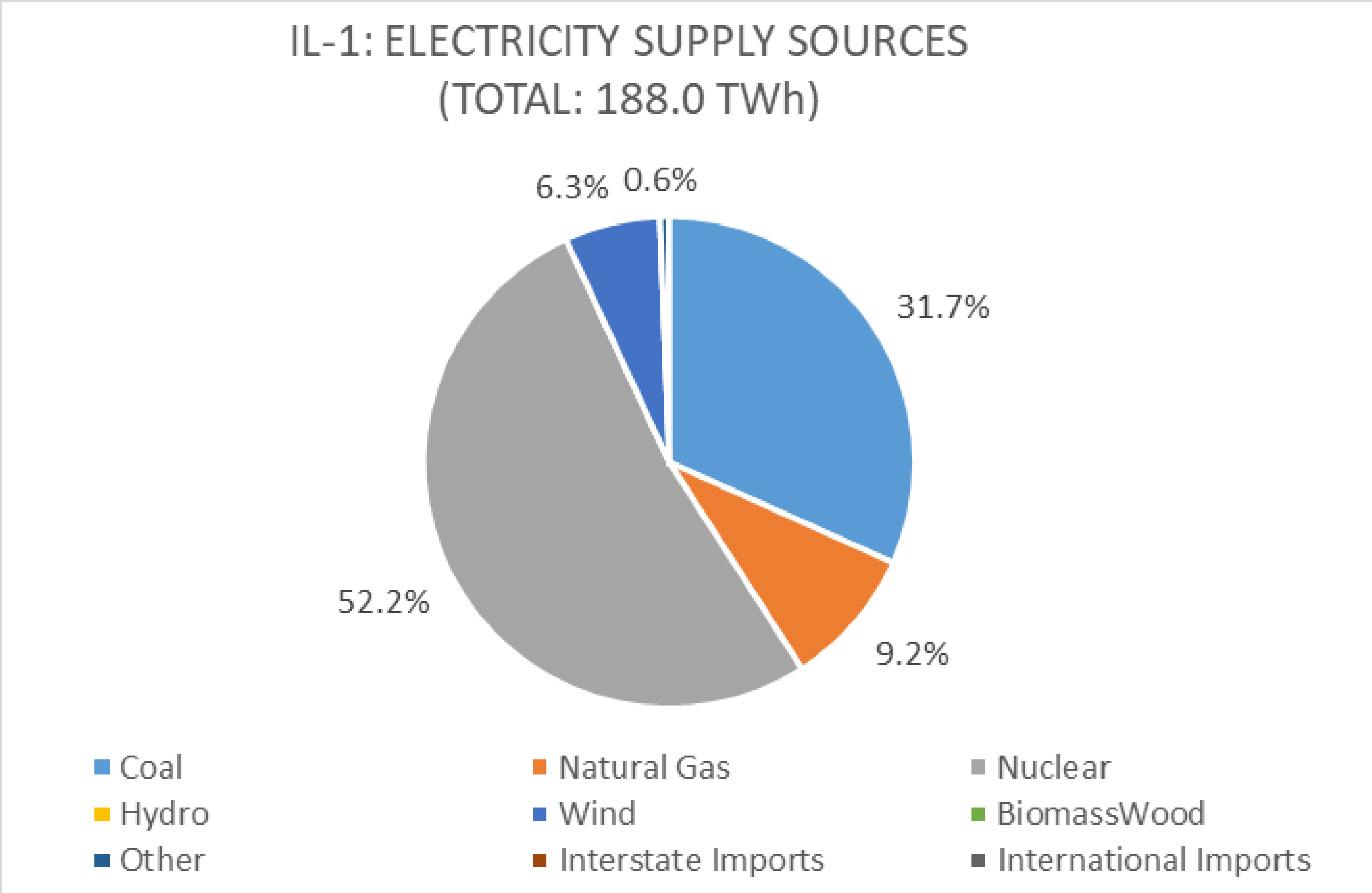
Illinois exported in 2018 some 33.1 TWh or 17.6% of its total supply to other states (Figure IL-2) while trade with Canada was negligible.

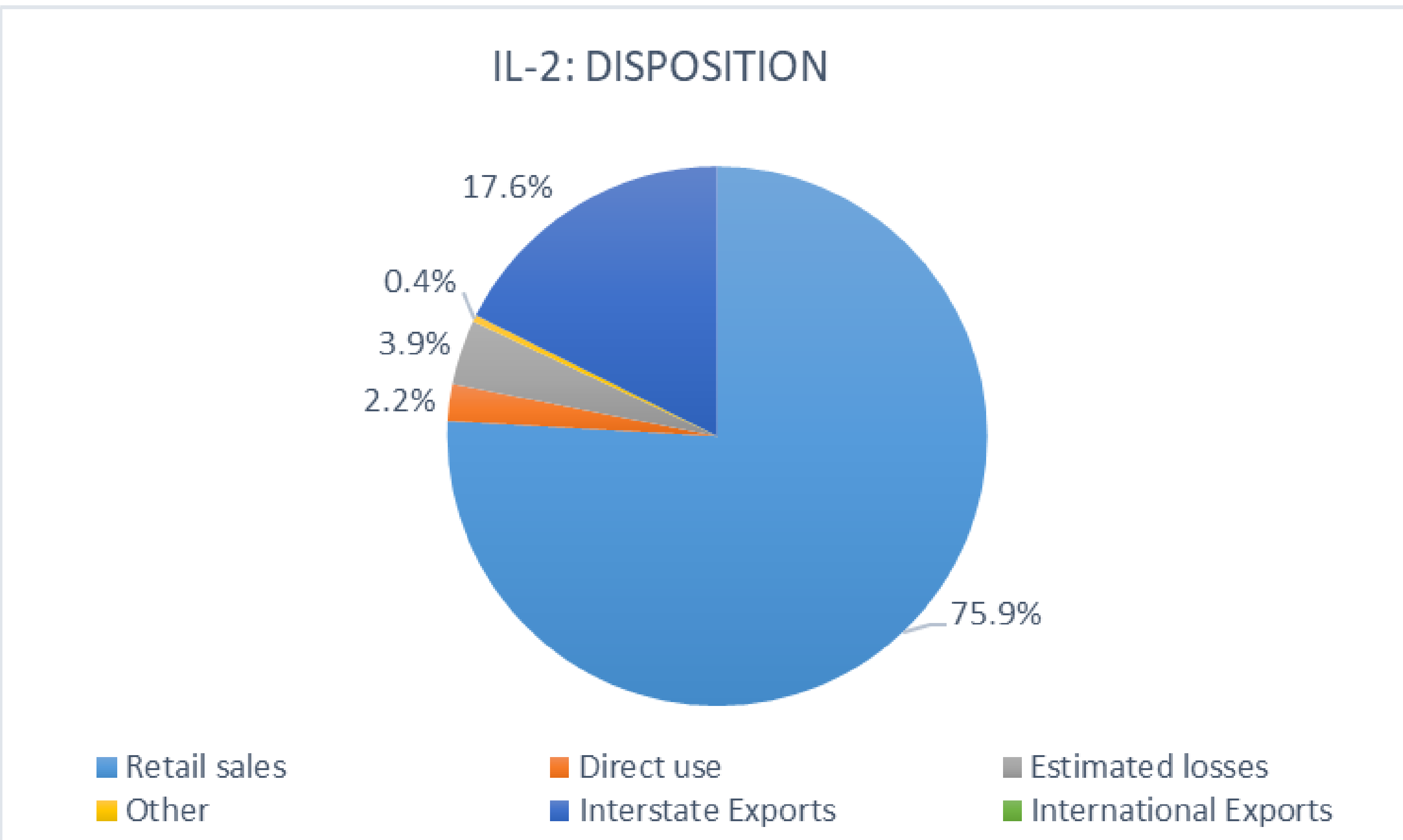
Nuclear and coal have been the main electricity suppliers within the state for the last decades with nuclear being responsible for 52% in 2001 and 54% in 2019, while coal went from 44% to 27% between 2001 and 2019. The loss in coal's market share was replaced by the growing importance of both natural gas and wind which rose from 4% to 10% and from 0% to 8% respectively. The objective is to have 25% of consumption coming from renewable sources by 2025.

There are five big nuclear plants within the state all operated by Exelon Nuclear which together amount to more than 89.76 TWh or 47.7% of the state's 188 TWh production. The main one is the Byron Generating Station which produced 20.05 TWh or 10.7% of the state's production, followed by the Lasalle Generating Station with a production of 19.35 TWh or 10.3% of the state's production, the Braidwood Generating Station with 19.34 TWh or 10.3% of the state's production, the Dresden Generating Station with 15.54 TWh or 8.27% of total production, and finally the Quad Cities Generating Station which produced 15.48 TWh or 8.23% of the state's production.

Illinois electricity production compact was responsible for the emission of more than 846 lbs/MWh in 2018, which was a 24.9% decrease since 2010 and a 27.6% decrease since 2000. Much like Pennsylvania, Illinois has seen its total emission rate remain rather stable from 1990 to 2008. In 2008, the state started to see its total emission rate diminish gradually until 2016 when it reached 848 lbs/MWh, a number very similar to 2018's number.

In 2018, full service providers (full service providers sell bundled electricity services e.g., both energy and delivery, to end users) were responsible for servicing some 64.7% of the total number of retail customers within the state, generating 36.6% of sales in MWh and 43.1% of all revenues. Of the full service providers, investor-owned ones represented 73.3% of retails sales and 71.9% of revenues. The average retail price of investor-owned full service providers reached 11.08 cents/kWh in 2018 compared with 11.88 cents/kWh for public owned providers and 12.55 cents/kWh for cooperatives. The average price for all providers statewide was 9.60 cents/kWh.


IL-1: ELECTRICITY SUPPLY SOURCES
(TOTAL: 188.0 TWh)
6.3%
0.6%
31.7%
52.2%
9.2%
Coal
Natural Gas
Nuclear
Hydro
Wind
BiomassWood
Other
Interstate Imports
International Imports


IL-2: DISPOSITION
17.6%
0.4%
3.9%
2.2%
75.9%
Retail sales
Direct use
Estimated losses
Other
Interstate Exports
International Exports

INDIANA

Indiana produced 97% (113.49 TWh) of its 117 TWh electricity supply in 2018 within the state (Figure IN-1) and mainly through coal and natural gas which amounted for 77.46 TWh or 68.3% of the state's total production profile (66.2% of total supply) and 26.79 TWh or 23.6% (22.9% of supply) respectively.

Wind amounted for 5.38 TWh or 4.74% of the state's output while other sources were responsible for the remaining 3.4%.

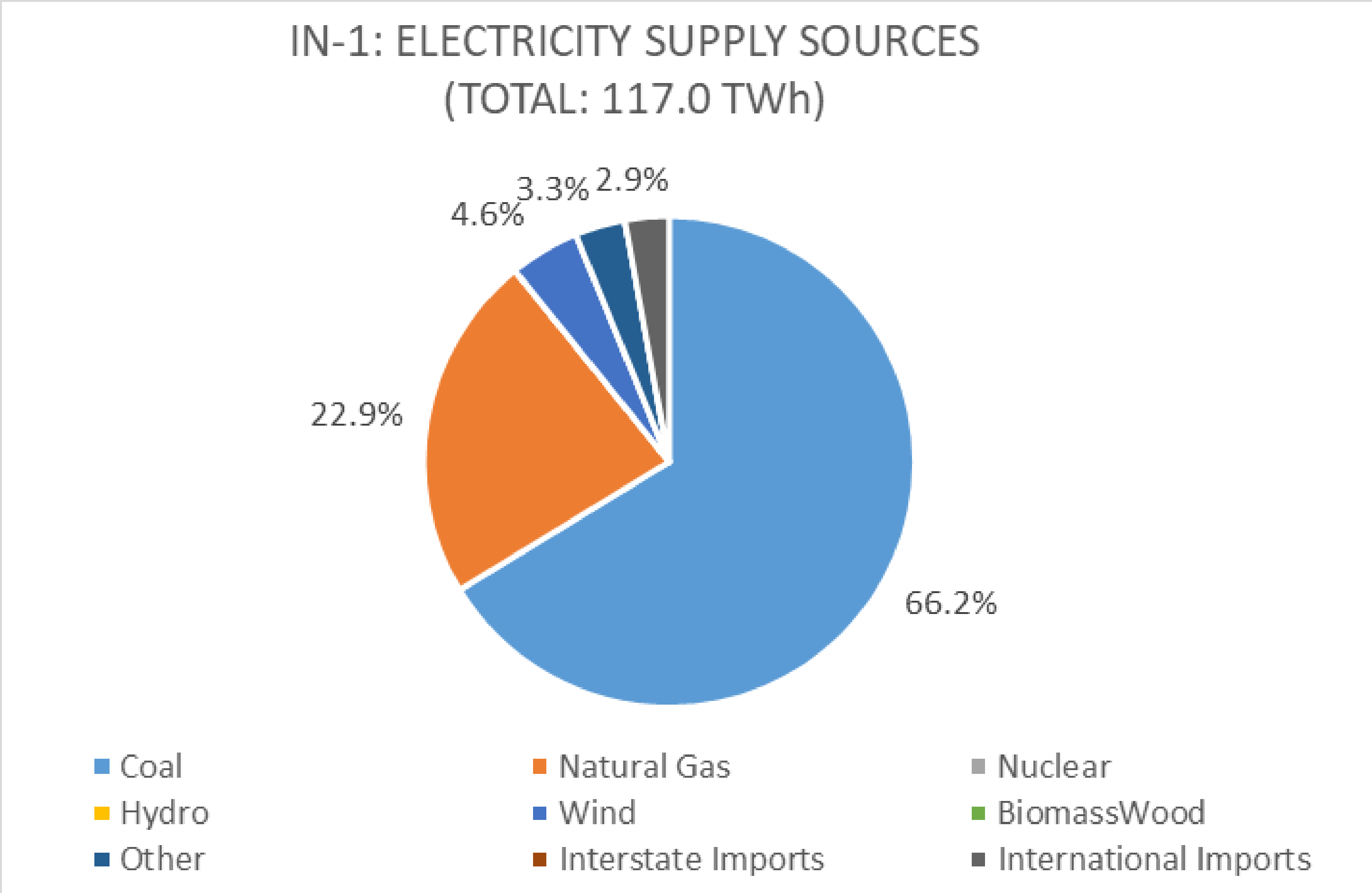
Indiana did not export any electricity as the totality of the state's supply was consumed internally (Figure IN-2).

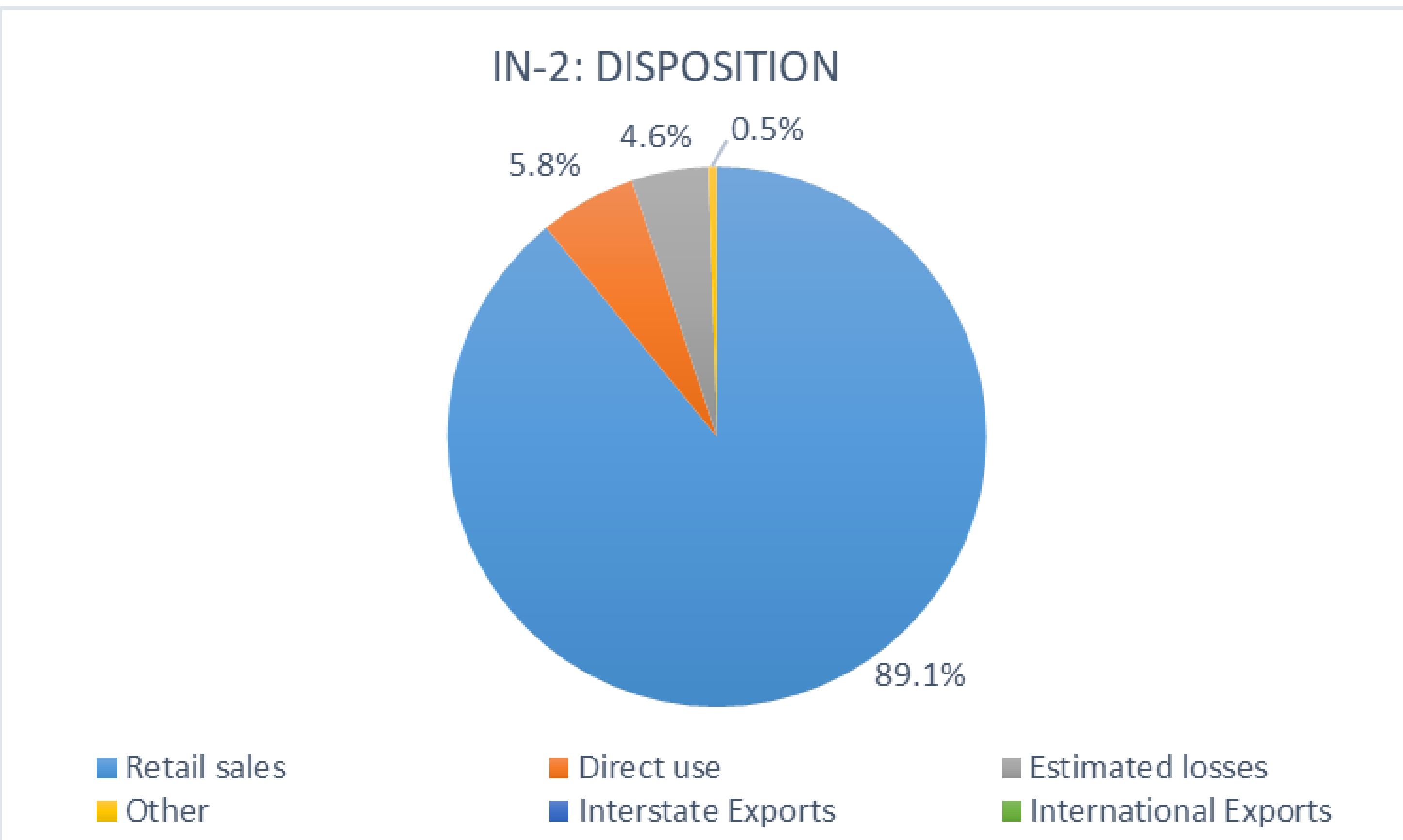
Coal has been of significant importance for Indiana during the last decades with more than 95% of the state's total output in 2001 and 59% in 2019. This dependency has gradually diminished in favor of natural gas which was practically inexistent in 2001 but amounted for 31% in 2019. This shift toward natural gas has been accelerating in recent years, most notably in 2019. Wind has also benefited from this shift away from coal making its apparition in 2009. It now accounts for 6% in 2019.

The eight biggest coal plants in term of generated electricity accounted for more than 68.05 TWh or 60.0% of the state's 113.49 TWh production. The biggest one is the Gibson coal plant which generated 17.63 TWh or 15.5% of the state's production, followed by the Rockport coal plant which accounted for more than 11.89 TWh or 10.5% of the state's production, and the AES Petersburg coal plant which produced 9.1 TWh or 8.0% of the state's production. The Lawrenceburg Power Natural Gas plant was also a major contributor as it produced 7.13 TWh or 6.3% of the state's production.

Being an important producer of electricity and doing so mostly through coal and natural gas plants, it is unsurprising to see the huge amount of carbon dioxide the state emits year after year. In 2018, that number reached 1 775 lbs/MWh, which represents a 13.2% decrease from 2010 and a 16.9% decrease from 2000. Much like Pennsylvania and Illinois, the state's total emission rate has been relatively constant throughout the years. It was in 2008 that the state saw its emission rate starting to decrease, but very slowly.

In 2018, full service providers (full service providers sell bundled electricity services e.g., both energy and delivery, to end users) were responsible for servicing all the retail customers within the state of Indiana. Investor-owned full service providers accounted for 78.3% of all retail sales in MWh while generating 77.0% of all revenues. The average retail price for such investor-owned full service providers was 9.58 cents/kWh compared to 9.54 cents/kWh for publicly owned full service providers, 10.82 cents/kWh for cooperatives and 20.88 for non-utilities. The average for all providers, regardless of type was 9.75 cents/kWh.


IN-1: ELECTRICITY SUPPLY SOURCES
(TOTAL: 117.0 TWh)
4.6%
3.3%
2.9%
22.9%
66.2%
Coal
Natural Gas
Nuclear
Hydro
Wind
BiomassWood
Other
Interstate Imports
International Imports


IN-2: DISPOSITION
5.8%
4.6%
0.5%
89.1%
Retail sales
Direct use
Estimated losses
Other
Interstate Exports
International Exports

MICHIGAN

In 2018, Michigan’s total electricity supply totaled 122.4 TWh, 94.7% (115.91 TWh) of which was produced within the state (Figure MI-1). This production was divided between coal, natural gas, and nuclear. Coal amounted for more than 42.35 TWh or 36.5% of the state’s output (34.6% of total supply), while natural gas totaled 30.97 TWh or 26.7% and nuclear 30.47 TWh or 26.3% of the state’s production.

Wind (4.75%) and other sources (5.70%) amounted for the remaining output.

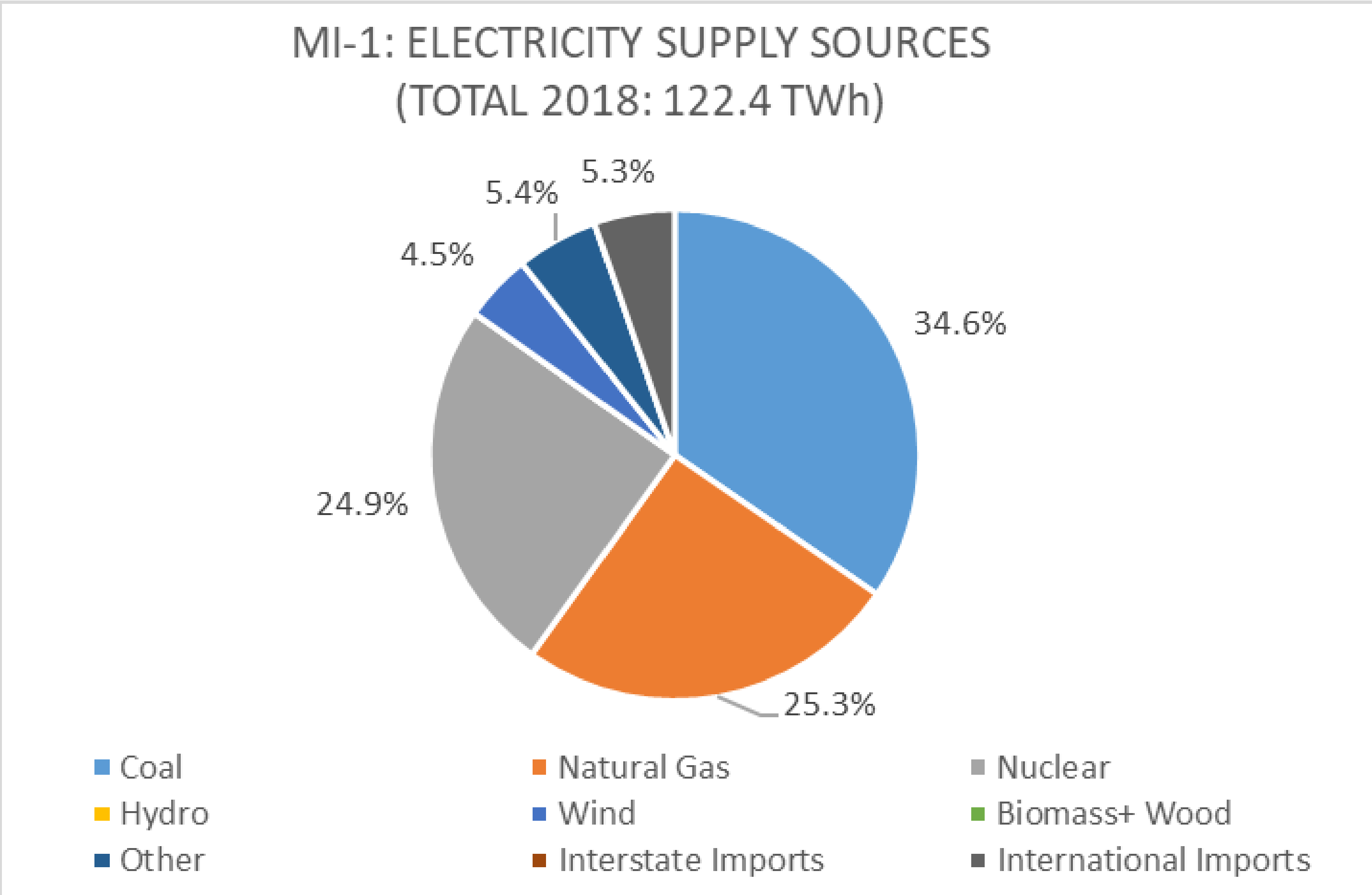
Despite importing 6.14 TWh of electricity or 5.3% of its total supply, Michigan also exported 8.94 TWh or 7.3% of its supply to other states while consuming the remaining 92.7% within the state (Figure MI-2).

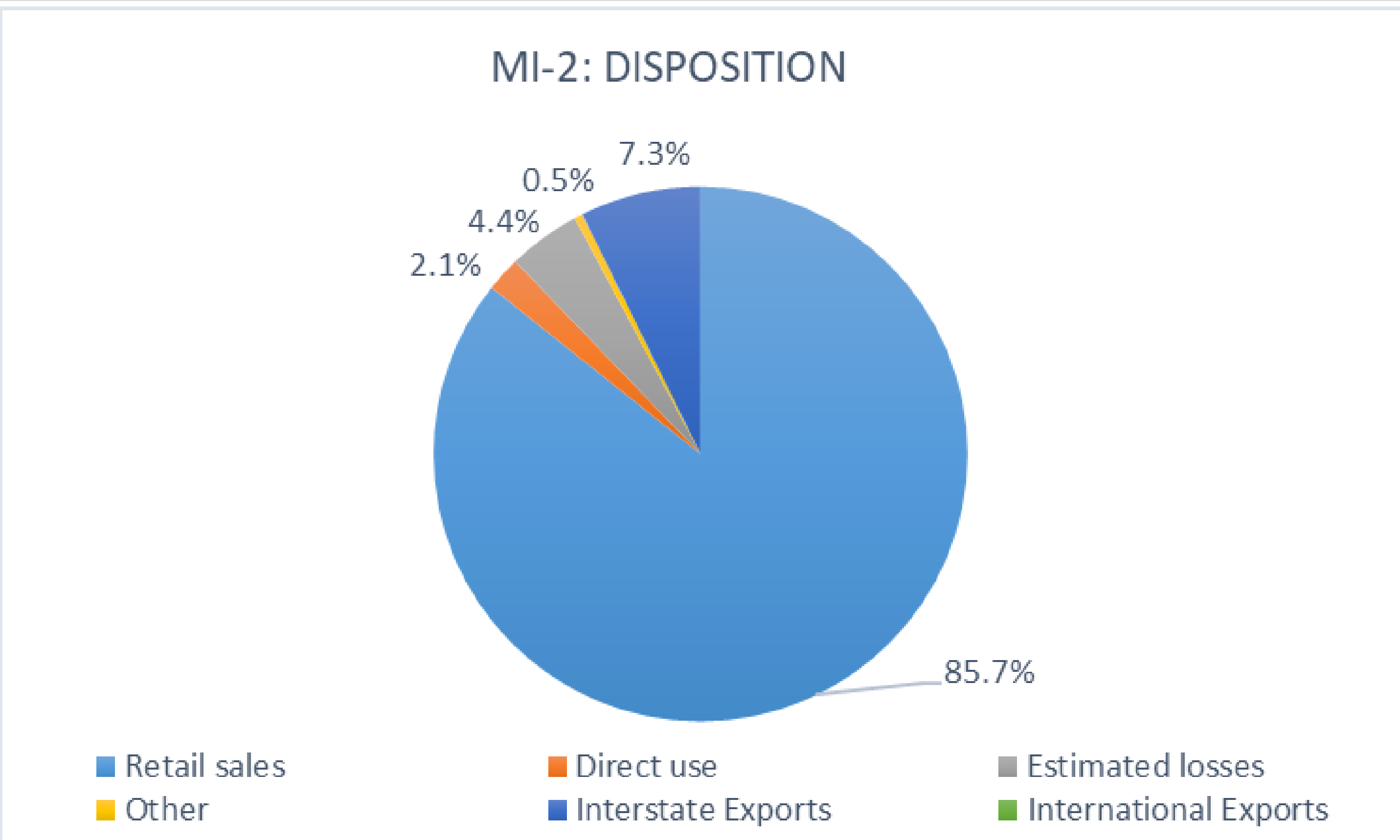
Michigan’s electricity supply output hasn’t really changed during the last two decades. Coal, nuclear, and natural gas were and have remained the state’s main production technologies (96% in 2001 and 89% in 2019). However, as we’ve seen with other states, coal has lost market share (from 61% in 2001 to 32% in 2019) in favor of nuclear (from 24% to 28%) and most importantly, natural gas (from 12% to 29%). Wind has also benefited from this as it became a non-negligible factor in 2011 and hasn’t looked back since with a close to 5% of output. The objective is to get 15% of consumption from renewable sources by 2021.

There are two major plants in Michigan which together in 2018 produced more than 34.07 TWh or 29.4% of the state’s 115.91 TWh production. The Donald C Cook nuclear plant is the biggest, accounting for 17.61 TWh or 15.2% of the state’s production, followed by the Monroe coal plant which produced 16.46 TWh or 14.2% of the state’s production. Next comes the Belle River coal plant and the Midland Cogeneration Venture natural gas plant, each producing some 7.90 TWh or 6.8% of the state’s production. Then comes the J. H. Campbell coal plant accounting for 7.66 TWh or 6.6% of the state’s production.

Michigan’s electricity production compact was responsible for the emission of 1 167 lbs/MWh of carbon dioxide in 2018, which is a 20.6% decrease since 2010 and a 29.9% decrease since 2000. The emission rate had increased by 13.9% from 1990 to 1998 when it reached 1 798 lbs/MWh. Since then, the state has taken action and has seen the total emission rate fall considerably.

In 2018, full service providers (full service providers sell bundled electricity services e.g., both energy and delivery, to end users) were responsible for servicing virtually all (99.9%) retail customers within the state, generating 91.5% of sales in MWh and 95.1% of revenues. Of the full service providers, investor-owned ones were responsible for 87.4% of retail sales while generating some 87.9% of revenues. The average retail price for the investor-owned full service providers was 11.90 cents/kWh compared to 11.11 cents/kWh for publicly owned full service providers, 12.81 cents/kWh for cooperatives and 3.31 for non-utilities. The total average regardless of service within the state was 11.40 cents/kWh.


MI-1: ELECTRICITY SUPPLY SOURCES
(TOTAL 2018: 122.4 TWh)
34.6%
25.3%
24.9%
4.5%
5.4%
5.3%
Coal
Natural Gas
Nuclear
Hydro
Wind
Biomass+ Wood
Other
Interstate Imports
International Imports


MI-2: DISPOSITION
7.3%
0.5%
4.4%
2.1%
85.7%
Retail sales
Direct use
Estimated losses
Other
Interstate Exports
International Exports

OHIO

In 2018, Ohio's total electricity supply was estimated to be 162.8 TWh, 77.5% (126.17 TWh) of which was produced within the state (Figure OH-1). Coal and natural gas were the two main production technologies amounting for more than 58.77 TWh or 46.6% of total state production (36.1% of total supply) and 44.27 TWh or 35.1% of total state production (27.2% of total supply) respectively.

Nuclear was also an important factor with more 18.23 TWh or 14.5% of the state's output while other sources of energy were responsible for the remaining 4% of production.

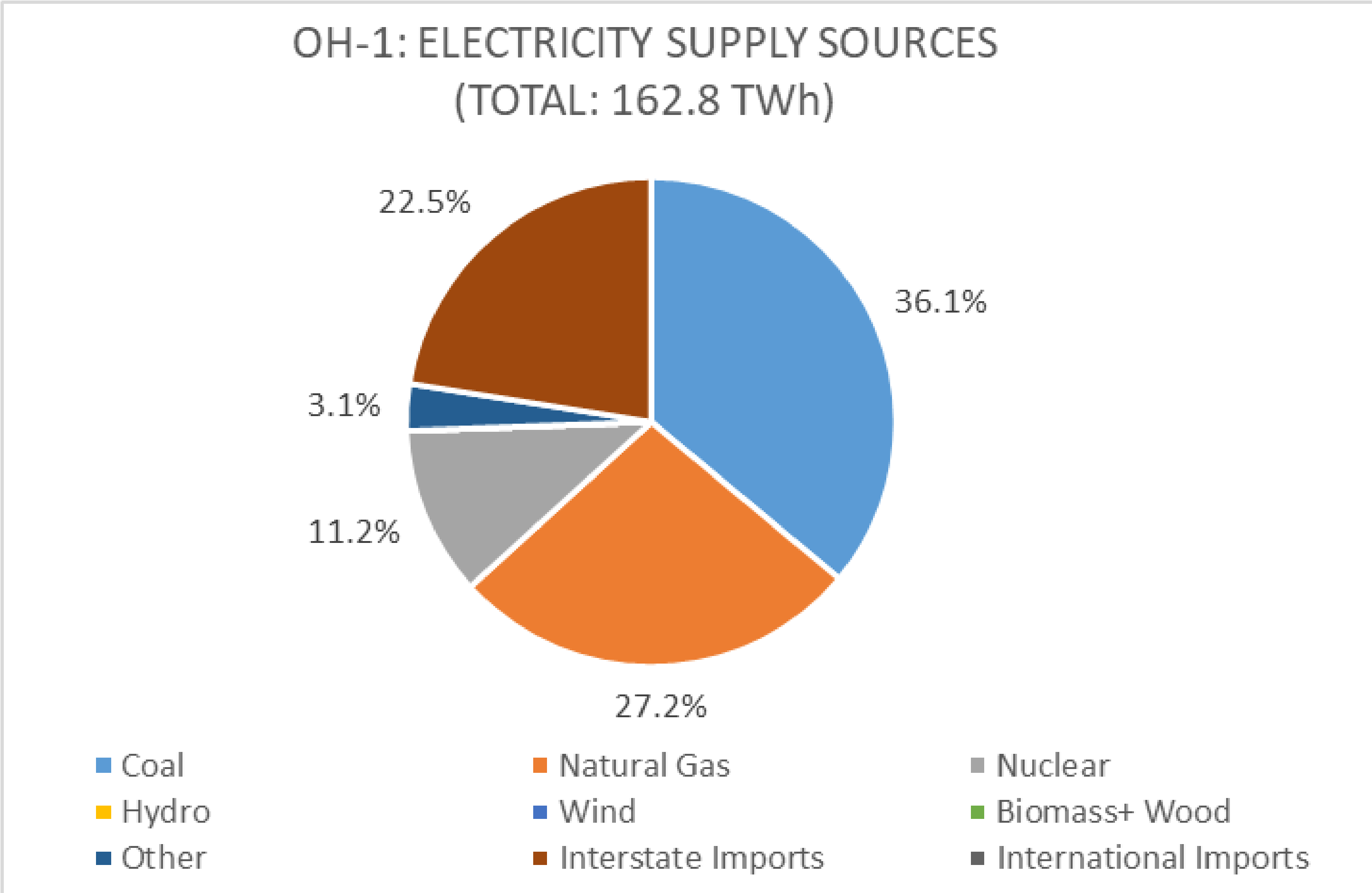
The state did not export any electricity (Figure OH-2).

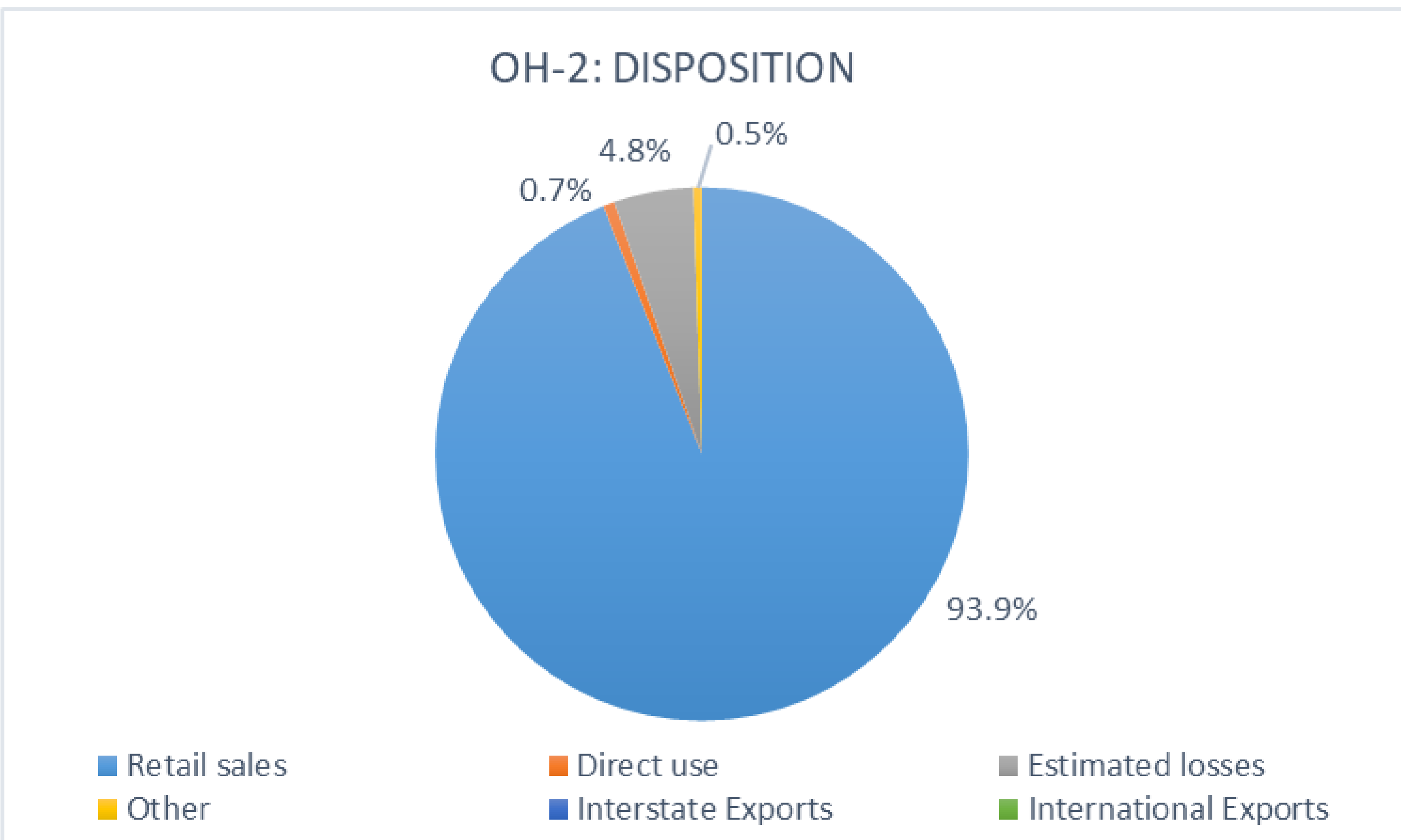
In 2001, coal was responsible for more than 87% of the state's total output and the remaining 13% was mainly nuclear. Much has changed since then, as coal has rapidly declined and is now down to 39% of the state's production. Natural gas has risen from being practically inexistent to being the main supply driver in 2019, representing more than 43% of the state's total output. Nuclear went from 11% in 2001 to 14% in 2019. Renewable energy remains negligible within the state.

The Gavin Power coal plant is by a considerable margin the largest plan in Ohio. In 2018, it generated more than 16 TWh or 12.7% of the state's 126.17 TWh production, while its closest competitor, the Perry nuclear plant, generated 10.93 TWh or 8.7% of the state's production. The Cardinal coal plant, the Hanging Rock Energy Facility natural gas plant and the W. H. Zimmer coal plant were in 2018 the following three largest plants in terms of generated electricity accounting for 10.04 TWh or 8.0% of the state's production, 9.29 TWh or 7.4% of the state's production, and 8.11 TWh or 6.43% of the state's production respectively.

In 2018, the state emitted more than 1 361 lbs/MWh of carbon dioxide through its electricity production. Although it seems like a high emission rate, it represents a 27.2% decrease from 2010. The total emission rate hasn't fluctuated much from 1990 to 2010. It wasn't until 2011 that the total emission rate started to gradually diminish and eventually pick up some speed in 2016.

The state's full service providers (full service providers sell bundled electricity services e.g., both energy and delivery, to end users) were responsible for servicing 58.8% of retail customers within the state, generating 30.6% of sales in MWh and 35.15% of revenues. Of the full service providers, investor-owned ones accounted for 58.9% of retail sales in MWh while generating 59.1% of revenues. Those same investor-owned full service providers had an average retail price of 11.55 cents/kWh compared to 11.24 cents/kWh for publicly owned full service providers, and 11.93 cents /kWh for cooperatives. The total statewide average for both full service providers and others was 9.94 cents/kWh.


OH-1: ELECTRICITY SUPPLY SOURCES
(TOTAL: 162.8 TWh)
22.5%
36.1%
3.1%
11.2%
27.2%
Coal
Natural Gas
Nuclear
Hydro
Wind
Biomass+ Wood
Other
Interstate Imports
International Imports


OH-2: DISPOSITION
4.8%
0.5%
0.7%
93.9%
Retail sales
Direct use
Estimated losses
Other
Interstate Exports
International Exports

WISCONSIN

In 2018, Wisconsin produced 85.7% or 65.9 TWh of the 76.9 TWh which constituted its total electricity supply (Figure WI-1). This production was mainly attributed to coal, natural gas, and nuclear witch combined for more than 91% of the state's total production output. In fact, coal represented 50.5% (33.30 TWh) of the state's production or 43.3% of the state's total supply, natural gas 25.4% (16.76 TWh), and nuclear 15.4% (10.15 TWh).

Hydro was the last non-negligible production technology, amounting to more than 3.6% (2.39 TWh) of the state's output while other energy sources represented 5%.

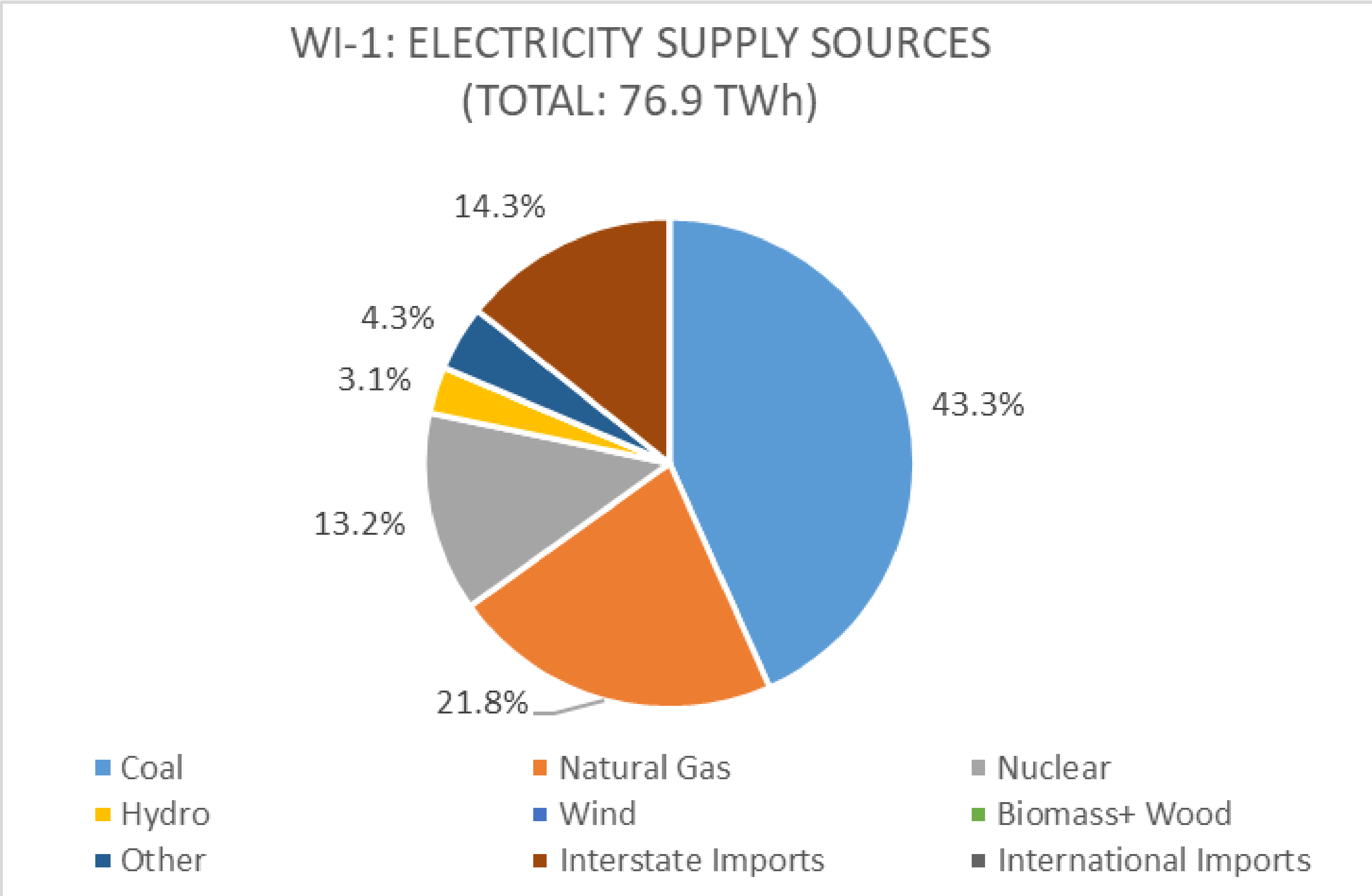
The state did not export any electricity (Figure WI-2).

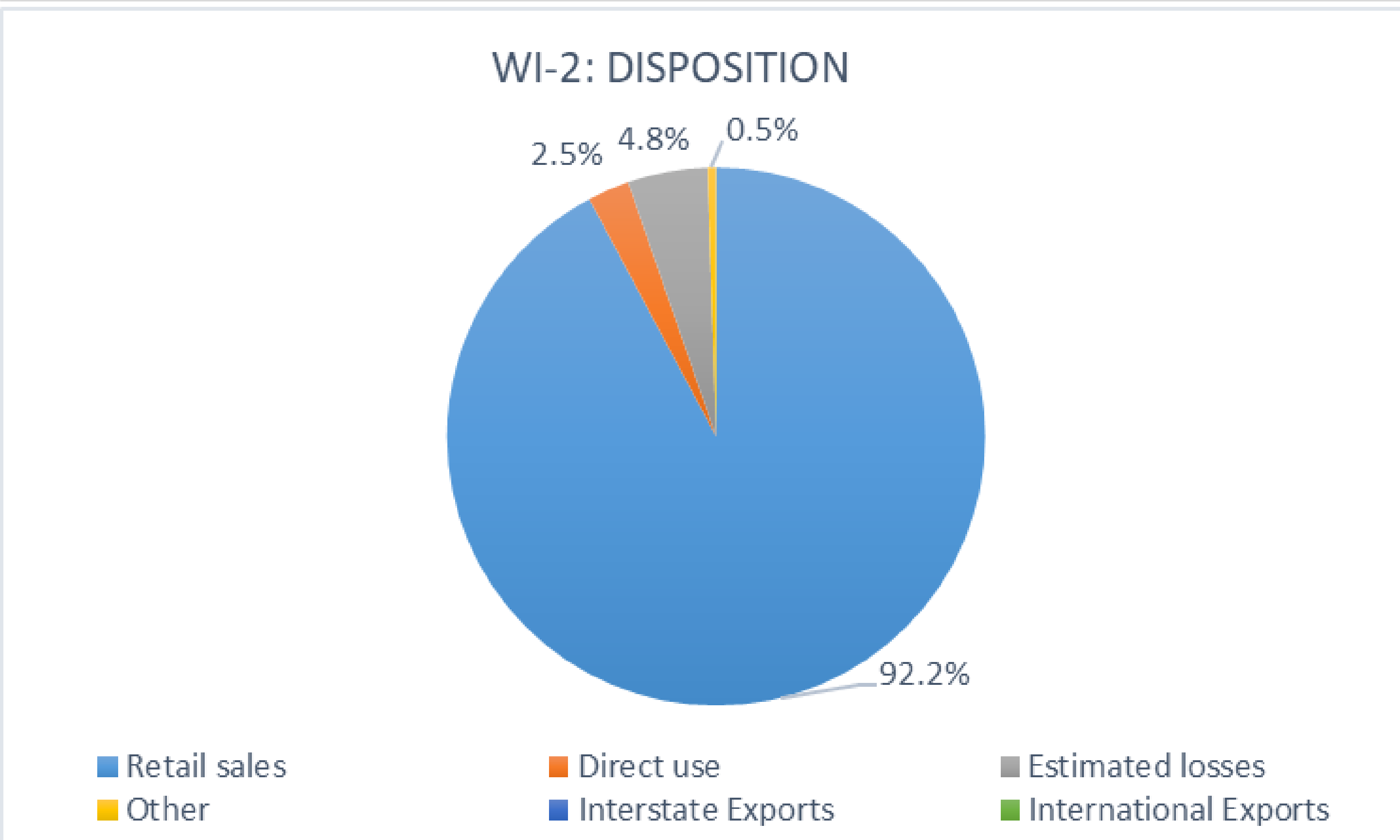
Wisconsin has been very much dependent on coal during the last decades. However, this dependence has gradually diminished with coal losing more than 28% market share (from 70% in 2001 to 42% in 2019). In the meantime, nuclear has gone from 20% in 2001 to 16% in 2019 while natural gas, as we've seen with many states, has gone from practically inexistent to more than 34% of the total production output. Hydro has been present within the state for the last decades, but it hasn't shown any sign of concrete growth. The objective is to reach 100% of consumption from clean energy by 2050.

The Point Beach nuclear plant was the largest plant production-wise in Wisconsin in 2018. It generated more than 10.13 TWh TWh or 15.4% of the state's 65.9 TWh production, while the second largest plant, the Elm Road Generating Station accounted for 7.91 TWh or 12% of the state's production. Five other coal plants were also within the ten biggest plants, combining for a total of 21.21 TWh or 32.2% of the state's production. The Port Washington Generating Station was the only natural gas plant within the top five in the state and it produced more than 5.83 TWh or 8.8% of the state's production. The top ten plants by generation in the state accounted for more than 78% of the state's total electricity production.

Despite producing only 65.9 TWh within the state, Wisconsin was responsible for the emission of more than 1 394 lbs/MWh of carbon dioxide in 2018. It was actually a 13.7% decrease from 2010 and a 26.8% decrease from 2000. The state saw its total emission rate rise substantially from 1990 until 1997 when it reached its highest point of 2 124 lbs/MWh, and then started to diminish slowly but gradually until reaching its lowest point in 2016 with 1 385 lbs/MWh.

In 2018, the state's full service providers (full service providers sell bundled electricity services e.g., both energy and delivery, to end users) were responsible for servicing all the retail customers within the state of Wisconsin. Investor-owned full service providers accounted for 82.9% of all retail sales in MWh while generating 83.2% of all revenues. The average retail price for investor-owned full service providers was 10.62 cents/kWh compared to 9.18 cents/kWh for publicly owned ones and 12.54 cents/kWh for cooperatives. The total statewide average for all providers was 10.58 cents/kWh.


WI-1: ELECTRICITY SUPPLY SOURCES
(TOTAL: 76.9 TWh)
14.3%
4.3%
3.1%
43.3%
13.2%
21.8%
Coal
Natural Gas
Nuclear
Hydro
Wind
Biomass+ Wood
Other
Interstate Imports
International Imports


WI-2: DISPOSITION
2.5%
4.8%
0.5%
92.2%
Retail sales
Direct use
Estimated losses
Other
Interstate Exports
International Exports

DELAWARE

Delaware produced internally 47.4% (6.26 TWh) of its total electricity supply (13.2 TWh) in 2018 while 52.6% (6.94 TWh) was imported from other states (Figure DE-1). Natural gas was by far the main producing technology within the state accounting for more than 86.5% (5.41 TWh) of the state's total production output.

Other sources of energy such as coal, petroleum and solar were responsible for 13.5% of the state's production value.

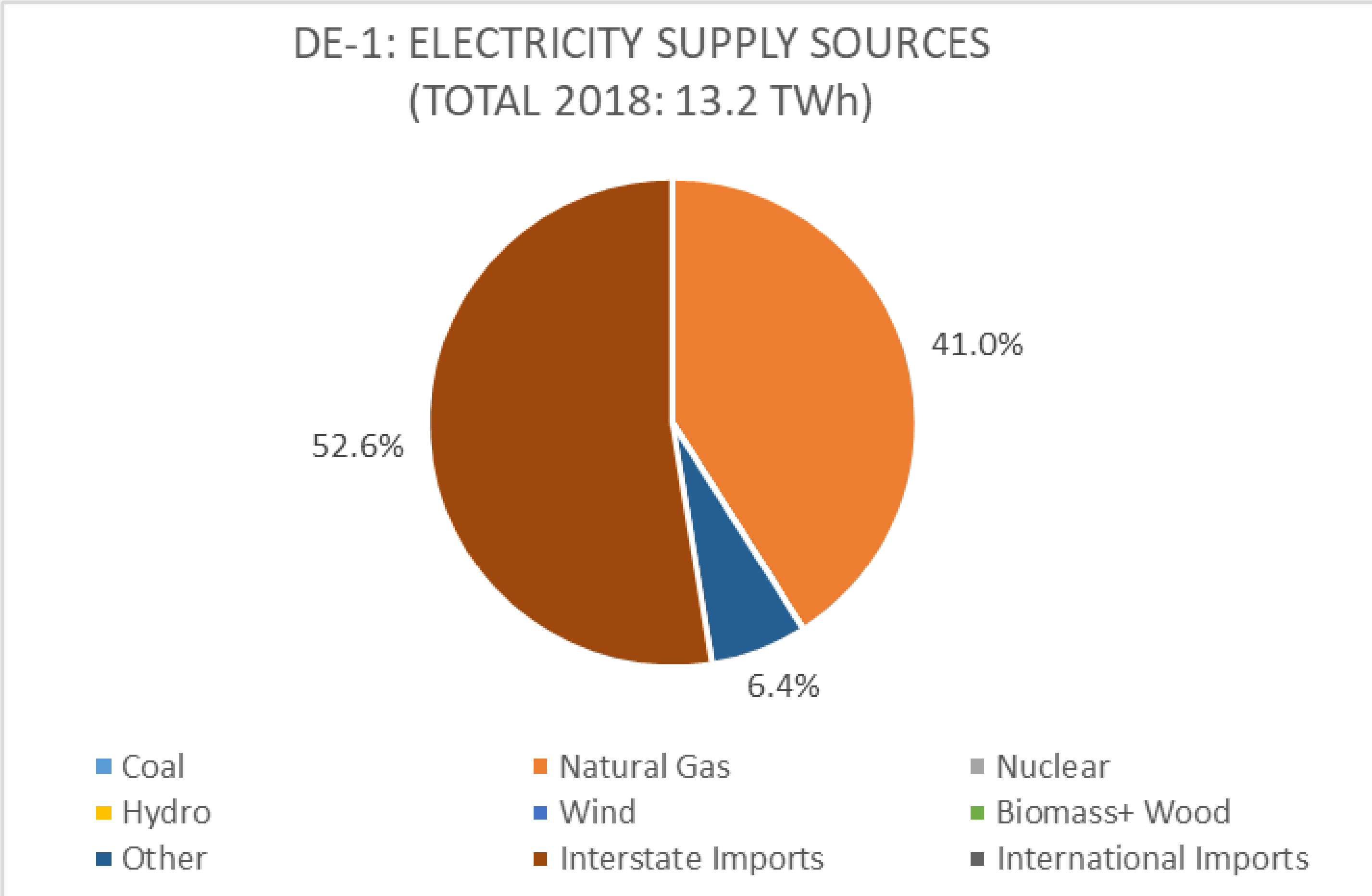
The state did not export any electricity in 2018 (Figure DE-2).

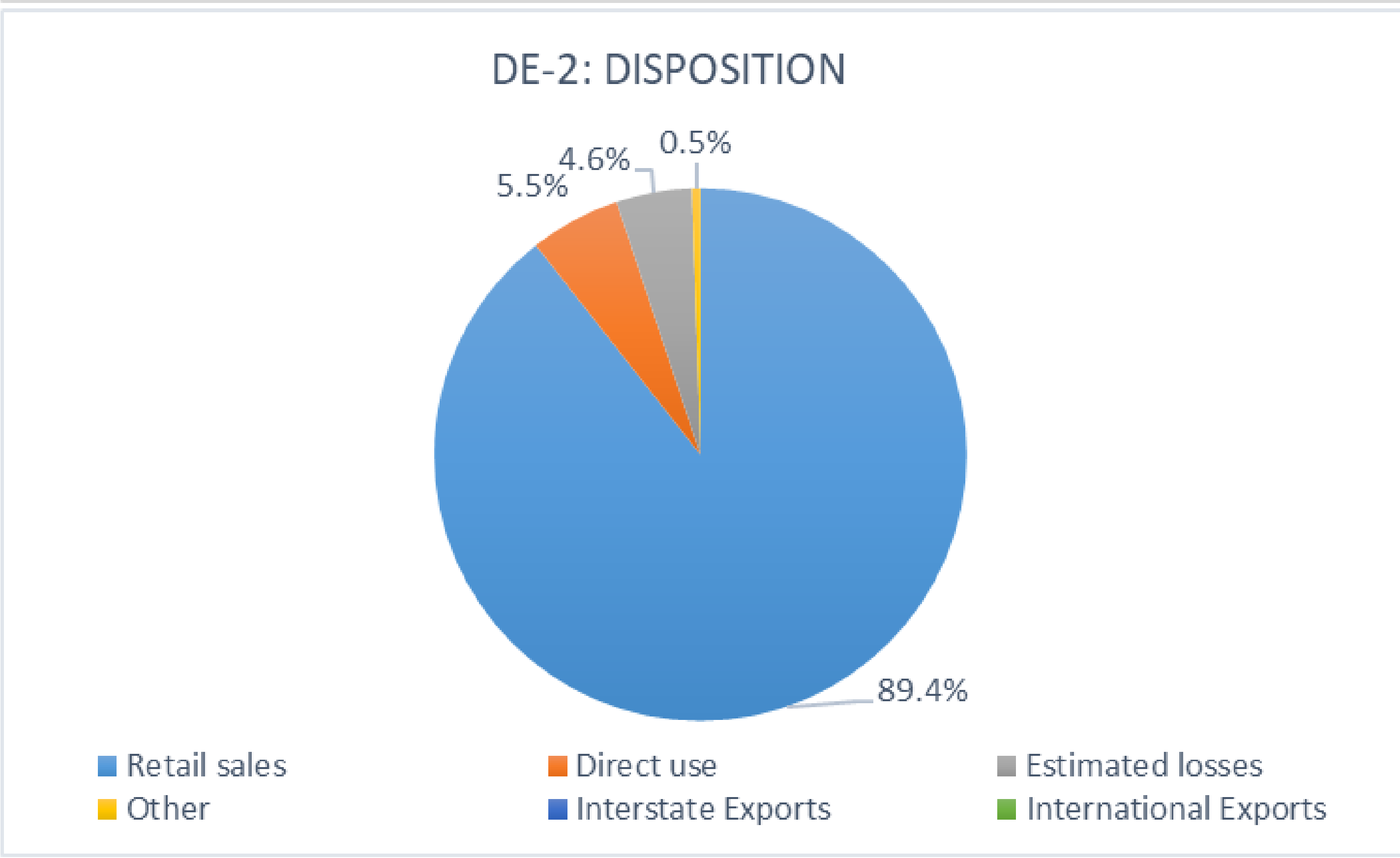
In 2001, coal was the main productive source of electricity amounting for more than 49% of the state's total output. That percentage is down to less than 3% in 2019. The drastically diminished importance of coal within the state has been compensated by the expansion of the natural gas industry which went from 23% of the output in 2001 to more than 89% in 2019. It is also interesting to note that in 2001, petroleum accounted for more than 25% of the state's total output while becoming almost insignificant in 2019. Renewable energy was practically inexistent within the state for the last decades, but solar energy has seen its importance gradually increase in recent years and picking up steam in 2019. The objective is to get 25% of consumption from renewable sources by 2025.

Considering the utmost importance of natural gas within the state's production profile, it's understandable that eight of the ten largest plants by generation were operating on natural gas. Those plants accounted for more than 5.81 TWh or 92.8% of the state's 6.26 TWh production. The Hay Road plant was by far the largest one, producing more than 2.75 TWh or 43.9% of the state's production, while the Garrison Energy Center and the Delaware City plant, which generated 1.34 TWh or 21.4% of the state's production and 1.06 TWh or 16.9% of the state's production respectively, followed in second and third position. Delaware is quite dependent on its three largest plants which together produce 82.3% of the total in-state production.

Despite being one of the lowest producing state in terms of generated electricity with 6.26 TWh produced in 2018, the carbon dioxide emitted by the state in 2018 reached 1 126 lbs/MWh, a 31.2% decrease from the 2010 level and a 49.6% decrease from 2000. Delaware was responsible for the emission of 2 493 lbs/MWh of carbon dioxide in 1990, a rather astonishing amount. The state's total emission rate has been quite stable throughout the years 1990-2008, then slowly diminishing until reaching its lowest point in 2017 with 1 065 lbs/MWh. The significant drop of coal based production seems to be the main driving force: coal based production represented 65.2% of total production in 1990, 49.3% in 2001 and 4.4% in 2018.

In 2018, full service providers (full service providers sell bundled electricity services e.g., both energy and delivery, to end users) were responsible for servicing 92.2% of retail customers within the state, generating 63.2% of sales in MWh and 70.7% of revenues. Of the full service providers, investor-owned ones accounted for 52.7% of retail sales in MWh, while generating 53.8% of all revenues. The average retail price for such investor-owned full service providers was 12.05 cents/kWh compared to 11.68 cents/kWh for publicly owned ones, 11.30 cents/kWh for cooperatives and 7.56 cents/kWh for non-utilities. The total statewide average price regardless of the type of providers was 10.55 cents/kWh.


DE-1: ELECTRICITY SUPPLY SOURCES
(TOTAL 2018: 13.2 TWh)
41.0%
52.6%
6.4%
Coal
Natural Gas
Nuclear
Hydro
Wind
Biomass+ Wood
Other
Interstate Imports
International Imports


DE-2: DISPOSITION
4.6%
0.5%
5.5%
89.4%
Retail sales
Direct use
Estimated losses
Other
Interstate Exports
International Exports

MARYLAND

In 2018, Maryland's electricity supply totaled 66.7 TWh, 65.7% (43.82 TWh) of which was produced within the state (Figure MD-1). This production was mainly divided between nuclear, natural gas, and coal which combined for more than 88% of the state's total production profile. Nuclear was the main producing technology with 34.3% (14.99 TWh) of the total output, closely followed by natural gas with 31.6% (13.85 TWh) and finally coal with 23.0% (10.07 TWh). It is estimated that more than 34.3% (22.88 TWh) of the state's total supply was imported from other states.

Hydro was the last statistically significant production technology used with 6.4% of the state's production profile, while other energy sources accounted for the remaining 4.7%.

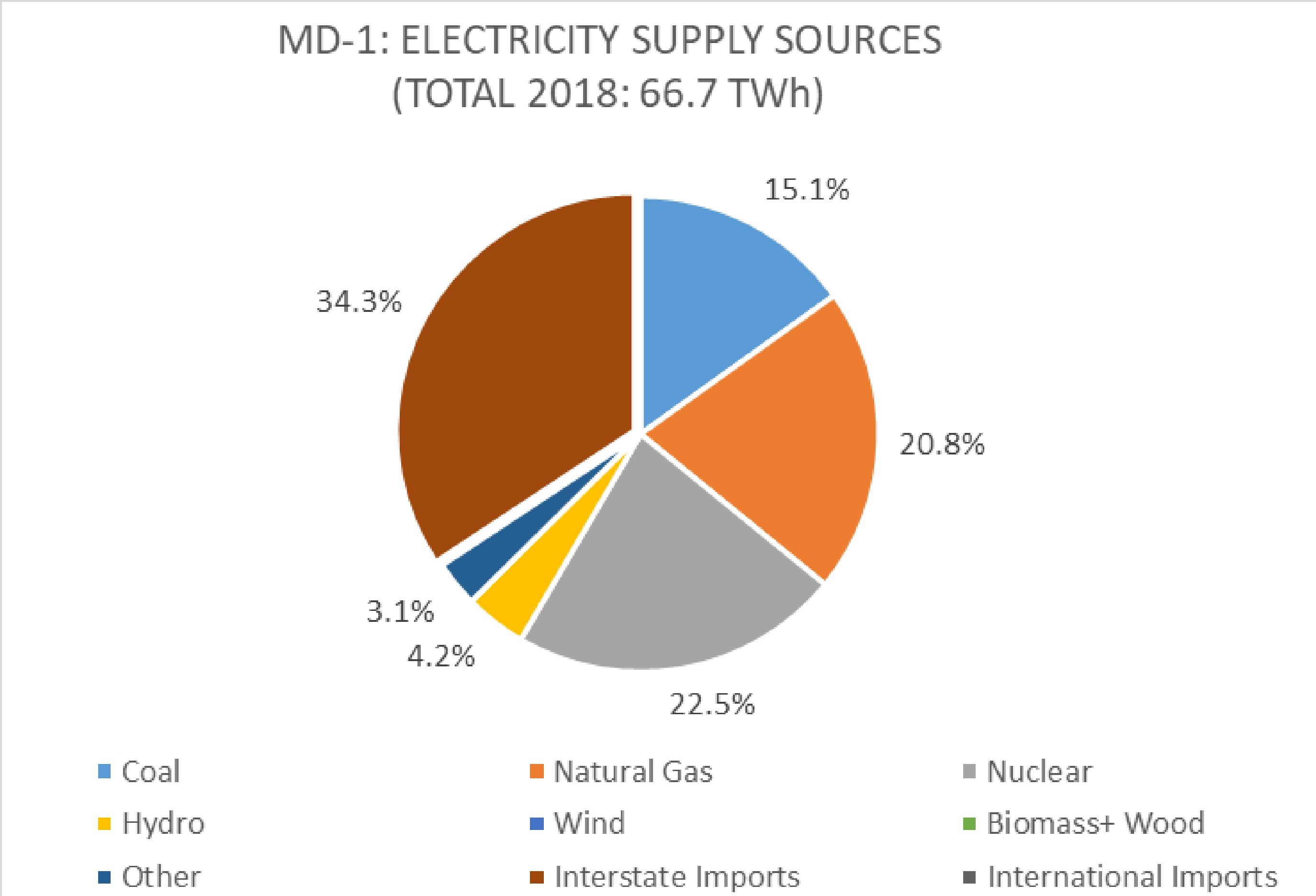
The state did not export any electricity (Figure MD-2).

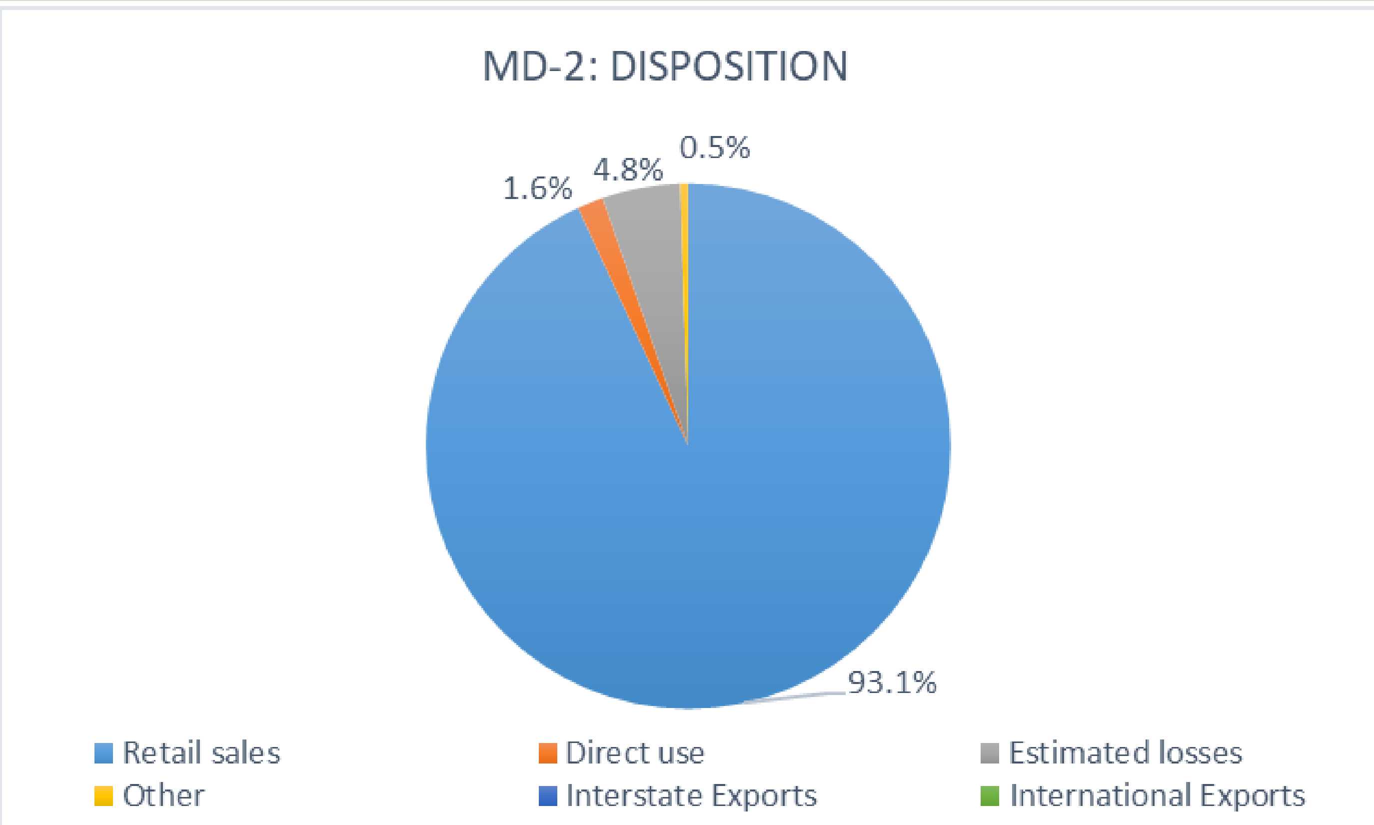
Maryland's 2001 production profile was different from what it is today. Although natural gas, coal and nuclear were and remain the three main production technologies with more than 90% of the total output in 2001 and 88% in 2019, nuclear has risen up from 27.8% in 2001 37% in 2019, coal has seen its production share gradually diminish down from 57.8% in 2001 to 14% in 2019, and natural gas has grown by a big leap from 3.6% in 2001 to 37% in 2019. Petroleum, responsible for 6% of the total output in 2001, was insignificant in 2019 (less than 1%). Hydro doubled its production share from 2.4% in 2001 to 5% in 2019. The objective is to get 50% of consumption from renewable sources in 2030.

The largest Maryland plant by generation is the Calvert Cliffs nuclear power plant which produced 14.99 TWh or 34.2% of the state's 43.82 TWh production. It is followed by the Brandon Shores coal plant which generated more than 4.73 TWh or 10.8% of the state's production and the CCOV St. Charles Energy Center which totaled 4.31 TWh or 9.8% of the state's production. The state's top ten plants were responsible for 38.9 TWh or 88.9% of the state's production.

In 2018, Maryland's electricity production compact was responsible for the emission of more than 896 lbs/MWh of carbon dioxide, a 32.6% reduction from 2010 and a 35.9% decrease from 2000. The state saw its total emission rate stay relatively constant around 1 400 lbs/MWh between 1990 till 2007, from which time it started to gradually fall to reach a low of 863 lbs/MWh in 2017.

Full service providers (full service providers sell bundled electricity services e.g., both energy and delivery, to end users) were responsible for servicing 78.9% of retail customers within the state, generating 48.8% of sales in MWh and 52.9% of revenues. Of the full service providers, investor-owned ones represented 82.2% of retail sales in MWh while generating more than 83.6% of all revenues. The average retail price for those investor-owned full service providers reached 12.74 cents/kWh compared to 9.30 cents/kWh for publicly owned full service providers, 11.98 cents/kWh for cooperatives and 7.53 cents/kWh for non-utilities. The total statewide average for all providers was 11.57 cents/kWh in 2018.


MD-1: ELECTRICITY SUPPLY SOURCES
(TOTAL 2018: 66.7 TWh)
15.1%
20.8%
22.5%
4.2%
3.1%
34.3%
Coal
Natural Gas
Nuclear
Hydro
Wind
Biomass+ Wood
Other
Interstate Imports
International Imports


MD-2: DISPOSITION
1.6%
4.8%
0.5%
93.1%
Retail sales
Direct use
Estimated losses
Other
Interstate Exports
International Exports

WEST VIRGINIA

In 2018, West Virginia imported none of its 67.3 TWh total electricity supply, of which 92.2% (62.05 TWh) was produced from coal (Figure WV-1). Hydro, natural gas and wind were also used, with 2.8% (1.85 TWh), 2.1% (1.42 TWh) and 2.6% (1.77 TWh) of the state's total production output. Petroleum and other gas accounted for the remaining 0.3% (0.18 TWH) of the state's supply and production.

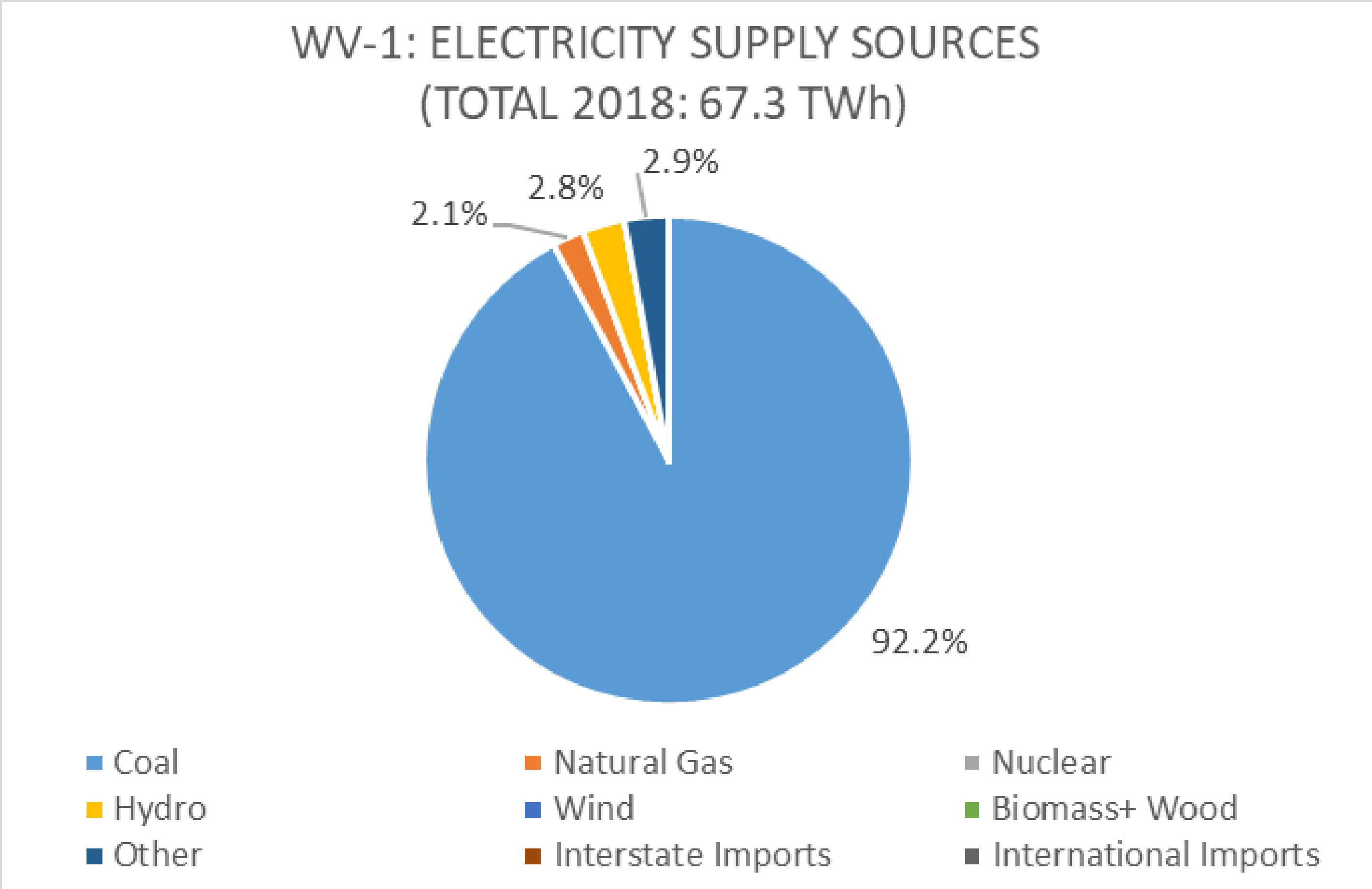
West Virginia exported to other states 46.4% (31.23 TWh) of its total supply in 2018 (Figure WV-2).

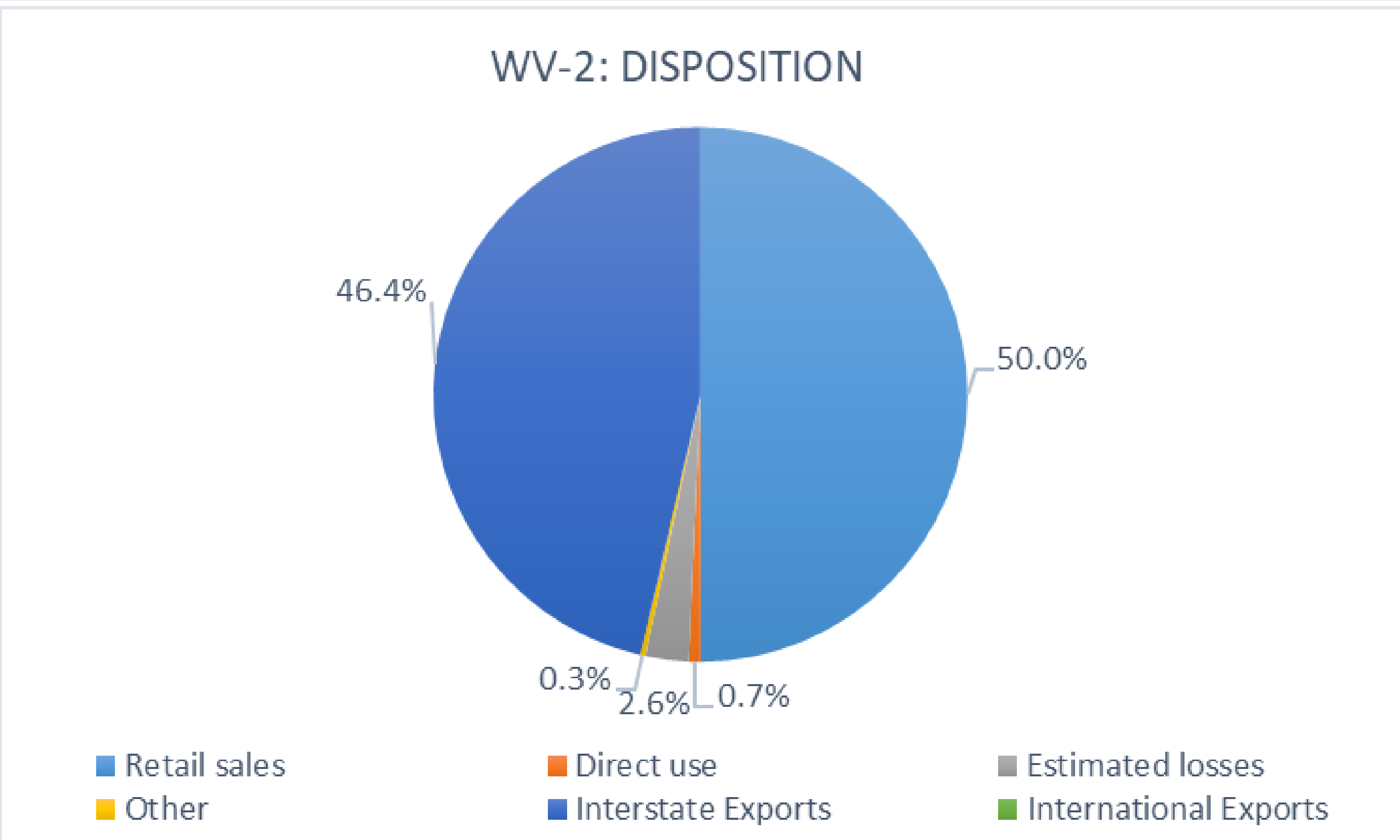
In 2001, coal accounted for more than 98% of the state's output, a situation quite comparable to 2019 with 91%. Not much has changed regarding the sources of the state's production in the last two decades. Wind, natural gas and hydro shared almost equally the last 9% of the total output in 2019. The objective of getting 25% of consumption from renewable sources by 2025 was repealed in 2015.

The eight largest plants by generation were all coal plants and accounted for 61.4 TWh or 91.2% of the state's 67.3 TWh production. The three larger ones were the First Energy Harrison Power Station which produced 13.25 TWh or 19.7% of the state's production, the John E. Amos plant which generated 12.98 TWh or 19.3% of the state's production, and the FirstEnergy Pleasants Power Station with 7.02 TWh or 10.4% of total production.

Being extremely dependent on coal, it's expected to see that the state emitted more than 1 970 lbs/MWh of carbon dioxide in 2018. That is only a 2.62% decrease from 2010 and an even smaller 2.57% decrease from 2000. The total emission rate has been constant throughout the years with no observable trend statistic.

The state's full service providers (full service providers sell bundled electricity services e.g., both energy and delivery, to end users) were responsible for servicing all retail customers within the state. Investor-owned full service providers accounted for more than 99.5% of all retail sales while also generating more than 99.2% of all revenues at an average retail price of 8.69 cents/kWh. The publicly owned full service providers charged an average retail price of 10.77 cents/kWh while it was 16.23 cents/kWh for cooperatives. The total statewide average retail price was 8.72 cents/kWh.


WV-1: ELECTRICITY SUPPLY SOURCES
(TOTAL 2018: 67.3 TWh)
2.1%
2.8%
2.9%
92.2%
Coal
Natural Gas
Nuclear
Hydro
Wind
Biomass+ Wood
Other
Interstate Imports
International Imports


WV-2: DISPOSITION
46.4%
50.0%
0.3%
2.6%
0.7%
Retail sales
Direct use
Estimated losses
Other
Interstate Exports
International Exports

KENTUCKY

Kentucky produced 96.9% or 78.80 TWh of its total supply of 81.35 TWh in 2018 (Figure KY-1). This represents a drop of nearly 20% in both production and supply since 2010. The 2018 production was mainly attributed to coal which accounted for more than 75.0% (59.16 TWh) of the state's total output. Natural gas and hydro were also significant productive entities with 18.6% (14.65 TWh) and 5.6% (4.39 TWh) of the state's production profile.

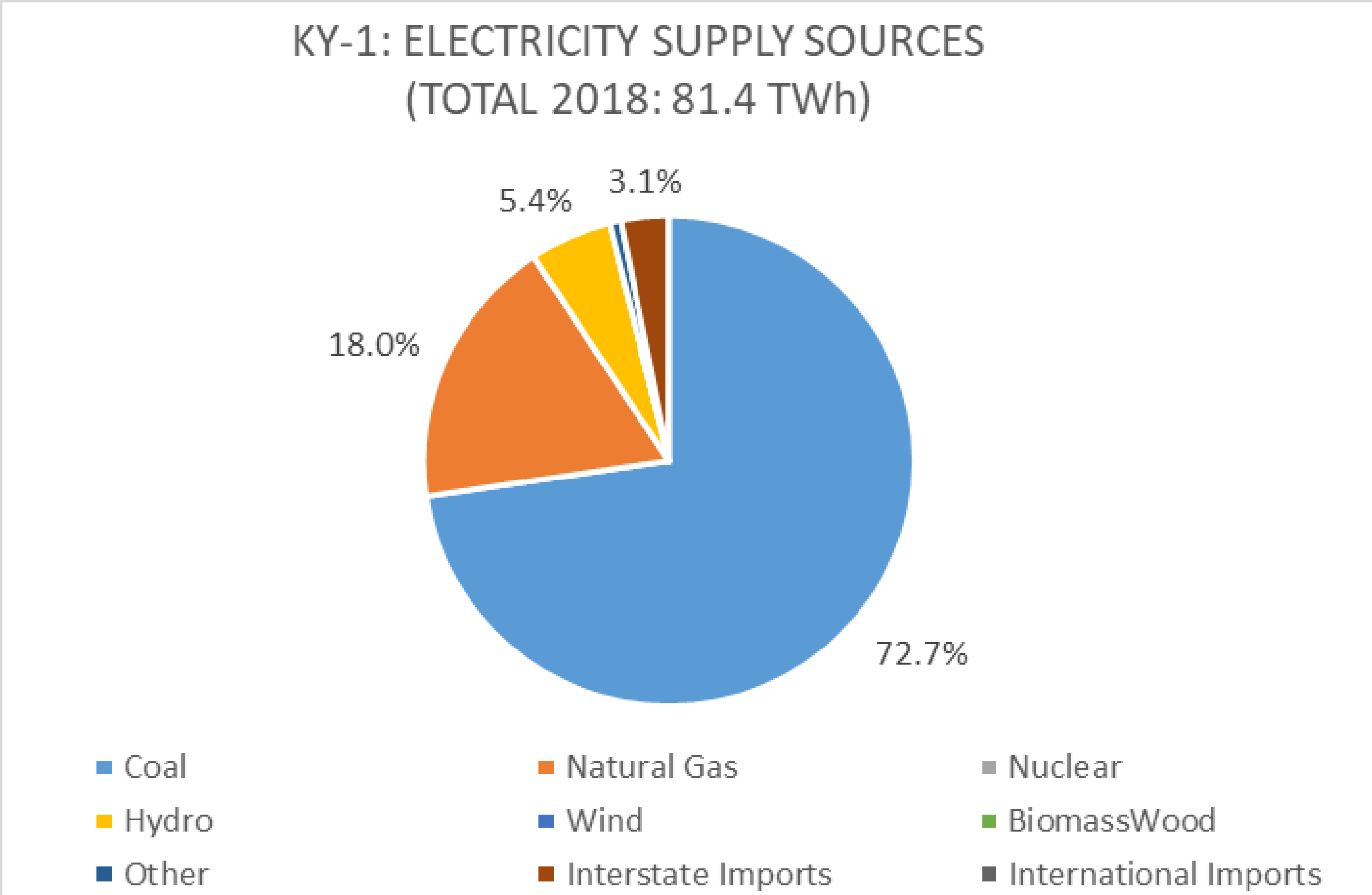
The state did not export any electricity in 2018 (Figure KY-2).

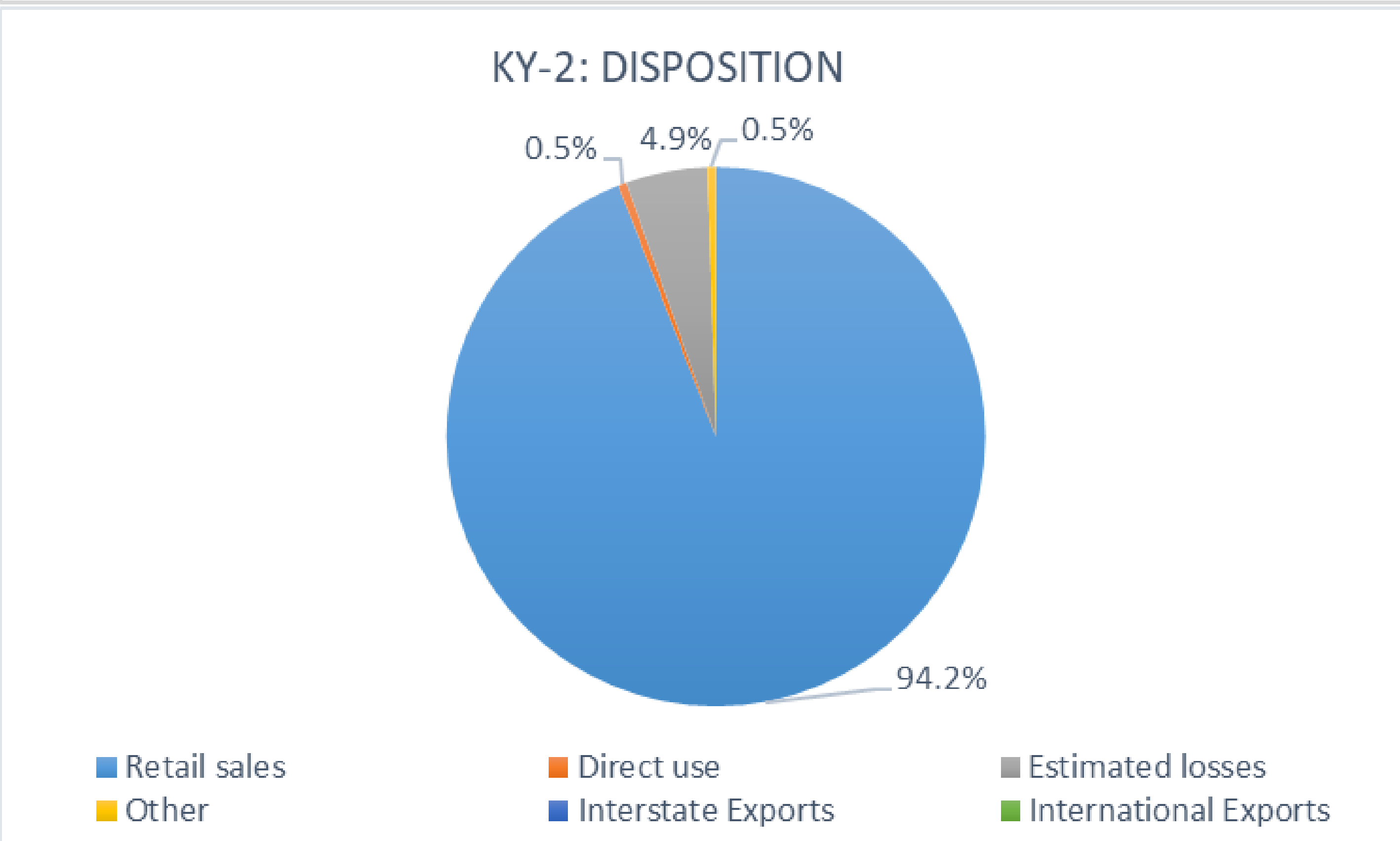
Kentucky is one of those states that has mainly been powered by coal during the last decades and, while its importance is gradually diminishing, going from a 95.1% share in 2001 to a 73% share in 2019, coal remains by far the main output contributor. However, since 2009, natural gas has gained significantly in importance, going from less than 1% in 2001 and 2008 to more than 21% in 2019. Hydro has been present within the state during the last decades, but it hasn't experienced any sustainable or significant growth during those years, going from a production of 4% to 6% in 2019.

More than 83.4% of the state's total production was the result of the state's ten largest plants by generation. The largest one, the Ghent coal plant accounted for more than 11.26 TWh or 14.3% of the state's 78.80 TWh production. It is followed by the Paradise natural gas plant which generated 9.70 TWh or 12.3% of the state's production and the Trimble County coal plant which produced 9.03 TWh or 11.5% of the state's production.

Kentucky is another big coal-using state and that is reflected in the 1 850 lbs/MWh of carbon dioxide the state emitted in 2018. That is a 11.4% decrease from 2010 and a 10.7% decrease from 2000. The state has actually seen its total emission rate gradually rise from 1990 until the 2008 high of 2 114 lbs/MWh. From then on, the state has seen a slight decrease until 2018's low.

Full service providers were responsible for servicing all the retail customers within the state in 2018. Of those full service providers, investor-owned ones accounted for more than 52.8% of all retail sales in MWh while generating more than 54.1% of all revenues. Those same investor-owned full service providers had an average retail price of 8.74 cents/kWh compared to 10.10 cents/kWh for publicly owned ones and 8.29 cents/kWh for cooperatives. The average retail price for all statewide providers was 8.52 cents/kWh.


KY-1: ELECTRICITY SUPPLY SOURCES
(TOTAL 2018: 81.4 TWh)
3.1%
5.4%
18.0%
72.7%
Coal
Natural Gas
Nuclear
Hydro
Wind
BiomassWood
Other
Interstate Imports
International Imports


KY-2: DISPOSITION
0.5%
4.9%
0.5%
94.2%
Retail sales
Direct use
Estimated losses
Other
Interstate Exports
International Exports

4. THE WIN-WIN VALUE OF ELECTRICITY TRADE.

Trade in electricity is an important activity in NEA as measured by the ratio of (EX+IM) over Total Supply (Table 1). The role of Independent System Operators (ISO) in managing electric flows and revealing competitive prices, at least at the wholesale level, is already well known and accepted throughout the region. Nevertheless, exports and/or imports are being challenged all the time.

Table 1: Trade in Electricity in NEA (INTER-national and INTRA-national) - 2018

Province/State	Total Supply TWh	Exports (EX) TWh ; % of Supply		Imports (IM) TWh ; % of Supply		Net EX or IM TWh ; % of Supply	Total EX+IM TWH ; % of Supply
		INTER	INTRA	INTER	INTRA		
NL	44.1						
NS	10.6						
NB	16.8						
QC	213.9	25.2 ; 11.8%	12.4 ; 5.8%	0.17 ; 0.08%	34.2 ; 16%	EX 3.2 ; 1.5%	72.0 ; 33.6%
ON	156.0	15.8 ; 10.1%	2.8 ; 1.8%	0.3 ; 0.2%	8.2 ; 5.3%	EX 10.1 ; 6.4%	27.1 ; 17.4%
CT	40	--	8.5 ; 21.3%	0.5 ; 1.3%	--	EX 8.0 ; 20.0%	9.0 ; 22.6%
ME	15.6	0.1 ; 0.7%	0.4 ; 2.8%	4.3 ; 27.8%	--	IM 3.8 ; 24.3%	4.8 ; 31.3%
MA	57.1	--	--	1.0 ; 1.7%	29.0 ; 50.7%	IM 30.0 ; 52.4%	30.0 ; 52.4%
NH	17.3	--	5.5 ; 31.8%	--	--	EX 5.5 ; 31.8%	5.5 ; 1.8%
RI	8.5	--	0.3 ; 3.3%	--	--	EX 0.3 ; 3.3%	0.3; 3.3%
VT	11.9	--	6.1 ; 50.7%	9.7 ; 81.7%	--	IM 3.6 ; 31.0%	15.8 ; 132.4%
NJ	81.6	--	--	--	6.7 ; 8.3%	IM 6.7 ; 8.3%	6.7 ; 8.3%
NY	160.5	--	--	15.7 ; 9.8%	12.3 ; 7.7%	IM 28.0 ; 17.4%	28.0 ; 17.4%
PA	215.4	--	52.6 ; 24.4%	--	--	EX 52.6 ; 24.4%	52.6 ; 24.4%
IL	188.0	--	33.1 ; 17.6%	--	--	EX 33.1 ; 17.6%	33.1 ; 17.6%
IN	117.0	--	--	3.4 ; 2.9%	--	IM 3.4 ; 2.9%	3.4 ; 2.9%
MI	122.4	--	8.9 ; 7.3%	6.5 ; 5.3%	--	EX 2.4 ; 1.9%	15.4 ; 12.6%
OH	162.8	--	--	--	36.6 ; 22.5%	IM 36.6 ; 22.5%	36.6 ; 22.5%
WI	76.9	--	--	--	11.0 ; 14.3%	IM 11.0 ; 14.3%	11.0 ; 14.3%
DE	13.2	--	--	--	6.9 ; 52.6%	IM 6.9 ; 52.6%	6.9 ; 52.6%
MD	66.7	--	--	--	22.9 ; 34.3%	IM 22.9 ; 34.3%	22.9 ; 34.3%
WV	67.3	--	31.2 ; 46.4%	--	--	EX 31.2 ; 46.4%	31.2 ; 46.4%
KY	81.4	--	--	--	2.5 ; 3.1%	IM 2.5 ; 3.1%	2.5 ; 3.1%

4.1 Opposition to importation / exportation of electricity

The opposition in Canadian (provinces) and US (States) jurisdictions regarding trade, importation and/or exportation, in electricity takes its roots in the ideology of protectionism. The main arguments are based on job and local business protection and development and on energy security.

Numerous Americans and Canadians argue for instance that by importing electricity from Quebec, they are promoting job creation in Quebec, jobs that could be created in their own provinces or states. Why shouldn’t their government develop their own electricity-producing entities, creating thousands of jobs in the process, well-paying jobs that would invigorate their state's economy instead of their neighbour's economy?

Moreover, being in the position of importer makes the state dangerously dependent on the exporter's production entities and on the international and national political agreements. Some would refer to recent shortages of fuel in Europe[1] as instances in which a country or a state may prefer keeping its energy including its electricity within the state rather than selling it abroad. It is claimed that being excessively dependent on importation would make these sorts of situations go from bad to catastrophic.

When it comes to the exportation of (excess) electricity, the opposition is considerably less important. Most would agree that exporting any excess electricity is favorable to the exporter's population, but some argue that it erodes the state's ability to encourage the development of renewable sources of energy.

The case of British Columbia is quite interesting. Most would accurately believe that British Columbia is an important producer of electricity through renewables. However it is interesting to note that the province, despite producing enough electricity to meet its own demand, imports a considerable amount of electricity from American states such as Wyoming, Utah, Nebraska, and Montana, which all produce the majority of their energy through coal.[2] The province agrees to sell its hydroelectricity to neighboring states while also buying coal-produced electricity. The difference is a considerable profit for the province as hydroelectricity offers operational flexibility that coal-produced electricity can't offer. The province buys the dirty electricity when the price is low (at night) and sells the clean electricity when the price is high (during the day). The opposition thus argues that despite itself being a strong believer in renewable sources of energy, the province, through trade in electricity, is promoting the coal industry in the United States.

In Ontario, the main argument is that the government, through the exportation of electricity, is subsidizing the province's competitors. Conservatives are of the opinion that, between 2009 and 2016, the province sold $6 billion worth of excess electricity at a big loss, figures that are contested by the Liberals.[3] Conservatives argue that Ontarians would be better off not selling this excess electricity or forcing its competitors to buy it at "reasonable" prices rather than at "competitive" prices that look like subsidies.

In Quebec, those opposing the exportation of electricity through the state-controlled Hydro-Québec argue that important investments in the exporting infrastructures would also be required. These investments, they argue, make all exporting agreements vastly unprofitable.

The electricity producing industry demands tremendous amounts of capital. Hydro is the preferred generating technology in Quebec, but the initial fixed costs of building a hydroelectric dam and the ensuing distribution infrastructures are immense. Opening these distribution infrastructures to more customers through free-trade agreements would allow the producers to spread these fixed costs over more customers which could lower the price per customer.

[1] https://www.theguardian.com/business/2018/mar/01/uk-is-running-out-of-gas-national-grid-warns-freezing-weather
[2] https://thenarwhal.ca/clean-b-c-is-quietly-using-coal-and-gas-power-from-out-of-province-heres-why/
[3] https://www.macleans.ca/news/ontario-has-given-away-millions-in-electricity-say-pcs/

One of the most difficult things to deal with regarding electricity is the fact that it cannot be stored for future usage. Produced electricity that cannot be consumed is simply lost, as the economic potential of batteries is very limited. The development of a regional interconnected grid would allow the producing entities to prepare and plan their operations, thus offering them more flexibility and promoting the enhancement of the electric system's reliability.

4.2 The arguments in favor of trade as seen from Ontario

Ontario is an important net overall (international and interprovincial) trader in electricity in Canada with net exports of 10.1 TWh or 6.4% of its supply (Table 1). In comparison, the numbers for Québec are 3.2 TWh and 1.5%. In terms of total overall trade (exports plus imports, international and interprovincial), Québec is a more important trader with total trade reaching 72.0 TWh or 33.6% of its total supply. In comparison, the numbers for Ontario are 27.1 TWh and 17.4%.

According to the Independent Electricity System Operator (IESO),[4] Ontario's connections with neighbouring jurisdictions have provided both economic and reliability benefits to Ontario for over a century. The following discussion follows the presentation in IESO documents.

Economic Efficiency

Interties between electricity markets provide a significant opportunity to efficiently utilize the energy generated from a diverse range of resources over a much greater geographic area, thereby lowering the cost for all parties.

Interties benefit Ontario by allowing cheaper power to access Ontario's electricity market when it is available, and enabling our generation to reach other markets across eastern North America whenever it is economic. These real-time economic transactions are a result of the differences in energy prices with power predominantly flowing from low cost energy providers towards the higher cost regions. In recent times Ontario has been a net exporter on an annual basis, reflecting today's strong supply conditions. However, it wasn't long ago that Ontario was a net importer of power when Ontario demand was high and Ontario did not benefit from such a robust supply mix. On an hourly basis, power flows to and from Ontario providing an important balancing function that helps smooth the peaks and troughs for domestic producers and ultimately results in lower cost to consumers.

Electricity trade provides a revenue opportunity for Ontario's less flexible resources (such as baseload hydroelectric and nuclear) when Ontario demand is low and attracts imports when they are a lower cost option than producing power domestically. Interties are increasingly viewed as playing an important role in efficiently integrating intermittent renewable generation. For example, because the output of renewable resources varies across markets, the use of interties across wider geographic

[4] https://www.ieso.ca/en/Power-Data/Supply-Overview/Imports-and-Exports. See also Boyer, M., et alii, *Méthodes avancées d'évaluation d'investissement / Advanced Methods of Investment Evaluation*, Monographie CIRANO Monograph (2 tomes / volumes), Hiver/Winter 2017, 601 pages, in particular chap. 8 Fundamentals of Real Options Valuation; chap.12 Identifying, Creating and Managing Real Options; and chap.15 Application de la théorie d'options réelles pour l'évaluation économique d'une interconnexion entre deux marchés d'électricité. http://cirano.qc.ca/files/publications/2017MO-03.pdf (Tome 1) and http://cirano.qc.ca/files/publications/2017MO-04.pdf (Tome 2).

areas helps offset the uncertainty and variability of renewable resources. Additionally, interties can increase system flexibility by allowing the output from resources to be balanced efficiently over a larger geographic footprint.

Capacity and Energy

Capacity, measured in megawatts (MW), is the maximum instantaneous level of electricity that is consumed and that must be supplied by the power system. Ontario must have adequate capacity resources available, either within the province, or through firm imports, to supply electricity customers during the peak demand periods of the year. In the context of imports, capacity has two essential components, the capability of the interties and related transmission system in both the sending and receiving jurisdictions, as well as the generating capability at peak of the sending jurisdiction, over and above their domestic requirements.

Energy, measured in megawatt hours (MWh) or terawatt hours (TWh) is the volume of electricity that is consumed or supplied over some period of time, for example over a day or over the course of a year. Energy has been, and continues to be, economically imported and exported over the interties through Ontario's wholesale energy market. It is important to keep in mind that while a given volume of energy may be supplied over the course of a year, at no time can the profile of this energy exceed the capacity of the equipment that is required to supply or transmit it. However, the difference between energy and capacity is that with energy the exporter would not have to offer their energy in any given hour.

The IESO has traditionally planned to meet Ontario peak demand by only considering domestic resources. The role of interties has been limited to supplying energy when real-time market-to-market transactions are more economic than internal resources. However, going forward the IESO is considering how Ontario's electricity market and transmission assets could facilitate both capacity and energy transactions between regional buyers and sellers, providing the transmission connections are robust enough to support the scheduled quantity of electricity and that the reliability services such as voltage control provided by Ontario resources (and that cannot be provided by imports) are provided by other resources.

Capacity transactions are a well-established feature of many North American markets. Firm capacity imports can be a cost effective alternative to meet domestic reliability needs. Capacity exports can provide an asset owner with an opportunity to earn revenues even if the facility is not required to maintain home market reliability. Enabling capacity transactions improves market efficiency since it allows excess or shortages of capacity to be bought and sold on an as needed basis. Capacity transactions can avoid the need to build an expensive new generation resource that might only be required for a short period of time, and can also provide bridging revenue for a domestic asset that is not needed today, but might be required in the future in its home market.

If a capacity-based firm import arrangement is created, the IESO must ensure that both the interties and the Ontario transmission system have sufficient deliverability (from the intertie to load centres) to meet the maximum energy transfers for this firm import under virtually all system conditions and demand scenarios. Essentially, the IESO must be confident it can rely on the firm import for reliability and that the interties and Ontario transmission network can support the full flow of power under a wide variety of system conditions.

By contrast non-firm imports (i.e., energy-only transactions) do not require such a rigorous assessment since they are an economic transaction and not relied upon for reliability. As such, the interties and the Ontario transmission system are not required to support the full import flow under all system conditions. In addition, these non-firm imports are likely to be curtailed by the source system operator under shortage conditions so that the electricity can be used to meet their internal needs first. By contrast a capacity-backed import (firm energy trade) can only be curtailed under very specific circumstances. This treatment of firmness is the key difference between a capacity-backed trade and non-firm imports.

Reliability

The interties have provided operating flexibility to help the IESO better deal with routine and extreme events on the power system. The interties are also a source of reliability services, such as operating reserve.

Ontario relies on the interties in the seconds and minutes following an event on the Ontario power system (e.g., loss of a large common mode generation resource or transmission asset, such as the western Toronto flash flooding event of July 2013). In such cases, Ontario will temporarily draw on neighbouring systems to assist with maintaining system frequency and partially make up the lost energy, or absorb the extra energy. To manage these events, it is important to maintain a reliability margin on the interties to provide the IESO with additional options for managing the system, especially during those extreme events that rarely occur but that would likely impact reliable operation of the system. In practice, the IESO applies this reliability margin on all of the interties in aggregate and not necessarily on each individual intertie in the province.

From an operational perspective, it is preferable to have this reliability margin on the interties with New York and Michigan rather than Quebec. Ontario, New York and Michigan are all part of the same interconnected, synchronous power system, referred to as the Eastern Interconnection. Following an event in Ontario, the interties with New York and Michigan instantly spread the impact of the event across the entire Eastern Interconnection (i.e., to neighbouring jurisdictions) and, in that way, provide support until replacement resources can be brought online or output is reduced. Quebec is not part of the Eastern Interconnection. The nature of the special transmission and generation connections between Quebec and Ontario prevent Quebec resources from providing the same significant support following events in Ontario. In fact, the power transfers from Quebec usually stay almost constant immediately after an Ontario event.

As such, delivering firm import capacity on the interties with Quebec up to the capability of the intertie (i.e., have no reliability margin on the interties with Quebec) is technically possible, as long as there is sufficient flexibility on the New York and Michigan interties. It may be necessary to reserve some room, specifically, on the Outaouais HVDC tieline with Hydro-Quebec to allow for the provision of reliability services such as operating reserve. For example, today the IESO's electricity market may economically select Quebec resources, across the Outaouais tieline, to supply operating reserve rather than using more costly Ontario resources.

Operability

It is critical that the IESO have the ability to balance supply and demand using a mix of flexible internal resources (which are able to quickly adjust energy output) and by scheduling transactions (imports and exports) through Ontario tielines. The continued growth of wind and solar generation can create significant operability challenges for any system operator as there is a corresponding need for other supply resources to quickly respond to changes in wind and solar generation output. Other markets have sought means to maintain an operable system by developing more frequent intertie scheduling processes with their neighbouring markets. By moving from hourly scheduling of imports and exports to a more frequent 15-minute cycle, other markets such as MISO, PJM, NYISO and ISO-NE have a better mechanism to manage intra-hour fluctuations in intermittent generation output across their regional markets. Ontario-Quebec Interconnection Capability 9

These examples are some of the ways that system operators are increasingly turning to interties as a way to help manage the challenges of a changing supply mix and greater supply uncertainty. As part of its Market Renewal project the IESO is also considering what changes can be made to the existing market design to fully optimize the potential that interties can offer in meeting Ontario's operability needs. Opportunities to facilitate greater trading with Quebec need to be considered in light of these broader market reforms to identify any linkages and potential overlaps.

4.3 Why free-trade benefits everyone, even if it would mean higher prices for Quebecers

While it is fairly obvious that a free-trade agreement regarding electricity would lower the cost paid by the customer in most American states and Ontario, the contrary would most likely occur in Quebec, the third most important electricity producer (179.5 TWh) in NEA in 2018, after Pennsylvania (215.4 TWh) and Illinois (188.0 TWh).

However, the price that Quebecers are currently paying for their electricity, which is considerably lower than the market price (opportunity cost), isn't sustainable and growth-prone. Sustainability and growth are best promoted not by low prices but by proper prices, that is, prices that represent the opportunity cost of the resources. The effective subsidization that low prices may represent promotes the development of energy-intensive economic activities, thus generating important distortions in industrial activity. This stratagem acts against sustainable development as energy conservation programs developed by the government and business fall on deaf ears.

Electricity prices is a subject on which everybody seems to have an opinion. Consumer groups oppose price increases because they, among other effects, hurt low-income families. Better-off Quebecers remain quiet because they, too, like low prices. Energy-intensive industries, eager to preserve their "competitive advantage", also favour maintaining low prices. Politicians are only too happy to cooperate, and appropriate the easy political payoffs that flow from a low-price policy.

Compared to other North-American jurisdictions, electricity prices in Quebec are indeed very low (Table 2). For society as a whole, however, maintaining electricity prices below their opportunity costs — the real economic costs — makes Quebec poorer. The underlying social pact must be rethought.

Table 2: Comparative index of residential electricity pre-tax prices in different cities for a consumption of 1 000 kWh/month[5]
(Hydro-Québec, April 1, 2005 and 2020)

City	Price index 2005	Price index 2020	Index of change 2020/2005
Montréal QC	100	100	100
Toronto ON	175	152	87
Vancouver BC	101	158	156
Edmonton AB	140	203	145
Chicago IL	149	262	176
Detroit MI	179	329	184
New York NY	320	461	144
Boston MA	285	470	165

https://www.hydroquebec.com/data/documents-donnees/pdf/comparison-electricity-prices.pdf

Quebec's energy potential is phenomenal, not only because of its many indigenous sources, but also because of the experience and competency it has acquired (and thanks to visionary leaders such as former Premier Robert Bourassa). However, an uninformed and misguided coalition of legislators, business and union leaders exercise inordinate control over Québec's energy resources. The result is a directionless resource-development policy, based on price manipulation, that benefits only the groups directly involved, while squandering the potential welfare gains for all citizens from a socially optimal resource-exploitation plan. The current low-price policy — financed by higher public debt and taxes, and possibly leading to a deterioration of social services — is not only an inefficient subsidy to big energy consumers, including both individuals and corporations, but also a regressive transfer from the poor to the wealthy.

Commentators often hail the relatively low level of electricity prices in Quebec as helping achieve a high level of economic development. What that hides, however, is the real social cost of the policy. The real price of electricity is not its production cost, particularly low in Quebec because of plentiful hydro-electric power, but its opportunity cost. That opportunity cost is significantly higher because it equals the maximum competitive price at which electricity can be exported. The traditional response of

[5] The cost of such a level of consumption (residential electricity rate D on April 1 2020) is obtained as follows: a fixed access charge of 40.64¢/day and a price of 6.08¢/kWh, that is, for an average 30.5 days per month, an access charge of $12.40 and a variable cost of $60.80 for a monthly total of $73.20 or $878.34 for a year. Rate D has two price levels: 6.08¢/kWh for the first 2440 kWh (over two months) and 9.38¢/kWh for each additional kWh above 2440 kWh.

customer and consumer groups that gain from this policy is: *Everybody benefits from low prices*. *Nothing could be further from the truth.*

Politicians, industrialists and union leaders often argue that low electricity prices help produce jobs, while neglecting to mention other employment opportunities that are forfeited. The reason is clear: the benefits to the few better-offs are easily identifiable and appropriated by well-organized political and industrial organizations, while the costs to the many worse-offs are diffuse and hidden under the rug.

If the authorities were to offer Montreal households that consume 12,000 kWh per year at a pre-tax cost of $878.34,[6] the option of cutting their electricity consumption by 10 percent (1,200 kWh), using means that are not onerous, in exchange for lowering their electricity bill by 20 percent, a $175.67 saving, a great majority of consumers would accept the deal, which is not unrealistic in view of the prices that prevail in surrounding jurisdictions, because the true cost of the last 1,200 kWh would be $175.67, or 16.64¢/kWh. To withhold such an option is unfair because it induces the family to consume 1,200 kWh at the apparent but misleading price of 6.08¢/kWh, while the real cost is at the margin almost 2.5 times higher.

The real social cost of selling electricity at a subsidized price lower than its opportunity cost is that it promotes the development of energy-intensive economic activity, producing distortions in industrial activity. It also sends signals that are unfavorable to sustainable development. To top the irony, Quebecers must now spend tax dollars to finance government programs that promote energy conservation.

The economists Jean-Thomas Bernard, Marcel Boyer, Mr. Martin Boyer and Pierre Fortin agreed[7] with this general proposition in their defense of a Québec energy policy resolutely focused on the creation of wealth rather than on the sale of Québec energy at a discount to unprofitable sectors and businesses, thus selling off and squandering the potential social wealth of Quebecers.

We must re-introduce the cheapest, most equitable, most effective and most efficient mechanism to ensure the right level of development and the right level of conservation: a price equal to the real economic (opportunity) cost. If the government wanted to alleviate the impact on lower-income households, it could use the appropriate income redistribution mechanisms that are already in place, combined with incentive programs, to shelter them from the price increases.

Quebecers should militate for policies that would lead to true wealth creation. To achieve that, some important changes are in order. For one thing, government should allow transparent and independent analysis of the true costs and benefits of Quebec's current energy policy. For another, it should let the price of electricity rise and reflect its true opportunity cost. As well, it should allow as much energy

[6] https://www.hydroquebec.com/data/documents-donnees/pdf/electricity-rates.pdf?#page=16

[7] Jean-Thomas Bernard, Marcel Boyer, Martin Boyer, Pierre Fortin, « Cessons le bradage ! Le développement énergétique du Québec doit servir à une véritable création de richesse », *La Presse*, p. A-19, 12 avril 2007. https://www.iedm.org/fr/2814-cessons-le-bradage-le-developpement-energetique-du-quebec-doit-servir-a-une-veritable-creation-de-richesse/

development of electricity, natural gas and oil as is compatible with security, environmental protection and profitability constraints.

4.4 Long term impacts of a NEA free trade agreement in electricity

The future of coal-fired power stations

We saw in Section 3 above that there are still many coal-fired plants in NEA. It is unrealistic to think that we can close all NEA coal-fired power stations in the short term unless economic alternatives can be offered to producers and consumers of electricity. This would be the case if a large market were set up in NEA. In such a case, baseload and peak hydroelectricity could be more economical than coal-fired thermal electricity. A second possibility is shale gas, which is already becoming increasingly important. But except for GHG emissions, these plants are not clearly superior to coal plants. The master card is hydroelectricity (HQ), hence the interest for Quebec in offering this large NEA market.

The future of nuclear power stations

As with coal-fired power plants, it is unrealistic to think that we can close nuclear power plants in the short or medium term unless economic alternatives can be offered to electricity producers and consumers, in particular in Ontario. In addition, the large lobby of the nuclear industry in Ontario will be a major obstacle. The only credible way to confront it is to go not through a policy of replacing nuclear power with hydroelectricity but rather through a policy of a large open and transparent market in which the different production technologies can compete in the short term, medium term and long term. This would be the case if a large market were set up in the NEA with spot and forward components and capacity calls for tenders (with substantial financing). In such a case, base and peak hydroelectricity would obviously be more economical than nuclear thermal electricity. Hence the interest for Quebec and Newfoundland-Labrador in this large NEA market.

The future of natural gas power stations

As with coal-fired and nuclear power plants, it is illusory to think of shutting down gas-fired power plants in the short or medium term unless economic alternatives can be offered to electricity producers and consumers, in particular in the Northeastern USA. For these private producers, the calculation will be one of economic profitability and not of political lobbying. Gas thermal: the great advantage of hydroelectricity from large dams (compared to run-of-river or tidal hydroelectricity) is flexibility. It is through competition between sources of electric energy that flexibility becomes crucial and highly valued and valuable, hence Quebec's and Newfoundland-Labrador enviable position.

The future of hydroelectric power stations

For many years, this important value of hydroelectricity has been wasted in Quebec and Newfoundland-Labrador. The only credible way for their citizens to take full advantage of this value is to promote the establishment of a large open and transparent market in which the different production technologies can compete in the short, medium and long term. Once again, if a large market were set up in the NEA with spot and forward components and capacity calls for tenders (with substantial financing), base and peak hydropower would obviously be more economical than gas-fired thermal electricity, at least for a good part of annual production, gas-fired thermal power stations possibly remaining profitable for some peak hours given their low fixed investment cost. Hence, once again, Quebec's interest in proposing this large NEA market.

The future of electricity needs

Predicting electricity needs over a 25-year horizon is very complex. At the outset, it is necessary to see the evolution of technologies, regulations and investments in energy efficiency over the same horizon, to foresee the evolution of the structure of the economy according to the different industrial sectors, to foresee the increase in electricity consumption in depending on the level of economic activity, and finally the variation (long-term elasticity) in the consumption of electricity as a function of its price and therefore foresee the evolution of the price of electricity itself.

Depending on the weight given to these five developments and the assumptions made about the level of future technological progress, we can arrive at different values for electricity needs. One thing is certain: the best estimate that we can give today of these needs is a range of increase in needs ranging from 45% (based on an average annual growth rate for the next 25 years of 1, 5%) to 65% and perhaps more (based on an average annual growth rate for the next 25 years of 2.0% and more), from which we could subtract the 25-year rate of energy efficiency gains in the use of electricity. For the purposes of a first analysis, we can consider the most important variable, which is the level of growth of the economy as a whole. Thus, for Ontario for instance, an increase in capacity of the order of 16,000 MW to 23,000 MW, from 35,000 MW to an interval of 51,000 MW to 58,000 MW and an increase in the production of electric energy in the order of 70 TWh to 100 TWh, going from 156 TWh to an interval ranging from 226 TWh to 255 TWh.

For the reasons mentioned above, the best estimate that we can give today of the needs in US NEA is a range of increase in needs ranging from 65% (according to an average annual growth rate for the next 25 years of 2.0%) to 85% and maybe more (based on an average annual growth rate for the next 25 years of 2.5% and more). Thus, for the North-East of America (New England, Middle Atlantic, East North Central) which includes a large number of electricity production plants, some of which are of limited capacity, an increase in electricity production needs of around from 510 TWh to 730 TWh, going from 1140 TWh to an interval going from 1650 TWh to 1870 TWh. Ultimately, this increase will depend a lot on the evolution of the prices of electricity and other sources of energy and the effects of the fight against global warming (GHG) and therefore gains in energy efficiency (intensity of GDP in electricity).

The refurbishing cost of Ontario's nuclear power plants

It is difficult to have a precise estimate for the renovation of nuclear plants in Ontario as the renovations will take place over a planned period of 16 years. But we are talking about "several billion dollars". On December 3, 2015, Ontario announced that the Bruce nuclear power plant (6,300 MW) would be renovated between 2020 and 2033 at a cost of $13 billion.[8] Interestingly, the work should

[8] https://ici.radio-canada.ca/nouvelle/753212/renovation-centrales-nucleaires-bruce-darlington-details-plan-chiarelli

create up to 23,000 jobs and generate annual spinoffs of $6.3 billion. This is the source of the nuclear lobbying in Ontario that proposals to substitute hydropower for nuclear power have to contend with. In addition, the private operator of the plant - Bruce Power - owned by TransCanada will fund the refurbishment of the reactors. Further reducing the pressure on Ontario's public finances.

The future needs of power transmission lines

Most of the power lines are used not only for export, but also to meet internal needs. For example, the La Romaine complex, which according to some observers will mainly serve to improve exports to Ontario and the USA, will benefit from the already built HQ-TransÉnergie network while helping to secure its financing. However, we can mention as an indication the costs of transmission line projects between the Quebec border and the major markets of NYPool and PJM, of which HQ is a "partner": Northern Pass, Vermont Green Line, New England Clean Power Link, and the Champlain Hudson Power Express. More generally, a complex and rigorous exercise of cost sharing and infrastructure pricing must be carried out.[9]

Investments in transmission lines will be a major concern in the perspective of the large NEA market, of which Quebec should be a leader. No precise estimates can be given without more extensive engineering and economic studies, spread over several years, than those available at this time. Those studies will only be undertaken if a real interest in them develops. Such interest would arise, for example, from a proposal and discussions for the establishment of a large electricity market in NEA, with appropriate auction mechanisms for the development of generation and transmission capacities. This is a very large project, but the spinoffs for Quebec and NEA are obviously considerable even if they are difficult if not impossible to quantify precisely at this stage. The evaluation of these transport lines also poses complex methodological problems. These interconnection projects can be evaluated using a Real Options evaluation model of the type of the model developed in Chapters 8, 12 and 15 of my 2017 CIRANO monograph.[10]

One tricky issue in this regard is the NIMBY (not in my backyard) syndrome. See proposition #3 in the Conclusion below.

The future potential of hydroelectric power plants

There is no fully reliable public data on the potential new dam projects in Québec and Newfoundland-Labrador. But the cost of the four dams of the La Romaine project can serve as a guide. According to HQ, the La Romaine complex includes four reservoir plants with a capacity of 1,550 MW and will produce some 8 TWh of hydroelectric power per year. The cost of the project, including the transmission lines connecting the dams to the HQ network, is of the order of $8 billion. According to

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[9] See Marcel Boyer, Michel Moreaux and Michel Truchon, "Partage des coûts et tarification des infrastructures", CIRANO monograph 2006MO-01, . http://www.cirano.qc.ca/files/publications/2006MO-01.pdf

[10] See also Boyer, M., et alii, *Méthodes avancées d'évaluation d'investissement / Advanced Methods of Investment Evaluation*, Monographie CIRANO Monograph (2 tomes / volumes), Hiver/Winter 2017, 601 pages, in particular chap. 8 Fundamentals of Real Options Valuation; chap.12 Identifying, Creating and Managing Real Options; and chap.15 Application de la théorie d'options réelles pour l'évaluation économique d'une interconnexion entre deux marchés d'électricité.
http://cirano.qc.ca/files/publications/2017MO-03.pdf (Tome 1) and http://cirano.qc.ca/files/publications/2017MO-04.pdf (Tome 2).

Bernard & Bélanger (MEI 2007),[11] the production cost will amount to 10¢/kWh. The investment cost is approximately $5.2M/MW.

As the potential future development of power dams is estimated at 20,000 MW to 25,000 MW,[12] we can estimate that the cost of developing these dams would be in the order of $ 100 billion to $ 125 billion dollars. No more precise estimates can be given without more extensive engineering and economic studies, spread over several years, than those available at this time. They will only be undertaken if a real interest in producing them develops. Such interest would, for example, stem from a proposal and discussions for the establishment of a large electricity market in the NEA.

In addition, rational exploitation of the floods of the Broadback, Waswanipi and Bell rivers, conveying them to the Ottawa River, would make it possible to produce some 14 TWh of electricity per year without significant environmental damage.[13] This project would also make it possible to concretize Quebec's collaboration in the exploitation of the waters of the Great Lakes and the St. Lawrence River upstream of the Quebec portion of the St. Lawrence Seaway. In addition, there are 16 potential sites for the development of tidal turbines with an average power of 268 MW per site, or a total average potential of 4,288 MW. In Quebec, along the coast of Ungava Bay is a geographically ideal location for exploiting Quebec's tidal power potential.

In terms of future impacts of a large scale program of hydroelectric development, we can rely at this time on the largest current project, the $8 billion investment project, including the transmission lines to be built, for the four dams on La Romaine. According to Hydro-Québec, of the contracts awarded in 2010, 48% were obtained by companies from the North Shore. The site had an average number of 819 workers per week, 58.1% of which came from the entire Côte-Nord region. In April 2013, according to the weekly, Le Nord-Côtier, out of the 787 workers at work, 91 workers were from Mingan. According to other HQ data, in 2014, the Romaine complex project created 1,608 jobs, including 42% of workers from the North Shore. The value of contracts awarded in the region is $ 105 million. HQ grants an amount equivalent to 1% of the initial authorized value of its infrastructure projects to communities that host power lines or substations in their territory. HQ says it favors regional subcontracting or launches calls for tenders reserved for regional companies for contracts under a million dollars, provided that the principles of competition are respected.

The effects of a massive development of natural gas power plant

This massive influx of natural gas represents a great challenge for Quebec hydroelectricity. The dramatic increase in the production of shale gas has resulted in a significant drop in the price of gas (and oil due to the simultaneous increase in shale oil production) and the substitution of gas for coal in the production of gas thermal electricity production among other effects. This shale gas boom is no

[11] Gérard Bélanger and Jean-Thomas Bernard, *Subsidies for Aluminum Producers: Benefits That Don't Add Up*, Montréal Economic Institute, April 2007. https://www.iedm.org/sites/default/files/pub_files/avril07_en.pdf

[12] See F. Pierre Gingras (2015), *Réseau de transport pancanadien, Sommaire du rapport technique*.

[13] See F. Pierre Gingras (2009), *L'Eau du Nord, Un projet réaliste, durable et rentable pour exploiter l'or bleu québécois*, Note économique, Institut économique de Montréal

stranger to America's strong economic recovery relative to Canada and Europe. This trend will continue in the coming years.

But it should be remembered that natural gas power stations, although less polluting and more economical than coal power plants, remain thermal power plants and therefore relatively inflexible and less profitable in base, compared to hydropower and nuclear electricity, given their relatively high operating costs. It is less a war of substitutes that will be played out between natural gas, hydroelectric and nuclear power than a competition of complements, the three technologies of electricity production having different characteristics and different advantages and disadvantages. As electricity cannot be stored, it is a combination of the three types of power plants that will improve customer satisfaction. In any case, there is not enough undeveloped hydroelectric capacity to replace all the thermal power plants, natural gas or nuclear, which will remain very important.

The fall in shale gas prices will lead to a fall in the price of electricity, which could make the profitability of reservoir hydropower plants - based on their greater flexibility and their low variable cost of production - even higher. The importance of electricity in the energy balance of countries and regions, including the NEA, is likely to increase significantly, thanks to the stimulus of a reduced cost of electricity on economic growth and job creation.

5. POLICY CONCLUSIONS AND RECOMMENDATIONS

Trade in electricity follows the same rationale as trade in other goods and services. There is a difference between, on the one hand, promoting a free-trade policy while providing individuals and firms with incentives, means and instruments to prepare for and benefit from this policy by taking steps to adapt to the expected changes and upheavals within a reasonable time-frame, and, on the other hand, unduly protecting firms and jobs, which need to adapt and adjust, through a policy of comprehensive and ongoing protections, using trade barriers and generous and costly direct and indirect, whether open or hidden, subsidies.

A serious effort must be made to consolidate domestic markets—as they are often splintered by intranational barriers to the mobility of goods, services, and labour—and to open up as much as possible to the vast international market and profit from opportunities created by free-trade agreements, including a NEA free trade agreement in electricity.

To do this, it needs to be said over and over again that international trade at competitive prices, just like intranational, interregional and interpersonal trade, can and must be developed for the wellbeing of all. And at the same time, it is necessary to promote intranational and international trade that is more competitive, more secure, more resilient, and better shielded against unilateral protectionist actions of governments.

It is not the interests of firms and workers in a specific industry that should be defended and protected, but rather the principles and mechanisms of healthy competition that must underlie international trade as well as in the case of intranational, interregional and interpersonal trade.

Targeted and protectionist defences of the interests of businesses and workers in a particular industry is always done at the expense of companies and workers in other industries.[14]

With every parties now incentivized to optimize the operational reliability of the electrical network, much-needed investments would be made into Canada's electrical grid to allow larger amounts of electricity to be exported to other states. These investments are substantial, but they would be shared by the multiple parties involved and thus diminishing the relative importance for each participant.

Electricity is a very unique and delicate activity to deploy. This essential product is difficult to store or even non-storable, is the subject of inelastic short-term demand and requires highly capital-intensive and long-term production and transmission equipment. These characteristics typical of a natural monopoly have led all over the world to entrust, for almost a century, the production and transmission (supply) of electricity to public monopolies or highly regulated monopolies planning investments, ensuring the production, transport and distribution of electricity and transferring costs and risks to users (regulation by the rate of return or of the cost plus type).[15] These public monopolies are anchored differently but deeply in most if not each of the regions, states and provinces, of the NEA.

The electricity sectors were partly deregulated from the 1990s, to gain efficiency in investments in production and transmission infrastructures as well as in the exploitation of these infrastructures, while better coordinating regional parks through exchange, although generally very limited, all for the (hoped) benefit of industrial consumers and households. Begun with US FERC directive 388, this transformation is not over. The development of a market model and the adoption of new network infrastructure for cross-border, international and interregional, transport is an important and even crucial element.

Transformation and integration of this magnitude can only be effective with a long-term horizon and with a strong commitment from public authorities, which are still very influential or even dominant in this key sector of national and regional economies.

The ubiquitous integration of renewable energies (wind, solar, bioenergy), resulting from the objectives of the States and Provinces in terms of green energy, has led to the establishment of devices, such as purchase obligations at guaranteed prices, which de facto have placed and still place this equipment off the market, while making the systems and markets even more complex and difficult to control given the intermittent nature of these energies.

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[14] Marcel Boyer, « Free Trade and Economic Policies: A Critique of Empirical Reason (The Working Paper Version) », CIRANO 2020s-56, November 2020. http://cirano.qc.ca/files/publications/2020s-56.pdf ; TSE WP #20-1166 EN https://www.tse-fr.eu/sites/default/files/TSE/documents/doc/wp/2020/wp_tse_1166_en.pdf

[15] The definition of an integrated electricity common market in Europe, which is already considerably more advanced than in Northeast America (NEA), can provide useful lessons on the challenges to be met (see the work of the European Electricity Markets Chair of the University of Paris-Dauphine, the OECD, and the TSE energy and climate center at the University of Toulouse I Capitole, among other sources).

Despite the difficulties, it is possible to combine public coordination, market regime and social equity in the field of electrical energy. We have already seen how different the power generation equipment parks were. These differences, combined with the characteristics of electricity, including primarily the impossibility of storing, the variance over time and the instantaneous volatility of demand, make the possibilities of collaboration and exchanges profitable for all parties. There are many, both in terms of investments in production capacity and transmission / transport, as well as in the scheduling of production between the sectors.

For a NEA free trade area

NEA citizens will benefit from adopting a common perspective on electrical challenges. The benefits of greater coordination of complementary fleets far exceed the constraints of reduced decision-making autonomy. Taking advantage of these considerable complementarities of the production equipment of the various States / Provinces will significantly increase the possibilities of common economic development with significant job and wealth creation. All the States and Provinces of the NEA will greatly benefit from the development of this common market either in their electrical sector as such or in their industrial, commercial and residential sectors thanks to cheaper, more reliable and greener electricity.

States and Provinces, whose natural endowments are particularly advantageous will greatly and particularly benefit from the development of this common market. Others will also benefit thanks to the expertise and skills that these States / Provinces will have acquired, developed and maintained over time. This is the case, for example, for the ON for its expertise and skills in nuclear energy.

It is difficult to quantify precisely the benefits that such a common electricity market could bring to QC, but they are obviously enormous. As a low-cost producer of clean and reliable electricity, QC could be the big winner in this common market in terms of net income and jobs. But you have to be at the forefront of influencing the competitive decision-making methods that will have to be imagined and put in place: "If you are not at the table, you will be on the menu".

However, given the complexity of the sector and taking into account the legacies of the past, compromises must be worked out with a number of States / Provinces. To move forward, it is important to accept that beyond the logic of market integration through competitive exchanges, local compromises (imperfect but taking into account regional realities) are established in the States / Provinces of the NEA, everything paying attention to their transitory nature.

<u>Main recommendation #1</u>: The Government of Quebec should formally propose to the governments of neighbouring American states and neighbouring Canadian provinces the creation of an integrated common market in electricity with appropriate competitive rules and appropriate interconnections and system management institutions (ISO) allowing effective, efficient, transparent and fluid exchanges for the benefit of all their respective population. Above all, rules would be defined to counter the real danger of crony interventions in electricity markets.

Beyond the complexity of these interregional and regional institutional arrangements, it is essential: to convince NEA consumers of the benefits of integrating electricity markets; to admit that regional arrangements derogating from the principles of integration by competition are admissible, provided that they are of a transitional nature; to ensure that integration through competition produces consistent long-term effects.

Opening/Sharing the ownership of production entities

Despite the strong opposition regarding this free-trade proposal, one change could thwart most of the opponents' claims: opening/sharing the ownership of production entities.

By doing so the profits and most importantly the decision making would be shared between the different parties of the free-trade agreement. That would ensure that the job gains achieved in relation to the different production and transportation infrastructures projects would be shared, and that even in desperate times, no lobbying groups in any state or province would receive preferential treatment at the expense of other citizens. The shared ownership of production entities would also incentivize all importing states to pay a fair and equitable or competitive price to ensure that the revenues be reinvested into the infrastructures allowing it to adequately develop and prosper.

<u>Main recommendation #2</u>: The Government of Quebec, together with governments of neighboring provinces and states, should formally agree on opening the capital structure of regional electricity producing entities with the purpose of gathering the support of local population for the NEA free trade area. As a gesture of good will, the Government of Québec should offer neighbouring Canadian provinces and neighbouring American states to acquire a total 40% ownership stake in the equity of Hydro-Québec. Each of the other state and provincial governments should offer, through proper regulation, out of province / out of state residents a similar ownership stake in the local producing entities on their respective province/state.

Conflicts relating to the implementation of risky or nuisance-generating projects, such as power plants and electricity transmission lines, are recurrent and, in most cases, all the actors involved can declare themselves dissatisfied : public promoters are confronted with local opponents (within the framework of consultation procedures or informal protests); political and administrative decision-makers find it difficult to reconcile the divergent interests of their constituents; the public concerned too often feels excluded from discussions and decisions concerning its living environment.

Avoiding the NIMBY syndrome

The syndrome "not in my backyard!" (NIMBY) designates all the conflicts which characterize the location of projects that are percieved as dangerous or as generating nuisances, to which local population will typically show some opposition. It is a difficult and subtle issue.

In recent decades, we have experienced an increase and diversification of this phenomenon of structured opposition, the intensity of which induces several public administrations to show a tendency to stand still. We can think of many cases, sucha as wind farms, LNG ports, electricity transmission lines, land, rail or maritime circuits for the transport of hazardous materials and even more trivial projects (new casino, snowmobile trails). These structured opposition movements, influenced by well-publicized disasters, stem from more or less realistic perceptions of the risks involved.

Too often or even systematically, we have forgotten or neglected the economic approach that could limit the emergence of this type of conflict. Centralized decision-making procedures, such as a localization imposed by expropriation or following a report from a commission or an office, could be abandoned in favor of decentralized market mechanisms such as auctions, which are a serious alternative in many contexts.

We can also think of applying the principles of the design of mechanisms in more complex contexts, such as transport networks for hazardous materials or systems that generate some level of nuisances affecting several municipalities or regions: the same principles and methods can apply, by correctly defining the various groups involved and the various options available.

Although research on the characterization of such mechanisms is already quite advanced, concrete applications are long overdue, mainly because of the ignorance of these mechanisms, which allows certain pressure groups who profit from the NIMBY syndrome to acquire inordinate power. The limit of our imagination is the only real constraint on the development of effective auction mechanisms to manage the NIMBY syndrome with reasonable accomodation of the recriminations of the groups and populations directly concerned. We can thereby avoid the tragedy of the anti-commons.

We face a potential tragedy of the anti-commons if the development of a worthwhile project is subject to so many legal or political veto rights of all kinds that it becomes almost impossible or very costly to realize it. More generally, the tragedy of the anti-commons is a type of coordination failure, which prevents the emergence of a socially desirable outcome.

Economic approaches based on market mechanisms are intended to be more "decentralized" and by definition leave more room for the groups concerned. The innovative idea of this type of mechanism is the following: taking into account the fact that the project is likely to provide significant benefits to the population or generate substantial profits and that the nuisances are essentially local, it is conceivable that citizens or promoters benefiting from the project compensate residents of potentially affected neighborhood. This approach is based on the principle that those who experience the project are the only ones who really know the costs of hosting of it. By putting different sites in competition to host or not the project in exchange for compensation, the representatives of those sites will be encouraged to reveal these costs and to volunteer or not to host the project, with a view of mutual gain.[16]

Reactions of opposition, long focused on projects that are especially polluting or risky, currently affect a surprising number of projects, both public and private. NIMBY-type reactions apply only to some of these projects, which generally have three characteristics in common. First, they create nuisances at

[16] Marcel Boyer, *How can the NIMBY syndrome be avoided?* MEI, March 2008. https://www.iedm.org/sites/default/files/pub_files/note0308_en.pdf. Voir également Nicolas Marchetti, *Les conflits de localisation : le syndrome NIMBY*, Rapport Bourgogne, CIRANO, mai 2005. http://www.cirano.qc.ca/files/publications/2005RB-05.pdf

the local level (noise from airports, odours from incinerators, visual blight and noise from wind farms, fear and insecurity from prisons, or visual blight and health risks from electricity transmission lines, refineries or natural gas ports). Second, they are likely to produce sizable advantages, but on a broad scale rather than a local scale. Third, these are often large projects, and their establishment in a given municipality often requires expropriations as well as long-lasting changes in the environment.

Opposition reactions, when pushed to the limit, can result in three downsides for the general well-being of citizens. In terms of the environment, victories by NIMBY activists in one place may create or worsen problems elsewhere. As regards infrastructure or services, the spread of the NIMBY syndrome can lead to delays in fulfilling important needs.[17] And with respect to land use, obstruction caused by this syndrome may result in projects being moved to unsuitable zones where there happens to be less opposition.

The use of special laws or regulations, including expropriations, to impose final decisions has too often been the preferred solution. Although some people may see this as necessary, it should be noted that is leads inevitably to tougher opposition from the citizens concerned. Using political force ends up causing feelings of frustration among local people and rarely settles matters.

The pursuit of new types of project that are safer and less harmful may sometimes be envisaged, but there is a risk that this simply shifts the problem elsewhere. For example, "pro-environment" demonstrators often oppose thermal power plants or even hydroelectric plants and look to "clean" alternatives such as wind farms. It is quite obvious today that these alternatives also pose many problems and are subject to fervent opposition.

Accordingly, the most promising strategy is to set up competitive compensation mechanisms both to respect the citizens concerned and to manage the NIMBY syndrome sustainably.

Compensation mechanisms developed to overcome opposition from people nearby must take account of the characteristics of the projects at issue. Compensation must be paid by a project's beneficiaries and must go to its real victims. In a private project, the developers will compensate the neighbours. In a public project, the entire population that benefits from it will have to pay. Moreover, people living near a dangerous or risky project should get compensation mainly if an accident occurs, thereby guaranteeing that those receiving payment have truly suffered direct prejudice. Furthermore, when a nuisance-creating project is built, compensation should begin as soon as the project is in place and should last as long as the nuisances do.

The response to the NIMBY syndrome from public authorities is a result mainly of centralized decision-making. Decision-makers select a site, announce the choice to the public, defend it and undertake the project by force, if necessary. Awareness of the failures linked to this type of procedure has led gradually to mechanisms allowing a greater role for citizens. The participative aspect is important but insufficient to prevail over the syndrome. The procedure should be competitive and show greater

[17] This brings to mind the much postponed Hertel-Des-Cantons electricity transmission line. Its conflict-ridden erection following the 1998 ice storm crisis caused deep resentment, which persists even today.

respect toward the preferences of the parties concerned. Both these aspects have been largely cast aside by political leaders. However, economists have developed mechanisms of varying complexity that are participative, competitive and, at the same time, more respectful of the preferences of those most closely involved.

Economic approaches based on market mechanisms aim to be more "decentralized" and, by definition, allow a greater role for the groups concerned. The innovative idea behind this type of mechanism is as follows: considering that a project is likely to provide significant advantages to the general public or to generate substantial profits, and considering also that the nuisances are essentially local, it is possible to picture the citizens or developers who benefit from the project compensating the likely neighbours. This approach is based on the principle that those subjected to the project are the only ones who really know the costs of its eventual advent. With various sites in competition to host (or not host) the project in return for compensation, an incentive will arise to disclose these costs and to volunteer (or not volunteer) in a perspective of mutual gain.[18]

The decentralized procedures generally proceed in three stages. First, a socioeconomic analysis assesses the scope of a project's private and public benefits.[19] Next, with major benefits involved, a multi-criterion technical analysis identifies a limited number of potential sites. Any site under consideration at the end of this stage could, under the traditional approach, have been imposed as the project's location by public authorities. Finally, a "consultation" mechanism is established to enable representatives[20] from the various potential sites to "agree" on a given site and on the size of transfers, compensation and contributions. Potential sites would thus all lie at the heart of the decision-making process and would be used in determining the best location. The first two stages are subject to pitfalls and must be conducted diligently and impartially, but they do not seem to pose serious methodological problems.[21] We are focusing our remarks here on the third stage.

Three types of decentralized procedure have been suggested: auctions, lotteries and insurance.[22] Lotteries and insurance present particular difficulties: lotteries leave too much to chance, and insurance leads too often to endless legal disputes when accidents occur. In contrast, auctions merit particular attention; this is the type of mechanism we will analyze here.

The auction rules must be both transparent and efficient and must rely on competition between several groups, municipalities or regions that, despite initial opposition, can come to show interest in

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[18] These approaches are not unrelated to the theory devised by Ronald Coase (1991 Nobel Prize in Economics), which states that markets will lead to an efficient solution as long as property rights (to particular sites or to the environment) are well defined and transaction costs are sufficiently low.

[19] The project may come initially from private or public entities, but the confirmation of the existence and scope of benefits will sometimes be the responsibility of political authorities even in a private project.

[20] Representatives of sites (groups or regions) will usually be elected officials with authority over the territory concerned and over the decision to be made. Devising open and transparent procedures may require that the respective roles, powers and responsibilities of the various parties involved be reaffirmed.

[21] Some disagreements may persist as to the nature of nuisances, as well as to the costs and the benefits, but these disagreements should focus on empirical measurement of the various elements rather than on the method applied.

[22] These potential solutions are not mutually exclusive, and various combinations may be considered.

hosting the project at issue under certain conditions. In implementing a new project, it is fundamental to retain a limited but adequate number of potential sites, paying particular attention to the conditions of participation to favour the entry of new "competitors" for hosting the project. The issue of mechanism design is delicate:[23] it can enable the right solution and the correct level of compensation to be identified, with the true costs of hosting the project being disclosed; it must prevent behaviour based on opportunistic strategies from taking advantage of shortcomings in the mechanism, which could lead to the wrong results.

Economists have suggested various auction mechanisms for overcoming the NIMBY syndrome. The simplest mechanism is the so-called Dutch reverse auction: the developer or government offers a level of compensation to representatives of the various potential sites. If there is no taker for the project, the compensation on offer is increased until a taker is found.

A second mechanism is the so-called modified low-bid auction:[24] each group issues, through its representatives, a bid for compensation for hosting the project on its territory; whichever makes the lowest bid hosts the project and gets the compensation that it sought plus a certain percentage; the other groups each pay a "tax" proportionate to their bid for compensation, with the total being equal to the amount to be paid to the winner. Despite having to pay something, these groups all come out as winners in the auction: to avoid hosting the project, they will pay less than hosting it would have cost, based on their own assessments.

A third mechanism is the so-called modified high-bid auction:[1] each group issues a bid for compensation, and whichever makes the lowest bid not only hosts the project but receives, in return for the prejudice suffered, compensation equal to the highest bid for compensation; the other groups each pay a tax proportionate to their respective bids, with the total equal to the amount to be paid to the winner. Thus, none of the groups comes out losing in the auction, with the group hosting the project in effect achieving a net gain compared to its assessment of the cost of hosting it.

To illustrate the spirit of these procedures, let us consider the following hypothetical case.[25] The City of Montreal wishes to select a location for a garbage incinerator on the island. A technical study has identified the desired characteristics (capacity, layout, number of trucks per day, atmospheric discharges, etc.) and has determined five potential sites in five different boroughs. A call for tenders is launched, leading to five bids for compensation with the costs for each borough estimated respectively at $1 million, $1.2 million, $1.8 million, $2 million and $2.6 million. In this instance, the incinerator would be located in borough 1, which bid $1 million. Under a modified low-bid auction, borough no. 1 would receive the compensation it sought plus, for example, 50%, hence $1.5 million, while the other boroughs would have to pay a tax equal to 19.7% of their respective bids (for a total of $1.5 million).

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[23] The Nobel Prize in Economics was awarded in 2007 to economists Leonid Hurwicz, Eric Maskin and Roger Myerson specifically for their work on mechanism design.

[24] Howard Kunreuther and Paul R. Kleindorfer, "A sealed-bid auction mechanism for siting noxious facilities", *American Economic Review*, Vol. 76 (1986), No. 2, pp. 295-299. The modification makes the proposed auction budget balanced.

[25] The application of those processes must also take account of the possibility that the participants may have an interest in overestimating their costs and thus their compensation requests, a problem which is not discussed here.

Under a modified high-bid auction, borough 1 would receive the highest amount of compensation that any of the participants bid for ($2.6 million), thereby achieving a major gain compared to its original bid, while the other boroughs would have to pay a tax equal to 34.2% of their respective bids for compensation (for a total of $2.6 million).

These mechanisms ensure, at relatively low cost, true disclosure of a project's costs and location values in the best possible place. Based on context, one of these mechanisms, or a variant, will be most effective in managing the NIMBY syndrome adequately, respecting all parties involved.[26]

Conflicts related to implementing risky or nuisance-creating projects occur often. In most cases, all players involved may say they are dissatisfied: public developers must face local opponents (in consultation procedures or informal protests); political and administrative decision-makers have trouble reconciling the conflicting interests of their constituents; concerned members of the public are too often excluded from discussions and decisions concerning their daily lives.

The economic approach is likely to limit the emergence of this type of conflict. It is also possible to consider applying the principles used to devise mechanisms in more complex contexts such as networks for shipping hazardous or nuisance-creating goods, including electricity transmission lines, that affect several municipalities or regions: similar principles and practical details can apply by delineating correctly the various groups concerned and the various options at hand.

Although research on the characterization of such mechanisms is already quite advanced, actual applications remain held back mainly by lack of awareness of these mechanisms. This lets certain pressure groups that benefit from the NIMBY syndrome acquire disproportionate power. Limits to our imagination form the only real constraint to developing effective auction mechanisms for managing the NIMBY syndrome in full respect of the groups directly concerned and of the general public.

Recommendation #3: Develop competitive win-win compensation mechanisms capable of bringing affected populations to resolutely accept investment projects in electricity production and transmission capacities improving the wellbeing of all.

[26] It is possible to adjust the auction to take account of the fact that the sites initially retained may not be of the same quality as regards implementing the project.